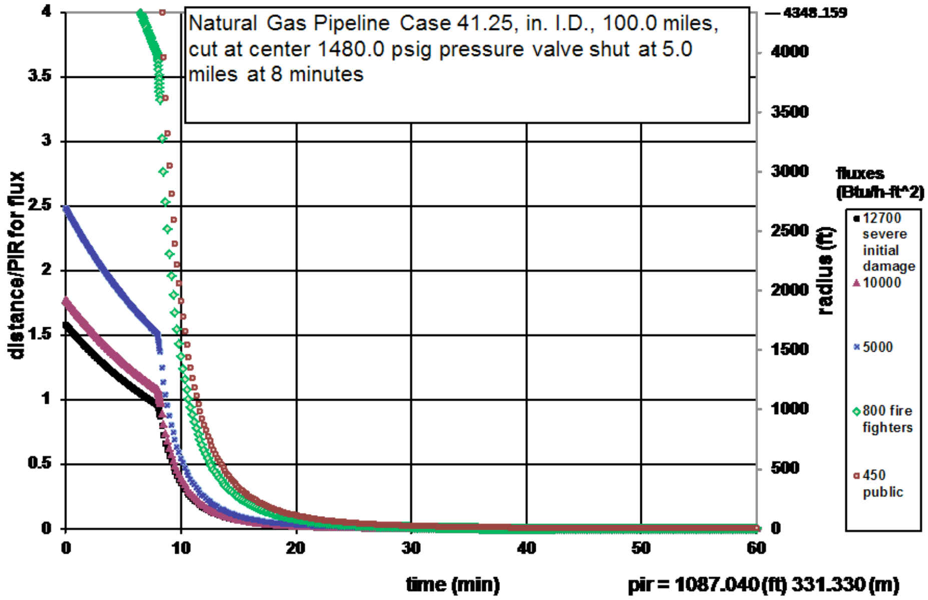


Fig. 3.61. Separation distances for 42-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break.

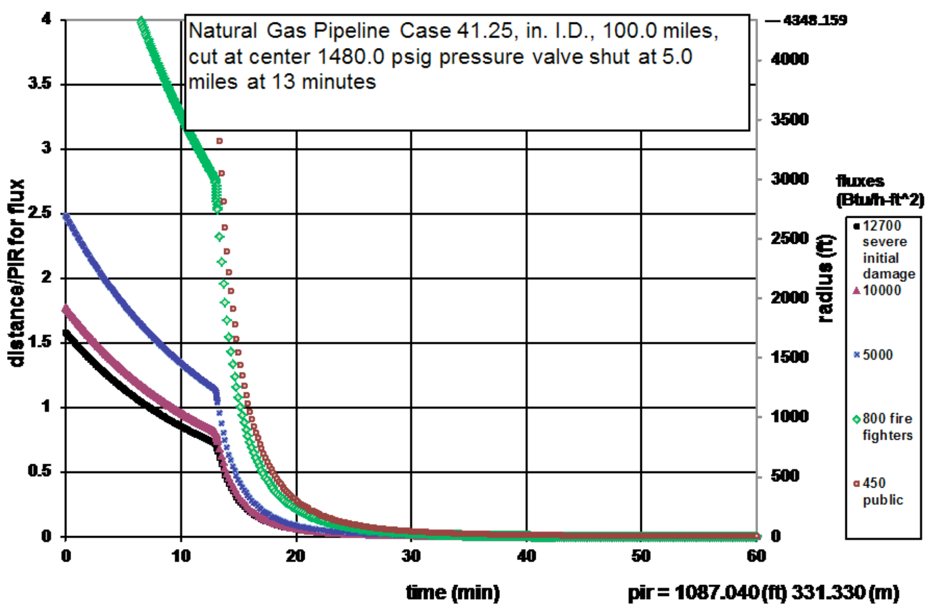


Fig. 3.62. Separation distances for 42-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break.

Figures 3.59 and 3.60 for 12-in. nominal diameter natural gas pipeline releases show that delaying block valve closure from 8 to 13 minutes after the break reduces the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR from 10 to 14 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparison of time-dependent blowdown behavior plots in Figs. 3.15, 3.16, and 3.59 show that closing block valves within 8 minutes increases the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR by 17 minutes (27 minutes - 10 minutes) without compressor inflow and 27 minutes (37 minutes - 10 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blowdown behavior plots in Figs. 3.15, 3.16, and 3.60 show that closing block valves within 13 minutes increases the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR by 13 minutes (27 minutes - 14 minutes) without compressor inflow and 23 minutes (37 minutes - 14 minutes) if the compressor inflow is 15 ft/s.

Figures 3.61 and 3.62 for 42-in. nominal diameter natural gas pipeline releases show that delaying block valve closure from 8 to 13 minutes after the break reduces the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR from 10 to 14 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparisons of time-dependent blowdown behavior plots in Figs. 3.17, 3.18, and 3.61 show that closing block valves within 8 minutes increases the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR by 15 minutes (25 minutes - 10 minutes) without compressor inflow and 23 minutes (33 minutes - 10 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blowdown behavior plots in Figs. 3.17, 3.18, and 3.62 show that closing block valves within 13 minutes increases the time fire fighters are able to conduct fire fighting activities within a distance of 1.5 times PIR by 11 minutes (25 minutes - 14 minutes) without compressor inflow and 19 minutes (33 minutes - 14 minutes) if the compressor inflow is 15 ft/s.

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines, in Class 4 Locations are considered to assess effects of valve closure time on fire damage to buildings with four or more stories above ground. Design features and operating conditions for these hypothetical natural gas pipelines are defined in Table 3.3. The four case studies compare the following effects on avoided damage costs.

- Case studies 4A and 4B compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 12-in. nominal diameter natural gas pipelines with MAOPs equal to 300 psig and valve closure durations of either 8 minutes or 13 minutes after the break.
- Case studies 4C and 4D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 42-in. nominal diameter natural gas pipelines with MAOPs equal to 1,480 psig and valve closure durations of either 8 minutes or 13 minutes after the break.

Results of the case studies including comparisons to baseline conditions and the avoided damage costs attributed to block valve closure swiftness are shown in Tables 3.18 and 3.19. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines within Class 4 Locations with buildings with four or more stories above ground are shown in Figs. 3.63 to 3.66.

Table 3.18. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 4 Locations with buildings with four or more stories above ground

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 4A	Case Study 4B
Nominal Line Pipe Diameter, in.	12	12	12	12
MAOP, psig	300	300	300	300
Potential Impact Radius (PIR), ft	143	143	143	143
Detection Phase Duration, minutes	N/A	N/A	5	5
Valve closure after break, minutes	N/A	N/A	8	13
Severe Damage Heat Flux, Btu/hr ft^2	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break
Moderate Damage Heat Flux, Btu/hr ft^2	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break
Minor Damage Heat Flux, Btu/hr ft^2	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break
Common Fire Fighting Heat Flux Threshold, Btu/hr ft^2	800	800	800	800
Total Severe Damage Cost for Building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building
Total Moderate Damage Cost for Building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building
Total Minor Damage Cost for Building	$500,000 per building	$500,000 per building	$500,000 per building	$500,000 per building
Potentially Severe Damage Radius, ft	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	11	49
Potentially Minor Damage Radius, ft	77	102	1	2
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	10	14
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	3	3	3	3
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	3	3	3	3

Table 3.18. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 4 Locations with buildings with four or more stories above ground (Cont.)

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 4A	Case Study 4B
Avoided Severe Damage Cost for Valve Closure in 8 minutes Compared to Baseline	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0
Avoided Severe Damage Cost for Valve Closure in 13 minutes Compared to Baseline	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0	$\pi(244 - 244)^2 = 0$ acres $0
Avoided Moderate Damage Cost for Valve Closure in 8 minutes Compared to Baseline	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Moderate Damage Cost for Valve Closure in 13 minutes Compared to Baseline	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Minor Damage Cost for Valve Closure in 8 minutes Compared to Baseline	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Minor Damage Cost for Valve Closure in 13 minutes Compared to Baseline	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Damage Cost Resulting from Fire Fighting Activities within 1.5 times PIR Compared to Baseline	$0	$0	(50% - 0%) * 3 * $1,000,000 = $1,500,000	(50% - 20%) * 3 * $1,000,000 = $900,000

Note: The perimeter of the potentially severe damage area is 1,348 ft. Three fire hydrants are available outside the potentially severe damage area. Twelve engines arrive on scene and fire fighters begin fire fighting activities within 10 minutes. Each fire hydrant can provide enough water for one engine to extinguish one building fire or vehicles parked outside within an area of 0.25 acres.

Table 3.19. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 4 Locations with buildings with four or more stories above ground

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 4C	Case Study 4D
Nominal Line Pipe Diameter, in.	42	42	42	42
MAOP, psig	1,480	1,480	1,480	1,480
Potential Impact Radius (PIR), ft	1,115	1,115	1,115	1,115
Detection Phase Duration, minutes	N/A	N/A	5	5
Valve closure after break, minutes	N/A	N/A	8	13
Severe Damage Heat Flux, Btu/hr ft^2	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break
Moderate Damage Heat Flux, Btu/hr ft^2	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break	At least 10,000 for 15 minutes after break
Minor Damage Heat Flux, Btu/hr ft^2	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break	At least 5,000 for 30 minutes after break
Common Fire Fighting Heat Flux Threshold, Btu/hr ft^2	800	800	800	800
Total Severe Damage Cost	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building
Total Moderate Damage Cost	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building	$1,000,000 per building
Total Minor Damage Cost	$500,000 per building	$500,000 per building	$500,000 per building	$500,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	78	345
Potentially Minor Damage Radius, ft	546	719	8	14
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	10	14
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	21	21	21	21
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	12	12	12	12

Table 3.19. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 4 Locations with buildings with four or more stories above ground (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 4C	Case Study 4D
Avoided Severe Damage Cost for Valve Closure in 8 minutes Compared to Baseline	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0
Avoided Severe Damage Cost for Valve Closure in 13 minutes Compared to Baseline	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0	$\pi(1{,}716 - 1{,}716)^2 =$ 0 acres $0
Avoided Moderate Damage Cost for Valve Closure in 8 minutes Compared to Baseline	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Moderate Damage Cost for Valve Closure in 13 minutes Compared to Baseline	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Moderate Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Minor Damage Cost for Valve Closure in 8 minutes Compared to Baseline	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Minor Damage Cost for Valve Closure in 13 minutes Compared to Baseline	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0	Potentially Minor Damage Radius is less than Potentially Severe Damage Radius $0
Avoided Damage Cost Resulting from Fire Fighting Activities within 1.5 times PIR Compared to Baseline	$0	$0	(50% - 0%) * 12 * $1,000,000 = $6,000,000	(50% - 20%) * 12 * $1,000,000 = $3,600,000

Note: The perimeter of the potentially severe damage area is 10,509 ft. Twenty-one fire hydrants are available outside the potentially severe damage area. Twelve engines arrive on scene and fire fighters begin fire fighting activities within 10 minutes. Each fire hydrant can provide enough water for one engine to extinguish one building fire or vehicles parked outside within an area of 0.25 acres.

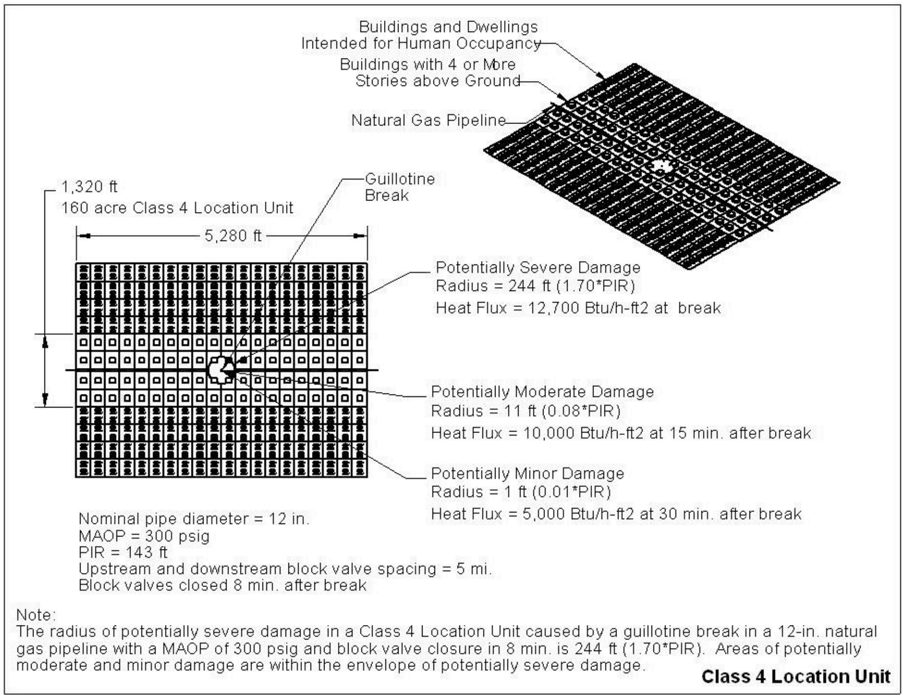


Fig. 3.63. Case Study 4A – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 300 psig MAOP and block valve closure 8 minutes after break.

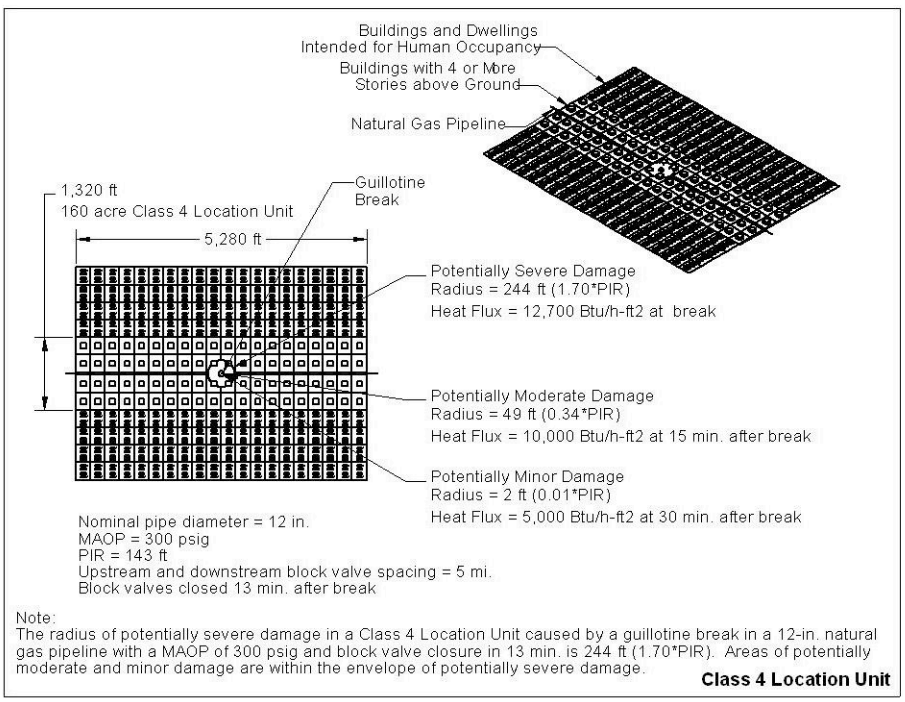


Fig. 3.64. Case Study 4B – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 300 psig MAOP and block valve closure 13 minutes after break.

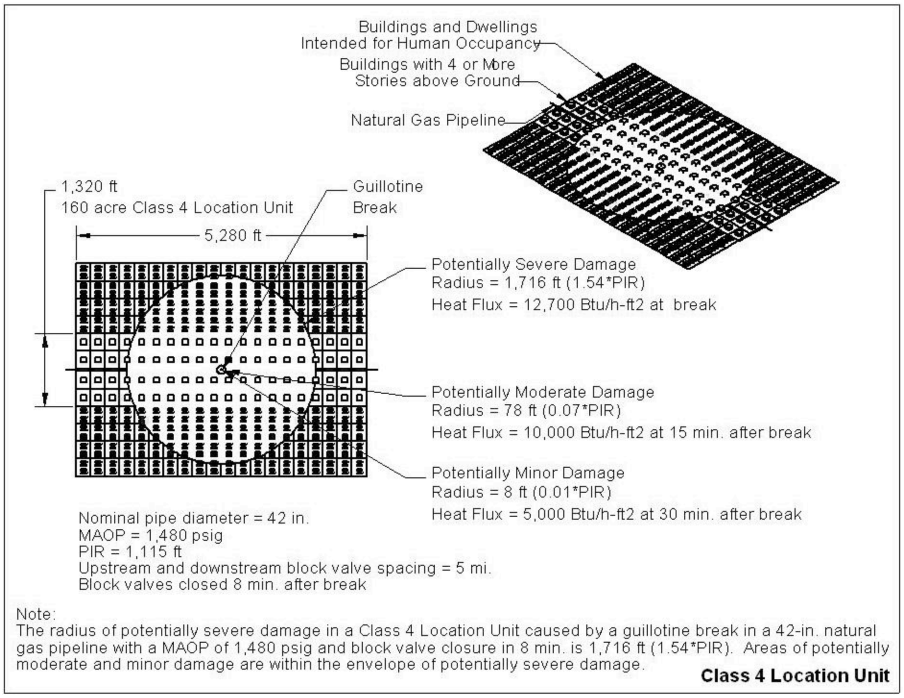


Fig. 3.65. Case Study 4C – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break.

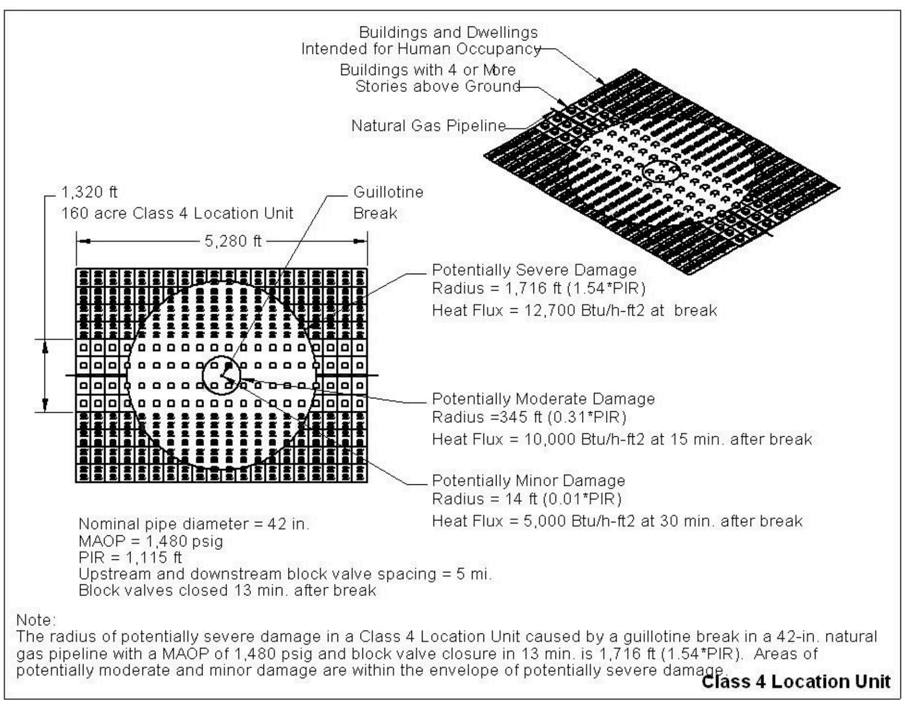


Fig. 3.66. Case Study 4D – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break.

Damage Resulting from Hypothetical Natural Gas Pipeline Releases in Class 4 Locations

Fire damage to buildings with four or more stories above ground in Class 4 Locations resulting from natural gas combustion immediately following guillotine-type breaks in natural gas pipelines is considered potentially severe for all areas within 1.5 to 1.7 times the PIR. Severe damage to buildings and personal property within these areas is possible because the heat flux produced by natural gas combustion immediately following the break equals or exceeds the severe damage threshold, 40 kW/m^2 (12,700 Btu/hr ft^2). The radii for severe damage envelopes the radii for moderate, 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, and minor damage, 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 minutes These results are based on computed heat flux versus time data and apply to natural gas pipelines with nominal diameters ranging from 12-in. to 42-in. and MAOPs ranging from 300 to 1,480 psig.

Benefits of Block Valve Closure Swiftness for a Hypothetical Natural Gas Pipeline Releases in Class 4 Locations

Without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings with four or more stories above ground in Class 4 Locations resulting from natural gas pipeline releases. The basis for this result follows.

- The heat flux produced by hydrocarbon combustion immediately following the break equals or exceeds the threshold of 40.0 kW/m^2 (12,700 Btu/hr ft^2) for potentially severe damage within a distance of approximately 1.5 times PIR.
- The time required to detect the break, isolate the damaged line section by closing the block valves, and begin reducing the natural gas discharge rate exceeds the time required to cause potentially severe building and personal property damage.

Valve closure swiftness also has no effect on reducing building and personal property damage costs. Consequently, without fire fighter intervention, there is no quantifiable benefit in terms of cost avoidance for damage to buildings and personal property attributed to swiftly closing block valves located upstream and downstream from guillotine-type breaks in natural gas pipelines.

When combined with fire fighter intervention, the swiftness of block valve closure has a potentially beneficial effect on mitigating fire damage to buildings and personal property in Class 4 Locations. The benefit in terms of cost avoidance is based on the ability of fire fighters to mitigate fire damage to buildings and personal property located within a distance of approximately 1.5 times PIR by conducting fire fighting activities as soon as possible upon arrival at the scene. The ability of fire fighters to conduct fire fighting activities within a distance of approximately 1.5 times PIR is only possible if the heat flux at this distance is below 2.5 kW/m^2 (800 Btu/hr ft^2) and fire hydrants are available at locations where needed. Block valve closure within 8 minutes after the break can result in a potential cost avoidance of at least $1,500,000 for 12-in. nominal diameter natural gas pipelines and $6,000,000 for 42-in. nominal diameter natural gas pipelines. Delaying block valve closure by an additional 5 minutes reduces the cost avoidance by approximately 50%.

3.1.4.5 Comparative Analysis for Natural Gas Pipeline Releases

The analytical approach and computational models described in Section 3.1.2 were used to study the San Bruno natural gas pipeline release that occurred in a residential area in San Bruno, California on September 9, 2010, in the segment of intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (NTSB, 2011). The study results provide evidence that the analytical approach and computational models produce credible results compared to an actual natural gas pipeline release.

Figures 3.67 and 3.68 show separation distance versus time plots for the San Bruno 30-in. nominal diameter natural gas pipeline release at an operating pressure of 386 psig. These plots were developed using the computational models and present results for two different release scenarios. Figure 3.67 corresponds to a release from 59.4 miles of pipeline, and Fig. 3.68 corresponds to a release from 124.6 miles of pipeline. Release scenarios involving different pipeline lengths were modeled to study the contribution of other pipelines that were cross-connected with Line 132 to overall severity of the incident. Comparison of the 2.5 kW/m^2 (800 Btu/hr ft^2) plots in Figs. 3.67 and 3.68 suggests that fire fighters were unable to conduct fire fighting activities within the potentially severe damage radius (1.5 times PIR) for approximately 80 minutes after the break and that cross-connected pipelines did not contribute significantly to the delay or incident severity. These plots also demonstrate the effectiveness of block valve closure in reducing the heat flux intensity within the potentially severe damage radius. The PIR that corresponds to the pressure at the time of the release is approximately 400 ft.

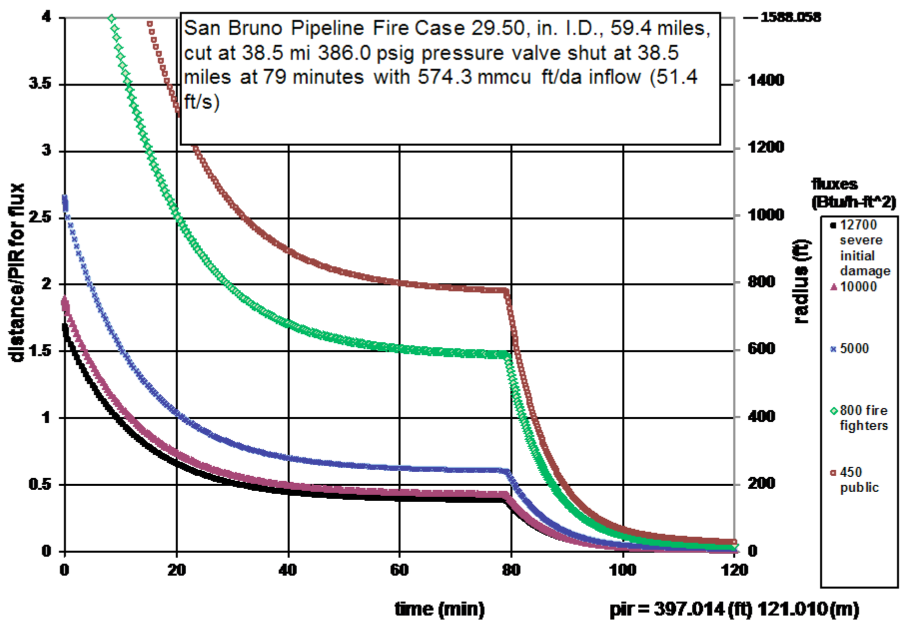


Fig. 3.67. Separation distance versus time plot for the San Bruno natural gas pipeline release –59.4 to 38.5 mi. segment.

Figures 3.67 and 3.68 also show that the heat flux at a distance of 600 ft (1.5 PIR) from the break exceeded the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold for fire fighting activities until block valve closure isolated the damaged pipeline segment approximately 79 minutes after the break. These plots also show that the radius for potentially severe damage envelopes the radii for moderate, 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, and minor damage, 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 minutes.

Although the analytical approach and computational models do not consider terrain features or wind effects[6], which are factors that contributed to the distribution of fire damage for this release, Fig. 3.69 shows that the computed potentially severe damage radius of 1.5 times PIR envelopes most of the damaged and destroyed buildings located in the area surrounding the rupture site.

[6] The wind across the northern and central portion of the San Francisco peninsula was estimated to have been from the west with magnitudes from 17–29 mph (NTSB, 2011).

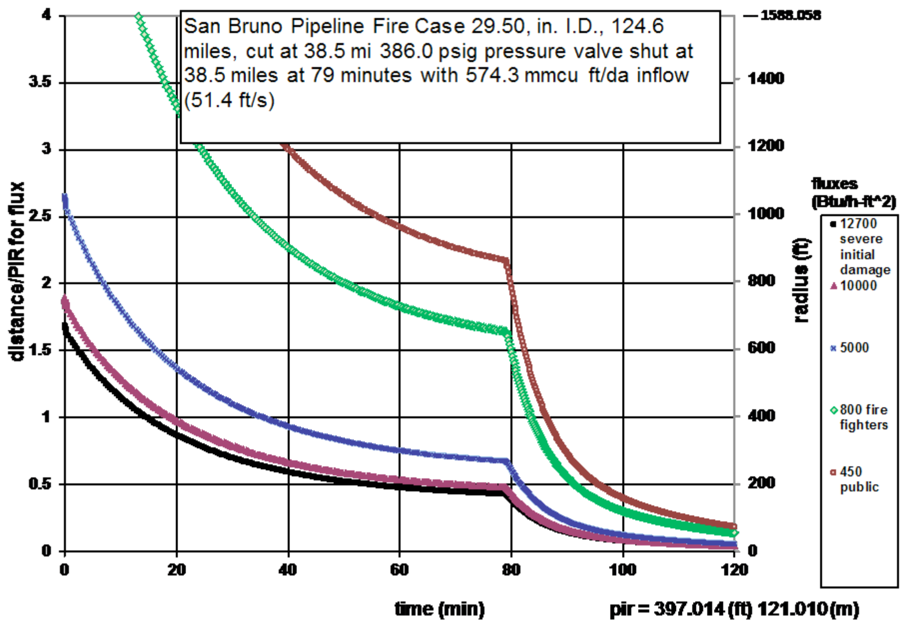


Fig. 3.68. Separation distance versus time plot for the San Bruno natural gas pipeline release –124.6 to 38.5 mi. segment.

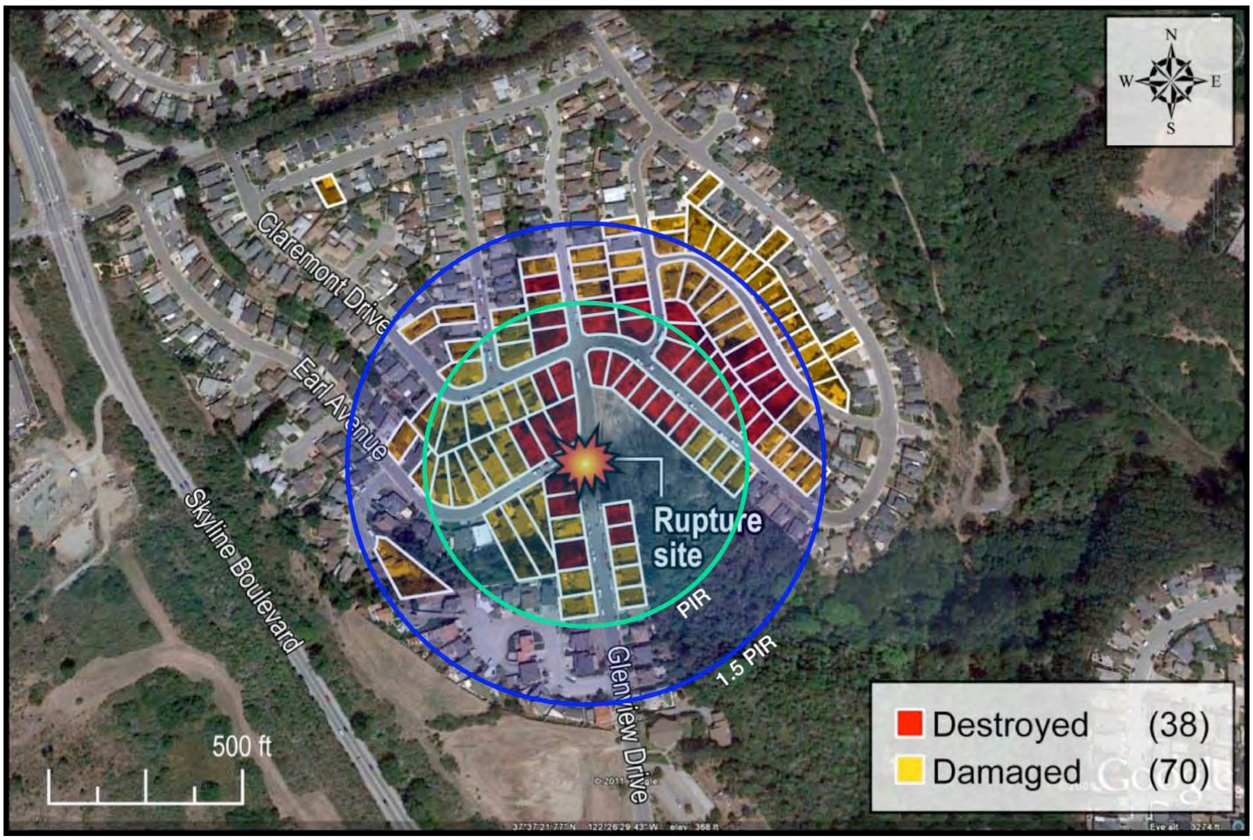


Fig. 3.69. Aerial view of the September 9, 2010 San Bruno natural gas pipeline release showing residential properties damaged and destroyed.

These study results are consistent with the timeline for emergency response and the damage assessments discussed in the NTSB accident report for the San Bruno natural gas transmission pipeline rupture and fire (NTSB, 2011). They also provide the basis for concluding that the analytical approach and computational models described in Section 3.1.2 produce credible results.

3.2 HAZARDOUS LIQUID PIPELINES WITH IGNITION

Following a guillotine-type break in a hazardous liquid pipeline and ignition of the released hydrocarbon, a pool fire begins to form and continues to increase in diameter as liquid flows from the break. Eventually, the pool reaches an equilibrium diameter when the mass flow rate from the break equals the fuel mass burning rate. The fire will continue to burn until the liquid that remains in the isolated pipeline segments stops flowing from the pipeline.

A pipeline break can range in size and shape from a short, through-wall crack to a guillotine fracture that completely separates the line pipe along a circumferential path. Guillotine-type breaks are less common than other pipeline breaks such as fish-mouth type openings, but they can occur as a result of different causes including landslides, earthquakes, soil subsidence, soil erosion (e.g. scour in a river) and third-party damage. The guillotine-type break is the largest possible break and is therefore considered in this study as the worst case scenario. Although the volume of the discharge depends on many factors, to enable analysis, the event is divided into four sequential phases with the total discharge volume equal to the sum of the volumes released during each phase. The four phases (detection, continued pumping, block valve closure and pipeline drain down) are explained in Section 1.3.2.1.

The thermal radiation hazards from a hydrocarbon release and resulting pool fire depend on a variety of factors including the composition of the hydrocarbon, the size and shape of the fire, the duration of the fire, its proximity to the objects at risk, and the thermal characteristics of the object exposed to the fire. Estimating the thermal radiation fields surrounding a fire involve the following steps.

- Determine the geometric characteristics of the pool fire including the burning rate and the physical dimensions of the fire.
- Determine the average irradiance of the pool fire flames based on consideration of the fuel type, fire size, flame temperature, and composition.
- Compute time-dependent variations in distance from the break for specified heat flux intensities.

3.2.1 Analysis Scope, Parameters, and Assumptions

After a hazardous liquid pipeline ruptures, the resulting discharge is assumed to pool on the ground, ignite, and burn until all of the fuel is consumed. In this study, fire damage resulting from propane, butane, propylene, and gasoline releases were considered. However, propane was selected as the study variable because propane has the greatest heat of combustion and produces the worst case fire damage compared to the other fuels.

The following simplifying assumptions were used to determine thermal radiant intensities for a propane pool fire.

- The fuel mass burning rate per unit area per unit time, $\dot{m}''$, is 0.099 kg/m^2-s for propane.
- The effective heat of combustion, H, is 46,000 kJ/kg for propane.
- The empirical constant, $k\beta$, is 1.4 $m^{-1}$for propane.
- The regression rate, B, is 1.37×10^{-4} m/s for propane.

- The density of propane, ρ, is 545 kg/m^3 for propane.
- The flame can be represented by a small source thermal energy.
- The energy radiated from the flame is a specified fraction of energy released during combustion.
- The thermal radiation intensity varies proportionally with the inverse square of the distance from the source.

The following limitations apply to the ORNL methodology for estimating the time-dependent thermal radiant intensity resulting from fires produced by combustion of the released liquids.

- The proposed methodology is based on a point source radiation model which overestimates the intensity of thermal radiation at target locations close to the fire.
- The energy radiated from the flame is a specified fraction of the energy released during combustion.
- The pool fire is circular and horizontal, the ambient air temperature is 70°F, and the wind is calm.
- The pool fires burn in the open and are characterized by instantaneous and complete involvement of the hazardous liquids.
- The constants used in this study are only used for computational purposes, the exact values are unknown.

Study variables used to characterize hazardous liquid pipeline releases are listed in Table 3.20.

Table 3.20. Study variables for hypothetical hazardous liquid pipeline releases

Variable	Description	Proposed Variable Values
H	Elevation distance from break, ft	100, 500, 1,000
L	Maximum length between plateaus and peaks, mi.	3
D	Nominal line pipe diameter, in.	8, 12, 16, 24, 30, 36
v_p	Flow rate, ft/s	5, 10, 15
v_g	Drain down liquid velocity	Calculated based on H
t_d-t_0	Duration of detection phase, minutes	5
t_p-t_d	Duration of continued pumping phase, minutes	5
t_s-t_p	Duration of block valve closure phase, minutes	3, 30, 60, 90
t_{dd}-t_s	Duration of drain down phase, minutes	Calculated based on v_g
P_1	Maximum allowable operating pressure (MAOP), psig	400, 800, 1,200, 1,480

3.2.2 Analytical Approach and Computational Models

The Society of Fire Protection Engineers (SFPE) published equations for determining fire hazards from large open hydrocarbon fires in its Handbook of Fire Protection Engineering (NFPA, 1995). According to these equations, the flame diameter of a hydrocarbon pool fire depends on the spill size and the regression rate. The flame height depends on the flame diameter and the type of fuel. In the case of a continuous release, the liquid spreads and increases the burning area until the total regression rate is equal to the spill rate. The maximum or equilibrium diameter of a pool fire, D_{eq}, depends on the release mode, release rate, and regression rate. This diameter is computed using the following equation.

$$D_{eq} = 2(Q_{fr} / \pi B)^{1/2} \tag{3.22}$$

where

D_{eq}	is the pool fire diameter, m,
Q_{fr}	is the maximum flow rate, m^3/s, and
B	is the regression rate (liquid burn rate), m/s.

In some cases, the regression rate is not known for various hazardous liquids. The regression rate is calculated using the following equation.

$$B = \dot{m}''/\rho_l \tag{3.23}$$

where

$\dot{m}''$	is the fuel mass burning rate, kg/m^2-s, and
ρ_l	is the density of the liquid, kg/m^3.

Equation 3.21 is also used to calculate the pool fire diameter for the four phases of the release.

The diameter of the pool fire is greatly dependent on the flow rate through the break. From the time the break occurs until the equilibrium diameter is reached, the computed pool fire diameter is calculated through backward interpolation from the equilibrium diameter which may occur during the detection phase, continued pumping phase, or block valve closure phase. The equilibrium diameter is determined using the applicable input variables for a particular release scenario.

Requirements in 49 CFR 194.105(b) (1) state that the worst case discharge is the largest volume of fluid released based on the pipeline's maximum release time, plus the maximum shutdown response time, multiplied by the maximum flow rate, which is based on the maximum daily capacity of the pipeline, plus the largest line drainage volume after shutdown of the line sections. In this methodology, the maximum flow rate can be estimated by multiplying the fluid speed at the pump by the cross sectional area of the line pipe. Although operators can use this rule to determine a worst case discharge, the actual flow rate during the block valve closure phase may be greater (less conservative) due to factors such as fluid density, pressure changes, pump performance characteristics, and the elevation profile of the pipeline which are not reflected in the methodology. These factors are important in a risk analysis because their effects influence time-dependent damage resulting from a release.

The influence of fluid density, pressure changes, and the elevation profile of the pipeline is taken into consideration in this study by using Bernoulli's equation to calculate the flow rate during the block valve closure and drain down phases. However, there are recognized limitations in using Bernoulli's equation to determine drain down time because it does not model the effects of air flow through the pipeline break which occurs as the fluid escapes following block valve closure. Although Bernoulli's equation does not produce an exact solution to this fluid dynamics problem, comparison of the results provides a consistent approach for evaluating the effectiveness of block valve closure swiftness on mitigating release consequences. Bernoulli's equation follows.

$$z_1 + \frac{\mathrm{v}_1^2}{2g} + P_1 v_1 \frac{g_c}{g} = z_2 + \frac{\mathrm{v}_2^2}{2g} + P_2 v_2 \frac{g_c}{g} \tag{3.24}$$

where

z_1	is the elevation of the closed valve, ft,

z_2	is the elevation of the break, ft,
v_1	is the average velocity of the fluid at the closed valve, ft/s,
v_2	is the average velocity of the fluid at the break (also known as v_{exit}), ft/s,
P_1	is the pressure of the fluid at the closed valve, psig,
P_2	is the pressure of the fluid at the break, psig,
v	is the specific volume of the fluid, $ft^3/lb.$,
g	is the acceleration due to gravity, ft/s^2, and
g_c	is the gravitational constant, (32.17 $ft\text{-}lbm/lbf\text{-}s^2$).

After rearranging Bernoulli's equation, the velocity of the liquid that exits the pipe is determined using the following equation.

$$v_{exit} = \sqrt{2g[(z_1 - z_2) + (P_1 - P_2)v\frac{g_c}{g} + \frac{v_1^2}{2g}]} \quad (3.25)$$

When the diameter of the pool fire is determined using this equation, lateral pool spreading will stop and a steady pool fire will result as long as the flow and burn rates are maintained. The equilibrium diameter given by this equation is reached over a time given by the following equation.

$$t_{eq} = 0.564[D_{eq} / (g'BD_{eq}^{1/3})] \quad (3.26)$$

where

t_{eq}	is the time required for the pool fire to reach the equilibrium diameter, s, and
g'	is the effective acceleration of gravity (determined by the following equation), m/s^2,

$$g' = g(1 - \rho_l / \rho_w) \quad (3.27)$$

where

g	is the acceleration of gravity (9.81), m/s^2, and
ρ_w	is the density of water (978), kg/m^3.

3.2.3 Thermal Radiation Intensities and Thresholds

The methodology used for determining hazardous liquid pipeline pool fire thermal radiant intensities is based on a point source radiation model also found in the SPFE Handbook of Fire Protection Engineering (NFPA, 1995). The following equation expresses the radiant intensity at any distance from the source.

$$q''_r = \dot{Q} / 4\pi x^2 \quad (3.28)$$

where

q''_r	is the thermal radiant intensity or heat flux, W/m^2, and
$\dot{Q}$	is the total energy radiated per unit of time (determined by the following equation), W

$$\dot{Q} = \dot{m}'' H A_f (1 - e^{-k\beta D_{eq}}) \tag{3.29}$$

where

A_f	is the horizontal burning area of the fuel ($D_{eq}^2\pi/4$), m^2,
$k\beta$	is the empirical constant for the fire's fuel, m^{-1},
H	is the effective heat of combustion, kJ/kg, and
x	is the radial distance from center of flame to edge of target (building, person, etc.).

The methodology developed at ORNL for quantifying potential fire damage resulting from a natural gas pipeline release applies to: (1) buildings and dwellings intended for human occupancy, and (2) personal property. This methodology, which is discussed in Section 3.1.3, applies equally to fire damage resulting from combustion of hydrocarbons released from a hazardous liquid pipeline following a guillotine-type break.

3.2.4 Risk Analysis Results for Propane Pipeline Releases

Effects of block valve closure swiftness on mitigating potential fire damage to buildings and personal property resulting from a hazardous liquid pipeline release were evaluated based on a hypothetical liquid propane pipeline release in a HCA. The evaluation focused on damage to buildings intended for human occupancy arranged into the configuration described in Section 3.1.3.1 and shown in Fig. 3.11. Fire damage to buildings intended for human occupancy within the HCA is considered worst case because potential fire damage to other building types and configurations that qualify as HCAs is less in comparison. Section 2.2 includes additional information about hazardous liquid pipeline HCAs defined in 49 CFR 195.450. The method used in this analysis for defining maximum flow rate through the break during the detection and continued pumping phases are based on the worst case discharge as defined the method as defined in 49 CFR 194.105(b)(1). While in the block valve closure and drain down phases are defined by Bernoulli's equation.

Hypothetical Liquid Propane Pipeline Releases in HCA with Buildings Intended for Human Occupancy

Eight case studies involving 8-in. and 30-in. nominal diameter hazardous liquid pipelines in HCAs are considered to assess effects of valve closure time on fire damage to buildings intended for human occupancy and personal property. Design features and operating conditions for these hypothetical pipelines are defined in Table 3.21.

Table 3.21. Design features and operating conditions for hypothetical hazardous liquid pipelines considered in the risk analysis

Design Feature	Nominal Line Pipe Diameter, in.	
	8	30
Hazardous liquid	Propane	Propane
MAOP, psig	400 and 1,480	400 and 1,480
Drain down length. mi.	3	3
Overall length of pipeline, mi.	100	100
Elevation change, ft	100	1,00
Velocity, ft/s	5	5
Block valve spacing, mi.	50	50
Detection phase duration, minutes	5	5
Continued pumping phase duration, minutes	5	5
Block valve closure time, minutes after break	13 and 70	13 and 70

Characteristics for Case Study 5A, 5B, 5C, and 5D that involve 8-in. nominal diameter liquid propane pipelines are tabulated in Table 3.22. These case studies compare the following effects on avoided damage costs.

- Case studies 5A and 5B compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter liquid propane pipelines with MAOPs equal to 400 psig and valve closure durations or either 13 minutes or 70 minutes after the break.
- Case studies 5C and 5D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter liquid propane pipelines with MAOPs equal to 1,480 psig and valve closure durations or either 13 minutes or 70 minutes after the break.
- Case studies 5A and 5C compare effects of MAOP on the avoided damage costs for hypothetical 8-in. nominal diameter liquid propane pipelines with valve closure durations of 13 minutes after the break.
- Case studies 5B and 5D compare effects of MAOP on the avoided damage costs for hypothetical 8-in. nominal diameter liquid propane pipelines with valve closure 70 minutes after the break.

Note that the avoided damage costs are not sensitive to pressure and elevation changes because the model is based on the methodology in 49 CFR 194.105 (b)(1) for a worst case discharge which has a constant flow rate.

Figures 3.70 to 3.73 show potentially severe, moderate, and minor damage radii as a function of time for hypothetical 8-in. nominal diameter liquid propane pipelines.

Table 3.22. Avoided damage costs for hypothetical 8-in. liquid propane pipeline releases

Characteristic	Case Study 5A	Case Study 5B	Case Study 5C	Case Study 5D
Nominal Line Pipe Diameter, in.	8	8	8	8
MAOP, psig	400	400	1,480	1,480
Elevation Change, ft	100	100	100	100
Equilibrium Diameter, ft	70	70	70	70
Detection Phase Duration, minutes	5	5	5	5
Continued Pumping Phase Duration, minutes	5	5	5	5
Valve closure after break, minutes	13	70	13	70
Severe Damage Heat Flux, Btu/hr ft^2	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break
Moderate Damage Heat Flux, Btu/hr ft^2	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break
Minor Damage Heat Flux, Btu/hr ft^2	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break
Total Severe Damage Cost	$3,108,000/acre	$3,108,000/acre	$3,108,000/acre	$3,108,000/acre
Total Moderate Damage Cost	$1,524,000/acre	$1,524,000/acre	$1,524,000/acre	$1,524,000/acre
Total Minor Damage Cost	$540,000/acre	$540,000/acre	$540,000/acre	$540,000/acre
Potentially Severe Radius, ft	186	186	186	186
Potentially Moderate Radius, ft	104	209	104	209
Potentially Minor Radius, ft	42	289	42	289
Avoided Severe Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(186 - 186)^2 =$ 0 acres $0	$\pi(186 - 186)^2 =$ 0 acres $0	$\pi(186 - 186)^2 =$ 0 acres $0	$\pi(186 - 186)^2 =$ 0 acres $0
Avoided Moderate Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(209 - 186)^2 =$ 0 acres $0 M	$\pi(209 - 209)^2 =$ 0 acres $0 M	$\pi(209 - 186)^2 =$ 0 acres $0 M	$\pi(209 - 209)^2 =$ 0 acres $0 M

Table 3.22. Avoided damage costs for hypothetical 8-in. liquid propane pipeline releases (Cont.)

Characteristic	Case Study 5A	Case Study 5B	Case Study 5C	Case Study 5D
Avoided Minor Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(289 - 186)^2$ = 0.77 acres $0.416 M	$\pi(289 - 289)^2$ = 0 acres $0	$\pi(289 - 186)^2$ = 0.77 acres $0.416 M	$\pi(289 - 289)^2$ = 0 acres $0
Total Damage Cost Avoided for Valve Closure in 13 minutes	$0.416 M	$0	$0.416 M	$0

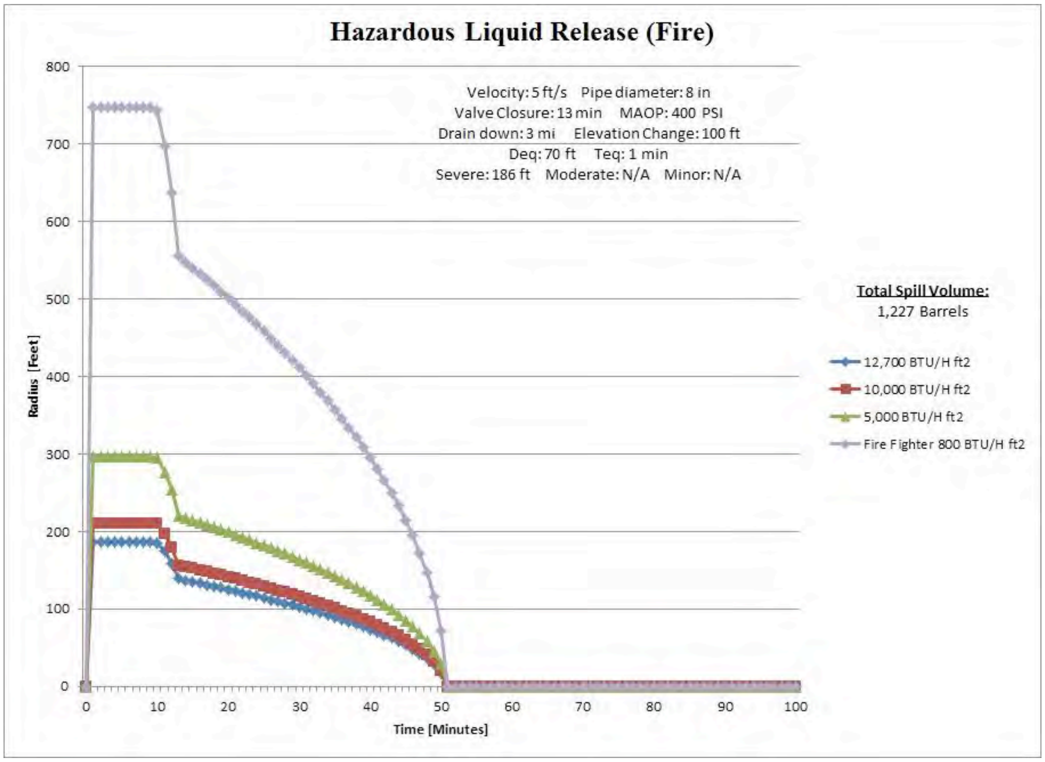


Fig. 3.70. Case Study 5A – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 13 minutes.

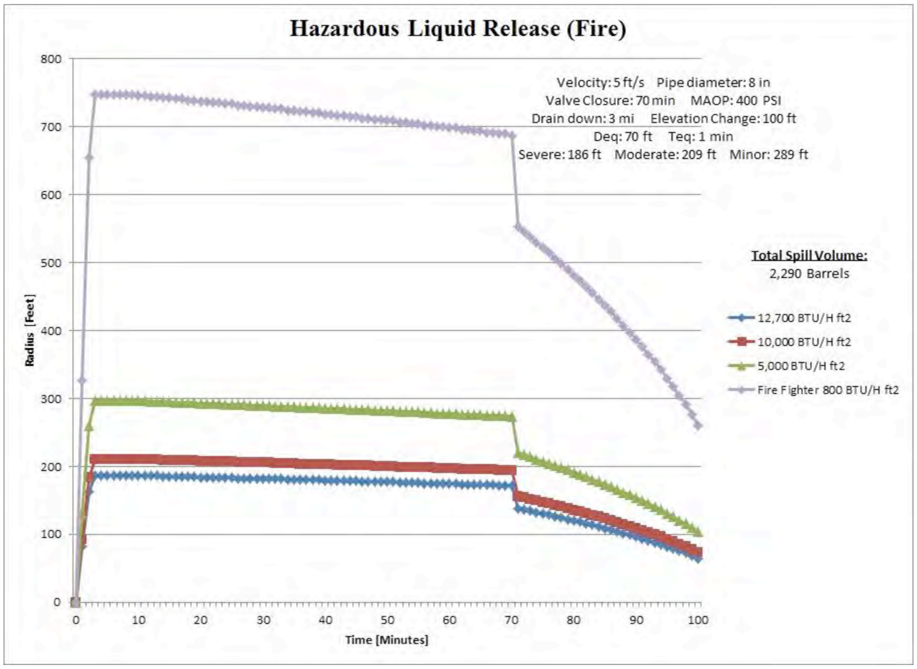


Fig. 3.71. Case Study 5B – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 70 minutes.

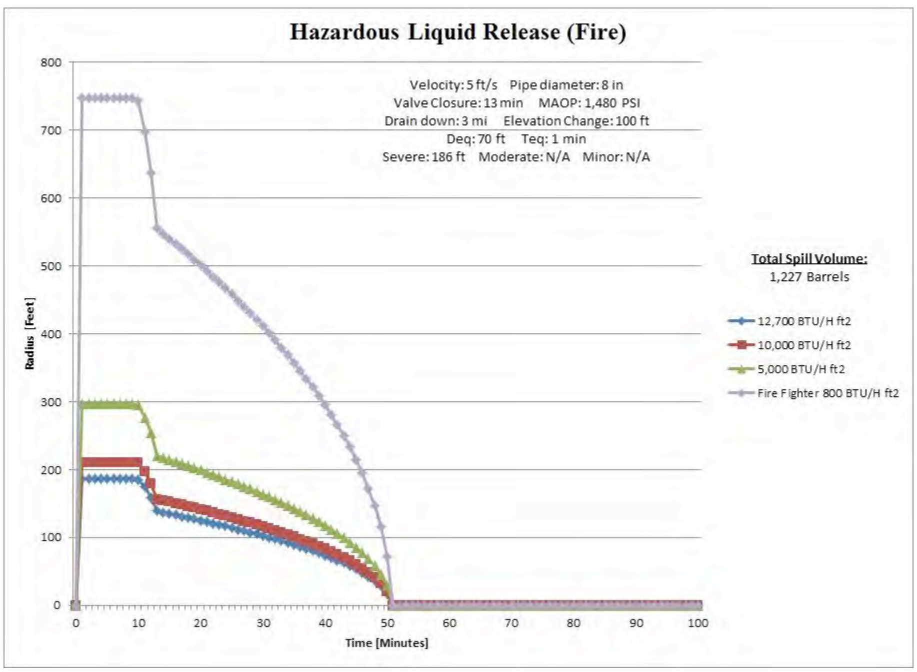


Fig. 3.72. Case Study 5C – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 13 minutes.

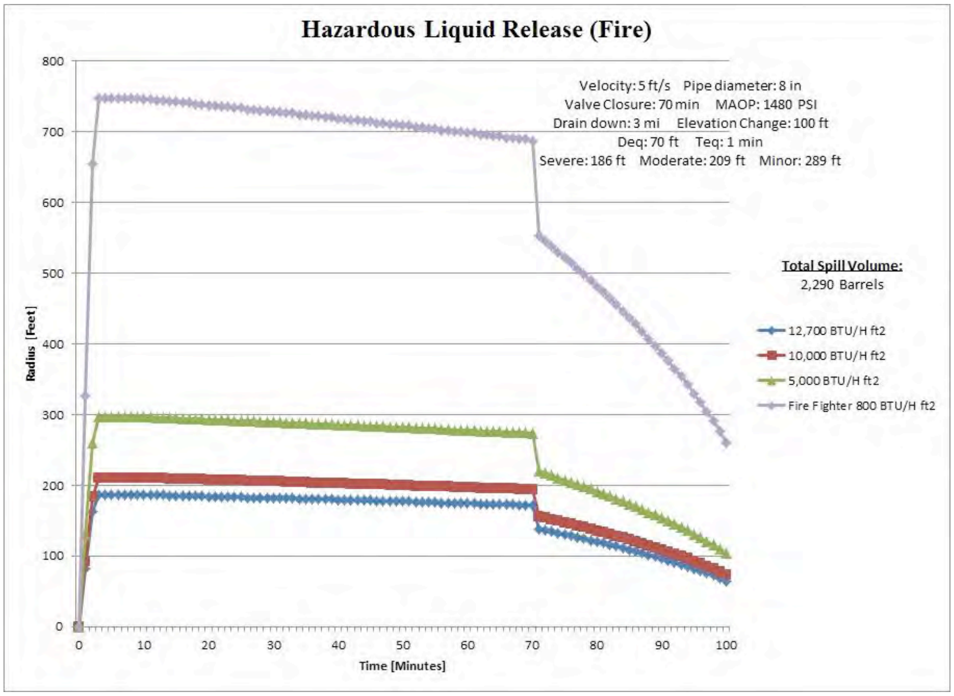


Fig. 3.73. Case Study 5D – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 70 minutes.

Characteristics for Case Study 6A, 6B, 6C, and 6D that involve 30-in. nominal diameter liquid propane pipelines are tabulated in Table 3.23. These case studies compare the following effects on avoided damage costs.

- Case studies 6A and 6B compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 30-in. nominal diameter liquid propane pipelines with MAOPs equal to 400 psig and valve closure durations or either 13 minutes or 70 minutes after the break.
- Case studies 6C and 6D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 30-in. nominal diameter liquid propane pipelines with MAOPs equal to 1,480 psig and valve closure durations or either 13 minutes or 70 minutes after the break.
- Case studies 6A and 6C compare effects of MAOP on the avoided damage costs for hypothetical 30-in. nominal diameter liquid propane pipelines with valve closure durations of 13 minutes after the break.
- Case studies 6B and 6D compare effects of MAOP on the avoided damage costs for hypothetical 30-in. nominal diameter liquid propane pipelines with valve closure 70 minutes after the break.

Note that the avoided damage costs are not sensitive to pressure and elevation changes because the model is based on the methodology in 49 CFR §194.105 (b) (1) for a worst case discharge which has a constant flow rate.

Figures 3.74 to 3.77 show potentially severe, moderate, and minor damage radii as a function of time for hypothetical 30-in. nominal diameter liquid propane pipelines.

Table 3.23. Avoided damage costs for hypothetical 30-in. liquid propane pipeline releases

Characteristic	Case Study 6A	Case Study 6B	Case Study 6C	Case Study 6D
Nominal Line Pipe Diameter, in.	30	30	30	30
MAOP, psig	400	400	1,480	1,480
Elevation Change, ft	1,000	1,000	1,000	1,000
Equilibrium Diameter, ft	264	264	264	264
Detection Phase Duration, minutes	5	5	5	5
Continued Pumping Phase Duration, minutes	5	5	5	5
Valve closure after break, minutes	13	70	13	70
Severe Damage Heat Flux, Btu/hr ft^2	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break	12,700 or greater at break
Moderate Damage Heat Flux, Btu/hr ft^2	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break	At least 10,000 for 15 min, after break
Minor Damage Heat Flux, Btu/hr ft^2	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break	At least 5,000 for 30 min, after break
Total Severe Damage Cost	$3,108,000/acre	$3,108,000/acre	$3,108,000/acre	$3,108,000/acre
Total Moderate Damage Cost	$1,524,000/acre	$1,524,000/acre	$1,524,000/acre	$1,524,000/acre
Total Minor Damage Cost	$540,000/acre	$540,000/acre	$540,000/acre	$540,000/acre
Potentially Severe Radius, ft	699	699	699	699
Potentially Moderate Radius, ft	571	784	571	784
Potentially Minor Radius, ft	613	1085	613	1085
Avoided Severe Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(699 - 699)^2 =$ 0 acres $0	$\pi(699 - 699)^2 =$ 0 acres $0	$\pi(699 - 699)^2 =$ 0 acres $0	$\pi(699 - 699)^2 =$ 0 acres $0

Table 3.23. Avoided damage costs for hypothetical 30-in. liquid propane pipeline releases (Cont.)

Characteristic	Case Study 6A	Case Study 6B	Case Study 6C	Case Study 6D
Avoided Moderate Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(784 - 699)^2 =$ 0.52 acres $0.792 M	$\pi(784 - 784)^2 =$ 0 acres $0	$\pi(784 - 699)^2 =$ 0.52 acres $0.792 M	$\pi(784 - 784)^2 =$ 0 acres $0
Avoided Minor Damage Cost for Valve Closure in 13 minutes Compared to 70 minutes	$\pi(1{,}085 - 699)^2 =$ 10 acres $5.40 M	$\pi(1{,}085 - 1{,}085)^2 =$ 0 acres $0	$\pi(1085 - 699)^2 =$ 10 acres $5.40 M	$\pi(1{,}085 - 1{,}085)^2 =$ 0 acres $0
Total Damage Cost Avoided for Valve Closure in 13 minutes	$6.19 M	$0	$6.19 M	$0

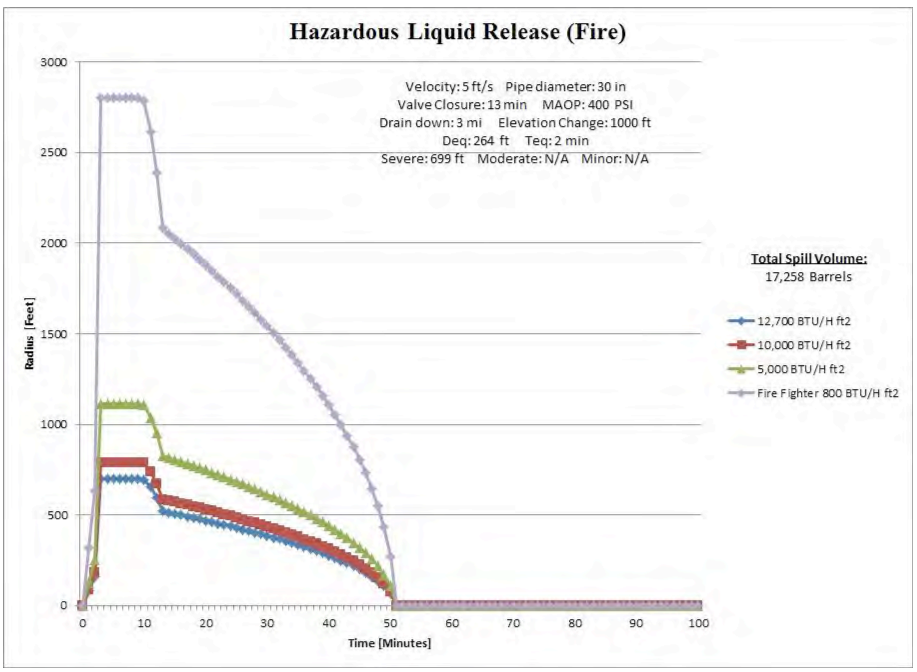


Fig. 3.74. Case Study 6A – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 13 minutes.

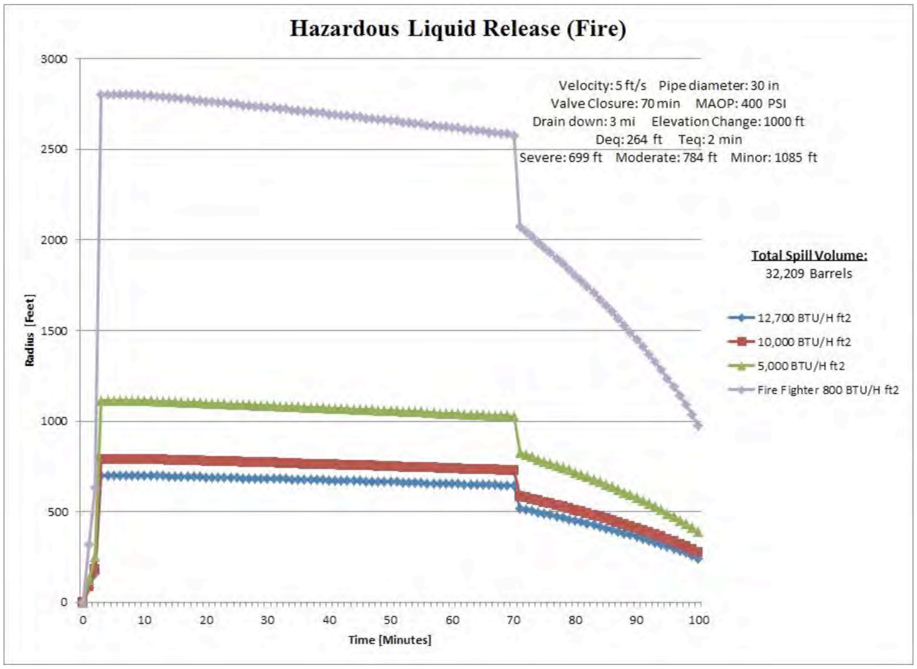


Fig. 3.75. Case Study 6B – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 70 minutes.

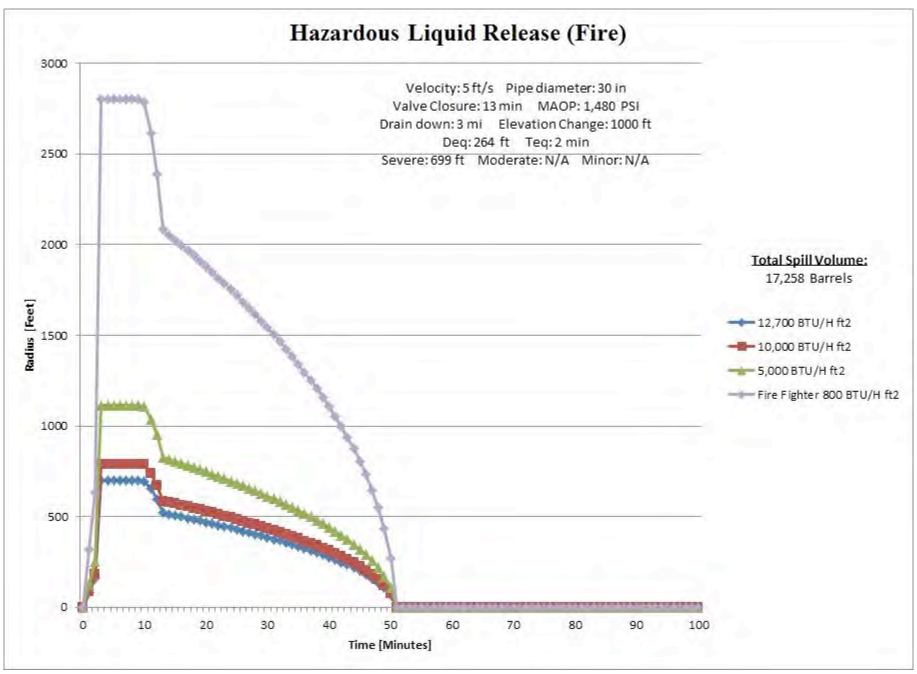


Fig. 3.76. Case Study 6C – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 13 minutes.

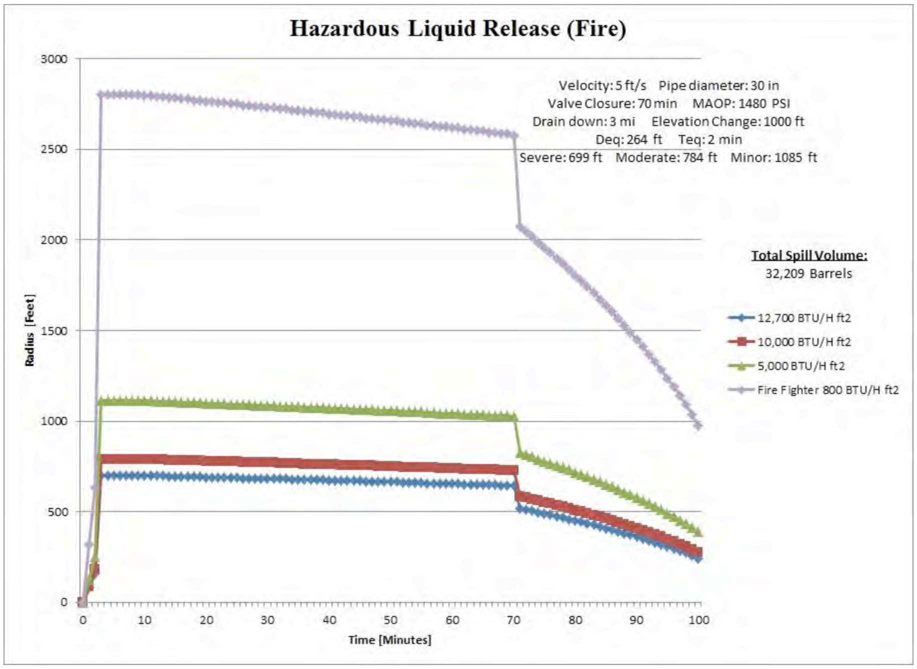


Fig. 3.77. Case Study 6D – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 70 minutes.

Damage Resulting from Hypothetical Liquid Propane Pipeline Releases with Ignition in a HCA

The potentially severe damage radius for each of the 8-in. nominal diameter liquid propane pipeline release scenarios considered in this study are unaffected by the swiftness of block valve closure. The pools reach their equilibrium diameters in 1 minute which is less than the 13 minutes required to detect the leak (5 minutes), shutdown the pumps (5 minutes), and close the valves (3 minutes). Similarly, the potentially severe damage radius for each of the 30-in. nominal diameter liquid propane pipeline release scenarios considered in this study are unaffected by the swiftness of block valve closure because the pools reach their equilibrium diameters in 2 minutes. Therefore, the avoided damage costs associated with the potentially severe damage radius cannot be actualized unless the detection phase and the continued pumping phase decrease to much less than 5 minutes.

The avoided damage costs attributed to block valve closure swiftness within areas of potentially moderate damage are calculated as follows.

- Determine the potentially severe damage radius for a heat flux of 40 kW/m^2 (12,700 Btu/hr ft^2).
- Determine the potentially moderate damage radius determined for a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes and block valve closure in 70 minute. Note that the severe damage radius is used as the limiting factor because the potentially moderate damage radius corresponding to block valve closure in 70 minutes exceeds the potentially severe damage radius.
- Use the difference between these two radii to compute the area of potentially moderate damage.
- Compute the avoided damage cost by multiplying the area of potentially moderate damage by the appropriate unit cost for moderate damage.

The avoided damage costs attributed to block valve closure swiftness within areas of potentially minor damage are calculated as follows.

- Determine the potentially severe damage radius for a heat flux of 40 kW/m^2 (12,700 Btu/hr ft^2).
- Determine the potentially minor damage radius determined for a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 minutes and block valve closure in 70 minute. Note that the severe damage radius is used as the limiting factor because the potentially minor damage radius corresponding to block valve closure in 70 minutes exceeds the potentially severe damage radius.
- Use the difference between these two radii to compute the area of potentially minor damage.
- Compute the avoided damage cost by multiplying the area of potentially minor damage by the appropriate unit cost for minor damage.

Fire damage to buildings and personal property in a HCA resulting from liquid propane combustion immediately following guillotine-type breaks in liquid propane pipelines is considered potentially severe for a radius up to 2.6 times the equilibrium diameter. Severe damage to buildings and personal property within this area is possible because the heat flux produced by liquid propane combustion following the break eventually reaches or exceeds the severe damage threshold, 40 kW/m^2 (12,700 Btu/hr ft^2). The radii for moderate, 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, and minor damage, 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 min, are reduced or eliminated as the block valves closure time decreases. These results are based on computed heat flux versus time data for liquid propane pipelines with nominal diameters ranging from 8 to 30 in. and MAOPs ranging from 400 to 1,480 psig.

Benefits of Block Valve Closure Swiftness for Hypothetical Liquid Propane Pipeline Releases with Ignition

The swiftness of block valve closure has a significant effect on mitigating potential fire damage to buildings and personal property in a HCA resulting from liquid propane pipeline releases in large diameter pipelines. The benefit in terms of cost avoidance for damage to buildings and personal property attributed to block valve closure swiftness increases as the duration of the block valve shutdown phase decreases.

3.3 HAZARDOUS LIQUID PIPELINES WITHOUT IGNITION

The socioeconomic and environmental effects of an oil spill are strongly influenced by the circumstances surrounding the spill including the type of product spilled, the location and timing of the spill, sensitive areas affected or threatened, liability limits in place, local and national laws, and cleanup strategy. The most important factors determining a per-unit cost are location and oil type, and possibly total spill amount.

The amount of oil spilled can have a profound effect on the cleanup costs. Obviously, the more oil spilled, the more oil there is to remove or disperse, and the more expensive the cleanup operation. However, cleanup costs on a per-unit basis decrease significantly with increasing amounts of oil spilled. Smaller spills are often more expensive on a per-unit basis than larger spills because of the costs associated with setting up the cleanup response, bringing in the equipment and labor, as well as bringing in the experts to evaluate the situation (Etkin, 1999).

The following methodology was used to determine: (1) the time-dependent discharge from a hazardous liquid transmission pipeline resulting from a guillotine-type break, and (2) the quantity of hazardous liquid released during the detection, continued pumping, block valve closure, and drain down phases needed to estimate cleanup costs. The total volume of a hazardous liquid pipeline release is primarily influenced by the flow rate at the time of the break; the combined durations of the detection, continued pumping, block valve closure phases; and the size and shape of the break. For worst case, guillotine-type breaks, where the effective hole size is equal to the line pipe diameter, the governing parameters are the line pipe diameter and the pipeline length between plateaus and peaks in the vicinity of the break.

Appendix A: Spill Volume Released Due to Valve Closure Times in Liquid Propane Pipelines, contains a family of curves for various hazardous liquid pipeline release scenarios that quantify the volume of liquid released following a guillotine-type break.

3.3.1 Analysis Scope, Parameters, and Assumptions

The methodology is based on fundamental fluid mechanics principles for computing the time-dependent response of hazardous liquid pipelines following a guillotine-type break. It is also suitable for determining the effects that detection, continued pumping, block valve closure duration have on a worst case discharge release determined in accordance with federal pipeline safety regulations in 49 CFR 194 for estimating worst case discharges from hazardous liquid pipelines (DOT, 2011e).

The configuration of the hypothetical hazardous liquid pipeline used to evaluate the effectiveness of RCVs and ASVs in mitigating the consequences of a release has the following design features and operating characteristics:

- The pump stations are located at 100 mile intervals along the pipeline.
- Each pressure pump station has a remote control device that can be activated by the pipeline operator to shut down the compressors after a rupture occurs.
- The rupture is a guillotine-type break that initiates the release event.
- The break is located at a low point in the pipeline elevation profile.
- The following times are study variables.
    - ✓ The time when the operator detects the leak.
    - ✓ The time when the operator stops the pumps.
    - ✓ The time when the upstream and downstream block valves are closed and the line section with the break is isolated.
- The total volume of the hazardous liquid release equals the volume of liquid released during the detection, continued pumping, block valve closure, and drain down phases.
- The time-dependent flow rate is a study variable.

Study variables used to characterize hazardous liquid pipeline releases are listed in Table 3.24.

3.3.2 Analytical Approach and Computational Models

After a hazardous liquid pipeline ruptures without ignition, liquid begins flowing from the break and continues until draining is complete. A pipeline break can range in size and shape from a short, through-wall crack to a guillotine fracture that completely separates the line pipe along a circumferential path. Although the volume of the discharge depends on many factors, the event is subdivided into the four sequential phases with the total discharge volume equal to the sum of the volumes released during each phase. The phases of a hazardous liquid pipeline release are outlined in Section 1.3.2.1.

Table 3.24. Study variables for characterizing hazardous liquid pipeline releases.

Variable	Description	Variable Values
H	Elevation distance from break, ft	100, 500, 1,000
L	Maximum length between plateaus and peaks, mi.	3
D	Nominal line pipe diameter, in.	8, 12, 16, 24, 30, 36
v_p	Flow rate, ft/s	5, 10, 15
v_g	Drain down liquid velocity	Calculated based on H
t_d-t_0	Duration of detection phase, minutes	5
t_p-t_d	Duration of continued pumping phase, minutes	5
t_s-t_p	Duration of block valve closure phase, minutes	3, 30, 60, 90
t_{dd}-t_s	Duration of drain down phase, minutes	Calculated based on v_g
P_1	Maximum allowable operating pressure (MAOP), psig	400, 800, 1,200, 1,480

The flow rate through the break remains constant through both the detection and continued pumping phases. In the block valve closure phase, the maximum flow rate through the break is based on the elevation difference of liquid in the pipeline. During the pipeline drain down phase, the maximum flow rate through the break is based on the difference between the operating pressure of the pipeline and atmospheric pressure. Requirements in 49 CFR 194.105(b)(1) state the worst case discharge is the largest volume of fluid released based on the pipeline's maximum release time, plus the maximum shutdown response time, multiplied by the maximum flow rate, which is based on the maximum daily capacity of the pipeline, plus the largest line drainage volume after shutdown of the line sections. In this methodology, the maximum flow rate can be estimated by multiplying the fluid speed at the pump by the cross sectional area of the line pipe. Although operators can use this rule to determine a worst case discharge, the actual flow rate during the block valve closure phase may be greater (less conservative) due to factors such as fluid density, pressure changes, pump performance characteristics, and the elevation profile of the pipeline which are not reflected in the methodology. These factors are important in a risk analysis because their effects influence time-dependent damage resulting from a release.

The influence of fluid density, pressure changes, and the elevation profile of the pipeline is taken into consideration in this study by using Bernoulli's equation to calculate the flow rate during the block valve closure and drain down phases. However, there are recognized limitations in using Bernoulli's equation to determine drain down time because it does not model the effects of air flow through the pipeline break which occurs as the fluid escapes following block valve closure. Although Bernoulli's equation does not produce an exact solution to this fluid dynamics problem, comparison of the results provides a consistent approach for evaluating the effectiveness of block valve closure swiftness on mitigating release consequences. Bernoulli's equation follows.

$$z_1 + \frac{v_1^2}{2g} + P_1 v_1 \frac{g_c}{g} = z_2 + \frac{v_2^2}{2g} + P_2 v_2 \frac{g_c}{g} \qquad (3.30)$$

where

- z_1 is the elevation of the closed valve, ft,
- z_2 is the elevation of the break, ft,
- v_1 is the average velocity of the fluid at the closed valve, ft/s,
- v_2 is the average velocity of the fluid at the break (also known as v_{exit}), ft/s,
- P_1 is the pressure of the fluid at the closed valve, psig,
- P_2 is the pressure of the fluid at the break, psig,
- v is the specific volume of the fluid, ft^3/lb.,
- g is the acceleration due to gravity, ft/s^2, and
- g_c is the gravitational constant, (32.17 ft-lbm/lbf-s^2).

After rearranging Bernoulli's equation, the following equation is used to determine the velocity of the liquid exiting the break.

$$\mathrm{v}_{exit} = \sqrt{2g[\Delta z + \Delta P v \frac{g_c}{g} + \frac{\mathrm{v}_1^2}{2g}]} \tag{3.31}$$

3.3.3 Socioeconomic and Environmental Effects

The methodology for quantifying potential environmental effects resulting from a hazardous liquid release involves computing the quantity of hazardous liquid released and then using this quantity to establish the total damage cost. The total damage cost, C_d, is determined by adding the response cost, C_r, the socioeconomic damage cost, C_s, and the environmental damage cost, C_e. This methodology applies to crude oil and light fuel (gasoline) releases that affect the following areas.

- Commercially navigable waterways which means a waterway where a substantial likelihood of commercial navigation exists.
- High population areas and another populated areas which mean an urbanized area as defined and delineated by the Census Bureau that contains 50,000 or more people and has a population density of at least 1,000 people per square mile and a place as defined and delineated by the Census Bureau that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area, respectively.
- Unusually Sensitive Areas (USAs) which is defined in 49 CFR 195.6 to mean a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

The response cost, C_r, is determined by multiplying the applicable unit response cost shown in Table 3.25 by the applicable medium modifier shown in Table 3.26.

Table 3.25. Unit response costs for crude oil and light fuel releases

Release Quantity, barrels	Crude Oil, $ per barrel	Light Fuels, $ per barrel
<12	9,240	4,200
12-24	9,156	4,116
24-240	9,030	4,074
240-2,400	8,190	3,654
2,400-240,000	5,166	3,108
> 240,000	3,864	1,302

Note: 2004 cost basis

Table 3.26. Modifier for location medium categories for crude oil and light fuel releases

Medium Category	Medium Modifier
Open Water/Shore	1.0
Soil/Sand	0.6
Pavement/Rock	0.5
Wetland	1.6
Mudflat	1.4
Grassland	0.7
Forest	0.8
Taiga (boreal forest)	0.9
Tundra	1.3

The socioeconomic damage cost, C_s, is determined by multiplying the applicable unit socioeconomic cost shown in Table 3.27 by applicable the socioeconomic cost modifier shown in Table 3.28.

Table 3.27. Unit socioeconomic and environmental costs for crude oil and light fuel releases

Release Quantity, barrels	Crude Oil, $ per barrel		Light Fuels, $ per barrel	
	Socioeconomic	Environmental	Socioeconomic	Environmental
<12	2,100	3,780	3,360	3,570
12-24	8,400	3,654	13,860	3,360
24-240	12,600	3,360	21,000	2,940
240-2,400	5,880	3,066	8,400	2,730
2,400-240,000	2,940	1,470	4,200	1,260
> 240,000	2,520	1,260	3,780	1,050

Note: 2004 cost basis

Table 3.28. Socioeconomic and cultural value ranking for crude oil and light fuel releases

Value Rank	Release Impact Site Description	Examples	Cost Modifier Value
Extreme	Predominated by areas with high socioeconomic value that may potentially experience a large degree of long-term impact if oiled.	Subsistence/commercial fishing, aquaculture areas	2.0
Very High	Predominated by areas with high socioeconomic value that may potentially experience some long-term impact if oiled.	National park/reserves for ecotourism/nature viewing; historic areas	1.7
High	Predominated by areas with medium socioeconomic value that may potentially experience some long-term impact if oiled.	Recreational areas, sport fishing, farm/ranchland	1.0
Moderate	Predominated by areas with medium socioeconomic value that may potentially experience short-term impact if oiling occurs.	Residential areas; urban/suburban parks; roadsides	0.7
Minimal	Predominated by areas with a small amount of socioeconomic value that may potentially experience short-term impact if oiled.	Light industrial areas; commercial zones; urban areas	0.3
None	Predominated by areas already moderately to highly polluted or contaminated or of little socioeconomic or cultural import that would experience little short- or long-term impact if oiled.	Heavy industrial areas; designated dump sites	0.1

Note: Long-term impacts are those impacts that are expected to last months to years after the spill or be relatively irreversible. Short-term impacts are those impacts that are expected to last days to weeks after the spill occurs and are generally considered to be reasonably reversible.

The environmental damage cost, C_e, is determined by multiplying the applicable unit environmental cost shown in Table 3.27 by one half of the applicable freshwater modifier shown in Table 3.29 plus the wildlife modifier shown in Table 3.30.

Table 3.29. Freshwater vulnerability categories for crude oil and light fuel releases

Freshwater Vulnerability Category	Freshwater Vulnerability Modifier
Wildlife Use	1.7
Drinking	1.6
Recreation	1.0
Industrial	0.4
Tributaries to Drinking/Recreation	1.2
Non-Specific	0.9

Table 3.30. Habitat and wildlife sensitivity categories for crude oil and light fuel releases

Habitat and Wildlife Sensitivity Category	Habitat and Wildlife Sensitivity Modifier
Urban/Industrial	0.4
Roadside/Suburb	0.7
River/Stream	1.5
Wetland	4.0
Agricultural	2.2
Dry Grassland	0.5
Lake/Pond	3.8
Estuary	1.2
Forest	2.9
Taiga	3.0
Tundra	2.5
Other Sensitive	3.2

This methodology is consistent with the U.S. Environmental Protection Agency (EPA) Basic Oil Spill Cost Estimation Model (BOSCEM) that was developed to provide the US EPA Oil Program with a methodology for estimating oil spill costs, including response costs and environmental and socioeconomic damages, for actual and hypothetical spills (Etkin, 2004).

Total Damage Cost Validation

The following case studies compare the actual damage costs for two hazardous liquid pipeline releases to the corresponding total damage costs determined using BOSCEM.

Case Study 1 – Enbridge 2010

The Enbridge Line 6B pipeline ruptured in Marshall, Michigan on July 25, 2010, and released approximately 20,000 barrels of crude oil. This release from the 30-in. nominal diameter pipeline caused environmental impacts along Talmadge Creek and the Kalamazoo River (Nicholson, 2012). Cleanup and recovery costs for this release totaled $767,000,000.

Using the EPA BOSCEM, the estimated total damage cost for this release is approximately $307,900,000. This total damage cost, C_d, includes the response cost, C_r, the socioeconomic damage cost, C_s, and the environmental damage cost, C_e, determined as follows.

Response cost, C_r = unit response cost × medium modifier (Wetland) = $5,166 × 1.6 = $8,265/barrel

Socioeconomic damage cost, C_s = unit socioeconomic cost × socioeconomic cost modifier (High) = $2,940 × 1.0 = $2,940/barrel

> Environmental damage cost, C_e = unit environmental cost × 0.5 × [freshwater modifier (Wildlife Use) + wildlife modifier (Wetland)] = \$1,470 × 0.5 × (1.7 + 4.0) = \$4,190/barrel
>
> Total damage cost (2004 basis), C_d = 20,000 barrels × (\$8,265 + \$2,940 + \$4,190)/barrel = \$307,900,000.

After adjusting for inflation, the total damage cost (2012 basis), C_d = \$307,900,000 × 1.25 (inflation factor) = \$384,875,000 which is approximately 50% of the actual cost.

Case Study 2 – Yellowstone 2011

A 12-in. hazardous liquid pipeline owned by ExxonMobil Pipeline Company ruptured on July 1, 2011 under the Yellowstone River 20 miles upstream from Billings, Montana. The Yellowstone River is navigable water in the United States (EPA, 2011). The ruptured pipeline released an estimated 1,509 barrels of oil that entered the river before the pipeline was closed. Cleanup and recovery costs for this release totaled \$135,000,000.

The estimated total damage cost for this release is \$48,044,000 based on 2004 cost data. This total damage cost, C_d, includes the response cost, C_r, the socioeconomic damage cost, C_s, and the environmental damage cost, C_e, determined as follows.

> Response cost, C_r = unit response cost × medium modifier (Wetland) = \$8,190 × 1.6 = \$13,104/barrel.
>
> Socioeconomic damage cost, C_s = unit socioeconomic cost × socioeconomic cost modifier (Very High) = \$5,880 × 1.7 = \$9,996/barrel.
>
> Environmental damage cost, C_e = unit environmental cost × 0.5 × [freshwater modifier (Wildlife Use) + wildlife modifier (Wetland)] = \$3,066 × 0.5 × (1.7 + 4.0) = \$8,738/barrel.
>
> Total damage cost (2004 basis), C_d = 1,509 barrels × (\$13,104 + \$9,996 + \$8,738)/barrel = \$48,044,000.

After adjusting for inflation, the total damage cost (2012 basis), C_d = \$48,044,000 × 1.25 (inflation factor) = \$60,054,000 which is approximately 44% of the actual cost.

Damage Cost Adjustment Factor

For this study, total damage costs of hazardous liquid pipeline releases are determined using the EPA BOSCEM and then increased by a damage cost adjustment factor of 2.1. This factor aligns the model with cleanup and recovery costs for two recent hazardous liquid pipeline releases of crude oil into sensitive socioeconomic and environmental areas.

3.3.4 Risk Analysis Results for Hazardous Liquid Pipeline Releases

The methodology for assessing socioeconomic and environmental damage to HCAs is based on computed release volumes corresponding to the detection, continued pumping, block valve closure, and drain down phases of a hazardous liquid pipeline release of crude oil without ignition. The method used in this analysis for defining maximum flow rate through the break is as defined in 49 CFR 195.105(b)(1) for the detection, pump shut down, block valve closure, and drain down phases. The damage is quantified using the EPA BOSCEM and the damage cost adjustment factor described in Section 3.3.3.

Eight case studies involving hypothetical hazardous liquid pipeline releases in HCAs are considered to assess effects of block valve closure time on socioeconomic and environmental damage resulting from a guillotine-type break. The duration of the detection and continued pumping phases for the hypothetical hazardous liquid pipelines are 5 minutes and 5 minutes, respectively. The duration of the block valve closure phases is 3 minutes.

Characteristics for Case Study 7A, 7B, 7C, and 7D that involve 8-in. nominal diameter hazardous liquid pipelines are tabulated in Table 3.31. These case studies compare the following effects on avoided damage costs.

- Case studies 7A and 7B compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter hazardous liquid pipelines with MAOPs equal to either 400 psig or 1,480 psig, an elevation change of 100 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes
- Case studies 7C and 7D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter hazardous liquid pipelines with MAOPs equal to either 400 psig or 1,480 psig, an elevation change of 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.
- Case studies 7A and 7C compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter hazardous liquid pipelines with MAOPs equal to 400 psig, an elevation change equal to either 100 ft or 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.
- Case studies 7B and 7D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 8-in. nominal diameter hazardous liquid pipelines with MAOPs equal to 1,480 psig, an elevation change equal to either 100 ft or 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.

Table 3.31. Avoided damage costs for hypothetical 8-in. hazardous liquid pipeline releases without ignition

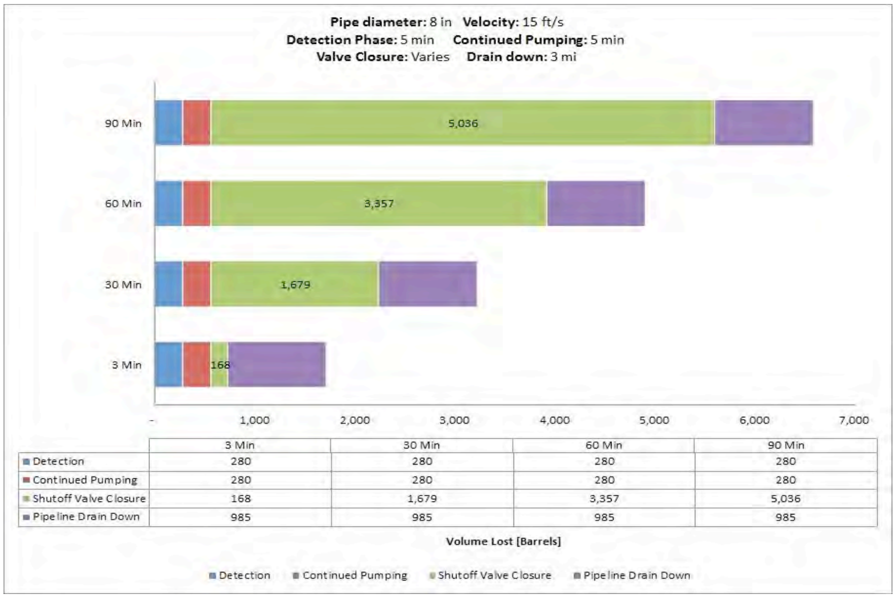
Characteristic	Case Study 7A		Case Study 7B		Case Study 7C		Case Study 7D	
Type Hazardous Liquid	Crude Oil		Crude Oil		Crude Oil		Crude Oil	
Flow Velocity, ft/s	15		15		15		15	
Nominal Line Pipe Diameter, in.	8		8		8		8	
Drain Down Length, mi.	3		3		3		3	
MAOP, psig	400		1,480		400		1,480	
Elevation Change, ft	100		100		1,000		1,000	
Detection Phase Duration, minutes	5		5		5		5	
Continued Pumping Phase Duration, minutes	5		5		5		5	
Released Amount, barrels*	240 – 2,400	2,400 – 240,000	240 – 2,400	2,400 – 240,000	240 – 2,400	2,400 – 240,000	240 – 2,400	2,400 – 240,000
Medium Modifier (Wetland)	1.6		1.6		1.6		1.6	
Response Cost, C_r	13,104	8,266	13,104	8,266	13,104	8,266	13,104	8,266
Unit Socioeconomic Cost, $/barrel	5,880	2,940	5,880	2,940	5,880	2,940	5,880	2,940
Socioeconomic Cost Modifier (Very High)	1.7		1.7		1.7		1.7	
Socioeconomic Damage Cost, C_s	9,996	4,998	9,996	4,998	9,996	4,998	9,996	4,998
Unit Environmental Cost, $/barrel	3,066	1,470	3,066	1,470	3,066	1,470	3,066	1,470
One half Freshwater Modifier (Wildlife Use = 1.7) and Wildlife Modifier (Wetland = 4.0)	2.85		2.85		2.85		2.85	
Environmental Damage Cost, C_e	8,738	4,190	8,738	4,190	8,738	4,190	8,738	4,190
Total Damage Unit Cost, C_d, $/barrel	31,838	17,454	31,838	17,454	31,838	17,454	31,838	17,454
Damage Cost Adjustment Factor for Hazardous Liquid Pipeline Releases	2.1		2.1		2.1		2.1	
Total Damage Unit Cost on 2012 Basis, $/barrel	66,860	36,653	66,860	36,653	66,860	36,653	66,860	36,653
Detection Phase Release, barrels	280		280		280		280	
Continued Pumping Phase Release, barrels	280		280		280		280	
Drain Down Phase Release, barrels	985		985		985		985	
Block Valve Closure Phase for Valve Closure in 3 minutes, barrels	168		168		168		168	

Table 3.31. Avoided damage costs for hypothetical 8-in. hazardous liquid pipeline releases without ignition (Cont.)

Characteristic	Case Study 7A	Case Study 7B	Case Study 7C	Case Study 7D
Block Valve Closure Phase for Valve Closure in 30 minutes, barrels	1,679	1,679	1,679	1,679
Block Valve Closure Phase for Valve Closure in 60 minutes, barrels	3,357	3,357	3,357	3,357
Block Valve Closure Phase for Valve Closure in 90 minutes, barrels	5,036	5,036	5,036	5,036
Avoided Damage Cost for Valve Closure in 3 minutes Compared to 90 minutes	5,036 – 168 = 4,868 Barrels $173 M	5,036 – 168 = 4,868 Barrels $173 M	5,036 – 168 = 4,868 Barrels $173 M	5,036 – 168 = 4,868 Barrels $173 M
Avoided Damage Cost for Valve Closure in 30 minutes Compared to 90 minutes	5,036 – 1,679 = 3,357 Barrels $123 M	5,036 – 1,679 = 3,357 Barrels $123 M	5,036 – 1,679 = 3,357 Barrels $123 M	5,036 – 1,679 = 3,357 Barrels $123 M
Avoided Damage Cost for Valve Closure in 60 minutes Compared to 90 minutes	5,036 – 3,357 = 1,679 Barrels $61.5 M	5,036 – 3,357 = 1,679 Barrels $61.5 M	5,036 – 3,357 = 1,679 Barrels $61.5 M	5,036 – 3,357 = 1,679 Barrels $61.5 M
Avoided Damage Cost for Valve Closure in 90 minutes Compared to 90 minutes	5,036 – 5,036 = 0 Barrels $0 M	5,036 – 5,036 = 0 Barrels $0 M	5,036 – 5,036 = 0 Barrels $0 M	5,036 – 5,036 = 0 Barrels $0 M

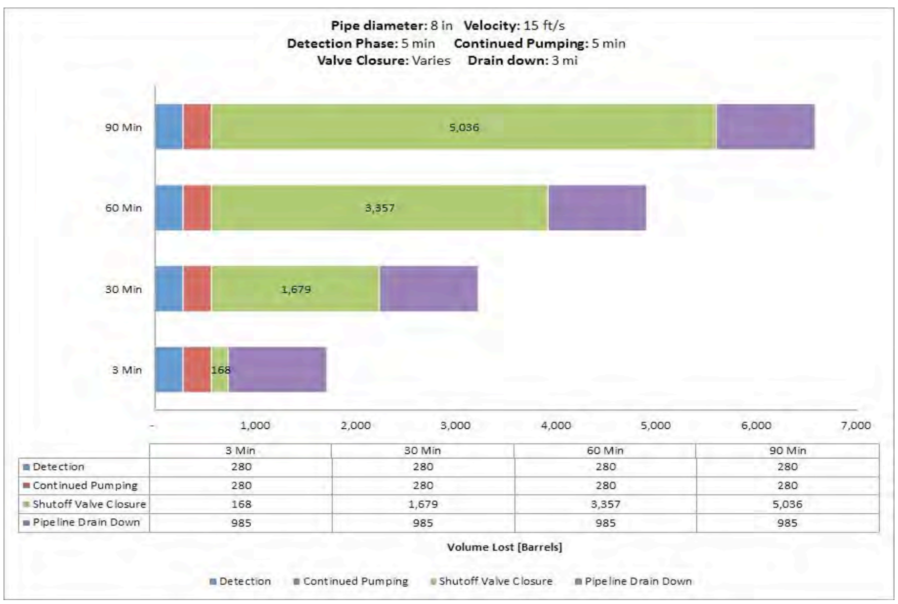
Notes: *See Tables 3.25 and Table 3.27. The avoided cost resulting from reducing the block valve closure phase is significantly more than the cost for converting a manually operated block valve to either a RCV or ASV for hazardous liquid pipelines with 8-in. nominal diameters.

Figures 3.78 to 3.81 list the discharge volumes in barrels for Case Study 7A, 7B, 7C, and 7D. Discharge volumes listed in Table 3.31 for each case study are determined by adding the discharge volumes for the detection (5 minutes), continued pumping (5 minutes), block valve closure (3, 30, 60, and 90 minutes), and drain down (3 miles) phases. Avoided damage costs, which are also listed in Table 3.31, represent the differences between the discharge volumes for the various block valve closure durations and the 3 minute block valve closure duration multiplied by the avoided damage unit cost. The total damage unit cost for these case studies is estimated at $66,860 per barrel for a released amount of 240 – 2,400 barrels and $36,653 per barrel for a released amount of 2,400 – 240,000 barrels. This total damage cost is the sum of the response cost plus the socioeconomic damage cost plus the environmental damage cost. Note that the avoided damage costs are not sensitive to pressure and elevation changes because the model is based on the methodology in 49 CFR 194.105 (b) (1) for a worst case discharge which has a constant flow rate.



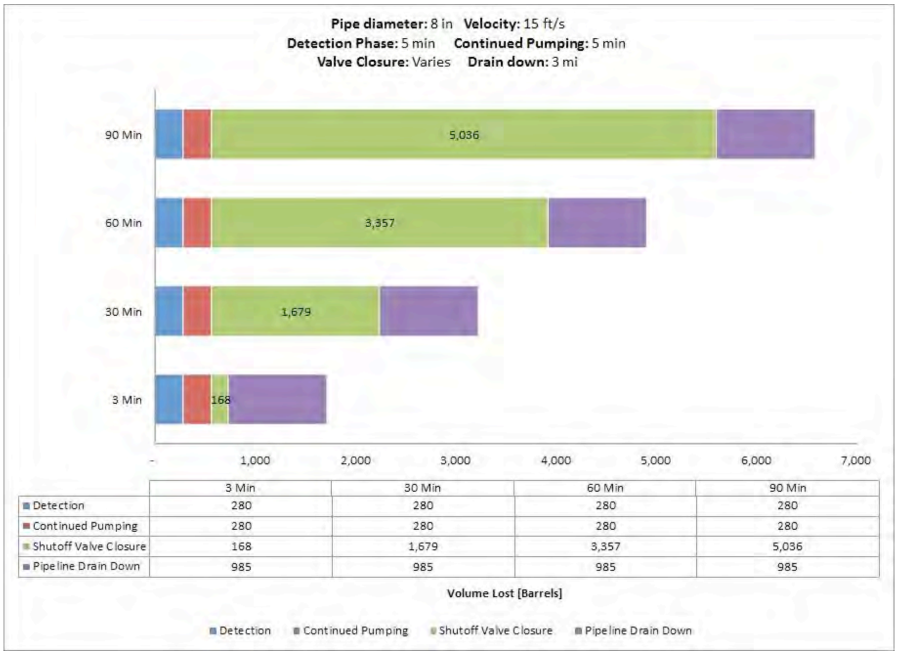
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. 3.78. Case Study 7A – Discharge volumes for an 8-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.



	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. 3.79. Case Study 7B – Discharge volumes for an 8-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.



	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. 3.80. Case Study 7C – Discharge volumes for an 8-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. 3.81. Case Study 7D – Discharge volumes for an 8-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

Characteristics for Case Study 8A, 8B, 8C, and 8D that involve 36-in. nominal diameter hazardous liquid pipelines are tabulated in Table 3.32. These case studies compare the following effects on avoided damage costs.

- Case studies 8A and 8B compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 36-in. nominal diameter hazardous liquid pipelines with MAOPs equal to either 400 psig or 1,480 psig, an elevation change of 100 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.
- Case studies 8C and 8D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 36-in. nominal diameter hazardous liquid pipelines with MAOPs equal to either 400 psig or 1,480 psig, an elevation change of 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.
- Case studies 8A and 8C compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 36-in. nominal diameter hazardous liquid pipelines with MAOPs equal to 400 psig, an elevation change equal to either 100 ft or 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.
- Case studies 8B and 8D compare effects of block valve closure swiftness on the avoided damage costs for hypothetical 36-in. nominal diameter hazardous liquid pipelines with MAOPs equal to 1,480 psig, an elevation change equal to either 100 ft or 1,000 ft, a drain down length of 3 mi., and block valve closure durations of 3, 30, 60, and 90 minutes.

Figures 3.82 to 3.85 list the discharge volumes in barrels for Case Study 8A, 8B, 8C, and 8D. Discharge volumes listed in Table 3.32 for each case study are determined by adding the discharge volumes for the detection (5 minutes), continued pumping (5 minutes), block valve closure (3, 30, 60, and 90 minutes), and drain down (3 miles) phases. Avoided damage costs, which are also listed in Table 3.32, represent the differences between the discharge volumes for the various block valve closure durations and the 3 minute block valve closure duration multiplied by the avoided damage unit cost. The total damage unit cost for these case studies is estimated at $29,520 per barrel. This total damage cost is the sum of the response cost plus the socioeconomic damage cost plus the environmental damage cost. Note that the avoided damage costs are not sensitive to pressure and elevation changes because the model is based on the methodology in 49 CFR §194.105 (b) (1) for a worst case discharge which has a constant flow rate.

Benefits of Block Valve Closure Swiftness for a Hypothetical Hazardous Liquid Pipeline Releases without Ignition

The swiftness of block valve closure has a significant effect on mitigating potential socioeconomic and environmental damage to the human and natural environments resulting from hazardous liquid pipeline releases. The benefit in terms of cost avoidance for damage to the human and natural environments attributed to block valve closure swiftness increases as the duration of the block valve shutdown phase decreases.

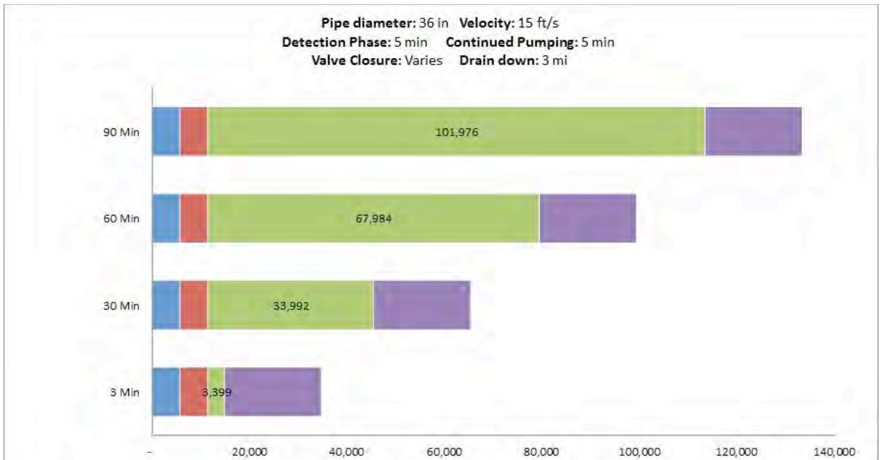
Table 3.32. Effects of hypothetical 36-in. hazardous liquid pipeline releases without ignition

Characteristic	Case Study 8A	Case Study 8B	Case Study 8C	Case Study 8D
Type Hazardous Liquid	Crude Oil	Crude Oil	Crude Oil	Crude Oil
Flow Velocity, ft/s	15	15	15	15
Nominal Line Pipe Diameter, in.	36	36	36	36
Drain Down Length, mi.	3	3	3	3
MAOP, psig	400	1,480	400	1,480
Elevation Change, ft	100	100	1,000	1,000
Detection Phase Duration, minutes	5	5	5	5
Continued Pumping Phase Duration, minutes	5	5	5	5
Unit Response Cost, $/barrel	3,864	3,864	3,864	3,864
Medium Modifier (Wetland)	1.6	1.6	1.6	1.6
Response Cost, C_r	6,182	6,182	6,182	6,182
Unit Socioeconomic Cost, $/barrel	2,520	2,520	2,520	2,520
Socioeconomic Cost Modifier (Very High)	1.7	1.7	1.7	1.7
Socioeconomic Damage Cost, C_s	4,284	4,284	4,284	4,284
Unit Environmental Cost, $/barrel	1,260	1,260	1,260	1,260
One half Freshwater Modifier (Wildlife Use = 1.7) and Wildlife Modifier (Wetland = 4.0)	2.85	2.85	2.85	2.85
Environmental Damage Cost, C_e	3,591	3,591	3,591	3,591
Total Damage Unit Cost, C_d, $/barrel	14,057	14,057	14,057	14,057
Damage Cost Adjustment Factor for Hazardous Liquid Pipeline Releases	2.1	2.1	2.1	2.1
Total Damage Unit Cost on 2012 Basis, $/barrel	29,520	29,520	29,520	29,520
Detection Phase Release, barrels	5,665	5,665	5,665	5,665
Continued Pumping Phase Release, barrels	5,665	5,665	5,665	5,665
Drain Down Phase Release, barrels	19,942	19,942	19,942	19,942
Block Valve Closure Phase for Valve Closure in 3 minutes, barrels	3,399	3,399	3,399	3,399
Block Valve Closure Phase for Valve Closure in 30 minutes, barrels	33,992	33,992	33,992	33,992

Table 3.32. Effects of hypothetical 36-in. hazardous liquid pipeline releases without ignition (Cont.)

Characteristic	Case Study 8A	Case Study 8B	Case Study 8C	Case Study 8D
Block Valve Closure Phase for Valve Closure in 60 minutes, barrels	66,984	66,984	66,984	66,984
Block Valve Closure Phase for Valve Closure in 90 minutes, barrels	101,976	101,976	101,976	101,976
Avoided Damage Cost for Valve Closure in 3 minutes Compared to 90 minutes	101,976 – 3,399 98,577 Barrels $2.91 B	101,976 – 3,399 98,577 Barrels $2.91 B	101,976 – 3,399 98,577 Barrels $2.91 B	101,976 – 3,399 98,577 Barrels $2.91 B
Avoided Damage Cost for Valve Closure in 30 minutes Compared to 90 minutes	101976 – 33,992 = 97,984 Barrels $2.01 B	101976 – 33,992 = 97,984 Barrels $2.01 B	101976 – 33,992 = 97,984 Barrels $2.01 B	101976 – 33,992 = 97,984 Barrels $2.01 B
Avoided Damage Cost for Valve Closure in 60 minutes Compared to 90 minutes	101,976 – 67,984 = 33,992 Barrels $1.00 B	101,976 – 67,984 = 33,992 Barrels $1.00 B	101,976 – 67,984 = 33,992 Barrels $1.00 B	101,976 – 67,984 = 33,992 Barrels $1.00 B
Avoided Damage Cost for Valve Closure in 90 minutes Compared to 90 minutes	101,976 – 101,976 = 0 Barrels $0 B	101,976 – 101,976 = 0 Barrels $0 B	101,976 – 101,976 = 0 Barrels $0 B	101,976 – 101,976 = 0 Barrels $0 B

Note: The avoided cost resulting from reducing the block valve closure phase is significantly more than the cost for converting a manually operated block valve to either a RCV or ASV for hazardous liquid pipelines with 36-in. nominal diameters.



	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. 3.82. Case Study 8A – Discharge volumes for a 36-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

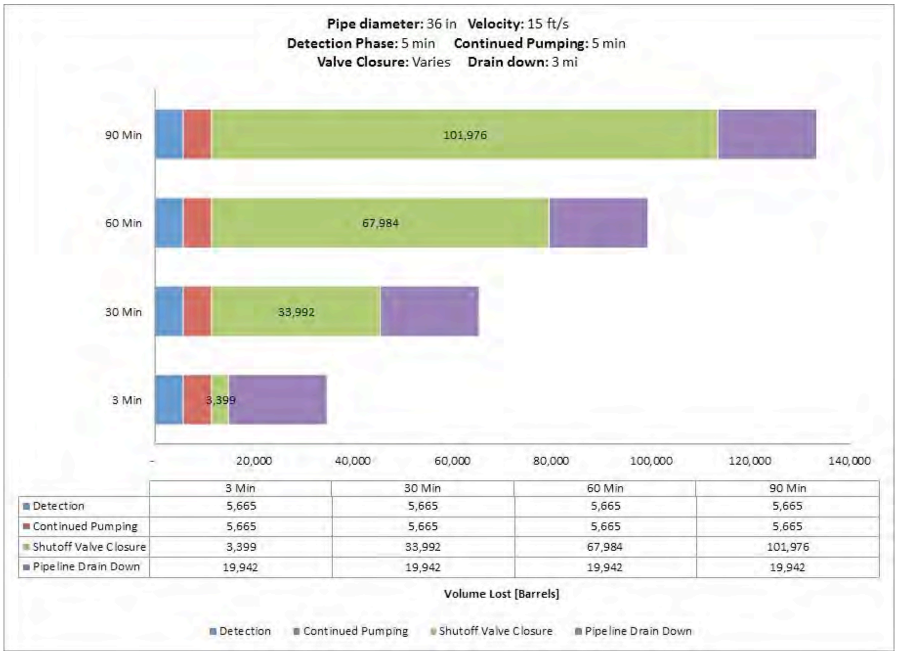
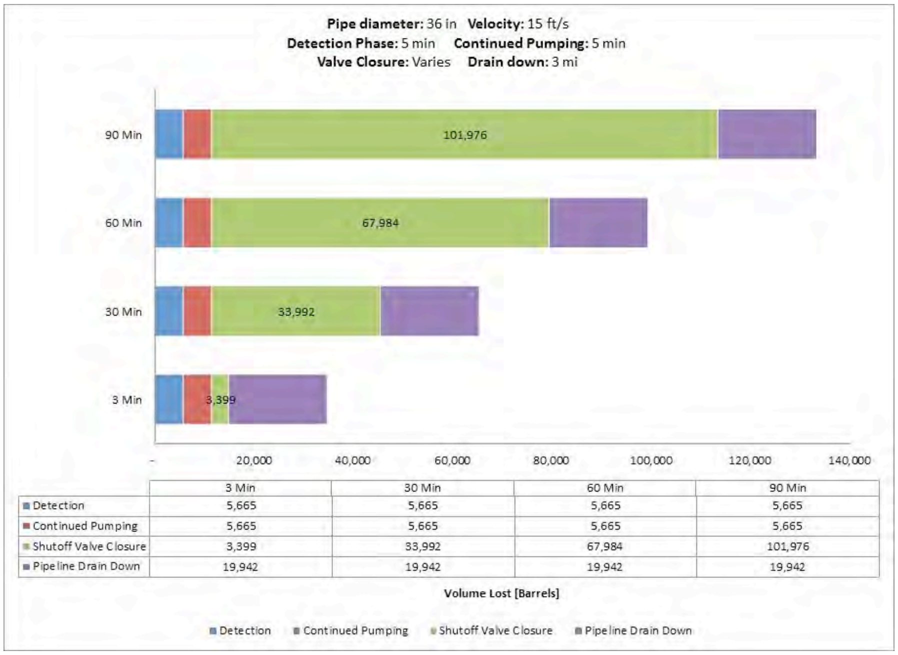


Fig. 3.83. Case Study 8B – Discharge volumes for a 36-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

Fig. 3.84. Case Study 8C – Discharge volumes for a 36-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.



	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. 3.85. Case Study 8D – Discharge volumes for a 36-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

4. TECHNICAL AND OPERATIONAL FEASIBILITY

In its simplest form, a transmission line is a single pipeline segment that connects a product supply to a receiving terminal via a compressor or pumping station and operates continuously under steady-state conditions. However, in reality, most interstate transmission lines are integrated into complex infrastructure systems with parallel and cross connected lines and continuous product supply and demand fluctuations. During normal operation, the computer-based SCADA system collects and processes feedback and control signals from pressure and temperature sensors, flow meters, and other types of mechanical and electrical devices located at various points along the pipeline. These real-time signals are used by the SCADA system and the control room operators to maintain continuous operations while accommodating routine maintenance and in-service testing, equipment repairs and replacements, and product supply and demand fluctuations. In emergency situations, these signals are used to detect deviations that may indicate a leak or rupture.

After detecting a signal deviation that exceeds established limits, an analysis is initiated to determine the cause for the deviation and to determine if the deviation is: (1) consistent with acceptable system performance, or (2) an indication of a system failure such as a leak or rupture. In the event of a system failure, the signals are used to identify the type and possible causes for the failure, locate the point of failure, and determine the proper course of action to limit the potential consequences of the failure and to minimize impacts on the remainder of the system. Without positive evidence of a leak or failure based on field observations, the decision by control room operators to close block valves to isolate a line segment only occurs after analysis confirms a critical emergency situation. However, pipeline operators use different decision-making processes because every pipeline has unique design features, control schemes, and operating requirements that affect the decision to initiate block valve closure.

Standards that specify requirements and provide recommendations for the design, manufacturing, testing and documentation of ball, check, gate, and plug valves for application in pipeline systems for the petroleum and natural gas industries are provided in API Specification 6D (API, 2008). This standard requires valves fitted with manual or powered actuators[7] to have a visible indicator to show the open and the closed position of the obturator[8]. Valve actuators are categorized as follows.

- Manual Control Valve (MCV) where a human travels to the valve location and then closes the valve by operating a mechanical or electrical device. These valves are typically geared to close against line pressure and accommodate human strength. Closure times may exceed 30 minutes for some large-diameter MCVs.
- Remote Control Valve (RCV) where the valve closure mechanism is controlled from a remote location and value closure is initiated through human intervention. Some RCVs are capable of closing in about 3 minutes.
- Automatic Shutoff Valve (ASV) where the valve closure mechanism is connected to sensors that monitor specific operating parameters and initiate valve closure, without human intervention, when the feedback signal exceeds a specified limit or set point. Some ASVs are capable of closing in about 3 minutes.

Types of block valves commonly installed in pipelines include gate valves, plug valves, reduced-port ball valves, and full-port ball valves. A gate valve contains a rectangular or circular plate that is lowered into

[7] A powered actuator is an electric, hydraulic, or pneumatic device bolted or otherwise attached to the valve for powered opening and closing of the valve.
[8] An obturator is a part of a valve, such as a ball, clapper, disc, gate, or plug that is positioned in the flow stream to permit or prevent flow.

the line pipe to stop flow when closed. Plug valves contain a tapered plug with a rectangular opening that is lowered into the line pipe to stop flow when closed. The rectangular opening is relatively small compared to the inside cross-section of the pipe, restricting the flow significantly and presenting an obstacle to the passage of in-line inspection (ILI) tools. A reduced-port ball valve contains a spherical ball with an opening that allows flow when the valve is rotated to the open position. This opening is larger than the opening in a plug valve, but still smaller than the cross-section of the line pipe, restricting flow and presenting a potential obstacle to the passage of ILI tools. Full-port ball valves are similar to reduced-port ball valves except that the opening in the spherical ball is approximately the same size as the cross-section of the line pipe, presenting little restriction to flow and the passage of ILI tools.

Plug valves and gate valves are more commonly found in older transmission lines. The majority of block valves installed in newer transmission lines are reduced-port or full-port ball valves. Since 1994, Federal pipeline safety regulations require all new transmission line installations to be capable of passing an ILI tool. For this reason, operators generally install full-port ball valves in new transmission lines or fully replaced transmission lines.

Flow and pressure sensors used to monitor pipeline operations are generally located adjacent to block valves. However, additional sensors may be required between block valves to provide complementary or redundant feedback signals. These signals are monitored by the SCADA system and operators and used to detect abnormal operating conditions, especially for systems with complex piping configurations with multiple cross connections.

Differences between ASV and RCV feedback and control schemes are gradually merging with advances in sensor technology and improvements in the capabilities of microprocessor-based programmable logic controllers to detect deviations consistent with a leak or rupture and initiate valve closure. However, without effective integration of these technologies into an efficient control system, delays in identifying and locating leaks or ruptures can occur. The following statement from the NTSB accident report for San Bruno supports this conclusion (NTSB, 2011).

> *The PG&E SCADA system lacked several tools that could have assisted the staff in recognizing and pinpointing the location of the rupture, such as real-time leak or line break detection models, and closely spaced flow and pressure transmitters. A real-time leak detection application is a computer-based model of the transmission system that runs simultaneously with SCADA and provides greater feedback to SCADA operators when a large scale leak, line break, or system anomaly is present. Such models use actual SCADA pressures and flows to calculate actual and expected hydraulic performance; when the values do not match, an alarm is generated. Appropriate spacing of pressure transmitters at regular intervals allows SCADA operators to quickly identify pressure decreases that point toward a leak or line break.*

Technologies, equipment, and sensors used in ASV and RCV feedback and control schemes to detect and locate pipeline breaks and initiate valve closure are important factors that affect the overall time required to isolate a damaged pipeline segment. These factors are beyond the scope of this study. However, this study considers variations in detection time in evaluating the effectiveness of block valve closure swiftness in mitigating the consequences of an unintended release.

When ASVs or RCVs are used to isolate a damaged pipeline segment following a guillotine-type break and subsequent fire, the overall amount of natural gas or hazardous liquid released is reduced which in turn reduces the radiant heat flux produced by combustion of the released hydrocarbon. However, the swiftness of block valve closure will not prevent a release from occurring and may not lessen any related injury to persons or damage to property. The amount of time for a section of transmission line to "blowdown" (depressurize to 0 psig) following block valve closure is based on a number of variables including the diameter of the pipeline, distance between block valves, internal pipeline restrictions, pressure at the time of valve closure, and physical dimensions of the opening at the point of pipeline failure. Depending on these physical parameters, a pipeline may take a considerable amount of time (30 minutes or more) to depressurize after the block valves close and isolate the damaged pipeline segment.

The swiftness of block valve closure in mitigating the consequences of a pipeline release depends on the time required to dispatch a human to manually close the appropriate block valves or the sophistication of the ASV and RCV feedback and control schemes to detect a leak or rupture and initiate block valve closure. An ASV or RCV will normally close more rapidly than a MCV because operating personnel must first travel to the valve location and then close the valve. However, traffic congestion during an emergency can increase the normal travel time or even prevent operating personnel from completing the trip.

Federal safety standards for natural gas and hazardous liquid pipelines require operators to conduct risk analyses to evaluate the need for ASVs and RCVs to protect HCAs in the event of a release. Sections 2.1 and 2.2 identify the regulations that apply to natural gas and hazardous liquid pipelines and summarize the applicable evaluation criteria.

Regulations defined in 49 CFR 192.935 require operators of natural gas pipelines to conduct a risk analysis of its pipeline in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5 (ASME, 2010). According to this regulation, if an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a HCA in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

Preventative and mitigative measures that operators of hazardous liquid pipelines in HCAs must take to protect the HCAs are defined in 49 *CFR* 195.452(i). These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls. If an operator determines that an EFRD is needed on a pipeline segment to protect a HCA in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shut down capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the HCA, and benefits expected by reducing the spill size.

Although ASVs and RCVs are capable of isolating damaged pipeline segments more quickly than MCVs, their use introduces the possibility of unintended or unnecessary block valve closure and the associated consequences for the operator and the public. For example, human error could be the cause for unnecessary or unwanted RCV closure or an ASV could inadvertently close due to a plausible, but infrequent, event such as a decrease in pipeline pressure caused by changes in demand resulting from extremely cold or hot weather. The resulting service disruption could adversely affect thousands of customers including residences, hospitals, schools, nursing homes, chemical plants, and power plants for days or weeks (AGA, 2011). Possible causes for inadvertent or undesired block valve closure that can adversely affect pipeline operators, the public, and the environment include the following.

- Failure to activate an automated mainline valve during a line break.
- Failure to close a remote or manual mainline valve during a line break.
- Failure of alarm to indicate a line break.
- Leak detection software failure or false alarm.
- Failure of SCADA communications during a line break.

The cost to install a block valve with automatic closure capability in a newly constructed or fully replaced pipelines ranges from approximately $100,000 to $1,000,000 (AGA, 2011 and INGAA, 2012). This cost range is significantly affected by a multitude of factors such as pipe size, location, operating pressure, and proximity to adjacent utilities. The costs to install block valves with automatic closure capability in a rural location is generally lower due to less congestion with other utilities in the underground rights-of-way and the possibility of installing the block valve in above-ground locations that do not require the installation of a vault. For pipelines in urban areas or contained within distribution systems, the lack of underground space immediately adjacent to the existing valve, which is necessary to install a vault to contain the block valve and the actuating equipment, make the conversion of a manual valve to an ASV or RCV extremely difficult or nearly impossible. Complementary cost data for installing new block valves and automating existing valves that range in size from 12-in. to 42-in. are reported in a letter, which was submitted to PHMSA in May 2012, commenting on the leak and valve study mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (INGAA, 2012). Table 4.1 shows the costs for adding automatic closure capability to block valves installed in newly constructed or fully replaced pipelines used to perform the cost benefit analyses discussed in Section 5.

Table 4.1. Estimated cost for adding automatic closure capability to block valves installed in newly constructed or fully replaced pipelines

System/Item	12-in. nominal diameter	42-in. nominal diameter
RCV System		
• Actuator	$30,000	$120,000
• RCV Adder	$100,000	$100,000
• Alternative Power and Telemetry System	$50,000	$50,000
• Reserve Gas Bottle	$5,000	$15,000
• Building	$15,000	$15,000
Total	$200,000	$300,000
ASV System	$30,000	$30,000

Source: INGAA 2012 and AGA 2011.

4.1 AUTOMATIC SHUTOFF VALVES

An ASV is a block valve equipped with an electric, pneumatic, or natural gas-powered actuator capable of closing the valve automatically when a change in pressure or flow rate exceeds a specified limit. Data needed to determine change are provided by sensors attached to the pipeline. Under most leak or rupture scenarios, ASVs will not close instantaneous after a pipeline break occurs because the required change in pressure or flow rate needed to trigger closure may not be detected for a number of minutes after the break. In addition, ASVs do not allow or require human evaluation or interpretation of other pertinent information and relevant sensor data to determine if the change in pressure or flow rate is caused by a legitimate leak or rupture. Consequently, ASVs are subject to inadvertent closure for a variety of causes other than a leak or break.

The time required for an ASV to detect a leak or rupture and close automatically depends on a number of factors including the initial operating pressure of the pipeline, distance from the rupture to the ASV, physical characteristics (size and type) of the fracture, set point of the actuator to initiate valve closure, rate at which additional material is added to the damaged pipeline segment either from interconnected pipelines or contributions from compressor or pumping stations, and the amount of time it takes the valve to completely close following actuation. If the ASV detects a change in pressure or flow rate that exceeds the specified limit or set point immediately following the break, the ASV can close in about 3 minutes. However, if the ASV does not detect a change in pressure or flow rate that exceeds the specified limit or set point, the valve will remain open.

4.1.1 Automatic Shutoff Valve Features and Operating Characteristics

Early versions of ASVs used mechanical pressure sensors to detect high or low pressure and to sense an excessive rate of pressure change. As soon as the sensors detected a predetermined pressure change, the valve closed automatically. Current versions of ASVs use redundant sensors and other electronic technology to filter interference that can trigger inadvertent valve closure.

Specifying an optimum pressure change limit for detecting legitimate leaks or ruptures while preventing unwanted valve closure is sometimes difficult because pressure fluctuations from one valve location to another are sometimes significantly different. For example, when normal operating conditions such as compressor start up causes a pressure change that exceeds the specified pressure-change limit, false or unnecessary valve closure occurs resulting in service disruptions. Conversely, relaxing the pressure change limit to avoid the possibility of false valve closure may not trigger valve closure following a pipeline break. Advances in microprocessor-based technology for ASV applications allow recording (or learning) normal system pressure fluctuations and, over time, establishing an acceptable pressure or flow rate change limit.

4.1.2 Automatic Shutoff Valve Technical Feasibility Assessment

Current designs for ASVs include actuators, power sources, pressure and flow sensing devices, and other types of mechanical and electrical components that occupy relatively large spaces compared to simpler MCVs. Depending on the application, this space may be located either above or below ground. In a HCA, such as a subdivision or downtown location, this equipment must be installed in an underground vault large enough to house the valve body, actuators, power source, sensors and related electronic equipment, and maintenance personnel. Vaults are typically about 10 ft by 16 ft by 10 ft, but may be larger depending on the size of the valve and the configurations of utilities and other pipelines in the vicinity.

Underground infrastructure around a pipeline in a HCA that is buried under a city street is typically congested with water pipes, sewer lines, communication cables, power and traffic signal lines, and other underground infrastructure. Finding enough underground real estate to house the ASV and the related equipment needed to operate the valve is sometimes not feasible. In addition, the vault must be designed and constructed to structurally support vehicular traffic loads and accommodate surface and ground water infiltration.

Installation of ASVs in newly constructed and fully replaced pipelines is considered technically feasible provided sufficient space is available for the valve body, actuators, power source, sensors and related electronic equipment, and personnel required to install and maintain the valve.

4.1.3 Automatic Shutoff Valve Operational Feasibility Assessment

Instrumentation and activation of ASVs requires a reliable power source. Sources of pneumatic power for closing ASVs include pressure obtained from a tap in the natural gas pipeline or compressed gas storage cylinders located at the valve site. In areas that are susceptible to electrical power outages, reliability is a potential concern and redundant, alternative, or backup power sources may be required to ensure continuous availability of electricity for motors, solenoids, and electronic components. Proper valve maintenance involving seat and valve-body cleaning, packing and gasket replacement, and valve closure testing to ensure that ASVs actuate on command and close completely are issues that influence operational feasibility.

Operators must consider downstream system demands when scheduling maintenance. Due to service reliability considerations, there may be limited times during the year that pipelines serving critical customers can be shutdown. In addition, working on a pressurized pipeline presents some of the most safety-sensitive work performed by pipeline operators, and operators must strictly follow company safety practices when conducting such work.

In practice, natural gas pipeline operators tend to install ASVs on pipeline segments that:

- do not experience wide pressure fluctuations,
- are not expected to experience wide pressure fluctuations in the future,
- where the risk analysis indicates the ASV will provide added protection to an HCA, and
- in certain remote locations due to access restrictions or excessive travel time (AGA, 2011).

Use of ASVs in hazardous liquid pipelines is potentially problematic from an operational viewpoint because inadvertent block valve closure can:

- result in pumping against a closed valve, or
- initiate undesirable fluid hammer and flow transient effects capable of damaging equipment or triggering other ASVs to close unnecessarily.

Installation of ASVs in newly constructed and fully replaced pipelines is considered operationally feasible provided: (1) inadvertent block valve closure does not cause damage to equipment or trigger other ASVs to close unnecessarily, and (2) the consequences of service disruptions to critical customers due to inadvertent block valve closure do not exceed the potential public and environmental safety benefits realized by rapid block valve closure.

4.2 REMOTE CONTROL VALVES

A RCV is a block valve equipped with an electric, pneumatic, or natural gas-powered actuator capable of closing the valve based on a signal from a remote location such as a control room. These valves also include a communications link between the sensors, which are located near the RCV and at various points along the pipeline, and the remote location. The communications link generally involves telemetry which is a highly automated communications process by which data are collected from instruments located at remote or inaccessible points and transmitted to receiving equipment for measurement, monitoring, display, and recording. Transmission of the information may be over wires (telephone lines or fiber optic cables), or, more commonly, by wireless communication. Although RCVs are designed to close automatically, human intervention is required to initiate closure. In the event of communication loss between the block valve and the control room, microprocessor equipped RCVs can be programmed to act autonomously.

The decision to close a RCV involves evaluating the sensor data received at the remote location and determining whether a problem does, or does not, exist. The evaluation process includes consideration of real-time pressure and flow data and communications with the public, emergency responders, or company field personnel. If the operator determines that block valve closure is necessary, the operator initiates the closure procedure by sending a signal to the valve site via the communications link. The time between a pipeline break and RCV closure can vary from about 3 minutes for immediate leak or rupture detection to hours if field confirmation of a break is necessary to validate the closure decision.

4.2.1 Remote Control Valve Features and Operating Characteristics

Sources of pneumatic power for closing RCVs include pressure obtained from a tap in the natural gas pipeline or compressed gas storage cylinders located at the valve site. In areas that are susceptible to electrical power outages, reliability is a potential operational concern. Redundant, alternative, or backup power sources may be required to ensure continuous availability of electrical components including the communications link. Proper valve maintenance involves seat and valve body cleaning, packing and gasket replacement, and valve closure testing to ensure that RCVs actuate on command and close completely.

Successful use of RCV technology to mitigate the consequences of a pipeline release requires effective communication between the RCV and the remote location where the sensor signals are received and processed. Maintenance and reliability of the communication link and the primary and backup electrical power sources are additional design and operational considerations for RCV technology compared to simpler ASV and MCV technology.

Operators must consider downstream system demands when scheduling maintenance. Due to service reliability considerations, there may be limited times during the year that pipelines serving critical customers can be shutdown. In addition, working on a pressurized pipeline presents some of the most safety-sensitive work performed by pipeline operators, and workers must strictly follow company safety practices when conducting such work.

4.2.2 Remote Control Valve Technical Feasibility Assessment

In 1999, the Research and Special Programs Administration (RSPA) published a report that addresses the four main issues raised by the Congressional mandate to study RCVs (DOT, 1999). These issues include effectiveness, technical feasibility, economic feasibility, and risk reduction. The report also contains the results of an RCV field evaluation conducted by Texas Eastern Transmission Corporation (TETCO) that provides information on TETCO's experience with RCVs. According to conclusions in this report,

> *The results from the TETCO one year field evaluation of 90 installed RCVs reported in section 3.0 confirm that RCVs are effective. The valves were operated approximately 200 times with no valve closure problems. They closed the first time when commanded to close 100 percent of the time.*

and

> *The TETCO experience demonstrates that RCVs are technically feasible. TETCO has installed 90 RCVs and has proven that they operate reliably when remotely commanded. There is considerable anecdotal evidence from other operators of successful installations of RCVs, mostly at compressor stations, that confirms their technical feasibility. It is unquestionably feasible to install equipment on manually operated valves to convert them to RCVs because the necessary equipment exists and has been used for years.*

Current designs for RCVs include actuators, power sources, pressure and flow sensing devices, communications equipment, and other types of mechanical and electrical components that occupy relatively large spaces compared to simpler MCVs. Depending on the application, this space may be located either above or below ground. In a HCA, such as a subdivision or downtown location, this equipment must be installed in an underground vault large enough to house the valve body, actuators, power source, sensors and related electronic equipment, and maintenance personnel. Vaults are typically about 10 ft by 16 ft by 10 ft, but may be larger depending on the size of the valve and the configurations of utilities and other pipelines in the vicinity.

Installation of RCVs in newly constructed and fully replaced pipelines is considered technically feasible based on field evaluations in which RCVs performed reliably and as intended. However, sufficient space must be available for the valve body, actuators, power source, sensors and related electronic equipment, communications equipment, and personnel required to install and maintain the valve.

4.2.3 Remote Control Valve Operational Feasibility Assessment

Although RCVs are less susceptible to inadvertent closure compared to ASVs, use of RCV technology introduces the possibility of human error into the valve closure process (AGA, 2011). In practice, natural gas pipeline operators tend to install RCVs on the following pipeline segments.

- In HCAs at remote locations
- At sites where severe weather or traffic congestion limit accessibility
- In dense urban environments

For hazardous liquid pipelines, inadvertent RCV closure due to operator error or computer system design deficiencies can result in pumping against a closed valve or initiate undesirable fluid hammer and flow transient effects capable of destroying equipment.

Installation of RCVs in newly constructed and fully replaced pipelines is considered operationally feasible provided inadvertent block valve closure does not cause damage to equipment, the communications link between the RCV and the control room is continuous and reliable, and the consequences of service disruptions to critical customers due to inadvertent block valve closure do not exceed the potential public and environmental safety benefits realized by rapid block valve closure.

5. COST BENEFIT AND ECONOMIC FEASIBILITY

Previous studies published by the Gas Research Institute (Sparks, 1998) and RSPA (DOT, 1999) present results of cost benefit and economic feasibility assessments of installing RCVs in natural gas transmission lines. These studies considered the following potential benefits of installing RCVs.

- reducing personal injuries and fatalities associated with pipeline rupture
- preventing property damage
- minimizing product loss

Conclusions from the "Cost Benefit Study of Remote Controlled Main Line Valves" (Sparks, 1998) follow.

1. *Virtually all injuries caused by pipeline breaks occur at, or very near, the time of the initial rupture. Of 81 injury incidents reviewed (1970 to 1997 NTSB Incident Reports), 75 reported injuries at the initial rupture. Of the other six incidents, four occurred within 3 minutes of the rupture. It seems clear, therefore, that early valve closure time will have little or no effect on injuries sustained, and no effect on rupture severity. Valve closure will be "after the fact" as far as most injuries and damage are concerned. There is no evidence that prolonged blowdown of a ruptured line causes injuries.*
2. *Further, a line break does not immediately evacuate the pipeline. Because of line pack (gas compressibility) some 5 to 10 minutes are normally required for low pressure alarms to be generated at Gas Control and/or nearby compressor stations. Delays depend upon break size and location, line size, operating pressure, and other operating and configurational variables. Additional time is then required (a) to determine the cause of low line pressure (e.g., loss of compression, load transients, faulty instrumentation, line break, or other causes) and (b) to determine break location. This will likely consume an additional 5 minutes. Consequently, delays of about 10 minutes will be required before RCV closure can be initiated for a typical line break scenario, if field verification of the break is not required. Early valve closure can, however, have a significant effect in reducing the volume of gas lost after a line break. Simulations show savings of about 50% for valve closure at 10 minutes versus closure at 40 minutes in a typical 30-inch/900-psi rupture scenario.*
3. *Because of potential damage and safety hazards associated with false closures, some companies require field verification of a break before line valves are remotely closed. Much of the quick response capability of the RCV can be lost in that instance. (Policies regarding field verification should be established as a part of the pipeline's risk management activities.)*
4. *From a survey of equipment suppliers and gas industry users, the estimated cost for retrofitting existing main line valves varies from $25,000 to $39,000 each, depending upon valve size. This cost includes retrofit actuator equipment, a communication link, and retrofit labor. If 50% of the existing 300,000 miles of U.S. gas transmission lines were retrofitted for RCV operation, the total estimated cost to the industry would amount to some $300 million to $400 million, with no discernible improvement in safety.*

The RSPA (DOT, 1999) study conclusions follow.

We can not find that RCVs are economically feasible. The quantifiable costs far outweigh the quantifiable benefits from installing RCVs.

and

Installation of RCVs would reduce risk, but the degree of reduction is unknown. The reduction is primarily due to less gas escaping to the atmosphere after a rupture because RCV closure can be in 10 minutes versus 40 minutes (4) if the valves require manual closing, resulting in possible reduced effects, such as property damage. There is some evidence from the NTSB report on the Edison failure (1), that faster valve closure might have allowed firemen to enter the area sooner to extinguish the blazes and might have controlled the spread of the fires to adjacent buildings. However, a quantifiable value can not be placed on this savings to property damage.

The RSPA report also states that property damage prevention and the value of gas saved from early valve closure are the only measurable benefits of RCVs. It further states that comparing property damage from ruptures where RCVs are installed versus where manually operated valves are installed is not possible because RSPA is not aware of any studies that have been conducted that compared these damages.

The bibliography included in this report lists all of the documents that were identified during the literature search conducted by ORNL and used as resources for this study. The literature search identified no publically available reports that discuss the cost benefits and economic feasibility of installing ASVs and RSVs in hazardous liquid pipelines. However, a DOT report published in 1994 titled "Remote Control Spill Reduction Technology: A Survey and Analysis of Applications for Liquid Pipeline Systems" describes findings from a survey and assessment of the effectiveness of EFRDs (including remotely controlled valves and check valves) and other procedures, systems, and equipment used to detect and locate pipeline ruptures and minimize commodity releases from pipeline facilities (Borener, 1994). One of the study objectives involved investigating the feasibility and cost to liquid pipeline operators of EFRDs. The report includes a model for deriving the optimal utilization of EFRDs based on their cost and the estimated spill volume reductions attributable to the EFRDs. The report also repeats the statement in the California State Fire Marshal's Hazardous Liquid Pipeline Risk Assessment report (California State Fire Marshal, 1993) that adding more block valves to all pipelines would not be cost effective, because the average spill size is a very small fraction of the amount of product that could be contained in a pipeline segment of average length.

5.1 EVALUATION METHODOLOGY AND ACCEPTANCE CRITERIA

The agreement between PHMSA and ORNL required an evaluation of the economic feasibility of requiring installation of ASVs or RCVs on newly constructed or entirely replaced pipelines. Section 3 describes the risk analysis methodology used to quantify potential economic benefits to the public and the surrounding environment attributed to the application of ASV and RCV technology. This methodology is based on engineering principles and fire science practices and is consistent with the federal pipeline safety regulations discussed in Section 2. Section 4 defines the estimated costs for adding ASV and RCV technology to block valves installed on newly constructed or entirely replaced pipelines. These costs, which are summarized in Table 4.1, are used in the cost benefit analysis discussed in Section 5.2.

5.1.1 Damage Costs for Natural Gas Pipeline Releases with Ignition

Potential cost benefits of rapid block valve closure are quantified based on results of risk assessments for a range of hypothetical natural gas and hazardous liquid pipeline release scenarios. Cost benefits for these scenarios are measured in terms of avoided costs associated with reduced fire damage attributed to fire fighter actions and decreased exposure to damaging thermal radiation produced by hydrocarbon combustion. The basis for quantifying avoided costs of property damage caused by fire are discussed in Sections 3.1.3.1 through 3.1.3.4 and summarized in Table 3.2.

Risk analysis results discussed in Section 3.1.4 show that without fire fighter intervention following natural gas pipeline releases, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in HCAs. Block valve closure swiftness also has no effect on reducing building and personal property damage costs (with no fire fighter intervention) because thermal radiation is most intense immediately following the break. Consequently, without fire fighter intervention, there is no quantifiable benefit in terms of cost avoidance for damage to buildings and personal property attributed to block valve closure swiftness in natural gas pipelines. However, when combined with fire fighter intervention, the swiftness of block valve closure has a potentially beneficial effect on mitigating fire damage to buildings and personal property in HCAs. Closing block valves sooner decreases the natural gas release rate which in turn reduces the thermal radiation intensity at a specific location and point in time. After the heat flux at a particular location decreases to an acceptable level, fire fighters can safely initiate fire fighting activities.

The benefit of block valve closure swiftness in terms of cost avoidance is based on the ability of fire fighters to mitigate fire damage to buildings and personal property located within a distance of approximately 1.5 times the PIR by conducting fire fighting activities as soon as possible upon arrival at the scene. Block valve closure within 8 minutes after the break can result in significantly less damage to buildings and property compared to delaying block valve closure by 5 minutes or allowing block valves to remain open for a substantially longer period of time (60 minutes or more) after the break. Table 5.1 summarizes the avoided damage costs for hypothetical natural gas pipeline releases following guillotine-type breaks resulting from fire fighting activities within the potentially severe damage radius (approximately 1.5 times PIR) compared to the baseline. The baseline is a guillotine-type break in a hypothetical natural gas pipeline without block valve closure for 60 minutes or longer.

5.1.2 Damage Costs for Hazardous Liquid Pipeline Releases with Ignition

Risk analysis results for liquid propane pipeline releases that ignite immediately following a guillotine-type break are discussed in Section 3.2.4. These results show that for large diameter pipelines the swiftness of block valve closure has a significant effect on mitigating potential fire damage to buildings and personal property in HCAs designated high population areas or other populated areas for large diameter pipelines. The benefit in terms of cost avoidance for damage to buildings and personal property attributed to block valve closure swiftness increases as the time required to isolate the damaged pipeline segment decreases.

The benefit of block valve closure swiftness in terms of cost avoidance of fire damage to buildings and personal property for the release scenarios considered in this study is based on the differences in potentially moderate and minor damage radii for block valve closure in 13 minutes rather than delaying block valve closure for a longer period of time. The radii for potentially moderate damage, 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, and potentially minor damage, 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 minutes decrease as the block valves closure time decreases. Table 5.2 summarizes the avoided damage costs for hypothetical liquid propane pipeline releases following a guillotine-type break and block valve closure in 13 rather than 70 minutes.

Table 5.1. Summary of avoided damage costs for hypothetical natural gas pipeline releases resulting from fire fighting activities within 1.5 times PIR

Location	Nominal diameter = 12-in. MAOP = 300 psig		Nominal diameter = 42-in. MAOP = 1,480 psig	
	Valve closure 8 min. after break	Valve closure 13 min. after break	Valve closure 8 min. after break	Valve closure 13 min. after break
Class 1 HCA				
Buildings or dwellings intended for human occupancy and a PIR greater than 660 ft	N/A PIR is less than 660 ft	N/A PIR is less than 660 ft	$4.572M	$1.829M
Identified site consisting of buildings with four or more stories	$0.600M	$0.300M	$4.572M	$1.829M
Outside recreational facility	$0.803M	$0.446M	$1.785M	$0.714M
Class 2 HCA				
Buildings or dwellings intended for human occupancy and a PIR greater than 660 ft	N/A PIR is less than 660 ft	N/A PIR is less than 660 ft	$4.572M	$1.829M
Identified site consisting of buildings with four or more stories	$0.600M	$0.300M	$4.572M	$1.829M
Outside recreational facility	$0.803M	$0.446M	$1.785M	$0.714M
Class 3 HCA				
Buildings or dwellings intended for human occupancy.	$2.057M	$1.143M	$8.230M	$4.572M
Outside recreational facility	$0.803M	$0.446M	$3.213M	$1.785M
Class 4 HCA				
Buildings or dwellings intended for human occupancy.	$1.500M	$0.900M	$6.000M	$3.600M

Although the swiftness of block valve closure has a beneficial effect in reducing potentially moderate and minor damage for larger diameter pipelines, it has no effect on reducing potentially severe fire damage to buildings and personal property in high population areas or other populated areas located within a radius up to 2.6 times the equilibrium diameter. Severe damage to buildings and personal property within these areas is possible because the heat flux produced by liquid propane combustion following the break exceeds the severe damage threshold, 40 kW/m^2 (12,700 $Btu/hr\ ft^2$).

Table 5.2. Summary of avoided fire damage costs for hypothetical hazardous liquid pipeline releases of propane with block valve closure in 13 minutes after break

Area	Nominal diameter = 8 in. 100 ft elevation change		Nominal diameter = 30 in. 1,000 ft elevation change	
	MAOP = 400 psig Case Study 5A	MAOP = 1,480 psig Case Study 5B	MAOP = 400 psig Case Study 6A	MAOP = 1,480 psig Case Study 6C
Avoided Minor Damage Cost	$0.416M	$0.416M	$5.4M	$5.4M
Avoided Moderate Damage Cost	$0	$0	$0.792M	$0.792M
Avoided Severe Damage Cost	$0	$0	$0	$0

5.1.3 Damage Costs for Hazardous Liquid Pipeline Releases without Ignition

Risk analysis results discussed in Section 3.3.4 for hazardous liquid pipeline releases that do not ignite show that the swiftness of block valve closure has a significant effect on mitigating potential socioeconomic and environmental damage to the human and natural environments. The benefit in terms of cost avoidance for damage to the human and natural environments attributed to block valve closure swiftness increases as the time required to isolate the damaged pipeline segment decreases.

Avoided socioeconomic and environmental costs for hazardous liquid pipeline releases that do not ignite are based on EPA's BOSCEM (Etkin, 2004) discussed in Section 3.3.3 and the information presented in Tables 3.25 through 3.30.

Tables 5.3 and 5.4 summarize the beneficial effects of rapid block valve closure on avoided damage costs for hypothetical crude oil pipeline releases in HCAs following a guillotine-type break.

Table 5.3. Summary of avoided socioeconomic and environmental damage costs for 8-in. nominal diameter hypothetical crude oil pipeline releases in HCAs

Avoided Socioeconomic and Environmental Damage Cost	Nominal diameter = 8-in. Flow velocity = 15 ft/s			
	MAOP = 400 psig Elevation change = 100 ft Case Study 7A	MAOP = 1,480 psig Elevation change = 100 ft Case Study 7B	MAOP = 400 psig Elevation change = 1,000 ft Case Study 7C	MAOP = 1,480 psig Elevation change = 1,000 ft Case Study 7D
Avoided damage cost for valve closure in 3 min. compared to 90 min.	$173M	$173M	$173M	$173M
Avoided damage cost for valve closure in 30 min. compared to 90 min.	$123M	$123M	$123M	$123M
Avoided damage cost for valve closure in 60 min. compared to 90 min.	$61.5M	$61.5M	$61.5M	$61.5M

Table 5.4. Summary of avoided socioeconomic and environmental damage costs for 36-in. nominal diameter hypothetical crude oil pipeline releases in HCAs

Avoided Socioeconomic and Environmental Damage Cost	Nominal diameter = 36 in. Flow velocity = 15 ft/s			
	MAOP = 400 psig Elevation change = 100 ft = 100 ft Case Study 8A	MAOP = 1,480 psig Elevation change = 100 ft Case Study 8B	MAOP = 400 psig Elevation change = 1,000 ft Case Study 8C	MAOP = 1,480 psig Elevation change = 1,000 ft Case Study 8D
Avoided damage cost for valve closure in 3 min. compared to 90 min.	$2.91B	$2.91B	$2.91B	$2.91B
Avoided damage cost for valve closure in 30 min. compared to 90 min.	$2.01B	$2.01B	$2.01B	$2.01B
Avoided damage cost for valve closure in 60 min. compared to 90 min.	$1.0B	$1.0B	$1.0B	$1.0B

5.2 COST BENEFIT ANALYSIS

A series of hypothetical natural gas and hazardous liquid pipeline releases resulting from guillotine-type breaks were used to quantify the avoided costs attributed to block valve closure swiftness. The cost benefits were quantified by comparing the avoided cost of fire damage to buildings and property to the cost for adding automatic closure capability to block valves installed in newly constructed or fully replaced pipelines. Avoided costs for fire damage were determined for buildings and property located in Class 1, Class 2, Class 3, and Class 4 HCAs for natural gas pipelines and in HCAs designated as high population areas and other populated areas for hazardous liquid pipelines. Avoided socioeconomic and environmental costs were determined for hazardous liquid pipeline releases without ignition in HCAs.

A cost benefit is considered positive if the avoided cost of damage attributed to block valve closure swiftness exceeds the cost of adding automatic closure capability to block valves installed in newly constructed or fully replaced pipelines. Conversely, a cost benefit is considered negative if the cost of adding automatic closure capability exceeds the avoided cost of damage attributed to block valve closure swiftness.

The cost benefit analysis methodology does not include the cost of avoided product loss attributed to block valve closure swiftness. This cost is not considered a public or environmental safety concern and is therefore beyond the scope of this study.

5.2.1 Cost Benefit Analysis for Natural Gas Pipeline Releases with Ignition

Risk analysis results presented in Section 3.1 demonstrate that there are avoided fire damage costs attributed to block valve closure swiftness following a guillotine-type break and subsequent fire in natural gas pipelines located in Class 1, Class 2, Class 3, and Class 4 HCAs. The magnitude of these avoided costs depends primarily on the type, configuration, and density of buildings located within the particular HCA and the replacement value of the buildings and property damaged by the fire, but also on the efforts of fire fighters to mitigate fire damage to buildings and property located within the potentially severe damage radius.

The risk analyses show that there are no avoided costs for fire damage to buildings and property attributed to block valve closure swiftness because potentially severe damage occurs before block valve closure can isolate the damaged pipeline segment and begin limiting the amount of natural gas that escapes and burns. Immediately following the break, buildings and property located within the potentially severe damage radius (approximately 1.5 times PIR) are exposed to thermal radiation that exceeds the heat flux threshold of 40.0 kW/m^2 (12,700 Btu/hr ft^2) which can cause potentially severe damage. In addition, injuries to unsheltered humans and emergency responders located within this radius are very probable because the thermal radiation far exceeds the heat flux threshold of 1.4 kW/m^2 (450 Btu/hr ft^2) which is considered the acceptable level of thermal radiation for people in open spaces. Firefighting activities are also limited within areas where the thermal radiation exceeds the heat flux threshold of 2.5 kW/m^2 (800 Btu/hr ft^2) which is considered the acceptable level for common firefighting activities.

Although the cost for adding either RCV or ASV closure capability is considered a negative cost benefit because the swiftness of block valve closure has no effect on mitigating fire damage to buildings and property located within the potentially severe damage radius, positive cost benefits attributed to block valve closure swiftness may be realized when all of the following conditions are satisfied.

- Fire fighters arrive on the scene and are ready to begin fire fighting activities within 10 minutes after the break.
- Fire hydrants are accessible and uniformly spaced around the perimeter of the potentially severe damage circle.
- Block valves close in time to reduce the heat flux at the potentially severe damage radius to 2.5 kW/m^2 (800 Btu/hr ft^2) within 20 minutes or less after the break.

Comparison of the avoided damage costs listed in Table 5.1 and the estimated costs listed in Table 4.1 for adding either RCV or ASV closure capability to a minimum number of block valves[9] needed to isolate a damaged natural gas pipeline segment suggests that positive cost benefits attributed to block valve closure swiftness may be realized for the following natural gas pipeline release scenarios.

- For a 12-in. nominal diameter natural gas pipeline located in either a Class 3 or Class 4 HCA with a MAOP of 300 psig, block valve closure within 8 minutes after the break, and a cost of $600,000 for adding remote closure capability to three block valves.
- For a 12-in. nominal diameter natural gas pipeline located in either a Class 3 or Class 4 HCA with a MAOP of 300 psig, block valve closure in 13 minutes after the break, and a cost of $600,000 for adding remote closure capability to three block valves.
- For a 42-in. nominal diameter natural gas pipeline located in a Class 1, Class 2, Class 3, or Class 4 HCA with a MAOP of 1,480 psig, block valve closure in 8 minutes after the break, and a cost of $900,000 for adding remote closure capability to three block valves.
- For a 42-in. nominal diameter natural gas pipeline located in a Class 1, Class 2, Class 3, or Class 4 HCA (except a Class 1 or Class 2 HCA with an identified site consisting of an outside recreational facility) with a MAOP of 1,480 psig, block valve closure in 13 minutes after the break, and a cost of $900,000 for adding remote closure capability to three block valves.

[9] At least three block valves are required to isolate a damaged natural gas pipeline segment because for these hypothetical release scenarios the break occurs at a block valve and renders the valve inoperable.

The cost benefit analysis should only consider costs for automating block valves because block valves (with or without automation) must be installed in newly constructed and fully replaced pipelines in accordance with 49 CFR 192 requirements. Consequently, the technical, operational, and economic feasibility and potential cost benefits of automating valves in newly constructed or fully replaced pipelines need to be evaluated on a case-by-case basis.

5.2.2 Cost Benefit Analysis for Hazardous Liquid Pipelines with Ignition

Risk analysis results presented in Section 3.2 demonstrate that there are avoided fire damage costs attributed to block valve closure swiftness following a guillotine-type break and subsequent fire in propane pipelines for some, but not all areas located in HCAs designated high population areas or other populated areas with buildings and dwellings intended for human occupancy.

The risk analyses show that there are no avoided costs for fire damage to buildings and property attributed to block valve closure swiftness because the damage occurs within the potentially severe damage radius block valve closure can isolate the damaged pipeline segment and begin limiting the amount of propane that escapes and burns. Within minutes after the break, buildings and property located within the potentially severe damage radius (approximately 2.6 times the equilibrium diameter) are exposed to thermal radiation that exceeds the heat flux threshold of 40.0 kW/m^2 (12,700 Btu/hr ft^2) which can cause potentially severe damage. In addition, injuries to unsheltered humans and emergency responders located within this radius are very probable because the thermal radiation far exceeds the heat flux threshold of 1.4 kW/m^2 (450 Btu/hr ft^2) which is considered the acceptable level of thermal radiation for people in open spaces. Firefighting activities are also limited within areas where the thermal radiation exceeds the heat flux threshold of 2.5 kW/m^2 (800 Btu/hr ft^2) which is considered the acceptable level for common firefighting activities. Consequently there is a negative cost benefit for adding automatic block valve closure capability to mitigate fire damage to buildings and property located within the potentially severe damage radius.

However, positive cost benefits attributed to block valve closure swiftness may be realized in areas located beyond the potentially severe damage radius for the following reason. The radii for potentially moderate damage, 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, and potentially minor damage, 15.8 kW/m^2 (5,000 Btu/hr ft^2) for 30 minutes, decrease as the block valves closure time decreases. Difference in areas of potentially moderate and minor damage associated with block valve closure times of 13 and 70 minutes after the break translate into substantial avoided damage costs.

Comparison of the avoided damage costs listed in Table 5.2 and the estimated costs listed in Table 4.1 for adding either RCV or ASV closure capability to two block valves[10] needed to isolate a damaged pipeline segment suggests that positive cost benefits attributed to block valve closure swiftness may be realized because the avoided cost for fire damage to buildings and personal property far exceeds the cost of adding automatic closure capability to two RCVs or two ASVs in newly constructed or fully replaced hazardous liquid pipelines.

5.2.3 Cost Benefit Analysis for Hazardous Liquid Pipelines without Ignition

Risk analysis results presented in Section 3.3 demonstrate that there are avoided socioeconomic and environmental damage costs attributed to block valve closure swiftness following a guillotine-type break in crude oil pipelines located in HCAs. These results suggest that the swiftness of block valve closure has a significant effect on mitigating potential socioeconomic and environmental damage to the human and

[10] At least two block valves are required to isolate a damaged pipeline segment because for these propane pipeline release scenarios the break occurs between block valves.

natural environments resulting from hazardous liquid pipeline releases. The benefit in terms of cost avoidance for damage to the human and natural environments attributed to block valve closure swiftness increases as the duration of the block valve shutdown phase decreases.

Comparison of the avoided damage costs listed in Tables 5.3 and 5.4 and the estimated costs listed in Table 4.1 for adding either RCV or ASV closure capability to two block valves[11] needed to isolate a damaged pipeline segment suggests that positive cost benefits attributed to block valve closure swiftness may be realized because the avoided cost for socioeconomic and environmental damage far exceeds the cost of adding automatic closure capability to two RCVs or two ASVs in newly constructed or fully replaced hazardous liquid pipelines.

5.3 ECONOMIC FEASIBILITY ASSESSMENT

Results of the cost benefit analysis discussed in Section 5.2 provide evidence that installation of ASVs or RCVs in newly constructed or fully replaced pipelines is economically feasible. This result is based on risk analysis results for hypothetical natural gas pipelines located in Class 1, Class 2, Class 3, and Class 4 HCAs and for hypothetical hazardous liquid pipelines located in HCAs with operating parameters and release scenarios within the range of those considered in this study. However, this result may not be valid for all pipelines located in HCAs for the following reasons.

The risk analyses described in Sections 3.1, 3.2, and 3.3 use various methodologies to quantify the effectiveness of block valve closure swiftness in mitigating damage to the human and natural environments by evaluating a series of case studies for a limited number of hypothetical natural gas and hazardous liquid pipeline release scenarios. These case studies were used to determine the avoided fire damage costs for natural gas and hazardous liquid pipeline releases with ignition and the avoided socioeconomic and environmental damage costs for hazardous liquid pipeline releases without ignition for a range of valve closure times and pipeline operating parameters. The hypothetical natural gas and hazardous liquid pipeline release scenarios were selected for comparison purposes to bound the risk analysis results and provide a consistent technical basis for comparing the results. However, these release scenarios do not model any particular or unique pipeline configurations or site-specific conditions that could invalidate the underlying assumptions or reduce consequence severity. In addition, the risk analyses are based on theoretical models that approximate actual pipeline release behavior, but do not account for natural phenomena such as weather conditions at the time of the release and physical barriers such as terrain features and vegetation that can also affect reduce consequence severity.

Consequently, economic feasibility assessments for specific pipeline segments need to be based on avoided damage costs and valve automation costs that reflect the actual pipeline design features and operating conditions and the site-specific parameters appropriate for the area where the pipeline segment is located. Avoided damage costs needed to assess economic feasibility could be determined using methodologies similar to those described in Sections 3.1, 3.2, and 3.3 or other, more appropriate, methodologies for characterizing specific types of damage and quantifying the associated damage costs. Consideration of site-specific variables in the risk analysis is essential in determining whether the cost benefit is positive or negative and whether installation of ASVs or RCVs in newly constructed or fully replaced pipelines is economically feasible.

[11] At least two block valves are required to isolate a damaged pipeline segment because for these crude oil pipeline release scenarios the break occurs between block valves.

5.4 COST EFFECTIVE IMPLEMENTATION STRATEGIES FOR CONSEQUENCE REDUCTION

Installation of ASVs or RCVs in newly constructed or fully replaced natural gas or hazardous liquid pipelines can be a cost effective strategy for mitigating the consequences of a guillotine-type break for some, but not necessarily all, release scenarios. Key factors to consider in evaluating cost effectiveness include the cost of installing automatic closure capability to all of the block valves that need to close to isolate the damage pipeline segment and the potential public and environmental safety benefits realized by reducing the time required to close these block valves after the release.

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 all of the following conditions are satisfied.

- Fire fighters arrive on the scene and are ready to begin fire fighting activities within 10 minutes or less after the break.
- Fire hydrants are accessible in the vicinity of the potentially severe damage radius.
- 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.
- Block valves close in time to reduce the heat flux at the potentially severe damage radius to 2.5 kW/m^2 (800 Btu/hr ft^2) within 20 minutes or less after the break.

The cost effectiveness of installing ASVs or RCVs in newly constructed or fully replaced natural gas pipelines decreases as delays in leak detection and block valve closure increase. If the damaged pipeline segment is not isolated within 20 minutes after the break, fire fighting activities may evolve from controlling fire damage to preventing fire spread.

For hazardous liquid 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 damage resulting from a guillotine-type break and subsequent ignition provided one of the following conditions is satisfied.

- The leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 15 minutes after the break. After continuous exposure to a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, buildings located with the potentially moderate damage radius may begin burning.
- The leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 30 minutes after the break. If the damaged pipeline segment is not isolated within 30 minutes after the break, buildings located with the potentially minor damage radius that are continuously exposed to a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) may begin burning.

The cost effectiveness of installing ASVs or RCVs in newly constructed or fully replaced hazardous liquid pipelines decreases as delays in leak detection, pump shutdown, and block valve closure increase.

Adding automatic closure capability to block valves in newly constructed or fully replaced hazardous liquid pipelines may also be a cost effective strategy for mitigating potential socioeconomic and environmental damage resulting from a release that does not ignite. Delays in isolating the damaged pipeline segment beyond immediate block valve closure following the break result in a release rate that approximates the normal pipeline flow rate.

The cost effectiveness of installing ASVs or RCVs in newly constructed or fully replaced hazardous liquid pipelines increases as the number of barrels released decreases because socioeconomic and environmental damage costs are often measured in tens of thousands of dollars per barrel.

6. SUMMARY OF RESULTS

Section 4 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (U.S. Congress, 2012) states that the DOT Secretary, if appropriate, shall require by regulation the use of automatic or remote controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced. The Act also requires a study to discuss the ability of transmission pipeline facility operators to respond to a hazardous liquid or natural gas release from a pipeline segment located in a HCA. In March 2012, PHMSA requested assistance from ORNL in preparing a report titled "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." This study addresses issues defined in Section 4 of the Act and those raised by the NTSB in its accident report for the San Bruno incident (NTSB, 2011). The study scope includes the following work activities:

1. Study the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in a high-consequence area as well as Class 3 and Class 4 areas for natural gas transmission;
2. Study the economic, technical, and operational feasibility of requiring the installation of automatic or remote controlled shutoff valves on newly constructed or entirely replaced facilities;
3. Analyze the requirements of valve spacing and the effects of requiring a more stringent minimum spacing of either ASVs or RCVs;
4. Evaluate the fire science behind initial accident rupture and response time provided by ASVs and RCVs by developing models that show the benefits of rapid response time; and
5. Conduct cost, risk, and benefit analysis of installing ASVs and RCVs in HCAs and Class 3 and Class 4 areas.

Initial study efforts involved attending a public workshop on Improving Pipeline Leak Detection System Effectiveness and Understanding the Application of Automatic/Remote Control Valves that was held on March 27–28, 2012, and conducting a literature search to identify publically available references and resources that discuss relevant topics such as emergency response, fire science, building and fire code requirements, methods for assessing socioeconomic and environmental impacts, and ASV and RCV technology. The study is based on results of risk analyses that were conducted using engineering principles and fire science practices to quantify the consequences of pipeline releases and to determine the effectiveness of block valve closure swiftness in mitigating the consequences of the releases. The risk analyses evaluated the following types of damage resulting from pipeline releases in HCAs and Class 3 and Class 4 areas.

1. Fire damage to buildings and property in Class 1, Class 2, Class 3, and Class 4 HCAs caused by natural gas pipeline releases and subsequent ignition of the released natural gas.
2. Fire damage to buildings and property in HCAs designated as high population areas and other populated areas caused by hazardous liquid pipeline releases and subsequent ignition of the released propane.
3. Socioeconomic and environmental damage in HCAs caused by crude oil releases without ignition in hazardous liquid pipelines.

The study also evaluated the technical, operational, and economic feasibility of installing ASVs and RCVs in newly constructed and fully replaced pipelines and determined the potential cost benefits to public and environmental safety.

6.1 POTENTIAL CONSEQUENCES AND EFFECTS

Potential effects of unintended natural gas and hazardous liquid pipeline releases are categorized as human impacts including personal injuries and fatalities, property damage, environmental impacts, and supply losses and business interruptions. These effects were considered in evaluating the effectiveness of RCVs and ASVs in mitigating the consequences of a release. Modeling focused on potential fire consequences and thermal radiation effects resulting from guillotine-type breaks in natural gas pipelines and hazardous liquid pipelines that transport gasoline, propane, butane, and propylene because evaluating all potential release scenarios is not practical. Although ignition of the released product following a guillotine-type break is not ensured, this study only considered release scenarios that result in immediate ignition of the released product at the break location. Models were also developed to study the socioeconomic and environmental effects of crude oil pipeline releases on the human and natural environments.

Natural gas pipeline release events are subdivided into three sequential phases – (1) Detection Phase, (2) Block Valve Closure Phase, and (3) Blowdown Phase. The total discharge volume equals the sum of the volumes released during each phase. Guillotine-type breaks with immediate ignition of the escaping natural gas produce thermal radiant intensities that are considered worst case because this type of rupture results in the greatest release of natural gas in the shortest time period. Block valves have no influence on the volume of natural gas released during the detection phase because the block valves are open and the compressors are operating when natural gas begins escaping from the break. However, rapid detection of the break followed by immediate implementation of corrective actions including closing block valves to isolate the damaged pipeline segment reduces the total volume of natural gas released which in turn reduces the radiant heat flux produced by combustion of the released natural gas. The effectiveness of block valve closure swiftness in mitigating the consequences of a natural gas pipeline release decreases as the duration of the detection and block valve closure phases increases.

Thermal radiation is the primary mechanism for injury or damage from fire and is the significant mode of heat transfer for situations in which a target is located laterally to the exposure fire source. Models were developed to quantifying the time-dependent variations in separation distances (radii) for specific heat flux intensities because thermal radiation effects on buildings and humans are a function of heat flux intensity and exposure duration. The model results were used to quantify thermal radiation effects on buildings and humans based on the following heat flux and exposure duration criteria:

- Exposure to a heat flux of 1.4 kW/m^2 (450 Btu/hr ft^2) is considered acceptable for outdoor, unprotected facilities or open spaces where people congregate;
- Exposure to a heat flux of 2.5 kW/m^2 (800 Btu/hr ft^2) is considered acceptable while conducting fire fighting and emergency response activities;
- Exposure of a building to a heat flux of 15.8 kW/m2 (5,000 Btu/hr ft^2) is considered acceptable for an extended period of time (30 minutes) without burning and the threshold for minor damage to buildings;
- Exposure of a building to a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) is considered acceptable for an extended period of time (15 minutes) without burning and the threshold for moderate damage to buildings; and
- Exposure to a heat flux of 40.0 kW/m^2 (12,700 Btu/hr ft^2) is considered the maximum tolerable level of radiation at the facade of an exposed building and the threshold for severe damage to buildings;

Hazardous liquid pipeline release events are subdivided into four sequential phases – (1) Detection Phase, (2) Continued Pumping Phase, (3) Block Valve Closure Phase, and (4) Pipeline Drain Down Phase. The total discharge volume equals the sum of the volumes released during each phase. The effectiveness of block valve closure swiftness on limiting the spill volume of a release is influenced by the location of the block valves relative to the location of the break, the pipeline elevation profile between adjacent block valves, and the time required to close the block valves after the break is detected and the pumps are shut down. Block valves do not affect the volume of liquid spilled during the detection and continued pumping phases because the block valves are open. However, the total spill volume is reduced by rapidly detecting the break and taking immediate corrective actions including shutting down the pumps and closing the block valves. The effectiveness of block valve closure in mitigating the consequences of a hazardous liquid pipeline release decreases as the time required to isolate the damaged pipeline segment increases.

Potential consequences on the human and natural environments resulting from a hazardous liquid release without ignition generally involve socioeconomic and environmental impacts. These impacts are influenced by the total quantity of hazardous liquid released and the habitats, resources, and land uses that are affected by the release. The methodology used to quantify socioeconomic and environmental impacts resulting from a hazardous liquid release involves computing the quantity of hazardous liquid released and then using this quantity to establish the total damage cost. The total damage cost is determined by adding the response cost, the socioeconomic damage cost, and the environmental damage cost based on the EPA's BOSCEM and applying a damage cost adjustment factor. This factor aligns the total damage cost with the actual cleanup costs reported for recent crude oil spills in environmentally sensitive areas.

6.2 TECHNICAL AND OPERATIONAL FEASIBILITY ASSESSMENT RESULTS

In general, installation of ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is technically and operationally feasible. However, the technical and operational feasibility of installing ASVs and RCVs at specific locations is conditional because unique design features and operating conditions can affect feasibility assessment results.

Installation of ASVs and RCVs is considered technically feasible provided sufficient space is available for the valve body, actuators, power source, sensors and related electronic equipment, and personnel required to install and maintain the valve. Although field evaluations of RCVs show that they are reliable and function as intended, the technical feasibility of installing RCVs also depends on the availability of additional space required by the communications equipment that links the site to the control room.

Installation of ASVs and RCVs is considered operationally feasible provided communication links between the RCV site and the control room are continuous and reliable. It is also important that inadvertent block valve closure does not occur. It is undesirable to disrupt service to critical customers, and also sudden block valve closure that occurs inadvertently may cause a pressure surge that could damage equipment.

6.3 COST BENEFIT AND ECONOMIC FEASIBILITY ASSESSMENT RESULTS

Installation of ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is economically feasible with a positive cost benefit for the release scenarios considered in this study. However, these release scenarios do not model the unique features of a particular pipeline facility or its site-specific design features and operating conditions. These unique features and conditions can invalidate the underlying assumptions in this study and, therefore, reduce or eliminate the positive cost benefits attributed to block valve closure swiftness.

Meaningful economic feasibility assessments and cost benefit analyses for specific pipeline segments need to be based on avoided damage costs and valve automation costs that reflect the actual pipeline design features and operating conditions and the site-specific parameters appropriate for the area where the pipeline segment is located. Consideration of site-specific variables is essential in determining whether the cost benefit is positive or negative and whether installation of ASVs or RCVs in newly constructed or fully replaced pipelines is economically feasible.

6.4 STRATEGIES FOR CONSEQUENCE REDUCTION

In theory, installing ASVs and RCVs in pipelines can be an effective strategy for mitigating potential consequences of unintended releases because decreasing the total volume of the release reduces overall impacts on the public and to the environment. However, block valve closure has no effect on preventing pipeline failure or stopping the material that remains inside the isolated pipeline segments from escaping into the environment. Positive effects in terms of reduced fire, socioeconomic, and environmental damage resulting from rapid block valve closure are only realized through the combined efforts of pipeline operators and emergency responders.

Installing ASVs and RCVs in newly constructed or fully replaced natural gas and hazardous liquid pipelines can be an effective strategy for mitigating potential fire consequences resulting from a release and subsequent ignition provided all of the following conditions are satisfied.

- 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.
- Fire fighters arrive on the scene and are ready to begin fire fighting activities within 10 minutes or less after the break.
- Fire hydrants are accessible in the vicinity of the potentially severe damage radius.
- Block valves close in time to reduce the heat flux at the potentially severe damage radius to 2.5 kW/m^2 (800 Btu/hr ft^2) within 20 minutes or less after the break.

Adding automatic closure capability to block valves in newly constructed or fully replaced hazardous liquid pipelines can be an effective strategy for mitigating potential fire damage resulting from a guillotine-type break 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 15 minutes after the break. After continuous exposure to a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) for 15 minutes, buildings located with the potentially moderate damage radius may begin burning. If the damaged pipeline segment is not isolated within 30 minutes after the break, buildings located with the potentially minor damage radius that are continuously exposed to a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) may begin burning. The cost effectiveness of installing ASVs or RCVs in newly constructed or fully replaced hazardous liquid pipelines decreases as delays in leak detection, pump shutdown, and block valve closure increase.

Adding automatic closure capability to block valves in newly constructed or fully replaced hazardous liquid pipelines can also be an effective strategy for mitigating potential socioeconomic and environmental damage resulting from a release that does not ignite. Delays in closing block valves immediately following a break result in a release rate that approximates the normal pipeline flow rate.

This flow rate continues until block valve closure isolates the damaged pipeline segment and the drain down phase begins. The cost effectiveness of installing ASVs or RCVs in newly constructed or fully replaced hazardous liquid pipelines increases as the time required to isolate a damage pipeline segment decreases because block valve closure swiftness affects the amount of product released following an unintended hazardous liquid pipeline rupture.

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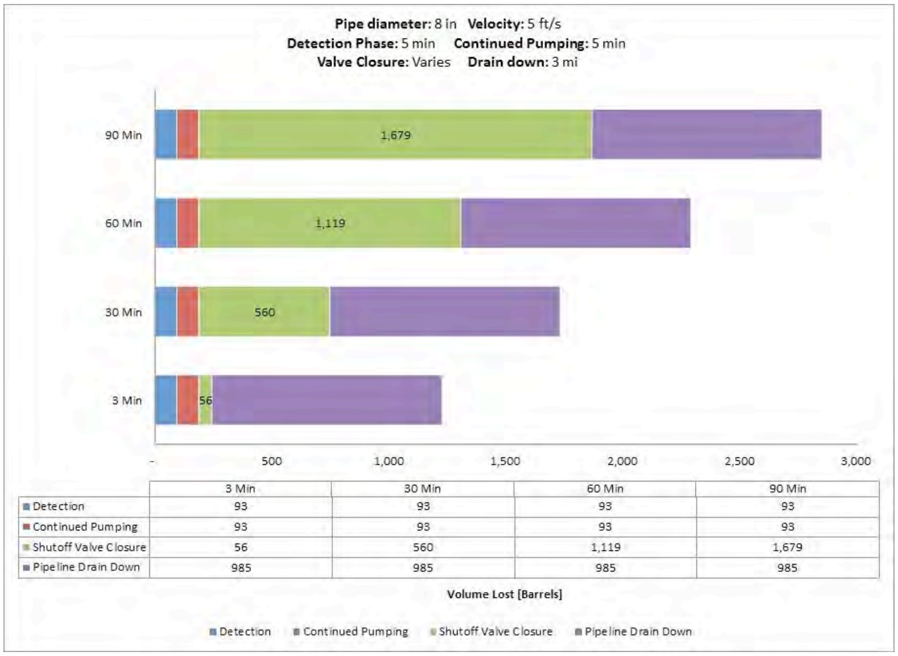
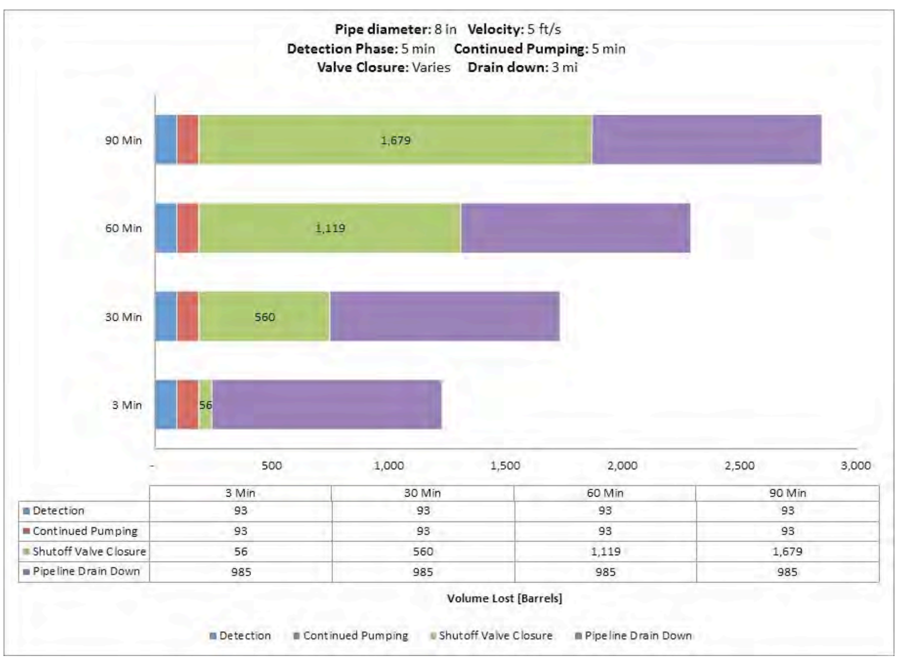
APPENDIX A: SPILL VOLUME RELEASED DUE TO VALVE CLOSURE TIMES IN LIQUID PROPANE PIPELINES



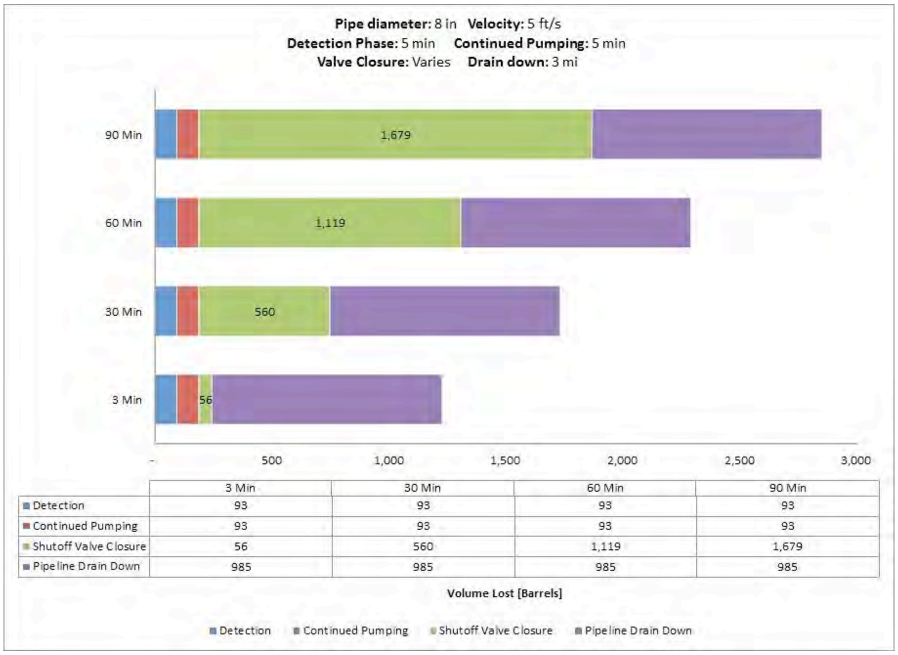
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-1.8 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



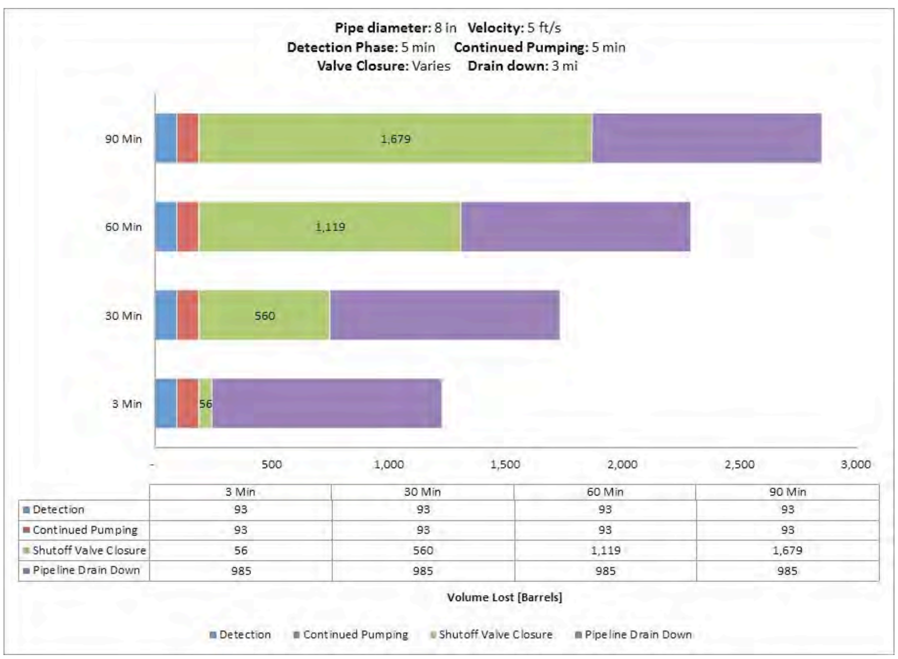
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-2.8 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-3.8 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-4.8 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

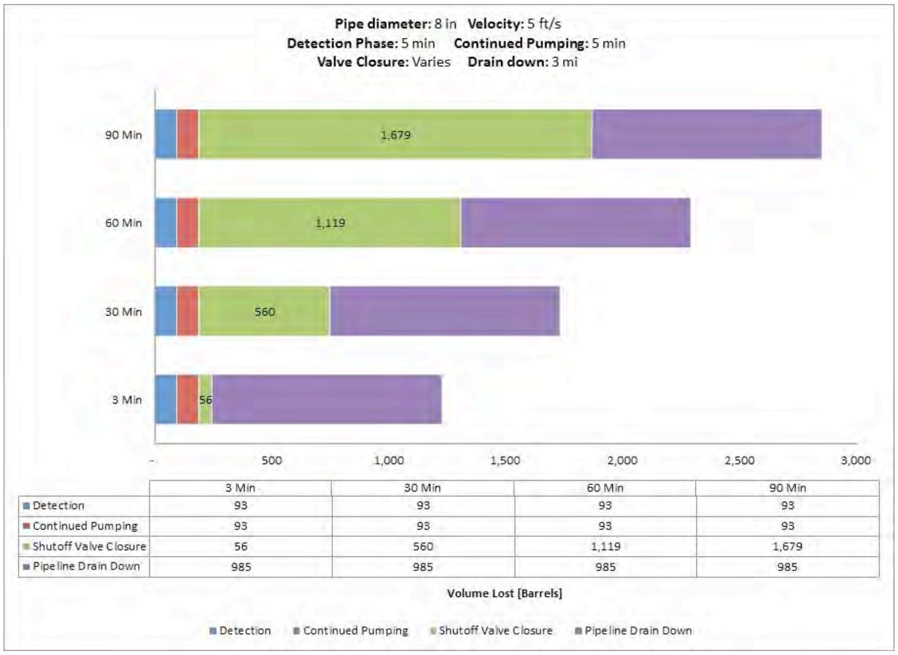


Fig. A-5. 8 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

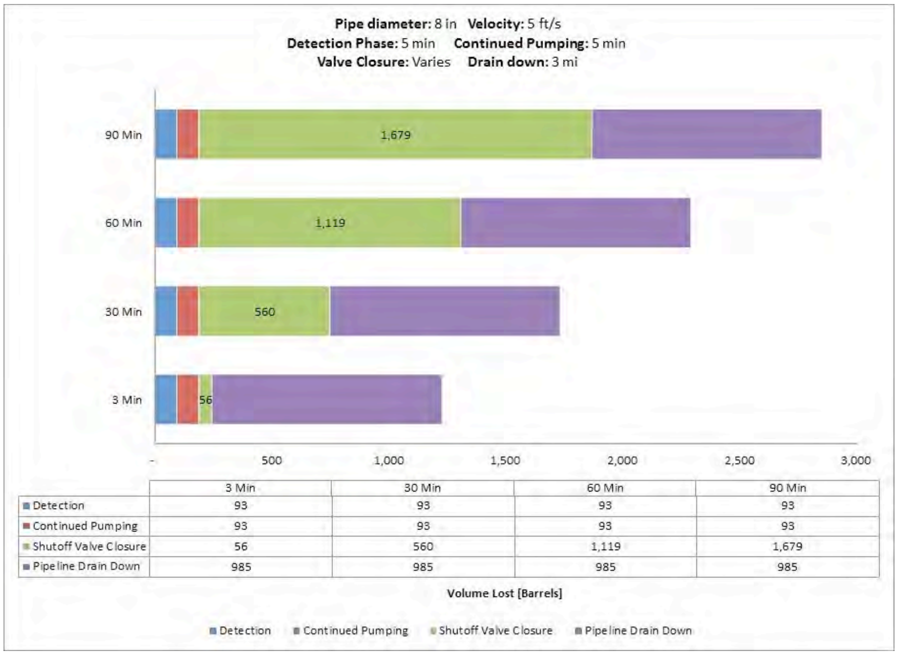


Fig. A-6.8 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

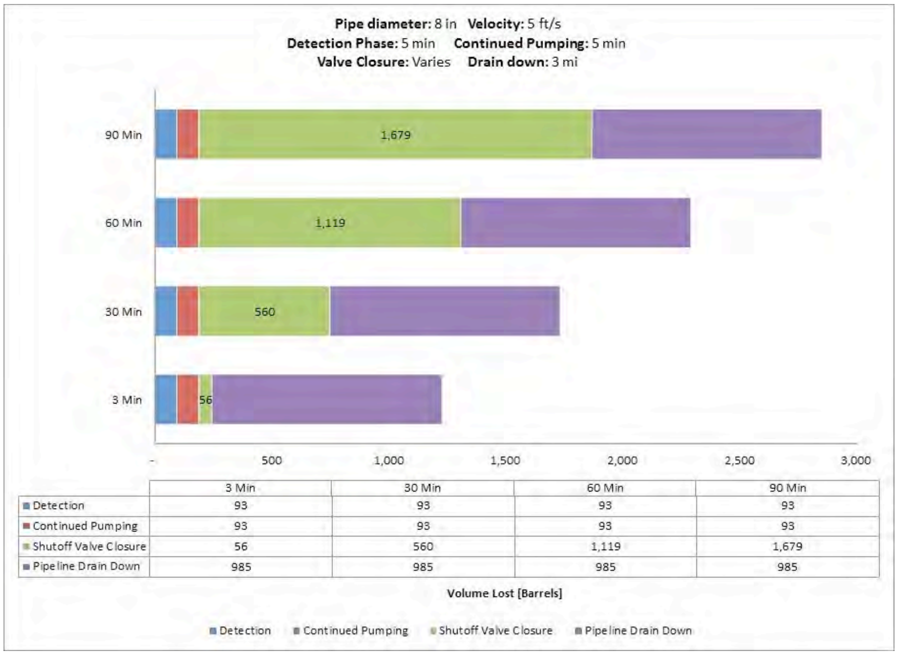


Fig. A-7.8 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

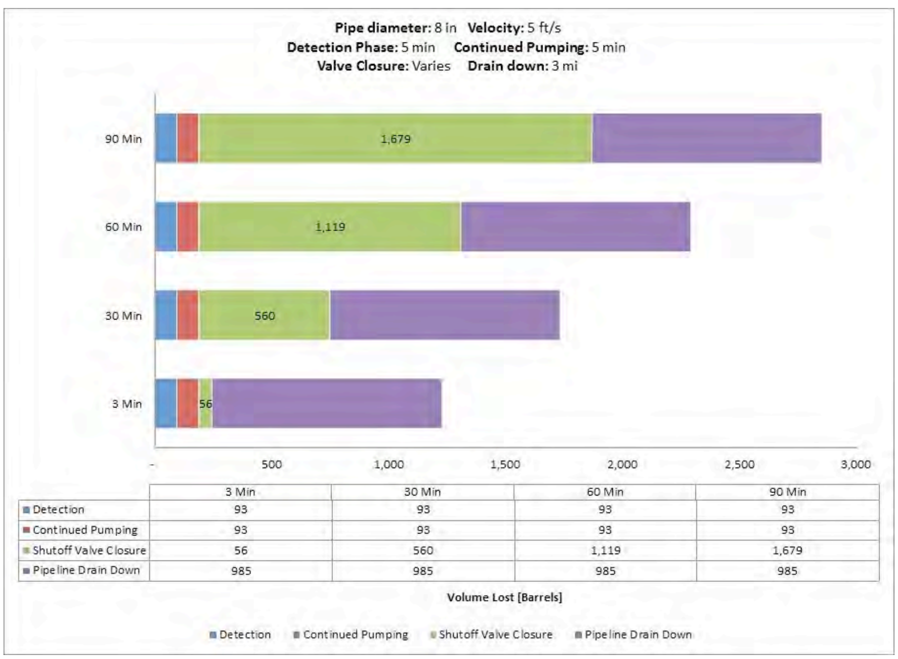
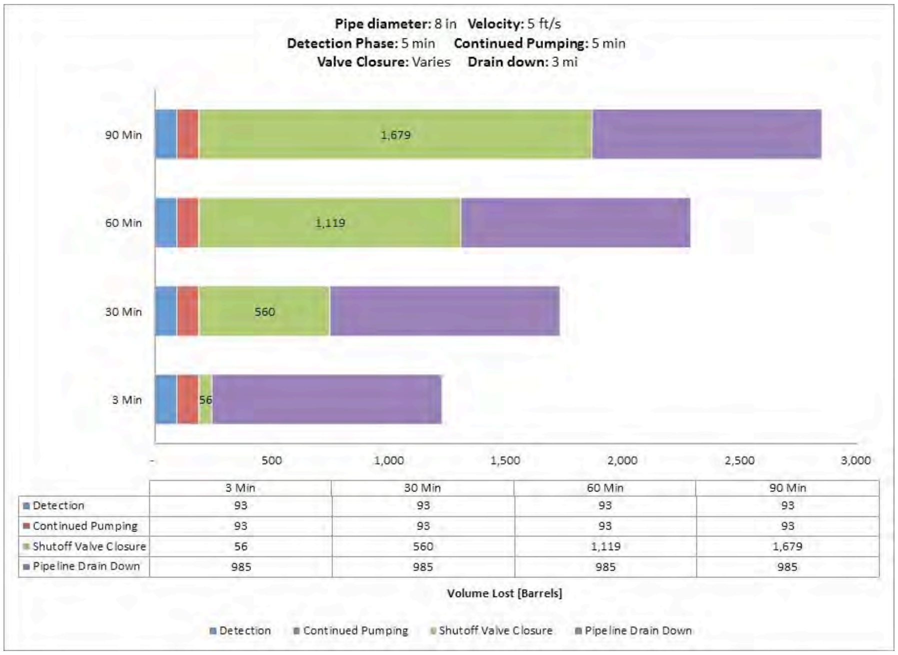
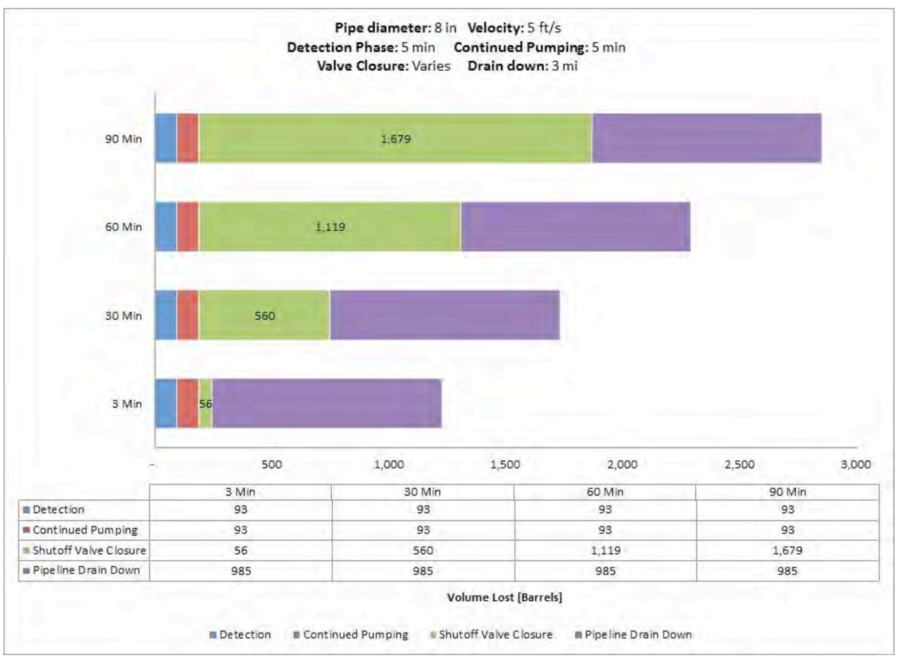


Fig. A-8.8 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



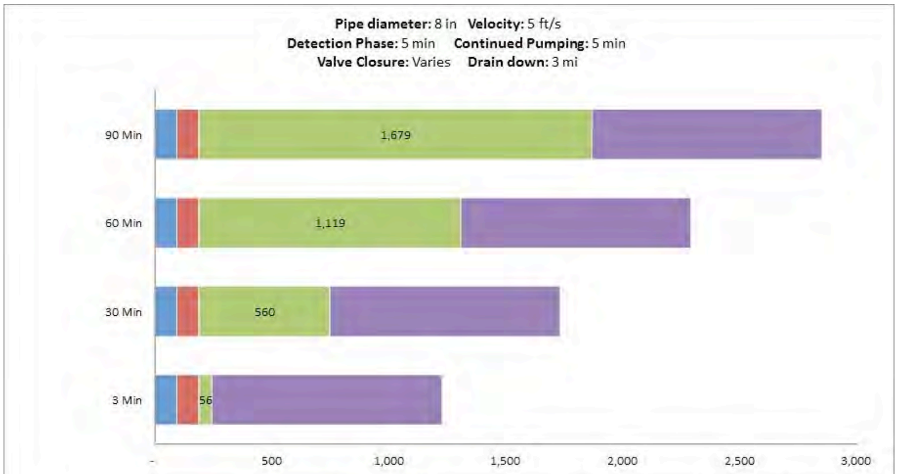
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-9. 8 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-10. 8 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

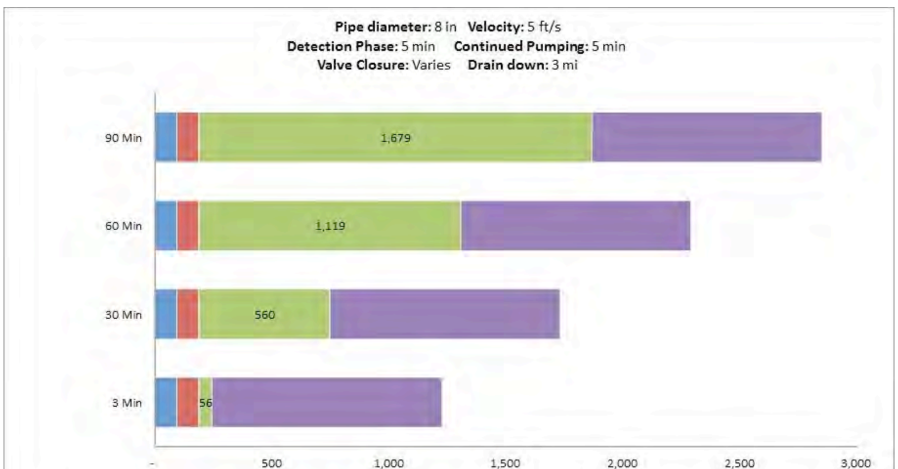


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-11. 8 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

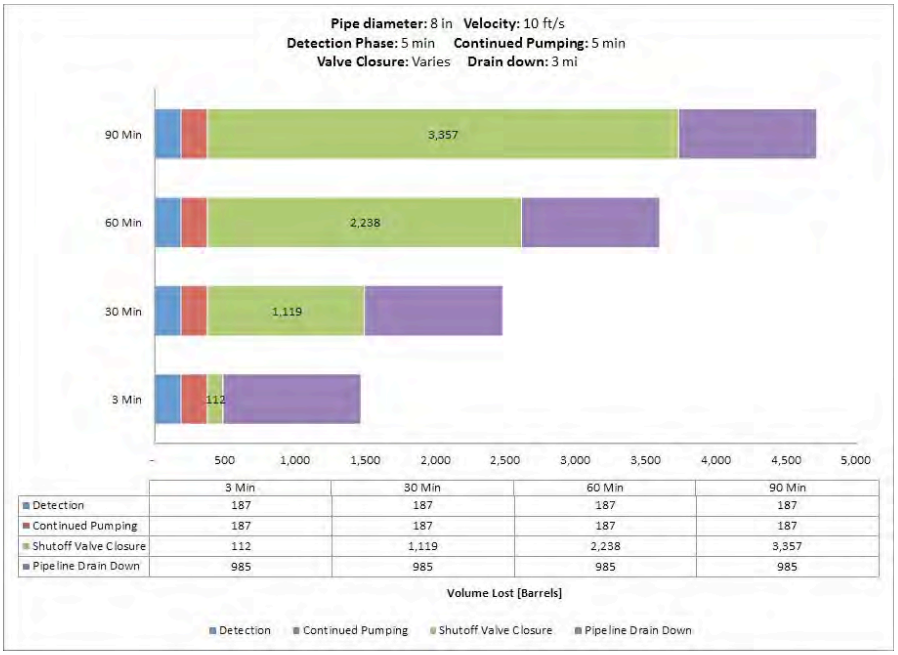


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-12. 8 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

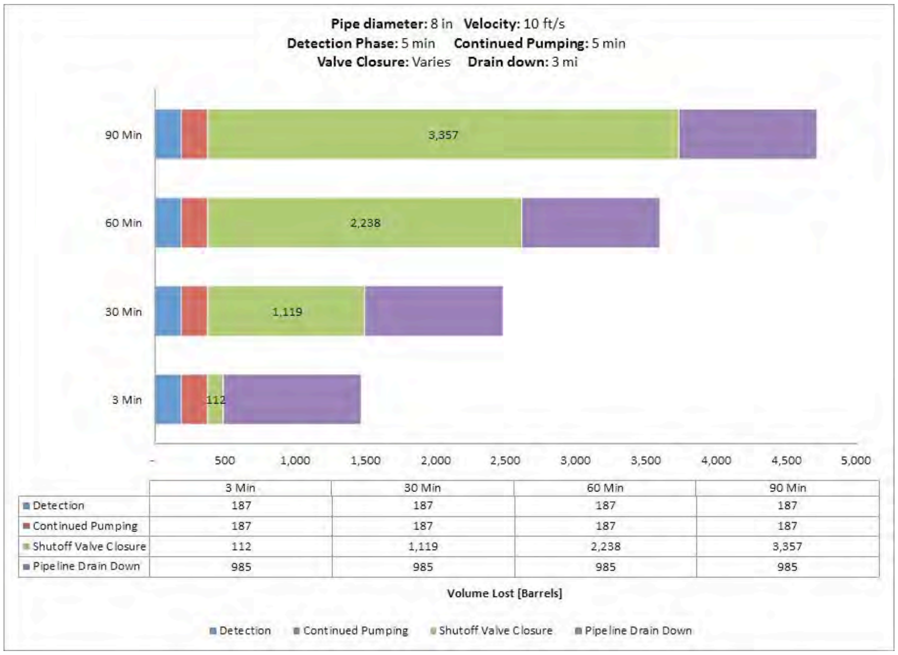


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-13. 8 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-14. 8 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

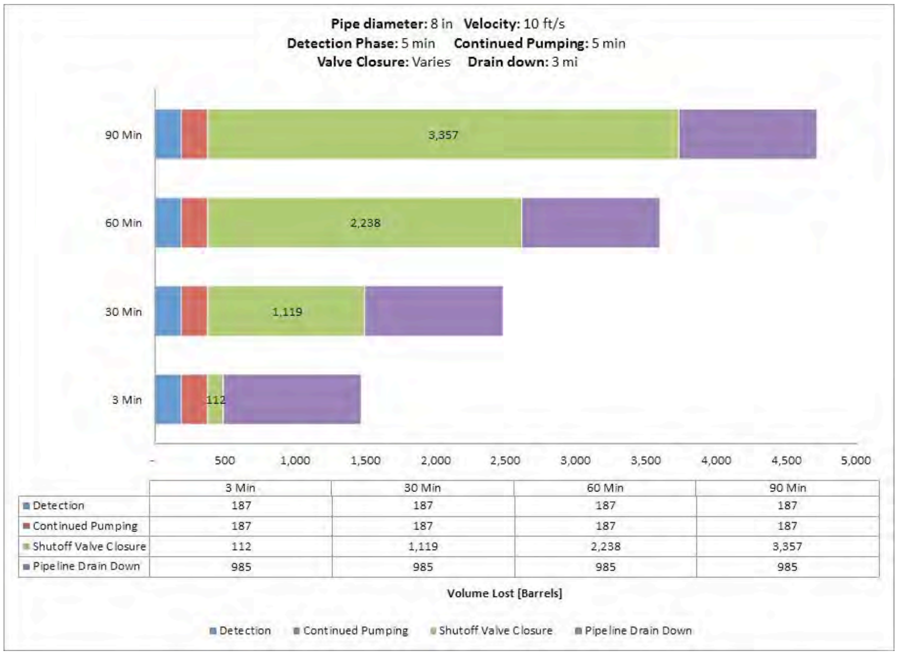


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-15. 8 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-16. 8 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

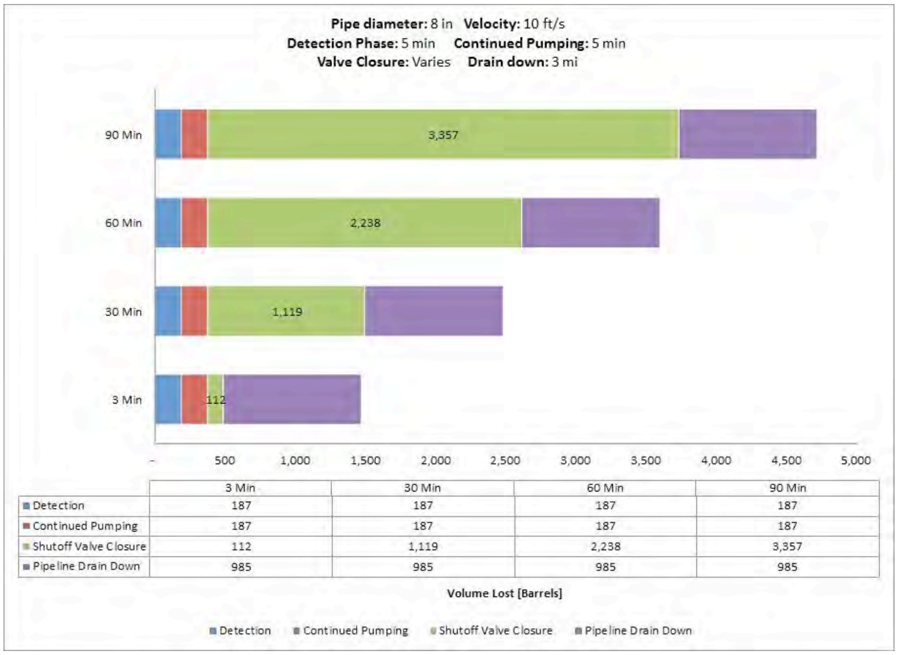


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-17. 8 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-18. 8 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

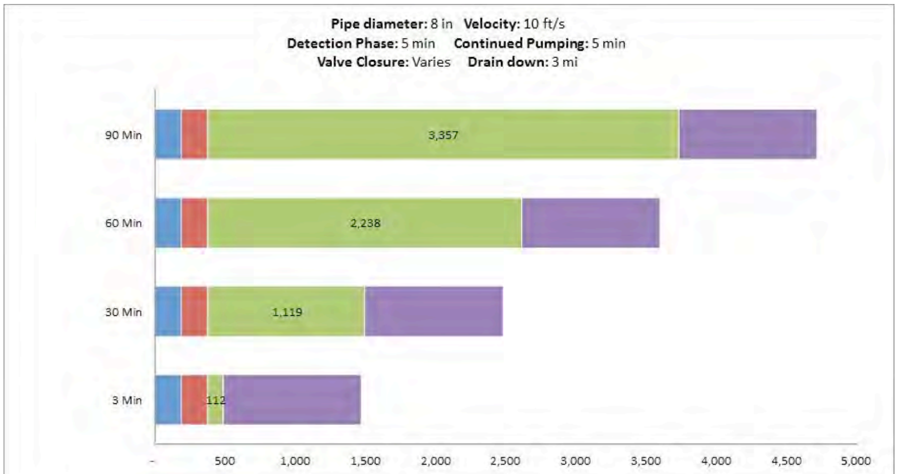


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-19. 8 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-20. 8 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

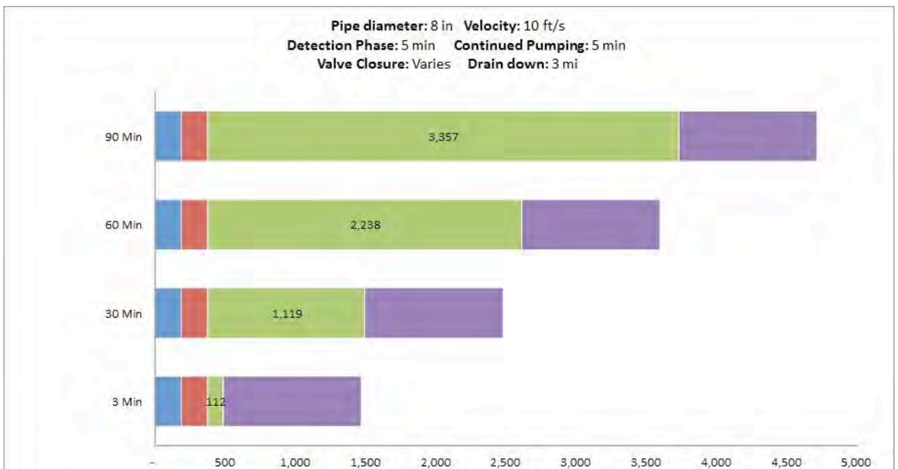


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-21. 8 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

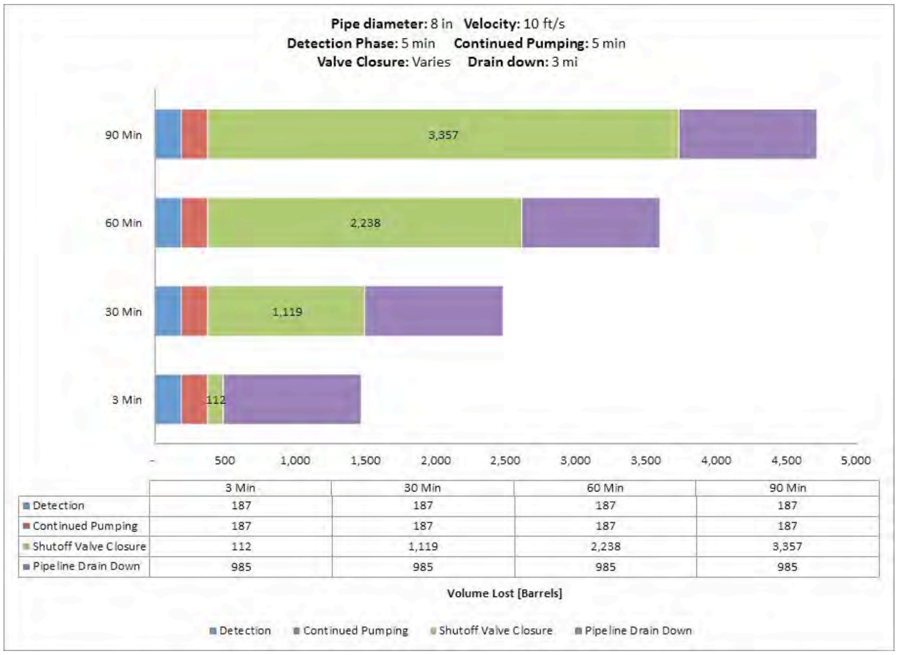


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-22. 8 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

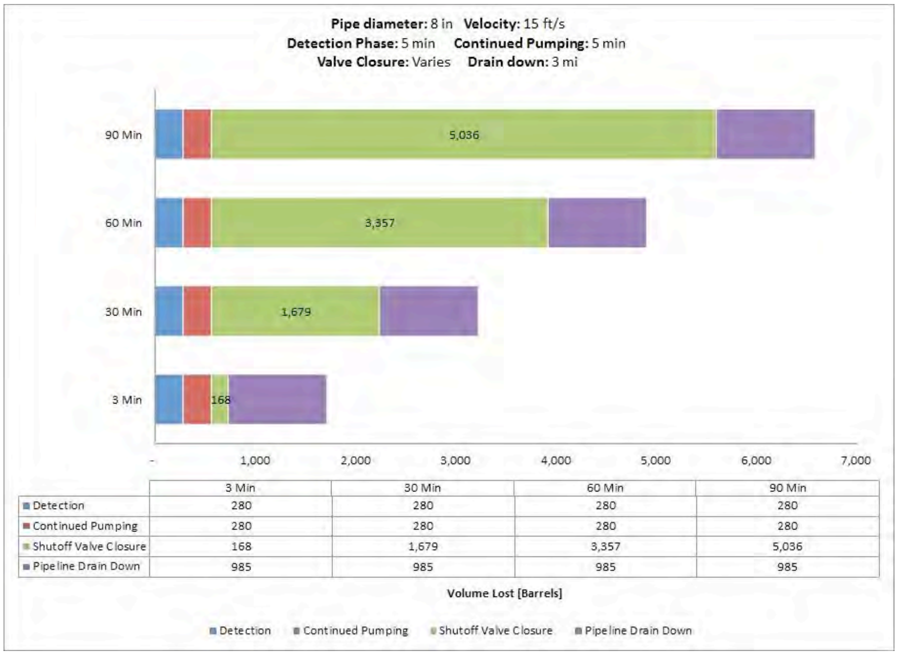


	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-23. 8 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

Fig. A-24. 8 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-25. 8 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-26. 8 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

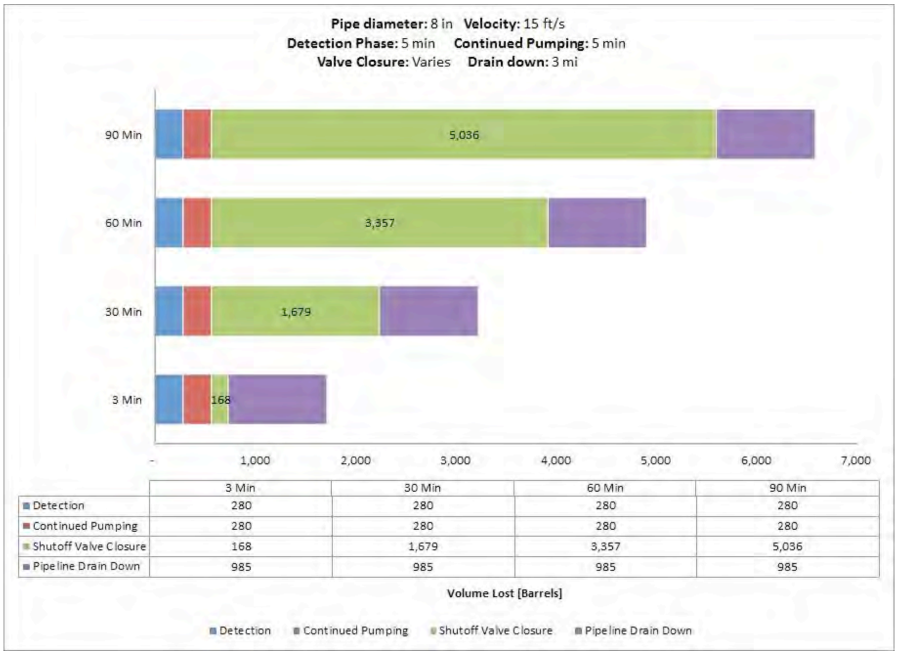
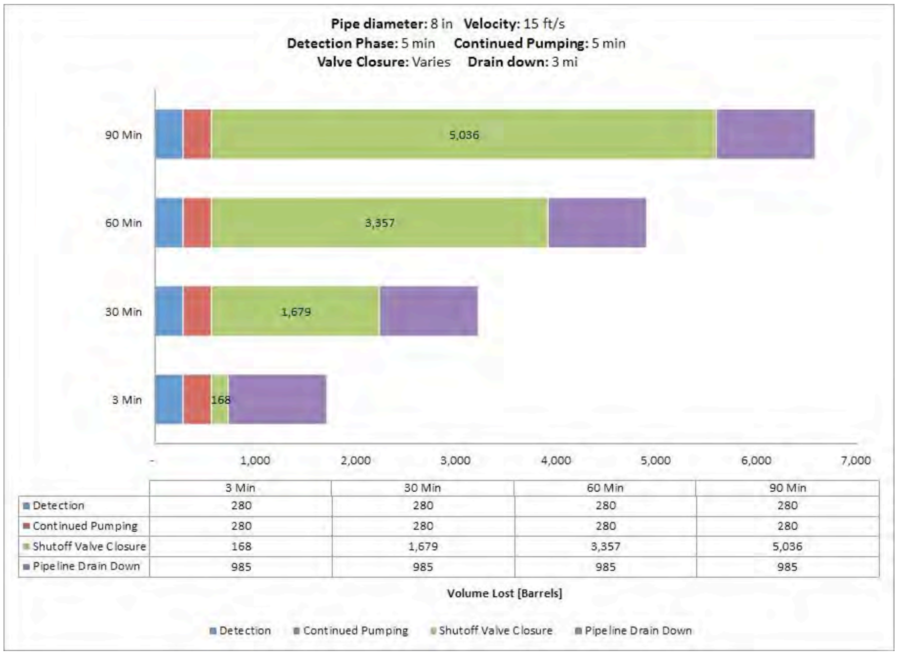


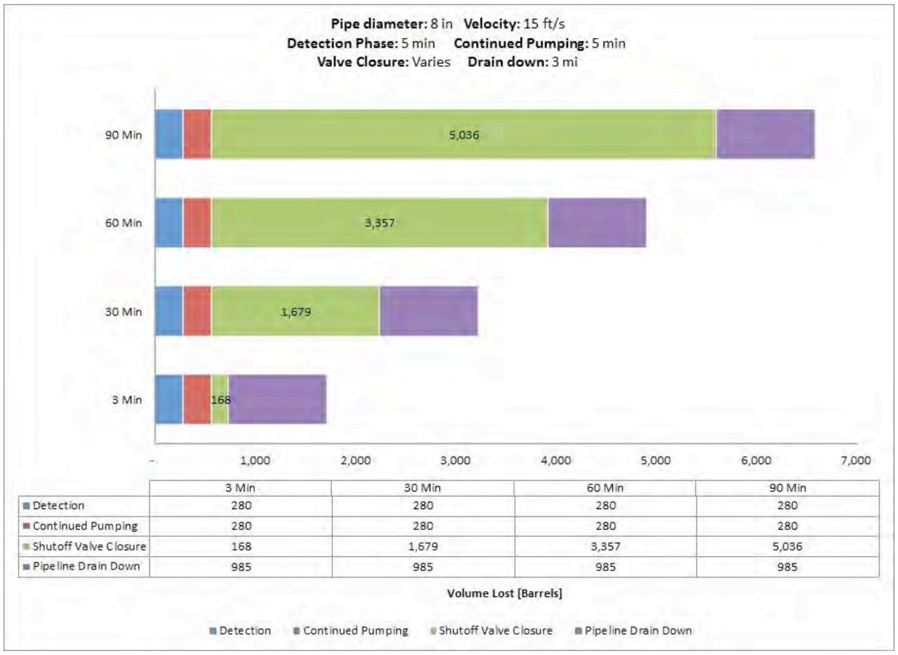
Fig. A-27. 8 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

Fig. A-28. 8 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



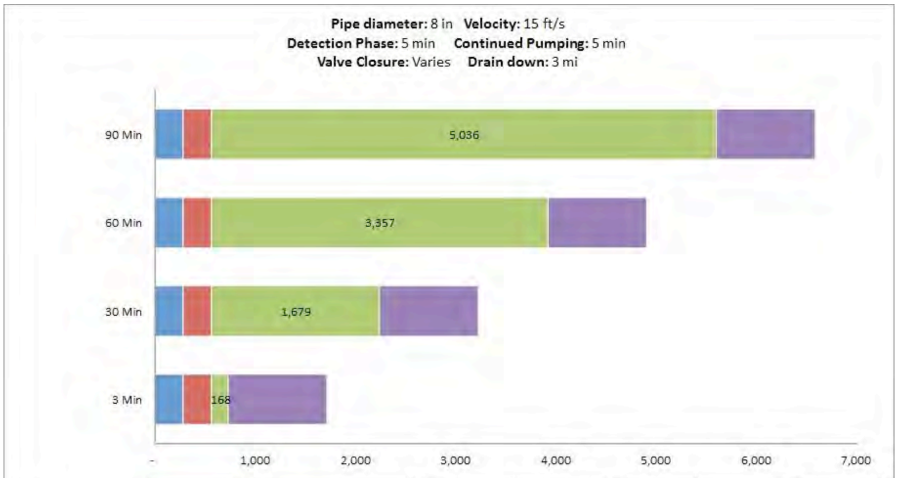
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-29. 8 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



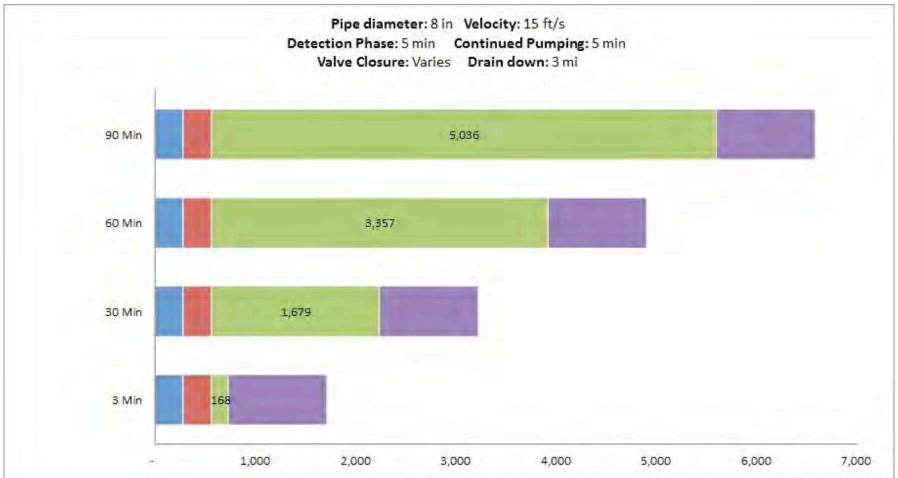
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-30. 8 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-31. 8 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Fig. A-32. 8 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

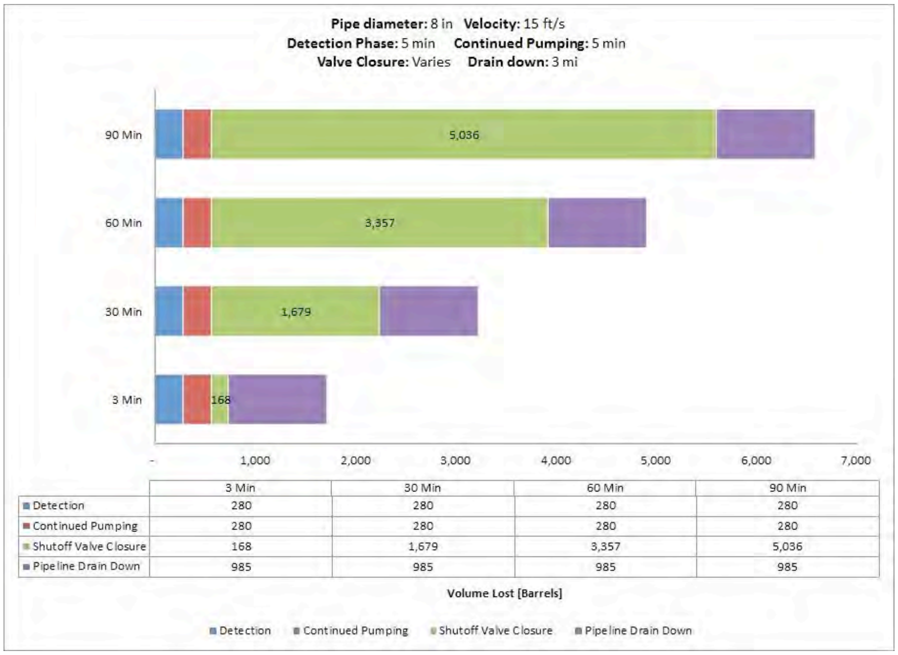
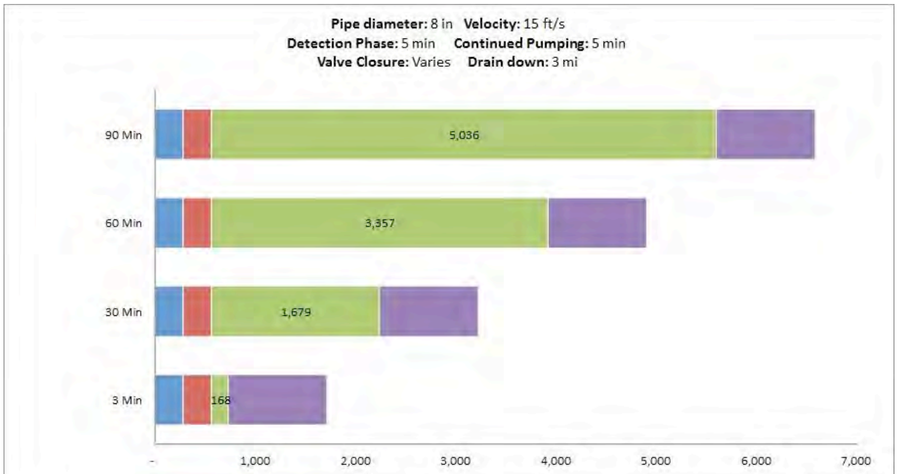


Fig. A-33. 8 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

Fig. A-34. 8 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

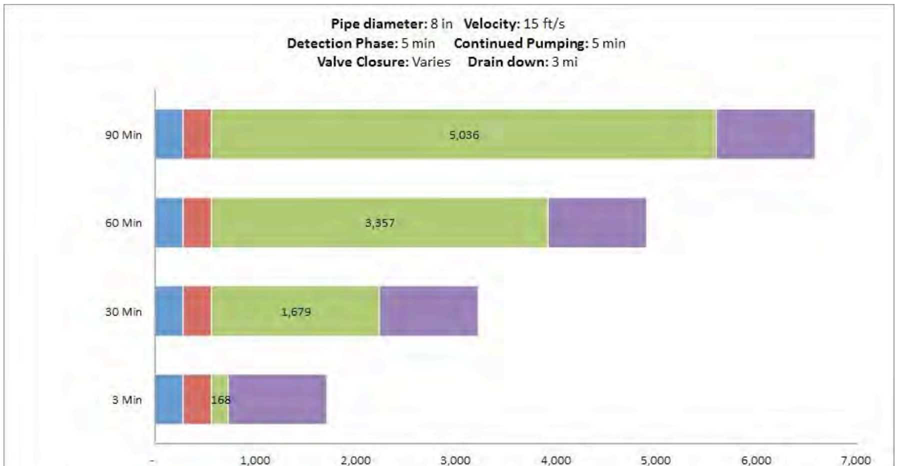


	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-35. 8 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

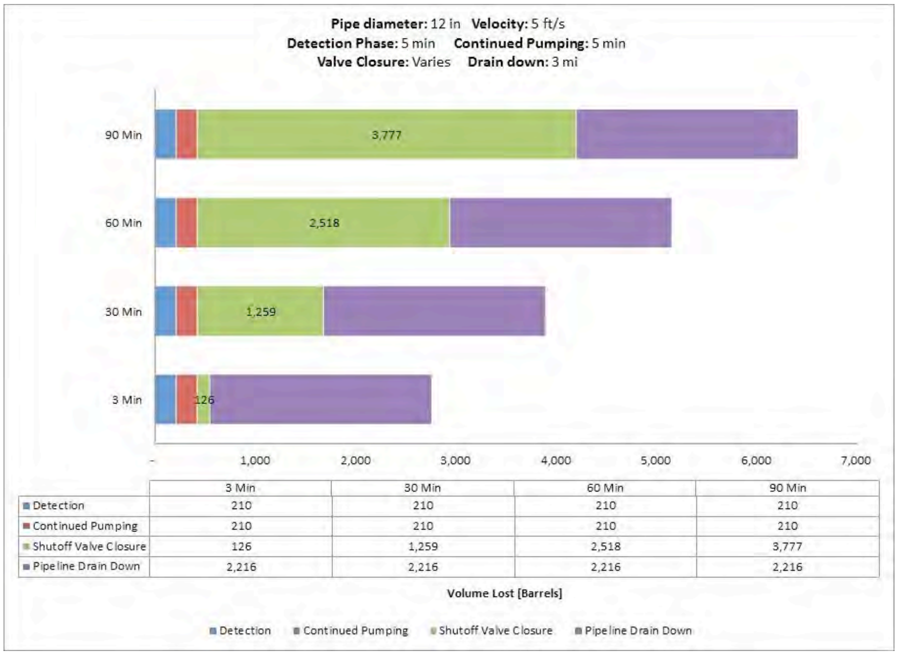


	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-36. 8 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

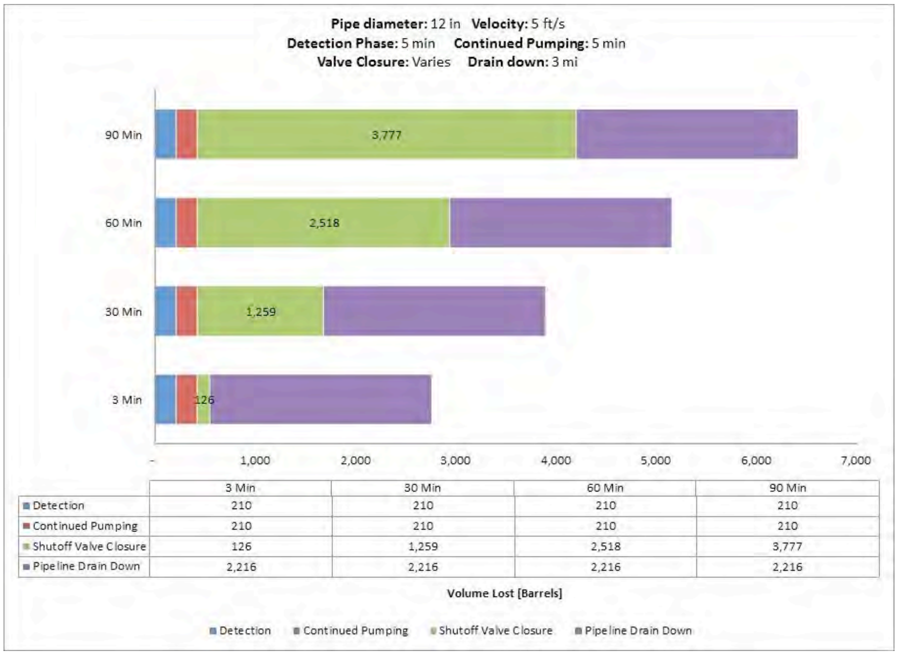


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-37. 12 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

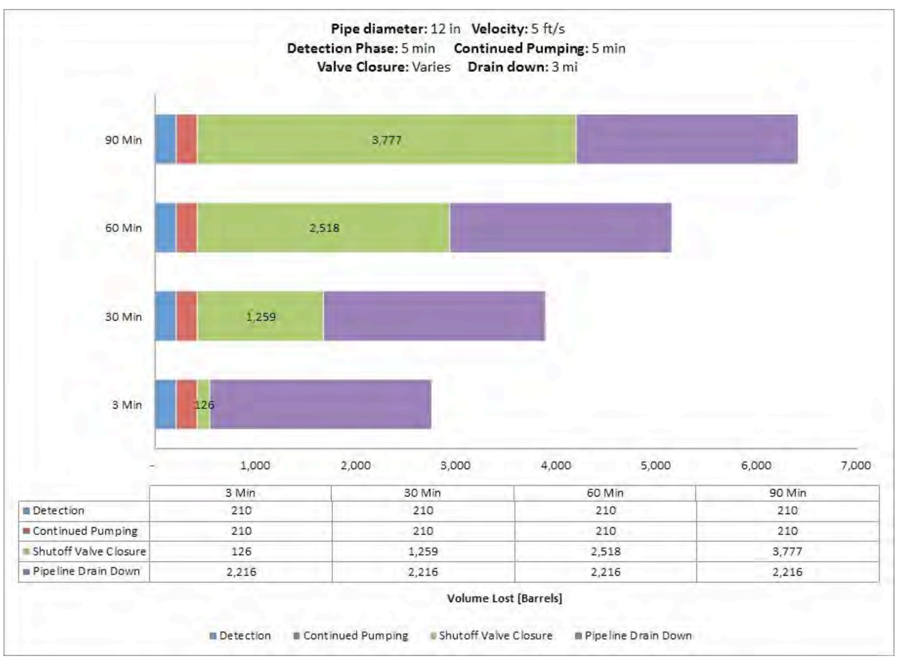
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-38. 12 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



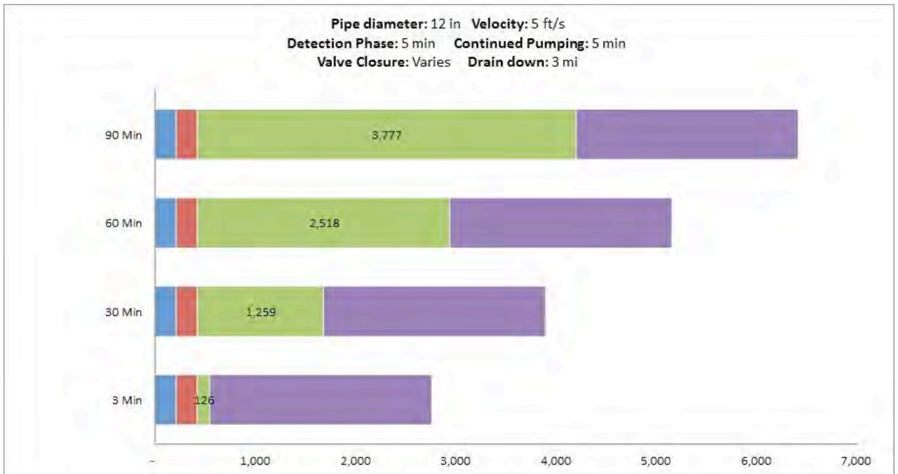
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-39. 12 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-40. 12 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

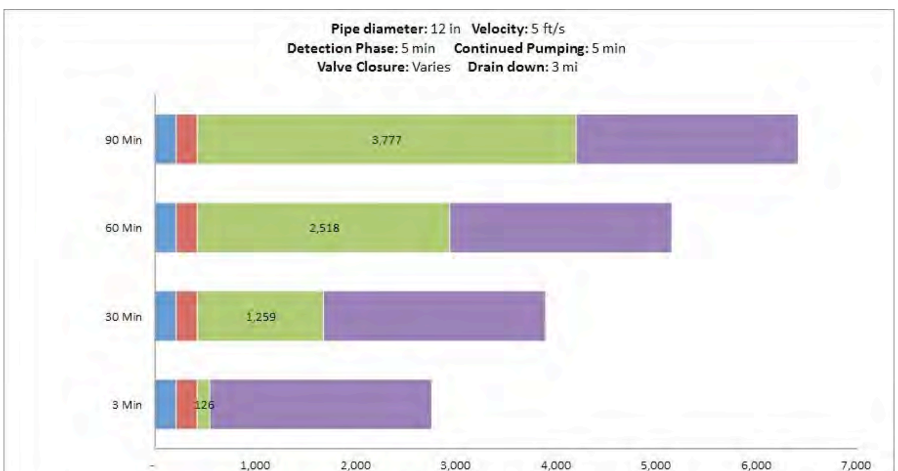


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-41. 12 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

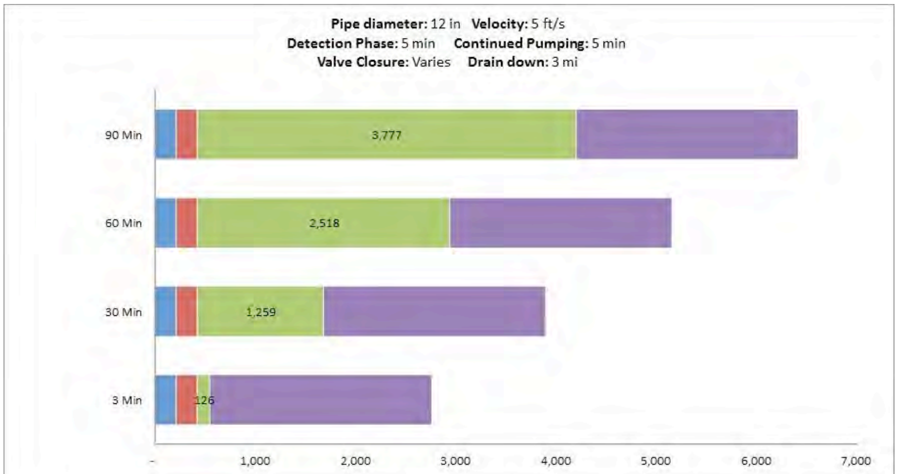


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-42. 12 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

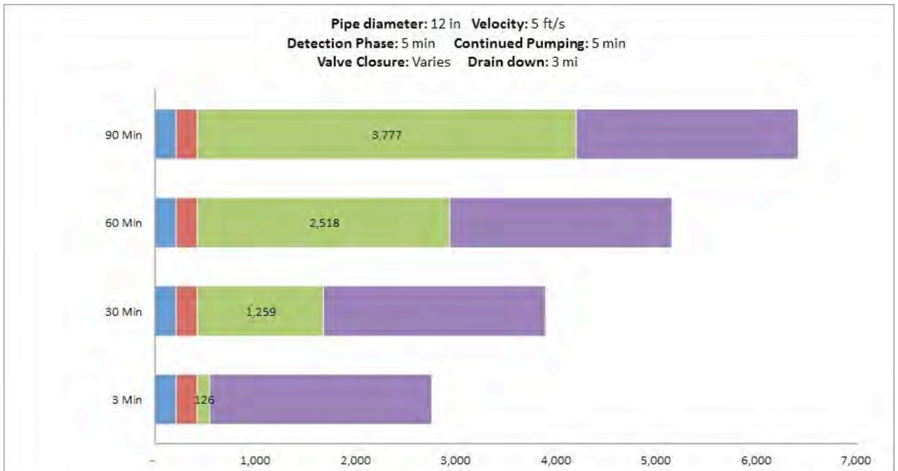


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-43. 12 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

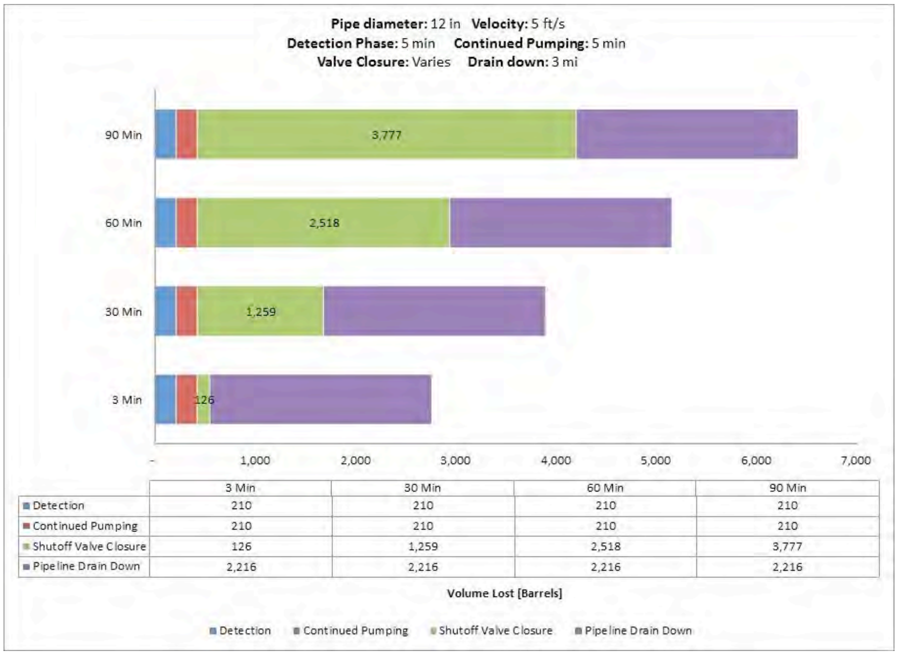


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

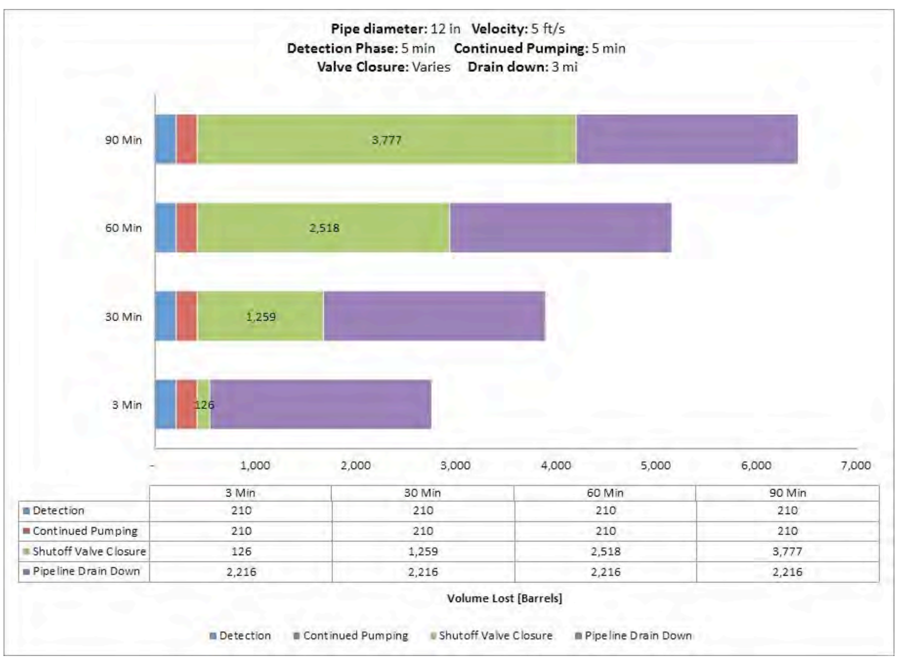
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-44. 12 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



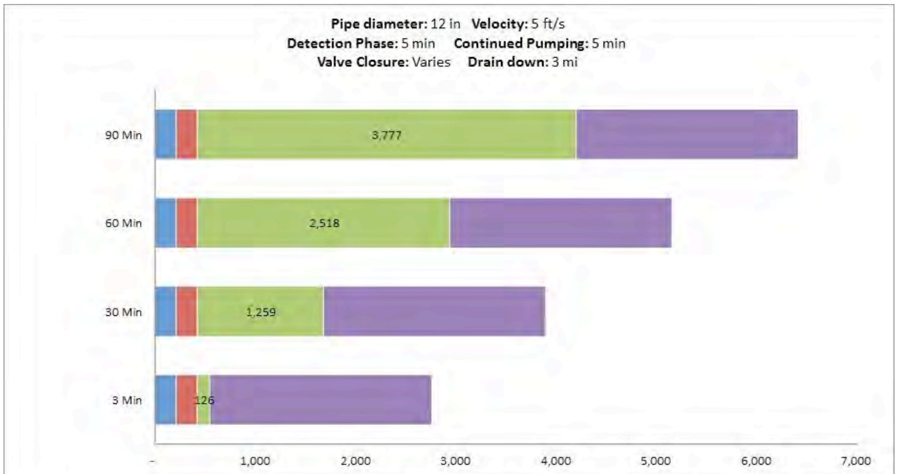
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-45. 12 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-46. 12 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

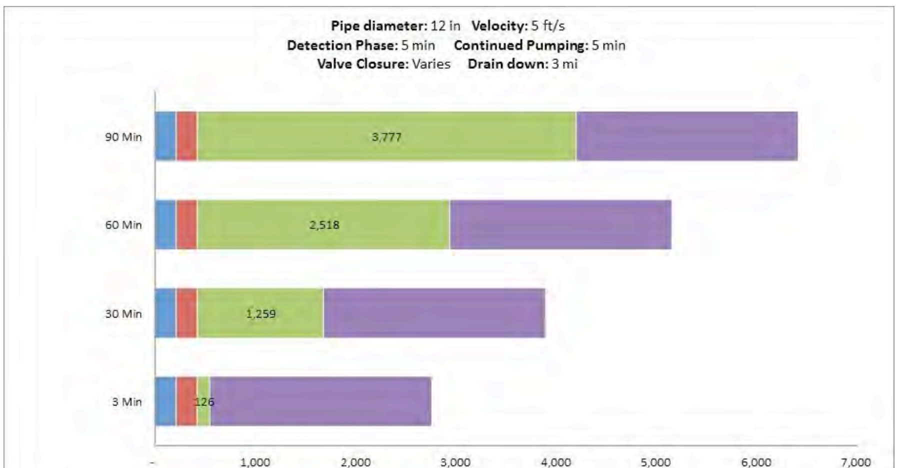


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-47. 12 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

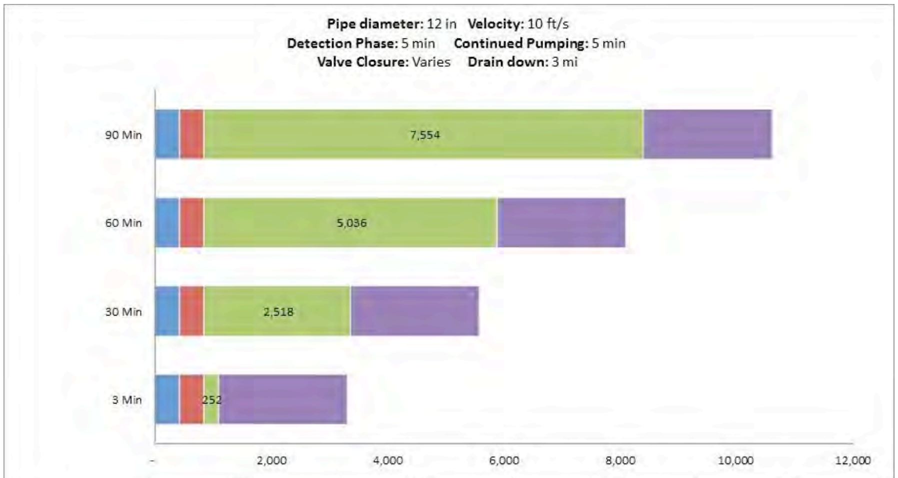


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

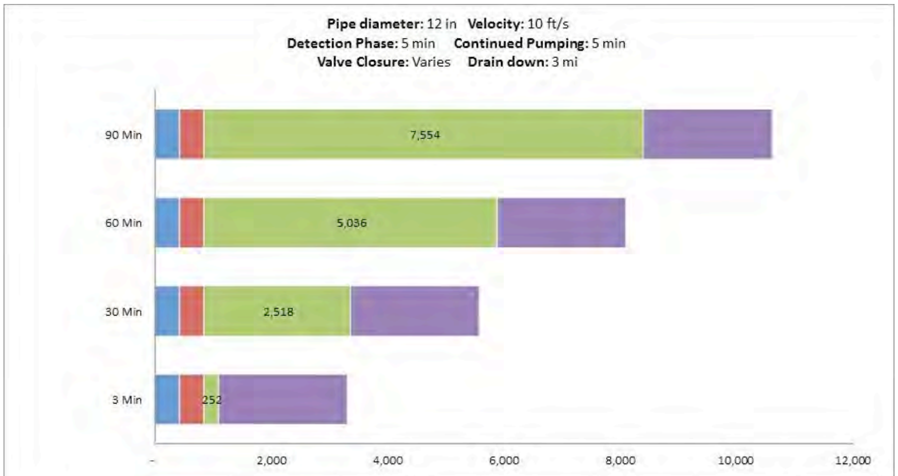
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-48. 12 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



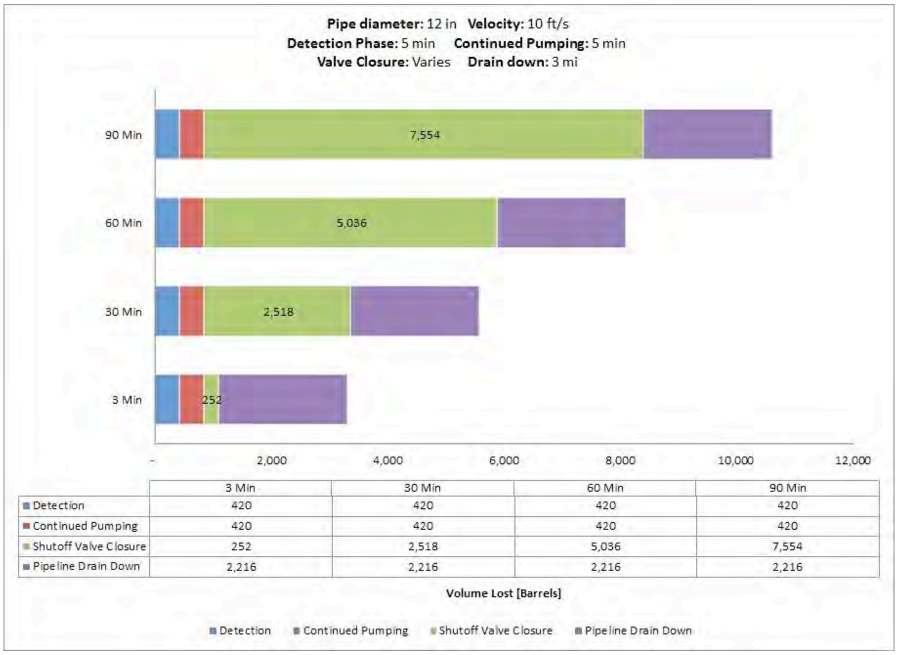
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-49. 12 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



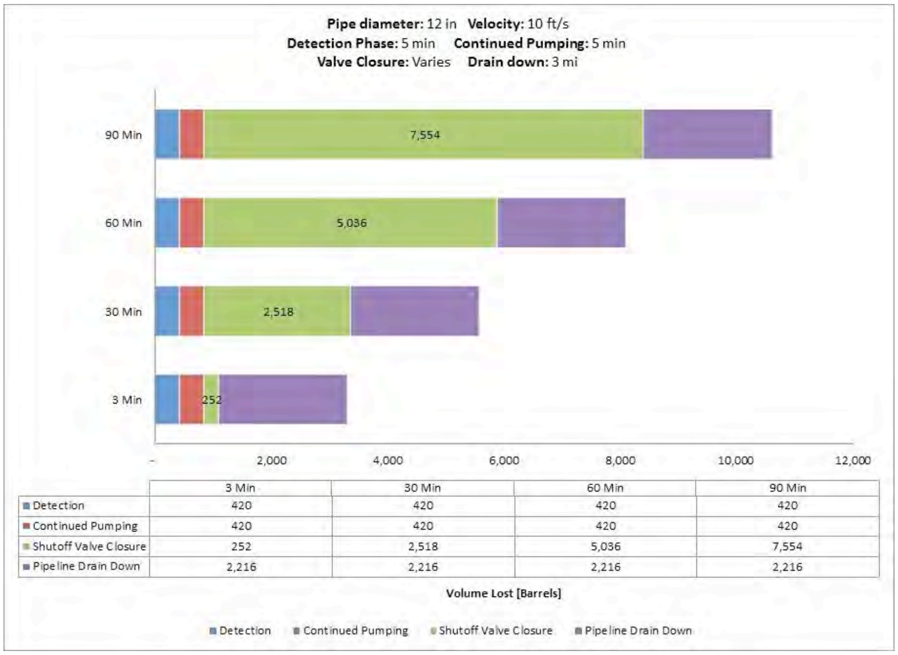
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-50. 12 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-51. 12 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-52. 12 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

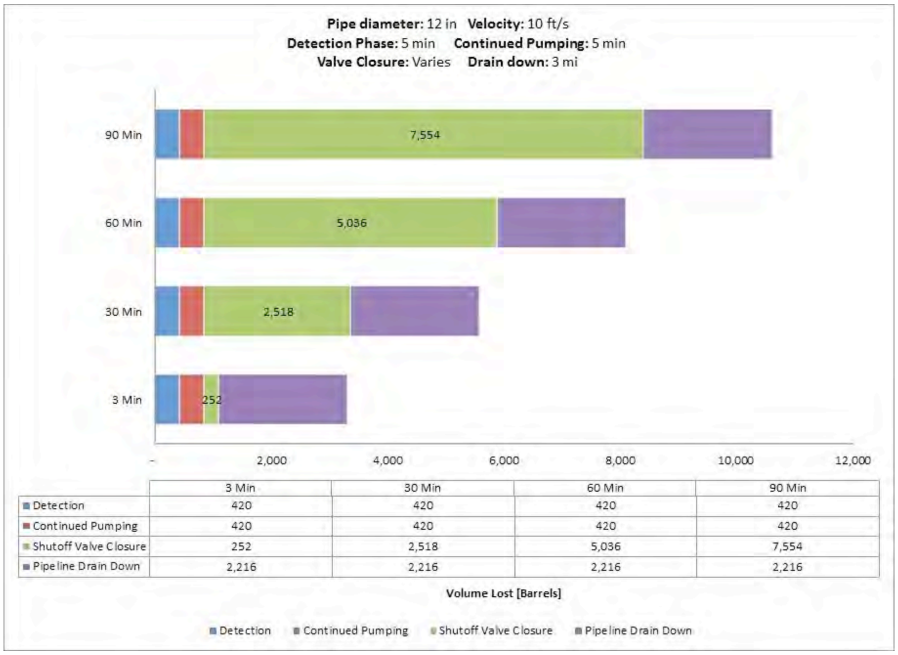


Fig. A-53. 12 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

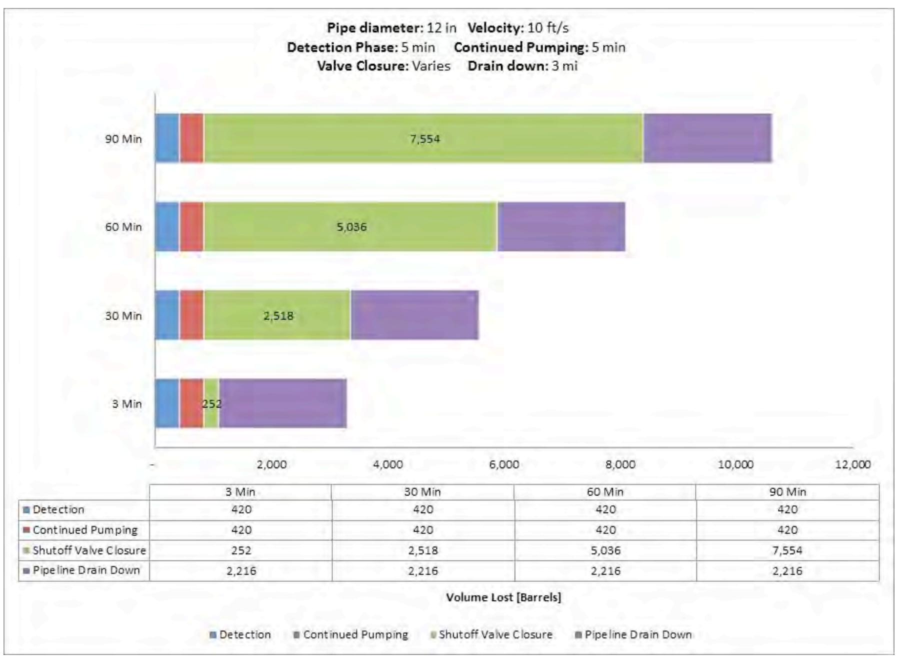
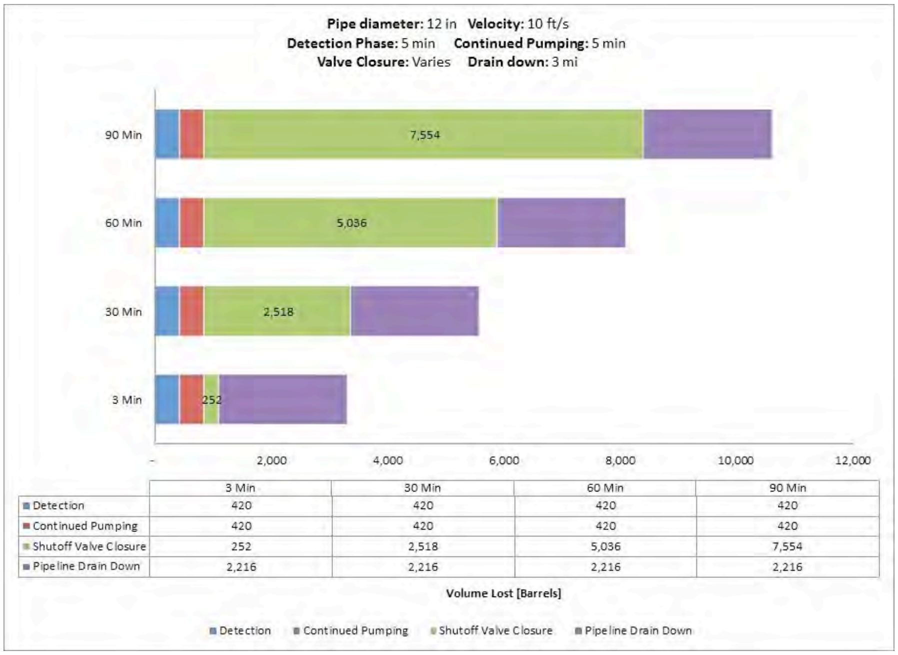
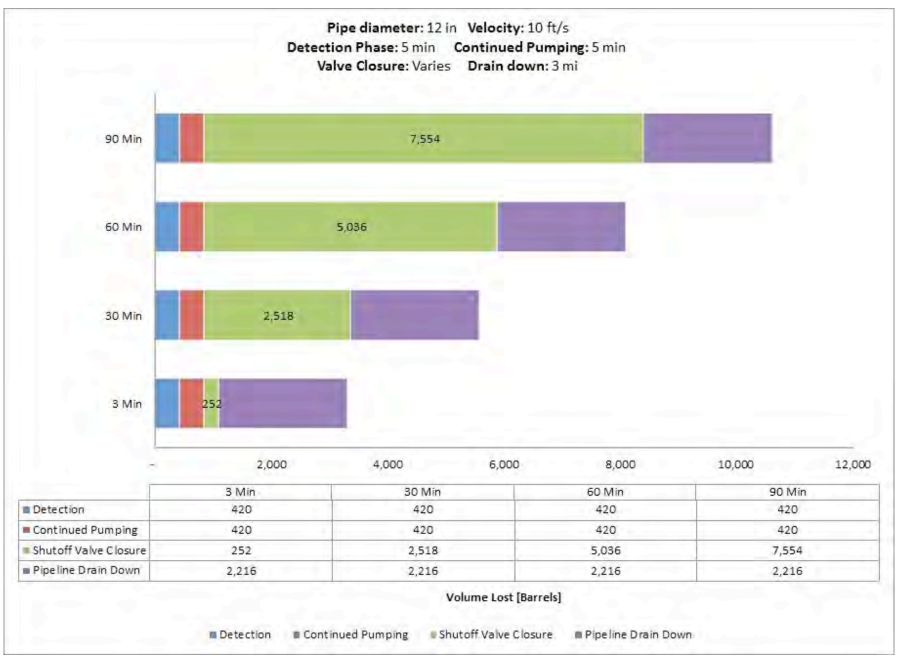


Fig. A-54. 12 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



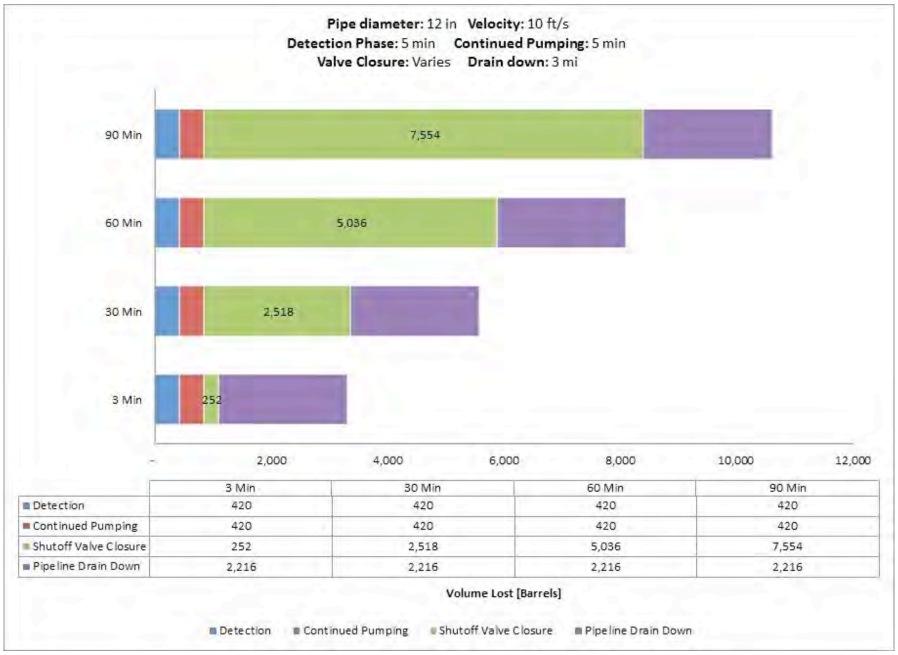
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-55. 12 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



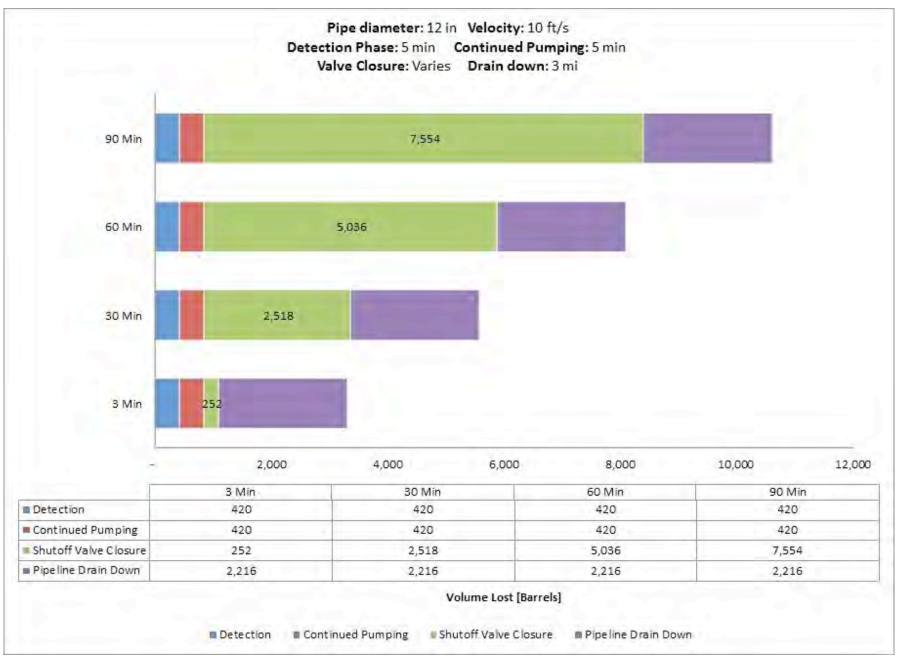
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-56. 12 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



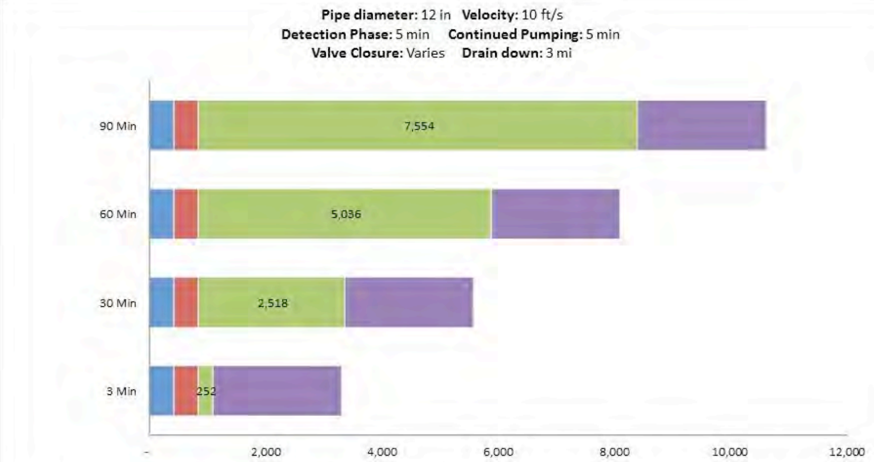
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-57. 12 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-58. 12 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

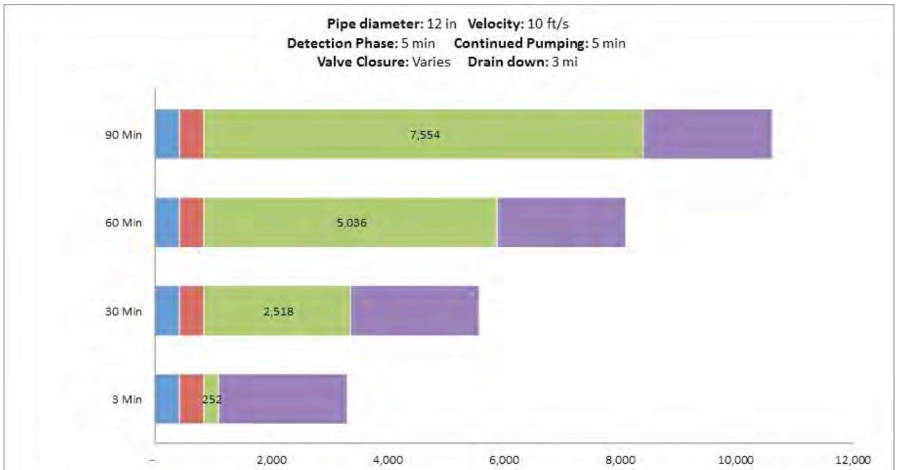


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-59. 12 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-60. 12 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

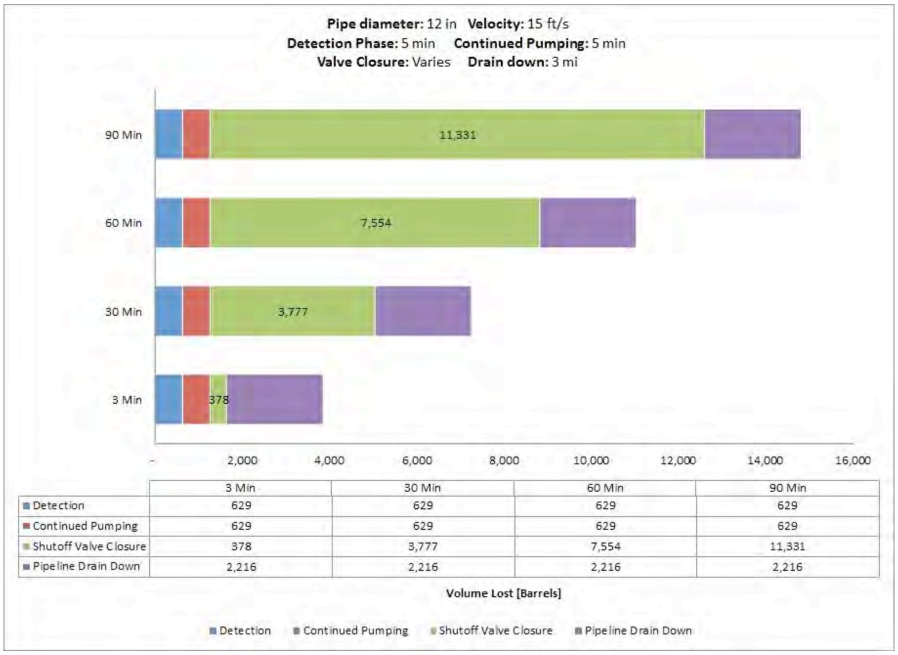


Fig. A-61. 12 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

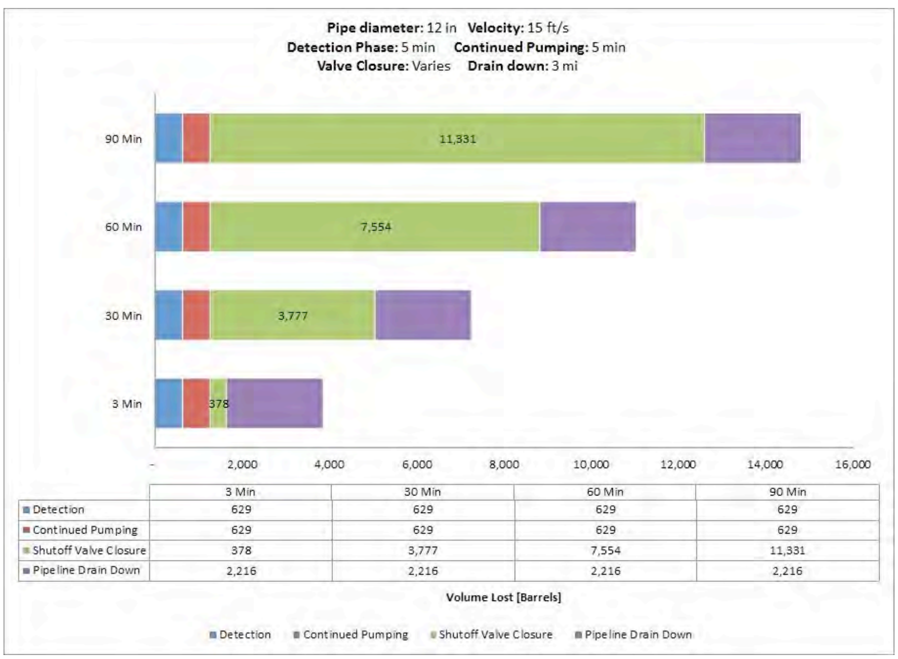
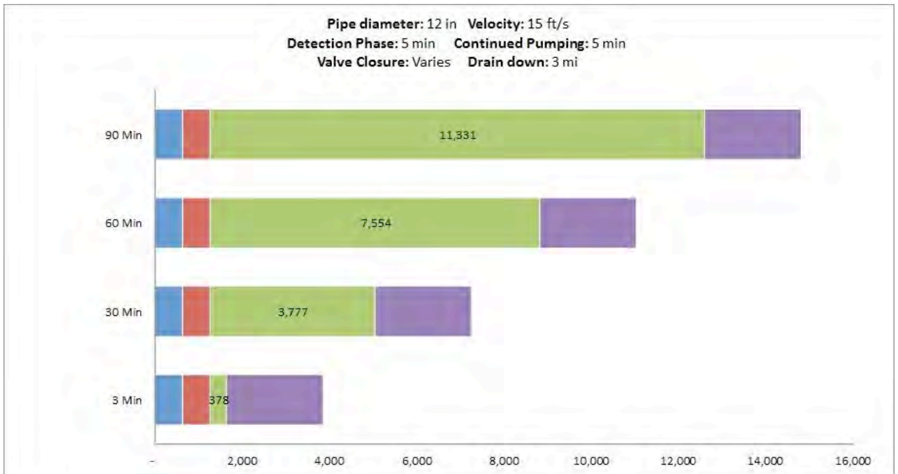


Fig. A-62. 12 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

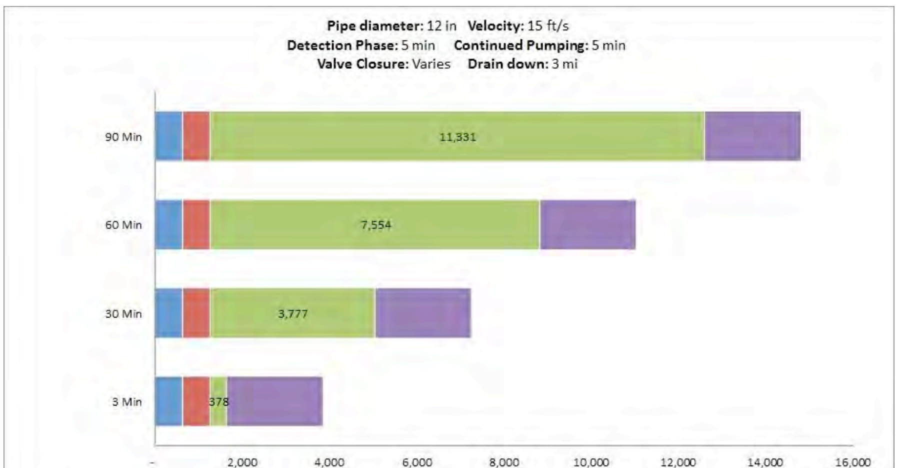


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-63. 12 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

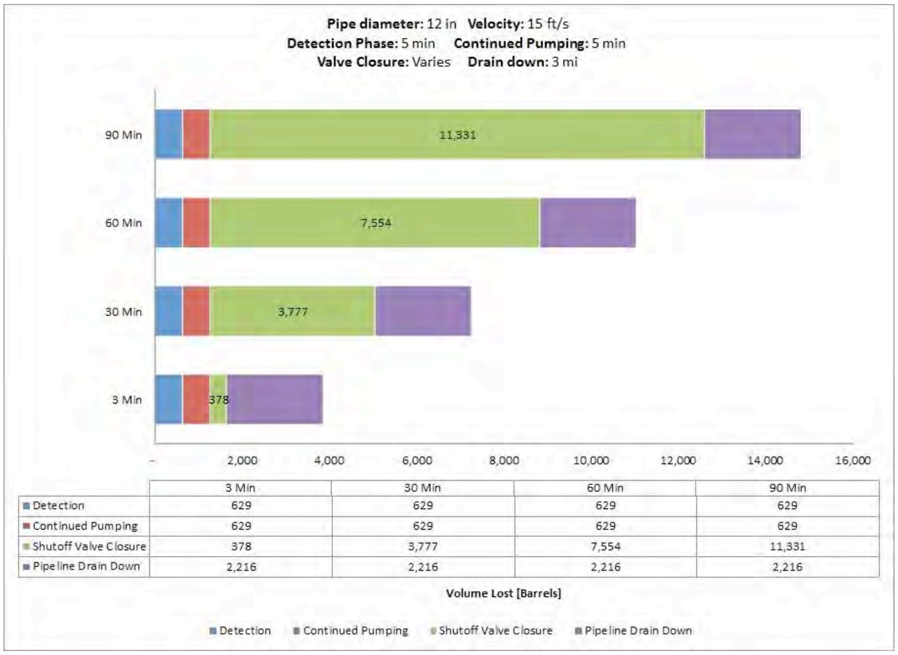


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

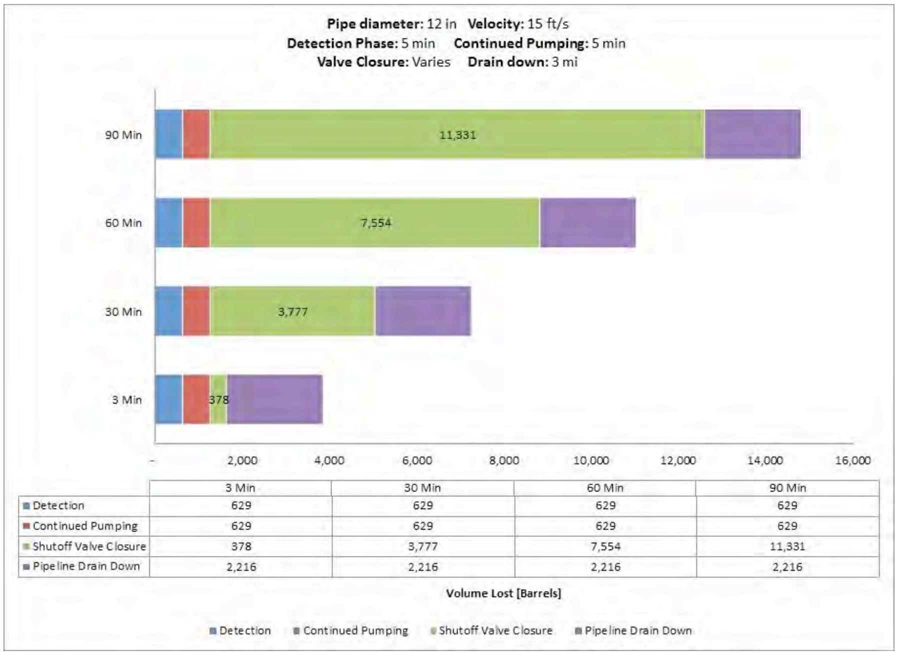
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-64. 12 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-65. 12 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-66. 12 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

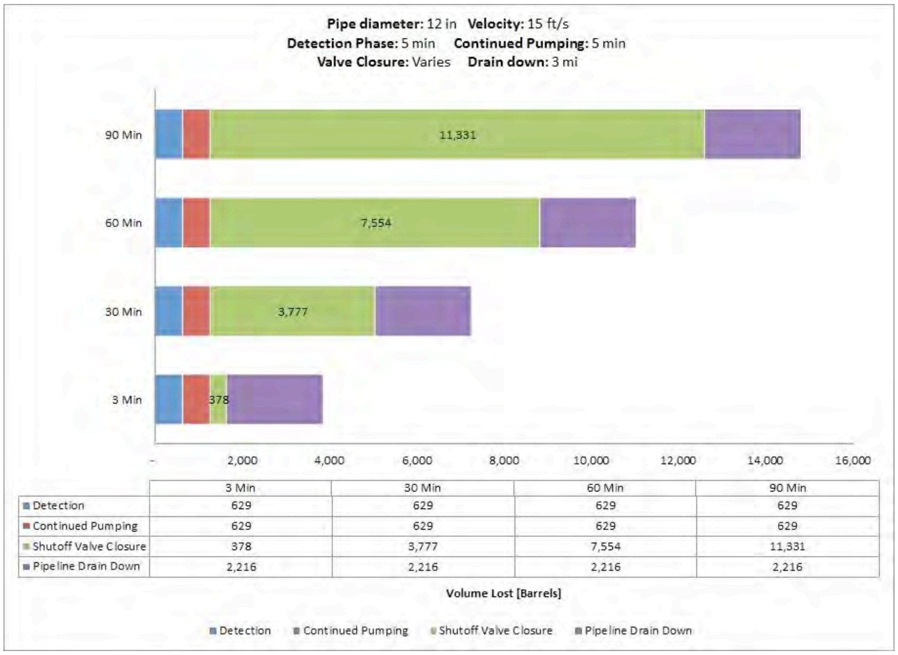


Fig. A-67. 12 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

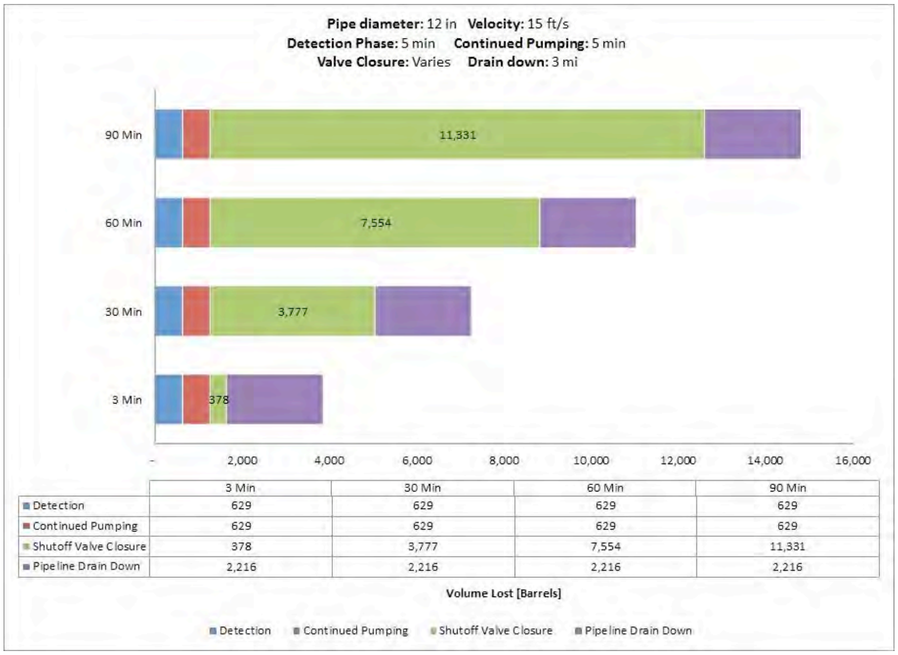
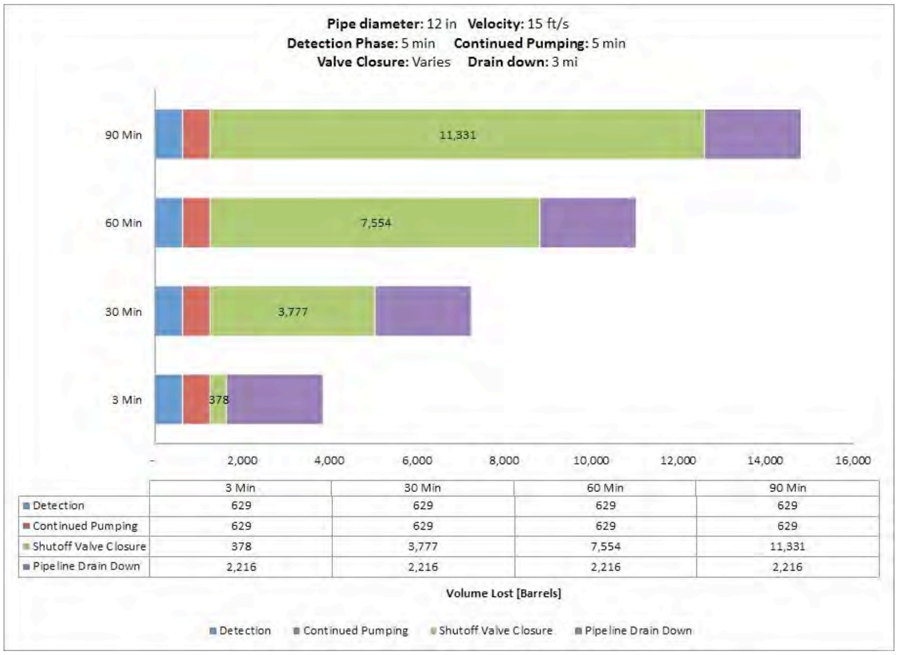


Fig. A-68. 12 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

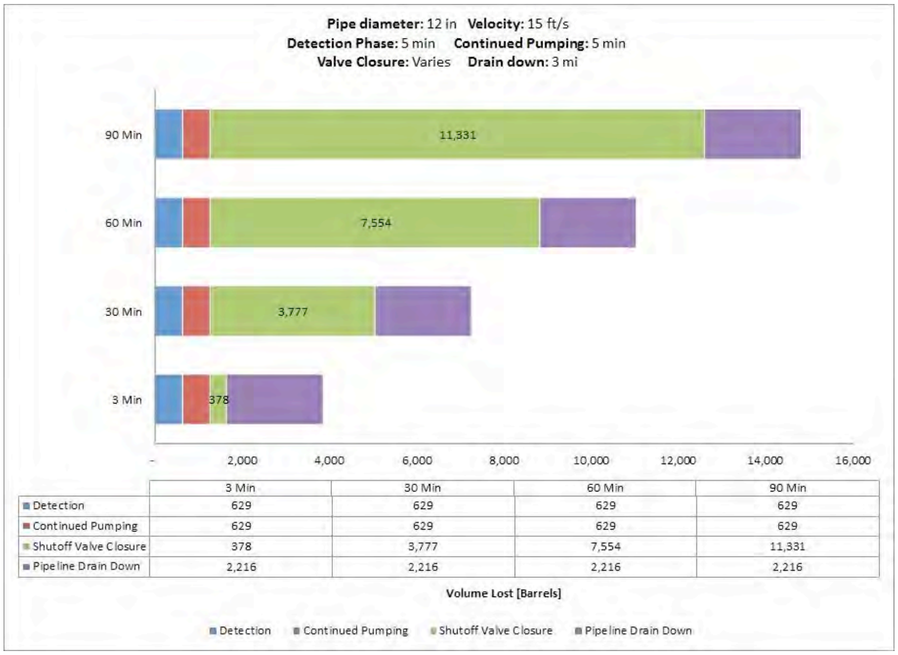


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-69. 12 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

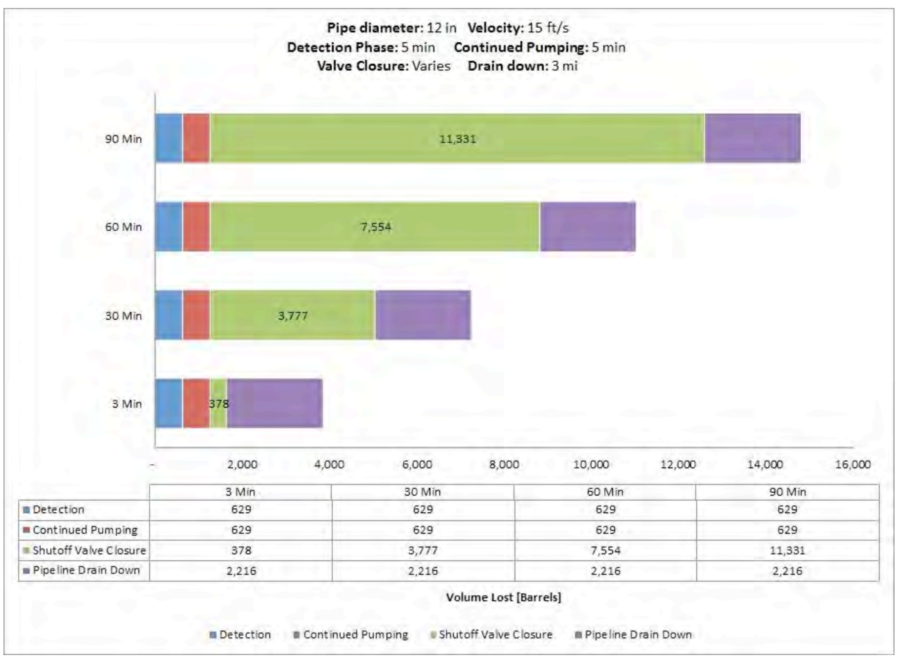
	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-70. 12 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-71. 12 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Fig. A-72. 12 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

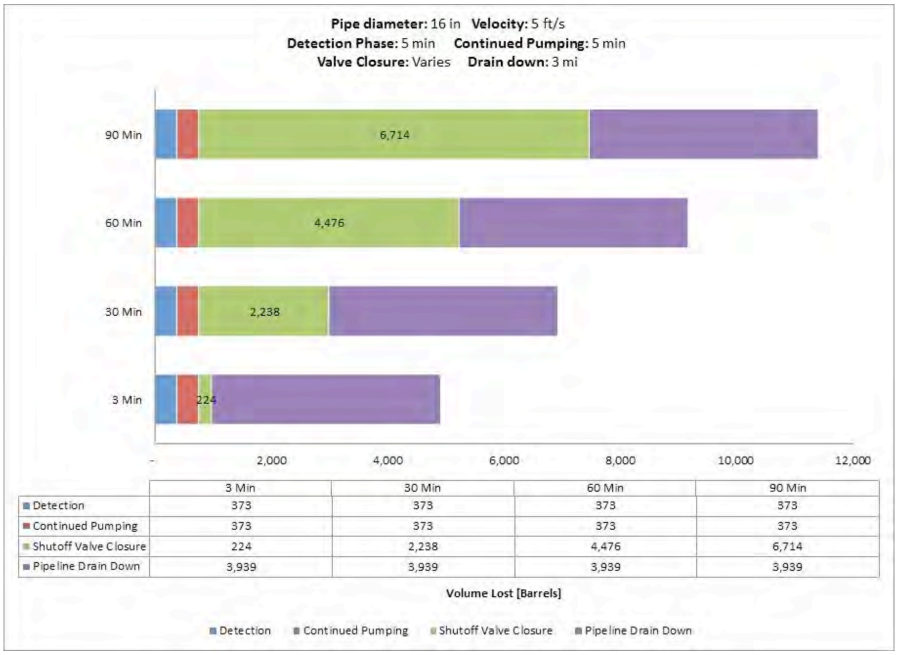


Fig. A-73. 16 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

Fig. A-74. 16 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

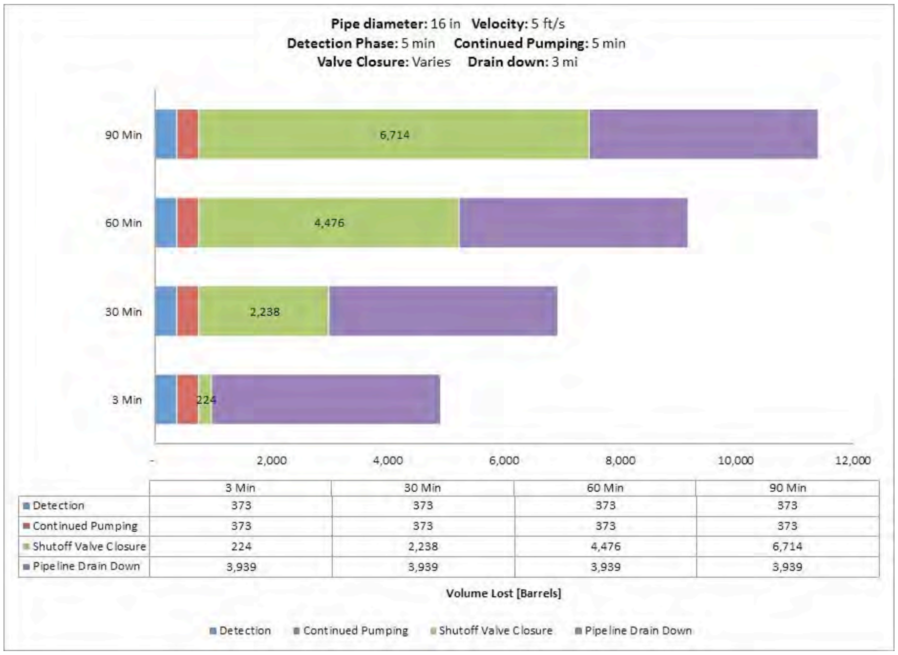
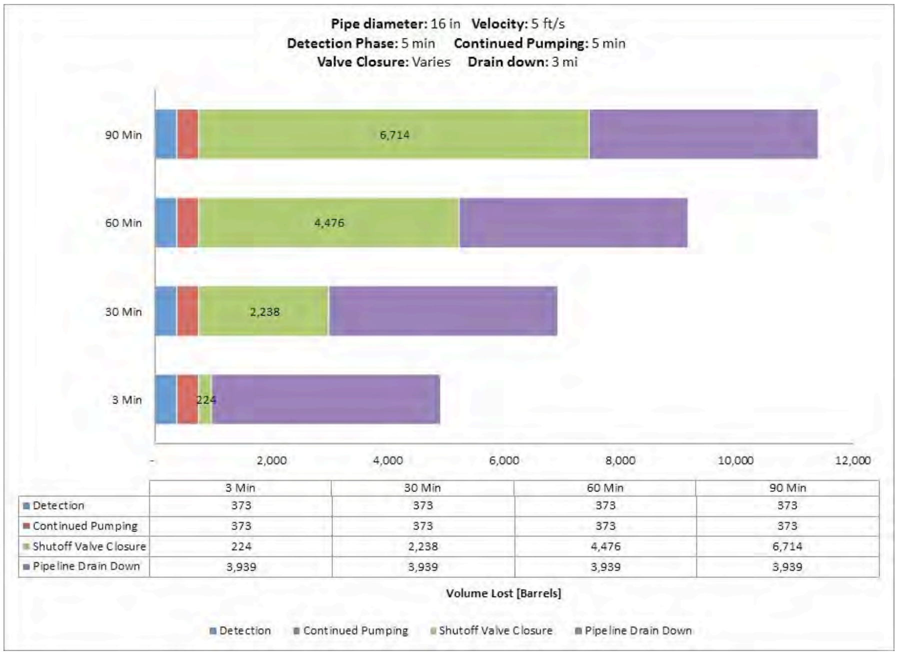


Fig. A-75. 16 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

Fig. A-76. 16 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

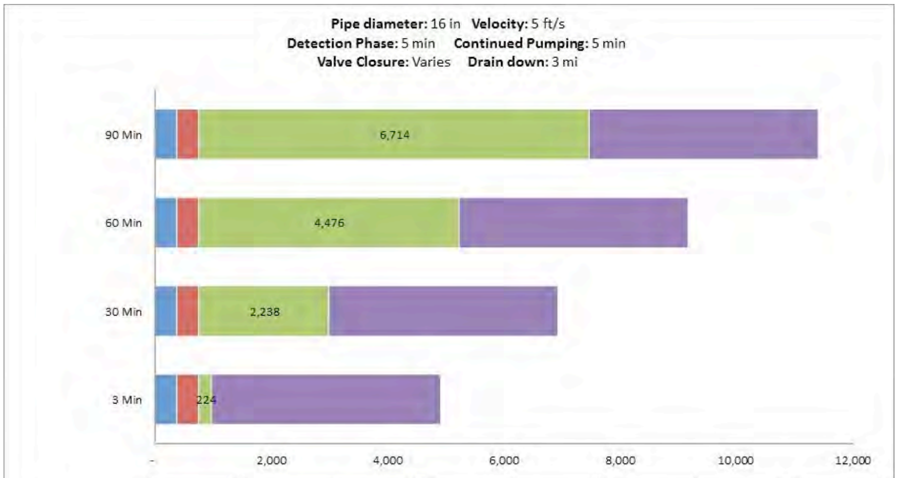


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-77. 16 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

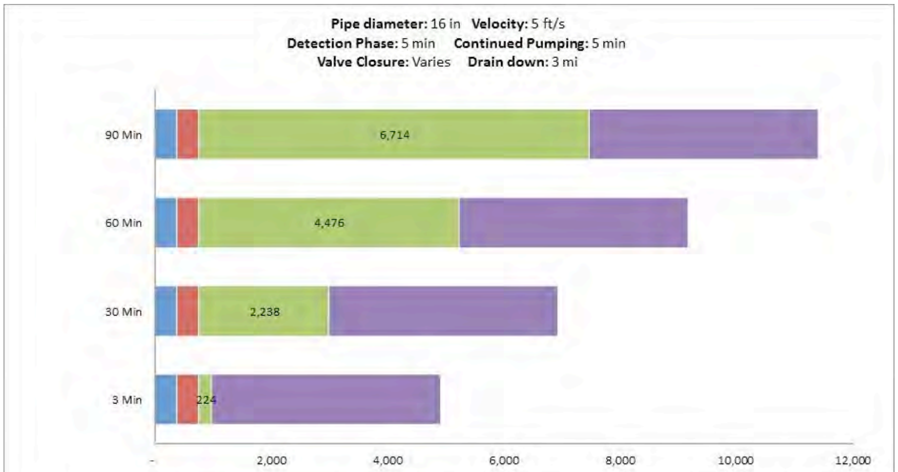
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-78. 16 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



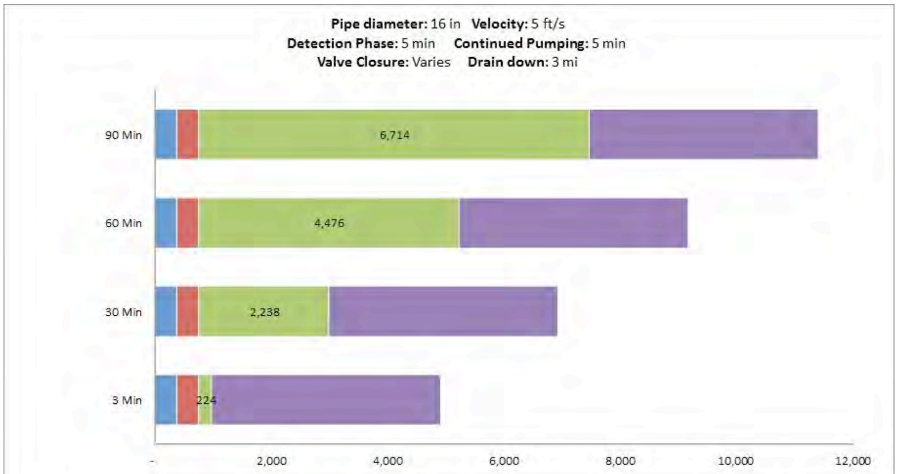
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-79. 16 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-80. 16 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

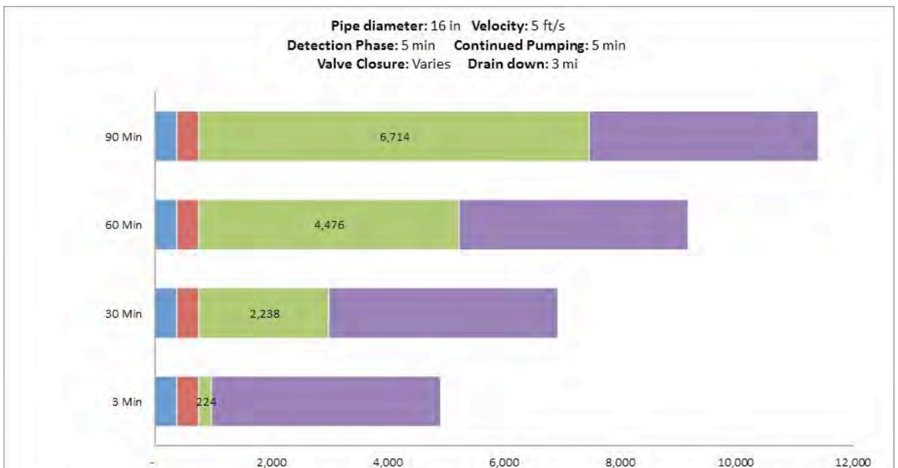


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-81. 16 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

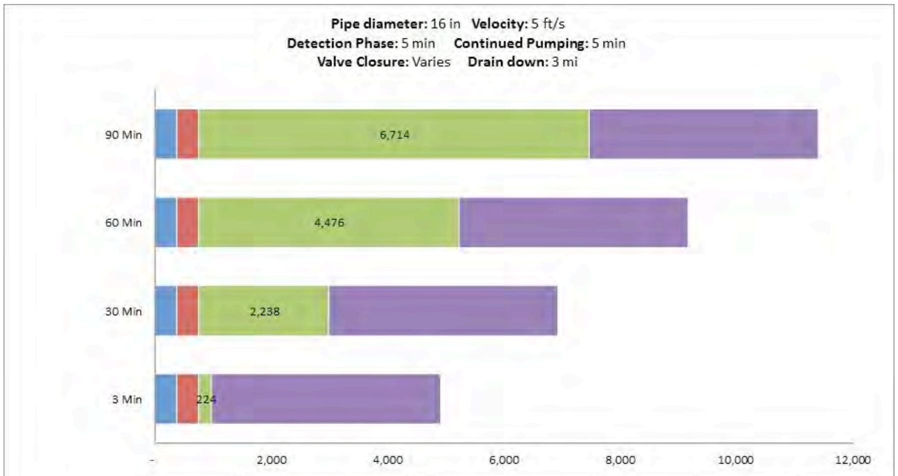


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-82. 16 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

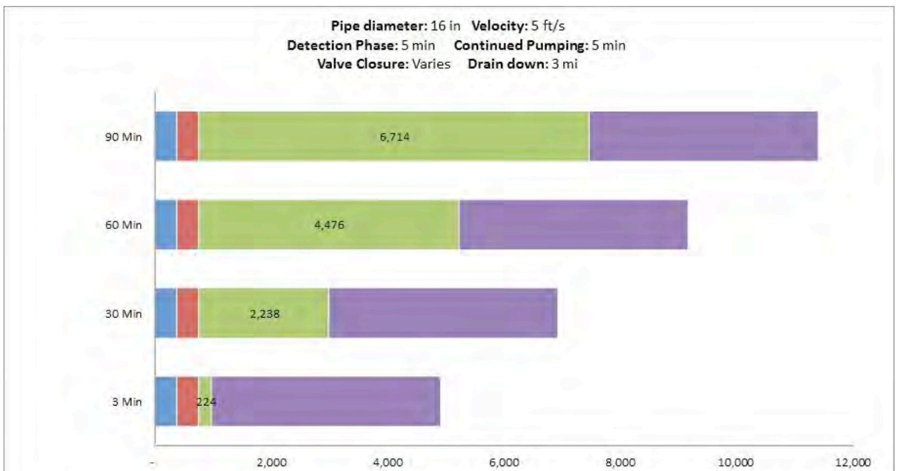


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-83. 16 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

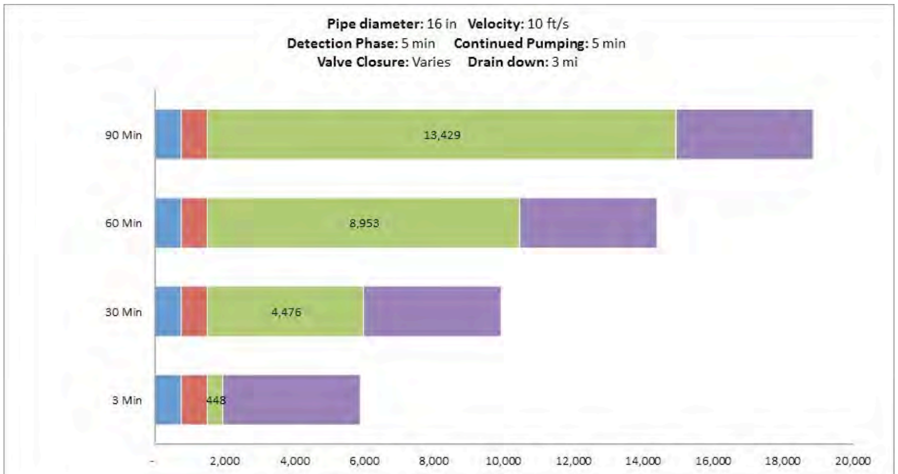


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-84. 16 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

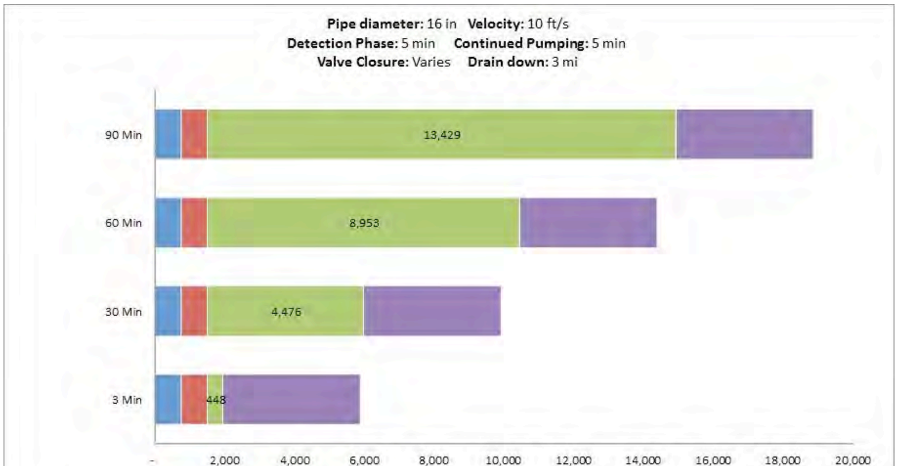


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-85. 16 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

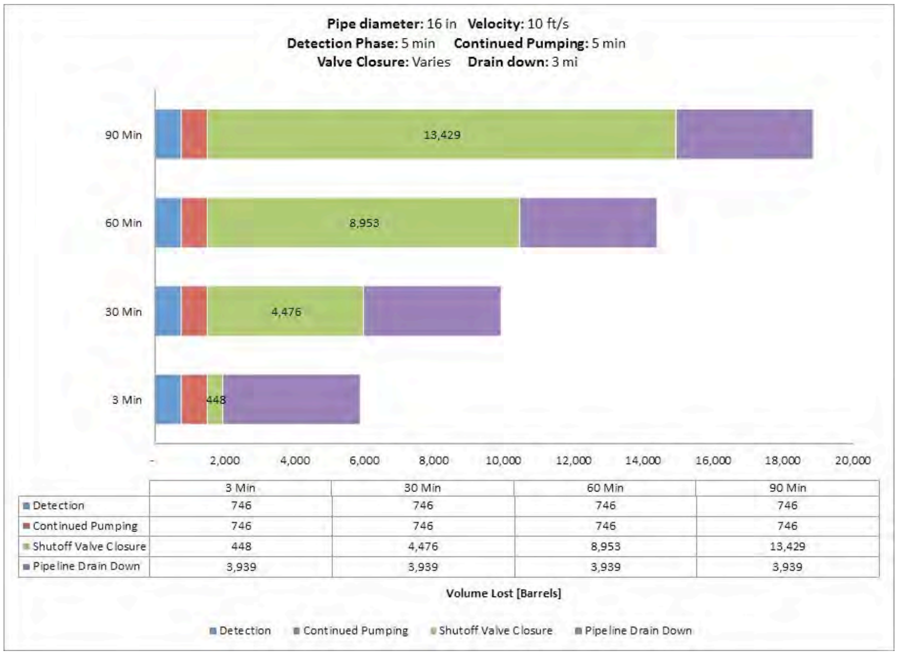


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

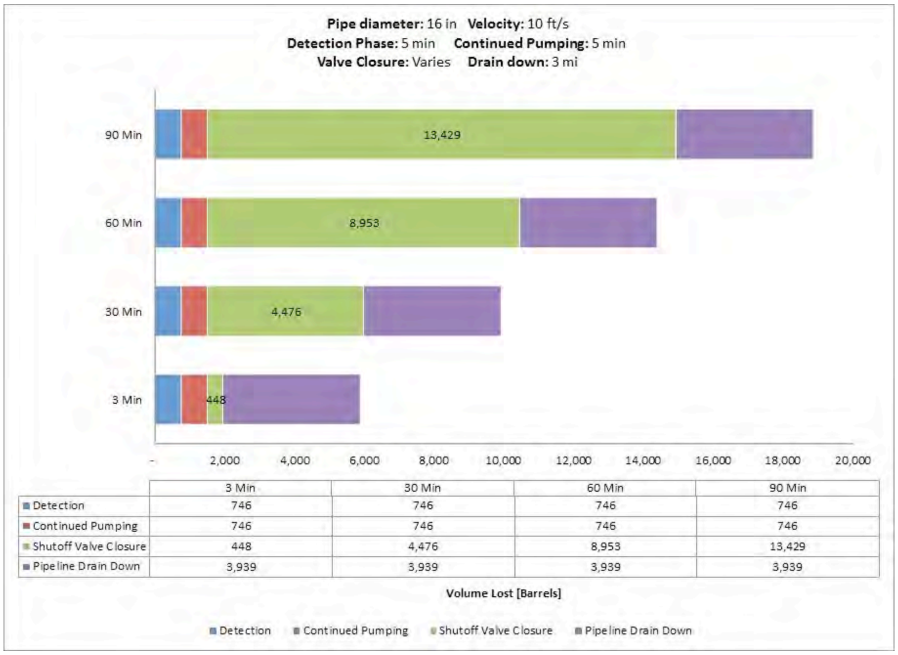
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-86. 16 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



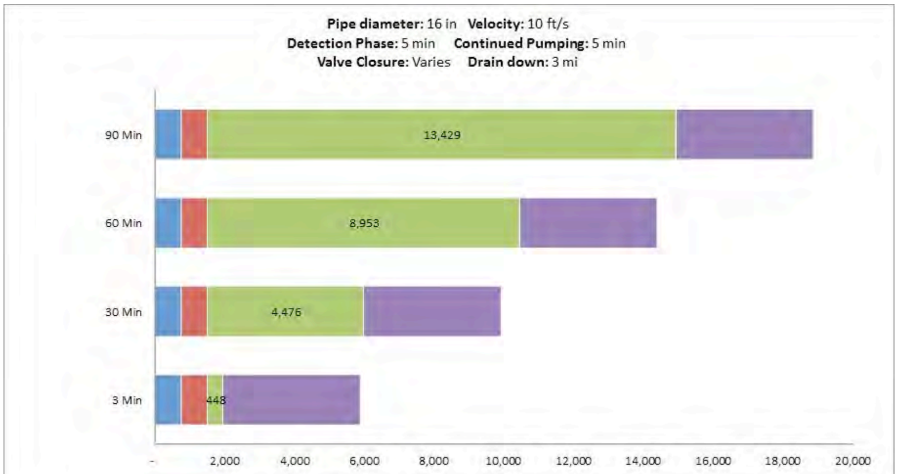
	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-87. 16 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-88. 16 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

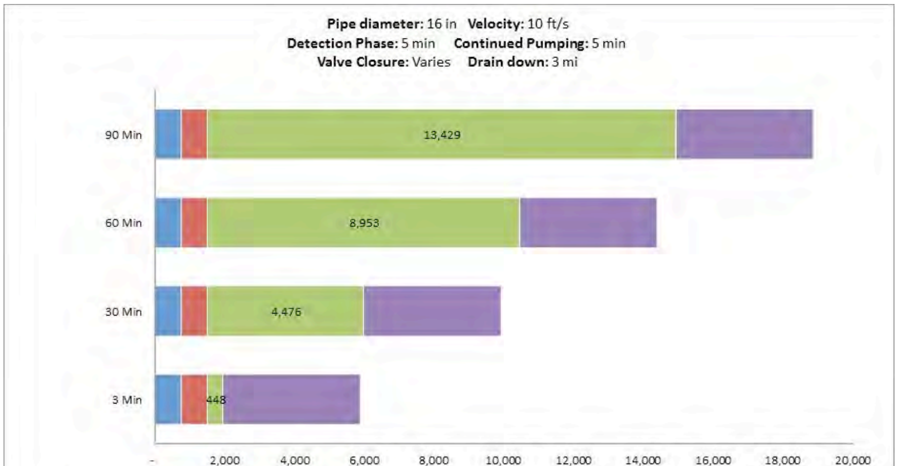


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-89. 16 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

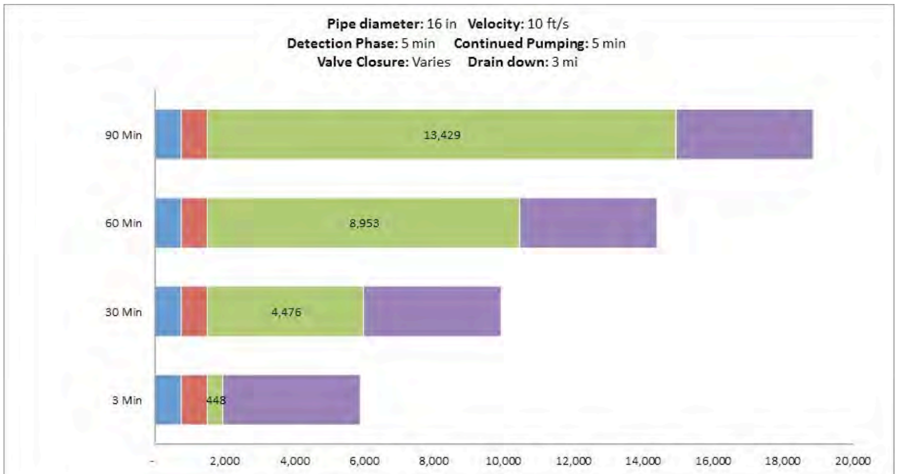


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-90. 16 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

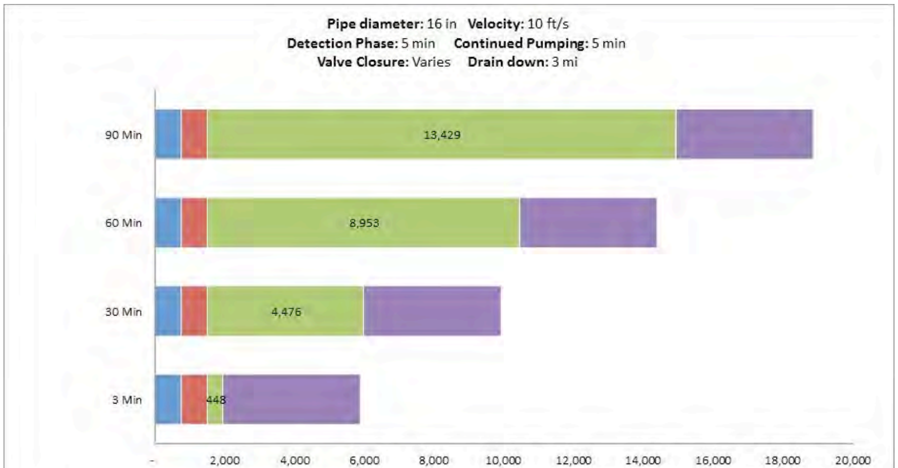


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-91. 16 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-92. 16 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

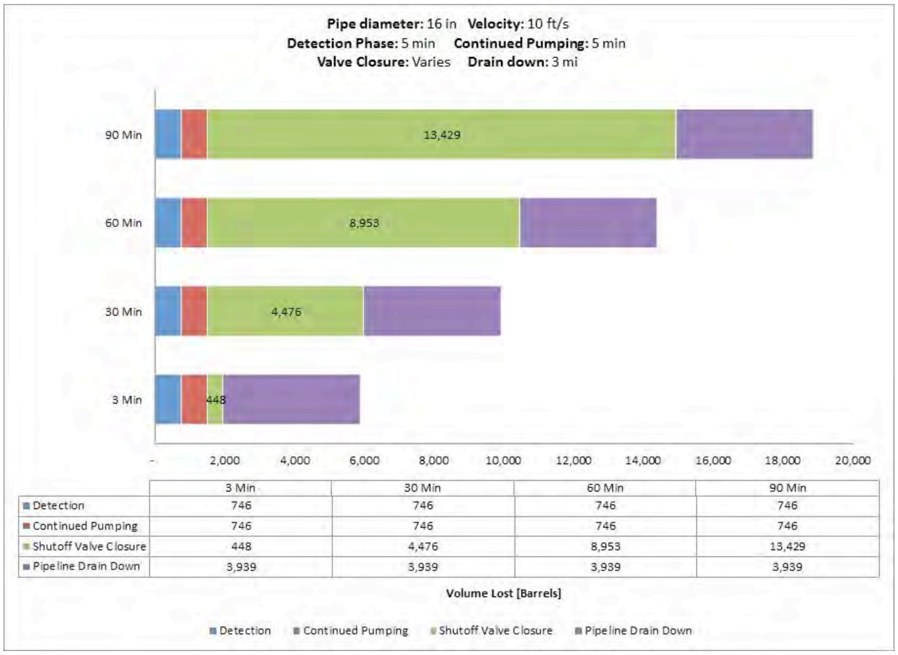


Fig. A-93. 16 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

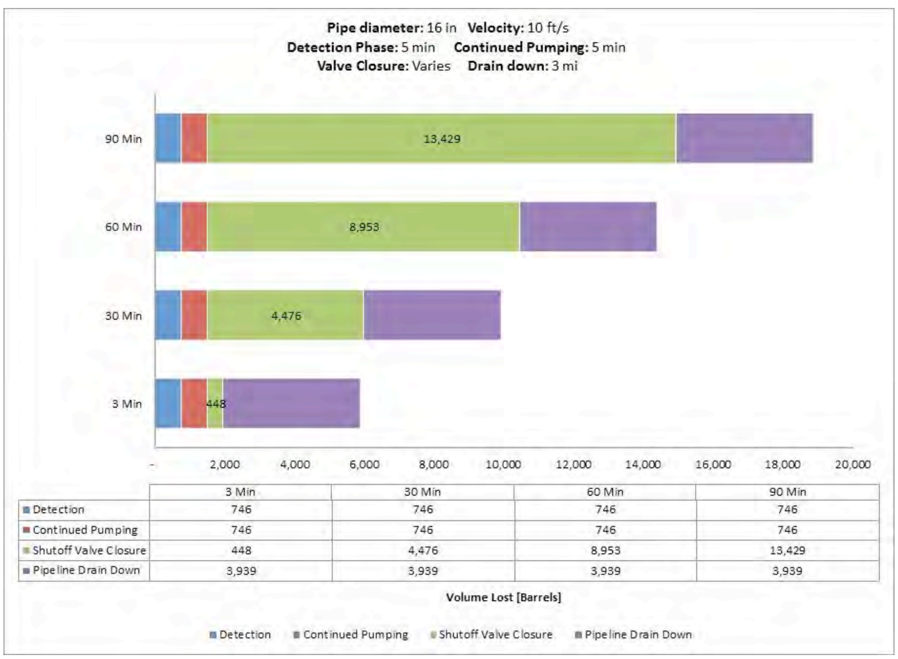
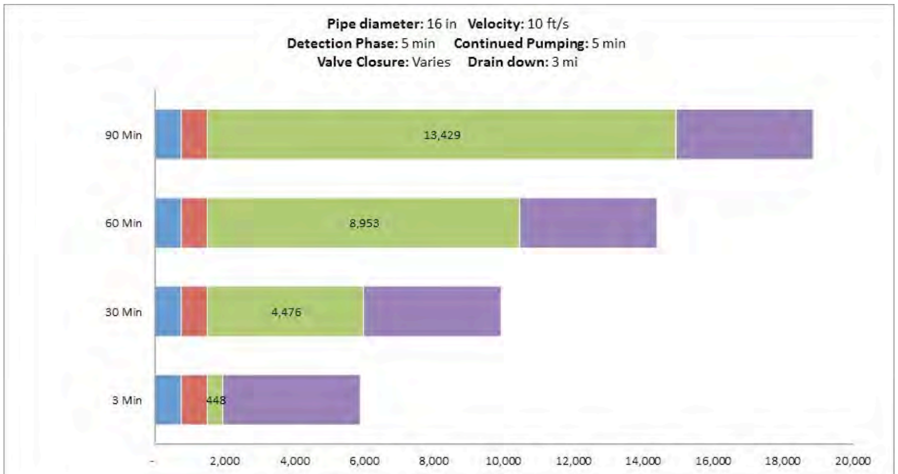


Fig. A-94. 16 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

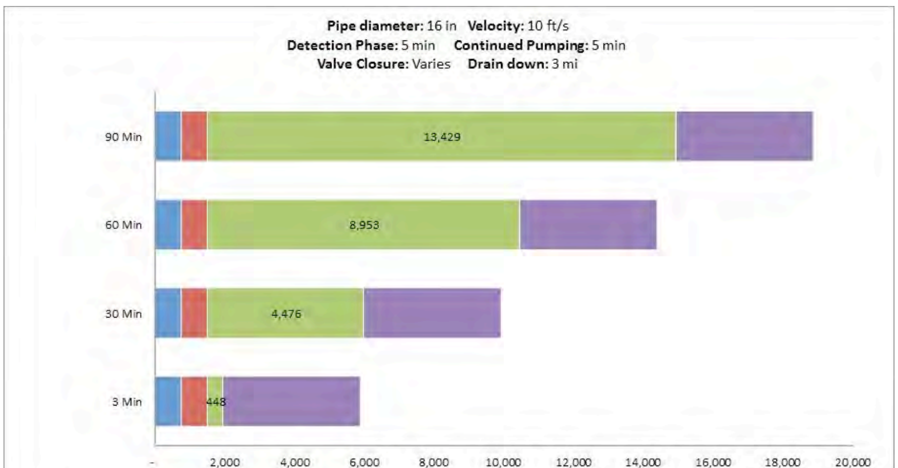


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-95. 16 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

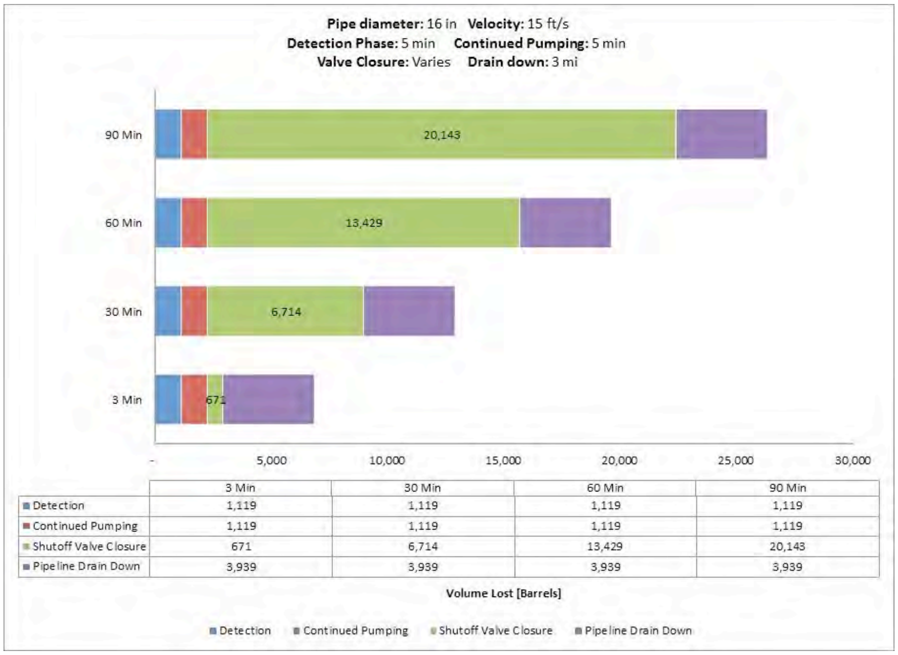


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

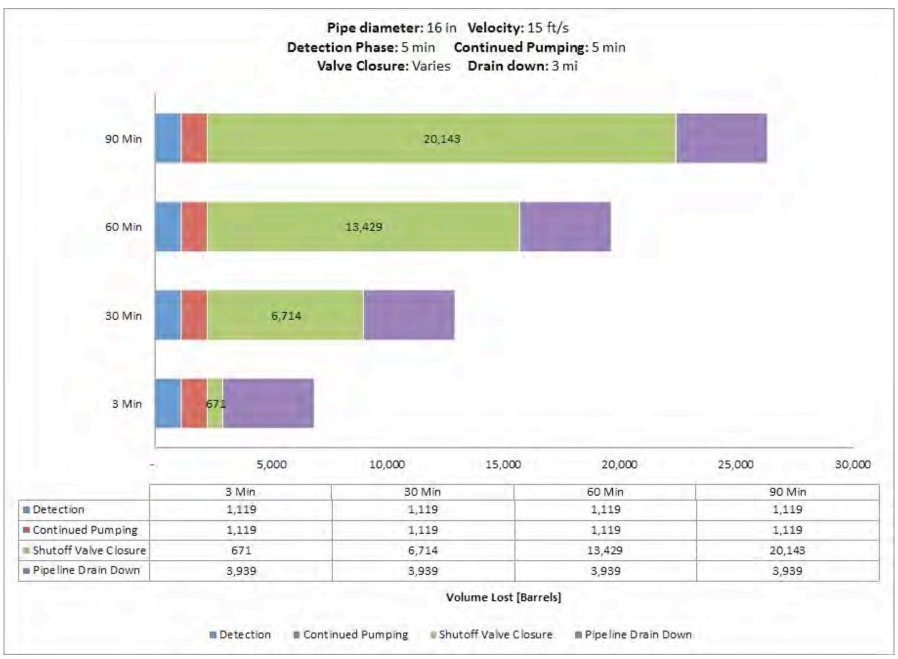
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-96. 16 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



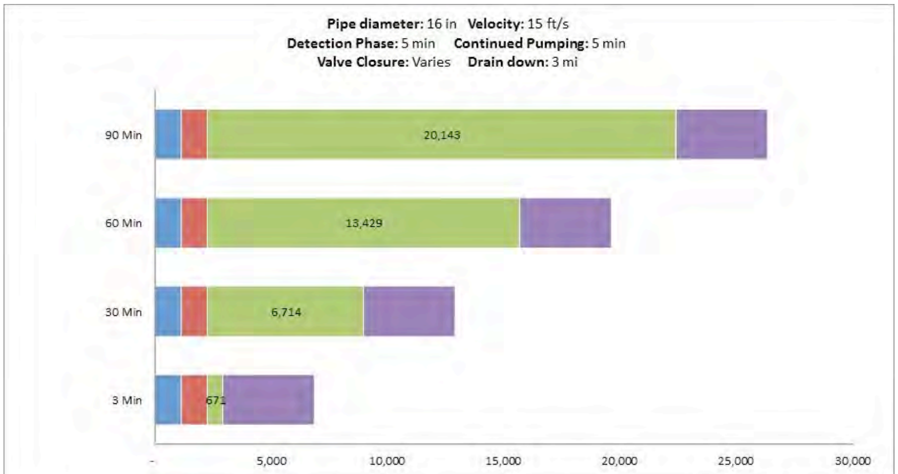
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-97. 16 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-98. 16 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

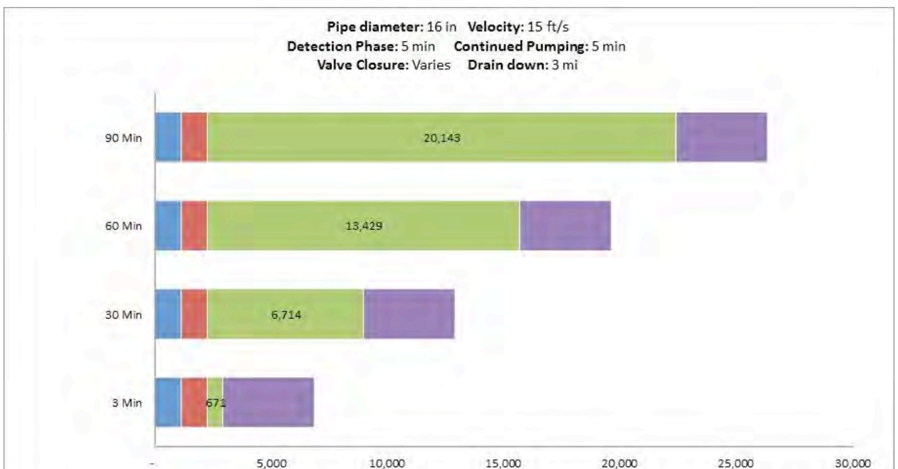


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-99. 16 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

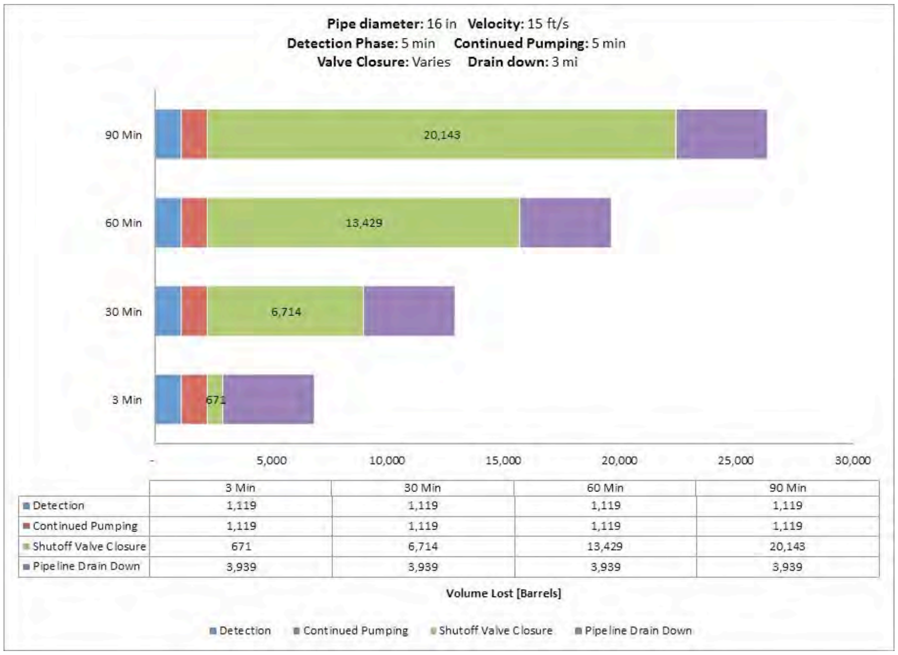


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

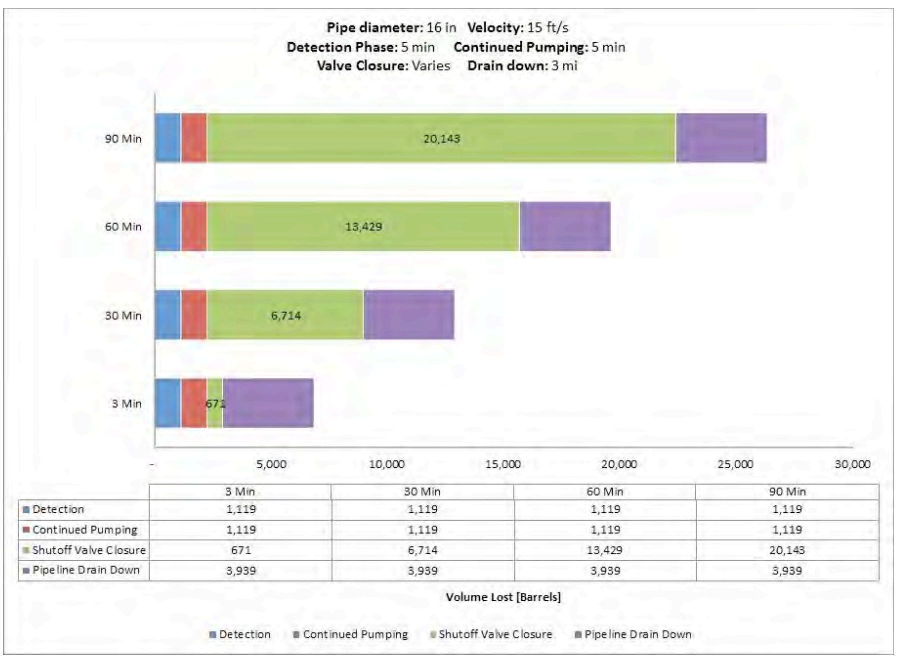
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-100. 16 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



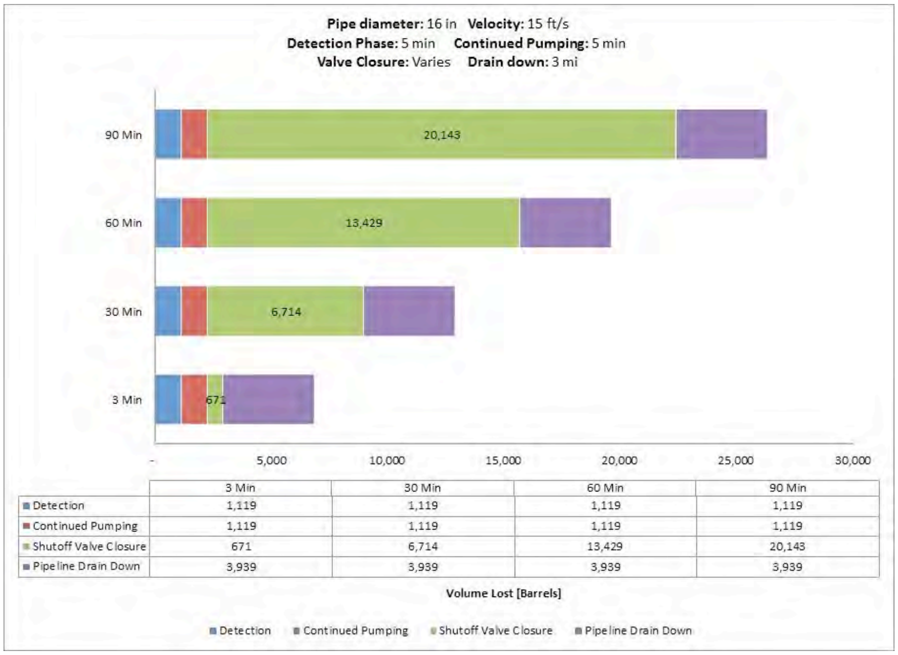
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-101. 16 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



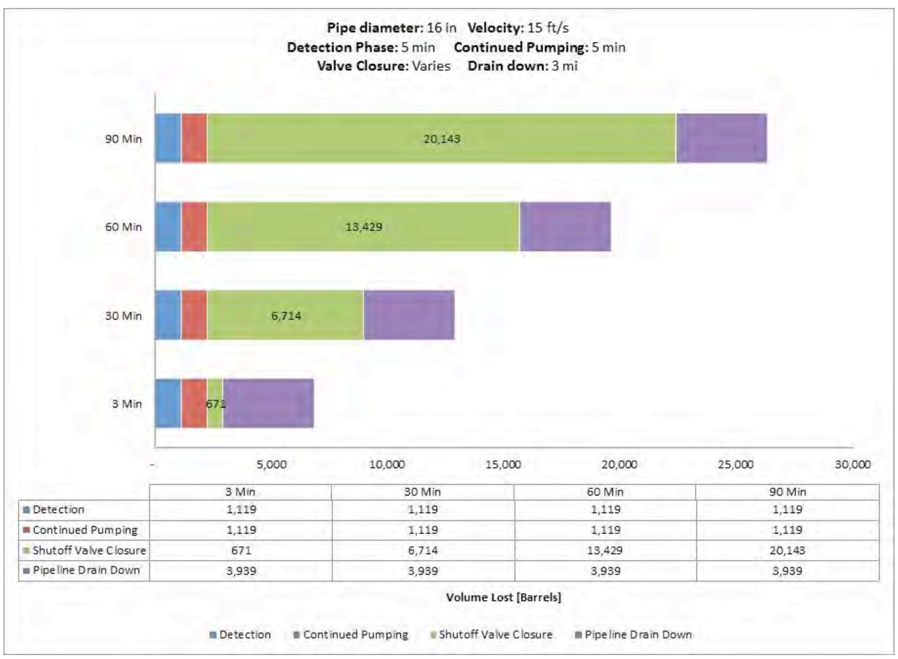
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-102. 16 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



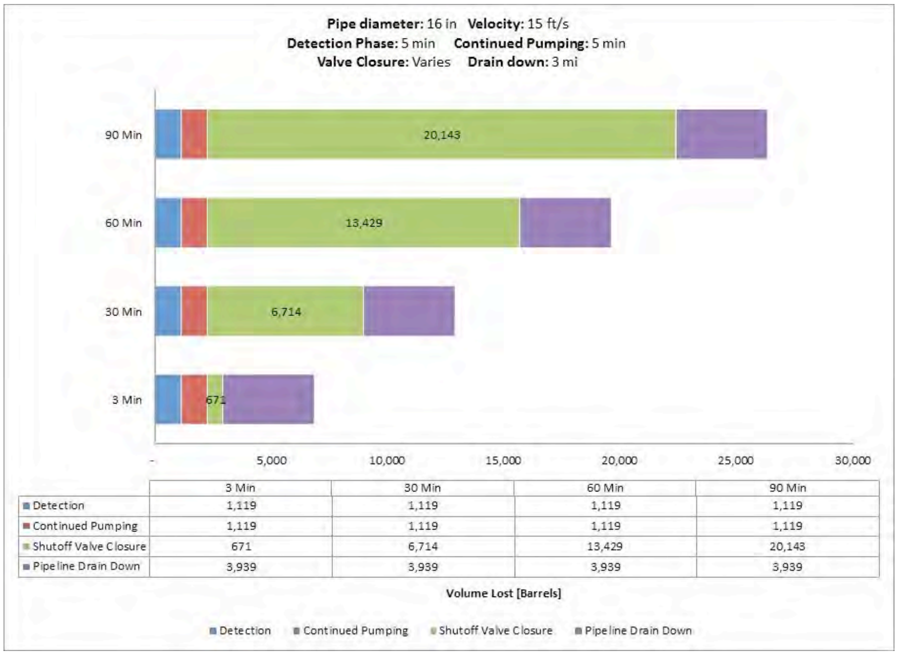
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-103. 16 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



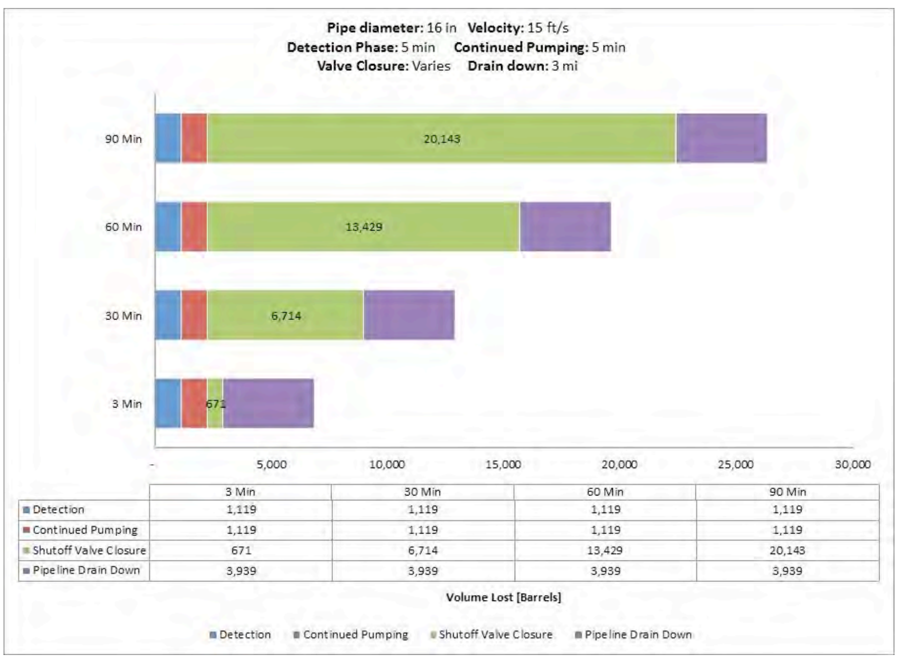
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-104. 16 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



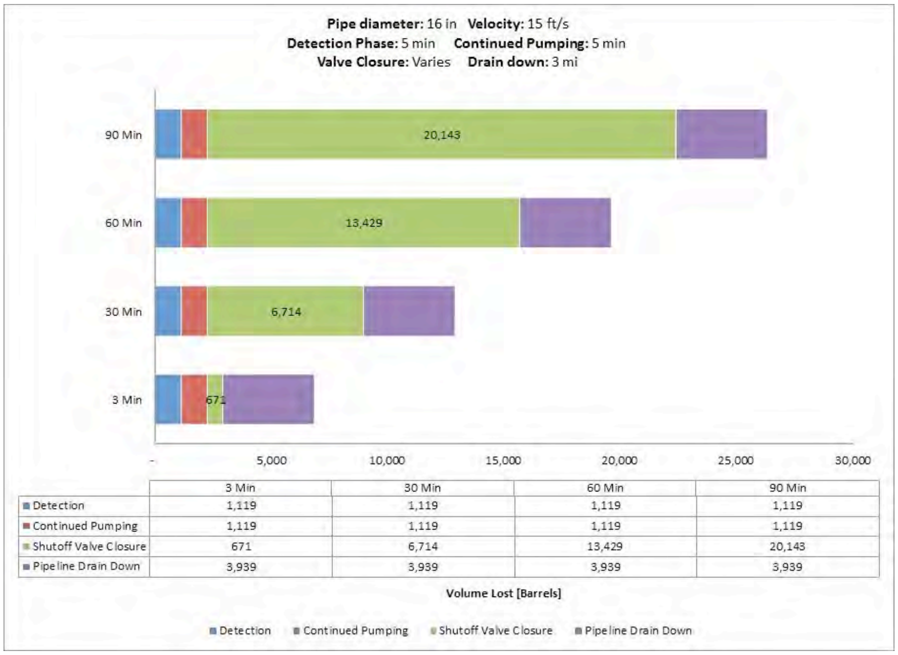
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-105. 16 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



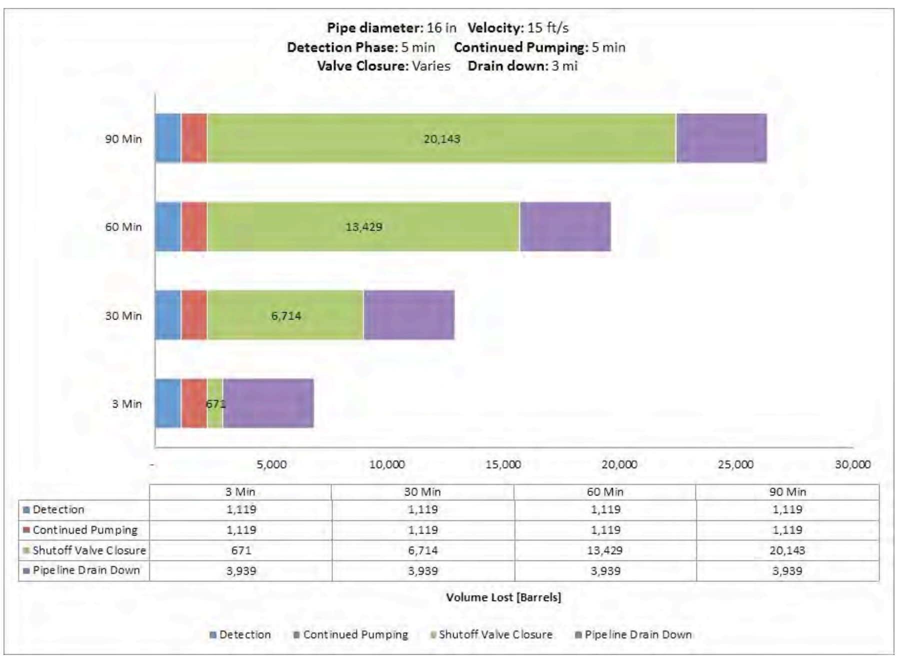
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-106. 16 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



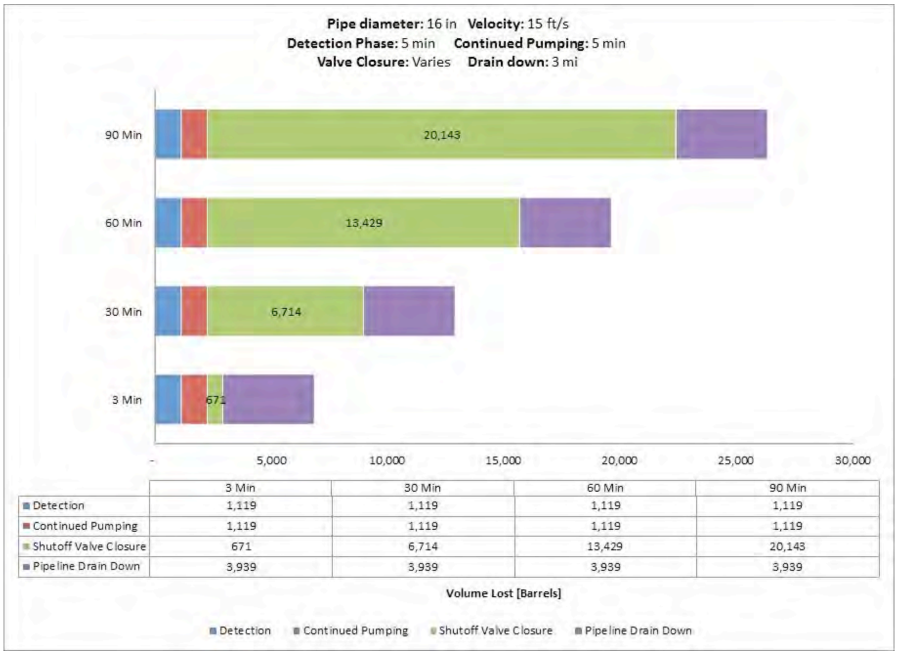
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-107. 16 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



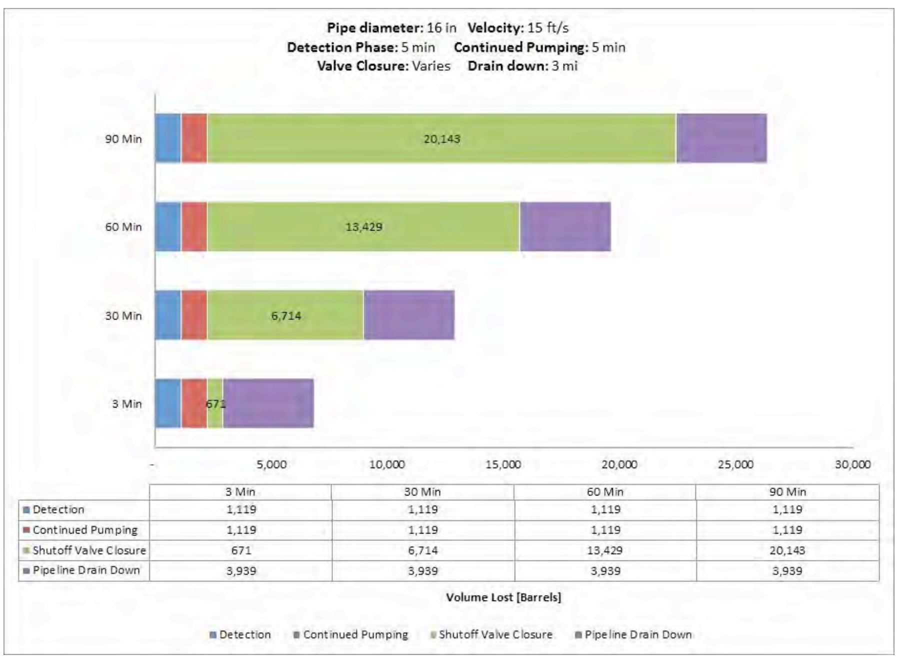
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-108. 16 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



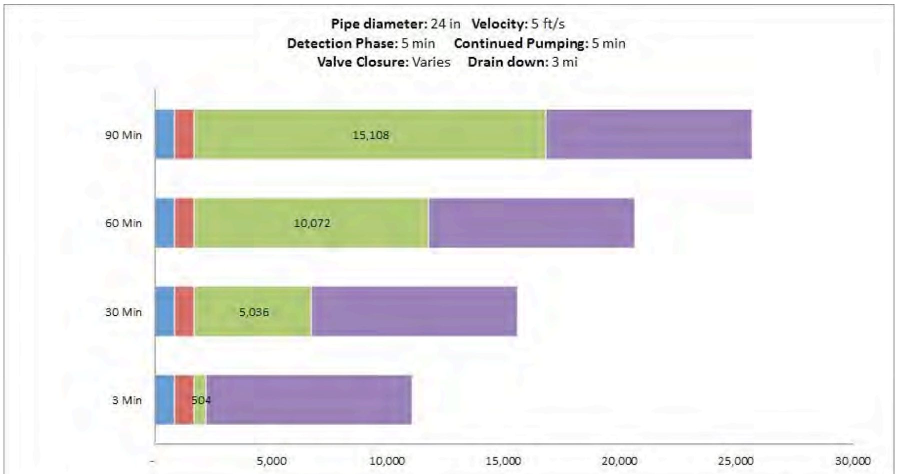
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-109. 24 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-110. 24 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

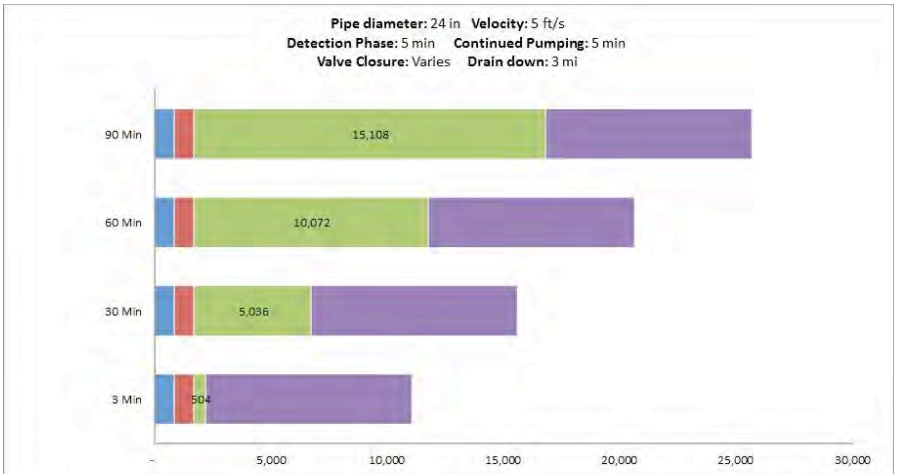


	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-111. 24 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

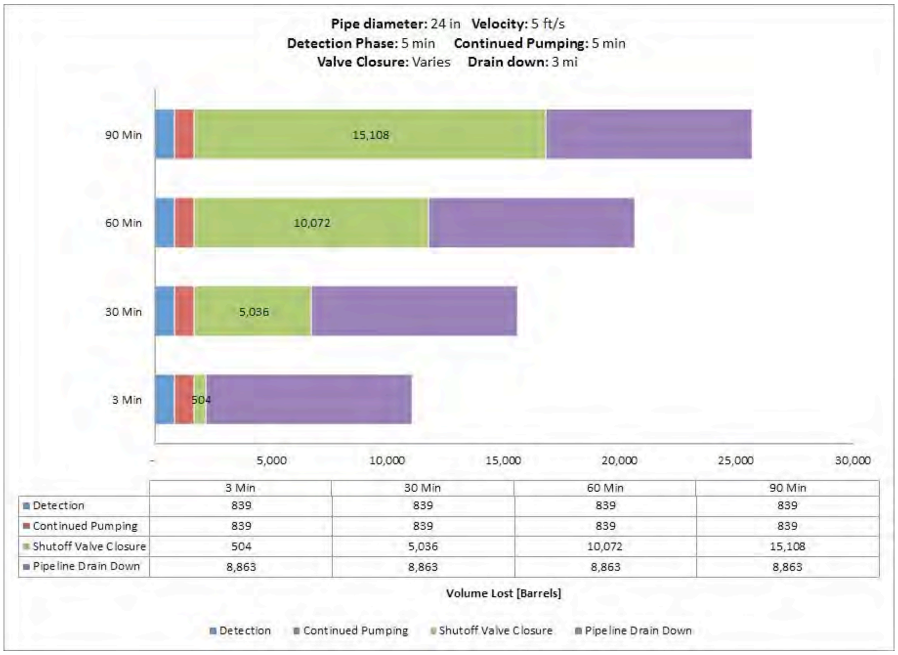


	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

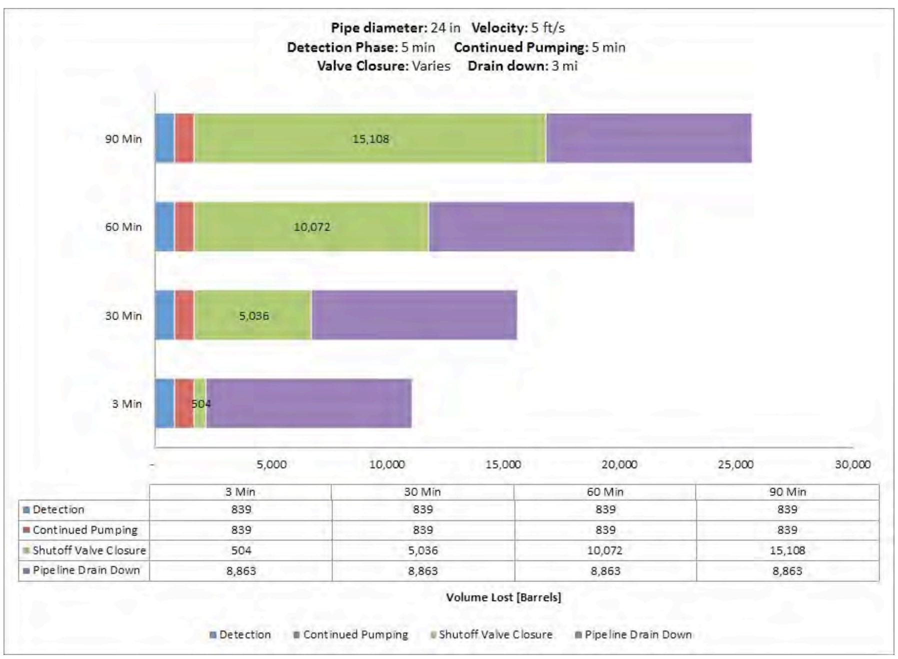
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-112. 24 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



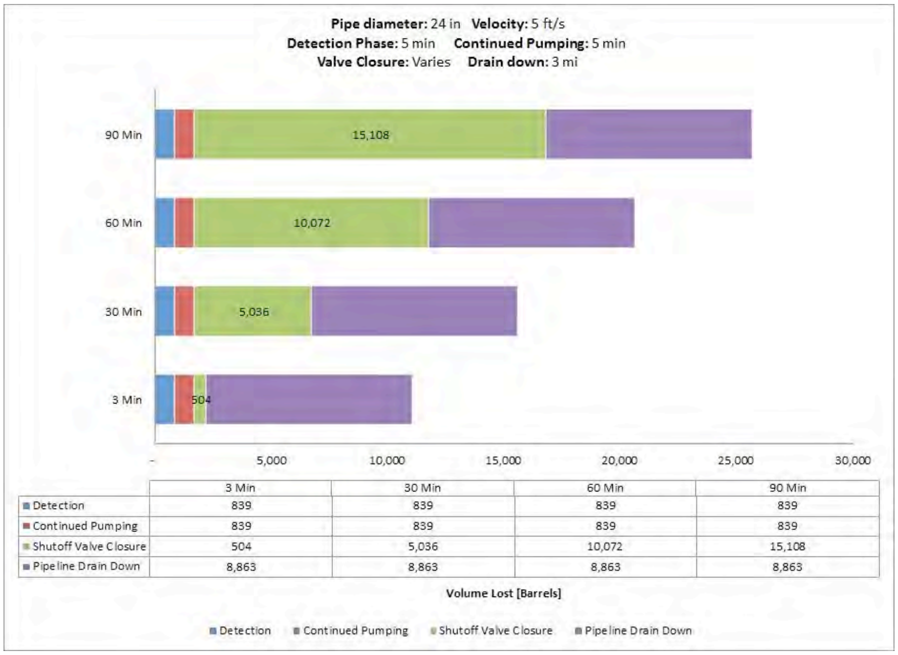
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-113. 24 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



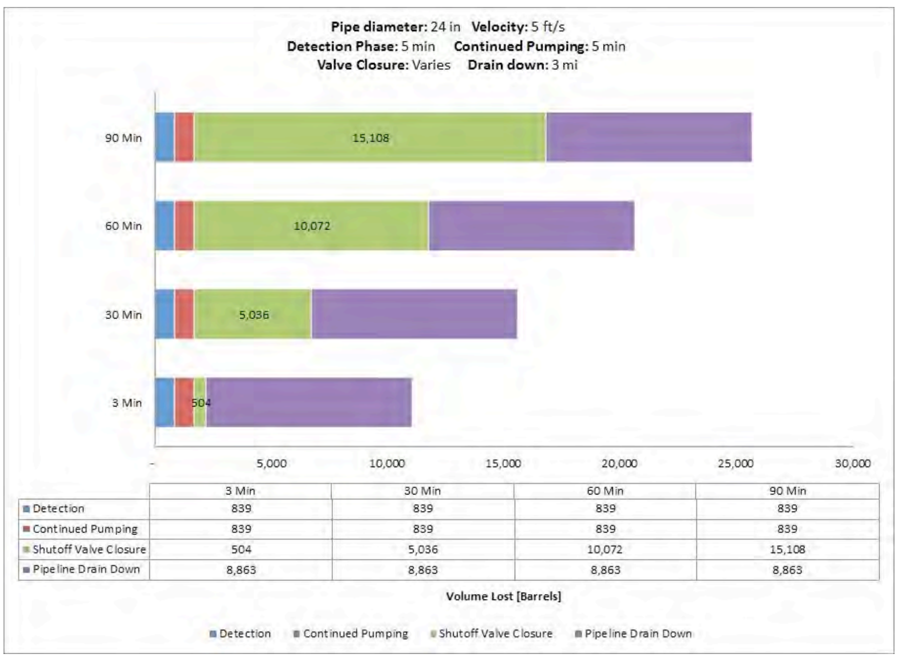
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-114. 24 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



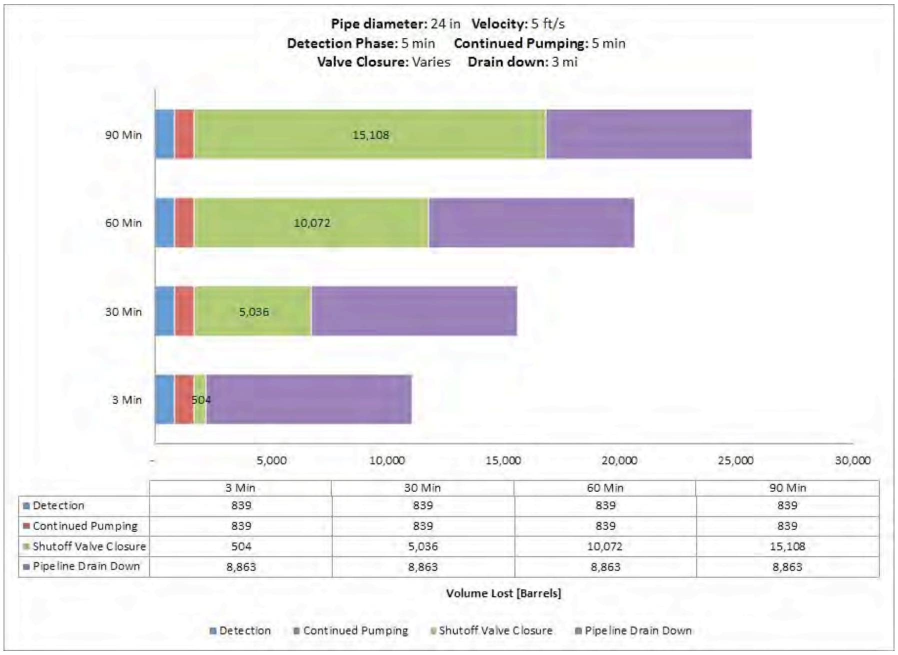
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-115. 24 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



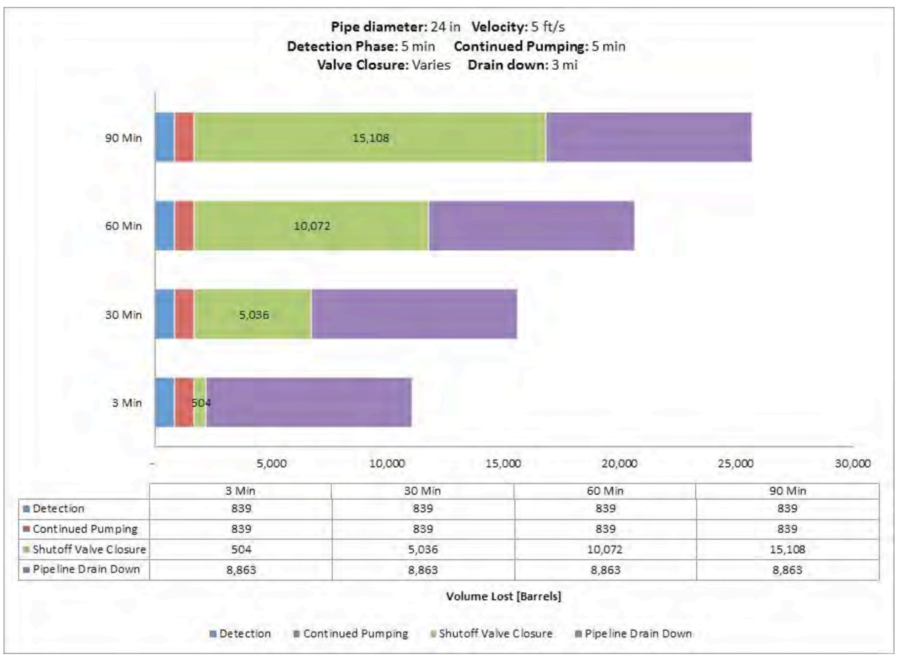
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-116. 24 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



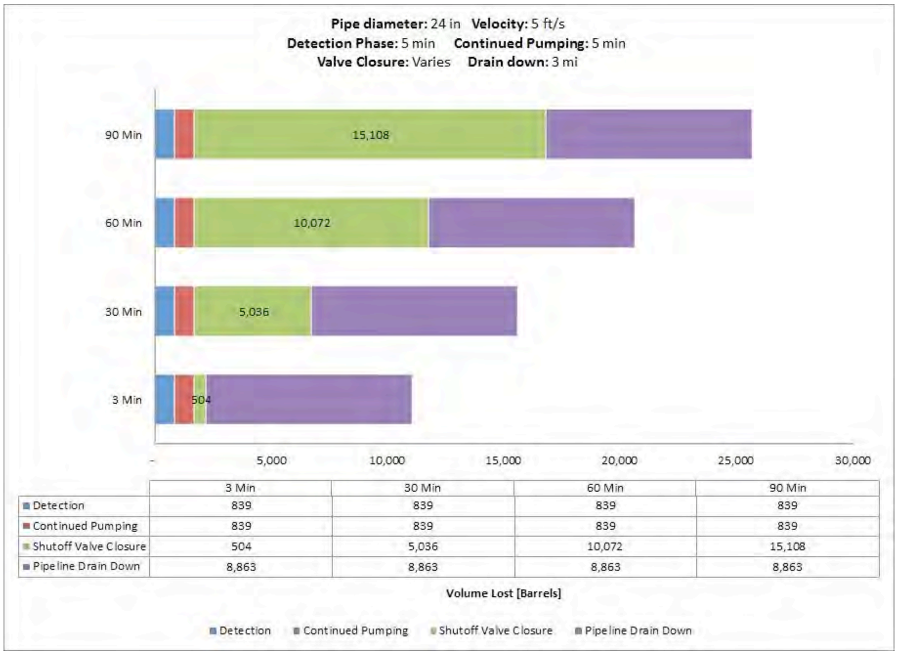
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-117. 24 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



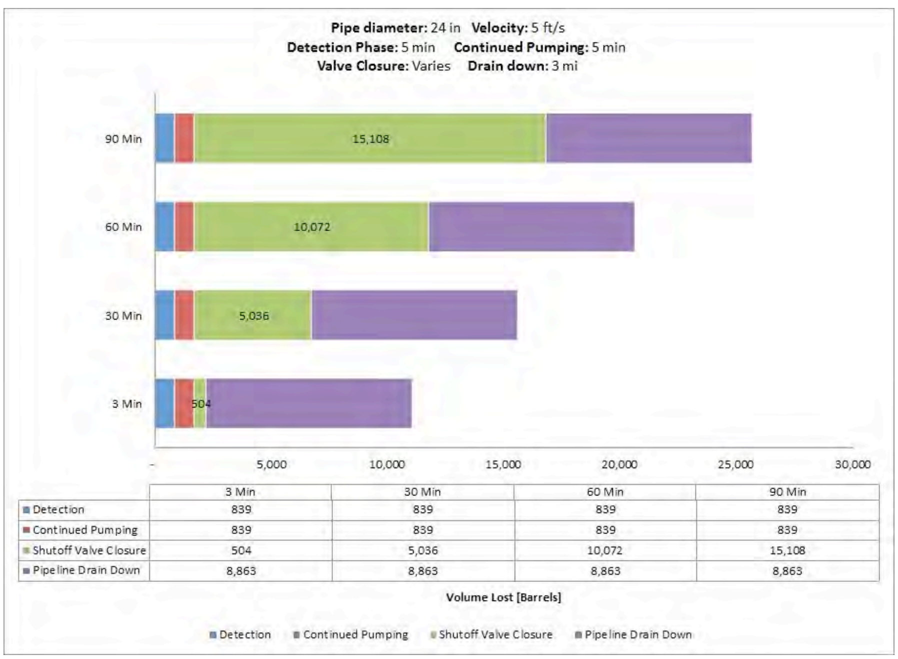
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-118. 24 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



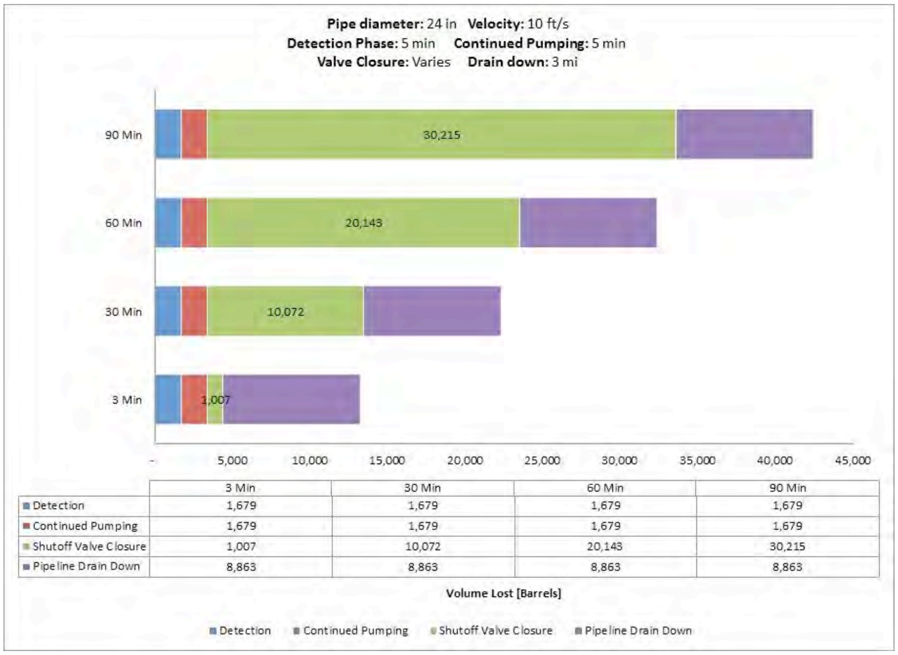
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-119. 24 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



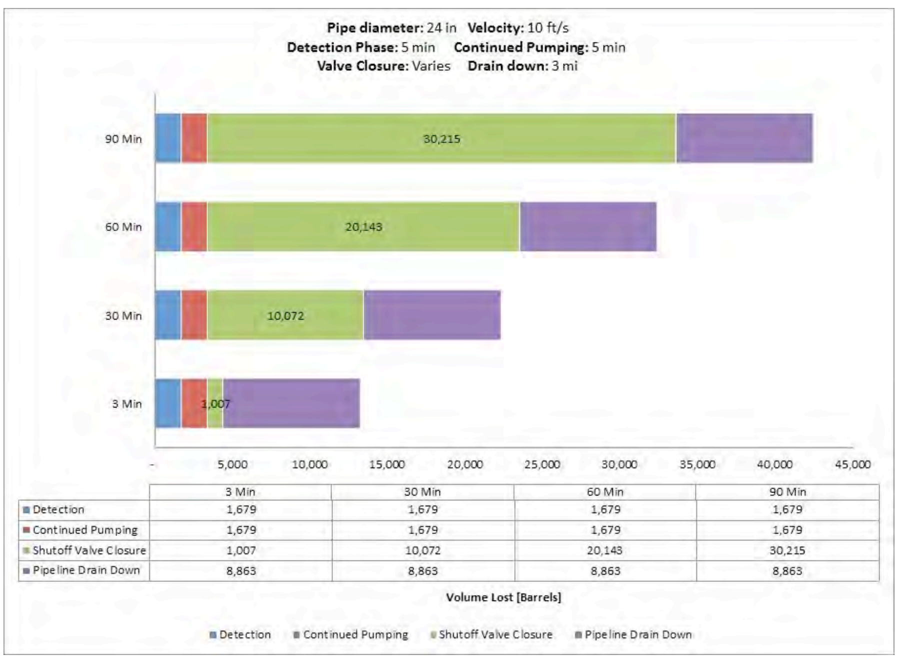
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-120. 24 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



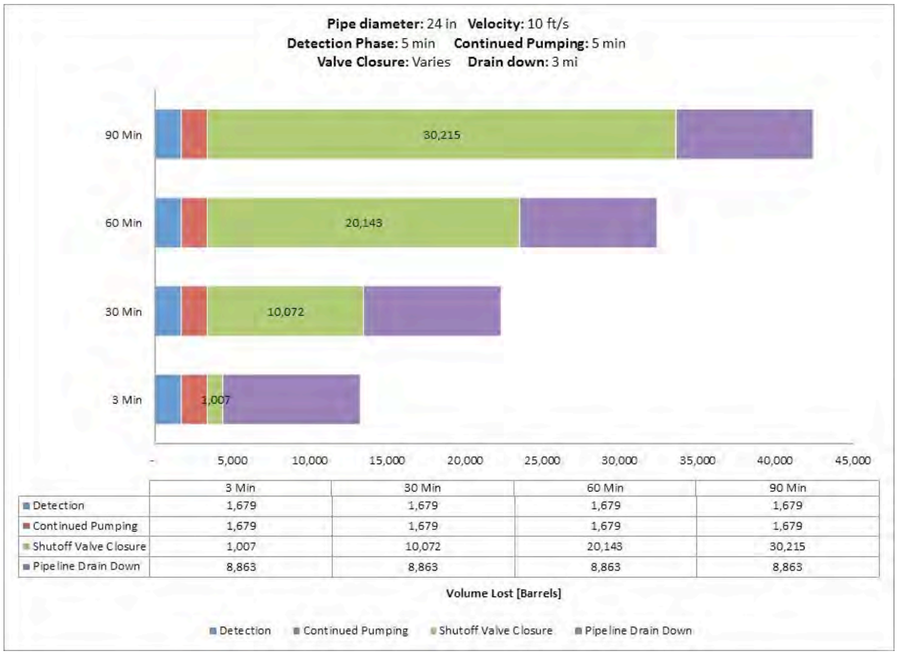
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-121. 24 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



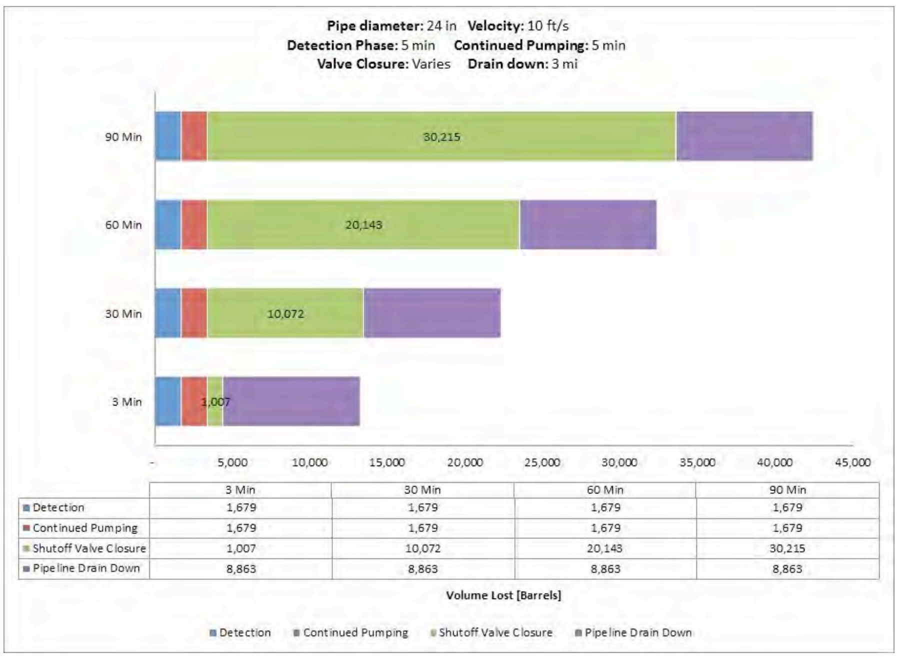
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-122. 24 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



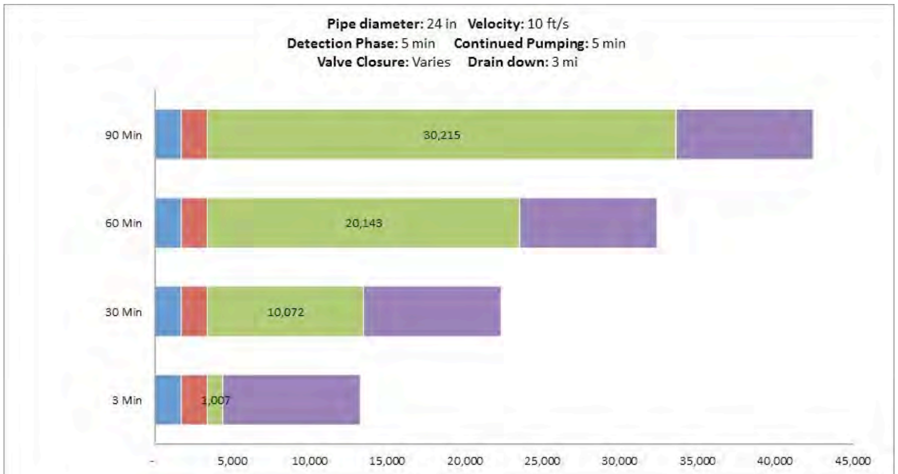
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-123. 24 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-124. 24 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

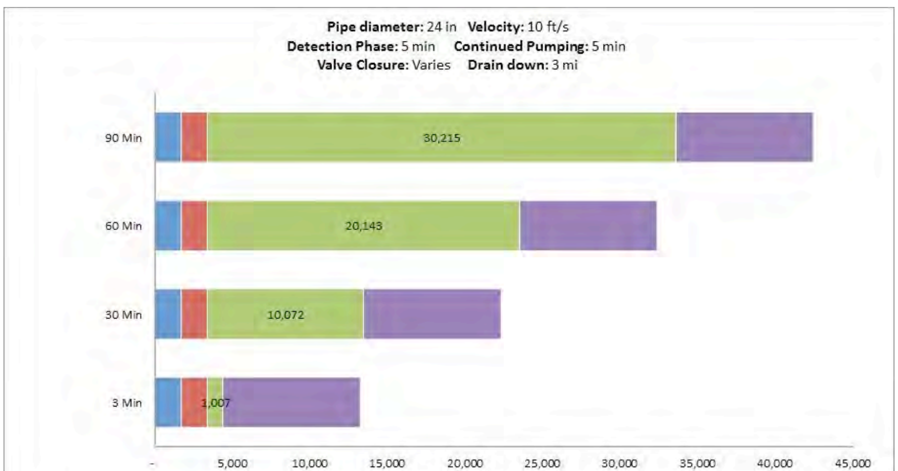


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-125. 24 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

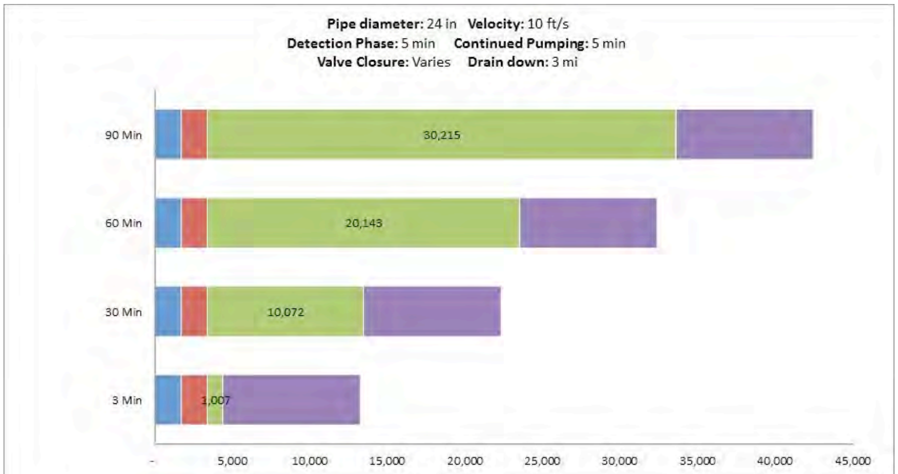


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-126. 24 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

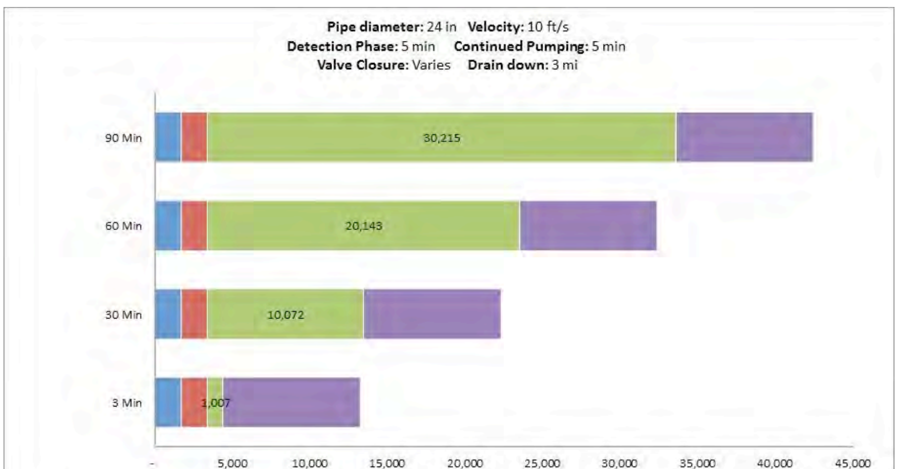


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-127. 24 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

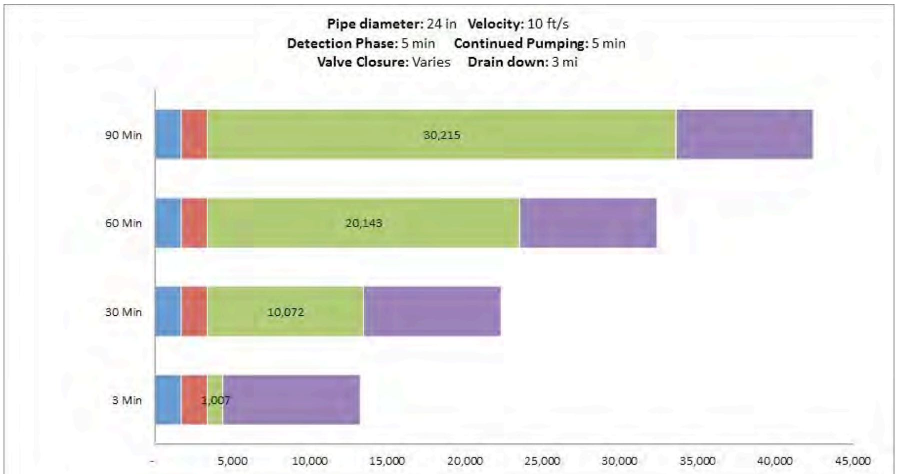


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-128. 24 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

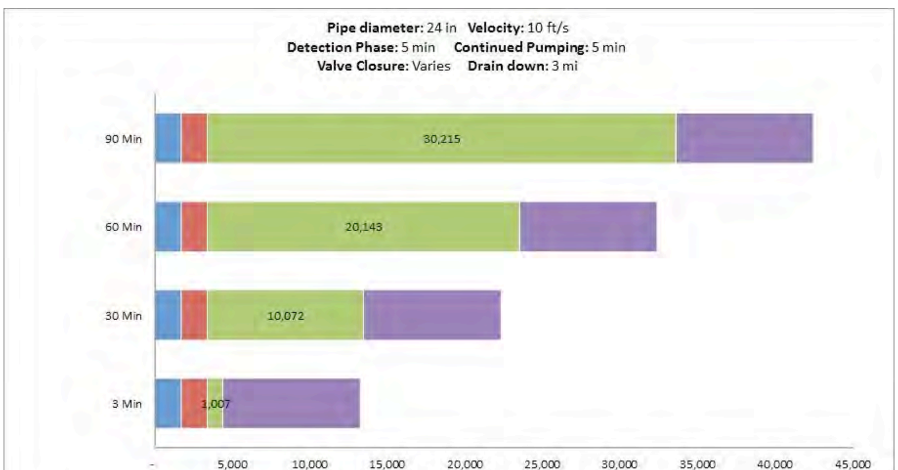


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-129. 24 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

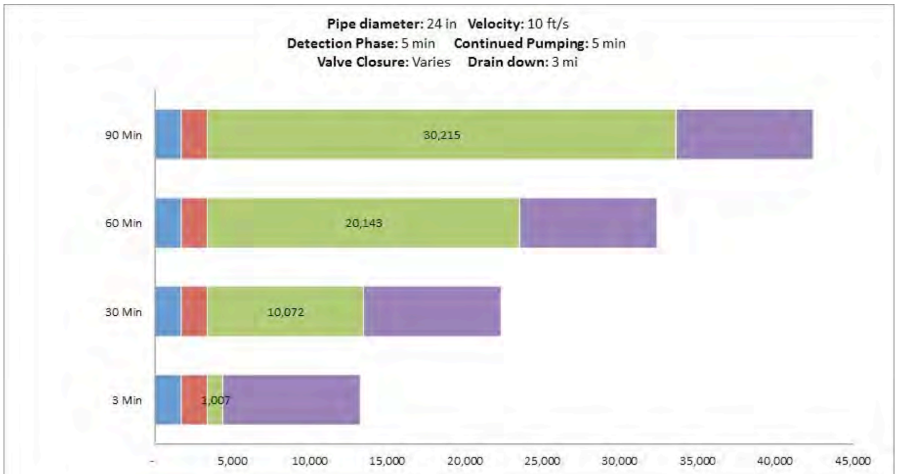


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-130. 24 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

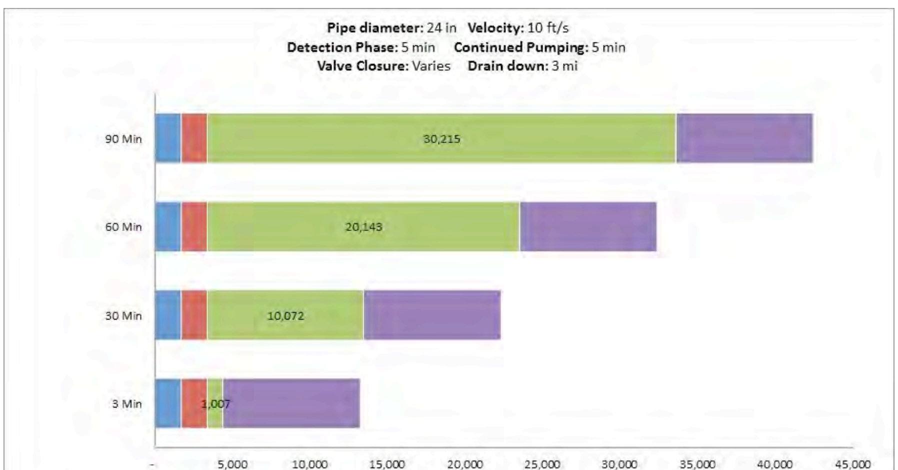


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-131. 24 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

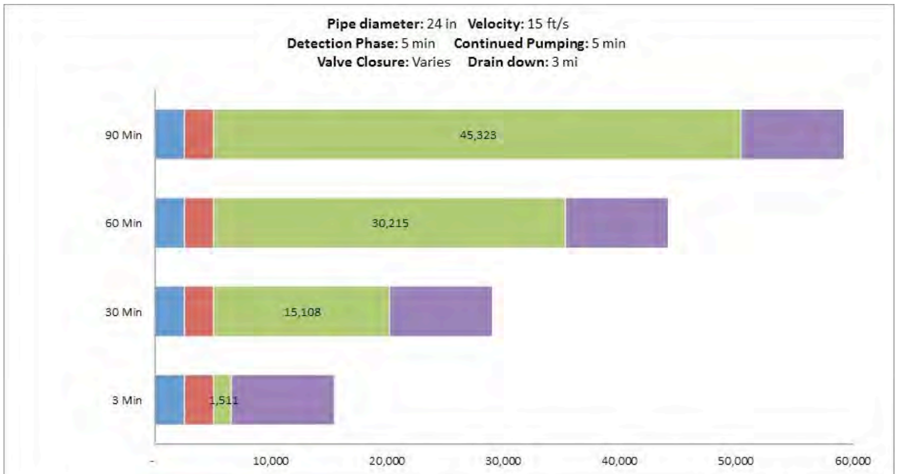


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-132. 24 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

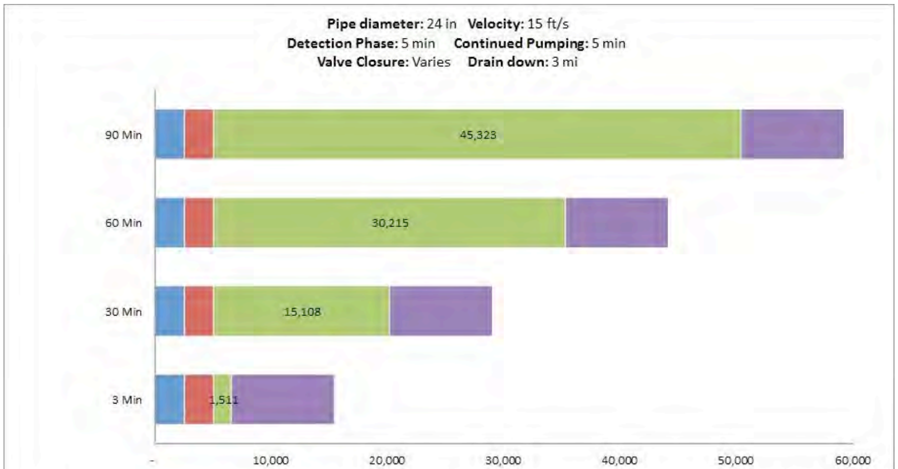


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-133. 24 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

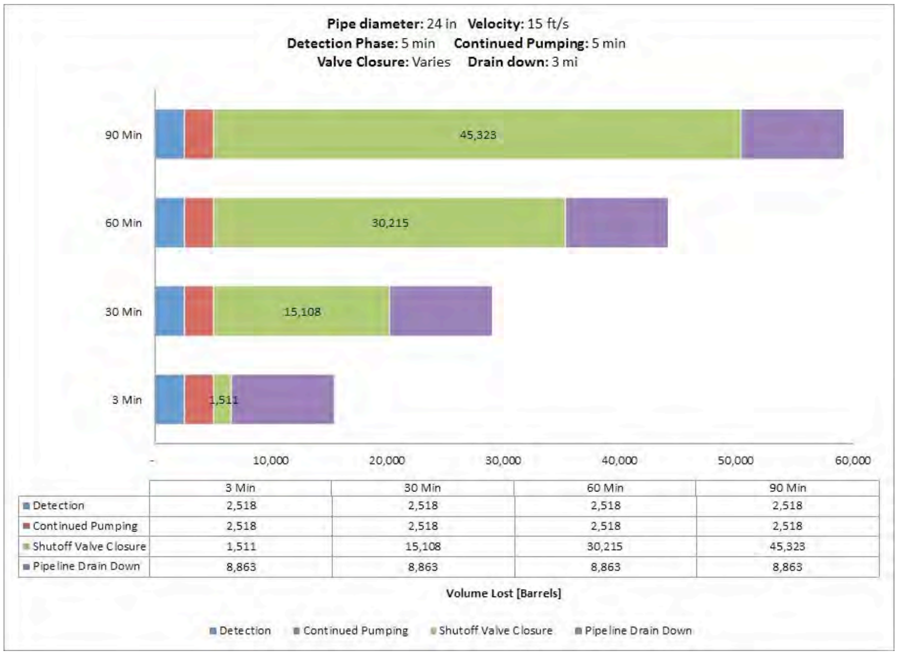


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

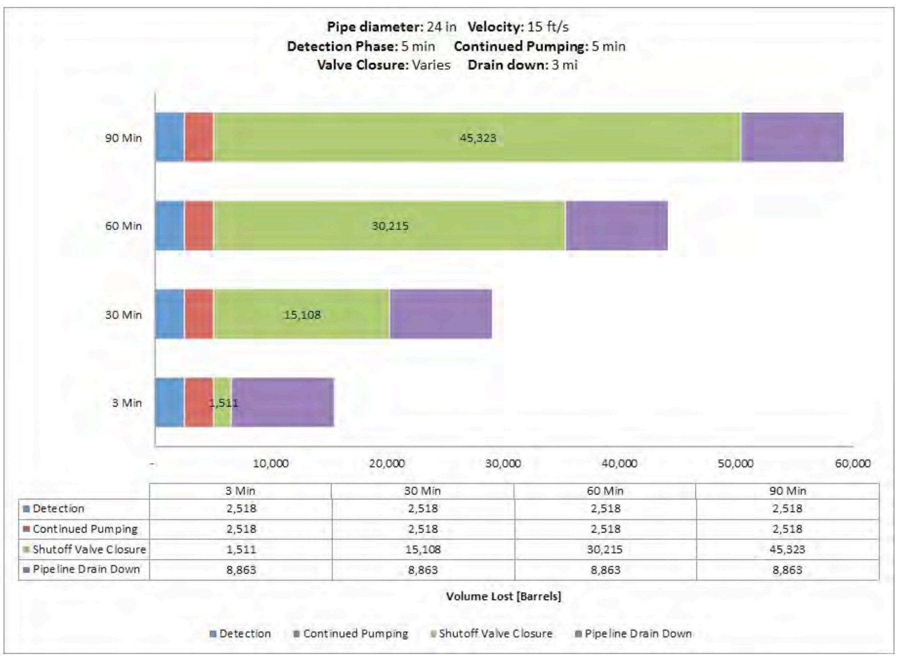
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-134. 24 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



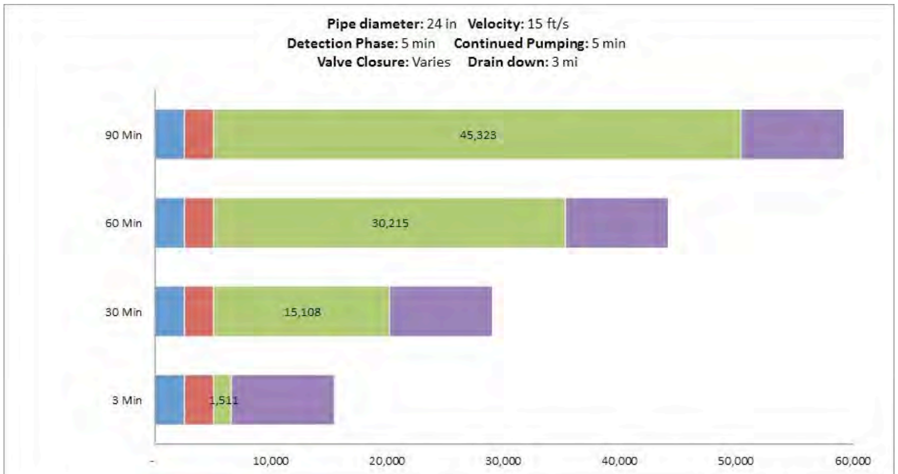
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-135. 24 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-136. 24 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

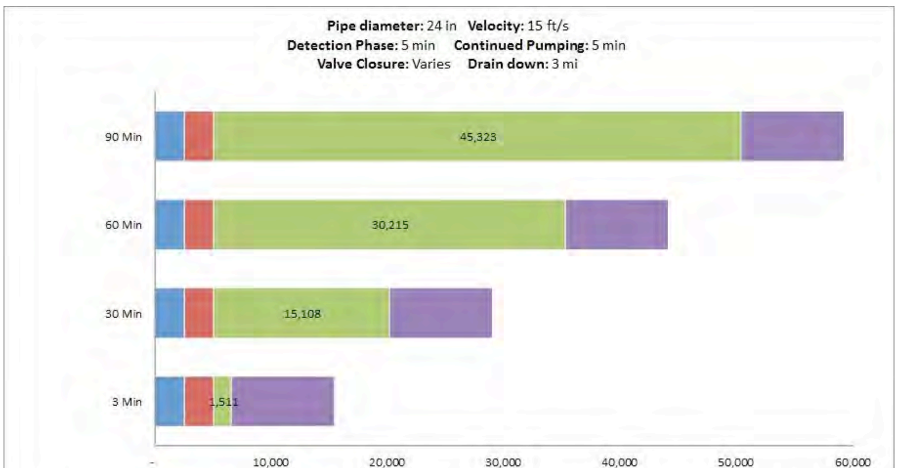


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-137. 24 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

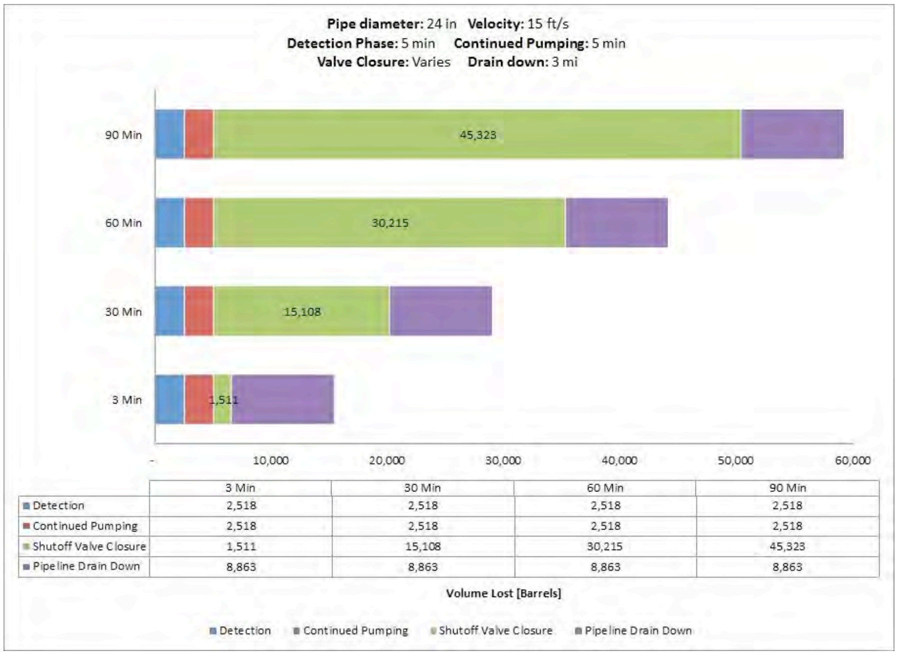


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

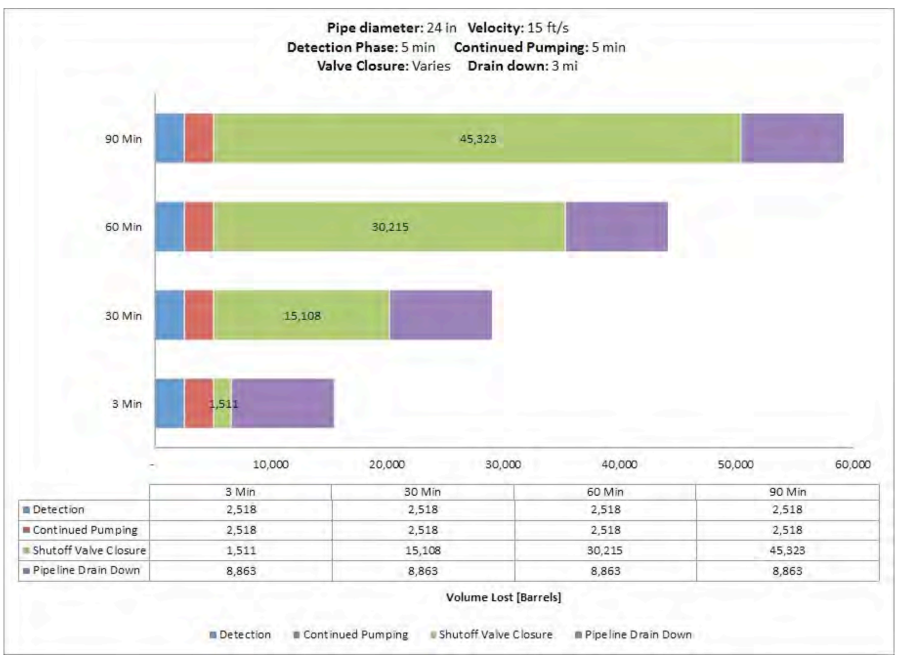
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-138. 24 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



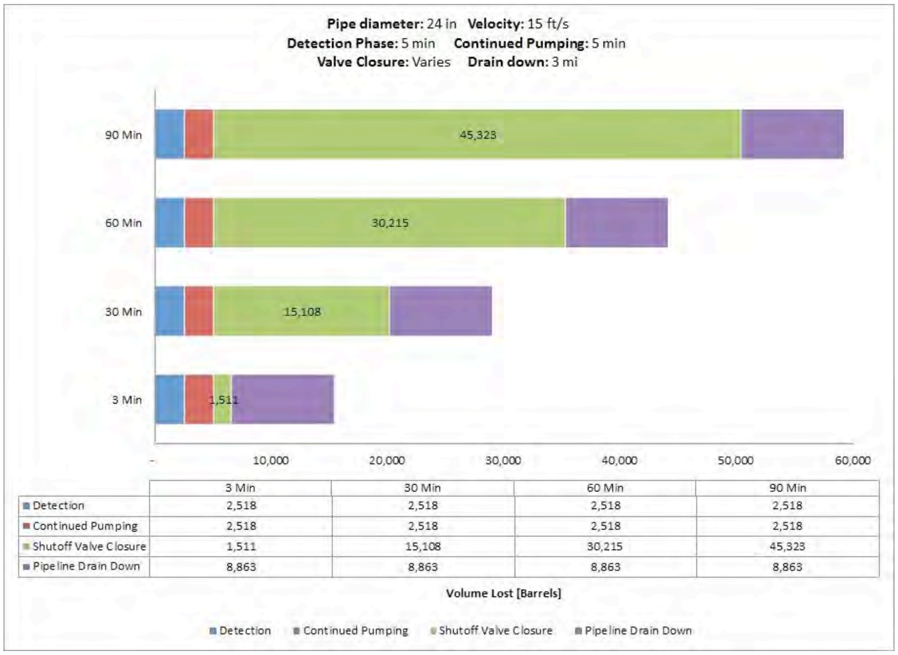
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-139. 24 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



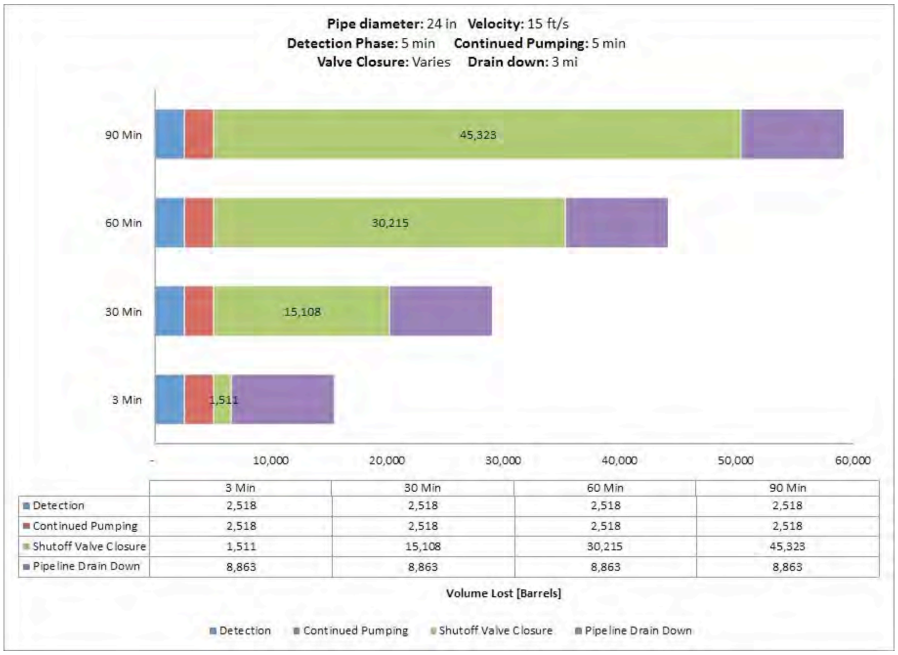
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-140. 24 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



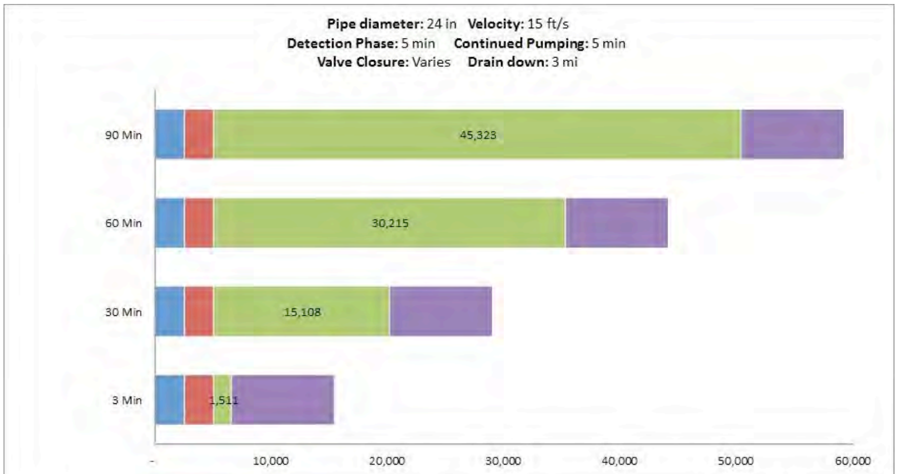
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-141. 24 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Fig. A-142. 24 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

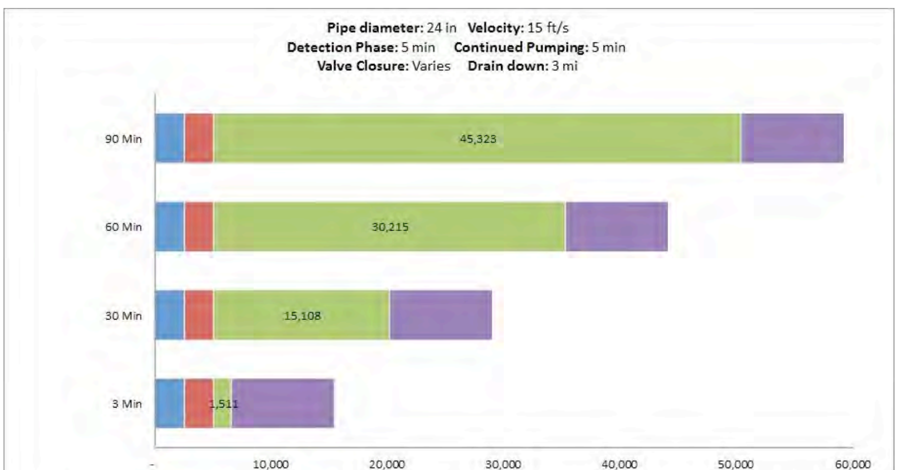


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-143. 24 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

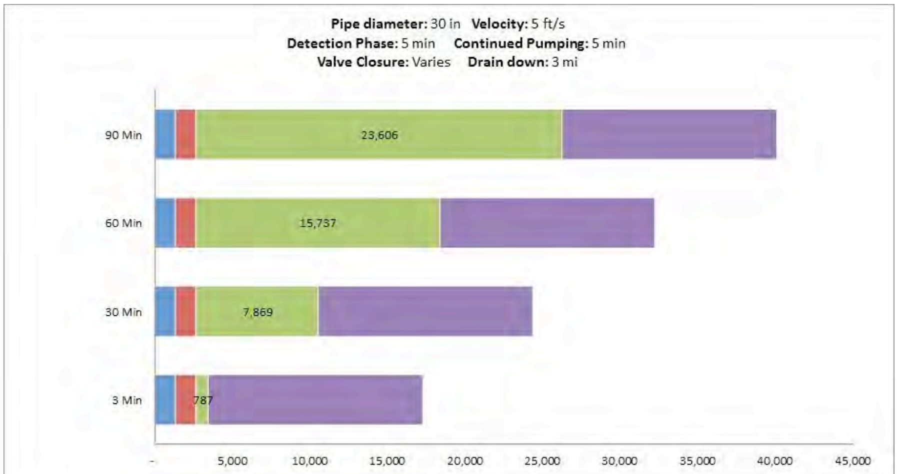


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-144. 24 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

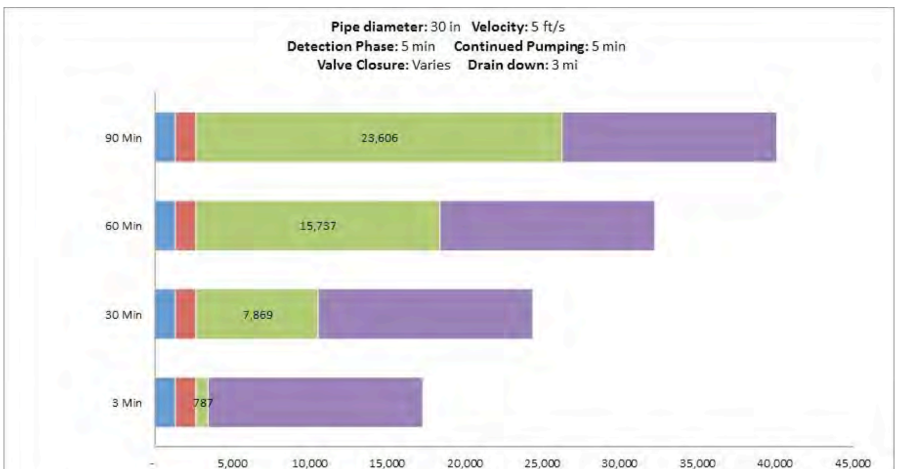


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-145. 30 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

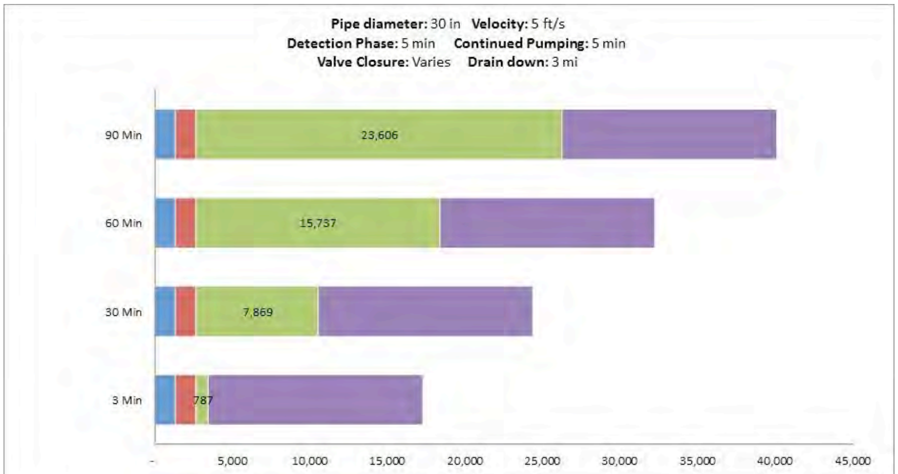


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-146. 30 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

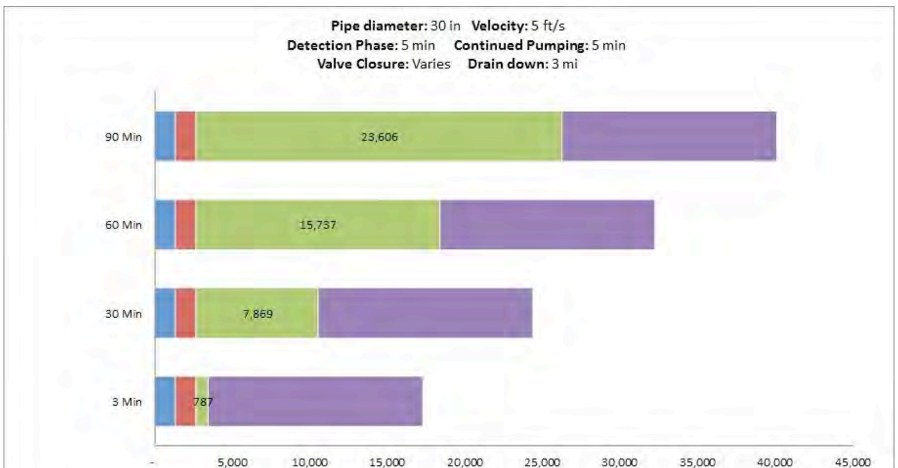


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-147. 30 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

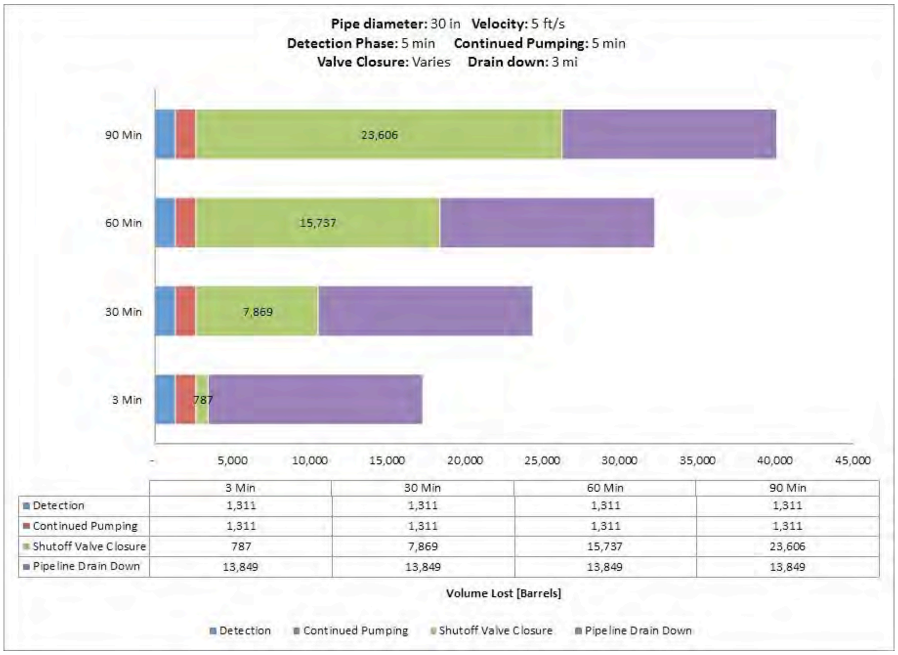


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

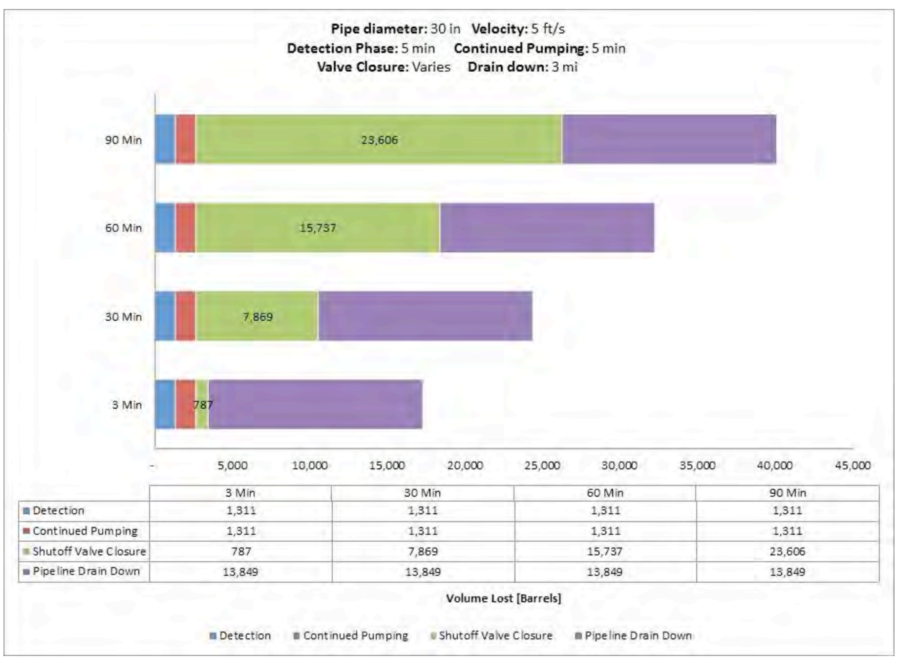
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-148. 30 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



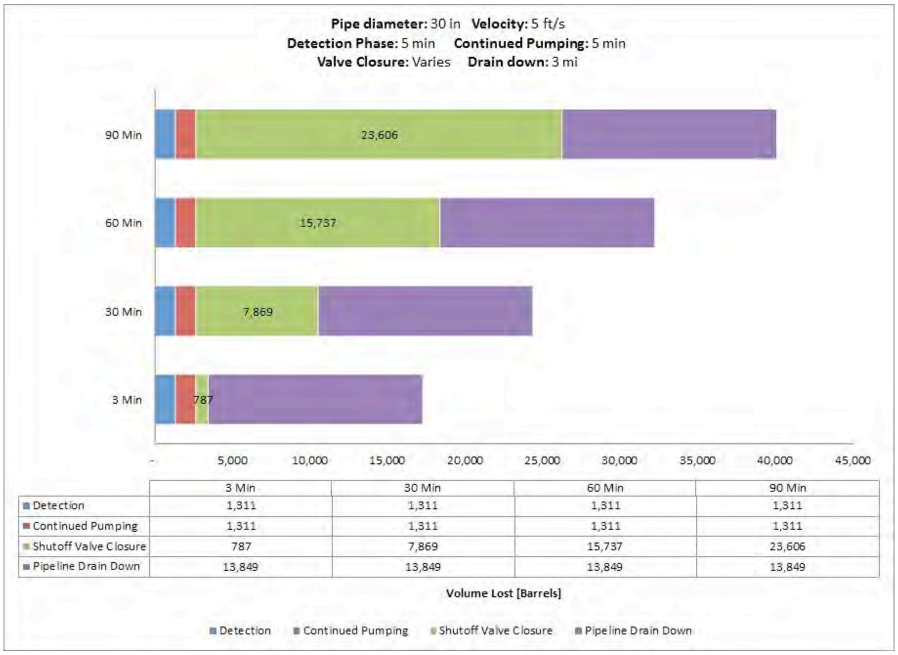
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-149. 30 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-150. 30 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

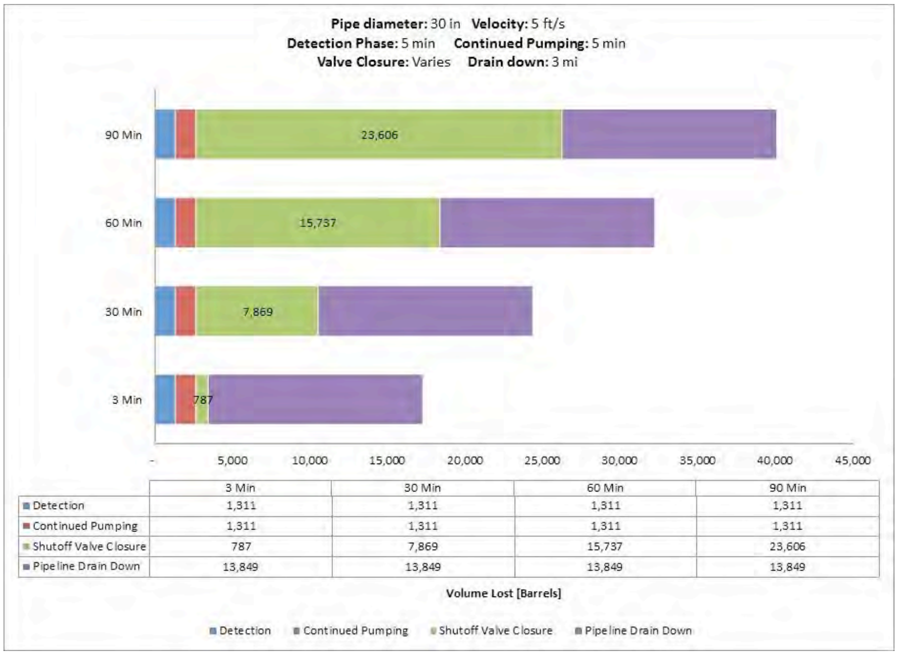


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-151. 30 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-152. 30 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

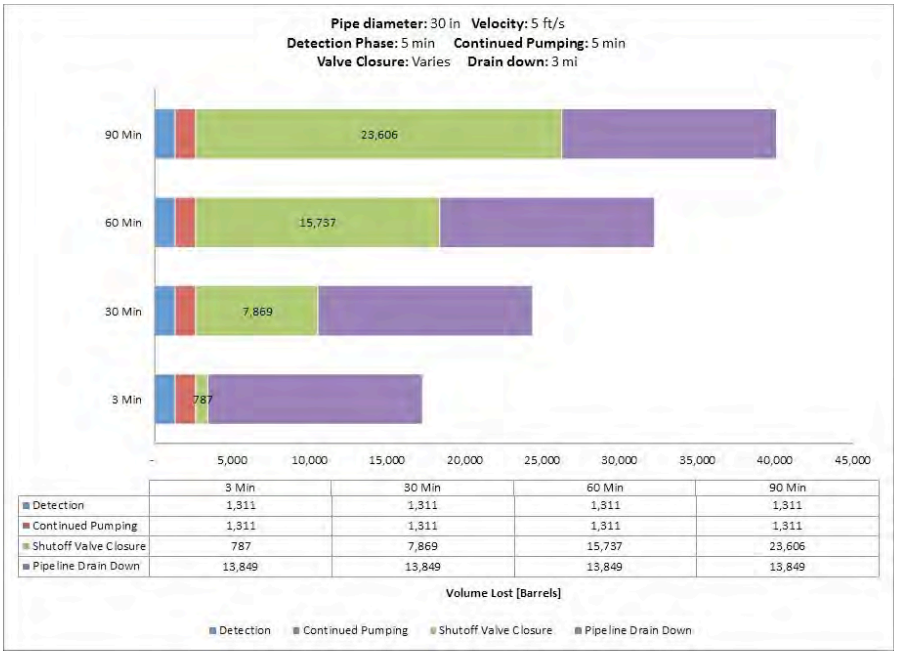


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-153. 30 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-154. 30 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

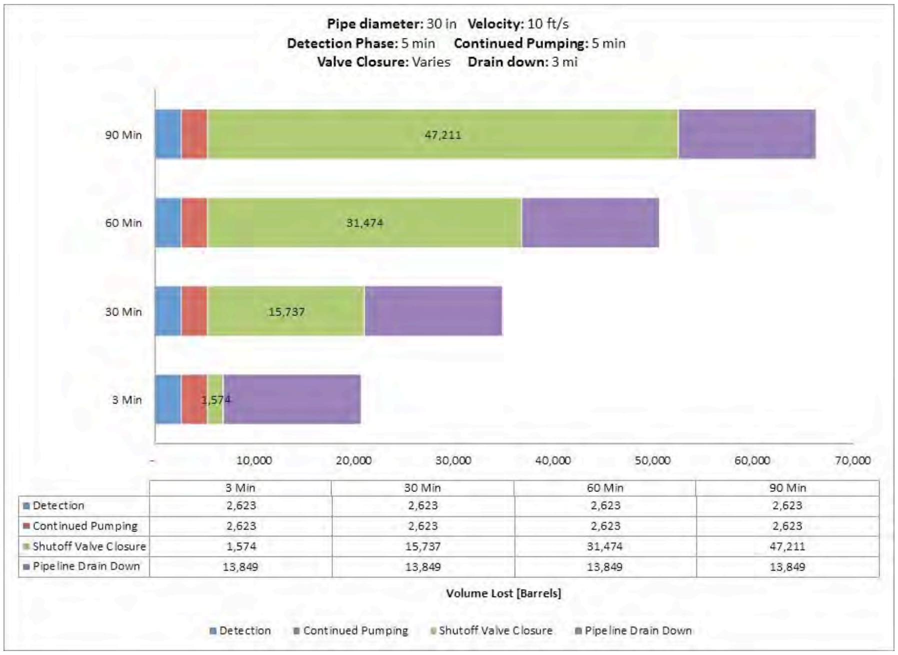


	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-155. 30 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

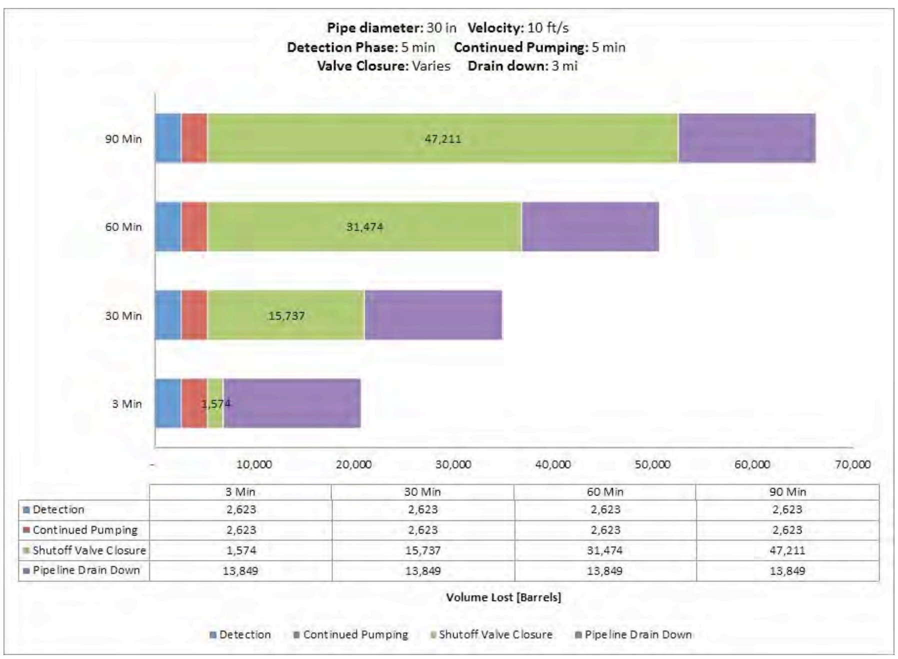
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-156. 30 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



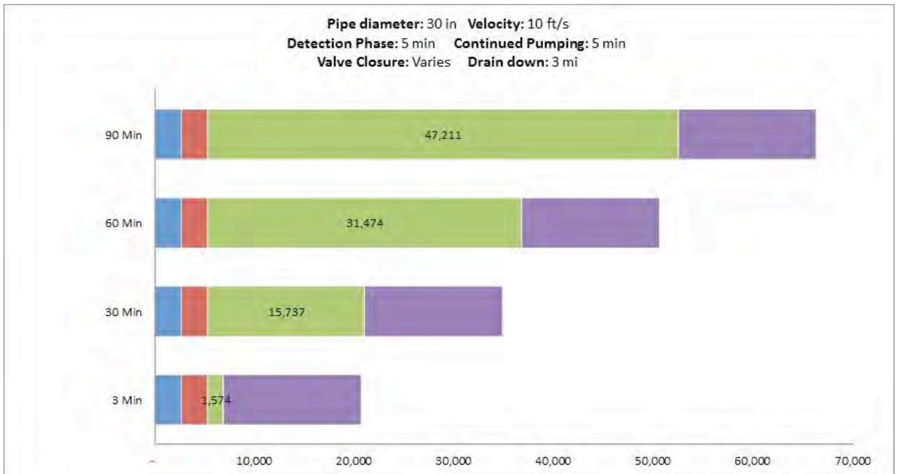
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-157. 30 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-158. 30 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

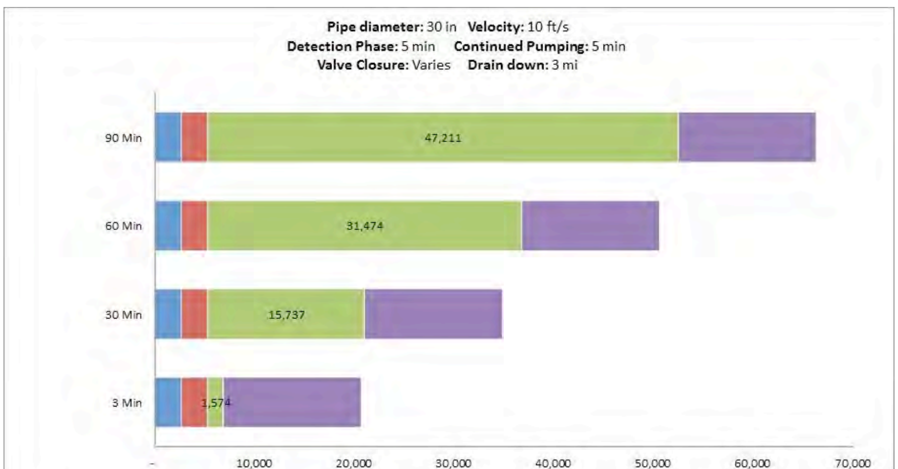


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-159. 30 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

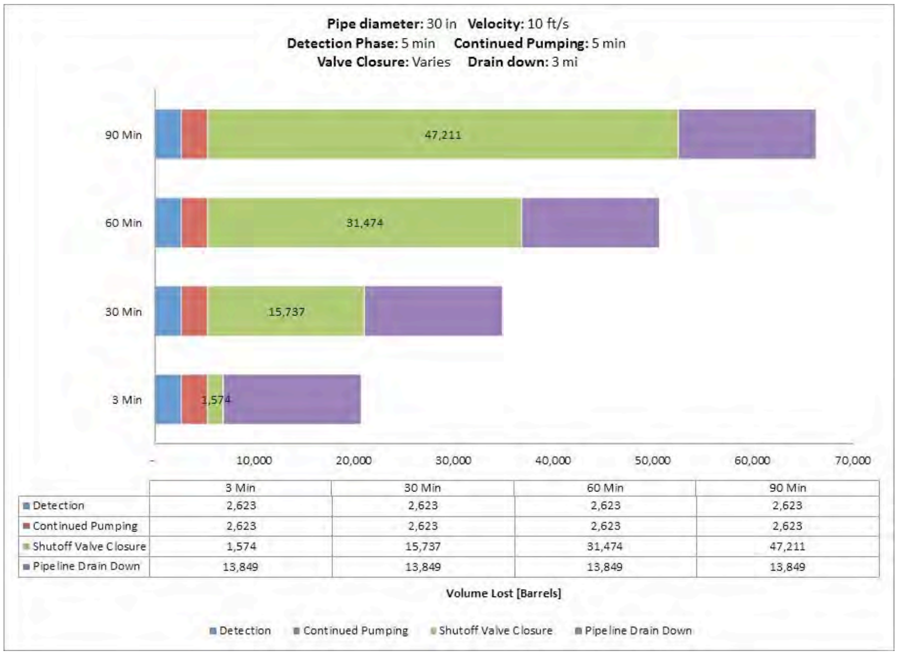


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

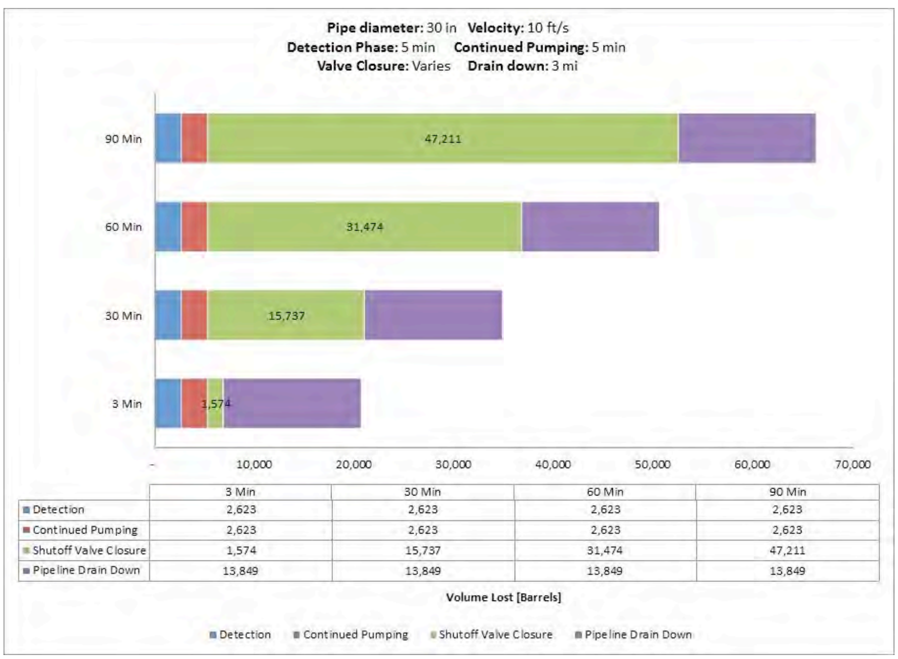
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-160. 30 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



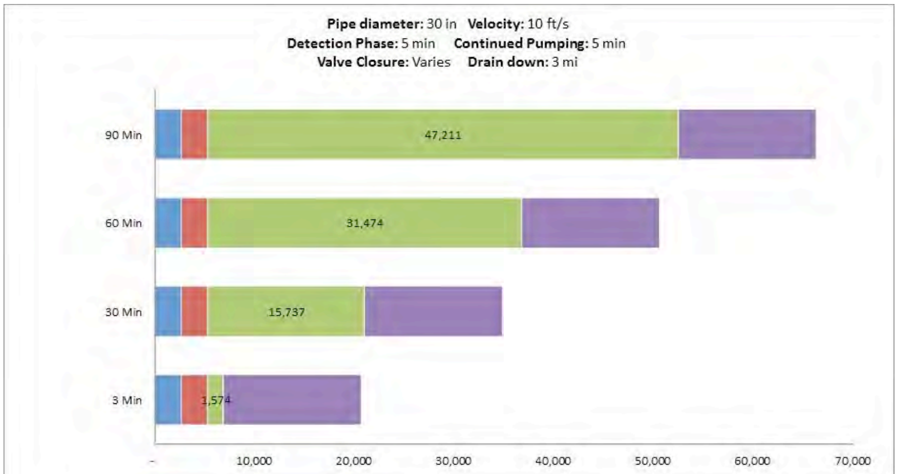
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-161. 30 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-162. 30 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

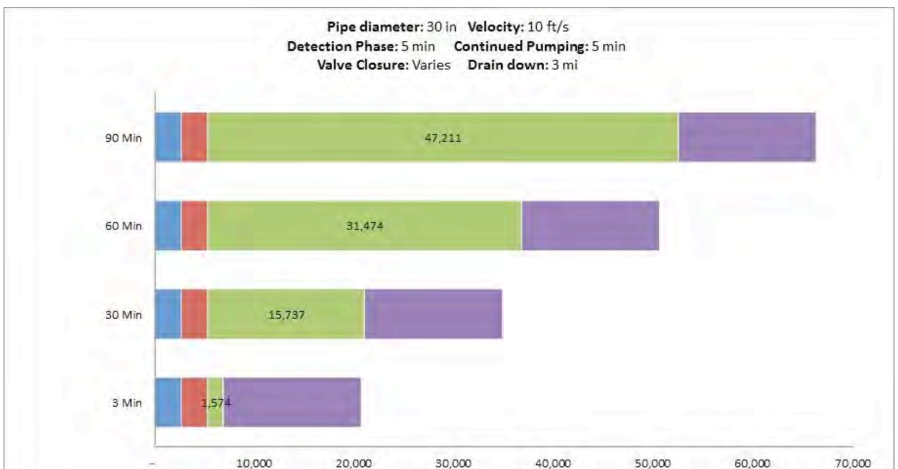


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-163. 30 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

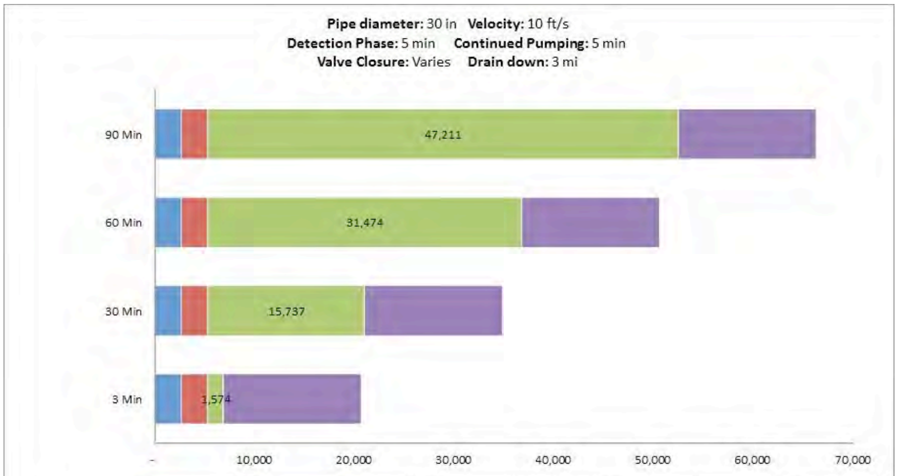


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

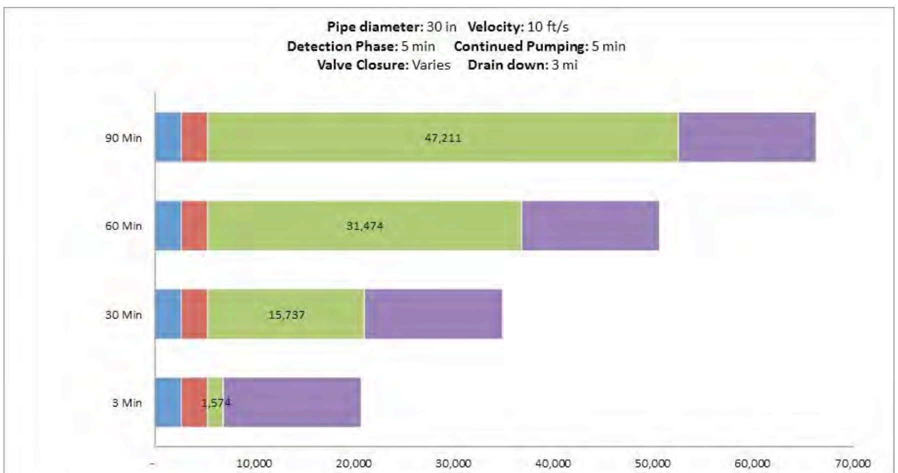
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-164. 30 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



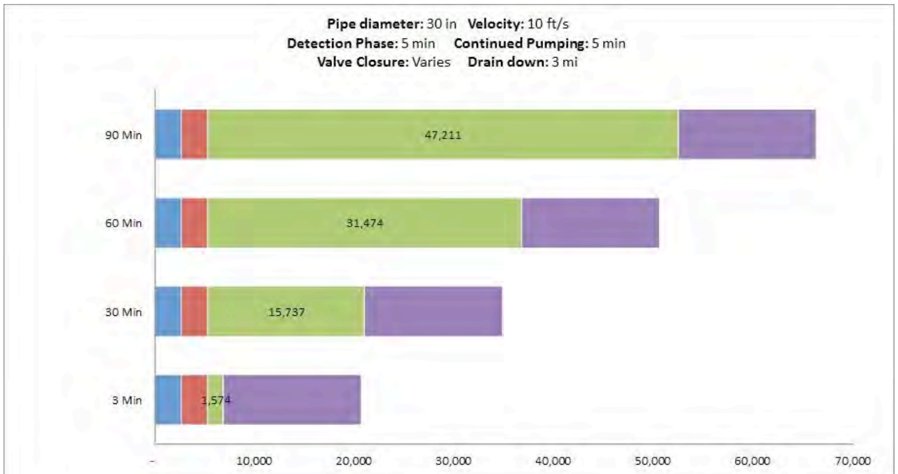
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-165. 30 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-166. 30 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

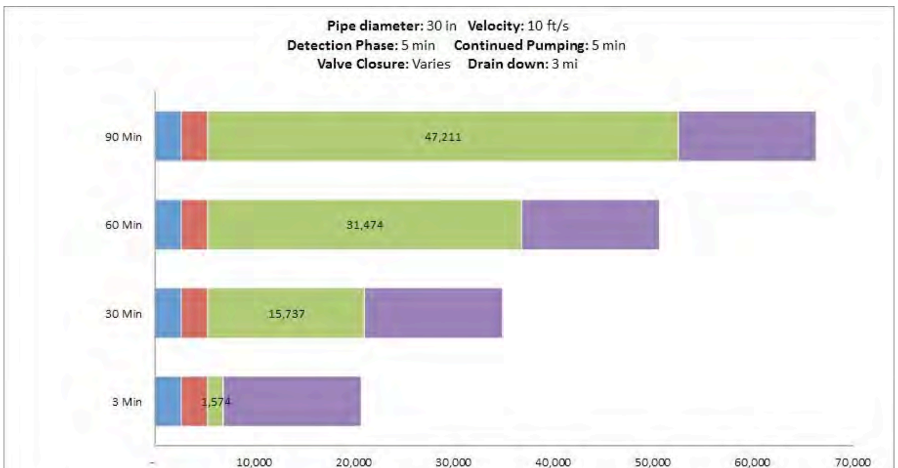


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-167. 30 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-168. 30 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

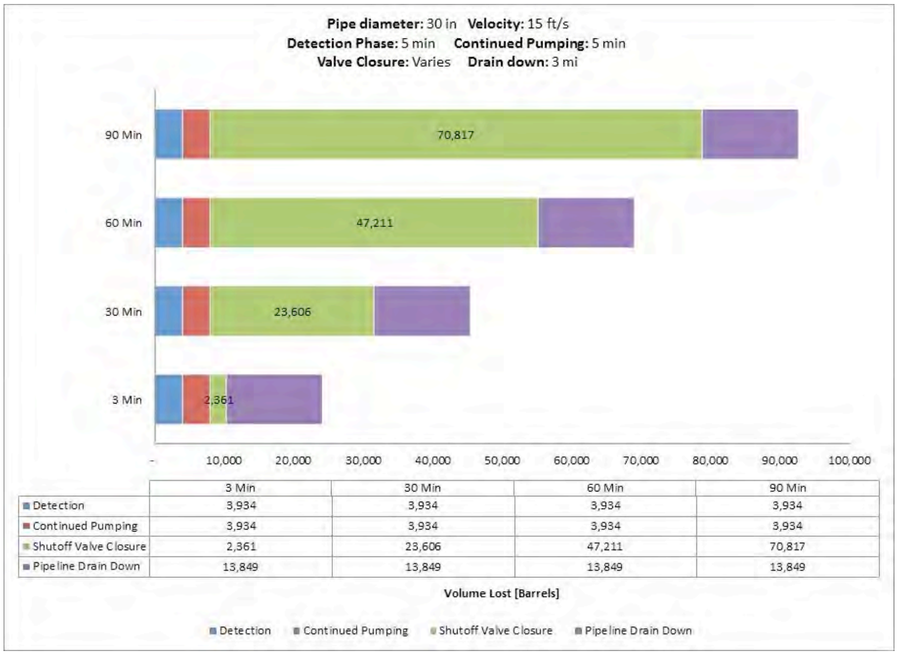


Fig. A-169. 30 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

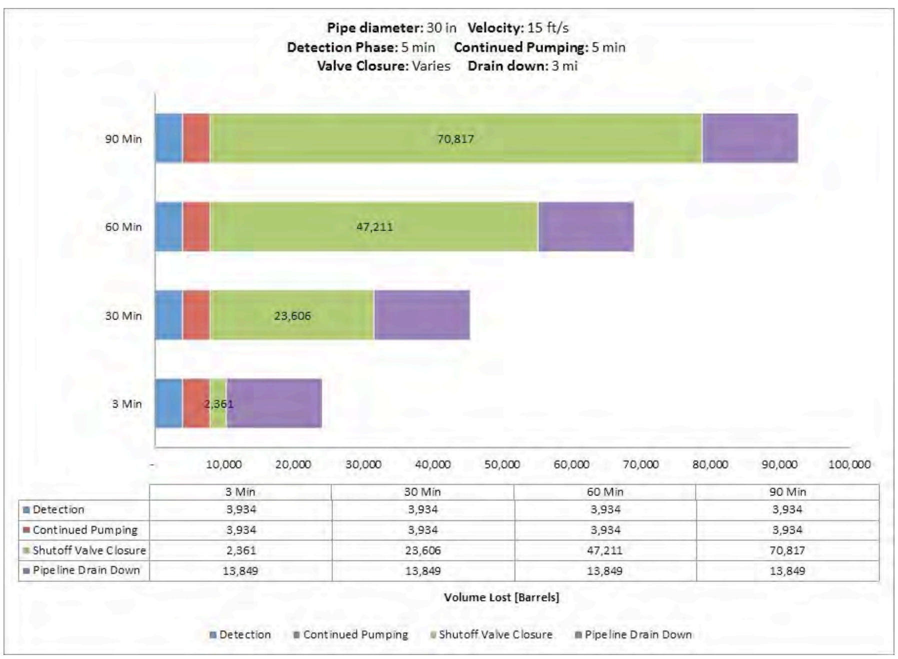
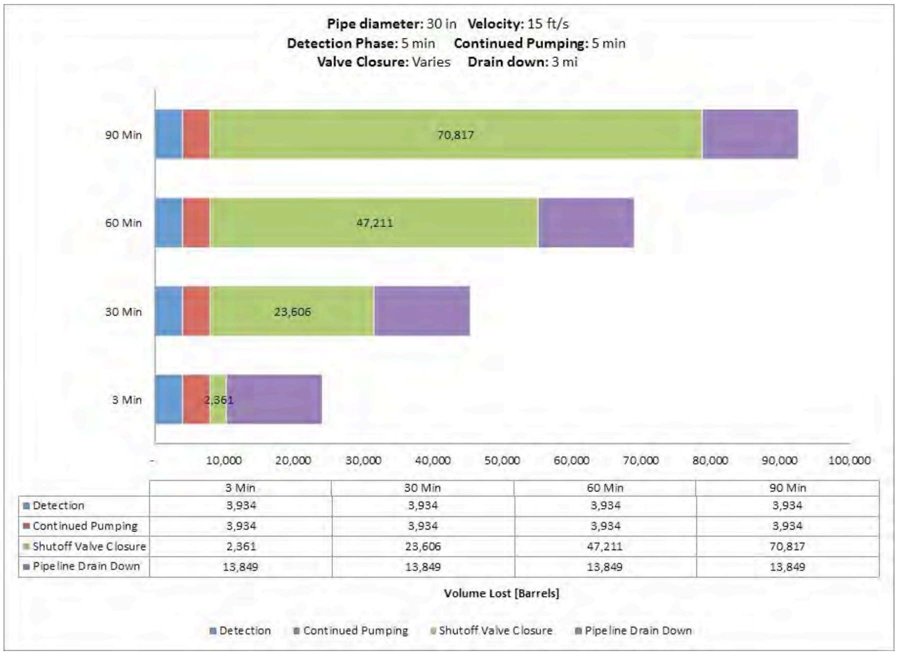
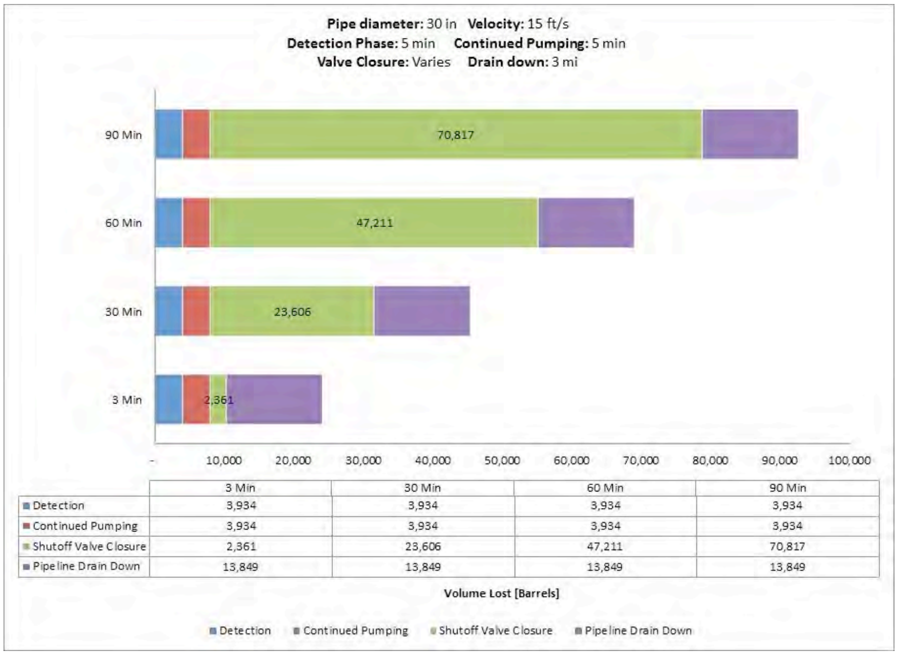


Fig. A-170. 30 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



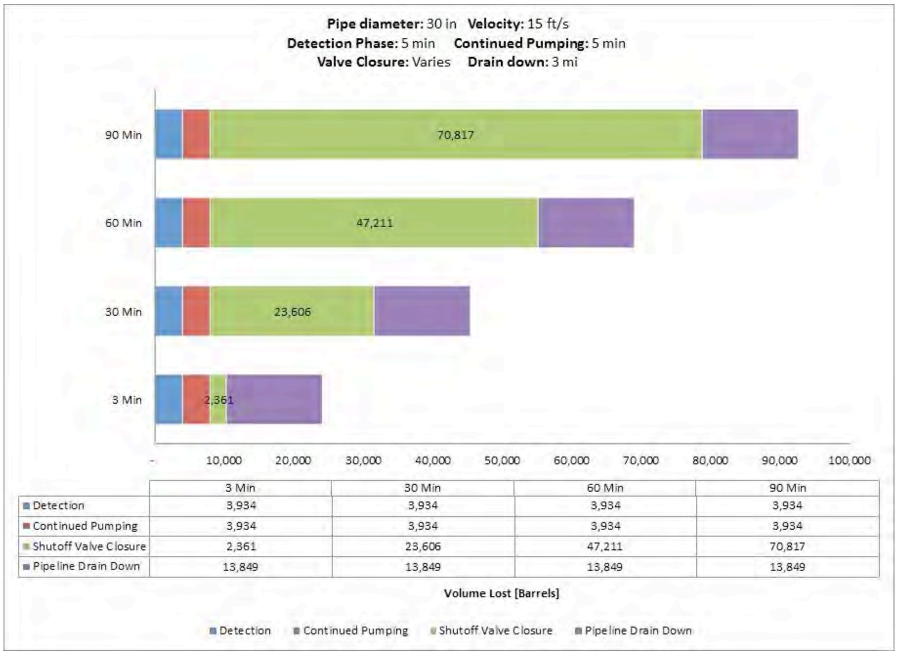
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-171. 30 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



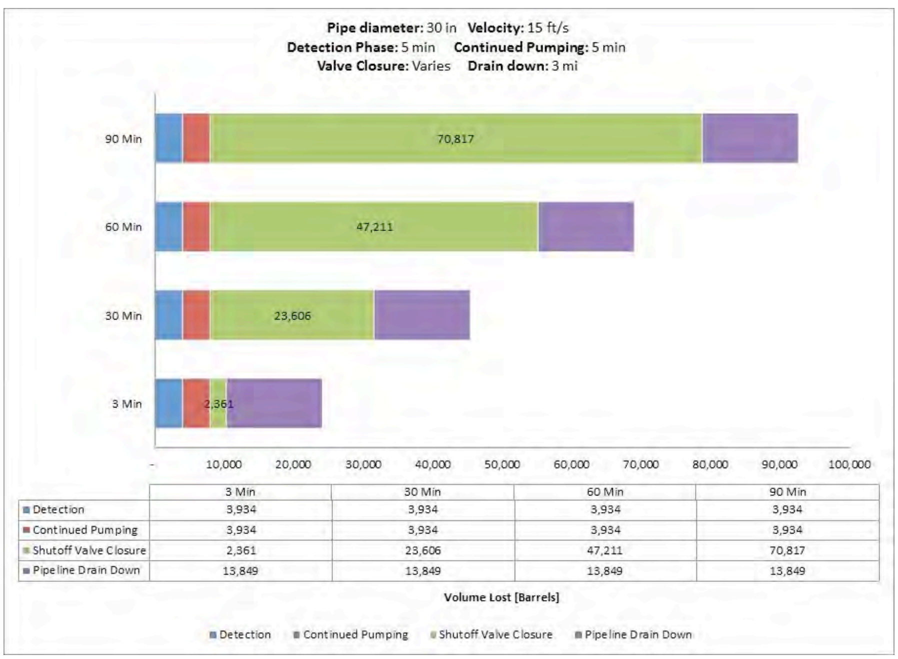
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-172. 30 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



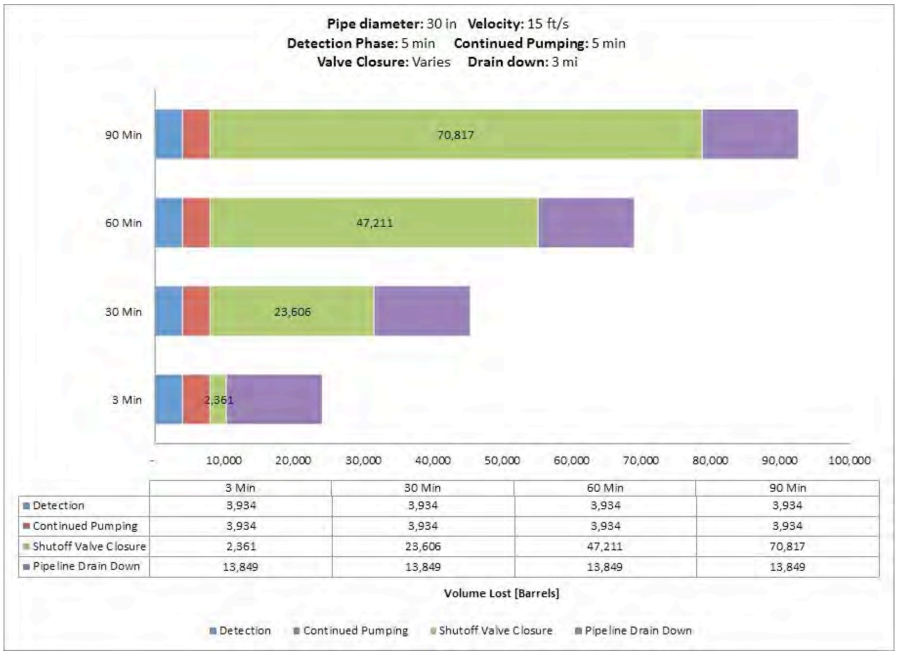
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-173. 30 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



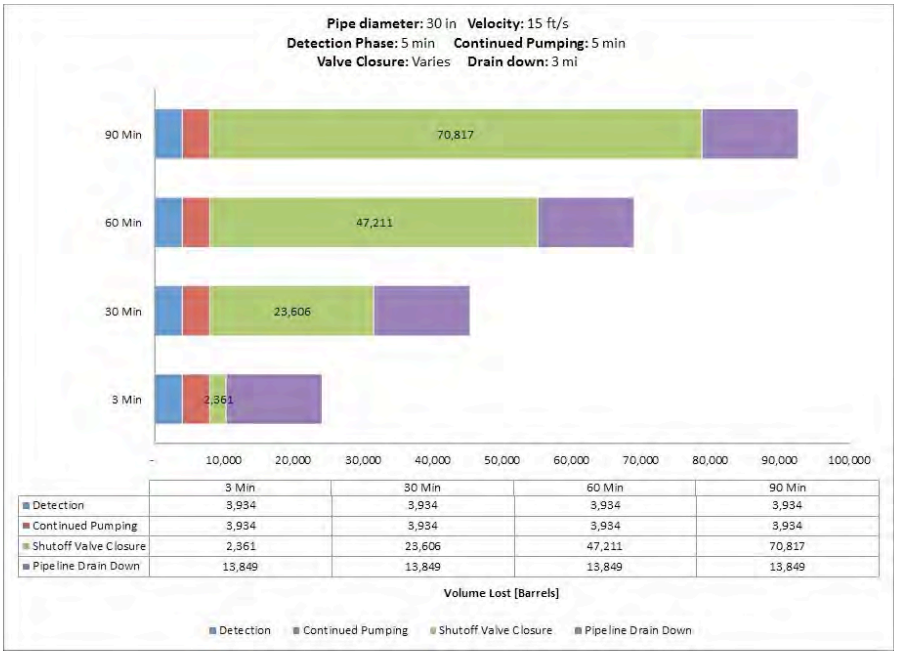
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-174. 30 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



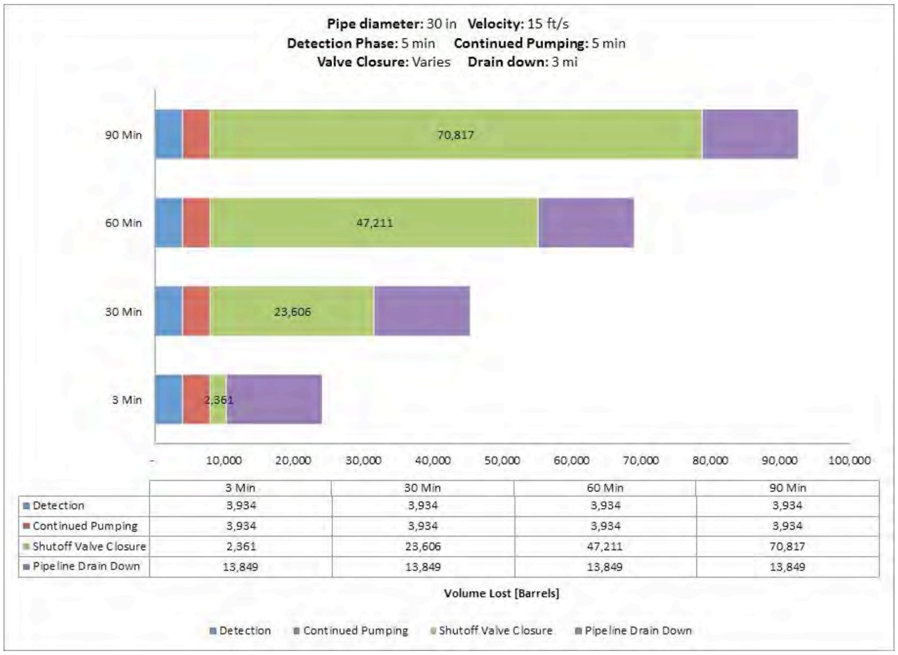
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-175. 30 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



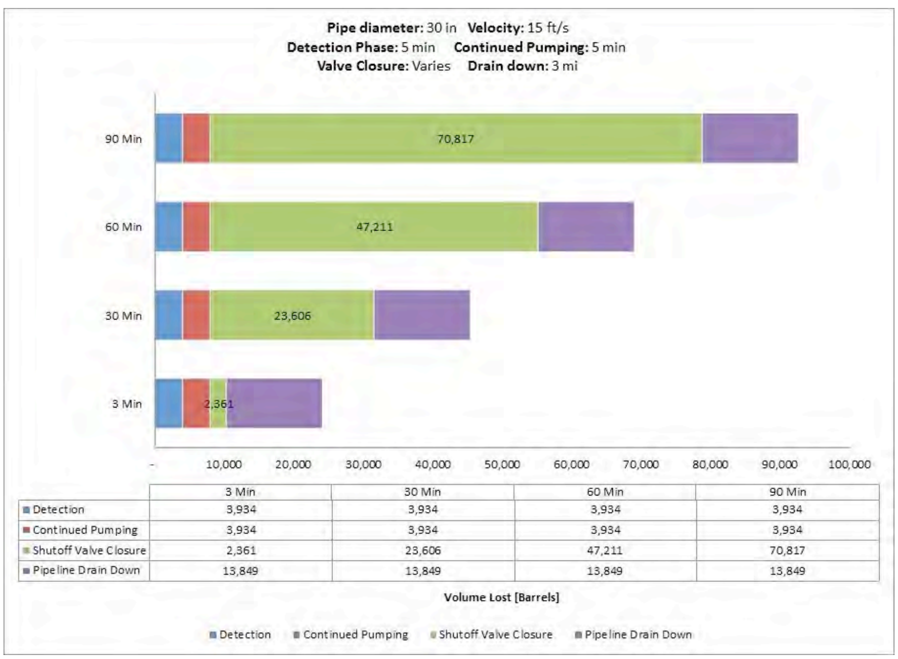
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-176. 30 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



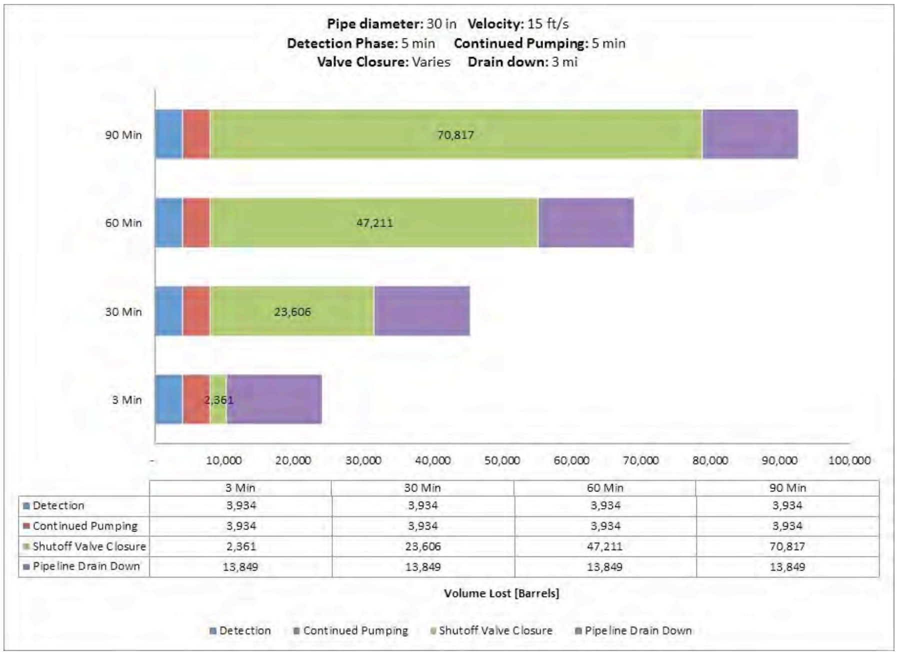
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-177. 30 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



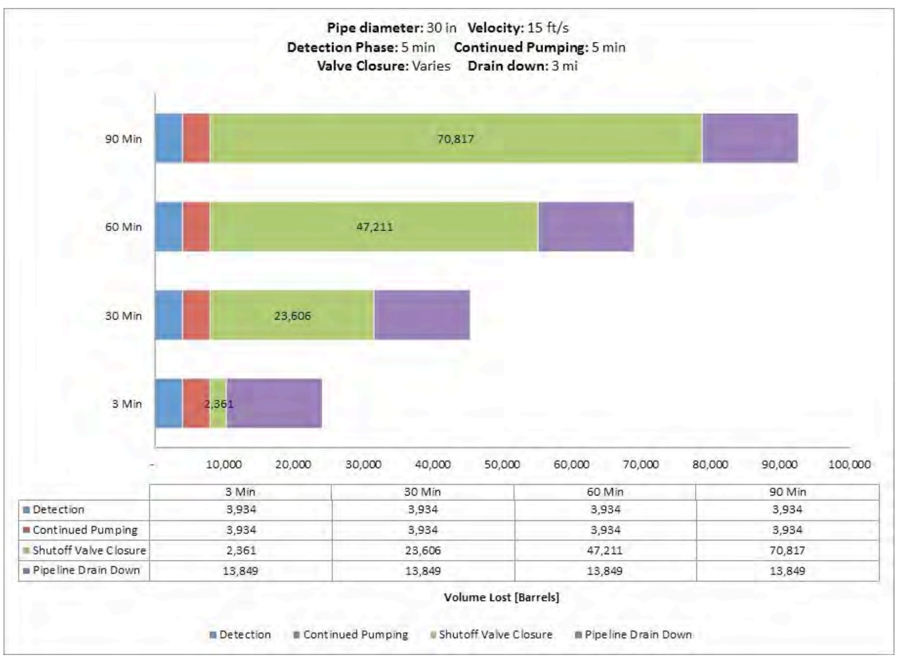
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-178. 30 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



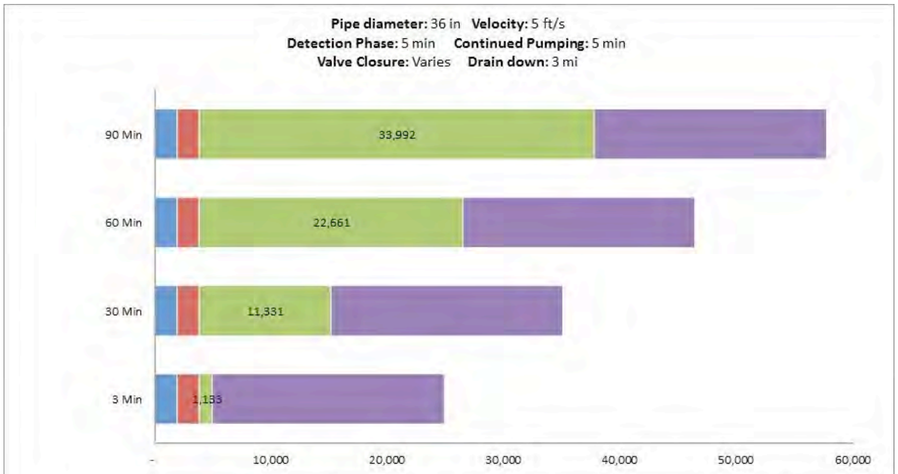
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-179. 30 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



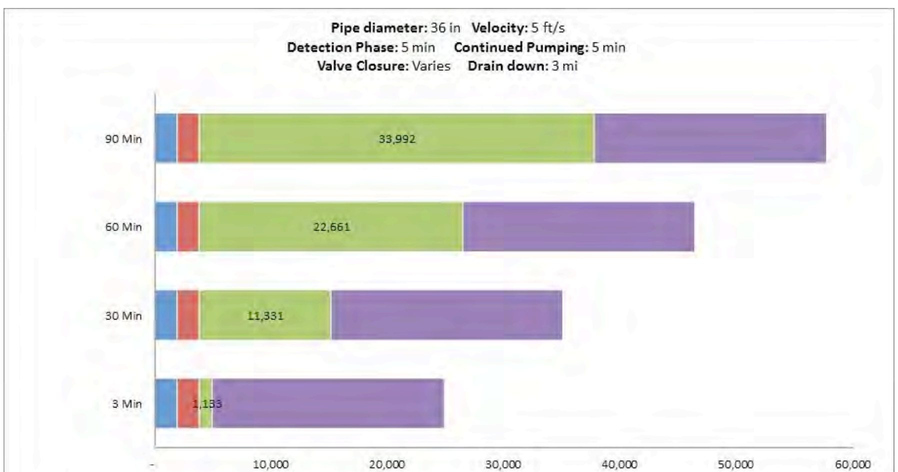
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Fig. A-180. 30 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



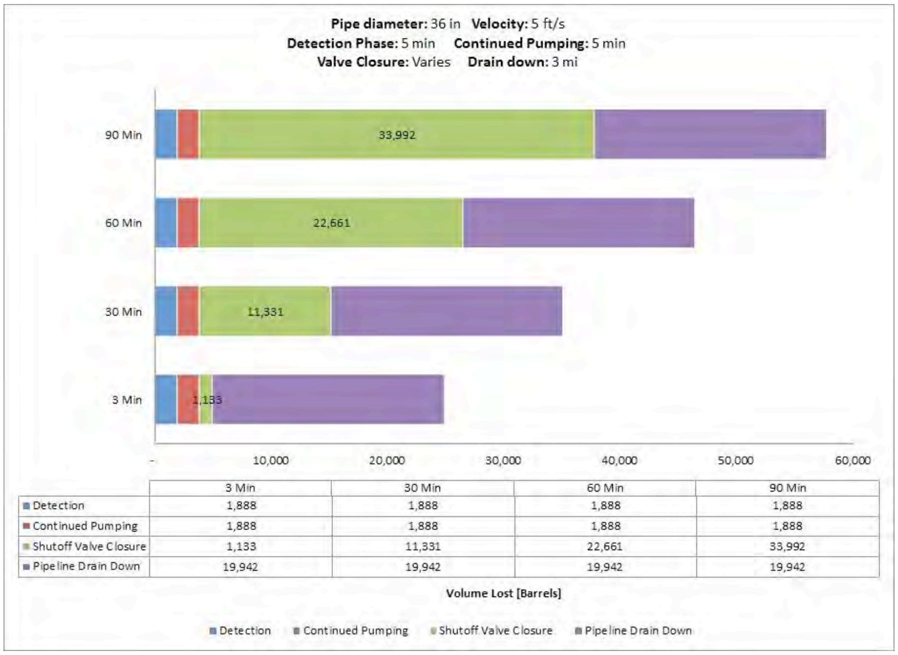
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-181. 36 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



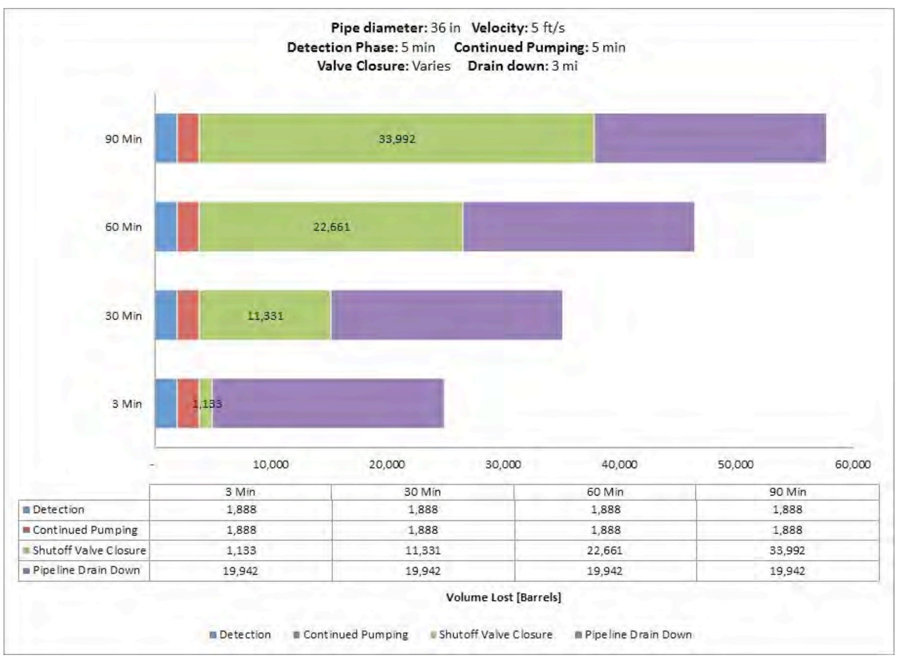
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-182. 36 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



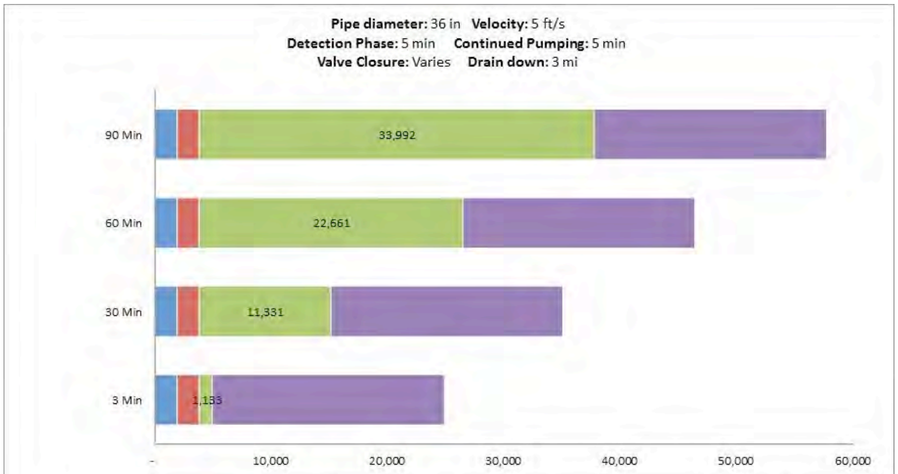
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-183. 36 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-184. 36 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

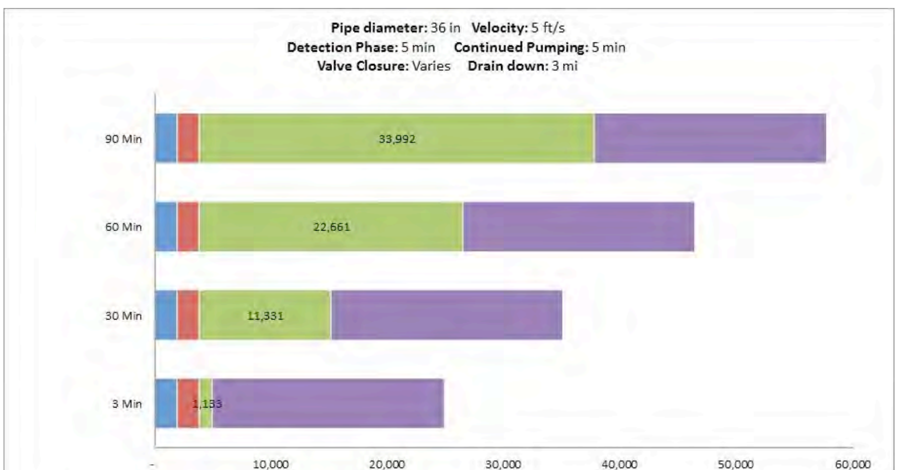


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-185. 36 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

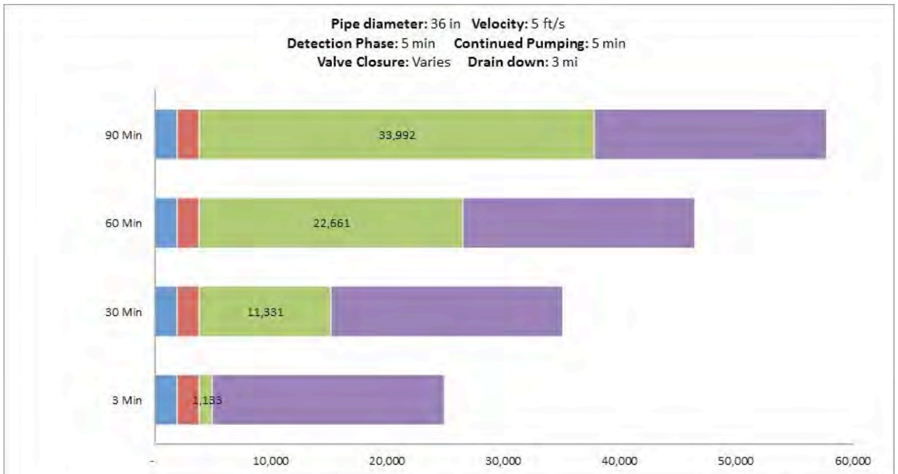


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-186. 36 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

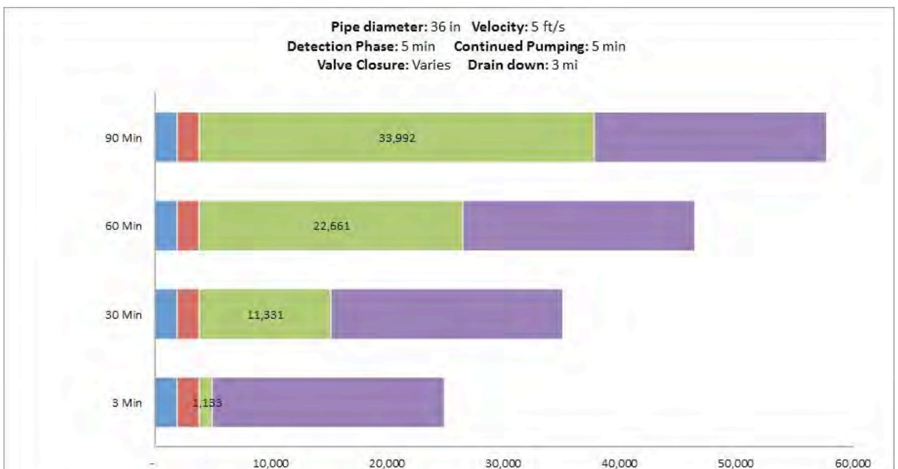


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-187. 36 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

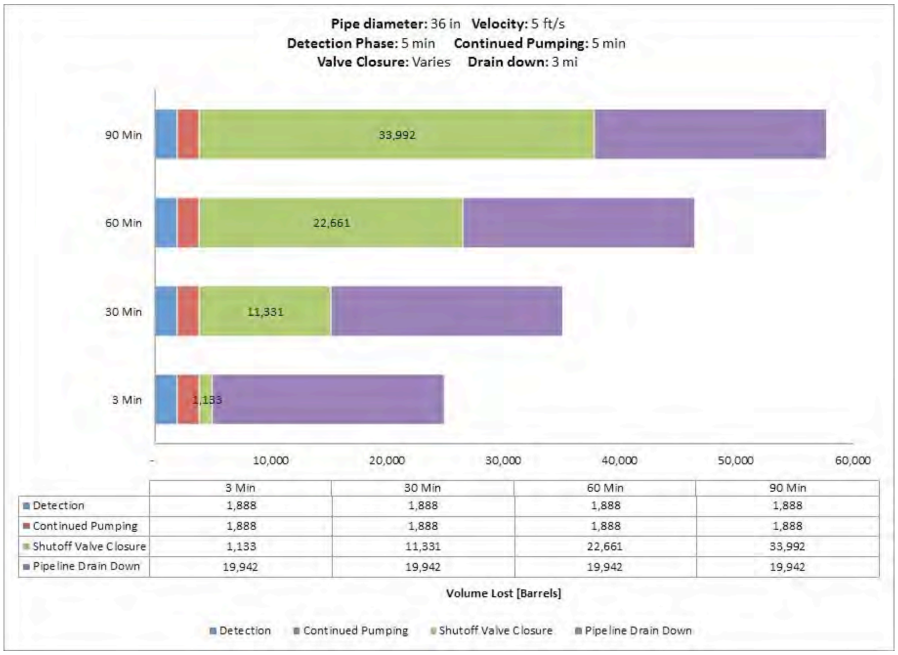


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

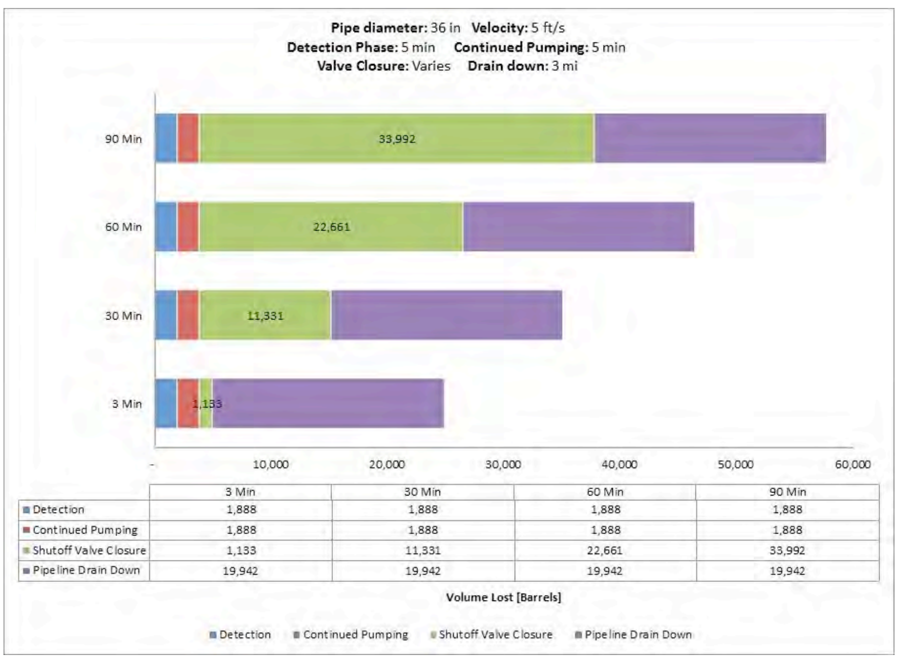
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-188. 36 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



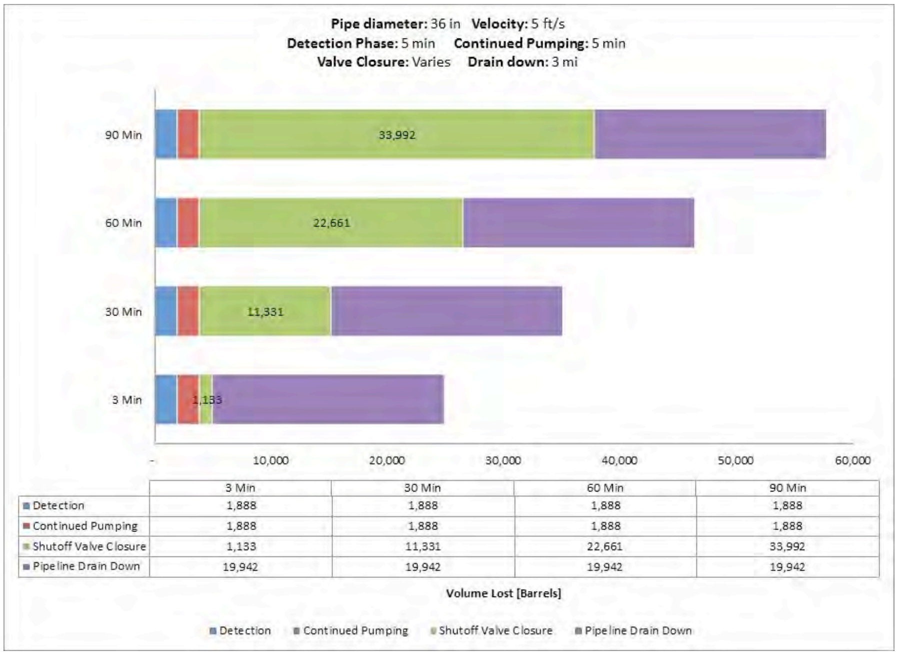
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-189. 36 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



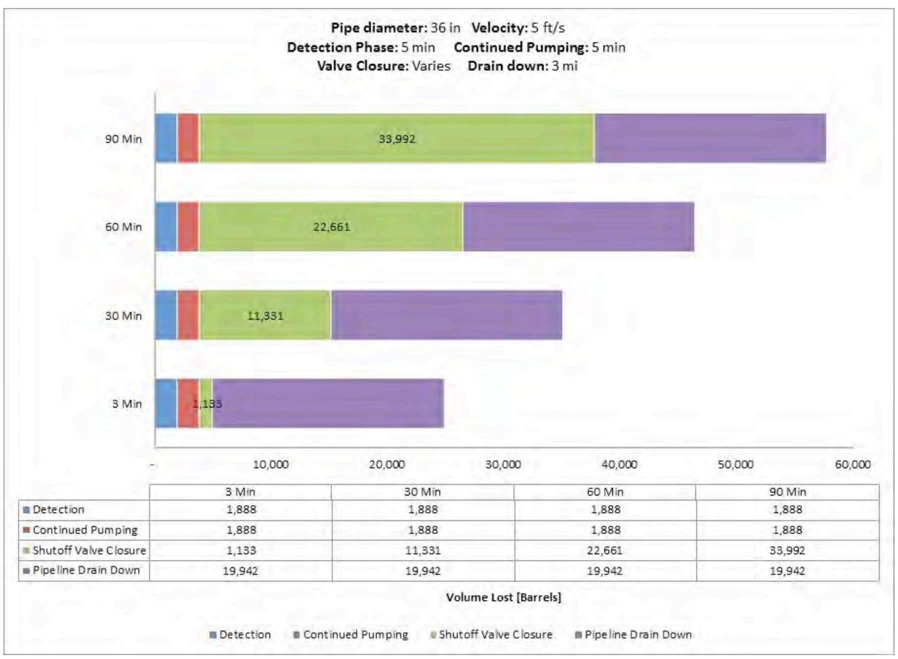
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-190. 36 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



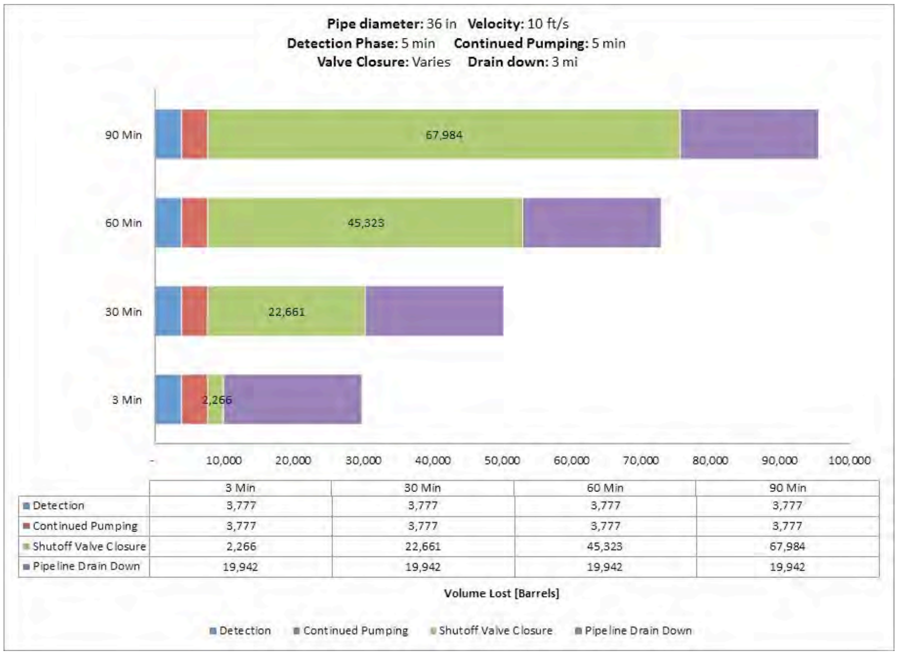
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-191. 36 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



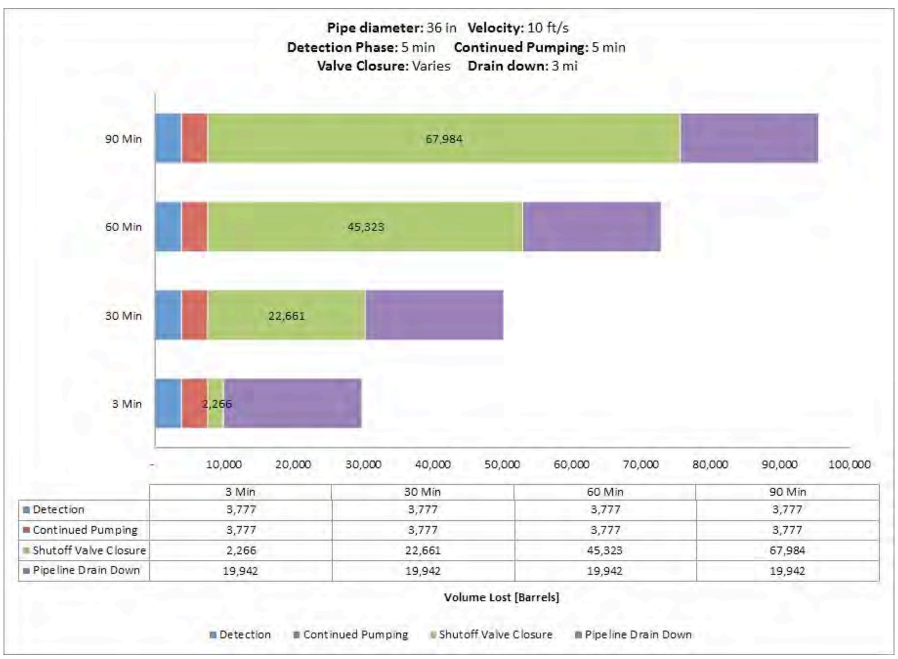
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-192. 36 Inch Pipe Diameter, 5 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



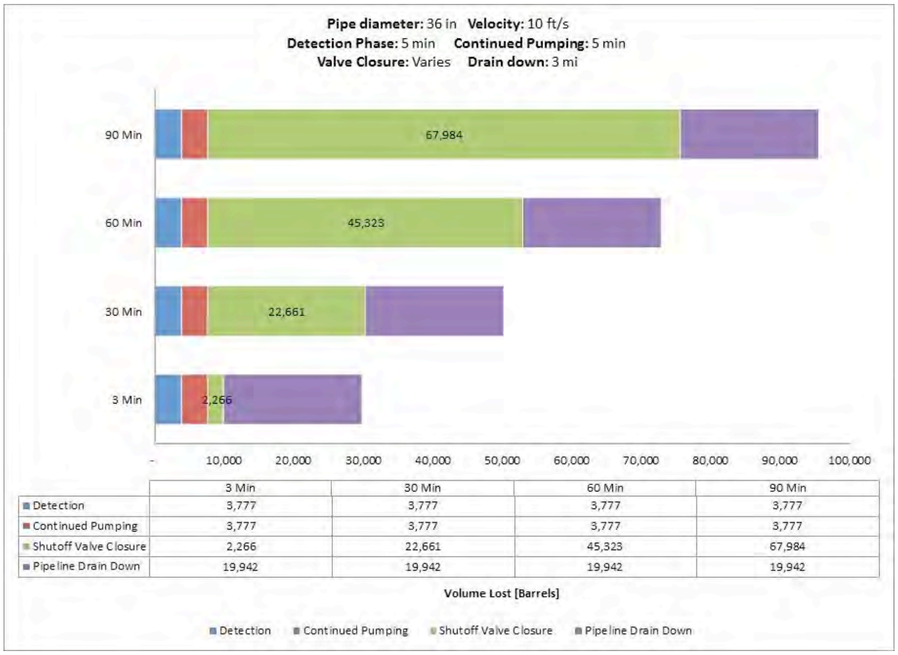
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-193. 36 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 100 Feet Elevation Change.



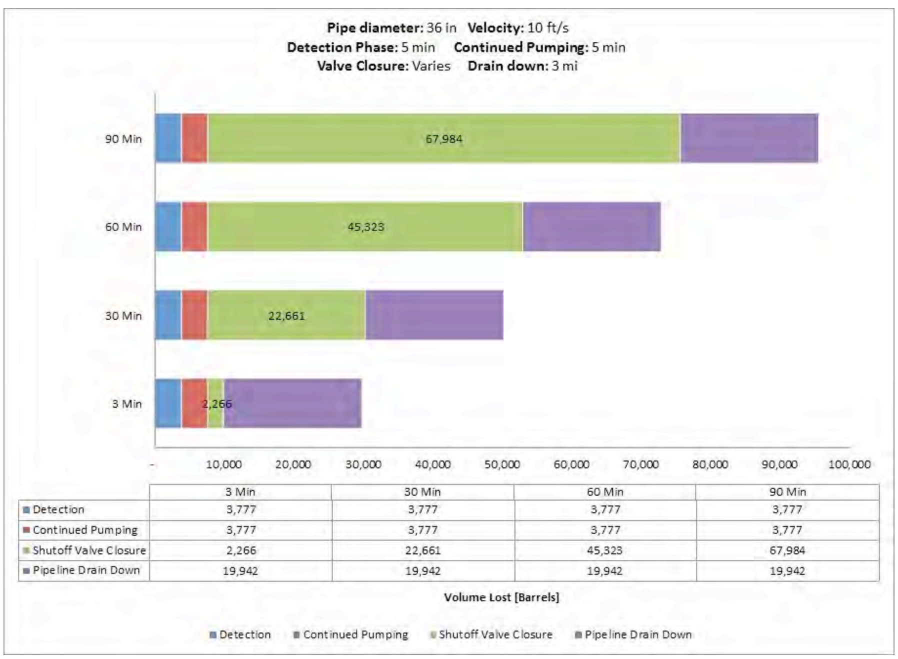
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-194. 36 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 500 Feet Elevation Change.



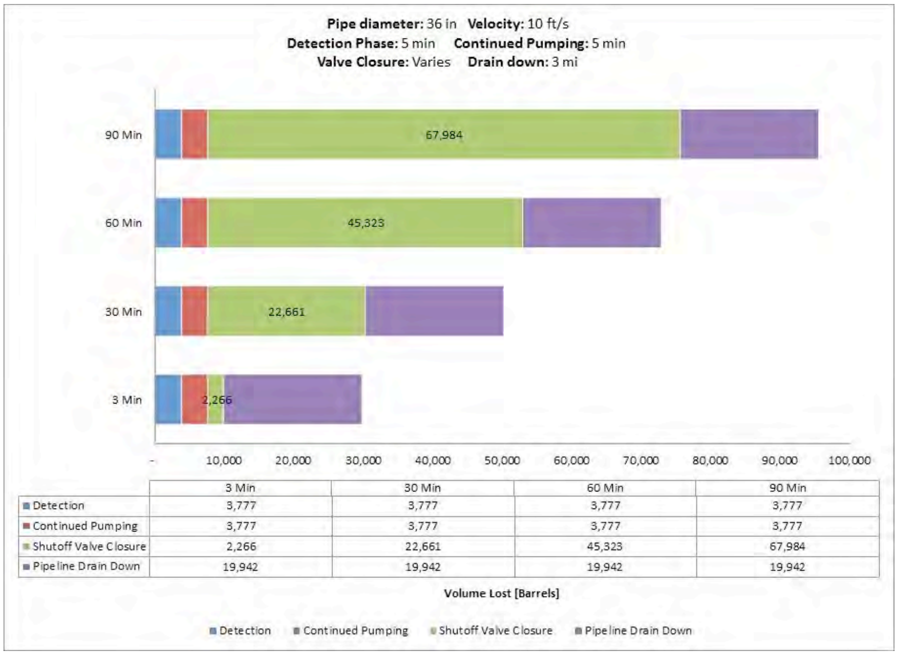
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-195. 36 Inch Pipe Diameter, 10 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.



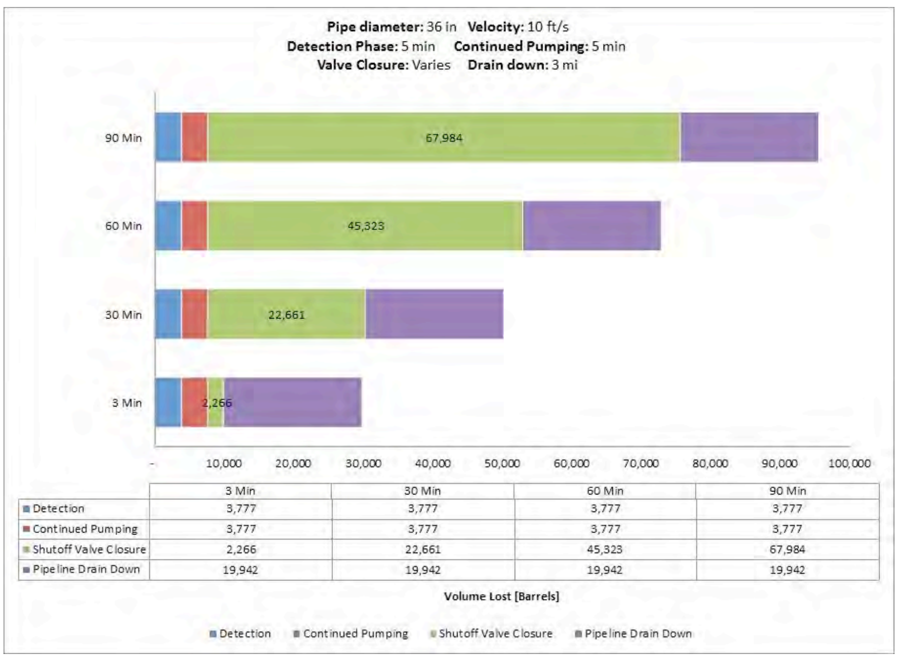
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-196. 36 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



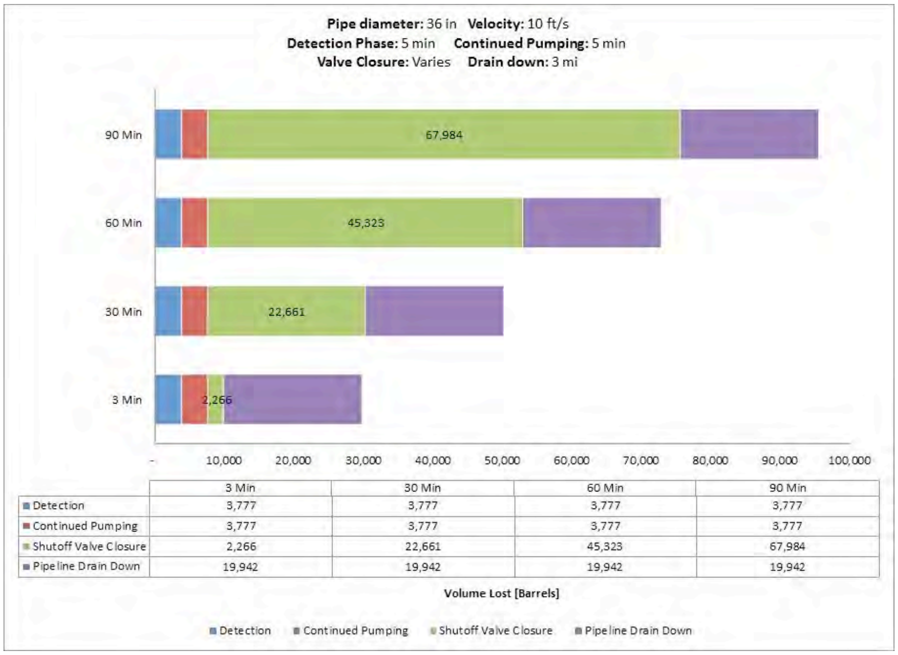
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-197. 36 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 500 Feet Elevation Change.



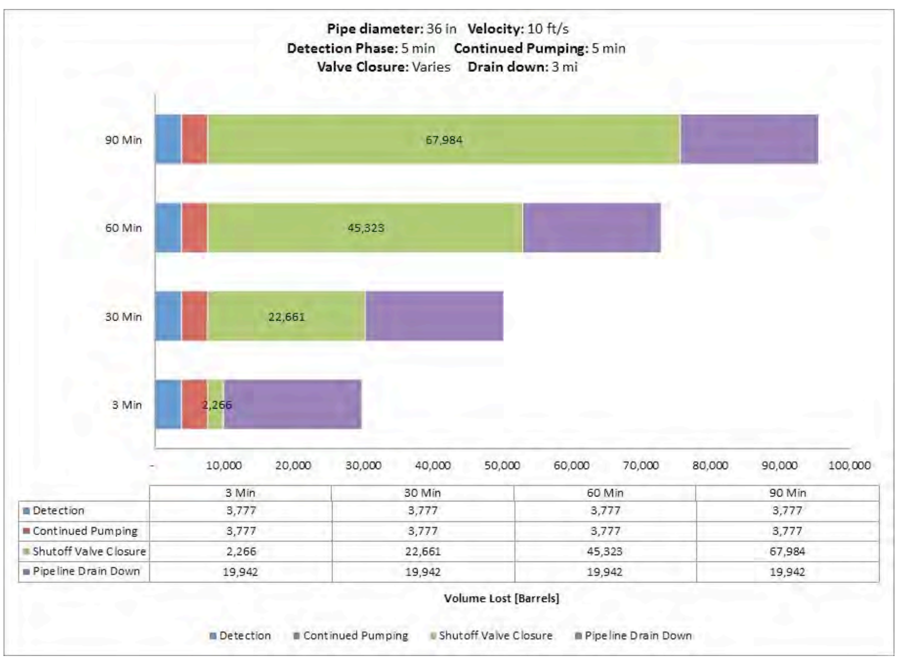
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-198. 36 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



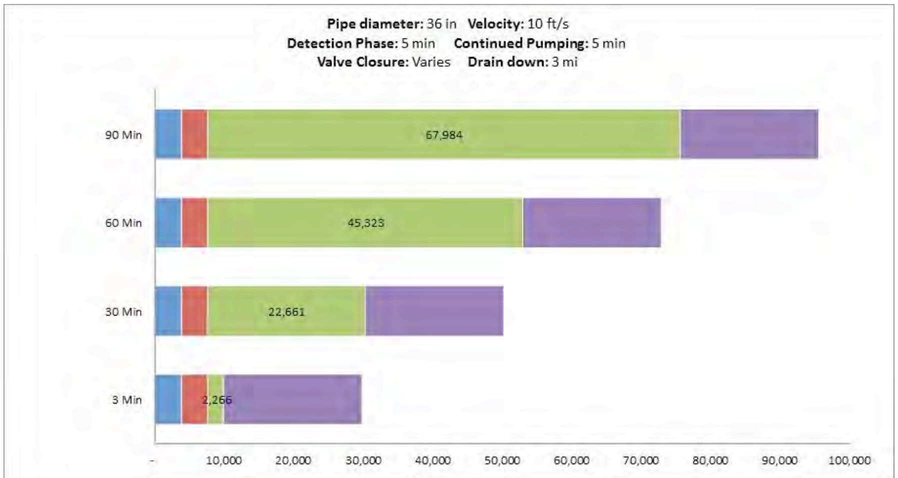
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-199. 36 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



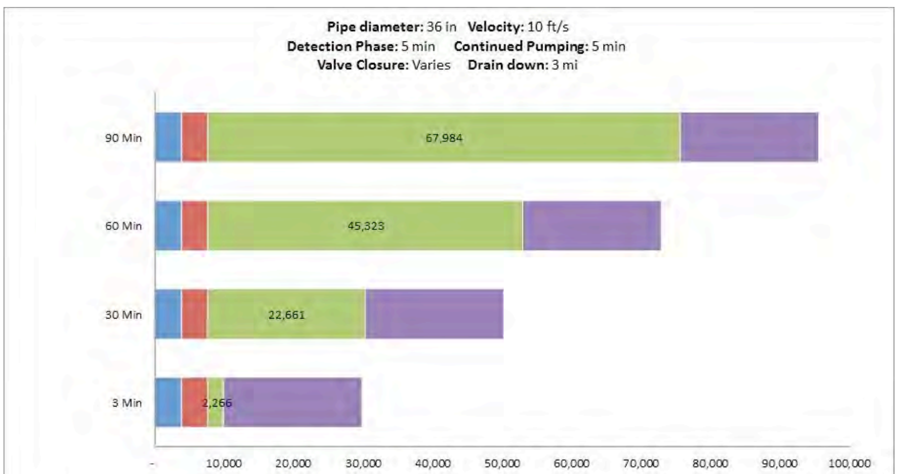
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-200. 36 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.



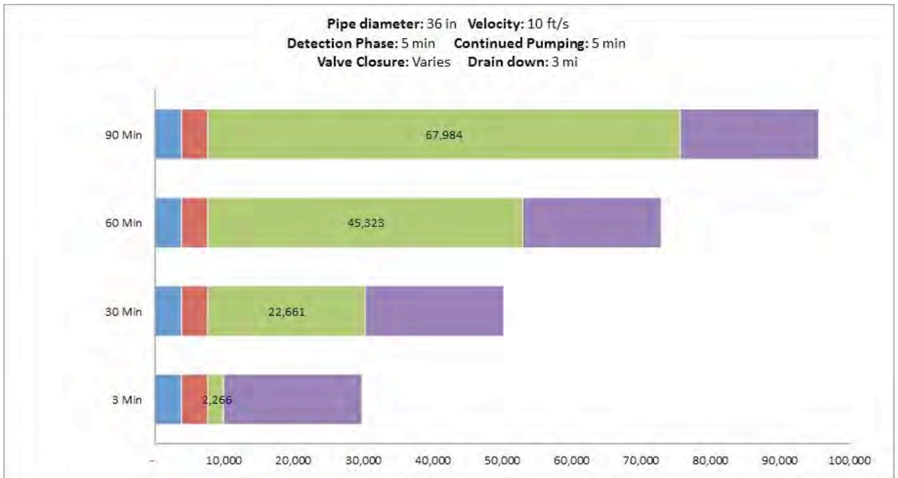
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-201. 36 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



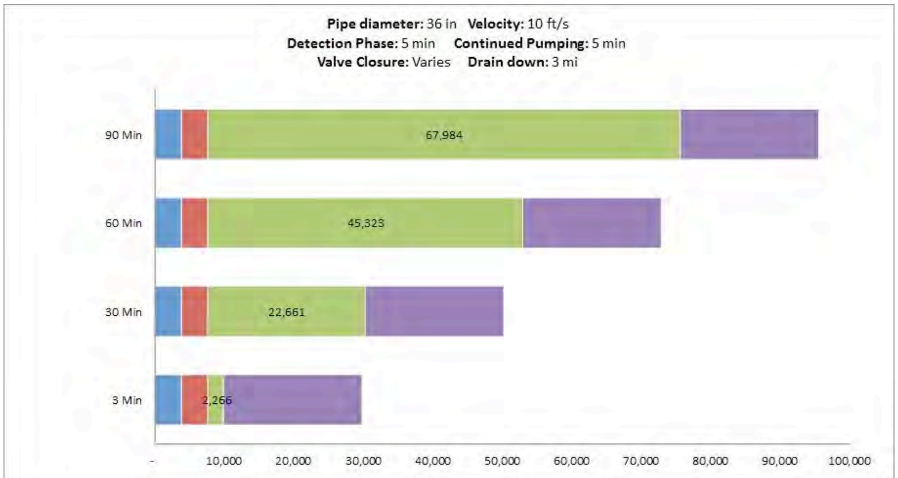
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-202. 36 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-203. 36 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-204. 36 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

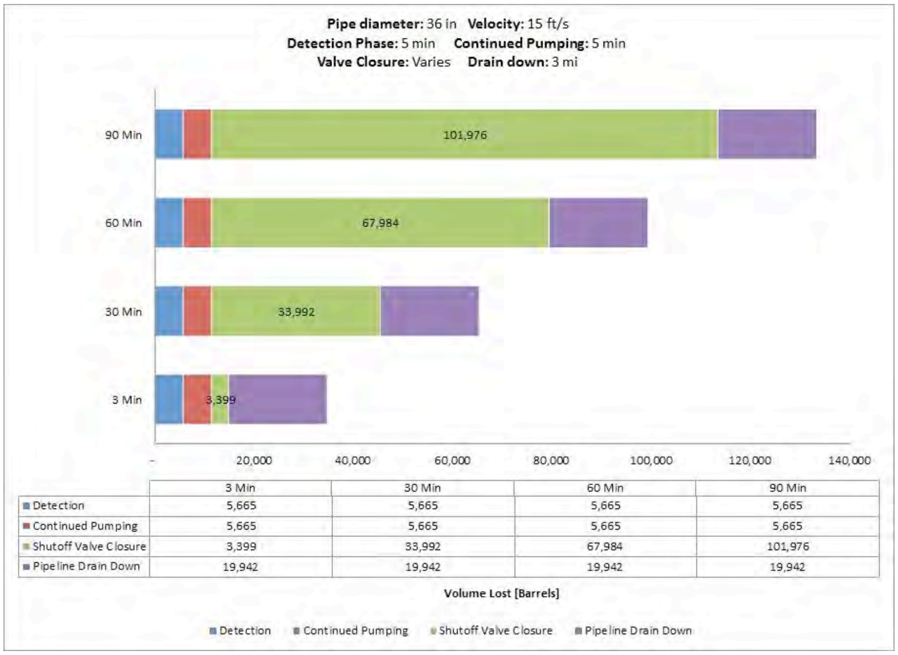
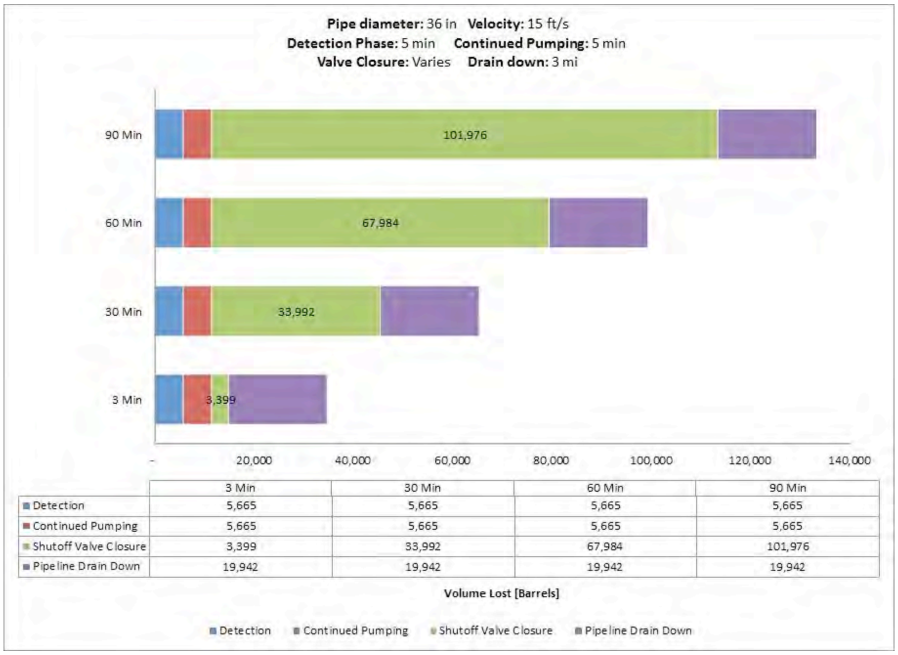


Fig. A-205. 36 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 100 Feet Elevation Change.

Fig. A-206. 36 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

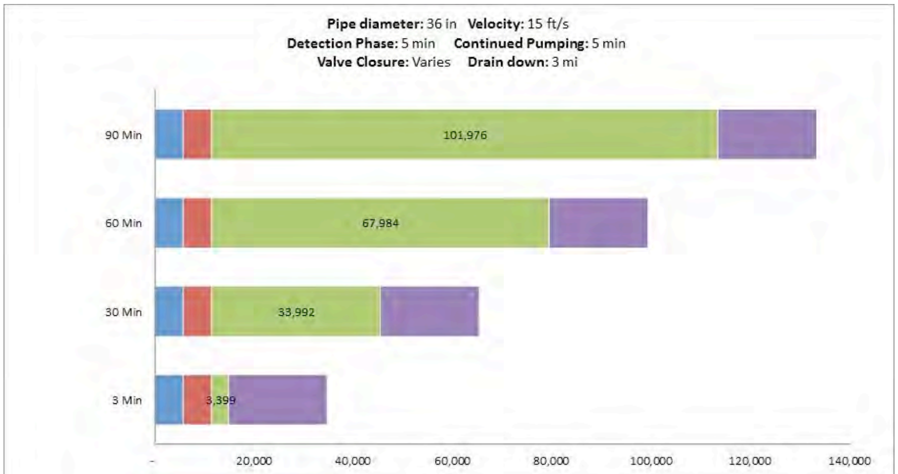


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-207. 36 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-208. 36 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

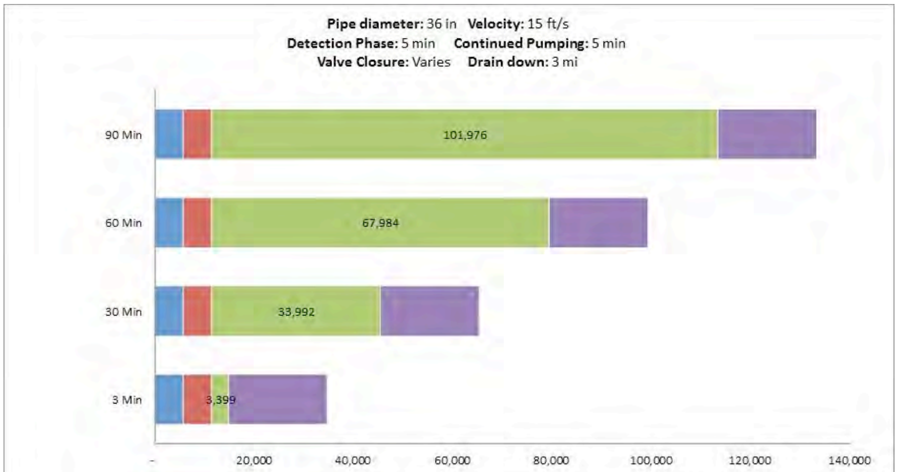


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-209. 36 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 500 Feet Elevation Change.

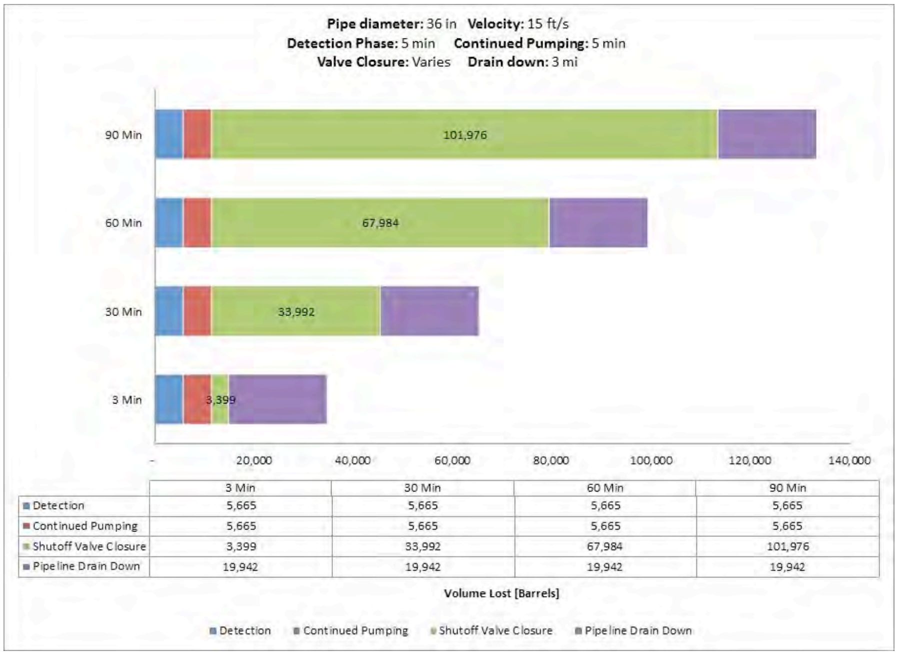


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

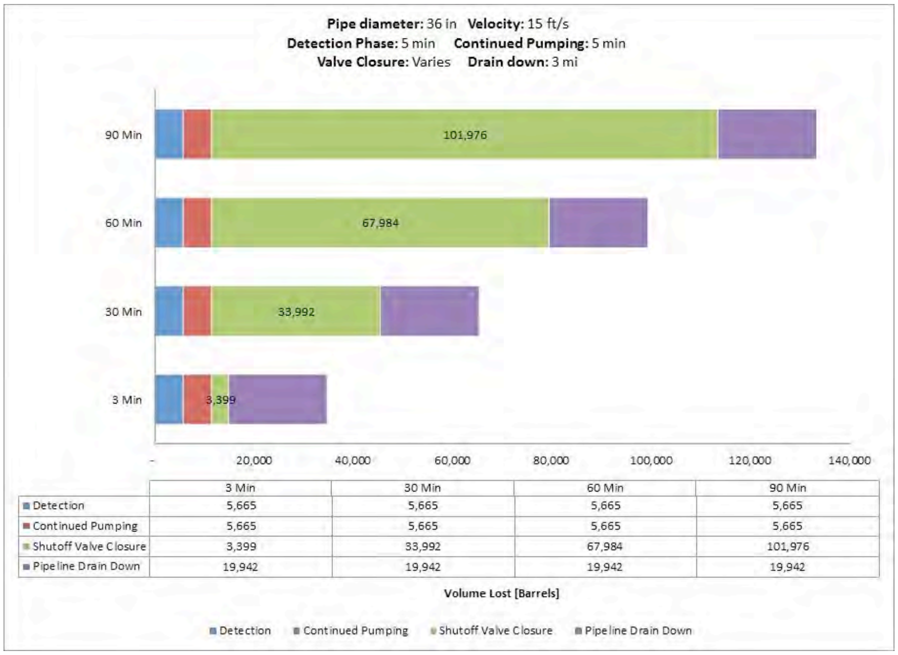
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-210. 36 Inch Pipe Diameter, 15 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.



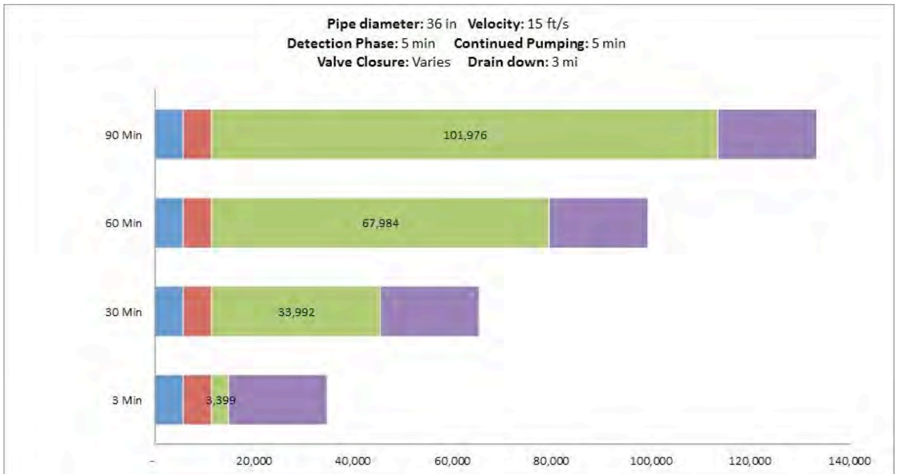
	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-211. 36 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-212. 36 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

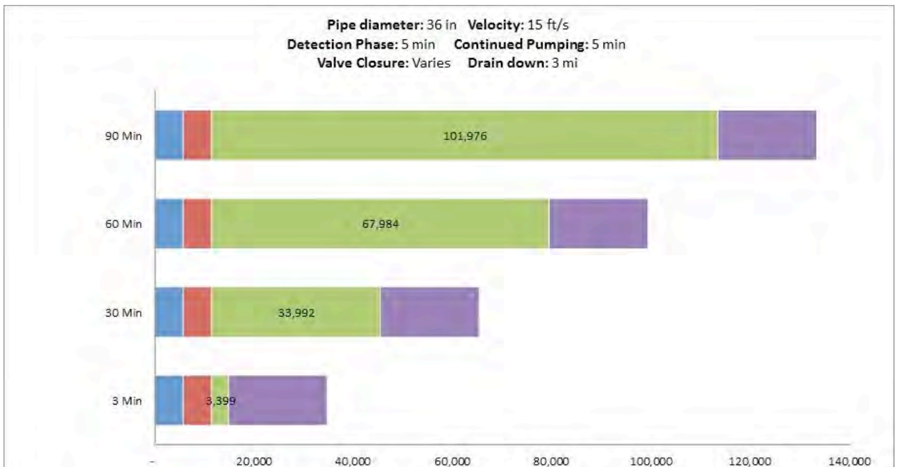


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-213. 36 Inch Pipe Diameter, 15 ft/s, 1200 psi MAOP, 1000 Feet Elevation Change.



	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-214. 36 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 100 Feet Elevation Change.

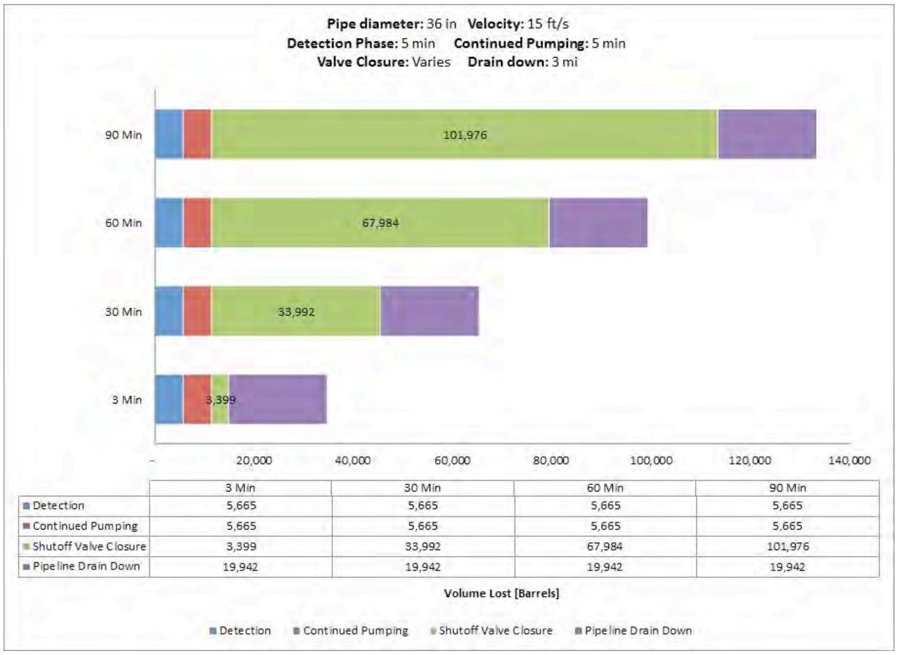


Fig. A-215. 36 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

Fig. A-216. 36 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

QuickTime™ and a
decompressor
are needed to see this picture.

Potential Impacts of Large-diameter Pipelines to Wetlands

From NE, overview of Mud Lake, Clearwater County.

The ice road in the marshes of Mud Lake.

Ice road.

Water, ice slush and peat soil slurry refills trench, Mud Lake.

Blocks of driven-in ice on W side of ROW off trench, Mud Lake.

Ice block with plant debris and soil on bottom, Mud Lake.

Though melting occurred, soil and plant material remain on surface off trench, Mud Lake.

Trench and blocks of material laden ice prominent on the surface of Mud Lake.

Another view from N, Mud Lake.

From E side ROW looking SW across Mud Lake.

From far E side of ROW near mid-crossing, looking SW across ROW through Mud Lake.

From N, trench and piles of spoil to Mud Lake.

From W side ROW looking SE across transition from upland to wetland, Mud Lake.

Overview from N ROW crossing, Mud Lake.

Status of a portion of ditchline within DNR LC 6, Mud Lake.

View from N across Mud Lake.

Drilling mud over HDD within S side of Hay Creek.

Frac bubbling up within containment over depression of HDD.

From S, view of Hay Creek clean-up operation.

Turbidity indication of frac disturbance near frac mound at Hay Creek.

Enbridge LSr Pipeline Project
Site Inspection

Inspector: Steve Toman

Inspection Date: 9/5/2008

Report Type: Frac-out

Agency: DNR

Compliance Level: Problem Area

Activity: Boring

County: Marshall

Begin Station: 3824+00

End Station:

Milepost Start: 845.7

Milepost End: 0

Tract Number 1: T-901

Tract Number 2:

Frac-out Location:

In stream: ☐

Upland: ☐

Near Stream: ☐

Wetland: ☑

Drill Phase: Pull-Back

Drill Pass:

Containment Measures:

None

Amount of Bentonite Dispersed:

100 Gallons within wetland W-845D, 500 Gallons within wetland W-845E

Control Measures Implemented to Continue Drilling:

The frac-out in wetland W-845D occurred during the last moments of the pipe pullback. The pullback was completed. No additional drill mud was released once the pullback stopped.

DNR Waterbody:

Wetland and/or Non-DNR Waterbody: W-845D

Inspection Notes:

A frac-out occurred during the guided bore beneath the south bar ditch of 250th St. NW. Communication confusion resulted, due to earlier frac-outs that occurred during this bore. Environmental Inspector Aric Donajkowki was present when a 500-gallon frac-out emerged from the road surface and within the north bar ditch of wetland W-845E. A short time later a 100-gallon frac-out occurred within wetland W-845D.
The contractor assumed that proper agency notification was occurring with Aric's presence. However, Aric was not present during the W-845D frac-out occurrence.

Frac-out containment could have been better. Inadequate sand bags were available for the containment of the frac-out and no vacuum truck was present. All the frac-outs have now been cleaned up.

Designed and Developed by Merjent, Inc. ©2008

MP 845.80, Frac-out, W-845D, view southeast.

Designed and Developed by Merjent, Inc. ©2008

MP 845.80, Frac-out cleanup, W-845D, view east.

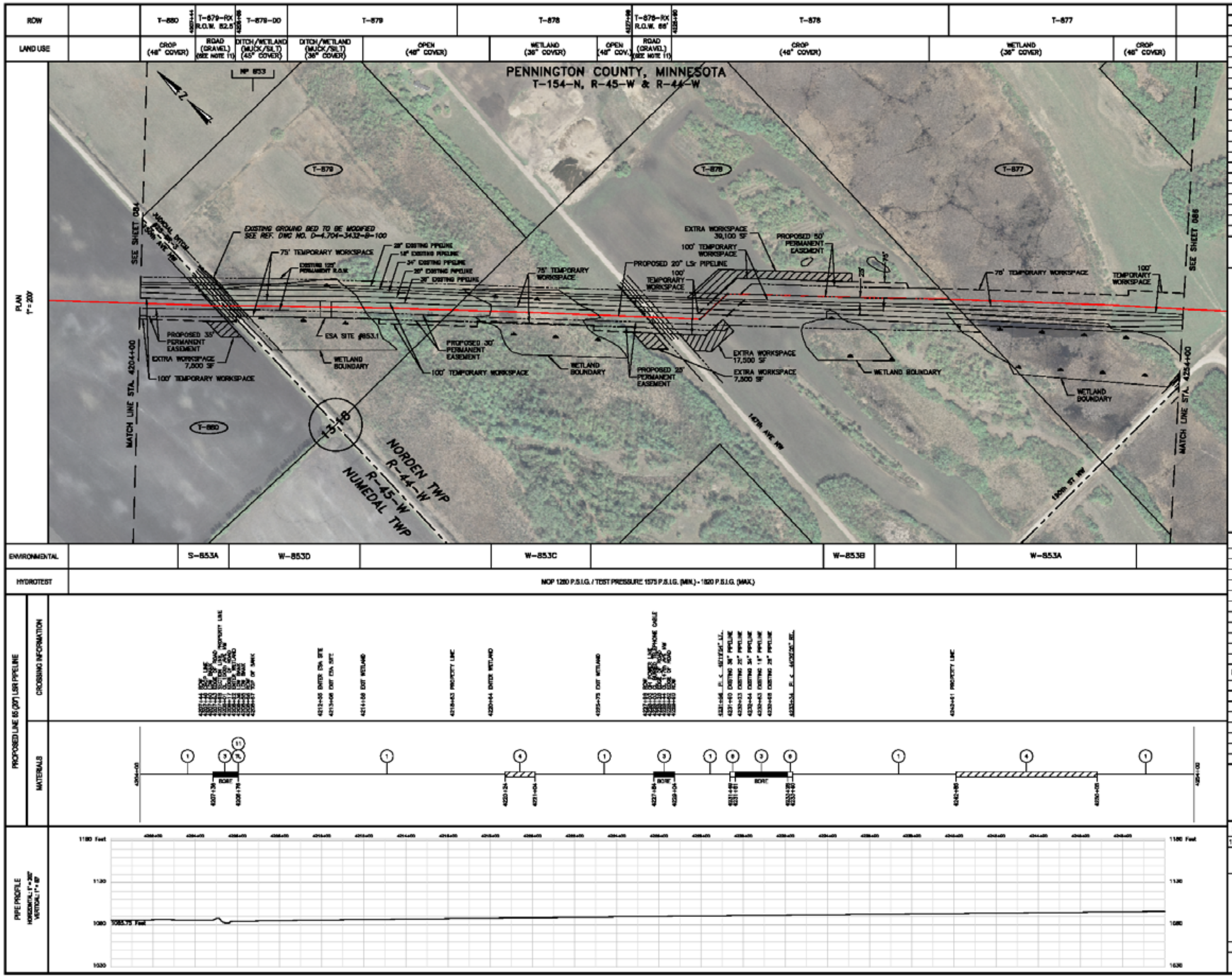
Designed and Developed by Merjent, Inc. ©2008

MP 845.70, Wetland W-845E and road surface frac-out, view southeast.

Designed and Developed by Merjent, Inc. ©2008

MP 845.70, Wetland W-845E, Frac-out cleanup, view east.

Designed and Developed by Merjent, Inc. ©2008



NO.	LSR (20") PIPELINE MATERIAL SUMMARY	QTY.
1	20" O.D. x 0.250" W.T. x API-5L X-70, ERW,	3249 LF
	14 MILS FBE	
3	20" O.D. x 0.312" W.T. x API-5L X-70, ERW,	427 LF
	40 MILS A.R. FBE	
4	20" O.D. x 0.312" W.T. x API-5L X-70, ERW,	600 LF
	18 MILS FBE W/ 3" CONC. COATING	
6	INDUCTION BEND(S) 20" O.D. x 0.312" W.T. x	24 LF
	API-5L X-70, ERW, 14 MILS FBE	
11	TEST LEAD(S)	1 EA

SCALE IN FEET

1. ENBRIDGE ENERGY EMERGENCY NUMBER: 1-800-858-5253
2. CONTRACTOR IS REQUIRED TO HAVE UTILITIES LOCATED BEFORE THEY DIG. CALL 811 OR THE STATE UTILITY LOCATE SERVICE APPLICABLE TO THE STATE IN WHICH CONTRACTOR IS WORKING.
3. ALL DIMENSIONS SHALL BE FIELD VERIFIED.
4. ALL HORIZONTAL AND VERTICAL DIMENSIONS ARE IN FEET, UNLESS OTHERWISE SPECIFIED.
5. HYDROTEST: CONTRACTOR SHALL SUBMIT A HYDROTEST PLAN FOR COMPANY (ENBRIDGE ENERGY) APPROVAL BEFORE PERFORMING A HYDROTEST.
6. CONTRACTOR SHALL ADDITIONALLY COMPLY WITH THE REQUIREMENTS SPECIFIED IN THE REFERENCE DRAWINGS NOTED ON THIS ALIGNMENT SHEET.
7. QUANTITY OF SET ON WEIGHTS IS APPROXIMATE. THE ACTUAL QUANTITY OF SET ON WEIGHTS SHOULD BE DETERMINED BY THE GIVEN FIELD CONDITIONS.
8. WETLAND STATIONING IS APPROXIMATE ONLY. ACTUAL WETLAND BOUNDARIES WILL BE STAKED BY THE APPROPRIATE COMPANY ENVIRONMENTAL PERSONNEL.
9. CONTRACTOR SHALL COMPLY WITH ALL REQUIREMENTS OF THE PROJECT AGRICULTURAL MANAGEMENT PLAN (AMP) AND ENVIRONMENTAL MANAGEMENT PLAN (EMP).
10. PIPELINE IS HORIZONTALLY STATIONED AND PIPELINE LOCATION IS BASED ON MINNESOTA STATE PLANE (NORTH ZONE) COORDINATE SYSTEM, NAD 83, U.S. SURVEY FEET UNITS.
11. AS A MINIMUM, THE DEPTH OF COVER UNDER ROAD DITCHES SHALL BE 54", AND UNDER THE ROAD SURFACE SHALL BE 60", UNLESS SHOWN OTHERWISE.

DWG. NO.	REFERENCE DRAWING TITLE

NO.	REVISION - DESCRIPTION	BY	DATE	CHK'D	APP'D
A	ISSUED FOR REVIEW	GIE	12-15-07	LR	RH
B	GENERAL REVISIONS	GIE	2-08-08	LR	RH
C	ISSUED FOR CONSTR. PLANNING	GIE	3-31-08	LR	RH
D	ISSUED FOR CONSTRUCTION	GIE	5-16-08	LR	RH

SCALE	DATE	DESIGNED	DRAWN	CHK'D	APP'D	APP'D
1"=200'	11/19/07	GIE	GIE	LR	RH	

ENBRIDGE

LSr PIPELINE
PROPOSED 20" LINE
M.P. 852.9 TO M.P. 853.8
PENNINGTON COUNTY, MINNESOTA

DRAWING NUMBER	ROUTE SHEET
D-65-5.92-1386-085-D-100	085

Clearwater River Crossings, Beltrami County, a designated trout stream. Indicates long-term changes in the floodplain and river channels. Photo 6 was taken on Nelson Dam Road in the upper right corner of this photo. Milepost

Close-up of the Clearwater River Crossing, Beltrami County.

ATV traffic up and down Clearwater River bluffs through slope-breakers constructed to prevent erosion on Terrace III project.

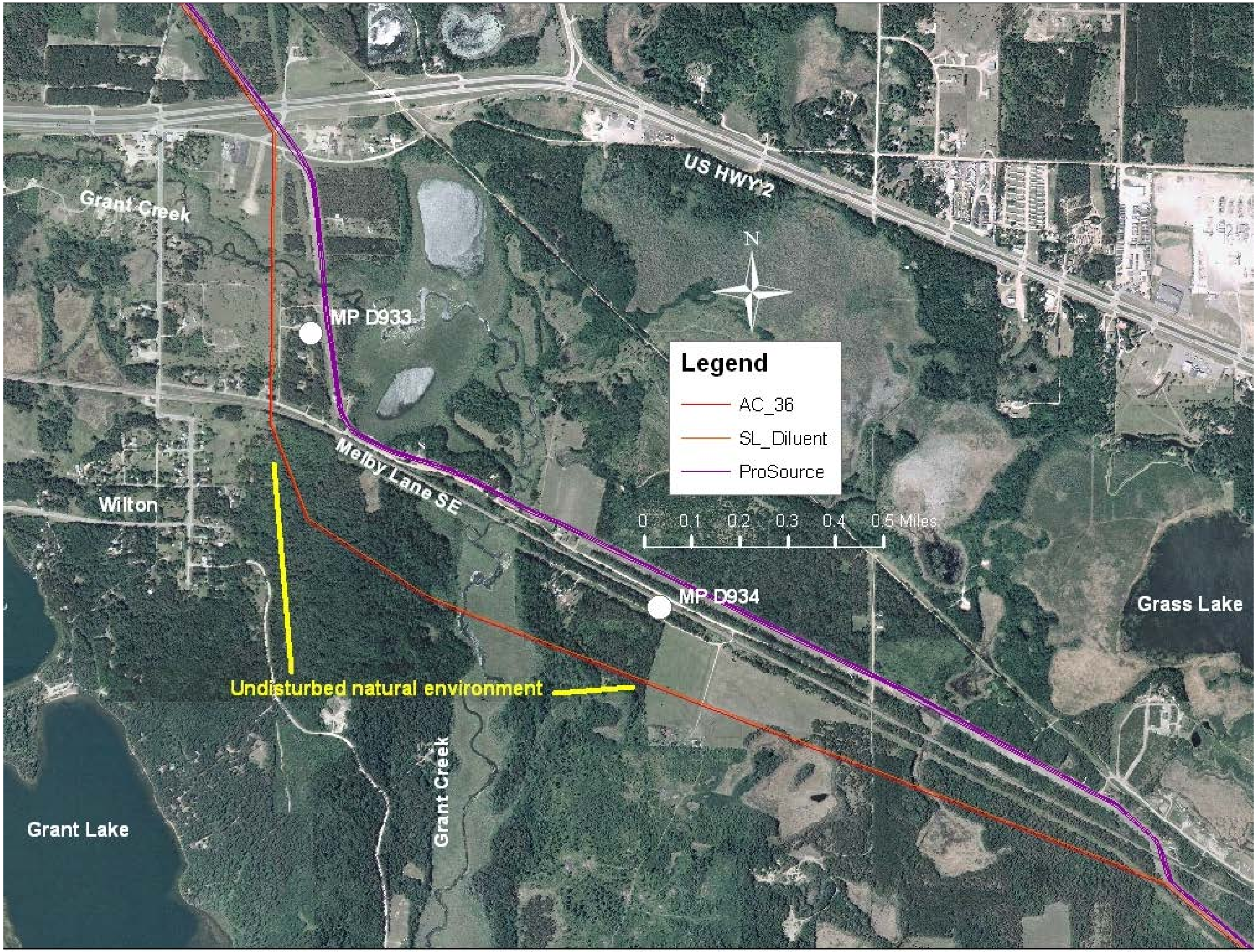
Clearwater River floodplain indicating permanent changes to wetlands from the existing corridor as well as slope erosion and sparse re-vegetation from Terrace III. Top of bluff is about 60 feet above the Floodplain.

Clearwater River, bottom of E bluff. Cement barriers used to impede ATV access to the ROW after an access road was recently constructed for pipeline repair.

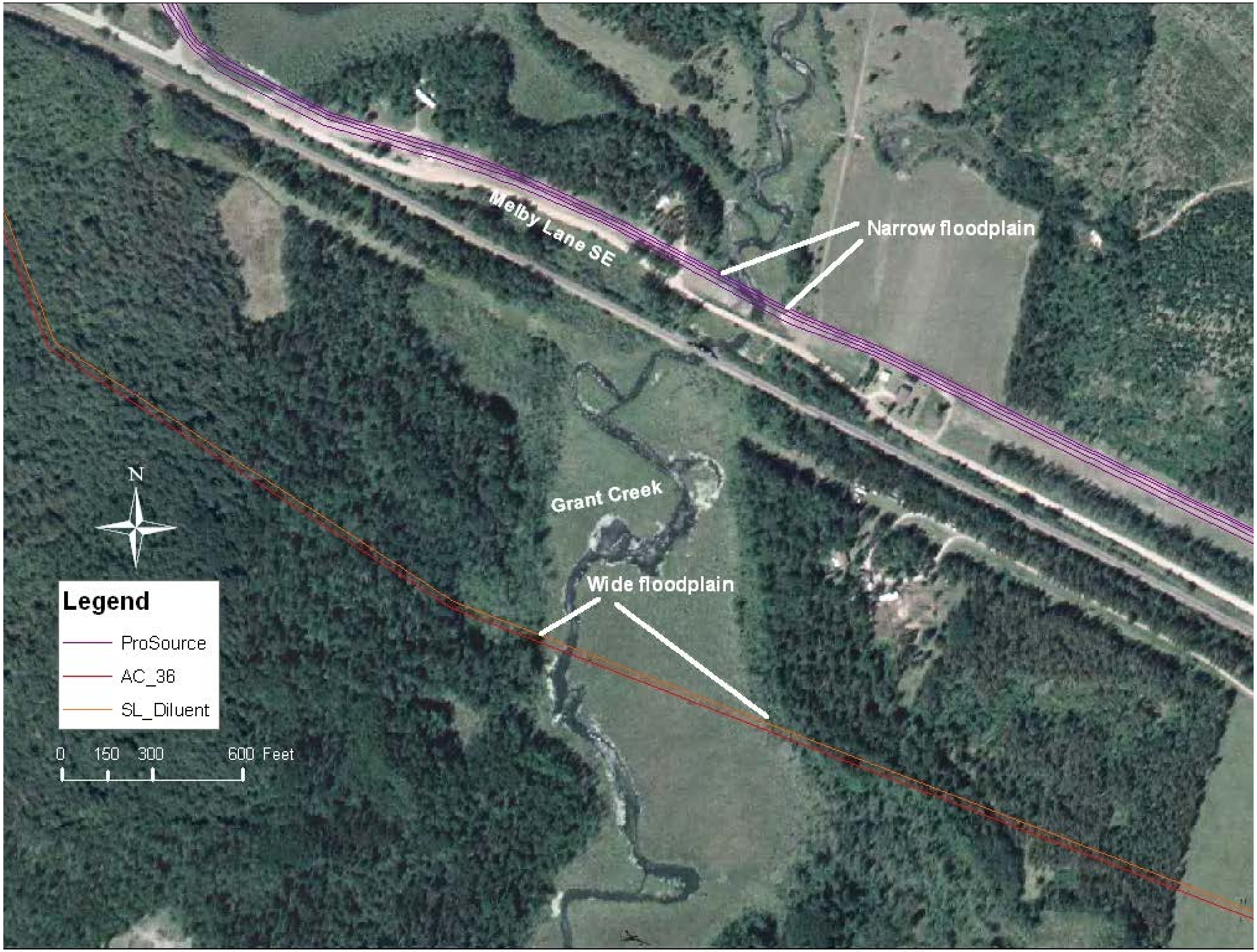
Site is adjacent to Clearwater River by railroad grade, which is now a motorized OHV recreational trail. Boulders placed at base of slope to impede ATV off-trail use.

Grant Creek pipeline corridor crossing at approximately MP 929.8. OHV trail is on railroad grade.

Close-up of Grant Creek pipeline corridor looking N toward OHV trail on railroad grade, indicating OHV off-trail destruction of stream banks and vegetation



New corridor proposed through undisturbed natural area and new Grant Creek crossing, a revision of the June 2007 filing. Approximately MP 932.5 through MP935.3



Close-up view of new Grant Creek crossing and corridor, portion of Photo 9 area.

Enbridge crossing of Necktie River, a designated trout stream indicating brook trout spawning habitat adjacent to the crossing, MP 927.