NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 5, 2011

Mr. Tim Heilig
Vice President of Mechanical Operations
Norfolk Southern Corporation
1200 Peachtree Street NE (Box 184)
Atlanta, GA 30309

CPF 2-2011-6001M

Dear Mr. Heilig:

On December 13 and 14, 2010, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected the Norfolk Southern Corporation (NSC) procedural manual for operations, maintenance, and emergencies at your pipeline facility in Macon, Georgia, pursuant to Chapter 601 of 49 United States Code.

On the basis of the inspection, PHMSA has identified apparent inadequacies found within NSC's procedures as described below:

1. **§195.52 Telephonic notice of certain accidents.**
   (a) At the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in §195.50, the operator of the system shall give notice, in accordance with paragraph (b) of this section, of any failure that:
   (1) Caused a death or a personal injury requiring hospitalization;
   (2) Resulted in either a fire or explosion not intentionally set by the operator;
   (3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;
   (4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or
   (5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

(b) Reports made under paragraph (a) of this section are made by telephone to 800-424-8802 (in Washington, DC 20590-0001 (202) 372-2428) and must include the following information:
(1) Name and address of the operator.
(2) Name and telephone number of the reporter.
(3) The location of the failure.
(4) The time of the failure.
(5) The fatalities and personal injuries, if any.
(6) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

While NSC's procedures required the telephonic reporting of certain events to the National Response Center (NRC), the procedures were inadequate because they did not identify all the events requiring a telephonic report to the NRC. NSC's procedures did not require the reporting of events that NSC determined to be significant that do not meet other criteria of §195.52; and/or, events resulting in the pollution of any stream, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines.

Moreover, NSC's procedures were inadequate because they did not identify the information to be included in the telephonic reports to the NRC.

2. **§195.54 Accident reports.**
(a) Each operator that experiences an accident that is required to be reported under §195.50 shall as soon as practicable, but not later than 30 days after discovery of the accident, prepare and file an accident report on DOT Form 7000-1, or a facsimile.
(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

While NSC's procedures required that an accident report be filed, the procedures were inadequate because they did not require that an accident report be submitted not later than 30 days after discovery of an accident or that a supplemental report be filed when NSC receives any changes in the information reported or any additional information not included in the original report.

3. **§195.55 Reporting safety-related conditions.**
(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving pipelines in service:
(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.
(2) Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, that impairs its serviceability.
(3) Any material defect or physical damage that impairs the serviceability of a pipeline.

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.
(5) A leak in a pipeline that constitutes an emergency.
(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
(b) A report is not required for any safety-related condition that–
(1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;
(2) Is an accident that is required to be reported under §195.50 or results in such an accident before the deadline for filing the safety-related condition report; or
(3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

NSC's procedures were inadequate because they did not require NSC personnel to observe and report safety-related conditions (SRC) nor did they properly define what is an SRC and which SRCs are required to be reported.

NSC's procedures require that "*Norfolk Southern's maintenance contractors have the responsibility for identifying, reporting and correcting, as directed, any safety-related conditions as defined by Sec. 195.55, including wall corrosion, movement or abnormal loading, and physical damage*." NSC's procedures, however, did not require that NSC personnel identify and report SRCs nor did they specifically identify conditions which are SRCs and those which are required to be reported.

4. **§195.56 Filing safety-related condition reports.**
(a) Each report of a safety-related condition under §195.55(a) must be filed (received by the Administrator) in writing within 5 working days (not including Saturdays, Sundays, or Federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. To file a report by facsimile (fax), dial (202) 366-7128.
(b) The report must be headed "Safety-Related Condition Report" and provide the following information:
(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.
(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.
(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

While NSC's procedures required reporting SRCs, the procedures were inadequate because they did not address the time limits for reporting, the method to report SRCs, and the information to be reported on SRCs.

5. **§195.120 Passage of internal inspection devices.**
(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced; must be designed and constructed to accommodate the passage of instrumented internal inspection devices

NSC's procedures were inadequate because they did not contain any requirements that newly constructed pipelines, and pipeline sections where line pipe, valves, fittings, or other line components are replaced, be designed and constructed to accommodate the passage of internal inspection devices.

6. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
…. (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
…. (4) Determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned.

While NSC's procedures called for NSC to identify pipeline facilities that require an immediate response to prevent hazards to the public if the facilities failed or malfunctioned, the procedures were inadequate because they did not identify how NSC determined these facilities. In addition, NSC's procedures identified where High Consequence Areas (HCAs) and environmentally sensitive areas were defined in its manuals and procedures, but NSC's procedures did not explain that these are the areas on the pipeline that would require an immediate response nor did the procedures identify other areas that would require an immediate response.

7. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
…. (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
…. (10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities

left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §195.59 of this part.

While NSC procedures required that all proper procedures be followed when abandoning a pipeline, the procedures were inadequate because they did not include procedures to follow for purging, disconnecting, and sealing pipeline facilities to be abandoned.

That is, NSC's procedures state, " … *all proper procedures will be followed, including the safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place …."* but NSC does not have procedures nor guidance for performing these actions.

8. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
   …. (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
   …. (13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

   NSC's procedures were inadequate because they did not include procedures covering the periodic review of work done by NSC or contractor personnel to determine the effectiveness of procedures used in maintenance and operations, and for taking corrective action when deficiencies are found.

9. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
   (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
   (14) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

   NSC's procedures were inadequate because NSC's procedure for trench safety did not address protecting personnel in excavated trenches from unsafe accumulations or vapor or gas, nor making available emergency rescue equipment.

   NSC's procedures for *Trench Safety (195.402(c)(14)* state "… *when performing operations which require excavation and trenching, NSR will require workers to take adequate precautions in excavated trenches as required by OSHA.*" While NSC's procedures included a general statement to follow OSHA requirements for trench safety, they did not specifically address the requirements for how personnel will be protected from the unsafe accumulation of vapor or gas, nor the provision of emergency rescue equipment as required by PHMSA pipeline safety regulations.

10. §195.406 Maximum operating pressure.

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:
(1) The internal design pressure of the pipe determined in accordance with §195.106. However, for steel pipe in pipelines being converted under §195.5, if one or more factors of the design formula (§195.106) are unknown, one of the following pressures is to be used as design pressure:
(i) Eighty percent of the first test pressure that produces yield under section N5.0 of appendix N of ASME B31.8, reduced by the appropriate factors in §§195.106(a) and (e); or
(ii) If the pipe is 12¾ in (324 mm) or less outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.
(2) The design pressure of any other component of the pipeline.
(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Subpart E of this part.
(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §195.305.
(5) For pipelines under §§195.302 (b)(1) and (b)(2)(i) that have not been pressure tested under subpart E of this part, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.
(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

NSC's procedures were inadequate because NSC identified the normal operating pressure and maximum operating pressure (MOP) of its pipeline, but did not identify how the MOP was determined. Moreover, the procedures did not cover how NSC would provide adequate controls to prevent the pressure from exceeding 110% of the MOP during surges and other variations from normal operations.

NSC's procedure for *Maximum Operating Pressure (195.406)* stated "*The normal operating pressure for the Brosnan Yard pipeline is 265 psi and the maximum operating pressure is 450 psi.*" The procedure, however, did not address how NSC determined the MOP nor did the procedure address how NSC will protect the pipeline from exceeding 110% of the MOP during surges and other variations from normal operations.

11. §195.422 Pipeline repairs.

(a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.
(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

While NSC's procedures required that repairs to its pipeline system be made in a safe manner and that any replacement parts, valves and fittings be designed and constructed appropriately, the procedures were inadequate because they did not address how repairs would actually be made or how the regulatory requirements of Part 195, Subpart D for construction, inspection, welding, welder qualification, and nondestructive examination or Subpart E for pressure testing when making repairs would be met. That is, NSC's procedures did not address repair methods, repair requirements, welding, nondestructive examination, pressure testing, construction methods, and inspections associated with repair activities.

12. §195.428 Overpressure safety devices and overfill protection systems.
(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

NSC's procedures were inadequate because the procedures did not address the testing of overpressure safety devices. NSC relies on NuStar Terminals Operating Partnership (NuStar) for the overpressure pressure protection on its pipeline. That is, NuStar provides the NSC pipeline with pressure switches. NSC's procedures, however, did not address the requirement that the pressure switches used to protect NSC's pipeline be tested.

13. §195.442 Damage prevention program.
(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations.

NSC's procedures were inadequate because NSC has not developed a damage prevention program.

NSC's procedure *Damage Prevention Program (195.442)* stated "*A damage prevention program will be developed and included in this plan upon its completion. The damage prevention plan will include a written program to prevent damage to that pipeline form excavation activities. The term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations*." The referenced damage prevention to be developed and included in the plan had not been developed or included in the plan.

14. **§195.555 What are the qualifications for supervisors?**
    You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.402(c)(3) for which they are responsible for insuring compliance.

    NSC's procedures were inadequate because NSC did not address having supervisors maintain a thorough knowledge of the corrosion control procedures for which they are responsible for insuring compliance.

15. **§195.557 Which pipelines must have coating for external corrosion control?**
    Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is –
    (a) Constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c), not including the movement of pipe covered by §195.424; or
    (b) Converted under §195.5 and –
    (1) Has an external coating that substantially meets §195.559 before the pipeline is placed in service; or
    (2) Is a segment that is relocated, replaced, or substantially altered.

    NSC's procedures were inadequate because NSC did not have procedures addressing the requirement to coat pipelines for the external corrosion control.

16. **§195.559 What coating material may I use for external corrosion control?**
    Coating material for external corrosion control under §195.557 must –
    (a) Be designed to mitigate corrosion of the buried or submerged pipeline;
    (b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
    (c) Be sufficiently ductile to resist cracking;
    (d) Have enough strength to resist damage due to handling and soil stress;
    (e) Support any supplemental cathodic protection; and
    (f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

    NSC's procedures were inadequate because NSC did not have procedures addressing the requirements for pipeline coating materials.

17. **§195.561 When must I inspect pipe coating used for external corrosion control?**
    (a) You must inspect all external pipe coating required by §195.557 just prior to lowering the pipe into the ditch or submerging the pipe.
    (b) You must repair any coating damage discovered.

    NSC's procedures were inadequate because NSC did not have procedures addressing the requirements to inspect external pipeline coatings before lowering a pipe in a ditch and to repair any coating damage found.

18. **§195.563 Which pipelines must have cathodic protection?**
    (a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after

the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

NSC's procedures were inadequate because they did not address the requirements to have a cathodic protection system to protect the pipeline.

19. **§195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?**
    (a) General. Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.
    (b) Installation. You must install test leads as follows:
    (1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.
    (2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.
    (3) Prevent lead attachments from causing stress concentrations on pipe.
    (4) For leads installed in conduits, suitably insulate the lead from the conduit.
    (5) At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.
    (c) Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §195.571.

    NSC's procedures were inadequate because NSC procedures did not address the installation and maintenance of test leads.

20. **§195.569 Do I have to examine exposed portions of buried pipelines?**
    Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under §195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

    While NSC's procedures required that exposed pipe be examined for corrosion, the procedures were inadequate because they did not require that the pipeline be examined circumferentially and longitudinally beyond the exposed portion whenever external corrosion is found requiring corrective action under §195.585.

21. **§195.571 What criteria must I use to determine the adequacy of cathodic protection?**
    Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169 (incorporated by reference, see § 195.3).

NSC's procedures were inadequate because NSC procedures did not address the criteria used to determine that cathodic protection on the pipeline is adequate.

22. **§195.573 What must I do to monitor external corrosion control?**
    (a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with §195.571:
    …. (2) Identify not more than 2 years after cathodic protection is installed, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE SP 0169 (incorporated by reference, see § 195.3).

    NSC's procedures were inadequate because they did not address the circumstances when NSC would determine that a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE SP 0169 (incorporated by reference, see § 195.3).

23. **§195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
    (a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.
    (b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
    (c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.
    (d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.
    (e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

    NSC's procedures were inadequate because they did not address electrically isolating the pipeline and what inspections and tests, and safeguards are required.

24. **§195.579 What must I do to mitigate internal corrosion?**
    …. (c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under §195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

    NSC's procedures were inadequate because NSC procedures did not require investigating beyond the removed pipe for internal corrosion when localized corrosion pitting is found.

NSC's procedure *Internal Corrosion (195.418)* requires that adjacent pipe be investigated for internal corrosion whenever the internal surface of removed *"…pipe is generally corroded such that the remaining wall thickness is less than the minimum required ….*" The procedure, however, did not address investigating adjacent pipe for internal corrosion whenever localized corrosion pitting is found that could result in leakage.

25. §195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?
(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
(b) Coating material must be suitable for the prevention of atmospheric corrosion.
(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will –
(1) Only be a light surface oxide; or
(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

NSC's procedures were inadequate because they did not include an atmospheric corrosion control program identifying which pipelines must be protected against atmospheric corrosion and what coating materials must be used.

26. §195.583 What must I do to monitor atmospheric corrosion control?
(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months.**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months.**

(b) During inspections you must give particular attention to pipe 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.
(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.

NSC's procedures were inadequate because they did not include an atmospheric corrosion control program identifying inspections for atmospheric corrosion, their frequency, and actions to be taken if atmospheric corrosion is found.

27. §195.585 What must I do to correct corroded pipe?
(a) General corrosion. If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you –
(1) Reduce the maximum operating pressure commensurate with the strength of the

pipe needed for serviceability based on actual remaining wall thickness; or
(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
(b) Localized corrosion pitting. If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

NSC's procedures were inadequate because NSC procedures did not address actions to take if corroded pipe is found.

28. §195.587 What methods are available to determine the strength of corroded pipe?

Under §195.585, you may use the procedure in ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines," or the procedure developed by AGA/Battelle, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)," to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

NSC's procedures were inadequate because they did not include methods used to determine the strength of corroded pipe.

29. §195.589 What corrosion control information do I have to maintain?
(a) You must maintain current records or maps to show the location of –
(1) Cathodically protected pipelines;
(2) Cathodic protection facilities, including galvanic anodes, installed after January 29, 2002; and
(3) Neighboring structures bonded to cathodic protection systems.
(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.
(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §§195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

NSC's procedures were inadequate because they did not identify the corrosion control records to be maintained.

Response to this Notice
This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with

the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 60 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 2-2011-6001M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Wayne T. Lemoi
Director, PHMSA Southern Region
Office of Pipeline Safety

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*