SUMMARY OF TRANSMISSION INTEGRITY MANAGEMENT PROGRAM

I. BACKGROUND

The Transmission Integrity Management Program (“TIMP”) was developed pursuant to the Pipeline Safety Improvement Act of 2002 and the regulations promulgated thereunder by the United States Office of Pipeline Safety. The program is now administered by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”). The rules specify how pipeline operators must identify, assess, prioritize, evaluate, repair and validate the integrity of gas transmission pipelines. The rules focus on the potential impacts of pipeline failures or leaks on heavily populated or occupied areas, referred to as High Consequence Areas (“HCAs”). All pipeline operators must assess all of its pipelines in HCAs by December 17, 2012, and reassess the lines on a periodic cycle no longer than every seven years. While the program is prescriptive and extensive, its direction to pipeline operators can be summarized as follows:

- Know your assets, i.e., understand their history, maintenance, construction methodology, location, soil condition, etc.
- Understand the threats against your assets, e.g., corrosion, manufacturing defects, third-party damage, construction methods, etc.
- Assess the pipelines using one or more methods.
- Be proactive in addressing threats against assets, i.e., develop and implement preventive and mitigation measures for the threats, monitor the results, and change programs as needed.
- Record data and report.

The Company began the required assessments in 2004 primarily using direct assessments or pressure tests. As the program and technology evolved, the Company elected to use In-Line Inspection (“ILI”) as the preferred inspection method, as this tool yields the most complete and high-quality information necessary to address the threats on our system. The devices used for such inspection are commonly referred to as Pipeline Inspection Gadgets (“PIGs”), also referred to as a “smart PIG.” When using a PIG is impractical due to the configuration of the pipeline or other code-related reasons, the Company utilizes pressure tests to assess the lines. Such testing provides operating pressure tolerances of the pipeline, and can identify problems if the pipeline segment fails the test, but usually requires follow-up excavation to identify the exact location of and reason for the failure. The Company might also perform ILI inspections prior to conducting a pressure test to identify with more specificity potential failure points on the line. This is particularly useful when much of the pipeline is under asphalt and finding a pressure test failure point is difficult.

This reliance on ILI must be implemented carefully. Not every pipeline is configured to allow for smooth passage of a PIG. It can be very expensive to extricate the PIG and repair facilities when a PIG becomes stuck in a pipeline. Consequently, the Company must carefully evaluate pipe sections before attempting an ILI procedure. Specifically, the Company researches legacy records, maps and test results to supplement or validate data in the Company’s Pipeline Data Management System (“PDMS”). The PDMS is the Geographic Information System (“GIS”) of record for our pipeline assets. To the extent available, the locations, materials, manufacturers and vintages of the Company’s pipelines are stored in PDMS. The Company also “potholes” or
excavates pipes to determine pipeline configuration when insufficient information is available, and replaces fittings or other impediments to the PIG’s smooth passage through the pipe.

Regardless of which inspection method is used, the purpose of a pipeline inspection is the same - to identify corrosion on the internal or external pipeline walls, dents, cracks, weaknesses around fittings or welds, and/or other factors impairing the integrity of the pipeline. Essentially, the goal is to identify potential points of failure and perform repairs.

Due to the activities summarized above, the Company’s knowledge of our transmission system has improved significantly – and will continue to improve. We have also completed numerous repairs based on our assessments and have authorized replacements when necessary. Because the scope and composition of our TIMP-related work has changed from what we originally anticipated, our TIMP-related O&M and capital expenditures have correspondingly increased. A discussion of the more significant cost variances is provided below.

II. BREAKDOWN OF 2012 TIMP ACTIVITIES AND COSTS

Pipeline Assessments
To date, the Company has assessed over 300 miles of the 360 miles of pipeline in HCAs that must be assessed under TIMP regulations by December 17, 2012. As part of this initiative, the Company anticipates, and is working toward, de-rating over 100 miles, which will reduce the operating pressures of these lines and consequently remove them from the scope of the December 2012 TIMP assessment mandate. The Company is on target for completing the remaining required inspections before the deadline.

The Company has also assessed close to 500 miles of additional transmission pipeline that are not specifically earmarked for inspection under TIMP. These segments are often interspersed with, or located in very close proximity with, targeted pipelines in HCAs; therefore, the Company can inspect the additional lines at a modest cost premium over inspecting only the required lines in HCA. In addition, the lessons learned from assessments in HCAs (and those pipelines in close proximity thereto) are informing the Company’s inspections and maintenance of all of our pipeline assets – particularly pipelines in similarly-situated areas.

While the insights resulting from our TIMP activities have been invaluable, they have sometimes necessitated departures from our planned or budgeted work. One example is re-assessing some lines using a better method or performing additional excavations and examinations to obtain sufficient information regarding the integrity of the line. Another example is repeated failures of pressure testing on lines, requiring additional excavations, inspections and repairs of failure points. The additional O&M and capital costs associated with these efforts have been recorded as part of TIMP. A salient example is the West Main line, which has incurred repeated failures in the course of conducting hydrostatic pressure tests. Compared to the system as a whole, which has experienced a failure rate of approximately 15 percent, the West Main line has experienced a failure rate in excess of 40 percent. The expenses incurred to maintain the reliability and safety of the pipeline, and to ensure continued service while sections of the line are being repaired, have been recorded as TIMP O&M or capital. Of course, the costs of renewing the West Main line are assigned to the West Main project.
We originally estimated approximately $20 million of capital expenditures and $8.5 million of O&M expenses for 2012 pipeline assessments. We now anticipate $24.5 million of capital expenditures and $9.6 million of O&M expenses in 2012. These increases in anticipated spending are attributable to the reasons discussed above.

**Data Project (Pipeline Data Project (“PDP”) and Maximum Allowable Operating Pressure (“MAOP”))**

One of the more significant insights discovered through the TIMP was that the existing Company data on pipeline locations and materials were less complete and of a lower quality than previously believed, or necessary to comply with increasing federal mandates. In 2011, the Company began to develop a comprehensive initiative to remedy those data deficiencies. The primary objectives of this initiative are to improve data quality, eliminate data gaps, improve the functionality of the system, and facilitate the storage of the extensive data generated through ILI and pressure tests. For example, with these improvements, the Company will be able to cross-reference maintenance records with the Company’s pipeline database and review the history of a particular pipeline. We are currently undertaking a quality assurance program to improve the data, with a projected completion date of December 2013.

To date, the Company has achieved the following milestones toward this initiative:

- Competitively bid and awarded a contract to a consulting firm with experience in this area to lead the project.
- Amassed a team of approximately 30 individuals to obtain, review and consolidate legacy records and paper documents.
- Identified and secured the services of “subject matter experts” that perform critical functions such as quality assurance/quality control (“QA/QC”) oversight of data collection and engineering interpretation.
- Electronically scanned and cataloged over one million individual documents or records related to transmission pipe assets and facilities.

A related effort is the MAOP initiative, which focuses more narrowly on the need to gather and validate records supporting the MAOP for the Company’s transmissions pipelines. The Company is gathering data from existing paper documents and other sources to populate missing or inaccurate fields within PDMS. Improving this data will facilitate better planning, enhance public and worker safety, and reduce the number of system outages.

As Congress and the PHMSA continued to clarify their position and requirements related to MAOP, the Company recognized the need for even more rigorous data collection and storage requirements. As such, and following an extensive scope of work development as mentioned above, the Company awarded a contract during the second quarter of 2012. Due to the timing of the contract award, and the complexity of managing a project of this magnitude, the project efforts and costs have been concentrated in the second half of 2012. The result is less 2012 spending than originally projected.

The Company originally estimated 2012 capital expenditures of about $6.5 million and O&M expenses of $1.2 million for the work associated with rectifying data deficiencies and the MAOP initiative. The Company now estimates 2012 capital expenditures of about $6.0 million and O&M expenses of about $200,000.
III. BREAKDOWN OF 2013 TIMP ACTIVITIES AND COSTS

Although the Company has anticipated changes to the industry as a result of significant pipeline incidents across the nation, the Pipeline Safety Act of 2012 resulted in additional and significant mandates to be administered by PHMSA. Two of those mandates -- the verification of MAOP and the installation of Automatic Shutoff/Remote Control Valves ("ASV/RCV") -- must be implemented in accordance with very prescriptive requirements and aggressive timeframes. As such, the successful execution of these initiatives necessitates a keen focus, extensive resource pool, and associated funding. Meeting these two mandates will be one of the Company’s primary TIMP objectives in 2013.

The other primary objective in 2013 is to complete our planned reassessments of transmission pipelines as required under the TIMP rule.

**Data Project (PDP and MAOP)**

As a continuation of our formal effort, the Company embarked on an initiative in 2012 to identify and correct data deficiencies. This initiative, originally referred to as PDMS, has evolved into a more far-reaching endeavor that we now refer to as the PDP. In concert with the strategy described above, the main objective of this project is to create a single access point for complete, accurate, and reliable pipeline asset information that is available in real time. This information will enable the organization to better support critical business and compliance needs for engineering, operations and pipeline integrity. The project has several short-term and longer-term goals.

The Company projects capital expenditures of about $11.4 million and O&M expenses of about $367,000 in 2013.

Additionally, an Advisory Bulletin (ADB-12-06, Docket No. PMHSA-2012-0068) issued by PHMSA and contained in the Federal Register specifically addressed Pipeline Safety in terms of Verification of Records. Initial language in the advisory required operators to “take action as appropriate to assure that all MAOP and MOP ("Maximum Operating Pressure") are supported by records that are traceable, verifiable and complete”. This initiative requires obtaining adequate proof of said records and ensuring that they become part of the Company’s official system of record. Further, the cost to test those pipelines that have been identified as having insufficient documented proof of operating maximum allowable operating pressure will be part of the 2013 planned work.

The Company projects capital expenditures of about $10 million and O&M expenses of about $3 million in 2013.

**Automatic Shutoff/Remote Control Valves (ASV/RCV)**

The installation of Automatic Shutoff/Remote Control in strategic locations supports public safety by providing the ability to isolate a portion of the gas system in the event of an incident or significant event and also to minimize customer impacts during these events. The installation of this type of equipment also became a requirement of the industry as a part of the Pipeline Safety Act of 2012.
The Company projects capital expenditures of about $3 million and O&M expenses of about $180,000 in 2013.

**Pipeline Assessments**
As mentioned above, the program requires that the baseline assessments of all pipelines that are in HCAs be completed by December 17, 2012. The Company must also reassess these pipelines not less than once every seven years. In order to obtain the most comprehensive data and information regarding the integrity of a line, some pipelines will be reassessed using in-line inspection rather than the same type of inspection method initially used.

The Company projects capital expenditures of about $17.5 million and O&M expenses of about $7 million in 2012.

**Total Program Costs**
For 2013, the Company projects total TIMP-related O&M expenses of approximately $10.7 million and capital expenditures of about $38.9 million. Given the anticipated in-service dates of the capital projects, the projected 2013 revenue requirement is $22.3 million.