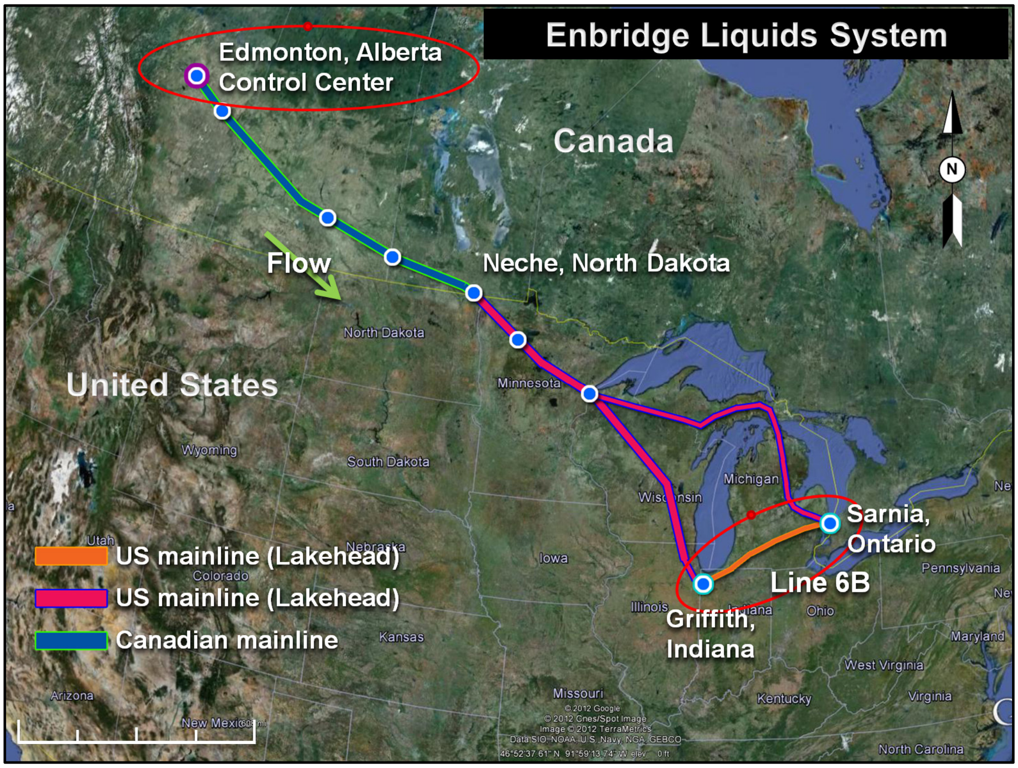
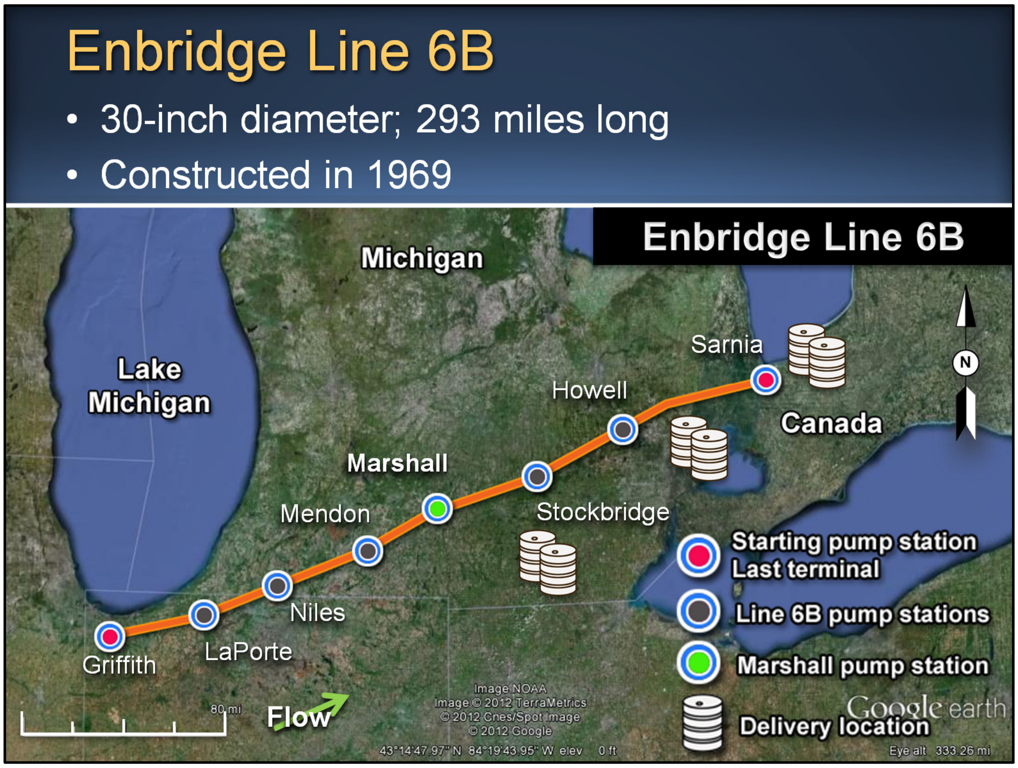
Good morning Chairman Hersman, Vice Chairman Hart, and members of the Board. Today I will provide an overview of the July 25, 2010, Enbridge Line 6B pipeline rupture and crude oil release that occurred in Marshall, Michigan, and resulted in large environmental impacts along Talmadge Creek and the Kalamazoo River. **[Click]**



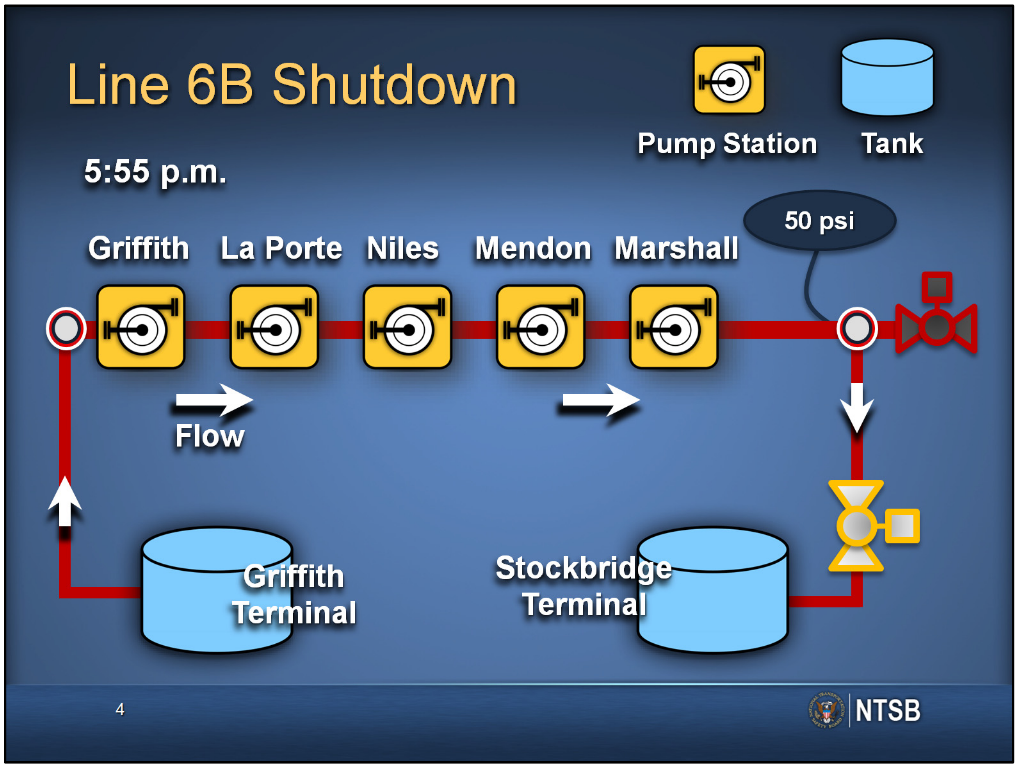
Line 6B is part of the Enbridge liquids mainline system, shown here, which is a collection of multi-diameter parallel transmission lines capable of shipping over 105 million gallons of crude oil per day, from Western Canada to refineries in the upper Midwest of the United States and eastern Canada. **[Click]**

The Canadian portion of the liquids system, starts in Edmonton, Alberta, Canada, and spans over 1,400 miles before crossing the U.S. border at North Dakota. The U.S. portion of the mainline system extends 1,900 miles across the upper Midwest and is known as the Lakehead system. It is shown here as the red and orange lines. The Lakehead system includes multiple parallel transmission lines traversing Minnesota, Wisconsin, and Illinois before tying into Line 6B at Griffith, Indiana. **[Click]**

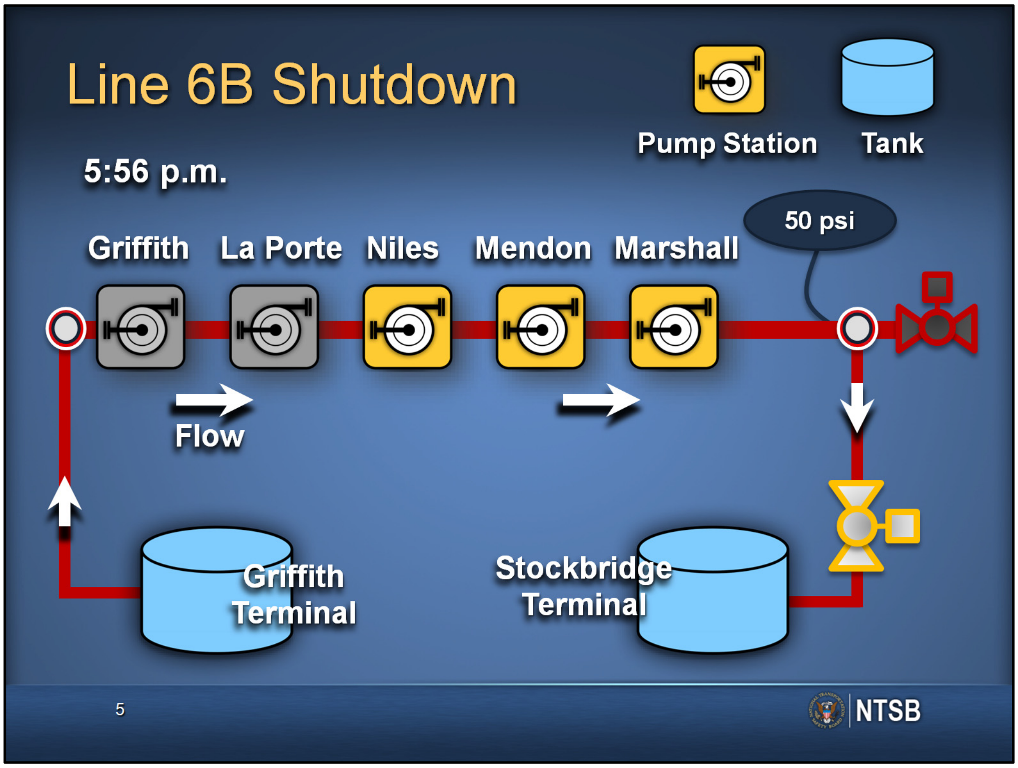
The entire liquids mainline system is controlled from a single control center located in Edmonton, Alberta, Canada, shown near the upper left-hand corner of this slide. **[Click]**



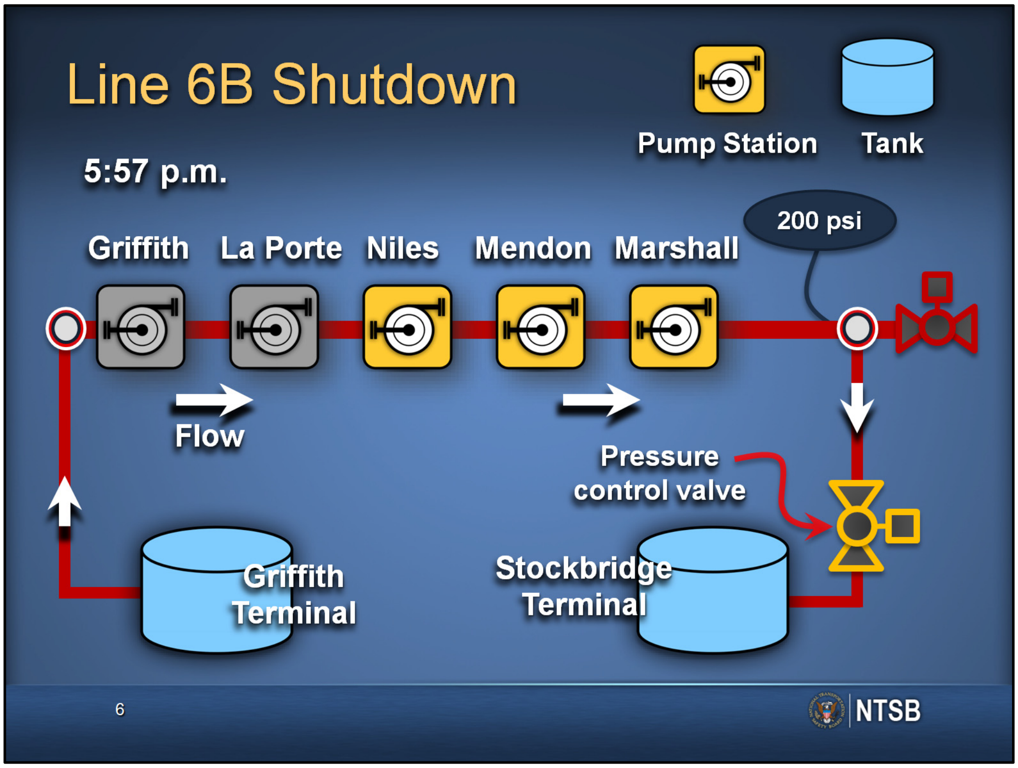
Line 6B is a 293-mile-long 30-inch-diameter pipeline spanning the state of Michigan and connecting Griffith, Indiana, with Sarnia, Ontario. Constructed in 1969, Line 6B makes up a final portion of the Lakehead pipeline system and includes seven pump stations with delivery locations near Stockbridge, Michigan, and Sarnia, all of which are operated from the Edmonton control center. **[Click]**



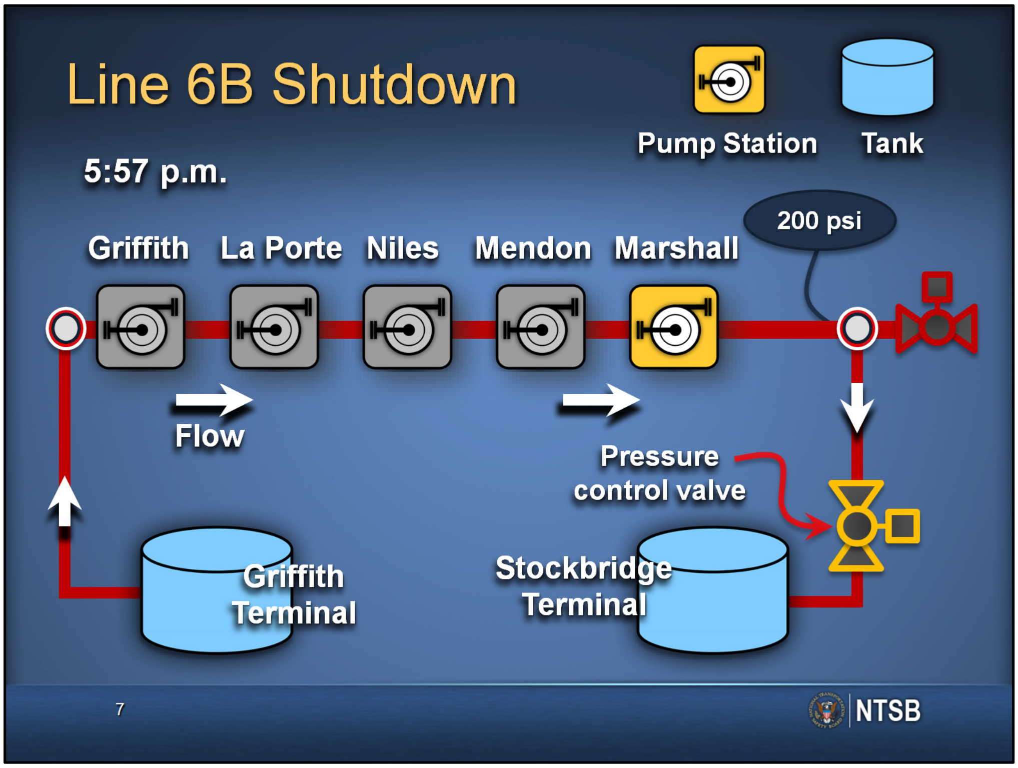
On Sunday, July, 25, 2010, a scheduled shutdown was planned for Line 6B. The shutdown was started about 5:55 p.m., immediately following a delivery of oil to the Stockbridge terminal. **[Click]**



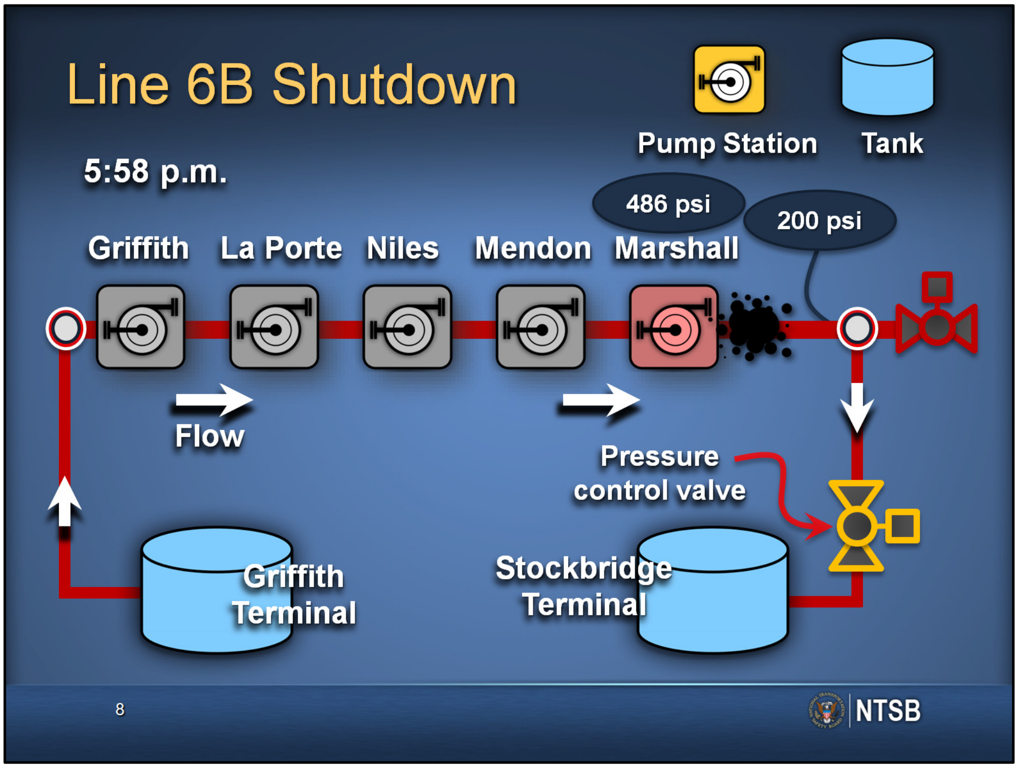
The control center operator shut off pumps at Griffith and La Porte pump stations about 5:56 p.m. **[Click]**



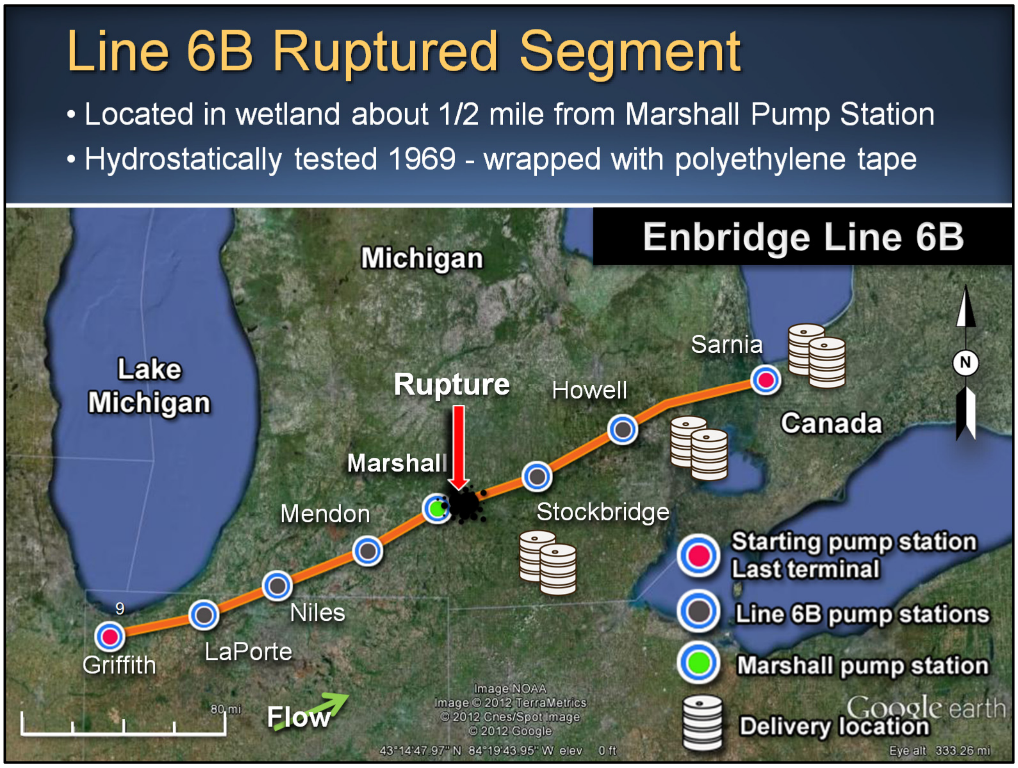
Next, the control center operator changed a setting at a pressure control valve located downstream of the Marshall pump station. The control valve increased the upstream pressure from 50 to 200 psi in roughly 16 seconds. **[Click]**



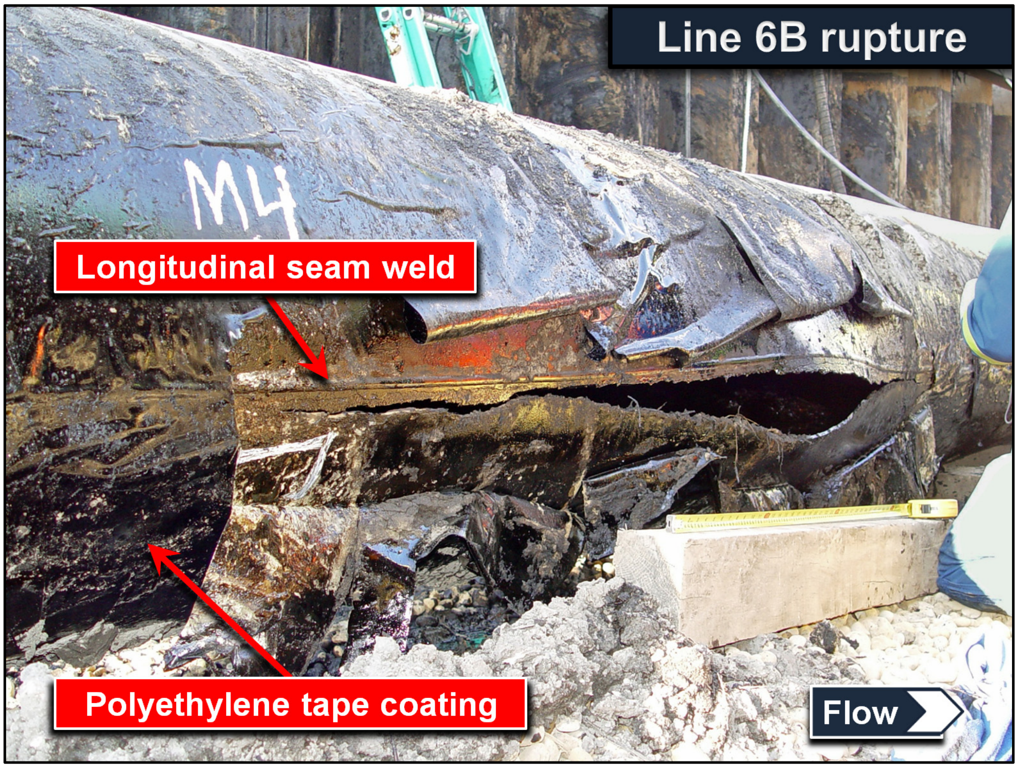
Over the next 45 seconds, the control center operator shut down pumps at Niles and Mendon. [Click]



About one minute after the change in pressure at the control valve, a pipeline segment, downstream of the Marshall pump station, ruptured, and the pump automatically shut down due to low pressure. The highest recorded pressure, at the time of failure, was 486 psi. The stated maximum operating pressure of the ruptured segment was 624 psi. **[Click]**

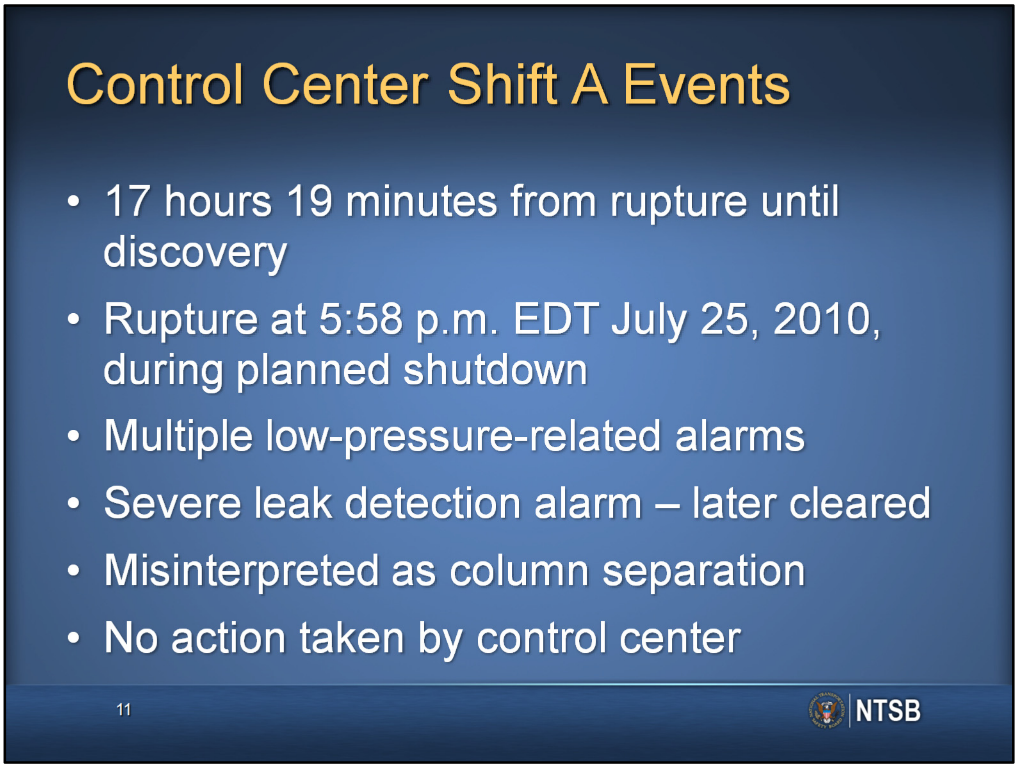


The ruptured pipeline segment was located in a mostly rural wetland region just over a half mile downstream from the Marshall pump station and designated as a high consequence area by Enbridge. The segment was constructed from double submerged arc welded carbon steel pipe, fabricated and shipped from Italy. The segment was hydrostatically pressure tested at the time of construction and wrapped with a polyethylene tape coating. **[Click]**



The rupture, shown here, occurred below the longitudinal seam weld and measured over 6.5 feet long and over 5 inches wide at its widest point.

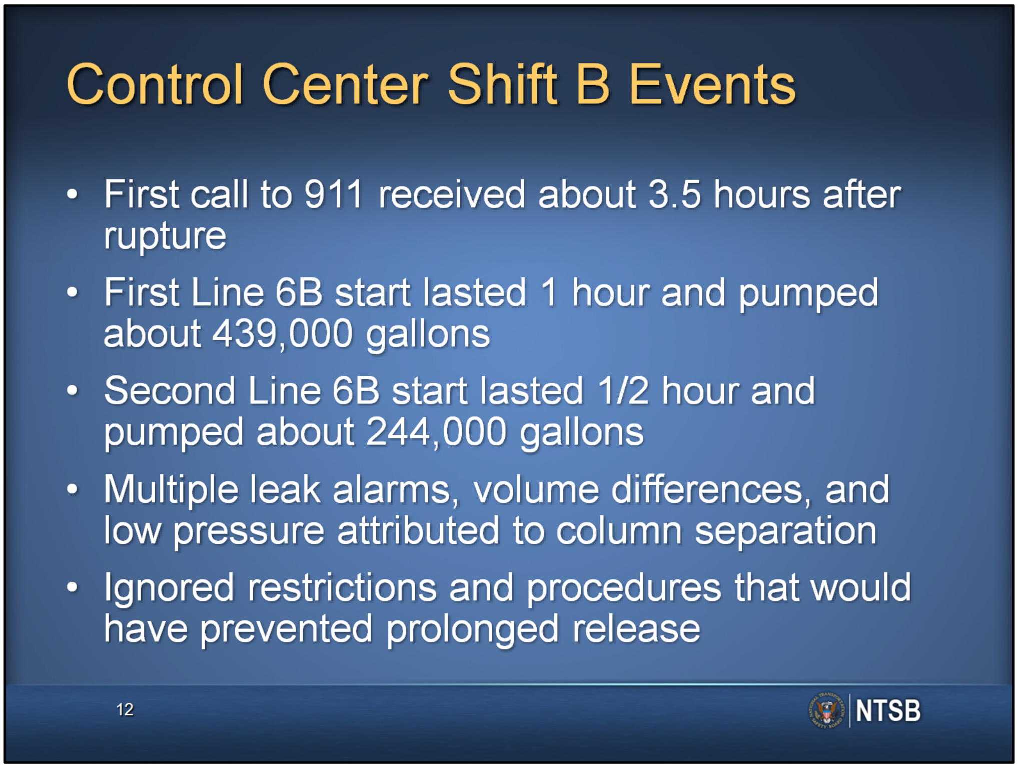
The rupture was made up of numerous small cracks in areas of corrosion that grew larger and joined together over time under a disbonded tape coating. Enbridge had inspected Line 6B for corrosion in 2004 and for cracks in 2005. The group of small cracks that ultimately grew to failure had been detected but misidentified as a single 51.6-inch-long crack following the 2005 pipeline inspection. The crack was analyzed under the Enbridge integrity management program, which determined that no remediation or repair was necessary. **[Click]**



Seventeen hours 19 minutes elapsed between the time of the rupture and the time of discovery, which spanned three Edmonton control center shifts, referred to here as shifts A, B, and C.

The rupture occurred on Shift A at 5:58 p.m. eastern daylight time on Sunday, July 25, as Line 6B was being shut down as part of a scheduled 10-hour event. When the rupture occurred, it generated several low-pressure-related alarms and a severe leak alarm, which cleared within a matter of minutes.

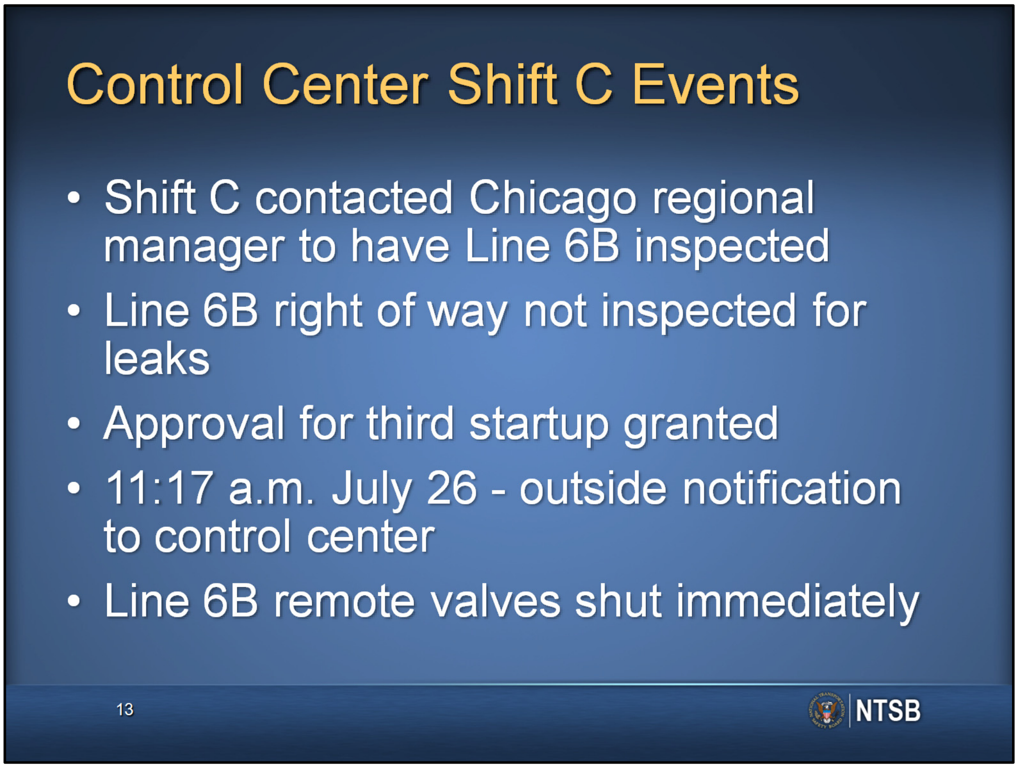
All of the alarms were dismissed as related to the shutdown and a condition known as column separation or an incompletely filled pipeline. In addition, because the leak alarm cleared, no control center action was taken and Line 6B remained shut down. **[Click]**



Shift B took over the control center 2 hours after the rupture. About 1 1/2 hours into shift B, the first of many calls to 9-1-1 was made, reporting odors of natural gas or crude oil. Two local fire departments were dispatched to the area, looking for natural gas, but they could not locate the source of the odors.

During the 14 hours following the 9-1-1 call and before discovery of the rupture, Line 6B was started and stopped two times by Shift B. The first startup lasted 1 hour and pumped about 439,000 gallons into Line 6B, and the second startup lasted about a half hour and pumped another 244,000 gallons.

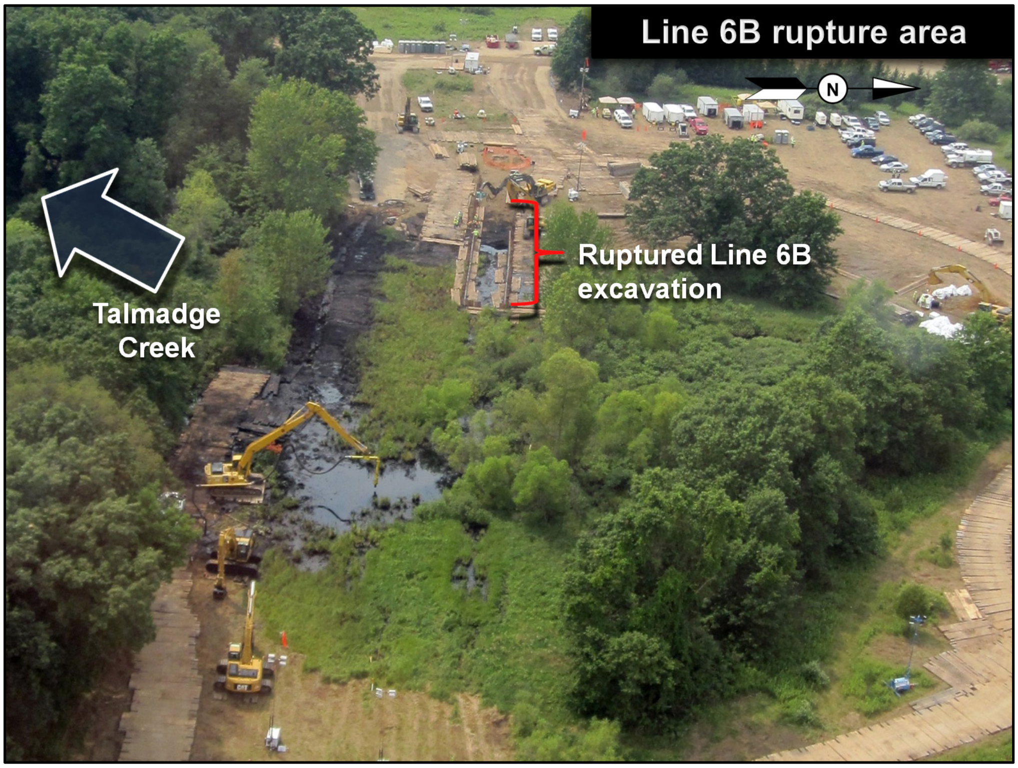
Both startups resulted in repeated severe leak detection alarms, large differences in volume of oil injected versus delivered, and continual low pressure at Marshall; however, the control center staff ignored restrictions and procedures put in place to prevent a prolonged release during periods of uncertain operation. The leak detection alarms and control center data were repeatedly misinterpreted as column separation, and the control center staff pumped additional oil into the pipeline expecting the problem to correct itself. **[Click]**



Shift C took over on Monday morning, July 26, about 14 hours following the rupture. Based on a review of information from Shift A and Shift B, Shift C notified the Chicago regional manager to have the Line 6B right of way inspected near the Marshall Pump Station.

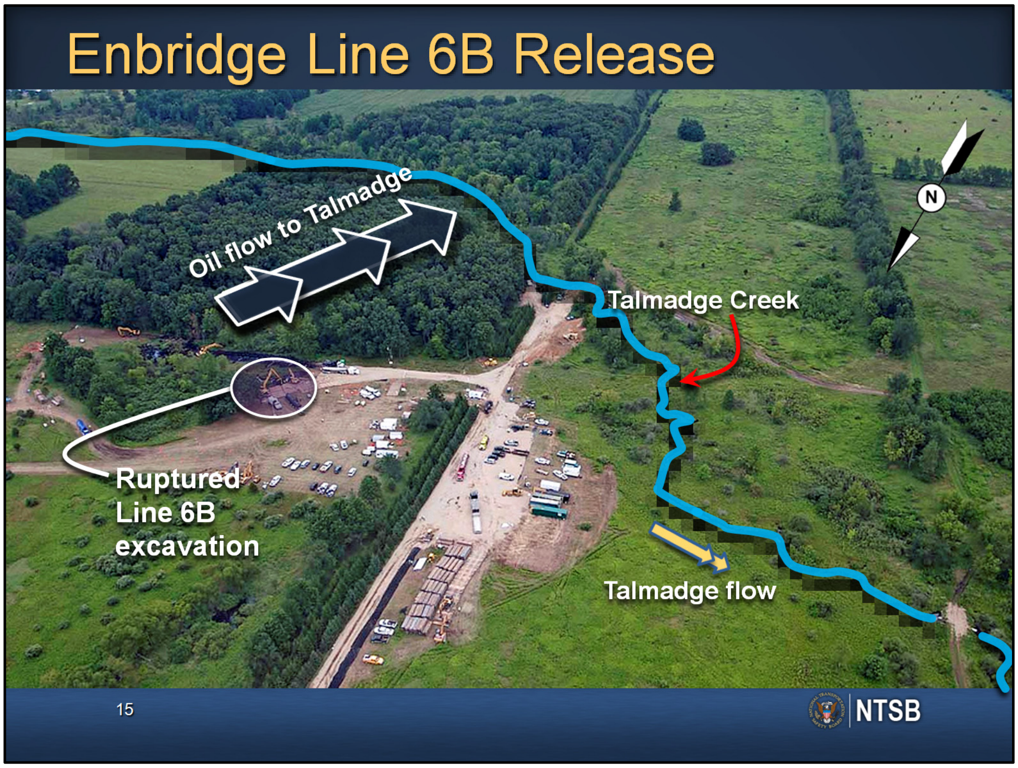
In part because there had been no outside calls to the control center reporting an oil release, Line 6B was not inspected and instead permission was granted to the Edmonton control center for a third startup.

A third startup never occurred, and 1 hour later, at 11:17 a.m. on July 26, the Edmonton control center was notified by an outside caller of oil on the ground in Marshall and entering Talmadge Creek. The Enbridge control center immediately shut remote valves following the notification. **[Click]**

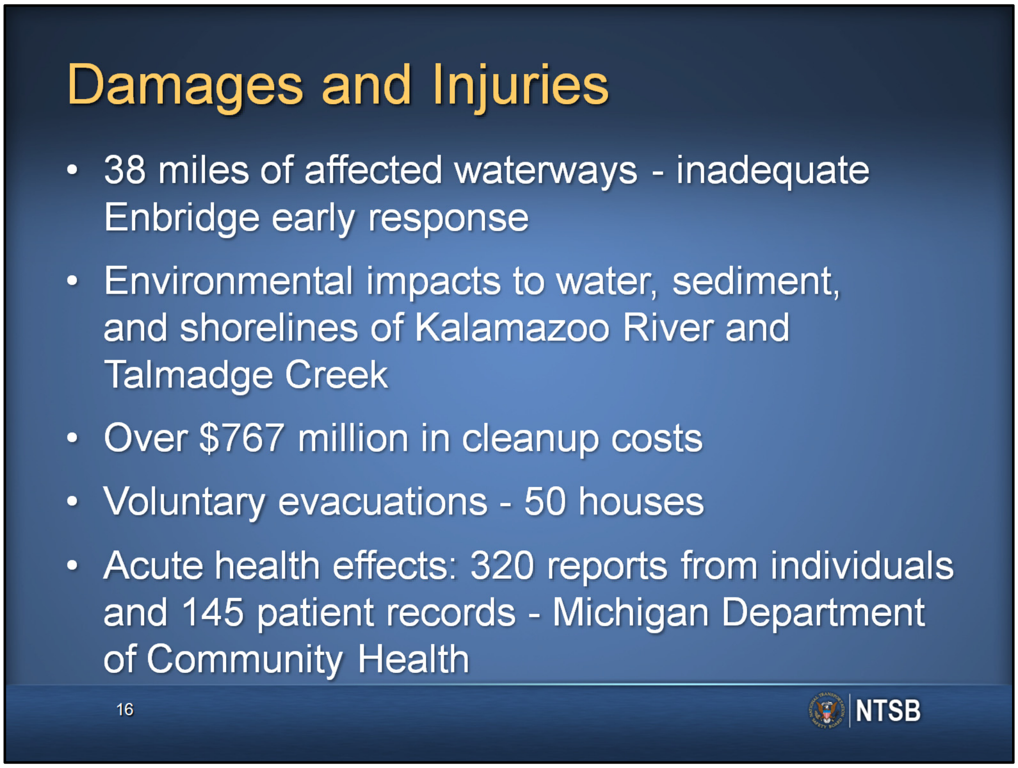


Shown here is an area adjacent to the ruptured segment, about a week after the release. The segment is being excavated for removal near the top of the photo. Talmadge Creek is located through the trees to the left of the pool of oil.

The rupture and delayed recognition resulted in a total Enbridge reported release of over 843,000 gallons of crude oil. This would produce enough gasoline for one person to drive around the world about 500 times. **[Click]**



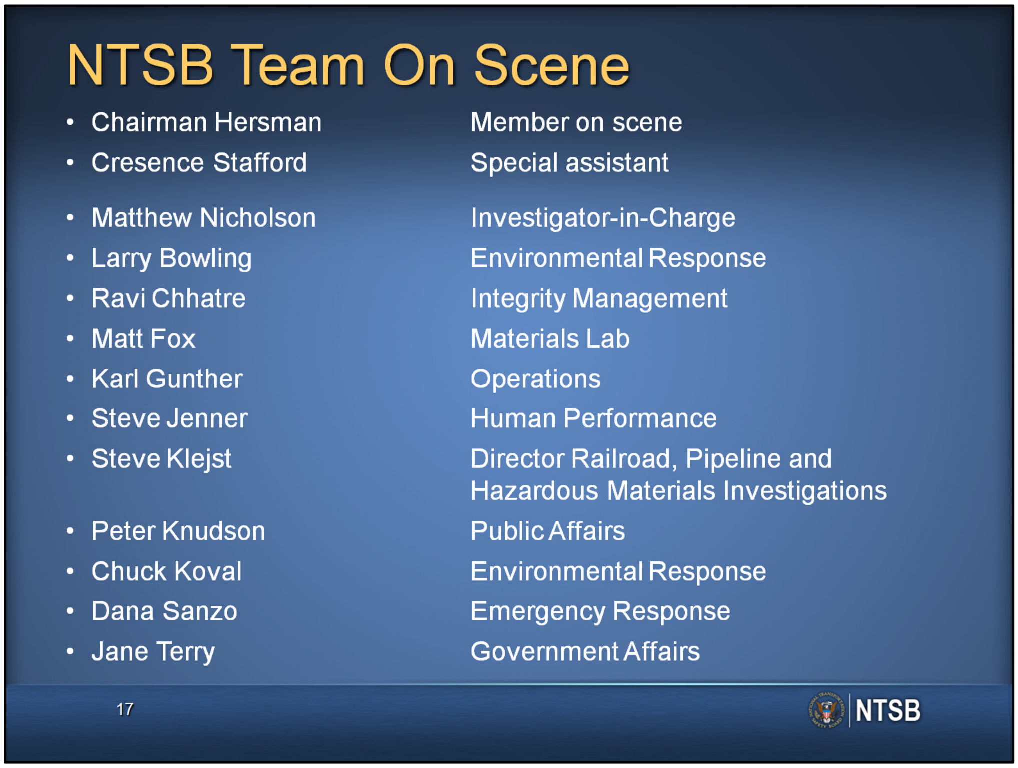
This photo provides another vantage point of the rupture site and nearby Talmadge Creek. During the almost 17.5 hours preceding discovery of the rupture, oil followed the terrain south from the rupture site and into Talmadge Creek. Once in the creek, the oil was eventually carried into the Kalamazoo River, about 2 miles west. Both waterways were flowing fast due to the recent heavy rains. **[Click]**



The Enbridge early response resources were inadequate to address the spill size and waterway conditions present near Marshall. In addition, efforts were not focused on containment near the source of the release. As a result, the affected waterways stretched nearly 38 miles west of the rupture site and included cleanup of the water, sediment, and shorelines.

As of October 2011, Enbridge had estimated the cleanup and recovery costs at $767 million dollars. This estimate was recently increased by an additional $42 million dollars.

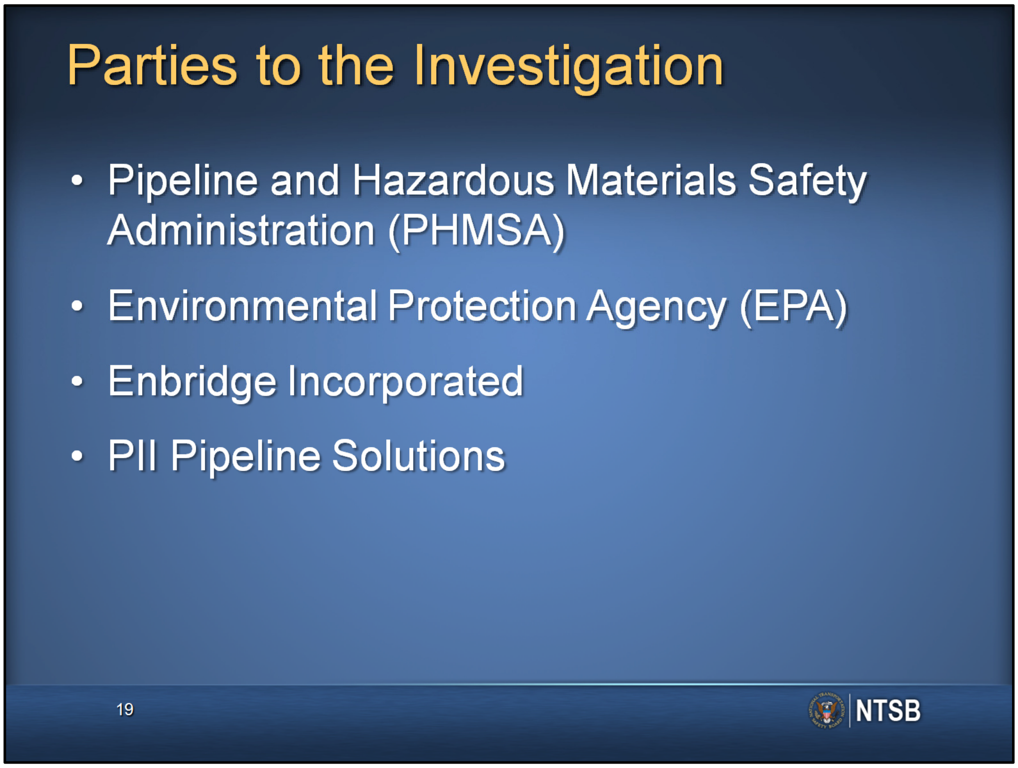
Following the discovery of the release, a voluntary evacuation notice was issued to 50 houses along the affected waterways, which lasted through mid-August. In a November 2010 report, the Michigan Department of Community Health identified 320 individuals and 145 patient records where symptoms were consistent with the health effects associated with acute exposure to crude oil. **[Click]**



The NTSB was notified on July 27, 2010, and a team of accident investigators was launched to the accident site from headquarters and from Jacksonville, Florida. Another investigator was launched to the Enbridge control center in Edmonton, Alberta, Canada.

Chairman Hersman and her special assistant joined the investigative team at the accident site. **[Click]**

Additional NTSB staff support was provided following the on-scene phase of the investigation by those people listed on this slide. **[Click]**



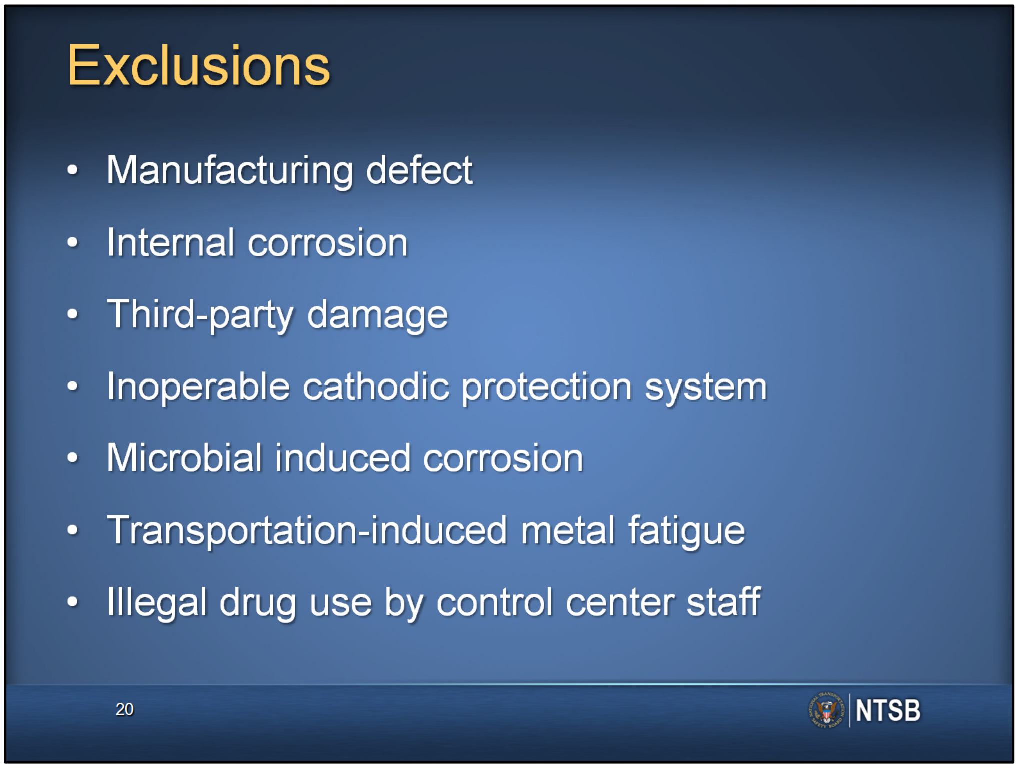
Parties to the investigation include:

The Pipeline and Hazardous Materials Safety Administration (PHMSA)

The Environmental Protection Agency (EPA)

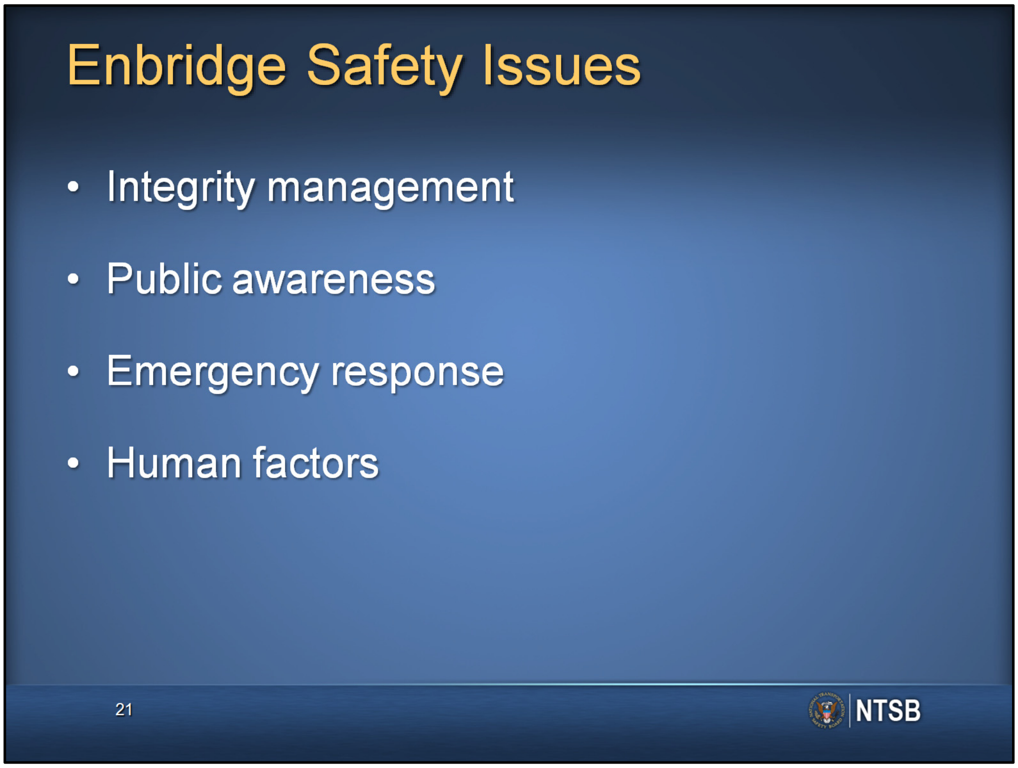
Enbridge Incorporated

and P-I-I Pipeline Solutions **[Click]**



Investigators found no evidence that manufacturing defects, internal corrosion, third-party damage, inoperable cathodic protection, microbial induced corrosion, or transportation-induced metal fatigue contributed to the failure of the pipeline.

In addition, investigators found no evidence that illegal drug use played a role in the control center decisions. However, the investigation did identify a number of safety issues that are addressed in the draft report, some of which will be discussed here. **[Click]**



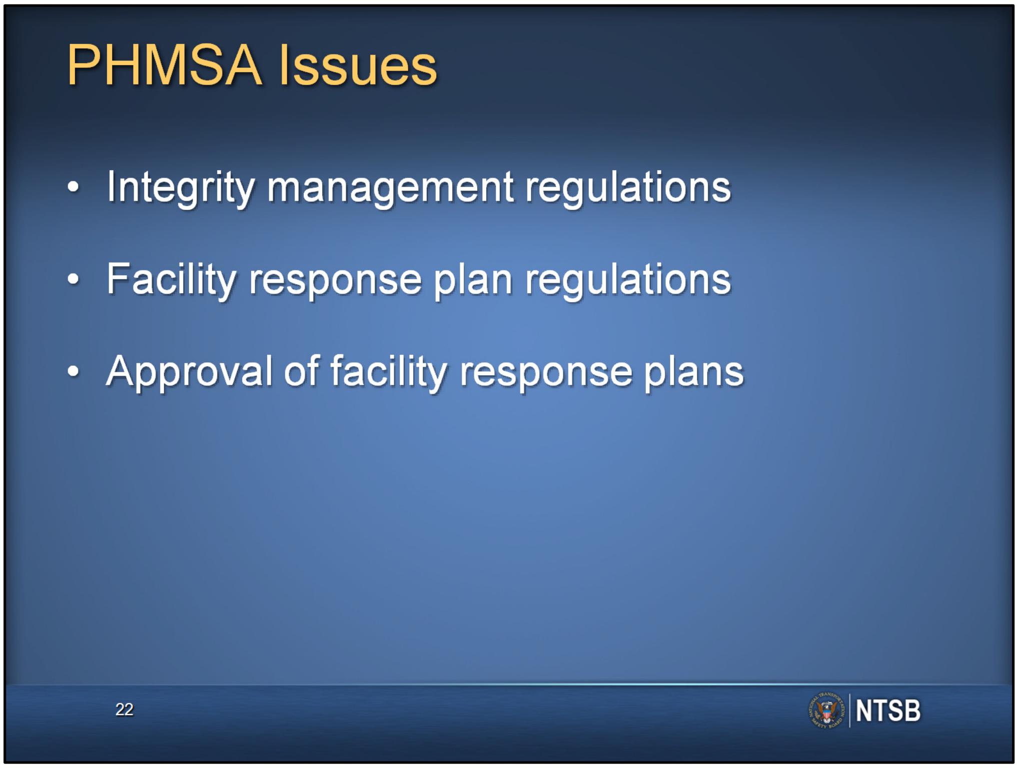
Today you will hear presentations by staff covering safety issues related to Enbridge deficiencies in the areas of

Integrity management

Public awareness

Emergency response and

Human factors **[Click]**



In addition, staff will discuss PHMSA issues related to

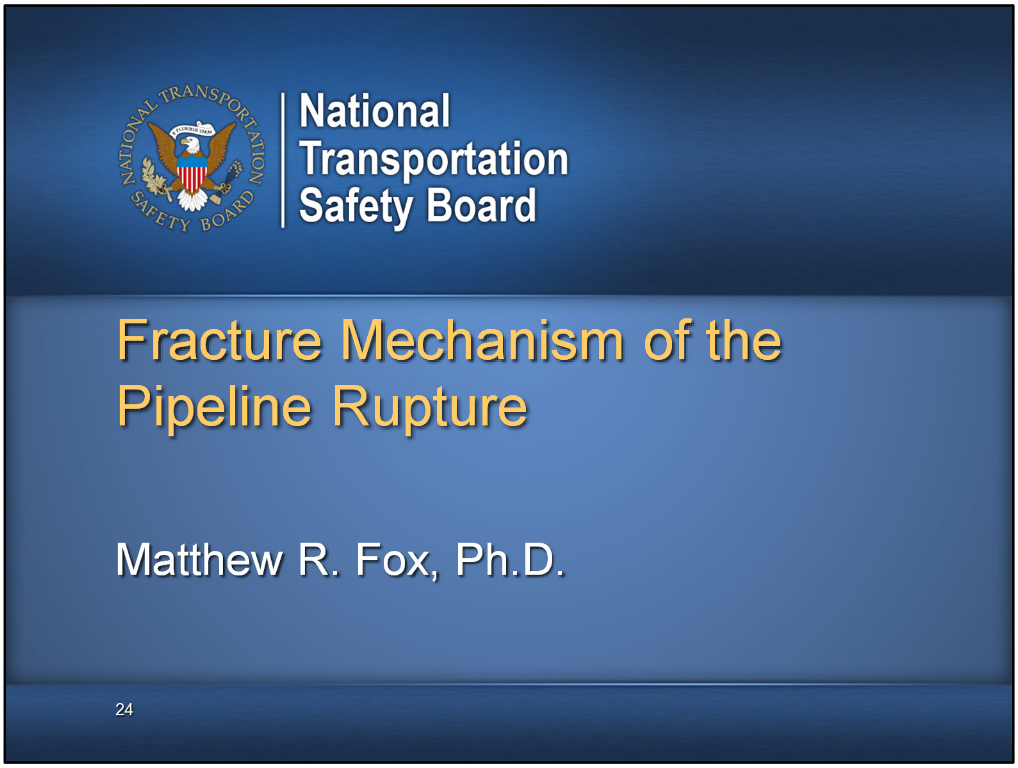
Integrity management regulations

Regulations governing facility response plans

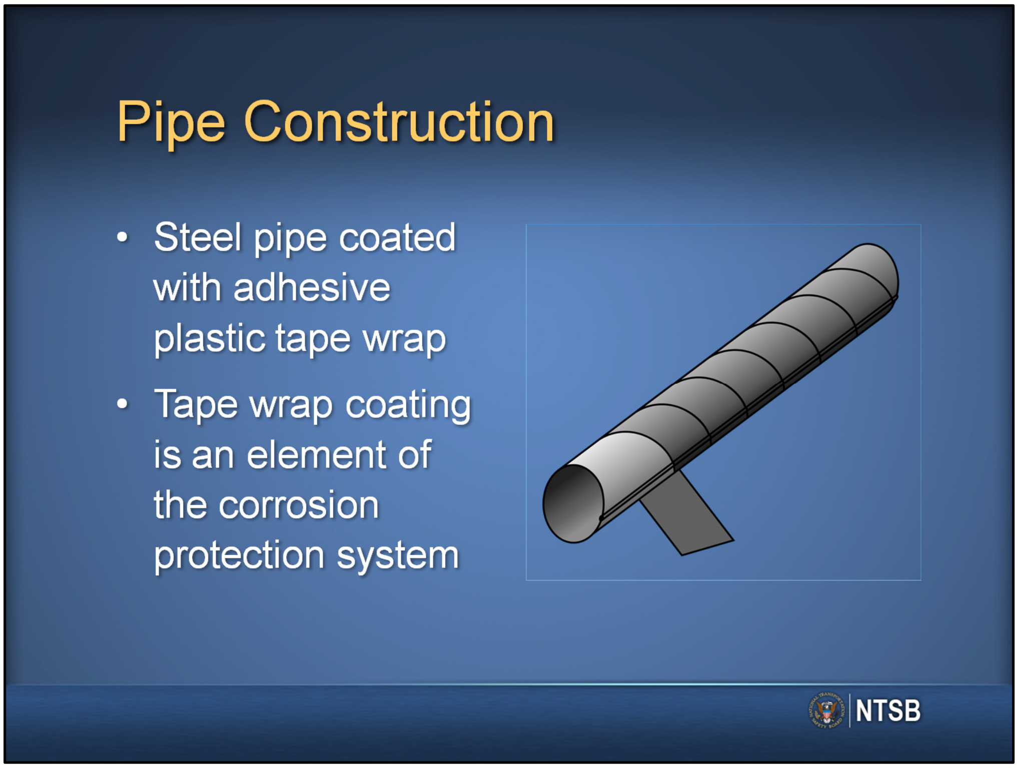
And PHMSA’s review and approval of facility response plans. **[Click]**

This concludes the overview of the accident and the safety issues.

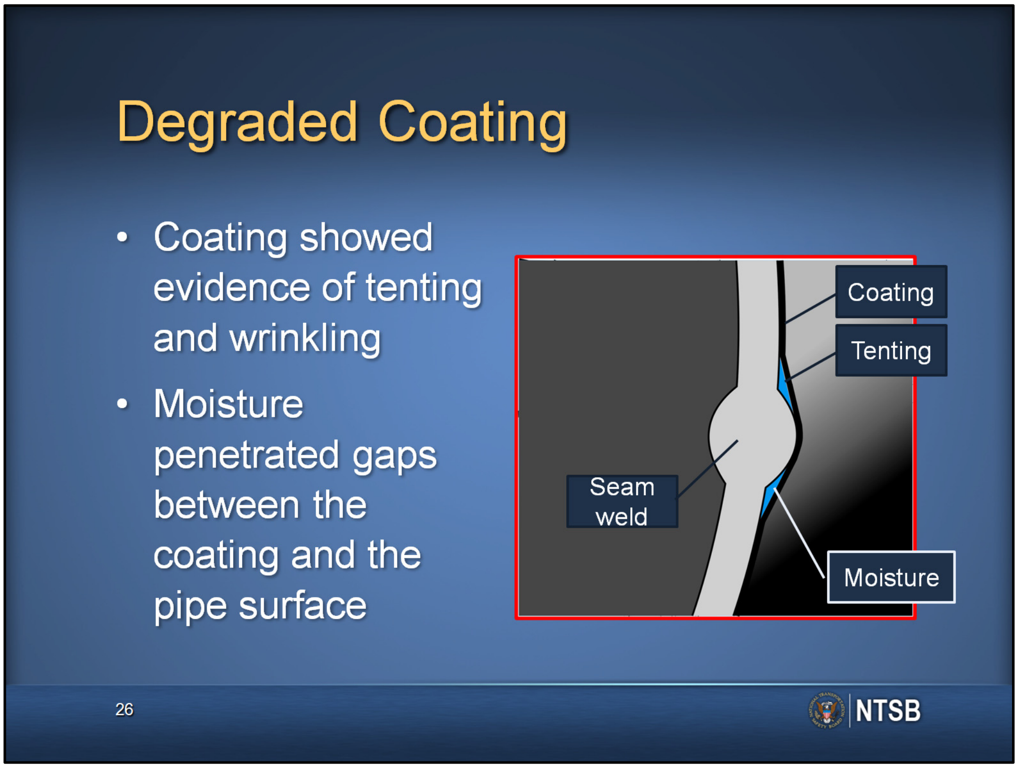
Dr. Fox will now discuss the fracture mechanism of the rupture. **[Click]**



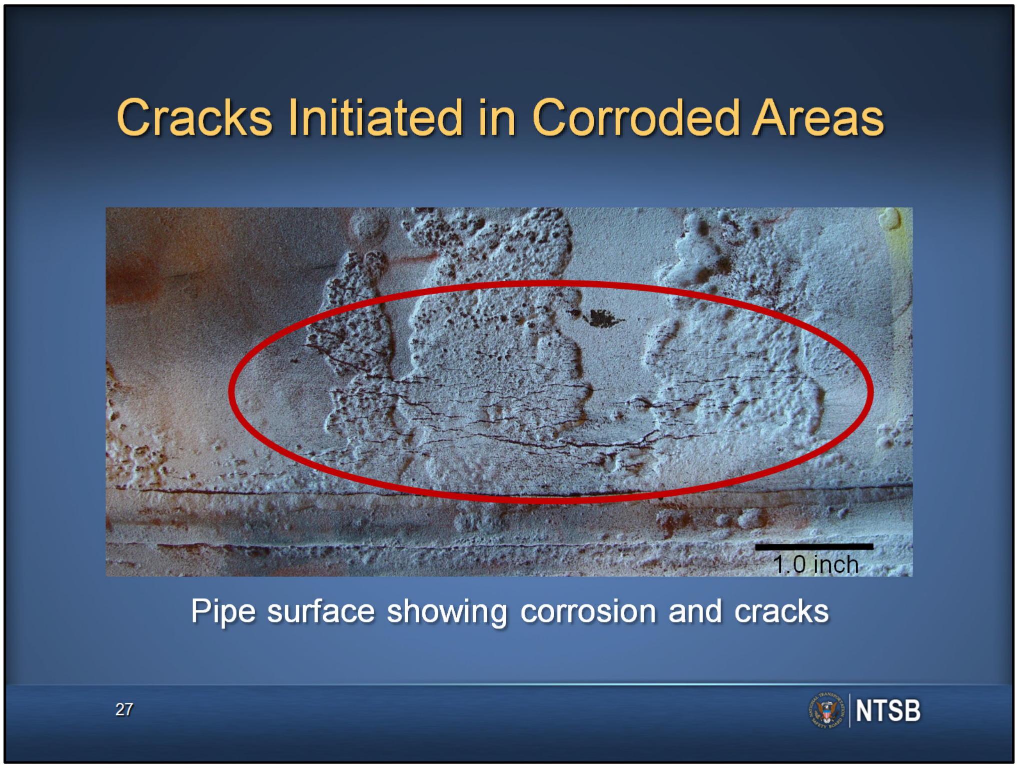
Good morning. I will present the NTSB Materials Laboratory findings regarding the fracture mechanism of the pipeline rupture. [CLICK]



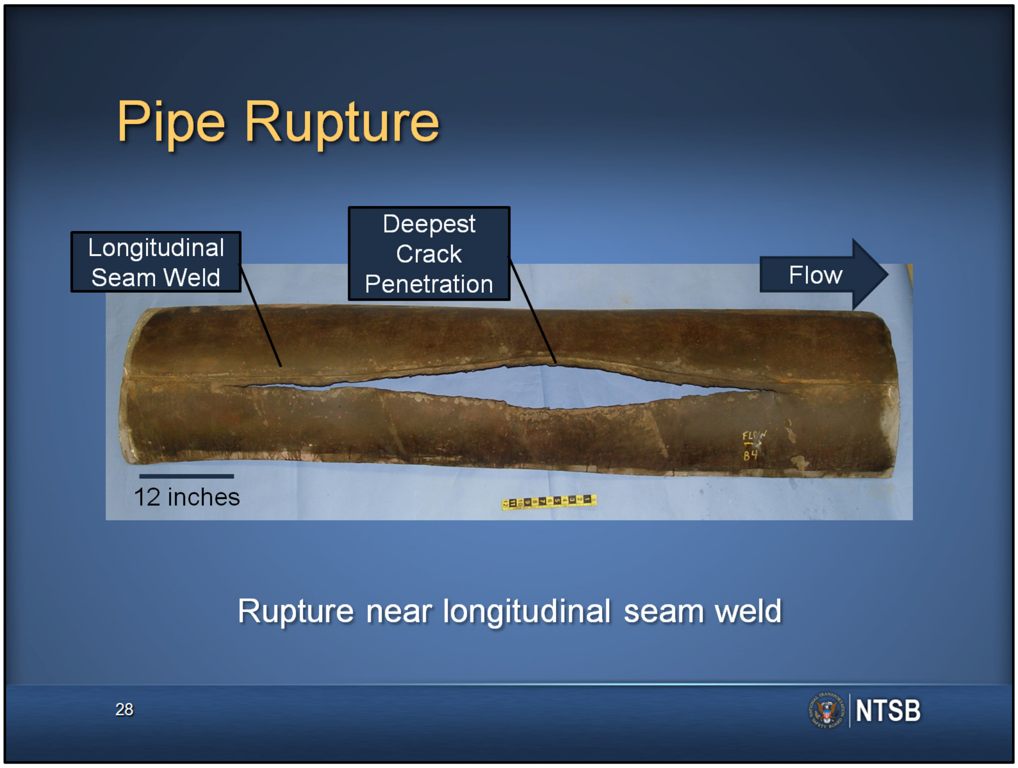
The ruptured pipe segment was made of steel with a one quarter inch nominal wall thickness and a double submerged arc welded longitudinal seam. The pipe was coated with an adhesive plastic tape applied in a spiral wrap as shown in this slide. The coating was an element of the outer surface corrosion protection system for the steel pipe. [CLICK]



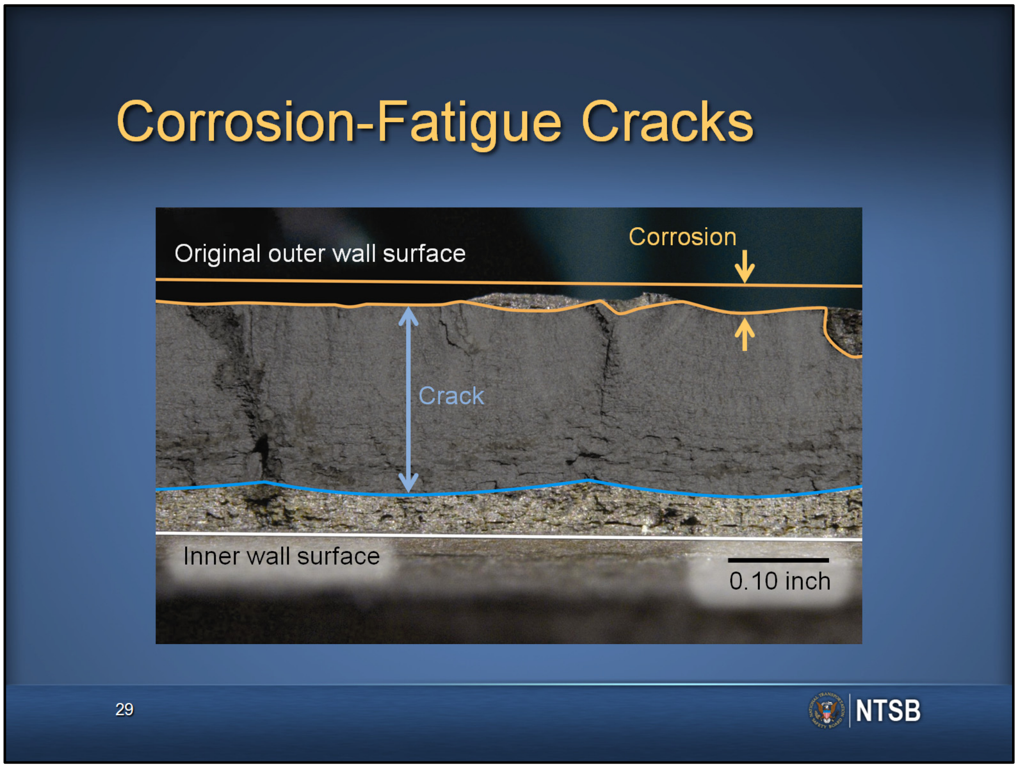
However, the corrosion protection system on the ruptured segment of the pipe failed to protect the external pipe surface from corrosion. Plastic tape coating has a known susceptibility to tenting and wrinkling. In this slide, we will zoom in on a cross-section of the double submerged arc weld seam to show gaps associated with tenting. [CLICK] Tenting forms at the edges of the longitudinal seam weld due to the height of the external weld bead as shown in this close-up view of the weld cross-section. Moisture then penetrates the gap between the pipe surface and the coating, leading to corrosion of the pipe surface. Soil loads can increase the size of the tenting gaps and can cause the coating to wrinkle, particularly at the sides of the pipe. Tenting and wrinkles on the ruptured pipe segment produced gaps between the coating and the pipe surface that allowed moisture to reach the pipe wall, resulting in corrosion at the outer surface. [CLICK]



Many areas of corrosion and clusters of cracks were observed on the outer surface of the ruptured pipe near the longitudinal seam. The image in this slide shows typical corrosion and crack clusters on the external surface of the pipe adjacent to the seam weld. These features indicated the surfaces had been exposed to moisture that led to corrosion and cracking. [CLICK]



A piece of the pipe wall containing the rupture is shown in this slide after the tape coating was removed and the surfaces were cleaned. The rupture was located near the longitudinal seam weld on the side of the pipe, which is an area susceptible to tape coating wrinkling and tenting. The fracture consisted of many smaller cracks that grew and linked together to form the rupture. The area of deepest crack penetration was located near the widest opening in the rupture. [CLICK]



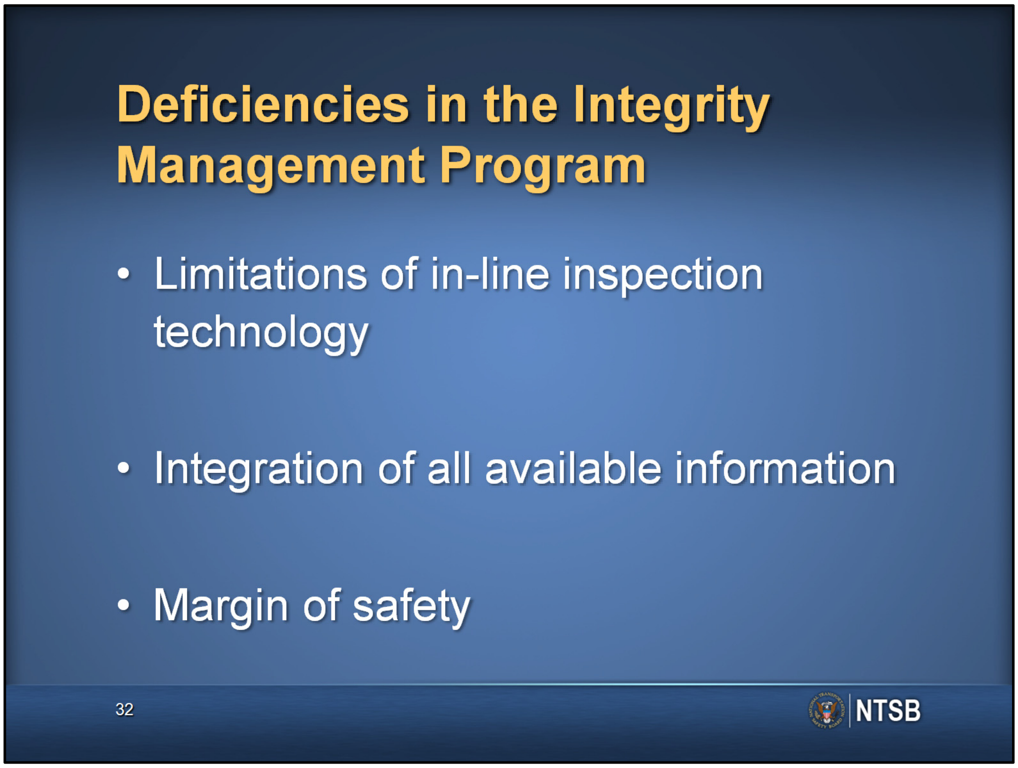
This slide shows the fracture surface at the area of deepest crack penetration. Cracks initiated from corrosion pits, at first growing due to near-neutral-pH stress corrosion cracking. As the cracks grew deeper, they continued to grow due to corrosion fatigue. Near-neutral-pH stress corrosion cracking and corrosion fatigue are two forms of environmentally assisted cracking where crack growth can be accelerated due to the synergistic effect of loading combined with a corrosive environment. The corrosion and cracks in the ruptured segment extended through 84 percent of the wall thickness before the pipe ruptured under normal operating pressure during the scheduled Line 6B shutdown. [CLICK]

This concludes my presentation discussing the fracture mechanism for the ruptured pipe. Mr. Chhatre will now present the findings regarding integrity management.
[CLICK]

Good morning. The Enbridge Integrity Department is responsible for evaluating the risks associated with metal loss, cracks, geometry-related issues, and determining the appropriate inspection timeline for each of Enbridge's pipeline segments.

If damage was detected, Enbridge stated that *'the pipeline condition is restored so that a constant-base integrity level is preserved.'*

However, during the investigation, the staff discovered several deficiencies in the Enbridge Integrity Management program, and I will be discussing these deficiencies briefly in the following slides. (**CLICK**)

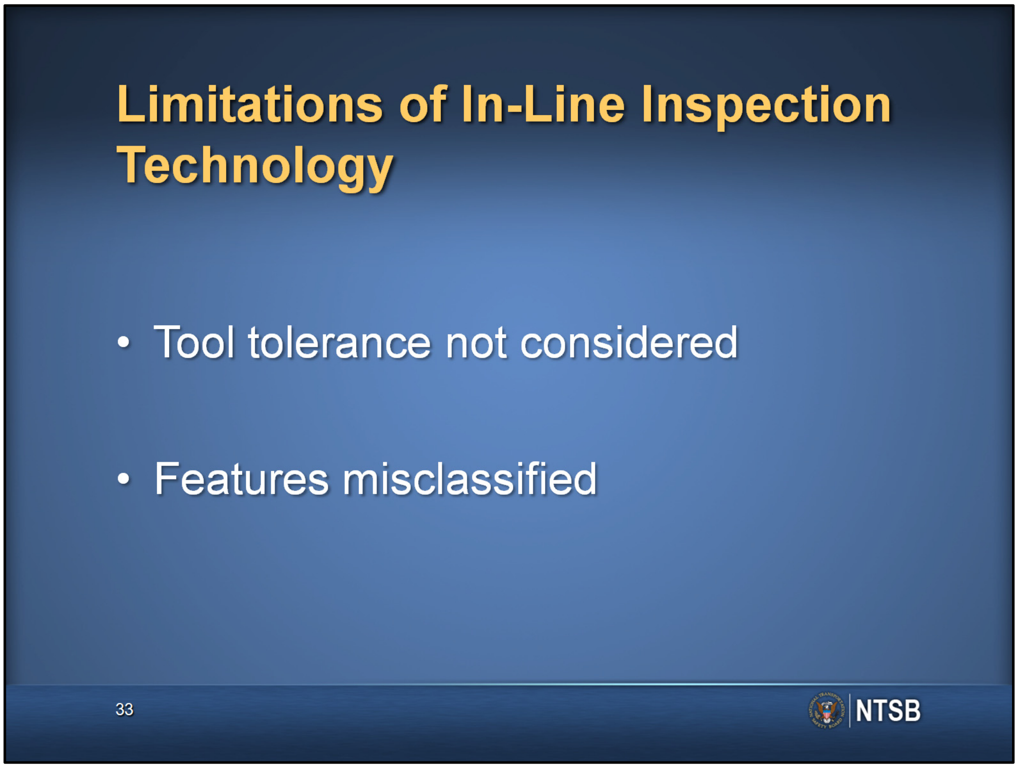


Enbridge did not give adequate consideration to the inherent limitations of In-Line Inspection technology.

Enbridge did not integrate all available information when evaluating the integrity of their hazardous liquid pipelines.

AND

Enbridge did not use an adequate margin of safety when evaluating crack-like defects. (**CLICK**)

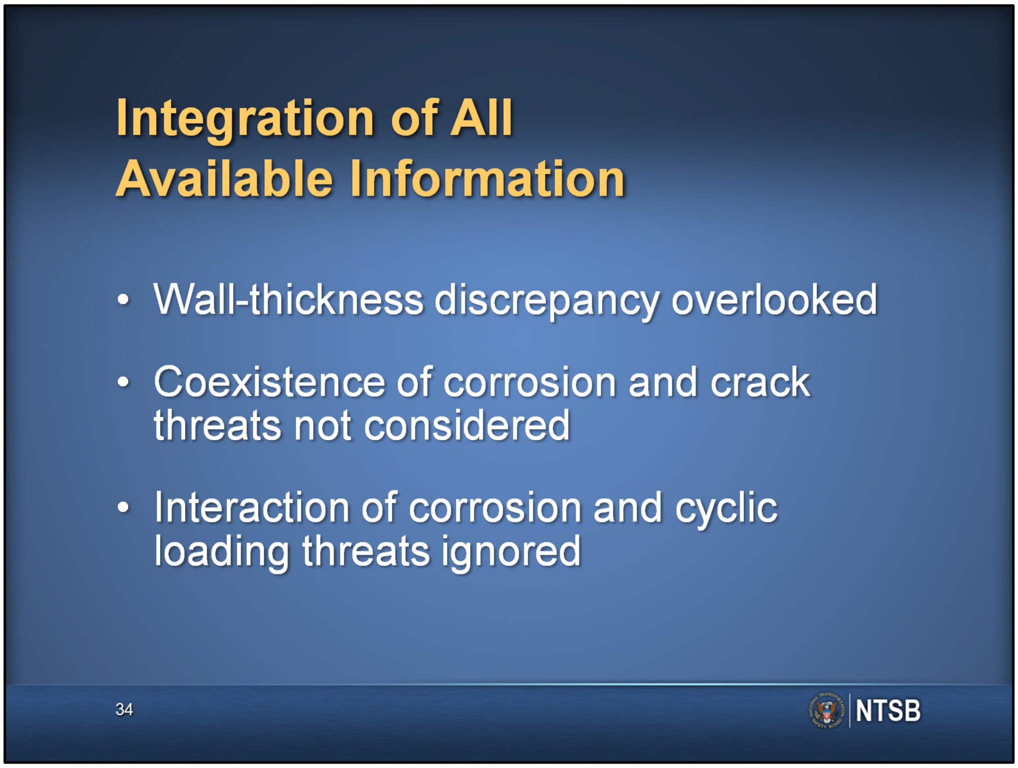


In-Line Inspection tools, or ILI tools, typically have specific tolerances for the type of defect or feature that is being inspected. This should be considered when evaluating corrosion or crack features for excavation.

Use of ILI crack depth data without due consideration to the tool tolerance may result in underreporting of depth for some cracks. Then the calculated rupture pressure for these cracks may not meet Enbridge excavation criteria. These cracks would then continue to grow unabated.

The defect that caused the rupture at Marshall was misclassified after the 2005 crack in-line inspection as a “crack like” feature by P I I. This misclassification resulted in the defect’s not meeting Enbridge’s excavation criteria, and it remained in the pipeline unabated until the rupture.

These limitations clearly show the disadvantage of in-line inspection tools or technology to ensure pipeline integrity. (**CLICK**)



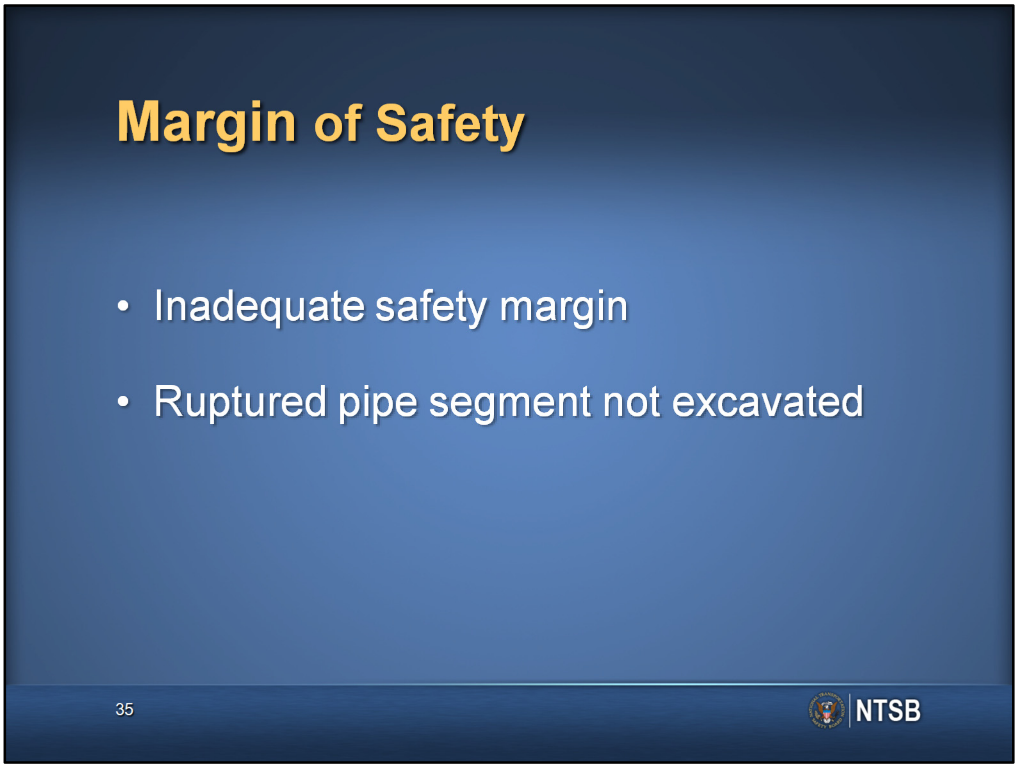
According to API Standard 1160, integration of available information regarding risks to a pipeline is a key component for managing system integrity. Federal regulation also states this as one of the minimum requirements of an integrity program.

Enbridge did not notice the significant discrepancy between the wall thickness data reported by its Ultrasonic Crack Detection tool, or crack tool, in 2005, and its 2004 ultrasonic wall measurement data. By using the crack tool-reported higher wall thickness in its assessment, Enbridge increased the maximum allowable pressure rating of the ruptured pipe segment in its integrity analysis.

Also, Enbridge did not consider co-existence of threats. There were many areas in the ruptured pipe segment where corrosion and cracks overlapped. However, wall loss due to corrosion was not considered by Enbridge when evaluating crack data, thus reducing the effective depth of these cracks during its rupture pressure calculations.

If Enbridge had given due consideration to the co-existence of threats, it is likely that the ruptured pipe segment would have been excavated and the accident possibly could have been prevented. The Enbridge integrity management program did not address interaction of threats. For example, the effect of a corrosive environment on crack growth under cyclic loading was not considered. Instead, Enbridge used a fatigue crack growth model to predict the remaining life of the pipeline and for selecting in-line inspection intervals.

Because interaction of threats was not sufficiently considered by Enbridge, the inspection interval was too long and the pipeline ruptured before the next in-line inspection could be completed. (**CLICK**)

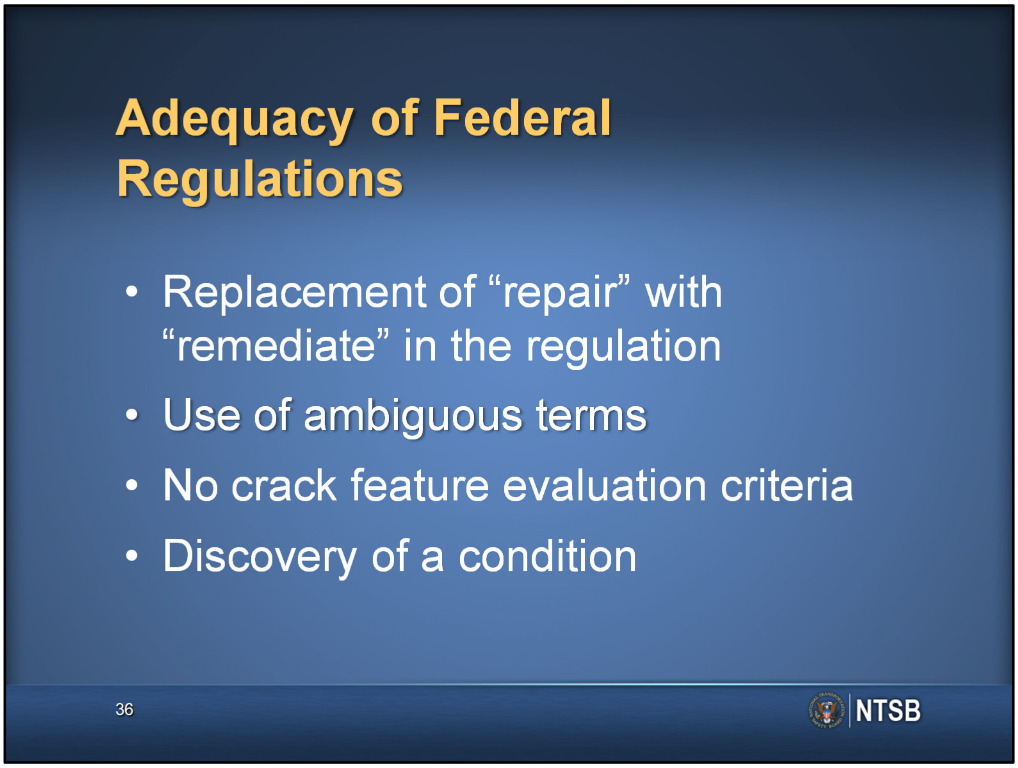


Enbridge did not use an adequate <u>safety margin</u> when evaluating crack-like defects.

The safety margin for crack features was lower than the safety margin for corrosion features. This is inconsistent with the Enbridge integrity management goal of restoring a constant-base integrity level.

After the 2005 in-line inspection of Line 6B, six crack-like defects were identified in the ruptured segment. The calculated rupture pressure for one of the six features that was 51.6 inches long was slightly higher than the Enbridge minimum safety margin for crack-like defects. Therefore, according to the Enbridge criterion, this feature was not excavated. However, for the same feature, calculated rupture pressure was slightly lower than the Enbridge minimum safety margin for corrosion features. The feature would have been identified for excavation, if Enbridge had used same safety margin for cracks as it did for corrosion features, and the accident likely would have been prevented.

As a result of these findings, the staff has proposed safety recommendations to Enbridge and PHMSA. (**CLICK**)



The actions an operator must take to address integrity issues for hazardous liquid pipelines are described in Title 49 Code of Federal Regulations, Part 195.452 paragraph (h).

PHMSA amended the regulation and replaced the word “repair” with the word “remediate” throughout paragraph (h) in the regulation. PHMSA believed “remediate” could encompass a broad range of actions, which include mitigative measures such as environmental changes and operational changes, as well as repair. PHMSA stated that although it firmly believes that repair is necessary to address many anomalies, it may not be necessary in all cases. However, PHMSA did not identify which anomalies should be repaired, and where “mitigative measures” are appropriate, leaving that critical decision to pipeline operators.

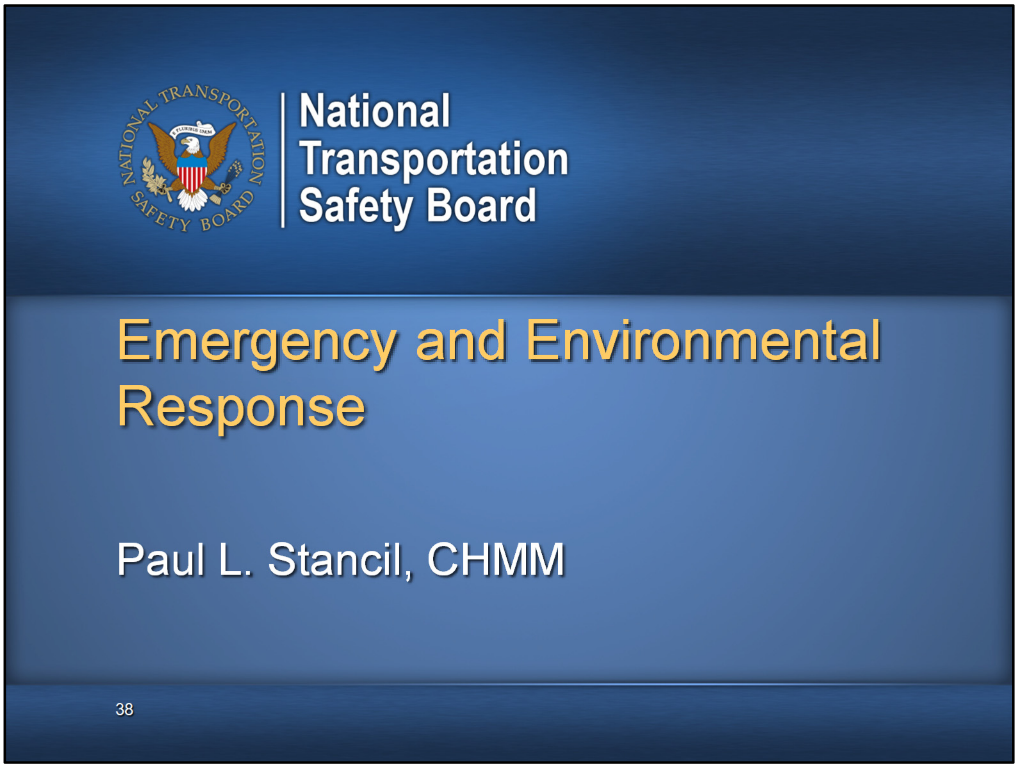
The regulation uses many ambiguous terms such as *”A potential crack indication that when excavated is determined to be a crack.”* However, the regulation does not state whether or not an operator must excavate a potential crack indication. This allowed Enbridge to establish crack excavation criteria, rather than excavating all crack indications.

Additionally, the regulation is not explicit about how crack features should be evaluated, nor does it mandate the minimum safety factor that should be used when evaluating cracks. Therefore Enbridge could use a lower safety factor when evaluating cracks than the safety factor it uses for evaluating corrosion defects, where the regulation is more explicit.

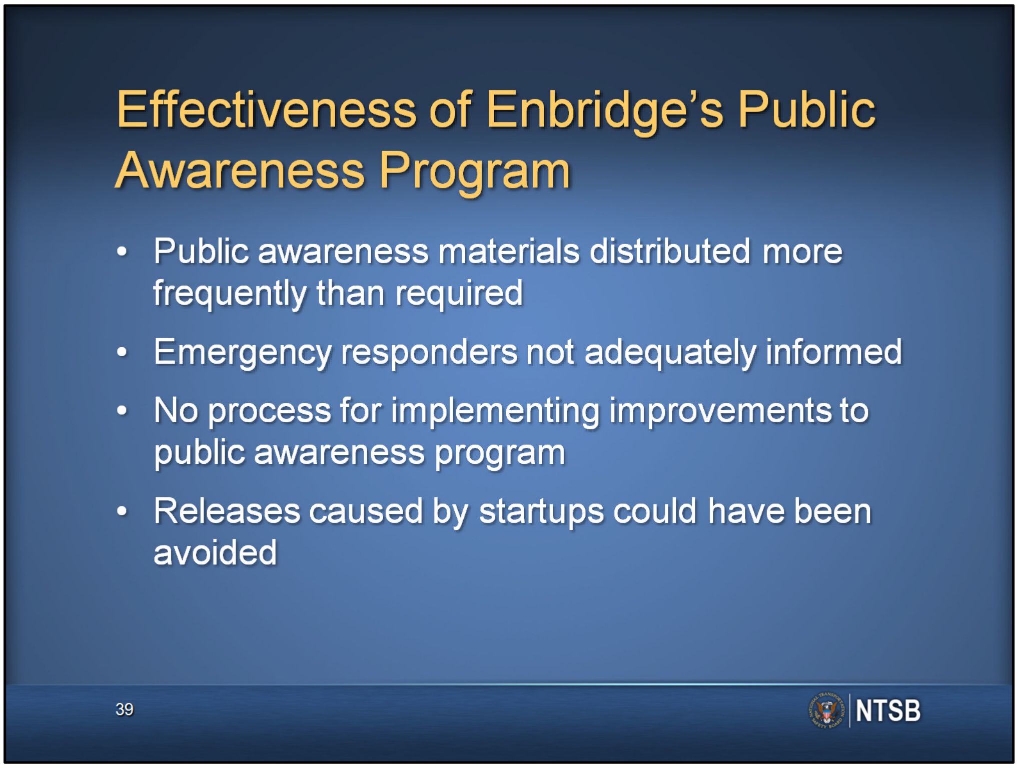
The ‘discovery of a condition’ occurs when an operator has adequate information to determine that the condition presents a potential threat to the integrity of the pipeline. However, the regulation does not clearly define what it considers ‘adequate information.’

As a result of these findings, staff has proposed safety recommendations to PHMSA. (**CLICK**)

Madam Chairman, this concludes my presentation. Mr. Paul Stancil will make his presentation on Emergency and Environmental Response next. (**CLICK**)



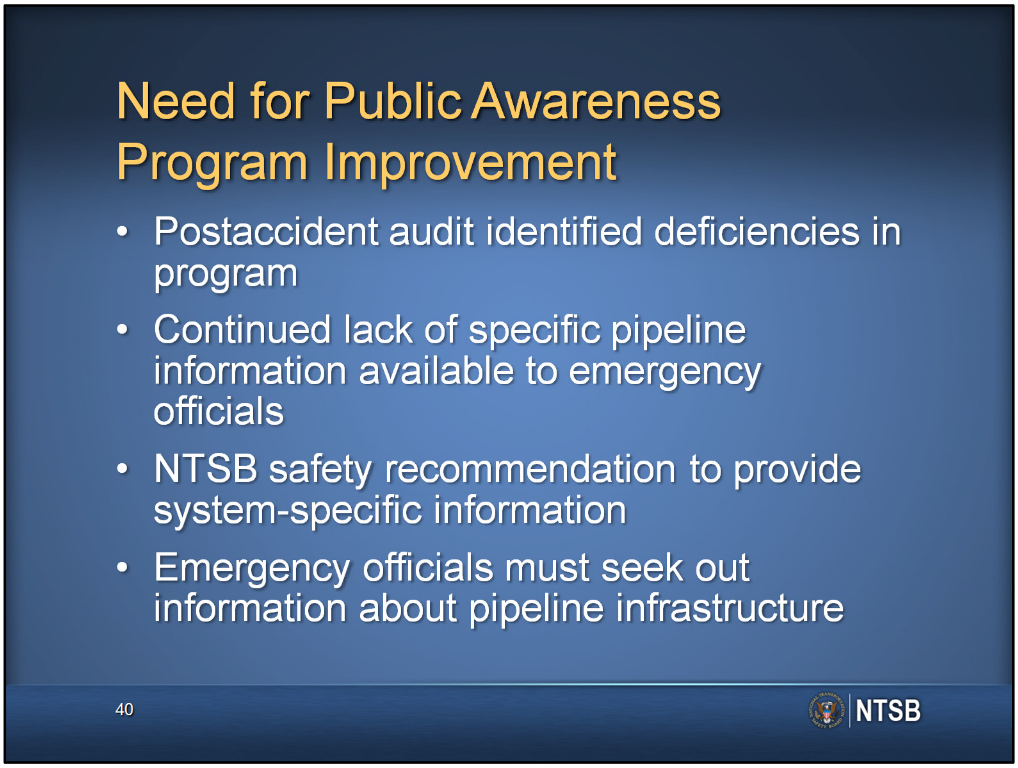
Good morning. Today I will be discussing the effectiveness of Enbridge's pipeline public awareness program, its response to the oil spill, and the effectiveness of PHMSA's spill response planning regulations and oversight. **[CLICK]**



Although Enbridge distributed public awareness materials more frequently than required by industry standards, local emergency responders still were not adequately informed about the pipeline facilities and were unable to identify the source of crude oil odors despite multiple 9-1-1 calls received over a 17-hour period.

Enbridge's public awareness program does not include a process for implementing improvements, suggesting there is a lack of commitment to ensure the quality of the program.

If the program had been more effective, the oil spill might have been detected earlier, the response might have started sooner, and Enbridge could have avoided the release of additional oil caused by its two pipeline startups after the initial rupture. **[CLICK]**

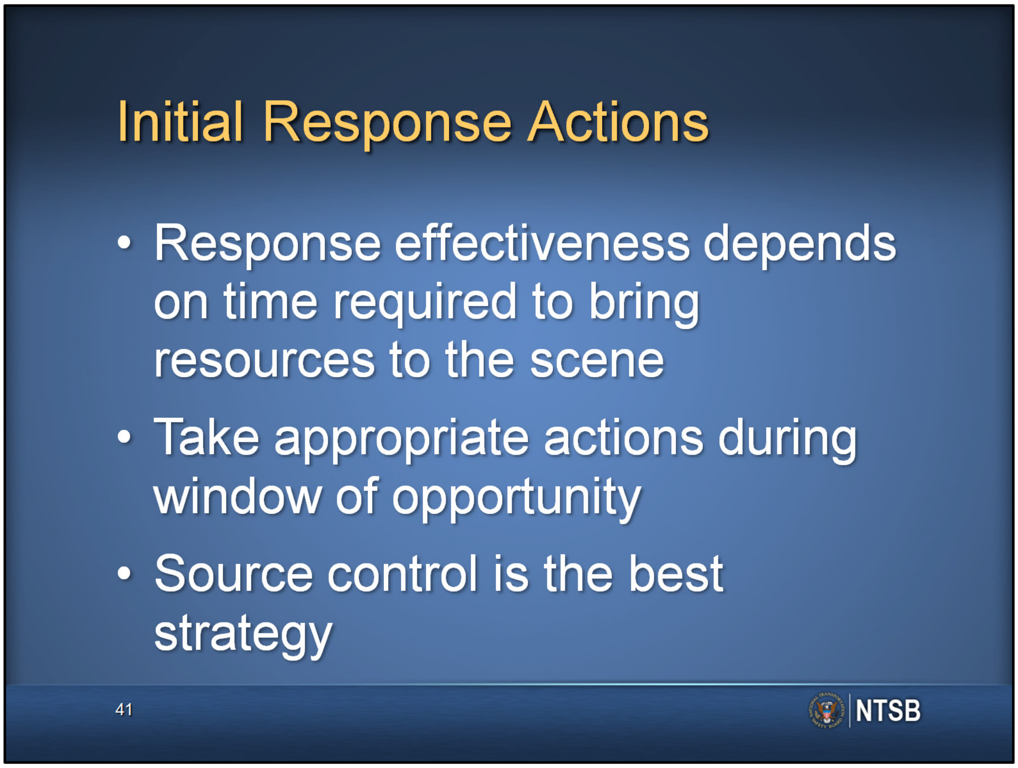


PHMSA conducted a regularly-scheduled post-accident audit of Enbridge's public awareness program and required correction of deficiencies in the program and its effectiveness reviews. Nonetheless, staff remains concerned about the lack of specific information that pipeline operators have given to emergency officials.

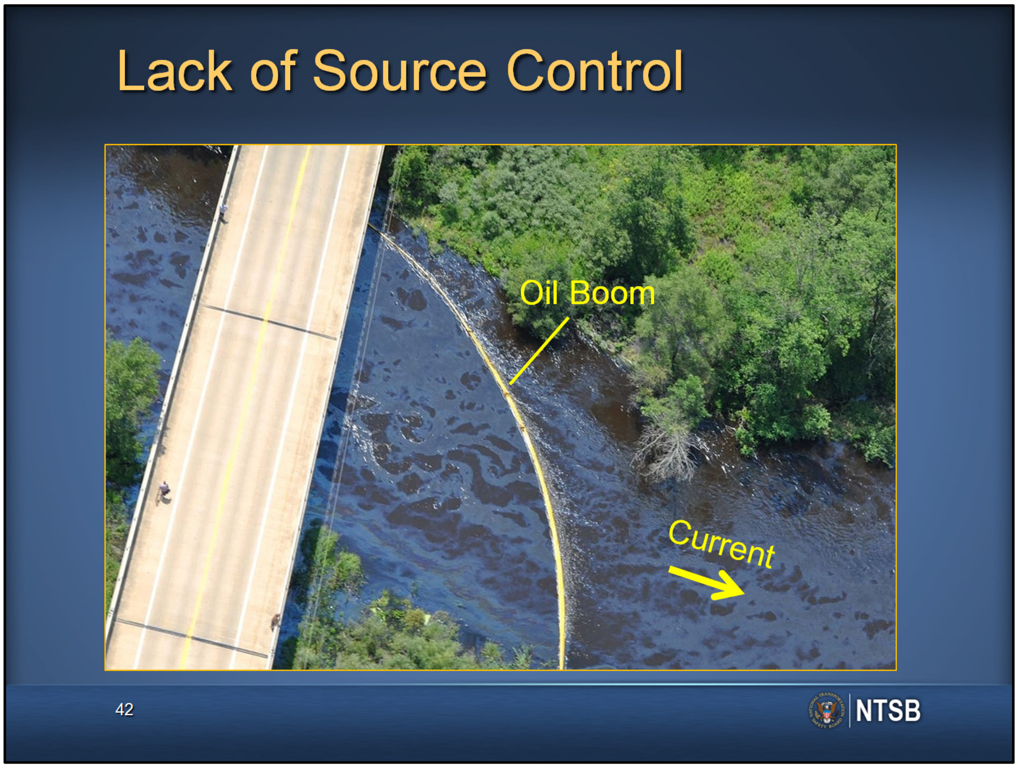
In response to the 2010 PG&E natural gas transmission pipeline rupture in San Bruno, California, the NTSB issued a safety recommendation to PHMSA to require pipeline operators to provide detailed system-specific information to emergency response agencies, however PHMSA has thus far not initiated rulemaking.

This accident and previous accidents demonstrate a pattern of fire and emergency service agencies not being aware of the presence of major pipeline infrastructure in their communities. It is incumbent upon emergency officials to seek out information about pipeline systems in their jurisdictions to ensure timely and coordinated responses to releases when they occur.

Staff proposes to reiterate the safety recommendation to PHMSA and has proposed a new recommendation in this area. **[CLICK]**



Critical to the effectiveness of an oil spill response is the time required to bring personnel and resources to the scene and to take the appropriate actions to contain the oil during the window of opportunity in which response actions are most viable and effective. Guidance for oil spill response planning published by the Coast Guard, EPA, NOAA, and the American Petroleum Institute suggests that soon after the pipeline rupture, when the oil was freshly concentrated near the source area, Enbridge should have focused on source control and containment as the best strategy for mitigating the effects of the discharge. **[CLICK]**



This aerial view taken on the second day of the spill response shows the Interstate 94 bridge over the Kalamazoo River about 8.9 miles downriver of the pipeline rupture site. While a considerable amount of Enbridge's initial effort was expended here on the first day, the deployed oil booms had little effect containing oil when it finally arrived in the strong current.

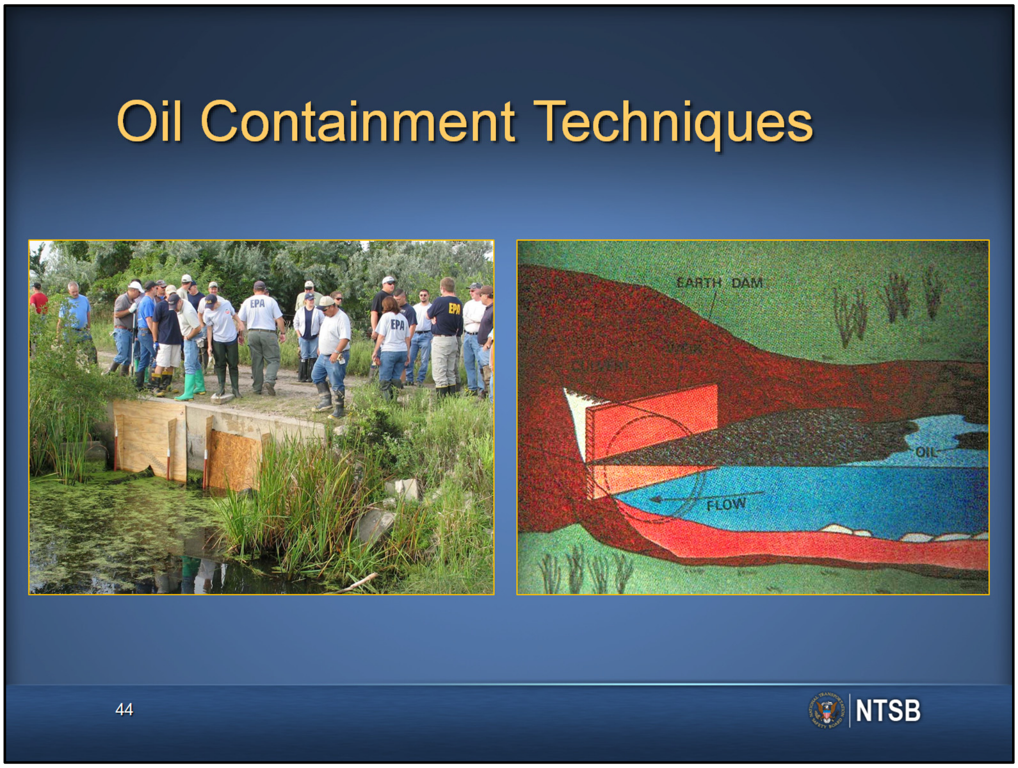
A crew of 4 Enbridge maintenance employees provided the initial response on Talmadge Creek, but booms they installed far below the pipeline release site were not effective for the environmental conditions and did not prevent much of the oil from escaping into the Kalamazoo River. The opportunity to mitigate the spread of the oil spill was lost before follow-on resources arrived.

Minimizing the release of oil from the source area could have reduced exposures suffered by the 320 citizens living downriver who reported adverse health effects, and could have reduced the severity of the environmental pollution, which resulted in a $767 million cleanup – 5 times more costly than any previous pipeline accident. The release of oil ultimately contaminated 38 miles of river – indicating that the available equipment and containment methods were ineffective for the environmental conditions that the responders encountered. **[CLICK]**

This photograph shows oil containment actions attempted later at the culvert on Talmadge Creek at Division Drive with crews installing a combination of white sorbent boom and orange skirted oil boom. This would have been a prime location for initial response action to contain the release within 1/4 mile from the ruptured pipeline.

On the day the spill was discovered, first responders noted that the majority of the released oil was upstream of this location, yet they focused most of their attention on placing containment measures much farther downstream.

Industry and Federal guidance suggests that the skirted oil booms Enbridge had available were not suitable for small and fast flowing streams, and the sorbent booms were an ineffective method of containing oil except for small oil spills in stagnant waters. **[CLICK]**



More effective methods that could have been employed to reduce the amount of oil that escaped the source area include the use of underflow dams as demonstrated in this EPA training exercise.

The Coast Guard Research and Development Center published the diagram displayed on the right side of the screen in its field guide for oil spill response in fast moving currents to depict how a wooden underflow dam would function to contain oil at a culvert. Seven such culvert pipes where this technique could have been used were located on Talmadge Creek between the source area and the Kalamazoo River. **[CLICK]**

Enbridge initially did not have adequate resources on site to deal with the magnitude of the oil spill, and it experienced significant difficulty locating necessary resources.

The two oil spill response contractors identified in Enbridge's facility response plan were headquartered outside of Michigan and were not capable of providing a timely response. The plan considered that Enbridge would mount its own initial response effort following a discharge, but it did not include agreements with local contractors to have resources on stand-by.

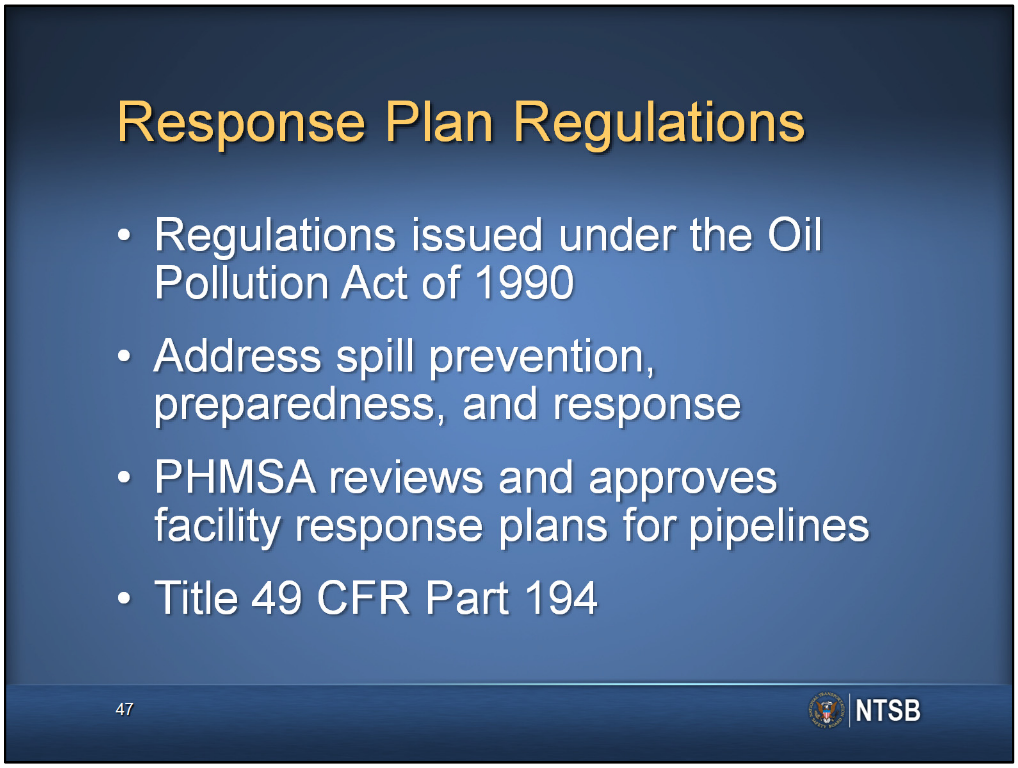
This photograph shows the contents of Enbridge's boom trailer, which was the only first-line oil containment asset that was available in Marshall, Michigan. This equipment was supposed to satisfy planning requirements for initial response to a worst-case discharge of 1,111,000 gallons, which is equivalent to the magnitude of the release that occurred in this accident. **[CLICK]**

To improve its response to releases of oil from its pipelines, Enbridge should train first responders on best practices for spill containment techniques that are appropriate for all environments and adverse weather.

Further, emergency response procedures and equipment resources need to be updated to facilitate more appropriate methods that conform to the environments present along pipeline rights of way.

And finally, the facility response plan must be revised to ensure availability of adequate spill response resources.

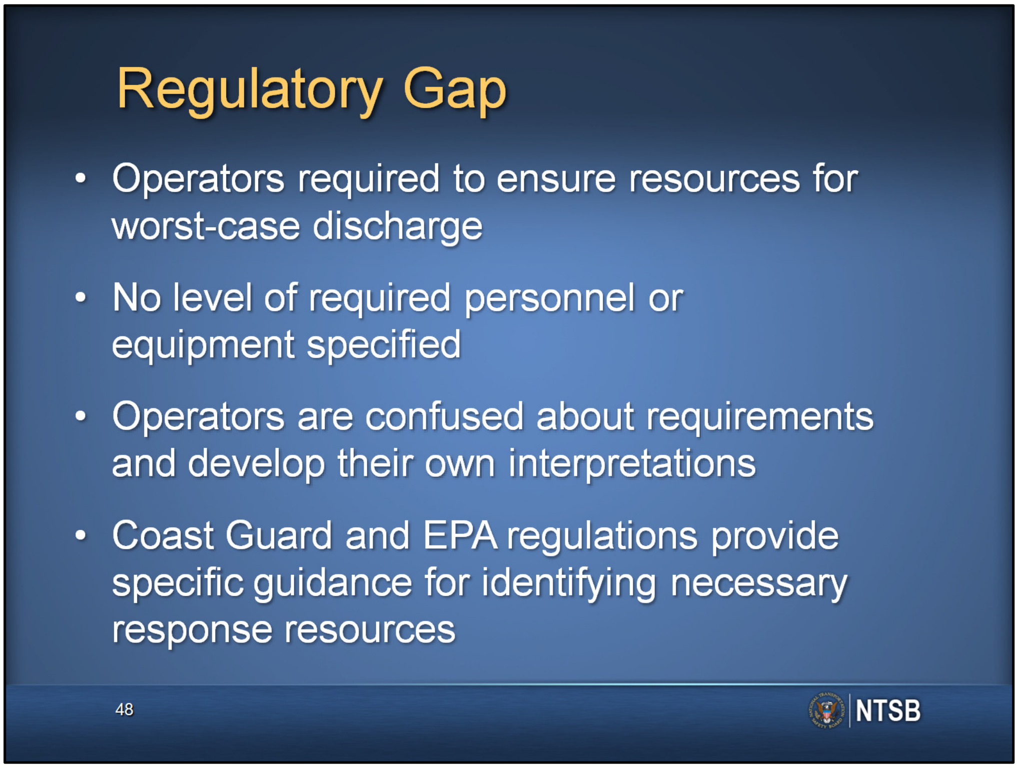
Staff has proposed recommendations to address these issues. **[CLICK]**



PHMSA has responsibility for issuing regulations to implement the Oil Pollution Act of 1990 as it applies to onshore oil pipelines. The Oil Pollution Act was enacted in response to the 1989 Exxon Valdez oil spill and was designed to address oil spill prevention, preparedness, and response capabilities of the Federal government and industry.

Just as oil tankers are required to submit oil spill response plans to the Coast Guard and refineries are required to submit such plans to the EPA, oil pipeline operators must submit their plans to PHMSA for review and approval.

PHMSA regulations governing response plans for on-shore oil pipelines are found in Title 49 Code of Federal Regulations Part 194. **[CLICK]**



PHMSA regulations require pipeline operators to identify and ensure by contract or other means the resources available to mitigate a worst-case discharge. The regulation provides the time frames in which response resources must be available on-scene, but does not define the level of personnel and equipment required.

This regulatory gap confuses operators about planning requirements, and consequently they develop their own interpretations of what constitutes sufficient resources.

Coast Guard and EPA regulations for vessels and fixed facilities provide specific guidance for spill response planning because these regulations mandate the oil recovery capability that must be provided by the plan holder. A more meaningful standard for pipeline operators would exist if PHMSA were to harmonize its response planning regulations with those of the Coast Guard and EPA to ensure an equivalent level of spill response from all facilities that handle and transport petroleum products.

Staff has proposed recommendations to address this issue. **[CLICK]**

Response Plan Review

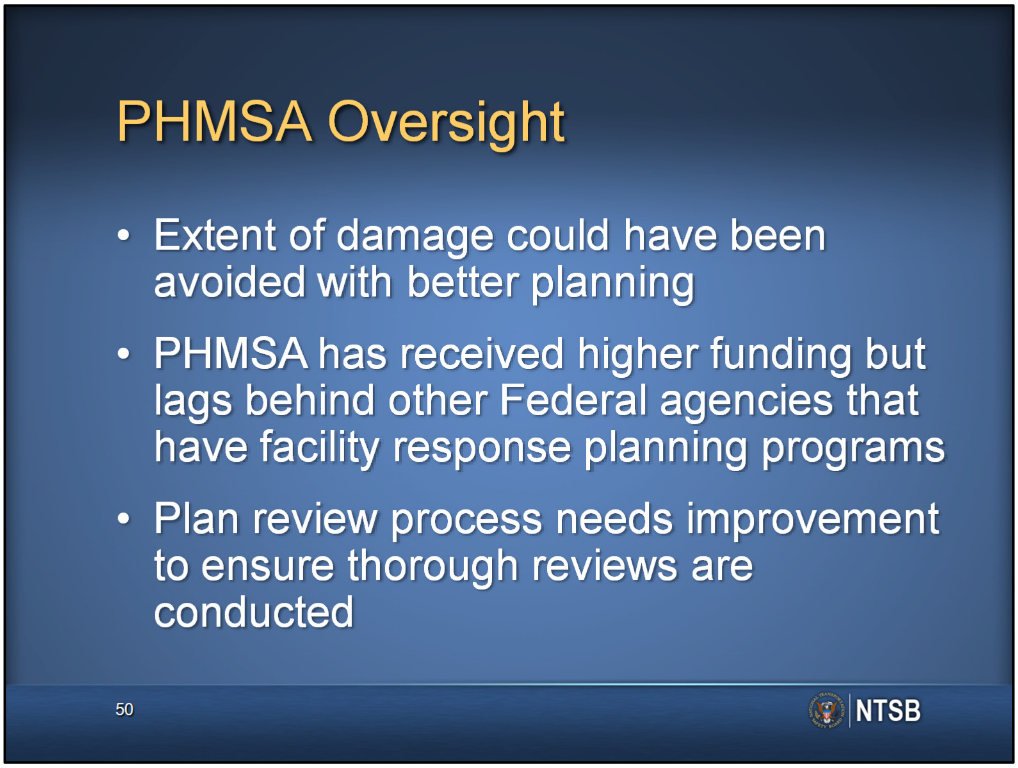
	PHMSA	EPA	USCG
Number of plans	450	2,000 (Regions 5 & 6)	3,100 (vessels and facilities)
Number of staff	1.5	40 (Regions 5 & 6)	21 (HQ) + 100's in the field
Completeness review	✓	✓	✓
Second level review		✓	✓
Drills or excercises		✓	✓

49 NTSB

At the time of the accident, PHMSA had just 1.5 full-time positions dedicated to managing response plans for the nation's pipelines, which equates to about 450 plans. This pales in comparison to the EPA's and the Coast Guard's commitments to their programs.

PHMSA's review of the Enbridge plan consisted of having the company submit a self-assessment questionnaire that affirmed the adequacy of the plan, followed by a completeness review to assess whether the plan met appropriate regulatory requirements. In contrast to EPA and the Coast Guard, PHMSA does not perform second level reviews that consist of on-site audits or follow-up reviews by senior staff. Also, PHMSA has not recently conducted any drills or exercises to test plan holders' abilities to respond to oil spills.

Based on these facts, it is doubtful that the Enbridge plan could have received more than a cursory review. If PHMSA had dedicated the resources necessary to conduct thorough reviews, it likely would have identified deficiencies and disapproved the Enbridge plan because it lacked sufficient resources for response to a worst-case discharge. [CLICK]



The extent of environmental damage caused by the oil spill could have been avoided had there been better planning and preparedness in advance of this accident. Thorough reviews of response plans must therefore be conducted to ensure the adequacy of resources and the ability to conduct recovery operations in a timely and effective manner.

PHMSA has received annual appropriations from the Oil Spill Liability Trust Fund for administering Oil Pollution Act activities. In past years, PHMSA has received more funding from this source than has the EPA, with a funding level of $18.9 million at the time of the accident, yet its response planning program lags significantly behind other Federal agencies.

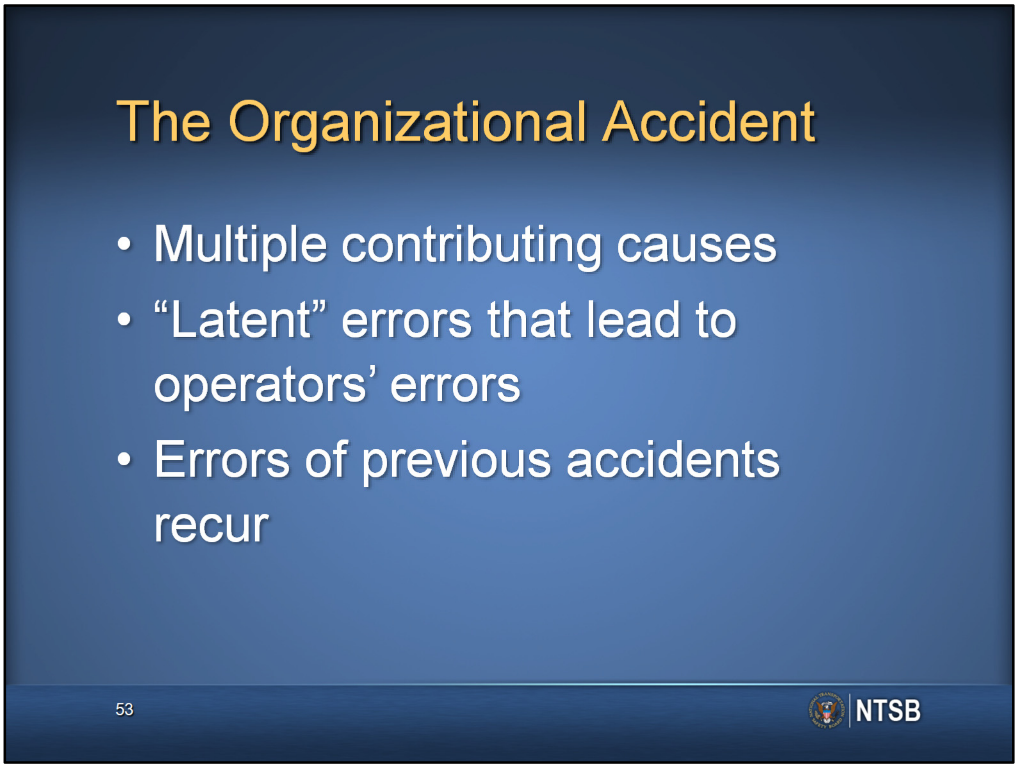
PHMSA’s facility response plan review process needs improvement to ensure that plans are being thoroughly vetted, and the process could be more effective if features such as an on-site audit program were implemented.

Given the noted deficiencies in PHMSA’s response plan reviews, an audit of PHMSA’s onshore pipeline response plan program is warranted to ensure that it is meeting the requirements of the Oil Pollution Act.

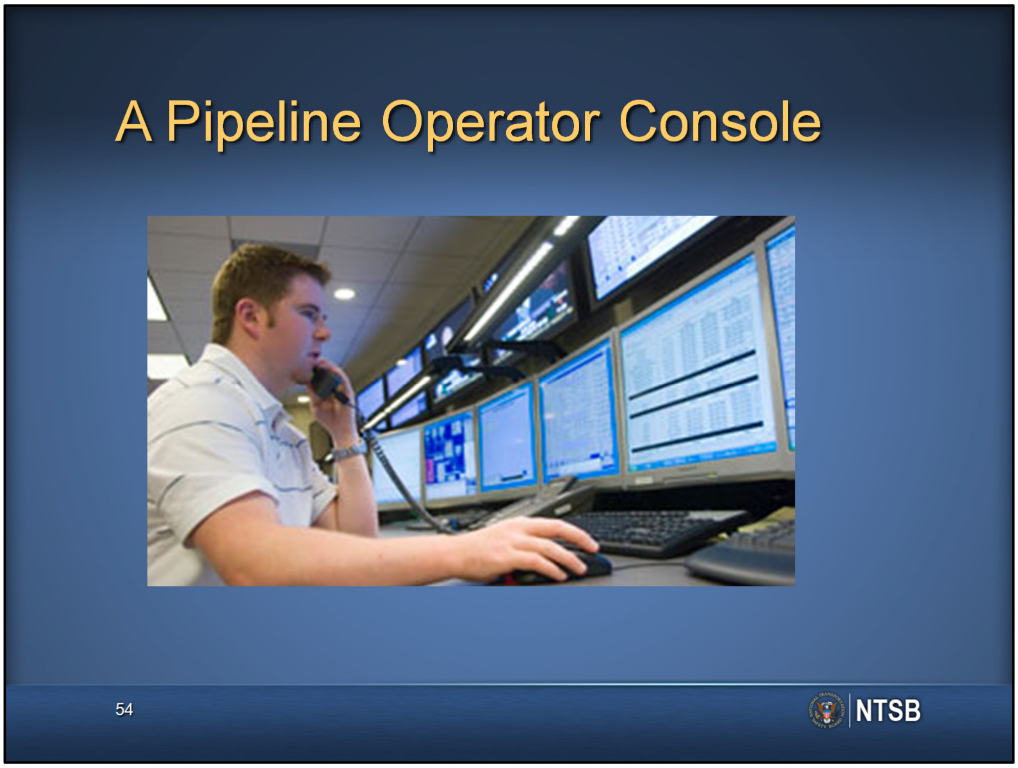
Staff has proposed recommendations to address these issues. **[CLICK]**

This concludes my presentation on the emergency and environmental response. Dr. Strauch will now discuss human factors issues. **[CLICK]**

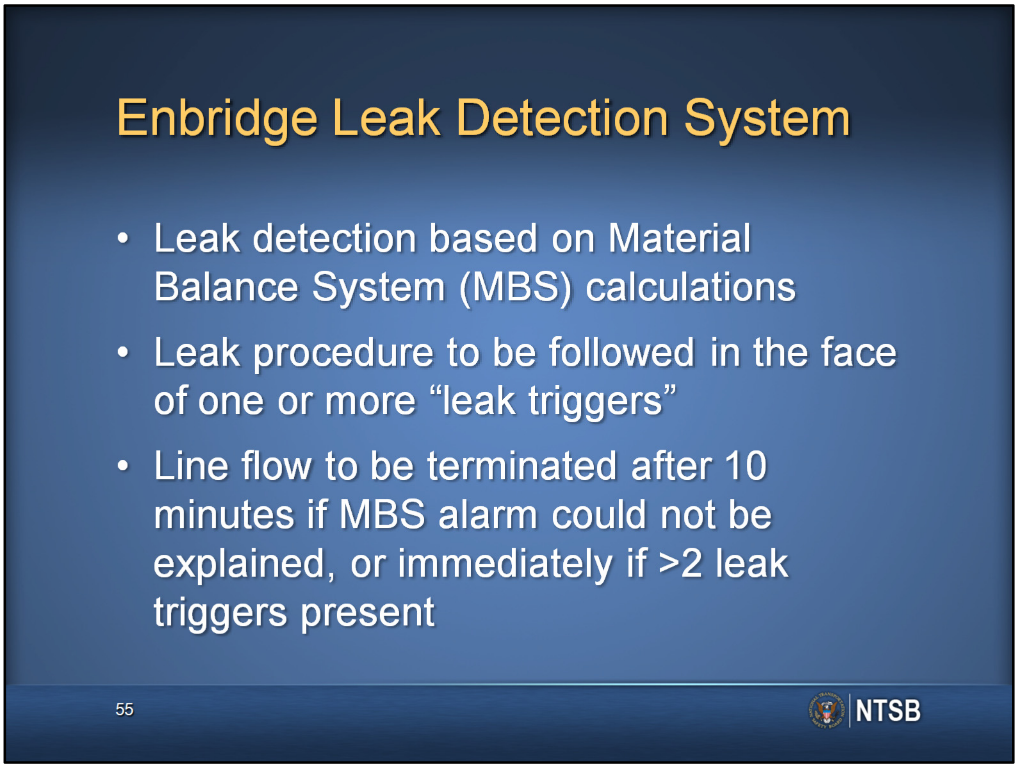
Good morning. I will discuss some of the human factors issues involved in this accident. These address the Enbridge pipeline control center, the errors that control center staff committed, and the quality of both the company's and the regulator's oversight of pipeline safety. **[Click]**



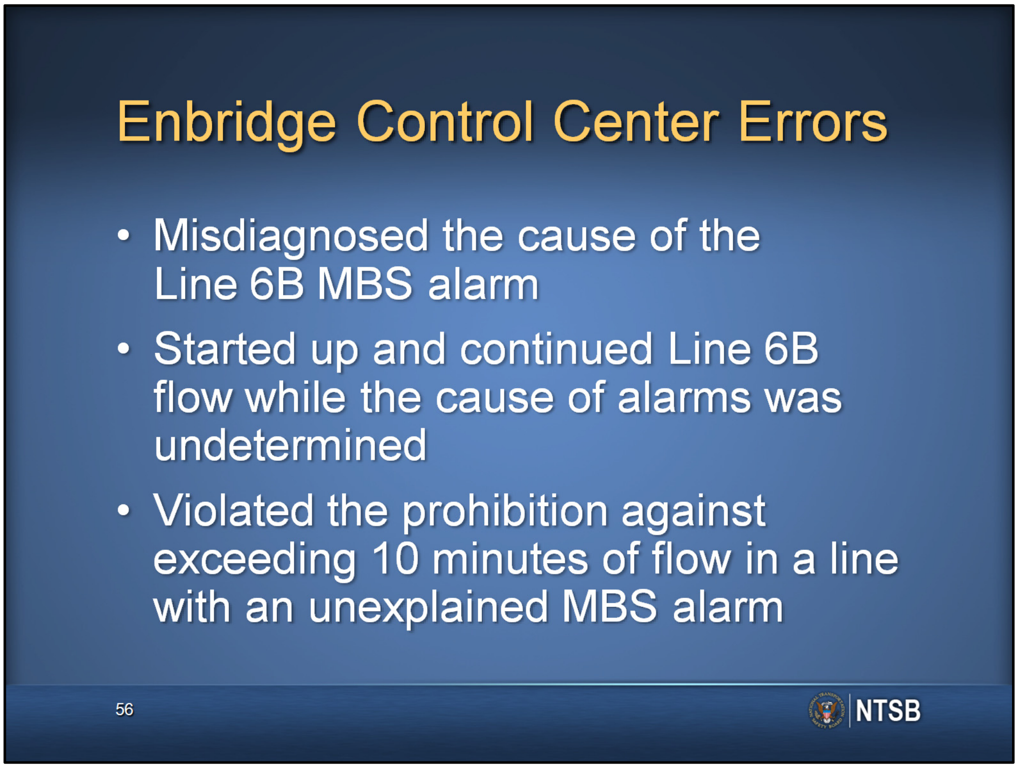
The term 'organizational accident' was proposed some years ago by a prominent human factors researcher, and the NTSB has applied it in recent accident investigations. In organizational accidents multiple errors, known as "latent errors," have often been committed by the operating company and the regulator. This type of error refers to organizational elements such as oversight, training, and management that created the conditions that led to the errors potentially involved in the accident under investigation. Organizational accidents also tend to manifest errors observed in previous accidents, as the organizations in question failed to apply lessons learned in previous accidents. Staff believes that these organizational elements were evident in this accident. **[Click]**



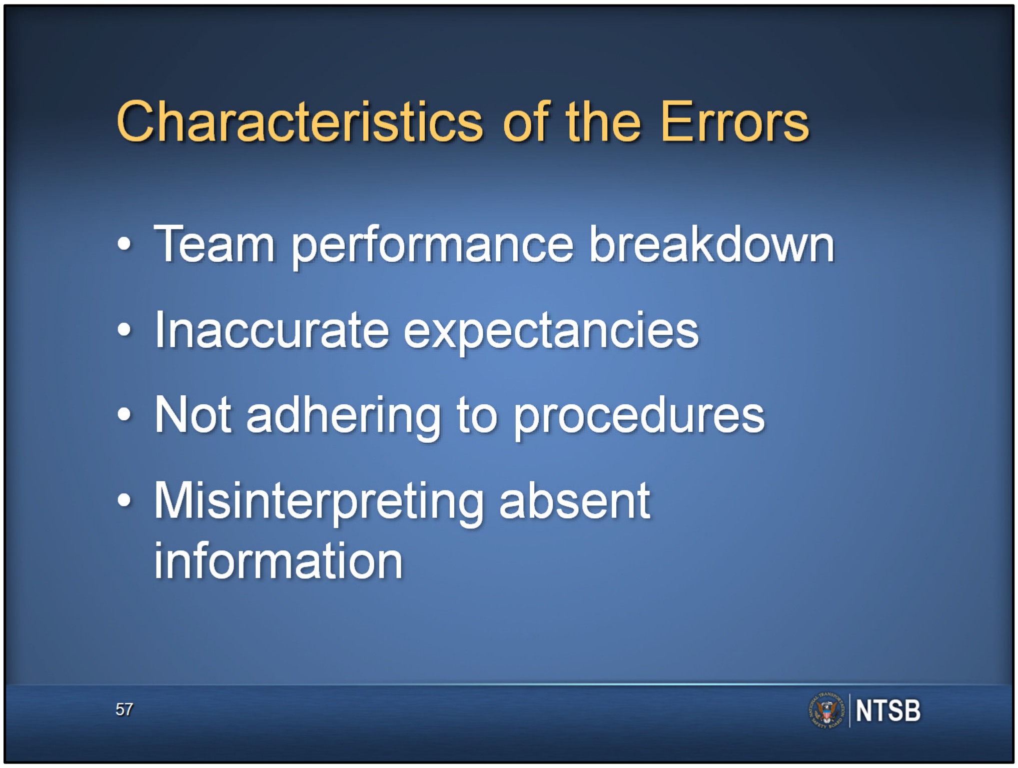
In Enbridge's Edmonton pipeline control center, four types of specialists were involved in pipeline operations. Operators, who directly controlled pipeline flow, and who had the authority to terminate pipeline flow when circumstances warranted; their immediate supervisors – the shift leads, who served as liaisons between operators and others involved in pipeline operations; analysts who determined the validity of MBS alarms, which I will discuss in more detail shortly; and control center supervisors who were the final authority in pipeline operating decisions. **[Click]**



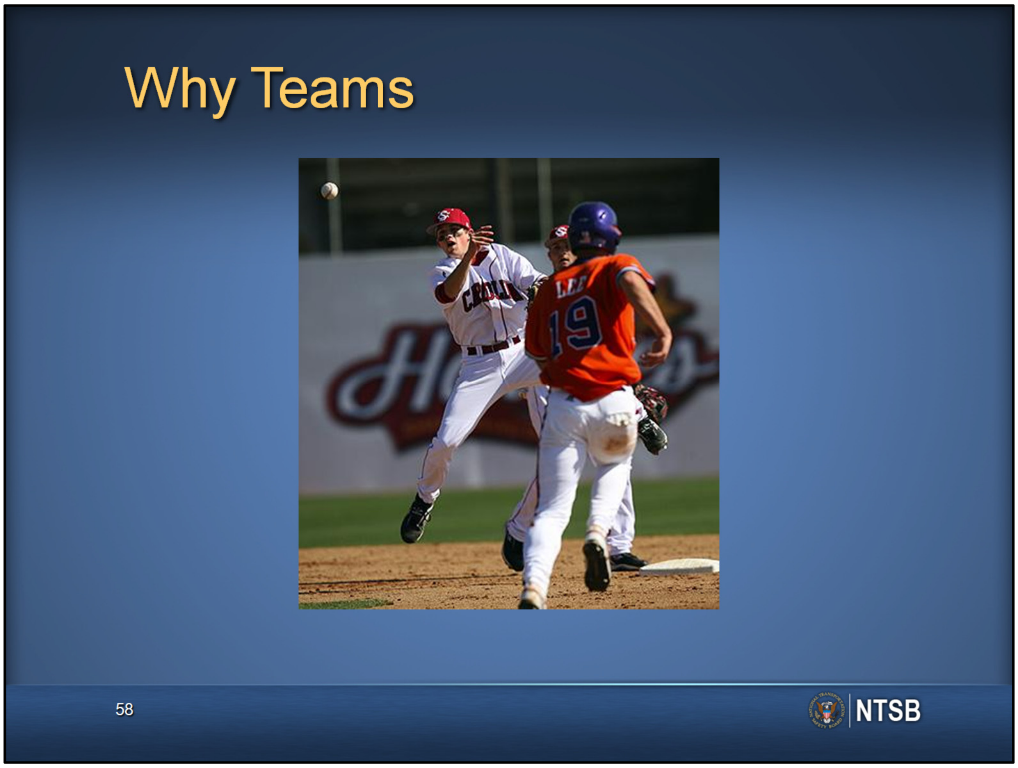
Enbridge's leak detection system was based on a computational model, the material balance or MBS system that, with its pipeline monitoring and operating system, compared expected pipeline flow to actual flow parameters. Discrepancies beyond predetermined levels would trigger an MBS alarm, an alarm that was one of several potential signs that operators and shift leads were expected to use to recognize a pipeline leak. The MBS alarm often alerted following, and was most often associated with, shutdowns and startups of line flow, when column separation, which is a vapor bubble present in the pipeline that disrupts the column of oil, occurs. In addition to startups and shutdowns, it is typically associated with hilly terrain. Operators were expected to shut down line flow in the presence of 3 or more leak triggers, triggers that also included sudden drops in discharge or suction pressure, and sudden changes in flow rate, loss of pump stations, and sudden increase in pump speed, among others. **[Click]**



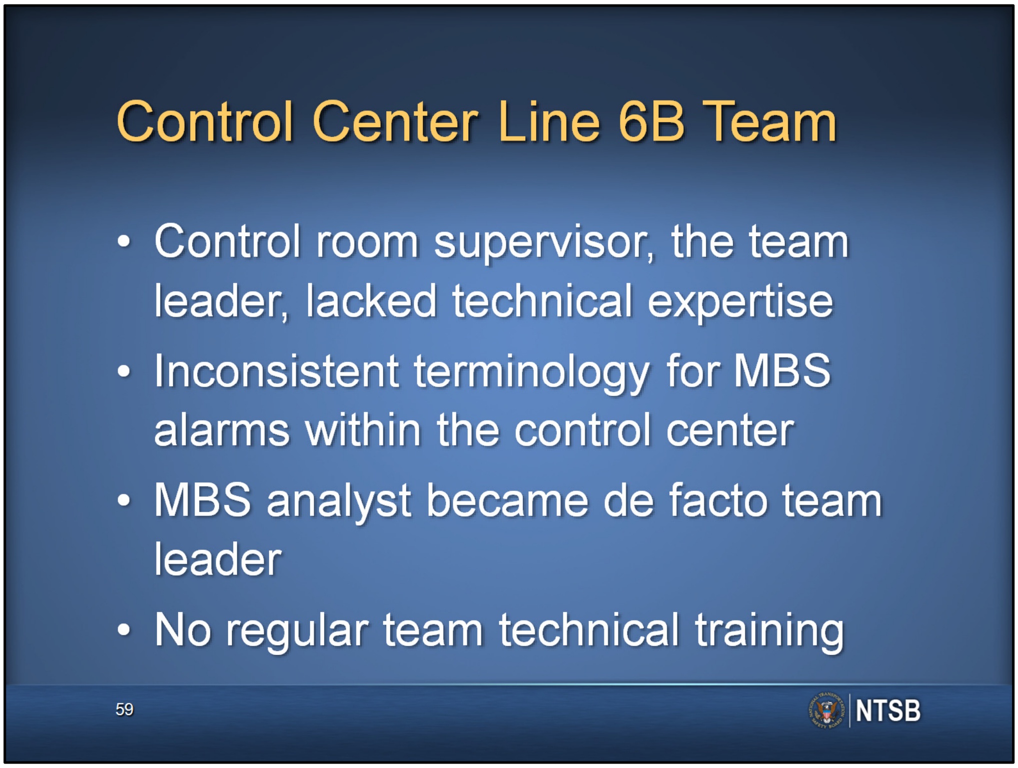
During the more than 17 hours between the time of the Line 6B rupture and the time that control center staff were informed of the leak by a Marshall area public utility representative, Enbridge control center staff misdiagnosed the cause of the Line 6B MBS alarm, then twice started line flow, each time knowingly violating Enbridge's restriction on continuing flow more than 10 minutes in a line with an unexplained MBS alarm. **[Click]**



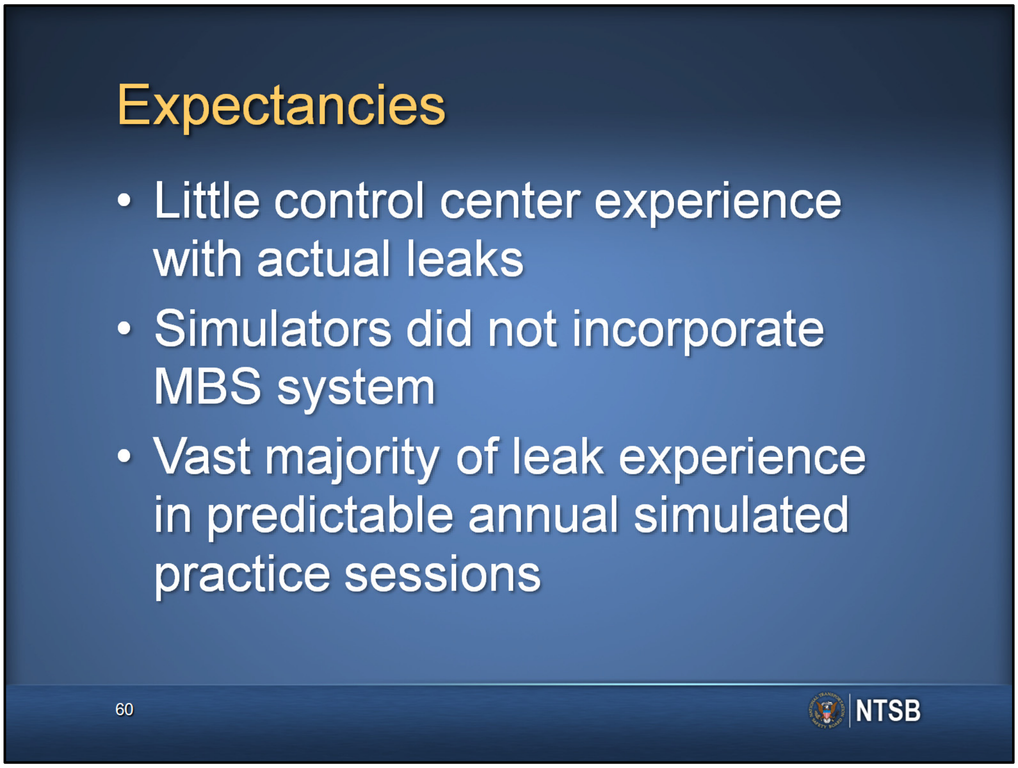
These errors resulted, among other factors, from a breakdown in the performance of Enbridge's control center teams, expectancies regarding the cause of MBS alarms that did not match the accident circumstances, an increasing tolerance for not adhering to procedures, and misinterpreting the absence of an external leak report. **[Click]**



Teams, defined as two or more people working together to achieve a common objective, provide unique advantages over the use of single operators in complex system operations. Just as players on a baseball team, each with different expertise, work together under the guidance of the manager to achieve a common objective, winning, Enbridge's control center teams, consisting of people with different types of expertise, worked together under the guidance of supervisors in a common objective, safely delivering crude oil to customers. **[Click]**

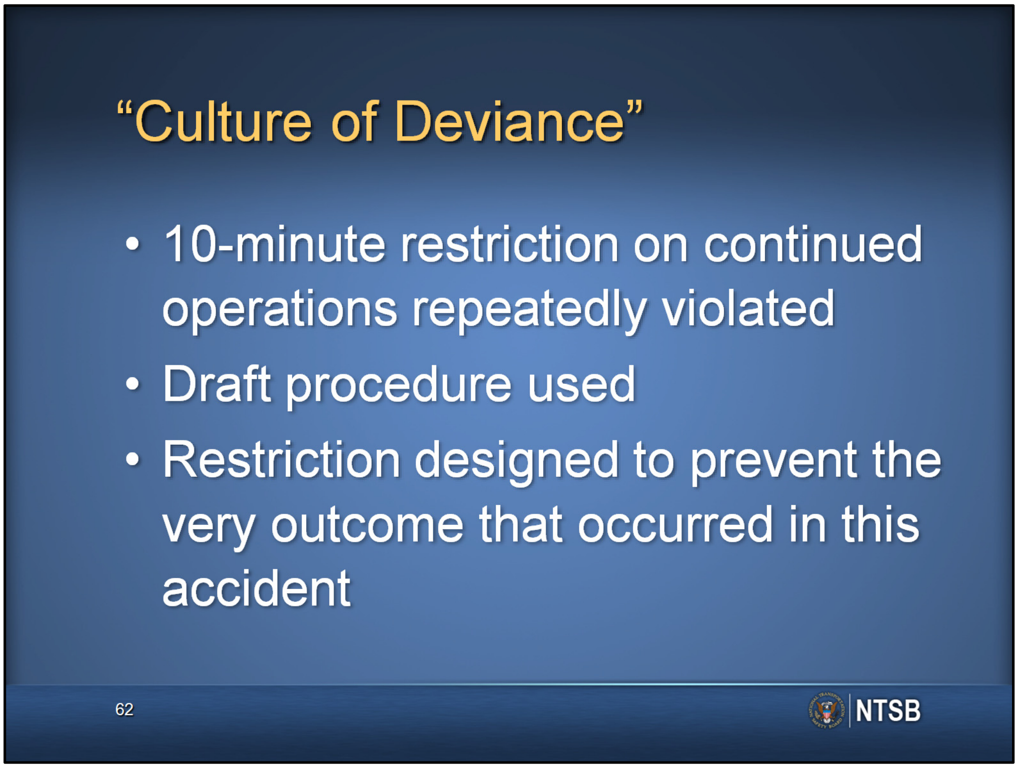


Control center staff team performance broke down when the operator, who had final authority on line flow, with the shift lead and supervisor, deferred critical decision making to the MBS analyst. The MBS analyst exceeded his authority in suggesting actions to the operator to restart line flow, MBS analysts used different terms to respond to MBS alarms than did others in the control center, and the supervisor lacked the technical expertise to question the recommendations of others on the team. Further, Enbridge did not conduct, nor was it required to conduct, team technical training at regular intervals. Staff has proposed safety recommendations to address these issues. **[Click]**

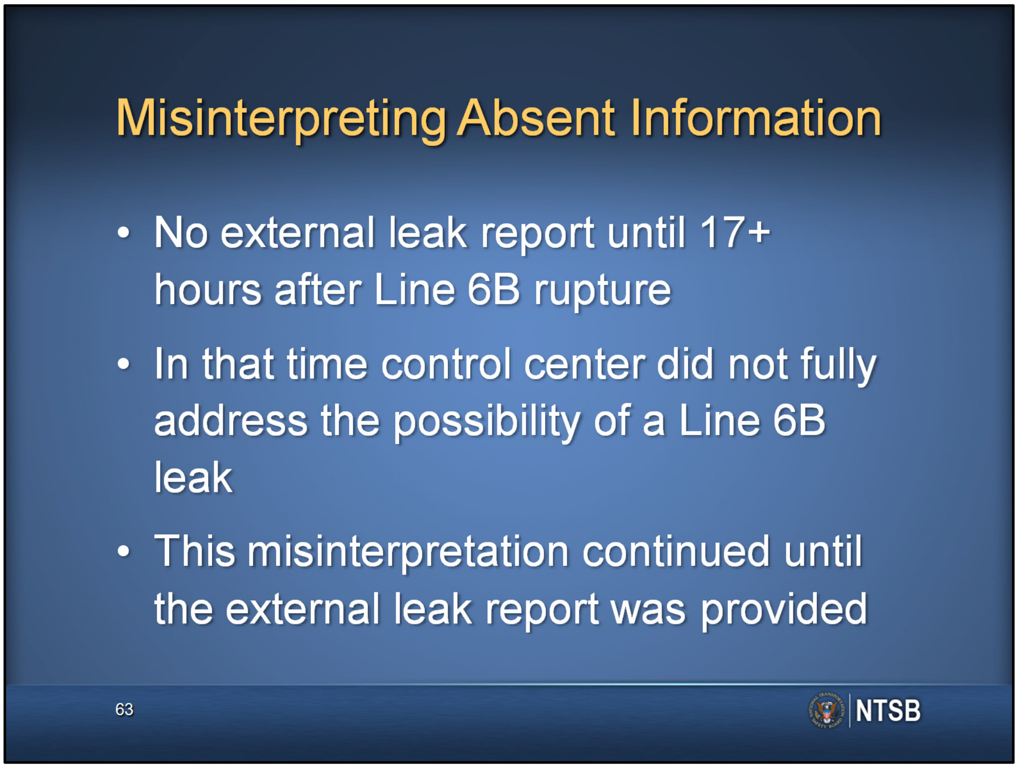


Further, control center staff had little first hand experience with realistic pipeline ruptures, with the primary exposure to leak scenarios through regularly scheduled, predictable simulator sessions, in accordance with PHMSA requirements, using simulators that did not incorporate MBS system capabilities. Over time, control center staff came to associate MBS alarms with column separations and not leaks because invariably, in actual pipeline operations, MBS alarms were precipitated by column separations. Leaks are, and should be, rare events. However, other industries in which operators cannot be presented with practice realistic emergencies during regular operations have found alternate ways to train them to recognize and appropriately respond to emergency situations. Staff has proposed safety recommendations to address this. **[Click]**

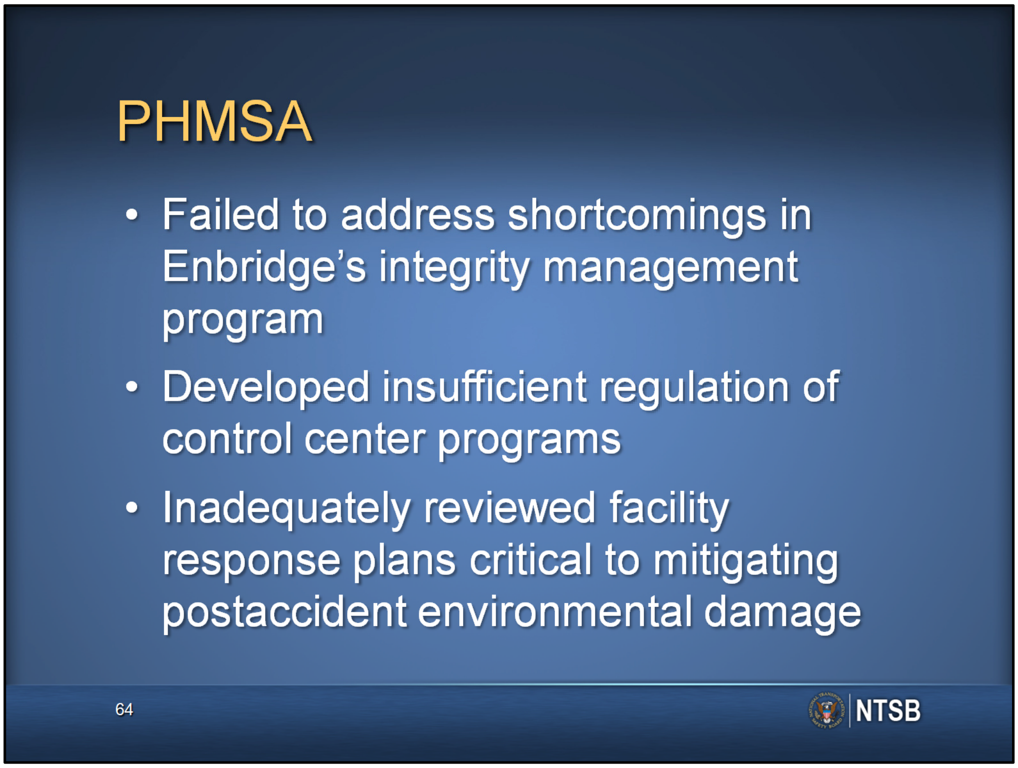
In a study of the January 28, 1986, accident involving the Space Shuttle Challenger, a researcher coined the term Culture of Deviance to describe the increasing tolerance of NASA and contractors for procedural violations. This eventually led to a decision to launch the shuttle after it had been exposed to subfreezing temperatures, despite a prohibition against such a decision in those circumstances. **[Click]**



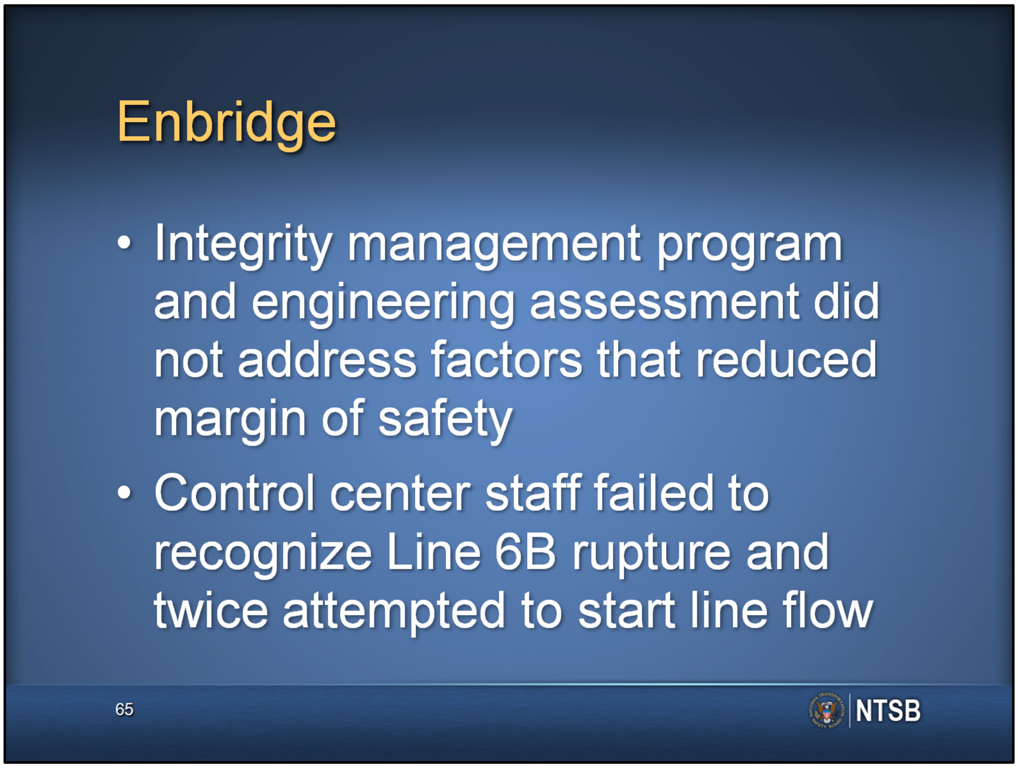
A Culture of Deviance in the Enbridge control center was displayed in this accident, and in the accounts of numerous pipeline operators, by operators and their supervisors knowingly continuing pipeline flow beyond the 10-minute limit Enbridge had established in the presence of unexplained MBS alarms and in using a procedure that was still in draft form and thus, unapproved. Ironically, the 10-minute prohibition had been put in place to prevent the very outcome that occurred in this accident – continued, extended line flow in the presence of unexplained MBS alarms – so that a pipeline leak does not lead to a catastrophic crude oil release. **[Click]**



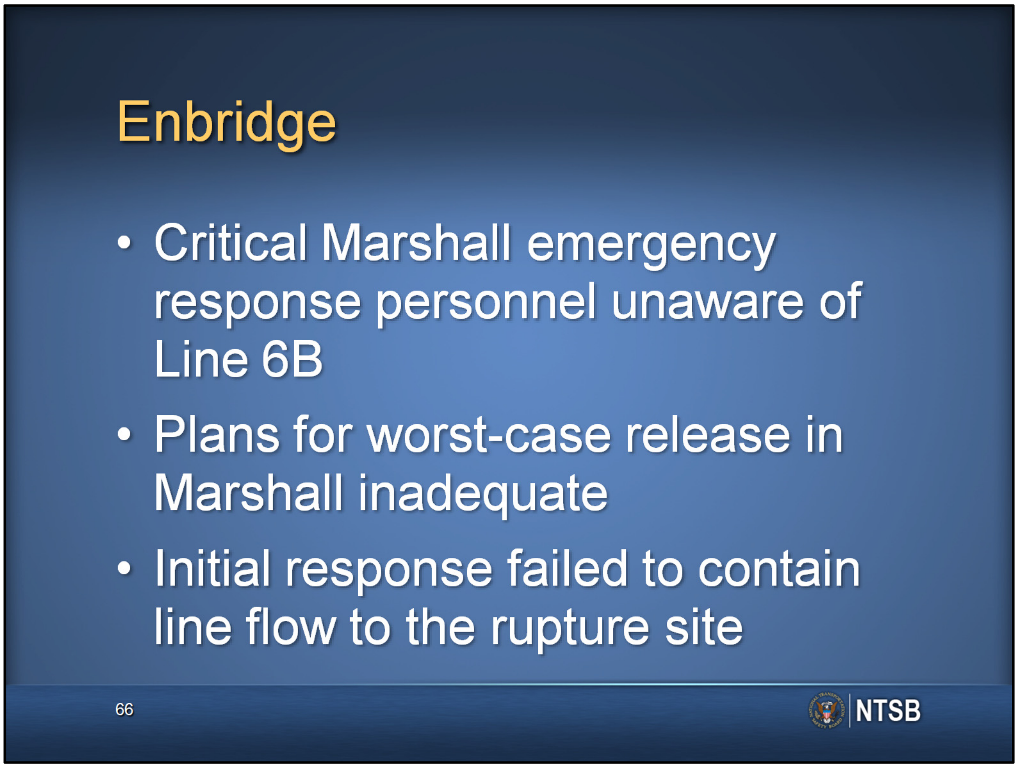
Finally, this accident illustrates an additional type of error often encountered in loss of situation awareness scenarios – misinterpreting absent information as actual, consequential information. Critical Enbridge control center staff interpreted the absence of an external leak report from the Marshall, Michigan, area as support for a column separation as the cause of the Line 6B MBS alarm. In fact, this misinterpretation was so powerful that it continued over three separate shifts, despite the presence of several leak triggers through the more than 17-hour period. **[Click]**



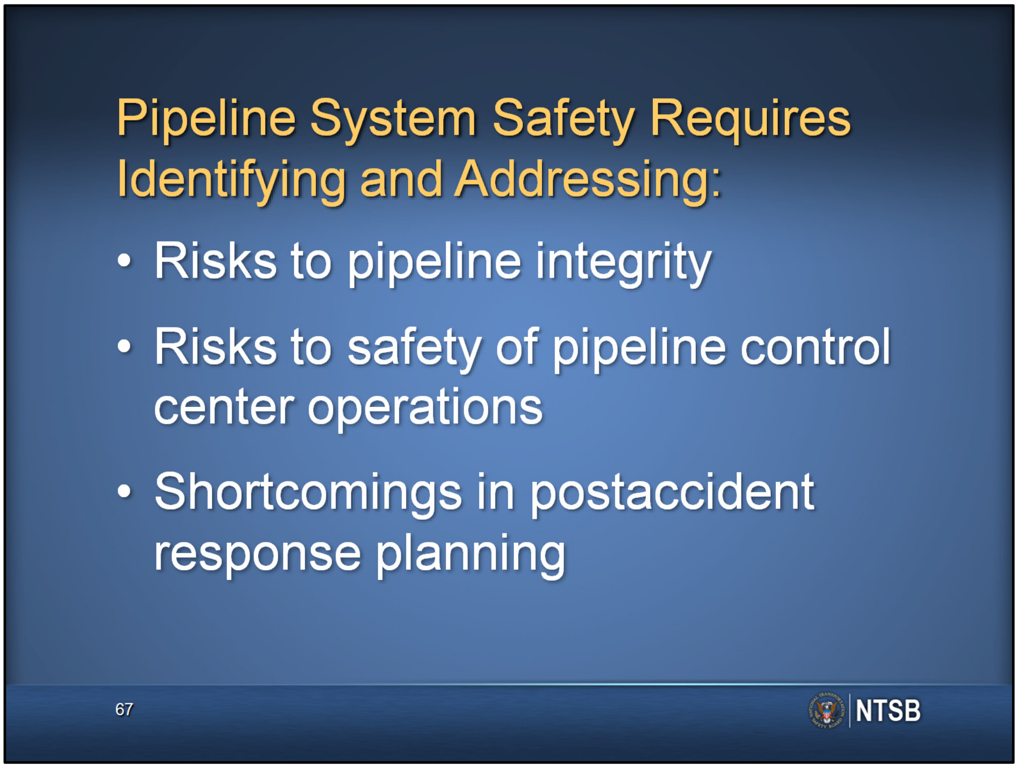
As noted previously, the errors found in this accident reflect organizational, rather than individual, error antecedents, and Enbridge did not operate its system in a regulatory vacuum. As Mr. Chhatre observed, PHMSA's oversight of integrity management programs was insufficient to address obvious shortcomings in Enbridge's program and its response to anomalies found in Line 6B. Its control room management program, although not fully implemented until after this accident, was inadequate to prevent the types of control center errors identified in Enbridge's control center, despite the fact that those errors were similar to ones identified in most of the accidents cited in the NTSB's 2005 safety study of SCADA systems and in other pipeline accidents that the NTSB has investigated. Further, as Mr. Stancil noted, PHMSA accepted an inadequate Enbridge plan to respond to a worst-case leak scenario in Marshall. **[Click]**



In examining Enbridge's role in this accident, a role that staff believes directly led to the Line 6B rupture and to the severe consequences of that rupture, essentially three major types of deficiencies are evident. These involve pipeline integrity management, control center management, and postaccident response. As Mr. Chhatre has noted, Enbridge's integrity management program had numerous shortcomings that failed to identify risks to the integrity of the Line 6B pipeline. As I discussed, several critical control center staff errors occurred that led to the discharge of hundreds of thousands of gallons of crude oil after Line 6B had ruptured, **[Click]**



Further, as Mr. Stancil observed, Enbridge's public awareness program failed to sufficiently inform 911 personnel and emergency responders of the presence of Line 6B in the Marshall area, thereby contributing to the prolonged misdiagnosis of the leak. In addition, Enbridge's planned response to a worst-case scenario in Marshall, and its initial response to this accident, were ineffective, the latter leading to the substantial amount of crude oil that was not contained within the immediate area of the pipeline rupture. **[Click]**



Therefore, staff believes that the lessons of this accident point to pipeline safety as the interaction of three key fundamental elements: identifying and addressing risks to pipeline integrity, effectively attending to control center safety, and thorough postaccident response planning. This accident demonstrates that inadequately addressing risk in any one area heightens the threat to the safety of a pipeline system. **[Click]**

Staff believes that the causes of the errors and shortcomings noted in this accident could and should have been identified and addressed proactively, before this accident occurred. The NTSB has identified and supported the implementation of Safety Management or SMS Systems as an effective way to enhance the safety of complex system operations because it systematically and continuously identifies and addresses risks to system safety. As the Federal Aviation Administration wrote in its Advisory Circular on SMS systems, in these systems "business and governmental roles are well defined, expectations are based upon sound systems engineering and system safety principles, and both regulators and regulated industries participate in a unified safety effort." Staff has proposed safety recommendations to address this issue. **[Click]**

This concludes my presentation. Staff is prepared to answer questions at this time.