LOUISIANA DEPARTMENT OF NATURAL RESOURCES

2021 PIPELINE SAFETY CONFERNECE

PHMSA INTERPRETATIONS

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PHMSA INTERPRETATIONS

WHAT IS A PHMSA INTERPRETATION?

"The Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety provides written clarifications of the Regulations (49 CFR Parts 190-199) in the form of interpretation letters. These letters reflect the agency's current application of the regulations to the specific facts presented by the person requesting the clarification. Interpretations are not generally applicable, do not create legally-enforceable rights or obligations, and are provided to help the specific requestor understand how to comply with the regulations."

WHO CAN REQUEST AN INTERPRETATION?

- OWNER/OPERATORS
- STATE REGULATORS
- TRADE ORGANIZATIONS
- MISCELLANOUS INTEREST GROUPS
- ANYONE!

PER THE STATE GUIDELINES: ANY INTERPRETATION OF A REGULATION ADOPTED BY A STATE AGENCY MUST NOT CONFLICT WITH ANY OPINION/INTERPRETATION ISSUED BY PHMSA.

https://www7.phmsa.dot.gov/regulations/title49/b/2/1/list?filter=Pipelines

NEVADA PUC 20-0001

The Nevada PUC requested it's two largest regulated gas pipeline operators to provide documentation of the maximum safe delivery pressure for each of its "large volume customers" (recipient) where the delivery pressure provided to the recipient's facilities exceeds 5 pound per square inch gauge (psig) pressure. The PUC is aware that operators set the overpressure/relief devices at the recipient sites at a pressure above the minimum delivery pressure to maintain service to each recipient but operators only provide documentation of the minimum pressure required and not the safe maximum delivery pressures.

Pressures delivered vary from 6 psig to 690 psig to approximately 200 recipients, including power plants, resort properties and industrial facilities. The PUC argues that operators should have a record of the maximum safe delivery pressure for each recipient; and that the operators make that information available to personnel when overpressure protection equipment at a recipient's facility is being worked on or maintained.

NEVADA PUC 20-0001

§192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

NEVADA PUC 20-0001

PHMSA'S RESPONSE

§192.197 requires operators to have one or more regulators or pressure limiting devices "to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer." This in turn requires high-pressure distribution operators to know the maximum safe pressure that can be delivered to each customer.

§192.605 requires operators to prepare and follow a manual of written procedures for conducting operations and maintenance activities and for emergency response. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted…

PENNSYLVANIA PUC 21-0003

The Pennsylvania Public Utility Commission is investigating a natural gas explosion. The suspected cause of the explosion is a leak on a consumer-owned line connected to an unregulated well pad production pipeline. The leak was upstream of the outlet of the meter. Pennsylvania seeks to determine whether the portion of the consumer-owned line that leaked meets the definition of a "service line" and whether the producer was the operator of this portion of the line.

PENNSYLVANIA PUC 21-0003

A gas well is located on the property of House A and the well supplies gas to House A and to a neighboring property House B. There is one tap off of the production line for the consumer-owned lines that take natural gas to House A and House B. The tap is located on the property of House A and there is a T (tee) and a shut-off valve on each side of the tap. The meter and regulator for the line to House A are immediately adjacent to the tap. Prior to the end of March 2020, the meter and regulator for the line to House B have also been immediately adjacent to the tap; however, less than one month prior to the explosion, the owners of House B relocated the meter and the regulator to the property of House B and closer to their residential structure. At the tapping point, the line is split to serve House A and House B. The line to House B originates on House A's property, crosses a public township road and then ends on House B's property. Prior to the end of March 2020, the pressure in the production line upstream of both regulators for House A and House B was 10 psig and the pressure in the lines downstream of both regulators was 4-6 ounces. Subsequent to the relocation of the meter and regulator for House B, the pressure in the line upstream of the relocated House B regulator (now downstream from the original location) increased from 4-6 ounces to 10 psig. House B notified the producer of its intentions to move the meter and regulator and received permission from the producer to move the producer's meter.

PENNSYLVANIA PUC 21-0003

PENNSYLVANIA PUC 21-0003

QUESTIONS

1. Is the House B line from the split at the tap to the outlet of the relocated House B meter a service line?
2. Does the lease agreement, which provides that the operator is responsible for the meter and House B is responsible for the regulator and all other piping from the production line tap valve, impact the determination of whether the line is a service line?
3. Is the producer an operator and regulated under 192?

PENNSYLVANIA PUC 21-0003

PHMSA'S RESPONSE

1) Under 49 CFR §192.3, a service line is any distribution line that transports gas from a common source of supply to an individual customer through a meter header or manifold. Under certain circumstances, a service line may also be referred to as a "farm tap," which is the common name for a pipeline directly connected to a gas transmission, production, or gathering pipeline that provides gas to a customer.

On a farm tap, the "source" piping ends and the service line begins at the first accessible point where the downstream service line can be isolated from source piping (e.g., the inlet to a valve or regulator). In this case, this point appears to be the shut-off valve downstream of the tap. PHMSA notes that additional safety regulations govern service-line valves, including the location of valves pursuant to §192.365, and operators must comply with applicable recordkeeping requirements in Part 192.

Under the definition of service line, §192.3, the service line ends at the outlet of the customer meter or at the connection to a customer's pipeline, whichever is further downstream, or at the connection to customer piping if there is no meter. Here, the House B line transports gas from the production line to the customer. The service line would end at the outlet of the meter, or the connection to customer owned piping, whichever is further downstream. Since the outlet of the meter is further downstream than the connection to customer owned piping, the service line would end at the outlet of the relocated meter.

PENNSYLVANIA PUC 21-0003

PHMSA'S RESPONSE

2) No. The private lease agreement does not impact the determination of whether the line is a service line under 49 CFR § 192.3.

3) Yes. An "operator" is a person who engages in the transportation of gas, which includes the distribution of gas by pipeline in or affecting interstate commerce (49 CFR §§ 191.3 and 192.3). From the information provided, the producer provided natural gas from its production line to the consumers which was measured by the producer-owned customer meter. While production lines are not regulated, 49 CFR Parts 191 and 192 apply to distribution lines regardless of whether the "common source of supply" is a regulated line. Therefore, because the producer is engaged in the transportation of natural gas via a regulated service pipeline, it is an operator under 49 CFR Parts 191 and 192 and must comply with all applicable requirements contained therein on the "service line" defined in the **Response to question 1**.

RCP 20-0015

In an April 13, 2021, letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), you requested an interpretation of 49 CFR Part 195. Specifically, you requested an interpretation of §195.454, which was adopted in the final rule titled, "Pipeline Safety: Safety of Hazardous Liquid Pipelines," which became effective on October 1, 2019 (84 FR 52260). You stated it is your understanding that the October 1, 2019, final rule was intended to address pipelines in a navigation channel more than 150 feet deep. You stated that while the legislation and the rule may have been written with deep water bodies in mind, both are written in a way that might apply to other pipelines that are directionally drilled deep below a shallow water body. Therefore, you asked PHMSA to clarify whether "the rule only applies to crossings of waterbodies that are themselves more than 150 feet deep – not to deep directional drills under shallow water bodies."

RCP 20-0015

§ 195.454 Integrity assessments for certain underwater hazardous liquid pipeline facilities located in high consequence areas.

Notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required under §195.452, each operator of any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water must ensure that:

(a) Pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months, and;

(b) Pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, are completed on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the pipeline facility is located.

RCP 20-0015

PHMSA'S RESPONSE

The requirements of § 195.454 apply to "any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water." This provision was adopted in response to the self-executing provisions of section 25 of the 2016 PIPES Act, which requires operators of such pipelines to complete in-line inspection assessments appropriate to the integrity threats specific to those pipelines, no less frequently than once every 12 months. Section 25 of the 2016 PIPES Act also requires that operators use pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, as necessary to assess the integrity of those pipelines on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the facility is located. As explained at the time §195.454 was adopted, "PHMSA determined that one pipeline, Enbridge Line 5 at Mackinaw, Michigan, meets the applicability requirements for this provision. This line consists of two 20-inch pipelines where it crosses the Straits of Mackinac, over a distance of approximately 5 miles." PHMSA did not interpret § 195.454 or Section 25 of the 2016 PIPES Act to apply to pipelines directionally drilled deep below the surface of a shallow water body. If a pipeline is installed and operated underwater at a depth greater than 150 feet under the surface of a body of water, similar to Enbridge Line 5, the operator of that pipeline would be subject to this regulation.

SHELL PIPELINE COMPANY 21-0006

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), dated June 4, 2021, you requested an interpretation of 49 CFR Part 195. Specifically, you requested an interpretation as to the applicability of §195.412 to the use of drones to perform an aerial inspection of pipelines' rights-of-way (ROW). You stated Shell Pipeline Company LP (SPLC) proposes to use drones to perform aerial inspection of ROW on a new pipeline in the PHMSA Eastern Region. The drone would be equipped with video equipment to fly over the ROW while Operator Qualified personnel will review the footage in real time. You provided, as attachment, examples of the quality of the images produced by the drone. You stated the video footage has an additional benefit of the ability to go back and review the footage. In addition, you stated if necessary, the video footage would also be stored for over time comparisons. You asked PHMSA whether the use of the drone technology complies with the §195.412 ROW inspection requirements.

Section 195.412(a) requires each operator to inspect the surface conditions on or adjacent to each Part 195 regulated pipeline ROW at intervals not exceeding 3 weeks but at least 26 times each calendar year. Also, §195.412(a) specifies the methods of inspection to include walking,
driving, flying or other appropriate means of traversing the ROW.

SHELL PIPELINE COMPANY 21-0006

SHELL PIPELINE COMPANY 21-0006

§195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.

(b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

SHELL PIPELINE COMPANY 21-0006

PHMSA'S RESPONSE

Therefore, where aerial ROW inspection is appropriate, §195.412(a) does not exclude drone (Unmanned Aerial System (UAS)) use as long as the images provided by the UAS have sufficient resolution to provide the necessary details of the surface conditions on and adjacent to each pipeline ROW. However, nothing in this interpretation affects the operator's obligation to operate the UAS in accordance with all laws and regulations regarding UAS use.

Can I use a drone if my right-of-way looks like this? →

ARIZONA CORP COMMISSION 19-0019

You stated that during an annual audit of an operator of a high-pressure gas distribution system, records of relief device inspections revealed that the set pressure at which the relief device starts to open was in excess of the system's maximum allowable operating pressure (MAOP). You also observed that the set point of the monitor regulator was higher than the downstream system's MAOP at numerous worker/monitor stations.

Your letter raised the concern that, during an emergency pressure-control occurrence, should the worker regulator fail and the monitor regulator activate and take-over pressure control, there would be no remaining overpressure protection as required by §192.195 for the duration of these operating conditions. You referenced an earlier PHMSA interpretation (PI-14-0016) that stated that overpressure conditions are only allowed for the time taken to activate the overpressure protection device and not for long-term or frequently-occurring normal operating conditions.

Therefore, immediate response by the operator either to shut down or reduce the operating pressure to normal operating conditions is required under Part 192.

You stated that in the case of the worker/monitor stations that supply a distribution system with more than one source of supply, the electronic pressure recording (EPR) device at each regulating station is read once each month, so if there are any indications that the worker regulator failed, then the overpressure condition may continue for up to 30 days before corrective action is taken. When EPR units are not required under §192.741, then a failed worker regulator may not be discovered for up to 15 months. You believe that any activation of an overpressure protection device requires an immediate response at the time of occurrence, not the time of discovery.

ARIZONA CORP COMMISSION 19-0019

QUESTIONS

You request clarification on the following questions for a *high-pressure distribution pipeline system*:

1) Does the relief valve set point at a pressure above the MAOP violate 192.739(a)(3) and 192.619?

2) Does a monitor regulator set-point above the downstream MAOP violate 192.739(a) and 192.619?

3) Does the activation of an overpressure protection device require an immediate response at the time of occurrence or at the time of discovery?

4) Are operators required to provide overpressure protection that includes a means whereby the operator is alerted to the emergency operating conditions at the time they occur?

5) Is within 30 days or up to a period of 15 months considered by PHMSA an immediate response?

ARIZONA CORP COMMISSION 19-0019

§192.739 Pressure limiting and regulating stations: Inspection and testing.

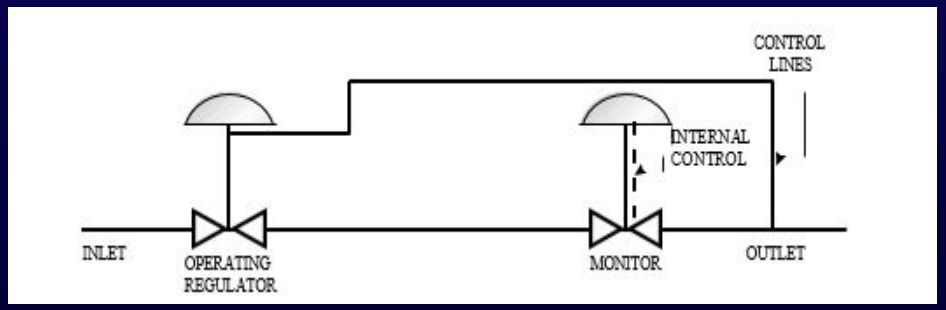
(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is -

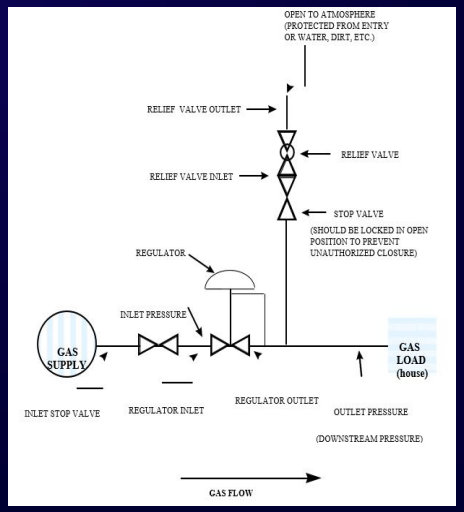
(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.





ARIZONA CORP COMMISSION 19-0019

PHMSA'S RESPONSE

1) Does the relief valve set point at a pressure above the MAOP violate 192.739(a)(3) and 192.619?

No, setting a relief valve set-point at a pressure higher than MAOP does not violate §§192.619 or 192.739(a)(3) if the operator meets the applicable relief valve set pressures for MAOP, as defined in either §§192.201 or 192.739, for the maximum relief valve set pressures above MAOP. Note that §192.619 prohibits operating a segment of steel or plastic pipeline at a pressure that exceeds a pipeline's MAOP during normal operation.

2) Does a monitor regulator set-point above the downstream MAOP violate 192.739(a) and 192.619?

No, a monitor regulator set-point above the downstream MAOP does not violate §§192.739(a)(3) and 192.619 if the operator installs and operates pressure-relieving or pressure-limiting devices that meet the requirements of §§192.195, 192.197, 192.199, 192.201 and 192.739, and does not exceed the pipeline's MAOP during normal operation.

ARIZONA CORP COMMISSION 19-0019

PHMSA'S RESPONSE

3) Does the activation of an overpressure protection device require an immediate response at the time of occurrence or at the time of discovery?

Overpressure control devices must be designed, operated and maintained in accordance with all the applicable sections of Part 192, including §§192.195, 192.197, 192.199, 192.201, and 192.739, as they relate to high-pressure gas distribution systems. For example, operators must determine that these pressure-limiting devices are in good mechanical condition and are adequate from the standpoint of capacity and reliability of operation for the service in which they are employed.

Section 192.739(a)(1) & (2); *see also* § 192.605(b)(10)(iii) (requiring operators to prepare and follow written procedures for systemic and routine testing and inspection of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity); *see also* § 192.615 (requiring written emergency plans for immediate response to gas pipeline emergencies). In order to fulfill these regulatory obligations, operators must respond to these overpressure events at the time of discovery. If operators are not timely responding to these events, then it is unclear how they can confirm that this critical equipment is operating as intended, pursuant to the various regulatory requirements set forth above.

ARIZONA CORP COMMISSION 19-0019

PHMSA'S RESPONSE

4) Are operators required to provide overpressure protection that includes a means whereby the operator is alerted to the emergency operating conditions at the time they occur?

Section 192.741 sets forth requirements for the installation of telemetering or recording gauges at pressure limiting and regulating stations for gas pipeline distribution systems. Pressure limiting or regulating stations with indications of abnormally high or low pressure must be inspected and measures necessary to correct any unsatisfactory condition must be employed. This would include safety measures to ensure that overpressure protection equipment malfunctions are identified and remediated in a timely manner. Further, overpressure regulation devices with a history of operational pressure exceedance do not meet the requirements set forth in §192.739(a)(2) and may require repair, replacement or additional monitoring, including monitoring pursuant to §192.613. Finally, pursuant to §192.605(b)(10)(iii), operators must prepare and follow written procedures governing the systemic and route testing and periodic inspection of pressure limiting equipment to determine that it is in a safe operating condition. Also, for operators that have a control room, §192.631 requires monitoring of pipeline systems for abnormal and emergency operating conditions.

PHMSA'S RESPONSE

5) Is within 30 days or up to a period of 15 months considered by PHMSA an immediate response?

Section 192.613 requires a procedure for "continuing surveillance" for facilities with "unusual operating and maintenance conditions." A pressure limiting or regulating station with a history of operational and maintenance failures that cause the MAOP to be exceeded, where a monitoring regulator is being used, would require a means of "continuing surveillance" to meet the requirements of §192.613. PHMSA does not consider within 30 days or up to a period of 15 months (which is a period for inspection) an immediate response nor does the agency consider this period of time to comport with continuing surveillance requirements under §192.613.

WRIGHT AND ASSOCIATES 21-0005

If a pipeline has been physically disconnected, cleaned, and purged with nitrogen, does not cross over, under or through a commercially navigable waterway, no longer transports hazardous liquids, and is not intended to be returned to service, then would that pipeline be subject to the 49 CFR Part 195 regulations?

WRIGHT AND ASSOCIATES 21-0005

§195.59 Abandonment or deactivation of facilities.
For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

§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.

WRIGHT AND ASSOCIATES 21-0005

PHMSA'S RESPONSE

If the pipeline is not an offshore pipeline or is an onshore pipeline that does not cross over, under or through a commercially navigable waterway, is permanently removed from service, safely disconnected from an operating pipeline system, purged of combustibles, and sealed to minimize safety and environmental hazards, then that pipeline is no longer regulated under 49 CFR Part 195 regulations. Based on the information you provided, 195.59 and 195.402(c)(10) reporting requirements for abandoned offshore pipelines or onshore pipelines that cross over, under or through a commercially navigable waterway do not apply. However, the pipeline operator may need to confirm with the U.S. Environmental Protection Agency and the respective State regulator for any applicable compliance requirements, including reporting and proof of proper physical disconnection work requirements.

TENNESSEE PUC 20-0012

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), dated May 21, 2020, you requested an interpretation of 49 Code of Federal Regulations (CFR) Part 193. Specifically, the Tennessee Public Utilities Commission (TPUC) asked for an interpretation on whether 49 CFR §193.2441(c) "is fulfilled when an LNG operator leaves the control center to perform assigned duties when an offsite SCADA control room is assigned and equipped only to monitor LNG alarms and is without an LNG trained operator." TPUC requests this interpretation to resolve a disagreement with a liquefied natural gas (LNG) operator as to the correct application of §193.2441(c) to the operator's proposed one-man operator procedure.

The letter indicates that on May 17, 2020, an LNG operator implemented a one-man operation procedure that includes the requirement that when the control center is manned by only a single qualified operator, the operator is to contact an off-site Supervisory Control and Data Acquisition (SCADA) control room to monitor the alarms of the vacant LNG control center. This off-site SCADA control room has no ability to control any of the functions or operating components of the LNG facility; it can only monitor the alarm system. The off-site SCADA control room also only has Part 192 qualified gas operation personnel, with no Part 193 qualified LNG operators in attendance.

TENNESSEE PUC 20-0012

If the operator's procedure is followed, you stated that TPUC believes that as soon as the LNG operator leaves the LNG control center, a violation of §193.2441(c) will have occurred. You stated the operator disagrees because its LNG facility is equipped with automatic shutdown capability, and the off-site SCADA control room monitoring the LNG facility's alarm systems will contact the LNG operator if an alarm goes off while the LNG control center is vacant. Based on these operational factors, the operator contends that its procedure meets the requirement of the regulation.

TENNESSEE PUC 20-0012

Section 193.2441(c) requires that "[e]ach control center must have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance."

TENNESSEE PUC 20-0012

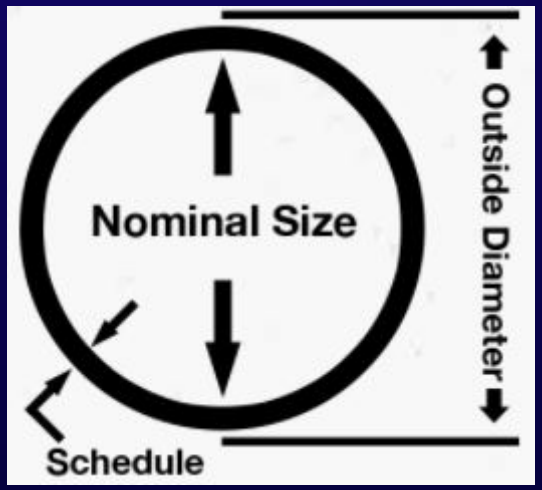
The regulation requires that an LNG facility has at least one person in the control center at all times (i.e. uninterrupted) while any of the components under the control center's control are in operation. This does not necessarily preclude the LNG control center operator from taking short breaks in the area of the control center to attend to physiological needs. Furthermore, §193.2441(c) states that the "continuous attendance" requirement at the LNG control center does not apply if the control of any components in operation is being performed from another control center which has personnel in continuous attendance. However, §193.2441(c) specifically requires that this "[other] control center" be capable of controlling any of the components at the LNG facility while in operation. Therefore, a control center operator may perform duties outside the control center during his/her shift as long as another control center's operator has control of any operating components with uninterrupted attendance of the control center.

<u>In this case, the operator would not meet these regulatory requirements by relying on a SCADA system to monitor alarms without controlling the facility.</u> Therefore, to respond to your question, the requirement in §193.2441(c) is not fulfilled any time the operator's offsite SCADA control room is assigned and equipped to monitor LNG alarms without being able to control any of the operating components at the LNG facility whenever the LNG operator leaves the LNG control center vacant to perform other assigned duties.

AUDUBON FIELD SERVICES 21-008

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), dated March 10, 2021, you requested an interpretation of the 49 Code of Federal Regulation (CFR) Part 195. Specifically, you requested an interpretation on the term "nominal diameter" as it relates to the requirements of §195.11(a).

You asked for clarification on the size of pipelines intended for inclusion in §195.11 and that PHMSA consider adding a definition to §195.3.



AUDUBON FIELD SERVICES 21-008

The nominal pipe size (NPS) is related to the inside diameter in inches, and NPS 12 and smaller pipe has outside diameter greater than the designated size. Therefore, a 6 inches nominal diameter pipe is a 6 ⅝-inches nominal outside diameter pipe and an 8-inches nominal diameter pipe is an 8 ⅝-inches nominal outside diameter pipe. However, for NPS 14 and larger, the NPS is the same as the nominal outside diameter. That is, a 14-inch nominal diameter pipe is the same as a 14-inch nominal outside diameter pipe. API Specification 5L, Specification for Line Pipe, 45th Edition incorporated by reference in 49 CFR §195.3(b)(13) (API 5L) uses "specified outside diameter" for the nominal outside diameter of pipe. Sections 195.2 (gathering line) and 195.11(a) reference terms "nominal diameter" or "nominal outside diameter" for pipe, with both references being the same nominal outside diameter for pipe that is referenced in API 5L. In addition, the Research and Special Programs Administration (RSPA) (the predecessor to PHMSA) clarified and addressed this issue in a 1994 final rule. Also, it should be clear that outside diameters are furnished by pipe mills in nominal outside diameters that are not in whole numbers for less than or equal to 12-inches pipe diameters. For example, pipe with an outside diameter of 2 ⅜-inches is used by pipe mills for a nominal outside diameter of 2-inches. Other examples include 8 ⅝-inches instead of 8 inches, and 10 ¾-inches instead of 10-inches.

AUDUBON FIELD SERVICES 21-008

Therefore, PHMSA has addressed this issue by regulation as explained by the June 28, 1994, final rule which added using both 6⅝-inches and 8⅝-inches pipe nominal diameters under the §195.11(a) requirements as pipe outside diameters.

MARKWEST 20-0010

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), dated April 27, 2020, MarkWest requested that PHMSA clarify a statement in a supplemental interpretation issued by the agency on April 7, 2020. In the supplemental interpretation, PHMSA confirmed an earlier interpretation dated October 15, 2019, that pipelines delivering gas to MarkWest's gas processing plant were transmission lines. PHMSA described the pipelines as delivering off-gas from refineries to the MarkWest Javelina processing plant, where the plant "uses the off-gas as chemical and plastic feedstocks and sends residue gas back to the refineries" for their use as fuel. The interpretation noted that the plant processed approximately 28,000 bbl/day of liquid hydrocarbons in this manner. PHMSA stated further that it disagreed with Markwest's opinion that the gas processing plant is not a large volume customer for purposes of the transmission line definition in §192.3.

MARKWEST 20-0010

In its April 27, 2020 letter, MarkWest asserted that during a November 19, 2019, meeting with PHMSA, the company indicated that none of the refinery off-gas received at the plant is used as a feedstock for other products, but rather Mark West processes the off-gas to create pipeline-quality gas for delivery to another downstream customer. Unless something has significantly changed in its processing of the feedstock into chemical feedstocks, this assertion appears to be inconsistent with information MarkWest provided to PHMSA on November 14, 2016, which explained in more detail how the Javelina plant separates off-gas into valuable components as the off-gas contains light hydrocarbon components that are more valuable as chemical and plastic feedstocks. In addition, the information provided by MarkWest on November 14, 2016, appears to be consistent with information provided to PHMSA by the Texas Railroad Commission. The products produced include propane, butane, ethane, and other NGLs. In addition, PHMSA notes that the Javelina plant receives up to 142 mmscfd of off-gas from refineries, a volume consistent with, if not exceeding, volumes received by large volume customers. Accordingly, PHMSA finds no reason to modify its April 7, 2020, interpretation.

Finally, as this pipeline is regulated by the Texas Railroad Commission, PHMSA encourages MarkWest to work directly with its regulator to resolve any future issues.

THUMS LONG BEACH CO 20-0008

In a December 13, 2019, letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA), you requested an interpretation of 49 Code of Federal Regulations (CFR) Part 195 (Request). Specifically, you requested an interpretation regarding the applicability of §195.1(b)(5). You stated that THUMS Long Beach Company has nine subsea pipelines that transport a multi-phase crude oil, natural gas, and water mix from four man-made oil production islands located in Long Beach Harbor within California State waters to onshore facilities. You also stated that the fluids coming up from the wells contain approximately 2% oil and the remainder is water and some entrained gases and solids. You further stated that there is gross separation of oil and water on the islands that is accomplished by gravity separation in the Free Water Knock-Out (FWKO) vessel located on the islands. Finally, the bulk water removal at the islands is necessary for two purposes: 1) re-injection into the reservoir for pressure maintenance of the formation; and 2) State and City-mandated subsidence control. You noted that after bulk water separation on each island, the composition of the fluid stream transported to shore within the subsea pipelines is between 25-30% crude oil with maximum crude oil concentration of 30-40%, and that the multiphase fluid undergoes final separation, processing, and dehydration at THUMS's Pier J facilities to yield sales-quality crude oil.

THUMS asked PHMSA if the exception under § 195.1(b)(5) applies to the nine subsea pipelines between the islands and the Pier J facilities.

THUMS LONG BEACH CO 20-0008

Section 195.1(b)(5) exempts the following pipelines from Part 195 requirements: "[t]ransportation of hazardous liquid or carbon dioxide in an offshore pipeline in state waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility: The facility where hydrocarbons or carbon dioxide are produced or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed." The exception is narrow, and applies only if the following factors are met: (1) the transportation of hazardous liquid or carbon dioxide; (2) in an offshore pipeline in state waters; and (3) the segment is located upstream from the outlet flange of the farthest downstream facility, either where hydrocarbons or carbon dioxide are produced, or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed. There is no dispute that the first and second prongs to the exception are met. The third prong requires an analysis of whether the point of "first separation" occurs on the four islands where water is removed from the product.

Line	Description	Nominal Diameter	Length (miles)	MOP (psig)	% SMYS at MOP	Low Stress	Gravity Line	Rural	Cross NPMS Defined Commercially Navigable Waterway	U.S. Coast Guard Jurisdiction
CW-2	Island Chaffee to Island White	8"	1.53	400	15.31%	YES	NO	NO	NO	NO
CW-7	Island Chaffee to Island White	8"	1.53	400	15.31%	YES	NO	NO	NO	NO
FW-2	Island Freeman to Island White	8"	0.75	400	15.31%	YES	NO	NO	NO	NO
FW-3	Island Freeman to Island White	6"	0.75	400	13.52%	YES	NO	NO	NO	NO
FW-5	Island Freeman to Island White	6"	0.75	400	13.52%	YES	NO	NO	NO	NO
WG-2R	Island White to Island Grissom	12"	1.60	400	14.57%	YES	NO	NO	NO	NO
WG-4	Island White to Island Grissom	12"	1.60	400	19.43%	YES	NO	NO	NO	NO
GJ-2	Island Grissom to Onshore Pier J	12"	1.15	400	19.43%	YES	NO	NO	YES	NO
GJ-6	Island Grissom to Onshore Pier J	12"	1,15	400	19.43%	YES	NO	NO	YES	NO

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It is undisputed that water is removed from the product on the islands where it is produced. For the exception to apply, this removal must not constitute "first separation" under the regulation. PHMSA has consistently interpreted this regulation to apply only where the initial separation is performed exclusively for the purpose of enhancing or assisting production operations, such as through reinjection for gas lift, or to provide power to the production platform instruments or equipment.* PHMSA has never interpreted this exception to apply where the separation is being performed for any purpose not solely related to production operations.

* *See e.g.,* PHMSA Letter of Interpretation to L.G. Otteman – Offshore Operators Committee, No. PI-79-025 (Aug. 2, 1979) ("The separation to which Sections 192.1 and 195.1 refer is a type of processing of hydrocarbons for purposes of their further transportation by pipelines. This type of processing does not include separation of minor amounts of gas exclusively for the purpose of running instruments or equipment.").

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In the case of THUMS, there is bulk water separation at the four islands, resulting in an increase of fluid oil content from approximately 2% to 25-30% crude oil composition. This separation is not minor, nor is it being performed only to assist production operations. Instead, it is being performed for pressure maintenance of the formation and to comply with state and local mandates. Additional processing at the Pier J facilities does not alter the fact that at this location the pipeline already carries a commodity that has been initially separated at an upstream facility, regardless of the fact that it is not considered sales-quality crude. Therefore, the bulk water separation occurring on the four islands constitutes "first separation" for purposes of the regulation, and therefore, the nine pipelines from the outlet flange of the four islands to the Pier J facilities would not fall under the §195.1(b)(5) exception. In sum, the nine transportation-related pipelines moving hydrocarbons from the four offshore production islands to the onshore facilities for further processing are subject to Part 195 regulations.

FLINT HILLS RESOURCES 19-0017

In a letter dated October 17, 2019, to the Pipeline and Hazardous Materials Safety Administration (PHMSA), Flint Hills Resources (FHR) requested an interpretation of 49 Code of Federal Regulations (CFR) Part 195. Specifically, FHR requested an interpretation of the application of Part 195 to its pipeline that transports jet fuel from the FHR Pine Bend Refinery to the Minneapolis St. Paul Airport (Airport Pipeline), in particular the points of demarcation between the regulated Airport Pipeline and the connecting in-plant and airport facilities. The Airport Pipeline is an intrastate pipeline subject to the regulatory authority of the Minnesota Office of Pipeline Safety (MNOPS) under a §60105 certification. You provided supplemental letters related to this matter on September 25, 2020.

You stated FHR received a PHMSA interpretation dated February 25, 2019 (Interpretation Response PI-17-0011) issued to MNOPS concerning the applicability of 49 CFR Part 195 to the Airport Pipeline. You stated both the PHMSA interpretation and underlying MNOPS request were based on inaccurate information regarding the Airport Pipeline and connecting facilities. In particular, you noted that factual information was incorrect with regard to pipeline operating pressure, pressure control and leak detection. For example, you stated the pipeline does not operate above 20% SMYS and there is no surge relief on the pipeline, as were stated in Interpretation PI-17-0011.

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In light of your submission, PHMSA finds that it has conflicting information about the design and operating specifications of the Airport Pipeline that influence demarcation of the regulated portion. While PHMSA is not validating one statement of facts over another, PHMSA can affirm its longstanding interpretation of the scope of Part 195, including the end points of regulation when a pipeline leaves a refinery or delivers product to a materials transportation terminal.

Part 195 applies to all pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities, with certain exceptions. Among those exceptions, §195.1(b)(8) and (b)(9)(ii) exclude from Part 195 certain facilities, including in-plant piping systems associated with refining, and terminal facilities used exclusively to transfer hazardous liquid to or between a non-pipeline mode of transportation, respectively.

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With respect to the in-plant piping exception in §195.1(b)(8), Part 195 does not apply to the transportation of hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities. In-plant piping system means, pursuant to §195.2, piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b). With respect to terminal facilities, §195.1(b)(9)(ii) excepts facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer materials between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. Like the in-plant piping exception, PHMSA has treated the demarcation point of the materials terminal facility to be the same as under §195.1(b)(8).

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PHMSA has previously explained that the point of demarcation between a regulated pipeline and unregulated in-plant piping is the inlet of the pressure control device if the pipeline is moving product away from plant grounds or the outlet of the pressure control device if the pipeline is supplying the plant. If there is no such pressure control device on plant grounds, in-plant piping would extend to the boundary of plant grounds. *See, e.g.*, Regulatory Review: Hazardous Liquid and Carbon Dioxide Pipeline Safety Standards, Notice of Proposed Rulemaking, 57 FR 56304, 56305 (Nov. 27, 1992); and PHMSA Letter of Interpretation to Buckeye Texas Processing, PI-20-0004 (Apr. 7, 2020). The regulation does not indicate any other component serves as the demarcation point, such as a meter or leak detection component, if such device is not necessary to control pressure in the pipeline under § 195.406(b). *See* Regulatory Review: Hazardous Liquid and Carbon Dioxide Pipeline Safety Standards, Final Rule, 59 FR 33388, 33389 (Jun. 28, 1994) (recognizing components, such as pipe, meters, instruments, and manifolds, located on plant grounds may fall outside Part 195, and affirming the plant boundary is a more convenient demarcation of in-plant piping than an unspecific inside-the-plant component).

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PHMSA has also explained the exception for in-plant piping associated with refining applies only to piping located on the grounds of the plant. If the refinery is separated by a public thoroughfare, the exception still applies to transfer piping crossing the road, but the exception does not apply to inter-facility lines or delivery lines off plant grounds. Final Rule, 59 FR at 33389.

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With respect to the terminal facilities exception in §195.1(b)(9)(ii), Part 195 does not apply to transportation of hazardous liquid or carbon dioxide through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. The exception does not include any device and associated piping necessary to control pressure in the pipeline under §195.406(b). Like the in-plant piping exception, PHMSA has treated the demarcation point between a regulated pipeline and unregulated materials terminal facility to be the pressure control device that is necessary to control pressure on the pipeline. PHMSA has also explained the exception does not include breakout tanks and associated piping, because such facilities are not used exclusively for transfers between non-pipeline and pipeline modes. NPRM, 57 FR at 56305. While PHMSA did not mention demarcation where there is no pressure control device on terminal grounds, it is reasonable to apply the same demarcation as the in-plant piping exception, namely, the terminal boundary. The terminal facilities exception applies only to those terminal facilities located on the grounds of the terminal. Terminal facilities located off terminal grounds do not fall within the exception and are, therefore, subject to Part 195. Final Rule, 59 FR at 33389.

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In light of the longstanding application of these exceptions, PHMSA recommends that FHR and MNOPS jointly evaluate the design and operating specifications of the Airport Pipeline and determine the demarcation points consistent with this interpretation. In particular, PHMSA notes that FHR has described design limitations of its pipeline in which the pumps cannot cause the Airport Pipeline to experience pressures exceeding the maximum operating pressure (MOP) and, therefore, the pipeline is not required to have pressure control devices on the plant grounds. If MOP could be exceeded (such as by the outlet pressure capacity of the pump, change-out of a pump impeller or the closing or opening of a valve) however, the Airport Pipeline must have adequate controls and protective equipment to control the pressure within the limits established by §195.406.

QUESTIONS OR COMMENTS

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