Mr. Scott Jepsen
Cook Inlet Asset Manager
Phillips Alaska, Inc.
700 G Street ATO 1420
Anchorage, AK 99510

Re: CPF No. 56301-M and CPF No. 56004

Dear Mr. Jepsen:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced cases. It makes findings of violation and requires certain corrective action. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

Gwendolyn M. Hill
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

<u>CERTIFIED MAIL - RETURN RECEIPT REQUESTED</u>

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
WASHINGTON, DC 20590

In the Matter of	
Phillips Petroleum Company,	CPF No. 56301-M CPF No. 56004
Respondent.	

FINAL ORDER

On October 22-24, 1995, pursuant to 49 U.S.C. § 60117, representatives of the Office of Pipeline Safety (OPS) conducted an on-site pipeline safety inspection of Respondent's liquefied natural gas (LNG) facilities and records in Kenai, Alaska. On October 23-26, 1995, OPS representatives conducted an on-site pipeline safety inspection of Respondent's gas pipeline between the Tyonek Platform and Respondent's LNG facility in Kenai, Alaska. As a result of the inspections, the Director, Western Region, OPS, issued to Respondent, by letters dated March 6, 1996, a Notice of Probable Violation and Notice of Amendment (Notice 1)(CPF No. 56301-M) and a Notice of Probable Violation and Proposed Compliance Order (Notice 2)(CPF No. 56004). In accordance with 49 C.F.R. § 190.237, Notice 1 proposed that Respondent amend certain Operating and Maintenance Procedures. In accordance with 49 C.F.R. § 190.207, Notice 2 proposed finding that Respondent had violated 49 C.F.R. §§ 192.465(a) and 192.481 and proposed that Respondent take certain measures to correct the alleged violations.

Respondent responded to the Notices by letter dated April 3, 1996. Respondent did not contest Notice 1 and submitted its revised procedures. Respondent contested the allegations in Notice 2 and requested a hearing that was held on July 11, 1996. Respondent submitted supplemental responses on July 11, 1996 and July 15, 1996.

FINDINGS OF VIOLATION

Item 1 in Notice 2 alleged that Respondent had violated 49 C.F.R. § 192.465(a) because it did not have procedures to annually monitor 13 miles of its submerged pipelines. The regulation requires that each pipeline under cathodic protection be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection is meeting the regulatory requirements.

Item 2 in Notice 2 alleged that Respondent violated 49 C.F.R. § 192.481, which requires an operator to re-evaluate each offshore pipeline exposed to the atmosphere at least once each calendar year, but with intervals not exceeding 15 months. The regulation further requires an operator to take remedial action when necessary to maintain protection against atmospheric corrosion. The Notice alleged that Respondent did not have procedures to re-evaluate its offshore pipeline for atmospheric corrosion and to remedy the condition were atmospheric corrosion found.

Both allegations concerned Respondent's natural gas pipeline system extending from the Tyonek platform in Cook Inlet to the Kenai plant: two parallel 10 3/4-inch offshore pipelines, extending from the offshore platform to the east shore of Cook Inlet at Moose Point, and a 16-inch onshore pipeline extending from Moose Point to the Kenai plant.

Description of the LNG Pipeline System

Respondent argued that OPS does not regulate the above-described pipeline system: the two parallel 10 3/4-inch pipelines because they are field-to-plant pipelines located upstream from the facility where hydrocarbons are first processed(the Kenai plant) and the 16-inch onshore line because it is a rural gathering line.

Respondent maintained that the lines deliver gas from the offshore platform to the plant for traditional gas processing and for subsequent liquefaction. Respondent explained that gas leaving the platform flows through the parallel 10 3/4-inch pipelines. The pipelines come ashore at Moose Point, where they tie into the 16-inch pipeline that runs from Moose Point to the plant that produces liquefied natural gas (LNG) by means of a cryogenic process.

Respondent contended that because the lines deliver gas from the platform to the plant for gas processing and liquefaction, and liquefaction is a basic cryogenic process used by traditional LNG plants, the plant is similar enough to a processing plant to conclude that the lines are gathering lines.

Definition

Part 192 defines a gathering line as a pipeline that transports gas from a current production facility to a transmission line or main. Certain gathering lines are excepted from the regulations. (See §192.1) Of relevance here -

> offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are

> first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.[1]
>
> onshore gathering of gas outside of an area within the limits of any incorporated or unincorporated city, town or village.

In 1991, OPS proposed to revise the definition of gathering line to clearly describe the beginning and end of gas gathering. (Notice of Proposed Rulemaking, 56 Fed. Reg. 48505; September 25, 1991). In 1999, OPS held an electronic public discussion forum to seek new ideas and information on how to define gas gathering (64 Fed. Reg. 12147; March 11, 1999). OPS has not yet issued final regulations.

<u>The Platform - Production or Processing?</u>

Respondent contended that the parallel 10 3/4-inch lines are offshore pipelines located in State waters and are not regulated because they are field-to-plant pipelines located upstream from the facility where hydrocarbons are first processed, the Kenai plant.[2]

Under the current definition, OPS has been interpreting a gathering line to end at the outlet of the gas processing plant. Thus, determining whether the parallel 10 3/4-inch lines are excepted from Part 192 depends on whether the offshore Tyonek platform is a production or processing facility.

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[1] This wording was changed in June 1996 when OPS issued a final rule that changed several gas pipeline safety regulations to provide clarity, eliminate unnecessary or burdensome requirements and foster economic growth. (61 Fed. Reg. 28770; June 6, 1996). The revised wording became effective in July 1996 and now reads "offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream." OPS deleted the phrase on the outer continental shelf to make it clear that the exception applies to offshore gathering no matter where located. OPS also replaced the phrase offshore gathering of gas with offshore pipelines to clarify that the pipelines excepted could be either production or gathering lines. Neither wording change affects the determination of whether the lines at issue are gathering or transmission.

[2] At the hearing, Respondent referred to a clarification OPS had made concerning the scope of Part 192 to gathering lines located in state offshore waters. In a final rule issued in June 1996, OPS clarified that it treats Outer Continental Shelf and state offshore gathering alike under Part 192. (61 Fed. Reg. 28770; June 6, 1996). Cook Inlet waters are offshore; therefore, whether the lines at issue are located in state waters does not affect the determination as to whether they are excepted offshore gathering lines.

Respondent contended that the platform is a production facility. Respondent explained that the platform consists of 13 wells, four separators, two scrubbers, two compressors and three dehydrator trains, all production facilities. Respondent explained that the gas from the wells contains saturated water vapor and free water; the separators remove this free water, a process that does not affect the composition of the gas. Respondent said that the gas leaving the separators contains saturated water vapor, and undergoes limited dehydration for water dew point control purposes. Without this limited dehydration, Respondent said that the water vapor could condense and create myriad problems for the pipelines. Respondent maintained that this dehydration does not alter the composition of the gas and is for enabling the gas to move to the plant, not for improving the quality of the gas or making it saleable.[3]

Respondent further explained that the gas leaving the separators is routed either through suction scrubbers, compressors and air fin exchangers to the glycol dehydration system or through production scrubbers directly to the glycol dehydration system. Respondent said that the compressors increase the pressure of the gas so that it is sufficient to meet the delivering pipeline's required pressure and that the glycol dehydration system removes some of the water vapor. Again, Respondent maintained that neither of these processes alter the gas's composition. Respondent said that the gas then flows through gas heat exchangers into a 12-inch pipeline, and from there into the two 10 3/4-inch pipelines, for delivery to the Kenai plant.

OPS contended that the Tyonek platform is a processing facility because it contains production and processing facilities. OPS explained that the pipeline transports gas from the production field (the 13 wells), the gas is gathered through headers and then processed by being separated, dehydrated, scrubbed and compressed. OPS argued that the separation of free water, dehydration and scrubbing of natural gas that occur at the platform facilitates transportation of the gas.

The gas pipeline safety regulations do not define production or processing. Without a definition as a guide, I must look to the language of the regulation. Section 192.1 excepts offshore gathering to the point where produced hydrocarbons are first separated, dehydrated, or otherwise processed. Separation and dehydration occur both at the Tyonek platform and the Kenai plant. At the platform the gas is sent through separators to remove free water, and then either sent through suction scrubbers, compressors and air fin exchangers to the glycol dehydration system or through production scrubbers to the glycol dehydration system. Thus, the first separation and dehydration occur at the platform. No distinction is made in the regulation between separation and dehydration done for removal of free water and dew point control purposes from separation

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[3] Respondent also referred to training materials supporting its contention. Respondent submitted training materials used by the Transportation Safety Institute as part of its curriculum. These materials state that dehydration is not considered to be part of gas processing. These materials refer to the four-point test OPS has used to determine where onshore gathering ends. These materials do not refer to offshore gathering. They also state that a determination is made on a case-by-case basis.

and dehydration done for other purposes, such as improving the quality of the gas for commercial reasons. Therefore, based on the language used in the regulation, the offshore gathering ends at the Tyonek platform because this is where the gas first undergoes, inter alia, separation and dehydration.

Primary Function [4]

Respondent contended that the primary function of the system is to gather gas. Other than dehydration, Respondent argued that no significant activity occurs on the platform that would indicate a transportation function rather than a gathering function. Respondent explained that when considering the factors that the primary function test relies on (diameter and length, extension beyond the central point in the field, geographical configuration, location of compressors and processing plants, and location of wells), the lines at issue are consistent with gathering.

OPS maintained that the pipeline system's primary function is the transmission of saleable gas from the Tyonek platform gathering system to a storage facility, the Kenai LNG manufacturing facility, for ultimate export overseas. As support, OPS explained that the pipeline operates over 20% of SMYS, and that Respondent previously had the ability to deliver marketable natural gas to end users other than the LNG facility.[5] OPS further maintained that the extension of the facility beyond a central point in the field and the system's geographical configuration support its contention that the pipeline system's primary function is transmission.

Although OPS has considered using the primary function test to determine the end of gathering when produced gas does not move through processing plants or change custody downstream, OPS has not adopted this test. In any event, this test would not be determinative of whether Respondent's system is either gathering or transmission. Neither Respondent nor OPS demonstrated that the diameter (10 3/4-inch and 16-inch) and length (13 miles offshore and 31 miles onshore) of the lines are typical of either gathering or transmission. As for the geographical configuration of the lines, they can be viewed as delivering gas from a production facility to a manufacturing facility (gathering) or as transporting gas from a gathering facility to a storage facility (transmission). And the location of the compressors at the platform is not conclusive because the compression, as Respondent argued, is performed incidental to gathering or, as OPS argued, is part of processing. Therefore, I cannot conclude from these factors whether the primary function is gathering or transmission.

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[4] Primary function is a test FERC uses. It is a determinative procedure based on several indicia FERC has found common to gathering - pipe diameter and length, location of compressors and processing plants, extension of the facility beyond the central point in the field, location of wells along the facility and geographical configuration. OPS has not adopted the primary function test.

[5] As discussed at the hearing, Respondent now sells all the gas to Japan.

Operational differences

Respondent further argued that OPS must consider the differences between onshore and offshore pipelines in determining the status of the lines. Respondent maintained that to require an offshore gathering line to be connected directly to an offshore gas well for it to be considered a gathering line ignores the operational and functional differences between offshore and onshore operations. Respondent encouraged OPS to follow the Congressional mandate in how OPS defines gathering lines.

When Congress re-authorized the pipeline safety program in 1992, it said OPS was to consider the functional and operational characteristics of the line when defining gathering but was not required to follow the FERC classification. (49 U.S.C. 60101(b)). In 1999, OPS discussed this mandate when it opened an electronic discussion forum to seek suggestions on how to best define gas gathering. OPS continues its development of a definition.

OPS does not disagree that there can be operational differences between onshore and offshore gathering. However, there is no definition yet that takes into account such differences. Based on the language in §192.1, offshore gathering ends where the first separation or dehydration of produced hydrocarbons occurs. This occurs at the Tyonek platform.

Onshore line - Rural Gathering?

The allegations of violation did not apply to the onshore segment of the pipeline system. However, what occurs at the plant is relevant to Respondent's argument about where the gathering system ends. If the gathering process ends at the platform, not at the plant, this onshore line would be a transmission line.

Respondent maintained that the 16-inch pipeline, from Moose Point to the plant, except for 14,375 feet, is a rural gathering line. Respondent explained that other than some segments that traverse Class 1 or Class 2 areas, the line does not pass by populated or commercial areas.[6]

Respondent asserted that the Kenai plant, which produces LNG by means of a cryogenic process, is where the gas processing activities occur for preparing the gas for delivery. Respondent explained that the plant consists of a liquefied natural gas liquefaction plant, along with storage and LNG ocean tanker loading facilities. Respondent maintained that except for the dehydration that occurs at the platform for water dew point control purposes, all activities for conditioning, processing and preparing the gas for delivery to customers are located at the plant. Respondent explained that the gas delivered to the plant is routed to an amine treater for removal of carbon dioxide and hydrogen sulfide, to a dehydrator gas scrubber, to a dehydrator for removal of water vapor, and then enters a carbon filter for removal of mercury gas, and dry gas filters for removal

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[6] OPS does not contest that, except for certain portions, the line runs along non-populated areas.

of carbon dust. Respondent said that after these activities, the liquefaction manufacturing process starts, and the LNG is then piped directly from the storage tanks to LNG ocean tankers for transportation to and sale in Japan.

The treatment or processing of the gas at the plant that Respondent described (removal of carbon dioxide, scrubbing, dehydration, filtering) is in addition to the separation, compression and dehydration done at the platform. Other gas delivered to the plant (from Marathon) is also subject to these same processes. Whatever the reason for what is done to the gas before the LNG liquefaction takes place - preparing the gas for delivery or additional preparation for the LNG manufacturing - these activities occur after the first separation and dehydration that occur at the platform.

Previous Enforcement Action

Respondent contended that the 1980 final order issued in a previous pipeline enforcement action regarding these same lines (CPF 5017) found Respondent's argument sufficient to rebut the assertion that the lines were regulated, and dismissed the action.

In that action, the Materials Transportation Bureau[7] found that its Office of Operations and Enforcement had not met its burden of proving that the lines were regulated. The Bureau did not determine whether the lines were subject to the pipeline safety regulations, but dismissed the allegations of violation because the burden of proof had not been met.

Transmission

If the offshore gathering ends at the platform where the first compression, scrubbing, and dehydration occurs, then the lines would have to satisfy the definition of a transmission pipeline. When the Notice in this case was issued, a transmission line was defined, in relevant part, as a pipeline that -

> transports gas from a gathering line or storage facility to a distribution center or storage facility; or
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> operates at a hoop stress of 20% or more of SMYS.[8]

Respondent's pipeline system satisfies either of these definitions. The parallel offshore lines transport gas from the Tyonek platform gathering system to Moose Point, where the gas enters an

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[7] The Materials Transportation Bureau was the predecessor agency to OPS.

[8] The changes made to the definition in 1996 (61 Fed. Reg. 28770)to reflect that a transmission line includes pipelines that connect large volume customers to gathering or transmission lines do not affect the outcome of this case.

onshore pipeline and is transported to the Kenai plant, where the gas undergoes liquefaction. The LNG that is produced is stored in tanks and piped to ocean tankers for transportation to Japan.

The system also operates at more than 20% of SMYS. The MAOP of the offshore parallel lines is 1636 psig. The pressure switches on the platform are set at 1400 psig, which is 37% of SMYS. The onshore segment from Moose Point to the Swanson River crossing operates at 1035 psig, or 72% of SMYS. The segment from Swanson River to the plant operates at 862 psig, or 60% SMYS.

Therefore, under either definition, the pipeline system at issue fits as a transmission pipeline system.

Conclusion

The decision in this case would be easier if OPS had a clear definition of a gathering line, particularly, with respect to what constitutes production and processing activities on an offshore line. Nonetheless, I have concluded that the gathering process ends at the Tyonek platform where the gas produced from the wells first goes through separators, scrubbers and compressors, and undergoes dehydration. Although further scrubbing and dehydration take place at the plant, the first series of actions occur at the platform.

Accordingly, I find that Respondent violated 49 C.F.R. §§ 192.465(a) and 192.481. Although not a consideration in my conclusion that the pipeline system is a transmission system, I want to note that this system poses safety risks - the offshore lines pose a risk to vessel traffic in Cook Inlet and the onshore line to the public where the line traverses populated areas.

COMPLIANCE ORDER

Notice 2 proposed a compliance order with respect to both of the alleged violations. As discussed in the previous section, Respondent disputed the allegations that the lines from the platform to the plant were regulated under Part 192. I found that the lines are regulated.

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of gas or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is hereby ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations.

With respect to the two parallel 10 3/4-inch lines that extend from the Tyonek platform to the east shore of Cook Inlet, at Moose Point, Respondent must -

1. Develop and implement procedures to carry out the requirements of 49 C.F.R. §192.465(a).

2. Develop and implement procedures to carry out the requirements of 49 C.F.R. §192.481.

3. Complete development of the written procedures within 60 days following receipt of a Final Order. Submit a copy of the completed procedures to the Western Regional Director, OPS.

4. Implement the procedures within 120 days after developing the procedures.

5. Upon request and good cause shown, the Regional Director may grant an extension of time to complete any of the required items.

AMENDMENT

Notice 1(CPF No. 56301-M) alleged that two of Respondent's procedures used in operation of its LNG facility were inadequate, and proposed that Respondent amend these procedures. In its Response dated April 3, 1996, Respondent did not dispute the allegations concerning the inadequacy of procedures concerning site security and drug retesting of positive test results. Therefore, in accordance with 49 C.F.R. §190. 237, I find that the procedures, as described in Notice 1, were inadequate. However, because Respondent submitted revised procedures that the Region reviewed and found adequate, no further action is needed.

Under 49 C.F.R. § 190.215, Respondent has a right to petition for reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The terms of the Order, including any required corrective action, remain in full effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective upon receipt.

Failure to comply with this Final Order may result in the assessment of civil penalties of up to $25,000 per violation per day, or in the referral of the case for judicial enforcement.

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Stacey Gerard
Associate Administrator
for Pipeline Safety

Date Issued