Panhandle Energy

Panhandle Eastern Pipe Line
Trunkline Gas
Trunkline LNG
Sea Robin Pipeline
Florida Gas Transmission

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January 31, 2008

Department of the Interior
Regulations and Standards Branch (RSB)
Minerals Management Service
381 Elden Street, MS-4024
Herndon, VA. 20170-4817

RE: **RIN 1010-AD11**
Pipelines and Pipeline Rights-of-way

Please find attached the comments regarding the proposed rewrite of Subpart J in 30 CFR250 the Department of the Interior (DOI), submitted by Trunkline Gas Company, LLC and Sea Robin Pipeline Company, LLC operating collectively under the Panhandle Energy (PE) name, and operating 966 miles of offshore pipelines.

PE is responding to the Department of the Interior's (DOI's) request for comments. Comments and recommendations are enclosed.

If you have any questions or require any additional information, please contact me at 713-989-7471.

Sincerely,

Jerry Rau
Director of Pipeline Integrity

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Introduction

Trunkline Gas Company, LLC and Sea Robin Pipeline Company, LLC, operating collectively under the Panhandle Energy (PE) name, operate an extensive interstate natural gas transmission system, of which 966 miles are offshore. This pipeline system receives natural gas from the major production areas of the Gulf Coast for transportation and sale in the Upper Midwest of the United States. The operation of this pipeline system is subject to the requirements of Title 49 Code of Federal Regulation Parts 190, 191, 192, 193, and 199 and Title 30 Code of Federal Regulations Part 250, Subpart J, regarding Pipeline Rights-of-Way.

DOI requested Comments (General)

A. Panhandle Energy's (PE's) Request for Extension(s) of Time to Comment to DOI and OMB, submitted October 24, 2007 and January 11, 2008.

PE previously submitted a request for an extension of time in order to prepare comments per the notice at Volume 72, No. 191 FR 56442, which was received by both the Office of Management and Budget (OMB) and Regulations and Standards Branch (RSB) of DOI on October 24, 2007. At that time, PE pointed out that this Rulemaking is significant and that the Administrative Burden has been underestimated. PE further pointed out that it would take longer than the November 2 deadline to prepare complete comments. PE requested that the deadline for comments to OMB be extended from November 2, 2007 to the same as that for the rule comments to DOI, January 31, 2008.

PE has extensively reviewed the proposed rulemaking and has found various confusing and conflicting proposals. It is PE's understanding that MMS has agreed to a Workshop that may address or clarify some of the issues that PE has raised in this document.

Although PE has requested both an extension to comment to OMB and an extension to comment on the proposed language, PE has seen No Notice of a time extension. In order to meet the abbreviated deadline for comments, PE offers the following comments, which PE believes to still be compelling although not as complete as PE would have preferred. If the comment period is extended, then PE will provide additional comments.

B. Regulation Applicability – Proposed Regulation application to DOI jurisdictional pipelines, but wording implying ALL pipelines

Immediately following the Definitions in §250.1000, §250.1002, 1003, 1004 and 1005 establish the jurisdiction as follows (emphasis added):

§250.1002 What are the types of OCS pipelines?

An OCS pipeline is either a lease term pipeline or an ROW pipeline.

§250.1003 Which departments have jurisdiction over OCS pipelines?

An OCS pipeline is under the jurisdiction of **either** the Department of the Interior (DOI) **or** the Department of Transportation (DOT).

§250.1004 What are the criteria for determining jurisdiction?

(a) ***DOI jurisdiction criteria.*** An OCS pipeline is under DOI jurisdiction if it is:
(1) A lease term pipeline that is not subject to regulation under 49 CFR, parts 192 and 195, and does not cross into State waters; or

(2) An ROW pipeline that is operated by an identified pipeline operator (the person or entity identified by the pipeline ROW holder as authorized to control or manage the pipeline's operations), and that is either:

(i) A producing pipeline operator (the identified pipeline operator of an ROW pipeline that is a lessee or designated lease operator of one or more OCS leases), unless it is subject to regulation under 49 CFR, parts 192 and 195, and crosses into State waters; or
(ii) A transporting pipeline operator (the identified pipeline operator of an ROW pipeline that is not a lessee or a designated lease operator of an OCS lease), and the pipeline is not subject to regulation under 49 CFR, parts 192 and 195.

(b) ***DOT jurisdiction criteria.*** An OCS pipeline that is not under DOI jurisdiction (see paragraph (a) of this section) is under DOT jurisdiction.

(c) ***Jurisdiction transfer.*** You may request that a pipeline under DOI jurisdiction be transferred to DOT jurisdiction, or that a pipeline under DOT jurisdiction be transferred to DOI jurisdiction, by submitting a written petition for approval to the Regional Supervisor and the DOT Office of Pipeline Safety (OPS) Regional Director. In the petition, you must provide sufficient justification for the transfer. The Regional Supervisor and the DOT OPS Regional Director will decide jointly whether to approve the petition.

250.1005 What are the requirements regarding jurisdiction transfer points?

(a) ***Jurisdiction transfer point.*** For each applicable pipeline, you must meet the requirements of this paragraph (a).
(1) You must identify the specific point at which regulatory jurisdiction transfers from

DOI to DOT, or from DOT to DOI, by:
(i) Durably marking an above-water jurisdiction transfer point or, if that is not practical, identifying the transfer point on a schematic; or
(ii) Identifying an underwater jurisdiction transfer point on a schematic.
(2) You must keep the schematics referenced in paragraph (a)(1) of this section at the nearest OCS facility and make them available to MMS upon request.

(b) ***Jurisdiction transfer point disagreement.*** If the lessee(s), designated lease operator(s), or pipeline ROW holder(s) of connecting pipelines cannot agree upon a transfer point, the Regional Supervisor and the DOT OPS Regional Director will jointly determine the jurisdiction transfer point.

This shows a clear delineation between DOI and DOT jurisdiction, with DOI jurisdiction extending to only those pipelines not subject to 49 CFR Parts 192 or 195.

However, the next section of the proposed rule, §250.1006, appears to contradict this clear separation of jurisdiction by beginning with the phrase "For **all** OCS pipelines . . ."(emphasis added). It states:

250.1006 When must I submit the applications, requests, plans and reports, and make the notifications required by this subpart?
(a) Applications and requests. For **all** OCS pipelines you must submit applications to MMS, and receive approvals, according to the following table:

The table includes items, timing, number of copies, and section of Part 250 that contains the details of the requirements.

The intent of this wording is not clear; it may be easily construed as conflicting with or contradicting the jurisdictional split in the previous sections. If the intent is that §250.1006 and following sections apply to OCS pipelines under DOI jurisdiction, that could be easily clarified by modifying §250.1006(a) above to read:

(a) ***Applications and requests.*** **For all OCS pipelines under DOI jurisdiction you must submit applications to MMS, and receive approvals, according to the following table:**

DOI requested Comments on the Proposed Rulemaking (If DOI contends that this rulemaking is applicable to all pipelines, not just those under DOI jurisdiction)

Analysis has been made to determine the MMS requirements for natural gas pipeline transporters according to the MMS Subpart J Notice of Proposed Rulemaking (NPRM), if DOI contends that these regulations apply to DOT regulated pipelines. The NPRM requirements are extensive and reach far beyond the current Subpart J requirements for both DOT and DOI pipelines. PE's comments focus only on those requirements that would have a "major impact" on the natural gas transmission (transporters) industry if it were required to comply with the NPRM as currently proposed. Major changes are defined as requiring a significant increase in an operator's:

1) work hours or staffing in order to be in compliance or,
2) either O&M or capital dollars expended to be in compliance or,
3) administrative monitoring and reporting to be in compliance.

Analysis of the NPRM reveals several points:

1) PE believes that MMS is infringing on the current regulatory jurisdiction of PHMSA and drastically expanding the jurisdiction of DOI,
2) MMS is requiring extensive record keeping and mandatory reporting,
3) MMS is being more restrictive on required reporting time-lines and design life criteria than either they or DOT currently require,
4) MMS is blurring the distinction between DOT and DOI jurisdictional lines (it should be noted that the design, construction, operation, and maintenance of natural gas transmission pipelines are subject to DOT regulations as outlined in the current laws, regulations, and MOU of both the DOI and the DOT) ,
5) MMS is incorporating previous NTL's (Notice To Leaseholders) into the NPRM (and in some cases MMS is expanding the requirements beyond their existing NTLs. For example, NTL T-186 was released in August 2007 for comments and it has been both expanded and included in the NPRM),
6) MMS is giving broad and unilateral discretionary authority to the Regional Supervisor, with little or no due process.

Beyond the major impacts that are identified in these comments, other "concerns" with the NPRM are also identified. These other concerns will clearly have an impact on the gas transmission industry if it has to comply with the NPRM requirements as proposed, but they are not as onerous as the major impacts. Therefore, they are listed as concerns. It should be pointed out that there are many other "minor" concerns with NPRM that are not identified in this report. These minor concerns are around issues like vague language, broad and confusing language, certain mandated reports, and generally accelerated notification and reporting time frames. These comments are not addressed in this document, but these concerns shall be addressed also, if the comment period is extended.

DOI's Omission of a Cost/Benefit Analysis

Other than the paperwork burden DOI has omitted any analysis of the cost to industry vs. the perceived benefit. In previously submitted comments to OMB and DOI, PE has illustrated just a few of the costs that were omitted by DOI in the Proposed Rulemaking. DOI has not presented any Benefit other than the consolidation, with no stated and certainly no quantified benefit of improved protection of the OCS.

DOI's contention that this is not a significant Rulemaking (Regulatory Flexibility and Cost/Benefit Analysis)

The reference to all pipelines in the Regulatory Flexibility Act paragraph raises the question about the intended scope of the proposed rule:

> *The Department certifies that this proposed rule would not have a significant economic effect on a substantial number of small entities under the RFA (5 U.S.C. 601 et seq.). A regulatory flexibility analysis is not required.*
> *This proposed rule applies to all lessees, designated lease operators, and pipeline ROW holders on the OCS*
>
> Lessees/operators are classified under the Small Business Administration's North American Industry Classification System (NAICS) code 211111, Crude Petroleum and Natural Gas Extraction. Under this NAICS code, companies with fewer than 500 employees are considered small businesses. ***MMS*** estimates that 130 lessees/operators explore for and produce oil and gas on the OCS. Approximately 70 percent of them (91 companies) fall into the small business category1.

Generally the most clear description of jurisdiction should be set forth in the opening section (s) of a new rule, i.e., an Applicability or a Scope Section, which is what 49 CFR Part 192 and 195

1 Fed Reg. Vol. 72 No. 191, October 3, 2007.

have done. Whether DOI considered this approach remains unknown. It could be DOI did not use a scope section because they consider some parts of Part 250 to be applicable to DOT pipelines such as ROW applications. Therefore, blanket exclusion could not be placed in an applicability or scope section. PE believes that it is imperative, particularly for a sweeping rule changes such as this one, to clearly define the scope and applicability at the beginning. Otherwise, multiple interpretations are likely, leading to varying degrees of compliance and ensuing enforcement actions, all of which could be avoided by adequate clarity.

Further, PE believes that DOI has incorrectly deemed this rulemaking as not significant. The requirements of this rule will shift the economics associated with the production of certain smaller wells to make them unprofitable to continue operation at their current levels. Costs will include the cost of modification of platforms to accommodate extended launchers and receivers for integrity management required ILI inspections. Additional expenditures will be required to modify existing pipelines to accommodate inspection pigs. Increased expenditures for the disposal of contaminated water from integrity management program-required hydrostatic tests. The unprofitable nature of these small production wells will cause them to be shut in reducing the overall production from the Gulf of Mexico. Any reduction in production will result in an incremental increase in the cost of gas or oil to the consumer. Only a 1.5 cent per barrel increase in the price of a barrel of oil will result in an incremental $100 million increase in the price of oil to oil consumers, based upon the 6.6 billion barrels of oil annual usage by the United States. Less than a 0.5 cent increase in the price of natural gas for a million cubic feet of gas would be required to meet the $100 million criteria. Since both oil and gas Producers are affected, increases smaller than these will result in the $100 million consumer impact.

Further, as part of the Proposed Rule, DOI is requiring an Operator Qualification Program and an Integrity Management Program, as well as a written Operations & Maintenance Manual and Emergency Manual. On October 27, 1998, the Research and Special Programs Administration (RSPA) which was the predecessor of the Pipeline and Hazardous Material Safety Administration (PHMSA) of the Department of Transportation (DOT), proposed an Operator Qualification Rule that was considered to be a significant regulatory action (Volume 63, No. 207, Page 57276). On January 28, 2003, RSPA proposed an Integrity Management Rule that was considered to be a significant regulatory action (Volume 68, No. 18, Pages 4308 & 4309). DOI proposes this rule with not only the requirements for both Operator Qualification and Integrity Management Programs, but also the additional requirements for written Operations and Maintenance and Emergency Manuals and believes that it is not a significant rulemaking.

PE believes that the rulemaking is significant and subject to review under Executive Order 12866. PE also believes that since the majority of lower margin production, which would become unprofitable to maintain is operated by small entities as defined in the Regulatory Flexibility Act, a regulatory flexibility analysis should be done.

Non-Technical– Purpose, Use & Authority

Currently ROW pipelines are subject to Regulation by the DOT for design, construction, operations and maintenance. Lease holder pipelines are operated under the jurisdiction of DOI for these same areas.

The new regulations, as proposed, eliminate the boundary for jurisdiction as previously agreed to in a Memorandum of understanding dated December 10, 1996.

DOT rules are tailored to transportation facilities, while MMS rules have been tailored to production facilities. Production facilities are much more complicated in their design and operation, which deserves more prescriptive oversight. DOT facilities fundamentally operate offshore the same as onshore and don't require a separate, more stringent set of rules. DOT-jurisdictional offshore facilities have historically performed very well from a safety standpoint without the need or justification for new regulations.

The proposed rule appears to violate the terms of the DOI/DOT MOU. The MOU was designed to accomplish the primary goals of establishing a jurisdictional boundary and avoiding duplicative regulations. The proposed rule is counter to both of these goals. It also indicates the MOU was designed with the flexibility to allow the new authority in the proposed rule. This also seems counter to the clear language of the MOU.

The Department of Interior is expressly prohibited from affecting the authority provided by Law to the Secretary of Transportation with respect to Pipeline Safety by 43 USC 1347(d) and is charged with consulting with other departments to prevent inconsistent or duplicate requirements in 43 USC 1347(f).

The intent of NTLs is to provide interpretation and clarification of MMS rules as they are applicable to the appropriate identified constituency. MMS has used the NTLs as a tool to impose inapplicable regulations on DOT operators. The majority of transportation operators have never accepted MMS published NTLs that pertain to activities that conflict with the MOU, except for those that are considered useful guidance. However, MMS has misrepresented the

NTLs in the NPRM as recognized and accepted practices that operators already agree with. MMS has misrepresented published NTLs regarding the applicability of NTLs that overlap with DOT requirements by indicating they apply to all lease term and right of way holders. This practice has gone unchecked because MMS does not apply formal penalties to operators who do not comply. MMS does have O&M jurisdiction over the right of way holders (typically producers who happen to operate ROW pipelines in addition to production lines) who have chosen to be under MMS as allowed under the MOU. They have used this explanation when NTLs have been challenged by operators.. DOT has never challenged the NTLs that clearly intend to extend authority beyond statutory or agreed-upon limits.

D. Apparent Authority of the Regional Supervisor – Timely recourse to due process

The Regional Supervisor carries great authority in much of the proposed rulemaking. The myriad of approval and reporting requirements offers the opportunity for the system to become bogged down, delaying projects, which costs both time and money due to the delays.

For adverse issues or orders, the only recourse would seem to be that allowed under §30 CFR 290 Appeal Procedures. Specifically, pay a $125.00 Fee and appeal within the 60 day time limit to the Interior Board of Land Appeals (IBLA), with a concurrent informal resolution with the Regional Supervisor's superior, which is a more burdensome and formal approach than that used by PHMSA. Because of the myriad of approval and reporting requirements, there may be numerous opportunities for operators to use the appeals process.

PHMSA dedicates Part 190 of Title 49 Code of Federal Regulations (CFR) to Pipeline Safety Programs and Rulemaking Procedures. Specifically, §49 CFR 190.209 Response Options; §190.211 Hearing; and §190.215 Petitions for reconsideration allow for informal judicial review of adverse findings.

E. DNV standard

Det Norske Veritas (DNV), headquartered in Oslo, Norway, is an international consulting firm. DNV writes standards and recommended practices (RP), which reflect the practices of DNV. DNV is not a voluntary consensus standard body and RP's written by DNV are not technical standards that are developed and adopted by voluntary consensus standards bodies. Incorporating DNV RP B401 would seem to violate certain provisions of the National Technology Transfer and Advancement Act of 1995. Voluntary consensus standards bodies would be Organizations such as the American Petroleum Institute (API), National Association of Corrosion Engineers (NACE), American Society of Mechanical Engineers (ASME), etc.

Congress, through the National Technology Transfer and Advancement Act of 1995, signed into law on March 7, 1996, stated clearly that the Executive Branch of the federal government should transition from a developer of internal standards to a customer of external standards. However, Section 12 of this law, titled "Standards Conformity", states, in part that "...all Federal agencies and departments shall use technical standards that are developed and adopted by voluntary consensus standards bodies, using such technical standards as a means to carry out policies objectives or activities determined by the agencies and departments."

F. Definitions

DOI has added numerous definitions with confusing or contradictory meaning. For example DOI defines "Leak" as a release of product, which would seem to include venting, purging and operator initiated blow downs. This is completely different than industry thinking, where leaks are unintended releases of product. PE suggests that DOI use Definitions from consensus Industry Standards to promote common understanding.

Pipeline Design (250.1031 – 250.1036)

A. Other Concerns

1) Design Life Definition

There are several requirements in the NPRM where the MMS is requiring the design life of a particular system (e.g. anode system) to have a life expectancy of X years or for the design life of the pipeline, whichever is longer. Many systems, such as anodes, are designed for a finite life such as 20 years. However, natural gas pipelines are not designed to have a finite life. DOT Part 192 does not have a design formula or methodology for determining a "design life" on a pipeline. The life expectancy of a pipeline is determined by a number of factors including original design, ongoing maintenance, operating conditions, etc.

As to the "design life" for offshore gas transportation lines, there is not any single factor or formula for determining the design life of a pipeline. DOT Part 192 specifies a formula that determines the minimum pipe wall thickness given certain other factors (i.e. yield strength of the pipe, operating pressure, OD, temp, etc.) but there is no "age factor" in the formula. The overall design, maintenance, operating conditions, certain external factors and the application of the pipeline determine how long it will last. In theory, a steel pipeline that is properly designed, operated, and maintained and is transporting good quality gas can last for many decades.

As an example on the design side, the type and thickness of external and internal coatings, the cathodic protection (i.e. mass of anodes), the wall thickness above minimum requirements, protection from external forces, etc. are all factors that would extend the life of a pipeline. Maintenance such as ongoing testing of the efficiency of anodes and timely replacement to ensure adequate protection, painting of piping exposed to the environment, all serve to extend the life of the pipeline. Both design and maintenance tend to protect the pipeline "from the outside".

The application in which the pipeline is placed determines its life "from the inside." If a pipeline is used to move or exposed to particular substances with corrosive properties, then internal coatings (type, thickness, quality), chemical inhibitors (type, frequency, efficacy) and pigging type (scraper, poly pig) and frequency all have an impact on its life. A pipeline operated near its maximum pressure for extended periods will have endured more stress than one operated at lower pressures and may be a candidate for stress related failures.

If these regulations pass as proposed, then the design life of each pipeline would very likely have to be determined in order to comply. This would be a very costly endeavor to *attempt* to calculate the design life given the lack of a "design life formula," and any attempts to determine such design life would likely require very extensive testing (i.e. – determine the remaining wall thickness). With the various factors that could be used, any such analysis could be very highly subjective since a myriad of factors come into play such as: what products will flow through this line?; for how long?; what is the corrosivity?; will there be any low spots that *might* hold water?; how long would water be held?; what chemicals will be injected and what is their efficacy?; how often will be line be pigged?; and what is the efficiency of the pigging?

There are tens of thousands of miles of offshore pipelines that have been in place for decades very reliably delivering their products. These pipelines are routinely maintained and prove that pipelines can work effectively for long periods of time without having been designed for a finite life expectancy.

As mentioned earlier, the NRPM states in 250.1033 (d) that a company must design its anode cathodic protection (CP) system to have a life expectancy of 30 years (versus 20 currently) or for the design life of the pipeline, which is longer. Platforms would typically have a design life longer than 30 years and it may not make sense to design the CP system for the life of the platform. The CP system can be monitored, repaired, replaced or upgraded as necessary to ensure it is working effectively. Also, technology improvements may make a current CP system out-dated, and it can be upgraded as necessary. Therefore, it is not practical or economic to design a CP system beyond 20, or possibly 30 years.

Pipeline Construction (250.1040 – 250.1051)

Pipeline Design in the NPRM contains all the MMS requirements in the current rule, plus it has added several new requirements. Most of the changes involve required notifications prior to construction, delineating the horizontal component and its protection requirements, riser protection, and specific construction requirements in or near designated use areas, sensitive biological features or areas, and near an archaeological resource. Transportation pipelines should not have to maintain the original depth of cover unless the pipeline can be reasonably determined to present a hazard to people, the environment or other OCS activities. The operator's justification must rely on industry accepted risk based principles and DOT based performance requirements (i.e. 192.613 and 192.703(b)).

B. Major Impacts

1. Burial of pipelines (250.1044) (d) Other protective measures

The NPRM states that the Regional Supervisor may require the burial or other protection of the pipeline in any water depth if the Regional Supervisor determines that such measures will reduce the likelihood of environmental degradation, or mitigate a potential hazard to trawling operations of other uses of the OCS, but no guidance or objective criteria for this determination are indicated. This requirement could result in the Regional Supervisory unilaterally requiring companies to bury miles of pipelines at significant costs.

C. Other Concerns

1. Buoying hazards (250.1042) (a)

The NPRM requires that before beginning construction operations or other bottom disturbing activities in areas congested with pipelines or debris, use buoys to outline a safe working area. It requires a company to buoy all existing pipelines and other potential hazards located within 500 feet of the operation, including anchor patterns. In lieu of using buoys, a company can use state-of-the art, real-time primary navigational positioning equipment to depict pipelines and other potential hazards. The concern with the requirement for buoying is one of jurisdiction. Currently, the USCG is responsible for buoying requirements.

2. H_2S contingency planning (250.1050)

The NPRM requires a company to prepare an H_2S Contingency Plan before it constructs a pipeline (using an anchor-supported construction vessel) that crosses a pipeline which transports a product with an H_2S concentration that if released could result in atmospheric concentrations of 20 ppm or more. It would be an administrative burden for pipelines to contact each pipeline it crosses during construction to ascertain whether or not they transport H_2S and if it were released to the atmosphere would it exceed the 20 ppm threshold. It would be simpler and more effective if the MMS would ask each pipeline that currently transports H_2S where an atmospheric release could exceed the threshold to identify those specific pipelines to the MMS. A database of those pipelines could be maintained by MMS and accessed by companies before construction proceeds to determine if any pipeline being crossed would require a contingency plan to be developed.

MMS could require companies to update their H_2S pipelines annually to make sure their database remains current. MMS could capture this data for new pipelines that are being constructed as part of the construction permitting process. Information on these pipelines could be captured and entered into a pipeline database, which could lead to a one-call system, enhancing damage prevention.

Pipeline Pressure Testing (250.1057 – 250.1061)

A. General Comments

The requirements of the NPRM are similar to the current requirements other than some wording changes and more detailed time periods for certain tests. The NPRM does set out new pressure test requirements after using a clamp for a repair which is a commonly used repair technique today.

B. Major Impacts

1. Hydrostatic pressure test after making a repair with a clamp (250.1060) (b)

The NPRM requires that before a company can return a pipeline to service following a repair using either a mechanical or welded clamp it must successfully perform one of two leak tests. Typically, a welded clamp repair will be used above water and a mechanical clamp repair used below water. The latter repair requires a leak-test of the pipeline, including the riser or risers, or if required by the Regional Supervisor an 8-hour hydrostatic pressure test of the pipeline, including the riser or risers. In most cases, isolating the riser or risers where the clamp has to placed in order to perform a hydrostatic pressure test is extremely difficult and not practical. For the former, it is often difficult to isolate the section where the clamp was placed and, in many cases, would result in pressure testing miles of pipeline in order to pressure test the welded clamp. Additionally, DOT doesn't require the pressure testing of pipelines or risers repaired with clamps. Using clamps for repairs is a routine and common practice today in order to expedite repairs and minimize service impacts. This NPRM requirement would have a significant cost impact to the industry. Pipeline repair requirements are adequately covered by DOT regulations.

2. Taking a pipeline out of service (250.1086)

The NPRM defines out of service as "a pipeline that has not been used to transport oil, natural gas, sulphur, or produced water for more than 30 consecutive days. The out of service period begins on the 31st day of inactivity." This is almost the same language in the current MMS requirements. On the 31st day on inactivity, the NPRM requires a company to immediately equip the out-of-service pipeline with either a blind flange or block valve locked in the closed position at each end. After a year but less than 3 years, a company must flush and fill the pipeline with inhibited seawater and after 5 years the pipeline has to be decommissioned.

However, the current language related to out-of-service pipelines is targeted to pipelines under the jurisdiction of DOI and the required actions are only for DOI pipelines. The NPRM makes no distinction between DOI or DOT pipelines, implying that pipelines currently under DOT jurisdiction would be required to follow this NPRM requirement. It is not unusual for natural gas pipelines to temporarily have lines that aren't flowing or that have been temporarily taken out of service. The NPRM makes no distinction between an abandoned line and an out-of-service line. The NPRM appears also to go beyond the recent (August 2007) NTL concerning pipeline decommissioning.

Transportation pipeline abandonment and deactivation requirements are adequately covered by DOT regulations. Under DOT regulations, a pipeline is not considered abandoned, unused or "out of service" if it is periodically transporting gas or being actively maintained with reasonable anticipation of future use.

C. Other Concerns

1. MAOP definition (250.1000) and MAOP requirements (several sections including 250.1058 and 250.1060 (a) (2)).

MMS defines MAOP as the highest operating pressure allowable at any point in a pipeline. This is different than the DOT definition, which creates inconsistency in addition to jurisdiction concerns. It appears that MMS equates MAOP with MOP; the two are clearly different. MOP is not mentioned in DOT Part 192 but is an accepted industry term basically meaning the maximum pressure at which an interconnected system of pipelines can be operated based on the pipeline with the lowest MAOP of all pipelines in they system. When interconnected pipelines have different MAOPs, the system operating pressure is limited by the pipeline with the lowest MAOP, which is the system MOP. The MOP is always less than or equal to the MAOP.

Pipeline Leak Detection (250.1071)

A. General Comments

This is a short section in the NPRM and in the current requirements specifically is targeted at only oil pipelines. The NPRM expands leak detection to any "pipeline that transports liquid hydrocarbons to shore." Many of the gas transportation pipelines are wet or two-phase systems that transport some liquid hydrocarbons. Depending on certain operating conditions, dry systems can have liquid hydrocarbons fall out of the gas stream.

B. Major Impacts

Those natural gas pipelines that do transport liquid hydrocarbons to shore would be significantly impacted by this section. Those pipelines would be required to use a computational pipeline monitoring (CPM) system or equivalent methodology to detect leaks by continuously determining or calculating the imbalance between the incoming (receipt) and outgoing (delivery) volumes of a pipeline. A CPM system means an algorithmic monitoring tool that allows a company to respond to a pipeline operating anomaly that may indicate a release of hydrocarbons. The company must equip the CPM system with an alarm that signals when the imbalance exceeds a predetermined threshold for a selected time interval; and use SCADA technology to gather, process, and display the data the company uses in their CPM system.

The cost of installing such a system would be prohibitive. Additionally, gas transportation pipelines are not transporting liquid hydrocarbons as their primary product. Liquid hydrocarbons are sometimes found in the gas stream or may fall out of the gas stream during transportation due to temperature and pressure changes. Consequently, it is difficult to determine the incoming (receipt) and outgoing (delivery) volumes of such a pipeline. SCADA-based CPM systems are generally accepted as useful on liquid-only systems, but not on those that transport gas.

It is clear that the primary intention of this section is for oil pipelines and not gas transportation pipelines and the NPRM should be revised accordingly.

C. Other Concerns

None

Pipeline Internal Corrosion and Flow Assurance (250.1074 – 250.1075)

A. General Comments

This is a new section and not found in the current requirements. It is a short section that requires companies to establish and implement internal corrosion control measures as well as establish and implement measures to ensure that adequate flow can be sustained throughout the service life of the pipeline under all expected flow conditions.

B. Internal corrosion control measures (250.1075)

The NPRM requires a company to establish and implement internal control measures (e.g. running pipeline scrapers; dehydrating; using corrosion inhibitors, bactericides, or oxygen scavengers) to protect the pipeline over its service life. This would imply these measures are required whether or not a corrosive environment is present. This is much broader than current DOT requirements and would be costly to implement and maintain such a program on all pipelines. A corrosion control program is a good idea when a corrosive environment is present. Most operators have developed cost-effective programs of their own, as part of their maintenance procedures to effectively mitigate internal corrosion of offshore pipelines. Corrosion control requirements are adequately covered by DOT regulations.

C. Other Concerns

1. Low flow from producer lines

The NPRM requires a company to ensure that adequate flow can be sustained throughout the service life of the pipeline under all expected flow conditions and for the range of pressures. There are many pipelines where over the years the production is largely depleted and little gas flows through the lines. The flows and pressures are often too low to run pigs and the producers, who control the flow, usually don't want to de-commission the line. Flow control and others issues that affect the integrity of a transportation pipeline are covered by DOT regulations.

Pipeline Safety Equipment (250.1062 – 250.1069)

A. General Comments

Safety related equipment is addressed to a large degree in the current requirements as applicable to DOI pipelines. The NPRM has more detailed language regarding safety equipment and includes some new items like manned platforms, maximum source pressure, etc. The NPRM defines safety related equipment as:

a. pressure safety high and low sensors
b. flow safety valves
c. subsea tie-in block valves
d. shut down valves
e. surface safety valves
f. pipeline pumps (mentions API requirements; should apply only to oil pipelines)

This section will continue to primarily affect producers more than transporters. Most OCS natural gas transmission facilities have a limited number of safety devices. Those tend to be flow safety valves (e.g. check valves), subsea tie-in block valves and shut down valves. Most of these devices are relatively simple and don't have high failure rates.

It should be noted that there are a number of safety related device requirements in the Operations and Maintenance requirements sections. Gas transportation pipeline safety equipment requirements are adequately covered by DOT regulations.

B. Major Impact

None

C. Other Concerns

1. Suspending operations (250.1069)

The NPRM states that if safety equipment fails, the operator must immediately suspend operations and shut-in the pipeline. The current requirements do not call for immediately shutting-in the pipeline. Shutting-in the pipeline would normally be done to possibly prevent a product release or to make the necessary repair. However, the NPRM also calls for notifying the Regional Supervisor if the safety repairs will result in the pipeline being out-of-service for more than two hours. Also, if you shut-in the pipeline due to the safety equipment being out-of-service for more than two hours, you must submit a detailed repair application and receive approval from the Regional Supervisor before any repair work can begin. This requirement seems overly burdensome, unnecessary and could result in unwarranted delays in getting a pipeline back into service. Operations, maintenance, and emergency response requirements for gas transportation pipelines are adequately covered by DOT regulations.

Pipeline Operations and Maintenance (250.1078 – 250.1091)

A. General Comments

This section of the NPRM is expanded significantly beyond the current requirements. Among the more significant changes, MMS is requiring an expansion of the O&M manual, an integrity management program, emergency operating plans, operator qualification programs, H_2S contingency plans, and pipeline safety equipment testing. It appears MMS is adopting some of the DOT requirements, like integrity management, but from a totally difference perspective.

B. Major Impacts

1. Maintaining approved burial depth throughout the life of the pipeline, including after it is decommissioned. (250.1078) (d)

This is not a requirement or practice today. A company faces significant challenges in maintaining the approved burial depth of many pipelines throughout the life of the pipelines. This would require a company that discovers that any of its pipelines aren't at the approved depth to rebury the pipeline immediately. For example, if a pipeline was approved to be at a three foot depth and it's now at a 2.5 foot depth, it would have to be reburied. Complying with this requirement would be impractical, time consuming and very costly and unnecessary.

As pointed out earlier in the construction section, gas transportation pipelines should not have to maintain the original depth of cover unless the pipeline can be reasonably determined to present a hazard to people, the environment or other OCS activities. The operator's justification must rely on industry accepted risk based principles and DOT based performance requirements (i.e. 192.613 and 192.703(b)).

2. Operation and Maintenance Manual, Emergency Plan and Personnel Qualification Program (250.1079) (a, c &d)

The proposed rule requires operators to develop and implement a written Personnel Qualification Program, Operations & Maintenance Manual and Emergency Plan. DOI has not provided sufficient clarity for what is required for these manuals.

PE also has concern about the written manuals requirement that DOI has stipulated. PE currently has these manuals available electronically on their internal web site, with an electronic management of change notification process. This was implemented to make sure that the latest changes are immediately available to the field locations. If paper copies of specific procedures are needed, personnel have the ability to make a copy of the latest approved electronic procedure.

3. Integrity Management Program (250.1079) (b)

The NPRM calls for all OCS Pipelines to have a written pipeline integrity management plan that includes numerous components such as pigging all pipelines. Today, the DOT IMP requires that only HCA's fall under an integrity management plan. The DOT integrity management program is logically targeted at protecting the general public in HCAs where the risks and consequences are the greatest. An offshore integrity management program serves no such public safety concern (beyond any offshore HCAs) and would be impractical with little or no perceived benefit in terms of safety or efficiency.

PE also has concern about the written Integrity Management Plan requirement that DOI has stipulated. PE currently has all aspects of its Integrity Management Program only available electronically on a separate server. All data integration, updates and compliance functions are maintained electronically. This was implemented to make sure that the latest changes are immediately available to the field locations. If paper copies of the Plan and data are needed, PE can not assure that the latest information is available.

4. Evacuating personnel from an OCS platform due to an impending storm or other emergency (250.1083)

In this situation, the NPRM requires the operator to shut-in any connecting pipeline unless there is remote operations capability. Furthermore, the operator can conduct remote operations on the pipeline during an evacuation only if the Regional Supervisor has given the operator prior approval, the operator has remote monitoring and shut-in capability, and the company's circuitry has local storm timers designed to shut-in a pipeline no more than 4 hours after the capability to monitor and control a process is lost, and this circuitry must be included in the SCADA logic. Also, it is not clear whether this approval is given on a continuing basis or must be given for each impending storm.

When evacuating their platforms, natural gas pipeline companies rarely shut-in connecting pipelines. The decision to shut-in production or flow is made by the producer. Furthermore, most natural gas pipelines don't have full remote shut-in capability which, under the NPRM, would require them to shut-in the pipelines. Shutting in the pipelines, depending on the number of platforms evacuated, could have an enormous impact of the deliverability coming out of the Gulf. Adding remote monitoring and shut-in capability that is integrated into a company's SCADA system would be very costly.

Emergency response and preparedness is already required by DOT regulations. Offshore gas transportation operators have well tested hurricane evacuation plans and other site specific contingency plans as required by the DOT.

5. Pipeline safety equipment testing requirements (250.1084)

The NPRM requires testing of safety related equipment monthly or annually, depending on the safety device. For example, check valves are not inspected today, but would have to be inspected annually, not to exceed 13 months (note DOT is typically 15 months). Similarly, shut-down valves must be inspected monthly and fully-closed annually. Conducting these inspections is impractical and would have significant manpower impacts on the operators with no added safety benefits. Inspection and maintenance requirements are adequately covered by DOT regulations.

6. MMS suspension or prohibiting pipeline operations (250.1091)

The NPRM give the Regional Supervisor unilateral authority to suspend or temporarily prohibit any pipeline operations if the Supervisor determines that continued activity would threaten or result in serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, mineral resources; or the marine, coastal or human environment. Also, if the Regional Supervisor determines a company has failed to comply with a provision of the OCSLA or any other applicable law, a provision of this part or other applicable regulations, or a condition of a pipeline application approval or of a pipeline ROW grant; or protecting the nation's security, the Regional Supervisor can suspend or temporarily prohibit any pipeline operations. There appears to be no warning, fines, etc. or any type of an appeal process as seen with the DOT. The judgment of safety and operations of DOT pipeline activities is covered under the Pipeline Safety Act and not the OCLSA. Response to spills from transportation pipelines is subject to OCSLA and MMS authority under 30 CFR 254. Again here, there is concern about the operator's lack of access to due process or timely recourse and the lack of guidance or objective criteria for making these determinations.

Pipeline Modifications and Repair (250.1093 – 10.97)

A. General Comments

Similar to the other sections of the NPRM, this section has added some wording changes and reporting requirements. The definition of what comprises a modification has been expanded to include installing or replacing a pig receiving/launching facility; changing a pipeline riser configuration; changing the MAOP; replacing or adding anodes; and adding a hot-tap.

B. Major Impacts

The proposed rule would require an application to the Regional Supervisor for approval to make a permanent repair when a mechanical clamp is used to temporarily repair a riser in or above the splash zone. Operators would be required within 30 calendar days after they install the mechanical clamp to complete the permanent repair using a welded clamp, spool piece, or other method approved by the Regional Supervisor. DOT does not require this today and at times the use of a mechanical clamp is an accepted practice to expedite a repair or maintain deliverability.

C. Other Concerns

1. To commence and complete a repair (250.1095)

The NPRM requires a company to submit an application to the Regional Supervisor for approval before any modifications or repair work on a pipeline can commence. Today, under the current requirements the Regional Supervisor may require a detailed repair procedure be submitted prior to conducting the work. Currently a company must notify the Regional Supervisor before the repair of the pipeline or as soon as practicable along with a detailed report of the repairs within 30 days after completion of the work. The NPRM requires an even more detailed repair application that has to be submitted at the same time as the notification to the Regional Supervisor.

The Regional Supervisor may also require the company to submit a work plan that describes specific measures it intends to take, and the specific procedures it intends to follow, to ensure the safety of offshore workers and to prevent pollution. The Regional Supervisor may also require a company to analyze a pipeline failure, and examine samples of a failed pipe or associated equipment in a laboratory to determine the cause of the failure. When so directed the company must submit a comprehensive written report of its findings to the Regional Supervisor.

Additionally, the Regional Supervisor may require a company to submit a corrective action plan for approval, if there are internal or external conditions that could detrimentally affect a pipeline. Having to get approval from and submit a detailed application to the Regional Supervisor before any repair work can commence will impede a company's ability to quickly restore service thereby affecting deliverability and reliability.

It should be noted as the MMS rules are currently written, the repairs would be reportable under 1008(e) if it involves a right-of-way modification, so there is a situation where a repair is now reportable to MMS. Section 1009(c)(1) states: "Department of Interior pipelines, as defined in 250.1001, must meet the requirements in 250.1000 through 250.1008."

Today, sections 1000 through 1008 specifically apply to DOI pipelines as defined in 1000 (c) (1). Section 1009 (a) requires DOT operators to comply with the **applicable** sections of 1000 – 1008, which are sections relating to right-of-way approval and modification, or sections of 1009 – 1019 that cross reference 1000 – 1008. The NPRM goes well beyond the current requirements for repairs

Pipeline Surveying, monitoring, and inspecting a pipeline (250.1100 – 250.1103)

A. General Comments

The NPRM takes a current requirement for DOI pipelines to inspect its pipelines monthly for leakages and applies it to all pipelines. It also requires time based inspections on other pipeline components.

B. Major Impacts

1. Pipeline route surveys (250.1101)

The NPRM says a company must conduct a visual survey of each of its pipeline routes at least monthly (or at a frequency specified by the Regional Supervisor) for indication of pipeline leaks. Currently, natural gas pipelines patrol their offshore lines annually for leaks. A monthly requirement would have an enormous manpower and cost impact on companies. Helicopters and boats in the OCS are constantly checking for leaks as they go about their normal daily activities and offshore leaks are easily detected by bubbles on the surface. Offshore natural gas leaks do not constitute a hazard sufficient to require patrolling monthly for leaks. Pipeline patrols and leak surveys are adequately covered under DOT regulations.

C. Other Concerns

None

Pipeline Decommissioning (250.1105 – 250.1113)

A. General Comments

The NPRM is revised to include some new requirements and wording changes. It provides some positive new options for companies for protecting the ends of a cut pipeline with sandbags provided the seafloor slope has a rise to run of 1:3. There are some new requirements for the use of concrete mats as cover. As seen throughout the NPRM, there are some additional record keeping and reporting requirements.

B. Major Impacts

None

C. Other Concerns

None

Pipeline Right-of-Way (ROW) Grants Category (250.1115 – 250.1138)

250.1115 What is a pipeline ROW grant?
250.1116 When must I obtain a pipeline grant?
250.1117 Who can be a pipeline ROW grant holder?
250.1118 What are the financial security requirements for holding a pipeline ROW grant?
250.1119 When will MMS terminate the period of liability of my financial security?
250.1120 When will MMS cancel my financial security?
250.1121 What happens if my financial security is reduced or lapses?
250.1122 How will MMS determine that my financial security is forfeited?
250.1123 What penalties can MMS assess if my financial security is not sufficient, is reduced or lapses, or is forfeited?
250.1124 What happens to my financial security after a pipeline ROW grant terminates?
250.1125 How do I submit an application for a pipeline ROW grant?
250.1126 What information must I include in an application for a pipeline ROW grant?
250.1127 How does MMS process an application for a pipeline ROW grant?
250.1128 When will MMS temporarily suspend or prohibit construction of an ROW pipeline?
250.1129 What must I do if the as-built location of the associated ROW pipeline deviates from the approved pipeline ROW grant?
250.1130 What rental fees and payment schedules apply to a pipeline ROW grant?
250.1131 What are the terms and conditions for holding a pipeline ROW grant?
250.1132 How do I modify a pipeline ROW grant?
250.1133 How does temporary cessation and cessation of pipeline operations affect a pipeline ROW grants?
250.1134 How do I assign a pipeline ROW grant?
250.1135 When may MMS suspend a pipeline ROW grant?
250.1136 How do I relinquish a pipeline ROW grant?
250.1137 When will a pipeline ROW grant be cancelled, be forfeited, or expire?
250.1138 What must I do after a pipeline ROW grant terminates?

A. General Comments

This category covers the terms and conditions for holding a pipeline ROW grant, including when a grant is needed, who may hold a grant, and how to apply for a grant. It also covers: bonding, application submittal, MMS review, compliance, environmental review, state consistency review, modifications, and cessation of operations, assigning a grant, suspensions, relinquishing a grant, and terminating a grant.

Because of certain administrative similarities between pipeline ROW grants and OCS leases, many of the proposed changes are based on or derived from the regulations in 30 CFR 256, which addresses OCS leasing. Each separate ROW pipeline requires a separate ROW grant. The proposed financial security requirements are more detailed than in the current regulations. Currently, pipeline companies must furnish an area bond in the amount of $300,000 to hold pipeline ROW grants in an MMS OCS region. The proposed rule would allow a pipeline ROW holder the option of choosing to cover the pipeline ROW with either a $300,000 pipeline ROW grant individual bond or a $1,000,000 pipeline ROW grant bond. The $1,000,000 area bond will cover all pipeline ROW grants held by a company in one MMS OCS region.

These requirements represent an increase from the current bonding amount, and will more accurately reflect the actual liabilities in decommissioning pipelines. The new proposed amounts would apply to all existing and future grants. Companies would be required to cover existing pipeline ROW grants by these increased amounts within 6 months after the rule becomes effective.

The Regional Director may also require additional security based on an evaluation of a company's ability to carry out present and future financial obligations under the pipeline ROW grant. Companies have the opportunity to provide MMS with written or oral arguments during the evaluation. These securities are required primarily to ensure that the U.S. Government has sufficient funds available to properly decommission a pipeline in the event that the pipeline company is unable or unwilling to do so. The proposed rule includes language giving MMS the ability to reduce the amount required by a bond, to deal with lapse in bonds, and to determine bond forfeiture.

The service fee for a pipeline ROW grant would remain unchanged. The proposed rule addresses pipeline ROW grant assignments. The conditions for when MMS would suspend a ROW grant are spelled out more clearly.

The MMS is proposing to increase the annual rental fees for pipeline ROW grants to reflect the current rates established for new rights-of-use and easement (see 30 CFR 250.160(f) and (g) and pipeline accessory structures (see 30 CFR 250.1012(b). The amount established by these regulations are $5.00 per acre per year for sites in water depths less than 200 meters and $7.50 per acre per year for sites in water depths 200 meters or greater. The current rental rate for pipeline ROW grants is $15 per mile. A pipeline ROW is 200 feet wide. Therefore the area of a pipeline ROW grant is 24.24 acres per mile. At $5.00 per acre, the rental rate would be approximately $125 per mile (actually $121.20).

Since raising the rental for pipeline ROW grants to $125 per mile from $15 per mile is a major increase, MMS is proposing to raise the rental in two steps. This proposed rule would increase the annual rental for pipeline ROW grants to $70 per mile. MMS will propose the second increase to $125 per mile in a future rule making. Although this is a large increase, MMS believes the higher fee is a fair and reasonable amount to pay for access to Federal lands.

The terms and conditions for holding a pipeline ROW grant remain unchanged with respect to the OCS Lands Act provisions requiring ROW pipelines to transport oil and natural gas produced in the vicinity of the pipeline without discrimination, and to provide open access. The proposed rule 250.1131(j) would make compliance with the Executive Order 11246, regarding non-discrimination in employment, a condition for holding a pipeline ROW grant. Therefore, the requirement (currently 250.1015(d)) for pipeline ROW grant applicants to include the "Non-discrimination in Employment" form (YN 3341-1) with their applications is eliminated.

This category also covers relinquishing a pipeline ROW grant. It addresses the application requirements, rental payments, delinquent payments, the effective date of relinquishment, and financial securities. Proposed 250.1137 covers cancellation, forfeiture, and expiration of pipeline ROW grants. One of the grounds for forfeiture in this proposed rule (250.1137(b)(2)) concerns open and nondiscriminatory access to shippers. The MMS recently published in the Federal Register a proposed rule (72 CFR 17047, April 6, 2007) which would establish 30 CFR, part 291, Open and Nondiscriminatory Movement of Oil and Gas as Required by the Outer Continental Shelf Lands Act. Part 291 will be referenced in this regulation when it (part 291) becomes final.

The proposed rule covers the obligations of the pipeline ROW holder after a pipeline ROW grant is terminated for any reason. The pipeline ROW holder has 1 year after the grant terminates to decommission the associated ROW pipeline. Current regulations require that the company remove the pipeline. However, the proposed rule allows for ROW pipelines to be decommissioned in place if the Regional Supervisor approves. The proposed rule also provides requirements for re-commissioning of decommissioned pipelines.