BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

MEGHAN FLYNN	:	
ROSEMARY FULLER	:	
MICHAEL WALSH	:	
NANCY HARKINS	:	
GERALD MCMULLEN	:	DOCKET NOS. C-2018-3006116
CAROLINE HUGHES and	:	P-2-18-3006117
MELISSA HAINES	:	
Complainants	:	
v.	:	
	:	
SUNOCO PIPELINE L.P.,	:	
Respondent	:	

FLYNN COMPLAINANTS' POST-HEARING APPENDIX OF EXHIBITS

PART 1 of 2

PART 1

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October 23, 2019 Supporting Flynn Lay Testimony Part 1 of 2

October 23, 2019 Supporting Flynn Lay Testimony Part 1 of 2

Eric Friedman

Friedman_01

MOVIE CLIP
Video Link

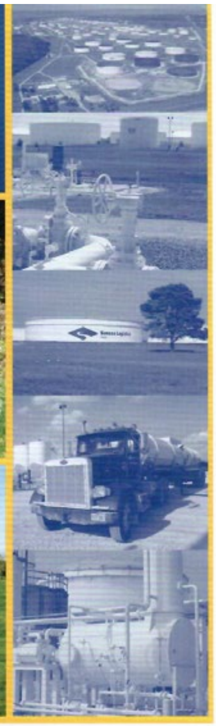
https://www.middletowncoalition.org/

VIEW in MOBILE DEVICE by scanning QR code

Friedman 01_Narrated Flyover

Important Safety Message

for your neighborhood

Sunoco Logistics
Sunoco Pipeline L.P.

Operator of the Inland and Harbor pipeline systems

24-Hour Emergency Number: 800-786-7440

Non-Emergency Number: 877-795-7271
Website: www.sunocologistics.com

You are receiving this brochure because Sunoco Pipeline L.P. operates a pipeline in your community. Our underground pipelines provide a safe and efficient method of transporting a variety of products, including crude oil, gasoline, diesel fuel, kerosene, heating oil, jet fuel, butane, ethane, propane, and natural gas.

Petroleum Pipelines In Your Community

There are almost 200,000 miles of petroleum pipelines in the United States. According to the U.S. Department of Transportation, pipelines are the most reliable and safest way to transport the large volume of natural gas and petroleum used in the United States. Pipelines transport two-thirds of all the crude oil and refined products in the United States. Pipelines are made of steel, covered with a protective coating and buried underground. They are tested and maintained through the use of cleaning devices, diagnostic tools, and cathodic protection. Since Americans consume over 700 million gallons of petroleum products per day, pipelines are an essential component of our nation's infrastructure.

Keeping you safe

Maintaining safe pipeline operations is critical in all areas where we operate. In high population and environmentally sensitive areas known as High Consequence Areas, we perform additional inspections and analyses as part of our Integrity Management Program (IMP). Additional information on our IMP efforts is available on our website: **www.sunocologistics.com**.

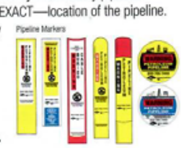
811 Know what's below. Call before you dig.

Always call 811 before you dig

One easy phone call to 811 starts the process to have your underground pipelines and utility lines marked. When you call 811 from anywhere in the country, your call will be routed to your state One Call Center, who will contact underground facility owners in the area. So you can dig safely, Sunoco Pipeline personnel will contact you if one of our pipelines are in the area of the planned excavation. More information about 811 is at **www.call811.com**.

How to know where pipelines are located

Most pipelines are underground, where they are more protected from the elements and minimize interference with surface uses. Even so, pipeline rights-of-way are clearly identified by pipeline markers along pipeline routes that identify the approximate—NOT EXACT—location of the pipeline. Every pipeline marker contains information identifying the company that operates the pipeline, the product transported, and a phone number that should be called in the event of an emergency. **Markers do not indicate pipeline burial depth, which will vary.** Markers are typically seen where a pipeline intersects a street, highway or railway. For any person to willfully deface, damage, remove, or destroy any pipeline marker is a federal crime.



Pipeline Marker — This marker is the most common. It contains Sunoco Pipeline information, type of product, and our emergency contact number. Size, shape and color may vary.

Aerial Marker — These skyward facing markers are used by patrol planes that monitor pipeline routes.

Casing Vent Marker — This marker indicates that a pipeline (protected by a steel outer casing) passes beneath a nearby roadway, rail line or other crossing.

How would you recognize a pipeline leak?

While pipelines are the safest method of transporting the fuel and products we use every day, knowing how to recognize a pipeline leak is important. The following may indicate a pipeline leak:

- ***Sight:*** Liquid pools, discolored or abnormally dry soil/vegetation, continuous bubbling in wet or flooded areas, an oily sheen on water surfaces, and vaporous fogs or blowing dirt around a pipeline area can all be indicative of a pipeline leak. Dead or discolored plants in an otherwise healthy area of vegetation or frozen ground in warm weather are other possible signs.
- ***Sound:*** Volume can range from a quiet hissing to a loud roar depending on the size of the leak and pipeline system.
- ***Smell:*** An unusual smell, petroleum odor, or gaseous odor will sometimes accompany pipeline leaks.

What to do in the event a leak were to occur:

- Public safety and protecting the environment are the top priorities.
- ***Turn off*** any equipment and eliminate any ignition sources without risking injury.
- ***Leave the area*** by foot immediately. Try to direct any other bystanders to leave the area. Attempt to stay upwind.
- From a safe location, ***call 911*** or your local emergency response number and call the 24-hour emergency number for the pipeline operator. Provide your name, phone number, a brief description and location of the incident so a proper response can be initiated.

What not to do in the event a leak were to occur:

- ***DO NOT*** cause any open flame or other potential source of ignition such as an electrical switch, vehicle ignition, light a match, etc. Do not start motor vehicles or electrical equipment. Do not ring doorbells to notify others of the leak. Knock with your hand to avoid potential sparks from knockers.
- ***DO NOT*** come into direct contact with any escaping liquids or gas.
- ***DO NOT*** drive into a leak or vapor cloud while leaving the area.
- ***DO NOT*** attempt to operate any pipeline valves yourself. You may inadvertently route more product to the leak or cause a secondary incident.
- ***DO NOT*** attempt to extinguish a petroleum product fire. Wait for local firemen and other professionals trained to deal with such emergencies.

What to do in case of damaging/disturbing a pipeline

If you cause or witness even minor damage to a pipeline or its protective coating, please immediately notify the pipeline company. Even a small disturbance to a pipeline may cause a future leak. A gouge, scrape, dent or crease is cause enough for the company to inspect the damage and make repairs.

All damages to underground gas or hazardous liquid pipeline facilities are required by law to be reported to the operator. Excavators must notify the pipeline company immediately upon damaging a pipeline.

What is a right-of-way and can I build or dig on it?

Sunoco Pipeline works diligently to establish written agreements, or easements, with landowners to allow for ease of construction and maintenance when they cross private property. Rights-of-way (ROW) are often recognizable as corridors that are clear of trees, buildings or other structures except for the pipeline markers. A ROW may not have markers clearly present and may only be indicated by cleared corridors of land, except where farmland or crops exist. County Clerk or Recorder of Deeds offices may also have records of the pipeline easements.

Encroachments upon the pipeline right-of-way inhibit the pipeline operator's ability to reduce the chance of third-party damage, provide right-of-way surveillance and perform routine maintenance and required federal/state inspections. In order to perform these critical activities, pipeline maintenance personnel must be able to easily and safely access the pipeline right-of-way, as well as areas on either side of the pipeline. Keeping trees, shrubs, buildings, fences, structures and any other encroachments well away from the pipeline ensures that the pipeline integrity and safety are maintained.

Before any excavation project on or near Sunoco Pipeline's right-of-way, contact Sunoco Pipeline at 877-795-7271.

How can you help?

While incidents involving pipeline facilities are very rare, awareness of the location of the pipeline, the potential hazards, and what to do if a leak occurs can help to minimize the impact of a pipeline release. A leading cause of pipeline incidents is unauthorized excavation near pipelines. Pipeline operators are responsible for the safety and security of their respective pipelines. To help maintain the integrity of pipelines and their rights-of-way, it is essential that pipeline and facility neighbors protect against unauthorized excavations or other destructive activities. Here's what you can do to help:

- **Become familiar with the pipelines and pipeline facilities in the area (marker signs, fence signs at gated entrances, etc).**
- **Record the operator name, contact information and any pipeline information from nearby marker/facility signs and keep in a permanent location near the telephone.**
- **Be aware of any unusual or suspicious activities or unauthorized excavations taking place within or near the pipeline right-of-way or pipeline facility; report any such activities to the pipeline operators and CALL 911.**

Transmission Pipeline Mapping

The U.S. Department of Transportation's Office of Pipeline Safety has developed the National Pipeline Mapping System (NPMS) to provide information about gas transmission and liquid transmission operators and their pipelines. The NPMS website is searchable by zip code or by county and state, and can display a county map that is printable. For a list of pipeline operators with pipelines in your area and their contact information, go to **www.npms.phmsa.dot.gov/**.

US DOT npms national pipeline mapping system

Usted está recibiendo este folleto porque Sunoco Pipeline L.P. opera una línea de tuberías en su comunidad. Nuestras líneas de tuberías subterráneas proveen un método seguro y eficiente para el transporte de varios productos, incluyendo el petróleo crudo, la gasolina, el combustible diesel, querosén, aceite para calefacción, combustible para jets, butano, etano, propano y el gas natural.

Oleoductos en su comunidad

Existen más de 200,000 millas de líneas de petróleo en los Estados Unidos. De acuerdo al Departamento de Transporte de EE.UU., las líneas de tuberías son el método más fiable y seguro de transportar el gran volumen de gas natural y petróleo utilizado en los Estados Unidos. Los oleoductos transportan dos tercios de todo el petróleo crudo y productos refinados en los Estados Unidos. Están fabricados de acero, cubiertos con un revestimiento protector y enterados. Se someten a pruebas y se mantienen mediante el uso de aparatos de limpieza, herramientas de diagnóstico y protección catódica. Debido a que los estadounidenses consumen más de 700 millones de galones de productos de petróleo por día, los oleoductos son un componente esencial de la infraestructura de nuestra nación.

Manteniendo su seguridad

Mantener operaciones seguras de nuestros ductos es primordial en todas las áreas donde operamos. Nosotros ejecutamos inspecciones y análisis adicionales como parte de nuestro Programa de "Manejo de Integridad (IMP)" en áreas de alta población y en áreas ambientalmente sensibles establecidas cómo "Áreas de Altas Consecuencia." La información adicional sobre nuestros esfuerzos de IMP está disponible en nuestro sitio web: **www.sunocologistics.com**.

Siempre llame al 811 antes de excavar

Una facil llamada al numero 811 da comienzo al proceso para que marquen sus lineas de tuberías subterráneas y de servicios de utilidades. Cuando usted llama al 811 desde cualquier lugar del país, su llamada será transferida al Centro de One-Call (Una-Llamada) de su estado, quienes contactarán a los dueños de esas facilidades en su área.Para que usted pueda excavar con seguridad, un representante de Sunoco Pipeline se contactará con usted si una de nuestras líneas de tuberías se encuentra en el área donde se propone excavar. Usted puede encontrar más información acerca del 811 en el sitio web **www.call811.com**.

Como puede usted saber donde se encuentran localizadas las líneas de tuberías

La mayoría de las líneas de tuberías se encuentran debajo de la tierra, donde están mejor protegidas de los elementos y donde minimizan la interferencia con usos en la superficie. Aun así, los derechos de paso de las líneas de tubería están claramente identificados con marcadores de líneas de tuberías a lo largo de la ruta de la línea de tubería, los cuales identifican la ubicación aproximada—NO EXACTA—de la línea de tubería. Cada marcador de la línea de tubería contiene información que identifica la compañía que opera la línea de tubería, el producto transportado y un número de teléfono al cual se debe llamar en caso de una emergencia. **Los marcadores no indican la profundidad a la cual una línea de tubería se encuentra enterrada, la cual puede variar.** Los marcadores se pueden ver típicamente donde una línea de tubería atraviesa una calle, autopista o ferrocarril. Es un delito federal que una persona voluntariamente estropee, dañe, quite o destruya un marcador de una línea de tubería.

Marcador de Línea de Tubería

Marcador de Líneas de Tuberías — Este tipo de marcador es el más común. Contiene la información de Sunoco Pipeline, tipo de producto y nuestro número de contacto en caso de una emergencia. El tamaño, forma y color pueden variar.

Marcador Aéreo — Estos marcadores colocados mirando hacia el cielo son usados por los aviones de patrullas que monitorean las rutas de las líneas de tuberías.

Marcador de Tubos de Ventilación — Este marcador indica que una línea de tubería (protegida por un revestimiento de acero) pasa por debajo de una carretera, ferrocarril u otro cruce.

¿Cómo puede usted reconocer una fuga en una línea de tuberías?

Aun cuando los oleoductos son el método más seguro de transportar el combustible y los productos que usamos todos los días, saber reconocer una fuga en la tubería es importante. Lo siguiente puede indicar una fuga en la tubería:

- ***Vista:*** Charcos de líquido, terreno/vegetación descolorida o anormalmente seca, burbujeo continuo en áreas mojadas o inundadas, un brillo aceitoso en la superficie del agua, niebla de vapor o tierra volando en el aire pueden ser muestras de que ocurre una fuga en la línea de tubería. Otras posibles indicacioes son la presencia de plantas descoloridas o muertas, o terreno congelado durante temporadas caliente.
- ***Sonido:*** El volumen del ruido puede ser desde un silbido silencioso hasta un rugido fuerte, dependiendo del tamaño de la fuga y del sistema de líneas de tuberías.
- ***Olor:*** Un olor inusual, olor a petróleo o un olor gaseoso puede a veces salir de una fuga en una línea de tuberías.

Lo que si debe hacer en el caso de que ocurriese una fuga:

- Las prioridades principales son la seguridad del público y la protección del medio ambiente.
- ***Apague*** cualquier equipo y elimine cualquier fuente de encendido sin ponerse en riesgo a sí mismo.
- Inmediatamente ***salga del área*** caminando. Trate de avisar a otras personas que se encuentren cerca para que se alejen del área. Intente mantenerse en contra del viento.
- Desde un lugar seguro, ***llame al 911*** o a su número local de respuesta a emergencias y llame al número de emergencias de 24-horas del operador de la línea de tuberías. Provee su nombre, número de teléfono, una breve descripción del incidente y la ubicación para así poder iniciar una respuesta apropiada.

Lo que no debe hacer en el caso de que ocurriese una fuga:

- ***NO*** cause ninguna llama ni use otras fuentes potenciales de encendido tales como los interruptores de electricidad, vehículos de ignición, fósforos, etc. No encienda ningún vehiculo de motor ni equipo eléctrico. No toque ningún timbre de casa para notificar a las personas acerca de la fuga. Golpee la puerta con su mano para evitar crear chispas con la aldaba.
- ***NO*** se ponga en contacto directo al gas o líquido que se esté escapando.
- ***NO*** maneje hacia ninguna fuga o nube de vapor cuando esté saliendo del área.
- ***NO*** intente operar usted mismo ninguna válvula. Sin quererlo, usted podría dirigir más producto hacia la fuga o causar otro incidente.
- ***NO*** intente extinguir un fuego de productos de petróleo. Espere a que los bomberos locales y otros profesionales entrenados manejen la emergencia.

Lo que usted debe hacer en el caso que dañe/disturbe una línea de tubería

Si usted ocasiona o tiene conocimiento de algún daño, por más mínimo que sea, a una línea de tubería o a el revestimiento protector de la tubería, por favor notifique inmediatamente a la compañía de la línea de tubería. Cualquier daño pequeño a una línea de tubería, puede causar una fuga en el futuro. Un agujero, arañazo, dobladura o una arruga pueden ser una causa suficiente para que la compañía tenga que inspeccionar el daño y hacer reparaciones.

Esta requerido por la ley que todos los daños causados a tuberías subterráneas de gas o facilidades líquidas peligrosas sean reporteado a la compañía que opera esas tuberías. Los excavadores deben comunicarse con la compañía de esas tuberías inmediatamente al causar daños.

¿Qué es un derecho de paso y puedo yo construir o excavar en ellos?

Sunoco Pipeline trabaja diligentemente para establecer acuerdos escritos, o servidumbres con los dueños de terreno para así permitir y facilitar el acceso de construcción y mantenimiento cuando atravesamos esas propiedades privadas. Los derechos de paso usualmente se reconocen al ver caminos de terreno que están libres de árboles, edificios y de otras estructuras, con excepción de los marcadores de líneas de tuberías. Un derecho de paso puede que no tenga marcadores claramente visibles y puede que solo sean evidentes al ver solo los caminos de terreno libres, con excepción de granjas o tierras de cultivo.

Las oficinas del Secretario del Condado mantienen los registros de las servidumbres, los cuales son información pública. Ocupando espacio en los derechos de paso de las líneas de tubería impiden la habilidad del operador de la línea de tubería de poder reducir los daños por terceras personas, de proveer vigilancia en el derecho de paso y de hacer mantenimiento rutinario e inspecciones requeridas federalmente y estatalmente. Para poder ejecutar estas actividades críticas, el personal de mantenimiento de la línea de tubería necesita poder tener acceso de una manera fácil y segura al derecho de paso de la línea de tubería, y a las áreas a cada lado de la línea de tubería. Para poder conservar la integridad y seguridad en las líneas de tubería, se debe mantener distancia entre los árboles, arbustos, edificios, cercas, estructuras y otros impedimentos y las líneas de tubería.

Antes de cualquier proyecto de excavación cerca de los derechos de paso de Sunoco Pipeline al 877-795-7271.

¿Cómo usted puede ayudar?

Aunque incidentes que implican facilidades de oleoductos son muy raros, el conocimiento de la ubicación de la tubería, el potencial de los peligros, y qué hacer si una fuga ocurre puede ayudar a minimizar el impacto de una emisión de la tubería. La causa principal de incidentes en las tuberías subterráneas es excavaciones sin autorización. Los operadores de las líneas de tuberías son responsables por la seguridad de sus respectivas líneas de tuberías. Para poder conservar la integridad de las líneas de tuberías y de los derechos de paso, es esencial que los vecinos cerca de las facilidades y de las líneas de tuberías protejan contra excavaciones sin autorización y contra actividades destructivas. A continuación listamos lo que usted puede hacer para ayudar:

- **Familiaricese con las líneas de tuberías y las facilidades de líneas de tuberías en el área (señales de marcadores, señales en las cercas de los lugares cercados, etc.).**
- **Escriba el nombre del operador o compañía, información de contacto y cualquier otra información de la línea de tubería que se encuentran en las señales o marcadores cerca de usted y mantenga esa información cerca de su teléfono.**
- **Esté al tanto de cualquier actividad inusual o sospechosa o de excavaciones no autorizada tomando lugar dentro o cerca del derecho-de-paso de la línea de tuberías o instalación de línea de tuberías; informe cualquiera de estas actividades a los operadores de la línea de tuberías y LLAME AL 911.**

Mapas de Líneas de Tubería de Transmisión

La Oficina Estadounidense del Departamento de Transporte de Seguridad de Líneas de Tubería ha desarrollado el Sistema Nacional de Mapas de Líneas de Tubería ("NPMS" por sus iniciales en inglés) para proporcionar información acerca de los operadores de líneas de tubería y de sus mismas líneas de tuberías. El Sitio web de "NPMS" puede ser buscado en el internet usando el CÓDIGO POSTAL o el nombre del condado y estado, y en el mismo sitio usted puede adquirir un mapa del condado, el cual puede ser imprimido desde cualquier impresora personal. Para obtener una lista de los operadores con líneas de tuberías en su área y su información de cómo contactarlos, visite la página **www.npms.phmsa.dot.gov/**.

For more information regarding pipeline safety and an overview of the pipeline industry please visit the following websites:

Pipeline Resources and Information

- 811 - **www.call811.com**
- Pipeline 101 - **www.pipeline101.com**
- Association of Oil Pipe Lines (AOPL) - **www.aopl.org**
- American Petroleum Institute (API) - **www.api.org**
- Common Ground Alliance (CGA) - **www.commongroundalliance.com**

Government/Regulatory Agencies

- Pipeline Hazardous Materials Safety Administration (PHMSA) - **phmsa.dot.gov**
- Department of Transportation (DOT) - **www.dot.gov**

To learn more about Sunoco Pipeline L.P., or to take our survey, visit our website at: **www.sunocologistics.com**

Sunoco Pipeline L.P. operates the Inland and Harbor pipeline systems.

PRODUCTS THAT MAY BE TRANSPORTED IN YOUR AREA

PRODUCT	LEAK TYPE	VAPORS
HIGHLY VOLATILE LIQUIDS [SUCH AS: BUTANE, PROPANE, ETHANE, E/P MIX]. ONLY IN GLOUCESTER COUNTY, NJ: NATURAL GAS	Gas	Initially heavier than air, spread along ground and may travel to source of ignition and flash back. Product is colorless, tasteless and odorless.
HEALTH HAZARDS	May be ignited by heat, sparks, or flames and may form combustible mixture with air. Vapors may cause dizziness or asphyxiation and be toxic if inhaled at high concentrations. Contact with gas or liquefied gas may cause burns, severe injury and/or frostbite.	
HAZARDOUS LIQUIDS [SUCH AS: CRUDE OIL, DIESEL FUEL, JET FUEL, GASOLINE, AND OTHER REFINED PRODUCTS]	Liquid	Initially heavier than air and spread along ground and collect in low or confined areas. Vapors may travel to source of ignition and flash back. Explosion hazards indoors, outdoors or in sewers.
HEALTH HAZARDS	Inhalation or contact with material may irritate or burn skin and eyes. Fire may produce irritating, corrosive and/or toxic gases. Vapors may cause dizziness or suffocation. Runoff from fire control or dilution water may cause pollution.	

LOS PRODUCTOS QUE TRANSPORTAMOS EN SU ÁREA

PRODUCTO	TIPO DE FUGA	VAPORES
LIQUIDOS ALTAMENTE VOLÁTILES [TALES COMO: BUTANO, PROPANO, ETANO, E/T MIX]. SOLO EN GLOUCESTER COUNTY, NJ: GAS NATURAL	Gas	Inicialmente más pesado que el aire, se propaga en el suelo y puede viajar hasta fuentes de encendido y ocasionar retrocesos de llamas. El producto no tiene color, sabor ni olor.
RIESGOS A LA SALUD	Puede incendiarse con calor, chispas o con llamas y puede formar una mezcla inflamable con el aire. Los vapores pueden causar mareos o asfixia si estos son inhalados en concentraciones altas. El contacto con el gas o con el gas licuado puede causar quemaduras, lesiones graves y/o congelación.	
LIQUIDOS PELIGROSOS [TALES COMO: PETROLEO CRUDO, COMBUSTIBLE DIESEL, COMBUSTIBLE PARA JETS, GASOLINA Y OTROS PRODUCTOS REFINADOS]	Liquido	Inicialmente más pesado que el aire y se propaga en el suelo y se acumula en áreas bajas o confinadas. Los vapores pueden viajar hasta fuentes de encendido y ocasionar retrocesos de llamas. Los peligros de explosión ocurren adentro, afuera o en los alcantarillados.
RIESGOS A LA SALUD	La inhalación o el contacto con el material pueden irritar o quemar la piel y los ojos. El fuego puede producir gases irritantes, corrosivos y/ tóxicos. Los vapores pueden causar mareos o sofocación. La escorrentia que proviene del control del fuego o de las aguas de dilución puede causar contaminación.	

24-Hour Emergency Number: 800-786-7440

Sunoco Logistics
Sunoco Pipeline L.P.

Non-Emergency Number: 877-795-7271
Website: www.sunocologistics.com

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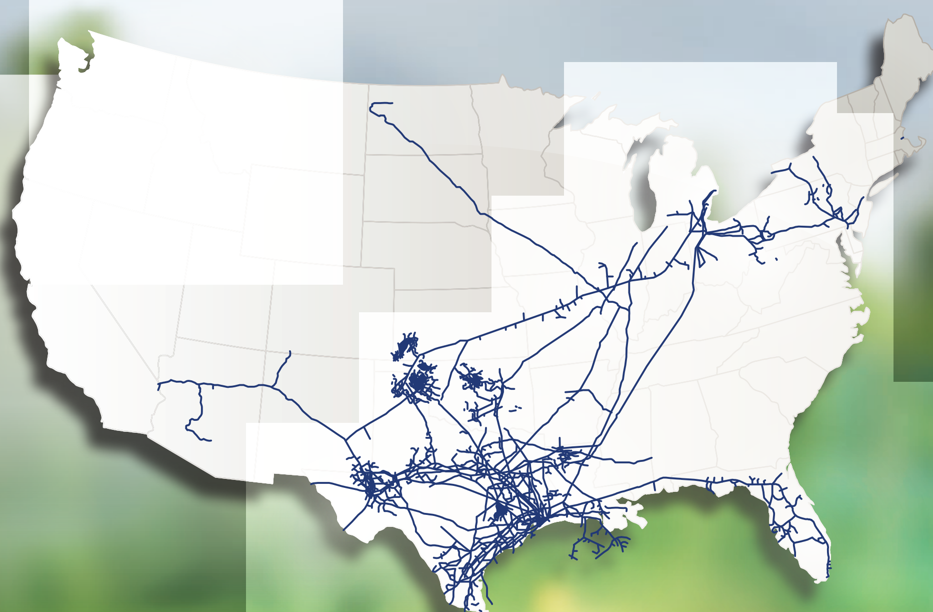
Friedman_03_Sunoco brochure Oct. 2018

ENERGY TRANSFER

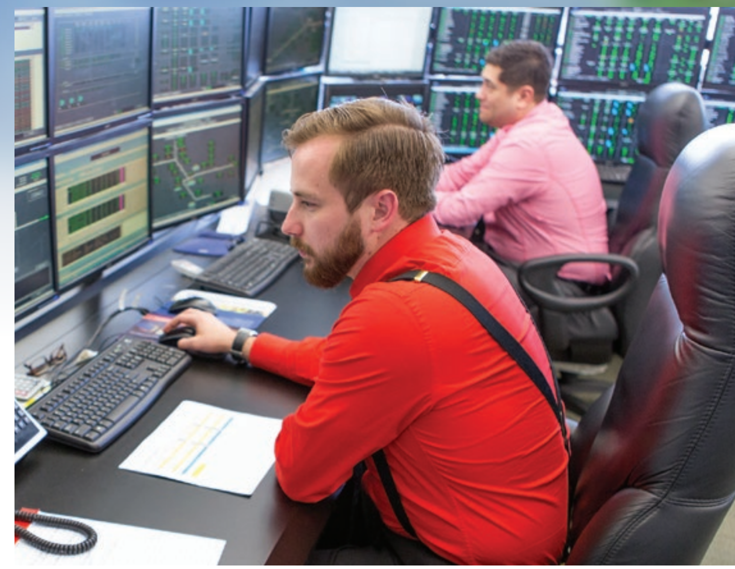
Energy Transfer, a Texas-based energy company founded in 1995 as a small intrastate natural gas pipeline company, is now one of the largest and most diversified master limited partnerships in the United States. Strategically positioned in all of the major U.S. production basins, the company owns and operates a geographically diverse portfolio of energy assets, including midstream, intrastate and interstate transportation and storage assets. Energy Transfer operates nearly 90,000 miles of natural gas, crude oil, natural gas liquids and refined products pipelines and related facilities, including terminalling, storage, fractionation, blending and various acquisition and marketing assets in 38 states.



Approximately two-thirds of the natural gas and petroleum products we use every day are transported through underground pipelines – making them an essential part of the nation's infrastructure. Studies have confirmed that pipelines are the safest way to transport energy in the United States.

You are receiving this information because Energy Transfer, or one of its affiliates, may operate or maintain a pipeline in your community. We ask that you review the following important safety information, encourage you to share it with others and retain for future reference.

If you would like more information, please visit us at energytransfer.com or call our non-emergency number at 877-795-7271.



National Pipeline Mapping System

Everyone can contribute to safety and security by knowing where pipelines are in their community and recognizing unauthorized activity. To find out who operates transmission pipelines in your area, visit the National Pipeline Mapping System at www.npms.phmsa.dot.gov. To download the mobile application to your iOS device free of charge, visit the App Store and search for “NPMS Public Viewer.”

Pipeline Safety

Our pipelines are regularly tested and maintained using cleaning devices, diagnostic tools and cathodic protection. We perform regular patrols, both on the ground and in the air, along our routes to ensure the security and integrity of our lines. For the safety of our system and for the people around it, we monitor pipeline operations 24 hours a day, 365 days a year.

Special Protective Measures

Certain pipelines are designated as being in “High Consequence Areas” (HCA) due to their location in high population or environmentally sensitive areas. In accordance with regulations, we have developed and implemented a written Integrity Management Program that addresses the risks on certain pipeline segments. Baseline and periodic assessments are conducted to identify and evaluate potential threats to our pipelines. Any significant defects discovered are remediated and the company monitors program effectiveness so that modifications can be recognized and implemented.

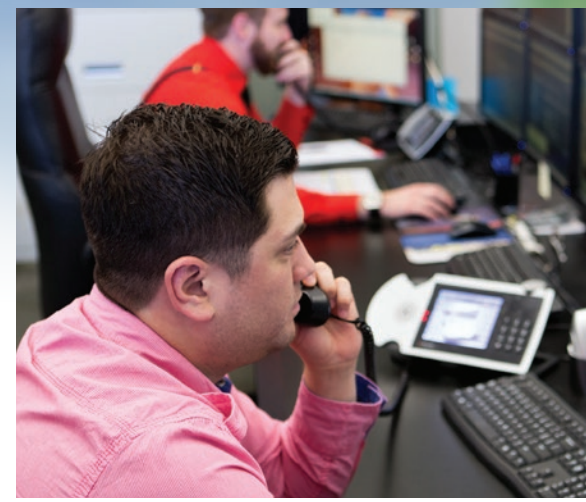
Along the Right-of-Way

Rights-of-way provide a permanent, limited access to privately owned property to enable us to operate, inspect, repair, maintain and protect our pipeline. Rights-of-way must be kept free of structures and other obstructions. Property owners should not dig, plant, place or build anything on the right-of-way without first calling 811 and having our personnel mark the pipeline, stake the easement and explain our property development guidelines to you.

RESPONDA
RECONOZCA
INFÓRMESE
COMUNÍQUESE

Sistema Nacional de Mapas de Tuberías

Todos pueden contribuir a la seguridad y protección sabiendo dónde se encuentran las tuberías en sus comunidades y reconociendo si hay actividad no autorizada. Para averiguar quién opera tuberías de transmisión en su zona, visite el Sistema Nacional de Mapas de Tuberías en www.npms.phmsa.dot.gov. Para descargar la aplicación móvil en su dispositivo iOS sin cargo alguno, viste el Apple Store y busque “NPMS Public Viewer.”



La seguridad de las tuberías

Realizamos pruebas y mantenimiento periódicos a nuestras tuberías usando dispositivos de limpieza, herramientas de diagnóstico y protección catódica. Patrullamos regularmente, tanto por tierra como por aire, nuestras rutas para garantizar la seguridad y la integridad de nuestras líneas. Para conservar la seguridad de nuestro sistema y de las personas a su alrededor, monitoreamos las operaciones de las tuberías las 24 horas del día, los 365 días del año.

Medidas especiales de protección

Ciertas tuberías son designadas como de “Áreas de altas consecuencias” (High Consequence Areas, HCA) debido a su ubicación en áreas de mucha población o con ecosistemas frágiles. En conformidad con las normas, hemos desarrollado e implementado por escrito un Programa de Gestión de Integridad que trata los riesgos de ciertos segmentos de tuberías. Se realizan evaluaciones iniciales y periódicas para identificar y analizar las amenazas potenciales a nuestras tuberías. Se corrigen todos los defectos significativos detectados y la compañía monitorea la eficacia del programa para que se puedan reconocer e implementar las modificaciones.

En el derecho de paso

El derecho de paso provee un acceso limitado y permanente a una propiedad privada para permitirnos operar, inspeccionar, reparar, mantener y proteger nuestra tubería. El derecho de paso se debe mantener libre de estructuras y otras obstrucciones. Los dueños de la propiedad no deben excavar, plantar, colocar o construir nada sobre el derecho de paso sin llamar primero al 811. Nuestro personal tiene que indicar la tubería, colocar estacas en el paso y explicarle a usted nuestras directivas para el desarrollo de la propiedad.

Pipelines are typically made of steel, covered with a protective coating and buried several feet underground. For your safety, markers are used to indicate the approximate location of pipelines. The markers contain the name of the pipeline operator, products transported and emergency contact information. Keep in mind that pipelines may not follow a straight line between markers, nor do markers indicate the exact location and depth of the pipeline.

Leaks from pipelines are unusual, but we want you to know what to do in the unlikely event one occurs. The table below describes the types of products transported by our pipelines. Refer to the Contact page to find out which products may be transported in your area. You may be able to recognize a leak by the following signs:

	Natural Gas	Natural Gas Liquids (Butane, Ethane, Propane)	Petroleum (Crude Oil, Gasoline, Diesel, Jet Fuel, Kerosene)	Hydrogen Sulfide (H_2S)
By Sight	• Dust blowing from a hole in the ground. • Continuous bubbling in wet or flooded areas. • Dead or discolored vegetation in a green area. • Flames, if a leak has ignited.	• Dust blowing from a hole in the ground. • Continuous bubbling in wet or flooded areas. • Dead or discolored vegetation in a green area. • Flames, if a leak has ignited. • Ice around a leak. • Vapor cloud or mist.	• Pool of liquid on the ground. • Rainbow sheen on the water. • Continuous bubbling in wet or flooded areas. • Vapor cloud or mist. • Flames, if a leak has ignited. • Dead or discolored vegetation in a green area.	• Dust blowing from a hole in the ground. • Continuous bubbling in wet or flooded areas. • Dead or discolored vegetation in a green area. • Flames, if a leak has ignited.
By Sound	• Blowing or hissing sound.	• Blowing or hissing sound.	• Blowing or hissing sound.	• Blowing or hissing sound.
By Smell	• Odorless unless mercaptan, a chemical odorant, is added to give it a distinctive smell.	• Odorless in its natural state, however a faint small may be present.	• An unusual smell or gaseous odor.	• Foul sulfur odor, similar to rotten eggs. • H_2S exposure may result in asphyxiation (suffocation) and prolonged exposure to low concentrations can deaden the sense of smell.

Las tuberías son típicamente de acero, tienen un revestimiento protector y se entierran a varios pies. Para su seguridad, la ubicación aproximada de las tuberías se indica con señales. Las señales contienen el nombre del operador de la tubería, los productos transportados y la información de contacto en caso de emergencia. Recuerde que la tubería quizá no siga una línea recta entre una señal y otra o quizá las señales no indiquen la ubicación y la profundidad exactas de la tubería.

Las fugas de tuberías son poco comunes pero queremos que sepa qué hacer si se produce este evento poco probable. El cuadro de abajo describe los tipos de productos que nuestras tuberías transportan. Consulte la página de Contacto para averiguar cuáles productos pueden ser transportados en su zona. Es posible que reconozca una fuga por las siguientes señales:

	Gas Natural	**Líquidos de Gas Natural** (Butano, Etano, Propano)	**Petróleo** (Petróleo crudo, Gasolina, Diesel, Combustible pesado, Kerosén)	**Sulfuro de Hidrógeno** (H_2S)
Por la vista	• Polvo que vuela de un orificio en la tierra. • Burbujeo continuo en áreas húmedas o inundadas. • Vegetación muerta o descolorida en un área verde. • Llamas, si la fuga se encendió.	• Polvo que vuela de un orificio en la tierra. • Burbujeo continuo en áreas húmedas o inundadas. • Vegetación muerta o descolorida en un área verde. • Llamas, si la fuga se encendió. • Hielo alrededor de una fuga. • Una nube de vapor o neblina.	• Charco de líquido en el suelo. • Mancha de brillo policromo en el agua. • Burbujeo continuo en áreas húmedas o inundadas. • Una nube de vapor o neblina. • Llamas, si la fuga se encendió. • Vegetación muerta o descolorida en un área verde.	• Polvo que vuela de un orificio en la tierra. • Burbujeo continuo en áreas húmedas o inundadas. • Vegetación muerta o descolorida en un área verde. • Llamas, si la fuga se encendió.
Por el sonido	• Sonido de soplido o silbido.	• Sonido de soplido o silbido.	• Sonido de soplido o silbido.	• Sonido de soplido o silbido.
Por el olfato	• Es inodoro a menos que se agregue mercaptano, un odorante químico, para darle un olor característico.	• Es inoloro en su estado natural, sin embargo, puede haber un leve olor presente.	• Un olor inusual u olor a gas.	• Olor desagradable a azufre, similar a huevos podridos. • La exposición al H_2S puede causar asfixia (sofocación) y la exposición prolongada a bajas concentraciones puede reducir el sentido del olfato.

CONTACT KNOW RECOGNIZE **RESPOND**

Know what's below. Call before you dig.

Don't ever assume you know where the underground utilities are located.

One of the greatest single challenges to safe pipeline operations is the accidental damage caused by excavation. In accordance with state and federal guidelines, a damage prevention program has been established to prevent damage to our pipelines from excavation activities, using non-mechanical or mechanical equipment or explosives to move earth, rock or other material below existing grade. Laws vary by state, but most require a call to 811 between 48 to 72 hours before you plan to dig. Your local One-Call Center will let you know if there are any buried utilities in the area, and the utility companies will be notified to identify and clearly mark the location of their lines at no cost to you.

ALWAYS CALL 811 BEFORE YOU DIG.

WAIT THE REQUIRED AMOUNT OF TIME.

RESPECT THE MARKS.

DIG WITH CARE.

If you should happen to strike the pipeline while working in the area, it is important that you phone us immediately. Even seemingly minor damage, such as a dent or chipped pipeline coating, could result in a future leak if not promptly repaired.

What should I do if I suspect a leak?

- Leave the area immediately, on foot, if possible, in an uphill, upwind direction. Follow direction of local emergency response agencies.
- Abandon any equipment being used in or near the area.
- Avoid any open flame or other sources of ignition.
- Warn others to stay away.
- From a safe location, call 911 or local emergency response agencies.
- Notify the pipeline company immediately.
- Do not attempt to extinguish a pipeline fire.
- Do not attempt to operate pipeline valves.

Wait for the site to be marked. Marking could be either by paint, flags or stakes.

APWA Color Code

- (White) Proposed excavation
- (Pink) Temporary survey markings
- (Red) Electric power lines, cables, conduit and lighting cables
- (Yellow) Gas, oil, steam, petroleum or gaseous materials
- (Orange) Communication, alarm or signal lines, cables or conduit
- (Blue) Potable water
- (Purple) Reclaimed water, irrigation and slurry lines
- (Green) Sewers and drain lines

COMUNÍQUESE · INFÓRMESE · RECONOZCA · RESPONDA

811® Determina lo que está **bajo tierra.** **Llama antes de excavar.**

Nunca suponga que sabe dónde están los servicios públicos subterráneos.

Uno de los retos más grandes a las operaciones seguras de las tuberías es el daño accidental causado por una excavación. De acuerdo con las pautas estatales y federales, se ha implementado un programa de prevención de daños para prevenir que nuestras tuberías sean dañadas durante actividades de excavaciones, donde se emplean equipos mecánicos y no mecánicos o explosivos para mover tierra, piedra o algún otro tipo de material debajo de la superficie actual. Las leyes varían de estado a estado, pero la mayoría de los estados requieren que haga una llamada al 811 de 48 a 72 horas antes de cuando piensa excavar. Su centro One-Call local le informará si hay algún servicio público enterrado en el área, y se notificará a las compañías de servicios públicos para que identifiquen y señalen claramente la ubicación de sus líneas sin costo para usted.

SIEMPRE LLAME 811 ANTES DE EXCAVAR.

ESPERE LA CANTIDAD DE TIEMPO EXIGIDA.

RESPETE LAS SEÑALES.

EXCAVE CON CUIDADO.

Si llegara a golpear la tubería mientras trabaja en el área, es importante que nos llame por teléfono inmediatamente. Incluso los daños que parecen mínimos, como una abolladura o el raspón del recubrimiento de la tubería, podrían causar una fuga en el futuro si no se reparan rápidamente.

¿Qué debe hacer si sospecha que hay una fuga?

- Retírese del área inmediatamente, en lo posible a pie, cuesta arriba y en contra del viento. Siga las instrucciones de las agencias de respuesta a emergencias locales.
- Abandone cualquier equipo que esté utilizando en el área o cerca de ella.
- Evite llamas abiertas u otras fuentes de ignición.
- Advierta a otras personas que se mantengan alejadas.
- Llame al 911 ó a las agencias de respuesta a emergencias locales desde un lugar seguro.
- Notifique inmediatamente a la compañía de la tubería.
- No intente extinguir un incendio de una tubería.
- No intente manipular las válvulas de la tubería.

Aguarde la marcación del sitio. Las marcas pueden ser con pintura, banderas o estacas.

Código de colores de APWA

- Excavación propuesta
- Señales temporalis de relevos topograficos
- Líneas de energía eléctricia, cables, conductos y cables de iluminación
- Gas, aceite, vapor, petróleo o materiales gaseosos
- Comunicación, líneas de señales o de alarma, cables o conductos
- Agua potable
- Agua recuperada, lineas de irrigación
- Líneas de drenaje y alcantarillado

Energy Transfer, una compañía energética con sede en Texas, fundada en 1995 como una pequeña compañía interestatal de tuberías de gas natural, es ahora una de las sociedades de responsabilidad limitada más grandes y más diversificadas de los Estados Unidos. Ubicada en una posición estratégica en una de las principales zonas de producción de los EE. UU., la compañía posee y opera una cartera geográficamente diversa de activos de energía, que incluyen activos de transporte y almacenamiento intermedio, intraestatal e interestatal. Energy Transfer opera cerca de 90,000 millas de tuberías de gas natural, petróleo crudo, líquidos de gas natural y productos refinados, así como instalaciones relacionadas, que incluyen instalaciones de terminales, almacenamiento, fraccionamiento, mezcla y varios activos de adquisición y marketing en 38 estados.

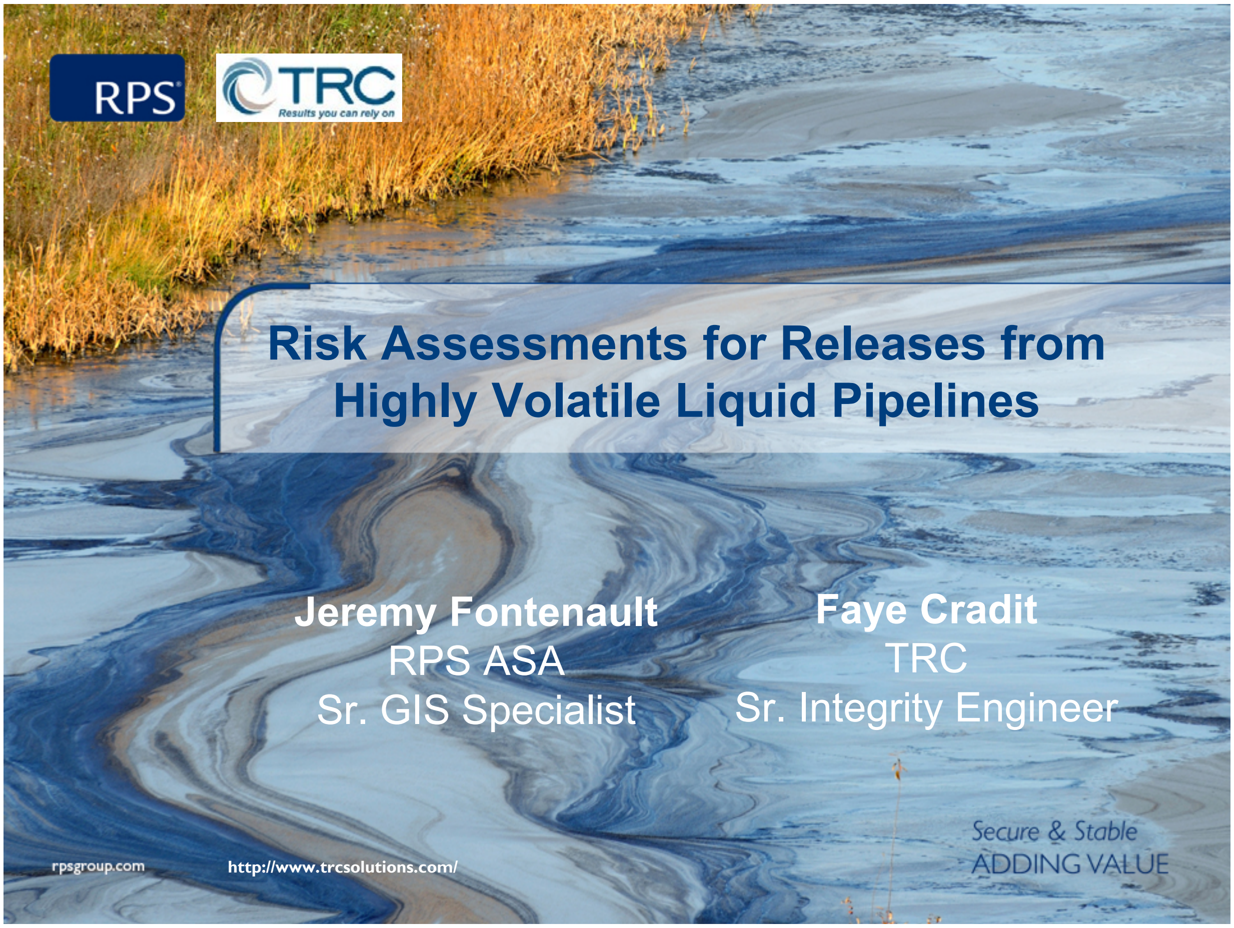
Aproximadamente dos tercios del gas natural y de los productos del petróleo que usamos a diario se transportan a través de tuberías subterráneas, convirtiéndose en una parte esencial de la infraestructura del país. Los estudios han confirmado que las tuberías son la manera más segura para transportar energía en los Estados Unidos.

Usted está recibiendo esta información porque es posible que Energy Transfer, o uno de sus socios, opere o realice el mantenimiento de una tubería en su comunidad. Le pedimos que repase la siguiente información de seguridad importante, lo alentamos a que la comparta con otros y la conserve para consulta en el futuro.

Please share this important safety information with others – anyone who plans to dig.

Sírvase compartir esta importante información de seguridad con los demás o con cualquiera que tenga planeado hacer trabajos de excavación.

Si desea obtener más información, visítenos en energytransfer.com o llame a nuestro número que no es para emergencias al 877-795-7271.



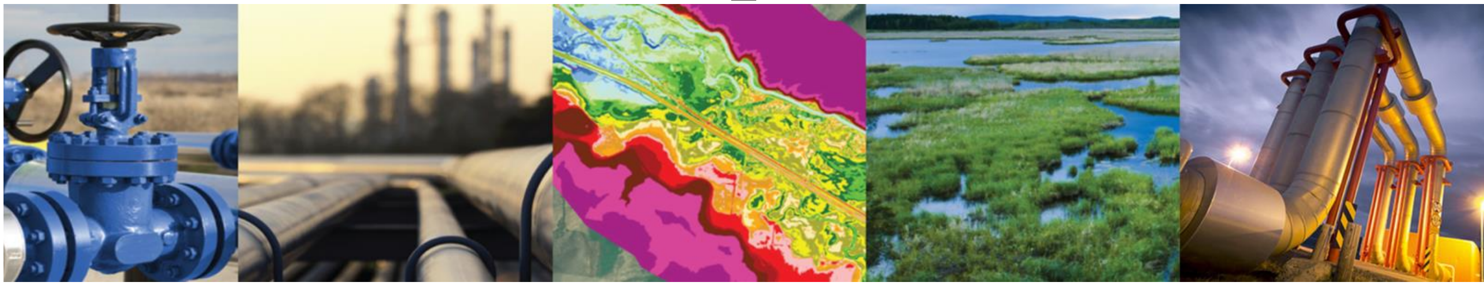
RPS TRC Results you can rely on

Introduction

Pipeline operators are required by code (49 CFR Part 195.452) to have a process in place for identifying pipeline segments that could affect a high consequence area (HCA).

In addition to having the HCAs identified, pipeline operators must take special measures to protect these areas and mitigate the associated risks.

Depending on the type of product being transported, a product release could result in liquid plumes, vapor dispersion, or a combination of both; which the operators need to account for in their processes.



G2 INTEGRATED SOLUTIONS

Mariner East 2 Pipeline and Existing Adelphia Pipeline Risk Assessments

Submitted on: November 13, 2018
Submitted to: Timothy A. Boyce, Director of DES, BoyceT@co.delaware.opa.us
Submitted by: Courtney R. Phillips, Courtney.Phillips@g2-is.com
Tracking codes: 113097

Version	Date	Author	Checked by	Approved by	Summary
1.1	11/02/2018	R. Mancik	C. Phillips	J. F. Kill	Issue for Client Review
2.1	11/13/2018	R. Mancik	C. Phillips	J. F. Kill	Final Issue

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About G2-IS

G2 Integrated Solutions (G2-IS) delivers expertise to pipeline operators, utility companies, and other energy stakeholders in seven specialized service disciplines:

- Asset Integrity
- Engineering
- Regulatory and Strategic Consulting
- Geospatial
- Field Assurance
- Programmatic Management Solutions
- Software & Technology

We provide asset life cycle solutions that help manage risk, assure compliance, and optimize performance. G2-IS is committed to maintaining a safe and incident-free working environment for our people and our customers, and to sound environmental stewardship. We work within controlled management systems that achieve continual improvement and assure reliable delivery of high quality products, services and outcomes.

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1.0 EXECUTIVE SUMMARY

Residents of Delaware County, Pennsylvania desire to better understand the risks associated with the operation of the Mariner East 2 pipeline and the converted Adelphia pipeline. In response to public discussions, this risk assessment was undertaken to estimate the level of individual risk to those people located within the County of Delaware from either the Mariner East 2 pipeline or the converted Adelphia pipeline and then compare to other common sources of risk experienced by the general population.

The Mariner East 2 pipeline and Adelphia pipeline quantitative risk assessments were executed in a systematic process in which potential accident events were identified, the associated consequence and likelihood of such events were determined, and the risk measures estimated. The risk measure calculated for each of the pipelines is individual fatality risk, which is the measure of the likelihood of an individual suffering a fatal injury, as the result of an accident event, in a period of a year.

The concluding intent of these risk assessments was to present a comparison of the Mariner East 2 pipeline and Adelphia pipeline estimated individual fatality risk levels against other individual fatality risk levels from common sources. This comparative evaluation establishes an improved perspective when interpreting the meaning of the pipeline individual fatality risks.

It was concluded that the individual fatality risk levels estimated for both the Mariner East 2 pipeline and the Adelphia pipeline fall within a range of other common risk sources such as traffic accident, house fire, or fall from stairs.

2.0 INTRODUCTION

Residents of Delaware County, Pennsylvania desire to better understand the risks associated with the operation of the Mariner East 2 pipeline and the converted Adelphia pipeline. In response to public discussions, the Delaware County Council would like to estimate the level of individual risk to those people located within the County of Delaware from either the Mariner East 2 pipeline or the converted Adelphia pipeline, and compare these risk results to other common sources of risk experienced by the general population.

The County of Delaware has contracted G2 Integrated Solutions to undertake the following two tasks:

- An independent risk assessment of the event of an accidental release located within Delaware County from the Mariner East 2 pipeline
- An independent risk assessment of the event of an accidental release located within Delaware County from the converted existing Adelphia pipeline

This document provides the results of these risk assessments.

2.1 Objectives

The specific objectives of the Mariner East 2 pipeline and Adelphia pipeline risk assessments were to:

- Calculate the individual fatality risk as a function of distance from the pipeline route and generate a risk transect
- Compare the level of individual fatality risk to other common risk sources

2.2 Scope of Work

The following sections detail the scope of work for the Mariner East 2 pipeline and Adelphia pipeline risk assessments.

The risk measure calculated for each of the pipelines is individual fatality risk ("individual risk"), which is the measure of the likelihood of an individual suffering a fatal injury, as the result of a hazardous accident event, in a period of a year. Such a risk measure is preferred because it can be compared to readily available statistics.

2.2.1 Mariner East 2 Pipeline Risk Assessment

The scope of the Mariner East 2 pipeline risk assessment is for the quantification of individual fatality risk to the Delaware County public residing and working nearby the future 20-inch natural gas liquid (NGL) transmission pipeline. The physical scope of work is an accidental release from the body of the Mariner East 2 pipeline segment located within the Delaware County boundaries.

The following items are excluded from the Mariner East 2 pipeline risk assessment scope of work:

- Associated pipeline equipment such as meters, pumps, valves, compressors, etc.
- Escalation events resulting from an initiating event from the Mariner East 2 pipeline
- Other pipelines connected to, or nearby, the Mariner East 2 pipeline
- Societal fatality risk calculation

2.2.2 Adelphia Pipeline Risk Assessment

The scope of the Adelphia pipeline risk assessment is for the quantification of individual fatality risk to the Delaware County public residing and working nearby the existing 18-inch natural gas transmission pipeline. The physical scope of work is an accidental release from the body of the existing Adelphia pipeline segment located within the Delaware County boundaries.

The following items are excluded from the existing Adelphia pipeline risk assessment scope of work:

- Associated pipeline equipment such as meters, pumps, valves, compressors, etc.
- Escalation events resulting from an initiating event from the existing Adelphia pipeline
- Other pipelines connected to, or nearby, the existing 18-inch Adelphia pipeline
- Societal fatality risk calculation

3.0 DEFINITIONS

Release Event	An accidental loss of containment from the pipeline via a pinhole, leak, or rupture.
Accident Event	A hypothetical event, such as a jet fire, flash fire, or explosion, that results from a pipeline release.
Accident Event Frequency	A measure of how often a hypothetical accident event could occur. For pipelines, the accident event frequency is measured on an annual per mile basis (i.e., per mile-year).
Accident Event Consequence	The potential harmful effect of an accident event, such as jet fire thermal radiation, flash fire, or explosion overpressure.
Atmospheric Condition	The condition of the atmosphere in terms of both Pasquill stability class (e.g., stable "F" or neutral "D") and wind speed.
Individual Fatality Risk	Individual fatality risk is the annual chance an individual will suffer a fatal level of harm due to hazards to which they are exposed.
Societal Fatality Risk	Societal fatality risk is the annual chance that a specified number of people will suffer a fatal level of harm due to hazards to which they are exposed.
Full Bore Release	A full bore release is the equivalent to a complete severing of the pipeline diameter resulting in discharge from pipe on both sides of the rupture point. The equivalent can occur by a large longitudinal rip or tear – complete severing is not required. Note that PHMSA uses the term "rupture" for full bore and any size longitudinal rip or tear, and then details the size of the longitudinal rip or tear.
Jet Fire	A directional flame resulting from the combustion of a fuel continuously released.
Flash Fire	A fire resulting in a rapidly spreading flame front; characterized by short duration and without damaging explosion overpressure.

Vapor Cloud	A region or volume containing a vaporized fuel in flammable concentrations; below a certain concentration, the cloud is not flammable.
Vapor Cloud Explosion	A vapor cloud that expands so rapidly, such as from a spreading flame front, as to result in a damaging overpressure or shockwave.

4.0 METHOD

A quantitative risk assessment is a systematic process in which hazards from an activity or operation are identified, and the consequence and likelihood of potential accidental events are estimated.

The following approach was executed for the Mariner East 2 pipeline and the Adelphia pipeline quantitative risk assessments:

1. Establish study context
2. Define the releases and accident events to be assessed
3. Determine accident event frequency
4. Determine magnitude of the harmful consequence and impact
5. Calculate individual risk results
6. Compare individual risk results to other common risk sources

5.0 STUDY CONTEXT

The descriptions and operating conditions of both the Mariner East 2 and Adelphia pipelines as assessed in this report are taken from publicly available sources. Where specific information needed for this assessment is not detailed in the publicly available sources, conservative interpretation of the available information and/or judgement is used to provide the necessary basis for the risk assessment. Such specific information may be used only indirectly in the analysis; for example: the depth of cover.

Table 1 is a summary of the Mariner East 2 pipeline information used as the basis of the risk assessment.

Table 2 is a summary of the Adelphia pipeline information used as the basis of the risk assessment.

Table 1: Mariner East 2 Pipeline Risk Assessment Basis

Item	As Assessed	Comment
Pipeline diameter	20 inches	Reference [2]
Total pipeline length	306 miles	Reference [2]
Commodity transported	Natural gas liquids	Reference [3]
Commodity composition	Propane	Assumption: Mariner East 2 pipeline to carry propane or butane, batched and not mixed [2]. The pipeline is anticipated to carry primarily propane [4]. Thus, propane is the representative single component for the Mariner East 2 risk assessment.
Operating pressure	1,480 psig	Reference [2]
Operating temperature	12.5°C (54.5°F)	Assumed to be same as the average outdoor air temperature. Average outdoor air temperature from Reference [22].
Flowrate	275,000 barrels/day (258 kg/s)	Reference [4]
Emergency flow restriction devices	2 located in Delaware County	Both automated and manual valves will be located along the pipeline route. Two emergency flow restriction devices (EFRD) will be located in Delaware County [2]. For the purposes of consequence modeling, this risk assessment will assume that the 2 EFRDs located in Delaware County will isolate a volume equivalent to 8 miles of a 20-inch pipeline within 15 minutes.
Isolated length	8 miles	Reference [2] Approximate distance between the EFRD valves located in Delaware County.

Item	As Assessed	Comment
Isolation time	15 minutes	Reference [1] Sensing devices along the pipeline send data every 15 seconds to 15 minutes.
Depth of cover	4 feet	Reference [8]
Pipeline route surroundings in Delaware County	Varies from urban to suburban. Mixed residential and commercial land use.	Google Maps, Google Earth
Atmospheric condition	D-4.5 m/s	D-4.5 m/s is the neutral atmospheric condition in this risk assessment. Atmospheric stability class "D" is the dominating atmospheric condition based on published fractions. [9]. 4.5 m/s average wind speed from Reference [22].
	F-1.5 m/s	F-1.5 m/s is the stable atmospheric condition in this risk assessment. It represents the allocation of both atmospheric classes "F" (i.e., stable) and "E" (i.e., slightly stable) and the lowest wind speed category used in Purple Book for "F" and "E" stability conditions [9]. Stable wind conditions tend to have much greater dispersion distances than average wind conditions.

Table 2: Adelphia Pipeline Risk Assessment Basis

Item	As Assessed	Comment
Pipeline diameter	18 inches	Reference [6]
Pipeline length (overall)	84 miles	Reference [6]
Commodity transported	Natural gas	Reference [6], [7]
Commodity composition	Methane	Simplification: Natural gas is primarily methane. Methane is used as the representative single component for this risk assessment.
Operating pressure	1,083 psig	Reference [6]
Operating temperature	12.5°C (54.5°F)	Reference [22]
Flowrate	250 MMSCFD (58.8 kg/s)	Reference [6]
Isolated length	N/A	While natural gas pipelines typically are equipped with emergency isolation capability, such capability does not factor into the consequence modeling approach used for this risk assessment. See Section 8.1 for details.
Isolation time	N/A	See Section 8.1 for details.
Depth of cover	4 feet	Assumption: 4 feet of cover is considered typical.
Pipeline route surroundings in Delaware County	Varies from urban to suburban. Mixed residential and commercial land use.	Google Maps, Google Earth

Item	As Assessed	Comment
Atmospheric condition	D-4.5 m/s	D-4.5 m/s is the neutral atmospheric condition in this risk assessment. Atmospheric stability class “D” is the dominating atmospheric condition based on published fractions [9]. 4.5 m/s average wind speed from Reference [22].

6.0 DEFINE RELEASE AND ACCIDENT EVENTS

This study considers the loss of containment, or unwanted releases, from the pipeline body and assesses the potential events and associated impact on individuals exposed within the potential consequence zones. This section defines the loss of containment characteristics, accident event frequencies, and potential associated consequences.

The defined characteristics of a loss of containment, or release event, include:

- Release hole-size
- Release location
- Release orientation

The following accident event frequencies, associated consequences, and impacts were considered:

- Jet fires resulting in harmful thermal radiation levels
- Flash fire resulting in harmful thermal radiation levels
- Vapor cloud explosion resulting in harmful overpressures

6.1 Release Hole-Size

Loss of containment hole-sizes can range from full bore ruptures to pinhole punctures. For this risk assessment, the following two hole-sizes were considered:

- Full bore rupture
- 50 mm equivalent hole (i.e., approximately two inches)

As specified in the "Guidelines for Quantitative Risk Assessment" (widely referred to as the "Purple Book") [9], simplifying the potential range of pipeline release hole-sizes to two (2) representative hole-sizes is sufficient for calculating risk and is consistent with pipeline release scenarios.

A full bore rupture event is when the pipeline body is completely severed (sometimes called "guillotine" break) or has a longitudinal split or crack with a large area. In such an event, the resulting discharge comes from both the portion of the pipeline upstream of the rupture point and the portion downstream of the rupture point. Such releases are characterized by a massive, but a rapidly decreasing discharge rate.

A 50 mm equivalent hole represents an event with a much smaller discharge rate. Such releases are characterized by discharge rates that do not decrease appreciably over the time periods relevant to quantitative risk assessments. Although such events might range from tiny pinhole leaks to leaks considerably larger than 50 mm, 50 mm is selected to represent the range of possible leaks.

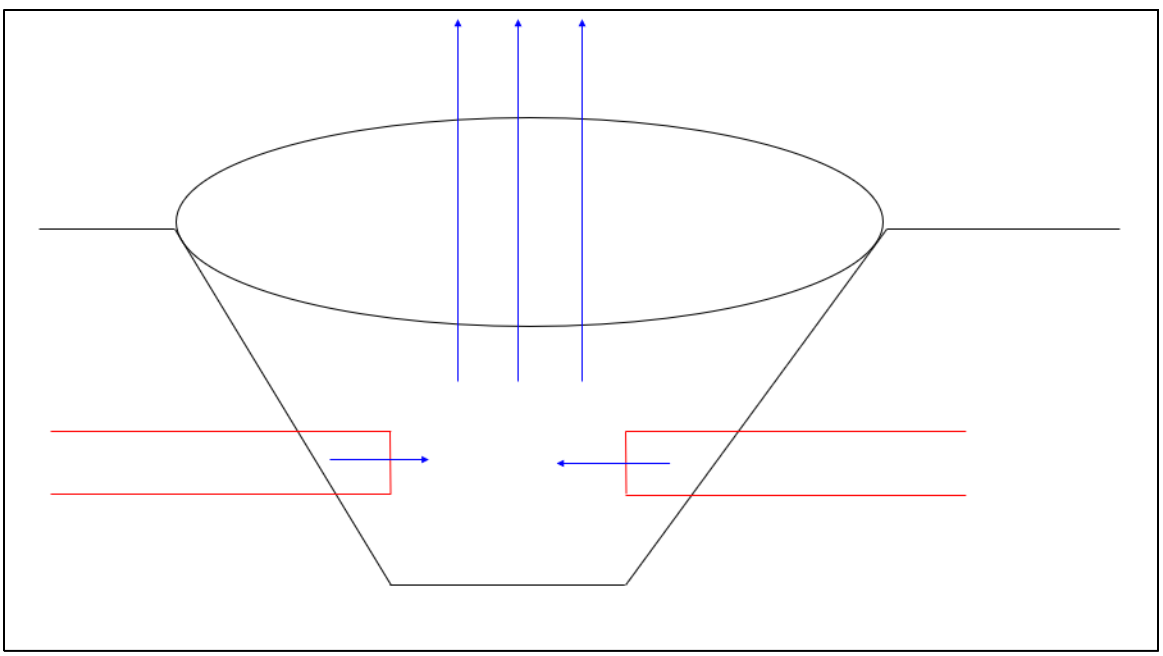
6.2 Release Location and Release Orientation

For the objectives of these risk assessments, only below-ground, shallow depth, pipeline body release locations are considered.

Given a shallow depth of cover, a gas or two-phase flashing liquid release from a buried pipeline can result in the formation of a crater at the release location. The crater has the effect of directing the resulting discharge into an upwards direction with a reduced velocity, as compared to a free jet. Such effects can greatly alter the impact of the resulting consequence at ground level.

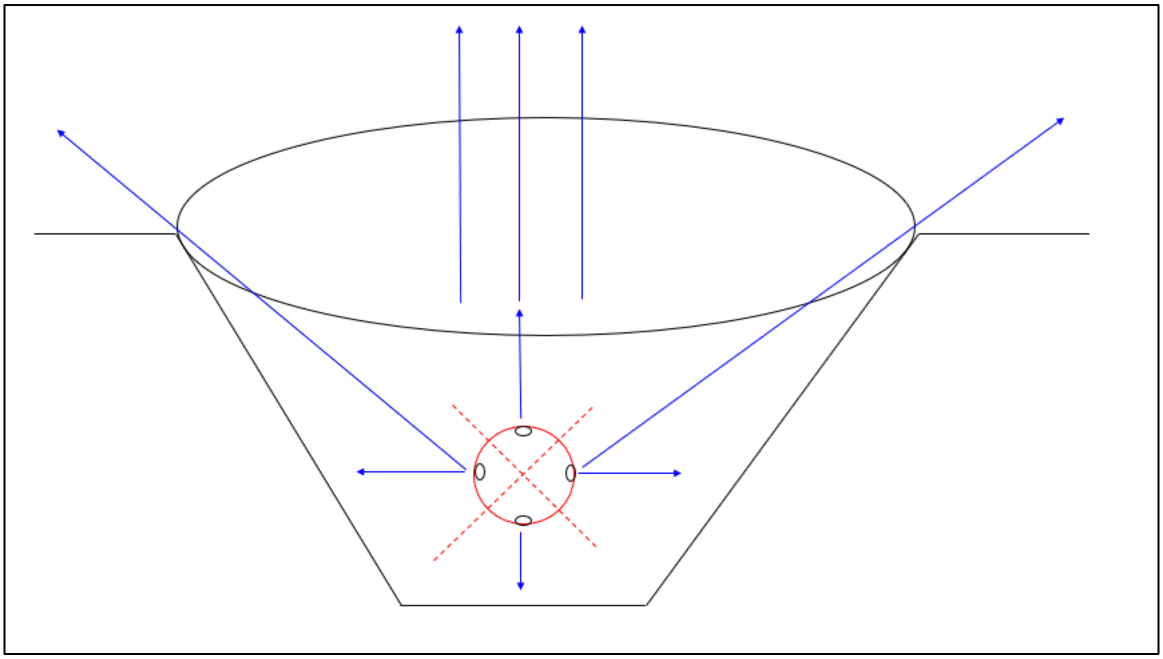
Figure 1 is a simplified diagram that illustrates the release orientation of a full bore release, with a shallow depth of cover. The discharge comes from both upstream and downstream portions of the ruptured pipeline. The two flows impinge on each other, form a crater, and exit the crater in a vertical orientation.

Figure 1: Full Bore Release Orientation



For the 50 mm hole-size, the release location can be anywhere around the pipeline body. For releases located near the top or bottom of the pipe, the release orientation will be nearly vertical as caused by the walls of the resulting crater. For releases located near the side of the pipeline body, the release orientation will be some angle closer to horizontal when exiting the crater. Figure 2 is a simplified diagram that illustrates the release orientation of a 50 mm hole-size release.

Figure 2: 50 mm Release Orientation



6.3 Accident Event Frequencies

After defining the release characteristics, the frequency of the associated potential accident events (i.e., jet fire, explosion, etc.) were determined. PHMSA historical data was used to estimate the frequency of an initiating release event for the Mariner East 2 pipeline and the Adelphia pipeline.

Event tree diagrams were then used to model and examine the potential accident event frequencies based on pathways from the initiating release event. The initiating release event starts at the left side of the tree and is followed by the occurrence, or not, of subsequent events and continues until the consequential outcome, or accident event, is reached. The frequency of each evaluated accident event is determined by multiplying the initiating release event frequency and the probabilities assigned to each of the subsequent events along the relevant pathway.

The event trees specific to the Mariner East 2 pipeline risk assessment and the Adelphia pipeline risk assessment are discussed in Section 7.0 and Section 8.0, respectively.

6.4 Accident Event Consequences

For the purposes of quantitative risk assessment, accident event consequence refers to the potential physical effects from pipeline loss of containment events. For this risk assessment, the accident event consequences relevant to the risk assessment of the Mariner East 2 and Adelphia pipelines are:

- Discharge rate
- Ignition
- Jet fire thermal radiation
- Flash fire thermal radiation
- Vapor cloud explosion overpressure

Each of these has specific meanings and relevant characteristics as applied within a quantitative risk assessment, which are described in the following sections.

The consequence modeling was performed using the DNV GL Phast software package.

6.4.1 Discharge Rate

In determining individual risk levels, the discharge rate, rather than the total quantity released, establishes the magnitude of the harmful consequence assessed. The discharge rate is based on the release hole-size and the pipeline operating parameters.

For the 50 mm release hole-size used in this risk assessment, the discharge rate is less than the normal pipeline flowrate, and is, therefore, nearly constant for over an hour, even with emergency isolation.

For a full bore rupture release, the initial discharge rate will be much greater than the normal pipeline flowrate but will decrease rapidly over time. The location of the rupture along the pipeline, the location of upstream and downstream isolation valves, and the isolation time for stopping the incoming flow may influence the discharge rate as a function of time.

The DNV GL Phast consequence modeling software was used to calculate the discharge rate over time for each of the two hole-sizes considered, based on the pipeline diameter, operating pressure, pipeline length, and isolation valve locations.

6.4.2 Ignition

A release of flammable material from a pipeline could result in the following ignition scenarios:

- Not ignite
- Ignite immediately
- Ignite after some time delay

Ignition of released flammable contents of a pipeline can potentially result in a jet fire, flash fire, or explosion.

Ignition sources for such accident events may be remote from the pipeline, in the form of open flames, electrical equipment, motorized vehicles, and other heat or spark sources. Additionally, the release event itself or electrostatic ignition sources near the release location can also be a source of ignition.

6.4.3 Jet Fire Thermal Radiation

A jet fire results from either the immediate or delayed ignition of a release of pressurized flammable gas. The resulting jet fire produces thermal radiation that can harm people directly by causing burns to people exposed over time or indirectly by starting secondary fires.

The thermal radiation level reaching a given point is largely determined by the:

- Size of the resulting flame (i.e., the larger the flame, the greater the distance to a given thermal radiation level)
- Composition of the fuel

It should be noted that the composition of the materials involved in the subject pipelines has an effect that is secondary compared to the flame size.

A jet fire from an ignited buried pipeline release will be oriented upwards as a result of the crater formed, with a near vertical flame tilting downwind. This flame tilt has the net effect of “shifting” the thermal radiation consequence zone downwind. Because the flame shift downwind is minimal, assessing the event at varying wind speeds was not warranted and, therefore, an average wind speed is used in this risk assessment for jet fire thermal radiation.

The modeling software also accounts for the effects the crater has on the momentum of the resulting jet, which can influence the thermal radiation footprint.

6.4.4 Flash Fire Thermal Radiation

If there is sufficient ignition delay to allow the release of pressurized flammable gas to disperse and form a flammable cloud, a flash fire results once the flammable cloud is ignited. Unlike a jet fire, a flash fire has a short duration but may be followed by a jet fire.

Although capable of starting secondary fires, in a quantitative risk assessment the harmful impact of a flash fire is simplified by limiting harm only to people directly exposed outdoors. The consequence zone of a flash fire is taken as equivalent to the area of the flammable cloud.

6.4.5 Vapor Cloud Explosion Overpressure

A vapor cloud explosion results in a shockwave, measured as an overpressure, that can cause harm directly to persons exposed outdoors, or indirectly to persons indoors by causing damage or collapse of buildings or structures. If the overpressure is sufficient to cause harm it is referred to as a damaging overpressure. At some low overpressure, there is insufficient energy to cause significant harm.

It should be noted that in common language usage, outside of risk assessment, the term "explosion" is often used rather loosely to describe any large ignited release of highly flammable gas or liquid. Such terminology use may make no distinction between jet fire, flash fire, or damaging vapor cloud explosion. Written material using the term outside of a quantitative risk assessment context should be interpreted accordingly.

6.5 Accident Event Impact

The accident event impact effects of the harmful accident event consequences described in Section 6.4 are needed to estimate an individual risk. For each of the consequence types, a vulnerability to an exposed person is applied. The vulnerability can be described as the fatality fraction of those persons exposed.

The vulnerability values used in this risk assessment are taken from the Purple Book [9] and are summarized in the following sections.

6.5.1 Jet Fire Thermal Radiation

For jet fire thermal radiation, the vulnerability varies with the thermal radiation level. For this risk assessment, the thermal radiation levels are divided into four ranges and an average vulnerability is applied to each range. The value of the vulnerability for each range is calculated from the radiation level and exposure time relationship published in the Purple Book [9], using a maximum of a 20-second exposure time. The 20-second maximum exposure time is also stipulated in the Purple Book [9].

Table 3 summarizes the vulnerability values applied in this risk assessment to people directly exposed (i.e., outdoors) to jet fire thermal radiation consequence.

Table 3: Jet Fire Thermal Radiation Vulnerability, Persons Outdoors

Consequence Level	Fatality Vulnerability	Basis
Greater than 35 kW/m^2	1.0	20 second exposure to unprotected skin
18 kW/m^2 to 35 kW/m^2	0.69	20 second exposure to unprotected skin
12.5 kW/m^2 to 18 kW/m^2	0.23	20 second exposure to unprotected skin
9.46 kW/m^2 to 12.5 kW/m^2	0.04	20 second exposure to unprotected skin
Less than 9.46 kW/m^2	0	20 second exposure to unprotected skin

People inside buildings are mostly shielded from direct exposure to thermal radiation. However, being present in a building does not eliminate vulnerability to thermal radiation, such as if the thermal radiation results in the building catching fire. The Purple Book stipulates an indoor vulnerability of 1.0 for jet fire thermal radiation levels greater than 35 kW/m^2 and zero for levels less than 35 kW/m^2, as summarized in Table 4 [9].

Table 4: Jet Fire Thermal Radiation Vulnerability, Persons Indoors

Consequence Level	Fatality Vulnerability	Basis
Greater than 35 kW/m^2	1.0	Assumes buildings are set on fire
Less than 35 kW/m^2	0	Below building ignition threshold

6.5.2 Flash Fire Thermal Radiation

For flash fire thermal radiation, the harmful impact is assumed not to vary by radiation level nor exposure time, because flash fires have very short durations (See Table 5). The Purple Book stipulates an outdoor vulnerability of 1.0 for persons in the flash fire flame envelope and zero for persons outside the flame envelope [9]. The Purple Book further stipulates that the flash fire flame envelope is equal to the flammable cloud footprint (the lower flammable level concentration contour) at the time of ignition [9].

Persons inside buildings are assumed to not be vulnerable to flash fire. The rationale for this simplification is not discussed in the Purple Book [9]; however, can be presumed to be related to the very short durations of flash fires. Persons inside buildings are likely able to escape after the flash fire, even if the building catches fire.

Table 5: Flash Fire Thermal Radiation Vulnerability

Consequence Level	Fatality Vulnerability	Basis
Inside LFL Cloud, Outdoors	1.0	Inside flash fire flame envelope
Inside LFL Cloud, Indoors	0	Inside flash fire flame envelope
Outside LFL Cloud, Outdoors or Indoors	0	Outside flash fire flame envelope

6.5.3 Vapor Cloud Explosion Overpressure

The Purple Book provides both indoor and outdoor vulnerabilities for vapor cloud explosion overpressure (See Table 6 and Table 7) [9]. The Purple Book [9] does not cite a specific basis or rationale for these vulnerabilities, however the Purple Book often cites the related Green Book [10]. The Green Book describes in detail the impact on humans of exposure to toxic substances, heat radiation, and overpressure [10].

Table 6: Vapor Cloud Explosion Vulnerability, Persons Outdoors

Consequence Level	Fatality Vulnerability	Basis
Overpressure greater than 4.35 psig (0.3 bar)	1.0	Not provided[1]
Overpressure less than 4.35 psig (0.3 bar)	0	Not provided[1]
[1] The Purple Book does not provide a basis for the vulnerability values provided. See Section 6.5.3.		

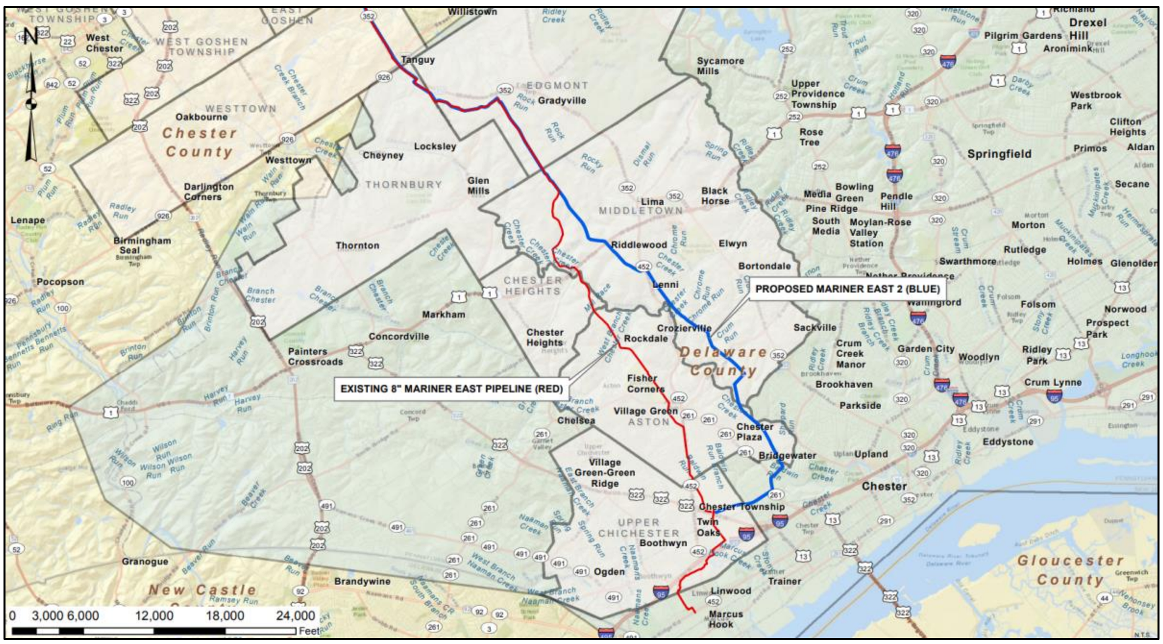
Table 7: Vapor Cloud Explosion Vulnerability, Persons Indoors

Consequence Level	Fatality Vulnerability	Basis
Overpressure greater than 4.35 psig (0.3 bar)	1.0	Not provided[1]
Overpressure greater than 1.45 psig (0.1 bar) but less than 4.35 psig (0.3 bar)	0.025	Not provided[1]
Overpressure less than 1.45 psig (0.1 bar)	0	Not provided[1]
[1] The Purple Book does not provide a basis for the vulnerability values provided. See Section 6.5.3.		

7.0 MARINER EAST 2 PIPELINE RISK ASSESSMENT

The Mariner East 2 pipeline is an expansion of the existing Mariner East pipeline system and will transport NGLs from Ohio and the Pittsburgh area to the Marcus Hook facility for both domestic distribution and export. Mariner East 2 will be a 20-inch diameter pipeline with an initial transporting capacity of approximately 275,000 barrels per day of NGLs. The high-pressure pipeline will tunnel beneath 17 counties with a length of approximately 11.4 miles through Delaware County, Pennsylvania. Figure 3 shows the proposed route for the Mariner East 2 pipeline.

Figure 3: Proposed Route of Mariner East 2 Pipeline through Delaware County [11]



The following sections describe the risk assessment details specific to the Mariner East 2 pipeline.

7.1 Accident Event Consequence

The Mariner East 2 pipeline is modelled as pure propane to determine the accident event consequences. Upon release, liquid propane vaporizes to a dense gas, and, if not ignited immediately, the vaporized propane disperses downwind as a low-to-the-ground flammable cloud. After the pipeline is isolated and the content has leaked out, the flammable cloud will decrease in size until it is no longer at flammable concentrations.

For the purposes of this risk assessment, the dynamic nature of the Mariner East 2 pipeline accident event and associated consequences was reflected by considering two wind speed-stability conditions and dividing the event into three ignition periods.

The size of flammable cloud that is passively dispersing can vary considerably depending on the wind speed and atmospheric stability, which also varies.

The dispersing flammable cloud could ignite at any point in time and the time of ignition, with respect to the changing size of the flammable cloud means that the resulting consequence can vary greatly. If ignited early, the size of the flammable cloud will be small and jet fire thermal radiation will be the dominant harmful effect. A delayed ignition will result in a smaller jet fire due to the reducing discharge rate.

If ignition is delayed, the size of the flammable cloud means that a flash fire or vapor cloud explosion will occur, with the size of the flash fire or explosion increasing with increasing ignition delay, up to the maximum extent of dispersion. Additionally, at some delayed time, the effect of the flash fire or explosion will be greater than the effect of the delayed jet fire and will dominate the harmful effect.

For the full bore release event the following consequence outputs are contained in Appendix A:

- Release (i.e., discharge rate versus time)
- Jet fire thermal radiation footprint
- Side view of the early and late flammable cloud dispersion
- Early and late dispersion footprint of the flammable cloud (used for early and late flash fire consequence)
- Early and late vapor cloud explosion overpressure footprint

For the 50 mm release event the following consequence outputs are contained in Appendix A:

- Release (i.e., discharge rate versus time)
- Jet fire thermal radiation footprint
- Side view of the early and late flammable cloud dispersion

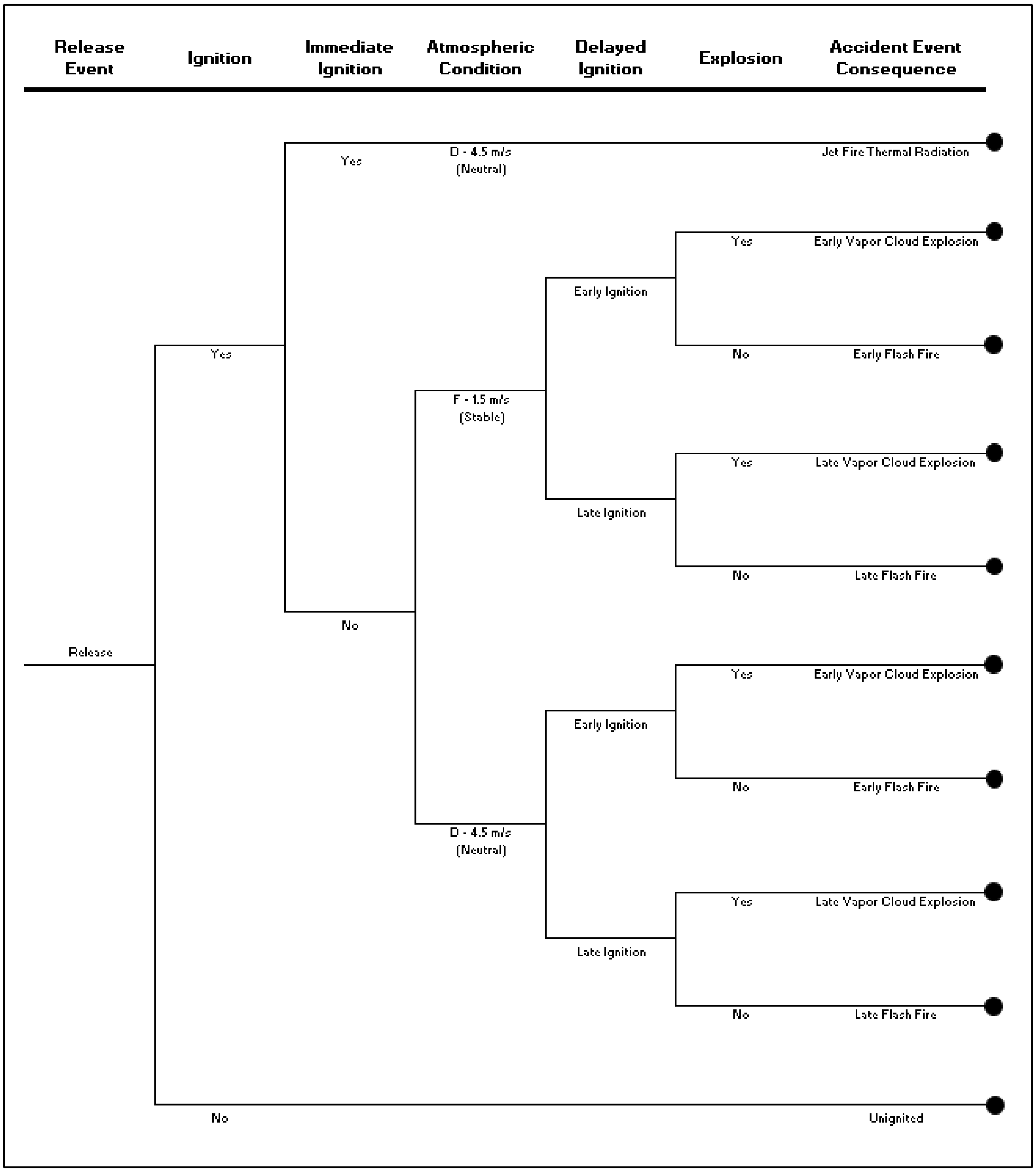
It should be noted that the side view flammable cloud dispersion figures for a 50 mm release event illustrate an upward dispersion, away from ignition sources and people, such that flash fire and vapor cloud explosion events do not contribute to the individual fatality risk level, if they were to occur.

For the purposes of this risk assessment, the following ruleset was defined:

- Assume immediate ignition and use the initial discharge rate (the average rate of the first 20 seconds of discharge) for jet fire thermal radiation consequence.
- Assume an intermediate ignition delay to represent an early flash fire or an early explosion of the expanding flammable cloud. The ignition delay is such that the flammable cloud would not have reached the maximum extent possible before ignition occurs (chosen to be approximately halfway to the maximum extent). Also, the discharge rate will have fallen to a point where the jet fire thermal effects will be smaller than the flash fire or explosion effects.
- Assume a longer ignition delay to represent a late flash fire or late explosion. The ignition delay is long enough that the expanding flammable cloud would have reached the steady-state, maximum extent. Again, the discharge rate will have fallen to a point where the jet fire thermal effects will be smaller than the flash fire or explosion effects.
- For jet fire thermal radiation consequence, only the overall average wind speed and neutral atmospheric stability is used (D – 4.5 m/s).
- For early and late flash fire or explosion, two wind speed and atmospheric stability combinations are used:
  - Overall average wind speed and neutral atmospheric stability
  - A worst-case condition reflecting a stable atmosphere (F – 1.5 m/s)

Figure 4 presents the event tree used to examine a chronological series of subsequent events and finally the frequency of consequential outcomes, or potential accident events resulting from a Mariner East 2 pipeline release. Additionally, the above rulesets are illustrated in the event tree shown in Figure 4. The branch probabilities used for each event tree branch in the risk summation is described in Section 7.2.

Figure 4: Mariner East 2 Pipeline Risk Assessment Event Tree



7.2 Accident Event Frequencies

The following subsections detail the release frequencies and conditional probabilities used in the Mariner East 2 pipeline risk assessment. Note that all values are taken directly from, or utilize common, published risk assessment references, including the Purple Book. The purpose of the Purple Book is to provide common starting points to facilitate obtaining verifiable, reproducible, and comparable quantitative risk assessment results [9].

7.2.1 Release Frequencies

A Mariner East 2 pipeline full bore release frequency was derived from the following available data sets:

1. PHMSA incident report statistics from hazardous liquid transmission pipelines for the period from 2002 through mid-2018 [11][14]
2. PHMSA hazardous liquid transmission pipeline mileage statistics [15]

The PHMSA incident and mileage data were refined, or filtered, to include the following relevant information:

- Highly volatile liquid (HVL) full bore release incidents
- Pipelines of diameter 12-inch and greater, to represent the 20-inch diameter Mariner East 2 pipeline
- Below-ground HVL transmission pipeline mileage

It should be noted that even though PHMSA details NGL pipeline incidents, PHMSA does not detail the mileage of NGL pipelines. Therefore, obtaining release frequencies specific to NGL pipelines is not possible using only the PHMSA data.

The filtering resulted in the following relevant historical data:

- Six HVL full bore release incidents
- 253,371 mile-years of HVL pipeline (12-inch or greater diameter)

Based on this data, an HVL pipeline full bore release frequency of 2.4E-05 incidents per mile-years (1.5E-05 incidents per km-years), was calculated.

The full bore release frequency value derived from PHMSA data compares well to that for a generic pipeline located in a dedicated route given in the Purple Book [9] (note that the pipeline diameter is not specified in the Purple Book values). The Purple Book value of 7E-06 incidents per km-year for full bore rupture is only a factor of 2 lower than the value derived from the PHMSA data.

Additionally, the Purple Book states that the release frequencies for pipelines located in a dedicated route are lower than other pipelines because of extra preventative measures [9]. The PHMSA data includes all pipelines and, according to the Purple Book, should be expected to be higher than full bore release frequency for pipelines located only in a dedicated route.

In determining a Mariner East 2 pipeline 50 mm release frequency, the estimated Mariner East 2 pipeline full bore release frequency was multiplied by a factor of 2.5 to result in a 50 mm release frequency of 5.9E-05 incidents per mile-years (3.7E-05 incidents per km-years). The 2.5 multiplying factor is taken from International Association of Oil and Gas Producers (OGP) recommended distribution of non-full bore hole sizes and full bore hole sizes for onshore oil pipelines [18].

Details of the PHMSA HVL incident and mileage data filtering and frequency calculations are provided in Appendix C.

7.2.2 Ignition Probability

OGP published ignition probability look-up correlations, which relate ignition probabilities to discharge rates for typical scenarios, were used in determining an overall (total) ignition probability given a release [19].

Specifically, Ignition Probability Correlation Number 3 was used as it is applicable for releases of flammable gases, vapor, or liquids significantly above their normal boiling point from onshore cross-country pipelines running through industrial or urban areas (many ignition sources as opposed to a rural area which would have sparse ignitions sources). This correlation is considered appropriate because the Mariner East 2 pipeline is transporting NGL, a liquid significantly above its normal boiling point, and the pipeline route through Delaware County can be described as urban. The values published for Ignition Probability Correlation Number 3 are provided in Table 8.

Table 8: OGP Published Ignition Probability Correlation #3 [19]

Discharge Rate (kg/s)	Ignition Probability
0.1	0.0010
0.2	0.0017
0.5	0.0033
1.0	0.0056
2.0	0.0095
5.0	0.0188
10	0.0316
20	0.0532
50	0.1057
100	0.1778

Discharge Rate (kg/s)	Ignition Probability
200	0.2991
500	0.5946
1000	1.0000
Ignition Probability Correlation #3: Flammable gases, vapor, or liquids significantly above their normal boiling point from onshore cross-country pipelines running through industrial or urban areas.	

Applying this correlation to the 20-inch Mariner East 2 pipeline discharge rates, for the two (2) hole-sizes, results in the following ignition probabilities:

- 50 mm release @ 3.4 kg/s, ignition probability = 0.01384 (interpolated)
- Full bore release @ 1586 kg/s (average of first 20 seconds), ignition probability = 1.0

Note that these are total ignition probabilities and do not indicate the timing of ignition.

7.2.3 Immediate Ignition

For the conditional probability of immediate ignition (given ignition) the Purple Book specifies a value of 0.3 for rupture of a liquefied flammable gas, buried cross-country pipeline [9].

The Purple Book does not detail the time delay criteria used to define “immediate” ignition. However, in the Mariner East 2 pipeline risk assessment, “immediate” is used as a differentiating factor between the jet fire and flash fire/explosion accident event consequences. Given that it takes some time for a dense flammable cloud to disperse passively downwind, the relevant time frame for “immediate” ignition in this risk assessment is roughly about one minute or less.

Note that in the case of an NGL release, a risk assessment using an immediate ignition probability that is lower than the delayed ignition probability produces more conservative results because the lower immediate ignition probability puts more emphasis on the effects of a delayed flash fire or explosion.

7.2.4 Atmospheric Condition

As a reference, the meteorological condition distribution of several locations in the Netherlands, as published in the Purple Book, was reviewed. The published fractions of stable and slightly stable atmospheric conditions added together result in a probability value slightly lower than 0.2.

Based on this information a conditional probability of a stable ("worst case") atmospheric condition was set at 0.25 in this risk assessment. The use of a higher value is to be conservative and accommodate uncertainty of the differences between the Netherlands locations and eastern Pennsylvania.

7.2.5 Ignition Delay

As discussed in Section 7.1, the Mariner East 2 pipeline risk assessment divides the delayed ignition effects into two periods:

- An intermediate (or early) delay, where the flammable cloud ignites before the maximum, steady-state size is reached resulting in an early flash fire or early vapor cloud explosion.
- A long (or late) delay (for late flash fire, or late explosion), where the flammable cloud reaches a maximum, steady-state size resulting in a worst case late flash fire or late vapor cloud explosion.

For the purposes of this risk assessment, the conditional probability that the ignition delay is late is set at 0.1 resulting in an early ignition conditional probability of 0.9. This is a conservative simplification that is justified by the argument that in a populated, urban area such as Delaware County, a dispersing flammable NGL cloud is more likely to ignite sooner rather than later due to the likely presence of numerous ignition sources.

Furthermore, to support the validity of this argument, the probability of early delayed ignition was checked using the model presented in Appendix 4.A of the Purple Book [9]. The inputs to this model are the area of the flammable cloud, the time interval the cloud is exposed over the ignition sources, and the effectiveness of the ignition sources.

Using the early flash fire flammable cloud area with a corresponding exposure time, and an ignition effectiveness based on the overall population density of Delaware County, the Purple Book delayed ignition model predicts a probability of ignition of 1.0 for the smaller, early flammable cloud. This supports that it is unlikely for a cloud to reach the maximum size before igniting in such an urban area.

To be conservative, the late ignition conditional probability is not set to zero, as suggested by the Purple Book delayed ignition model argument. A value of 0.1 is used in this risk assessment, which reflects that 10% of the delayed ignition events are assumed to have a late ignition, versus an early ignition, and result in the flammable clouds reaching the maximum, steady-state size before igniting.

7.2.6 Vapor Cloud Explosion

This Mariner East 2 pipeline risk assessment assumes that a vapor cloud explosion is a viable accident event given the combination of a propane flammable fuel source, a ground hugging flammable cloud, and some likely congestion near the pipeline. Thus, a suitable event tree branch probability split between a flash fire outcome and a vapor cloud explosion outcome is required.

This risk assessment uses a simple 0.6 flash fire/0.4 vapor cloud explosion split, as suggested by the Purple Book [9], for both the early ignition scenario and the late ignition scenario.

7.3 Individual Risk Results

The Mariner East 2 pipeline accident event consequences (Section 7.1), accident event frequencies (Section 7.2), and defined accident event impacts (Section 6.5) are combined to produce outdoor and indoor individual risk results. The individual risk results are then plotted on a grid to produce transects showing individual risk levels as a function of distance from the pipeline route. Separate risk transects for outdoor and indoor locations are provided, since different impact rulesets are used for the two location types (Section 6.5).

Note that the individual risk transects reflect an individual's continuous presence (i.e., 24-hours per day, 7-days per week) at a select location. This assumption is consistent with common quantitative risk assessment methodology; the continuous presence at a select location reflects a most exposed individual and, therefore, represents a maximum individual risk level.

The outdoor and indoor individual risk transects are shown in Figure 5 and Figure 6. Note that distance from the pipeline are expressed in meters.

Figure 5: 20-inch Mariner East 2 Pipeline, Outdoor Individual Risk Transect

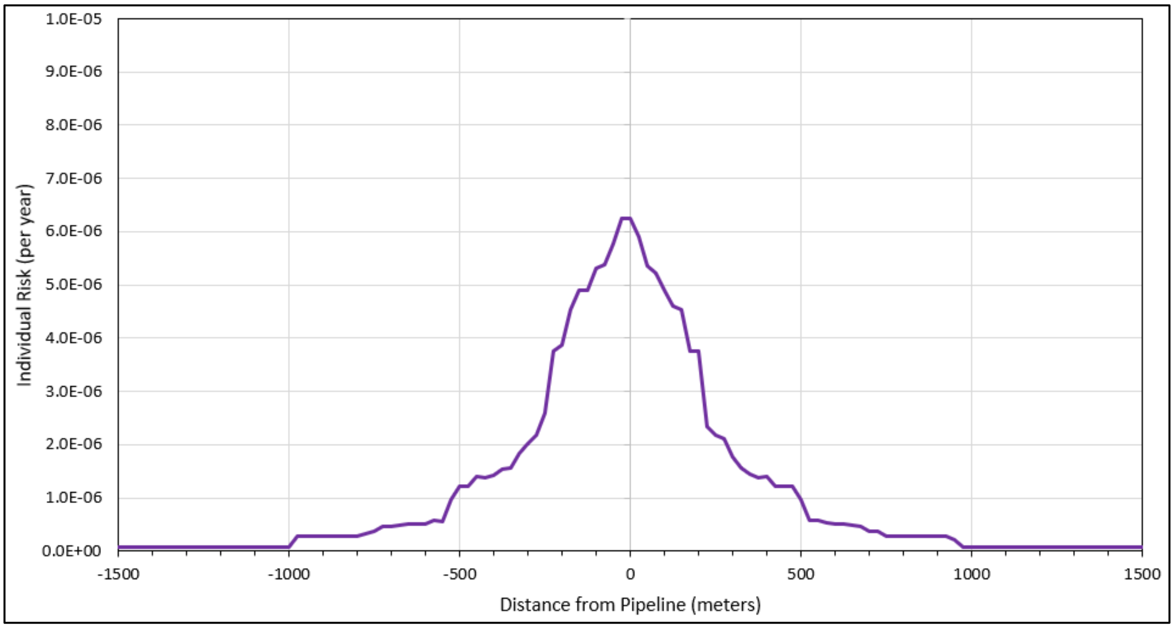
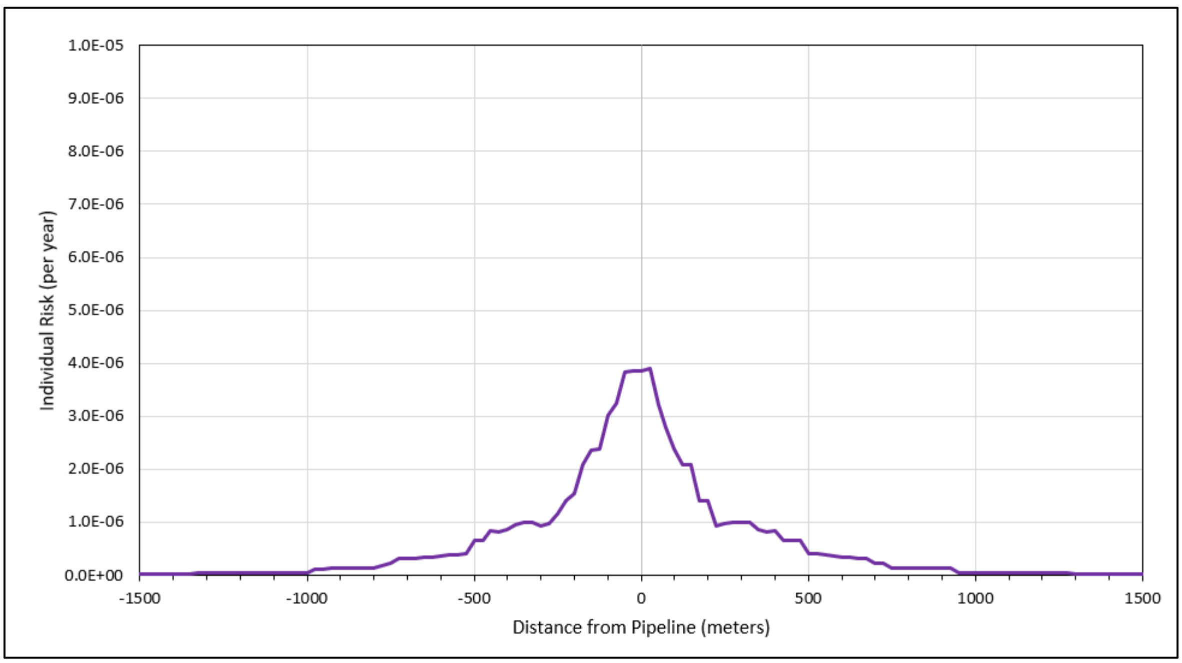


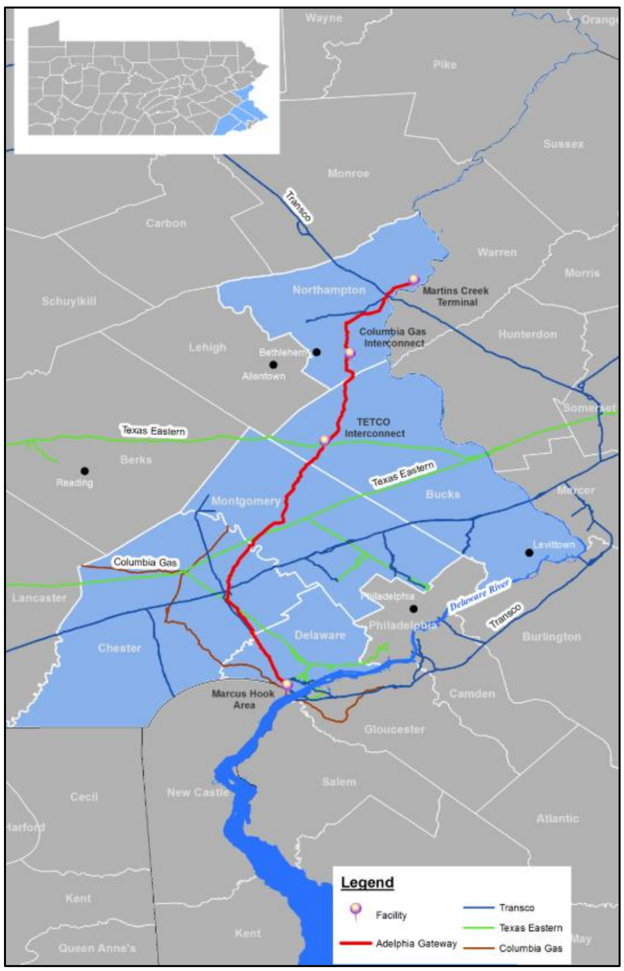
Figure 6: 20-inch Mariner East 2 Pipeline, Indoor Individual Risk Transect



8.0 ADELPHIA PIPELINE RISK ASSESSMENT

The existing Adelphia pipeline is an 84-mile pipeline that runs through five Pennsylvania counties, including Delaware County, and was originally constructed to transport oil from Marcus Hook to Martins Creek, Pennsylvania. In 1996, the northern 34 miles of the Adelphia pipeline was converted to transport natural gas. The remaining 50 miles of existing Adelphia pipeline is planned to be converted to transport natural gas, of which approximately 12 miles traverses Delaware County. Figure 7 shows the route of the existing Adelphia pipeline.

Figure 7: Route of Existing Adelphia Pipeline [12]

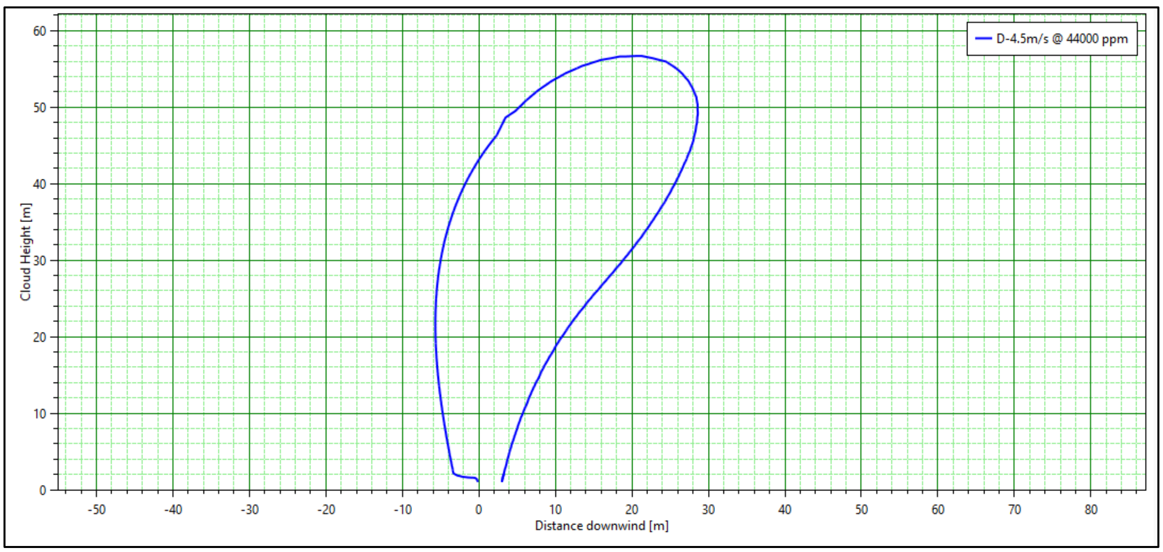


The following sections describes the risk assessment details specific to the Adelphia pipeline.

8.1 Accident Event Consequences

The Adelphia natural gas pipeline is modeled as pure methane to determine the accident event consequences. Upon release, the gas rapidly mixes with air to concentrations below the lower flammable limit. This rapid dilution combined with the vertical orientation of the resulting flammable cloud, caused by a combination of the effects of the crater and the buoyancy of the released gas, results in a small flammable gas cloud footprint near the ground level. This is illustrated in Figure 8 with a side view plot of the flammable vapor cloud from a full bore release.

Figure 8: Side View of Flammable Cloud from Full Bore Adelphia Gas Pipeline Release



The two key implications of the nearly vertical flammable vapor cloud from a natural gas release from a buried pipeline are:

1. A flash fire impact would be negligible since near the ground level only the immediate vicinity of the release (just a few square meters) is within the flash fire envelope.
2. A vapor cloud explosion is very unlikely because, with natural gas, the confinement or congestion needed within the cloud (See Section 6.5) is unlikely to be present immediately above the transmission pipeline.

For these reasons, the Adelphia pipeline risk assessment only considers jet fire thermal radiation consequences and excludes the minimal contributions of flash fire thermal radiation and vapor cloud explosion overpressure consequences to the pipeline risk estimations.

For the full bore release event the following consequence outputs are contained in Appendix B:

- Release (i.e., discharge rate versus time)
- Jet fire thermal radiation footprint
- Side view of the flammable cloud dispersion

For the 50 mm release event the following consequence outputs are contained in Appendix B:

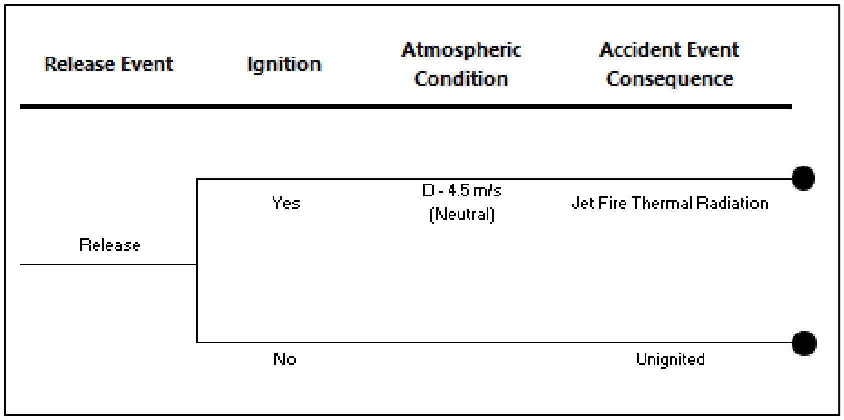
- Jet fire thermal radiation footprint
- Side view of the flammable cloud dispersion

The approach for this risk assessment is to assume that if the release ignites, it is ignited immediately, and the initial discharge rate is used for thermal radiation consequence. This ruleset is a conservative simplification. In reality, the ignition could be delayed. If delayed, then the discharge rate will have reduced and the jet fire thermal radiation consequence will be smaller. The greater the ignition delay, the greater the discharge is reduced and the smaller the consequence.

The Purple Book references for "immediate" ignition probability do not provide criteria of what time frame constitutes "immediate" ignition. However, it could be interpreted to be as quickly as only a few seconds, if not instantaneous. This could leave "non-immediate" ignition thermal radiation consequence similar in magnitude to "immediate" ignition thermal radiation consequence. This justifies simply using the initial discharge rate for jet fire thermal consequence without applying an immediate ignition conditional probability.

The consequence rulesets described above are illustrated in the event tree shown in Figure 9. The release event frequency and probabilities used for each event tree branch in the risk summation is described in Section 8.2.

Figure 9: Adelphia Pipeline Risk Assessment Event Tree



8.2 Accident Event Frequencies

The following subsections detail the release frequencies and conditional probabilities used in the Adelphia pipeline risk assessment. Note that all values are taken directly from, or utilize common, published risk assessment references, including the Purple Book. The purpose of the Purple Book is to provide common starting points to facilitate obtaining verifiable, reproducible, and comparable quantitative risk assessment results [9].

8.2.1 Release Frequencies

An Adelphia pipeline full bore release frequency was derived from the following available data sets:

1. PHMSA incident report statistics from natural gas transmission pipelines for the period from 2007 through mid-2018 [16].
2. PHMSA natural gas transmission pipeline mileage statistics [17].

The PHMSA incident and mileage data were refined, or filtered, to include the following relevant information:

- Natural gas full bore release incidents
- Pipelines of diameters greater than 10-inches but less than 28-inches to represent the 18-inch diameter Adelphia pipeline
- Below-ground natural gas transmission pipeline mileage

The filtering resulted in the following relevant historical data:

- 128 full bore release incidents
- 2,214,615 mile-years of natural gas pipeline (10-inch to 28-inch diameter range)

Based on this data, a natural gas pipeline full bore release frequency is 5.8E-05 incidents per mile-years (3.6E-05 incidents per km-years) was calculated.

The full bore release frequency value derived from PHMSA data compares reasonably well to that given in the Purple Book [9] for a generic pipeline located in a dedicated route (note that the pipeline diameter is not specified in the Purple Book values). The Purple Book value of 7E-06 incidents per km-year for full bore rupture is 5 times lower than the value derived from the PHMSA data. The Purple Book value reflects pipelines located "in a dedicated route", whereas the PHMSA data is for all pipelines.

The Purple Book states that the release frequencies for pipelines located in a dedicated route are lower than other pipelines because of extra preventative measures [9]. Additionally, the PHMSA data includes all pipelines and so could be expected to be higher than pipelines located only in a dedicated route.

In determining an Adelphia pipeline 50 mm release frequency, the estimated Adelphia pipeline full bore release frequency was multiplied by a factor of 6 to result in a 50 mm release frequency of 3.5E-04 incidents per mile-years (2.2E-04 incidents per km-years). The multiplying factor of 6 is taken from OGP recommended distribution of non-full bore hole sizes and full bore hole sizes for onshore gas pipelines [18].

Details of the PHMSA natural gas incident and mileage data filtering and frequency calculation are provided in Appendix D.

8.2.2 Ignition Probability

OGP published ignition probability look-up correlations, which relate ignition probabilities to discharge rates for typical scenarios, were used in determining an overall (total) ignition probability given a release [19].

Specifically, Ignition Probability Correlation Number 3 was used as it is applicable for releases of flammable gases, vapor, or liquids significantly above their normal boiling point from onshore cross-country pipelines running through industrial or urban areas. This correlation is considered appropriate because the Adelphia pipeline is transporting natural gas and the pipeline route through Delaware County can be described as urban (many ignition sources as opposed to a rural area which would have sparse ignitions sources). The values published for Correlation Number 3 are shown in Table 9.

Table 9: OGP Published Ignition Probability Correlation #3 [19]

Discharge Rate (kg/s)	Ignition Probability
0.1	0.0010
0.2	0.0017
0.5	0.0033
1.0	0.0056
2.0	0.0095
5.0	0.0188
10	0.0316
20	0.0532
50	0.1057
100	0.1778
200	0.2991
500	0.5946
1000	1.0000
Ignition Probability Correlation #3: Flammable gases, vapor, or liquids significantly above their normal boiling point from onshore cross-country pipelines running through industrial or urban areas.	

Applying this correlation to the 18-inch Adelphia pipeline discharge rates, for the two (2) hole-sizes, results in the following ignition probabilities:

- 50 mm release @ 8.8 kg/s (nominally 10 kg/s), ignition probability = 0.0316
- Full bore release @ 434 kg/s (average of first 20 seconds, nominally 500 kg/s), ignition probability = 0.5946

8.3 Individual Risk Results

The Adelphia pipeline accident event frequencies (Section 8.2), accident event consequences Section 8.1), and defined accident event impacts (Section 6.5) are combined to produce outdoor and indoor individual risk results. The individual risk results are then plotted on a grid to produce transects showing individual risk levels as a function of distance from the pipeline route. Separate risk transects for outdoor and indoor locations are provided, since different impact rulesets are used for the two location types (Section 6.5).

Note that the individual risk transects reflect an individual's continuous presence (i.e., 24-hours per day, 7-days per week) at a select location. This assumption is consistent with common quantitative risk assessment methodology; the continuous presence at a select location reflects a most exposed individual and, therefore, represents a maximum individual risk level.

The outdoor and indoor individual risk transects are shown in Figure 10 and Figure 11. Note that distance from the pipeline is expressed in meters.

Figure 10: 18-inch Adelphia Pipeline, Outdoor Individual Risk Transect

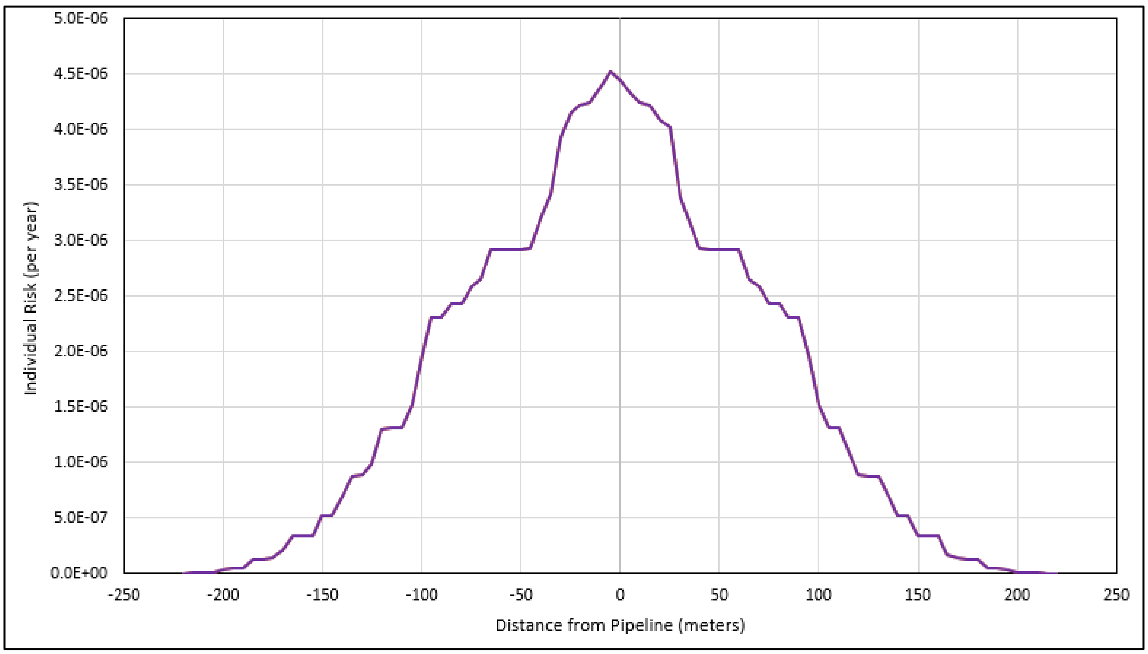
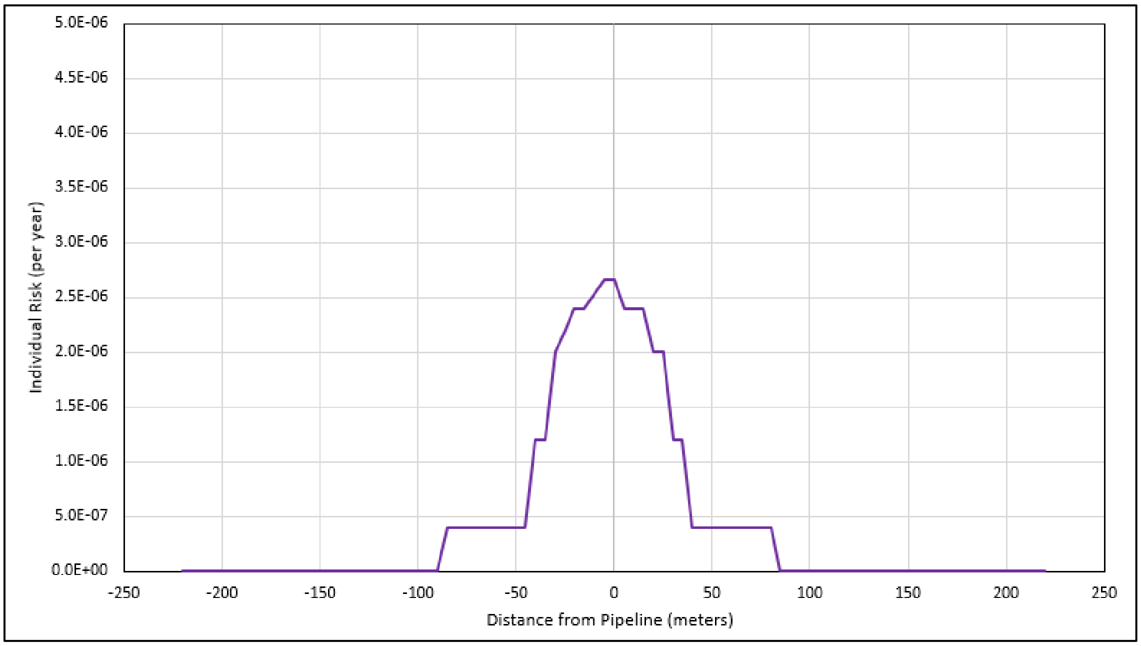


Figure 11: 18-inch Adelphia Pipeline, Indoor Individual Risk



9.0 COMMON INDIVIDUAL RISK SOURCES

Table 10 provides a list of common risk sources and corresponding published individual risk levels derived from United States fatality statistics [20]. The one-year odds are the number of deaths in one year that occurred in the United States divided by the total population of the United States. The individual risk level equates to the inverse of the one-year odds.

Note that the values in Table 10 are shown in the order of decreasing risk level (i.e., highest risk to lowest) and range from approximately 1.2E-04 per year (motor vehicle accident fatalities) to 1.1E-07 per year (lightning fatalities).

Table 10: Odds of Death in The United States by Selected Cause, 2016

Cause [20]	Number of Deaths (2016) [20]	One Year Odds[1] [20]	Individual Risk (per year)[2]
Motor vehicle accident	40,327	8,013	1.2E-04
Assault by firearm	14,415	22,416	4.5E-05
Exposure to smoke, fire, flames	2,730	118,362	8.4E-06
Falls from stairs or steps	2,344	137,853	7.3E-06
Swimming pool	780	414,266	2.4E-06
Firearm accident	300	1,077,092	9.3E-07
Hurricane, tornado, blizzard, storm	66	4,895,871	2.0E-07
Lightning	36	8,975,764	1.1E-07

[1] Values are based on total U.S. population and not on a number of activity participants.

[2] Calculated based on one year odds and rounded to the nearest decimal.

Source Insurance Information Institute
https://www.iii.org/fact-statistic/facts-statistics-mortality-risk

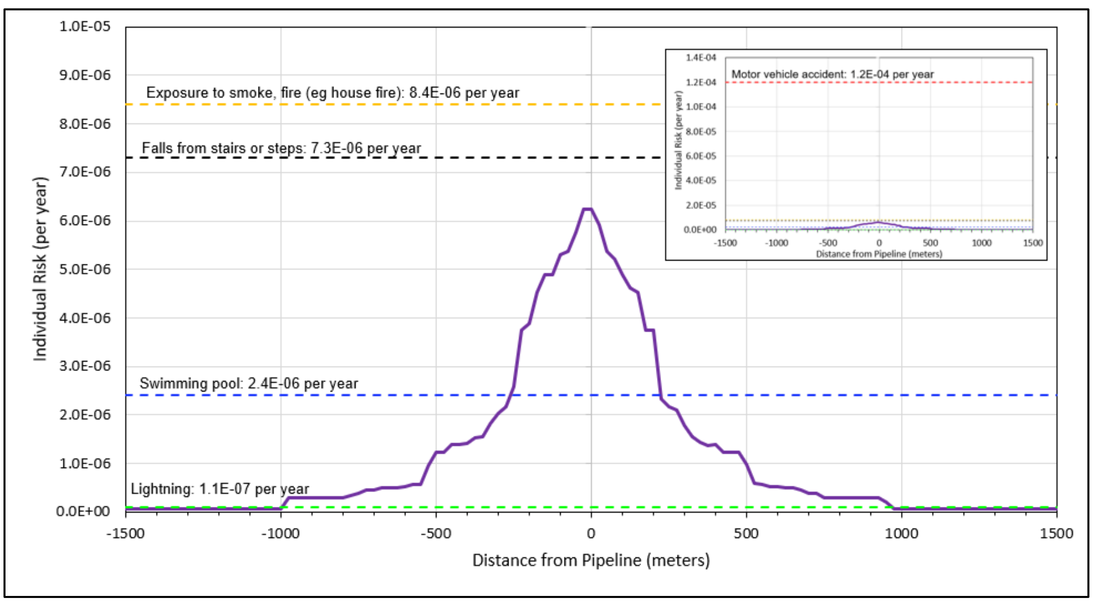
10.0 CONCLUSIONS

The final objective of these assessments was to present a comparison of the Mariner East 2 pipeline and Adelphia pipeline estimated individual risk levels against other individual risk levels from common sources. This is done in order to establish an improved perspective when interpreting the meaning of the individual fatality risks.

Figure 12 presents such comparisons using the resulting outdoor individual risk transect for the Mariner East 2 pipeline together with several common risk sources presented in Section 9.0.

Note that the plot contains an inset figure using a compressed risk axis to accommodate the 1.2E-04 per year motor vehicle accident individual risk value, which would otherwise be off the scale of the main plot (i.e., greater than 1.0E-05 per year).

Figure 12: Mariner East 2 Outdoor Individual Risk versus Common Risk Sources



The following are examples of how to interpret the above Mariner East 2 pipeline comparative plot:

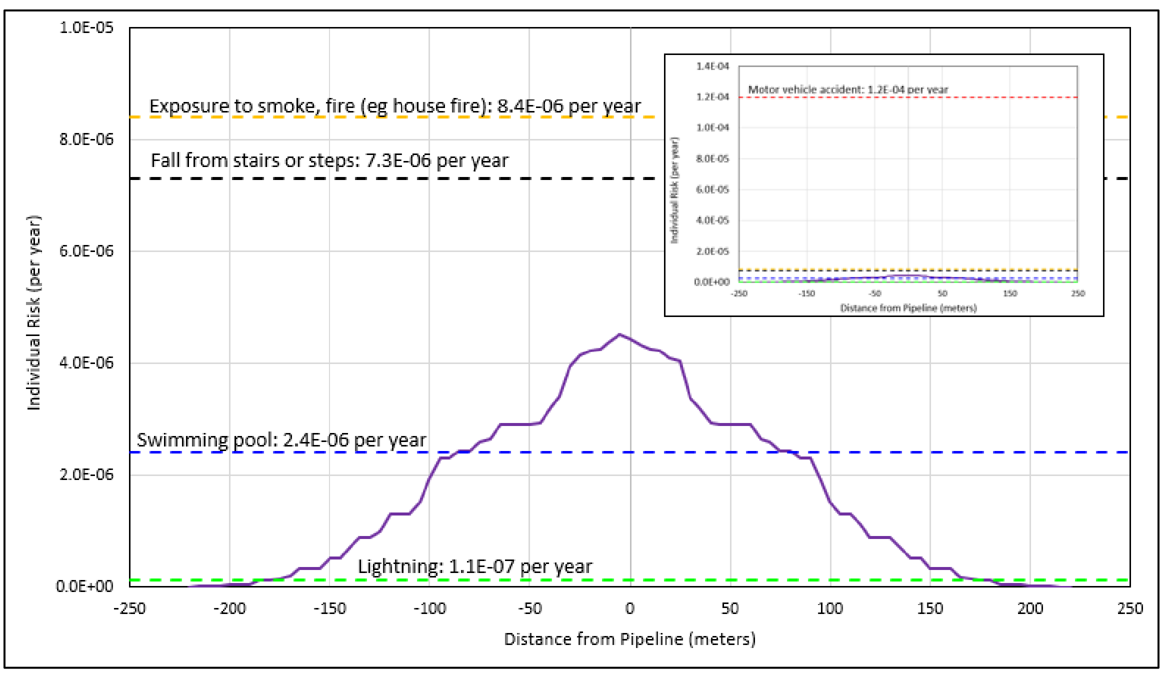
- The average person's annual exposure to a fatal traffic accident (1.2E-04 per year) is approximately 20 times greater than that of the annual individual risk level (6.2E-06 per year, or odds of 1 in 161,290) of a person present 24 hours per day, 7 days per week at a zero distance from the Mariner East 2 pipeline route (i.e., on the centerline).

- The average person's exposure to fatal house fires (8.4E-06 per year) is approximately 35% greater than that of the individual risk level (6.2E-06 per year, or odds of 1 in 161,290) of a person present 24 hours per day, 7 days per week at a zero distance from the Mariner East 2 pipeline route (i.e., on the centerline).
- The average person's exposure to a fatal fall from stairs (7.3E-06 per year) is approximately 20% greater than that of the individual risk level (6.2E-06 per year, or odds of 1 in 161,290) of a person present 24 hours per day, 7 days per week at a zero distance from the Mariner East 2 pipeline route (i.e., on the centerline).

Figure 13 presents such comparisons using the resulting outdoor individual risk transect for the Adelphia pipeline together with several common risk sources presented in Section 9.0.

Note that the plot contains an inset figure using a compressed risk axis to accommodate the 1.2E-04 per year motor vehicle accident individual risk value, which would otherwise be off the scale of the main plot (i.e., greater than 1.0E-05 per year).

Figure 13: Adelphia Outdoor Individual Risk versus to Common Risk Sources



The following are examples of how to interpret the above Adelphia pipeline comparative plot:

- The average person's exposure to a fatal traffic accident (1.2E-04 per year) is approximately 27 times greater than that of the individual risk level (4.5E-06 per year, or odds of 1 in 222,222) of a person present 24 hours per day, 7 days per week at a zero distance from the Adelphia pipeline route (i.e., on the centerline).
- The average person's exposure to fatal house fires (8.4E-06 per year) is approximately 2 times greater than that of the individual risk level (4.5E-06 per year, or odds of 1 in 222,222) of a person present 24 hours per day, 7 days per week at a zero distance from the Adelphia pipeline route (i.e., on the centerline).
- The average person's exposure to a fatal fall from stairs (7.3E-06 per year) is approximately 60% greater than that of the individual risk level (4.5E-06 per year, or odds of 1 in 222,222) of a person present 24 hours per day, 7 days per week at a zero distance from the Adelphia pipeline route (i.e., on the centerline).

In conclusion, based on the figures above, it can be stated that the individual risk levels estimated for both the Mariner East 2 pipeline and the Adelphia pipeline fall within a range of other common risk sources.

11.0 REFERENCES

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[15] Pipeline and Hazardous Materials Safety Administration, PHMSA. Data and Statistics. Gas Distribution, Gas Gathering, Gas Transmission, Liquified Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data. Hazardous Liquid Annual Data – 2004 to 2009 and 2010 to Present. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids (downloaded August 2018).

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[20] Insurance Information Institute. Facts + Statistics: Mortality Risk. https://www.iii.org/fact-statistic/facts-statistics-mortality-risk (downloaded October 2018).

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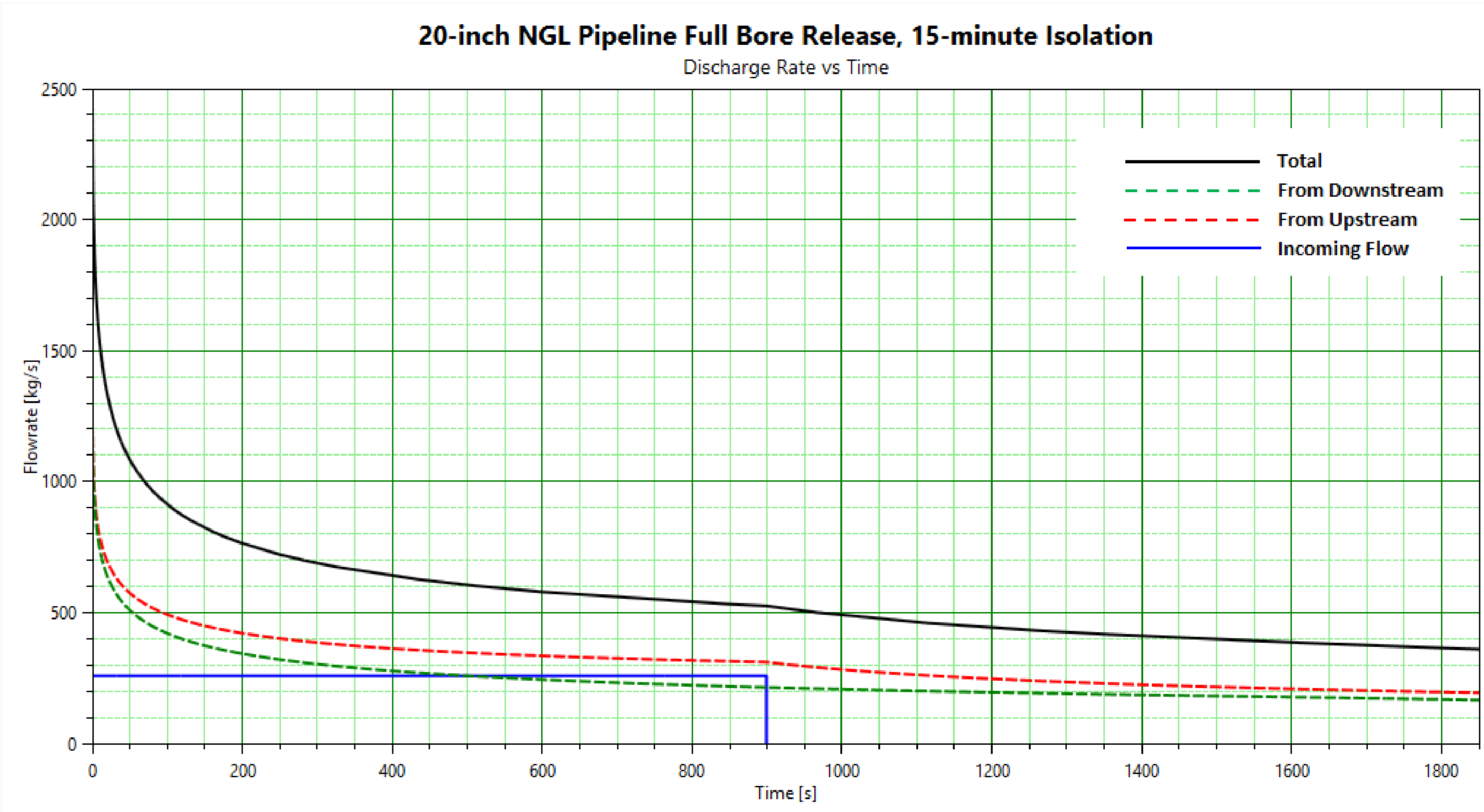
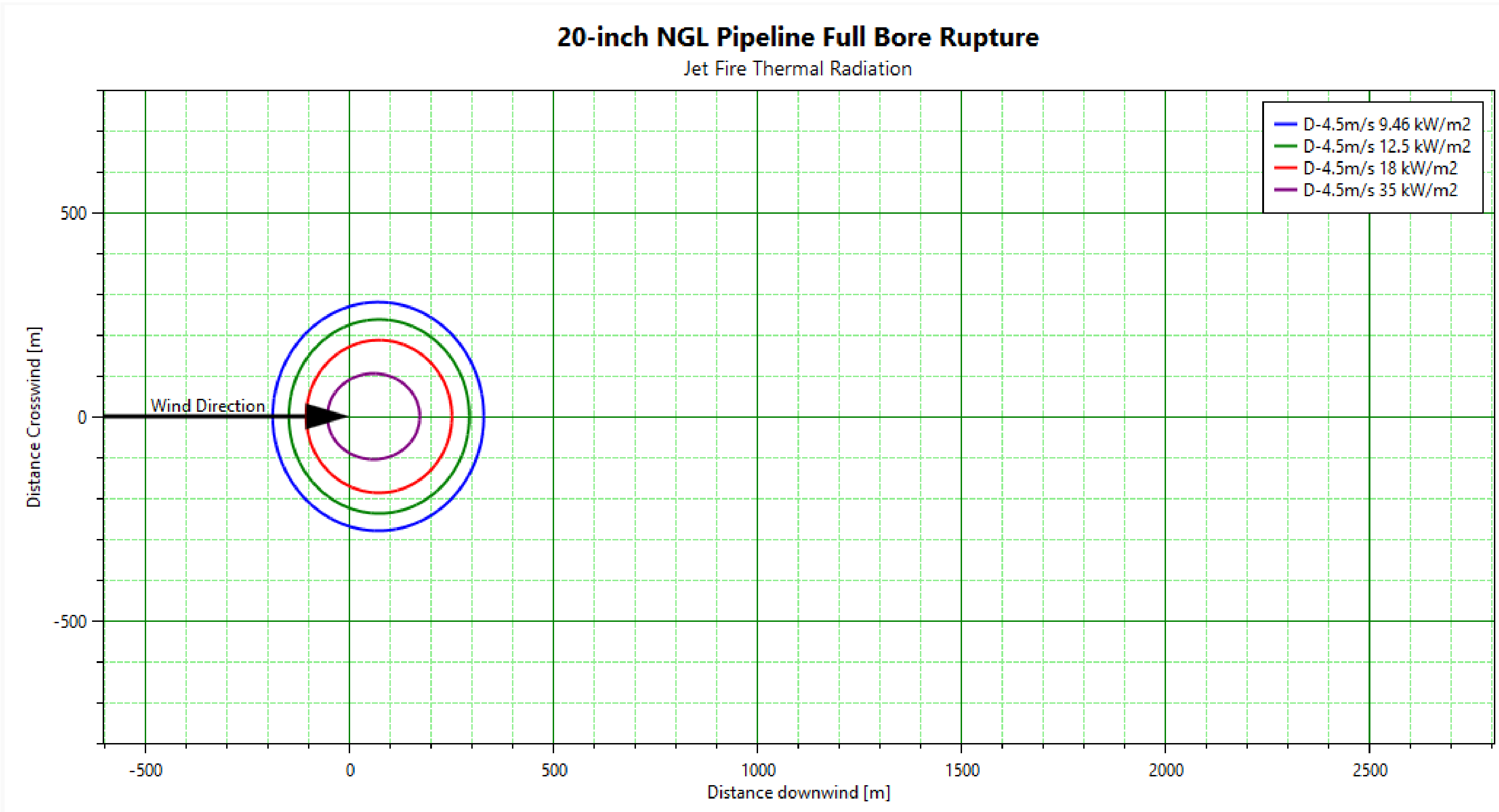
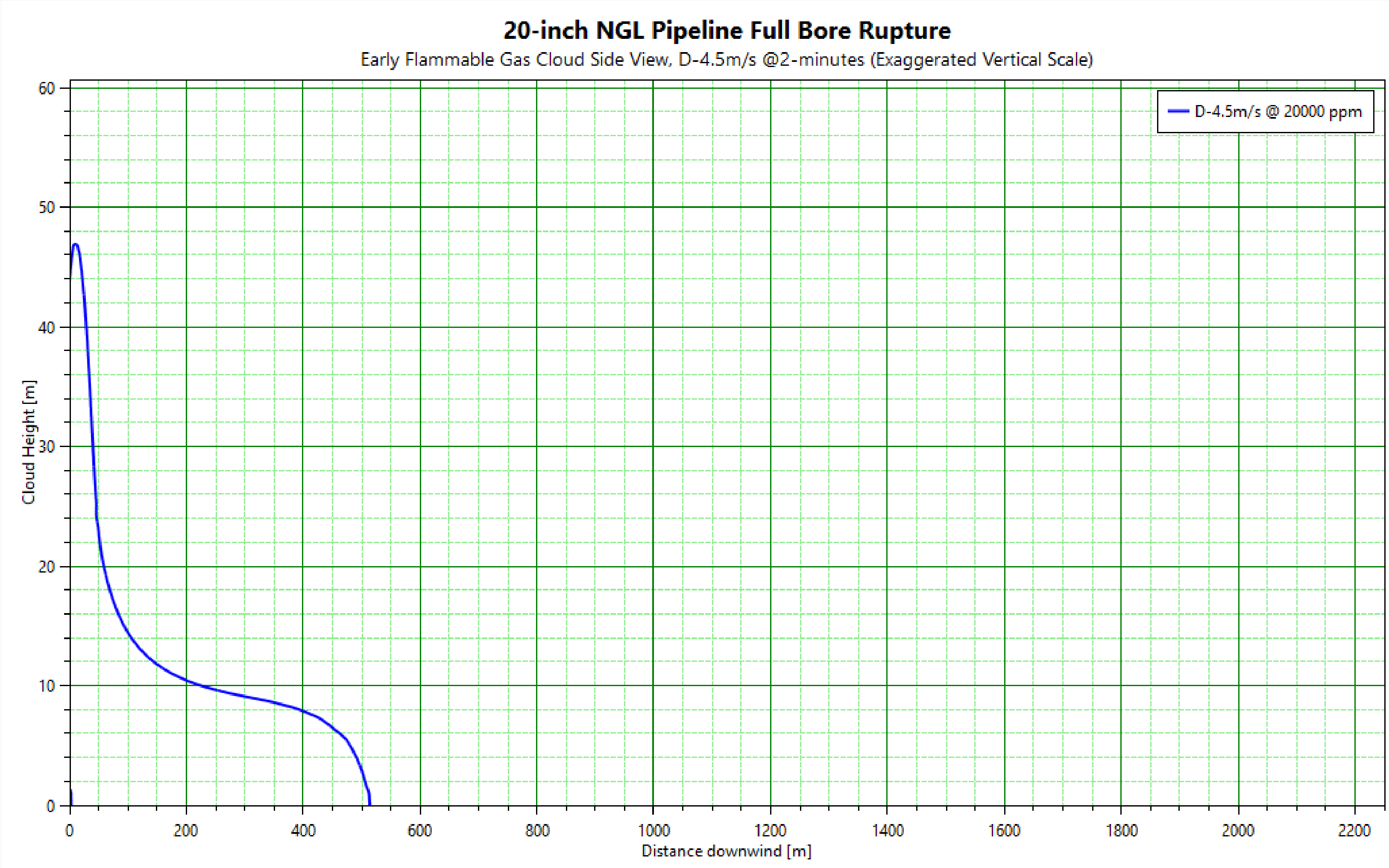
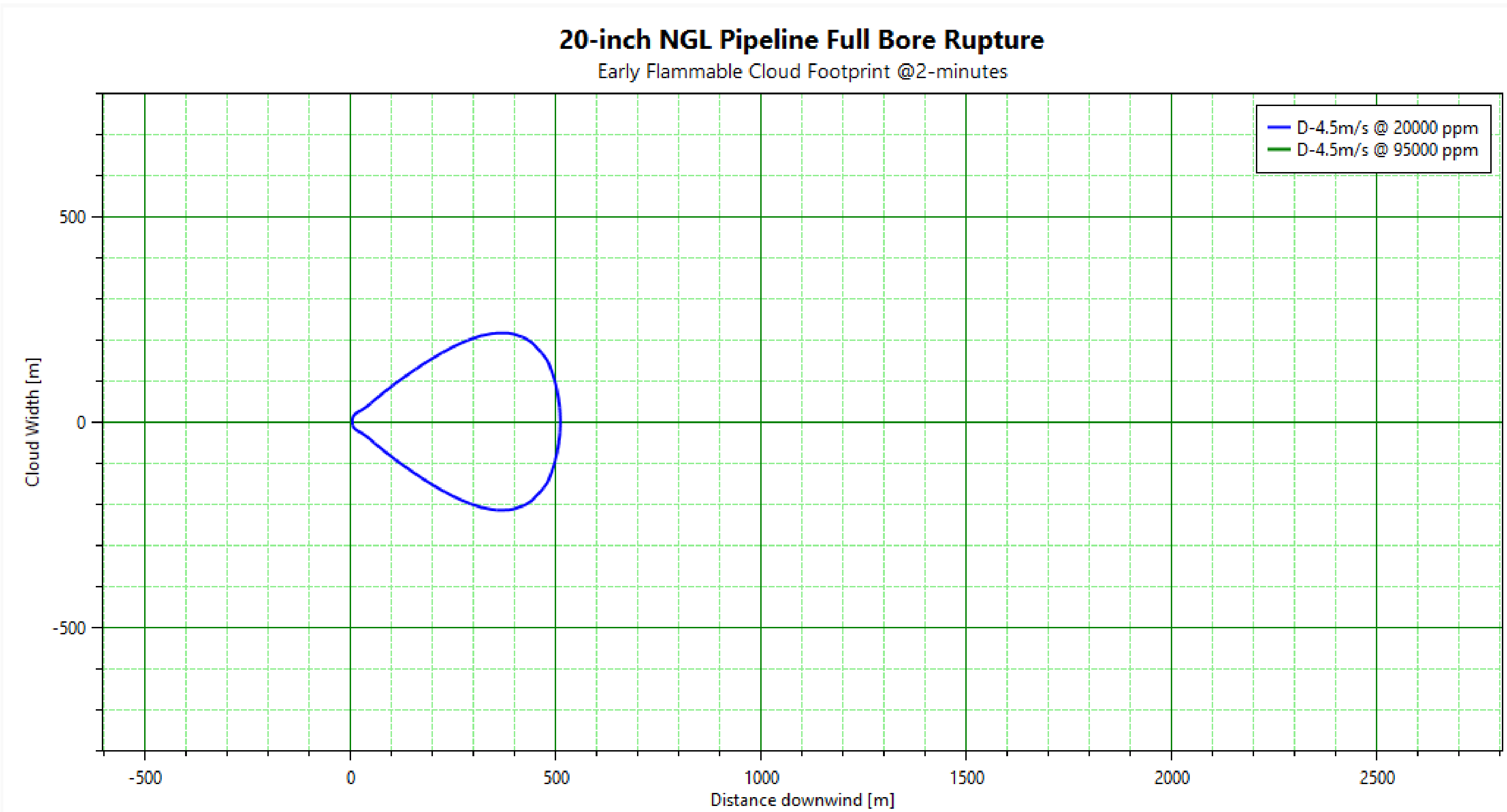
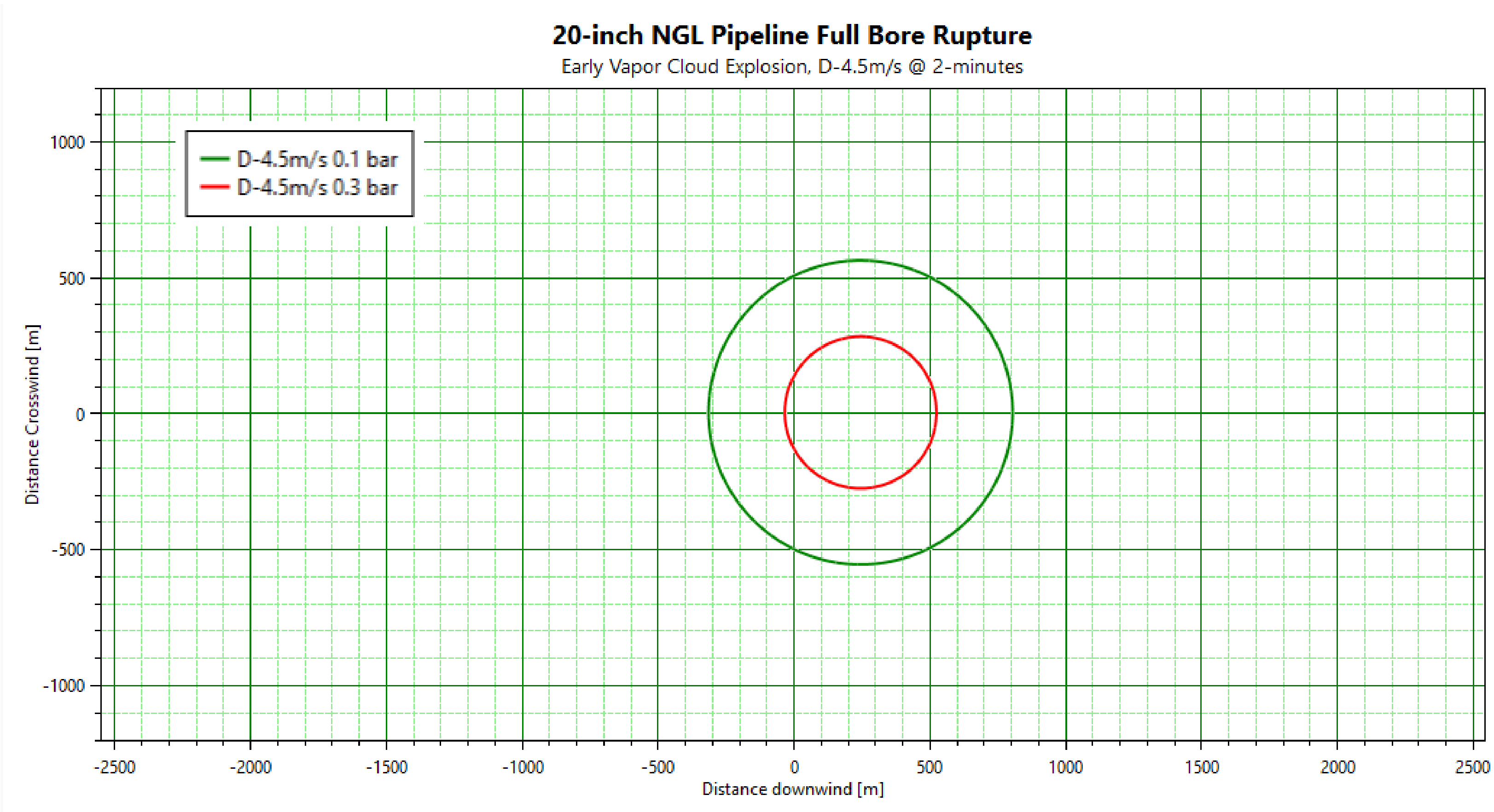
APPENDIX A: MARINER EAST 2 PIPELINE CONSEQUENCE PLOTS

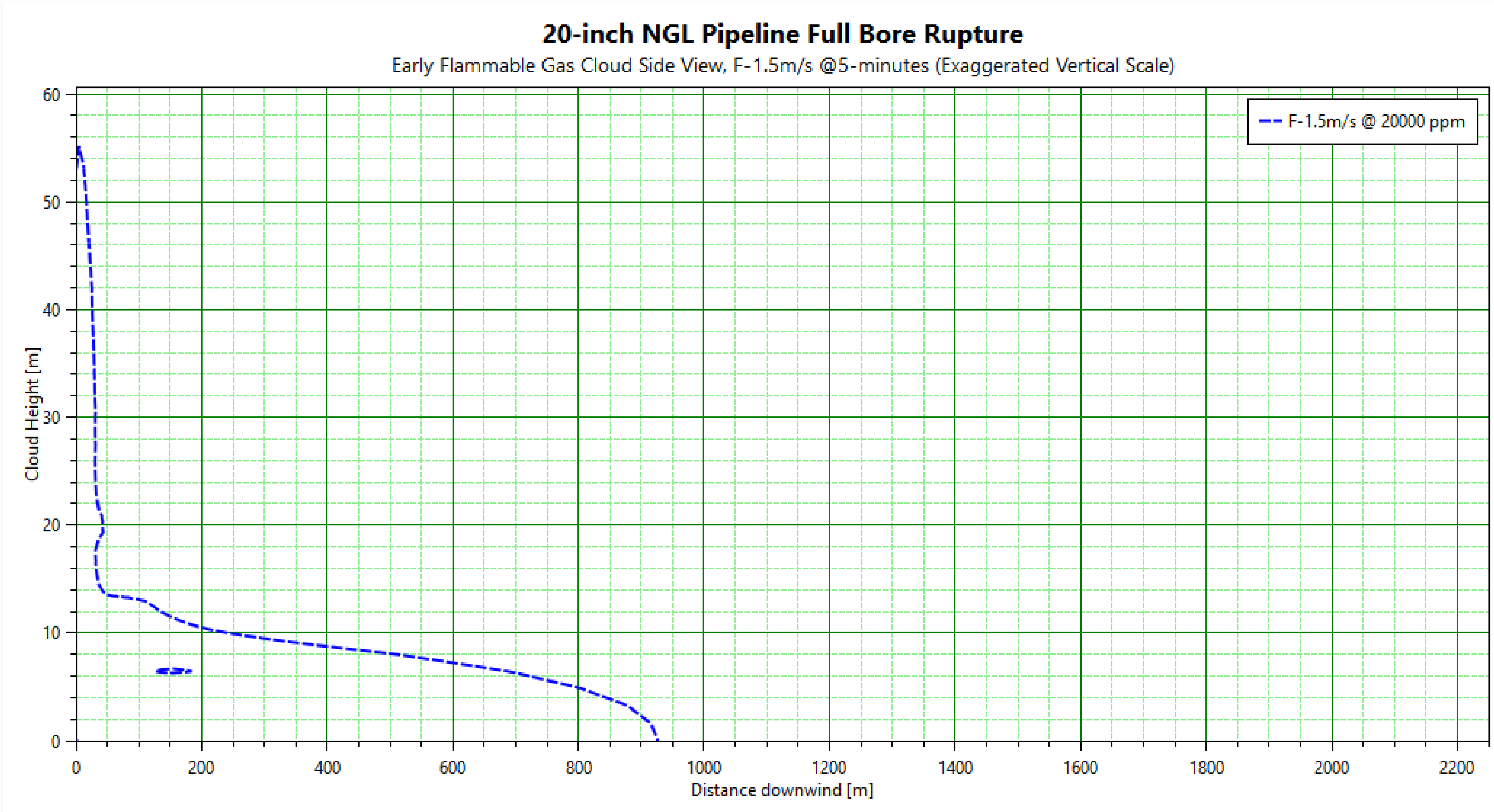

20-inch NGL Pipeline Full Bore Release, 15-minute Isolation
Discharge Rate vs Time
Flowrate [kg/s]
Time [s]
Total
From Downstream
From Upstream
Incoming Flow
2500
2000
1500
1000
500
0
200
400
600
800
1000
1200
1400
1600
1800


20-inch NGL Pipeline Full Bore Rupture
Jet Fire Thermal Radiation
D-4.5m/s 9.46 kW/m2
D-4.5m/s 12.5 kW/m2
D-4.5m/s 18 kW/m2
D-4.5m/s 35 kW/m2
Wind Direction
Distance Crosswind [m]
500
0
-500
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline Full Bore Rupture
Early Flammable Gas Cloud Side View, D-4.5m/s @2-minutes (Exaggerated Vertical Scale)
D-4.5m/s @ 20000 ppm
Cloud Height [m]
0
10
20
30
40
50
60
Distance downwind [m]
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200


20-inch NGL Pipeline Full Bore Rupture
Early Flammable Cloud Footprint @2-minutes
D-4.5m/s @ 20000 ppm
D-4.5m/s @ 95000 ppm
Cloud Width [m]
500
0
-500
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline Full Bore Rupture
Early Vapor Cloud Explosion, D-4.5m/s @ 2-minutes
D-4.5m/s 0.1 bar
D-4.5m/s 0.3 bar
Distance Crosswind [m]
Distance downwind [m]
1000
500
0
-500
-1000
-2500
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500


20-inch NGL Pipeline Full Bore Rupture
Early Flammable Gas Cloud Side View, F-1.5m/s @5-minutes (Exaggerated Vertical Scale)
F-1.5m/s @ 20000 ppm
Cloud Height [m]
0
10
20
30
40
50
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Distance downwind [m]
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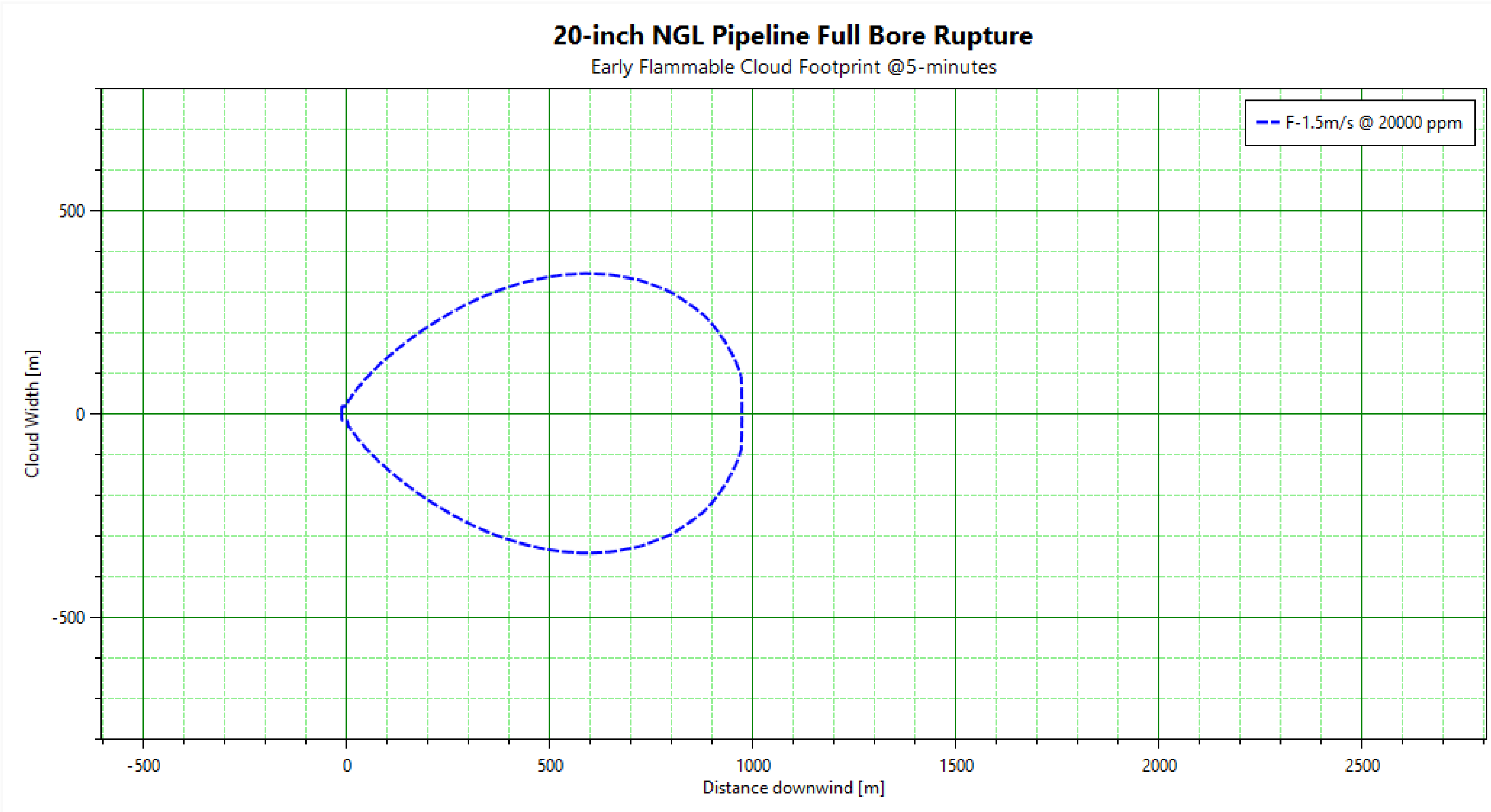
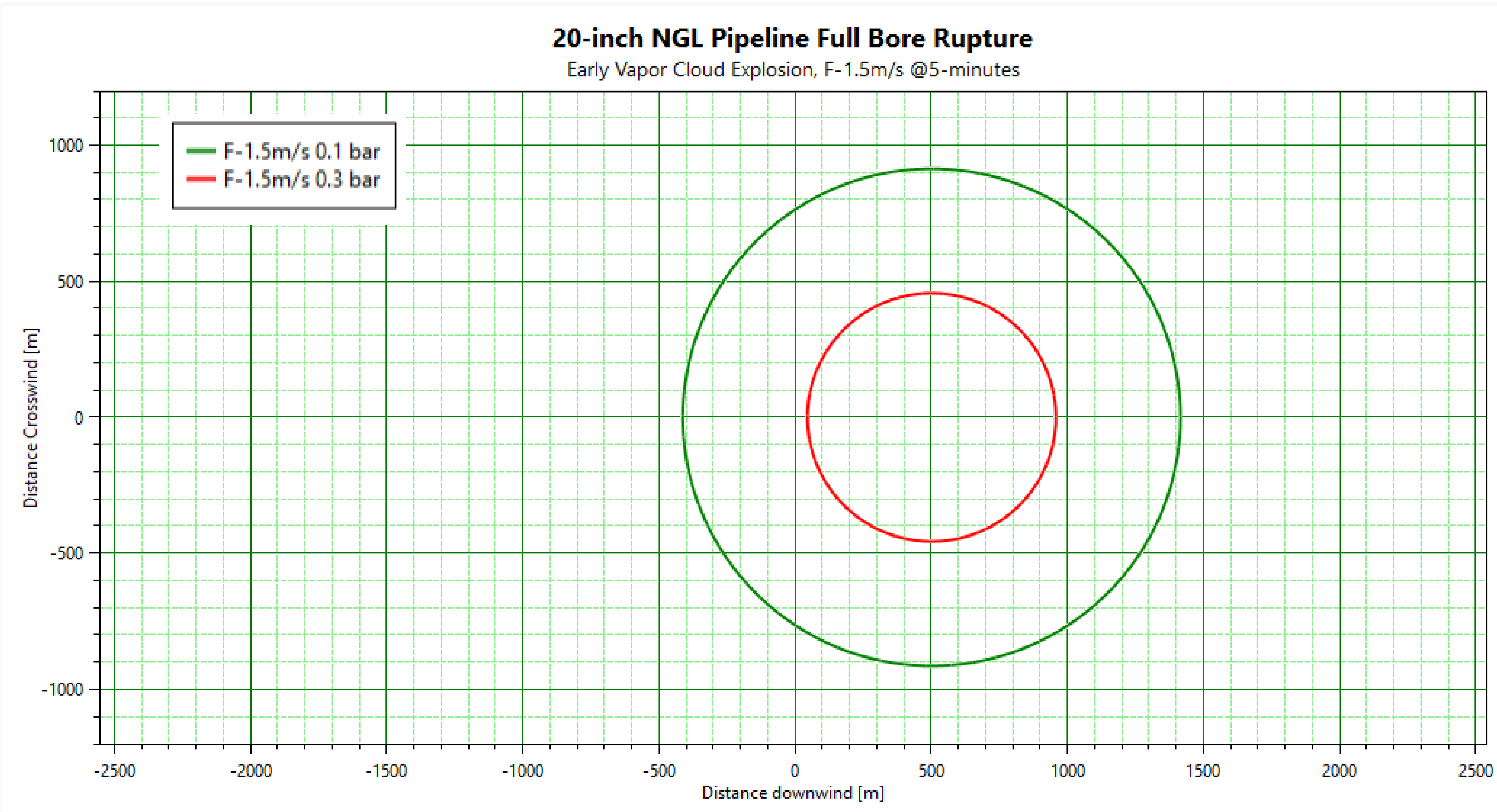
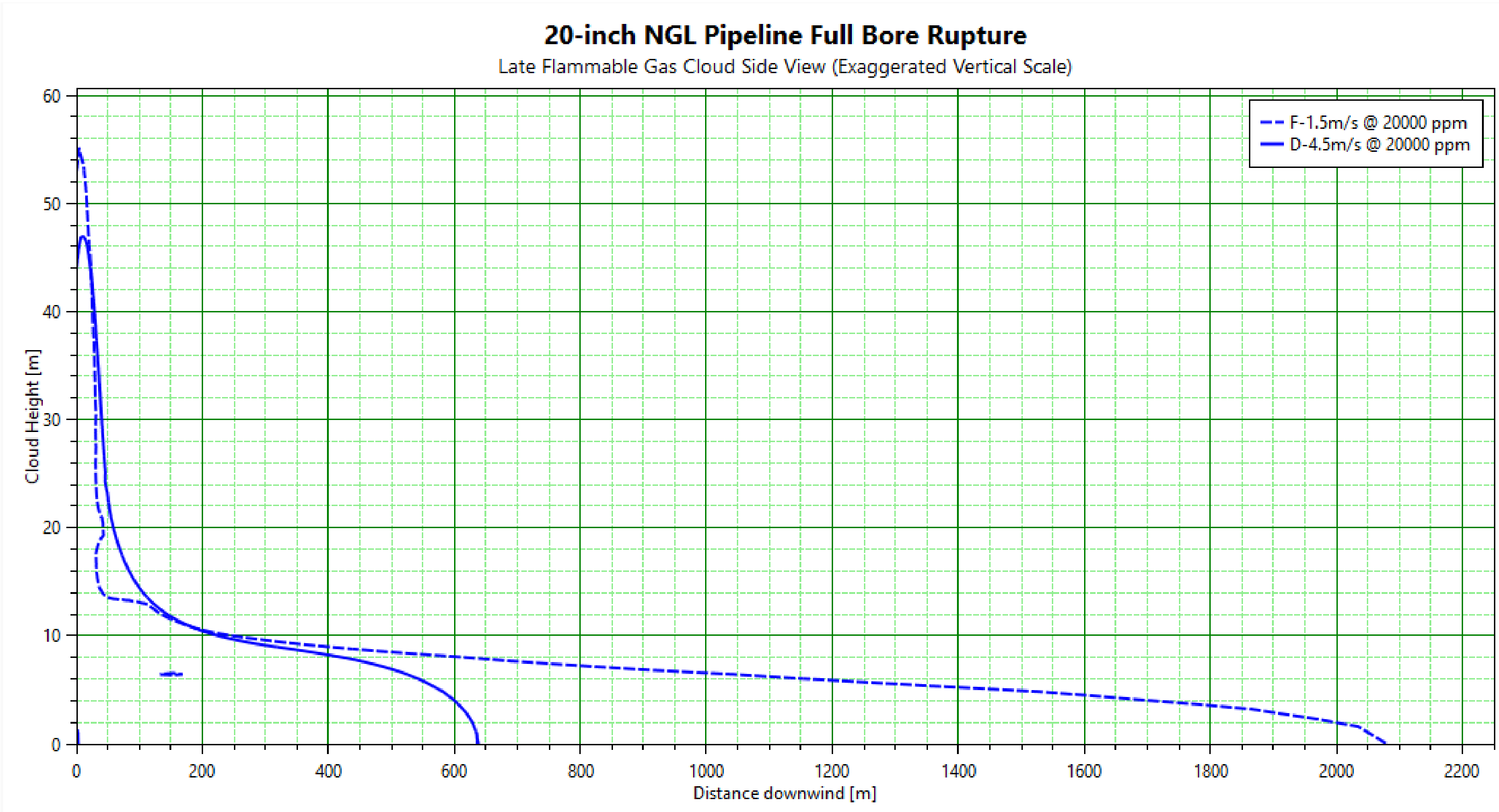
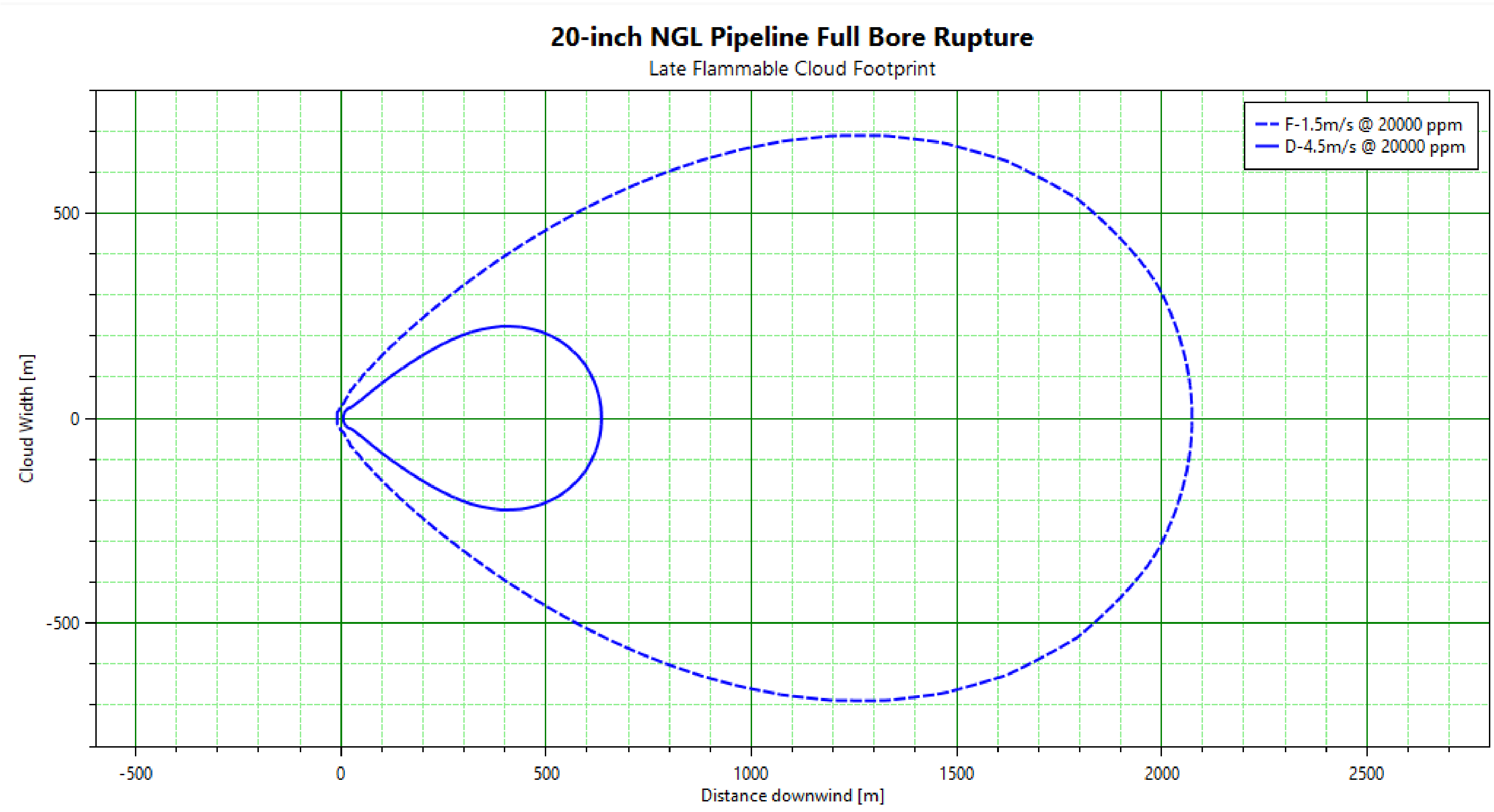
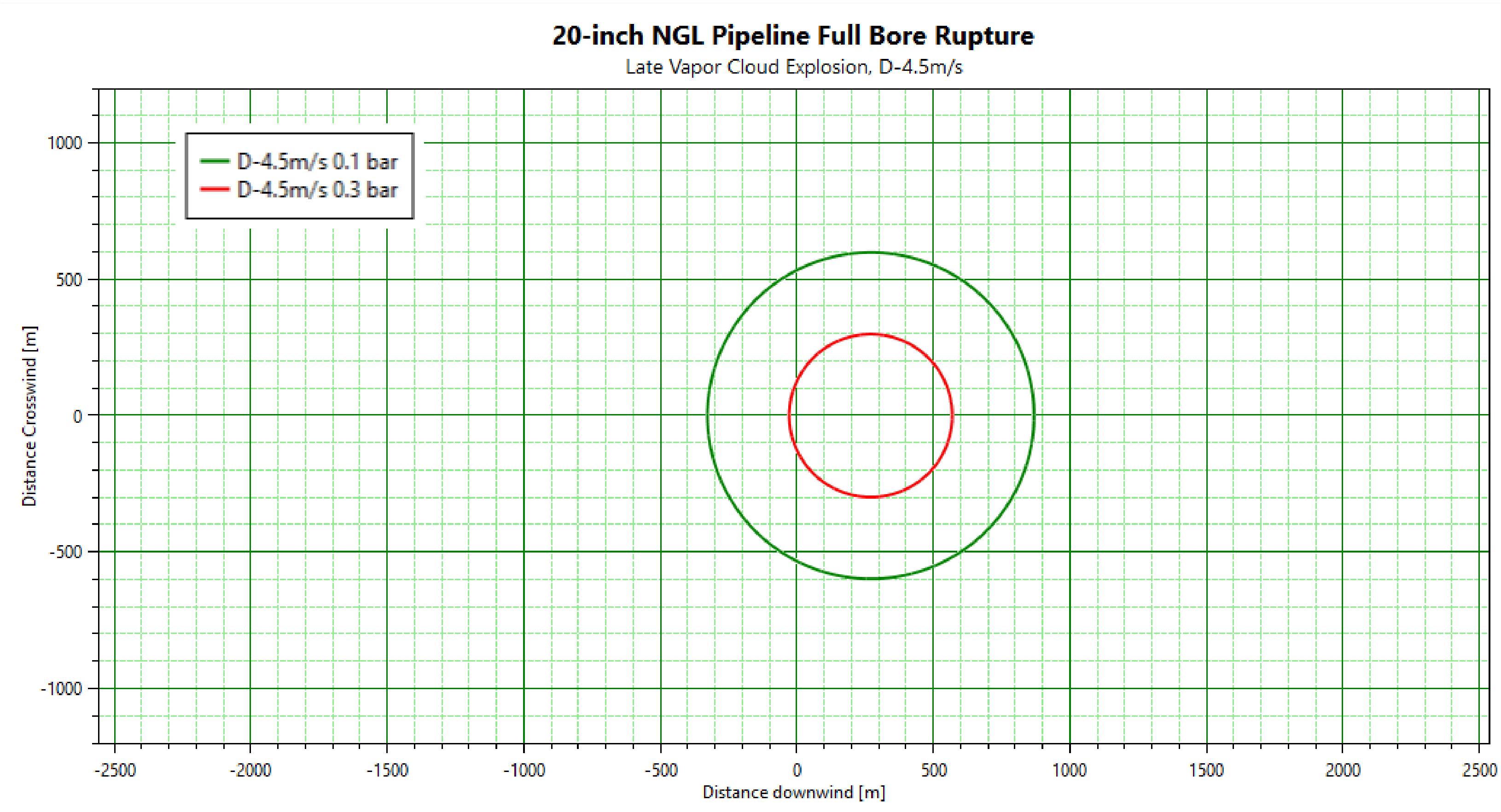
1400
1600
1800
2000
2200

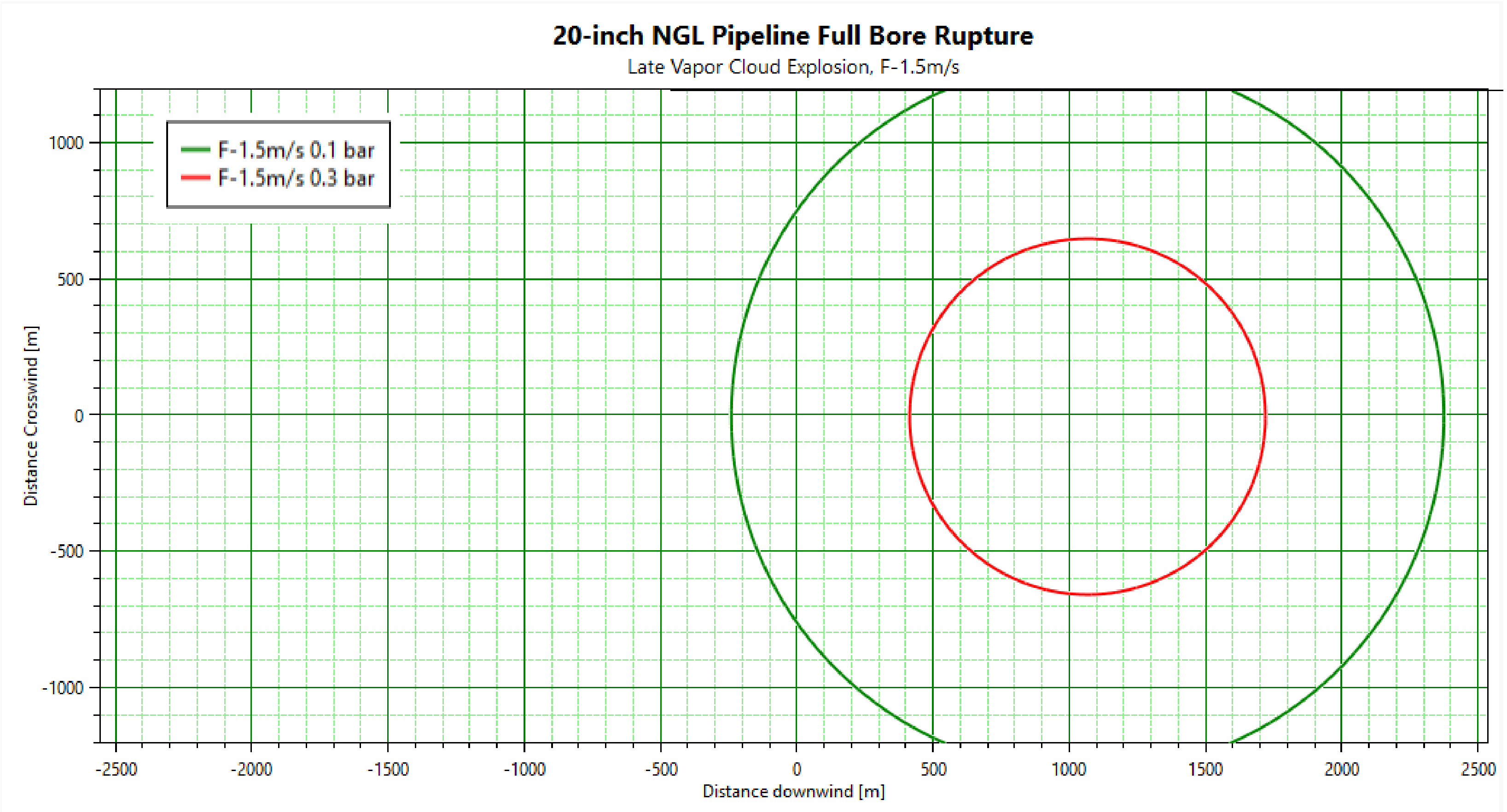

20-inch NGL Pipeline Full Bore Rupture
Early Flammable Cloud Footprint @5-minutes
F-1.5m/s @ 20000 ppm
Cloud Width [m]
500
0
-500
-500
0
500
1000
1500
2000
2500
Distance downwind [m]

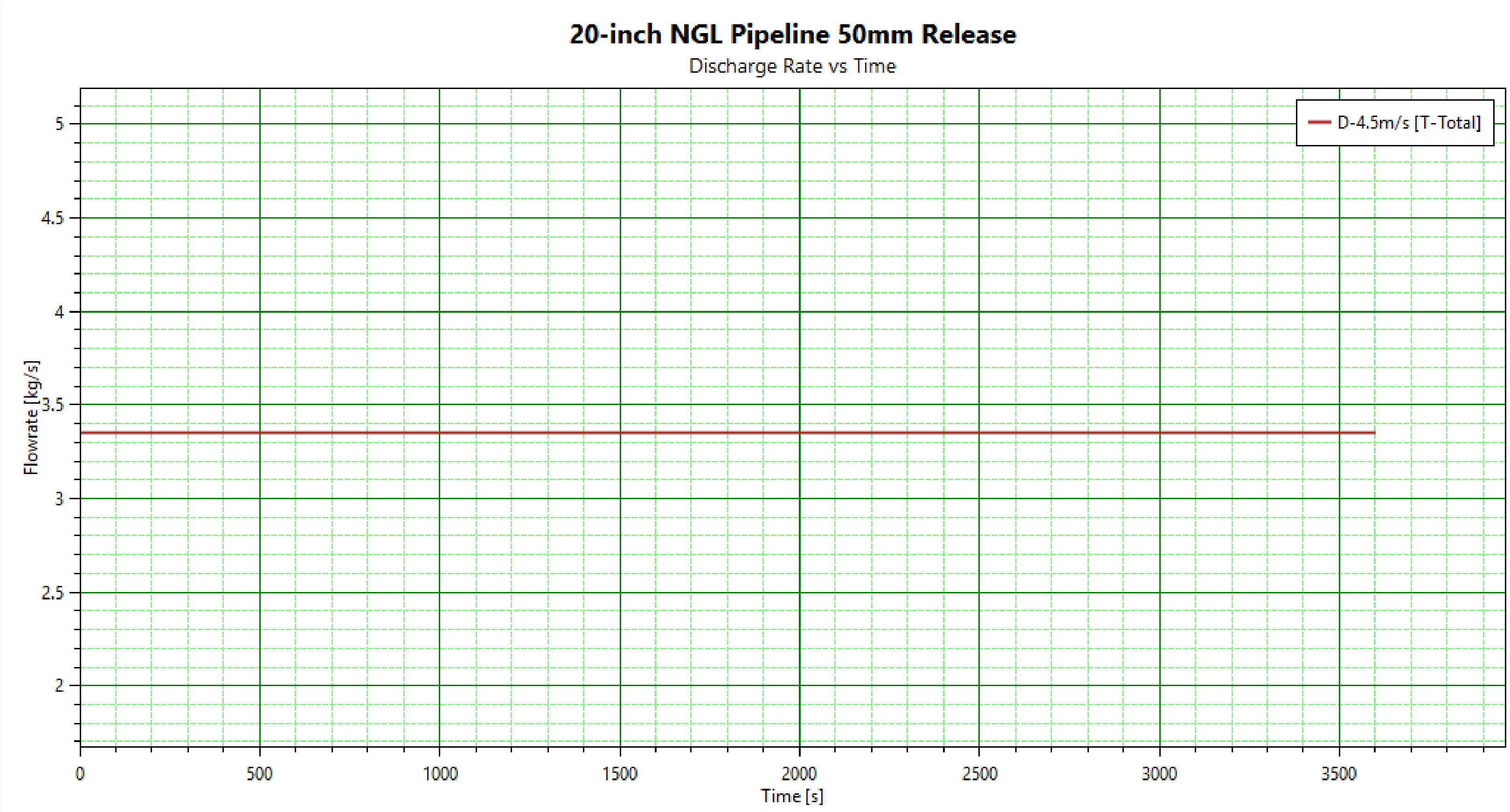

20-inch NGL Pipeline Full Bore Rupture
Early Vapor Cloud Explosion, F-1.5m/s @5-minutes
F-1.5m/s 0.1 bar
F-1.5m/s 0.3 bar
Distance Crosswind [m]
1000
500
0
-500
-1000
-2500
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500
Distance downwind [m]

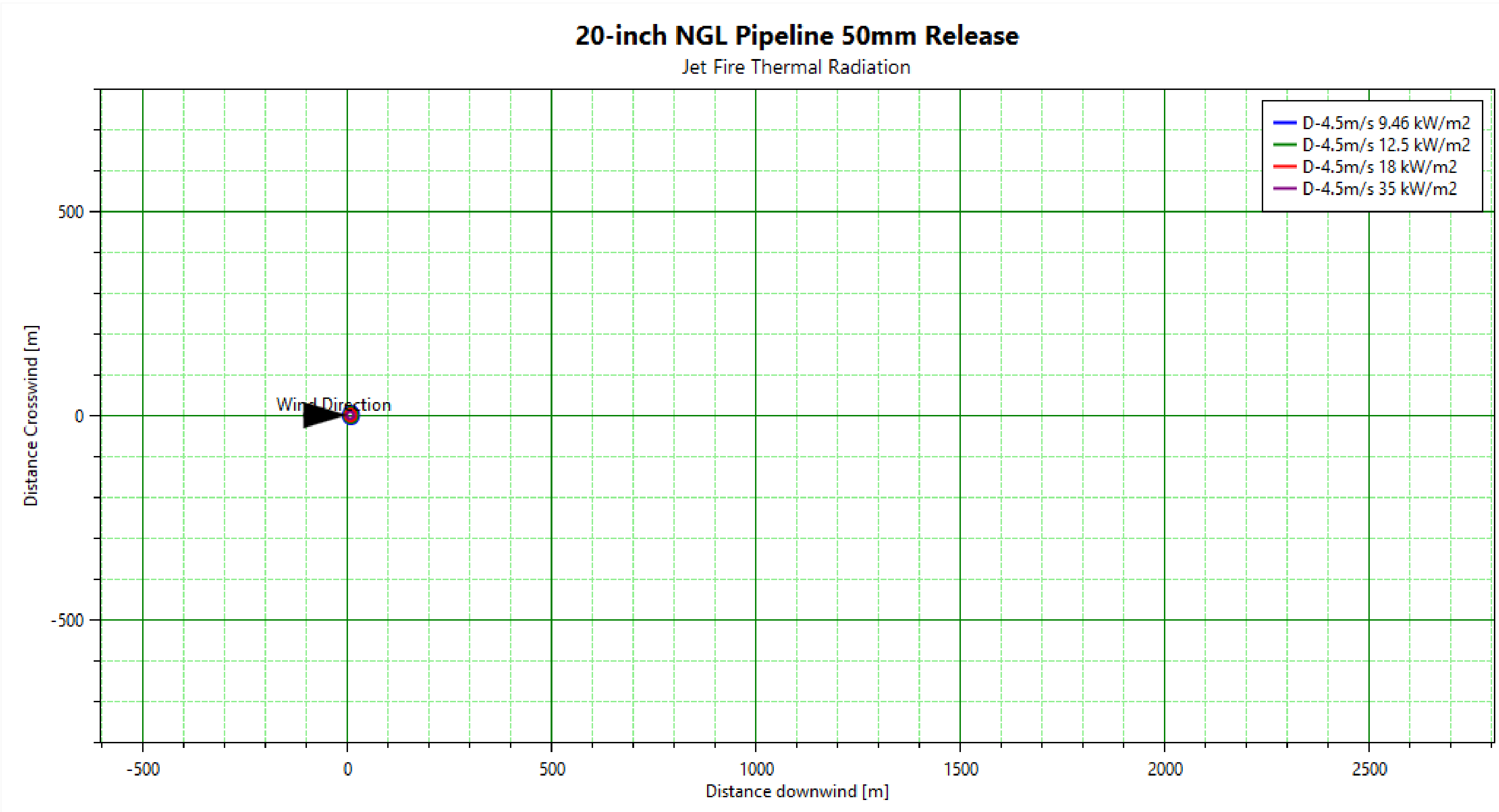

20-inch NGL Pipeline Full Bore Rupture
Late Flammable Gas Cloud Side View (Exaggerated Vertical Scale)
F-1.5m/s @ 20000 ppm
D-4.5m/s @ 20000 ppm
Cloud Height [m]
Distance downwind [m]
0
10
20
30
40
50
60
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200


20-inch NGL Pipeline Full Bore Rupture
Late Flammable Cloud Footprint
F-1.5m/s @ 20000 ppm
D-4.5m/s @ 20000 ppm
Cloud Width [m]
500
0
-500
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline Full Bore Rupture
Late Vapor Cloud Explosion, D-4.5m/s
D-4.5m/s 0.1 bar
D-4.5m/s 0.3 bar
Distance Crosswind [m]
1000
500
0
-500
-1000
-2500
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline Full Bore Rupture
Late Vapor Cloud Explosion, F-1.5m/s
F-1.5m/s 0.1 bar
F-1.5m/s 0.3 bar
Distance Crosswind [m]
1000
500
0
-500
-1000
-2500
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline 50mm Release
Discharge Rate vs Time
D-4.5m/s [T-Total]
Flowrate [kg/s]
5
4.5
4
3.5
3
2.5
2
0
500
1000
1500
2000
2500
3000
3500
Time [s]


20-inch NGL Pipeline 50mm Release
Jet Fire Thermal Radiation
D-4.5m/s 9.46 kW/m2
D-4.5m/s 12.5 kW/m2
D-4.5m/s 18 kW/m2
D-4.5m/s 35 kW/m2
Wind Direction
500
0
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Distance Crosswind [m]
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0
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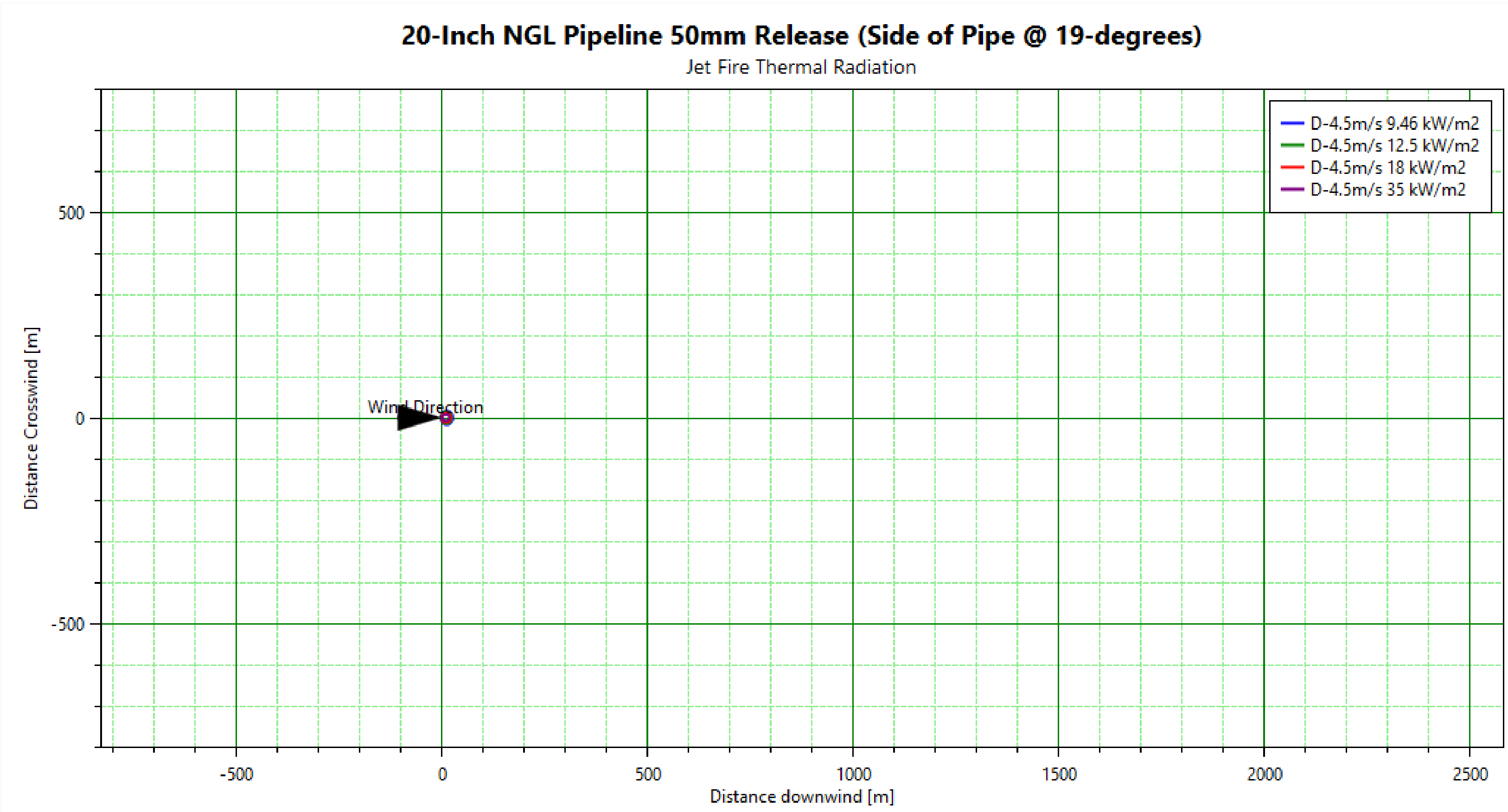
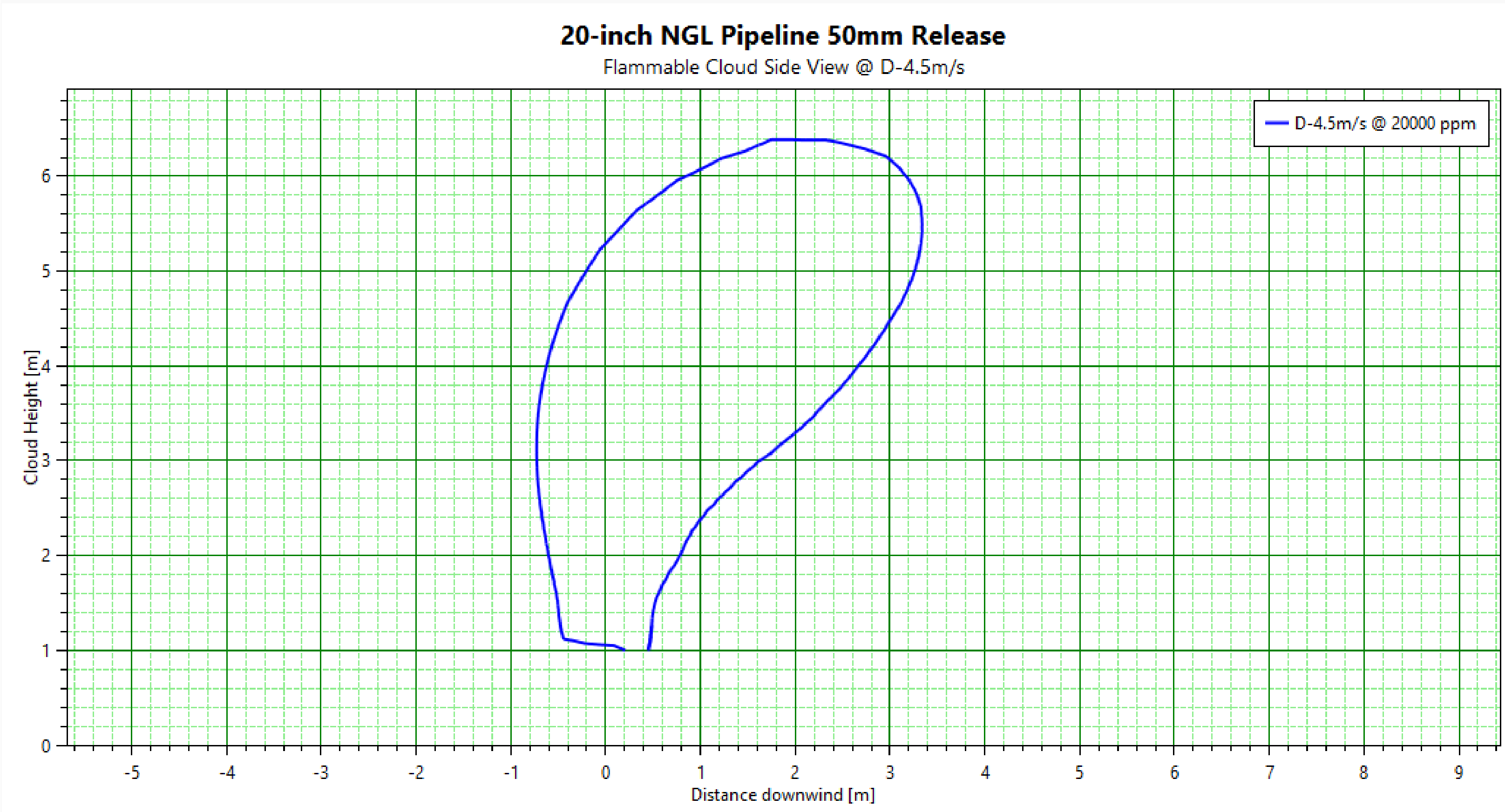
1000
1500
2000
2500
Distance downwind [m]


20-Inch NGL Pipeline 50mm Release (Side of Pipe @ 19-degrees)
Jet Fire Thermal Radiation
D-4.5m/s 9.46 kW/m2
D-4.5m/s 12.5 kW/m2
D-4.5m/s 18 kW/m2
D-4.5m/s 35 kW/m2
Wind Direction
Distance Crosswind [m]
500
0
-500
-500
0
500
1000
1500
2000
2500
Distance downwind [m]


20-inch NGL Pipeline 50mm Release
Flammable Cloud Side View @ D-4.5m/s
D-4.5m/s @ 20000 ppm
Cloud Height [m]
0
1
2
3
4
5
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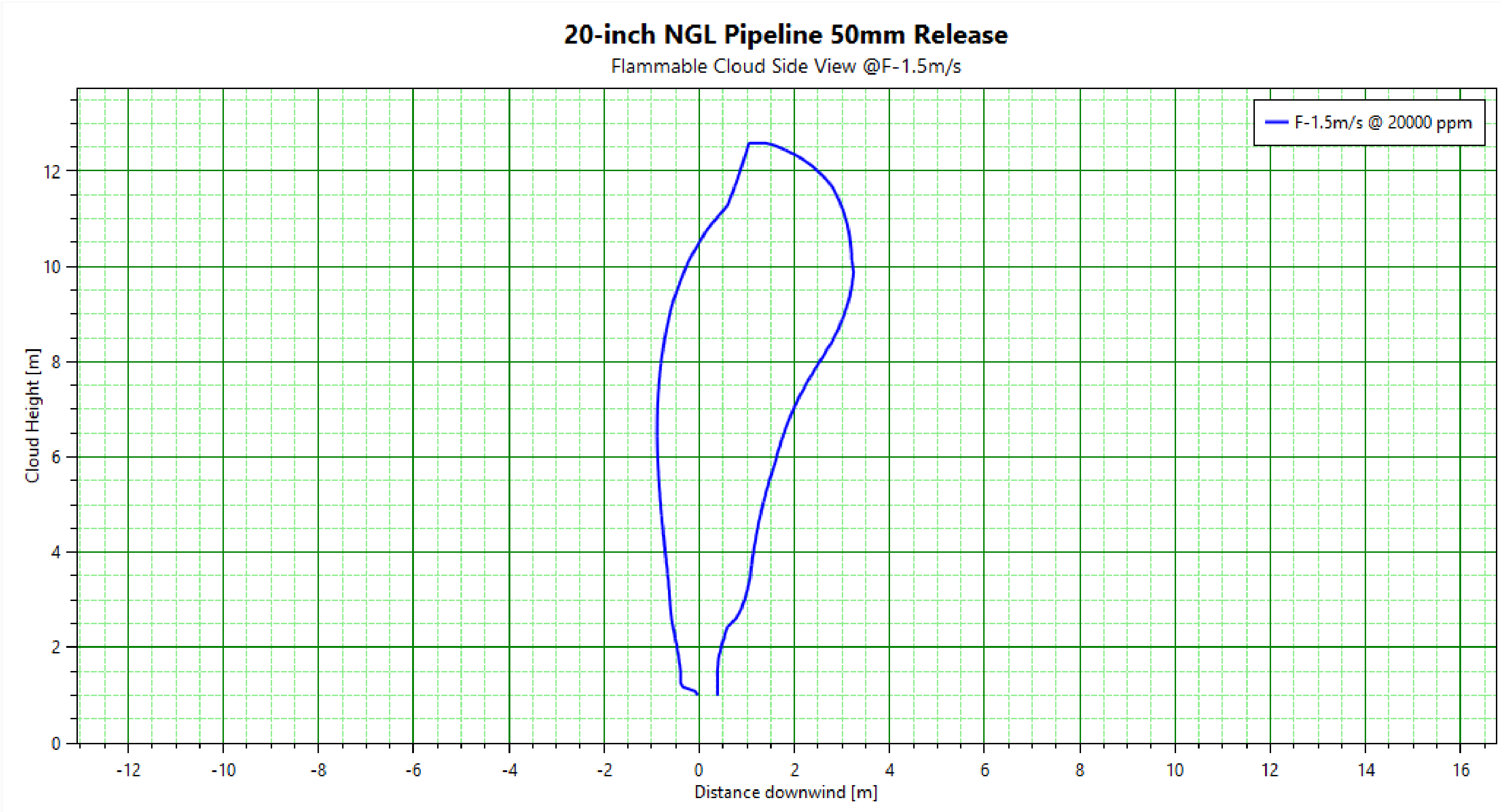
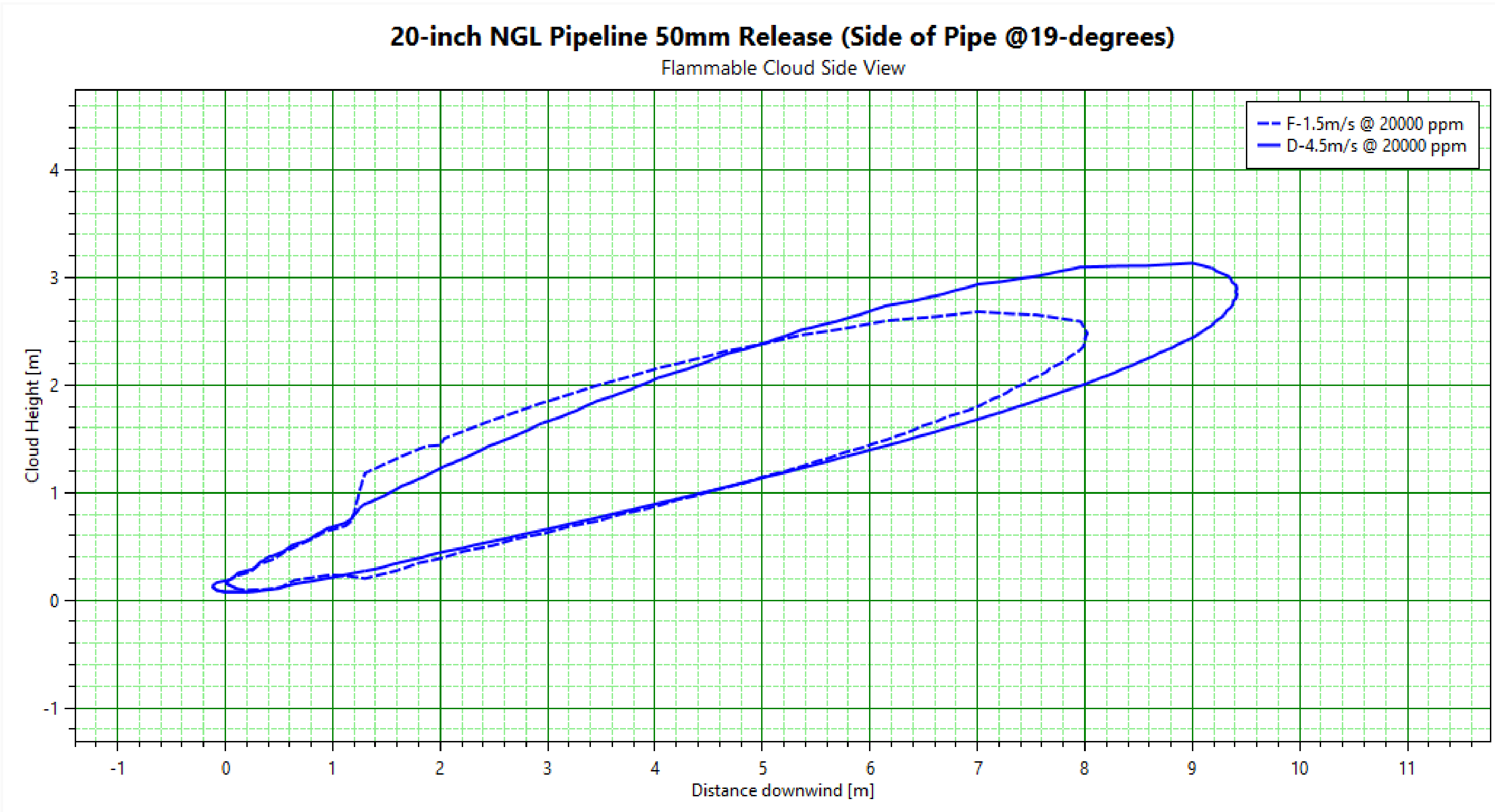
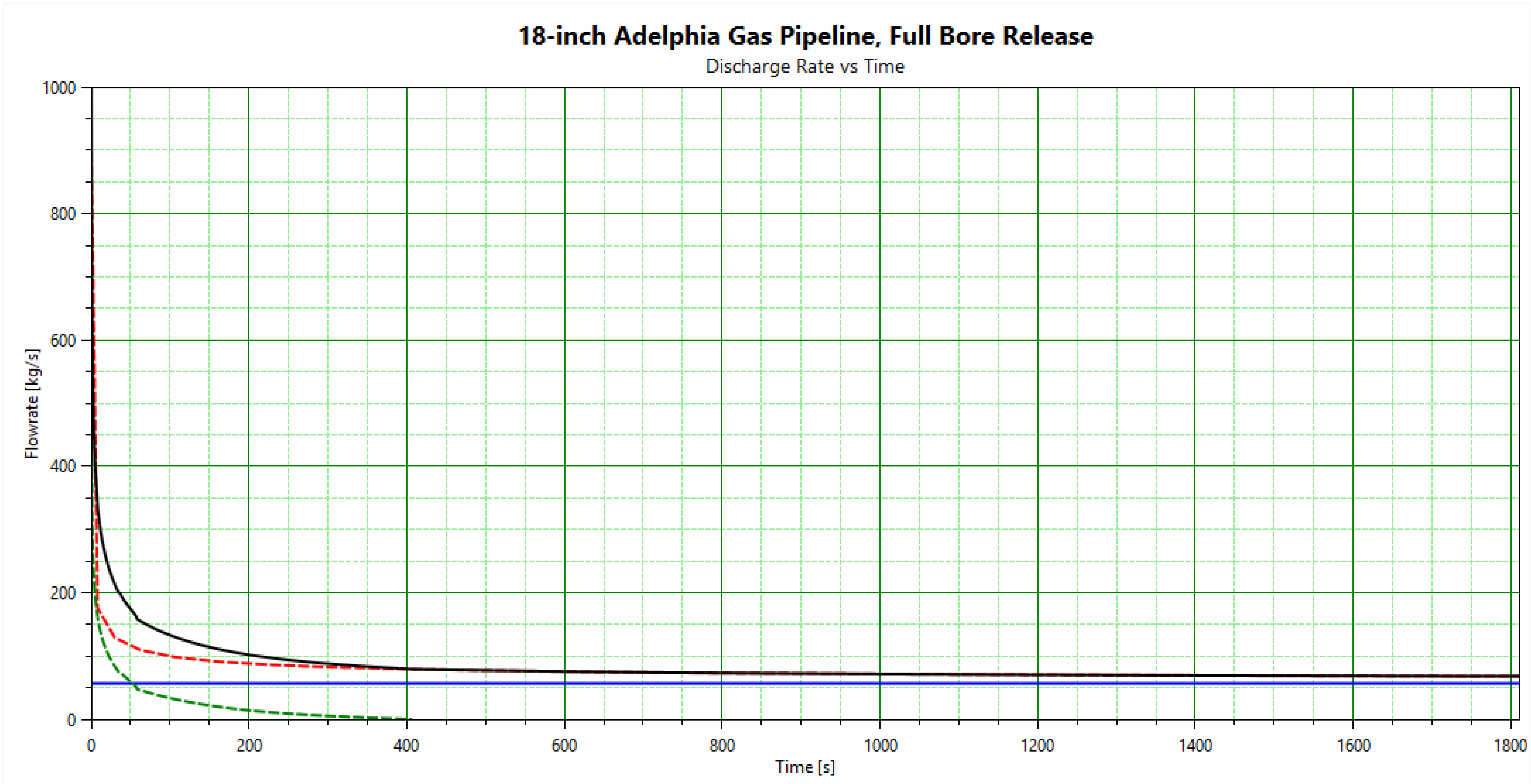
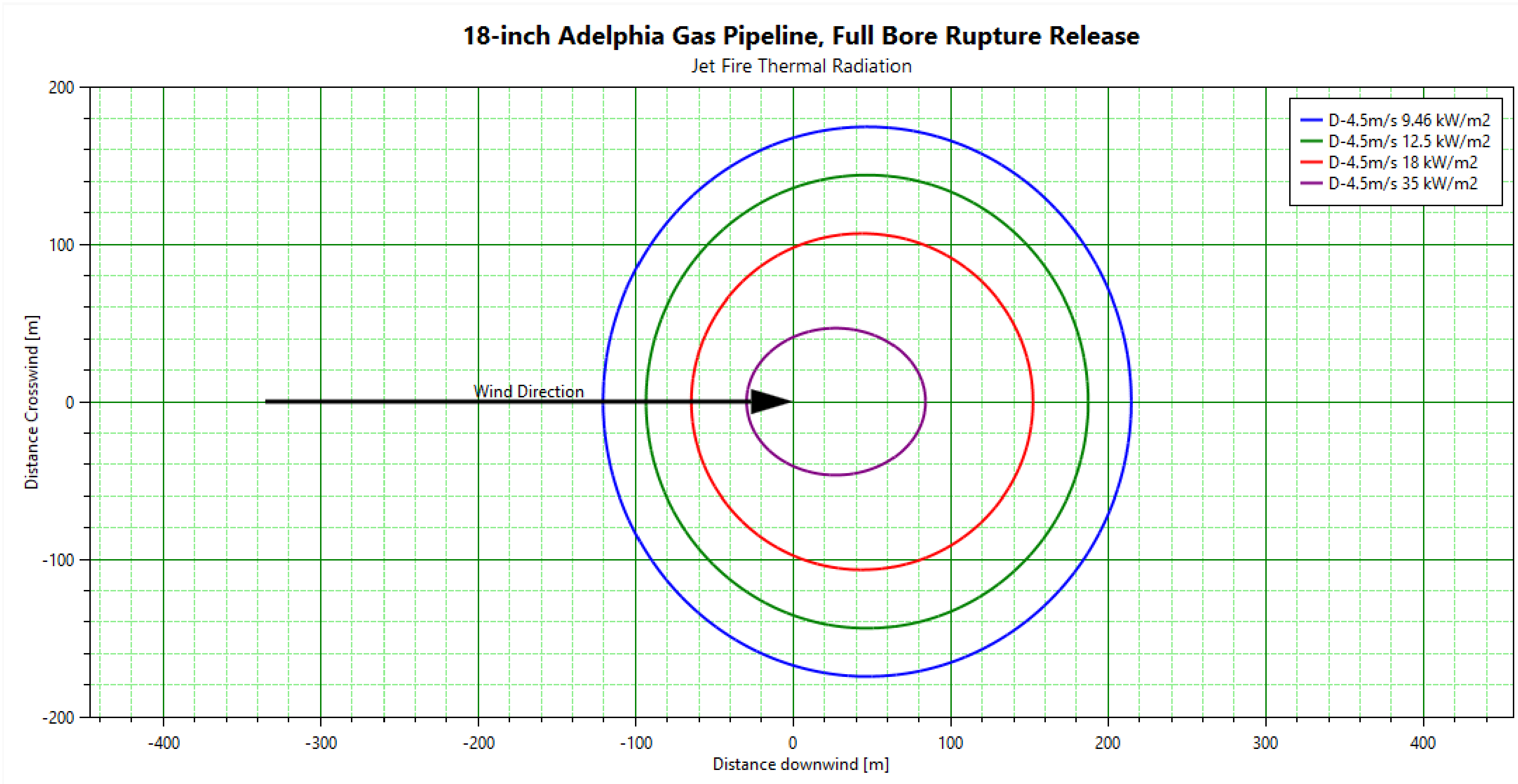
2
3
4
5
6
7
8
9
Distance downwind [m]

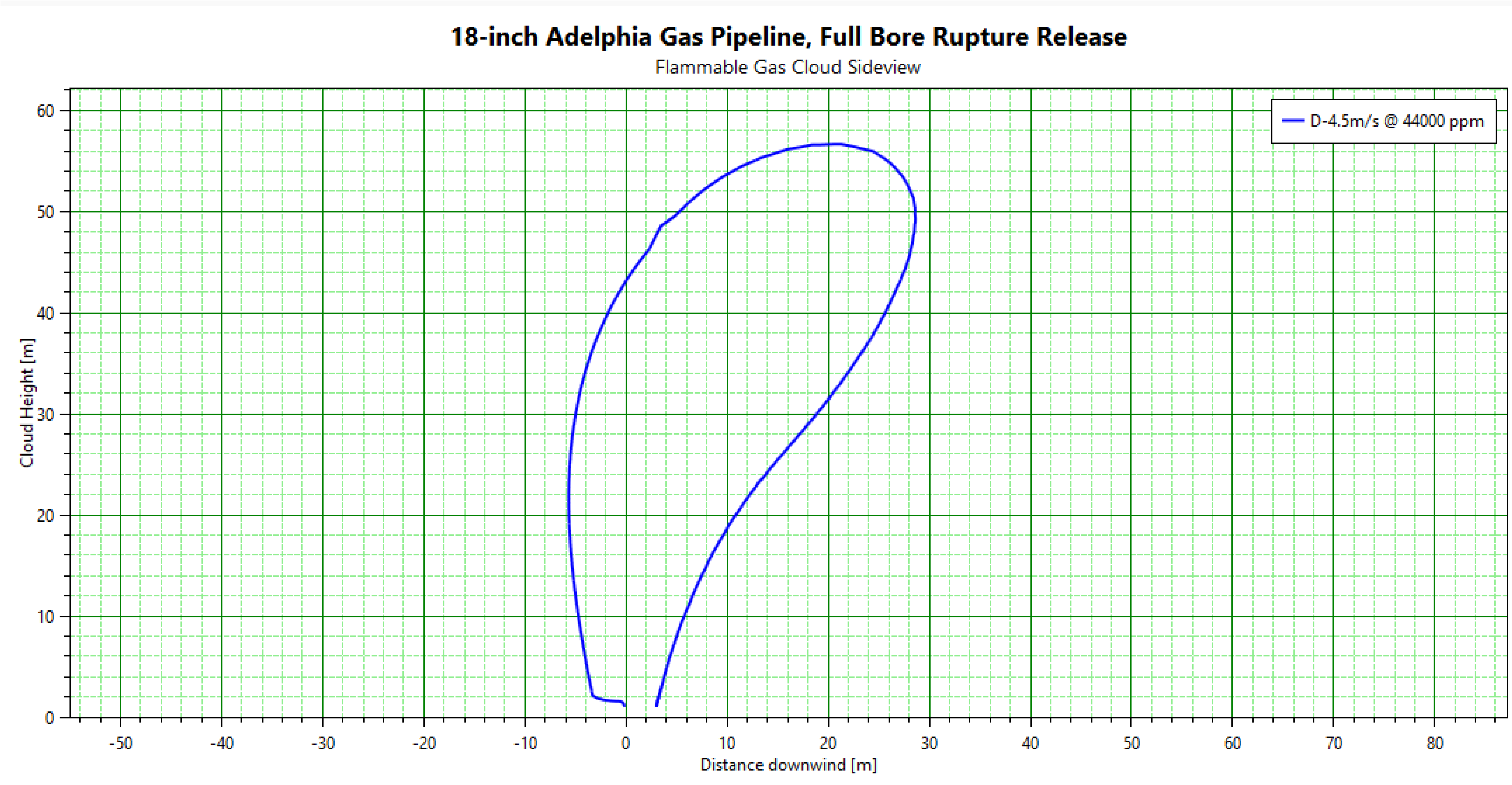

20-inch NGL Pipeline 50mm Release
Flammable Cloud Side View @F-1.5m/s
F-1.5m/s @ 20000 ppm
Cloud Height [m]
Distance downwind [m]
0
2
4
6
8
10
12
-12
-10
-8
-6
-4
-2
0
2
4
6
8
10
12
14
16

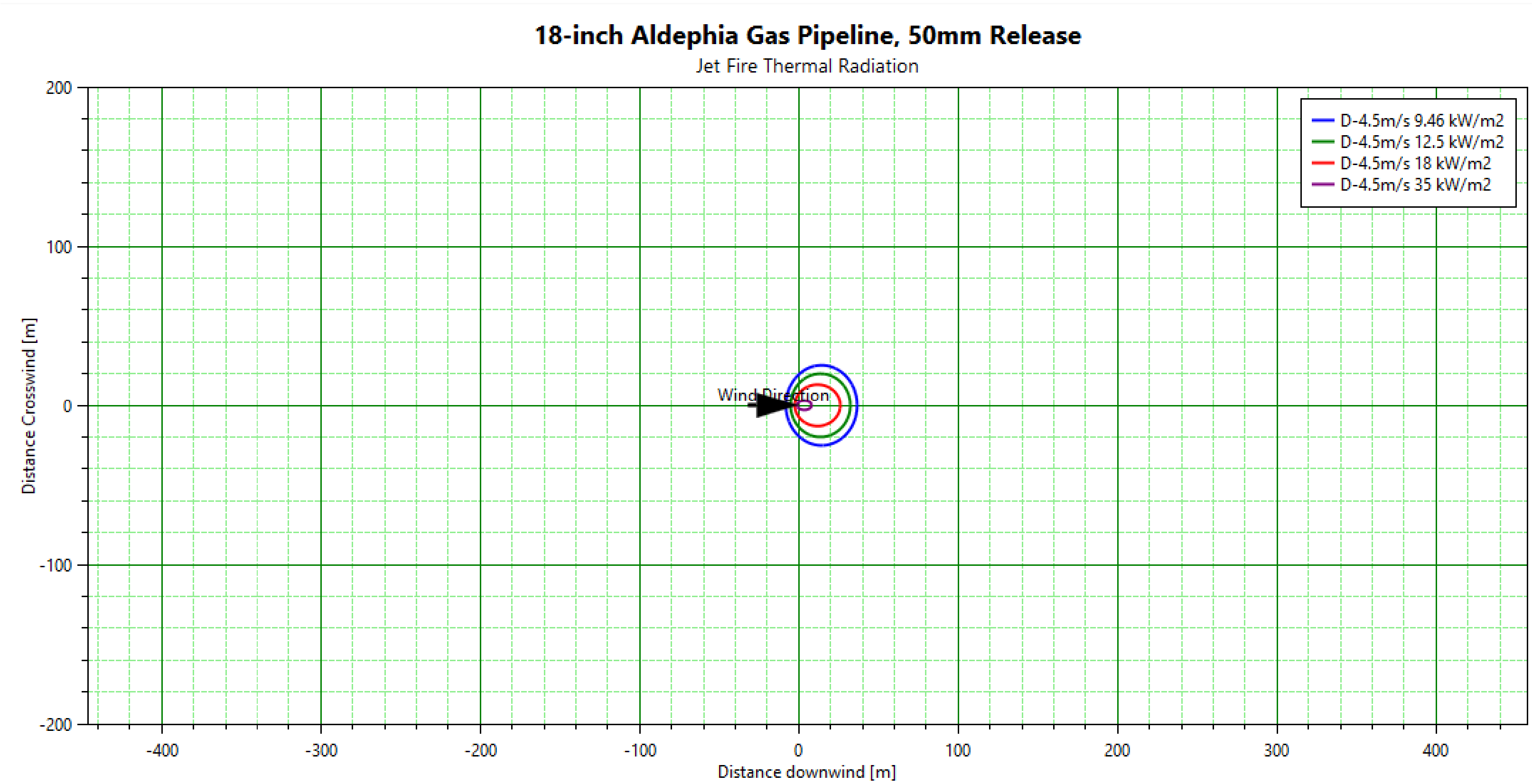

20-inch NGL Pipeline 50mm Release (Side of Pipe @19-degrees)
Flammable Cloud Side View
F-1.5m/s @ 20000 ppm
D-4.5m/s @ 20000 ppm
Cloud Height [m]
Distance downwind [m]
4
3
2
1
0
-1
-1
0
1
2
3
4
5
6
7
8
9
10
11

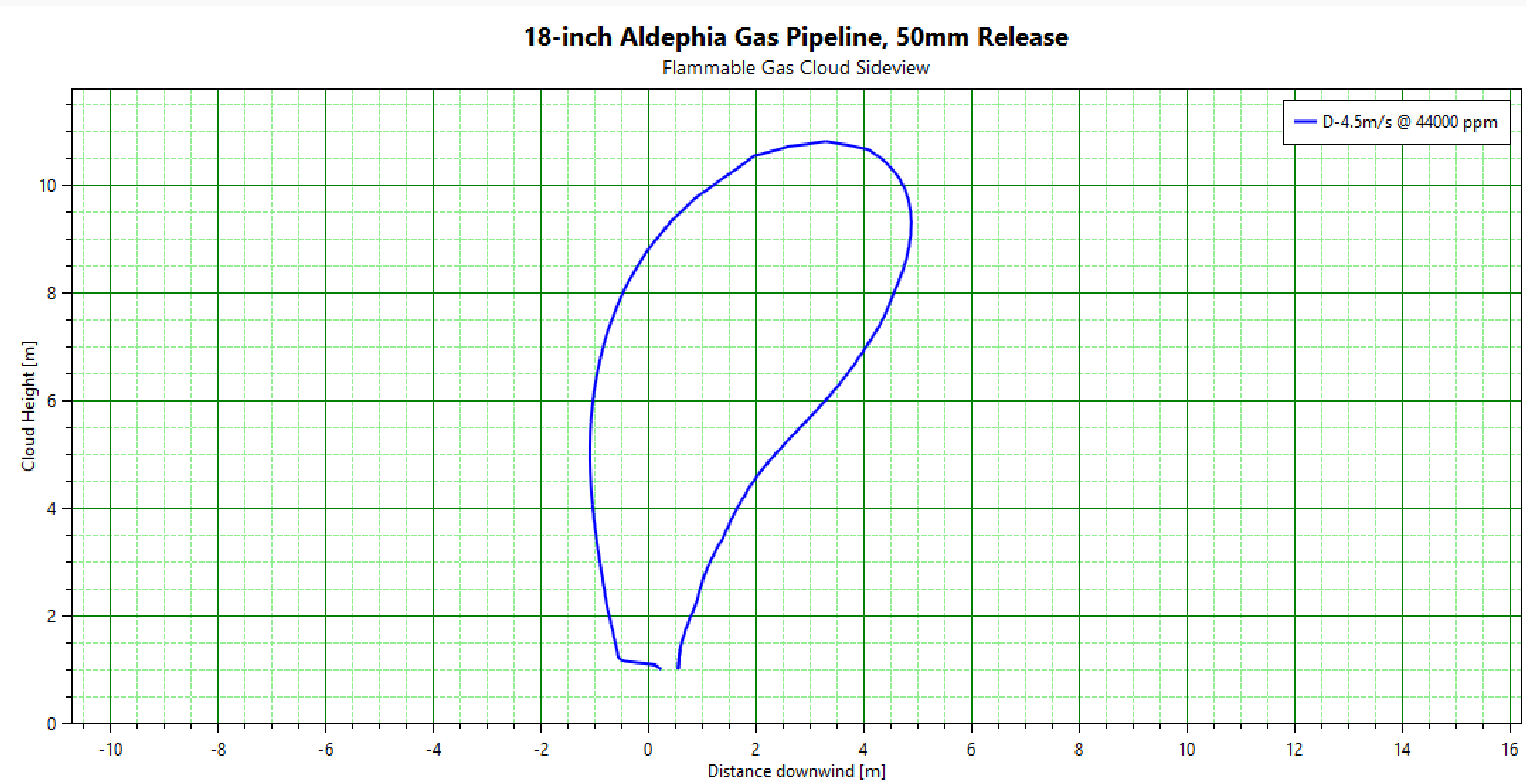
APPENDIX B: ADELPHIA PIPELINE CONSEQUENCE PLOTS


18-inch Adelphia Gas Pipeline, Full Bore Release
Discharge Rate vs Time
Flowrate [kg/s]
1000
800
600
400
200
0
0
200
400
600
800
1000
1200
1400
1600
1800
Time [s]


18-inch Adelphia Gas Pipeline, Full Bore Rupture Release
Jet Fire Thermal Radiation
D-4.5m/s 9.46 kW/m2
D-4.5m/s 12.5 kW/m2
D-4.5m/s 18 kW/m2
D-4.5m/s 35 kW/m2
Wind Direction
Distance Crosswind [m]
Distance downwind [m]
200
100
0
-100
-200
-400
-300
-200
-100
0
100
200
300
400


18-inch Adelphia Gas Pipeline, Full Bore Rupture Release
Flammable Gas Cloud Sideview
D-4.5m/s @ 44000 ppm
Cloud Height [m]
Distance downwind [m]
0
10
20
30
40
50
60
-50
-40
-30
-20
-10
0
10
20
30
40
50
60
70
80


18-inch Aldephia Gas Pipeline, 50mm Release
Jet Fire Thermal Radiation
D-4.5m/s 9.46 kW/m2
D-4.5m/s 12.5 kW/m2
D-4.5m/s 18 kW/m2
D-4.5m/s 35 kW/m2
Wind Direction
Distance Crosswind [m]
Distance downwind [m]
200
100
0
-100
-200
-400
-300
-200
-100
0
100
200
300
400


18-inch Aldephia Gas Pipeline, 50mm Release
Flammable Gas Cloud Sideview
D-4.5m/s @ 44000 ppm
Cloud Height [m]
Distance downwind [m]
0
2
4
6
8
10
-10
-8
-6
-4
-2
0
2
4
6
8
10
12
14
16

APPENDIX C: PHMSA HVL TRANSMISSION PIPELINE STATISTICS

Summary HVL Onshore Below Ground Pipeline Mileage, 2002 to Mid 2018 (inclusive)

Year	Diameter Less than 12-inch (mile-years)	Diameter 12-inch or greater (mile-years)	All Diameter Sizes (mile-years)	Comment
2002	41,135	10,621	51,757	Assume to be similar to 2004
2003	41,135	10,621	51,757	Assume to be similar to 2004
2004	41,135	10,621	51,757	
2005	40,236	10,970	51,207	
2006	41,090	11,442	52,532	
2007	42,485	11,896	54,382	
2008	43,794	13,231	57,024	
2009	43,667	13,565	57,233	
2010	43,887	14,090	57,977	
2011	44,178	14,401	58,578	
2012	44,154	15,684	59,839	
2013	44,445	18,321	62,766	
2014	45,585	20,208	65,793	
2015	46,500	21,169	67,670	
2016	46,473	22,385	68,858	
2017	46,037	22,763	68,799	
Mid 2018*	23,018	11,381	34,400	Assume 2018 similar to 2017 and prorate*
Total	**718,956**	**253,371**	**972,328**	

* Count only half of 2018 to align with incidents used

HVL Onshore Below Ground Pipeline Incident Frequency

Diameter	Number of Full Bore LoC Incidents 2002 to Mid 2018 (inclusive)	Full Bore LoC Incidents Frequency (LoC incidents/mile-year)
Less than 12-inch	22	3.1E-05
12-inch or greater	6	2.4E-05
All Diameter Sizes	**28**	**2.88E-05**

APPENDIX D: PHMSA NATURAL GAS TRANSMISSION PIPELINE STATISTICS

Summary Natural Gas Onshore Below Ground Pipeline Mileage, 2002 to 2017 (inclusive)

Year	Diameter 10-inches and less (mile-years)	Diameter Over 10-inches thru 28-inches (mile-years)	Diameter Over 28-inches (mile-years)	All Diameter Sizes (mile-years)	Comment
2002	93,339	135,496	67,013	295,849	
2003	88,242	138,374	68,333	294,949	
2004	88,409	137,564	70,882	296,855	
2005	89,295	133,985	68,716	291,996	
2006	86,887	136,430	70,329	293,646	
2007	89,576	134,039	71,136	294,751	
2008	88,530	135,070	73,617	297,217	
2009	86,379	135,952	76,527	298,857	
2010	89,264	134,793	75,307	299,364	
2011	88,255	132,434	79,035	299,723	
2012	86,670	133,155	78,830	298,654	
2013	86,150	133,015	79,228	298,392	
2014	85,586	132,746	79,583	297,915	
2015	85,994	132,060	79,279	297,333	
2016	85,286	131,766	79,866	296,918	
2017	84,273	131,823	81,474	297,570	
2018	42,136	65,912	40,737	148,785	Extrapolated 2017 mileage and prorated for the 6 months of 2018. This was done to match the incident data range 2002-2018 (half year)
Total	**1,444,269**	**2,214,615**	**1,239,890**	**4,898,775**	

Natural Gas Onshore Below Ground Pipeline Incident Frequency

Diameter	Number of Full Bore LoC Incidents 2002 to mid-2018 (inclusive)	Full Bore LoC Incidents Frequency (LoC incidents/mile-year)	Small to Large LoC Incident Frequency* (LoC incidents/mile-year)
10-inches and less	47	3.3E-05	8.1E-05
Over 10-inches thru 28-inches	128	5.8E-05	1.4E-04
Over 28-inches	37	3.0E-05	7.5E-05
All Diameter Sizes	212	4.3E-05	1.1E-04

* Assumed 50mm frequency to be 2.5X Full Bore Frequency, per OGP recommendation distribution for onshore oil pipelines

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 NORTH STREET, HARRISBURG, PA 17120

IN REPLY PLEASE
REFER TO OUR FILE

February 16, 2018

REFERENCE:
L-01-18

Mr. Albert Kravatz, DOT
NEB Compliance Specialist
Energy Transfer
Sunoco Pipeline L.P.
4041 Market Street
Aston, PA 19014

Dear Mr. Kravatz:

The PUC's Investigation and Enforcement Bureau's Safety Division is reviewing Sunoco Pipelines' Emergency Response Plans.

Due to the potential safety risks associated with the Sunoco Mariner East 1, 2 and 2X pipeline projects and to evaluate your company's contingency plans, the PUC's Safety Division requests Sunoco to submit on or before, March 12, 2018 the following:

1.) Provide a list of all valves for ME1, ME2, ME2X along with a map showing the locations of the valves.

2.) Provide HCA maps for ME1, ME2, ME2X.

3.) Identify which valves can be operated using SCADA (EFRD).

4.) Identify the distance between each valve.

5.) Identify the maximum amount of product, by volume and product type, that can be transported in each pipeline between the valves.

6.) Provide the response time to close each valve.

7.) For each type of product in the pipelines (including mixed products), provide a real time modeling result for the following:

   a. Calculate the Immediate Ignition Impact Zone (IIIZ) for a pipeline failure in cold and warm weather. Model the IIIZ between each valve segment. Identify the population included within the zone. Include in the modeling the width and length of the evacuation zone and the estimated evacuation time frame. Also provide the Emergency Response Plans for this type of accident. List the parameters utilized to model the release. Finally, identify all schools, hospitals, nursing homes, etc. located within the IIIZ.

Friedman_09_ PUC letter to Sunoco seeking accident consequence information 2-16-2018.

b. Calculate the Buffer Zone for a pipeline failure that produces a flammable vapor cloud in cold and warm weather. Model this scenario between each valve segment. Identify the population included within the Buffer Zone. Describe the width/length of the vapor cloud modeled. Estimate the evacuation time frame. Also provide the Emergency Response Plans for this type of accident. Finally, identify all schools, hospitals, nursing homes, etc. located within the Buffer Zone.

8.) Documentation for Emergency Responder training for each section of pipe and vales on ME1, ME2 and ME2X.

This office is committed to ensuring that all natural gas companies comply with the provisions of the Public Utility Code. Therefore, you are advised that, if you fail to comply with the above requests this office will initiate all appropriate enforcement actions pursuant to the Public Utility Code against the utility and its officers, agents and employees.

Yours truly,

Paul J. Metro

Paul J. Metro, Manager
Safety Division
Bureau of Investigation and Enforcement

PM:bb

PC: Richard A. Kanaskie, Director, I&E

§195.440 Public awareness.

(a) Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see §195.3).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a hazardous liquid or carbon dioxide pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and

(5) Procedures to report such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports hazardous liquid or carbon dioxide.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

[Amdt. 195-84, 70 FR 28843, May 19, 2005]

CERTIFICATE

By Authority Of
THE UNITED STATES OF AMERICA
Legally Binding Document

By the Authority Vested By Part 5 of the United States Code § 552(a) and Part 1 of the Code of Regulations § 51 the attached document has been duly INCORPORATED BY REFERENCE and shall be considered legally binding upon all citizens and residents of the United States of America. *HEED THIS NOTICE*: Criminal penalties may apply for noncompliance.

Document Name:

CFR Section(s):

Standards Body:

Official Incorporator:
THE EXECUTIVE DIRECTOR
OFFICE OF THE FEDERAL REGISTER
WASHINGTON, D.C.

Public Awareness Programs for Pipeline Operators

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

American
Petroleum
Institute

**Helping You
Get The Job
Done Right.℠**

Public Awareness Programs for Pipeline Operators

Pipeline Segment

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

American
Petroleum
Institute

**Helping You
Get The Job
Done Right.℠**

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FOREWORD

This document is a Recommended Practice (RP) for pipeline operators to use in development and management of Public Awareness Programs. Pipeline Operators have conducted Public Awareness Programs with the affected public, government officials, emergency responders and excavators along their routes for many years. The goal of this RP is to establish guidelines for operators on development, implementation, and evaluation of Public Awareness Programs in an effort to raise the effectiveness of Public Awareness Programs throughout the industry.

Representatives from natural gas and liquid petroleum transmission companies, local distribution companies, and gathering systems, together with the respective trade associations, have developed this Recommended Practice. The working group was formed in early 2002. Additionally, representatives from federal and state pipeline regulators have provided input at each step of development and feedback from all interested parties has been solicited through a wide variety of sources and surveys.

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Page

Public Awareness Programs for Pipeline Operators

1 Introduction, Scope and Glossary of Terms

1.1 INTRODUCTION

This Recommended Practice (RP) provides guidance to be used by operators of petroleum liquids and natural gas pipelines to develop and actively manage Public Awareness Programs. This RP will also help to raise the quality of pipeline operators' Public Awareness Programs, establish consistency among such programs throughout the pipeline industry, and provide mechanisms for continuous improvement of the programs. This RP has been developed specifically for pipelines operating in the United States, but may also have use in international settings.

Public awareness and understanding of pipeline operations is vital to the continued safe operation of pipelines. Pipeline operators' Public Awareness Programs are an important factor in establishing communications and providing information necessary to help the public understand that pipelines are the major transportation system for petroleum products and natural gas in the United States, how pipelines function, and the public's responsibilities to help prevent damage to pipelines.

Public Awareness Programs should address the needs of different audiences within the community and be flexible enough to change as the pipeline system changes or as the public's needs for information change. When effectively and consistently managed, a Public Awareness Program can provide significant value to the pipeline operator in several areas: enhanced public safety, improved pipeline safety and environmental performance, building trust and better relationships with the public along the pipeline route, less resistance to pipeline maintenance and right-of-way activities, preservation of rights-of-way, enhanced emergency response coordination, and improved pipeline operator reputation.

Public awareness messages need to provide a broad overview of how pipelines operate, the hazards that may result from activity in close proximity to pipelines and those hazards possible due to pipeline operations, and the measures undertaken to prevent impact to public safety, property or the environment. These messages should be coupled with information regarding how pipeline operators prepare for emergencies in a way that minimizes the consequences of a pipeline incident.

This RP identifies for the pipeline operator four specific stakeholder audiences and associated public outreach messages and communication methods to choose from in developing and managing a successful Public Awareness Program. It also provides information to assist operators in establishing specific plans for public awareness that can be evaluated and updated.

This RP is comprised of a main body (Sections 1 – 8), and Appendices. The main body of this document contains the general, baseline program recommendations and the supplemental program components. Summary tables and diagrams are also provided in the main body. These summaries can be used as quick reference guides to assist operators when customizing their Public Awareness Programs to reflect the unique characteristics of their pipeline and facilities. The Appendices provide operators with additional, optional information and resources for further reference. The Appendices repeat many areas of the main body in order to provide the operator with comprehensive information.

1.2 SCOPE

This RP is intended as a resource that can assist pipeline operators in their public awareness efforts. Operators are urged to develop, implement and actively manage Public Awareness Programs within their companies. In implementing these programs, operators should select the most appropriate mix of audiences, message types, and delivery methods and frequencies, depending on their needs and the needs of the communities along a given pipeline segment. The guidance set forth in this RP establishes a baseline for Public Awareness Programs and describes considerations for program expansion that can further enhance specific public awareness outreach.

This RP provides guidance for the following pipeline operators:

- Intrastate and interstate hazardous liquid pipelines
- Intrastate and interstate natural gas transmission pipelines
- Local distribution systems, and
- Gathering systems.

This guidance is intended for use by pipeline operators in developing and implementing Public Awareness Programs associated with the normal operation of existing pipelines. The guidance is not intended to focus on public awareness activities appropriate for new pipeline construction or for communications that occur immediately after a pipeline-related emergency. Communication regarding construction of new pipelines is highly specific to the type of pipeline system, scope of the construction, and the community and state in which the project is located. Likewise, public communications in response to emergency situations are also highly specific to the emergency and location. This RP is also not intended to provide guidance to operators for communications about operator-specific performance measures that are addressed through other means of communication or regulatory reporting.

The primary audience for this RP is the pipeline operator for use in developing a Public Awareness Program for the following stakeholder audiences:

- The affected public—i.e., residents, and places of congregation (businesses, schools, etc.) along the pipeline and the associated right-of-way (ROW)
- Local and state emergency response and planning agencies—i.e., State and County Emergency Management Agencies (EMA) and Local Emergency Planning Committees (LEPCs)
- Local public officials and governing councils
- Excavators.

DESCRIPTION OF PIPELINE INFRASTRUCTURE

To clarify the scope of the pipeline industry covered by this RP, a brief description of the affected infrastructure components is provided below. Mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included. Unless otherwise noted, the use of the term "pipeline" in this RP will refer to all three of the following types of systems. The RP recognizes some differences between the three pipeline types and provides the operator flexibility based on the needs of the stakeholders along a particular pipeline.

1.2.1 Transmission Pipelines

The transmission pipeline systems for liquid petroleum and natural gas, move large amounts of liquids and natural gas from the producing and/or refining locations to local "outlets", such as bulk storage terminals (for liquids) and natural gas distribution systems. Transmission pipeline systems can be classified as either "intrastate pipelines", located within one state's borders, or "interstate pipelines" crossing more than one state's borders. Natural gas transmission pipelines deliver gas to direct-served customers and local distribution systems' stations, referred to as "city gates", where the pressure is lowered for final distribution to end users. Liquids transmission pipelines usually transport crude oil, refined products, or natural gas liquids. Transmission pipelines are generally the middle of the transportation link between gathering and distribution systems.

1.2.2 Local Distribution Systems

The local distribution systems for liquid petroleum and natural gas differ because of the nature and use of the products. Liquid petroleum products are distributed from bulk terminals by other modes of transportation, such as by rail cars and tank trucks. Local natural gas distribution companies (LDCs) receive natural gas at "city gates" and distribute it through distribution systems, These consist of "mains", which are usually located along or under city streets and smaller service lines that connect to the mains to further distribute natural gas service to the local end users - homes and businesses.

1.2.3 Gathering Systems

Gathering pipelines link production areas for both crude oil and natural gas to central collection points. Some gathering systems include processing facilities; others do not. Some gathering systems are regulated by the Office of Pipeline Safety, U.S Department of Transportation, while most are not. Gathering systems connect to transmission pipelines for long distance transportation of crude oil and natural gas to refinery centers and distribution centers, respectively.

1.3 GLOSSARY OF TERMS

1.3.1 Appendices: The Appendices' role is to provide a pipeline operator with additional information to develop and actively manage its Public Awareness Programs. The Appendices' mirror the main body of the RP while providing additional information such as: resources and contacts, examples of stakeholder audiences, public awareness messages, enhanced delivery methods and media, and program evaluation information.

1.3.2 Baseline Public Awareness Program: Refers to general program recommendations, set forth in Recommended Practice 1162, The baseline recommendations do not take into consideration the unique attributes and characteristics of individual pipeline operators' pipeline and facilities. Supplemental or enhanced program components are described in the RP to provide guidelines to the operator for enhancing its Public Awareness Programs. This is described more fully in Sections 2 and 6.

1.3.3 CFR: *Code of Federal Regulations*

1.3.4 Dig Safely: Dig Safely is the nationally recognized campaign to enhance safety, environmental protection, and service reliability by reducing underground facility damage. This damage prevention education and awareness program is used by pipeline companies, One-Call Centers, and others throughout the country. Dig Safely was developed through the joint efforts of the Office of Pipeline Safety and various damage prevention stakeholder organizations. Dig Safely is now within the purview of the Common Ground Alliance (CGA). For more information see www.commongroundalliance.com.

1.3.5 Enhanced Public Awareness Program: The concept developed in RP 1162 for assessing particular situations in which it is appropriate to enhance or supplement the Baseline Public Awareness Program. This is described more fully in Section 6.

1.3.6 High Consequence Areas (HCAs): A high consequence area is a location that is specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Pipeline safety regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA.

1.3.7 HVL (Highly Volatile Liquid): A highly volatile liquid, as defined in pipeline safety regulations, is a hazardous liquid that will form a vapor cloud when released to the atmosphere and has a vapor pressure exceeding 276kPa (40 psia) at 37.8 degrees C (100 degrees F).

1.3.8 Integrity Management Program (IMP): In accordance with pipeline safety regulations, an operator's integrity management program must include, at a minimum, the following elements:

- a process for determining which pipeline segments could affect a High Consequence Area (HCA)
- a Baseline Assessment Plan
- a process for continual integrity assessment and evaluation
- an analytical process that integrates all available information about pipeline integrity and the consequences of a failure
- repair criteria to address issues identified by the integrity assessment method and data analysis (the regulations provide minimum repair criteria for certain, higher risk, features identified through internal inspection)
- a process to identify and evaluate preventive and mitigative measures to protect HCAs
- methods to measure the integrity management program's effectiveness and
- a process for review of integrity assessment results and data analysis by a qualified individual.

1.3.9 IMP Overview: An overview of an operator's IMP program should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be a few pages and its availability could be mailed upon request or made available on the operator's website.

1.3.10 LDCs: Local Distribution Companies for natural gas

1.3.11 "may" versus "should": Clarification is necessary for RP 1162's use and definition of the words "may" versus "should":

- The use of the word "may" provides the operator with the option to incorporate the identified component into its Public Awareness Program.
- The use of the word "'should" provides the operator with the Public Awareness Program components that are recommended to be incorporated into the operator's Public Awareness Program.

1.3.12 NPMS: National Pipeline Mapping System (See Section 4.6.2)

1.3.13 One-Call Center: The role of the One-Call Center is to receive notifications of proposed excavations, identify possible conflicts with nearby facilities, process the information, and notify affected facility owners/operators.

1.3.14 Operator: All companies that operate pipelines that are within the scope of this RP.

1.3.15 OPS: Office of Pipeline Safety, part of the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation. OPS develops and enforces safety and integrity regulations for pipelines and pipeline operations.

1.3.16 Pipeline Right-of-Way (ROW): a defined strip of land on which an operator has the rights to construct, operate, and/or maintain a pipeline. A ROW may be owned outright by the operator or an easement may be acquired for specific use of the ROW.

1.3.17 Supplemental Public Awareness Program: Refer to the definition above, "Enhanced Public Awareness Program".

1.3.18 Third-Party Damage: outside force damage to underground pipelines and other underground facilities that can occur during excavation activities. Advanced planning, effective use of One-Call Systems, accurate locating and marking of underground facilities, and the use of safe digging practices can all be very effective in reducing third-party damage.

2 Public Awareness Program Development

The overall goal of a pipeline operator's Public Awareness Program is to enhance public environmental and safety property protection through increased public awareness and knowledge.

PUBLIC AWARENESS PROGRAM OBJECTIVES

2.1 OBJECTIVES

- **Public Awareness of Pipelines**

Public Awareness Programs should raise the awareness of the affected public and key stakeholders of the presence of pipelines in their communities and increase their understanding of the role of pipelines in transporting energy. A more informed public along pipeline routes should supplement an operator's pipeline safety measures and should contribute to reducing the likelihood and potential impact of pipeline emergencies and releases. Public Awareness Programs will also help the public understand that while pipeline accidents are possible, pipelines are a relatively safe mode of transportation, that pipeline operators undertake a variety of measures to prevent pipeline accidents, and that pipeline operators anticipate and plan for management of accidents if they occur. Finally, a more informed public will also understand that they have a significant role in helping to prevent accidents that are caused by third-party damage and ROW encroachment.

- **Prevention and Response**

Public Awareness Programs should help the public understand the steps that the public can take to prevent and respond to pipeline emergencies. "Prevention" refers to the objective of reducing the occurrences of pipeline emergencies caused by third-party damage (versus other causes under the control of the operator) through awareness of safe excavation practices and the use of the One-Call System. "Response" refers to the objective of communicating to the public the appropriate steps to take into account in the event of a pipeline release or emergency.

These objectives, together with others that may be identified by individual pipeline operators, provide the foundation on which a pipeline Public Awareness Program is built. Two important objectives of this RP include:

- Assist each pipeline operator to develop a framework for managing its Public Awareness Program so that the quality of Public Awareness Programs can be continually improved throughout the pipeline industry and
- Provide the operator with considerations to determine how to enhance its program to provide the appropriate level of public awareness outreach for a given area and certain circumstances.

2.2 OVERVIEW FOR MEETING PUBLIC AWARENESS OBJECTIVES

In general, Public Awareness Programs should communicate relevant information to the following stakeholder audiences (as defined in Section 3):

2.2.1 The Affected Public

- Awareness that they live or work near a pipeline
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to recognize and respond to a pipeline emergency
- What protective actions to take in the unlikely event of a pipeline release
- How to notify the pipeline operator regarding questions, concerns, or emergencies
- How to assist in preventing pipeline emergencies by following safe excavation/digging practices and reporting unauthorized digging or suspicious activity
- How community decisions about land use may affect community safety along the pipeline ROW
- How individuals can create undesirable encroachments upon a pipeline ROW
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas located in their area, land use practices, emergency preparedness or other matters.

2.2.2 Local Public Officials

- Information regarding transmission pipelines that cross their area of jurisdiction
- Land use practices associated with the pipeline ROW that may affect community safety
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operators with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction, land use practices, emergency preparedness or other matters.

2.2.3 Emergency Officials

- Location of transmission pipelines that cross their area of jurisdiction, and how to get detailed information regarding those pipelines
- Name of the pipeline operator and the emergency contact information for each pipeline
- Information about the potential hazards of the subject pipeline
- Location of emergency response plans with respect to the subject pipelines
- How to notify the pipeline operator regarding questions, concerns, or emergency
- How to safely respond to a pipeline emergency
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction,

land use practices, emergency preparedness or other matters.

2.2.4 Excavators

- Awareness that digging and excavating along the ROW may affect public safety, pipeline safety and/or pipeline operations
- Information about one-call requirements and damage prevention requirements in that jurisdiction
- Information about safe excavation practices in association with underground utilities
- How to notify the operator regarding a pipeline emergency or damage to a pipeline
- Hazards associated with unintended releases
- Name of the pipeline operator and who to contact for emergency or non-emergency information.

This RP focuses on those four segments of the public, as listed above, that are most directly affected by or could have the most affect on pipeline safety. The general public is a larger audience for general pipeline awareness information. General knowledge about energy pipelines is useful to the general public and may be obtained through a variety of sources, including the Office of Pipeline Safety, US Department of Transportation, pipeline industry trade associations and pipeline operators.

2.3 REGULATORY COMPLIANCE

This RP is intended to provide a framework for Public Awareness Programs designed to help pipeline operators in their compliance with federal regulatory requirements found in 49 *CFR* Parts 192 and 195.

The three principal compliance elements include:

2.3.1 Public Education (49 *CFR* Parts 192.616 and 195.440):

These regulations require pipeline operators to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the fire, police, or other appropriate public officials. The programs are to be provided in both English and in other languages commonly used by a significant concentration of non-English speaking population along the pipeline.

2.3.2 Emergency Responder Liaison Activities (49 *CFR* Parts 192.615 and 195.402):

These regulations require that operators establish and maintain liaison with fire, police, and other appropriate public officials and coordinate with them on emergency exercises or drills and actual responses during an emergency.

2.3.3 Damage Prevention (49 *CFR* Parts 192.614 and 195.442):

These regulations require pipeline operators to carry out written programs to prevent damage to pipelines by excavation activities.

2.4 OTHER RESOURCES

In addition to operator personnel, various other resources are available to assist pipeline operators in developing their Public Awareness Programs and related informational materials. These resources can often shorten development time and reduce the implementation cost of an operator's Public Awareness Program. Some of these other resources are described below.

2.4.1 Trade Associations

The major pipeline industry trade associations take an active role in sponsoring various efforts that can help operators meet public awareness objectives. These trade associations include the:

- American Petroleum Institute (API)
- Association of Oil Pipe Lines (AOPL)
- American Gas Association (AGA)
- Interstate Natural Gas Association of America (INGAA) and
- American Public Gas Association (APGA).

The websites of these associations provide a wide range of information to assist operators in developing and managing Public Awareness Programs, and developing information to use in implementing those programs. The trade associations also undertake specific efforts in public outreach, such as:

- Printing of pipeline safety brochures that can be customized by the operator
- Development and distribution of pipeline safety decals and materials
- Development of videos and brochures to aid in the education of public officials regarding pipeline emergency response
- Development of website information specifically for pipeline public awareness
- Distribution of periodic newsletters that provide additional guidance and information to operators on issues related to Public Awareness Programs
- Development and sponsorship of television and radio public service announcements (PSA)
- Participation in appropriate trade shows to inform excavators, regulators, legislators, and others.

For additional information on these efforts, contact the trade associations directly. Contact information and website addresses are provided in Appendix A.

2.4.2 One-Call Centers

The primary purpose of a One-Call System is to prevent damage to underground facilities, including pipelines, which could result from excavation activities. All states and the District of Columbia have established One-Call Systems (some states may have two or more One-Call Systems). State One-Call Centers may develop public awareness information materials and may be able to gather extensive information about excavation contractors. If available to the pipeline operator, this information will be useful to fulfill the requirements of 49 *CFR* Part 192.614 and 195.442 (Damage Prevention Programs). Many One-Call Systems perform their own public awareness outreach through public service announcements and other advertising. Some One-Call Systems may also sponsor statewide excavation hazard awareness programs. One-Call System contacts can be found at the "Dig Safely" website (see Appendix A).

2.4.3 Federal and State Agencies

Although pipeline operators are the primary sponsors of Public Awareness Programs on pipeline safety, some state agencies with regulatory authority for pipeline safety can provide training and materials. In addition, some state pipeline safety regulatory agencies sponsor or conduct pipeline public awareness efforts. The federal agency responsible for pipeline safety, the Office of Pipeline Safety of the U.S. Department of Transportation, is also a source of relevant information.

2.4.4 Common Ground Alliance

The Common Ground Alliance (CGA) is a nationally recognized nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices identified in the landmark *Common Ground Study of One-Call Systems and Damage Prevention Best Practices*. This report is available online from CGA's website (see Appendix A). Building on the spirit of shared responsibility resulting from the Common Ground Study, the purpose of the CGA is to ensure public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices. The "Dig Safely" campaign is now a component of the Common Ground Alliance.

The Common Ground Alliance is supported by its sponsors, member organizations, the Office of Pipeline Safety, and individual members. CGA sponsorship and membership is open to all stakeholder organizations that want to support the CGA's damage prevention efforts.

2.4.5 Outside Consultants

Many outside consultants are available to support an operators' Public Awareness Program. Direct-mail vendors are capable of producing pipeline safety materials and providing distribution services. These vendors can assist operators in identifying residents and special interest groups, such as excavators along the pipeline route, and can support the operator in production and distribution of the material. Public relations firms are also available to assist operators in developing material specifically geared to the intended audience. Their expertise can help heighten the readability of the public awareness materials and improve the operator's overall success in communicating the intended message.

2.4.6 Other Pipeline Companies

Pipeline companies have developed a variety of creative ways to meet their public awareness objectives. Cooperative information exchanges or shared public awareness activities between operators can be beneficial and economical.

2.4.7 Operator Employee Participation

As members of communities and community service organizations, informed employees of a pipeline operator can play an important role in promoting pipeline awareness. An operator should include in its Public Awareness Program provisions for familiarizing its employees with its public awareness objectives. Information and material used by the operator should be made available to employees who wish to promote pipeline awareness in their communities. Many Public Awareness Programs include components for key employee training in public awareness and specific communication training for specific key employees.

Operator employees can be a key part of public awareness efforts. Grass-roots employee contacts and communications can be particularly important in effectively reaching out to a community. Employees who are interested in and capable of performing a greater public communication role should be given the necessary training, communications materials and, as appropriate, be provided with opportunities for direct involvement with the community.

2.5 MANAGEMENT SUPPORT

For a Public Awareness Program to achieve its objectives, ongoing support within the operator's organization is crucial. Management should demonstrate its support through company policy, management participation, and allocation of resources and funding. Funding and resource requirements for an operator's Public Awareness Program development and implementation will vary according to the program's objectives, design, and scope. Full organizational support can make a marked difference in the way the Public Awareness Program is received and can affect the overall effectiveness and success of the program.

2.6 BASELINE AND SUPPLEMENTAL PUBLIC AWARENESS PROGRAMS

For the development of a Public Awareness Program, this RP recognizes that there are differences in pipeline conditions, release consequences, affected populations, increased development and excavation activities and other factors associated with pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. For example, some geographic areas have a low population, low turn over in residents, and little development or excavation activity; whereas other areas have very high population, high turn over, and extensive development and excavation activity.

This RP provides the operator with the elements of a recommended baseline Public Awareness Program. It also provides the operator with considerations to determine when and how to enhance the program to provide the appropriate level of public awareness outreach. Details for assessing the need for program enhancement are presented in Section 6. The appropriateness of enhanced or supplemental messages, delivery frequency and methods, and/or geographic coverage area is also one aspect of program evaluation. Recommendations on the evaluation of Public Awareness Programs are presented in Section 8.

2.7 PROGRAM DEVELOPMENT GUIDE

It is recommended that pipeline operators develop a written Public Awareness Program. The following guide may be helpful to pipeline operators in the development and implementation of their Public Awareness Programs.

Overall Program Administration

Step 1. Define Program Objectives

- Define program objectives in accordance with Section 2 of this RP.

Step 2. Obtain Management Commitment and Support

- Develop a company Policy and "statement of support" for the Public Awareness Program. This should include a commitment of participation, resources, and funding for the development, implementation, and management of the program.
- Reference Section 2.5.

Step 3. Identify Program Administration

- Name program administrator(s)
- Identify roles and responsibilities
- Document program administration
- Reference Section 7.

Step 4. Identify Pipeline Assets to be Included within the Program

- The overall program may be a single Public Awareness Program for all pipeline assets, or may be divided into individual, asset-specific programs for one or more specific pipeline systems, one or more pipeline segments, one or more facilities, or one or more geographic areas. Smaller companies and LDCs may have just one overall program.
- Name an administrator for each asset specific program.
- Reference Section 7 for documentation.

Program Development (applied to each identified asset- specific program)

Step 5. Identify the Four Stakeholder Audiences

- Establish methods to be used in audience identification.
- Establish a means of contact or address list for each audience type:
  - Affected public
  - Emergency officials
  - Local public officials
  - Excavators.
- Document methods used and output.
- Reference Section 3 for detail on stakeholder audiences.

Step 6. Determine Message Type and Content for Each Audience

- Establish which message types are to be used with which audience(s).
- Determine content for each message type.
- Document message type and content selected.
- Reference Section 4 for details on message development.

Step 7. Establish Baseline Delivery Frequency for Each Message

- Suggested delivery frequencies are described in Section 2.8.
- Document delivery frequencies selected.

Step 8. Establish Delivery Methods to Use for Each Message

- Select appropriate methods.
- Utilize alternate methods as appropriate.
- Document delivery methods selected.
- Establish process for management of input/feedback/comments received.
- Reference Sections 2.8 and 5 for additional detail.

Step 9. Assess Considerations for Supplemental Program Enhancements

- Review the criteria in this RP for enhanced programs (e.g. supplemental activities).
- Assess pipeline assets contained in the program and apply supplemental program elements.
- Solicit input from appropriate pipeline personnel (e.g. pipeline operations and maintenance personnel, other support personnel, etc.).
- Apply identified supplemental program elements to the program.
- Document supplemental program elements (describes when, what, and where program enhancements are used).
- Reference Sections 2.8 and 6.

Step 10. Implement Program and Track Progress

- Develop resource and monetary budgets for program implementation.
- Identify, assign and task participating company employees needed to implement the program.
- Identify external resources or consultants needed.
- Conduct program activities (e.g. mass mailings, emergency official meetings).
- Periodically update the program with newly identified activities.
- Collect feedback from internal and external sources.
- Document the above. Reference Section 7 for documentation and record keeping recommendations.

Step 11. Perform Program Evaluation

- Establish an evaluation process.
- Determine input data sources (e.g. company surveys, industry surveys, reply cards, feedback from participating employees, and feedback from recipient audiences, etc.).
- Assess results and applicability of operator and/or industry-sponsored evaluations.
- Document evaluation results. Reference Section 8 for program evaluation recommendations.

Step 12. Implement Continuous Improvement

- Determine program changes or modifications based on results of the evaluation to improve effectiveness. Program changes may be areas such as: audience, message type or content, delivery frequency, delivery method, supplemental activities or other program enhancements.
- Document program changes.
- Determine future funding and internal and external resource requirements resulting from program changes made.
- Implement changes.

Return to Step 5; Initiate new cycle for updating the Public Awareness Program.

The figurative description of the program development process is shown below, highlighting the continuous nature of the development, implementation and evaluation process.

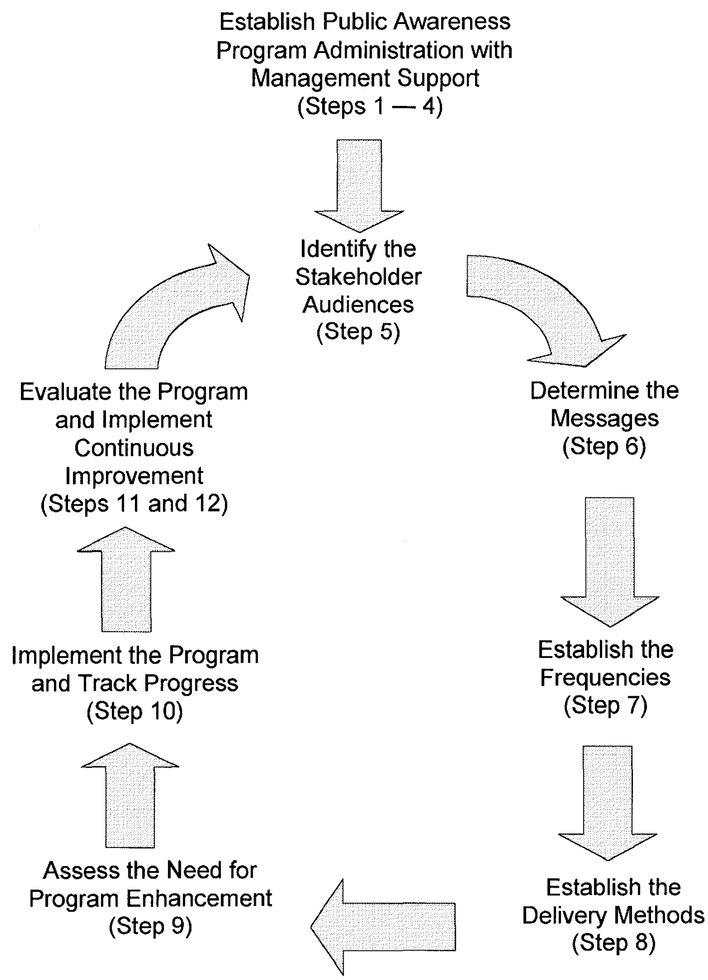

Figure 2-1—Public Awareness Program Process Guide

2.8 SUMMARY OF PROGRAM RECOMMENDATIONS

This RP has defined three categories of pipeline operators to which the RP applies. The three categories are:

1. Hazardous Liquid and Natural Gas Transmission Pipeline Operators (Table 2-1)
2. Local Natural Gas Distribution (LDC) Companies (Table 2-2)
3. Gathering Pipeline Operators (Table 2-3).

This RP recognizes that the communications and public awareness needs and activities may vary by the category of pipeline. Operators may customize their programs to best suit the needs of the stakeholder audiences and make them relevant to the type of potential hazards posed by their pipeline systems.

The tables 2-1 through 2-3 summarize the baseline recommendations for conducting public awareness for operators of Hazardous Liquid, Natural Gas Transmission, Local Natural Gas Distribution (LDC), and Gathering Pipelines. Guidance is also provided to assist the operators in determining if supplemental efforts affecting the frequency or method of message delivery and/or message content are called for, by evaluating the effectiveness of the program and the specifics of the pipeline segment or environment. Considerations for when and how an operator should implement program enhancements are described in Section 6. Further information of stakeholder audiences (Section 3); message types (Section 4); and message delivery methods (Section 5) may be found in their respective sections and related appendices.

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.1 Affected Public			
Residents located along transmission pipeline ROW **and** **Places of Congregation**	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	**Baseline Frequency** = 2 years	**Baseline Activity:** • Targeted distribution of print materials • Pipeline markers
	Supplemental Message: • Information and/or overview of operator's Integrity Management Program • ROW encroachment prevention • Any planned major maintenance/construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses
Residents near storage or other major operational facilities	**Supplemental Message:** • Information and/or overview of operator's Integrity Management Program • Special incident response notification and/or evacuation measures *if* appropriate to product or facility • Facility purpose	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency Preparedness Communications • Potential hazards • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Message: • Provide information and /or overview of Integrity measures undertaken • Maintenance construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Emergency tabletop, deployment exercises • Facility tour • Open house
2-1.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • One-call requirements • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • If applicable, provide information about designation of HCA (or other factors unique to segment) and summary of integrity measures undertaken • ROW encroachment prevention • Maintenance construction activity	**Supplemental Frequency:** • If in HCA, then annual contact to appropriate public safety officials • Otherwise, as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers
	Supplemental Messages: Pipeline purpose, prevention measures and reliability	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Group meetings
Land Developers	**Supplemental Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • One-call Requirements • Leak Recognition and Response • ROW Encroachment Prevention • Availability of list of pipeline operators through NPMS	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Pipeline markers • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.1 Affected Public			
Residents along the Local Distribution System (LDC)	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Public service announcements, OR • Paid advertising, OR • Bill stuffers (for combination electric & gas companies)
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Newspaper and magazines • Community events or • Community neighborhood newsletters
LDC Customers	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = Twice annually	**Baseline Activity:** • Bill stuffers
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials
2-2.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Print materials, OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Telephone calls • Personal contact • Videos and CDs
2-2.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Group meetings • Telephone calls • Personal contact

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies (Continued)

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Leak recognition and response • One-call requirements • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • One-Call Center outreach OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Videos and CDs • Open houses
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** • As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.1 Affected Public			
Residents, **and** **Places of Congregation within area of potential impact**	**Baseline Messages:** • Gathering pipeline purpose • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = 2 years	**Baseline Activity:** • Targeted distribution of print materials OR • Personal contact
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason.	**Supplemental Frequency:** • Annually for sour gas gathering lines • Additional frequency as determined by specifics of the pipeline segment or environment.	**Supplemental Activity:** • Pipeline markers • Print materials • Personal contact • Telephone calls • Group meetings • Mass media • Other activities described in Section 5

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Gathering pipeline location and purpose • Awareness of hazards • Prevention measures undertaken • Emergency preparedness communications, company contact and response information • Specific description of products transported and any potential special hazards • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason		**Supplemental Activity:** • Emergency tabletop deployment exercises • Facility tour • Open house
2-3.3 Local Public Officials			
Public Officials	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Copies of materials provided to affected public and emergency officials • Company contacts • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • ROW encroachment prevention • Maintenance construction activity • Special emergency procedures if sour gas or other segment specific reasons.	**Supplemental Frequency:** • If in HCA, then more frequent or annual contact with appropriate public safety officials • Otherwise as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers **Supplemental Activity:** • Personal contact • Group meetings • One-Call Center outreach • mass media
Land Developers	**Supplemental Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

3 Stakeholder Audiences

One of the initial tasks in developing a Public Awareness Program is to identify the audience(s) that should receive the program's messages. This section defines the intended audiences for the operator's Public Awareness Program and provides examples (not all inclusive) of each audience. Further explanation and examples are included in Appendix B. This information should help the operator clarify whom it is trying to reach with its program. The following audiences are considered "stakeholders" of the pipeline operator's Public Awareness Program. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

The operator should consider tailoring its communication coverage area to fit its particular pipeline location and release consequences. The operator would be expected to consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand its communication coverage area as appropriate.

The "Stakeholder Audience" definitions listed in the table below are used in the remaining sections of this RP, as applicable.

3.1 THE AFFECTED PUBLIC

Stakeholder Audience	Audience Definition	Examples
Residents located adjacent to the transmission pipeline ROW	People who live adjacent to a natural gas and/or hazardous liquid transmission pipeline ROW.	• Occupants or residents • Tenants • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along distribution systems	People who live on or immediately adjacent to the land wherein gas distribution pipelines are buried.	• LDC customers • Non-customers living immediately adjacent to the land wherein distribution pipelines are buried
Gas transmission pipeline customers	Businesses or facilities that the pipeline operator provides gas directly to for end use purposes. This does not include LDC customers.	• Power plants • Businesses • Industrial facilities
LDC customers	People that are served by gas distribution facilities.	• LDC customers
Residents near liquid or natural gas storage and other operational facilities along transmission lines	People who live adjacent to or near a tank farm, storage field, pump/compressor station and other facilities.	• Occupants or residents tenants • Farmers • Homeowner associations or groups • Neighborhood organizations
Places of congregation	Identified places where people assemble or work on a regular basis—on or along a transmission pipeline ROW, unrelated to habitation.	• Businesses • Schools • Places of worship • Hospitals and other medical facilities • Prisons • Parks & recreational areas • Day-care facilities • Playgrounds
Residents located along rights-of-way for gathering pipelines	• People who live or work on land along which the gathering pipeline is located, and within the right-of-way. • For higher consequence gathering lines (e.g. H_2S), people who live or work a distance on either side of right-of-way that is based on the potential impact in the event of an emergency.	• Occupants or residents • Tenants • Farmers • Businesses • Schools

3.2 EMERGENCY OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Emergency officials	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction along the pipeline route.	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • County and State Emergency Management Agencies (EMA) • Other emergency response organizations • Other public safety organizations

3.3 LOCAL PUBLIC OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Public officials	Local, city, county or state officials and/or their staffs having land use and street/road jurisdiction along the pipeline route.	• Planning boards • Zoning board • Licensing departments • Permitting departments • Building code enforcement departments • City and county managers • Public and government officials • Public utility boards • Includes local "Governing Councils" as defined by many communities • Public officials who manage franchise or license agreements

3.4 EXCAVATORS

Stakeholder Audience	Audience Definition	Examples
Excavators	Companies and local/state government agencies who are involved in any form of excavation activities.	• Construction companies • Excavation equipment rental companies • Public works officials • Public street, road and highway departments (maintenance and construction) • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Well drillers
Land developers	Companies and private entities involved in land development and planning.	• Home builders • Land developers • Real estate sales
One-Call Centers	Excavation One-Call Centers relevant to the area.	• Each state, region, or other organization established to notify underground facility owner/operators of proposed excavations. Excavation One-Call Centers relevant to the area.

4 Message Content

An operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. Information materials may also include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message conveyed to the intended audience should provide information that will allow the operator to meet the program objectives. The communications should include enough information so that in the event of a pipeline emergency, the intended audience will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator. Several components of these messages are discussed in this section.

4.1 PIPELINE PURPOSE AND RELIABILITY

Operators should consider providing a general explanation of the purpose of the pipeline and/ or facilities and the reliability of pipelines to meet the energy needs of the region, even though this is not a primary objective of pipeline public awareness. Operators should provide assurances that security is considered.

4.2 HAZARD AWARENESS AND PREVENTION MEASURES

Operators should provide a very broad overview of potential hazards, their potential consequences and the measures undertaken by the operator to prevent or mitigate the risks from pipelines (including, at the operator's discretion, an overview of the industry's safety record). Additionally, operators should provide an overview of their preventative measures to help assure safety and prevent incidents. The scope of the hazard awareness and prevention message should be more detailed for the emergency responder audience than for other audiences, and should include how to obtain more specific information upon request from the operator.

4.3 LEAK RECOGNITION AND RESPONSE

The pipeline operator should provide information in the following key subject areas to the affected public and excavator stakeholder groups.

4.3.1 Potential Hazards of Products Transported

Information about specific release characteristics and potential hazards posed by hazardous liquids or gases should be included.

4.3.2 How to Recognize a Pipeline Leak

Information should address how to recognize a pipeline leak through the senses of sight, unusual sound, and smell and describe any associated dangers as appropriate to the product type.

4.3.3 Response to a Pipeline Leak

Information should address an outline of the appropriate actions to take if a pipeline leak or release is suspected.

4.3.4 Liaison with Emergency Officials

Information should describe the ongoing relationship between the operator and local emergency response officials to help prevent incidents and assure preparedness for emergencies.

4.4 EMERGENCY PREPAREDNESS COMMUNICATIONS

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. Operators should provide a summary of emergency preparedness information to local public officials and should indicate that detailed information has been provided to emergency response agencies in their jurisdictions. The following information should be provided to the emergency officials stakeholder audience.

4.4.1 Priority to Protect Life

The operator's key messages to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

4.4.2 Emergency Contacts

Contact information for the operator's local offices and 24-hour emergency telephone line should be shared with local and state emergency officials. Operators should also use the contacts with emergency officials to confirm that both emergency officials and the operators have the current, correct contact information and calling priorities.

4.4.3 Emergency Preparedness Response Plans

Operators are required by federal regulations to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state emergency regulations. 49 *CFR* 192 and 195 and some state regulations outline the specific requirements for emergency response plans and who to contact for additional information. The operator should include information about how emergency officials can access the operator's emergency response plans covering their jurisdiction.

4.4.4 Emergency Preparedness—Drills and Exercises

A supplemental means of two-way communication about emergency preparedness is to establish a liaison with emergency response officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

4.5 DAMAGE PREVENTION

Because even relatively minor excavation activities can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the key "Dig Safely" messages developed by the Common Ground Alliance (CGA). CGA contact information is located in Appendix A.

The use of an excavation One-Call Notification system should be explained to the audience. Information on the prevalence of digging-related damage, also known as "third-party" damage, should be provided as appropriate. The audience should be requested to call the state or local One-Call System in their area before they begin any excavation activity. If the state or locality has established penalties for failure to use established damage prevention procedures, that fact may also be communicated, depending on the audience and situation. Additional information is located in Appendix C.

Additionally, third-party contractors are subject to the Occupational Safety and Health Administration's (OSHA) requirements. OSHA cites in its "General Duty Clause" possible regulatory enforcement action that could be taken against excavation contractors who place their employees at risk by not utilizing proper damage prevention practices. The lack of adequate damage prevention could subject the excavator to OSHA regulatory enforcement. OSHA contact information is located in Appendix A.

4.6 PIPELINE LOCATION INFORMATION

4.6.1 Transmission Pipeline Markers

The audience should know how to identify a transmission pipeline ROW by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. The operator's awareness communications should include information about what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in certain areas. As such, use of the One-Call Notification system should be encouraged. Additional detail is located in Appendix C.

4.6.2 Transmission Pipeline Mapping

Pipeline maps developed by transmission pipeline operators can be an important component of an operator's Public Awareness Program. The level of detail provided on the map should, at a minimum, include the line size, product transported and the approximate location of the pipeline, as well as any other information deemed reasonable and necessary by the operator. National energy infrastructure security issues should be considered in determining information and distribution related to pipeline maps. The public can also receive information about which pipelines operate in their community by accessing the National Pipeline Mapping System (NPMS). The NPMS will provide the inquirer a list of pipeline operators and operator contact information. Operators should include information on the availability of the NPMS within their public awareness materials. NPMS information is provided in Appendix A. Additional mapping information is provided in Appendix C.

4.7 HIGH CONSEQUENCE AREAS (HCAs) AND INTEGRITY MANAGEMENT PROGRAM OVERVIEW FOR TRANSMISSION OPERATORS

4.7.1 Message Content for Affected Public within HCAs

Public awareness materials should include a general explanation that, in accordance with federal regulations, some segments along transmission pipelines have been designated as High Consequence Areas (HCAs) and that supplemental hazard assessment and prevention programs (called Integrity Management Programs) have been developed. Information provided to the affected public should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.7.2 Message Content for Emergency Officials within HCAs

For emergency official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should include an overview of the operator's Integrity Management Programs. Inclusion of this information during emergency official liaison interface will provide an opportunity for feedback from the emergency official on the operator's Integrity Management Programs.

4.7.3 Message Content for Public Officials within HCA's

For public official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.8 CONTENT ON OPERATOR WEBSITES

Pipeline operators who maintain websites can include the following information (further examples of this information are provided in Appendix C):

- Company information
- General information on pipeline operations
- General or system pipeline map(s)
- Affected public information
- Emergency and security information
- Damage prevention awareness and One-Call Notification.

4.9 RIGHT-OF-WAY ENCROACHMENT PREVENTION

Pipeline operators should communicate that encroachments upon the pipeline ROW inhibit the operator's ability to respond to pipeline emergencies, eliminate third-party damage, provide ROW surveillance, perform routine maintenance, and perform required federal/state inspections. Stakeholder specific information is listed in Appendix D.

4.10 PIPELINE MAINTENANCE CONSTRUCTION ACTIVITIES

Pipeline maintenance-related construction activities should be communicated to the audience affected by the specific activity in a timely manner appropriate to the nature and extent of the activity.

4.11 SECURITY

Where applicable and in accordance with the national Homeland Security efforts, pipeline operators should communicate an overview pertaining to security of their pipelines and related facilities.

4.12 FACILITY PURPOSE

Where appropriate, communication with the affected public and emergency and public officials in proximity to major facilities (such as storage facilities, compressor or pump stations) should include information to promote understanding of the nature of the facility. Operators should communicate general information regarding the facility and product(s) stored or transported through the facility. Communication with emergency officials should also include emergency contact information for the specific facility.

5 Message Delivery Methods and/or Media

This section describes several delivery methods and tools available to pipeline operators to foster effective communications with the intended stakeholder audiences previously described. The operator is reminded that not all methods are effective in all situations. The content of the communication efforts should be tailored to:

- Needs of the audience
- Type of pipeline and/or facilities
- Intent of the communication, and
- Appropriate method/media for the content.

A more detailed discussion of the summary information below is provided in Appendix D.

5.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audience and message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed below.

5.1.1 Brochures, Flyers, Pamphlets, and Leaflets

Brochures, flyers, pamphlets and leaflets are probably the most common message delivery methods currently used by the pipeline industry. These print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. These print materials also afford an effective opportunity to communicate content in a graphical or pictorial way.

5.1.2 Letters

Research has indicated that letters mailed to residents along the pipeline ROW are an effective tool to communicate specific information, such as how to recognize and what to do in the event of a leak, how to identify and report suspicious activity, and notification of planned operator activities.

5.1.3 Pipeline Maps

Pipeline maps can be an important component of an operator's Public Awareness Program and should be considered where they can enhance the appropriate stakeholder(s) awareness of the operator's pipeline and facilities. Additional information regarding pipeline mapping is available in Appendix C.

5.1.4 Response Cards

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other items. The inclusion of a response card can be used in a variety of ways (refer to Appendix D).

5.1.5 Bill Stuffers

Bill stuffers are printed brochures frequently used by local distribution companies (LDCs) in conjunction with customer invoices. Due to the nature of customers for transmission and gathering pipelines, bill stuffers are not considered an appropriate option. LDCs using bill stuffers can easily reach their customers with appropriate messages and can increase their effectiveness by using bill stuffers repeatedly. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even those that may not be natural gas customers.

5.2 PERSONAL CONTACT

Personal contact describes face-to-face contacts between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication and allows for two-way discussion. Personal contacts may be made on an individual basis or in a group setting. Some examples of personal contact communications are described further in Appendix D and include:

- Door-to-door contact along pipeline ROW
- Telephone calls
- Group meetings
- Open houses
- Community events
- Charitable contribution presentations by pipeline companies.

5.3 ELECTRONIC COMMUNICATION METHODS

5.3.1 Videos and CDs

There are a variety of approaches operators may use to supplement their public awareness efforts with videos and CDs. While considered a supplement to the baseline components of an effective Public Awareness Program, videos and CDs may be quite useful with some stakeholders or audiences in some situations. These media can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual responses in ways that printed materials cannot.

5.3.2 E-mail

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholder audiences. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by postal mail or personal contact.

5.4 MASS MEDIA COMMUNICATIONS

5.4.1 Public Service Announcements

Public Service Announcements (PSAs) can be an effective means for reaching a large sector of the public. Radio and television stations occasionally make some airtime available for PSAs. They are no longer required by law to donate free airtime and as a result, there is great competition from various public interest causes for the small amount of time made available. If the operator is an advertiser with the radio or television station, this might be leveraged to gain advantage in acquiring PSA time.

5.4.2 Newspapers and Magazines

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline companies can submit or encourage reporters to write constructive and informative articles about pipeline issues, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure.

5.4.3 Paid Advertising

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community.

5.4.4 Community and Neighborhood Newsletters

Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with other outreach to those communities and/or neighborhoods. This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

5.5 SPECIALTY ADVERTISING MATERIALS

Specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These materials also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods. Examples are included in Appendix D.

5.6 INFORMATIONAL OR EDUCATIONAL ITEMS

Companies can develop informational and educational materials to heighten pipeline awareness. The cost-effectiveness of producing such materials can be increased through partnering with an industry association or group of other operators.

5.7 PIPELINE MARKER SIGNS

The primary purposes of aboveground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency and
- Facilitate aerial or ground surveillance of the pipeline ROW by providing aboveground reference points.

Refer to Section 4 and Appendix C for additional information on marker sign types and information content.

Below-ground markers, such as warning tape or mesh, can also be effective warnings to excavators of the presence of buried pipe. When burying pipe following repairs, relocations, inspections, etc., operators should consider whether it is appropriate to add below-ground markers in the location.

5.8 ONE-CALL CENTER OUTREACH

Most state One-Call Centers provide community outreach or conduct public awareness activities about one-call requirements and damage prevention awareness, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such communication as a part of their own Public Awareness Programs. Many One-Call Centers host awareness meetings with excavators to further promote the damage prevention and one-call messages. It is the operator's responsibility to request documentation for these outreach activities.

To enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become one-call members in localities where they operate pipelines. Since all One-Call Center members share the center's public awareness outreach costs, the costs to an individual operator are usually comparatively low.

5.9 OPERATOR WEBSITES

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Additional information located in Appendix C.8 describes features for a company's pipeline operations that should fit into any corporate structure and overall website design. A company's website will supplement the other various direct outreach delivery tools discussed in this RP.

6 Recommendations for Supplemental Enhancements of Baseline Public Awareness Program

The pipeline operator has a number of stakeholder audiences for delivering messages regarding the safe operation of pipelines. The message content, the delivery medium, delivery frequency, and audience's retention of the delivered message should be carefully considered during the development and implementation of the operator's Public Awareness Program to achieve maximum effectiveness. Many of the communications should be available on demand or evergreen (e.g., websites, pipeline markers) and others are periodic in nature (e.g., mass mailings, public meetings, and advertisements). The combination of the specific messages, delivery methods, and delivery frequencies should be designed into the operator's program for each audience. These elements should allow each audience to develop and maintain an awareness of the pipeline's safe operation appropriate to the audience's responsibilities for pipeline awareness, response to pipeline emergencies, and its possible exposure to pipeline emergencies.

Section 2 includes summary tables of the overall Public Awareness Program recommendations. The summary tables include a baseline Public Awareness Program for the three pipeline categories. The tables also provide a recommended delivery frequency for each of the message types intended for the respective audiences. These frequencies are the suggested baselines and the pipeline operator should consider to what extent an enhanced, supplemental program is warranted.

The term "program enhancement" refers to the operator's decision to supplement its Public Awareness Program beyond the recommended baseline. Throughout this RP the terms "enhancement" and "supplemental" are used interchangeably and mean those communications measures added to the Public Awareness Program beyond the baseline program elements. To support this decision, the operator should consider external factors along the pipeline system and determine if some additional level of public awareness communications is warranted, beyond the recommended baseline program. Those supplemental aspects would then be incorporated into the Public Awareness Program for that pipeline segment or system. Supplemental enhancement considerations are discussed in detail on the following pages.

In addition, the operator should include in its Public Awareness Program Evaluation a periodic review and evaluation of its program (see Section 8), determine if supplemental public awareness efforts/activities are warranted and include those enhancements and related documentation into its program.

6.1 CONSIDERATIONS FOR SUPPLEMENTAL ENHANCEMENTS FOR THE BASELINE PROGRAM

This RP recognizes that there are differences in pipeline conditions, consequences, population, property development, excavation activities and other issues along pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. This RP recommends that an operator enhance its baseline program with supplemental program components when conditions along the pipeline suggest a more intensive effort is needed.

Baseline program recommendations are established for each of the three pipeline categories. The following sections are provided for guidance when the operator's consideration of relevant factors along the pipeline route indicates that supplemental program enhancement is warranted. Three primary forms of enhancement are provided for consideration in the development and administration of each Public Awareness Program:

6.1.1 Increased Frequency (Shorter Interval)

Increased frequency refers primarily to providing communications to specific stakeholder audiences on a more frequent basis (shorter interval) than the baseline recommended components to reach the intended audience.

6.1.2 Enhanced Message Content and Delivery/Media Efforts

Enhanced message content and delivery/media efforts refer to providing additional or supplemental communications activities beyond those identified in the baseline, using an enhanced or custom-tailored message content and/or different, or additional, delivery methods/media to reach the intended audience.

6.1.3 Coverage Areas

Coverage areas refer to broadening or widening the stakeholder audience coverage area beyond those contained in the baseline for delivery of certain communications messages. This can also be considered relative to widening the buffer distance for reaching the stakeholder audience along the pipeline route.

6.2 CONSIDERATIONS OF RELEVANT FACTORS

When the operator develops its Public Awareness Program and performs subsequent periodic program evaluations, it is recommended that a step for assessing relevant factors along the pipeline route be included to consider what components of the Public Awareness Program should be enhanced.

The operator should consider each of the following factors applied along the entire route of the pipeline system:

- Potential hazards
- High Consequence Areas
- Population density
- Land development activity
- Land farming activity
- Third-party damage incidents
- Environmental considerations
- Pipeline history in an area
- Specific local situations
- Regulatory requirements
- Results from previous Public Awareness Program evaluations
- Other relevant needs.

The presence of federally designated High Consequence Areas (HCAs) should prompt an operator to consider public awareness activity above the baseline level described in the RP. For natural gas transmission pipelines, 49 *CFR* Part 192.761 defines HCAs related to the population or places of congregation. For hazardous liquid transmission pipelines, 49 *CFR* Part 195.450 describes HCAs related to high population, Unusually Sensitive Areas (USAs) and navigable waterways.

Another factor to consider is the hazard associated with the pipeline as perceived by either the operator or the audience. For example, if a pipeline segment has experienced third-party damage, the operator could increase the frequency of messages to those third-parties and other relevant audiences. If the public's confidence in pipeline safety is undermined by a high profile emergency, even though an individual operator is experiencing no upward trend in incidents, that operator could consider expanding its public awareness communications to its public audiences to further increase awareness of its nearby pipeline system.

Further detail of considerations for program enhancement is discussed in the following sections.

6.3 HAZARDOUS LIQUID AND NATURAL GAS TRANSMISSION PIPELINE OPERATORS

Since Hazardous Liquids and Natural Gas Transmission pipelines are similar in many aspects with respect to public awareness, the two categories of pipelines have been combined.

Considerations for program enhancement for transmission pipelines could include, for example:

6.3.1 The Affected Public

Consideration should be given to *supplemental program enhancement* where:

- The occurrences indicate an elevated potential for third-party damage. Examples include:
  - A mailing to farmers along the right-of-way just prior to the deep plowing season where deep till plow methods are used
  - An additional or interim mass mailing to or face-to-face communications with residents of new housing developments in areas along the pipeline route that may not have previously been reached
  - Increasing the frequency of baseline communication efforts
- The pipeline runs through heavily developed urban areas that are more likely to have a frequently changing population than a more stable, less dense suburban or rural areas. Frequently changing population in an identified audience area should be considered when determining supplemental efforts to:
  - Residents in areas such as multi-family developments or densely populated urban areas
  - Increase the frequency of communications to residents
- Right-of-way encroachments have occurred frequently. Examples of supplemental efforts include:
  - Enhanced mailings to, face-to-face communications with, or increasing the frequency of communications to residents/developers/contractors in areas of right-of-way encroachment
- The potential for concern about consequences of a pipeline emergency is heightened. Consideration should be given to widening the coverage area for:
  - HVL pipelines in high population areas, extend the coverage area beyond the $1/8^{th}$ mile minimum distance each side of the pipeline
  - Large diameter, high pressure, high volume pipelines where a pipeline emergency would likely affect the public outside of the specified minimum coverage area—extend the coverage area to a wider distance as deemed prudent.

6.3.2 Public Officials

Consideration should be given to *supplemental program enhancement* where:

- Heightened public sensitivity to pipeline emergencies exists in the area, independent of cause or which operator was involved
- Significant right-of-way encroachments (such as new construction developments) are occurring.

6.3.3 Emergency Officials

Consideration should be given to *supplemental program enhancement* where:

- Emergency officials have heightened sensitivity to pipeline emergencies
- After post-emergency review, or where there's potential for enhanced "liaison activities" between the operator and emergency officials that could have improved the emergency response to a pipeline emergency
- Requested by emergency officials to provide additional communications.

6.3.4 Excavators/Contractors and One-Call Centers

Consideration should be given to *supplemental program enhancement* where:

- There are instances that indicate an elevated potential for third-party damage
- Developers and contractors are performing a high number of excavations along a pipeline route in developing areas
- There are instances of problems identified with excavators' use or lack of use of the One-Call System. In those cases the operator should also request that the one-call Center perform additional public awareness outreach activities

6.4 LOCAL NATURAL GAS DISTRIBUTION COMPANIES (LDCs)

Many of the aspects of Public Awareness Programs for LDCs are similar to liquid and transmission pipeline operators. However, there are some differences because LDCs serve a different audience. Unlike transmission pipeline operators, LDCs have many more individual customers and have existing communication paths with those customers through monthly billing statements and other customer relationships. Table 2-2, for LDCs, in Section 2, provides baseline and supplemental communication recommendations for each of the different audiences.

Among LDCs there may be some variability in the frequency of communications with specific audiences. Public officials and emergency response personnel in a small rural city will likely be more accessible to the LDC pipeline operators than those in a major metropolitan area. Therefore, LDC operators should tailor their programs based on specific local considerations.

6.5 GATHERING PIPELINE OPERATORS

Gathering pipelines are usually small in diameter and operate at low pressures. In general, the audiences involved in public awareness communications for gathering pipelines tend to be in rural areas. The operator should tailor the specific communication program to fit the needs of the audiences and the circumstances in the particular area. Table 2-3 for gathering pipeline operators provides baseline and supplemental recommended communication frequencies for different audiences.

7 Program Documentation and Recordkeeping

Each operator should establish policies and procedures necessary to properly document its Public Awareness Program and retain those key records for purposes of program evaluation.

7.1 PROGRAM DOCUMENTATION

Each operator of a hazardous liquid pipeline system, natural gas transmission pipeline system, gathering pipeline system or a natural gas distribution pipeline system should establish (and periodically update) a written Public Awareness Program designed to cover all required components of the program described in this RP.

The written program should include:

a. A statement of management commitment to achieving effective public/community awareness.
b. A description of the roles and responsibilities of personnel administering the program.
c. Identification of key personnel and their titles (including senior management responsible for the implementation, delivery and ongoing development of the program).
d. Identification of the media and methods of communication to be used in the program, as well as the basis for selecting the chosen method and media.
e. Documentation of the frequency and the basis for selecting that frequency for communicating with each of the targeted audiences.
f. Identification of program enhancements, beyond the baseline program, and the basis for implementing such enhancements.
g. The program evaluation process, including the evaluation objectives, methodology to be used to perform the evaluation and analysis of the results, and criteria for program improvement based on the results of the evaluation.

In addition, some operators are required to have an Operations and Maintenance Procedure (O&MP) manual under 49 *CFR* Part 192 or 195. While the overall written program will likely be too extensive and schedule-specific to be suitable for an O&MP manual, the operator should include in the manual an overall statement of management commitment, roles and responsibilities (by group or title), a requirement for a written program and evaluation process, and a summary of the operator's Public Awareness Program.

7.2 PROGRAM RECORDKEEPING

The operator should maintain records of key program elements to demonstrate the level of implementation of its Public Awareness Program. Record keeping should include:

a. Lists, records or other documentation of stakeholder audiences with whom the operator has communicated.
b. Copies of all materials provided to each stakeholder audiences.
c. All program evaluations, including current results, follow-up actions and expected results.

7.3 RECORD RETENTION

The record retention period for each category in Section 7.2 should be a minimum of five (5) years, or as defined in the operator's Public Awareness Program, whichever is longer.

8 Program Evaluation

This section provides guidance to operators on how to periodically evaluate their Public Awareness Programs. The overall written plan for the Public Awareness Program should include a section describing the operator's evaluation program that includes the baseline elements described in the following paragraphs. Also included are suggestions for operators to consider in periodically supplementing their evaluation efforts in a particular segment, with a selected stakeholder audience or to provide greater depth of evaluation. This section includes only a brief description of each element. Appendix E provides additional explanations and examples for operator personnel who are new to developing Public Awareness Program evaluations.

8.1 PURPOSE AND SCOPE OF EVALUATION

The primary purposes of the evaluation of the Public Awareness Program are to:

- Assess whether the current program is effective in achieving the objectives for operator Public Awareness Programs as defined in Section 2.1 of this RP, and
- Provide the operator information on implementing improvements in its Public Awareness Program effectiveness based on findings from the evaluation(s).

A secondary purpose for Public Awareness Program evaluation is to demonstrate to company management and regulators, for pipelines subject to federal or state pipeline safety jurisdiction, the status and validity of the operator's Public Awareness Programs.

8.2 ELEMENTS OF EVALUATION PLAN

A program evaluation plan should include the measures, means and frequency for tracking performance. The selected set of measures should reflect:

- Whether the program is being implemented as planned—**the process**
- Whether the program is effective—**program effectiveness**.

Based on the results of the evaluation addressing these two questions, the operator may need to make changes in the program implementation process, stakeholder identification effort, messages, means and/or frequency of delivery. The sections below suggest specific measures and methods recommended to complete a baseline evaluation of the Public Awareness Program.

8.3 MEASURING PROGRAM IMPLEMENTATION

The operator should complete an annual audit or review of whether the program has been developed and implemented according to the guidelines in this RP. The purpose of the audit is to answer the following two questions:

- Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described Section 2 and the remainder of this RP?
- Has the Public Awareness Program been implemented and documented according to the written program?

Appendix E includes a sample set of questions that will aid an operator in auditing the program implementation process.

The operator should use one of the following three alternative methodologies when completing an annual audit of program implementation.

- Internal self-assessments using, for example, an internal working group, or
- Third-party audits where the evaluation is undertaken by a third-party engaged to conduct an assessment and provide recommendations for improving the program design or implementation, or
- Regulatory inspections, undertaken by inspectors working for federal or state regulators who inspect operator pipeline programs subject to pipeline safety regulations.

8.4 MEASURING PROGRAM EFFECTIVENESS

Operators should assess progress on the following measures to assess whether the actions undertaken in implementation of this RP are achieving the intended goals and objectives:

- Whether the information is reaching the intended stakeholder audiences
- If the recipient audiences are understanding the messages delivered
- Whether the recipients are motivated to respond appropriately in alignment with the information provided
- If the implementation of the Public Awareness Program is impacting bottom-line results (such as reduction in the number of incidents caused by third-party damage).

The following four measures describe how the operator should evaluate for effectiveness:

8.4.1 Measure 1—Outreach: Percentage of Each Intended Audience Reached with Desired Messages

This is a basic measurement indicating whether the operator's public awareness messages are getting to the intended stakeholders. A baseline evaluation program should establish a methodology to track the number of individuals or entities reached within an intended audience (e.g., households, excavating companies, local government, and local first responder agencies). Additionally, this measure should estimate the percentage of the stakeholders actually reached within the target geographic region along the pipeline. This measurement will help to evaluate the effectiveness of the delivery methods used.

- **Supplemental measures:** Other indicators that an operator may want to consider tracking as a supplement to measuring program outreach effectiveness include:
  - Track the number of inquiries by phone to operator-personnel or to the public awareness portions of an operator's website (however operators are cautioned that unless such information is specifically sought by the operator, this measure would not define if the caller or website viewer is a member of the target stakeholder audience nor whether this measure includes counts of repetitive website reviewers)
  - Track input received via feedback postcards (often called reply or bounce-back cards) from representatives of the stakeholder audience at events or meetings, sent by mail, or as a result of the operator's canvassing of the rights-of-way
  - Track the number of officials or emergency responders who attend emergency response exercises (this is an indicator of interest and the opportunity to gain knowledge).

8.4.2 Measure 2—Understandability of the Content of the Message

This measure would assess the percentage of the intended stakeholder audience that understood and retained the key information in the message received. This measurement will help to evaluate the effectiveness of the delivery media and the message style and content. This measurement will also help to assess the effectiveness of the delivery methods used.

- **Pre-test materials:** Operators should pre-test public awareness materials for their appeal and the messages for their clarity, understandability and retain-ability before they are widely used. A pre-test can be performed using a small representative audience, for example, a small sample group of operator employees not involved in developing the Public Awareness Program, a small section of the intended stakeholder audience or others (often referred to as focus groups described more fully in Appendix E).
- **Survey target stakeholder audiences:** An effective method for assessing understandability is to survey the target stakeholder audience in the course of face-to-face contacts, telephone or written surveys. Sample surveys are included in Appendix E. Factors to consider when designing surveys include:
  - Sample size appropriate to draw general conclusions
  - Questions to gauge understandability of messages and knowledge or survey respondent
  - Retention of messages
  - Comparison of the most effective means of delivery.

Program effectiveness surveys are meant to validate the operator's methodologies and the content of the materials used. Upon initial survey, improvements should be incorporated into the program based on the results. Once validated in this initial manner, a program effectiveness survey is only required about every four years. However, when the operator introduces major design changes in its Public Awareness Program a survey to validate the new approaches may be warranted.

An operator may choose to develop and implement its own program effectiveness survey in-house; have a survey designed with the help of third-party survey professionals; or participate in and use the results of an industry group or trade-association survey. If the latter approach is used, the industry or trade-association survey should allow the operator to assess the results relevant to the operator's own pipeline corridors and Public Awareness Programs.

8.4.3 Measure 3—Desired Behaviors by the Intended Stakeholder Audience

This measure is aimed at determining whether appropriate prevention behaviors have been learned and is taking place when needed and whether appropriate response or mitigation behaviors would occur and have taken place. This is a measure of learned and, if applicable, actual reported behavior.

- **Baseline evaluation:** The survey conducted as the means of assessing Measure 2 (above) should be designed to include questions that ask respondents to report on actual behaviors following incidents.
- **Supplemental evaluation:** As a supplement to these measures, operators may also want to assess whether the Public Awareness Program successfully drove other behaviors. Operators may consider the following examples as a supplemental means of assessing this measure:
  - Whether excavators are following through on all safe excavation practices, in addition to calling the One-Call Center
  - The number of notifications received by the operator from the excavation One-Call Center (e.g. is there a noticeable increase following distribution of public awareness materials?)
  - An assessment of first responder behaviors, including the response to pipeline-related calls, and a post-incident assessment to determine whether their actions would be and were consistent with the key messages included in the public awareness communications. Assessments of actual incidents should recognize that each response would require unique on-scene planning and response to specifics of each emergency.
  - Measuring the appropriateness of public stakeholders' responses is also anecdotal but could include tracking whether an actual incident that affected residents was correctly identified and whether reported and personal safety actions undertaken were consistent with public awareness communication.

8.4.4 Measure 4—Achieving Bottom-Line Results

One measure of the "bottom-line results" is the damage prevention effectiveness of an operator's Public Awareness Program and the change in the number and consequences of third-party incidents. As a baseline, the operator should track the number of incidents and consequences caused by third-party excavators. This should include reported near misses; reported pipeline damage occurrences that did not result in a release; and third-party excavation damage events that resulted in pipeline failures. The tracking of leaks caused by third-party excavation damage should be compared to statistics of pipelines in the same sector (e.g. gathering, transmission, local distribution). While third-party excavation damage is a major cause of pipeline incidents, data regarding such incidents should be evaluated over a relatively long period of time to determine any meaningful trends relative to the operator's Public Awareness Program. This is due to the low frequency of such incidents on a specific pipeline system. The operator should also look for other types of bottom-line measures. One other measure that operators may consider is the affected public's perception of the safety of pipelines.

8.5 SUMMARY OF BASELINE EVALUATION PROGRAM

Table 8-1—Summary of Baseline Evaluation Program

The results of the evaluation need to be considered and revisions/updates made in the public awareness program plan, implementation, materials, frequency and/or messages accordingly

Evaluation Approaches	Evaluation Techniques	Recommended Frequency
Self Assessment of Implementation	Internal review, ***or*** third-party assessment ***or*** regulatory inspection	Annually
Pre-Test Effectiveness of Materials	Focus groups (in-house or external participants)	Upon design or major redesign of public awareness materials or messages
Evaluation of effectiveness of program implementation: • Outreach • Level of knowledge • Changes in behavior • Bottom-line results	1. Survey: Can assess outreach efforts, audience knowledge and changes in behavior • Operator-designed and conducted survey, or • Use of pre-designed survey by third-party or industry association, or • Trade association conducted survey segmented by operator, state or other relevant separation to allow application of results to each operator. 2. Assess notifications and incidents to determine anecdotal changes in behavior. 3. Documented records and industry comparisons of incidents to evaluate bottom-line results.	No more than four years apart. Operator should consider more frequent as a supplement or upon major redesign of program.
Implement changes to the Public Awareness Program as assessment methods above suggest.	Responsible person as designated in written Public Awareness Program	As required by findings of evaluations.

APPENDIX A—RESOURCE CONTACT INFORMATION

A.1 Trade Associations

American Petroleum Institute
www.api.org
1220 L Street, NW
Washington, DC 20005

Association of Oil Pipe Lines
www.aopl.org
1101 Vermont Avenue, NW, Suite 604
Washington, DC 20005

American Gas Association
www.aga.org
400 N. Capitol Street, NW
Washington, DC 20001

American Public Gas Association
www.apga.org
11094-D Lee Highway, Suite 102
Fairfax, VA 22030-5014

Interstate Natural Gas Association of America
www.ingaa.org
10 G Street NE, Suite 700
Washington, DC 20002

A.2 Government Agencies

Office of Pipeline Safety
www.ops.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Rm. 7128
Washington, DC 20590-0001

The National Pipeline Mapping System (OPS/DOT)
www.npms.rspa.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Room 7128
Washington, DC 20590-0001

Transportation Safety Institute
www.tsi.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
6500 South MacArthur Blvd.
Oklahoma City, OK 73169

Occupational Safety and Health Administration
www.osha.gov
"Hazards Associated with Striking Underground Gas Lines"
www.osha.gov/dts/shib/shib_05_21_03_sugl.pdf

A.3 Private Organizations

Common Ground Alliance
www.commongroundalliance.com

Dig Safely
www.digsafely.com

A.4 Publications

The AGA's Gas Pipeline Technology Committee's GPTC Guide—ASC GPTC Z-380.1

APPENDIX B—EXAMPLES OF STAKEHOLDER AUDIENCES

When a Public Awareness Program is being developed, one of the initial tasks is to identify the audience(s) that should receive the program's messages. Section 3 identified the intended audiences for the operator's Public Awareness Program and included a "Stakeholder Audience Definition Table". This appendix will provide further examples. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

B.1 Stakeholder Audience Identification

Identification of the individual stakeholder audiences (i.e., members of the four target audiences) may be done by any means available to the operator. Several methods are available. Operators may identify their stakeholder audiences on their own or may elect to hire outside consultants who specialize in audience identification. Where lists are developed, they should be kept current or redeveloped prior to effecting a particular communication.

B.1.1 AFFECTED PUBLIC

Some examples of how an operator may determine specific affected public stakeholder addresses along the pipeline, such as within a specified distance either side of the pipeline centerline, include the use of nine-digit zip code address databases and geo-spatial address databases. These databases generally provide only the addresses and not the names of the persons occupying the addresses. Broad communications to this audience are typically addressed to "Resident." It is important to note that when contacting apartment dwellers, individual apartment addresses should be used, not just the address of the apartment building or complex.

Some operators maintain "line lists" which provide current information on names and addresses of people who own property on which the pipeline is located. It should be noted, however, that not all property owners live on the subject property and that the program should address those people living on the property. Additionally, where the operator has a customer base, the operator can use its customer databases for identifying audience members.

For the sub-groups "Residents located along transmission pipeline ROW" and "Places of Congregation," it is recommended that transmission pipeline operators provide communications within a minimum coverage area distance of 660 feet on each side of the pipeline, or as much as 1000 feet in some cases. The transmission pipeline operator should tailor its communications coverage area (buffer) to fit its particular pipeline, location, and potential impact consequences. At a minimum, operators should consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand the coverage area accordingly.

A sub-set of the affected public that the operator may desire to send specific public awareness materials to is farmers. Farmers engage in deep plowing and clearing activities that could impact pipelines. One method of determining names and addresses of farmers along a pipeline route is the use of third-party vendors who purchase periodicals databases related to the farming and agricultural community. Due to the size of farming operations in some areas and the proximity of farming residents, it is recommended that the operator increase its affected public awareness mailing coverage as appropriate.

B.1.2 EMERGENCY OFFICIALS

There are several methods used by operators to identify the names and addresses of emergency officials. Depending upon the size of the county or parish, this may include all emergency officials in the affected jurisdiction.

The means used by many operators is through the use of SIC (Standard Industrial Classification) code. Where SIC codes are utilized to identify emergency officials, the operator should include the list of code categories applicable to the emergency officials stakeholder group.

The pipeline operator should consider all appropriate emergency officials who have jurisdiction along the pipeline route and should communicate with any emergency officials that the operator deems appropriate for a given coverage area. This will generally include all emergency officials whose jurisdictions are traversed by the pipeline.

B.1.3 LOCAL PUBLIC OFFICIALS

Operators use several methods to identify names and addresses for specific public officials. These primarily include the use of local company resources, local phone books, and the Internet. Where SIC codes are used to identify public officials, the operator should include the categories applicable the public officials stakeholder group.

B.1.4 EXCAVATORS

While "excavators" is a broad category, its use here is intended to identify companies that perform or direct excavation work. Operators should identify, on a current basis, persons who normally engage in excavation activities in the areas in which the pipeline is located. There are several methods used by pipeline operators to identify specific excavator stakeholder names and addresses.

Where SIC codes are used to identify excavators, the operator should include the categories applicable to the Excavator stakeholder group. The SIC/NAICS list should be considered the minimum for excavator audience identification where those codes are used. The operator may add to or expand the list as other excavator information becomes available. Another source for identifying excavators is the One-Call Center that covers the area designated by the Public Awareness Program. Several One-Call Centers provide "excavator lists" to their members. This may also be accomplished by the use of a third-party vendor who specializes in this service.

APPENDIX C—DETAILED GUIDELINES FOR PUBLIC AWARENESS MESSAGES

Section 4 of this RP recommends that an operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. This appendix expands that recommendation by providing further explanation or examples of the content of messages to be communicated.

Information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message is conveyed to the intended audience should provide information that will allow the operator to meet the program objectives set forth in Section 2. The communications should include enough information so that in the event of a pipeline emergency, the intended audience members will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator.

C.1 Pipeline Purpose and Reliability

While not a primary objective, pipeline operators should consider providing general information about pipeline transportation, such as:

- The role of pipelines in U.S. energy supply
- Pipelines as part of the energy infrastructure
- Efficiency and reliability of pipelines
- Positive messages about the energy transportation pipeline safety record
- The individual operator's pipeline safety actions and environmental record.

For local distribution companies:

- Typical distribution network (stations, mains, services, meters)
- How to detect a natural gas leak (e.g., how natural gas smells)
- Who uses natural gas and why.

Many of these messages are available in print and videos from the pipeline industry trade associations listed in Section 2 and Appendix A.

The operator should describe the purpose and function of the pipeline and/or associated facilities and the nature, uses, and purposes of the products transported. Where practical, it might be helpful to communicate the benefit(s) of the pipeline to the community. Examples of "benefits" include:

- "This pipeline provides gasoline to motorists at X gas stations in the area of Y."
- "This natural gas pipeline network provides gas to X thousands of homes and businesses in Y city or Z state."

Pipelines are a safe and reliable means of transporting energy. Where appropriate, operators should describe how pipelines are a reliable means of transporting energy products and point out that they are extensively regulated by Federal and State regulations with regard to design, construction, operation and maintenance. Operators may also describe applicable operational activities that promote pipeline integrity, safety and reliability, which could include initial and periodic testing practices, internal inspections and their frequency, patrolling types and frequencies, and other such information. Operators may also reference the National Transportation Safety Board finding that pipelines provide the highest level of public safety as compared to other transportation modes.

C.2 Hazard Awareness and Prevention Measures

C.2.1 OVERVIEW OF POTENTIAL HAZARDS

General information about the nature of hazards posed by pipelines should be included in the message, while also assuring the stakeholder audience that accidents are relatively rare. The causes of pipeline failures, such as third-party excavation damage, corrosion, material defects, worker error, and events of nature can also be communicated.

C.2.2 OVERVIEW OF POTENTIAL CONSEQUENCES

Information should identify the product release characteristics and potential hazards that could result from an accidental release of hazardous liquids or gases from the pipeline.

C.2.3 SUMMARY OF PREVENTION MEASURES UNDERTAKEN

The potential hazard message should be coupled with a general overview of the preventative measures undertake by the operator in the planning, design, operation, maintenance, inspection and testing of the pipeline. This message should also reinforce how the stakeholder audience can play an important role in preventing third-party damage and right-of-way encroachments.

C.2.4 OPTIONAL SUMMARY OF PIPELINE INDUSTRY SAFETY RECORD

Depending on the stakeholder audience and the delivery methods used, the operator may want to consider including a general overview of the industry's safety record.

Communication materials should also convey the qualification that the information provided on hazards, consequences and preventative measures is very general and that more specific information could be obtained from the operator or other sources (noting phone or website(s) for contacts). Information communicated to emergency responders needs to be more specific, provide an opportunity for two-way feedback and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison. Operators may want to consider referring to publications or websites produced by the trade associations listed in Appendix A for specific example language developed to provide overviews of hazards, consequences and preventative measures tailored to each stakeholder audience.

C.3 Leak Recognition and Response

The pipeline operator should provide the following information to the affected public and excavator stakeholder groups. To accomplish this, operators may want to consider using generic or standard printed materials developed by trade associations as aides for their member companies. However, operators will need to ensure the materials used are specific to the type of pipeline and product(s) transported in their systems.

C.3.1 POTENTIAL HAZARDS

Specific information about the release characteristics and potential hazards posed by the accidental release of hazardous liquids or gases from the pipeline should be included in the operator's communications.

C.3.2 RECOGNIZING A PIPELINE LEAK

Operators should include in their communications information on how to recognize a pipeline leak through the senses of sight, unusual sound, and smell (as appropriate to the product type) and describe any associated dangers.

- By Sight—What to Look for...
- By Sound—What to Listen for...
- By Smell—What to Smell for...

C.3.3 RESPONDING TO A PIPELINE LEAK

Operators should include in their communications an outline of the appropriate actions to take once a pipeline leak or release is suspected. This information should include:

- What to do if a leak is suspected
- What not to do if a leak is suspected.

It is especially important to include specific information on detection response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of hydrogen sulfide).

C.3.4 LIAISON WITH EMERGENCY OFFICIALS

This information should indicate that both the operator and the local emergency response officials have an ongoing relationship designed to prepare and respond to an emergency.

C.4 Emergency Preparedness Communications

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. The following information should be provided to the emergency officials stakeholder audience. Local public officials should be provided a summary of the information that is available in more detail from the emergency response agencies in their jurisdictions.

C.4.1 PRIORITY TO PROTECT LIFE

Operator emergency response plans and key messages relayed to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

C.4.2 EMERGENCY CONTACTS

Contact information on the operator's local offices and 24-hour emergency telephone numbers should be communicated to local and state emergency officials. Operators should also use the public awareness contact opportunity to confirm the contact information for the local and state emergency officials and calling priorities.

C.4.3 EMERGENCY PREPAREDNESS—RESPONSE PLANS

Operators are required by federal regulation to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state regulations. 49 *CFR* 192 and 194 and some state regulations outline the specific requirements for emergency response plans. In developing Emergency Response Plans, the operator should work with the local emergency responders to enhance communications and response to emergencies.

C.4.4 EMERGENCY PREPAREDNESS—DRILLS AND EXERCISES

A very effective means of two-way communication about emergency preparedness is the liaison with emergency officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

C.5 Damage Prevention

Because even relatively minor excavation activities (for example: installing mail boxes, privacy fences and flag poles, performing landscaping, constructing storage buildings, etc.) can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the damage prevention best practices developed by the Common Ground Alliance (CGA).

The use of an excavation One-Call Notification system should be explained to the audience. The audience should be reminded to call the state or local One-Call System before beginning any excavation activity and that in most states it is required by law. Information on the prevalence of "third-party" damage should be provided as appropriate. If the state or locality has established penalties for failure to use established damage prevention procedures, that information may also be communicated, depending on the audience and situation.

As a baseline practice, excavation and one-call Information should include:

- Request that everyone contact the local One-Call System before digging
- Explain what happens when the One-Call Center is notified
- Provide the local or toll-free One-Call Center telephone numbers
- Explain that the one-call locate service is typically free (Note: Some exceptions by state)
- Remind, if applicable, that to call is required by law.

One-Call Center telephone numbers for all 50 states can be found at the Dig Safely website or by calling the Dig Safely national referral number at 1-888-258-0808.

The "Dig Safely" message should be included in public awareness materials distributed to the affected public and excavators by the operator in its communications:

- Call the One-Call Center before digging
- Wait for the site to be marked
- Respect the marks
- Dig with care.

For information see the "Dig Safely" website listed in Appendix A. Operators may also consider use of the widely recognized "No Dig" symbol in their materials.

C.6 Pipeline Location Information

C.6.1 TRANSMISSION PIPELINE MARKERS

The audience should know how to identify transmission pipeline rights-of-way by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. Communications should include what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in some areas.

Public awareness materials should include illustrations and descriptions of pipeline markers used by the operator and the information that the markers contain. Displaying the penalties for removing, defacing, or otherwise damaging a pipeline marker may also be beneficial.

In addition to meeting applicable federal and state regulations, transmission pipeline markers may:

- Indicate a pipeline right-of-way (not necessarily the exact pipeline location)
- Identify the product(s) transported
- Provide the name of the pipeline operator
- Provide the operator's telephone number, available 24-hours a day and 7-days a week
- Be brightly colored and highly visible
- Have weather resistant paint and lettering
- Include "Warning Petroleum Pipeline" or "Warning Gas Pipeline" and show the universal "No Dig" symbol
- Provide a one-call number.

Additional guidance for liquid pipeline marker design, installation, and maintenance is provided in API Recommended Practice 1109.

C.6.2 TRANSMISSION PIPELINE MAPPING

Transmission pipeline maps can be an important component of an operator's Public Awareness Program. The level of detail in the map provided will be relevant to the stakeholder's need, taking security of the energy infrastructure into consideration.

Members of the general public can also receive information about operators who have pipelines that might be located in their community by accessing the National Pipeline Mapping System (NPMS) on the Internet. The NPMS will provide the inquirer a list of pipeline operators and contact information for operators having pipelines in a specific area. Inquiries are made by zip code or by county and state. Operators should include information on the availability of the NPMS within their public awareness materials.

Following is a summary of the types of maps that are referred to in this RP in describing how operators can incorporate pipeline maps in their efforts to improve public awareness.

- *System Maps*—Typically system maps provide general depiction of a pipeline transmission system shown on a state, regional or national scale. This type of map generally is not at a scale that poses security concerns and is often used by operators in a number of publications available to the industry and general public. A system map generally depicts a portion of the pipeline system shown in relationship to a region of the country. Generally these types of maps do not include any detail on the location of facilities.

- *General Maps*—General maps are another form of system map, which may be presented, in a more graphical format or smaller scale.
- *Local Maps*—Local maps are generally shown on a neighborhood, town, city or county level and usually do not show the entire pipeline system. Local maps are especially appropriate in communication with local emergency officials, One-Call Centers and elected public officials. Local maps should be distributed in accordance with regulatory or operator's company security guidelines. Local maps could include pipeline alignment maps, GIS-system produced maps, or other types of mapping that show more detail about the physical location of the pipeline system.
- *Community Pipeline Infrastructure*—Maps of communities that depict all of the natural gas and liquid transmission pipeline systems in the area. Available from the state or OPS to public and emergency officials.
- *National Pipeline Mapping System (NPMS)*—The U.S. Department of Transportation's Office of Pipeline Safety has developed the National Pipeline Mapping System, through which pipeline location maps are made available electronically to state and local emergency officials, in accordance with federal security measures.

Operators of transmission pipelines should make available appropriate system or general maps to the affected public and provide them guidance in how they can determine the location of the pipelines near where they live and work. Such maps should include company and emergency contact information and a summary of the type of products transported.

As part of the damage prevention program, all operators should also communicate the process for contacting the excavation One-Call System so that the specific location of the pipeline (and other nearby utilities) can be marked prior to excavation activity.

Operators of transmission pipelines should make available local maps to public and emergency officials in their effort to assure effective emergency preparedness and land use planning. In addition, operators must follow regulatory guidelines on providing such maps as required under 49 *CFR* Part 192 and 195. Maps should include company and emergency contacts, information on the type of products transported, and sufficient detail on landmarks, roads or location information relevant to the official's needs.

Operators should provide paper or digitized maps, or alternative information to the state or regional excavation One-Call Center, consistent with the One-Call System's requirements.

C.7 High Consequence Areas and Integrity Management Program (IMP) Overview for Transmission Pipelines

C.7.1 MESSAGE CONTENT FOR AFFECTED PUBLIC WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of Integrity Management Program (IMP) Plans for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry. The information should make system maps of HCAs available to the general or affected public. An overview of an operators IMP should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The summary may only be a few pages long and its availability could be mailed upon request or made available on the operator's website.

C.7.2 MESSAGE CONTENT FOR EMERGENCY OFFICIALS WITHIN HCAs

When conducting liaison activities with emergency officials required by the public awareness plan, operators should include information on how the emergency official may gain access to the National Pipeline Mapping System for their jurisdiction through the Office of Pipeline Safety. In addition, the operator may supplement their messages and materials by including overviews of IMPs and specifically solicit feedback from the emergency official about local conditions or activities that may be useful and/or prompt changes to the operator's IMP for that area. For example, mitigation measures that may be included in a HCA segment's risk analysis and action plan is supplemental emergency response planning, staging area identification or equipment deployment. A two-way discussion with emergency officials of the components of the HCA risk mitigation plan would be helpful.

C.7.3 MESSAGE CONTENT FOR PUBLIC OFFICIALS WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of IMPs for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry.

An overview of an operator's IMP plan should include a description of the basic requirements and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be several pages long and its availability could be mailed upon request or made available on the operator's website.

C.8 Content on Company Websites

The information listed below will guide pipeline operators who maintain websites on the recommended informational components to be included on the website.

C.8.1 COMPANY INFORMATION

In addition to describing the purpose of the pipeline and markets served, the website should include a general description of the pipeline operator and system. This could include:

- Operator and owner name(s)
- Region and energy market served
- General office and emergency contacts telephone numbers and e-mail addresses
- Products being transported by pipeline
- System or general map and location of key offices (headquarters, region or districts).

C.8.2 INFORMATION ON PIPELINE OPERATIONS

A broad overview of the operator's pipeline safety and integrity management approach should be included describing the various steps the company takes to ensure the safe operation of its pipelines. While not specifically recommended, additional information to consider for the website includes:

- General pipeline system facts
- An overview of routine operating, maintenance and inspection practices of the system
- An overview of major specific inspection programs and pipeline control and monitoring programs.

C.8.3 TRANSMISSION PIPELINE MAPS

A general or system map (see previous section describing types of maps) should be on the website. Details on how to obtain additional information should be provided, including reference to the National Pipeline Mapping System ((NPMS).

C.8.4 PUBLIC AWARENESS PROGRAM INFORMATION

The operator should include a summary of its Public Awareness Program developed under the guidance of this RP and should consider including printed material used in these efforts on the website. The public should also be provided information on company contacts to request additional information.

C.8.5 EMERGENCY INFORMATION

The website should contain emergency awareness information from two aspects. First, it should contain a summary of the operator's emergency preparedness. Second, it should contain information about how the public, and residents along the pipeline rights-of-way, and/or public officials should help protect, recognize, report and respond to a suspected pipeline emergency. Emergency contact information should be prominent and accessible from anywhere on the pipeline portion of the website.

C.8.6 DAMAGE PREVENTION AWARENESS

Pipeline operators are encouraged to either provide or link the viewer to additional guidance on preventing excavation damage, such as "Dig Safely" program information, contact information for the One-Call System in each of the states in which the operator has pipelines, and the "Common Ground Alliance" website noted in Appendix A.

C.9 Right-of-way Encroachment Prevention

Pipeline operators should communicate that encroachments upon the pipeline right-of-way inhibit the operator's ability to reduce the chance of third-party damage, provide right-of-way surveillance and perform routine maintenance and required federal/state inspections. The communication can describe that in order to perform these critical activities, pipeline maintenance personnel must be able to access the pipeline right-of-way, as provided in the easement agreement. It should also describe that to ensure access; the area on either side of the pipeline contained within the right-of-way must be maintained clear of trees, shrubs, buildings, fences, structures, or any other encroachments that might interfere with the operator's access to the pipeline. It should also point out that the landowner has the obligation to respect the pipeline easement or right-of-way by not placing obstructions or encroachments within the right-of-way, and that maintaining a pipeline right-of-way free of encroachments is an essential element of maintaining pipeline integrity and safety.

Residents, excavators, and land developers should be requested to contact the pipeline operator if there are questions concerning the pipeline or the right-of-way, especially if property improvements or excavations are planned that might impact the right-of-way. These audiences should also be informed that they are required by state law to provide at least 48 hours advance notice, more in some states, to the appropriate One-Call Center prior to performing excavation activities. Longer lead times for planning major projects are advised and sometimes required by state law.

Operators should consider communicating with local authorities regarding information concerning effective zoning and land use requirements/restrictions that will protect existing pipeline rights-of-way from encroachment. Communications with local land use officials could include consideration of:

- How community land use decisions (e.g. planning, zoning,) can impact community safety
- Establishing setback requirements for new construction and development near pipelines

- Requiring prior authorization from easement holders in the permit process so that construction/development does not impact the safe operation of pipelines
- Requiring pipeline operator involvement in road widening or grading, mining, blasting, dredging, and other activities that may impact the safe operation of the pipeline.

C.10 Communication of Pipeline Maintenance Activities

When planning pipeline maintenance-related construction activities, operators should communicate to the audience affected by the activity in a manner that is appropriate to the nature and extent of the activity. For major maintenance construction projects (such as main-line rehabilitation or replacement projects) operators should also notify appropriate emergency and local public officials and include information on further communications appropriate to the nature or local impact of the maintenance or construction activity. Operators should communicate appropriately in accordance with requirements associated with the acquisition of permits.

C.11 Security

Operators should include in their communications, where applicable, appropriate information pertaining to security of their pipelines and related facilities. Communications messages could include:

- General information about the pipeline or aboveground facility security measures
- Increased public awareness about security
- Communications to pipeline and facility neighbors to:
  - Become familiar with the pipelines in their area (identification via pipeline marker signs)
  - Become familiar with the pipeline facilities in their area (identification via fence signs at gated entrances)
  - Record the operator name, contact information and any pipeline information from nearby pipeline marker signs or facility signs and keep in a permanent location near the telephone
  - Be observant for any unusual or suspicious activities and unauthorized excavations taking place within or near the pipeline right-of-way or pipeline facility. Report such activities to their local law enforcement and the pipeline operator.

Pipeline neighbors are the operator's first line of defense against unauthorized excavation and other such activity in the right-of-way, and they can help by contacting the operator or the proper local authorities of suspicious activities if they have contact information available.

C.12 Facility Purpose

Communication with the affected public, emergency and public officials in proximity of major facilities (such as storage facilities, compressor or pump stations) should include an understanding of the nature of the facility. Operators should include in their communications general information about the facility and the product(s) stored or transported through the facility. Liaison with emergency officials should also include an understanding of emergency contact information for the specific facility.

APPENDIX D—DETAILED GUIDELINES FOR MESSAGE DELIVERY METHODS AND/OR MEDIA

Section 5 describes the delivery methods and tools available to pipeline operators to foster effective communication programs with the stakeholder audiences previously described. This Appendix expands on those guidelines by providing further explanation or examples of delivery methods and/or media. This section does not imply that all methods are effective in all situations. The content of the communication efforts should be tailored to the needs of the audience and the intent of the communication. Refer to Section 4 for a detailed description of the message content that the following materials or delivery methods should contain for each intended audience.

D.1 Print Materials

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audiences and the message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed here.

D.1.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

This is the most common message delivery mechanism currently used by the pipeline industry. Print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. Print materials also afford an effective opportunity to communicate content in a graphical or pictorial way. However, note that targeted distribution of print materials alone should not be considered effective communication with local emergency response personnel.

Consideration should be given to joining with other pipeline companies in a local, regional or national setting (including both the local distribution company and transmission pipelines) to produce common message materials that can be either jointly sponsored, (e.g., include all sponsors company names/logos) or used as a "shell" and then customized to each company's individual needs, to help ensure that a consistent message is being delivered. This approach can also effectively reduce the cost to individual operators.

Print materials can be mailed to residents or communities along the pipeline system or handed out at local community fairs, open houses, or other public forums. Operators can hire facilitators to organize mass mailings, using nine-digit zip codes or geo-spatial address databases; to designated residents in the community located along the pipeline, such as within an appropriate distance either side of the pipeline centerline. In this case it is often advisable to get information from the postal service or service provider on size, folding and closure requirements to minimize the postage costs for mass mailings. There are services that can handle the printing of materials, mailing address identification, mailing and documentation for the operator as a package.

D.1.2 LETTERS

Research has indicated that letters mailed to residents along a pipeline system are an effective tool for the operator to use to communicate specific information, such as what to do in the event of a leak, identification of suspicious activity or notification of planned maintenance activities within the right-of-way.

Notification letters are usually effective where there is a high likelihood for third-party damage such as in agricultural areas, new developments and where other types of ground-disturbing activities may take place. Similar letters may also be send to contractors, excavators and equipment rental companies informing them of the requirement to use One-Call Systems and providing other important safety information for their workers and the public.

Letters, along with other print materials, should provide information about where the recipient can obtain further information (such as website address, e-mail address, local phone numbers and one-call numbers).

D.1.3 PIPELINE MAPS

Pipeline maps can be presented as printed material and are an important component of an operator's Public Awareness Program. The operator should consider whether maps should be part of the communications to appropriate local stakeholder(s), and what type of maps should be used to accomplish the objective. See Appendix C.6.2 for further explanation of types and availability of maps.

D.1.4 RESPONSE CARDS

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other print materials. When delivering public awareness information to nearby residents, public or emergency officials, the inclusion of response cards can be used in a variety of ways:

- To maintain/update current mailing lists. Response cards permit the recipients to notify the operator of any changes in address
- To provide a convenient venue for recipients to provide comments, request additional information, raise concerns or ask questions
- To help evaluate the effectiveness of the operator's Public Awareness Program.

D.1.5 BILL STUFFERS

Bill stuffers are printed materials frequently used by local distribution companies (LDCs) in conjunction with invoice mailings to their customers. Due to the nature of their customers, these are not an appropriate option for transmission and gathering pipelines. LDCs using bill stuffers can increase the effectiveness of their programs by communicating to their active customers frequently through the repeated use of bill stuffers. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even when some may not be natural gas customers.

D.2 Personal Contact

Personal contact describes face-to-face contact between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication, and it allows for two-way discussion. This may be done on an individual basis or in a group setting. Some examples of communications through personal contact are described below:

D.2.1 DOOR-TO-DOOR CONTACT ALONG PIPELINE RIGHT-OF-WAY

This method is often used to make contact with residents along the pipeline right-of-way to relay pipeline awareness information or information on upcoming pipeline maintenance. This method can help to build stakeholder trust, which is an integral part of communication and an enhancement to the long-term Public Awareness Program. Operator representatives conducting door-to-door contact should be knowledgeable and courteous, be prepared for these types of communications and be able to discuss and respond to questions relating to the communication materials provided so that contact is meaningful and positive. They should provide the landowner/resident with basic pipeline safety information and a means for future contact.

If pipeline safety is to be discussed in this forum, the operator representative should be generally knowledgeable about the company's pipeline integrity program and emergency response procedures. In addition to the general information described in Section 4, the following additional information should also be considered:

a. Description of facilities on or near the property (i.e., pipelines, meter/regulator stations, compressor/pump stations, wellheads, treating facilities, tankage, line markers, cathodic protection, communication, etc.)
b. Description of easement and property owner's rights and limitations within the easement
c. Name and phone number of local contact within company for further information and the operator's emergency notification number to report emergencies or suspicious activity
d. Information on damage prevention and local "Call Before You Dig" programs
e. What to do in case of emergency (fire, leak, noise, suspicious person)
f. Informational items (i.e., calendar, magnetic card, pens, hats, etc.) to retain important telephone numbers
g. As appropriate, additional local information such as upcoming maintenance, projects, events and/or company community involvement such as United Way, other charities, environmental projects, etc.

D.2.2 TELEPHONE CALLS

When the intended audience is small in number, the operator may find it effective to communicate by telephone. This personal form of contact allows for two-way discussion. The operator should decide which elements of their Public Awareness Program are suitable for conducting via telephone calls.

D.2.3 GROUP MEETINGS

Group meetings can be an effective way to convey the messages to selected audiences. Meetings may be between the operator (or group of operators) and an individual stakeholder audience or between the operator (or group of operators) and a number of the stakeholder audience groups at one time.

For example, the operator could conduct individual meetings with emergency response officials, combined industry meetings with emergency response officials, and participation by emergency response officials and personnel in the operator's emergency response tabletop drills and deployment exercises. Meetings are particularly effective in conducting liaison activities with the emergency official stakeholder group.

Another example is group meetings conducted by the operator in classrooms and with educators at local schools. Informational materials can be presented to school administrators and students and can contain important public awareness messages for students to take home to their parents. This method of personal contact can readily reach a large number of people with the operator's public awareness messages and reinforce positive messages about the operator and/or the pipeline industry.

Additional group meetings could include those with state One-Call System events, local excavators, contractors, land developers, and municipalities.

D.2.4 OPEN HOUSES

Operators often hold open houses to provide an informal setting to introduce an upcoming project, provide a "get to know your neighbor" atmosphere or to discuss an upcoming maintenance activity such as pipeline segment replacement. Tours of company facilities, question and answer sessions, videos, or presentations about pipeline safety and reliability do well in an open house environment. Even without formal presentations, allowing the public to see the facility can also be very effective. Often this type of forum would include refreshments and handouts (e.g. print material, trinkets, etc.) that attendees can take with them. Targeted or mass mailings can be used to announce planned open houses and can, in themselves, communicate important information.

D.2.5 COMMUNITY EVENTS

Community sponsored events, fairs, charity events, or civic events may provide appropriate opportunities where public awareness messages can be communicated to the event participants. Companies can participate with a booth or as a sponsor of the event.

These forums are generally used to remind the community of the operator's presence, show support for community concerns, and heighten public awareness about the benefits of pipeline transportation and about pipeline safety. Examples of community events include:

- County and state fairs
- Festivals and shows
- Job fairs
- Local association events
- Trade shows (Energy Fair)
- Chamber of Commerce events.

Operators should plan in advance and secure a large number of handout materials; as such events often include a large number of attendees and can take place over several days.

D.2.6 CHARITABLE CONTRIBUTIONS BY PIPELINE OPERATORS

While contributions to charities and civic causes are not in themselves a public awareness effort, companies should consider appropriate opportunities where public awareness messages can be conveyed as part of or in publicity of the contribution. Examples include:

- Contribution of gas detection equipment to the local volunteer fire department
- Donation of funds to acquire or improve nature preserves or green space
- Sponsorship to the community arts and theatre
- Support of scholarships (especially when to degree programs relevant to the company or industry)
- Sponsorship of emergency responders to fire training school.

D.3 Electronic Communications Methods

D.3.1 VIDEOS AND CDs

There are a variety of approaches companies may use to supplement their delivery tools with videos. While a supplement to the baseline components of an effective Public Awareness Programs, videos may be quite useful with some stakeholders or audiences in some situations. Videos can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual response that printed materials often cannot. Companies may seek industry specific videos from trade organizations or develop their own customized version. Such videos can be used for landowner contacts, emergency official meetings, or the variety of community or group meetings described elsewhere in this section. Companies could also consider adding such videos to their company websites.

D.3.2 E-MAIL

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholders. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by mail, by person or in meetings.

E-mail contact information can be provided on company handouts, magazine advertisements, websites and other written communications. This provides an effective mechanism for the public to request specific information or to be placed on distributions lists for specific updates.

An advantage of e-mail is the ease of requesting and receiving return information from the recipient, similar to contact information, survey or feedback described in bounce-back cards explained above. Note that it is important for the operator to designate a response contact within the organization to handle follow-up responses to e-mail queries in a timely manner.

D.4 Mass Media Communications

D.4.1 PUBLIC SERVICE ANNOUNCEMENTS (PSAs)

Radio and television stations occasionally make airtime available for public service announcements. There is great competition from various public interest causes for the small amount of time available because the broadcast media is no longer required by law to donate free airtime for PSAs. Given the popularity of radio and television and the large areas covered by both, public service announcements can be an effective means for reaching a large sector of the public. Pipeline operators (or groups of pipeline operators) could consider contacting local stations along the pipeline route to encourage their use of the PSAs. The use of cable TV public access channels may also be an option.

D.4.2 NEWSPAPERS AND MAGAZINES

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline operators can encourage reporters to write constructive stories about pipeline issues in various topics of relevance, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure. Even if the reporter is covering an emergency or controversial issue, pipeline operators can leverage the opportunity to reinforce key safety information messages such as damage prevention and the need to be aware of pipelines in the community. Trade magazines such as those for excavators or farmers often welcome guest articles or submission or assistance in writing a positive, safety-minded story for their readers. Local weekly newspapers and "metro" section inserts will sometimes include a news release verbatim at no cost to the sender.

D.4.3 PAID ADVERTISING

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community. This type of advertising can be very expensive, but can be made more cost effective by joining with other pipelines, including the local utilities, to deliver a consistent message. One example is placement of a public awareness advertisement on a phone book cover, thus achieving repetitive viewing by the audience for a whole year. Another example is advertising in local shopping guides.

D.4.4 COMMUNITY AND NEIGHBORHOOD NEWSLETTERS

Information provided should be similar to that made available for newspapers and magazines. Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with outreach to those communities and/or neighborhoods and is usually done for free. Operators can also develop their own newsletters tailored to specific communities. These newsletters can be used to highlight the operator's involvement in that community, provide the operator's public awareness messages, and to address any pipeline concerns that community may have.

This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

D.5 Specialty Advertising Materials

Company specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These tools also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. Many such materials or items exist, including refrigerator magnets, calendars, day planners, thermometers, key chains, flashlights, hats, jackets, shirts, clocks, wallet cards, and other such items containing a short message (i.e. "Call Before You Dig"), the company logo and/or contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods.

D.6 Informational Items

Operators can develop (or participate in industry associations or along with other companies) informational materials for groups or schools that heighten pipeline awareness. Operators (and their industry associations) may also sponsor or develop training materials for emergency response agencies that are designed to increase knowledge and skills in responding to pipeline emergencies. Alternatively, local emergency officials will hold training as part of their own continuing education, and attendance by pipeline personnel at these sessions is often welcome and an ideal setting for relaying public awareness information about pipelines.

D.7 Pipeline Marker Signs

The primary purposes of above ground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency
- Facilitate aerial or ground surveillance of the pipeline right-of-way by providing aboveground reference points.

Refer to Section 4 for additional information on marker sign types and information content.

Below ground markers are also effective warnings. While some may not consider this part of a proactive public awareness communication program, buried warning tape or mesh can be an effective reminder to excavators of the presence of underground utilities and have proven effective in preventing damage to pipelines and other buried utilities.

D.8 One-Call Center Outreach

Most state One-Call Centers provide community outreach or implement public awareness activities about the one-call requirements and the Dig Safely awareness messages, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such Public Awareness Programs within their own Public Awareness Program. Some One-Call Centers focus on hosting awareness meetings with excavators to further promote the Dig Safely and One-Call Messages. It is the operator's responsibility to request documentation for these outreach activities.

In order to enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become members of one-call organizations in areas where they operate pipelines. Since all underground facility members share One-Call Center public awareness outreach costs, the costs to an individual operator are usually comparatively low, and can demonstrate effectiveness by increased use of the One-Call Notification system.

D.9 Operator Websites

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Since corporate websites may vary in serving the business needs of the company (e.g. investor relations, marketing, affiliate needs), the guidance in Appendix C.8 describes features of the components of a website for a company's pipeline subsidiary or operations that should fit into any corporate structure and overall website design. Many pipeline operators may choose to place additional or more detailed information on their websites to supplement their public awareness and informational efforts.

An operator's website will supplement the other various direct outreach delivery tools discussed in this RP.

APPENDIX E—ADDITIONAL GUIDELINES FOR UNDERTAKING EVALUATIONS

This appendix provides additional explanation for several methods described in Section 8 for conducting program evaluations and provides a sample survey.

E.1 Focus Groups (Interview Panels)

A focus group is a group of people representative of one or more target audiences who are gathered to provide feedback about the materials or other aspects of a planned Public Awareness Program or to comment on an existing one.

Typically, a focus group has about 6 to 12 participants. While focus groups can be professionally facilitated, feedback about public awareness materials can be gained by an informal discussion run by individuals connected with the public education program. Often participants will be asked to review draft materials and to comment on what they understood from the materials and whether the materials would draw appeal when received by mail. Focus groups can also be used to provide input on the relative effectiveness of various means of delivery.

Focus group participants might be operator employees who are not familiar with the Public Awareness Program, citizens living along a stretch of pipeline or representatives of homeowner associations or business people along the right-of-way. Target stakeholder audiences should not be mixed. The participants usually are not chosen at random but rather are selected to be reasonably representative of their focus group and capable of articulating their reactions to the materials.

E.2 Sample Assessment of Program Implementation

Table E-1—Sample Audit of Program Implementation

I Program Development and Documentation: Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described in Section 2 and the remainder of this RP?
1. Does the operator have a written Public Awareness Program?
2. Have all of the elements described in Section 2 of this RP been incorporated into the written program?
3. Does the written program address all of the objectives of this RP as defined in Section 2.1?
4. Does the documented program address regulatory requirements identified in Section 2.2 of this RP and other regulatory requirements that the operator must comply with?
5. Does the operator have a plan that includes a schedule for implementing the program?
6. Does the program include requirements for updating responsibilities as organizational changes are made?
II Program Implementation: Has the public awareness plan been implemented and documented according to the written plan?
1. Is the program updated and current with any significant organizational or major new pipeline system changes that may have been made?
2. Are personnel assigned responsibilities in the written program aware of their responsibilities and have management support (budget and resources) for carrying out their responsibilities on the program?
3. Has the program implementation been properly and adequately documented?
4. Have all required elements of the program plan been implemented in accordance with the written plan and schedule?
5. Does the operator have documentation of the results of evaluating the program for effectiveness?
6. Are the results of the evaluation of program effectiveness being used in a structured manner to improve the program or determine if supplemental actions (e.g. revised messages, additional delivery methods, increased frequency) in some locations?

E.3 Supplemental Information to Operators Conducting Surveys to Evaluate Effectiveness

E.3.1 Type of Survey—Surveys may be conducted in person, over the phone, or via mail questionnaires. Conducting them in person is more labor intensive and costly but yields the best result and the largest return. Mail surveys are least expensive but typically have only 10-20 percent of the forms returned, which raises questions about whether the results are representative. Incentives for completing mail surveys may improve participation. Telephone surveys are a good compromise for the modest size samples needed to draw broad conclusions, but any of the methodologies can be made to work.

E.3.2 Sample Size—Typically a survey is designed to reach a random number of the targeted stakeholder audience. A variation on the random sample when conducting surveys in person is a "cluster sample" in which a block may be chosen at random and then a cluster of several households on the block visited at the same time. That is a relatively efficient way to increase sample sizes and not sacrifice much in statistical validity. The telephone number for affected residents is typically not readily accessible to the operator, although a random survey in a designated zip code or geographic area may include questions on whether the respondent lives or works along the right-of-way (to ensure a sufficient number of the affected public is included in the survey). For conducting a survey in person, the operator can work with a random selection of homes or businesses drawn from aerial maps or simply by selecting segments at random to be visited near the right-of-way. Mail surveys might be sent to all in a census tract, all in a zip code, or sub-zip code area. Third-party experts in conducting surveys can readily assist, at least for the first time a survey is attempted.

E.3.3 Statistical Confidence—There is typically concern about being statistically reliable. Often this leads to needlessly expensive surveys when one really only needs to know the approximate percentage of the target group that has been reached and is knowledgeable.

In deciding sample size, one can keep in mind a simplification of a lot of statistical rules and tables:

> The statistical error associated with a random survey is approximated by $1/\sqrt{n}$,where n is the size of the sample. A sample of 100 gives an accuracy of approximately $\pm 1/\sqrt{100}$, or about 10 percent.

There are a number of detailed assumptions behind that approximation, which is more valid the larger the total population to be surveyed. For smaller populations, the sampling error is actually even smaller than that approximation. Very modest-size surveys can be used for evaluating pipeline safety for public awareness and still have statistical validity to support broad conclusions that, in turn, drive changes (as necessary) or support continuation (when supported) to the Public Awareness Program.

E.3.4 Content—Different sets of questions are needed for different audiences. There obviously would be a different set of questions asked of households along a pipeline versus those asked of excavators. The survey questionnaire should be clear, brief and pre-tested to increase the participation and minimize the cost. Operators should try to keep their questions the same over time so that trends can be evaluated. The questions can be yes/no, multiple choice, or open-ended. It is easier to analyze data from multiple choice or yes/no questions than open-ended questions; the latter require someone to read and interpret them, and then complete computer-readable tallies or do a tally by hand. A combination of both open-end and multiple-choice questions can be used. A survey can focus on only one program element or several elements and can measure the following with one or more of the selected stakeholder audiences:

- **Outreach:** Surveys can determine whether the audience received the public awareness communication.
- **Knowledge:** Surveys can also inquire about what the person would do hypothetically in certain situations, such as "If you observed a suspected leak in a pipeline, what would you do?"
- **Behavior:** In addition to knowledge and attitudes, surveys can be designed to inquire of actual behaviors; e.g., "Have you ever called to inquire about the location of a pipeline," "Have you ever been involved in any way with a pipeline break or spill," etc.

As a supplement to the baseline survey, the operator or operators working in collaboration or with trade associations may also include information about general attitudes about pipelines and knowledge of their role in delivering energy.

Some thought is needed as to whether it is better to get open-ended responses that do not prompt the respondent, to avoid bias. A short example: One might be tempted to ask, "What number would you call if you saw a break in a pipeline," but that question already assumes somebody would look up a number, which may be what you are trying to determine. A less biased question would be "what would you do if you saw a break in a pipeline?"

E.3.5 Implementation—An operator can:

- Develop and conduct a survey on its own system using internal or external expertise
- Select a survey format designed by external parties or an industry association
- Adapt surveys designed by others and conduct on its own systems, or
- Join with others in a regional survey.

E.4 Sample Survey

E.4.1 Survey Questions—The content of the questions on the survey should reflect the goals of the public education program. The wording of questions is critical.

Developing appropriate wording is more difficult than it may appear to be on the surface. It is easy to inadvertently build in biases or confuse the person being interviewed. The questionnaires should be tested before use. A focus group or small sample can be used for that purpose. If the wording is changed, the questions should be retested.

Preferably, the same wording would be used for a group of operators if not all of the industry, to achieve comparability and be able to compare statistics for the industry or a region. Individual operators should try to keep their questions the same over time so that trends can be evaluated.

Where possible, it is preferable to use multiple-choice questions rather than open-ended questions, because the former are easier to analyze objectively. A combination of both open-end and multiple-choice questions can be used. Negative answers or problems raised by respondents preferably should be followed up by a diagnostic question to understand the respondent's point of view better, and to get insight for making improvements.

In the tables below are two sample sets of survey questions—one for the general public near pipelines, the other for excavators. These lists of questions can be used as menus from which to choose if there is time only for a few questions. The asterisked questions are the most important.

The questions may refer to the respondent's experience in the past six months, year, or two years; generally one does not ask about information older than one year because of memory problems, except for dramatic events likely to be remembered.

E.4.2 Introduction—In administering a survey, there should be a brief introduction to set the stage. For example:

> "Our company [or insert company name association] believes it is important to get feedback from people (excavators) such as you about pipeline safety. We would like to ask you a few questions and would greatly appreciate your candid answers. The information on your particular response will be kept confidential. Let me start by asking ...."

E.4.3 Venues—Basically the same questions can be asked during a formal survey, whether undertaken by mail, telephone, or in person. They also can be used during customer contacts or as part of contacts with appropriate personnel from excavators.

Tables

Table E-2—Sample Survey Questions for Affected Public

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Outreach	*1.	In the last year [or 2 years], have you seen or heard any information from [our company] relating to pipeline safety? *[Yes or No]* If yes: 1a. What was the source of the information (check all that apply): a. Written material (brochure, flyer, handout) b. Radio? c. TV? d. Newspaper ad or article? e. Face-to-face meeting? f. Posted information (e.g., on or near pipeline) g. Other: ______ 1b. About how many times did you see information on pipeline safety in the last year?______
Outreach	2.	Have you or has or anyone in your household ever tried to obtain information about pipeline safety in the last 12 months? *[Yes or No]* ______ 2a. If yes, where did you try? Check all that apply: a. Internet b. Call c. Letter d. Visit e. Other: ______
Knowledge	*3.	Do you live close to a petroleum or gas pipeline? *[Yes, No, do not know]* 3a. If yes, where is it (or how close are you to it)?______ ______
Knowledge	*4.	What would you do in the event you were first to see damage to a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ______
Knowledge	5.	What would you do if you saw someone intentionally trying to damage a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ______
Behavior	*6.	Have you ever called a pipeline operator, 911, or anyone else to report suspicious or worrisome activity near a pipeline? *[Yes or No]* 6a. If yes, what did you report: a. Break b. Product release c. Digging d. Other: ______

Table E-2—Sample Survey Questions for Affected Public (Continued)

Attribute Measured	Sample Questions (Asterisk * marks most important questions.)
Behavior	*7. Have you or has anyone in your household [or company if a business] ever encountered a damaged pipeline or product released from a pipeline? *[Yes or No]* If yes, what did you do? ____________ ____________ ____________
Behavior	8. Have you ever passed information about pipeline safety to someone else? *[Yes or No]* If yes, what information and to whom: ____________ ____________ ____________
Outcomes	9. Has anyone in your household or have nearby neighbors ever had any injuries or damage associated with a pipeline break or spill? *[Yes or No]* 9a. If yes, describe event. ____________ ____________ ____________
Attitude	10. Do you agree or disagree that your local pipeline operator has been doing a good job of informing people like you about pipeline safety? a. Strongly agree b. Agree c. Disagree d. Strongly disagree If you disagree, why: ____________ ____________ ____________

Table E-3—Sample Survey Questions for Excavators

The questions below could be worded for a specific operator or for any operator; some excavators may deal with more than one pipeline.

Outreach	*1.	In the last 12 months, have you been contacted or received written information from [local pipeline operator] regarding pipeline safety? *[Yes or No]* If yes, what was the source: a. Telephone call b. Mail c. Visit or in-person meeting d. E-mail e. Sign or billboard f. Other:________
Outreach	2.	Have you received information from any other sources about pipeline safety? *[Yes or no]* 2a. If yes, which? ________
Behavior	3.	Have you contacted [pipeline operator name] in the past year to inquire about the location of pipelines? *[Yes or no]* 3a. If yes, about how many times? ________ 3b. If yes, how did you make the contact: a. Telephone b. E-mail c. Letter d. In-person e. Other: ________
Behavior	*4.	How often would you say your operator checks whether a pipeline exists before digging in a new spot? a. Always b. Usually c. Sometimes d. Rarely or Never e. Don't know. 4a. If not always: why not? a. Didn't know where to get information b. Not necessary c. Didn't think about it d. Takes too much time e. Think we can tell where pipeline is on our own f. Other: ________
Outreach	5.	How do you make sure that all the right people in the company get the information on whom to call before digging? That is, how do you disseminate the information? a. Post it b. Discuss in meetings c. E-mail d. Calls e. Put in company's written procedures f. Put in company newsletter g. Other: ________
Outreach (Audience Size)	6.	About how many people in your company actually determine where to dig? ________

Table E-3—Sample Survey Questions for Excavators (Continued)

	6a. What jobs do they have (e.g., excavator equipment operator; executive; operations boss; etc.): ______
Outreach	6b. How many of them probably have information on where to call before digging? a. All b. Most c. Some d. Few or None
Outcome	*7. Has your company ever unexpectedly encountered a pipeline while digging? *[Yes or No]*
	7a. If yes, how often has this occurred? ______ Explain whether pipeline location was unknown and why. ______
	7b. If yes, how many were "close calls"? ______
	7c. How many resulted in damage: ______

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ____________________ representing ____________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have an oil or gas pipeline running through your community? _____(Y/N)
If not yes, tell them. [Reviewers: Should we also ask if they know where it is?]

2. Do you know the name of your local pipeline operator? ________ (Y/N)

2a. If yes, who? ______________________________
[This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding pipeline safety in the last 12 months?
__________ (Y/N)

3a. If yes, about how many? __________

4. Before today, about when was your last contact with someone from the pipeline industry related to pipeline safety? ________________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call in the pipeline company if there is an incident or you need more information? __________(Y/N)

6. Have you heard of the Office of Pipeline Safety in the U. S. Department of Transportation?
________ (Y/N)

7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a pipeline? _______ (Y/N)

7a. If yes, what are they? ______________________________

8. Are you familiar with the one-call line? ________ (Y/N)
(If no, they should be informed about it.)

9. How would you rate the adequacy of information you have about pipeline safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
a. About right? _______
b. Too much? _____
c. Not enough? _____

[This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a pipeline break (regard less of whether intentional or accidental)? _______(Y/N)

Outcome

11. Are you aware of any pipeline breaks that occurred in your community in the last 10 years?
__________ (Y/N)

11a. If yes, how many? _______

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines (Continued)

11b. What were they? ____

[The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding pipeline safety? __________ (Y/N)

12a. If yes, what was it? ____

13. Overall, do you feel the pipeline industry has an adequate public safety awareness program?
   a. Definitely yes ________
   b. Pretty much so _______
   c. Not sure ____________
   d. Don't know _________
   e. Probably not ________
   f. Definitely not _______

[This is an overall perception of their awareness program. The operatory could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-4.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you know where the nearest oil or gas pipeline is in or near your community? ______(Y/N) [If not, tell them after the interview.]
2. Do you know the name of your local pipeline operator? ________ (Y/N)

   15a. If yes, who? ____

3. Do you know who to call in the pipeline company if there is an incident, or if you need more information? _________(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding pipeline safety in any media in the last year? ________ (Y/N)

   17a. If yes, do you recall what? ____________________________________

5. Have you or anyone else in your department to your knowledge met with any representatives of the pipeline company to discuss pipeline safety within the last 12 months, prior to today? _____________(Y/N)

   18a. If yes, when?_________________________

   18b. With whom? ____

Behavior

6. Do you have a response plan or SOPs for responding to a pipeline incident, such as a break? __________ (Y/N)
7. Have you done any practical training to deal with a break? ___________(Y/N)

Outcome

8. Do you know if there were any pipeline incidents within the last ten years in your community? _________ (Y/N)

   8a. If yes, about when? ____________

   8b. What was the incident? ____

   8c. Did the department respond? ________(Y/N)

   8d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.]

   ____

   ____

   ____

   ____

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ______________________ representing ______________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have natural gas pipelines running through your community? _____(Y/N)

2. Do you know the name of your local natural gas company? ________ (Y/N)

 2a. If yes, who? ______________________________________
 [This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding natural gas safety in the last 12 months? __________ (Y/N)

 3a. If yes, about how many? ___________

4. Before today, about when was your last contact with someone from the natural gas industry related to pipeline safety? _____________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call the natural gas company if there is an incident or you need more information? __________(Y/N)

6. Do you know who regulates the natural gas company in this community? _________ (Y/N) (If no, they should be informed about it.)

7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a natural gas pipeline? _________ (Y/N)

 7a. If yes, what are they? ______________________________________

8. Are you familiar with the one-call line? _________ (Y/N) (If no, they should be informed about it.)

9. How would you rate the adequacy of information you have about natural gas safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
 a. About right? ________
 b. Too much? ______
 c. Not enough? ______

 [This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a natural gas leak (regardless of whether intentional or accidental)? _______(Y/N)

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies (Continued)

Outcome	11. Are you aware of any pipeline leaks that occurred in your community in the last 2 years? ___________ (Y/N) 11a. If yes, how many? ________ 11b. What were they? ____ [The interviewer should be prepared to tell the local official the correct answer.] 12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding natural gas safety? _________ (Y/N) 12a. If yes, what was it? ____ 13. Overall, do you feel the natural gas industry has an adequate public safety awareness program? a. Definitely yes _______ b. Pretty much so ______ c. Not sure ___________ d. Don't know ________ e. Probably not _______ f. Definitely not ______ [This is an overall perception of their awareness program. Could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-5.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

First Responders/Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you have natural gas pipelines running through your community?? ______(Y/N)
[If not, tell them after the interview.]

2. Do you know the name of your local natural gas company? ________ (Y/N)

15a. If yes, who? ____

3. Do you know how to contact the local natural gas company if there is an incident, or if you need more information? __________(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding natural gas safety in any media in the last year? ____________ (Y/N)

17a. If yes, do you recall what? ________________________________

5. Have you or anyone else in your department to your knowledge met with any representatives of the natural gas company to discuss pipeline safety within the last 12 months, prior to today? _____________(Y/N)

18a. If yes, when?____________

18b. With whom? ____

Behavior

6. Do you have a response plan or SOPs for responding to a natural gas incident, such as a leak? ______ (Y/N)

7. Have you done any practical training to deal with a leak? ____________(Y/N)

8. Do you feel reasonably well prepared to deal with a natural gas leak, should one occur in your community? ___________(Y/N) If not, in what areas are there deficiencies? (Check all that apply.)
   a. Training ______
   b. Special Equipment _____
   c. Knowledge about leaks _____
   d. Inherent dangers _____
   e. Other: (Write in.)____

9. If you heard a report of a natural gas leak right now, what actions would you or your department take? [Write in the steps; someone should grade the responses to get a sense of whether there has been adequate training or preparation, or if the respondent just mentioned general procedures applicable to any kind of incident.]

____

____

Outcome

10. Do you know if there were any natural gas leaks within the last two years in your community? _________ (Y/N)

10a. If yes, about when? ____________

10b. What was the incident? ____

10c. Did the department respond? ________(Y/N)

10d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.] ____________________________

____

SUNOCO PIPELINE
An ENERGY TRANSFER Partnership

EMERGENCY RESPONSE PROCEDURES MANUAL

FOR

SUNOCO PIPELINE, LP 8” ETHANE PIPELINE

SARNIA, ON CANADA

Revision Log:

Rev.	Date	Comment	Approval	Approval
0	3/5/2014	Original Issue	[redacted]	[redacted]
1	4/24/2015	Revision 1	[redacted]	[redacted]
2	3/4/2016	Revision 2	[redacted]	[redacted]
3	8/30/16	Revision 3	[redacted]	[redacted]
4	3/30/2017	Revision 4	[redacted]	[redacted]
5	3/15/2018	Revision 5	[redacted]	[redacted]

APPROVAL

- The manual is under the approval of SPLP.

Name [redacted]

Manager, Emergency Management

20180321

Date

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APPENDICES

1.0 EMERGENCY RESPONSE PROGRAM

1.1 EMERGENCY RESPONSE POLICY

The health and safety of all workers, the public and environment are integral to effective business planning. Emergency response ensures a timely and appropriate response to emergencies and compliance with applicable laws (domestic and/or international) and industry and legal codes of practice.

SPLP has the ultimate responsibility for this policy.

This shall be done through provision and availability of:

- Effective Emergency Response plans which encompass necessary on-site responses
- Competent Emergency Response personnel
- Reliable Emergency Response equipment
- Training for First Response personnel

1.2 BACKGROUND

Sunoco Logistics Pipeline LP (SPLP) owns an ethane line that connects the SPLP Ethane delivery system at the [redacted] valve compound located in [redacted] crossing then connecting to an above ground valve compound. The line then carries on underground to the Sarnia Station. This line is regulated by National Energy Board to the center of the St. Clair River.

1.3 EMERGENCY PLAN PURPOSE, SCOPE, AND OBJECTIVES

1.3.1 PURPOSE

The purpose of this emergency response plan is to minimize the effect of potential hazardous situations that may arise from this pipeline, and bring them under control in order to prevent them from developing into a full-scale emergency. This is accomplished by outlining procedures whereby personnel and equipment can be mobilized rapidly and efficiently in order to facilitate a prompt, coordinated, and safe response to any emergency incident.

This plan defines:

- The organization, roles and responsibilities for designated personnel during emergencies,
- The guidelines for emergency response actions as they relate to the pipeline operations, and
- The resources available/accessible for emergency response operations.

This plan is NOT intended to provide procedures for the following which are captured separately in different emergency response plans:

- Transportation (Corporate Transportation Emergency Response Plan),
- Community (County Emergency Response Plan), and
- Crisis Management (Corporate Crisis Management Plan).

1.3.2 SCOPE

For the purpose of the Pipeline Emergency Response Manual for SPLP 8" Ethane Pipeline, the "Contractor" is [redacted].

The health and safety of all workers, the public and the environment are integral to SPLP business planning. Emergency response ensures a timely and appropriate response to emergencies, compliance with applicable laws (domestic and/or international) and industry/ legal codes of practice.

1.3.3 OBJECTIVES

The objectives of this plan are to:

- Identify the SPLP Emergency Response Planning Philosophy and Policy,
- Identify authority, organization, roles and responsibilities for designated personnel during emergency, and
- Define procedures for emergency response actions as they relate to pipeline operations.

1.4 PLAN REVIEW and UPDATE PROCEDURES

1.4.1 REGULATORY COMPLIANCE

SPLP shall review the Sarnia Emergency Procedures Manual at a minimum of once per year and file annual plan updates by April 1 of each year or alternatively, file a letter indicating that there have been no changes to the plan. As stated in Section 1.4 (5), Canada's NEB must be provided plan revisions.

In Canada, SPLP files both one hard copy and one electronic copy of their respective plans with the National Energy Board (NEB). When filing plan updates, as required by subsection 32(2) of the OPR and paragraph 35(c) of the OPR, SPLP files a new, complete plan in both electronic and hard copy incorporating all updates.

1.4.2 SPLP EMERGENY RESPONSE MANUAL UPDATING

- Reviewed annually by the SPLP Area Operations Manager, the SPLP Manager of Emergency Preparedness & Security, the Contractor's Pipeline Integrity Manager, and the Contractor's First Response Team.
- Paper revisions will be distributed to manual holders.
- Electronic copy of the Pipeline Emergency Response Manual will be the most recent.

1.4.3 INCORPORATION OF PLAN REVISIONS

The plan resides as a web-based document, which permits authorized corporate and field staff access to make:

- Appropriate revisions as required by operational or organizational changes,
- Appropriate revisions as required by changes in the names and phone numbers detailed in Section 2.0, and
- Appropriate revision as required by improved procedures or deficiencies identified during response team tabletop exercises or actual emergency responses.

Once updates are made, email notification allows Authorized Plan Holders to update hard copy plans as changes occur. The Individual Plan Holder shall:

- Review and insert the revised pages into the plan,
- Discard or archive the obsolete pages, and
- Agency Revision Requirements.

1.5 MANUAL DISTRIBUTION

The Emergency Management Team is responsible for maintenance and distribution of this plan. Distribution will be handled in the following manner:

- Distribution of controlled plans is determined by the copy number assigned to agency and designated corporate Plan Holders. A distribution list is included as Table 1 below.
- Company personnel who may be called upon to provide assistance during discharge response activities will have access to a copy of the plan for their use and training.
- Any person holding a controlled copy of the plan shall ensure that the copy is transferred to their replacement in the event of reassignment or change in responsibility.
- Various regulatory agencies will also be distributed a controlled copy of the plan. The list of agencies is also detailed in Table 1.

TABLE 1-5 MANUAL DISTRIBUTION

Manual No.	Manual Steward	Manual Distribution	Name
C01	[redacted]	[redacted] – Senior Maintenance Technician	[redacted]
C02	[redacted]	[redacted] – Safety Specialists	[redacted]
C03	[redacted]	City of Sarnia Emergency Operations Coordinator	[redacted]
C04	[redacted]	Houston Control Room	[redacted]
C05	[redacted]	St. Clair Twp. Fire Chief	[redacted]
C06	[redacted]	Sarnia Fire Dept. Chief	[redacted]
CO7	[redacted]	NEB - distribute as per their direction	[redacted]
C08	[redacted]	[redacted] - Pipeline Integrity Manager	[redacted]
CO9	[redacted]	[redacted] - Incident Commander	[redacted]
C10	[redacted]	Sr Manager	[redacted]
C11	[redacted]	Manager, Emergency Management	[redacted]
C12	[redacted]	SCPL Manager	[redacted]
C13	[redacted]	[redacted] – Maintenance Planner	[redacted]
C14	[redacted]	Aamjiwnaag, First Nations	[redacted]

Note: The distribution of this plan is controlled by the front cover or compact disk (CD) label. The plan distribution procedures provided in Section 1.3 and the plan review and update procedures provided in Section 1.4 should be followed when making any and all changes.

1.6 PRODUCT LINES & PRACTICES

	Pipeline Number	NEB Lines	Owner
Ethane delivery line which runs under the St. Clair River to an above ground valve station [redacted] then continues to the Sun Canadian Pipeline Compound for further distribution.	13001	X	SPLP

In Canada, pipeline operations will be handled by the SPLP contractor [redacted]. When responding to a pipeline emergency, [redacted] will:

- Protect human life and the environment.
- Provide leadership in the management of a quick safe termination of any loss of containment incidents.
- Provide technical advice to the provincial, municipal and industrial emergency/disaster services responding to such incidents in the interests of the public and the environment until such time a SPLP representative arrives to the incident scene.
- Secure resources as necessary to render pipeline facilities safe for repair as quickly as possible
- Advise on and, if necessary, arrange for appropriate clean up or other mitigation actions.

2.0 ORGANIZATION

2.1 EMERGENCY RESPONSE ORGANIZATION

This section describes the functions of individuals designated in the Pipeline Emergency Response. Emergency response positions have been designed around the availability of personnel on a 24-hour/day basis. All positions in the Emergency Response Organization are filled by people who can be reached through call-out systems.

The local authority of each municipality or county is responsible for the direction and control of the local authority's emergency response. SPLP will offer advisory support and technical advice to any and all emergency response agencies who may be involved in response efforts for any pipeline incidents operated by [redacted] in their joint areas of collaboration to protect the public and environment.

[redacted] Emergency Response Team [redacted]

[redacted] is assuming the responsibility of a First Responder to any fire, incident or loss of containment on the SPLP 8" ethane pipeline which runs under the St. Clair River and surfaces to a valve compound on the [redacted] in Froomfield, Corunna Ontario then continues to the SPLP Sarnia meter station and ERFD.

It is expected that [redacted] as first responders will fill the appropriate positions in the Incident Command System on behalf of SPLP, until properly relieved by SPLP resources cascading in from the United States. As SPLP resources arrive, [redacted] employees will continue to remain integral members of the Incident Command as assigned. All roles & responsibilities of all designated employees who have a key role in the emergency response of an incident will follow basic incident command protocols and the basic job descriptions for each position are found in **APPENDIX J**.

Initial Team Members

Operations Section Chief or Alternate Incident Commander	[redacted]
Emergency Response Coordinator/Incident Commander	[redacted]
Planning Section Chief	[redacted]
Logistics Section Chief	[redacted]
Safety Specialists	[redacted]
Documentation Specialist	[redacted]
Houston Control Centre	SPLP, On Duty- Pipeline Controller (PC)

SPLP EMERGENCY RESOURCE:	**Houston Control Centre**

ROLE:

To respond to pipeline emergencies as a leak is identified.

Upon notification of an alarm, Pipeline Controller (PC) will follow the guidance in their Houston Control Room Manual regarding the Sarnia Station. The essence of that guidance is provided below:

- Ascertain the authenticity of the alarm or notification.
- Automated shut down of the pipeline or isolate the line as soon as it is determined to be appropriate.

In the event of an emergency at Sarnia Station, or involving any of our assets in Canada, the PC shall immediately make the following notifications (in order):

- Contact the Public Emergency Services, if necessary, as indicated above,
- Contact [redacted] to initiate an immediate local response,
- Contact the SPLP Pipeline Supervisor to initiate the SPLP response (see contact information below), and
- Contact the customer and inform them of the shutdown.

TRAINING / SKILLS PROVIDED:

Knowledge of product, hazards, pipeline facilities, emergency response plans, customer impacts.

EMERGENCY CONTACT:

Houston Control Center	(800) 786-7440

[redacted] **RESOURCE:**	**First Responder/Incident Commander**

ROLE:

To respond to pipeline emergencies as First Responder/Incident Commander once a leak has been identified.

FIRST RESPONDER ACTIONS:

The First Responder and Senior Maintenance Technician will respond to the emergency scene and verify the magnitude of the emergency.

Regardless of the magnitude of the emergency, the priorities for any [redacted] responder remains the same:

1. People safety
2. Environmental Impacts
3. Property Loss

INCIDENT COMMANDER ACTIONS:

Public and personnel safety is the foremost priority for the Incident Commander. Most emergency situations will involve provincial and municipal governments as well as local disaster service agencies. Emergencies within the Chemical Valley will also involve CVECO. It is of utmost importance that the [redacted] Pipeline Manager interacts and cooperates with these agencies in the field. It is expected that [redacted] will serve as the SPLP IC until relieved by a designated IC from SPLP. The priorities of the Incident Commander are:

1. Safety of all personnel Take action to minimize impact of the release (See Section 2.6)
2. Notification of local and provincial government agencies (See Section 2.4)
3. Support the local Emergency Operations Centre (EOC) as needed
4. Communicate and liaise with SPLP leadership
5. Maintain log/documentation (include names, times, use tape recorder if available)

In addition:

- Establish an Incident Command Post
- Confirm Emergency Level (Alert, Level 1,2, or 3)
- Secure access to emergency area (CVECO Code 6 activation). SPLP pipeline guidelines are a minimum area of 1.6km in all directions from a leak site if a vapor cloud exists.
- Recommend evacuations as required.
- Designate a media representative at the site
- Closely monitor environmental /personal impacts of the release
- Assess need for additional support at the scene and get additional resources from SPLP if warranted.

RESOURCE PROVIDED:

- Investigate leak location to confirm SPLP product leaking,
- Isolate pipeline,
- Verify and evaluate the severity of the leak,
- Assess situation, and CVECO Code activation,
- Maintain contact with Houston Control Centre, and
- Respond to requests from the Houston Control Centre – (800) 786-7440.
- Life safety,
- Emergency management,
- Environmental impacts and property loss,
- Technical management of the emergency site,
- Verification and evaluation of leak severity,
- Assist in evacuation and securing of the area,
- Decide if ignition is appropriate, and if so, initiate or recommend to local authorities,
- Serve as source of pipeline expertise,
- Document actions,
- Work with other responding agencies in incident management,
- Liaison with Municipal EOC Manager,
- Provide technical advice for media statement,
- Mobile first response team. Make decision to allocate resources to respond to emergency,
- Arrange travel to/from scene, and
- Notify and report internal/external.

TRAINING/SKILLS PROVIDED:

☐ Initial on scene personnel with initial IC designation/capabilities
☐ Detailed knowledge of SPLP Ethane delivery system.
☐ Knowledge of pipeline corridor (who shares pipeline corridors).
☐ Knowledge of pipeline product hazard.
☐ Ability to assist with pipeline isolation if required.
☐ Coordinate product removal, pipeline repairs and pipeline re-pressurization.
☐ Customer impact awareness and contacts.
☐ Knowledge of local emergency response plans
☐ Incident Command process
☐ CVECO code awareness and familiarity

EMERGENCY CONTACT:

Name [redacted] Name [redacted]	Phone # [redacted]

[redacted] **RESOURCE:**	[redacted] **Senior Maintenance Technician**

ROLE:

To respond to pipeline emergencies as support to the First Responder to assist once a leak has been identified.

RESOURCE PROVIDED:

Responsible to:

- ☐ Investigate leak location to confirm SPLP product leaking,
- ☐ Verify and evaluate the severity of the leak,
- ☐ Assist where appropriate with the isolation of the pipeline,
- ☐ Notifies and maintains contact with SPLP Sarnia Pipeline Supervisor. [redacted]
- ☐ Recommend CVECO Code Classification, and
- ☐ Serve as source of pipeline expertise

TRAINING/SKILLS PROVIDED:

Knowledge of product, hazards, pipeline facilities, emergency response plan, customer impacts and incident command process, and CVECO codes awareness.

EMERGENCY CONTACT:

[redacted]	[redacted]

SPLP RESOURCE:	**Incident Commander**

ROLE:

Focal point for facilitating the deployment of resources to the scene of pipeline emergencies as requested. Assists the Unified Command with the assembly of response groups and resources to the scene.

- ☐ To respond requests from [redacted] Incident Commander, [redacted]
- ☐ After the initial calls are made, reports to SPLP Incident Management Team and assembles staff as needed.
- ☐ Debriefs and reports on emergency.
- ☐ Notifies:
  - NEB (National Energy Board), 403-807-9473
  - MOE (Ministry of Environment), 1-800-268-6060
  - OEB (Ontario Energy Board), 1-888-632-6273 Press 0
  - TSB (Transportation Safety Board), 819-997-7887
  - TSSA Technical Standards and Standards Authority, 1-877-682-8772

RESOURCE PROVIDED:

Detailed knowledge of SPLP Business Policies
Knowledge of pipeline product and hazards
Interface with Emergency Operations Center for the County/Province
Customer impact awareness
Provides continued coverage to the Houston Control Centre.
Addresses resource request from Mutual Aid
Provides regular status updates to appropriate groups and individuals within the organization.

- Coordinates off-site media contact and inquiries referring them to the Sunoco Communications – Jeff Shields (215) 313-3056 (Mobile);.(215) 977-6056 (Office)
- ☐ Notifies other companies impacted.
- ☐ Ensures log of communications, times, etc. is kept.
- ☐ Arranges for continued role coverage during extended incidents.
- ☐ Initiates Repair Plan as required.
- ☐ Considers use of 3rd party expert.

TRAINING/SKILLS REQUIRED:

Knowledge of the Emergency Response Plan, business policies, product and hazards, EOC familiarity, Incident Command awareness, contacts and available resources, as well as crisis management skills and the ability to effectively communicate with all organizational levels

EMERGENCY CONTACT:

Name [redacted]	Phone # [redacted]
Name [redacted]	Phone # [redacted]

<u>SPLP Emergency Response Team (SPLP)</u>

Mobilized SPLP response team members will deploy to the local Incident Command Post to supplement the emergency response efforts.

SPLP RESOURCE:	**Incident Management Team**

ROLE: To supplement and support an initial response from [redacted] when an incident exceeds or has the potential to exceed local resources. This multi-person team will be activated by SPLP leadership and will cascade in to fulfill ICS positions as needed. Also to liaise with applicable regulatory agencies that may include but are not limited to:

Environment Canada
Transportation Safety Board of Canada (TSB)
National Energy Board Onshore Pipeline Regulations (NEB)
Ontario Ministry of Labour (MOL)
Ontario Parks Association (OPA)
Ontario Energy Board (OEB)

RESOURCE PROVIDED: Expertise and experience in all facets of SPLP business workings, emergency response for pipeline HVP incidents, and ICS roles and responsibilities, regulatory and environmental specialists. This team includes contractor technical support for HVP emergencies with a variety of equipment, and environmental expertise if needed for wildlife protection strategies, environmental impact assessment (air, groundwater, soil and/or water impacts). This includes current and historical analytical monitoring data and waste management support as needed.

TRAINING/SKILLS PROVIDED: Knowledge of the Emergency Response Plan, product and hazards, EOC familiarity, expertise with regard to interfacing with applicable pipeline system regulatory agencies, Incident Command awareness, HAZWOPER training, crisis management skills and the ability to effectively communicate with all organizational levels

EMERGENCY CONTACT:

[redacted]	[redacted]

<u>Chemical Valley Emergency Coordinating Organization (CVECO)</u>

The Chemical Valley Emergency Coordinating Organization (CVECO) is the mutual aid resource in the event of a pipeline emergency in the area. It is intended that [redacted] will become a member in this organization and will activate CVECO notifications and support any pipeline emergencies. Section V of the CVECO Manual (See **APPENDIX F**) covers incidents outside industry boundaries, e.g. pipelines.

<u>Government Agency or Other Support</u>

Various organizational partners outside of SPLP fulfill specific roles and bring to bear their own specified action plans during an emergency event. (See also **APPENDIX I**.) Provincial government departments may have a regulatory responsibility, expertise, or other resources available to support the [redacted] and/or local authority emergency to an industry incident. These departments/organizations include, but are not limited to:

Aamjiwnaang First Nations - can come in several forms of local knowledge, response capabilities, established communication processes, evacuation support, and recognized, familiar community leadership.

Canadian Coast Guard- **Fisheries and Oceans Canada** (DFO) has the lead federal role in managing Canada's fisheries and safeguarding its waters. **The Canadian Coast Guard** (CCG), a Special Operating Agency within DFO, is responsible for services and programs that contribute to the safety, security, and accessibility of Canada's waterways

Community Safety & Correctional Services- responsible for Emergency Management in Ontario, the coordinating Agency for Government emergency management.

Contractors- organizations under contract that bring specific support or expertise to an emergency response effort. These can be but are not limited to; response/clean up contractors, environmental experts, wildlife clean up organizations, public affairs specialists and/or waste management resources etc.

Emergency Management Services (EMS) - responsible for first responder duties during an incident.

Emergency Medical Assistance Team- a provincial field unit that can be requested by the health system in Ontario when health resources are significantly stressed by emergency or major incident from the Minister of Health and Long Term Care.

Environment Canada- responsible for the application of the Environmental Protection and Enhancement Act and the Water Act.

Heavy Urban Search and Rescue Team- group of specialized individuals with rescue skills supplemented by search, medical, and structural assessment resources combined in a mobile highly integrated team.

Mutual Aid Partners- partnerships formed through formal or informal agreements to extend support and services to sister organizations during an emergency. Examples of these are municipal organizations such as fire departments, or industry organizations that share emergency response equipment,

Ontario Energy Board (OEB) - the mission is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services that are cost effective. They have direct oversight of the Sarnia pipeline operations.

Ontario Ministry of Environment and Climate Change-- is responsible for protecting clean and safe air, land and water to ensure healthy communities, ecological protection and sustainable development for present and future generations of Ontarians.

Ontario Ministry of Labour- Through the ministry's key areas of occupational health and safety, the agency can support site safety needs during an emergency response- and may also be involved in the investigation from a workplace safety standpoint.

Ontario Ministry of Transportation- is the primary agency moving people and goods safely, efficiently and sustainably across the province. This agency can assist with establishing contacts to support a mass evacuation or identifying the best transportation routes available.

Provincial Emergency Operations Centre- responsible for the Coordination and Information Centre (CIC), the 24/7 emergency call centre for OEMA, Environment, Dangerous Goods, and the OER.

Royal Canadian Mounted Police (RCMP) - The RCMP is unique in the world since it is a national, federal, provincial and municipal policing body. As such it is a multi-faceted organization that can provide support in many areas of a response. It includes preventing and investigating crime; maintaining peace and order; enforcing laws; contributing to national security; and providing vital operational support services to other police and law enforcement agencies within Canada and abroad.

Transport Canada- Although this agency does not deal directly with transportation via pipeline, it does address transportation of dangerous goods, and oversees CANUTEC and Emergency Response Task Force that may provide some synergies during an ethane incident.

2.2 EMERGENCY PLANNING ZONE

The High Vapor Pressure Ethane pipeline which has a high vaporization rates expand into plumes of flammable vapor and follows topography with wind direction and will include all areas within 1.0 km (0.6 mi) of the pipeline. Emergency responders should be familiar with resident locations and local topography within the planning zone.

[redacted] will establish an emergency planning and response zone for the SPLP pipeline based on the location of the incident. The planning zone will be representative of the immediate area where losses can be minimized through appropriate and timely action.

Pipelines that are included in the Emergency Response are identified in Section 1.6

Table 2-2 EMERGENCY PLANNING ZONE

DEFINING THE HAZARD AREA

EMERGENCY PLANNING and RESPONSE ZONES

EMERGENCY PLANNING ZONE

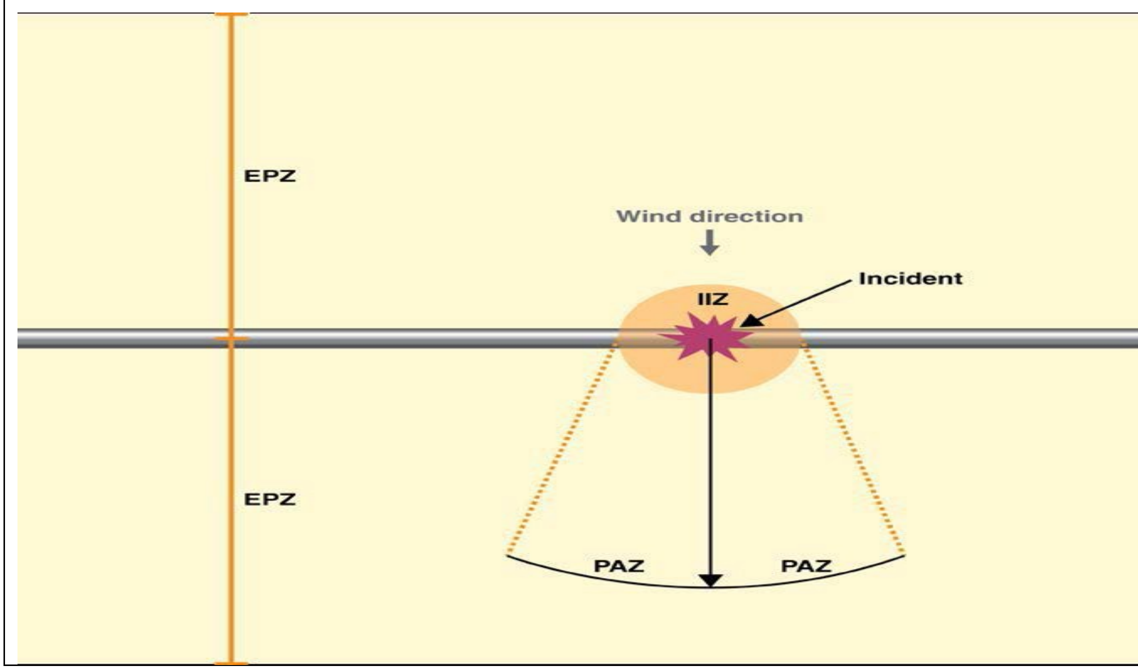
An Emergency Planning Zone (EPZ) is a geographical area surrounding the pipeline that requires specific emergency response planning. SPLP has applied the technical parameters covered in the EPZ analysis for HVP pipelines and has determined that the following EPZ distances for the selected pipeline diameters be used:

8"	700 meters

The measurements to be used are from the center of the pipeline to either side.

Initial Isolation Zone (IIZ) - the IIZ defines an area in close proximity to a continuous hazardous release where indoor sheltering may provide temporary protection due to the proximity of the release. If safe to do so, the company must work with local authorities to evacuate the residents from the IIZ.

Protective Action Zone (PAZ) - the estimated size of the PAZ is calculated using ERG. Immediately following a release of HVP product, the approximate size and direction of the PAZ can be determined using actual conditions at the time. Once monitoring equipment arrives, the actual size of the PAZ can be determined based on the monitored conditions.



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2.3 EMERGENCY LEVELS

A hazard is defined as "a physical situation with the potential for human injury, damage to property, damage to the environment, or some combination of these". Emergency levels define the hazard to the public from a High Vapor Pressure (HVP) product release and [redacted] ability to handle the emergency response. Each level has a different impact on the response and amount of resources required to resolve incident. Using common terminology in level identification should result in consistent interpretation of an emergency situation. Refer to Tables 1, 2, and 3 below for designating emergency levels. Then based on the Assessment Results from Table 3, actions for each emergency level can be ascertained.

The sequence of events and responses described in the flowcharts and tables herein are a guideline only, and response may vary depending on the nature and circumstances of the emergency. The Incident Commander/ Unified Command (IC/UC) will decide whether Table 3 appropriately assigned the correct level. The emergency level will then be communicated to all emergency responders and agencies as required.

Table 1. Consequence of Incident

Rank	Category	Example of consequence in category
1	Minor	• No worker injuries. • Nil or low media interest. • Liquid release contained on lease. • Gas release impact on lease only.
2	Moderate	• First aid treatment required for on-lease worker(s). • Local and possible regional media interest. • Liquid release not contained on lease. • Gas release impact has potential to extend beyond lease.
3	Major	• Worker(s) requires hospitalization. • Regional and national media interest. • Liquid release extends beyond lease—not contained. • Gas release impact extends beyond lease—public health/safety could be jeopardized.
4	Catastrophic	• Fatality. • National and international media interest. • Liquid release off lease not contained—potential for, or is, impacting water or sensitive terrain. • Gas release impact extends beyond lease—public health/safety jeopardized.

Table 2. Likelihood of incident escalating*

Rank	Descriptor	Description
1	Unlikely	The incident is contained or controlled and it is unlikely that the incident will escalate. There is no chance of additional hazards. Ongoing monitoring required.
2	Moderate	Control of the incident may have deteriorated but imminent control of the hazard by the licensee is probable. It is unlikely that the incident will further escalate.
3	Likely	Imminent and/or intermittent control of the incident is possible. The licensee has the capability of using internal and/or external resources to manage and bring the hazard under control in the near term.
4	Almost certain or currently occurring	The incident is uncontrolled and there is little chance that the licensee will be able to bring the hazard under control in the near term. The licensee will require assistance from outside parties to remedy the situation.

* What is the likelihood that the incident will escalate, resulting in an increased exposure to public health, safety, or the environment?

Sum the rank from both of these columns to obtain the risk level and the incident classification

Table 3. Incident Classification

Risk level	Assessment results
Very low 2-3	Alert
Low 4-5	Level-1 emergency
Medium 6	Level-2 emergency
High 7-8	Level-3 emergency

3.0 COMMUNICATIONS

3.1 INTRODUCTION

SPLP is committed to operating its business to the highest achievable standards to protect the health and safety of workers, the public and environment.

- ☐ The safe, timely deployment of trained employees to perform Emergency Response and remediation of SPLP Pipeline is paramount to our business. The ability to respond to pipeline emergencies is also integral to SPLP business planning. Emergency response ensures a timely and appropriate response to external pipeline emergencies and compliance with applicable laws (domestic and/or international) and industry and legal codes of practice.
- ☐ In the event of a pipeline emergency, releases must be reported at the first available opportunity, as soon as the responsible person knows about the release.
- ☐ In the event of a pipeline emergency, communication to the public will be initiated through the CVECO Code Notification Process. The appropriate CVECO Code will be issued by the Unified Command.
- ☐ Communication to the public of impending changes, e.g. evacuations, all clear will be managed by the local jurisdictional authorities (Police/Fire).
- ☐ Communication to SPLP Management will be the responsibility of the Contractor Incident Commander/delegate.
- ☐ Communication networks between the Incident Commander and County Incident Commander are the responsibility of the Contractor Incident Commander. The Contractor Incident Commander will ensure communication lines are clearly established. Communications between SPLP and the County EOC are the responsibility of the SPLP Incident Commander.
- ☐ A written report may be required to be submitted to the appropriate agency within seven days after the immediate report.
  SPLP is enlisted in the Ontario One Call System and [redacted] is a member of ORCGA (Ontario Regional Common Ground Alliance).

3.2 NOTIFICATION/ REPORTING RESPONSIBILITIES

EMEREGNCY NOTIFICATIONS

Information of an emergency situation may arise from different sources. These sources include:

- Process alarms (e.g. Leak Warn),
- Gas detectors,
- Equipment Alarms (Flow Rate, Pressure, Temperature, LEL),
- Company personnel,
- Regulatory personnel,
- Police,
- Public, and
- Pipeline Control Centre.

Once the initial notification is made, additional emergency notifications will take place across the [redacted]/SPLP system to ensure that all appropriate and required notification obligations are met.

[redacted] WILL contact SPLP with full details on any and all situations and remediation. When an emergency situation is detected, emergency notifications will take place.

TABLE 4- COMMUNICATIONS MATRIX

RESPONSES	ALERT	LEVEL 1	LEVEL 2	LEVEL 3
Communications				
Internal	Discretionary depending on Name policy	Notification of offsite management	Notification of offsite management	Notification of offsite management
External public	Courtesy at Name discretion	Mandatory for those who have requested notification within the EPZ	Planned and instructive in accordance with the specific ERP.	Planned and instructive in accordance with the specific ERP.
Media	Reactive as required	Reactive as required	Proactive media management to local or regional interest	Proactive media management to national interest
Government	Reactive as required. Notify EMO if public or media is contacted	Call local authority and Ontario Health Service (OHS) if public or media is contacted.	Name notify local authority , OHS, and TSB.	Name notify local authority , OHS, and TSB.
Actions				
Internal	On site, as required by Name	On site, as required by Name Initial response undertaken in accordance with the site-specific or corporate level ERP.	Predetermined public safety actions are underway, Corporate management team alerted and may be appropriately engaged to support on-scene responders.	Full implementation of incident management system.
External	As required by Name	As required by Name	Potential for multi-agency (operator, municipal, provincial, or federal response)	Immediate multi-agency (operator, municipal, provincial, or federal) response.
Resources				
Internal	Immediate and local. No additional personnel required.	Established what resources would be required.	Limited supplemental resources or personnel required.	Significant incremental resources required.
External	None	Begin to establish resources that may be required.	First responders and government agencies are likely to be directly involved.	Immediate and significant government agency involvement.
Pipeline Ownership	Notification to pipeline ownership Reactive as required if EMO, public , or media is contacted	Notification to pipeline ownership Reactive, depending on impact of incident.	Notification to pipeline ownership. Reactive, depending on impact of incident.	Notification to pipeline ownership. Reactive, depending on impact of incident.

DOWNGRADING THE LEVEL OF EMERGENCY- Once the incident improves, the decision to downgrade an emergency will be made by the Incident Commander in consultation with the applicable regulatory agency, (EMO, TSB), local authority, Provincial and/or State Emergency Management Services authorities.

Table 5- EMERGENCY CONTACTS:	
Houston Control Centre	(800) 786-7440
Contractor Incident Commander – Name [redacted] Mobile Home Office	Phone # [redacted] [redacted] [redacted]
Contractor Senior Maintenance Technician-Name [redacted] Mobile	Phone # [redacted]
Contractor Pipeline Manager- Name [redacted] Mobile Home	Phone # [redacted] [redacted]
Contractor Maintenance Planner Name [redacted] Mobile Office Home	Phone # [redacted] [redacted] [redacted]
Contractor Safety Specialist Name [redacted] Mobile	Phone # [redacted]
SPLP Pipeline Supervisor, Name [redacted] Mobile Office	Phone # [redacted] [redacted]
SPLP Manager, Name [redacted] Mobile Office	Phone # [redacted] [redacted]
CVECO Fax	(519) 332-2010 (519)332-2015
Union Gas – Utility Services	(877) 969-0999; Press 1
Transportation Safety Board – Occurrence Hotline Fax	(819) 997-7887 (819) 953-7876
National Energy Board – On Call Responder	(403) 807-9473
Ontario MOE Spills Action Center	(800) 268-6060 (ON Only) (416) 325-3000 (Outside ON)

Ministry of Labour	(877) 202-0008
Canadian Coast Guard	(800) 265-0237 (24 hours)
US Coast Guard	Primary (313) 568-9580 Non-urgent (313) 568-9564
Sun-Canadian Pipeline Control Center	(800) 263-6641
[redacted]l, SCPL	[redacted]
[redacted], SCPL	[redacted]
[redacted], SCPL	[redacted]
[redacted], SCPL	[redacted]
Ontario Energy Board	(888) 632-6273 Press 0
St. Clair Township Fire Department [redacted], Fire Chief	911 (519) 481-0111
Ontario Provincial Police Business	(888) 310-1122; 519-680-4600(admin Office)
City of Sarnia Fire Services [redacted], Fire Chief Fire Administration	(519) 332-0330, ext. 4302 (519) 332-1122
Sarnia Police Services/CEMC	(519) 344-8861, ext. 5206; (519) 344-8861 Press 0
Aamjiwnaang First Nations Environment Department- Primary Contact. Chief [redacted] Mobile Office If Chief [redacted] is not available contact: [redacted] - Office or Mobile or [redacted] - Office Mobile -	 (519) 384-8410 (519) 336-8410 X 236 (519) 336-8410 X 243 (519) 330-8749 (519) 336-8410 X 288 (519)330-2644

REGULATORY NOTIFICATION REQUIREMENTS

NATIONAL ENERGY BOARD (NEB) – NEB 24hr Incident Line 1- 403-807-9473

Notification of an Emergency Situation
The NEB has a formal relationship with the Transportation Safety Board (TSB) in the form of a Memorandums of Understanding (MOU), which came into effect in 1994 and have adopted a single window reporting approach, however, in some areas, the TSB reporting requirements are somewhat different than the NEB requirements. The purpose of the MOU is to coordinate activities when both parties attend or investigate an incident/ emergency occurrence. The NEB is the lead regulatory agency in emergency situations that occur on NEB-regulated facilities or operations and the TSB is the lead investigator for determining the cause and contributing factors leading to an incident/emergency. A company designated representative shall immediately notify the NEB of any incident relating to the construction, operation or abandonment of its pipeline and shall submit a preliminary and detailed incident report to the NEB as soon as is practicable. Any incident must also be reported to the TSB Reporting Hotline

NEB EVENT REPORTING SYSTEM (On Line Event Reporting System - OERS)
The events that are reportable using the online reporting system are:

- Incidents under the *NEB Onshore Pipeline Regulations* (OPR),
- Serious accidents or incidents under the *Canada Oil and Gas Geophysical Operations Regulations,*
- Emergencies or accidents under the *Canada Oil and Gas Installation Regulations/Oil and Gas Installation Regulations*,
- Accidents, illnesses, and incidents under the Canada Oil and Gas Diving Regulations/Oil and Gas, and
- Diving Regulations.

In the event that OERS is unavailable, companies are directed to report events to the TSB Reporting Hotline.

TRANSPORTATION SAFETY BOARD OF CANADA (TSB)- TSB 24hr Hot Line at 819-997-7887

Where an event qualifies as a significant incident and must be reported immediately, companies are required to notify TSB.

INSTRUCTIONS TO CALL THE TSB HOTLINE
All significant incidents must be reported via the TSB line on National Energy Board (NEB) regulated pipelines and facilities, report all events in the NEB's Online Event Reporting System (OERS) (https://apps.neb-one.gc.ca/ers) and the kinds of events to report. For example this might include:

A significant incident is an acute event that results in:

- Death,
- Missing person (as reportable pursuant to the *Canada Oil and Gas Drilling and Production Regulations (DPR)* under the *Canada Oil and Gas Operations Act (COGOA)* or the *Oil and Gas Operations Act (OGOA),*
- A serious injury (as defined in the OPR or TSB regulations),
- A fire or explosion that causes a pipeline or facility to be inoperative,
- A LVP hydrocarbon release in excess of 1.5 m3 that leaves company property or the right of way,
- A rupture, or
- A toxic plume as defined in CSA Z662

Note: A rupture is an instantaneous release that immediately impairs the operation of a pipeline segment such that the pressure of the segment cannot be maintained. For all other events that must be reported immediately, companies must report within twenty - four hours of occurrence or discovery to the online reporting system. For additional details on the TSB reporting requirements, refer to the TSB website **www.tsb.gc.ca/eng/incidents-occurance/pipeline/inex.asp**

ENVIRONMENT SPILL REPORTING REQUIREMENTS –

WHEN TO REPORT

The discharge of a substance is reportable under Environmental Management and Protection Act (EMPA) 2002 when the discharge is in an amount, concentration or level or at a rate of release that may cause or is causing an adverse effect, unless otherwise expressly authorized. An adverse effect is impairment of, or damage to the environment, or harm to human health.

The spill of a pollutant is reportable under The Environmental Spill Control Regulations when the pollutant is in an amount equal to or exceeding the specified amount and time period listed in the Appendices of the Regulation. Immediate reporting helps to ensure adverse effects are addressed properly and minimized, if possible, to safeguard the public and protect the environment.

WHO MUST REPORT

The person who discharges, allows the discharge, or has control of the substance discharged is responsible for reporting. Police officers and employees of municipalities or government agencies are also required to report.

HOW TO REPORT

Discharges must be reported to the Minister at the first available opportunity, as soon as that person knows or ought to know of the discharge. Reports can be made by phoning **1-800-667-7525** (toll-free, 24 hours-a day); or in person during regular office hours at any Ministry of Environment office.

If the spill exceed defined maximum limits a written report must be submitted to the Minister within seven days after the immediate report.

3.3 NOTIFICATION BETWEEN COMMAND CENTRES

In the event that notification is required between Command Centres, the communication protocol will be by phone. Depending on the incident, the Contractor Incident Commander may choose to send another [redacted] manager to the Local Emergency Management EOC to facilitate communication and/or the Local Emergency Management may choose to send a local representative to the Incident Command Post for the same purpose. [redacted] will provide if requested, one or more pipeline technicians to respond to the local EOC to enhance communication and understanding of the incident and associated progress for containment. The communication frequency will depend on the size and circumstances of the incident.

3.4 COMMUNICATION TOOLS

Pipeline Emergency Response requires extensive use of mobile and static communication systems. This section describes the alternate and complementary systems currently employed by the Contractor.

- **(800) 786-7440** on signs in Ontario area ring into Houston Control Centre
- Mobile Telephones
- Radios

3.5 POST EMERGENCY COMMUNICATIONS

Once the emergency is over, there are a number of follow-up activities that should be considered, e.g. communication to the public, communication to Regulatory bodies having jurisdiction, emergency debriefing, area restoration, CVECO updates, site updates, etc.

AFTER A Level 3 EMERGENCY, A NUMBER OF ITEMS WILL BE CONSIDERED:

- Debriefings,
- Critical incident stress debriefing of the response personnel and for members of the public that may have been significantly impacted by the emergency,
- Establishing an information center within the community where the emergency occurred to answer any questions posed by the public, and
- Correspondence with media, providing details of the investigation into the incident that may be pertinent to the public as they become available.

INCIDENT INVESTIGATION

The SPLP Incident Commander will establish timing to complete an incident investigation Root Cause Analyses (RCA). The incident investigation process will identify the RCA of the event, as well as, identify measures to prevent recurrence.

RESPONDER DEBRIEFING

Immediately after the emergency, the SPLP Incident Commander will review and evaluate the response with the personnel involved. This review will focus on improvements to the response procedures and equipment used as well as the effectiveness of the lines of communication. The review should include response agencies or other industry personnel who assisted with the emergency.

PUBLIC DEBRIEFING (By SPLP)

When the public is impacted, they will be debriefed <u>as soon after the emergency as possible</u>, to answer any questions or concerns. Of prime concern will be the actions that the operator is taking to ensure another incident does not happen again. Although the operator may not be able to answer all concerns at the time, it is important to meet with the public immediately after the emergency to identify their concerns and to assure them that their questions will be answered once a proper evaluation of the incident has been completed.

The Public Information Officer will fully support any efforts to keep the public apprised of an emergency situation in conjunction with the Unified Command.

CRITICAL INCIDENT STRESS DEBRIEFING
The Unit Leadership Representative is responsible for evaluating the need and initiating Critical Stress Debriefing. This will be done through the Sarnia Fire Department.

The Sarnia Fire Department/Sarnia Police Service have a Fire Service Critical Incident Team.

The Contractor Incident Commander can access this service by calling Sarnia Police Services at 519-344-8861 and then dial "0".

They will then ask you four questions:

1. Your name and telephone number,
2. Agency name and telephone number,
3. Possible back-up number (i.e., mobile), and
4. Nature of incident.

Fire Service Critical Incident Team
C/O 240 East Street North
Sarnia, Ontario
N7T 6X7

Resources to assist with Critical Incident Stress Management can be obtained at:

Sarnia Fire Administration (519) 332-1122

EMERGENCY RESPONSE ACTIVITY DEBRIEF

The emergency response debrief is used to evaluate the incident looking for area that 'went well' as well as areas for improvement. Debriefs should be done as soon after the incident as possible. Participation in the debrief should include all the responders so as to get a total response review.

1	**Name of Emergency Incident:**		
	ITEM	YES	N/A
2	**What went well:**		
	ERT Incident Command		
	Response		
	Unit Information		
	Water supply		
	Communications		
	Fire control equipment		
	Accounting for people		
	Securing unit		
	Rehabilitation of squad (feeding, Gatorade, oxygen, etc.)		
	Outside assistance, Police (road control), etc.		
	Medical/dispensary		
	Other		
3	**Areas for Improvement:**		
	ERT Incident Command		
	Response		
	Unit Information		
	Water supply		
	Communications		
	Fire control equipment		
	Accounting for people		
	Securing scene		
	Rehabilitation of squad (feeding, Gatorade, oxygen, etc.)		
	Outside assistance, Police (road control), etc.		
	ETM/dispensary		
	Other		
4	**Other comments on incident:**		
5	**Recommendations:**		
6	**Resources Restored:**		
	(i.e. Response Equipment, Fire Rescue, Medical, Hazmat)		

4.0 EMERGENCY RESPONSE ACTIVATION

4.1 INTRODUCTION

The plan may be initiated as a result of:

- Low pressure alarm activated on any of the high vapor pressure or low pressure pipelines,
- Phone call to the Houston Control Centre, from the public, police, fire authorities or other industrial company representative in the Chemical Valley, or
- Phone call from SPLP emergency responding agency representative.

The panel operator would refer to the attached Block Valve closing policy (**APPENDIX A**) for direction, if required.

4.2 GUIDELINES: CONTRACTOR ERT RESPONSE to PIPELINE LEAK

Step 1 Record details of leak
- location
- leak type vapor/liquid
- caller name/return phone number, etc.

Step 2 Immediately notify SPLP.
Step 3 Notify customers for potential of shutting down pipeline.
Step 4 Immediately dispatch the Contractor's ERT's to area of leak to verify product (may not be SPLP pipeline).
Step 5 Initiate appropriate CVECO Code
Step 6 Initiate call to SPLP Incident Commander/Pipeline Supervisor (Emergency Contact List Section 6).
Step 7 Leak confirmed, Pipeline Control Room Operator closes block valves as appropriate Incident Commander Activated
Step 8 Is CVECO Code appropriate? Refer to Section 3.9
Step 9 Pipeline shutdown, de-pressured product containment and control as per environmental procedure.
Step 10 Pipeline secured and all clear initiated. Note: Only the Police or Fire Chief will initiate an All Clear in the community.
Step 11 Repair plan developed, approved and initiated.
Step 12 Pipeline operation restored.
Step 13 Complete cleanup of area.

Note: See Decision Flow Charts, Section 5.3 Emergency Response Activation

4.3 EMEREGNCY ACTIONS HVP PRODUCT PIPELINES:

4.3.1 BASIC ACTIONS –

Regardless of the magnitude of the emergency, the initial response should always be the same because HVP pipelines present hazards that warrant more specific response actions at the site. So, determine whether or not responders should intervene and what strategic objectives and tactical options should be pursued to control the problem at hand. Take actions to minimize the impact of the release.

- **Shut off the flow to pipeline** (control room personnel)
- **Stop leak if you can do it without risk**
- Allow fire to burn out if fire is contained and exposures are protected
- Eliminate all ignition sources in the immediate area
- Prevent entry into waterways, sewers, or confined spaces
- Ground all equipment used for handling the product
- Use non-sparking tools to collect absorbed material
- Collect, prioritize, and manage hazard data and information from all sources, as appropriate, including:
  - ✓ Ethane produces hazardous vapors, which are ignitable from a distance with possible flashback. Personal protective equipment is required in all cases.
  - ✓ Technical reference manuals, and information sources (i.e., Emergency Response Manual),
  - ✓ Technical Information Specialists (i.e., Pipeline Industry or Facility Representatives),
  - ✓ Safety Data Sheet (See **APPENDIX C**), and
  - ✓ Air monitoring and detection equipment.

4.3.2 PROCEDURES FOR FIELD LOCATION OF A PIPELINE LEAK:

Before travelling to a suspected leak site, ensure that you have a reliable method of communication (radio and/or mobile telephone) and a Pipeline Emergency Response Manual.

- Know where you are at all times and update the Houston Control Centre periodically. (Update timing to be determined by onsite manager.)
- Ensure that you are a safe distance from the pipeline at all times – 1 km (0.6 mi) or more, Pipeline Security [redacted]
- When a leak location is confirmed, relay all information back to the Incident Commander and restrict travel into the area where possible until municipal services arrive. Request CVECO CODE 9 to be activated.

4.3.3 IC/UC BASIC RESPONSIBILITIES DURING PIPELINE LEAK:

- Secure access to emergency area. SPLP emergency guidelines are to secure a minimum area of 1.6 km (1.0 mi) in all directions from a leak site if a vapor cloud exists.
- When minimizing the impact of the release, the following must be considered:
  - ✓ Ignition of vapor cloud – IC/UC will determine need for the ignition of vapor clouds.
  - ✓ Use nitrogen to push HVP product past the leak point. Product is to be flared at a block valve site or pushed through an open block valve to the storage facilities. In the latter case, when the nitrogen/HVP product interface reaches a block valve, gas testing will confirm this valve would be closed.
- Recommend evacuations as required.
- Work co-operatively with other emergency response organizations. Most provincial, government and local emergency response agencies may not be familiar with products. Incident Commander must communicate and co-operate with these agencies to ensure safe, appropriate and timely response to the emergency. (Each commander should have adequate supply of SDS sheets.)

Then depending on the situation, follow the general guidance provided in Table 6

4.3.4 DISCIPLINE APPROACH TO AN EMERGENCY (Taken out of CAN/CSA-Z731-95)

BLOCK VALVE CLOSING (Sunoco Operations)

PURPOSE

The purpose of this policy is to provide the SPLP Technicians with a guideline on when to close pipeline block valves in emergency situations. The operating technician must in all emergency situations use their experience and discretion. Pipeline Security [redacted]. Management commits to providing the necessary training, simulations, drill etc. to ensure that operating technicians are competent on pipeline operation. Refer to P&ID **APPENDIX H**

POLICY

1. When a leak call is confirmed by any Contractor ERT.
2. When a leak call is received from a recognized public authority such as:
    - Police / Fire Chief 911 / Code 6
    - County Emergency Response authority
    - This call must be verified with a return phone call to a phone number identified in the Pipeline Emergency Response Manual.

2\. When a leak call is received from an industrial company representative in the Chemical Valley.

4\. When a leak is called in by someone in the public and verified by the Contractor.

The pipeline panel operating technician must follow the appropriate operating procedure, notifying customers of the situation.

TABLE 6 BASIC RELEASE MITIGATION PROCEDURES- NGLs

TYPE	MITIGATION PROCEDURE
Failure of Pump or Valve	1. Call PCC and get out- evacuate others safely 2. Notify local fire and police departments through 911. 3. ISCL will shut down operations. 4. Eliminate sources of vapor cloud ignition by shutting down all engines and motors. *5.* Follow *SPLP's Liquefied Petroleum Gases Guidelines (HS-G-030)* 6. Establish a safe perimeter.
Piping Rupture/Leak (under pressure an no pressure)	1. Hit E-Stop and get out- evacuate others safely 2. Notify local fire and police departments through 911. 3. ISCL will shut down operations. 4. Eliminate sources of vapor cloud ignition by shutting down all engines and motors. *5.* Follow *SPLP's Liquefied Petroleum Gases Guidelines (HS-G-030)* 6. Relieve pressure by flaring if safe to do so.
Manifold Failure	1. PCC and get out- evacuate others safely 2. Notify local fire and police departments through 911 3. ISCL will shut down operations. 4. Eliminate sources of vapor cloud ignition by shutting down all engines and motors. *5.* Follow *SPLP's Liquefied Petroleum Gases Guidelines (HS-G-030)* 6. Relieve pressure by flaring if safe to do so
Fire/Explosion	1. PCC and get out- evacuate others safely 2. Notify local fire and police departments through 911. 3. ISCL will shut down operations. 4. <u>DO NOT</u> extinguish fire. 5. Follow SPLP's Liquefied Petroleum Gases Guidelines (HS-G-030) 6. Allow fire professionals to protect adjacent property and assets.

4.3.4 BASIC ACTIONS BY POSITION –

On notification of an emergency incident occurrence, follow emergency response procedures according to established Alert, Level 1, 2 and 3 Emergencies under SPLP Pipeline Emergency Response Plan found in Table 7

TABLE 7: INCIDENT RESPONSE (ALERT & LEVEL 1)

			ACTIONS: All activities associated with an ALERT Level would be required supplemented by the following response procedures.	
Position	**ALERT - Internal Actions**	**ALERT External Public**	**LEVEL 1 - Internal Actions**	**LEVEL 1 External Public**
First On-Scene	• Assess the situation for safe approach. • Determine the appropriate emergency level. • Secure access. • Eliminate source of leak if possible. • Determine and communicate location of field command post. • Contact Houston Pipeline Control Center to isolate if required. • Contact Pipeline Operations and Maintenance Team Leader. • Gather information for incident investigation.	• Determine immediate risk to public. Determine CVECO Code activation	Interface with Pipeline Control Room • If leak has been validated, and is not able to be isolated at the field location, determine wind direction, speed, & dispersion characteristics • Maintain safety perimeters • If leak has been slowed or stopped, downgrade the emergency level back to an Alert – only after consultation with applicable Provincial / State regulatory agency (i.e, OEM, TSB, and IC).	• Take necessary actions to reduce any risk to the public or environment if release has potential to leave lease/site. • If leak is in St Clair County, determine zones potentially impacted and communicate with EOC • If leak increases the risk to the public – elevate to a Level 2 emergency.
Name Incident Commander (May be First on Scene)	• Establish or report to the field command post. • Take command of the command post. • Verify wind direction and speed and evaluate dispersion and risk to public. • Establish air monitoring requirements and assign monitoring duties to Pipeline Technicians. • Verify Emergency Level and communicate to Houston Control Room. • Assess isolation options and request appropriate resources (flares etc.) through the Pipeline Operations and Maintenance Team Leader.	• Determine if required to notify Local Emergency Authorities. Determine CVECO Code activation	• Communicate with the EOC on the nature and status of the incident and tactical response operations, i.e. wind direction, speed and relevant product size and dispersion characteristics. • Communicate recommendations to SPLP Operations and Maintenance Team Leader.	• Liaison with external emergency support services if they are requested and arrive on site.

ACTIONS: All activities associated with an ALERT Level would be required supplemented by the following response procedures.

Position	ALERT - Internal Actions	ALERT External Public	LEVEL 1 - Internal Actions	LEVEL 1 External Public
	• Allocate resources to respond to emergency (Mobilize response teams as appropriate).			
[redacted] **Senior Maintenance Coordinator**	• Contact EOC manager and apprise them of the situation. • Activate Pipeline Team Emergency Call in if warranted. • Determine flaring options if leak is validated. • Contact Environment and Regulatory Team and communicate the emergency level. • Dispatch other pipeline technicians if warranted. • Follow through with Incident investigation.	• Determine immediate risk to public. • Consider notifying Pipeline Ownership	• Establish communication with the EOC Manager and advise them of the situation. • Activate Local Pipeline Incident Mgmt Team if warranted. • Verify closest isolation valves, and commence flaring if required.•	• Ensure required contact is made with local authority, police, the local Health Services Agency, government agencies, and support services required to assist with initial response if the hazardous release goes off site and has the potential to impact the public or if [redacted] has contacted members of the public or the media. Consider notifying Pipeline Ownership
	• Conduct scene survey, assess situation, report and prioritize activities and take required action to protect the safety of people, property and the environment. • Establish a safety perimeter through LEL detector monitoring. • Contact Houston Pipeline Control Room Operator. • If leak cannot be isolated, establish On Scene Command Post. • If there is no risk to the public, maintain safety perimeter	• Establish a safety perimeter through LEL detector monitoring.	• Take direction from [redacted] on site Incident Commander. • Close or verify closed, the closest upstream and downstream valves. • Set up flares and commence flaring if required. • Contact Municipal Director of EMS / Emergency Management • Communicate status of incident to EOC Manager	•. Maintain the safety perimeter through LEL detector monitoring. • Identify any special needs.
Pipeline Control Center	• Isolate pipeline upstream and downstream if required. • Contact Pipeline Operations and Maintenance Team Leader or Designate • If Leak is Validated by Leak Warn then request EOC notification.		• Isolate pipeline upstream and downstream if required. • Contact Pipeline Operations and Maintenance Team Leader or Designate • Maintain stable operations and isolate as required.	

ACTIONS: All activities associated with an ALERT Level would be required supplemented by the following response procedures.

Position	ALERT - Internal Actions	ALERT External Public	LEVEL 1 - Internal Actions	LEVEL 1 External Public
	• EOC designate will contact EOC Manager and apprise them of the situation. Incident Commander • Monitor leak detection system. • Maintain stable operations.		• Incident Commander • Contact supply/customer plants and advise them of the situation and operational restrictions.	
Communications Officer			• Maintain contact between [redacted] Incident Command on scene and EOC.	Provide info to UC
Liaison- Regulatory		• • Contact regulator of product released. • Alert regulator of venting and/or flaring requirements.	• Assess additional Regulatory team requirements.	• Notify applicable Provincial / regulatory agency i.e,OEM, TSB, local authority, i.e. Ontario Health Services, police, if required for initial response, and if public or media is contacted and after internal resources have been communicated with and activated to confirm the level of emergency and convey the specifics of the incident.
EOC Manager (Sarnia Local)	Determine support requirements and activate complete EOC if any potential for escalation exists above Alert Level.		• Activate the EOC • Determine EOC requirements. • Prepare to activate Communicator System for St Clair County, if required. • Determine availability of [redacted] representative to travel to Local Authority EOC if required.	
Operations Section Chief	• Work with the EOC Communications Leader to ensure that all pertinent information is communicated. • Act as a fundamental resource to the EOC Manager to ensure all information has an appropriate action taken. • Acts as a liaison between the field activities and EOC management group		• Work with the EOC Communications Leader to ensure that all pertinent information is communicated. • Act as a fundamental resource to the EOC Manager to ensure all information has an appropriate action taken. • Acts as a liaison between the field activities and EOC management group • Identify critical actions to protect critical assets	

ACTIONS: All activities associated with an ALERT Level would be required supplemented by the following response procedures.

Position	ALERT - Internal Actions	ALERT External Public	LEVEL 1 - Internal Actions	LEVEL 1 External Public
			• Assist with development and execution of Incident Action Plan Is responsible for managing and supporting all emergency response operations, including rescue, fire suppression, hazardous materials, security, and environmental response • Supervise / support EOC Communications Leader • Manage security aspects of the incident •	
Planning Section Chief	• Ensures appropriate incident documentation Calculate leak volumes for reporting to regulator. Maintain an ongoing display of emergency status and actions taken by the response team (i.e. Story Board)		• Provides specific information related to the impacted areas. Specific Data related to design capacity. • Provides calculated rated flow based on known information. • Ensures appropriate incident documentation • Develops Incident Action Plan Develop and implement business continuity plans and business resumption plans Calculate leak volumes for reporting to regulator. Maintain an ongoing display of emergency status and actions taken by the response team (i.e. Story Board	• Continue plume tracking /monitor potentially impacted Public using Resident stakeholder database. • Maintain communication with regulatory bodies to validate emergency level.
Logistics / Finance Section Chief			Is responsible for timely, cost-effective procurement, delivery, and staging of essential resources • Manages all costs incurred during incident response	• Manages Third Party claims
Public Information Officer			• Prepare standby statement for the media if required. • Prepare statement for individuals in the impacted EPZ.	• Prepare media statement. • Coordinate any media releases with regulatory bodies prior to release.

ACTIONS: All activities associated with an ALERT Level would be required supplemented by the following response procedures.

Position	ALERT - Internal Actions	ALERT External Public	LEVEL 1 - Internal Actions	LEVEL 1 External Public
				• Contact impacted residents who have requested early notification.
EOC Liaison IC	• Act as link to On Scene Incident Command and EOC.	• In St Clair County, activate the communicator system with the resident data base to notify residents of incident and what appropriate actions to take. • Manages radio and telephone communication to and from EOC.	• Act as link to On Scene Incident Command and EOC.	• In St Clair County, activate the communicator system with the resident data base to notify residents of incident and what appropriate actions to take. • Manages radio and telephone communication to and from EOC.

INCIDENT CLASSIFICATION RESPONSE (LEVEL 2 & LEVEL 3)

	ACTIONS: All activities associated with LEVEL 1 would be required supplemented by the following response procedures.		ACTIONS: All activities associated with LEVEL 2 would be required supplemented by the following response procedures.	
Position	**Level 2 - Internal Actions**	**Level 2 External Public**	**LEVEL 3 - Internal Actions**	**LEVEL 3 External Public**
First On-Scene	Interface with Houston Pipeline Control Center and call 911 requesting services.	• Determine immediate risk to public.	Same As Level 2	Same As Level 2
[redacted] **Incident Commander (May be First on Scene)**	• Establish contact with 911 Emergency Services and direct to site. • Communicate Level of Emergency to EOC. • Communicate recommendations to Pipeline Operations and Maintenance Team Leader.	• Incident Command will establish EOC interface as they deem required. • Develop a Unified Command Post or relinquish and support Local Authorities Command Post. • Work with Local Authorities to determine Shelter in Place or Evacuate recommendation, block locations and determine plume ignition options. • •	• Communicate elevated level to EOC. •	• Support Local Incident Command Post. • Continue to maintain safety perimeter. • Continue assisting with evacuation or notification. • Support in all aspects as with Level 2.
Operations Section Chief	• Is responsible for managing and supporting all emergency response operations, including rescue, fire suppression, hazardous materials, security, and environmental response • Assist with development and execution of Incident Action Plan Drive to site as required. • Maintain communication with the EOC Manager and advise them of the situation.	• Call and maintain contact with Emergency Management Regional Field Officer responsible for contacting Regional Health Authority and all other Government Agencies and Emergency Broadcast notifications. • Notify Pipeline Ownership	• Is responsible for managing and supporting all emergency response operations, including rescue, fire suppression, hazardous materials, security, and environmental response • Supervise / support EOC Communications Leader • Manage security aspects of the incident	• Maintain contact with Emergency Management Regional Field Officer responsible for contacting Regional Health Authority and all other Government Agencies and Emergency Broadcast notifications. • Provide [redacted] Occupational Health contact for Regional Health Authority interface.

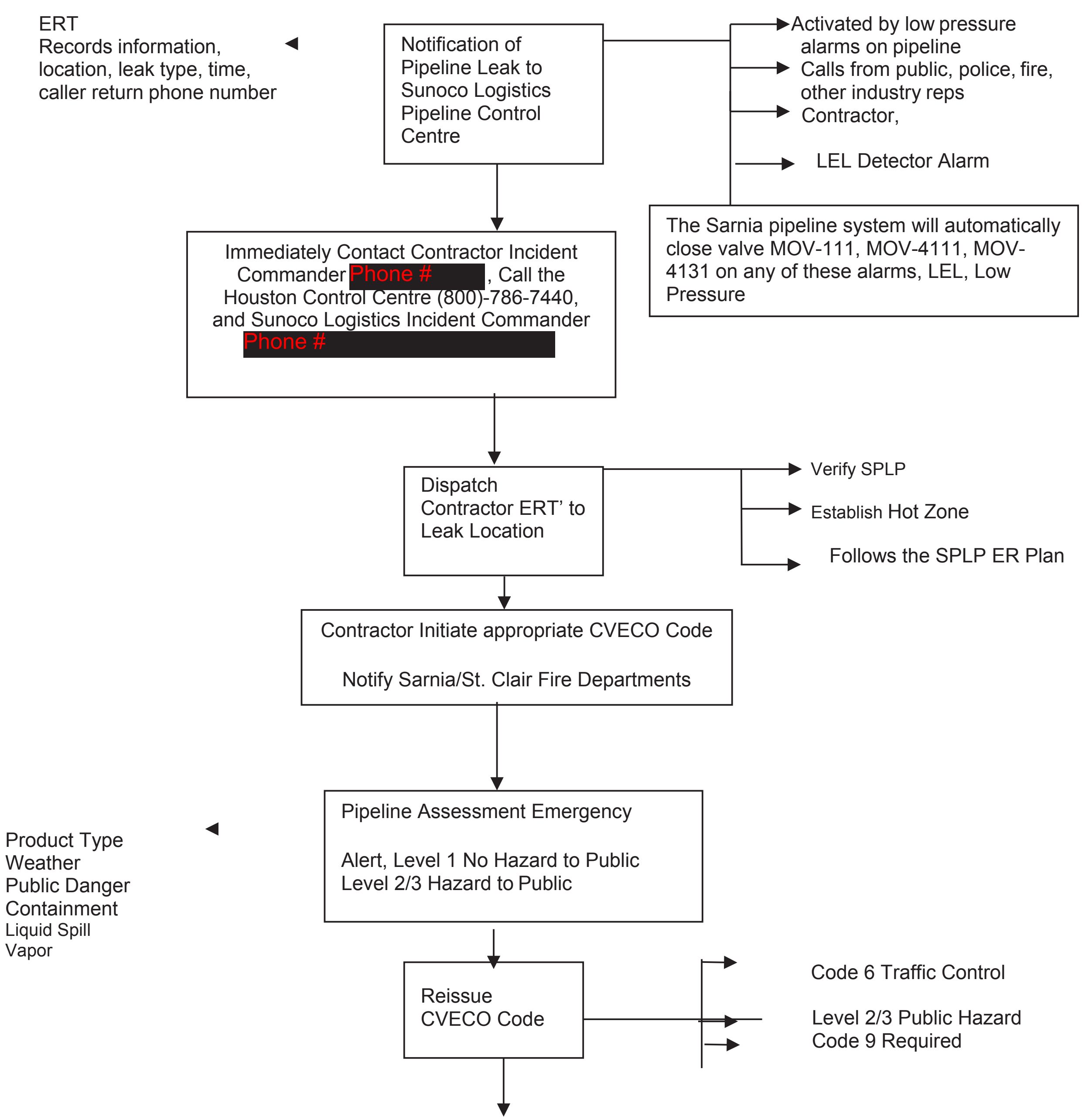
Position	Level 2 - Internal Actions	Level 2 External Public	LEVEL 3 - Internal Actions	LEVEL 3 External Public
	ACTIONS: All activities associated with LEVEL 1 would be required supplemented by the following response procedures.		**ACTIONS: All activities associated with LEVEL 2 would be required supplemented by the following response procedures.**	
	• Act as resource of the Name Incident Command.		• Assist with development and execution of Incident Action Plan EMS Support • Maintain communication with Local EOC. • Install Nitrogen purge to sweep line. • Continue flaring if warranted.	
Pipeline Technician	• Take direction from OSC • Ignite plume if authorized by UC • Continue flaring or set up flares at the closest upstream and downstream location and begin flaring product as required.	• Set up road blocks as required and maintain a safety perimeter through LEL detector monitoring.	• Take direction from on-site command post. • Continue flaring as required. • Advise Incident Commander of any change of conditions. • Install Nitrogen purge to sweep line if required.	• Maintain a safety perimeter and adjust if required.
Pipeline Control Room	• Maintain stable operations. • Activate secondary isolation as required.		• Maintain stable operations. • Monitor Pressures and manage system operations	
Liaison Officer	• Act as link to On Scene Incident Command and EOC.• Provide on scene assistance as requested by IC/UC.	• Liaison with external Government Regulatory Agencies as required.	• Act as link to On Scene Incident Command and EOC.	• Liaison with external Government Regulatory Agencies as required.
EOC Manager	• Has overall accountability to ensure the emergency is managed from a local perspective. • Determine EOC requirements.	• Dispatch EOC representative to Name ICP if requested. • As requested by Incident Command, activate emergency Communications System to	• Determine EOC requirements. • Provide direction to the EOC.	• Dispatch EOC representative to Name ICP if requested. • Manages radio and telephone communication to and from EOC. • As requested by Incident Command, activate emergency Communications System to impacted

	ACTIONS: All activities associated with LEVEL 1 would be required supplemented by the following response procedures.		**ACTIONS: All activities associated with LEVEL 2 would be required supplemented by the following response procedures.**	
Position	**Level 2 - Internal Actions**	**Level 2 External Public**	**LEVEL 3 - Internal Actions**	**LEVEL 3 External Public**
	• Provide direction to the EOC. • Communicate with SPLP management and apprise them of the situation.	impacted zones within the High Density Area in St Clair County. • Initiate Shelter in Place or evacuation as required. • Work with St Clair County Emergency Management for Broadcast Message. • Update the EMO and local Emergency Services Agencies for the Sarnia Pipeline incident. • Update the NEB, TSB, and local Emergency Management team for the Pipeline incident. • Manages radio and telephone communication to and from EOC.	• Contact Pipeline owners and apprise them of the situation. • Update status of incident to pipeline owners • Prepare for any back-up resources & accommodations • Update the Municipal Director of Emergency Management	zones within the High Density Area in St Clair County. • Initiate Shelter in Place or evacuation as required. • Work with St Clair County Emergency Management for Broadcast Message.•
Planning Section Chief	• Provides specific information related to the impacted areas. Specific Data related to design capacity. • Provides calculated rated flow based on known information. • Ensures appropriate incident documentation • Develops Incident Action Plan Maintain an ongoing display of emergency status and actions taken by the response team. • Supports all Sections of the ICP administratively	• Continue plume tracking /monitor potentially Impacted Public • Maintain communication with regulatory bodies to validate emergency level.	• Provides specific information related to the impacted areas. Specific Data related to design capacity. • Provides calculated rated flow based on known information. • Ensures appropriate incident documentation • Develops Incident Action Plan • Maintain an ongoing display of emergency status and actions taken by the response team.	• Continue plume tracking /monitor potentially impacted Public using Resident stakeholder database. • Maintain communication with regulatory bodies to validate emergency level.

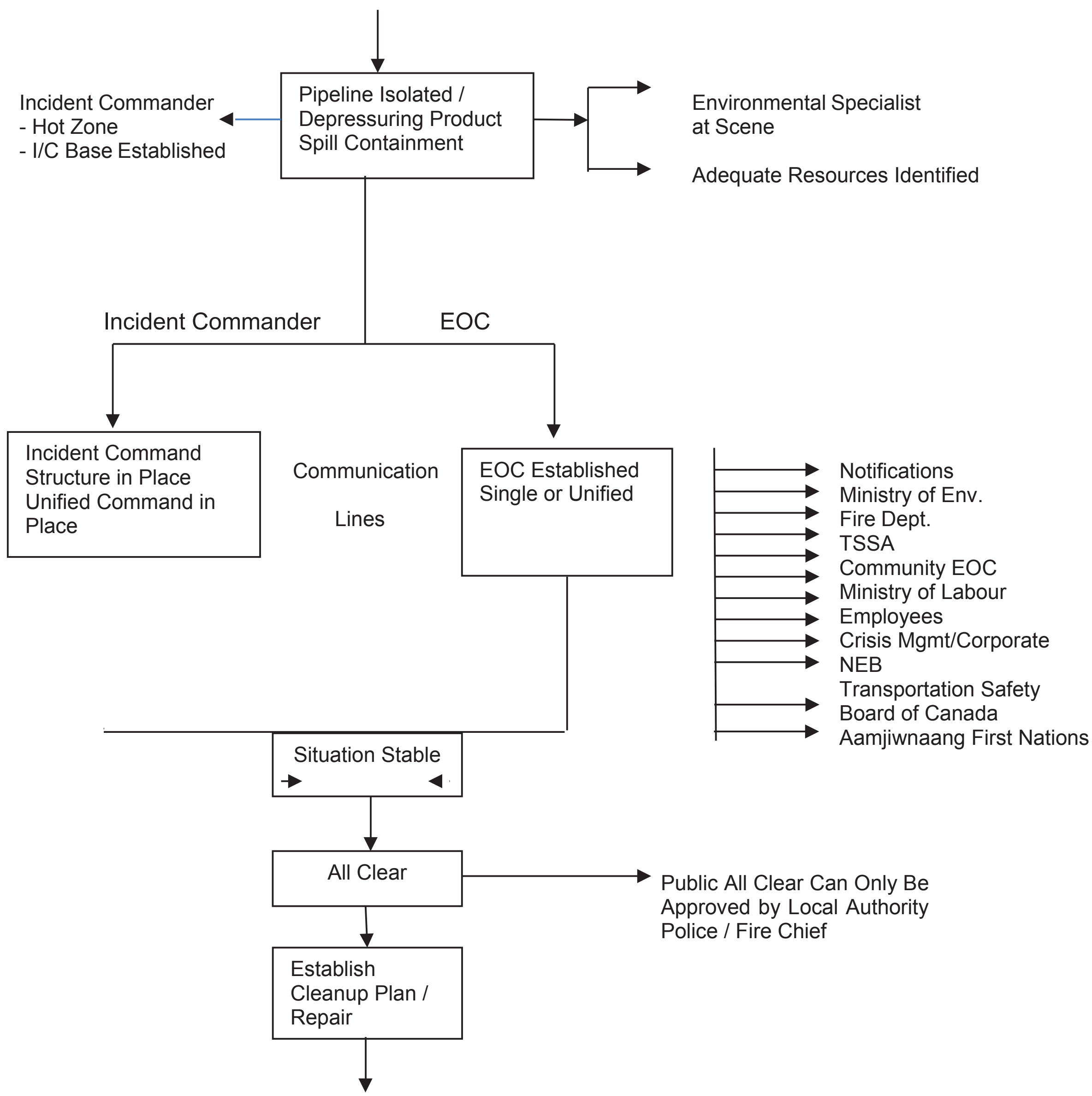
	ACTIONS: All activities associated with LEVEL 1 would be required supplemented by the following response procedures.		ACTIONS: All activities associated with LEVEL 2 would be required supplemented by the following response procedures.	
Position	**Level 2 - Internal Actions**	**Level 2 External Public**	**LEVEL 3 - Internal Actions**	**LEVEL 3 External Public**
			• Supports all Sections of the ICP administratively	
Logistics / Finance Section Chief	• Is responsible for timely, cost-effective procurement, delivery, and staging of essential resources • Coordinate with Pipeline team the dispatch of Nitrogen purge and tankage to assist in a nitrogen sweep of the line if requested. • Arrange on going back up to field resources and accommodations as required. • Manages all costs incurred during incident response • Manage security aspects of the incident • Set up Medical Branch • Set up Communications Branch	• Assist Local authorities in arrangement of Public Transportation if requested. • Manages Third Party claims• Supervise / support EOC Communications Leader	• Is responsible for timely, cost-effective procurement, delivery, and staging of essential resources • Coordinate with Pipeline team the dispatch of Nitrogen Purge and tankage to assist in a nitrogen sweep of the line if requested. • Arrange on going back up to field resources and accommodations as required. • Manages all costs incurred during incident response	• Assist Local authorities in arrangement of Public Transportation if requested. • Manages Third Party claims
Public Information Officer	• Is responsible to communicate with employees, public and the media.	• Contact Public as requested from IC/UC and communicate the appropriate message. • Provide and maintain media interface as required.	• Is responsible to communicate with employees, public and the media.	• Establish Communications with Local Authority Emergency Operations Centre • Assist Local Authorities as requested. • Develop a corporate media statement. • Determine public follow-up. • Manage pipeline owner interface and public response.
Safety Officer	• Is responsible for all matters of safety (including safety of emergency responders, employees, and affected	• Maintain communication with regulatory bodies	• Is responsible for all matters of safety (including safety of emergency responders,	• Maintain communication with regulatory bodies • Validate elevation of the emergency level with applicable regulatory agencies

	ACTIONS: All activities associated with LEVEL 1 would be required supplemented by the following response procedures.		**ACTIONS: All activities associated with LEVEL 2 would be required supplemented by the following response procedures.**	
Position	**Level 2 - Internal Actions**	**Level 2 External Public**	**LEVEL 3 - Internal Actions**	**LEVEL 3 External Public**
	public), health, hygiene, environment, and regulatory compliance • • Supports/fulfills safety incident goals and strategic objectives set by IC/UC • Ensures adherence to safe policies and principles and regulatory requirements during response operations. •Travel to site if required	• Validate elevation of the emergency level with applicable regulatory agencies • Obtains support as necessary from other safety officers from other agencies • Interface with Ontario Health Services If required.	employees, and affected public), health, hygiene, environment, and regulatory compliance • Obtains support as necessary from other safety officers from other agencies • Ensures adherence to safe policies and principles and regulatory requirements during response operations. Travel to site if required	• Interface with Ontario Health Services If required

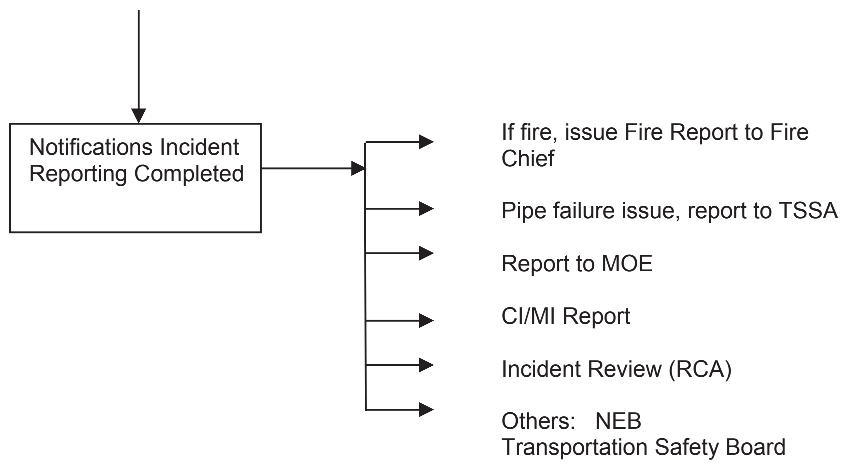
4.4 DECISION FLOW CHART



4.4 DECISION FLOW CHART (cont'd.)



4.4 DECISION FLOW CHART (cont'd.)



4.5 EMERGENCIES CAUSED BY 3rd PARTY DAMAGE

Emergency plans cannot identify all potential causes of an emergency on the pipeline system. These, however, are the greatest risk to a buried structure.

POTENTIAL CAUSES:

- 3rd Party companies excavating close to existing pipeline, for another pipeline, cable or road, installation, etc.
- Residents along the pipeline right-of-way (R.O.W.) installing fences or dugouts.
- Seismic work.

4.6 EVACUATION PLANNING

As previously mentioned, public safety is the top priority when managing a pipeline emergency. This should be addressed with two approaches:

1. Emergency scene securing:
   * Roadblocks, Incident Command base established, CVECO called, etc.
2. Evacuations:
   * Immediate evacuations – residents that are in immediate danger. These would occur in a Level 2or 3 emergency only.
   * Subsequent evacuations – residents that could be in danger should the situation worsen such as shift in wind or ignition.

The Contractor expects local authorities to provide emergency scene securing and evacuations.

4.6.1 SHELTER IN PLACE

Sheltering indoors for HVP releases is the preferred way of protecting residents. It is a viable public protection measure when:

- There is insufficient time or warning to safely evacuate the public that might be at risk,
- The residents are willing to wait for evacuation assistance,
- The release will be of limited size/duration,
- The specific location of the release is not identified, and
- The public is at greater risk if they are evacuated than if they remain indoors.

If there is an emergency situation in progress along the SPLP pipeline, and shelter in place is deemed the most appropriate course of action for the public, a message will be communicated to the community requesting everyone to go inside, check local radio or T.V. or municipal website for information. Close all doors, windows and openings, shut off ventilations systems that draw outdoor air inside (fans, air conditioning units, clothes dryers, turn down furnace, and close fireplace dampers). They will also be asked to avoid unnecessary use of their telephones and will be kept informed as conditions change through the automated communications system established by the local authorities.

CVECO Code 5 and then Code 6

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5.0 PRODUCT DATA

This section contains product information, specifications, physical properties, characteristics and spill control measures. For additional product information see the Houston Control Centre Manual for Sarnia Station to obtain flow and pressure rates.

5.1 GENERAL INFORMATION ON ETHANE

WHAT IS IT?

Ethane is a colorless liquefied petroleum gas derived from hydrocarbon raw materials.

ACCIDENTAL RELEASE

- Ethane could escape during transportation as a result of mechanical failure such as ruptured valves or seals, or a major impact of a large object such as a bulldozer, backhoe or vehicle, which strikes the pipeline and breaks or punctures it. PIpeline Security [redacted]
- Pipeline Security [redacted]

EFFECTS OF EXPOSURE

- Pipeline Security [redacted]

MEDICAL ATTENTION

- Use breathing equipment, remove the victim from exposure. Pipeline Security [redacted] Keep victim still. Get medical help.
- Cold burns require prompt medical help. Treat frostbite immediately by placing affected area in warm water until circulation returns. Get medical attention. Flushing and first aid is required for eye irritation.

WHAT TO DO

- Evacuate the immediate area. Warn those downwind. Allow no smoking, flares or other ignition sources in the general area. Only trained emergency personnel should remain in the area.

CHARACTERISTICS OF ETHANE

- Ethane is a colorless gas with no odor or taste. The gas is slightly heavier than air under similar conditions of temperature and pressure.
- Ethane is highly flammable in mixtures from 3.2% to 12.45% in air
- Ethane is usually transported as a liquid under pressure in High Vapor Pressure Pipelines. Liquid ethane boils at -88.6°C (-127.5°F) at atmospheric pressure.
- Critical temperature is 32.3°C (90.14°F) and Critical Pressure is 4915 kPa
- A large leak of ethane will form a cloud of cold vapor heavier than air, due to the low Pipeline Security [redacted]

THE MAIN HAZARDS FROM ESCAPING ETHANE LIQUID/GAS ARE:

- Pipeline Security [redacted]

NOTE:

a) A vapor cloud (plume) will be visible, at least initially, due to the condensed water vapor Pipeline Security [redacted]

TABLE 5-1 PHYSICAL PROPERTIES OF ETHANE

Property	Units	Methane	Ethane
Molecular Weight	MW	16.04	30.07
Boiling Point	°C	-161.5	-88.6
Freezing Point	°C	-182.5	-183.3
Critical Temperature	°C	-82.1	32.3
Critical Pressure	atm	45.8	48.5
Critical Density	g/cm^3	0.163	0.212
Flammable Limits: Lower Upper	% by vol	 5.0 15.0	 3.0 12.5
Solubility in water at 25°C and 1atm	ppm by wt	21	56
Vapor Density	(air=1)	0.6	1.04
Heat of Combustion at 25°C	kcal/ mole	212.79	372.81
Heat of Formation at 25°C	kcal/mole	-17.89	-20.24

SCHEDULE "A"

ETHANE SPECIFICATIONS

Ethane	95.0 vol. % min.
Total impurities	Commercially free
Methane	2.5 ppm vol. max.
Propylene and Higher Olefins	1 ppm vol. max.
Chlorides	0.9 ppm vol. max.
Carbon Dioxide	2.5 ppm vol. max.
Total Sulphur Compounds	90 ppm vol. max.
Water	No entrained or free water at –30ºC and 1400 psig

Pipeline Security [redacted]

[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	

Pipeline Security [redacted]

The following are calculations of the blast effects of a pipeline leak based on both the leak rate and the distance to 20% of the lower explosive limit (LEL). The blast effects are given for each of the 1, 3, and 5 psi peak overpressure, and are measured from the centre of the explosive cloud. This center can be assumed to be half way toward the 20% LEL point downwind from the leak site. For personnel protection, the 1 psi blast radius should be used. The other levels can be used with the enclosed table of blast consequences to determine the effect, on surrounding structures, of igniting the vapor cloud. The blast effects calculated for a given leak rate are slightly conservative; however, to assure protection of personnel, is recommended that they be followed.

The table outlining the blast effects if the 20% LEL is known is slightly less accurate since the actual effect will depend on wind conditions and surrounding terrain. Since there is an inherent hazard associated with determining the extent of the explosive envelope, every attempt should be made to estimate the magnitude of the leak and use the first table.

Pipeline Security [redacted]

TABLE 5-3 – EFFECTS OF BLAST PEAK OVERPRESSURE

A) PHYSIOLOGICAL EFFECTS

1 psi	Knock people down
5 psi	Rupture the Eardrum
15 psi	Lung Damage

B) Pipeline Security [redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]

6.0 TRAINING

6.1 ERT MEMBERS TRAINING:

The following outlines the training requirements and frequency of training for the following personnel on ERT:

- Incident Commander
- Pipeline Engineer
- First Responders

TRAINING	INITIALLY	REQUALIFICATION	NOTES
Emergency Response Plan	First year of employment	Annual	All
Driver Safety Video	First year of employment	3 years	All
Test/Monitor Hazardous Atmos.	First 3 months of employment	3 years	All
Standard First Aid/CPR (Recertification)	First year of employment	3 years	IC/Sr. Maint. Coordinator
Pipeline Familiarization	First 3 months of employment	Annual	All
Transportation of Dangerous Goods	First 3 months of employment	Initial/3 years	Teamster
Incident Command System	First year of membership	Initial/4 years	IC/Pipeline Engineer

6.2 PIPELINE MANAGER:

- Incident Command Structure
- ERM Manual Review
- Drill Participation
- P/L Product Data

6.3 EXERCISE REQUIREMENTS

- Internal/External table top drills will be competed once per year.
- Action items from drills are documented, completed and reviewed.

6.3.1 Exercise Requirements and Schedules

SPLP in conjunction with their agent in Canada, pipeline maintenance and response contractor, [redacted] Industrial Contractors [redacted] will conduct the exercise requirements listed in TABLE 6-1 which meet the National Energy Board (NEB) Emergency Management Performance Measures and Guidance Notes for the NEB Onshore Pipeline Regulations Annex A - Part 8 - Emergency Response Exercises.

Table 6-1 provides the frequency of those exercises and the anticipated participants.

TABLE 6-1 - EXERCISE REQUIREMENTS

Exercise Type	Exercise Characteristics
Drills:	• A supervised activity that tests a single or specific operation or function. • Drills are commonly used to provide training on new equipment or test new procedures; to practice and maintain skills; or to prepare for more complex exercises. • Drills may be utilized to test emergency procedures and ensure that personnel are capable of conducting the initial actions necessary to mitigate or prevent the effects of a release. • For the purposes of this measure, a "man down" or fire drills are excluded and should not be reported.
Tabletop Exercise:	• A facilitated analysis of an emergency situation in an informal, stress-free environment. • A tabletop exercise is designed to elicit constructive discussion as participants examine and resolve problems based on existing operational plans and identify where those plans need to be changed. • Documents plan's effectiveness. • SPLP and their contracted agents are responsible for maintaining exercise documentation.
Functional Exercise:	• A single or multi-agency activity designed to evaluate capabilities and multiple functions using simulated response, without moving real people or equipment to a real site. • Allows personnel or teams to validate plans and readiness by performing duties in a simulated operational environment. • Designed to exercise team members, procedures and resources and agency interaction. • Designed to evaluate management of emergency operations centers, command posts and headquarters.
Full-Scale Exercise:	• A multi-agency, multi-jurisdictional activity involving the mobilization and actual movement of emergency personnel, equipment, and resources, as if a real incident had occurred. • Achieve realism through: On-scene actions and decisions, simulated of consequences or impact, resource deployment. • All decisions and actions by players occur in real time and generate real responses and consequences from other players. • May involves controller(s), players, simulators and evaluators.
Other Exercise Considerations	
Drill Program Evaluation Procedures	• Post-exercise meetings are held to discuss achievements as well as areas for improvement that are documented on an action item tracking list.
Records of Drills	• Company will maintain exercise records for five years following completion of each exercise • Records will be made available to NEB and other applicable agencies upon request • Company will verify appropriate records are kept for each spill response contractor listed in Plan.

Emergency responders, regulatory agencies and other stake holders may be invited to observe or participate in table top, functional and full scale exercises.

TABLE 6-2

Exercise Plan Schedule

Type	Description	Frequency	SPLP Control Center	Contractor Pipeline Company	SPLP NGL Operations	HES&S	External Agencies	Other Resources as Required
Emergency Procedure Drill	Ensure that personnel are capable of conducting the initial actions necessary to mitigate or prevent the effects of a release.	Semi-Annual	X	X	X	X		
Tabletop Exercise Functional Exercise* Full Scale Exercise *	See descriptions noted in Table 6-1. Participate in one type of exercise event annually.	Annual	X	X	X	X	X *	X *
Emergency Response Plan Telephone Verification	Verification	Semi-Annual		X	X			
Emergency Response Plan Review	Procedural	Annual		X	X	X		

The Company may take credit for an actual event as an exercise if it meets the same objectives as the planned exercise, if the incident occurs in the region that a planned exercise was to occur, and if appropriate methodology is used.

7.0 FORMS

7.1 NOTIFICATION PIPELINE LEAK FORM

Material Flow Pipeline Operator

Name

Time of Call   Date: (D/M/Y)

Name of Caller

Caller Return Phone Number

Leak Location (identify location by area, road, development)

Leak Specifics

☐ Injuries

☐ Smell

☐ Vapor Visible ☐ Small ☐ Big

☐ Liquid

☐ Noise ☐ Slight ☐ Loud

☐ Proximity to Public

☐ Fire

☐ Fire/Police Called ☐ Yes ☐ No

or at Scene ☐

☐ Wind Direction

Will Caller Remain or Meet Contractor Representatives?

☐ Yes   What Location?

Contractor Rep will be there within 10-15 minutes

STATEIMPACT PENNSYLVANIA Energy. Environment. Economy.

Sunoco's Mariner East 2 pipeline construction on Pennell Road in Middletown Township. (Emma Lee/WHYY)

MARCH 21, 2019 | 6:06 PM

Higher operating pressure prompts new safety concerns over Sunoco's Mariner East 2X pipeline

Pipeline safety advocates worry the pressure on the 16-inch Mariner East 2x would pose greater dangers

Susan Phillips

A tree clearing crew member on a property in Huntingdon County along the Mariner East pipeline path.

Pipeline opponents are raising new concerns about the safety of Energy Transfer/Sunoco Logistics' Mariner East 2x natural gas liquids line, which the company says will have a maximum operating pressure much higher than that of the Mariner East 1 and 2 lines.

The pressure on the Mariner East 2x had previously been reported in public documents as equal to the pressure of parallel Mariner East 2, which uses the same right-of-way. A pipeline's **"Maximum Allowable Operating Pressure," < http://www.puc.state.pa.us/transport/gassafe/pdf/Gas_Safety_Seminar_2PPT-PUC_MAOP_Ver.pdf>** or MAOP, is set by the **Department of Transportation < https://www.federalregister.gov/documents/2012/05/07/2012-10866/pipeline-safety-verification-of-records>** and, for safety reasons, is lower than what the design characteristics of the pipe can withstand.

http://files.dep.state.pa.us/RegionalResources/SWRO/SWROPortalFiles/
%20Project%20Descr/Penn%20Pipeline%20Project%20Description_032
, and with the Delaware River Basin Commission in 2015, Sunoco stated the MAOP for Mariner East 2 and 2x would be 1480 psig, or pounds per square inch gauge.

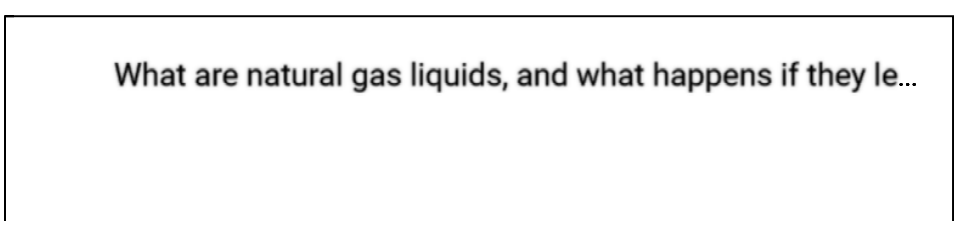
But a footnote in recent reports filed with the Pennsylvania Department of Environmental Protection point to a much higher number: 2100 psig.

Clean Air Council attorney Alex Bomstein, who says he discovered the difference while analyzing Sunoco's new horizontal directional drilling plans filed with DEP, said a risk assessment conducted of the pipeline project was based on a lower pressure.

"Every risk assessment done on Mariner East has used the 1480 psig figure in calculating destructive potential, because that's what Sunoco has always represented to the public and to regulators," Bomstein said.

Del-Chesco United for Pipeline Safety hired Quest Consultants to do a risk assessment < https://stateimpact.npr.org/pennsylvania/2018/08/29/risk-assessment-quantifies-mariner-east-hazards-for-residents-in-two-counties/> on the line. Quest's senior engineer Jeff Marx, who conducted the assessment, says the risks are greater with a higher pressure.

"Something up in the 2100 psi range would be a significant increase and will increase the hazard because the release rate of material is largely driven by pressure," Marx said.



Bomstein says air emissions are also impacted by the pressure, and in air permits **filed with DEP < http://files.dep.state.pa.us/RegionalResources/SCRO/SCROPortalFiles/C %20Mount%20Union%20Pump%20Station%20%E2%80%93%209-21-17%20DEP%20Addendum%20Memo%20and%20Revised%20Draft%20S Only%20Operating%20Permit%2031-03036.pdf>** for pumping stations, the pressure is reported by Sunoco as 1480 psig.

"If the pressure were 2100, that would increase emissions, meaning Sunoco's estimates would be off, meaning DEP's determination around air permitting of this would also be legally erroneous," Bomstein said.

Sunoco spokeswoman Lisa Dillinger confirmed in an email that the maximum operating pressure of the Mariner East 2x is 2100, but insists that is not a change.

"The pipe being used to construct ME2X is designed to safely accommodate a MOP up to 2100 psig," Dillinger wrote. "Its valves, wall thickness, grade, and **hydrostatic testing < https://primis.phmsa.dot.gov/comm/factsheets/fshydrostatictesting.htm>** are all designed to that pressure. This is recognized in our documentation with the DEP, PUC and PHMSA. We tested the

In a review of public documents submitted to the DEP as part of their permit applications in 2016 and to the Delaware River Basin Commission in 2015, StateImpact Pennsylvania could find no reference to the 16-inch Mariner East 2x line operating at 2100 psig. The only references are from the footnotes in recent drawings submitted to DEP as part of the revised construction plans involving horizontal directional drilling. The company was forced to revise its HDD plans after dozens of drilling mud spills resulted in DEP penalties and a lawsuit by Clean Air Council.

"Our greatest concern is that Sunoco has put into the ground pipeline that has not been properly tested," Bomstein said. "And if it can't withstand those pressures, that means there's a great and needless risk of rupture and explosion."

Sunoco's Dillinger said the currently operating Mariner East 2 pipeline is designed for 1480 psig and the line was tested at about 2160 psig. The parallel Mariner East 2x remains under construction, as do sections of the Mariner East 2. Although the Mariner East 2 is operational, construction accidents and delays forced the company to use an older section of pipe as a workaround while work on the rest of the line continues.

The Mariner East pipeline project includes three lines that carry natural gas liquids from eastern Ohio and western Pennsylvania about 350 miles across the state to Marcus Hook, Delaware County. The Pennsylvania Public Utility Commission shut down the Mariner East 1 line earlier this year after a sinkhole exposed the pipe in Chester County.

A spokesman for the Pipeline and Hazardous Materials Safety Administration said the agency is unaware that the maximum operating pressure on the Mariner 2x is now 2100 psig.

discuss the specific pressures of pipelines because they "are confidential security information." The PUC said federal safety regulations do not change based on the maximum operating pressure of a line.

A spokesperson for the DEP said pipeline safety and operations are not a part of their jurisdiction.

Pipeline safety consultant Richard Kuprewicz of Accufacts, which conducted a **safety review of the lines running through West Goshen Township < https://stateimpact.npr.org/pennsylvania/2017/01/16/consultants-report-endorses-safety-of-mariner-east-2-critics-unmoved/>** , said that historically, the pressure limits for natural gas liquids pipelines is at 1440 or 1480 psig.

A pressure of 2100 psig, Kuprewicz says, is "in a whole different ball game." He says components like valves and flanges may not be adequate for such a high maximum operating pressure.

"All I can say is federal regulations wouldn't prevent you from running it at 2100, but you would be out of your mind," Kuprewicz said.

Both Kuprewicz and Marx said failure at a higher pressure translates to greater safety risks.

Kuprewicz says his review of Sunoco's practices for the lines running through, or close to, West Goshen Township show the company exceeded federal safety standards with regard to the construction and operation of the Mariner East lines. He said he has not seen detailed information about the Mariner East 2x line.

was Del-Chesco United for Pipeline Safety that commissioned the study, the Council was the group's fiscal sponsor on the project.

EXPLAINERS

Corrections and Clarifications

<
https://stateimpact.npr.org/pennsylvania/tag/corrections-and-clarifications/>

Delaware Watershed

<
https://stateimpact.npr.org/pennsylvania/tag/delaware-watershed/>

Mariner East: A pipeline project plagued by mishaps and delays

aquifer

ABOUT STATEIMPACT PENNSYLVANIA

StateImpact Pennsylvania is a collaboration among **WITF**, **WHYY**, **WESA**, and **The Allegheny Front**. Reporters **Reid Frazier** and **Susan Phillips** cover the commonwealth's energy economy. Read their reports on this site, and hear them on public radio stations across Pennsylvania.

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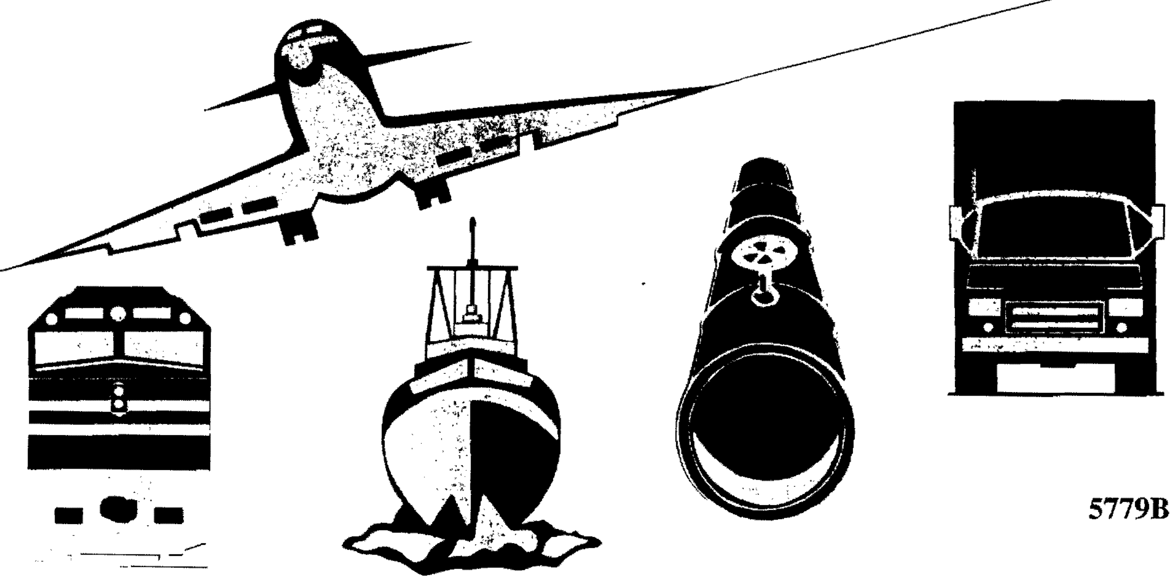
NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C. 20594

PIPELINE ACCIDENT REPORT

HIGHLY VOLATILE LIQUIDS RELEASE FROM UNDERGROUND STORAGE CAVERN AND EXPLOSION MAPCO NATURAL GAS LIQUIDS, INC. BRENHAM, TEXAS APRIL 7, 1992



5779B

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable cause of accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Information about available publications may be obtained by contacting:

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NATIONAL TRANSPORTATION SAFETY BOARD

Washington, DC 20594

Pipeline Accident Report

HIGHLY VOLATILE LIQUIDS RELEASE FROM UNDERGROUND STORAGE CAVERN AND EXPLOSION MAPCO NATURAL GAS LIQUIDS, INC. BRENHAM, TEXAS APRIL 7, 1992

ADOPTED: NOVEMBER 4, 1993

NOTATION 5779B

Abstract: This report explains how highly volatile liquid products escaped from an underground storage cavern and formed a vapor cloud that exploded, killing three people and damaging almost all buildings within 3 square miles of the storage facility. From its investigation of this accident, the Safety Board identified safety issues in the following areas: safety control systems, cavern management procedures, employee and management performance, emergency preparedness, and Federal and State safety requirements and oversight for underground storage and related pipelines.

The National Transportation Safety Board made safety recommendations addressing these issues to the Department of Transportation, the Research and Special Programs Administration, MAPCO Natural Gas Liquids, Inc., the Texas Department of Public Safety, Washington County, the American Petroleum Institute, the American Gas Association, and the International Association of Fire Chiefs.

CONTENTS

EXECUTIVE SUMMARY

On April 7, 1992, an uncontrolled release of highly volatile liquids (HVLs)[1] from a salt dome storage cavern in the Seminole Pipeline System near Brenham, Texas, formed a large, heavier-than-air gas cloud that exploded. Three people died from injuries sustained either from the blast or in the fire. An additional 21 people were treated for injuries at area hospitals. Damage from the accident exceeded $9 million.

The National Transportation Safety Board determines that the probable cause of the release of highly volatile liquid from the remotely operated and overfilled storage cavern and resulting explosion at Brenham station was the failure of MAPCO Natural Gas Liquids, Inc., (MAPCO) to incorporate fail-safe features in the station's wellhead safety system. The cause of the overfilling was the inadequacy of the company's procedures for managing cavern storage. Contributing to the accident was the lack of Federal and State regulations governing the design and operation of underground storage systems. Contributing to the severity of the accident was MAPCO's inadequate emergency response procedures.

From its investigation of this accident, the Safety Board identified safety issues in the following areas:

- o Safety control systems;
- o Cavern management procedures;
- o Employee and management performance;
- o Emergency preparedness;
- o Federal and State safety requirements and oversight for underground storage and related pipelines.

As a result of this investigation, the Safety Board issued recommendations to the Department of Transportation, the Research and Special Programs Administration, MAPCO Natural Gas Liquids, Inc., the State of Texas Department of Public Safety, Washington County, the American Petroleum Institute, the American Gas Association, and the International Association of Fire Chiefs.

[1] Highly volatile liquids are hazardous liquids that have a vapor pressure exceeding 40 psia (276 kPa) at 100° F (37.8° C) and that will form a vapor cloud when released to the atmosphere. The primary components in the HVL mixture in the Brenham storage dome were ethane and propane, which at 60° F and atmospheric pressure have a liquid to vapor expansion ratio of 300 and 270, respectively. (For further information, see "HVL Properties.")

NATIONAL TRANSPORTATION SAFETY BOARD
Washington, DC 20594

Pipeline Accident Report

Highly Volatile Liquids Release from Underground Storage Cavern and Explosion MAPCO Natural Gas Liquids, Inc. Brenham, Texas April 7, 1992

INVESTIGATION

The Accident

Events Before the Accident.--On April 7, 1992, the MAPCO[2] dispatch center in Tulsa, Oklahoma, was controlling the transport of highly volatile liquid (HVL) products from two south Texas processing plants through a section of the Seminole Pipeline Company's (Seminole's) system called the Bryan Lateral. From the lateral, the product was being injected into Seminole's salt dome storage cavern at the Brenham station near Brenham, Texas (see figure 1).

A dispatcher remotely controlled the Seminole pipeline system, including pump units that transported product through the Texas pipeline, from a telemetry system control console (see figure 2). At 6:09:39 a.m., the monitor screen began to flash an alarm indicating that one or more hazardous gas (HAZGAS) detectors had activated at Brenham station, which was an unattended facility. In accordance with company procedures, the dispatcher telephoned a technician at his home in the Brenham area, told him that the dispatch center had received a HAZGAS alarm from Brenham station, and requested that he check out the source of the alarm.

About 6:55 a.m., an Austin County resident, whose home on Glory Lane was adjacent to Brenham station, telephoned her mother, who lived on County Road (CR) 19, and told her that she smelled a "strong gas odor" outside her mobile home. The mother advised her daughter to call 911. At 6:59 a.m., when the mobile home owner dialed 911, the telephone system routed the call to the dispatcher for the Washington County Sheriff's Department (WCSD) in Brenham, Texas, about 8 miles away. According to the WCSD dispatcher, the caller sounded "woozy" when she told him that "...it smells like somebody has given a perm in my house." The caller

[2] MAPCO Natural Gas Liquids, Inc., currently has controlling interest in Seminole Pipeline Company, which is a stock corporation that has no employees. MAPCO Natural Gas Liquids, Inc., also wholly owns Mid-America Pipeline Company, which operates the dispatch center for all of its parent company's pipeline operations and which operates the Seminole system under contract. MAPCO Natural Gas Liquids, Inc., is a subsidiary division of the energy corporation MAPCO, Inc. Unless noted otherwise, the Safety Board uses the term "MAPCO" when referring to any company employee, operation, and procedure in the corporate tree. Additional information about the organization and ownership of companies involved in this accident appears later.

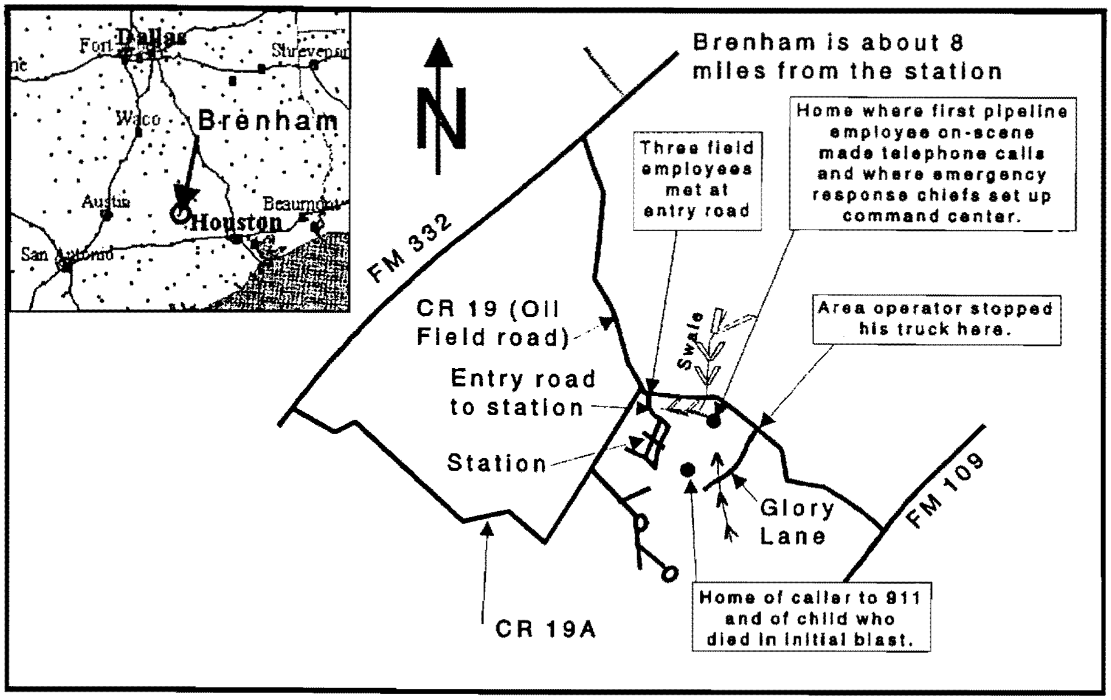

Figure 1. Map of accident area.

said "I don't know if something's happened over at the gas line ... I can hear something blowing out. It's never, never smelled like this. It's so strong."

The WCSD dispatcher transferred the caller to the Brenham Fire Department. While giving the fire department dispatcher directions to the Brenham station, the mobile home owner cautioned that CR 19 was "kinda foggy." In accordance with county procedures for a gas leak, the fire department dispatcher called MAPCO's dispatch center in Tulsa, and was advised that a technician in Brenham had already been alerted and was checking out the alarm.

The Explosion.--The mother of the mobile home owner stated that shortly after 7 a.m., she was driving her pickup northbound on CR 19 to pick up her daughter and grandson when she encountered another pickup stopped on the right side of the road, near the intersection of Glory Lane and CR 19. She said that when she started to pull around to the left side of the stopped pickup, a man blocked her.[3] She said that when she told him that she needed to go down Glory Lane to help her daughter, the man told her that "there has been a gas leak...it [the gas leak] has been turned off" and "they were not allowing any vehicles down there."

The mother of the mobile home owner said that she had put her pickup in reverse in

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[3] A MAPCO area operator had stopped his truck south of the intersection.

order to back up toward her driveway when she saw a car approaching CR 19 from the Glory Lane area. She said that when the car from Glory Lane reached CR 19, the woman driving glanced at the two pickups to her right, turned left, and proceeded north toward the cloudy swale.[4] The woman driving the pickup truck said that the man who had stopped her shouted at the car to stop, but the car driver failed to do so.

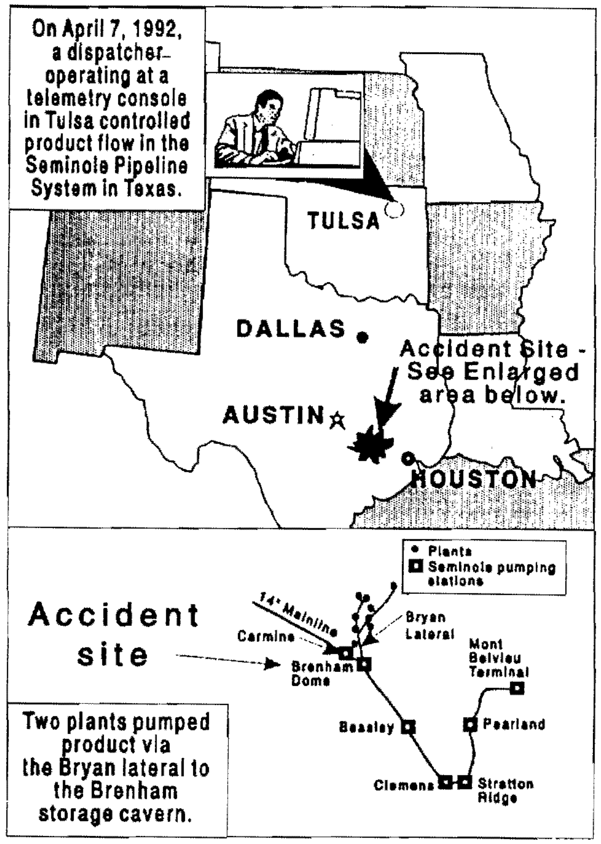

Figure 2. Employee at Tulsa dispatch center controls HVL transport in the Bryan Lateral.

Three pipeline employees were near the station entry road on the opposite side of the fog-filled swale. One testified that he saw the headlights of the northbound car. He later testified that he believed that the vehicle was that of a pipeline employee, the assistant maintenance supervisor. When the motorist continued to drive into the vapor cloud, he realized his mistake and tried to get the car driver to stop by yelling and waving.

According to descriptions of two employees, the oncoming car "disappeared" into the vapor-fog cloud. One man said that he next heard the sound of someone attempting to start a car. Another stated that a flash occurred where the vehicle had entered the vapor cloud. He said the flash "occurred over a great deal of land...up and toward the station and out [and] down the ravine [swale]."

The Brenham fire department dispatcher said that when he called the mobile home owner back to notify her that the pipeline company was checking out the gas alarm, "there was a tremendous boom and the phonelines went dead." At 7:13:57 a.m., the Tulsa telemetry system ceased receiving data transmission from Brenham station.

Two other employees who were en route to the site from different directions described the ignition of the gas cloud and resulting explosions. An assistant maintenance supervisor was driving north on CR 19 from Farm to Market (FM) 109 when he observed a large "fireball" reflecting off the clouds and three rapid flashes of light that jumped around like lightning. He felt three concussions immediately thereafter that violently shook his truck.

A lab technician stated that he was driving on FM 332 when he observed a large

[4] A low-lying stretch of land.

mushroom-shaped cloud covering the station area and several smaller clouds east of the site. He said that he was about 2 1/2 to 3 air miles from the station when "the [gas] cloud exploded as in a fire and turned orange. There was a series of explosions [that] sounded like thunder." He said that three or four "secondary explosions" occurred as smaller clouds, which had "detached from the larger cloud," exploded. The lab technician described the explosions as being "somewhat like a lightning storm."

The surface blast demolished all buildings at the Brenham station and caused varying degrees of damage to all homes within a 3-square-mile area. Seismological recordings at three Texas universities within 75 air miles of Brenham station showed that the surface tremor, which rattled the windows of homes more than 130 miles away, registered 3.5 to 4 on the Richter scale.[5] A young boy in the mobile home adjacent to Brenham station was killed when his parent's home was leveled by the force of the explosion. The car that entered the vapor cloud had three occupants, two adult women and a child, all of whom were seriously burned in the accident and MEDEVACed to Hermann Hospital Burn Center in Houston, Texas, where the two adults died later in the week. An additional 21 people were treated for blunt force trauma, lacerations, and burn injuries at area hospitals.

Emergency Actions

Before the Explosion.--The technician in Brenham testified that upon being notified of the gas alarm by the Tulsa dispatch center, he dressed and began the drive to the storage cavern, during which he stopped at a convenience store for a soft drink. He said that about 6:45 a.m., he was proceeding northwest on CR 19 near Brenham station when he smelled gas product and observed "a very thick mixture of gas and fog." He stopped his truck a short distance before the swale and turned the ignition switch off. He said that when the pickup continued to run, "I knew something serious had happened" because "there was enough gas in the air to keep feeding my engine." He did not have a self-contained breathing apparatus in his truck.

The technician stated that he was apprehensive about using the two-way radio in his company truck for fear of igniting the HVL vapor, so he left his truck, went to the nearest home, and asked to use the owner's phone. He called the Tulsa dispatcher, advised him that gas was in the area, and asked him to notify his (the technician's) immediate supervisor. He did not ask the dispatcher to contact other area employees that he knew should soon be reporting to the station to begin their workday. The technician left, but according to the homeowner, he returned less than a minute later and asked for a telephone book so that he could call his supervisor himself. The Assistant Maintenance Supervisor later testified that when the technician advised

[5] A logarithmic scale for expressing the magnitude of a seismic disturbance in terms of the energy dissipated in it. A reading of 2 indicates the smallest earthquake that can be felt, 4.5 indicates an earthquake causing moderate damage, and 8.5, an earthquake causing devastating damage. For example, the 1989 San Francisco Bay quake registered 6.9 on the Richter scale.

him that the leak was getting larger and that "gas was crossing CR 19," he instructed the technician to block the road and not enter the vapor cloud.

After he hung up, the technician told the residents that he was going to block the road and that they should shut off any electrical appliance they were operating, not operate any other appliance, and evacuate the area on foot toward FM 109. When one of the residents told him that a schoolbus was soon scheduled to come down CR 19 from the north, he rushed out of house and toward the station, not stopping to block the road. He covered his mouth and ran down CR 19, through the vapor-cloud fog in the swale, and up toward the station entry road.

A pipeliner and technician trainee, who were riding together in a company truck to the station, saw the vapor fog cloud as they turned off FM 332 onto CR 19 and approached the worksite from the northwest. About 7 a.m., they turned onto the station entry road and stopped their pickup about 200 yards from the station gate. When they rolled down the truck's windows, they smelled product and could hear a "roaring noise."

The pipeliner instructed the technician trainee to use the truck radio to determine who was in the area. While the trainee was calling on the radio, the pipeliner walked toward the station gate. About 100 feet from the gate, he saw that it was locked, which indicated to him that no one was at the station, so he stopped. He then saw a column of "water ... about 12 inches in diameter ... shooting about 50 feet into the air...." He believed the column was coming "...out of the brine line[6] in the corner of brine pond No. 1" and immediately returned to his truck.

The technician trainee was using the radio when the pipeliner returned to the truck. While the pipeliner got the truck keys to retrieve a portable gas detector from the vehicle, the trainee walked toward the direction of a noise "like a fountain ... bubbling water, spraying, and a hissing ...." When he got to the culvert in the entry road, he saw "fluid gushing up." As he walked closer to the station gate, he noted that the vapor was up to the level of his ears. He then returned to the truck and radioed the area operator to tell him of his observations. The area operator advised him that the two of them should leave the area.

The pipeliner and technician trainee next saw the technician running up the road toward them. After briefly discussing what actions they should take, one employee started walking toward the intersection of CR 19 and CR 19A to block traffic, another started walking south on CR 19 to block traffic on the other side of the swale, and the third started toward the station.

Meanwhile the area operator had turned onto CR 19 from FM 109. As soon as he saw

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[6] The brine tube, also referred to as the "brine line," contained salt water that, because of its greater specific gravity, contained the HVL product within the underground storage facility. Additional information about the underground storage facility will appear later in this report.

the fog/product in the swale, he got out of his truck and started to walk toward the station. He stopped before reaching the fog, looked toward the station, and saw "a water column shooting up." He returned to his truck and radioed the Tulsa dispatcher to shut down the gathering system. The area operator next tried unsuccessfully to radio his supervisor. He then used his mobile telephone to call the lab technician. The area operator described his observations and told the lab technician that he believed that HVLs were being released from the cavern. The area operator testified that he had finished talking with the lab technician when a pickup truck driver drove up and told him that she needed to pick up her daughter from a house down the gravel road to his left (Glory Lane). He said that he looked down Glory Lane, "saw clouds" in the area, and advised her that she could walk down to get her daughter but that she could not drive into the area. As the area operator was watching the pickup driver, another motorist exited Glory Lane and drove her car into the vapor cloud. Seconds later the explosions occurred.

Postexplosion

Actions by Area Employees.--The assistant supervisor approached the station via CR 19 from FM 109, stopping his vehicle just south of the swale. He said that because he was concerned about the potential for another explosion and because the residents that he passed appeared to be functioning satisfactorily, he went directly to the station, advising people whom he passed that ambulances were on the way. When the assistant supervisor entered the station gate, he was aware of fires in the station, but did not see any area where HVL vapors were being released or accumulating.

While en route via CR 19 from FM 332 to the station, the lab technician said that he stopped briefly whenever he observed residents near the road who looked as if they needed assistance and radioed the Tulsa dispatcher of the need for ambulances. When he first arrived at the station, he assisted two employees who had sustained minor injuries when the surface blast knocked them to the ground. When the lab technician initially glanced around the station, he noted fires burning at the following station and perimeter locations: the tool house, the hay barn, the transformers at the control building, an oil tank on the west side of the station, Coastline Gas Pipeline Company's (Coastline's)[7] above-ground piping, and the Seminole truck on the station entry road outside the compound.

While other employees tended to injured residents and established area roadblocks, the assistant maintenance supervisor, the lab technician, and the technician checked and closed valves within the station. The assistant maintenance supervisor walked over between the two brine ponds to close the 14-inch mainline valve. The lab technician checked the condition of the station piping and found that the only HVLs being released were coming from control equipment. He noted a leak from a valve stem at one piece of control equipment and one on

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[7] Coastline Gas Pipeline Company is a wholly-owned subsidiary of MidCon Texas Pipeline Corporation (formerly United Texas Transmission). Coastline owns a 6-inch-diameter HVL pipeline that originates in Colorado County, Texas, and extends approximately 45 miles to its terminus at Seminole's Brenham station.

meter piping. While walking through the station, the lab technician noticed that the cavern safety valve at the wellhead was tripped. He did not recall seeing any water or vapor being released near the wellhead or observing the position of any other equipment there. After closing and chaining closed various valves throughout the station, the lab technician reached the meter run for Coastline's pipeline, where he noted that both manual valves between the Seminole and Coastline pipelines were closed.

The assistant maintenance supervisor and the lab technician divided the station area to do a cursory check for damage to pipeline system components and to secure the site. In the course of his damage check, the lab technician walked up to the top of the berm surrounding pond No. 1 and noted a fire above the brine in the middle of the pond.

The assistant maintenance supervisor and other employees went to the wellhead. In a pile of debris near the wellhead, they found a component of the cavern safety valve system,[8] the Barksdale pressure switch, had broken from its mounting and separated from the electrical signal wire in the system. The assistant maintenance supervisor saw that another cavern safety valve system component, the brine pressure sensing tubing, was dangling down into the debris. He did not determine whether the sensing tubing was still connected to the Barksdale switch. He later testified that although he could not recall any water or vapor being released from the tubing, he believed that he reached up and closed the valve between the brine tube and the sensing tubing. When he returned to the wellhead after checking other station sites, the assistant maintenance supervisor noted that the valve from the brine tube to the brine pressure sensing tubing was closed and that the tubing was not attached to the Barksdale switch. When an employee who was with him opened the closed valve, HVL vapors escaped from the open end of the sensing tubing.

About 10:30 a.m., the lab technician returned to the wellhead. He also found that the valve from the brine tube to the brine pressure sensing tubing was closed, but that the sensing tubing was missing. He later testified that at the time, he believed the tubing had been blown away by the explosion.

Community Agencies' Actions (See figure 3 for a summary of the community response effort).--The Washington County Emergency Management Coordinator (EMC)/Emergency Medical Services (EMS) Director stated that he was getting out of bed when he heard a rumble and a loud explosion that rattled his brick home and its windows. As he left his house, which was several miles north of Brenham, he saw a large pink cloud rising to the south. When he got into his car, he overheard radio traffic say, "It's the salt dome." He testified that he immediately called the EMS dispatcher and told her to activate the Washington County Disaster Plan. As he proceeded to the scene, he called his dispatcher again to request that all available medical

[8] The wellhead had a cavern safety valve system. When closed, the cavern safety valve prevented the flow of HVLs from the cavern to the brine ponds. The various components of the system were designed to trigger the closure of the cavern valve should excessive pressure or heat be detected. An illustration of the cavern safety valve system appears later in this report.

evacuation helicopters be dispatched from Houston and Austin. He also called Trinity Medical Center and activated the hospital's disaster plan. When he arrived on scene, the EMC/EMS Director had to radio backup personnel to tell them to reroute because debris from fallen trees and disabled vehicles blocked CR 19.

The chief of the Brenham Fire Department was also at home when the explosion occurred. When he reached his vehicle, he received a radio call from the sheriff's department advising him of an explosion at the salt dome in southwest Washington County. He radioed for a fire alarm and proceeded to the station site via FM 109 to CR 19, which he found blocked by fallen trees and a charred car. He then had to radio fire fighting personnel to reroute to the station by way of FM 332 to CR 19. The fire chief stated that he made his way on foot, climbing through debris, up to Brenham station, where he talked to the pipeline employees and determined that none of the fires at the site posed an immediate life-threatening situation.

Fire Departments.--Four departments with a total of 7 pieces of fire fighting apparatus and over 100 firefighters

Law Enforcement Agencies.--Between 45 and 50 enforcement personnel representing 18 enforcement agencies

EMS.--Two county EMS departments with 39 personnel

Other.--Three medical evacuation helicopters from Houston.

Figure 3. Number of community responders to Brenham accident.

After observing the extent of injuries to area victims, the EMC/EMS director, the fire chief, and the chief deputy of the sheriff's department decided to set up the command post at the driveway of the residence closest to the Brenham station and to establish two triage areas on CR 19, one north of the station, near the intersection of CR 19 and CR 19A, and one south of the station, near the intersection of CR 19 and FM 109. The first patients evacuated arrived at Trinity Medical Center in Brenham at 7:45 a.m. The car's three occupants were initially taken to Trinity, from which they were MEDEVACed by LIFE-FLIGHT to the burn center at Hermann Hospital in Houston.

Documented Injuries.--Table 1 on the following page categorizes injuries sustained in the Brenham accident according to the International Civil Aviation Organization's method of injury coding as described in 49 *Code of Federal Regulations* (CFR) 830.2. The injury table does not include individuals who sought private medical treatment.

Station Damage.--Safety Board investigators found that the surface blast leveled all of the buildings and most of the fencing at the Brenham station, damaged the brine pond liners, shifted an above-ground storage tank on its concrete base, and knocked down the power lines. The station piping sustained minor damage. MAPCO estimated the cost of rebuilding the station to be $3,400,000. The company did not provide a cost estimate for business losses resulting from the station being out of service since April 7, 1992.

Other Damage.--More than 60 homes in Washington and Austin Counties were damaged. Of the damaged residences, 26 buildings within 1 1/2 miles of the station were declared a total loss and 33 residences within 1 1/2 to 2 miles of the station sustained moderate damage (see figure 4). The blast also killed 75 beef cattle and injured dozens more. Estimates of damage to area homes and structures exceeded $5 million.

INJURIES	PIPELINE EMPLOYEES	RESIDENTS	OTHERS	TOTAL
Fatal	0	3	0	3
Serious	0	2	0	2
Minor	2	17	0	19
TOTAL	**2**	**22**	**0**	**24**

Table 1. Injuries sustained in Brenham pipeline accident.

System Organization/Ownership

MAPCO, Inc., an energy company that is diversified through subsidiaries and affiliates, produces coal and natural gas liquids; refines and processes crude oil; transports natural gas liquids, refined petroleum products, and anhydrous ammonia by pipeline; markets and trades natural gas liquids, refined petroleum products, coal, fertilizers, and domestic and foreign crude oil; and markets convenience-store merchandise. Incorporated in Delaware in 1958, MAPCO, Inc., has executive offices in Tulsa, Oklahoma. It has three subsidiary divisions: MAPCO Natural Gas Liquids, Inc.,[9] MAPCO Coal, Inc., and MAPCO Petroleum, Inc. MAPCO Natural Gas Liquids, Inc., owns and/or directs all pipeline operations for MAPCO, Inc.

In September 1980, the corporation now known as Seminole Pipeline Company was formed to complete a project to construct, maintain, and operate a 14-inch pipeline for the transportation of natural gas liquids in Texas. When it was founded, Seminole was a partnership of subsidiary companies whose ultimate parent companies were MAPCO. Inc., Enterprise Products Company, Standard Oil Company of Indiana (now Amoco Corporation), and Getty Oil Company (now Texaco, Inc.). The Seminole system includes nearly 1,300 miles of pipeline, extending from Hobbs station in west Texas to the Mont Belvieu terminal on the Texas Gulf Coast.

In addition to the Brenham salt dome cavern, the Seminole system includes two other salt dome caverns and one bedded salt cavern. MAPCO Natural Gas Liquids, Inc., has no salt dome caverns but owns 75 mined or washed underground storage caverns in Texas, Oklahoma, Kansas, Nebraska, Iowa, and Illinois. All of these caverns are connected to the Mid-America's system of nearly 7,000 miles of pipeline.

[9] At the time of the accident, the subsidiary of MAPCO, Inc., that had controlling stock interest in Seminole Pipeline Company was MAPCO Transportation, Inc. In January 1993, MAPCO, Inc., merged the pipeline-related operations of all its subsidiaries under MAPCO Natural Gas Liquids, Inc.

(Above) This home was about 1/2 mile from Brenham station.

(Left) Site of mobilehome from which owner called 911 at 6:59 a.m.

(Below) Technician who was first on scene placed calls to his supervisor and the dispatch center from this home.

Photos courtesy of The Brenham Banner-Press

Figure 4. Area residences damaged by blasts.

Brenham Station.--The station is on a 51.35-acre site that straddles the Washington-Austin County line. According to a company representative, Brenham station's primary function is to transport HVLs for consignees along the Seminole pipeline. Brenham station also serves as an accumulation and delivery point. The site receives and accumulates HVLs from processing plants along the Bryan Lateral and from the Coastline pipeline; the site delivers HVLs to Seminole's 14-inch mainline and to Coastline's pipeline.

HVLs at the station are stored in a solution-mined cavern that is more than 1/2 mile below the surface in the Brenham salt dome (see figure 5). Because the Tulsa dispatch center could operate by remote control the pumps and valves needed to route HVLs at Brenham station, the facility was not staffed 24 hours per day. Field personnel assigned to the area went to the station each day to perform required readings, maintenance, and other duties. (Information about employees' specific job duties appears later in this report.)

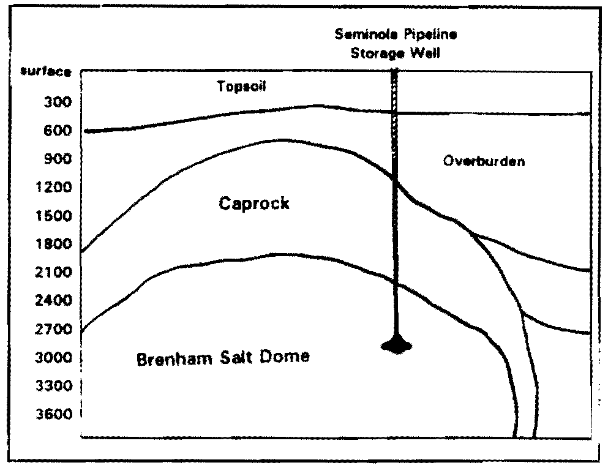


Figure 5. MAPCO geologist's drawing of the storage cavern within the Brenham salt dome.

Background of Cavern.--In July 1981, MAPCO applied to the Texas Railroad Commission (TRC), for a permit to "leach" a 150,000-barrel capacity cavern. The company constructed the underground cavern by drilling a well through the overburden and caprock and into the salt formation. In the well hole, the company installed 2,702 feet of 13 3/8-inch-diameter pipe, which was cemented in place. Inside the 13 3/8-inch pipe, the company installed an 8 5/8-inch-diameter pipe to a depth of 2,879 feet below the surface. The pipes initially served as channels through which the company pumped fresh water down to the salt strata. The injection process caused the water to circulate within the salt formation and dissolve the salt, forming a cavity that contained salt water solution, or brine. The company then pumped out the brine and stored it in an elevated brine pond at the surface. The bermed pond was lined with plastic to keep the brine that was removed from being absorbed into the ground.

The company continued injecting fresh water and removing brine solution until a cavern large enough to begin storage operations was formed (about 20,000 barrels). The 8 5/8-inch-diameter pipe served as a flow line for brine between the cavern and the surface. The annulus, or space, between the two pipes was the flow area through which liquid product could flow into or from the cavern.

Product Storage.--MAPCO added and removed HVLs to and from the Brenham station cavern by means of brine displacement (see figure 6). Brine filled the bottom of the cavern; HVL product filled the upper area of the cavern. Because the specific gravity of brine is more than twice that of HVLs, the weight of the brine in the brine tube contained the HVLs in the cavern. To add product into the cavern, the product pressure was increased by pumping. As product pressure became greater than the pressure produced by the weight of brine at the bottom of the brine tube, the brine level in the cavern was pushed lower and brine was pushed up the brine tube and into two brine ponds at the surface. Conversely, when product was removed from the cavern, the resulting drop in product pressure allowed the heavier brine to flow back down into the cavern from the surface ponds.

Brine Ponds.--Pond No. 2, which has a capacity of 150,000 barrels, is immediately adjacent to the wellhead (see figure 7). Pond No. 1, which has a capacity of 100,000 barrels, is northeast of and next to Pond No. 2. The two brine ponds are connected by a 12-inch-diameter pipeline, which also connects to the 8 5/8-inch brine tube near the wellhead. The 12-inch line is used to transfer brine to and from the cavern and to help keep the surface levels of the two ponds even. If the amount of brine is insufficient to displace HVLs from the cavern, the brine system has two pumps that can be used to inject fresh water into the brine tube.

Cavern Growth.--In a salt dome facility, whenever the brine is less than fully saturated, salt dissolves from the cavern walls, thereby gradually increasing the size of the cavern. The salinity of the brine can be reduced as a consequence of weather, such as when rainwater mixes with the brine in the ponds at the surface, or when an operator draws off some of the brine and replaces it with fresh water. Records show that MAPCO periodically sold brine to drillers. As a result of periodic dilution from rain and from partial substitution of fresh water for brine by the company, the volume of Brenham cavern had grown from about 20,000 barrels when operations began in September 1981 to about 336,000 barrels in May 1991 (see figure 8).

To determine the increase in cavern size, the company periodically contracted sonar measurements of the facility. In his research paper, "Instrumentation and Controls for Solution-Mined Underground Storage Systems," Neal E.Van Fossen describes the operation of the sonar caliper and states that the "order of accuracy" for the procedure is generally plus or minus 5 percent.[10] Other industry representatives have characterized the order of accuracy as 10 percent or greater. A spokesperson stated that MAPCO recognized that sonars were not precise and could not be used to determine the volume of a specific interval within the cavern. The spokesperson also stated that once the company determined the cavern's capacity, as an operating safeguard, it based product storage on a working capacity that was 10 percent below total capacity.

[10] From the *Fifth Symposium on Salt -- Volume Two*, The Northern Ohio Geological Society, Inc. (1988).

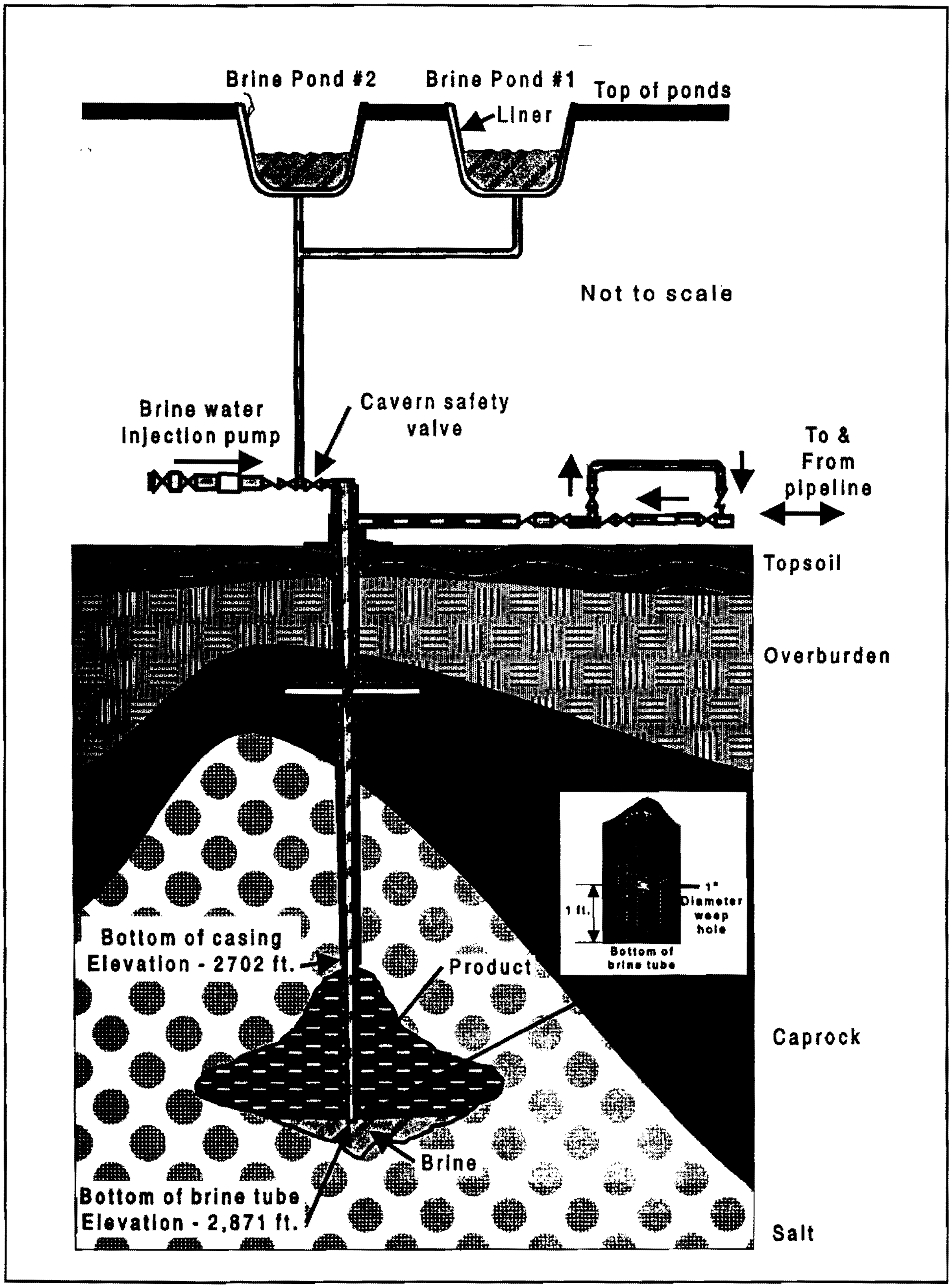


Figure 6. Cavern storage facility.

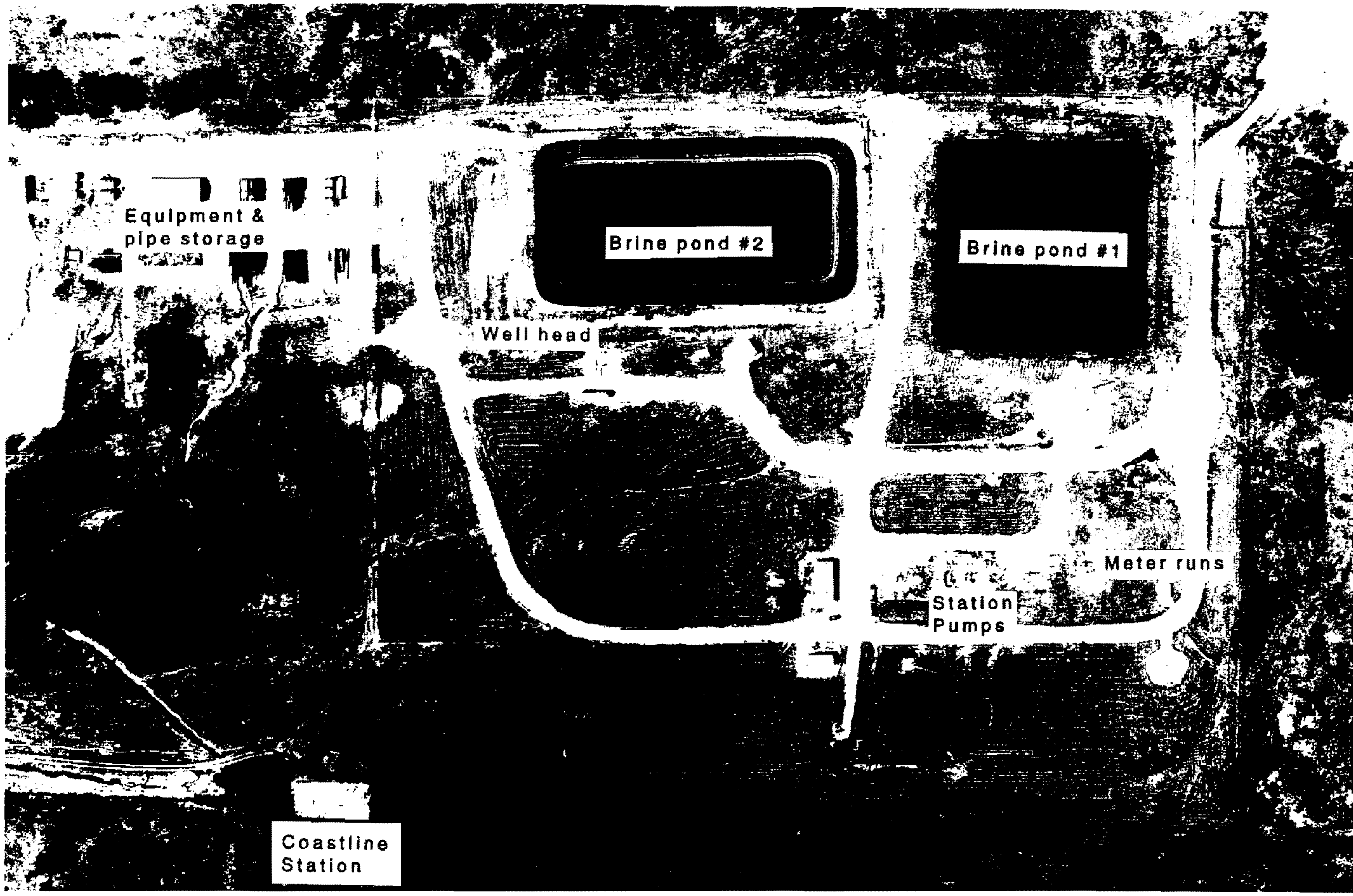


Figure 7. Overhead of station showing brine ponds.

Jul 1981	MAPCO files for authority to construct a cavern with a proposed capacity of 150,000 barrels.*
Sep 1981	MAPCO begins operating cavern with an initial volume of 20,000 barrels.
Nov 1982	Cavern volume tests indicate capacity is 65,938 barrels.
Oct 1986	Cavern volume tests indicate capacity is 111,000 barrels.
Nov 1987	Calculations indicate cavern capacity is about 154,000 barrels. MAPCO establishes the cavern working capacity at 130,000 barrels.
Mar 1988	After a February 1988 HVL release from Brenham cavern, MAPCO contracts a sonar measurement of the cavern from which volume was calculated to be 173,000 barrels. MAPCO sets cavern working capacity at 165,000 barrels.
May 1991	Based on sonar tests of the cavern, MAPCO calculates capacity to be 336,580 barrels and increases working capacity to 300,000 barrels.

*Although MAPCO's application was for a 150,000-barrel cavern, the Texas Railroad Commission order authorizing construction of the cavern did not include a capacity limitation.

Figure 8. Expansion of Brenham cavern.

Station Piping and Valves.--Three pipelines provided the primary means of product transport to and from Brenham station (see figure 9). The Bryan Lateral, an 8-inch pipeline spanning 41 miles, transported HVLs from several processing plants northeast of the station; a 6-inch line transported HVLs to and from Coastline's pipeline system at the southwest side of the station complex; and a 6-inch line transported HVLs to Seminole's 14-inch mainline.

Within the station piping system, the principal piping for transporting product was a 6-inch-diameter line that could take HVLs from the Bryan Lateral to Seminole's 14-inch-diameter mainline, to Coastline's 6-inch-diameter pipeline, or to the cavern piping and an 8-inch-diameter line that could move product to and from the cavern. Through valve, piping, and control equipment arrangements, only MAPCO could control the flow of HVLs in or out of Brenham. The motor-operated valves could be opened and closed either by a dispatcher in Tulsa or by on-site personnel at Brenham station. A control valve at the cavern pump regulated the pump suction pressure to maintain a pressure of 450 psig or more.

Coastline's Riser.--Coastline's 6-inch pipe connected to the Seminole system at the southwest boundary of the station. The pipe exited and re-entered the ground in an area enclosed by chain-link fence.

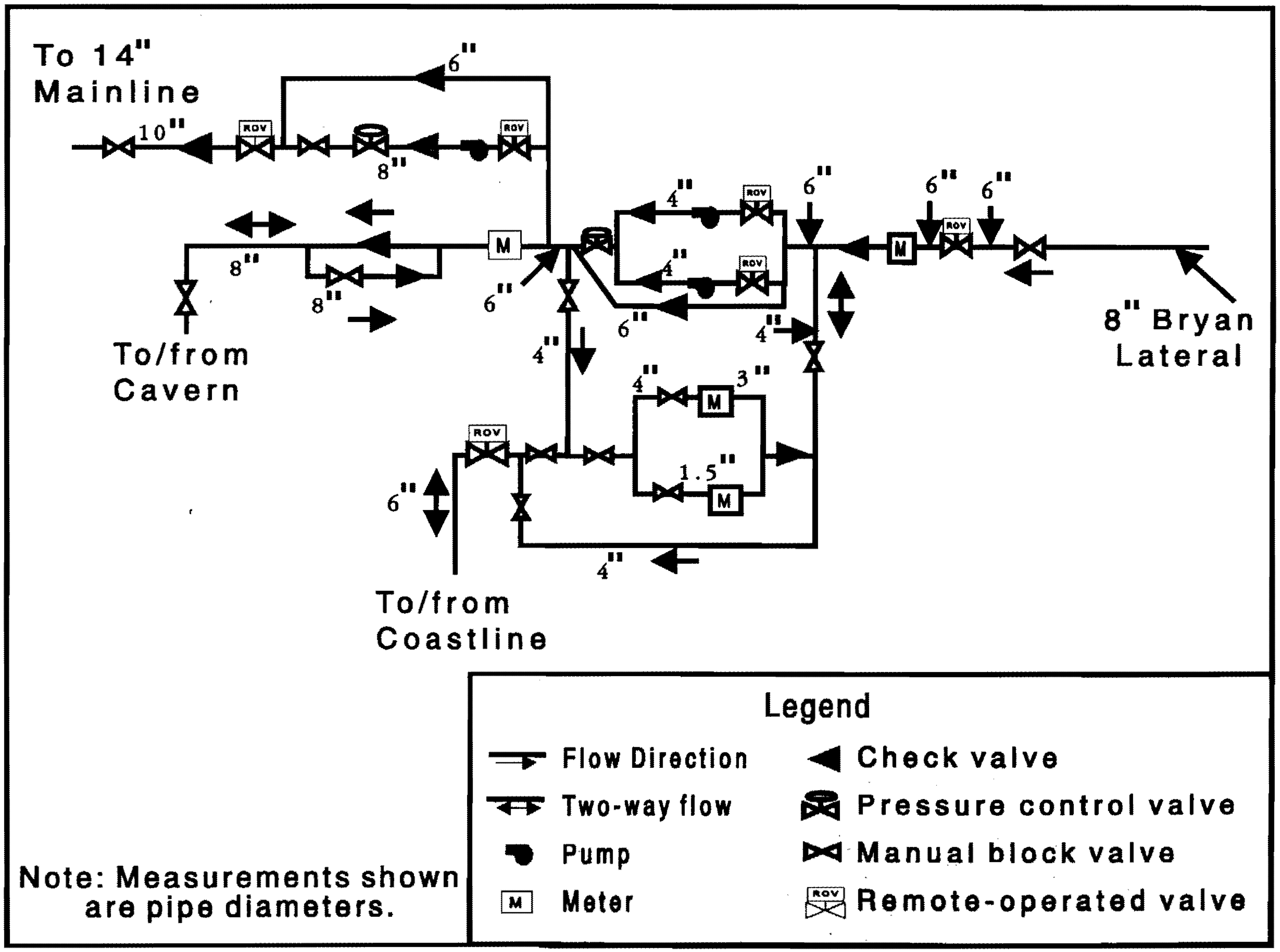
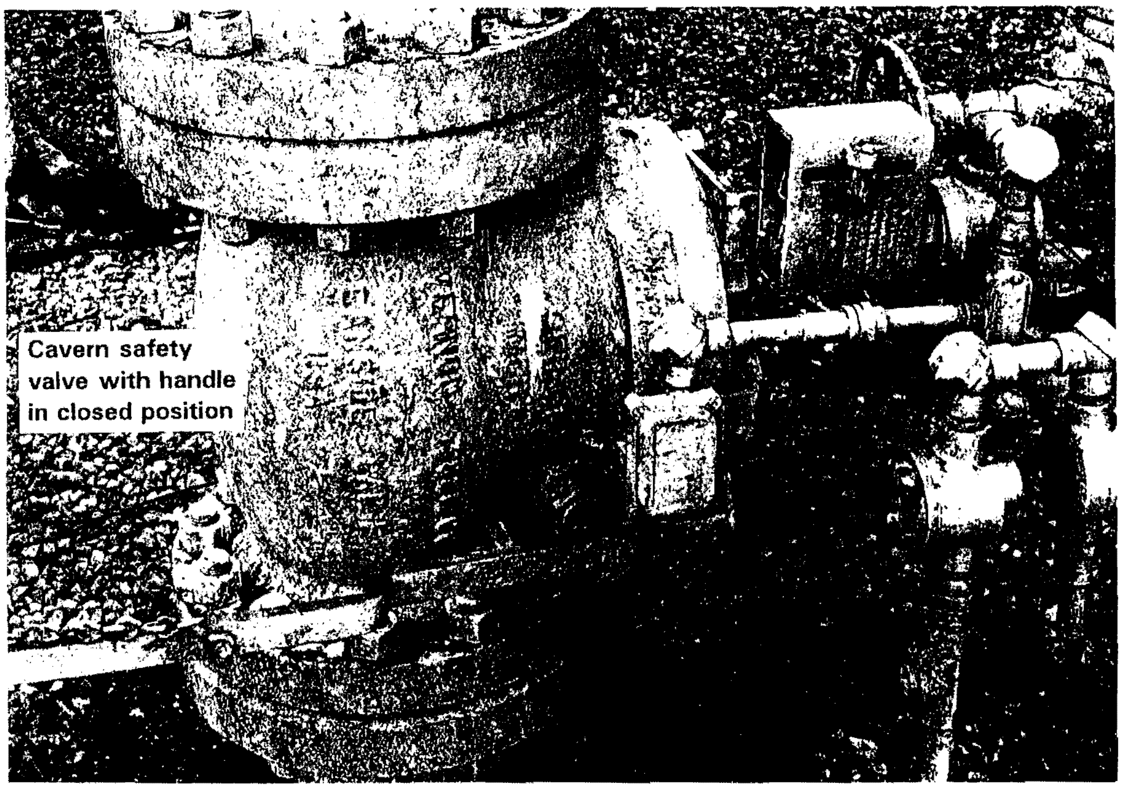
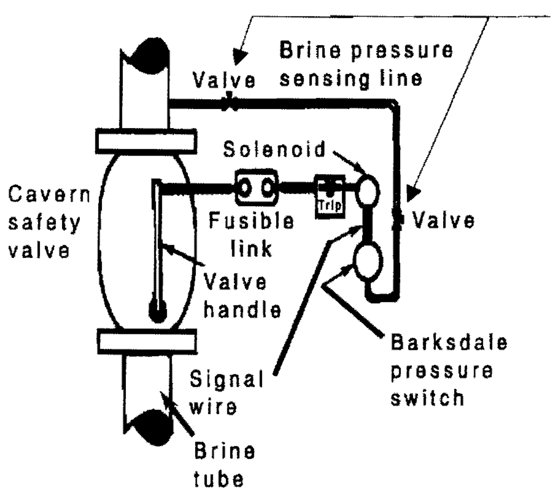


Figure 9. Schematic of Brenham station piping system.

Cavern Safety System (See figure 10).--When the Brenham station was constructed, no industry or government standards existed that described the type or design of equipment needed to provide a specified level of safety control. An executive officer and former chief engineer for

In the closed position, the cavern safety valve prevents HVLs from flowing from the cavern to the brine ponds. The manufacturer's literature advised that valve operation could be controlled by a fusible link, a manual cable, or a pneumatic or solenoid actuator.





For the system to function correctly, both manual valves in the brine pressure sensing line must be open.

A chain containing a fusible link (165° F) holds the spring-loaded cavern safety valve in the open position. The chain is connected to a lever on an electrically operated valve.

If the fusible link separates as a result of a fire or other heat source that increases the temperature of the link to 165° F or more, the cavern safety valve closes.

A Barksdale switch initiates movement of the cavern safety valve by sending an electrical signal to the solenoid lever to release the chain when the Barksdale switch detects a pressure of 100 psig in the brine tube.

Figure 10. Components of the cavern safety valve system.

the company said that MAPCO engineers designed the station, including the configuration of the station's cavern safety system and selected equipment, after reviewing the practices of other companies that were operating caverns at the time. He characterized Brenham's cavern safety system as "state of the art at the time it was installed and now" and added that other Seminole cavern storage facilities had comparable safety systems.

Near the wellhead, the company had installed equipment that was to automatically shut down the station pumps should the gas detectors sense a significant level of HVL in air. If excessive pressure built up in the brine tube or excessive heat built up near the wellhead, the cavern safety valve[11] in the brine tube was to close, thereby preventing HVLs from exiting the cavern through the brine ponds.

About 1 foot up from the base of the brine tube was a 1-inch-diameter weep hole. According to an executive officer of the company, the weep hole was installed to provide a "warning" that the product level was approaching the base of the brine tube and that the cavern was being overfilled. He explained that when the HVL level reaches the weep hole, product begins to enter slowly into the brine tube because the pressure differential across the weep hole is small. Product entering the brine tube through the weep hole then rises to the brine pond, where it escapes into the atmosphere as a vapor and triggers a gas detector that transmits an alarm signal to the Tulsa dispatch office. A small vapor release would also serve as a visual indicator to personnel who happen to be at the unmanned station that the cavern was becoming overfilled. They could then close the cavern valve manually.

The officer added that it is possible that while the HVL level is approaching the base of the brine pipe, enough product might enter the weep hole to sufficiently increase the pressure in the brine tube to activate the cavern shutdown system before the product reached the bottom of the brine tube.

Hazardous Gas Detectors.--Detectors were installed around the brine ponds and at other station locations to alert employees who might be at the station and the dispatch center of an HVL release within the station. Brenham station had 20 hazardous gas detectors: 8 spaced around each brine pond, 1 at the wellhead, 1 near the cavern injection pumps, 1 at the mainline injection pump, and 1 at the building housing station control equipment.

Detectors operated by pulling in nearby air and passing the air sample across a catalytic sensor. If the air sample contained hydrocarbons, the electrical circuit within the sensor oxidized the hydrocarbons, which caused a temperature increase in the circuit. The resulting increase in electrical resistance was transmitted as an electrical signal to a monitor in the control building, where the signal registered as a gas-in-air percentage of the lower explosion limit (LEL).

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[11] Also known as the trip check valve or emergency shutdown device.

In the control building, indicator lights lit up when a gas detector had been activated. When a yellow indicator light lit up, the detected gas-in-air concentration was at least 25 percent of the LEL. Illumination of a red indicator light meant that the detected gas-in-air concentration exceeded 38 percent of the LEL. At the 38 percent level, all pumps at the station automatically shut down, and a single signal was transmitted to the dispatch center, where it was displayed as a safety fault on the dispatcher's monitor screen and on the alarm screen and printed out on the alarm logger.

Regardless of whether one detector or several detectors at the Brenham station sensed gas and activated, the Tulsa dispatch center received only one signal. The dispatcher controlling the Seminole system did not have the capability to determine the location or magnitude of any gas release or the means to differentiate whether an alarm signal had been caused by an actual HVL release or some other cause. Company maintenance records showed that other factors also caused a gas alarm to activate, even when gas vapors were not present, including detector failure, excessive brine moisture in the detector, nearby lightning, and degeneration of electrical components in the detectors. To determine whether an actual emergency existed, MAPCO procedures required that the Tulsa dispatcher contact an area technician, who was to immediately check out the site to determine why an alarm had been transmitted from the station.

During the 8 years before April 7, 1992, less than 10 percent of all detector alarms received from Brenham were the result of HVL releases at the station; none of the releases detected were major. A review of the pump station log sheets from April 1, 1991, to March 1, 1992, showed that gas detectors at Brenham station activated eight times, four of which were during nonwork hours. In each instance, the activations were not caused by gas. When on-site personnel either replaced or recalibrated the detectors, the detector system promptly resumed normal operation. In postaccident testimony, the company executive officer stated that while he wished that the gas detectors around the brine ponds performed more reliably, he believed that the current devices were the best that the company could obtain when they were installed.

Properties of HVLs in the Brenham Cavern.[12] In the cavern, stored HVLs remain in liquid form because of the pressure that the brine exerts on them. The HVL mix stored at Brenham station comprised more than 40 materials, primarily ethane, propane, and butane. The table below shows the vapor pressure[13] and other selected constants of the three principal compounds in this HVL. Ethane, propane, and butane are all colorless, odorless, nontoxic, flammable gases. If a person inhales any one or a mix of these three gases at low concentrations in air (5 percent or less), the gas(es) will not cause any definite symptoms. At higher concentrations, each gas has an anesthetic effect and can act as an asphyxiant as it displaces the oxygen in the air. In liquid form, each product can freeze tissue if it comes in contact with the skin. One

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[12] *Handbook of Compressed Gases*, Second Edition, Compressed Gas Association, 1981, and *Engineering Data Book, Volume II*, Gas Processor Suppliers Association, 1987.

[13] At any given temperature, the pressure needed to keep an HVL as a liquid is called its vapor pressure.

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cubic foot of HVL will generate several hundred cubic feet of vapor. For example, at 60° F, 1 cubic foot of liquid ethane, propane, and butane will form 295, 273, and 254 cubic feet of vapor, respectively, if reduced to atmospheric pressure.

HVL PROPERTIES	ETHANE	PROPANE	BUTANE
Vapor pressure at 70°F	544 psig	109.73 psig	16.54 psig
Specific gravity of gas at 60°F, 1 atm	1.0469	1.5226	2.0068
Specific gravity of liquid at saturation and 60°F	0.3562	0.5070	0.5840
Flammable limits in air, by volume	3.0-12.4%	2.1-9.5%	1.8-8.4%
Flash point	-211 °F	-156 °F	-101 °F

Table 2. Properties of ethane, propane, and butane.

The Dispatch Center.--The dispatch center in Tulsa monitors and controls all pipeline product flow operations by means of a telemetry system called the Supervisory Control and Data Acquisition (SCADA) system. Before the Brenham accident, the center had three SCADA work stations or "boards." One board controlled the two Texas systems, Seminole and Snyder pipelines (see figure 11); a second board controlled MAPCO's northern division system; and the third controlled MAPCO's western division system.

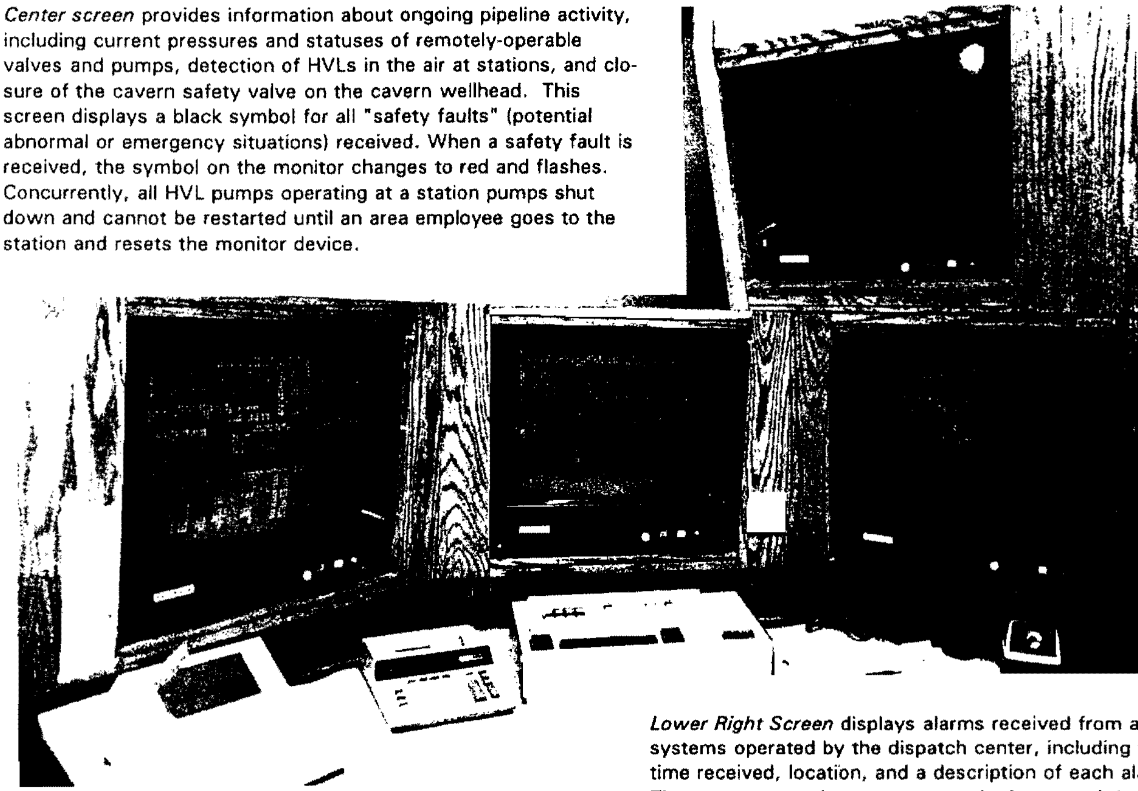
The SCADA system collects data from all monitored points within the Seminole pipeline system and MAPCO's systems, processes and displays the data on monitors, identifies operating data that are not within preselected parameters and displays them as alarms on monitor screens, displays a schematic of the pipe system, and stores operating data for later retrieval.

Dispatchers communicate with the SCADA telemetry system and the computer data base by typing in commands on a keyboard. In this manner, dispatchers are able to "command" changes in remotely operable valves, pump operations, and product flow routing on a given system and can retrieve information from the computer data base. Each of the four monitor screens displays data received about the pipeline system in different functional formats.

The SCADA telemetry system receives information from various monitoring devices throughout the Seminole pipeline system and updates the system information every 15 to 20 seconds. From Brenham station, the monitor screens at the Seminole/Snyder board display information such as shown in figure 12.

Upper Right Screen can be used to call up various information maintained in the dispatch center's computer database. Using this screen, the dispatcher can view piping diagrams for the stations, sections of the pipeline between stations, or historical data on pressures and flows that are in the computer database.

Center screen provides information about ongoing pipeline activity, including current pressures and statuses of remotely-operable valves and pumps, detection of HVLs in the air at stations, and closure of the cavern safety valve on the cavern wellhead. This screen displays a black symbol for all "safety faults" (potential abnormal or emergency situations) received. When a safety fault is received, the symbol on the monitor changes to red and flashes. Concurrently, all HVL pumps operating at a station pumps shut down and cannot be restarted until an area employee goes to the station and resets the monitor device.



Left screen displays the Seminole mainline flow rates and meter readings, and the pump pressures, HVL flow rates, valve status, location of different batches of HVLs moving through the system, and "safety faults" for the Snyder system. The computer records and permanently stores pressure and flow rate information at 15 minute intervals; the dispatcher can retrieve this information at any time.

Lower Right Screen displays alarms received from all systems operated by the dispatch center, including the time received, location, and a description of each alarm. The most recent alarm appears at the bottom of the screen and then moves up as subsequent alarms are received until it moves off the screen. Each alarm is also recorded by a printer in the dispatch center at the same time it appears on the screen, thereby providing an audible notice of an alarm. This screen affords dispatchers the opportunity to assisting one another without leaving their assigned stations, such as when many alarms are received or when a dispatcher needs to take a break.

Figure 11. The SCADA "Board" for the Seminole pipeline.

Personnel Information

The individuals discussed below include field personnel who were on site at Brenham station and dispatch personnel who were monitoring the Seminole/Snyder pipelines on the morning of the accident. The area safety regulations coordinator is also included.

Brenham Station.--Area operators, technicians, pipeliners, and an assistant supervisor are required to perform specific tasks at Brenham station each weekday. Before the accident, the facility was an "unattended station" in that the dispatch center in Tulsa remotely controlled product transport to and from the station and area personnel were not required to remain on-site once they had performed the required morning meter readings and other necessary functions, such as maintenance.

Flow rate of HVLs entering the station from the Bryan Lateral;

Flow rate of HVLs being injected into and removed from the cavern;

Status of pump operations (on or off) and the pump suction, case, and discharge pressures;

Status of remotely operated valves: open, closed, or in the process of changing positions;

Pressure of HVLs in the 14-inch mainline, the meter runs, the Bryan Lateral at the station, and the pipe between Seminole and Coastline;

Indication that the cavern safety valve on the cavern wellhead had closed; and

Detection of HVL in air by any one of the many combustible gas detectors located around the brine ponds and other locations within the station.

Figure 12. Types of data displayed by the SCADA monitors.

Assistant Maintenance Supervisor.--Before joining MAPCO, the assistant maintenance supervisor worked as an operator and a maintenance specialist for Colorado State Gas. He joined MAPCO in 1984 as a technician in the oil and gas division. As assistant maintenance supervisor, he supervised the technicians and was responsible for all technical maintenance performed on the 120 miles of mainline pipe from Burnet to Cat Springs.

Technician.--Before joining MAPCO in summer 1987 as a technician trainee, the technician worked in power (line) distribution. As a technician, his primary responsibility was to maintain electrical equipment, such as the pumps, meters, transformers, motor-operated valves, and calibrating switches. He also performed inspections and tests required by the Government and/or the company and some general station maintenance. He and several other technicians within the division rotated being on-call during nonduty hours for the purpose of checking out any abnormal reading or emergency signal that the Tulsa dispatch office might receive from equipment in their work area.

Technician Trainee.--An employee of MAPCO since summer 1991, he performed the same duties as a technician under the supervision of experienced personnel. As a trainee, he was not subject to being on-call to respond to emergency calls.

Pipeliner.--Before joining MAPCO in fall 1990, he had worked in the pipeline industry for about 12 years. As a pipeliner, he was responsible for maintaining the piping and nonelectrical equipment at a station and for performing general maintenance operations, such as taking care of the grounds. He also served as a system operator when needed. Originally assigned to Sugar Land, Texas, he transferred to Brenham about 6 months before the accident. His first-line manager, the supervisor of maintenance, was at the division office in Sugar Land.

Area Operator.--The area operator initially was assigned to Brenham station in 1990 as a pipeliner. After completing the company's area operator training course in April 1991, he assumed the duties of area operator, which entailed reading the various meters at the station and calculating actual cavern volumes, which he reported on the Daily Operating Volume (DOV) reports.[13] He also performed meter accuracy tests and operated all of the station's manually run equipment that impacted product transfer in the system piping. The area operator at Brenham station reported to the operations supervisor, who was based in Sugar Land.

Lab Technician.--The lab technician began work with MAPCO in February 1973. Since March 1981, he had been assigned to the Brenham station, serving in a variety of positions, including technician trainee, terminal man, and area operator. He was promoted to lab technician supervisor in May 1990. His first-line manager, the operations supervisor, was at the division office in Sugar Land.

Regulatory Coordinator.--The regulatory coordinator had worked 14 1/2 years for MAPCO. Before transferring to Sugar Land, he had worked as a fractionator in Kansas for about 3 years and then as an area operator at Scullytown, Texas, for 8 years. As the area regulatory coordinator, he was based at the division office in Sugar Land and reported to the division manager.

The Dispatch Center.--On the eve of the accident, the Seminole/Snyder board was manned by a dispatcher trainee and an experienced dispatcher, who was serving as trainer and overseeing the work of the trainee. About 6:30 a.m. on April 7, the nightshift dispatchers for the Seminole/Snyder board were relieved by the dayshift dispatcher.

Dispatcher (Trainer).--He had worked for MAPCO since 1981. His first assignment was as a pipeliner with the maintenance crew. In 1984, he transferred to the operations department, where he worked as an area operator for 2 years and then as a meter technician for almost 4 years. In 1989, he completed all required knowledge improvement courses and on-the-job training to become a dispatcher. Before reporting to work on the eve of the accident, the dispatcher (trainer) had worked the 7 p.m. to 7 a.m. shift on April 3, 4, and 5.

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[13] The measurements and calculations that an employee performed in preparing the DOV report appear under "Operations and Maintenance, Inventory Operations."

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Dispatcher Trainee.--He began work as a pipeliner at Brenham station in July 1989. In July 1990, he transferred to Hobbs station, where he worked as a utilityman until February 1992. At that time, he transferred to Tulsa to start training to become a dispatcher. The last time that the dispatcher trainee had worked before the eve of the accident was the 7 a.m. to 7 p.m. shift on April 4.

Dispatcher.--The dispatcher who was manning the Seminole/Snyder board at the time of the explosion had worked for MAPCO since 1974, when he was hired as a pipeliner. Three months later, he transferred to the Conway, Kansas facility, where he worked as a fractionator for 5 years. He had been a MAPCO dispatcher since 1979. Before reporting to work on the morning of April 7, he had last worked the 7 p.m. to 7 a.m. shift on April 4.

General Employee Training.--Pipeline Safety Regulations at 49 CFR 195.403, "Training," stipulate that "Each operator shall establish and conduct a continuing training program to instruct operating and maintenance personnel ..." in the following areas: normal operating procedures as outlined in the operator's employee operating handbook, characteristics of HVLs, identification of emergency situations and appropriate response actions, procedures for controlling or minimizing accidental releases, procedures for fighting fires and proper use of fire fighting equipment, and precautionary measures when repairing facilities.

The MAPCO training program for employees began on their first day with the company and continued throughout their employment. Training included orientation and initial instruction, mandatory and optional self-study courses, on-the-job training (OJT), in-house and contracted training, and safety seminars.

Orientation.--According to an outline of the orientation course, employees were briefed about the various sources from which they could obtain information about pipeline operations. Instruction included explanations of hazardous material labeling, fire extinguisher use, and company policies regarding safety clothing and drugs. Much of the instruction was presented in the form of videos. Instructors also told employees about available written material, such as procedural manuals, pipeline and pump station diagrams, and the material safety data sheet book. Employees were given several safety items, including a hard hat, safety glasses, goggles, work gloves, earplugs, a rainsuit, and rubber boots.

Self-study Courses.--Within 6 months of their hiring date, new employees had to complete the first eight courses of a "Knowledge Improvement Program," a self-paced, 36-course correspondence series. MAPCO contracted development of its correspondence program from Technical Publishing Company, a division of Telemedia, Inc., which specializes in developing standard basic training manuals and films for schools and industries. Required courses included blueprint reading, shop math, hand tools, plant safety, piping systems, product transportation, properties of products, and safety in product handling. In each course, the end of each lesson chapter had a self-check quiz and a summary of the important principles covered in the chapter.

As an employee completed a course, MAPCO sent him a final test to be completed and returned to the company for grading. The company maintained a record of the final test results in the employee's permanent file. According to company policy, which was confirmed by employee testimony, employees could neither be promoted from their initial position nor receive a pay raise until they had successfully completed the eight required courses. Employees could take the additional 28 courses of the Knowledge Improvement Program at their own pace and were permitted to keep course books for use as on-the-job reference materials.

Employees who had gained knowledge of the subject matter from prior work experience or coursework had the option of taking a pretest. If they scored 70 percent or higher on the pretest, they were not required to take the correspondence course. MAPCO also maintained records of employees' pretest scores in their personnel files.

OJT Instruction.--During OJT, a new employee was paired with an immediate supervisor and/or experienced co-worker, who performed required procedures at a worksite while the novice watched. Employee testimony and personnel records showed that the "trainers" had never received specialized training or coursework to prepare them to be instructors.

After the new employee observed the trainer a sufficient number of times to express confidence in his ability to perform the procedures, the experienced employee supervised while the novice performed a task. According to MAPCO, a new employee was allowed to perform a given task unsupervised only after repeatedly demonstrating the ability to perform the task in a supervised situation.

From interviews and a review of training manuals and guidelines used by field and dispatch personnel, Safety Board analysts determined that employees had few or no written procedures specific to their positions. For example, employees who performed volume calculations either at Brenham station or at other stations did not have a written protocol to which they could refer. Available manuals included one that explained general procedures and one that contained product-specific and safety information.

While an employee was in the OJT phase, the trainer treated each procedural task separately. If a trainer determined that the new employee was proficient in some minor, non-dangerous field operating tasks, he might allow the trainee to perform those duties unsupervised but require that the trainee perform more involved or potentially dangerous tasks only when a senior person was present. Company policy stated and employee interviews confirmed that the OJT phase was no fixed period; new employees remained in the phase until they demonstrated they could perform all tasks correctly.

Personnel records showed that with one exception, all dispatchers were experienced in pipeline field operations before being selected as dispatcher trainees. The dispatcher training program did not include formal classroom instruction; all instruction was OJT. A trainee initially sat with and observed as an experienced dispatcher operated one of the three dispatch boards during the 12-hour workshift. As information appeared on the monitors, the trainer explained what was being shown and what operations had to be performed. In the next phase of dispatcher OJT, the trainee sat at the keyboard and performed the required functions under the supervision of a trainer seated nearby.

During the several months that a trainee was in dispatcher OJT, the individual rotated among all experienced dispatchers for training and supervision and worked each of the three boards at the dispatch center. Trainees were exposed to different facets of operations. For Brenham station, trainees were instructed how to monitor and/or respond to the readings and alarms listed earlier in this report in figure 12.

Toward the end of the dispatcher OJT program, trainees were given a mock drill involving a leak or product release from a pipeline and were evaluated on their response actions. Trainees had to correctly identify and simulate calls to the appropriate field and public emergency response agencies and take corrective action by operating the remote equipment available to isolate the problem. The trainee was required to handle all essential tasks with no prompting while the head dispatcher and other dispatchers observed and evaluated the trainee's performance.

Interviews with dispatchers revealed that trainees were not required to demonstrate they could handle an abnormal cavern situation as part of the drill. MAPCO also did not require that dispatcher trainees take a final written examination to become full dispatchers. Whether an individual successfully completed dispatcher training was based solely on the judgment of the head dispatcher and dispatcher trainers who supervised the trainee during the OJT training phase. Company supervisors had the final decision whether and when a trainee was qualified for promotion to dispatcher.

Safety Meetings.--Company records show that between January 1, 1991, and the date of the accident, supervisory personnel and the division regulatory coordinator conducted 23 employee safety meetings systemwide. These in-house seminars were held both at the stations and on a divisionwide basis. Accordingly, personnel based at Brenham station attended ten safety meetings that the company held at the station and at the Sugar Land division warehouse. The division manager, supervisors, and regulatory coordinator determined the meeting agendas, which, among other subjects, included emergency response procedures. Additional safety meetings were conducted whenever the division manager or one of the supervisors determined that a matter required immediate attention, such as learning how to use new equipment or the impact of a new government regulation.

Safety meetings were structured to foster discussion of the safety topic and/or procedures. For instance, during an October 1991 safety meeting on abnormal operations, employees were given five emergency scenarios. Of the five, three scenarios dealt specifically with the Brenham area and included an HVL release from the cavern. Personnel were to evaluate the cause of the problem and what steps should be taken to resolve it. The scenarios were first completed individually, then later discussed by the group. Following the safety meetings, class participants usually were not required to take written tests or demonstrate proficiency in emergency drills. Safety Board investigators determined from a review of safety meeting agendas and from interviews that Brenham station employees had attended sessions that covered emergency response procedures for handling major HVL releases.

Dispatchers and on-scene personnel were provided with video tapes and the procedural manual discussing abnormal operations and emergency procedures. Investigators found that the material provided did not include written procedures for either the dispatchers or on-scene employees that would assist them in gathering and reporting product-release information.

All materials provided to both dispatch and on-scene personnel stressed that the dispatcher has the authority to shut down the pipeline system and implement emergency procedures without having to seek supervisory approval. The dispatchers are considered the main link in communications among the emergency responders. Their critical procedures include calling out field personnel to check out suspected damage, shutting down all pumping units and closing fire valves, notifying company personnel and local people designated as emergency contacts, directing personnel to the leak area, monitoring the SCADA for pressure and flow information, and informing the supervisor of abnormal operations and what action has been taken to correct it. In handling an emergency, a dispatcher can request assistance from other dispatchers working the same shift. However, MAPCO did not provide procedures or training that identified the most effective allocation of emergency response tasks among the dispatchers.

According to the procedural manual, when handling an abnormal or emergency situation, the responsibilities of on-scene personnel included closing valves, establishing road blocks, evaluating the hazard, warning people, and in general, preventing damage to life and property. One company representative capable of evaluating, planning, and coordinating leak-site activities was to go directly to the leak site, take charge, and determine the proper way of controlling the liquid or vapor release.

Supplemental Training.--In addition to the safety meetings, MAPCO either conducted or contracted vendors to conduct in-house schools and seminars. For example, an in-house school for area operators and technicians was conducted every year to train new employees and update experienced personnel. Between January 1, 1991, and April 6, 1992, MAPCO conducted five in-house schools and contracted one vendor class that provided more detailed training on equipment maintenance. Safety Board investigators determined that MAPCO encouraged employees to attend schools conducted by independent organizations and vendors on company time and at company expense.

Performance Evaluations.--Federal regulations stipulate that "at intervals not exceeding 15 months, but at least once each calendar year," operators must review with personnel their performance in meeting the objectives of the training program in the six areas listed at CFR 195.403 (see figure 13).

Safety Board investigators determined that company supervisors routinely monitored the work of their subordinates. The acting area manager at the time of the accident said that he checked calculations, inspected on-site, and held discussions with his employees to determine whether they were correctly performing their responsibilities.

A Safety Board inspection of personnel records indicated that company supervisors formally reviewed their employees' work performance annually and rated them on such factors as dependability, attention to detail, and cost consciousness. Personnel files also contained records of training that each employee had completed. A MAPCO representative testified that company managers annually reviewed and made adjustments to the established training program to ensure the effectiveness of their training.

> Carry out the operating, maintenance, and emergency procedures that relate to assignments.
>
> Know the characteristics of hazardous liquids, including the flammability of mixtures with air, odorless vapors, and water reactions.
>
> Recognize conditions likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquid spills, and take appropriate corrective action.
>
> Take steps necessary to control any accidental release of hazardous liquid and minimize the potential for fire, explosion, toxicity, or environmental damage.
>
> Learn the proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated emergency.
>
> (For maintenance personnel) Safely repair facilities using appropriate special precautions.

Figure 13. Excerpts from 49 CFR 195.403.

Dispatcher Workshifts.--Dispatchers worked a rotating schedule of 12-hour shifts. According to MAPCO, a typical work cycle required that a dispatcher work two or three day shifts, which were scheduled from 7 a.m. to 7 p.m., have 2 days off, and then work two or three consecutive night shifts, which were scheduled from 7 p.m. to 7 a.m. The dispatcher then had 2 days off before the above rotational schedule began anew. This rotational cycle continued throughout the month.

The three dispatchers interviewed by Safety Board investigators stated that they arrived 20 to 30 minutes before their scheduled shift so that dispatchers whose shift was ending could brief them about any situations that might require particular attention and operations that were to be conducted during the upcoming shift.

Safety Board investigators reviewed the work schedule sheets of dispatchers from March 1 to April 7, 1992. They determined that the dispatcher trainer had worked the night shift 4 nights in a row before the morning of the accident. The dispatcher trainee had worked the day shift on April 4 and had been off 60 hours before starting his night shift on April 6, the eve of the accident. The dispatcher who relieved the dispatcher trainer and trainee at the Seminole/Snyder board the morning of the accident had worked the midnight shift on April 3 and had been off 72 hours. Work schedule sheets also showed that two company dispatchers had worked 8 consecutive days without a day off during the 2-month period.

From interviews, Safety Board investigators determined that the dispatchers did not have regularly scheduled breaks. Dispatchers were allowed to leave their stations momentarily to use the restroom or get a snack. While a dispatcher was away from his board, the other dispatchers would listen for alarms printing out on the alarm logger, which recorded alarms received from all pipeline systems monitored by the Tulsa dispatch office. If a dispatcher heard an alarm printing on the logger that was not on his console monitor, he could switch his screen to bring up the information for the other pipeline system. Dispatchers usually ate their lunches at their boards while they continued to monitor the SCADA.

Toxicological Testing.--The Pipeline Safety Regulations at 49 CFR 199.11 stipulate the following in regard to postaccident drug testing:

> As soon as possible, but no later than 32 hours after an accident, an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident.... An operator may decide not to test under this paragraph but such a decision must be based on the best information available immediately after the accident that the employee's performance could not have contributed to the accident or that, because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use.

About 31 hours after the explosion, MAPCO managers required urine samples from the three dispatchers who were monitoring the Seminole board on the eve and the morning of the accident. Field personnel at the Brenham station were not asked to submit samples.

According to a company spokesperson, MAPCO did not test its dispatchers earlier because the company thought that Coastline's pipeline was the source of the release. He further stated that MAPCO did not require that field personnel submit to testing because the company believed that the accident did not result from any action performed by an on-site employee. The State agency responsible for investigating this pipeline accident, the TRC, did not require that on-scene employees submit to postaccident drug testing.

Samples were taken to Smith Kline-Bioscience, a National Institute for Drug Abuse (NIDA)-certified laboratory in Dallas, Texas, where they were analyzed for amphetamines, cocaine, PCP, marijuana, and opiates. The drug test results were negative.[14]

[14] Current Federal regulations do not require that blood samples be submitted for toxicological testing or that an individual be tested for alcohol.

Operations and Maintenance

According to a company spokesperson, MAPCO's operations called for timely delivery of the HVLs. Storage of mixed HVLs in caverns was viewed as a temporary measure to afford the company a more economical means to operate the entire pipeline system. MAPCO's contract with processing plants along the Bryan Lateral obligate the company to take all products that the plants produce so long as operating conditions permit. If product cannot be stored in the cavern, dispatchers sometimes must inject Y-Grade[15] products into pure products or shut down the plants, either of which is very costly to the company.

Inventory Operations.--As mentioned previously, each morning about 7 a.m., an employee prepared the Daily Operating Volume (DOV) report for Brenham station. He inventoried product volume by recording readings from the Bryan Lateral meter, the cavern meter, and the Coastline meter on a worksheet. According to a company spokesperson, the employee then corrected the readings for meter error[16] and converted all measured volumes to a standard temperature and pressure to allow direct comparisons of measured volumes, a procedure that is standard in the industry.

Employees corrected all measured volumes to 60° F and equilibrium pressures. Employees next corrected the meter reading volumes based on the applicable volume correction factor and then calculated the net volumes of HVLs received at the station from Coastline or the Bryan Lateral, delivered from the station to Coastline, delivered to and from the cavern, and the volume of HVLs stored in the cavern. The volume correction factor was derived using the weekly derived density volume correction factor (based on analysis of a sample of the HVL mix delivered to the Bryan Lateral from plants) and the flow-weighted average product temperature and pressure. The meter correction factor was based on periodic flow proof tests. Once the net volumes were calculated, the area operator entered the data into a computer at the station to create a DOV report.

The DOV report was sent to Tulsa, where the scheduler used it to make decisions on future HVL transportation within the Seminole pipeline system. The DOV report was also sent to the operations supervisor of Seminole's South Texas Division, who checked calculations on the DOV for mathematical accuracy. The Safety Board determined that the operations supervisor

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[15] MAPCO transported several grades of HVLs in its pipeline system: pure products, such as propane and iso-butane; mixtures of pure products, such as ethane and propane; and mixed products known as Y-Grade.

[16] According to a company spokesperson, employees at Brenham periodically tested the accuracy of the meters. A meter was tested whenever it had logged a given barrel volume dependent on the size of the device. To be acceptable, the test repeatability factor had to be within +/- 0.02 to 0.05 percent for five consecutive readings during the proof test. Additionally, a new meter factor for a meter had to be within +/- 0.25 percent of the previous meter factor and within +/- 0.5 percent of the original meter factor. A meter failing to meet these criteria was removed from service.

could not check the correction factors or temperature and volume computations that employees used because this information was not shown on the DOV report.

According to a company executive officer, Y-Grade product, which contains some gasses, is a very compressible material that always needs to be measured at all incoming and outgoing flow points if measurements are to balance. At Brenham station, product was not metered as it entered the 14-inch mainline. Y-Grade HVLs received from the plants into the Bryan Lateral were metered, and the metered volume was adjusted based on the representative density test results, the meter error factor, and the pressure and temperature at which the HVL was metered. The flow from the Bryan Lateral into the station was similarly metered and corrected. The sum of the corrected volumes for the plant deliveries was then compared, both daily and weekly, to the corrected volumes measured by the Bryan Lateral meter at the station. Any variations were investigated and, if necessary, corrective action was taken. Comparison of HVL volumes received at and transported from the station could not be made because HVLs transported from the station into the 14-inch mainline were not metered. Thus, the company could not compare the volume of HVLs entering the station to the volume leaving the station.

After the accident, MAPCO audited the work performed by area operators in developing the DOVs from the last time the cavern was empty (July 13, 1991) until the last DOV prepared before the accident (April 6, 1992). After correcting the errors found and recalculating the daily cavern volumes, company auditors reduced the quantity of HVLs entered into the cavern by 19,196 barrels and reduced the quantity of HVLs removed from the cavern by 50,872 barrels. In their recalculations, the auditors included 19,429 barrels injected into the cavern between 7 a.m., April 6, 1992, and 7 a.m., April 7, 1992.

As a result of the audit, the company determined that the cavern held 319,981 barrels at the time of the accident, about 32,000 more barrels than the 288,305 barrels reflected in its records. The audit showed that MAPCO had exceeded its self-imposed 300,000-barrel maximum cavern storage volume on the following days: March 2, 4, 9, 11, 12, and 19, and April 6 and 7. The company's audit also showed that the volume in the cavern was greatest on March 11, 1992. On that day, 9,515 barrels were added to an existing quantity of 313,047 barrels, for a storage total of 322,562 barrels. Company records show that on March 11, the cavern contained more product than on April 7 and did not release product.

As part of its investigation, the Safety Board reviewed the pipeline company's audit, the area operator's worksheets, and the DOV reports for the period between July 13, 1991, and April 6, 1992. The Board determined that in a period spanning fewer than 260 days, on-scene employees made almost 700 errors in determining the volumes of product entered into and removed from the cavern. Of these errors, 2 percent were misapplication of metered volumes; 12 percent, incorrect math; 17 percent, use of wrong meter correction factor; and 69 percent, use of incorrect HVL temperature factor in determining the volume correction factor. The Safety Board determined that all employees who prepared DOVs at Brenham station had made these types of errors.

MAPCO's accounting procedures called for its caverns to be emptied annually to determine the accuracy of operations. Brenham cavern had been emptied more frequently. Each time, the company compared the product volume that its records showed had been stored in the cavern with the actual product quantity withdrawn. Before the April 1992 accident, the company had emptied Brenham cavern 160 times. In 1982, the station's first year of operation, MAPCO emptied the cavern 42 times. After that, the company emptied the cavern each time operations permitted. The number of emptyings per year were as follows: 27 in 1983, 8 in 1984, 13 in 1985, 19 in 1986, 17 in 1987, 15 in 1988, 7 in 1989, and 8 in 1991.

Before the 1992 accident, records show that measurement accuracy varied greatly. Errors ranged from 9.13 percent less to 59.97 percent more than the volume indicated on the DOV reports. Figure 14 shows MAPCO's cavern management measurement errors relative to the respective total flow in and out of Brenham cavern for the 4-year period from 1988 through 1991. During this time, most of MAPCO's cavern volume measurement errors were within its accuracy goal of 0.25 percent when total volume flowing into and out of the cavern between emptyings exceeded 1 million barrels. However, between February 20 and July 31, 1989, the company experienced a 1.33 percent error when 1,830,480 barrels of HVLs flowed through the cavern. On several occasions when total volume through the cavern was less than 1 million barrels, MAPCO experienced errors over 1 percent and up to 2.6 percent.

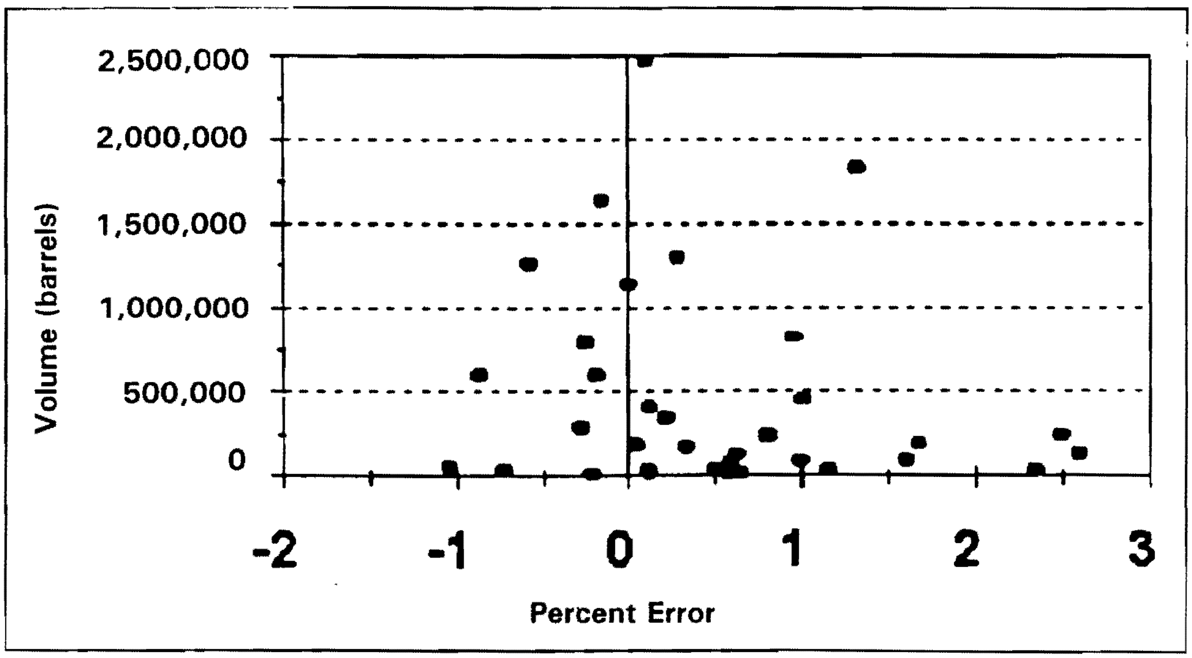

Figure 14. Measurement accuracy versus cavern flow.

Records show that before the accident, the maximum quantity of HVLs that MAPCO pumped into and from the cavern between emptyings was 2,685,095 barrels during the 4-month period between February 29, 1984, and July 7, 1984. In the 9 months between July 12, 1991, when the cavern was last emptied, and the accident, the company had pumped almost 5 million barrels into and from the cavern. The company's senior vice president testified that he became aware of measurement inaccuracies at Brenham cavern only after the accident. He said that some weeks before the April 1992 accident, the division manager had recommended that the cavern be emptied because of the high volume that had passed through the cavern since it was last emptied. The division manager had been given the go-ahead to schedule the cavern for emptying, but he had not set a date to do so before the accident occurred.

Scheduling.--Based on the orders received during the month, a scheduler in Tulsa developed schedules for moving HVLs within the Seminole system, including those that were to be temporarily stored in or removed from underground caverns.

The scheduler developed a weekly agenda on the HVLs that were to go into the mainline from plants and caverns. From the weekly agenda, he developed a schedule showing who was to make the deliveries, when deliveries were to be made, and at what rate they were to be made. The schedule was sent to dispatchers as instructions that they were to follow and to the employees at stations to inform them of planned operations.

The scheduler used information provided daily, such as deliveries that dispatchers indicated were made to customers, the HVL quantities for which customers contracted, and the meter measurements showing the quantity of HVLs stored in caverns, to determine whether the transportation schedules that he prepared should be altered.

When scheduled deliveries to a cavern approached the maximum working storage capacity established for that cavern, the scheduler discussed the situation with station employees so that they could take whatever precautions they believed necessary, such as having employees be on-site at the station. From interviews, the Safety Board determined that the company followed such a procedure on March 11, 1992. When the scheduler believed that the quantity of product scheduled to be stored at Brenham would put the cavern at its maximum working capacity of 300,000 barrels, he notified area personnel, who stayed on-site to monitor the brine tube for HVLs and to manually close the cavern valve if the brine tube contained HVLs.

Role of the Dispatcher.--According to MAPCO, to ensure the least disruption to future customer deliveries, dispatchers maintained logs so that they had a reasonable estimate of where HVL batches were located within the pipeline system and of the quantity of HVLs in the caverns. Dispatchers were required to plot the locations of batches every 4 hours and to be aware of the storage within each cavern by reviewing the scheduler's instructions and the dispatch log, which showed cavern deliveries and withdrawals. If confronted with a situation not covered by the scheduler's instructions, such as an emergency, a dispatcher might have to reroute or mix products in the pipeline or shut down a plant providing HVLs for deliveries. Company procedures did not allow dispatchers to knowingly exceed the maximum working capacity of underground caverns.

According to MAPCO, when a dispatch board received a gas alarm from an unattended station, the alarm was to be considered a potential rather than an actual emergency. Operating procedures required that the dispatcher immediately contact a technician to respond to the station to determine the reason for the alarm.

Tests and Maintenance of Safety Equipment.--While MAPCO required that employees check the cavern shutdown system every 6 months to ensure that it was functioning properly, the company had no written guidelines outlining the procedures to follow. An employee learned how to check the cavern shutdown system through OJT under the supervision of a technical supervisor or experienced technician.

In postaccident testimony, the technician who performed the March 1992 test recounted the steps that he followed when checking the shutdown system. He stated that he secured the cavern safety valve in the open position so that it did not operate during the test. As a safety precaution, he closed the valve near the Barksdale switch on the brine sensing line (steel tubing) before disconnecting it from the tubing to the Barksdale switch. After disconnecting the sensing line, he reopened the valve so that brine could flow through the line.

The technician next installed a hand-operated pump to the inlet of the Barksdale switch, applied pressure, and watched the switch to see whether it activated at 100 psig pressure. He said that during the March 1992 test, the switch tripped at 89 psig pressure, so he adjusted the switch setting. On retesting, the switch activated at 100 psig. When the switch activated, he checked the tripping lever on the solenoid valve to ensure that it released the chain holding the cavern safety valve open. The system tripped at the set pressure during three consecutive tests. The technician said that he then reconnected the sensing line to the Barksdale switch. He testified that no other checks of the sensing system were scheduled until the next 6-month inspection.

At 6-month intervals, the technician calibrated the hazardous gas detectors using the manufacturer's test procedures and a test gas of propane in air. The technician also periodically monitored the gas detector units and recalibrated or replaced them as necessary. He assessed the performance of the detector units by periodically viewing the readings on the station control monitor. When the monitor indicated a small increase in the expected voltage for any of the detectors, he used a hand-held gas detector to check the area of the station monitored by the detector in question. If no HVLs were detected, the detector was recalibrated and/or replaced.

Safety Oversight.-- Each division manager designated an employee to be the regulatory coordinator for the division. As such, the individual was responsible for reviewing both existing and proposed regulations, including safety regulations, that applied to Seminole's operations and for keeping the division manager up-to-date on regulatory requirements. The division manager determined which requirements applied to his operations and directed the regulatory coordinator to implement them. Implementation of regulatory requirements was accomplished through coordination with the division's supervisors. The regulatory coordinator also received guidance from a regulatory and safety coordinator from the headquarters engineering department and through periodic meetings with other division regulatory coordinators.

In early 1992, before the accident, the South Texas Division formed a Safety Inspection Committee, which was composed of the regulatory coordinator and representatives from the operations, maintenance, and technical groups, to inspect the stations and valve sites along the route of the pipeline for safety and environmental problems. Results of each inspection were recorded and provided to the division manager, who forwarded the report to the appropriate supervisors for corrective action. Supervisors receiving the report were required to report to the committee what actions had been taken to correct identified problems. After receiving a report on corrective actions taken, the safety inspection committee revisited stations and locations to ensure the adequacy of the actions taken. The Safety Board determined that the committee had planned a review of Brenham station, but had not scheduled an inspection before the the accident occurred.

Abnormal Operating Procedures.--The MAPCO employee procedures manual,[17] in part, states that the pipeline systems operated by MAPCO:

> are designed and installed to operate as FAIL SAFE systems. Each location is equipped with instrumentation and controls that will maintain operating conditions within the set, safe, normal operating parameters. The pipeline systems are controlled remotely by a central dispatching section via a state-of-the-art computerized telemetering system. Normal operating parameters have been established for the systems covering such items as pressure, flow rates, tank levels, valve positions, unit status, communication system status, and others.

The manual also describes Outside Normal Operating Limits (ONOL) conditions, which are unintended or unexpected operating conditions that may develop on the pipeline systems but do not necessarily indicate an emergency. The manual advises that when an ONOL condition develops, in most cases, the dispatcher is automatically notified via the telemetry system. In some instances, an ONOL condition may indicate that an emergency is imminent; therefore, "each instance of an ONOL shall be investigated and analyzed. The Manager of Operations Control shall investigate and analyze the variance and respond with necessary action to resolve the abnormal condition." The manual further states that "when warranted, the central dispatcher shall notify the appropriate field personnel in the area affected."

Among conditions that the dispatcher is to monitor are pressures and flow rates for the system, such as those listed in figure 15, and the position of valves in the system. On identifying an abnormal situation, he is to have it corrected; until the ONOL is corrected, he is to maintain extra diligence. The dispatcher has the authority and is encouraged to notify field personnel to check areas of suspected damage when warranted. For a sudden decrease in pres-

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[17] MAPCO *Procedural Manual*, Revised March 21, 1991.

sure that is not accompanied by a change in flow rate and for which the cause cannot readily be determined, the dispatcher is to notify appropriate field personnel and request an on-site investigation.

Injection Rate (bbls/hour)		Injection Pressure (daily psig)	
Avg	Max	Avg	Max
1,500	5,000	850	1,400

Figure 15. Normal pressure and flow rates.

The procedural manual advises that storage operations may occur when terminals (stations) are unmanned; for that reason, safety devices have been built into the delivery facilities to prevent abnormal conditions from becoming emergency situations. The manual also covers appropriate dispatcher responses to a high tank level, a high delivery pressure, and loss of communications. The manual advises that in the event of high delivery pressure, a switch will automatically activate, which will cause the release of the cavern safety valve, automatically stopping flow into the terminal and closing the terminal delivery valve.

The manual also lists as abnormal conditions: loss of communications, unintended closure of valves, unintended starting or stopping of pumping units, operation of a safety device, and failure of a pressure switch. The manual reemphasizes that all facilities are equipped to fail safe.

Dispatch Center Activities on the Morning of the Accident.--Throughout the previous night, data received at the Tulsa dispatch center from the Seminole system were within normal operating parameters.[18] At 3:30 a.m., the entire SCADA computer system briefly went down. When it was restarted, the Seminole system readings were still normal and remained relatively constant until just before 6 a.m. As shown in figure 16, the cavern pump discharge pressure began to decrease slowly; soon after, the suction pressure began to increase. At 6:09:34 a.m., the suction pressure had increased to 546 psig, which generated an alarm on the alarm monitor.[19]

At 6:09:39 a.m., a HAZGAS alarm began to flash on the monitor screen and was recorded on the computer logger (printer). In accordance with MAPCO procedures, the dispatcher trainee telephoned the on-call technician in the Brenham area to have him check out the cause of the alarm at Brenham station. At 6:09:40 a.m., the screen showed that the cavern pump had automatically shut down; 10 seconds later the monitor showed that product flow in the Bryan Lateral had dropped to zero, and an HVL flow Rate of Change (ROC) alarm flashed on the screen. The dispatcher later testified that he took no notice of the drop in flow and alarm because such events are to be expected when a pump shuts down.

[18] Under normal conditions, the SCADA readings showed pump suction pressures for the mainline and cavern pumps above 524 and 474 respectively, flow rates into the cavern less than 1,500 barrels per hour, and a differential of 400 to 450 psig between the cavern pump suction pressure and the discharge pressure.

[19] The SCADA computer has preset alarm points programmed into its system to alert a dispatcher of significant operating changes. Each time the cavern pump suction pressure equalled 474 psig, an alarm was transmitted to the dispatch center. The alarm was to assist the dispatcher in determining when one or two pumps were needed to keep the Y-Grade HVL above its flashpoint pressure of 325 psig. An alarm also alerted the dispatcher when the mainline pump suction pressure equalled 524 psig.

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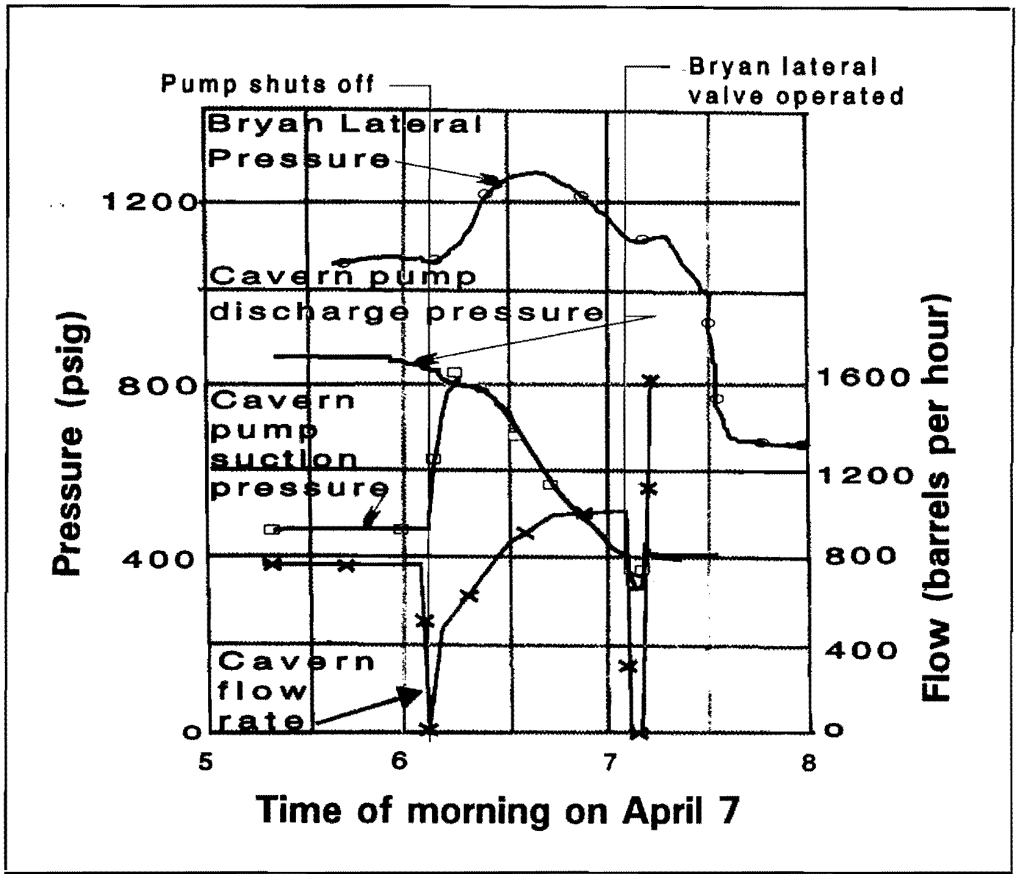

Figure 16. Graph of pressure and flow rates the morning of the accident.

By 6:15 a.m., the SCADA monitor showed that flow through the Bryan Lateral had resumed and that flows within the station piping were abnormal. Instead of the previous differential of 400 psi between the suction pressure and the discharge pressure at the cavern pump, the pressures were about equal. Flow rates for the Bryan Lateral and into the cavern were almost half what they were minutes earlier. The dispatcher said that he continued to monitor readings from Brenham station, but did not observe anything that he thought represented an emergency.

About 6:30 a.m., the dispatcher who was scheduled to monitor the Seminole/Snyder board during the next shift reported to work. The dispatchers going off duty briefed him about the status of operations on the Snyder system and told him that they had received a HAZGAS alarm from Brenham station and that they had dispatched an area technician to determine the cause of the alarm. The dayshift dispatcher said that he checked the computer alarm printout and saw that all pressure readings were within the operating norms. Beginning at 6:40:43 a.m., the dispatcher manning the Seminole board began to receive a number of pressure alarms from Brenham (see figure 17).

About 6:46 a.m., the dispatcher at the Seminole board received a call from the on-scene technician, who told him gas was in the station yard and to call the technician's immediate supervisor.

About 7:03 a.m., the area operator, who was driving to work on CR 19, saw HVL vapor around the station. He radioed the dispatcher and advised him to shut down the Bryan Lateral. The dispatcher testified that his first action was to stop the flow of HVLs to the station. At 7:06 a.m., he closed the Bryan Lateral valve and asked his two co-workers at the dispatch center to contact the processing plants that were injecting product into the lateral and have them cease pumping.

About 7:07 a.m., the lab technician telephoned from the Brenham area to tell the dispatcher that they had "popped the top" on the cavern. The lab technician told the dispatcher to take HVL product from the cavern and inject it into the mainline. The dispatcher responded that he had G-Grade product (ethane-propane) in the mainline, which was not compatible with the Y-Grade mix that was in the cavern. The lab technician told the dispatcher to go ahead and inject the cavern HVLs into the mainline. The dispatcher again questioned whether the lab technician really wanted to mix the two grades of HVLs. The lab technician, who was not aware that an earlier HAZGAS alarm had shut off all pumps at the station, said to do so.

Time	Alarms Received
6:40:43	Mainline pump pressure alarm
6:41:13	Mainline pump pressure alarm
6:44:19	Mainline pump pressure alarm
6:45:11	Mainline pump pressure alarm
6:45:44	Cavern pump pressure alarm
6:46+/-	Technician calls dispatcher, tells him that vapor is in the station yard, and asks him to call his (the technician's) supervisor.
6:46:11	Cavern pump pressure alarm
6:48:48	Cavern pump pressure alarm
6:48:59	Cavern pump pressure alarm
6:51:02	Mainline pump pressure alarm
6:53:23	Cavern pump pressure alarm
6:57:31	Cavern pump pressure alarm
6:57:54	Loss of Suction Pressure (LOSP) alarm for Bryan Lateral

Figure 17. Pressure alarms and calls received by dispatcher beginning at 6:40:43 a.m.

The other dispatchers were able to contact personnel at one of the two plants pumping into the Bryan Lateral and have them shut down operations almost immediately. However, when they could not get anyone to answer at the second plant, the dispatcher at the Seminole board became apprehensive that if a plant continued to pump product against a closed valve, the pressure might rupture the lateral, so he reopened the Bryan Lateral. He was not aware that the plant pumps were designed to shut down automatically when the pump pressure increased to 1,550 psig.

Within a few minutes, the operator of the first plant contacted was able to reach someone at the second plant by telephone and have him shut down operations. The dispatcher controlling the Seminole system was still on the phone with the lab technician when the lab technician told him about the explosions at the station. The dispatcher then typed in a command on his SCADA keyboard trying to reclose the Bryan Lateral valve, but his telemetry system showed that data transmission with Brenham station had ceased.

Dispatcher Work Load.--The dispatcher who had been monitoring Brenham station on the morning of the accident, described his work load in the moments before the explosion as having to handle several tasks in a short period. In enumerating his responsibilities, he listed shutting the Bryan Lateral and the mainline, telling other dispatchers what to do, directing the plants to shut down the lateral, reopening the lateral, and monitoring the SCADA for additional information. In describing the period during which he was attempting to reopen the valve, the dispatcher stated, "While this was going on ... it was ... like I said, chaotic up there." He said that no one from the dispatch center had an opportunity to call the fire department before the explosion; however, he did receive word from the other dispatchers that the fire department had called the dispatch center, although he was not aware of the content of their discussions.

The dispatcher stated that although the technician had called (about 6:46 a.m.) and confirmed that the hazardous gas alarm was real, he had not indicated the seriousness of the situation. The dispatcher added that he "was caught off guard" when the area operator called him at 7:03 a.m. and told him that the cavern was possibly full.

Explanation of Flow Data.--After reviewing recorded pressure and flow data,

Time	Alarm and/or Response
7:03	Area operator calls and advises dispatcher to shut down Bryan Lateral
7:06:04	LOSP alarm for cavern pump
7:06:09	Dispatcher types code to close Bryan Lateral valve
7:06:31	ROC alarm; telemetry system shows rate of flow is 21 bbls/hr
7:06:38	Bryan Lateral valve closed
7:06:49	ROC alarm; flow rate is 3 bbls/hr
7:07+/-	Lab technician calls to report large mushroom-shaped cloud over the station and directs dispatcher to pump product from cavern to the mainline
7:09:33	Dispatcher types code to open delivery valve to 14-inch mainline
7:10:25	Delivery valve to mainline is open
7:10:46	Dispatcher enters command to open Bryan Lateral
7:11:23	ROC alarm; system shows Bryan Lateral flow is 1,671 bbls/hr
7:11:33	Bryan Lateral valve fully open
7:11:40	ROC alarm; cavern flow out is 1,650 bbls/hr
7:13:57	"XMIT ERROR" on alarm logger

Figure 18. Alarms and actions taken by Seminole board dispatcher before explosions.

a MAPCO spokesperson testified that on April 7, 1992, the following occurred:

> Between 3 a.m. and 6 a.m., the cavern was receiving Y-Grade product from the Bryan Lateral at a rate of about 800 barrels an hour. At 6:09 a.m., when the HAZGAS alarm shut the cavern pump down, flow through the cavern meter ceased immediately. As pressure in the Bryan Lateral increased enough to override the pressure in the cavern, flow in the lateral resumed. The resumption of flow was interrupted periodically as pressure equalization occurred. Records indicate that the flow rate through the cavern meter was as follows: 6:15 a.m. - about 400 barrels an hour; 6:30 a.m. - about 850 barrels an hour; 6:45 a.m. - about 1,000 barrels an hour; and 7 a.m. - about 1,000 barrels an hour. After 7 a.m., flow varied substantially when the Bryan Lateral closed; flow in through both the Bryan Lateral and the cavern meters went to zero. About 2 to 3 minutes elapsed, the Bryan Lateral valve was reopened, and flow resumed.

Meteorological Information

Surface data obtained from a Man computer Interactive Data Access System (McIDAS) station box located 26 nautical miles north of Brenham, Texas, showed that at 0700 local time on April 7, 1992, the temperature was 54° F, the dewpoint was 50° F, winds were northerly at a speed of less than 2 knots, and pressure was about 1,018 millibars.

Medical and Pathological Information

A 6-year-old child died from blunt force trauma when the impact of the blast demolished his parent's mobile home. Another resident of the same home suffered serious blunt force trauma and was MEDEVACed by LIFE-FLIGHT from the accident site to the emergency trauma center at Hermann Hospital, Houston, Texas. The three occupants of the vehicle that entered the vapor cloud sustained serious burns and were taken by ambulance to Trinity Medical Center in Brenham, where they were MEDEVACed by LIFE-FLIGHT to the burn center at Hermann Hospital in Houston. Two of the three burn victims died within 5 days of the explosion.

Excluding the 3 burn victims who were transferred to Hermann Hospital, Trinity Medical Center received 17 patients, 2 of whom were admitted. Bellville General Hospital, Bellville, Texas, received 2 patients, both of whom were treated and released. From interviews with paramedics and a survey of area residents, Safety Board investigators determined that dozens of other residents sustained minor injuries, mostly lacerations from broken glass.

Emergency Preparedness

Community Preparedness.--In December 1991, the Texas Department of Public Safety (DPS) approved the Washington County Disaster Plan as meeting all applicable State and Federal requirements. According to the county EMC, Washington County had previously tested its disaster plan by simulating tank truck roll-overs and tank car derailments involving hazardous materials. Before the Brenham station explosion, the county's disaster plan had last been activated in January 1992, when heavy rains caused area flooding.

Under the disaster plan, the county judge (the chief executive officer of Washington County) is responsible for the overall emergency management, planning, and operation. The Washington County EMC is responsible for coordinating the actions of the local government response agencies, including law enforcement, fire, and emergency medical services. The EMC is responsible for activating the emergency operations center, providing emergency information to the public, and, if necessary, arranging for evacuation of the public.

Company Preparedness.--Under 49 CFR 195, pipeline operators are required to:

> Develop and follow procedures notifying fire department, police, and other appropriate public officials of hazardous liquid pipeline emergencies, and to coordinate preplanned and actual responses with them during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid. (195.402 (e)(7))
>
> Establish a continuing educational program to enable the public, appropriate organizations, etc. to recognize and report a hazardous liquid pipeline emergency to the operator, fire department, police, or other appropriate official. (195.440)

In addition to the above regulations, on November 20, 1991, the Research and Special Programs Administration (RSPA) of the U. S. Department of Transportation (DOT) issued an alert notice advising all owners and operators of hazardous liquid pipelines to review their public education programs and consider both elevation and distance from the pipeline in carrying out their public education programs.

The RSPA alert notice was issued in response to the Safety Board's investigation of the March 13, 1990, liquid propane pipeline accident at North Blenheim, New York, in which the Board recognized that existing Federal public education requirements on recognizing and responding to emergencies were inadequate for pipelines that transport HVLs. As a result of the North Blenheim accident findings, the Safety Board recommended that the RSPA:

> Require operators of pipelines that transport highly volatile liquids to extend their public education program to include persons who reside at elevations lower than and within 1 mile of the pipeline. (P-91-3)

During a Safety Board hearing on the Brenham explosion, MAPCO officials testified that while they were aware of the RSPA alert notice, they had not taken action to extend the company's public information program beyond owners along the pipeline right-of-way.

Procedural Guidelines.--The MAPCO operating manual contains the following guidelines in regard to emergency procedures:

> All Central Dispatch and Field efforts must be directed to securing the area by getting personnel to the leak area to close valves, establish road blocks, evaluate hazards, warn people, and in general, prevent damage to life and property. One company representative capable of evaluating, planning, and coordinating leak site activities must go directly to the leak site and take charge.

The MAPCO's protocol for responding to a hazardous gas alarm required that the individual who received the call-out proceed to the scene and determine the reason for the alarm. If a release had occurred, the respondent was to notify the dispatcher and his (the respondent's) supervisor. If the release was significant, the respondent was to secure the area, warn local residents who might be exposed to the product, and evacuate or blockade the area to ensure that no one entered it. The spokesperson further stated that the Tulsa dispatchers had telephone numbers for the emergency response agencies of each county through which the pipeline crosses.

Public Education.--The emphasis of MAPCO's public education program was to inform owners of property along the pipeline, appropriate Government organizations, and people who might engage in excavation how to recognize a hazardous liquid pipeline emergency and to whom they should report an emergency. MAPCO had a two-part program. For property owners of record, the company annually mailed out packets of information; for local government agencies, the pipeline company provided pamphlets containing its emergency procedures and a master key to unlock valves and gates to facilities; for local response agencies, the company annually conducted periodic emergency response training.

Safety Board investigators determined that MAPCO mailed the information packet to property owners in December. Each packet contained a number of items commonly used about the home and each item prominently displayed the dispatch center's telephone number. For example, the company sent residents a calendar imprinted with emergency response telephone numbers and the suggestion that recipients hang it near their telephones.

Records show that MAPCO last conducted a fire school for response agencies near Brenham station on January 27, 1990. More than 84 firefighters from Washington and Austin Counties and Brenham station field employees attended the school. Participants received information about the station, MAPCO's emergency procedures, and the properties of HVLs that were transported through the station. They were also shown how to inspect and maintain a portable dry chemical fire extinguisher and how to extinguish fires involving small, confined pools of HVLs, fires at leaking flanges, and fires at open pipe ends.

MAPCO also provided local fire departments, sheriffs' departments, and government agencies with an emergency response package. The package included a master key to the station gate and any mainline block valve along the pipeline and a booklet describing the pipeline system, products being transported, how to recognize emergency situations involving the Seminole line, and what actions to take (see figure 19).

1. Call Seminole Pipeline Company dispatcher collect at telephone number (918) 584-4471 Tulsa, Oklahoma.

2. Give dispatcher your location and the location and seriousness of the emergency, especially the size of the vapor cloud.

3. Follow dispatcher's instructions as to closing block valves, checking size of vapor cloud, and evacuating any residents under or in path of cloud. Guard area to avoid ignition if possible.

IF IGNITION HAS OCCURRED, DO NOT ATTEMPT TO PUT OUT FIRE

4. Block roads and keep people out of area.

5. Maintain contact with dispatch until company personnel arrive at the scene.

Figure 19. Response actions listed in Seminole's emergency response material.

Employee Training.--As mentioned previously, MAPCO conducted periodic safety meetings with employees to introduce new information impacting pipeline safety and to review required response procedures to emergency situations. A review of MAPCO's safety meeting agendas shows that, among other emergency response issues, the sessions included discussions of decision-making factors that were involved in establishing road blocks and evacuating endangered residents. These sessions emphasized what actions the first employee arriving at an emergency was expected to take and what information that employee was to obtain, such as location of exposures, ignition sources, and cloud size.

Safety Equipment.--At its Sugar Land office, which was about 87 miles from the Brenham station, MAPCO maintained a "safety trailer" that contained essential emergency response equipment to assist operating crews at remote locations. Equipment included an emergency flare stack, personal protective gear, such as self-contained breathing units and flame retardant coveralls, and repair tools used in emergency operations. Field employees testified that the personnel who conducted the safety meetings advised employees of the availability of the safety gear and described how the equipment was to be used.

Company/Community Coordination.--According to MAPCO's regulatory coordinator, the company did not coordinate with the local emergency response planning groups of communities along its pipeline when it developed its emergency procedures. He also stated that MAPCO had not attempted to determine whether the company's procedures met the training needs of local emergency response groups or whether the company's emergency response plan was consistent with the needs of communities. Before the Brenham accident, the regulatory coordinator had reviewed the MAPCO *Procedural Manual* and found that it did not address normal or emergency operations at unattended stations. The regulatory coordinator said that he brought the matter to the division management's attention and that the division manager said he believed the existing procedures were sufficient and that changes to the manual weren't warranted.

Postaccident Critique.--On May 7, 1992, the Emergency Management Director (EMD) convened a postaccident critique meeting at the Washington County Court House. According to the EMC, all Washington and Austin County public agencies that responded to the accident were invited to participate in the critique. Austin County agencies did not attend. The participants identified the following problems:

Communications.--Heavy radio and telephone traffic and loss of lines hampered communications. The explosion knocked out many telephone lines within several miles of the station. In addition, area residents trying to report injuries and damage and/or trying to determine the origin of the explosion jammed the 911 number with calls. A telephone company spokesperson reported that more than 31,000 calls were made to the area exchange during the first hour following the blasts. Responders stated that phone problems caused some confusion, miscommunication, and delay. Information could be relayed only by radio. According to the EMC/EMS director, because all responders were trying to use the same radio channels, "...you just got in [on the radio channel] when you could."

Product information.--The EMC stated that he "didn't know what kind of gas we were dealing with." He said that an on-site fireman told him it was methanol gas.[20] He said that he did not talk to any pipeline representative until 11 p.m., nearly 16 hours after the accident, when two pipeline employees came to the command post. The Brenham fire department chief stated that when he was on the station site, he had talked with pipeline employees and determined that the fires burning posed no danger. From postaccident interviews, Safety Board investigators determined that the fire chief neither relayed necessary information to the EMC nor requested that MAPCO provide a technical person at the command post. The EMC said that if he had to do it over again, he would immediately evacuate the whole 10-square-mile area because of the potential danger to rescue personnel and possibility of flammable gas in the area.

Access.--The primary road to the station, CR 19, is a narrow gravel road. The force of the explosions snapped and leveled trees surrounding the station and disabled the fire victims'

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[20] The fireman reportedly had seen "methanol" painted on an above-ground tank at Brenham station and concluded that it was the product with which responders were dealing.

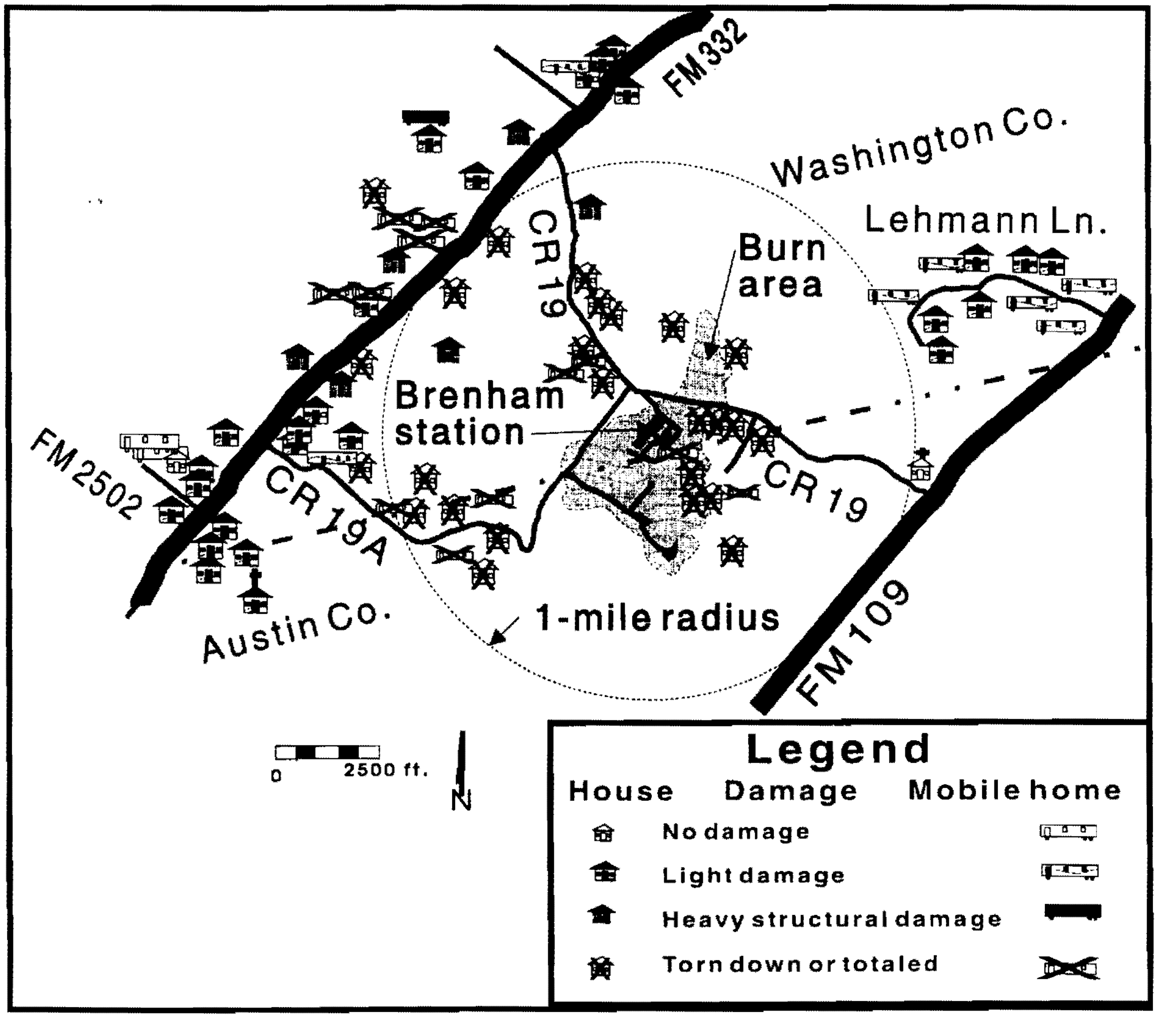

Figure 20. Damage to homes and structures near accident site.

car and the Seminole truck at the station entry road, which made CR 19 impassable. First responders to the scene had to radio follow-up units to reroute to FM 109. Response agency officials added that when it became evident to volunteer responders who had been placed on alert that phone lines were out or inoperative, many decided to proceed to the scene, increasing the potential for gridlock on the roads to the station. Although Department of Public Safety (DPS) personnel later blocked all access to CR 19, response personnel, residents, news media representatives, and clean-up crews, believing that the area posed no danger, moved freely on CR 19 after the explosions.

Training.--The EMC stated that he was not familiar with MAPCO procedures and had not participated in any pipeline-sponsored training held in the county. The Safety Board determined from interviews that when he had assumed the job several years earlier, Washington County had not provided the current EMC with any information about Brenham station or MAPCO's emergency response booklet.

Tests and Research

Gas Analysis.--On April 10, Safety Board investigators documented the pressure at the cavern wellhead as 440 psig in the brine tube and 420 psig in the product pipe. They also found that product filled the brine tube. Investigators removed an HVL sample from the brine pipeline above the wellhead and sent it to a private laboratory for analysis. Tests showed the HVL to be composed by weight primarily of propane (32.92 percent), ethane (32.51 percent), n-Butane (14.11 percent), n-Pentane (4.40 percent), Isopentane (4.30 percent), and n-Hexane (1.08 percent). Laboratory technicians also identified 38 other materials, including methane, none of which comprised more than 1 percent of the total sample weight (see appendix B). The weight percentages of the identified components approximated the HVL mix in the April 6 deliveries.

Cavern Test.--On May 26, 1992, MAPCO contracted a well-survey company to perform a sonar measurement of the cavern to determine its size and capacity. The survey, which was attended by Safety Board investigators, showed that the top of the cavern was 2,728 feet below ground and that the bottom of the cavern was 2,875.3 feet below ground. The approximate capacity of the cavern was 380,000 barrels.

To obtain a more accurate accounting of the amount of HVLs in the cavern, the Texas Railroad Commission recommended and MAPCO agreed to remove all product from the storage facility by means of displacement. A Commission representative monitored removal of the product, which occurred between July 8 and August 16, 1992. Tests of the brine in the ponds showed that it was not fully saturated with sodium chloride. Because the ponds did not contain sufficient brine to displace all of the product, MAPCO had to inject fresh water into the cavern. The volumes and salinities of the brine and the water used to empty the cavern were measured. A total of 338,995 barrels of HVLs were removed from the cavern, about 51,000 barrels more than the 288,305 barrels indicated in company records. A small, undetermined amount that remained in the cavern was released and flared.

When questioned about the almost 51,000 barrels of extra product that was in the cavern on April 7, 1992, the company executive officer stated that the way these caverns operate, there are several ways to have too much or too little product. He testified, "Just the accuracy of the measurement system itself in the volume of the product that goes through the cavern, simple multiplication, can give you some pretty wide areas in the volume that could be in the cavern."

On September 30 and on October 2, 1992, MAPCO contracted two other companies to do additional sonar surveys of the cavern to document the growth of the cavern after the accident. Calculated cavern capacity from the first survey was 384,925 barrels, a 1 percent variance from the May 1992 survey. Calculated capacity from the second survey was 356,965, a 7 percent variance from the May 1992 survey. As a consequence of these surveys, MAPCO found that the lower end of the 13 3/8-inch-diameter pipe was 2,702 feet below the wellhead, rather than 2,728 feet as indicated in the May 1992 survey.

Pumps.--In the process of inspecting and overhauling both cavern pumps, MAPCO found that the electric motors of the pumps were heavily damaged in the explosion, but that the pumps themselves were not damaged. Internal inspection of the pumps showed no damage from cavitation[21] or other causes; the impellers were not damaged and the casings contained no defects. Records showed that the pumps had no previous cavitation damage.

Metallurgy.--Investigators removed several system components from the accident scene and sent them to the Safety Board's laboratory in Washington, D.C., for metallurgical examination (see appendix B).

Coastline's 6-inch riser and associated components.--Investigators had a section of the carrier's 6-inch-diameter riser removed from Coastline's area that had been enclosed by chain link fence before the explosion. Only three of the four 1/2-inch pipe connections to the riser still were attached. The fourth 1/2-inch pipe connection was found partially imbedded in the ground about 47 feet from where the fence enclosure had been. Safety Board investigators also submitted this component to the lab for examination. Analysts determined that the soot deposits on the riser were consistent with exposure to a fire and that the deformation of the piping components resulted from bending load and not a pre-existing condition. Evidence also indicated that damage to the Coastline riser and associated components resulted from the enclosure fencing being blown onto the riser.

Overpressure sensing equipment.--Safety Board investigators also submitted for laboratory examination components that comprised the pressure sensing line between the brine ponds and the storage cavern. Safety Board metallurgists examined the pressure sensing tubing, fittings, two manual valves in the sensing line, the electric solenoid valve used to release the cavern safety valve, and the Barksdale pressure switch. Evidence indicated that damage to the tubings and fittings resulted from excessive loads and not from pre-existing conditions. An X-ray of the manual valve on the pressure sensing tubing and tests on its handle indicated that the valve was in the closed position when its handle separated from it.

Initial tests of the Barksdale switch were inconclusive. The Safety Board therefore arranged for the engineering department of Barksdale Controls, the manufacturer of the switch, to conduct additional tests at its laboratory in Los Angeles, California. A Safety Board investigator hand-carried the device to Barksdale for testing. Tests and examinations specified by the Safety Board were conducted in the presence of the parties to the Brenham investigation. Barksdale engineers tested the switch components and concluded that the set screws in the pressure fittings had been loosened and retightened because the screws were not to the manufacturer's torque specifications. They also found that the original bourdon tube sensing element and the switch housing had been replaced.

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[21] Cavitation is the formation of partial vacuums within a liquid. The collapse of the partial vacuums causes pitting or other damage to the metal surface that is in contact with the liquid.

The Barksdale engineers next conducted pressure tests of the micro switch. They applied nitrogen under pressure in 10 psig increments up to 200 psig and the micro switch failed to actuate. When engineers tried to change the pressure setting on the switch and could not turn the adjustment screw, they found that the adjustment screw was corroded and frozen in its bore.[22] Microscopic examination showed that both the inlet and outlet ports of the surge damper were blocked by a mixture of salt, rust, pipe scale, and sand. After removing the blocked surge damper, the engineers pressure tested the switch again and it tripped as designed. Based on visual examination of the switch components, the engineers concluded that the metal switch housing had been disassembled and reassembled in the field.

Fusible link.--Safety Board investigators submitted the separated half of a fusible link that was connected to the cavern safety valve chain and exemplar fusible links of the same design for laboratory examination. Safety Board laboratory personnel determined that the components showed no evidence of bending or twisting deformations and that the link had separated as a result of excessive temperature.

Explosion Modeling Calculations.--To estimate how much product had been released at Brenham station, the Safety Board used a computer program to model product release and explosion scenarios. Calculations were based on eyewitness accounts of the height of the vapor cloud, the size of the burned area, and assumptions that the gas vapor cloud was uniformly mixed and dispersed over the station area.

Pipeline employees who were on scene before the explosion testified that the vapor cloud was above tree-top level (20 to 30 feet), mushroom-shaped, and covered the entire station area. Three employees observed the column of liquid at brine pond No. 1 from different vantage points. The technician trainee, who was standing near the culvert of the entry road, saw "fluid rising about 10 feet" above the brine pond embankment. The pipeliner, who walked several feet farther up the entry road to a point just past the culvert, described a column shooting up "about 50 feet ... from the area of the brine discharge line in the corner of the pit." From his vantage point immediately south of the intersection of Glory Lane and CR 19, the area operator also observed "a column shooting up." The lab technician, who was in his truck en route to the station and was about 2 1/2 to 3 air miles from the scene, described a mushroom cloud "with a pointed top."

The Safety Board analyst used the observations of on-scene employees to develop two vapor cloud scenarios. Calculations in the first scenario were based on the average molecular

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22 When they removed the Barksdale switch at the accident site during the postaccident on-scene examination, Safety Board investigators noted that the cap that covered the adjustment screw was missing.

weight of the product mix;[23] calculations in the second scenario were based on the partial pressures of the products in the mix.

The burn area (see figure 20) at the accident site measured almost 8 million square feet. The Safety Board determined that about 78 barrels of product would have to be released to produce a 1-foot-high propane vapor cloud of 2 percent concentration, the lower flammability limit (LFL) of propane, that would cover an area the size of the burn area. About 7,020 barrels of propane product would produce a 20-foot cloud of 9 percent concentration, the upper flammability limit (UFL) of propane. Calculated amounts based on ethane were even higher. To produce a 1-foot-high ethane vapor cloud of 3 percent concentration, the LFL of ethane, about 167 barrels of product would have to be released. About 11,136 barrels of ethane product would produce a 20-foot cloud of 10 percent concentration, the UFL of ethane.

The Safety Board also ran a computer model to determine the impact of explosive forces on structures (excluding mobile homes) at various distances from the assumed point of ignition. The explosion efficiency factor of an unconfined vapor cloud is low, only about 3 percent of the heat of combustion.[24] When the Board used a yield efficiency factor that was almost 4 times the expected efficiency and an average product release amount of 1,380 barrels, the model did not produce an explosive force equivalent to the actual on-scene structural damages observed.

Based on the divergence between the damage modeling statistics and actual damage and the descriptions of the cloud height, the Safety Board analyst concluded that at least 3,000 barrels and possibly as many as 10,000 barrels of product were released at Brenham station. The lack of uniformity in damage at similar distances from the point of origin supported the finding that multiple explosions occurred.

From its analysis, the Safety Board found that the following scenario most realistically supports the finding that multiple explosions occurred and extensive structural damage occurred well beyond the visible vapor cloud that covered Brenham station: A hydrocarbon mix vapor cloud spread over the landscape. The wind velocity was very low, which allowed the components having a higher molecular weight and lower vapor pressure, such as butanes, pentanes, and propane, to spread along the ground, while the lighter-weight ethane constituted the upper part of the vapor cloud. The hydrocarbons along the ground were subject to low-level ignition. Most likely the low-level components were ignited first, in turn igniting the higher vapor cloud of ethane. The explosion of ethane at a relatively high elevation may have ignited higher molecular weight components that had accumulated in other low-lying areas. This scenario explains the destructive forces that were not symmetrical around the epicenter of the explosion.

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[23] The computer program used could not perform calculations based on a mixed product. The Safety Board therefore first calculated release amounts using a liquid product that was 100 percent propane and then a product that was 100 percent ethane. The molecular weight of the actual product mix was almost equal to the weight of propane, the second most abundant product in the mixture.

[24] D. Daniels and R. Alberty, *Physical Chemistry*, John Wiley & Sons (1955), pp. 113-114.

Prior Releases from Brenham Station.--A MAPCO technician who was at Brenham in 1982 stated in an affidavit that he recalled that "A product escaped from the cavern via the brine line [tube] and into the pit [pond]." The technician said that he believed that the release was on March 18, 1982, and recalled that he and the lab technician manually closed the cavern safety valve. He later determined that the Barksdale switch had activated and that the Tulsa dispatch office had received a signal indicating the Barksdale had activated. He tested the Barksdale switch and found that it did transmit a signal to the solenoid, but that the solenoid failed to release the cavern safety valve. He found the coil in the solenoid burned out, which rendered the release mechanism inoperative.

The lab technician, who has worked at Brenham since 1981, stated that he was aware of two previous incidents involving the cavern. In fall 1982, he was in the control building when he received a call from the division office at Sugar Land advising him of a HAZGAS alarm, which he believed had been received at the Tulsa dispatch center. From the door of the control building, he saw a column of water being sprayed about 20 to 30 feet above the berm of the brine pond.[25] He recognized the event as a disturbance in the cavern and went to the wellhead, where he closed a manual valve on the brine tube. MAPCO has no record of this incident.

The lab technician said that in spring 1988, he was walking along the top of pond No. 1 when he observed bubbling within the brine. He said that neither the HAZGAS detectors nor the cavern valve had activated and that he closed the manual valve. However, SCADA records show that in February 1988, the dispatch center received several HAZGAS alarms from Brenham station and that the Barksdale switch had activated in most instances. MAPCO shut the cavern down, removed the cavern brine tube, and, after examination, replaced it. The company's report of inspection shows that several corrosion holes were found at pipe connections in the brine tube. A company spokesperson said that after the incident, a technician cleaned and checked the Barksdale switch and returned it to service.

Federal, State, and Industry Oversight

Office of Pipeline Safety (OPS)--The OPS is part of the U.S. Department of Transportation's Research and Special Programs Administration (RSPA). Its representative testified that the OPS is responsible for issuing and enforcing safety regulations affecting the pipeline transportation of both liquids and gases. Section 205(a) of Public Law 102-508 provides that the OPS may allow a State agency to participate in the safety regulatory effort for intrastate liquid pipelines. The State agency becomes the primary inspection and enforcement agency when it certifies to the OPS that it has adopted all applicable Federal pipeline safety requirements, that it has staff qualified to inspect pipeline operations and determine whether they conform to the safety standards, and that it will take action against nonconforming operations as necessary. The

[25] In 1982, Brenham station had one brine pond. The original pond is now pond No. 1.

State agency can also impose on intrastate operations safety requirements more stringent than the Federal requirements. For a State agency to maintain its certification, it must submit to an annual OPS inspection of its operations.

The OPS certified the Transportation/Gas Utilities Division of the TRC as the Texas agency responsible for the safety of intrastate liquid pipeline operations and has annually inspected and found acceptable its pipeline safety regulations, inspection of intrastate pipeline operations, and safety enforcement actions. The OPS representative characterized that agency's operations as "fully adequate and we think it's one of the better programs of the States."

The OPS Associate Administrator of Pipeline Safety advised the Safety Board on June 11, 1992, that the OPS has not issued safety requirements on underground storage of hazardous liquids and natural gas even though both the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act give it that authority. The OPS administrator advised the Board that historically, the OPS views the end point of its regulations and inspections as the last valve on the wellhead through which gas or hazardous liquid enters storage.

The OPS representative at the Safety Board's hearing explained that the Federal pipeline safety standards initially developed by OPS were based on then-available industry standards (American National Standards Institute's B31.4 and B31.8 on liquid and gas pipelines, respectively), which did not address underground storage. Since issuing the initial Federal pipeline safety standards, the OPS has taken no action to address the safety of underground storage systems. The OPS representative said that even though the OPS had not developed requirements on underground storage, State agencies were not barred from developing such safety requirements and that the OPS was aware of a few State agencies that do regulate storage in geologic formations.

The OPS representative said that since the Brenham accident, the OPS has begun to collect information on the number and type of underground storage systems used in pipeline transportation, to review various sources of statistics that would assist in determining the numbers of releases of gases and liquids that occur annually, and to consider the actions that the OPS might take on gas and liquid underground storage systems. He said that the OPS was aware that many underground storage systems would not be subject to the safety standards it may issue because they would not be considered part of pipeline transportation. This would include underground storage systems for gases and liquids at transportation terminals, refineries, and chemical plants where the materials stored would not involve further pipeline transportation.

Texas Railroad Commission (TRC)--Responsibility for the safety of the Seminole pipeline system operations within the TRC was divided between the agency's Oil and Gas (O&G) Division and its Transportation/Gas Utilities (GU) Division. The GU division is responsible for pipeline operations, and the O&G division is responsible for underground hydrocarbon storage operations.

On August 10, 1981, the O&G division issued Seminole a permit to leach a 150,000-barrel capacity cavern and to store HVLs in the salt dome of Brenham Field, about 8 miles southwest of Brenham, Texas. The underground cavern was to be used to store mixed HVLs received from the Bryan Lateral when pure HVLs were being transported through the 14-inch mainline. This would prevent undue contamination of the pure HVLs and avoid expensive refractionization.[26] In support of the permit, the company's drilling engineer testified that in constructing the cavern, operations would be conducted to protect all water of useable quality and any oil and gas reserves, that two separate casings would be installed into the salt and cemented to the surface to prevent an escape of HVLs such as the one that occurred at Mont Belvieu, Texas, caverns, which only had one casing; and that the cavern storage facility would be operated at 0.56 psi pressure for each foot of depth. The permit conditions did not address wellhead safety equipment or the manner in which the cavern was to be operated and maintained to minimize the potential for HVL releases.

An O&G representative testified that the TRC considers that its jurisdiction over cavern storage systems begins at the outlet side of the injection pipe and continues toward the storage facility but does not include the wellhead safety equipment. Statewide Rule 74 addresses the safety requirements for the 582 natural gas and liquid underground storage systems subject to the O&G division's jurisdiction (440 are active).

Adopted in 1982, Rule 74 was enacted to meet the requirements of the Federal Safe Drinking Water Act, the purpose of which is to protect underground sources of drinking water. Anyone proposing to construct and operate an underground storage facility is required to file a permit request that includes the following information: nature of the proposed operation, proposed size, type of product to be stored, site geology, proposed facility construction procedures, type and location of active and inactive area wells (including the manner of closure if no longer active), and proof that the required notice has been given to the public. However, those previously granted permits have grandfather rights and do not have to reapply for a permit.

Although not specifically stated in the rule, the O&G division maintains that when Rule 74 became effective, it mandated that operators of underground storage facilities comply with the periodic testing and reporting requirements. Like its predecessors, Rule 74 does not include requirements for wellhead safety equipment or the manner in which the storage facility is to be operated and maintained. However, the rule does require that operators conduct periodic cavern pressure tests to prove structural soundness and report any detected leakage.

Based on hearings held as a result of several identified problems, on November 2, 1986, the O& G division adopted special safety requirements for the underground hydrocarbon storage caverns in the Barbers Hill Field, which is in Chambers County and adjacent to Mont Belvieu. The requirements addressed the use, design, and location of emergency shutdown valves; the notification of public and local officials of emergency agencies; fire prevention and response

[26] A process used to separate mixed HVLs into pure components, such as propane.

planning, including details about in-place fire suppression systems; contingency plans to address each potential emergency that might endanger public health and safety; employee safety training, including an annual drill of the emergency plan; and requirements for training contractors and their employees.

On April 15, 1991, the O&G division developed additional requirements for underground storage operations at Barbers Hill Field. All new storage facilities had to have at least two cemented concentric strings of casing through all strata between the salt and the surface. The O&G also stipulated that facilities had to be drilled at least 400 feet from any residential dwelling and at least 100 feet from any street, road, or highway in the city of Mont Belvieu.

A representative of the GU division testified that it has adopted the Federal natural gas and liquid pipeline safety requirements, as well as more stringent requirements of its own for intrastate pipeline operations in Texas. None of these requirements are applicable to underground storage facilities because the division's jurisdiction stops at the outlet of the storage injection pumps. The GU representative explained that this means that neither the TRC nor the RSPA has established standards on safety control equipment at the cavern wellhead, on the pipe between the cavern pump outlet and the cavern injection pipe outlet, and on the hazard detection and control systems needed to ensure public safety when operating an underground natural gas or HVL storage system integrally with a pipeline system. Those omissions are being reviewed by both TRC divisions.

State Regulation of Gas and Liquid Underground Storage.--During the investigation of this accident, the Safety Board sought to identify the number and location of natural gas and liquid underground storage facilities in the States and to determine what public safety requirements existed. The Board could find no single association or agency able to provide the desired information about these facilities. Consequently, the Safety Board asked that the States and several industry associations provide information on the number and location of underground storage facilities. The Board also asked that the States submit copies of their regulations governing underground storage facilities.

The Safety Board received information from 32 States, of which 17 reported having underground storage facilities. Of the 17, only 3 reported having public safety standards on HVL underground storage and only 4 reported having standards on natural gas underground storage. Five additional States reported that they require storage permits, the primary purpose of which is to protect ground water and/or to generate revenue for the State. The Board reviewed permit provisions on pressure tests of underground reservoirs and found that they provided some public safety benefits.

The Gas Processors Association provided the Safety Board with information that it had on locations of liquid underground storage facilities and the American Gas Association (AGA)[27] provided data on natural gas underground storage facilities. Figure 19 shows by State the number and location of underground storage facilities as compiled from all sources. These data indicate that about 1,400 liquid and more than 400 natural gas underground storage facilities are in the contiguous United States; none are in Alaska or Hawaii.

Through discussions with State agency and industry association staffs regarding how operators use these storage facilities, the Board determined that Federal requirements classify most as end point (terminal) storage facilities, where the liquid or gas is transferred from one type of transportation facility to another. Other uses include storage by gas distribution operators to handle peak customer demands during cold weather, storage by industry to handle peak demand fuel for heating and electric generation, and storage by chemical manufacturing industry for feed stock supplies.

Pipeline Industry Associations.--The Safety Board searched recommended practices and guidelines of several pipeline-related organizations to determine what guidance had been provided by industry associations on the design, construction, operation, and emergency preparedness of underground storage systems. Section 6 of the Gas Processors Suppliers Association's (GPSA's) *Engineering Data Book, 1987 Edition,* contains information on underground storage facilities, but not enough technical information to design or operate an underground storage facility. The book advises that underground storage is most advantageous when storing large volumes and identifies underground storage facilities as constructed and converted. Constructed underground facilities include solution-mined salt caverns, conventional-mined salt caverns, and conventional-mined nonporous rock facilities. Converted facilities include depleted coal, limestone, or salt mines. The book states that the GPSA knows of no standard procedures for storing HVLs underground in conventionally mined or solution caverns.

At its July 1992 public hearing, the Safety Board asked the American Petroleum Institute (API)[28] and the AGA what assistance they provided their members on underground storage. The API witness said that since 1981, it has recognized the need to develop standards for solution-mined underground storage facilities. Its transportation committee appointed a task force that began developing standards for solution-mined storage facilities, but the task force halted work because of an industry economic downturn. In December 1989, the task force resumed working on standards for design and construction, and in July 1990, resumed working on standards for operations and maintenance. According to a spokesperson, a draft of the design and construction standards includes recommended practices on designer qualifications, cavern design parameters and criteria, wellhead safety equipment, cavern drilling and completion, cavern integrity testing,

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[27] The AGA is a trade association comprising gas distribution, gathering, and transmission companies and related industries that represent the interests of the domestic natural gas industry before government and the public.

[28] The API, a trade association representing the domestic petroleum industry, promotes the interests of the industry, encourages development of petroleum technology, cooperates with the government in matters of national concern, and provides information to government and the general public on matters affecting the petroleum industry.

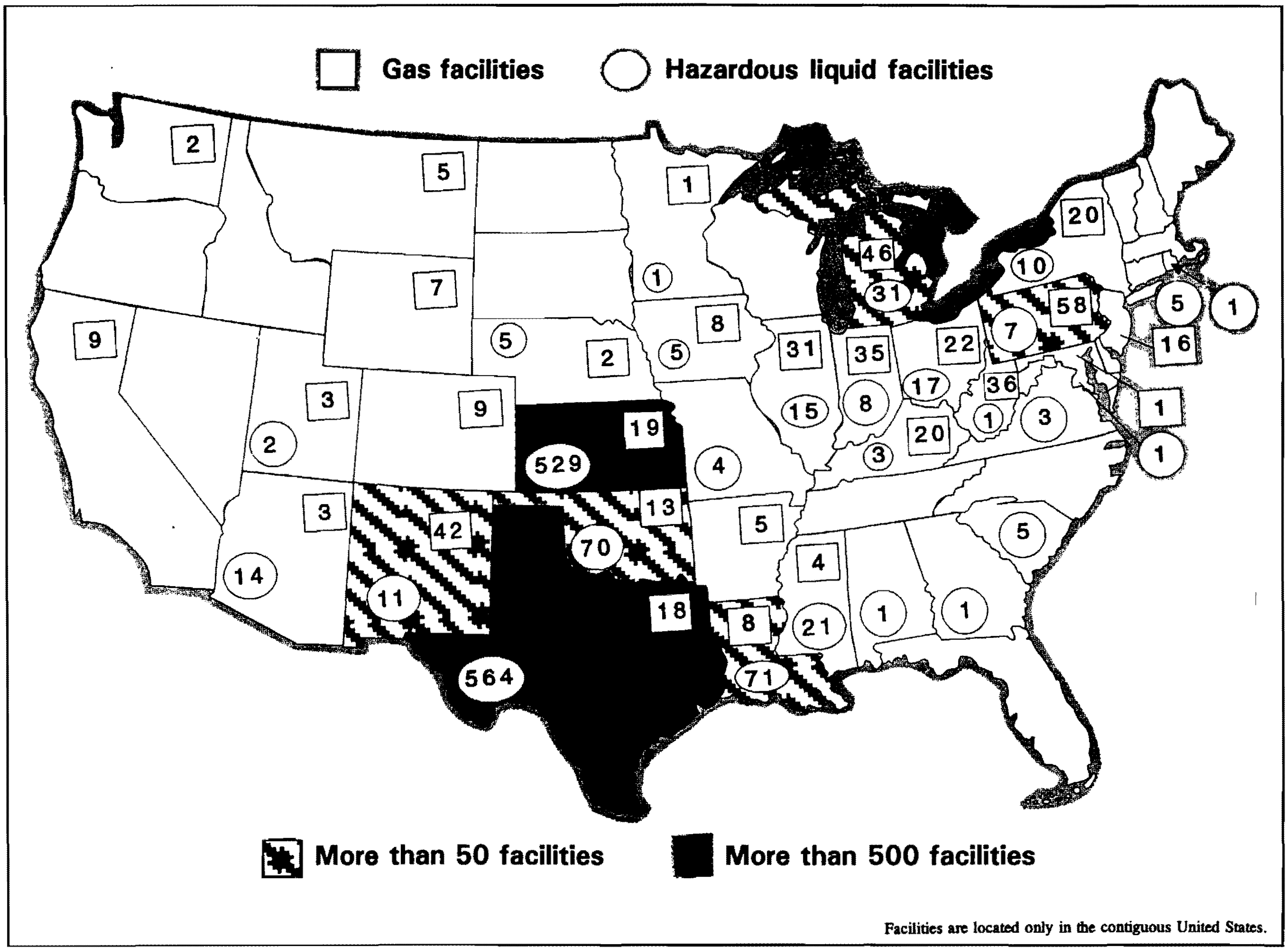

Figure 21. Number of underground gas and hazardous liquid facilities by State.

cavern product inventory measurement, cavern operation, and cavern abandonment. The API expects that both sets of standards will be issued by the end of 1993.

The AGA representative said that underground storage systems for natural gas have existed since 1916 and that they differ in several respects from systems for liquids. Natural gas is a lighter-than-air material that will rapidly dissipate into the atmosphere without posing a hazard to adjacent lower-lying areas, and it will not develop a vapor cloud and cannot detonate in the atmosphere. Underground facilities used to store natural gas are also different; about 85 percent of all storage is in depleted oil reservoirs, 13 percent in natural geologic structures such as aquifers, and 2 percent in salt caverns and an abandoned coal mine. Gas storage facilities are closed systems having no avenue to the surface, such as a brine tube, for product to escape.

The AGA witness stated that present standards applicable to underground natural gas storage were developed for the exploration and production of oil and gas. The API, the American National Standards Institute, and the International Association of Drilling Contractors have recommended practices on wellhead equipment, casing equipment, and drilling operations. The GPSA also has some educational and descriptive materials on underground storage.

The AGA witness identified those agencies having some safety control over underground storage of natural gas. A company proposing to build a system must first obtain a permit. For interstate operations, the Federal Energy Regulatory Commission (FERC) reviews the environmental studies, the construction, and the design proposals for the facility. For intrastate operations, a State agency, such as a utility regulatory commission, performs reviews similar to FERC's. The AGA witness stated that RSPA regulates all piping associated with underground storage facilities because storage is defined in the Federal gas pipeline safety standards as a gas transmission function. In most cases, the States regulate the performance of wellhead and down hole equipment.

While the AGA does not develop standards, the association has an underground storage committee that reviews and disseminates to its members technical information on the safe and efficient operation of both cavern and aquifer storage facilities. The committee works with standard-writing bodies by reviewing and recommending improvements; maintains technical papers; meets biannually to exchange technical information, to review research, and to review environmental regulatory requirements; and collects and publishes statistics on underground storage operations. Recently, the committee reviewed and proposed changes to the API's draft recommended practices on solution-mined caverns.

The AGA representative advised the Board about an affiliate of the Society of Petroleum Engineers (Society), the Midwest Gas Storage Mutual Aid Group, which assists member companies by providing lists of companies and sites having available emergency equipment that a storage operator can obtain rapidly in the event of an emergency. Another Society affiliate, the Appalachian Gas Storage Mutual Aid Group is now forming a similar mutual aid operation in Pennsylvania and adjacent States. The Safety Board is not aware of any similar actions within the pipeline industry.

Accidents Involving Gas and Liquid Underground Storage Facilities.--The Safety Board developed the following table on underground storage accidents using information from witness statements at the Safety Board's July 1992 public hearing in Austin, Texas, and from prior accident investigations. The table is provided only to show the consequences of some accidents at underground storage facilities. Because it was compiled from limited sources, the table should not be considered a representative sample. Neither the AGA nor the OPS provided detailed data on natural gas underground storage system accidents. The AGA representative stated that she had identified 20 accidents involving natural gas underground storage facilities from member discussions. She added that 10 of the 20 met OPS's requirements on reporting. The OPS spokesman stated that his agency does not require that underground storage accidents be reported to it; the incidents of which he was aware came from a variety of sources, including pipeline operators when damages to regulated pipeline facilities met or exceeded reporting requirements.

Date of Accident	Place of Accident	Company Involved	Details of Accident
Jan 23, 1975	Iowa City, Iowa	Mid-America Pipeline Company	A chiller used to cool the HVL before storage failed, releasing HVLs that ignited and killed two employees.
Mar 29, 1987	Clarmin, Illinois	Illinois Power Corporation.	Soil movement damaged the casing on a storage well, resulting in the release of natural gas. No injuries or deaths resulted.
April 1987	Iowa City, Iowa	Mid-America Pipeline Company.	A flexible pipe on a compressor failed, causing the release of HVLs that ignited. As a result, a relief valve failed in the open position, which released over a period of about 60 days all HVLs in the underground storage cavern. No injuries or deaths resulted.
Dec 5, 1987	Lewis County, West Virginia	Equitable Gas Company	An oxy-acetylene weld on an 8-inch-diameter gas storage field pipeline failed, releasing natural gas. No injuries or deaths resulted.
Jun 23, 1989	McPherson, Kansas	Mid-America Pipeline Company	Cavern overfilled, possibly due to operator error, and HVLs released to the brine pond ignited. No injuries or deaths resulted.
Nov 16, 1989	Carthage, Missouri	Williams Pipeline Company.	Cavern overfill resulted in the release of propane that ignited. No injuries or deaths resulted.
Dec 18, 1990	Navajo Dam, New Mexico	El Paso Natural Gas Company	A 1/2-inch-diameter fuel line to a dehydrator failed, releasing natural gas, which ignited. No injuries or deaths resulted.

Table 3. Underground storage accidents discussed at Austin hearing.

ANALYSIS

This analysis is divided into three main sections. In the first part, the Safety Board identifies station components that can be readily excluded as potential sources of product release. In the second part, "The Accident," the Board describes how the HVL product was released. In the third part, the Board discusses the safety issues identified in the following areas and the findings that support each issue: safety control systems; cavern management procedures; employee and management performance; and Federal and State safety requirements and oversight for underground storage and related pipelines.

Exclusions

The Safety Board excluded the following as sources through which the HVLs escaped:

Seminole's 14-inch Mainline and Station Piping.--After minor repairs were made to fittings damaged by the explosion, pressure tests showed that the mainline and station piping did not leak.

Coastline Piping.--Because escaping product from Coastline's above-ground piping was on fire after the explosion, investigators considered the Coastline riser a potential source of the initial HVL release. Laboratory examination revealed that damage to Coastline's pipe had resulted from external impact, specifically when the surface blast hurled the chain-link enclosure fencing onto the aboveground 6-inch piping, fracturing, cracking, and deforming the 1/2-inch pipes attached to the 6-inch piping.

Other factors support the finding that Coastline's piping was not the initial source of product release. Specifically, before the hazardous gas alarm and up to the time of the explosion, neither Seminole's nor Coastline's telemetry data system showed a pressure drop in the Coastline pipeline that was inconsistent with the change in temperature.

Cavern Structures.--Pressure tests taken after the accident showed that the reading at the cavern wellhead was 440 psig and holding and that the cavern showed no evidence of product leakage. Subsequent pressure and mechanical integrity tests indicated that the cavern walls, piping, and seals were structurally sound and did not leak.

Based on postaccident inspections and laboratory tests, the Safety Board concludes that product was not released from the mainline and station piping, the Coastline piping, or the cavern piping or structure.

Pressure graphs show that the computer outage that occurred about 3:45 a.m. at the dispatch center had no impact on operations and that readings from Brenham station were normal until shortly before 6 a.m. At that time, the cavern pump discharge pressure began decreasing, while the pump suction pressure remained constant (see figure 16). The Safety Board believes that the reduction in the pump discharge occurred when product began to enter the weep hole and brine in the brine tube began to be displaced. Because a downstream control valve was regulating the pump suction pressure, that pressure remained constant at this time. As more HVLs entered the brine tube and mixed with the brine, the specific gravity of the brine was lowered, causing less pressure to be applied to the product in the cavern.

Because HVLs have a specific gravity about half that of brine, the product entering the brine tube rose high enough in the brine tube that the pressure was insufficient to maintain some of the Y-Grade HVLs in a liquid state (calculations indicate that some of the liquids would change to vapor beginning about 1,000 feet below the surface). Some of the HVLs in the Y-Grade mix then changed into vapor and rapidly expanded, increasing the space that they occupied within the brine tube and displacing more brine. As more HVLs formed vapor, more brine was displaced, causing a further decrease in the pressure exerted on product within the cavern.

The HVL vapors rose through the brine tube and were released to the atmosphere through the brine ponds. When a concentration of HVL vapors sufficient to activate the station's gas detectors reached one or more of them, the HAZGAS alarm at the dispatch center was activated, and the station's pump shut-down system shut down the cavern pump. This caused a temporary cessation of HVL flow into the cavern and initiated a rapid increase in the cavern pump suction pressure and in the Bryan Lateral pressure because the plants were still pumping Y-Grade HVLs into the lateral. (Refer to 6:10 a.m. entry on figure 16).

The Brenham cavern shut-down system was not designed to automatically close key valves, including incoming and outgoing pipeline valves and the cavern valve. Thus, the flow into the cavern resumed even though the pump had shut down because the Bryan Lateral pressure kept the pressure at the pump above that needed to allow HVLs to enter the cavern. The Bryan Lateral pressure continued to increase while the cavern flow rate was less than the rate at which HVLs were being pumped into the Bryan Lateral by the plants. Because HVLs entering the tube through the weep hole were displacing brine, the rate of HVLs entering the cavern increased as the Bryan Lateral pressure increased and as the pressure exerted by the weight of the brine in the tube decreased.

Meanwhile, the dispatcher monitored the changing pressure and flow rate readings on his screen, but did not interpret them as constituting an emergency. The Safety Board believes the dispatcher failed to recognize the changing pressures in the station piping because his training on recognizing emergencies did not include emergencies occurring in station environments. Moreover, the computer did not provide a graphic display of historic data, which would have him to see pressure and flow rate trends, he was unable to identify the meaning of the numerous changes that were occurring.

So much HVL entered the brine line that the brine was displaced, allowing the HVLs nearing the bottom of the brine tube to flow directly into the tube. The Safety Board cannot determine precisely when this occurred because cavern and brine tube pressures were not recorded. However, figure 16 shows that the pressure at the pump was high enough (more than 790 psig) to allow the flow into the cavern to continue for about 20 minutes after the cavern pump shut down. By 6:30 a.m., pump pressure was too low for flow to continue under normal conditions. Nonetheless, flow did continue because pressure in the brine tube had been reduced by the infusion of HVLs through the weep hole; thus, less pressure was needed to flow HVLs into the cavern.

As reflected in figure 16, the pressure in the Bryan Lateral continued to build until about 6:35 or 6:40 a.m., an indication that the volume of HVLs flowing into the cavern was smaller than the volume of HVLs flowing from the plants into the lateral. These conditions further indicate that the HVL level had not yet reached the bottom of the brine tube. The curves show that the Bryan Lateral pressure began to decrease and product flow rate into the cavern increased, attaining flow rates higher than when the product was being pumped. The Safety Board concludes that soon after 6:40 a.m., HVLs began to flow from the cavern through the bottom of the brine tube, limited only by the tube's size and frictional characteristics.

After the explosion and during subsequent inspections, two manual valves in the sensing line were found closed. Had both valves been open at the time of the explosion, any one of several pipeline company employees who were at the wellhead soon after the explosion would have observed either a fire burning at the brine pressure sensing pipe, which explosive forces disconnected, or the escape of HVL vapors from the disconnected sensing line. Because no employee reported seeing either, the Safety Board concludes that one or both manual valves in the brine sensing line were in the closed position when the expansion of HVL vapor increased the pressure in the brine tube. Because the valves in the sensing line were closed, the Barksdale switch did not activate to close the cavern's safety valve. The last time that either manual valve would have been closed as a matter of routine was during a March 1992 maintenance test. However, sufficient information does not exist to conclude that either valve was left closed at that time.

Despite the cavern being overfilled, no substantial quantity of HVLs would have been released had the wellhead safety system been operative. The Safety Board concludes that HVLs were released from an overfilled underground storage cavern because Seminole's wellhead safety system, which was not equipped with fail-safe features, was inoperative.

Once the product was released, other factors were conducive for vapor to accumulate in the area. The temperature was 54° F, about the same as the dewpoint, which increased the tendency of the vapor to remain close to the ground. The winds were northerly at a speed of less than 2 knots, which allowed the mostly ethane product to evaporate and cool the air below the dewpoint, forming a fog. The terrain was gently rolling prairie; the station was atop a hill that dropped 40 feet to a low area, or swale, on the south side of the hill. The heavier-than-air vapor followed the terrain, flowing down the hillside, and filled the swale. With little or no wind to dissipate it, the vapor cloud continued to grow and remained in the area until it was ignited.

Adequacy of Safety Control Systems

This accident could have been avoided had the company done a comprehensive safety analysis of the Seminole pipeline system and Brenham station in order to identify potential points of failure and product release. Certain system components at both the dispatch center and the accident site did not allow dispatchers to readily identify an abnormal operating condition or to determine the scope of the problem. The Brenham station emergency shut-down system lacked fail-safe features.

SCADA System Format.--The SCADA pressure, flow rate, and alarm information that was transmitted to the dispatch center after 6 a.m. could have alerted a dispatcher trained in station operations that an abnormal condition had developed at Brenham station. The dispatcher's failure to identify the abnormal condition was due, in part, to his lack of training in recognizing abnormal conditions, a factor that will be covered later in this analysis under "Training."

In addition, the display format of the SCADA data did not facilitate ready identification of a problem by the dispatcher. The SCADA system format that MAPCO used before the explosion displayed only current data, and the data were in an alphanumeric format. The telemetry system updated the dispatch screens every 15 to 20 seconds, displaying pressure and flow rates for a given point in time. When the monitor displayed a reading, the dispatcher had to mentally compare the pressure shown to an established operating norm. A subsequent display of data replaced the previous display. At no time did the system monitor display a "history" of previous pressure or flow readings; such histories would have helped the dispatcher recognize trends.

Research has shown that graphic displays have several advantages over text description or tabulation.[29] First, graphic displays are easier to understand; thus, the user is more likely to detect trends. Second, it is easier to quickly scan and compare related sets of data; deviations are visually distinct from other data. Third, it is easier to detect critical changes, and thus easier to monitor changing data. As compared with static, printed displays, a continuous dynamic display of changing data is more likely to direct the user's attention to abnormalities.

The Safety Board concludes that had the SCADA system monitor displayed pressure and flow information in a graphic format for an extended time interval, such as shown in figure 16,

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[29] S. Smith & J. Mosier, "Guidelines for designating user interface software" (1986). Prepared for the United States Air Force, Hanscom Air Base, Massachusetts.

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a properly trained dispatcher could have more easily recognized that it was abnormal for HVLs to continue to flow into the cavern after the pump had shut down. Consequently, he would have had time to close the Bryan Lateral valve before the cavern overfilled. Even if he had not recognized the abnormality until 6:40 a.m. or later, too late to stop the release of HVLs from the cavern, he would have been able to give local agencies and his management early warning.

After the accident, MAPCO decided to graphically display both historical and current operational data on all boards at the dispatch center. Because the present SCADA transmission equipment and computer equipment and software are not compatible with a graphic display system, the company's entire SCADA system has to be replaced. It is estimated that the new SCADA system will be operational by the end of 1994.

HAZGAS Detectors.--The dispatch center received a single indication that a detector had activated. Regardless of whether an electrical malfunction or an actual HVL release activated one or more detectors, the system transmitted only one signal to the dispatch center. With the limited information provided, the dispatcher could not determine where the release had occurred, whether the release was large or small, or whether the situation was an emergency. Moreover, records show that most previous HAZGAS alarms received at the dispatch center from Brenham station had been caused by electrical problems and gas detector malfunctions. Consequently, the dispatcher could not tell from a HAZGAS alarm whether an actual emergency existed.

The Board believes that the existence and extent of a hazardous gas release would have been apparent to the dispatcher had Tulsa received either separate sequential alarms from each detector that activated or a "zone" signal when a set of detectors activated within a given area of the station. The Safety Board believes such an arrangement would allow management and employees to feel confident that they can tell when to take emergency actions, such as stopping all flow into, through, and out of stations, and when to notify local emergency agencies.

Emergency Shut-down Device (ESD).--When the Tulsa dispatch office received an emergency signal from the Brenham station, the dispatcher could only regulate pumps and valves to alter flow into and out of the station piping; he could not activate the ESD or otherwise close the cavern safety valve. The station ESD was designed to close automatically and to display to the dispatcher that it was closed. Given this arrangement and the limited information provided on operating conditions, the dispatcher's only course of action upon receiving a HAZGAS alarm from an unattended station was to notify an employee in the field or at home and to wait for him to check out the cause of the alarm. As this accident demonstrates, the consequences are a considerable loss of time and a considerable reduction in the ability of both the pipeline operator and the community to take prompt action.

The cavern wellhead valve was the only device for preventing an HVL release from the cavern. If the pressure monitoring system did not detect higher than normal pressures in the tube (an indication that HVLs had been released into the brine tube), the station safety control system had no backup mechanism that could prevent a product release into the air.

Sensing Line Design.--Using system safety analysis procedures, the Board identified many design deficiencies in the brine pressure sensing line and potential equipment malfunctions, any one of which could disable the sensing system without the pipeline company's knowledge (see figure 22). Also, the shut-down system design did not have any alternate way of remotely or automatically closing the cavern valve if the sensing system was rendered inoperative.

Fracture in the brine pressure sensing line
Break in the electric signal wire between Barksdale switch and solenoid valve
Blocked brine pressure sensing line (from salt crystals, rust, and/or foreign debris)
Malfunction of Barksdale pressure switch or electric solenoid valve
Failure of lever arm release mechanism to rotate

Figure 22. Factors that could disable the sensing system.

Past Safety Board Actions.--The failure of pipeline operators to perform safety analyses of their systems for potential systemic deficiencies is an issue that the Safety Board has addressed repeatedly for more than 20 years.

In a 1972 special study[30] the Safety Board reviewed systems analysis techniques and discussed their potential for improving pipeline safety. The Safety Board concluded that by using a systematic approach to safety, operators could predict and forestall most pipeline accidents. The Board further recognized that hazard control requires a trade-off between the application of resources and the practicality of risk assumption, stating:

> For pipeline managers to make sound decisions on risk assumption or reduction, they must first identify the hazards of a system, make an assessment of the risks posed in terms of probability of occurrence and potential losses, and then develop alternatives to risk acceptance and assess each in terms of available alternatives, costs of alternatives, and the extent of risk reduction.

The Safety Board concluded that each pipeline operator should use system safety analysis techniques in designing, operating, and maintaining its pipeline systems. Consequently, the Board recommended that the API and the American Society of Mechanical Engineers' Gas Piping Standards Committee (GPSC) develop and encourage the use of guidelines for pipeline operators on using system safety analysis techniques. The Board also recommended that the OPS and the Federal Railroad Administration (FRA)[31] encourage pipeline operators to use system safety analysis techniques in general and especially in their operation and maintenance programs (Safety Recommendations P-72-19 through -24).

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[30] Special Study, *A Systematic Approach to Pipeline Safety*, (NTSB/PSS-72/1).

[31] The DOT agency that was then responsible for liquid pipeline safety regulation.

The DOT's Assistant Secretary for Safety and Consumer Affairs responded on August 25, 1972, for both the OPS and the FRA, stating:

> We agree that "System Safety" will help to point out hazards, the likelihood of their activation, alternate methods of eliminating or controlling them, risks involved, and the feasibility of corrective measures. Under such a system, risks will no longer be assumed unknowingly, but only when a management decision has been made to assume them.

The Assistant Secretary explained that due to the magnitude of such a program, the DOT believed that the program should be carried out by the whole industry in a cooperative effort. He pledged that the DOT would make its pipeline information and accident files available, that the OPS would encourage gas operators and the AGA to cooperate in developing reports and manuals on particular segments of gas pipelines, and that the FRA would encourage the API to take similar action with liquid pipeline operators. Furthermore, individual pipeline operators would be encouraged to use the systematic approach to safety for reviewing and revising their operating and maintenance procedures.

In 1975, the AGA, in coordination with the GPSC, published its *Guide to System Safety Analysis in the Gas Industry*, which states:

> In the design of any vitally important transport system it is essential to anticipate and identify all possible elements or combinations of causes that might contribute to a failure so they can be eliminated at the earliest stage or design, and so that the performance of the system is predictable. This need led to the development of formalized procedures for the analysis of system safety that forced a logical examination of all elements of a system and the identification of all possible sources of accidents.
>
> This document is intended as a guide to the more common methods and procedures used in system safety analysis. It is addressed to a technical staff member who has little or no prior experience with system safety analysis, but who may be called upon to perform such an analysis. His task might be to identify the source or causative agents of potential accidents in some phase of gas system design and operation. Once such cases are identified, he would also suggest means for corrective action and estimate the consequences of an accident if one should occur if precautions are not taken. Based on this information, management would be in a better position to decide between alternate designs and methods of operation.

After reviewing the AGA guide, the Safety Board agreed that it met the intent of its Safety Recommendations P-72-19 and -20 and on December 30, 1975, classified the recommendations "Closed--Acceptable Action."

When the Safety Board reviewed the DOT's efforts to encourage the GPSC, the AGA, the API, and pipeline operators to use system safety analyses, the Board found that the efforts were satisfactory. On January 23, 1975, the Board classified Safety Recommendations P-72-23 and -24 "Closed--Acceptable Action."

The API advised the Safety Board that it had modified several of its recommended practices and had reviewed the industry code for liquid pipelines (ANSI B31.4-1974) to ensure that it embodied applicable systematic and proven safety analyses. The API said the code simplified the systematic consideration of pipeline design criteria because it is used throughout the petroleum pipeline industry and because it serves both as a guide and a checklist. Consequently, the API argued, for the most part, it was unnecessary to analyze each system separately. In 1986, the Safety Board replied that it had reviewed the code and found that it did not specifically advocate the use of proven safety analysis techniques to support the planning of work not specifically addressed in the code. On April 17, 1986, the Safety Board classified Safety Recommendation P-72-21 "Closed--Unacceptable Action."

On February 17, 1988, the Safety Board concluded that the API was not going to develop guidance on using system safety analysis and advised the API that Safety Recommendation P-72-22 had been classified "Closed--No Longer Applicable."

Since its 1972 special study, the Safety Board has investigated several product-release accidents in which either a dispatcher failed to realize that the data on the monitor screen represented an abnormal operating condition or a system that failed did not have fail-safe features.

In 1974, the Safety Board issued a report that discussed HVL releases at two different MAPCO facilities in Kansas.[32] The report said that hazards and high-risk areas in a pipeline operation can be identified through analysis and that once identified, they can be corrected. The Board concluded that in both accidents, the component failures and resulting hazards could have been identified through system safety analyses. The Board further concluded that the pipeline monitoring system was inadequate to notify and alert the dispatcher of the problem because a pressure sensing switch had not been installed at the correct location.

Following a 1983 MAPCO gas line rupture in West Odessa, Texas, the Safety Board determined that the dispatcher had not received enough information to allow him to distinguish a change in operations from an emergency.[33] The Board also found that frequent sensory equipment malfunctions had hampered the dispatcher in finding out why the system operating alarms had gone off. In its report, the Board said that MAPCO should determine why the system's electronic transmitters had malfunctioned, make necessary changes, and improve its communication system so that dispatchers would get the information they needed.

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[32] Pipeline Accident Report, *Mid America Pipeline System Anhydrous Ammonia Leak, Conway, Kansas, December 6 1973* (NTSB/PAR-74/6).

[33] Pipeline Accident Report, *Mid America Pipeline System Liquefied Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983* (NTSB/PAR-84/01).

Following a 1990 Texas Eastern Products Pipeline Company line rupture in North Blenheim, New York, the Board determined that the dispatcher had not received enough information to be able to promptly detect the rupture and the resulting release. The Safety Board also concluded that the people who did the repair work before the rupture were not given adequate instructions. Based on investigation findings, the Safety Board recommended that RSPA:

> Define the operating parameters that must be monitored by pipeline operators to detect abnormal operations and establish performance standards that must be met by pipeline monitoring systems installed to detect and locate leaks.(P-91-1)

On October 18, 1991, RSPA advised the Safety Board that it was undertaking a study to determine whether leak detection systems should be required on gas and liquid SCADA systems. On December 20, 1991, the Safety Board classified Safety Recommendation P-91-1 "Open--Acceptable Action" pending further response from RSPA. In May 1992, RSPA initiated a 3-year study on leak detection subsystems for SCADA systems. The first phase, which was completed in May 1993, examined the reliability, performance, interface with SCADA systems, and expected costs of various types of leak detection systems. The second phase of the study will evaluate the potential of leak-detection systems in reducing pipeline leak risks. In this phase, RSPA will evaluate how all pipeline system components affect leak detection.

The System Safety Society and other professional organizations have greatly improved safety analysis techniques in use since the Safety Board initially recommended their use. However, the pipeline industries have not adequately used the techniques even though the DOT has advocated their use and the AGA has developed guidelines to make them easier to apply. Even the OPS has not seriously considered adopting safety analysis techniques until recently. The OPS is now developing a risk-based analysis and prioritization process that it believes will provide an analytical basis for selecting from among potential pipeline safety improvement projects those that will lead to optimal use of its pipeline safety resources.

The Safety Board is encouraged by the OPS's action in using safety analysis techniques to improve the administration of the pipeline safety regulatory program. However, the Board believes that the OPS should extend its new-found appreciation of the advantages of system safety analyses by incorporating incentives into its pipeline regulations that will encourage individual pipeline operators and pipeline standards-writing organizations to also incorporate these techniques into their pipeline safety programs. The Safety Board believes that the OPS should require pipeline operators to apply system safety analyses to new and modified system designs and to evaluate the adequacy of existing underground storage systems. The OPS could motivate standards-writing organizations to use analysis techniques in assessing new or modified standards and practices by not incorporating into Federal regulations any standards that have not been appraised using safety analyses.

Postaccident Analysis and Reconstruction.--Following the accident, MAPCO analyzed the design of the Brenham station and examined employee operating and emergency response procedures to identify systemic problems. When the company reconstructed Brenham station, it installed redundant shut-down valves, repositioned the weephole and brine tube, and redesigned the gas detectors.

Shut-down Valves.--MAPCO installed cavern shut-down valves in the cavern HVL and brine lines and a redundant cavern safety valve in the brine tube between the wellhead and the brine ponds. These valves have pneumatic actuators and are to be spring-driven closed if a loss of air pressure occurs; they are designed to automatically close should any of the conditions shown in figure 23 occur. The valves can be operated from the dispatch center, from a control panel in the station's control building, and from key-operated controls near the station gate.

Weep Hole and Brine Tube.--MAPCO raised the brine tube higher within the cavern to provide greater clearance between the bottom of the tube and the cavern bottom and positioned the weep hole 6 feet above the bottom of the brine tube. As a result, the cavern is less likely to overfill because the amount of product needed to fill the space from the bottom of the brine tube to the weep hole has been increased by several thousand barrels.

Gas Detectors.--The company has installed additional gas detectors. Eight detectors specially designed to operate in the environs of the brine ponds have been installed around each pond, and one has been installed at the cavern wellhead piping. Other gas detectors have been installed at various locations in the station, at the pumps, at above ground piping runs, at buildings, and on the plant perimeter. Detectors around the brine ponds and the wellhead are designed to transmit an alarm to the dispatch center when a gas-in-air concentration of 50 percent of the LEL is detected. The detectors transmit a failure indication when they are activated for other reasons, such as detector failure.

All gas detectors are connected to a programmable logic computer that identifies which gas detector has been activated. Activation of any gas detector at the ponds or at the wellhead causes the cavern valves to close, pumps to shut down, remotely operable valves

Loss of electrical signal;

Failure of the station's programmable logic computer that monitored and operated the station's automatic equipment, including the gas detection system;

Loss of air supply to the valve pneumatic actuators;

Excessive heat at the wellhead;

Activation of the manual emergency shut-down button at either the well head control panel or at the station control center;

Activation of the key-operated control located at the station gate;

Activation of any brine pond gas detector or any three station gas detectors;

Activation of any of the following signals:

High/low pressure in the cavern meter piping or the cavern HVL wellhead pipe,

High flow rate in the cavern meter piping,

High pressure/flow rate from the cavern to the brine ponds

Figure 23. Conditions that will cause automatic closure of the cavern valves.

to close, and a message to be transmitted to the dispatcher identifying the location of the detector. Activation of any three other detectors in the station will trigger the same safety shutdown features.

The reconstructed underground storage safety control system at Brenham is considerably more complex and extensive. However, the company designed the system without using safety analyses to identify and document potential failures, to assess the likelihood of their occurrence, and to assess the feasibility of modifications that could eliminate or minimize potential failures. Without such an analysis, the ability of the control system to protect public safety is unknown. According to a MAPCO spokesperson, the company is currently performing safety analyses and will correct any identified deficiencies before the storage system is returned to service.

When the Brenham control system design has been finalized, MAPCO intends to accept the design as its standard for reviewing all of its other cavern storage control systems, and to make applicable improvements. MAPCO already has identified some improvements needed at other caverns by comparing the control system designs of those caverns to the proposed Brenham design. It is in the process of buying and installing the equipment needed for the improvements.

Adequacy of Cavern Management Procedures

MAPCO considered its volume accounting procedure a safeguard against overfilling its storage cavern. However, the significant opportunity for measurement and accounting errors that the procedure offered, the errors MAPCO that identified when emptying the cavern, and the fact that the procedure did not include balancing the cavern storage against product transported into and out of the Brenham station demonstrates that MAPCO's expectation was not realistic.

Accountability Measures.--MAPCO had adequate records on previous cavern measurement performance at Brenham for the Y-Grade product, but did not effectively use them in making decisions on managing the cavern storage. Had MAPCO used the records, it would have recognized that the error potential was much greater than its goal of +/- 0.25 percent. When MAPCO established its measurement accuracy goal, it installed monitoring and measurement equipment with accuracies that it believed compatible with this goal and developed a daily measurement accountability procedure that it believed would accurately reflect the daily storage volumes. During its years of operation, when it emptied the cavern and compared the quantity of stored product with the quantity shown on company records, MAPCO knew of the large differences being experienced. Even so, the company did not take steps to achieve its measurement accuracy goal.

Records show that the company often did not achieve its goal of +/- 0.25 percent accuracy. In the 4 years before the April 7 accident, the measurement was more accurate than it had been in previous years. Nevertheless, errors were as great as 2.35 percent in 1988, 2.6 percent in 1989, -0.72 percent in 1990, and -1.04 percent in 1991.

At Brenham station, several factors impeded the company's efforts to achieve its measurement goal:

Metering.--The station had meters to measure HVLs that entered the station, that were placed in or removed from the cavern, and that were delivered to Coastline. The HVL flow into the 14-inch mainline was not metered. Consequently, the company could not compare the daily measurement of HVL flows into and out of Brenham station to determine the accuracy of Brenham's measurement system. According to a MAPCO spokesperson, the reconstructed Brenham station has a meter that measures product that enters the 14-inch mainline. MAPCO will use this information to compare daily all volumes of HVLs entering and leaving the station and the storage cavern.

Specific Gravity Measurements of Mixed HVL.--The Y-Grade product is a mix of many liquids and some gases. The percentages of the various liquids and gases in the product being received at any time range constantly, but each generally stays within a specified range. The equipment used to define the composition of the Y-Grade HVL mix was not capable of accurately measuring the specific gravity of the continually changing product mixes as they were metered at various locations in the station. Inadequate identification of the Y-Grade HVL mix specific gravity as it is metered can result in significant errors in calculating the volume of HVLs stored in the cavern. MAPCO did not advise the Safety Board of any improvements in its specific gravity measurement procedures.

Employee Error.--The Safety Board found that employees at Brenham made many errors in obtaining and using the measurement data necessary to compute the flow of HVLs into and out of the storage cavern. Station employees did identify and correct some of their errors; however, the company did not identify the extent of the errors until it conducted a postaccident audit of all deliveries to and from the cavern. The Safety Board considered how the employee errors in MAPCO's accounting procedures affected the quantity of product stored in the cavern and found their effect to be significant, but insufficient by themselves to have caused the overfill. As a result of using incorrect temperatures, pressures, and meter correction factors in calculations, company records showed 31,000 fewer barrels of product in the cavern on April 7 than the quantity indicated by the subsequent audit.

Of potential measurement and accounting errors identified, the Board concludes that MAPCO's inability to balance cavern storage against station receipts and deliveries and its inability to accurately account for the varying specific gravity of Y-Grade product were the major reasons that the cavern was unknowingly overfilled. To estimate the size of the error necessary to account for the overfill and to consider MAPCO's view that more product was stored in the cavern on March 11 than on April 7, the Safety Board recalculated storage volumes between July 12, 1991, and April 7, 1992, by applying various error percentages to the corrected flows. Figure 24 shows the result of applying a 0.8-percent rate of error to flows into the cavern, which is less than the rate of error that MAPCO previously experienced when volumes exceeded 1 million barrels. This chart shows how MAPCO could incorrectly conclude from its cavern storage records that more product was in the cavern on March 11 than on April 7.

Under this assumption, slightly more product would have been in the cavern than was found after the accident. Nonetheless, it demonstrates how company records could have indicated that more product was stored on March 11 than on April 7, when the reverse was true. The chart shows how it was possible for 51,000 more barrels of product to have been stored in the cavern than the 288,000 barrels indicated in company records for April 7. The graph also shows that since the beginning of March, MAPCO often exceeded the cavern's 300,000-barrel working storage capacity and that it experienced a combined measurement inaccuracy (employee and procedure errors) of about 1 percent of the total product volume metered into and out of the cavern.

Cavern storage management procedures can and should be used to prevent the overfilling of underground storage facilities. Had MAPCO measured all HVL flows into and out of the station and cavern and then compared those measurements daily, the company could have identified and corrected significant individual and systemic measurement errors. Timely identification of measurement errors would have allowed MAPCO to correct equipment malfunctions and provide employees with adequate procedures, supervision, and training. The Safety Board believes that when the liquid pipeline industry uses measurement of HVLs, especially mixed-HVL streams, as an operational safeguard, the measurement procedures should include checks and balances adequate to detect both independent and systemic errors. The RSPA should require that operators of underground storage facilities develop measurement procedures adequate to identify both independent and systemic errors.

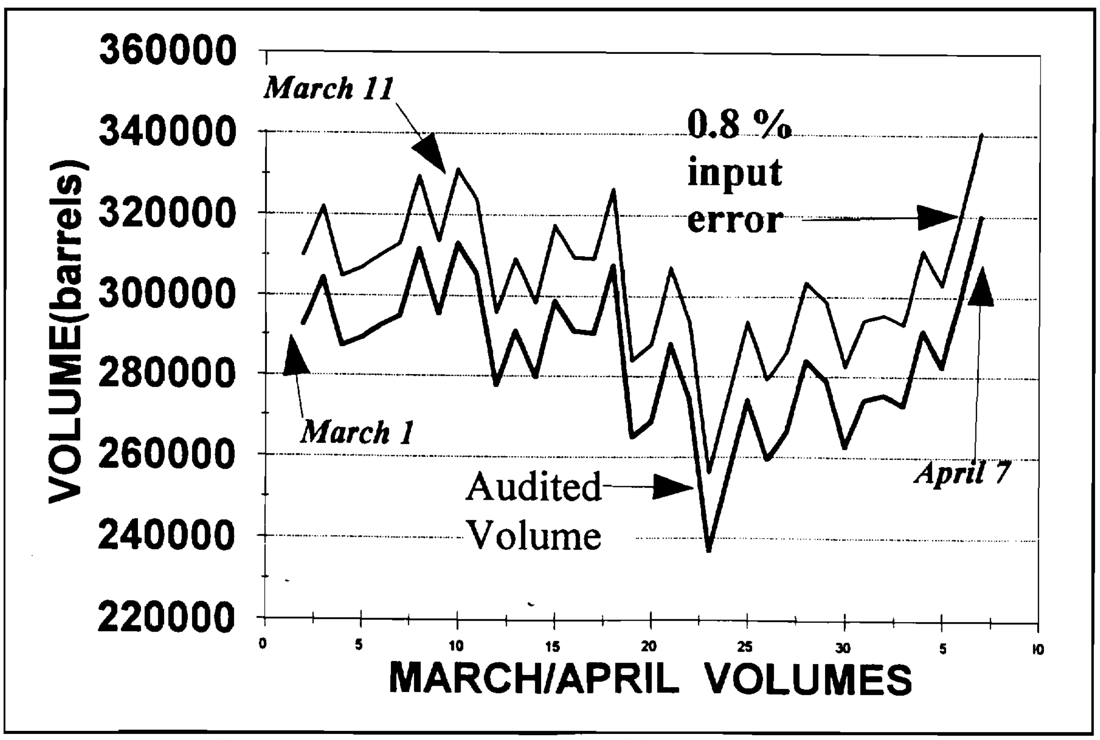

Figure 24. Above compares MAPCO's audited volumes with same volumes assuming an 0.8 percent rate of error.

For such controls to be effective, they must have a demonstrated capability to accurately measure the volume of stored HVLs. In addition, there must be an independent way to ensure that procedures are properly performed and to compare all measured flows into and out of stations that store HVLs. MAPCO now has the capability to measure all HVL flows into and out of Brenham station. The company plans to compare the station flow volumes with the cavern storage volume each day. A supervisor will also review measurement records and employee calculations daily. As stated earlier, MAPCO representatives have said that they are reviewing all storage cavern conditions and will upgrade them to be consistent with those at Brenham.

Employee and Management Performance

The Safety Board identified several factors that possibly resulted in human error and contributed to the accident and its severity. They included communication, supervisory oversight, training, dispatcher work/rest cycles, and drug impairment.

Communication.--Under the MAPCO emergency response procedures, the dispatcher is the main link in the chain of command that employees use in establishing communication. Deficiencies in communications among employees during the accident resulted in a series of other failures. For instance, the two employees who approached the station from the north about 7 a.m. did not initially communicate their location and observations to the dispatcher. When the first employee on-scene, who was unaware that any other personnel were in the area, learned that a schoolbus was headed toward the area, he left his position, where he should have been establishing a roadblock, and at risk to his own life, ran to intercept the bus. Shortly after that, a woman drove her car through the point where the blockade was inadequately established into the gas-filled area and may have ignited the products. The Safety Board concludes that the lack of communication adversely affected coordination among employees, increased the risk to initial responders, and ultimately contributed to the failure of employees to establish roadblocks that would have prevented the public from entering roads surrounding the cavern.

The Safety Board further examined the effect of inadequate communication on the dispatcher, who reported that the first technician on-scene at Brenham station did not indicate the magnitude of the gas release. Consequently, the dispatcher did not have a chance to prepare himself for the necessary procedures that followed: monitoring and operating the SCADA system, giving directions to other dispatchers, and talking on the phone to the on-site personnel and emergency-related agencies. Because the dispatcher did not have a complete understanding of the situation, he did not follow company procedure and contact the local emergency response agencies and company management. The Safety Board believes that had MAPCO provided the dispatcher with procedures for identifying the relevant product release information that he needed from on-site personnel, he would have become aware of the situation at the Brenham station and could have taken appropriate emergency response actions.

Complex tasks, such as those performed by pipeline dispatchers, involve more than simply detecting and responding to infrequent critical events. These operations require continuous attention to visual and auditory signals to detect and identify incoming information, followed by interpretations of significance, decisions concerning appropriate action, implementation of actions, and evaluation of consequences.[34]

The ability to perform tasks effectively is influenced by operator work load, which is based on environmental demands and operator capacity. Operators are most reliable under moderate levels of work load that do not change suddenly or unpredictably. Work load can increase whenever unexpected events occur, such as faulty equipment or a breakdown in communications. Work load extremes increase the likelihood of error, especially if the operator is not adequately trained for emergencies, because he is unable to cope with the high information rates imposed by the environment. As work load increases beyond an optimal level, stress also increases, which is associated with an overall loss or decrement in ability to perform complex operational tasks. The effects of high stress levels include eroded judgment, compromised performance, inattention, loss of vigilance and alertness, and preoccupation with a single task.

The detrimental effects of excessive work load quite likely affected the dispatcher's ability to perform all tasks effectively. After talking with the on-site technician, the influx of information directed to the dispatch center required that the dispatcher handle numerous operations, including attempting to shut the Bryan Lateral valve, giving orders to other dispatchers, reopening the lateral valve, talking with on-scene personnel, and continuing to monitor the system. The Safety Board believes that the dispatcher's need to manage several tasks concurrently placed him a situation of work overload. This condition was probably exacerbated by confusion and uncertainty due to inadequate communication among the pipeline employees. As a result, the dispatcher's ability to decipher available information may have been jeopardized, thereby delaying necessary emergency response actions. For instance, while monitoring the SCADA system, he received several pressure and flow rate alarms that indicated abnormal operating conditions. Determining the significance of these alarms and taking immediate emergency response actions required him to integrate the information with other data presented earlier on the SCADA system. The Safety Board believes that the combination of a heavy work load, the inadequate display of the SCADA output, and a lack of well-rehearsed training for cavern emergencies made it difficult for the dispatcher to integrate and properly interpret the significance of the SCADA information.

The importance of communication, coordination, and task allocation during an emergency cannot be overemphasized. Failure in any of these areas can result in people being removed from the decision-making process or becoming overwhelmed by an influx of information. To avoid the possibility of task overload, emergency response procedures should focus on relieving a single employee of added pressures and responsibilities. Distribution of emergency response actions would facilitate communication and strategic planning among the employees responding to the crisis. In this accident, an effective allocation of the responsibilities among other employ-

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[34] R. Thackray & R. Touchstone, "Effects of high visual taskload on the behaviors in complex monitoring," *Ergonomics 32* (1989), pp. 27-38.

ees would have allowed for the efficient execution of required tasks, such as notifying the local emergency response agencies, thereby reducing the "chaotic" environment experienced by the dispatcher. The Safety Board concludes that MAPCO's emergency procedures and training did not adequately prepare its employees in effective communication and task allocation.

Supervisory Oversight.--One role of management is to supervise operations and procedures conducted by employees. In this accident, inadequate management supervision allowed measurement errors to go undetected. The Safety Board found that employees made numerous measurement errors in determining the flow of HVLs into and out of the storage cavern. These errors occurred despite the fact that supervisors did some mathematical checks of figures, made on-site inspections, and held face-to-face discussions with employees to determine whether the employees correctly understood how to calculate the quantity of product in the cavern. Although MAPCO may have considered accurate measurement a safeguard against overfilling the cavern, the fact that numerous calculation errors went undetected over an extended period suggest that management's efforts to ensure effective cavern management were not effective.

MAPCO had trained Brenham station employees in the proper procedures to follow when performing measurements. However, the company neither tested employees to determine whether they understood the procedures nor sufficiently supervised or otherwise monitored them to ensure that they were performing their work correctly.

The Safety Board determined that Brenham station employees did detect and correct some of their measurement errors; however, MAPCO did not identify the extent to which employees were making errors until the company conducted a postaccident audit of all deliveries to and from the cavern. As a quality review measure, on-site supervisors could have periodically checked a sample of the calculations themselves or tasked a second employee either to check the first employee's calculations or to take readings and perform independent measurement calculations that could be compared with the first person's readings.

Training.--No current State or Federal regulations specify the qualifications or certification that a pipeline employee must have or the manner in which he must demonstrate proficiency. As a result, each company is responsible for determining the performance standards for its own employees.

MAPCO appears committed to providing its employees with thorough training. Its training program is multifaceted, and the courses are considerable in number and cover many important issues. However, in some instances either the company did not provide written operational procedures for employees to follow or the employees failed to adhere to specified procedures for normal and emergency operations. These errors occurred during product measurement (calculation of the HVL flow into and out of the cavern), communication (failure to relay information describing the extent of the gas release and failure of employees to identify their location around the cavern), supervision (failure to effectively check employees' measurements for accuracy), and other operations (improper inspection of the cavern valve, failure to establish adequate roadblocks, and the technician's failure to respond promptly to a HAZGAS alarm).

MAPCO did provide training for the above-mentioned operations during OJT, during in-house meetings (which included area operator/technician measurement seminars), and during safety meetings when discussing product release, blocking of highways, and evacuations. The employees' errors in these and other areas suggest that MAPCO needs to further evaluate the effectiveness of its training program.

For instance, MAPCO does not routinely administer written tests after safety instruction. Consequently, it cannot adequately evaluate its employees' acquisition of the class material. The Safety Board believes that to help ensure that class material is being mastered, employees in these courses need to demonstrate learning through formal examinations, such as those required in the Knowledge Improvement Program.

MAPCO also does not always provide opportunities for trainees to apply what they have learned. The company does not conduct emergency drills in which employees can perform safety-critical operations to demonstrate their knowledge of emergency techniques. The Safety Board believes a program of emergency procedure training is not adequate unless employees have the opportunity to practice their skills during a simulated emergency situation and receive feedback on their performances. Management must also be sensitive to the need for recurrent training because the infrequency of performing emergency response activities being trained makes it important to ensure that knowledge and skills are maintained with refresher training.

Following the accident, MAPCO provided the Safety Board with a description of its revised ongoing education and training program. Two employees in the environmental and safety department are now assigned to training full-time. Their duties are to regularly review, update, and expand the company's existing program. In addition, the training department evaluates new programs in response to regulatory, technical, or operational changes. These employees work with different committees in the company to make recommendations concerning new training or modifications to existing training.

Although MAPCO discusses lesson plans and test preparation for its in-house schools, the company does not mention the need to include testing in its safety seminars, nor does it discuss plans to include emergency drills or simulations as part of its training program.

The Safety Board previously identified shortcomings in pipeline operator training and selection in its 1987 report on accidents at Beaumont and Lancaster, Kentucky, and its 1990 report on an accident at North Blenheim, New York. In the latter, the Safety Board recommended that RSPA:

> Amend 49 CFR Parts 192 and 195 to require that operators of pipelines develop and conduct selection, training, and testing programs to annually qualify

employees for correctly carrying out each assigned responsibility that is necessary for complying with 49 CFR Parts 192 or 195 as appropriate. (P-87-2)

The Safety Board advised RSPA to develop and implement an employee qualification and training program that includes the following activities:

(a) Identification of each employee whose successful accomplishment of assigned responsibilities or tasks is a necessary part of an operator's actions for complying with Federal pipeline safety regulations.

(b) Analyses sufficient to identify for each employee the individual jobs, tasks, and responsibilities necessary to be performed as a part of the operator's program for complying with Federal requirements. These analyses should be documented and should include routine job performance, in-plant emergency duties, and emergency responsibilities for events that occur along the pipeline right-of-way. Furthermore, these analyses should be used for establishing measurable performance standards.

(c) Identification and implementation of the specific training methods to be employed to provide adequate knowledge to each employee for effectively carrying out applicable jobs, tasks, and responsibilities identified in the analyses.

(d) Identification of the method(s) to be used in evaluating the effectiveness of the training, including the identification of standard(s) for acceptance.

(e) Documentation for each employee of the training provided and training evaluations.

On March 23, 1987, RSPA issued an Advanced Notice of Proposed Rulemaking (ANPRM), Docket No. PS-94, entitled "Pipeline Operator Qualifications." The purpose of the ANPRM was to improve the competency of operator personnel, to establish licensing/ certification of operators, and to set minimum training and testing standards for employees. On April 7, 1987, the Safety Board supported the ANPRM and noted that between 1978 and 1986 it had issued 110 safety recommendations calling for the kinds of improvements suggested in the ANPRM. On June 24, 1987, because of the issuance of the ANPRM, the Safety Board classified Safety Recommendation P-87-2 "Open--Acceptable Action."

Four years later, in an October 18, 1991, letter, RSPA advised the Safety Board:

RSPA will soon issue a Notice of Proposed Rulemaking (NPRM) setting qualification standards for personnel who perform, or directly supervise the performance of operations, maintenance, and emergency response functions of gas pipelines, hazardous liquids pipelines, and carbon dioxide pipelines.

RSPA did not issue the NPRM. On April 9, 1992, it advised the Safety Board that it had been directed to "refrain from issuing any proposed or final rules for a 90-day period." RSPA advised that "this may slow the development of regulations, including those undertaken as a result of NTSB recommendations." The RSPA referenced a January 29, 1992, directive to all Federal agencies, including RSPA, stating that they should not issue proposed or final rules unless the rules were subject to statutory or judicial deadlines, responded to emergencies that posed an imminent danger to human safety, or fostered economic growth. In the same letter, all agencies were directed "to evaluate existing regulations and programs and to identify and accelerate action on initiatives that will eliminate any unnecessary regulatory burden or otherwise promote economic growth." On April 29, 1992, the January directive was extended for 120 days, and on September 15, 1992, it was extended for a year.

On September 2, 1992, RSPA informed the Safety Board that issuance of an NPRM on qualification of pipeline personnel had been delayed by the regulatory moratorium and the requirement to evaluate existing regulations to identify those that substantially impact economic growth, may no longer be necessary, or impose needless cost or red tape.

On December 24, 1992, RSPA advised the Safety Board that with the passage of the Pipeline Safety Improvement Act of 1992 (PL-102-508) and its requirement that operators test employees for qualifications, it will proceed with a rulemaking under the terms of the regulatory review directive, which exempts those rules that are statutorily mandated. RSPA further noted that if the regulatory review directive is lifted, this rulemaking will become a program priority.

In its report[35] on a January 17, 1992, accident at Chicago, Illinois, the Safety Board reviewed the status of Safety Recommendation P-87-2. The Board noted that RSPA had already had almost 5 years to establish qualification standards and that the Safety Board believed that achieving this objective should be a RSPA priority. The Board urged RSPA to consider the rulemaking a priority regardless of the directive, because the directive does not pertain to safety regulations and rulemaking mandated by legislation. The Safety Board also stated that it remained firmly convinced that the recommended training, qualification, and testing requirements and standards are essential. It urged RSPA to act expeditiously to amend the CFR to require that pipeline operators periodically train and test all employees assigned responsibilities that could affect public safety. On January 26, 1993, the Safety Board classified Safety Recommendation P-87-2 "Open--Unacceptable Response" and reiterated the recommendation to RSPA.

On May 11, 1993, the Safety Board again advised RSPA that it had already had more than 5 years to establish employee qualification standards and that the Safety Board believed that achieving those standards should be a RSPA priority. The Board reaffirmed its position that the recommended training, qualifications, and testing requirements and standards are essential and urged RSPA to act expeditiously on this matter. The RSPA has not yet responded.

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[35] Pipeline Accident/Incident Summary Report, "Over-Pressure of Peoples Gas Light and Coke Company Low-Pressure Distribution System, Chicago, Illinois, January 17, 1992 (NTSB/PAR-93/01/SUM).

Dispatcher Work Schedules.--Before the morning shift on the day of the accident, the dispatcher had not worked for 72 hours and was reportedly well rested. As a result, the Safety Board found that dispatcher fatigue was not a factor in this accident. However, the Board is concerned that strenuous work schedules could influence the performance of the dispatchers. For instance, between March 1 and April 30, 1992, two dispatchers had worked as many as 8 consecutive 12-hour days. Dispatchers who have worked several consecutive days or who are on a rotating-shifts schedule are, in general, more vulnerable to performance (vigilance and decision-making) errors than are well-rested dispatchers. Neither Federal nor State regulations for Texas and Oklahoma address permissible hours of service for pipeline dispatchers and other employees. The Safety Board has recommended that the DOT examine issues concerning fatigue and hours of service (Safety Recommendations I-89-1 through -3). The status of each of these recommendations is "Open--Acceptable Action."

Drug Testing.--According to Federal pipeline regulations, each employee whose performance contributed to or cannot be completely discounted as contributing to a reportable accident is to be tested for certain illicit drugs as soon as possible but no more than 32 hours after the accident occurs. Federal regulations do not require that pipeline employees be tested for alcohol. None of the employees who were on scene at Brenham station before or after the explosion were tested for drugs. The Safety Board believes that MAPCO should not have ruled out the possibility that the performance of on-site employees could have been impaired and believes that they also should have been tested for drugs.

Nothing suggests that any of MAPCO's employees were impaired by drugs. Nevertheless, the company's failure to test its on-scene employees made it impossible to determine conclusively that drugs did not have a role. The dispatchers' samples were collected 31 hours after the accident, within the 32 hours allowed by the CFR, but so long after the accident occurred that the samples were an unreliable guide to whether drugs had been used. If a drug testing program is to be a deterrent, it must be clear to pipeline operators that a long delay in obtaining specimens is not acceptable.

The Safety Board has recommended that specimens be collected "within 4 hours following a qualifying incident or accident" (Safety Recommendation I-89-6). Additionally, the Board has recommended "testing requirements that include alcohol and drugs beyond the five drugs or classes specified in the Department of Health and Human Services (DHHS) guidelines" (Safety Recommendation 1-89-7). In its April 14, 1993, letter responding to the DOT NPRM on workplace alcohol and testing, the Safety Board supported the proposed rule that specimens be collected within 2 hours of a qualifying incident. The Board stated that when collection is not accomplished within 2 hours, all blood and urine samples should be collected as soon as possible and an explanation for such delay should be submitted in writing to the administrator. The status of Safety Recommendations I-89-6 and -7 is "Open--Unacceptable Action."

In this accident, both the Texas Railroad Commission and MAPCO were uncertain about which employees should have been subjected to postaccident testing. As a result, several employees involved in the accident were not asked for samples. The Transportation Safety Institute's Pipeline Safety Division has provided guidelines for drug testing, stating that employees conducting emergency response functions are subject to postaccident testing. These guidelines also identify employees who may be subjected to testing. Thus, employees identified as emergency responders may or may not be tested, depending on their involvement in the accident. No criteria specify the response actions that determine whether employees did, in fact, contribute in the accident. The lack of criteria may result in operators interpreting the postaccident drug testing policy to their own advantage.

The Safety Board believes that guidelines need to be developed to assist operators in determining whether an employee contributed to an accident. For example, guidelines should include identifying those employees that the company has designated as first responders, that is, those employees whose specific safety-critical functions (actions and/or decisions) require that they take an active part in the accident. An operator would then know that these first responders are subject to postaccident testing. To eliminate the possibility of misinterpreting the testing policy, the Safety Board believes that RSPA should develop guidelines to help ensure that the appropriate employees undergo postaccident testing.

Adequacy of Emergency Preparedness

From the testimony of pipeline employees, area residents, and community-response personnel, the Safety Board identified several failures in emergency preparedness. The ineffective actions of MAPCO's first responders actually increased the risk to both area residents and to themselves:

- On-scene responders failed to give the dispatcher important information about site conditions.
- The dispatcher failed to notify local response agencies, and on-scene pipeline employees failed to effectively coordinate with them.
- On-scene responders failed to block vehicle traffic on CR 19, which HVL fog had blanketed.

MAPCO employees also did not have ready access to personal protective equipment, such as self-contained breathing apparatus. The company's "safety trailer," which had response equipment, was in Sugar Land, Texas, approximately 87 miles from Brenham, and was not available until several hours after the explosion.

MAPCO employees also lacked portable public address equipment for alerting the public. The Safety Board recognizes that because of the large accumulation of vapor at Brenham station and adjacent areas, pipeline personnel did not have sufficient time after they arrived on scene to evacuate all residents exposed to the released vapor. However, access to public address equipment would have afforded on-scene pipeline employees more options for dealing with area residents, such as broadcasting an alert to nearby homes or making announcements at roadblocks to oncoming motorists.

The preface to the *MAPCO Procedural Manual* used by employees states that procedures contained therein are intended to comply with requirements under 49 CFR. The Safety Board determined that both MAPCO's guidelines and Federal requirements regarding emergency response are severely lacking in specific criteria on performance, especially in the areas of timely detection, notification, and evacuation.

Despite the extremely hazardous properties of HVLs, the MAPCO manual does not list evacuation as a precautionary measure to be implemented prior to controlling a leak, but only as the final step after all initial attempts to control the release have failed. MAPCO's emergency procedures are primarily designed for small releases when the responder (technician) has time to receive a call-out, proceed to the scene, determine the reason for the alarm, and notify the dispatcher. With small releases, responders usually have sufficient time to secure the area, warn area residents, and set up blockades.

In this accident, if public safety officials had been quickly notified of the abnormal conditions, they could have prepared to evacuate people from the area of potential harm until the cause of the alarm had been verified. Valuable time was wasted when the dispatcher waited for the responding technician to verify the release. Although his action was in accordance with MAPCO procedures, the time between 6:09 and 6:45 a.m., about 35 minutes, was wasted. As noted earlier, the failure of the first responder on scene and the dispatcher to communicate vital information compounded the problems in this accident. The technician told the dispatcher that "gas was in the station yard," but did not indicate either the magnitude of the release or that it was not confined to the immediate station area. The dispatcher failed to ask for any details regarding the release. As a result, the dispatcher did not notify the local fire department, thereby negating any opportunity during the next 25 minutes for community response personnel to establish site security and control, to evacuate, or to plan for fire fighting.

The Safety Board determined that planning probably would have improved coordination between MAPCO and Washington County. Investigators determined that MAPCO had given an emergency response packet to members of the Local Emergency Planning Committee (LEPC) and that none of them suggested any revisions. Following the Brenham accident, the EMC, who was also an LEPC member, testified that he was not aware of or familiar with either the pipeline company's emergency response packet or Brenham station and had not attended any training that MAPCO had conducted at the station site.

In the Brenham accident, the EMC was in charge of the overall emergency coordination, acting not only as on-scene commander, but also as emergency medical director and public information officer. Because an individual who was not familiar with the site or prior planning activities was directing operations at the accident scene, many key tasks were not accomplished in a timely manner, including identification of the released product and its hazards, determination of the risks involved, evacuation of the affected area adjacent to the site, and liaison with the pipeline operators.

Public safety officials and pipeline operators need to understand what they can expect from one another in an emergency. To ensure compatibility, the principals in this accident should consider incorporating the following elements in their emergency planning:

- o Immediate notification by the MAPCO dispatcher of all releases, regardless of the origin or size, to the Washington County Emergency Communications Center. An immediate notification could place predetermined emergency units on alert or standby for immediate response.

- o Predetermined meeting at the site for the incident commander to initially meet and exchange information with a predesignated representative of the pipeline. The information exchange would include released product information and a list of recommended emergency action options, resources, and personnel-protective equipment available to assist in spill control, containment, and mitigation. At a minimum, personnel-protective equipment should include sufficient self-contained breathing apparatus, appropriate hydrocarbon gas detectors, intrinsically safe radios/communication equipment, and portable road barricades.

- o Map of the area with location of exposures and locations that can be isolated, along with predetermined road control points and evacuation routes.

- o Demonstrated ability to inform, warn, advise, or alert and, if need be, evacuate the exposed public in a timely manner.

- o At a minimum, establishment of and training for all key response personnel in the incident command system. Disaster drills should be conducted to ensure the adequacy of personnel readiness; for example, an annual tabletop exercise simulating a large release at the cavern that involves multijurisdictional public response agencies and all pipeline carriers/operators in Washington County.

Within 30 days of the Brenham accident, MAPCO formed a committee for cavern redesign, including emergency response planning and coordination with Washington County. The committee proposed a redesign of the cavern and establishment of a requirement that all employees be capable of participating in emergency response to HVL operations no matter where they occur; in doing so, it sought to comply with Occupational Safety and Health Administration (OSHA) regulations, 29 CFR 1910.9, "Process Safety Management of Highly Hazardous Chemicals." In November 1992, the committee drafted new procedures, "MAPCO's Brenham Emergency Action Plan," covering emergency planning, public emergency alerting, and MAPCO's emergency response actions in conjunction with the surrounding community's plan.

During August and September 1992, the EMC met on several occasions with various MAPCO representatives to discuss changes to the pipeline company's emergency response procedures. At the request of the local community, the company agreed to install a siren at Brenham station that can be activated by the sheriff's office dispatcher. Furthermore, the Brenham facility will be permanently manned 24-hours a day by MAPCO personnel when it becomes operational. As a result of the November 1992 public hearing, Washington County plans to conduct a multijurisdictional (Washington/Austin Counties) drill and training exercise with public response agencies to familiarize them with the recently drafted MAPCO emergency action plan and emergency warning system.

The Safety Board recognizes that the emergency action plan is intended to provide closer integration with the surrounding counties, use of a remotely activated audible alarm system, command liaison, and immediate county notification prior to station supervisor contact. Considering the concerns this accident raises, key personnel must also be familiarized with both the county's and operator's plans, including their limitations, primarily through drills and training. Moreover, the plan does not include a timetable for implementing the OSHA training requirements for MAPCO employees or an annual drill with the public response agencies, nor does it provide assurance that the public will be evacuated in a timely fashion.

In reviewing the emergency response requirements, the Safety Board notes the apparent absence of criteria for timeliness of detection, notification, and evacuation. The events and circumstances of this accident and of the North Blenheim accident show a need to develop standard procedures and guidelines for a precautionary evacuation within 1 mile of HVL facilities and to provide assurance that all HVL facilities are capable of alerting and evacuating the public in a timely fashion within 1 mile of the facility following a release. Because of the potential for widespread threats due to a release of HVL along pipelines, operators must be better prepared to serve as first responders. As this accident demonstrates, pipeline operators need to ensure timely emergency notification, coordination, and liaison with public agencies, while also taking any immediate corrective action necessary to control a release. If a cavern emergency plan is to be effective, these deficiencies must be addressed.

Because of the potential for risk at HVL and natural gas underground storage facilities, the Safety Board believes that public safety officials, such as State and local emergency planning committees, should develop emergency response plans specific to the underground storage facilities in their jurisdictions.

Regulation and Oversight of Underground Storage Systems

The safety standards issued by the OPS were not applicable to HVL or other liquid petroleum underground storage facilities, primarily because the industry standards from which OPS derived its standards did not apply to underground storage facilities. During the 25 years the DOT has had safety jurisdiction over liquid pipeline operations, several accidents involving HVL underground storage facilities have occurred, although their consequences were not as great as at Brenham. Even so, the OPS has not acted to regulate the safety of these facilities. The Safety Board believes that the OPS should have taken at least enough notice of such accidents to have initiated reporting requirements to assist it in assessing whether additional action was warranted.

The TRC has the authority to regulate underground storage facilities. However, the TRC did not consider that its authority extended to establishing safety standards for wellhead safety control systems. Consequently, Brenham station's wellhead safety equipment was never inspected by its personnel.

MAPCO's pipeline operations were subject to the OPS pipeline safety requirements and to those of the TRC. Texas, like most other States, has a small staff dedicated to monitoring the compliance of pipeline operators with safety standards. The OPS rates the TRC's pipeline safety program as one of the nation's best, yet major inadequacies in MAPCO's operations went undetected. As discussed earlier, MAPCO's emergency preparedness coordination with communities adjacent to its pipelines, employee training and oversight, and remote monitoring of Brenham station operations were all deficient, and those deficiencies were not identified before this accident by the regulatory compliance inspections. The Board believes that the TRC and the OPS should reassess Texas' pipeline safety program to identify resources and/or system improvements that needed to minimize the potential for omissions in future compliance inspections.

This accident and the lack of regulatory public safety oversight posed by more than 1,400 liquid and more than 400 natural gas underground storage facilities demonstrate that:

- The OPS needs to define in its regulations standards to protect the public from any threat posed by the operation of HVL underground storage facilities.
- The API needs to complete its recommendations about solution-mined storage caverns and to develop recommendations about the other types of underground storage facilities that are used to store dangerous materials, such as HVLs and natural gas.
- The AGA needs to cooperate with the API in completing and developing recommendations about underground storage facilities.
- States that have HVL underground storage facilities need to develop standards to protect public safety and need to effectively oversee the facilities.

The AGA spokesperson stated that underground storage of natural gas is regulated under OPS's pipeline standards; but the OPS informed the Safety Board that it has not issued safety requirements on the underground storage of natural gas. The industry spokesperson also pointed out that there are significant differences in the physical properties of natural gas and hazardous liquids and in the types of storage. The Safety Board recognizes these differences; nonetheless the Board believes that the underground storage of both can pose significant, albeit different, threats to public safety. The Safety Board concludes that the OPS needs to amend its natural gas pipeline safety regulations to specifically include safety standards on underground natural gas storage facilities that are adequate to protect public safety.

The OPS and the AGA spokespersons advised the Safety Board that most underground HVL and natural gas storage facilities would not be affected by any safety standards issued by the OPS because the OPS's jurisdiction applies only to those storage facilities operated in conjunction with pipelines when the stored materials are to be further transported by pipeline. Individual plants are not subject to OPS's jurisdiction, nor are those underground storage facilities at terminals where the stored materials will not be further transported or will be transported by systems other than pipelines.

In a March 14, 1988, letter to the Secretary of Transportation, the Safety Board addressed the lack of safety regulations for terminal operations where hazardous materials are interchanged among transportation modes and are stored:

> Terminal facilities provide important and necessary operations in an intermodal hazardous materials transportation and distribution system, and such operations should be conducted under reasonable DOT safety regulations. The Safety Board believes that reasonable safety requirements should be established for the public and for the employees of all segments of a hazardous materials transportation system and that the DOT has been given the authority to do so by Congress .... The lack of regulation in any portion of a hazardous materials transfer system may compromise the safety of the entire system. Therefore, the DOT should amend its regulations to remove those sections that exclude safety requirements for hazardous materials transportation operations at intermodal facilities.

The Safety Board then recommended that the DOT:

> Establish safety requirements for the movement and temporary storage of hazardous materials at intermodal transportation terminals. (I-88-1)

On September 30, 1988, the Secretary advised that the DOT was addressing the recommendation, but that it would take time to sort out the appropriate policy direction. The DOT's current safety regulations on the transportation of hazardous materials do not apply to all aspects of intermodal facility operations. While some operations at these facilities may be covered by individual regulations pertaining to specific modes of transportation, there are gaps in their coverage. The Secretary stated that RSPA has begun a review of jurisdictional authority to determine which Federal statutes may be used to regulate the operations of an intermodal facility. The analysis was to identify gaps in regulations and statutes and will be completed by the end of 1988. The Safety Board responded on November 8, 1988, complimenting the DOT on its prompt attention to this recommendation and advising that the recommendation had been classified "Open--Acceptable Action."

The Safety Board is not aware of any further action on this recommendation and urges the DOT to expeditiously complete the assessments necessary to take final action. Additionally, the Safety Board urges the DOT to include in its analysis, if it has not already done so, a review of the actions necessary to take to regulate underground storage facilities for HVLs and natural gas when those operations are not regulated under Federal statutes on pipeline operations. Therefore, the Safety Board reiterates Safety Recommendation I-88-1.

In June 1992, the TRC surveyed all underground storage facilities in Texas to document and research the extent of safeguards and types of controls in place at underground storage facilities. The TRC received responses from all pipeline companies that actively operate storage facilities. Survey responses indicated that the design of underground storage facilities differed somewhat. For example, while most facilities used hazardous gas and fire detectors that incorporated audible alarms, the location of the alarms varied greatly. Some were at the detector, some were in a nearby control room, and some were at a remote location. One alarm sounded at the local fire department. (See appendix D for survey and results.)

Based on its findings, the TRC proposed new and amended rules. On August 17, 1992, the TRC proposed amendments to Rule 46, repeal of Rule 74, and adoption of new Rules 74 and 97 to strengthen control over underground storage in salt formations. Under the proposals, each operator/storage facility would be required to prepare a written emergency response plan for coordination with local authorities, use of warning systems, procedures for citizen and employee evacuation, emergency notification, annual emergency drills, and employee safety training. The Safety Board is pleased that the State of Texas is responding to protect its citizens; however, the Board believes that the DOT needs to develop safety standards that are applicable nationwide.

CONCLUSIONS

Findings

1. The HVLs that formed the vapor cloud and that fueled the explosion were released from the overfilled underground storage cavern because the wellhead safety system at Brenham station, which was not equipped with fail-safe features, was inoperative by one or both brine sensing line manual valves being closed.

2. At the time MAPCO designed Brenham station, the company did not use system safety analysis and therefore, at that time, did not realize the cavern shutdown system lacked several fail-safe features.

3. Federal and State regulations governing underground storage facilities for natural gas and HVLs predominantly address environmental hazards and do not require an adequate level of safety for the public and employees.

4. MAPCO was not aware of the volume of product stored in the cavern because it lacked the ability to balance the cavern storage against station receipts and deliveries, because its procedures and oversight of employee measurement activities were insufficient, and because its measurement procedures did not adequately compensate for the varying specific gravity of the Y-Grade product.

5. Because the large quantity of HVLs released at Brenham station remained undected for an appreciable time period, responders had insufficient time to evacuate endangered residents.

6. The SCADA telemetry system monitor did not display data received from Brenham station in a format that facilitated ready interpretation by dispatchers.

7. The lack of effective communications among MAPCO employees during their response to the emergency increased the risk both to area residents and to themselves and resulted in poor emergency response coordination.

8. MAPCO was not fully aware of its employees' knowledge of operating and emergency procedures because most of company training did not include formal testing or other methods, such as exercises or drills, that required employees to demonstrate their ability to perform their duties.

9. The Safety Board could not determine whether drug impairment was a factor in this accident because not all employees involved were tested. Moreover, although Federal regulations were not violated, samples were collected 31 hours after the accident, when results were no longer reliable.

10. MAPCO's emergency response training and procedures, which are primarily designed for small releases that allow personnel time to investigate the circumstances surrounding a release, proved to be inadequate in this accident.

11. Adequate planning between MAPCO and Washington County would have improved coordination and initial response actions, including notification of public emergency response agencies and securing the immediate site area, and would have better prepared the responders and the public for the possibility of a large HVL release at Brenham station.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the release of highly volatile liquids from the remotely operated and overfilled storage cavern and the resulting explosion at Brenham station was the failure of MAPCO Natural Gas Liquids, Inc., to incorporate fail-safe features in the station's wellhead safety system. The cause of the overfilling was the inadequacy of the company's procedures for managing cavern storage. Contributing to the accident was the lack of Federal and State regulations governing the design and operation of underground storage systems. Contributing to the severity of the accident was the company's inadequate emergency response procedures.

RECOMMENDATIONS

As a result of its investigation of this accident, the National Transportation Safety Board makes the following safety recommendations:

--to the Research and Special Programs Administration:

Develop safety requirements for storage of highly volatile liquids and natural gas in underground facilities, including a requirement that all pipeline operators perform safety analyses of new and existing underground geologic storage systems to identify potential failures, determine the likelihood that each failure will occur, and assess the feasibility of reducing the risk; require that operators incorporate all feasible improvements. (Class II, Priority Action) (P-93-09)

-- to MAPCO Natural Gas Liquids, Inc.:

Perform safety analyses of the safety control systems for each of your underground storage systems and, based on those analyses, modify the control systems to provide an adequate level of safety for the public and employees. (Class II, Priority Action) (P-93-10)

Develop and implement training and procedures that focus on identifying and distributing emergency-response tasks, establishing communication, and coordinating on-scene personnel for all employees who respond to abnormal and emergency situations. (Class II, Priority Action) (P-93-11)

Develop procedures for dispatchers and on-scene employees to follow when gathering product-release information during an emergency to help ensure that employees promptly disseminate essential information to company and community officials responsible for emergency response actions. (Class II, Priority Action) (P-93-12)

Incorporate testing and practice drills or other emergency-procedure exercises into your employee training program so that managers can evaluate the effectiveness of the emergency response training. (Class II, Priority Action) (P-93-13)

In cooperation with Washington County, develop disaster plans for Brenham Station that identify conditions that warrant an evacuation, that identify the extent of the area to be evacuated, and that include procedures for carrying out an evacuation. (Class II, Priority Action) (P-93-14)

--to Washington County:

In cooperation with MAPCO Natural Gas Liquids, Inc., develop disaster plans for Brenham Station that identify conditions that warrant an evacuation, that identify the extent of the area to be evacuated, and that include procedures for carrying out an evacuation. (Class II, Priority Action) (P-93-15)

Evaluate the county's emergency disaster plan to determine whether it provides timely and effective response capabilities, site security and control, and personnel evacuation; and, if it does not, make necessary amendments. (Class II, Priority Action) (P-93-16)

--to the State of Texas, Department of Public Safety:

Develop guidance for communities adjacent to highly volatile liquid underground facilities that identify conditions that warrant an evacuation, that identify the extent of the area to be evacuated, and that include procedures for carrying out an evacuation. (Class II, Priority Action) (P-93-17)

--to the American Petroleum Institute:

Expedite completion of the recommended safety practices for design, construction, operation, and maintenance of solution-mined storage caverns. (Class II, Priority Action)(P-93-18)

Develop recommended safety practices for the design, construction, and operation of highly volatile liquid and natural gas geologic underground storage facilities other than solution-mined storage facilities. (Class II, Priority Action)(P-93-19)

In cooperation with the American Gas Association, develop standards and guidelines for the design and use of graphic information display systems used by dispatchers to control pipeline systems. (Class III, Longer Term Action)(P-93-20)

-- to the American Gas Association:

Cooperate with the American Petroleum Institute in completing recommended safety practices for the design, construction, operation, and maintenance of solution-mined storage caverns and in developing recommended safety practices for other types of highly volatile liquid and natural gas underground storage facilities. (Class II, Priority Action) (P-93-21)

In cooperation with the American Petroleum Institute, develop standards and guidelines for the design and use of graphic information display systems used by dispatchers to control pipeline systems. (Class III, Longer Term Action)(P-93-22)

--to the International Association of Fire Chiefs:

Advise your members of the circumstances of the April 7, 1992, explosion at Brenham, Texas, and urge them to determine whether highly volatile liquids or natural gas underground storage facilities are located in their jurisdictions; if such facilities are present, urge that your members ensure their disaster plans identify conditions that warrant an evacuation, identify the extent of the area to be evacuated, and include procedures for carrying out an evacuation. (Class II, Priority Action) (P-93-23)

The National Transportation Safety Board also reiterated the following safety recommendation:

--To the Secretary of the Department of Transportation:

Establish safety requirements for the movement and temporary storage of hazardous materials at intermodal transportation points. (Class II, Priority Action) (I-88-1)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

CARL W. VOGT
Chairman

SUSAN M. COUGHLIN
Vice Chairman

JOHN K. LAUBER
Member

JOHN A. HAMMERSCHMIDT
Member

CHRISTOPHER A. HART, Member, concurred in the adoption of this report but did not participate in the adoption of the recommendations.

November 4, 1993

APPENDIX A

INVESTIGATION AND HEARING

Investigation

The National Transportation Safety Board was notified on April 7, 1992, of the explosion and destruction adjacent to a highly volatile liquids pipeline station near Brenham, Texas. Immediately following the accident, the Safety Board dispatched an investigation team from Washington, D.C., comprising investigation groups for pipeline operations and survival factors. Later, the Board established investigation groups for human performance and metallurgy.

Hearing

The Safety Board conducted a public hearing in conjunction with this investigation in Austin, Texas, on July 29 and 30, 1992. Parties to the hearing included Seminole Pipeline Company, the Research and Special Programs Administration of the U.S. Department of Transportation, the Texas Railroad Commission, and Washington County, Texas.

Deposition

The Safety Board took depositions in conjunction with this investigation in Washington, D.C., on September 2 and 10, 1992. Parties to these proceedings were Seminole Pipeline Company and Coastline Pipeline Company.

APPENDIX B

METALLURGIST'S REPORT

NATIONAL TRANSPORTATION SAFETY BOARD
Office of Research and Engineering
Washington, D.C. 20594

July 6, 1992

Materials Laboratory
Report No. 92-71

METALLURGIST'S FACTUAL REPORT

A. ACCIDENT

Place : Brenham, Texas
Date : April 7, 1992
Pipeline : Seminole Pipeline Company
NTSB No. : DCA 92-M-P006
Investigator: George Mocharko, ST-60

B. COMPONENTS EXAMINED

1. Six-inch diameter riser, with a flanged valve and cap, and four pipe nipples and ball valves.

2. One half of a separated fusible link (165° Globe 84 UL) and exemplar fusible links.

3. Overpressure sensing equipment connected to the tube that transports brine between above-ground brine ponds and a storage cavern, including:

   a. 1/4 inch I.D. pressure sensing tubing,

   b. fitting (from which the pressure sensing tubing had separated) that connects the pressure sensing tubing to the brine tube,

   c. valve with a separated handle and the 1/4 inch tubing pulled out of one end,

   d. Barksdale class W pressure switch (SPDT), and

   e. shutoff valve solenoid.

C. DETAILS OF THE EXAMINATION

1. Six-inch diameter riser

The six-inch diameter riser is shown in an overall view in figure 1, after removal of sections of chain link fencing (shown at the bottom of figure 1). The majority of the riser was covered by soot deposits,

Flynn Exhibit Page 328

consistent with exposure to a fire. For the riser section, this report will discuss only the examination of the four 1/2-inch-inside-diameter nipples and ball valves that were threaded into the top of the horizontal portion of the riser section. There were two ball valves on each side of the large valve in the riser. The ball valves are indicated by arrows "1" through "4" in figure 1.

Figure 2 shows closer views of the four nipples and ball valves. The nipple from ball valve "2" had separated through the threads flush with the outside diameter of the riser. The mating faces of the fracture in this nipple are indicated by arrows "2a" in figure 1. This nipple and ball valve were painted a light blue and showed no evidence of soot accumulation or fire damage. Examination of the mating fracture surfaces on this nipple revealed that the fracture surface was on a 45 degree plane, consistent with an overstress separation. No evidence of fatigue or other type of preexisting cracking was found. Deformation of the nipple adjacent to the fracture indicated that the overstress separation was a result of bending of the nipple to the right, as the components are displayed in figures 1 and 2.

The nipples from ball valves "1", "3", and "4" were also deformed to the right at angles of 40 degrees, 30 degrees, and 10 degrees from the vertical, respectively. Nipples "1" and "3" were partially separated where they were threaded into the riser. No separations were noted on the nipple from ball valve "4".

2. <u>Fusible links</u>

The separated fusible link and attached chain are shown in figure 3, as received. Also shown, is one of the exemplar fusible links of the same design. The separated link came apart along the soldered joint between the two halves of the link. The other half of the link was not submitted for examination. No evidence of bending or twisting deformation was noted in the separated link.

Information supplied by the manufacturer of the link indicated that the Model "B" 165 degree link has an ambient temperature exposure limit of 100 degrees and a maximum tensile load limit of 20 pounds. Also, the links "are designed for a straight pull load application. Those applications involving a torque or twisting are to be avoided."

A scanning electron microscope (SEM) was used to examine the separated surface of the link. The features appeared nondescript and no fracture mode could be identified. The SEM examination revealed that the underlying structure of the link piece (made from a copper alloy) was completely covered with a solder alloy. X-ray energy dispersive spectroscopy of the separation surface indicated that the solder was composed primarily of lead, bismuth, nickel, and tin. Much smaller amounts of oxygen, copper, silicon, aluminum, calcium, iron, and zinc were also detected.

Two intact exemplar fusible links were inserted into a tensile testing machine and subjected to an increasing tensile load while at room temperature. Separation of both links occurred at the base of one of the end rings. No evidence of an incipient separation was noted along the soldered joints.

One end of another intact exemplar link was inserted into a vise and the other end was bent with a pair of pliers (as if to peel the soldered joint apart). This action resulted in separation along the soldered joint; however, the two pieces of the link were heavily deformed during the separation process.

3. Overpressure sensing equipment

3.1. General

Figure 4 shows an overall as-received view of most of the overpressure sensing equipment attached to the salt cavern brine tube. The equipment consisted of a fitting (removed from the brine tube), a Barksdale pressure switch, a shutoff valve solenoid (not shown in figure 4), a longer length of 1/4-inch internal-diameter pressure sensing tubing with an attached valve, and a shorter length of 1/4 inch tubing attached to the Barksdale switch. The longer length of the pressure sensing tubing had separated from the brine tube fitting at the location indicated by arrow "A" in figure 4, and material was found packed in the released end of the tubing at this location. In addition, the shorter length of the pressure sensing tubing had pulled out of one end of the valve at the location indicated by arrow "B" in figure 4, and the stem of the valve (arrow "C", figure 4) was fractured, allowing release of the valve handle.

3.2. Fitting and pressure sensing tubing separation

Figure 5 shows a closer view of the tubing and fitting indicated by arrow "A" in figure 4. The bracket in figure 5 indicates the portion of the tubing that had been inserted into the fitting. Minor kinking, consistent with an excessive sideward bending load on the tube, was noted adjacent to the inserted portion of the tubing. However, examination of the pulled-out portion of the tubing revealed only small axial scratch marks, consistent with separation of the tube from the fitting primarily as a result of direct tensile loading of the tubing.

The arrow in figure 5 indicates the material packed into the separated end of the tubing. No evidence of similar material was noted in the fitting. The material in the tubing was removed by probing it with a metal tool. The material appeared to be yellow clay-colored dirt.

3.3 Valve with separated handle and pulled-out tubing

Figure 6 shows a closer view of the valve (shown without its separated handle) and a pulled-out piece of the pressure sensing tubing. Arrow "1" in this figure indicates where the tubing had been inserted into the valve, and arrow "2" indicates where the valve handle had been attached to the valve body.

Examination of the pulled-out tubing revealed bending deformation, but no kinking, adjacent to the inserted portion of the tubing. The pulled-out portion of the tubing contained small axial scratch marks, consistent with separation of the tubing from the valve primarily as a result of direct tensile loading of the tubing.

An overall view of the valve body and separated handle is shown in figure 7. The handle appeared to be deformed in the downward direction (in the direction of the unlabeled arrow in figure 7). The handle contained an elongated slot (arrow "S", figure 7) that engaged the flat sides of the valve stem (arrow "VS", figure 7) when properly assembled. The valve stem was fractured where it entered the valve body. Heavy deposits were noted on the valve stem fracture and surrounding area. The valve is shown in figure 7 after a substantial portion of these deposits had been cleaned off, allowing an easier determination of the orientation of the handle to the stem.

Figure 8 shows the handle assembled on top of the separated valve stem with the sides of the elongated slot in the handle aligned with the flat sides of the valve stem shank. In this orientation, the handle is at an angle of approximately 75 degrees to the axis of the valve.

Figure 9 shows a closer view of the separated valve stem and adjacent portion of the valve body. The valve body contained two raised bolt heads that serve as stops for a tab on the handle. Arrows "Shut" in figures 8 and 9 indicate the fully closed stop and arrows "Open" indicate the fully open stop. The open stop contained damage (also indicated by arrow "Open", figure 9) that was consistent with the handle tab overriding the open stop as the handle is turned slightly past the fully open position. Based on the damage to the open stop and other markings on the valve body, it was clear that the handle had been last assembled onto the valve stem in the orientation shown in figure 8, as opposed to being assembled 180 degrees to the position shown in figure 8.

Detailed visual examination of the valve stem fracture surface revealed fracture features typical of an overstress separation as a result of excessive bendings loads. The fracture initiation area was located along one of the flat sides of the valve stem, at the location indicated by arrow "O" in figure 9. No evidence of fatigue cracking or other type of preexisting defect was noted on the stem fracture.

Downward loading of the handle (in the direction of the unlabeled arrow in figure 7) would produce maximum tension on the portion of the valve stem furthest from the handle. Also, loading of the handle in the direction indicated by the unlabeled arrow in figure 8 would tend to bend the valve stem because the handle is above the level of the stem. This bending would produce maximum tension in the valve stem along one of the flat sides of the valve stem (the side with arrow "O" in figure 9). Therefore, the location of the initiation area of the valve stem fracture is consistent with a combination of these two directions of loading on the handle.

Loading of the handle in the direction of the unlabeled arrow in figure 8 would also induce a torsion load on the valve stem. Evidence of this torsional loading was found on the corner of the fracture diagonally opposite from the initiation area. This corner contained a lip of metal that was smeared in the counterclockwise direction, as if the handle had been rotated toward the open position during the final stage of fracturing.

The valve was subjected to an X-ray inspection to determine the orientation of the valve ball on the inside of the valve. This inspection indicated the ball was very close to the closed position. In addition, alcohol was poured into one end of the valve, and, after waiting several minutes, none passed through the valve, consistent with a closed ball. Adding pressurized air to one end of the valve resulted in a small amount of air passing through the valve, consistent with a closed or nearly closed ball.

3.4 Barksdale pressure switch

The Barksdale pressure switch is visible in the lower left corner of figure 4. With the cover plate removed, the switch and the shut off valve solenoid were electrically connected and supplied with 110 volt power in a manner consistent with the installation before removal during the accident investigation. Increasing increments of regulated gas pressure were supplied to the pressure sensing side of the switch. The switch did not actuate, as indicated by a lack of release of the solenoid, at pressures up to 175 psi. The test was repeated several times with similar results until the switch body was lightly tapped. While being lightly tapped, it was found that the switch would actuate at various pressures as low as 80 psi.

James F. Wildey, II

James F. Wildey, II
National Resource Specialist - Metallurgy

Supporting photographs follow

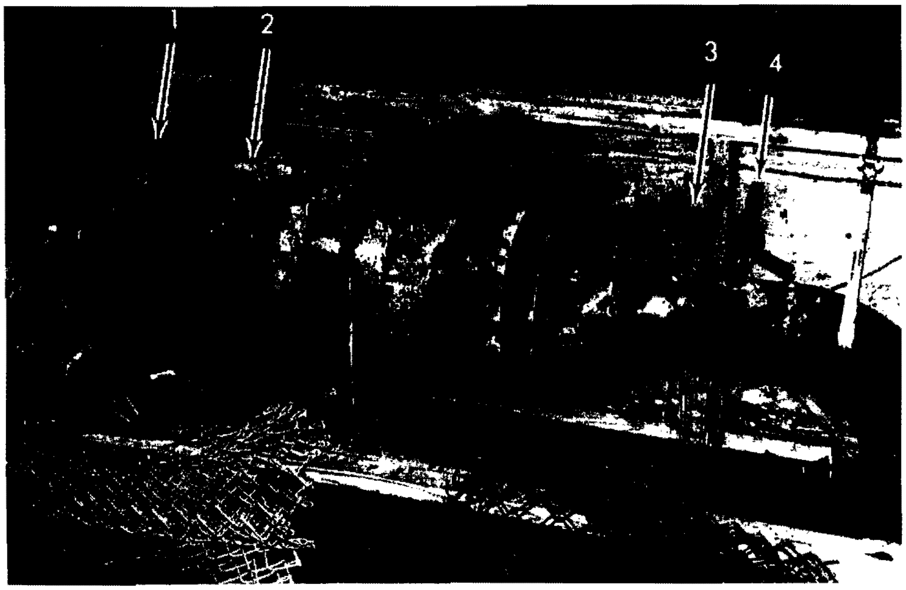
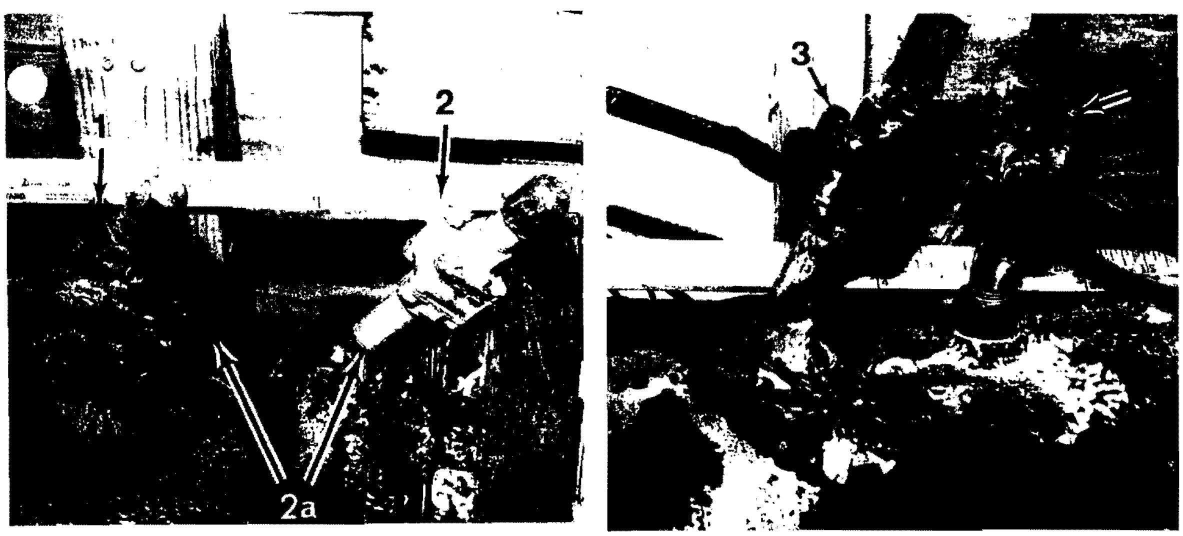


Figure 1: Overall view of the 6-inch diameter riser; arrows 1 through 4 indicate the ball valves.



Figures 2a and 2b. Close-up of ball valves and nipples. Arrow 2a shows mating fracture faces.

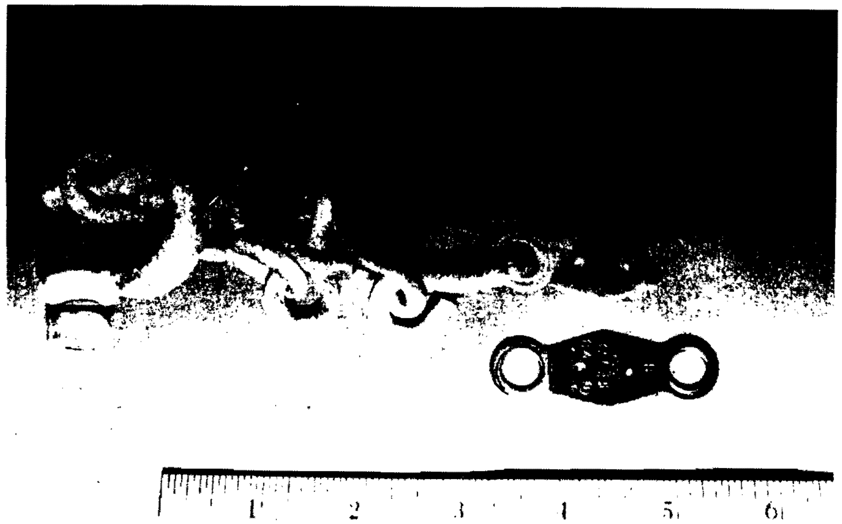


Figure 3: Overall view of the separated fusible link and attached chain (top) and an exemplar fusible link.

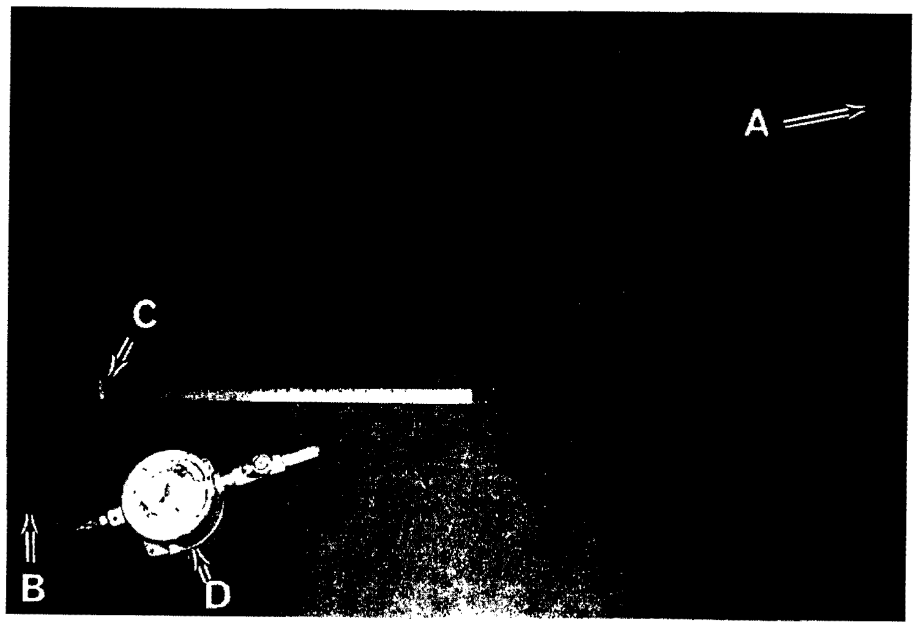


Figure 4. Overall view of pressure sensing equipment. Arrow A indicates where tubing pulled out of the brine tube fitting, arrow B indicates where tubing pulled out of the valve, and arrow C indicates the released valve handle. Arrow D indicates the Barksdale switch.

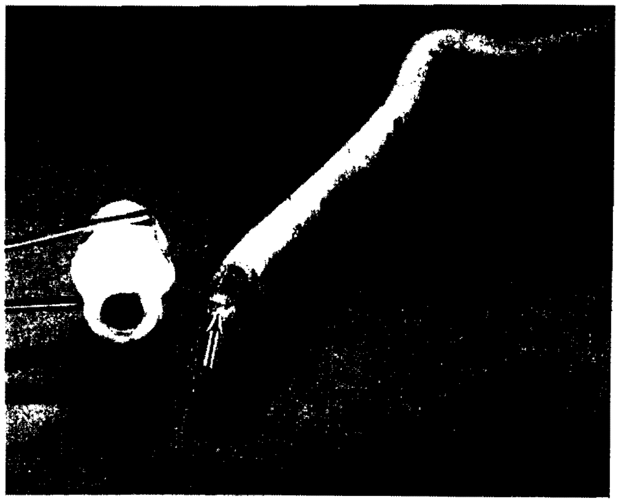


Figure 5: Closer view of tubing and fitting indicated by arrow A in figure 4. Arrow indicates material in end of tubing. The fitting is held by tweezers. X0.54

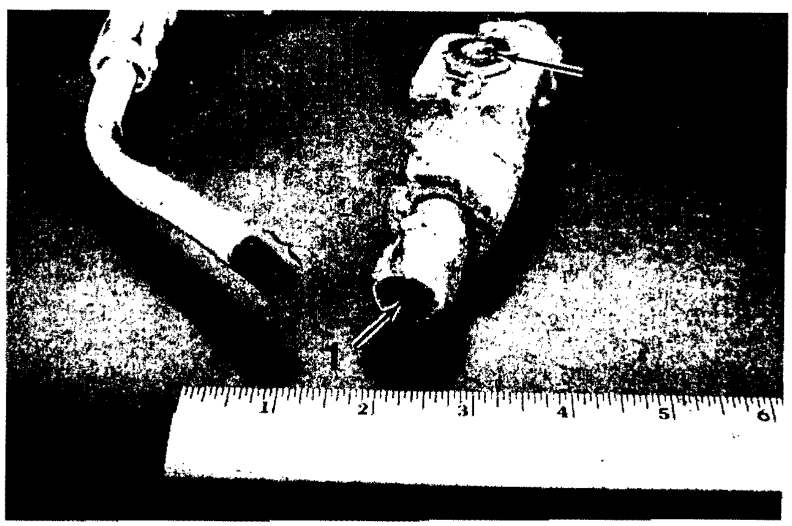


Figure 6. Closer view of valve and tubing indicated by arrow B in figure 4. Arrow 1 shows where tubing was inserted into the valve; arrow 2 shows where handle attaches to valve stem. The bracket indicates the inserted portion of the tubing.

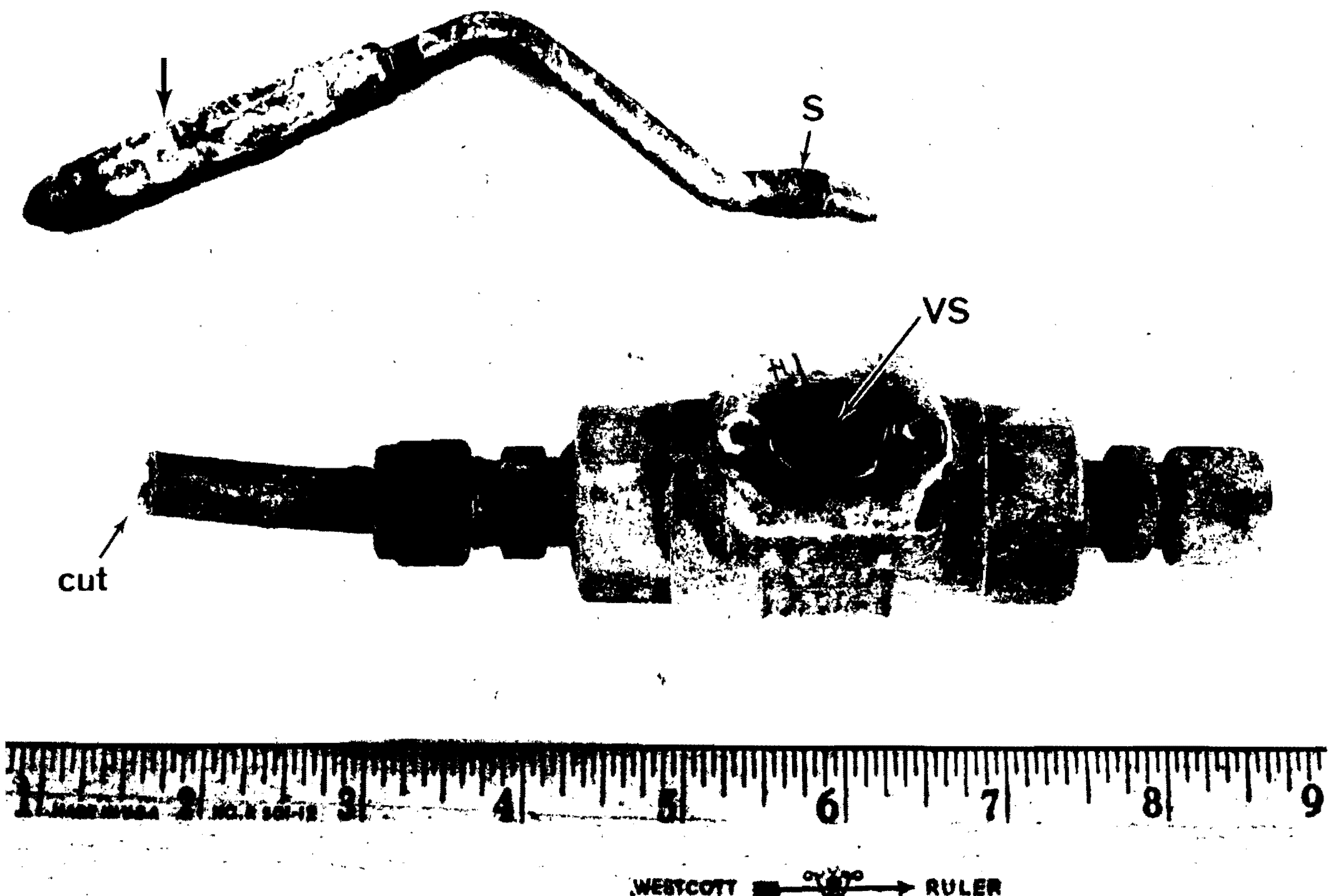


Figure 7. Overall view of valve body with separated handle. Arrow S indicates location of an elongated slot in the handle; arrow VS shows fractured valve stem.

Flynn Exhibit Page 336

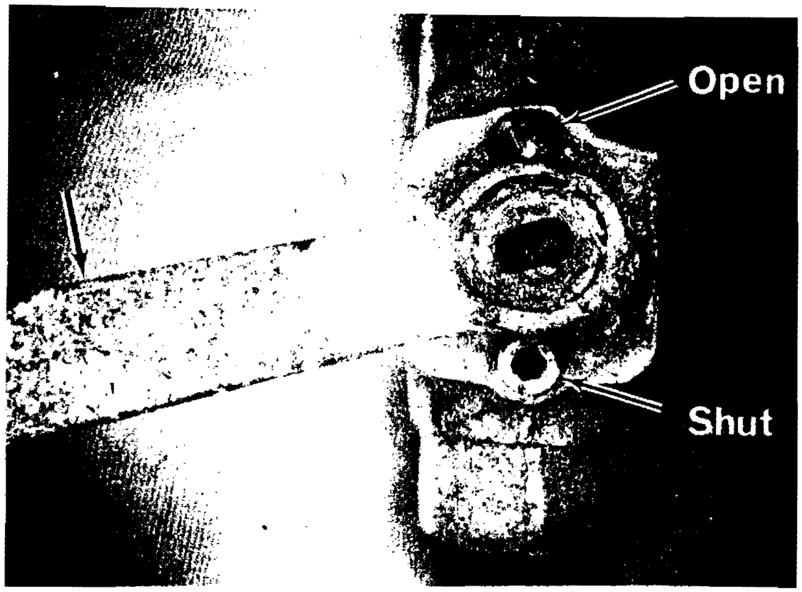


Figure 8: Valve handle assembled on top of the separated valve stem. Unlabeled arrow indicates a loading direction on handle consistent with the bending overstress separation of the valve stem.

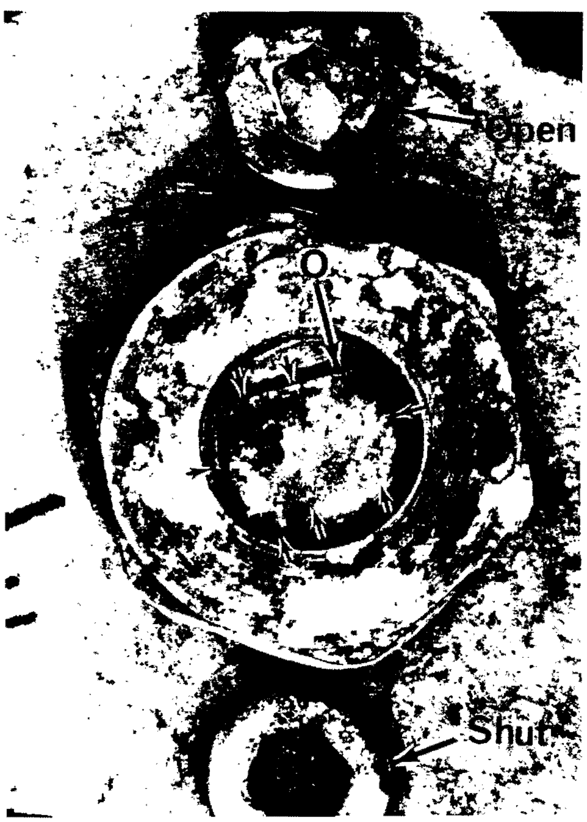


Figure 9. Closer view of fractured valve stem, after cleaning. Unlabeled arrows outline the fracture, and arrow O denotes initiation area of fracture. Arrows SHUT and OPEN indicate the fully closed and fully open stops for the handle. X4

APPENDIX C

CHRONOLOGY

April 6, 1992

AM

10:00 +\- Two manual valves at Brenham station meter run used to deliver product to Coastline are closed and locked.

MAPCO begins delivering product from plants on Bryan Lateral into cavern.

April 7, 1992

AM

3:30+ MAPCO computer system goes down for undetermined reasons and is restarted. Operations show as normal after computer restarted.

6:09:34 Dispatch center receives alarm as cavern suction pressure passes 474 psig. That pressure was shown as 546 psig.

6:09:39 Dispatch center receives HAZGAS alarm from Brenham station.

6:09:40 Dispatch center is notified that cavern pump shut down automatically.

6:09:50 Dispatch center receives flow rate of change alarm for Bryan Lateral. That flow rate was shown as 0 barrels per hour.

6:10+/- Dispatcher notifies technician at his home of HAZGAS alarm and requests that it be checked.

6:30+/- Day dispatcher replaces night dispatcher.

6:40:43 Dispatch center receives alarm as the mainline pump suction pressure passes 524 psig. That pressure was shown as 508 psig.

6:41:13 Dispatch center receives alarm as the mainline pump suction pressure passes 524 psig. That pressure was shown as 528 psig.

6:44:19 Dispatch center receives alarm as the mainline pump discharge pressure passes 524 psig. That pressure was shown as 520 psig.

6:45 +/- MAPCO technician arrives in area of Brenham station, observes fog/vapors, and parks his truck; after turning off the ignition of his truck, the engine continues to run.

6:45:11	Dispatch center receives alarm as the mainline pump suction and discharge pressures pass 524 psig. The suction pressure was 506 psig and the discharge pressure was 586 psig.
6:45:44	Dispatch center receives alarm as the cavern pump suction pressure passes 474 psig. That pressure was shown as 464 psig.
6:46+/-	MAPCO technician calls dispatcher, advises that vapor is in the station yard, and asks dispatcher to call his (technician's) supervisor.
6:46:11	Dispatch center receives alarm as the cavern pump suction pressure passes 474 psig. That pressure was shown as 528 psig.
6:47+/-	Technician calls his supervisor, advising that the leak is getting larger and that gas is crossing CR 19.
6:48:48	Dispatch center receives alarm as the cavern pump suction pressure passes 474 psig. That pressure at this time was shown as 436 psig.
6:48:59	Dispatch center receives alarm as the cavern pump suction pressure passes 474 psig. That pressure was shown as 500 psig.
6:51:02	Dispatch center receives alarm as the mainline pump discharge pressure passes 524 psig. That pressure was shown as 518 psig.
6:53:23	Dispatch center receives alarm as the cavern pump suction pressure passes 474 psig. That pressure was shown as 460 psig.
6:57:31	Dispatch center receives alarm as the cavern pump discharge pressure passes 474 psig. That pressure was shown as 466 psig.
6:57:54	Dispatch center receives Loss of Suction Pressure (LOSP) alarm for Bryan Lateral.
6:59	Resident near Brenham station calls 911 to report the odor of gas in area, that she is next to the Brenham station, that she hears something blowing out, and that there is a fog in the area.
	Brenham Fire Department reports resident's call to MAPCO dispatch center and is told that a technician has been alerted and is checking out the gas alarm.
7:00+/-	MAPCO pipeliner and technician trainee arrive in station area from the north to start their normal work duties. They observe vapor in area, turn off CR 19 onto station entrance road, and stop about 200 yards from station entrance gate. They

hear a noise coming from area of brine pit that sounds like a water fountain. The vapor in the area is ear-deep.

7:03+/- MAPCO area operator arrives on CR 19 near Brenham station, sees vapor in area and liquid column shooting up from station, and notifies lab technician that they have "popped the top" of the cavern and that the station is engulfed in vapor cloud. Asks for instructions.

Pipeliner walks to within 100 feet of station gate, where he observes a column of liquid rising above the brine pond.

7:06:04 Dispatch center receives LOSP alarm for Bryan Lateral.

7:06:09 Dispatcher initiates closing of Bryan Lateral valve.

7:06:21 Dispatch center receives notice that Bryan Lateral valve is half closed.

7:06:31 Dispatch center receives flow rate of change alarm for Bryan Lateral. Flow rate shown as 21 barrels per hour.

7:06:38 Dispatch center receives flow rate of change alarm for Bryan Lateral. Flow rate shown as 0 barrels per hour.

7:06:49 Dispatch center receives flow rate of change alarm on cavern line. Flow rate shown as 3 barrels per hour.

7:07 +/- Lab technician tells area operator to notify another employee and then calls dispatcher to advise him that a large vapor cloud is over the station and to direct him to pump product from the cavern into the mainline.

Lab technician advises dispatcher that he sees station and that it is covered by a large mushroom-shaped vapor cloud that is more pointed at the top, that there are smaller vapor clouds to the east, and that the main cloud is growing and flowing to the east.

7:09:33 Dispatcher enters command to open station delivery valve to mainline.

7:09:48 Dispatch center receives notice that station delivery valve to mainline is half open.

7:10 +/- Technician arrives on CR 19 near station entrance road and meets with pipeliner and trainee. After discussion, the technician walks toward station and the pipeliner and trainee leave to block roadways.

Area operator stops woman on CR 19 from driving truck onto Glory Lane.

Area operator fails to stop car on Glory Lane from entering onto CR 19 and driving toward the station.

7:10:25 Dispatch center receives notice that station delivery mainline valve is open.

7:10:46 Dispatcher initiates opening of Bryan Lateral valve.

7:11:12 Dispatch center receives notice that Bryan Lateral valve is half open.

7:11:23 Dispatch center receives flow rate of change alarm for Bryan Lateral. Flow rate shown as 1,671 barrels per hour.

7:11:33 Dispatch center receives notice that Bryan Lateral valve is open.

7:11:40 Dispatch center receives flow rate of change alarm for cavern line. Flow rate shown as 1,650 barrels per hour.

7:12 +/- Car from Glory Lane turns left onto CR 19 while Area Operator is talking with driver of pickup truck on CR 19.

As Brenham Fire Department employee tries to place call to advise resident who reported the gas odor that pipeline company is checking report, he hears a loud boom, and then his phone line goes dead.

7:13:57 Dispatcher initiates command to close Bryan Lateral valve. Telemetry system responds with transmission error.

7:14:18 Dispatcher initiates command to close Bryan Lateral valve. Telemetry system responds with transmission error.

7:14:48 Dispatcher initiates command to close Bryan Lateral valve. Telemetry system responds with transmission error. Computer shows Brenham remote system as out of service.

7:14:54 Dispatcher initiates command to close Bryan Lateral valve. Telemetry system responds with transmission error.

APPENDIX D

TRC SURVEY

Phone
(512) 463-6789
Fax
(512) 463-6780

RAILROAD COMMISSION
OF TEXAS

Underground Hydrocarbon Storage
Facility Survey

Return to: DIRECTOR
Underground Injection Control
Oil and Gas Division
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

INSTRUCTIONS. Please answer all questions. Check the Yes or No box or, if a question is not applicable to your facility, the NA box. For example, facilities that store only natural gas will not have brine displacement systems and facilities that store only crude oil will not have LPG loading racks and vessels. Use the remarks space at the end to provide any other pertinent information or to further explain your answers. Print or type using dark blue or black ink.

Operator Name ______________________ Facility Name ______________________
Lease Name ______________________ Field Name ______________________
Lease No. __________ County ______________________ RRC District No. __________

Yes No

A. Operations

☐ ☐ manned onsite 24 hours a day?
☐ ☐ monitored offsite 24 hours a day?
☐ ☐ If offsite, are well valves remotely controlled?
☐ ☐ Are pipeline valves remotely controlled?
☐ ☐ Is there a written emergency response/evacuation plan?
☐ ☐ TV camera surveillance?

B. Emergency Shutdown Valves (ESVs)

Location: distance from wellhead: __________ feet;
☐ ☐ product side of well?
☐ ☐ brine side of well?

Actuation:
☐ ☐ remotely actuated?
☐ ☐ pressure sensor?
☐ ☐ heat (thermal couple)?
☐ ☐ fail-closed?

Explain what causes actuation: ______________________

ESV operation check frequency: ______________________

Describe any "breaks" in pipe between wing valves and ESVs (include valves, meter runs, blind flanges, check valves, pressure release devices, etc.): ______________________

☐ ☐ If there are any pressure measurement devices, are they in fire proof containers?

(Attaching photographs of wellheads or typical wellhead is recommended)

Yes No NA

C. Gas Detectors

☐ ☐ ☐ at wellhead?
☐ ☐ ☐ at transfer/storage equipment?
☐ ☐ ☐ at brine discharge?
☐ ☐ ☐ at brine pit?

Describe locations at brine pits: ______________________

Gas detector testing frequency: ______________________

D. Fire Detectors

☐ ☐ at wellhead?
☐ ☐ at process equipment?
☐ ☐ at transfer/storage equipment?

E. Flare/Degasifier

☐ ☐ ☐ permanent flare?
☐ ☐ ☐ degasifier?
☐ ☐ ☐ at brine discharge?
☐ ☐ ☐ other location?

Type of flare ignition: ______________________

F. Wind Socks

☐ ☐ present? Number of socks: __________
☐ ☐ night visible?

G. Fire Water Systems

☐ ☐ present? No. of hydrant/hose stations: ____

Water pump engine: ☐ electrical
☐ internal combustion

☐ ☐ backup water pump?
☐ electrical
☐ internal combustion

Yes No NA

Fire Water Systems *continued*

☐ ☐ wells equipped with fixed deluge or monitor nozzles?

☐ ☐ nozzles/monitors remotely operated?

☐ ☐ other locations with nozzles/monitors?

Describe:______________________________

____

____

H. Barriers

☐ ☐ around wellhead?

☐ ☐ around meter runs?

I. Warning Systems — alarms

☐ ☐ ☐ connected to gas detectors?

☐ ☐ connected to fire detectors?

☐ ☐ audible at local area of detector?

☐ ☐ audible at control room?

☐ ☐ audible/visible at remote control location?

☐ ☐ audible/visible at public safety/fire department?

J. Storage Well Monitoring

Pressure monitoring by gauges on well

☐ ☐ on wellhead?

☐ ☐ on product side?

☐ ☐ ☐ on brine side?

☐ ☐ ☐ on safety string annulus?

☐ ☐ safety string exists?

Pressure monitors in control room

☐ ☐ ☐ monitoring product side?

☐ ☐ ☐ monitoring brine side?

☐ ☐ ☐ monitoring safety string?

☐ ☐ ☐ preset pressure alarms?

☐ ☐ ☐ pressure records kept by hard copy?

☐ ☐ ☐ pressure records kept by computer?

REMARKS: (attach continuation sheet if required)

Yes No NA

Storage Well Monitoring, *continued*

Volume monitoring

☐ ☐ of product in?

☐ ☐ of product out?

☐ ☐ ☐ of brine in?

☐ ☐ ☐ of brine out?

Product level monitoring

☐ ☐ by interface detector?

☐ ☐ interface detector continuous monitor?

☐ ☐ interface detector alarm?

☐ ☐ ☐ by holes in brine string?

weep hole (window) distance above bottom of string: ____________ feet;

weep hole size: ____________ inches;

no. of holes: ____________

K. Provide a plat of the facility showing pipelines and internal piping.

- Identify internal piping including product and brine piping, meter runs, pump locations, and fresh water piping.
- Identify pipelines associated with the facility and their diameters.

L. Associated LPG Facilities

☐ ☐ ☐ truck loading rack(s)?

☐ ☐ ☐ rail loading rack(s)?

☐ ☐ ☐ surface storage vessels? No. in use:_____

Water capacity in gallons of each vessel in use:______________________

____

____

Mark the location of loading racks and vessels on the facility plat.

______________________________ ______________________________

Signature (company representative preparing form) Name (print or type)

______________ ______________ (   )______________

Title Date Phone

______________ ______________ (   )______________

Company Contact Title Phone

UHCS6/9/92

APPENDIX D

Underground Hydrocarbon Storage Facility Survey Summary
State Wide

	Yes	No	Non-Applicable
OPERATIONS:			
Manned 24 hours	50	13	
Monitored 24 hours	19	44	
Valves Remotely Controlled	15	47	
Pipeline Valves Remotely Controlled	31	32	
Written Emergency Response/Evac. Plan	51	12	
TV Camera Surveillance	10	53	
EMERGENCY SHUTDOWN VALVES:			
Product Side of Well	48	15	
Brine Side of Well	45	18	
Remotely Actuated	43	20	
Pressure Sensor	45	18	
Heat (Thermal Couple)	21	42	
Fail-Closed	44	19	
GAS DETECTORS:			
Wellhead	16	38	9
Transfer/Storage Equipment	33	23	7
Brine Discharge	4	39	20
Brine Pit	9	39	15
FIRE DETECTORS:			
Wellhead	14	49	
Process Equipment	16	43	
Transfer/Storage Equipment	28	35	
FLARE/DEGASIFIER:			
Permanent Flare	35	18	10
Degasifier	27	23	13
Brine Discharge	24	25	14
WIND SOCKS:			
Present	45	18	
Night Visible	37	26	
FIRE WATER SYSTEM:			
Present	40	23	
Backup Present	0	0	
Fixed Deluge or Monitor Nozzles	26	37	
Nozzles/Monitors Remotely Operated	13	50	
Other Locations with Nozzles/Monitors	24	31	
BARRIERS:			
At Wellhead	39	24	
Around Meter Runs	24	39	

Date: 09/11/92 Railroad Commission of Texas Page 2

Underground Hydrocarbon Storage Facility Survey Summary
State Wide

	Yes	No	Non-Applicable
WARNING SYSTEMS - ALARMS:			
Connected to Gas Detectors	35	14	14
Connected to Fire Detectors	31	31	
Audible at Local Area of Detector	18	45	
Audible at Control Room	42	21	
At Remote Control Location	37	26	
At Public Safety/Fire Department	1	62	
STORAGE WELL MONITORING:			
Pressure Monitoring by Gauges on Well:			
On Wellhead	51	12	
On Production Side	54	9	
On Brine Side	45	9	14
On Safety String Annulus	22	12	29
Safety String Exists	25	38	
Pressure Monitors in Control Room:			
Monitoring Product Side	44	14	5
Monitoring Brine Side	29	22	12
Monitoring Safety String	10	24	29
Preset Pressure Alarms	40	18	5
Pressure Records Kept by Hard Copy	43	15	5
Pressure Records Kept by Computer	27	30	6
Volume Monitoring:			
Product In	58	5	
Product Out	59	4	
Brine In	24	26	13
Brine Out	23	27	13
Product Level Monitoring:			
By Interface Detector	16	46	
Interface Detector Continuous Monitor	4	59	
Interface Detector Alarm	1	62	
By Holes in Brine String	33	17	13
PLAT:			
Plat Provided	54	8	
ASSOCIATED LPG FACILITIES:			
Truck Loading Rack	23	21	19
Rail Loading Rack	11	33	19
Surface Storage Vessels	27	21	15

APPENDIX D

REVIEW OF UNDERGROUND HYDROCARBON STORAGE SURVEY INFORMATION

Summary of downhole safety methods for the 55 facilities that store LPG or crude oil.

Number of downhole safety methods, ie. safety string, interface detector, downhole brine string pressure sensor or gas sensor, or brine string weephole:

No. of safety methods used:	0	1	2	3	4
No. of facilities:	16	16	12	9	2

Number of facilities using safety strings: 24
Of the 31 facilities not using safety strings the following methods are used:

- 16 None (no interface detector, downhole sensor or weephole)
- 4 interface detector
- 14 brine string weephole
- 1 downhole gas sensor
- 4 combination of interface detector and weephole

*U.S. G.P.O.:1993-300-644:80011

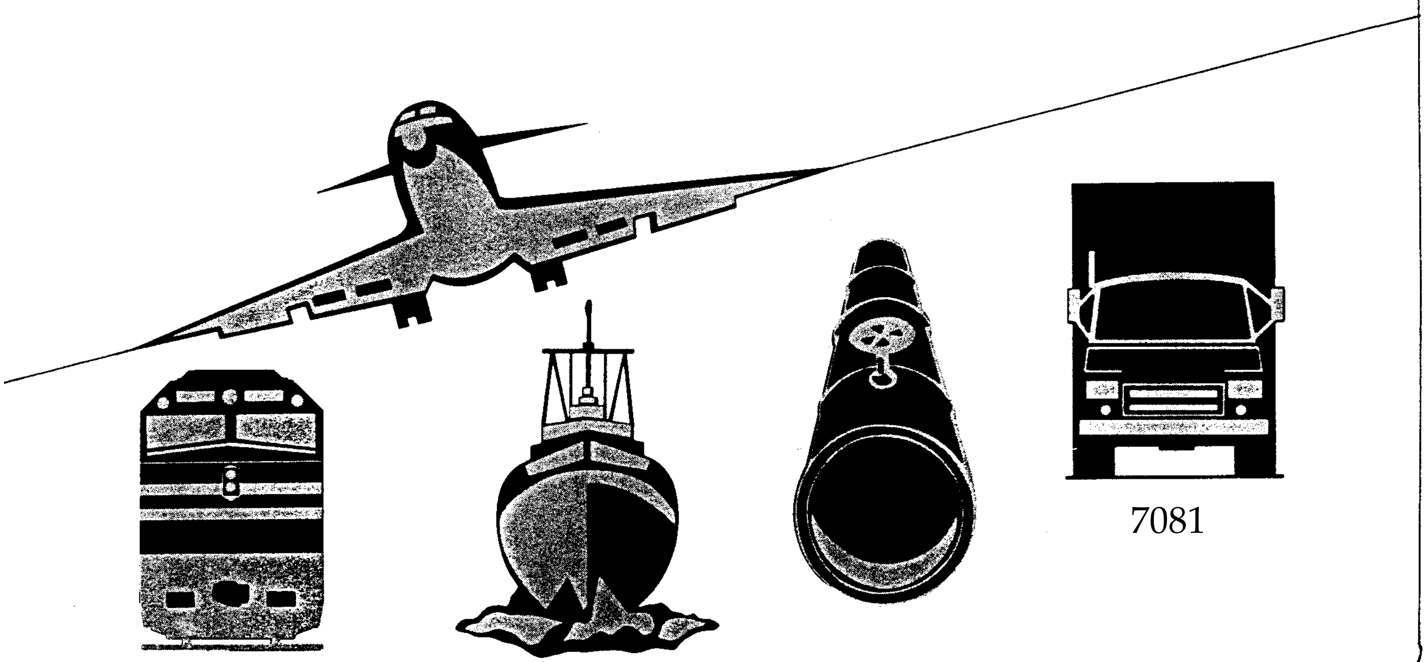
PB98-916503
NTSB/PAR-98/02/SUM

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT SUMMARY REPORT

PIPELINE RUPTURE, LIQUID BUTANE RELEASE, AND FIRE
LIVELY, TEXAS
AUGUST 24, 1996



7081

Abstract: This report explains the August 24, 1996, rupture of a steel pipeline operated by Koch Pipeline Company, LP (Koch), which sent a butane vapor cloud into the surrounding residential area. The butane vapor ignited as two residents in a pickup truck drove into the cloud. The occupants of the truck died from thermal injuries. About 25 families were evacuated from the area. Damages related to the accident exceeded $217,000.

From its investigation of this accident, the Safety Board identified safety issues in the following areas: the adequacy of Koch's corrosion inspection and mitigation actions, and the effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

As a result of its investigation of this accident, the Safety Board issued recommendations to the Research and Special Programs Administration, Koch, and NACE International.

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable cause of accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Recent publications are available in their entirety on the Web at **http://www.ntsb.gov/**. Other information about available publications may be obtained by contacting:

National Transportation Safety Board
Public Inquiries section, RE-51
490 L'Enfant Plaza East, S.W.
Washington, D.C. 20594
(202) 314-6551

Safety Board publications may be purchased, by individual copy or by subscription, from:

National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161
(703) 605-6000

PIPELINE ACCIDENT SUMMARY REPORT

Pipeline Rupture, Liquid Butane Release, and Fire
Lively, Texas
August 24, 1996

NTSB/PAR-98/02/SUM
PB98-916503
Notation 7081
Adopted: November 6, 1998

National Transportation Safety Board
490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

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Executive Summary

On Saturday, August 24, 1996, about 3:26 p.m., an 8-inch-diameter steel LPG (liquefied petroleum gas) pipeline transporting liquid butane, operated by Koch Pipeline Company, LP (Koch), ruptured near Lively, Texas, sending a butane vapor cloud into a surrounding residential area. The rupture occurred under a roadway in the Oak Circle Estates subdivision.

The butane vapor ignited as two residents in a pickup truck drove into the vapor cloud. According to the sheriff's report, they were on their way to a neighbor's house to report the release to 911. The two people died at the accident site from thermal injuries. No other injuries were reported at that time; however, about 25 families were evacuated from Oak Circle Estates.

Koch estimated its direct pipeline losses, including the loss of product from the line, to be about $217,000. Other property losses included damage to the roadway under which the rupture occurred and damage to a pickup truck, a mobile home, several outbuildings, and adjacent woodlands.

The National Transportation Safety Board determines that the probable cause of this accident was the failure of Koch to adequately protect its pipeline from corrosion. The major safety issues identified by this investigation are as follows:

- Adequacy of Koch's corrosion inspection and mitigation actions, and
- Effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

As a result of its investigation of this accident, the Safety Board issued recommendations to the Research and Special Programs Administration, Koch, and NACE International.

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Factual Information

Accident Narrative

On Saturday, August 24, 1996, about 3:26 p.m.,[1] an 8-inch-diameter steel LPG (liquefied petroleum gas) pipeline transporting liquid butane,[2] operated by Koch Pipeline Company, LP (Koch),[3] ruptured near Lively, Texas, sending a butane vapor cloud into a surrounding residential area. The rupture occurred under a roadway in the Oak Circle Estates subdivision (figure 1).

The butane vapor ignited (figure 2) as two residents in a pickup truck drove into the vapor cloud. According to the sheriff's report, they were on their way to a neighbor's house to report the release to 911. The two people died at the accident site from thermal injuries. No other injuries were reported at that time; however, about 25 families were evacuated from Oak Circle Estates.

Koch estimated its direct pipeline losses, including the loss of product from the line, to be about $217,000. Other property losses included damage to the roadway under which the rupture occurred and damage to a pickup truck, a mobile home, several outbuildings, and adjacent woodlands.

Preaccident Events

At 2:05 p.m. on the day of the accident, Koch's Cleveland pump station (see figure 3 for station locations) experienced an automated shutdown due to the activation of a hydrocarbon vapor detection alarm in the station. A technician who was called out to check the station found no vapor or evidence of a leak at the station. Cleveland pump station is about 200 pipeline miles downstream of the accident site, and this shutdown reduced flow through the pipeline. Corsicana station, the first pump station upstream of Cleveland station, automatically shut down at 3:05 p.m. because the rising pipeline pressure activated a high-discharge pressure alarm.[4] The Corsicana pump shutdown created a

---

[1] Times given in this report are central daylight time.

[2] Liquid butane is a highly volatile liquid (HVL) petroleum product that vaporizes at atmospheric pressure and room temperature. Upon release, the liquid vaporizes into a highly flammable white or nearly transparent fog-like cloud. Because the vapor is heavier than air, it stays close to the ground and settles into low-lying areas. While the liquid is not odorized, it has a faint but noticeable petroleum-like smell. Observation of a vapor or a fog-like cloud is typically how butane is detected in the atmosphere near a release.

[3] Koch Pipeline Company, LP (Limited Partnership), is owned by Koch Industries, Inc.

[4] A high-discharge pressure alarm is triggered when the station discharge pressure to the pipeline rises above the set-point limit; the instrument's switch will shut down the station.

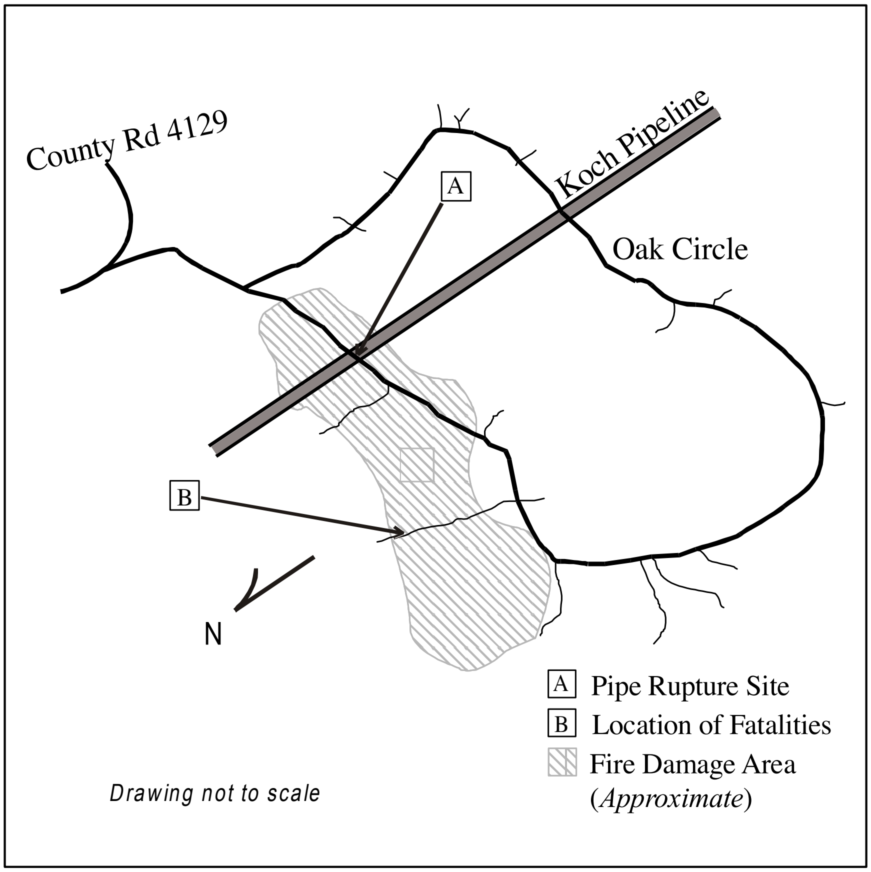

Figure 1. Sketch showing area of butane vapor dispersement and corresponding fire

Figure 2. Accident site before the butane fire was extinguished

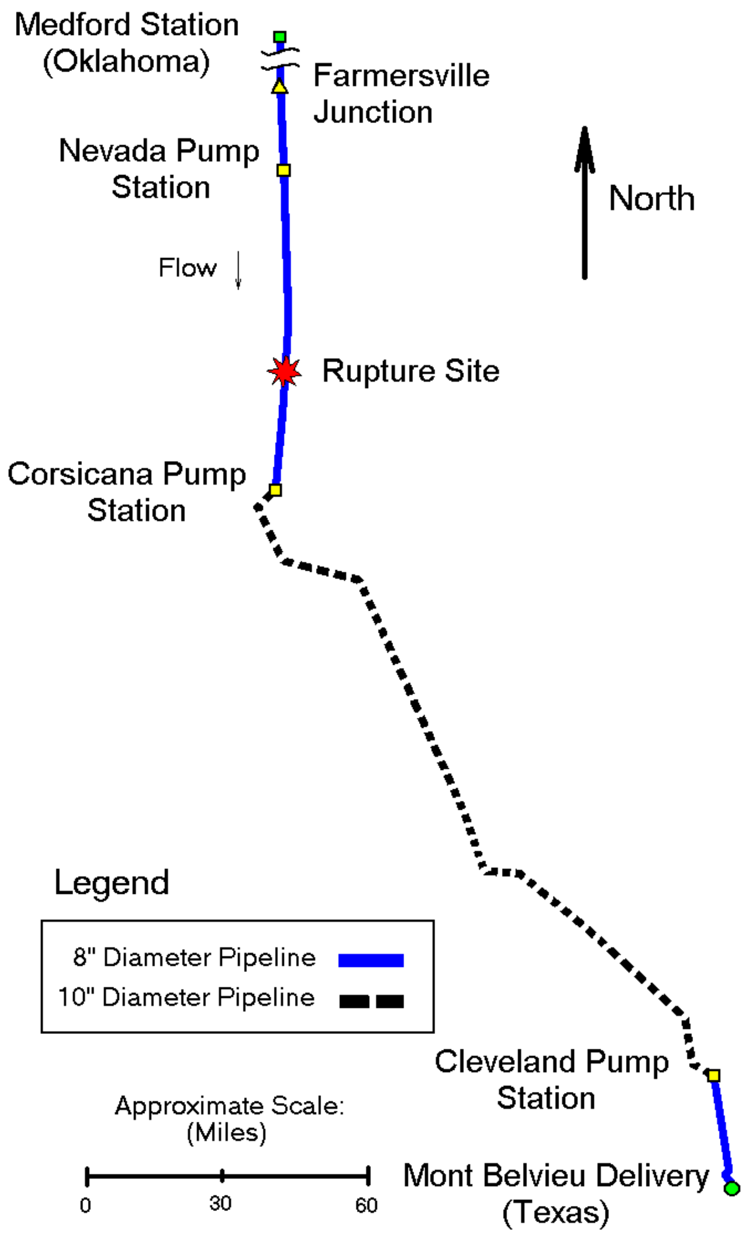

Figure 3. Koch Pipeline Company—
Medford, Oklahoma, to Mont Belvieu, Texas

pressure surge[5] in the pipeline that traveled upstream to the previous station, Nevada pump station. The rupture occurred between Nevada and Corsicana pump stations.

The maximum operating pressure (MOP) established by Koch for this pipeline was 1,440 pounds per square inch, gauge (psig).[6] After the accident, Koch calculated the highest surge pressure at Nevada pump station to be 1,448 psig based on pipeline pressure and flow conditions before the rupture. The pipeline discharge pressure was throttled to 1,438 psig by the pump station control valve, and the pump continued to operate. The highest surge pressure at the pipeline rupture location after the Corsicana station pump shut down was calculated by Koch to be 1,273 psig at 3:14 p.m.

Postaccident Events

At 3:29 p.m., Koch's supervisory control and data acquisition (SCADA) system generated a discharge pressure rate-of-change alarm[7] at Nevada pump station. At 3:36 p.m., another rate-of-change alarm was generated at Nevada pump station, and the pipeline controller shut down the pump because of the unexplained pressure loss. At 3:39 p.m., Koch received a telephone call from an Oak Circle Estates resident reporting a pipeline leak near his home. Koch immediately began shutdown procedures for the entire pipeline, dispatched an employee to the accident site, and called the Kaufman County sheriff's department. During its call to the sheriff's department, Koch learned that the butane had ignited. The sheriff's department and 911 each received a call about the release at about the same time that Koch received its call.

Following the shutdown of its pump stations, Koch began to isolate the ruptured section of the pipeline by closing the manual block valves upstream (4:20 p.m.) and downstream (4:37 p.m.) of the rupture. At 5:25 p.m., Koch reported the release to the National Response Center. By 6:00 p.m. the next day, line-plugging equipment[8] had been installed and used to isolate a section of pipeline about 100 yards on either side of the rupture. With the closing of the line-plugging equipment, the fuel was cut off and the fire extinguished within minutes. The pipeline remained shut down until March 1997.

---

[5] A pressure surge is a transient or temporary increase in pressure caused by a change in flow conditions on a pipeline such as a valve closing or a pump shutting down.

[6] The Federal pipeline safety regulation in 49 *Code of Federal Regulations* (CFR) Part 195.406(b) requires that the pressure in a pipeline during surges not exceed 110 percent of the MOP.

[7] A rate-of-change alarm is generated when station discharge pressure decreases a preset amount within a specific time as previously determined by the pipeline operator.

[8] Line-plugging equipment can be installed even when the pipeline contains product without exposing that product to the atmosphere.

Investigation

The National Transportation Safety Board was notified of the accident on August 24, 1996, by the National Response Center. The Office of Pipeline Safety, Research and Special Programs Administration, conducted the on-scene investigation. Segments of the pipeline, including the ruptured pipe, were shipped to the Safety Board Materials Laboratory in Washington, D.C., for metallurgical examination.

Personnel and Toxicological Information

The pipeline controller, who had been on duty for about 8 1/2 hours when the accident occurred, had been employed with Koch for 6 1/2 years. About 2 hours after the accident, the controller was tested for drugs and alcohol; both test results were negative.

Pipeline Information

When the accident occurred, Koch's Sterling I pipeline system was transporting liquid butane from Medford, Oklahoma, to Mont Belvieu, Texas (about 570 miles). This pipeline system contains sections of 8- and 10-inch-diameter pipe.

The 10-inch-diameter portion of the pipeline between Corsicana and Cleveland pump stations (see figure 3 pipeline map) was constructed in 1929 and later purchased by Koch. In April 1995, Koch completed replacement of the original 1929 section with new 10-inch-diameter epoxy-coated pipe to improve this section's integrity.

The pipeline rupture occurred in the 70-mile section of 8-inch-diameter pipeline between Nevada and Corsicana pump stations. The ruptured line, originally constructed in 1981, was a nominal 8-inch outside diameter, American Petroleum Institute (API) Specification 5L, Grade X-46, 0.188-inch wall thickness, Electric Resistance Weld steel pipe. The pipe was externally field coated with spiral wrapped polyolefin tape to protect it from corrosion. In the early 1990s, the road for the housing development was constructed over the 8-inch-diameter pipeline at the accident site.

During construction of the 10-inch-diameter pipe in 1995, Koch shut down the pipeline from Farmersville Junction (north of Nevada pump station) to Cleveland pump station. Before moving LPG products again, the 8-inch-diameter section from Farmersville Junction to Corsicana pump station was hydrostatically pressure tested in two segments to confirm its integrity. Three failures were documented during the pressure testing. The northern segment failed two times: the first time due to external corrosion at 1,941 psig and the second time due to a longitudinal weld seam failure at 1,938 psig. The failure in the southern test segment, about 1.5 miles north of the accident site, occurred because of external corrosion. The pipeline pressure when the southern segment failed was 1,400 psig, which was less than the previously established maximum operating pressure of 1,440 psig.

Internal Pipeline Inspection

May 1995 Internal Inspection

In May 1995, after the three hydrostatic pressure test failures, Koch had an internal inspection performed to determine the pipeline's condition. An internal inspection tool (also known as a "smart pig") was run through the 8-inch-diameter pipeline to determine the condition of 46 miles of pipeline in the southern section. A metal-wall-loss inspection was performed using a low-resolution magnetic-flux-leakage (MFL) internal inspection tool. This inspection identified numerous sites of external corrosion for possible repair.

Actual corrosion pit depths were measured on pipe excavated for correlation digs and then compared with the log of corrosion indications from the May 1995 internal inspection. All of the pipe-wall-thickness loss indications were graded by the internal inspection tool company as being light (15 to 30 percent loss), moderate (> 30 and < 50 percent loss), or severe (≥ 50 percent loss). The log results were reported by individual pipe length[9] and the grade of the maximum corrosion anomaly.

The May 1995 internal inspection log identified 62 moderately and 18 severely corroded pipe lengths. According to Koch, the company excavated all pipe lengths graded as having moderate or severe wall-thickness loss. Excavated pipe was either recoated, repaired, or replaced. Koch took action based on its determination of the effect of corrosion on remaining pipe strength and allowable operating pressure using ASME/ANSI B31G.[10] The pipe that ruptured in 1996 was not excavated in 1995 because the associated pipe length was identified by the internal inspection tool as having light corrosion.

Comparisons of the wall-thickness measurements of the pipe lengths excavated during the repair digs with the inspection log results revealed few discrepancies. Koch's records from the repair digs indicate only three instances of a discrepancy between the inspection log and actual dig report measurement. In each case, the internal inspection tool predicted a pipe-wall-thickness loss greater than was actually measured.

The minimum hydrostatic test pressure required by pipeline safety regulations is 125 percent of the MOP. In this case, the MOP was 1,440 psig, making the minimum test pressure for the line 1,800 psig. After pipeline repairs based on data from the internal inspection had been completed, the line was hydrostatically tested without failure to 1,855 psig on August 18, 1995, and subsequently returned to service.

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[9] In this pipeline, the individual 8-inch-diameter pipe lengths were about 59 feet.

[10] *Manual: Determining Remaining Strength of Corroded Pipelines: Supplement to B31 Code-Pressure Piping (B31G).* American Society of Mechanical Engineers/American National Standards Institute, Inc., New York, August 30, 1991.

Postaccident Internal Inspection

On September 23, 1996, about 1 month after the accident, a 10-mile section of Koch's pipeline around the rupture site was inspected using a high-resolution MFL internal inspection tool. (The inspected section did not include that segment of pipe around the rupture that was removed after the accident.) The internal inspection was required by Hazardous Facility Order (HFO) CPF No. 46510-H that was formally issued on October 7, 1996, by the Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA). The inspection identified numerous areas that were graded by the internal inspection company as having moderate and severe corrosion. Indications of severe corrosion were identified in about 15 lengths of pipe. These areas were not identified during the May 1995 inspection as having either moderate or severe corrosion.

External Corrosion Control

Koch uses an impressed current cathodic protection[11] system to mitigate corrosion on this pipeline. The *Koch Procedure Manual* (section 4.8.1) for this pipeline defined the minimum acceptable pipe-to-soil potential[12] level for adequate cathodic protection as at least -0.85 volts (V).[13] To comply with 49 CFR 195.416(a), pipeline operators must perform annual testing to determine whether cathodic protection is adequate to control external corrosion. The regulation does not provide criteria for "adequate cathodic protection." Company corrosion technicians performed annual surveys[14] of the cathodic protection system. Koch personnel also recorded cathodic protection readings on its field reports.[15]

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[11] Cathodic protection is a corrosion mitigation method used by the pipeline industry to protect underground metal pipes using rectifier stations along the pipeline that supply protective electrical current. Cathodic protection current is forced to flow in the opposite direction of currents produced by corrosion cells. A rectifier converts alternating current from the utility service to direct current and supplies it to a ground bed that typically contains a string of suitable anodes, with soil as an electrolyte, to provide a path for the current from the rectifier to the pipeline. A cable connected to the pipeline provides the return path to the circuit.

[12] Defined as "the voltage difference between a buried metallic structure [pipe] and the electrolyte [soil], measured with a reference electrode in contact with the electrolyte [soil]." From Gordon, H. L., *Cathodic Protection,* Power Plant Electrical Reference Series, Project 2334, Electric Power Research Institute, Palo Alto, California, 1991, vol. 11, p. 11.2.

[13] One of the cathodic protection criteria for pipelines transporting gas listed in 49 CFR 192, appendix D, is maintaining cathodic protection of at least -0.85 V pipe-to-soil potential to a saturated copper-copper sulfate half cell.

[14] Pipeline companies perform pipe-to-soil potential surveys by measuring and recording the voltages and currents at test stations along the pipeline and at rectifiers. Measurement intervals vary widely from less than 100 feet to miles apart.

[15] Koch refers to the company form used for field reporting of aerial, foreign crossing, exposed pipe, and pipeline revisions as a "4-in-1" report.

Preaccident Inspections and Action

Before the accident, six rectifiers were used in the pipeline cathodic protection system from Nevada to Corsicana pump stations. In the first quarters of 1994 and 1995, Koch personnel conducted an annual corrosion control survey that indicated the pipeline met the company standard for cathodic protection (pipe-to-soil potentials at least as negative as -0.85 V). During the annual survey in February 1996, potentials below the company's accepted protection level were recorded between rectifiers M-7 and M-10. The pipeline rupture occurred between rectifiers M-9 and M-9.5, which were the existing units on either side of the rupture location. (Figure 4 shows the location of the rectifiers and the rupture.)

In field reports completed after the May 1995 internal pipeline inspection, some readings indicated potential levels that did not meet the company standard. For example, records show that on August 28, 1995, an area about 1/4 mile south of the rupture had an approximate pipe-to-soil potential of -0.59 V and on August 24, 1995, an area 7/8 mile north of the rupture had a potential of -0.59 V. Similar low potentials were recorded up to 50 miles north of the rupture site to an area upstream of Nevada station.

On February 6, 1996, during Koch's 1996 annual survey, the output of rectifier M-8 was increased to improve pipe-to-soil potentials. On February 13, 1996, potentials as low as -0.68 V were recorded between rectifiers M-7 and M-8. Additionally, seven of nine readings taken on that date between rectifiers M-8 and M-9 were less negative than -0.85 V. These low potential measurements were in the -0.62 to -0.72 range.

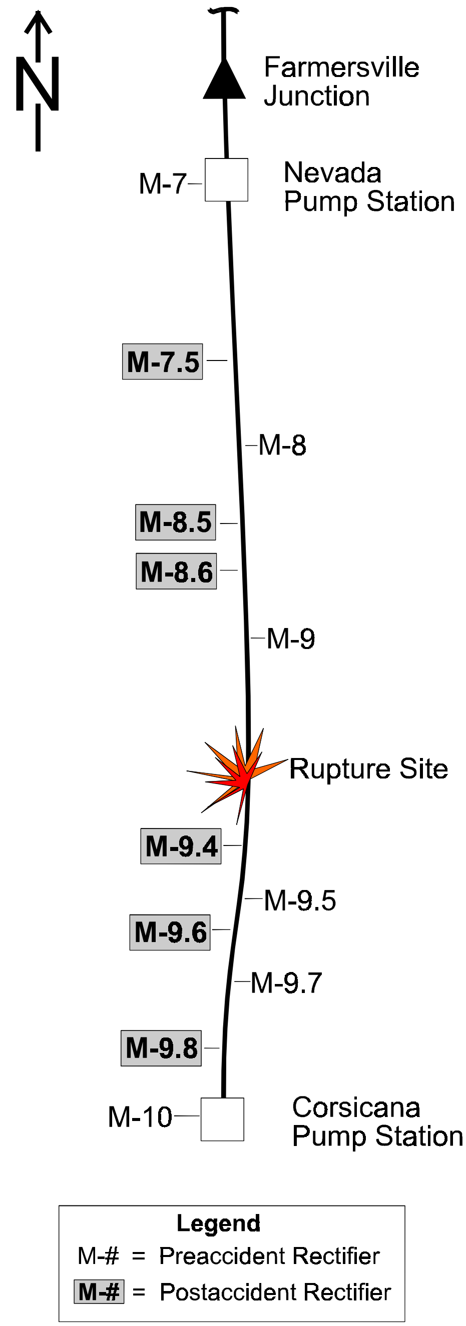

Figure 4. Koch pipeline rectifier sites M-7 through M-10

Potential measurements taken between rectifiers M-9 and M-10 on February 13, 1996, were -0.815 V about 1.3 miles north of the rupture location and -0.827 V about 1.5 miles south. In addition to these readings, the lowest potential recorded on that date between rectifiers M-9 and M-10 was -0.78 V.

In a memorandum dated February 19, 1996, the corrosion supervisor recommended that a new rectifier be installed north of the eventual rupture site between M-8 and M-9. The area from rectifiers M-9 to M-10 was reported by the corrosion supervisor as having "good" readings. On February 26, 1996, Koch division personnel authorized installation of a new rectifier, which was initially labeled M-8.5 but was subsequently redesignated M-8.6.

On March 29, 1996, rectifier M-9 was not operating at its designated level and its ground bed needed replacement. No recorded pipe-to-soil readings are available for that date. Koch Division personnel discussed whether M-9 should be moved or the ground bed replaced. They decided to wait until the new rectifier was installed to verify its cathodic protection coverage and to determine how M-9 would be repaired.

Postaccident Inspections and Action

According to Koch, pipe-to-soil potentials were measured but not recorded for the accident site after the rupture on August 24, 1996. However, potential readings recorded 500 feet north and south of the rupture site on August 27 ranged from -0.49 V to -0.52 V. Shortly after the accident, on September 4, 1996, Koch replaced the ground bed for rectifier M-9. Koch installed the new rectifier (M-8.6) and activated it on September 11, 1996. Pipe-to-soil potentials taken during the close-interval survey[16] in the rupture area remained low, about -0.65 V, after these rectifiers were activated.

After the rectifiers were activated, pipe-to-soil potentials were obtained during repair digs made following the September 23, 1996, internal inspection. Readings recorded on the field reports at several dig locations up to 1 1/4 miles north of the rupture ranged from -0.70 to -0.75 V and up to 1/4 mile south of the rupture ranged from -0.59 to -0.73 V. These areas were reported on the 1995 internal inspection survey as having either light (15 to 30 percent) or no reportable corrosion (< 15 percent). When the pipe was excavated after the accident, corrosion pinholes (very small-diameter holes through the pipe wall) were found, and corrosion pits greater than 0.180-inch deep were measured at several locations along the pipeline. These reports also noted that the pipeline coating

[16] In a close-interval survey, pipe-to-soil potential is measured every few feet (typically every 2.5 feet). This survey is useful for identifying cathodic protection problems such as low potentials between established test points, the presence of stray currents, and areas of gross coating loss.

had some "holidays" (breaks or bare spots), stress cracking, wrinkles, and disbonded areas.[17] Tree roots were also observed in the backfill next to the pipe in one of these areas.

In October 1996, Koch completed a close-interval survey of the 10-mile section around the rupture site. Potentials less negative than -0.85 V were recorded in many areas during this survey. In addition, some areas of missing coating were noted. No indications of stray currents were found.

Additional rectifier installations were proposed for five new locations between Nevada and Corsicana pump stations as well as for other locations in the pipeline system. The last rectifier of this group was activated on February 17, 1997.

After the accident, the soil resistivity near the accident area was measured. Soil resistivity data are useful for determining corrosive characteristics of the soil and estimating their impact on cathodic protection. Low soil resistivity readings of 507 ohm-cm at the rupture site, 862 ohm-cm 50 feet north of the rupture site, and 1,149 ohm-cm 50 feet south of the rupture site were recorded. Soil resistivity values at these levels generally indicate highly corrosive soil.[18]

Pipe Examination

After the fire was extinguished, the accident site was excavated and the ruptured pipe exposed. The backfill contained partially decomposed organic material including tree roots and had a sewer-like odor. Shortly after the accident, about 95 feet of pipe was removed from the pipeline. A 46-inch section containing the rupture (figure 5) and three nearby sections (6 to 7 feet long) were examined at the Safety Board's Materials Laboratory in Washington, D.C.

The pipe rupture was longitudinal, approximately 12.5 inches long (figure 5, right to left). The rupture occurred at the 4 o'clock circumferential position relative to the pipe's position in the ground, with 12 o'clock being the top of the pipe. Significant corrosion was found at the center of the pipe rupture. Most of the tape coating on the ruptured segment was destroyed in the fire, thus the coating condition before the rupture could not be determined.

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[17] Cathodic protection current requirements are significantly reduced when buried pipeline is properly coated using an effective barrier coating. However, factors such as overprotection (potentials significantly more negative than -0.85 V), inadequate coating selection, improper surface preparation or application of the primer or coating, or soil stresses may result in coating disbondment. If soil or moisture is present on the pipe surface underneath the disbonded coating, the pipe could corrode even in a cathodically protected system. Because the disbonded coating acts as an electrical shield, the amount of current reaching the metal underneath the disbonded coating depends upon the resistance of the soil or water present in the gap created by the disbonded coating. Though some current may flow to the pipe surface in this space, more current goes to other, more easily accessible, areas (low resistance path). Typically, the current density underneath the disbonded coating is insufficient to provide adequate corrosion protection.

[18] *Corrosion Control/Systems Protection.* Volume VI—*Technical Services*, Book TS-1, American Gas Association, Arlington, Virginia, 1986, p. 79.

Figure 5. Pipe section containing 12.5-inch rupture

The center of the rupture contained an area of corrosion about 5 inches long by 3 inches wide. In the rupture area, corrosion pits appeared to have substantially penetrated the pipe wall indicating nearly 100-percent wall-thickness loss. No other pitting was observed on the remainder of the 46-inch section of pipe containing the rupture. No evidence of a material flaw or of mechanical damage (dents, gouges, or scrapes) to the pipe was observed. Figure 6 is a composite of two photographs, one of each side of the rupture, constructed to show the two sides of the corroded area in proximity. The arrows in the photo indicate where corrosion pitting had substantially penetrated the pipe wall.

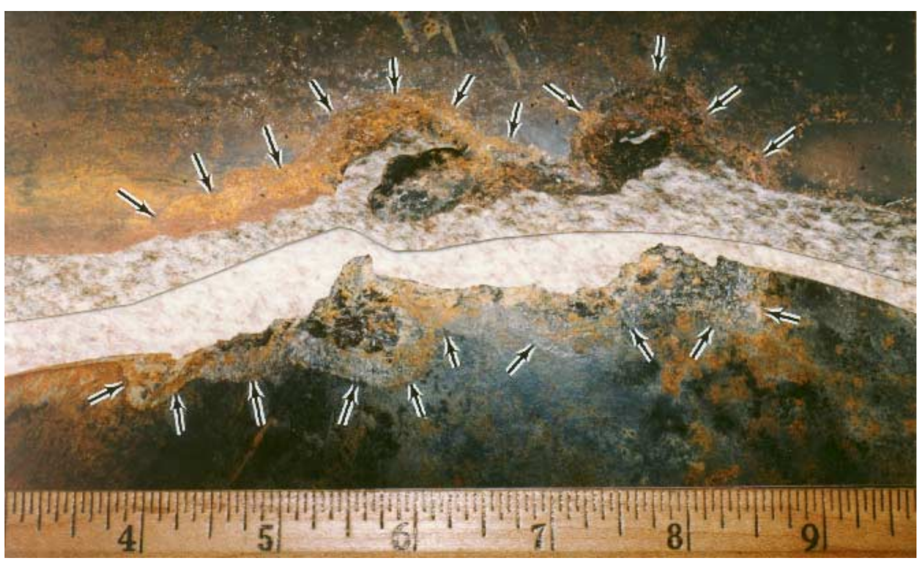

Figure 6. Composite photograph showing corroded area at center of rupture

Coating damage as observed in the field is shown in figures 7 and 8. The three pipe sections (both upstream and downstream of the rupture) brought to the Materials Laboratory for testing had disbonded and cracked spiral wrapped tape coating at several locations. Mechanical damage to the tape coating similar to damage caused by a pipe-locating probe was also observed. Scratches were found on the pipe at several of the coating tears. Corrosion was observed on the exposed pipe surfaces at the damaged areas.

Figure 7. Disbonded tape coating on 8-inch pipe extracted at accident site (Arrows show disbonded area under tape coating.)

All of the nearby pipe segments examined by the Materials Laboratory displayed corrosion damage, from 30- to 64-percent wall-thickness loss. Five principal areas of corrosion damage correlated with five corrosion areas on the 1995 inspection log; however, these areas had been graded as having less than 30-percent pipe-wall-thickness loss in 1995.

A consultant for Koch performed testing and analysis for bacteria[19] on the pipe using a procedure similar to NACE International Standard TM 0194-94.[20] An area selected for bacteria testing included one of the corrosion areas containing rust tubercles[21]

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[19] Microorganisms, such as bacteria and fungi, can cause underground corrosion.

[20] NACE International Standard TM 0194-94, *Field monitoring of bacterial growth in oil field systems.* NACE International (formerly National Association of Corrosion Engineers—NACE), Houston, Texas, 1994.

[21] Knob-like mounds formed on the pipe as the result of localized corrosion.

within 20 feet of the rupture. The consultant's report provided the following laboratory analysis results:

- Pipe surface samples were acidic with a pH of 5 to 6,
- Sulfides were present in small amounts,
- Sulfate-reducing bacteria were present in insignificant amounts,
- Anaerobic acid-producing bacteria were present in small amounts (100 bacteria/ml), and
- Aerobic acid-producing bacteria were "strongly present" (10,000 bacteria/ml).

The consultant's report concluded, "The results of the testing performed here indicate that Aerobic Acid Producing bacteria are the main contributor to the corrosion found on this pipe."

Concerning the testing, the consultant's report said the results "may not be representative of bacteria activity" because of the inadequate sampling techniques and handling time. The report further noted, "Bacteria typically have a life of 30 to 40 hours and can change their populations significantly in 2 days if their environment is changed." In this instance, Koch had cleaned the pipe when it was removed from the ground, and laboratory tests were not performed until about 48 hours later. The consultant used tap water for sample preparation instead of the phosphate-buffered saline solution recommended in NACE International Standard TM 0194-94.

Figure 8. Cracks in the tape coating on 8-inch pipe excavated at accident site

Public Education

Preaccident Public Education Mailings

In 1991, Koch conducted a public education program for people living within 1/4 mile of the pipeline. In 1991 and 1992, public education materials were hand-distributed door to door by company representatives. In 1992, Koch produced a report that included tabulations of the total number of material packets issued and the response cards returned to the company.

From 1993 through early 1996, Koch distributed its public education materials by annual mailings, using addresses compiled from returned response cards, from lists developed by company representatives canvassing the area, and from property right-of-way records. Koch solicited and received public education information from other pipeline companies for comparison with its program. Koch representatives also attended industry meetings where public education information was reviewed.

An "Information Bulletin" was provided as part of the 1996 public education materials mailed to residents before the accident. (See appendix A.) The bulletin highlighted telephone numbers for notifying Koch before performing excavation near the pipeline or during a pipeline emergency. The bulletin discussed the propane-butane family of products transported by the pipeline, how to recognize a product release, and the importance of keeping "sources of ignition" away from liquid spill areas. In addition, the 1996 mailing included a calendar bearing a warning not to perform excavation near the pipeline until Koch is notified. Recipients also received response cards for providing their addresses and address corrections or for requesting additional information.

In 1996, about 45 families lived on two roads in the area of the accident, Oak Park Circle and County Road 4129 (figure 1). Of the 45 residences listed on the two roads, only 5 addresses appeared on Koch's 1996 preaccident mailing list. The two families that suffered fatalities were not on the mailing list. The person who called Koch to report the release was on the mailing list.

Koch's public education program provided educational materials to public offices and emergency response organizations serving the areas in which the pipeline was operated. The head of the Kaufman County Emergency Management Office indicated that Koch had provided information and communicated with the office. The Kaufman County Sheriff's Department was on Koch's mailing list and had been invited to yearly governmental liaison meetings in 1995 and 1996.

Industry Public Education Program Standard

American Petroleum Institute (API) Recommended Practice 1123, *Development of Public Awareness Programs by Hazardous Liquid Pipeline Operators*,[22] provides information on reaching the public, safety message content, communications methods, and program evaluation. API Recommended Practice 1123 provides some information on resources available to companies for developing and distributing their own safety materials and on other methods of providing information. Section 6.8 of the publication states that "Operators that use their own mailing lists when they mail public awareness materials to the public should maintain up-to-date lists" and that response cards "permit the recipients to notify the operators of any changes of address and could measure the effectiveness of the safety message." Section 9 provides information that a pipeline operator can use to evaluate the effectiveness of its public awareness program, including scientifically based evaluation techniques available to ensure that program objectives are being met (section 9.4).

Postaccident Public Education Mailing

As a result of an HFO issued after the accident by the OPS, Koch revised and reformatted its public education materials (appendix B). Some of the changes Koch made to its public education program include:

- Replacing its previous mailing list for residents along the pipeline right-of-way with a mailing list developed using mapping grid databases.
- Revising safety information to include pertinent information on detecting a pipeline leak and actions to take when a leak is suspected.
- Prominently highlighting material in the new safety brochure on:
    1. how to identify Koch's pipelines,
    2. precautions to take around Koch's pipelines during excavation activity,
    3. how to identify a pipeline leak and a highly flammable vapor cloud, and
    4. actions to take in addition to notifying Koch, when a leak is suspected or a vapor cloud is detected.

[22] Recommended Practice 1123, *Development of Public Awareness Programs by Hazardous Liquid Pipeline Operators,* American Petroleum Institute, Washington, D.C., August 1996.

Regulations and Orders Governing Pipeline Operation

External Corrosion Control Safety Regulation

Title 49 CFR 195.416 contains a number of requirements concerning safe pipeline operations:

> (a): Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.
>
> (e): Whenever any buried pipe is exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.
>
> (g): If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness of the pits.

This regulation does not provide specific criteria for "adequate cathodic protection" for liquid pipelines. Specific criteria for cathodic protection can be found in appendix D of the gas pipeline safety regulations, 49 CFR 192.

Public Education Safety Regulation

Title 49 CFR 195.440 requires that pipeline operators establish a continuing education program to enable the public, appropriate Government organizations, and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and report it to the operator or to fire, police, or other appropriate officials. The regulation does not specifically identify the information that must be provided or require that the pipeline operator periodically evaluate the effectiveness of its public education program. The OPS inspection of Koch's public education program before the accident in May 1993 identified no deficiencies.

Office of Pipeline Safety Hazardous Facility Order

On October 7, 1996, about 6 weeks after the accident, the OPS issued an HFO that directed Koch to submit written plans, to include performing corrective actions concerning pipeline operation and public education. The HFO's requirements include but are not limited to the following provisions:

> Submit for approval by the Regional Director, within 30 days after an Order is issued, a written plan addressing a program of tests or studies that will identify the extent of and propose a solution to the external corrosion problem on the HVL line and allow for verification and maintenance of the HVL line. The plan is to include, at minimum, provisions and time frames for identifying the extent of corrosion and correcting the external corrosion problems on the HVL line. The plan should address, at minimum—
>
> *The 8-inch [diameter] pipeline section [containing the accident location] between block valves at stations 17316+16 to 17849+48 (approximately 10 miles).*
>
> i. Run an ultrasonic "smart" pig or high resolution magnetic flux "smart" pig [internal inspection instrument] to determine pipe wall condition.
>
> ii. Complete installation of new ground bed and test, and activate rectifier.
>
> iii. Perform a close interval survey.
>
> iv. Retain any exposed pipe removed from the line during preparation for the "smart" pig run [internal inspection] for OPS examination. Provide a detailed pipe and coating condition report.
>
> v. Notify the appropriate public officials of Henderson and Kaufman Counties whenever tests are performed involving the movement of HVLs through the pipeline.
>
> vi. Expose anomalies indicating 20 percent or greater wall loss, and repair or replace areas of 20 percent or greater wall loss, or as may be agreed upon with the Regional Director.
>
> vii. Determine MOP subject to final approval by the Regional Director.
>
> viii. The Corrosion mitigation measures must conform with approved industry standards such as NACE Standard RP-0169-92, *Recommended Practices for Control of External Corrosion on Underground or Submerged Metallic Piping Systems*.
>
> ix. Results of test and metallurgical and chemical analysis of pipe now underway.

Except for items ii, iii, and ix, the above requirements also apply to the remainder of the 8-inch and 10-inch-diameter sections of Koch's HVL pipeline. In addition, the HFO modifies item v for those pipeline sections as follows: "Notify the appropriate public officials in affected counties whenever tests [are performed] involving the movement of HVLs through the pipeline."

The HFO also addresses Koch's public education program. The HFO specifies that Koch—

Submit for approval by the Regional Director, within 30 days after an Order is issued, a written plan to provide a public awareness program for residents located along the pipeline right-of-way. The program, at minimum, should include the following information—

a. Identification of pipeline location.

b. Recognizing an HVL pipeline leak and action to be taken.

c. Reporting to Koch any right-of-way encroachments or other activity which could damage the pipeline.

d. Information about the danger of operating motorized vehicles and equipment in or near a vapor cloud caused by HVLs escaping from a ruptured pipeline.

Provide verification to the Regional Director that this program is being carried out.

Koch submitted the plan required by the HFO to the OPS.

Safety Issues

This analysis is divided into two general sections. The first section reviews the accident itself, highlighting the actions and events that resulted in problem conditions. The balance of the analysis discusses the safety issues identified as a result of this accident:

- Adequacy of Koch's corrosion inspection and mitigation actions, and
- Effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

Accident Discussion

At 2:05 p.m. on the day of the accident, the pump at Cleveland pump station (see figure 3) experienced an automated shutdown due to a hydrocarbon vapor detection alarm in the station. As a result of the shutdown, pressure increased on the pipeline upstream of Cleveland pump station. At 3:05 p.m., Corsicana pump station automatically shut down due to a high-discharge pressure alarm being activated. When the Corsicana pumps shut down, a pressure surge traveled from Corsicana upstream toward Nevada pump station. Based on an analysis of SCADA data, the pipeline ruptured between the two stations about 3:26 p.m.

No indications of excavation damage, such as dents or gouges on the pipe, were observed at the rupture site. The rupture occurred at a location where the pipe wall had been reduced due to corrosion. However, when the internal inspection tool was run about 15 months earlier, the wall-thickness loss in this area of the pipeline was identified as being significantly less than at the time of the accident. Therefore, this analysis examines the adequacy of Koch's corrosion inspection and mitigation actions.

When the pipe ruptured, it sent a butane vapor cloud into the surrounding residential area. The butane vapor ignited (figure 2) as two residents in a pickup truck drove into the vapor cloud on their way to a neighbor's house to report the release to 911. Therefore, the analysis also examines the effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

Internal Pipeline Inspection

A possible explanation for the pipeline's rapid corrosion and failure in 15 months was that the 1995 internal inspection significantly underreported pipe-wall-thickness loss at the rupture site. Defect geometry related to size and orientation, such as dents, gouges, or narrow cracks in the longitudinal direction may create corrosion-feature-reporting problems. However, the Safety Board Materials Laboratory examination of pipe excavated near the rupture site identified no such defects. Also, comparison of actual wall-thickness-loss data with the internal inspection logs for the pipe locations excavated for repair by Koch showed good correlation. In the three instances where discrepancies between the 1995 log and the actual dig reports were observed, the internal inspection instrument predicted a wall-thickness loss that was greater than actually measured.

The Safety Board recognizes that the possibility of underreporting of corrosion damage at the accident site during the 1995 internal pipe inspection cannot be totally eliminated. However, the good correlation between the 1995 inspection log and actual dig reports and the absence of problematic defect geometry indicate that underreporting of corrosion damage probably did not occur. Therefore, the Safety Board concludes that it is unlikely that the pipeline corrosion damage near the rupture location was underreported by the 1995 internal inspection.

In addition, about 15 lengths of pipe in a 10-mile section around the rupture site were graded as exhibiting severe corrosion by the September 1996 internal inspection performed a month after the accident. However, none of the pipe lengths examined in the 1996 inspection had been identified as being either moderately or severely corroded by the May 1995 inspection. Therefore, the Safety Board concludes that corrosion damage found during the 1996 postaccident inspection indicated that rapid corrosion had occurred on the pipeline since the 1995 internal inspection.

Microbial Testing

A procedure similar to NACE International's TM 0194-94 oil field standard was used by Koch's consultant to obtain corrosion samples and test them for bacteria. The consultant's analysis of corrosion products from a pipe location within about 20 feet of the accident site indicated low levels of anaerobic bacteria and sulfides and an even smaller number of sulfate-reducing bacteria. The consultant noted that aerobic acid-producing bacteria were primarily present in the corrosion products. The consultant concluded that aerobic acid-producing bacteria mainly contributed to the pipe's corrosion. However, the report provided no information about the corrosion rate or time frame in which corrosion may have occurred.

The consultant's analysis could be inaccurate because Koch personnel cleaned the pipe after it was removed from the ditch and before the samples were collected. Another inaccuracy may have been introduced because laboratory tests were performed about

2 days after the pipe was removed from the ground. The consultant's report suggested that the adverse effect of the cleaning and delay in sampling might have been offset by the fact that samples were taken from tubercles on the pipe. However, these factors are important because of their significant impact on the aerobic and anaerobic bacteria populations. As noted in the consultant's report, bacteria typically have a life of 30 to 40 hours, and their populations can change significantly within 2 days of a change to their environment.

More importantly, and not specifically stated in the report, is the sensitivity of anaerobic and sulfate-reducing bacteria to an oxygen environment. The relevant factor in sample preparation was the use of tap water, which most likely contaminated the sample with oxygen and thus created a bias for aerobic microbes. No additional microbial testing was done, and the accuracy of the testing performed remains questionable. Therefore, the Safety Board concludes that the contribution of microbes to the corrosion damage cannot be accurately determined because of inadequate sampling and testing techniques. Furthermore, as noted earlier, Koch's consultant used a procedure similar to the one in the NACE International Standard (TM 0194-94), which describes field testing methods for estimating bacteria populations commonly found inside oil field piping systems and is not directly applicable to sampling and testing for microbes from an external pipeline surface. The Safety Board believes that NACE International should develop a standard for microbial sampling and testing of external surfaces on an underground pipeline.

External Corrosion Control

The cause of pipeline corrosion can be difficult to determine because different corrosion phenomena could operate simultaneously in the same general area, resulting in multiple damage sites with corrosion progressing at widely varying rates.

Stray currents constitute one phenomenon that can contribute to corrosion. However, the annual cathodic protection system surveys that Koch performed before the accident gave no indication that stray currents were present. Close-interval surveys performed after the accident in 1996 also indicated that the system did not have stray current problems. The Safety Board concludes that stray currents did not contribute to the corrosion observed on the pipeline.

Another factor that can contribute to corrosion is the failure to maintain adequate cathodic protection. After the internal inspection in 1995, the pipe-to-soil potentials recorded on field reports during repairs were below the acceptable cathodic protection level established by the company. Koch did not correct this observed low potential problem. The Safety Board therefore concludes that inadequate corrosion protection at the rupture site and at numerous other locations on the pipeline allowed active corrosion to occur before the accident.

Coating condition also affects the ability to adequately protect pipe from corrosion. Stress-cracked and disbonded coating was observed after the accident near the rupture location. In the case of the pipe near the accident site, the stress-cracked and disbonded coating created areas where soil and moisture could come in contact with the pipe surface.

In addition to exposing pipe to microbial corrosion, stress-cracked and disbonded coating may have interfered with Koch's ability to provide adequate cathodic protection by exposing more bare pipe surface and consequently increasing the pipe's demand for protective current. The disbonded coating may have further decreased the effectiveness of cathodic protection by creating a barrier or shield to the protective current. The low potentials observed at a number of excavations before the accident indicated that the pipe was not receiving the necessary protective current. The Safety Board concludes that because cathodic protection levels were inadequate, the stress cracks that existed in the coating created areas in which rapid corrosion could occur. The Safety Board further concludes that the disbonded tape coating most likely created locally shielded areas on the pipe that prevented adequate cathodic protection current from reaching its surface, creating other areas where rapid corrosion could occur. In addition, the Safety Board concludes that stress cracks and disbonded tape coating on the pipe created areas where microbial corrosion could potentially occur.

Since the accident, Koch has taken action to improve corrosion protection on its pipeline. After the accident, pipe-to-soil potentials were still low in the vicinity of the rupture. Therefore, in the 2 weeks following the accident, Koch replaced an anode ground bed to repair one rectifier and installed the previously proposed new rectifier. By February 1997, the company had installed five additional rectifiers between rectifiers M-7 and M-10 because potentials were still below the company standard.

Koch also advised the Safety Board that it has been evaluating two alternatives to ensure the integrity of its line. One is to repair and re-coat a 70-mile section of its pipeline between Nevada and Corsicana pump stations; the other is to replace this 70-mile section of the pipeline. Koch has communicated these proposals to the OPS. The Board recognizes that the OPS has included a number of requirements in the HFO to specifically address identifying the extent of the external corrosion problem on the HVL pipeline. However, the HFO does not contain a specific requirement to evaluate coating condition, and Koch's field reports indicate that the corrosion problem extends beyond the 70-mile section proposed for repair or replacement. The Safety Board concludes that the tape coating on Koch's entire 8-inch pipeline may have stress cracking and disbondment. Therefore, the Safety Board believes that RSPA should require that Koch evaluate the integrity of the remainder of its HVL pipeline, including the condition of the coating, and rehabilitate the pipeline as necessary. Further, the Safety Board concludes because no overall requirement exists for operators to evaluate pipeline coating condition, problems similar to those that occurred on Koch's pipeline could occur on other pipelines. The Safety Board believes that RSPA should revise 49 CFR Part 195 to require pipeline operators to determine the condition of pipeline coating whenever pipe is exposed and, if degradation is found, evaluate the coating condition of the pipeline.

The OPS requires that pipeline operators conduct tests annually (not to exceed 15 months between tests) for pipelines under cathodic protection to determine that the protection is adequate (49 CFR 195.416). However, the regulation does not provide performance measures for "adequate cathodic protection" for liquid pipelines. Performance measures for cathodic protection can be found in appendix D of the gas pipeline safety regulations, 49 CFR 192. The Safety Board, as a result of its investigation of a 1986 accident[23] involving a liquid pipeline, recommended that RSPA provide cathodic protection criteria for liquid pipelines:

> <u>P-87-24</u>
>
> Revise 49 CFR Part 195 to include criteria, similar to those found in Part 192, against which liquid pipeline operators can evaluate their cathodic protection systems.

Because RSPA failed to take meaningful action to address this recommendation, the Safety Board classified Safety Recommendation P-87-24 "Closed—Unacceptable Action" on January 23, 1996. The Safety Board concludes that this accident illustrates the continuing need for performance measures for adequate cathodic protection on liquid pipelines and believes that RSPA should revise 49 CFR 195 to include performance measures for the adequate cathodic protection of liquid pipelines.

In addition to having appropriate cathodic protection performance measures, an operator should promptly evaluate all available corrosion-related data, such as potential measurements, internal inspection results, and coating condition to maintain adequate corrosion protection levels throughout a pipeline.

The need for a timely evaluation of corrosion-related data is evident in this accident. Catastrophic failure occurred in an area of the pipeline where significantly less corrosion had been identified by an internal inspection tool about 15 months earlier. Corrosion found on the pipe excavated as a result of the 1995 internal inspection confirms that active corrosion was occurring at various locations on the pipeline system. When buried pipe was exposed in 1995 after this internal inspection, Koch recorded low pipe-to-soil potentials on its field reports. Even though the recorded pipe-to-soil potentials in many cases were below the company standard for cathodic protection, Koch did not ensure that cathodic protection levels were restored to the company standard. In addition, stress cracking and disbonded coating were observed at numerous locations and recorded in the exposure reports. Excavations made as a result of the accident and during the 1996 internal inspection done after the accident indicate that active corrosion was continuing on the pipeline. The Safety Board concludes that although Koch's records contained information that cathodic protection levels were inadequate and that active corrosion was occurring on its pipeline system before the accident, the conditions went uncorrected.

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[23] For more detailed information, read Pipeline Accident Report—*Williams Pipe Line Company Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986* (NTSB/PAR-87/02).

Koch informed the Safety Board that as of September 1998, the company was expanding the distribution of its field reports and notifying corrosion technicians when specific conditions are detected so that a field inspection can be made. However, Koch needs to take more comprehensive action to evaluate data so that it can promptly provide adequate corrosion protection to its pipeline. The Safety Board believes that Koch should establish a procedure to promptly evaluate all data related to pipeline corrosion, such as annual cathodic protection surveys, field reports, internal inspection results, and coating condition data, to determine whether the pipeline's corrosion protection is adequate, and take necessary corrective action.

Public Education

The content of the 1996 bulletin sent by Koch (appendix A) as part of its public education package before the accident had two important shortcomings. The bulletin's first shortcoming was that key information on recognizing a leak and taking appropriate action lacked clarity and was not formatted to alert readers of its importance. In addition, the complex language used in the bulletin diluted the warning. For example, while the bulletin stated that vapors are extremely flammable, it also provided technical information on vapor ignition temperature and atmospheric concentration that distracted readers' attention from the message that such vapors pose a major hazard and require caution if their presence is suspected.

The bulletin's second shortcoming was that the warning was not specific enough. It omitted crucial information such as warning people not to operate switches, equipment, machinery, or motor vehicles in or near a vapor cloud; not to light a match or smoke; and not to drive into or go back into the vapor cloud. Furthermore, the bulletin failed to urge readers to inform others in the household of the warning, which is a way to disseminate crucial safety information beyond the initial reader. The Safety Board concludes that the format and content of the public education bulletin mailed by Koch before the accident did not effectively convey important safety information to the public.

Another significant issue involved the distribution of Koch's public education materials. Before the accident, Koch developed its mailing list through door-to-door canvassing and then used response card returns to verify the accuracy of coverage in the accident area. However, during the 1996 mailing, only 5 of the 45 residences near the accident site were sent Koch's educational materials. Significantly, Koch's 1996 mailing list did not include the two families that suffered fatalities in the accident. In all, Koch's mailing on the dangers of a pipeline release and actions to take during a pipeline emergency reached only a limited number of people living near the accident location. Therefore, the Safety Board concludes that Koch's distribution program for its public education materials before the accident was inadequate. Since the accident, Koch has improved the information presented in its educational bulletin and its method for distributing public education materials.

The pipeline safety regulations do not provide clear and specific requirements for the content and distribution of a pipeline operator's public education program. The lack of such requirements contributed to the failure, before the accident, to identify deficiencies in Koch's public education program. After the accident, the OPS issued an HFO that included requirements for Koch to improve its mailing list and revise its safety brochure to prominently feature information on recognizing a pipeline leak and on actions people should take in response to a leak.

Further, existing safety regulations do not require pipeline companies to evaluate the effectiveness of their public education programs. Without such evaluations, operators may not realize that a program is not achieving its objectives. One source for developing a scientific means to evaluate the effectiveness of public education programs is API Recommended Practice 1123, which contains information on evaluation methods. The Safety Board concludes that requirements for the content, format, and periodic evaluation of public education programs can help pipeline operators ensure that their programs are effective. The Safety Board believes that RSPA should revise 49 CFR Part 195 to include requirements for the content and distribution of liquid pipeline operators' public education programs. The Safety Board also believes that RSPA should revise 49 CFR Part 195 to require that pipeline operators periodically evaluate the effectiveness of their public education programs using scientific techniques.

The Safety Board has long been concerned about the issue of pipeline public education programs, including the content, distribution and the effectiveness of pipeline operators' safety materials for both hazardous liquid and natural gas pipelines. As a result its investigation of a series of 5 natural gas accidents[24] in Kansas, from September 16, 1988, to March 29, 1989, the Safety Board recommended on April 20, 1990, that RSPA:

> <u>P-90-21</u>
> Assess existing gas industry programs for educating the public on the dangers of gas leaks and on reporting gas leaks to determine the appropriateness of information provided, the effectiveness of educational techniques used, and those techniques used in other public education programs, and based on its findings, amend the public education provisions of the Federal regulations.

On April 5, 1993, RSPA published Advisory Bulletin ADB-93-02, which directed "gas pipeline facility owners and operators to review and assess their continuing education programs as applied to customers and the public." The Safety Board did not consider that action responsive because RSPA failed to assess the existing industry programs or amend the public education regulations. Therefore, the Board classified Safety Recommendation P-90-21 "Open—Unacceptable Action."

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[24] For more detailed information, read Pipeline Accident Report—*Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988 to March 29, 1989* (NTSB/PAR-90/03).

As a result of its investigation of a natural gas explosion and fire in Edison, New Jersey, on March 23, 1994,[25] the Safety Board reiterated Safety Recommendation P-90-21 to RSPA on February 7, 1995. The Board found that the Edison accident illustrated the need for RSPA to take an active role in ensuring that pipeline operator public education programs effectively provide the information the public needs to recognize the location of pipelines, recognize potential hazards, report a pipeline emergency condition, and safely evacuate an area.

Another recent accident investigated by the Safety Board in which public education was a major safety issue was the propane gas explosion in San Juan, Puerto Rico,[26] which resulted in 33 fatalities and 69 injuries. At the June 1997 public hearing, OPS's Director of the Enforcement, Compliance, and State Operations Division stated that the OPS had received $800,000 in funding to develop a national public education program format to be used by pipeline operators. The OPS planned to work closely with industry to determine the most effective way to educate the public about gas pipeline safety. The Safety Board noted that although past actions on this issue had not been timely, it was pleased that the development of a national public education format was on RSPA's agenda and encouraged the OPS to expedite work on this project. Because of RSPA's renewed activity, the Board reclassified Safety Recommendation P-90-21 "Open—Acceptable Response" on December 21, 1997.

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[25] For more detailed information, read Pipeline Accident Report—*Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994* (NTSB/PAR-95/01).

[26] For more detailed information, read Pipeline Accident Report—*San Juan Gas Company, Inc./Enron Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996* (NTSB/PAR-97/01).

Conclusions

Findings

1. The corrosion damage found during the 1996 postaccident inspection indicated that rapid corrosion had occurred on the pipeline since the 1995 internal inspection.

2. It is unlikely that the pipeline corrosion damage near the rupture location was underreported by the 1995 internal inspection.

3. Stray currents did not contribute to the corrosion observed on the pipeline.

4. Inadequate corrosion protection at the rupture site and at numerous other locations on the pipeline allowed active corrosion to occur before the accident.

5. Because cathodic protection levels were inadequate, the stress cracks that existed in the coating created areas in which rapid corrosion could occur.

6. Disbonded tape coating most likely created locally shielded areas on the pipe that prevented adequate cathodic protection current from reaching its surface, creating other areas in which rapid corrosion could occur.

7. Although Koch's records contained information that cathodic protection levels were inadequate and that active corrosion was occurring on its pipeline system before the accident, the conditions went uncorrected.

8. The tape coating on Koch's entire pipeline may have tape cracking and disbondment.

9. Because no overall requirement exists for operators to evaluate pipeline coating condition, problems similar to those that occurred on Koch's pipeline could occur on other pipelines.

10. This accident illustrates the continuing need for performance measures for adequate cathodic protection on liquid pipelines.

11. Stress cracks and disbonded tape coating on the pipe created areas where microbial corrosion could potentially occur.

12. The contribution of microbes to the corrosion damage cannot be accurately determined because of inadequate sampling and testing techniques.

13. The format and content of the public education bulletin mailed by Koch before the accident did not effectively convey important safety information to the public.

14. Koch's distribution program for its public education materials before the accident was inadequate.

15. Requirements for the content, format, and periodic evaluation of public education programs can help pipeline operators ensure that their programs are effective.

Probable Cause

The National Transportation Safety Board determines that the probable cause of this accident was the failure of Koch Pipeline Company, LP, to adequately protect its pipeline from corrosion.

Recommendations

As a result of its investigation of this accident, the National Transportation Safety Board makes the following safety recommendations:

to the Research and Special Programs Administration:

Require that Koch Pipeline Company, LP, evaluate the integrity of the remainder of its HVL (highly volatile liquid) pipeline, including the condition of the coating, and rehabilitate the pipeline as necessary. (P-98-34)

Revise 49 *Code of Federal Regulations* Part 195 to require pipeline operators to determine the condition of pipeline coating whenever pipe is exposed and, if degradation is found, to evaluate the coating condition of the pipeline. (P-98-35)

Revise 49 *Code of Federal Regulations* Part 195 to include performance measures for the adequate cathodic protection of liquid pipelines. (P-98-36)

Revise 49 *Code of Federal Regulations* Part 195 to include requirements for the content and distribution of liquid pipeline operators' public education programs. (P-98-37)

Revise 49 *Code of Federal Regulations* Part 195 to require that pipeline operators periodically evaluate the effectiveness of their public education programs using scientific techniques. (P-98-38)

to Koch Pipeline Company, LP:

Establish a procedure to promptly evaluate all data related to pipeline corrosion, such as annual cathodic protection surveys, field reports, internal inspection results, and coating condition data, to determine whether the pipeline's corrosion protection is adequate, and take necessary corrective action. (P-98-39)

to NACE International:

Develop a standard for microbial sampling and testing of external surfaces on an underground pipeline. (P-98-40)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JAMES E. HALL
Chairman

ROBERT T. FRANCIS II
Vice Chairman

JOHN A. HAMMERSCHMIDT
Member

JOHN J. GOGLIA
Member

GEORGE W. BLACK, JR.
Member

November 6, 1998

Appendix A

Public Education Information Bulletin (issued before 1996 accident)

KOCH

KOCH PIPELINE COMPANY LP

INFORMATION BULLETIN

Koch Pipeline Company, L.P. and Koch Hydrocarbon Company, in a continuing effort to inform the public about the operation of it's pipeline systems, would like to pass on to you some pertinent information in the event that you are working near our pipeline.

The Koch Pipeline systems were established to safely and efficiently gather natural gas liquids in the states of Oklahoma, Texas, New Mexico and Kansas and transport them to Medford, Oklahoma, Hutchinson, Kansas or Mont Belvieu, Texas for separation into specification products.

The welded steel pipelines were constructed in accordance with applicable state and federal regulations and are monitored from a pipeline control center in Wichita, Kansas. This control center is operated by personnel on duty 24-hour a day, seven days a week.

The pipelines operate at pressures from 740 to 1440 psi. The natural gas liquids, which are of the propane-butane family, would quickly vaporize into a flammable gas if released to the atmosphere. A large spill will create a fog-like cloud from atmosphere moisture being condensed, but the gas itself is colorless. Depending on weather conditions, it can collect in low places, become transparent or dissipate into the atmosphere.

The product is not odorized, but usually can be identified by the typical petroleum product odor. The vapors are extremely flammable, having an ignition temperature of approximately 800° F in an atmosphere containing 2% to 10% mixture of vapor. All care should be taken to keep sources of ignition a safe distance from any liquid spill area.

Our greatest concern regarding line failure is with others working near the pipeline with earth moving equipment. We have an ongoing program of advising the public of the location of our pipeline, requesting that they call us prior to digging near the pipeline. The location of our line is marked with signs and markers which indicates the presence of the line. The only sure way of locating our pipeline, is by calling the number listed on the markers and having our company representative come out and flag the line. Digging near our lines without knowing exactly where the pipelines are located can result in a pipeline rupture and possible risk to personal safety.

Should a failure or malfunction of the pipeline system occur, our operating personnel will notify various agencies and/or companies as assistance is required. Likewise, if you are the first to be informed, notify us by calling our pipeline control center in Wichita at 800-666-9041 or 800-666-0125.

In addition to the control center monitoring the pipeline, the Company has operating and maintenance personnel located at various points along the pipeline. In the event of an incident, these personnel have training in the response to a pipeline emergency and would be responsible for the orderly handling of an emergency situation. They will be in a position to advise public agencies of the magnitude of the problem and how best to cope with it. If evacuation of people in the vicinity is warranted, the Company Representative will so advise and will assist the various agencies and/or companies in the notification.

If you desire further information, please contact Koch Pipeline Company, L.P. or Koch Hydrocarbon Company at our Medford Division office, phone 405-395-2377, during normal business hours.

BEFORE EXCAVATING OR IN CASE OF EMERGENCY
800-666-9041 or 800-666-0125

P.O. Box 29 ▪ Medford, Oklahoma 73759 ▪ 405/395-2377

Appendix B
Revised Pipeline Safety Brochure (issued since 1996 accident)

promptly and properly repaired by pipeline representatives. Do not cover a pipeline that has been damaged – it makes it difficult to find the damaged area.

How Can You Identify A Natural Gas Liquids Pipeline Leak

Often you can see a pipeline leak and in many cases you can smell it. The following signs might indicate a pipeline leak:

- A strange or unusual odor near the pipeline (the products will have a typical petroleum odor)
- A hissing or roaring sound (from escaping gas)
- A patch of dead or discolored vegetation in an otherwise green setting along the pipeline
- A slight mist of ice or a frozen area on exposed pipes, valves or the ground
- Flames originating from the ground or valves along the pipeline route
- Continuous bubbling in wet, flooded areas or marshlands, rivers, creeks and bayous
- Depending on weather conditions, leaked gas can collect in low places, become transparent or dissipate into the air
- A dense white cloud of fog

What To Do If You Find A Pipeline Leak

Pipeline leaks can form a highly flammable white fog called a "vapor cloud." If you find a pipeline leak or suspect there might be a problem on the pipeline, please take the following precautions:

- **Turn off any machinery and/or equipment** in the immediate area. (Note: If a vapor cloud has surrounded a piece of running equipment, **do not go into the vapor cloud** to turn off the equipment.)
- **Do not create any sparks or heat sources** which could ignite escaping gas or liquids. For example, **do not** start a car, turn **on** or **off** any light switches, or light a match or cigarette. Turn off any lit gas pilots.
- **Immediately leave the area on foot in a crosswind direction** away from the vapor cloud and maintain a safe distance.
- **Warn others** to stay away from the leak.
- **Do not drive into or near** a vapor cloud. The car engine might ignite the vapor cloud.

Notify us and give your name, the location and a description of the leak. For our pipelines call us at **800-666-9041** or **800-666-0125**.

KOCH

KOCH PIPELINE COMPANY LP

PIPELINE SAFETY

WARNING
HIGH PRESSURE
PETROLEUM PIPELINE
KOCH
KOCH PIPELINE COMPANY LP
MEDFORD, OKLAHOMA
1-800-666-9041

Information you need to know about pipelines.

Hello Neighbor

Please read and share with your family this information about the pipeline that runs through your area. These background facts and safety instructions will help you avoid potentially dangerous activity around the line and guide you to proper actions if you see or suspect a problem.

Who is Koch Pipeline Company, L.P.

Koch Pipeline Company, L.P. is a pipeline operating company with lines that gather and transport natural gas liquids in Oklahoma, Texas, New Mexico and Kansas. Koch provides transportation services for many different companies that need to move products throughout the central United States. Koch owns and operates more than 8,000 miles of gas liquids pipelines.

Koch operates a pipeline control center in Wichita, Kansas, 24 hours a day, seven days a week in which technicians keep track of flow and pressures in our lines. In addition to the pipeline control center, Koch has operations & maintenance people located at various points along the pipeline and conducts frequent aerial patrols of the pipelines.

Koch transports natural gas liquids consisting of a mixture of ethane, propane, butane, natural gasoline, ethane-propane mix and propylene. These products are also commonly known as NGL – Natural Gas Liquids, LPG – Liquefied Petroleum Gas, or HVL – Highly Volatile Liquid.

Pipelines Make Good Neighbors

Pipelines carry gas and liquids used in the manufacture of many vital consumer products such as paints, plastics and clothing.

Pipelines have the best safety record in the transportation industry and we need your help, as our neighbor along the pipeline, to keep it that way.

It is unlikely that we would experience a leak, but should a leak occur, the information contained in this brochure will help you:

- Know how to identify our pipelines by our signs and markers
- Know how to recognize a leak
- Know what to do if you notice a leak
- Know how to immediately report a leak

By working together, we can keep our pipeline operating safely and quietly without any disturbances or inconvenience to our neighbors. If you have questions about this safety information or our operations in your area, please write us at the following address:

Koch Pipeline Company, L.P.
Safety Department
P.O. Box 29
Medford, Oklahoma 73759

Or, you can call us in Medford at (405) 395-2377 during normal business hours.

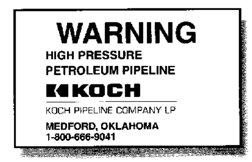
Why Transport Products by Pipeline

Pipelines are by far the safest means of transporting liquid products. Statistics from the federal government show pipelines have a safety factor unequal to any other mode of transportation. If it were not for underground pipelines, all petroleum products would need to be transported by truck, rail car or barge at a greater risk to the public and the environment.

Pipelines are constructed of steel pipe and are protected to prevent corrosion (rust). Assuming nothing strikes the pipeline, a properly designed, constructed, operated and maintained pipeline can last indefinitely.

How To Identify Our Pipelines

Since most pipelines are underground, pipeline markers are used to show their approximate location. We have installed the colorful pipeline markers shown below at public roads, railroad and river crossings, and various other places along the pipeline's path.



Working Around Our Pipeline

The number one cause of pipeline leaks is third-party damage (excavation, posthole digging, etc.). If you plan to dig or construct anywhere near our pipeline, call our pipeline control center at 1-800-666-9041 or 1-800-666-0125. We will then identify the location of our pipeline for you by sending a pipeline representative to locate and mark our pipeline prior to any work performed in the area.

It is important that you phone us immediately if you strike our pipeline. Even seemingly minor damage, such as a dent, chipped or scraped pipeline coating, is serious because it could result in a future leak or incident if not

Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane Carmichael, Mississippi November 1, 2007

Accident Report
NTSB/PAR-09/01
PB2009-916501

National Transportation Safety Board

NTSB/PAR-09/01
PB2009-916501
Notation 7979A
Adopted October 14, 2009

Pipeline Accident Report

Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane Carmichael, Mississippi November 1, 2007

National Transportation Safety Board

490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

National Transportation Safety Board. 2009. ***Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane, Carmichael, Mississippi, November 1, 2007.*** **Pipeline Accident Report NTSB/PAR-09/01. Washington, DC.**

Abstract: On November 1, 2007, at 10:35:02 a.m. central daylight time, a 12-inch-diameter pipeline segment operated by Dixie Pipeline Company was transporting liquid propane at about 1,405 pounds per square inch, gauge, when it ruptured in a rural area near Carmichael, Mississippi. The resulting gas cloud expanded over nearby homes and ignited, creating a large fireball that was heard and seen from miles away. About 10,253 barrels (430,626 gallons) of propane were released. As a result of the ensuing fire, two people were killed and seven people sustained minor injuries. Four houses were destroyed, and several others were damaged. About 71.4 acres of grassland and woodland were burned. Dixie Pipeline Company reported that property damage resulting from the accident, including the loss of product, was $3,377,247.

The safety issues identified in this accident are the failure mechanisms and safety of low-frequency electric resistance welded pipe, the adequacy of Dixie Pipeline Company's public education program, the adequacy of federal pipeline safety regulations and oversight exercised by the Pipeline and Hazardous Materials Safety Administration of pipeline operators' public education and emergency responder outreach programs, and emergency communications in Clarke County, Mississippi.

As a result of the investigation of this accident, the National Transportation Safety Board makes recommendations to the Pipeline and Hazardous Materials Safety Administration, the Dixie Pipeline Company, the American Petroleum Institute, and the Clarke County Board of Supervisors.

The National Transportation Safety Board is an independent federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable causes of the accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The NTSB makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Recent publications are available in their entirety on the Internet at <http://www.ntsb.gov>. Other information about available publications also may be obtained from the website or by contacting:

National Transportation Safety Board
Records Management Division, CIO-40
490 L'Enfant Plaza, SW
Washington, DC 20594
(800) 877-6799 or (202) 314-6551

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National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161
(800) 553-6847 or (703) 605-6000

The Independent Safety Board Act, as codified at 49 U.S.C. Section 1154(b), precludes the admission into evidence or use of NTSB reports related to an incident or accident in a civil action for damages resulting from a matter mentioned in the report.

Contents

Figures

Acronyms and Abbreviations

API	American Petroleum Institute
API RP 1162	API Recommended Practice 1162
CFR	*Code of Federal Regulations*
CVFD	Carmichael Volunteer Fire Department
Dixie	Dixie Pipeline Company
DOT	U.S. Department of Transportation
Enterprise	Enterprise Products Operating
ERW	Electric resistance welded
GE	General Electric
Hunt	Hunt Crude Oil Supply Company
Magpie	Magpie Systems Inc.
NTSB	National Transportation Safety Board
Paradigm	Paradigm Alliance, Inc.
PHMSA	Pipeline and Hazardous Materials Safety Administration
psi	pounds per square inch
psig	pounds per square inch, gauge
SCADA	Supervisory control and data acquisition
Stork	Stork Metallurgical Consultants

Executive Summary

On November 1, 2007, at 10:35:02 a.m. central daylight time, a 12-inch-diameter pipeline segment operated by Dixie Pipeline Company was transporting liquid propane at about 1,405 pounds per square inch, gauge, when it ruptured in a rural area near Carmichael, Mississippi. The resulting gas cloud expanded over nearby homes and ignited, creating a large fireball that was heard and seen from miles away. About 10,253 barrels (430,626 gallons) of propane were released. As a result of the ensuing fire, two people were killed and seven people sustained minor injuries. Four houses were destroyed, and several others were damaged. About 71.4 acres of grassland and woodland were burned. Dixie Pipeline Company reported that property damages resulting from the accident, including the loss of product, were $3,377,247.

The National Transportation Safety Board determines that the probable cause of the November 1, 2007, rupture of the liquid propane pipeline operated by Dixie Pipeline Company near Carmichael, Mississippi, was the failure of a weld that caused the pipe to fracture along the longitudinal seam weld, a portion of the upstream girth weld, and portions of the adjacent pipe joints.

The following safety issues were identified as a result of the investigation of this accident:

- The failure mechanisms and safety of low-frequency electric resistance welded pipe,
- The adequacy of Dixie Pipeline Company's public education program,
- The adequacy of federal pipeline safety regulations and oversight exercised by the Pipeline and Hazardous Materials Safety Administration of pipeline operators' public education and emergency responder outreach programs, and
- Emergency communications in Clarke County, Mississippi.

Safety recommendations to the Pipeline and Hazardous Materials Safety Administration, the Dixie Pipeline Company, the American Petroleum Institute, and the Clarke County Board of Supervisors are included in the report.

Factual Information

Accident Synopsis

On November 1, 2007, at 10:35:02 a.m.[1] central daylight time,[2] a 12-inch-diameter pipeline segment operated by Dixie Pipeline Company (Dixie) was transporting liquid propane at about 1,405 pounds per square inch, gauge (psig), when it ruptured in a rural area near Carmichael, Mississippi. The resulting gas cloud expanded over nearby homes and ignited, creating a large fireball that was heard and seen from miles away. About 10,253 barrels (430,626 gallons) of propane were released. As a result of the ensuing fire, two people were killed and seven people sustained minor injuries. Four houses were destroyed, and several others were damaged. About 71.4 acres of grassland and woodland were burned. Dixie reported that property damages resulting from the accident, including the loss of product, were $3,377,247.

Accident Narrative

At 10:35:02 a.m. central daylight time, Dixie's 12-inch-diameter propane pipeline segment ruptured about 2,650 feet downstream of Carmichael Pump Station near Carmichael, Mississippi. The map in figure 1 shows the route of the entire pipeline—from Mont Belvieu, Texas, to Apex, North Carolina—which comprises various sizes of pipe from several pipe manufacturers. The 12-inch-diameter pipeline segment starts on the west side of the Mississippi River near Erwinville, Louisiana, and continues eastward about 395 miles to Opelika, Alabama. Yellow Creek Pump Station is 19.28 miles upstream of Carmichael Station. The first pump station downstream of Carmichael is Butler Station, which is 18.3 miles east of Carmichael.

[1] The times associated with events indicated in hours:minutes:seconds are from either the Supervisory Control and Data Acquisition (SCADA) system or the 911 system.

[2] All times in this report are central daylight time except where otherwise noted.

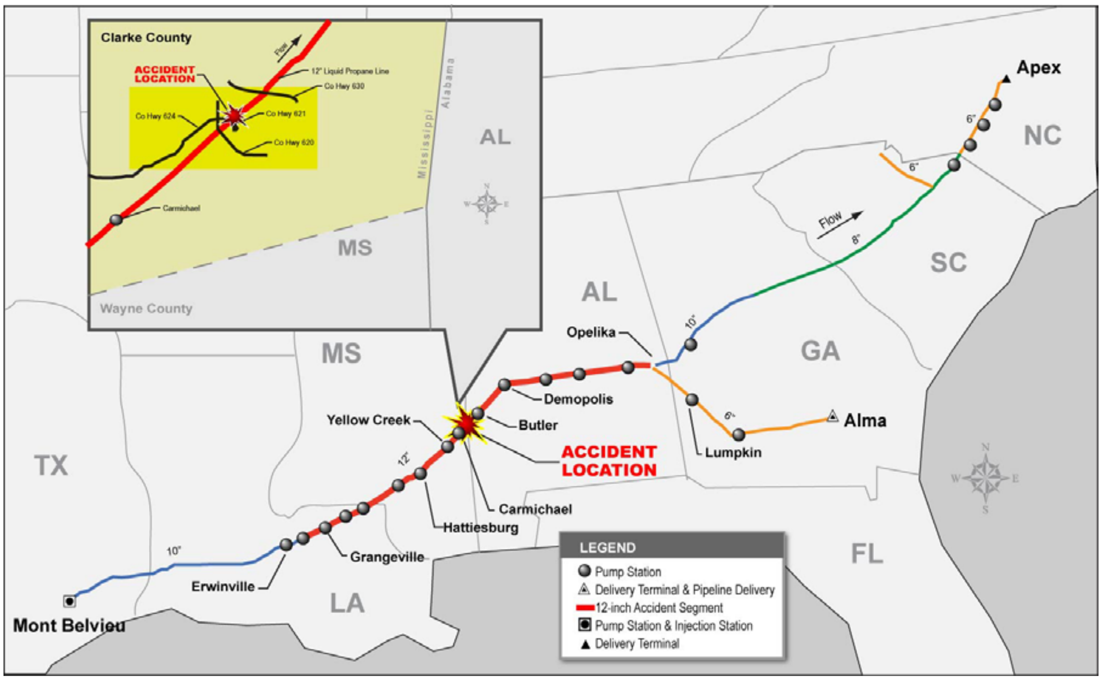

Figure 1. Map of Dixie pipeline.

The Dixie pipeline is owned by Enterprise Products Operating (Enterprise); the controller for the accident pipeline was located at Enterprise's liquid pipeline Supervisory Control and Data Acquisition (SCADA) Control Center in Houston, Texas. The first indication of a problem was when the SCADA control panel displayed sequential discharge pressure measurements that indicated a large change in pressure at Carmichael Pump Station. At 10:35:07 a.m., the display showed a discharge pressure of 1,079 psig; at 10:35:13 a.m., the discharge pressure was 154 psig, indicating a large, sudden drop in pipeline pressure. Additionally, the display showed that Carmichael Station's unit 2 pump had shut down because of low suction pressure. At 10:35:46 a.m., the SCADA display indicated that the rate-of-change in pressure at Butler Station, the next station downstream from Carmichael, was starting to decrease. Also, at 10:35:50 a.m., the SCADA display indicated that the rate-of-change in pressure at Yellow Creek Station, the first station upstream of Carmichael Station, was starting to come down.

When the pipeline ruptured at 10:35:02 a.m., liquid propane was released and instantaneously began to vaporize and form a low-lying propane gas cloud over the area. The propane gas did not ignite immediately; it ignited about 7 1/2 minutes later, at 10:42:30 a.m. Witnesses miles away reported seeing and hearing a large fireball and heavy black smoke over the area. The fire extended about 950 feet southwest and about 1,250 feet south of the rupture site. (See figure 2.) The fire fueled by the residual propane gas escaping from the pipeline continued to burn at the ruptured pipe joint[3] until the following day, when the fire at the pipe extinguished itself after flow control valves on both sides of the rupture were closed.

Figure 2. Aerial view of fire from pipeline rupture showing nearby destroyed houses.

At the time of the rupture, the flow of propane had increased from 5,952 barrels per hour to 7,354 barrels per hour. At 10:36:25 a.m., a little more than 1 minute after the SCADA display of the sudden pressure reduction, the controller decided that there was a leak in the Carmichael Station area, and he began shutting down the pipeline to reduce the amount of product released. At 10:37:12 a.m., the controller started the unit 1 pump at Butler Station (downstream of the rupture) to pull product away from the rupture area. About 10:38 a.m., the controller started calling field personnel from Hattiesburg and Demopolis Pump Stations to respond to the release.

About 10:41 a.m., a person in a house in the 8500 block of County Road 630 called the toll-free emergency number for Dixie to report an explosion and smoke near her house. Dixie's SCADA controller on duty recognized this report as indicating a product release from a pipeline in the Carmichael area.

At 10:46 a.m., the Dixie pipeline controller in Houston received a telephone call in which the caller described four explosions, fire 200 feet in the air, and two columns of white and black smoke. The caller said these were in "the area where a crude oil pipeline owned by Hunt [Crude]

[3] A joint is a single length of pipe; the accident joint was about 52 feet long.

Oil [Supply Company] (Hunt) crosses the Dixie pipeline." The controller then directed a contractor in the Carmichael area to go to the site. At 10:48 a.m., a Hunt employee told the controller that the Hunt pipeline had been shut down and blocked off in the area of the release.

At 10:49:51 a.m., the Dixie pipeline controller telephoned Clarke County Central Dispatch to provide notification of a pipeline leak in the Carmichael Station area. The controller was told that Clarke County officials were already aware of an event near that location and had dispatched trucks to the scene from several fire departments. The controller continued to isolate the rupture site by issuing commands through SCADA to close the remotely controlled block valves at the Butler and Carmichael Stations starting at 10:52:37 a.m. By 12:36 p.m., field technicians had closed the nearest manually controlled block valves, thereby completing the shutdown and isolation of the leaking section of the pipeline.

Weather conditions at the National Weather Service station in Meridian, Mississippi, around the time of the accident were reported as a clear sky (that is, no precipitation), a surface visibility of 10 miles, wind from the north-northeast about 7 mph with no significant wind gusts, and a ground level atmospheric temperature of 69° F. Sunrise was at 6:37 a.m. and sunset at 4:49 p.m.

Emergency Response

The first call received at Clarke County Central Dispatch, which operates the county's 911 emergency call center, came in at 10:39:56 a.m. Two operators were on duty at the time. The call was from a person calling from a house at 4195 County Road 621. The caller reported that a gas explosion had occurred somewhere around the area and that smoke and gas surrounded the house. When asked if there was fire, the caller said that she did not see any fire but she saw white gas and smelled gas. The 911 operator told the caller that an emergency responder would be sent. The operator did not tell the caller to get out of the house and run away from the smoke. The call lasted 1 minute 20 seconds. The house at this address was subsequently identified as the house in which one of the two fatalities was discovered. At 10:40:13 a.m., during the first 911 call, the second 911 operator received a telephone call from a caller in a house in the 4300 block of County Road 621, about 600 feet south of the house where the first 911 call had originated. The caller reported that an explosion had occurred and he could see smoke when he walked out to the road. The call lasted 1 minute 33 seconds and concluded at 10:41:46 a.m. Clarke County Central Dispatch subsequently received numerous additional calls reporting the incident.

About 10:42 a.m., after receiving the first two 911 calls, Clarke County Central Dispatch placed a radio dispatch page to the Carmichael Volunteer Fire Department (CVFD) to respond to the house at 4195 County Road 621. The Clarke County Central Dispatch operating personnel did not know at that time that their fire department radio signal repeater[4] did not transmit the page to the CVFD. Later, it was determined that the repeater system did not send a signal because it had been disabled during routine cleaning in the Clarke County Central Dispatch facility when a floor mop had accidentally dislodged the connector fittings of several communication cables about 90 minutes before the accident.

The assistant chief of the CVFD was at work about 1/4 mile from the CVFD fire station when, about 10:43 a.m., he heard the sound of a distant explosion. According to the assistant chief, the sound was followed shortly thereafter by the sound of a second explosion and perhaps the sound of a third explosion. About 10 to 15 seconds later, he saw a large plume and a cloud of heavy black smoke rising above the trees. The assistant chief immediately began mobilizing CVFD fire apparatus and personnel to the scene.

At 10:42:50 a.m., a caller at a construction site on a road north of Waynesboro, used a cellular telephone to call Wayne County, Mississippi, 911. The caller reported that an explosion had occurred northeast of his location. In a postaccident interview, this caller indicated that he had placed the 911 call about 20 seconds after he heard the sound of what appeared to be an explosion that occurred in the distance and after he saw a large plume and a cloud of heavy black smoke rising above the trees and moving northeast from his location. Following another 911 call that was received about 17 seconds after the 10:42:50 phone call, Wayne County 911 sent a Wayne County deputy sheriff to verify the incident location, and then, under a mutual aid agreement with Clarke County, dispatched Wayne County fire and rescue units to the scene.

About 10:44 a.m., because Clarke County Central Dispatch had not received a response from the CVFD acknowledging the page that had been placed about 2 minutes earlier, Clarke County Central Dispatch sent a second page, this time to the Theadville Volunteer Fire Department to respond to 4195 County Road 621.[5] Clarke County Central Dispatch was still unaware at that time that the radio signal repeater was not functioning and the page to the Theadville fire department also had not been transmitted.

The Clarke County sheriff was at his residence about 20 miles from the accident site when about 10:44 a.m. he received a telephone call from Clarke County Central Dispatch asking whether there were any pipelines near County Roads 630 and 621, because a 911 call had just reported an explosion in that area. The sheriff responded that there was a pipeline in the Carmichael area. During postaccident interviews, the sheriff stated that he had been casually listening to his service radio just before this phone call, and there had not been any radio traffic

[4] A *radio signal repeater* is a combination of a radio receiver and a radio transmitter that receives a radio signal and retransmits it at a higher level or higher power to relay radio signals across a wider area.

[5] In accordance with Clarke County Central Dispatch operations protocol, a page is to be acknowledged by the department receiving the page. If no acknowledgement is received within about 2 minutes, the next closest fire department is paged and directed to respond. Clarke County Central Dispatch is to continue to page and dispatch a sequence of fire departments until an acknowledgement is received.

about an incident occurring in the Carmichael area. Clarke County Central Dispatch told the sheriff that two units (deputies) had been dispatched to that location and the CVFD had been paged to respond. The sheriff then told Clarke County Central Dispatch that he would monitor the radio closely for updates.

About 10:48 a.m., Clarke County Central Dispatch had not received a response from the Theadville Volunteer Fire Department acknowledging the page that had been placed about 4 minutes earlier. Clarke County Central Dispatch then repeated the page, this time to the Theadville, Quitman, and Carmichael Volunteer Fire Departments and the Desoto Fire Department.

About 10:55 a.m., the Clarke County Central Dispatch dispatcher had not received any responses acknowledging his pages to the four fire departments, and he began to suspect that the fire department radio signal repeater was not working and that none of the pages to the fire departments had been transmitted or received. Therefore, following the Clarke County Central Dispatch backup communication plan, the dispatcher switched to the Clarke County Sheriff's Department radio signal repeater, which was operating correctly.[6]

Concurrently, the Clarke County sheriff continued monitoring his service radio and did not hear any responses to the Clarke County Central Dispatch pages. The sheriff suspected that the fire department radio signal repeater had failed to transmit, but he was unable to contact Clarke County Central Dispatch because of the range limitations of his service radio. Accordingly, about 10:55 a..m., he contacted a deputy who was within transmission range and directed the deputy to notify Clarke County Central Dispatch that the radio signal repeater appeared not to be working and to use the Clarke County Sheriff's Department radio signal repeater to establish radio communications with the fire and rescue agencies. The sheriff then drove his personal vehicle to the site.

Accident Site

The pipeline rupture occurred in a cattle pasture in a relatively unpopulated area in Carmichael, Mississippi, which is an unincorporated section of Clarke County. The site was occupied by livestock at the time of the rupture. Clarke County has a population of 21,979 and an area of about 416 square miles. The accident site is about 12 miles southeast of Quitman, the Clarke County seat, about 3 miles north of the Wayne County line, and about 3 1/2 miles west of the Alabama-Mississippi state line. (See figure 1.)

About 200 residents live within a 1-mile radius of the accident site. The pipeline right-of-way in this area is oriented generally southwest-northeast. The ground rises slightly to the east and west of the rupture site, such that the rupture site is located at the base of a shallow valley. The pipeline is flanked on both sides by uncultivated fields and wooded lots. A 100-foot-wide

[6] The Clarke County Fire Department and the Clarke County Sheriff Department can transmit and receive on each other's radio signal frequency.

zone in the middle of the right-of-way had been cleared of trees and shrubs. Federally required warning markers were located along the right-of-way to alert the public to the pipeline's presence and location, the product being transported, the identification of the owner/operator, and emergency contact information.

The buried Dixie pipeline crosses several feet above an 8-inch-diameter hazardous liquid (crude oil) pipeline operated by Hunt. The two pipelines cross about 170 feet east of the northeastern end of the ruptured pipe joint. Hunt representatives told National Transportation Safety Board (NTSB) investigators that the Hunt pipeline was neither involved with nor affected by the rupture of Dixie's liquid propane pipeline.

The Dixie pipeline passes beneath County Road 621 about 900 feet southwest of the ruptured pipe joint. A cluster of six houses is located about 500 feet southwest of the rupture site, with an additional cluster of five houses located a short distance farther south. All 11 houses are on County Road 621.

On-Scene Response

Upon hearing the explosion and seeing the fireball and heavy black smoke, at 10:43 a.m., the CVFD assistant chief drove his personal vehicle in the direction of the smoke to see the situation firsthand. While en route, the assistant chief spoke to the CVFD chief using his personal cell phone, which had a short-range wireless communication feature similar to a walkie-talkie. The two conferred briefly about what had occurred, made a preliminarily identification of the location sufficient to direct CVFD resources to the general area of the accident, and agreed to mobilize the CVFD in response to the accident. The assistant chief then drove toward the CVFD fire station and used the short-range wireless feature on his cell phone to tell several other CVFD personnel what had occurred and to direct resources (two tanker trucks) to the scene.

A few moments later, the assistant chief and the CVFD captain arrived simultaneously at the CVFD fire station. They left immediately in a pumper truck and unsuccessfully attempted by radio to contact Clarke County Central Dispatch to report that they were en route to the scene. About 10:55 a.m. the assistant fire chief and the captain received word that the fire department radio signal repeater had apparently malfunctioned, and in accordance with the back-up communication plan, on-scene fire and rescue units were to switch to the Sheriff's Department radio frequency that used the sheriff's department radio signal repeater.

About 10:56 a.m., Clarke County Central Dispatch received a message from one of the on-scene deputy sheriffs reporting that the CVFD pumper truck with the CVFD assistant chief and the CVFD captain aboard, had just arrived at the scene at the intersection of County Roads 620 and 621, that the CVFD pumper truck was the first firefighting apparatus at the scene, that the CVFD had already begun to dispatch additional CVFD resources to the scene, and that the instruction to switch to the sheriff's department radio frequency had been received by the CVFD.

About 11:15 a.m., the Clarke County sheriff arrived at the intersection of County Roads 620 and 621, which later became the incident command post location. As prescribed by the Clarke County emergency management plan, the sheriff proceeded to implement an incident command process and assumed the role of incident commander. Later the incident command structure was elevated to a unified command system.

When the assistant fire chief and the fire captain approached the scene and saw a substantial fire and a cloud of heavy black smoke, they strongly suspected that the likely source of the fire was the propane pipeline buried underneath the cattle pasture. At the time, they did not know the extent of the fire and the number and locations of residents who might be endangered. Both recognized that the houses on County Road 621 would probably be in the greatest danger, so they drove the fire truck toward those houses.

The CVFD assistant chief stated during postaccident interviews that although he was aware that the pipeline transported highly flammable propane, the cause of what appeared to be a substantial rupture and product release and a fully involved fire, and the extent of damage to the rest of the pipeline, were not apparent to him at the time. Accordingly, the assistant chief drove the pumper truck on County Road 621 and stopped just short of the location where the Dixie pipeline passed beneath the road. The pumper truck was initially staged at that location, which became the initial forward command staging location. Additional fire and rescue units from other local fire departments were later staged at the parking lot of the Baptist church at the intersection of County Roads 630 and 632. Responding units from Alabama were staged on County Road 630 at the Alabama state line, and responding Wayne County resources were staged on County Road 620 at the Wayne County line.

When the assistant fire chief and the fire captain performed their initial assessment of the situation, they observed several civilians, whom they assumed to be residents of County Road 621 or 620, assisting others to leave the scene. Several sheriff's deputies arrived about that time, and they also began to assist civilians to leave the scene and to establish motor vehicle traffic control at the west end of County Road 621. A short distance to the east, CVFD personnel observed the burned remains of several houses and several other houses that were fully engulfed in flames and thus were deemed not salvageable. Fire had extensively charred the trees and grass in the area, but had essentially self-extinguished. Several small spot fires remained in the area, but they did not appear to present immediate danger to the evacuating civilians. In the open field, about 900 feet northeast of the initial staging location on County Road 621, there was a large, billowing, uncontrolled fire, which was believed by the CVFD to be within the linear boundary of the Dixie pipeline right-of-way. Flames extended into the air up to an estimated several hundred feet, and the heat generated could be felt as far away as 900 feet from the fire.

The two CVFD command officers were joined by the CVFD fire chief about 10:57 a.m. The CVFD chief assumed operational command of the responding fire and rescue resources. The CVFD fire chief and the assistant fire chief were aware that another pipeline traversed the open field in the vicinity of the fire; and, given the extent of heavy black smoke, it was unclear at first which pipeline was involved or whether both pipelines were involved.

The CVFD chief instructed the responding CVFD firefighters to search several residences in the immediate area and confirm that the occupants had been evacuated. Due to limited on-scene fire suppression resources at that time and the need to evacuate the area, fire suppression for the fully engulfed houses was deferred. The initial evacuation effort focused on houses and the one business located within about a 1/4-mile radius of the fire. A short time later, the evacuation radius was increased to about 1 mile. The CVFD conducted a brief inspection of what remained of the houses at 4195 and 4207 County Road 621, where the two fatalities were found (one at each location).

Upon completion of the initial civilian evacuation within a 1/4-mile radius, the CVFD began to put out the still burning fires in houses in the area. When those fires were out, about 12:00 p.m., the CVFD began to put out several small spot fires that remained in the wooded areas near the burned houses on County Road 621. These fires were suppressed by 2:00 p.m. Upon guidance from Dixie's *The Pipeline Group Emergency Response Manual* and the on-scene tactical response plan, the CVFD did not attempt to extinguish the ongoing fire at the ruptured pipeline. Accordingly, after the CVFD completed as much of the evacuation and fire suppression efforts that could be accomplished, it withdrew equipment and personnel to the intersection of County Roads 620 and 621 about 2:30 p.m.

Evacuations

After the propane gas cloud ignited, several residents of County Road 621 self-evacuated. The initial evacuation by the CVFD started about 11:00 a.m. on November 1 and was concluded about 7:20 p.m. for houses and one business that were not located in the immediate area surrounding the accident. For residences located on County Road 621 and the east side of County Road 620, the mandatory evacuation order was lifted at 10:00 a.m. on November 2.

Conclusion of On-Scene Response

On-scene activities continued until fire suppression and evacuation activities were fully concluded. A law enforcement presence at the site was deemed necessary only to provide security for the houses on County Road 621 that were damaged by the fire. The fire at the rupture site was officially declared extinguished about 5:05 p.m. on November 2, when the residual propane in the pipeline was exhausted. Incident command activities concluded on November 4 about 4:00 p.m. when on-scene activities ended.[7]

[7] Several of the incident command staff remained at the relocated site for several days thereafter to continue to monitor the site and provide logistical support while pipeline removal and replacement activities continued.

Injuries

Two fatalities resulted from the fire, and seven people went on their own (not transported by ambulance) to hospitals or a medical center for emergency medical treatment. All of the injuries were minor, and all of the individuals were treated and subsequently released. No injuries to emergency responders or pipeline employees were reported. (See table 1.)

Table 1. Injuries.

Injuries[a]	Number
Fatal	2
Serious	0
Minor	7

[a] Title 49 *Code of Federal Regulations* 830.2 defines a fatal injury as: any injury that results in death within 30 days of the accident. A serious injury is defined as: an injury which requires hospitalization for more than 48 hours, commencing within 7 days from the date the injury was received; results in a fracture of any bone (except simple fractures of the fingers, toes, or nose); causes severe hemorrhages, nerve, muscle, or tendon damage; involves any internal organ; or involves second or third degree burns, or any burns affecting more than 5 percent of the body surface.

Damages

The fire destroyed four houses and caused structural damage to several others. The burned area encompassed an area of about 71.4 acres of grassland and woodland. Dixie reported that property damage resulting from the accident, including the loss of product, was $3,377,247.

Postaccident Inspections

Pipeline

NTSB investigators and representatives of organizations participating in the investigation conducted a joint visual examination of the ruptured pipeline beginning about 11:00 a.m. on November 2. The ruptured segment of Dixie's 12-inch-diameter steel pipeline was visible in a narrow ditch. (See figure 3.) A longitudinal fracture of the pipe at about the 12 o'clock position was visible. At the rupture location the pipeline ran in a southwest to northeast direction, and the product flow was in the same direction. Flames about 3 to 5 feet high, resulting from residual fuel burnoff, were visible at the northeast end of the ruptured pipeline. Flames contained within the pipeline were also visible at the southwest end of the pipeline. A circumferential weld (girth weld) was visible at the upstream end of the fractured pipeline segment. The topsoil had covered a portion of the downstream end of the segment. In addition, some debris was present in the middle of the exposed pipeline segment.

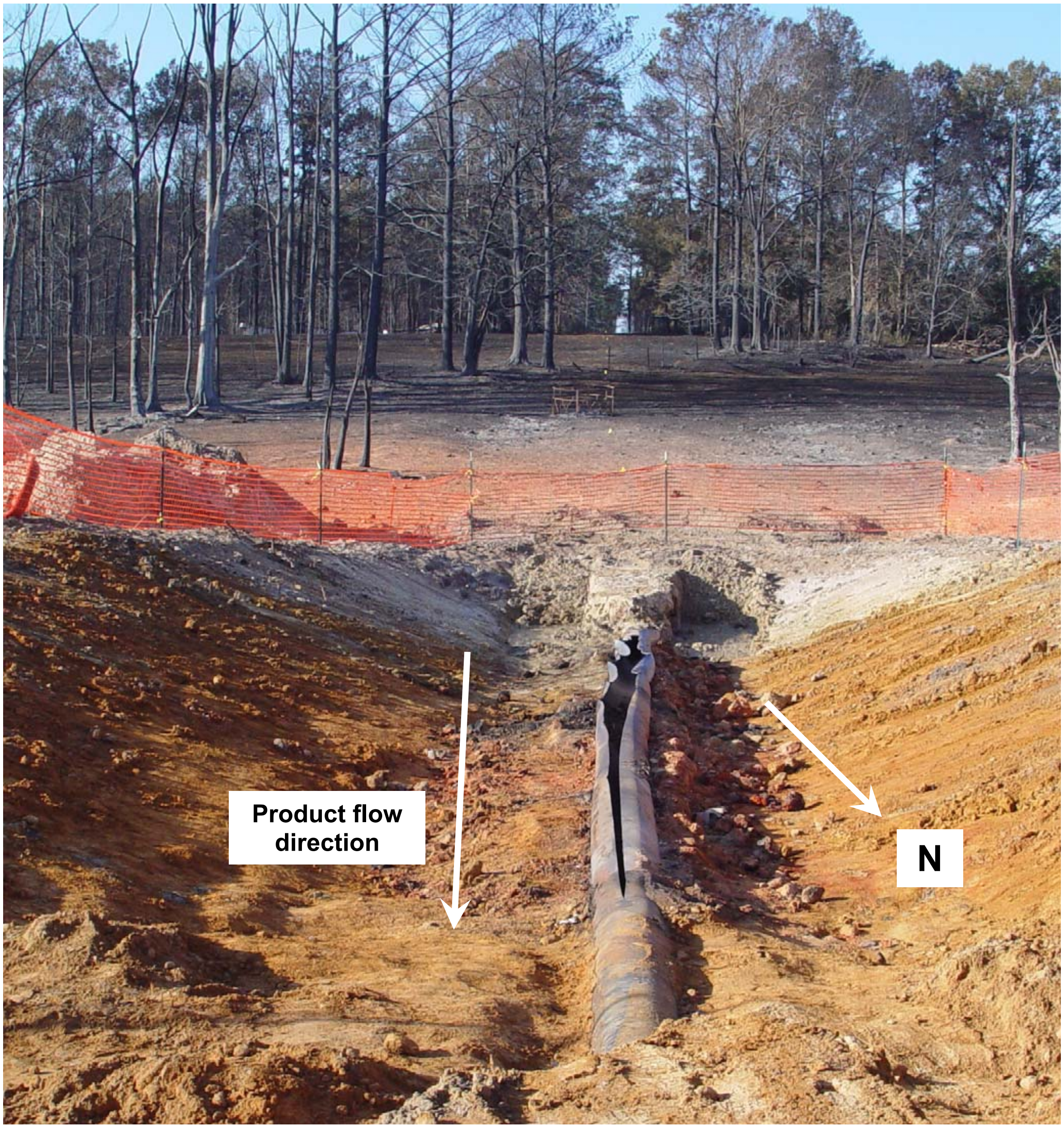

Figure 3. Ruptured pipe at Carmichael looking southwest. (Soil has been removed from around pipe to facilitate on-site examination.)

After it was safe for personnel to approach the pipeline, the ditch that contained the ruptured pipe was excavated by widening the ditch and reducing the steepness of its slope. During this excavation, the downstream end of the pipe joint was exposed. At the girth weld at the downstream end, the longitudinal fracture extended about 2 inches beyond the girth weld into the next pipe joint. The total fracture length and width at various locations along the fracture were measured. The widest separation, about 17 7/8 inches, was about 36 feet upstream from the downstream girth weld of the ruptured pipe joint. Before the ruptured pipe joint was cut out and removed from the ditch, a surveying contractor measured the depth profile of the pipeline and estimated that the pipe joint had about 3 1/2 feet of cover for about 5 feet on either side of the trench at the time of the accident.

The on-site examination revealed no significant internal or external corrosion or fractographic features suggesting a potential location of fracture origin. As a result, about 72 feet of pipe that included the entire fractured joint and several feet of the pipe joints on both sides of the fractured joint were shipped to the NTSB Materials Laboratory for further evaluation. To facilitate shipment, the 72-foot-long section was divided into four smaller segments: two about 20 feet long and two about 16 feet long.

Surrounding Area

The grassland near the trench was burned, and the trees over a wide area displayed indications of fire damage. The Mississippi Forestry Commission estimated the area of fire-damaged woodlands and grasslands to be about 71.4 acres. About 40 head of cattle that were close to the accident site died as a direct result of the ignition of the propane gas cloud or were seriously injured and subsequently euthanized.

A cluster of six houses located on County Road 621 began about 512 feet southwest of the pipeline rupture site and extended west for about 500 feet. Two of the six houses were moderately damaged. The other four houses were fully consumed by fire. The two fatalities were found in and near, respectively, two of these houses.

A second cluster of five houses located on County Road 621 began about 600 feet further south of the first cluster of houses. Several of these houses also received fire and/or structural damage.

Pipeline Controller

The pipeline controller, who was operating the pipeline with the SCADA system at the time of the rupture, began his training in March 2006 and became a qualified controller in June 2006. The training completed by the controller was typical of that completed by other controller trainees at Dixie. The stages of training included learning the procedures, manuals, rules, and regulations governing the safe operation of the pipeline; on-the-job-training with a senior SCADA controller present; demonstration of competence in areas such as product flow, pressures, alarms, and valves; and simulator training.

Postaccident toxicology testing of the on-duty pipeline controller was performed and test results were negative for alcohol and illicit drugs.

Pipeline Information

The accident pipeline transported exclusively propane. Under the federal safety regulations for hazardous liquid pipelines codified in Title 49 *Code of Federal Regulations* (CFR) Part 195, propane is classified as a highly volatile liquid.[8] The ruptured pipe joint was not located in a high consequence area.[9]

Design and Construction

The 395-mile-long 12-inch-diameter pipeline was constructed from American Petroleum Institute (API) grade X52 steel pipe that had a 12.75-inch outside diameter, and a 0.25-inch nominal wall thickness. Specifications for the grade X52 steel stipulate a minimum yield strength of 52,000 pounds per square inch (psi). Lone Star Steel Company (now owned by United States Steel Corporation) manufactured the pipe for Dixie in 1961 using a low-frequency electric resistance welding (ERW) process followed by a full-body normalizing treatment at a temperature of about 1,650° F. Individual pieces of pipe were joined together at the construction site using the shielded metal arc welding process. To prevent corrosion, the pipeline was field coated with coal tar enamel and felt wrap.[10]

The original 1961 pipeline construction documents contain welding specifications and procedures that included test welds; acceptance standards for the girth welds, all of which were to be subjected to radiographic inspection before installation; the repair or removal of defects; and a qualification test for welders. Although radiographic inspection was specified for field weld quality control during construction of the pipeline, Dixie did not find any documentation to indicate which girth welds were subjected to radiographic inspection. Also, no construction x-rays were found by Dixie.

Operating History

Records for the 2005 and 2006 annual external corrosion control surveys were reviewed. The company that performed annual cathodic protection surveys for Dixie found the system in good operating condition.

[8] A highly volatile liquid is a hazardous liquid that will form a vapor cloud when released to the atmosphere and that has a vapor pressure exceeding 276 kPa (40 pounds per square inch [atmospheric pressure]) at 37.8° C (100° F).

[9] *High consequence area* as defined in 49 CFR 195.450 means (1) a *commercially navigable waterway,* which means a waterway where a substantial likelihood of commercial navigation exists; (2) a *high population area,* which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile; (3) an *other populated area,* which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; or (4) an *unusually sensitive area,* as defined in 49 CFR 195.6.

[10] *Coal tar enamel*, a pipeline coating, and *felt wrap*, a pipeline wrapping, often containing fiberglass, are external corrosion protection measures to isolate pipelines from environmental factors.

On November 1, 2007, the highest discharge pressure recorded at Carmichael Station was 1,417 psig, which was the pressure at the time of the rupture. The calculated pressure at the rupture site was about 1,405 psig at the time of the pipe failure. At the time of the accident, the calculated maximum operating pressure for the pipeline segment between Carmichael and Butler Stations was 1,448 psig.

The demand for propane is subject to seasonal variation, with the greatest demand in winter during heating season and the lowest during the summer months. During times of high demand, moving a greater volume of propane requires the pipeline to be operated at higher pressures. Pressure charts from Carmichael Station show that the most recent time period during which the pipeline at Carmichael had experienced operating pressures at or above 1,405 psig was from November 6, 2006, through February 23, 2007. On February 23, 2007, the last day the pressure was higher than 1,405 psig before the accident, the discharge pressure ranged between 562 and 1,435 psig; it was between 1,405 and 1,435 psig for about 5 hours 18 minutes.

Investigators reviewed aerial patrol[11] reports and pipeline contact reports since 2005, and they indicate no excavation activity in the area of the rupture. Dixie's *Report of Visual Inspection and Repair* forms also show that no work occurred at the rupture location.

Previous In-service Pipeline Failures

Before the accident, there had been no known leaks in the rupture area. However, for the entire 395-mile-long 12-inch-diameter pipeline, eight in-service releases had been reported to the U.S. Department of Transportation (DOT) before the Carmichael rupture. Four of the releases involved pump station piping. Of the remaining four releases, two were the result of third-party damage in Alabama, and two were the result of river floods in Louisiana. A non-reportable leak[12] caused by a 2-inch-long crack in a longitudinal seam weld occurred on September 2, 1984, in Alabama while the pipeline was operating at 1,440 psig. No in-service pipeline ruptures in girth welds have been reported for the entire pipeline.

[11] *Aerial patrol* refers to routine visual inspection of a pipeline from the air.

[12] Title 49 CFR 195.50 requires a leak of 5 gallons or more to be reported.

Preaccident Hydrostatic Pressure Tests

In October and November 1961, the entire 395-mile-long pipeline segment was hydrostatically pressure tested[13] before it was placed in service. The test resulted in 13 pipe failures. Ten of the failures were characterized as seam splits or ruptures in the longitudinal ERW weld seams, and the remaining three included a pinhole leak in the seam weld, an undefined leak in the seam weld, and a leak from pipe laminations. The pipeline segment containing the accident pipe joint was successfully tested to 1,600 psig for a minimum of 4 hours on October 13, 1961.

Since the pipeline was installed, hydrostatic pressure tests that resulted in 60 longitudinal seam failures were conducted on segments of the 12-inch pipeline in 1983, 1984, 2001, 2002, 2004, 2006, and 2007 (May). (See table 2.) Dixie did not find any documentation that provided the reasons for the 1983 and 1984 hydrostatic pressure testing; however it was generally thought that these tests were conducted for maximum operating pressure validation as a result of new rules and guidance under 49 CFR Part 195. The hydrostatic pressure tests conducted from 2001 through May 2007 on the 12-inch pipeline served as baseline assessments or reassessments as required by the integrity management program. The pressure at which seams failed during these tests ranged from 1,670 to 2,006 psig.

Table 2. Dixie 12-inch Propane Pipeline's Preaccident Hydrostatic Pressure Retest Failure History.

Test Year	Segment	Failure Pressure Range (psi)	Failure Location
1983	Demopolis–Opelika	1,702–1,980	12 seam splits
1984	Hattiesburg–Carmichael	1,698–1,832	6 seam splits 1 weeping seam
	Carmichael–Demopolis	1,802–1,949	8 seam splits
2001	Mississippi River Trap–Grangeville	1,920	1 seam split
2002	Amite River–Grangeville–Hattiesburg	1,670–1,926	16 seam splits 1 seam seep leak
2004	Demopolis–Opelika (2nd retest)	1,900–2,006	8 seam splits
2006	Mississippi River Trap–Grangeville (2nd retest)	No Failures	None
2007	Amite River–Grangeville–Hattiesburg (2nd retest)	1,895–1,960	7 seam splits

[13] In a *hydrostatic pressure test*, a pipe segment is filled with water at a specific pressure to test the strength and leak-resistance of the pipe.

In May 1984, Dixie conducted a hydrostatic pressure test on the pipeline segment between the Carmichael and Demopolis Stations, which included the accident pipe joint. During the test, eight seam splits occurred at pressures ranging from 1,802 to 1,949 psig. (See table 2.) The 1984 test was the only pressure test of the accident joint since it was installed in 1961.

Additionally, the 1984 hydrostatic test failures between Hattiesburg and Carmichael Stations included 6 seam splits and a seeping leak at a seam occurring between 1,698 and 1,832 psig.

Laboratory Examination of Previous Hydrostatic Pressure Test Failures. On February 17, 2006, Kiefner and Associates, an engineering contractor for Dixie, completed an analysis of the eight seam failures that occurred during the 2004 hydrostatic pressure test of the 12-inch-diameter low-frequency ERW pipe between Demopolis, Alabama, and Opelika.[14] All of the seam failures were determined to be manufacturing defects including stitching,[15] low ductility of the weld bond line, hook cracks,[16] and cold welds.[17] Seven of the eight failures had no obvious point of origin, and none showed any evidence of pressure-cycle-induced fatigue crack growth. The failure pressures on the 12-inch-diameter pipe were between 1,825 and 1,966 psig. Additionally, all eight failures occurred at stress levels exceeding 89.5 percent of the specified minimum yield stress of 2,039 psi.

On September 17, 2007, Stork Metallurgical Consultants (Stork), another Dixie contractor, prepared an analysis of the May 2007 hydrostatic pressure test from the Louisiana-Mississippi state line to Hattiesburg Station that included seven seam ruptures in the pipe. (See table 2.) The pipe failed at pressures between 1,895 psig and 1,960 psig. The contractor found no definitive features on the fracture surface to confirm the likely fracture origins. Three ruptures were attributed to hook cracks, three showed stitching, and one was at a weak and brittle weld that appeared to be a cold weld. Stitching was also evident in two of the ruptures with hook cracks.

In-Line Inspection Information

In May 1998, Tuboscope Vetco Pipeline Services inspected the pipeline segment from Hattiesburg, Mississippi, to Demopolis, Alabama, with a standard-resolution axial magnetic flux

[14] *Final Report on Investigation of Hydrostatic Test Breaks that Occurred during the 2004 Hydrostatic Test of the Demopolis-to-Milner Segment of the Dixie Pipeline*, Kiefner and Associates, 2004.

[15] *Stitching* is a variation in the properties of a weld from repetitive variation in welding heat. The variation creates a regular pattern of light and dark areas visible only when the weld is broken along the weld line. Stitching is associated with low-frequency ERW seams; the exposed fracture face exhibits faint repeated patterns that extend transversely through the wall thickness. (Information from *API Standard 5T*, 10th Edition, September 2003.)

[16] A *hook crack* is a metal separation resulting from imperfections at the edge of a plate that are parallel to the surface and that turn to the inside diameter or outside diameter pipe surface when the edges are upset during welding. (Information from *API Standard 5T*.)

[17] A *cold weld* is a metallurgically inexact term generally indicating a lack of adequate bonding strength of the abutting edges due to insufficient heat or pressure. A cold weld may or may not have a separation in the weld line. (Information from *API Standard 5T*.)

leakage metal loss tool for evidence of metal loss caused by internal corrosion. The test did not find any anomalies related to metal loss in the pipe joint that ruptured in this accident.

Before Enterprise Products LLC took over, Conoco Phillips was responsible for management of Dixie until 2005. On March 28, 2002, the managing partner of Dixie—Phillips Pipe Line Company—developed the initial integrity management program for Dixie. The initial baseline assessment completed under the integrity management program determined that a special ERW seam integrity assessment was needed for the Hattiesburg-to-Demopolis pipeline segment. In 2005, Dixie conducted the special assessment using a transverse magnetic flux leakage in-line inspection.

Dixie conducted the special ERW seam integrity assessment in 2005 using the General Electric (GE) UltraScan crack detection tool, which is an in-line inspection tool. This crack detection tool has the capability to detect defects in the pipe in the longitudinal direction, including lack of fusion, undercuts, weld cracks, and hook cracks in the longitudinal seam welds of ERW pipe. The smallest anomaly detection limits for the tool are 0.039 inch (1 mm) for depth and 0.984 inch (25 mm) for length, with an 85-percent probability of detection. This tool is not designed to detect defects in the girth welds.

The in-line inspection with the GE crack detection tool was conducted over the entire Hattiesburg-to-Demopolis segment in two separate runs from June 29 to July 1, 2005, and from August 2 to August 4, 2005. Two features were identified in the pipe joint that ruptured at Carmichael.[18] The first was located 51 feet 5.2 inches downstream from the upstream girth weld. The feature was described as a 4.6-inch-long notch-like feature adjoining the seam weld whose depth was less than 12.5 percent of the wall thickness of the pipe.[19] The second feature was located 51 feet 10.2 inches downstream from the upstream girth weld and was described as a geometry feature (that is, a deformation or a dent anomaly) 2.8 inches long and terminating 1.36 inches from the center of the downstream girth weld. Both features were reported in the pipe base metal close to the longitudinal weld seam. After the accident in Carmichael, GE reevaluated both features as adjoining the longitudinal seam weld.

In March 2006, Magpie Systems Inc. (Magpie) was hired by Dixie to inspect the Hattiesburg-to-Demopolis pipeline segment using a geometry tool to determine geometric anomalies (for example, dents and deformations) in the pipe, followed by a high-resolution axial magnetic flux leakage metal loss tool. A high-resolution magnetic flux tool like the one used by Magpie typically can detect metal loss in or near a girth weld at an 80 percent confidence level if the depth of the metal loss is 10 percent or more of the wall thickness of the pipe. Magpie reported no geometric anomalies and detected no metal-loss-related anomalies in the joint that ruptured in Carmichael.

[18] For this inspection of the 120.7-mile pipeline segment, GE reported 14,357 features.

[19] Although 12.5 percent of the wall thickness (0.031 inch) is less than the 0.039-inch detection limit of the tool, it is large enough to be detected with a reasonable degree of confidence (less than 85 percent).

Laboratory Examination of Pipe Removed After 2005 In-line Inspection. Based on the data from the 2005 in-line inspection of the Hattiesburg-to-Demopolis pipeline segment with the GE crack detection tool, GE identified 21 pipe joints of the 12-inch-diameter pipe with reportable indications. Dixie subsequently removed the 21 pipe joints, including the girth welds on each end of each joint, as part of its pipeline integrity repair program.

Dixie contracted with Stork to conduct hydrostatic pressure burst tests on the extracted joints and girth welds.[20] The pressures at which the 21 joints ruptured during the burst tests ranged from 2,055 psig to 3,250 psig. All of the pipe joint ruptures occurred above the specified minimum yield strength and along the longitudinal weld seam, although one also propagated partially along a girth weld. None of the fracture surfaces of the ruptured longitudinal weld seams exhibited any indications of fatigue crack growth.

For a majority of the 21 pipeline joints, Stork identified a general region or area of the fracture surface as the origin of the fracture. For each of these joints, either there was no definable fracture characteristic indicating the origin or an apparent fracture origin was not identifiable. For example, the fracture surface of one pipe joint had a chevron pattern[21] that pointed to a general area of the fracture's origin, but no defect was observed to identify the exact location of the fracture initiation site. According to the Stork report, two joints had fracture surfaces with multiple flaws near the identified fracture origin region, and no hook cracks were found near the identified area of origin. The designated fracture origin sites for 11 of the pipe joints had hook cracks but did not have any definable fracture features, such as chevrons, pointing to an origin. Stork was unable to clearly identify an area of fracture origin for six pipe joints, even though hook cracks were present in the fracture surfaces of each joint. The fracture surface of only one pipe joint had a hook crack with chevrons found on each side pointing to the fracture initiation site.

Stork also correlated the location of the identified fracture origin for the pipe joints with indications reported from the 2005 in-line inspection by the GE crack detection tool. The report stated that for three of the pipe joints, the identified fracture origin coincided with an indication detected during the 2005 in-line inspection. The burst pressures for these three pipe joints were between 2,250 and 3,190 psig. Stork's report further stated that the in-line inspection had reported indications along the entire fracture surface for nine other pipe joints, and five other pipe joints had no reported indications from the in-line inspection along the entire fracture surface. For the remaining four pipe joints, Dixie reviewed the in-line inspection test data and confirmed that these four pipe joints also had no reported indications along their fracture surfaces from the in-line inspection.

[20] Stork submitted its draft report, *Testing and Examination of Pipe from Dixie Pipeline Company's 12-inch Hattiesburg, MS, to Demopolis, AL, Pipeline,* on March 30, 2007. The final report (No. 0270-07-17309), issued March 14, 2008, had no significant changes from the draft report.

[21] A *chevron pattern,* also called a *herringbone pattern,* occurs on an overstress fracture surface and contains features that look like nested V's. The V's point in the direction opposite the direction of fracture propagation.

Stork also performed fatigue tests on sections cut from two of the ruptured pipe joints from the burst tests in which the fracture did not extend along the entire length of the pipe joint, thereby leaving sufficient undamaged pipe to create test sections. The two sections used for the fatigue tests were taken from separate pipe joints that failed during the burst tests at 2,250 psig (section 1) and at 3,025 psig (section 2). Each section contained a single girth weld. The two fatigue tests were conducted with pressure cycling between 300 psig and 1,440 psig.

Section 1 ruptured along the longitudinal weld seam after 1,768 cycles. The rupture was 3 feet 8 inches long and was in a region where no indications had been reported during the 2005 in-line inspection. Stork reported that the appearance of the fracture surface indicated that the failure started at a large hook crack with some bright fracture marks present that indicated likely fatigue crack propagation. Oxide scale was found along the surface of the hook crack, and Stork believed that this indicated that the scale originated during manufacture of the pipe. Smaller hook cracks were also present on the fracture surface. The fracture surface of section 1 had two regions that contained lack-of-fusion indications; the lack-of-fusion indications were 18 inches long with a depth of 34.4 percent of the wall thickness, and 24 inches long with a depth of 38 percent of the wall thickness, respectively.

Section 2 had indications of three cracks along the longitudinal seam from the 2005 in-line inspection. The data from the in-line inspection indicated that the longest crack was about 54 inches long with a depth of 36.8 percent of the wall thickness. Despite this large indication, Stork reported that section 2 failed to rupture after 92,636 pressure cycles, at which point the test was terminated.

Tests and Research

Metallurgical Examination of Accident Pipe

The rupture extended over a longitudinal distance of about 52 feet 4.75 inches. A major portion of the fracture extended through the longitudinal ERW seam. The downstream end of the fracture crossed a girth weld and continued about 1 inch into the body of the adjoining pipe joint. (See figure 4.) On the upstream side of the ruptured pipe joint, the fracture followed the downstream edge of the circumferential girth weld for about 1.8 inches. At this point it ran longitudinally across the girth weld and then progressed another 1.2 inches along the upstream edge of the girth weld. The fracture then continued along a curved trajectory for about 12 inches into the base metal of the upstream pipe joint, leaving an open flap of pipe at the upstream girth weld. (See figure 5.)

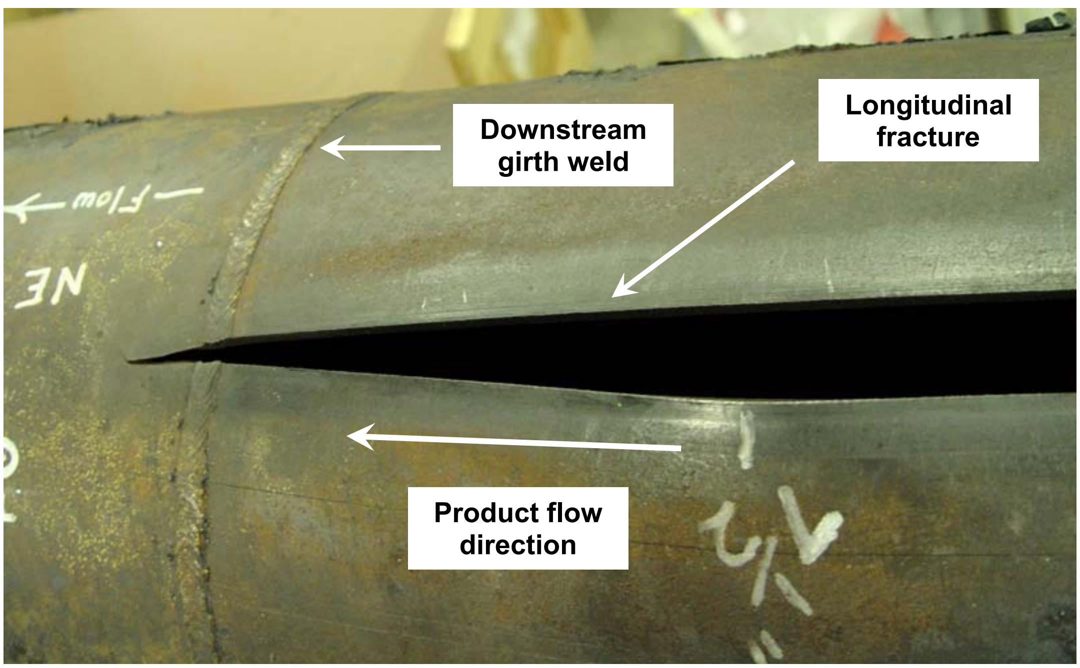

Figure 4. Downstream end of rupture.

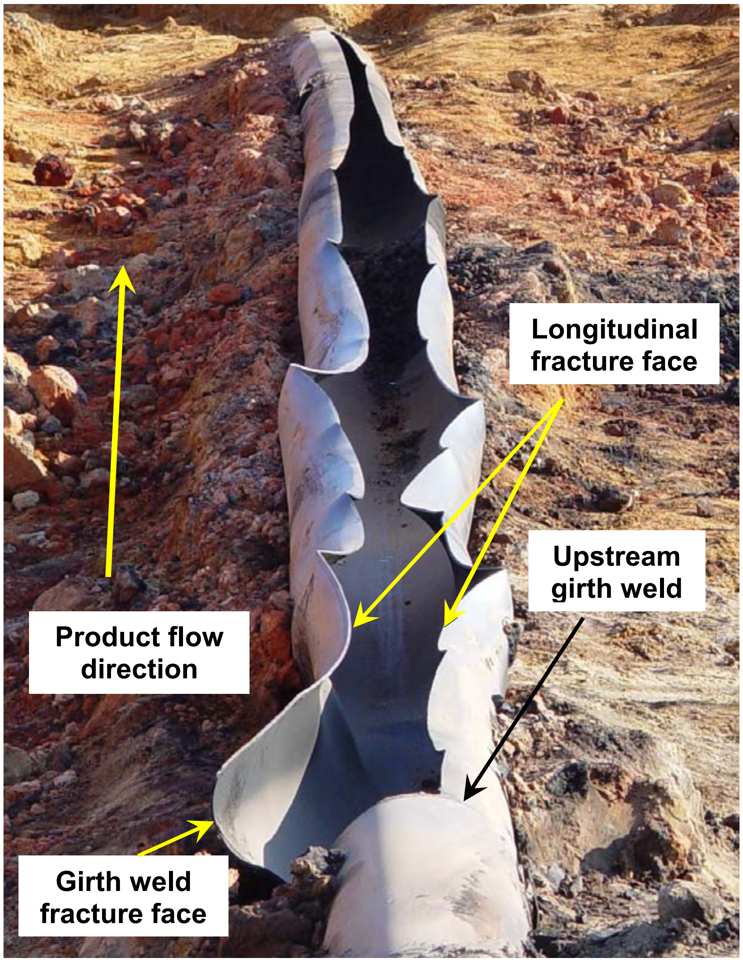

Figure 5. Ruptured pipe.

Fractographic examination[22] of the entire fracture along the longitudinal seam and the upstream girth weld did not reveal a definitive point of fracture origin in the accident pipe, although the fracture faces along both welds had various features of interest that were thoroughly examined during the investigation.

The fracture faces along the seam weld were covered with a layer of oxide that is consistent with exposure to fire. The fracture faces of the seam weld between the center and upstream end of the ruptured pipe joint had regions containing what appeared to be smooth island-like[23] features. In this area the fracture followed the upturned grains that resulted from the ERW process. The island-like features appeared as projections surrounded by a fracture with a rougher texture. In cross-section, the island-like features looked like the letter "J;" they followed

[22] A *fractographic examination* looks at the characteristics of a fracture surface to determine the direction of crack propagation and the fracture mechanisms.

[23] An island feature has a flat top with cliff-like sides above the flat fracture face. On the mating fracture face, the island-like feature extends below the flat fracture face.

a fracture path similar to a hook crack. Inspection of the longitudinal weld seam fracture faces also showed faint repeated patterns that extended transversely across the wall in many areas consistent with features called stitching in ERW seam welds.

Examination of the fracture faces of the longitudinal ERW seam fracture revealed chevron pattern fragments in areas located about 2.5 inches and 4 inches downstream from the upstream girth weld. (See figure 6.) The orientation of the chevron patterns indicated that the fracture was propagating in the upstream direction, along the longitudinal seam weld toward the girth weld. The longitudinal ERW seam fracture and the upstream girth weld fracture intersected at about a right angle. At the transition between the fractures was a branching crack, which also indicates fracture propagation in the upstream direction, toward the girth weld.

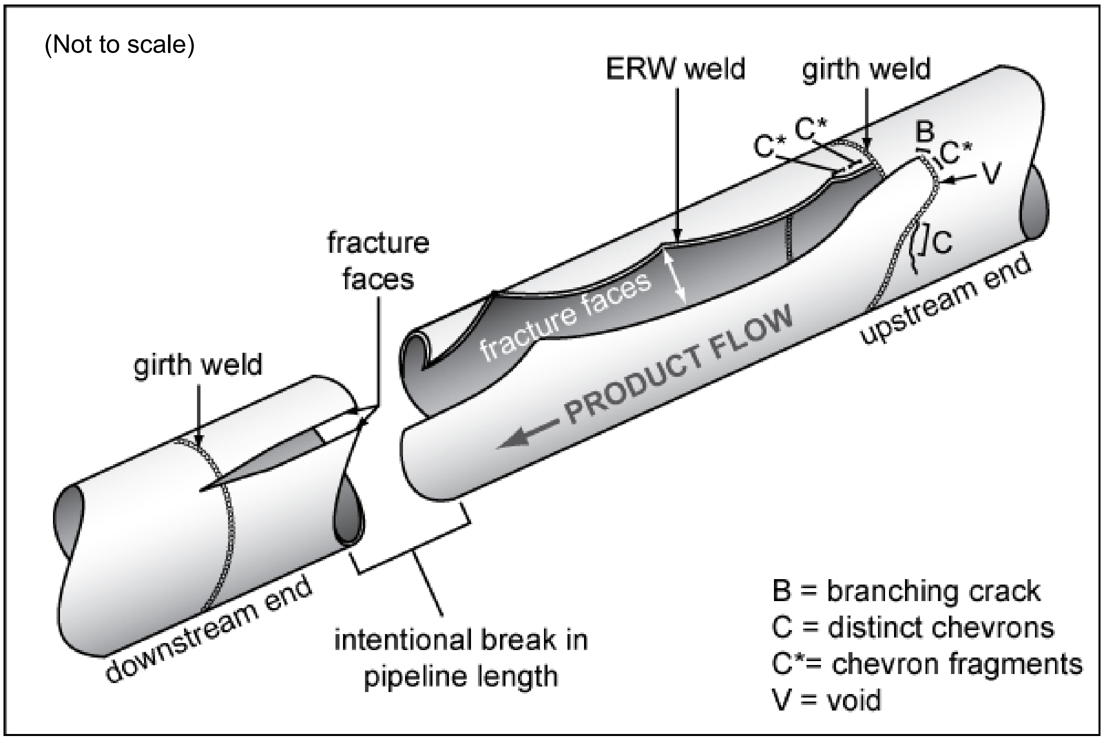

Figure 6. Schematic drawing of accident pipe identifying welds and showing fracture features of interest.

Fractographic examination of the girth weld showed no evidence of a preexisting crack (such as radial or crack arrest marks that originate from a specific location). Examination of the downstream face of the girth weld fracture revealed that a 1-inch fracture portion adjacent to the ERW seam fracture contained faint chevron fragments indicating that the fracture was propagating away from the seam. A void[24] found in the upstream girth weld was about 0.05 inches in cross section at the fracture surface. Welding standards in effect both at the time

[24] A *void* in a metal is any discontinuity manifested by a lack of material by pullout or other conditions. A *pore* in a metal is a cavity discontinuity formed by shrinkage or gas entrapment during solidification.

of pipeline construction and currently permit a pore that is the smaller of 25 percent of the pipe wall thickness or 0.0625 inch. Accordingly, the void in the accident pipe as measured along the plane of the fracture surface would have been within the permissible size.

The fractured wall (base metal) of the upstream pipe joint adjacent to the upstream girth weld had a distinct chevron pattern between 2.5 inches and 7.5 inches from the intersection of the longitudinal weld seam and the upstream girth weld. The orientation of the chevrons shows that in this region the crack propagated away from the ruptured welds.

Transverse Charpy V-notch[25] impact tests were also conducted on specimens from the pipe wall (base metal) and the ERW seam of the pipe joint downstream from the accident pipe joint to compare the toughness of the base metal in the pipe wall to that of the metal in the seam weld. The results of the Charpy tests showed that the average impact value for the ERW seam was about 44 percent lower than that of base metal.

Two nearly parallel scratch marks were observed on the outside surface of the accident pipe about 37 feet 10 inches upstream from the downstream girth weld and about 2.5 inches from the ERW seam. No significant inward denting of the pipe wall was observed near the scratch marks. There also was no evidence of general corrosion damage, V-groove corrosion[26] along the longitudinal weld seam, or indications of stress corrosion cracking.

Finite Element Analysis

Because of the unique shape of the ruptured pipe in the vicinity of the upstream girth weld fracture, a series of finite element analyses were performed to simulate the deformation of the pipe for various fracture initiation sites and fracture propagation sequences. The following specific deformation characteristics were used as benchmarks to evaluate the simulations:

- The 5-inch (45-degree) segment of the girth weld fracture adjoining the seam weld fracture had its radius reduced from about 6 inches to about 4 inches. The remainder of the circumferential fracture was flat rather than curved.

- The pipe flap surface in the region of the seam fracture sloped down toward the original pipe location for about 1 1/2 feet from the girth weld fracture in the downstream direction.

[25] *Charpy V-notch* impact testing is a method for determining the dynamic toughness of a material. In Charpy testing, a falling pendulum strikes a rectangular specimen that has a V-shaped notch in the middle and is supported at each end. The test measures the amount of impact energy (typically in foot-pounds) that is required to fracture a specimen. In a transverse Charpy V-notch specimen, the width of the notch is aligned parallel to the longitudinal direction of the pipe.

[26] *V-groove corrosion* is localized crevice corrosion that intersects the longitudinal weld seam and forms an external deep, narrow crack-like groove.

- On the side of the pipe that did not have a girth weld fracture, the pipe wall showed almost zero deformation for about 2 feet in the downstream direction from the upstream girth weld.

More than 60 simulations were performed covering a wide range of fracture initiation and propagation scenarios and pressure decay spatial distributions. The simulation results were first classified by their correlation to the three deformation benchmarks.

For fracture initiation in the seam weld, two series of simulations were performed. The first series assumed that a crack initiated far downstream from the upstream girth weld and propagated into the upstream region and then along the path of the circumferential fracture. The second series assumed that a crack initiated in the seam near the upstream girth weld and propagated in both directions. When the crack intersected the upstream girth weld, it transitioned to a circumferential fracture. No simulation for either of these scenarios predicted deformation characteristics consistent with the three benchmarks.

For fracture initiation in the girth weld, a series of simulations were performed that assumed that a crack initiated somewhere along the girth weld, grew along the circumferential fracture path, and initiated a fracture along the seam weld when the crack and the seam weld intersected. All of these simulations were in general agreement with the three deformation benchmarks.

Another simulation was performed in which the fracture was assumed to initiate at the location of the void found along the girth weld fracture surface. When the predicted stress state for this fracture sequence was evaluated, it was noted that after the fracture had grown from the void and approached the seam weld, a region of high stress—centered about 1 inch downstream of the upstream girth weld—developed along the seam weld. The simulation was therefore rerun with the assumption that in this high-stress region, another fracture initiated in the seam weld. This fracture sequence resulted in the best agreement with the deformation benchmarks in shape and correlated very well with the accident pipe in magnitude of deformation.

A very specific type of stress distribution is required to create the distinct chevron pattern that was observed on the circumferential fracture where it transitioned into the upstream pipe joint. Examination of the predicted stresses at this stage of the fracture sequence showed that most of the girth weld initiation sequences were consistent with chevron development. None of the seam weld initiation simulations predicted stress states consistent with chevron development in the upstream pipe joint.

ERW Pipeline

Early (pre-1970) ERW processes used low-frequency alternating current (30 to 60 hertz) to produce welding heat. Since 1970, ERW pipe has been produced using high-frequency alternating current (350 to 500 kilohertz).[27] Based on the 2007 hazardous liquid pipeline annual reports submitted by the pipeline operators to the Pipeline and Hazardous Materials Administration (PHMSA), there were 47,772 miles of low-frequency ERW pipe in liquid pipeline service, including 12,058 miles that transport highly volatile liquids. Additionally, there were about 68,021 miles of high-frequency ERW pipe in liquid pipeline service, including 33,337 miles that transport highly volatile liquids. Together, low- and high-frequency ERW pipe account for 115,793 miles, or about 68 percent of the 170,069 miles of hazardous liquid pipelines in service in 2007.

Performance of Low-Frequency ERW Pipe

During discussions with NTSB staff, PHMSA has stated that low-frequency ERW pipe manufactured before 1970 has presented more fracture problems than pipe constructed with any other method, and that the pre-1970s-era low-frequency ERW pipe has a much higher failure rate than newer ERW pipe. PHMSA attributed these performance problems to the quality of available steels and problems associated with the welding process. According to PHMSA, over the years, steel production processes evolved with better quality controls, which led to the production of steels with improved properties like higher yield strengths, increased toughness, and improved weldability. By the 1970s, the low-frequency ERW process was superseded by the high-frequency ERW process, resulting in the improvement of both seam weld quality and the production rate of ERW pipe. PHMSA representatives further noted that for ERW seam ruptures, identification of a definitive fracture origin is not possible about 50 percent of the time, and that usually only a region in which the fracture originated can be identified.

In August 1989, PHMSA[28] released Technical Report OPS 89-11, *Electric Resistance Weld Pipe Failures on Hazardous Liquid and Gas Transmission Pipelines*. According to the report, for in-service failures between 1977 and 1988 in low-frequency ERW hazardous liquid pipelines for which metallurgical reports were available, lack-of-fusion defects accounted for 23 percent of the failures, selective corrosion for 23 percent of the failures, and fatigue/corrosion fatigue for 31 percent of the failures. Hook cracks accounted for 15 percent of the failures.

PHMSA data from 2002 through 2007 indicate that 12 reported pipeline incidents (8 seam ruptures and 4 seam leaks) involved low-frequency ERW seams and 7 incidents (5 seam ruptures and 2 seam leaks) involved high-frequency ERW seams. PHMSA data state that during the same period, there were eight girth weld incidents; all involved leaks with no catastrophic ruptures. According to PHMSA, although ERW pipe seam failures are infrequent, they tend to be

[27] *Integrity of Vintage Pipelines*, Interstate Natural Gas Association of America, 2004.

[28] In a DOT reorganization, the Research and Special Programs Administration (RSPA) ceased operations on February 20, 2005. RSPA's Office of Pipeline Safety programs moved to the new Pipeline and Hazardous Materials Safety Administration. All references to predecessor agencies are designated as PHMSA in this report.

catastrophic, and about 98 percent of all ERW pipe failures involve the seam weld. Historically, girth weld failures that have been reported usually involved soil movement. Both on-scene and subsequent examinations found no evidence of soil pipe movement.

PHMSA also stated that because more pressure cycling results in greater fatigue, the high numbers of pressure cycles in older low-frequency ERW pipelines has to be considered when determining pipeline longevity. PHMSA is looking at ways for operators to minimize pressure cycling and characterized Dixie's pipeline pressure cycling as higher than average. However, because pipe performance varies depending on many factors, PHMSA felt that there is no uniform pressure cycling standard that can be applied to all pipeline operators when calculating flaw growth rates.

Federal Oversight and Studies

In 1988 and 1989, PHMSA issued two Alert Notices to all natural gas transmission operators and all hazardous liquid pipeline operators who had ERW pipe manufactured before 1970. In the first notice (ALN-88-01, issued January 28, 1988), PHMSA recommended that

> all operators reevaluate the potential for safety problems on their high-pressure pre-1970 ERW pipelines. All operators who have pre-1970 ERW pipe in their systems should carefully review their leak, failure, and test history as well as their corrosion control records to ensure that adequate cathodic protection has been and is now being provided. In areas where cathodic protection has been deficient for a period or periods of time, the operators should conduct an examination of the condition of the pipeline, including close interval pipe-to-soil corrosion surveys, selective visual examination of the pipe coating, and/or other appropriate means of physically determining the effects of the environment on the pipe seam. If an unsatisfactory condition is found, or if a pre-1970 ERW pipeline has not been hydrostatically tested to 125 percent of the maximum allowable pressure, operators should consider hydrostatic testing to assure the integrity of the pipeline.

In the second notice (ALN-89-01, issued March 8, 1989) PHMSA stated the following:

> [PHMSA] is planning to conduct research aimed at characterizing ERW defects and their growth rates for a variety of environmental conditions, in addition to the pipe having cathodic protection at less than standard pipe-to-soil potentials, coating disbondment, fatigue, and corrosion fatigue. If the research is successful, the resulting data could provide a basis for establishing criteria regarding when an ERW pipeline should be re-hydrotested.

The notice included the following recommendations:

> (1) Consider hydrostatic testing on all hazardous liquid pipelines that have not been hydrostatically tested to 125 percent of the maximum allowable pressure, or alternatively reduce the operating pressure 20 percent;
>
> (2) Avoid increasing a pipeline's long-standing operating pressure;
>
> (3) Assure the effectiveness of the cathodic protection system. Consider the use of close interval pipe-to-soil surveys after evaluating the pipe coating and corrosion/cathodic protection history; and
>
> (4) In the event of an ERW seam failure, conduct metallurgical examinations in order to determine the probable condition of the remainder of the ERW seams in the pipeline.

In May 1994, 49 CFR Part 195 was amended to include pressure testing requirements for older hazardous liquid and carbon dioxide pipelines. The amendment required that operators not transport a hazardous liquid in a steel interstate pipeline constructed before January 8, 1971, a steel interstate offshore gathering line constructed before August 1, 1977, or a steel intrastate pipeline constructed before October 21, 1985, unless the pipeline had been hydrostatically pressure tested for at least 4 continuous hours at a pressure equal to 125 percent or more of the maximum operating pressure (and, in the case of a pipeline that was not visually inspected for leakage during the test, for at least an additional 4 continuous hours at a pressure equal to 110 percent or more of the maximum operating pressure) or the pipeline operated at 80 percent or less of a qualified prior test or operating pressure.

After an accident involving a pre-1970 low-frequency ERW pipeline, PHMSA usually requires the operator to reduce operating pressure and conduct spike tests. The spike test is a variation of a hydrostatic pressure test in which a higher hydrostatic pressure (typically 100 percent of specified minimum yield strength or 1.39 times the maximum allowable pressure) is applied for a short duration of time, typically less than 30 minutes. The spike test is intended to eliminate flaws that may otherwise grow to failure at normal operating pressures. In comparison to a normal hydrostatic pressure test, the spike test limits the time the line is at the higher pressure to reduce the potential amount of crack growth. To ensure long-term integrity, PHMSA requires the operators to establish a conservative reinspection interval based on the potential defect size, pipe characteristics, and cyclic operating pressure data. The actual inspection interval typically is half of the calculated interval to take unknowns into account. PHMSA believes that it has been fairly successful in making certain that flaw growth rate projections are conservatively calculated in order to determine the appropriate pipeline inspection frequency.

PHMSA advised that during every integrity management and other audit, it checks to see that each pipeline operator that uses low-frequency ERW pipe, flash welded pipe, or lap welded pipe (a process from the 1930s) has a plan that describes how the operator intends to mitigate potential threats posed by the pipelines. The plan must be risk based and requires a baseline assessment and remedial measures. The results of pipeline tests are factored into the plan so that more aggressive assessments can be pursued when needed.

At PHMSA's June 24–25, 2009, public forum, topics for potential future research were discussed. One area for research for PHMSA's consideration was identification and understanding of failure mechanisms in ERW pipe.

Postaccident Actions

PHMSA

PHMSA issued a Corrective Action Order on November 2, 2007, requiring Dixie and its corporate owner, Enterprise, to immediately take the following corrective actions:

- Not operate the pipeline segment until authorized to do so by the director for PHMSA's southern region.

- Develop a return-to-service plan for the pipeline.

- Maintain a 20-percent pressure reduction along the entire 12-inch pipeline segment from Erwinville, Louisiana, to Opelika, Alabama.

- Hire a consultant to examine the in-line inspection surveys for the pipeline and tabulate the results.

- Submit a written plan and schedule to PHMSA for verifying the integrity of the entire pipeline segment. The plan must provide integrity testing that addresses all factors known or suspected in the failure, which may include, but not be limited to the following:

    - In-line inspection tool surveys and remedial action. The type of in-line inspection tools used shall be technologically appropriate for assessing the system based on the type of failure that occurred on November 1, 2007, with emphasis on identifying and evaluating the following: (1) anomalies associated with dents, grooves, and gouges; (2) metal loss due to corrosion; (3) the orientation of the longitudinal pipe seam; (4) pipe deformation; and, (5) longitudinal cracks, mill defects, and stress corrosion cracking.

- A detailed description of the inspection and repair criteria to be used in the field evaluation of the anomalies that are excavated. This includes a description of how many defects are to be graded and the schedule for repairs or replacement.

The corrective action order stated that Dixie or Enterprise could request approval from the director of PHMSA's southern region to increase the operating pressure above the interim maximum pressure when Dixie or Enterprise submitted an analysis demonstrating that the hazard had been abated or that a higher pressure was justified based on an analysis of all known defects, anomalies, and operating parameters of the pipeline segment.

On February 19, 2008, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order to Dixie for failing to follow the procedures in 49 CFR 195.402 pertaining to the operator's procedure manual for operations, maintenance, and emergencies. The alleged violation was exceeding the design pressure for a component covered under 49 CFR 195.406, *Maximum Operating Pressure*. The compliance order required Dixie to review the data presented in the manual and then follow its procedures to establish maximum operating pressures meeting all requirements of Part 195.406. In response to the PHMSA notice, Dixie made changes to the manual, and on May 1, 2008, Dixie gave PHMSA an additional response on exceeding the design pressure for a component.

Dixie Pipeline

After the pipeline rupture, Dixie conducted a hydrostatic pressure test of a 12-mile segment of the 12-inch-diameter pipeline downstream of Carmichael Station on November 8, 2007. The test was required by PHMSA before Dixie was allowed to return the pipeline to service at a reduced operating pressure. During the higher stress portion of the hydrostatic pressure test (spike test), the pipe was pressurized to 1,979 psig at the hydrostatic test pressure recorder location at milepost 427.29, near Bucatuma Creek. This pressure was about 1.38 times the maximum operating pressure of 1,435 psig for Carmichael Station. About 6.71 miles downstream of Carmichael Station, a 10-foot 6-inch-long longitudinal seam weld rupture occurred in a pipe joint located about milepost 432.19. The calculated pressure at the rupture location was 1,915 psig.

The 10-foot 6-inch rupture was examined by the NTSB Materials Laboratory. This fracture also was in and adjacent to the longitudinal ERW seam. The fracture faces contained island-like features similar to those found on the accident pipe and that are associated with hook cracks. No fractographic features indicative of the origin of the fracture were observed. Isolated regions of the "J" fracture were covered with a thin, uniform layer of iron oxide scale that extended from the exterior surface to as much as 20 percent of the wall thickness.

After this hydrostatic pressure test, GE reviewed its data from the 2005 in-line inspection and confirmed that its data showed a crack-like feature 3.5 inches long with a depth of 25 to 40 percent of wall thickness.[29] The crack-like feature adjoined the ruptured seam weld, about 13 feet 7 inches downstream of the upstream girth weld. Additionally, Magpie reviewed its data from the 2006 in-line inspection and found that its inspection neither recorded nor detected any features on the ruptured pipe joint.

In August 2008, Dixie radiographed 68 girth welds from the 12-inch pipeline that were removed for various reasons and found 4 welds that would not have met current welding standards. Of those four welds, three had inadequate penetration of the root-weld pass and the fourth had a hole in the girth weld, caused by excessive heat during the welding process, that was later repaired. The three welds with inadequate penetration also would not have met the standards in place in 1961 at the time the pipeline was constructed.

Postaccident Emergency Response Debriefing

On November 4, NTSB staff conducted a debriefing after the on-scene fire and rescue response to the Carmichael accident had been concluded. The debriefing was attended by principals of the primary responding fire and rescue agency (CVFD), the primary responding law enforcement agency (Clarke County Sheriff's Department), the jurisdictional emergency management agency (Clarke County Emergency Management), Dixie and Enterprise pipeline personnel, and PHMSA.

The Clarke County sheriff, the Clarke County communications director, and a member of the County Board of Supervisors discussed the difficulties with the fire and rescue radio communication system that required the switch to the sheriff's department radio system. They stated that the Clarke County government had completed a hardware modification to help prevent future accidental disconnections of the communication cables and that since the accident the County conducts biweekly tests of the radio dispatch system. The County indicated that it would also improve coordination with the technical maintenance contractor of its radio communications equipment and enhance countywide communications.

Pipeline Operator Public Education Programs

Regulations and Standards

Under the Pipeline Safety Improvement Act of 2002, each pipeline operator was required to develop and implement a written, continuing public education program (including both awareness for the general public and training for and outreach to emergency response agencies), and the DOT was to issue standards prescribing the elements of an effective public education program. In response to these mandates, PHMSA issued a final rule on May 19, 2005, that

[29] Although this crack-like feature was detected by GE, the flaw was considered subcritical, with an estimated life of about 10 years. Therefore, the pipe joint was not recommended for immediate replacement.

required each operator of a gas or hazardous liquid pipeline to develop and implement a written, continuing public education program that follows the guidance provided in API Recommended Practice 1162 (API RP 1162), *Public Awareness Programs for Pipeline Operators*, which was also incorporated by reference in 49 CFR Parts 192 (gas transmission lines) and 195 (hazardous liquid pipelines) under this final rule. Operators in business on June 20, 2005, were to have completed their written programs not later than June 20, 2006. An operator's program documentation and evaluation results also had to be available for periodic review by appropriate regulatory agencies.

Following the publication of the new regulations, PHMSA established a process to review by the June 2006 deadline all public education plans and to identify those plans that did not meet the critical elements and that required revision. In response to the mandate for operators and PHMSA to evaluate the effectiveness of the public education programs, PHMSA stipulated that operators were to assess the effectiveness of their programs within 4 years, that is, by June 20, 2010.

Before the passage of the Pipeline Safety Improvement Act, the pipeline industry had developed recommended practices for public education programs. In 2001, at the request of PHMSA, the API developed a new standard, designated API RP 1162, for public education programs by hazardous liquid pipeline operators. In the preamble to the May 2005 final rule, PHMSA stated that "with the support of PHMSA, [the] API expanded the scope of the recommended practice to include gas transmission and distribution operators." A multi-industry task force, including representatives of hazardous liquid, gas transmission, and distribution pipeline operators, developed the expanded version of API RP 1162, resulting in the publication of the first (still current) edition in December 2003.

API RP 1162 contains specific guidance about the development of public awareness programs directed to the general public and training and outreach programs directed to emergency response agencies. API RP 1162 also defines stakeholder audience, includes information to be disseminated to the stakeholder audience, discusses message delivery methods and enhancements to a baseline public awareness program, and describes program documentation, record-keeping, and evaluation. Regarding training and outreach programs for emergency response agencies, section 3.2 of API RP 1162 lists examples of emergency officials and stakeholders that pipeline operators should invite to participate in this program. The recommended list of stakeholders includes fire departments, police and sheriff's departments, members of local emergency planning committees, and county and state emergency management agencies. However, 911 emergency call and dispatch centers and emergency communications agencies are not identified in API RP 1162 as stakeholders.

Dixie's Public Education Program

Dixie used API RP 1162 as a model for the content and organization of its public education program. Dixie submitted its program to PHMSA for review on September 5, 2006. On August 31, 2007, Dixie received confirmation from PHMSA that its review of Dixie's plan had been completed and that PHMSA had found six areas that that needed improvement before the plan would be approved. After Dixie submitted revisions in these areas, PHMSA approved the plan on September 5, 2007, and noted that the plan complied with API RP 1162.

Safety Literature Distribution. The core element of Dixie's public education program was the distribution of safety literature to identified stakeholders that include residents, businesses, emergency response agencies, excavators, and public officials. Under the plan, Dixie mailed pipeline public awareness and safety literature each year to all emergency response officials and excavators in the county, every 2 years to the residents and businesses located within 1 mile on either side of the pipeline, and every 3 years to public officials within the county.

Dixie did not mail the literature itself; instead, it relied upon contractors to acquire the mailing data and mail the literature. Dixie did not exercise any oversight of its contractors to ensure that the mailings were accurate, nor did Dixie survey residents and businesses about the content of the mailings to determine their effectiveness.

In May 2007, Paradigm Alliance, Inc. (Paradigm), a contractor for Dixie, reported that it had mailed 258,284 copies of the brochure, *A Public Service Message—Pipeline Safety is Everyone's Responsibility,* to all stakeholders, including the residents and businesses within 1 mile of the pipeline in the Carmichael area. Paradigm used mailing data provided by a second company, Tele Atlas. On November 4, 2007, 3 days after the accident, Dixie's public awareness and damage prevention coordinator discovered that 10 addresses on County Road 621 were missing from the mailing data used by Paradigm in the May 2007 mailing. The 10 addresses included those of the houses and one business on County Road 621 that were destroyed and most heavily damaged in the Carmichael accident. Also, the houses on County Road 621 that were missed in the 2007 mailing included the homes of the two fatalities. In February 2008, Paradigm wrote to Dixie to explain why the addresses had been missed and confirmed that the error had been corrected. Paradigm told Dixie that, in May 2007, it had used one street database to identify the stakeholders within the 1-mile buffer around the Dixie pipeline. For its database, Paradigm had used a street *GeoCoding Index*, produced by Tele Atlas, which reversed the address range along County Road 621, incorrectly placing 10 houses on County Road 621 outside of the 1-mile buffer zone. Therefore, none of these addresses received the May 2007 mailing.

To minimize the possibility of this error occurring again, Paradigm said it plans to use two street databases and one parcel point database to analyze addresses. Any address that falls within the 1 mile buffer in any one of these three databases will be included in the mailing. A residential address will be excluded from the mailing only when all three databases show the address as outside the 1-mile buffer.

Because of the accident in Carmichael and the addresses missed from 2007, Dixie conducted a second mailing in June 2008 to all stakeholders, including residences and businesses that otherwise would not have received another mailing until 2009. In addition, Dixie has developed a process to validate the accuracy of its mailing list. For each of many randomly selected sample locations along the pipeline, Dixie will select an address within a 1-mile radius and cross-reference the addresses with the mailing list provided by Dixie's mailing contractor. The process of compiling addresses for this validation process began in September 2009.

Dixie told the NTSB and PHMSA in January 2009 about the addresses missed in 2007, after Dixie's public awareness coordinator realized that they had not been told after the accident about the missed addresses. As a result of this oversight, PHMSA stated that it is evaluating the circumstances as a possible regulatory violation. According to a PHMSA representative, as of April 2009, PHMSA is considering the following:

- Conducting some targeted public awareness inspections, because of the long time between the June 2006 date for operators to have completed their public education plans and the June 2010 date for their first evaluation of these plans. Such inspections may follow the guidelines PHMSA used to evaluate the plans originally submitted by the operators.

- Issuing an advisory bulletin to remind operators that their public awareness programs are intended to show continuous improvement and that operators should not wait until the full 4 years have elapsed before evaluating and modifying their plans to make them more effective.

- To provide better enforcement guidance for inspectors, undertaking research to determine an acceptable percentage of residences, businesses, emergency responders, excavating contractors, public officials, and other stakeholders that an operator could be expected to identify and reach through the use of mailings based on a variety of databases.

As of September 2009, PHMSA has not completed action on these initiatives.

Outreach to Emergency Response Agencies. Under its Government Liaison-Emergency Response Program, Dixie conducted, through a technical contractor, periodic familiarization events. These events were for fire and rescue departments, law enforcement, members of local emergency planning committees, and regional emergency management and support organizations, such as the Red Cross, in the eight Mississippi and Alabama counties in which Dixie had pipeline facilities.[30] However, emergency services communications agencies, such as 911 emergency call and central dispatch centers, were not specifically identified as stakeholders in Dixie's public education program plan.

Three Government Liaison-Emergency Response Program training sessions were held in Meridian, Mississippi, on April 26, 2005, April 18, 2006, and April 5, 2007. This training consisted of a lecture and was offered to local emergency response agencies in Clarke County and the other regional counties in Mississippi and Alabama. Dixie also conducted a training

[30] Dixie's pipelines ran through Clarke, Jasper, Kemper, Lauderdale, Neshoba, Newton, and Scott Counties in Mississippi and Choctaw County in Alabama.

exercise in August 2006 at Waynesboro, Mississippi, which is about 25 miles south of Carmichael. The scenario of the half-day exercise involved the simulation of a high-pressure liquid propane pipeline rupture caused by an unauthorized excavation, resulting in a release of product, fire, and injuries. The scope of the exercise required a comprehensive emergency response and involved the participation of fire and rescue departments, police departments, ambulance services; the exercise of incident command and mutual aid protocols; and pipeline operator response.

Dixie distributed three publications to address emergency response procedures to those emergency response organizations that participated in drills, exercises, and training events. Dixie also mailed these publications to those agencies and organizations identified as stakeholders that did not participate in the training events. The first publication was *The Pipeline Group Emergency Response Manual*. The second publication, *General Information Guide to a Pipeline Emergency*, is essentially identical to parts of the publication, *Emergency Response Guidebook*, that is available from the DOT. There is some overlap of information between these two publications.

A third publication, *A Guideline for Emergency Response Agencies*, included general information about Dixie's overall pipeline operation, a summary of the chemical properties and characteristics of propane, and basic instructions for responding to an emergency event involving the pipeline. This also was distributed to the emergency response agencies participating in the Government Liaison-Emergency Response Program training sessions. This publication included specific guidelines for recognizing the significant signs of a massive propane gas pipeline release, including the presence of a dense white cloud or fog accompanied by a roaring sound, and instructions for a pipeline emergency that could serve as guidance to 911 operators on what to tell callers to do immediately to avoid danger. Specifically, in the event of a large flammable gas release, the guidance suggests the elimination of potential ignition sources, such as an open flame, a lighted cigarette, and starting a vehicle, and the immediate evacuation of the area to an upwind location. Also, the guidance includes basic procedures for emergency response agencies, including implementing an immediate evacuation and identifying the appropriate technical resources that need to be requested from the pipeline owner.

Emergency Response Agency Participation. Table 3 shows the participants from Clarke County in the emergency response training held in Meridian in the 3 years before the accident.

Table 3. Clarke County Participation in Training Sponsored by Dixie.

Year	Attendees		
	CVFD	Sheriff's Department	Emergency Management
2005	2	0	0
2006	0	0	2
2007	2	1	2

No member of the CVFD attended the 2006 exercise in Waynesboro. CVFD officials reported that the CVFD had not participated in any formal hands-on preparedness training with Dixie in the 5 years before the accident. However, the CVFD officials stated their belief that all CVFD firefighting operations personnel have a basic familiarization with the Dixie propane pipeline operation in their jurisdiction and that the lack of familiarization training was not an impediment and did not result in an unwarranted risk to their personnel or the civilian population in this accident. The CVFD officials stated that they would make an effort to incorporate more simulated table-top tactical response drills involving the release and ignition of propane gas from a pipeline in upcoming preparedness training sessions.

Clarke County Central Dispatch personnel did not receive familiarization training sponsored by Dixie that specifically covered the operation of a propane or other large pipeline, nor did they receive Dixie's booklet, *A Guideline for Emergency Response Agencies*, or the other two safety publications that Dixie routinely distributed to emergency response agencies. Further, the initial training and qualification of Clarke County Central Dispatch operating personnel does not address pipeline emergencies. The training consists of both formal classroom instruction and an on-the-job instructional regimen in which new personnel are closely monitored and supervised by experienced operating personnel. The classroom and on-the-job training includes instruction about processing emergency calls and about obtaining information from callers regarding the nature of the incident, the location, and the current situation. Trainees also receive guidance about providing instructions to the caller to avoid or escape from danger or harm. Trainees also receive information about available resources, such as caller ID and maps, that may be useful in responding to emergency calls.

Clarke County Central Dispatch personnel also have not participated in drills and exercises simulating a propane pipeline rupture, a substantial product release, and subsequent ignition and fire. In the 3 years before the accident, Clarke County Central Dispatch personnel had not participated in the emergency responder outreach program conducted or sponsored by Dixie. Clarke County Central Dispatch personnel have routinely participated in scheduled preparedness drills and training exercises that have been conducted on the local level within Clarke County and on occasion by neighboring counties and state agencies, such as the highway patrol. However, there is no indication that any of these exercises involved a pipeline accident or emergency.

Clarke County Emergency Management and Communications

Emergency Management

Clarke County is governed by a Board of Supervisors. Three primary county emergency response agencies that are autonomous and under the direct supervision of the Board of Supervisors are the Clarke County Emergency Management Agency, Clarke County Central Dispatch, and the Clarke County Sheriff's Department.

Various volunteer fire departments and emergency medical units within the county provide fire and rescue emergency services; however, these departments are not under the Clarke County Board of Supervisors. The CVFD is a fully volunteer department with 17 active members that provides fire and rescue protection for about 38 square miles of Clarke County. The CVFD is under the command of the chief of the department, who is supported by an assistant chief. The CVFD has three vehicles—one pumper truck and two tanker trucks.

Emergency Communications

Communications for all emergency services within Clarke County (that is, all fire and rescue, sheriff's department, emergency medical services [ambulance], and emergency management) are performed by the Clarke County communications agency through its operation of the 911 emergency call and central dispatch center. Clarke County Central Dispatch typically has two qualified 911 operators on duty at all times. An operational supervisor, who is also fully qualified to perform all operational duties, is usually present during daylight hours.

Telephone requests for emergency services in Clarke County, are received and processed by Clarke County Central Dispatch, which does not have a computer-aided dispatch system. Procedurally, for fire and rescue operations, initial dispatching is done manually by transmitting a page over the fire department radio channel to the appropriate county fire department. Information about the emergency location and type is then relayed by voice over a conventional service radio to responding fire department personnel who received the communication via units installed in fire trucks, hand-held service radios, and/or base station radio units in fire stations.

Clarke County Central Dispatch uses a conventional service radio communication system for routine mobile communications with the emergency services agencies of the county. A radio signal repeater is used by Clarke County Central Dispatch because the range of the service radio main transmitter is not sufficient to cover the area of the entire county.

Clarke County's radio communication system, including the fire and rescue and sheriff's department radio signal repeater equipment, is maintained by a maintenance service contractor. The radio signal repeater equipment in use at the time of the accident was installed in June 2007 and had not experienced any system malfunctions or performance failures until November 1, 2007. Separate radio signal repeater transmitter units operating on different frequencies are used to transmit fire and rescue radio signal communications and the sheriff's department radio signal communications. The service radio equipment in all fire department and sheriff's department vehicles can be switched to either department's frequency. However, the fire department and the sheriff's department do not routinely monitor the other's radio frequency. Fire and sheriff's department personnel must be directed to switch frequencies in order to establish radio communications.

Analysis

Exclusions

One call reports, aerial patrol reports, and pipeline contact reports since 2005 for the Dixie pipeline were reviewed for indications of past excavation activity in the vicinity of rupture, and no instances of excavation activity were found. No grooves or gouges were found on the ruptured portion of the pipe during the laboratory examination. The two nearly parallel scratch marks on the outside surface of the ruptured pipe joint were not near the rupture and thus not involved in the fracture. No significant inward denting of the pipe wall was observed near the scratch marks. Neither the longitudinal nor the girth weld fracture was adjacent to or intersected the scratch marks. Therefore, damage from third-party activity was ruled out as a factor in the cause of the rupture.

The annual corrosion survey reports for the pipeline in the vicinity of the rupture were reviewed, and no problems associated with cathodic protection were found. No external or internal corrosion was observed on the ruptured pipe during the field investigation. During the laboratory examination, no corrosion damage was observed on the fracture surfaces of the ruptured pipe, and fractographic examination showed no indication of stress corrosion cracking. Therefore, degradation of the pipeline from corrosion was eliminated as a factor in the cause of the rupture.

The pipeline controller on duty at the time of the accident was adequately trained. The controller was not affected by fatigue, illicit drugs, alcohol, or medications, and he was fit for duty when the accident occurred. He detected and identified the leak in the pipeline system in a timely manner. The pipeline controller used information from the SCADA system, from people in the Carmichael area, and from personnel at the control center to respond efficiently to the emergency situation. Therefore, the actions of the pipeline controller on duty were ruled out as a factor in the cause of the rupture. The pipeline was operating under normal operating conditions, and no unusual conditions, such as pipeline overpressure or an equipment failure, were detected in the system at the time of the accident that could have caused or contributed to the accident. The NTSB, therefore, concludes that corrosion, excavation damage, the controller's actions, and the operating conditions of the pipeline were not factors in the accident.

The pipeline rupture occurred at 10:35:02 a.m. The first 911 call to Clarke County Central Dispatch was initiated at 10:39:56 a.m., and the second call concluded at 10:41:46 a.m. The ignition of the propane gas cloud occurred at 10:42:32 a.m. The interval between the end of the two 911 calls and the ignition of the propane was about 45 seconds. The NTSB concludes that the short interval between the conclusion of the 911 calls and the ignition of released propane was insufficient time for the CVFD and other emergency response agencies to evacuate the area before the explosion and fire. Decisions made by and actions of the emergency responders regarding initial fire suppression efforts and the immediate search for and evacuation of residents near the rupture site and the decision to allow the residual propane in the pipeline to continue to burn until it self-extinguished minimized the risk to emergency responders and the public. The NTSB concludes that the actions of the Clarke County Sheriff's Department, the CVFD, and other fire departments and agencies responding under mutual aid agreements were timely, well executed, and effective.

Fracture of the Pipeline

The fracture extended along the entire length of the longitudinal ERW seam of the ruptured pipe joint. Regions of the fracture faces along the longitudinal seam weld followed the upturned grains that resulted from the ERW process, with fracture paths similar to hook cracks and with repeated patterns transverse to the wall thickness that are consistent with stitching in ERW pipe. The Charpy testing showed that the ERW seam was less resistant to crack propagation than the base metal, which is to be expected for this type of pipe.[31]

The precise location where the fracture initiated could not be identified through fractographic examination of the ruptured pipe. This is not unusual, and PHMSA noted that, for ERW seam ruptures, the identification of a definitive fracture origin is not possible in many cases. Further, the review of information on numerous ERW seam fractures from hydrostatic pressure tests of the Dixie pipeline shows that in many cases the failures examined had no obvious point of fracture origin.

Examination of a pipe joint that failed during a postaccident hydrostatic pressure test on November 8, 2007, revealed fracture features similar to the accident fracture. The test fracture was along the longitudinal ERW seam as was the accident fracture. Also like the accident fracture, the fracture faces of the test fracture contained the island-like features that are associated with hook cracks. The test fracture also lacked features indicative of the fracture origin.

Although the fracture faces in the accident pipe revealed multiple features of interest, they were degraded by oxidation damage resulting from the fire that occurred after the propane ignited. The lack of well-defined fractographic features to pinpoint the location where the fracture initiated led investigators to use finite element analysis (simulation) to further explore possible fracture origination sites. Two possible scenarios for the origin of the pipeline fracture were considered in the finite element analysis:

- A crack originated in or near the longitudinal seam weld.
- A crack originated in the upstream girth weld.

[31] Cold welds, stitching, hook cracks, and other undesirable flaws in ERW steel pipeline longitudinal welds can adversely affect Charpy V-notch toughness.

Numerous computational simulations were performed in an attempt to replicate the residual pipe deformation patterns in the accident pipe. On the upstream side of the ruptured pipe joint, the fracture followed the circumferential girth weld for about 3 inches and then continued diagonally about 12 inches into the base metal of the adjacent pipe joint, leaving an open flap of pipe at the upstream girth weld. A primary objective of the finite element simulations was to replicate the shape of the upstream end of the pipe joint including the open flap.

A series of finite element simulations that assumed fracture initiation in the girth weld predicted pipe deformation patterns consistent with those observed in the accident pipe in the region around the upstream girth weld. The simulations that assumed fracture initiation in the girth weld also predicted a stress state consistent with the generation of the distinct chevron pattern observed in the circumferential fracture as it transitioned into the upstream pipe joint. However, the simulations that assumed fracture initiation in the seam weld did not predict pipe deformations consistent with those observed in the accident pipe near the upstream girth weld.

To evaluate the likelihood of one scenario over the other, the NTSB closely examined all available evidence. The NTSB also evaluated submissions received from two parties to the investigation, PHMSA and Dixie. Both parties indicated in their submissions that the pipeline rupture was most likely due to a fracture initiating in the longitudinal ERW seam. In the submission from Dixie, one of Dixie's contractors stated that initiation in the girth weld could not be ruled out.

No confirmed in-service pipeline failures in girth welds have been reported for the entire pipeline since it was installed in 1961. A review of the past failures experienced during hydrostatic pressure testing since the pipeline was installed shows that the vast majority of the failures have involved the ERW seam, with only one failure at a girth weld (recorded as a seeping leak at a field weld that Dixie indicated was likely a girth weld) that occurred in 1984.

Although the specific region in the accident pipe where the fracture initiated could not be located, fractographic examination did reveal multiple features consistent with the scenario in which the fracture initiated in the ERW seam. Examination of the fracture faces of the longitudinal seam revealed two areas with chevron pattern fragments within about 4 inches of the upstream girth weld. The orientation of these chevron patterns indicated that the fracture was propagating in the upstream direction along the longitudinal seam toward the girth weld. Also, in the region where the fracture transitioned between the ERW seam and the upstream girth weld, a branching crack feature was noted that indicates fracture propagation in the upstream direction, toward the girth weld. The examination of the downstream face of the girth weld fracture revealed that a 1-inch fracture portion adjacent to the ERW seam fracture contained chevron pattern fragments indicating that the fracture was propagating away from the longitudinal seam. Finally, an examination of the fracture faces in the upstream girth weld showed no evidence of a preexisting crack. The NTSB, therefore, concludes that the pipe contains multiple fracture features that indicate that a crack initiated in the longitudinal seam weld; however, finite element simulations raise the possibility that a crack could have initiated in the upstream girth weld.

Safety and Performance of ERW Pipe

PHMSA's data from 2002 through 2007 indicate that there were 19 hazardous liquid pipeline incidents involving failures of seam welds in both low- and high-frequency ERW pipe. According to PHMSA, although ERW pipe failures are relatively infrequent, they tend to be catastrophic. PHMSA further noted that pre-1970 low-frequency ERW pipe has a much higher failure rate than newer ERW pipes and that the quality of low-frequency ERW pipe can vary from manufacturer to manufacturer. ERW pipe constituted 68 percent of the total miles of hazardous liquid pipelines in 2007. Additionally, about one-fourth of the low-frequency and about one-half of the high-frequency ERW pipelines transport highly volatile liquids, such as propane and anhydrous ammonia. As these pipelines age and cumulative pressure cycles increase, the failure incidence may also increase.

Identifying the causes and the initiation sites of pipeline fractures is important for understanding the factors that are involved in and contribute to pipe failures. Even more important is to be able to locate a critical flaw or condition before it leads to a catastrophic failure, such as occurred in Carmichael. Currently, most pipeline operators rely upon in-line inspections to identify, detect, and monitor the growth of potential defects in their pipeline systems. In-line inspections are conducted to detect and size the anomalies that may be present in the pipe wall. The data then can be analyzed to evaluate the severity of the anomalies (that is, the size [length and depth] and the rate of growth). The data can be used by a pipeline operator to establish a schedule to repair or remove the pipeline before an anomaly grows to a critical size and causes a pipe rupture.

Segments of the Carmichael pipeline had been inspected using in-line inspection tools multiple times in the 9 years before the November 2007 rupture. In 1998, Tuboscope Vetco Pipeline Services inspected the pipeline segment from Hattiesburg to Demopolis, using a first-generation metal-flux leakage tool to search for evidence of metal loss caused by internal corrosion. The test did not find any anomalies related to metal loss in the pipe joint that ruptured in this accident.

In 2005, Dixie conducted a special ERW seam integrity assessment over the entire Hattiesburg-to-Demopolis segment, using the GE UltraScan crack detection tool that can detect defects in the pipe in the longitudinal direction. This tool is not designed to detect circumferentially oriented defects in the girth welds. This inspection identified 21 pipe joints with reportable indications, and Dixie removed all 21 pipe joints, including the girth welds on each end of each joint, as part of its pipeline integrity repair program. The inspection also identified two features in the pipe joint that ruptured at Carmichael, but the features did not meet the criteria for reportable indications and were not factors in the accident.

In 2006, Magpie inspected the Hattiesburg-to-Demopolis pipeline segment, using a geometry tool followed by a high-resolution axial magnetic flux leakage metal loss tool to detect metal loss in the pipe. The latter tool is used to detect metal loss in or near the girth weld. Magpie reported no geometric anomalies and detected no metal-loss-related anomalies in the joint that ruptured in Carmichael.

The results of the three in-line inspections that were conducted in the 9 years before the accident found no defects or anomalies in the Carmichael pipe joint that could be correlated with the 2007 rupture. It is possible that detectable anomalies did not exist at the times of the three tests, or the inspection tools did not find detectable anomalies that may have existed, or anomalies existed below detection limits but grew at a very fast rate.

Dixie contracted with Stork to conduct hydrostatic pressure burst tests on the pipe joints and girth welds that had been removed after the 2005 in-line inspection. All 21 pipe joints ruptured during the burst tests at pressures ranging from 2,055 psig to 3,250 psig. Over this pressure range, ruptures occurred above the specified minimum yield strength. Stork's conclusions after examination of the ruptures show the difficulty of identifying fracture origins in ERW pipe. For a majority of the 21 pipe joints, Stork identified a general region or area of the fracture surface as the origin of the fracture when an apparent fracture origin was not identifiable. The fracture surface of only one pipe joint had a hook crack with chevrons on each side pointing to the fracture initiation site.

Stork also correlated the location of the identified fracture origin for the pipe joints with indications reported from the 2005 in-line inspection. Stork found that for 12 of the 21 ruptures, an indication from the 2005 in-line inspection coincided with either an identified fracture origin or a point on the fracture surface. No reportable indications were found during the in-line inspection for 9 of the 21 ruptured pipe joints.

The accumulated data from the three in-line inspections of the Carmichael pipeline and from the examination of the pipe joints that were removed and subjected to hydrostatic testing illustrate the limitations of current in-line inspection technology for detecting significant flaws in low-frequency ERW pipe. PHMSA believes that in-line inspection technology is improving and data analysis capabilities are increasing each year. Reliable and effective in-line inspection tools have become more critical in recent years as the focus of the pipeline safety program has shifted to risk-based integrity management plans that are developed and implemented by individual pipeline operators. The NTSB concludes that current inspection and testing programs are not sufficiently reliable to identify features associated with longitudinal seam failures of ERW pipe prior to catastrophic failure in operating pipelines.

Hydrostatic pressure tests have been effective in eliminating potentially critical anomalies leading to in-service ruptures. However, these tests may cause some anomalies to grow to a critical size much faster than they might have without a hydrostatic test. The tests also introduce water into the pipeline, requiring action to prevent internal corrosion.

According to PHMSA, the pressure spike test is also beneficial because it subjects a pipeline to a higher pressure for a shorter time than the standard hydrostatic test. The rationale is that higher pressure is more likely to cause critical cracks to fail, while the shorter time limits the potential for smaller cracks to grow during the test. Although PHMSA has been requiring operators to conduct a spike test before returning a pipeline to service following a failure, the spike test is not being used in place of the hydrostatic test or conducted on a periodic basis. PHMSA has stated that it is examining these methods and may require them after pipeline failures. PHMSA is also examining methods that operators can use to minimize pressure cycling in low-frequency ERW pipelines to reduce fatigue on the pipeline. The NTSB recommends that PHMSA conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in ERW pipe; at a minimum, the study should include assessments of the effectiveness and effects of in-line inspection tools, hydrostatic pressure tests, and spike pressure tests; pipe material strength characteristics and failure mechanisms; the effects of aging on ERW pipelines; operational factors; and data collection and predictive analysis.

Pipeline Operator Public Education Programs

The NTSB has long been concerned about pipeline operators' public education programs, including the content, distribution, and effectiveness of pipeline operators' safety materials for both hazardous liquid and natural gas pipelines. From the late 1980s through the late 1990s, the NTSB investigated several accidents[32] in which deficiencies in operators' public education programs were safety issues. In the report of the investigation of the pipeline rupture, liquid butane release, and fire in Lively, Texas, on August 24, 1996, the NTSB concluded that requirements for the content, format, and periodic evaluation of public education programs can help pipeline operators ensure that their programs are effective. The NTSB made the following recommendations to PHMSA:

> <u>P-98-37</u>
>
> Revise 49 *Code of Federal Regulations* Part 195 to include requirements for the content and distribution of liquid pipeline operators' public education programs.
>
> <u>P-98-38</u>
>
> Revise 49 *Code of Federal Regulations* Part 195 to require that pipeline operators periodically evaluate the effectiveness of their public education programs using scientific techniques.

The NTSB classified both recommendations "Closed—Acceptable Action" on November 21, 2003, based on various PHMSA initiatives with the natural gas and hazardous liquid pipeline industries. PHMSA's initiatives included assisting with the development and adoption of consensus standards embodied in API RP 1162, committing to incorporate the consensus standards by reference into the pipeline safety regulations (49 CFR Parts 192 and

[32] Pipeline Accident Report—*Kansas Power and Light Company Natural Gas Accidents, September 16, 1988 to March 29, 1989* (NTSB/PAR-90/03); Pipeline Accident Report—*Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994* (NTSB/PAR-95/01); Pipeline Accident Report—*San Juan Gas Company, Inc./Enron Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996* (NTSB/PAR-97/01); and Pipeline Accident Summary Report—*Pipeline Rupture, Liquid Butane Release, and Fire, Lively, Texas, August 24, 1996* (NTSB/PAR-98/02/SUM).

195), assisting pipeline operators in aligning their existing public education programs with API RP 1162, and conducting workshops to facilitate operators' understanding of API RP 1162.

The problems with Dixie's public education program that were uncovered in this investigation and documented in this report led the NTSB to reassess the public education standards and oversight.

Public Awareness Program

Dixie's public awareness program distributed safety literature to identified stakeholders that include residents, businesses, emergency response agencies, excavators, and public officials. Under the program, Dixie, through its contractor, mailed pipeline public awareness and safety literature each year to all emergency response officials and excavators in the county, every 2 years to the residents and businesses within 1 mile of either side of the pipeline, and every 3 years to public officials within the county. After the accident, Dixie discovered that 10 addresses on County Road 621 were missing from the mailing data used for the May 2007 distribution of *A Public Service Message—Pipeline Safety is Everyone's Responsibility*; the 10 addresses included the houses of the two fatalities and the houses and one business on County Road 621 that were destroyed and most heavily damaged in the Carmichael accident.

Dixie has told investigators that since the accident, its contractor has corrected the mailing data. Also, Dixie planned a second mailing to all stakeholders, including those that had been missed previously. These actions are responses to specific problems identified in Dixie's public education program and cannot be considered as active oversight of its program. Before the accident, Dixie relied upon its contractors to obtain accurate mailing data and ensure the mailings to the public were completed. Dixie did not perform oversight to ensure that all appropriate recipients were on the mailing lists and that the mailings met its requirements and those of API RP 1162, nor did it initiate actions to evaluate the effectiveness of the program. For example, Dixie did not conduct customer surveys to verify that the mailing lists were complete, that mailings had been received, and that customers understood the guidance contained in the safety literature mailed to them. Without such efforts, Dixie could not accurately assess the effectiveness of its public awareness program as required under federal pipeline standards (49 CFR Parts 192 and 195) and API RP 1162.

Outreach Program to Emergency Responders

Dixie's outreach program to emergency response agencies provided opportunities for emergency responders in Clarke County and neighboring counties to receive familiarization training and participate in exercises related to the propane pipeline so that they would be prepared in case of accident or emergency. In addition, the safety literature and guidance that training participants and invitees received contained important information about the hazards of propane and actions to protect the public and emergency responders. These materials also contained specific guidance that 911 operators could use to recognize the signs of a massive propane release and the information to give to callers so they can avoid danger during such a release. Dixie did not identify central dispatch centers, such as Clarke County Central Dispatch, as stakeholders and participants in its outreach program for emergency response agencies. In the 3 years before the Carmichael accident, employees of the Clarke County Sheriff's Department, the County Emergency Management Agency, and the CVFD attended Dixie's emergency response training sessions, but Clarke County Central Dispatch was not included in the list of attendees to this type of session and the Clarke County 911 operators did not attend. API RP 1162, the pipeline industry's standard for public education programs, did not identify central dispatch centers as organizations to contact although Dixie, as a regional pipeline operator, had the responsibility to identify and offer training to the appropriate emergency response agencies in those regions in which it operates. Had personnel from Clarke County Central Dispatch participated in Dixie's periodic familiarization training or received the guidance to 911 operators, they may have promptly recognized that the information initially reported indicated a massive propane release in the area and would have been better prepared to address it. Such actions may have included warning callers to avoid ignition sources and telling them to immediately evacuate the area.

Because addresses were omitted from public awareness mailing lists and 911 operators were not invited to attend the outreach program for emergency responders, the NTSB concludes that Dixie Pipeline Company's oversight and evaluation of the effectiveness of its public education programs were inadequate. The NTSB recommends that the Dixie Pipeline Company take measures to determine that all residences and businesses within its operating regions are included on its mailing list and receive mailings of safety guidance information. The NTSB further recommends that the Dixie Pipeline Company implement procedures to evaluate the effectiveness of its public education program. Regarding outreach to emergency response agencies, the NTSB recommends that Dixie Pipeline Company verify that all 911 emergency centers within its operating regions are included on its mailing list, invited to participate in operator-sponsored training activities, and receive mailings of safety guidance information.

The circumstances of the Carmichael accident, particularly the lack of training and guidance for the Clarke County Dispatch Center about propane pipeline operations, raise concerns about the adequacy of API RP 1162 and oversight by operators and PHMSA to ensure effective public education programs are implemented and followed. The section of API RP 1162 pertaining to outreach programs to emergency response agencies identifies the following as attendees and participants:

> Fire departments, Police/Sheriff departments, [local emergency planning committees], County and State Emergency Management Agencies, other emergency response organizations, and other public safety organizations.

Although it is reasonable to interpret "other emergency response organizations" to include emergency 911 dispatch centers, there is no certainty that such an interpretation will be universal, as exhibited in this accident. Emergency 911 dispatch centers in many jurisdictions are part of either the fire or the police department. In areas of the country that are served by volunteer fire departments, there may be a greater possibility that the local 911 dispatch center is independent from the fire and police departments. In such instances, a pipeline operator may overlook the inclusion of an independent 911 center as a potential attendee and participant in its outreach program. The NTSB concludes that the absence of emergency 911 dispatch centers from the list of stakeholders in API RP 1162 increases the possibility that 911 dispatch center personnel might not receive the necessary training to recognize the hazards of a large release of propane and other flammable products from a pipeline and thereby be able to warn 911 callers of imminent danger. Therefore, the NTSB recommends that the API revise API RP 1162 to explicitly identify 911 emergency call centers as emergency response agencies to be included in outreach programs under a pipeline operator's public education program.

The timetable set forth in PHMSA's final rule published in May 2005 gave pipeline operators until June 2006 to develop public education programs and, in supplemental guidance following publication of the final rule, until June 2010 to evaluate the effectiveness of those programs. After Dixie acknowledged in January 2009 that it had failed to tell the NTSB and PHMSA about the addresses missed in the May 2007 mailing, PHMSA began to consider possible actions to assess operators' self-evaluations of the effectiveness of their public awareness program plans. The actions under consideration include conducting targeted public awareness inspections, issuing an advisory bulletin urging pipeline operators to conduct their self-evaluations and modify their plans before the 2010 deadline, and initiating research about effectively reaching the public with the appropriate safety information. However, PHMSA has not completed action on these initiatives. The Carmichael accident has shown that although an operator's public awareness program plan may meet API RP 1162 requirements and federal pipeline standards, this is not a guarantee that implementation of the program is effective or that the operator is exercising sufficient oversight. The NTSB recommends that PHMSA initiate a program to evaluate pipeline operators' public education programs, including pipeline operators' self-evaluations of the effectiveness of their public education programs, and provide the NTSB with a timeline for implementation and completion of this evaluation.

Clarke County Emergency Communications

Preparedness of Clarke County 911 Dispatch Center

The first call reporting a gas explosion to Clarke County Central Dispatch came in about 5 minutes after the pipe rupture, and the ignition of the released propane occurred about 2 1/2 minutes after that. Although Clarke County Central Dispatch personnel paged fire resources to respond to the scene and told the caller that a fire truck was on its way, they did not tell the caller what to do in the meantime to respond to the emergency. With the circumstances of this accident, however, even if the dispatcher receiving the call had instantly recognized the impending danger, warned the caller not to use any ignition sources, and directed the caller to immediately evacuate and get away from the gas cloud, the caller at best had very little time to reach safety before the ignition and fire. Nevertheless, Clarke County Central Dispatch personnel need to be able to assess the significance of telephoned descriptions of pipeline emergencies so that they can give callers the correct information about how to keep themselves safe. Heightened awareness and knowledge attained through appropriate training and participation in drills involving pipeline operators and other local emergency response agencies can improve the ability of Clarke County Central Dispatch to provide timely information and guidance to citizens and county emergency response agencies in future emergencies. The NTSB concludes that at the time of the accident, the Clarke County Central Dispatch emergency 911 personnel were not sufficiently knowledgeable about the dangers of a large release of propane and the appropriate actions to take. The NTSB recommends that the Clarke County Board of Supervisors require and document that the Clarke County Central Dispatch emergency 911 personnel receive regular training and participate in regional exercises and drills pertaining to pipeline safety.

Emergency Radio Communications

About 1 1/2 hours before the accident, the radio signal repeater for the fire department, the primary radio system for Clarke County Central Dispatch, was not working, but dispatch personnel were not aware of this. (Communication cables of the radio signal repeater equipment had been inadvertently disconnected during routine housekeeping earlier that morning.) After Clarke County Central Dispatch began receiving 911 calls, an operator promptly sent a page to the CVFD to respond. When acknowledgements from CVFD were not received as required, dispatch center personnel began to contact nearby fire departments in accordance with their operational protocol and mutual aid agreements. However, when fire department personnel failed to acknowledge the pages, the dispatch center personnel did not immediately recognize the possibility of a communications equipment problem.

It was not until about 10:55 a.m., or about 15 minutes after the first 911 call was received at the dispatch center, that the Clarke County sheriff, who was monitoring the radio communications, contacted the dispatch center through a deputy and informed the dispatch center that the primary fire and rescue radio signal repeater appeared not to be working. About the same time, dispatch center personnel began to suspect a malfunction of the radio signal repeater and switched to the backup system, which was working.

Despite the radio communications problem, the CVFD became aware of the event when the assistant chief of the CVFD heard the explosion at 10:43 a.m., saw a large fireball plume and a cloud of heavy black smoke in the east seconds later, and then promptly mobilized resources and responded to the accident scene. By about 10:55 a.m., CVFD personnel and fire trucks were at the accident scene. Consequently, the NTSB concludes that despite the failure of Clarke County Central Dispatch to immediately recognize that its primary radio communications system was not working, the CVFD was able to respond to the accident in a timely manner. Since the accident, the Clarke County government has fixed the problem of inadvertent cable disconnection that caused failure of the primary system and is considering further enhancements to the communications system. Specifically, since the accident, Clarke County Central Dispatch conducts bi-weekly tests of the radio repeater system to ensure it is performing normally and has modified the connection hardware to cable connector fittings and connection sockets that have positive engaging, screw-type locking features to help prevent future inadvertent disconnections of the communication cables. Because these actions sufficiently address this problem, the NTSB does not believe a safety recommendation in this area is needed.

Conclusions

Findings

1. Corrosion, excavation damage, the controller's actions, and the operating conditions of the pipeline were not factors in the accident.

2. The short interval between the conclusion of the 911 calls and the ignition of released propane was insufficient time for the Carmichael Volunteer Fire Department and other emergency response agencies to evacuate the area before the explosion and fire.

3. The actions of the Clarke County Sheriff's Department, the Carmichael Volunteer Fire Department, and other fire departments and agencies responding under mutual aid agreements were timely, well executed, and effective.

4. The pipe contains multiple fracture features that indicate that a crack initiated in the longitudinal seam weld; however, finite element simulations raise the possibility that a crack could have initiated in the upstream girth weld.

5. Current inspection and testing programs are not sufficiently reliable to identify features associated with longitudinal seam failures of ERW pipe prior to catastrophic failure in operating pipelines.

6. Dixie Pipeline Company's oversight and evaluation of the effectiveness of its public education programs were inadequate.

7. The absence of emergency 911 dispatch centers from the list of stakeholders in American Petroleum Institute Recommended Practice 1162 increases the possibility that 911 dispatch center personnel might not receive the necessary training to recognize the hazards of a large release of propane and other flammable products from a pipeline and thereby be able to warn 911 callers of imminent danger.

8. At the time of the accident, the Clarke County Central Dispatch emergency 911 personnel were not sufficiently knowledgeable about the dangers of a large release of propane and the appropriate actions to take.

9. Despite the failure of Clarke County Central Dispatch to immediately recognize that its primary radio communications system was not working, the Carmichael Volunteer Fire Department was able to respond to the accident in a timely manner.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the November 1, 2007, rupture of the liquid propane pipeline operated by Dixie Pipeline Company near Carmichael, Mississippi, was the failure of a weld that caused the pipe to fracture along the longitudinal seam weld, a portion of the upstream girth weld, and portions of the adjacent pipe joints.

Recommendations

As a result of its investigation of the November 1, 2007, rupture of the liquid propane pipeline operated by Dixie Pipeline Company the National Transportation Safety Board makes the following recommendations:

To the Pipeline and Hazardous Materials Safety Administration:

> Conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in electric resistance welded (ERW) pipe; at a minimum, the study should include assessments of the effectiveness and effects of in-line inspection tools, hydrostatic pressure tests, and spike pressure tests; pipe material strength characteristics and failure mechanisms; the effects of aging on ERW pipelines; operational factors; and data collection and predictive analysis. (P-09-1)
>
> Based on the results of the study requested in Safety Recommendation P-09-1, implement the actions needed. (P-09-2)
>
> Initiate a program to evaluate pipeline operators' public education programs, including pipeline operators' self-evaluations of the effectiveness of their public education programs. Provide the National Transportation Safety Board with a timeline for implementation and completion of this evaluation. (P-09-3)

To the Clarke County Board of Supervisors:

> Require and document that the Clarke County Central Dispatch emergency 911 personnel receive regular training and participate in regional exercises and drills pertaining to pipeline safety. (P-09-4)

To the American Petroleum Institute:

> Revise American Petroleum Institute Recommended Practice 1162 to explicitly identify 911 emergency call centers as emergency response agencies to be included in outreach programs under a pipeline operator's public education program. (P-09-5)

To Dixie Pipeline Company:

Take measures to determine that all residences and businesses within your operating regions are included on your mailing list and receive mailings of safety guidance information. (P-09-6)

Implement procedures to evaluate the effectiveness of your public education program. (P-09-7)

Verify that all 911 emergency centers within your operating regions are included on your mailing list, invited to participate in operator-sponsored training activities, and receive mailings of safety guidance information. (P-09-8)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

DEBORAH A.P. HERSMAN
Chairman

ROBERT L. SUMWALT
Member

CHRISTOPHER A. HART
Vice Chairman

Adopted: October 14, 2009

Appendix A

Investigation

The NTSB was notified of the rupture of the liquid propane pipeline operated by Dixie Pipeline Company about 12:53 p.m. on November 1, 2007. The investigator-in-charge and other investigative team members were launched from the NTSB's Washington, D.C., Headquarters office. Robert L. Sumwalt was the Board Member on scene. Investigative groups were formed for pipeline operations, metallurgy, human performance, and survival factors. The NTSB later established a group for in-line inspection factors. No hearing or depositions were held in conjunction with this accident.

Parties to the investigation included the Pipeline and Hazardous Materials Safety Administration, Dixie Pipeline Company, United States Steel Company, Clarke County Sheriff's Department, and Carmichael Volunteer Fire Department.

Appendix B

Accident Timeline

Day	Time	Event
Thursday November 1	10:35:02 a.m.	Rupture of 12-inch-diameter pipeline operated by Dixie Pipeline Company near Carmichael, Missippi.
	10:35:13 a.m.	Pipeline controller in Houston, Texas, control center receives rate-of-change alarm on SCADA panel for Carmichael Pump Station.
	10:35:46 a.m.	Second rate-of-change alarm received for Butler Pump Station.
	10:35:50 a.m.	Rate-of-change alarm received for Yellow Creek Pump Station. Automatic shutdown of Carmichael Pump Station unit 2 pump.
	10:36:25 a.m.	Pipeline controller began to shut down pipeline.
	10:37:12 a.m.	Pipeline controller started a pump at Butler Station to pull product away from rupture area.
	10:38 a.m.	Controller started contacting field personnel from Hattiesburg and Demopolis Pump Stations to respond to release.
	10:39:56 a.m.	Clarke County Central Dispatch (Emergency 911) received call reporting gas explosion & white gas in the area but no fire. Clarke County Central Dispatch began to contact and dispatch police, fire, & rescue resources.
	10:40:13 a.m.	Clarke County Central Dispatch received call reporting pipeline release.
	10:41 a.m.	Dixie control center received call from resident near rupture site reporting pipeline release.
	10:43 a.m.	CVFD asst. chief heard distant explosion followed by plume and black smoke; began mobilizing CVFD fire apparatus and personnel to the scene.
	10:46 a.m.	Pipeline controller received call reporting four major explosions, fire 200 feet high, and two columns of white and black smoke. Controller identified location of leak as area where a Hunt pipeline crosses Dixie pipeline. Controller directed contractor in Carmichael area to the site.
	10:48 a.m.	Hunt employee notified pipeline controller that Hunt pipeline was shut down and blocked off in area of release.
	10:49:51 a.m.	Clarke County Central Dispatch received call from pipeline controller reporting leak in Carmichael station area. Clarke County Central Dispatch told controller they were aware of event and had dispatched three fire and rescue units to the scene.
	10:52:37 a.m.	Pipeline controller closed remotely controlled suction and discharge valves at Carmichael and Butler Pump Stations.

Day	Time	Event
Thursday November 1	11:00 a.m.	Emergency responders decided to allow controlled burn of residual propane in pipeline.
Friday November 2	5:05 p.m.	Fire at pipeline self extinguished.
Sunday November 4	4:00 p.m.	Incident command concluded tactical on-scene activities.

Product Information Sheets ....

Product Information sheets contained in this section have been compiled from the 2008 Emergency Response Guidebook and only include the products transported by the operators represented. Information contained in these sheets is believed to be up-to-date and correct at the time of printing. The next available update to the ERG will be in 2012.

Further product-specific information may be found in the US Department of Transportation (DOT) Emergency Response Guidebook for First Responders. The Guidebook is available at **http://hazmat.dot.gov/pubs/erg/gydebook.htm**.

BUTANE: N-BUTANE, ISO-BUTANE, BUTANE MIX ....

Po TEn TIal Haza RdS

f IRE o R Ex Plo SIon
- **EXTREMELY FLAMMABLE.**
- Will be easily ignited by heat, sparks or flames
- Will form explosive mixtures with air.
- Vapors from liquefied gas are initially heavier than air and spread along ground. **Ca UTIon : Hydrogen (Un 1049), d euterium (Un 1957), Hydrogen, refrigerated liquid (Un 1966) and methane (Un 1971) are lighter than air and will rise. Hydrogen and d euterium fire are difficul to detect since they burn with an invisible flame Use an alternate method of detection (thermal camera, broom handle, etc.)**
- Vapors may travel to source of ignition and flash back
- Cylinders exposed to fire may vent and release flammable gas through pressure relief devices.
- Containers may explode when heated.
- Ruptured cylinders may rocket.

HEal TH
- Vapors may cause dizziness or asphyxiation without warning.
- Some may be irritating if inhaled at high concentrations.
- Contact with gas or liquefied gas may cause burns, severe injury and/or frostbite.
- Fire may produce irritating and/or toxic gases.

PUbl IC Saf ETy
- **CALL Emergency Response Telephone Number on Shipping Paper first If Shipping Paper not available or no answer, refer to appropriate telephone number listed on the inside back cover.**
- As an immediate precautionary measure, isolate spill or leak area for at least 100 meters (330 feet) in all directions.
- Keep unauthorized personnel away.
- Stay upwind.
- Many gases are heavier than air and will spread along ground and collect in low or confined areas (sewers, basements, tanks).
- Keep out of low areas.

PRo TECTIv E Clo THIng
- Wear positive pressure self-contained breathing apparatus (SCBA).
- Structural firefighter protective clothing will only provide limited protection.
- Always wear thermal protective clothing when handling refrigerated/cryogenic liquids.

Eva CUa TIon
l arge Spill
- Consider initial downwind evacuation for at least 800 meters (1/2 mile).

f ire
- If tank, rail car or tank truck is involved in a fire, ISOL TE for 1600 meters (1 mile) in all directions; also, consider initial evacuation for 1600 meters (1 mile) in all directions.

EmERg En Cy RESPon SE

f IRE
- DO NOT EXTINGUISH A LEAKING GAS FIRE UNLESS LEAK CAN BE STOPPED. **Ca UTIon : Hyd Rog En (U n 1049), dEUTERIU m (Un 1957) and Hyd Rog En, REf RIg ERa TEd l IQUId (Un 1966) b URn w ITH an Inv ISIbl E flam E. Hyd Rog En and mETHan E mIx TURE, Com PRESSEd (U n 2034) may b URn w ITH an Inv ISIbl E flam E.**

Small f ire
- Dry chemical or CO2.

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g UId E #: 115

CHEmICal nam ES:
N-BUTANE:
- “Normal” Butane
- Butyl Hydride
- LP Gas
- LPG
- Liquefied Butan

ISO-BUTANE:
- 2-Methylpropane
- “Iso”

CHEmICal f am Il y:
Petroleum Hydrocarbon, Aliphatic Hydrocarbon, Alkane, Paraffi

Com Pon En TS:
Butane: n-Butane, Iso-Butane, Propane, Butylenes, Pentane and heavier Hydrocarbons Iso-Butane: Iso-Butane, n-Butane, Propane, Butylenes

l arge f ire
- Water spray or fog.
- Move containers from fire area if you can do it without risk.

f ire involving Tanks
- Fight fire from maximum distance or use unmanned hose holders or monitor nozzles.
- Cool containers with flooding quantities of water until well after fire is out
- Do not direct water at source of leak or safety devices; icing may occur.
- Withdraw immediately in case of rising sound from venting safety devices or discoloration of tank.
- ALWAYS stay away from tanks engulfed in fire
- For massive fire, use unmanned hose holders or monitor nozzles; if this is impossible, withdraw from area and let fire burn.

SPIll o R l Eak
- ELIMINATE all ignition sources (no smoking, flares, sparks or flames i immediate area).
- All equipment used when handling the product must be grounded.
- Do not touch or walk through spilled material.
- Stop leak if you can do it without risk.
- If possible, turn leaking containers so that gas escapes rather than liquid.
- Use water spray to reduce vapors or divert vapor cloud drift. Avoid allowing water runoff to contact spilled material.
- Do not direct water at spill or source of leak.
- Prevent spreading of vapors through sewers, ventilation systems and confined areas.
- Isolate area until gas has dispersed. **Ca UTIon : w hen in contact with refrigerated/cryogenic liquids, many materials become brittle and are likely to break without warning.**

f IRST a Id
- Move victim to fresh air.
- Call 911 or emergency medical service.
- Give artificial respiration if victim is not breathing.
- Administer oxygen if breathing is difficult
- Remove and isolate contaminated clothing and shoes.
- Clothing frozen to the skin should be thawed before being removed.
- In case of contact with liquefied gas, thaw frosted parts with lukewarm water.
- In case of burns, immediately cool affected skin for as long as possible with cold water. Do not remove clothing if adhering to skin.
- Keep victim warm and quiet.
- Ensure that medical personnel are aware of the material(s) involved and take precautions to protect themselves.

Po TEn TIal Haza RdS

f IRE o R Ex Plo SIon
- **EXTREMELY FLAMMABLE**
- Will be easily ignited by heat, sparks or flames
- Will form explosive mixtures with air.
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- Keep out of low areas.

PRo TECTIv E Clo THIng
- Wear positive pressure self-contained breathing apparatus (SCBA).
- Structural firefighter protective clothing will only provide limited protection.
- Always wear thermal protective clothing when handling refrigerated/cryogenic liquids.

Eva CUa TIon
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- Consider initial downwind evacuation for at least 800 meters (1/2 mile).

f ire
- If tank, rail car or tank truck is involved in a fire, ISOL TE for 1600 meters (1 mile) in all directions; also, consider initial evacuation for 1600 meters (1 mile) in all directions.

EmERg En Cy RESPon SE

f IRE
- **DO NOT EXTINGUISH A LEAKING GAS f IRE Unl ESS l Eak Can b E STo PPEd. Ca UTIon : Hydrogen (Un 1049), d euterium (Un 1957) and Hydrogen, refrigerated liquid (Un 1966) burn with an invisible flame Hydrogen and methane mixture, compressed (Un 2034) may burn with an invisible flame**

Small f ire
- Dry chemical or CO2.

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CHEmICal nam ES:
- Ethane
- Bimethyl
- Dimethyl
- Methyl Methane
- Ethyl Hydride

CHEmICal f am Il y:
Petroleum Hydrocarbon, Aliphatic Hydrocarbon, Paraffin, Alkane

Com Pon En TS:
Ethane, Methane, Carbon Dioxide, Propane, Propylene, Ethylene, Iso-Butane, n-Butane, Higher Hydrocarbons

l arge f ire
- Water spray or fog.
- Move containers from fire area if you ca do it without risk.

f ire involving Tanks
- Fight fire from maximum distance o use unmanned hose holders or monitor nozzles.
- Cool containers with flooding quantities o water until well after fire is out
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Small f ire

- Dry chemical or CO2.

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CHEmICal nam ES:

- Propane
- Propyl Hydride
- Dimethylmethane
- LP Gas
- LPG
- Liquefied Petroleum Ga
- Commercial-Grade Liquefied Propane
- “P-Rich Furnace Feed”

CHEmICal f am Il y:
Petroleum Hydrocarbon, Aliphatic Hydrocarbon, Paraffin, Alkane

Com Pon En TS:

Propane	Propylene
Butane	Iso-Butane
Ethane	Ethyl Mercaptan
Sulfur	

l arge f ire

- Water spray or fog.
- Move containers from fire area if you can do it without risk.

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- Fight fire from maximum distance or use unmanned hose holders or monitor nozzles.
- Cool containers with flooding quantities of water until well after fire is out
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- Do not direct water at spill or source of leak.
- Prevent spreading of vapors through sewers, ventilation systems and confined areas.
- Isolate area until gas has dispersed. **Ca UTIon : w hen in contact with refrigerated/cryogenic liquids, many materials become brittle and are likely to break without warning.**

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- Move victim to fresh air.
- Call 911 or emergency medical service.
- Give artificial respiration if victim is not breathing.
- Administer oxygen if breathing is difficult
- Remove and isolate contaminated clothing and shoes.
- Clothing frozen to the skin should be thawed before being removed.
- In case of contact with liquefied gas, thaw frosted parts with lukewarm water.
- In case of burns, immediately cool affected skin for as long as possible with cold water. Do not remove clothing if adhering to skin.
- Keep victim warm and quiet.
- Ensure that medical personnel are aware of the material(s) involved and take precautions to protect themselves.

ID	OPERATOR	SYSTEM TYPE	STATUS	MILES	Incidents 2006-2016YTD	Federal Inspections 2006-2016YTD	Federal Enforcement Actions 2006-2016YTD
18718	SUNOCO PIPELINE L.P.	HL,GT	Active	5,774	276	161	27
31618	ENTERPRISE PRODUCTS OPERATING LLC	HL,GT,GG	Active	26,946	257	229	28
30829	ENTERPRISE CRUDE PIPELINE LLC	HL,GG	Active	3,743	247	39	9
300	PLAINS PIPELINE, L.P.	HL	Active	9,209	222	146	28
22610	MAGELLAN PIPELINE COMPANY, LP	HL,GT	Active	10,957	218	229	40
2552	COLONIAL PIPELINE CO	HL	Active	5,599	187	218	17
31684	PHILLIPS 66 PIPELINE LLC	HL,GT,GG	Active	10,136	185	298	54
1845	BUCKEYE PARTNERS, LP	HL	Active	6,645	157	231	46
11169	ENBRIDGE ENERGY, LIMITED PARTNERSHIP	HL	Active	4,688	111	125	15
32147	MARATHON PIPE LINE LLC	HL,GT	Active	5,694	110	190	17
32109	ONEOK NGL PIPELINE, LLC	HL,GT	Active	11,507	106	115	22
26041	KINDER MORGAN LIQUID TERMINALS, LLC	HL	Active	88	105	40	10
19160	TENNESSEE GAS PIPELINE COMPANY	GT	Active	11,780	103	186	26
31174	SHELL PIPELINE CO., L.P.	HL	Active	3,617	102	83	13
4805	EXPLORER PIPELINE CO	HL	Active	1,817	83	47	8
4906	EXXONMOBIL PIPELINE CO	HL,GT	Active	3,413	77	61	18
405	ANR PIPELINE CO	GT	Active	9,898	70	150	15
22855	KOCH PIPELINE COMPANY, L.P.	HL,GT	Active	4,200	63	60	4
13750	NORTHERN NATURAL GAS CO	GT	Active	14,778	63	191	14
602	ENABLE GAS TRANSMISSION, LLC	GT	Active	5,933	61	75	20
2731	CHEVRON PIPE LINE CO	HL,GT	Active	3,362	58	125	30
2616	COLUMBIA GAS TRANSMISSION, LLC	GT,GG	Active	10,527	58	366	47
9175	JAYHAWK PIPELINE LLC	HL	Active	996	56	34	7
19570	TRANSCONTINENTAL GAS PIPE LINE COMPANY	GT,GG	Active	9,743	56	252	33
31728	GULF SOUTH PIPELINE COMPANY, LP	GT,GG	Active	6,732	53	102	14
12470	MID - VALLEY PIPELINE CO	HL	Active	1,103	53	36	6
10012	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P.	HL	Active	4,368	52	60	8
15007	PACIFIC GAS & ELECTRIC CO	GT,GD	Active	6,541	51	2	0
15674	PLANTATION PIPE LINE CO	HL	Active	3,173	50	85	5
12105	MAGELLAN AMMONIA PIPELINE, L.P.	HL	Active	1,090	49	29	3
18092	SFPP, LP	HL	Active	2,852	49	115	15
31189	BP PIPELINE (NORTH AMERICA) INC.	HL,GT	Active	2,138	44	71	6
22442	WEST TEXAS GULF PIPELINE CO	HL	Active	582	44	17	6
18516	SOUTHERN NATURAL GAS CO	GT	Active	7,000	39	121	10
31711	SOUTHERN STAR CENTRAL GAS PIPELINE, INC	GT	Active	5,831	37	67	8
19235	TEXAS EASTERN TRANSMISSION, LP (SPECTRA ENERGY...	GT	Active	9,076	36	181	21
2620	COLUMBIA GULF TRANSMISSION, LLC	GT	Active	3,341	35	62	7
31476	ROSE ROCK MIDSTREAM L.P.	HL	Active	551	35	29	11

19237	TE PRODUCTS PIPELINE COMPANY, LLC	HL	Inactive	4,634	35	28	11
32099	ENERGY TRANSFER COMPANY	HL,GT,GG	Active	10,821	33	9	3
32011	HOLLY ENERGY PARTNERS - OPERATING, L.P.	HL,GT	Active	1,678	32	45	12
31555	KINDER MORGAN CO2 CO. LP	HL	Active	1,306	32	17	5
32537	WYOMING PIPELINE COMPANY	HL	Active	151	31	6	5
31580	MAGELLAN TERMINALS HOLDINGS, LP	HL	Active	47	30	16	3
26085	PLAINS MARKETING, L.P.	HL,GT	Active	728	30	31	4
31947	ENBRIDGE PIPELINES (OZARK) L.L.C.	HL	Active	495	27	18	5
19270	TEXAS GAS TRANSMISSION, LLC	GT	Active	6,016	27	75	11
26134	EXXONMOBIL OIL CORP - WEST COAST	HL,GT	Active	772	24	5	0
13120	NATURAL GAS PIPELINE CO OF AMERICA (KMI)	GT	Active	9,117	24	92	15
15774	NORTH DAKOTA PIPELINE COMPANY LLC	HL	Active	756	23	26	1
31130	DCP MIDSTREAM	HL,GT,GG	Active	5,778	22	48	10
1248	BELLE FOURCHE PIPELINE CO	HL	Active	783	21	28	8
4280	EL PASO NATURAL GAS CO	GT	Active	10,131	21	84	15
2748	CONSUMERS ENERGY CO	GT,GD	Active	2,467	20	7	0
31957	KINDER MORGAN WINK PIPELINE LLC	HL	Active	457	20	13	3
31454	NUSTAR LOGISTICS, L.P.	HL	Active	3,698	20	28	5
31610	BP WEST COAST PRODUCTS L.L.C.	HL,GT	Inactive	161	19	5	2
15105	PANHANDLE EASTERN PIPELINE CO	GT	Active	5,984	19	65	14
31720	EXPRESS HOLDINGS (USA), LLC	HL	Active	1,453	18	50	4
5304	FLORIDA GAS TRANSMISSION CO	GT	Active	5,360	18	67	13
12628	MOBIL PIPE LINE COMPANY	HL,GT	Active	1,130	18	35	11
26330	ENABLE OKLAHOMA INTRASTATE TRANSMISSION, LLC	HL,GT	Active	2,290	17	0	0
31888	CENTURION PIPELINE L.P.	HL	Active	2,516	16	19	7
31672	CHAPARRAL ENERGY, LLC	HL,GG	Active	283	16	14	6
13845	NORTHWEST PIPELINE LLC	GT	Active	3,855	16	133	7
31666	ROCKY MOUNTAIN PIPELINE SYSTEM, LLC	HL	Inactive	1,678	16	32	2
15156	SINCLAIR TRANSPORTATION COMPANY	HL	Active	1,131	16	58	9
22430	WEST SHORE PIPELINE CO	HL	Active	618	16	31	6
31978	ATMOS PIPELINE - TEXAS	GT	Active	5,446	15	0	0
32080	CCPS TRANSPORTATION, LLC	HL	Active	1,179	15	30	1
3445	DIXIE PIPELINE COMPANY LLC	HL	Active	1,306	15	30	9
2170	CENEX PIPELINE LLC	HL	Active	683	14	28	15
38987	KINETICA ENERGY EXPRESS LLC	GT,GG	Active	1,328	14	3	1
31531	ONEOK WESTEX TRANSMISSION, LLC	GT	Active	2,193	14	1	0
18484	SOUTHERN CALIFORNIA GAS CO	GT,GD	Active	3,485	14	0	0
26149	ALYESKA PIPELINE SERVICE CO	HL,GT	Active	950	13	151	25
12576	ENABLE MISSISSIPPI RIVER TRANSMISSION, LLC	GT	Active	1,663	13	19	5
18646	ENBRIDGE OFFSHORE (GAS TRANSMISSION) LLC	GT,GG	Inactive	359	13	4	0
30782	HARVEST PIPELINE COMPANY	HL,GT,GG	Active	584	13	10	2

30003	HOUSTON REFINING LP.	HL	Active	3	13	0	0
12624	MOBIL CORP	HL,GT	Active	247	13	0	0
32296	TARGA RESOURCES OPERATING LLC	HL,GT,GG	Active	1,309	13	10	1
2714	DOMINION TRANSMISSION, INC	HL,GT,GG	Active	3,704	12	155	27
32334	TC OIL PIPELINE OPERATIONS INC	HL	Active	1,869	12	62	13
22655	WBI ENERGY TRANSMISSION, INC.	GT	Active	3,691	12	40	8
26125	CALNEV PIPELINE CO	HL	Active	569	11	29	0
32103	CRIMSON PIPELINE L.P.	HL	Active	661	11	0	0
4472	CYPRESS INTERSTATE PIPELINE LLC	HL	Active	104	11	21	10
30777	MOTIVA ENTERPRISE LLC	HL	Active	111	11	0	0
31286	ONEOK GAS TRANSPORTATION, LLC	GT,GG	Active	2,595	11	1	0
31994	PANTHER OPERATING COMPANY, LLC	HL,GG	Active	525	11	7	4
12874	QUESTAR PIPELINE, LLC.	GT	Active	2,667	11	59	8
19730	TRUNKLINE GAS CO	GT	Active	2,217	11	24	2
395	AMOCO OIL CO	HL	Active	1,151	10	26	5
31878	BRIDGER PIPELINE LLC	HL	Active	406	10	27	6
30755	CITGO PRODUCTS PIPELINE CO	HL	Active	346	10	3	1
5081	COFFEYVILLE RESOURCES CRUDE TRANSPORTATION, LLC	HL	Active	360	10	10	7
32258	KINDER MORGAN COCHIN LLC	HL	Active	1,244	10	24	1
18152	SEA ROBIN PIPELINE CO	GT	Active	867	10	11	4
2564	COLORADO INTERSTATE GAS CO	HL,GT	Active	6,197	9	91	9
31570	TESORO HIGH PLAINS PIPELINE COMPANY LLC	HL	Active	403	9	19	8
3	ACADIAN GAS PIPELINE SYSTEM	GT,GG	Active	731	8	0	0
32044	BP USFO/LOGISTICS	HL	Active	4	8	16	2
31371	BUCKEYE DEVELOPMENT & LOGISTICS, LLC	HL,GT	Active	1,511	8	6	2
12408	DTE GAS COMPANY	GT,GG,GD	Active	2,119	8	5	2
31045	GENESIS PIPELINE USA, L.P.	HL	Active	387	8	9	4
31451	KINDER MORGAN TEXAS PIPELINE CO	GT,GG	Active	1,557	8	1	0
13769	NORTHERN BORDER PIPELINE COMPANY	GT	Active	1,409	8	18	5
31325	PACIFIC PIPELINE SYSTEM LLC	HL	Inactive	339	8	0	0
20160	PETROLOGISTICS OLEFINS, LLC	HL,GT	Inactive	492	8	0	0
31574	WESTERN REFINING PIPELINE, LLC	HL	Active	635	8	12	7
2371	WESTERN REFINING SOUTHWEST, INC	HL	Active	39	8	12	9
30826	WILLIAMS FIELD SERVICES	HL,GT,GG	Active	1,496	8	29	6
22830	WOLVERINE PIPELINE CO	HL	Active	915	8	20	5
32551	BKEP PIPELINE, LLC	HL	Active	784	7	0	0
2190	CENTRAL FLORIDA PIPELINE CORP	HL	Active	206	7	13	2
31556	CHEVRON MIDSTREAM PIPELINES LLC	HL,GT	Active	417	7	0	0
31336	CHEVRON U.S.A. INC	HL,GG	Active	48	7	14	4
39149	IMTT-BAYONNE	HL	Active	49	7	5	1
4900	KINDER MORGAN TEJAS PIPELINE	GT,GG	Active	2,801	7	1	0

14194	OILTANKING, HOUSTON LP	HL	Active	5	7	0	0
30781	OLYMPIC PIPE LINE COMPANY	HL	Active	413	7	35	4
15931	PUBLIC SERVICE CO OF COLORADO	GT,GG,GD	Active	2,129	7	0	0
32052	WHITE MARLIN OPERATING COMPANY, LLC	HL,GG	Active	81	7	0	0
31554	BOARDWALK PETROCHEMICAL PIPELINE, LLC	HL	Active	178	6	8	6
26065	CHS MCPHERSON REFINERY INC.	HL	Active	267	6	7	2
2704	CONSOLIDATED EDISON CO OF NEW YORK	GT,GD	Active	48	6	0	0
11551	DELEK LOGISTICS OPERATING, LLC.	HL	Active	567	6	15	5
32678	KINDER MORGAN CRUDE AND CONDENSATE LLC	HL	Active	253	6	0	0
26086	SEADRIFT PIPELINE CORP	HL	Active	1,031	6	0	0
39043	TALLGRASS PONY EXPRESS PIPELINE, LLC	HL	Active	763	6	22	3
792	ATLANTA GAS LIGHT CO	GT,GD	Active	1,051	5	1	0
1960	BUTTE PIPELINE CO	HL	Active	459	5	10	3
4060	DOMINION EAST OHIO	GT,GG,GD	Active	1,760	5	2	0
31613	ENBRIDGE PIPELINES (EAST TEXAS) L.P.	HL,GT,GG	Active	1,227	5	0	0
32005	ENLINK LIG, LLC	GT	Active	1,876	5	0	0
31604	EQT MIDSTREAM	HL,GT,GG	Active	1,063	5	59	9
32283	FRONT RANGE PIPELINE, LLC.	HL	Active	428	5	14	8
6660	GREAT LAKES GAS TRANSMISSION CO	GT	Active	2,115	5	31	6
32619	HILAND CRUDE, LLC	HL	Active	147	5	9	0
10250	KIANTONE PIPELINE CORP	HL	Active	85	5	23	7
32035	LDH ENERGY PIPELINE L.P.	HL	Inactive	1,446	5	0	0
11733	LOOP LLC	HL	Active	114	5	18	5
14210	OKLAHOMA NATURAL GAS COMPANY, A DIVISION OF ONE GAS,...	GT,GD	Active	711	5	0	1
15518	PIEDMONT NATURAL GAS CO INC	GT,GD	Active	2,878	5	2	0
32450	ROADRUNNER PIPELINE, L.L.C.	HL	Active	69	5	2	0
18779	SUNOCO, INC (R&M)	HL,GT,GD	Inactive	27	5	11	4
39013	TESORO SOCAL PIPELINE COMPANY LLC	HL,GT	Active	167	5	4	0
30909	TRANSMONTAIGNE OPERATING COMPANY L.P.	HL	Active	159	5	18	5
4430	VALERO TERMINALING AND DISTRIBUTION COMPANY	HL,GT	Active	126	5	18	4
39307	VITOL MIDSTREAM, LLC	HL	Active	73	5	0	0
32288	WHITE CLIFFS PIPELINE, LLC	HL	Active	1,055	5	22	2
879	CHEMOIL TERMINALS CORP.	HL	Active	31	4	0	0
99031	CITGO PETROLEUM CORPORATION (TERMINALS)	HL	Active	19	4	10	4
2387	CITGO PIPELINE CO	HL	Active	82	4	28	5
26049	COUNTRYMARK REFINING AND LOGISTICS, LLC	HL	Active	445	4	8	2
12696	CYPRESS GAS PIPELINE COMPANY	GT	Active	582	4	0	0
31627	DENBURY ONSHORE, LLC	HL,GT	Active	348	4	15	8
39023	DOUBLE EAGLE PIPELINE LLC	HL	Active	204	4	0	0
4070	EAST TENNESSEE NATURAL GAS, LLC (SPECTRA ENERGY...	GT	Active	1,526	4	38	2
25146	EQUISTAR CHEMICALS, L.P.	HL,GT	Active	1,504	4	2	0

39080	GLASS MOUNTAIN PIPELINE	HL	Active	215	4	0	0
7063	HARBOR PIPELINE CO	HL	Active	80	4	5	2
31816	MID-CONTINENT FRACTIONATION AND STORAGE, L.L.C.	HL	Active	62	4	6	2
12634	MOBIL CHEMICAL CO	HL,GT	Active	218	4	0	0
31166	MUSTANG PIPE LINE LLC	HL	Active	210	4	6	2
13063	NATIONAL FUEL GAS SUPPLY CORP	GT,GG,GD	Active	1,654	4	127	10
6141	NEW MEXICO GAS COMPANY	GT,GD	Active	1,631	4	0	0
31885	PACIFIC TERMINALS LLC	HL	Inactive	68	4	0	0
32163	ROCKIES EXPRESS PIPELINE LLC	GT	Active	1,713	4	47	7
31822	SUNCOR ENERGY (USA) PIPELINE CO.	HL	Active	330	4	32	2
32209	TEPPCO MIDSTREAM COMPANIES, LLC	HL,GG	Inactive	1,673	4	0	0
19610	TRANSWESTERN PIPELINE COMPANY LLC	GT	Active	2,547	4	32	2
21252	VIKING GAS TRANSMISSION CO	GT	Active	672	4	20	2
207	ALASKA PIPELINE CO	GT,GD	Active	391	3	16	3
32513	AMEREN ILLINOIS COMPANY	GT,GD	Active	1,246	3	0	0
31056	ASIG - HONOLULU	HL	Active	6	3	13	10
18386	BP OIL PIPELINE CO	HL	Active	108	3	19	3
12350	CENTERPOINT ENERGY RESOURCES CORP., DBA CENTERPOINT...	GT,GD	Active	151	3	2	0
39084	CRIMSON GULF, LLC	HL	Active	659	3	4	2
31846	DOMINION CAROLINA GAS TRANSMISSION, LLC	GT	Active	1,465	3	21	3
31423	ENBRIDGE ENERGY MARKETING LLC	HL	Inactive	38	3	4	0
31448	ENBRIDGE PIPELINES (TOLEDO) INC	HL	Active	148	3	3	2
15014	GAS TRANSMISSION NORTHWEST LLC	GT	Active	1,378	3	50	13
26045	HAWAII INDEPENDENT ENERGY	HL	Active	24	3	13	5
32683	INLAND CORPORATION	HL	Active	571	3	7	0
9011	J - W GATHERING CO	GT,GG	Active	49	3	0	0
32632	JP ENERGY MARKETING, LLC	HL	Inactive	115	3	2	0
30658	KERN OIL & REFINING CO.	HL	Active	24	3	0	0
30792	LAMAR OIL & GAS	HL,GG	Active	67	3	0	0
11272	LAVACA PIPELINE CO	HL,GT,GG	Active	149	3	0	0
11824	LOUISVILLE GAS & ELECTRIC CO	GT,GD	Active	400	3	0	0
39183	MEDALLION OPERATING COMPANY, LLC	HL	Active	209	3	0	0
30005	MOBIL PACIFIC PIPELINE CO	HL	Active	28	3	0	0
840	MOJAVE PIPELINE OPERATING COMPANY	GT	Active	562	3	20	1
31663	NAVAJO NATION OIL AND GAS COMPANY	HL	Active	88	3	8	6
26136	PARAMOUNT PETROLEUM CORP	HL,GT	Active	139	3	3	1
15329	PEOPLES GAS LIGHT & COKE CO	GT,GD	Active	424	3	0	0
32169	PLAINS PRODUCTS TERMINALS LLC	HL	Inactive	8	3	2	2
20044	PRAXAIR, INC	GT	Active	376	3	12	8
32335	REGENCY INTRASTATE GAS LP	GT	Inactive	456	3	0	0
18273	SHELL PIPELINE CORP	GT,GG	Active	362	3	4	0

18536	SOUTHWEST GAS CORP	GT,GD	Active	630	3	1	0
1007	TALLGRASS INTERSTATE GAS TRANSMISSION, LLC	GT,GG	Active	4,305	3	42	8
22175	TARGA MIDSTREAM SERVICES, L.P.	HL,GT,GG	Inactive	346	3	8	4
30959	THE DOW CHEMICAL COMPANY	HL,GT	Active	247	3	0	0
20202	ULTRAMAR INC	HL,GT	Active	34	3	2	1
26303	UNOCAL PIPELINE CO - EASTERN REGION	HL	Active	5	3	2	0
31296	VENOCO, INC	HL,GT,GG	Active	67	3	17	7
32688	WEST COAST TERMINAL PIPELINE (WCTP)	HL	Active	38	3	4	0
117	AIR PRODUCTS & CHEMICALS INC	GT	Active	738	2	16	6
1541	BP PIPELINES (ALASKA), INC	HL,GT	Active	83	2	56	16
11820	BRIDGELINE HOLDINGS, LP	GT	Active	962	2	0	0
32178	CALIFORNIA RESOURCES CENTRAL VALLEY	HL,GT,GG	Active	63	2	13	8
31455	CALUMET MONTANA REFINING, LLC	HL	Active	3	2	6	8
30825	CITGO PETROLEUM CORPORATION (REFINERY)	HL,GT	Active	9	2	1	0
26120	COLLINS PIPELINE CO	HL	Active	125	2	9	4
2596	COLUMBIA GAS OF OHIO INC	GT,GD	Active	132	2	0	0
31506	CONOCOPHILLIPS COMPANY (E&P-L-48)	HL	Active	115	2	0	0
515	DAKOTA GASIFICATION COMPANY	HL,GT	Active	208	2	5	6
26061	DELEK CRUDE LOGISTICS, LLC.	HL	Active	220	2	0	0
31485	ENBRIDGE OFFSHORE (GAS GATHERING) L.L.C.	HL,GT,GG	Active	465	2	9	1
32532	ENERGY XXI PIPELINE, LLC	HL,GG	Active	152	2	7	0
32107	ENLINK NGL PIPELINE, LP	HL	Active	309	2	2	0
32113	ENLINK NORTH TEXAS PIPELINE, LP	GT	Active	136	2	0	0
31983	EPL PIPELINE, LLC	HL,GG	Active	39	2	5	0
31723	EXXONMOBIL REFINING AND SUPPLY COMPANY	HL	Active	34	2	0	0
39068	FIELDWOOD ENERGY, LLC	HL,GG	Active	130	2	2	0
5656	FRONTIER PIPELINE CO	HL	Inactive	289	2	1	0
32658	HARVEST-MARKS PIPELINE, LLC	HL	Inactive	58	2	0	0
31659	IBC PETROLEUM INC	GG	Inactive	33	2	0	0
31159	KANSAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.	GT,GD	Active	1,547	2	0	0
10035	KPC PIPELINE, LLC	GT	Active	1,000	2	18	7
11032	LACLEDE GAS CO	HL,GT,GD	Active	271	2	5	0
32246	LDH ENERGY MONT BELVIEU L.P.	HL	Inactive	102	2	0	0
12127	MARATHON ASHLAND PIPE LINE LLC	GT	Inactive	0	2	0	1
9171	MARKWEST JAVELINA PIPELINE COMPANY, LLC	HL,GT,GG	Active	54	2	0	0
32412	MARKWEST LIBERTY MIDSTREAM & RESOURCES, LLC	HL,GG	Active	518	2	2	0
31871	MARKWEST MICHIGAN PIPELINE, LLC	HL	Active	40	2	13	0
32414	MARKWEST OKLAHOMA GAS COMPANY, LLC	GT,GG	Active	53	2	3	1
857	MARKWEST PINNACLE PNG UTILITY, LLC	GT	Active	140	2	0	0
32174	MCCAIN PIPELINE COMPANY	HL	Active	6	2	5	2
12498	MIDWESTERN GAS TRANSMISSION CO	GT	Active	402	2	8	1

32262	PAA NATURAL GAS STORAGE, LLC	GT,GG	Active	184	2	9	2
999	PACIFIC COAST ENERGY COMPANY, LP	HL,GG	Active	10	2	4	4
15350	PEOPLES NATURAL GAS COMPANY LLC	GT,GG,GD	Active	432	2	0	0
99043	PETROLEUM FUEL AND TERMINAL COMPANY	HL	Active	3	2	0	0
15915	PIPELINES OF PUERTO RICO INCD, THE	HL	Active	10	2	9	6
15938	PUBLIC SERVICE CO OF NORTH CAROLINA	GT,GD	Active	577	2	0	0
32668	PVR MARCELLUS GAS GATHERING, LLC	GT,GG	Inactive	72	2	0	0
31852	REGENCY FIELD SERVICES LLC	HL,GG	Inactive	110	2	0	0
17620	ROCKY MOUNTAIN NATURAL GAS CO INC	GT	Active	513	2	1	0
18156	SEADRIFT PIPELINE CORP	GT	Active	247	2	0	0
32602	SOCAL HOLDINGS, LLC / LA BASIN	HL,GT,GG	Active	8	2	8	0
31594	SOUTHCROSS CCNG TRANSMISSION LTD	GT	Active	405	2	0	0
31835	STERLING EXPLORATION & PRODUCTION CO LLC	HL,GG	Inactive	37	2	0	0
39012	SUMMIT MIDSTREAM PARTNERS, LLC	HL,GG	Active	31	2	8	0
31779	SWISSPORT FUELING INC	HL	Active	12	2	0	0
26099	TAMPA BAY PIPELINE CO.	HL	Active	93	2	15	8
38933	TESORO LOGISTICS OPERATIONS LLC - SOUTHERN CALIFORNIA	HL	Active	15	2	0	0
18532	TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.	GT,GD	Active	314	2	0	0
19410	THUMS LONG BEACH CO	HL,GT,GG	Active	33	2	11	2
38894	THUNDER BASIN PIPELINE, LLC	HL	Active	45	2	4	0
30834	TIDELANDS OIL PRODUCTION COMPANY	HL,GT	Active	5	2	3	0
31013	TRANSPETCO TRANSPORT CO.	HL	Active	179	2	5	1
39105	VALERO PARTNERS OPERATING CO. LLC	HL,GT	Active	292	2	3	1
32223	VALERO REFINING COMPANY - CALIFORNIA	HL	Active	25	2	0	0
26112	VALERO REFINING-TEXAS L.P.	HL,GT	Active	76	2	0	0
31470	VECTREN ENERGY DELIVERY OF OHIO	HL,GT,GD	Active	234	2	3	3
21349	VIRGINIA NATURAL GAS	GT,GD	Active	191	2	0	0
30940	WILLIAMS ENERGY, LLC	HL,GT,GG	Active	543	2	6	1
31968	WTG GAS TRANSMISSION COMPANY	GT	Active	559	2	1	0
288	ALGONQUIN GAS TRANSMISSION, L.L.C. (SPECTRA ENERGY...	GT	Active	1,133	1	114	11
8170	ALLIANT ENERGY - INTERSTATE POWER AND LIGHT COMPANY	GT,GD	Active	810	1	1	0
12462	AMERICAN MIDSTREAM (MIDLA), LLC	GT	Active	345	1	11	5
32013	AMERIGAS PROPANE LP	HL,GT,GD	Active	6	1	24	12
31264	AQUILA NETWORKS	GT,GD	Inactive	279	1	0	0
31245	ATI METALS	GT,GD	Active	5	1	0	0
22476	ATMOS ENERGY CORPORATION - KY/MID-STATES (KENTUCKY)	GT,GD	Active	196	1	0	0
1217	BEAR CREEK STORAGE CO	GT	Active	25	1	4	0
32453	BHP BILLITON PETROLEUM (EAGLE FORD GATHERING) LLC	HL,GT	Active	201	1	0	0
32088	BIG WEST OF CALIFORNIA, LLC	GT	Inactive	2	1	4	3
1472	BLACK MARLIN PIPELINE CO	GG	Active	55	1	4	1
1552	BLUE DOLPHIN PIPELINE COMPANY	GT,GG	Active	70	1	4	2

39010	BLUE RACER MIDSTREAM, LLC	HL,GG	Active	298	1	1	0
32249	BLUEWATER GAS STORAGE, LLC	GT,GG	Inactive	36	1	2	0
1734	BRIDGELINE GAS DISTRIBUTION LLC	GT	Inactive	476	1	0	0
32483	BRIDGER LAKE, LLC	HL	Active	24	1	4	1
31824	CALUMET LUBRICANTS CO., L.P.	HL	Active	34	1	0	0
39229	CAMINO REAL GATHERING CO LLC	HL,GG	Active	47	1	0	0
31670	CELANESE LTD	HL	Inactive	51	1	0	0
2196	CENTRAL HUDSON GAS & ELECTRIC CORP	GT,GD	Active	165	1	0	0
32646	CHESAPEAKE OPERATING, L.L.C.	HL,GT,GG	Active	29	1	0	0
2339	CHEVRON PRODUCTS COMPANY - HAWAII	HL	Active	45	1	12	1
32177	CHIEF ETHANOL FUELS INC.	GT	Active	2	1	0	0
32379	COBRA PIPELINE COMPANY, LTD.	GT,GG,GD	Active	170	1	0	0
39191	CONSOLIDATED EDISON CO OF NY	HL	Active	1	1	0	0
31571	CONSUMERS ENERGY	GT,GD	Inactive	12	1	0	0
18104	CPS ENERGY	GT,GD	Active	89	1	0	0
2859	CRANBERRY PIPELINE CORP (WV)	GT,GG,GD	Active	213	1	0	0
32205	DAVIS PETROLEUM PIPELINE, LLC.	GG	Active	15	1	0	0
32543	DENBURY GREEN PIPELINE-TEXAS, LLC	HL	Active	144	1	5	0
32545	DENBURY GULF COAST PIPELINES, LLC	HL	Active	370	1	8	0
31088	DESTIN PIPELINE COMPANY, LLC	GT	Active	272	1	6	3
31304	DEVON GAS SERVICES, LP	HL,GT	Active	47	1	3	2
3466	DOME PETROLEUM CORP	HL	Inactive	136	1	3	0
2162	DOW PIPELINE CO - CAYUSE	HL	Active	249	1	5	1
5320	DUKE ENERGY FLORIDA, LLC D/B/A DUKE ENERGY	HL	Active	33	1	9	1
2364	DUKE ENERGY OHIO	GT,GD	Active	71	1	0	0
15825	EAGLE US 2 LLC	GT	Active	43	1	7	4
4350	ELIZABETHTOWN GAS CO	GT,GD	Active	22	1	0	0
31202	ENABLE MIDSTREAM PARTNERS, LP	HL,GT,GG	Active	271	1	0	0
32502	ENBRIDGE PIPELINES (SOUTHERN LIGHTS) L.L.C.	HL	Active	816	1	8	1
39286	ENERGY XXI USA, INC	HL	Active	158	1	2	0
32118	ENLINK NORTH TEXAS GATHERING, LP	GT,GG	Active	237	1	0	0
32117	ENLINK PROCESSING SERVICES, LLC	HL,GT	Active	450	1	0	0
30666	ENMARK ENERGY, INC	HL,GT,GD	Active	100	1	6	6
32009	EXXONMOBIL OIL CORPORATION-TERMINALS	HL	Active	4	1	10	2
26039	FLORIDA POWER & LIGHT CO	HL,GT	Active	91	1	22	2
18667	FREEPORT-MCMORAN OIL & GAS	HL,GT,GG	Active	107	1	30	11
39264	FRONTIER ENERGY SERVICES, L.L.C.	HL	Active	130	1	1	0
39047	GEL OFFSHORE PIPELINE, LLC	HL	Active	70	1	2	0
32410	GENESIS FREE STATE PIPELINE, LLC	HL	Active	91	1	2	0
32407	GENESIS PIPELINE TEXAS, L.P.	HL	Active	114	1	0	0
31527	GORDON TERMINAL SERVICES	HL	Inactive	5	1	3	1

6580	GRANITE STATE GAS TRANSMISSION INC	GT	Active	86	1	12	4
6640	GRAYVILLE GAS DEPT, CITY OF	GT,GD	Active	14	1	0	0
31712	GUARDIAN PIPELINE, LLC	GT	Active	263	1	4	1
6911	GULF STATE PIPELINE CO INC	HL	Active	55	1	0	0
7050	HAMPSHIRE GAS CO	GT	Active	18	1	8	0
31863	HFOTCO LLC	HL	Active	21	1	0	0
39055	JP ENERGY PERMIAN, LLC	HL	Active	150	1	0	0
31705	KATY STORAGE & TRANSPORTATION LP	GT	Active	16	1	0	0
31082	KEY PIPELINE LIMITED	HL	Inactive	17	1	4	2
1800	KEYSPAN ENERGY DELIVERY - NY CITY	GT,GD	Active	70	1	0	0
39467	KURARAY AMERICA, INC.	HL	Active	9	1	0	0
31836	LEGACY RESOURCES CO LP	GT	Inactive	4	1	0	0
31673	LONE STAR NGL REFINERY SERVICES LLC	HL	Inactive	105	1	0	0
12180	MARSHALL COUNTY GAS DISTRICT	GT,GD	Active	85	1	0	0
32051	MARTIN OPERATING PARTNERSHIP, L.P.	HL	Active	213	1	0	0
31686	MASTERS RESOURCES LLC	GG	Inactive	99	1	0	0
30750	MIDAMERICAN ENERGY COMPANY	GT,GD	Active	705	1	4	0
32436	MIDCONTINENT EXPRESS PIPELINE LLC	GT	Active	512	1	10	1
30769	MISSOURI GAS ENERGY	GT,GD	Active	46	1	0	0
12684	MONTANA - DAKOTA UTILITIES CO	GT,GD	Active	93	1	1	1
12732	MONTEZUMA NATURAL GAS DEPT	GT,GD	Active	19	1	0	0
13299	NEW JERSEY NATURAL GAS CO	GT,GD	Active	227	1	0	0
38924	NGL CRUDE TERMINALS	HL,GG	Active	60	1	4	0
13480	NIAGARA MOHAWK POWER CORP	GT,GD	Active	272	1	1	2
13710	NORTHERN ILLINOIS GAS CO	GT,GD	Active	1,159	1	1	0
13840	NORTHWEST NATURAL GAS CO	GT,GD	Active	653	1	0	0
39090	NUTAAQ PIPELINE, LLC	HL,GT	Active	57	1	3	1
14145	OHIO RIVER VALLEY PIPELINE, LLC	HL	Active	68	1	5	1
32613	OILTANKING PORT NECHES, LLC	HL	Inactive	3	1	0	0
30629	ONEOK FIELD SERVICES COMPANY, L.L.C.	GT,GG	Active	188	1	1	2
31532	ONEOK GAS STORAGE, LLC	GT	Active	50	1	1	0
1031	ONYX PIPELINE CO	GT	Inactive	65	1	0	0
15033	PAIUTE PIPELINE CO	GT	Active	859	1	31	2
15348	PEOPLES GAS SYSTEM INC	GT,GD	Active	162	1	0	0
15485	PHILLIPS 66 COMPANY - SWEENY REFINERY	HL,GT	Active	341	1	0	0
32037	PITT LANDFILL GAS, LLC	GT	Active	3	1	0	0
15786	PORTLAND PIPE LINE CORPORATION	HL	Active	332	1	18	7
12876	QUESTAR GAS COMPANY	GT,GD	Active	826	1	0	0
32167	QUICKSILVER RESOURCES INC	HL,GT,GG	Active	35	1	0	0
39085	RIMROCK MIDSTREAM	HL	Active	46	1	3	0
18112	SAN DIEGO GAS & ELECTRIC CO	GT,GD	Active	228	1	0	0

39104	SKEISUI SPECIALTY CHEMICALS AMERICA	HL	Inactive	2	1	0	0
18408	SOUTH CAROLINA ELECTRIC & GAS CO	GT,GD	Active	447	1	0	0
31557	SOUTHCROSS GULF COAST TRANSMISSION, LTD	GT,GG	Active	106	1	0	0
32341	SOUTHEAST SUPPLY HEADER, LLC	GT	Active	287	1	7	2
32266	ST. JAMES OIL CORPORATION	HL	Inactive	3	1	0	0
18608	STANDARD PACIFIC GAS LINE INC	GT	Active	56	1	0	0
32380	STECKMAN RIDGE, LP (SPECTRA ENERGY PARTNERS, LP)	GT	Active	9	1	8	0
31591	STONE ENERGY	HL,GG	Active	25	1	14	8
31583	TESORO LOGISTICS OPERATIONS LLC - MOUNTAIN REGION	HL	Active	19	1	10	3
32327	TEXAS PIPELINE LLC	HL,GT	Active	93	1	0	0
39098	TEXSTAR MIDSTREAM LOGISTICS, LP	HL	Active	144	1	0	0
19269	TGG PIPELINE LTD	GG	Active	17	1	0	0
32346	TOTAL PETROCHEMICALS PIPELINE USA , INC.	HL	Active	39	1	0	0
19319	TPC GROUP, LLC	HL,GT	Active	134	1	0	0
32487	TRANSCANADA NORTHERN BORDER INC	GT	Active	302	1	19	5
19580	TRANSCOLORADO PIPELINE CO.	GT	Active	312	1	14	3
31270	TRI-STATES NGL PIPELINE LLC	HL	Active	167	1	9	4
19892	UCAR PIPELINE INCORPORATED	HL,GT	Active	417	1	12	4
15259	UGI PENN NATURAL GAS	GT,GD	Active	50	1	0	0
20035	UNOCAL PIPELINE COMPANY	HL,GG	Inactive	65	1	1	1
39349	USG WHEATLAND PIPELINE, LLC	HL	Active	23	1	2	0
31356	VECTOR PIPELINE, L.P.	GT	Active	274	1	11	7
22435	WEST TEXAS GAS INC	GT,GG,GD	Active	813	1	15	9
31563	WHITECAP PIPE LINE COMPANY, L.L.C.	HL	Active	44	1	6	2
31703	WILLIAMS MLP OPERATING, LLC	HL,GT,GG	Active	736	1	1	0
32096	WYNNEWOOD REFINERY COMPANY	HL	Active	2	1	0	0
32460	1486 GAS PIPELINE, LLC	GT	Active	5	0	0	0
899	5P GAS PIPELINE COMPANY	GT	Active	8	0	0	0
31564	7-D GAS SUPPLY CORP	GG	Active	2	0	0	0
31544	ABARTA OIL & GAS CO	GG	Active	2	0	0	0
32665	ABBOTT NUTRITION SUPPLY CHAIN	GT	Active	1	0	0	0
32662	ABBS VALLEY PIPELINE LLC	GG	Inactive	1	0	0	0
32350	ABSOLUTE ENERGY L.L.C.	GT	Active	3	0	0	0
21	ACACIA NATURAL GAS, L.L.C.	GT,GG	Active	125	0	0	0
31759	ACADIA PARTNERS PIPELINE	GT	Active	8	0	0	0
32317	ACME BRICK	GT	Active	7	0	0	0
31313	ACME BRICK LATERAL - KN ENGERY	GT	Active	9	0	0	0
39056	ACTIVA RESOURCES, LLC	GG	Active	1	0	0	0
31007	ADM CORN PROCESSING DIVISION-NW GAS CONTRACTED	GT	Active	18	0	0	0
32538	ADVANCED REFINING CONCEPTS, LLC	GT	Active	0	0	0	0
31749	AECC- OSWALD GENERATING STATION	GT	Active	5	0	0	0

32306	AEP GENERATION RESOURCES-DARBY GENERATING STATION	GT	Active	1	0	0	0
31067	AERA ENERGY LLC	HL,GT,GG	Active	12	0	20	0
39356	AETHON ENERGY OPERATING LLC	GT,GG	Active	5	0	0	0
32294	AG PROCESSING INC A COOPERATIVE	GT	Active	9	0	0	0
32073	AGAVE ENERGY COMPANY	HL,GT,GG	Active	71	0	0	0
31181	AGC FLAT GLASS NORTH AMERICA, INC	GT	Active	7	0	0	0
32190	AGC FLAT GLASS NORTH AMERICA, INC., GREENLAND PLANT	GT,GD	Active	0	0	0	0
31375	AGRIUM US, INC	HL,GT	Inactive	2	0	0	0
842	AIR LIQUIDE LARGE INDUSTRIES U.S. LP	GT	Active	375	0	0	0
30901	AIRCRAFT SERVICES INTERNATIONAL GROUP (ASIG)	HL	Active	7	0	14	9
39250	AIX ENERGY LLC	GT	Active	1	0	0	0
39235	AJAX PIPE LINE COMPANY, LLC	GG	Active	3	0	0	0
144	AJAX PIPELINE CO	GG,GD	Inactive	10	0	0	0
31225	AK STEEL CORP	GT	Active	10	0	0	0
32197	AKA ENERGY GROUP, LLC	GT,GG	Active	7	0	0	0
32358	AKZO NOBEL PULP AND PERFORMANCE CHEMICALS.	GT	Active	1	0	0	0
180	ALABAMA GAS CORPORATION	GT,GD	Active	224	0	0	0
32605	ALAMO PIPELINE LLC	GT	Active	33	0	0	0
30851	ALBEMARLE CORPORATION	GT	Active	6	0	0	0
250	ALERT OIL & GAS CO INC	GG	Inactive	10	0	0	0
38954	ALLEGHENY LAND AND EXPLORATION	GG	Active	7	0	0	0
31389	ALLIANCE ENERGY TRANSMISSIONS - SYRACUSE, LLC	GT	Active	10	0	0	0
39256	ALLIANCE PETROLEUM CORPORATION	GG	Active	6	0	0	0
31199	ALLIANCE PIPELINE L.P.	HL,GT	Active	969	0	27	4
22784	ALLIANT ENERGY - WISCONSIN POWER & LIGHT CO	GT,GD	Active	40	0	0	0
32559	ALON USA KROTZ SPRINGS REFINERY, INC	HL	Active	18	0	0	0
31443	ALON USA, LP	HL,GT	Active	62	0	0	0
31552	ALPINE TRANSPORTATION CO.	HL	Active	35	0	8	0
32593	ALTA MESA SERVICES, LP	GT,GG	Active	5	0	0	0
31758	ALTAGAS FACILITIES (US) INC	HL,GT	Active	2	0	1	1
383	AMARILLO NATURAL GAS INC	GT,GD	Active	19	0	0	0
2200	AMERENCILCO	GT,GD	Inactive	197	0	0	0
2204	AMERENCIPS	GT,GD	Inactive	288	0	0	0
8040	AMERENIP	GT,GD	Inactive	767	0	0	0
20050	AMERENUE	GT,GD	Active	66	0	0	0
32434	AMERESCO EVANSVILLE LLC	GT	Active	5	0	0	0
32435	AMERESCO JEFFERSON CITY LLC	GT,GD	Active	4	0	0	0
32433	AMERESCO MCCARTY ENERGY LLC	GT	Active	6	0	0	0
31771	AMERESCO PALMETTO	GT	Active	10	0	0	0
32126	AMERESCO PINE BLUFF, LLC	GT	Active	3	0	0	0
31911	AMERICAN ENERGIES GAS SERVICE, LLC	GT	Active	5	0	0	0

31909	AMERICAN ENERGIES PIPELINE, LLC	GT	Active	2	0	0	0
30948	AMERICAN MIDSTREAM (ALABAMA GATHERING) LLC	GT,GG	Inactive	19	0	0	0
30946	AMERICAN MIDSTREAM (ALABAMA INTRASTATE) LLC	GT	Active	118	0	0	0
189	AMERICAN MIDSTREAM (ALATENN), LLC	GT	Active	295	0	12	3
31577	AMERICAN MIDSTREAM (BAMAGAS INTRASTATE) LLC	GT	Active	52	0	0	0
2879	AMERICAN MIDSTREAM (LOUISIANA INTRASTATE), LLC	GT	Active	138	0	0	0
31910	AMERICAN MIDSTREAM (MISSISSIPPI), LLC	GT,GG	Active	8	0	0	0
31365	AMERICAN MIDSTREAM (SEACREST), LP	GT,GG	Active	81	0	0	0
31424	AMERICAN MIDSTREAM (SIGCO INTRASTATE), LLC	GT	Active	40	0	0	0
31395	AMERICAN MIDSTREAM (TENNESSEE RIVER) LLC	GT	Active	39	0	0	0
39277	AMERICAN MIDSTREAM BAKKEN, LLC	HL	Active	44	0	0	0
31256	AMERICAN MIDSTREAM GAS SOLUTIONS, LP	HL,GT	Active	38	0	0	0
31426	AMERICAN MIDSTREAM ONSHORE PIPELINES, LLC	GT	Active	25	0	0	0
39459	AMERICAN MIDSTREAM PERMIAN, LLC	GT	Active	1	0	0	0
31688	AMERICO ENERGY RESOURCES LLC	GG	Active	9	0	0	0
39430	AMP GATHERING I, LP	GG	Active	2	0	0	0
31757	ANADARKO E & P COMPANY LP	HL,GG	Inactive	221	0	4	4
473	ANADARKO PETROLEUM CORP	HL,GT,GG	Active	970	0	28	5
469	ANADARKO PRODUCTION CO	GT,GG	Inactive	147	0	0	0
32489	ANCHOR POINT ENERGY, LLC	GT	Active	7	0	11	1
31523	ANDERSON OIL LTD	HL,GT	Active	3	0	0	0
38914	ANDROSCOGGIN VALLEY REGIONAL REFUSE DISPOSAL DISTRICT	GT	Active	2	0	0	0
39005	ANGELINA GATHERING COMPANY, LLC	GT,GG	Active	25	0	0	0
937	ANSCHUTZ - RANCH EAST PIPELINE CO	GT	Inactive	39	0	1	0
32680	ANSCHUTZ EXPLORATION CORPORATION	GG	Inactive	4	0	0	0
39162	ANTERO MIDSTREAM LLC	GT,GG	Active	10	0	0	0
550	APACHE CORP	GG	Inactive	13	0	0	0
31864	APACHE CORPORATION	HL,GT	Active	44	0	5	2
31540	APACHE GAS TRANSMISSION	GT	Active	18	0	0	0
32261	APC , INC	GT,GD	Active	2	0	0	0
32465	APPALACHIA MIDSTREAM SERVICES, L.L.C.	GT,GG	Inactive	28	0	0	0
980	APPALACHIAN NATURAL GAS DISTRIBUTION COMPANY	GT,GD	Active	8	0	0	0
31760	AQUILA SERVICES INC	GT	Inactive	6	0	0	0
32521	ARAPAHO COMMUNICATIONS, LP	GT,GD	Active	15	0	0	0
38962	ARBOL RESOURCES, INC.	GG	Inactive	7	0	0	0
32082	ARC TERMINALS	HL	Active	2	0	7	5
39241	ARC TERMINALS JOLIET HOLDINGS LLC	HL	Active	5	0	0	0
32416	ARCADIA GAS STORAGE, LLC	GT	Active	26	0	0	0
31662	ARCHER DANIELS MIDLAND CO	GT,GD	Active	1	0	0	0
39148	ARGOS CEMENT LLC	GT	Active	20	0	0	0
31367	ARGUELLO, INC.	HL,GG	Inactive	38	0	0	0

585	ARGYLE MUNICIPAL GAS SYSTEM	GT,GD	Active	2	0	0	0
39273	ARIA ENERGY	GT	Active	3	0	0	0
32618	ARKALON ETHANOL, LLC	GT	Active	1	0	0	0
621	ARKANSAS OKLAHOMA GAS CORP	GT,GD	Active	141	0	0	0
660	ARLINGTON GAS PIPELINE CO, LP	GT	Active	12	0	0	0
32490	ARLINGTON STORAGE COMPANY LLC	GT	Inactive	50	0	2	3
665	ARMADILLO PIPELINE CO	GG	Inactive	4	0	0	0
31786	AROC (TEXAS) INC	HL,GT	Inactive	13	0	0	0
39002	ARP BARNETT PIPELINE, LLC	GG	Active	4	0	0	0
39011	ARP BARNETT, LLC	GT,GG	Active	3	0	0	0
39083	ARROW PIPELINE	HL	Inactive	102	0	0	0
31517	ASCEND PERFORMANCE MATERIALS TEXAS INC	HL	Active	123	0	0	0
39337	ASCENT RESOURCES	GG	Active	22	0	0	0
31624	ASH GROVE CEMENT COMPANY	GT	Active	1	0	0	0
31114	ASSOCIATED MILK PRODUCERS INC PIPELINE	GT	Inactive	20	0	0	0
32421	ATCHLEY RESOURCES INC.	GG	Inactive	5	0	0	0
39118	ATLAS BARNETT, LLC	GT,GG	Active	4	0	0	0
38884	ATLAS PIPELINE TENNESSEE, LLC	GT	Active	28	0	0	0
32463	ATMOS ENERGY CORPORATION - ATMOS GATHERING COMPANY, LLC	GT	Active	4	0	0	0
31729	ATMOS ENERGY CORPORATION - ATMOS PIPELINE AND STORAGE,...	GT	Active	26	0	0	0
6720	ATMOS ENERGY CORPORATION - COLORADO/KANSAS	GT,GD	Active	9	0	1	0
20211	ATMOS ENERGY CORPORATION - KY/MID-STATES (MID-STATES)	GT,GD	Active	66	0	0	0
11800	ATMOS ENERGY CORPORATION - LOUISIANA	GT,GD	Active	21	0	0	0
31348	ATMOS ENERGY CORPORATION - MID-TEX	GT,GD	Active	314	0	0	0
12582	ATMOS ENERGY CORPORATION - MISSISSIPPI	GT,GD	Active	294	0	0	0
11017	ATMOS ENERGY CORPORATION - TRANS LOUISIANA GAS PIPELINE	GT	Active	50	0	0	0
4473	ATMOS ENERGY CORPORATION - WEST TEXAS	GT,GD	Active	116	0	0	0
39007	AURORA GAS, LLC	GT	Active	20	0	2	0
32094	AUX SABLE LIQUID PRODUCTS	HL,GT	Active	78	0	8	1
32641	AUX SABLE MIDSTREAM	GT	Active	85	0	0	0
31232	AVISTA CORP	GT,GD	Active	123	0	0	0
31685	AZTECA MILLING LP	GT	Active	8	0	0	0
39417	AZURE SHELBY ASSETS, LLC	GG	Active	0	0	0	0
39411	AZURE TGG, LLC	GG	Active	13	0	0	0
32059	B. D. DEANS LLC	GT	Inactive	5	0	0	0
39026	BAGLEY PIPELINE, LLC	GG	Active	2	0	0	0
38945	BAKKEN PIPELINE COMPANY LP	HL	Active	76	0	3	0
1065	BALCONES STARR PIPELINE	GG	Active	29	0	0	0
1088	BALTIMORE GAS & ELECTRIC CO	GT,GD	Active	161	0	0	0
31481	BANGOR GAS CO LLC	GT,GD	Active	9	0	0	0
32124	BARNETT GATHERING, LLC	GT,GG	Active	381	0	0	0

31116	BARON EXPLORATION COMPANY	GG	Inactive	1	0	0	0
1134	BARROW UTILITIES & ELECTRIC CORP	GT,GD	Active	6	0	9	4
39303	BASA RESOURCES, INC.	HL	Active	16	0	0	0
31059	BASF CORPORATION	HL	Active	9	0	0	0
32145	BASIN ELECTRIC POWER COOPERATIVE	GT	Active	25	0	0	0
31714	BASIN FROZEN FOODS	GT	Inactive	4	0	0	0
1130	BASIN PIPELINE CORP	GG	Inactive	1	0	0	0
31726	BASIN PIPELINE LLC	GT,GG	Active	90	0	0	0
30073	BASS ENTERPRISES PRODUCTION CO	GG	Inactive	26	0	0	0
32511	BATON ROUGE RENEWABLE ENERGY, LLC	GT	Active	5	0	0	0
1176	BATTLE CREEK GAS CO	GT,GG,GD	Inactive	22	0	0	0
31901	BAXTER HEALTHCARE CORP.	GT	Active	2	0	0	0
30026	BAY GAS STORAGE CO. LTD.	GT	Active	96	0	0	0
31782	BAYSIDE POWER STATION	GT	Active	1	0	0	0
1213	BAZZLE GAS CO	GG	Inactive	4	0	0	0
30968	BEARTOOTH PIPELINE	HL	Inactive	76	0	2	0
1232	BEDFORD NATURAL GAS SYSTEM	GT,GD	Active	17	0	0	0
6710	BELVAN PARTNERS LP	HL	Inactive	9	0	0	0
1228	BENAVIDES, CITY OF	GT,GD	Inactive	11	0	0	0
1320	BENSON-MONTIN-GREER DRILLING CORP	GG	Inactive	60	0	0	0
1344	BERKSHIRE GAS CO	GT,GD	Active	6	0	0	0
26009	BERRY PETROLEUM CO	GT	Inactive	3	0	1	0
32224	BETA OFFSHORE	HL	Active	18	0	12	4
32649	BHP BILLITON PETROLEUM (ARKANSAS) INC.	GT,GG	Active	90	0	0	0
39059	BHP BILLITON PETROLEUM (TX GATHERING), LLC	GT	Inactive	1	0	0	0
1426	BIG SANDY GAS COMPANY	GG	Active	0	0	0	0
32583	BIG SANDY PIPELINE, LLC (SPECTRA ENERGY PARTNERS, LP)	GT	Active	67	0	2	0
1432	BIG TWO MILE GAS CO	GG	Inactive	6	0	0	0
39278	BIGHORN GAS OPERATING LLC	HL,GT,GG	Inactive	9	0	0	0
31480	BIS TEPSCO INC.	GT	Inactive	3	0	0	0
32544	BLACK BELT ENERGY	GT	Active	14	0	0	0
32625	BLACK ELK ENERGY LLC	HL,GG	Inactive	18	0	5	2
15359	BLACK HILLS ENERGY	GT,GD	Active	644	0	0	0
2537	BLACK HILLS NORTHWEST WYOMING GAS UTILITY COMPANY, LLC	GT,GD	Active	197	0	0	0
31754	BLACK HILLS POWER INC	GT	Active	1	0	0	0
32564	BLACK HILLS SERVICE COMPANY	GT	Active	16	0	0	0
39372	BLACK HILLS SHOSHONE PIPELINE, LLC	GT	Active	30	0	0	0
1466	BLACK LAKE PIPE LINE CO	HL	Inactive	313	0	1	0
32244	BLACK POOL ENERGY, L.P.	GG	Active	8	0	0	0
1486	BLACK WARRIOR TRANSMISSION CORP	GT,GD	Active	11	0	0	0
30047	BLANDING, CITY OF	GT,GD	Active	33	0	0	0

39021	BLUE STONE NATURAL RESOURCES, LLC	GT	Active	4	0	0	0
39108	BLUEFISH PIPELINE LLC	HL	Active	4	0	0	0
38932	BLUESTONE PIPELINE COMPANY OF PA, LLC	GT	Active	55	0	0	0
32161	BMC HOLDINGS, INC.	HL	Inactive	5	0	0	0
38903	BOARD OF PUBLIC UTILITIES	HL	Inactive	3	0	2	0
32606	BOARDWALK FIELD SERVICES, LLC	HL,GT,GG	Active	120	0	0	0
39138	BOARDWALK LOUISIANA MIDSTREAM, LLC	HL,GT	Active	468	0	0	0
39210	BOARDWALK STORAGE COMPANY, LLC	GT	Active	14	0	2	0
32396	BOBCAT GAS STORAGE (SPECTRA ENERGY PARTNERS, LP)	GT	Active	24	0	2	0
12990	BOBWHITE PRODUCTION CO INC	GT	Active	3	0	0	0
31973	BOC GASES	HL	Active	7	0	5	2
31149	BOIS DARC OFFSHORE, LTD	HL,GG	Inactive	10	0	1	3
32233	BOPCO, L.P.	GT,GG,GD	Active	15	0	0	0
32257	BORAL BRICKS, INC.	GT	Active	3	0	0	0
1640	BOSTON GAS CO	GT,GD	Active	6	0	1	0
31630	BP AMERICA PRODUCTION	HL,GT,GG	Active	28	0	2	2
30062	BRADKEN-ATCHISON/ST. JOSEPH, INC	GT,GD	Active	2	0	0	0
30657	BRAVO PIPELINE COMPANY	HL	Active	899	0	8	4
1700	BRAZOS ELECTRIC POWER COOPERATIVE INC	GT	Active	71	0	0	0
39249	BRD ONE, LLC	GT	Active	3	0	0	0
30546	BREA CANON OIL COMPANY	GG	Inactive	11	0	1	0
38899	BREITBURN MANAGEMENT COMPANY, LLC	HL	Active	2	0	0	0
32228	BREITBURN OPERATING (TEXAS)	GG	Active	56	0	0	0
30029	BREITBURN OPERATING L.P.	HL,GT,GG	Active	144	0	0	0
955	BRIDGELINE STORAGE COMPANY	GT	Inactive	11	0	0	0
39046	BRIDGER TRANSFER SERVICES, LLC	HL	Active	4	0	3	0
1752	BRIGHTON MUNICIPAL GAS SYSTEM	GT,GD	Active	14	0	0	0
39058	BROWN INDUSTRIAL GAS, INC	GG	Inactive	6	0	0	0
30984	BRYAN, CITY OF	GT	Active	4	0	0	0
32633	BUCCANEER ALASKA OPERATIONS, LLC	GT	Inactive	1	0	5	0
39230	BUFFCO PRODUCTION, INC.	GG	Active	1	0	0	0
30965	BULLDOG GAS & POWER LLC	GT,GD	Active	3	0	7	2
30981	C W RESOURCES	GG	Active	5	0	0	0
2001	CABOT OIL & GAS CORP	GT,GG,GD	Active	20	0	0	0
38950	CADEVILLE GAS STORAGE, LLC	GT	Active	8	0	2	2
39294	CAELUS NATURAL RESOURCES ALASKA, LLC	HL	Active	8	0	0	0
32629	CAIMAN EASTERN MIDSTREAM, LLC	GT	Inactive	1	0	0	0
31933	CALCASIEU REFINING COMPANY	HL,GT	Active	6	0	0	0
32394	CALEDONIA ENERGY PARTNERS, LLC	GT	Active	3	0	2	0
38904	CALERA GATHERING LLC	GT	Active	23	0	0	0
32685	CALGAS LLC	GT	Active	6	0	0	0

39099	CALIBER MIDSTREAM	HL,GT,GG	Active	30	0	3	0
31394	CALIFORNIA GAS GATHERING INC	GT	Active	33	0	5	1
31228	CALIFORNIA RESOURCES ELK HILLS, LLC	HL,GT	Active	60	0	8	0
39227	CALIFORNIA RESOURCES VENTURA BASIN	HL,GT,GG	Active	62	0	5	0
2042	CALLIDUS TECHNOLOGIES BY HONEYWELL	GT	Active	2	0	0	0
992	CALLON OFFSHORE PRODUCTION, INC	GG	Inactive	6	0	0	0
31763	CALPINE NATURAL GAS LP	GT	Inactive	8	0	0	0
31788	CALPINE TEXAS PIPELINE LP	GT	Active	41	0	0	0
31847	CALUMET LUBRICANTS CO., L. P.	HL	Active	6	0	0	0
32503	CALUMET SHREVEPORT FUELS, LLC	HL	Active	8	0	0	0
12913	CALUMET SUPERIOR, LLC	HL	Active	6	0	5	9
32531	CAMBRIAN ENERGY/ SOUTHTEX FT. SMITH TREATERS	GT	Active	1	0	0	0
32345	CAMERON INTERSTATE PIPELINE	GT	Active	37	0	8	1
31789	CAMPEON GAS CORPORATION	GT	Inactive	8	0	0	0
39308	CANTERA OPERATING	GT,GG	Active	20	0	0	0
39419	CANYON TRANSMISSION, LLC.	GG	Active	26	0	0	0
32158	CAPCO OPERATING CORPORATION	GG	Inactive	17	0	0	0
2066	CAPE COD GAS CO (DIV OF COLONIAL GAS CO)	GT,GD	Active	0	0	0	0
32176	CARDINAL FG	GT	Active	3	0	0	0
32554	CARDINAL MIDSTREAM LLC	HL,GT	Inactive	19	0	0	0
32657	CARDINAL OPERATING COMPANY, LLC	GT	Active	105	0	0	0
32515	CARGILL SALT	GT	Active	3	0	0	0
39444	CARRIZO (EAGLE FORD) LLC	GT,GG	Active	9	0	0	0
39446	CARRIZO (MARCELLUS) LLC	GT	Active	2	0	0	0
1017	CARRIZO OIL & GAS, INC.	GT	Inactive	4	0	0	0
2128	CASCADE NATURAL GAS CORP	GT,GD	Active	204	0	0	0
32142	CASCADE PIPELINE	HL	Active	13	0	0	0
30860	CASKIDS OPERATING COMPANY	GG	Inactive	1	0	0	0
39050	CASPER CRUDE TO RAIL, LLC	HL	Active	6	0	5	2
39030	CCI PARADOX MIDSTREAM LLC	GG	Active	2	0	0	0
31775	CCI ROBINSON�S BEND LLC	GT,GG	Active	14	0	0	0
32230	CDX GAS, LLC	GT	Inactive	23	0	0	0
39258	CEDARLINE LLC	GG	Active	6	0	0	0
32404	CEI PIPELINE, LLC	GT	Active	11	0	0	0
39037	CEJA CORPORATION	GT	Active	1	0	0	0
2168	CELANESE CHEMICAL CO	HL,GT	Inactive	16	0	0	0
39492	CELANESE CHEMICALS, INC	HL	Active	21	0	0	0
32612	CELERO ENERGY II, L.P.	HL	Inactive	18	0	0	0
32389	CENTAURI TECHNOLOGIES, LP	GT	Active	6	0	0	0
32024	CENTERPOINT ENERGY INTRASTATE PIPELINES, INC.	GT,GD	Active	184	0	0	0
31790	CENTERPOINT ENERGY PIPELINE SERVICES	GT	Inactive	44	0	0	0

603	CENTERPOINT ENERGY RESOURCES CORP.	GT,GD	Active	105	0	0	0
4499	CENTERPOINT ENERGY RESOURCES CORPORATION	GT,GD	Active	148	0	0	0
31024	CENTRA PIPELINE MINNESOTA INC.	GT	Active	68	0	10	3
2180	CENTRAL CITY GAS SYSTEM DEPT	GT,GD	Active	4	0	0	0
2188	CENTRAL FLORIDA GAS CORP	GT,GD	Active	10	0	0	0
31584	CENTRAL IOWA POWER COOPERATIVE	GT	Active	5	0	0	0
31546	CENTRAL LOUISIANA ENERGY PIPELINE CO (CLEPCO)	HL,GT	Active	41	0	0	0
31783	CENTRAL NEW YORK OIL AND GAS CO LLC	GT	Inactive	95	0	12	8
32104	CENTRAL RESOURCES, INC.	HL	Inactive	3	0	0	0
32603	CENTRAL VALLEY GAS STORAGE, LLC	GT	Active	16	0	0	0
32106	CENTURY ALUMINUM	GT	Active	13	0	0	0
32058	CHACO ENERGY CO.	GG	Inactive	1	0	0	0
31211	CHALKEY TRANSMISSION COMPANY, LTD	GT	Inactive	40	0	0	0
39341	CHALMETTE LOUISIANA LIQUIDS, LLC	HL	Active	42	0	0	0
39409	CHALMETTE REFINING, L.L.C.	HL	Active	4	0	0	0
39201	CHANDELEUR PIPE LINE, LLC	GT	Active	216	0	3	0
32475	CHANDLER CONSTRUCTION SERVICES, INC	GT	Inactive	6	0	0	0
2256	CHANUTE, CITY OF	GT,GD	Active	0	0	0	0
2288	CHATTANOOGA GAS CO	GT,GD	Active	7	0	4	5
32264	CHENIERE CREOLE TRAIL PIPELINE, L.P.	GT	Active	96	0	6	2
32609	CHEROKEE BASIN PIPELINE, LLC	GT,GG	Active	5	0	0	0
38920	CHERRY ISLAND RENEWABLE ENERGY, LLC (CIRE)	GT	Active	4	0	0	0
31246	CHESAPEAKE APPALACHIA, L.L.C.	GT,GG	Active	187	0	1	1
2309	CHESAPEAKE UTILITIES CORPORATION	GT,GD	Active	9	0	0	0
31826	CHEVRON PRODUCTS COMPANY	GT	Inactive	2	0	0	0
38963	CHEVRON U.S.A. INC - APPALACHIAN/MICHIGAN BUSINESS UNIT	GG	Active	33	0	0	0
31707	CHEVRON U.S.A. INC - PERMIAN BASIN	HL,GT,GG	Active	9	0	0	0
2332	CHEYENNE LIGHT FUEL & POWER	GT,GD	Active	314	0	0	0
39196	CHEYENNE RAIL HUB	HL	Active	2	0	2	1
32510	CHIEF GATHERING, LLC	GT	Inactive	1	0	0	0
2304	CHILDERSBURG GAS BOARD	GT,GD	Active	28	0	0	0
30713	CHINN EXPLORATION COMPANY	GG	Active	24	0	0	0
39320	CHISOS PIPELINE COMPANY LLC	GG	Active	8	0	0	0
32406	CHROMA OPERATING, INC.	GT,GG	Inactive	6	0	0	0
31908	CHS OILSEED PROCESSING-NW GAS CONTRACTED	GT	Active	5	0	0	0
31382	CIMAREX ENERGY CO. OF COLORADO	GT,GG	Inactive	10	0	0	0
39024	CINCO NATURAL RESOURCES CORPORATION	GG	Active	20	0	0	0
39123	CINNABAR ENERGY LTD.	GT	Active	10	0	0	0
2382	CITATION OIL & GAS CORP	GT	Active	6	0	0	0
32676	CITATION PIPELINE LLC	GG	Active	3	0	0	0
31023	CITGO REFINING & CHEMICAL CO. L.P.	HL,GT	Active	66	0	0	0

2392	CITIZENS GAS & COKE UTILITY	GT,GD	Active	240	0	0	0
2408	CITIZENS GAS FUEL CO	GT,GD	Active	16	0	0	0
38965	CITY OF ALBUQUERQUE, SOLID WASTE MANAGEMENT DEPT.	GT	Active	2	0	0	0
32520	CITY OF BANGOR	HL	Active	1	0	4	2
32431	CITY OF CALHOUN	GT,GD	Active	1	0	0	0
3590	CITY OF DULUTH PUBLIC WORKS & UTILITIES	GT,GD	Active	5	0	9	8
31093	CITY OF FOSSTON MUNICIPAL GAS	GT,GD	Active	0	0	0	0
32287	CITY OF GARDNER	GT	Active	1	0	0	0
30040	CITY OF GIRARD	GT	Active	2	0	0	0
31986	CITY OF GLENDALE, GLENDALE WATER & POWER	GT,GD	Active	6	0	6	4
39113	CITY OF GREENSBORO	GT	Active	3	0	0	0
32567	CITY OF LITTLE ROCK	GT	Active	1	0	0	0
38959	CITY OF MIDLAND UTILITIES DIVISION	GT	Active	3	0	0	0
32304	CITY OF REDDING	GT	Active	3	0	4	2
32263	CITY OF ULYSSES	GG	Inactive	3	0	0	0
31955	CITY OF VERNON	GT,GD	Active	4	0	16	4
31416	CITY OF WALL LAKE	GT,GD	Active	11	0	0	0
31494	CITY WATER AND LIGHT PLANT	GT	Active	23	0	0	0
2465	CLAIBORNE NATURAL GAS INC	GT,GD	Active	26	0	0	0
2456	CLARKE - MOBILE COUNTIES GAS DIST	GT,GD	Active	150	0	0	0
31974	CLAUSEN-KOCH APC	GT	Inactive	3	0	0	0
30943	CLE INTRASTATE PIPELINE INC	GT	Active	2	0	0	0
32637	CLEAN HARBORS LONE MOUNTAIN FACILITY	GT	Active	5	0	0	0
2480	CLEARFIELD MUNICIPAL GAS SYSTEM	GT,GD	Active	6	0	0	0
38890	CLEARWATER PIPELINE COMPANY LLC	GG	Inactive	1	0	0	0
31330	CLECO POWER LLC	GT	Active	9	0	0	0
2512	CLINTON - NEWBERRY NATURAL GAS AUTH	GT,GD	Active	103	0	0	0
39025	CLOVER PRODUCTION COMPANY	GG	Active	2	0	0	0
31263	CMF OF KANSAS LLC	GT,GD	Active	2	0	0	0
30688	CMS GAS TRANSMISSION CO	GT,GG	Inactive	58	0	0	0
38910	CNX GAS COMPANY LLC	GT,GG,GD	Active	38	0	0	0
39127	COAL GAS RECOVERY II, LLC	GT	Active	0	0	0	0
31725	COALFIELD PIPELINE COMPANY	GT	Active	16	0	0	0
39000	COASTLAND OPERATIONS LLC	HL	Active	1	0	0	0
39345	COBRA OIL & GAS CORP.	GT	Active	3	0	0	0
31791	COBRA OPERATING COMPANY	GG	Inactive	3	0	0	0
11856	COLONIAL GAS CO - LOWELL DIV	GT,GD	Active	6	0	0	0
32654	COLONIAL RESOURCES	GG	Active	2	0	0	0
32076	COLORADO ENERGY MANAGEMENT	GT	Inactive	5	0	0	0
31316	COLORADO NATURAL GAS INC.	GT,GD	Active	7	0	0	0
2585	COLUMBIA GAS OF KENTUCKY INC	GT,GD	Active	57	0	0	0

2588	COLUMBIA GAS OF MARYLAND INC	GT,GD	Active	5	0	0	0
1209	COLUMBIA GAS OF MASSACHUSETTS	GT,GD	Active	2	0	0	0
2600	COLUMBIA GAS OF PENNSYLVANIA	GT,GD	Active	63	0	1	0
2604	COLUMBIA GAS OF VIRGINIA INC	GT,GD	Active	75	0	0	0
39132	COLUMBIA MIDSTREAM GROUP, LLC	HL	Active	36	0	2	0
38990	COLUMBUS ENERGY, LLC	GG	Active	8	0	0	0
39110	COMINS LUMBER SALES, INC.	GT	Active	1	0	0	0
39270	COMMERCE MIDSTREAM, LLC	GT	Active	13	0	0	0
32128	COMMERCE PIPELINE L.P.	GT	Inactive	3	0	0	0
38909	COMPRESSED ENERGY SYSTEMS, LLC	GT	Active	0	0	0	0
32238	CONAGRA FOODS LAMB WESTON, INC	GT	Active	0	0	0	0
32351	CONNECT NGL PIPELINE, LLC	HL	Inactive	20	0	0	0
38973	CONNECT TERMINALS, LLC	HL,GT	Active	2	0	0	0
13131	CONOCOPHILLIPS (E&P - L-48)	GT,GG	Active	34	0	1	0
15480	CONOCOPHILLIPS ALASKA NATURAL GAS CORP.	GT	Active	44	0	19	1
31970	CONOCOPHILLIPS ALASKA, INC.	HL	Active	35	0	9	1
39253	CONSOLIDATED ASSET MANAGEMENT SERVICES (TX), LLC	GT	Active	20	0	0	0
2710	CONSTITUTION GAS TRANSPORT CO	GT,GD	Inactive	16	0	0	0
31895	CONTINENTAL BUILDING PRODUCTS	GT	Active	6	0	0	0
31776	CONTINUUM MIDSTREAM LLC	HL,GT,GG	Active	31	0	2	2
39091	COOK INLET ENERGY, LLC	GT,GG	Active	8	0	0	0
2767	COOK INLET PIPE LINE CO	HL	Active	44	0	9	2
32144	COOS COUNTY PIPELINE	GT	Active	77	0	0	0
30691	COPANO FIELD SERVICES/COPANO BAY LP	GG	Inactive	24	0	0	0
32293	COPANO FIELD SERVICES/NORTH TEXAS, LLC	GT,GG	Active	16	0	0	0
39172	COPANO FIELD SERVICES/SOUTH TEXAS LLC	GG	Active	12	0	0	0
31924	COPANO FIELD SERVICES/UPPER GULF COAST LLC	GG	Active	2	0	0	0
32541	COPANO NGL SERVICES (MARKHAM), LLC	HL	Active	176	0	0	0
32114	COPANO NGL SERVICES LLC	HL	Active	159	0	0	0
31925	COPANO PIPELINES/SOUTH TEXAS LLC	GG	Active	2	0	0	0
31926	COPANO PIPELINES/UPPER GULF COAST LLC	GT,GG	Active	107	0	0	0
39487	COPANO PROCESSING LLC	HL	Active	3	0	0	0
32049	CORLENA OIL COMPANY	GG	Inactive	3	0	0	0
39063	CORN, LP	GT	Active	6	0	0	0
2796	CORNING MUNICIPAL UTILITIES	GT,GD	Active	14	0	0	0
32319	CORONADO ENERGY E&P COMPANY, LLC	GT,GG	Inactive	3	0	0	0
39184	CORONADO MIDSTREAM, LLC	HL,GT,GG	Inactive	34	0	0	0
32507	CORONADO PIPELINE COMPANY , LLC	HL	Active	16	0	0	0
31231	COTTRELLVILLE PIPELINE	GT,GG	Active	4	0	0	0
39431	COVEY PARK RESOURCES LLC	GG	Active	2	0	0	0
32526	COWTOWN PIPELINE PARTNERS L.P.	HL,GT,GG	Active	122	0	0	0

32143	COYOTE SPRINGS PLANT - PORTLAND GENERAL ELECTRIC	GT	Active	0	0	0	0
31477	CPN PIPELINE COMPANY	GT,GG	Active	142	0	23	7
32505	CPR PIPELINE	GT	Active	11	0	0	0
32639	CRAWFORD COUNTY GAS GATHERING, LLC	GT	Active	0	0	0	0
32568	CRESTWOOD ARKANSAS PIPELINE LLC	GT	Inactive	43	0	0	0
32677	CRESTWOOD DAKOTA PIPELINE LLC	HL	Inactive	21	0	2	2
39368	CRESTWOOD MIDSTREAM PARTNERS LP	HL,GT,GG	Active	404	0	8	2
32576	CRESTWOOD PANHANDLE PIPELINE LLC	HL,GT	Active	21	0	0	0
38928	CRESTWOOD PIPELINE EAST LLC	GT	Inactive	37	0	0	0
31919	CRESTWOOD WEST COAST LLC	HL,GG	Inactive	51	0	4	1
39282	CRISP COUNTY POWER COMMISSION	GT	Active	13	0	0	0
31090	CROOKS MUNICIPAL GAS, CITY OF	GT,GD	Active	14	0	0	0
993	CROSSROADS PIPELINE COMPANY	GT	Active	202	0	7	0
31596	CROSSTEX ENERGY SERVICES, L.P.	GT	Inactive	1	0	0	0
2899	CROSSTEX PIPELINE PARTNERS, LTD	GG	Inactive	3	0	0	0
32644	CUMBERLAND PIPELINE COMPANY, L.L.C.	GT	Inactive	10	0	0	0
7640	CYPRESS GAS MARKETING COMPANY	GT	Inactive	2	0	0	0
30518	D & L INC	GT	Active	1	0	0	0
32328	DAIRY FARMERS OF AMERICA	GT	Active	5	0	0	0
39221	DAKOTA MIDSTREAM	HL	Active	21	0	4	0
3081	DAL - TILE CORP	GT	Inactive	3	0	0	0
32372	DAL-TILE CORPORATION	GT	Inactive	3	0	0	0
31408	DALLAS PRODUCTION INC	GT,GG	Active	9	0	0	0
3090	DALTON WATER LIGHT & SINKING FUND COMMISSION	GT,GD	Active	29	0	0	0
32384	DALTON-WHITFIELD REGIONAL SOLID WASTE MANAGMENT...	GT	Active	2	0	0	0
3093	DAMASCUS GAS CO	GG	Inactive	1	0	0	0
31100	DANISCO CULTOR USA INC	GT,GD	Active	3	0	0	0
3133	DART OIL & GAS CORP	GT	Active	1	0	0	0
3156	DAVIS GAS PROCESSING	HL,GT	Active	32	0	0	0
3170	DAYTON POWER & LIGHT CO	GT	Active	14	0	0	0
32083	DCOR, LLC	HL,GG	Active	97	0	29	2
39028	DCP MIDSTREAM - PEPL	GT	Active	427	0	2	1
39293	DDS RENTALS LLC	GT	Active	7	0	0	0
32575	DEEPROCK OIL OPERATING, LLC	HL	Active	13	0	2	0
99001	DEFENSE FUEL SUPPLY POINT	HL	Active	5	0	2	0
39150	DELAWARE BASIN MIDSTREAM, LLC	GT	Inactive	9	0	0	0
39129	DELAWARE BASIN NGL PIPELINE LLC	HL	Active	24	0	0	0
32495	DELAWARE PIPELINE COMPANY, LLC	HL	Active	23	0	5	2
31252	DELAWARE SOLID WASTE AUTHORITY	GT	Inactive	1	0	0	0
31526	DELAWARE STORAGE AND PIPELINE COMPANY	HL	Active	10	0	6	2
26031	DELAWARE TERMINAL CO	HL	Inactive	3	0	0	0

15851	DELEK MARKETING AND SUPPLY, LP	HL	Active	105	0	0	0
39520	DELFIN OFFSHORE PIPELINE LLC	GT	Active	30	0	1	0
3240	DELMARVA POWER & LIGHT COMPANY	GT,GD	Active	8	0	0	0
31393	DELTA GAS GATHERING INC	GG	Inactive	24	0	1	0
3260	DELTA NATURAL GAS CO INC	GT,GG,GD	Active	168	0	0	0
32168	DENTON GATHERING MANAGEMENT, L.L.C.	GG	Inactive	3	0	0	0
32533	DESOTO GATHERING COMPANY LLC	GG	Active	7	0	0	0
32187	DETROIT EDISON - GREENWOOD ENERGY CENTER	HL	Inactive	19	0	1	0
3345	DEVON ENERGY PRODUCTION CO. LP	HL,GT,GG	Active	53	0	1	0
32427	DEWBRE PETROLEUM CORP	GT,GG	Active	11	0	0	0
32354	DFW MIDSTREAM SERVICES, LLC	GT,GG	Active	117	0	0	0
3370	DIAMOND SHAMROCK REFINING & MARKETING CO	HL,GT	Inactive	13	0	0	0
32213	DIAMOND SHAMROCK REFINING CO. LP	GT	Active	9	0	0	0
32116	DICK BROWN TECHNICAL SERVICES	HL,GT	Active	21	0	13	1
39248	DIVIDE CREEK GATHERING SYSTEM, LLC	GT	Active	4	0	0	0
31460	DOD DEFENSE ENERGY SUPPORT CENTER	HL	Active	80	0	0	0
32265	DOGWOOD ENERGY, LLC	GT	Active	7	0	0	0
31679	DOMINION EXPLORATION & PRODUCTION	GT,GG	Inactive	10	0	0	0
7348	DOMINION HOPE	GG,GD	Active	62	0	0	0
39133	DOMTAR PAPER COMPANY	GT	Active	0	0	0	0
39440	DOUBLE H	HL	Active	512	0	1	0
31442	DOUGLAS PIPELINE CO	GT,GD	Active	65	0	3	0
31307	DOW HYDROCARBONS & RESOURCES, INC	GT	Active	3	0	0	0
3532	DOW INTRASTATE GAS CO	GT	Active	8	0	0	0
3527	DOW PIPELINE CO	HL,GT,GG	Active	649	0	6	2
3535	DOW PIPELINE CO	HL,GT	Active	226	0	0	0
32454	DRY TRAILS MIDSTREAM ENERGY, LLC	HL,GT	Active	46	0	2	0
32574	DTE METHANE RESOURCES, LLC	GT,GG	Inactive	11	0	0	0
31866	DUKE ENERGY - ASHEVILLE COMBUSTION TURBINE	GT	Active	3	0	0	0
31892	DUKE ENERGY - DEBARY COMBUSTION TURBINE	GT	Active	3	0	0	0
31893	DUKE ENERGY - INTERCESSION CITY COMBUSTION TURBINE...	GT	Inactive	0	0	0	0
20110	DUKE ENERGY KENTUCKY	GT,GD	Active	25	0	0	0
31887	DUKE ENERGY KENTUCKY - LIQUID	HL	Active	3	0	5	6
31886	DUKE ENERGY OHIO - LIQUID	HL	Active	4	0	3	3
39178	DUKE ENERGY- INDIANA NOBLESVILLE STATION	GT	Active	2	0	0	0
32210	DYNEGY KENDALL ENERGY, LLC	GT	Active	2	0	0	0
4005	E M W GAS ASSOCIATION	GT,GD	Active	68	0	0	0
31075	E&B NATURAL RESOURCES MANAGEMENT CORP	HL,GT,GG	Active	6	0	5	1
39038	E&T LLC	HL	Active	0	0	0	0
32636	EAGLE CHIEF MIDSTREAM, LLC	GT	Active	3	0	0	0
38892	EAGLE ENERGY DEVELOPMENT COMPANY	GG	Inactive	6	0	0	0

38943	EAGLE FORD MIDSTREAM, LP	GT	Active	167	0	0	0
32014	EAGLE MOUNTAIN PIPELINE CO LP	GT,GG	Inactive	78	0	0	0
32045	EAGLE ROCK DESOTO PIPELINE, L.P.	GT,GG	Inactive	274	0	0	0
32635	EAGLE ROCK ENERGY SERVICES, L.P.	HL	Inactive	12	0	0	0
32236	EAGLE ROCK FIELD SERVICES, L.P.	HL,GT,GG	Inactive	58	0	0	0
32112	EAGLE ROCK MIDSTREAM, LP	GG	Inactive	1	0	0	0
32234	EAGLE ROCK OPERATING, L.P.	HL,GT,GG	Inactive	49	0	0	0
39271	EAGLECLAW MIDSTREAM VENTURES	GT	Active	3	0	0	0
39267	EAGLERIDGE OPERATING, LLC	GG	Active	3	0	0	0
32655	EAST CHEYENNE GAS STORAGE, LLC	GT	Active	7	0	2	0
31000	EAST KENTUCKY POWER CORPORATION	GT	Active	7	0	0	0
31512	EAST RESOURCES INC	GG,GD	Inactive	10	0	0	0
32586	EAST TEXAS RENEWABLES	GT	Active	1	0	0	0
4149	EASTERN SHORE NATURAL GAS CO	GT,GD	Active	442	0	19	5
32590	EASTMAN GAS COMPANY, LLC	GG	Active	8	0	0	0
32491	EASTOK PIPELINE LLC	GT	Active	12	0	0	0
32561	ECOELECTRICA L.P.	GT	Active	2	0	7	3
31361	EDMOND CITYLINK LLC	GG	Inactive	2	0	0	0
39017	EFS MIDSTREAM LLC	GT	Inactive	25	0	0	0
30028	EGAN HUB STORAGE, LLC (SPECTRA ENERGY PARTNERS, LP)	GT	Active	59	0	3	0
4273	EGYPTIAN GAS STORAGE CORP	GT	Active	16	0	0	0
32577	EIF KC LANDFILL GAS, LLC	GT	Active	1	0	0	0
32056	EL PASO CGP GAS TRANSMISSION CO.	GT	Inactive	8	0	0	0
30950	EL PASO FIELD SERVICES	HL,GT,GG	Inactive	72	0	2	0
32497	EL PASO REMEDIATION COMPANY	GG	Inactive	9	0	0	0
4310	ELBERTON NATURAL GAS SYSTEM	GT,GD	Active	12	0	0	0
32540	ELECTRAGAS INC.	HL	Active	3	0	0	0
4360	ELIZABETHTOWN NATURAL GAS	GT,GD	Active	3	0	0	0
39074	ELK HILLS POWER, LLC	GT	Active	10	0	2	0
39369	ELLSJET TERMINAL	HL	Active	7	0	1	0
39323	ELLWOOD REALTY ACQUISITION COMPANY (ERAC)	GT	Active	12	0	0	0
32217	ELWOOD ENERGY LLC	GT	Active	3	0	0	0
39094	ELYSIUM JENNINGS, LLC	GT,GG	Active	12	0	0	0
38882	EM BIOGAS, LLC	GT	Active	7	0	0	0
38989	EMERALD GATHERING AND TRANSMISSION	GG	Active	8	0	0	0
38941	EMKEY GATHERING LLC	GG	Active	1	0	0	0
38944	EMKEY TRANSPORTATION INC	GT	Active	28	0	0	0
4440	EMMETSBURG MUNICIPAL UTILITIES	GT,GD	Active	3	0	0	0
32569	EMPIRE GENERATING COMPANY LLC.	GT	Active	5	0	0	0
32171	EMPIRE PIPELINE CORPORATION	GT,GG	Active	79	0	0	0
31592	EMPIRE PIPELINE INC	GT	Active	270	0	10	0

39069	EMPIRE PIPELINE, LLC	HL	Active	50	0	0	0
32239	EMS USA, INC.	GT	Active	106	0	1	0
39147	ENABLE GAS GATHERING, LLC	GG	Active	23	0	0	0
8035	ENABLE ILLINOIS INTRASTATE TRANSMISSION, LLC	GT	Active	20	0	0	0
32318	ENABLE TEXAS LIQUIDS PIPELINE, LLC	HL	Inactive	86	0	0	0
31722	ENBRIDGE G & P (OKLAHOMA), L.P.	GT	Inactive	26	0	0	0
31943	ENBRIDGE GATHERING (NORTH TEXAS) L.P.	HL,GT,GG	Active	265	0	0	0
31615	ENBRIDGE GATHERING (TEXARKANA) L.L.C.	GG	Inactive	36	0	0	0
32101	ENBRIDGE MARKETING (NORTH TEXAS) L.P.	HL	Inactive	28	0	0	0
39354	ENBRIDGE OFFSHORE FACILITIES	HL,GG	Active	269	0	0	0
31616	ENBRIDGE OFFSHORE PIPELINES (UTOS) LLC	GT	Inactive	29	0	0	0
31884	ENBRIDGE PIPELINES (LOUISIANA LIQUIDS) L.L.C.	HL	Inactive	42	0	0	0
31614	ENBRIDGE PIPELINES (NE TEXAS) L.P.	HL,GT	Inactive	10	0	0	0
31944	ENBRIDGE PIPELINES (NORTH TEXAS) L.P.	GT,GG	Inactive	121	0	0	0
31425	ENBRIDGE PIPELINES (TEXAS GATHERING) L.P.	HL,GT	Active	392	0	0	0
31322	ENBRIDGE PIPELINES (TEXAS INTRASTATE) L.P.	GT	Inactive	39	0	0	0
31778	ENCANA OIL & GAS (USA) INC	HL,GT,GG	Active	90	0	6	0
915	ENCINAL GATHERING, LTD	GG	Inactive	49	0	0	0
32474	ENCORE OPERATING, L.P.	GT,GG	Inactive	56	0	0	0
39142	ENERFIN FIELD SERVICES LLC	GG	Active	23	0	0	0
30588	ENERFIN RESOURCES I LIMITED PARTNERSHIP	GT,GG	Active	30	0	0	0
952	ENERFIN RESOURCES II-92 LIMITED PARTNERSHIP	GT	Active	10	0	0	0
19102	ENERGEN RESOURCES CORP.	HL,GT,GG	Active	10	0	0	0
31740	ENERGY CORPORATION OF AMERICA	GT,GG	Active	27	0	0	0
31772	ENERGY MANAGEMENT & SVCS CO	GT	Inactive	9	0	0	0
16667	ENERGY NORTH NATURAL GAS INC	GT,GD	Active	3	0	0	0
4489	ENERGY PRODUCTION CORP	GT	Active	5	0	0	0
31879	ENERGY WEST DEVELOPMENT, INC.	GT,GD	Inactive	30	0	7	4
32536	ENERVEST OPERATING, LLC	GT,GG	Active	56	0	0	0
32060	ENGLISH BAY PIPELINE, L.P.	GT,GG	Inactive	3	0	0	0
32488	ENI US OPERATING CO, INC	HL	Active	19	0	9	1
39202	ENLINK CALCASIEU, LLC	GT	Active	13	0	0	0
31643	ENLINK DC GATHERING COMPANY, JV	GG	Inactive	24	0	0	0
31883	ENLINK LOUISIANA GATHERING, LLC	GG	Inactive	2	0	0	0
39112	ENLINK MIDSTREAM SERVICES, LLC	GT,GG	Active	288	0	0	0
32597	ENLINK PERMIAN II, LLC	HL	Active	17	0	0	0
32634	ENLINK PERMIAN, LLC	HL,GT	Active	9	0	0	0
39075	ENLINK TEXAS NGL PIPELINE, LLC	HL	Active	36	0	0	0
19761	ENLINK TUSCALOOSA, LLC	GT	Active	34	0	0	0
32659	ENREMA, LLC	GT	Active	51	0	0	0
4483	ENSTAR NATURAL GAS CO	GT,GD	Active	1	0	44	16

31238	ENTERGY CORP	GT	Inactive	8	0	0	0
13360	ENTERGY NEW ORLEANS, INC	GT,GD	Active	36	0	0	0
31773	ENTERGY SERVICES INC	GT	Inactive	4	0	0	0
30006	ENTERPRISE PELICAN PIPELINE L.P.	GT	Active	27	0	0	0
39214	ENVEN ENERGY VENTURES LLC.	HL	Active	28	0	3	0
32221	ENVIROGAS LP	GT	Inactive	2	0	0	0
4461	EOG RESOURCES, INC	HL,GT,GG	Active	189	0	0	0
31774	EP ENERGY E&P COMPANY, L.P.	HL,GT	Active	14	0	0	0
31876	EP ENERGY GATHERING COMPANY, L.L.C.	GT,GG	Inactive	28	0	0	0
38887	EPIC MIDSTREAM LLC	HL	Active	85	0	5	1
32184	EQUILON ENTERPRISES LLC DBA SHELL OIL PRODUCTS US -...	HL	Inactive	9	0	0	0
4510	EQUITABLE GAS COMPANY, LLC	GT,GG,GD	Inactive	141	0	2	1
4511	EQUITRANS INC	GT,GG	Inactive	782	0	15	1
4476	ERG RESOURCES, LLC	GG	Inactive	11	0	0	0
39095	ERGON - TEXAS PIPELINE	HL	Active	42	0	0	0
15979	ERGON TERMINALING, INC.	HL	Active	38	0	6	4
32449	EROC GATHERING COMPANY, L.P.	GT,GG	Inactive	7	0	0	0
32298	ESG PIPELINE (JC), LLC	GT,GD	Active	4	0	0	0
32467	ETC TIGER PIPELINE, LLC	GT	Active	197	0	4	0
32046	ETHANOL 2000 LLP (NORTHWEST GAS CONTRACTED)	GT	Active	1	0	0	0
32667	EUREKA HUNTER PIPELINE, LLC	GT,GG	Active	18	0	0	0
32093	EX EL PIPELINE SERVICES LLC	GT	Active	12	0	8	1
32366	EXCELERATE ENERGY LP	GT	Inactive	8	0	3	1
32087	EXCO OPERATING COMPANY, LP	GT,GG	Inactive	178	0	0	0
7009	EXCO RESOURCES (PA), LLC	GT	Active	29	0	4	0
32278	EXCO RESOURCES, INC	GG	Inactive	1	0	0	0
31593	EXCO-NORTH COAST ENERGY, INC	GG	Inactive	16	0	0	0
30639	EXOKO GAS TECHNOLOGIES, INC	GT,GD	Active	4	0	0	0
31121	EXPRO ENGINEERING INC	GG	Inactive	8	0	0	0
4908	EXXONMOBIL PRODUCTION COMPANY, A DIVISION OF EXXON...	HL,GG	Active	258	0	24	3
5334	F M C CORP	GG	Inactive	67	0	0	0
5335	F M C CORPORATION	GT	Active	14	0	0	0
860	FAIRBANK, CITY OF	GT,GD	Active	8	0	0	0
99128	FAIRBANKS NATURAL GAS	GT,GD	Active	1	0	33	15
31992	FAIRPLAY GAS GATHERING, L.P.	GG	Inactive	6	0	0	0
32274	FALCON BAY OPERATIONS, LLC	GG	Inactive	2	0	0	0
39115	FAMCOR TRANSPORTATION, INC	GG	Active	4	0	0	0
32401	FARADAY PIPELINE COMPANY	GG	Active	7	0	0	0
39252	FASKEN OIL AND RANCH, LTD.	GT	Active	11	0	0	0
32469	FAYETTEVILLE EXPRESS PIPELINE, LLC	GT	Active	185	0	3	0
31204	FAYETTEVILLE GAS PRODUCERS, LLC	GT,GD	Active	2	0	0	0

32461	FAYETTEVILLE GATHERING COMPANY	GT,GG	Active	23	0	0	0
39291	FDL OPERATING LLC	HL	Active	155	0	0	0
570	FERNDALE PIPELINE SYSTEM	GT	Active	36	0	0	0
38961	FIDELITY EXPLORATION & PRODUCTION COMPANY	GT,GG	Inactive	10	0	0	0
39022	FINLEY RESOURCES, INC.	GT,GG	Active	6	0	0	0
30579	FLASH GAS & OIL SOUTHWEST, INC	GG	Inactive	7	0	0	0
39067	FLINT HILLS RESOURCES ARTHUR, LLC	GT	Active	22	0	0	0
2432	FLORIDA CITY GAS	GT,GD	Active	104	0	0	0
5330	FLORIDA PUBLIC UTILITIES CO	GT,GD	Active	13	0	8	6
32182	FLORIDA ROCK INDUSTRIES, INC.	GT,GD	Inactive	26	0	0	0
39434	FOOTHILLS TEXAS, INC.	HL	Active	2	0	0	0
26040	FOREST OIL CORP	GG	Active	4	0	2	0
39155	FORESTA GATHERING, LLC	GG	Active	13	0	0	0
39154	FORT APACHE ENERGY, INC.	GG	Active	1	0	0	0
32202	FOUNDATION ENERGY MANAGEMENT CO, LLC	GT	Inactive	11	0	0	0
39251	FOUNDATION ENERGY MANAGEMENT, LLC	GT	Active	48	0	0	0
31853	FOUNTAIN VALLEY POWER LLC	GT	Active	6	0	0	0
5524	FOUR STAR OIL & GAS CO	HL,GT,GG	Inactive	95	0	0	0
32393	FREEBIRD GAS STORAGE, LLC	GT	Active	8	0	3	0
39233	FREEDOM PIPELINE COMPANY, LLC	GG	Active	2	0	0	0
39312	FREEDOM PIPELINE, LLC	GG	Active	12	0	0	0
32206	FREEPORT LNG DEVELOPMENT, L.P.	GT	Active	10	0	8	2
5605	FREEPORT PIPELINE CO	GT	Inactive	3	0	0	0
38946	FRESNO ENERGY LLC	GT	Inactive	1	0	0	0
39156	FRIO LASALLE PIPELINE, LP	HL	Active	197	0	0	0
31406	FRONTIER ENERGY	GT,GD	Active	139	0	0	0
32248	FRONTIER FIELD SERVICES, LLC	HL,GT	Active	26	0	0	0
32385	FRONTIER GAS SERVICES, LLC	HL,GT	Inactive	54	0	0	0
39086	FT. BEND POWER PRODUCERS	GT	Active	3	0	0	0
6030	GAINESVILLE REGIONAL UTIL GAS DEPT	GT,GD	Active	0	0	1	1
31988	GALLAGHER DRILLING INC	GT	Active	0	0	0	0
31429	GALLOWAY ENERGY CO	GG	Active	5	0	0	0
39014	GALVESTON BAY ENERGY, LLC	HL,GG	Active	38	0	0	0
3830	GARLAND, CITY OF	GT	Active	6	0	0	0
31745	GAS RECOVERY SYSTEMS, LLC	GT	Active	4	0	4	2
38992	GATEWAY COMMERCE LLC	GT	Inactive	3	0	0	0
39078	GATEWAY DELMAR LLC	GT	Active	1	0	0	0
31804	GATEWAY OFFSHORE PIPELINE CO	GG	Active	79	0	0	0
30785	GATEWAY PIPELINE COMPANY	GT,GG,GD	Active	20	0	0	0
32587	GATEWAY RED OAK LLC	GT	Active	13	0	0	0
31753	GATHERCO INC	GG	Active	15	0	0	0

3082	GAYLYN INC	GT	Active	14	0	0	0
39126	GENERAL GAS PIPELINE, LLC	GT	Active	68	0	0	0
32409	GENESIS C02 PIPELINE, L.P.	HL	Active	9	0	1	0
32492	GENESIS CRUDE OIL, L.P.	HL,GT	Active	8	0	0	0
32408	GENESIS NATURAL GAS PIPELINE, L.P.	GT,GG	Inactive	4	0	0	0
39352	GENESIS OFFSHORE HOLDINGS, LLC	HL,GT,GG	Active	2,002	0	2	1
32411	GENESIS PIPELINE ALABAMA, LLC	HL	Active	46	0	1	2
32130	GENON ENERGY - OSCEOLA	GT	Inactive	2	0	0	0
31538	GENON PINEY POINT, LLC	HL	Inactive	52	0	0	0
32066	GEOMET INC.	GT	Inactive	17	0	0	0
39428	GEOPETRO LLC	GG	Active	3	0	0	0
6345	GEORGIA PACIFIC LLC - CROSSETT PAPER OPERATIONS	GT	Active	20	0	6	2
31096	GEORGIA-PACIFIC CONSUMER PRODUCTS (CAMAS) LLC	GT	Active	1	0	0	0
32172	GERDAU MACSTEEL	GT,GD	Active	3	0	0	0
39169	GIBBS DIE CASTING, INC	GT	Active	1	0	0	0
31737	GILA RIVER POWER LLC	GT	Active	19	0	0	0
32549	GILL RANCH STORAGE LLC	GT	Active	32	0	0	0
30619	GLADEWATER GATHERING CO., L.P.	GG	Active	6	0	0	0
32305	GLOBAL ETHANOL	GT	Active	2	0	0	0
32220	GOLDEN PASS LNG TERMINAL LLC	GT	Active	70	0	9	3
32512	GOLDEN TRIANGLE STORAGE, INC.	GT	Active	17	0	2	1
31536	GOLDEN VALLEY ELECTRIC ASSOCIATION, INC	HL	Active	5	0	12	5
30574	GOLDSTON OIL CORPORATION	GT	Active	3	0	0	0
32604	GORHAM PAPER AND TISSUE, LLC	GT	Active	1	0	0	0
32420	GRAMA RIDGE STORAGE AND TRANSPORTATION, LLC	GT	Active	6	0	0	0
32136	GRANGER ENERGY OF HONEY BROOK, LLC	GT,GD	Active	13	0	0	0
30850	GREAT LAKES CHEMICAL CORP	GT,GG	Active	8	0	0	0
6690	GREAT PLAINS NATURAL GAS CO	GT,GD	Active	75	0	7	3
32315	GREATER MINNESOTA TRANSMISSION, LLC	GT,GD	Active	13	0	0	0
32381	GREEN PLAINS FAIRMONT LLC-NW GAS CONTRACTED	GT	Active	5	0	0	0
32566	GREENCORE PIPELINE COMPANY LLC	HL	Active	235	0	3	0
32682	GREENLEAF CO2 SOLUTIONS, LLC	HL,GT	Active	41	0	1	0
31622	GREENLIGHT GAS INC	GT,GD	Active	94	0	0	0
6810	GREENWOOD COMMISSION OF PUBLIC WORKS	GT,GD	Active	50	0	0	0
2651	GREER COMMISSION OF PUBLIC WORKS	GT	Active	43	0	0	0
31541	GREKA ENERGY	GG	Active	13	0	6	7
30563	GROVE MUNICIPAL SERVICES AUTHORITY	GT,GD	Active	19	0	0	0
39128	GUARDIAN INDUSTRIES CORPORATION	GT	Active	3	0	0	0
26325	GULF COAST ENERGY INC	HL,GG	Active	25	0	0	0
32055	GULF COAST MINERAL, LLC	GG	Active	35	0	0	0
1021	GULF COAST PIPELINE COMPANY	GG	Inactive	2	0	0	0

32299	GULF CROSSING PIPELINE COMPANY LLC	GT	Active	374	0	4	0
31629	GULF PIPELINE LLC	GG	Active	4	0	0	0
32323	GULF STATES TRANSMISSION CORPORATION	GT	Active	10	0	0	0
32365	GULFPORT ENERGY CORPORATION	HL,GT	Active	8	0	0	0
31619	GULFSHORE MIDSTREAM PIPELINES LTD	GG	Inactive	107	0	0	0
31565	GULFSTREAM MANAGEMENT & OPERATING SERVICES,LLC	GT	Active	746	0	12	0
39006	HALCON FIELD SERVICES, LLC	GT,GG	Active	32	0	0	0
39041	HALL-HOUSTON EXPLORATON II, L.P.	HL,GG	Active	1	0	0	0
7020	HALLOCK GAS DEPT, VILLAGE OF	GT,GD	Active	2	0	0	0
31439	HARDEE POWER PARTNERS LTD	GT	Active	10	0	0	0
32255	HARVEST OIL & GAS, LLC	GG	Active	2	0	0	0
30788	HAVRE PIPELINE COMPANY	GT	Active	71	0	0	0
6243	HAWAII GAS	GT,GD	Active	22	0	37	9
32477	HAWK GATHERING CO, LTD	GG	Active	1	0	0	0
32447	HAWTHORN OIL TRANSPORTATION (NORTH DAKOTA), INC.	HL	Active	4	0	2	1
32455	HAWTHORN OIL TRANSPORTATION (OKLAHOMA), INC	HL	Active	17	0	0	0
39263	HAYNESVILLE GATHERING LP	GT,GG	Active	5	0	0	0
32260	HEARTLAND GAS PIPELINE, LLC	GT	Active	26	0	0	0
31344	HEARTLAND PIPELINE CO	HL	Inactive	52	0	4	0
31057	HECO - HAWAIIAN ELECTRIC COMPANY, INC.	HL	Active	18	0	10	6
31862	HEELENA/WEST HELENA/PHILLIPS COUNTY PORT ATHY.	GT	Inactive	4	0	0	0
31083	HELCO-HAWAII ELECTRIC LIGHT COMPANY, INC.	HL	Active	3	0	10	7
32565	HELIS OIL & GAS COMPANY, L.L.C.	HL,GG	Active	11	0	0	0
38999	HEMCO GAS GATHERING, L.L.C.	GG	Active	3	0	0	0
32111	HENDERSON GATHERING LLC	GG	Active	1	0	0	0
26372	HENDERSON PIPELINE CO	GG	Inactive	5	0	0	0
32110	HERMISTON OPERATIONS COMPANY, LLC	GT	Active	0	0	0	0
31690	HESCO PIPELINE CO. LLC	GT,GG	Inactive	57	0	0	0
386	HESS CORP	GT	Active	6	0	0	0
401	HESS CORPORATION	HL	Active	32	0	0	0
1047	HESS CORPORATION	HL	Active	16	0	9	2
38891	HESS FIRST RESERVE REGULATED PIPELINE	HL	Inactive	0	0	0	0
39065	HESS ND	HL,GG	Active	67	0	7	0
38993	HG ENERGY, LLC	GT,GG	Active	12	0	0	0
32269	HICKORY CREEK GAS GATHERING LP	GG	Inactive	3	0	0	0
38986	HIGH ISLAND GAS, LLC	HL,GT	Inactive	51	0	0	0
7272	HIGH ISLAND PIPELINE SYSTEM (AMOCO)	HL	Inactive	390	0	0	0
32595	HIGH POINT GAS GATHERING, LLC	GG	Active	120	0	3	0
38902	HIGH POINT GAS TRANSMISSION, LLC	GT	Active	422	0	3	2
39052	HIGH SIERRA TRANSPORTATION LLC	HL	Inactive	17	0	2	0
31562	HIGHLANDS PIPELINE CO LLC	GG	Inactive	3	0	0	0

31719	HILAND PARTNERS HOLDINGS LLC	HL,GT,GG	Active	51	0	2	0
32645	HILCORP ALASKA, LLC	HL,GT,GG	Active	471	0	32	7
30711	HILCORP ENERGY COMPANY	GT,GG	Active	100	0	2	0
31687	HILL-LAKE GAS STORAGE, LLC	HL,GT	Active	19	0	0	0
39306	HILLTOP RESORT GS, LLC	GG	Active	2	0	0	0
32664	HOCKING GAS CO. LLC	GG	Active	1	0	0	0
32353	HOLCIM (US) INC.	GT	Active	6	0	0	0
30994	HOLLAND, CITY OF - BOARD OF PUBLIC WORKS	GT	Active	9	0	0	0
39071	HOLLIMON OIL CORPORATION	HL	Active	14	0	0	0
32079	HOLLOMAN OPERATING CORPORATION	GT	Inactive	37	0	0	0
31805	HOLLY REFINING & MARKETING COMPANY	HL,GT	Active	14	0	0	0
32466	HOMELAND ENERGY SOLUTIONS LLC	GT	Active	9	0	0	0
32501	HONDO PIPELINE, INC	GG	Inactive	1	0	0	0
7338	HONEOYE STORAGE CORP	GT,GG	Active	13	0	9	3
32459	HOOKS GAS PIPELINE, LLC	GT	Active	12	0	0	0
32383	HORIZON PRODUCTION AND OPERATING, LLC	GT	Active	4	0	0	0
31966	HORSESHOE RUN SERVICES LLC	GG	Inactive	21	0	0	0
31285	HOUSTON AMMONIA TERMINAL	HL	Active	6	0	0	0
31872	HUBER PIPELINE CORP.	GT	Active	9	0	0	0
32072	HUDSON VALLEY GAS CORPORATION	GT	Active	4	0	0	0
32189	HUGHES GAS SYSTEM, LLC	GG	Active	1	0	0	0
7655	HUMPHREYS COUNTY UTILITY DISTRICT	GT,GD	Active	45	0	0	0
7660	HUNT CRUDE OIL SUPPLY CO	HL	Active	219	0	8	6
31799	HUNT PETROLEUM CORPORATION	GG	Inactive	20	0	0	0
26048	HUNT REFINING CO	HL	Active	47	0	1	0
38883	HUNT SOUTHLAND REFINING COMPANY	GT	Active	3	0	0	0
31649	HUNTSMAN CORPORATION	HL	Inactive	4	0	0	0
30709	HUNTSMAN PETROCHEMICAL LLC	HL,GT	Active	29	0	0	0
31339	HUNTSMAN POLYMERS CORP	HL	Inactive	10	0	0	0
7695	HUTCHINSON UTILITIES COMMISSION	GT,GD	Active	93	0	0	0
30922	HYPERION ENERGY LP	GT	Inactive	0	0	0	0
8322	I P INVESTMENT HOLDINGS LTD	GT	Inactive	1	0	0	0
39036	IACX ENERGY LLC	GT	Active	0	0	0	0
39521	IACX GATHERING LLC	GT	Active	3	0	0	0
8014	IDAHO PIPELINE CORP	HL	Active	2	0	8	5
39347	ILLINOIS EXTENSION PIPELINE COMPANY, L.L.C.	HL	Active	168	0	2	0
32516	IMPACT MIDSTREAM, LLC	GT	Active	15	0	0	0
32062	IMTT-PIPELINE	HL	Active	10	0	12	8
39383	INDECK ENERGY SERVICES OF SILVER SPRINGS	GT	Active	0	0	0	0
8070	INDIANA GAS CO INC	GT,GD	Active	631	0	5	2
39061	INDORAMA VENTURES (OXIDE & GLYCOLS) LLC	HL	Active	3	0	0	0

39436	INDORAMA VENTURES OLEFINS LLC	HL	Active	33	0	0	0
38934	INDUSTRIAL DEVELOPMENT AUTHORITY OF CARROLL COUNTY...	GT,GD	Active	0	0	0	0
8140	INLAND EMPIRE PAPER CO	GT	Active	3	0	0	0
31463	INNOVENE USA, LLC	HL	Inactive	24	0	0	0
32042	INNOVIA FILMS, INC.	GT	Active	1	0	0	0
876	INTEGRATED SERVICES, INC	GT	Inactive	10	0	0	0
32428	INTERCONTINENTAL TERMINAL COMPANY, LLC	HL	Active	3	0	0	0
8160	INTERMOUNTAIN GAS CO	GT,GD	Active	290	0	0	0
30659	INTERNATIONAL PAPER COMPANY - ALBANY	GT	Active	8	0	0	0
8166	INTERSTATE ENERGY COMPANY	HL,GT	Active	88	0	10	2
31912	INTERSTATE NATURAL GAS COMPANY	GT	Inactive	1	0	0	0
8175	INTERSTATE STORAGE & PIPELINE C0	HL	Active	12	0	8	4
39180	INVENERGY NELSON LLC	GT	Active	6	0	0	0
31932	INVESTMENT EQUIPMENT COMPANY	GG	Inactive	5	0	0	0
32097	IOCHEM CORPORATION	GT	Active	1	0	0	0
8310	IROQUOIS GAS CORP	GT	Active	414	0	64	5
8326	ITAWAMBA INDUSTRIAL GAS CO	GT,GG	Active	22	0	0	0
9012	J - W PIPELINE CO	GT,GG	Active	45	0	0	0
1042	J CLEO THOMPSON	GT,GG	Active	6	0	0	0
32395	J.R. SIMPLOT COMPANY	GT	Active	1	0	0	0
39009	J5 INC.	GG	Inactive	1	0	0	0
9045	JACKSON PIPELINE CO	GT	Inactive	25	0	0	0
32630	JAG OPERATING LLC	GT,GG	Inactive	12	0	0	0
32457	JDP RENEWABLES	GT	Active	2	0	0	0
9200	JEFFERSON - COCKE CO UTIL DIST	GT,GD	Active	16	0	0	0
39101	JEFFERSON BLOCK 24 OIL & GAS LLC	HL,GT,GG	Active	29	0	0	0
878	JEFFERSON GAS, LLC	GT,GG	Active	62	0	0	0
31226	JEFFERSON ISLAND STORAGE AND HUB LLC	GT	Active	34	0	0	0
32316	JENKINS BRICK COMPANY	GT	Inactive	2	0	0	0
32050	JIL OIL CORP.	GT	Inactive	1	0	0	0
32282	JO-CARROLL ENERGY	GT,GD	Active	32	0	0	0
18199	JOHN H. HAYS	GG	Inactive	11	0	0	0
38886	JOHNSTOWN REGIONAL ENERGY	GT	Active	15	0	0	0
31967	JORDAN DEVELOPMENT COMPANY, L.L.C.	GG	Active	18	0	0	0
10031	K L C ENTERPRISES	GG	Inactive	1	0	0	0
30910	K O TRANSMISSION COMPANY	GT,GD	Active	52	0	0	0
39114	K. PETROLEUM, INC.	GT,GD	Active	0	0	0	0
32254	KAHUNA OPERATING, LLC	HL,GT	Inactive	19	0	0	0
30718	KAISER-FRANCIS OIL COMPANY	GG	Active	11	0	0	0
32596	KAISER-FRONTIER MIDSTREAM LLC	GT	Active	20	0	1	0
31855	KANSAS CITY POWER & LIGHT	GT	Active	3	0	0	0

10029	KANSAS INDUSTRIAL ENERGY SUPPPLY CO	GT	Active	17	0	0	0
3146	KARBUHN OIL COMPANY	GG	Active	1	0	0	0
31522	KB PIPELINE	GT	Active	19	0	13	4
32078	KCS RESOURCES, INC.	GG	Inactive	1	0	0	0
10170	KENTUCKY - WEST VIRGINIA GAS CO	GT	Inactive	121	0	2	1
30054	KENTUCKY UTILITIES CO	GT	Active	11	0	0	0
31743	KEPCO OPERATING, INC.	GG	Inactive	2	0	0	0
844	KERN RIVER GAS TRANSMISSION CO	GT	Active	1,417	0	34	7
31586	KERR-MCGEE GATHERING LLC	HL,GT,GG	Inactive	88	0	0	0
26054	KEY WEST PIPELINE CO	HL	Active	7	0	12	5
32674	KEYROCK ENERGY, LLC	GT,GG	Active	11	0	0	0
11713	KEYSPAN ENERGY DELIVERY - LONG ISLAND	GT,GD	Active	136	0	0	0
31668	KEYSTONE GAS CORP	GG	Active	5	0	0	0
31841	KIAWAH RESOURCES LLC	GG	Inactive	6	0	0	0
32620	KILLAM OIL CO., LTD	GG	Active	8	0	0	0
38947	KINDER MORGAN ALTAMONT LLC	GG	Active	2	0	0	0
31727	KINDER MORGAN KEYSTONE GAS STORAGE, LLC	GT	Active	12	0	0	0
32437	KINDER MORGAN LOUISIANA PIPELINE LLC	GT	Active	136	0	3	0
31269	KINDER MORGAN NORTH TEXAS PIPELINE	GT	Active	82	0	2	0
32529	KINDERHAWK FIELD SERVICES LLC	GG	Active	25	0	0	0
38917	KING-MURRAY OPERATING COMPANY LLC	GT	Active	2	0	0	0
31894	KISSIMMEE UTILITY AUTHORITY	GT	Active	7	0	0	0
31092	KM FEEDERS, LLC	GT,GD	Active	3	0	0	0
13702	KMI CASPER	GT	Inactive	784	0	2	1
30930	KNG ENERGY INC	GT,GD	Active	12	0	0	0
32086	KNOX ENERGY COOPERATIVE ASSOCIATION, INC. C/O UTILITY...	GG,GD	Active	23	0	1	0
31982	KOCH FERTILIZER, LLC.	HL,GT	Active	5	0	3	2
10346	KUPARUK TRANSPORTATION CO	HL	Active	37	0	10	1
31929	L.E. JONES OPERATING INC.	GG	Active	2	0	0	0
32498	L.O.G. ENERGY EXPLORATION, LTD.	GG	Inactive	3	0	0	0
32539	LA CROSSE COUNTY	GT	Active	2	0	0	0
32243	LA STORAGE, LLC	GT	Active	23	0	2	0
31212	LAFAYETTE UTILITIES SYSTEMS	GT	Active	10	0	0	0
872	LAFITTE GAS PIPELINE	GT	Active	12	0	0	0
11080	LAGRANGE GAS DEPT, CITY OF	GT,GD	Active	52	0	0	0
11104	LAKELAND, CITY OF (EX. LAKELAND UTILITIES, CITY OF	GT	Active	9	0	0	0
977	LAKIN, CITY OF	GT	Active	1	0	0	0
11175	LAMAR UTILITIES BOARD, CITY OF	GT,GG	Active	70	0	0	0
32560	LAMB WESTON/BSW	GT	Active	4	0	0	0
31848	LANDFILL GAS PRODUCTION LLC	GT	Inactive	5	0	0	0
11240	LAS CRUCES, CITY OF	GT,GD	Active	20	0	0	0

11248	LAS VEGAS NATURAL GAS SYSTEM	GT,GD	Active	50	0	0	0
32524	LASALLE PIPELINE, LP	GT	Active	53	0	0	0
32550	LASER NORTHEAST GATHERING COMPANY, LLC	GG	Inactive	43	0	0	0
11251	LAUREL FUEL CO	GT	Active	77	0	0	0
978	LAWRENCE PAPER CO	GT	Active	1	0	0	0
32095	LBC HOUSTON, L.P.	HL	Active	7	0	0	0
32245	LDH ENERGY HASTINGS LLC	HL	Inactive	36	0	0	0
32452	LEAF RIVER ENERGY CENTER LLC	GT	Active	75	0	7	1
30786	LEE 8 STORAGE PARTNERSHIP	GT	Active	12	0	3	0
11360	LEFORS GAS DEPT, CITY OF	GT,GD	Active	2	0	0	0
38919	LEGACY RESERVES OPERATING LP	HL,GT	Active	45	0	1	0
32542	LEGADO PERMIAN, LLC	HL	Inactive	3	0	0	0
32417	LEGEND GATHERING LLC	GG	Active	4	0	0	0
32337	LEGEND NATRUAL GAS III, LP	GG	Active	6	0	0	0
32218	LEGEND NATURAL GAS II, LP	GG	Active	4	0	0	0
32413	LEGEND NATURAL GAS IV, LP	GG	Active	18	0	0	0
32650	LEMM CORPORATION - OPERATIONS	HL	Active	9	0	3	0
11384	LENOX MUNICIPAL GAS SYSTEM	GT,GD	Active	20	0	0	0
32528	LGS RENEWABLES I, LC	GT	Active	33	0	0	0
38967	LIBERTY ENERGY (GEORGIA) CORP D/B/A LIBERTY UTILITIES...	GT,GD	Active	67	0	0	0
32582	LIBERTY PIPELINE GROUP, LLC	HL	Inactive	87	0	0	0
38906	LIBERTY UTILITIES (MIDSTATES NATURAL GAS) CORP. D/B/A...	GT,GD	Active	227	0	0	0
32273	LIG GAS COMPANY, LLC	GT,GG	Active	5	0	0	0
38915	LINC GULF COAST PETROLEUM, INC	HL	Active	25	0	0	0
32359	LINCOLN ELECTRIC SYSTEM	GT	Active	9	0	0	0
32280	LINCOLN GENERATING FACILITY LLC	GT	Active	5	0	0	0
31391	LINDE GAS NORTH AMERICA, LLC	GT	Active	33	0	0	0
11525	LINDSEY & ELLIOTT	GG	Active	100	0	0	0
32388	LINN OPERATING, INC	HL,GT,GG	Active	43	0	0	0
31806	LINN WESTERN OPERATING, INC	HL,GG	Active	8	0	4	2
39475	LION ELASTOMERS LLC.	GT	Active	1	0	0	0
32300	LITTLE SIOUX CORN PROCESSORS, LLLP	GT	Active	1	0	0	0
1035	LIVE OAK RESERVES, INC	GG	Inactive	8	0	0	0
31063	LKL GATHERING INC	GT	Inactive	1	0	0	0
11613	LLOG EXPLORATION CO	GG	Inactive	4	0	0	0
31735	LOBO PIPELINE LP	GT,GG	Inactive	43	0	0	0
32570	LOCKHART POWER COMPANY	GT	Active	6	0	0	0
11630	LOCUST RIDGE GAS CO	GG	Inactive	31	0	0	0
31697	LODI GAS STORAGE, LLC	GT	Active	45	0	0	0
11730	LONGHORN PIPELINE CO	GT	Inactive	1	0	1	0
11760	LORIMOR MUNICIPAL GAS SYSTEM	GT,GD	Active	4	0	0	0

32402	LOUIS DREYFUS COMMODITIES GRAND JUNCTION	GT	Active	9	0	0	0
39015	LOUISIANA ENERGY CONSULTANTS, INC.	GG	Active	4	0	0	0
31516	LOUISIANA GENERATING, LLC	GT	Active	19	0	0	0
31813	LOUISVILLE FIRE BRICK WORKS INC	GT	Inactive	1	0	0	0
31044	LOWER VALLEY POWER & LIGHT INC.	GT,GD	Active	65	0	0	0
39305	LPC CRUDE OIL MARKETING LLC	HL	Active	9	0	0	0
31384	LSP ENERGY LP	GT	Inactive	15	0	0	0
32464	LSP UNIVERSITY PARK LLC	GT	Active	1	0	0	0
32514	LT GATHERING, LLC	GG	Active	194	0	0	0
32643	LT PIPELINE, INC.	HL	Active	5	0	0	0
32303	LUBBOCK GAS GATHERING, LTD. LLP	GG	Inactive	3	0	0	0
11885	LUBBOCK POWER & LIGHT	GT	Active	6	0	0	0
39035	LUCID ENERGY WESTEX, LLC	GT	Active	17	0	0	0
31490	LUMEN ENERGY CORP	GT,GG	Inactive	2	0	0	0
32297	LUMEN MIDSTREAM PARTNERSHIP, LLC	HL,GT	Active	34	0	0	0
31917	LYNCHBURG GAS PRODUCERS, LLC	GT	Inactive	1	0	0	0
38929	LYNX OPERATING CO., INC.	GT	Active	11	0	0	0
31259	LYONDELL CHEMICAL WORLDWIDE INC	GT	Inactive	2	0	0	0
12264	M G T C INC	GT,GD	Inactive	250	0	0	0
12059	M H M PIPELINE CO INC	GG	Active	2	0	0	0
12270	M I G C INC	GT	Inactive	264	0	0	0
31501	M-R VENTURES, LLC	GT,GG	Active	3	0	0	0
32367	M2 FAIRPLAY, LLC	GG	Inactive	26	0	0	0
32486	M2 LOUISIANA GAS SERVICE, LLC	GT,GG	Inactive	7	0	0	0
39003	M3 APPALACHIA GATHERING, LLC	GG	Active	13	0	0	0
32638	MACPHERSON OIL COMPANY	GT	Active	7	0	2	1
32240	MADILL GAS PROCESSING	GG	Active	2	0	0	0
38912	MAGELLAN E&P HOLDINGS, INC	GG	Active	5	0	0	0
31579	MAGELLAN PIPELINES HOLDINGS, LP	HL	Active	174	0	2	1
32352	MAGNOLIA GAS GATHERING, LLC	GG	Active	6	0	0	0
30065	MAGNUM GAS PIPELINE, INC.	GG	Active	12	0	0	0
32624	MAGNUM HUNTER PRODUCTION INC	GT,GG	Active	35	0	0	0
39424	MAGNUM OPERATING, LLC	HL,GG	Active	16	0	0	0
31913	MAIN ENERGY, INC.	GT	Inactive	23	0	0	0
30969	MAIN PASS OIL GATHERING SYSTEM	HL	Inactive	97	0	1	0
31487	MAINE NATURAL GAS	GT,GD	Active	2	0	0	0
7237	MALARKEY ROOFING PRODUCTS	GT	Active	2	0	0	0
12057	MALLARD PIPELINE CO	GT	Inactive	5	0	0	0
12102	MANNING NATURAL GAS DEPT	GT,GD	Active	10	0	0	0
31934	MANSFIELD PIPELINE, LLC	GG	Active	1	0	0	0
32002	MAP PRODUCTION COMPANY, INC.	GT,GG	Inactive	3	0	0	0

38897	MARABOU SUPERIOR PIPELINE	GT	Active	15	0	0	0
12125	MARATHON OIL COMPANY	GT,GG	Inactive	6	0	12	6
30845	MARATHON OIL COMPANY	GT,GG	Inactive	15	0	0	0
32138	MARDI GRAS PIPELINE, LLC	GT	Inactive	23	0	4	3
30954	MARINER ENERGY, INC	HL,GG	Inactive	19	0	1	1
31335	MARITIMES & NORTHEAST PIPELINE, L.L.C. (SPECTRA ENERGY...	GT	Active	346	0	12	1
402	MARKWEST EAST TEXAS PNG UTILITY, LLC	HL,GG	Active	64	0	0	0
26026	MARKWEST RANGER PIPELINE COMPANY, L.L.C.	HL	Active	140	0	11	8
32131	MARLIN MIDSTREAM, LLC	HL,GT,GG	Active	22	0	0	0
32164	MARSHALL MUNICIPAL UTILITIES	GT	Active	23	0	0	0
32482	MARSHFIELD UTILITIES	GT	Active	2	0	0	0
32377	MARYSVILLE HYDROCARBONS	HL	Inactive	6	0	0	0
31748	MASSACHUSETTS WHOLESALE ELECTRIC CO	GT	Active	6	0	0	0
39232	MATADOR PRODUCTION COMPANY	GG	Active	2	0	0	0
39313	MAVERICK TERMINAL THREE RIVERS, LLC	HL	Active	2	0	0	0
31049	MCCHORD PIPELINE CO.	HL	Active	14	0	0	0
32599	MCLEAN GAS PROCESSING, LLC	HL	Active	21	0	0	0
31374	MCLEOD GAS GATHERING & PROCESSING CO	GG	Inactive	7	0	0	0
12303	MCMORAN OIL & GAS CO	HL,GT	Active	23	0	0	0
31767	MCNIC MICHIGAN HOLDINGS INC	GT	Active	103	0	0	0
39130	MCP OPERATING LLC	GT,GG	Active	365	0	0	0
39051	MCR TRANSMISSION, LLC	GT	Inactive	7	0	0	0
31899	MEADWESTVACO CORPORATION TEXAS, LP	GT	Inactive	9	0	0	0
39179	MEMORIAL PRODUCTION OPERATIONS, LLC	HL	Active	20	0	1	0
12342	MEMPHIS LIGHT GAS & WATER DIVISION	GT,GD	Active	184	0	0	0
31428	MERIT ENERGY COMPANY	HL,GG	Inactive	21	0	6	5
31875	MERIT ENERGY COMPANY	HL,GG	Active	345	0	3	0
31106	MERRION OIL AND GAS	GG	Active	7	0	0	0
12395	METRO GAS CO	GG	Inactive	2	0	0	0
12390	METROPOLITAN UTILITIES DISTRICT	GT,GD	Active	1	0	0	0
12410	MICHIGAN GAS CO	GT,GD	Inactive	7	0	0	0
12420	MICHIGAN GAS UTILITIES CO	GT,GD	Active	127	0	0	0
32281	MICHIGAN PIPELINE AND PROCESSING LLC	GT,GG	Inactive	58	0	0	0
31581	MID LOUISIANA GAS TRANSMISSION, LLC	GT	Active	54	0	0	0
32342	MID MISSOURI ENERGY	GT	Active	13	0	0	0
32363	MID-CONTINENT MARKET CENTER	GT	Active	196	0	1	0
39019	MID-KANSAS ELECTRIC COMPANY	GT	Active	0	0	0	0
39177	MID-SET COGENERATION COMPANY	GT	Active	2	0	0	0
38937	MIDCOAST OPERATING , L.P.	HL	Active	117	0	0	0
12455	MIDLAND COGENERATION VENTURE	GT	Active	30	0	0	0
997	MIDWAY SUNSET COGENERATION CO	GT	Active	4	0	5	4

12479	MIDWEST ENERGY INC	GT,GD	Active	59	0	0	0
30022	MIDWEST GAS STORAGE, INC.	GT	Inactive	14	0	0	0
30059	MIDWEST GRAIN PIPELINE, INC.	GT	Inactive	20	0	0	0
32321	MILAGRO EXPLORATION, LLC	GG	Inactive	6	0	0	0
32581	MILWAUKEE METROPOLITAN SEWERAGE DISTRICT	GT	Active	19	0	0	0
39031	MINARD RUN OIL CO.	GT,GG	Active	5	0	0	0
32198	MINNESOTA ENERGY RESOURCES CORPORATION	GT,GD	Active	26	0	0	0
32446	MINNESOTA INTRASTATE PIPELINE COMPANY	GT	Active	31	0	0	0
32423	MINNESOTA POWER	GT	Active	1	0	0	0
39396	MINNESOTA POWER LASKIN ENERGY CENTER	GT	Active	1	0	0	0
32026	MINNESOTA SOYBEAN PROCESSORS	GT	Active	7	0	0	0
38922	MIPC LLC	HL	Active	50	0	4	2
32105	MIRANT BOWLINE, LLC	GT	Active	1	0	0	0
31520	MISSION NATURAL GAS	GT	Active	1	0	0	0
31519	MISSION PIPELINE CO	GT	Inactive	22	0	0	0
32132	MISSION VALLEY PIPELINE	GT	Active	1	0	0	0
32504	MISSISSIPPI HUB, LLC	GT	Active	39	0	5	0
31746	MISSOURI INTERSTATE GAS LLC	GT	Inactive	7	0	1	3
12601	MISSOURI PIPELINE CO	GT	Inactive	145	0	0	0
32415	MISTLETOE PIPELINE, LLC	GT	Inactive	12	0	0	0
39255	MK MIDSTREAM HOLDINGS, LLC	GT,GG	Active	7	0	0	0
32183	MOAB PIPELINE, LLC	GT,GD	Active	4	0	0	0
25160	MOBIL VANDERBILT-BEAUMONT PIPELINE CO	GT	Active	6	0	1	0
12642	MOBILE GAS SERVICE CORP	GT,GD	Active	46	0	1	0
32362	MOCKINGBIRD PIPELINE, LP	GG	Inactive	39	0	0	0
31167	MOEM PIPELINE LLC	HL	Active	56	0	6	1
31486	MOGAS PIPELINE LLC	GT	Active	267	0	8	4
39351	MONARCH OIL PIPELINE, LLC	HL	Active	52	0	1	1
32374	MONROE GAS STORAGE COMPANY, LLC	GT	Active	27	0	5	0
12672	MONROE NATURAL GAS DEPT, CITY OF	GT,GD	Active	43	0	0	0
32023	MONTGOMERY GAS TRANSMISSION, INC.	GT	Active	6	0	0	0
30944	MONUMENT CHEMICAL KENTUCKY, LLC	GT	Active	58	0	0	0
32231	MONUMENT PIPELINE, LP	GT,GG	Active	157	0	0	0
12794	MORNING SUN MUNICIPAL GAS SYSTEM	GT,GD	Active	3	0	0	0
31430	MORTIMER PRODUCTION COMPANY	GG	Active	3	0	0	0
31251	MORTON INTERNATIONAL INC, - SALT DIVISION	GT,GD	Active	3	0	0	0
12817	MOSS BLUFF HUB, LLC (SPECTRA ENERGY PARTNERS, LP)	GT	Active	23	0	2	0
39342	MOTIVA DISTRIBUTION	HL	Active	1	0	0	0
12823	MOULTON MUNICIPAL GAS SYSTEM	GT,GD	Active	5	0	0	0
15844	MOUNTAIN GAS RESOURCES INC.	HL,GT	Inactive	69	0	0	0
38898	MOUNTAIN GATHERING, LLC	GG	Active	42	0	0	0

12894	MOUNTAINAIR, TOWN OF	GT,GD	Active	14	0	0	0
12878	MOUNTAINEER GAS CO	GG,GD	Active	16	0	1	0
25170	MOUNTAINEER GAS SERVICES	GG,GD	Inactive	14	0	0	0
14071	MURPHY EXPLORATION & PROD CO	GG	Inactive	13	0	0	0
39093	MUSKEGON DEVELOPMENT COMPANY	GG	Active	2	0	0	0
12930	MUSTANG GAS PRODUCTS LLC	GT,GG	Active	42	0	0	0
32019	MUSTANG ISLAND GATHERING, LLC	GG	Inactive	20	0	0	0
26302	MUSTANG PIPELINE CO	HL	Active	89	0	0	0
31898	MV PIPELINE COMPANY	GT	Active	9	0	0	0
31247	N G TRANSMISSION	GT	Active	110	0	0	0
32642	NAFTEX OPERATING COMPANY	GT	Active	5	0	2	0
13041	NASHVILLE GAS CO	GT,GD	Inactive	81	0	0	0
13061	NATIONAL FUEL GAS DISTRIBUTION CORP	GT,GD	Active	66	0	1	0
13062	NATIONAL FUEL GAS DISTRIBUTION CORP - NEW YORK	GT,GG,GD	Active	65	0	1	0
13302	NATIONAL GAS & OIL CORP	GT,GG,GD	Active	20	0	0	0
31110	NATIONAL SERV ALL	GT,GD	Inactive	3	0	0	0
30772	NATURAL GAS OF KENTUCKY, INC.	GT	Active	31	0	0	0
13161	NAVAJO PIPELINE CO	HL	Inactive	40	0	0	0
13162	NAVAJO REFINING CO	HL	Inactive	47	0	0	0
38949	NAVARRO MIDSTREAM SERVICES, LLC.	GG	Active	3	0	0	0
32333	NAVASOTA ODESSA ENERGY PARTNERS, L.P.	GT	Active	2	0	0	0
32349	NAVASOTA WHARTON ENERGY PARTNERS, LP	GT	Active	1	0	0	0
39039	NAVIDAD RESOURCES LLC	GG	Inactive	2	0	0	0
39443	NAVITAS MDSTR MIDLAND BASIN, LLC	GT,GG	Active	32	0	0	0
39268	NAVITAS PIPELINE TEXAS, LLC	GT	Active	9	0	0	0
38900	NC MUNICIPAL GAS, LLC	GT,GG	Inactive	3	0	0	0
13180	NEBRASKA CITY UTILITIES	GT,GD	Active	55	0	0	0
32081	NEBRASKA PUBLIC POWER DISTRICT	GT	Active	3	0	0	0
32422	NEPTUNE LNG, LLC	GT	Active	13	0	7	2
39033	NESSON GATHERING SYSTEM, LLC	GG	Active	2	0	0	0
39223	NET MEXICO PIPELINE PARTNERS, LLC	GT	Active	138	0	0	0
31518	NETCO PIPELINE LLC	GG	Inactive	27	0	0	0
30716	NEUMIN PRODUCTION CO.	HL,GG	Active	32	0	0	0
32137	NEW CENTURY EXPLORATION	GG	Inactive	1	0	0	0
31931	NEW DOMINION, L.L.C.	GG	Active	2	0	0	0
4604	NEW MEXICO NATURAL GAS, INC.	GT	Inactive	9	0	0	0
13331	NEW WASKOM GAS GATHERING INC	GG	Inactive	9	0	0	0
13420	NEW YORK STATE ELECTRIC & GAS CORP	GT,GD	Active	20	0	6	5
13440	NEWELLTON, TOWN OF - ST JOSEPH JOINT LINE	GT,GD	Active	9	0	0	0
861	NEWFIELD EXPLORATION COMPANY	GT	Inactive	10	0	0	0
30052	NEWMONT GOLD COMPANY	GT	Active	28	0	0	0

32553	NEWTON COUNTY LANDFILL PARTNERSHIP	GT,GD	Active	1	0	0	0
39087	NFG MIDSTREAM CLERMONT, LLC	GT	Active	11	0	0	0
32506	NFG MIDSTREAM COVINGTON, LLC	GT	Active	8	0	2	0
32672	NFG MIDSTREAM TROUT RUN, LLC	GT	Active	21	0	0	0
39185	NGG GAS GATHERING COMPANY, LLC	GG	Active	13	0	0	0
31914	NGL SUPPLY TERMINAL COMPANY LLC	HL	Active	5	0	7	2
32034	NGO TRANSMISSION, INC.	GT	Active	170	0	0	0
22515	NIPPON DYNAWAVE PACKAGING COMPANY	GT	Active	9	0	0	0
30787	NIPPON OIL EXPLORATION USA LIMITED	HL,GT	Inactive	45	0	5	4
31755	NOBLE MIDSTREAM SERVICES, LLC	HL,GT,GG	Active	46	0	7	5
31699	NORFOLK SOUTHERN RAILWAY-BROSNAN YARD PIPELINE	HL	Inactive	6	0	3	5
31896	NORSTAR PIPELINE COMPANY, INC.	GT	Active	2	0	1	0
32302	NORTH ALBANY TERMINAL COMPANY, LLC	HL	Inactive	0	0	0	0
31891	NORTH BAJA PIPELINE LLC	GT	Active	86	0	15	5
12585	NORTH CENTRAL OIL CORP	GG	Inactive	12	0	0	0
32043	NORTH COAST GAS TRANSMISSION, LLC	GT	Active	261	0	0	0
30679	NORTH COUNTRY GAS PIPELINE	GT	Active	22	0	0	0
32571	NORTH PLATTE LIVESTOCK FEEDERS, LLC	GT	Active	5	0	0	0
13656	NORTH RIDGE CORP	GG	Inactive	1	0	0	0
13660	NORTH SHORE GAS CO	GT,GD	Active	98	0	0	0
31142	NORTH SLOPE BOROUGH ENERGY MANAGEMENT	GT,GD	Active	20	0	19	11
32669	NORTHEAST NATURAL ENERGY LLC	GG	Active	2	0	0	0
13635	NORTHEAST OHIO NATURAL GAS CORP	GT,GD	Active	9	0	0	0
13630	NORTHEAST OKLAHOMA PUBLIC FACILITIES AUTH	GT,GD	Active	15	0	0	0
32308	NORTHERN CALIFORNIA POWER AGENCY	GT	Active	1	0	6	0
31054	NORTHERN ECLIPSE	GT	Inactive	1	0	0	0
13730	NORTHERN INDIANA PUBLIC SERVICE CO	GT,GD	Active	665	0	0	0
13725	NORTHERN INDUSTRIAL ENERGY DEVELOPMENT INC	GG,GD	Active	5	0	0	0
13707	NORTHERN MINNESOTA UTILITIES	GT,GD	Inactive	37	0	0	0
31636	NORTHERN STATES POWER CO OF MINNESOTA	HL,GT,GD	Active	98	0	0	0
13783	NORTHERN STATES POWER CO OF WISCONSIN	GT,GD	Active	3	0	0	0
13795	NORTHERN UTILITIES INC (ME)	GT,GD	Active	31	0	0	0
13800	NORTHERN UTILITIES, INC. (NH)	GT,GD	Active	0	0	0	0
32012	NORTHSTAR GOM, L.L.C	GT	Inactive	2	0	0	0
39189	NORTHSTAR OFFSHORE GROUP, LLC	HL,GT	Active	11	0	0	0
32120	NORTHVILLE INDUSTRIES CORP.	HL	Active	37	0	0	0
39370	NORTHWEST GAS PROCESSING, LLC	HL,GG	Active	22	0	0	0
31632	NORTHWESTERN CORPORATION	GT,GD	Active	2,154	0	0	0
32215	NOVA CHEMICALS (CANADA) LTD.	HL	Active	11	0	9	3
38966	NOVA CHEMICALS INC.	HL	Active	127	0	6	0
39027	NRG ENERGY SERVICES	GT	Active	6	0	1	1

32522	NRG OSWEGO HARBOR POWER	HL	Active	4	0	0	0
32391	NRG TEXAS POWER LLC	GT	Active	1	0	0	0
2652	NSTAR GAS COMPANY	GT,GD	Active	1	0	0	0
38925	NUCOR STEEL KINGMAN, LLC	GT	Active	2	0	0	0
39468	NUENERGY OPERATING, INC.	GG	Active	1	0	0	0
31268	NUSTAR JOINT VENTURE	HL	Inactive	52	0	0	0
18308	NV ENERGY	GT,GD	Active	8	0	0	0
30951	O.I. AUBURN, INC. C/O DUFCO	GG,GD	Inactive	35	0	0	0
31196	OAKHILL PIPELINE	GT,GG	Inactive	78	0	0	0
38968	OASIS PETROLEUM NORTH AMERICA	GG	Active	3	0	1	0
30544	OCCIDENTAL CHEMICAL CORP	HL,GT	Active	45	0	2	1
31502	OCCIDENTAL PERMIAN LTD	HL,GT	Active	66	0	2	1
39073	OCI BEAUMONT LLC	HL	Active	5	0	0	0
31569	ODESSA - ECTOR POWER PARTNERS L.P	GT	Active	10	0	0	0
31849	OGLETHORPE POWER CORPORATION	HL,GT	Active	7	0	3	0
32439	OGP OPERATING, INC.	GT,GG	Inactive	138	0	0	0
14180	OHIO VALLEY GAS CORP	GT,GD	Active	57	0	0	0
31784	OHIO VALLEY HUB LLC	GT	Active	13	0	0	0
32162	OHM OPERATING	GG	Inactive	2	0	0	0
39088	OIL ENERGY CORP.	GG	Active	7	0	0	0
32386	OILTANKING BEAUMONT PARTNERS L.P.	HL	Inactive	14	0	0	0
14200	OKALOOSA COUNTY GAS DISTRICT	GT,GD	Active	139	0	0	0
32129	OKLAHOMA GAS PROCESSING	HL	Active	11	0	0	0
30630	OKTEX PIPELINE COMPANY, LLC	GT	Active	116	0	13	7
32204	OLD RIVER PIPELINE, LLC.	GT	Inactive	9	0	0	0
31341	OLIKTOK PIPELINE COMPANY	HL,GT	Active	56	0	7	2
39276	OLIN CORPORATION	GT	Active	1	0	0	0
31920	OMIMEX CANADA, LTD.	GT	Active	16	0	7	3
848	OMIMEX ENERGY, INC	GG	Inactive	57	0	0	0
31533	ONEOK GAS GATHERING, LLC	GG	Inactive	3	0	0	0
31582	ONEOK ROCKIES MIDSTREAM, LLC	HL,GT	Active	193	0	18	5
31534	ONEOK TEXAS GAS STORAGE, LLC	GT	Active	11	0	1	0
30575	ONEOK TRANSMISSION COMPANY	GT,GD	Active	97	0	0	0
39174	ONEOK WESTERN TRAIL PIPELINE	GT	Active	139	0	1	0
31830	ONYX NATURAL GAS, L.C.	GG	Inactive	13	0	0	0
31765	OPTIGAS INC	GT,GG	Inactive	9	0	0	0
14330	ORANGE & ROCKLAND UTILITY INC	GT,GD	Active	1	0	0	0
38972	ORANGE COUNTY SANITATION DISTRICT	GT	Active	4	0	2	0
14356	ORBIT GAS TRANSMISSION, INC.	GT,GG	Active	19	0	0	0
31390	OREGON STEEL MILLS	GT	Active	1	0	0	0
32578	ORIGIN MINING COMPANY, LLC.	GT	Active	24	0	0	0

14391	OSAGE PIPE LINE COMPANY, LLC	HL	Active	136	0	0	0
31450	OSBORN, W B OIL & GAS OPERATIONS	GG	Active	3	0	0	0
31651	OSPREY PETROLEUM CO INC	GG	Inactive	5	0	0	0
14410	OWATONNA PUBLIC UTILITIES	GT,GD	Active	5	0	0	0
32259	OWENS-ILLINOIS	GT	Active	1	0	0	0
32277	OXEA CORPORATION	HL	Active	51	0	0	0
38889	OXY USA INC - SOUTH TEXAS	GT,GG	Active	40	0	0	0
31219	OZARK GAS GATHERING, L.L.C. (SPECTRA ENERGY PARTNERS,...	GT,GG	Active	1	0	0	0
14435	OZARK GAS TRANSMISSION, L.L.C. (SPECTRA ENERGY...	GT	Active	367	0	14	6
31381	OZONA RESIDUE SYSTEM CO	GT	Inactive	6	0	0	0
31890	P B ENERGY STORAGE SERVICES INC.	HL,GT	Active	161	0	5	3
38935	PACER ENERGY TERMINALS, LLC	HL	Active	1	0	0	0
39049	PACIFIC ENERGY & MINING CO	GT	Active	21	0	0	0
31695	PACIFIC MARKETING AND TRANSPORTATION LLC	HL	Inactive	72	0	0	0
31295	PACIFIC OPERATORS OFFSHORE	HL,GT	Active	12	0	9	6
32494	PADUCAH POWER SYSTEM	GT	Active	16	0	0	0
15036	PAISANO TRANSMISSION CO	GG	Inactive	5	0	0	0
32338	PAL ENERGY, LLC	GT	Active	8	0	0	0
31511	PALADIN ENERGY PARTNERS LLC	GT	Inactive	11	0	0	0
31434	PALMER PETROLEUM INC	HL	Active	9	0	0	0
31995	PANTHER INTERSTATE PIPELINE ENERGY, LLC	GG	Active	48	0	0	0
39060	PANTHER PIPELINE, LLC	GT,GG	Active	51	0	0	0
39272	PARADIGM MIDSTREAM SERVICES - ND, LLC	HL	Active	24	0	0	0
32326	PARKWAY LLC	GT	Inactive	58	0	0	0
32679	PARKWAY PIPELINE LLC	HL	Active	140	0	3	0
32331	PASADENA REFINING SYSTEM, INC.	HL	Active	16	0	0	0
32548	PATARA OIL & GAS LLC	GT,GG	Inactive	4	0	0	0
38930	PATOKA TERMINAL COMPANY, LLC	HL	Active	0	0	0	0
32134	PATRIOTS ENERGY GROUP	GT,GD	Active	59	0	0	0
32557	PAULSBORO NATURAL GAS PIPELINE COMPANY, LLC	GT	Active	3	0	3	0
31215	PCS NITROGEN FERTILIZER LP	HL,GT	Inactive	4	0	0	0
15444	PDC MOUNTAINEER, LLC	GT	Inactive	6	0	0	0
32041	PEAK GAS GATHERING L.P.	GG	Inactive	1	0	0	0
32472	PECAN PIPELINE (NORTH DAKOTA), INC.	GT	Inactive	76	0	0	0
32286	PECAN PIPELINE COMPANY	GT,GG	Active	9	0	0	0
15462	PECO ENERGY CO	GT,GD	Active	30	0	0	0
32485	PECOS PIPELINE LLC	GG	Active	20	0	0	0
31255	PEDESTAL OIL COMPANY, INC	GG	Active	4	0	0	0
31453	PEI POWER CORP	GT	Inactive	24	0	1	2
15208	PELICAN RESERVE PIPELINE CO	GT,GG	Active	3	0	0	0
32376	PELICAN TRANSMISSION, LLC	GT	Inactive	5	0	0	0

31738	PENN VIRGINIA OIL AND GAS CORPORATION	GG	Active	14	0	0	0
38951	PENNSYLVANIA GENERAL ENERGY COMPANY, LLC	GG	Active	7	0	0	0
39173	PENNTEX MIDSTREAM PARTNERS, LLC	HL,GT,GG	Active	59	0	0	0
39432	PENNTEX PERMIAN, LLC	GT	Active	1	0	0	0
32284	PENNZOIL-QUAKER STATE D/B/A SOPUS PRODUCTS	HL	Active	12	0	0	0
15476	PEOPLES TWP LLC	GT,GD	Active	10	0	0	0
32160	PEREGRINE PIPELINE, L.P.	GT,GG	Active	48	0	0	0
31922	PERRYVILLE ENERGY PARTNERS	GT	Inactive	1	0	0	0
38901	PERRYVILLE GAS STORAGE, LLC	GT	Active	15	0	2	1
39119	PETRO QUEST ENERGY, LLC	HL,GG	Active	10	0	0	0
30848	PETRO-CHEM OPERATING CO.	GG	Inactive	3	0	0	0
31135	PETRO-DIAMOND TERMINAL COMPANY	HL	Active	1	0	0	0
30868	PETRO-HUNT CORPORATION	GG	Inactive	5	0	0	0
32108	PETROHAWK OPERATING COMPANY	GG	Inactive	1	0	0	0
15454	PETROLEUM FUELS CO	GT,GG	Active	101	0	0	0
32652	PETROSANTANDER (USA) INC.	HL	Active	14	0	6	0
39070	PGP OPERATING, LLC	GT,GG	Active	10	0	0	0
32499	PGPIPELINE, LLC.	GT	Active	8	0	0	0
31156	PGPL, LC	GT	Inactive	1	0	0	0
38964	PHILADELPHIA ENERGY SOLUTIONS REFINING AND MARKETING,...	HL	Active	17	0	2	0
15469	PHILADELPHIA GAS WORKS	GT,GD	Active	2	0	0	0
32135	PHILLIPS 66 COMPANY - LOS ANGELES REFINERY	HL	Active	13	0	0	0
30952	PHILLIPS UTILITY GAS CORPORATION	GT	Active	5	0	0	0
905	PHOENIX HYDROCARBONS OPERATING CORP	GG	Inactive	4	0	0	0
32039	PIMALCO GAS	GT	Active	0	0	0	0
15589	PINE PIPELINE INC	GT	Active	17	0	0	0
967	PINEDALE NATURAL GAS, INC	GT,GD	Active	7	0	0	0
31902	PINNACLE GAS PRODUCERS, LLC	GG,GD	Active	1	0	0	0
31165	PINNACLE GAS TREATING, INC.	GT,GG	Inactive	22	0	0	0
31832	PINNACLE WEST ENERGY	GT	Inactive	1	0	0	0
32301	PIONEER AMERICAS LLC DOING BUSINESS AS OLIN CHLOR...	GT	Active	6	0	0	0
15602	PIONEER NATURAL RESOURCES	GT	Active	7	0	0	0
31164	PIONEER NATURAL RESOURCES, USA, INC.	GT,GG	Inactive	32	0	0	0
31811	PIPELINE OPERATORS OF TEXAS, LLC	GT	Inactive	13	0	0	0
31721	PIPELINE TECHNOLOGY	HL	Active	28	0	0	0
15645	PLACID PIPELINE COMPANY LLC	HL,GT	Active	11	0	0	0
15652	PLAINS, CITY OF	GT,GD	Active	9	0	0	0
32390	PLATINUM ETHANOL, LLC	GT	Inactive	22	0	0	0
31646	PLATTE RIVER POWER AUTHORITY	GT	Active	16	0	0	0
32373	PLYMOUTH ENERGY, LLC	GT	Active	8	0	0	0
32290	POET BIOREFINING - JEWELL	GT	Active	10	0	0	0

31612	POGO PRODUCING CO	GG	Inactive	10	0	0	0
31257	PONDEROSA GATHERING, LLC	GG	Active	1	0	0	0
15790	PONTCHARTRAIN NATURAL GAS SYSTEM	GT	Active	2	0	0	0
32140	PORT WESTWARD POWER PLANT	GT	Active	0	0	0	0
31145	PORTLAND NATURAL GAS TRANSMISSION SYSTEM	GT	Active	188	0	11	3
31963	POTATO HILLS GAS GATHERING SYSTEM	GT	Inactive	11	0	0	0
39239	POWDER RIVER OPERATING, LLC	HL	Active	60	0	1	0
38958	PPG, LLC	GG	Active	12	0	0	0
15815	PRAIRIE PIPELINE CO	GG	Active	7	0	0	0
38908	PRAIRIELAND PIPELINE, LLC	GT	Active	5	0	0	0
31742	PREMCOR PIPELINE COMPANY	HL	Inactive	248	0	4	3
32656	PREMIER NATURAL RESOURCES II, LLC	GT,GG	Inactive	42	0	0	0
32123	PRINCE GEORGES COUNTY GOVERNMENT	GT,GD	Active	2	0	0	0
1045	PRINCESS THREE CORPORATION	GG	Inactive	2	0	0	0
31869	PRISM GAS SYSTEMS I, L.P.	HL,GG	Inactive	53	0	0	0
39106	PROGRESS SOLUTIONS LLC	HL	Active	38	0	3	0
38923	PROSPECTOR PIPELINE COMPANY	GT	Active	27	0	0	0
31411	PROVIDENCE PARTNERS LLC	GG	Inactive	35	0	0	0
15900	PRUET PRODUCTION CO	GG	Inactive	2	0	0	0
38936	PSI MIDSTREAM, LLC	GG	Active	11	0	0	0
15952	PUBLIC SERVICE ELECTRIC & GAS CO	GT,GD	Active	62	0	1	0
22189	PUGET SOUND ENERGY	GT,GD	Active	27	0	17	1
32534	PULSE ENERGY SYSTEMS, LLC	GT	Active	0	0	0	0
31208	PVR CHEROKEE GAS PROCESSING LLC	GG	Inactive	4	0	0	0
31585	PVR GAS GATHERING, LLC	GT,GG	Inactive	31	0	0	0
31209	PVR GAS PROCESSING LLC	GT	Inactive	53	0	0	0
2756	PVR HAMLIN, L.P.	GT	Inactive	1	0	0	0
32004	QEP FIELD SERVICES COMPANY	HL,GT,GG	Inactive	133	0	19	4
32003	QEP MARKETING COMPANY	GT	Active	18	0	6	4
32309	QUALITY NATURAL GAS, LLC	GG	Active	8	0	1	0
32527	R. LACY SERVICES, LTD	GG	Active	1	0	0	0
39499	RANGER GAS GATHERING, LLC	GG	Active	2	0	0	0
17090	RATON GAS TRANSMISSION CO	GT	Active	23	0	8	2
32340	RAYWOOD GAS PLANT, LLC	HL,GT,GG	Inactive	26	0	0	0
32292	RED CEDAR GATHERING COMPANY	GT,GG	Active	21	0	0	0
39437	RED GATE PIPELINE, LP	GT	Active	26	0	0	0
39001	REEF EXPLORATION, LP	GG	Inactive	1	0	0	0
32219	REEF INTERNATIONAL LLC	GT	Inactive	8	0	0	0
32355	REGENCY LIQUIDS PIPELINE LLC	HL	Inactive	40	0	0	0
39316	RENAISSANCE OFFSHORE, LLC	HL,GG	Active	32	0	5	0
31769	RENAISSANCE PIPELINE COMPANY	GT	Inactive	9	0	0	0

32681	RENEWCO-MEADOW BRANCH, LLC	GT	Active	9	0	0	0
31800	RENOVAR ENERGY CORP	GT	Active	28	0	0	0
32141	RESOLUTE NATURAL RESOURCES COMPANY	HL,GT	Active	35	0	5	2
39265	RICE OLYMPUS MIDSTREAM LLC	GG	Active	3	0	0	0
39448	RICE POSEIDON MIDSTREAM LLC	GG	Active	25	0	0	0
17325	RICHARDSON FUELS INC	HL,GT,GG	Inactive	82	0	3	0
39211	RICHLAND STRYKER GENERATION, LLC	GT	Active	0	0	0	0
17360	RICHMOND, CITY OF	GT,GD	Active	0	0	40	24
14225	RINGWOOD GATHERING CO	GT	Active	8	0	0	0
31551	RIO VISTA ENERGY PARTNERS, LP	HL	Inactive	33	0	1	1
39081	RIVERSIDE GENERATING COMPANY, LLC	GT	Active	9	0	0	0
39207	RIVERSIDE PETROLEUM INDIANA	GG	Active	0	0	0	0
17540	ROANOKE GAS CO	GT,GD	Active	66	0	0	0
31838	ROBIN OF PERRYTON, CORPORATION	GG	Inactive	1	0	0	0
17570	ROCHESTER GAS & ELECTRIC CORP	GT,GD	Active	105	0	0	0
32440	ROCKFORD CORPORATION	GT,GD	Inactive	14	0	0	0
32628	ROOSTH PRODUCTION COMPANY	GG	Inactive	2	0	0	0
17681	ROSEBURG FOREST PRODUCTS CO	GT,GD	Active	3	0	0	0
32203	ROSETTA RESOURCES	GT,GG	Inactive	11	0	4	1
31108	ROYAL PRODUCTION CO., INC.	GG	Active	4	0	0	0
31656	RUTHERFORD OIL CORP	GG	Active	4	0	0	0
32671	RW GATHERING, LLC	GG	Active	3	0	0	0
32661	RYCKMAN CREEK RESOURCES, LLC	GT	Active	9	0	3	0
32451	SABINE OIL & GAS LLC	GG	Active	8	0	0	0
18012	SABINE PIPELINE LLC	GT	Active	132	0	4	1
31250	SABINE VALLEY PIPELINE, INC	GG	Inactive	1	0	0	0
30749	SACRAMENTO MUNICIPAL UTILITY DISTRICT	GT	Active	76	0	12	1
32617	SADDLE BUTTE PIPELINE, LLC	HL	Inactive	17	0	0	0
39048	SAGA PETROLEUM, LLC	GT	Inactive	17	0	0	0
32125	SALMON RESOURCES LTD.	HL	Inactive	6	0	3	4
31528	SALT PLAINS STORAGE INC	GT	Active	22	0	0	0
30963	SALTVILLE GAS STORAGE COMPANY, L.L.C. (SPECTRA ENERGY...	GT	Active	32	0	5	0
32675	SAMSON EXPLORATION, LLC	GG	Active	1	0	0	0
30056	SAMSON RESOURCES COMPANY	GG	Active	5	0	0	0
32272	SAN ANTONIO PIPELINE CORPORATION	HL	Active	14	0	0	0
31961	SAN FELIPE PIPELINE L.P.	GG	Inactive	109	0	0	0
31491	SANCHEZ OIL & GAS CORP	GT	Active	3	0	0	0
31471	SANDRIDGE CO2, LLC	HL	Active	159	0	0	0
38942	SANDRIDGE ONSHORE, LLC	HL,GG	Inactive	9	0	0	0
31768	SANTEE COOPER - RAINEY GENERATING STATION	GT	Active	3	0	7	4
21359	SASOL CHEMICALS USA LLC	HL,GT	Active	20	0	0	0

31987	SCEPTER GREENEVILLE, INC	GT,GD	Active	2	0	0	0
31472	SCISSORTAIL ENERGY LLC	GT,GG	Active	112	0	0	0
39317	SCOUT ENERGY MANAGEMENT LLC	GT,GG	Active	9	0	0	0
32623	SEACOAST GAS TRANSMISSION, LLC	GT	Active	24	0	0	0
39004	SEADRIFT COKE LP	GT	Active	0	0	0	0
31068	SEAL BEACH GAS PROCESSING VENTURE	GT,GG	Active	4	0	7	1
929	SEBRING GAS SYSTEM, INC	GT,GD	Active	0	0	0	0
30585	SELKIRK COGEN PROJECT	GT	Active	2	0	0	0
39116	SEM OPERATING COMPANY, LLC	GG	Active	2	0	0	0
18472	SEMCO ENERGY GAS COMPANY	GT,GD	Active	101	0	0	0
18473	SEMCO PIPELINE CO	GT	Active	50	0	0	0
32166	SEMGAS, L.P.	GT,GG	Active	17	0	0	0
38955	SENECA LANDFILL	GT	Active	2	0	0	0
32378	SENECA POWER PARTNERS, L.P.	GT	Active	11	0	0	0
18201	SENECA RESOURCES CORP	HL,GT,GG	Active	21	0	3	0
38905	SENECA RESOURCES EAST DIVISION	GG	Active	5	0	0	0
38916	SG INTERESTS	GT	Inactive	4	0	0	0
32375	SG RESOURCES MISSISSIPPI, LLC	GT	Inactive	59	0	1	0
31999	SHELBY COUNTY ENERGY CENTER, LLC	GT	Active	2	0	0	0
18275	SHELL CHEMICAL CO	HL	Active	13	0	0	0
30765	SHELL OIL PRODUCTS COMPANY	HL,GT	Inactive	9	0	2	0
18286	SHELL WESTERN E & P INC - CENTRAL DIV	GT,GG	Inactive	112	0	0	0
32348	SHELL WESTERN E&P	GG	Inactive	16	0	0	0
18292	SHENANDOAH GAS CO	GT,GD	Inactive	24	0	0	0
31689	SHERWIN ALUMINA COMPANY	GT	Active	2	0	0	0
32627	SHORELINE OFFSHORE LLC	GT	Active	7	0	0	0
32343	SHOW ME ETHANOL, LLC	GT	Active	5	0	0	0
32329	SIEMENS INDUSTRY, INC	GT	Active	16	0	0	0
39426	SIEMPRE ENERGY OPERATING, LLC	HL	Active	6	0	0	0
31148	SIENERGY, LP	GT,GD	Active	3	0	0	0
39194	SIERRITA GAS PIPELINE LLC	GT	Active	61	0	3	0
32195	SIGNAL HILL PETROLEUM, INC.	HL	Inactive	1	0	0	0
32054	SILICON VALLEY POWER	GT	Active	2	0	7	6
31605	SILVER CREEK OIL & GAS, LLC	GG	Active	2	0	0	0
32663	SIMCON OIL & GAS CORP	GG	Active	5	0	0	0
18336	SIOUX CENTER MUNICIPAL GAS UTILITY	GT,GD	Active	5	0	0	0
31640	SIOUX CITY BRICK AND TILE	GT,GD	Active	1	0	0	0
32357	SIOUX FALLS REGIONAL SANITARY LANDFILL	GT	Active	11	0	0	0
18340	SIPCO GAS TRANSMISSION CORP	GT	Active	1	0	0	0
32651	SLEEPY HOLLOW OIL AND GAS	GT,GG,GD	Active	27	0	0	0
39238	SM ENERGY - HOUSTON REGION	GG	Active	3	0	0	0

39089	SM ENERGY COMPANY	GG	Active	5	0	0	0
31368	SMARR ENERGY FACILITY	GT	Active	1	0	0	0
17215	SMITH PRODUCTION INC (EX - RENRAG INC)	GG	Inactive	2	0	0	0
39318	SN OPERATING, LLC	HL	Active	9	0	0	0
39290	SND OPERATING, LLC.	GT,GG	Active	12	0	0	0
18380	SOCORRO NATURAL GAS CO	GT,GD	Active	38	0	0	0
32509	SOMERSET GAS GATHERING OF PENNSYLVANIA, LLC	GT,GG	Active	23	0	0	0
18388	SOMERSET GAS SERVICE	GT,GG,GD	Active	147	0	0	0
18383	SOMOCO INC	GG	Inactive	2	0	0	0
31980	SOTEX FUELS,LLC.	GT,GG	Inactive	13	0	0	0
630	SOURCEGAS ARKANSAS INC.	GT,GG,GD	Inactive	886	0	0	0
10030	SOURCEGAS LLC	GT,GD	Inactive	2,011	0	1	0
2688	SOUTH ALABAMA GAS DISTRICT	GT,GD	Active	103	0	0	0
25169	SOUTH CAROLINA PIPELINE CORP	GT	Inactive	1,978	0	1	2
30024	SOUTH DAKOTA INTRASTATE PIPELINE CO.	GT	Active	178	0	0	0
18440	SOUTH JERSEY GAS CO	GT,GD	Active	146	0	0	0
31647	SOUTH SHORE PIPELINE CO LLC	GT	Active	26	0	0	0
99037	SOUTH WILMINGTON-PIPELINE	HL	Inactive	29	0	4	2
31882	SOUTHCROSS ALABAMA GATHERING SYSTEM, L.P.	GT,GG	Inactive	25	0	0	0
32626	SOUTHCROSS ALABAMA PIPELINE LLC	GT,GG	Active	429	0	0	0
31595	SOUTHCROSS CCNG GATHERING LTD	GT,GG	Active	30	0	0	0
32444	SOUTHCROSS GATHERING LTD.	GT	Active	3	0	0	0
31881	SOUTHCROSS MISSISSIPPI INDUSTRIAL GAS SALES, L.P.	GT	Active	12	0	0	0
31880	SOUTHCROSS MISSISSIPPI PIPELINE, L.P.	GT,GG	Active	423	0	0	0
32445	SOUTHCROSS NGL PIPELINE LTD.	HL	Active	114	0	0	0
39140	SOUTHCROSS NUECES PIPELINES LLC	GT	Active	33	0	0	0
18456	SOUTHEAST ALABAMA GAS DISTRICT	GT,GD	Active	622	0	0	0
32653	SOUTHEAST GAS TRANSMISSION	GT	Active	111	0	0	0
32508	SOUTHEASTERN KANSAS PIPELINE & TRANSMISSION CO, LLC	GT	Active	26	0	0	0
18465	SOUTHEASTERN NATURAL GAS CO	GG,GD	Active	3	0	0	0
31724	SOUTHERN COMPANY PIPELINES	GT	Active	104	0	2	0
32175	SOUTHERN DOME, LLC	GT,GG	Active	12	0	0	0
18499	SOUTHERN GAS TRANSMISSION CO	GT	Active	50	0	0	0
38907	SOUTHERN ILLINOIS POWER COOPERATIVE	GT	Active	5	0	0	0
18508	SOUTHERN INDIANA GAS & ELECTRIC CO	GT,GD	Active	143	0	0	0
30992	SOUTHERN MISSOURI GAS COMPANY, L.P.	GT,GD	Inactive	207	0	0	0
18526	SOUTHERN UNION GAS SERVICES, LTD	HL,GT	Inactive	235	0	2	0
32256	SOUTHERN UNION INTRASTATE GAS PIPELINE	GT	Inactive	11	0	0	0
32562	SOUTHWEST GAS TRANSMISSION COMPANY A LIMITED...	GT	Active	10	0	1	0
32419	SOUTHWEST IOWA RENEWABLE ENERGY, LLC	GT	Active	1	0	0	0
18548	SOUTHWESTERN GAS PIPELINE INC	GT,GG	Inactive	3	0	0	0

18555	SOUTHWESTERN PUBLIC SERVICE CO	GT	Active	20	0	0	0
18560	SOUTHWESTERN VIRGINIA GAS CO	GT,GD	Active	14	0	0	0
39097	SOWEGA POWER LLC & BACONTON POWER LLC	GT	Active	2	0	0	0
30962	SPECTRA ENERGY VIRGINIA PIPELINE COMPANY	GT	Inactive	87	0	1	0
32585	SPELMAN PIPELINE HOLDINGS LLC	GT,GD	Active	121	0	0	0
31600	SPINNAKER EXPLORATION COMPANY, L.L.C.	GG	Inactive	2	0	0	0
18558	SPORT PIPELINE CORP	GT	Inactive	1	0	0	0
18584	SPRINGFIELD, CITY UTILITIES OF	GT,GD	Active	49	0	1	0
18594	SPUR, CITY OF	GT,GD	Active	43	0	0	0
18084	ST LAWRENCE GAS CO INC	GT,GD	Active	78	0	0	0
18678	ST LOUIS PIPELINE OPERATING LLC	HL	Active	22	0	5	4
32523	ST. PAUL PARK REFINING CO. LLC	HL	Active	5	0	0	0
38913	STATOIL OIL & GAS LP	HL	Active	60	0	4	0
39124	STATOIL PIPELINES LLC	HL	Active	23	0	0	0
39422	STATOIL USA ONSHORE PROPERTIES INC	GG	Active	2	0	0	0
18636	STEPHEN, CITY OF	GT,GD	Active	1	0	0	0
31104	STEPHENS AND JOHNSON OPERATING CO.	GG	Active	5	0	0	0
32268	STEPHENS PRODUCTION COMPANY	GT,GG	Active	8	0	0	0
32237	STERLING ETHANOL, LLC	GT	Inactive	6	0	0	0
30573	STEUBEN GAS STORAGE COMPANY	GT,GG	Inactive	16	0	6	2
32584	STL PIPELINE, LLC	GG	Inactive	6	0	4	2
31868	STONEWATER PIPELINE COMPANY, LLC	GT	Inactive	6	0	0	0
31803	STROUD PETROLEUM INC	GG	Active	2	0	0	0
32456	SUFFOLK TRANSMISSION PARTNERS, LP	GT	Active	2	0	0	0
849	SUMAS COGENERATION CO., L.P.	GT	Inactive	4	0	0	0
32438	SUMMIT GAS GATHERING, LLC	GT,GG	Inactive	11	0	0	0
39066	SUMMIT NATURAL GAS OF MAINE, INC.	GT,GD	Active	68	0	0	0
32074	SUMMIT NATURAL GAS OF MISSOURI	GT,GD	Active	300	0	0	0
30034	SUMMIT PETROLEUM CORP - GAS DIV.	GG	Active	26	0	0	0
31392	SUNFLOWER ELECTRIC POWER CORP	GT	Active	18	0	0	0
31904	SUNRISE POWER COMPANY, LLC	GT	Active	3	0	4	3
39131	SUNVIT PIPELINE LLC	HL	Active	27	0	2	1
32670	SUPERIOR APPALACHIAN PIPELINE, L.L.C.	GT,GG	Active	4	0	0	0
32007	SUPERIOR PIPELINE COMPANY L.L.C.	HL,GT,GG	Active	156	0	0	0
18752	SUPERIOR WATER LIGHT & POWER CO	GT,GD	Active	8	0	0	0
39109	SUSQUEHANNA GATHERING COMPANY I, LLC	GT,GG	Active	13	0	0	0
31949	SW GATHERING	GG	Active	4	0	0	0
39107	SWEPI LP	GG	Active	6	0	0	0
39111	SWG PIPELINE, L.L.C.	GT,GG	Active	353	0	0	0
32517	SWISSPORT FUELING INC	HL	Active	0	0	0	0
11288	SYCAMORE GAS COMPANY	GT,GD	Active	4	0	0	0

31962	SYCAMORE GAS SYSTEM	GG	Inactive	0	0	0	0
18784	SYLACAUGA GAS SYSTEM	GT,GD	Active	20	0	0	0
30715	SYNERGY PRODUCTION COMPANY	GG	Inactive	2	0	0	0
19481	T & M TERMINAL CO	HL	Active	1	0	2	0
38931	TABULA RASA ENERGY LLC	HL	Active	30	0	3	1
19035	TALCO MIDSTREAM ASSETS LTD	GG	Active	23	0	0	0
32312	TALISMAN ENERGY USA INC	HL,GG	Active	23	0	0	0
31756	TALL GRASS GAS SERVICES LLC	GT,GG	Inactive	4	0	0	0
39216	TALLGRASS MIDSTREAM LLC	HL	Active	18	0	1	0
32471	TALON OIL & GAS, LLC	GG	Inactive	56	0	0	0
39325	TALOS ENERGY, LLC	HL,GG	Active	3	0	1	0
99002	TAMPA AIRPORT PIPELINE CORPORATION	HL	Active	11	0	11	6
31716	TAMPA ELECTIC CO - POLK POWER	GT	Inactive	1	0	0	0
31801	TANDEM ENERGY CORPORATION	GG	Active	11	0	0	0
32615	TANOS EXPLORATION, LLC	GG	Inactive	7	0	0	0
30748	TARGA INTRASTATE PIPELINE, LLC.	GT,GG	Active	42	0	0	0
30626	TARGA NGL PIPE LINE CO	HL	Active	106	0	7	0
31492	TARGA PIPELINE MID-CONTINENT LLC	GT,GG	Active	8	0	0	0
32478	TARGA PIPELINE MID-CONTINENT WEST OK LLC	GG	Active	16	0	0	0
22465	TARGA PIPELINE MID-CONTINENT WESTTEX LLC	HL,GT,GG	Active	90	0	2	0
31977	TARGA RESOURCES, INC.	HL,GT,GG	Inactive	373	0	0	1
38921	TARGA SOUND TERMINAL LLC	HL	Active	3	0	1	0
30976	TATA CHEMICALS	GT	Active	10	0	0	0
39309	TEA ENERGY SERVICES, LLC	GG	Active	6	0	0	0
19125	TEAVEE OIL & GAS INC	GT,GG,GD	Active	18	0	0	0
32588	TECHNISAND INC.	GT	Active	4	0	0	0
32226	TECPETROL CORPORATION	GT	Active	10	0	0	0
32200	TEMA OIL & GAS COMPANY	GG	Active	5	0	0	0
39016	TEMPEST ENERGY RESOURCES	GG	Active	6	0	0	0
31747	TENASKA GEORGIA PARTNERS LP	GT	Active	1	0	0	0
19140	TENOAKS PIPELINE CO	GT	Inactive	3	0	0	0
32400	TEPEE PETROLEUM COMPANY, INC.	GG	Inactive	3	0	0	0
39338	TESORO ALASKA COMPANY LLC	GT	Active	0	0	0	0
30735	TESORO ALASKA PIPELINE COMPANY LLC	HL	Active	73	0	9	1
32631	TESORO GREAT PLAINS MIDSTREAM LLC	HL	Active	116	0	6	2
39029	TESORO LOGISTICS NORTHWEST PIPELINE LLC	HL	Active	1,201	0	7	2
31874	TESORO LOGISTICS OPERATIONS LLC - GOLDEN EAGLE	HL	Active	5	0	0	0
39228	TESORO LOGISTICS ROCKIES	HL,GT	Active	158	0	3	0
32253	TESORO REFINING & MARKETING COMPANY LLC - LOS ANGELES...	HL,GT	Active	16	0	7	5
32484	TESUQUE PIPELINE, LLC	GG	Active	2	0	0	0
19233	TEXACO EXPLORATION & PRODUCTION INC	GG	Inactive	7	0	0	0

32276	TEXANA MIDSTREAM COMPANY LP	GT,GG	Inactive	107	0	0	0
31681	TEXAS CRUDE ENERGY INC	GG	Inactive	14	0	0	0
26103	TEXAS EASTMAN DIVISION, EASTMAN CHEMICAL CO	HL	Active	471	0	0	0
39125	TEXAS ENERGY MIDSTREAM L.P.	GT,GG	Inactive	4	0	0	0
39441	TEXAS GAS PIPELINE COMPANY, LLC	GT	Active	2	0	0	0
19301	TEXAS MUNICIPAL POWER AGENCY	GT	Active	17	0	0	0
30721	TEXAS SOUTHEASTERN GAS GATHERING CO.	GT	Inactive	2	0	0	0
38885	TEXSTAR MIDSTREAM UTILITY, LP	HL	Inactive	49	0	0	0
32673	TEXTRAN PIPELINE, LLC	GG	Active	1	0	0	0
31870	TGS RIO, L.L.C.	GT	Inactive	528	0	0	0
12606	THE EMPIRE DISTRICT GAS COMPANY	GT,GD	Active	87	0	0	0
31897	THE GEORGE R. BROWN PARTNERSHIP, L.P.	HL	Active	8	0	0	0
30036	THE HOUSTON EXPLORATION COMPANY	GG	Inactive	4	0	0	0
31575	THE QUINTIN LITTLE CO INC	GG	Active	2	0	0	0
19360	THIBODAUX GAS DEPT, CITY OF	GT,GD	Active	88	0	0	0
31422	THUNDER CREEK GAS SERVICES LLC	GG	Inactive	1	0	0	0
39187	THUNDER CREEK NGL PIPELINE, LLC	HL	Active	106	0	3	0
31372	TICONA POLYMERS INC	GT	Active	27	0	0	0
31051	TIDEWATER, INC	HL	Active	18	0	1	0
32608	TIGER DEVELOPMENT LLC	GT	Active	1	0	0	0
30914	TIMBERLAND GATHERING & PROCESSING CO., INC	GG	Active	0	0	0	0
32403	TIMBERLINE ENERGY LLC	GT	Active	7	0	0	0
39339	TINSLEY RESOURCES LLC	HL	Active	37	0	1	0
39092	TITAN ALASKA LNG	GT	Active	1	0	3	2
39236	TITANIUM METALS CORPORATION	GT	Active	1	0	0	0
19490	TOCCOA NATURAL GAS SYSTEM, CITY OF	GT,GD	Active	90	0	0	0
32572	TOLEDO REFINING COMPANY, LLC	HL	Active	4	0	4	1
39344	TOM-STACK	GT	Active	3	0	0	0
39153	TOMPC LLC	GT,GG	Active	13	0	0	0
19529	TORCH MIDSTREAM SERVICES, LLC	GT	Inactive	23	0	2	1
32063	TORO ENERGY OF INDIANA, LLC	GT	Active	8	0	0	0
32067	TORO ENERGY OF MARYLAND, LLC	GT	Active	6	0	0	0
32325	TORO ENERGY OF MISSISSIPPI, LLC	GT	Active	5	0	0	0
30801	TOTAL GAS PIPELINE USA, INC	HL,GT	Active	17	0	0	0
31937	TPCO, LLC	HL	Active	10	0	2	0
19538	TPI PIPELINE CORP	GT	Inactive	11	0	0	0
38952	TPL ARKOMA HOLDINGS LLC	HL,GT	Active	19	0	0	0
39082	TPL SOUTHTEX MIDSTREAM LLC	GT,GG	Active	67	0	0	0
31856	TPM, INC	HL	Inactive	9	0	8	4
32430	TRADITION RESOURCES OPERATING, LLC	HL,GG	Active	58	0	0	0
19574	TRAILBLAZER PIPELINE CO	GT	Active	454	0	10	0

19585	TRANS MOUNTAIN PIPELINE (PUGET SOUND) LLC	HL	Active	64	0	14	3
31543	TRANS-UNION INTERSTATE PIPELINE, L.P.	GT	Active	42	0	7	1
32476	TREETOP MIDSTREAM SERVICES, LLC	HL	Active	0	0	3	1
32592	TREK RESOURCES, INC	GG	Active	4	0	0	0
32181	TREND GATHERING & TREATING, LLC	GG	Active	24	0	0	0
32448	TRES PALACIOS GAS STORAGE LLC	GT	Active	100	0	3	1
32151	TRI-C RESOURCES, INC.	GG	Inactive	7	0	0	0
32155	TRIAD ENERGY CORPORATION	GT	Inactive	3	0	0	0
31475	TRINITY PIPELINE GP LLC	HL	Active	180	0	5	3
39326	TRINITY RIVER ENERGY OPERATING, LLC	GT,GG	Active	74	0	0	0
39045	TRISTATE ETX, LLC	GG	Active	11	0	0	0
32610	TRISTREAM EAST TEXAS, LLC	HL	Active	34	0	0	0
39447	TRONOX ALKALI CORPORATION	GT	Active	14	0	0	0
31915	TROPICANA PRODUCTS, INC.	GT,GD	Active	0	0	0	0
30838	TUSCARORA GAS TRANSMISSION COMPANY	GT	Active	305	0	8	1
30050	TWISTER GAS SERVICES, LP	GG	Inactive	4	0	0	0
39117	TX PIPELINE WEBB CO LEAN SYS, LLC	GT	Active	41	0	0	0
39120	TX PIPELINE WEBB CO RICH SYS, LLC	GT	Active	37	0	0	0
32222	TYSON FOODS, INC.	GT	Active	3	0	0	0
31087	U.S. BORAX	GT,GD	Inactive	2	0	2	1
19890	UCAR LOUISIANA PIPELINE CO	GT	Active	1	0	0	0
31467	UGI CENTRAL PENN GAS, INC	GT,GD	Active	131	0	0	0
38927	UGI ENERGY SERVICES	GT,GG	Active	45	0	2	1
20010	UGI UTILITIES, INC	GT,GD	Active	122	0	8	0
32493	UNEV PIPELINE, LLC	HL	Active	427	0	12	0
20046	UNION CARBIDE CHEMICALS & PLASTICS CO INC	HL,GT	Active	14	0	0	0
20042	UNION CARBIDE CHEMICALS & PLASTICS INC -TEXAS CITY	HL,GT	Inactive	9	0	0	0
20040	UNION CARBIDE CORP	GT	Inactive	4	0	0	0
20120	UNION OIL & GAS INC	GT,GD	Active	24	0	0	0
20132	UNION OIL CO OF CALIFORNIA	GG	Active	6	0	0	0
31347	UNION OIL COMPANY OF CALIFORNIA (UOCC)	HL,GT,GG	Inactive	130	0	19	6
31840	UNISOURCE ENERGY SERVICES	GT,GD	Active	30	0	0	0
32199	UNIT PETROLEUM COMPANY	GG	Inactive	3	0	0	0
39234	UNITED GAS PIPELINE COMPANY, LLC	GG	Active	0	0	0	0
26111	UNITED REFINING CO	HL	Active	2	0	0	0
20236	UNITED STATES GYPSUM CO	GT,GD	Active	77	0	4	0
20237	UNITED STATES STEEL CORP	GG	Inactive	2	0	0	0
39361	UNIVERSITY OF ARKANSAS, FAYETTEVILLE	GT	Active	1	0	0	0
20263	UNIVERSITY OF ILLINOIS - LATERAL	GT,GD	Active	22	0	0	0
31665	UNIVERSITY OF NEW HAMPSHIRE	GT,GD	Active	13	0	0	0
32426	UNIVERSITY PARK ENERGY, LLC	GT	Active	0	0	0	0

25172	UNOCAL ENERGY RESOURCE DIVISION	GT,GG	Inactive	16	0	0	0
39266	URBAN OIL & GAS GROUP	GT,GG	Active	1	0	0	0
32429	US AMINES	GT	Active	20	0	0	0
99054	US STEEL	GT,GD	Active	17	0	4	1
31127	USG INTERIORS INC	GT	Inactive	2	0	0	0
31839	USG PIPELINE COMPANY, LLC	GT	Inactive	16	0	3	1
32458	UTAH ASSOICIATED MUNICIPAL POWER SYSTEMS	GT	Active	5	0	0	0
39122	UTICA EAST OHIO MIDSTREAM LLC	HL,GT,GG	Active	79	0	2	0
31814	UTILITY SAFETY AND DESIGN, INC.	GT,GD	Inactive	11	0	0	0
32021	VALENCE MIDSTREAM LIMITED	GG	Inactive	2	0	0	0
30807	VALENCE OPERATING COMPANY	GG	Active	4	0	0	0
31243	VALERO NATURAL GAS PIPELINE	GT	Inactive	3	0	5	3
32033	VALERO REFINING COMPANY - LOUISIANA	HL,GT	Inactive	5	0	0	0
32212	VALERO REFINING COMPANY - OKLAHOMA	GT	Active	11	0	0	0
32032	VALERO REFINING COMPANY - TEXAS	HL	Inactive	51	0	0	0
32364	VALERO REFINING-NEW ORLEANS, L.L.C.	HL,GT	Active	8	0	0	0
21030	VALLEY ENERGY, INC.	GT,GD	Active	14	0	0	0
39439	VALLEY LFG, LLC	GT	Active	2	0	0	0
32591	VAMOS OIL AND GAS, LLC	GG	Active	11	0	0	0
38888	VANTAGE FORT WORTH ENERGY LLC	GG	Active	4	0	0	0
21153	VARIBUS CORP	GT	Active	29	0	0	0
32600	VELMA-ALMA SCHOOL	GT	Inactive	1	0	0	0
39358	VELOCITY CENTRAL OKLAHOMA PIPELINE, LLC	HL	Active	41	0	0	0
32320	VENTURA REFINING AND TRANSMISSION, LLC	GT	Inactive	1	0	0	0
21190	VERMONT GAS SYSTEMS INC	GT,GD	Active	74	0	0	0
6255	VERNON E FAULCONER INC	GT	Active	1	0	0	0
39135	VICTORIA EXPRESS PIPELINE, L.L.C.	HL	Active	57	0	0	0
32525	VINLAND ENERGY OPERATIONS	GT,GG	Active	30	0	0	0
30804	VINTAGE PETROLEUM, INC.	HL	Inactive	3	0	0	0
21315	VINTAGE PIPELINE INC	GT,GG	Inactive	80	0	0	0
32279	VINTON PIPELINE, LLC	GT	Inactive	5	0	0	0
21350	VIRGINIA POWER	GT	Inactive	17	0	0	0
30794	VIRTEX PETROLEUM CO., INC.	GG	Active	2	0	0	0
39246	VISTA ENERGY, INC.	GG	Active	8	0	0	0
31420	VOPAK TERMINAL LOS ANGELES INC.	HL	Active	11	0	0	0
32115	VOYAGER EXPLORATION, INC.	GT	Inactive	7	0	1	0
30020	W & T OFFSHORE INC	GT,GG	Active	52	0	0	0
39275	WACKER POLYSILICON NORTH AMERICA, LLC	GT	Active	1	0	0	0
32361	WAGNER & BROWN LTD.	GG	Inactive	3	0	0	0
31708	WAGNER OIL COMPANY	GT,GG	Inactive	4	0	0	0
22035	WAKEFIELD MUNICIPAL LIGHT DEPT	GT,GD	Active	0	0	0	0

30839	WALDEN, TOWN OF	GT,GD	Active	46	0	0	0
22110	WALTER OIL & GAS CO	GG	Active	10	0	0	0
22154	WARNER ROBINS GAS SYSTEM	GT,GD	Active	25	0	0	0
22168	WARREN GAS DEPT, CITY OF	GT,GD	Active	1	0	0	0
990	WARRIOR GAS CO	GG	Active	5	0	0	0
32310	WARRIOR MET COAL GAS,LLC	GT	Active	7	0	0	0
22182	WASHINGTON GAS LIGHT CO	GT,GD	Active	181	0	0	0
32556	WASKOM MIDSTREAM	GG	Inactive	10	0	0	0
32589	WASKOM TRANSMISSION LLC	GG	Inactive	2	0	0	0
32311	WATERLOO GAS TRANSPORT, LLC	GT,GD	Active	1	0	0	0
22235	WAUKEE MUNICIPAL GAS	GT,GD	Active	14	0	0	0
22280	WAYLAND MUNICIPAL GAS CO	GT,GD	Active	10	0	0	0
22343	WEIR NATURAL GAS SYSTEM, TOWN OF	GT,GD	Active	5	0	0	0
22357	WELLMAN MUNICIPAL GAS SYSTEM	GT,GD	Active	7	0	0	0
22368	WEST BAY EXPLORATION CO	GT	Active	9	0	0	0
32090	WEST FORK PIPELINE COMPANY, L.P.	GT	Inactive	2	0	0	0
31312	WEST PHOENIX POWER PLANT	HL,GT	Active	3	0	0	0
22434	WEST TENNESSEE PUBLIC UTIL DIST	GT,GD	Active	5	0	0	0
39357	WEST THOMAS FIELD SERVICES, LLC	GT	Active	1	0	0	0
32225	WESTECH ENERGY CORPORATION	GT	Inactive	21	0	0	0
39040	WESTERN ENERGY GROUP	GG	Active	5	0	0	0
22448	WESTERN FARMERS ELECTRIC COOP	GT	Inactive	161	0	0	0
22462	WESTERN GAS INTERSTATE CO	GT	Active	236	0	8	1
30581	WESTERN GAS RESOURCES-TEXAS, INC	GT	Inactive	37	0	0	0
30001	WESTERN PIPELINE INC	GG	Active	1	0	0	0
31877	WESTERN REFINING TERMINALS, LLC	HL	Active	5	0	0	0
22410	WESTGAS INTERSTATE, INC	GT	Active	11	0	4	0
30683	WESTLAKE PETROCHEMICALS LLC	HL,GT	Active	29	0	0	0
30941	WESTLAKE PVC CORPORATION	GT	Active	3	0	0	0
39451	WEYERHAEUSER	GT	Active	2	0	0	0
31730	WGP-KHC, LLC	GG	Active	3	0	0	0
39269	WHITE OAK OPERATING COMPANY, LLC	GT,GG	Active	7	0	0	0
31352	WHITING PETROLEUM CORP	HL,GT,GG	Active	59	0	4	2
39288	WHITMAR NEW YORK, LLC	GG	Active	4	0	0	0
39377	WHITNEY OIL & GAS, LLC	HL	Active	10	0	0	0
31206	WICHITA GAS PRODUCERS, LLC	GT,GD	Inactive	10	0	0	0
31136	WICKLAND OIL COMPANY	HL	Active	12	0	0	0
22605	WILCOX COUNTY GAS DISTRIBUTION	GT,GD	Active	44	0	0	0
31287	WILD GOOSE STORAGE INC	GT	Active	34	0	0	0
38926	WILDCAT MIDSTREAM OPERATING LLC	HL,GT,GG	Active	53	0	0	0
32252	WILLIAMS ARKOMA GATHERING LLC	GT	Inactive	29	0	0	0

32250	WILLIAMS BARNETT GATHERING SYSTEM, LP	GT,GG	Inactive	26	0	0	0
994	WILLIAMS FIELD SERVICES - GULF COAST COMPANY, LP	HL,GG	Active	499	0	12	3
32091	WILLIAMS OIL GATHERING, LLC	HL	Active	378	0	6	0
32614	WILLIAMS OLEFINS FEEDSTOCK PIPELINES, LLC	HL,GT	Active	580	0	4	1
22662	WILLOWTEX PIPELINE CO	GT	Inactive	15	0	0	0
32216	WINDSOR ENERGY GROUP, LLC	HL	Inactive	1	0	1	1
30515	WINFIELD MUNICIPAL GAS	GT,GD	Active	6	0	0	0
22742	WINONA, TOWN OF	GT,GD	Active	7	0	0	0
22777	WISCONSIN ELECTRIC POWER COMPANY DBA WE ENERGIES	GT,GD	Active	193	0	0	0
22763	WISCONSIN GAS LLC DBA WE ENERGIES	GT,GD	Active	354	0	0	0
22791	WISCONSIN PUBLIC SERVICE CORP	GT,GD	Active	229	0	0	0
31916	WM RENEWABLE ENERGY, LLC	GT	Active	22	0	0	0
32064	WMRE OF KENTUCKY, LLC	GT	Inactive	5	0	0	0
32068	WMRE OF MICHIGAN, LLC	GT	Active	2	0	0	0
32070	WMRE OF OHIO, LLC	GT	Active	3	0	0	0
32071	WMRE OF OHIO-AMERICAN, LLC	GT	Active	9	0	0	0
3120	WOLF ENERGY	GG	Inactive	3	0	0	0
22818	WOLVERINE POWER SUPPLY COOP INC	GT	Active	2	0	0	0
32616	WOODLAND PULP, LLC	GT	Active	5	0	0	0
32001	WOODLAWN PIPELINE COMPANY, INC.	HL,GG	Inactive	38	0	0	0
18542	WOODWARD APPLE SPRINGS, LLC	GG	Active	3	0	0	0
32285	WORSHAM-STEED GAS STORAGE, LLC	HL,GT	Active	67	0	0	0
31936	WORTHINGTON GENERATION	GT	Active	1	0	0	0
31718	WPS-ESI GAS STORAGE LLC	GT	Inactive	6	0	0	0
38988	WPX ENERGY MARCELLUS GATHERING, LLC	GG	Inactive	1	0	0	0
32232	WTG GAS PROCESSING, L.P.	HL,GT	Inactive	67	0	0	0
38938	WTG NGL PIPELINE COMPANY, LLC	HL	Active	42	0	0	0
32314	WTG-HUGOTON, LP	GT,GG	Active	154	0	3	1
32405	WYCKOFF GAS STORAGE COMPANY, LLC	GT	Active	12	0	0	0
32271	WYNN-CROSBY OPERATING, LTD	GG	Active	2	0	0	0
30756	WYOMING REFINING CO	HL	Active	40	0	5	1
39204	XLAKE PIPELINE CO., LLC	GT	Inactive	6	0	0	0
39231	XPLORER MIDSTREAM LLC	HL,GT	Active	3	0	0	0
31178	XTO ENERGY INC	HL,GT,GG	Active	188	0	10	7
39413	XTR MIDSTREAM, LLC	GG	Active	30	0	0	0
31939	XTX PIPELINE COMPANY, LLC	GT	Inactive	2	0	0	0
32368	YALE OIL ASSOCIATION, INC.	GG	Inactive	1	0	0	0
24030	YORK COUNTY NATURAL GAS AUTH	GT,GD	Active	9	0	0	0
31837	ZADECK ENERGY GROUP, INC.	GG	Inactive	12	0	0	0
31387	ZAPCO ENERGY TACTICS	GT	Active	4	0	0	0
39134	ZEELAND FARM SERVICES, INC.	GT	Active	6	0	0	0

25000	ZIA NATURAL GAS CO	GT,GD	Active	123	0	3	2
32036	ZINN PETROLEUM COMPANY	GG	Inactive	1	0	0	0