LETTER OF CONCERN

July 11, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. B. W. Crocker
Vice President Operations
Columbia Gulf Transmission Company
2603 Augusta
Houston, TX 77057

CPF No. 220001002C

Dear Mr. Crocker:

Between April 10, 2000 and May 5, 2000, representatives from the Southern Region, Office of Pipeline Safety (OPS) inspected Columbia Gulf Transmission Company's (Columbia Gulf) pipeline facilities in Mississippi, Tennessee, and Kentucky. Records were also reviewed at your Hartsville and Hampshire, TN, Banner, Inverness, and Corinth, MS, and Stanton and Clementsville, KY, offices. The inspection revealed some areas that are cause for concern.

Gas Detector Alarms

- Columbia Gulf's gas detector alarm system is designed to alarm personnel upon detection of a gas concentration of 15% of the lower explosive limit (gas in air) inside compressor buildings. The system does not meet the pipeline safety regulation requirements of CFR 49 §192.736(b)(2), in that the alarms may not ". . . warn persons about to enter the building and persons inside the building of the danger." Although the current system triggers "common" building alarms (audible and visual), the alarms are not "unique" in warning personnel specifically of gas detection in the building. I understand that Columbia Gulf has subsequently assigned a project engineer to modify the alarms on a system-wide basis, to remedy this problem.

Inspection and Test Records

- The observed relief valve serial number (valve Number 5SG-01, Corinth Compressor Station LSV fuel gas facility), was different from the serial number recorded on the 7/23/99 relief valve inspection report.

- Some valve inspection/test records did not indicate that all transmission line emergency valves were being, at least partially, operated. Some non-mainline valves (such as meter station tap valves on the main lines) were not on the valve lists. (Hartsville, Corinth, Stanton, and Banner sections).

Engineering Drawings, Piping Schematics, SCADA Screen Displays

- SCADA graphic screens (Houston Gas Control and local) of the Inverness Station yard piping did not reflect recent station yard piping modifications. I understand the screens were subsequently corrected. Although the inconsistency in this case was not safety related, I want to emphasize the importance of assuring that SCADA/electronic graphic screens are accurate and are kept up to date.

- Station yard piping schematics were found to be inaccurate/incomplete at Corinth and Hartsville compressor stations. A schematic observed at Stanton should have been labeled or stamped as a preliminary, for-review type of drawing. Also, two valve numbers that were indicated on the Inverness section pipeline schematic did not match the numbers displayed on the valves. I understand that your field personnel (system-wide) are reviewing piping schematics for accuracy, and that new field valve number displays (Inverness) are on order.

- No engineering "as-built" drawings were readily available (during the OPS inspection) at Hartsville (TN-1): TVA Meter Station facility "in-service" on 12/98; Inverness (MS-2): compressor horsepower replacement "Mars" unit completed 10/97; and Banner (MS-1): 1998 station filter separator installation.

ESD Tests

- Some lever switches and fixed temperature sensors were not tested at the frequency required of the safety regulations for ESD tests (Hampshire and Stanton stations). Since these devices are part of the ESD system, they are required to be tested at intervals not exceeding 15 months, but at least once each calendar year.

Valves

- Two 24" valves at valve setting No. 811 (Line 300 east side of Mississippi River - Inverness section) had not been operated since prior to the 1/18/99 valve inspections. The inspection records convey that these valves were unable to be operated because of high water inside of the river levee. I understand that other isolation valves are located on the other side of the levee, and can serve the identical emergency function of the two 24" valves. Regardless, I want to convey that the pipeline safety regulations (CFR 49 §192.745) require transmission line valves that might be required during any emergency to be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. If the two above-referenced valves are not covered under §192.745, then your records should indicate such.

Training

- Columbia Gulf's emergency training procedures convey, in part, that training courses ". . . shall be presented to all appropriate operating personnel as often as necessary to assure an adequate trained staff for handling compressor station and pipeline emergencies." I recommend these procedures be more specific as to the individual employee emergency training requirements (such as required emergency subject/courses and maximum time intervals between training for each applicable employee). I also encourage you to periodically conduct "mock" emergency exercises on the pipeline at all of your locations, involve as many employees as practical, and to critique these exercises to indicate effectiveness, lessons learned, etc.

Damage Prevention/Public Education

- I understand that Columbia Gulf is in the process of evaluating the "Common Ground Study of One-Call Systems and Damage Prevention Best Practices." I encourage you to consider these best practices as may be applicable to your pipeline. Best practices include a pro-active liaison approach with public construction project and land use officials, engineers, contractors, local school officials, churches, industrial areas, etc.

- Currently, your educational mail-out to the public (addresses that are within one-eighth of a mile of either side of your right-of-way) is performed on a 3 year frequency. The concern is that this frequency may not be adequate to keep the public in the pipeline area knowledgeable of your pipeline, and informed on how to recognize and respond to a pipeline emergency (ref. CFR 49 §192.616). Also, your Public Education procedures do not specify: 1) field personnel responsibilities and, 2) maximum time intervals between educational material distributions (from your corporate office and from field personnel).

Ongoing Remedial Activities

I understand that the following conditions on your pipeline require(d) remedial action, and that they are being addressed.

- "Low" pipe to soil potentials were observed during the inspection at:
    - New Albany meter station liquid separator (-0.832 v) (Banner Section)
    - Unit 305 compressor discharge piping (-0.820 v) (Hartsville Station)
- 4 mile "gap" between cathodic protection test stations (MP 82.2 to MP ~86.5) (Inverness Section).
- Observed exposed pipe segments:
    - MP 0.6 Line 100 downstream of Stanton c/s (Stanton Section)
    - MP 40.4 Line 100 downstream of Stanton c/s (Stanton Section)
    - MP ~ 63.2 Rockhouse Creek, Line 200 (Hampshire Section)

I hope you also consider these areas of concern and comments as constructive relating to pipeline safety. I understand that the above issues and comments were covered by the inspector with the appropriate Columbia Gulf field and regulatory personnel in exit interviews. Also, I commend you and your personnel for the expeditious commitments and follow-up actions that were initiated as a result of the inspection.

If we can answer any questions or be of any help, please call us at (404) 562-3530.

Sincerely,

Frederick A Joyner
Director, Southern Region
Office of Pipeline Safety

cc: Compliance Registry, OPS Headquarters