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PIPELINE SAFETY: AN ON-THE-GROUND LOOK AT SAFEGUARDING THE PUBLIC

FIELD HEARING

BEFORE THE

COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION UNITED STATES SENATE

ONE HUNDRED THIRTEENTH CONGRESS

FIRST SESSION

JANUARY 28, 2013

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SENATE COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION

ONE HUNDRED THIRTEENTH CONGRESS

FIRST SESSION

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PIPELINE SAFETY: AN ON-THE-GROUND LOOK AT SAFEGUARDING THE PUBLIC

MONDAY, JANUARY 28, 2013

U.S. SENATE,
COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION,
Charleston, WV.

The Committee met, pursuant to notice, at 12:36 p.m., in the Ceremonial Courtroom, Seventh Floor of the Robert C. Byrd Courthouse, Hon. John D. Rockefeller IV, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. JOHN D. ROCKEFELLER IV, U.S. SENATOR FROM WEST VIRGINIA

The CHAIRMAN. Welcome everybody. This hearing will come to order. This is a full and regular meeting of the Commerce Committee. We did this about a year ago on the same subject up north. Now we have new motivation because of what's happened here in the last several days.

Let me just make a statement and then Senator Manchin, who joins us here today will make his statement, and I'm very happy about that.

These pipes, pipelines, crisscross underneath our cities and our countryside. They're everywhere, 2.5 million miles, maybe more. Yet most of the time we're not even aware that they are there or have been there for 30, 40, 50, 60, 70 years or more recently. They deliver the critical fuel that powers our homes, our factories, and offices. And they also transport the oil and gas that keep our cars, trucks, and planes operating. They are the critical conduit between the shale gas development boom in our region and the rest of the country.

And most days the network of pipelines operates across the country without a hitch. Let me be clear in saying that. Compared to other forms of transportation, pipelines are a relatively safe, clean, and efficient way of transporting the goods that they carry. Unfortunately, this is not always the case.

Everyone in this room knows all too well what can happen when something does go wrong. Sue Bonham will be our first testifier, and she certainly knows. Wes, who has worked with me for 28 years, lives very close to there.

So last month's incident in Sissonville was a startling reminder of the destruction that can occur when a pipeline does in fact rupture, explode. Houses were destroyed and portions of the nearby interstate were literally dismantled, disintegrated by the overwhelming heat of the flames from the ruptured pipeline.

We can only thank our lucky stars that nobody was killed and that nobody was badly injured. I think there's a lot of pretty shaken up people out there, but there were no serious injuries. As we have seen in other accidents in the last few years, we're not always so lucky.

After the explosion in Sissonville, we must sustain our focus on making sure the pipeline industry and all industries operate as safely as possible. That's my duty. That's what I swore an oath to.

While we do not yet know the exact cause of the Sissonville incident, today's hearing provides the opportunity to examine where we stand in regard to the safety of our nation's pipeline system, which is vast. And —and just you know in your mind, feel the surge of that industry as it diverges and grows everywhere. People can't go fast enough.

And in the building of that, some of the platforms you have trucks that carry water that can be up to 80,000 pounds going over West Virginia roads, which are built for far less than that, sometimes going right through people's front yard because they can't make the turn. So there's a lot of hurt that goes on just in the construction of these matters.

When I took over as Chairman of the Commerce Committee, I made consumer protection and public safety my key priorities, and I really did. It was a good committee. It was a nice committee. It did its work. But accordingly, with the changes that I made, the Committee has been very active on the safety front. We actually established an idea that I got from Henry Waxman in the investigations unit which is made up—we made it up with very, very bright people, all lawyers with sharp teeth looking for bad people and doing something about it.

These efforts have resulted in safety improvements across several industries from aviation to trucking to automobiles and on. As for pipeline safety, the Committee has held multiple hearings and successfully worked with our colleagues in the House to pass a Pipeline Safety Bill into law last year. It was not all that I had wanted, and it was compromised a good deal in the House, which is something that you get a bit familiar with in the Congress.

This law which is called the Pipeline Safety Regulatory Certainty and Job Creation Act of 2011, welcome to Washington speak, was largely based on legislation that we in fact had developed in the Commerce Committee over a period of years and then passed out of the Commerce Committee and then through the Senate and then on to conference. And then both Houses then voting for it and the President signed it.

This legislation included a number of new requirements that will move the ball forward in pipeline safety. For example, we laid the foundation to require the use of remote controlled and automatic shutoff valves on new pipelines. That's something I know that we're going to discuss today.

We removed exemptions from requirements to call and get underground lines marked before you excavate. Year after year, excavation damage is the leading cause of pipeline accidents, and it certainly is time to pay attention to that. Removing exemptions from who has to "call before you dig" is now history, and it will help reduce the problem.

We required operators to verify records and to reestablish lines, maximum operating pressure, PSI. How much can it take? I believe Ms. Hersman said the maximum pressure was 1,000 was what it was out there, maximum. And it was up to 970, 997 or something like that. It was a very, very close margin. So pressure within the pipelines becomes an enormously important effort. Should you have to set a reasonable pressure standard? I think the answer is yes.

Lack of records predictively is a huge problem about older pipelines and just in general and contributed to the catastrophic pipeline explosion in California that killed eight people and injured many more, dozens more, I think.

We require that critical pipeline location and inspection and information be provided to the public to build greater awareness of the lines that exist in and around our communities. That's something that is important now that people now are just living in a website world. And if you put information about pipelines and where they're located and make it available to the public, that's what government ought to be doing. That's what we ought to be doing.

Does everybody immediately go to a website? Does everybody necessarily use the technology to get to a website? No. But it's going to keep going and increase each and every year.

Finally, we increased penalties on operators who ensure the safety regulations. This will help deter bad actors from avoiding their safety obligations. And there's a lot that was pointed out this morning in the stop at Sissonville that had it been another series of companies that it could have been things might have been a whole lot worse.

So while I'm pleased with the progress that we made in last year's law, I pushed for stronger requirements to move pipeline safety even further ahead. The Senate-passed bill, while not perfect, included a number of more stringent requirements for operators but House negotiators demanded watered down provisions for an agreement to move forward. And, of course, if you don't get their votes in conference you can't have a bill, so we went with the best we could possibly do.

On the bright side, I'm confident that we will see strong but fair and sensible safety regulations out of our legislation. That's one of the things I want to discuss today with our Federal panel of witnesses. The questioning will be somewhat technical, and please forgive me for that. It was a tough fight to get pipeline safety legislation signed into law. However, it's important that we continue to provide a rigorous oversight into the industry to determine whether serious gaps still exist in our safety requirements.

So today is a perfect opportunity to take stock in where we are and consider what steps might be necessary moving forward. One word too. One of our main jobs on the committees that Senator Manchin and I sit is something called oversight. And it is much maligned by many but not by us and not by me.

Everybody has to be accountable to somebody else within a free society and a free enterprise society. There have to be limits. There have to be rules. In a country with over 300 million people and so many different kinds of industries, that just is something that has to happen. It's something that only the Congress can do and then hopefully turn some of that into law.

Anyway, I'm very excited about the witnesses we will hear from today, and particularly right now, Sue Bonham, a resident of Sissonville, whose house, fence, former house, former fence I saw this morning because it was right across from where we were in that 17-foot hole. And she's going to tell her great personal story about her experiences the day of the Sissonville explosion.

Ms. Bonham provides a unique and important perspective as someone who was directly affected, and it's vital that we hear her point of view and that we keep it in our minds. As we consider what steps are necessary moving forward, we must remember there are crucial decisions and policies that have real impact on people's lives.

And, Ms. Bonham, if you'll excuse me, I'm very happy that Senator Manchin is here and if he has some comments, hopefully shorter than mine, you're welcome to make them, sir. And I'm very happy you took the time to come.

STATEMENT OF HON. JOSEPH MANCHIN, U.S. SENATOR FROM WEST VIRGINIA

Senator MANCHIN. Thank you, Senator, and to all of you here today, I appreciate so much your attendance. To all of the citizens of Sissonville who are affected directly or indirectly, I'm so pleased that nobody was injured but I'm sorry for the losses you've had and I hope all that will be restored fully.

And, Sue, we'll be anxious to hear from you also.

I want to thank Senator Rockefeller for his leadership as Chairman of the Senate Committee on Commerce, Science, and Transportation to make sure that our pipelines are constructed, maintained, and operated safely. I also want to thank the Senator for organizing the field hearing to make sure horrific explosions like the one in Sissonville never happen again.

This is the fourth pipeline safety hearing held by Senator Rockefeller and the Commerce Committee in the last three years, which reflects the importance of the issue to the people of West Virginia, to Senator Rockefeller, and to myself. Of course we're not the only state interested in pipeline safety. In the last couple of years, there have been fatal pipeline ruptures in Pennsylvania and California. In any given year, there are between 32 to 61 pipeline incidents involving a fatality or hospitalization.

We are so fortunate that no one was seriously injured last December when the gas pipeline ruptured in Sissonville. And I'm so thankful that all of you—and, Sue, I know that you were trapped in your home for quite some time, and survived that ordeal. And we'll be anxious to hear from you.

We're all fortunate, indeed, that we had no West Virginians injured. We can't count on being that lucky the next time. The best thing that we can do is to make sure there is no next time ultimately. That's why we're all here today.

I was exchanging a few comments with the families. I remember, it had to be about 20 years ago in Farmington, we had a horrific explosion, the same type. And the first time in my life I had ever seen anything like it. And I was visiting my father and mother in

Farmington. And this had to be 20 or more years ago. And that's back when most of the cars were carbureted.

So my dad and I jumped in the car and went up to the scene immediately, and horrific noise, just like a blowtorch but magnified many, many times. And my first thought is, is why doesn't somebody just shut the gas off? That was my first reaction. Why would they continue to let this happen? And the next of all, I saw all these cars lined up on U.S. Route 250 and they all come to a standstill. And I thought, oh, my goodness, Senator, the worst possible. These people had all gotten killed in their cars. So I'm running through the cars very quickly and looking in and didn't see. A couple of the houses, the paint was melting. And I found out later that when the line exploded it sucked all the oxygen out and the cars stopped dead in their tracks. And it was just horrific. So I have witnessed that myself.

So today I look forward to hearing how the Pipeline and Hazardous Material Safety Administration, with the help of the National Transportation Safety Board and the Government Accountability Office, plans to work with natural gas companies to develop and to enforce regulations that ensure pipelines are being operated safely and maintained properly and inspected regularly. We need common sense guidelines to prevent these incidents like the recent rupture in Sissonville.

And, again, I want to thank Senator Rockefeller for holding this hearing and for also his many years of service which are going to be greatly missed. I can tell you he's been a great mentor, and he's been very helpful to me. And his staff has been absolutely unbelievable during my transition into the Senate. We're going to miss him, but we still have him for a while and we're going to work him hard while we still have him.

The CHAIRMAN. And I've upgraded my clothing.

Senator MANCHIN. He has done that. He sometimes——

The CHAIRMAN. I'm an embarrassment to Senator Manchin on the Senate floor. I don't dress well enough for him, so I'm trying to improve my act. Now this is not a time for frivolous things.

Senator MANCHIN. You can imagine he comes to consult with me on proper clothing.

With that being said, I just want to thank him again. It's a pleasure to serve with him and an honor. But also the care and the concern we have for all the citizens of West Virginia—we hope together we can figure out ways this won't happen and we can continue to improve the quality of safety and the quality of lives. Thank you, Senator.

The CHAIRMAN. Thank you, Senator Manchin.

Sue Bonham, please take your time.

STATEMENT OF SUE BONHAM, RESIDENT OF SISSONVILLE, WEST VIRGINIA

Ms. BONHAM. Thank you, Senator Rockefeller and Senator Manchin, for your gracious invitation to share my experience during the gas pipeline explosion in Sissonville on Tuesday, December 11, 2012.

Not only am I honored by your invitation, I am truly blessed to have survived my 40 to 45 minute ordeal and to be able to share that story with you today.

The front of my home faced Sissonville Drive where the explosion occurred. On the backside to the left there's a flower garden and an in-ground pool, both of which are surrounded by a large privacy fence with a gate access to the front of the home. Toward the right backside are the driveway and garage areas where my vehicle and another vehicle were parked. But the corner of the flower garden is where I sought shelter that afternoon.

I was ready to walk out the door to run errands when I received a phone call from a lady named Trudy to schedule an appliance repair. Within seconds, Trudy and her coworkers became my only lifeline. I believe that call kept me from exiting my driveway onto Sissonville Drive when and where the blast occurred and where I believe I would have been killed instantly during the explosion.

Instead, I stood in the center of my home where it was trembling, shifting, shaking, grinding all around me, the ground rumbling beneath me thinking the earth would open up at any moment and swallow me. The noise was so loud I had to scream for Trudy to please stay on the line, because I believed there was an earthquake or possibly a plane had crashed.

Projectiles began falling like missiles through the ceiling into my home and I felt an immediate intense heat that took my breath away. As everything around me became more intense, I became more frightened. I dove underneath my dining room table and I looked out the bottom of the sliding glass doors only to see everything sizzling, blistering, or melting. The vehicles on the ground were literally rocking, moving in ways, and hot steam was filtering up out of the ground like hot springs.

I crawled from my shelter to peek out a front window only to see a huge wall of fire roaring as far as I could see. At that moment I realized a gas line may have exploded and that I was in extreme danger. I ran out the back doors toward my flower garden thinking that if necessary I could jump into the pool to protect myself from the fire. My first attempt failed because the heat was so intense that I was driven back inside my home.

I returned to my spot under the table becoming even more frightened realizing the house must be on fire and if it was a gas line explosion both my home and I could explode at any moment. Frightened, but thinking I had no other choice, I made another attempt to escape to the flower garden where I hid in the corner behind a withering vine and the privacy fence.

I continued to scream into the phone hoping Trudy could hear me because I could no longer hear her over the roar of the explosion which was so deafening that I felt my eardrums would explode. The heat became more intense, suffocating, and the only area I could breathe was in that corner of the garden.

I attempted once to run for the pool but the heat and lack of air drove me back to my corner. I failed at several attempts of stacking landscaping stones around me hoping that they might protect me from the overwhelming heat. I feared the landscaping mulch surrounding me might burst into flame at any moment.

I rolled onto the ground to absorb some coolness believing I would soon be burned alive if I couldn't stay damp. At one point I threw my purse over the fence to mark my location for any rescue attempts. My only exits were to the front gate where the explosion was or to the driveway area where the blast and huge fireball were also located. I was trapped.

I witnessed the earth being scorched, my home burning and melting. Everything was blistering or exploding. My stepdaughter's home imploding into ashes and hearing the continuing roar of the explosion. I looked into the sky and wondered if maybe this was simply the end of the world.

I portrayed to Trudy that it was important to me that my family knew I fought hard to survive and that my last thoughts were of them because I became defeated. Suddenly two great firemen, Scott Holmes and Eddie Elmore, came into sight. Word had been received I was trapped. They wrapped their arms around me and escorted me to safety where I was loaded into an ambulance, treated for smoke inhalation, and then transported to a triage location where my family was awaiting. The relief I felt when I saw my daughter's beautiful face will remain in my heart forever.

As the shock somewhat wore off, I began to understand the enormity of my experience. Overwhelmed by the odds that I had defied, I learned that I most likely would have been scalded alive had I jumped into the pool. And mostly certainly I would have died from lack of oxygen and smoke inhalation had I remained inside my home.

Perhaps over the years, I've picked up some survival skills from surviving breast cancer, losing our home to a fire 5 years ago in that same location or listening to my youngest son's survival experiences with 130th Air Guard and for putting up with war stories from my husband Paul, a retired Charleston firefighter.

All I know for sure is that I'm truly blessed by God to be here today. And, again, I thank you for this opportunity to share my survival experience of the Sissonville gas line pipeline explosion on December, 11, 2012.

The CHAIRMAN. Ms. Bonham, thank you very, very much. In reading one of the stories, something that just stuck in my mind was that you, early on in the process, put up some rocks to hide behind.

Ms. BONHAM. Yes, I did.

The CHAIRMAN. And then so that people would know that there was somebody behind there you sort of put your purse over on the other side.

Ms. BONHAM. I did.

The CHAIRMAN. And what that says to me is the fullness of desperation, the fullness of the instinct for survival. And that was before you had to run because you didn't want to run because you didn't know that you'd make it to get under that bush.

But we're so glad that you did. You, yourself, and your testimony and just the example that you've set already around the state now is important for every one of us, and I thank you very, very much for your testimony.

Ms. BONHAM. Thank you for the opportunity.

[The prepared statement of Ms. Bonham follows:]

PREPARED STATEMENT OF SUE BONHAM, RESIDENT OF SISSONVILLE, WEST VIRGINIA

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Again, thank you for this opportunity to share my survival experience of the Sissonville gas pipeline explosion on December 11, 2012.

The CHAIRMAN. And you may want to go back and join your family.

All right. Our second panel will be the Honorable Cynthia Quarterman, who is the Administrator of the Pipeline and Hazardous Materials Safety Administration and the Honorable Deborah Hersman, Chairman, National Transportation Safety Board. They go to all kinds of tragedies and they are constantly being worked. And Ms. Susan Fleming, Director of Political Infrastructure issues of the United States Government Accountability Office.

A lot of people may not know what the Government Accountability Office does, but it's one of those groups in the government in Washington that you can really trust when you ask them for their ideas or their report, the reflections on something which has happened and people believe them.

Not that they don't believe you, Debbie, or you, Cynthia.

And, Debbie, I think I should say NTSB, National Transportation Safety Board, should be the first witness. We welcome you and we thank you for coming down today and going out their and spending time and being here.

STATEMENT OF HON. DEBORAH A.P. HERSMAN, CHAIRMAN, NATIONAL TRANSPORTATION SAFETY BOARD

Ms. HERSMAN. Thank you very much, Senator Rockefeller. Thank you for your chairmanship of the Committee and for your leadership on pipeline safety issues as well as all transportation safety issues.

Senator Manchin, thank you for having me here today.

And, Sue, thank you for your story of personal survival. It's very important for all of us to hear your story because it is why we are here today.

On December 11, the NTSB sent a full go team to Sissonville to investigate the Columbia Gas pipeline rupture that destroyed three homes, damaged several more, and burned through I–77 about 15 miles from where we are today. The NTSB's investigation is still ongoing, but today I will review the sequence of events that we have developed so far.

Line SM–80 is a 20-inch diameter gas transmission line running west to east from Lanham to Broad Run near Clendenin. It is interconnected with two other Columbia Gas pipelines that are operating nearby as you can see in the diagram.

At approximately 12:41 p.m. the line was operating at 929 PSI. It ruptured at a point about 112 feet west of I–77 and ejected a 20-foot section of the pipe 40 feet from where it originated. Almost immediately the 911 call center received the first call from a nearby retirement home.

After hearing the explosion and seeing the fire, a Cabot Oil & Gas field technician, who was driving nearby, called the Cabot control center. At 12:43 p.m. the Columbia Gas operations center in Charleston received the first three pressure drop alerts from the Lanham compressor station. Over the next 10 minutes, 13 more alerts were received in the control center in Charleston.

Each alert was acknowledged by the controller but it was not until 12:53 PM when Columbia Gas received a call from Cabot did the Columbia Gas controller begin to understand that one of its pipelines had likely ruptured. By that time the pressure on all three interconnected transmission lines had dropped by 100 pounds per square inch (PSI). The four valves at Rocky Hollow downstream of the rupture were closed manually by 1:19 p.m. However, additional time elapsed before the six valves at the upstream Lanham compressor station were closed.

While the compressor at Lanham was shut down in the compressor station by 12:59, the valves required personnel to be physically present to close them. Technicians started closing the valves at 1:15 and notified the operations manager at 1:40 that the valves were fully closed, nearly one hour after the rupture.

While on scene, NTSB investigators found the ruptured pipeline wall thickness had deteriorated by 70 percent from its original thickness at installation, and the external corrosion covered an area of about 12 square feet. The 20-foot segment that was ejected is now at the NTSB's lab near Washington, D.C.

Issues of particular interest to our investigation are integrity management and inspections, control center operations, and automatic or remote shutoff valves.

More than 2.5 million miles of pipelines operate in the United States. Thousands of those miles run near or close to our streets, our interstates, our churches, businesses, homes, and schools. They are a largely unseen part of the U.S. transportation system.

Most people do not notice pipeline markers, like these pictured here, that identify where a pipeline is located in their neighborhood. But as you saw in Sissonville, when things go wrong the results can be catastrophic.

Fortunately there were no fatalities in this accident, but sadly that is not always the case.

Pipeline safety is on the NTSB's most wanted list of transportation safety improvements because we are focused on improving safety and the oversight of their operations in order to prevent future accidents like the one that occurred in Sissonville.

Thank you very much for inviting me to West Virginia to participate in the hearing today. I'll be ready to answer your questions.

[The prepared statement of Ms. Hersman follows:]

PREPARED STATEMENT OF HON. DEBORAH A.P. HERSMAN, CHAIRMAN, NATIONAL TRANSPORTATION SAFETY BOARD

Chairman Rockefeller, Members of the Committee, and Senator Manchin, thank you for the opportunity to address you today concerning the National Transportation Safety Board's (NTSB) ongoing investigation of the pipeline rupture and fire in Sissonville, West Virginia, 7 weeks ago.

Mr. Chairman, as you have indicated, this is the fourth Senate Commerce Committee hearing on the issue of pipeline safety during your tenure as chairman. This hearing is also the NTSB's fourth Senate Commerce Committee hearing on this issue since I became Chairman. It is regrettable that major pipeline safety accidents continue to be a significant transportation and public safety concern. It is also regrettable that in the area of pipeline safety, philosopher George Santayana's aphorism that those who do not learn from history are doomed to repeat it, is certainly true. Indicative of the safety risks posed by pipelines, just four weeks prior to the Sissonville accident, the NTSB added pipeline safety to its Most Wanted List of the top 10 transportation safety challenges for 2013—the first time this general subject has appeared on our annual List.

Today, I will discuss the safety risks posed by the transportation of oil and natural gas by pipeline, the rupture and fire that occurred in Sissonville on December 11, 2012, the NTSB's response to the accident and the status of its investigation, and key NTSB findings and recommendations as the result of its past investigations of major pipeline accidents.

As described in our Most Wanted List, today, in the United States there are some 2.5 million miles of pipelines transporting natural gas, oil, and other hazardous liquids, with a significant amount of new pipeline design and construction activity underway. The pipeline network in this country includes 300,000 miles of gas transmission pipelines. Because pipelines are usually underground, most people don't even know they exist, much less where they are located. Therefore, it is incumbent on pipeline operators and regulators to ensure that the Nation's pipelines are safe. Sufficient resources should be available to regulators to carry out critical oversight and enforcement efforts. These pipelines power thousands of homes and deliver important resources, such as oil and gasoline, to consumers. While one of the safest and most efficient means of transporting these commodities, there is an inherent risk that can lead to tragic consequences, especially when safety standards are not observed or implemented.

As was evident in Sissonville last December 11, pipeline ruptures can cause significant damage. Last July, the NTSB issued its accident report for the July 2010 hazardous liquid pipeline rupture in Marshall, Michigan—a rupture that was not discovered for over 17 hours. As a result, almost 850,000 gallons of crude oil spilled into the surrounding wetlands and flowed into local waterways, costing nearly a billion dollars to date for clean-up and recovery—by far the most expensive environmental clean-up for an onshore oil spill. Also, in September 2010, one of the worst gas pipeline ruptures occurred in San Bruno, California, when a natural gas transmission pipeline ruptured and ignited, killing 8 persons. In addition, 58 persons were injured, 38 homes were destroyed and 70 more were damaged as a result of this horrific and tragic accident.

The Sissonville Accident

On December 11, 2012, at about 12:41 pm eastern standard time, a buried 20-inch diameter natural gas transmission pipeline (Line SM–80), running west to east, perpendicular to Interstate 77, and owned and operated by Columbia Gas Transmission Corporation, ruptured about 112 feet west of Interstate 77 in Sissonville, Kanawha County, West Virginia, near Route 21 and Derricks Creek. The pipeline maximum allowable operating pressure (MAOP) was 1,000 pounds per square inch gauge (psig), and the operating pressure at the time of the rupture was about 929 psig. After the escaping high-pressure natural gas ignited, fire damage extended nearly 1,100 feet along the pipeline and about 820 feet wide. About 20 feet of pipe was ejected from the underground pipeline and landed more than 40 feet from its original location.

The rupture occurred in a pipe that was a part of a pipeline segment installed in 1967 with a nominal wall thickness of 0.281 inches. The 20-foot ejected section of the pipe was found to have a fracture along the entire longitudinal direction at the bottom of the pipe. The outside surface of the pipe was heavily corroded near the midpoint and along the longitudinal fracture. The thinned area was approximately 6 feet in the longitudinal direction and 2 feet in the circumferential direction. The wall thickness had degraded so significantly that it measured only 0.078 inches at the point along the fracture—about 70 percent thinner than the uncorroded pipe.

The force of the released gas created a crater about 75 feet long by 35 feet wide and up to14 feet deep. Escaping high-pressure natural gas from the ruptured pipeline ignited. The intense fire destroyed three near-by homes, caused damage to several others, and heavily damaged both the northbound and southbound lanes of I–77, closing both lanes for about 14–19 hours until the roadway surfaces were repaired.

The first call to 911 about the pipeline rupture and fire was made by a person at a nearby retirement home at 12:41 p.m. At 12:43 p.m. the Columbia Gas controller on duty at the gas control center in Charleston, West Virginia, began receiving alerts on the Supervisory Control and Data Acquisition (SCADA) system from instrumentation at the Lanham Compressor Station, located 4.7 miles upstream from the rupture location. Over the next ten minutes, 16 SCADA alerts indicated that the discharge pressure was dropping on Line SM–80 and two other pipelines in the SM–80 system (Line SM–86 and Line SM–86 Loop). The first notification to the Columbia Gas control center in Charleston, West Virginia, was provided by a controller from Cabot Oil and Gas Company at about 12:53 p.m., who had received a report of a "huge boom and flames shooting over the interstate" from a field technician who was near the accident location. Columbia Gas SCADA data indicate that the discharge pressures on the three pipelines leaving Lanham had dropped about 100 psig.

At about the same time that the control center was notified of the rupture, a Columbia Gas Operations Manager was called by a separate Columbia Gas field operator and told about the release and fire. The Operations Manager sent a crew to the Rocky Hollow valves approximately 3.2 miles downstream of the rupture, where two technicians, closer to the accident site, had already self-dispatched. Columbia Gas field technicians closed the downstream isolation valves at about 1:19 p.m., preventing the backflow of gas. The Operations Manager also notified personnel at the Lanham compressor station to shut the upstream valves. The 6 valves at the Lanham compressor station required a technician for closure. Technicians started closing the valves at 1:15 p.m., and notified the Operations Manager at 1:40 p.m. that the valves were fully closed, stopping gas flow to the rupture nearly one hour after the rupture occurred.

The NTSB's Investigation

After learning of the accident, a 10-person team from the NTSB, led by Board Member Robert Sumwalt, launched to Sissonville. According to our team's surveys conducted at the accident site, the rupture occurred in a nearly 38-foot long pipe joint that was a part of the pipeline segment installed in 1967. According to Columbia Gas documents, the ruptured segment of Line SM–80 was pressure tested twice in 1967: first at about 1,800 psig and then at about 1,750 psig. According to Columbia Gas records, the nominal wall thickness of the 20-inch ruptured pipe segment was 0.281 inches, had a longitudinal electric resistance weld seam, and was manufactured according to American Petroleum Institute specifications.

Parties to the Investigation are: Pipeline and Hazardous Materials Safety Administration, (PHMSA), Public Service Commission of West Virginia, Columbia Gas Transmission Corporation, Kanawha County Sheriff's Office, and West Virginia State Police South Charleston Detachment.

The NTSB issued a preliminary report on the Sissonville accident on January 16. Our investigative work, including metallurgical analysis of sections of the ruptured pipe at our laboratory in Washington, DC, is ongoing. Additional reports, analysis and a finding of probable cause will come later in the investigation.

Recurring Pipeline Safety Issues

Although it is premature for the NTSB to determine the cause of the Sissonville accident, issue findings, or draw conclusions, there are a number of recurring safety issues we have identified in previous pipeline accidents we have investigated that merit highlighting today. In particular, these safety issues include:

- Automatic and/or remote control shut-off valve installation
- Use of in-line inspection tools
- Integrity management program
- SCADA training

Automatic and/or remote control shut-off valves

The NTSB has long been concerned about the lack of standards for rapid shutdown and the lack of requirements for automatic shutoff valves (ASV) or remote control valves (RCV) in high consequence areas (HCA) and class 3 and 4 areas. As far back as 1971, the NTSB recommended the development of standards for rapid shutdown of failed natural gas pipelines. In 1995, the NTSB recommended that the Research and Special Programs Administration—the predecessor agency of PHMSA—expedite requirements for installing automatic-or remote control valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. The current PHMSA integrity management regulation, which was promulgated in 2003, leaves the decision whether to install ASVs or RCVs in HCAs to the gas transmission operator.

In Sissonville, it took the operator approximately 58 minutes after the pipeline rupture and explosion to stop the gas flow by closing manual shutoff valves. Although the operator did not identify an HCA associated with the site of the Line SM–80 rupture, as the NTSB has pointed out in previous accidents involving pipelines located in an HCA, the availability of ASVs or RCVs is an important tool in containing the safety risks after a pipeline rupture.

Use of in-line inspection tools

One of the 13 recommendations the NTSB made to PHMSA as a result of the San Bruno pipeline rupture and fire is to require all natural gas transmission pipelines be configured to accommodate in-line inspection (also known as internal inspection) tools with priority given to older pipelines. This recommendation was predicated on the NTSB's concern that in-line inspection is not possible in many of the Nation's pipelines, which—because of the date of their installation—have been subjected to less scrutiny than more recently installed pipelines. As indicated earlier, the Sissonville rupture occurred in a pipeline segment installed in 1967. Due to construction limitations such as sharp bends and the presence of plug valves, many older natural gas transmission pipelines, including the ruptured segment in Sissonville, cannot accommodate modern in-line inspection tools without modifications.

In-line inspection tools travel through the pipeline to determine the nature and extent of any anomalies in the pipe. Another option for this type of testing is hydrostatic pressure testing that yields information about the integrity of the pipeline.

In the NTSB's judgment, the use of specialized in-line inspection tools that identify and evaluate damage caused by corrosion, dents, gouges, and circumferential and longitudinal cracks is a uniquely promising option. Unlike other assessment techniques, only in-line inspection can provide visualization of the pipeline integrity throughout the entire pipeline segment and, when performed periodically, can provide useful information about corrosion and crack growth. Although in-line inspection technology has detection limitations (generally a 90 percent probability that certain type of anomalies will be detected), the probability of detecting a crack may be improved with multiple runs, and it is nonetheless a more effective method for detecting unacceptable internal and external pipeline anomalies before a leak or rupture occurs.

Integrity management system assessments

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, enacted a little more than one year ago, includes a provision requiring the Secretary of Transportation to evaluate whether integrity management system requirements first set forth in the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (the PIPES Act), should be expanded beyond HCAs and report the analysis findings to this Committee and the Committee on Transportation and Infrastructure, U.S. House of Representatives, by early next January. If the Secretary determines that integrity management system requirements should be expanded beyond HCAs, the Secretary must issue regulations to implement these requirements after a Congressional review period has elapsed.

Although the NTSB certainly welcomes the statutorily-required evaluation and recognizes that Columbia Gas and other operators of natural gas transmission pipeline facilities in non-HCAs are not required to establish integrity management programs that meet minimum performance standards established in PHMSA regulations, the NTSB views these programs as important business practices that these operators should consider for implementation. In our San Bruno, California and Marshall, Michigan, investigations, we determined the Pacific Gas and Electric Company and Enbridge Incorporated, respectively—both of whom must comply with PHMSA's integrity management program requirements—nonetheless had ineffective programs. Deficiencies identified by the NTSB included use of inappropriate inspection methods and tools and failures to detect pipeline defects.

The NTSB does, however, recognize that achieving a robust and effective integrity management program—whether mandated or voluntary—requires dedication, sustained effort, and resources.

SCADA training

As indicated above, the Columbia Gas controller on duty received 16 "pressure-drop" alerts—but did not receive any "critical" alarms—on the SCADA system, before receiving notification from another pipeline operator. These alerts showed the discharge pressure dropping on Line SM–80 and the two other pipelines in the SM–80 system.

The NTSB has addressed SCADA training in a number of instances. In 2005, the NTSB conducted a study of SCADA in liquid pipelines. The study examined the role of SCADA systems in 13 hazardous liquid line accidents investigated between 1992 and 2004. In ten of the accidents cited by the study, there was a delay in recognizing the leak by the control center operators. As a result of one of the NTSB safety recommendations resulting from this study and requirements enacted in the PIPES Act, in December 2009, PHMSA promulgated its control room management rule for pipeline facilities in Title 49, Code of Federal Regulations, section 192.631.

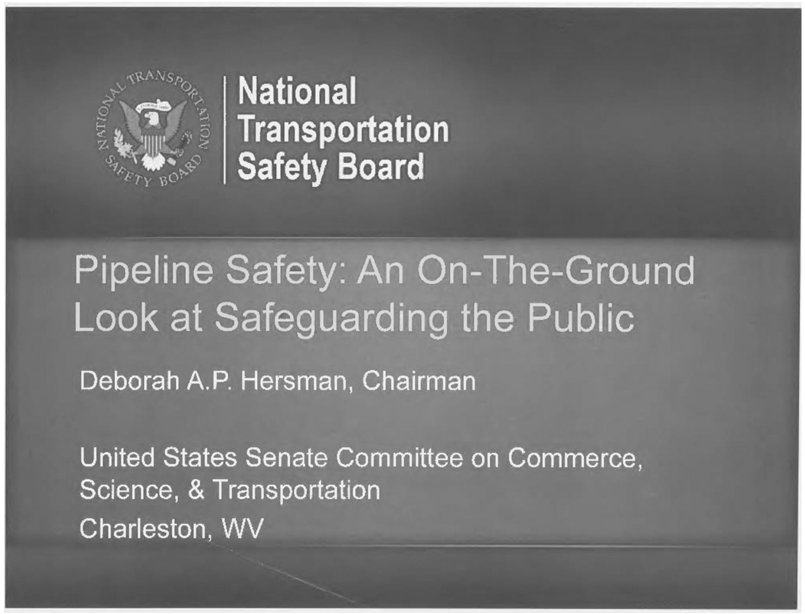
In the Marshall, Michigan pipeline rupture, the NTSB determined that inadequate training of control center personnel allowed the rupture to remain undetected for 17 hours, including two startups of the pipeline. In the San Bruno, California accident, the NTSB found "that it was evident from the communications between the SCADA center staff, the dispatch center, and various other PG&E employees that the roles and responsibilities for dealing with such emergencies were poorly defined."

As part of its investigation in Sissonville, the NTSB is looking into the operator's control room operations, its SCADA system, and the capabilities and training of its control room staff.

Closing

Although the rupture and fire did not result in any fatalities or serious injuries, the Sissonville accident could easily have caused significant injuries and fatalities. Pipeline accidents that have occurred in San Bruno, California; Marshall, Michigan; Sissonville; and elsewhere are devastating to the affected communities. Particularly regrettable are the recurring frequency of these accidents and the resource constraints that hamper regulators' pipeline safety oversight.

This concludes my testimony and I would be happy to answer any questions you may have.


National
Transportation
Safety Board
NATIONAL TRANSPORTATION SAFETY BOARD
Pipeline Safety: An On-The-Ground
Look at Safeguarding the Public
Deborah A.P. Hersman, Chairman
United States Senate Committee on Commerce,
Science, & Transportation
Charleston, WV


Derricks Creek Road
I-77 South
NORTH
SM-86 26-in
165-ft
40-ft
SM-86 - Loop 30-in
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The CHAIRMAN. Thank you, Ms. Hersman.

And now the Honorable Deborah—I'm sorry. The Honorable Cynthia Quarterman, Administrator of the Pipeline and Hazardous Materials Safety Administration, PHMSA. The nickname is PHMSA.

STATEMENT OF CYNTHIA L. QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Ms. QUARTERMAN. Thank you, Mr. Chairman. Thank you, Senator Manchin, and thank you, Senator Rockefeller, for all your leadership over the past few years associated with pipeline safety. We really appreciate the emphasis that you have put on that and look forward to working with you further as we implement the provisions of the Pipeline Safety Act 2011.

Thank you also, Chairman Rockefeller, for your leadership in helping with the passage of that act and for your efforts to advance pipeline safety. The act has given us important tools and authority that we need to help us achieve our mission.

While pipeline safety is improving, high profile incidents like the one that occurred in Sissonville underscore how important it is to be ever vigilant in preventing pipeline failures. Safety is the top priority for Secretary Lahood and for myself and for all of the employees of PHMSA, and we are working hard to protect the American people and the environment from the risks that are inherent in the transportation of hazardous materials by pipeline.

There are 2.6 million miles of pipeline that crisscross our nation. PHMSA works hand in hand with a variety of partners, including state officials, to share the enormous responsibility of keeping our community safe while ensuring the nation's energy supply is moved efficiently.

Thanks to the provisions of the act we are currently able to cover 77 percent of the program costs that our state partners incur. This funding covers personnel and equipment needs, public outreach programs, and other activities that allow states to inspect and regulate intrastate pipelines.

West Virginia, as a full partner of ours, is responsible for inspecting their gas and liquid intrastate lines as well as serving as our interstate agent on gas transmission lines. This partnership has proven an important and strong partnership for the pipelines in West Virginia.

The explosion in Sissonville, as Chairman Rockefeller has said, was terrible, serious, and dangerous. We are especially concerned for those families like the Bonham family who lost their homes in this incident. Fortunately no one was killed and it was not a greater tragedy.

We're working closely with the NTSB and the Public Service Commission of West Virginia on the investigation of that incident. NTSB recently issued a preliminary report but there's still a lot of work to do before final conclusions can be made about that incident.

PHMSA issued a corrective action order to immediately implement precautionary measures and assure safety elsewhere on that line. The pipeline will not be placed back into service until we are absolutely satisfied with the restart plan from Columbia Gas Transmission.

When the pipeline is placed back into service it must operate at a 20 percent pressure reduction until a series of tests and evaluations have been completed and have been reviewed by our engineers. That will not be the end of our involvement.

In addition to our assistance to NTSB and West Virginia and to the incident investigation, we will also perform our own compliance investigation to determine whether any regulations were violated with respect to the pipeline at issue.

We will also take aggressive steps to apply any lessons that we learn here into our broader oversight mission with respect to pipeline safety. Lessons we learn here will help us prevent future accidents in other communities and will help us to continue to fulfill the goals and the purpose of the Act.

The leadership of Chairman Rockefeller and the bipartisan effort associated with creating and passing the Pipeline Safety Act shows that there is some common agreement about the importance and of the safe and reliable pipeline system.

PHMSA takes that responsibility very, very seriously and we've been taking a deliberate approach to implementing the provisions of that act. We are a small agency but with a big mission. We worked very hard with what we have, and I'm proud of what we've been able to accomplish in the first year since the act was passed.

We were not only able to complete all the mandates that were required by January 3, 2013. We also completed additional mandates and performed more work than was required. In total, of the 42 mandates the act gave us, we have already successfully implemented 16 or 38 percent of them in just 1 year.

Reports on important issues like leak detection, automatic and remote control shutoff valves, depth of cover over buried pipelines at river crossings, and inventory of cast iron pipeline infrastructure have been completed.

Furthermore, we have planned or initiated rulemakings on eight additional mandates, including access flow valves, and work is continuing and progressing on schedule for the remaining 18 mandates. We are confident that we will complete all the 42 mandates as specified and on time even without the additional—any additional resources.

Additionally, we want to continue to look for ways to improve our existing regulations. We currently have a blend of performance based and prescriptive safety regulations. This year we're going to hold a public meeting to begin to talk about the Integrity Management Program which has been in place for more than a decade.

We're also working to continuously improve our oversight. As an example, we significantly accelerated the implementation of a control room management regulation which relates to the supervisory control and data acquisition systems in pipeline system control rooms. We're going to use all that information and the information that we get from the recently released general accountability offices study on pipelines as we move forward.

Despite the fact that the traditional risks of pipelines, including population, development, energy consumption have steadily increased over the years, over the past 20 years the number of serious incidents has gone down by 50 percent. Fortunately 2012 marked the fewest number of pipeline incidents in a decade. Despite those successes we continue to face large challenges in fulfilling our mission.

Much like the members of the Committee, the President has recognized that the need for a more aggressive approach to safety on the Nation's pipeline systems from the discovery of vast energy shale deposits which will require more pipelines to the maintenance and rehabilitation to the aging pipelines already in place, the nation's infrastructure needs are growing and changing. The President's aggressive and historic budget requests for Fiscal Year 2013 for our agency reflects this need.

The Act and the outreach and oversight is working. We have a long way to go to reach our goal of no deaths, no injuries, no environmental harm, and no property damage. But we have a solid foundation on which to build as we continue to advance pipeline safety.

In closing, we look forward to working with this committee and with Congress in continuing to address pipeline safety issues. Everyone at PHMSA is dedicated and committed to fulfilling the remaining mandates and accomplishing our pipeline safety mission. It's an honor to serve the American people and to work with the dedicated career employees at the Pipeline and Hazardous Materials Safety Administration.

Thank you again for the opportunity to speak here today.

[The prepared statement of Ms. Quarterman follows:]

PREPARED STATEMENT OF CYNTHIA L. QUARTERMAN, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Chairman Rockefeller and members of the Committee, thank you for the opportunity to appear today to discuss the progress the Pipeline and Hazardous Materials Safety Administration (PHMSA) has made to implement the mandates of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act).

Thank you for your leadership in helping to secure passage of the Pipeline Safety Act and for your efforts to advance pipeline safety. The Act has given us important tools and authority that we need to help us achieve our mission. While pipeline safety is improving, high-profile incidents like the one that occurred at Sissonville underscore how important it is to be ever-vigilant in preventing pipeline failures.

Safety is the top priority for Secretary of Transportation Ray LaHood and myself, and everyone at PHMSA is working hard to protect the American people and environment from the risks that are inherent in the transportation of hazardous materials by pipeline. PHMSA works to achieve its safety mission through prevention, rigorous enforcement, strong partnerships, and continuing education.

This testimony will focus on several issues such as to the implementation of the Pipeline Safety Act mandates; our response to the Sissionville, WV pipeline incident and the Government Accountability Office (GAO) study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release.

First, I will give an overview of PHMSA's pipeline safety program, including the role that the States take in ensuring the safety of pipelines. Second, I will provide an overview of the mandates we have completed and the efforts we have taken to improve pipeline safety. Third, I will discuss how, incidents like the one at Sissonville show us that we have a long way to go to succeed in our mission and that there is still a lot of work to be done in preventing pipeline incidents. Finally, I will reiterate the importance of a robust pipeline safety program, and the importance of reviewing the findings of the GAO study especially with regard to the Nation's changing and growing infrastructure needs.

I. Overview of Phmsa Pipeline Safety Program

There are 2.6 million miles of pipelines that crisscross our Nation; those pipelines offer the safest and most cost-efficient way to transport hazardous materials. To ensure that this vast network is operating safely and reliably and that communities and families are protected, PHMSA works together with a variety of partners, including other Federal agencies, State and local officials, emergency responders, environmental groups, and the public.

Federal oversight agencies like the National Transportation Safety Board (NTSB), the Office of Inspector General (OIG), and the Government Accountability Office (GAO) also have a vested interest in the safe and reliable operation of the Nation's pipeline infrastructure. For years, we have worked aggressively to respond to their recommendations. In addition to the mandates of the Act, we are currently working on 26 open NTSB recommendations, 9 recommendations from the OIG, and 4 recommendations from the GAO. Some of these recommendations are similar to the requirements of the Pipeline Safety Act, which suggests that there is a shared understanding of some of the challenges for the Nation's pipeline system.

We have taken each and every mandate and recommendation that has been issued to us very seriously, and we have many completed and ongoing initiatives to provide protection to the American people and environment.

Overall, the pipeline safety record is good. PHMSA's regulatory oversight program has led to many successes. Despite the fact that the traditional measures of risk—population, energy consumption, pipeline ton-miles—have steadily increased over the past two decades, the risk of pipeline incidents with death or major injury have decreased by about 10 percent every 3 years. The risks of hazardous liquid pipeline spills that have environmental consequences have decreased by an average of 5 percent per year. Nonetheless, there is more work to be done.

In 2012, the number of pipeline-related fatalities was at a level not seen since 2008, and the number of pipeline-related injuries was at the lowest level since 2007. Furthermore, 2012 had the fewest total pipeline incidents in a decade. However, PHMSA, as an organization, cannot accept death or injury as an inevitable consequence of transporting hazardous materials. We are working continuously to find new ways to reduce risk to operators and the public, and we aim to sustain and improve upon these long-term trends.

II. Implementation of the Pipeline Safety Act

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The Act is designed to examine and improve the state of pipeline safety regulations and authorizes funding, through Fiscal Year 2015, for provisions of the pipeline statute in the U.S. Code related to gas and hazardous liquids. Ultimately, the Act gives enhanced safety authority to PHMSA and will improve pipeline transportation, by strengthening the enforcement capabilities of current laws.

The leadership of Chairman Rockefeller and this committee, as well as the bipartisan effort that led to the creation and passage of the Pipeline Safety Act shows there is a common agreement about the importance of a safe and reliable pipeline system for the welfare of the Nation. PHMSA takes this responsibility very seriously. As the committee is aware, we have struggled to hire pipeline inspectors over the last several years, but by the end of FY 2012, we achieved and successfully filled our targeted 135 pipeline inspector billets. We now look forward to working with this committee to continue to strengthen our pipeline inspector program and further implement PHMSA's Pipeline Safety Reform effort.

PHMSA not only completed all of the mandates that were due by January 3, 2013, it also completed additional mandates and performed more work than required. PHMSA has already successfully completed 16 of the 42 requirements in the Pipeline Safety Act. PHMSA has reported on cover over buried pipelines at river crossings, leak detection, remote controlled and automatic shut-off valve (RCV/ASV) use, increasing civil penalties authority, improved the quantity, quality, and transparency of our data, and inventoried the status of cast iron pipeline infrastructure. Information gathered from these reports will be used to inform us as we determine how best to move forward with updated requirements to address these topics.

The following is a brief description of PHMSA's work the Pipeline Safety Act requirements:

Section 2—Civil Penalties

The Act authorized PHMSA to increase the maximum civil penalty for pipeline safety violations from $100,000 to $200,000 per violation per day. In addition, the agency will be able to collect a maximum of $2,000,000 for a related series of violations, up from $1,000,000.

PHMSA is currently addressing this activity through a rulemaking to update Part 190 of the Code of Federal Regulations. A Notice of Proposed Rulemaking (NPRM) entitled "Administrative Procedures; Updates and Technical Corrections" was published on August 13, 2012.

Section 3—Pipeline Damage Prevention

The Act required PHMSA to incorporate new standards for state one-call programs into the State Damage Prevention (SDP) grant program criteria, including no state and local exemptions.

Some state excavation damage prevention laws include exemptions from one-call system participation that detract from the goals of the system. The following are examples of two typical types of exemption:

> Facility Owners—some state laws exempt owners of specific types of underground facilities (*e.g.,* municipalities, State departments of transportation, and small water and sewer companies from participation in the one-call system). Excavators—some excavators (*e.g.,* homeowners and State departments of transportation) are exempted from calling for underground facilities to be located and marked before they begin digging. PHMSA has discussed these exemptions with the National Association of Pipeline Safety Representatives (NAPSR) and One Call Systems International (OCSI). A public meeting regarding these issues is scheduled for March 2013. These new requirements were included in the SDP grant program criteria.

The Act also requires for PHMSA to conduct a study on the impact of excavation damage on pipeline safety, including exemptions, frequency, severity, and type of damage, and report these results to Congress.

PHMSA met with the United States Infrastructure Corporation (USIC) to discuss performing a data analysis regarding damage prevention. As mentioned above, PHMSA is planning a public meeting in March 2013 to discuss damage prevention issues with industry stakeholders. PHMSA is considering using data from the Common Ground Alliance's (CGA's) Damage Information Reporting Tool (DIRT) to help with this study it will reach out to states to discuss the use of this data in the analysis.

Section 4—Automatic and Remote-Controlled Shut-Off Valve Use

The Act requires PHMSA to issue regulations requiring the use of automatic or remote-control shut-off valves on transmission pipelines constructed or entirely replaced after the date of the rule, if appropriate.

PHMSA began to collect information on the use of automatic shut-off valves (ASVs) and remote-controlled shut-off valves (RCVs) on hazardous liquid and gas transmission pipelines prior to the enactment of the Pipeline Safety Act, through issuance of two Advanced Notice of Proposed Rulemakings (ANPRM) entitled "Safety of On-Shore Hazardous Liquid Pipelines" and "Safety of Gas Transmission Pipelines". For hazardous liquid transmission pipelines, an ANPRM issued on October 18, 2010, requested public comments on the use of RCVs. For gas transmission pipelines, an ANPRM issued on October 25, 2011, requested public comments on requiring the use of ASV and RCV installation.

To gather sufficient input on ASV/RCV feasibility, PHMSA sponsored a public workshop on March 28, 2012 with the National Association of Pipeline Safety Representatives, entitled "Understanding the Application of Automatic Control & Remote Control Valves." PHMSA then commissioned an independent study on the feasibility and effectiveness of ASVs and RCVs on hazardous liquid and natural gas transmission pipelines. Public comments and workshop input were used to develop the commissioned study entitled, "Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquid and Natural Gas Pipelines with Respect to Public and Environmental Safety" (ASV–RCV study), including the original scope of work.

The ASV–RCV study performed by the Oak Ridge National Laboratory, while not mandated by the Act, will help to determine the effectiveness of block valve closure swiftness in mitigating the consequences of natural gas and hazardous liquid pipeline releases on the safety of the public and the environment. Additionally, a related NTSB recommendation, NTSB P–11–11, was incorporated into the parameters of the study. The recommendation suggested ASVs and RCVs be required in high-consequence areas (HCAs). A public web-based seminar (webinar) and public comment period was also held for input on the draft study. The ASV–RCV study addressed the submitted comments and incorporated substantive technical recommendations. The ASV–RCV study, which is 344 pages, was transmitted to Congress on December 27, 2012.

The information from this study will assist in providing additional guidance for potential rulemaking. PHMSA also anticipates progressing with a rulemaking related to ASV and RCV installation and use on hazardous liquid and gas transmission pipelines in 2013.

In addition, PHMSA is soliciting a research project specific to technology used in ASVs that will provide important insight on their ability to provide reliability and flow assurance to pipelines. Automatic shut-off valves are often recommended to minimize valve shut-off times after a leak is detected. However, they may lead to unintended valve closures because of an inaccurate leak determination. The project aims to study and identify technologies and systems to minimize inaccurate leak alarms and unintended valve closures on ASV systems. .

Section 5—Integrity Management

The Act required PHMSA to conduct an evaluation on whether integrity management programs (IMPs) should be expanded beyond high-consequence areas (HCAs) and whether gas IMPs should replace the class location system. This section also asks, PHMSA to consider issuing regulations expanding IMP requirements and/or replacing class locations.

As mentioned above, PHMSA initiated an ANPRM, entitled "Safety of On-Shore Hazardous Liquid Pipelines" and "Safety of Gas Transmission Pipelines" for both gas and liquid pipeline safety that addresses these issues. PHMSA is also holding an integrity management program (IMP) 2.0 workshop in 2013.

This section of the statute also suggests that PHMSA may extend a gas pipeline operator's 7-year reassessment interval by 6 months if the operator submits written notice with sufficient justification of the need for an extension, and that PHMSA should publish guidance on what constitutes sufficient justification. PHMSA is currently considering this issue in the context of a gas transmission NPRM, which is a follow on from the ANPRM entitled "Safety of Gas Transmission Pipelines" mentioned above. PHMSA anticipates this NPRM to be published by August 2013.

Section 6—Public Education and Awareness

There were several mandates in this section of the Act. One mandate requires that PHMSA maintain a map of all gas HCAs as a part of the National Pipeline Mapping System (NPMS). PHMSA has already begun implementing this with the information we have currently available, and we are continuing to work on expanding the information available. PHMSA was also requested to update the NPMS map biennially.

In addition, PHMSA was required to implement a program for promoting greater awareness of the NPMS to state and local emergency responders and other parties. To address this issue, PHMSA hosted a meeting of Public Safety and Emergency Response officials to discuss pipeline emergency preparedness and response on December 9, 2011. Additionally, PHMSA made contact with various emergency responder groups through its Emergency Responder (ER) Outreach program and the Community Assistance and Technical Services (CATS) program. PHMSA has also begun publishing articles regarding its public resources, including the NPMS, in ER publications. A brochure, designed for widespread distribution in the ER community, was also created that described available resources.

PHMSA was also required to issue guidance to operators to provide system-specific information about their pipelines to emergency responders after consulting with those responders. This mandate fell closely in line with an NTSB recommendation (P–11–8), which recommended pipe diameter, operating pressure, product transported, and potential impact radius, among other information, is shared.

PHMSA, in partnership with the Pipeline Emergency Response Working Group (PERWG), met with emergency responders at a pipeline emergency response focus group during the HOTZONE conference in Houston on October 19, 2012. The PERWG had its follow up meeting last week. On October 11, 2012, PHMSA published (Advisory Bulletin ADB–12–09) about Communication During Emergency Situations that reminds operators of gas, hazardous liquid, and liquefied natural gas pipeline facilities that operators should immediately and directly notify the Public Safety Access Point that serves the communities and jurisdictions in which those pipelines are located when there are indications of a pipeline facility emergency. We also met with the Associate of Public Communication Offices to discuss how to increase awareness and develop training for 911 center personnel.

Additionally, PHMSA is funding a Transportation Research Board study that will produce a guide for communication between pipeline operators and emergency responders.

PHMSA recognizes and agrees that the emergency response to an incident or a leak is critical. In addition to strengthening the capabilities of local emergency responders with increased coordination, targeted planning, and training grants. PHMSA has also worked to increase the visibility of prevention and response efforts to better prepare the public.

The final mandate from this section required PHMSA to maintain the most recent oil facility response plans (FRPs), which are currently collected from operators and provide copies of those FRPs to any requester through the FOIA process. The copies can exclude sensitive information. PHMSA has implemented this mandate and continues to improve the FRP program.

Section 7—Cast Iron Gas Pipelines

The Act required PHMSA to follow-up on the industry's progress in replacing cast iron gas pipelines. PHMSA has collected updates and has published the responses on its website which can be found at http://opsweb.phmsa.dot.gov/pipelineforum/. This inventory was developed and posted before the December 31, 2012 due date.

Section 8—Leak Detection

The Act requires PHMSA to submit a report to Congress on leak detection systems used by operators of hazardous liquid pipeline facilities and transportation related flow lines. The Act requires the following be included in the report:

- an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies; and

- an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.

PHMSA began working on leak detection for a number of years before the Act. As mentioned above, on October 18, 2010, an ANPRM for the Safety of On-Shore Hazardous Liquid Pipelines was published. Among the issues discussed in the ANPRM was whether to establish and/or adopt standards and procedures for minimum leak detection requirements for all pipelines.

In addition, PHMSA sponsored a public workshop in March 2012 with the National Association of Pipeline Safety Representatives entitled "Improving Pipeline Leak Detection System Effectiveness." It also held a Pipeline Research and Development (R&D) Forum in July 2012 that included a working group discussion focused specifically on leak detection and mitigation. As a result, PHMSA has issued a research announcement and solicitation for proposals for research and development on a number of topics, including leak detection. As part of its research and development activities, PHMSA has been active in studying and improving other leak detection technologies, including automated monitoring systems, sensors for small leak detection, aerial surveillance, satellite imaging, and improvements in the cost and effectiveness of current leak detection systems.

As with valves, PHMSA also commissioned an independent study on leak detection. In conjunction with satisfying the requirements of the Act, PHMSA is also addressing a leak detection related recommendation for natural gas transmission and distribution pipelines from the NTSB (NTSB recommendation P–11–10, which involves Supervisory Control and Data Acquisition (SCADA) enhancements to Identify and Locate Leaks). PHMSA's leak detection work included systems used in gas transmission and distribution pipelines as well as hazardous liquid pipelines. While the different types of pipeline systems have various and distinct characteristics and considerations for leak detection, PHMSA brought all pipeline industry stakeholders together to more efficiently communicate the issues affecting the respective sectors and to share lessons learned.

The review of leak detection systems was not limited to the technology but also extended to pipeline facilities and infrastructure. Effective leak detection relies heavily on how well any technology is implemented through people, procedures, and the environment in which it is installed and operated.

The leak detection study performed was based on input received through the workshops and a public comment period for the original scope of work. A public web-based seminar (webinar) and public comment period was also held for input on the draft report of the study. Additionally, some operators were interviewed as part of the work. The final leak detection study, which is almost 300 pages, has been posted electronically for review and has been transmitted to Congress.

PHMSA will use all of the input gathered from the above initiatives as well as other data when considering any future rulemakings. A rulemaking is under consideration for this item.

PHMSA is also creating a Leak Detection webpage on the PHMSA website to provide background information about leak detection issues.

Section 9—Accident and Investigation Notification

PHMSA was required by the Act to revise regulations to require telephonic reporting of incidents or accidents not later than 1 hour following a "confirmed discovery" and to require revising the initial telephonic report after 48 hours if practicable. An NPRM entitled "Miscellaneous Rule II" regarding these revisions is expected to be issued in late 2013.

The Act also requires PHMSA to review and revise, as necessary, procedures for operators and the National Response Center (NRC) to notify emergency responders, including local public safety answering points or 911 centers. PHMSA is continuing to develop a means to address this issue.

Section 10—Transportation-Related Onshore Facility Response Plan Compliance

Administrative Enforcement and Civil Penalties

While there was no specific mandate with this item, the section did suggest that PHMSA should update Part 190 to be consistent with the new authority to enforce Part 194 regulations. A rulemaking entitled "Administrative Procedures; Updates and Technical Corrections" is under consideration for this item.

Section 11—Pipeline Infrastructure Data Collection

PHMSA is considering collecting other geospatial and technical data for the NPMS. Although there was no specific mandate for this action, as mentioned in Section 11 above, a rulemaking is under consideration for this item.

Section 12—Transportation-Related Oil Flow Lines

There is no mandate related to this section, but PHMSA is considering collecting geospatial and other data on transportation-related oil flow lines, as mentioned in Section 11 above, as defined in the Act.

Section 13—Cost Recovery for Design Reviews

PHMSA was required to prescribe a fee structure and procedures for assessment and collection in order to implement authority to recover design review costs for projects that cost over $2.5 billion or that involve "new technologies." PHMSA is currently developing guidance on this issue.

This section also mandates that PHMSA issue guidance on the meaning of the term "new technologies." This guidance was completed and was posted on the external PHMSA website prior to the January 3, 2013 deadline.

Section 15—Carbon Dioxide Pipelines

The Act requires that PHMSA issue regulations for transporting carbon dioxide by pipeline in a gaseous state. PHMSA is currently exploring rulemaking options with this item.

Section 16—Study of Transportation of Diluted Bitumen

PHMSA was required to review and report to Congress on whether current regulations are sufficient to regulate pipelines transporting diluted bitumen. A study has been contracted to perform this analysis to the National Academy of Sciences (NAS), which is meeting on the issue on January 31 and February 1, 2013, and it is on track for timely completion. Once the study is completed, a report to Congress will follow.

Section 17—Study of Nonpetroleum Hazardous Liquids Transported by Pipeline

This section allows PHMSA to analyze the extent to which pipelines transporting non-petroleum hazardous liquids, such as chlorine, are unregulated, and whether being unregulated presents risks to the public. The results of any analysis must be made available to Congress as directed by the Act. PHMSA is currently reviewing this issue.

Section 19—Maintenance of Effort

PHMSA was required to grant waivers of the maintenance of effort clause in FY12 and FY13 to States that demonstrate an inability to maintain funding to their pipeline safety program due to economic hardship. This action has been completed for FY12, and we are addressing this issue as it pertains to future years.

Section 20—Administrative Enforcement Process

This section requires PHMSA to issue regulations for enforcement hearings that require a presiding official, implement a separation of functions, prohibit ex parte communications and provide other due process provisions. This issue is currently being addressed in the Part 190 Rule referred to in Section 20 above. The NPRM entitled "Administrative Procedures; Updates and Technical Corrections" was published on August 13, 2012.

Section 21—Gas and Hazardous Liquid Gathering Lines

The Act requires PHMSA to review and report to Congress on existing Federal and State regulations for all gathering lines, existing exemptions, and the application of existing regulations to lines not presently regulated. PHMSA has contracted Oak Ridge National to assist in the research of this issue and a report is under development.

PHMSA must also consider issuing regulations that would subject offshore liquid gathering lines to the same standards as other liquid gathering lines. PHMSA will determine whether these regulations are necessary based on the results of the research and report.

Section 22—Excess Flow Valves

The Act requires PHMSA to consider issuing regulations requiring the use of excess flow valves on new or entirely replaced distribution branch services, multi-family facilities, and small commercial facilities. PHMSA issued an ANPRM entitled "Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences " on November 25, 2011 and is currently analyzing public comments.

Section 23—Maximum Allowable Operating Pressure (MAOP)

PHMSA was required to issue an Advisory Bulletin regarding the existing requirements to verify records confirming MAOP in Classes 3 and 4 and in HCAs. An Advisory Bulletin on "Verification of Records" was issued for this item on May 7, 2012.

PHMSA was also required to issue regulations requiring operators to report by July 3, 2013, any pipelines without sufficient records to confirm MAOP. As part of meeting the mandate, PHMSA determined they had the authority under existing regulations to collect this additional data. Therefore, PHMSA revised its gas transmission annual reporting form to collect this information which we will receive for the first time on June 15, 2013. The information collected will be used to address the mandate in the Act.

This section also required PHMSA to issue regulations that require operators to report any exceedance of MAOP within 5 days, and to ensure the safety of pipelines without records to confirm MAOP. PHMSA published an advisory bulletin in the Federal Register on December 21, 2012 on Reporting the Exceedances of Maximum Allowable Operating Pressure (ADB–2012–11). A rulemaking is under consideration for this item.

PHMSA was also required to issue regulations requiring tests to confirm the material strength of previously untested gas transmission pipelines in HCAs. As part of meeting the mandate, PHMSA determined they had the authority under existing regulations to collect this additional data. PHMSA will use its revised gas transmission annual report to collect this relevant data by June 15, 2013. This information will be used to meet the mandate in the Act.

Section 24—Limitation of Incorporation of Documents by Reference

This section requires PHMSA, starting in one year, to stop incorporating by reference into its regulations or guidance materials any industry standard unless it is publicly available free of charge on the internet. PHMSA is continuing to work with organizations that develop standards in order to make Incorporation-By-Reference (IBR) material available for free on the Internet. We are pleased that many standards setting organizations have agreed and are assisting PHMSA in complying with this item.

Section 28—Cover Over Buried Pipelines

PHMSA was required to conduct a study and report to Congress on hazardous liquid pipeline accidents at water crossings to determine if depth of cover was a factor. This study was completed and was transmitted to Congress before the January 3, 2013, deadline.

If the study shows depth of cover was a factor, PHMSA must review the sufficiency of existing depth of cover regulations and consider possible regulatory changes and/or legislative recommendations. The Administration is still determining whether legislative changes should be recommended.

Section 29—Seismicity

There was no specific mandate within this section, but it was suggested that PHMSA should issue regulations to be consistent with the requirement in statute that operators consider seismicity in identifying and evaluating all potential threats to each pipeline pursuant to Parts 192 and 195. PHMSA has conducted research on this issue, which is currently under review.

Section 30—Tribal Consultation for Pipeline Projects

The Act requires PHMSA to develop and implement a protocol for consulting with Indian tribes to provide technical assistance for the regulation of pipelines that are under the jurisdiction of Indian tribes. This protocol was posted on the PHMSA website prior to the January 3, 2013, deadline.

Section 31—Pipeline Inspection and Enforcement Needs

PHMSA was required to report to Congress on the total number of full-time equivalents (FTEs) for pipeline inspection and enforcement, the number of such FTEs that are not presently filled and the reasons they are not filled, the actions being taken to fill the FTEs, and any additional resources needed. This action has been completed by PHMSA, and a report was submitted to Congress on December 20, 2012.

Section 32—Authorization of Appropriations

This section of the act required PHMSA to ensure at least 30 percent of the costs of program-wide Research and Development (R&D) activities are carried out using non-Federal sources. These efforts are currently ongoing and are on-track.

This section additionally mandates that PHMSA transmit a report to Congress on the status and results-to-date of implementation of the R&D program every 2 years. The R&D program is designed to identify gaps in needed pipeline technology and map a path forward to assure there is no duplicative research and that resources are leveraged appropriately. PHMSA is finalizing a draft of this report.

III. Sissonville and the Challenges We Face

Despite our successes, we continue to face challenges in fulfilling our mission, and this is obvious when taking a look at what happened in Sissonville, WV. The explosion at Sissonville, as Chairman Rockefeller has said, was terrible, serious, and dangerous. Although several homes were destroyed or damaged, and portions of a major interstate highway were severely damaged, it is fortunate that no one was killed and there were only minor injuries. It could have been a much larger tragedy. We are working closely with the National Transportation Safety Board (NTSB) and the Public Service Commission of West Virginia in the investigation, and we are also undertaking our own compliance investigation. In addition we are taking immediate action to determine what additional steps need to be taken to prevent accidents like this from occurring in the future.

We have issued a Corrective Action Order (CAO) based on our preliminary findings. The pipeline will not be placed back into service until we are completely satisfied with the restart plan that Columbia Gas is required to submit. When the pipeline is eventually placed back into service, it will operate at a 20 percent pressure reduction from the maximum allowable pressure, while our engineers oversee a series of tests and evaluations and review the results. It is only after PHMSA is fully satisfied that the pipeline is safe for full operation that the pipeline can return to regular operating pressure.

One of the greatest challenges that we as an organization face is assisting our State partners to succeed in the inspection, regulation, and enforcement of the pipelines for which they are responsible. With the exception of Alaska and Hawaii, State pipeline safety agencies are the first line of defense in protecting the American public, and they have always been a critical component of PHMSA's success.

Thanks to provisions in the Act, we are currently able to cover 77 percent, or approximately $43.5 million, of the program costs that States incur. This funding covers personnel and equipment needs, public outreach programs, and other activities that allow the States to inspect and regulate intrastate pipelines. Currently, we partner with 52 state pipeline safety programs through certification and agreements for the inspection of the Nation's intrastate gas and hazardous liquid pipelines. PHMSA also has interstate agent agreements with 10 states to perform interstate pipeline inspections. We are pleased to report that the State of West Virginia participates as an interstate pipeline agent for gas transmission lines. This partnership has proven to be a great asset in helping to strengthen the safety of pipelines in West Virginian communities.

The day this incident happened, several of my top staff members and I were visiting the Marcellus Shale area. We received a call that alerted us to the incident, and we were able to launch our response from the meeting we were conducting in Pennsylvania. Tim Butters, my Deputy Administrator, was in contact with emergency response officials from Sissonville shortly after the explosion occurred. It is because of the great relationship PHMSA and our State partners have with the pipeline industry and emergency responder community that we were contacted directly for support. PHMSA exists for the safety of the public, and we have been involved from the onset of this incident up through this point in time. We continue to support our fellow partners on the ground at the incident. As well as work with the emergency response community in order to share best practices and lessons learned.

In fact, we recently returned to Sissonville to meet with the local emergency responders and emergency management officials of Sissonville and Kanawha County to discuss the response to this incident, and what prior interaction they had with the operator.

We were very encouraged to learn that there was a good working relationship with the utility operator and the local public safety community. These established relationships, coupled with the fact that the local responders were well-trained, made it possible for the successful and effective management of this incident. The fact that there were only minor civilian injuries and no injuries to emergency responders is a testament to the capability of the local emergency response system and the importance of cooperation with the pipeline industry, and Federal and state regulators.

However, we also learned there is still much work to do. Both the pipeline operators and local officials recognize that additional training and exercises are needed. As the statute now requires, operators will be providing more detailed information about their pipeline systems, including location, size of pipe, and other critical elements. A rulemaking is under consideration that will allow PHMSA to collect additional information as part of its emergency responder outreach program. While Columbia Gas had been engaged with the local community, we were informed that cooperation and coordination between the local community and other pipeline operators could be improved. We will do what is necessary to ensure that this is corrected as quickly as possible.

We always make an aggressive effort to apply the information from specific pipeline incidents to the broader, national context of pipeline safety. We accelerated the implementation of control room management regulations based upon lessons learned about supervisory control and data acquisition (SCADA) system challenges. This year we will hold a public workshop to evaluate lessons learned during the last ten years of performance based integrity management regulations.

Lessons we learn from the Sissonville incident will also be used to help prevent accidents in other communities and will help us continue to fulfill the safety goals and purpose of the Act. Once our investigations into this incident are complete, we will release our findings and information to the larger emergency responder community and operator network.

IV. Changing Infrastructure and the Importance of Oversight

Much like the members of this Committee, this Administration has recognized the need for an aggressive approach to the safety of the Nation's pipeline system and the Fiscal Year 2013 Budget includes a funding request to implement an aggressive Pipeline Safety Reform initiative, which seeks to significantly increase both Federal and State resources supporting pipeline safety, as well as furthering research and development, and enhancing information technology capabilities to address the safety of the national pipeline system. We just recently received the final GAO study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release. We are currently reviewing the findings and will be happy to discuss with your staff on how we plan to move forward.

From the discovery of vast energy shale deposits, which will require the creation of additional infrastructure, to the maintenance and rehabilitation of the infrastructure already in place, the Nation's infrastructure needs are growing and changing.

I have been to the Bakken and Marcellus Shales, and I have seen these changes and the evolution of the energy industry firsthand. And I can tell you that we must prepare for these new and shifting demands right now. We must make sure that people and the land are protected at the beginning of the process even before the pipe goes in the ground. Effective standards and regulations are one of the best ways to keep America's people and environment safe while providing for the reliable transportation of the Nation's energy supplies, and the oversight provided by PHMSA and our partners will become even more critically important in the future.

With that being said, I believe that the Pipeline Safety Act, and our outreach and oversight, is working. We have a long way to go to reach our goal of no deaths, injuries, environmental and property damage, or transportation disruptions, but we have a solid foundation to build on as we continue to advance pipeline safety.

In closing, we look forward to continuing to work with Congress to address pipeline safety issues and to improve pipeline safety programs. Together, we will keep America's people and environment safe while providing for the reliable transportation of the Nation's energy supplies. Everyone at PHMSA is dedicated and committed to fulfilling the remaining mandates and accomplishing our pipeline safety mission. It is an honor to serve the American people and to work with the dedicated public servants at PHMSA. Thank you again for the opportunity to speak with you today. I would be pleased to answer any questions you may have.

The CHAIRMAN. Thank you very much, Ms. Quarterman.

And now we will go to Ms. Susan Fleming, who is Director of the Physical Infrastructure Issues at the United States Government Accountability Office.

STATEMENT OF SUSAN A. FLEMING, DIRECTOR, PHYSICAL INFRASTRUCTURE ISSUES, U.S. GOVERNMENT ACCOUNTABILITY OFFICE

Ms. FLEMING. Mr. Chairman, I'd also like to add my appreciation for your leadership on pipeline safety and all the range of transportation issues this committee covers and for your kind words on GAO. I appreciate that.

I very much appreciate the opportunity to be here in West Virginia to discuss pipeline safety and incident response. As the recent transmission pipeline incident in Sissonville demonstrates, while pipelines are considered the safest means of transporting natural gas and hazardous liquids, pipeline incidents can and do occur.

The speed of a pipeline operator's response is critical to reduce the consequences of an incident. My statement is based on a recent report to the Committee covering variables that affect pipeline operator's ability to respond quickly to a response and opportunities we identified to measure and improve these operator's incident response times.

First, a number of variables, only some of which are within an operator's control can influence operator response time. For example, weather conditions and time of day are variables beyond an operator's control. Factors within an operator's control include the operator's leak detection capabilities, proximity of operator response personnel, the type of valve installed, automated or manual, and relationships with local first responders.

These factors affect incident response time to varying degrees depending on the specific incident. Given the Committee's interest in the topic of automated valves I'd like to take a moment to discuss that factor. PHMSA, which oversees pipeline safety, does not mandate the installation of automated valves but does require that such valves be considered as part of an operator's risk assessment for pipeline segments in highly populated or environmentally sensitive areas.

The primary potential advantage of installing these valves, whether automatic shutoff or remote controlled, is the speed they provide in isolating a pipeline segment. However, one potential downside of these valves is the risk of accidental valve closure which could lead to loss of service to customers.

The potential advantages and disadvantages of installing automated valves can vary based on the unique attributes of the valve's location. Therefore we concluded that the decision of whether to install automated valves should be made on a case-by-case basis. For example, if a valve is located at an operator's facility that is staffed 24 hours a day, a manual valve might be sufficient.

We found that most operators are currently making these decisions on a case-by-case basis and are using a variety of risk-based frameworks including decision tree and spill modeling software to aid in their decisionmaking.

Moving on to my second point, we identified potential opportunities for PHMSA to improve incident response time in two areas, performance-based requirements and information sharing. We and others have recommended that the Federal government move toward a more performance-based regulatory approach to allow those being regulated to determine the most appropriate way to achieve desired measurable outcomes.

PHMSA does not currently have a specific measurable response time requirement and told us that creating such a requirement would be difficult due to the often unique nature of incidents. However, some organizations in the pipeline industry have recently developed such a framework for incident response times. Therefore, we believe that the PHMSA should consider moving toward a more quantifiable performance-based goal in this area.

To do so PHMSA would first need to collect reliable data on incident response times. This data would allow PHMSA to measure incident response time and assist the agency in considering development of a performance-based approach for improvements.

In addition to reliable data, a performance-based approach would require strong oversight from PHMSA. PHMSA can further support improvements and response time by helping operators make more informed decisions on the use of automated valves through enhanced guidance and broader sharing of decision analysis methods used by operators.

In closing, improvements to incident response time can be achieved in a variety of ways. One solution may not be appropriate for all situations and locations. A performance-based framework, along with better data collection and communication could help both PHMSA and pipeline operators make evidence-based decisions on how and where to best apply resources to improve incident response time.

Mr. Chairman, this concludes my statement, and I would be pleased to answer questions you or Senator Manchin might have.

[The prepared statement of Ms. Fleming follows:]

PREPARED STATEMENT OF SUSAN A. FLEMING, DIRECTOR, PHYSICAL INFRASTRUCTURE ISSUES, U.S. GOVERNMENT ACCOUNTABILITY OFFICE

Chairman Rockefeller and Members of the Committee:

Thank you for the opportunity to participate in this hearing on pipeline safety. As you know, pipelines are a relatively safe means of transporting natural gas and hazardous liquids; however, catastrophic incidents can and do occur.[1] We are here today because such an incident occurred on December 11, 2012, near Sissonville, West Virginia, when a rupture of a natural gas transmission pipeline destroyed or damaged 9 homes and badly damaged a section of Interstate 77. Large-diameter transmission pipelines such as these that carry products over long distances from processing facilities to communities and large-volume users make up more than 400,000 miles of the 2.5 million mile natural gas and hazardous liquid pipeline network in the United States.[2] The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), working in conjunction with state pipeline safety offices, oversees this network, which transports about 65 percent of the energy we consume.

The best way to ensure the safety of pipelines, and their surrounding communities, is to minimize the possibility of an incident occurring. PHMSA's regulations require pipeline operators to take appropriate preventive measures such as corrosion control and periodic assessments of pipeline integrity. To mitigate the consequences if an incident occurs, operators are also required to develop leak detection and emergency response plans. One mitigation measure operators can take is to install automated valves that, in the event of an incident, close automatically or can

[1] In its regulations, PHMSA refers to the release of natural gas from a pipeline as an "incident" (49 C.F.R. § 191.3) and a spill from a hazardous liquid pipeline as an "accident." (49 C.F.R. § 195.50). For simplicity, this statement refers to both as "incidents."

[2] This statement uses the term "transmission pipeline" to refer to both onshore hazardous liquid and natural gas pipelines carrying product over long distances to users.

be closed remotely by operators in a control room.[3] Such valves have been the topic of several National Transportation Safety Board (NTSB) recommendations since 1971 and a PHMSA report issued in October 2012.[4]

As mandated in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, we issued a January 2013 report on the ability of transmission pipeline operators to respond to a hazardous liquid or natural gas release from an existing pipeline segment.[5] My statement today is based on this report and addresses (1) variables that influence the ability of transmission pipeline operators to respond to incidents and (2) opportunities to improve these operators' responses to incidents. My statement also provides information from two other recent GAO reports on pipeline safety (see app. I). For our January 2013 report, we examined incident data, conducted a literature review, and interviewed selected operators, industry stakeholders, state pipeline safety offices, and PHMSA officials. Our work on each pipeline safety report was conducted in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Summary

Numerous variables—some of which are under operators' control—influence the ability of transmission pipeline operators to respond to incidents. For example, the location of response personnel and the use of manual or automated valves can affect the amount of time it takes for operators to respond to incidents. However, because the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve's location, it is appropriate that operators decide whether to install automated valves on a case-by-case basis. Several operators we spoke with have developed approaches to evaluate the advantages and disadvantages of installing automated valves, such as using spill-modeling software to estimate the potential amount of product released and extent of damage that would occur in the event of an incident.

One method PHMSA could use to improve operator response to incidents is to develop a performance-based approach for incident response times. While defining performance measures and targets for incident response can be challenging, PHMSA could move toward a performance-based approach by evaluating nationwide data to determine response times for different types of pipeline (based on location, operating pressure, and pipeline diameter, among other factors). First, though, PHMSA must improve the data it collects on incident response times. These data are not reliable because operators are not required to fill out certain time-related fields in the reporting form and because operators told us they interpret these data fields in different ways. Furthermore, while PHMSA conducts a variety of information-sharing activities, the agency does not formally collect or share evaluation approaches used by operators to decide whether to install automated valves, and not all operators we spoke with were aware of existing PHMSA guidance designed to assist operators in making these decisions. We recommended that PHMSA should: (1) improve incident response data and use those data to explore the feasibility of developing a performance-based approach for improving operators' responses to pipeline incidents and (2) assist operators in deciding whether to install automated valves by formally collecting and sharing evaluation approaches and ensuring operators are aware of existing guidance. PHMSA agreed to consider these recommendations.

Background

Three main types of pipelines—gathering, transmission, and distribution—carry hazardous liquid and natural gas from producing wells to end users (residences and businesses) and are managed by about 3,000 operators. Transmission pipelines

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[3] For the purposes of this statement, the term "install an automated valve" refers to any actions that allow the operator to remotely or automatically close a valve. Such actions do not necessarily mean an operator is installing a completely new valve. For example, operators may install an actuator and communications at an existing valve location.

[4] Oak Ridge National Laboratory, *Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety,* ORNL/TM–2012/411 (Oct. 31, 2012). The study was conducted pursuant to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which directed the Secretary of Transportation to consider additional regulations requiring the use of automated valves where economically, technically, and operationally feasible on new transmission facilities. Pub. L. No. 112–90, § 4, 125 Stat. 1904, 1906 (2012).

[5] GAO, *Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response,* GAO–13–168 (Washington, D.C.: Jan. 23, 2013).

carry these products, sometimes over hundreds of miles, to communities and large-volume users, such as factories. Transmission pipelines tend to have the largest diameters and operate at the highest pressures of any type of pipeline. PHMSA has estimated there are more than 400,000 miles of hazardous liquid and natural gas transmission pipelines across the United States.

PHMSA administers two general sets of pipeline safety requirements and works with state pipeline safety offices to inspect pipelines and enforce the requirements. The first set of requirements is minimum safety standards that cover specifications for the design, construction, testing, inspection, operation, and maintenance of pipelines. The second set is part of a supplemental risk-based regulatory program termed "integrity management." Under transmission pipeline integrity management programs, operators are required to systematically identify and mitigate risks to pipeline segments that are located in highly populated or environmentally sensitive areas (called "high-consequence areas").[6]

According to PHMSA, industry, and state officials, responding to either a hazardous liquid or natural gas pipeline incident typically includes detecting that an incident has occurred, coordinating with emergency responders, and shutting down the affected pipeline segment. Under PHMSA's minimum safety standards, operators are required to have a plan that covers these steps for all of their pipeline segments and to follow that plan during an incident. Officials from PHMSA and state pipeline safety offices perform relatively minor roles during an incident, as they rely on operators and emergency responders to take actions to mitigate the consequences of such events. Operators must report incidents that meet certain thresholds—including incidents that involve a fatality or injury, excessive property damage or product release, or an emergency shutdown—to the Federal National Response Center.[7] Operators must also conduct an investigation to identify the root cause and lessons learned, and report to PHMSA. Federal and state authorities may use their discretion to investigate some incidents, which can involve working with operators to determine the cause of the incident.[8]

While prior research shows that most of the fatalities and damage from an incident occur in the first few minutes following a pipeline rupture, operators can reduce some of the consequences by taking actions that include closing valves that are spaced along the pipeline to isolate segments. The amount of time it takes to close a valve depends upon the equipment installed on the pipeline. For example, valves with manual controls (referred to as "manual valves") require a person to arrive on site and either turn a wheel crank or activate a push-button actuator. Valves that can be closed without a person at the valve's location (referred to as "automated valves") include remote-control valves, which can be closed via a command from a control room, and automatic-shutoff valves, which can close without human intervention based on sensor readings.[9] Automated valves generally take less time to close than manual valves. PHMSA's minimum safety standards dictate the spacing of all valves, regardless of type of equipment installed to close them,[10] while integrity management regulations require that transmission pipeline operators conduct a risk assessment for pipelines in high-consequence areas that includes the consideration of automated valves.

Incident Response Time Depends on Multiple Variables, Including the Use of Automated Valves

Multiple variables—some controllable by transmission pipeline operators—can influence the ability of operators to respond quickly to an incident, according to PHMSA officials, pipeline safety officials, and industry stakeholders and operators. Ensuring a quick response is important because according to pipeline operators and industry stakeholders, reducing the amount of time it takes to respond to an incident can reduce the amount of property and environmental damage stemming from an incident and, in some cases, the number of fatalities and injuries. For example,

[6] "High-consequence areas" are defined differently for hazardous liquid and natural gas. For natural gas, such areas typically include highly populated or frequented areas, such as parks. For hazardous liquid, high-consequence areas include highly populated areas, other populated areas, navigable waterways, and areas unusually sensitive to environmental damage.

[7] The National Response Center, managed by the United States Coast Guard, is the sole Federal point of contact for reporting oil and chemical spills.

[8] PHMSA may conduct an incident investigation in instances when an NTSB investigation is also under way. In such cases, PHMSA does not determine the cause of the incident; rather its review is to determine regulatory compliance.

[9] Hazardous liquid regulations refer to emergency flow restriction devices, which include remote-control valves and "check" valves that automatically prevent product from flowing in a specific direction. See 49 C.F.R. § 195.452(i)(4). We refer to all of these valves as automated valves.

[10] 49 C.F.R. §§ 192.179, 195.260.

several natural gas pipeline operators noted that a faster incident response time could reduce the amount of property damage from secondary fires (after an initial pipeline rupture) by allowing fire departments to extinguish the fires sooner. In addition, hazardous liquid pipeline operators told us that a faster incident response time could result in lower costs for environmental remediation efforts and less product lost. We identified five variables that can influence incident response time and are within an operator's control, and four other variables that influence a pipeline operator's ability to respond to an incident but are beyond an operator's control. The effect a given variable has on a particular incident response will vary according to the specifics of the situation. The five variables within an operator's control are:

- leak detection capabilities,
- location of qualified operator response personnel,
- type of valve,
- control room management, and
- relationships with local first responders.

The four factors beyond an operator's control are:

- type of release,
- time of day,
- weather conditions, and
- other operators' pipelines in the same area.

(See table 1 for further detail.) Appendix II provides several examples of response time in past incidents; response time varied from several minutes to days depending on the presence and interaction of the variables just mentioned.

Table 1.—Variables Influencing Pipeline Operator Incident Response Times

Variables within an operator's control	Variables beyond an operator's control
• *Leak detection capabilities.* Pipeline operators perform a variety of leak detection activities to monitor their systems and identify leaks, including periodic external monitoring, such as aerial patrols of the pipeline, as well as continuous internal monitoring, such as measuring the intake and outtake volumes or pressure flows in the pipeline. • *Location of qualified operator response personnel.* Response personnel who have a greater distance to travel to the facility or valve site can take longer to establish an incident command center or to close manual valves. • *Type of valves.* Automated valves, which can be closed automatically or remotely, can shorten incident response time compared to manual valves, which require that personnel travel to the valve site and turn a wheel crank or activate a push-button actuator to close the valve. • *Control room management.* Clear operating policies and shutdown protocols for control room personnel can influence response time to incidents. For example, incident response time might be reduced if control room personnel have the authority to shut down a pipeline or facility if a leak is suspected, and are encouraged to do so. • *Relationships with local first responders.* Operators that have already established effective communications with local first responders-such as fire and police departments-may respond more quickly during emergencies.	• *Type of release (leak vs. rupture).* Leaks are generally a slow release of product over a small area, which can go undetected for long periods. Once a leak is detected, it can take additional time to confirm the exact location. Ruptures, which usually produce more significant changes in the external or internal conditions of the pipeline, are typically easier to detect and locate. • *Time of day.* The operator's response personnel may be delayed in reaching facilities in urban or suburban areas during peak traffic times. Conversely, if an incident occurs during the evening or on a weekend, the operator's response personnel could be able to reach the facility more quickly, because of lighter traffic. • *Weather conditions.* Weather-such as storms, winter conditions, and wind-can affect how quickly an operator can detect and respond to pipeline incidents. • *Other operators' pipelines in the same area.* If two or more operators own pipeline in a shared right of way determining whose system is affected can increase incident response time.

Source: GAO analysis of information from PHMSA officials, pipeline safety officials, and industry stakeholders and operators.

As noted, one variable that influences operators' response times to incidents is the type of valve installed on the pipeline. Research and industry stakeholders indicate that the primary advantage of installing automated valves—as opposed to other safety measures—is related to the time it takes to respond to an incident. Although automated valves cannot mitigate the fatalities, injuries, and damage that occur in an initial blast, quickly isolating the pipeline segment through automated valves can reduce subsequent damage by reducing the amount of hazardous liquid and natural gas released.

Research and industry stakeholders also identified two disadvantages operators should consider when determining whether to install automated valves related to potential accidental closures and the monetary costs of purchasing and installing the equipment. Specifically, automated valves can lead to accidental closures, which can have severe, unintended consequences, including loss of service to residences and businesses. In addition, according to operators, vendors and contractors, the monetary costs of installing automated valves can range from tens of thousands to a million dollars per valve,[11] which may be significant expenditures for some pipeline operators. According to operators and other industry stakeholders, considering monetary costs is important when making decisions to install automated valves because resources spent for this purpose can take away from other pipeline safety efforts. Specifically, operators and industry stakeholders told us they often would rather focus their resources on incident prevention to minimize the risk of an incident instead of focusing resources on incident response. PHMSA officials stated that they generally support the idea that pipeline operators be given some flexibility to target spending where the operator believes it will have the most safety benefit.

Research and industry stakeholders also indicate the importance of determining whether to install valves on a case-by-case basis because the advantages and disadvantages can vary considerably based on factors specific to a unique valve location. These sources indicated that the location of the valve, existing shutdown capabilities, proximity of personnel to the valve's location, the likelihood of an ignition, type of product being transported, operating pressure, topography, and pipeline diameter, among other factors, all play a role in determining the extent to which an automated valve would be advantageous.

Operators we met with are using a variety of methods for determining whether to install automated valves that consider—on a case-by-case basis—whether these valves will improve response time, the potential for accidental closure, and monetary costs. For example, two natural gas pipeline operators told us that they applied a decision tree analysis to all pipeline segments in highly populated and frequented areas. They used the decision tree to guide a variety of yes-or-no questions on whether installing an automated valve would improve response time to less than an hour and provide advantages for locations where people might have difficulty evacuating quickly in the event of a pipeline incident. Other hazardous liquid pipeline operators said they used computer-based spill modeling to determine whether the amount of product release would be significantly reduced by installing an automated valve.

Performance-Based Approach Offers Opportunity to Measure and Improve Incident Response, but Better Data and Guidance Are Needed

In our report, we note that PHMSA has not developed a performance-based framework for incident response times, although some organizations in the pipeline industry have done so.[12] We and others have recommended that the Federal government move toward performance-based regulatory approaches to allow those being regulated to determine the most appropriate way to achieve desired, measurable outcomes.[13] According to our past work, such a framework should include: (1) national goals, (2) performance measures that are linked to those national goals, and (3) appropriate performance targets that promote accountability and allow organizations to track their progress toward goals. While PHMSA has established a national goal for incident response times, it has not linked performance measures or targets to this goal. Specifically, PHMSA directs operators to respond to certain incidents—

[11] The cost of installing an automated valve ranges depending on the location and size of the pipeline and the type of equipment being installed, among other things.

[12] For example, according to the National Association of Pipeline Safety Representatives, several state pipeline safety offices have initiatives that require natural gas pipeline operators to respond within a specified time frame to reports of pipeline leaks. In addition, members of the Interstate Natural Gas Association of America have committed to achieving a 1-hour incident response time for large diameter (greater than 12 inches) natural gas pipelines in highly populated areas. To meet this goal, operators are planning changes to their systems, such as relocating response personnel and automating over 1,800 valves throughout the United States.

[13] In addition, NTSB has recommended that the Department of Transportation conduct an audit to assess the effectiveness of PHMSA's oversight of performance-based safety programs. See NTSB, *Pipeline Accident Report: Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California,* September 9, 2010, NTSB/PAR–11/01 (Washington, D.C: Aug. 30, 2011). In response to the NTSB recommendation, the Department of Transportation is currently conducting an audit, which it expects to issue in early 2013, that will evaluate the effectiveness of PHMSA's inspection and oversight of pipeline operators' integrity management programs, including expanding the use of meaningful metrics and setting goals for pipeline operators and tracking performance against those goals.

emergencies that require an immediate response[14]—in a "prompt and effective" manner, but neither PHMSA's regulations nor its guidance describe ways to measure progress toward meeting this goal. Without a performance measure and target for a prompt and effective incident response, PHMSA cannot quantitatively determine whether an operator meets this goal and track their performance over time. PHMSA officials told us that because pipeline incidents often have unique characteristics, developing a performance measure and associated target for incident response time would be difficult. In particular, it would be challenging to establish a performance measure using incident response time in a way that would always lead to the desired outcome of a prompt and effective response. In addition, officials stated it would be difficult to identify a single response time target for all incidents, as pipeline operators likely should respond to some incidents more quickly than others.

Defining performance measures and targets for incident response can be challenging, but one possible way for PHMSA to move toward a more quantifiable, performance-based approach would be to develop strategies to improve incident response based on nationwide data. For example, performing an analysis of nationwide incident data—similar to PHMSA's current analyses of fatality and injury data—could help PHMSA determine response times for different types of pipelines (based on characteristics such as location, operating pressure, and diameter); identify trends; and develop strategies to improve incident response. However, we found that PHMSA does not have the reliable nationwide data on incident response time data it would need to conduct such analyses. Specifically, the response time data PHMSA currently collects are unreliable for two reasons: (1) operators are not required to fill out certain time-related fields in the PHMSA incident-reporting form and (2) when operators do provide these data, they are interpreting the intended content of the data fields in different ways. Our report recommended that PHMSA improve incident response data and use these data to evaluate whether to implement a performance-based framework for incident response times. PHMSA agreed to consider this recommendation.

We also found that PHMSA needs to do a better job of sharing information on ways operators can make decisions to install automated valves. For example, many of the operators we spoke with were unaware of existing PHMSA enforcement and inspection guidance that could be useful for operators in determining whether to install automated valves on transmission pipelines. In addition, while PHMSA inspectors see examples of how operators make decisions to install automated valves during integrity management inspections, they do not formally collect this information or share it with other operators. Given the variety of risk-based methods for making decisions about automated valves across the operators we spoke with, we believe that both operators and inspectors would benefit from exposure to some of the methods used by other operators to make decisions on whether to install automated valves. Our report recommended that PHMSA share guidance and information on operators' decision-making approaches to assist operators with these determinations. PHMSA also agreed to consider this recommendation.

Chairman Rockefeller this concludes my prepared remarks. I am happy to respond to any questions that you or other Members of the Committee may have at this time.

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[14] Emergencies include natural gas detected inside or near a building, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, fire or explosion occurring near or directly involving a pipeline facility, operational failure causing a hazardous condition, or natural disaster affecting pipeline facilities.

APPENDIX I: SUMMARY OF RECENT GAO REPORTS ON GATHERING PIPELINES AND LOW-STRESS TRANSMISSION PIPELINES

GAO recently issued two reports related to the safety of certain types of pipelines. The first, GAO–12–388, reported on the safety of gathering pipelines, which currently are largely unregulated by the Federal government. The second, GAO–12–389R, reported on the potential safety effects of applying less prescriptive requirements, currently levied on distribution pipelines, to low-stress natural gas transmission pipelines. Further detail on each report is provided below. For the full report text, go to www.gao.gov.

GAO–12–388: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety

Included in the Nation's pipeline network are an estimated 200,000 or more miles of onshore gathering pipelines, which transport products to processing facilities and larger pipelines. Many of these pipelines have not been subject to Federal regulation because they are considered less risky due to their generally rural location and low operating pressures. For example, out of the more than 200,000 estimated miles of natural gas gathering pipelines, the Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates roughly 20,000 miles. Similarly, of the 30,000 to 40,000 estimated miles of hazardous liquid gathering pipelines, PHMSA regulates about 4,000 miles.[1]

While the safety risks of onshore gathering pipelines that are not regulated by PHMSA are generally considered to be lower than for other types of pipelines, PHMSA does not collect comprehensive data to identify the safety risks of unregulated gathering pipelines. Without data on potential risk factors—such as information on construction quality, maintenance practices, location, and pipeline integrity—pipeline safety officials are unable to assess and manage safety risks associated with gathering pipelines. Further, some types of changes in pipeline operational environments could also increase safety risks for federally unregulated gathering pipelines. Specifically, land-use changes are resulting in development encroaching on existing pipelines, and the increased extraction of oil and natural gas from shale deposits is resulting in the construction of new gathering pipelines, some of which are larger in diameter and operate at higher pressure than older pipelines. As a result, PHMSA is considering collecting data on federally unregulated gathering pipelines. However, the agency's plans are preliminary, and the extent to which PHMSA will collect data sufficient to evaluate the potential safety risks associated with these pipelines is uncertain.

In addition, we found that the amount of sharing of information to ensure the safety of federally unregulated pipelines among state and Federal pipeline safety agencies appeared limited. For example, some state and PHMSA officials we interviewed had limited awareness of safety practices used by other states. Increased communication and information sharing about pipeline safety practices could boost the use of such practices for unregulated pipelines.

We recommended that PHMSA should collect data on federally unregulated onshore hazardous liquid and gas gathering pipelines, subsequent to an analysis of the benefits and industry burdens associated with such data collection. Data collected should be comparable to what PHMSA collects annually from operators of regulated gathering pipelines (*e.g.,* fatalities, injuries, property damage, location, mileage, size, operating pressure, maintenance history, and the causes of incidents and consequences). Also, we recommended that PHMSA establish an online clearinghouse or other resource for states to share information on practices that can help ensure the safety of federally unregulated onshore hazardous liquid and gas gathering pipelines. This resource could include updates on related PHMSA and industry initiatives, guidance, related PHMSA rulemakings, and other information collected or shared by states. PHMSA concurred with our recommendations and is taking steps to implement them.

[1] According to PHMSA officials, Alaska, California, Louisiana, and Oklahoma have the majority of federally unregulated gathering pipeline mileage in the United States.

GAO–12–389R: Safety Effects of Less Prescriptive Requirements for Low-Stress Natural Gas Transmission Pipelines Are Uncertain

Gas transmission pipelines typically move natural gas across state lines and over long distances, from sources to communities. Transmission pipelines can generally operate at pressures up to 72 percent of specified minimum yield strength (SMYS).[2] By contrast, local distribution pipelines generally operate within state boundaries to receive gas from transmission pipelines and distribute it to commercial and residential end users. Distribution pipelines typically operate well below 20 percent of SMYS. Connecting the long-distance transmission pipelines to the local distribution pipelines are lower stress transmission pipelines that may transport natural gas for several miles at pressures between 20 and 30 percent of SMYS.

Applying PHMSA's distribution integrity management requirements to low-stress transmission pipelines would result in less prescriptive safety requirements for these pipelines. Overall, requirements for distribution pipelines are less prescriptive than requirements for transmission pipelines in part because the former operate at lower pressure and pose lower risks in general than the latter. For example, the integrity management regulations for transmission pipelines allow three types of in-depth physical inspection. In contrast, distribution pipeline operators can customize their integrity management programs to the complexity of their systems, including using a broader range of methods for physical inspection. While PHMSA officials stated that "less prescriptive" does not necessarily mean less safe, they also stated that distribution integrity management requirements for distribution pipelines can be more difficult to enforce than integrity management requirements for transmission pipelines.

In general, the effect of changing PHMSA's requirement for low-stress transmission pipelines for pipeline safety is unclear. While the consequences of a low-stress transmission pipeline failure are generally not severe because these pipelines are more likely to leak than rupture, the point at which a gas pipeline fails by rupture is uncertain and depends on a number of factors in addition to pressure, such as the size or type of defect and the materials used to conduct the pipeline. In addition, the mileage and location of pipelines that would be affected by such a regulatory change are currently unknown, although PHMSA recently changed its reporting requirements to collect such information. The concern is that because distribution pipelines are located in highly populated areas, the low-stress transmission pipelines that are connected to them could also be located in highly populated areas. As a result, we considered the current regulatory approach of applying more prescriptive transmission pipeline requirements reasonable.

[2] Pipelines will begin to deform at a certain level of operating pressure. As a result, pipelines operate at a percentage of the level of pressure that will cause the pipeline to deform, known as SMYS. The SMYS depends on the type of metal and is an indicator of when the metal in the pipe starts to yield, deforming in a way that does not return to its original shape. By definition, transmission pipelines operate at or above 20 percent of SMYS (49 CFR § 192.3). Some transmission pipelines operate under special permits that allow different maximum operating pressure that could exceed 72 percent of SMYS.

APPENDIX II: EXAMPLES OF PIPELINE INCIDENT RESPONSE TIMES

Operators we spoke with stated that the amount of time it takes to respond to an incident can vary depending on a number of variables (see table 2).

Table 2.— Examples of Response Times in Select Pipeline Incidents from 2009 to 2011

Incident response time	Description
1 minute	A rupture on a natural-gas transmission pipeline located underground in a sparsely populated area was caused when a construction company worker accidentally struck the pipeline, which then ignited and exploded. When the line broke, automatic-shutoff valves on either side of the rupture closed within one minute. Despite the fast valve closure, the explosion caused one fatality-the worker who struck the pipeline-and injured seven others. The affected pipeline segment was 20 miles long. Though the valves were closed, there was enough gas remaining in the pipeline to fuel the fire for several hours. In addition to causing a fatality and injuries, the incident cost the operator an estimated $1 million, due primarily to the value of the lost product ($740,000), as well as damage to the pipeline ($288,000).
3 minutes	A rupture on a hazardous liquid transmission pipeline, located underground near a creek in a sparsely populated area, was caused when heavy rains shifted the land which broke the pipeline, releasing over 1,700 barrels of propane. The line break was immediately picked up by the operator's computer-based leak detection system, and operator personnel on site closed manual valves to isolate the segment within 3 minutes. Because propane is a highly volatile liquid, which turns to gas when released into the atmosphere, there was no soil or water contamination or environmental cleanup costs. The incident cost the operator an estimated $128,000, due primarily to the cost of repairs ($73,000) and value of lost product ($55,000).
8 minutes	During the night, unknown individuals operating construction equipment punctured a hazardous liquid transmission pipeline located underground in an environmentally sensitive area, causing 56 barrels of crude oil to leak into the soil. The puncture caused a drop in pressure that the control room operator detected in 2 minutes. Six minutes later, the control room operator shut down the pipeline and isolated the affected segment with remotely controlled valves. About 2 hours later, the operator's response personnel arrived on site. The incident cost the operator an estimated $1.3 million, due primarily to its environmental remediation efforts ($1 million) and emergency response ($250,000).
2 hours	A crack on an above-ground portion of a hazardous liquid pipeline, located in a populated area, caused 120 barrels of crude oil to spray into the air. About 15 minutes after the incident started, a local resident reported to the fire department that crude oil was spraying into the air at a pipeline station. The fire department went to the incident site and, about 30 minutes after the initial call, notified the pipeline operator of a broken oil pipeline. About 20 minutes after receiving the fire department's call, the control room began shutting down the pipeline system and isolating the affected segment by ordering the closure of the upstream valve. Approximately 50 minutes later-about 2 hours after the incident started-response personnel arrived on site and manually closed the valve, which stopped the leak. The incident cost the operator an estimated $183,000, due primarily to its emergency response ($118,000) and environmental remediation efforts ($61,000).
7 days	A natural gas transmission pipeline, located underground in a sparsely populated area, developed a small leak as the result of a construction defect. The operator did not discover the leak on the pipeline for almost a week following initial reports due to the size of the leak in combination with wind gusts in the area that dissipated the escaping natural gas, reducing the common signs of a gas leak, such as the smell and damage to vegetation. Once the operator detected the leak during routine, periodic external monitoring of the pipeline, it took over a day to identify its exact location. The incident cost the operator an estimated $128,000 in repairs ($106,000) and lost product ($22,000).

Source: GAO presentation of information obtained during interviews with pipeline operators.

The CHAIRMAN. Thank you very much. I have to do an immediate apology because as I praised GAO it occurred to me that I wasn't praising the agencies seated to your right. And there's a reason for that. They have specific tasks used to cover the world. In other words, I could write you a letter saying what do you think the future of whales are or coral reefs, and I would get an answer.

Ms. FLEMING. Right.

The CHAIRMAN. A very academic reason to answer. So I just make that separation for my own protection from these two very nice people whose agencies I desperately need.

Ms. Quarterman, I thank all of you for your statements. And any time we have a pipeline incident we hear about the amount of time that it took the operator to respond to that incident and therefore shut down the flow of gas or oil through the affected pipeline.

The aftermath of the Sissonville incident is no different. While the cause of the event is still under investigation, there has been a lot of discussion about how quickly the operator did or did not respond, and I want to delve into this a bit.

Ms. Quarterman, what is an acceptable amount of time that an operator should take to respond to a rupture? And I understand there are a lot of variables that can impact how it takes an operator to respond, nature and lots of things. But there are metrics that you can put in place to measure how well operators are performing; is that not right?

Ms. QUARTERMAN. That is correct. We require that an operator respond promptly. After the incident that occurred in San Bruno we came forward and——

The CHAIRMAN. That's California?

Ms. QUARTERMAN. California, yes. I'm sorry. In August 2011 we put out an advanced Notice of Proposed Rulemaking where we asked a series of questions about gas transmission and pipelines in particular. And ways that our regulations could be improved included among the questions that were asked related to remote and automatic shutoff valves and whether or not that is an option that should be considered moving forward.

When the Pipeline Safety Act passed there was a provision in that Act as well that required us to study it with respect to existing pipelines and report back, which is one of the reports that we finished at the end of this year, and ask GAO to study it with respect to existing pipelines. And the report that came out today is associated with that.

Another thing that we are looking at, and I think I mentioned during our testimony, is that later on this year we're planning to have a workshop with respect to the integrity management program and begin to ask some of these questions about how we might expand upon what is right now a performance-based system to ensure that operators are really assessing the risks and responding on a timely basis.

The CHAIRMAN. Can you explain to me more specifically what you mean by the way in which they choose to respond or not respond? What is it that they go through? I'm going to also ask this to another witness later on. What is it they go through in order to decide—first they have to know about it. Then they have to make a decision based upon several factors.

Now, Ms. Hersman was referring to 16 fluctuations that took place before this Sissonville pipe blew. What's the way that they planned in how they're going to respond? What goes through their head?

Ms. QUARTERMAN. I think perhaps Columbia Gas would answer this better. But what I hope goes through their head is when they have an alarm or alert at a control room, as was the case here, they should take that very seriously because it indicates that something severe may have happened and they should alert the authorities. They should talk among themselves within the control room and immediately move toward shutting a pipeline in if there's an indication that there is a loss of pressure in that pipeline. Because that's an indication that there is a leak.

One of the other studies that we also completed recently was an independent study on leak detection because of concerns we had about the fact that in many instances a leak is not found until someone in the public calls and says something has exploded or there's oil all over the place, another provision also of the act that we're looking at closely.

So, in part, it's detecting a problem, and the second is stopping the problem. If you have an automatic or remote control shutoff valve you can do that instantaneously.

The CHAIRMAN. And you can do that from the response——

Ms. QUARTERMAN. From the control room.

The CHAIRMAN. Yes.

Ms. QUARTERMAN. It should be right there. And ideally, if you have a good safety culture, you should have given every one in that control room the authority to shut down the pipeline if they're concerned. So it's not a question of, you know, calling the boss who might not be there and saying there's a problem, but immediate authority to shut the pipeline in. And also notifying the public officials that there is a problem so that they know, if there is an incident that's out there, they know the cause of it and they can immediately start communicating and responding to it.

They should also notify the National Response Center, notify so that we in the public sector know that there has been an incident. And that gets communicated all around government so everyone knows immediately that there is a problem.

The CHAIRMAN. All right. I thank you.

For Ms. Fleming, you note a lack of data that the Department of Transportation had about incident response times. Can you identify specific data that would be helpful for the department in order to make timely collections? What type of metrics would work best to measure operator's performance on how quickly they respond given the number of variables such as weather, traffic, rupture location? Can you provide examples from other industries? Large question, but interesting.

Ms. FLEMING. Yes. All right. So I think your first question was regarding data that would help measure incident response. So there are a couple of key areas, four to be exact, that we feel would really help PHMSA try to get a sense of incident response time.

The first is the amount of time it takes an operator to identify and confirm an incident. The second would be when an operator or emergency response folks arrive at a scene. Third would be how much time it takes an operator to close a valve and isolate a pipeline segment. And then last would be the amount of time it takes for the operator or emergency response folks to assess the incident and declare it safe again.

Currently PHMSA does not collect information in all of these areas. They only require the date and time the incident occurs. And we feel that all of these areas are important in order to be able to move toward a performance-based framework. So currently the data is unreliable because it's not complete. It doesn't encompass all of those areas. And when operators do try to provide information they're providing, it's kind of spotty because they're interpreting the data fields differently amongst the operators.

So if PHMSA was able to collect this information they would be able to then take a step back and analyze to look for average incident response times and also look for trends amongst the different types of incidents and also amongst the pipeline operators.

Your second question, I think, gets to the metrics. So in our work we've identified several characteristics of performance measures that really help organizations to identify, target, and track safety efforts.

The first would be to really develop specific measurable goals that make clear the results you're trying to achieve. An example of that would be the Federal Motor Carrier Safety Administration has a range of measurable goals that they use to assess progress in how their enforcement programs are working and also in terms of the compliance with safety regulations and in reducing crashes, fatalities, and injuries.

The second characteristic that we think is important for metrics would be that the goals should really be targeted toward your key dimension in terms of your performance measures. So an example of that would be the Federal Railroad Administration's annual budget submission has very specific numeric targets in terms of trying to reduce average train accident rates.

And another example would be other emergency response organizations really have response requirements. For instance, the National Fire Protection Association requires that fire departments, the first fire engine must arrive within 4 minutes of an incident and all subsequent fire engines must arrive within 8 minutes. So these types of performance measures allow different entities to kind of take a step back and to gauge and see what adjustments need to be made in order to really improve your response time.

The CHAIRMAN. So it is possible even though conditions vary, terrain varies, geology varies, all kinds of things vary, it is possible to set out a general metric with specific timelines which can be aimed for or met?

Ms. FLEMING. Absolutely, Mr. Chairman. I think the first step is to get a handle on the data and see what the data is telling you so that you can look across and say, OK, for this type of gas operator here's what the trend is telling us or this type of liquid operator with this type of dimension and pressure, here's the incident, here's what's happening in the last, you know, couple of years. Here's what the trends are showing.

And then you really definitely could start setting some performance time related requirements and—and metrics and—and see and make adjustments and work to improve response time and safety.

The CHAIRMAN. Just to close my point, the general thought that some might have, well, you know, just too much depends on what the circumstance is, and you yield some veracity to that point. But you say that in general where you were collecting relevant data, data is data, no matter what it's used for.

Ms. FLEMING. Yes.

The CHAIRMAN. If it's collected honestly and interpreted honestly, it leads to a point of decision when you can do something if you are going to do that.

Ms. FLEMING. Absolutely. Absolutely.

The CHAIRMAN. Thank you.

Senator Manchin, do you want to ask any questions—I've got so many questions here.

Senator MANCHIN. I've got a few, if I may.

The CHAIRMAN. Yes, please.

Senator MANCHIN. To Ms. Hersman, we have pipelines still in operation that are as old if not older than the line that ruptured. And I'm sure that you have to be concerned about the age and conditions of some of these lines.

And finding out that the line that ruptured, where it ruptured, was one-third of the thickness it had originally been, I think, was start out——

Ms. HERSMAN. Reduced by 70 percent. That's right.

Senator MANCHIN. OK. How could that happen? And if that's the case and we have all these lines out there and we're much more dependent now, and I think we're going to be sometime in the future on natural gas, how vulnerable are we as a society?

Ms. HERSMAN. About 50 percent. I mentioned 2.5 million miles of pipeline exist in our country. And about 50 percent of those lines were installed prior to 1970. So we indeed do have an aging pipeline infrastructure system like we do in all of our modes of transportation where we do see aging.

One of the things that's really important is if a pipeline is adequately maintained and it's inspected properly its age is not the critical factor. The condition of the pipe is a critical factor. And so in this situation what we saw is a pipe that did not have any inline inspections and so there was not a recognition that this external corrosion was occurring reducing the thickness of the pipe.

And so we are very concerned. We've made recommendations about inspections, that those have to be done regularly. And I think it's like anything else that we have, you've got to maintain it, you've got to invest in it, you've got to inspect it. Things can last a long time but it is important to understand the condition of them. And that's not what we're seeing in many of our investigations. We've investigated three major accidents in the last three years, and those pipelines were laid in the 1950s. There was a manufacturing defect in that one. In the 1960s in Michigan—the first one is California, San Bruno that people have referred to.

The second one was in Michigan, and that was cracking and corrosion. And here now again we're seeing a 1960s era pipe where we're seeing significant corrosion. We have to do better.

Senator MANCHIN. Ms. Quarterman, as I'm understanding in the vicinity there was three lines, SM–86, which is a 26-inch. And then the one that blew was an SM–80, was a 20-inch. And I'm understanding that the smart pig, so-called smart pig, and you probably want to explain that. I just understand that the inspection device creates a squealing noise and that's how it got its name the smart pig.

Ms. QUARTERMAN. That's one rumor I've heard, yes.

Senator MANCHIN. OK. You might have other ones you might not want to talk about in here. Anyway, I'm understanding that's the only one that was not able to be or was not fitted with a smart pig to be inspected. Why would that be? That's still a big line, 20-inch.

Ms. QUARTERMAN. It is a big line. And the three pipelines that are at issue, one was, as you mentioned, 26. I believe the other one is 30-inch. There was the SM–86 loop, which was 26-inch. The SM–86 loop was 30 inches. These three pipelines were essentially parallel in the same area.

Senator MANCHIN. Right.

Ms. QUARTERMAN. Under the integrity management rules that were issued in 2003, a pipeline that is in a high consequence area as determined by the rule must have assessments of it, one—one version of—one assessment method, a very popular one, is an inline inspection tool or a pig.

With respect to the two larger pipelines, because of the size of the line, the diameter, as well as the pressure of the line, there was a calculation made that is called the PIR, the potential impact radius. So depending upon how big the pipe—how much pressure it is, the diameter of the pipeline, the bigger radius upon which the explosion would have an effect.

With respect to the two larger pipelines, the explosion radius was bigger. The way it works is it's sort of a bubble that travels up and down the pipeline. If there are 20 residences within a bubble it is considered a high consequence area.

Senator MANCHIN. Is your thought process changing on that now? And I'm sure the industry might have other thoughts. But I'm sure everybody wants to be as safe as they can, and they don't want these things to happen either. Are you—would your recommendation be now that these are all treat—they should be inspected by the pig, smart pig?

Ms. QUARTERMAN. I mentioned earlier the rulemaking that we came out with in August 2011. One of the questions on that was, number one, should we redefine the high consequence area, expanding the scope. Or, number two, should we require more pipelines to be inspected or assessed. That is still the rulemaking process, so I can't comment on where we're going with that. But that's something that we are very, very, very seriously considering amending.

Senator MANCHIN. And one real quickly, Ms. Fleming, if I may ask, the automated valves, my experience was I kept thinking why don't they just shut this thing off? Why is it still burning? And I understand the location, demographics and all that.

And I'm understanding also that some of the valves may cause a problem as much as they might prevent a problem. Does that advance to the position to where you all have taken the position that there should be automated valves? And at what increments do you believe this should happen?

Ms. FLEMING. We leave the increments to PHMSA.

Senator MANCHIN. OK.

Ms. FLEMING. You know, there are a number of means to try to improve response time. And it may make sense for an operator to install them every single location. It really is on a case-by-case. There are other factors——

Senator MANCHIN. What do you mean by every single location? Because some of these lines are quite, quite long.

Ms. FLEMING. Right. Right. Absolutely. We spoke to eight operators.

Senator MANCHIN. Between compressing stations and things of that sort.

Ms. FLEMING. Yes. We spoke to eight operators. And one operator, a gas operator, said that, you know, they just made a decision that they are going to replace them and put automated valves regardless of risk. Because in their view they wanted to remove any judgment that control room staff would have in terms of whether or not to shut down the operation. So they just didn't want that to come into play during an incident.

And there are other factors that are very critical too to a response. And really upgrading your leak detection capabilities, making sure your response personnel are close to the valve. Again, the control room procedures are very important to make sure that folks have adequate training and the authority to shut down the system.

So we just feel that operators should take all of these factors into consideration knowing their characteristics of the pipeline location, and really do what they feel in working with PHMSA to come up with the optimal solution. Because as we know, automated valves absolutely improve safety but only in conjunction with a rapid well coordinated response.

Senator MANCHIN. Thank you, Senator.

The CHAIRMAN. Thank you, Senator Manchin.

Just a quick one. Are you aware of any pipeline companies where when the control room lights up that the people that run the control room feel that they need to call a higher up to get permission to shut off the flow of gas?

Ms. FLEMING. We talked to eight operators. And a couple of folks told us that the old way of doing things was that, you know, kind of keep it running at all costs, right. And they said that they were very pleased that things were changing in that environment, that at least for their company safety was becoming the most important thing. But, again, we only spoke to eight operators and I think there's over 600 in the country with pipeline in highly populated and environmentally sensitive areas.

So I think control room protocols, procedures are critical. And I think folks need to have adequate training and have the proper authority to shut down a system to make sure that there's no rupture or leaks.

The CHAIRMAN. Yes, that was brought to my attention first through that movie the China Syndrome.

Ms. FLEMING. Right.

The CHAIRMAN. I mean, that was the whole—that was the whole ball game.

Ms. FLEMING. That was the premise, right?

The CHAIRMAN. Yes. All right.

For Ms. Quarterman, last year's Pipeline Safety Bill required that automatic or remote controlled shutoff valves be installed on new and/or reconstructed pipelines where feasible. Now, the phrase "where feasible" perplexes me. I know you've started working on this requirement. What kind of process—progress are you making in terms of this requirement? When can you expect to finalize this requirement?

And I won't ask you whether OMB is being difficult. I didn't ask you that. I was just talking to myself. If you could answer the first part of the question, please.

Ms. QUARTERMAN. With respect to the automatic and remote controlled shutoff valves, I believe the requirement is that we perform a study and then determine whether to regulate. Fortunately we had already started the regulations before the law passed so we are well along the way in terms of looking at that.

As I mentioned, there was a study released at the end of 2012 that was performed by an independent expert on those valves. And the next act will be ours in terms of proposing a regulation going forward. I think the new pipelines are the easy part of this. It is the existing pipelines that will be much more difficult for us.

The CHAIRMAN. But the general feeling is that the words "where feasible" is not one which I should worry about?

Ms. QUARTERMAN. I think candidly that not only we but the entire industry is now committed to making sure that this happens going forward, that the valves are in place going forward for new pipelines.

The CHAIRMAN. And you have the power through rule making, et cetera, to make sure?

Ms. QUARTERMAN. Absolutely.

The CHAIRMAN. Thank you.

This is a question is for Ms. Hersman and Ms. Fleming. The NTSB has advocated for requiring automatic or remote controlled shutoff valves on existing pipelines.

Ms. Fleming, GAO has ultimately said that requiring these valves across the board may not be appropriate as a way forward. If these valves increase safety levels, why shouldn't we push for them to be installed as much as possible and why this conflicting approach?

Ms. HERSMAN. The NTSB is charged with investigating accidents and making recommendations to prevent their reoccurrence or the loss of life or injury. We have seen in multiple investigations like San Bruno, CA where we had loss of life in a natural gas accident; Marshall, Michigan where they had a catastrophic release of crude oil, and here in Sissonville, WV.

What we see is, one, a lack of recognition that the pipeline has leaked. In two of these events, an outside source called in and reported the rupture.

The CHAIRMAN. Somebody else calling in?

Ms. HERSMAN. Somebody else calling in and saying there's a problem. That is because the systems that have been set up to operate these pipelines are really operational systems. They are not leak detection systems. They monitor and control the distribution of gas and oil to customers in the most efficient manner.

These systems are not sophisticated. In fact, here in Sissonville, there were three parallel lines and they all interconnected at various points. When Columbia needed to isolate and identify the ruptured line, the technology they had would not provide the appropriate information to them. They didn't——

The CHAIRMAN. Would or would not?

Ms. HERSMAN. Would not because they could not identify which of the three lines had ruptured and they had to shut down all three lines. The Control Centers do not have that level of sophistication.

In Marshall, MI, it took Enbridge, the operator, 17 hours to identify the leak on a hazardous liquid line. They restarted the line twice, and they were about to do it for a third time. During the 17 hours, there were three shifts of employees who did not recognize that there was leaking petroleum. It was the worst onshore oil spill we have had in the United States, almost $1 billion worth of damages.

The control systems are not recognizing ruptures. These automatic systems—and, again, Ms. Fleming mentioned it—takes the decisionmaking process out in some instances. If you have a huge outflow of gas on a single line, you know you need to shut that line down. In Sissonville, the rupture occurred on the smallest line where this rupture occurred of the three interconnected pipelines. The interconnection of the lines massed the drop in pressure because it was pulling gas from all three of those lines so the controller only saw a 100 PSI drop.

If the controller had known on those cross flows where the gas was going, that it wasn't going this direction, that it was escaping, it would have helped. The future is really to improve the technology. To understand what is going on, to provide the controllers better information, and to have automatic valves, because we know that people have problems shutting these valves down. In San Bruno, an urban area, it took them almost 90 minutes to close the valves. That was not because they were far away. It was because of traffic congestion. They physically could not get to the valves.

In an area like West Virginia the situation could have been very different if it had been in the middle of the night, or during rush hour with more people on I–77. At the time of the rupture, there were four people in the compressor station at Lanham because it was during the work day. They actually could shut those valves down. It took them an hour to do it, but they could close the valves. They did not have to come from somewhere else to shut them down.

Technology will help improve all of this. That being said, the NTSB makes recommendations for safety. That's our focus. We don't have to do the cost benefit analysis that Administrator Quarterman does to decide how much this costs versus how much the gain is. We look at what is in the best interest of the public when it comes to safety. We have a different mission.

The CHAIRMAN. And the new technology, which I assume is in use in many places, is not mind bogglingly complex and expensive.

Ms. HERSMAN. Well, I would say expensive is probably a relative term. It depends on who is paying for it.

The CHAIRMAN. That's what I want you to say.

Ms. HERSMAN. That this is technology that is certainly available. And as I mentioned to Senator Manchin earlier, the problem with these systems that are based on infrastructure that's 50 years old, is like the difference between having a paper map versus an electronic map with location technology when you're on the highway and understanding that you're in between two cities.

With a paper map, maybe you know the closest mile marker, but you don't know exactly where you are. With a smartphone with GPS technology, however, you know exactly where you are. You can probably see weather and traffic on it too. The paper map is where we are with these pipeline systems. But, we need better technology to provide better information to people in the control rooms to identify, isolate, and shut down ruptured pipelines more efficiently and effectively.

The CHAIRMAN. OK. Ms. Fleming, did you have——

Ms. FLEMING. I absolutely agree. I mean, I think automated—our work has shown that automated valves is a very effective means for improving response time and addressing an incident. But it is one—it's just one of the means. We also think it's very important to update leak detection technologies, to really take a look at your control room procedures, and then to really—each operator has to make an assessment in order to come up—and maybe it's a combination or maybe it really is installing valves everywhere. But each one of them really needs to take a step back and figure out the optimum solution to their particular situation.

We spoke to one pipeline operator, it was interesting, and one location would have taken them—they decided to automate this valve because they figured out that it would really take them about two and a half to 3 hours to get there. Once there it would take at least 30 minutes to shut down the valve. So by automating this particular valve they were able to reduce their incident response time to less than an hour.

And so I think each entity has to go through this exercise, look at where the valves are, look at the characteristics of their system, look at the control room procedures, take a look at their leak detection capabilities, location of their response personnel really in order to come up with an optimal solution.

The CHAIRMAN. Thank you.

I want to ask a question to the panel, that in the absence of these valves that we've been discussing, are there feasible alternatives to help shut off ruptured lines more quickly? I'm just asking for a yes or a no. I would think it would be pretty much a standard.

Ms. HERSMAN. Yes.

The CHAIRMAN. Yes, there are?

Ms. HERSMAN. You're asking about technologies to shut the lines down quicker?

The CHAIRMAN. Yes.

Ms. HERSMAN. Yes. I think that's some of the technology improvements that we have been talking about today. For example, what I saw actually this morning out at the Lanham Compressor Station are three types of valves. There are hydraulic valves that will actuate on their own once they are activated.

There are electric valves that will close the pipelines that are slower. And there are manual valves. Some of the valves have to be physically operated. They require human beings to turn a hand crank hundreds and hundreds of times with significant force to close the valves.

That is the reason why it took so long to close some of those valves at Lanham. People may imagine that somebody presses a button and the valves are closed, but every situation is different depending on the infrastructure. Some valves require a person to be physically present if they are not automatic or remote control valves.

The CHAIRMAN. Understood.

Ms. FLEMING. And I think what we're highlighting today is first you have to know that you have a problem. And so that's the idea of really having the leak detection capabilities. But in some cases it's also a robust public awareness program.

You know, I think there are many incidents where it's not necessarily the operator that's the first one to make that call. And then once you have a problem then you have to have the best technology, whether it's an automated valve, in order to shut down and isolate a segment. So it's really taking a look at all of these different things to make sure that the public is aware of how to identify, how to report a problem. And then you have the capability to address a particular incident.

The CHAIRMAN. I would think, Ms. Quarterman, before you answer, that particularly those people who live near gathering pipelines who recognize that there's a major amount of activity taking place under their feet and in their area would be pretty quick to get familiar with a website with the right kind of information. Please?

Ms. QUARTERMAN. One would hope so. But we understand that that is not always the case. From a technological perspective I'm not aware of any other technology beyond the ones you were talking about here today. But the public awareness point, I think, is an excellent one. We do require operators to put in place a public awareness plan so that individuals living near these facilities are aware of what's there. They should be aware of what to look for if there's a problem and how to respond to it.

I understand from some of the conversations we've had here that Columbia Gas had done a reasonable job with that, the public awareness piece of it. We should also point to the prevention piece as well. I want to say a very great thanks for the state, for the Public Safety Commission, for the firefighters who were involved with this incident. I understood it went extremely smoothly given what had happened. I think they were aware that the pipeline was there, which has not always been the case in some of these incidents.

And we're trying to make sure that that doesn't happen again by reaching out to emergency responders so they know in advance where the pipelines are in their area, who the operators are, who to call if there is a problem. That's a big part of what we could be doing here as well.

The CHAIRMAN. Senator Manchin has a question. I just wanted to put in when I was out there this morning talking with a fire chief who I knew from D-block and other subjects. There seemed to be a sense that they knew what they were meant to do. In other words, you go out there, you see this huge hole, vast amounts of straw covering land.

And, you know, Sue Bonham's, the remainder for their house, et cetera, that there would be a sense of, my heavens, we've never had this before. But to the contrary, the folks that live there and work there and have responsibilities there seem to be rather calm about what their duties were and they proceeded to do them. That was my impression. So that's not really a question.

Ms. QUARTERMAN. I agree with that. I would also just like to add that when this incident occurred we happened to have been in Pennsylvania looking at some of the new development there. And my deputy is a former fire chief, Mr. Butters, got a call from the West Virginia folks and so we were talking to them immediately about this incident. And they have been fantastic throughout this period. Mr. Butters has been here and visited with those folks and we are really impressed with what they were able to do. And we are going to make sure that they are even better prepared in the future.

The CHAIRMAN. OK. Senator Manchin?

Senator MANCHIN. Very quickly. The Senator had mentioned about having apparatuses today that could automatically shut down and prevent, let's say, these type of disasters to the extent that they are.

The thing that comes to mind is the BP oil spill, and I think to all of our amazement how that thing could have blown for so long and spewed out for so long and we didn't have the right equipment, if you would. And trying to design something in real time that would take care of the problem is difficult. And I'm sure that we've moved further ahead so that hopefully never happens again.

I think the same thing is happening here. You're saying that it should be strategically located when you have personnel, that you know you're going to have personnel at some of these substations, that's one thing. Knowing in a remote area is another thing. And are these rules and regulations or do you need codification from the legislation or—to move forward, where—where are you at on these things?

Ms. QUARTERMAN. We don't need codification. We have the authority to move forward in rulemakings on these things. I think some of the things that were being recommended by GAO are beyond rulemaking, putting in place some performance measures.

We had a workshop earlier this year on the subject of data, something that I think we have not nearly enough of and need more of. And we actually have a rulemaking in progress to request more data from operators on a geospatial basis so that you can click on any point in a pipeline and know a lot about it.

Senator MANCHIN. Yes. Are you all working with the company's operators, people responsible for the lines so that we all come up with a conclusion on what's the best method to take?

Ms. QUARTERMAN. Absolutely.

Senator MANCHIN. And they've been cooperative working with you?

Ms. QUARTERMAN. They have been cooperative, yes.

Senator MANCHIN. So you're not having a problem there? It's just making sure you get the right equipment in the right place?

Ms. QUARTERMAN. Actually, we did a pilot program very recently because we were trying to get more geospatial base information. And NiSource was one of the volunteers for that to see if we could actually get the kind of data we wanted to get.

Senator MANCHIN. My final question, very quickly, is if that line had deteriorated to one-third of the actual size it should have been to carry safely the pressures it was carrying, it led me to believe that maybe there was other parts of that line that might blow. Are you sure that there's a safety on that, which is the SM–80 line, the 20-inch line? Since the other ones have been inspected I assume that this line is not inspected anywhere? Or have you started inspections on it?

Ms. QUARTERMAN. It will be before it returns to operations.

Senator MANCHIN. Got you.

Ms. QUARTERMAN. One of the requirements in our corrective action order was that before they could begin operating again they would change the valves at the ends of the pipeline so that they can actually accept an inline inspection tool and run a corrosion test within that pipeline.

And we have required that before they begin, you know, complete operations they will do that and they will then repair the line as though it was in a high consequence area even though under the official regs it is not.

Senator MANCHIN. Thank you.

The CHAIRMAN. There's a final question before we go to the third panel and before I thank you all.

The fire chief, who I said is a good friend, told me that there is in fact a length, he didn't describe it, but a semi lengthy amount of plastic pipe sitting on the ground out in Sissonville carrying gas. And I'm trying to think how could that possibly be?

Ms. QUARTERMAN. I am guessing, and I don't know anything about that particular situation. I haven't talked to him about that. I'm guessing it is a gas gathering line. This is another area that when the President put forward a request for reauthorization we requested the authority to be able to oversee gas gathering that had not traditionally been regulated.

And when I mentioned my trip to Pennsylvania to see some of the shale plays, one of our concerns is that a great deal of gas gathering lines are going into place, some of them 20 inches or larger, high pressure lines that are currently not within our regulatory authority because they are in a rural area. We are extremely concerned that we get ahead of that problem by beginning to know what is out there, where pipelines are, and begin to regulate those lines in some way or fashion.

The CHAIRMAN. In a rural area and therefore not within your jurisdiction?

Ms. QUARTERMAN. Right.

The CHAIRMAN. That strikes me as odd. I want to thank all three of you, and I don't want you to move. I want you to stay right where you are because coming down on the plane with you, you all had briefing books that were like 10 inches thick in sort of biblically small handwriting and you've all read all of it. And I was just very impressed.

And I was also concerned, Ms. Quarterman, with respect to your situation, because you indicate you do not have a large agency. And therefore the number of people as this burgeoning industry merges further, it will be important for you to be able to monitor it. And you have been there through a situation where you had 75 people.

Then you were taken down to 39 people and now you're over 100 people or whatever it is. That doesn't sound like a very healthy way of doing business. You need stability, don't you? You need enough people and you need stability.

Ms. QUARTERMAN. Absolutely. We have a very small agency. Despite overseeing 2.6 million miles of pipeline, we have 200 people, 135 of which are inspection enforcement personnel.

The President was very generous in his request in Fiscal Year 2013, which would add another 120 inspectors. We desperately need those people because those people not only do the day-to-day meat and potatoes inspection, when you have a boom as you're having now with gas and oil production in this country, what happens next to the pipelines going to there.

So they want to be there to see the construction as it happens. In addition to that, with all these incidents we also have to take people away from the day-to-day bread and butter inspections to do that. And the infrastructure is not getting any younger. So it is a huge challenge for us.

The CHAIRMAN. I thank you all a lot.

And I now call upon the third panel to sit over there. And that's Mr. Jimmy Staton, who is Executive Vice President and Group CEO of the NiSource Gas Transmission & Storage. And second, Mr. Rick Kessler, President of the Board of the Pipeline Safety Trust. If you gentlemen could have a seat.

And, Mr. Staton, if you could start with your statement, I would appreciate it.

STATEMENT OF JIMMY D. STATON, EXECUTIVE VICE PRESIDENT AND GROUP CEO, NISOURCE GAS TRANSMISSION & STORAGE

Mr. STATON. Good afternoon, Chairman Rockefeller and Senator Manchin.

The CHAIRMAN. Could you pull that a little closer?

Mr. STATON. Certainly. My name is Jimmy Staton, and I live in Clarksburg, West Virginia. And I'm the CEO of Columbia Gas Transmission, whose operational headquarters are located here in Charleston. And I appreciate the opportunity to be with you today.

Columbia Gas is a proud member of the West Virginia community. And while we clearly recognize that the incident along our SM–80 pipeline near Sissonville was unacceptable, I want to assure you that we operate with a daily commitment to safety. We have been and will continue to work with all of our focus and our energy to make things right and to learn from this incident.

In the wake of this incident we moved quickly to address the needs of the local residents and agencies. We partnered with the Red Cross to ensure that no necessity was overlooked as we took steps to address longer term issues like home repair and relocations. We are providing full reimbursements to local and state agencies for their emergency response costs and have made charitable contributions to other local entities who pitched in to help following the incident.

We are also working with the NTSB and Administrator Quarterman and her team at PHMSA to identify the cause of the event and apply the findings to our operations systemwide.

The NTSB has noted that line SM–80 had experienced external corrosion. They also confirmed in a preliminary report that Columbia's SCADA system detected a drop in pressure on the pipeline as it was designed to do. SCADA system alerts are a critical first step toward the initiation of our emergency response programs.

We will continue to work cooperatively with these agencies as the NTSB completes its final analysis and will apply lessons learned to our processes, procedures, and all of our pipeline assets.

We are also working with PHMSA to implement an integrity assurance plan that will ensure the long-term safety of the SM–80 pipeline. Our plan is designed to safely return the line to limited service, to facilitate a comprehensive integrity assessment, including an internal or smart pig, as we've talked about today, inspection before we return to full service. A copy of our plan is attached to my written testimony.

In addition to the steps we are taking to address the incident, we are undertaking a systemwide modernization of our pipeline infrastructure. This modernization program is designed to replace and rebuild our pipeline and compression facilities in order to improve the safety, reliability, and efficiency of our system.

Our modernization program includes the replacement of nearly 1,000 miles of older pipelines, provides for pipeline upgrades to expand the use of smart pigs, and the replacement of compression equipment to improve efficiency and environmental performance.

Our modernization program is aligned with the U.S. Transportation Secretary Ray Lahood's call to action as well as key provisions of the recent Pipeline Safety Act that you led reauthorization of a year ago.

We developed our modernization program with the input and assistance of our customers and other stakeholders, and I am pleased to report that the Federal Energy Regulatory Commission recently endorsed our plan by issuing an affirmative order that clears the way for our modernization efforts to continue and more importantly to accelerate.

And some of our most critical modernization projects will occur right here in West Virginia. We will invest close to three-quarters of a billion dollars in West Virginia in the first 5 years of our program alone on projects that will expand our ability to use smart pigs, replace older pipelines and upgrade compressors to improve efficiency and significantly reduce emissions. These infrastructure investments will not only improve safety but will also create jobs and generate new tax revenue for the state and localities.

In closing, we recognize the importance of pipeline safety and are committed to applying the lessons learned from the Sissonville incident. In addition, the pipeline safety legislation you helped enact sought to drive investment in newer and more advanced pipeline systems all in the name of safety. Columbia's modernization program helps accomplish this crucially important goal.

Mr. Chairman, Senator, I was in Sissonville the evening of the event, and I saw the impact on the community. And I also looked at the faces of my employees who work and live in the Sissonville area. And I vowed to them at that time that we would do right and we would make it right for the people of Sissonville and that we would make the right investments, continue to make the right investments to ensure that our system does not incur another incident like this. And I make that same commitment to you all today.

I thank you. That concludes my testimony, and I look forward to your questions.

[The prepared statement of Mr. Staton follows:]

PREPARED STATEMENT OF JIMMY D. STATON, EXECUTIVE VICE PRESIDENT AND GROUP CEO, NISOURCE GAS TRANSMISSION & STORAGE

Introduction

Mr. Chairman and Members of the Committee:

My name is Jimmy Staton. I live in Clarksburg, West Virginia, and I am CEO of NiSource Gas Transmission & Storage, parent company of Columbia Gas Transmission whose operational headquarters are located in Charleston.

Columbia Gas Transmission owns and operates approximately 12,000 miles of natural gas pipelines, including roughly 2,500 miles of pipeline in West Virginia. Our pipeline system is integrated with one of the largest underground storage systems in North America and we deliver domestically produced natural gas to businesses and communities across the Midwest, Mid-Atlantic and Northeast regions of the United States. Through our predecessor companies, NiSource and Columbia Gas have been a safe pipeline operator, an employer of choice and a community partner of West Virginia and surrounding states for more than a century.

Personally, I have worked in the natural gas and energy industry for nearly 30 years—serving in a variety of roles ranging from rates and regulatory to operations and engineering. At no other time during my career has there been such a promising outlook for America's domestic energy potential—and the economic and national security related benefits that comes with it—but that energy potential must be grounded in a daily commitment to operating safely.

At Columbia Gas we take our commitment to safety very seriously. I appreciate the opportunity to share with you the various initiatives we are undertaking to ensure we continue to provide safe and reliable pipeline service.

Sissonville Incident

Mr. Chairman, let me take a moment to provide you with an update on our efforts to respond to the incident that occurred on December 11, 2012, on our Line SM–80 pipeline near Sissonville.

This was a terrible incident—one in which I hope we never see the likes of again. Thankfully, no one was seriously injured. Please be assured that we are fully committed to making this right and taking any steps necessary to ensure the safety of our company's pipeline system.

In working with local emergency responders, we were able to isolate the incident, secure the site, and focus on the following three key areas:

(1) Making the area safe and immediately addressing the needs of any local residents and community agencies impacted by the pipeline incident;

(2) Collaborating with the National Transportation Safety Board (NTSB) and other federal, state and local authorities to identify the root cause of the event and apply "lessons learned" to our operations systemwide; and,

(3) Working proactively with Federal and state officials to design and implement an Integrity Assurance plan that will ensure a safe return to service and the long-term integrity of Line SM–80.

Attending to Community Needs

Immediately following the incident, a team of local Columbia employees identified and made contact with each impacted resident to ensure that basic essentials, including temporary housing, food, and transportation were provided. Our team remained in constant contact with residents to ensure that no necessity was overlooked. In addition, we partnered with the regional office of the Red Cross—to tap into their special expertise, provide additional support for those in need, and facilitate Columbia employees and others in the community looking to help their neighbors through charitable giving. Our team has worked closely with all of the impacted residents to resolve the issues associated with the Line SM–80 incident.

We know this incident impacted the lives of several families living in the area, and we will continue to work to make things right.

We have also been working with various local and state agencies that assisted our efforts to safely secure the incident site. As a longtime West Virginia resident, I know first-hand that during challenging times, we come together to help each other—and that has certainly been the case here. We are grateful for the dedication and commitment of the first responders, the Department of Highways, and other local agencies that provided support and recovery efforts that day. We also have moved quickly to ensure that the operating budgets for these public agencies were not adversely impacted by this incident, and are providing full reimbursements for costs associated with the emergency response services rendered by these groups.

We've also provided contributions to the Aldersgate United Methodist Church and Sissonville High School in recognition of the important role they played in the hours and days following the incident.

We recognize this was a difficult time for Sissonville and Kanawha County. It has been and will continue to be our priority to work proactively with those who were impacted, as well as those who lent a helping hand. We've enjoyed a positive working relationship with a number of local agencies in Kanawha County over our many years of providing service in West Virginia, and we look forward to continuing this cooperative partnership in the future.

Cooperating with the NTSB

As I mentioned earlier, we have been working in close collaboration with the NTSB to determine the cause of the incident and to implement lessons learned across our policies, procedures and pipeline assets. The NTSB has noted, both in press briefings and a recently issued Preliminary Report, that the ruptured line had experienced significant external corrosion.

The NTSB has also confirmed that Columbia's SCADA system detected a drop in pressure in the SM–80 line, as well as the nearby SM–86 and SM–86 Loop pipelines, as designed. Alerts issued by our SCADA system are the first critical step toward the initiation of our Emergency Response plan and the dispatching of personnel to a pipeline rupture site. Columbia's SCADA system is staffed 24-hours a day, seven days a week by trained operations employees to provide a real-time monitoring of the flow of gas through our pipeline system. The proper functioning of our SCADA system and the procedures followed by our Control Room personnel were a crucial component to our response to the Sissonville incident. We will continue to work closely with the NTSB as it produces its final report and are committed to applying lessons learned to our Control Room procedures.

A Safe Return to Service

As NTSB's investigation proceeds, our engineering team has been hard at work developing a comprehensive Integrity Assurance plan [1] to ensure the safe return to limited service for Line SM–80. This line is an important part of a pipeline system that plays a vital role in supplying natural gas to West Virginia and other critical eastern markets.

Our Integrity Assurance plan is designed to help facilitate an advanced internal inspection of the SM–80 pipeline. It addresses a comprehensive Corrective Action Order (CAO) recently issued by the U.S. Department of Transportation's Pipelines and Hazardous Materials Safety Administration (PHMSA). The CAO requires the implementation of a number of measures prior to restarting Line SM–80 to restricted service. We will address each requirement and, in fact, have elected to supplement the order in several important ways in order to provide an even greater level of assurance that we are fully committed to operating safely.

Under the Integrity Assurance plan, Columbia's engineering team will identify and complete the repair work needed to ensure the integrity of the pipeline for operation at a reduced pressure, and ready the line for further evaluation using "smart pig" in-line inspection tools. The work will include: the replacement of mainline valves along a 30-mile stretch of Line SM–80 from the Lanham Compressor Station to Columbia's Broad Run Valve Setting; the installation of launcher and receiver facilities at points along the line to enable passage of in-line inspection tools; a verification that the cathodic protection system is operating properly on all three of Columbia's pipelines in the vicinity of the incident origin; and the installation and adjustment of pressure regulation and overpressure protection equipment to support operation of the pipeline at a safe temporary maximum allowable pressure. These steps will allow us to return the pipeline to a restricted level of service so that additional integrity assessment can be performed. Columbia will then implement the appropriate preventive and mitigative measures based on this assessment to provide

[1] A copy of the Executive Summary of the Columbia Gas Transmission Integrity Assurance Plan as submitted to PHMSA is included in Appendix A. Supporting materials are available upon request.

for the safe return of Line SM–80 to full commercial service and to ensure the long-term integrity of the pipeline.

We will only return Line SM–80 to service once we have received approval from PHMSA and the West Virginia Public Service Commission, as well as communicated with our neighbors in Sissonville. We have also elected to hire an independent monitor experienced in pipeline safety and integrity related issues to provide a third party review of the plan and actions taken by Columbia in the course of carrying it out. The independent monitor will review pipeline integrity plans and inspections and provide feedback to both Columbia and PHMSA on the effectiveness of our work.

Modernization

In addition to our response to the SM–80 incident, Columbia is taking significant steps forward to assure the continued safe operation of our entire pipeline system for generations to come.

Aligning our efforts with the "Call to Action" by U.S. Department of Transportation Secretary Ray LaHood, we developed a comprehensive modernization plan that ensures pipeline and system upgrades; improves public safety, customer reliability and service; and provides economic benefits. This modernization effort will strategically and systematically replace, revamp or rebuild key pipeline and compression facilities across our entire system.

Our Modernization program, which is the first of its kind in the industry, is the culmination of a multi-year effort to evaluate our system and identify areas in need of investment. The program's system improvements include:

- Replacing Aging Infrastructure—replacing approximately 1,000 miles of existing interstate transmission pipelines, primarily bare steel (400 miles in the first five years);
- Expanding In-Line Inspection Capabilities—facilitating Columbia's ability to perform state-of-the-art maintenance and inspections without interrupting service;
- Increasing Pipeline System Reliability—uprating pressures and looping systems where needed to ensure gas is reliably delivered to critical markets; and,
- Upgrading Natural Gas Compression Systems—replacing and modernizing more than 50 critical compressor units along the pipeline system that will enhance system efficiency and improve environmental performance.

We anticipate investing more than $2 billion in this program over the next five years—dollars that will be directly focused on increasing pipeline safety and service reliability.

The Columbia Modernization program is aligned with key provisions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 that you and this Committee led the enactment of one year ago. Recently, Secretary LaHood publicly pledged to support and assist our efforts to navigate the Federal and state permitting process under the auspices of an Executive Order issued by President Obama in March of 2012 aimed at encouraging investment in vital and economically significant national infrastructure.[2]

We developed this initiative with the input and assistance of our customers, and filed a broadly supported settlement agreement with the Federal Energy Regulatory Commission (FERC) in September of last year. Just recently, on January 24, the FERC endorsed our plan by issuing an affirmative order[3] that clears the way for our modernization efforts to continue and accelerate.

A number of our most critical Modernization projects will be occurring in West Virginia. One of the largest of those projects will be the $38 million WB Pipeline project, which will upgrade a number of older pipelines to accommodate in-line inspection equipment, or so-called "smart pigs." Our WB pipeline system runs across central West Virginia and delivers natural gas to the state and other eastern markets. Upgrading this system to accommodate today's latest safety technology will not only allow for enhanced integrity assessment, but it will also greatly improve the efficiency and reliability of the pipeline.

Our plan also calls for over $100 million in critical compression facility upgrades in West Virginia. Three compressor stations have been identified for enhancement at Seneca, Frametown, and Lost River. These investments will provide increased reliability, system flexibility and efficiency. Work at the stations will improve com-

[2] The Department of Transportation press release is attached in Appendix B.
[3] Columbia Gas Transmission, LLC, 142 FERC Paragraph 61,062 (2013), included in Appendix C.

pressor horsepower, dramatically improve emissions performance, and result in a significant reduction in fuel consumption.

In total, over the first six years of our Modernization program, Columbia will invest close to three-quarters of a billion dollars in safety and reliability related improvement projects in West Virginia alone. A recent economic analysis of our program estimates that Modernization will result in more than $1.1 billion in economic output in the state, including the creation or support of approximately 1,700 total jobs at the peak of our program in 2016 ranging from engineering to construction services. In addition to private economic activity, our Modernization investment is anticipated to generate approximately $80 million in new revenue for the State of West Virginia and its units of local government. Most importantly, our work in the state will make our systems safer and more reliable.

Closing

Mr. Chairman, Columbia's Modernization program is good news for pipeline safety and good news for job creation. At its core, the legislation you spearheaded in the 112th Congress sought to drive investment in newer and more advanced pipeline systems and facilities—all in the name of safely and reliably transporting this important resource. Columbia's Modernization program helps accomplish this important goal and will keep us on a solid footing to safely and reliably deliver natural gas to the next generation of natural gas consumers.

As a constituent, I cannot close without thanking you for your public service of nearly 50 years and your tireless dedication to the residents of West Virginia and this Nation.

Thank you for the invitation to appear before the committee today. I am pleased to answer any questions you may have.

APPENDIX A

COLUMBIA GAS TRANSMISSION—INTEGRITY ASSURANCE PLAN (EXECUTIVE SUMMARY)—JANUARY 8, 2013

Columbia Gas Transmission, LLC—January 8, 2013

LINE SM–80—LANHAM TO BROAD RUN—INTEGRITY ASSURANCE PLAN—PHASE 1

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COLUMBIA GAS TRANSMISSION—LINE SM–80

LANHAM COMPRESSOR STATION TO BROAD RUN

INTEGRITY ASSURANCE PLAN—PHASE 1

Executive Summary

On December 11, 2012, at approximately 12:41 p.m., a natural gas pipeline incident involving an ignition and fire occurred in northern Kanawha County, WV, along the 20 inch diameter Columbia Gas Transmission (Columbia Gas) Line SM–80. Line SM–80 is approximately 30 miles long and runs from the Lanham Compressor Station to the Broad Run Valve Setting. In response to the incident, a pipeline segment approximately 8 miles long, from the Lanham Compressor Station to the Rocky Hollow Valve setting, was isolated, blown down and has remained out of service since the time of the rupture. In addition, a section approximately 22 miles long, from Rocky Hollow to the Broad Run valve setting, has been isolated and remains out of service, with a static pressure of less than 300 psig. The maximum allowable operating pressure (MAOP) of Line SM–80 is 1,000 psig, and the discharge pressure at Lanham was approximately 929 psig at the time of the incident.

This integrity assurance plan details the first phase in a four-phase approach designed to implement corrective measures to prevent recurrence, and ensure the safe return to service of Line SM–80. Phase 1 of the plan focuses on making repairs and ensuring the near term safety and integrity of Line SM–80, while preparing the line for Phase 2. Phase 2 focuses on performing a comprehensive integrity assessment of Line SM–80. Based on the integrity assessment, Columbia Gas will implement appropriate preventive and mitigative measures to provide for the safe return of Line SM–B0 to full service and ensure the long-term integrity of the pipeline. Phase 3 includes completion of necessary repairs, summarizing the work completed, requesting regulatory approval to return Line SM–80 to service, and upon approval, restoring normal service to the pipeline. Phase 4 focuses on steps that Columbia Gas will take to document and communicate the work conducted, including keeping regulators informed of progress, maintaining records, and tracking expenditures associated with implementation of this plan.

Phase 1 Key Elements

Phase 1 includes the steps that Columbia Gas will take to repair the damaged sections of the pipeline, ensure the integrity of the pipeline for operation at a reduced/restricted pressure, and ready the pipeline for further evaluation using in-line inspection tools. Key elements of Phase 1 are:

(1) Verification of the integrity of the pipeline in the vicinity of the incident origin

(2) Complete repairs to Line SM–80 at the incident origin

(3) Verification that the cathodic protection (CP) system is operating properly on all three pipelines in the vicinity of the incident origin

(4) Replacement of mainline valves along Line SM–80 from Lanham to Broad

(5) Installation of a temporary launcher at Lanham Station and a temporary receiver at Broad Run to enable the passage of in-line inspection tools (a permanent launcher and receiver will be installed in Phase 2)

(6) Verification of the discharge pressure at Lanham Station immediately prior to the incident to establish a safe temporary maximum allowable pressure

(7) Installation and adjustment of pressure regulation and overpressure protection to support operation of the pipeline at the safe temporary maximum allowable pressure.

(8) Return of Line SM–80 to service at or below the safe temporary maximum allowable pressure on a temporary basis for purposes of conducting an in-line inspection. The pressure will be restored through a stepped approach that includes instrumented leak surveys.

Background

The NTSB conducted a field investigation following the incident. The *NTSB* reported that a 20 foot section of pipe was ejected during the event. The NTSB further reported that the ruptured pipeline was found to have areas consistent with external corrosion. According to the NTSB, visual examination of the ruptured pipe revealed a six foot area that ran along the bottom of the pipe where the pipe thickness was measured to be less than 1/10 inch thick in some places (approximately .078 inch thick). On December 20, 2012, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order (CAO) that requires the implementation of certain measures prior to restarting the pipeline to restricted service.

The purpose of this plan is to detail the work that will be completed both in the vicinity of the incident origin as well as along Line SM–80 from Lanham Compressor Station to the Broad Run valve setting to safely return the pipeline to restricted service so that additional integrity assessment can be completed. This plan also details the other actions Columbia Gas will take to comply with the requirements set out in the CAO issued by PHMSA. As further detailed in this Plan, Phase 1 includes:

Preliminary Cause Determination

- Continue to support the NTSB in the ongoing investigation of the incident and incorporate findings, as appropriate, into the Integrity Assurance Plan.

Repairs to Incident Origin

- Verification of the integrity of the pipeline in the vicinity of the incident origin.
- Repairs to Line SM–80 at the incident origin.

Verification of Cathodic Protection

- Verification that the cathodic protection (CP) system is operating properly on SM–80 and the two adjacent pipelines, SM–86 and SM–86 Loop, within three miles upstream and three miles downstream of the incident origin.

Preparation of Line SM–80 for In-Line Inspection

- Replacement of mainline valves along Line SM–80 from Lanham to Broad Run with new, full bore valves to enable passage of in-line inspection tools.
- Investigation and, where necessary, replacement of other potential restrictions to the passage of in-line inspection tools.
- Installation of a temporary launcher at Lanham Station and a temporary receiver at Broad Run to enable the passage of in-line inspection tools. A permanent launcher and receiver will be installed in Phase 2 (see Element 9 of "Summary and Overview of Integrity Assurance Plan—Phase 2," below).

Safe Return to Temporary Maximum Allowable Pressure

- Verification of the discharge pressure at Lanham Station immediately prior to the incident for establishing a safe temporary maximum allowable pressure.
- Inspection and full operation of all critical valves that might be required during an emergency to ensure they can be completely closed.
- Installation and adjustment of pressure regulation and overpressure protection to support operation of the pipeline at a restricted pressure.
- Return of Line SM–80 to service at or below the safe temporary maximum allowable pressure on a temporary basis for purposes of conducting an in-line inspection. The pressure will be restored through a stepped approach that includes instrumented leak surveys.

In the course of completing the Phase 1 work, detailed documentation of measurements, pipe characteristics, pipe condition, pipe coating characteristics, environmental and other conditions will be collected. This information will be used, where appropriate, to support Phase 2 of the Integrity Assurance Plan. The results of the work outlined in this Integrity Assurance Plan will be shared with PHMSA, as well as the National Transportation Safety Board (NTSB) and the West Virginia Public Service Commission (WVPSC).

Safety

Employee and public safety will be the highest priority in the course of conducting the work outlined in this plan. All work will be conducted in a safe manner and will comply with all Columbia Gas safety plans and procedures. Daily safety meetings will be held that will include employees, contractors and authorized visitors at the beginning of each work day. All company and state required one-calls shall be completed and the site cleared before any excavation activities occur. In addition, all persons performing tasks covered by 49 CFR Part 192, Subpart N shall be qualified according to the Columbia Gas Operator Qualification Plan.

Independent Review and Monitoring

Columbia Gas will hire a qualified outside contractor ("independent monitor") experienced in pipeline safety and pipeline integrity related issues to provide independent third party review and monitoring of the Integrity Assurance Plan prepared for Line SM–80 and the actions taken by Columbia Gas in the course of carrying out the work specified in the Plan. The independent monitor will (1) review and provide feedback to Columbia and PHMSA concerning the prudence and effectiveness of plans for verification of the integrity of Line SM–80, (2) review the results of inspections, tests and analysis completed for Line SM–80 during the course of this plan, (3) review the actions taken pursuant to the plan to ensure that they are reasonable and prudent, and (4) provide PHMSA with a quarterly report of progress towards compliance with the CAO and the Columbia Gas Integrity Assurance Plan.

Preliminary Cause Determination

Following the Line SM–80 pipeline incident, an investigation into the cause of the incident was initiated by the National Transportation Safety Board (NTSB). As stated, the NTSB has reported that the ruptured pipeline was found to have areas consistent with external corrosion and that visual examination of the ruptured pipe revealed a six foot area that ran along the bottom of the pipe where the pipe thickness was measured to be less than 1/10 inch thick in some places (approximately .078 inch thick). The NTSB, however, has not released a preliminary cause determination, and the investigation is ongoing.

Columbia Gas has been fully cooperating with the NTSB investigation and is committed to supporting the ongoing investigation of the incident. Columbia Gas has provided and will continue to provide requested information and support to the NTSB and will incorporate, as appropriate, the findings of the investigation into the Integrity Assurance Plan.

Repairs to Incident Origin

The removed sections of pipe near the rupture origin will be replaced with new, coated pipe. Repair and testing of the pipe will follow the Pipe Repair, Modification and Hydrostatic Testing Plan provided in Attachment A. Up to approximately four joints (160 feet) of new 20 inch diameter, 0.375 wall thickness, API–5L X65 pipe will be installed at the location, The pipe will be hydrostatically tested for not less than eight hours at a minimum test pressure of 2,438 psig (100 percent SMYS). The minimum test pressure of 2,438 psig is equivalent to 244 percent of the pipeline MAOP of 1,000 psig.

All girth welds will be non-destructively tested in accordance with the Columbia Gas Welding Manual and will be coated with a 100 percent solids two-part epoxy in accordance with Procedure 70.001.026 External Coating—Underground Facilities—New Construction or Maintenance Application (See Attachment B). In addition, the pipe will be supported with sand bags, covered in rock shield, and soft fill will be installed below and around the pipe to ensure the pipe is protected from damage. Prior to backfilling the pipe, an instrumented inspection of the coating will be performed in accordance with Procedure 70.001,013—Inspect Pipe Coating with Holiday Detector (See Attachment C).

Verification of Cathodic Protection

Columbia Gas will inspect and verify the proper operation of all CP rectifiers, test stations and other CP equipment on Lines SM–80, SM–86 and SM–86 Loop within three miles upstream and three miles downstream of the incident origin. CP inspections will be completed after the pipe replacements described in the previous section. Inspections will include test station and rectifier readings that will be performed in accordance with Procedures 70.002.008—P/S Reading—Test Stations, 70.002.001-Readings—Casing and 70.002.003—Reading—Rectifier (See Attachment D) and will be documented in the company Work Management System. Any deficiencies will be documented and remediated prior to continuing the Phase 1 Plan.

Preparation of Line SM–80 for In-Line Inspection

Line SM–80 from Lanham Compressor Station to the Broad Run valve setting is currently not equipped to allow the passage of in-line inspection tools. Pipe replacements, equipment replacements and facility enhancements, as follows, will be performed to prepare the pipeline for the passage of in-line inspection tools:

- The existing mainline plug valves on Line SM–80 at Rocky Hollow and Patterson Fork Valve Settings will be removed and replaced with new ball valves that will support the passage of ILI tools. The replacement and testing of the pipe at these locations will follow the Pipe Repair and Hydrostatic Testing Plan shown in Attachment A. Pipe exposed during the course of the valve replacement work will be inspected following the Columbia Gas pipe inspection protocols (see Attachment E).
- A review of pipe materials and mapping will be completed to identify any other restrictions that would inhibit the passage of in-line inspection tools. Where such restrictions are identified they will be investigated and, if necessary, replaced to ensure the passage of in-line inspection tools. The replacement and testing of the pipe at these locations will follow the Pipe Repair and Hydrostatic Testing Plan shown in Attachment A. Pipe exposed during the course of investigation or replacement work will be inspected following the Columbia Gas pipe inspection protocols (see Attachment E).
- Temporary launchers and receivers sized and compatible with high resolution in-line inspection tools will be installed. A temporary launcher will be installed at Lanham Compressor Station and a temporary receiver will be installed at the Broad Run Valve setting. Due to the long lead time associated with permanent launchers and receivers, temporary facilities will be used to allow for in-line inspection in the near term. However, permanent facilities will be fabricated and installed in Phase 2, and will be installed prior to the return of Line SM–80 to full service. See section titled "Summary and Overview of Integrity Assurance Plan—Phase 2".

- All girth welds will be non-destructively tested in accordance with the Columbia Gas Welding Manual and will be coated with a 100 percent solids two-part epoxy in accordance with Procedure 70.001.026 External Coating—Underground Facilities (See Attachment *B). In* addition, the pipe will be supported with sand bags, covered in rock shield, and soft fill will be installed below and around the pipe to ensure the pipe is protected from damage. An instrumented inspection of the coating will be performed prior to backfilling the pipe in accordance Procedure 70.001.013 Inspect Pipe Coating with Holiday Detector (See Attachment C).

A drawing showing the areas along SM–80 where work is planned to prepare the line for the passage of in-line inspection tools is included in Attachment F.

Safe Return to Temporary Maximum Allowable Pressure

The following measures will be taken to ensure the integrity of Line SM–80 before it is returned to restricted service.

- Repairs—Any actionable anomalous conditions discovered on the SM–80 pipeline during the course of completing Phase 1 of the Integrity Assurance Plan will be repaired following Operations and Maintenance Plan 220.02.01 Pipeline Repair (see Attachment G).
- Critical Valves—All critical valves along the SM–80 pipeline system from Lanham to Broad Run that may be required during an emergency will be inspected and fully operated to ensure that they can be completely closed. Valve inspections will follow Plan 220.03.02 Valve Inspection and Operation and Procedure 220.002.001 inspection & Operation—Valve (see Attachment H) except that each valve will be fully operated. A schematic depicting all critical valves that will be inspected and operated is provided in Attachment I.
- Discharge Pressure Review and Validation—A report validating the SM–80 discharge pressure at Lanham Compressor Station at the time of the incident is included in Attachment *J.* Columbia Gas has reviewed SCADA pressure data and has validated that the discharge pressure at Lanham Compressor Station on Line SM–80 at the time of failure was greater than,929 psig, which Supports a temporary MAOP of 741 psig (80 percent of 929 psig). However, due to favorable market conditions, Columbia Gas has determined that additional safety measures can be taken and will further restrict the temporary MAOP to 600 psig for the duration of the Integrity Assurance Plan.
- Return to Service under Temporary Maximum Allowable Operating Pressure—Once the pipeline repair work is completed, the measures prescribed in this plan have been satisfactorily completed, and approval is received from the Director of the PHMSA Eastern Region, Columbia Gas will follow the Return to Service plan provided in Attachment K, to safely return Line SM–80 to restricted operation for purposes of conducting an in-line inspection. Columbia Gas plans to return the pipeline pressure to no more than is necessary to efficiently and effectively conduct an in-line inspection on Line SM–80 between Lanham and Broad Run (not to exceed 600 psig). After successful completion of the necessary in-line inspections, Columbia Gas will isolate Line SM–80 from other sources of natural gas supply and reduce the pressure of the pipeline to below 300 psig until completing the remaining requirements of this Integrity Assurance Plan and PHMSA has granted the necessary approvals to restore full service to the pipeline.
- The Return to Restricted Service Plan (Attachment K) requires step increases in pressure in quarter increments up to the temporary MAOP of 600 psig. Each quarter step will be followed by a 30 minute idle period. Following each 30 minute idle period, an instrumented leak survey will be conducted over the entire pipeline using instrumented aerial patrol. In addition, an on-ground instrumented leakage patrol will be conducted for 300 feet upstream and downstream from the incident location. Any leaks discovered will be investigated and resolved before continuing the quarter step process. 24 hours after the fourth pressure increment is completed, another set of aerial and ground leak surveys will be conducted. Any leaks discovered will be investigated and resolved as soon as practical, but within 24 hours.
- The Return to Restricted Service Plan will be initiated only during weather conditions conducive to ensure successful aerial leakage patrol of the pipeline (not during periods of high winds or severe weather). Should conditions change during implementation of the Return to Restricted Service Plan and aerial patrol can no longer be effectively conducted, the pressure on the pipeline will be low-

ered to the previous step up in pressure until effective aerial patrol can be completed.

- All pressure control and overpressure protection devices will be set to ensure that the temporary MAOP of 600 psig will not be exceeded. Line SM–80 will continue to be isolated from Line SM–86 and SM–86 Loop while the temporary maximum allowable operating pressure is in effect. Overpressure protection devices at Lanham Compressor Station will be used to limit the operating pressure at or below the pressure necessary to effectively and efficiently run the in-line inspection tools, and in no case above 600 psig.

Preliminary Phase I Schedule

The schedule for completion of tasks outlined in this Phase 1 plan is dependent upon many factors including receipt of environmental and other clearances, weather, availability of materials and other factors. A Gantt chart containing a preliminary schedule for the completion of each major item outlined in this plan is included in Attachment L. This schedule is based upon information known at this time and is subject to change as actions under this plan are carried out.

Summary and Overview of Integrity Assurance Plan—Phase 2

Upon completion of Phase 1 of the Integrity Assurance Plan, Line SM–80 will have been repaired at the rupture site and verified safe for a return to service at a temporary maximum allowable pressure not to exceed 600 psig for purpose of performing additional integrity assessment. Line SM–80 will have been made capable of passage of in-line inspection tools and additional work will have been completed to aid in the comprehensive integrity assessment of Line SM–80.

Following the successful completion of Phase 1, Columbia Gas will seek approval from the Director of PHMSA Eastern Region for initiation of a Phase 2 plan. The Phase 2 plan will be documented and submitted for approval prior to initiation. Key elements of the Phase 2 plan will include:

1. Continued support of the ongoing NTSB investigation and incorporation, as appropriate, of findings of the investigation into the Integrity Assurance Plan.
2. Verification of Line SM–80 pipe properties and data to ascertain if records reflect actual pipe specifications, including representative sampling with bell-hole excavation, inspection and validation.
3. Verification of MAOP records for Line SM–80 and implementation of corrective measures if records do not substantiate current MAOP.
4. The SM–80 pipeline from Lanham to near Broad Run will be prepared for the passage of instrumented in-line inspection tools by running cleaning pig(s) and a pig equipped with a gauge plate to further ensure that there are not restrictions for the in-line inspection tools. Columbia plans to conduct an in-line inspection using Baker Hughes 20 inch high resolution magnetic flux leakage (MFL) and high resolution caliper ILI tools coupled with an inertial mapping unit along Line SM–80, from Lanham to Broad Run.
5. After successful completion of the necessary in-line Inspections, Columbia will isolate Line SM–80 from other sources of natural gas supply and reduce the pressure of the pipeline to below 300 psig until such time as Columbia has completed the necessary steps under this Integrity Assurance plan and PHMSA has granted the necessary approvals to restore full pressure service to the pipeline.
6. Investigation of anomalies and repairs (as necessary), based on *ILI results*
7. Performance of a close interval survey from Lanham to Broad Run of Lines SM–80, SM–86 and SM–86 Loop.
8. Performance of a coating integrity survey and correction of any deficiencies in areas where the survey indicates potentially inadequate cathodic protection (*i.e.,* where readings fail to meet the criteria of 49 CFR Part 192, Subpart I).
9. Installation of a permanent launcher at the Lanham Compressor Station and permanent receiver at Broad Run on Line SM–80, to enable the passage of in-line inspection tools in the future.
10. Establishment of a long term integrity assurance and reassessment plan for Line SM–80 for incorporation into the Columbia Gas Integrity Management Plan.
11. Columbia Gas will contract with a qualified contractor to provide a geotechnical survey of Line SM–80 between Lanham Compressor Station and Broad Run to identify any areas of significant earth movement within the

pipeline right of way that could adversely impact the pipeline. Any such areas identified will be investigated and remediated, as necessary.

Criteria—Assessment, Repair, Documentation, Request for Approval and Restoration of Full Service—Phase 3

The following elements will be completed under Phase 3:

1. Columbia Gas will complete the assessment in Phase 2 and perform any necessary repairs by December 20, 2013.
2. Columbia Gas will maintain records of all work performed as part of the Integrity Assurance Plan and will prepare a complete package of information for presentation to the PHMSA Eastern Region, once the steps under Phase II have been completed. Based on successful completion of the Integrity Assurance measures, Columbia Gas will present this information and seek PHMSA Eastern Region approval to return Line 5M–80 to full and normal service.
3. Line SM–80 will only be returned to normal service after all work has been successfully completed and approval has been granted by the Director of the PHMSA Eastern Region.

Conclusion Criteria—Periodic and Summary Reporting and Documentation—Phase 4

Columbia Gas will take steps to ensure that PHMSA is kept informed of progress during each phase of implementation of this plan, will provide summary reports and will maintain documentation and report certain expenditures associated with implementation of this plan as further detailed below:

1. Monthly reports for Phase 1—Columbia Gas will submit monthly reports to the Director of the PHMSA Eastern Region that: (1) include all available data and results of the testing and evaluations required by the CAO; and (2) describe the progress of the repairs or other corrective and/or remedial actions undertaken. The first monthly report is due by the third of each month until Phase 1 has been completed. The Director may adjust the reporting period upon written request of Columbia Gas.
2. Quarterly Reports for Phase 2 Columbia Gas will submit quarterly reports to the Director of PHMSA Eastern Region that: (1) include all available data and results of the testing and evaluations required by the CAO; and (2) describe the progress of the repairs or other corrective and/or remedial actions being undertaken. The first calendar quarterly report is due once Phase I has been completed, as determined by the Director of the Eastern Region. There should be four quarterly report submissions while this order is still in effect.
3. Summary Report for Phase II—Once Phase 2 has been completed, a composite summary of all work performed will be assembled and presented to the Director of the PHMSA Eastern Region. The Director will review the summary as part of the consideration for approval to return Line 5M–80 to normal service.
4. Documentation—Columbia Gas will maintain documentation of the costs associated with the implementation of the CAO and will include in each monthly report submitted the to-date costs associated with: (1) preparation and revision of procedures, studies and analysis; (2) physical changes to the pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

APPENDIX B

U.S. Department of Transportation Press Release—April 20, 2012

SECRETARY LAHOOD PLEDGES SUPPORT TO EXPEDITE PIPELINE MODERNIZATION PROJECT

Increased Safety, More Energy Capacity & Thousands of New Jobs

PITTSBURGH, Pa.—U.S. Department of Transportation Secretary Ray LaHood today announced that the agency will lead the effort to help expedite Federal permitting for a 1,000 mile pipeline modernization project by NiSource, Inc. that will produce thousands of jobs, enhance safety and increase energy capacity.

"A year ago, I asked pipeline operators to take a hard look at their infrastructure and identify those sections of pipeline that need to be repaired, rehabilitated or replaced to ensure safer and more reliable delivery of energy resources," said Secretary LaHood. "And we are happy to help NiSource speed up construction and replace some of the oldest pipelines in the nation, ensuring good jobs and increased safety for people in Pittsburgh, as well as throughout Pennsylvania and the other states that will benefit from this project.''

Secretary LaHood and PHMSA Administrator Cynthia Quarterman met with Pittsburgh Mayor Luke Ravenstahl and representatives from NiSource in Pittsburgh today to pledge their support in expediting the construction. NiSource, Inc. has announced it will modernize its Columbia Gas Transmission, LLC gas transmission and storage system by replacing aging infrastructure that serves communities in six states, including the Marcellus shale gas production region, where the majority of the pipeline infrastructure is more than 40 years old and running on inefficient platforms.

Project Spans Six States

This massive modernization project will take place in Kentucky, Maryland, Ohio, Pennsylvania, Virginia and West Virginia, and it will promote the safe and reliable delivery of energy resources across the Midwest, Mid-Atlantic and Northeastern regions of the United States. NiSource projects that the modernization project will:

- Invest $4 billion over 10 to 15 years, beginning in 2012;
- Produce an estimated 7,000 to 8,000 direct jobs by replacing aging infrastructure with safer and more reliable pipelines; and
- Replace approximately 1,000 miles of large diameter pipeline using domestic-made steel.

''A modern pipeline infrastructure is crucial for the efficient and safe delivery of our nation's resources, and this is exactly the kind of project that government should help facilitate,'' said PHMSA Administrator Cynthia Quarterman. ''We will help them work through the process, and make sure the project is constructed safely.''

A year ago, Secretary LaHood issued a *Call to Action* to the nation's pipeline operators, asking them to take a hard look at their infrastructure and identify pipelines that need to be repaired, requalifed or replaced to ensure safer and more reliable delivery of energy resources. This project is also in accordance with the President's Executive Order to Improve Performance of Federal Permitting and Review of Infrastructure Projects.

''I commend Pennsylvania for making pipeline safety a priority by passing the Gas and Hazardous Liquids Pipeline Act,'' said Secretary LaHood. ''This is personal for all of us—none of us ever want to see another tragedy like the one that happened in Allentown.''

DOT will coordinate with other government entities to identify opportunities to remove overlaps and expedite the regulatory and approval processes without sacrificing safety or lowering industry standards.

About PHMSA

There are more than 2.5 million miles of pipelines that deliver oil and gas to communities and businesses throughout the United States. PHMSA provides information and resources to the public to help them stay safe around pipelines through its *Pipeline Safety Awareness website, State Pipeline Profiles* and pipeline safety workshops for operators and emergency responders. PHMSA also urges the public to learn more about 811, a toll-free number that everyone should call before beginning any excavation project.

The Pipeline and Hazardous Materials Safety Administration develops and enforces regulations for the safe, reliable, and environmentally sound operation of the Nation's 2.5 million mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air. Please visit http://phmsa.dot.gov for more information.

APPENDIX C

142 FERC ¶ 61,062

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

Columbia Gas Transmission, LLC Docket No. RP12–1021–000

ORDER APPROVING CONTESTED SETTLEMENT

(Issued January 24, 2013)

1. On September 4, 2012, Columbia Gas Transmission, LLC (Columbia) filed with the Commission a Stipulation and Agreement of Settlement (Settlement) that represents a settlement of Columbia's base rate levels and other issues related to the repair and maintenance of Columbia's aging pipeline system. According to Columbia, the Settlement represents a collaborative resolution between Columbia and the vast majority of its shippers to address complex issues arising from recent and anticipated changes in pipeline safety requirements and the aging nature of Columbia's system. As discussed below, we approve the contested Settlement on the basis that it provides an overall just and reasonable result.

Background

2. Columbia states that the Settlement arose from Columbia's comprehensive evaluation of its interstate pipeline transmission facilities, which identified areas for rehabilitation or replacement in order to modernize its system, improve system integrity, and enhance service reliability and flexibility. According to Columbia, approximately 73 percent of the 12,000 miles of its system subject to the United States Department of Transportation's (DOT) regulation was constructed before the enactment of Federal pipeline safety standards in 1970. In addition, Columbia states that its system contains approximately 1,272 miles of bare steel pipeline, which is at higher risk for corrosion and failure. According to Columbia, this is significantly more bare steel pipeline than any other interstate pipeline subject to DOT regulation. Columbia states that the majority of its system cannot accommodate in-line inspection and cleaning tools.

3. Columbia also states that approximately 55 percent of its more than 300 compressor units were installed before 1970. Columbia states that it has 18 compressor facilities, with 57 compressor units, which must be available 100 percent of the time during the November to March winter period in order to ensure that Columbia can make all of its firm deliveries.

4. Columbia states that its evaluation of its interstate facilities identified a number of specific rehabilitation and modernization projects that comprise its Modernization Program. Columbia states that pursuant to its Modernization Program, the pipeline will make significant capital expenditures over the next 10 to 15 years to modernize its interstate pipeline system infrastructure, and to enhance the system's reliability, safety and regulatory compliance. These projects focus on replacing high pressure bare steel pipelines and pipelines with a history of failure in locations where there is the greatest risk that a pipeline failure would cause a disruption of service or threaten public safety. These projects also focus on modernizing compressor units along constrained mainlines serving a broad customer base.

5. Columbia avers that the Settlement represents a fair and balanced resolution of numerous issues relating to Columbia's base rate levels, the Modernization Program, and the recovery of revenue requirements associated with the Program.

The Settlement

6. Columbia's September 4, 2012 Settlement generally provides for the following:

- An annual $35 million rate reduction (retroactive to January 1, 2012), and an additional base rate reduction of $25 million each year beginning January 1, 2014, both reductions to end on the effective date of Columbia's next Natural Gas Act (NGA) section 4 general rate case, or a subsequent NGA section 5 rate adjustment.
- Initial refunds to firm shippers of $50 million in two equal installments.

- A rate moratorium through January 31, 2018 and an NGA section 4 general rate filing obligation no later than February 1, 2019.
- A capital cost recovery mechanism (CCRM), through which Columbia would recover the revenue requirements associated with the Modernization Program.
- A revenue sharing mechanism under which Columbia will refund to its customers 75 percent of any base rate revenues it collects over $750 million in any year after January 1, 2012.
- The standard of review for future changes to the Settlement is the just and reasonable standard.

7. Pursuant to the Settlement, the CCRM would recover the costs (up to $300 million annually, subject to a 15 percent tolerance) associated with "Eligible Facilities" that have been placed in service and remain in service. The Settlement includes an initial five-year term for the CCRM (January 1, 2014 –January 1, 2019) to recover costs Columbia incurs during the 2013–2017 period as part of the Modernization Project. Appendix E to the Settlement identifies the specific eligible replacement and upgrade projects that Columbia intends to undertake each year between 2013 and 2017, and the estimated costs of each project. Appendix E sets forth the location of each pipeline replacement and looping project and the number of miles of pipeline to be replaced or constructed in each project. Appendix E also identifies the location of each compressor unit to be replaced, the horse power of the replacement compressor unit, and which existing units will be converted to standby service.

8. Section 7.2 of the Settlement requires Columbia to obtain the consensus of 75 percent of the shippers paying the CCRM rate (determined by billing determinants) to add, remove or substitute Eligible Facility projects, or to modify an Eligible Facility. Columbia retains the discretion to unilaterally perform projects that it reasonably believes could lead to imminent unsafe conditions, including replacing bare steel pipeline, subject to the cost and scope limitations otherwise applicable to projects eligible for CCRM recovery. Columbia also agrees to a $100 million annual capital maintenance expenditure for transportation and storage projects that will not be recouped through the CCRM recovery mechanism, and to use any amounts less than $100 million spent in a given year as a reduction to plant investment. Storage and gathering projects are also specifically excluded from recovery as Eligible Facilities.

9. The Settlement provides for Columbia to earn a return on the capital costs included in the CCRM through a total net rate base multiplier of 14 percent, made up of a pre-tax rate of return of 12 percent, and Taxes Other Than Income of 2 percent. Columbia will recalculate the CCRM on an annual basis. Further, Columbia states that, in order to provide rate stability and safeguard shippers against losses in billing determinants, the Settlement requires Columbia to calculate the annual per unit CCRM rate based on the greater of (1) actual annual billing determinants for all non-incremental rate customers adjusted for discounting [1] or (2) an agreed-upon minimum level of billing determinants (billing determinant floor). The Settlement provides that in each annual CCRM filing, Columbia will true up any over or under-recovery of its CCRM revenue requirement during the preceding year.[2] However, if Columbia's discounted rate transactions reduce Columbia's CCRM revenue below the level that would result from the billing determinant floor, Columbia must impute the revenue it would achieve by charging the maximum rate for service at the level of billing determinant floor. Columbia must also assume that all negotiated rate transactions are at the maximum rate. Absent agreement of the parties and approval of the Commission, the CCRM will not be used to recover Modernization Program costs incurred after 2017.

10. Columbia states that the CCRM will avoid "pancaking" NGA section 4 rate cases. Columbia also claims the CCRM will make the rate review process more efficient by limiting the scope of an annual review to whether Columbia's actual capital

[1] The Settlement treats the CCRM as an add on to Columbia's base rate and provides that Columbia will attribute any discounts to the total base rate, including the CCRM add-on, proportionately between the CCRM and the remainder of the applicable base rate.

[2] Section 7.7 of the Settlement provides that each CCRM Rate calculation will include an annual true-up so that any over-or under-recovery of revenue requirements from the previous year shall be recovered in the next succeeding CCRM Rate filing, calculated each year (subject to the annual and overall CCRM caps) by comparing the actual revenue requirements to the revenues received during the recovery period. The Settlement provides that each subsequent annual CCRM filing shall include revenue requirements related to Eligible Facilities placed in service during the prior November 1 through October 31 period, except that if the CCRM remains in place for the full five year Initial Term, the final year of the CCRM shall include revenue requirements related to the Eligible Facilities placed in service during November and December of 2017.

expenses in the past year meet its Eligible Facilities Plan. The Settlement also provides that Columbia will remove its existing daily scheduling penalty provision from its tariff.

11. The Settlement provides that Columbia will not propose any new cost tracking mechanism during the term of the Settlement.

12. The Settlement states that Columbia will not propose market based rates for new storage projects during the term of the Settlement.

13. The Settlement provides that it is not precedential and is being agreed to only in light of existing circumstances on Columbia's system, particularly that approximately 50 percent of Columbia's system was constructed prior to 1960 and approximately 55 percent of Columbia's compressor units were installed prior to 1970. In addition, Columbia's system contains approximately 1,272 miles of bare steel pipeline subject to DOT regulation, and the majority of the system cannot accommodate in-line inspection and cleaning tools.

14. The Settlement also provides for the severance of the direct interests of Contesting Parties, and an option for Columbia to withdraw the settlement offer if there are contesting parties that represent 10 percent or more of total peak day transportation entitlements on the system.

Comments on Settlement

15. Numerous customers from all sectors of the industry filed in support of the Settlement.[3] Those customers filing in support all note that given the unique circumstances of Columbia's system, the Settlement represents a fair and balanced resolution that allows Columbia to make critical necessary modernization upgrades to its system while providing its customers with real and meaningful benefits in terms of both improved services and flexibility through the modernization efforts, and rate relief and predictability. The supporting customers note that Columbia's system serves customers in eleven states and the District of Columbia and provides significant take away capacity for gas producers in the expanding Marcellus and Utica shale plays.[4] The customers state that they will benefit from increased operational flexibility and reliability, as well increases in public safety, as a result of the Modernization Program. Those customers also specifically identify the Settlement's significant base rate reduction, the retroactive decrease in base rates, the $50 million in refunds, the revenue sharing provision and the rate predictability resulting from the moratorium as key rate components underlying their support of the Settlement. Exelon, NiSource, the Virginia Cities, and others also note that by allowing Columbia to recover the costs associated with the necessary system upgrades through the CCRM, it can avoid successive rate case filings and the inherent financial costs and distractions of resources associated with protracted litigation. Chesapeake notes that customers also benefit through Columbia's agreement to spend $100 million annually on maintenance, and the fact that the CCRM recovery mechanism is capped on both an annual and full program basis. It also approves of the fact that the CCRM proposal specifically identifies projects and provides shippers with the right to monitor and challenge Columbia's expenditures. In sum, Columbia's shippers support the Settlement because they find the CCRM to be a fair mechanism for Columbia to complete and recover the costs of needed system modernizations that will enable Columbia to maintain the integrity and reliability of its system and protect the public's safety, while also providing the customers with immediate and concrete benefits in the form of rate reductions and predictability.

16. Only the Maryland Public Service Commission (Maryland PSC) opposes the Settlement. It asserts that the surcharge mechanism proposed to recover the costs of the Modernization Program is an inappropriate method to recover capital costs, and generally challenged the 14 percent rate base multiplier to be used to determine a pre-tax rate of return and taxes other than income taxes to be recovered through the CCRM. According to the Maryland PSC, it and the Commission have repeatedly considered trackers such as the CCRM to be inappropriate for core infrastructure spending because they reduce the pipeline's incentive to maximize revenues and minimize costs. The Maryland PSC also asserts that the CCRM would shift the burden of investment costs from Columbia to its customers, and its approval could start the slide down a slippery slope toward such mechanisms replacing rate cases as the

[3] Those filing comments in support of the Settlement include Cabot Oil and Gas Corporation (Cabot), Exelon Corporation (Exelon), the NiSource Delivery Companies (including Columbia Gas of Maryland), New Jersey Natural Gas Company and NJR Energy Services Company (NJR), Waterville Gas and Oil Company, The Cities of Charlottesville and Richmond, Virginia (Virginia Cities), Interstate Gas Supply, Indicated Shippers, Duke Energy of Ohio and Duke Energy of Kentucky, Antero Resources Appalachian Corporation, and Chesapeake Energy Marketing, Inc. (Chesapeake).

[4] *See, e.g.,* Comments of Cabot.

primary method for recovering major investment costs. The Maryland PSC also argues that the Commission has consistently disallowed such mechanisms, including recently rejecting a similar surcharge to recover safety charges,[5] because recovering such costs in a surcharge is contrary to the requirement in the Commission's regulations[6] to design rates based on estimated units of service.

17. In its reply to the Maryland PSC's protest, Columbia asserts that the Settlement represents a comprehensive package that enjoys the unanimous support of Columbia's shippers, and that the CCRM and rate base multiplier challenged in the protest are two integral components of the indivisible Settlement. Columbia asserts that the Settlement includes numerous protections insisted on by its shippers to ensure that Columbia has the incentive to perform the modernization work efficiently and effectively, including specifically defining the Eligible Facilities for which costs may be recouped by the CCRM, and placing caps on the recoverable amounts so that Columbia is at risk for costs that fall outside the scope of the defined projects and for any costs that exceed the caps. Columbia further asserts that the Settlement contemplates significant shipper oversight through a requirement for annual meetings to review projects and costs for the past period and for the upcoming year. Columbia also states that the Settlement limits each annual rate filing to recovery of revenues related to Eligible Facilities that are placed in service between November 1 and October 31 of the prior year. Columbia also claims that the Settlement is consistent with, and supported by, the Commission's policy strongly supporting negotiated settlements as a means of providing regulatory certainty and administrative efficiencies for the Commission and the parties, by avoiding lengthy and costly rate proceedings. Finally, Columbia argues that the Commission should not allow the Maryland PSC's protest to prevent Columbia's shippers from realizing the substantial benefits afforded by the Settlement.

Discussion

18. In order to approve Columbia's proposed Settlement over the objections of the Maryland PSC, the Commission must find that the settlement is just and reasonable.[7] In determining whether to approve a contested settlement under that standard, section 385.602(h)(1)(i)[8] of the settlement rules permits the Commission to decide the merits of the contested issues, if the record contains substantial evidence on which to base a reasoned decision, or if the Commission determines there is no genuine issue of material fact. In addition, as the Commission held in *Trailblazer,* even if some individual aspects of a settlement may be problematic, the Commission still may approve a contested settlement as a package if the overall result of the settlement is just and reasonable.[9]

19. As discussed more fully below, after considering the Maryland PSC's comments opposing the Settlement, the Commission finds that those comments do not raise any genuine issue of material fact. The Commission also finds that the overall result of the settlement is just and reasonable. Therefore, the Commission approves the Settlement for all parties, including the Maryland PSC and the local distribution companies subject to regulation by the Maryland PSC.

20. Maryland PSC's primary objection to the Settlement raises a policy issue, rather than any issue of fact: namely that the CCRM is contrary to the Commission's policy that capital costs incurred to comply with the requirements of the pipeline safety legislation should not be included in a cost-of-service tracking mechanism which guarantees the pipeline's recovery of those costs.[10] As Maryland PSC points out, the Commission has stated that pipelines commonly incur capital costs in response to regulatory requirements intended to benefit the public interest, and recovering those costs in a tracking mechanism is contrary to the requirement, in section 284.10(c)(2) of our regulations to design rates based on estimated units of service.[11] This requirement means that the pipeline is at risk for under-recovery of its costs

[5] Maryland PSC Protest at 2 (citing *Granite State Gas Transmission, Inc.,* 132 FERC ¶ 61,089 (2010) (*Granite State*)).

[6] 18 C.F.R. § 284.10(c)(2) (2012).

[7] *Trailblazer Pipeline Co.,* 85 FERC ¶ 61,345, at 62,339 (1998), *reh'g,* 87 FERC ¶ 61,110 (1999), *reh'g,* 88 FERC ¶ 61,168 (1999) (*Trailblazer*) (citing *Mobil Oil Corp.* v. *FERC,* 417 U.S. 283, 314 (1974)).

[8] 18 C.F.R. § 385.602(h)(1)(i) (2012).

[9] *Trailblazer,* 85 FERC ¶ 61,345 at 62,342–3, explaining what that order described as the second of three approaches the Commission has used to approve contested settlements, without severing the contesting parties.

[10] *Florida Gas Transmission Co.,* 105 FERC ¶ 61,171, at PP 47–48 (2003) (*Florida Gas*), distinguishing such capital costs from security-related costs which may be included in a surcharge mechanism under the policy set forth in *Extraordinary Expenditures Necessary to Safeguard National Energy Supplies,* 96 FERC ¶ 61,299 (2001); *Granite State,* 132 FERC ¶ 61,089 at P 11.

[11] *Florida Gas,* 105 FERC ¶ 61,171 at P 47.

between rate cases, but may retain any over-recovery. As the Commission explained in Order No. 436, this gives the pipeline an incentive both to (1) "minimize costs in order to provide services at the lowest reasonable costs consistent with reliable long-term service"[12] and (2) "provide the maximum amount of service to the public."[13] Cost-trackers undercut these incentives by guaranteeing the pipeline a set revenue recovery. Thus, in accordance with this policy, in *Florida Gas* and *Granite State,* the Commission rejected proposals for safety cost trackers, with true-up mechanisms, made in NGA section 4 filings. The Commission has, however, permitted such a regulatory surcharge for pipeline safety costs in uncontested settlements.[14]

21. The Commission recently followed this policy when it rejected a protested proposal by CenterPoint Energy—Mississippi River Transmission, LLC (MRT), in an NGA general section 4 rate case filing, to recover regulatory safety costs through a tracker with a true-up mechanism.[15] The order in that proceeding noted, however, that while the Commission was rejecting MRT's proposed safety tracker consistent with existing policy, that decision was based in part on the fact that the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) is in the early stages of developing regulations to implement the 2011 Act. The Commission stated that it is open to considering the need for additional action as the PHMSA process moves forward and pipelines face increased regulatory requirements.

22. In this case, the Commission finds that the Settlement and the CCRM provide a reasonable means for Columbia to recover the substantial costs of addressing urgent public safety and reliability concerns, without undercutting Columbia's incentives to operate efficiently and to maximize service to the extent that previously proposed and rejected surcharges would have done. As stated by Columbia, approximately half of its pipeline infrastructure regulated by the DOT is over fifty years old, approximately 55 percent of its compressors were installed before 1970 and there is limited horsepower back-up at many critical locations. In addition, the system contains approximately 1,272 miles of potentially dangerous bare steel pipeline, many of its control systems run on an obsolete platform and because the older part of the system was not designed to accommodate in-line inspection, Columbia will only be able to inspect approximately thirty-five percent of the DOT regulated portion of its system using modern in-line inspection tools. Our approval of the Settlement and the CCRM will facilitate Columbia's ability to make the substantial capital investments necessary to correct these very significant problems and thus provide more reliable service while minimizing public safety concerns.

23. We find that the CCRM surcharge proposed by Columbia includes numerous positive characteristics that distinguish the surcharge from those we have rejected previously, and that work to maintain the pipeline's incentives for innovation and efficiency. First, the development of the CCRM began with Columbia and its shippers engaging in a collaborative effort to review Columbia's current base rates, leading to Columbia's agreement to reduce its base rates by $35 million retroactive to January 1, 2012, by another $25 million effective January 1, 2014, and to provide refunds to firm shippers of $50 million. Maryland PSC does not contest this aspect of the Settlement, which provides the shippers rate relief which could otherwise only be obtained pursuant to NGA section 5 and could not take effect in the retroactive manner provided by the Settlement. The Commission finds that these provisions of the Settlement assure that the base rates, to which the CCRM surcharge will be added, have been updated in a just and reasonable manner to reflect current circumstances on Columbia's system.

24. Second, the Settlement identifies, by pipeline segment and compressor station, the specific Eligible Facilities for which costs may be recovered through the CCRM, and the Settlement delineates and limits the amount of capital costs and expenses for each such project.[16] The Settlement also limits Columbia's ability to add or change projects. In addition, it is significant that Columbia agrees to continue making annual capital maintenance expenditures of $100 million for transportation and

[12] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 436, FERC Stats. & Regs., Regulations Preambles 1982–1985 ¶ 30,665, at 31,534 (1985).

[13] *Id.* at 31,537.

[14] *See, e.g., Florida Gas Transmission Co.,* 109 FERC ¶ 61,320 (2004); *Granite State Gas Transmission, Inc.,* 136 FERC ¶ 61,153 (2011).

[15] *CenterPoint Energy—Mississippi River Transmission, LLC,* 140 FERC ¶ 61,253 (2012) (*MRT*).

[16] By contrast, the surcharge mechanisms proposed in *Florida Gas* and *MRT* contained only general definitions of what type of costs would be eligible for recovery, leaving the pipeline considerable discretion as to what projects it would subsequently propose to include in the surcharge and creating the potential for significant disputes concerning the eligibility of particular projects.

storage projects, which it will not seek to recover through the CCRM recovery mechanism. These provisions of the Settlement should assure that the projects whose costs are recovered through the CCRM go beyond the regular capital maintenance expenditures which Columbia would perform in the ordinary course of business and that the projects are critical to assuring safe and reliable operation of Columbia's existing system. In addition, these provisions should minimize disputes in Columbia's annual CCRM filings concerning the need for particular projects.

25. Third, and critically important to our approval of the CCRM, is Columbia's agreement to (1) establish a billing determinant floor for calculating the CCRM and (2) impute the revenue it would achieve by charging the maximum rate for service at the level of billing determinant floor before it trues up any cost under-recoveries.[17] Also, any such true-up is limited to the $300 million annual cap and other related cost caps. These provisions, along with the required base rate reductions and the provision for Columbia to continue substantial capital maintenance investments that will not be recovered in the CCRM surcharge, subject Columbia to a continuing risk of cost under-recovery. These aspects of the Settlement thus alleviate the Commission's historic concern that surcharges which guarantee cost recovery are not appropriate for recovering capital costs, because they diminish a pipeline's incentive to be efficient and to maximize service provided to the public. These provisions of the Settlement also protect Columbia's shippers from significant cost shifts if Columbia loses shippers or must provide increased discounts to retain business.

26. Fourth, the CCRM would not be a permanent part of Columbia's rates. The Settlement provides that the CCRM will terminate on January 1, 2019, unless the parties agree to extend it and the Commission approves the extension. Thus, subject to extension requiring the consent of all parties, the CCRM is meant to recover a set amount of costs over defined period, and will not become a permanent part of Columbia's rates.

27. Finally, the surcharge is broadly supported, or at least not opposed, by all Columbia's customers. Based on all these factors, the Commission finds that Maryland PSC's policy objections to the CCRM mechanism do not justify rejection of the Settlement.

28. Maryland PSC's only other contention in opposing the Settlement is its statement that an NGA general section 4 rate case in this instance would provide the opportunity to determine whether the 14 percent rate base multiplier, inclusive of a 12 percent pre-tax rate of return and taxes other than income taxes of 2 percent for eligible facilities is just and reasonable. Rule 602(f)(4) of the Commission's regulations requires that, "any comment that contests a settlement by alleging a dispute as to a genuine issue of material fact must include an affidavit detailing any issue of material fact by specific reference." Maryland PSC did not file any affidavit with its comments demonstrating an issue of fact concerning whether the rate base multiplier provides an unreasonable return. Thus, we cannot find that its protest raised a genuine issue of fact with respect to the return to be included in the CCRM surcharge.[18]

29. The Commission also finds that all of Columbia's customers are likely to be in better position with the Settlement than without it. To the extent the Commission was to sever the Maryland PSC and local distribution companies it regulates,[19] those LDCs and Maryland consumers could not receive the immediate benefits of the Settlement, including the retroactive rate reduction and refunds. Moreover, while the severed parties would not be subject to the CCRM when it takes effect next year, Columbia would be free to file section 4 rate cases to increase the severed parties' rates at such time as the CCRM resulted in Columbia's overall rates exceeding its current rates.

30. The Settlement also includes numerous other significant benefits for Columbia's shippers which would not be available absent the Settlement. Aside from the significant retroactive rate reduction and refund payments already discussed, these include (1) the revenue sharing mechanism under which Columbia will refund to its customers 75 percent of any base rate revenues it collects over $750 million in any year after January 1, 2012, (2) a rate moratorium that will provide rate certainty until 2018, (3) a requirement for the pipeline to file an NGA section 4 general rate

[17] By contrast, the surcharge mechanisms proposed in *Florida Gas, Granite State,* and *MRT* did not include a comparable billing determinant floor.

[18] *See, e.g., San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange Corporation, et al.,* 128 FERC ¶ 61,004, at P 16 (2009); *Duke Energy Trading and Marketing, L.L.C., et al.,* 125 FERC ¶ 61,345, at P 31 (2008).

[19] *See Trailbazer,* 85 FERC ¶ 61,345 at 62,345, explaining that, if the Commission severs a public service Commission from a settlement, it must also sever the local distribution companies regulated by the public service Commission.

case by February 2019, (4) the removal of Columbia's existing daily scheduling penalty, thus providing shippers greater flexibility to modify their daily takes to respond to unexpected changes in their need for gas without incurring additional costs, and (5) Columbia's agreement not to propose market-based rates for new storage projects during the term of the Settlement or to propose any additional cost tracking mechanisms.

31. The Commission finds that the very substantial benefits that will inure to Columbia's shippers through the Settlement outweigh the inclusion of an otherwise disfavored surcharge, particularly given the customer protections inherent in the CCRM. The Settlement is crafted to address undisputed circumstances on Columbia's system, namely that the system is aging and that Columbia needs to make significant upgrades and repairs to modernize the system and to ensure that it will be able to continue to provide reliable firm transportation service, consistent with public safety. The Commission concludes that the benefits of the Settlement render the overall Settlement package just and reasonable.

32. As we have stated repeatedly, the Commission favors collaborative efforts and settlements between pipelines and their shippers regarding rate and other contested issues, as such negotiated agreements conserve the Commission's time and resources. The instant Settlement is the result of an extensive and comprehensive effort on behalf of Columbia and its customers to review the pipeline's existing rates, to evaluate imminent issues with regard to the aging system, and to develop a plan to address and pay for the costs of modernizing that system. The Commission notes that the procedures undertaken by the pipeline and its customers are precisely the kind of pro-active discussions and communications between customers and the pipelines that the Commission has repeatedly encouraged, and we commend the parties for their efforts in reaching this agreement.

The Commission orders:

The Settlement is hereby approved as discussed in the body of this order.

By the Commission. Chairman Wellinghoff is concurring with a separate statement attached.

(S E A L)

KIMBERLY D. BOSE,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Columbia Gas Transmission Corporation — Docket No. RP12–1021–000

(Issued January 24, 2013)

WELLINGHOFF, Chairman, *concurring:*

I share the concerns about cost tracking mechanisms expressed in this proceeding by the Public Service Commission of Maryland. Cost tracking mechanisms reduce a pipeline's incentive for innovation, efficiency and cost minimization, and shift the risk embedded in the return on equity from the pipeline to the shippers.

I am voting to approve the instant settlement because Columbia's shippers have negotiated significant limits to this cost tracking mechanism that mitigate my concerns. In particular, the cost tracking mechanism is limited to specifically identified projects, establishes a billing determinant floor at maximum tariff rates, and is not permanent part of Colwnbia's rates. Further, Columbia agrees that it will not propose any new cost tracking mechanism nor market based rates during the term of the settlement. In addition, there are other significant consumer benefits to approving the settlement. The settlement provides for $50 million in refunds, an annual $35 million rate reduction (retroactive to January 1, 2012), and an additional base rate reduction of $25 million each year beginning January 1, 2014.

For these reasons, I am voting to approve the settlement. However, I encourage shippers of pipelines seeking to implement a cost tracking mechanism to consider additional limits to protect consumers. For example, I believe that it also would be appropriate for a pipeline to credit shippers all revenues from services provided over the facilities at issue that were not included in the rate design billing determinants and to explore a reduction in the return on equity that applies to those facilities.

JON WELLINGHOFF,
Chairman.

The CHAIRMAN. Thank you. You answered my first one.

Mr. Kessler?

STATEMENT OF RICK KESSLER, PRESIDENT, PIPELINE SAFETY TRUST

Mr. KESSLER. Thank you, Mr. Chairman and Senator Manchin. Good afternoon to the members of the Committee and the public. I want to thank you for inviting me back to testify before the Committee again. My name is Rick Kessler, and I am here in my wholly voluntary and uncompensated role as the president of the Pipeline Safety Trust.

And for years after each new tragedy we've been invited to testify about what's needed to prevent the next tragedy. Unfortunately, we're back again after the recent failure of the pipeline and the incident in Sissonville. The failure comes all too soon after a spate of incidents in California, Michigan, Pennsylvania, Montana, and Utah among many other places. Many of these failures had common threads and common solutions that could have prevented or at least minimized their impacts.

The Trust and I were very happy to work with you, Mr. Chairman, your colleague Senator Boxer and my former bosses, Senator Lautenberg and Congressman Dingell, to enact the 2011 Pipeline Safety Act. And that began to move regulators and industry in the right direction on some of these issues. But the speed of review, rulemaking, and implementation of the needed changes was and continues to be painfully slow and certainly not fast enough to have avoided the tragedy in Sissonville.

Now, we've provided a great deal of testimony in the past on how we think we could improve pipeline safety in this country. I'm going to try and highlight some of the more pertinent issues to the re—things that are pertinent to the recent Sissonville failure and explosion.

But since a lot of this information is still coming forward I don't want to judge too much because that would be unfair and premature. But I will say one of the critical issues related to any type of pipeline rupture is how quickly the pipeline operator, as you've pointed out, can identify the rupture has occurred and act to shut it down to minimize any further effects of the pipeline failure.

In a perfect world built-in leak detection systems would alert a pipeline controller to the drop in pressure and allow for the quickest response to shut down the pipeline. Unfortunately as the recent PHMSA leak detection report shows less than 50 percent of major failures such as in Sissonville are initially identified by current leak detection technologies. We really need to do better. I think you know that, and I think everyone here knows that.

Now once a failure is identified the pipeline operator still needs to be able to shut down the valves on either side of the failure site so that the natural gas boring into the community and subsequent fire is minimized. In the case of where natural gas ignites, such as in Sissonville, the closure of these valves is what we call a blowtorch effect on the neighborhood and allow emergency responders to get in there and take care of the people.

Now, the final report on remote control and on automated valves that PHMSA recently provided this committee concludes that a cost effective strategy for reducing the consequences of natural gas pipeline failures is automated valves that can be closed within 10 minutes of failure.

Now, I got to tell you, I've been working on this particular matter for upwards of 17 years as a staffer handling the authorization of Federal law after a very similar incident in Edison, New Jersey back in 1994, which you may remember. Same thing. Fortunately no one was killed, but a huge fireball and it took about 3 hours to shut down the line mainly because it was manual and just the mere act of turning the wheel took about an hour or more.

Now, we agree with NTSB that such valves should require the automatic or remote shutoff valves, and there is a difference. Yet the Pipeline Safety Bill that we all worked on fell short of this requirement on existing pipelines in Sissonville and San Bruno.

No doubt, Mr. Chairman, you opened your car this morning using a remote control. We use remote controls to turn off and on our TVs, to do all sorts of things, our garage doors, for instance. Yet somehow we find it acceptable that an industry can use 1960s technology in 2013 to close its valves. For industry, unfortunately we've seen far more stall than install of these technologies.

It's unclear to us whether Sissonville failure was in an area where the company would have been required to do an integrity management plan. Only a small fraction of areas fall under these requirements. As we've testified before, these integrity management requirements must be expanded to cover all pipelines. And yet while we support integrity management, these programs are often fairly weak and need to be more much effective and easier to evaluate.

Some of the issues that must be addressed include creating a clear way for regulators to establish whether a company is basing the risk assessments on valid records, minimizing direct assessment as an inspection tool, and ensuring that when direct assessment is used as opposed to, say, inline inspection, the techniques are adequate and being used correctly.

We also must determine whether repair criteria within these programs undermine safety factors based on faulty assumptions and therefore are not addressing or perhaps exacerbating the problem.

To summarize, the state of West Virginia, like surrounding states, has seen a dramatic increase in the development of natural gas resources and relating pipe—related pump lines. Speaking for myself alone, I actually think this is a good thing for our economy, for the nation, for energy security. But this boom in drilling has also led to the construction of more and more pipelines and facilities across the area and more and more particularly gathering lines, which you mentioned earlier which can be, as you said and the Administrator said, the same size as transmission pipelines, the same pressure as transmission pipelines. Unfortunately these lines are completely unregulated by the Federal Government. We agree with the Administrator that the Federal Government should have authority to regulate these lines.

Finally, we believe that PHMSA is critical of the pipeline safety but not as effective a regulator as it should be. Certainly PHMSA can and must do more to regulate better regardless of budget. There is no excuse for continuing decades. It's not necessarily on this administration or the last, but it's been decades of neglect of this agency. However, we agree that PHMSA also suffers from a very serious lack of financial and personnel resources. This is particularly dangerous and shortsighted at a time when shale resources are feeding the rapid growth of pipeline mileage across the country.

For that reason we support PHMSA's 2013 budget request which would provide significant and additional funding to support critical increases in inspectors and program development. It's good for the industry, the consumer, and the Nation because we need the public to have confidence in the safety of the system to ensure smooth growth and access to gas and oil from shale plays around the Nation.

Thank you again for the opportunity to testify today. And I stand ready to answer any questions and continue to work with you, and you, Senator Manchin, and the rest of the Congress to move safety forward. Thank you.

[The prepared statement of Mr. Kessler follows:]

PREPARED STATEMENT OF ERIC KESSLER, PRESIDENT, PIPELINE SAFETY TRUST

Good morning, Chairman Rockefeller and members of the Committee. Thank you for inviting me to speak today on the important subject of pipeline safety. My name is Rick Kessler and I am testifying today in my purely voluntary, uncompensated role as the President of the Pipeline Safety Trust. My involvement and experience with pipeline safety stems from my years as one of the primary staff members on such issues in the House of Representatives and my subsequent work with the Pipeline Safety Trust.

The Pipeline Safety Trust came into being after a pipeline disaster over thirteen years ago—the 1999 Olympic Pipeline tragedy in Bellingham, Washington that left three young people dead, wiped out every living thing in a beautiful salmon stream, and caused millions of dollars of economic disruption. While prosecuting that incident the U.S. Justice Department was so aghast at the way the pipeline company had operated and maintained its pipeline, and equally aghast at the lack of oversight from Federal regulators, that the Department asked the Federal courts to set aside money from the settlement of that case to create the Pipeline Safety Trust as an independent national watchdog organization over both the industry and the regulators. We have worked hard to fulfill that vision ever since, but with continuing major failures of pipelines, such as the one in Sissonville, West Virginia that brings us here today, we question whether our message is being heard.

Born from a tragedy in Bellingham, but also riding on the facts and emotion of other tragedies in places like Edison, New Jersey; Carlsbad, New Mexico; Walnut Creek, California and Carmichael, Mississippi, we have testified to Congress for years about the improvements needed in Federal regulations to help prevent more such tragedies. For years we have talked about the need for more miles of pipelines to be inspected by smart pigs. We have pleaded for clear standards for leak detection, requirements for the placement of automated shut off valves, closing the loopholes that allow a growing mileage of pipelines to remain unregulated, and for better information to be available so innocent people will know if they live near a large pipeline and whether that pipeline is maintained and inspected in a way to ensure their safety.

So here we are again after the very recent failure of a pipeline in Sissonville which completely destroyed three homes, damaged other homes, caused extensive damage to an interstate highway, and once again terrorized a community. This recent failure falls too soon after a spate of significant failures over the past few years in Michigan, California, Pennsylvania, Montana, and Utah. Many of these failures had common themes and common solutions that could have prevented or at least minimized their impacts. We have been asking for action on these issues in previous hearings following previous tragedies for years now. Last year, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which began to move the regulators and the pipeline industry in the right direction on some of these issues, but the speed of review, rule making, implementation and enforcement of the needed changes was not sufficient to prevent the tragedy in Sissonville. It is our sincere desire not to be back in front of this committee again in the future saying the same things after yet another tragedy.

The vision of the Pipeline Safety Trust is simple. We believe that communities should feel safe when pipelines run through them, and trust that their government is proactively working to prevent pipeline hazards. We believe that local communities who have the most to lose if a pipeline fails should be included in discussions of how best to prevent pipeline failures. And we believe that only when trusted partnerships between pipeline companies, government, communities, and safety advocates are formed, will pipelines truly be safer.

Clearly trust in pipeline safety has now been lost in the community around Sissonville, so add those people to people in Michigan, California, Pennsylvania, Montana, Utah and elsewhere, where people now question whether the industry, regulators and legislators are really doing all they can to keep people and the environment safe.

In my testimony today I will focus on areas that are pertinent to natural gas transmission pipelines like the one that failed in Sissonville. Since much of the pertinent information about the Sissonville failure, such as whether or not it had been previously inspected, what type of inspection was used, whether the failure site was within a high consequence designation, and the type of valves upstream and downstream of the rupture site, has not yet been released, specific conclusions related to this failure would be premature. I will also review areas addressed by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, and needed safety areas that bill failed to address. These are the issues I would like to speak to today:

- Response times to pipeline ruptures
- Expanding and clarifying integrity management requirements
- Inadequate Federal and state resources
- Non-regulated and under-regulated Gathering Lines
- Poor facility response planning (hazardous liquids)
- Lack of clear jurisdiction for new pipeline approval and routing decisions
- Pipe replacement programs (cast iron, bare steel, faulty plastics)
- Quantifying natural gas leak significance
- Depth of cover at river crossings
- Diluted bitumen study constraints

Response times to pipeline ruptures—One of the critical issues related to any type of pipeline rupture is how quickly the pipeline operator can identify that a rupture has occurred and then act to shut the pipeline down to minimize any further effects of the pipeline failure. In a perfect world, built in leak/rupture detection systems would alert a pipeline controller of a rupture immediately and allow for the quickest response to shut down the pipeline. Unfortunately, as the final report—*Leak Detection Study—DTPH56–11–D–000001,* which was recently provided to this Committee by PHMSA shows, for all leaks on natural gas transmission pipelines less than 16 percent are initially identified by the current leak detection systems. Even for the larger major releases that should be more easily identified with such systems less than 50 percent of these failures are initially identified by current leak detection systems. What this means is that someone other than the pipeline controller, such as local residents or emergency response personnel, or field employees with the pipeline company are the ones that initially identify the pipeline failure, and precious time is then lost as this failure identification is then relayed to the control room.

Once a failure has been identified, the pipeline operator still needs to be able to shut down the valves on either side of the failure site so the natural gas roaring into the local community is minimized as much as possible. In the case where the natural gas ignites, such as in Sissonville, the closure of these valves is what can halt the blowtorch effect on the neighborhood and allow emergency responders to access the area to do their jobs. The types of valves in these critical locations, and how far apart they are spaced, play an important role in how quickly the fuel will stop flowing into the community. The final report on automated valves—*Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety*—that PHMSA recently provided this Committee provides the following cost effective strategy for reducing the consequences of natural gas pipeline failures such as occurred in Sissonville.

> “For natural gas pipelines, adding automatic closure capability to block valves in newly constructed or fully replaced pipeline facilities may be a cost effective

strategy for mitigating potential fire consequences resulting from a release and subsequent ignition provided . . .

> The leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 10 minutes or less after the break, and fire fighting activities within the area of potentially severe damage can begin soon after the fire fighters arrive on the scene."

Unfortunately, as was seen in the recent Sissonville failure, and even more dramatically in the 2010 San Bruno tragedy, the leak detection systems combined with the associated valves were not capable of meeting the timeline in this cost effective consequence mitigation strategy. While these leak detection and valve issues have been talked about for years, current Federal regulations do not require such automated valves, and it appears adequate leak detection systems for natural gas pipelines are many years off and will only be developed if adequate funding is provided for ongoing research and development. We join with the NTSB in calling for new regulations to require these automated valves at a minimum in all High Consequence Areas.[1] The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 fell well short of these requirements by only requiring such valves for new or fully replaced pipelines. This shortcoming of the 2011 Act should be corrected to ensure that people living along existing natural gas transmission pipelines, such as in San Bruno and Sissonville, are afforded this additional protection also.

One other issue that Congress should keep a careful eye on relates to the development of a performance-based response time for companies to respond to and shut down pipelines in significant events such as Sissonville. The recent GAO report alludes to such a standard in its recommendations, which in part state:

> "evaluate whether to implement a performance-based framework for incident response times."

We certainly agree with GAO that the first step is to improve the incident response data available so such decisions can be made based on clear facts. In submittals to PHMSA on this issue, and at numerous public meetings, the Interstate Natural Gas Association of America (INGAA) has tried to create a starting point for such a standard response time discussion by repeating its findings and commitment of:

> "In populated areas, INGAA members have committed to having personnel on scene within one hour to coordinate with first responders and isolate failures."[2]

As the recent valve study provided to you by PHMSA, and mentioned previously states, to effectively mitigate potential fire consequences from natural gas pipeline ruptures the failed pipeline segment needs to be isolated within 10 minutes. While it is true that a good deal of the damage from such pipeline failures occurs in the first minutes after failure, there is also clear evidence from places such as San Bruno and Edison that faster isolation of failed lines can reduce fire consequences and reduce the terror that citizens within the area experience. This often needlessly prolonged terror is rarely figured into the equations for such response times to shut down pipelines, but talk to anyone that lives through one of these events and you will realize that the terror has ongoing personal effects for years. Getting operators on site to isolate the ruptured site within an hour means that it will frequently be well over an hour before firefighters can safely enter the area. For firefighters waiting to get access to a potentially growing fire scene, and for those who live and work in the areas at risk, particularly hard to evacuate populations, that hour would be interminable. We do not believe one hour is a fast enough response time, and we urge Congress to keep a careful eye on this response time discussion.

Expanding and clarifying integrity management requirements—The Pipeline Safety Trust has testified at numerous Congressional hearings on the need to expand integrity management processes for hazardous liquid and gas transmission pipelines beyond the current limited requirements of High Consequence Areas. Integrity management programs have shown value by being responsible for the identification and repair of thousands of flaws in pipelines over the past decade. Unfortunately these programs are only required on around 44 percent of hazardous liquid pipelines and 7 percent of natural gas transmission pipelines. This leaves thousands of people in more rural areas without the clear safety benefits that integrity management programs provide.

[1] NTSB recommendation P–11–011, 9/26/2011.

[2] Interstate Natural Gas Association of America, 11/2/11, comments on ANPRM for Safety of Gas Transmission Pipelines, Docket# PHMSA–2011–0023.

We are thankful that in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 Congress asked PHMSA to study the expansion of integrity management beyond High Consequence Areas, and we are also encouraged that PHMSA has already undertaken two significant Advanced Notices of Proposed Rulemakings to get this process started. Many progressive companies recognizing the value of integrity management programs have already moved to include all of their pipeline mileage under these programs, and the Interstate Natural Gas Association of America has publicly supported the expansion of integrity management to all miles of gas transmission pipelines.

While the Pipeline Safety Trust has been very supportive of the integrity management programs and would like to see them expanded, it is also clear that the program needs to be reevaluated to ensure that it is working as originally planned. There are a few areas within the integrity management programs that we believe need to be reassessed to ensure they are moving safety forward as intended. We understand that PHMSA is already preparing for a review and update of the integrity management program for transmission pipelines, and NTSB has also questioned whether regulators have clear evaluation metrics to effectively inspect and enforce such performance-based regulations. The most well publicized example of an issue that undermines proper integrity management related to the San Bruno tragedy where a lack of proper records led to incorrect assumptions about the type and quality of pipe in the ground. While much effort has been put into this record verification issue, there are other concerns with the integrity management program that still need to be addressed.

For example, also in the San Bruno tragedy, and perhaps in the recent Sissonville failure also, the use of Direct Assessment as a tool to inspect these large transmission pipelines has come into question. From the record of the development of the original integrity management program for natural gas transmission pipelines, it is clear that direct assessment was included as a way to appease the industry and help them avoid the large cost of retrofitting their pipelines so they could use the most up-to-date and effective internal inspection devices. Engineers from within regulatory agencies have shared concerns with us that the use of Direct Assessment is often done incorrectly, and is rarely as effective as the other approved integrity management inspection methods. We hope that a complete and thorough review of the use of Direct Assessment is undertaken soon, and that clearer criteria are developed for when and how it can be used. We support the NTSB recommendations that address this point by calling for hydrostatic pressure tests for all older pipe, and that all pipe be configured to accommodate inline inspection devices.[3]

One further piece of the integrity management program that we think needs to be reviewed is the repair criteria. Pipelines that do not fall under the integrity management rules have a fairly conservative safety factor built into the design and operation, to account for the fact that once put in the ground there are no current requirements that they be inspected using the best inspection technologies. The repair criteria under the integrity management program reduce this safety factor because it was assumed that companies would be regularly inspecting their pipelines and would catch any problems before they reach a critical state. As seen in many failures in recent years this is a dangerous assumption, so we believe the repair criteria within the integrity management programs need to be reviewed and probably tightened to ensure a sufficient safety factor is maintained, since to date integrity management assumptions have not always been accurate.

We are concerned that PHMSA has not issued proposed rules on the Advanced Notices of Proposed Rulemakings (ANPRMs) to update both natural gas and hazardous liquid pipeline safety requirements. The Trust, industry, and other stakeholders spent many hours developing comments to respond to the ANPRMs on pipeline safety needs, especially in the area of integrity management. We hope Congress ensures that PHMSA acts in a timely manner on these important regulatory issues concerning integrity management.

Inadequate Federal and state resources—For years the Pipeline Safety Trust has served on one of PHMSA's technical advisory committees, has helped with PHMSA workgroups on specific pipeline initiatives, and has had a great deal of interaction with PHMSA staff at all levels of the organization. All these interactions have confirmed our belief that this small agency is critical to pipeline safety, but is not as effective as it could be because of a lack of financial and personnel resources. The same issues also apply to state regulators who actually have more inspectors on the

[3] NTSB recommendations P–11–014 & P–11–017, 9/26/2011.

ground. For these reasons we support PHMSA's 2013 budget request,[4] which would provide additional funding to support the needed increase in inspectors and analysts, an Accident Investigation Team, an increase in state funding, greater research and development, and the development of the much needed National Pipeline Information Exchange to help ensure adequate and accurate information is being collected to make good safety decisions. We hope this Committee, as the Senate committee that has the clear understanding of pipeline safety needs, will work with your colleagues to obtain this critical funding.

Non-regulated and under-regulated Gathering Lines—With the huge increase in natural gas production in states such as West Virginia and Pennsylvania, thousands of miles of under-regulated or completely unregulated gathering lines have recently been installed and more are on the way. No one really knows how many miles of gathering lines are out there or where they are located or how many have releases because up until recently no one ever tracked them. For example, the March 2012 GAO report[5] on unregulated gathering pipelines stated "out of the more than 200,000 estimated miles of natural gas gathering pipelines, PHMSA regulates roughly 20,000 miles." While in years past these gathering lines were smaller and lower pressure, many of the new gathering lines now being used in formations such as the Marcellus Shale are the same size and even higher pressure than the pipeline that failed in Sissonville. Yet unlike the Sissonville transmission pipeline, the majority of these gathering lines in rural areas, which may have riskier safety profiles than the Sissonville pipeline, are completely unregulated by the Federal Government.

For the most part the 20,000 miles of gathering lines that do fall under PHMSA regulations are the gathering lines that lie within more populated areas. Again many of these "regulated" gathering lines in these populated areas are the same size and pressure as the transmission pipelines that failed in San Bruno and Sissonville, yet are not afforded equal level of pipeline safety protection. For example a transmission pipeline running through a town would be required to undertake the important integrity management inspections to help ensure its safety, yet a gathering line that has the exact same risk profile running through that same town is currently not required to ever undertake any form of the important integrity management inspection and risk analysis.

While the development of various natural gas shale plays around the Nation has arguably been a boon to our energy supplies and economy, because of this serious loophole in the pipeline regulations it has also increased the risk to thousands of people in these same areas. This is a loophole that needs to be closed as soon as possible before we have to gather for another hearing after a tragedy along one of these under-regulated or completely unregulated gathering pipelines.

Similarly, there are numerous unregulated hazardous liquid gathering lines with characteristics similar to regulated hazardous liquid lines. PHMSA needs to adequately regulate these gathering lines. Congress should consider elimination of the term "gathering" line for hazardous liquids. Doing so would ensure that all oil gathering lines are regulated, as the State of Alaska has done for its oil pipelines.

Poor facility response planning (hazardous liquids)—The NTSB in its report on the Marshall, Michigan spill of nearly a million gallons of oil into the Kalamazoo River made numerous recommendations targeted at improving facility response planning for hazardous liquid pipelines.[6] We support all of the NTSB recommendations and hope they will be acted upon as quickly as possible. As we have testified to this committee previously, the review and adoption of such response plans is a process that does not include the public. In fact PHMSA has argued that it is not required to follow any public processes, such as those under the National Environmental Policy Act, for the review of these plans. If the Enbridge pipeline spill in Marshall, Michigan and the BP Gulf tragedy have taught us nothing else it should have taught us that the industry and agencies could use all the help they can get to ensure such response plans will work in the case of a real emergency.

It is always our belief that greater transparency in all aspects of pipeline safety will lead to increased involvement, review and ultimately safety. There are many organizations, local and state government agencies, and academic institutions that have expertise and an interest in preventing the release of fuels to the environment. Greater transparency would help involve these entities and provide ideas from outside of the industry. The State of Washington has passed rules that when spill plans

[4] U.S. Department of Transportation, Budget Estimates, Fiscal Year 2013 *http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/FY%202013%20PHMSA%20BUDGET.pdf.*

[5] GAO, Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety, Report #GAO–12–388, March 2012.

[6] NTSB recommendations P–12–001, P–12–002, P–12–009, P–12–010, 7/25/2012.

are submitted for approval the plans are required to be made publicly available, interested parties are notified, and there is a 30 day period for interested parties to comment on the contents of the proposed plan.[7] We urge Congress to require PHMSA to develop similar requirements for review and approval of spill response plans across the country, and that PHMSA's review and approval of facility response plans for new pipelines be an integral part of any environmental reviews required as part of the pipeline siting process.

To encourage greater public education and awareness regarding these response plans, Section 6 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 required PHMSA to "provide upon written request to a person a copy of the plan." In April of 2012, three months after the 2011 Act became law, the Pipeline Safety Trust requested a few of these facility response plans from PHMSA. We received an acknowledgement of our request within 2 weeks, but nine months later we are still waiting to receive the plans requested. In the State of Washington if we request such a facility response plan it is normally delivered to us on a CD within the week. While we certainly understand that PHMSA is understaffed, such long delays in filling information requests does little to accomplish the Congressional intent for public education and awareness, and makes us wonder how long others are waiting for information also.

Lack of clear jurisdiction for new pipeline approval and routing decisions—Nearly everyone agrees that the people living along the rights-of-way of the pipelines in this country can serve a very valuable function as the eyes and ears for pipeline safety along those routes. Unfortunately, too often the lack of any clear routing process and overly aggressive tactics by right-of-way agents sour the relationship before it even gets started, leaving too many property owners disgruntled and no longer willing to cooperate on safety issues.

For interstate natural gas transmission pipelines FERC provides a predictable siting process that provides communities potentially impacted by proposed pipelines valuable information about the proposal and ways to have their concerns heard and hopefully addressed. For all hazardous liquid pipelines, and for intrastate natural gas pipelines there is no such predictable process or information source. Some states have developed their own processes, while others have not, allowing smaller and smaller pieces of the decisions to fall on cities, counties and townships that often lack much knowledge regarding the issues associated with pipelines. This mish mash of routing authority often leads to a high degree of frustration from property owners and local governments who will be impacted by these decisions, and we suspect does not lead to the best routing decisions. Throw into the mix the often early threat of eminent domain and it is easy to see why these routing decisions too often become news stories about gymnasiums full of angry people that ultimately undermine trust in pipeline safety.

While the problem is clear and being repeated more frequently because of our new sources of gas and oil, we hope that Congress will use its investigative powers to commission a comprehensive study on this important issue to help find a solution. The study should at a minimum look at the shortfalls of the current system, compare the outcomes from the FERC process to the outcomes that fall outside of FERC authority, and consider which Federal or state agencies are best equipped to help make these routing decisions for the various different types of pipelines. The study should also discuss any added benefits such cohesive route planning may produce in the form of lessening impacts by encouraging pipeline companies to better share infrastructure and rights-of-way, and in comprehensive environmental analysis allowing public review of potential alternatives.

Pipe replacement programs (cast iron, bare steel, faulty plastics)—Section 7 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 required the Secretary to conduct a survey every two years "to measure the progress that owners and operators of pipeline facilities have made in adopting and implementing their plans for the safe management and replacement of cast iron gas pipelines." After years of knowledge of the problems associated with this old cast iron pipe, and continued failures causing death and community destruction, this survey, which PHMSA has posted on their website, serves as a good way of shining a light on the operators who have taken this problem seriously and those who may not have. This was a great first step but could be expanded to be even more effective.

Cast iron pipe is not the only type of pipe in the ground that has clearly known deficiencies. There are some types of plastic pipe that also have been identified as in need of replacement, and older bare steel pipe that lacks the important protective coating of more modern pipe also poses a threat. These types of pipe should also

[7] Washington Administrative Code 173–182–640.

be added to the survey to provide a measurable metric of how well pipeline companies are doing to address these potential problems.

While the Pipeline Safety Trust's main concern is the replacement of these types of problematic pipes for safety reasons, we also realize that paying for these replacement programs is a complicated equation. Many of the companies that have these pipes operate as regulated monopolies with a guaranteed rate of return, so the success of replacement programs often also lies with how state utility commissions approve rates for these replacement programs. We certainly support companies getting a fair return on safety investments, but the mechanisms to provide that return have to be carefully crafted to ensure the ratepayers are not paying for more than their fair share or for replacing things just to increase the rate of return with no real safety benefit.

Quantifying natural gas leak significance—With recent failures and deaths from leaking natural gas distribution systems the public has come to question the safety of the very common small leaks, which both regulators and industry acknowledge. New technology has also been developed that allows a person to drive through a neighborhood and see these small leaks all around. Recent information estimates that between 1.4 percent to 3.6 percent of all natural gas could be lost during transport, storage and distribution.[8] A 2009 article in the Pipeline & Gas Journal[9] regarding just the cast iron pipe portion of the pipeline network stated:

> A significant source of natural gas losses from distribution systems is cast iron distribution pipes. U.S. cast iron distribution mains are estimated to have leaked 9 billion cubic feet (Bcf) of natural gas in 2007. This equates to $150 million worth of gas, assuming the average U.S. distribution price in 2007, or $50 to $115 million if gas were valued between $3 and $7 per thousand cubic feet (Mcf).

We are surprised that more information has not been developed to clarify the quantity and significance of such leaks. Often such small leaks do not represent a safety hazard, but it only makes common sense that the loss of such a potentially large amount of gas is a significant waste of a non-renewable natural resource. Furthermore, methane (the main constituent of natural gas) has a far more potent negative effect on climate change than carbon dioxide, so the real quantity of natural gas leaking from these pipelines is important to understand along with what efforts to correct these leaks may be cost effective. We hope that Congress will ask for a study to better quantify these leaks, and discuss the impacts they have to safety, user rates, resource conservation, and climate change. Following such a study, Congress should consider requiring PHMSA to monitor and address significant natural gas leak problems from pipelines, compressor stations and storage.

Depth of cover at river crossings—Section 28 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 requires the Secretary to "conduct a study of hazardous liquid pipeline incidents at crossings of inland bodies of water with a width of at least 100 feet from high water mark to high water mark to determine if the depth of cover over the buried pipeline was a factor in any accidental release of hazardous liquids." That study has been provided to this Committee, and concluded that depth of cover at river crossings was a factor in at least 16 incidents since 1991. A recent Wall Street Journal article[10] provides a good overview of this problem along just one section of one river:

> "The U.S. Geological Survey found severe scour last year at 27 sites surveyed along the Missouri River from Kansas City to St. Louis, with the riverbed deepened in places by nine to 41 feet. Other unpublished USGS research found more severe scouring upstream.
>
> Of the 55 oil and gas pipelines that cross the Missouri—which runs 2,300 miles from Montana to St. Louis—at least 24 have sections that lie 10 feet or less beneath the riverbed, within the range of scour observed on the river, according to Federal records obtained via a Freedom of Information Act request. During recent inspections, operators discovered at least two of those pipes, in Platte County, Mo. and near Boonville, Mo., were exposed but didn't break.

[8] Robert W. Howarth · Renee Santoro ·Anthony Ingraffea, 2011, Methane and the greenhouse-gas footprint of natural gas from shale formations—*http://www.psehealthyenergy.org/data/Howarth__Climatic__Change__Shale__Methane1.pdf.*

[9] Pipeline & Gas Journal, New Measurement Data Has Implications For Quantifying Natural Gas Losses From Cast Iron Distribution Mains, September 2009 Vol. 236 No. 9, Carey Bylin, Luigi Cassab, Adilson Cazarini, Danilo Ori, Don Robinson and Doug Sechler.

[10] *Wall Street Journal,* Floods Put Pipelines At Risk, Jack Nicas, December 2, 2012.

> Federal law requires operators to bury pipelines a minimum of four feet beneath waterways. Many river engineers say that standard is grossly inadequate. A congressional research report this year said the 4-foot minimum "appears to be insufficient to prevent riverbed pipeline exposure."

PHMSA already has a rulemaking in progress where they could address these findings. It is our hope that PHMSA in its rulemaking will develop clear standards that required companies, when geologically feasible, to use horizontal directional drilling (HDD) to place these pipelines at a depth under such river crossings to avoid future failures.

Depth of cover is not only an issue at such river crossings. Every year pipelines are struck and damaged, often leading to serious consequences, because of a lack of sufficient cover. Federal regulations require that hazardous liquid and gas transmission lines "must be installed with a minimum cover," but the regulations do not require that that level of cover be maintained. In some parts of the country normal erosion has led some pipelines to be at very shallow depth or even exposed, making them an easy target for plowing and various forms of excavation. While certainly excavators have a responsibility to call before they dig near such pipelines, the current depth of cover regulations need to be analyzed to determine if a change is warranted. An additional benefit of extending integrity management principles to more rural areas is that the assessment of foreseeable risks of third party damage to pipelines in agricultural areas from lack of cover will be made a necessary component of an adequate risk assessment by the operators, requiring them to undertake mitigative and preventative actions.

Diluted bitumen study constraints—Section 28 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 requires the Secretary to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen." PHMSA has contracted with the National Academy of Sciences for that review, which is due out next summer. Because of the high profile nature of the Keystone Pipeline proposed to carry this diluted bitumen, many people are already voicing concerns about the industry membership in the NAS review committee, as well as the fact that it appears the committee will not be doing any new research, just relying on existing information, a majority of which comes from industry.

The 2010 Enbridge spill of diluted bitumen into the Kalamazoo River in Michigan made clear that when diluted bitumen gets out of a pipeline it presents a difficult challenge to clean up because so much of it is prone to sinking. We had hoped that the diluted bitumen study that Congress required would be broad enough to also answer questions about the need for greater cleanup preparedness and technologies along pipelines that carry this unique material, but PHMSA's contract with NAS does not cover these problems. For these reasons we hope that Congress will pay careful attention when the report is released next summer, and ensure follow up of any questions left unanswered.

Thank you again for this opportunity to testify today. The Pipeline Safety Trust hopes you will closely consider the ideas and concerns we have raised today. If you have any questions about our testimony, the Trust would be pleased to answer them and, of course, we stand ready to work with you and your colleagues on improving this country's pipeline safety laws that are so important to ensuring the well-being of millions of Americans and the healthy environment that is their birthright.

The CHAIRMAN. Thank you, sir, very much.

Mr. Staton, I'm going to put you through a little exercise for my education, for all of our education. I want to hit on a few topics similar to what we discussed in the first panel. Whenever there is a pipeline incident, discussion of the affected operator's response surely follows, was it timely, was it not?

So let me just ask you this: How is your control room made aware when an incident occurs, one? Can you walk me through your company's process for responding to an incident? Does your company have performance metrics for response times to incidents? And how could industry improve response time?

Mr. STATON. The initiation of an event within our control center is indicated to one of the control room operators who are very well trained at understanding the implications on our system in what we call—we refer to as an alert.

Specifically on the SM–80 pipeline, we have three pipelines there that operate effectively as a common system, and those have been referred to earlier today. So we received—when we received it—when we saw pressure drop on all three of those pipelines, we immediately saw three alerts, one for each pipeline.

Two minutes later, which is not—by the way, it's not an absolutely uncommon occurrence on a pipeline. There are fluctuations in pressure from time to time. And so that initial alert indicated that there had been a pressure drop. We then subsequently received three additional alerts, one on each of those three pipelines 2 minutes later indicating that pressure was declining again.

That happened one more time and then our team in the control center began to react. At about that time, a few minutes after that, we received a call from the folks at Cabot that one of their technicians had identified a specific location. So now we had confirmation in the control center that indeed what we were seeing in our control system had—something had happened and there had been an incident. And we began to deploy our resources with the folks calling out to the field and alerting emergency responders, ultimately also alerting the National Response Center.

And so we deployed our folks. Our folks went to the locations in order to close the valves at the two locations. Those locations were about seven miles apart. One was at Lanham. One was downstream of Lanham. And then our operators began the process of closing and isolating that pipeline system.

The CHAIRMAN. Had you not received a phone call from Cabot, what would have been the result?

Mr. STATON. Had we not received that immediate phone call from Cabot there were also calls being made to local 911 folks because of the incident. We would have been able —and we would have deployed our folks on both ends of the system toward the particular incident.

The CHAIRMAN. All right. Now, I asked you for a bit more. The process by which you make decisions, you've described to me the first part, the company's process for responding. Does your company have performance metrics for response, et cetera?

Mr. STATON. We—I'm sorry. Our intent, we have over the last several years been continuing to improve our processes across the industry and here at Columbia. We have redeployed people on our—in our organization. Well, let me take a step back.

First, we have deployed in areas where we are comfortable the operations can utilize automated shutoff valves. We have deployed those. Along our system where, particularly in Appalachian, where our system is very integrated. It's an integrated set of network pipelines with a lot of inputs coming into a system and a lot outputs that create—that can create some additional pressure implications.

We have deployed people closer to the valve settings so that we can assure that we can close off valves and reduce the time-frame of an incident down to 1 hour.

The CHAIRMAN. Any—that would be it? Do you have the appropriate—it was mentioned there were four people in the response station. Does that—is that fairly regular or does that depend upon the time of day or whatever?

Mr. STATON. At different locations on the system it varies. At our Lanham station we have folks onsite. We do have some unmanned locations. And we ensure that we have the appropriate response personnel close enough to be able to respond in the event that those valves need to be actuated.

The CHAIRMAN. OK. If there's any comments from any of the second panel, I'd welcome them.

Mr. Staton, as you know, we included a requirement for remote controlled automatic shutoff valves on new or reconstructed pipelines in last year's law. So that's law. As we all know, the line that ruptured in Sissonville was equipped with a manual shutoff valve that required onsite attention, as you indicated was probably hard to do, physically hard to do. Although this requirement has not yet been made final, do you plan to install one of these valves on the Sissonville line once it is reconstructed?

Mr. STATON. Our first priority in any circumstance is to prevent an incident like this from happening, and that our primary——

The CHAIRMAN. I missed that. I'm sorry.

Mr. STATON. Is to prevent an event, an incident like this from ever happening on our system, and that is to—to learn more, continue to learn more about our system and to install the right technologies at the right times. With regard to ASVs in new areas, obviously we're going to comply with whatever the requirements are.

As we look at our SM–80 line, it is one of those integrated lines that I was talking about. And we are—it's a challenge for companies like ours to install automated shutoff valves on those types of systems because they can create inadvertent affects. And we want—we obviously want to avoid that.

Having said that, it is our plan as we learn more and finalize our analysis of bringing SM—the line SM–80 back into service along with support from PHMSA. We will consider putting automatic or remote controlled valves in place on line SM–80.

I would also indicate that our current modernization program that we are undertaking, it's about a $5 billion program to modernize our pipeline system across all of our pipeline system. Our intent is to expand the use of automated and remote control valves.

The CHAIRMAN. Let me ask one which is not strictly in our arena today but which is much on my mind. In a hearing we had a year ago in Clarksburg, there was talk that you're building a platform you need to have a lot of water and sometimes you get 80,000 pound trucks. 80,000 pound trucks and the average rural bridges that I have crossed in Pocahontas County and every other county in the state don't necessarily love each other. There's bound to be a problem, especially when they're one-way bridges.

But there was also talk of the fact that those who drove those trucks, and this haunts me, since they know they're going on to another job as soon as this platform is built, that they don't appear to respect neighbors, and this testimony came from the sheriff, and granted he wasn't running for office again so maybe he felt more free speak, but therefore I think he was saying what he really felt. Now that was a cynical comment, wasn't it?

That they tend to just go on a rampage. They just get to where they have to go as fast as they can get there and turn around and get back and there's sort of no real response or interest in the people whose land they're traversing. Do you have any comment?

Mr. STATON. Specifically on—I mean, we obviously did not feel that way about the folks that we serve, and we value the property. We value, more importantly, the life of everyone along our pipeline system. And that's why we're making and continuing to make the types of investments to ensure that we don't have instances like this and that we can create one of the strongest infrastructures in this industry. And so I don't—I don't think that I see anything like that.

The CHAIRMAN. I'm not talking about you.

Mr. STATON. With regard to our industry, is that—is there—maybe there will be instances where folks are moving on too quickly to other activities. I would imagine there are opportunities where you can be distracted by the next job or the next responsibility. And—but I think, again, we have to make the appropriate investments in our infrastructure, period, whether it be roads, pipeline systems, bridges across the entirety of the country.

The CHAIRMAN. Understood. As Senator Manchin and I discovered after the Sago mine disaster, there are large mines and there are small mines. There are large pipeline companies. There are small pipeline companies. And it would appear to me that there needs to be a certain level of largeness in order to afford to do business safely. And I'm not sure where that is or how that question can be answered, but could you reflect on that? And does INGAA discuss this?

Mr. STATON. There are organizations that are focused on bringing together parts of the—parts of this industry that are relatively small that in and of themselves may not be able to address all of the issues that larger pipelines like ours would be able to address. And I think those organizations enable the coming together of that portion of the industry to address infrastructure types of issues.

I think we've seen a fair amount of consolidation across this industry. And I believe that the capital and the capability to make the investments to operate safely, effectively, efficiently, those capabilities are there to operate effectively. And we intend to make those investments to be one of those—one of the safest pipeline operators in the country.

The CHAIRMAN. So there's actually an argument for consolidations in certain circumstances so as to be able to afford the equipment and the precision materials that you have to have.

Mr. STATON. I think across many levels of infrastructure there is a significant amount of investment that needs to be made. And in bringing the appropriate financial wherewith all to the table to accomplish that, I think, is a very important part of the overall process. And I do think that's why we've seen some consolidation and probably will see additional consolidation going forward.

The CHAIRMAN. OK, good.

Mr. Kessler, should there be a blanket requirement for these types of valves to be installed on all existing gas transmission that would be automatic?

Mr. KESSLER. Well, I don't know if I want to say it should be blanket. It should certainly be reason. But there should be a requirement for installation on existing lines. I continue to hear, and I've heard this since 1994 when I started, the concerns about the technology on remote valves.

And it's really starting to ring a bit hollow after these many years particularly when, say, the U.S. Government entrusts some of its most sensitive military operations to remotely controlled drones yet somehow we can't have the technology to safely operate a shutoff valve by remote control. I think it's time to really take a comprehensive look, and this is something your staff, you, our organization all discussed in the last go round of pipeline safety authorization, even just requiring companies to assess their own lines, existing lines, come forward with their own plans for where these things should be installed, where they shouldn't be, and file those and make them public.

That was rejected as being too much. Not a requirement that they actually install them, but to do the assessment much like we require pollution prevention assessments or security assessments. That was rejected.

So I don't want to sound like we want all remote all the time everywhere, but certainly a comprehensive look at where we should be putting these things and then actually installing them. Look, I think this is the time to do it when gas prices are going down, demand is growing. There's plenty of money to be made. Why not use some of the money being made to reinvigorate the system, not just with valves but also better replacing old segments of lines and things like that and better inspections.

Which I agree with Mr. Staton, that's where it starts is prevention. And better and more frequent inspections of more lines is really the beginning. But, yes, more valves, more remote valves.

The CHAIRMAN. The answer is yes?

Mr. KESSLER. I think so. Thank you, Mr. Chairman.

The CHAIRMAN. Panel two agrees?

Ms. QUARTERMAN. Yes.

The CHAIRMAN. I'm about finished, but not quite.

Mr. Kessler, because of their shape with or other reasons some transmission pipelines are unable to accommodate inline inspections to determine if any defects of risks exist. In lieu of inline inspections, operators often rely on direct assessment inspections which rely on walking the line or aerial surveys. I mean, this thing of helicopters flying over it——

Mr. KESSLER. Drones.

The CHAIRMAN.—with long ropes and an orange thing at the bottom.

Mr. KESSLER. Right.

The CHAIRMAN. And I'm not sure how that works. But it's trying just to assess how things are going. Do you include any kind of internal evaluation of a pipeline's condition?

Mr. KESSLER. I'm not sure I understand the last part of that question, Mr. Chairman.

The CHAIRMAN. Well, the first part indicated that sometimes the situations——

Mr. KESSLER. It's not possible.

The CHAIRMAN.—make it more difficult. And if you're trying to make sure that things like here don't happen again you don't want to really guess at what's inside.

Mr. KESSLER. Right.

The CHAIRMAN. And therefore the orange things at the end of ropes attached to a helicopter may be a good idea but may not really tell you that much.

Mr. KESSLER. So when into—when congress, you and others enacted the 2002 Pipeline Safety Act there was—and we formalized in law integrity management, there was an—part of the legislative record included a preference—well, not a preference. A statement that direct assessment should be the least preferred form of inspection in these situations.

It appears that that has been kind of flipped on its head. It's certainly the most cost effective but the least effective means of actually getting data. Certainly there are times when these lines cannot be inspected by inline inspection devices. But that is narrowing more and more as the devices themselves become smaller, more able to move in different directions. The lines become more capable. We certainly need—and the law was weakened in 1996 in terms of PHMSA's authority.

But really we should be requiring more and more circumstances where lines should be replaced to accommodate these smart pigs. And we should be doing better on technology. And there should be even more than just inline inspection at this point. So, yes, more—less direct assessment.

And by the way, Mr. Chairman, we're not always sure, just like you were saying, what that direct assessment is. Is it walking? Is it flying? Is it looking out the window and saying, hey, this looks pretty good to me. I think GAO has pointed that out. I think NTSB at times has talked about this. We really need good strict easily understandable for the industry's sake very clear standards on what direct assessment means, when you use it, and most importantly when you shouldn't.

The CHAIRMAN. All right. Thank you. I'll just make a comment and then Senator Manchin may have a closing statement to make, and I may or may not.

But let me just say that the very first question I said that you already answered is a really, really important one, and that is that you're committed to doing absolutely everything that it takes. Now, granted this is something one could say at almost any time. But the fact is even though transmission by pipeline is generally much safer than most other ways of transmitting things and we all recognize that, we have had an accident here and it's not been a good experience.

So the statement that you're going to do everything possible, everything necessary to bind the wounds, to help people understand, to stay with people, to be close to them is extremely important. And that's more difficult for you because you're head of a very large company. But it just seems to me that your presence is—it's amazing what that will do, what statement that will make. And so I was very encouraged to hear that.

And then I wanted to just say as a matter of what I've heard is that by and large you seem to be doing a very good job.

Mr. STATON. Thank you.

The CHAIRMAN. And I know of a couple people that are upset about this and that, which always happens and necessarily happens, but that you seem to be trying, people seem to feel that. I feel that at least. And so I wanted to make that statement.

Mr. STATON. Thank you. Thank you very much.

The CHAIRMAN. Senator Manchin?

Senator MANCHIN. Thank you, Senator.

Mr. Kessler, you mentioned quite a few things. Is there one thing you think we're not doing that we should be doing immediately that would be helping us to have a safer distribution system? Just one.

Mr. KESSLER. One thing would be better inspections, more often, with greater oversight. Prevention.

Senator MANCHIN. That's——

Mr. KESSLER. Even a good company, and that's why I've been declining to comment on this incident, because even a good company doing all the right things can still have an incident.

Senator MANCHIN. Sure.

Mr. KESSLER. But that said, as President Reagan said, "Trust, but verify," and I don't think we're doing quite enough verifying and doing it in the way we should be. So that would be my answer. Better and more inspections.

Senator MANCHIN. OK.

Mr. Staton, knowing what happened on this particular line when there are three lines parallel in the same area. This is the only one that didn't have that inspection. We've been told now, I think, that there will be valves so that you can do the inspections. Knowing that, do you have other lines in your system that you will take this same precautionary before, hopefully it will never happen again, are you doing that now systemwide?

Mr. STATON. Absolutely we are. We identified on this pipeline because of the size of the pipeline, as Administrator Quarterman indicated, that it was not in a high consequence area. Part of what our modernization program is all about is essentially making all of our system capable so that we can always find issues before they become incidents.

Senator MANCHIN. Is that part of the upgrade FERC if it's granted for you?

Mr. STATON. It is. That's part of the FERC upgrade and it is our intention as part of our corrective action order working with PHMSA to make this line pigable, to run a pig throughout the entirety of this line. And then most importantly, to your point, to take the learnings of similarly situated pipelines where we have crossings, tie-ins with different vintage pipelines, rocky soil, and apply that learning across anywhere else on our system.

Senator MANCHIN. Right. From an industry standard, from you all speaking upon the industry, knowing that we can't have all the people that we need and all the money that's going to be needed to do what we should for the safety of the public, do you recommend that all these companies, I'm sure you're pretty much in tune with all the distribution companies around the country, that this should be a rule that the Federal Government should take in order for this to happen?

Mr. STATON. I fully think—I fully believe that the industry is responding. We are responding beyond, above and beyond——

Senator MANCHIN. Sure.

Mr. STATON.—the requirements in HCAs. I know other pipelines are also responding above and beyond.

Senator MANCHIN. So you all will not have a problem if that rule was adopted by the agencies?

Mr. STATON. We're going to continue—we're going to continue to do the good things we're doing irrespective of—of what happens from a regulatory and legislative perspective.

Senator MANCHIN. And just final, one question, on all the parties that have been involved, I know you all have been making great strides, have you settled—or are you in the process of settling with all of the affected parties in Sissonville and making every effort you can to make sure that settlement is done as quickly as possible?

Mr. STATON. Absolutely we are. I've—my—I believe strongly that my team has worked in a collaborative, thoughtful consideration, taking consideration for what has happened here. And we continue to work to resolve issues. We have resolved a number of them already. But as you would expect——

Senator MANCHIN. Sure.

Mr. STATON.—there's—there are a lot of them.

Senator MANCHIN. You're working to fully reimburse or what we call make whole?

Mr. STATON. Yes. And we have—we've certainly made the state whole for the just amazing work they did on I–77. We made Kanawha County whole for the wonderful work that the emergency responders undertook, and they really did do just a tremendous job. And we are in the process with every affected property owner addressing anything that we can address.

Senator MANCHIN. Let me just say on my behalf in closing, I want to thank Senator Rockefeller for inviting me to be part of this hearing today, and it's truly informative. But encouraging also to see that everyone is trying to move in the most appropriate manner and taking the public safety first and foremost and high standard that we should be trying to achieve those levels of protection for. So from our agencies and also from the private sector we appreciate so much that, and thank you so much for your testimony and your appearances today.

Senator, thank you.

The CHAIRMAN. And I would agree with all of that, and point out that I'm sorry that I kept you, but I'm not because if something had been amiss you would have been pushed to correct it. That the whole concept of oversight, you know, it's very controversial right now in America. People don't like government. People don't like government agencies. People don't like us.

Senator MANCHIN. We've seen that.

The CHAIRMAN. But you cannot compromise on the business of oversight because the Congress is elected. The President is elected and appoints these good people. But there's something about an oversight, having a commerce committee which has, you know, aviation, oceans, weather, all kinds of things and pipelines in its jurisdiction.

I think the concept of oversight is very important. Not that it always causes the world to change vastly for the better but that it's there, that it's asking questions, and that it's frankly part of what democracy needs to be about.

Mr. KESSLER. Mr. Chairman?

The CHAIRMAN. Yes?

Mr. KESSLER. Let me say one thing. I could not agree more. Last Congress you and your Ranking Member, Senator Hutchinson, Chairman Upton, and Member Waxman came out with very good bills. And House—in the House they got watered down once out of those committees into other committees.

The one thing that can keep things moving along, I've learned, in all these years is a commitment to oversight. And the very things that you're talking about mean so much to my organization and I think the public who have all been affected by this. And I think it is good in the long run for this industry and the country. That will help make everyone feel safe and confident in this industry.

So thank you for that statement.

The CHAIRMAN. Good. Thank you all very much. This hearing is adjourned.

[Whereupon, at 2:48 p.m., the hearing was adjourned.]

A P P E N D I X

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. BARBARA BOXER TO PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Question 1. Similar to the tragic 2010 accident in San Bruno, California that killed 8 people and injured 52, the preliminary results of the NTSB's investigation on the Sissonville accident suggest that Columbia's failure to detect serious flaws in its transmission pipeline may have been a contributing factor to the accident. What is the status of PHMSA's rulemakings to improve oversight and communication to pipeline safety operators regarding proper recordkeeping and inspection protocols?

Answer. PHMSA issued an advance notice of proposed rulemaking (ANPRM), entitled "Safety of Gas Transmission Pipelines", RIN 2137–AE72 regarding natural gas transmission pipelines on August 25, 2011. That ANPRM requested public comments on issues raised by the San Bruno incident, including integrity management principles for gas transmission pipelines and gas gathering. PHMSA intends to issue a notice of proposed rulemaking related to those issues later this year. In order to support the required regulatory analysis for that rulemaking PHMSA took several actions last year. On January 10, 2011, PHMSA issued an Advisory Bulletin (AB) (76 FR 1504) to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP). On May 7, 2012, PHMSA issued an AB (77 FR 26822) to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for MAOP and MOP required by 49 CFR 192.517 and 49 CFR 195.310, respectively. On December 21, 2012, PHMSA issued an AB (77 FR 75699) to inform owners and operators of gas transmission pipelines that if the pipeline pressure exceeds MAOP plus the build-up allowed for operation of pressure-limiting or control devices, the owner or operator must report the exceedance to PHMSA (and States with regulatory authority) on or before the 5th day following the date on which the exceedance occurs. On December 5, 2012, the Office of Management and Budget (OMB) approved revisions to the gas transmission and gathering annual reporting requirement (PHMSA F–7100.2–1). On January 28, 2013, PHMSA issued a Federal Register notice (78 FR 5866) to owners and operators of gas transmission and gathering lines regarding significant changes to the annual reporting requirements. Those new annual reporting requirements require owners and operators to validate their Operator Identification Number data, and requests supplemental reports to correct gas transmission and liquefied natural gas annual report data issues when filing their next annual reports on June 15, 2013. This data will be used to support regulations required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which requires operators to conduct tests to confirm the material strength of previously untested natural gas transmission pipelines that operate at a pressure greater than 30 percent of specified minimum yield strength and are located in high-consequence areas. The pipeline in Sissonville was not such a pipeline, however, we are doing further analysis.

Question 2. Also similar to the San Bruno incident, the time it took to shut off the gas in the Sissonville incident may have been a factor contributing to the extent of the damage. It took several minutes for the Columbia Gas controller to even learn of the explosion, despite numerous pressure drop alerts beforehand. It then took company officials over an hour to isolate the section of pipeline where the explosion occurred. Could requiring automatic or remotely-controlled shutoff valves wherever technically and economically feasible help minimize damages in future transmission pipeline explosions?

Answer. In the ANPRM mentioned above, PHMSA also discussed the subject of automatic and remote controlled shutoff valves. PHMSA held a workshop on this subject on March 27, 2012. PHMSA also commissioned an independent study performed by Keiffner and Associates on this topic and held a workshop on the draft of the study and accepted comments on the draft. A copy of that study was submitted to Congress on December 27, 2012. Based on the study, PHMSA is considering a rulemaking action on the benefits and costs of both automatic shutoff valves as well as remote control valves.

Question 3. Why did PHMSA wait until January 31, 2013, to issue its Advisory Bulletin to pipeline owners and operators recommending that they contact the National Response Center within one hour of discovery of a pipeline incident?

Answer. PHMSA had issued a series of Advisory Bulletins' regarding the importance of operators promptly reporting incidents to the NRC. PHMSA's predecessor—Research and Special Programs Administration—issued AB's regarding these issues during the 1980s, and more recently on September 6, 2002 (67 FR 57060) to advise owners and operators of gas distribution, gas transmission, hazardous liquid pipeline systems, and liquefied natural gas (LNG) facilities to ensure that telephonic reports of incidents to the NRC are prompt (within 1 to 2 hours). In addition, on October 11, 2012, PHMSA issued an AB (77 FR 61826) to remind operators of gas, hazardous liquid, and liquefied natural gas pipeline facilities to immediately and directly notify the Public Safety Access Point (PSAP) that serves the communities and jurisdictions in which those pipelines are located when there are indications of a pipeline facility emergency. Furthermore, the AB stated operators should have the ability to immediately contact PSAP(s) along their pipeline routes if there is an indication of a pipeline facility emergency to determine if the PSAP has information which may help the operator confirm an emergency or to provide assistance and information to public safety personnel who may be responding to the event.

Question 4. In 2003, 2005, and 2010, PHMSA hosted public workshops on pipeline operator public awareness programs. Why has PHMSA not conducted any additional public workshops in 2½ years?

Answer. Since late 2010, PHMSA has been conducting inspections on the effectiveness of pipeline operators public awareness programs. Those inspections were completed at the end of December 2012 and we are currently analyzing the results. Once those results have been analyzed, PHMSA is planning to conduct a Public Awareness workshop in June 2013 to bring public awareness stakeholders together to share the inspection results and discuss ways to strengthen and expand public awareness for the public, emergency response officials, public officials, and excavators. The workshop will be webcast live to allow for broad public participation.

Question 5. PHMSA's current Strategic Plan calls for "increase[ing] the visibility of our prevention and response efforts to better prepare the public." Please describe the three major actions PHMSA plans to take to address this objective and its approach to evaluating the effectiveness of these actions?

Answer. PHMSA has already taken significant actions to increase the visibility of our prevention and response efforts and has much more planned. PHMSA is evaluating a number of major actions to increase the visibility of our prevention and response efforts to better prepare the public, including:

- PHMSA has pursued a strategy of institutionalizing pipeline awareness in the emergency response community over the past 18 months. The strategy commenced with a public, webcast Pipeline Emergency Response Forum on December 11, 2011. Since the forum, PHMSA has undertaken a variety of initiatives to better prepare emergency responders to safely and effectively respond to pipeline emergencies. PHMSA convened a Pipeline Emergency Response Working Group of emergency responders, pipeline operators, and government officials. PHMSA has also partnered with the National Association of State Fire Marshals, the U.S. Fire Administration, and Transportation Community Awareness and Emergency Response (TRANSCAER®). PHMSA has led a pilot project in Virginia to incorporate pipelines into the statewide emergency response plan and has led a pilot project in Georgia to ensure adequate pipeline training for emergency responders. PHMSA has also been represented annually at five major firefighter/emergency response conferences across the country. PHMSA has written several articles for major firefighter magazines and developed a brochure that highlights pipeline safety resources that PHMSA makes available to emergency responders. PHMSA is also funding a research project that will produce a guide for effective communication practices between pipeline operators and emergency responders. Additionally, the National Fire Protection Association (NFPA) is making a variety of changes to their standards that will elevate the importance of pipelines in the training competencies of firefighters.
- PHMSA also produced and distributed an 811 television and radio Public Service Announcement, expanded its efforts in supporting National Safe Digging

Month and National 811 Day, and incorporated social media messages into the 811 campaign. An annual survey is conducted to measure 811 awareness. PHMSA is also planning to conduct a public awareness workshop in June 2013 to bring public awareness stakeholders together to discuss recent public awareness inspections and to discuss ways to strengthen and expand public awareness.

- PHMSA is executing damage prevention initiatives and will, in the coming months, issue a Final Rule entitled "Pipeline Safety: Pipeline Damage Prevention Programs, RIN 2137–AE 43. The rule will focus on the enforcement of One Call laws; address exemptions in One Call laws through a study; grants to States for the purpose of strengthening damage prevention programs; and work with State stakeholders who seek to improve their One Call laws and programs through meetings, data analysis, and letters of support. Incidents caused by excavation damage have decreased by 30 percent since 2008.

RESPONSE TO WRITTEN QUESTIONS SUBMITTED BY HON. BARBARA BOXER TO JIMMY D. STATON

Question 1. Why did Columbia have to rely on another company's employee to notify Columbia of the explosion?

Answer. Columbia Gas relied on several pieces of information to determine that the Sissonville rupture had occurred. The primary source of information was the Supervisory Control and Data Acquisition System (SCADA) network. The SCADA system collects near-real-time electronic data from sensors strategically located throughout the pipeline system. Pipeline pressures, equipment status, station alarms and other information is relayed through the SCADA system to our Gas Control Center where the data is used by our Gas Control Team to monitor and safely control natural gas flow throughout the pipeline system.

Within approximately two minutes of the rupture occurring, Columbia's Gas Control personnel received and acknowledged SCADA alerts indicating a drop in operating pressure. The deviation alert was generated from pressure sensors located at Lanham Compressor Station, located approximately 4.7 miles west and upstream of the rupture location. Since pressure drops are not unusual and can have both normal and abnormal causes, our Gas Control personnel acknowledged receipt of the alerts and began to investigate potential causes of the pressure drop, such as compression changes, market (demand) changes, a leak, etc., to see whether any further action was needed.

After receipt of the SCADA alerts, Columbia's Gas Control Center received a call from a gas controller at Cabot Oil & Gas and were told that one of Cabot's field technicians happened to be driving near Sissonville and heard a loud noise and then a roaring sound, which he believed could have been caused by the rupture of a major gas pipeline. Since Cabot did not have any indications of a leak in their system, and the employee knew Columbia Gas had transmission lines in the Sissonville area, the Cabot gas controller conveyed this information to Columbia Gas Control.

In short, Columbia Gas did not rely on another company's employee to notify it of the Sissonville rupture. Among the several pieces of information Columbia Gas Control collected to analyze the situation was an eye witness report from a Cabot field technician who happened to be in the Sissonville area and witnessed the immediate aftermath of the rupture.

Question 2. What notifications to the community was Columbia required to make about the event, and did the company comply with these requirements?

Answer. Columbia Gas complied with all applicable reporting requirements. Columbia Gas is required to contact the National Response Center (NRC) following any event that meets the definition of an incident, in accordance with current pipeline safety regulations (49 CFR 191). Columbia personnel did in fact contact the NRC to report the Sissonville rupture immediately after the accident. After reporting the incident to the NRC, Columbia also contacted the Director of the West Virginia Public Service Commission and the Pipeline and Hazardous Materials Safety Administration's Eastern Regional Office to inform them of the incident.

In addition, Columbia's Operations personnel coordinated with the responding fire, police and emergency management services to isolate the rupture location and secure the site to ensure the safety of the public.

PREPARED STATEMENT OF TIM GOOCH, FIRE CHIEF, SISSONVILLE VOLUNTEER FIRE DEPARTMENT, WEST VIRGINIA

Thank you Senator Rockefeller and other esteemed members of the Committee for allowing me the opportunity to testify on the matter of Pipeline Safety: An on-the-ground look at safeguarding the public. My name is Tim Gooch and I am the Fire Chief of the Sissonville Volunteer Fire Department. I have served with the fire department for almost forty (40) years. I am proud of our department and of our community.

Our fire department protects a 125 square mile fire district in northern Kanawha County, West Virginia. We serve a population of just over 8,700 homes and over 150 businesses. In 2012 we answered over 600 fire and rescue calls and were dispatched to another 1,000 emergency medical calls. All of these calls were answered by volunteers—men and women who don't get paid to respond to events like this explosion. I would put our department's training up against any other volunteer fire department in the country—we take training very seriously.

One of the largest employers in the Kanawha Valley, the NGK Corporation, calls our community "home". We have four (4) public schools, a library, and almost twenty (20) miles of Interstate 77 that run through our area. Part of what we protect is over fifty (50) miles of natural gas transmission pipelines along with four (4) natural gas compressor stations and numerous production wells. While coal is often the first thing one thinks of when you hear West Virginia, we know about the other resource—natural gas—that is so critical to our Nation's energy future.

Our fire district is made up of a resilient population that have gone through four (4) natural disasters in the past fifteen (15) years—three (3) National Disaster floods and one (1) "Derecho". We have seen our fair share of destruction but we have also been blessed to see how a community can pull together with neighbor helping neighbor. Sissonville is not the "Buckwild" seen on TV—it is families and people, churches, civic groups and businesses—that pull together in tough times and rebuild. It is a fire department that nearly lost everything to fire in 2010 but rose like the Phoenix from the ashes to be even better than before. That is my view of Sissonville. I wouldn't have spent the last forty (40) years in the fire service if I didn't believe in the good in this community.

Tuesday, December 11, 2012

On Tuesday, December 11, 2012 I was looking forward to an afternoon off my paying job to do things to get ready for the holidays. At 12:41 p.m. our department—Station 26—dispatched to an explosion in the area of 2001 Teresa Lane—an apartment complex—in our area. The initial dispatch was that it may have been a gas well explosion. Within a brief period there was radio traffic about multiple structures on fire—possibly a nursing home—possibly a meth lab explosion. I started to respond to the station to get a truck immediately after the initial dispatch. Our department operates three (3) stations and the station that I was heading to is located in the southern part of our fire district. Once at the station, because of the radio traffic I was able to receive, I marked enroute with one (1) of our tankers and headed towards the scene. I could tell by the radio traffic that others were enroute as well but still had not received a clear size-up of what was the real situation.

I was fortunate that I was able to proceed to the scene by using Route 21 (Sissonville Drive) without encountering all of the traffic congestion that units who responded after the initial alarm had to deal with. As I got into the area of Sissonville High School (the 6100 Block of Sissonville Drive) I saw a large column of smoke and knew we had a large body of fire—there was a large thermal column of dark smoke—typical of what one would see with a structure fire. Keep in mind that this was approximately two (2) miles south of the fire scene and on the other side of Archibald Hill—a large hill that is between the high school and where the incident was actually located.

As I came up and over Archibald Hill I knew that the incident was not in the area of 2001 Teresa Lane as initially dispatched but was north of that location in the bottom of the valley near the intersection of Derrick's Creek and Route 21 (Sissonville Drive). As I reached the top of Archibald Hill it was quite clear that we had a large body of fire with an approximate size of 200 feet across and 100 to 150 feet high burning. When I marked on scene and got out of the truck there was a lot of noise from the gas venting from the breach. As I walked towards the other members of my department that had arrived before me I could also see, based on the smoke, that at least a couple of structures were involved. The nature and scope of the fire coupled with the radiant heat made doing a 360 walk-around impossible. My Lieutenant, Eddie Elmore, who had arrived before me in Engine 261 told me that he had requested mutual aid from other departments including trying to get units on the north end of the fire which was inaccessible from our location. I assumed command and began trying to formulate an Incident Action Plan.

You have to understand the nature of a volunteer fire department. During the day we often operate short on manpower because our firefighters have to work. I had four (4) firefighters on scene, multiple structures on fire, and an obvious natural gas based fire. I knew I had help coming but didn't know the time frame for when it would get there. My primary consideration was for the safety of my firefighters and then to get any victims out as safely as possible. Denying entry into the scene really wasn't an issue as nobody in their right mind would go near the incident with the volume of fire and the radiant heat being given off.

I saw that the Interstate was compromised but, again, couldn't get over to it and had to rely on common sense to prevail and that people would avoid the fire. I could see vehicle stopped so I assumed the road was blocked. Please understand that I am giving you "snapshots"—as a Fire Chief or an Incident Commander you have to look at the situation you have, what you have to work with, what needs to be done, in what order it needs to occur and how all this can be done safely. We received information that a woman was trapped behind a house and we formulated a plan for a "GO RESCUE" of her. A team went in and got her and safely removed her from harm's way.

As additional resources arrived we were able to do a more thorough recon of the area. An Incident priority was to get the gas shut off and that plan was implemented in what I thought was a short timeline. With the interstate and Sissonville Drive being closed because of the incident there were some issues getting additional resources to the scene but it is what it is and we had to deal with it. We responded to at least five (5) other related calls while handling the main incident and were able to arrange for emergency services coverage for the rest of our area during the event. I felt that the interagency cooperation was tremendous and contributed to the successful incident outcomes that we achieved—no loss of life, no life threatening injuries, and no First Responder injuries or deaths. As we needed resources, they were assigned and effectively managed. We returned units to service as quickly as practical.

Once the pipeline involved was identified, we received excellent cooperation from them. School children were sheltered in place at their schools until safe arrangements could be made to get them home. A church in our community quickly set up a shelter for those impacted—either displaced or those who couldn't get home because of the roads blocked. We worked with the media to help ensure that accurate information was getting out in a timely fashion. It was a true team effort. I am very proud of the efforts made by all of the First Responders who helped out in this event. As the Fire Chief it is good to know that our training and preparation paid off. We contained the event, made several rescues, and, although many were inconvenienced, no one died or was hurt other than those initially impacted by the blast.

Lastly, I am proud to continue to serve my community. This incident is now part of our history and will be used by my department to prepare for the future. We will learn and grow from what occurred. We will never stop trying to be better than we are.

Thank you all for your time today and for your concern about the countless Sissonville's of our nation. May God bless our community and our country.

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