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An Audit Report on

Pipeline Safety at the Railroad Commission

November 2011

Report No. 12-005

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Overall Conclusion

The Railroad Commission (Commission) performed standard pipeline safety inspections substantially in compliance with federal and state requirements. Each year, the Commission formulates a risk-based pipeline inspection work plan that prioritizes pipeline systems for inspection. Its inspection procedures were comprehensive and detailed. The Commission also cited violations and assessed penalties in accordance with Texas Administrative Code requirements.

The Commission has opportunities to strengthen its Pipeline Safety and Damage Prevention programs in four primary areas:

- Increasing the number of inspections of pipeline systems ranked as the highest priority.
- Increasing the accuracy and completeness of its annual pipeline inspection work plan and ensuring that it conducts required reviews of pipeline operators' integrity management plans.
- Consistently following its procedures for closing pipeline damage incidents and ensuring that investigations are completed before an incident is closed.
- Strengthening certain information technology controls, including addressing significant weaknesses in its Pipeline Evaluation System (PES).

Increasing Inspections of High-priority Systems

The Commission should increase the number of inspections it performs of the pipeline systems ranked as the highest priority for inspections. The Commission inspected only 65 percent of the pipeline systems ranked as highest priority in its 2010 annual pipeline inspection work plan.

Background Information

The Railroad Commission's (Commission) Pipeline Safety Division has offices in seven regions in Texas (see Appendix 7). It operates the Pipeline Safety and Damage Prevention programs.

Pipeline Safety Program - The Pipeline Safety Program regulates the safety of intrastate natural gas pipelines and hazardous liquid pipelines in Texas. The Commission's Pipeline Safety Program is certified by the U.S. Department of Transportation for the enforcement of federal pipeline safety regulations for intrastate pipeline facilities.

Damage Prevention Program - In 2005, the Texas Legislature gave the Commission compliance and enforcement authority, beginning September 1, 2007, over the movement of earth near pipelines. The Commission's Damage Prevention Program enforces the rules in Title 16, Texas Administrative Code, Chapter 18 (Underground Pipeline Damage Prevention). Those rules include safety standards and best practices for both excavators and pipeline operators.

Pipeline Safety Inspections - A standard Commission pipeline inspection includes reviewing pipeline operators' records and documentation on selected pipeline systems for compliance with federal and state pipeline safety regulations. An inspector may also select several items from an operator's records, such as the operating pressure on a pipeline, to verify in the field.

In addition, the Commission should improve the accuracy and completeness of its annual pipeline inspection work plan to ensure that the work plan accurately prioritizes all pipeline systems for inspection. Auditors identified errors and omissions in the annual pipeline inspection work plans reviewed. While those errors and omissions were isolated to certain processes or types of pipelines, they could result in the Commission not inspecting some pipelines. It is important to note, however, that this risk is mitigated by federal and state pipeline safety regulations that require pipeline operators to inspect and monitor all of their own systems.

Conducting Required Reviews of Integrity Management Plans

The Commission should comply with the Texas Administrative Code and review the required number of integrity management plans that pipeline operators prepare. An integrity management plan is a pipeline operator's overall approach to protecting its pipeline system from leaks and ruptures. Federal regulations require pipeline operators to provide assurance of safe pipeline operation in populated areas.

Following Damage Prevention Procedures

The Commission complied with federal requirements to establish a pipeline Damage Prevention Program. From September 2007 through April 2011, the Commission received 37,122 pipeline damage incident reports and cited 11,527 violations. It assessed \$4,242,958 in total penalties and collected \$3,420,133.

The Commission should consistently follow its procedures for closing pipeline damage incidents that are reported through its online reporting system, the Texas Damage Reporting Form (TDRF). In January 2010, the Commission closed a backlog of incident reports without completing an investigation to determine the cause of the incident, as required by its procedures. Because the Commission did not retain sufficient documentation, auditors could not determine how many of the 13,649 total incidents the Commission closed in 2010 were closed without a complete investigation.

Strengthening Controls Over Information Systems

The Commission should ensure that the data in PES is complete, accurate, and reliable. The Commission relies on PES to track pipeline systems and inspection information and to produce the key reports used to prioritize inspections and to plan and manage the Pipeline Safety Program. However, weaknesses related to pipeline jurisdictional status determination, data entry controls, pipeline coding, and coding language within the system limits the accuracy, completeness, and reliability of the data in PES and the Commission's annual pipeline inspection work plan reports. In addition, the Commission did not ensure that the data it migrated from its former systems to PES was complete and accurate. As a result of weaknesses in PES and the lack of other documentation, auditors concluded that the data in PES was not sufficiently reliable for the purposes of this audit.

The data in TDRF was sufficiently reliable for the purposes of this audit. However, the Commission should strengthen edit checks over the data in incident damage reports that pipeline operators upload into TDRF. In addition, the Commission should implement a secondary review process to verify that its staff enter into TDRF all the information needed to substantiate the Commission's decisions related to incident reports.

The Commission also should strengthen certain general controls to protect its automated systems, applications, and data. The weaknesses in application and general controls that auditors identified increase the risk of unauthorized access to the Commission's automated systems and unauthorized disclosure, modification, and/or destruction of data.

Auditors communicated less significant issues to Commission management separately in writing.

Summary of Management's Response

Commission management agreed with 13 of the 20 recommendations in this report. Commission management did not agree with recommendations related to performing surprise inspections on new pipeline construction projects, developing a risk-based schedule for integrity management reviews and inspections, and communicating pipeline damage incidents not caused by excavation to its Pipeline Safety Division. The Commission also disagreed with the auditors' determination that it did not follow its damage prevention procedures. The information in the Commission's management responses did not cause the State Auditor's Office to modify the issues or recommendations in this report.

The Commission's detailed management responses are presented immediately following each set of recommendations in the Detailed Results section of this report.

Summary of Objective, Scope, and Methodology

The objective of this audit was to determine whether the Commission adheres to state and federal law and agency policies and procedures in administering the Pipeline Safety Program and the Damage Prevention Program.

The scope of this audit covered January 1, 2009, through March 31, 2011, and included the Pipeline Safety Program and the Damage Prevention Program administered by the Commission. The scope also included the automated systems and processes in those areas.

The audit methodology included collecting information and documentation from the Commission; reviewing policies and procedures, statutes, and rules related to pipeline safety and damage prevention; and analyzing and evaluating data and the

results of tests. Specifically, auditors reviewed pipeline inspections and incident investigations, incident damage reports, pipeline permit documentation, waiver documentation, inspector training documents, annual certification reports and evaluations, program fee reports, and annual pipeline inspection work plan reports. Auditors also visited three regional areas in Austin, Houston, and Fort Worth to observe pipeline inspections.

Auditors also assessed the reliability of the data in the automated systems supporting the Commission's Pipeline Safety and Damage Prevention programs. As a result of weaknesses in PES and the lack of other documentation, auditors were not able to determine compliance with certain policies and procedures related to the Pipeline Safety Program. To the extent possible, auditors considered the data limitations when designing analytical and testing procedures.

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Detailed Results

Chapter 1

The Commission Substantially Complied with State and Federal Requirements for Pipeline Inspections; However, It Should Strengthen Certain Areas of Its Pipeline Safety Program

Intrastate Pipeline Systems in the Commission's Jurisdiction

The Commission is responsible for inspecting and monitoring:

- 2,162 gas distribution systems with 103,750 miles of pipelines.
- 2,891 gas transmission systems with 34,794 miles of pipelines.
- 1,342 hazardous liquid transmission systems with 27,485 miles of pipelines.
- 928 master meter systems with 452 miles of pipelines.

Basic Types of Pipelines

- **Gathering Line** - A pipeline that gathers gas or crude oil from the well or production location and moves it to a storage or processing facility. The gas or crude oil then goes into a transmission line.
- **Transmission Line** - A pipeline transporting gas or liquid from a gathering line or storage facility to a distribution center.
- **Distribution Line** - A pipeline serving both as a common source of supply and associated branch lines serving consumers. Distribution lines are the source of supply for residential and small commercial users.
- **Master Meter System** - A natural gas pipeline system for distributing natural gas for within, but not limited to, a distinct area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source.

Products transported by pipelines include natural gas, crude oil, condensates, gasoline, diesel fuel, hydrogen, methane, and liquefied petroleum gas.

The Railroad Commission (Commission) substantially complied with federal and state pipeline safety requirements regarding inspections. Each year, the Commission formulates a risk-based pipeline inspection work plan that prioritizes pipeline systems for inspection. The Commission conducted 2,646 inspections in calendar year 2010. Specifically, the Commission:

- Conducted comprehensive inspections.
- Ensured that pipeline inspectors were trained in accordance with federal requirements.
- Assessed violations and penalties that were consistent with Texas Administrative Code requirements.
- Issued permits for transferred pipeline systems according to the Commission's policies and procedures.

However, the Commission should increase the number of inspections of priority 1 gas and hazardous liquid pipeline systems. Priority 1 pipeline systems are systems that the Commission's risk assessment methodology ranks as the highest priority for inspections in the Commission's annual pipeline inspection work plan.

In addition, the Commission should strengthen its (1) preparation and compilation of its annual pipeline inspection work plan and other reports and (2) reviews and inspections of pipeline operators' pipeline integrity management plans.

Funding

The Commission was appropriated \$6,700,545 in fiscal year 2010 and \$6,476,231 in fiscal year 2011 in General Revenue for its Pipeline Safety Program and its Liquefied Petroleum/Compressed Natural Gas/Liquid Natural Gas Safety Program. This includes the annual pipeline inspection fees and federal fund allocations discussed below.

The Commission collects an annual pipeline inspection fee through natural gas distribution pipeline operators from end use customers and from master meter operators to cover its costs for administering the Pipeline Safety Program. The Commission does not have the statutory authority to assess or collect inspection fees from transmission or gathering pipeline operators. The Commission is required to deposit the fees it collects into the General Revenue Fund to be used for the Pipeline Safety Program, the Commission's Geographic Information System, and the Liquefied Petroleum Gas Safety Program. The Commission reported that it collected the following fees:

- Calendar year 2009: The Commission collected \$3,329,563 from distribution pipeline operators and \$70,400 from master meter operators, for a total of \$3,399,963.
- Calendar year 2010: The Commission collected \$3,343,757 from distribution pipeline operators and \$68,300 from master meter operators, for a total of \$3,412,057.

The Commission's Pipeline Safety Program also was allocated \$2,525,405 in calendar year 2009 and \$3,773,956 in calendar year 2010 in federal Pipeline Safety Grant funding from the U.S. Department of Transportation to reimburse costs related to the Commission's Pipeline Safety Program.

The 81st Legislature authorized 13.5 additional full-time equivalent positions for the Commission's Pipeline Safety Division for the 2010-2011 biennium; the Pipeline Safety Division had a total of 26 inspector positions as of March 2011. In addition to the 26 inspector positions, the Pipeline Safety Division has 4 supervisory employees who also perform inspections.

The Commission Performed Pipeline Safety Inspections Substantially in Accordance with State and Federal Requirements

Elements in Pipeline Inspections

During pipeline inspections, Commission inspectors conduct procedures to determine whether:

- Pipeline operators prepare reports as required by federal and state regulations on items such as maintenance and operation of pipeline systems.
- Pipeline operators' maintenance and operation plans are up to date.
- Pipeline operators maintain proper corrosion control on pipelines and components of those systems.
- Pipeline operators are patrolling and monitoring their pipelines.
- Emergency valves are tested.
- Leak repairs are tested and operators' records are in compliance with the Texas Administrative Code.
- Odorization levels for natural gas are in compliance with federal regulations.
- School gas pipe testing has been performed.
- Pipelines are operating within their maximum allowable operating pressure.
- Damage prevention and public safety awareness measures comply with federal and state requirements.
- Pipeline operator personnel are qualified to perform their job duties.
- Pipeline operators are conducting the required drug and alcohol testing on their employees.
- All incidents involving pipelines are properly reported by the pipeline operator.

The Commission's pipeline safety inspectors conducted complete and thorough inspections using an extensive inspection checklist that included the elements required to comply with federal and state regulations (see text box for examples of those elements). Auditors accompanied Commission inspectors on inspections of pipeline operators in the Houston, Fort Worth, and Austin regions. During those inspections, auditors observed Commission inspectors reviewing operators' records and performing field verifications on selected records to determine a pipeline operator's compliance with state and federal pipeline safety regulations.

In addition, auditors tested a sample of 55 standard inspections of gas and hazardous liquid pipelines and 5 inspections of master meter systems that the Commission conducted from January 2009 to March 2011 across all 7 of the Commission's regions (see Appendix 7 for a map of the regions). Auditors determined that:

- For 59 (98 percent) of 60 inspections, documentation showed that the inspector completed all required elements.
- For 53 (93 percent) of 57 inspections tested, documentation showed that the inspector verified that the pipeline operator had the required qualifications. This attribute did not apply to three inspections tested.
- For all 60 inspections tested, documentation showed that the inspector verified that the pipeline operator complied with federal and state drug and alcohol requirements.
- For all 60 inspections tested, the Commission sent inspection results to the operators for corrective action as needed.
- For 45 (75 percent) of 60 inspections tested, the inspectors had been rotated to prevent the same inspectors from inspecting the same operator on consecutive inspections. Auditors noted exceptions in all regions except Houston.
- For all 60 inspections tested, the Commission performed timely supervisory reviews of completed inspections to help ensure compliance with federal and state requirements.

- Of the 60 inspections tested, 19 had violations (see text box for examples of cited violations). In those 19 inspections, the Commission appropriately assessed violations. Additionally, the violations were consistent with Title 16, Texas Administrative Code, Section 8.135, and federal regulations that require the reporting of probable violations cited by state pipeline safety inspection agencies (see Chapter 1-B for additional information about the accuracy and reliability of the reported data). The Texas Administrative Code provides guidelines for typical penalties and the amounts to assess an operator. Commission inspectors cited 54 violations in 19 of the 60 inspections tested¹ for inspection completeness (see text box for descriptions of the general categories of violations cited in the inspections tested). Based on information from the Commission's Pipeline Evaluation System (PES), from January 1, 2009, through March 31, 2011, the Commission assessed a total of 5,739 pipeline safety violations against operators covering 228,110 miles of pipelines. PES is the primary application that the Commission uses to track pipeline systems (see Chapter 1-B and Chapter 3 for additional information about PES).

Examples of Cited Violations

Below is a list of the general categories of common safety violations the Commission cited in the inspections that auditors tested:

- Inadequate protection against corrosion on pipes, valves, or fittings.
- Operation and maintenance plans did not comply with requirements.
- Noncompliance with prescribed time intervals between patrols of transmission lines that cross highways and railroad crossings.
- Leak surveys were not conducted within the required time interval.

In addition, the Commission's pipeline inspectors received the federal training required to help ensure that they had knowledge of federal pipeline safety regulations. This training included courses in performing inspections of gas and liquid pipeline systems, corrosion control, welding inspection, operator qualifications, and pipeline failure investigations.

The Commission processed transfers of pipeline systems between operators in accordance with its policies and procedures and also accurately accounted for permit transfers of pipeline systems between operators. Pipeline systems are sometimes sold or leased by one operator to another. Whenever responsibility for operation of a pipeline changes, operators are required to submit transfer information to the Commission, which then issues a permit. Auditors tested 60 transfer permits and determined that (1) 59 (98 percent) transfers were properly completed and (2) 26 (96 percent) of the 27 applicable permits were accurately recorded and updated in PES.

The Commission should increase the number of priority 1 inspections.

During calendar year 2010, the Commission performed 846 inspections, or 65 percent of its planned priority 1 inspections, and 2,646 inspections, or 65

¹ An inspection can result in multiple violations being cited or no violations cited.

percent of its total planned pipeline system inspections. Priority 1 is the highest priority level for inspections and the Commission’s policy is to inspect those systems annually (see Chapter 1-B for additional information about how the Commission prioritizes pipeline systems in its annual pipeline inspection work plan).

Table 1 lists the percent of scheduled inspections that the Commission completed during calendar year 2010 for all three priority levels (see Chapter 1-B for additional information about the Commission’s annual pipeline inspection work plan).

Table 1

Pipeline Inspections That the Commission Completed Calendar Year 2010			
Inspection Priority	Number of Pipeline Systems Identified in the Work Plan	Number of Inspections Completed	Percent of Scheduled Inspections Completed
Priority 1	1,303	846	65%
Priority 2	1,902	1,238	65%
Priority 3	845	562	67%
Totals	4,050	2,646	65%

Source: Auditor analysis of the Commission’s annual pipeline inspection work plan reports for calendar year 2010 generated by the Commission’s Pipeline Evaluation System.

Within each work plan, the pipeline operators are listed in alphabetical order and are organized by unit and the systems within each unit. The units are normally geographic areas. The multiple pipeline systems in a unit can be ranked Priority 1, Priority 2, or Priority 3 by PES during the work plan generation process using the risk factors in PES. PES selects all of the systems ranked priority 1, 50 percent of the systems ranked priority 2, and 33 percent of the systems ranked priority 3. The Commission tries to inspect all systems in a unit; however, time and workload constraints may not allow all systems to be inspected. In calendar year 2010, 4,050 systems were scheduled for inspection on the Commission’s annual pipeline inspection work plan.

Inspecting groups of systems under operators within the same geographic location can result in fewer inspections of priority 1 pipeline systems. As shown in Table 1, the inspection rates for the priority 2 and 3 systems are comparable to the priority 1 systems.

Recommendation

The Commission should evaluate its pipeline inspection scheduling process to determine whether it is feasible to increase the number of priority 1 pipeline system inspections it conducts each year.

Management's Response

Management agrees to evaluate the pipeline inspection scheduling process to determine the feasibility of increasing the number of Priority 1 system inspections each year.

Chapter 1-B

The Commission Should Strengthen Its Processes Related to the Development of Its Annual Pipeline Inspection Work Plan and Other Reports

For its Pipeline Safety Program, the Commission uses PES to generate an annual pipeline inspection work plan, which is a prioritized list of which pipelines should be inspected during the year. The annual pipeline inspection work plan separates systems by type of line (gas distribution lines, gas transmission lines, hazardous liquid lines, and master meter systems).

In accordance with federal requirements, the Commission uses a risk-based methodology within PES to identify which pipeline systems to inspect each year. However, the Commission's methodology does not consider risk factors for internal and external events that affect pipeline operators, such as new construction and the operators' history of incidents and accidents. The Commission's risk-based methodology includes assigning each pipeline system a priority of 1, 2, or 3 (priority 1 is the highest priority for inspections). Factors that the risk analysis considers include:

- The location of a pipeline system, specifically whether it is near populated areas.
- The length of time since the most recent inspection.
- The history of previous violations cited against a pipeline system operator.
- The number of customers served by a pipeline system.
- A pipeline system's history of leaks.

However, the Commission should strengthen its processes for developing its annual pipeline inspection work plan in the following areas:

- The Commission should improve its review of data entered into PES and its ability to record the pipeline type to ensure that it accurately prioritizes all pipeline systems. Auditors identified errors and omissions in the Commission's annual pipeline inspection work plan that were caused by data entry errors or because PES offers an insufficient number of unique codes for identifying pipeline types.
- The Commission should correct errors in the PES computer coding used to generate reports that the Commission uses to manage its Pipeline Safety Program.
- The Commission should include new pipeline construction in the risk-based methodology used to develop its annual pipeline inspection work plan.

While the errors that auditors identified were isolated to certain processes or types of pipelines, they increase the risk that the Commission will not inspect some pipelines. Those errors are discussed in more detail below. It is important to note, however, that this risk is mitigated by federal and state pipeline safety regulations that require pipeline operators to inspect and monitor all of their own systems.

Inaccurate Data

The Commission issued 484 new pipeline permits between February 2009 and March 2011. Auditors tested a sample of those new permits and determined that:

- The Commission generally made a proper determination of jurisdictional status; however, it did not properly determine the jurisdictional status of 6 (10 percent) of 60 new pipeline permits tested. A pipeline system's jurisdictional status is the basis for establishing whether the Commission or the federal government is responsible for inspecting a pipeline.
- For the 40 permits tested for pipeline systems that were determined to be in the Commission's jurisdiction, the Commission did not enter 5 (13 percent) of those systems into PES because of errors that staff made during the manual process the Commission uses to enter new pipeline information into PES.

The Commission does not perform a review of staff's determination of jurisdictional status or of the pipeline permit data entered into PES, which increases the risk of errors and omissions. Incorrect determinations of jurisdiction and data entry errors could result in pipelines not being included on the Commission's annual pipeline inspection work plan.

Inadequate Pipeline Coding

The Commission assigns codes to pipeline systems in PES to identify (1) the pipeline type (such as gathering, transmission, distribution, or master meter system) and (2) the type of product being transported through the pipelines. PES includes 25 different codes that Commission staff can assign to each pipeline system. Auditors tested 30 pipeline systems coded in PES as gathering lines and determined that 20² (67 percent) of those 30 pipeline systems were actually crude oil transmission or production flow lines, according to the permitting and inspection documentation reviewed. This is significant because transmission lines have stringent regulations. Production flow lines are non-jurisdictional and gathering lines are generally not regulated unless they are located in a populated area or offshore. Incorrect coding could result in inappropriate prioritizations of those types of pipelines for inspection.

Incorrect Exclusion of Hazardous Liquid Pipeline Systems

Due to missing data in a table that PES uses to generate the annual pipeline inspection work plan, the Commission's 2011 hazardous liquid annual pipeline inspection work plan incorrectly excluded 69 hazardous liquid pipeline systems that were more than 10 inches in diameter, or about 8 percent of the total number of hazardous liquid systems that should have been included in the annual pipeline inspection work plan. After auditors brought this error to the Commission's attention, the Commission corrected the error and regenerated the 2011 hazardous liquid annual pipeline inspection work plan.

Incorrect Exclusion of Uninspected Pipeline Systems

Six pipeline systems classified as priority 1 for inspections in 2010 should have been carried forward to the Commission's 2011 annual pipeline inspection work plan because they were not inspected in 2010. However, those six pipeline systems were incorrectly excluded from the Commission's 2011 annual pipeline inspection work plan. Those six pipeline systems represented less than 0.15 percent of all pipeline systems in the Commission's 2010 annual pipeline inspection work plan. The Commission was unable to determine why those systems were excluded from its 2011 annual pipeline inspection work plan.

² Of the 20 incorrectly coded pipelines, auditors noted that 6 were abandoned pipelines and 3 were non-jurisdictional pipelines that do not receive pipeline safety inspections.

Inaccurate Annual Reports

Auditors noted discrepancies and errors in Pipeline Safety Program reports that PES generated. Those errors occurred because the coding used to generate the reports was incomplete or accessed duplicate records. As a

Reports Generated from PES

The Commission uses reports from PES to manage its Pipeline Safety Program. Those reports include:

- **Annual pipeline inspection work plan progress reports and status reports.** These reports list pipeline systems included on the annual pipeline inspection work plans for which an inspection has been completed.
- **Annual pipeline inspection work plan systems scheduled reports.** These reports show the number of pipeline systems included in the annual pipeline inspection work plans and the number of pipeline systems that were not included in the annual pipeline inspection work plans.
- **Hazardous liquid and natural gas certification reports.** The Commission submits these reports annually to the federal government.

result, the Commission's annual pipeline inspection work plan progress reports and status reports did not include accurate information on inspection activity for 2010 and 2011 (see text box for additional information about the reports that PES generates). The annual pipeline inspection work plan status reports are inaccurate due to omissions of inspections, and the annual pipeline inspection work plan progress reports are inaccurate due to PES counting canceled inspections in the total number of completed inspections.

The Commission submits annual reports on its inspection activities to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). Auditors reviewed the supporting information and documentation for selected portions of the reports the Commission submitted for calendar year 2010 and determined that (1) the summary of compliance actions reported for natural gas and hazardous liquid certification documents could not be verified and (2) the list of

incidents for the hazardous liquid documents did not include correct property damage amounts. The remaining certification documents reviewed in the reports appeared to be reasonable. Auditors could not determine the reasonableness of the summary of compliance actions reported for natural gas and hazardous liquid certification documents because coding errors in PES may have prevented the system from extracting all applicable records.

In addition, because of errors in the coding PES used to generate reports, the Commission lacks assurance that it included all pipeline systems in its annual pipeline inspection work plan scheduling reports. Inaccurate information in those reports could hinder the Commission's ability to monitor inspection activities.

New construction is not a component used to produce the annual pipeline inspection work plan.

New Construction Reports

The Commission received a total 1,486 new construction reports from 2005 through March 2011. Specifically, the Commission issued:

- 229 reports in 2005.
- 322 reports in 2006.
- 313 reports in 2007.
- 317 reports in 2008.
- 126 reports in 2009.
- 128 reports in 2010.
- 51 reports through March 2011.

The Commission does not include new pipeline permits and new construction as a component when it develops its annual pipeline inspection work plan (see text box for the number of new permits the Commission issued from 2005 through March 2011). The Commission typically does not inspect new construction unless there is a complaint or special investigation. However, PHMSA's *Guidelines for States Participating in the Pipeline Safety Program* requires the Commission to include inspections of new pipeline construction in its state inspection program. PHMSA recommends that state pipeline safety agencies at least perform periodic surprise inspections on new pipeline construction projects to determine whether pipeline operators are complying with detailed federal and state requirements for pipeline construction. There are significant risks common to new construction, including pipe coating damage, improper handling and installation of the new pipe, and improper welding of pipe joints.

Recommendations

The Commission should:

- Implement a review process for jurisdiction determinations and data entered into PES.
- Ensure that pipeline systems are appropriately coded in PES.
- Continue working to complete and correct the code in PES used to generate reports, conduct testing, and verify that all records are accurately extracted and reported for each calendar year.
- Comply with federal requirements to include new pipeline construction and history of incidents and accidents as components used to develop its annual pipeline inspection work plan.
- Consider conducting surprise inspections on new pipeline construction projects to determine whether operators are complying with federal and state requirements.

Management's Response

The Commission should implement a review process for jurisdiction determinations and data entered into PES.

Management disagrees that this review process is necessary or helpful. This recommendation appears to be the result of not understanding the difference

between the scope of the T-4 permit requirement and the scope of pipeline safety regulation. Other than gas distribution and master meter systems, every pipeline that leaves a lease of production must have a T-4 permit to operate a pipeline. However, not every pipeline that has a T-4 permit is subject to pipeline safety regulation (e.g., gathering lines in a Class 1 location). Conversely, not every pipeline system that is subject to pipeline safety regulation is required to have a T-4 permit (e.g., gas distribution and master meter systems). The T-4 permit section works from information supplied by the operator; that information cannot be verified until an inspector investigates or researches the system as part of an inspection. Merely confirming that information has been correctly transferred from the T-4 permit application into PES does not constitute a verification that the pipeline system is or is not jurisdictional to the pipeline safety program. The default classification for facilities is "jurisdictional," to ensure that all systems are included in the work plan data.

The Commission should ensure that pipeline systems are appropriately coded in PES.

Management disagrees that this is an issue. From the sample data used, it appears that there is disagreement with the classification of certain systems as "condensate gathering" which should have been classified as "crude transmission." However, because the work plan first identifies systems that are jurisdictional and then sorts based on specified risk factors, these systems have been inspected. Again, the default classification is "jurisdictional," and even if a system later becomes non-jurisdictional, the system history data remains in PES for future reference.

The Commission should continue working to complete and correct the code in PES used to generate reports, conduct testing, and verify that all records are accurately extracted and reported for each calendar year.

Management agrees that PES needs additional programming. Management has identified a number of refinements to the PES system that need to be made and is working with IT to engage programmers to implement these changes.

The Commission should comply with federal requirements to include new pipeline construction and history of incidents and accidents as components used to develop its annual pipeline inspection work plan.

Management agrees to endeavor to conduct more new construction inspections but does not agree that these can be included in the annual work plan. Including new construction inspections within the current work plan is not possible because that plan is generated using risk factors that are not associated with pipe that is not in service. New construction inspections are conducted as time and personnel availability permit, given the obligations to

conduct standard comprehensive inspections as well as special inspections for incidents and complaints.

The Commission should consider conducting surprise inspections on new pipeline construction projects to determine whether operators are complying with federal and state requirements.

Management disagrees with this recommendation. It is not feasible to conduct “surprise” inspections due to the need to coordinate site access with surface owners; however, it may be possible to conduct new construction inspections on shorter notice than would be typical for a standard inspection. Management plans to create a separate work plan for conducting new construction inspections.

The Commission Complied with the Federal Requirement to Establish an Integrity Management Plan Inspection Process; However, It Should Improve Its Compliance with Texas Administrative Code Requirements

Federal regulations require pipeline operators that have pipelines in high consequence areas (HCAs) to identify risks to their systems and develop

Integrity Management Plans

An integrity management plan is a pipeline operator's overall approach to protecting its system from leaks and ruptures. Federal regulations require operators to provide assurance of safe pipeline operation in locations where a pipeline failure might have significant adverse consequences. These locations are referred to as "high consequence areas," or HCAs. There are different specific requirements for operators of gas transmission systems, hazardous liquid transmission systems, and gas distribution systems. However, all integrity management plans must contain certain basic elements. Those elements include:

- Knowledge of the pipeline system.
- Identification of specific threats to the pipeline system.
- Evaluation and risk ranking of identified threats.
- Identification and implementation of measures to address the risks.
- Performance measurement, monitoring of results, and evaluation of effectiveness.
- Periodic evaluation of the system.
- Reporting results to PHMSA.

Additionally, Title 16, Texas Administrative Code, Section 8.101, prescribes specific requirements for operators of gas and hazardous liquid pipelines in Texas.

integrity management plans to mitigate those risks (see text box for additional information). An HCA includes populated areas, commercially navigable waterways, and environmentally sensitive areas. The Commission has established a process to review pipeline operators' integrity management plans and inspect pipeline operators' records in compliance with federal requirements. However, the Commission does not develop a work plan specific to integrity management plan inspections.

The Commission uses detailed inspection checklists based on state and federal requirements to inspect operators' integrity management plans. Those inspections are highly technical and comprehensive, and they require a significant expenditure of resources, both by Commission inspectors and the pipeline operator. Inspectors enter the results of those inspections into PES.

Auditors accompanied Commission inspectors on an integrity management plan inspection, which took one week to complete and involved two experienced inspectors and one inspection trainee, as well as four to six members of the operator's management staff. As of June 2011, the Commission had only two inspectors with the required experience and training to conduct integrity management plan inspections.

Title 16, Texas Administrative Code, Section 8.101, requires the Commission to obtain, review, and evaluate all integrity management plans from pipeline operators in Texas whose systems are subject to federal integrity management regulation.³ However, Commission management stated that inspectors review and evaluate the integrity management plans as time permits and that it had not reviewed and evaluated all submitted integrity management plans as required.

The Commission started receiving integrity management plans from pipeline operators in January 2006. Due to the large volume of integrity management

³ According to Section 8.101, hazardous liquids transmission pipeline operators must have completed all of their integrity management plans by January 2011. Operators of natural gas transmission pipelines must have completed 50 percent of their integrity management plans by December 17, 2007, and all integrity management plans by December 17, 2012.

plans submitted, the Commission is not current on its review of the integrity management plans; however, Commission inspectors review an operator's integrity management plan as part of an integrity management program inspection.

In addition, the Commission does not adequately track its reviews of the integrity management plans and inspections it performs. The Commission records integrity management plan inspections in the same spreadsheet that it uses to track the pipeline systems subject to integrity management plan requirements. However, it does not regularly update that spreadsheet. As a result, that spreadsheet did not contain complete information on the reviews performed or list all the inspections that the Commission had performed.

Federal regulations require the Commission to report the results of its integrity management plan inspections into a federal database. However, the Commission has not entered any results into that database since December 2007.

Distribution Integrity Management Program

Title 16, Texas Administrative Code, Section 8.209, required operators of gas distribution and master meter systems to implement a distribution integrity management program by August 1, 2011. The Commission is responsible for reviewing and inspecting those programs. Monitoring the distribution integrity management programs of gas distribution and master meter systems is important because, from January 2009 through March 2011, major incidents involving gas distribution pipelines in Texas occurred at almost four times the rate of incidents involving transmission and gathering pipelines. Of the 44 major incidents from that time period that auditors reviewed:

- Thirty-five involved distribution lines.
- Four involved transmission lines.
- Five involved gathering lines.

In May 2011, the Commission sent seven of its inspectors through the distribution integrity management program training offered by PHMSA. According to the Commission, it plans to develop a risk-based process using PES to identify and select operators and systems for which it will inspect integrity management plans and distribution integrity management programs.

Recommendations

The Commission should:

- Review and evaluate the integrity management plans that pipeline operators submit as required by Title 16, Texas Administrative Code, Section 8.101.
- Develop a risk-based schedule for its inspections of pipeline operators' integrity management plans and distribution integrity management programs.
- Train more inspectors to perform integrity management plans reviews and inspections.
- Enter completed integrity management plan inspections into the federal database in compliance with federal requirements.
- Assess how it will review and evaluate pipeline operators' distribution integrity management programs as required by Title 16, Texas Administrative Code, Section 8.209.

Management's Response

The Commission should review and evaluate the integrity management plans that pipeline operators submit as required by Title 16, Texas Administrative Code, Section 8.101.

Management agrees that integrity management plans submitted by operators should be reviewed and evaluated.

The Commission should develop a risk-based schedule for its inspections of pipeline operators' integrity management plans and distribution integrity management programs.

Management disagrees that it is feasible to develop a separate risk-based schedule for conducting integrity management inspections. Creating a separate risk-based work plans for IM inspections to be worked along with the standard inspections each year compromises the ability to prioritize all inspections. These IM reviews have been conducted concurrently with standard comprehensive inspections, to allow limited staff to work more efficiently.

The Commission should train more inspectors to perform integrity management plans reviews and inspections.

Management agrees and is already providing training to additional inspectors to be able to conduct more IM reviews.

The Commission should enter completed integrity management plan inspections into the federal database in compliance with federal requirements.

Management agrees and is training an administrative assistant to enter information into the IM database. However, management was notified this week that PHMSA is completely revamping the IMDB; the Pipeline Safety program will comply with whatever new procedure is established.

The Commission should assess how it will review and evaluate pipeline operators' distribution integrity management programs as required by Title 16, Texas Administrative Code, Section 8.209.

Management disagrees that it still needs to assess how distribution integrity management plans will be reviewed and evaluated. Management has already determined that compliance with new rule ' 8.209 will be part of the DIMP inspections that are just now beginning under the federal regulations.

The Commission Complied with Federal Requirements to Establish a Damage Prevention Program; However, It Should Improve Its Processing of Incident Reports

The Commission complied with the PHMSA's *Guidelines for States Participating in the Pipeline Safety Program* requirements to establish a Damage Prevention Program. From September 2007 through April 2011, the Commission received 37,122 incident reports related to excavation and cited 11,527 violations. It assessed \$4,242,958 in total penalties and collected \$3,420,133. As of June 2011, the Commission reported that it had nine Damage Prevention Program staff members.

The Commission should improve the Damage Prevention Program by:

- Consistently citing violations and assessing penalties in accordance with its policies and procedures.
- Gathering complete information about incidents from operators and excavators.
- Consistently sending letters to operators and excavators regarding incidents.
- Developing secondary review procedures for key processes such as processing incident reports, citing violations, and assessing violations.
- Completing investigations before closing incidents.
- Developing a process to track repeat violators and identify trends in incidents.

The Commission Complied with Federal Requirements to Establish a Damage Prevention Program

In compliance with federal requirements, the Commission established a Damage Prevention Program designed to (1) prevent damage to pipelines, such as that caused by demolition, excavation, tunneling, or construction activity and (2) subject persons who violate the applicable requirements to penalties and enforcement actions. In addition, the state established a One-Call Notification Program for natural gas and hazardous liquid pipelines under Texas Utilities Code, Chapter 251 (see text box). The Commission implemented its Damage Prevention Program requirements effective September 1, 2007, in Title 16, Texas Administrative Code, Chapter 18. Also, Texas Utilities Code, Chapter 251, requires:

- The Texas Underground Facility Notification Corporation to operate One Call Notification call centers (see text box for additional information).
- Excavators to contact a One Call Notification center no earlier than 14 days before excavation is to begin or no later than 48 hours before the time excavation is to begin.
- The One Call Notification Center to contact pipeline operators in the area of excavation within two hours of receiving the excavator's notice.
- Pipeline operators to mark the pipelines in the excavation area within 48 hours.
- All markings to conform to uniform color code requirements.

When a pipeline incident related to excavation activity occurs, both the excavator and pipeline operator must file reports with the Commission through the automated Texas Damage Reporting Form (TDRF, see text box for additional information). Any damage that occurs to a pipeline system is considered an "incident," and the Commission tracks incidents related to excavation in TDRF. The Commission maintains information on incidents caused by activities other than excavation in PES.

Commission policies and procedures require staff to process each excavation-related incident in TDRF. Commission Damage Prevention Program staff process the excavation-related incident reports through a compliance desk

One-Call Notification Program

The PHMSA's *Guidelines for States Participating in the Pipeline Safety Program* requires a state's pipeline safety program to adopt a one-call notification program that will notify a pipeline operator of excavation activity that could threaten the safety of a pipeline. Texas Utilities Code, Chapter 251, states that the Texas Underground Facility Notification Corporation (Corporation) shall provide statewide notification services and requires the Corporation to establish the one-call notification network.

Texas Damage Reporting Form

The Texas Damage Reporting Form (TDRF) is part of the Commission's Web-based RRC Online application that pipeline operators, excavators, and homeowners can use to report instances of pipeline damage. Texas law requires the pipeline operator and the person digging around a pipeline to report to the Commission all damage to pipelines that excavators cause. TDRF compiles the incident reports related to excavation and generates reports that the Commission can use to track the number and causes of incidents. The Commission implemented TDRF in July 2008 to increase the processing capabilities of its existing online reporting system.

review and do not perform field inspections. The Commission also imposes violations and penalties on excavators and pipeline operators that violate the damage prevention rules and requirements in the Texas Administrative Code.

Chapter 2-B

The Commission Should Improve Its Processing of Pipeline Incident Reports

The Commission should consistently follow its policies and procedures for processing incident reports. Auditors tested a sample of excavation-related

incident reports that pipeline operators and excavators submitted to the Commission through TDRF (see text box for information on the categories of incident reports in TDRF). Auditors identified several weaknesses in the Commission's damage prevention incident report process.

The Commission does not currently perform a secondary review of the Damage Prevention Program staff's processing of incident reports. By implementing a secondary review of its Damage Prevention Program staff's processing of incident reports, including the determination of violations and penalties, the Commission should address some of the weaknesses discussed below.

Citing Violations

Auditors tested a sample of matched excavator and operator incident reports and incidents closed as inconclusive. For 23 (24 percent) of 94 applicable incident reports tested, the

Commission did not cite violations in accordance with its documented policies and procedures or staff did not obtain sufficient information from the operators and/or excavators to determine whether violations occurred.

In addition, Damage Prevention Program staff did not consistently consider the results of the Pipeline Safety Division's investigations of the major impact excavation incidents that auditors tested. Pipeline Safety Division staff perform on-site field investigations, while Damage Prevention Program staff perform desk reviews of each major impact incident. The Commission's policies and procedures require Damage Prevention Program staff to review the results of the Pipeline Safety Division's investigation prior to determining fault, citing violations, and assessing penalties for an incident. However, for 3 (33 percent) of 9 major impact incidents that auditors tested, the incidents did not contain any documentation indicating that the Damage Prevention Program staff requested or reviewed the Pipeline Safety Division investigation or discussed the investigation with the Pipeline Safety Division.

Categories of Incident Reports

Matched Reports - Reports submitted by the excavator and pipeline operator for the same incident that the Commission then matches and processes in TDRF.

Single Reports - Reports submitted by only one party to an incident (such as the excavator or pipeline operator).

Inconclusive Report - Reports that Commission staff closed without assigning fault because of incomplete or contradictory information in the incident reports.

Major Impact Reports - Reports for incidents involving injury, death, fire, and property damage exceeding \$50,000. Commission inspectors are required to investigate all major impact incidents.

Reports Referred to Enforcement - Incident reports referred to the Commission's Enforcement Division to collect penalties from parties that contest the violations cited.

Assessing Penalties

The Commission did not consistently assess penalties in accordance with its policies and procedures. Auditors tested a sample of 157 incidents consisting of matched excavator and operator reports, incidents closed as inconclusive, major impact incidents, and incident reports referred to the Commission's Enforcement Division. For 31 (20 percent) of the 157 reports tested, the Commission did not assess penalty amounts in accordance with its policies and procedures.

Processing Incident Reports in TDRF

The Commission's Damage Prevention Program staff perform the following steps to process incident reports that the pipeline operators and excavators submit into TDRF:

- Match the operator's incident report with the excavator's incident report.
- Gather the facts from the parties involved in the incident.
- Determine which party is at fault or has violated damage prevention requirements.
- Cite violations.
- Assess penalties.
- Close out the incident.

Damage Prevention Letters

No Report letters - Sent to operators and excavators when they fail to submit the required incident report into TDRF.

Final Notice letters - Sent to operators and excavators when the Commission does not receive the party's incident report requested through a "No Report" letter within 30 days.

Outreach Letters - Sent to homeowners that cause the pipeline damage.

Request for Additional Information letters - Sent to operators and excavators when the Damage Prevention Program staff require additional information to process their incident reports.

Not consistently citing violations and assessing penalties could result in pipeline operators or excavators not being held accountable for violations.

Requesting Supporting Documentation

The Commission closed incidents as inconclusive without requesting adequate information from excavators and operators. The Commission's policies and procedures require staff to process each excavation-related incident in TDRF (see text box for additional information).

Staff may close incident reports as inconclusive when they are unable to determine who was at fault for the incident. For 16 (40 percent) of 40 tested excavation-related incident reports that were closed as inconclusive, Commission staff either did not request additional information from the pipeline operator or excavator who had originally submitted insufficient information about the incident or they closed the incident as inconclusive even though the incident reports contained sufficient information to determine fault. In addition, staff did not document in any of these incidents the reasons they classified the incidents as "inconclusive."

When the Commission closes incidents as inconclusive without requesting additional information, pipeline operators or excavators may not be held accountable for violations.

Sending Required Letters

The Commission did not consistently send letters to excavators and pipeline operators required by its policies and procedures (see text box for more information about the letters). Specifically:

- For 2 (17 percent) of 12 applicable incidents tested, the Commission did not send a no report letter to the party that did not submit an incident report into TDRF.
- For 6 (86 percent) of 7 applicable incidents tested, the Commission did not send an outreach letter to the homeowner that caused the pipeline damage.

- For 10 (27 percent) of 37 applicable incident reports tested, the Commission did not send a letter to the pipeline operators to request additional information as required.
- For 9 (26 percent) of 35 applicable incident reports tested, the Commission did not send a letter to the excavators to request additional information as required.

The Commission's policies and procedures require staff to send letters to the excavators and/or operators when the parties to an incident do not submit the required incident reports or when Damage Prevention Program staff require additional information related to a report to appropriately process the incident.

If the Commission does not consistently send out the required letters, it increases the risk that violators will not be held accountable. In addition, if the Commission does not send out required outreach letters to homeowners that cause damage to pipelines, the public will not be aware of requirements related to damage prevention.

Recommendation

The Commission should implement a secondary review of pipeline incident reports to verify that they are processed consistently, that the Commission adheres to policies and procedures, and that staff perform sufficient follow-up with operators and excavators.

Management's Response

Management agrees in principle that a secondary review process would be helpful, but cannot commit to fully implementing such a process because of staffing constraints. Training has been conducted with staff to address any possible alleged deficiencies and to take corrective action as needed to prevent future occurrences.

The Commission Closed Pipeline Damage Incident Reports Without Completing Investigations to Determine Responsibility for Damages

In January 2010, select Commission staff followed an internal memo directing them to close a backlog of open excavation-related incident reports that were (1) more than one year old and (2) had not been fully investigated to determine fault for the incident. The Commission did not maintain sufficient information to enable auditors to determine how many of the 13,649 excavation-related incidents the Commission closed in 2010 were closed without completing an investigation.

As a result of closing incidents without completing an investigation, the Commission cannot determine whether it should have taken enforcement actions against operators and excavators responsible for violations and/or pipeline damage. This could reduce the effectiveness of the Commission's Damage Prevention Program to ensure that pipeline operators and excavators comply with safety requirements.

Recommendation

The Commission should follow its damage prevention procedures to process pipeline incident reports and ensure that it completes investigations before it closes those incidents.

Management's Response

Management disagrees that damage prevention procedures have not been followed. Backlog project period incident reports were reviewed and processed with available data; alleged violations were cited and letters sent; but no penalties were assessed due to the limited investigation and the age of the reports. That incidents have had a limited investigation or have been closed without citing a penalty does not mean that procedures were not followed.

The Commission Should Develop a Process to Track Repeat Violators and Identify Trends in Incidents

The Commission does not track the history of violations for pipeline operators and excavators. The Commission uses TDRF to maintain information only on excavation-related incidents, but it could use the data from TDRF to categorize the causes of excavation-related incidents (see Appendix 4 for additional information about common causes of excavation-related incidents in Texas).

There are no state or federal requirements that specifically require the Commission to track repeat violators. However, if the Commission does not identify repeat violators, this may hinder its ability to review and analyze the effectiveness of its Damage Prevention Program, which is a requirement in the PHMSA's *Guidelines for States Participating in the Pipeline Safety Program*.

TDRF also receives incident reports for pipeline damage that was not caused by excavation activities, such as damage caused by equipment failure or pipeline corrosion; however, because the cause is not related to excavation, Damage Prevention Program staff close the incident and do not provide information on those types of incidents to the Commission's Pipeline Safety staff.

Recommendations

The Commission should:

- Develop a process to track repeat violators and identify trends in incidents.
- Develop a procedure to require Damage Prevention Program staff to provide information to the Pipeline Safety staff on incidents about pipeline damage not caused by excavation.

Management's Response

The Commission should develop a process to track repeat violators and identify trends in incidents.

Management agrees that this is desirable and has identified a number of refinements to the TDRF system that need to be made, particularly with respect to options for identifying repeat offenders. Management is working with IT to engage programmers to implement these changes.

The Commission should develop a procedure to require Damage Prevention Program staff to provide information to the Pipeline Safety staff on incidents about pipeline damage not caused by excavation.

Management disagrees that damage not caused by excavation (such as equipment failure or corrosion) should necessarily be reported to the Pipeline Safety staff. Not all incidents are reportable under the Pipeline Safety regulations. Just because such information is reported through TDRF does not mean it must be conveyed to Pipeline Safety staff. In any event, by the time it is reviewed in TDRF, the reporting deadline for a significant (and reportable) incident (two hours, maximum) would be long past.

The Commission Should Strengthen Application and General Information Technology Controls to Protect Its Automated Systems, Applications, and Data

The Commission should strengthen certain controls over the Pipeline Evaluation System (PES), which the Commission implemented in February 2009 as a new automated system to manage its Pipeline Safety Program. The Commission relies on PES to manage its Pipeline Safety Program (see text box). However, the procedures that the Commission used to migrate data from its former systems to PES lacked adequate controls to ensure that the data migrated into PES was accurate, complete, and reliable. In addition, most of the data in PES is entered directly into the system, and the Commission had no other documentation to verify the accuracy, completeness, and reliability of the information. As a result, the data in PES was not sufficiently reliable for the purposes of this audit. Because the Commission retains limited corroborating information and relies on PES to manage the Pipeline Safety Program, auditors still used the data for this audit.

PES

PES is the primary application that the Commission uses to track pipeline systems. PES also tracks the Commission's inspections and the violations associated with inspections. The Commission also uses PES to generate annual pipeline inspection work plans through a risk-based analysis and to generate multiple reports used to manage the Pipeline Safety Program.

Auditors determined that the data in the Commission's TDRF was sufficiently reliable for the purposes of this audit; however, the Commission should strengthen certain controls to help ensure the accuracy of data in incident reports that pipeline operators upload into TDRF.

In addition, auditors identified weaknesses in the Commission's general controls that increase the risk of unauthorized access to the Commission's automated systems and the unauthorized disclosure, modification, and/or destruction of data.

PES

The Commission did not have sufficient documentation showing that all of the data it migrated from its former systems into PES was complete and accurate. The Commission migrated the data, including pipeline operator information and pipeline inspection history, from its mainframe system and two Microsoft Access databases into PES.

The Commission documented its migration plan and schedule, the data tables it used during the migration, and examples of exceptions produced during the migration. However, the Commission did not have complete documentation of the system development methodology and process it used to migrate data from its mainframe and from its Pipeline Safety Access Database when it implemented PES in February 2009. Specifically, the Commission lacked documentation showing:

- Data conversion and migration procedures.

- Record counts for data that was merged together to help ensure that all data migrated accurately and completely.
- It performed reconciliations of the final data after duplicate records were eliminated to explain exceptions produced during the migration process.
- That end users tested the accuracy and completeness of the data migrated into PES and that they resolved exceptions.

The Commission did not adequately document that it followed a recommended industry information technology governance guideline, such as the Control Objectives for Information and Related Technology (COBIT) framework created by ISACA (formerly known as the Information Systems Audit and Control Association).

Because of the incomplete documentation, auditors could not quantify the effect of the data migration issues on the accuracy and completeness of the data in PES during the scope of this audit. Auditors did note the following during testing and analysis of PES:

- For 2 (5 percent) of 40 incidents tested, the data in PES did not match the information from the Commission's hard copy incident reports retained for incidents that occurred prior to implementing PES. The Commission stated that those discrepancies appeared to be a result of the migration of the Commission's incident Microsoft Access database into PES.
- The Commission makes updates to data in PES as inspectors identify errors; however, it does not track the errors or the corrections made.

TDRF

Auditors determined that the data in TDRF was sufficiently reliable for the purposes of this audit; however, the Commission should strengthen controls related to edit checks of data in incident reports that pipeline operators upload into TDRF. For example, an edit check is currently not in place within TDRF to prevent pipeline operators from entering an incident date that is in the future. Auditors identified one incident report uploaded in January 2011 that listed the incident date as November 12, 2011. In addition, the Commission should implement a secondary review process to verify that staff enter into TDRF all the information needed to substantiate the Commission's decisions related to incident reports (see Chapter 2-B for additional information).

General Controls

The Commission did not have policies and procedures in place for passwords or the management of user access from January 2009 through June 2011. However, the Commission provided auditors with newly developed information security policies in early July 2011. Because those policies and

procedures were not in effect during the audit period, auditors were not able to assess the effectiveness of the controls established.

Prior to June 2011, the Commission did not have appropriate password and access controls over the servers that host PES and TDRF or over each application. The Commission also either did not perform reviews of user access or perform reviews in a timely manner to determine whether access was appropriate. Title 1, Texas Administrative Code, Section 202.25, requires each state agency to implement controls over the identification and authentication of users.

In addition, 6 (12 percent) of 52 individuals had inappropriate access to the Commission's server room. The Commission removed physical access for those 6 individuals after auditors notified the Commission of the inappropriate access. Additionally, the Commission did not have policies and procedures in place to manage the granting and revoking of physical access to the server room. Title 1, Texas Administrative Code, Chapter 202.25, requires state agencies to (1) establish security policies for the granting, control, monitoring, and removal of physical access to information resources and (2) review physical security measures for information resources at least annually as part of a risk assessment process.

The Commission uses (1) a workload Microsoft Access database to prepare inspection activity information and (2) a civil penalties spreadsheet for its annual Pipeline Safety Program certification, which it submits to the U.S. Department of Transportation. Auditors identified eight individuals who had unauthorized access to the shared network on which those two databases reside. The Commission shifted those eight employees from the Pipeline Safety Division to another division, but it did not remove their access to the shared network. Title 1, Texas Administrative Code, Section 202.25, requires that a user's access authorization shall be appropriately modified or removed when the user's employment or job responsibilities within the state agency change.

Recommendations

The Commission should:

- Assess the completeness of the data in PES that was migrated from former systems, and document its investigation of discrepancies, the cause of the discrepancies, and the steps it takes to address the discrepancies.
- For future implementations of new information technology systems, develop and implement a formal program development methodology for the migration of data to new information technology systems. The Commission should also establish procedures to ensure that it retains adequate supporting documentation to demonstrate compliance with its

policies and procedures for implementing new information technology systems.

- Strengthen edit checks in TDRF to help ensure that pipeline operators upload accurate information related to incident reports.
- Implement and enforce its new information security policies and procedures related to password and user access management. The new policies and procedures should include:
 - ♦ Rules for granting, monitoring, and removing physical access to the server room.
 - ♦ Procedures for reviewing user access regularly to verify that users have the appropriate level of access based on a user's job duties and modifying or removing access as appropriate.
- Ensure that its workload Microsoft Access database and civil penalties spreadsheet are stored in a secured network location and restrict access to the database and spreadsheet to only authorized users.

Management's Response

The RRC has a software development methodology in place. For projects involving data migration, depending on the source and target environments, the process used may be different. The commission used an iterative approach for data migration into the PES system. This approach was chosen because data was being merged from multiple data sources. For each iteration, records that could not be migrated were documented on an exception report. Users were provided with this report and researched and corrected any data issues. The RRC will review the final PES migration exception reports and document the resolution of all discrepancies. The Commission will also establish procedures to ensure it retains adequate supporting documentation of each milestone for future implementations.

The defect identified by the Auditors with regard to an edit check using the EDI path for a particular date was corrected and a new software version of TDRF was deployed.

The RRC has implemented a new Information Security Policy to address the account management, password management, and physical access issues including provisions for regular review. The password strengths in both PES and TDRF are currently being updated.

The RRC is replacing the Microsoft Access workload database by incorporating its functionality in the PES application. Only individuals that have been granted rights to that function in PES will be able to view and

update workload information. The civil penalties spreadsheet is a user created convenience copy of information available to the public.

Appendices

Appendix 1

Objective, Scope, and Methodology

Objective

The objective of this audit was to determine whether the Railroad Commission (Commission) adheres to state and federal law and agency policies and procedures in administering the Pipeline Safety Program and the Damage Prevention Program.

Scope

The scope of this audit covered January 1, 2009, through March 31, 2011, and included the Pipeline Safety Program and the Damage Prevention Program administered by the Commission. The scope also included the automated systems and processes in those areas.

Methodology

The audit methodology included collecting information and documentation from the Commission; reviewing policies and procedures, statutes, and rules related to pipeline safety and damage prevention; and analyzing and evaluating data and the results of tests. Specifically, auditors reviewed pipeline inspections and incident investigations, incident damage reports, pipeline permit documentation, waiver documentation, inspector training documents, annual certification reports and evaluations, program fee reports, and annual pipeline inspection work plan reports. Auditors also visited three regional/field areas in Austin, Houston, and Dallas/Fort Worth to observe pipeline inspections.

Auditors assessed the reliability of the Commission's pipeline safety data in its automated Pipeline Evaluation System (PES) and determined that the data was not sufficiently accurate, complete, and reliable for the purposes of this audit due to weaknesses related to pipeline jurisdictional status determination, data entry controls, pipeline coding, and coding language within the system that affects the annual pipeline inspection work plan reports. PES is the primary application that the Commission uses to manage its Pipeline Safety Program. This includes using PES to track information on pipeline systems and inspections and to generate reports. The Commission enters information directly into PES. As a result of weaknesses in PES and the lack of other documentation related to data migration, auditors were not able to determine compliance with certain policies and procedures related to the Pipeline Safety Program. To the extent possible, auditors considered the data limitations when designing analytical and testing procedures.

Auditors also assessed the reliability of the Commission's damage prevention data in its automated Texas Damage Reporting Form (TDRF) by interviewing agency staff members knowledgeable of the data and performing testing of key data elements. In addition, auditors gained additional data reliability assurance by reviewing certain general controls and application controls related to the input and processing of incident damage reports and data. Auditors determined that the Commission's damage prevention data from TDRF was sufficiently reliable for the purposes of this audit.

Information collected and reviewed included the following:

- Policies and procedures for pipeline permit processing, complaint and incident investigations, pipeline inspections, integrity management plan inspections, damage prevention incident report processing, waiver processing, and the annual pipeline inspection work plan's risk assessment methodology.
- Pipeline permit and transfer documents, waiver documents, annual pipeline inspection work plan reports, inspector training documents, program fee tracking spreadsheets, integrity management plan inspection tracking spreadsheets, pipeline new construction reports, and annual certification reports and supporting documents.
- Pipeline operator and system information, inspections, and incident investigations in PES.
- Pipeline damage incident reports in TDRF.

Procedures and tests conducted included the following:

- Interviewed management and key personnel at the Commission.
- Analyzed and tested pipeline inspections, incident investigations, annual pipeline inspection work plan reports, pipeline permits and transfers, waivers, and damage incident reports.
- Reviewed and tested compliance with Commission policies and procedures, the Texas Administrative Code, the Texas Utilities Code, the Code of Federal Regulations, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's *Guidelines to States Participating in the Pipeline Safety Program*.
- Observed pipeline inspectors in three field/regional areas conduct inspections of various types of pipelines and facilities.
- Reviewed input controls and access rights for PES and TDRF.
- Reviewed general and application controls (input and processing) over PES and TDRF.

Criteria used included the following:

- The following chapters of Title 16, Texas Administrative Code:
 - ♦ Chapter 3 (Oil and Gas Division).
 - ♦ Chapter 8 (Pipeline Safety Regulations).
 - ♦ Chapter 18 (Underground Pipeline Damage Prevention).
- Texas Utilities Code, Chapters 121 and 251.
- Texas Natural Resource Code, Chapters 81 and Chapter 117.
- Commission policies and procedures including:
 - ♦ Standard inspections operating procedures.
 - ♦ Operator qualification standard operating procedures.
 - ♦ Integrity management plan inspection standard operating procedures.
 - ♦ Accident, incident, and special investigations standard operating procedures.
 - ♦ Permitting procedures.
 - ♦ TDRF operating procedures.
 - ♦ Annual pipeline inspection work plan system priorities and risk factors.
- U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's *Guidelines for States Participating in the Pipeline Safety Program*.
- Title 49, Code of Federal Regulations, Chapters 190-195 and Chapters 198-199.

Project Information

Audit fieldwork was conducted from May 2011 through July 2011. We conducted this performance audit in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

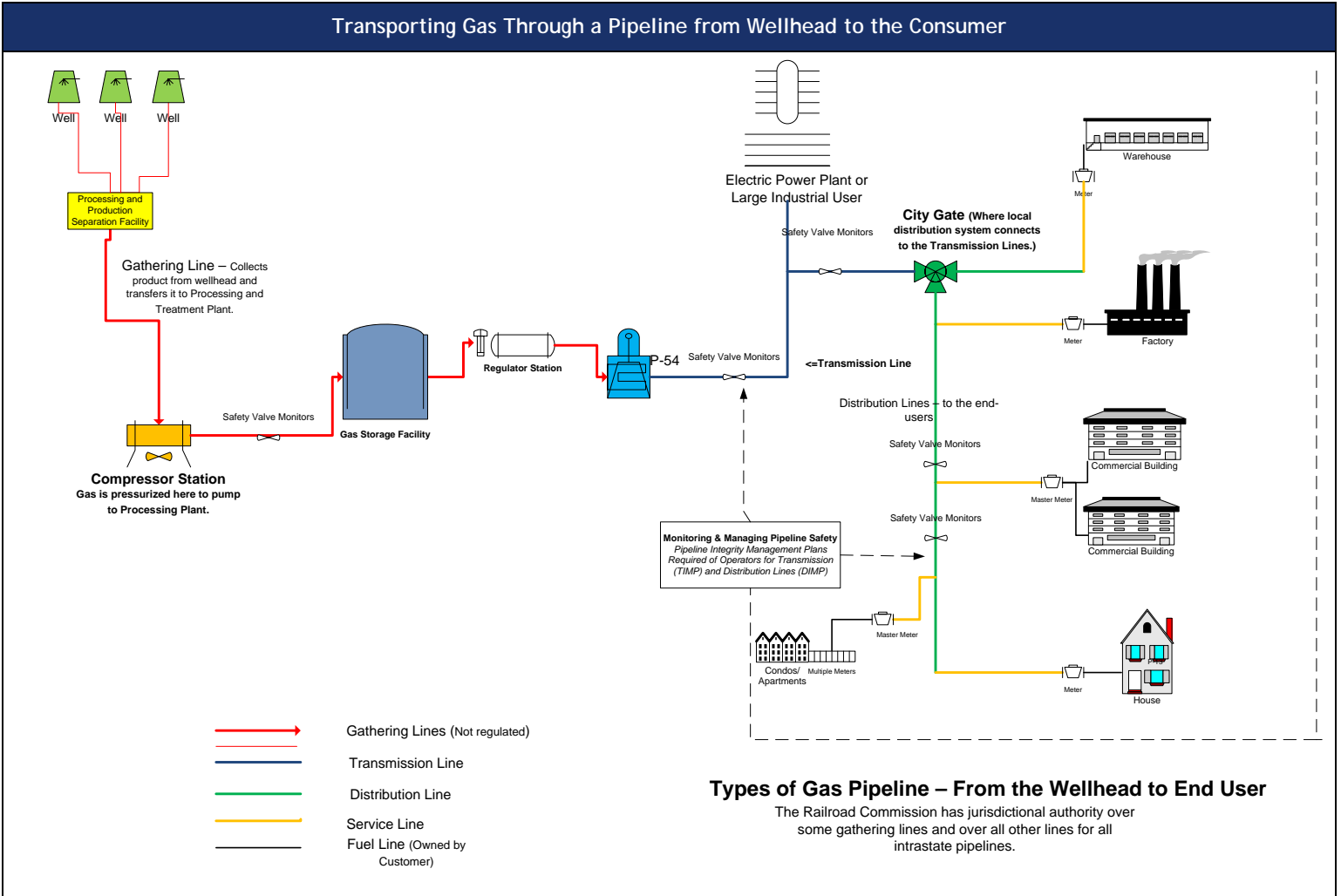
The following members of the State Auditor's staff performed the audit:

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- Jennifer Lehman, MBA, CGAP, CIA (Assistant Project Manager)
- Priscilla G. Bauer
- Ishani Baxi, CIDA
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- Michelle Feller, CIA, CPA (Quality Control Reviewer)
- John Young, MPAFF (Audit Manager)

Transporting Gas Through a Pipeline to the End User

Figure 1 is a basic diagram on how gas is transported through a pipeline from the wellhead to the end user.

Figure 1



Source: Auditors created the diagram based on information from U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration’s Web site.

Definition of Pipeline Terms

Below are definitions of pipeline-related terms based on information from the Railroad Commission.

Transmission Line – Pipeline transporting gas from a gathering line or storage facility to a distribution center. Transmission lines are typically operated at higher pressures and stress levels.

Non-Rural (Urban) Gathering Line – A gathering line that is located within city limits of a designated residential or commercial area, such as a subdivision, business, shopping center, or community development.

Rural Gathering Line – A gathering line located outside any incorporated municipality, commercial, or business area.

Federal Offshore Line – A pipeline located on outer continental shelf lands. Federal waters offshore from Texas begin at 3 marine leagues, or 10.3 miles.

State Offshore Line – A pipeline originating in a bay extending within 3 marine leagues, or 10.3 miles offshore.

Lease/Flow Line – A pipeline located within the lease of production, carrying full well stream production to a tank battery, separator, or other production treatment equipment located on the lease.

Distribution Line – A pipeline serving both as a common source of supply and associated branch lines serving consumers. Distribution lines are the source of supply for residential and small commercial users.

Master Meter System – A natural gas pipeline system for distributing natural gas within, but not limited to, a distinct area, such as a mobile home park, housing project, or apartment complex, for which the operator purchases metered gas from an outside source. The natural gas distribution pipeline system supplies the end-consumer who either purchases gas directly through a meter or by other means such as rent.

Interstate System – Typically, a natural gas pipeline transportation system extending beyond state boundaries. However for hazardous liquids systems, pipelines may be designated as interstate if they are connected to a pipeline that carries product out of state boundaries and affects foreign commerce subject to Federal Energy Regulatory Commission (FERC) tariffs.

Intrastate System – A pipeline system for transporting natural gas or hazardous liquids within a state and not subject to the jurisdiction of FERC.

Hazardous Liquids Line – A pipeline for transportation of petroleum or petroleum products such as gasoline, diesel fuels, or liquefied petroleum gas (LPG).

Sour Gas Line – A pipeline system containing greater than 100 parts per million (ppm) hydrogen sulfide.

Excavation-related Pipeline Damage Incidents

In calendar year 2010, the Railroad Commission (Commission) received 13,853 incident reports from pipeline operators and excavators related to damage caused to pipelines by excavation-related activities. The majority of the incidents were caused by operators not marking the pipelines sufficiently and excavators not notifying the One-Call Center before the excavation. Table 2 lists the recorded causes for excavation-related pipeline damage incidents reported in calendar year 2010.

Table 2

Reported Causes of Excavation-related Pipeline Damage Incidents		
Cause	Total Incidents Reported	Percent of Total Incidents Reported
No notification was made to the One-Call Center.	3,450	24.90%
Facility marking or location was not sufficient.	2,139	15.44%
Facility was not located or marked.	2,129	15.37%
Other.	2,008	14.50%
Failure to maintain clearance.	1,100	7.94%
Excavation practices not sufficient.	706	5.10%
Failure to use hand tools where required.	463	3.34%
Facility could not be found/located.	431	3.11%
Failure to maintain the marks.	275	1.99%
Notification to One-Call Center was made, but it was not sufficient.	271	1.96%
Incorrect facility records/maps.	211	1.52%
Data not collected. ^a	196	1.41%
Failure to verify location by test-hole (pot-holing).	124	0.90%
Abandoned facility.	87	0.63%
Wrong information provided.	86	0.62%
Failure to support exposed facilities.	54	0.39%
One-Call Center made a notification error.	47	0.34%
Improper backfilling.	33	0.24%
Deteriorated facility.	23	0.17%
Previous damage.	20	0.14%
Totals	13,853	100.00%
^a Pipeline operators and excavators can select this in the Commission's automated Texas Damage Reporting Form (TDRF) if they did not capture the cause when the damage occurred. Operators and excavators can update the cause if they later obtain additional information. The Commission's staff is restricted in TDRF from editing information on an operator's or excavator's report.		

Source: State Auditor's Office analysis of damage prevention incident data provided by the Commission.

Regulated Miles of Pipeline by State

Texas has the most miles of pipelines subject to federal pipeline safety regulation (interstate and intrastate) among all the states. Table 3 lists the total miles of pipeline in each state that were subject to federal pipeline safety regulations in calendar year 2009, based on information that pipeline operators report annually to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

Table 3

Regulated Miles of Pipeline Calendar Year 2009							
Rank	State	Hazardous Liquid	Gas Transmission	Gas Gathering	Gas Distribution	Total Pipeline Mileage	Percent of Total
1	Texas	50,834	56,685	7,292	97,362	212,173	12.26%
2	California	6,525	12,009	322	102,659	121,515	7.02%
3	Illinois	6,832	9,569	1	60,732	77,134	4.46%
4	Louisiana	15,185	30,729	4,657	25,588	76,159	4.40%
5	Ohio	3,371	10,241	1,138	56,474	71,224	4.12%
6	Michigan	2,810	8,977	438	55,777	68,002	3.93%
7	Pennsylvania	2,638	10,011	590	47,143	60,382	3.49%
8	New York	1,089	4,551	549	47,485	53,674	3.10%
9	Oklahoma	10,498	13,188	1,046	24,728	49,460	2.86%
10	Georgia	2,011	4,424	0	42,900	49,335	2.85%
11	Indiana	3,637	5,348	12	39,561	48,558	2.81%
12	Kansas	9,408	14,583	136	21,984	46,111	2.67%
13	Colorado	2,871	8,145	640	34,269	45,925	2.65%
14	Wisconsin	2,169	4,506	0	37,046	43,721	2.53%
15	Tennessee	1,052	4,901	0	36,998	42,951	2.48%
16	Minnesota	4,426	5,543	0	29,393	39,362	2.28%
17	Alabama	2,009	7,007	658	29,390	39,064	2.26%
18	Missouri	4,666	4,697	0	26,682	36,045	2.08%
19	New Jersey	533	1,469	0	33,247	35,249	2.04%
20	North Carolina	1,057	3,918	0	27,604	32,579	1.88%
21	Arizona	566	6,644	0	23,886	31,096	1.80%
22	Florida	475	4,871	0	25,291	30,637	1.77%
23	Mississippi	3,779	10,899	15	15,565	30,258	1.75%
24	Iowa	4,269	8,345	0	17,564	30,178	1.74%
25	Arkansas	1,720	7,545	688	19,662	29,615	1.71%
26	New Mexico	5,753	6,535	450	13,571	26,309	1.52%
27	Kentucky	861	7,366	550	17,158	25,935	1.50%

Regulated Miles of Pipeline Calendar Year 2009							
Rank	State	Hazardous Liquid	Gas Transmission	Gas Gathering	Gas Distribution	Total Pipeline Mileage	Percent of Total
28	Washington	782	1,931	0	21,603	24,316	1.41%
29	Virginia	1,072	2,951	5	20,265	24,293	1.40%
30	South Carolina	722	2,644	0	20,133	23,499	1.36%
31	Massachusetts	105	1,107	0	21,069	22,281	1.29%
32	Utah	1,487	3,609	5	16,338	21,439	1.24%
33	Nebraska	2,437	5,826	0	12,307	20,570	1.19%
34	Oregon	429	2,395	0	15,276	18,100	1.05%
35	Wyoming	5,835	6,511	156	4,829	17,331	1.00%
36	Maryland	309	960	0	14,182	15,451	0.89%
37	West Virginia	145	3,955	597	10,426	15,123	0.87%
38	Montana	2,843	3,856	0	6,683	13,382	0.77%
39	Nevada	213	1,678	0	9,647	11,538	0.67%
40	Idaho	659	1,522	0	7,875	10,056	0.58%
41	Connecticut	87	584	0	7,631	8,302	0.48%
42	North Dakota	2,204	2,152	2	2,944	7,302	0.42%
43	South Dakota	526	1,625	0	4,444	6,595	0.38%
44	Alaska	1,181	791	57	2,949	4,978	0.29%
45	Rhode Island	17	95	0	3,129	3,241	0.19%
46	Delaware	46	302	0	2,781	3,129	0.18%
47	New Hampshire	69	242	0	1,844	2,155	0.12%
48	Maine	268	430	0	776	1,474	0.09%
49	District of Columbia	3	20	0	1,189	1,212	0.07%
50	Vermont	117	70	0	666	853	0.05%
51	Hawaii	96	22	0	613	731	0.04%
Totals		172,696	317,984	20,004	1,219,318	1,730,002	100.00%

Source: The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

Miles of Pipelines in Texas

According to the Railroad Commission, there were 358,165 miles of pipelines in Texas as of October 28, 2010. Of those pipelines, 214,245 miles are regulated. Table 4 lists the types and miles of pipelines within Texas that the State regulates, that federal agencies regulate, and that are not regulated. Auditors have not verified the data presented in Table 4.

Table 4

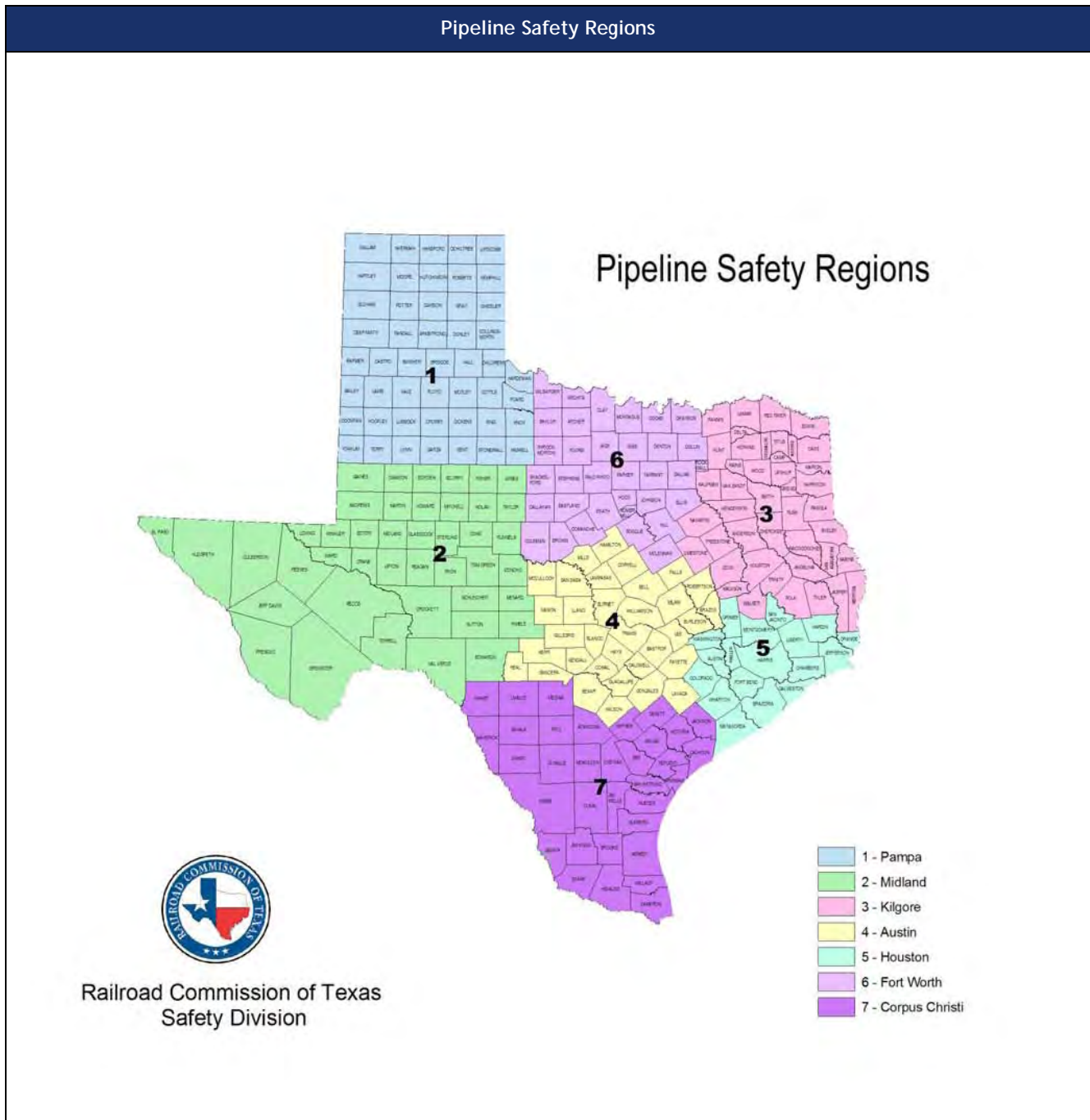
Miles of Pipelines in Texas As of October 28, 2010			
Type of Pipeline	Miles of Pipeline That Texas Regulates	Miles of Pipeline That Federal Agencies Regulate	Miles of Pipelines That Are Not Regulated
Hazardous Liquids Gathering	900	0	0
Hazardous Liquids Transmission and Storage	27,578	23,453	0
Intrastate Production and Gathering Lines Leaving Lease	0	0	143,920
Liquefied Petroleum (LP) Gas Distribution	136	0	0
Natural Gas Distribution	103,014	0	0
Natural Gas Gathering	3,283	0	0
Natural Gas Master Meter	480	0	0
Natural Gas Transmission and Storage	34,346	21,055	0
Total Miles	169,737	44,508	143,920

Source: The Railroad Commission.

Pipeline Safety Regions

Figure 2 shows the seven pipeline safety regions for the Railroad Commission's Pipeline Safety Division.

Figure 2



Source: The Railroad Commission.

Related State Auditor's Office Work

Related State Auditor's Office Work		
Number	Product Name	Release Date
07-046	An Audit Report on Inspection and Enforcement Activities in the Field Operations Section of the Railroad Commission	August 2007

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