Philip Sher
Pipeline Consultant

PROFESSIONAL PIPELINE ENGINEERING CAREER
PHILIP SHER

- ***PIPELINE CONSULTANT -*** gas pipeline safety (1990 - present), providing accident analysis and expert witness service; code compliance; plans, procedures and operator qualification; integrity management programs, coordinating emergencies with public officials; pipe replacement programs; underground damage prevention - 1-call systems; training programs & special projects.

- ***MANAGEMENT OF THE GAS PIPELINE SAFETY UNIT*** of the State of Connecticut Department of Public Utility Control (1979 - 2009) responsible for the formulation, promulgation and administration of the Department's gas pipeline safety program and underground damage prevention (***CALL BEFORE YOU DIG***) program. Liaison to and agent of U.S. DOT ***OFFICE OF PIPELINE SAFETY***. Experience includes: incident investigations; testimony at ***NTSB*** hearings; cross-examination of witnesses at NTSB hearings; formulation, promulgation and application of gas pipeline safety standards, including the Minimum Federal Safety Standards (49 CFR 191, 192); development and implementation of pipeline safety inspection program including field inspections and records reviews; the application of engineering enforcement techniques in furthering compliance with safety standards; and damage prevention programs. Extensive cross-examination of expert witnesses at hearings.

  Program function reviews include design, construction including welding and joining, operations and maintenance including corrosion control, excavation damage, emergency response including coordinating with other emergency responders, operator qualification and integrity management programs.

  Pipeline facilities covered under the program include gas transmission lines, gas distribution lines including extremely high pressure (750 psig) distribution lines, propane distribution lines, liquefied natural gas facilities (full plants and satellites), propane storage facilities, propane peak shaving facilities, hortonspheres, and gas holders.

  Experience also includes economic regulation including: rate structures; expansion of plant and equipment; cost of service studies; utility research programs; customer load analysis including normalization and annualization; gas supply planning and analysis; cost of gas analysis, pipeline refunds, deferred gas costs, fuel adjustment clauses; depreciation studies; master metering; cogeneration; and utility diversification.

- ***CO-RESPONSIBILITY*** for the management of the Connecticut Department of Public Utility Control Gas Section (1976-1978).

- ***ENGINEERING ADMINISTRATOR*** (1975-1976) responsible for the American Society of Mechanical Engineers' codes and standards activities for gas pipelines.

- ***PERFORMED*** approximately ***1,900 PIPELINE SAFETY INSPECTIONS*** and ***SUPERVISED*** an additional ***6,000*** pipeline safety inspections ***TOTALING 7,900*** pipeline safety inspections.

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EDUCATION
PHILIP SHER

❖ ***BACHELOR OF SCIENCE*** in Engineering, New York University School of Engineering and Science (1970).

❖ ***PIPELINE SAFETY*** courses at the U.S. DOT Transportation Safety Institute:

- Safety Eval. Inline Inspection/Pigging Programs
- Operator Qualification WBT
- Safety Eval. Pipeline Corrosion Control Systems I & II
- Liquefied Natural Gas (LNG) Safety Technology and Inspection
- Joining of Pipeline Materials
- Gas Pressure Reg. & Overpressure Protection
- Pipeline Failure Investigation Techniques
- Pipeline Safety Regulation Application and Compliance Procedures
- Pipeline Reliability Assessment Seminar
- Gas Integrity Management Protocol Seminar
- Investigating Pipeline Corrosion Seminar
- Fundamentals of SCADA Systems WBT
- Fund. Launching & Receiving Maint. Pigs WBT
- Safety Eval. of Gas Pipeline Systems (waived)

PROFESSIONAL AFFILIATIONS
PHILIP SHER

❖ ***NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES*** (NAPSR)

- ***NAPSR NATIONAL PAST CHAIRMAN*** (2007 - 2008)
- ***NAPSR NATIONAL CHAIRMAN*** (2006 - 2007)
- ***NAPSR NATIONAL VICE CHAIRMAN*** (2005 - 2006)
- ***NAPSR NATIONAL SECRETARY*** (2004-2005)
- ***NAPSR BOARD OF DIRECTORS*** (2003 – 2008)
- ***CHAIRMAN NAPSR EASTERN REGION*** (2004 - 2005)
- ***VICE CHAIRMAN NAPSR EASTERN REGION*** (2003 – 2004)
- ***CHAIRMAN NAPSR INTEGRITY MANAGEMENT PROGRAM COMMITTEE*** (2003 – 2007)
- ***NAPSR DISTRIBUTION INTEGRITY GOVERNMENT-INDUSTRY TEAM*** (2003 – 2005)
- ***NAPSR SECURITY COMMITTEE*** (2002 - 2006)
- ***CHARTER MEMBER*** and member NAPSR (1982 – 2009)

❖ Chairman of the ***NEW ENGLAND CONFERENCE OF PUBLIC UTILITY COMMISSIONERS*** Staff Committee on Gas (1980).

❖ Vice Chairman of the ***NEW ENGLAND PIPELINE SAFETY REPRESENTATIVES*** (1988 - 2009) and member (1979 - 2009).

❖ Member of the ***NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS*** (NARUC) Staff Committee on Pipeline Safety (1986 - 2009).

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PROFESSIONAL AFFILIATIONS (CON'T) PHILIP SHER

❖ ***SECOND VICE CHAIRMAN*** American National Standards Institute (ANSI) ***GAS PIPING TECHNOLOGY COMMITTEE*** (GPTC) (1989 - present). The GPTC has responsibility for developing guidelines for compliance with the minimum Federal Safety Standards that are published in the ANSI Z380.1, "Guide for Gas Transmission and Distribution Piping Systems." The GPTC also has responsibility for petitioning the federal government for changes in standards, and for commenting on proposed rulemakings.

- Member of the ***GPTC EXECUTIVE COMMITTEE*** (1989 - present).
- Member of the ***GPTC MAIN BODY*** (1976 - present) which has technical responsibility and policy oversight of the GPTC.
- Member of the ***GPTC DISTRIBUTION COMMITTEE*** (1976 - 1990).
- Member of the ***GPTC DI GUIDANCE TG*** (2006 - 2008) developing guidelines for the Distribution integrity management federal safety standards.
- Secretary of the ***GPTC EDITORIAL SECTION*** (1975 - 1990).
- Chairman of the ***GPTC PROCEDURES*** committee that revised the committee operating procedures and organization (1980 - 1981) and member (1989 - 1991).
- Coresponsbility for revising the "Guide for Gas Transmission and Distribution Piping Systems" 1976 Edition, including the development of technical material, and revising and reorganizing material for clarity, correctness, consistency and logical presentation.
- Secretary GPTC (1975 - 1976).

❖ ***SECRETARY OF THE 831.8*** American National Standards Committee for Gas Transmission and Distribution Piping Systems (1975 - 1976).

❖ ***SECRETARY OF THE B31.3*** American National Standards Committee for Chemical Plant and Petroleum Refinery Piping (1975 - 1976).

❖ Member of ***THE B31*** American National Standards Committee for Pressure Piping ***CONFERENCE GROUP*** (1976 - 2009).

❖ ***CHAIRMAN RISK CONTROL PRACTICES GROUP*** of the US Department of Transportation Office of Pipeline Safety (OPS) "Assuring the Integrity of Gas Distribution Pipeline Systems" effort. (2005 – 2006).

❖ Member of the US ***OPS LIQUEFIED NATURAL GAS*** regulations review committee (1992) dealing with portable and temporary LNG facilities.

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PROFESSIONAL AFFILIATIONS (CON'T) PHILIP SHER

- ***INSTRUCTOR*** at the New England Pipeline Safety Representatives/US Department of Transportation's Transportation Safety Institute ***PIPELINE SAFETY SEMINAR***., "Distribution IMP" (2008), "PIPES Act of 2006 + Integrity Management Programs" (2007), "Integrity Management Overview & Update" (2005 and 2006), "Emergency Plans" (2006), "Yankee Gas LNG Plant Waterbury, CT" (2005), "Integrity Management - Update" (2004), "Integrity Management" (2003), "Data Processing and 1-Call Enforcement" (2001), "Initial Responder Actions" (2001), "PBR and Safety" (2000), "Pressure Testing" (1999), "High Pressure Distribution Lines" (1998), "Accident Investigation" (1997), "Emergency Plans" (1996) and "Coordinating Emergency Response With Local Officials" (1995).
- ***INSTRUCTOR*** at the U.S. Department of Transportation's ***TRANSPORTATION SAFETY INSTITUTE*** - gas service lines and meter installations (1988 - 1989).
- ***INSTRUCTOR*** at the ***NORTHEAST GAS ASSOCIATION GAS OPERATIONS SCHOOL***. "Federal and State Pipeline Safety Regulations" (1978 – 1997, 1999 - 2014), Coordinating Emergency Response with Local Officials" (1996 - 1998), and "DOT Overpressure Protection Regulations" (1980 - 1981). Member Distribution Integrity Management Program (DIMP) panel (2005) and presentation on status of DIMP (2006).
- ***PRESENTER*** Northeast Gas Association 2009 Fall Operations Conference:
  - Preparing for and Responding to State and Federal Audits
  - Distribution Integrity Rule and Quality Assurance
  - Corrosion Control & the Distribution Integrity Management Plan
- ***PRESENTER*** US DOT Office of Pipeline Safety ***DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM WEBCAST*** on DIMP process and response to Notice of Proposed Rulemaking (2008).
- ***PRESENTER*** US DOT Office of Pipeline Safety ***DIRECT ASSESSMENT WORKSHOP*** (November 2003) and ***INTEGRITY MANAGEMENT WORKSHOP*** (2004).
- Member of the ***AMERICAN SOCIETY OF MECHANICAL ENGINEERS*** (1979 – present).
- Recipient of the American Society of Mechanical Engineers ***BOARD OF GOVERNORS CERTIFICATE OF APPRECIATION*** (1989).
- ***PRESENTER*** New England Gas Association Operating Division Meeting "***PIPELINE SECURITY***" (2002).
- Member of the ***NATIONAL FIRE PROTECTION ASSOCIATION*** (2011 – 2012)

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Philip Sher
Pipeline Consultant

UNDERGROUND DAMAGE PREVENTION ACTIVITIES
PHILIP SHER

- ***ESTABLISHMENT OF CONNECTICUT UNDERGROUND DAMAGE PREVENTION PROGRAM***
  - Assisted Commissioner during testimony before Connecticut Legislature to pass Connecticut's mandatory program (1977).
  - Connecticut's underground damage prevention is the oldest, Statewide, mandatory one-call system.
  - Responsible for the oversight of the establishment of the mandatory Statewide one-call system (1977).
  - Responsible for oversight of development of bylaws and operating procedures, including establishment of a non-stock, non-profit corporation (1977).
  - Responsible for development of State regulations to implement Statewide, mandatory one-call system (1977).
- ***ESTABLISHMENT OF ENFORCEMENT PROGRAM FOR CONNECTICUT UNDERGROUND DAMAGE PREVENTION PROGRAM***
  - Active in development and passage of PA 81-46 one-call enforcement (1981)
  - Developed enforcement program to implement Public Act 81-46 (1981)
- ***DEVELOPMENT OF REINVIGORATED ONE-CALL UNDERGROUND DAMAGE PREVENTION ENFORCEMENT PROGRAM***
  - Oversaw the development of in-house computerized system for enforcement.
  - Simplified procedure for negotiated settlement of civil penalties.
- ***OVERSIGHT OF OFFICE OF PIPELINE SAFETY RECOGNIZED COMPREHENSIVE ONE-CALL UNDERGROUND DAMAGE PREVENTION PROGRAM***
  - Over 33 years overseeing the Connecticut one-call underground damage prevention program.
  - Recognized by the US Department of Transportation Office of Pipeline Safety Integrity Management for Gas Distribution Pipelines Report of Phase 1 Investigations (December 2005) as one of five state damage prevention programs identified as having a "comprehensive" program.
  - "Analysis of five individual states with comprehensive damage prevention programs that include effective enforcement by the state agencies with responsibility for pipeline safety (Connecticut, Georgia, Massachusetts, Minnesota, and Virginia) shows a material improvement in gas distribution excavation damages per 1000 tickets compared to individual states that do not have effective enforcement programs." (Phase 1 Report)

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Northern Utilities, Inc.
Docket No. DG 15-121
PUC Staff Information Requests – Set 1

Received: July 27, 2015 Date of Response: August 10, 2015

Request No. NUNH-Staff 1-9 Witness: Christopher LeBlanc & Philip Sher

Request:

Please indicate whether Northern agrees it was "operating" at the time of each instance that regulator exceeded MAOP as described in NOV PS1501NU and/or NOV PS1502NU.

Response:

Staff's question appears to be asking whether, at the time of the incidents alleged in the NOVs, Northern was "operating" as the term "operate" is used in Section 192.619. As discussed below, Northern believes that the term "operate" as used in Section 192.619 refers to normal operations when all equipment is operating properly. Section 192.619 does not refer to operations during an equipment failure, including the failure (or simulated failure) of a worker regulator.

As a general matter, the regulations contained in 49 C.F.R. Part 192, particularly Subpart L (Operations), address "normal operations." For example, 49 C.F.R. § 192.605 (Procedural manual for operations, maintenance and emergencies) uses the term "normal operations" in reference to the requirements for operation and maintenance manuals. The term "normal operation" is not defined in Part 192, but it is commonly understood to be operation when all parts of the system are performing in accordance with their design and manufacturer's specifications.

With respect to regulators, 49 C.F.R. § 192.195(b) expressly states that operation of a worker regulator is "normal operation," and when a failure of the worker occurs it is no longer "normal operation" and becomes something else - an overpressure situation:

> Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—
>
> > (1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in ***<u>normal operation</u>*** of the system, and that could be activated in the event of failure of some portion of the system; and
> >
> > (2) Be designed so as to prevent accidental overpressuring.

Part 192 also describes conditions that are not "normal operation," but instead are "abnormal operating conditions." *See* 49 C.F.R. § 192.803.[1] Section 192.803 defines "abnormal operating condition" as:

> a condition identified by the operator that may indicate a ***malfunction of a component*** or ***deviation from normal operations*** that may:
>
> (a) Indicate a condition exceeding design limits; or
>
> (b) Result in a hazard(s) to persons, property, or the environment.

Thus, failure of a component of the pipeline to perform in the manner for which it was designed is an "abnormal operating condition" pursuant to Section 192.803. Northern acknowledges this in Task #70 in its Operator Qualification Plan. Failure of a worker regulator is an "abnormal operating condition," not "normal operation."

Finally, Section 192.605(a) refers to "abnormal operations." Although this section applies to transmission lines, it is still noteworthy because it is another example of the Code's distinction between "normal operations" and other operations that are not "normal." *See* Section 192.605(c)(1)(v) ("abnormal operation" includes any "deviation from normal operation").

In Docket No. PS-113; Amdt. 192-71, 195-49, PHMSA discussed the distinctions among abnormal conditions, emergency conditions and normal conditions:

> Abnormal conditions and emergency conditions are not equivalent. Abnormal conditions occur when operating design limits have been exceeded due to a pressure, flow rate, or temperature change outside the limits of normal conditions. As an example, for pressure surges, an abnormal condition would exist in a pipeline when pressure exceeds the MAOP but is within the differential allowed to activate pressure relieving and limiting equipment (see §192.201). Abnormal conditions are less severe, but could escalate to emergency conditions if not promptly corrected. Abnormal conditions do not pose as immediate a threat to life or property as do emergency conditions. Any transmission line operator that chooses to treat abnormal conditions as emergency conditions still must comply with §192.605(c).

Based on this analysis, Northern believes that the term "operate" as used in Section 192.619 refers to normal operations when all equipment is operating properly. Section 192.619 does not refer to operations during an equipment failure, including the failure (or simulated failure) of a worker regulator.

[1] 49 CFR 192.613 uses the phrase "unusual operating and maintenance conditions," another undefined term, but clearly is intended to mean something other than normal operations.

Interpretation 192.201 7

May 27, 1971

THIS INTERPRETATION IS CURRENTLY UNDER REVIEW BY PHMSA

Mr. Charles H. Batten

Utilities Safety Engineer

Florida Public Service Commission

700 South Adams Street

Tallahassee, Florida 32304

Dear Mr. Batten:

This is in reply to your letter of May 20, 1971, concerning difficulties encountered in complying with the requirements of 49 CFR, Section 192.201 (a) (1) and section 192.619 (a) (3).

This problem has been encountered before by the office of pipeline safety and we are now in the process of drafting a notice of proposed rulemaking in order to solve it. It will be published in the Federal Register soon.

Sincerely,

Original signed by:

Joseph C. Caldwell

Acting Director

Office of Pipeline Safety

****

Florida Public Service Commission

700 South Adams Street

Tallahassee 32304

May 20, 1971

Mr. Walter Kurylo

State Liaison Officer

Office of Pipeline Safety

Department of Transportation

400 Seventh Street

Washington, D. C. 20591

Dear Walter:

In our continuing effort to assure that the gas systems operating within the State of Florida meet the requirements of the Federal Minimum Standards, we have found a problem which causes considerable concern as it appears that it is next to impossible for some systems to comply. I refer to the combined effect of Paragraphs 192.201 (a) (1) and 192.619(a)(3). Many systems in Florida, and. I am sure throughout the United States, found that their highest actual operating pressure during the five years proceeding July 1, 1970, was 15 to 20 psi although the systems have been tested during initial installation to 100 psi. This provision now establishes their maximum allowable operating pressure at 15 to 20 psi and when coupled with Paragraph

192.201, it means that the relief valve must be set to keep the pressure from exceeding 10 per cent above the maximum allowable operating pressure. For systems such as previously described, this means that the relief valve setting must be set within 1 to 2 lbs of the actual operating pressure. It is not possible to set relief valves this close to the operation pressure without frequent operation of the relief valve and considerable loss of gas.

This problem must be researched and a more realistic approach taken for those systems operating at these low pressures. Please advise if the OPS Staff has encountered this problem before and what action, if any, may be expected by OPS in this regard.

CHARLES H. BATTEN

Utilities Safety Engineer

Amdt. 192-9; Docket OPS-13

PART 192-TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Modification of Pressure Relief Limitations

This amendment to §192.201(a) changes the restriction on accidental pressure buildup in pipelines, other than low pressure distribution systems, which have a maximum allowable operating pressure (MAOP) of less than 60 p.s.i.g.

On November 10, 1971, the Department issued a notice of proposed rule making in the FEDERAL REGISTER proposing these regulatory changes (OPS Notice 71-6, 36 F.R. 21834, November 16, 1971). Interested persons were afforded an opportunity to participate in the rule making by submitting written information, views, or arguments. Several comments subsequently were received and have been given full consideration. However, the amendment is issued without substantive change from the proposal.

Two commenters recommended making the proposed changes available for systems with MAOP's up to 150 p.s.i.g. Justification for such recommendations was based on an expressed desire to avoid possible difficulties arising in utilizing present pressure relief systems under the amended standards. As it is only when the MAOP of a system is below 60 p.s.i.g. that present-day regulating equipment cannot accurately limit accidental overpressure to the present 10 percent of MAOP standard, it is in the best interest of overall safety that the proposed amendment allowing an increase in the limits for accidental overpressure be restricted to systems with MAOP's of 60 p.s.i.g. or less.

Another comment suggested a revision in the proposed amendment to make the maximum pressure limitation applicable only at the most remotely located pressure limiting station in order to reduce the possibility of having to vent gas into the atmosphere in Class 3 or 4 locations. However, it is felt that the potential hazard of such venting is negligible in comparison with the greater risks involved in allowing the pressure in the entire system to be monitored at its most remotely located point. Such a procedure has the potential to allow pressure buildups well above the established limits in other parts of the distribution system.

Section 4(a) of the Natural Gas Pipeline Safety Act requires that all proposed standards and amendments to such standards be submitted to the Technical Pipeline Safety Standards Committee and that the Committee be afforded a reasonable opportunity to prepare a report on the "technical feasibility, reasonableness, and practicability of each such proposal." This amendment to Part 192 has been submitted to the Committee and it has submitted a favorable report. The Committee's report and the proceedings of the Committee which led to that report are set forth in the public docket for this amendment which is available at the Office of Pipeline Safety.

In consideration of the foregoing, Part 192 of Title 49 of the Code of Federal Regulations is amended by revising §192.201(a) to read as follows, effective November 4, 1972.

§192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system-

(i) If the maximum allowable operating pressure is 60 p.s.i.g. or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i.g. or more, but less than 60 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i.g.; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

****

(Sec. 3, Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1672; §1.58(d) of the regulations, Office of the Secretary of Transportation, 49 CFR 1.58(d); redelegation of authority to the Director, Office of Pipeline Safety, set forth in Appendix A to Part 1 of the regulations, Office of the Secretary of Transportation, 49 CFR Part 1)

Issued in Washington, D.C., on September 28, 1972.

JOSEPH C. CALDWELL

Director,

Office of Pipeline Safety

[FR Doc. 72-16933 Filed 10-3-72; 8:53 am]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of August 5, 2015

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart M—Maintenance

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§192.743 Pressure limiting and regulating stations: Capacity of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003, as amended by Amdt. 192-96, 69 FR 27863, May 17, 2004]

Interpretation 192.201 13

February 1, 1982

Mr. William A. Slagg, P.E., Director

Gas Bureau, Engineering Division

Wisconsin Public Service Commission

Hill Farms State Office Building

Madison, WI 53702

Dear Mr. Slagg:

We regret the delay in responding to your request for an interpretation of §192.201(a)(2)(i), and it is our conclusion that an interpretation, as such, is not necessary.

You are correct in stating that §192.201(a)(2)(i), when it states "may not exceed," means "may <u>never</u> exceed."

The allowable override of 10 percent of the MAOP is included in the regulation which, for your example, amounts to 6 psig. The MAOP plus the 6 psig equals 66 psig and not the 105 psig which the calculations, submitted by the operator, showed that the system could be subjected to for 21 seconds.

According to the relief regulator's manufacturer (see copy of Bulletin P-13F enclosed), the 2-inch model 63F back pressure regulator is undersized for this application.

If you have any further questions, please contact me.

Sincerely,

Melvin A. Judah

Acting Associate Director

for Pipeline Safety Regulation

Materials Transportation Bureau

Enclosure

****

September 29, 1980

Mr. Frank Fulton, Chief of Pipeline Safety

Enforcement Division

Room 8430 NASSIF Building

400 7th Street, South West

Washington, DC 20590

Dear Mr. Fulton:

The Gas Bureau of the Public Service Commission of Wisconsin encountered a field problem involving the sizing of relief valves which we believe requires an interpretation of the gas safety code by your office. The situation is not a particularly complicated one, per se, but neither is it an obvious one and the interpretation can have a considerable effect on both our inspection procedures and the design criteria of the gas utilities in Wisconsin.

Section 192.201 is entitled "Required capacity of pressure relieving and limiting stations" and states in subsection 192.201(a)(2)(i) that "If the maximum allowable operating pressure is 60 psig or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent or the pressure which produces a hoop stress of 75 percent of SMYS, whichever is lower."

The Wisconsin Gas Bureau has been interpreting the above usage of the term "may not exceed" as "may never exceed", (at least as far as overpressure relief design criteria are concerned) even for a period as short as a few seconds. Gas industry design criteria would appear to more generally base its calculations on the hourly considerations. It is this variance in interpretations which we are asking to be resolved by your office.

The problem which illustrates the differences in interpretations resulted from the Gas Bureau inspection of the Browntown town border and district regulator stations. The first district regulator station in Browntown in 10,900 feet of 2-inch pipe (equivalent) downstream from the town border station. The town border station supplies gas at 270 psig, which is assumed to be the maximum pressure available at the first regulator station inlet. The outlet of this single, 2 inch body, Fisher 57 "S" regulator supplies a distribution system with an MAOP of 60 psig which is protected against overpressuring by a 2-inch Fisher 63F relief valve set at 66 psig with a rated capacity of 186,000 cubic feet per hour. Calculations and flow chart data agree that the critical flow to this regulator station is 50,000 cubic feet per hour. Interpretation of the situation on an hourly basis would indicate that the overpressure relief capacity is more than adequate. Gas Bureau interpretation of the attached data (supplied to us by the utility) would indicate that failure of the single regulator in a wide open position would subject the downstream distribution system to pressures in excess of MAOP + 10% (up to 105 psig.) for up to 21 seconds and therefore, the relief valve capacity is inadequate under subsection 192.201(a)(2)(i).

Our analysis of the situation is that the single Fisher 57 "S" regulator in wide open position with any pressure at its inlet in excess of approximately 173 psig can supply more gas to the relief valve than it can vent without increasing its inlet pressure (and thus the downstream system pressure) above the MAOP plus 10% figure. In the "worst case" condition, the drawdown of the linepack is a significant factor for some 21 seconds in the overpressuring situation. The data on the attached lateral analysis sheets are from standard computations, flow chart review and manufacturer's data.

We will be awaiting your interpretation.

Sincerely,

William A. Slagg, P.E., Director

Gas Bureau

Engineering Division

Interpretation 192.201 15

March 31, 1983

Mr. Dale W. Johansen

Assistant Director, Gas Department - Engineering Section

Missouri Public Service Commission

P. O. Box 380

Jefferson City, Missouri 45102

Dear Mr. Johansen:

Thank you for your letter of February 24, 1983, in which you ask that we reconsider Interpretation 82-9 because it creates a conflict between §§192.201(a) and 192.743. You also asked why the §192.201 criteria should not be used for maintenance of "pre-code" installations.

Interpretation 82-9 was issued to answer whether the pressure limitations prescribed by §192.201 for the design of relief valves installed after Part 192 became effective are determinative of the "desired maximum pressure that §192.743 prescribes for purposes of maintaining proper relief valve capacity. The interpretation stated that the value of "desired maximum pressure Is discretionary, but subject to the maximum allowable operating pressure (MAOP) of connected downstream facilities. Because the allowable limit on operating pressure may change (e.g., §192.611), Interpretation 82-9 concluded that §192.201, which sets original design limits, may not be used to determine future values for "desired maximum pressure." In other words, if "desired maximum pressure" decreases with any future reductions in allowable pressure limits, relief valve capacity would have to be increased above the capacity originally permitted for design purposes by §192.201.

Upon reconsideration, we confirm the merits of the interpretation as it relates to applying §192.201 to judging the capacities required by §192.743. However, we believe that the stated relationship between "desired maximum pressures and MAOP could be misconstrued and result in a conflict with §192.201 and an unjustified burden for operators of existing relief valves.

Pipeline operators historically have designed pressure relief valves with sufficient capacity to limit downstream pressure to a safe level above the MAOP. Such design is permitted under §192.201. However, if §192.743 were to require, as Interpretation 62-9 implies, that relief valve capacity limit downstream pressure to the MAOP, more capacity would be needed for new, replaced, or relocated valves than §192.201 requires, and the capacities of existing relief valves would probably have to be increased as well. Similarly, if the limitations of §192.301 (for example, MAOP plus 10 percent) were used as you suggest, for enforcing §192.743 against corresponding relief valves placed in operation before Part 192 became effective, additional capacity would be required if those relief valves were originally designed to limit accidental overpressure to levels higher then specified by §192.201 for new, replaced, or relocated valves. This would have the effect of illegally imposing design requirements co pre-existing facilities.

We believe the problem you have identified with Interpretation 82-9 would be resolved if the "desired maximum pressure" under §192.743 were interpreted to include a safe amount of pressure build-up above the MAOP. For valves subject to §192.201, the safe amount would be that set forth in §192.201, and the capacities required by §§192.201 and 192.743 would be the same until allowable operating pressure limits change. For pre-existing relief valves that do not conform with the criteria of §192.201, the safe amount would be that which a prudent operator would have established when the valve was installed.

Accordingly, a footnote has been added to Interpretation 82-9 to correct the problem, and the interpretation is reissued. A copy of the reissued interpretation is enclosed.

Sincerely,

Original signed by

Richard L. Beam

Associate Director for Pipeline Safety Regulation

Materials Transportation Bureau

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No. 82-9

Date: Sep 16, 1982

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
MATERIALS TRANSPORTATION BUREAU

PIPELINE SAFETY REGULATORY INTERPRETATION

NOTE: A pipeline safety regulatory interpretation applies a particular rule to a particular set of facts and circumstances, and as such, may be relied upon only by those persons to whom the interpretation is specifically addressed.

SECTION: 192.743.

SUBJECT: Pressure limiting and regulating stations. FACTS: None.

QUESTION: Should values for "desired maximum pressure" and "required capacity," as used in §192.743(a) and (b), respectively, be based upon the criteria for pressure relieving and limiting stations set forth in §192.201(a)?

INTERPRETATION: Under §192.743, paragraph (a) requires that relief devices at pressure limiting and regulating stations be tested annually to assure they have enough capacity to limit pressure on connected facilities to the "desired maximum pressure." Paragraph (b) provides that if testing is not feasible. The "required capacity" of the devices must be reviewed, calculated and compared with their rated or experimentally determined capacity.

The "desired maximum pressure" of facilities is not defined or specifically regulated by Part 192. However, the operating pressure of a pipeline may not exceed its maximum allowable operating pressure (§§192.619, 192.621, and 192.623) or any lower pressure that might be required as a remedial measure for safety (e.g.. §192.485). Thus, as long as these limits are not exceeded, 1/ the "desired maximum pressure" of facilities is subject to the operator's discretion. Should the "desired maximum pressure" be reduced (due to remedial measures, revision of the maximum allowable operating pressure (§192.611), or any other reason) and testing shows there is insufficient relief capacity to limit pressure to the lower level, new or additional relief capacity would have to be installed as required by §192.743(c).

The plain language of paragraphs (a), (b), and (c) makes it clear that the purpose of §192.743 is to assure that relief devices at pressure limiting and regulating stations have sufficient capacity to limit downstream pressure to the "desired maximum pressure." It follows that the term "required capacity" in paragraph (b) refers to the capacity of relief devices that is needed to achieve this purpose, and not to a capacity required by §192.201(a).

Section 192.201(a) prescribes capacities that apply to the design of pressure relief and limiting stations. The purpose of this rule is to assure that stations are installed with sufficient capacity to prevent accidental overpressure in connected facilities, based on specified safe pressure limits known at the time of design. As operating conditions change, these limits may exceed the "desired maximum pressure" of the facilities, so that additional capacity would be required to meet §192.743. Therefore, the capacity requirements of §192.201(a) should not be used to determine the capacity of relief devices needed to meet §192.743.

Richard L. Beam

Associate Director for Pipeline Safety Regulation

Materials Transportation Bureau

1/ for purposes of pressure relief capacity, operating pressure limits may be exceeded by a safe amount. Section 192.201 specifies the amounts for relief devices subject to that section. The allowable amount for other relief devices installed before Section 192.201 became effective would be that which a prudent operator would have established under similar circumstances.

Reissued in Washington, D.C., on March 31, 1983

Richard L. Beam

Associate Director for Pipeline Safety Regulation

Materials Transportation Bureau

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Missouri Public Service Commission

P.O. Box

Jefferson City, Missouri 65102

February 24, 1983

Mr. Richard L. Beam

Associate Director for

Pipeline Safety Regulation

DOT/RSPA/MTB/OPSR

400 Seventh Street, S.W.

Washington, D.C. 20590

Re: Pipeline Safety Regulatory Interpretation, No. 82-9

Dear Mr. Beam:

This letter is being written pursuant to a telephone conversation with your Mr. Buck Furrow yesterday.

The above interpretation was discussed at some length and by this letter I am requesting that the interpretation be reconsidered for the following reasons:

In my opinion, the interpretation produces a direct conflict between sections 192.201(a) and 192.743 with regard to the necessary capacity of relief valves. During our conversation, Mr. Furrow and I reached the basic agreement that the capacities specified in the design criteria could logically extend to the maintenance criteria. The interpretation basically equates "desired maximum pressure" to MAOP, which creates the conflict.

Equating "desired maximum pressure" to MAQP also creates a problem when considering "pre-code" relief valve installations. If the use of section 192.201(a) criteria is acceptable for maintenance considerations for "new" relief valves, then why shouldn't similar criteria also be used for "pre-code" installations?

If you have any questions or need further clarification on this matter, please do not hesitate to call me at 314/751-3456.

Sincerely,

Dale W. Johansen

Gas Department Engineering Section

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September 16, 1982

Mr. Dale W. Johansom

Assistant Director, Gas Department -

Engineering Section

Missouri Public Service Commission

P. O. Box 360

Jefferson City, Missouri 65102

Dear Mr. Johansen:

The enclosed pipeline safety interpretation has been issued in response to your recent inquiry regarding the relationship between §192.743 and §192.201(a). While your inquiry referred only to relief devices installed before Part 192 became effective. The interpretation applies to all relief devices that are subject to §192.743, and provides that §192.201(a) should not be used to determine the relief capacity needed to comply with §192.743.

Sincerely,

Original signed by:

Richard L. Beam

Associate Director for Pipeline Safety Regulation

Materials Transportation Bureau

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Missouri Public Service Commission

P.O. Box 360

Jefferson City, Missouri 65102

July 22, 1982

Melvin A. Judah

Acting Associate Director for

Pipeline Safety Regulations

MTB/RSPA/DOT

400 7th Street, S.W.

Washington, D.C. 20590

Dear Mr. Judah:

In preparation for compliance actions against an operator, I am requesting an interpretation of the following points of concern related to 49 CFR, Part 192.

Question: With regard to relief devices installed prior to the effective date of the code, should values for "the desired maximum pressure" and "the required capacity", as used in 192.743(a) & (b) respectively, be based upon the requirements set forth in 192.201(a)?

I will certainly appreciate the most expeditious treatment you can offer in answering this question. Should you have questions concerning this matter, please feel free to call me at 314/751-3456.

Sincerely,

Dale W. Johann, Assistant Director
Gas Department - Engineering Section

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Section 192.201(a) prescribes capacities that apply to the design of pressure relief and limiting stations. The purpose of this rule is to assure that stations are installed with sufficient capacity to prevent accidental overpressure in connected facilities, based on specified safe pressure limits known at the time of design. As operating conditions change, these limits may exceed the "desired maximum pressure" of the facilities, so that additional capacity would be required .to meet §192.743. Therefore, the capacity requirements of 192.201(a) should not be used to determine the capacity of relief devices needed to meet §192.743.

Richard L. Beam

Associate Director for Pipeline Safety Regulation

Materials Transportation Bureau