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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

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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

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CONTENTS

	Page
CONTENTS	v
LIST OF FIGURES	vii
LIST OF TABLES	xiii
ABBREVIATIONS AND ACRONYMS	xv
ACKNOWLEDGMENTS	xvii
ABSTRACT	xix
EXECUTIVE SUMMARY	xxi
E.1 CONSEQUENCE MODELS	xxii
E.2 ASSESSMENT METHODOLOGY AND RESULTS FOR NATURAL GAS PIPELINE RELEASES	xxiii
E.3 ASSESSMENT METHODOLOGY AND RESULTS FOR HAZARDOUS LIQUID PIPELINE RELEASES WITH IGNITION	xxv
E.4 ASSESSMENT METHODOLOGY AND RESULTS FOR HAZARDOUS LIQUID PIPELINE RELEASES WITHOUT IGNITION	xxvi
E.5 FEASIBILITY EVALUATIONS	xxvii
E.6 POTENTIAL CONSEQUENCE REDUCTION STRATEGIES	xxviii
1. INTRODUCTION	1
1.1 STUDY BASIS	1
1.1.1 Previous Studies and Recommendations	2
1.1.2 Study Authorization and Purpose	3
1.2 STUDY SCOPE AND OBJECTIVES	4
1.3 STUDY PARAMETERS AND BOUNDARIES	6
1.3.1 Natural Gas Pipeline Release Events	6
1.3.2 Hazardous Liquid Pipeline Release Events	11
1.3.3 Fire Science and Potential Fire Consequences	16
1.3.4 Thermal Radiation Effects	20
1.3.5 Socioeconomic and Environmental Effects of a Hazardous Pipeline Release	23
2. REGULATORY REQUIREMENTS	25
2.1 49 CFR 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS	25
2.2 49 CFR 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE	28
2.3 49 CFR 194—RESPONSE PLANS FOR ONSHORE OIL PIPELINES	30
3. RISK ANALYSIS	33
3.1 NATURAL GAS PIPELINES	34
3.1.1 Analysis Scope, Parameters, and Assumptions	34
3.1.2 Analytical Approach and Computational Models	35
3.1.3 Thermal Radiation Intensities and Thresholds	42

3.1.4 Risk Analysis Results for Natural Gas Pipeline Releases 54
3.2 HAZARDOUS LIQUID PIPELINES WITH IGNITION 135
3.2.1 Analysis Scope, Parameters, and Assumptions 135
3.2.2 Analytical Approach and Computational Models.. 136
3.2.3 Thermal Radiation Intensities and Thresholds.. 138
3.2.4 Risk Analysis Results for Propane Pipeline Releases.. 139
3.3 HAZARDOUS LIQUID PIPELINES WITHOUT IGNITION 149
3.3.1 Analysis Scope, Parameters, and Assumptions 150
3.3.2 Analytical Approach and Computational Models.. 150
3.3.3 Socioeconomic and Environmental Effects 152
3.3.4 Risk Analysis Results for Hazardous Liquid Pipeline Releases 156
4. TECHNICAL AND OPERATIONAL FEASIBILITY 167
4.1 AUTOMATIC SHUTOFF VALVES 170
4.1.1 Automatic Shutoff Valve Features and Operating Characteristics 171
4.1.2 Automatic Shutoff Valve Technical Feasibility Assessment.............................. 171
4.1.3 Automatic Shutoff Valve Operational Feasibility Assessment........................... 172
4.2 REMOTE CONTROL VALVES 172
4.2.1 Remote Control Valve Features and Operating Characteristics 173
4.2.2 Remote Control Valve Technical Feasibility Assessment.................................. 173
4.2.3 Remote Control Valve Operational Feasibility Assessment............................... 174
5. COST BENEFIT AND ECONOMIC FEASIBILITY 175
5.1 EVALUATION METHODOLOGY AND ACCEPTANCE CRITERIA 176
5.1.1 Damage Costs for Natural Gas Pipeline Releases with Ignition......................... 176
5.1.2 Damage Costs for Hazardous Liquid Pipeline Releases with Ignition 177
5.1.3 Damage Costs for Hazardous Liquid Pipeline Releases without Ignition 179
5.2 COST BENEFIT ANALYSIS..180
5.2.1 Cost Benefit Analysis for Natural Gas Pipeline Releases with Ignition 180
5.2.2 Cost Benefit Analysis for Hazardous Liquid Pipelines with Ignition................. 182
5.2.3 Cost Benefit Analysis for Hazardous Liquid Pipelines without Ignition............ 182
5.3 ECONOMIC FEASIBILITY ASSESSMENT 183
5.4 COST EFFECTIVE IMPLEMENTATION STRATEGIES FOR CONSEQUENCE REDUCTION 184
6. SUMMARY OF RESULTS...187
6.1 POTENTIAL CONSEQUENCES AND EFFECTS..188
6.2 TECHNICAL AND OPERATIONAL FEASIBILITY ASSESSMENT RESULTS 189
6.3 COST BENEFIT AND ECONOMIC FEASIBILITY ASSESSMENT RESULTS...........189
6.4 STRATEGIES FOR CONSEQUENCE REDUCTION 190
7. REFERENCES...193
BIBLIOGRAPHY 197
APPENDIX A: SPILL VOLUME RELEASED DUE TO VALVE CLOSURE TIMES IN LIQUID PROPANE PIPELINES.. A - 1

LIST OF FIGURES

Figure **Page**

Fig. 1.1. Crater resulting from natural gas pipeline release near Carlsbad, New Mexico (NTSB, 2003). 7

Fig. 1.2. Fire resulting from natural gas pipeline release near Carlsbad, New Mexico (NTSB, 2003). 7

Fig. 1.3. Fire damage resulting from hazardous liquid pipeline release in Bellingham, Washington (NTSB, 2002). 12

Fig. 1.4. Pipeline drain down segment, *L*. 15

Fig. 3.1. Relationships among heat flux intensities and exposure durations for fire damage categories for buildings and dwellings intended for human occupancy. 44

Fig. 3.2. Configuration of a Class 1 HCA with buildings or dwellings intended for human occupancy. 45

Fig. 3.3. Configuration of a Class 1 HCA with an identified site consisting of buildings with four or more stories. 46

Fig. 3.4. Configuration of a Class 1 HCA with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period. 46

Fig. 3.5. Configuration of a Class 2 HCA with buildings or dwellings intended for human occupancy. 47

Fig. 3.6. Configuration of a Class 2 HCA with an identified site consisting of buildings with four or more stories. 47

Fig. 3.7. Configuration of a Class 2 HCA with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period. 48

Fig. 3.8. Configuration of a Class 3 Location with buildings and dwellings intended for human occupancy. 48

Fig. 3.9. Configuration of a Class 3 Location with an outside recreational facility. 49

Fig. 3.10. Configuration of a Class 4 Location with buildings with four or more stories above ground. 49

Fig. 3.11. Configuration of a High Population Area or an Other Populated Area. 50

Fig. 3.12. Relationships among heat flux intensities and exposure durations for fire damage categories for buildings with four or more stories above ground. 51

Fig. 3.13. Relationships among heat flux intensities and exposure durations for fire damage categories for outside recreational facilities. 52

Fig. 3.14. Relationships among heat flux intensities and exposure durations for fire damage categories for vehicles parked outside. 54

Fig. 3.15. 12-in. Baseline-15: Separation distances for 12-in. natural gas pipeline operating at a MAOP of 300 psig with no block valve closure and compressor inflow equal to 15 ft/s....57

Fig. 3.16. 12-in. Baseline-0: Separation distances for 12-in. natural gas pipeline operating at a MAOP of 300 psig with no block valve closure and compressor inflow equal to 0 ft/s....57

Fig. 3.17. 42-in. Baseline-15: Separation distances for 42-in. natural gas pipeline operating at a MAOP of 1,480 psig with no block valve closure and compressor inflow equal to 15 ft/s....58

Fig. 3.18. 42-in. Baseline-0: Separation distances for 42-in. natural gas pipeline operating at a MAOP of 1,480 psig with no block valve closure and compressor inflow equal to 0 ft/s....58

Fig. 3.19. Separation distances for 12-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break....61

Fig. 3.20. Separation distances for 12-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break....61

Fig. 3.21. Separation distances for 42-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break....62

Fig. 3.22. Separation distances for 42-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break....62

Fig. 3.23. Case Study 1A – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 1 Location with buildings intended for human occupancy and a PIR greater than 660 feet – 1,480 psig MAOP and block valve closure 8 minutes after break....66

Fig. 3.24. Case Study 1B – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 1 Location with buildings intended for human occupancy and a PIR greater than 60 feet – 1,480 psig MAOP and block valve closure 13 minutes after break....66

Fig. 3.25. Case Study 1C – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break....72

Fig. 3.26. Case Study 1D – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break....72

Fig. 3.27. Case Study 1E – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break....73

Fig. 3.28. Case Study 1F – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break....73

Fig. 3.29. Case Study 1G – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 8 minutes after break. 79

Fig. 3.30. Case Study 1H – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 13 minutes after break. 79

Fig. 3.31. Case Study 1I – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 8 minutes after break. 80

Fig. 3.32. Case Study 1J – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 13 minutes after break. 80

Fig. 3.33. Separation distances for 12-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break. 83

Fig. 3.34. Separation distances for 12-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break. 83

Fig. 3.35. Separation distances for 42-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break. 84

Fig. 3.36. Separation distances for 42-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break. 84

Fig. 3.37. Case Study 2A – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 2 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 8 minutes after break. 88

Fig. 3.38. Case Study 2B – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 2 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 13 minutes after break. 88

Fig. 3.39. Case Study 2C – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 300 psig MAOP and block valve closure 8 minutes after break. 94

Fig. 3.40. Case Study 2D – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 300 psig MAOP and block valve closure 13 minutes after break. 94

Fig. 3.41. Case Study 2E – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break. 95

Fig. 3.42. Case Study 2F – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting

of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break. 95

Fig. 3.43. Case Study 2G – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 300 psig MAOP and block valve closure 8 minutes after break. 101

Fig. 3.44. Case Study 2H – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 300 psig MAOP and block valve closure 13 minutes after break. 101

Fig. 3.45. Case Study 2I – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 1,480 psig MAOP and block valve closure 8 minutes after break. 102

Fig. 3.46. Case Study 2J – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 1,480 psig MAOP and block valve closure 13 minutes after break. 102

Fig. 3.47. Separation distances for 12-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break. 105

Fig. 3.48. Separation distances for 12-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break. 105

Fig. 3.49. Separation distances for 42-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break. 106

Fig. 3.50. Separation distances for 42-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break. 106

Fig. 3.51. Case Study 3A – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 300 psig MAOP and block valve closure 8 minutes after break. 112

Fig. 3.52. Case Study 3B – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 300 psig MAOP and block valve closure 13 minutes after break. 112

Fig. 3.53. Case Study 3C – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 8 minutes after break. 113

Fig. 3.54. Case Study 3D – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 13 minutes after break. 113

Fig. 3.55. Case Study 3E – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 300 psig MAOP and block valve closure 8 minutes after break. 119

Fig. 3.56. Case Study 3F – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 300 psig MAOP and block valve closure 13 minutes after break. 119

Fig. 3.57. Case Study 3G – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 1,480 psig MAOP and block valve closure 8 minutes after break. 120

Fig. 3.58. Case Study 3H – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 1,480 psig MAOP and block valve closure 13 minutes after break. 120

Fig. 3.59. Separation distances for 12-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break. 123

Fig. 3.60. Separation distances for 12-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break. 123

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. 124

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. 124

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. 130

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. 130

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. 131

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. 131

Fig. 3.67. Separation distance versus time plot for the San Bruno natural gas pipeline release – 59.4 to 38.5 mi. segment.. 133

Fig. 3.68. Separation distance versus time plot for the San Bruno natural gas pipeline release – 124.6 to 38.5 mi. segment.. 134

Fig. 3.69. Aerial view of the September 9, 2010 San Bruno natural gas pipeline release showing residential properties damaged and destroyed. 134

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...................................... 142

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...................................... 143

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. 143

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. 144

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. 146

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. 147

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. 147

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. 148

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. 159

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. 159

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. 160

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. 160

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. 163

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. 164

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. 164

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. 165

LIST OF TABLES

Table **Page**

Table 1.1. Effects of thermal radiation intensity on buildings and humans ... 9

Table 1.2. Heat flux threshold basis ... 23

Table 3.1. Study variables for characterizing natural gas pipeline releases ... 35

Table 3.2. Estimated costs of property damage caused by fire resulting from a pipeline release ... 55

Table 3.3 Design features and operating conditions for hypothetical natural gas pipelines considered in the risk analysis ... 56

Table 3.4. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 1 Locations with buildings intended for human occupancy and a PIR greater than 660 feet ... 64

Table 3.5. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of buildings with four or more stories above ground ... 68

Table 3.6. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of buildings with four or more stories above ground ... 70

Table 3.7. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities ... 75

Table 3.8. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities ... 77

Table 3.9. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with buildings intended for human occupancy and a PIR greater than 660 feet ... 86

Table 3.10. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of buildings with four or more stories above ground ... 90

Table 3.11. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of buildings with four or more stories above ground ... 92

Table 3.12. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities ... 97

Table 3.13. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities ... 99

Table 3.14. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy ... 108

Table 3.15. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy ... 110

Table 3.16. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities ... 115

Table 3.17. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities 117

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 126

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 128

Table 3.20. Study variables for hypothetical hazardous liquid pipeline releases 136

Table 3.21. Design features and operating conditions for hypothetical hazardous liquid pipelines considered in the risk analysis 140

Table 3.22. Avoided damage costs for hypothetical 8-in. liquid propane pipeline releases 141

Table 3.23. Avoided damage costs for hypothetical 30-in. liquid propane pipeline releases 145

Table 3.24. Study variables for characterizing hazardous liquid pipeline releases. 151

Table 3.25. Unit response costs for crude oil and light fuel releases 152

Table 3.26. Modifier for location medium categories for crude oil and light fuel releases 152

Table 3.27. Unit socioeconomic and environmental costs for crude oil and light fuel releases 153

Table 3.28. Socioeconomic and cultural value ranking for crude oil and light fuel releases 153

Table 3.29. Freshwater vulnerability categories for crude oil and light fuel releases 154

Table 3.30. Habitat and wildlife sensitivity categories for crude oil and light fuel releases 154

Table 3.31. Avoided damage costs for hypothetical 8-in. hazardous liquid pipeline releases without ignition 157

Table 3.32. Effects of hypothetical 36-in. hazardous liquid pipeline releases without ignition 162

Table 4.1. Estimated cost for adding automatic closure capability to block valves installed in newly constructed or fully replaced pipelines 170

Table 5.1. Summary of avoided damage costs for hypothetical natural gas pipeline releases resulting from fire fighting activities within 1.5 times PIR 178

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 179

Table 5.3. Summary of avoided socioeconomic and environmental damage costs for 8-in. nominal diameter hypothetical crude oil pipeline releases in HCAs 179

Table 5.4. Summary of avoided socioeconomic and environmental damage costs for 36-in. nominal diameter hypothetical crude oil pipeline releases in HCAs 180

ABBREVIATIONS AND ACRONYMS

°C	Degree Celsius
°F	Degree Fahrenheit
AGA	American Gas Association
AIChE	American Institute of Chemical Engineers
ANPRM	Advanced Notice of Proposed Rulemaking
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASV	Automatic Shutoff Valve
B	Billion
BOSCEM	Basic Oil Spill Cost Estimation Model
Btu	British Thermal Unit
Btu/hr ft^2	British Thermal Unit per Hour Square Foot
CFR	Code of Federal Regulations
DHS	U.S. Department of Homeland Security
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EFRD	Emergency Flow Restricting Device
EPA	U.S. Environmental Protection Agency
ft	Foot
ft^2	Square Foot
ft^3	Cubic Foot
gpm	Gallons per Minute
HCA	High Consequence Area
hr	Hour
HUD	U.S. Department of Housing and Urban Development
ILI	In-line Inspection
IM	Integrity Management
in.	Inch
INGAA	Interstate Natural Gas Association of America
kg	Kilogram
km	Kilometer
kW/m^2	Kilowatt per Square Meter
l/min	Liter per Minute
lb.	Pound
m	Meter
M	Million
m^2	Square Meter
m^3	Cubic Meter
MAOP	Maximum Allowable Operating Pressure
MCV	Manual Control Valve
mi.	Mile
min.	Minute
mph	Miles per Hour
NFPA	National Fire Protection Association
NIST	National Institute of Standards and Technology
NTSB	National Transportation Safety Board
ORNL	Oak Ridge National Laboratory

PAPA	Pipeline Association for Public Awareness
PHMSA	Pipeline and Hazardous Material Safety Administration
PIR	Potential Impact Radius
psig	Pounds per Square Inch, gage
RCV	Remote Control Valve
RSPA	Research and Special Programs Administration
s	Second
SCADA	Supervisory Control and Data Acquisition System
SFPE	Society of Fire Protection Engineers
sq. ft.	Square Feet
TETCO	Texas Eastern Transmission Corporation
USA	Unusually Sensitive Area
W	Watt
yd	Yard

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Most respectfully,

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ABSTRACT

This study assesses the effectiveness of block valve closure swiftness in mitigating the consequences of natural gas and hazardous liquid pipeline releases on public and environmental safety. It also evaluates the technical, operational, and economic feasibility and potential cost benefits of installing automatic shutoff valves (ASVs) and remote control valves (RCVs) in newly constructed and fully replaced transmission lines. Risk analyses of hypothetical pipeline release scenarios are used as the basis for assessing: (1) fire damage to buildings and property in Class 1, Class 2, Class 3, and Class 4 high consequence areas (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; and (3) socioeconomic and environmental damage in HCAs caused by hazardous liquid pipeline releases of crude oil. These risk analyses use engineering principles and fire science practices to characterize thermal radiation effects on buildings and humans and to quantify the total damage cost of socioeconomic and environmental impacts. The risk analysis approach used for natural gas pipelines is consistent with risk assessment standards developed by industry and incorporated into Federal pipeline safety regulations. Feasibility evaluations for the hypothetical pipeline release scenarios considered in this study show that installation of ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is technically, operationally, and economically feasible with a positive cost benefit. However, these results may not apply to all newly constructed and fully replaced pipelines because site-specific parameters that influence risk analyses and feasibility evaluations often vary significantly from one pipeline segment to another and may not be consistent with those considered in this study. Consequently, the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed or fully replaced pipelines need to be evaluated on a case-by-case basis. 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 product that remains inside the isolated pipeline segments from escaping into the environment. The benefits in terms of cost avoidance attributed to block valve closure swiftness increase as the time required to isolate the damaged transmission pipeline segment decreases. Block valve closure swiftness is most effective in mitigating damage resulting from a pipeline release and subsequent fire when the damaged pipeline segment is isolated and the thermal radiation produced by the fire declines in time so that emergency responders can safely begin fire fighting activities immediately upon arrival at the scene. Similarly, the avoided cost of socioeconomic and environmental damage for hazardous liquid pipeline releases without ignition increase as time required to isolate the damaged pipeline segment decreases.

EXECUTIVE SUMMARY

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) is the Federal safety authority responsible for ensuring safety in the design, construction, operation and maintenance, and spill response planning for the 2.3 million (M) miles of natural gas and hazardous liquid transportation pipelines in the United States. Its mission is to protect people and the environment from the risks inherent in transportation of hazardous materials by pipeline and other modes of transportation. Section 4 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of the U.S. Department of Transportation (DOT) to require by regulation the use of automatic or remotely controlled shutoff valves, or equivalent technology, where it is economically, technically, and operationally feasible on hazardous liquid and natural gas transmission pipeline facilities constructed or entirely replaced after the final rule was issued. 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 high consequence area (HCA). In addition, PHMSA is evaluating related concerns raised by the National Transportation Safety Board (NTSB) in its accident report for the September 9, 2010, pipeline rupture in San Bruno, California that resulted in eight deaths. The NTSB concluded that the damage caused by the pipeline rupture could have been significantly reduced with the use of automatic shutoff valves (ASVs) and remote control valves (RCVs).

Gas transmission pipelines are currently required to incorporate sectionalizing block valves at intervals that vary depending on population density. These block valves are not required to be remotely operable or to operate automatically in the event of an unexpected reduction in pressure (*e.g.* from a pipeline rupture). However, pipeline operators are required to conduct risk assessments of their pipelines and take additional measures to mitigate the consequences of a pipeline failure in a HCA. Such additional measures may include, but are not limited to, installing ASVs or RCVs.

Hazardous liquid pipeline operators are required to install block valves at prescribed locations to facilitate isolation of pump stations, breakout storage tanks, and lateral takeoffs and other points along the pipeline near designated bodies of water and populated areas to minimize damage and pollution from an accidental hazardous liquid discharge. In addition, operators are required to consider installing emergency flow restricting devices such as check valves and RCVs on pipeline segments to protect a HCA in the event of a hazardous liquid pipeline release. In making this determination, an operator must, at least, consider the swiftness of leak detection and pipeline shut down capabilities and benefits expected by reducing the spill size.

In March 2012, PHMSA requested assistance from the Oak Ridge National Laboratory (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 report, which documents the study results, addresses the issues defined in Sect. 4 of the Act and those raised by the NTSB in its accident report for the San Bruno natural gas pipeline accident. The study assesses the effectiveness of block valve closure swiftness in mitigating the consequences of natural gas and hazardous liquid pipeline releases on public and environmental safety. It also evaluates the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed and fully replaced pipelines. The results of this study apply to natural gas and hazardous liquid transmission lines.

Potential effects of unintended releases from natural gas and hazardous liquid pipelines on public and environmental safety are categorized as personal injuries and fatalities, property damage, and environmental impacts. The scope and magnitude of these effects depends on the type and amount of product released; the exact sequence of events; and site-specific factors such as the separation distance between an individual or building and the release point, building type and construction, terrain features, and atmospheric conditions. In this study, fire consequence modeling is limited to thermal radiation effects resulting from unintended releases from: (1) natural gas pipelines, and (2) hazardous liquid pipelines that transport propane. Propane rather than gasoline, butane, or propylene was chosen to present the worst case fire consequences. The scope of the study is further limited by considering only worst case pipeline release scenarios in HCAs involving guillotine-type breaks rather than other more common breaks, such as punctures and through-wall cracks. Although ignition of the released product following a rupture is not ensured, this study only models release scenarios that result in immediate ignition of the released product at the break location. The study also assesses potential socioeconomic and environmental effects of unintended crude oil releases without ignition from hazardous liquid pipelines in HCAs.

E.1 CONSEQUENCE MODELS

Risk analyses of hypothetical pipeline release scenarios are used as the basis for assessing: (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; and (3) socioeconomic and environmental damage in HCAs caused by hazardous liquid pipeline releases of crude oil. These risk analyses use engineering principles and fire science practices to characterize thermal radiation effects on buildings and humans, and to quantify the total damage cost of socioeconomic and environmental impacts. The risk analysis approach used for natural gas pipelines is consistent with risk assessment standards developed by industry and incorporated into Federal pipeline safety regulations.

The methodology used to quantify the effectiveness of block valve closure swiftness in reducing potential consequences of an unintended natural gas or hazardous liquid pipeline release is based on a conservative approach to pipeline safety that considers effects of a time-dependent discharge resulting from a guillotine-type break. These consequences involve potential fire damage to buildings, vehicles, and personal property caused by ignition and combustion of the released hydrocarbon that begins as soon as the break in a natural gas or hazardous liquid pipeline occurs; potential burn injuries to fire fighters and the public caused by exposure to thermal radiation; and potential socioeconomic and environmental effects resulting from a hazardous liquid pipeline release without ignition. 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 following heat flux thresholds for fire damage to buildings, fire fighting activities, and open spaces where people congregate were established and used to quantify potential fire damage. By comparison, nominal solar radiant heat flux on a clear day is approximately 1.0 kW/m^2 (320 Btu/hr ft^2).

- 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 continuous fire fighting and emergency response activities.

- Exposure of a building to a heat flux of 15.8 kW/m^2 (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.
- Exposure to a heat flux of 40.0 kW/m^2 (12,700 Btu/hr ft^2) for any period of time is considered the maximum tolerable level of radiation at the facade of an exposed building and the threshold for severe damage to buildings. Based on analysis, the potentially severe damage radius for a natural gas pipeline release is approximately 1.5 times the potential impact radius (PIR).

Fire damage cost estimates are based on home and vehicle sales data published by the U.S. Census Bureau. Potential socioeconomic and environmental effects resulting from a hazardous liquid pipeline release without ignition are based on the Basic Oil Spill Cost Estimation Model (BOSCEM) used by the Environmental Protection Agency (EPA) for estimating response, socioeconomic damage, and environmental damage costs.

E.2 ASSESSMENT METHODOLOGY AND RESULTS FOR NATURAL GAS PIPELINE RELEASES

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. Immediately following a guillotine-type break in a natural gas pipeline, the gas begins flowing rapidly through the break and into the surrounding atmosphere. The escaping natural gas creates a highly turbulent mushroom shaped vapor cloud that increases in height above the release point due to the source momentum and buoyancy. The fireball, which is the result of combustion of the mushroom-shaped vapor cloud, typically lasts 30 seconds or less leaving a quasi-steady-state fire that continues to burn until all of the escaping natural gas is consumed. 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. The presumption of worst case, guillotine-type breaks is consistent with risk assessment standards adopted by industry and Federal pipeline safety regulations for natural gas pipelines.

The effectiveness of block valve closure swiftness in mitigating the potential consequences of a natural gas pipeline release was evaluated using the following methodology.

- Compute heat flux versus time data for hypothetical release scenarios involving 12-in. and 42-in. nominal diameter pipelines operating at 300 psig and 1,480 psig with block valve closure at 8 minutes (5 minutes for leak detection plus 3 minutes for block valve closure) and 13 minutes (10 minutes for leak detection plus 3 minutes for block valve closure) after the break. In addition, establish baselines for comparison by computing heat flux versus time data for release scenarios in which the block valves remain open for at least 60 minutes after the break.
- Use the heat flux versus time data to prepare separation distance (radius from break) versus time plots for specific heat flux thresholds.
- Compare the heat flux threshold curves for different block valve closure times and separation distances to the baseline curves.

- Determine the time when the heat flux equals 2.5 kW/m^2 (800 Btu/hr ft^2) at the potentially severe damage radius (1.5 times the PIR) for each separation distance versus time plot.
- Use these exposure time differences to evaluate the effectiveness of block valve closure swiftness on reducing the heat flux at the potentially severe damage radius. The difference in exposure times represents additional time available to fire fighters to conduct fire fighting activities at the potentially severe damage radius.
- Quantify avoided fire damage to buildings and property based on the exposure time difference.
- Determine the benefit in terms of avoided fire damage costs attributed to block valve closure swiftness.

Results of these comparisons and avoided fire damage cost determinations show that 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. Fire damage to buildings and personal property located in Class 1, Class 2, Class 3, and Class 4 HCAs 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). In addition, the radius for potentially severe damage envelopes the radii for potentially moderate damage, which corresponds to a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) and an exposure duration of 15 minutes, and potentially minor damage, which corresponds to a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) and an exposure duration of 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 operating pressures ranging from 300 psig to 1,480 psig.

Without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in Class 1, Class 2, Class 3, and Class 4 HCAs 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 the 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.

Block 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. 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 located in Class 1, Class 2, Class 3, and Class 4 HCAs.

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 the 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 the 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. The study results further show that for natural gas release scenarios, block valve closure within 8 minutes after the break can result in a potential cost avoidance of at least $2,000,000 for 12-in. nominal diameter natural gas pipelines and $8,000,000 for 42-in. nominal diameter natural gas pipelines depending on the configuration of buildings within the Class 3 HCA. Delaying block valve closure by an additional 5 minutes can reduce the cost avoidance by approximately 50%. In addition, block valve closure in 8 minutes increases the time fire fighters are able to conduct effective fire fighting operations within a distance of 1.5 times the PIR by approximately 15 minutes or more.

The analytical approach and computational models used to assess the hypothetical natural gas pipeline release scenarios were also used to study the San Bruno natural gas pipeline accident that occurred in a residential area in San Bruno, California on September 9, 2010. Study results for this actual natural gas pipeline release provide evidence that the analytical approach and computational models produce credible results.

E.3 ASSESSMENT METHODOLOGY AND RESULTS FOR HAZARDOUS LIQUID PIPELINE RELEASES WITH IGNITION

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. Following a guillotine-type break in a hazardous liquid pipeline and ignition of the released hydrocarbon onto level ground, 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.

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. The volume of liquid spilled during the detection and continued pumping phases is unaffected by block valve closure swiftness because the block valves are open from the time the break occurs until the end of the block valve closure phase. 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 swiftness in mitigating potential fire consequences of a liquid propane release from a hazardous liquid pipeline with ignition was evaluated using the following methodology.

- Compute heat flux versus time data for hypothetical release scenarios involving 8-in. and 36-in. nominal diameter propane pipelines with different elevation profiles operating at 400 and 1,480 psig with block valve closure at 13 minutes and 70 minutes after the break.
- Use the heat flux versus time data to prepare separation distance (radius from break) versus time plots for specific heat flux thresholds.
- Compare the heat flux threshold curves for the 13-minute and 70-minute block valve closure times and separation distances.

- Determine the potentially severe damage radius for a heat flux of 40.0 kW/m^2 (12,700 Btu/hr ft^2), the potentially moderate damage radius for a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) and an exposure duration of 15 minutes, and the potentially minor damage radius for a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) and an exposure duration of 30 minutes.
- Use these radii to compute areas of avoided moderate and minor damage.
- Quantify avoided fire damage to buildings and property based on these areas.
- Determine the benefit in terms of avoided fire damage costs attributed to block valve closure swiftness.

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 2 minutes 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 8 minutes. Therefore, the avoided damage costs associated with the potentially severe damage radius cannot be realized unless the detection phase and the continued pumping phase decrease to much less than 5 minutes.

Fire damage to buildings and personal property in a HCA resulting from liquid propane combustion immediately following guillotine-type breaks in hazardous liquid 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). Calculations show the radii for potentially moderate damage, which corresponds to a heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) for a minimum exposure period of 15 minutes, and potentially minor damage, which corresponds to a heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) for a minimum exposure period of 30 minutes, 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 operating pressures ranging from 400 psig to 1,480 psig.

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. 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. Risk analysis results for a hypothetical 30-in. nominal diameter hazardous liquid pipeline release of liquid propane show that the estimated total avoided cost for building and property damage resulting from block valve closure in 13 rather than 70 minutes is over $6M.

E.4 ASSESSMENT METHODOLOGY AND RESULTS FOR HAZARDOUS LIQUID PIPELINE RELEASES WITHOUT IGNITION

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 in this study to quantify socioeconomic and environmental impacts resulting from a hazardous liquid release involves computing the quantity of hazardous liquid released as a function of block valve closure time and then using this quantity to establish the total damage cost based on the EPA's BOSCEM. The total damage cost is determined as follows:

- Add the unit response cost, the unit socioeconomic damage cost, and the unit environmental damage cost;
- Multiply the sum of these costs by the number of barrels spilled; and
- Apply a damage cost adjustment factor which aligns the total damage cost with the actual cleanup costs reported for recent crude oil spills in environmentally sensitive areas. The damage cost for crude oil released in the Enbridge Line 6B pipeline rupture in Marshall, Michigan in 2010 was approximately $38,000 per barrel.

The BOSCEM accounts for effects of spill size on the total damage cost by reducing the unit cost of damage as the number of barrels spilled increases.

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 because damage costs increase as the spill size increases. 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.

E.5 FEASIBILITY EVALUATIONS

Feasibility evaluations conducted as part of this study show that under certain conditions installing ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is technically, operationally, and economically feasible with a positive cost benefit. However, these results may not apply to all newly constructed and fully replaced pipelines because site-specific parameters that influence risk analyses and feasibility evaluations often vary significantly from one pipeline segment to another, and may not be consistent with those considered in this study. Consequently, the technical, operational, and economic feasibility and potential cost benefits of installing ASVs and RCVs in newly constructed or fully replaced pipelines need to be evaluated on a case-by-case basis.

The technical feasibility of installing ASVs and RCVs in newly constructed or fully replaced pipelines depends primarily on physical space limitations at the valve installation location. 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 the appropriate personnel required to install and maintain the valves. Installation of RCVs in newly constructed and fully replaced pipelines is also considered technically feasible. However, sufficient space must be available for the valve body, actuators, power source, sensors and related electronic equipment, and personnel required to install and maintain the valves as well as additional space for the communications equipment that links the site to the control room. Installation of RCVs in newly constructed and fully replaced pipelines is also considered technically feasible based on field evaluations in which RCVs performed reliably and as intended.

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.

Operational feasibility evaluations also need to consider factors such as the remoteness and accessibility of the valve location; effects of service disruptions for valve maintenance, repair and testing; and possible travel delays caused by severe weather or traffic congestion. In addition, there may be limited times during the year that pipelines serving critical customers can be shutdown due to service reliability considerations. Therefore, operators must consider downstream system demands when scheduling maintenance. Operational feasibility evaluations may also need to consider workplace hazards. For example, 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.

Economic feasibility evaluations based on risk analysis results for the worst-case release scenarios considered in this study show that installing ASVs and RCVs in newly constructed and fully replaced natural gas and hazardous liquid pipelines is economically feasible with a positive cost benefit. 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.

E.6 POTENTIAL CONSEQUENCE REDUCTION STRATEGIES

In theory, installing ASVs and RCVs in newly constructed and fully replaced pipelines can reduce overall impacts on the public and to the environment by decreasing the total volume of the release. However, block valve closure has no effect on preventing pipeline failure or stopping the product 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.

For natural gas pipelines, installing ASVs and RCVs 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 (1.5 times the PIR) to 2.5 kW/m^2 (800 Btu/hr ft^2) or less within 10 to 20 minutes after the break.

For hazardous liquid pipelines, installing ASVs and RCVs 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.

1. INTRODUCTION

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) is the Federal safety authority responsible for ensuring safety in the design, construction, operation and maintenance, and spill response planning for the 2.3 million (M) miles of natural gas and hazardous liquid transportation pipelines in the United States. Its mission is to protect people and the environment from the risks inherent in transportation of hazardous materials by pipeline and other modes of transportation. Under Congressional action in 2004, PHMSA is required to consider the assignment and maintenance of safety as the highest priority, recognizing the clear intent, encouragement, and dedication of Congress to the furtherance of the highest degree of safety in pipeline transportation and hazardous materials transportation (U.S. Congress, 2004). In performing its duties, PHMSA promulgates comprehensive minimum safety standards for the transportation of gas and hazardous liquids by pipeline (U.S. Congress, 1996). These standards are contained in Title 49, Parts 186 to 199 of the *Code of Federal Regulations* (CFR).

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (U.S. Congress, 2012) calls for the Secretary of the U.S. Department of Transportation (DOT) to require by regulation the use of automatic or remotely controlled shutoff valves, or equivalent technology, where it is economically, technically, and operationally feasible on hazardous liquid and natural gas transmission pipeline facilities constructed or entirely replaced after the final rule was issued. 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 high consequence area (HCA). In addition, PHMSA is evaluating related concerns raised by the National Transportation Safety Board (NTSB) in its accident report for the pipeline rupture in San Bruno, California (NTSB. 2011) that resulted in eight deaths. The NTSB concluded that the damage caused by the pipeline rupture could have been significantly reduced with the use of automatic shutoff valves (ASVs) or remote control valves (RCVs).

In March 2012, PHMSA requested assistance from the Oak Ridge National Laboratory (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 report, which documents the study results, addresses the issues defined in Sect. 4 of the Act and those raised by the NTSB in its accident report for the San Bruno accident. The work is administered through an interagency agreement between the DOT and the U.S. Department of Energy (DOE) that authorizes ORNL to provide specialized engineering assistance and technical support to PHMSA.

1.1 STUDY BASIS

Gas transmission pipelines are currently required to incorporate sectionalizing block valves[1] at intervals that vary depending on population density. These requirements apply to initial gas transmission pipeline construction. However, if the population increases after a pipeline is placed in service, such that the class location changes, operators must reduce pressure, conduct pressure tests, or verify the adequacy of prior pressure tests, or replace the pipeline to allow continued operation at the existing pressure. If operators replace the pipeline, then these prescribed valve spacing intervals apply. If operators reduce pressure or verify that prior pressure tests are sufficient to justify continued operation without reducing pressure or replacing the pipeline, then current regulations do not require installation of additional block valves to comply with the prescribed spacing requirements. Further, block valves are not required to be remotely operable or to operate automatically in the event of an unexpected reduction in pressure (*e.g.* from a

[1] Sectionalizing block valves are used to isolate a section of pipeline for maintenance or in response to an incident. The term block valve is synonymous with sectionalizing block valve.

pipeline rupture). Section 2.1 discusses additional safety regulations adopted by PHMSA for natural gas pipelines.

Operators of hazardous liquid pipelines are required to install block valves at prescribed locations to facilitate isolation of pump stations, breakout storage tanks, and lateral takeoffs and other points along the pipeline near designated water bodies and populated areas to minimize damage and pollution from an accidental hazardous liquid discharge. In addition, operators are required to consider installing emergency flow restricting devices (EFRDs) such as check valves and RCVs on pipeline segments to protect a HCA in the event of a hazardous liquid pipeline release. Section 2.2 discusses additional safety regulations adopted by PHMSA for hazardous liquid pipelines.

On October 18, 2010, PHMSA published an advanced notice of proposed rulemaking (ANPRM) for safety of on-shore hazardous liquid pipelines (DOT, 2010a). In this rulemaking, PHMSA is considering whether changes are needed to the regulations covering hazardous liquid onshore pipelines. In particular, PHMSA sought comment on whether it should extend regulation to certain pipelines currently exempt from regulation; whether other areas along a pipeline should either be identified for extra protection or be included as additional HCAs for Integrity Management (IM) protection; whether to establish and adopt standards and procedures for minimum leak detection requirements for all pipelines; whether to require the installation of EFRDs in certain areas; whether revised valve spacing requirements are needed on new construction or existing pipelines; whether repair timeframes should be specified for pipeline segments in areas outside the HCAs that are assessed as part of the IM; and whether to establish and/or adopt standards and procedures for improving the methods of preventing, detecting, assessing and remediating stress-corrosion cracking in hazardous liquid pipeline systems.

Under separate action, PHMSA issued a related ANPRM on August 25, 2011 for safety of gas transmission pipelines (DOT. 2011a). In this rulemaking, PHMSA is considering whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether IM requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues involving IM requirements, PHMSA is considering whether the definition of a HCA should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods. With respect to non-IM requirements, PHMSA is considering whether revised requirements are needed on new construction or existing pipelines concerning mainline valves, including valve spacing and installation of remotely operated or automatically operated valves; whether requirements for corrosion control of steel pipelines should be strengthened; and whether new regulations are needed to govern the safety of gathering lines and underground gas storage facilities. Within this ANPRM, PHMSA sought public comments on valve spacing and the need for remotely or automatically controlled valves.

1.1.1 Previous Studies and Recommendations

Congress has previously required PHMSA to "assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture" and to require use of such valves if they were shown technically and economically feasible. The NTSB has also issued a number of recommendations concerning requirements for use of automatic or remotely operated mainline valves, including one following a 1994 pipeline rupture in Edison, New Jersey (NTSB, 1995a and NTSB, 1995b). PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA) conducted the evaluation mandated by Congress and concluded that remotely and automatically controlled mainline valves are technically feasible but not, on a generic basis, economically feasible (DOT, 1999). Nevertheless, IM regulations require that an operator must install an automatic or remotely operated valve if the operator determines, based on a risk analysis, that these would be an efficient means of adding protection to a

HCA in the event of a gas release (49 CFR 192.935(c)). In publishing this regulation, PHMSA acknowledged its prior conclusion that installation of these valves was not economically feasible but noted that this was a generic conclusion. PHMSA stated that it did not expect operators to re-perform the generic analyses but rather to "evaluate whether the generic conclusions are applicable to their HCA pipeline segments."

The accident in San Bruno, California on September 9, 2010, raised public concern about the ability of pipeline operators to isolate sections of gas transmission pipelines in the event of an accident promptly and whether remotely or automatically operated valves should be required to assure this. Based upon the investigation of this accident, the NTSB issued the following recommendation.

> **NTSB Recommendation P-11-11:**
> *Amend Title 49 Code of Federal Regulations Section 192.935(c) to directly require that automatic shutoff valves (ASV) or remote control valves (RCV) in high consequence areas and in class 3 and 4 locations be installed and spaced at intervals that consider the population factors listed in the regulations*.

The NTSB determined that the damage caused by the pipeline rupture could have been significantly reduced with the use of ASVs or RCVs and that the industry references for the evaluation of ASVs and RCVs are flawed. These industry references conclude that the majority of damage caused by a pipeline rupture occurs within the first 30 seconds and the duration of the fire's threat to human safety and property damage is minimal. In response to these concerns, PHMSA is considering changes to its requirements for sectionalizing block valves.

1.1.2 Study Authorization and Purpose

On January 3, 2012, Congress amended Title 49, United State Code, through the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (U.S. Congress, 2012). This Act provides for enhanced safety and environmental protection in pipeline transportation, enhanced reliability in the transportation of the Nation's energy products by pipeline, and other purposes. Requirements in Section 4 include the addition of a subsection and the removal of an existing subsection on Remotely Controlled Valves in The Pipeline Safety Statute 49 USC 60102. The removed section addressed a required study in 1998 and the implementation of requirements for Remotely Controlled Valves to shut off the flow of natural gas in the event of a rupture of an interstate natural gas pipeline. With the striking of the previous subsection, the new subsection calls for the DOT Secretary to require by regulation the use of automatic or remote controlled shutoff valves, or equivalent technology, where it is economically, technically, and operationally feasible on hazardous liquid and natural gas transmission pipeline facilities constructed or entirely replaced after the final rule was issued. In addition, the Act 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. The purpose of this study is to investigate the swiftness of leak detection and pipeline isolation capabilities, the location of the nearest response personnel as well as the cost, risk and benefit of installing ASVs and RCVs. The NTSB Recommendation P-11-11 falls in line with the Act's study requirements for natural gas transmission line while at the same time adds additional requirements for the consideration of ASVs and RCVs inside Class 3 and Class 4 areas.

On February 9, 2012, PHMSA published a "Pipeline Safety: Notice of Public Meetings on Improving Pipeline Leak Detection System Effectiveness and Understanding the Application of Automatic/Remote Control Valves" I the *Federal Register* (DOT, 2012a). The public workshop on "Improving Pipeline Leak Detection System Effectiveness and Understanding the Application of Automatic/Remote Control Valves" was held in Bethesda, Maryland on March 27 and 28, 2012. This workshop examined how to encourage operators to expand usage of leak detection systems and improve system effectiveness on the Nation's pipeline infrastructure and how remote control and automatic control valves can be installed to lessen the volume of natural gas and hazardous liquid released during catastrophic pipeline events. These public meetings provided an open forum for exchanging information on the challenges associated with leak detection systems and automatic/remote control valves.

Following the meeting, PHMSA published a notice of public comment on the scope of leak and valve studies mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (DOT, 2012b). This notice defined the tentative work scope for the automatic and remote control valve study and subdivided the work into the following tasks.

- Task 1: Kickoff Meeting
- Task 2: Attend Public Workshop The contractor will attend PHMSA's Understanding the Application of Automatic Control and Remote Control Valves public workshop on March 28, 2012.
- Task 3: Required Study on Automatic and Remote-Controlled Shut-off Valves on HCAs and Class 3 and Class 4 Areas on Natural Gas Pipelines
- Task 4: Required Study on Automatic and Remote Controlled Shut-Off Valves on Newly Constructed or Entirely Replaced Facilities
- Task 5: Review and Assess Previous Pipeline Incidents[2]

On May 4, 2012, the Interstate Natural Gas Association of America (INGAA) submitted comments on the leak and valve study mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (INGAA. 2012). After discussing a variety of incident management mitigation issues, INGAA concluded that the study should involve far more than an examination of valve spacing and technology including:

> *The respective roles of the pipeline, emergency responders and the public; the numerous, individual steps that go into pipeline incident management; the impact of false closures of automated valves; the overall cost and individual cost elements associated with valve automation and installation; the current and potential impact of emerging leak and rupture detection technologies; and the identification and development of appropriate incident management metrics.*

1.2 STUDY SCOPE AND OBJECTIVES

The objective of the agreement between PHMSA and ORNL is to address the requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the recommendations on ASVs and RCVs from the NTSB investigation of the San Bruno accident. The study scope includes the following work activities.

1. Study the ability of transmission pipeline facility operators to respond to a hazardous liquid 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 pipelines.

[2] PHMSA defines "incident" in 49 CFR 191.3 as an event that involves a release of gas from a pipeline causing death or personal injury necessitating inpatient hospitalization or estimated property damage, including the cost of gas lost, that is $50,000 or more.

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.
5. Conduct cost, risk, and benefit analysis of installing ASVs and RCVs in HCAs and Class 3 and Class 4 areas.

Completion of these objectives will facilitate a favorable closure of NTSB Recommendation (P-11-11) and will enable PHMSA to successfully report the status of transmission pipeline facility operator to respond to a hazardous liquid or gas release from a pipeline segment.

Key areas of assessment and evaluation include:

- Analysis of the technical and operational ability of the swiftness of the existing leak detection system and the operator's capability to shut down the affected pipeline;
- Consideration of upstream and downstream controls, automation, supervisory control and data acquisition (SCADA) systems, and valve spacing effects;
- Assessment of human factors of response including the minimum response time and the nearest required human to initiate isolation of the pipeline;
- Analysis of costs and benefits for installing ASVs and RCVs in HCAs and in Class 3 and Class 4 areas for gas transmission pipelines including the lifetime operational cost of the system, benefits that may be seen by the public and surrounding environment, and economic impacts of damage to surrounding environments and the public based on standard fire science practices;
- Assessment of risks of installing ASVs and RCVs as compared to local manual operation of isolation valves on transmission pipelines;
- Analysis of the benefits to the public and the environment resulting from installation of ASVs and RCVs within HCA and Class 3 and Class 4 areas;
- Comparison of all types of ASVs and RCVs and determine whether available technologies are able to adequately protect the public and environment from pipeline leaks and incidents through rapid valve closure;
- Analysis of technological shortfalls specific to ASV reliability;
- Assessment of alternative technology to ASVs and RCVs to determine if these technologies should be investigated and explained in the study;
- Review of current DOT regulations in regards to installation of ASVs and RCVs on hazardous liquid and natural gas pipelines and determine how operators are currently complying with these regulations;
- Consideration of reliability, availability, and maintainability system aspects;
- Analysis of how ASV and RCV installation could affect pipeline operations including operational aspects (i.e. procedures, protocols, best practices, workforce, etc.);
- Consideration of emergency first responders; and
- Examination of past pipeline incidents to determine whether installation of either ASVs or RCVs could have mitigated effects to the public and surrounding environment.

The results of this study apply to natural gas and hazardous liquid transmission lines.

1.3 STUDY PARAMETERS AND BOUNDARIES

Potential effects of unintended releases from natural gas and hazardous liquid pipelines are categorized as follows (Muhlbauer, 2006):

- human impacts including personal injuries and fatalities,
- property damage,
- environmental impacts, and
- supply losses and business interruptions.

These effects are considered in evaluating the effectiveness of RCVs and ASVs in mitigating the consequences of a release. The scope and magnitude of these effects depends on the type and amount of product released; the exact sequence of events; and site-specific factors such as the separation distance between an individual or building and the release point, building type and construction, terrain features, and atmospheric conditions. Modeling each potential release scenarios is not practical because an unlimited number of scenario permutations are possible.

In this study, modeling is limited to potential fire consequences and thermal radiation effects resulting from unintended releases from: (1) natural gas pipelines, and (2) hazardous liquid pipelines that transport gasoline, propane, butane, and propylene. The scope of the study is further limited by considering only worst case releases of these products resulting from a guillotine-type break[3] in the pipeline. Although ignition of the released product following a guillotine-type break is not ensured, this study only considers release scenarios that result in immediate ignition of the released product at the break location. Effects of hazardous liquid pipeline releases on the human and natural environments are discussed in Sections 3.2 and 3.3.

Blast, overpressure, shrapnel, and earthquake-type effects resulting from an unintended natural gas or hazardous liquid pipeline release are hazards that can adversely affect humans, property, and the environment. However, these effects are beyond the scope of this study because they occur immediately after the break and RCVs and ASVs, which typically require several minutes to close, cannot mitigate these hazards.

1.3.1 Natural Gas Pipeline Release Events

Immediately following a guillotine-type break in a natural gas pipeline, the gas begins flowing rapidly through the break and into the surrounding atmosphere. The escaping natural gas creates a highly turbulent mushroom shaped vapor cloud that increases in height above the release point due to the source momentum and buoyancy. Initially, the natural gas flow from each broken pipeline segment is balanced, and the natural gas escapes to the atmosphere in the form of jets that depend on the alignment of the line pipe ends. Natural gas will not burn unless the gas-to-air ratio is between 4% and 15%. Noise produced by the escaping natural gas is normally audible for a long distance.

[3] A guillotine-type break is defined as complete separation or rupture of line pipe along a circumferential fracture plane (as compared to more common breaks, such as punctures and through-wall cracks). The term leak is used in this study to describe the release of product resulting from a pipeline break.

For buried pipelines, the escaping natural gas ejects the overlying soil forming a crater of a size and shape which influences the behavior of the released gas. Figure 1.1 shows the crater produced by the natural gas pipeline rupture that occurred near Carlsbad, New Mexico (NTSB, 2003). As the release continues, the natural gas jet feeds the vapor cloud and entrains air that may contain ejected soil particles. Without an ignition source, the vapor cloud and the escaping gas disperse into the atmosphere.

Fig. 1.1. Crater resulting from natural gas pipeline release near Carlsbad, New Mexico (NTSB, 2003).

If ignition of the released natural gas occurs immediately, or shortly after, the guillotine-type break, a transient fireball[4] will occur. The fireball, which is the result of combustion of the mushroom-shaped vapor cloud, typically lasts 30 seconds or less leaving a quasi-steady-state fire that continues to burn until all of the escaping natural gas is consumed (Acton, 2000 and Cleaver, 2001). Figure 1.2 shows the fireball produced by the natural gas pipeline rupture that occurred near Carlsbad, New Mexico (NTSB, 2003).

Fig. 1.2. Fire resulting from natural gas pipeline release near Carlsbad, New Mexico (NTSB, 2003).

[4] A fireball is a burning fuel-air cloud whose energy is emitted primarily in the form of radiant heat (AIChE, 1994).

The possibility of a significant flash fire[5] resulting from delayed remote ignition of the released natural gas is extremely low due to the buoyant nature of the vapor which generally precludes the formation of a persistent flammable vapor cloud at ground level. Consequently, the dominant hazard from a natural gas pipeline release is thermal radiation from a sustained jet fire, which may be preceded by a short-lived fireball (Stephens, 2000). Fireballs and jet fires have the potential to injury humans, damage property, and impact the environment by damaging plants and animals in the vicinity of the break. Any potential environmental impacts on air and water quality caused by the released natural gas, its products of combustions, and runoff from fire fighting operations are beyond the scope of this study.

At later stages of the release, the flow through each pipeline segment may vary depending on the location and closure status of upstream and downstream block valves and the distance between the break and these block valves. The flow may also be affected by features such as compressor stations or connections with other pipelines. These boundary conditions determine whether the flow through the pipeline at the break decreases to zero or transitions to a quasi-steady-state condition (Acton, 2001). The size and intensity of a fire resulting from a natural gas pipeline release depends on the effective rate of gas released which is primarily influenced by the pressure differential and the size and shape of the break (Stephens, 2000). For worst case, guillotine-type breaks, where the effective hole size is equal to the line pipe diameter, the governing parameters are, therefore, the line pipe diameter and the internal operating pressure at the time of the break.

Thermal radiation hazard zones with increasing impact severity are described by concentric circles centered on the pipeline rupture. The thermal radiation intensities at the perimeters of these concentric circles increase as the radii decrease. Table 1.1 summarizes the effects of progressively higher heat fluxes on buildings and humans. Because thermal radiation effects on buildings and humans are a function of radiant heat flux and exposure duration, quantifying the time-dependent variations in heat flux intensity for specific radii is key to assessing the benefits of installing RCVs and ASVs in natural gas pipelines.
Given the wide range of actual pipeline sizes and operating pressures, leak detection periods, and block valve spacing and closure times, ORNL developed methodologies for quantifying the impacts of these parameters on areas affected by combustion of the escaping natural gas. The methodologies, which are described in Section 3.1, also characterize time-dependent radiant thermal intensities at various separation distances from the break.

The terms “sectionalizing block valve” and “block valve” are used interchangeably in 49 CFR 192 but these terms are not defined in the regulation. To minimize possible confusion, the terms “sectionalizing block valve” and “block valve” are used in this document to mean a valve that is installed in a natural gas pipeline to isolate a line section. A line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

1.3.1.1 Phases of a Natural Gas Pipeline Release

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. A break that occurs adjacent to a block valve and renders the block valve inoperable will result in the greatest volume of natural gas released to the atmosphere compared to a break that occurs at another location along the same line section. 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.

[5] A flash fire is the non-explosive combustion of a vapor cloud resulting from a release of flammable material into the open air which, after mixing with air, ignites (AIChE, 1994).

Table 1.1. Effects of thermal radiation intensity on buildings and humans

Approximate Radiant Heat Flux		Effects and Consequences
kW/m²	Btu/hr ft²	
1.0	320	Nominal solar radiant heat flux on a clear summer day (NFPA, 2011a)
1.4	450	Thermal radiation flux considered acceptable by HUD for outdoor, unprotected facilities or open spaces where people congregate (HUD, 2011a)
2.5	800	Common thermal radiation exposure while fire fighting. This energy level may cause burn injuries with prolonged exposure (NFPA, 2011a).
4.0	1,270	Glass breakage after exposure for 30 minutes (LaChance, 2009).
4.7	1,500	Maximum radiant heat flux in areas where emergency actions lasting 2 to 3 minutes can be required by personnel without shielding but with appropriate clothing. Appropriate clothing consists of hard hat, long-sleeved shirts with cuffs buttoned, work gloves, long-legged pants and work shoes. Appropriate clothing minimizes direct skin exposure to thermal radiation (API, 2007).
6.3	2,000	Maximum radiant heat flux in areas where emergency actions lasting up to 30 seconds can be required by personnel without shielding but with appropriate clothing. Appropriate clothing consists of hard hat, long-sleeved shirts with cuffs buttoned, work gloves, long-legged pants and work shoes. Appropriate clothing minimizes direct skin exposure to thermal radiation (API, 2007). Personnel are commonly protected from high thermal radiation intensity by restricting access to any area where the thermal radiation can exceed this radiant heat flux. The boundary of a restricted access area can be marked with signage warning of the potential thermal radiation exposure hazard. Personnel admittance to, and work within, the restricted access area should be controlled administratively. It is essential that personnel within the restricted area have immediate access to thermal radiation shielding or protective apparel suitable for escape to a safe location (API, 2007).
12.5	4,000	Minimum energy to ignite wood with a flame, melts plastic tubing, first-degree burns in 10 seconds, 1% lethality in 1 minute (NFPA, 1995).
15.8	5,000	Threshold radiant heat flux used as the basis for determining *Potential Impact Radius* (PIR) which is defined by PHMSA in 49 CFR 912.903 as the radius of a circle within which the potential failure of a natural gas pipeline could have significant impact on people or property (Stephens, 2000 and DOT, 2011b). Radiant heat flux at which human skin experiences pain within 3 seconds and blisters within 6 seconds of exposure with second-degree burn injury (NFPA, 2011a). Radiant heat flux: • at which a wooden structure is not expected to burn and it, thereby, affords indefinite protection to sheltered persons; • corresponding to piloted ignition of whitewood after about 20 minutes of sustained exposure; and • corresponding to approximately a 1% chance of fatality for persons exposed for a credible period of time before reaching shelter (Stephens, 2000).

Table 1.1. Effects of thermal radiation intensity on buildings and humans (Cont.)

Approximate Radiant Heat Flux		Effects and Consequences
kW/m²	Btu/hr ft²	
20	6,340	Radiant heat flux for average ignition time of dry wood (poplar) in 75 seconds (McAllister, 2010). Cable insulation degrades after exposure for 30 minutes (LaChance, 2009). Heat flux on residential family room floor at the beginning of flashover (NFPA, 2011a).
25	7,930	Minimum energy to ignite wood at indefinitely long exposure without a flame (NFPA, 1995). Steel deformation after exposure for 30 minutes (LaChance, 2009).
29	9,200	Radiant heat flux at which wood ignites spontaneously after prolonged exposure (NFPA, 2011a)
30	9,510	Radiant heat flux for average ignition time of dry wood (poplar) in 30 seconds (McAllister, 2010)
31.5	10,000	Allowable thermal radiation flux for determining the acceptable separation distance of a proposed HUD-assisted project building from a hazardous facility. This is based upon the assumption that there will be fire department response to protect exposed combustible buildings within 15 minutes and that the exposed combustible materials will not spontaneously ignite before the fire department responds (HUD, 2011b).
37.5	11,900	Damage to process equipment, 100% lethality in 1 minute, 1% lethality in 10 seconds (NFPA, 1995). Process equipment and structural damage after exposure for 30 minutes (LaChance, 2009).
39.4	12,500	Maximum tolerable level of radiation at the facade of an exposed building. This value, originally derived from work of the Joint Fire Research organization in the United Kingdom, is now generally accepted as that below which the pilot ignition of most cellulosic materials (wood) is unlikely to occur. Pilot ignition is the ignition of a material by radiation where a local high-temperature igniting source is located in the stream of gases and volatiles issuing from the exposed material. Substantially higher levels of radiation are necessary to cause spontaneous ignition (NFPA, 2011b).
40	12,700	Radiant heat flux for average ignition time of dry wood (poplar) in 17 seconds (McAllister, 2010)
50	15,900	Radiant heat flux for average ignition time of dry wood (poplar) in 10 seconds (McAllister, 2010)
52	16,500	Radiant heat flux at which fiberboard ignites spontaneously after 5 seconds (NFPA, 2011a)
100	31,700	Steel structures collapse after exposure for 30 minutes (LaChance, 2009).

Although the volume of natural gas released depends on many factors, natural gas releases are subdivided into three sequential phases – Phase 1: Detection, Phase 2: Block Valve Closure, and Phase 3: Blowdown. The total discharge volume equals the sum of the volumes released during each phase. Events associated with each phase are described below.

Phase 1 – Detection: The detection phase begins immediately after the pipeline ruptures, t_0, and continues until the leak is detected by any method and recognized by the Pipeline Operator, t_d. The volume of natural gas discharged during the detection phase depends on the duration of this phase, t_d - t_0, and is influenced by factors such as the size, shape, and location of the rupture; the performance characteristics of the compressors; the pipeline pressure at the time of the release; and the effectiveness of the leak detection system. In theory, the entire length of the pipeline and its branch lines contribute to the release during the detection phase because the compressors are operating and the block valves are open.

Phase 2 – Block Valve Closure: The block valve closure phase begins after the leak is detected and corrective actions are initiated to mitigate the consequences of the release, t_d, and continues until the upstream and downstream block valves are closed, isolating the line section with the break, t_s. During the block valve closure phase, natural gas continues to flow from the break. The compressors may continue to operate after the block valves are closed, but their operation does not further affect the gas release. The duration of this phase can vary from a few minutes for systems with remotely operated block valves to an hour or more for manually operated equipment located in remote areas. The volume of natural gas discharged during the block valve closure phase, t_s- t_d, depends on the duration of this phase and is influenced by factors such as the type of equipment controls (automatically, remotely, or manually operated) and personnel travel time to shut down manually operated equipment. The volume of natural gas discharged during the block valve closure phase is affected by the swiftness of block valve closure.

Phase 3 – Blowdown: The blowdown phase begins when the portion of the pipeline that includes the break is isolated by closure of upstream and downstream block valves. This phase ends when the natural gas remaining in the isolated portions of the upstream and downstream pipeline segments flows from the break and burns, reducing the line pressure to one atmosphere. The volume of natural gas discharged during the blowdown phase depends on the duration of the previous phases and is influenced by the line pipe diameter and the distances from the break to the nearest upstream and downstream block valves.

1.3.1.2 Block Valve Effects on a Natural Gas Pipeline Release

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 leak and implementation of corrective actions including closing block valves to isolate the line section with the break reduce the total volume of natural gas released. The effectiveness of block valve closure in mitigating the consequences of a natural gas pipeline release decreases as the duration of the detection and block valve closure phases increase because thermal radiation effects on buildings and humans are a function of radiant heat flux and exposure duration.

1.3.2 Hazardous Liquid Pipeline Release Events

After a hazardous liquid pipeline ruptures, liquid begins flowing from the break and continues until draining is complete. The amount of material released following the break is influenced by a variety of factors. These factors include the type of liquid, the operating pressure of the pipeline, the size and position of the hole through which the liquid is released, the rate at which the liquid is being pumped through the pipeline, the response of the operator in terms of shutting off pumps and closing valves, the pipeline route and elevation profile, and the location of the break relative to the pumps and block valves. Block valves are installed in hazardous liquid pipelines to facilitate maintenance, operations, or construction and to limit the amount of liquid spilled following a pipeline rupture. For worst case, guillotine-type breaks, the effective hole size is equal to the line pipe diameter.

The behavior of the released liquid depends on its physical properties and the terrain in the vicinity of the break. For example, the liquid could flash on release of pressure to form a vapor cloud containing a fine mist of residual liquid droplets, accumulate in a pool on the ground surface near the pipeline break, create a stream that flows away from the release point, or soak into the surrounding soil (Acton, 2001).

If the released liquid ignites following the break, it could result in a pool fire, a flash fire, or, under certain conditions, a vapor cloud explosion. Pool fires can spread out in all directions or flow in a particular path depending on the terrain. Figure 1.3 shows fire damage along a creek caused by a hazardous liquid pipeline release in Bellingham, Washington (NTSB, 2002). If ignition is delayed, the resulting evolution of vapor from the release could influence the magnitude and extent of a subsequent flash fire or explosion.

Fig. 1.3. Fire damage resulting from hazardous liquid pipeline release in Bellingham, Washington (NTSB, 2002).

Impacts resulting from time-dependent radiant thermal intensities at various separation distances from the break are based on the following hazardous liquid pipeline release scenario. The release occurs following a guillotine-type break where the escaping liquid accumulates in a pool on an impermeable level ground surface and ignites immediately upon release. Pool size is affected by the type of liquid released, the line pipe diameter, the pipeline operating pressure, the time required to detect the leak and initiate corrective actions to mitigate the consequences of the release, the spacing of block valves, the time required to close block valves and isolate the break, and the terrain features. Any potential environmental impacts to air and water quality caused by the released liquids and their products of combustions are beyond the scope of this study.

As discussed in Section 1.3.1, thermal radiation hazard zones with increasing impact severity are described by concentric circles centered on the pipeline rupture. The thermal radiation intensities at the perimeters of these concentric circles increase as the radii decrease. Effects of progressively higher heat fluxes on buildings and humans are described in Table 1.1. Because thermal radiation effects on buildings and humans are a function of radiant heat flux and exposure duration, quantifying the time-dependent variations in radiant heat fluxes for specific radii is key to assessing the benefits of installing RCVs and ASVs in hazardous liquid pipelines.

Given the wide range of actual pipeline sizes and operating pressures, leak detection periods, and block valve spacing and closure times, ORNL developed methodologies for quantifying the impacts of these parameters on areas affected by combustion of the escaping liquid hydrocarbon. The methodologies, which are described in Section 3.2, also characterize time-dependent radiant thermal intensities at various separation distances from the break.

Without ignition, the escaping liquid could adversely affect waterway navigation, surface and ground water quality, and other aspects of the human and natural environments. In addition, the cost to remediate the affected areas could be substantial. Consequence mitigation for a hazardous liquid pipeline release without ignition requires rapid detection, pump shutdown, and block valve closure. However, even if these actions are taken quickly, some amount of liquid in the pipeline will drain out of the broken pipeline segments. Methodologies for quantifying spill volumes for hazardous liquid pipelines releases and for estimating socioeconomic and environmental damage caused by the spill are described in Section 3.3.

1.3.2.1 Phases of a Hazardous Liquid Pipeline Release

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 four sequential phases – Phase 1 Detection, Phase 2 Continued Pumping, Phase 3 Block Valve Closure, and Phase 4 Pipeline Drain Down (Borener, 1994 and California State Fire Marshal, 1993). The total discharge volume equals the sum of the volumes released during each phase. Events associated with each phase are described below.

Phase – 1 Detection: The detection phase begins immediately after the pipeline ruptures, t_0, and continues until the leak is detected by any means and the Operator initiates corrective actions to mitigate the consequences of the release, t_d. The volume of liquid discharged during the detection phase, V_d, depends on the duration of this phase and is influenced by factors such as the size, shape, and location of the rupture; the pumping rate; the pipeline pressure; and the effectiveness of the leak detection system.

The volume of liquid discharged during the detection phase is determined using the following equation.

$$V_d = Q_d(t_d - t_0) \tag{1.1}$$

where

V_d is the volume of liquid discharged during the detection phase, barrels (m^3)

Q_d is the discharge rate through the break that depends on the size and shape of the rupture, the pipeline pressure at the time of the rupture, and the pipeline pressure resulting from continued pumping, barrels (m^3) per minute

t_d - t_0 is the interval between the time the pipeline ruptures and the time the operator detects the leak and takes corrective actions to mitigate the consequences of the release, minutes

The closure swiftness of block valves located upstream and downstream from the break has no effect on the volume of liquid discharged during the detection phase.

Phase 2 – Continued Pumping: The continued pumping phase starts after corrective actions are initiated to mitigate the consequences of the release, t_d, and ends when the pumps stop operating, t_p.

During this time, additional hazardous liquid spills from the break. The duration of this phase can vary from a few minutes for systems with remotely operated pumps to hours for manually operated equipment located in remote areas. The volume of liquid discharged during the continued pumping phase, V_p, depends on the duration of this phase and is influenced by factors such as the type of equipment controls (automatically, remotely, or manually operated); personnel travel time to shutdown manually operated equipment; and the flow rates of the pumps.

The volume of liquid discharged during the continued pumping phase can be determined using the following equation.

$$V_p = Q_p(t_p - t_d) \quad (1.2)$$

where

- V_p is the volume of liquid discharged during the continued pumping phase, barrels (m^3)
- Q_p is the discharge rate through the break that depends on the size and shape of the rupture and the pipeline pressure resulting from continued pumping, barrels (m^3) per minute
- $t_p - t_d$ is the interval between the time the operator detects the leak and takes corrective actions to mitigate the consequences of the release and the time the pumps stop operating, minutes

The swiftness of block valve closure has no effect on the volume of liquid discharged during the continued pumping phase.

Phase 3 – Block Valve Closure: The block valve closure phase starts when the pumps stop operating, t_p, and ends when the upstream and downstream block valves close, t_s. During this time, an additional amount of liquid in the pipeline spills from the break. The volume of liquid discharged during the block valve closure phase, V_s, depends on the duration of this phase and is influenced by factors such as the speed at which block valves located upstream and downstream from the break close. The duration of this phase can vary from a few minutes for systems with automatic or remotely controlled valves to hours for systems with manually operated valves located in remote areas.

The volume of liquid discharged during the block valve closure phase can be determined using the following equation.

$$V_s = Q_s(t_s - t_p) \quad (1.3)$$

where

- V_s is the volume of liquid discharged during the block valve closure phase, barrels (m^3)
- Q_s is the discharge rate through the rupture that depends on the size and shape of the break and the transient pipeline pressure after the pumps stop operating, barrels (m^3) per minute
- $t_s - t_p$ is the interval between the time the pumps stop operating and the time the block valves close, minutes

The swiftness of block valve closure has a significant effect on the volume of liquid discharged during the block valve closure phase.

Phase 4 – Pipeline Drain Down: The pipeline drain down phase starts when the upstream and downstream block valves close isolating the portion of the pipeline that includes the break, t_s. This phase ends when the remaining contents of the isolated portion of the damaged pipeline segment drain from the break, t_f. The volume of liquid discharged during the drain down phase, V_f, is affected by the pipeline elevation profile including siphon action and the location of the break. A break that occurs at the highest elevation in the isolated portion of the pipeline results in no drain down volume, whereas a break that occurs at the lowest elevation could result in significant or complete drain down of the isolated portion of the pipeline.

The rate at which liquid drains from a break in the isolated portion of the damaged pipeline segment depends primarily on the size of the break and the pipeline elevation profile. It is also affected by the flow rate of air that must enter the break to replace the liquid and allow the draining to continue. In hilly or mountainous terrain, determining the length of pipeline, L, available to drain from a break must consider site-specific design and construction details. The volume of liquid discharged from the contributory length of pipeline, L, during the drain down phase, V_f, and the transient discharge rate, Q_f, cannot be accurately determined without knowing the actual pipeline elevation profile as illustrated in Fig. 1.4.

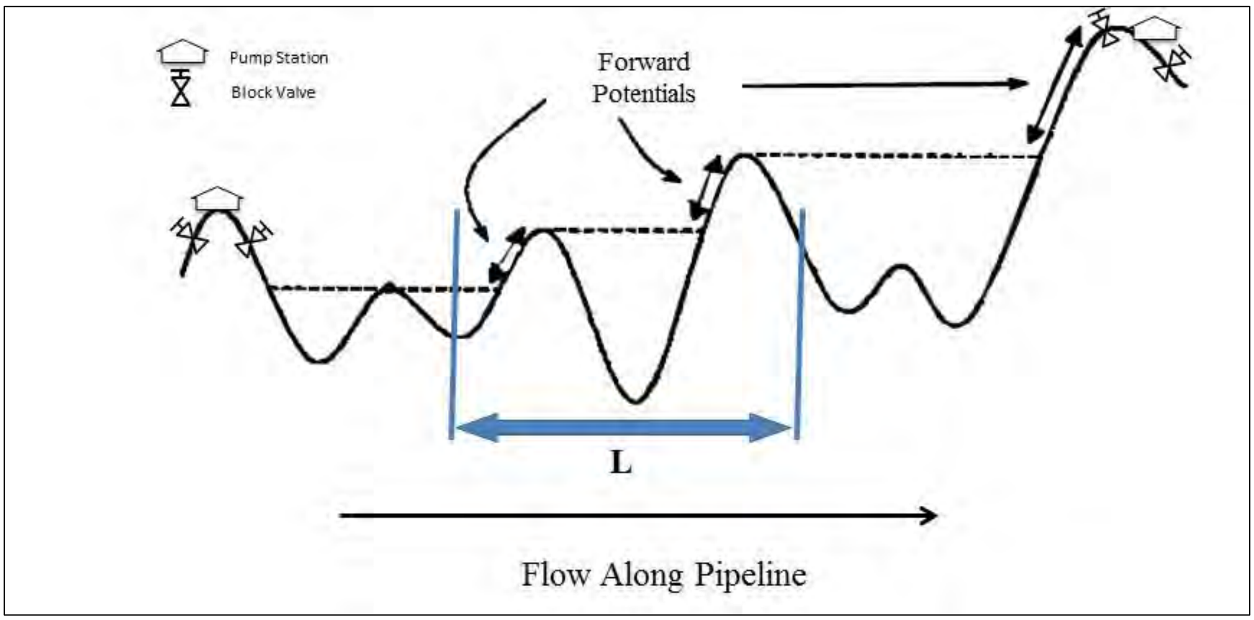


Fig. 1.4. Pipeline drain down segment, *L*.

Block valve closure is an effective means for reducing the drain down volume of a ruptured hazardous liquid pipeline, but the terrain can reduce the actual drain down volume to only a fraction of the total volume contained within the damaged line section. Peaks and plateaus in a pipeline elevation profile have a significant effect on the drain down volume because they have a higher potential than the surrounding pipeline segments and thus act to restrict flow.

1.3.2.2 Block Valve Effects on a Hazardous Liquid Pipeline Release

The effectiveness of block valve closure swiftness on limiting the spill volume of a hazardous liquid pipeline 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 reduce the volume of liquid spilled during the detection and continued pumping phases because they are open. However, the total spill volume can be reduced by rapidly detecting the leak and taking immediate corrective actions including shutting down the pumps and closing the block valves to mitigate the consequences of the release. The effectiveness of block valve closure in mitigating the consequences of a hazardous liquid pipeline release decreases as the time required to close the block valve increases.

1.3.3 Fire Science and Potential Fire Consequences

Fire is a combustion or burning process accompanied by flame in which substances combine chemically with oxygen from the air and typically evolve bright light, heat, and smoke. A fuel is any substance that can undergo combustion. Most fuels must be in a gaseous or vapor state to ignite. Combustion of liquids and most solid fuels occurs above the surface in a region of vapors created by heating the surface of the material. The time and energy required for ignition to occur is a function of the energy of the ignition source, the thermal inertia of the fuel, the minimum ignition energy, and the geometry of the fuel. For fuel to increase in temperature, the rate of heat transfer to the fuel must be greater than the sum of the conduction losses, convection losses, radiation losses, energy associated with phase changes (such as the heat of vaporization), and energy associated with chemical changes. For fuel to reach its ignition temperature, the heat source itself must have a temperature higher than the fuel's ignition temperature.

Fire can spread either by direct flame impingement or by remote ignition of adjacent fuel packages through heat transfer by conduction, convection, or radiation. A fuel package is a collection or array of fuel items in close proximity with one another such that flames can spread throughout the array of fuel items. Flame impingement involves the deflection of flames from one fuel package to adjacent fuel packages. If the surfaces of adjacent fuel package are combustible, they can ignite through direct flame contact. However, the dominant method of spreading fire from one remote location to another remote location is through radiation (NFPA, 2011a).

Pipeline releases present some of the most dangerous situations that emergency responders encounter. Key strategic considerations for fire fighters and other emergency responders to a pipeline release and fire are life safety, extinguishment, and property conservation. Upon arrival at the scene, when resources are often limited, initial response typically focuses on life safety as the number one priority, followed by extinguishment and then property conservation. Extinguishment and life safety are often related. If the fire is extinguished, rescue may take care of itself and emergency responder operations are much safer. Response time by fire fighters and emergency personnel involves the following sequential components: ignition, combustion, discovery, call processing, dispatch time, turnout time, drive time, setup time, combat, and extinguishment. Based on data from 2000 and 2001, response times were less than 5 minutes nearly 50% of the time and less than 8 minutes about 75% of the time. Nationally, average response times were generally less than 8 minutes. The overall 90th percentile was less than 11 minutes (DHS, 2006).

1.3.3.1 Standard for Organization and Deployment of Fire Suppression Operations

The NFPA established minimum requirements for organization and deployment of fire suppression operations, emergency medical operations, and special operations to the public by career fire departments in NFPA 1710, 2010 edition (NFPA, 2010). These requirements state the following objectives.

- The turnout time for fire and special operations response is 80 seconds.
- The turnout time for first responder response is 60 seconds.

- The travel time for the arrival of the first arriving engine company at a fire suppression incident is 4 minutes or less to 90% of the incidents.
- The deployment of an initial full alarm assignment at a fire suppression incident is 8 minutes travel time or less to 90% of the incidents.

Based on these objectives, the time interval from receipt of the alarm until the first emergency response unit initiates action or intervenes to control the incident is 9 minutes and 20 seconds.

The NFPA also requires that the initial full alarm assignment to a 2,000 sq. ft., two-story single-family dwelling fire involves establishing an effective water flow application rate of 300 gpm (1,140 l/min) from two handlines, each of which has a minimum flow rate of 100 gpm (380 l/min) with each handline operated by a minimum of two individuals to effectively and safely maintain the line (NFPA, 2010).

1.3.3.2 Fireground Field Experiments

The National Institute of Standards and Technology (NIST) conducted live-fire experiments to study the effects that varying crew sizes have on response and operational times at structure fires and provide true operating times for typical fireground operations and tasks at a common residential structure fire (Averill, 2010). The results provide true scale operational times using actual fire fighters at a true structure fire and provides data that can be accurately applied to approximate at what time in the fire development curve fire fighters most likely arrive on the scene, prepare to make entry, stretch lines to the fire compartment, and initiate fire attack.

The overall response time assumptions used to design the NIST experiments involved the following segments based on a previous edition of NFPA 1710 (Averill, 2010).

1. Fire ignition = time zero.
2. 60 seconds for recognition (detection of fire) and call to 9-1-1.
3. 60 seconds for call processing/dispatch.
4. 60 seconds for turnout (80 seconds in NFPA 1710, 2010 edition).
5. Close Stagger = 240 seconds travel time first engine with 60 seconds ladder-truck lag and 90 seconds lag for each subsequent engine.
    a. Truck arrives at 300 seconds from notification.
    b. Second engine at 330 seconds from notification.
    c. Third engine at 420 seconds from notification.
6. Far Stagger = 240 seconds travel time first engine with 120 seconds ladder-truck lag and 150 seconds lag for each subsequent engine.
    a. Truck arrives at 360 seconds from notification.
    b. Second engine arrives at 390 seconds from notification.
    c. Third engine arrives at 540 seconds from notification.

In the study, times for fire fighters to begin their travel to the fire started at 3-1⁄2 minutes from when the fire started, and response times are 3 to 5 minutes. These times placed the first-due engine arriving at 6-1⁄2 minutes and 8-1⁄2 minutes after the fire started. The study also recorded the “Advance Attack Line Time,” which is the time required for the first engine to arrive, stretch the first line, and initiate fire attack.

The report states that a three-person engine company took 3 minutes and 36 seconds, and a four-person engine company took 3 minutes and 2 seconds to stretch the initial attack line to the fire. The time at which water was first applied to the room-and-contents fire area ("Time to Water") for the first-due engine company was 9 minutes and 15 seconds for the three-person company and 8 minutes and 41 seconds for the four-person company (Averill, 2010).

1.3.3.3 Emergency Response Guidance

The *2008 Emergency Response Guidebook* (DOT, 2008) provides guidance to aid first responders in quickly identifying the hazards of the materials involved in an incident and protecting themselves and the general public during the initial response phase of the incident. The initial response phase is that period following arrival at the scene of an incident during which the presence and identification of dangerous situations is confirmed, protective actions and area securement are initiated, and assistance of qualified personnel is requested. The *Guidebook* includes the following safety guidance that applies to all types of incidents including natural gas and hazardous liquid pipeline releases.

- **Approach Cautiously from Upwind.** If wind direction allows, consider approaching the incident from uphill. Resist the urge to rush in; others cannot be helped until the situation has been fully assessed.
- **Secure the Scene.** Without entering the immediate hazard area, isolate the area and assure the safety of people and the environment, keep people away from the scene and outside the safety perimeter. Allow enough room to move and remove your own equipment.
- **Identify the Hazards.** Placards, container labels, shipping documents, material safety data sheets, Rail Car and Road Trailer Identification Charts, and/or knowledgeable persons on the scene are valuable information sources. Evaluate all available information and consult the recommended guide to reduce immediate risks. Additional information, provided by the shipper or obtained from another authoritative source, may change some of the emphasis or details found in the guide. Remember, the guide provides only the most important and worst case scenario information for the initial response in relation to a family or class of dangerous goods. As more material-specific information becomes available, the response should be tailored to the situation.
- **Assess the Situation.** Consider the following:
  - ✓ Is there a fire, a spill or a leak?
  - ✓ What are the weather conditions?
  - ✓ What is the terrain like?
  - ✓ Who/what is at risk: people, property or the environment?
  - ✓ What actions should be taken: Is an evacuation necessary? Is diking necessary? What resources (human and equipment) are required and are readily available?
  - ✓ What can be done immediately?
- **Obtain Help.** Advise your headquarters to notify responsible agencies and call for assistance from qualified personnel.
- **Decide on Site Entry.** Any efforts made to rescue persons, protect property or the environment must be weighed against the possibility that you could become part of the problem. Enter the area only when wearing appropriate protective gear.
- **Respond.** Respond in an appropriate manner. Establish a command post and lines of communication. Rescue casualties where possible and evacuate if necessary. Maintain control of the site. Continually reassess the situation and modify the response accordingly. The first duty is to consider the safety of people in the immediate area, including your own.

- **Above All**. Do not walk into or touch spilled material. Avoid inhalation of fumes, smoke and vapors, even if no dangerous goods are known to be involved. Do not assume that gases or vapors are harmless because of lack of a smell—odorless gases or vapors may be harmful.

The *Guidebook* also includes the following precautionary statements. A natural gas pipeline fire should not be extinguished unless the leak can be stopped and use of water spray when fighting a hazardous liquid pipeline fire may be ineffective for fires involving very low flash point materials such as gasoline.

The Pipeline Association for Public Awareness (PAPA) published the *Pipeline Emergency Response Guidelines* as a concise resource for reference prior to and during a pipeline emergency (PAPA, 2011). This publication includes an incident response checklist that is subdivided into the following four action categories applicable to fire fighters and other emergency response personnel.

1. Assess the Situation.
2. Protect People, Property, and the Environment.
3. Call for Assistance of Trained Personnel.
4. Work Together with the Pipeline Operator.

This checklist includes the following additional guidance.

> *Pipeline operators will concentrate on shutting down pipeline facilities. Responders should focus on protecting the public and isolating or removing ignition sources.*

Appendix A to the *Pipeline Emergency Response Guidelines* includes a table of recommended minimum evacuation distances for natural gas pipeline leaks and ruptures. These distances vary depending on the pipeline pressure and size and apply to leak or rupture condition for a sustained trench fire fueled by non-toxic natural gas escaping from two full bore pipe ends but not for butane, propane, or other hazardous liquids. The evacuation distances listed in the table are intended to provide protection from burn injury and correspond to a thermal heat flux exposure level of 1.4 kW/m^2 (450 Btu/hr ft^2) which is accepted by the HUD as the limit of heat exposure for unprotected outdoor areas where people congregate (HUD, 2011a).

The methodology used by PAPA to compute the recommended minimum evacuation distances was developed by the Gas Research Institute (Stephens, 2000) for sizing high consequence areas associated with natural gas pipelines. However, it does not take into consideration wind or other factors that could greatly influence thermal heat flux contours. Recommended minimum evacuation distances range from 474 ft for 12-in. natural gas pipelines that operate at 300 psig to 3,709 ft for 42-in. pipelines that operate at 1,500 psig. Users of recommended minimum evacuation distances are advised by PAPA that these distances are considered to be “general information” only and are not intended to replace a site specific risk analysis.

1.3.3.4 Standard for Fire Hydrant Spacing and Flow Rate

Water needed to conduct effective fire fighting operations is normally supplied from fire hydrants located in the vicinity of the fire. According to International Fire Code requirements, the maximum average spacing between fire hydrants with a maximum fire-flow requirement of 1,750 gpm is 500 ft (ICC, 2012a). However, additional fire hydrants with greater fire-flow requirements and closer average spacing available to a building are required for a complex or subdivision.

1.3.3.5 Fire Science and Potential Fire Consequence Assessment Criteria

After considering the various factors that contribute to overall response time and the studies performed to quantify actual response time, ORNL selected 10 minutes as the overall fire fighter response time to evaluate the effectiveness of block valve closure swiftness on mitigating the consequences of a fire resulting from a natural gas or hazardous liquid pipeline release. This time begins when the pipeline break occurs and ends when the engines arrive at the scene and the fire fighters deploy equipment and begin fire fighting operations. Overall fire fighter response times for the first, second, and third engines that arrive at the scene are 9, 9-1/2, and 10 minutes, respectively.

In determining the effectiveness of fire fighting activities, ORNL based its assessment on the following assumptions.

- Fire hydrants are located equally around the perimeter of the area affected by the pipeline release at a maximum spacing of 500 ft.
- The maximum number of engines that respond to a natural gas pipeline release within 10 minutes after the break is 12.
- Each fire hydrant provides adequate water flow for one engine.
- Each engine can extinguish one building fire within 30 minutes after the break.
- Without fire fighter intervention, the value of each building (including contents) that ignites as a result of the break reduces linearly from 100% to 0% at 20 minutes after the break, at which time fire fighting activities evolve from controlling fire damage to preventing fire spread.
- With fire fighter intervention, the avoided damage cost for each building (including contents) that ignites as a result of the break increases at a rate of 5% per minute for each additional minute that fire fighting activities begin up to a maximum of 10 minutes.

1.3.4 Thermal Radiation Effects

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 (Iqbal and Salley, 2003). Radiation is the transfer of heat energy from a hot surface or gas to a cooler material by electromagnetic waves without the need of an intervening medium. Thermal radiation from flames to a remote surface decreases rapidly with distance.

The rate of heat transfer from a radiating material is proportional to that material's absolute temperature raised to the fourth power. Thermal radiation hazards from a hydrocarbon fire depend on a number of parameters including the composition of the hydrocarbon, the size and shape of the fire, the duration of the fire, its proximity to the object at risk, and the thermal characteristics of the object exposed to the fire (NFPA, 1995). A range of thermal radiation effects on buildings and humans are described in Table 1.1.

1.3.4.1 Effects on Humans

Hyperthermia is the condition of overheating of the body. Victims exposed to the hot environment of a fire, including high moisture content, are subject to incapacitation or death due to hyperthermia, especially if the person is active. The time duration and type of exposure can lead to either simple hyperthermia or acute hyperthermia.

Simple hyperthermia results from prolonged exposures (typically more than 15 minutes) to hot environments where the ambient temperature is too low to cause burns. Such conditions range from 80°C to 120°C (176°F to 248°F) depending on the relative humidity, and usually result in a gradual increase in the body core temperature. High humidity makes it harder for the body to dispel excess heat by evaporation and thereby accelerates the heating process. Core body temperatures above approximately 43°C (109°F) are generally fatal within minutes unless treated.

Acute hyperthermia involves exposure to high temperatures for short periods of time (less than 15 minutes). This type of hyperthermia is accompanied by burns. However, when death occurs shortly after exposure to severe heat, the cause of death is generally considered to be from a rise in blood temperatures rather than from burns (NFPA, 2011a).

When the temperature of the skin reaches approximately 45ºC (113ºF), pain will result and an additional increase in temperature will cause thermal burns. Thermal burns can result from conductive, convective, or radiant heat exposure. Clothing, especially heavier cellulosic fabrics like denim or canvas, can transmit enough heat by conduction to cause skin burns even though the fabric does not exhibit any burning or charring. When skin is exposed to convective heat, pain and the onset of burns occur at air temperatures above 120ºC (248ºF).

When radiant heating raises the temperature of the skin, the higher the radiant flux, the faster damage will occur. For instance, a heat flux of 2 kW/m^2 (635 Btu/hr ft^2) will cause pain after a 30-second exposure, while a heat flux of 10 kW/m^2 (3,175 Btu/hr ft^2) will cause pain after just 5 seconds. A heat flux of 2 kW/m^2 (635 Btu/hr ft^2) will not cause blisters, but a heat flux of 10 kW/m^2 (3,175 Btu/hr ft^2) will blister in 12 seconds. A heat flux of 20 kW/m^2 (6,350 Btu/hr ft^2), typically associated with flashover, is sufficient to ignite clothing or cause severe burns or death by brief thermal exposure. Radiant heat, sufficient to cause burns, can be reflected from some surfaces. Heat can be transferred through clothing, causing burns to the underlying skin, without any readily identifiable damage to the clothing (NFPA, 2011a).

The NFPA *Guide for Fire and Explosion Investigations* states that heat flux of 2.5 kW/m^2 (800 Btu/hr ft^2) is a common thermal radiation exposure while fighting fires, however, this energy level may cause burn injuries with prolonged exposure (NFPA, 2011a).

According to HUD, a thermal radiation heat flux of 1.4 kW/m^2 (450 Btu/hr ft^2) is considered the acceptable level of thermal radiation for people in open spaces where people congregate, such as parks and playgrounds (HUD, 2011b).

The NTSB defines *fatal injury* as any injury that results in death within 30 days of the accident and *serious injury* as an injury that: (1) requires hospitalization for more than 48 hours, commencing within 7 days of the date the injury was received; (2) results in a fracture of any bone (except simple fractures of fingers, toes, or nose); (3) causes severe hemorrhages or nerve or tendon damage; (4) involves any internal organ; or (5) involves second- or third-degree burns, or any burn affecting more than 5% of the body surface (DOT, 2011c).

1.3.4.2 Effects on Buildings and Construction Materials

The NFPA *Guide for Fire and Explosion Investigations* describes observed effects of radiant heat fluxes on various materials used for building construction (NFPA. 2011a). For instance, fiberboard ignites spontaneously after 5 seconds of exposure to a radiant heat flux of 52 kW/m^2 (16,500 Btu/hr ft^2). Wood ignites spontaneously after prolonged exposure to a radiant heat flux of 29 kW/m^2 (9,200 Btu/hr ft^2) and wood volatiles ignite with extended exposure and piloted ignition to a radiant heat flux of 12.5 kW/m^2 (4,000 Btu/hr ft^2).

According to HUD, the tolerance on combustible materials on the maximum thermal radiation exposure reduces gradually as the thermal heat flux increases from 15.75 kW/m^2 (5,000 Btu/hr ft^2) to 28.35 kW/m^2

(9,000 Btu/hr ft^2). In addition, HUD determined that a thermal radiation heat flux of 31.5 kW/m^2 (10,000 Btu/hr ft^2) is an acceptable standard for buildings. This standard is based upon the assumption that there will be fire department response to protect exposed combustible buildings within 15 minutes and that the exposed combustible materials will not spontaneously ignite before the fire department responds (HUD, 2011b).

Following the Pacific Gas and Electric Company natural gas transmission pipeline rupture and fire in San Bruno, California on September 9, 2010, the city of San Bruno, California used the following damage categories to classify structural damage to houses at the accident site: (1) severe indicated that a house was not safe to occupy and most likely would need to be demolished or completely renovated prior to occupancy, (2) moderate indicated that a house had substantial damage and repairs would be necessary prior to occupancy, and (3) minor indicated that a house had the least amount of damage and could be legally occupied while repairs were being made (NTSB, 2011).

Thermal radiation hazard zones with increasing impact severity are described by concentric circles centered on the pipeline rupture. The thermal radiation intensities at the perimeters of these concentric circles increase as the radii decrease. However, the thermal radiation intensity at a particular radius changes with time as the blowdown progresses and the amount of natural gas that escapes decreases. A threshold heat flux of 15.8 kW/m^2 (5,000 Btu/hr ft^2) was used by PHMSA as the basis for determining Potential Impact Radius (PIR) which is defined in 49 CFR 192.903 as the radius of a circle within which the potential failure of a natural gas pipeline could have significant impact on people or property (DOT, 2011a). Because spontaneous ignition is not possible at this heat flux, it represents a reasonable estimate of the heat flux below which wooden structures are not destroyed, and below which wooden structures should afford indefinite protection to occupants (Stephens, 2000).

Quantifying time-dependent variations in heat flux for specific radii is key to assessing the benefits of installing RCVs and ASVs in natural gas and hazardous liquid pipelines, because thermal radiation effects on buildings, vehicles, personal property, and humans are a function of heat flux intensity and exposure duration. For this reason, ORNL developed heat flux versus time data needed to quantify the effects of block valve closure time on exposure durations for the radiant heat flux intensities listed in Table 1.2. The heat flux intensities and exposure durations defined in this table correspond to specific thresholds used to quantify fire damage and establish safe separations distances for fire fighters, emergency responders, and the public. The methodologies used to compute heat flux vs. time data for natural gas and hazardous liquid pipelines are discussed in Sections 3.1 and 3.2, respectively.

Table 1.2. Heat flux threshold basis

Heat Flux Threshold		Threshold Basis
kW/m^2	Btu/hr ft^2	
1.4	450	Maximum heat flux for continuous exposure considered acceptable for outdoor, unprotected facilities or open spaces where people congregate
2.5	800	Maximum heat flux for continuous exposure considered acceptable for common fire fighting and emergency response activities
15.8	5,000	Heat flux threshold for minor damage to buildings after 30-minutes exposure
31.5	10,000	Heat flux threshold for moderate damage to buildings after 15-minutes exposure
40.0	12,700	Heat flux threshold for severe damage to buildings after instantaneous exposure

1.3.5 Socioeconomic and Environmental Effects of a Hazardous Pipeline Release

Potential consequences and effects on the human and natural environments resulting from a hazardous liquid pipeline 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 quantifying 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 as described in Section 3.3.3.

2. REGULATORY REQUIREMENTS

The CFR is a codification of the general and permanent rules published in the Federal Register by the Executive departments and agencies of the Federal Government. The Code is divided into 50 titles which bear the name of the issuing agency and represent broad areas subject to Federal regulation. Title 49—Transportation is composed of nine volumes. The second volume (Parts 100–185) and the third volume (Parts 186–199) contain current regulations issued under Chapter I—Pipeline and Hazardous Materials Safety Administration (DOT). Parts192, 194, and 195 include safety regulations issued by PHMSA specifically for natural gas and hazardous liquid pipelines. The following sections summarize pipeline safety regulations that affect strategies and response plans for mitigating the consequences of an accidental release.

2.1 49 CFR 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Minimum safety requirements for pipeline facilities and the transportation of gas are defined in 49 CFR 192, Subparts A through P (DOT, 2011b). According to definitions in Part 192, a pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. In addition, a pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Prescribed minimum requirements for the design and installation of natural gas pipeline components and facilities are contained in Subpart C. According to rules in 49 CFR 192.179, each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2–1⁄2 mi. (4 km) of a valve,

(2) Each point on the pipeline in a Class 3 location must be within 4 mi. (6.4 km) of a valve,

(3) Each point on the pipeline in a Class 2 location must be within 7–1⁄2 mi. (12 km) of a valve, and

(4) Each point on the pipeline in a Class 1 location must be within 10 mi. (16 km) of a valve.

Class locations are defined in 49 CFR 192.5 as follows.

- A Class 1 location is an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy.
- A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
- A Class 3 location is any class location unit that has 46 or more buildings intended for human occupancy; or an area where the pipeline lies within 100 yd (91 m) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
- A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

The term class location unit is defined as an onshore area that extends 220 yd (200 m) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. The length of Class locations 2, 3, and 4 may be adjusted as follows: (1) A Class 4 location ends 220 yd (200 m) from the nearest building with four or more stories above ground, (2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yd (200 m) from the nearest building in the cluster. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

Pipeline operators are also required to take additional measures beyond those already required by 49 CFR 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a HCA. According to 49 CFR 192.935, an operator must base the additional measures on the threats the operator has identified to each pipeline segment. An operator must 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) to identify additional measures to protect the HCA and enhance public safety. Such additional measures include, but are not limited to, installing ASVs or RCVs, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

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.

A HCA is defined in 49 CFR 192.903 as follows.

> *High consequence area* means an area established by one of the methods described in paragraphs (1) or (2) as follows:
>
> (1) An area defined as—
> - (i) A Class 3 location under § 192.5; or
> - (ii) A Class 4 location under § 192.5; or
> - (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 ft (200 m), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
> - (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
>
> (2) The area within a potential impact circle containing—
> - (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
> - (ii) An identified site.
>
> (3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1) (iii) of this definition or paragraph (2) (i) of this definition, the radius of the potential impact circle is greater than 660 ft (200 m), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 ft (200 m) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 ft (200 m) to the area of the potential impact circle (i.e. the prorated number of buildings intended for human occupancy is equal to 20 × (660 ft) [or 200 m] / potential impact radius in ft [or m]^2).

An identified site means each of the following areas as defined in 49 CFR 192.903.

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

The term PIR means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. The PIR is determined by the following formula.

$$R = 0.69(pd^2)^{1/2} \tag{2.1}$$

where

- R is the radius of a circular area in ft surrounding the point of failure
- p is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch
- d is the nominal diameter of the pipeline in inches.

A potential impact circle is a circle of radius equal to the PIR.

According to requirements in 49 CFR 192.745, each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

2.2 49 CFR 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

Safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide are defined in 49 CFR 195, Subparts A through G (DOT, 2011d). A hazardous liquid is defined in 49 CFR 195.2 as petroleum, petroleum products, or anhydrous ammonia. The term petroleum means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Valve location requirements for hazardous liquid pipeline are included in 49 CFR 195.260. According to these requirements, a block valve must be installed at each of the following locations.

1. On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.
2. On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.
3. On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.
4. On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.
5. On each side of a water crossing that is more than 100 ft (30 m) wide from high-water mark to high-water mark unless the DOT Administrator finds in a particular case that valves are not justified.
6. On each side of a reservoir holding water for human consumption.

Pumping equipment requirements for hazardous liquid pipeline are included in 49 CFR 195.262. According to these requirements, each pump station must include the following features.

- Safety devices that prevent over pressurizing of pumping equipment, including the auxiliary pumping equipment within the pumping station.
- A device for the emergency shutdown of each pumping station.
- If power is necessary to actuate the safety devices, an auxiliary power supply.

Preventative and mitigative measures that operators of hazardous liquid pipelines in HCAs must take to protect the HCAs are included 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.

The term HCA is defined in 49 CFR 195.450 as a follows.

- A commercially navigable waterway means a waterway where a substantial likelihood of commercial navigation exists.
- A high population area means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

- Another populated area means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.
- An unusually sensitive area (USA) means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release. The terms USA drinking water resource and USA ecological resource are defined in 49 CFR 195.6.

An EFRD is either a check valve or a RCV. The term check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction. An RCV is any valve that is operated from a location remote from where the valve is installed and is usually operated by the SCADA system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

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.

Based on the definition of EFRD in 49 CFR 195.450, an ASV is not considered an EFRD. However, installing an ASV in a hazardous liquid pipeline to protect an HCA could be considered a preventative or mitigative measure that is consistent with the safety objectives in 49 CFR 195.452(i).

Hazardous liquid pipeline operators must prepare a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. According to requirements in 49 CFR 195.402, the manual must include procedures for providing safety when an emergency condition occurs. These procedures must address the following areas.

- Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.
- Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.
- Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.
- Taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid that is released from any section of a pipeline system in the event of a failure.
- Control of released hazardous liquid at an accident scene to minimize the hazards, including possible intentional ignition in the cases of flammable highly volatile liquid.
- Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

- Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid.
- In the case of failure of a pipeline system transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas.
- Providing for a post-accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found.
- Actions required to be taken by a controller during an emergency.

An operator of a hazardous liquid pipeline facility with a controller working in a control room that monitors and controls all or part of a pipeline facility through a SCADA system must have and follow written control room management procedures. These procedures must be integrated with the operator's written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. According to requirements in 49 CFR 195.446 for control room management, operators must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2013.

Hazardous liquid pipeline operators are also required to establish and conduct a continuing training program for instructing emergency response personnel. Emergency response training requirements in 49 CFR 195.403 state that the training must instruct emergency response personnel in performing the following duties.

- Carry out emergency procedures in accordance with the procedural manual for operations, maintenance, and emergencies that relate to their assignments.
- Know the characteristics and hazards of the hazardous liquids transported, including, in case of flammable of highly volatile liquids, flammability of mixtures with air, odorless vapors, and water reactions.
- Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action.
- Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.
- Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.

2.3 49 CFR 194—RESPONSE PLANS FOR ONSHORE OIL PIPELINES

Requirements for oil spill response plans to reduce the environmental impact of oil discharged from onshore oil pipelines are defined in 49 CFR 194, Subparts A and B (DOT, 2011e). Oil is defined in 49 CFR 194.5 as oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, vegetable oil, animal oil, sludge, oil refuse, oil mixed with wastes other than dredged spoil.

Regulations in Subpart B require each operator of an onshore pipeline facility to prepare and submit a response plan to PHMSA. The term response plan means the operator's core plan and the response zone appendices for responding, to the maximum extent practicable, to a worse case discharge of oil, or the substantial threat of such a discharge. The term worst case discharge is defined as the largest foreseeable discharge of oil, including a discharge from fire or explosion, in adverse weather conditions.

A hazardous liquid pipeline operator is required to determine the worst case discharge for each of its response zones (49 CFR 194.105). A response zone is a geographic area either along a length of pipeline or including multiple pipelines, containing one or more adjacent line sections, for which the operator must plan for the deployment of, and provide, spill response capabilities. The size of the zone is determined by the operator after considering available capability, resources, and geographic characteristics. A line section is a continuous run of pipe that is contained between adjacent pressure pump stations, between a pressure pump station and a terminal or breakout tank, between a pressure pump station and a block valve, or between adjacent block valves.

Federal regulations included in 49 CFR 194.105(b) require operators to provide the methodology, including calculations, used to arrive at the worst case discharge volume. Operators must determine the worst case discharge, which is the largest volume, in barrels (m^3), based on one of the following methods:

(1) The pipeline's maximum release time in hours, plus the maximum shut down response time in hours (based on historic discharge data or in the absence of such historic data, the operator's best estimate), multiplied by the maximum flow rate expressed in barrels per hour (based on the maximum daily capacity of the pipeline), plus the largest line drainage volume after shut down of the line section(s) in the response zone expressed in barrels (m^3), or

(2) The largest foreseeable discharge for the line section(s) within a response zone, expressed in barrels (m^3), based on the maximum historic discharge, if one exists, adjusted for any subsequent corrective or preventive action taken, or

(3) If the response zone contains one or more breakout tanks, the capacity of the single largest tank or battery of tanks within a single secondary containment system, adjusted for the capacity or size of the secondary containment system, expressed in barrels (m^3).

3. RISK ANALYSIS

The risk of an unintended natural gas or hazardous liquid pipeline release is a function of two independent variables: (1) magnitude of consequences, and (2) probability of failure. From a historical viewpoint, the probability of an unintended release is low, but the consequences are potentially catastrophic for humans and the environment (DOT, 2010b).

Unintended releases are categorized as either line pipe leaks (punctures) or breaks (ruptures). These releases often result from internal or external corrosion; cracking; fatigue; welding defects; natural phenomena such as earthquakes, landslides, and floods; third party damage; and other failure mechanisms (ASME, 2010). The failure mode is determined by the length, depth, and type of defect, and is dependent on the pipe diameter, wall thickness, material properties, stress state, and the operating pressure. Inspecting, testing, repairing, and replacing deficient pipeline segments and implementing one-call notification systems are effective methods for reducing, but not eliminating, risk by decreasing the probability of an unintended release.

Mitigating the consequences of an unintended release requires limiting the overall volume of natural gas or hazardous liquid that escapes from the pipeline and flows into the surrounding environment. However, completely eliminating the consequences of an unintended release is not possible because pipelines operate above atmospheric pressure and any puncture or through-wall break in the pipeline will result in an unintended release. Isolating the damaged pipeline segment by quickly closing upstream and downstream block valves is an effective method for mitigating the consequences of an unintended release and thus reducing risk by controlling the overall volume of the release. Although block valve closure swiftness is often effective in limiting the magnitude of potential consequences, block valve closure has no effect on reducing the probability of an unintended release.

The effectiveness of block valve closure swiftness in reducing potential consequences of an unintended natural gas or hazardous liquid pipeline release is assessed in Sections 3.1, 3.2, and 3.3. These risk analyses examine the effectiveness of ASV and RCV installation in newly constructed or entirely replaced pipeline facilities in mitigating the consequences of a release compared to the effectiveness of manually operated block valves installed at the same locations.

The methodology used to quantify the effectiveness of block valve closure swiftness in reducing potential consequences of an unintended natural gas or hazardous liquid pipeline release is based on a conservative approach to pipeline safety that considers consequences of a time-dependent discharge resulting from a guillotine-type break. These consequences involve:

- potential fire damage to buildings, vehicles, and personal property caused by ignition and combustion of the released hydrocarbon that begins as soon as the break in a natural gas or hazardous liquid pipeline occurs;
- potential burn injuries to fire fighters and the public caused by exposure to thermal radiation; and
- potential socioeconomic and environmental effects resulting from a hazardous liquid pipeline release without ignition.

Table 1.1 describes the effects and consequences of various thermal radiation intensities on buildings, materials, and humans. Heat flux thresholds used to assess potential fire damage resulting from natural gas and hazardous liquid pipeline releases are defined in Table 1.2. Potential socioeconomic and environmental effects resulting from a hazardous liquid release are discussed in Section 3.3.

3.1 NATURAL GAS PIPELINES

A methodology for quantifying the consequences of a natural gas pipeline release was developed at ORNL and used to determine: (1) the time-dependent discharge from a natural gas transmission pipeline resulting from a guillotine-type break, and (2) the time-dependent thermal radiant intensities resulting from a fire produced by combustion of the released natural gas. The size and intensity of a fire resulting from a natural gas pipeline release depends on the effective rate of gas release which is primarily influenced by the pressure differential 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, pipeline length, and the internal operating pressure when the break occurs.

The risk analysis approach used by ORNL to evaluate the consequences of a natural gas pipeline release is consistent with the *(1) Subject Matter Expert* and the *(3) Scenario-Base Models* risk assessment approaches described in ASME/ANSI B31.8S, Section 5 – Risk Assessment (ASME, 2010). The risk analysis results discussed in this report only address consequences of unintended natural gas pipeline releases because the risk analysis approach is based on the premise that the releases occur (100% failure likelihood). This presumption is considered acceptable because ASVs and RCVs are installed in natural gas pipelines to mitigate the consequences of an unintended release. Their installation and operation have no effect on failure likelihood. The presumption of worst case, guillotine-type breaks is also consistent with the release scenario used to develop the PIR equation in 49 CFR 192.903, and the following statements in ASME/ANSI B31.8S, Section 5.

> *Ruptures have more potential for damage than leaks. Consequently, when a risk assessment approach does not consider whether a failure may occur as a leak or rupture, a worst-case assumption of rupture shall be made.*

3.1.1 Analysis Scope, Parameters, and Assumptions

The methodology is based on fundamental fluid mechanics and heat transfer principles for computing the time-dependent pressure response of natural gas pipelines following a guillotine-type break. It is also suitable for assessing the effects of leak detection, block valve closure, and blowdown durations on fire damage to buildings and property located in Class 1, Class 2, Class 3, and Class 4 HCAs. The heat flux versus time data computed using this methodology were used to quantify effects of block valve closure swiftness on thermal radiant intensities and exposure durations based on a series of case studies for hypothetical release scenarios.

The methodology is consistent with federal safety regulations in 49 CFR 192 for natural gas pipelines (DOT, 2011b) and fire science and fire hazard assessment techniques developed by the Society of Fire Protection Engineers (NFPA, 1995) and the National Fire Protection Association (NFPA, 2011a).

The configuration of the hypothetical natural gas 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 pressure pump stations are located at 100 mile intervals along the pipeline;
- Each pressure pump station has an emergency shutdown system that can be activated by the pipeline operator to shutdown compressor stations consistent with compressor station emergency shutdown requirements in 49 CFR 192.167;
- The rupture is a guillotine-type break that initiates the release;

- The break is located adjacent to a block valve and renders the valve inoperable following the break;
- The block valves are spaced at the maximum allowable distance specified in 49 CFR 192.179 for the particular class where the line section is located;
- The following times are study variables:
  - ✓ The time when the operator detects the leak, and
  - ✓ 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 release equals the combined volumes of natural gas released during the detection, shutdown, and blowdown phases; and
- The time-dependent mass flow rate is a study variable.

Study variables used to characterize natural gas pipeline releases are listed in Table 3.1.

Table 3.1. Study variables for characterizing natural gas pipeline releases

Variable	Description	Variable Values
LHV	Lower heating value of natural gas, Btu/ft^3	1,000
L	Minimum upstream and downstream pipeline length, mi	50
D	Nominal line pipe diameter, in.	12, 16, 20, 24, 30, 36, 42
t_0	Time pipeline ruptures	See discussion in Section 1.3.1.1
t_d	End of detection phase	See discussion in Section 1.3.1.1
t_s	End of block valve closure phase	See discussion in Section 1.3.1.1
t_b	End of blowdown phase	See discussion in Section 1.3.1.1
$t_d - t_0$	Duration of detection phase, minutes	5, 10
$t_s - t_d$	Duration of block valve closure phase, minutes	3, 30, 60, 90, 180
$t_b - t_s$	Duration of blowdown phase, minutes	Determined by calculation
$\dot{Q}$	Time-dependent mass flow, ft^3/h	Determined by calculation
S	Block valve spacing based on class location, mi.	Class 1 locations: 20 mi. Class 2 locations: 15 mi. Class 3 locations: 8 mi. Class 4 locations: 5 mi.
P_1	Maximum allowable operating pressure, psig	300, 400, 500, 600, 700, 800, 900, 1,000, 1,100, 1200, 1,300, 1,400, 1,480

3.1.2 Analytical Approach and Computational Models

Computational models used to determine time-dependent mass flow for different pipeline diameters, operating and pressures, and detection and block valve closure durations are described in Section 3.1.2.1. Models used to compute heat flux intensities at different distances from the break (separation distances) are described in Section 3.1.2.2. These models are tools for identifying differences in release scenarios and for quantifying the effectiveness of block valve closure swiftness in mitigating consequences resulting from the natural pipeline release scenarios discussed in Sect. 3.1.4. Analytical results are presented using the PIR as a scalar to effectively quantify and normalize the radial distance from the pipeline break for different heat flux intensities.

The models are based on engineering principles and fire science practices but are not intended to be exact solutions to these complex engineering problems or for use in complying with the risk analysis requirements in 49 CFR 192.935 to identify additional measures to protect a high consequence area and enhance public safety. In addition, the mass flow and heat flux data computed using the models were not validated by comparison with actual pipeline release events or experimental pipeline release test data.

3.1.2.1 Computational Model for Determining Mass Flow Rates for Natural Gas Pipeline Releases

The basic calculation for the pipeline blowdown uses a solution developed at ORNL (Sulfredge, 2006). The solution is a simple blowdown calculation using a total pipe length and adiabatic expansion of the gas through the orifice with the flow rate given by the expression for choked flow. The result gives closed-form expressions for pressure and temperature as functions of time. The model is also capable of determining the mass loss rate through the orifice as a function of time.

A key aspect of analyzing natural gas pipeline releases is developing a model for the gas discharge rate as a function of time. According to the Gas Research Institute report (Stephens, 2000), the choked discharge of gas from a reservoir has a mass flow rate, m_{dot}, given by the following equation.

$$M_{dot} = C_D\, P\, A_c\, [(\gamma/RT)\,(2/(\gamma+1))^{((\gamma+1)/(\gamma-1))}]^{1/2} \tag{3.1}$$

where

P	is the absolute reservoir pressure,
T	is the absolute temperature,
γ	is the ratio of specific heats for the gas, and
R	is the ideal gas constant for the gas involved.

In Eq. 3.1, A_c is the cross-sectional area of the opening and C_D is an empirical factor called the discharge coefficient (approximately 0.62), which accounts for the fact that the outflow stream tends to narrow and not make full use of the entire cross-sectional area of the opening. The minimum flow area is called the "vena contracta."

Equation 3.1 shows that the discharge mass flow rate depends on both the reservoir pressure and reservoir temperature, which are themselves changing throughout the transient blowdown. It is reasonable to assume an adiabatic condition for the gas due to the blowdown process being relatively rapid not allowing much time for heat transfer between the reservoir walls and the gas. A relationship between the reservoir gas temperature and pressure is obtained by applying the energy equation. Under adiabatic conditions, the energy equation requires the sum of time rate of change for the internal energy of the gas in the reservoir and the rate of enthalpy transport by the escaping gas to equal zero, seen in the equation below.

$$d/dt\,(mu) + m_{dot}\, h = 0 \tag{3.2}$$

where

m	is the mass of gas in the reservoir,
u	is the internal energy of the gas, and
h	is the enthalpy, $[u + Pv]$ (Van Wylen and Sonntag, 1985).

If one expands the first term in Eq. 3.2 and notes that $m_{dot} = -\, dm/dt$ from the conservation of mass, then:

$$m\,(du/dt) + u\,(dm/dt) - h\,(dm/dt) = 0 \tag{3.3}$$

Because $h = u + Pv$ and $Pv = RT$ from the ideal gas law, it follows that:

$$m(du/dt) = RT\ (dm/dt) \tag{3.4}$$

The internal energy of an ideal gas can be expressed in terms of the gas temperature as $u = c_v T$ where c_v is the specific heat of the gas at constant volume.

$$M\ c_v\ (dT/dt) = RT\ (dm/dt) \tag{3.5}$$

Simplify Eq. 3.5, using the chain rule by noting that $dT/dt = (dT/dm)(dm/dt)$:

$$m\ c_v\ (dT/dm) = RT \tag{3.6}$$

Furthermore, $R/c_v = \gamma - 1$, separating Eq. 3.6, dT/T can be expressed as:

$$dT/T = (dm/m)\ (\gamma - 1) \tag{3.7}$$

Integrating Eq. 3.7 yields:

$$T/T_i = (m/m_i)^{\gamma-1} \tag{3.8}$$

Converting Eq. 3.8 into a relationship between pressure and temperature, recognizing gas specific volumes are the inverse ratio of the reservoir gas masses,

$$T/T_i = (v_i/v)^{\gamma-1} \tag{3.9}$$

noting $Pv = RT$ from the ideal gas law. The calculation then yields:

$$T/T_i = (P/P_i)^{(\gamma-1)/\gamma} \tag{3.10}$$

Equation 3.10 is a standard relationship for the temperature and pressure of an ideal gas undergoing an isentropic process (Van Wylen and Sonntag, 1985).

The equation for calculating the mass of the gas in the reservoir consists of a pipe segment of length L, with the same cross-sectional area as the pipe diameter is given by:

$$m = A_c LP/(RT) \tag{3.11}$$

Replacing m_{dot} in Eq. 3.1 with dm/dt yields:

$$(d/dt)\ [A_c\, L\ P/(RT)] = -\ C_D\, P\, A_c\ [(\gamma/RT)\ (2/(\gamma+1))^{(\gamma+1)/(\gamma-1)}]^{1/2} \tag{3.12}$$

Eq. 3.10 is used to eliminate T in terms of P in Eq. 3.12 to obtain a single differential equation for the reservoir pressure as a function of time.

$$P_i^{(\gamma-1)/(2\gamma)}\ (L/T_i^{1/2})(1/\gamma)\ P^{(1/\gamma)\ -1}(dP/dt) = -\ C_D\ [\gamma R\ (2/(\gamma+1))^{(\gamma+1)/(\gamma-1)}]^{1/2}\ P^{(\gamma+1)/(2\gamma)} \tag{3.13}$$

Defining constant, ζ, as:

$$\zeta = -\ C_D\ [\gamma R\ (2/(\ \gamma+1))^{(\gamma+1)/(\gamma-1)}]^{1/2}\ P_i^{-\ (\gamma-1)/(2\gamma)}\ T_i^{1/2}/L \tag{3.14}$$

and separating variables in Eq. 3.14 gives:

$$(1/\gamma)\ P^{(1-3\gamma)/(2\gamma)}\ dP = \zeta\ dt \tag{3.15}$$

Integrating between pressure P_i at time $t = 0$ and pressure P at some later time, the resulting equation becomes:

$$P(t) = [((1-\gamma)/2)\ \zeta\ t + P^{(1-\gamma)/(2\gamma)}]^{2\gamma/(1-\gamma)} \tag{3.16}$$

After determining the pressure at time, t, using Eq. 3.16, the temperature for that time is obtained from Eq. 3.10. The corresponding discharge mass flow rate is then obtained from Eq. 3.1. The calculated flow rate remains valid, assuming the reservoir pressure is high enough to cause choked flow at the exit plane, such that (John, 1984):

$$P > P_{atm}\ [(\gamma+1)/2]^{\gamma/(\gamma-1)} \tag{3.17}$$

Using $\gamma = 1.32$ for natural gas and $P_{atm} = 14.7$ psi for the absolute atmospheric pressure, Eq. 3.17 indicates that choked flow will occur for reservoir pressures of $P > 27.1$ psi.

The preceding model was coded using spreadsheet software for determining the mass flow rates of escaping gas from natural gas pipeline releases as a function of time following the break. The approximation has some flaws. The initial outflow rate is independent of the assumption of spatially uniform pressure and is considered correct. However, that assumption gives a slower reduction in flow rate in the minutes after the break compared to real life situations. Given that the early time outgas rates are the most significant from the standpoint of fire hazards, this is a conservative error. At later times, i.e. when the content of the pipeline is below approximately 20-25%, the outgas rate given by the Sulfredge (2006) solution should be lower than expected in real life.

The Sulfredge (2006) solution was modified to account for closing of valves using a simple approximation. At time, t_{close}, the volume of the pipeline is reset to the new pipeline length. The pressure and temperature are set to the same values that were appropriate for time, t_{close}. The result is a continuation of the blowdown computation, only with changes in volume.

The simulation of constant inflow to the unbroken end of the pipe that models the additional natural gas supplied by compressors to the broken line as they continue to operate after the break is approximated by adding the inflow rate to the outflow rate calculated by the Sulfredge (2006) blowdown solution. However, it is well recognized that the "true" state of the flow under these conditions is not exactly simulated by this simple linear addition. Instead, the inflow leads to a mixing of the inflowing material with the expanding material in the pipe so that both the pressure and temperature inside the pipe are higher than given by the blowdown solution. On the other hand, given the other approximations inherent in the assumption of spatially uniform pressure and temperature for the gas in the pipe, this additional approximation is not considered a significant error. In any case, the flow rates for the inflow are only a few percent of the blowdown rates until late in the blowdown phase.

The model used to approximate the effects of block valve closure on the constant inflow is a simple exponential decay of the rate that starts when the valve closes. The model is based on a presumption that there is an amount of natural gas in the pipeline that represents the flow of the inflow from its initial entry to the exit. At the instant of valve closure, there is a hypothetical additional partial pressure due to this flow. After the valve is closed, the mass in the portion of the pipeline still outgassing is the volume of the pipeline times this notional additional pressure. The model assumes that the velocity of the gas remains the same, but that the extra pressure drops and, therefore, so does the outflow rate. As a simple approximation, this flow velocity is given by the mass flow rate divided by the flow area and further divided by the initial density of the gas. The declining mass flow rate is determined as follows.

$$\text{Rate } (t>t_{close}) = \text{initial inflow rate*exp}[-(\textit{inflowvelocity/newpipelength}\ (\text{time}-t_{close})] \quad (3.18)$$

where

newpipelength is the length of pipe between the break and the closed valve.

To account for different upstream and downstream pipeline lengths, the model was used to independently compute the mass flow rates from each damaged segment. These two mass flow rates were then added to create a total mass flow rate. This approach is considered acceptable because as long as the separate segments have the same initial pressure and line pipe diameter, the combined mass flow rates and, therefore, the initial heat flux intensities are unaffected by different upstream and downstream pipeline lengths. In addition, this approach provides a method for computing the mass flow rates from pipelines with block valves spaced at different distances from the break or pipelines with different block valve closure times. This was certainly the case for the San Bruno (NTSB, 2011a) release where the distance to the Milpitas station was approximately 38.5 miles and the distance to Martin station was approximately 7 miles.

3.1.2.2 Computational Model for Determining Heat Flux Intensities for Natural Gas Pipeline Releases

The analytical approach used by PHMSA to establish the PIR equation in 49 CFR 192.903 is described in a report titled "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines" published by the Gas Research Institute (Stephens, 2000). In this report, the PIR is defined as the potential hazard area from a jet or trench fire and is the radius inside which people and structures could be exposed to an average heat flux that exceeds 15.8 W/m^2 (5,000 Btu/hr ft^2) for the first 30 seconds following a double ended guillotine pipeline break and immediate ignition of the escaping gas. The point source fire model used in this study to determine heat flux, I, follows.

$$I = \eta X_g Q_{eff} H_c / 4\pi r^2 \quad (3.19)$$

where

- I is the thermal radiant intensity or heat flux, W/m^2 (Btu/h ft^2),
- η is the combustion efficiency factor = 0.35 (Technica, Ltd. 1988),
- X_g is the emissivity factor = 0.2 (Technica, Ltd. 1988),
- Q_{eff} is the gas release rate fraction of heat radiated,
- H_c is the heat of combustion = 50,000 kJ/kg for methane, and
- r is the radial distance from the heat source to the location of interest.

The Gas Research Institute report (Stephens, 2000) states that the heat flux versus distance relationship given by Eq. 3.19 represents an extension of the widely recognized flare radiation model given in American Petroleum Institute (API) Recommended Practice 521, Third Edition, 1990. The report further states that it can be shown to be less conservative than the API flare model (i.e., it gives lower heat intensity estimates at a given distance) but this should not be considered surprising since the API model is widely recognized to be conservative.

The Gas Research Institute report (Stephens, 2000) also states that the model is preferred over some of the more generic, multi-purpose models available for industrial fire hazard analysis because it acknowledges factors ignored by other models that play a significant role in mitigating the intensity of real-world jet fire events. In particular, it accounts for the incomplete combustion of the escaping gas stream (through the combustion efficiency factor, η), and it acknowledges (through the emissivity factor, X_g) that a significant portion of the radiant heat energy is absorbed by the atmosphere before it reaches targets at any significant distance from the flame surface. Additional discussions about these factors are presented in a report published by Michael Baker Jr., Inc. in 2005 (Baker, 2005).

Although the PIR model considers both heat flux and duration, it does not take into account such factors as total exposure time, total quantity of gas released, area of service disrupted, or impacts on emergency responders that arrive at the scene soon after the release begins (Sulfredge, 2006). Consequently, ORNL developed an alternative analytical approach for estimating thermal radiation fields surrounding natural gas pipeline jet and trench fires. This approach involved the following steps.

- Determine the geometric characteristics of the fire including the burning rate and the physical dimensions of the fire.
- Determine the average irradiance of the flames based on consideration of the fuel type, fire size, flame temperature, and composition.
- Calculate the thermal radiant intensity at a specified distance from the fire.

The alternative analytical approach is based on a point source radiation model and the following assumptions.

- The flame can be represented by a small source of 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 equation, which is reported as Eq. 24 in API Standard 521, expresses the thermal radiant intensity, *K*, at any distance, *X*, from the source, (NFPA, 1995 and API, 2007).

$$K = \tau F \mathrm{Q} / 4\pi X^2 \tag{3.20}$$

where

K	is the thermal radiant intensity or heat flux, W/m^2 (Btu/hr ft^2),
Q	is the heat release rate (lower heating value), W (Btu/hr),
τ	is the fraction of radiated heat transmitted through the atmosphere,
F	is the fraction of heat radiated, and
X	is the radial distance from center of flame to edge of target (building, person, etc.), m (ft).

Although the variables in Eq. 3.19 are defined differently from those in Eq. 3.20, both equations are based on the common approach for determining the flame radiation from a single radiant epicenter to a point of interest as defined in API Standard 521, Eq. 24 (API, 2007).

The following simplifying assumptions for the alternative analytical approach provide the basis used to determine thermal radiant intensities for natural gas pipeline jet and trench fires.

- All of the natural gas that escapes from a guillotine-type break is consumed by fire. The heat release (lower heating value) for natural gas, Q, kW (Btu/hr) is determined by multiplying the heat content of natural gas 37,260 kJ/m^3 (1,000 Btu/ft^3) times the volumetric flow rate of the escaping gas, $\dot{Q}$, m^3/h (ft^3/hr).

- The fraction of heat radiated, F, ranges from 0.192 to 0.232 for natural gas depending on the diameter of the flame source (API, 2007). A value of 0.2 is used to solve Eq. 3.20 because it is within the range of values reported in API Standard 521 (API, 2007) and equal to the corresponding values reported in the Gas Research Institute report (Stephens, 2000), the Journal of Pipeline Safety (Haklar and Dresnack, 1999), and The World Bank report (Technica, Ltd. 1988) to determine thermal radiant intensity.
- The fraction of radiated heat transmitted through the atmosphere, τ, is determined using the following equation, which is reported as Eq. C11 in API Standard 521 (API, 2007).

$$T = 0.79[(100 / R_H)^{1/16}][(100 / D)^{1/16}] \tag{3.21}$$

where

τ	is the fraction of radiated heat transmitted through the atmosphere,
R_H	is the relative humidity, expressed as a percentage, and
D	is the distance from the flame to the illuminated area, m (ft).

The following limitations apply to the methodology used to estimate the time-dependent thermal radiant intensity resulting from fires produced by combustion of the released natural gas.

- The alternative analytical approach 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 fire has a cylindrical shape, the ambient air temperature is 70°F, the relative humidity is 50%, and the wind is calm.
- The natural gas that escapes from the upstream and downstream pipeline segments burn in the open.
- The constants used in this study are only used for computational purposes because the exact values for a specific release scenario are unknown.

The following discussion identifies the key differences between heat flux intensities computed using Eqs. 3.1 and 3.2 and explains the reasons for the differences.

The equation for determining thermal radiation intensities provided in the Gas Research Institute report (Eq. 3.19) and the equation used in the alternative analytical approach (Eq. 3.20) are each based on the flare radiation model in API Standard 521 (API, 2007) which considers the flame to have a single radiant epicenter and is a common approach for determining the flame radiation to a point of interest. Although Eqs. 3.19 and 3.20 are based on the same model, the thermal radiant intensities computed using Eq. 3.19 are significantly less than the thermal radiant intensities computed using Eq. 3.20 for the following reasons.

In Eq. 3.19, the computed thermal radiant intensity is proportional to the combustion efficiency factor, η, which equals 0.35. The basis for this value is not discussed in either the Gas Research Institute report (Stephens, 2000) or the cited reference source (Technica, Ltd, 1988).

In Eq. 3.20, the computed thermal radiant intensity is proportional to the fraction of the radiated heat transmitted through the atmosphere, τ. This factor varies depending on relative humidity and the distance between an object and the flame according to the relationship established by Eq. 3.21. At a relative humidity of 50%, the factor, τ, ranges from 1.000 at a distance of 60 ft to 0.839 at a distance of 1,000 ft. Although Eqs. 3.20 and 3.21 are reported in a consensus standard, API does not provide any experimental evidence for validating these equations. However, a complementary value, $\tau = 0.746$, is reported in the Journal of Pipeline Safety (Haklar, and Dresnack, 1999) and is based on a relative humidity of 50% and a distance of 500 ft from the flame. The corresponding value computed using Eq. 3.21 for a relative humidity of 50% and a distance of 500 ft from the flame is 0.876.

Comparisons of thermal radiant intensities computed using Eqs. 3.19 and 3.20 confirm the statement by the Gas Research Institute (Stephens, 2000) that the adopted heat flux versus distance relationship given by Eq. 3.19 is less conservative (i.e. it gives lower heat intensity estimates at a given distance) than the API flare model given by Eq. 3.20. The comparisons also confirm that thermal radiant intensities computed using Eqs. 3.20 and 3.21 are between 2.9 (1.000 / 0.35) and 2.4 (0.839 / 0.35) times those computed using Eq. 3.19 for distances from the flame between 60 and 1,000 ft, respectively.

For these reasons, the thermal radiant intensities computed using Eqs. 3.20 and 3.21, which are equivalent to Eqs. 24 and C.11 in API Standard 521 (API, 2007), are considered conservative from a safety viewpoint and appropriate for assessing effects of block valve closure swiftness on the heat flux versus time response of natural gas pipelines under the same release conditions. Therefore, these equations are used in the alternative analytical approach as the basis for determining time-dependent heat flux intensities during natural gas pipeline releases.

3.1.3 Thermal Radiation Intensities and Thresholds

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, (2) buildings with four or more stories above ground, (3) identified sites with outside recreational facilities, and (4) personal property. The methodology is also used to quantify potential fire damage resulting from a hazardous liquid pipeline release with ignition.

3.1.3.1 Potential Fire Damage to Buildings and Dwellings Intended for Human Occupancy

Thermal radiation resulting from combustion of hydrocarbons can damage buildings and dwellings intended for human occupancy, particularly if they are constructed with materials such as plastic (vinyl) and wood that can melt or ignite and burn. Damage severity depends on the types of materials used to construct the buildings and dwellings, the heat flux intensity, and the exposure duration.

Following the Pacific Gas and Electric Company natural gas transmission pipeline rupture and fire in San Bruno, California on September 9, 2010, the city of San Bruno used the following damage categories to classify structural damage to houses at the accident site (NTSB, 2011).

- Severe indicates that a house is not safe to occupy and most likely needs to be demolished or completely renovated prior to occupancy. (Such damage may be perceived as catastrophic to the homeowner.)
- Moderate indicates that a house has substantial damage and repairs are necessary prior to occupancy.
- Minor indicates that a house has the least amount of damage and could be legally occupied while repairs are made.

The methodology uses these terms and definitions to characterize fire damage to buildings and dwellings intended for human occupancy. Conditions for categorizing severe, moderate, and minor damage to buildings and dwellings intended for human occupancy are defined as follows.

Severe Damage to Buildings and Dwellings Intended for Human Occupancy

Damage to a building or dwelling intended for human occupancy caused by fire resulting from a pipeline release is considered severe if all or part of the building or dwelling is consumed by flames. Buildings and dwellings with severe damage are considered a total (100%) loss. Each dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

Without direct flame impingement, an average heat flux of 50 kW/m^2 (15,900 Btu/hr ft^2) will cause dry wood to ignite in about 10 seconds. A lower average heat flux of 40 kW/m^2 (12,700 Btu/hr ft^2) will cause dry wood to ignite in about 17 seconds (McAllister, 2010). For this study, any building or dwelling intended for human occupancy exposed to a heat flux greater than 40 kW/m^2 (12,700 Btu/hr ft^2) is conservatively considered to have severe damage and a total loss.

Moderate Damage to Buildings and Dwellings Intended for Human Occupancy

Moderate damage to a building or dwelling intended for human occupancy caused by fire resulting from a pipeline release can occur when the building or dwelling is exposed to a heat flux of 39.4 kW/m^2 (12,500 Btu/hr ft^2) for a prolonged period. These exposure conditions can distort vinyl windows, melt vinyl siding, and degrade other nonstructural plastic elements.

For this study, any building or dwelling intended for human occupancy exposed to a heat flux greater than 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes is conservatively considered to have moderate damaged. The cost to repair a building or dwelling with moderate damage is estimated to be 50% of the cost of a new house constructed at the same location.

Minor Damage to Buildings and Dwellings Intended for Human Occupancy

Damage to buildings and dwellings intended for human occupancy caused by fire resulting from a pipeline release is considered minor if the heat flux does not exceed 15.8 kW/m^2 (5,000 Btu/hr ft^2) because: (1) residential buildings and dwellings exposed to this heat flux intensity are not expected to burn, and (2) they are capable of affording indefinite protection to sheltered persons (Stephens, 2000). However, glass breakage can occur at heat flux intensities that exceed 4.0 kW/m^2 (1,270 Btu/hr ft^2) for 30 minutes (LaChance, 2009).

For this study, any building or dwelling intended for human occupancy exposed to a heat flux that exceeds 15.8 kW/m^2 (5,000 Btu/hr ft^2) for a prolonged period of at least 30 minutes is conservatively considered to have minor damage. The cost to repair a building or dwelling with minor damage is estimated to be 20% of the cost of a new house constructed at the same location.

Figure 3.1 illustrates the relationships among heat flux intensities and exposure durations for severe, moderate, and minor damage categories for buildings and dwelling intended for human occupancy.

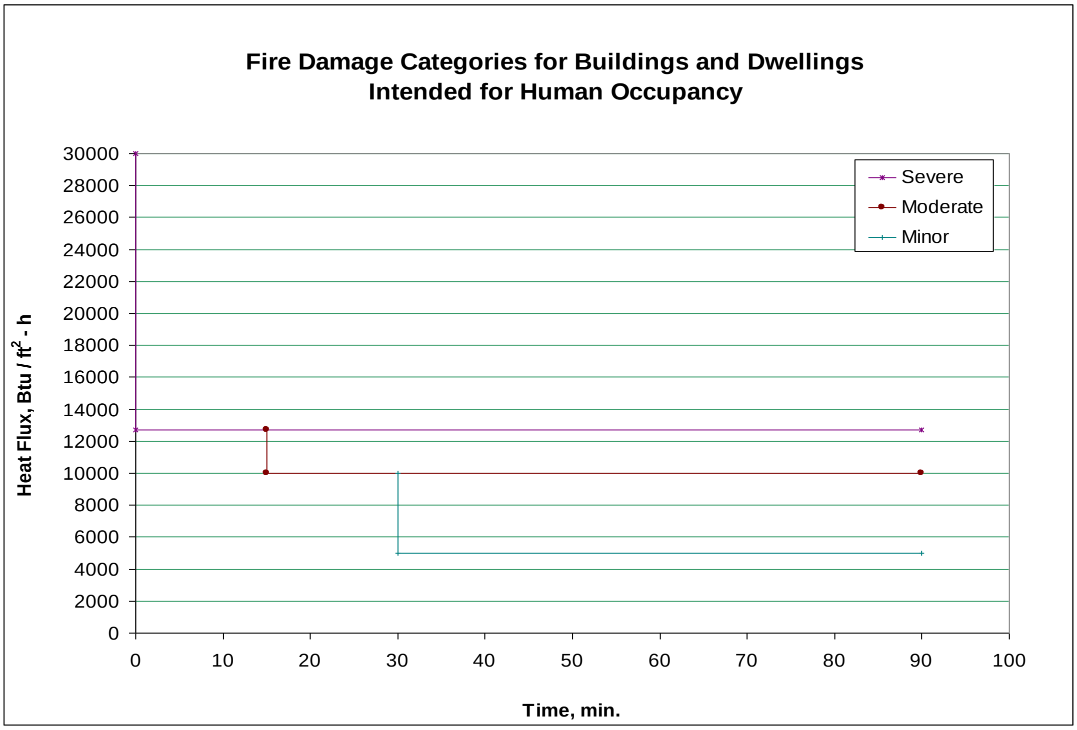


Fig. 3.1. Relationships among heat flux intensities and exposure durations for fire damage categories for buildings and dwellings intended for human occupancy.

The cost of fire damage to buildings and dwellings intended for human occupancy resulting from a pipeline release are based on the median cost of new homes sold in the United States. According to recent data published by the U.S. Census Bureau, the median and average sales prices of new homes sold in United States in 2009 including land is $221,800 and $272,900, respectively (U.S. Census Bureau. 2012a). Using a land value of 20% of the total sale price, the unit value of buildings and dwellings intended for human occupancy damaged or destroyed by fire resulting from a pipeline release is estimated at $180,000.

Buildings and dwellings intended for human occupancy that are potentially susceptible to fire damage resulting from a natural gas pipeline release are located in the following areas.

- Areas within and adjacent to HCAs in Class 1 Locations with buildings or dwellings intended for human occupancy configured as shown in Fig. 3.2
- Areas adjacent to HCAs in Class 1 Locations with an identified site consisting of buildings with four or more stories above ground configured as shown in Fig. 3.3
- Areas within and adjacent to HCAs in Class 1 Locations with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period configured as shown in Fig. 3.4
- Areas within and adjacent to HCAs in Class 2 Locations with buildings or dwellings intended for human occupancy configured as shown in Fig. 3.5
- Areas within and adjacent to HCAs in Class 2 Locations with an identified site consisting of buildings with four or more stories above ground configured as shown in Fig. 3.6

- Areas within and adjacent to HCAs in Class 2 Locations with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period configured as shown in Fig. 3.7
- Areas within and adjacent to Class 3 Locations with buildings or dwellings intended for human occupancy configured as shown in Fig. 3.8
- Areas adjacent to Class 3 Locations with an outside recreational facility configured as shown in Fig. 3.9
- Areas adjacent to Class 4 Locations with buildings with four or more stories above ground configured as shown in Fig. 3.10

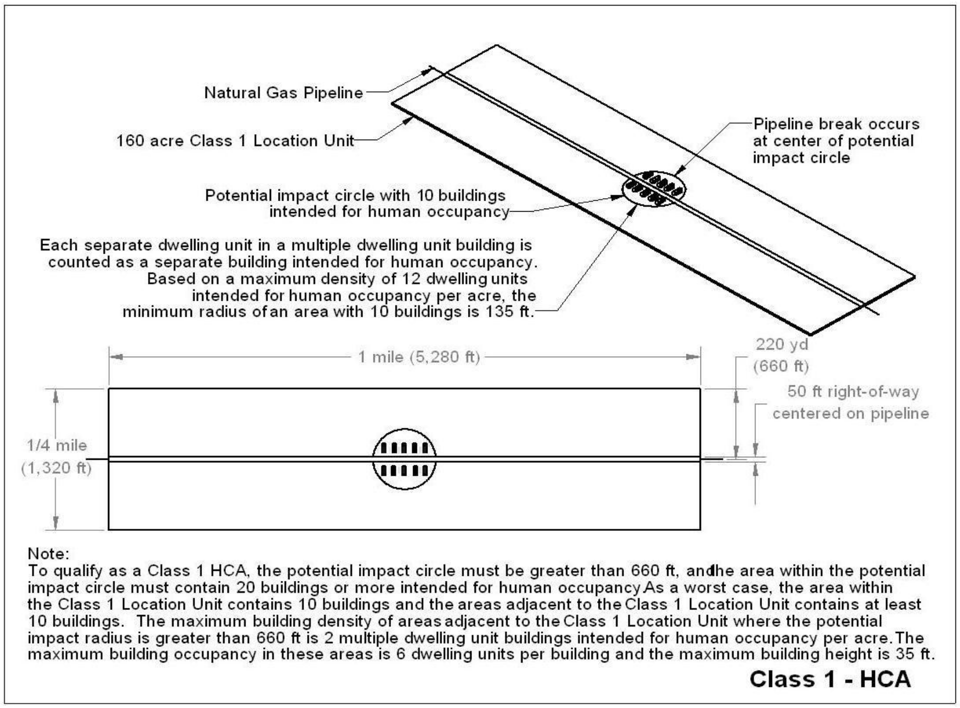


Fig. 3.2. Configuration of a Class 1 HCA with buildings or dwellings intended for human occupancy.

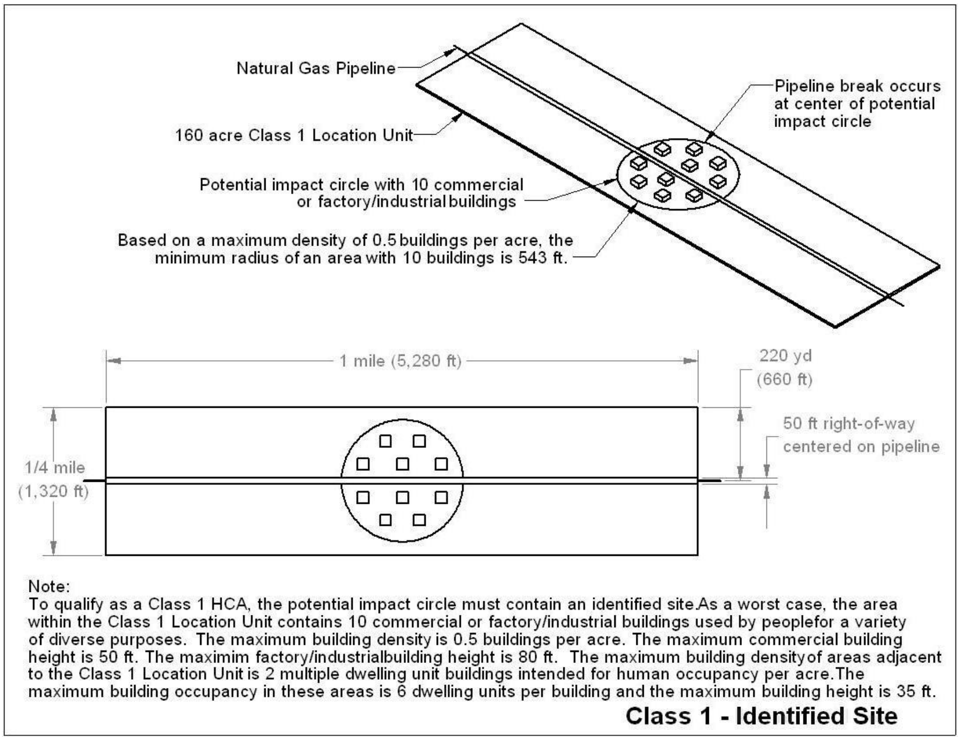


Fig. 3.3. Configuration of a Class 1 HCA with an identified site consisting of buildings with four or more stories.

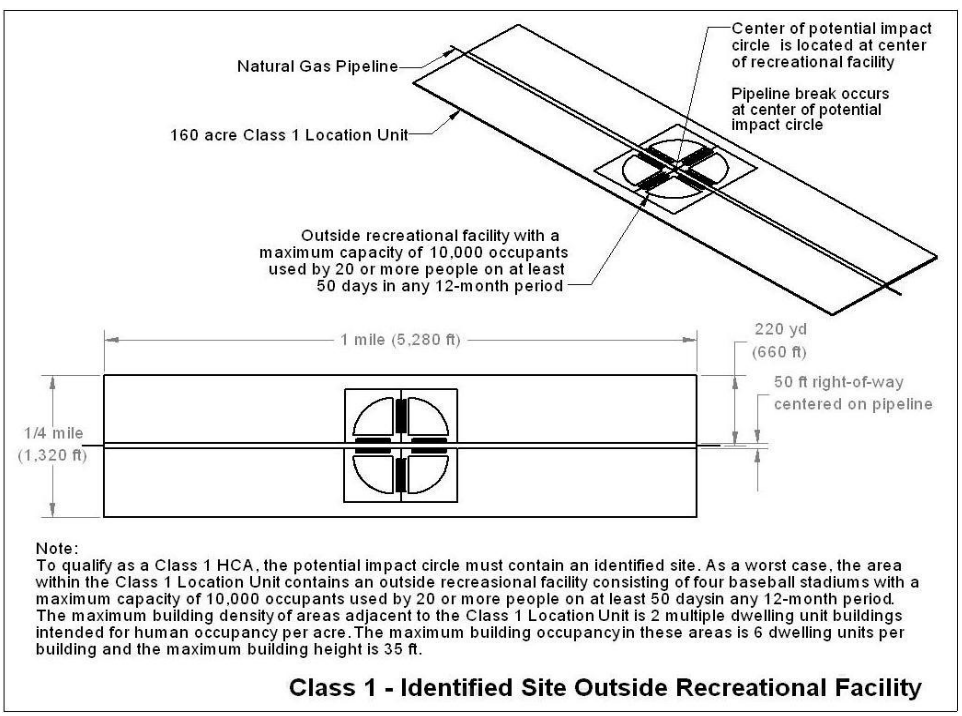


Fig. 3.4. Configuration of a Class 1 HCA with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period.

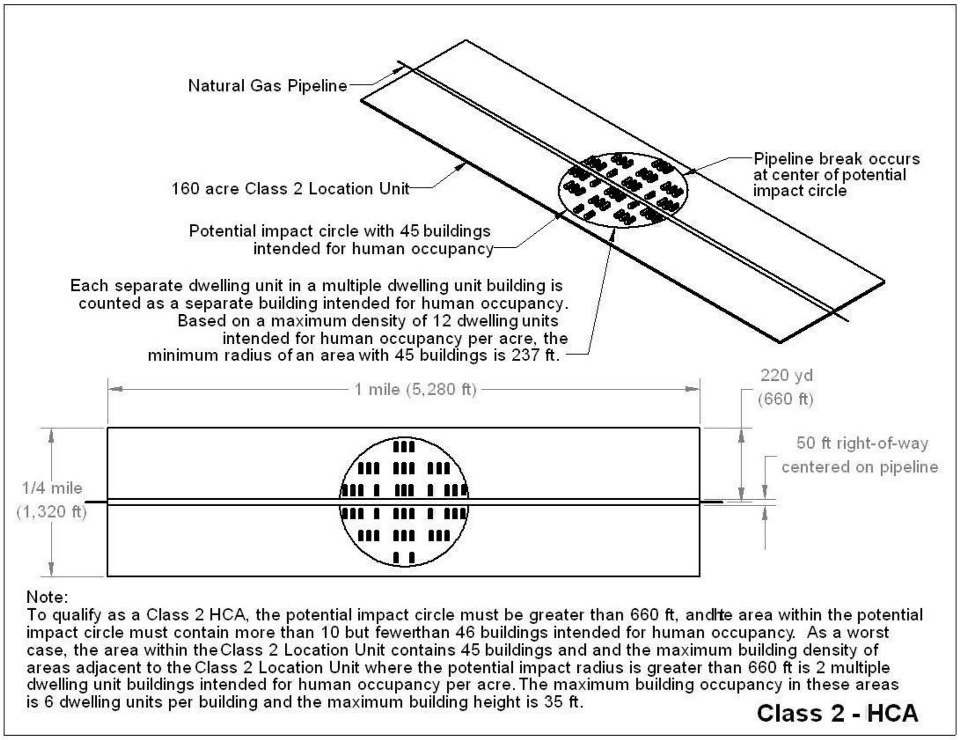


Fig. 3.5. Configuration of a Class 2 HCA with buildings or dwellings intended for human occupancy.

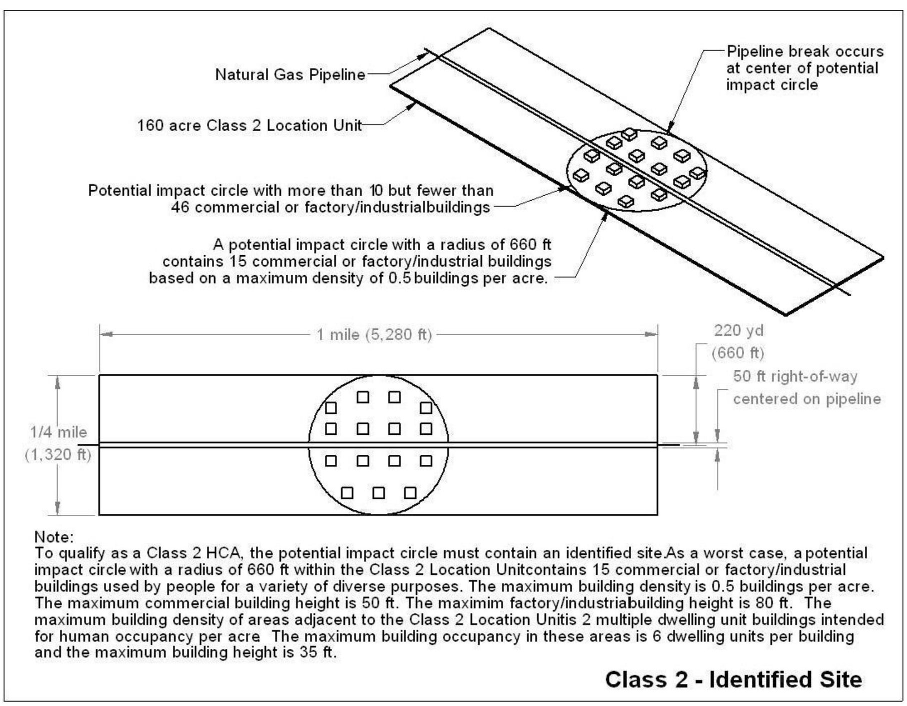


Fig. 3.6. Configuration of a Class 2 HCA with an identified site consisting of buildings with four or more stories.

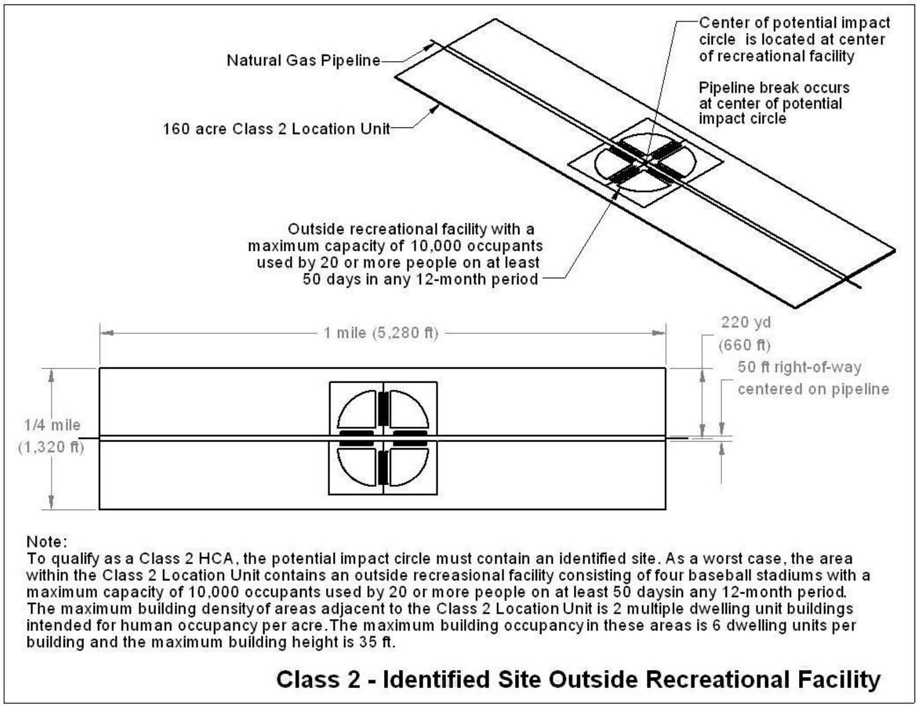


Fig. 3.7. Configuration of a Class 2 HCA with an identified site consisting of an outdoor recreational facility that is occupied by 20 or more people on at least 50 days in any 12-month period.

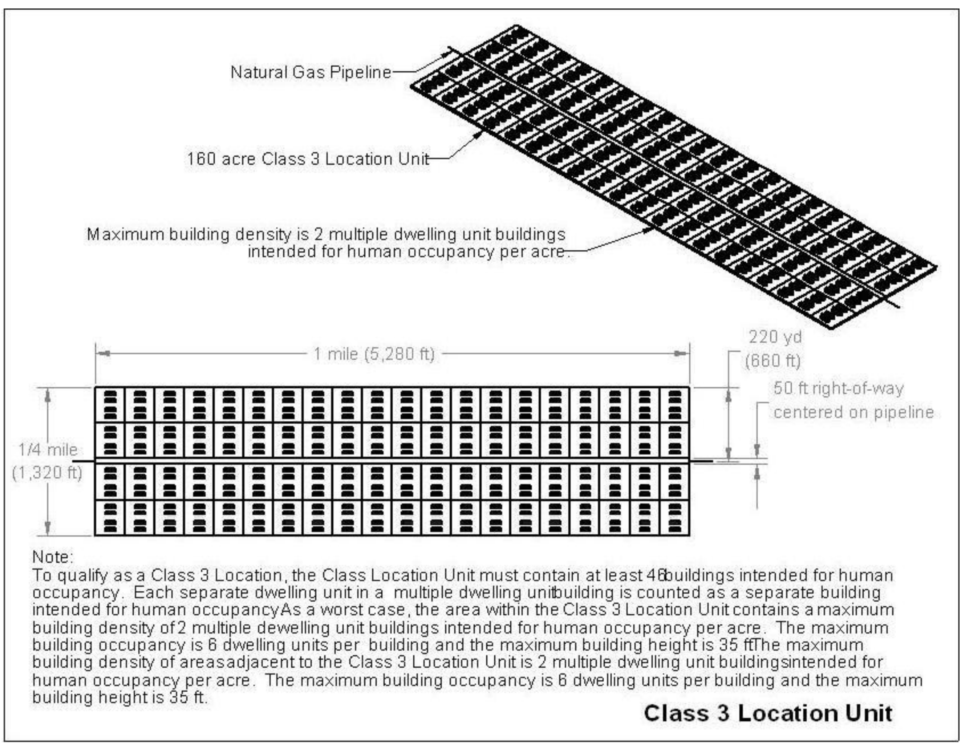


Fig. 3.8. Configuration of a Class 3 Location with buildings and dwellings intended for human occupancy.

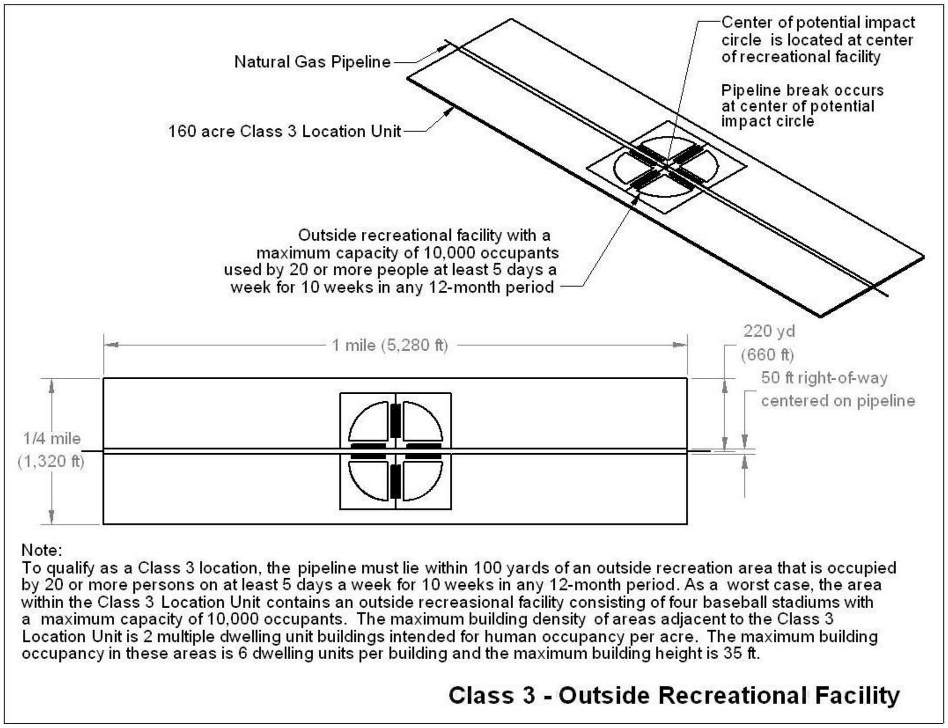


Fig. 3.9. Configuration of a Class 3 Location with an outside recreational facility.

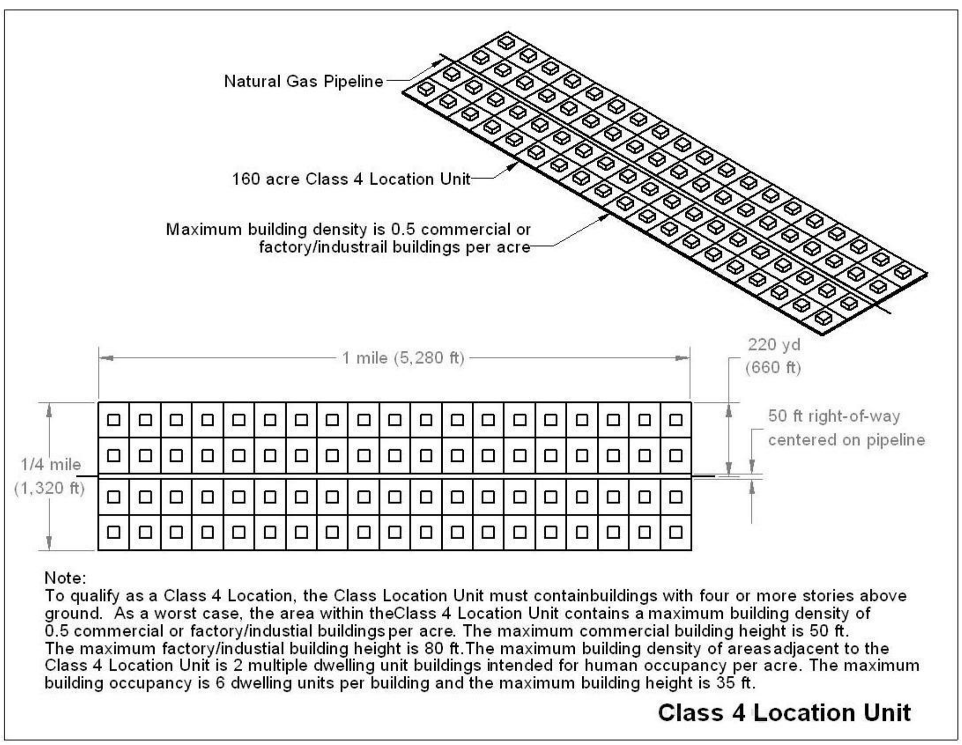


Fig. 3.10. Configuration of a Class 4 Location with buildings with four or more stories above ground.

In addition to buildings and dwellings intended for human occupancy that are potentially susceptible to fire damage resulting from a natural gas pipeline release located in Class 1, Class 2, Class 3, and Class 4 HCAs, buildings and dwellings intended for human occupancy that are potentially susceptible to fire damage resulting from a hazardous liquid pipeline release in HCAs as defined in 49 CFR 195.450 (DOT, 2011d). The configuration of buildings and dwellings intended for human occupancy in HCAs designated as either high population areas or other populated areas is shown in Fig. 3.11.

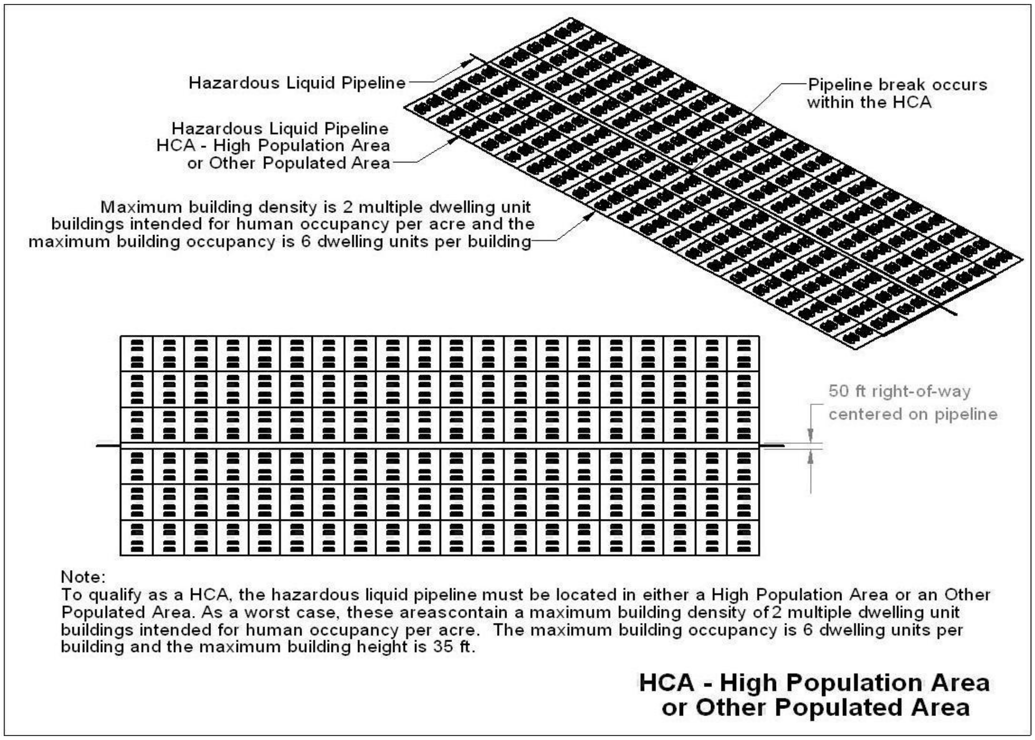


Fig. 3.11. Configuration of a High Population Area or an Other Populated Area.

3.1.3.2 Potential Fire Damage to Buildings with Four or More Stories above Ground

Buildings with four or more stories above ground are categorized as either a Commercial zone with a maximum permitted building height ranging from 40 to 50 ft or a Factory/Industrial zone with a maximum permitted building height ranging from 60 to 80 ft based on zoning criteria in the 2012 International Zoning Code (ICC, 2012b). For this study, each building with four or more stories above ground that is susceptible to fire damage resulting from a natural gas pipeline release has the following design features:

- a total gross floor area of 40,000 sq. ft.,
- 200 parking spaces with stall dimensions of 9 ft by 22 ft,
- two-way enter and exit driveways that are 24 ft wide,
- sidewalks that are at least 4 ft wide,
- a lot size of 2 acres, and
- designs that comply with International Fire Code and International Building Code requirements (ICC, 2012a and ICC, 2012c).

Buildings with four or more stories above ground that comply with International Fire Code and International Building Code requirements (ICC, 2012a and ICC, 2012c) generally include design features such as fire walls and fire doors with required fire ratings. They also have automatic sprinklers or other types of fire-suppression systems capable of limiting fire spread and protecting the building occupants. In addition, the exterior surfaces of buildings with four or more stories above ground are typically constructed with metallic and cement-based materials that are fire resistant. Consequently, fire damage to buildings with four or more stories above ground resulting from a natural gas pipeline release is not expected if the heat flux is less than 31.5 kW/m^2 (10,000 Btu/hr ft^2). Minor damage to non-structural building elements such as adhesives and sealants is possible if the building is exposed to a heat flux greater than 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes. Severe and moderate damage such as curtain-wall panel buckling and window breakage is expected if the building is exposed to a heat flux greater than 40 kW/m^2 (12,700 Btu/hr ft^2).

For this study, the cost to repair minor damage to a building with four or more stories above ground caused by fire resulting from a pipeline release is conservatively estimated to be 10% of the cost of a new building constructed at the same location. Based on an estimated cost of $125 per sq. ft. to construct a building with four or more stories above ground and 40,000 sq. ft. of gross floor space, the cost to repair minor damage is $500,000. The cost to repair severe and moderate damage to a building with four or more stories above ground caused by fire resulting from a pipeline release is conservatively estimated to be 20% of the cost of a new building constructed at the same location. The cost to repair severe and moderate damage to a building with four or more stories above ground and 40,000 sq. ft. of gross floor space is $1,000,000.

Relationships among heat flux intensities and exposure durations for severe, moderate, and minor damage to buildings with four or more stories above ground are illustrated in Fig. 3.12.

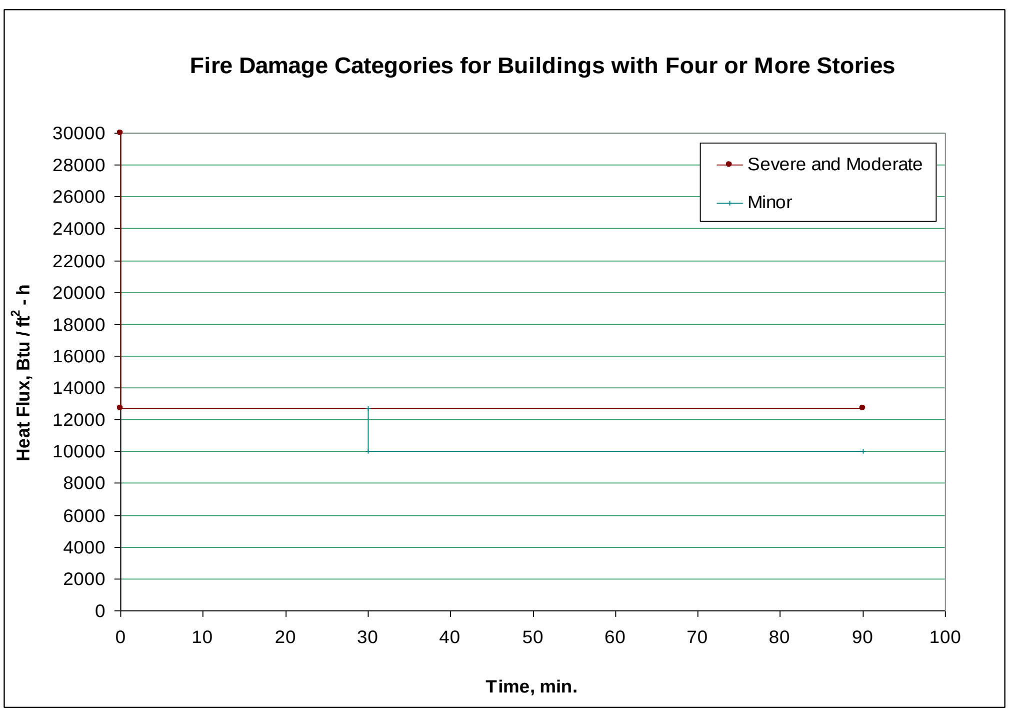


Fig. 3.12. Relationships among heat flux intensities and exposure durations for fire damage categories for buildings with four or more stories above ground.

3.1.3.3 Potential Fire Damage to Outside Recreational Facility

Damage to an outside recreational facility caused by fire resulting from a pipeline release is based on a facility with the following design features.

- The outside recreational facility has a maximum capacity of 10,000 occupants.
- The facility is used by 20 or more people at least 5 days a week for 10 weeks in any 12-month period.
- Design and construction of the outdoor recreational facility buildings and structures comply with applicable International Fire Code and International Building Code requirements (ICC, 2011a and ICC, 2012c).

Bleachers and food preparation, utility, storage, and toilet rooms at outside recreational facilities are generally constructed with metallic and cement-based materials that are fire resistant. Consequently, fire damage to these items from a natural gas pipeline release is not expected if the heat flux exceeds 40 kW/m^2 (12,700 Btu/hr ft^2). However, severe and moderate damage to seating, signs, coatings, food storage and preparation equipment, supplies, and retail commodities is expected if the heat flux exceeds 40 kW/m^2 (12,700 Btu/hr ft^2). Minor damage to these items is expected if the heat flux exceeds 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes.

The replacement cost of seating, signs, coatings, food storage and preparation equipment, supplies, and retail commodities with severe and moderate damage caused by exposure to a heat flux greater than 40 kW/m^2 (12,700 Btu/hr ft^2) is conservatively estimated at $500,000. The replacement cost of food storage and preparation equipment, supplies, and retail commodities with minor damage caused by exposure to a heat flux greater than 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes is conservatively estimated at $250,000.

Relationships among heat flux intensities and exposure durations for severe, moderate, and minor damage to outside recreational facilities are illustrated in Fig. 3.13.

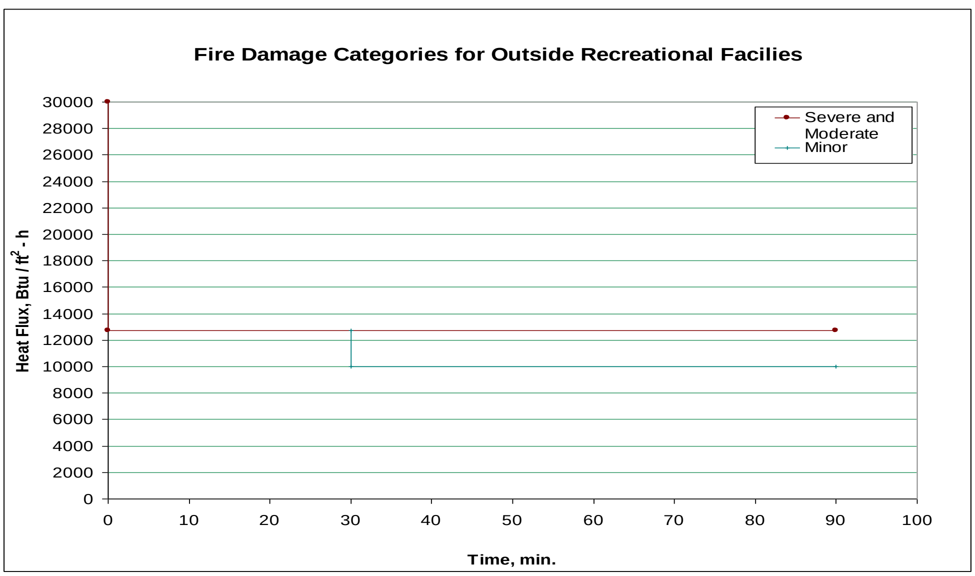


Fig. 3.13. Relationships among heat flux intensities and exposure durations for fire damage categories for outside recreational facilities.

3.1.3.4 Potential Fire Damage to Personal Property

Personal property damaged caused by a fire resulting from a pipeline release is categorized as either: (1) vehicles that are parked outside, or (2) personal possessions that are destroyed inside buildings and dwellings intended for human occupancy.

Fire Damage to Vehicles Parked Outside

Passenger cars, vans, and trucks; watercraft; camping trailers; and motor cycles are types of vehicles that may be parked outside of buildings and dwellings intended for human occupancy, buildings with four or more stories above ground, and outside recreational facilities. Severe damage to these vehicles is expected if the heat flux exceeds 40 kW/m^2 (12,700 Btu/hr ft^2). Moderate damage is expected if the heat flux exceeds 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes because these vehicles include non-metallic parts that can degrade, melt, or distort. No damage is expected if the heat flux does not exceed 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes.

Based on U.S. Census Bureau sales data for 2009 (U.S. Census Bureau, 2012b), the retail price of new and used passenger cars, vans, and trucks was $26,245 and $8,483, respectively, and the total value of new and used vehicle sales was approximately equal. Therefore, the estimated retail sales price for each passenger car, van, or truck damaged by a fire resulting from a pipeline release is $17,000. The retail sales price for other types of vehicles including watercraft; camping trailers; and motor cycles is conservatively estimated at $17,000 per unit.

For this study, fire damage to vehicles parked outside will be based on the following simplifying assumptions.

- The cost of severe damage to vehicles parked outside caused by exposure to a heat flux that exceeds 40 kW/m^2 (12,700 Btu/hr ft^2) is estimated at $17,000 per vehicle which is 100% of the retail sales price of the vehicle.
- The cost to repair moderate damage to a vehicle parked outside caused by exposure to a heat flux that is greater than 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes is estimated at $5,000 which is approximately 30% of the retail sales price of the vehicle.
- No damage to vehicles parked outside is expected if the heat flux does not exceed 31.5 kW/m^2 (10,000 Btu/hr ft^2) for more than 15 minutes.

According to the 2012 International Zoning Code (ICC, 2012b), at least two off-street parking spaces are required for each residential dwelling unit. Therefore, multiple dwelling unit buildings with a maximum density of 12 dwellings per acre require a minimum of 24 parking spaces (24 per acre). Similarly, a building with four or more stories above ground which is located on a 2-acre plot and has a total floor area of 40,000 sq. ft. is required to have at least 200 parking spaces (100 per acre). The vehicle density of parking lots for outside recreational facilities is approximately 140 parking spaces per acre based on stall dimensions that are 9 ft by 22 ft and two-way enter and exit driveways that are 24 ft wide.

The cost of fire damage to vehicles parked outside resulting from a pipeline release is estimated as follows.

- $408,000 per acre for vehicles with severe damage parked outside of buildings and dwellings intended for human occupancy.
- $120,000 per acre for vehicles with moderate damage parked outside of buildings and dwellings intended for human occupancy.

- $1,700,000 per acre for vehicles with severe damage parked outside of buildings with four or more stories.
- $500,000 per acre for vehicles with moderate damage parked outside of buildings with four or more stories.
- $2,380,000 per acre for vehicles with severe damage parked outside of outside recreational facilities.
- $700,000 per acre for vehicles with moderate damage parked outside of outside recreational facilities.

Relationships among heat flux intensities and exposure durations for severe and moderate damage to outside recreational facilities are illustrated in Fig. 3.14.

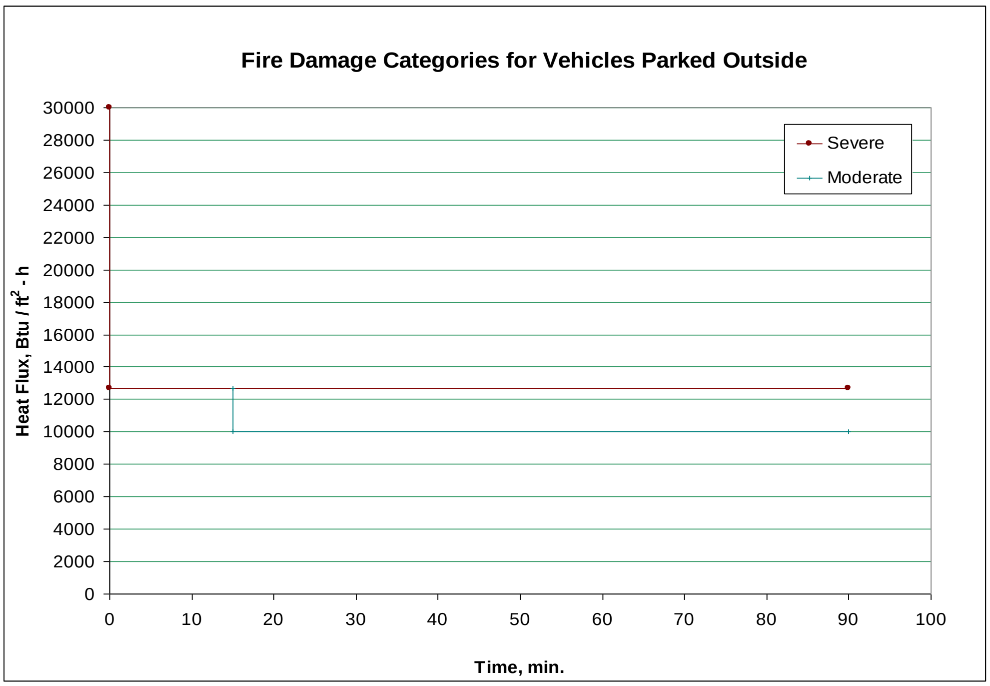


Fig. 3.14. Relationships among heat flux intensities and exposure durations for fire damage categories for vehicles parked outside.

<u>Fire Damage to Personal Possessions</u>

The replacement cost of personal possessions that are destroyed inside a building or dwelling intended for human occupancy with severe damage caused by fire resulting from a pipeline release is estimated at $45,000 which is 25% of the value of the building. Similarly, the replacement cost of personal possessions that are destroyed inside a building or dwelling intended for human occupancy with moderate and minor damage caused by fire resulting from a pipeline release is estimated at $27,000 and $9,000 which is 15% and 5% of the value of the building, respectively.

3.1.4 Risk Analysis Results for Natural Gas Pipeline Releases

The methodology for assessing effects of valve closure time on fire damage resulting from a natural gas pipeline release is based on: (1) the cost avoidance for damage to buildings and personal property within areas susceptible to severe, moderate, and minor damage, and (2) the cost avoidance for damage to buildings and personal property attributed to actions taken by fire fighters. Computed heat flux versus time data and the applicable heat flux thresholds for severe, moderate, and minor damage listed in Table 1.2 are used to quantify the radii of areas susceptible to each of these damage levels. The cost of damage to buildings and personal property located within the various damage areas are based on the applicable repair and replacement data described in Sections 3.1.3.1 to 3.1.3.4 and summarized in Table 3.2.

Table 3.2. Estimated costs of property damage caused by fire resulting from a pipeline release

Property Damage Type	Minimum Heat Flux, kW/m^2 (Btu/hr ft^2)		
	40 (12,700) for any duration	**31.5 (10,000) for at least 15 minutes**	**15.8 (5,000) for at least 60 minutes**
Buildings Intended for Human Occupancy	Severe Damage	Moderate Damage	Minor Damage
Dwellings (12/acre or 6/building)	\$2,160,000/acre \$1,080,000/building	\$1,080,000/acre \$1,080,000/building	\$432,000/acre \$216,000/building
Vehicles (24/acre or 2/building)	\$408,000/acre \$204,000/building	\$120,000/acre \$60,000/building	\$0/acre \$0/building
Possessions (12/acre or 6/building)	\$540,000/acre \$45,000/building	\$324,000/acre \$22,500/building	\$108,000/acre \$9,00/building
Total Damage Cost	\$3,108,000/acre \$1,554,000/building	\$1,524,000/acre \$762,000/building	\$540,000/acre \$270,000/building
Building Unit with 4 or More Stories	Severe Damage	Moderate Damage	Minor Damage
Building (0.5/acre)	\$500,000/acre \$1,000,000/building	\$500,000/acre \$1,000,000/building	\$250,000/acre \$500,000/building
Vehicles (100/acre or 200/building)	\$1,700,000/acre \$3,400,000/building	\$1,700,000/acre \$3,400,000/building	\$0/acre \$0/building
Total Damage Cost	\$2,200,000/acre \$4,400,000/building	\$2,200,000/acre \$4,400,000/building	\$250,000/acre \$500,000/building
Outside Recreational Facility	Severe Damage	Moderate Damage	Minor Damage
Buildings and Structures	\$0	\$0	\$0
Vehicles (140/acre)	\$2,380,000	\$700,000	\$0
Equipment and Supplies	\$500,000	\$500,000	\$250,000
Total Damage Cost per Facility:	\$500,000 + \$2,380,000/acre	\$500,000 + \$700,000/acre	\$250,000

Notes: Combustible materials exposed to a heat flux that exceeds 40 kW/m^2 (12,700 Btu/hr ft^2) for any time are considered a total loss. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy. Estimated damage costs are based on U.S. Census Bureau data for 2009.

The avoided cost of damage to buildings and personal property resulting from fire fighting activities is based on the following considerations and simplifying assumptions.

- **12-in. Natural Gas Pipeline Releases**

  The number of fire hydrants available for extinguishing building fires resulting from a 12-in. nominal diameter natural gas pipeline release with a MAOP equal to 300 psig is 3 based on a maximum spacing of 500 ft. 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. Up to 12 engines arrive at the scene and connect to the available fire hydrants within 10 minutes after the break, but fire fighters cannot begin fire fighting operations within areas where the heat flux exceeds 2.5 kW/m^2 (800 Btu/hr ft^2). The avoided damage cost for each four-story building or each building intended for human occupancy (including contents) that ignites when the break occurs is 50% within the first 10 minutes after the break and increases at a rate of 5% per minute for each additional minute that fire fighting activities are delayed beyond the 10 minute deployment time because the heat flux at 1.5 times PIR exceeds the severe damage threshold or 40.0 kW/m^2 (12,700 Btu/hr ft^2). The avoided damage cost for vehicles parked outside within an area of 0.25 acres is 50% within the first 10 minutes after the break and increases at a rate of 5% per minute for each additional minute that fire fighting activities are delayed beyond the 10 minute deployment time because the heat flux at 1.5 times PIR exceeds the severe damage threshold.

- **42-in. Natural Gas Pipeline Releases**

  The number of fire hydrants available for extinguishing building fires resulting from a 42-in. nominal diameter natural gas pipeline release with a MAOP equal to 1,480 psig is 21 based on a maximum spacing of 500 ft. 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. Up to 12 engines arrive at the scene and connect to the available fire hydrants within 10 minutes after the break, but fire fighters cannot begin fire fighting operations within areas where the heat flux exceeds 2.5 kW/m^2 (800 Btu/hr ft^2). The avoided damage cost for each four-story building or each building intended for human occupancy (including contents) that ignites when the break occurs is 50% within the first 10 minutes after the break and increases at a rate of 5% per minute for each additional minute that fire fighting activities are delayed beyond the 10 minute deployment time because the heat flux at 1.5 times PIR exceeds the severe damage threshold or 40.0 kW/m^2 (12,700 Btu/hr ft^2). The avoided damage cost for vehicles parked outside within an area of 0.25 acres is 50% within the first 10 minutes after the break and increases at a rate of 5% per minute for each additional minute that fire fighting activities are delayed beyond the 10 minute deployment time because the heat flux at 1.5 times PIR exceeds the severe damage threshold.

Design features and operating conditions for the hypothetical natural gas pipelines considered in the risk analysis are summarized in Table 3.3. Natural gas pipelines with these design features and operating conditions envelope the range of natural gas pipelines within the scope of this study.

Table 3.3 Design features and operating conditions for hypothetical natural gas pipelines considered in the risk analysis

Design Feature	Nominal Line Pipe Diameter, in.	
	42	12
MAOP, psig	1,480	300
PIR, ft	1,115	143
Overall length of pipeline, mi.	100	100
Block valve closure time, minutes after break	8 and 13	8 and 13
Compressor inflow after break, ft/s	0 and 15	0 and 15
Block valve spacing, mi.		
Class 1	20	20
Class 2	15	15
Class 3	8	8
Class 4	5	5

Note: The break occurs adjacent to a block valve rendering the block valve inoperable.

The baseline for the natural gas pipeline risk analysis is represented by separation distance versus time plots shown in Figs. 3.15, 3.16, 3.17, and 3.18.

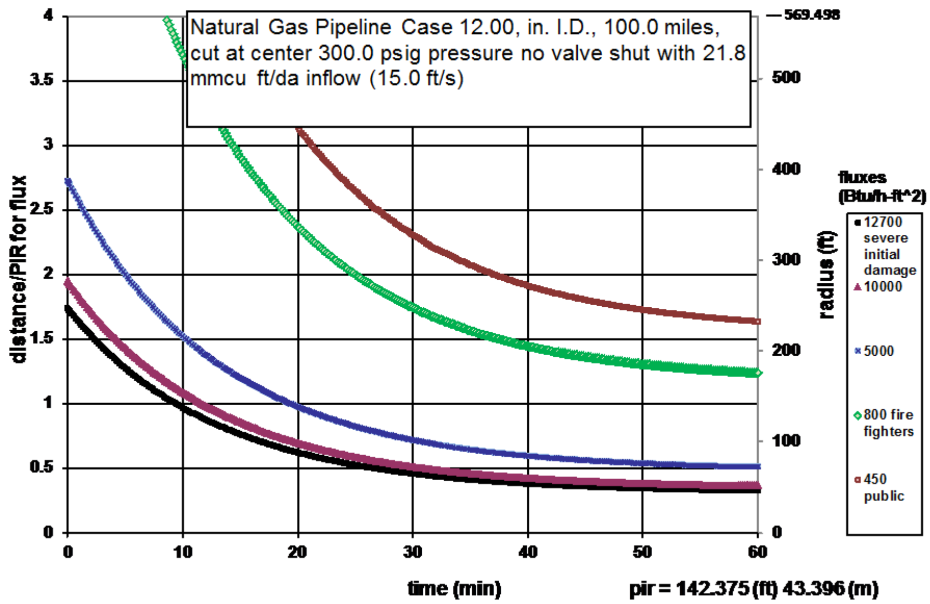


Fig. 3.15. 12-in. Baseline-15: Separation distances for 12-in. natural gas pipeline operating at a MAOP of 300 psig with no block valve closure and compressor inflow equal to 15 ft/s.

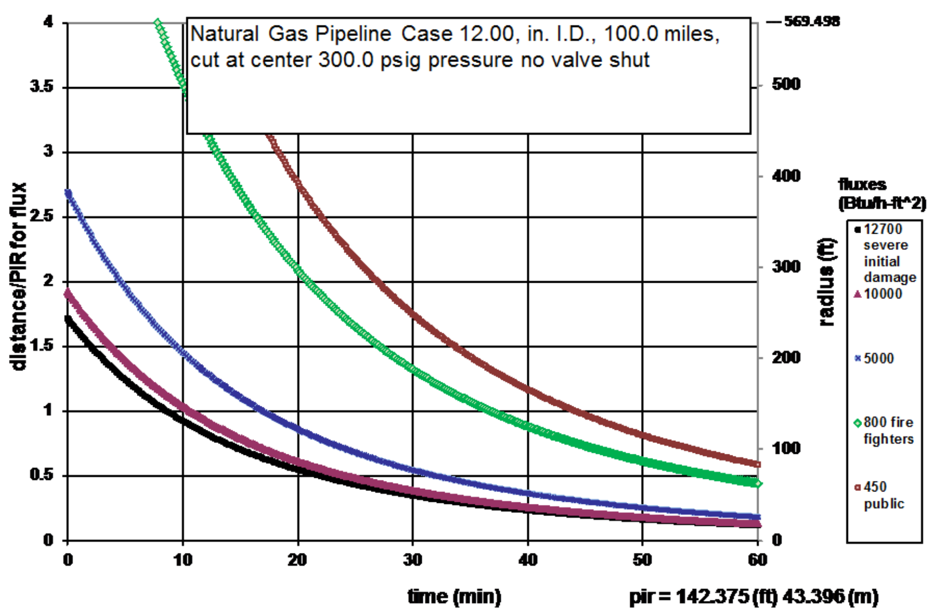


Fig. 3.16. 12-in. Baseline-0: Separation distances for 12-in. natural gas pipeline operating at a MAOP of 300 psig with no block valve closure and compressor inflow equal to 0 ft/s.

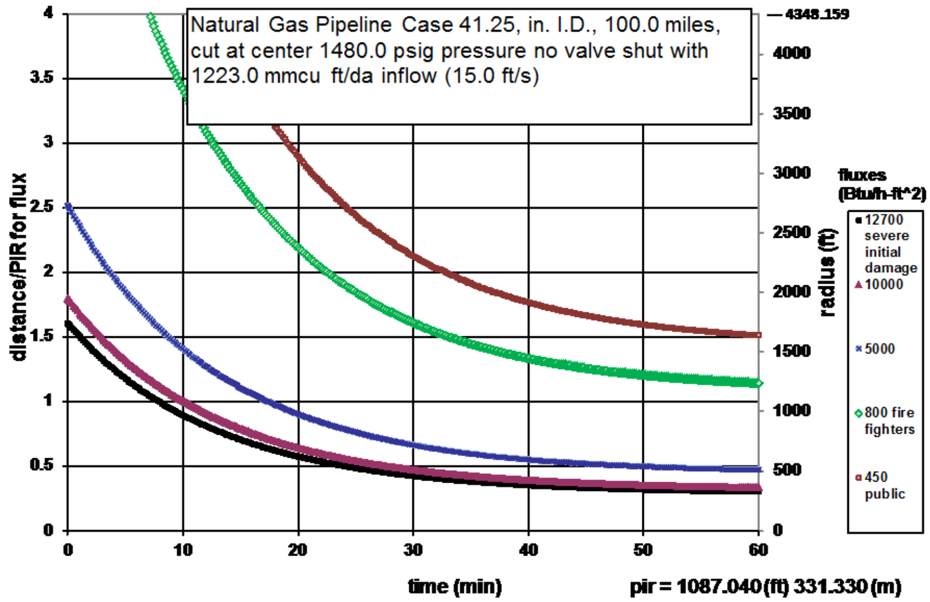


Fig. 3.17. 42-in. Baseline-15: Separation distances for 42-in. natural gas pipeline operating at a MAOP of 1,480 psig with no block valve closure and compressor inflow equal to 15 ft/s.

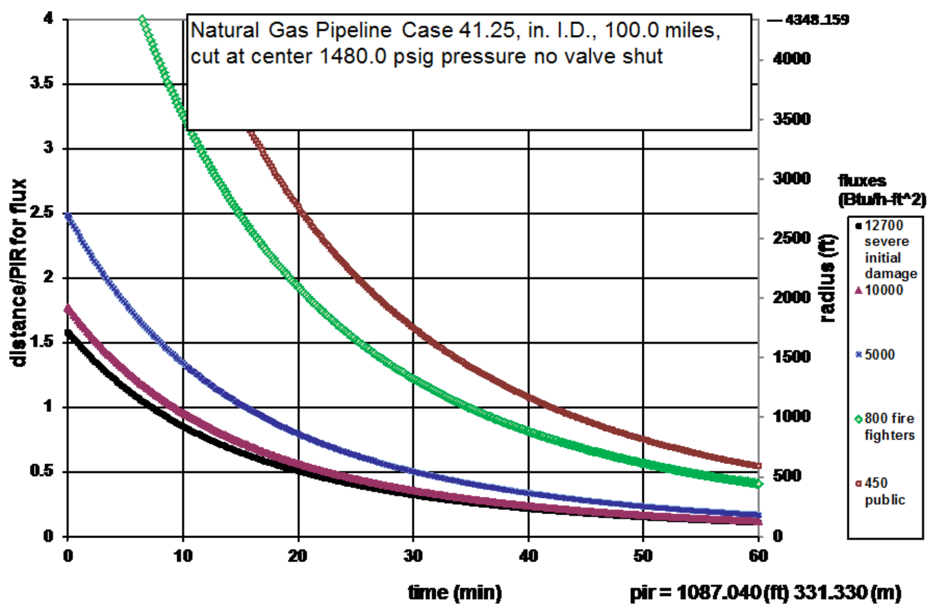


Fig. 3.18. 42-in. Baseline-0: Separation distances for 42-in. natural gas pipeline operating at a MAOP of 1,480 psig with no block valve closure and compressor inflow equal to 0 ft/s.

These plots compare the contribution of compressor inflow on time-dependent blowdown behavior for a 100-mi. pipeline segment with a break in the exact middle of the segment and no block valve closure. Figures 3.15 and 3.17 are plots of blowdown behavior for pipeline segments with compressor inflow equal to 15 ft/s. Figures 3.16 and 3.18 are plots of blowdown behavior for the same pipeline segments without compressor inflow. The separation distance versus time plots shown in Figs. 3.15, 3.16, 3.17, and 3.18 apply to pipelines located in Class 1, 2, 3, and 4 Locations because the model assumes that the block valves, which are located at different intervals along each 50-mi. line section depending on the class location, remain open.

The plot in Fig. 3.15 for the 12-in. natural gas pipeline with compressor input (12-in. Baseline-15) shows that without block valve closure and compressor inflow equal to 15 ft/s, fire fighting activities within a distance of 1.5 times PIR cannot begin for at least 37 minutes after the break occurs because the heat flux at this distance is greater than 2.5 kW/m^2 (800 $Btu/hr\ ft^2$). Similarly, the plot in Fig. 3.17 for the 42-in. natural gas pipeline with compressor input (42-in. Baseline-15) shows that without block valve closure and compressor inflow equal to 15 ft/s, fire fighting activities within a distance of 1.5 times PIR cannot begin for at least 33 minutes. Without compressor inflow, these times decrease to 27 and 25 minutes, respectively.

Hypothetical natural gas pipeline releases and associated separation distance versus time plots are discussed in Section 3.1.4.1 through 3.1.4.4 for 12-in. and 42-in. natural gas pipeline releases in Class 1, 2, 3, and 4 Locations, respectively. These plots provide the basis for comparing effects of different block valve closure times on time-dependent blowdown behavior to the baseline plots shown in Figs. 3.15, 3.16, 3.17, and 3.18 and evaluating the effectiveness of block valve closure swiftness on mitigating the potential consequences of a natural gas pipeline release.

3.1.4.1 Hypothetical Natural Gas Pipeline Releases in Class 1 Locations

A Class 1 Location is defined in 49 CFR 192.5 as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy. An HCA in a Class 1 Locations is defined in 49 CFR 192.903 as: (1) any area where the PIR is greater than 660 ft (200 m) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy, and (2) area where the potential impact circle contains an identified site. Identified sites are described in Section 2.1.

For this study, the effects of valve closure time on fire damage resulting from a natural gas pipeline release in an area in a Class 1 Location that meets the criteria for an HCA were considered for hypothetical natural gas pipeline releases that affect areas with the following characteristics.

- Areas where the PIR is greater than 660 ft (200 m) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy as described in Section 3.1.3.1. As a worst case, 10 buildings are located within the Class 1 Location Unit near the break as shown in Fig. 3.2 and at least 10 buildings are located greater than 660 ft (200 m) from the break.
- Areas where the potential impact circle contains an identified site consisting of a building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. As a worst case, the identified site includes 10 office buildings with four or more stories above ground that are located in the Class 1 Location Unit within the potential impact circle near the break as described in Section 3.1.3.2 and shown in Fig. 3.3. In addition, if the identified site is within a potential impact radius greater than 660 ft (200 m), areas located greater than 660 ft (200 m) from the break contain buildings intended for human occupancy as described in Section 3.1.3.1.

- Areas where the potential impact circle contains an identified site consisting of an outside recreational facility described in Section 3.1.3.3 and shown in Fig. 3.4. In addition, if the identified site is within a PIR greater than 660 ft (200 m), areas located greater than 660 ft (200 m) from the break contain buildings intended for human occupancy as described in Section 3.1.3.1.

Fire damage to these areas is considered worst case because the cost of potential fire damage to other areas that qualify as an HCA in a Class 1 Location is less in comparison.

Separation distance versus time plots for 12-in. and 42-in. nominal diameter natural gas pipelines in Class 1 Locations are shown in Figs. 3.19, 3.20, 3.21, and 3.22. These plots compare the effects of block valve closure swiftness on time-dependent blowdown behavior. Figures 3.19 and 3.21 are plots of blowdown behavior for block valve closure 8 minutes after the break (i.e. 5 minutes to detect the leak plus 3 minutes to close the valve). Figures 3.20 and 3.22 are plots of blowdown behavior for the same pipeline segments with block valve closure 13 minutes after the break (i.e. 10 minutes to detect the leak plus 3 minutes to close the valve).

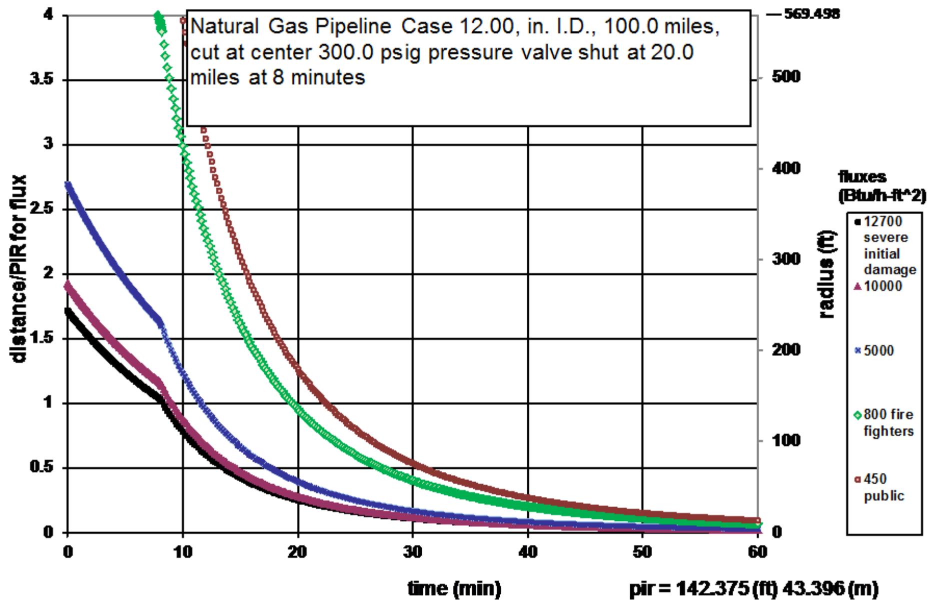


Fig. 3.19. Separation distances for 12-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break.

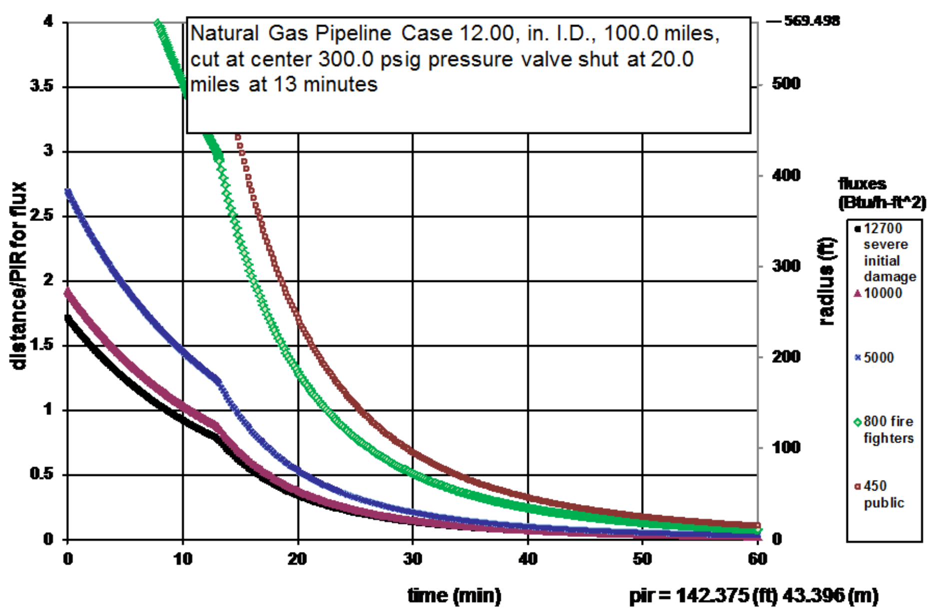


Fig. 3.20. Separation distances for 12-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break.

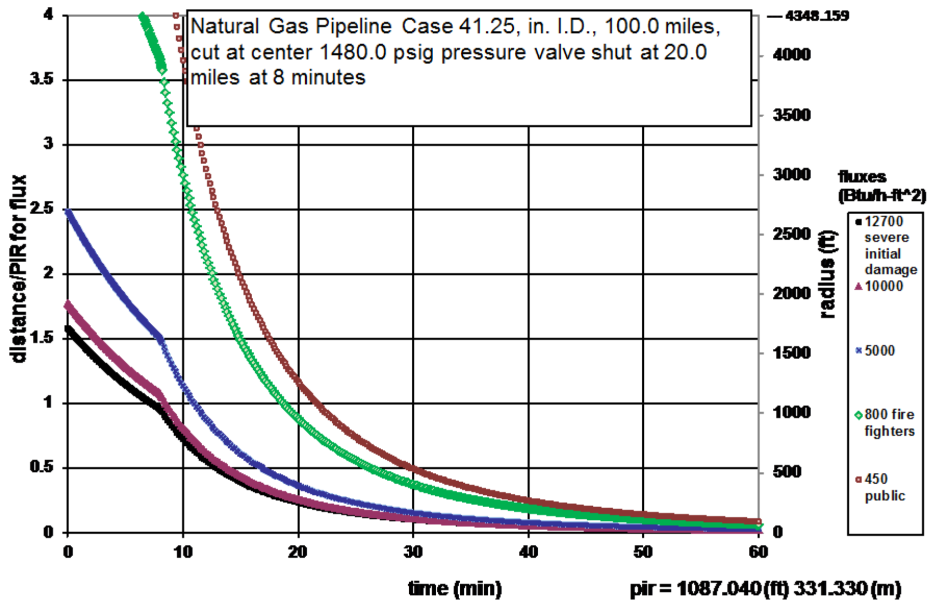


Fig. 3.21. Separation distances for 42-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break.

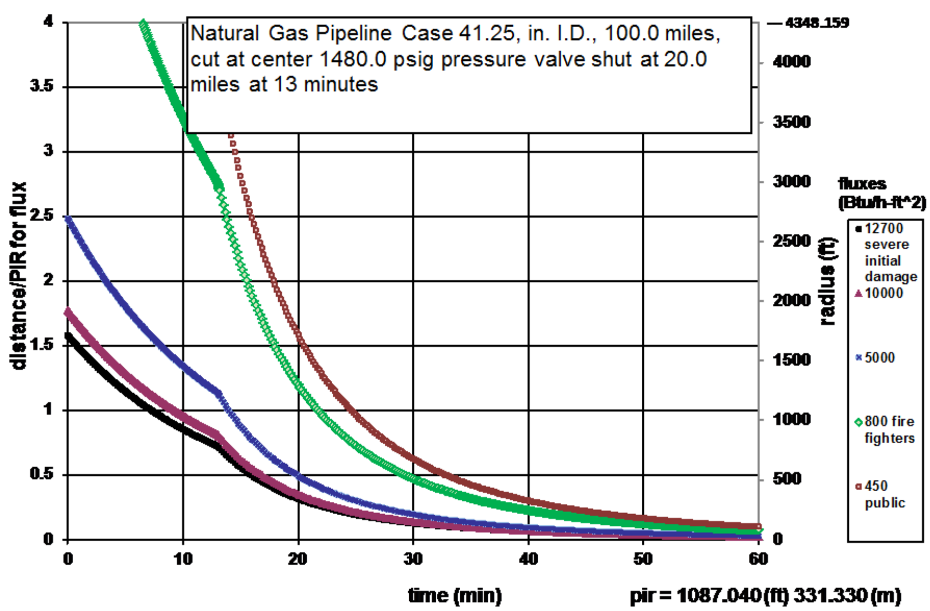


Fig. 3.22. Separation distances for 42-in. natural gas pipeline in a Class 1 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break.

Figures 3.19 and 3.20 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 19 to 16 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 3.19 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 11 minutes (27 minutes – 16 minutes) without compressor inflow and 21 minutes (37 minutes – 16 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blowdown behavior plots in Figs. 3.15, 3.16, and 3.20 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 8 minutes (27 minutes – 19 minutes) without compressor inflow and 18 minutes (37 minutes – 19 minutes) if the compressor inflow is 15 ft/s.

Figures 3.21 and 3.22 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 15 to 18 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 3.21 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 10 minutes (25 minutes – 15 minutes) without compressor inflow and 18 minutes (33 minutes – 15 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blown behavior plots in Figs. 3.17, 3.18, and 3.22 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 7 minutes (25 minutes – 18 minutes) without compressor inflow and 15 minutes (33 minutes – 18 minutes) if the compressor inflow is 15 ft/s.

Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 1 Location with Buildings Intended for Human Occupancy and a Potential Impact Radius Greater than 660 feet

Two case studies involving 42-in. nominal diameter hypothetical natural gas pipelines in HCAs in Class 1 Locations 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 natural gas pipelines are defined in Table 3.3. Case studies 1A and 1B 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 or 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 Table 3.4. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines in HCAs in Class 1 Locations with buildings intended for human occupancy and a PIR greater than 660 ft are shown in Figs. 3.23 to 3.24.

Table 3.4. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 1 Locations with buildings intended for human occupancy and a PIR greater than 660 feet

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1A	Case Study 1B
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	476	709
Potentially Minor Damage Radius, ft	546	719	166	211
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	15	18
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	15	15	15	15

Table 3.4. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 1 Locations with buildings intended for human occupancy and a PIR greater than 660 feet (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1A	Case Study 1B
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	12	12	12	12
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% - 25%) * 12 * $1,524,000 = $4,572,000	(50% - 40%) * 12 * $1,524,000 = $1,828,800

Note: The arc length of the potentially severe damage area located outside the Class 1 Location unit is 7,795 ft. Fifteen 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.

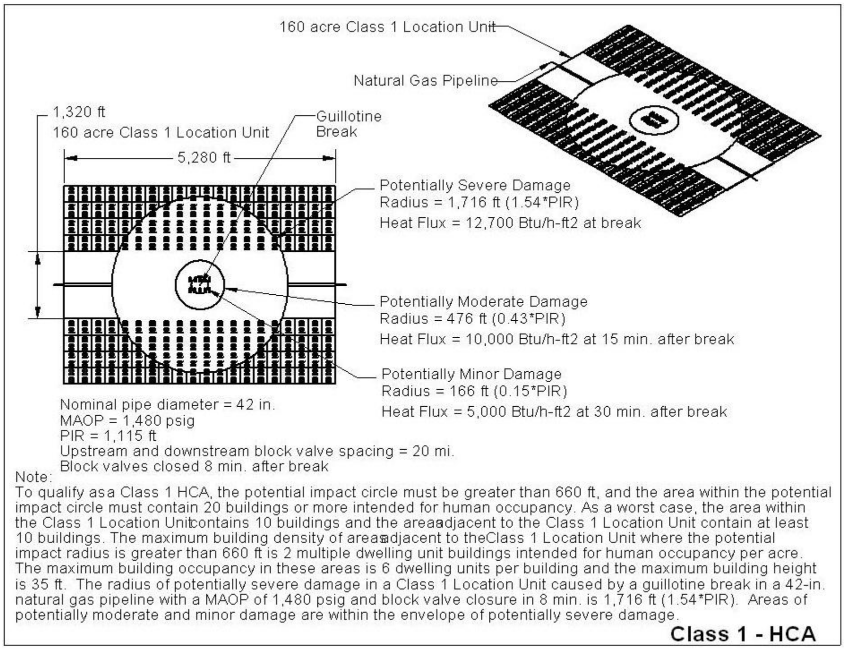


Fig. 3.23. Case Study 1A – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 1 Location with buildings intended for human occupancy and a PIR greater than 660 feet – 1,480 psig MAOP and block valve closure 8 minutes after break.

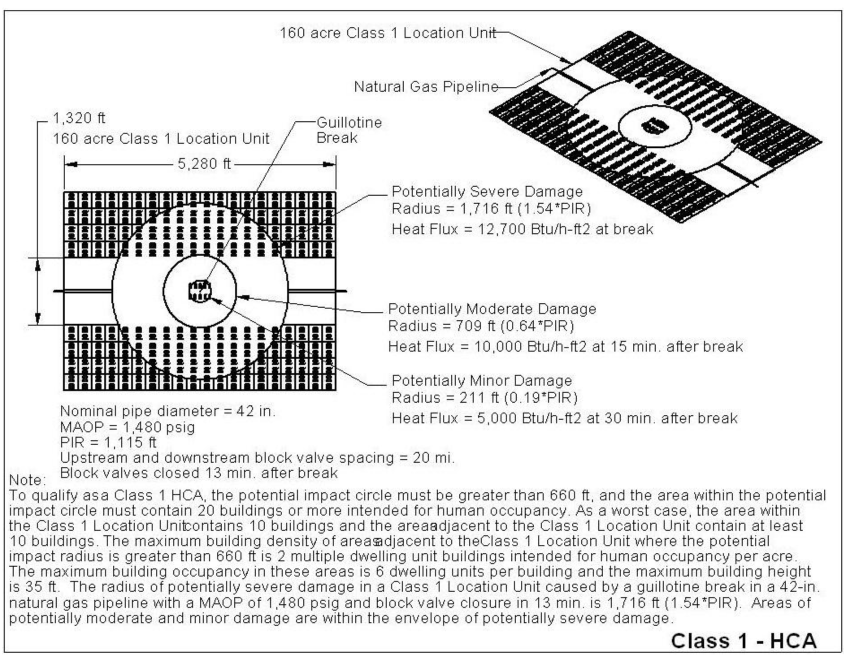


Fig. 3.24. Case Study 1B – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 1 Location with buildings intended for human occupancy and a PIR greater than 60 feet – 1,480 psig MAOP and block valve closure 13 minutes after break.

Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 1 Location with an Identified Site Consisting of Buildings with Four or More Stories above Ground

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in HCAs in Class 1 Locations are considered to assess effects of valve closure time on fire damage to identified sites consisting of 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 1C and 1D 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 or either 8 minutes or 13 minutes after the break.
- Case studies 1E and 1F 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 or 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 3.5 and 3.6. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines within HCAs in Class 1 Locations with identified sites consisting of buildings with four or more stories above ground are shown in Figs. 3.25 to 3.28.

Table 3.5. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of 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 1C	Case Study 1D
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	$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	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	68	97
Potentially Minor Damage Radius, ft	77	102	24	30
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	16	19
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 3.5. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of 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 1C	Case Study 1D
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% - 30%) * 3 * $1,000,000 = $600,000	(50% - 40%) * 3 * $1,000,000 = $300,000

Note: The perimeter of the potentially severe damage area is 1,348 ft. Three fire hydrants are available outside the potentially severe damage area. Three engines arrive on scene and fire fighters begin fire fighting activities within 10 minutes.

Table 3.6. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of 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 1E	Case Study 1F
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	476	709
Potentially Minor Damage Radius, ft	546	719	166	211
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	15	18
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	15	15	15	15
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	12	12	12	12

Table 3.6. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 1 Locations with identified sites consisting of 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 1E	Case Study 1F
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% - 25%) * 12 * $1,524,000 = $4,572,000	(50% - 40%) * 12 * $1,524,000 = $1,828,800

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.

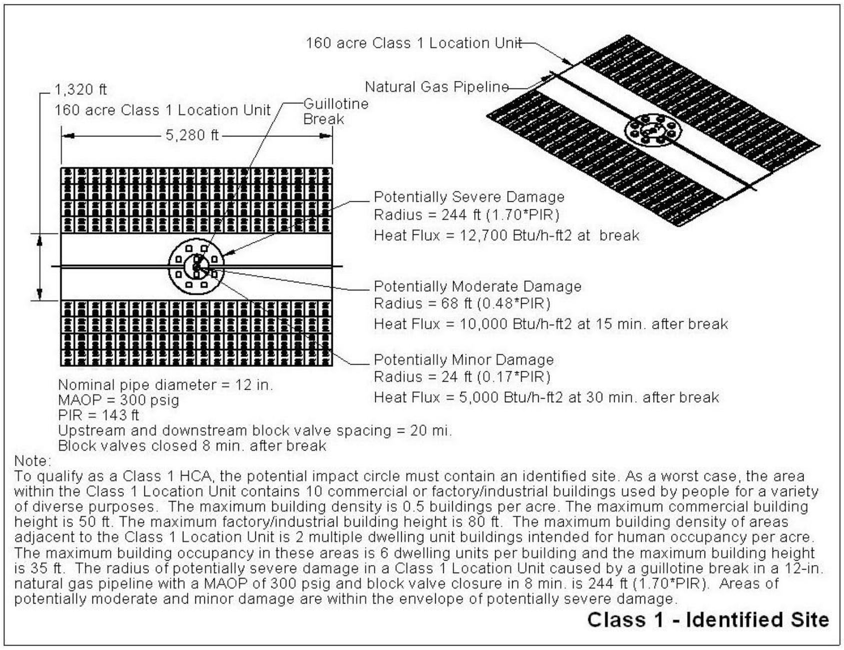


Fig. 3.25. Case Study 1C – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break.

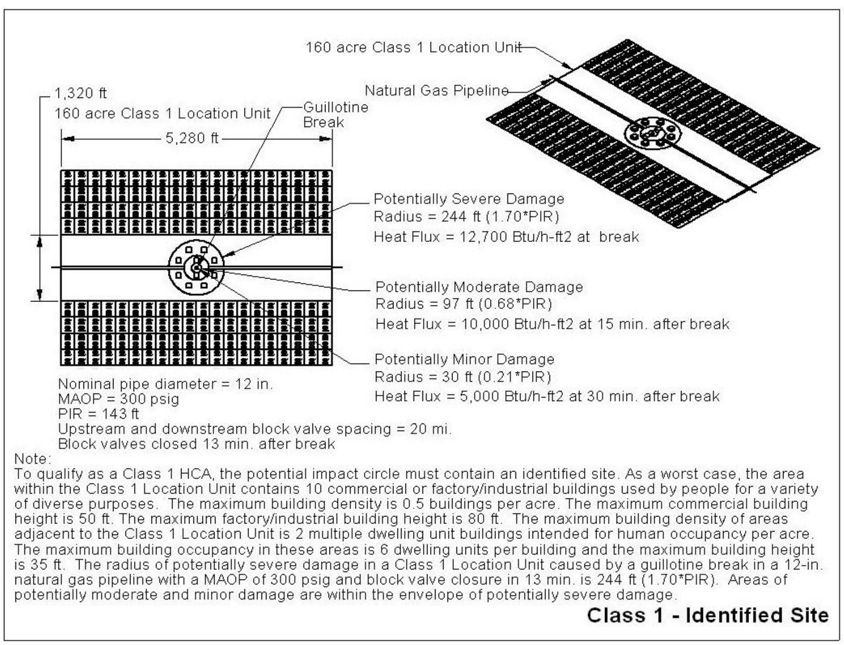


Fig. 3.26. Case Study 1D – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break.

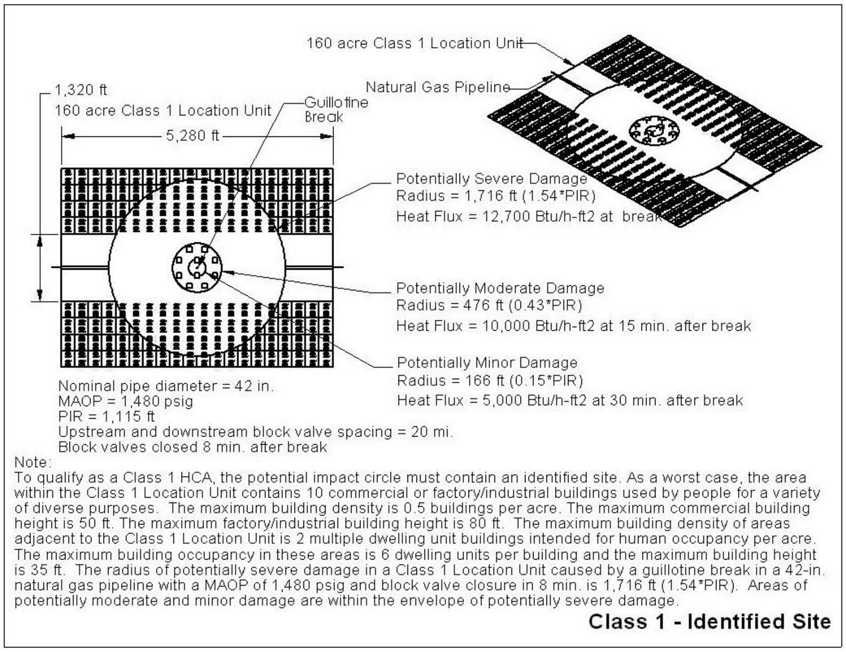


Fig. 3.27. Case Study 1E – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break.

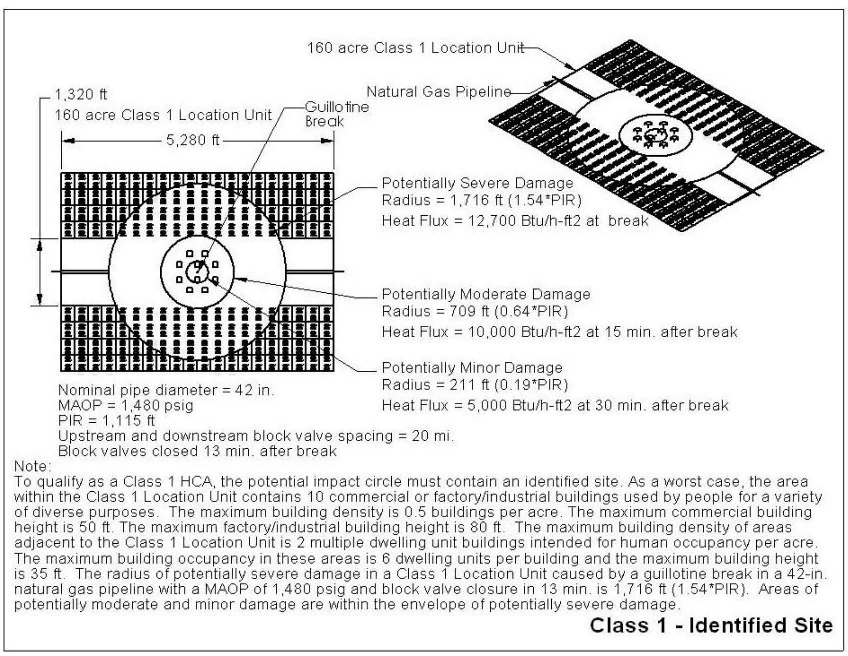


Fig. 3.28. Case Study 1F – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break.

Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 1 Location with an Identified Site Consisting of Outside Recreational Facility

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in HCAs in Class 1 Locations are considered to assess effects of valve closure time on fire damage to identified sites consisting of outside recreational facilities. 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 1G and 1H 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 1I and 1J 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 3.7 and 3.8. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines in HCAs in Class 1 Locations with identified sites consisting of outside recreational facilities are shown in Figs. 3.29 to 3.32.

Table 3.7. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1G	Case Study 1H
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	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre
Total Moderate Damage Cost	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre
Total Minor Damage Cost	$250,000	$250,000	$250,000	$250,000
Potentially Severe Damage Radius, ft	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	68	97
Potentially Minor Damage Radius, ft	77	102	24	30
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	16	19
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 3.7. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities (Cont.)

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1G	Case Study 1H
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% - 5%) * 3 * $595,000 = $803,250	(50% - 25%) * 3 * $595,000 = $446,250

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 3.8. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1I	Case Study 1J
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	476	709
Potentially Minor Damage Radius, ft	546	719	166	211
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	15	18
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 3.8. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in an HCA in a Class 1 Location with an identified site consisting of outside recreational facilities (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 1I	Case Study 1J
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% - 25%) * 12 * $595,000 = $1,785,000	(50% - 40%) * 12 * $595,000 = $714,000

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.

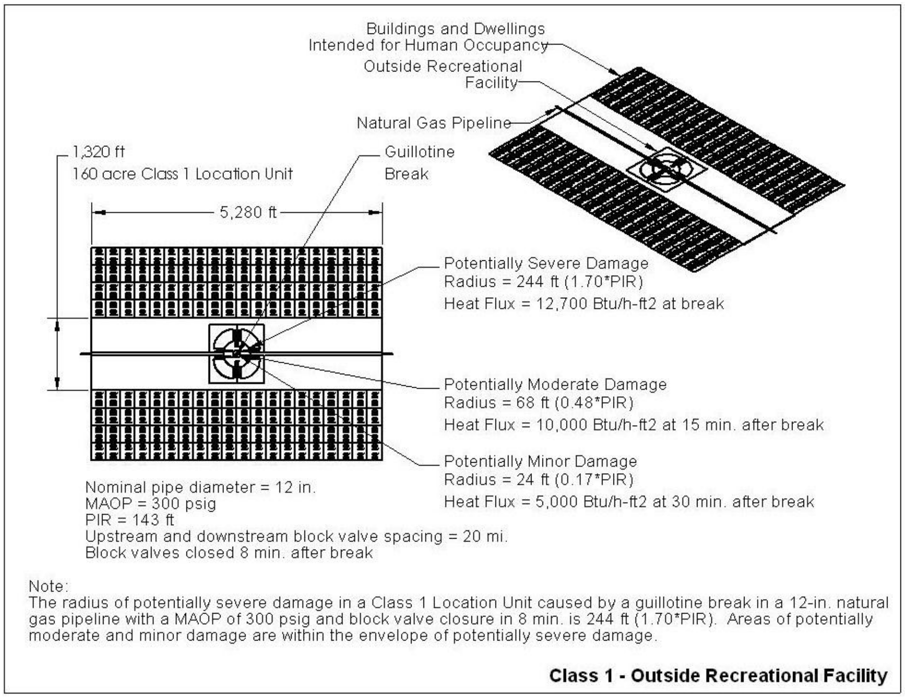


Fig. 3.29. Case Study 1G – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 8 minutes after break.

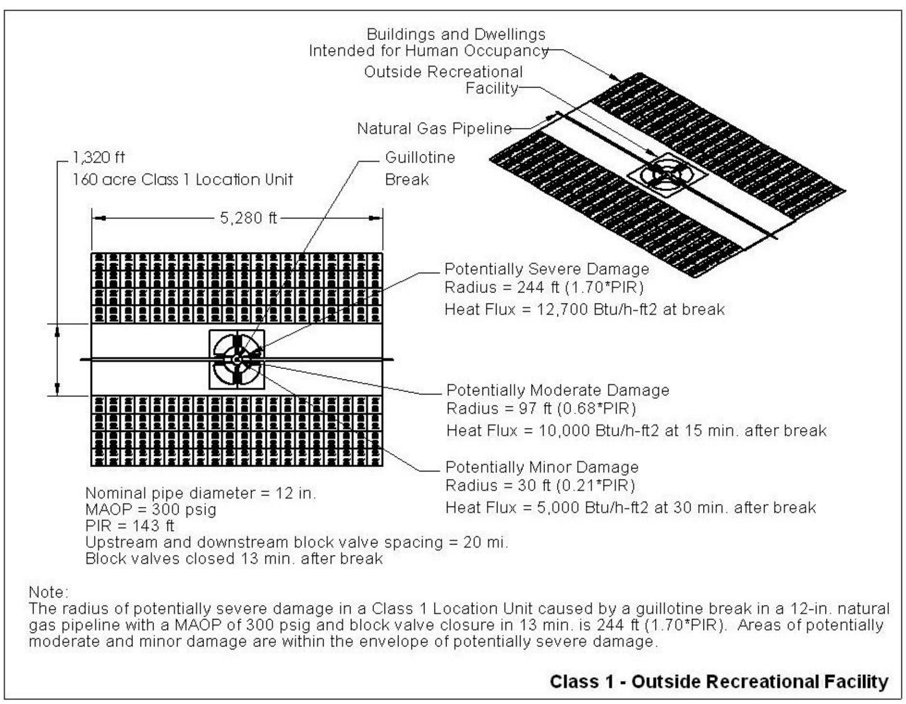


Fig. 3.30. Case Study 1H – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 13 minutes after break.

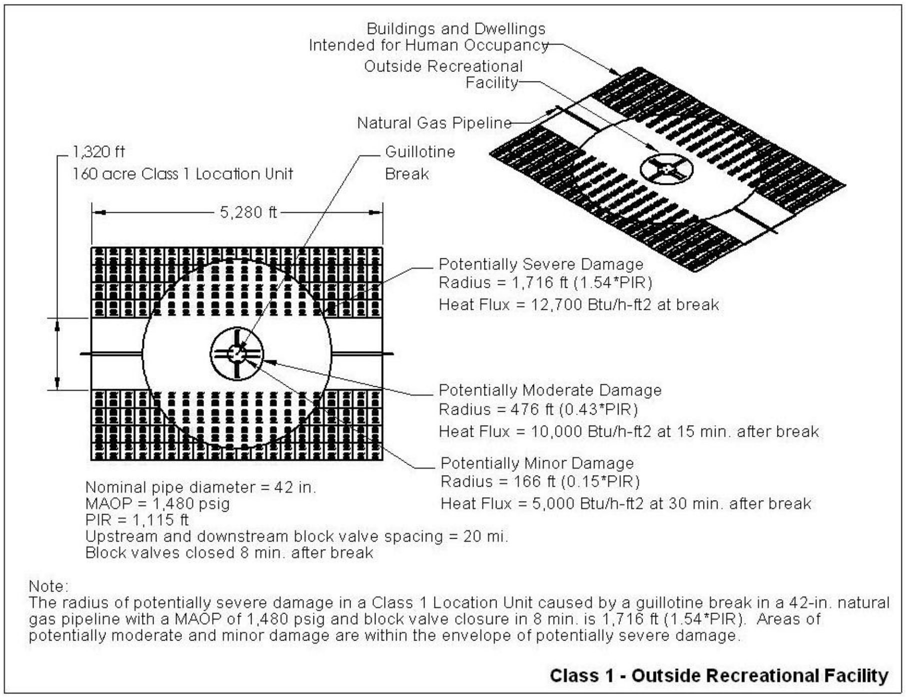


Fig. 3.31. Case Study 1I – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 8 minutes after break.

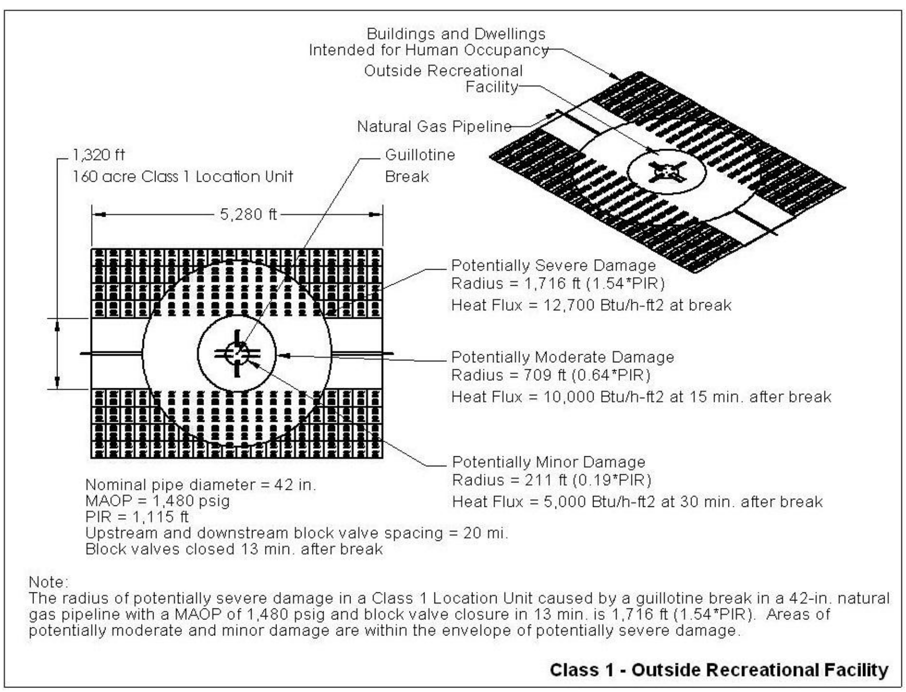


Fig. 3.32. Case Study 1J – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in HCAs in Class 1 Location with an identified site consisting of outside recreational facilities – 1,480 psig MAOP and block valve closure 13 minutes after break.

Damage Resulting from Hypothetical Natural Gas Pipeline Releases in HCAs in Class 1 Locations

Fire damage to buildings and personal property in HCAs in Class 1 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 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 1 Locations

Without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in HCAs in Class 1 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 HCAs in Class 1 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 $800,000 for 12-in. nominal diameter natural gas pipelines and $1,700,000 for 42-in. nominal diameter natural gas pipelines depending on the configuration of buildings within the Class 1 HCA. Delaying block valve closure by an additional 5 minutes reduces the cost avoidance by approximately 50%.

3.1.4.2 Hypothetical Natural Gas Pipeline Releases in Class 2 Locations

A Class 2 Location is defined in 49 CFR 192.5 as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy. An HCA in a Class 2 Locations is defined in 49 CFR 192.903 as: (1) any area where the PIR is greater than 660 ft (200 m) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy, and (2) area where the potential impact circle contains an identified site. Identified sites are described in Section 2.1.

For this study, the effects of valve closure time on fire damage resulting from a natural gas pipeline release in an area in a Class 2 Location that meets the criteria for an HCA were considered for hypothetical natural gas pipeline releases that affect areas with the following characteristics.

- Areas where the PIR is greater than 660 ft (200 m) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy as described in Section 3.1.3.1. As a worst case, 10 buildings are located within the Class 2 Location Unit near the break as shown in Fig. 3.5 and at least 10 buildings are located greater than 660 ft (200 m) from the break.
- Areas where the potential impact circle contains an identified site consisting of a building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. As a worst case, the identified site includes 10 office buildings with four or more stories above ground that are located in the Class 2 Location Unit within the potential impact circle near the break as described in Section 3.1.3.2 and shown in Fig. 3.6. In addition, if the identified site is within a PIR greater than 660 ft (200 m), areas located greater than 660 ft (200 m) from the break contain buildings intended for human occupancy as described in Section 3.1.3.1.
- Areas where the potential impact circle contains an identified site consisting of an outside recreational facility described in Section 3.1.3.3 and shown in Fig. 3.7. In addition, if the identified site is within a PIR greater than 660 ft (200 m), areas located greater than 660 ft (200 m) from the break contain buildings intended for human occupancy as described in Section 3.1.3.1.

Fire damage to these areas is considered worst case because the cost of potential fire damage to other areas that qualify as an HCA in a Class 2 Location is less in comparison.

Separation distance versus time plots for 12-in. and 42-in. nominal diameter natural gas pipelines in Class 2 Locations are shown in Figs. 3.33, 3.34, 3.35, and 3.36. These plots compare the effects of block valve closure swiftness on time-dependent blowdown behavior. Figures 3.33 and 3.35 are plots of blowdown behavior for block valve closure 8 minutes after the break (i.e. 5 minutes to detect the leak plus 3 minutes to close the valve). Figures 3.34 and 3.36 are plots of blowdown behavior for the same pipeline segments with block valve closure 13 minutes after the break (i.e. 10 minutes to detect the leak plus 3 minutes to close the valve).

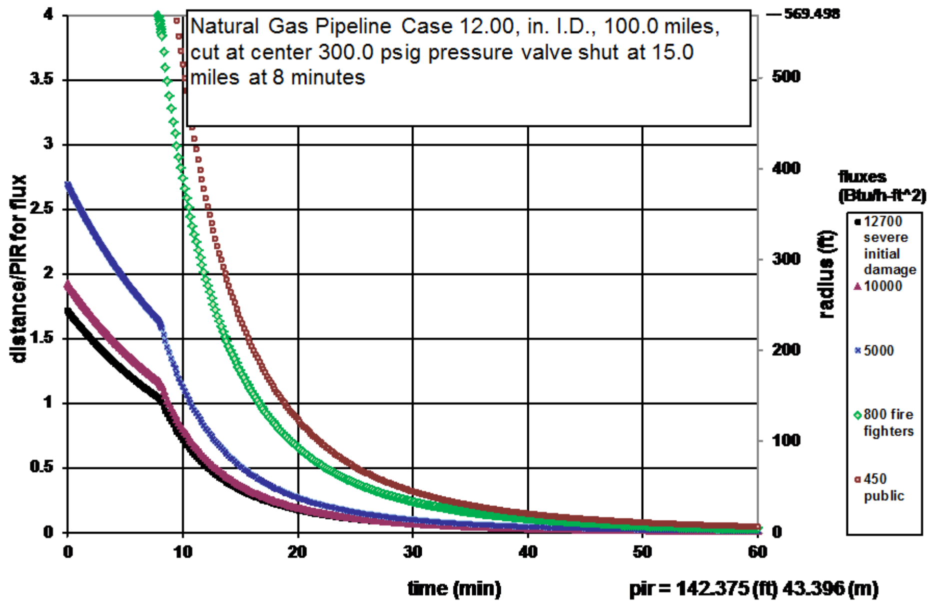


Fig. 3.33. Separation distances for 12-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break.

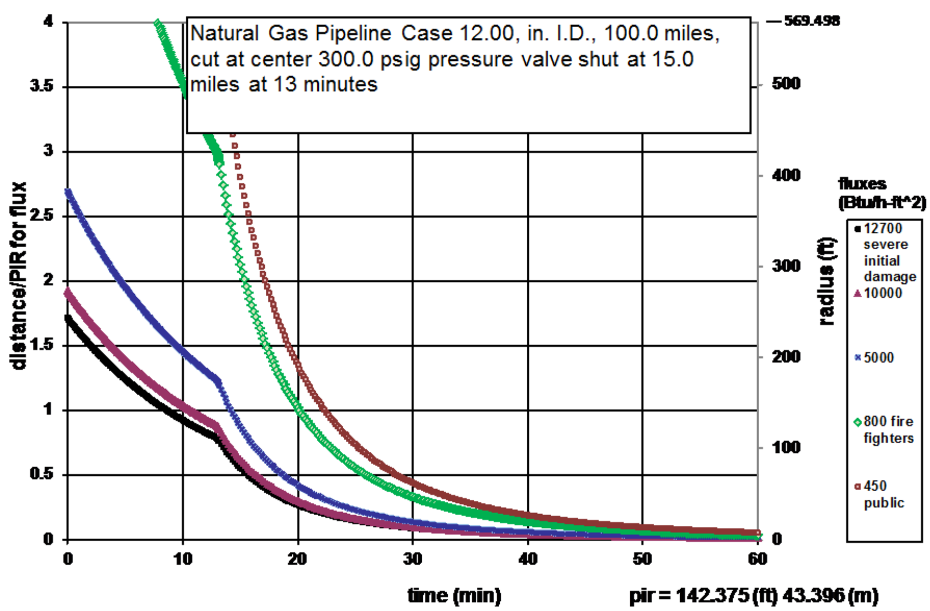


Fig. 3.34. Separation distances for 12-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break.

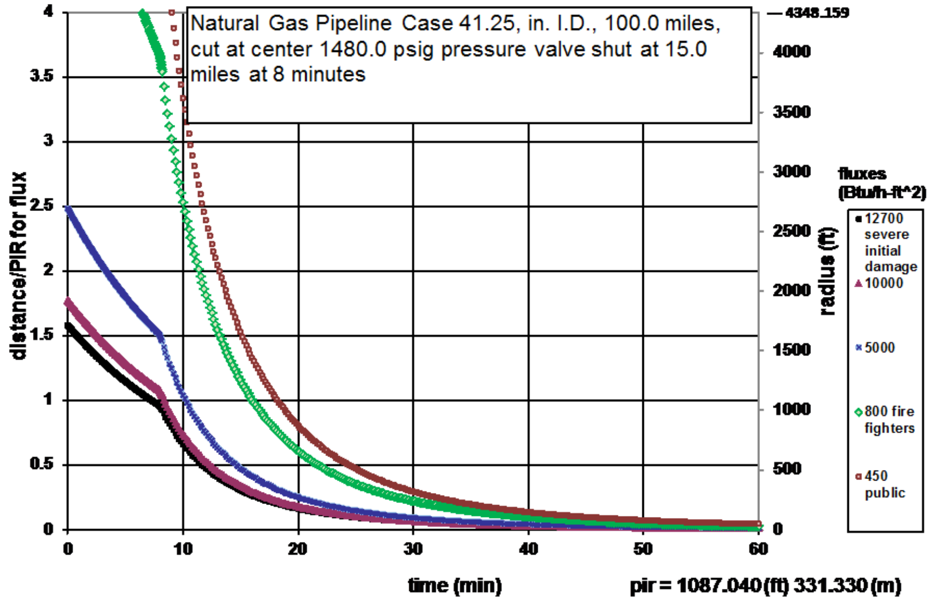


Fig. 3.35. Separation distances for 42-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break.

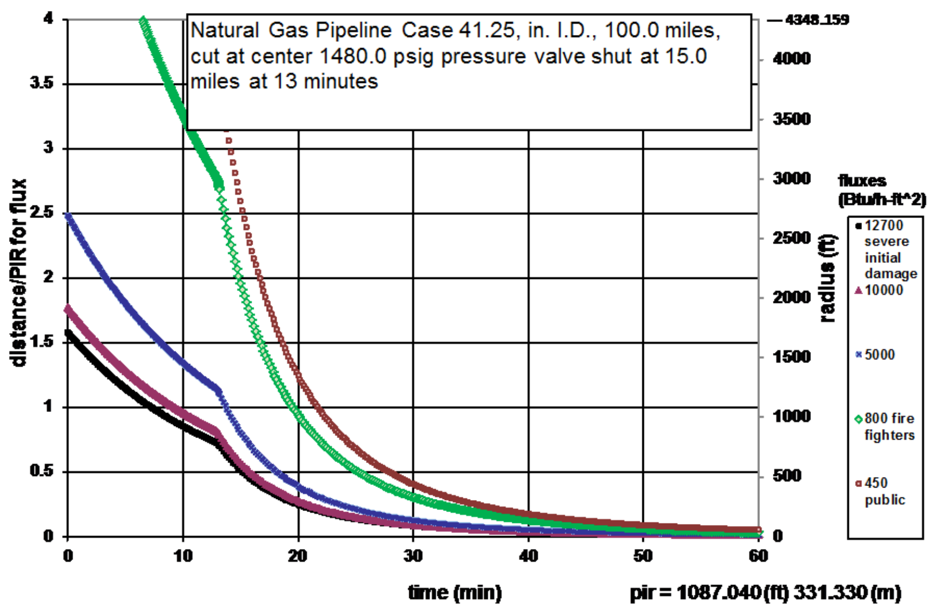


Fig. 3.36. Separation distances for 42-in. natural gas pipeline in a Class 2 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break.

Figures 3.33 and 3.34 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 17 to 14 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparison of time-dependent blown behavior plots in Figs. 3.15, 3.16, and 3.33 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 13 minutes (27 minutes - 14 minutes) without compressor inflow and 23 minutes (37 minutes - 14 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blown behavior plots in Figs. 3.15, 3.16, and 3.34 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 10 minutes (27 minutes - 17 minutes) without compressor inflow and 20 minutes (37 minutes - 17 minutes) if the compressor inflow is 15 ft/s.

Figures 3.35 and 3.36 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 15 to 17 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparisons of time-dependent blown behavior plots in Figs. 3.17, 3.18, and 3.35 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 12 minutes (25 minutes - 13 minutes) without compressor inflow and 20 minutes (33 minutes - 13 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blown behavior plots in Figs. 3.17, 3.18, and 3.36 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 8 minutes (25 minutes - 17 minutes) without compressor inflow and 16 minutes (33 minutes - 17 minutes) if the compressor inflow is 15 ft/s.

Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 2 Location with Buildings Intended for Human Occupancy and a PIR Greater than 660 feet

Two case studies involving 42-in. nominal diameter hypothetical natural gas pipelines in HCAs in Class 2 Locations are considered to assess effects of valve closure time on fire damage to buildings intended for human occupancy and an impact radius greater than 660 ft. Design features and operating conditions for these hypothetical natural gas pipelines are defined in Table 3.3. Case studies 2A and 2B 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 or 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 Table 3.9. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines in HCAs in Class 2 Locations with buildings intended for human occupancy and PIR greater than 660 ft are shown in Figs. 3.37 to 3.38.

Table 3.9. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with buildings intended for human occupancy and a PIR greater than 660 feet

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2A	Case Study 2B
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	368	626
Potentially Minor Damage Radius, ft	546	719	99	137
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	13	17
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	15	15	15	15
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	12	12	12	12

Table 3.9. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with buildings intended for human occupancy and a PIR greater than 660 feet (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2A	Case Study 2B
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% - 25%) * 12 * $1,524,000 = $4,572,000	(50% - 40%) * 12 * $1,524,000 = $1,828,800

Note: The arc length of the potentially severe damage area located outside the Class 2 Location unit is 7,795 ft. Fifteen 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.

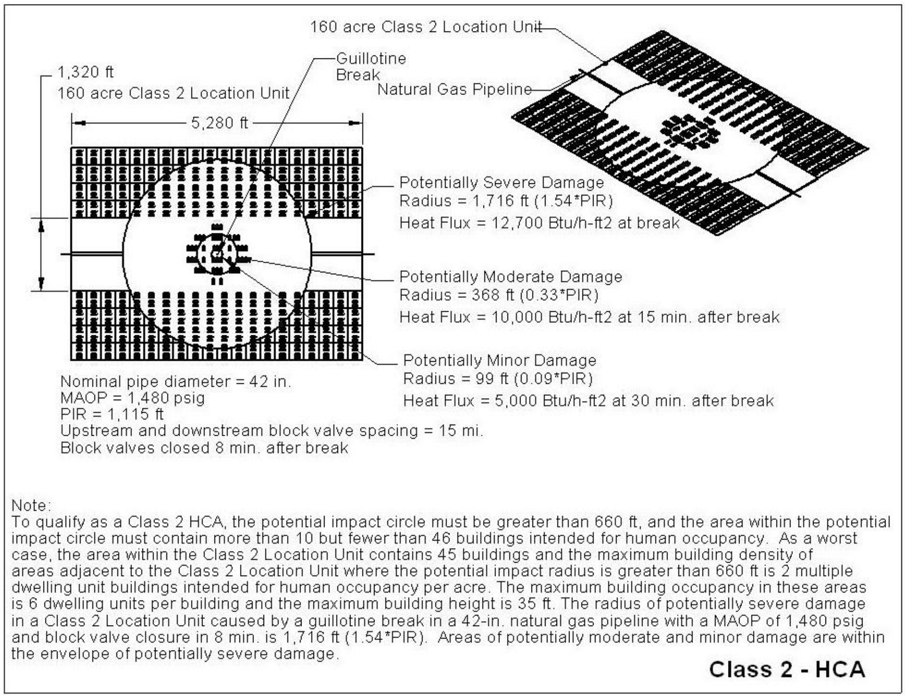


Fig. 3.37. Case Study 2A – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 2 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 8 minutes after break.

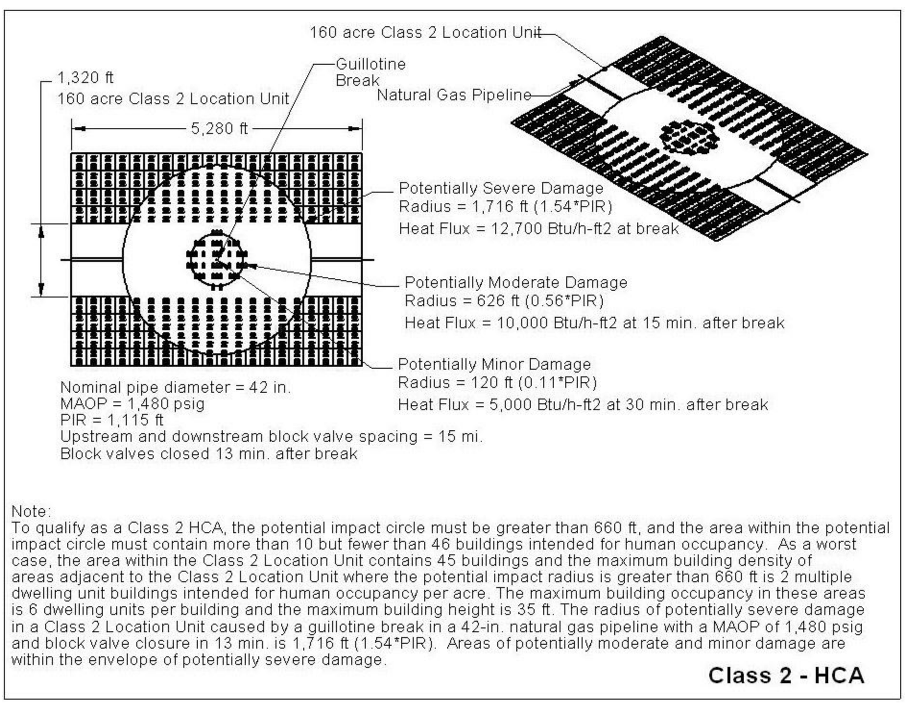


Fig. 3.38. Case Study 2B – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 2 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 13 minutes after break.

Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 2 Location with an Identified Site Consisting of Buildings with Four or More Stories above Ground

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in Class 2 Locations are considered to assess effects of valve closure time on fire damage to identified sites consisting of 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 2C and 2D 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 or either 8 minutes or 13 minutes after the break.
- Case studies 2E and 2F 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 or 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 3.10 and 3.11. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines within Class 2 Locations with identified sites consisting of buildings with four or more stories above ground are shown in Figs. 3.39 to 3.42.

Table 3.10. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of 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 2C	Case Study 2D
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	$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	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	52	89
Potentially Minor Damage Radius, ft	77	102	14	19
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	14	17
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 3.10. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of 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 2C	Case Study 2D
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% - 30%) * 3 * $1,000,000 = $600,000	(50% - 40%) * 3 * $1,000,000 = $300,000

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 3.11. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of 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 2E	Case Study 2F
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	368	626
Potentially Minor Damage Radius, ft	546	719	99	137
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	13	17
Number of Fire Hydrants Available for Fire Fighting Activities within 10 minutes after break	15	15	15	15
Number of Fire Engines Involved in Fire Fighting Activities within 10 minutes after break	12	12	12	12

Table 3.11. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in HCAs in Class 2 Locations with identified sites consisting of 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 2E	Case Study 2F
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% - 25%) * 12 * $1,524,000 = $4,572,000	(50% - 40%) * 12 * $1,524,000 = $1,828,800

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.

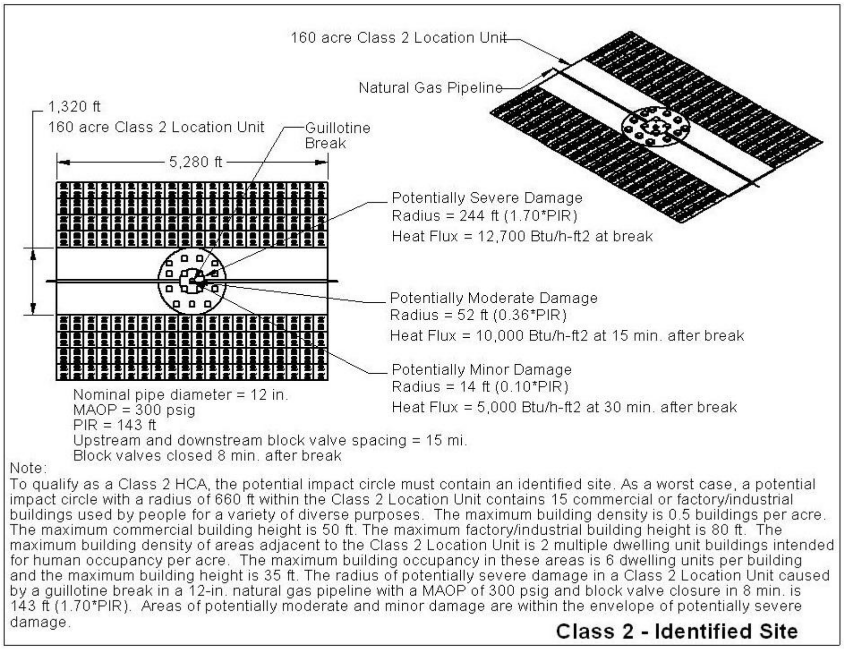


Fig. 3.39. Case Study 2C – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 300 psig MAOP and block valve closure 8 minutes after break.

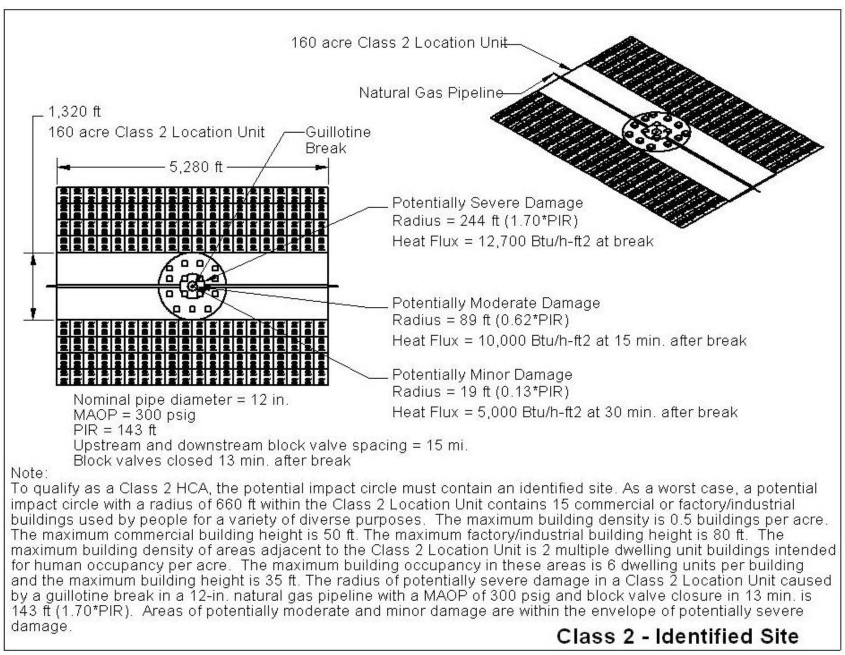


Fig. 3.40. Case Study 2D – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 300 psig MAOP and block valve closure 13 minutes after break.

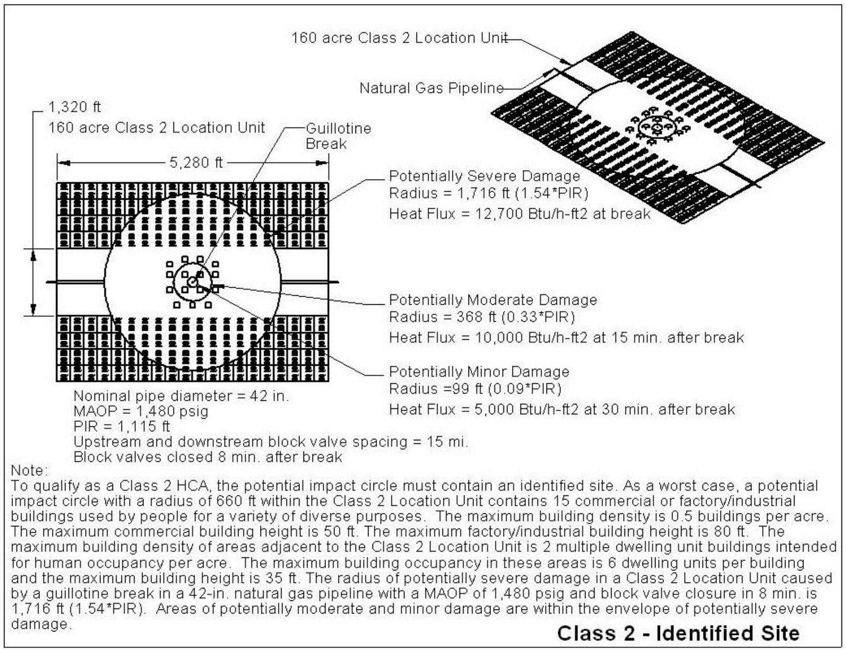


Fig. 3.41. Case Study 2E – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break.

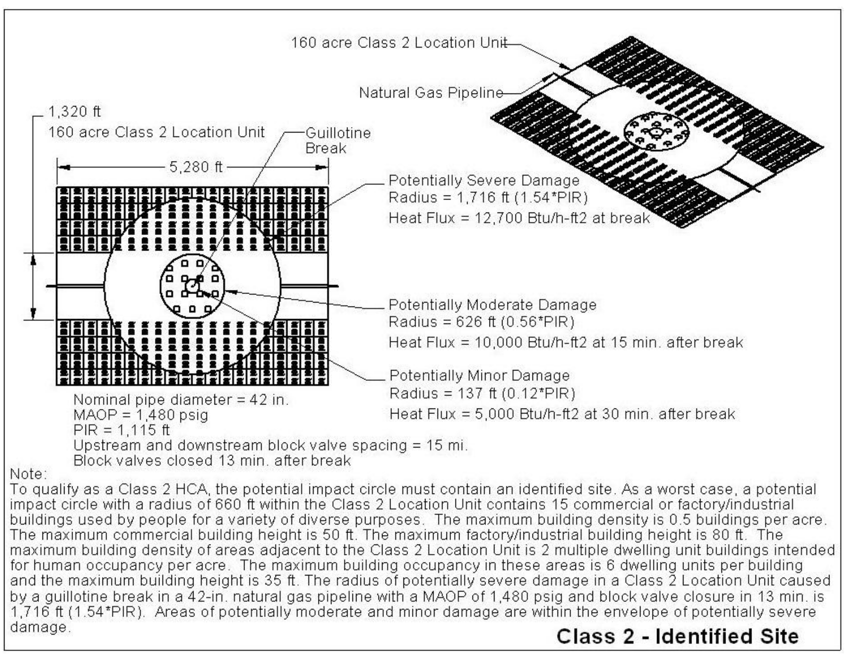


Fig. 3.42. Case Study 2F – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of buildings with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break.

<u>Hypothetical Natural Gas Pipeline Releases in a HCA in a Class 2 Location with an Identified Site Consisting of an Outside Recreational Facility</u>

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in HCAs I Class 2 Locations are considered to assess effects of valve closure time on fire damage to identified sites consisting of outside recreational facilities. 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 2G and 2H 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 2I and 2J 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 3.12 and 3.13. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines in HCAs in Class 2 Locations with identified sites consisting of outside recreational facilities are shown in Figs. 3.43 to 3.46.

Table 3.12. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2G	Case Study 2H
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	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre
Total Moderate Damage Cost	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre
Total Minor Damage Cost	$250,000	$250,000	$250,000	$250,000
Potentially Severe Damage Radius, ft	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	52	89
Potentially Minor Damage Radius, ft	77	102	14	19
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	14	17
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 3.12. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities (Cont.)

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2G	Case Study 2H
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% - 5%) * 3 * $595,000 = $803,250	(50% - 25%) * 3 * $595,000 = $446,250

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 3.13. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2I	Case Study 2J
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	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre
Total Moderate Damage Cost	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre
Total Minor Damage Cost	$250,000	$250,000	$250,000	$250,000
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	368	626
Potentially Minor Damage Radius, ft	546	719	99	137
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	13	17
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 3.13. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in a HCA in a Class 2 Location with an identified site consisting of outside recreational facilities (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 2I	Case Study 2J
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% - 25%) * 12 * $595,000 = $1,785,000	(50% - 40%) * 12 * $595,000 = $714,000

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.

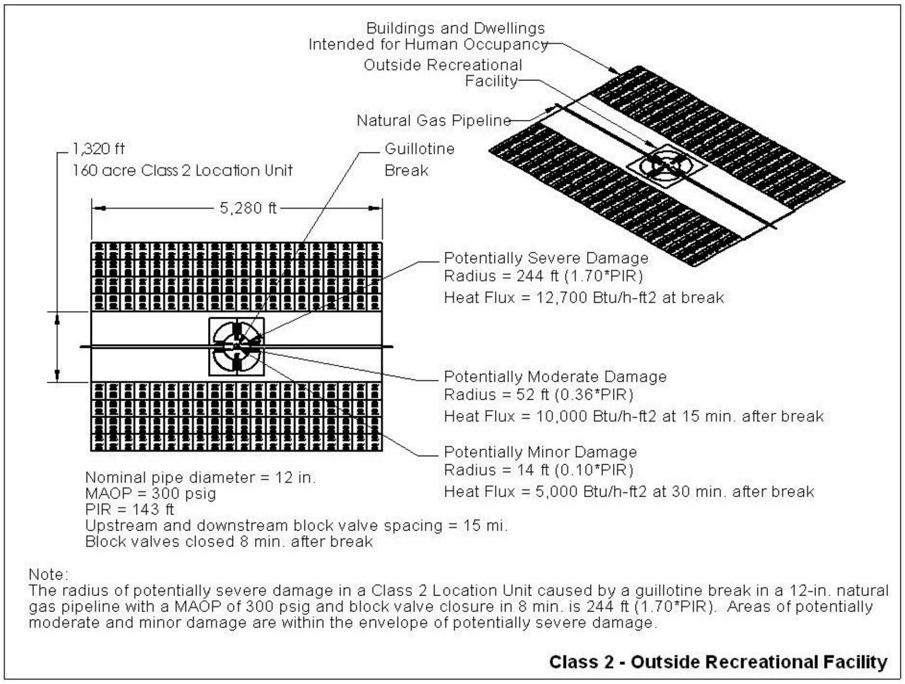


Fig. 3.43. Case Study 2G – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 300 psig MAOP and block valve closure 8 minutes after break.

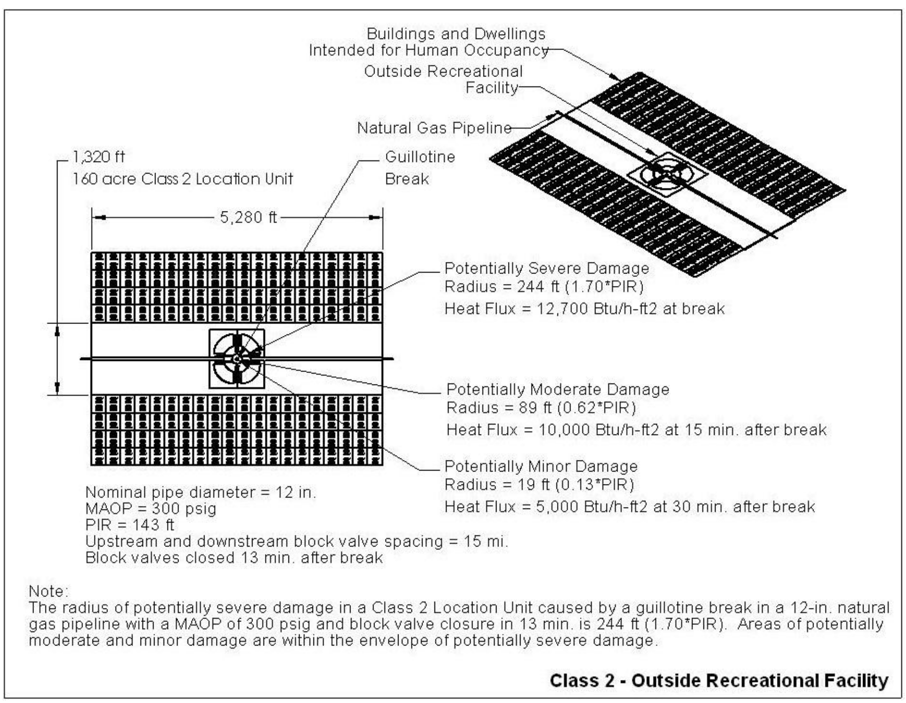


Fig. 3.44. Case Study 2H – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 300 psig MAOP and block valve closure 13 minutes after break.

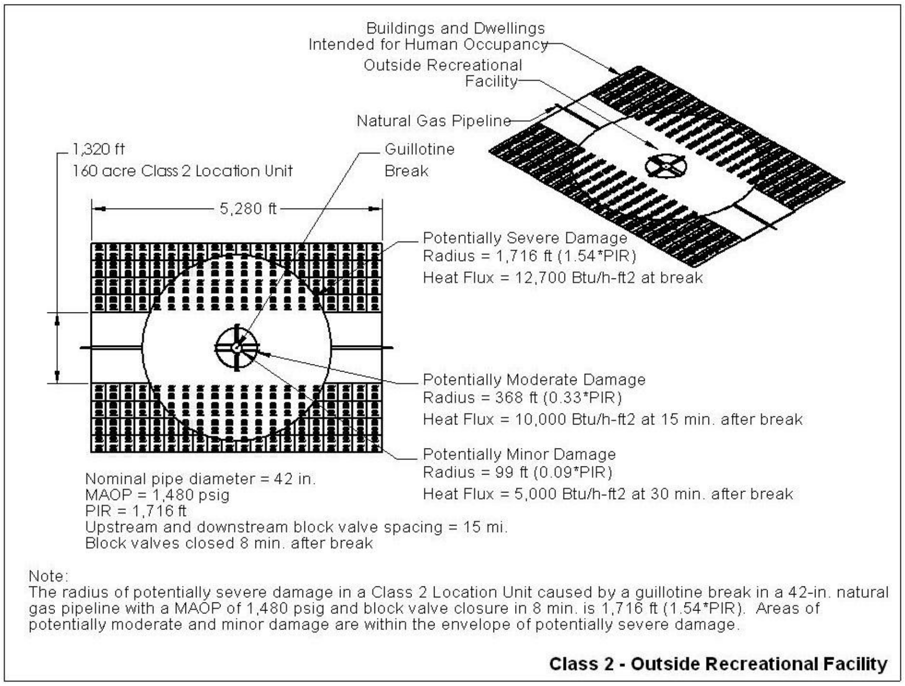


Fig. 3.45. Case Study 2I – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 1,480 psig MAOP and block valve closure 8 minutes after break.

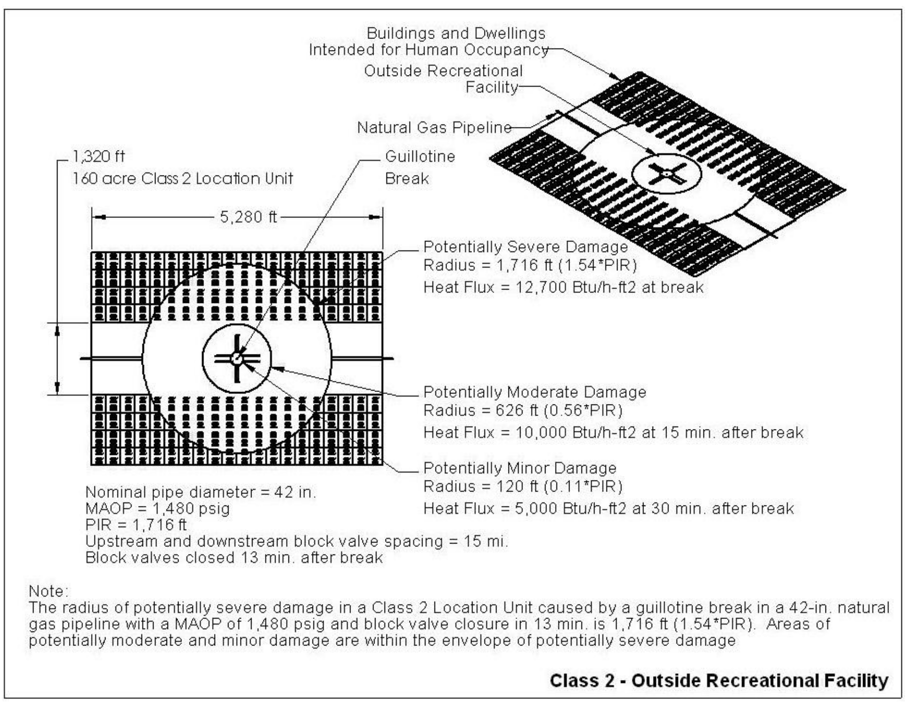


Fig. 3.46. Case Study 2J – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a HCA in a Class 2 Location with an identified site consisting of an outside recreational facility – 1,480 psig MAOP and block valve closure 13 minutes after break.

Damage Resulting from Hypothetical Natural Gas Pipeline Releases in HCAs in Class 2 Locations

Fire damage to buildings and personal property in HCAs in Class 2 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 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 2 Locations

Without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in HCAs in Class 2 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 HCAs in Class 2 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 $800,000 for 12-in. nominal diameter natural gas pipelines and $4,500,000 for 42-in. nominal diameter natural gas pipelines depending on the configuration of buildings within the Class 2 HCA. Delaying block valve closure by an additional 5 minutes reduces the cost avoidance by approximately 50%.

3.1.4.3 Hypothetical Natural Gas Pipeline Releases in Class 3 Locations

According to the definition of a Class 3 Location in 49 CFR 192.5, a Class 3 Location is any class location unit that has: (1) 46 or more buildings intended for human occupancy; or (2) an area where the pipeline lies within 100 yd (91 m) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. Based on the definition of HCA in 49 CFR 192.903, all Class 3 Locations are classified as HCAs.

For this study, the effects of valve closure time on fire damage resulting from a natural gas pipeline release in a Class 3 Location were considered for hypothetical natural gas pipeline releases that affect areas with buildings intended for human occupancy as described in Section 3.1.3.1 and shown in Fig. 3.8 and the outside recreational facility described in Section 3.1.3.3 and shown in Fig. 3.9.

Fire damage to these areas is considered worst case because the cost of potential fire damage to other areas that qualify as a Class 3 Location is less in comparison.

Separation distance versus time plots for 12-in. and 42-in. nominal diameter natural gas pipelines in Class 3 Locations are shown in Figs. 3.47, 3.48, 3.49, and 3.50. These plots compare the effects of block valve closure swiftness on time-dependent blowdown behavior. Figures 3.47 and 3.49 are plots of blowdown behavior for block valve closure 8 minutes after the break (i.e. 5 minutes to detect the leak plus 3 minutes to close the valve). Figures 3.48 and 3.50 are plots of blowdown behavior for the same pipeline segments with block valve closure 13 minutes after the break (i.e. 10 minutes to detect the leak plus 3 minutes to close the valve).

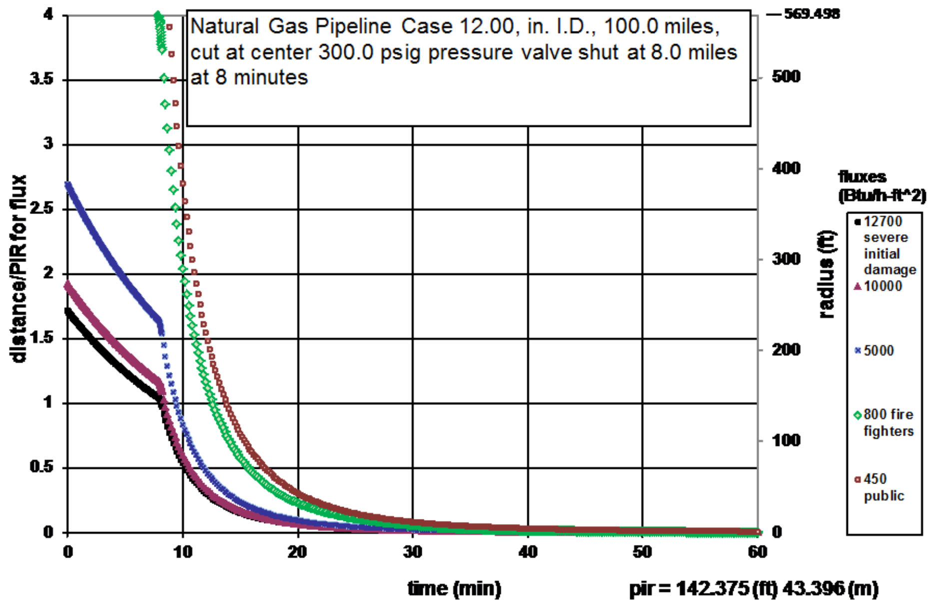


Fig. 3.47. Separation distances for 12-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break.

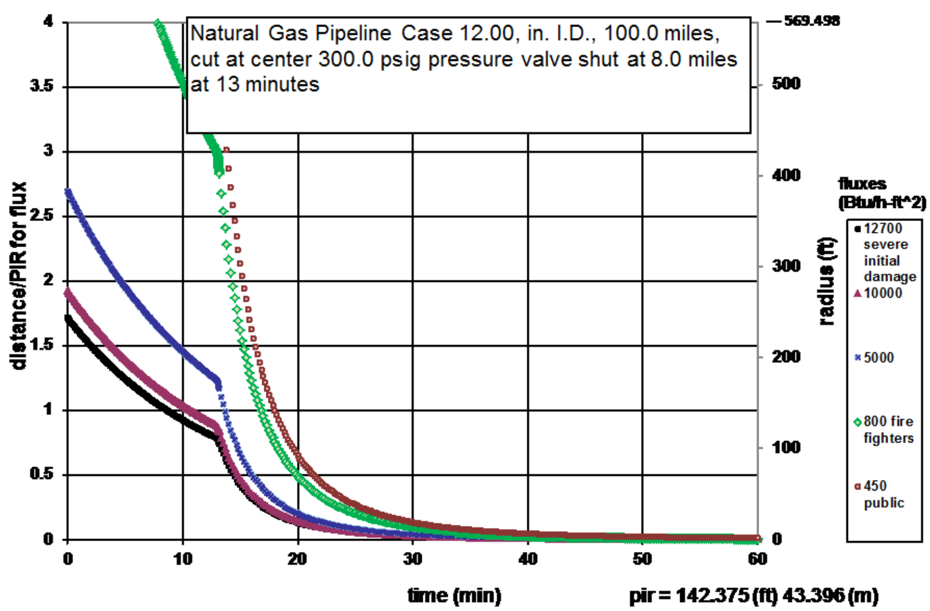


Fig. 3.48. Separation distances for 12-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break.

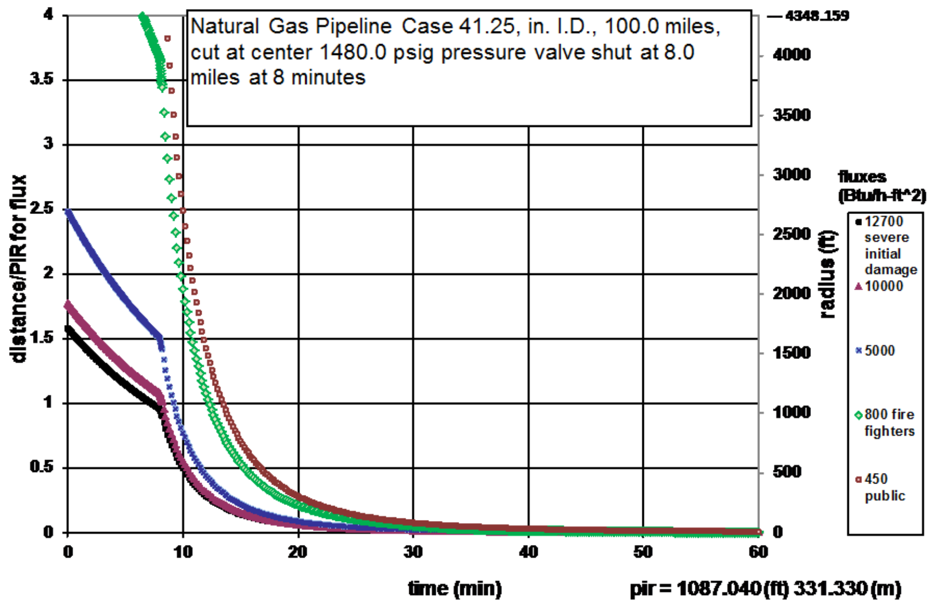


Fig. 3.49. Separation distances for 42-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break.

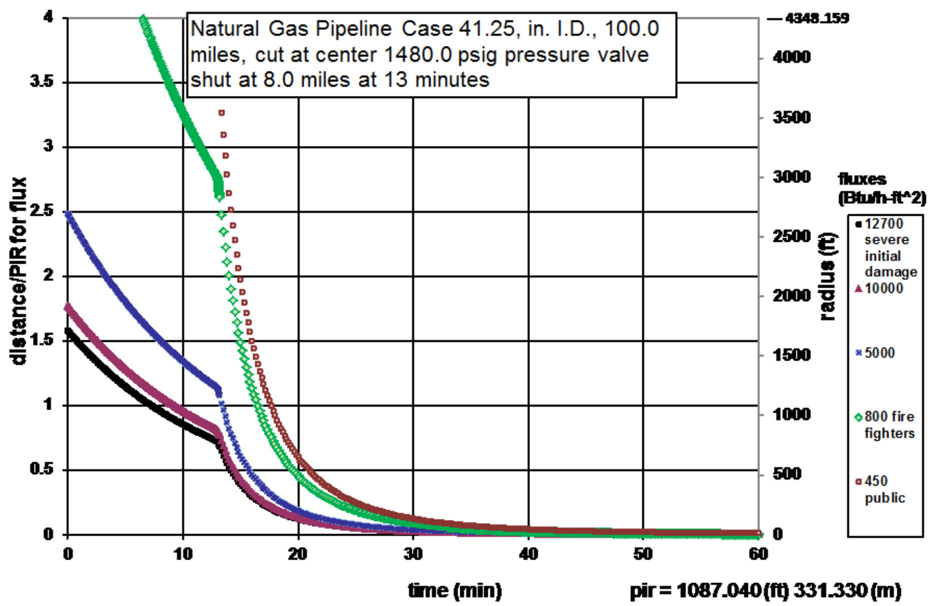


Fig. 3.50. Separation distances for 42-in. natural gas pipeline in a Class 3 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break.

Figures 3.47 and 3.48 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 11 to 15 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparison of time-dependent blown behavior plots in Figs. 3.12, 3.13, and 3.47 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 16 minutes (27 minutes - 11 minutes) without compressor inflow and 27 minutes (37 minutes - 11 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blown behavior plots in Figs. 3.12, 3.13, and 3.48 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 12 minutes (27 minutes - 15 minutes) without compressor inflow and 22 minutes (37 minutes - 15 minutes) if the compressor inflow is 15 ft/s.

Figures 3.49 and 3.50 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 11 to 15 minutes without exceeding the 2.5 kW/m^2 (800 Btu/hr ft^2) heat flux threshold. Comparisons of time-dependent blown behavior plots in Figs. 3.14, 3.15, and 3.49 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 14 minutes (25 minutes - 11 minutes) without compressor inflow and 22 minutes (33 minutes - 11 minutes) if the compressor inflow is 15 ft/s. Similarly, comparison of time-dependent blown behavior plots in Figs. 3.14, 3.15, and 3.50 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 10 minutes (25 minutes - 15 minutes) without compressor inflow and 18 minutes (33 minutes - 15 minutes) if the compressor inflow is 15 ft/s.

Hypothetical Natural Gas Pipeline Releases in Class 3 Locations with Buildings Intended for Human Occupancy

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in Class 3 Locations 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 natural gas pipelines are defined in Table 3.3. The four case studies compare the following effects on avoided damage costs.

- Case studies 3A and 3B 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 3C and 3D 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 3.14 and 3.15. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines within Class 3 Locations with buildings intended for human occupancy are shown in Figs. 3.51 to 3.54.

Table 3.14. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3A	Case Study 3B
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	24	67
Potentially Minor Damage Radius, ft	77	102	4	6
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	11	15
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 3.14. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy (Cont.)

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3A	Case Study 3B
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% - 5%) * 3 * $1,524,000 = $2,057,400	(50% - 25%) * 3 * $1,524,000 = $1,143,000

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 3.15. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3C	Case Study 3D
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	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building	$1,554,000 per building
Total Moderate Damage Cost	$762,000 per building	$762,000 per building	$762,000 per building	$762,000 per building
Total Minor Damage Cost	$270,000 per building	$270,000 per building	$270,000 per building	$270,000 per building
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	171	476
Potentially Minor Damage Radius, ft	546	719	25	41
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	11	15
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 3.15. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with buildings intended for human occupancy (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3C	Case Study 3D
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% - 5%) * 12 * $1,524,000 = $8,229,600	(50% - 25%) * 12 * $1,524,000 = $4,572,000

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.

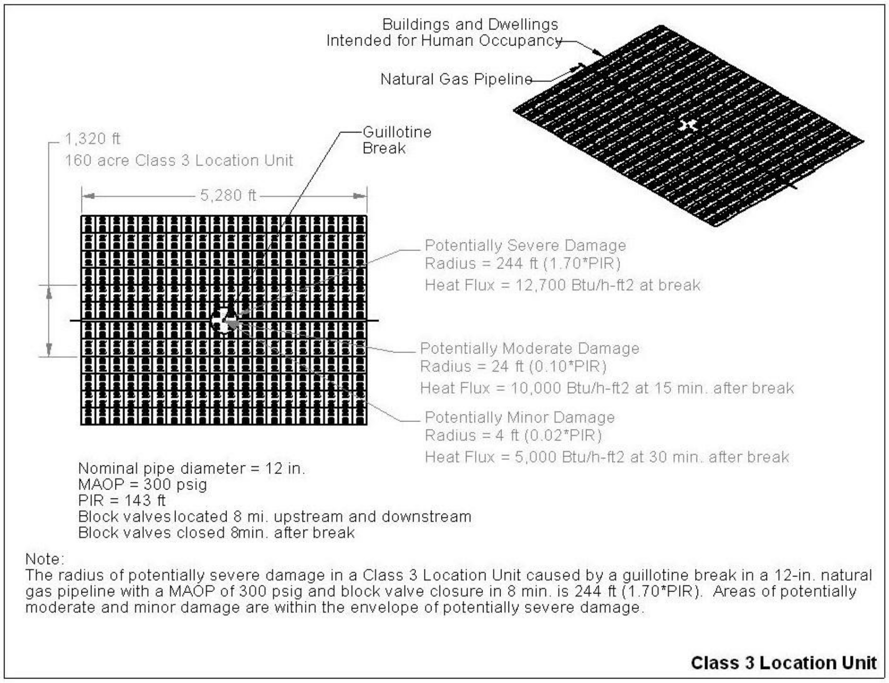


Fig. 3.51. Case Study 3A – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 300 psig MAOP and block valve closure 8 minutes after break.

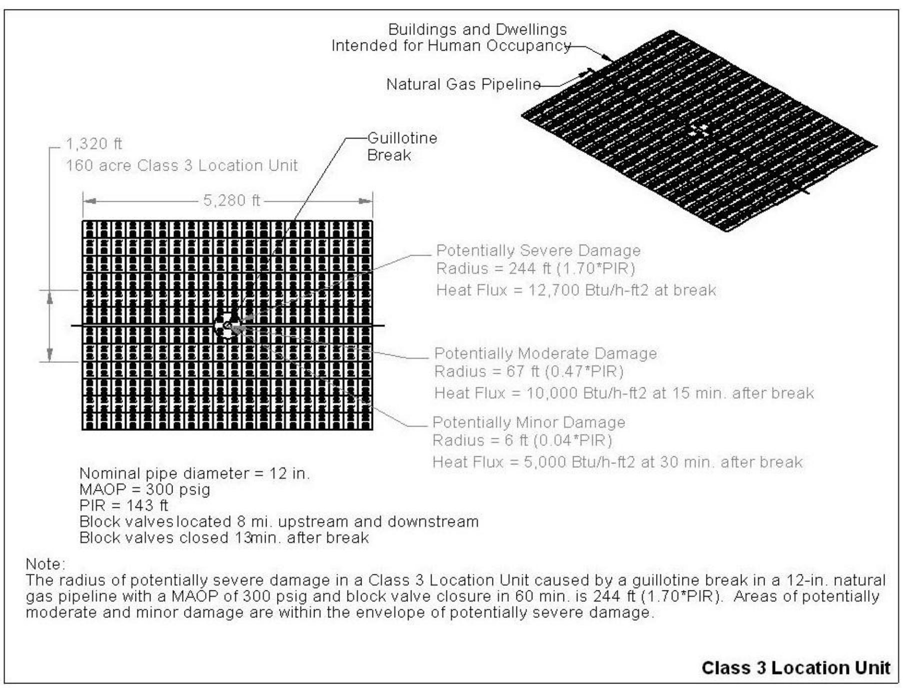


Fig. 3.52. Case Study 3B – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 300 psig MAOP and block valve closure 13 minutes after break.

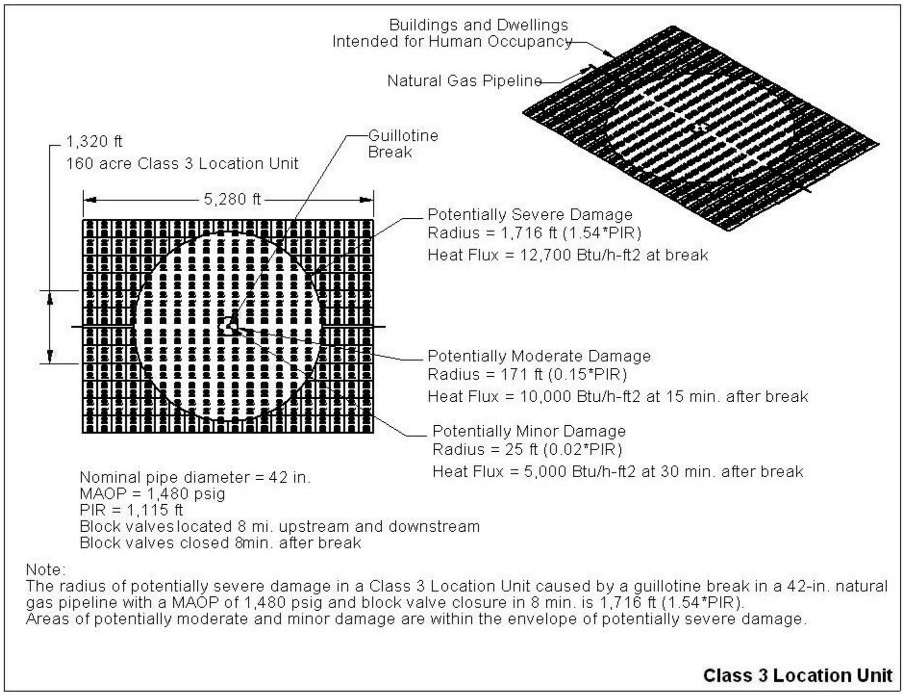


Fig. 3.53. Case Study 3C – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 8 minutes after break.

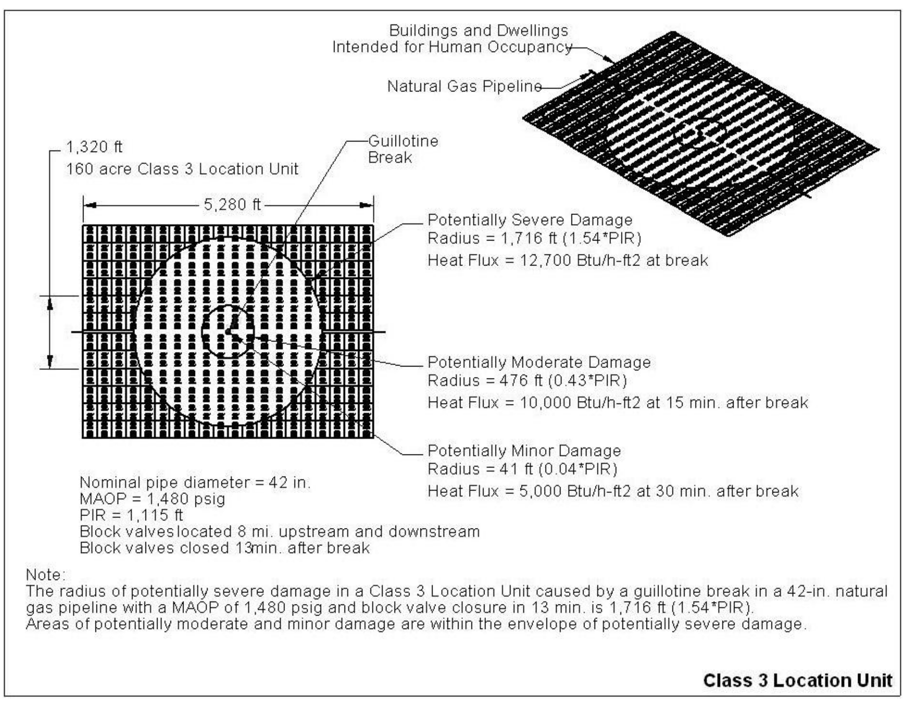


Fig. 3.54. Case Study 3D – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with buildings intended for human occupancy – 1,480 psig MAOP and block valve closure 13 minutes after break.

Hypothetical Natural Gas Pipeline Releases in Class 3 Locations with an Outside Recreational Facility

Four case studies involving 12-in. and 42-in. nominal diameter hypothetical natural gas pipelines in Class 3 Locations are considered to assess effects of valve closure time on fire damage to outside recreational facilities. 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 3E and 3F 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 3G and 3H 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 3.16 and 3.17. Areas with potentially severe, moderate, and minor damage for the hypothetical natural gas pipelines within Class 3 Locations with outside recreational facilities are shown in Figs. 3.55 to 3.58.

Table 3.16. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3E	Case Study 3F
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	$100,000 + $2,380,000 per acre	$100,000 + $2,380,000 per acre	$100,000 + $2,380,000 per acre	$100,000 + $2,380,000 per acre
Total Moderate Damage Cost	$100,000 + $700,000 per acre	$100,000 + $700,000 per acre	$100,000 + $700,000 per acre	$100,000 + $700,000 per acre
Total Minor Damage Cost	$50,000	$50,000	$50,000	$50,000
Potentially Severe Damage Radius, ft	244	247	244	244
Potentially Moderate Damage Radius, ft	112	122	24	67
Potentially Minor Damage Radius, ft	77	102	4	6
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	27	37	11	15
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 3.16. Avoided damage costs for hypothetical 12-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities (Cont.)

Characteristic	12-in. Baseline-0, compressor inflow = 0 ft/s	12-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3E	Case Study 3F
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% - 5%) * 3 * $595,000 = $803,250	(50% - 25%) * 3 * $595,000 = $446,250

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 3.17. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3G	Case Study 3H
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	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre	$500,000 + $2,380,000 per acre
Total Moderate Damage Cost	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre	$500,000 + $700,000 per acre
Total Minor Damage Cost	$250,000	$250,000	$250,000	$250,000
Potentially Severe Damage Radius, ft	1,716	1,740	1,716	1,716
Potentially Moderate Damage Radius, ft	792	858	171	476
Potentially Minor Damage Radius, ft	546	719	25	41
Initiate Fire Fighting Activities at 1.5 times PIR, minutes after break	25	33	11	15
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 3.17. Avoided damage costs for hypothetical 42-in. natural gas pipeline releases in Class 3 Locations with outside recreational facilities (Cont.)

Characteristic	42-in. Baseline-0, compressor inflow = 0 ft/s	42-in. Baseline-15, compressor inflow = 15 ft/s	Case Study 3G	Case Study 3H
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% - 5%) * 12 * $595,000 = $3,213,000	(50% - 25%) * 12 * $595,000 = $1,785,000

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.

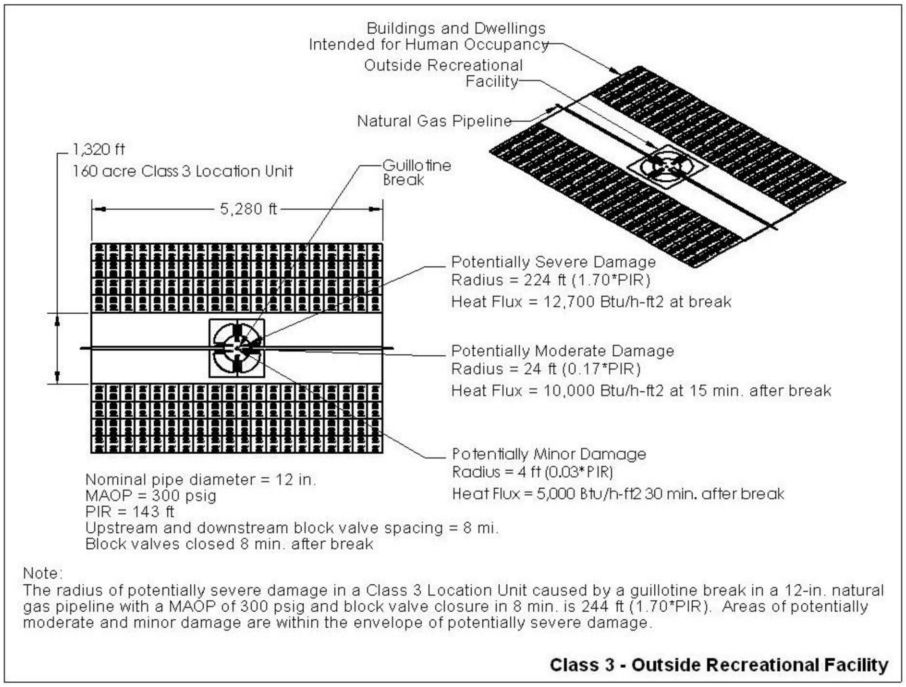


Fig. 3.55. Case Study 3E – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 300 psig MAOP and block valve closure 8 minutes after break.

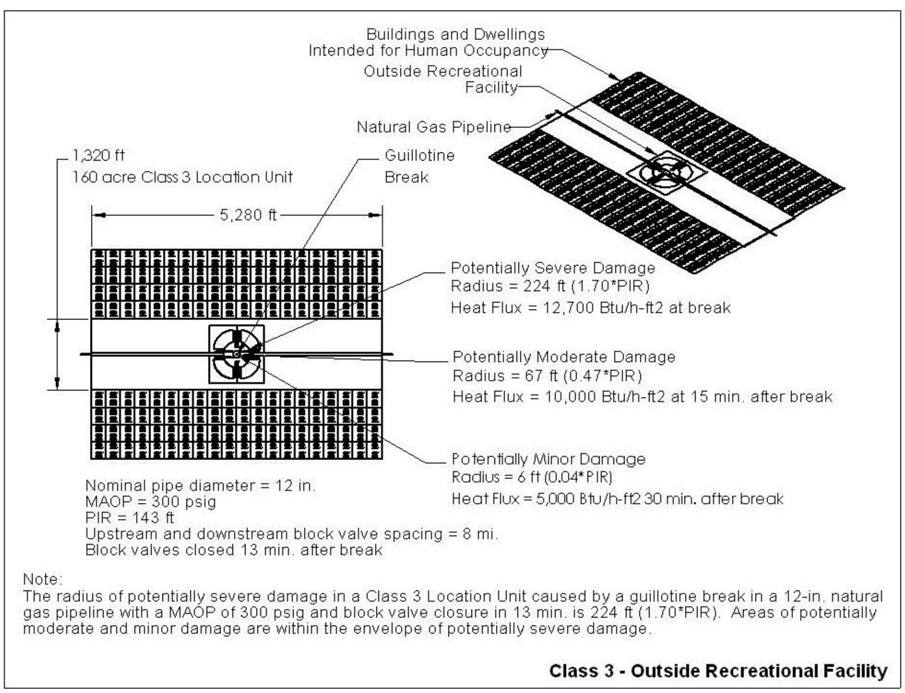


Fig. 3.56. Case Study 3F – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 300 psig MAOP and block valve closure 13 minutes after break.

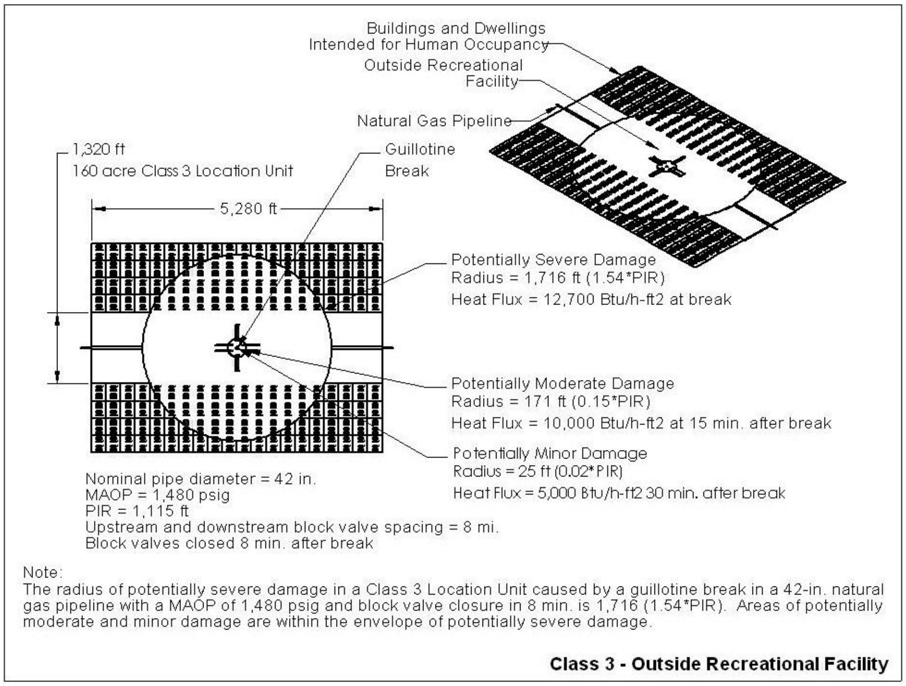


Fig. 3.57. Case Study 3G – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 1,480 psig MAOP and block valve closure 8 minutes after break.

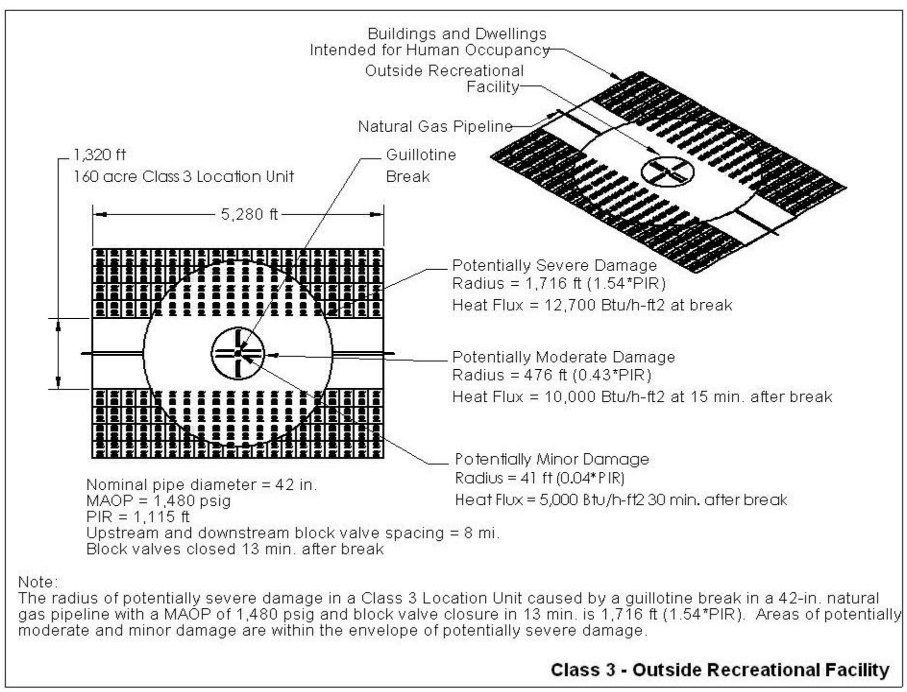


Fig. 3.58. Case Study 3H – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in Class 3 Location with an outside recreational facility – 1,480 psig MAOP and block valve closure 13 minutes after break.

Damage Resulting from Hypothetical Natural Gas Pipeline Releases in Class 3 Locations

Fire damage to buildings and personal property in Class 3 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 3 Locations

Without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in Class 3 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 3 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 $2,057,400 for 12-in. nominal diameter natural gas pipelines and $8,229,600 for 42-in. nominal diameter natural gas pipelines with buildings intended for human occupancy. Similarly, block valve closure within 8 minutes after the break can result in a potential cost avoidance of at least $803,250 for 12-in. nominal diameter natural gas pipelines and $3,213,000 for 42-in. nominal diameter natural gas pipelines with outside recreational facilities. Delaying block valve closure by an additional 5 minutes reduces the cost avoidance by approximately 50%.

3.1.4.4 Hypothetical Natural Gas Pipeline Releases in Class 4 Locations

According to the definition of a Class 4 Location in 49 CFR 192.5, a Class 4 Location is any class location unit where buildings with four or more stories above ground are prevalent. Based on the definition of HCA in 49 CFR 192.903, all Class 4 Locations are classified as HCAs.

For this study, the effects of valve closure time on fire damage resulting from a natural gas pipeline release in a Class 4 Location were considered for hypothetical natural gas pipeline releases that effect areas with buildings with four or more stories above ground as described in Section 3.1.3.2 and shown in Fig. 3.10.

Separation distance versus time plots for 12-in. and 42-in. natural gas pipelines in Class 4 Locations are shown in Figs. 3.59, 3.60, 3.61, and 3.62. These plots compare the effects of block valve closure swiftness on time-dependent blowdown behavior. Figures 3.59 and 3.61 are plots of blowdown behavior for block valve closure 8 minutes after the break (i.e. 5 minutes to detect the leak plus 3 minutes to close the valve). Figures 3.60 and 3.62 are plots of blowdown behavior for the same pipeline segments with block valve closure 13 minutes after the break (i.e. 10 minutes to detect the leak plus 3 minutes to close the valve).

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.

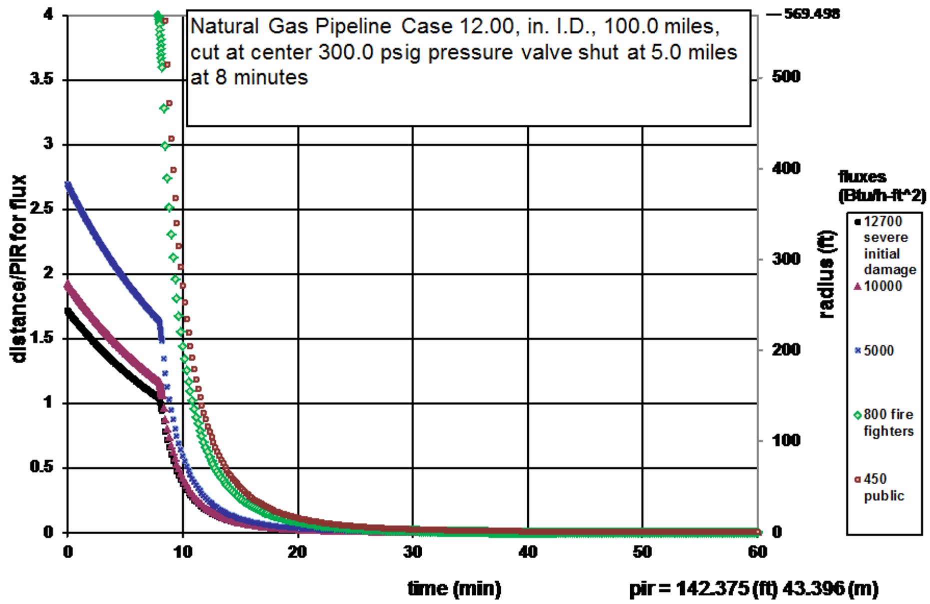


Fig. 3.59. Separation distances for 12-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 300 psig with block valve closure 8 minutes after break.

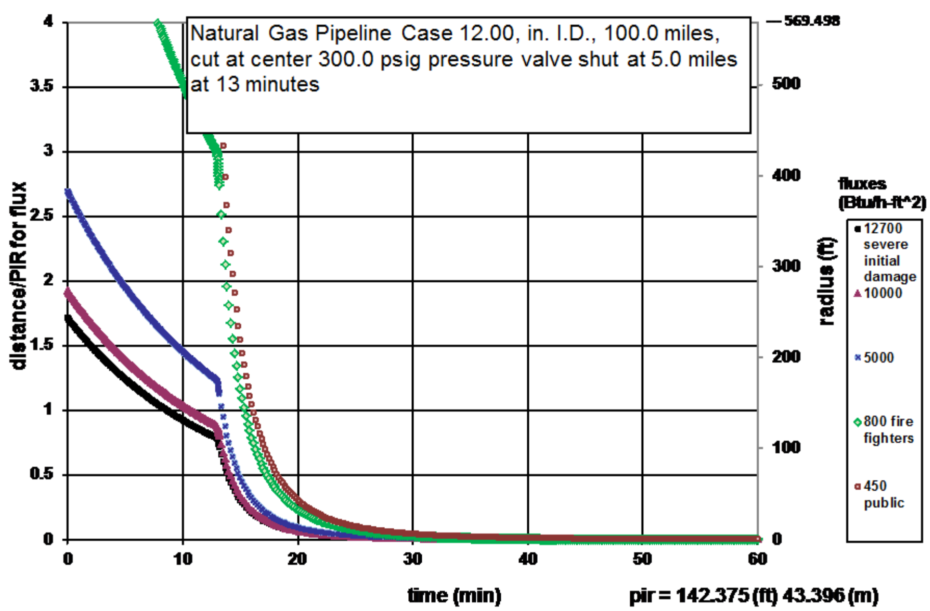


Fig. 3.60. Separation distances for 12-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 300 psig with block valve closure 13 minutes after break.

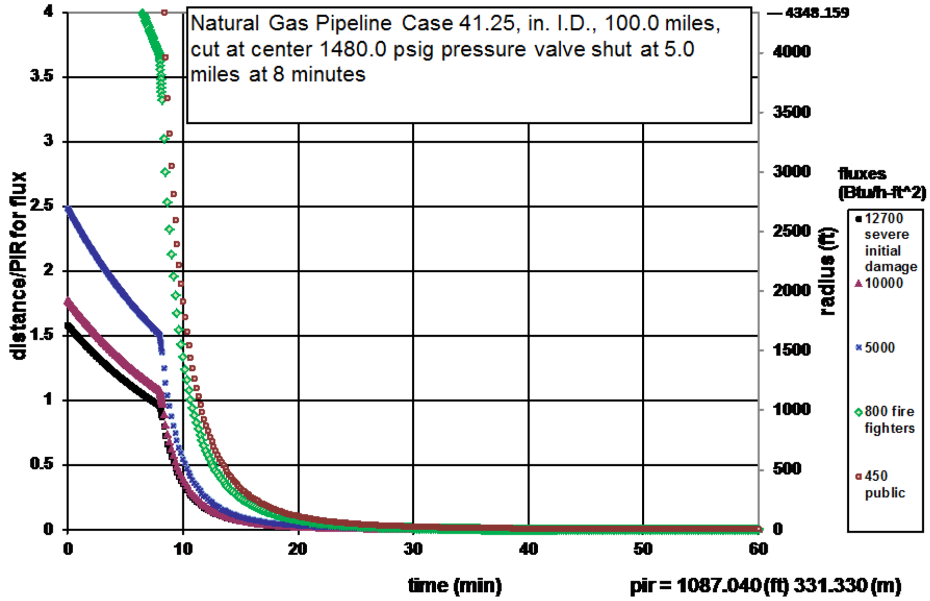


Fig. 3.61. Separation distances for 42-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 1,480 psig with block valve closure 8 minutes after break.

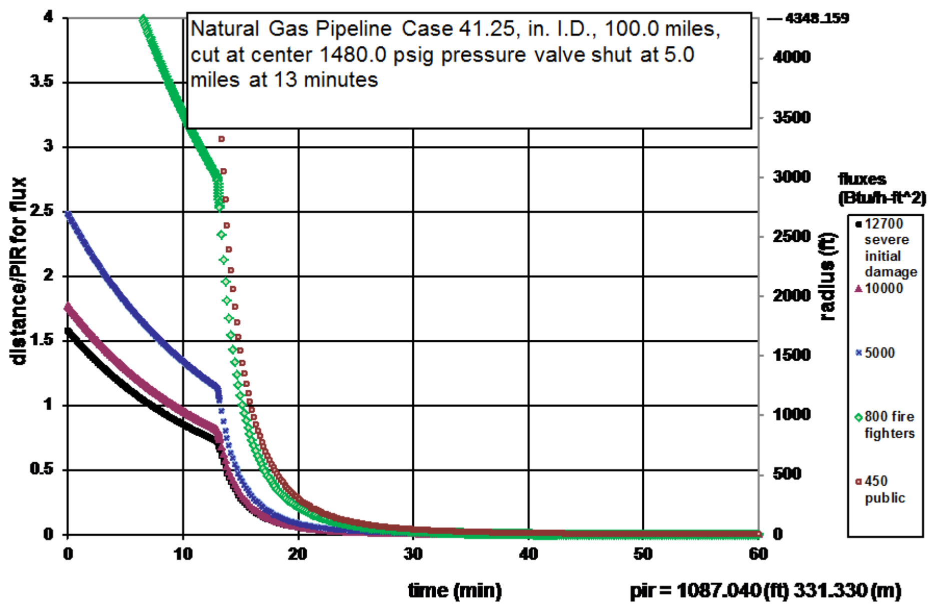


Fig. 3.62. Separation distances for 42-in. natural gas pipeline in a Class 4 Location operating at a MAOP of 1,480 psig with block valve closure 13 minutes after break.

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.

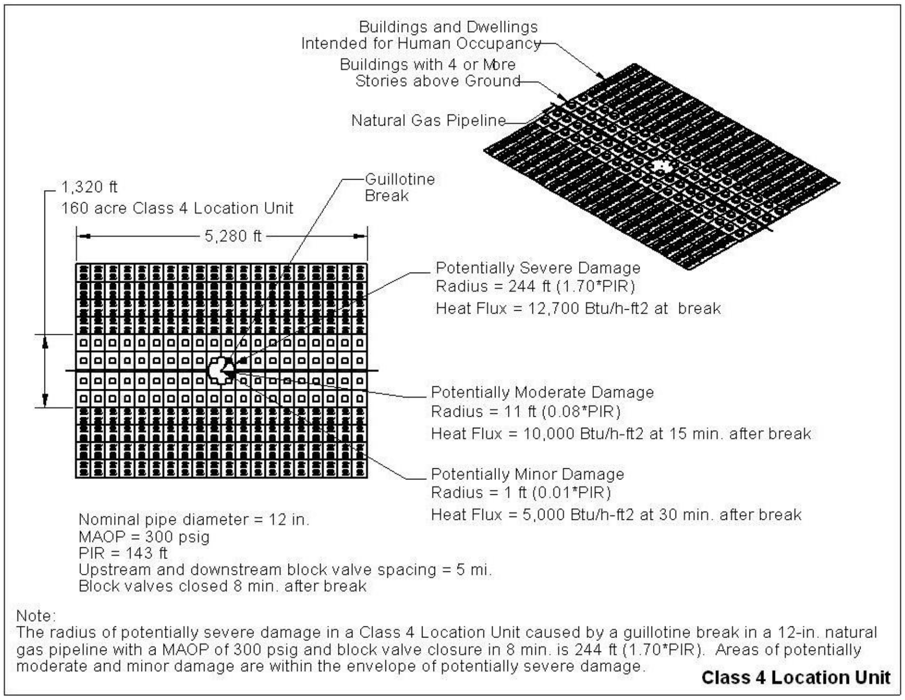


Fig. 3.63. Case Study 4A – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 300 psig MAOP and block valve closure 8 minutes after break.

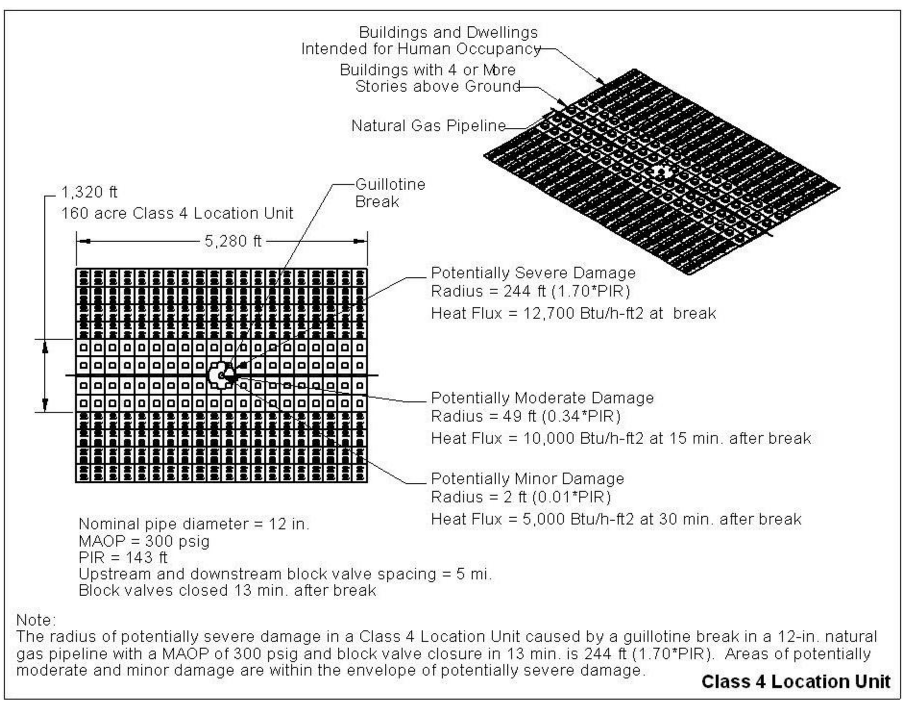


Fig. 3.64. Case Study 4B – areas affected by 12-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 300 psig MAOP and block valve closure 13 minutes after break.

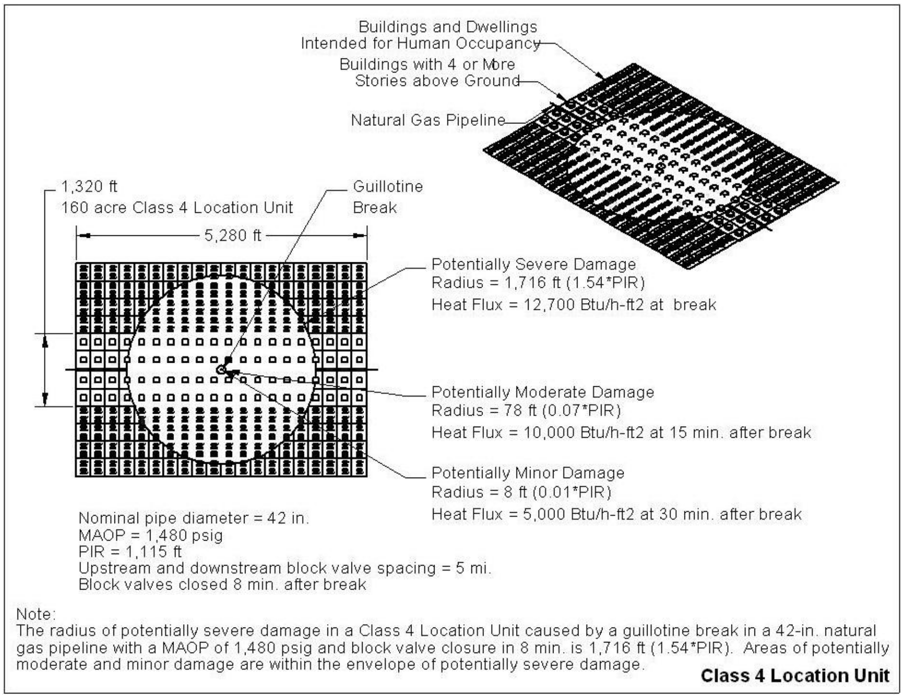


Fig. 3.65. Case Study 4C – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 1,480 psig MAOP and block valve closure 8 minutes after break.

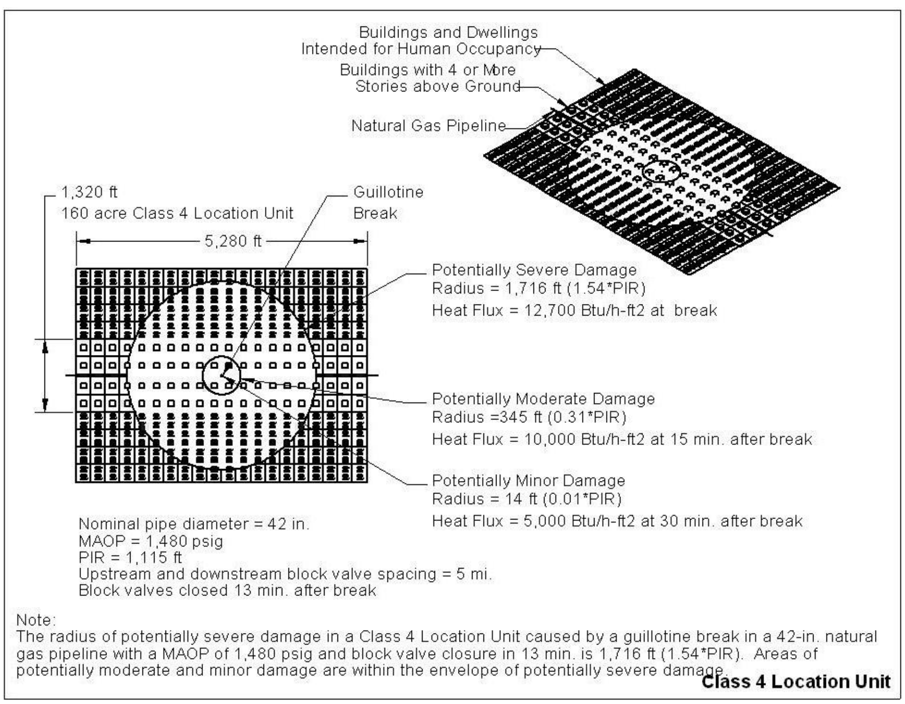


Fig. 3.66. Case Study 4D – areas affected by 42-in. nominal diameter hypothetical natural gas pipeline release in a Class 4 Location with four or more stories above ground – 1,480 psig MAOP and block valve closure 13 minutes after break.

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.

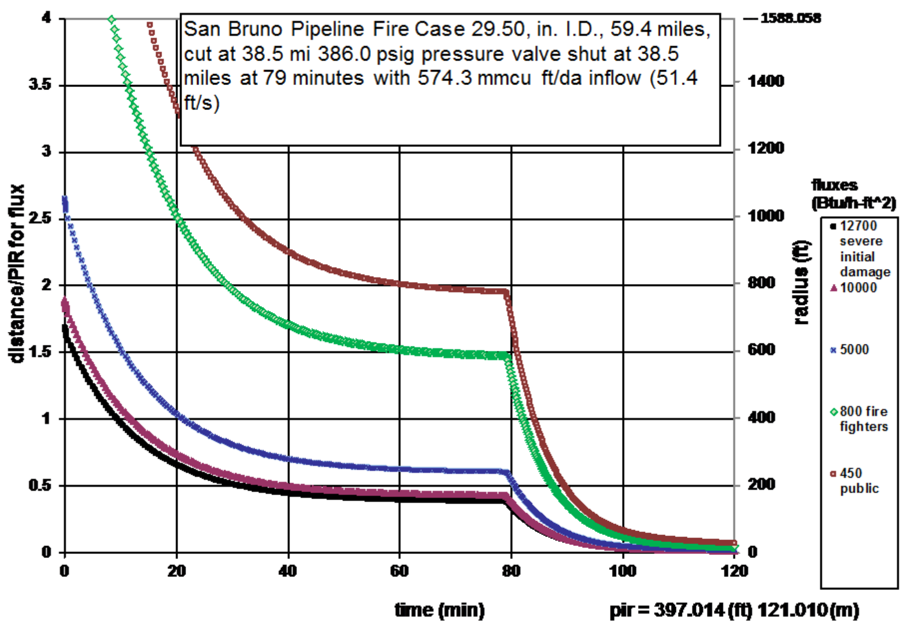


Fig. 3.67. Separation distance versus time plot for the San Bruno natural gas pipeline release –59.4 to 38.5 mi. segment.

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).

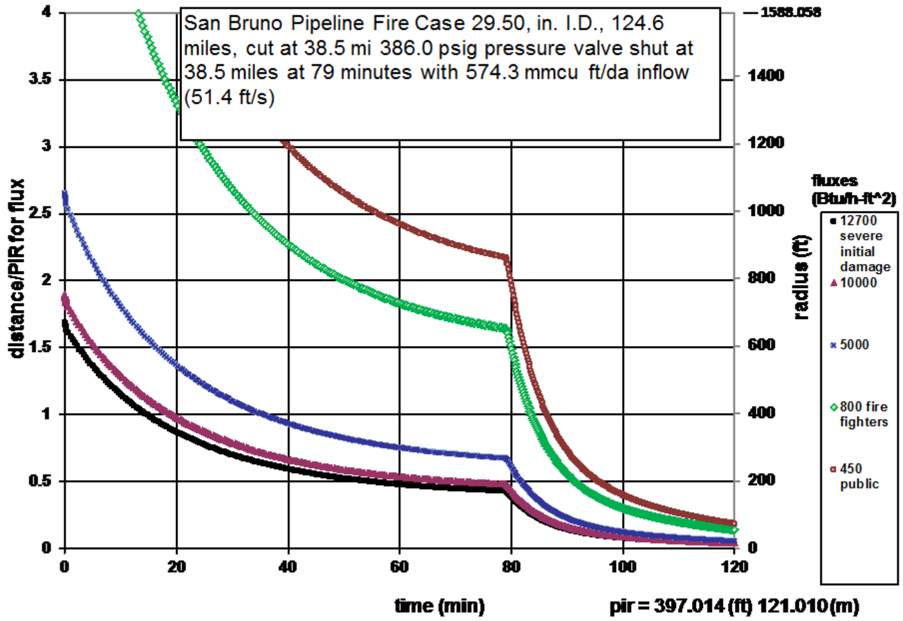


Fig. 3.68. Separation distance versus time plot for the San Bruno natural gas pipeline release –124.6 to 38.5 mi. segment.

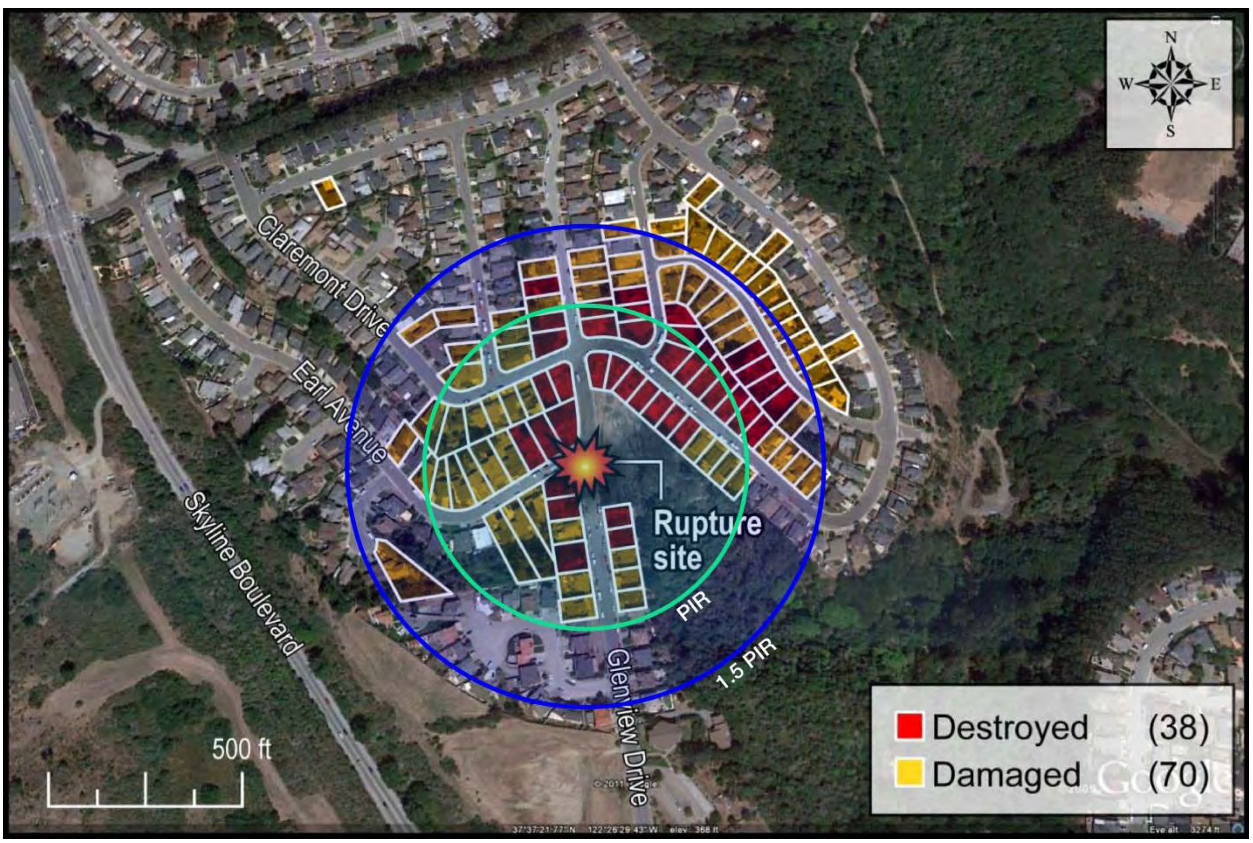


Fig. 3.69. Aerial view of the September 9, 2010 San Bruno natural gas pipeline release showing residential properties damaged and destroyed.

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.

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

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.

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

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.

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

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,

$$g' = g(1 - \rho_l / \rho_w) \tag{3.27}$$

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.

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

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

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

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.

<u>Hypothetical Liquid Propane Pipeline Releases in HCA with Buildings Intended for Human Occupancy</u>

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

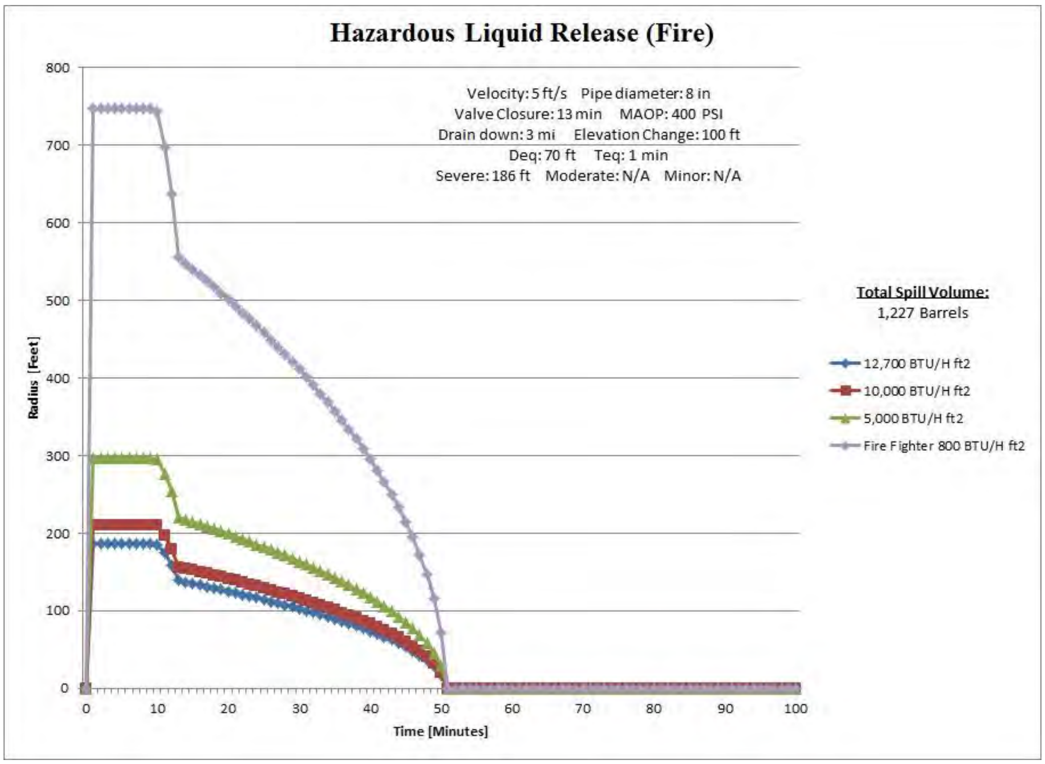


Fig. 3.70. Case Study 5A – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 13 minutes.

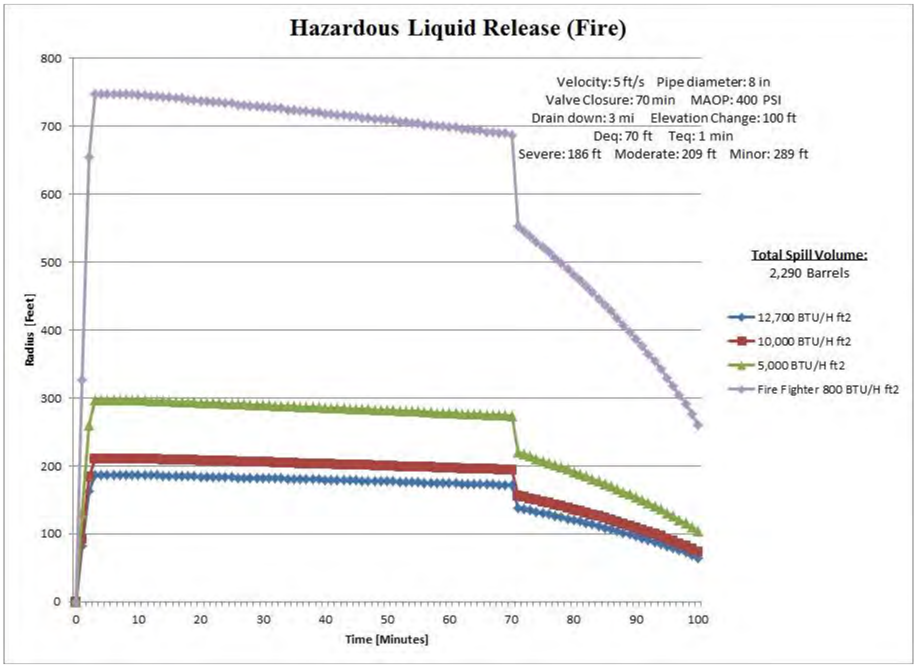


Fig. 3.71. Case Study 5B – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 70 minutes.

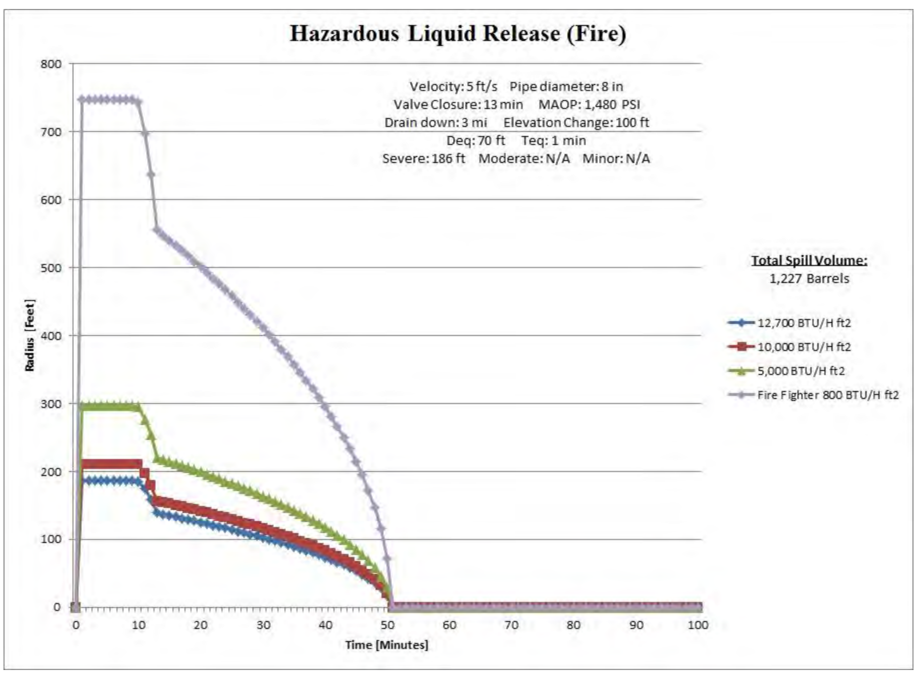


Fig. 3.72. Case Study 5C – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 13 minutes.

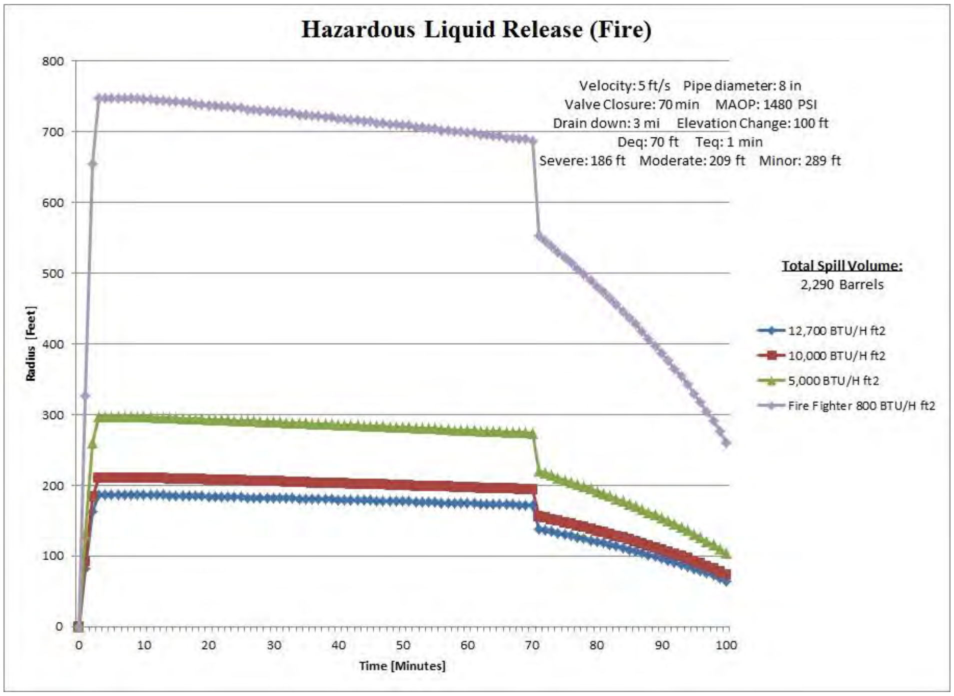


Fig. 3.73. Case Study 5D – Separation distance for 8-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 100 ft, drain down length = 3 mi., valve closure time = 70 minutes.

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

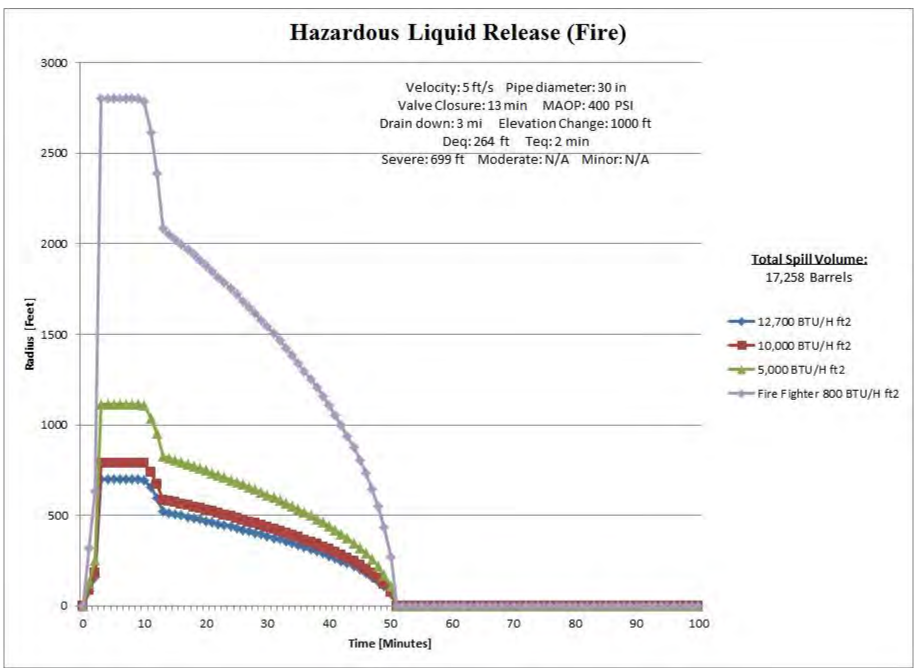


Fig. 3.74. Case Study 6A – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 13 minutes.

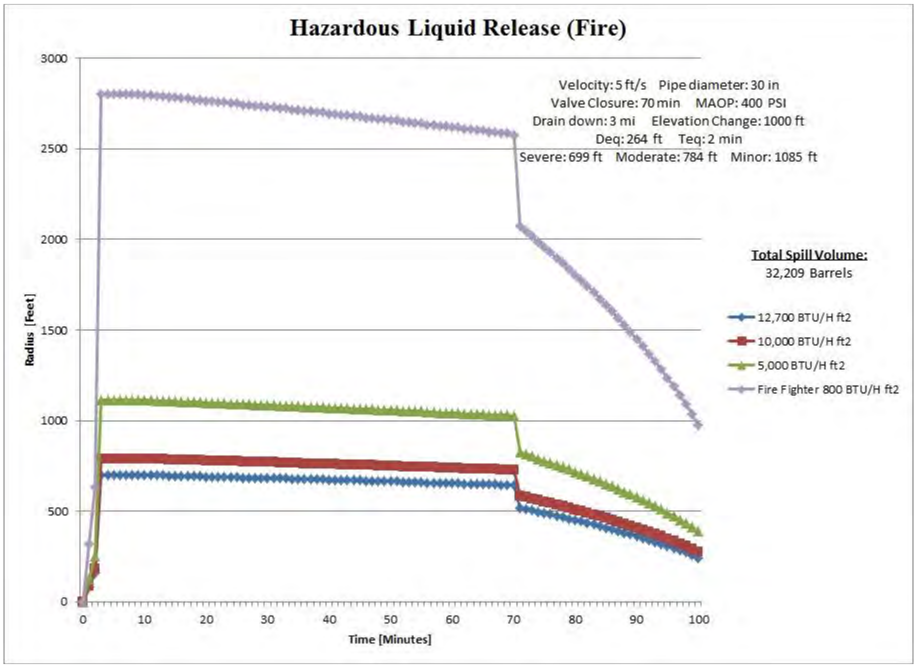


Fig. 3.75. Case Study 6B – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 400 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 70 minutes.

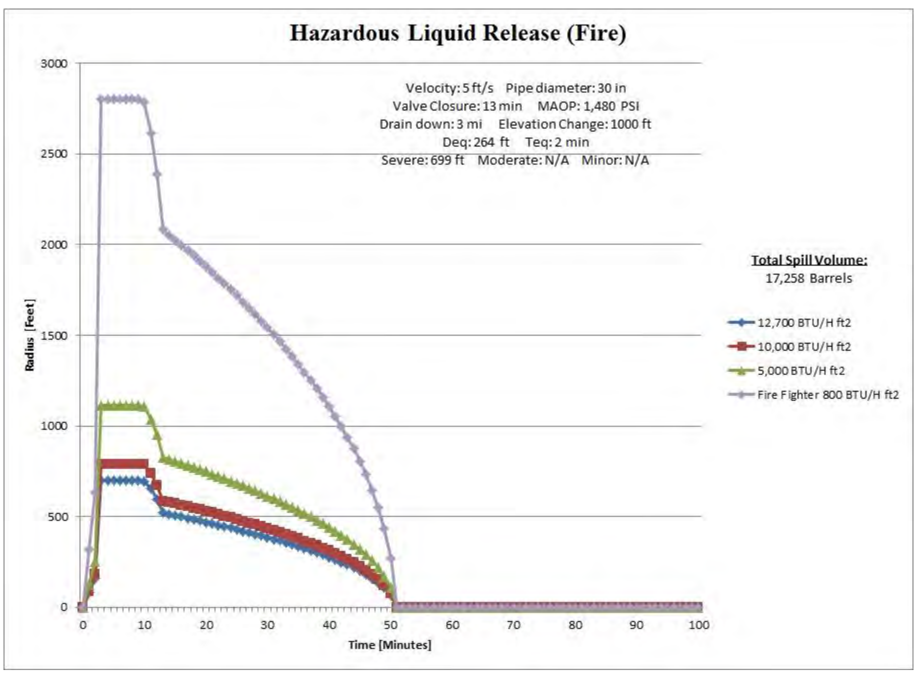


Fig. 3.76. Case Study 6C – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 13 minutes.

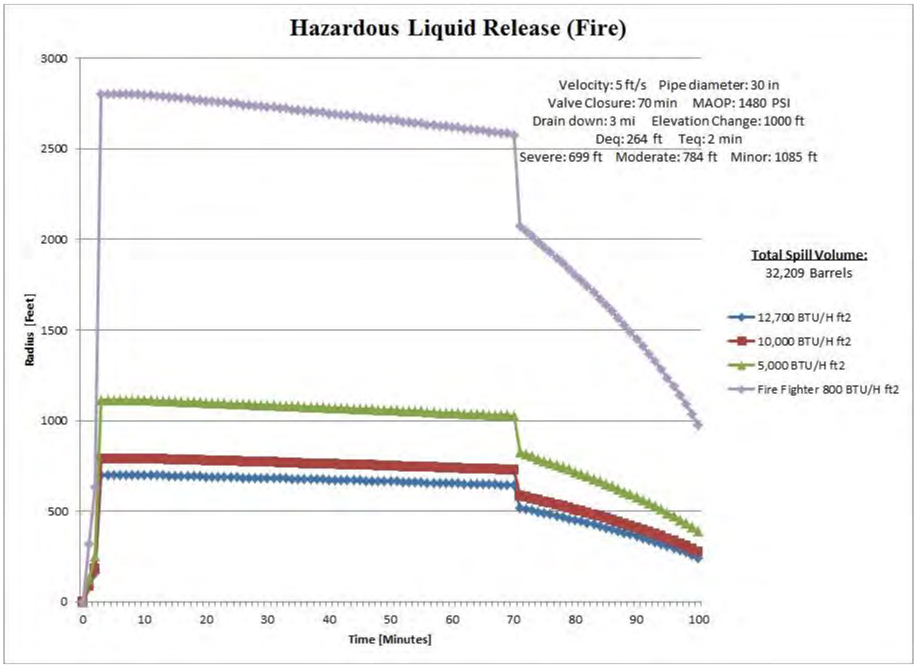


Fig. 3.77. Case Study 6D – Separation distance for 30-in. nominal diameter hazardous liquid pipeline release – velocity = 5 ft/s, MAOP = 1,480 psig, elevation change = 1,000 ft, drain down length = 3 mi., valve closure time = 70 minutes.

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.

$$z_1 + \frac{\mathrm{v}_1^2}{2g} + P_1 v_1 \frac{g_c}{g} = z_2 + \frac{\mathrm{v}_2^2}{2g} + P_2 v_2 \frac{g_c}{g} \tag{3.30}$$

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,
- ν 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.

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

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).

<u>Total Damage Cost Validation</u>

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

<u>Case Study 1 – Enbridge 2010</u>

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

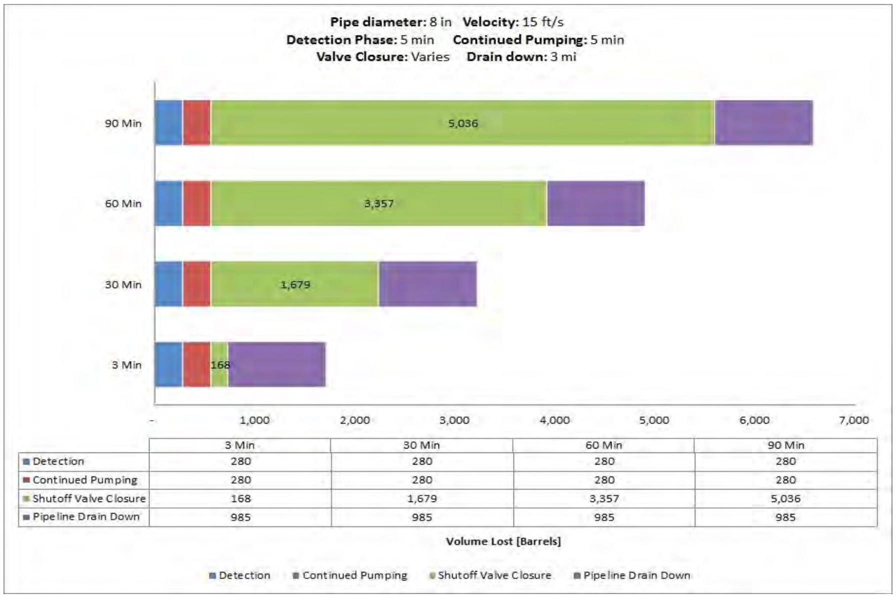
Characteristic	Case Study 7A		Case Study 7B		Case Study 7C		Case Study 7D	
Type Hazardous Liquid	Crude Oil		Crude Oil		Crude Oil		Crude Oil	
Flow Velocity, ft/s	15		15		15		15	
Nominal Line Pipe Diameter, in.	8		8		8		8	
Drain Down Length, mi.	3		3		3		3	
MAOP, psig	400		1,480		400		1,480	
Elevation 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

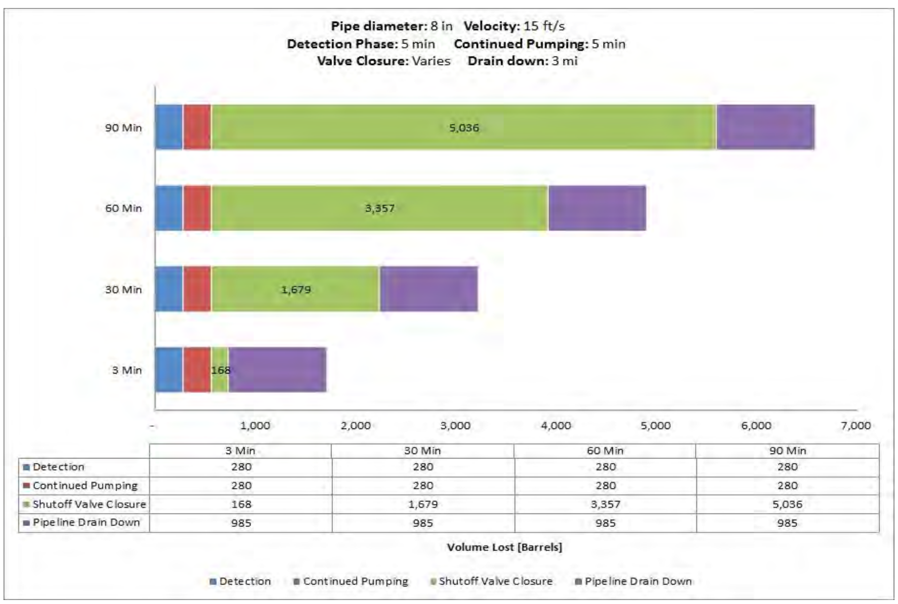
Notes: *See Tables 3.25 and Table 3.27. The avoided cost resulting from reducing the block valve closure phase is significantly more than the cost for converting a manually operated block valve to either a RCV or ASV for hazardous liquid pipelines with 8-in. nominal diameters.

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.



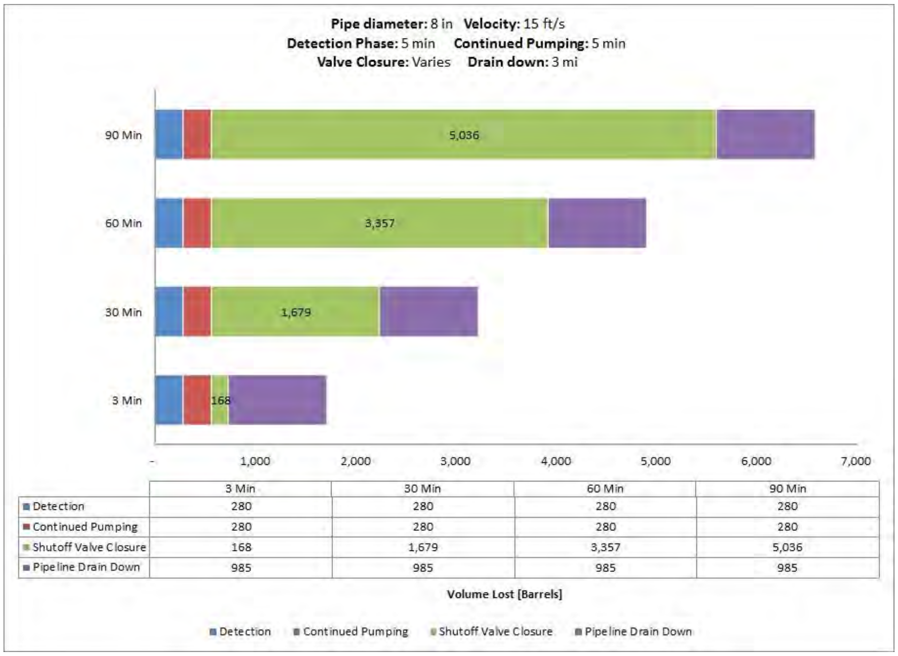
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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.

<u>Benefits of Block Valve Closure Swiftness for a Hypothetical Hazardous Liquid Pipeline Releases without Ignition</u>

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.

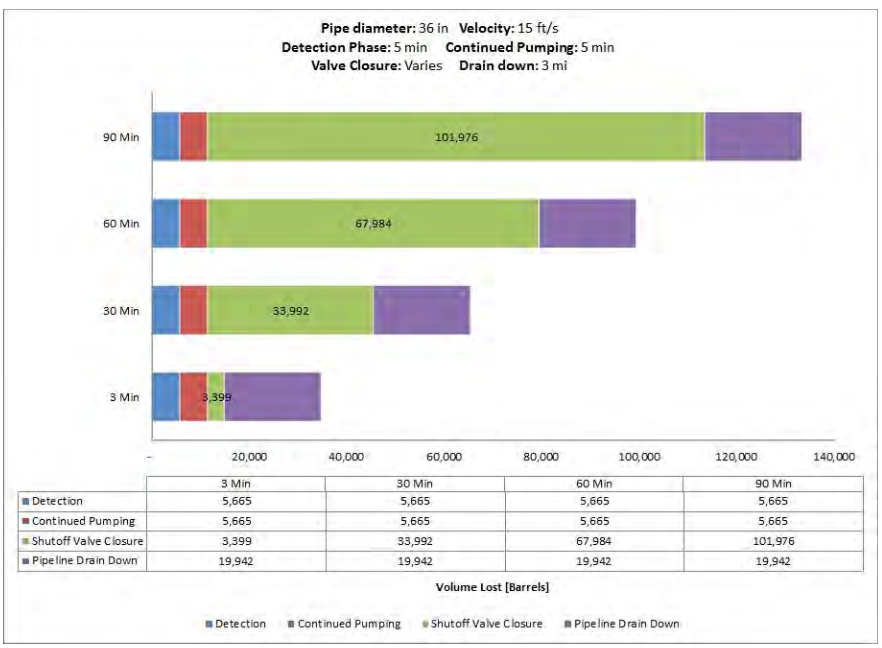


Fig. 3.82. Case Study 8A – Discharge volumes for a 36-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

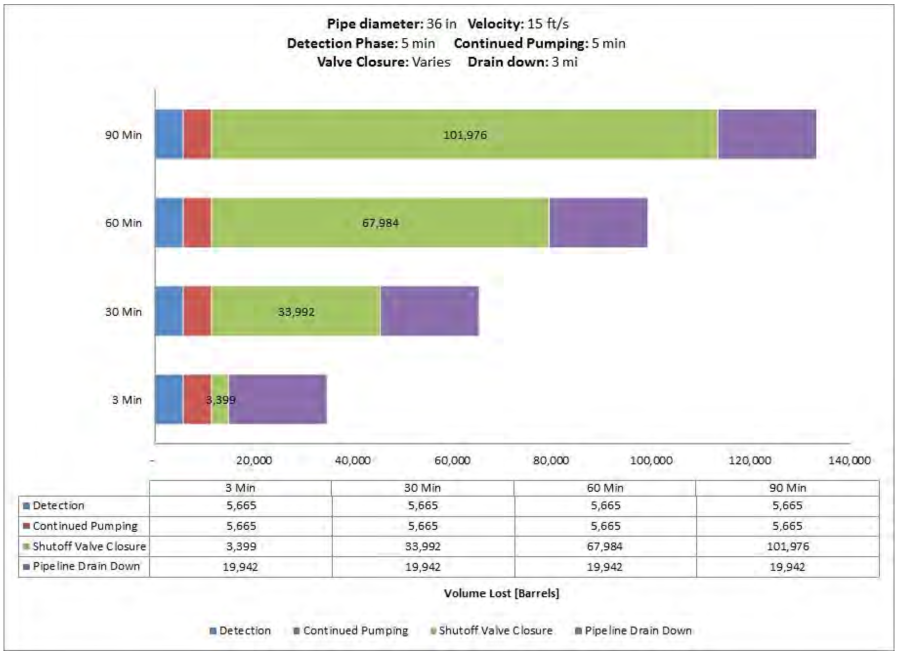


Fig. 3.83. Case Study 8B – Discharge volumes for a 36-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 100 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

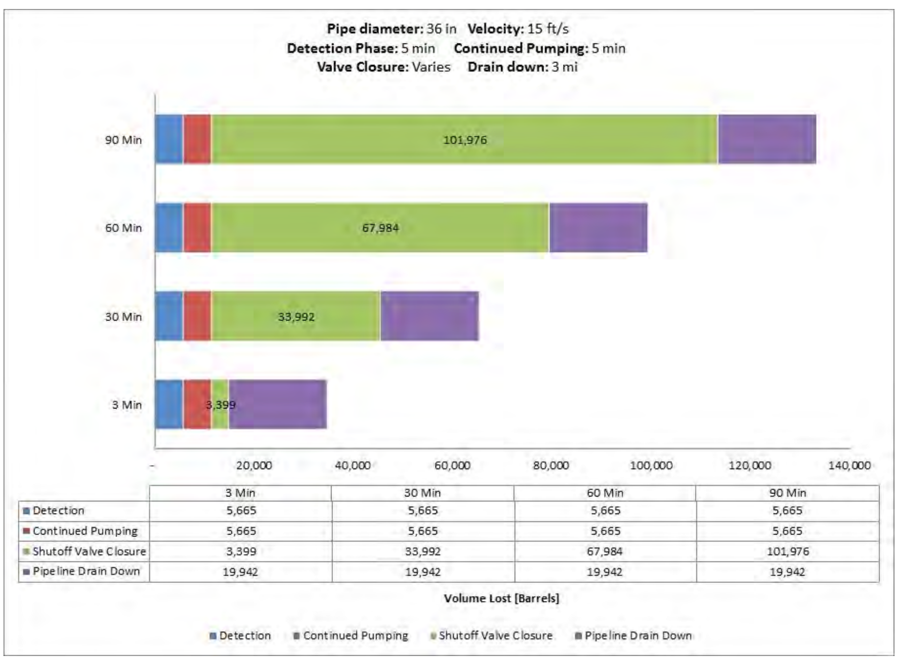


Fig. 3.84. Case Study 8C – Discharge volumes for a 36-in. hazardous liquid pipeline with a 400 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

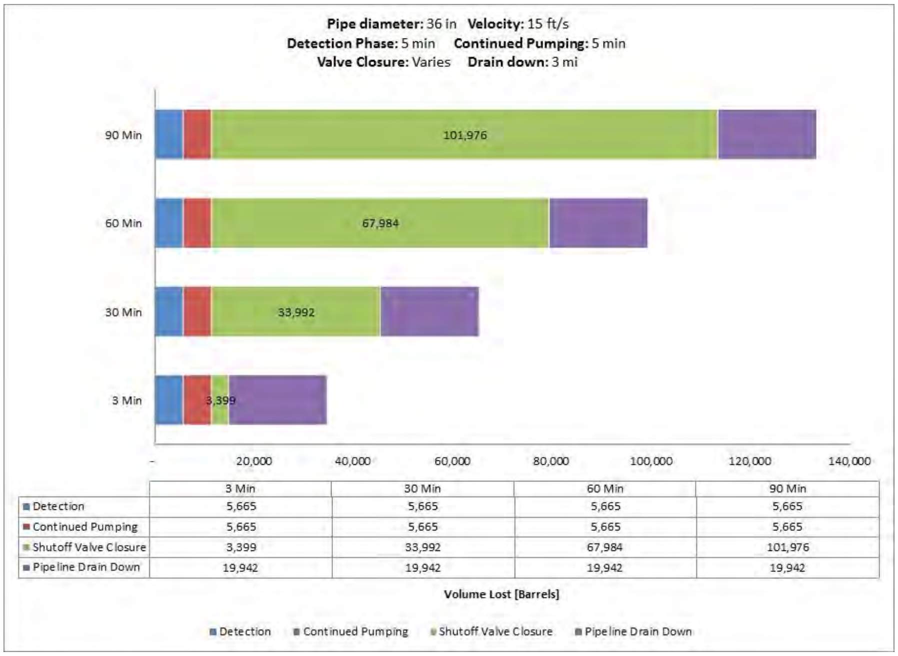


Fig. 3.85. Case Study 8D – Discharge volumes for a 36-in. hazardous liquid pipeline with a 1,480 psig MAOP and an elevation change of 1,000 ft with a 3, 30, 60, and 90 minutes block valve closure phase.

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

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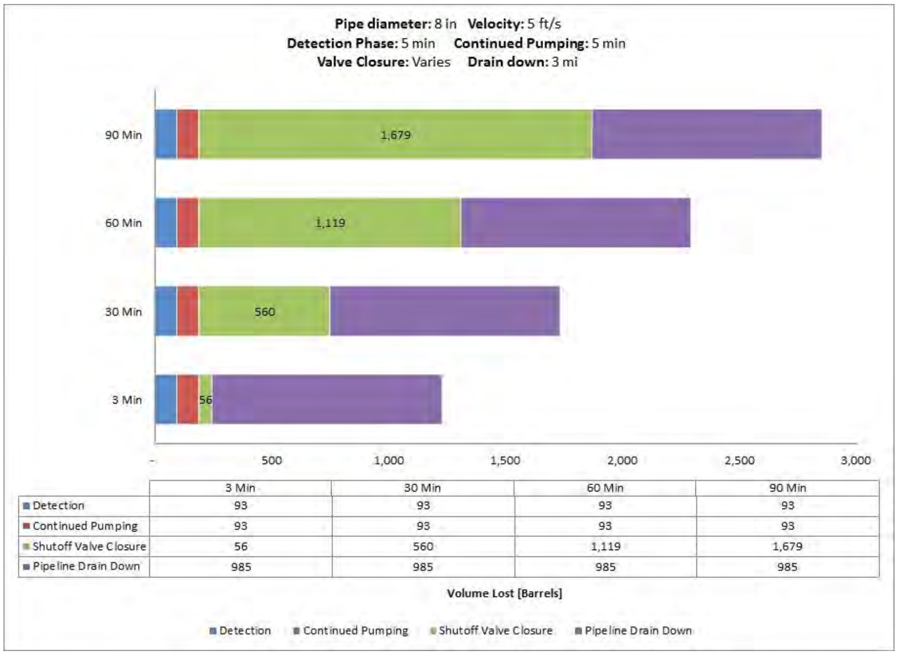
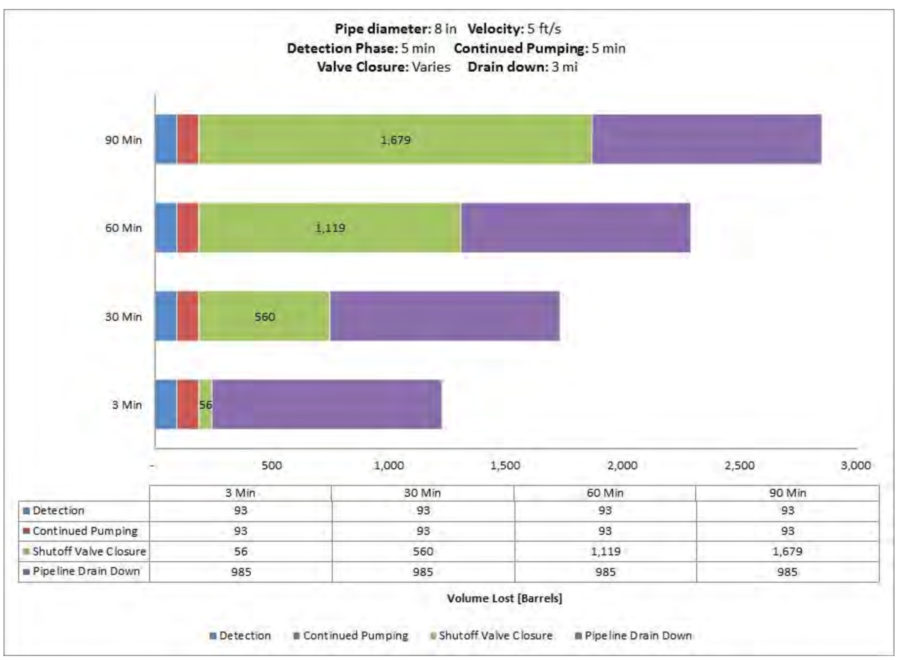
APPENDIX A: SPILL VOLUME RELEASED DUE TO VALVE CLOSURE TIMES IN LIQUID PROPANE PIPELINES

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



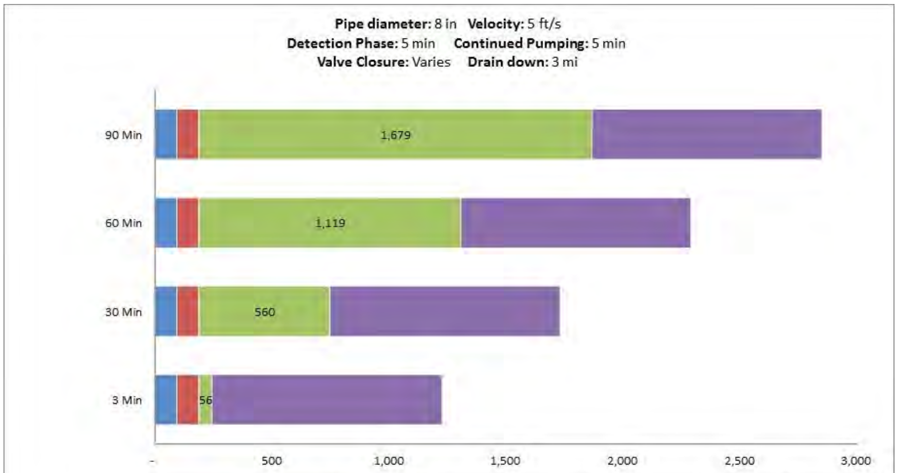
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

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.

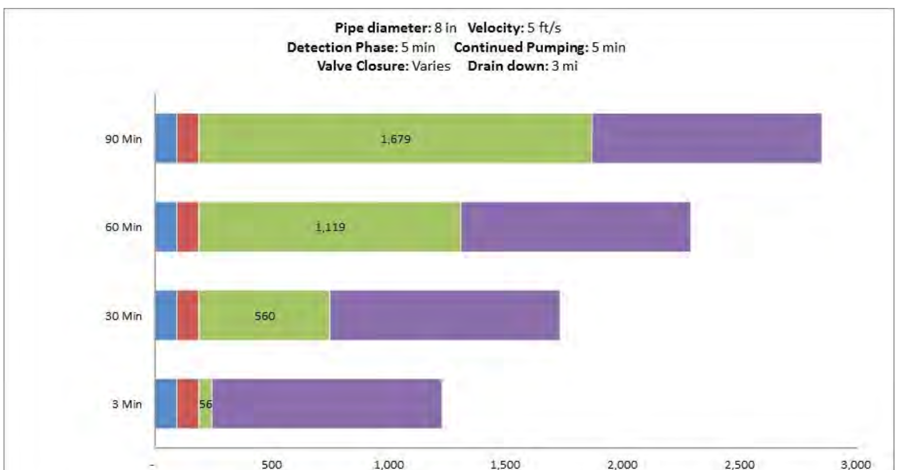


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

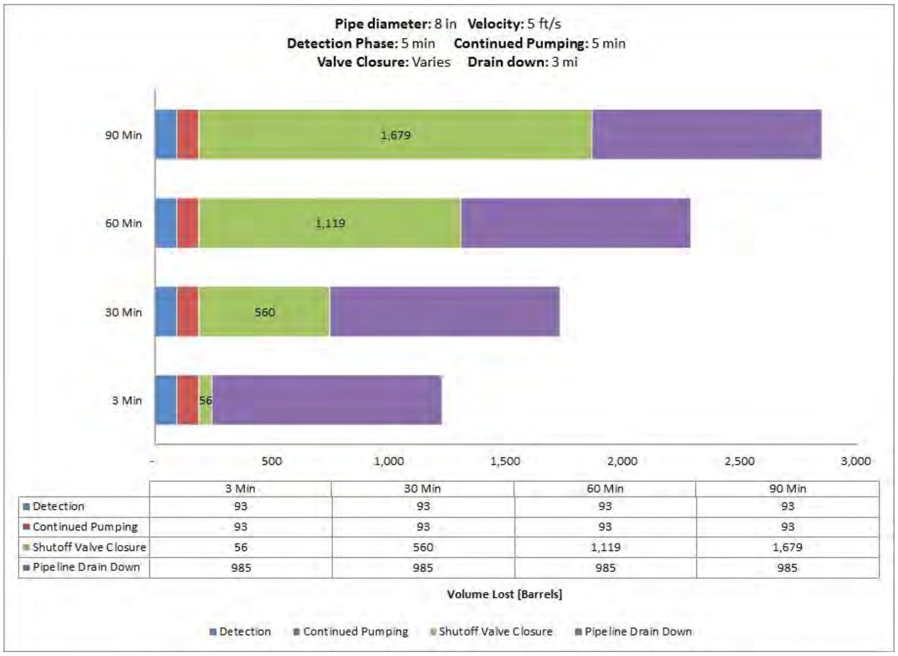


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

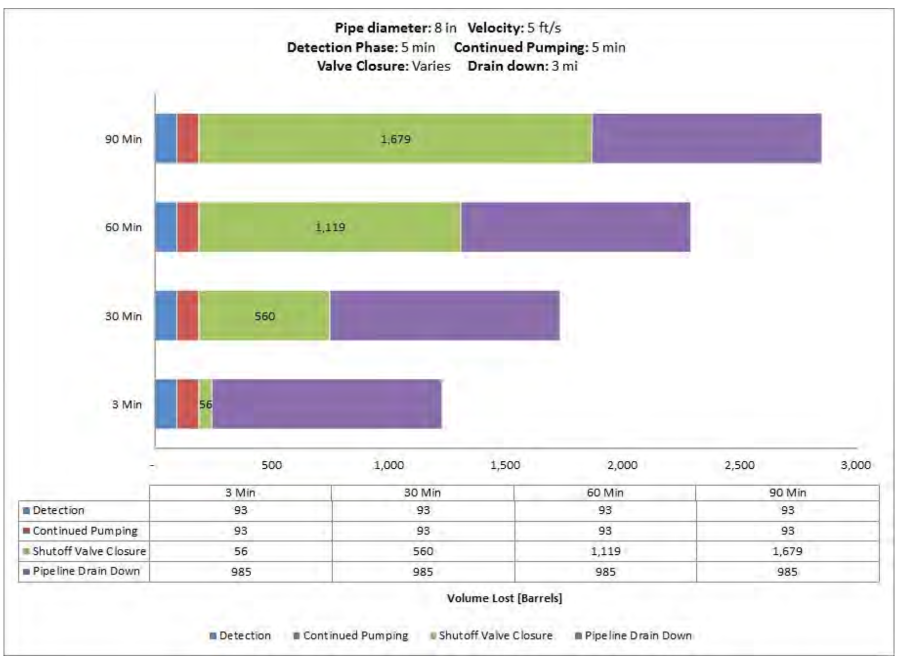
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



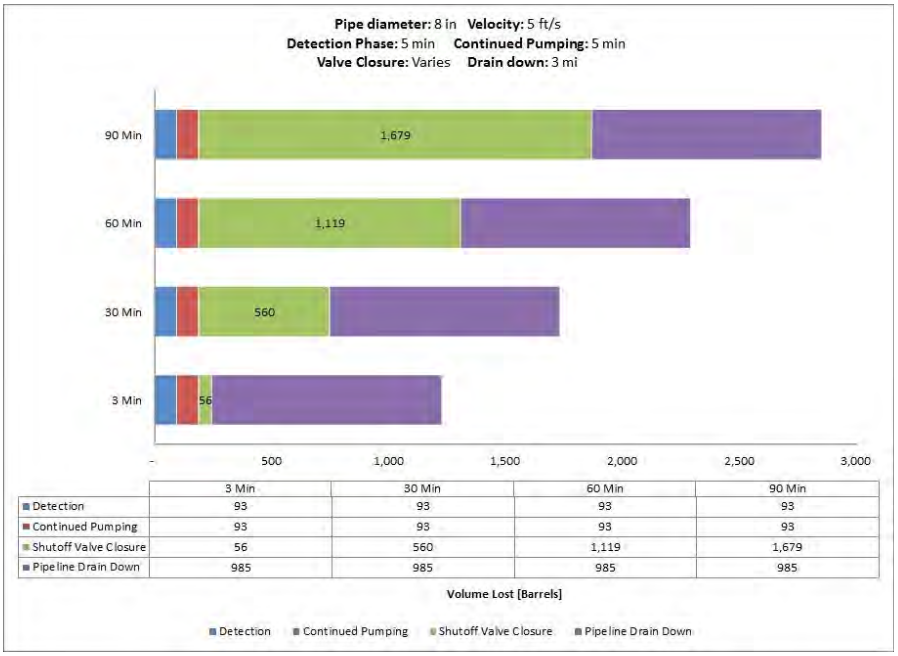
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

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



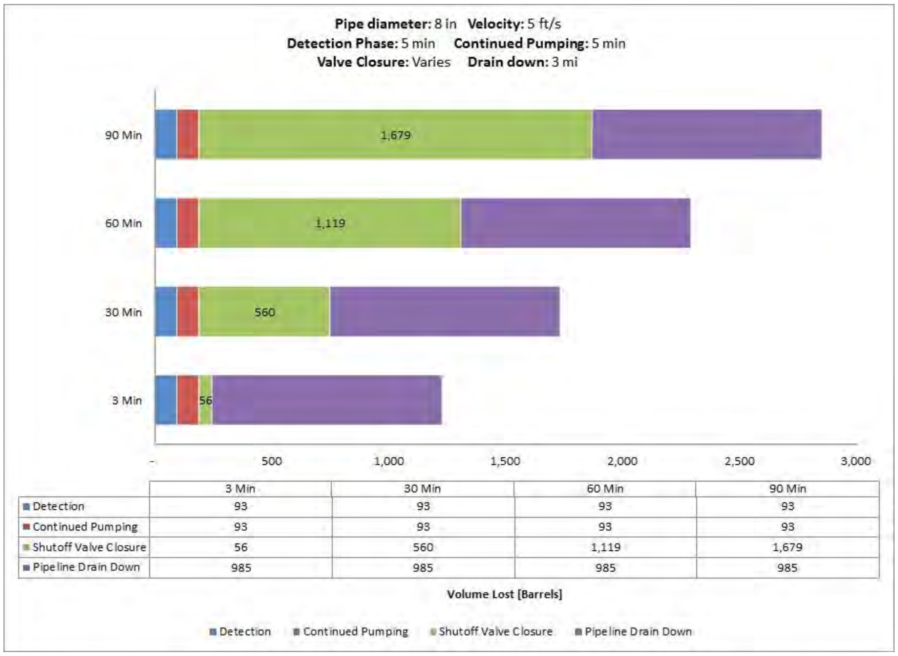
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

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



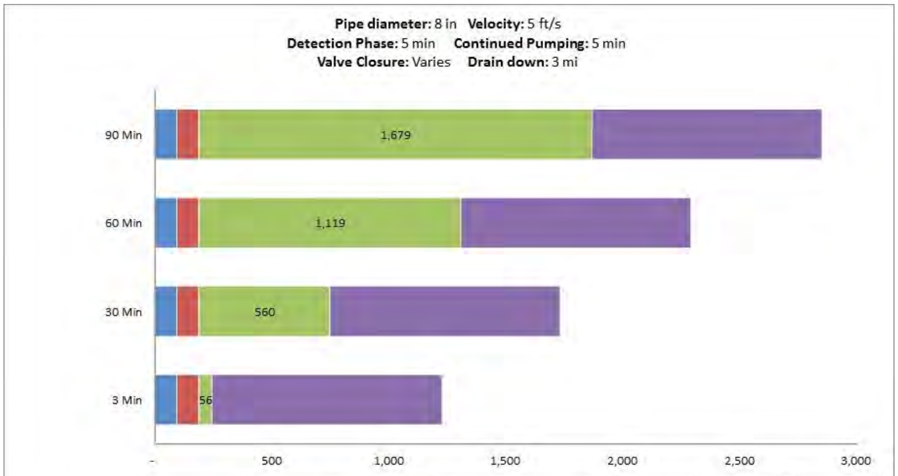
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Fig. A-7.8 Inch Pipe Diameter, 5 ft/s, 1200 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-8.8 Inch Pipe Diameter, 5 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

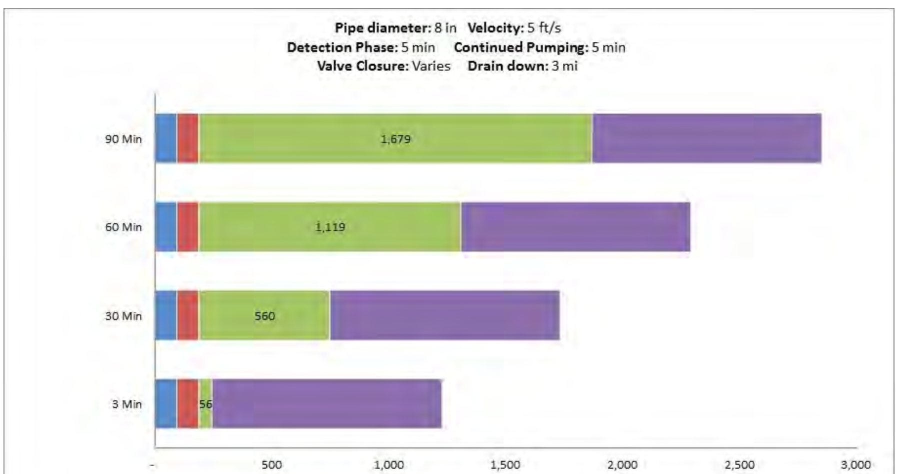


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

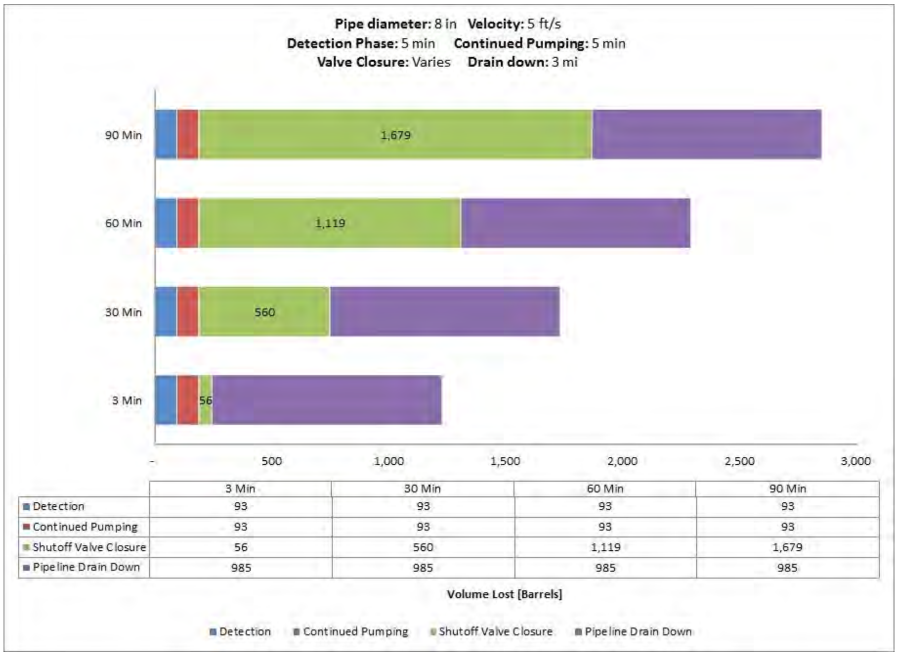


	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

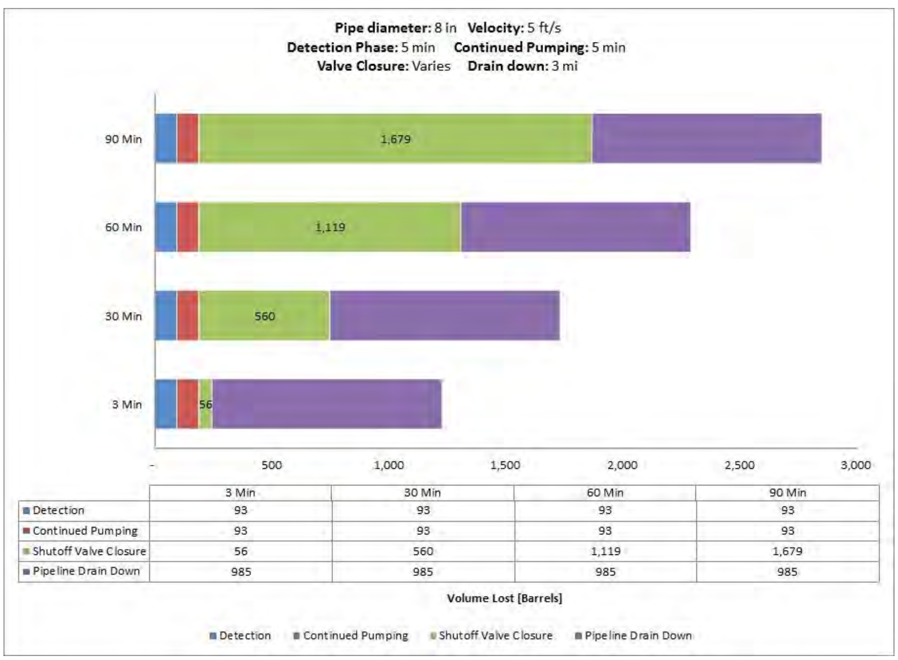
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



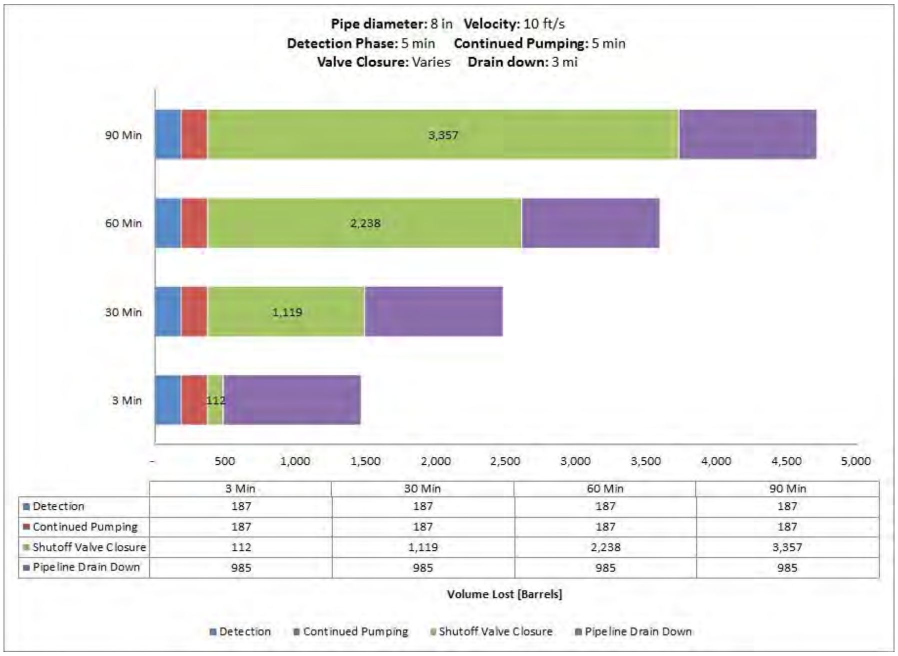
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

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



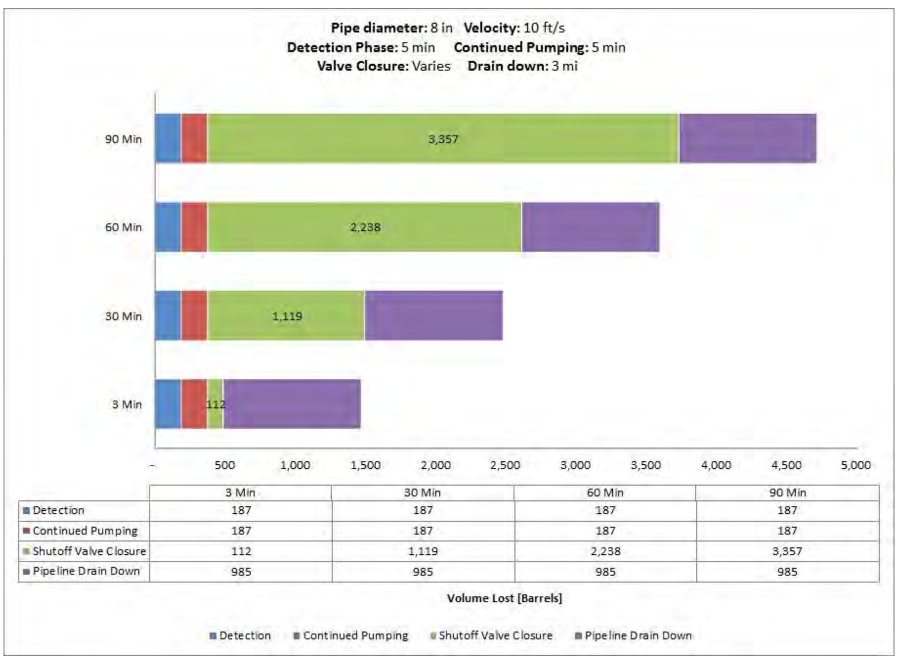
	3 Min	30 Min	60 Min	90 Min
Detection	93	93	93	93
Continued Pumping	93	93	93	93
Shutoff Valve Closure	56	560	1,119	1,679
Pipeline Drain Down	985	985	985	985

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



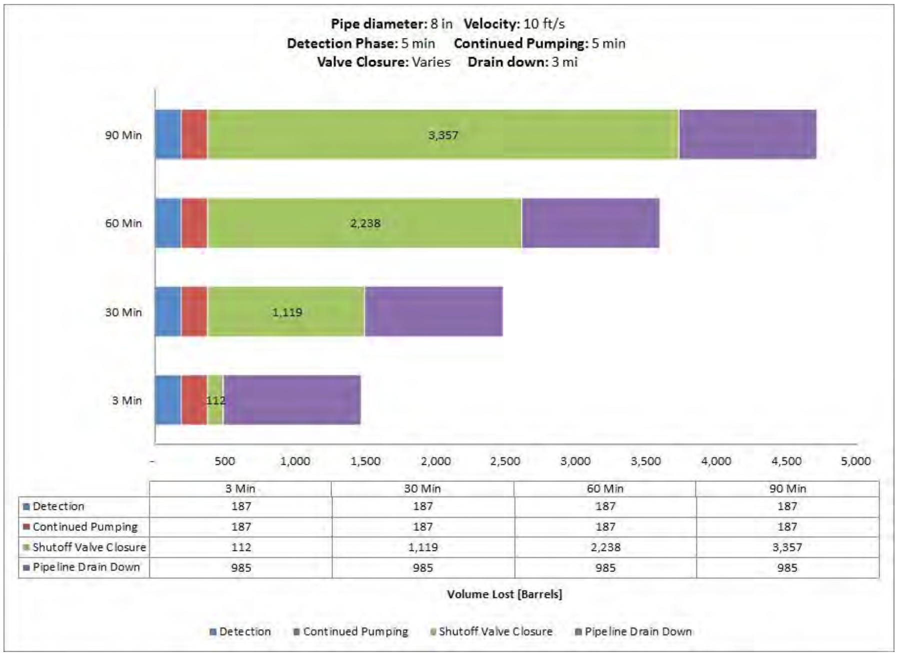
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



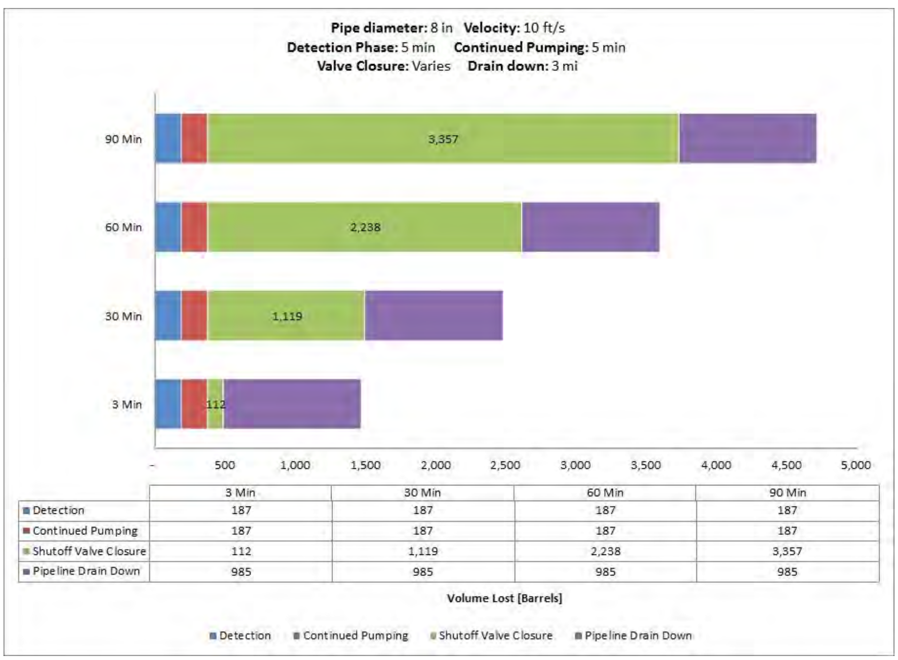
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



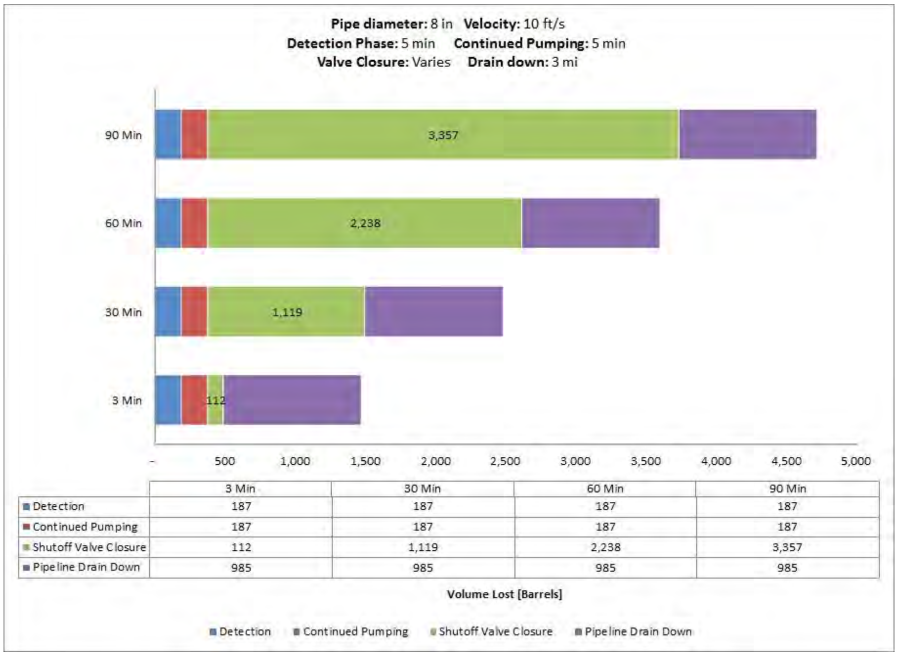
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



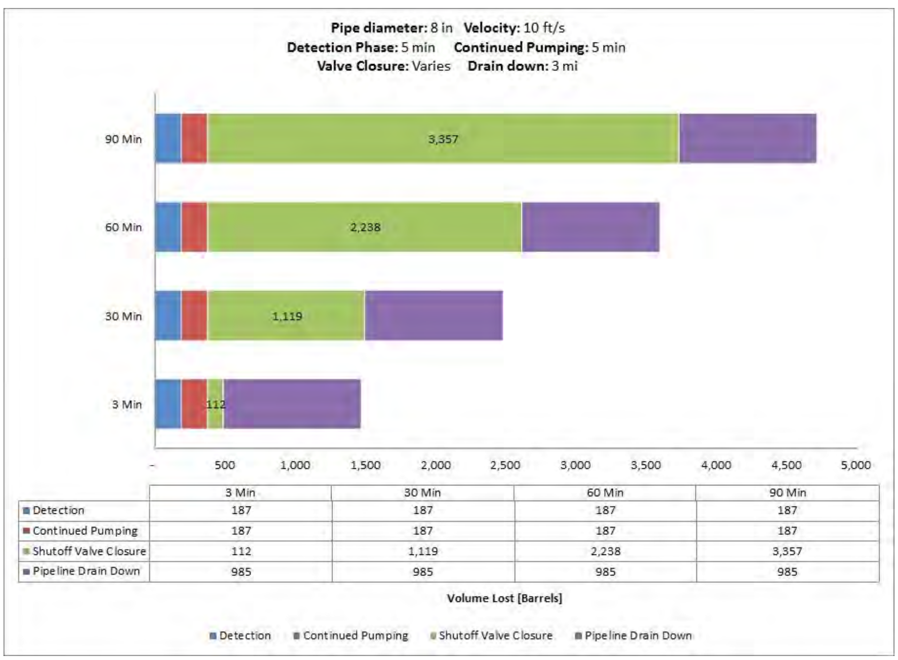
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



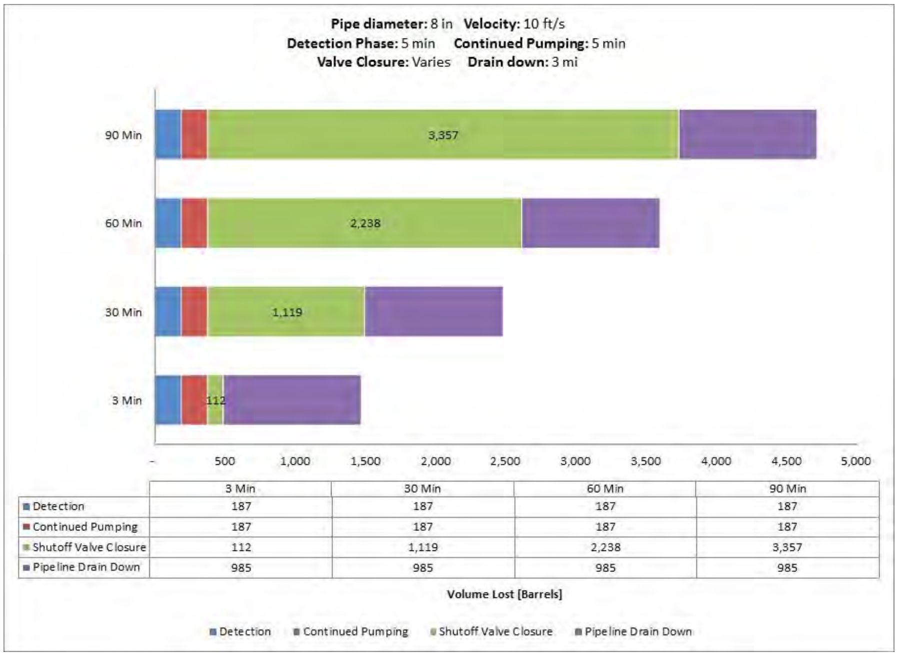
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



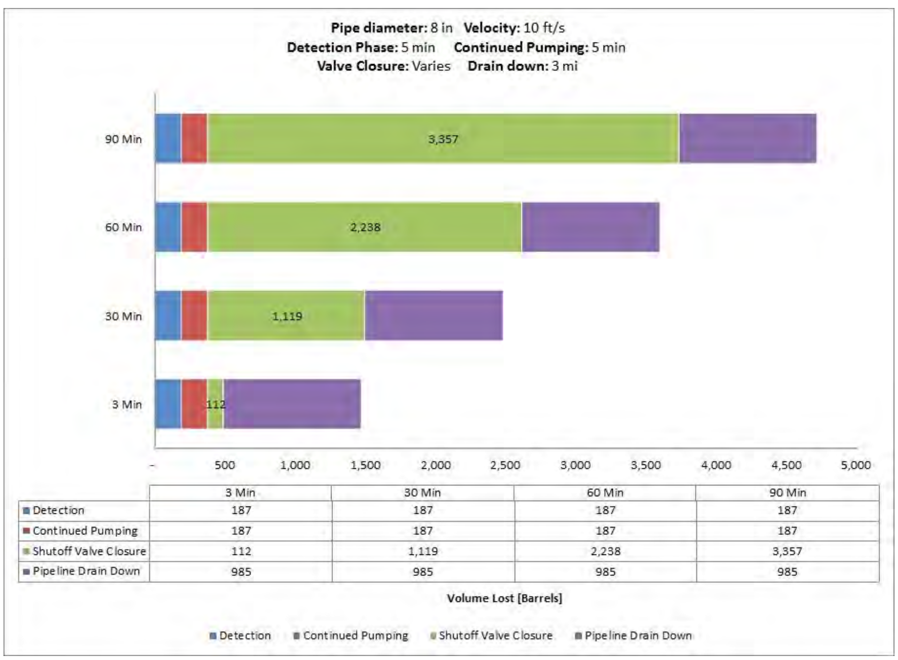
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



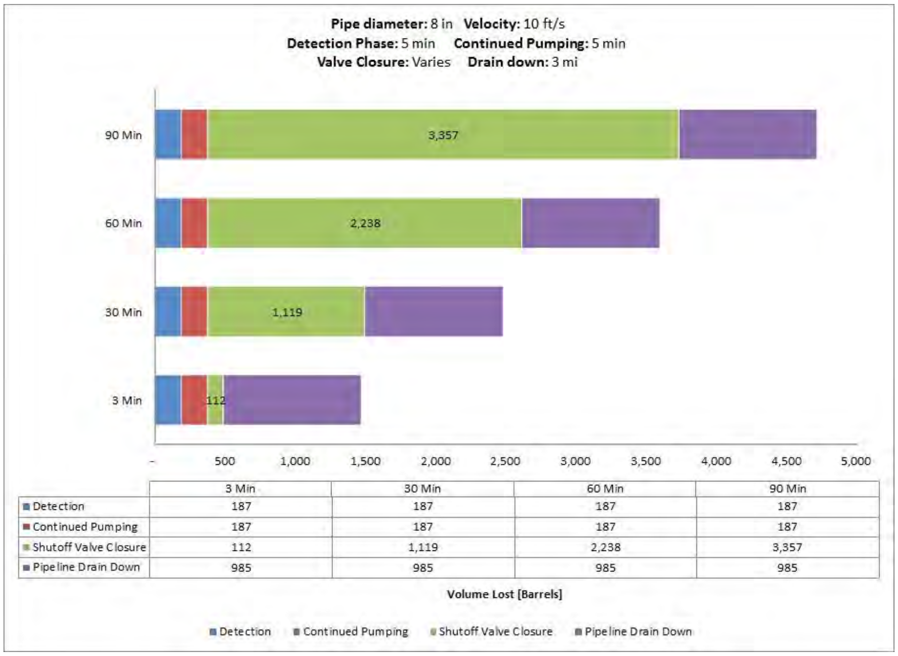
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



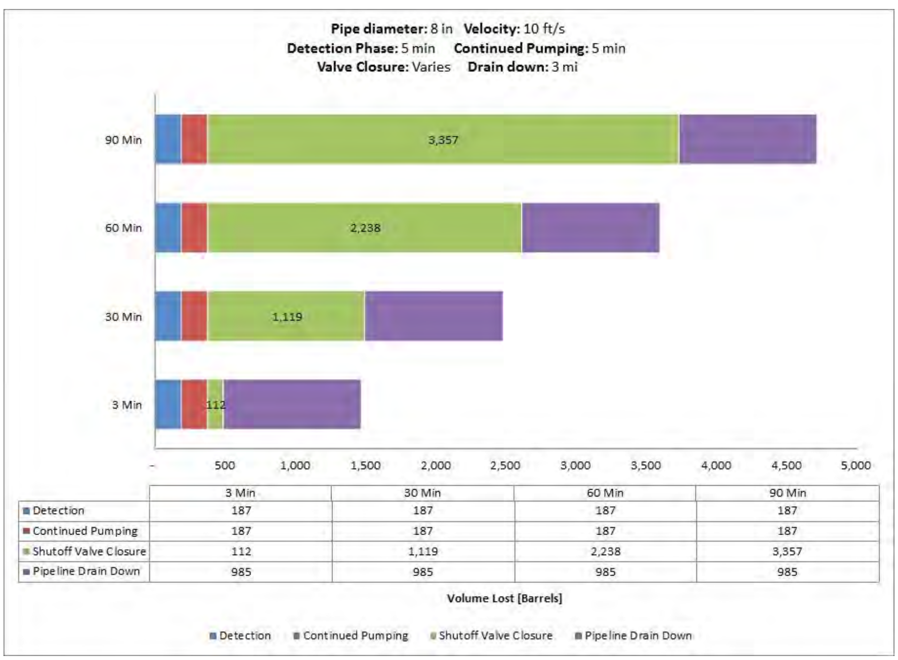
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



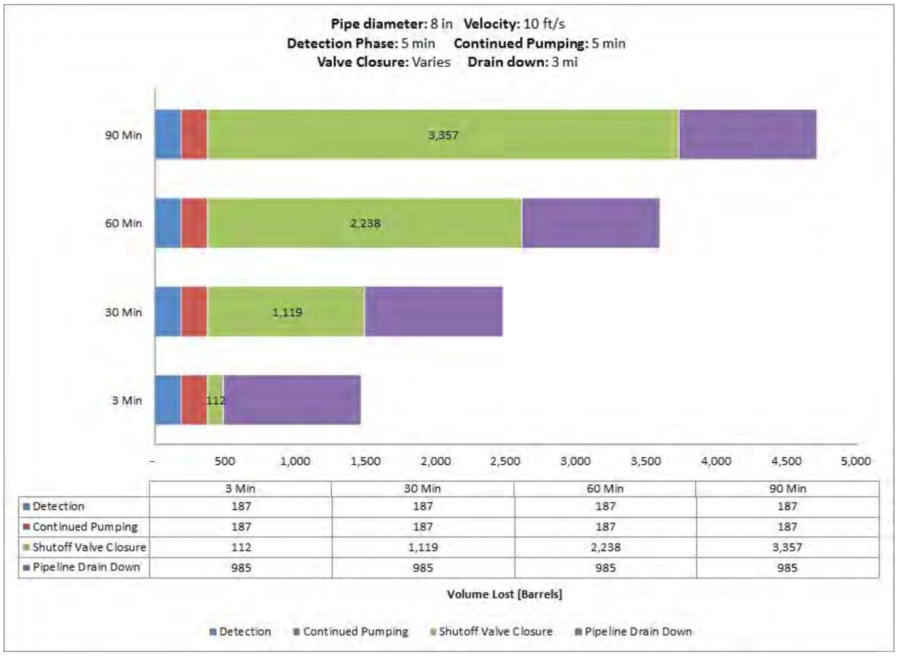
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



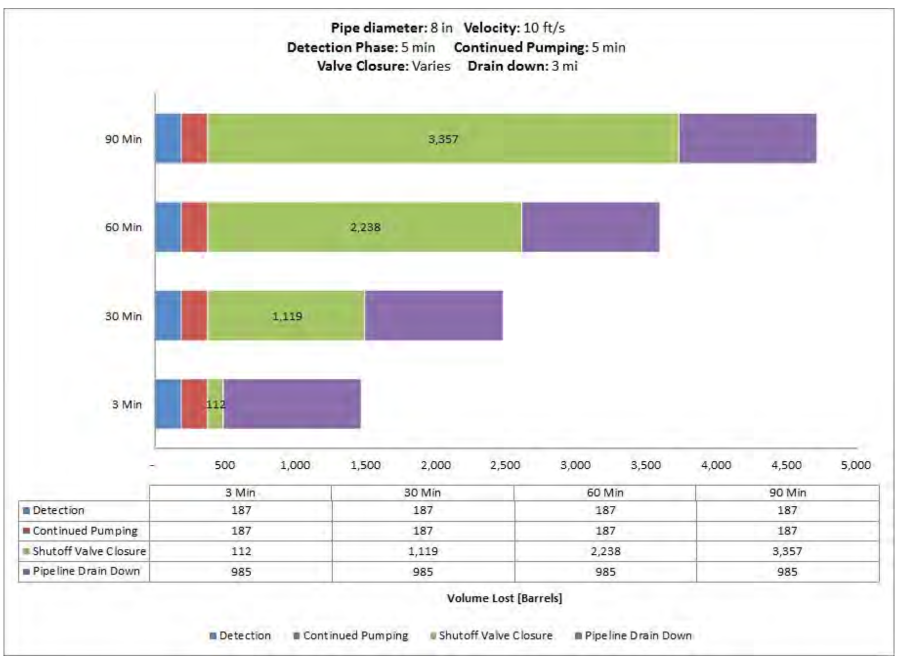
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



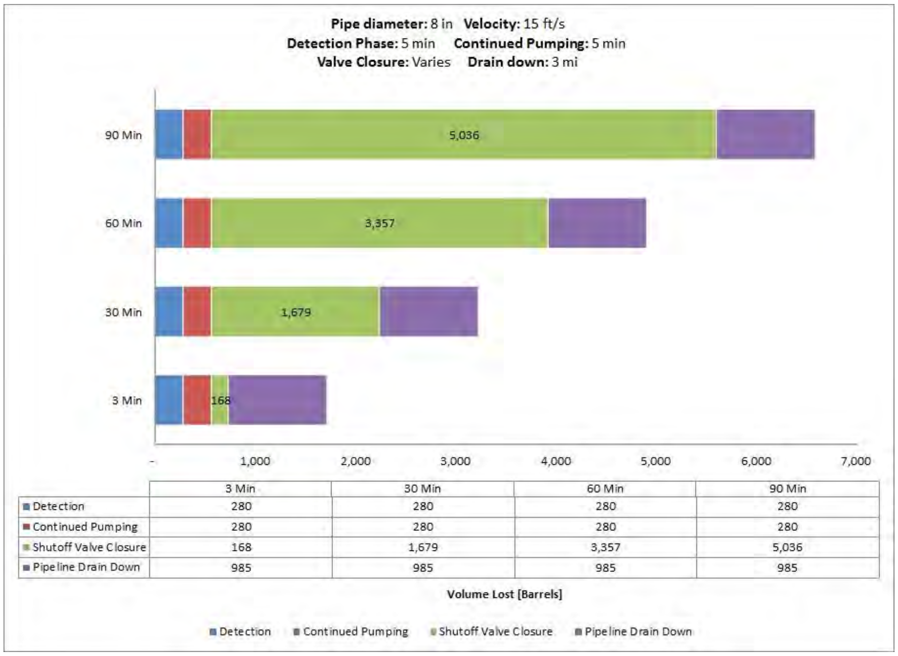
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



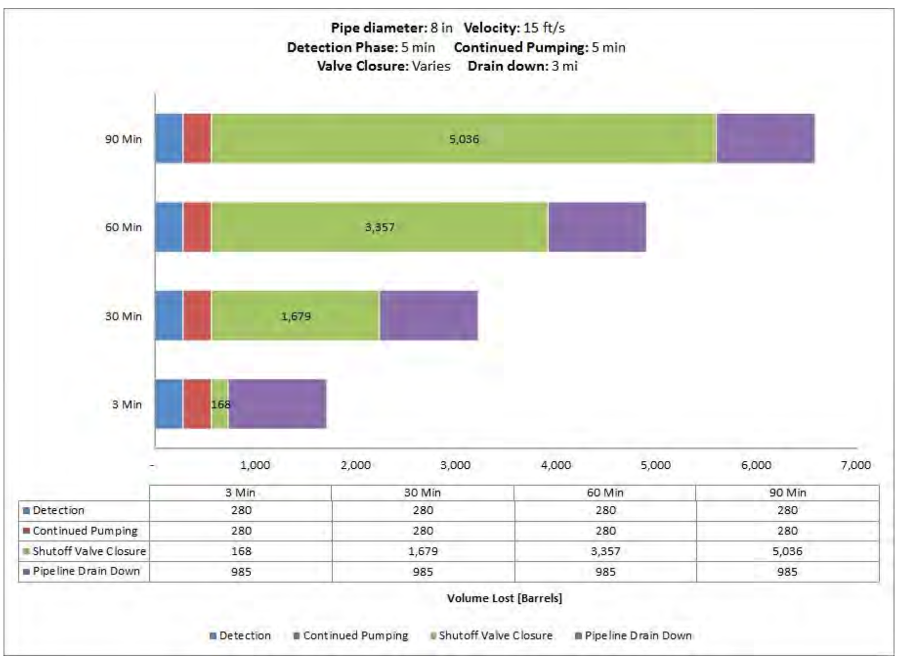
	3 Min	30 Min	60 Min	90 Min
Detection	187	187	187	187
Continued Pumping	187	187	187	187
Shutoff Valve Closure	112	1,119	2,238	3,357
Pipeline Drain Down	985	985	985	985

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



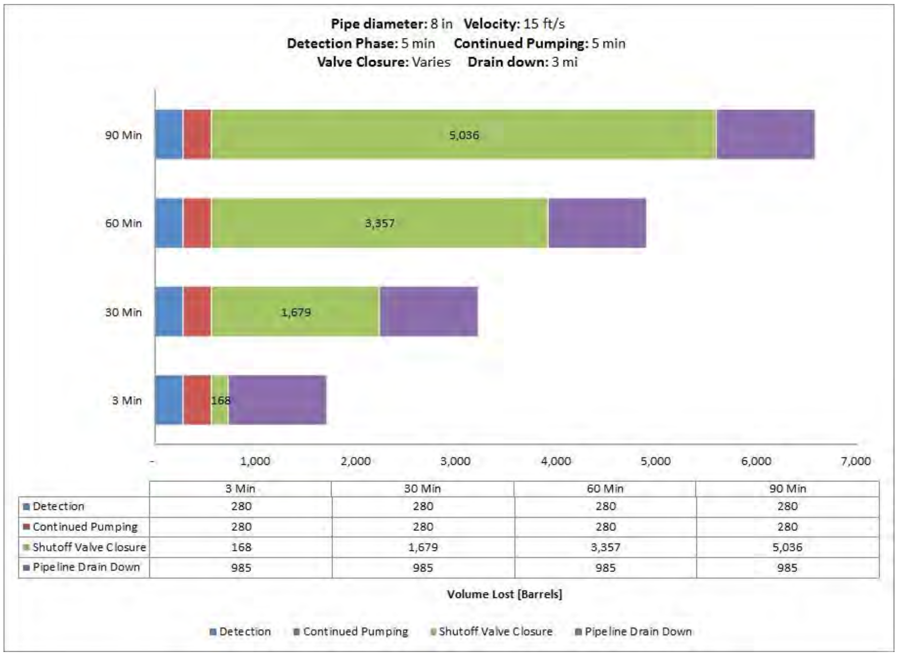
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



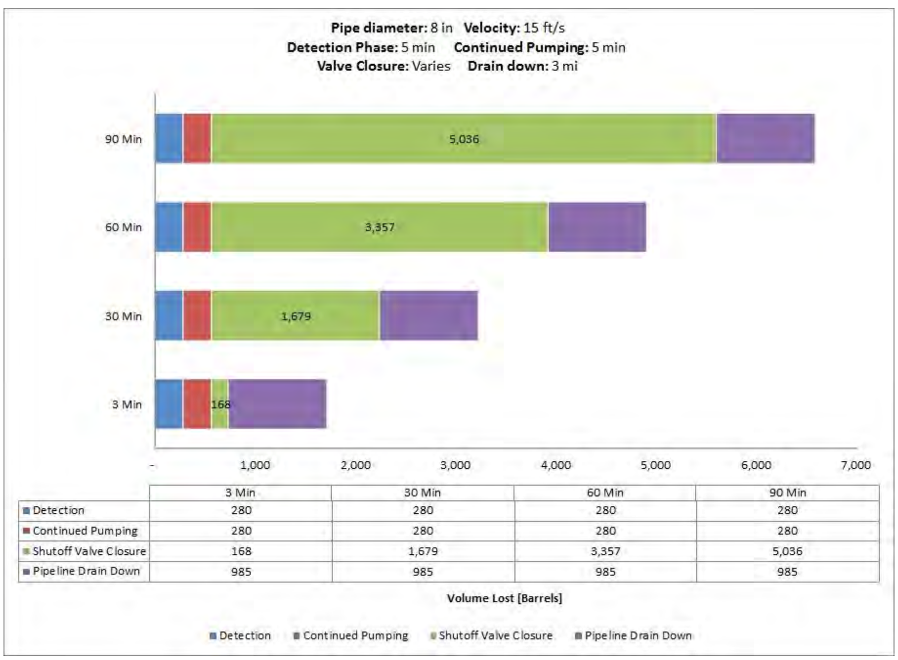
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



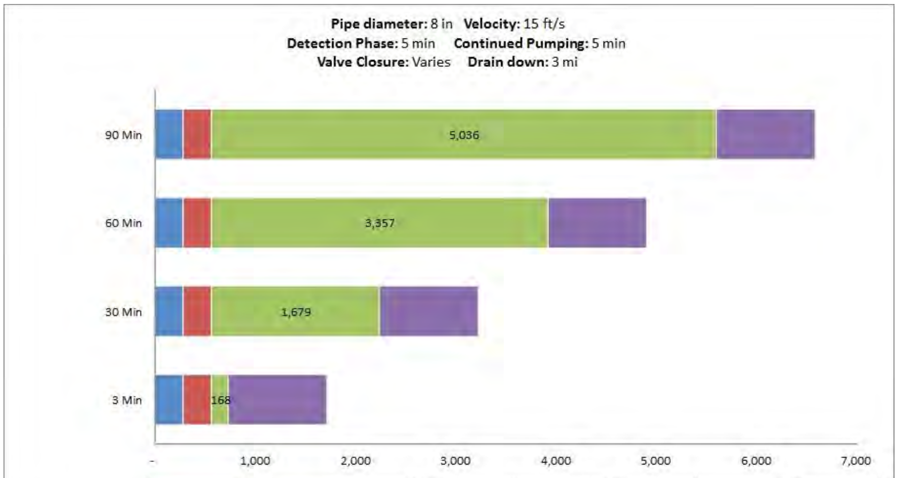
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



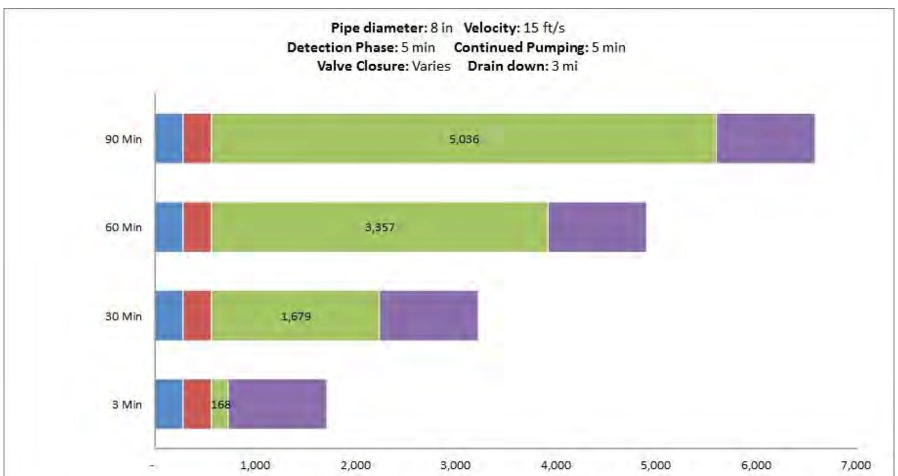
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



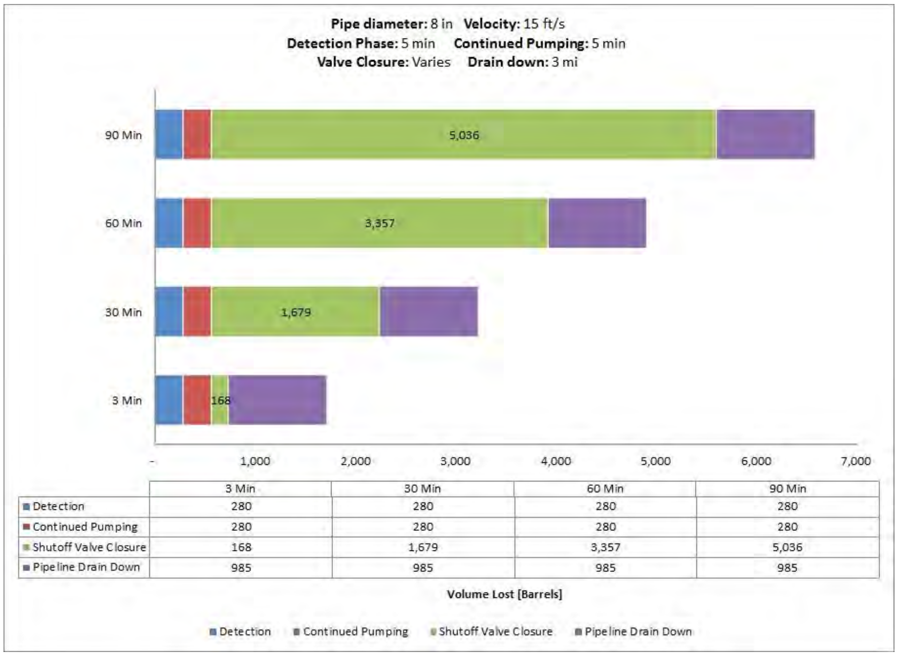
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



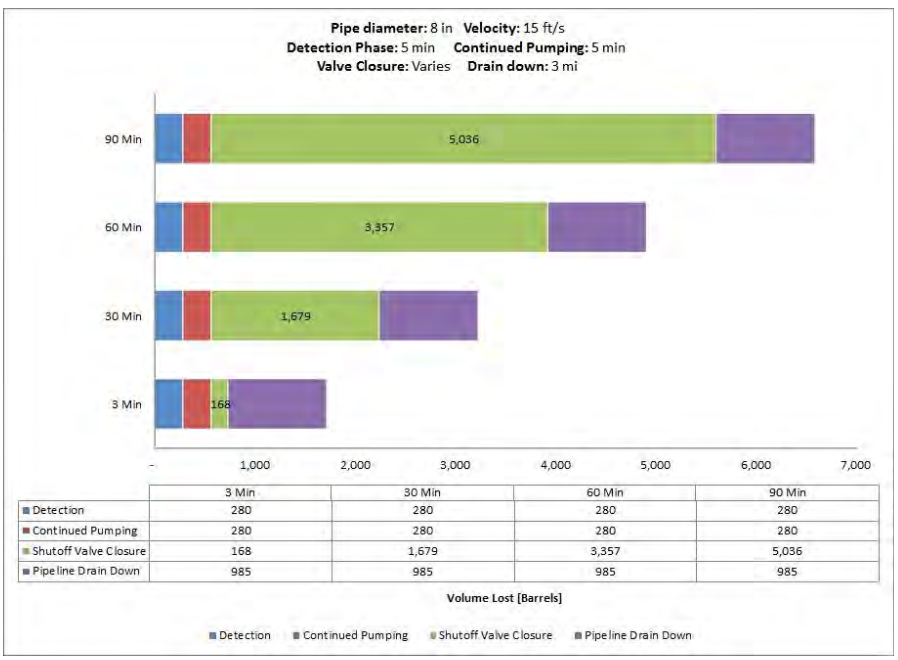
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



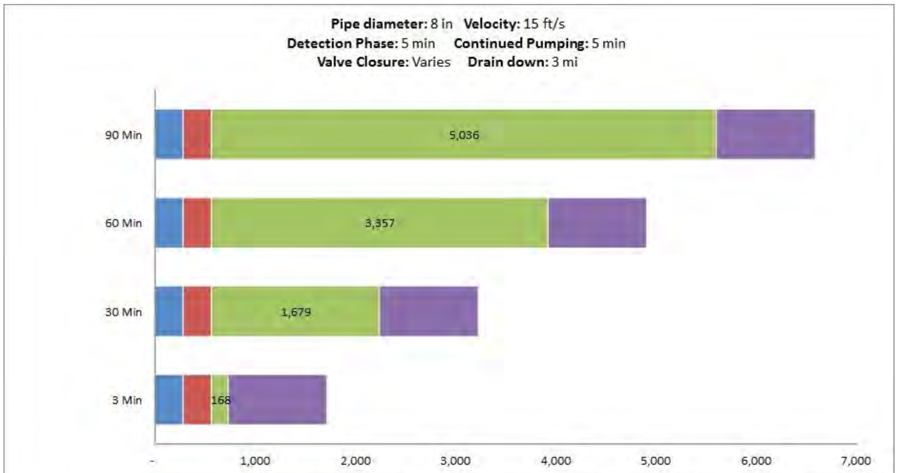
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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.

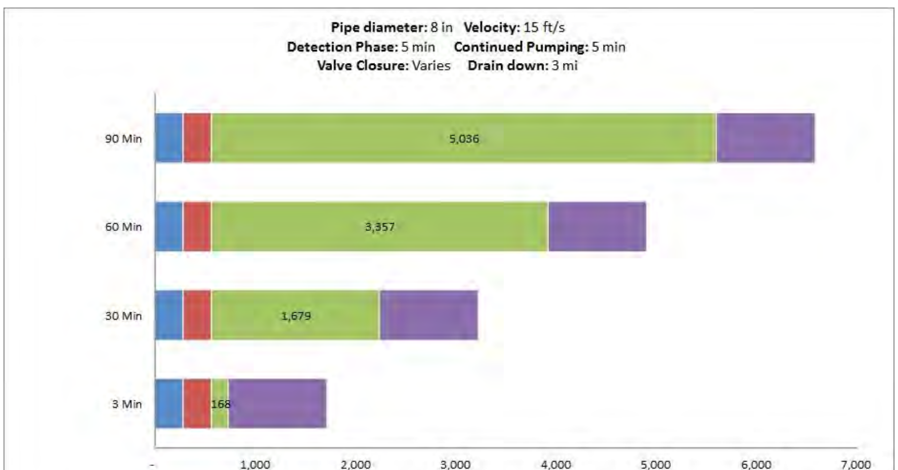


	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

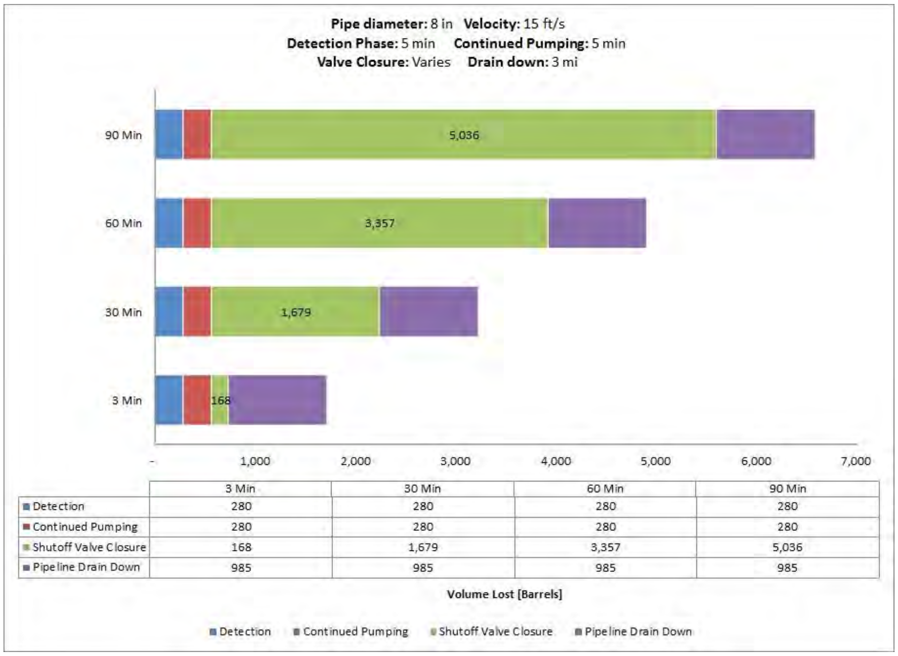


	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

Volume Lost [Barrels]

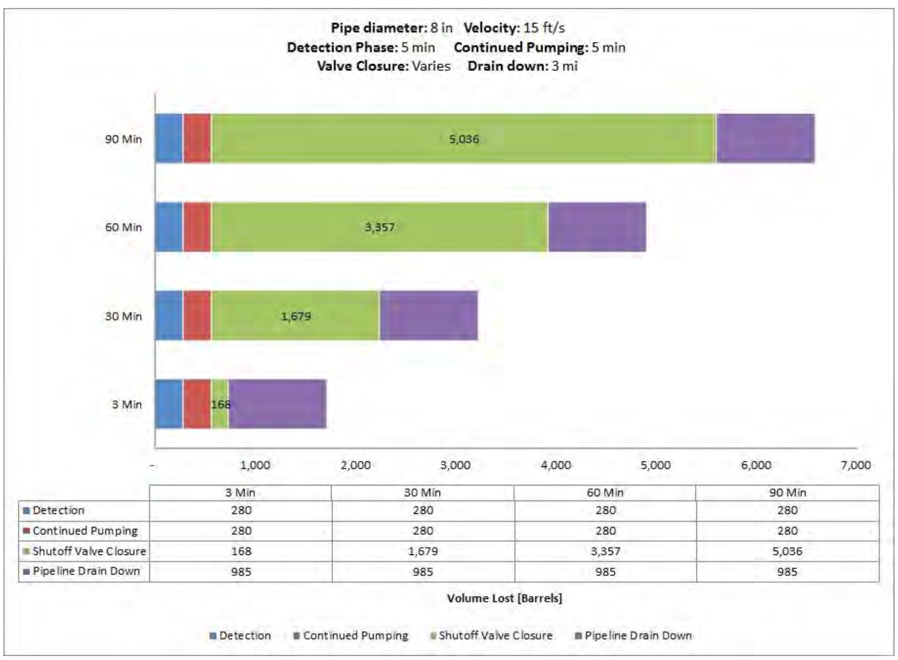
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



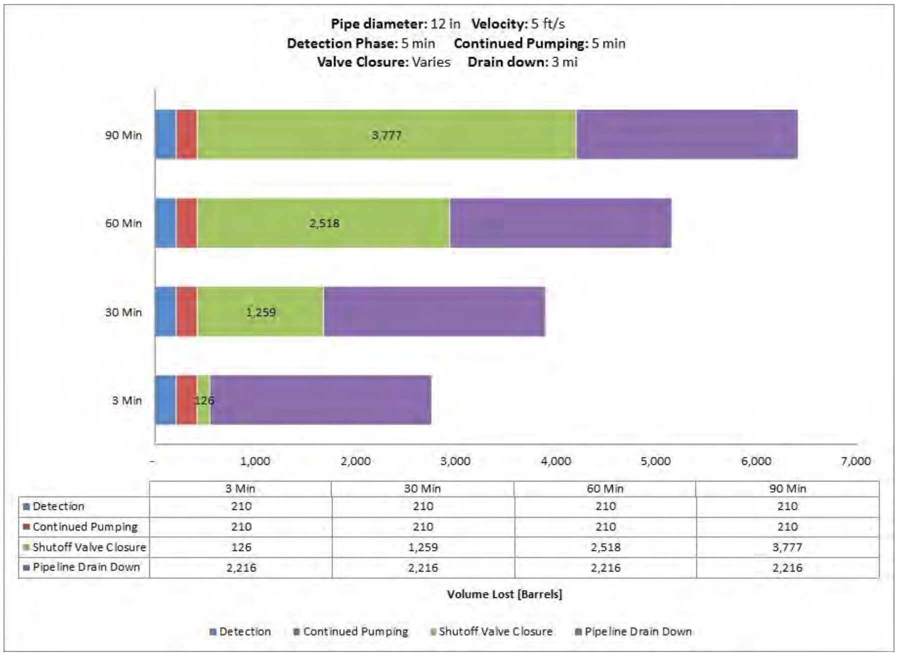
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



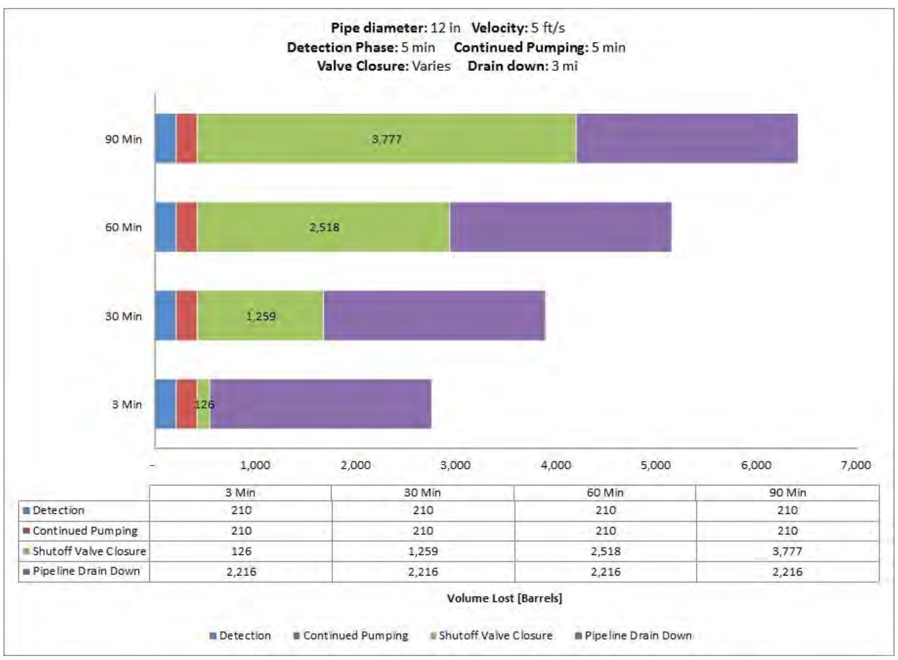
	3 Min	30 Min	60 Min	90 Min
Detection	280	280	280	280
Continued Pumping	280	280	280	280
Shutoff Valve Closure	168	1,679	3,357	5,036
Pipeline Drain Down	985	985	985	985

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



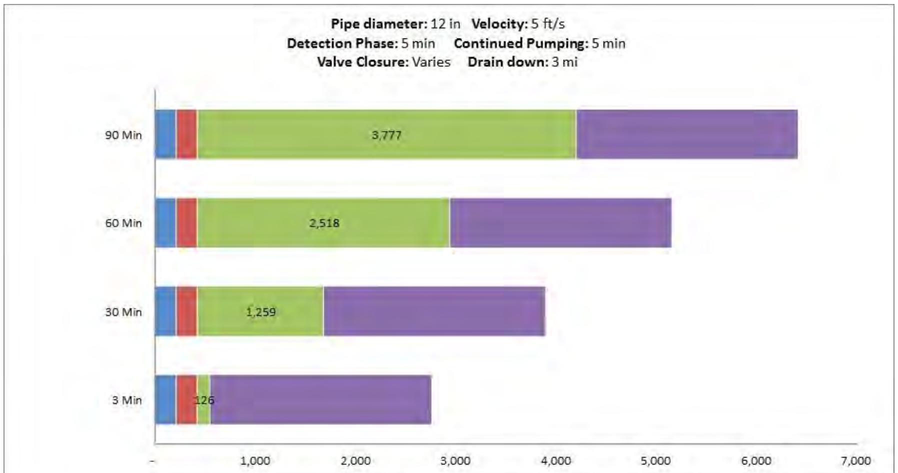
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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.

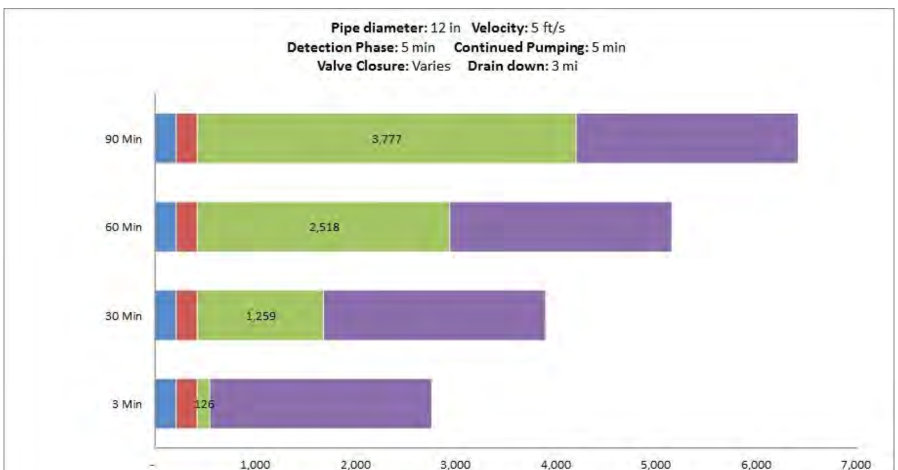


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

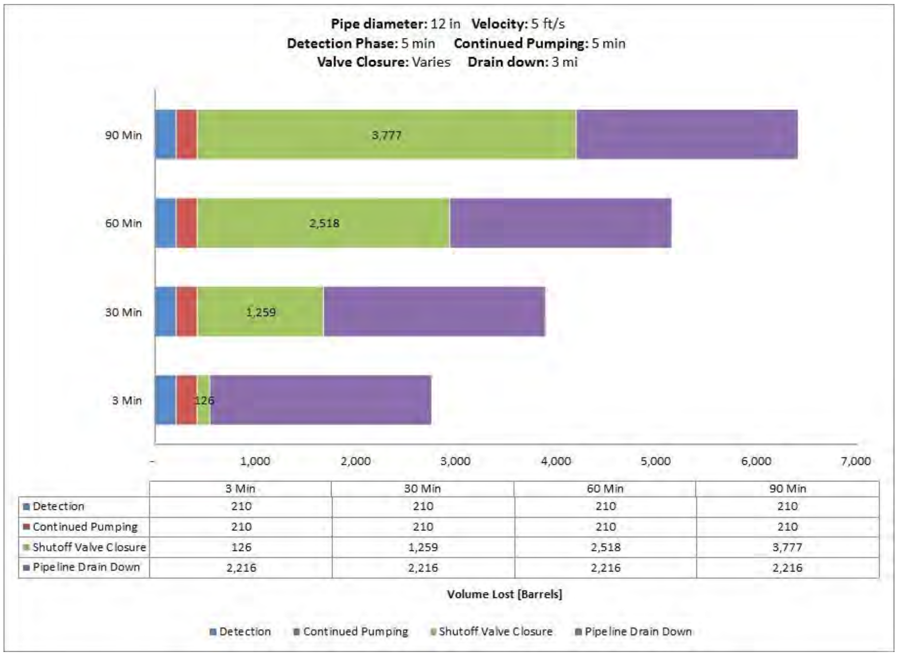


	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

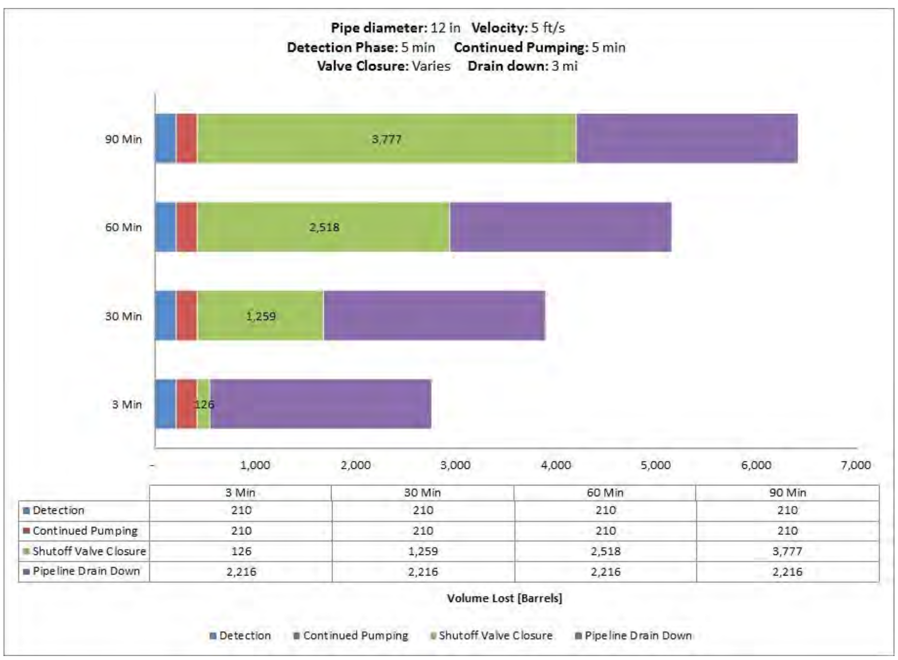
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



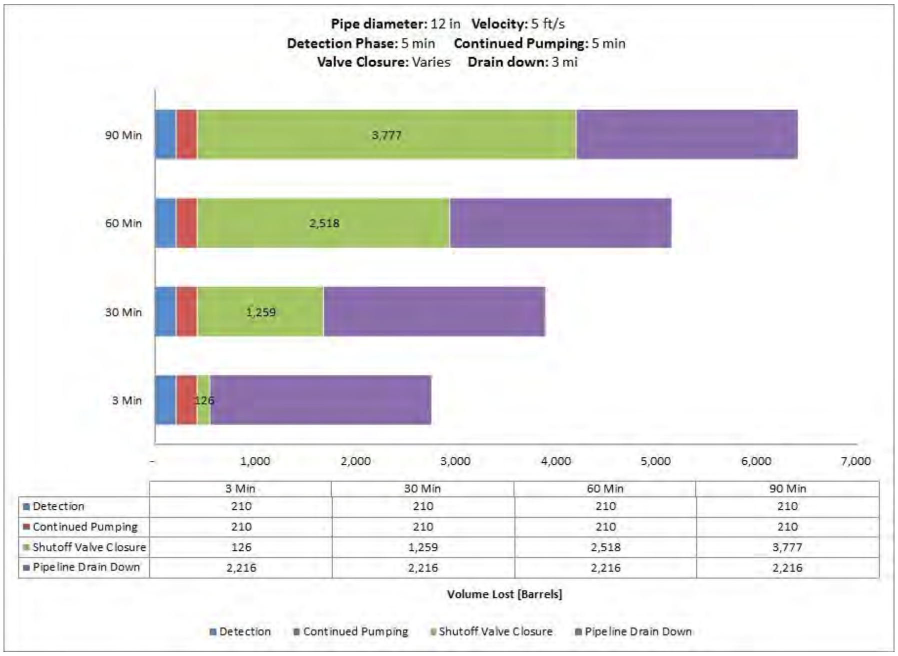
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



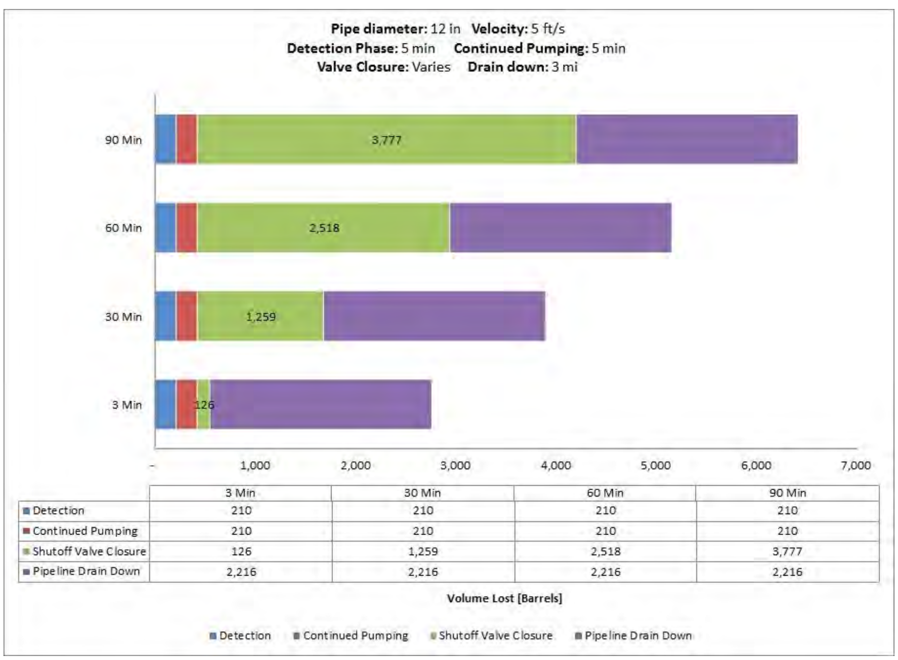
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



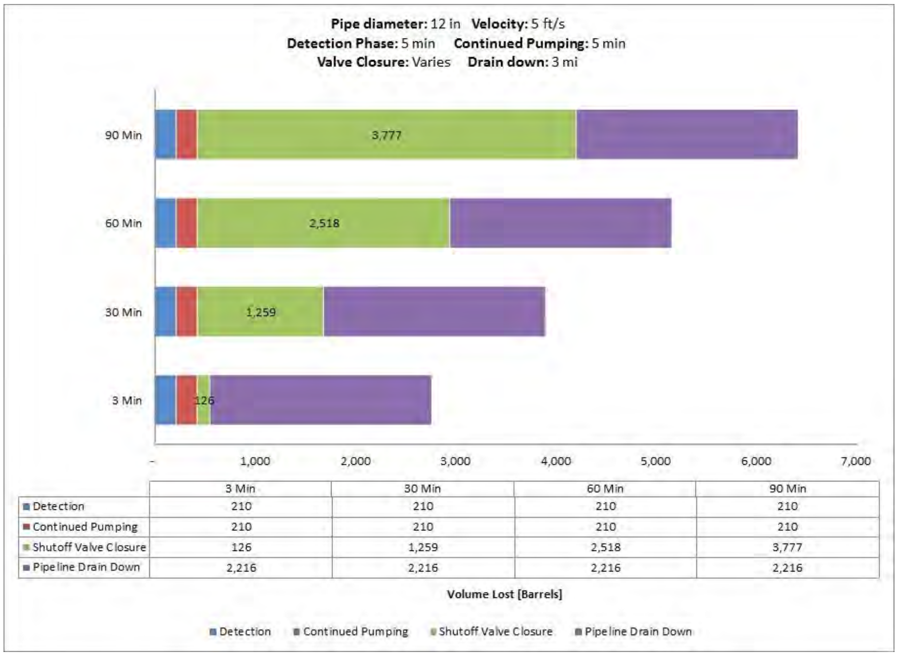
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



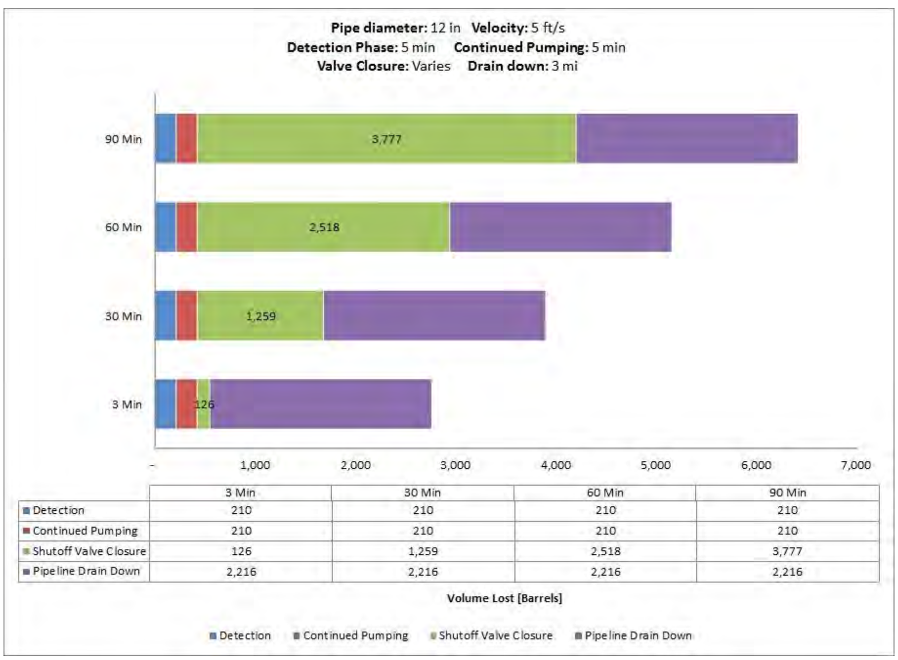
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



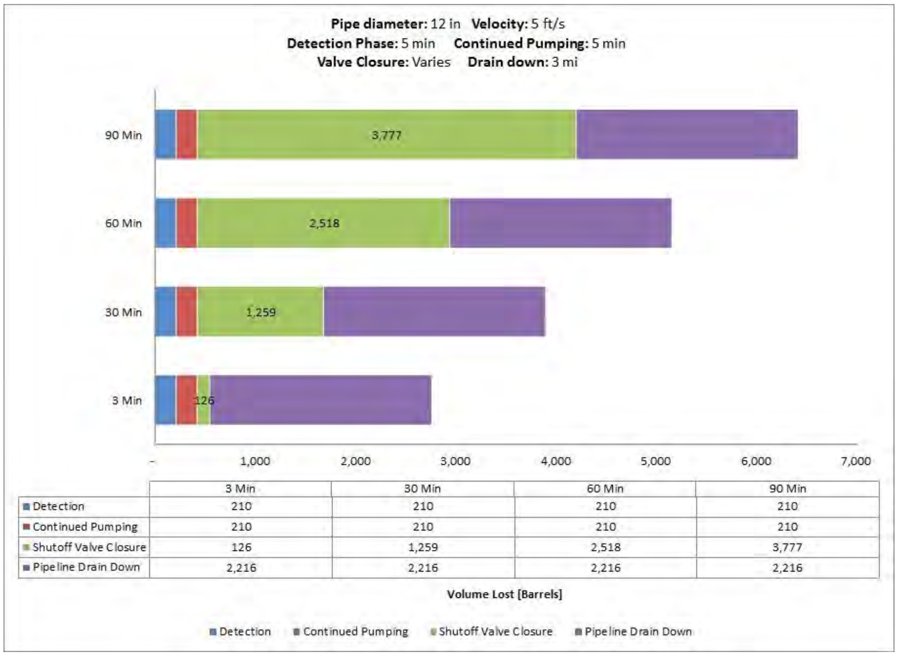
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



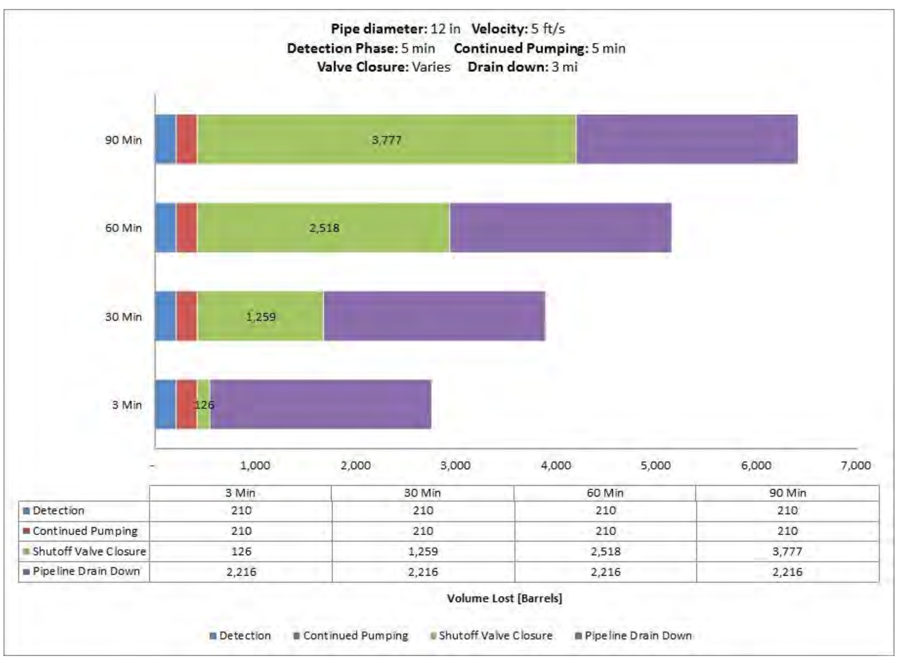
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



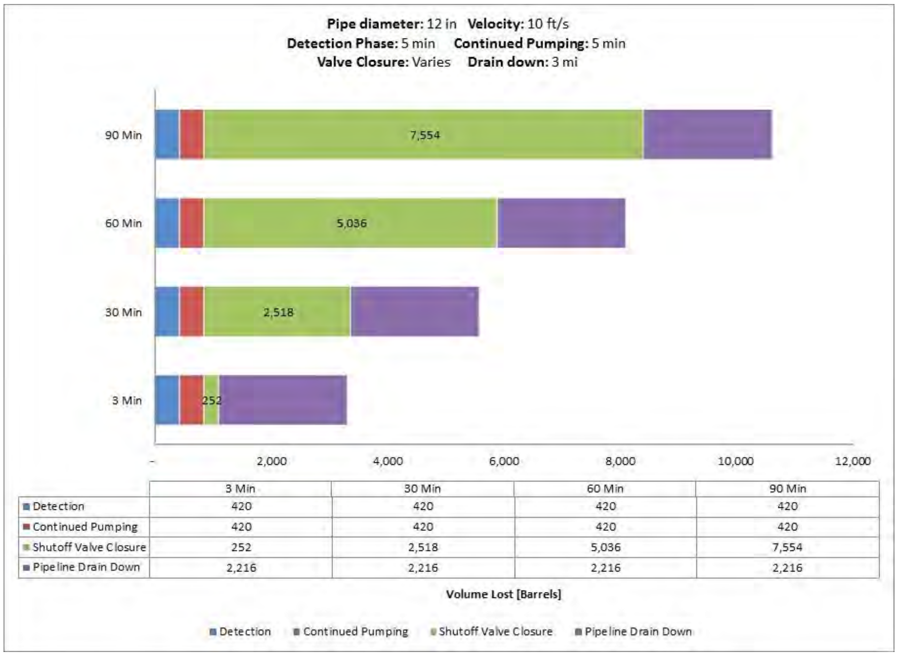
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



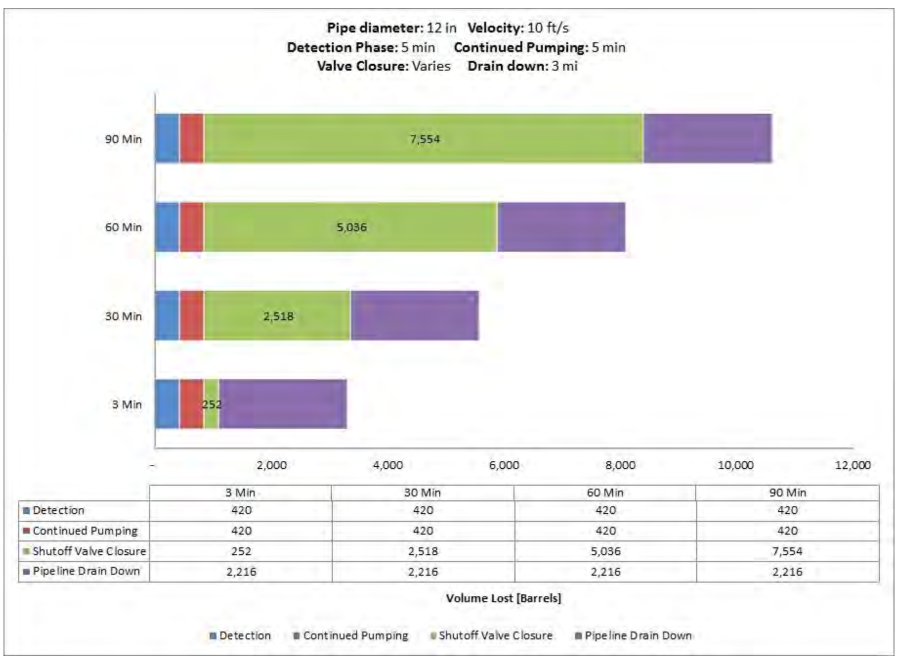
	3 Min	30 Min	60 Min	90 Min
Detection	210	210	210	210
Continued Pumping	210	210	210	210
Shutoff Valve Closure	126	1,259	2,518	3,777
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



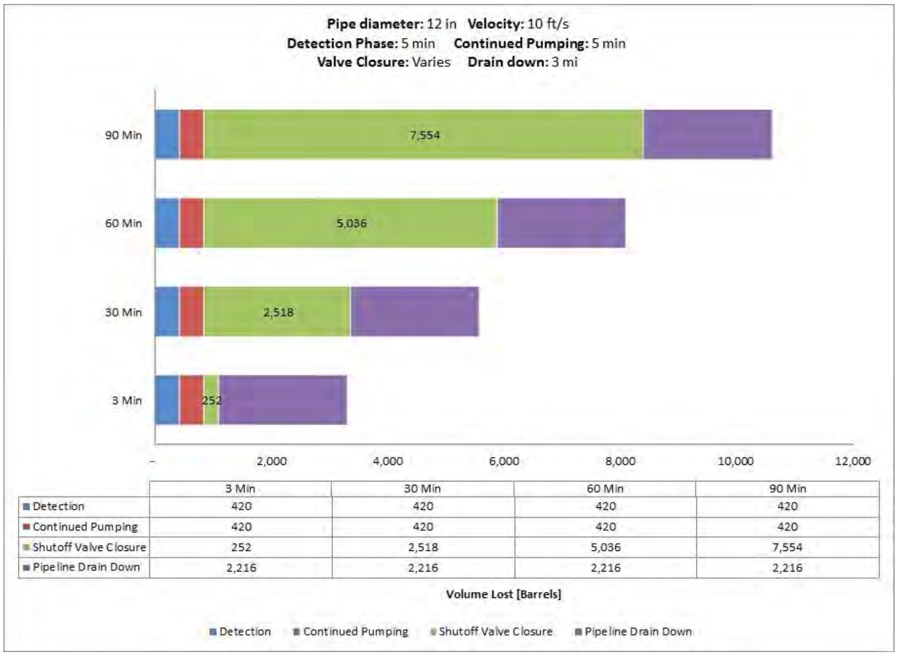
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



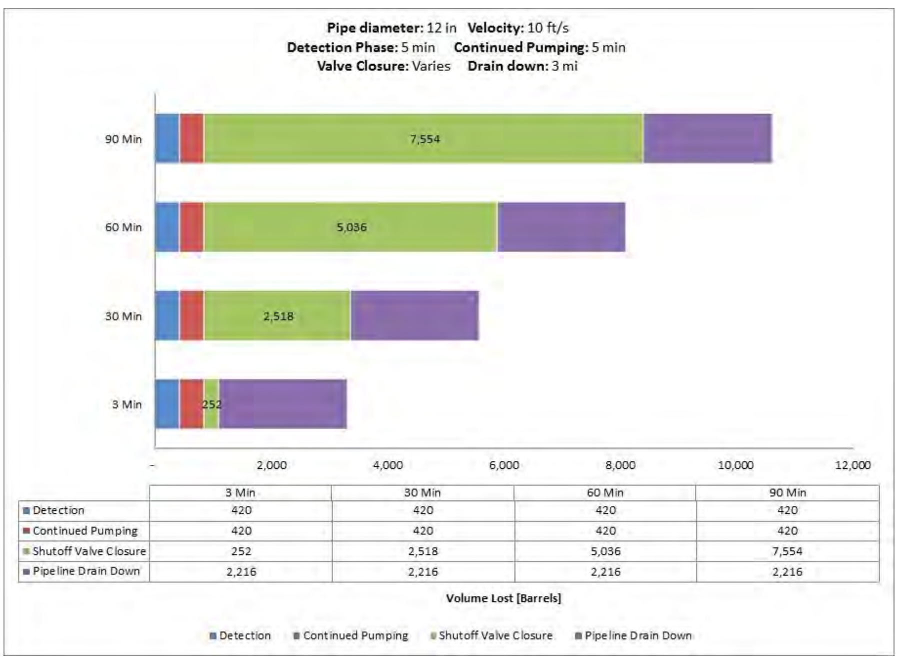
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



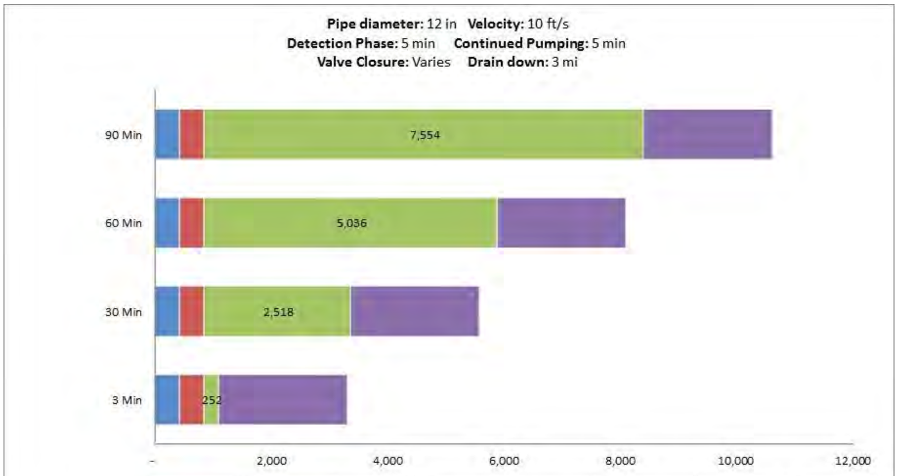
	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

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.

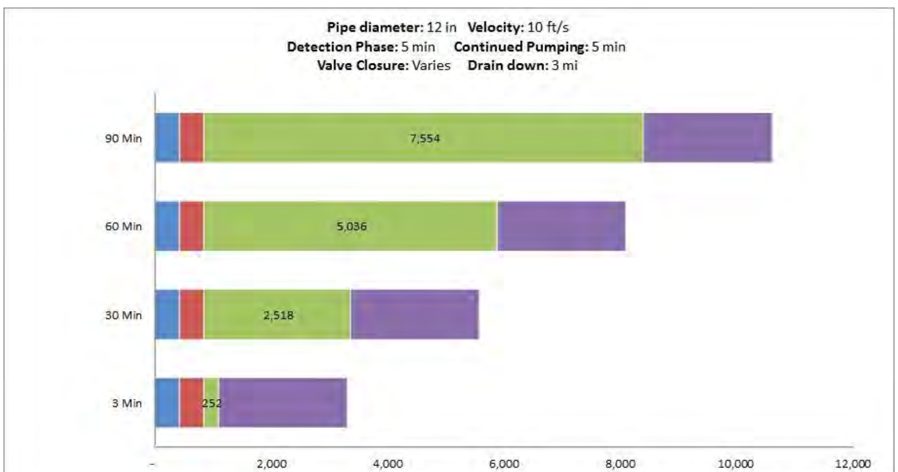


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-53. 12 Inch Pipe Diameter, 10 ft/s, 800 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-54. 12 Inch Pipe Diameter, 10 ft/s, 800 psi MAOP, 1000 Feet Elevation Change.

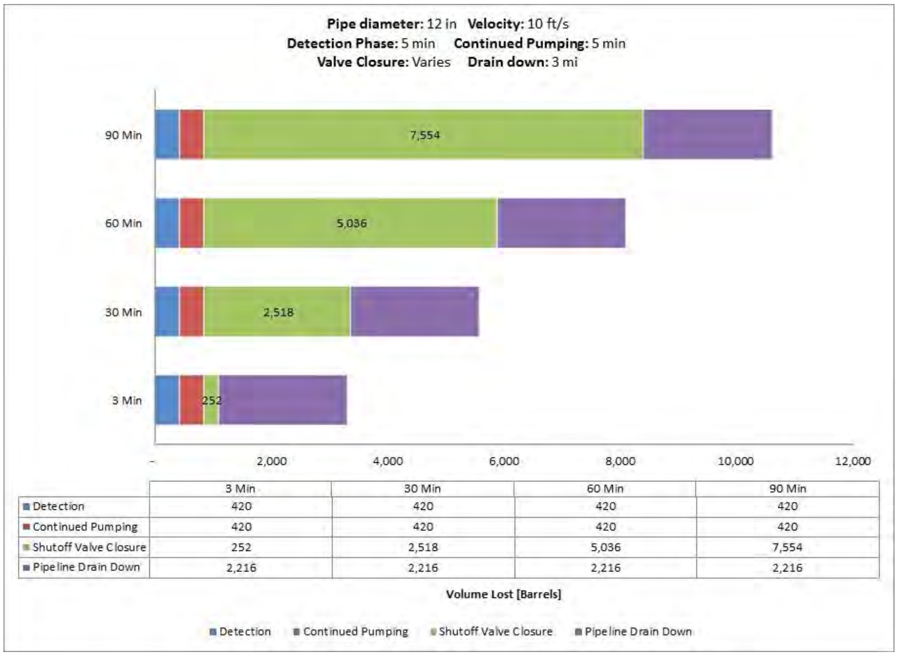


Fig. A-55. 12 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 100 Feet Elevation Change.

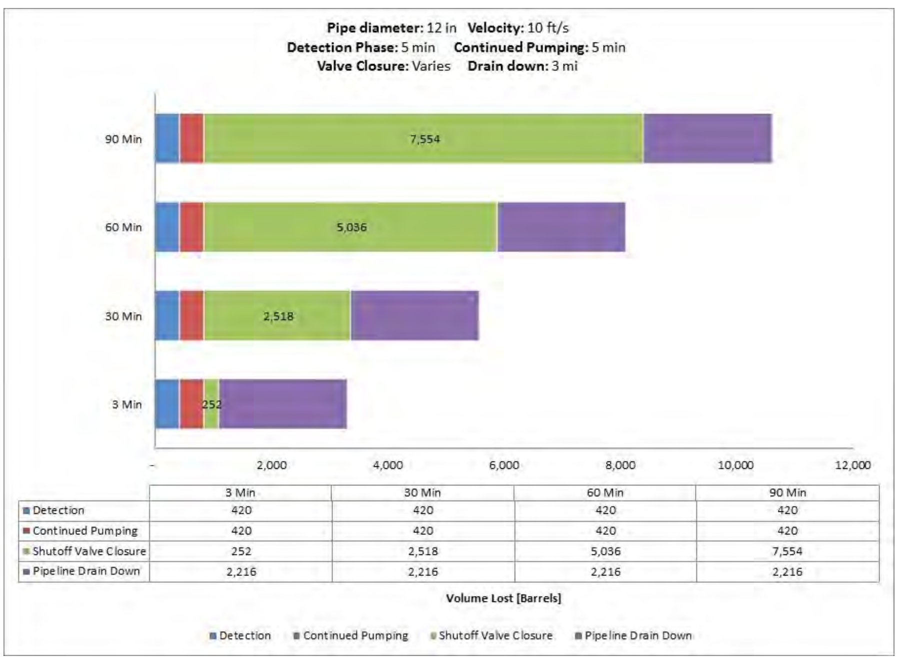
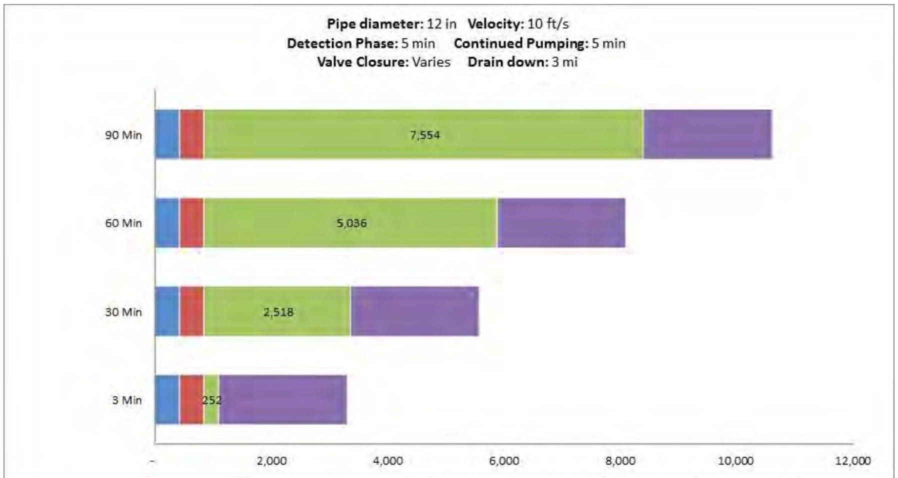


Fig. A-56. 12 Inch Pipe Diameter, 10 ft/s, 1200 psi MAOP, 500 Feet Elevation Change.

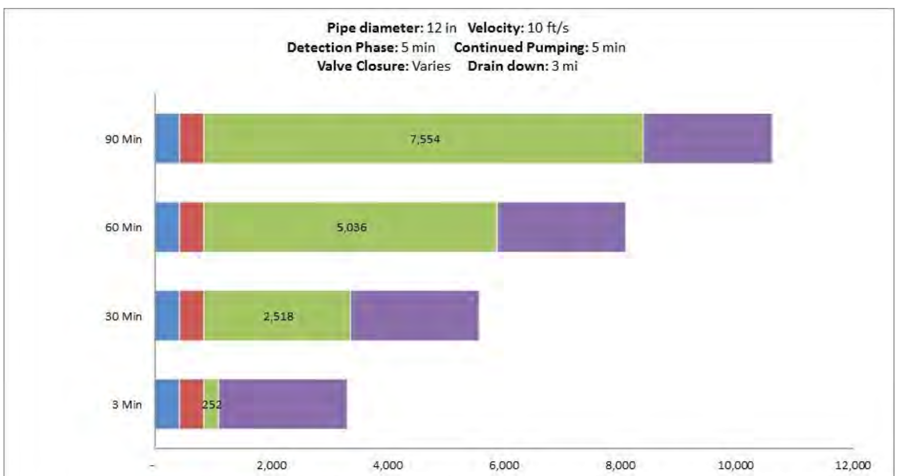


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

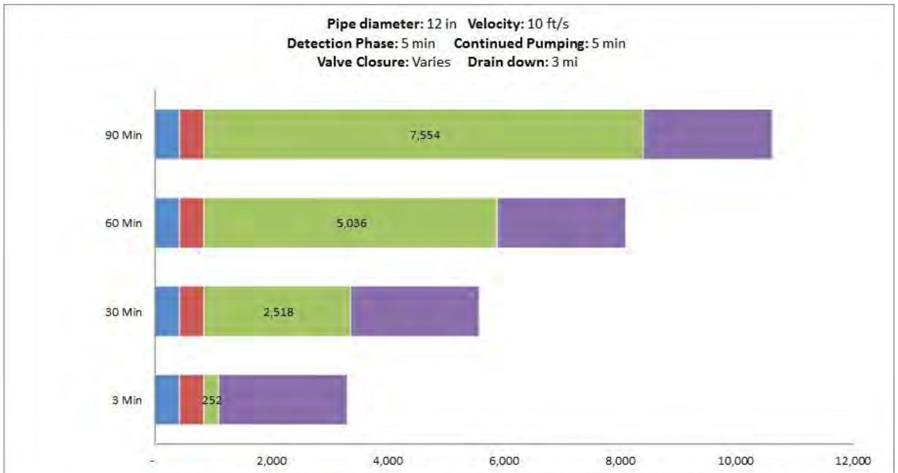


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

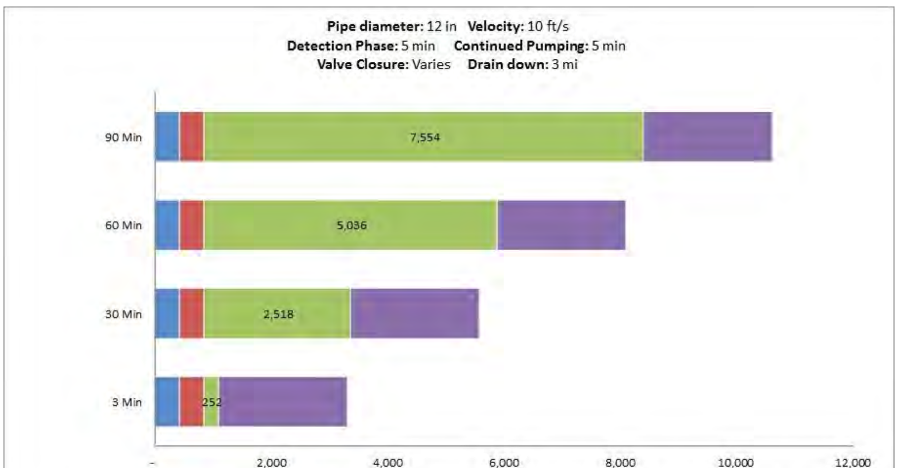


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

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.

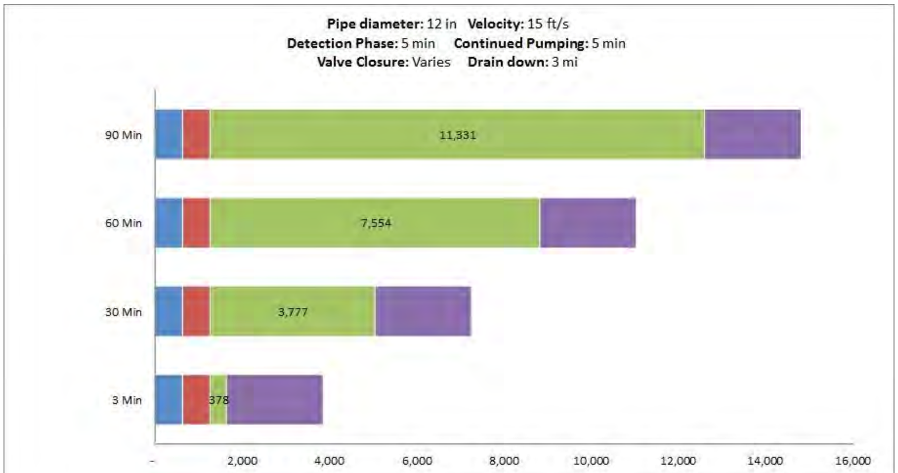


	3 Min	30 Min	60 Min	90 Min
Detection	420	420	420	420
Continued Pumping	420	420	420	420
Shutoff Valve Closure	252	2,518	5,036	7,554
Pipeline Drain Down	2,216	2,216	2,216	2,216

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.

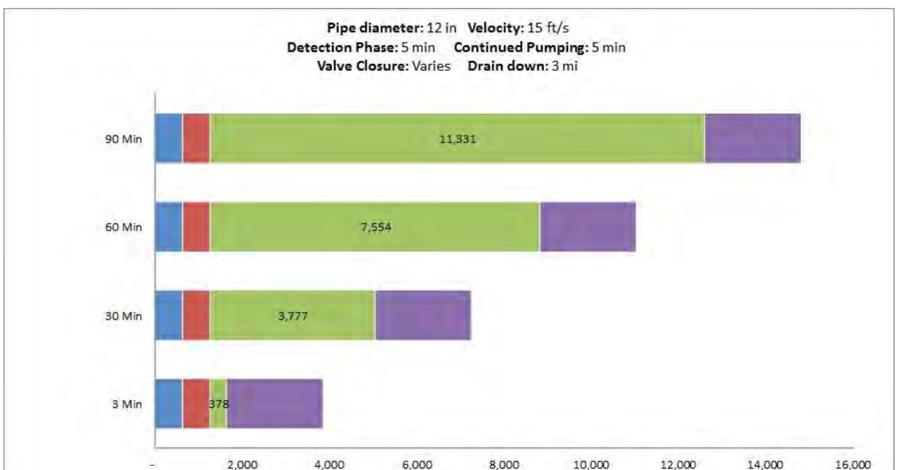


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

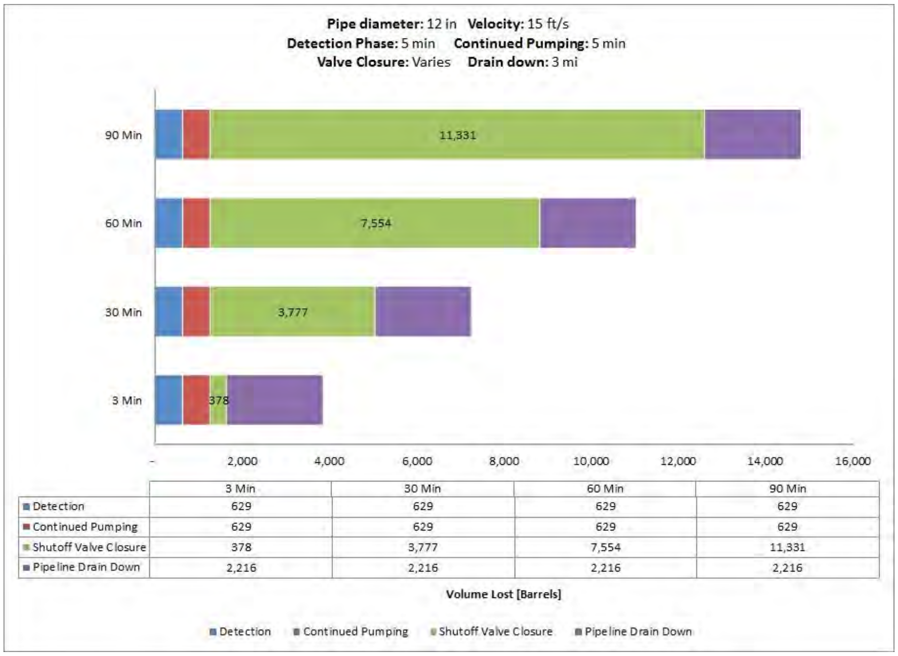


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

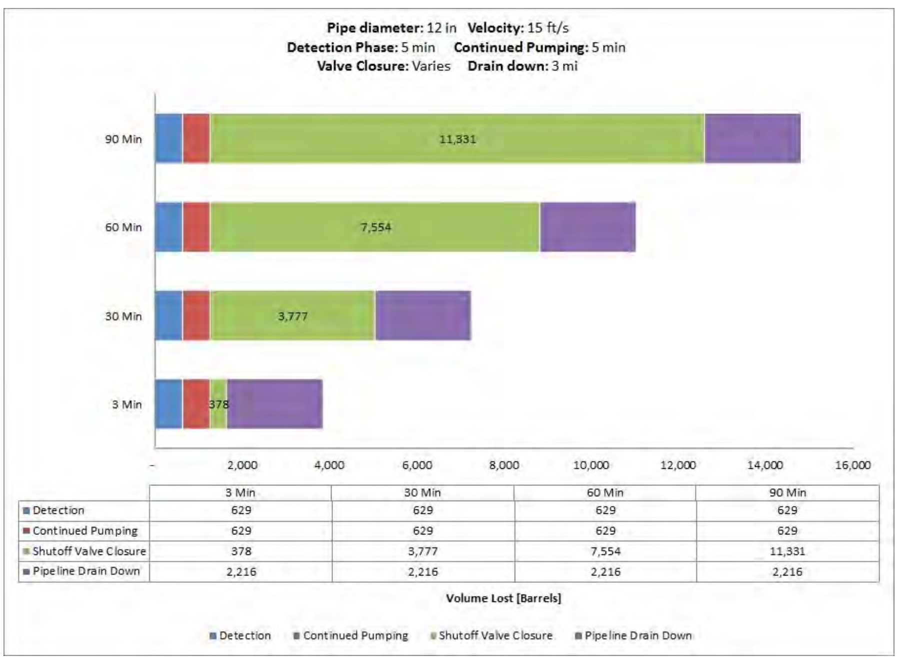
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



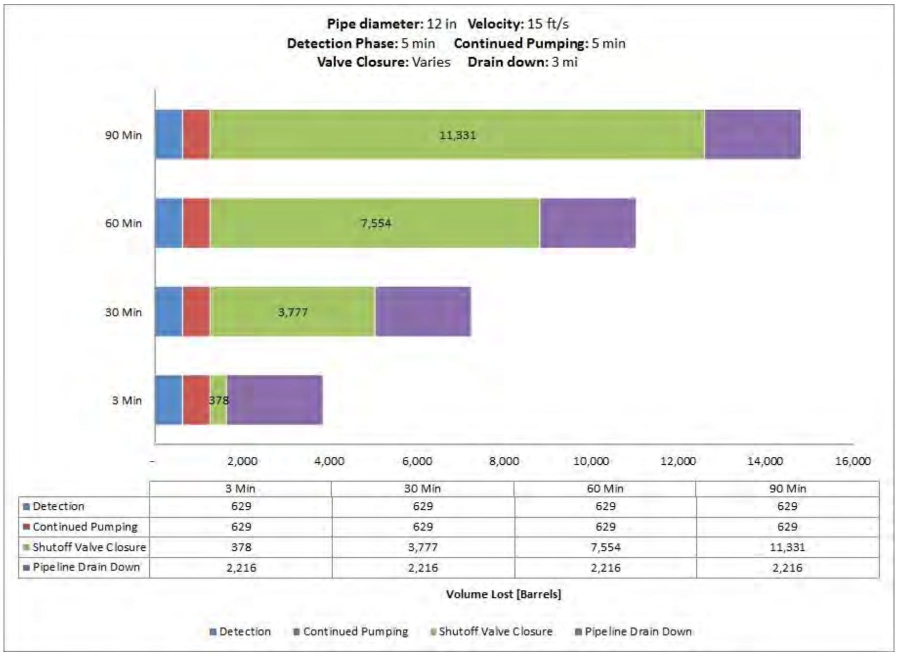
	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



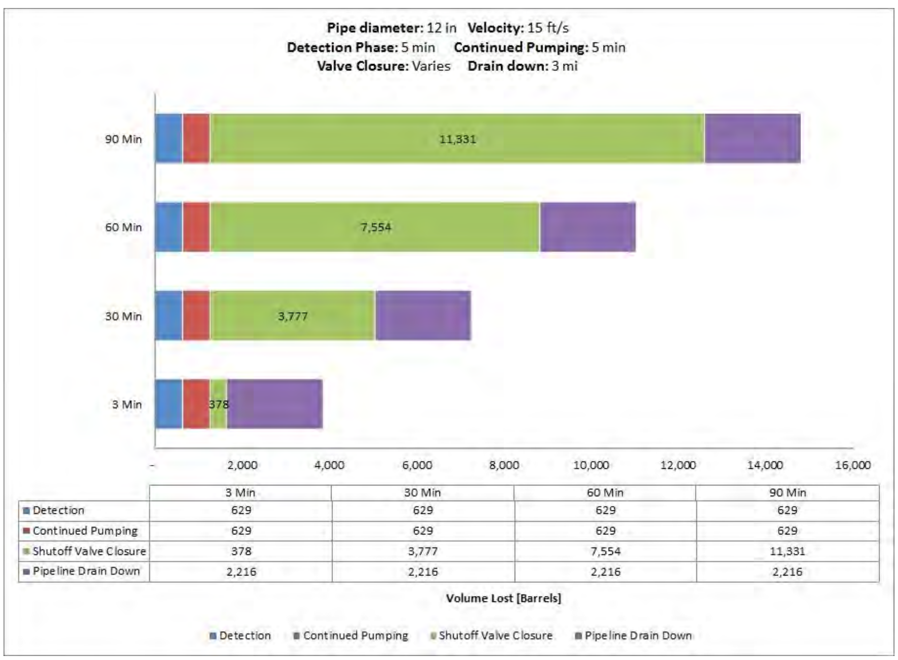
	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



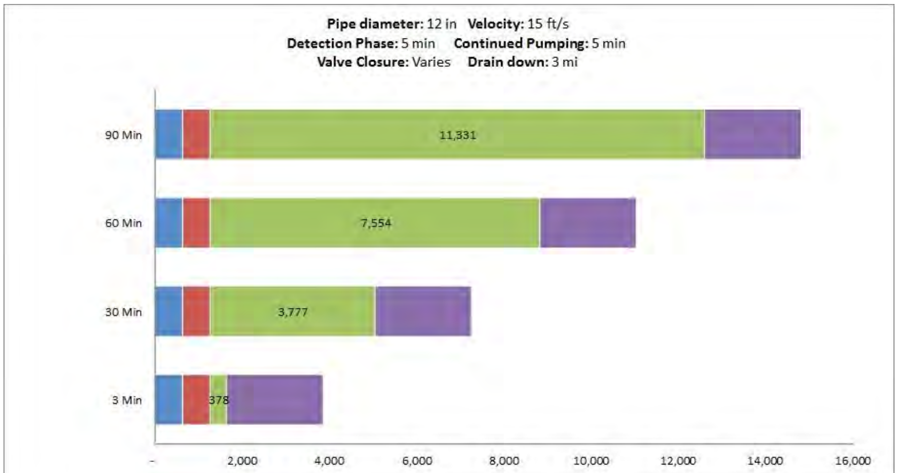
	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

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.

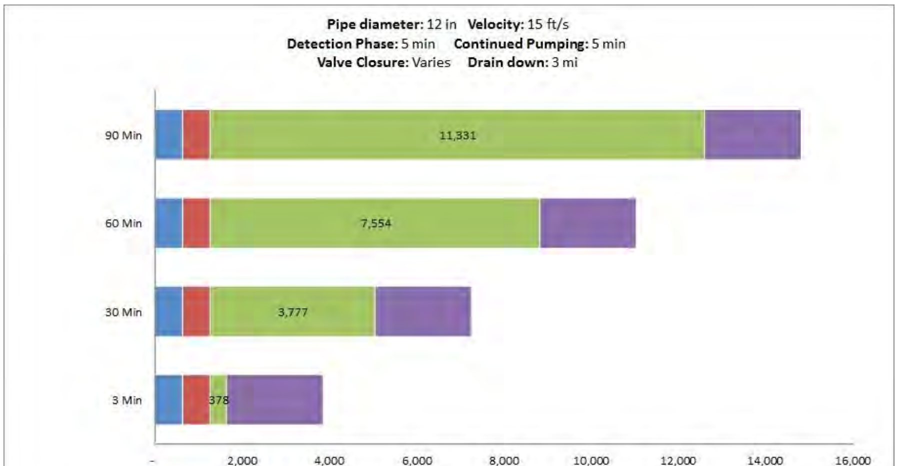


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

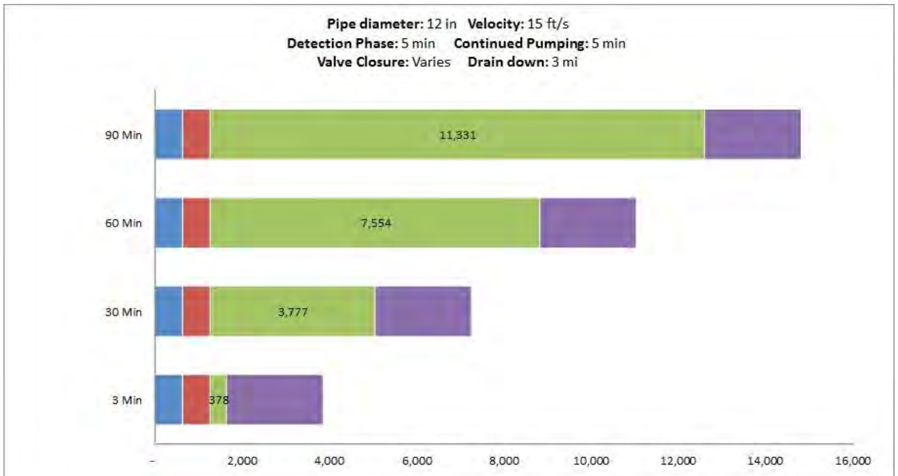


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

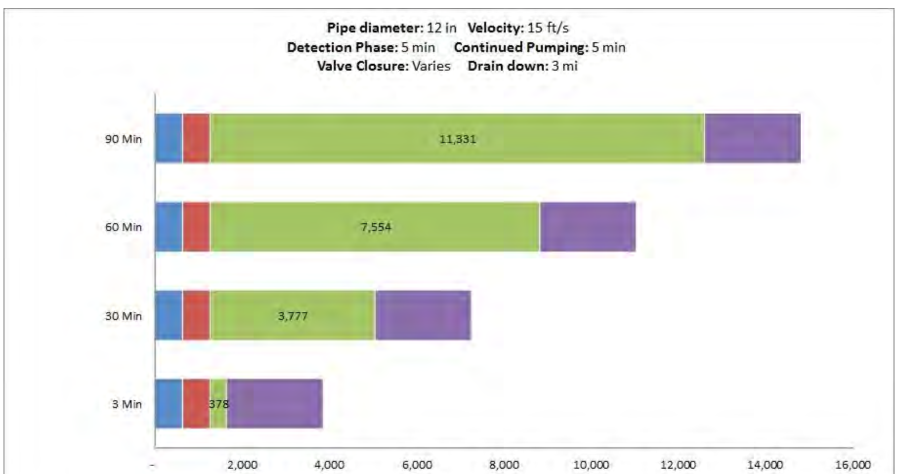


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

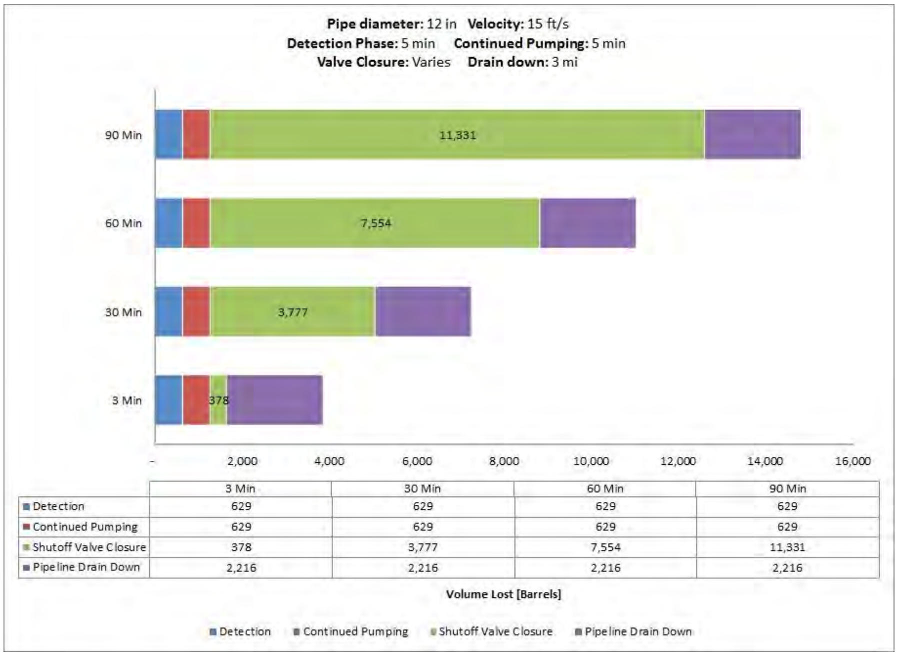


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

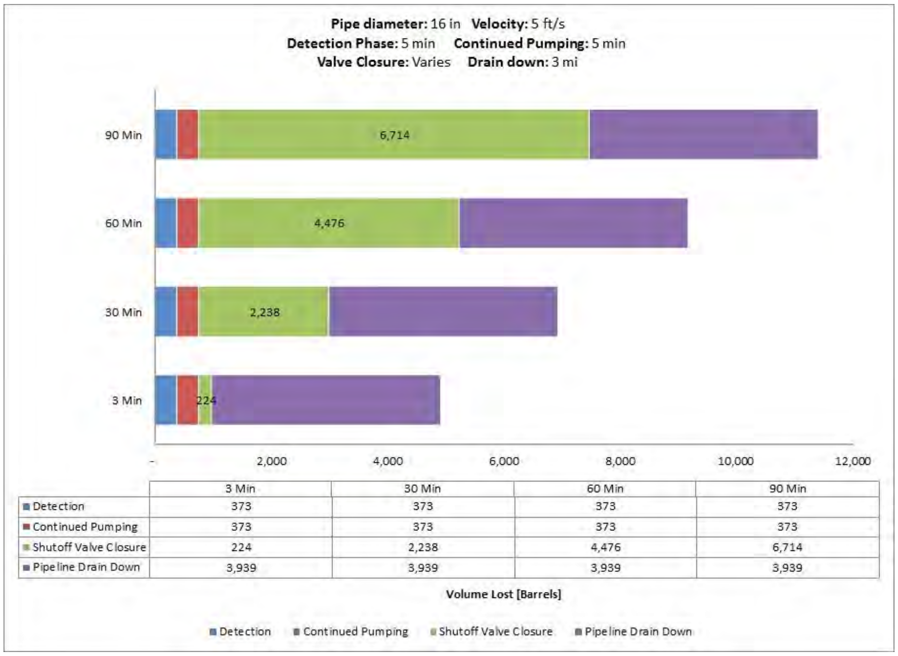


	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

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

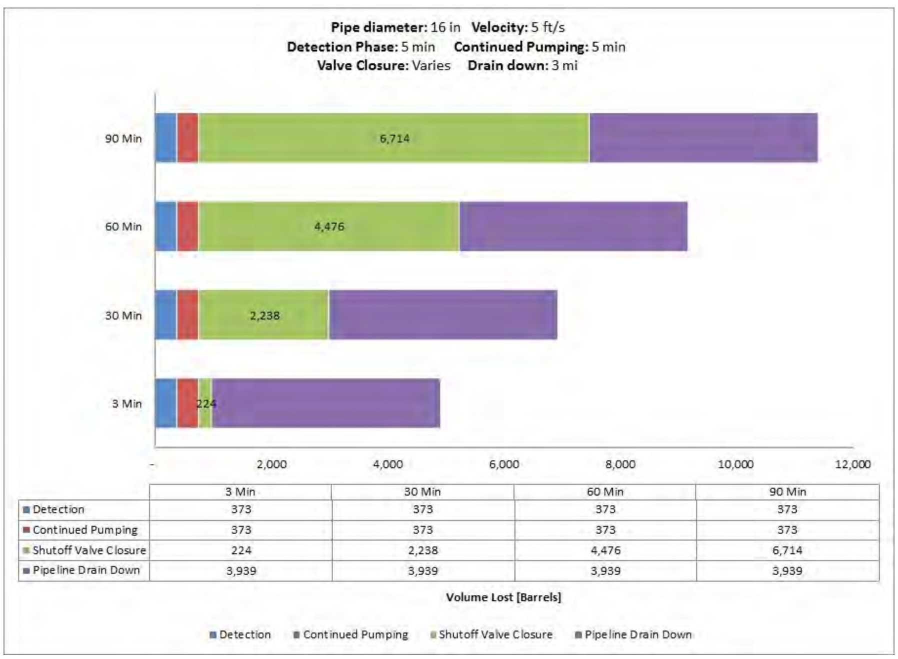
	3 Min	30 Min	60 Min	90 Min
Detection	629	629	629	629
Continued Pumping	629	629	629	629
Shutoff Valve Closure	378	3,777	7,554	11,331
Pipeline Drain Down	2,216	2,216	2,216	2,216

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



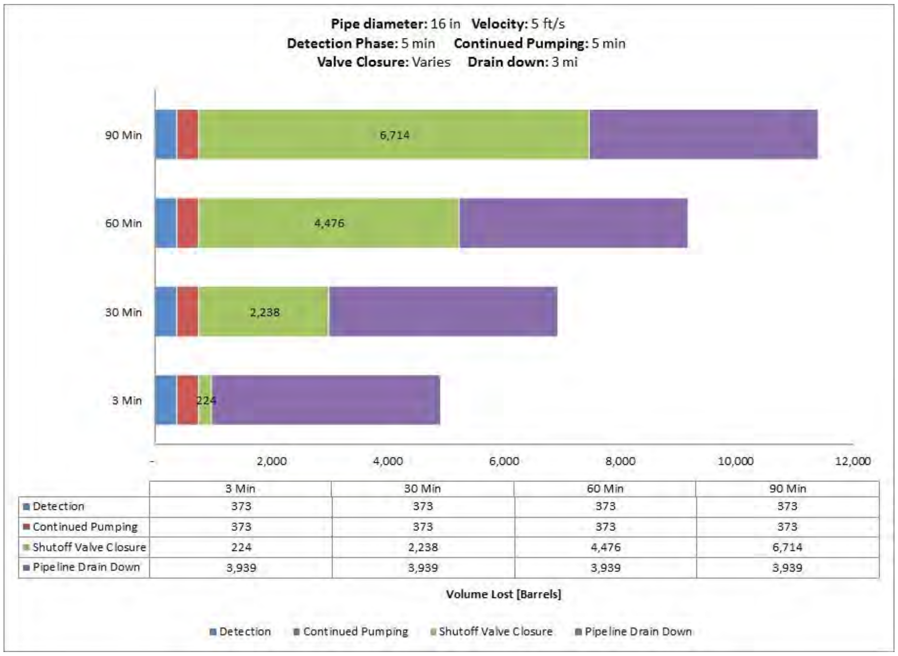
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



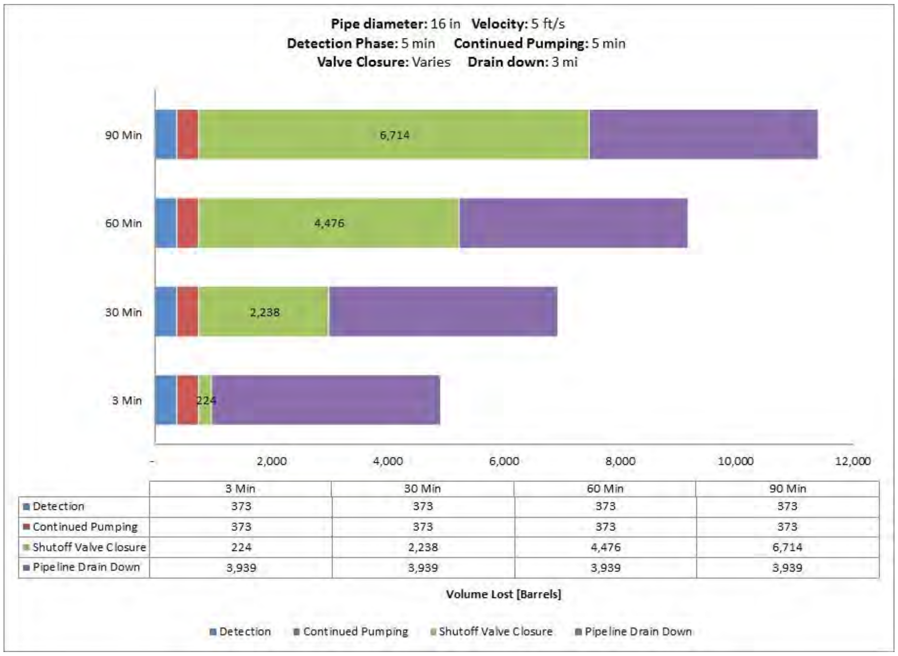
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



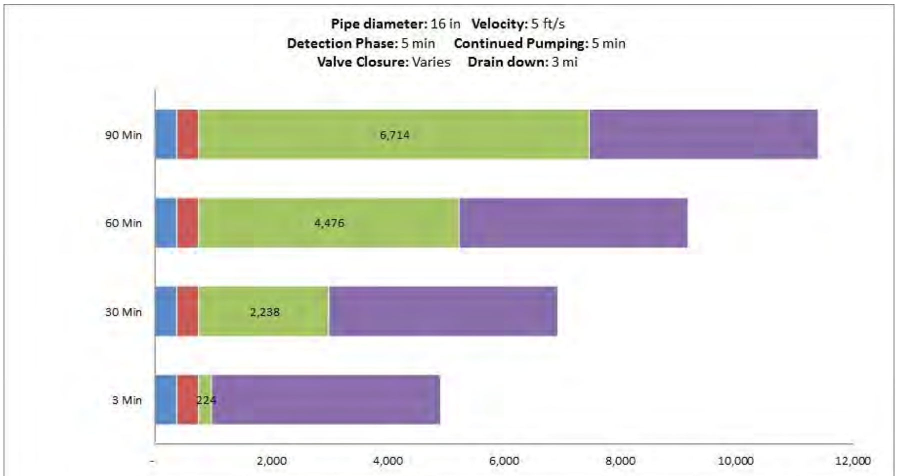
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Fig. A-75. 16 Inch Pipe Diameter, 5 ft/s, 400 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-76. 16 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.

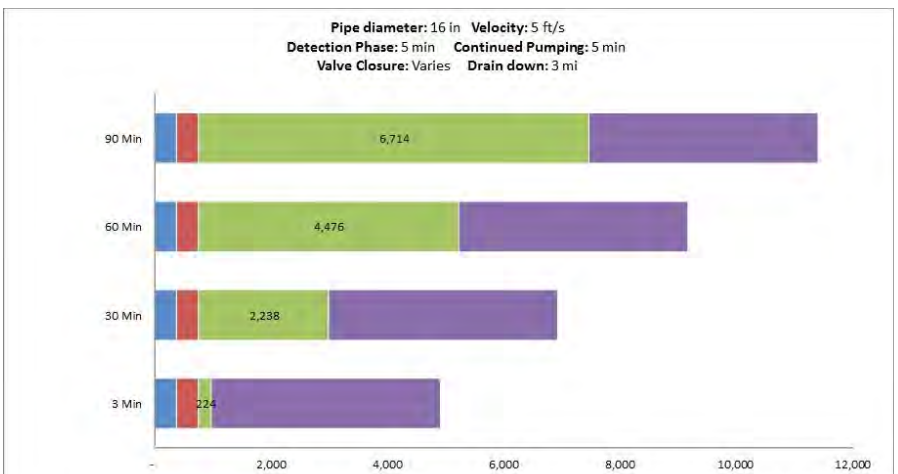


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection　Continued Pumping　Shutoff Valve Closure　Pipeline Drain Down

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

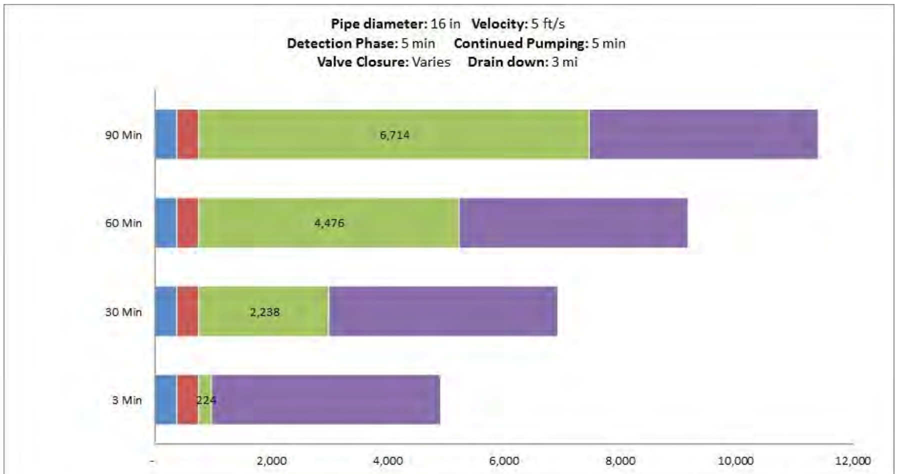


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection　Continued Pumping　Shutoff Valve Closure　Pipeline Drain Down

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

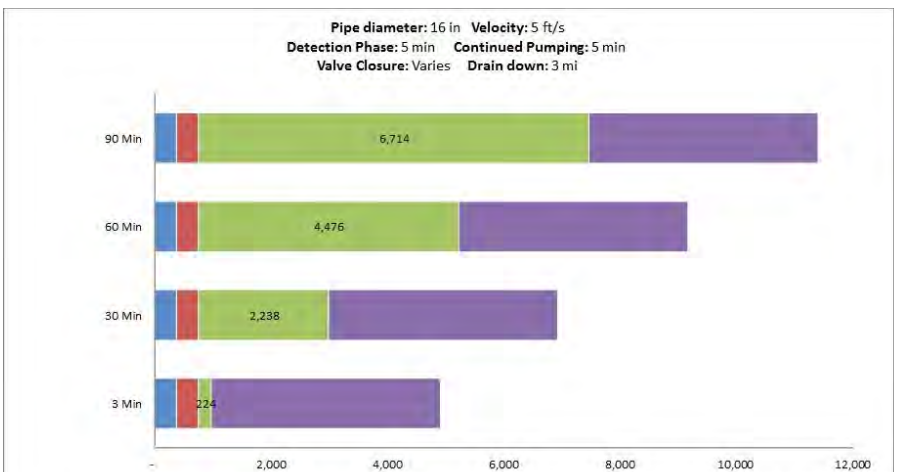


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection   Continued Pumping   Shutoff Valve Closure   Pipeline Drain Down

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

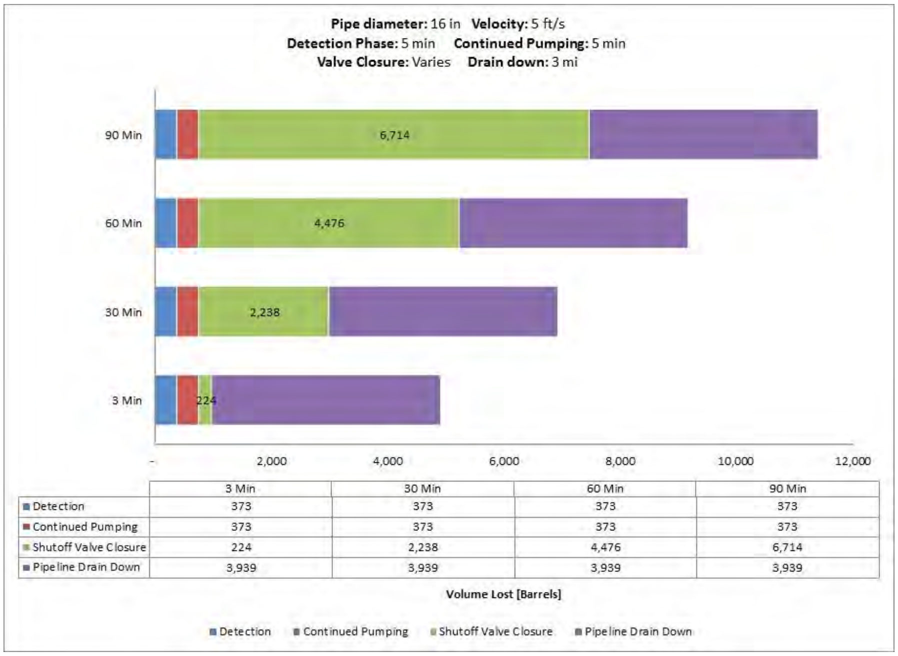


	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

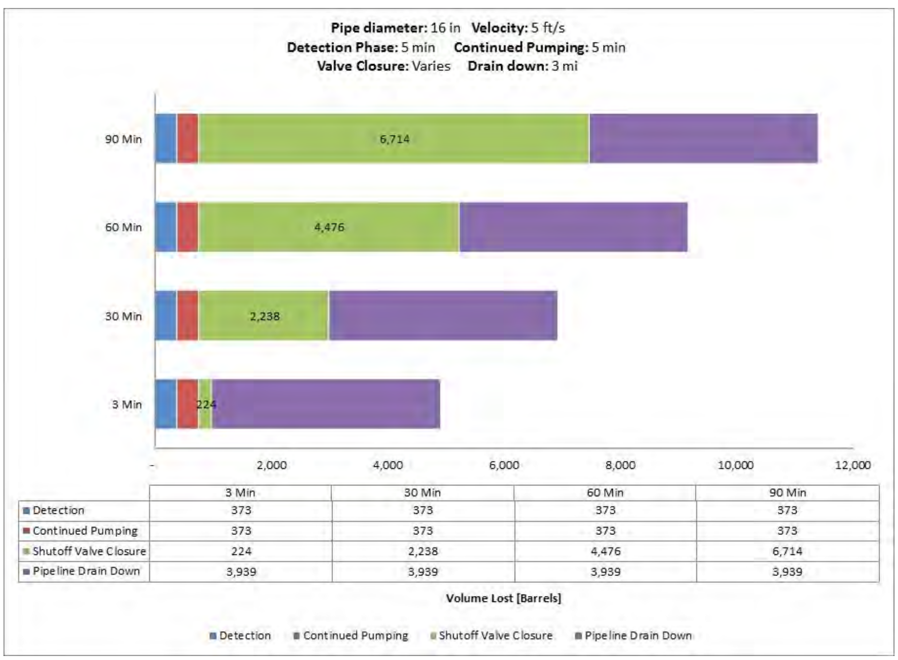
Detection   Continued Pumping   Shutoff Valve Closure   Pipeline Drain Down

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



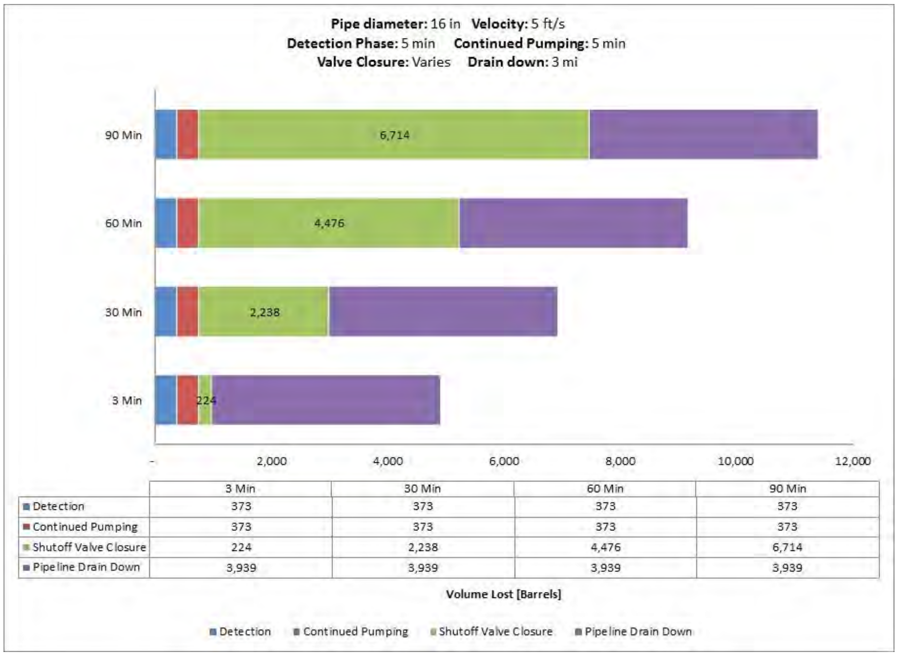
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



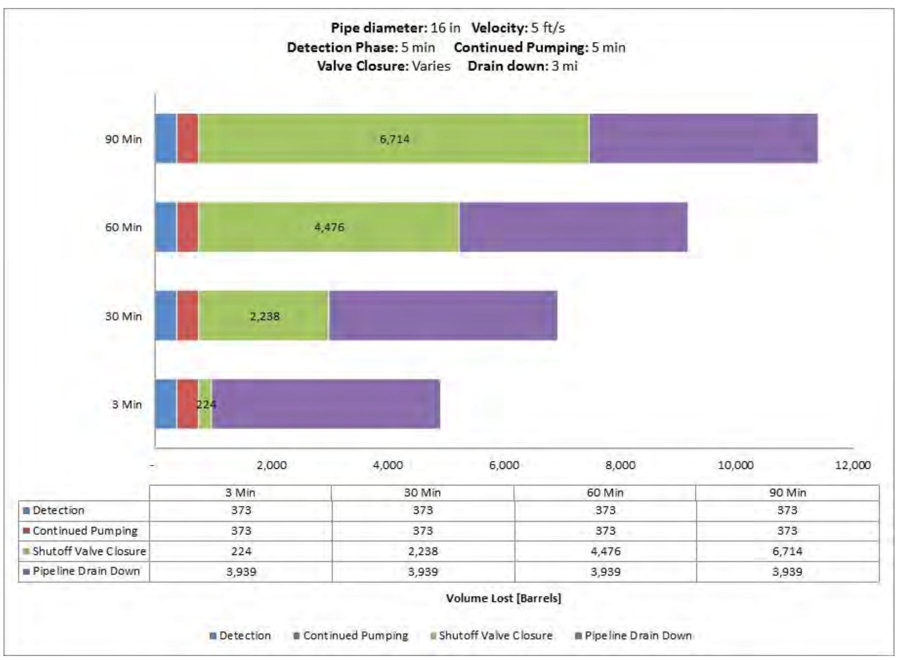
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



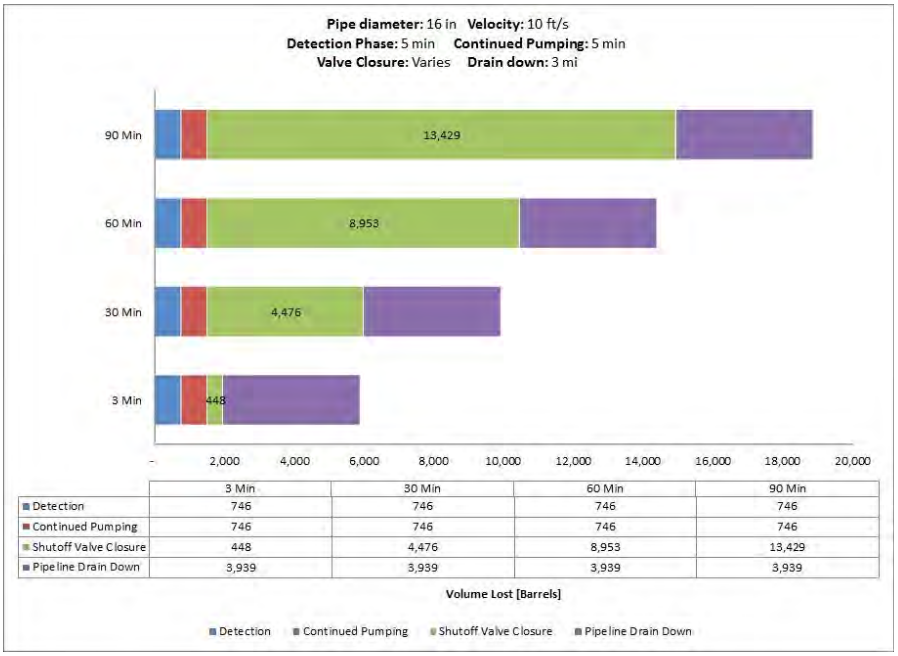
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



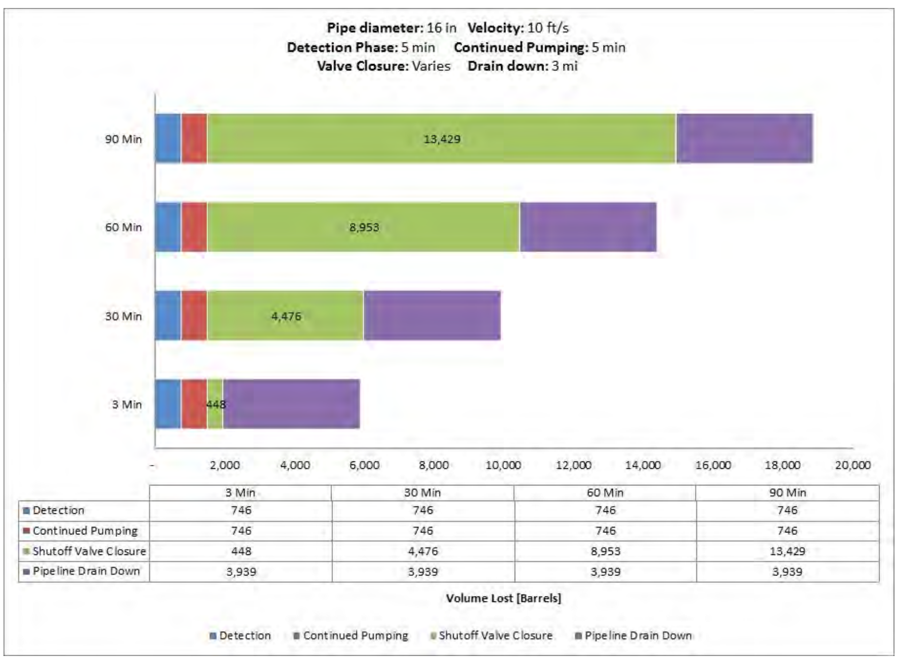
	3 Min	30 Min	60 Min	90 Min
Detection	373	373	373	373
Continued Pumping	373	373	373	373
Shutoff Valve Closure	224	2,238	4,476	6,714
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



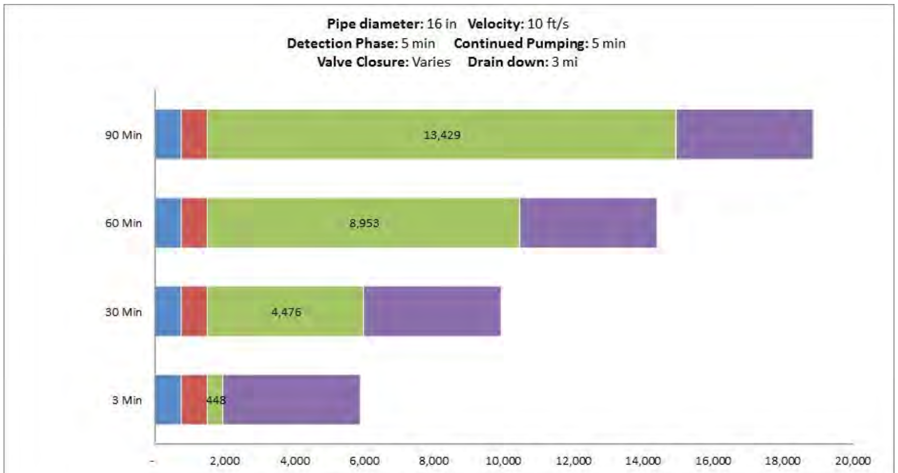
	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

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

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

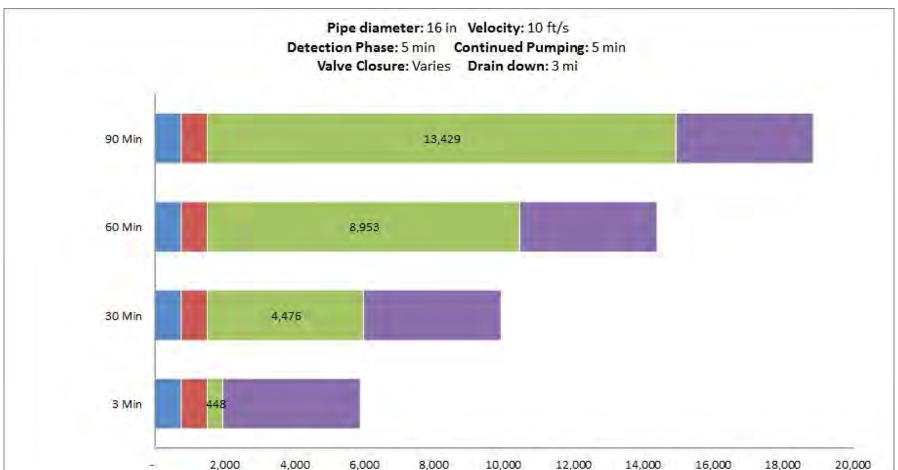


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

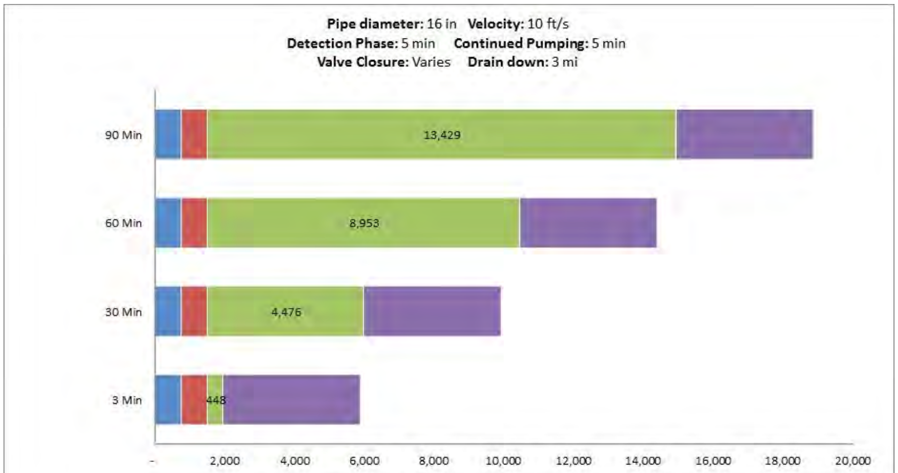


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

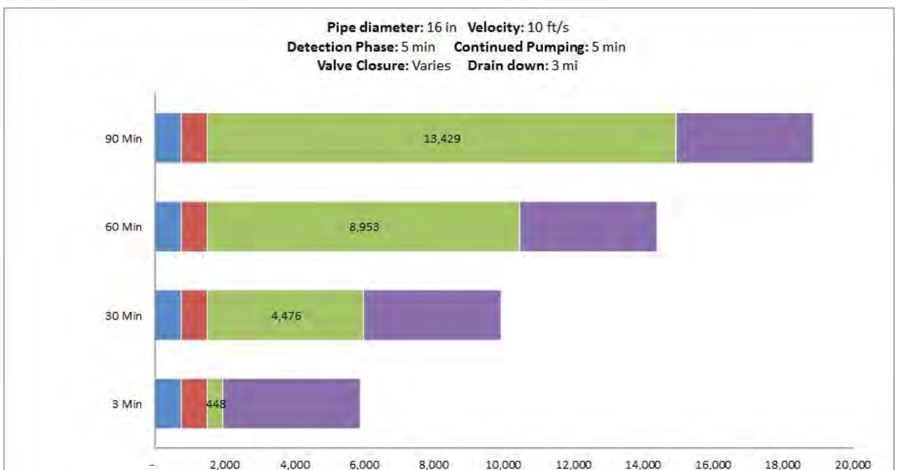


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

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.

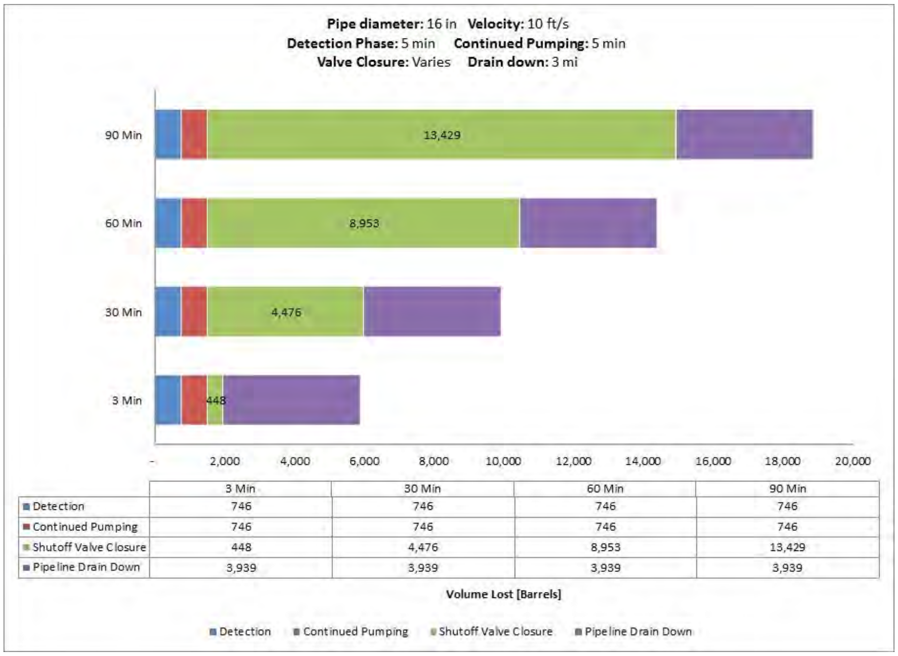


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

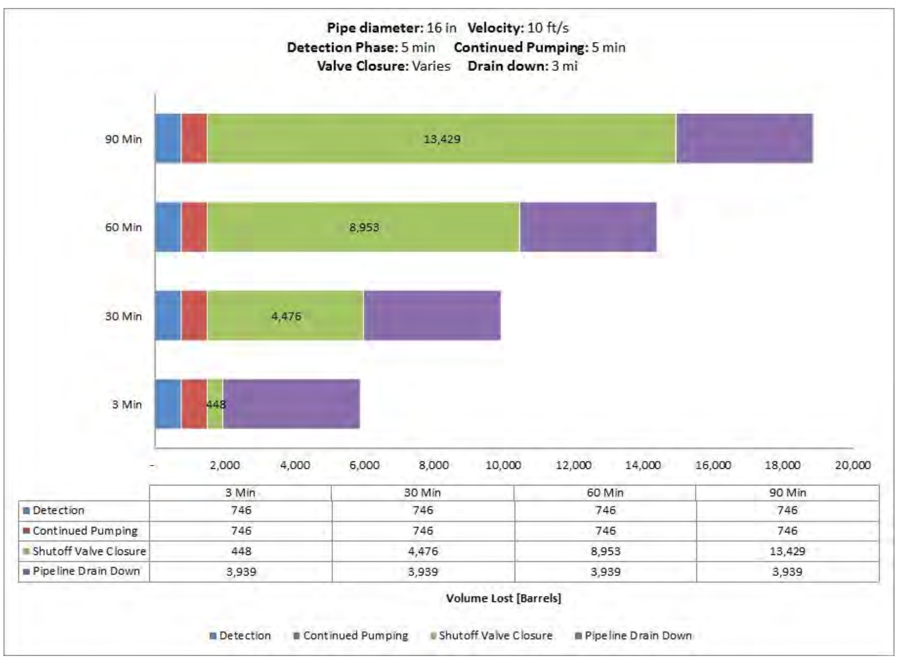
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



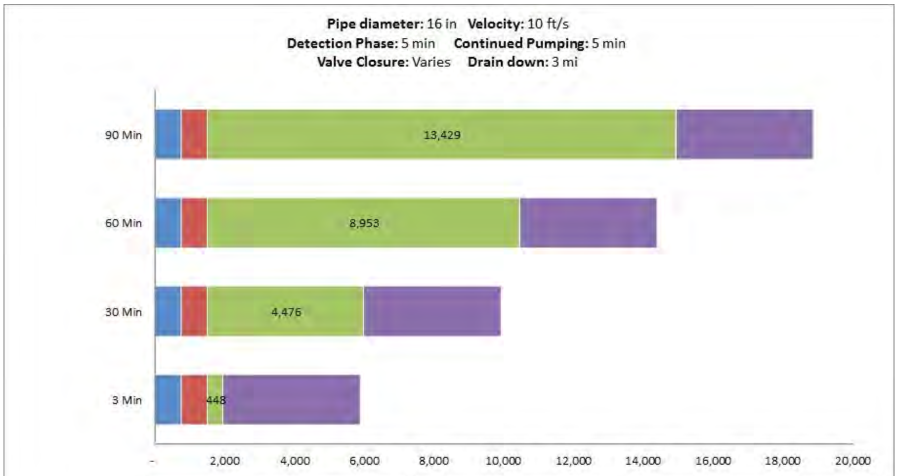
	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

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

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

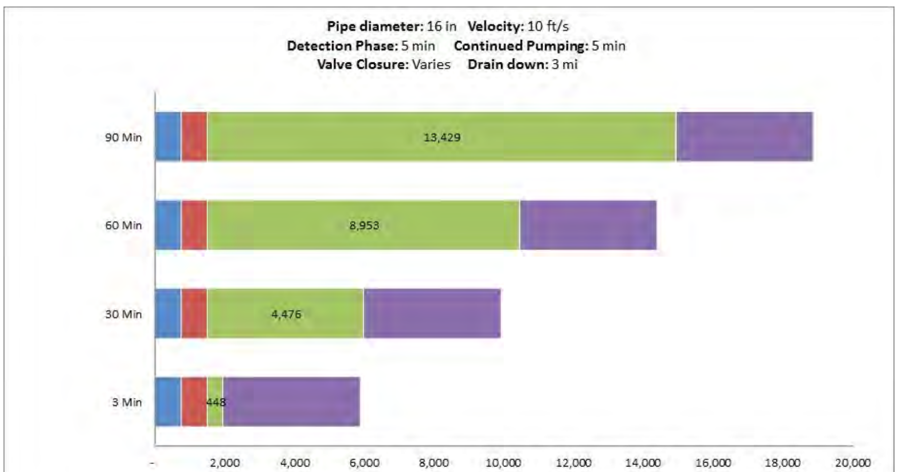


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

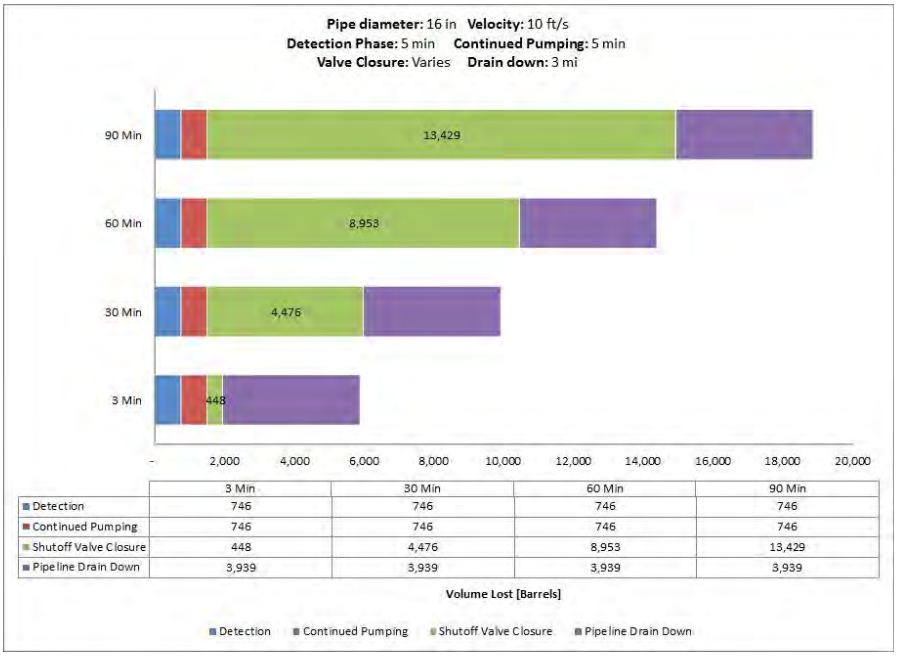


	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

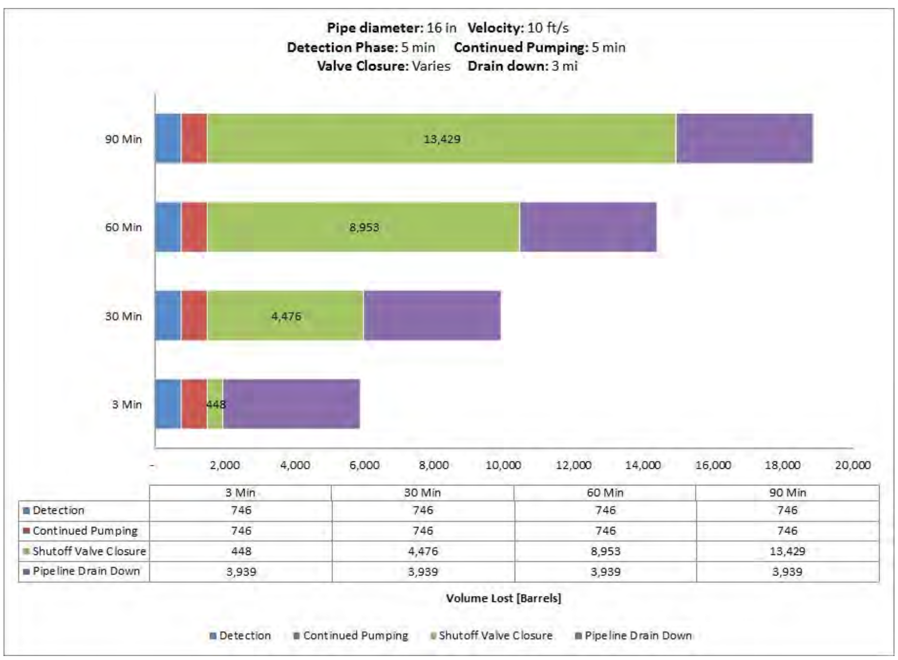
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



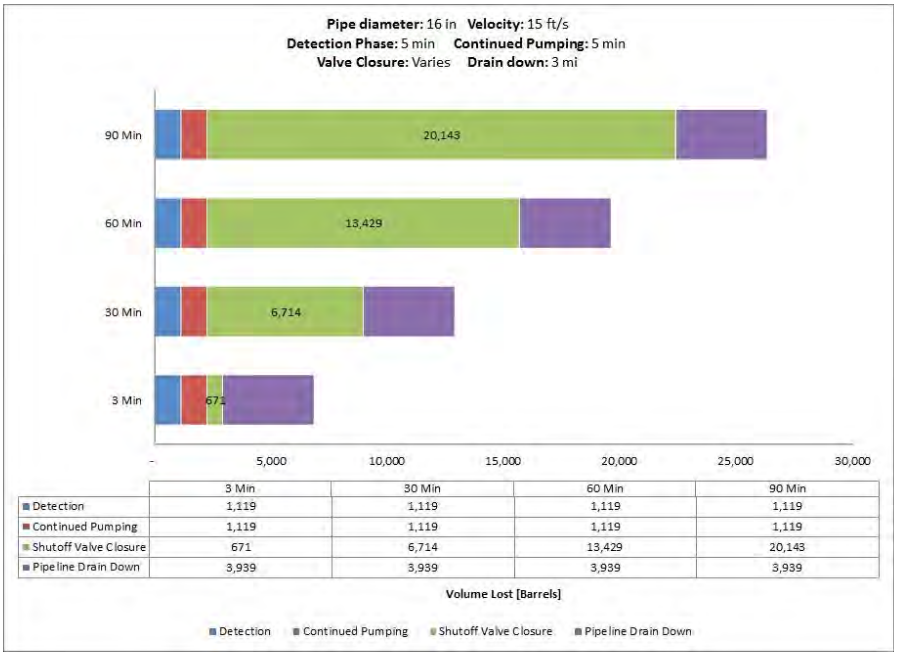
	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



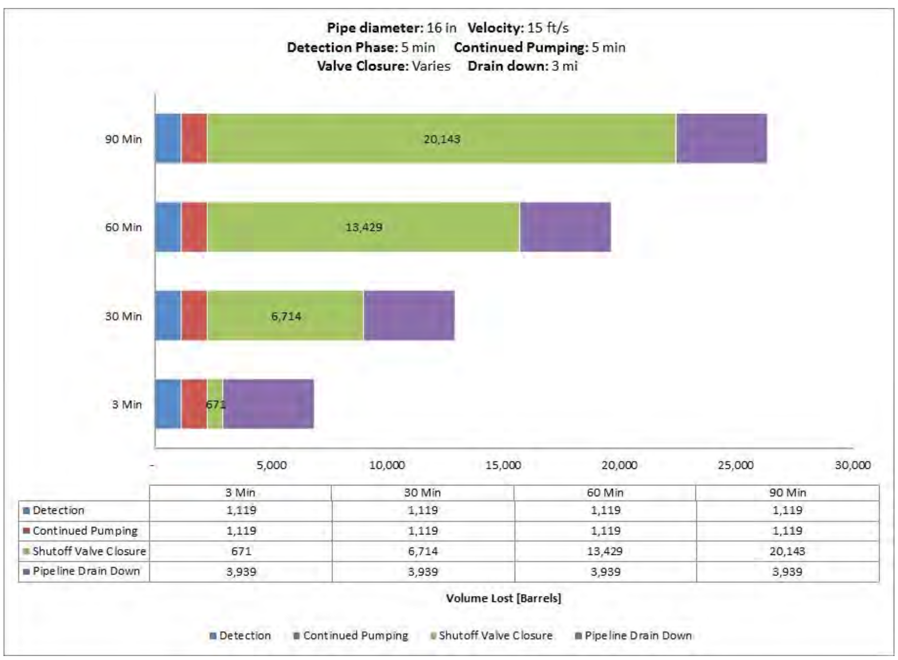
	3 Min	30 Min	60 Min	90 Min
Detection	746	746	746	746
Continued Pumping	746	746	746	746
Shutoff Valve Closure	448	4,476	8,953	13,429
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



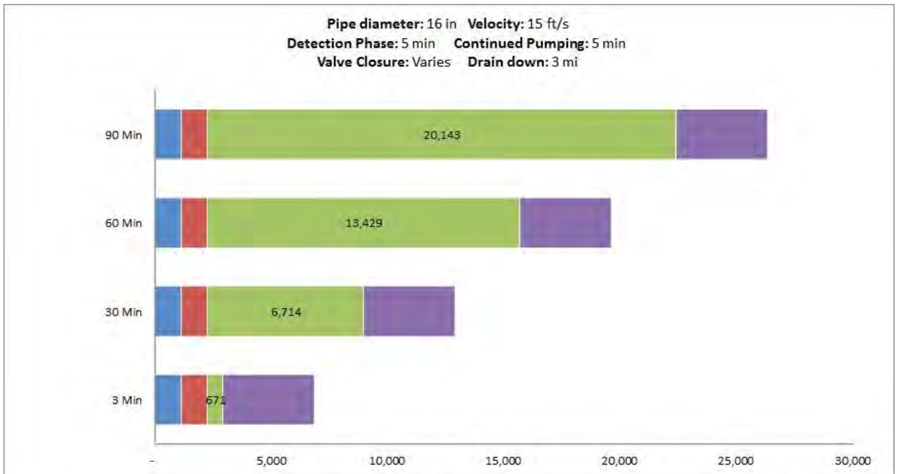
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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.

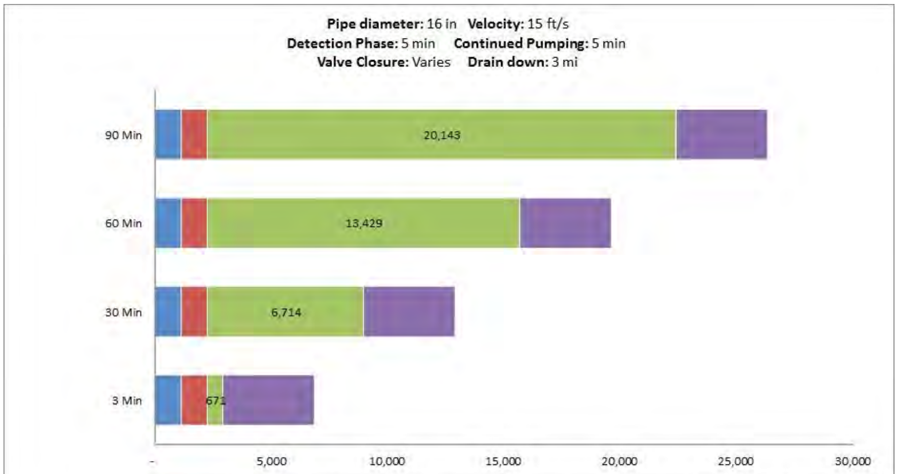


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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.

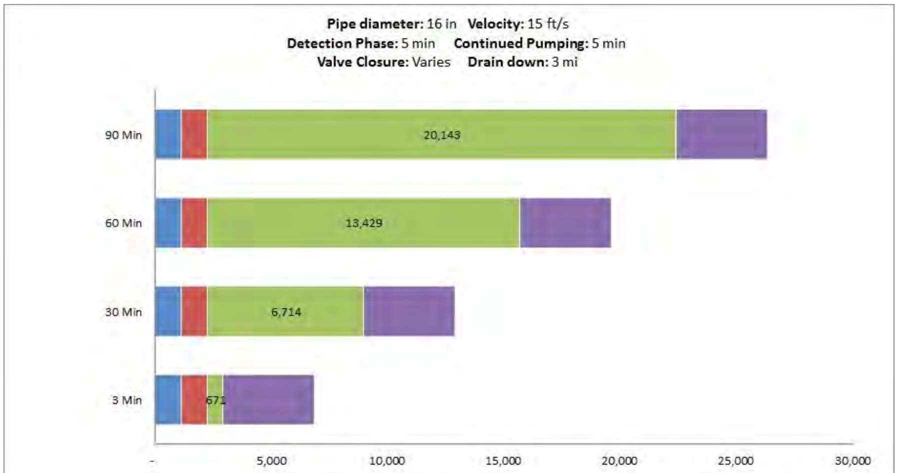


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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.

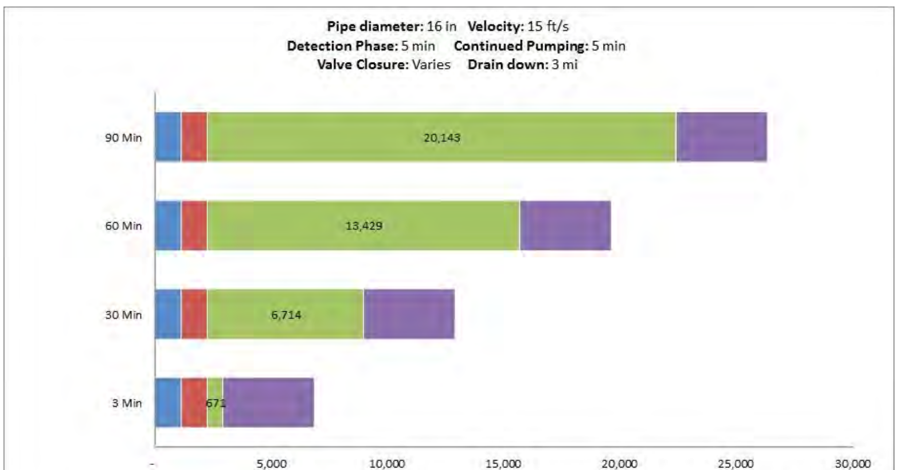


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

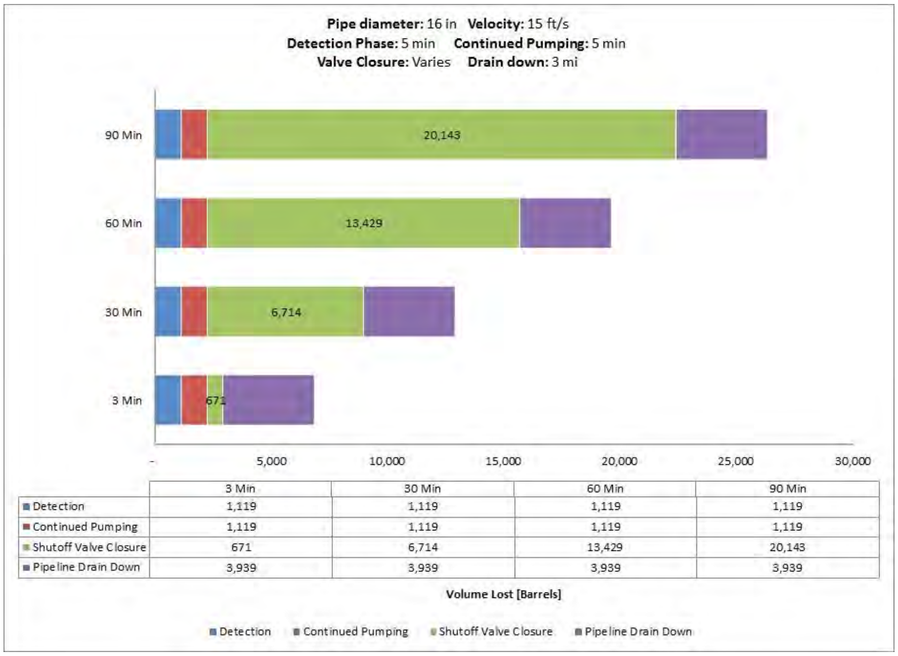


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

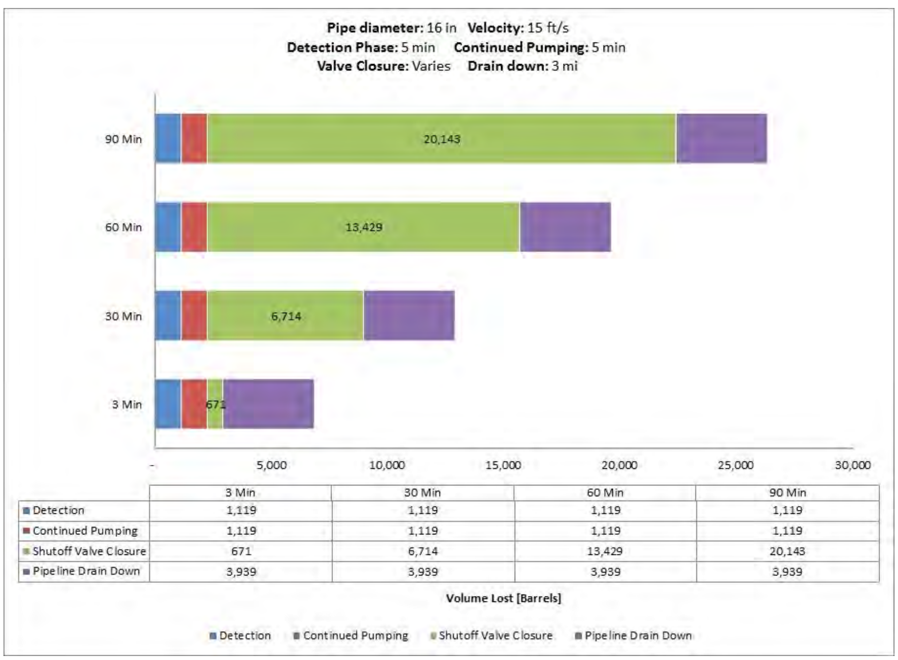
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



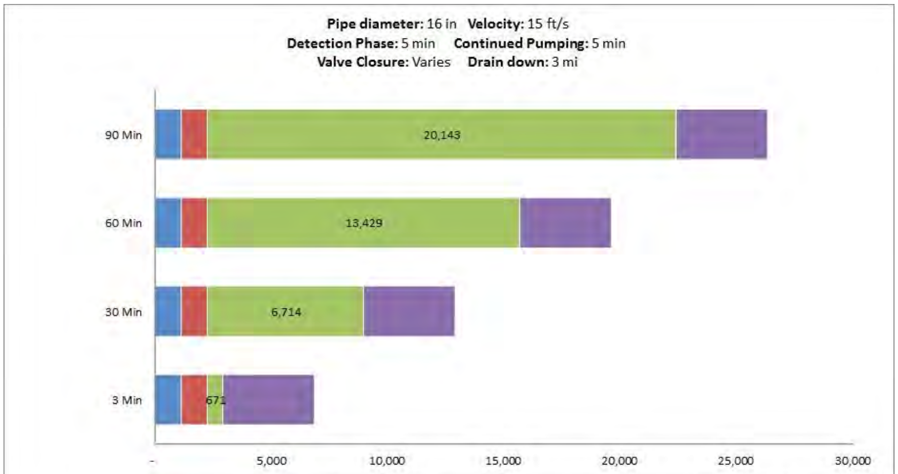
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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.

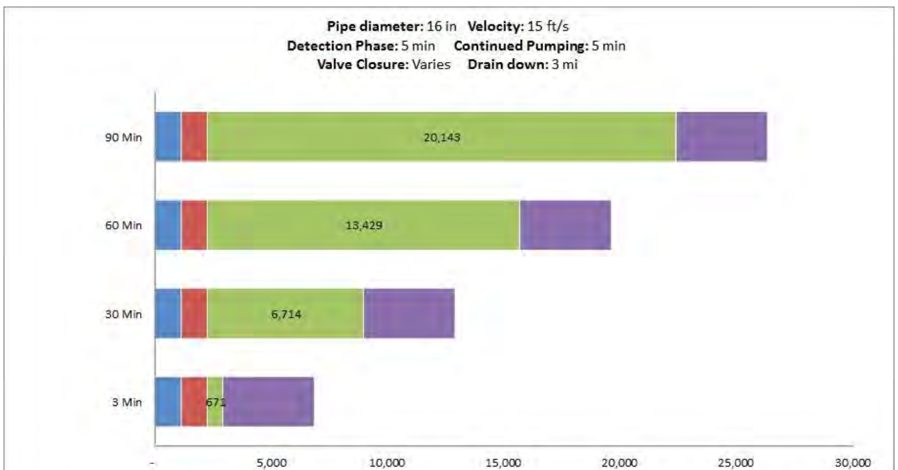


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

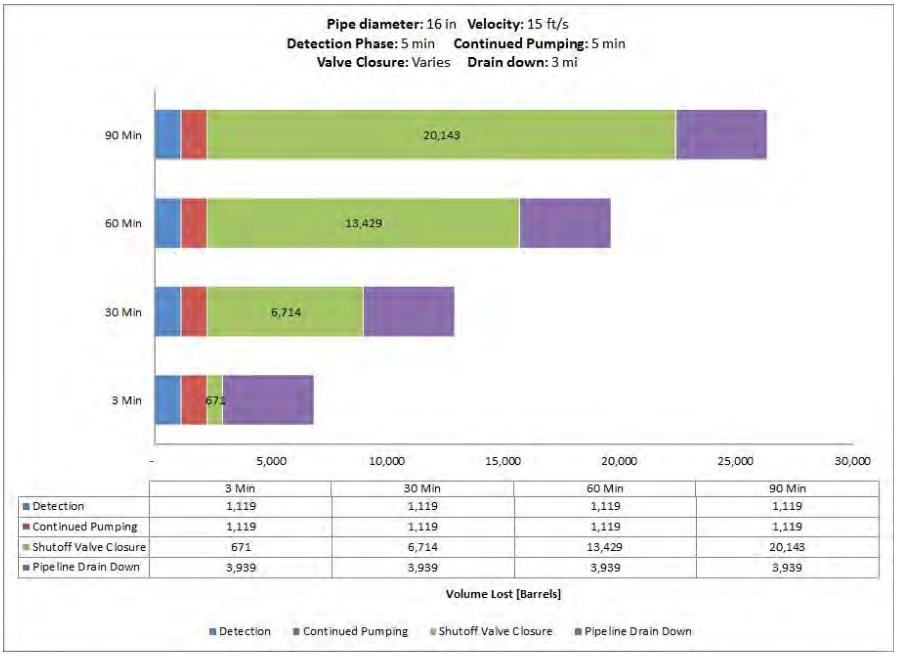


	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

Volume Lost [Barrels]

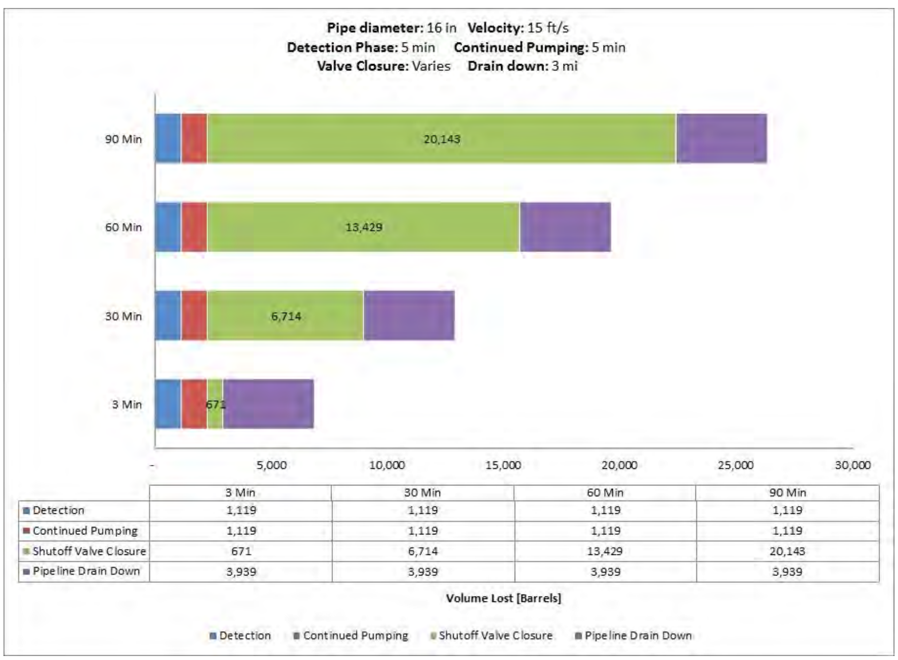
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



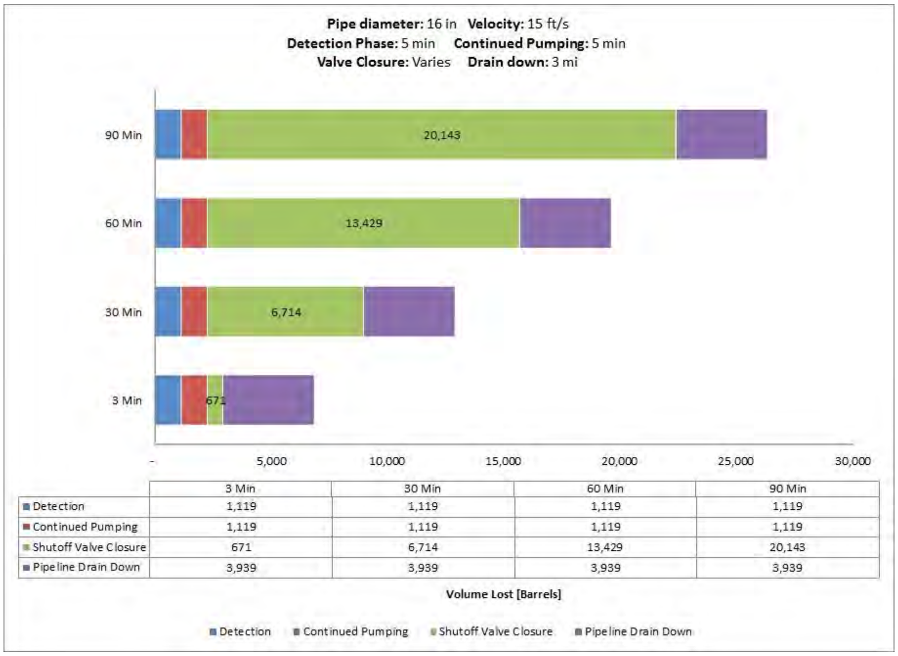
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



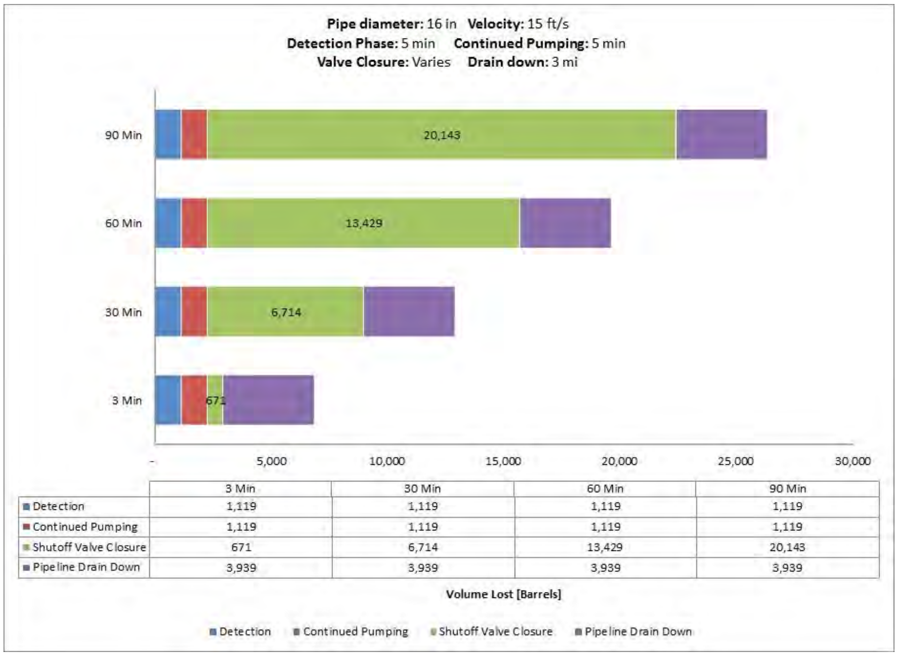
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



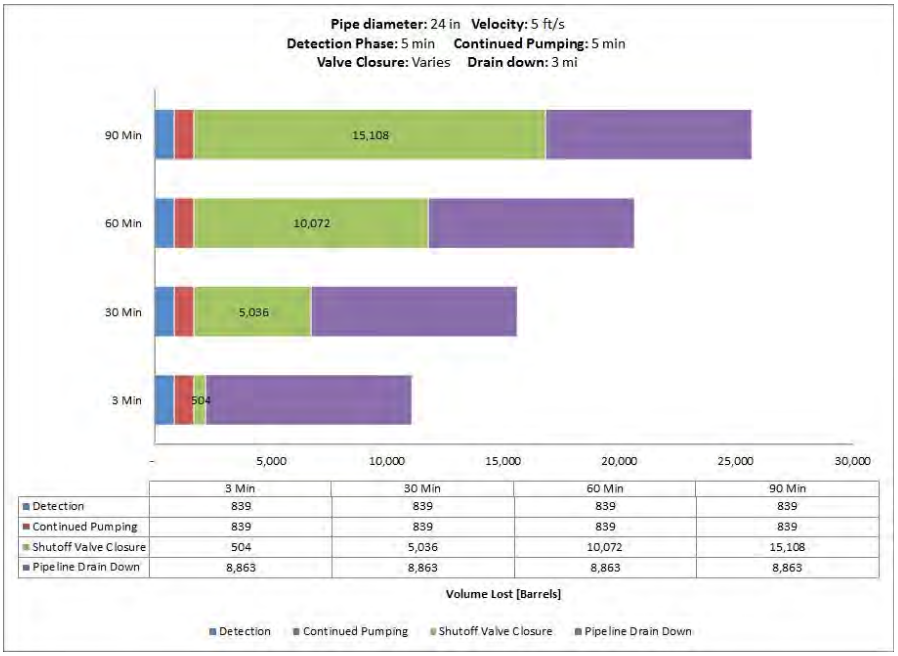
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



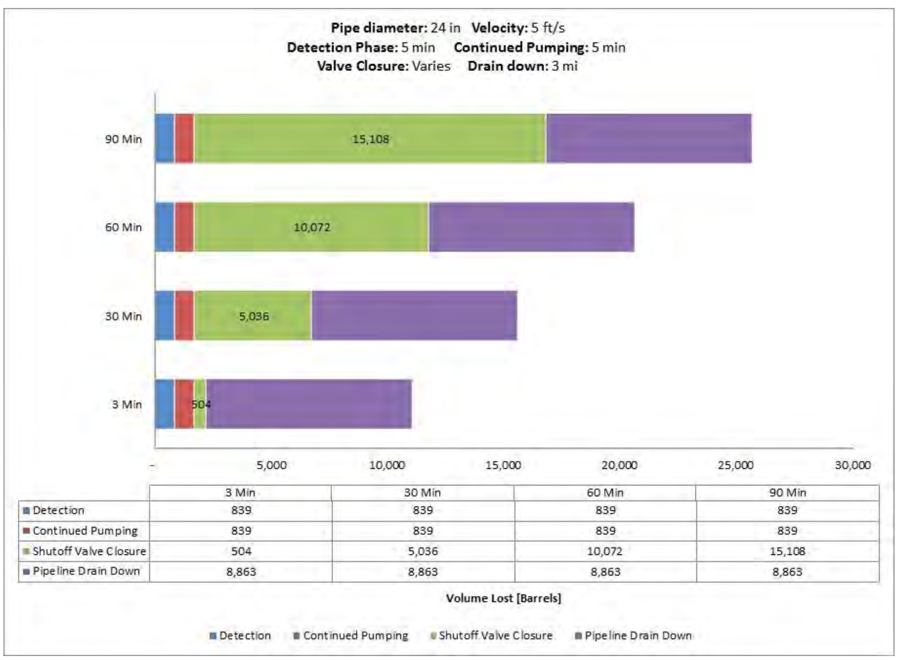
	3 Min	30 Min	60 Min	90 Min
Detection	1,119	1,119	1,119	1,119
Continued Pumping	1,119	1,119	1,119	1,119
Shutoff Valve Closure	671	6,714	13,429	20,143
Pipeline Drain Down	3,939	3,939	3,939	3,939

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



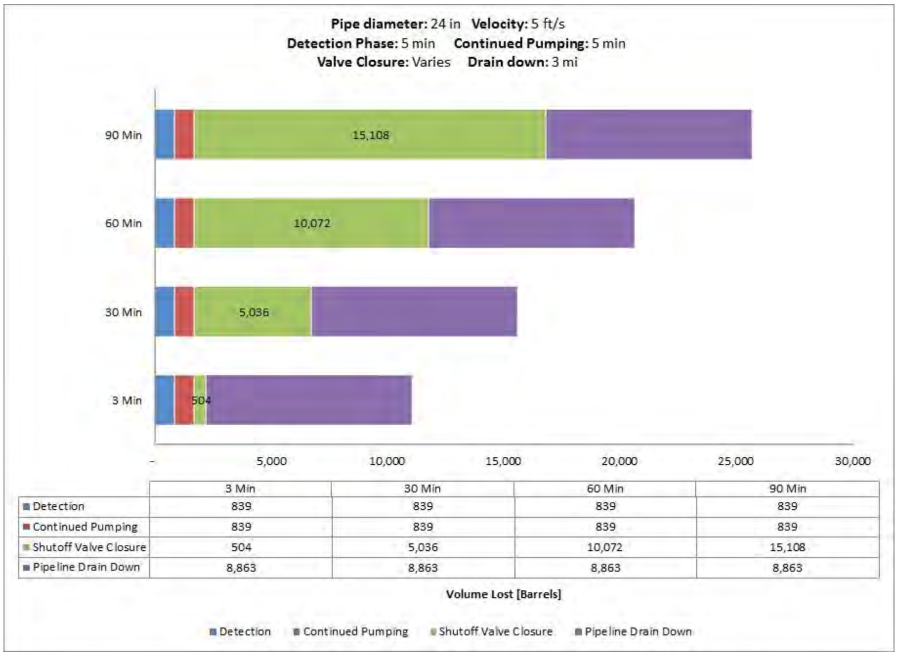
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



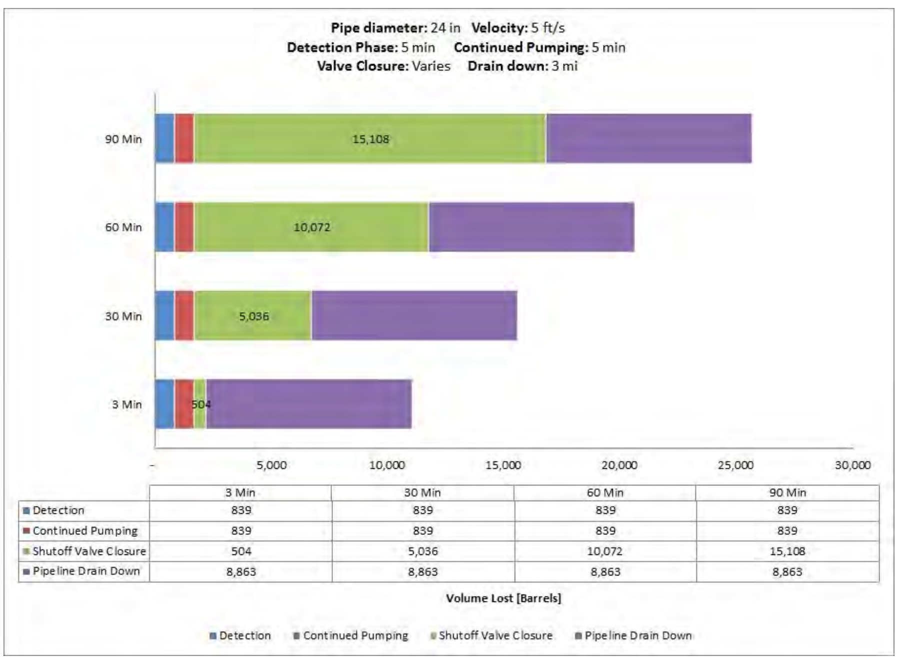
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



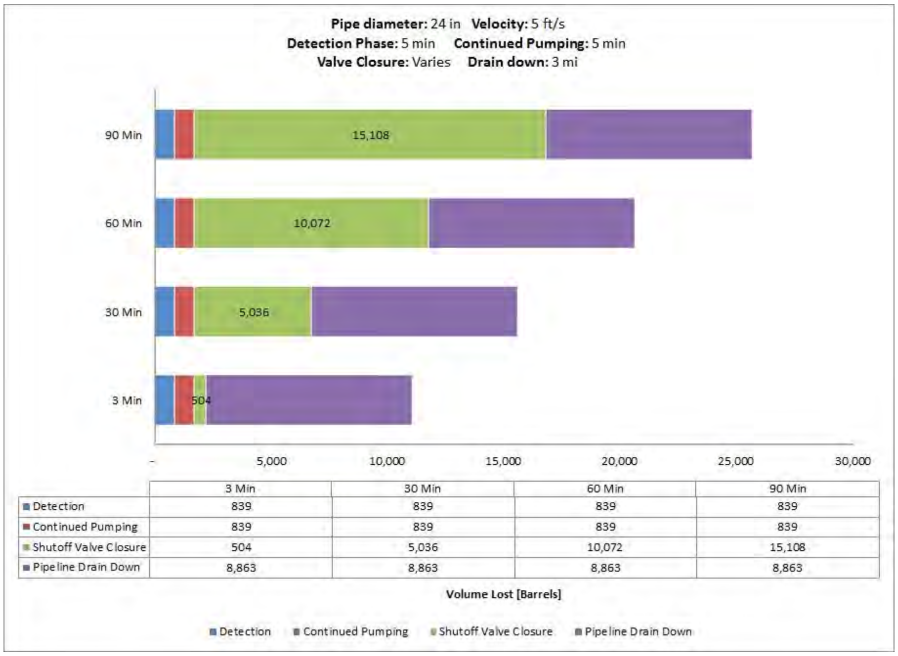
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



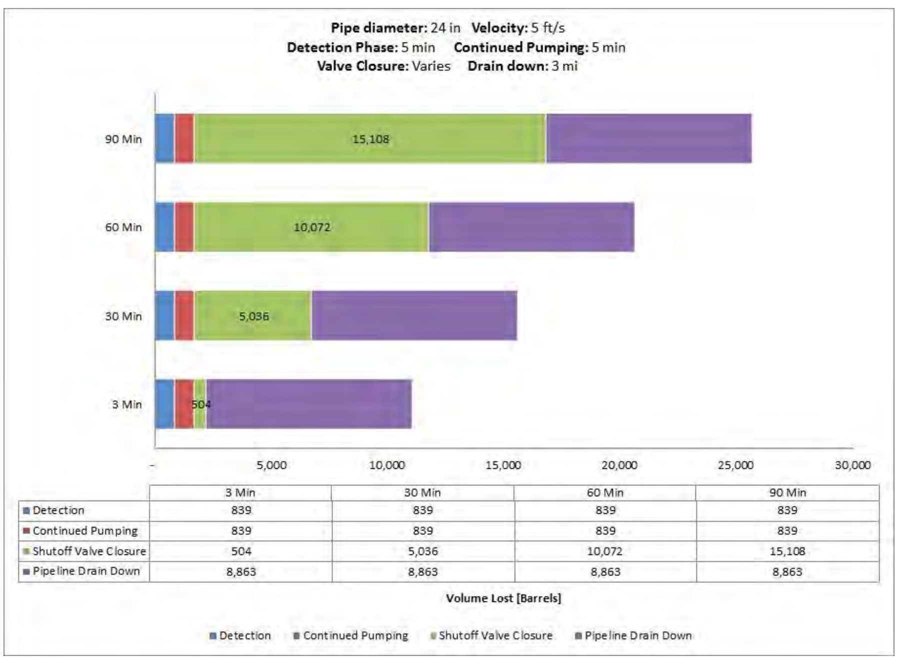
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



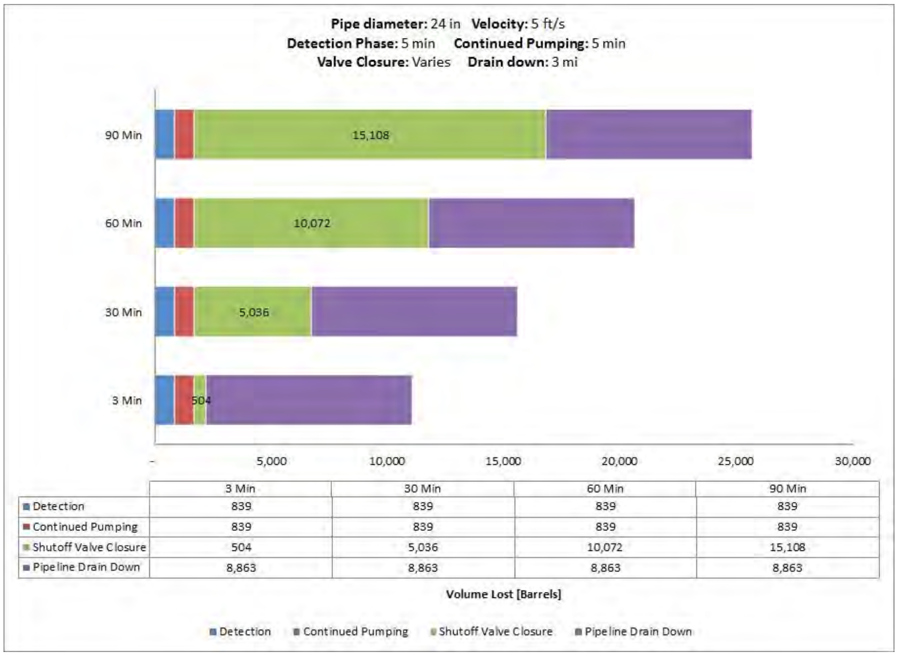
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



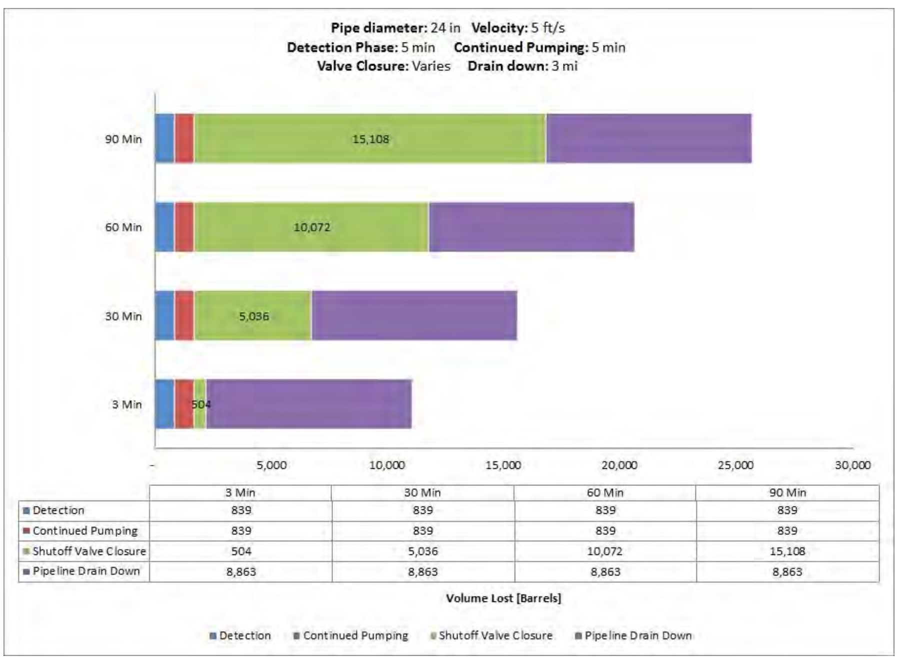
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



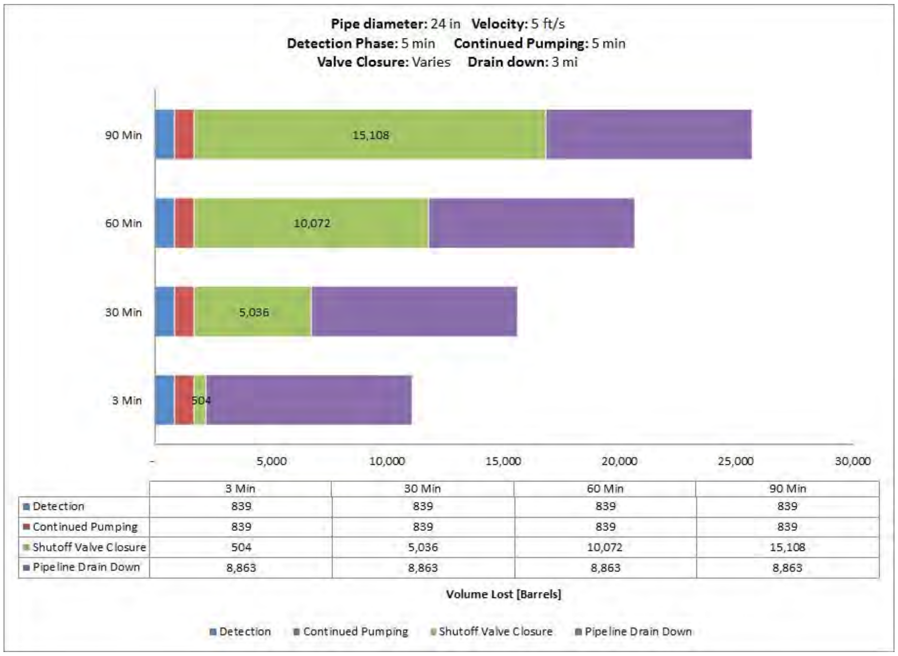
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



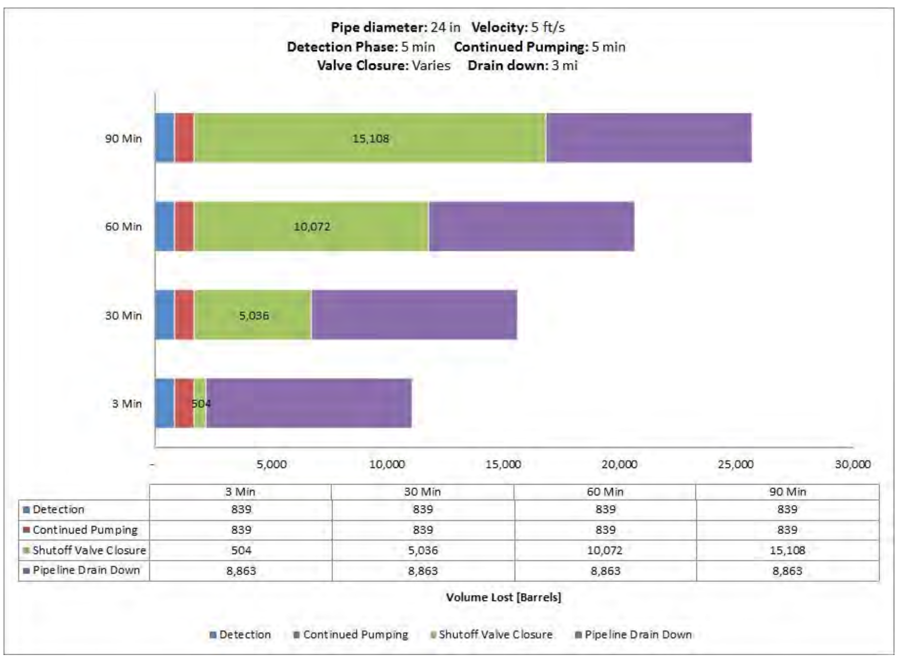
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



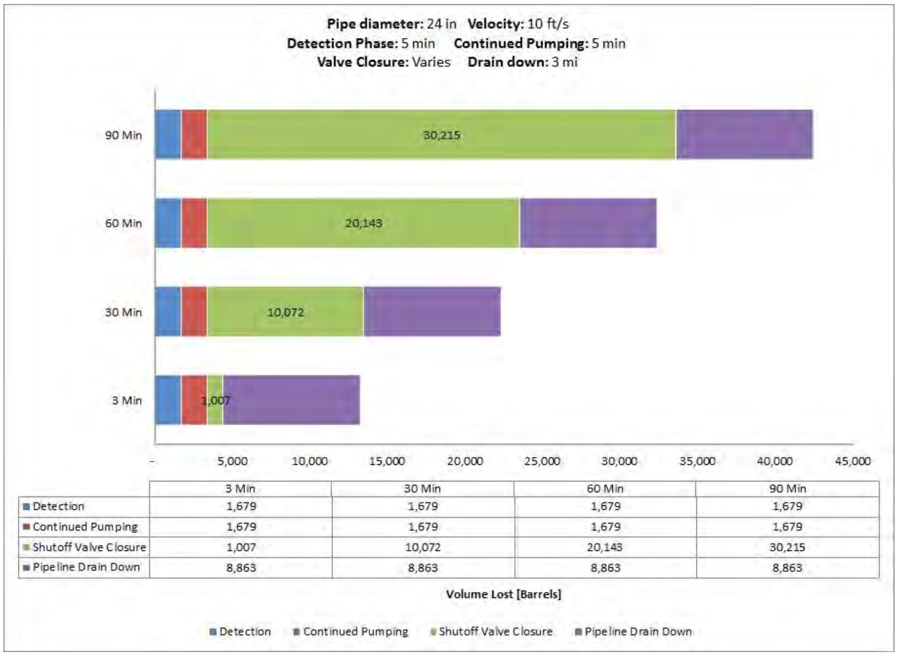
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



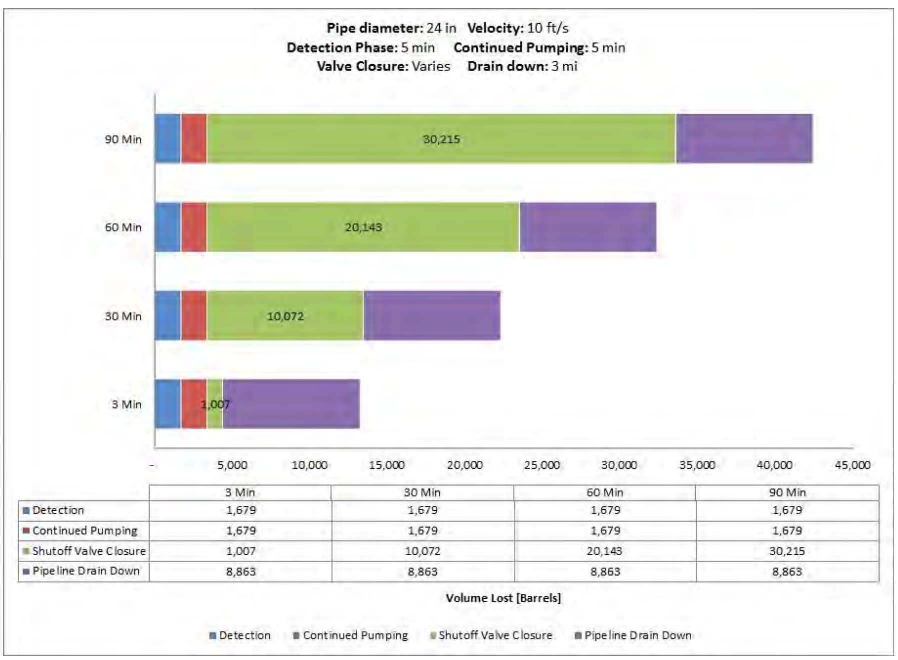
	3 Min	30 Min	60 Min	90 Min
Detection	839	839	839	839
Continued Pumping	839	839	839	839
Shutoff Valve Closure	504	5,036	10,072	15,108
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



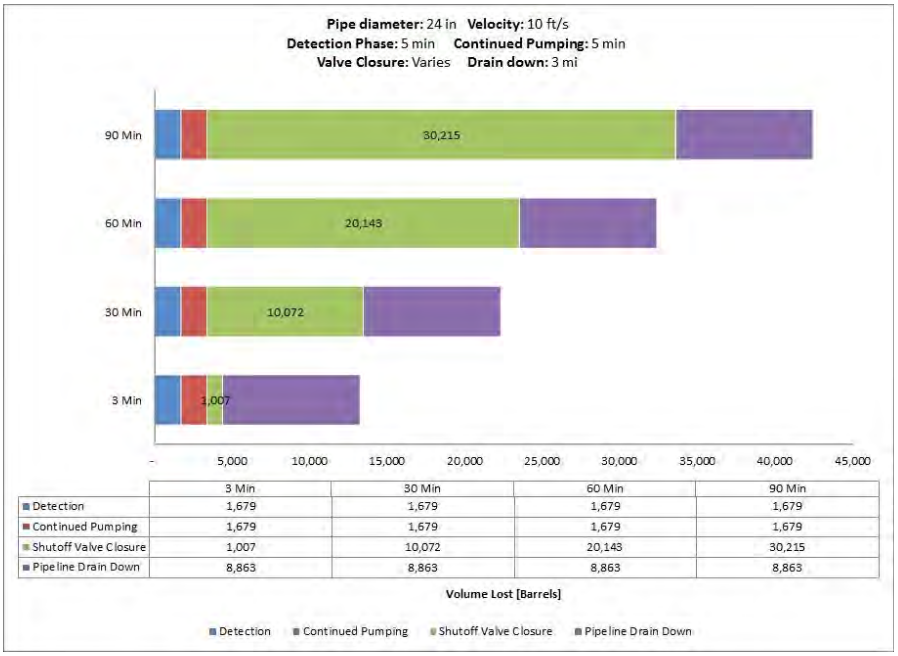
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



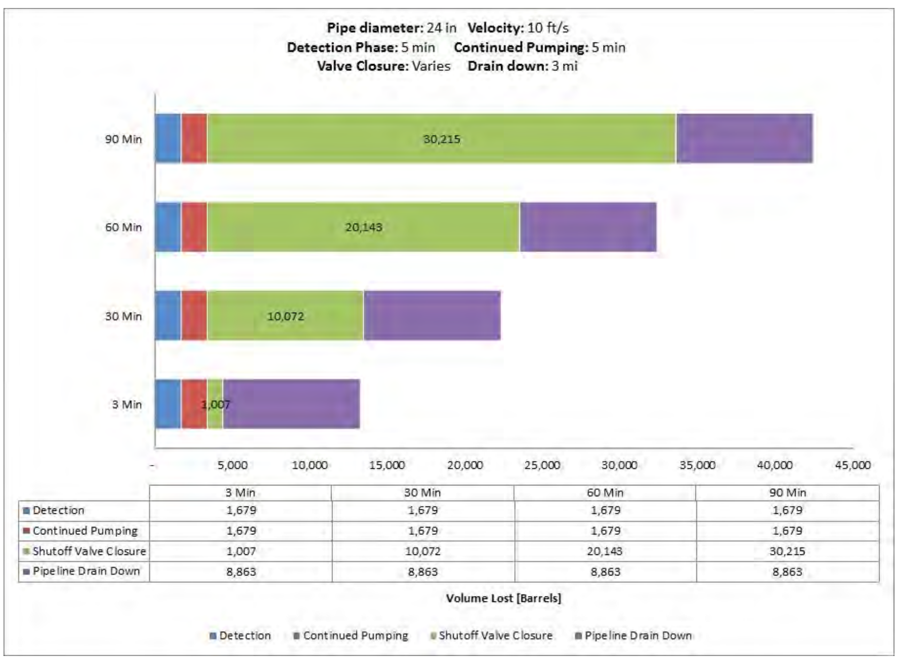
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



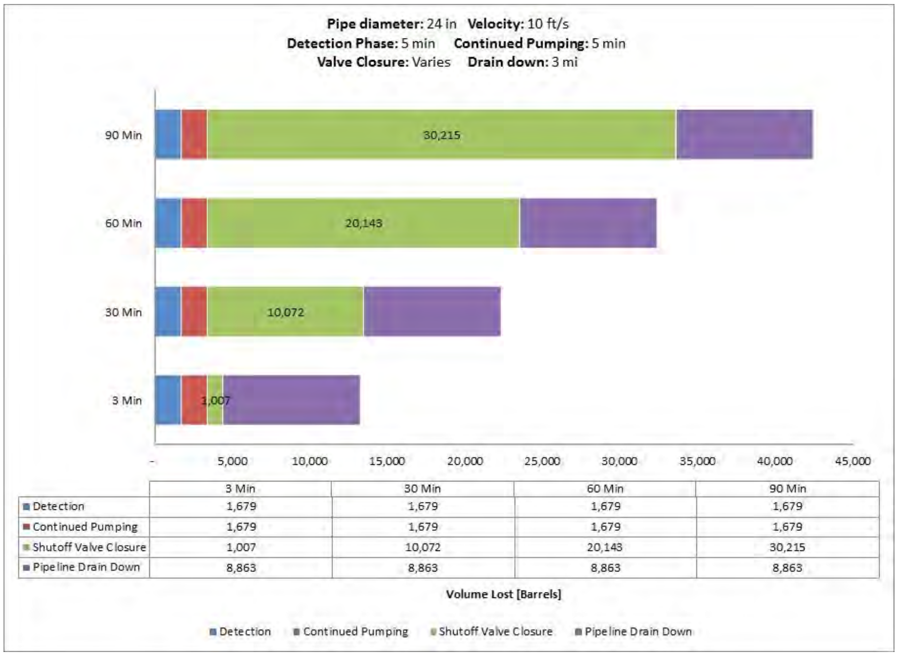
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



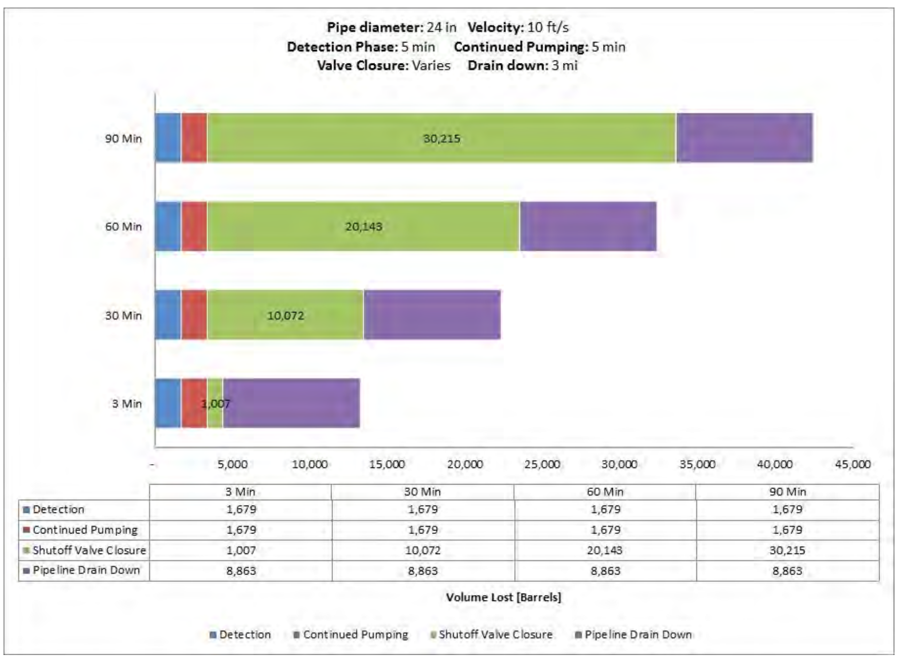
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



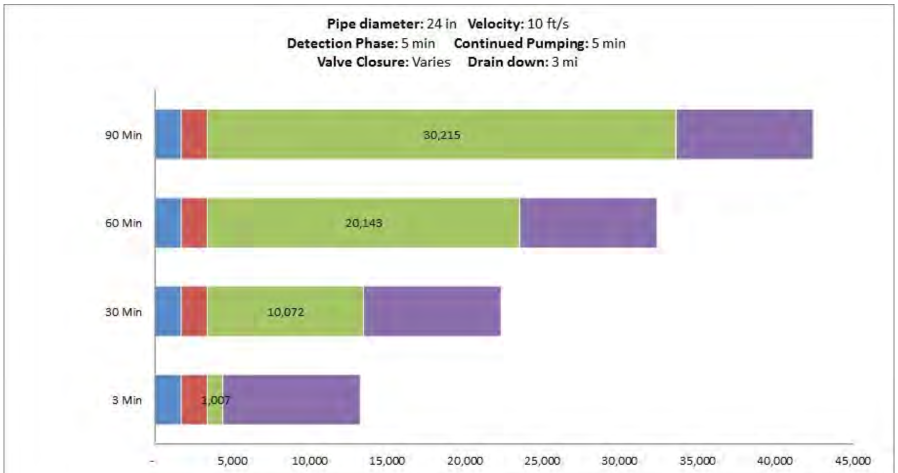
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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

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

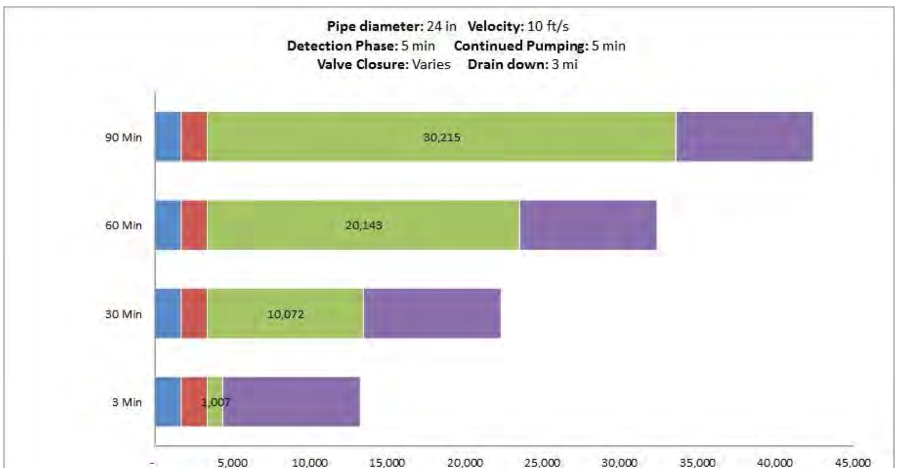


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

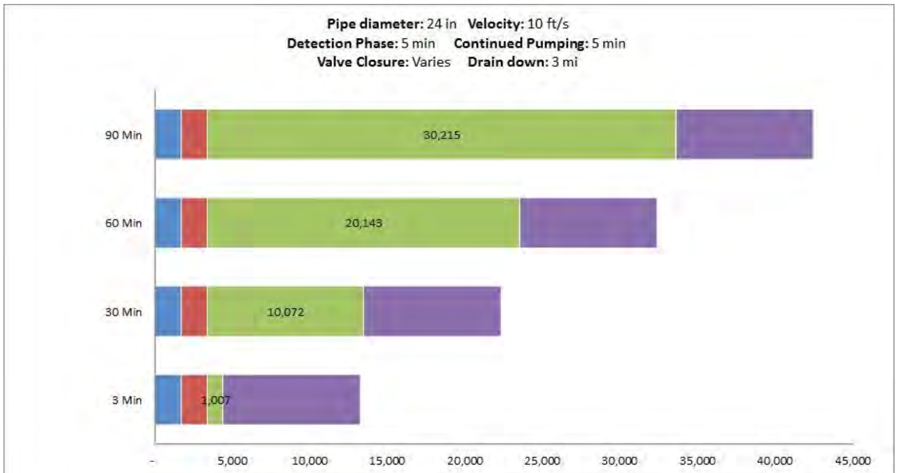


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

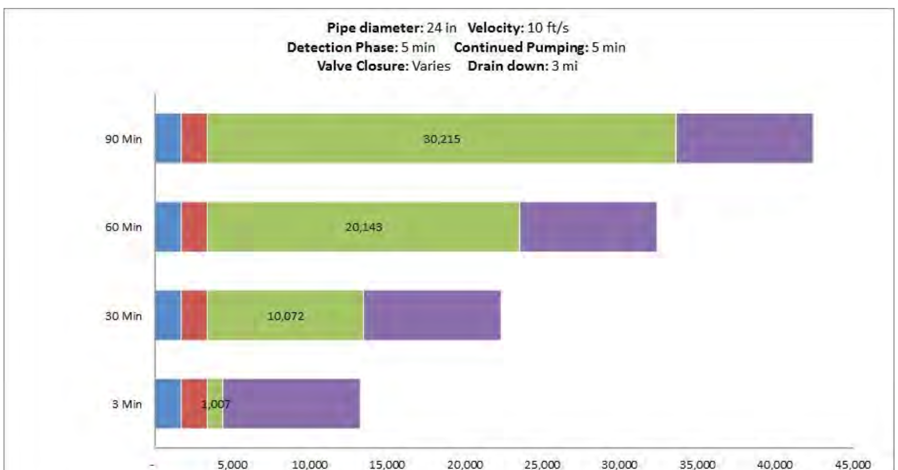


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

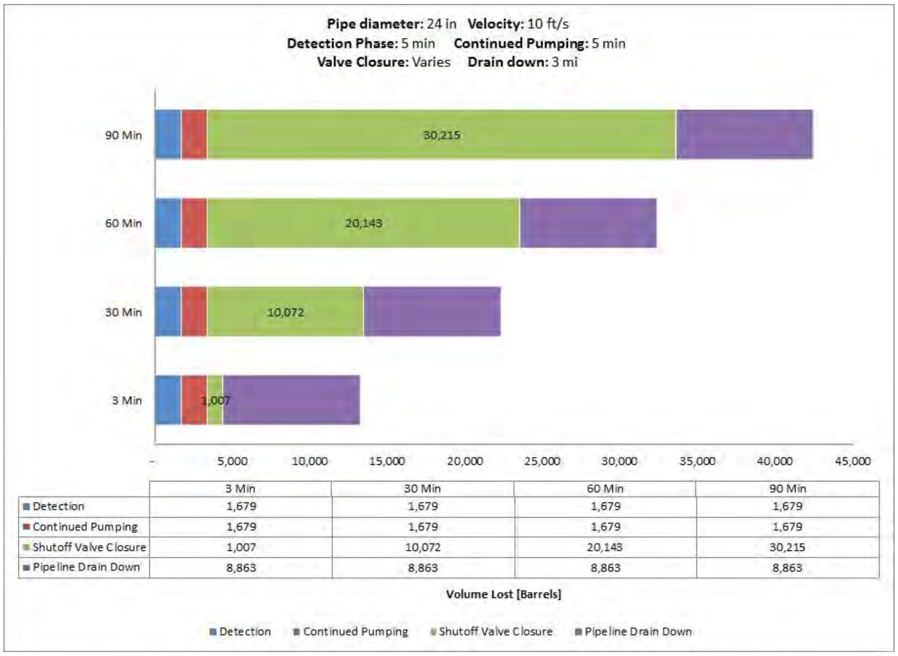


	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

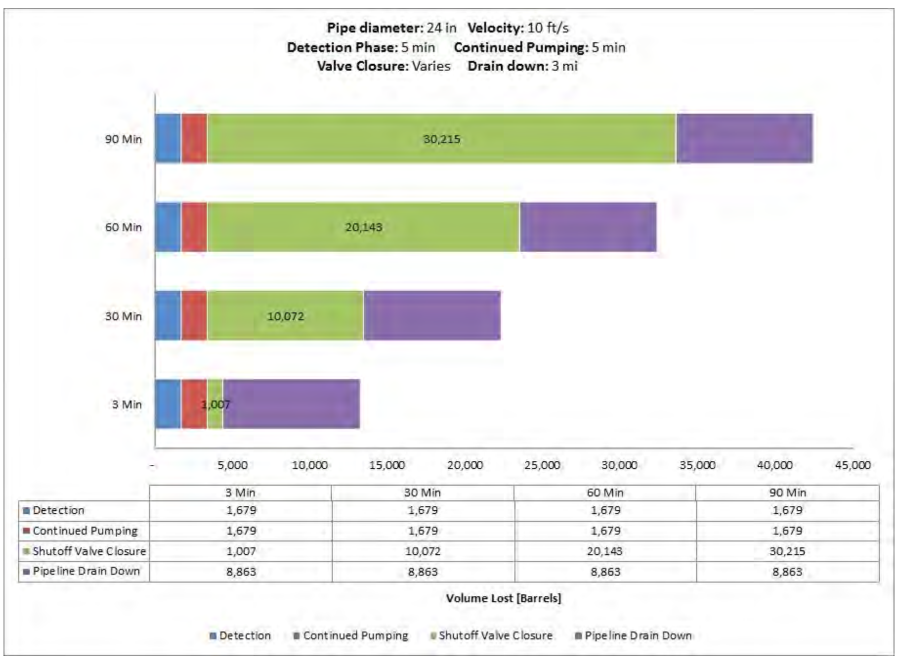
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



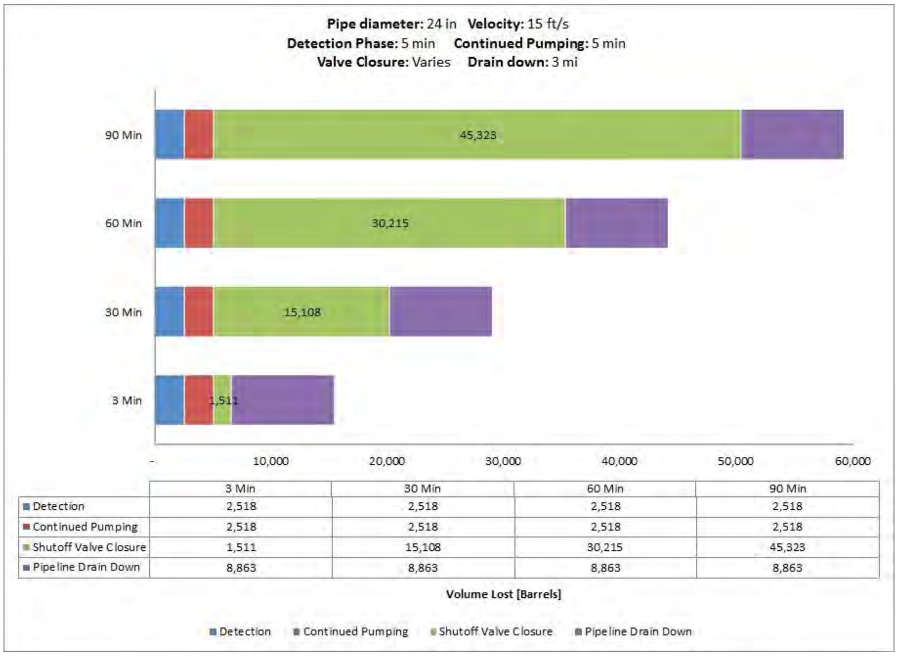
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



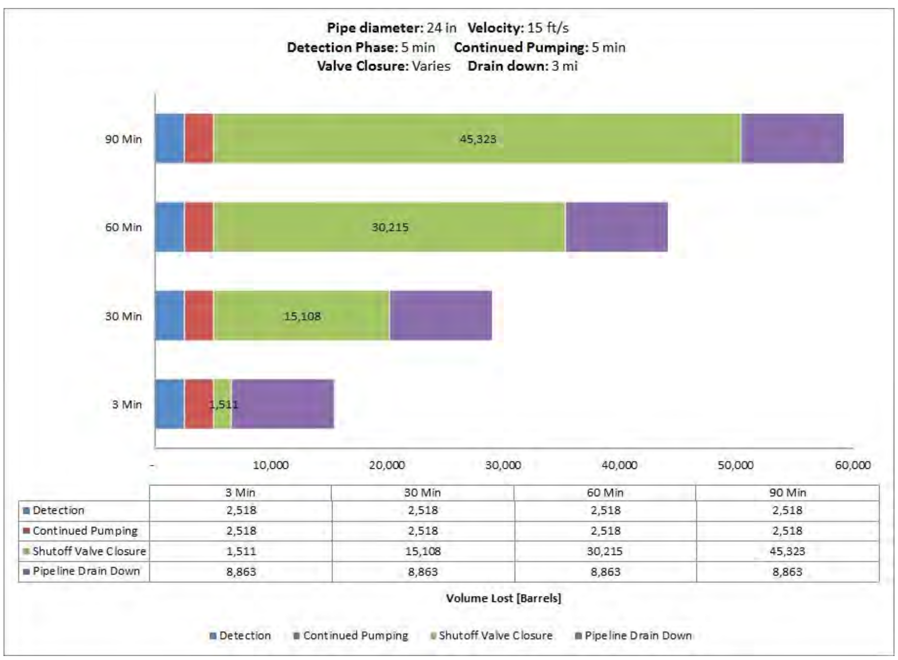
	3 Min	30 Min	60 Min	90 Min
Detection	1,679	1,679	1,679	1,679
Continued Pumping	1,679	1,679	1,679	1,679
Shutoff Valve Closure	1,007	10,072	20,143	30,215
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



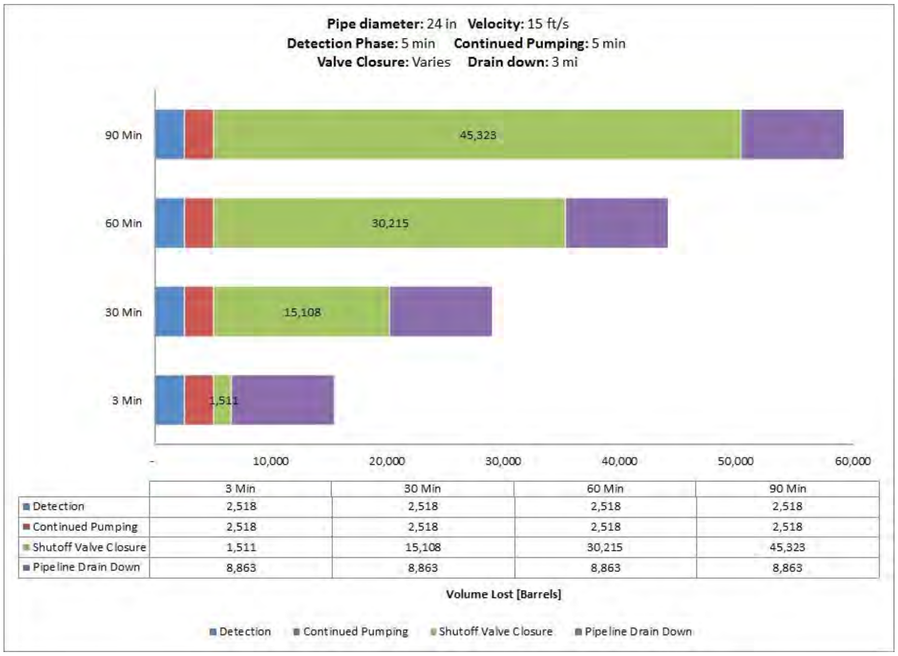
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



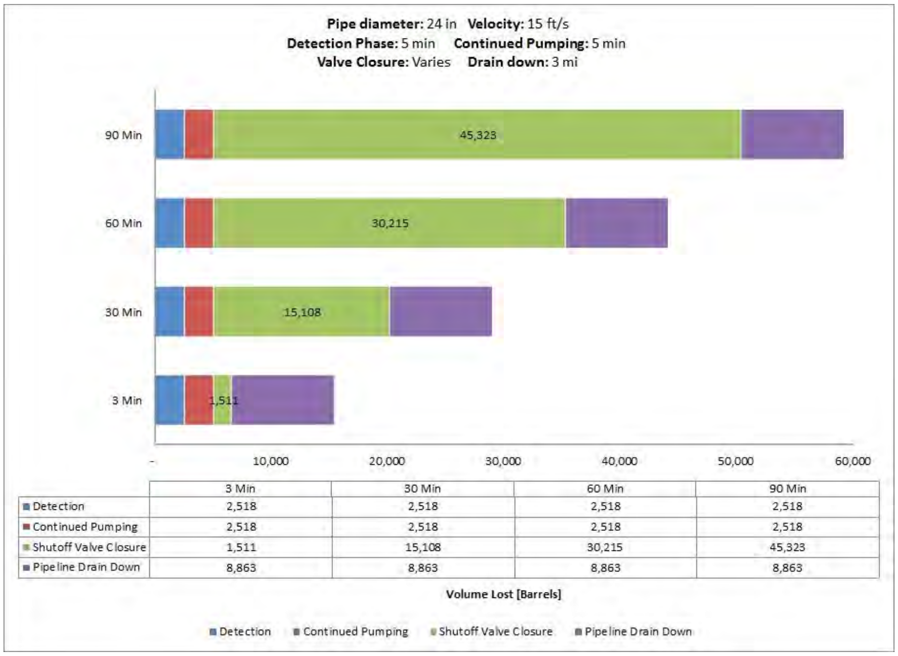
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



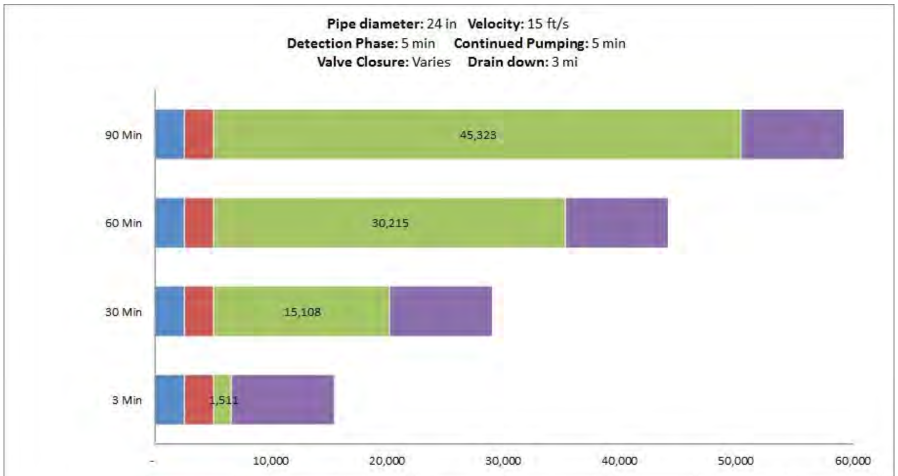
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

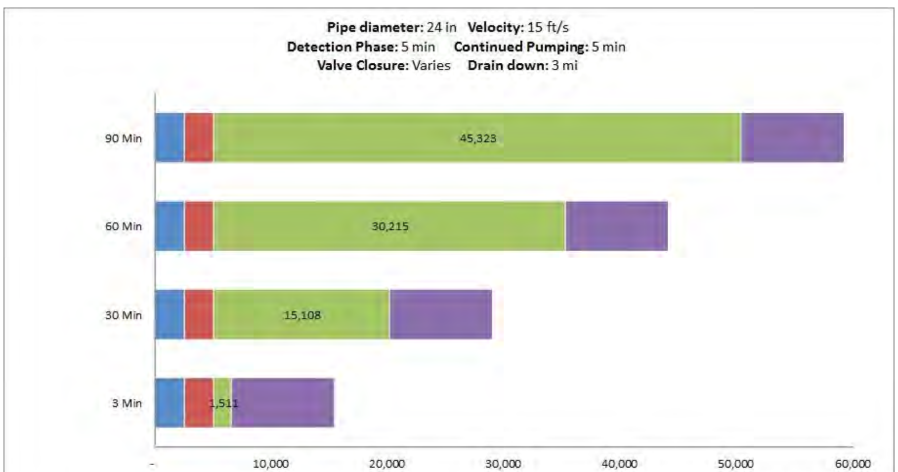


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

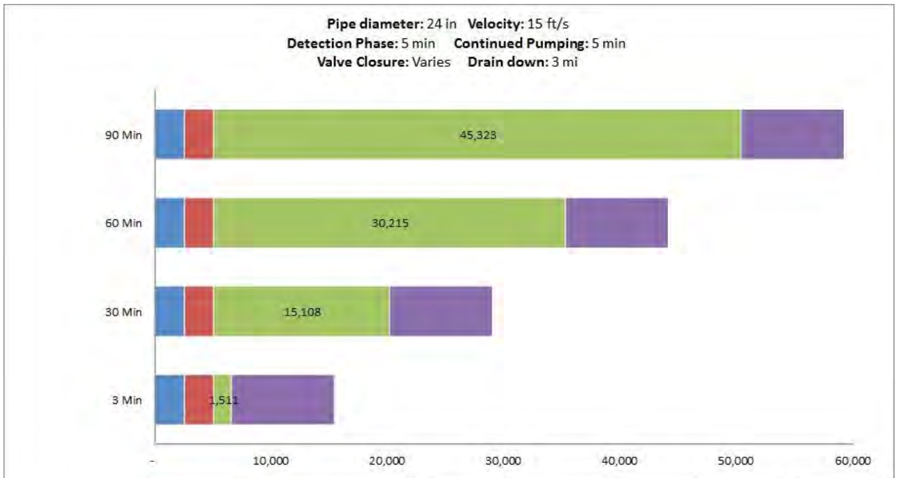


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

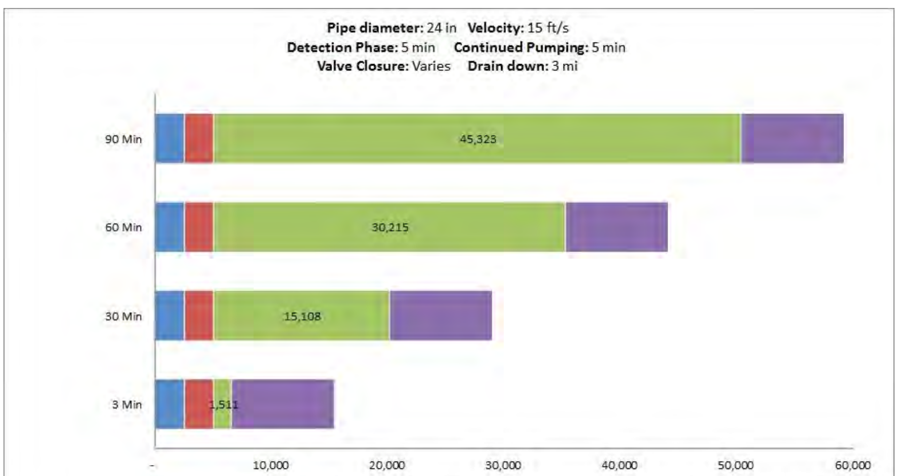
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



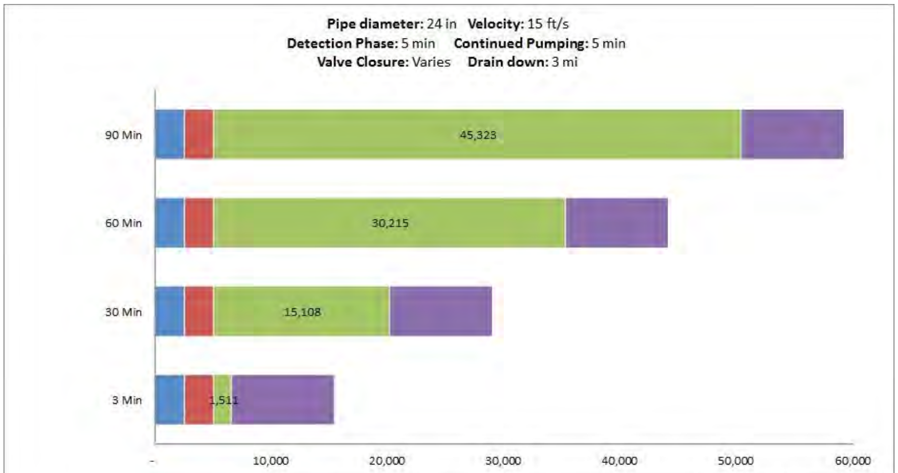
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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.

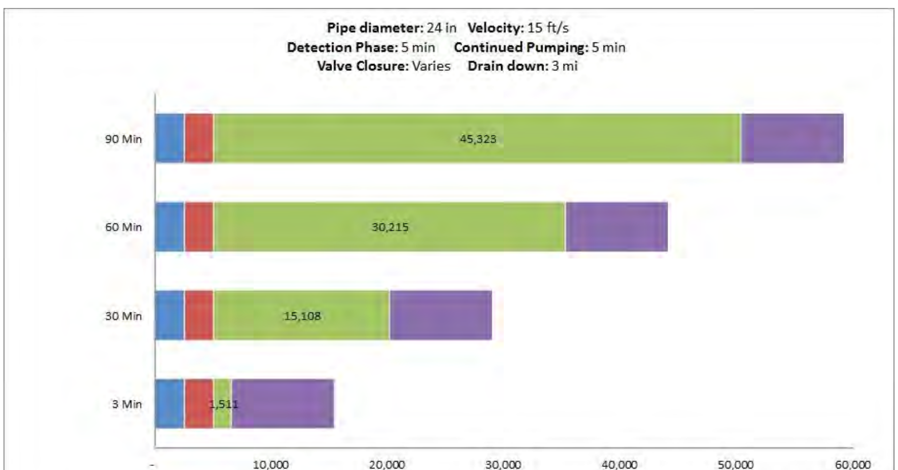


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

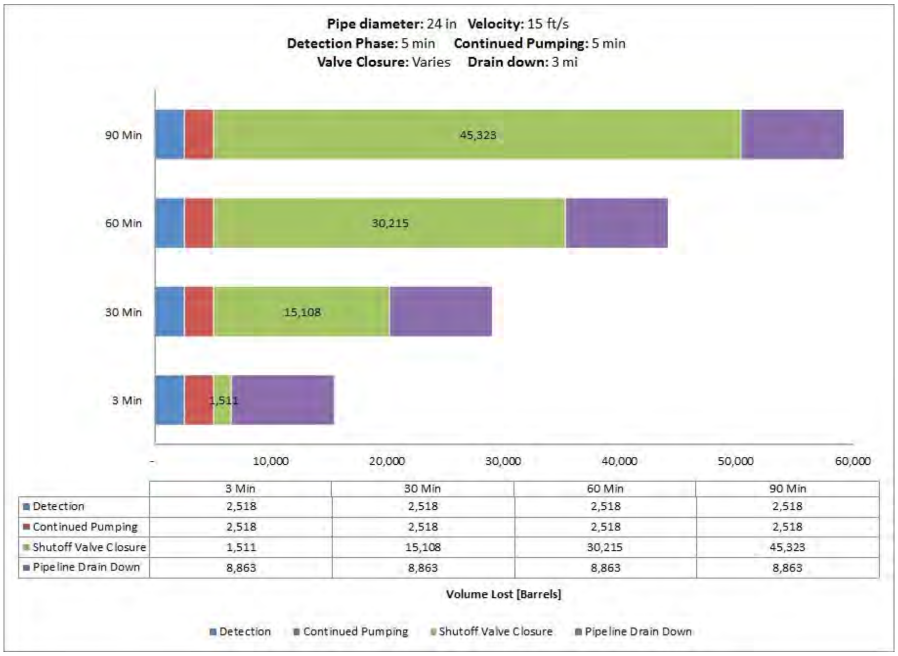


	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

Volume Lost [Barrels]

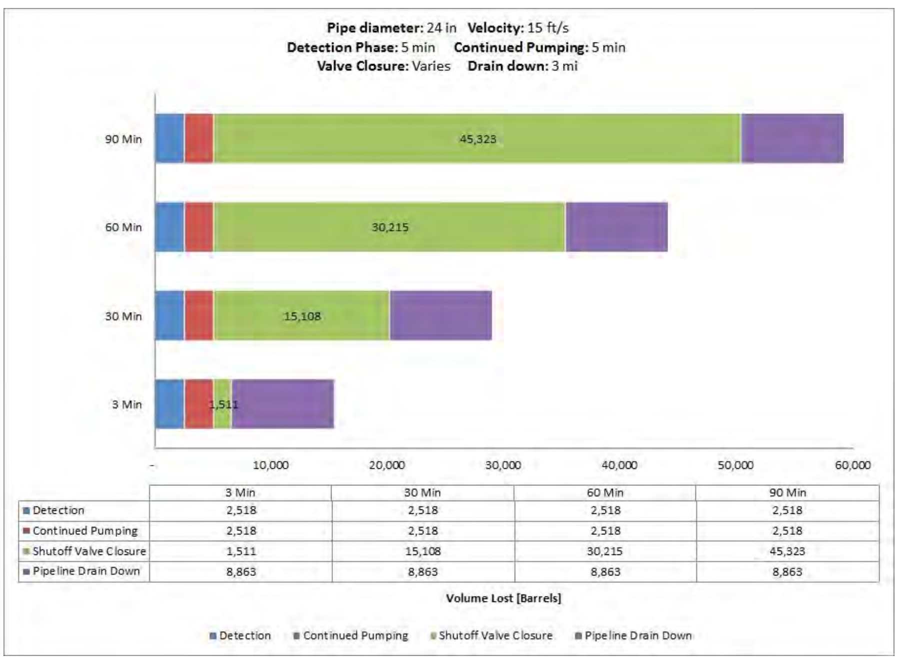
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



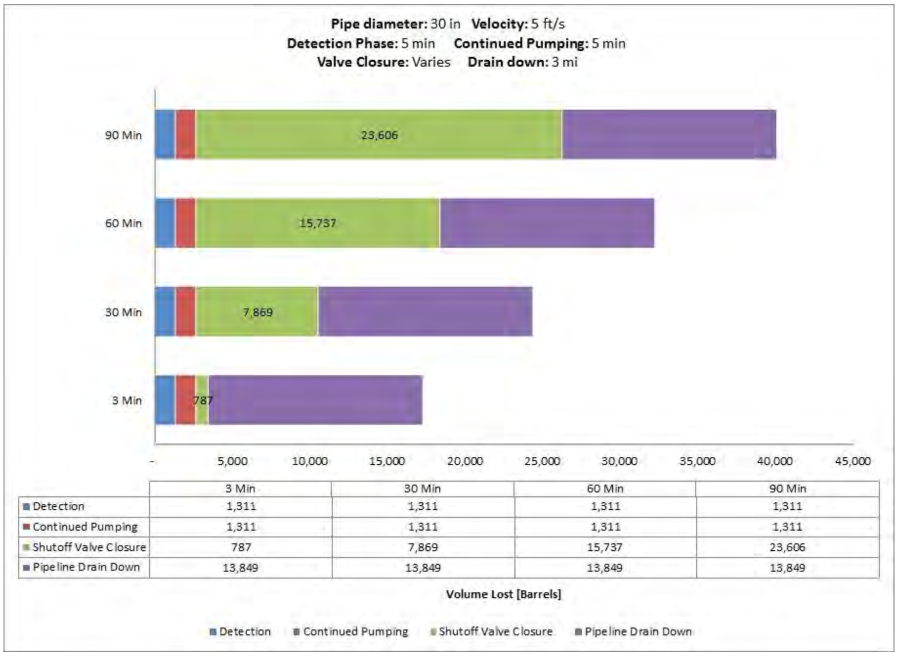
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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



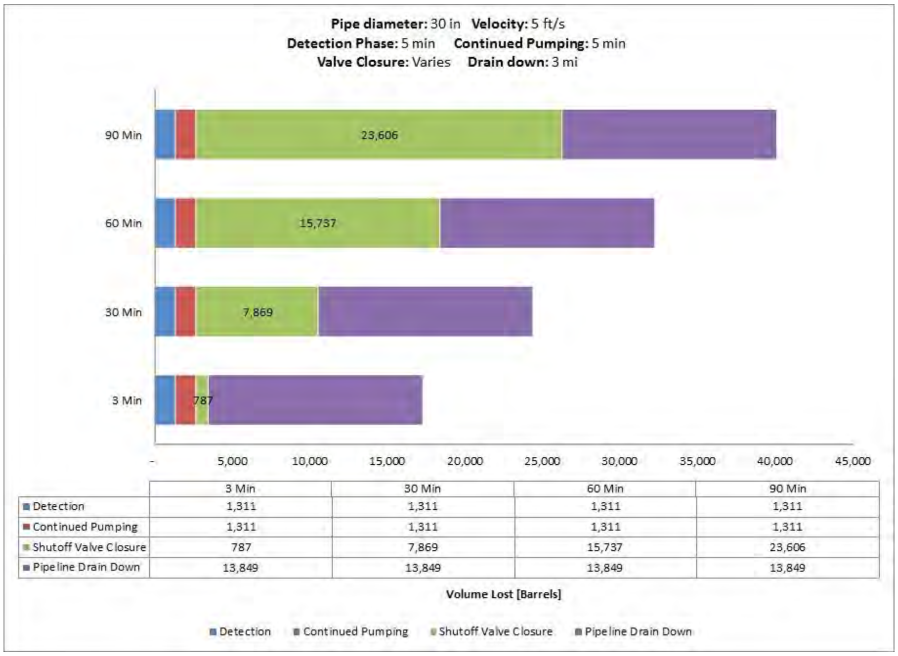
	3 Min	30 Min	60 Min	90 Min
Detection	2,518	2,518	2,518	2,518
Continued Pumping	2,518	2,518	2,518	2,518
Shutoff Valve Closure	1,511	15,108	30,215	45,323
Pipeline Drain Down	8,863	8,863	8,863	8,863

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

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

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

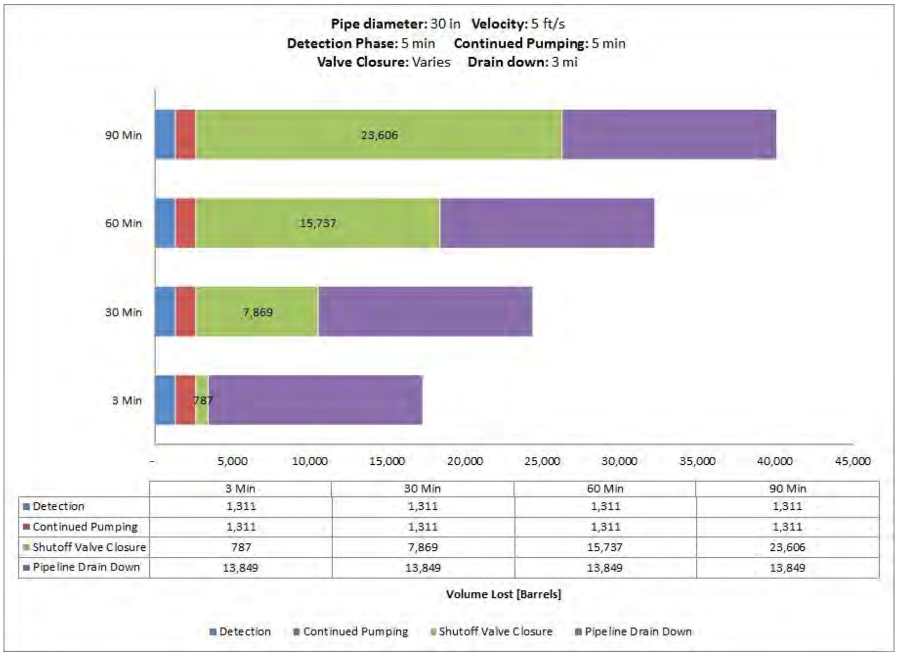


Fig. A-147. 30 Inch Pipe Diameter, 5 ft/s, 400 psi MAOP, 1000 Feet Elevation Change.

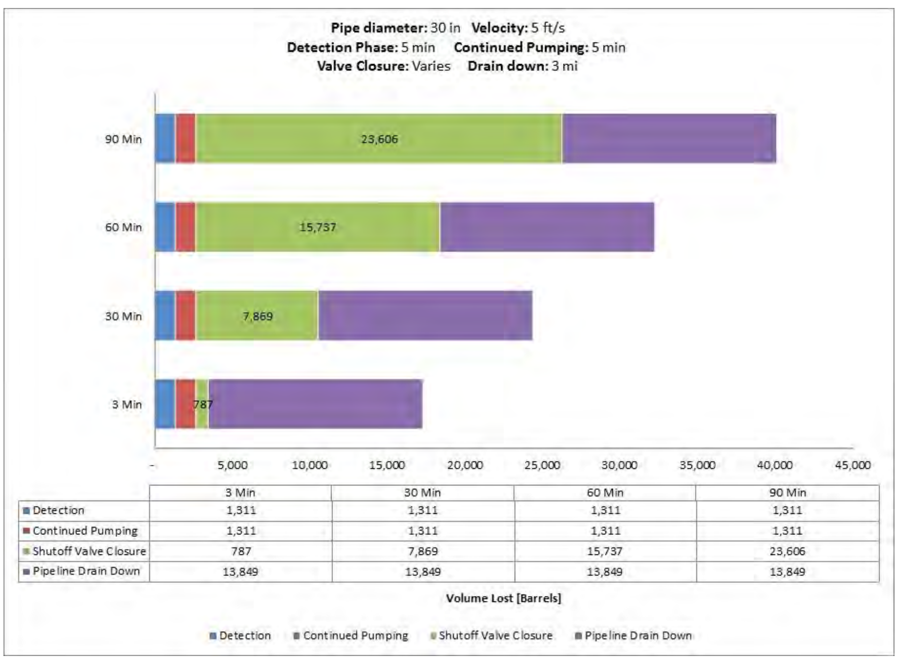
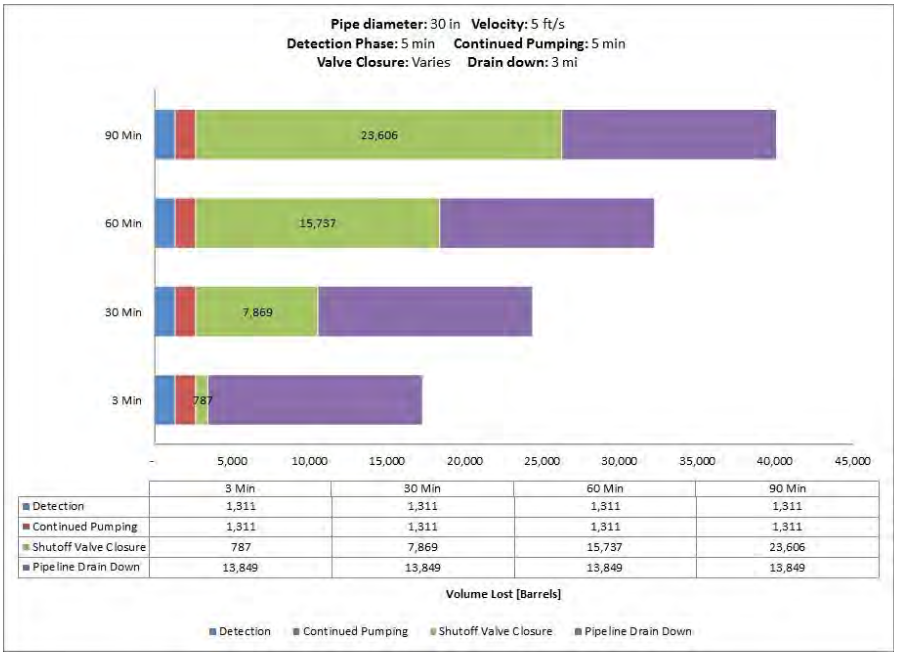
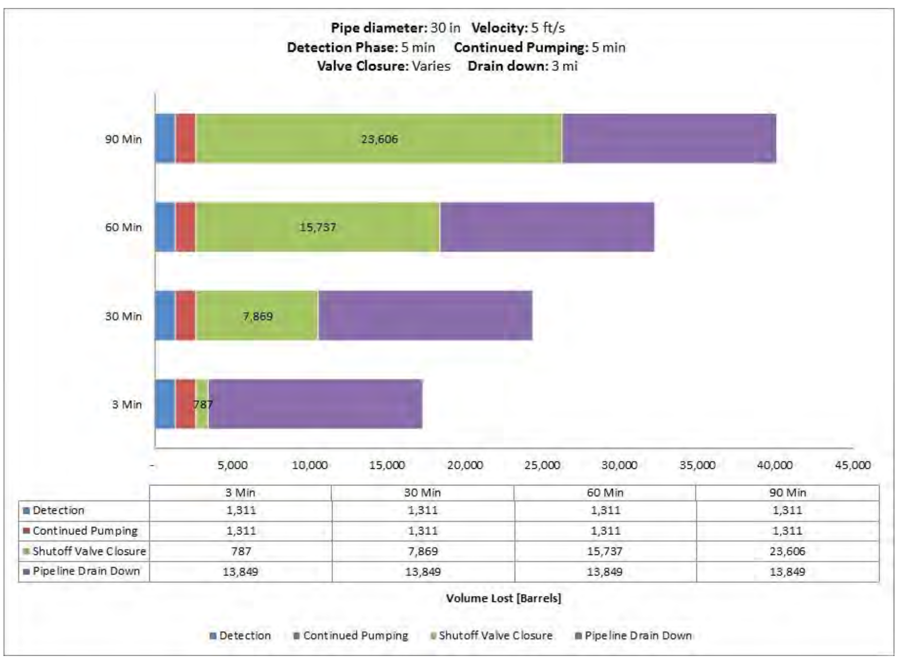


Fig. A-148. 30 Inch Pipe Diameter, 5 ft/s, 800 psi MAOP, 100 Feet Elevation Change.



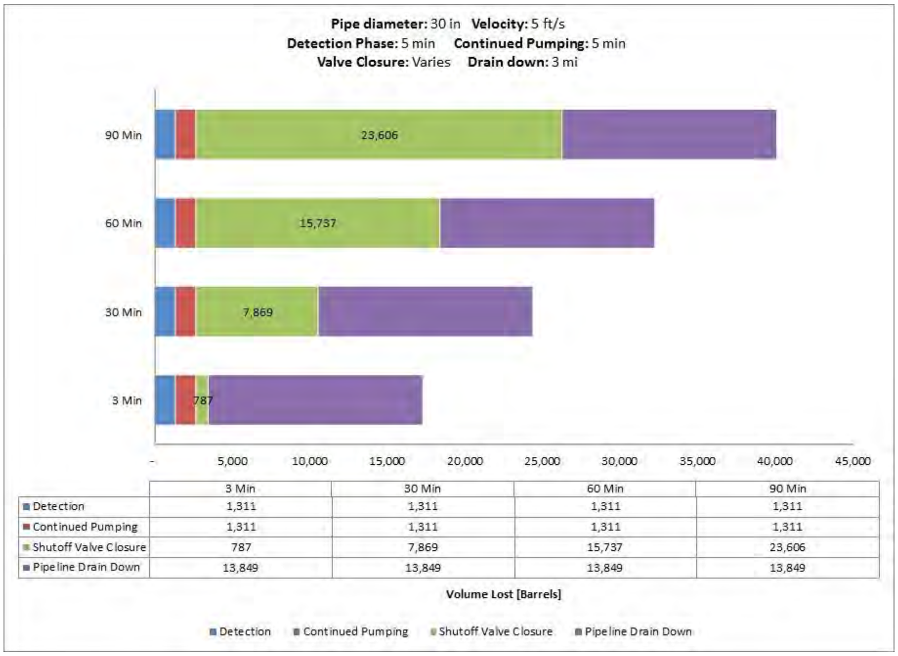
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



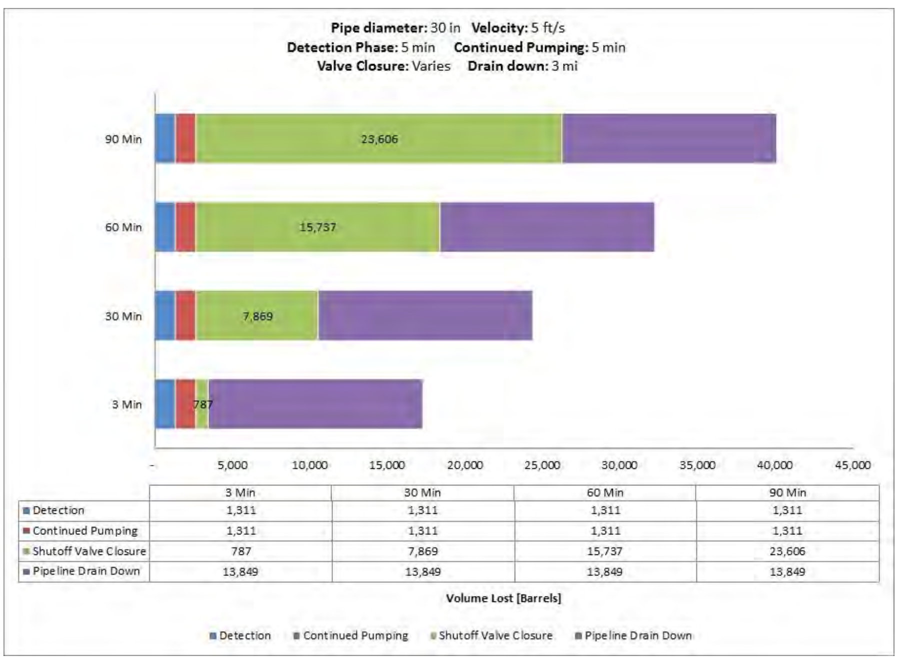
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



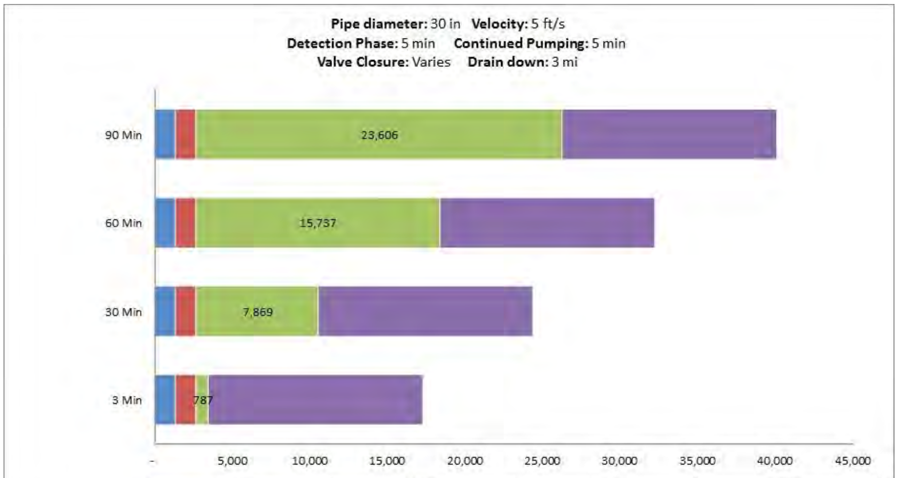
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



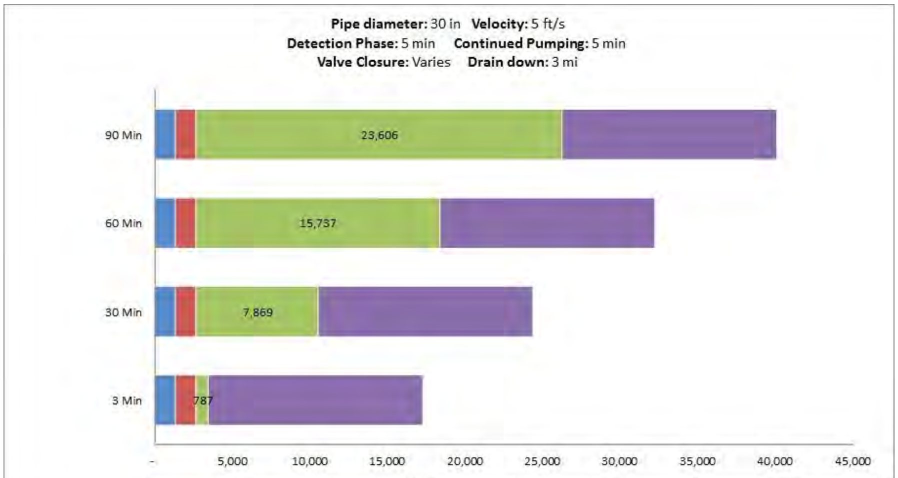
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



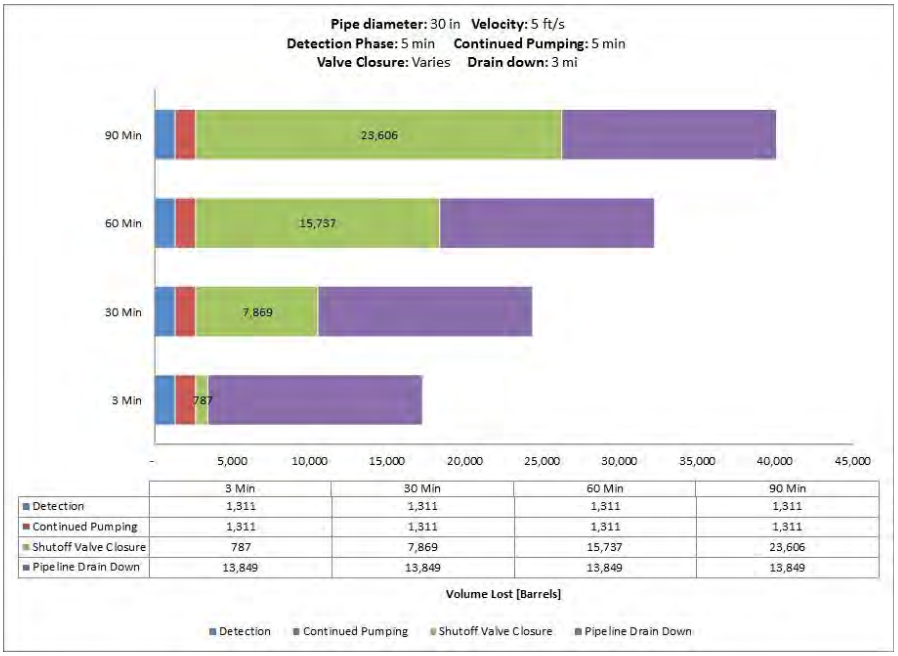
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



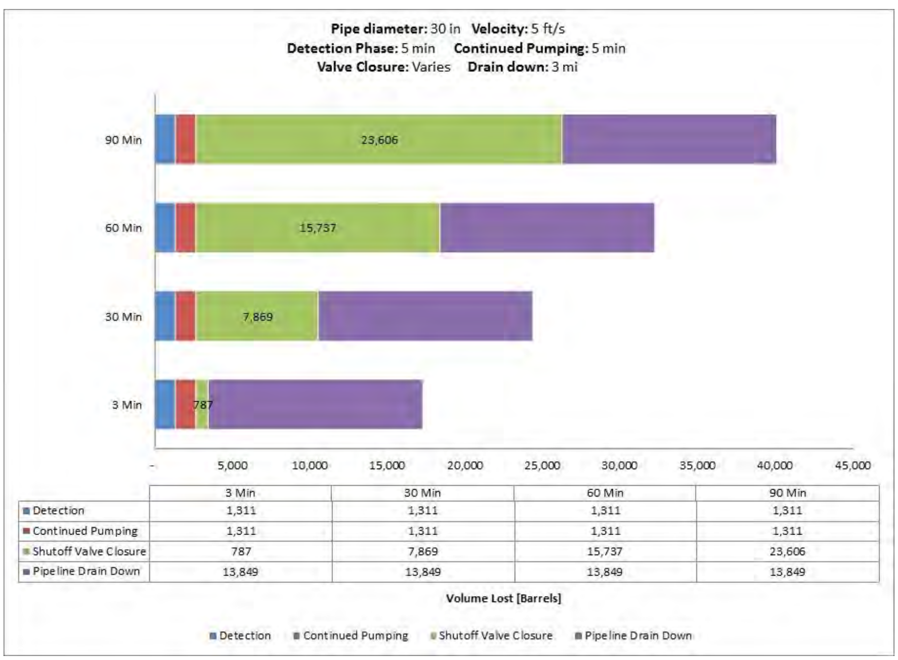
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



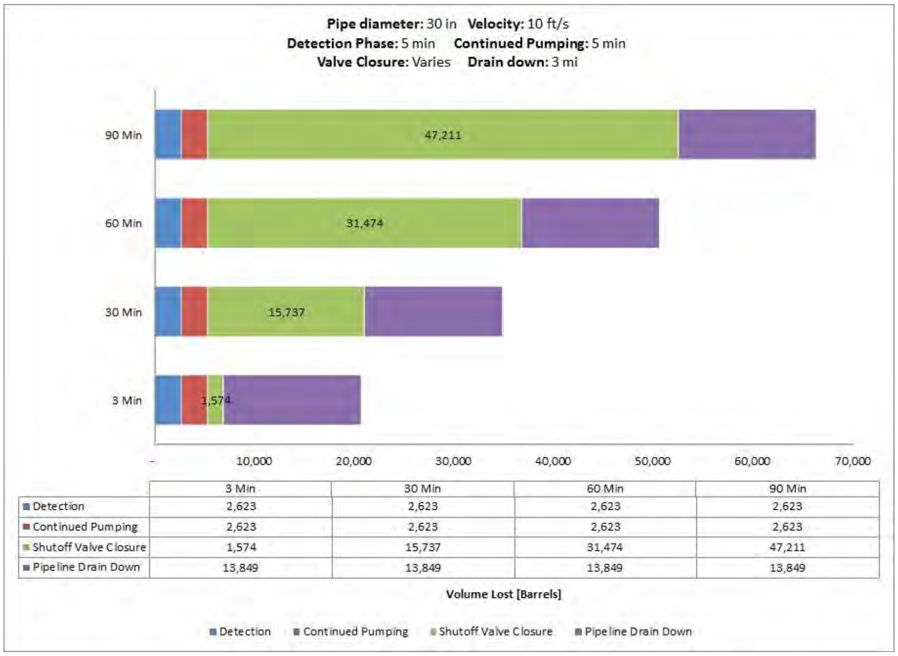
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



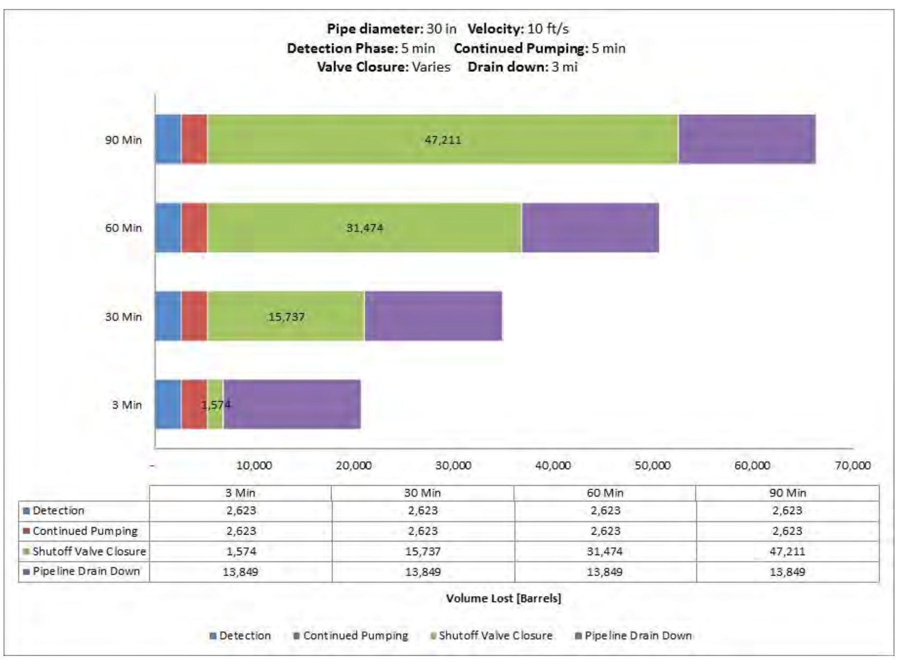
	3 Min	30 Min	60 Min	90 Min
Detection	1,311	1,311	1,311	1,311
Continued Pumping	1,311	1,311	1,311	1,311
Shutoff Valve Closure	787	7,869	15,737	23,606
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



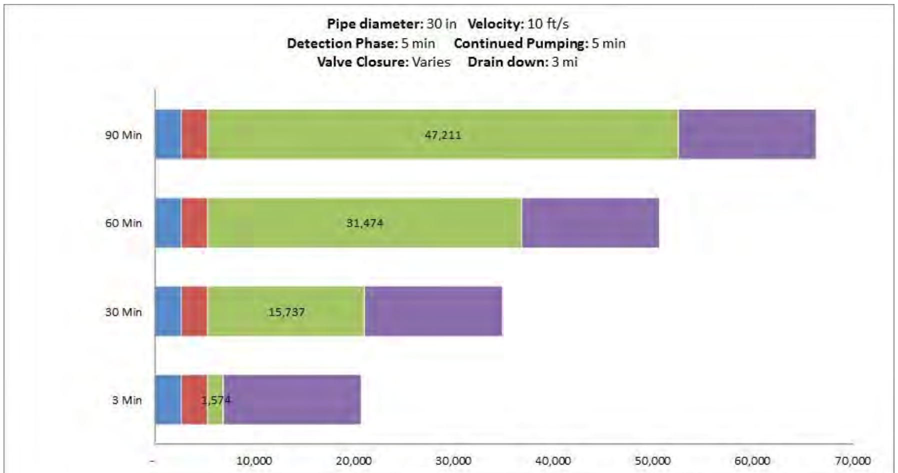
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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.

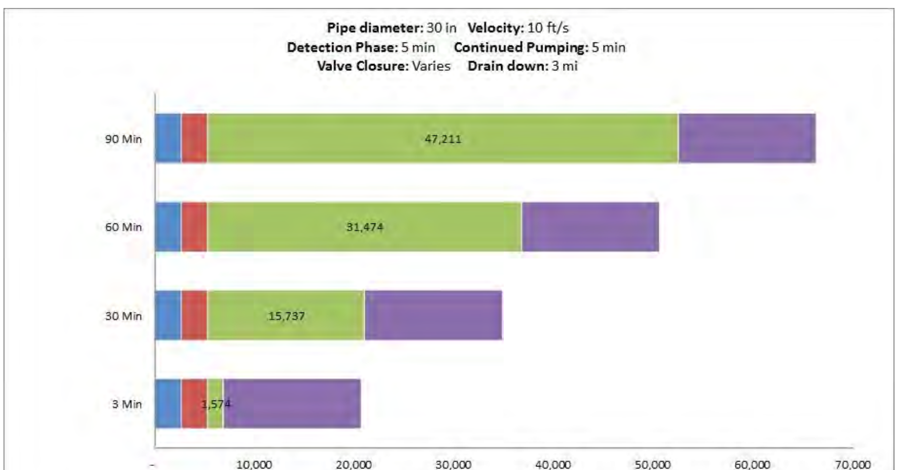


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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.

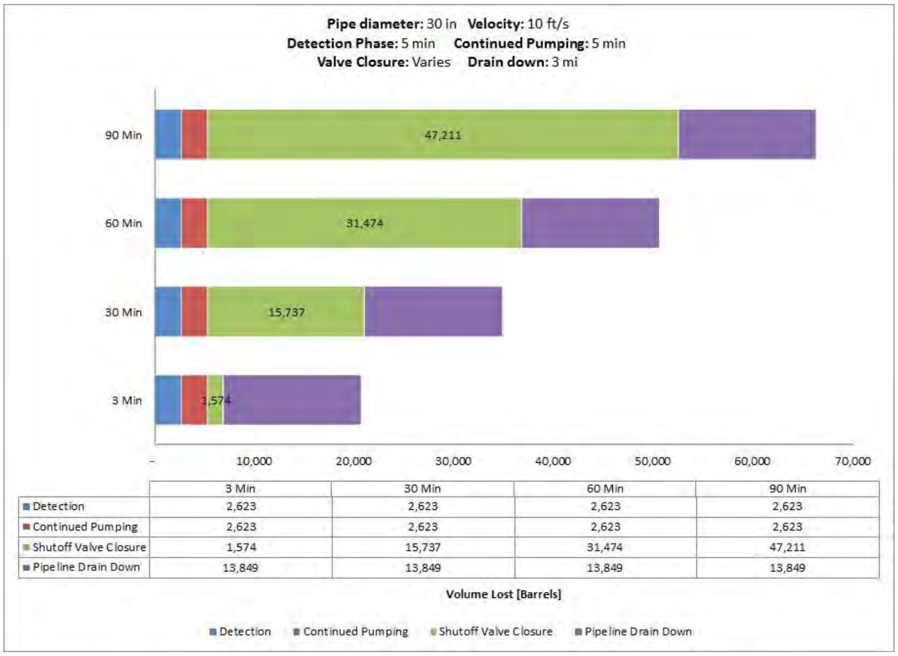


	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

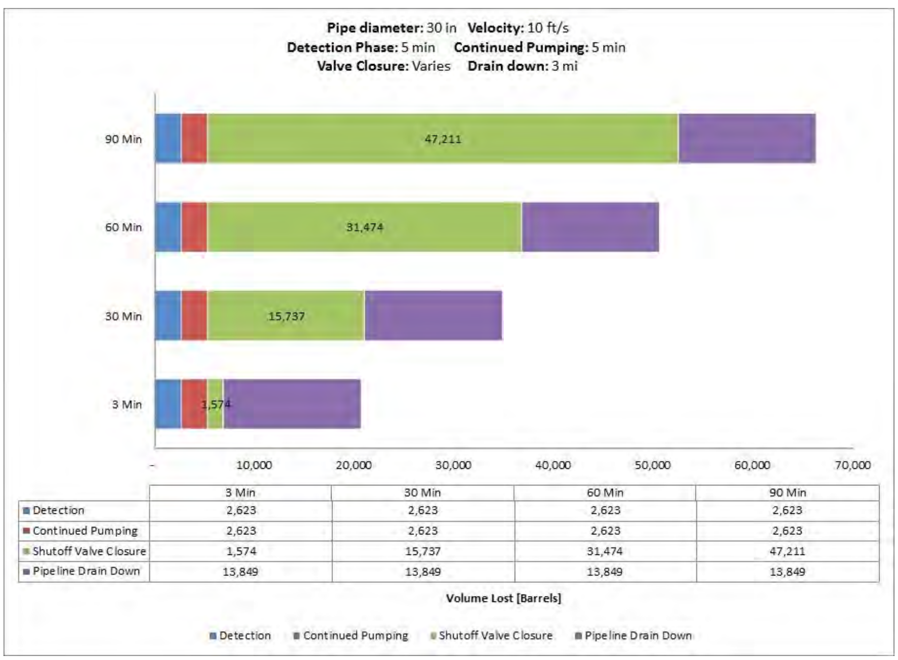
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



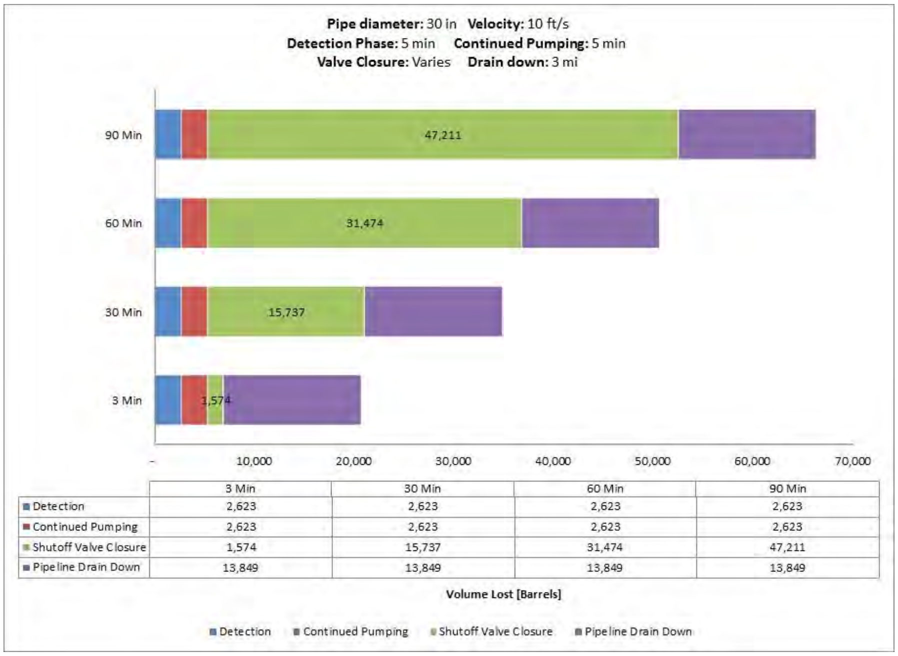
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



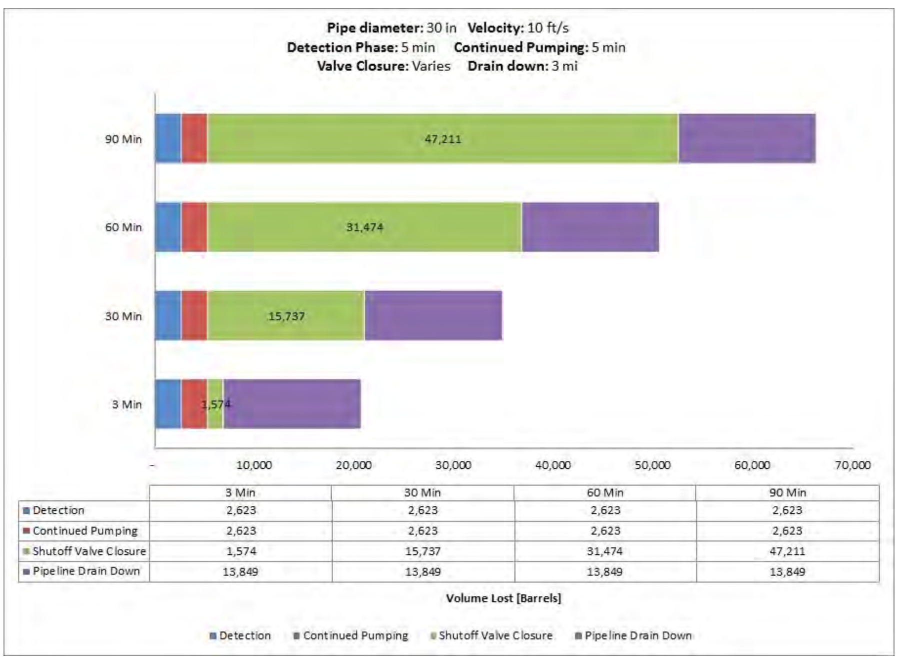
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



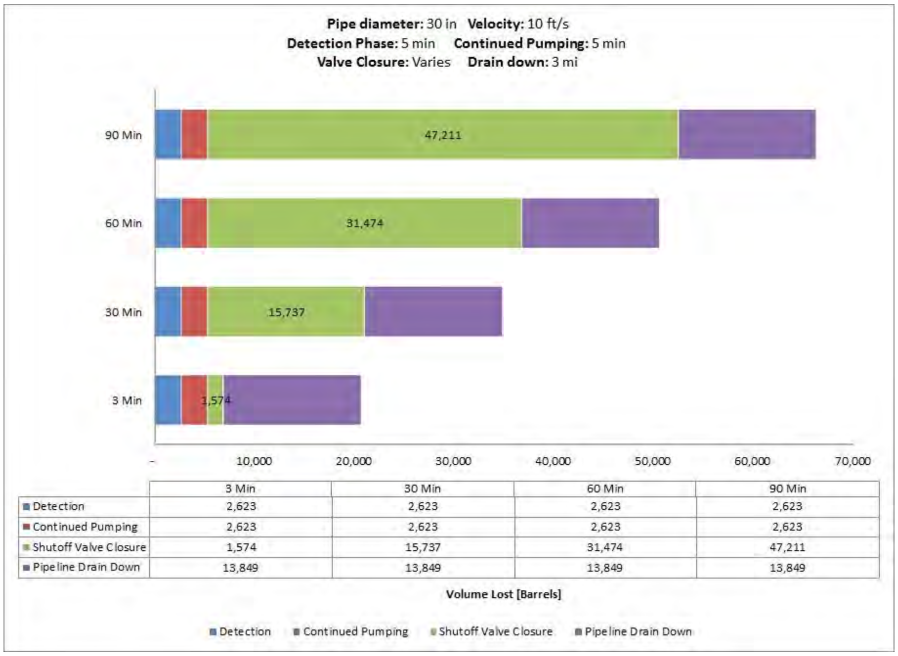
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



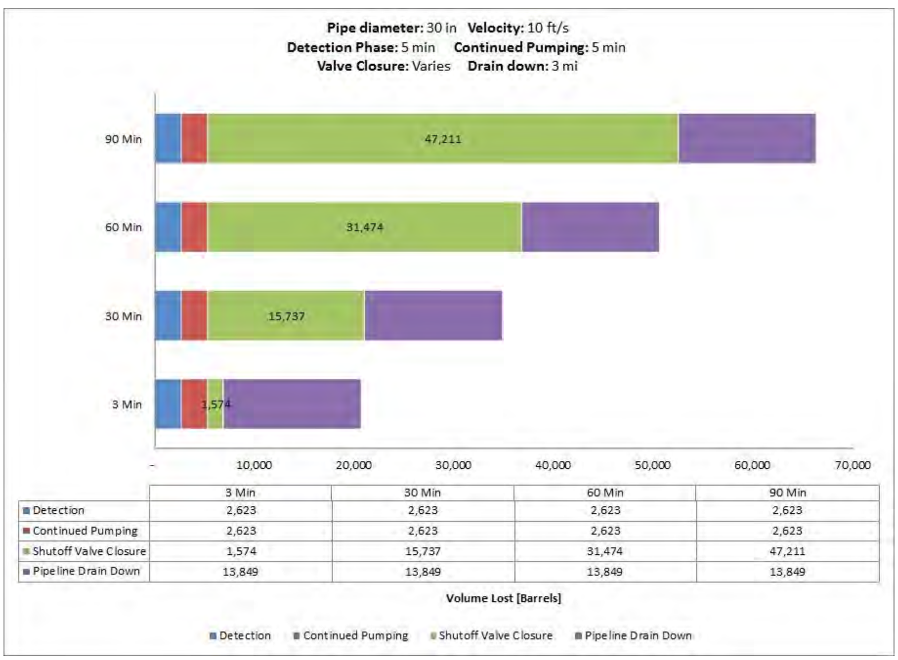
	3 Min	30 Min	60 Min	90 Min
Detection	2,623	2,623	2,623	2,623
Continued Pumping	2,623	2,623	2,623	2,623
Shutoff Valve Closure	1,574	15,737	31,474	47,211
Pipeline Drain Down	13,849	13,849	13,849	13,849

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.

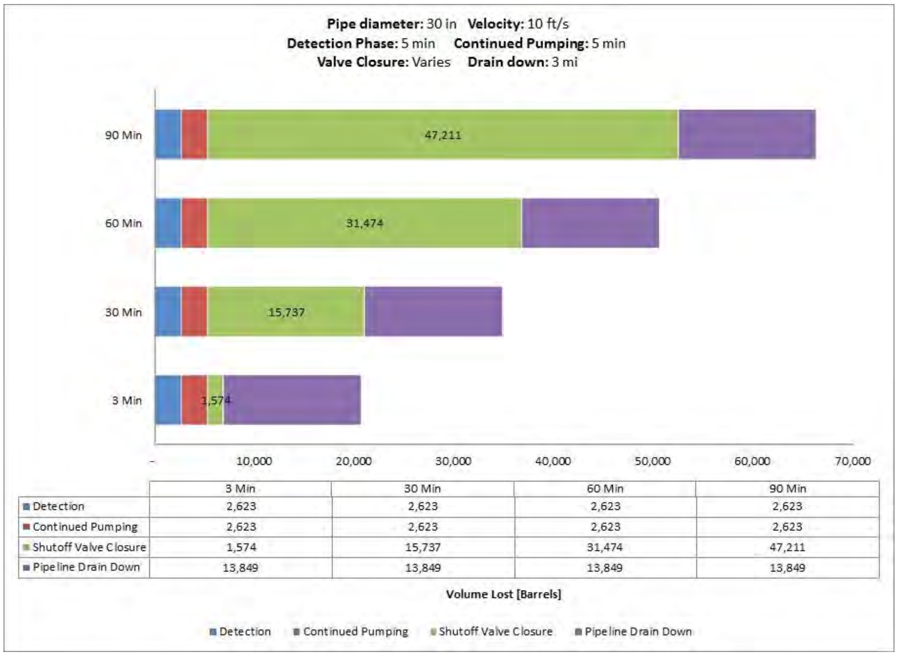


Fig. A-167. 30 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

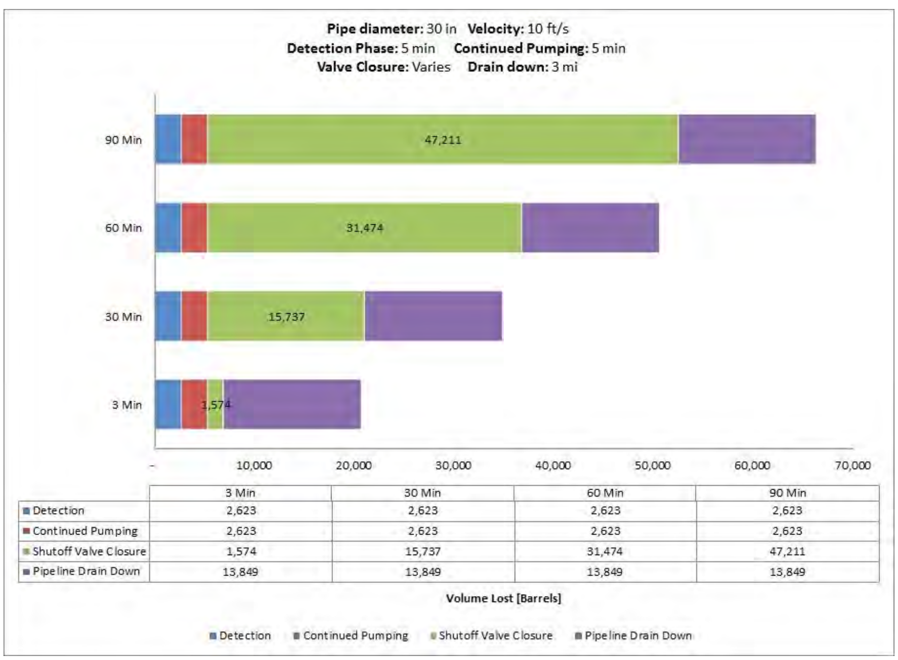
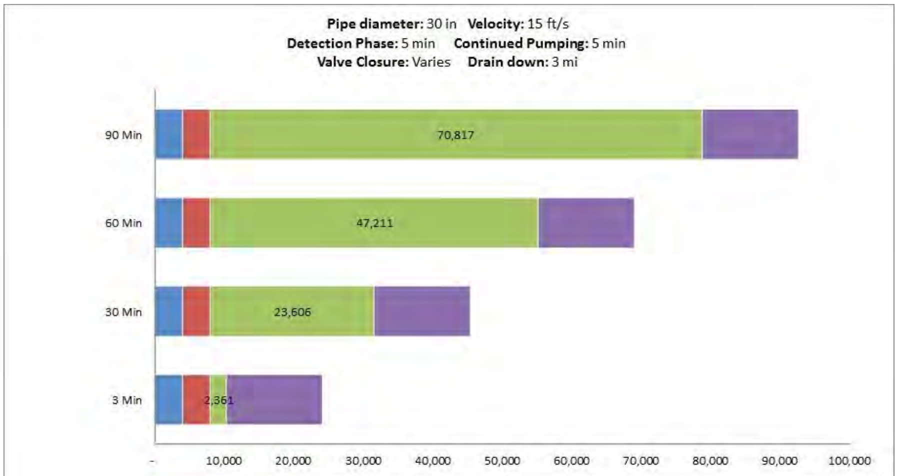


Fig. A-168. 30 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.

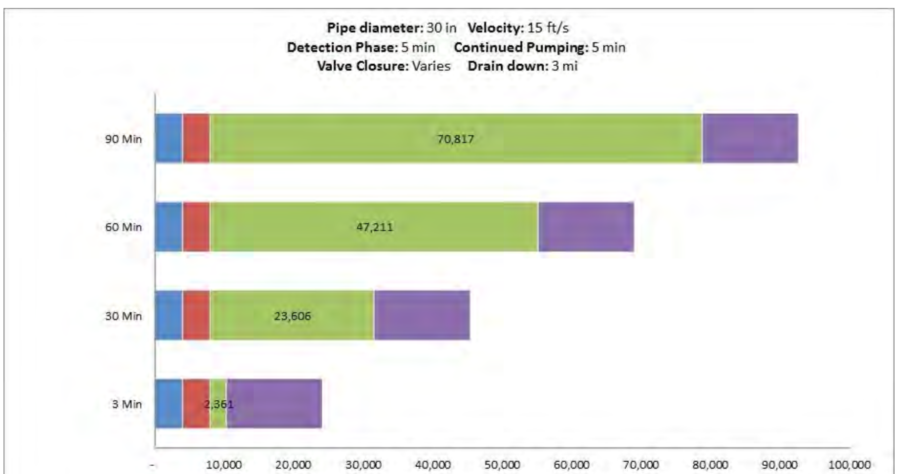


	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

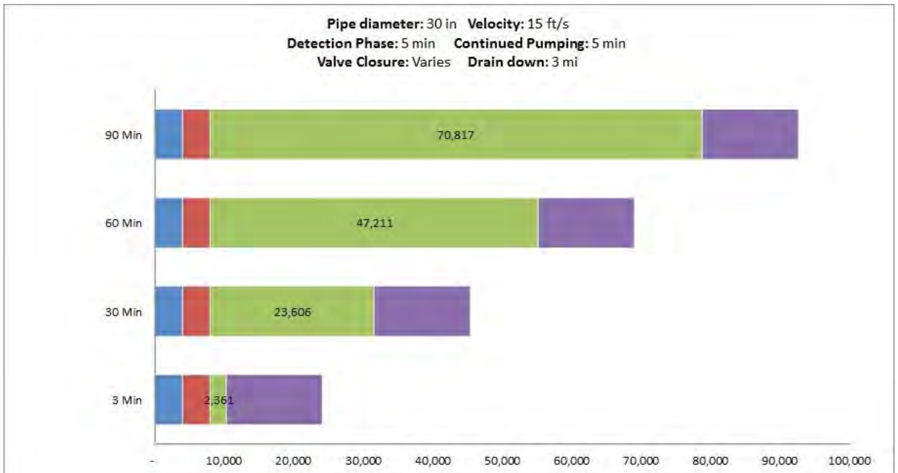


	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

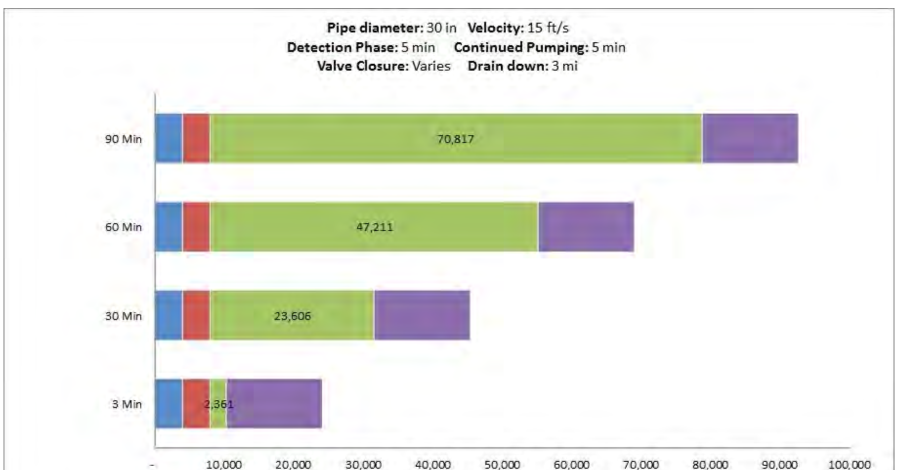


	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

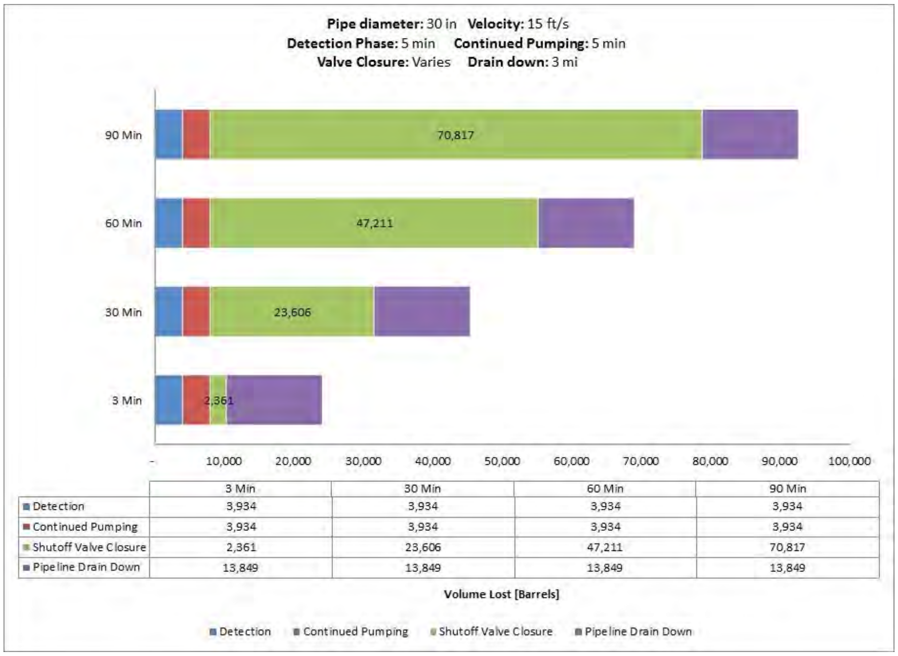


	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

Volume Lost [Barrels]

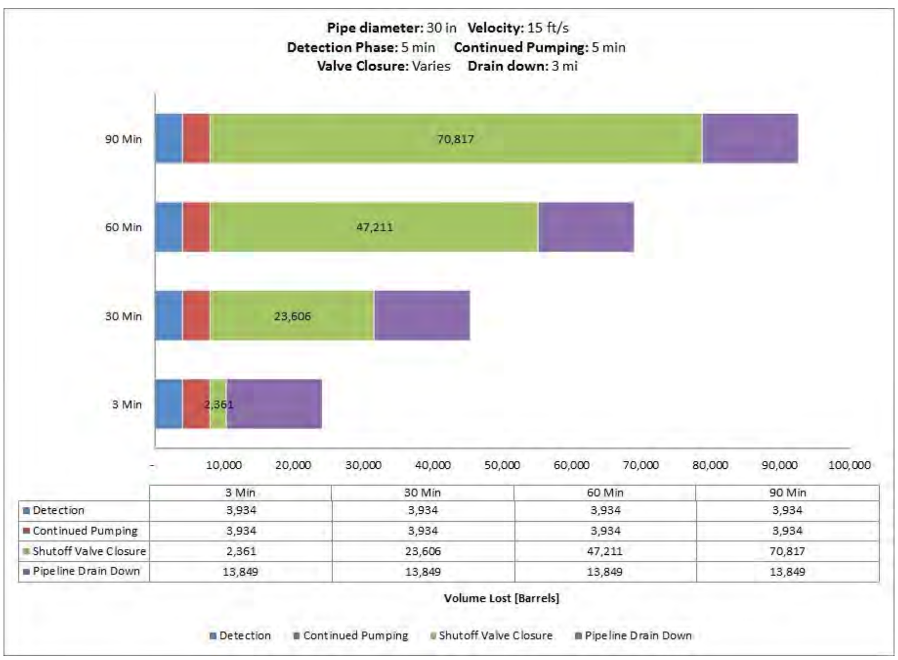
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



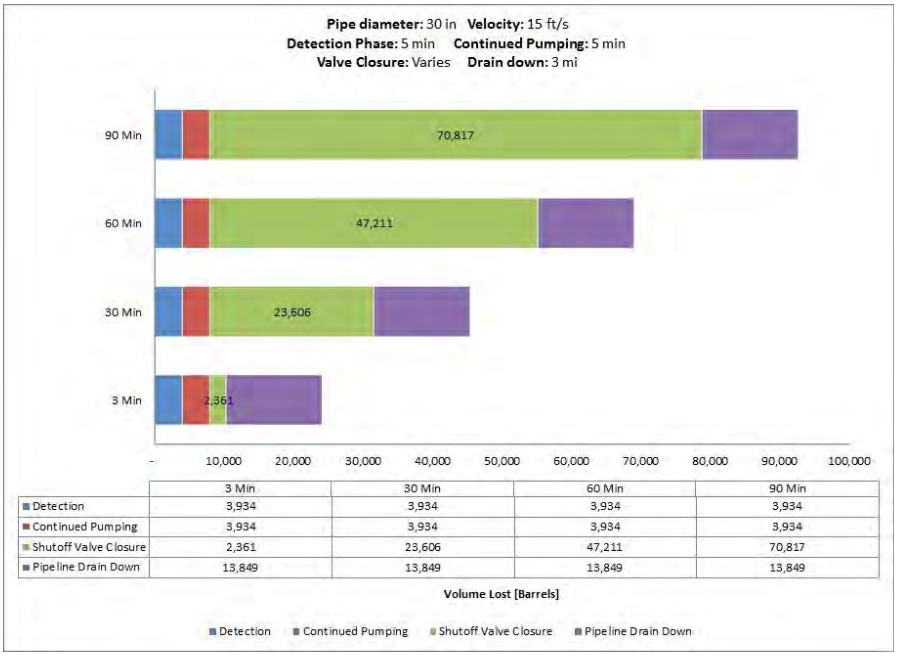
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



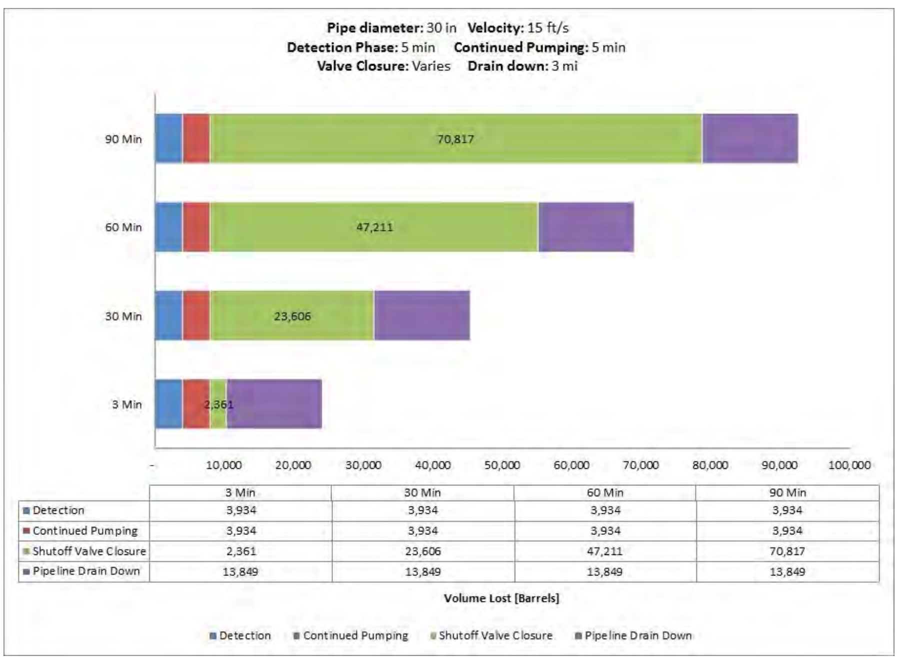
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



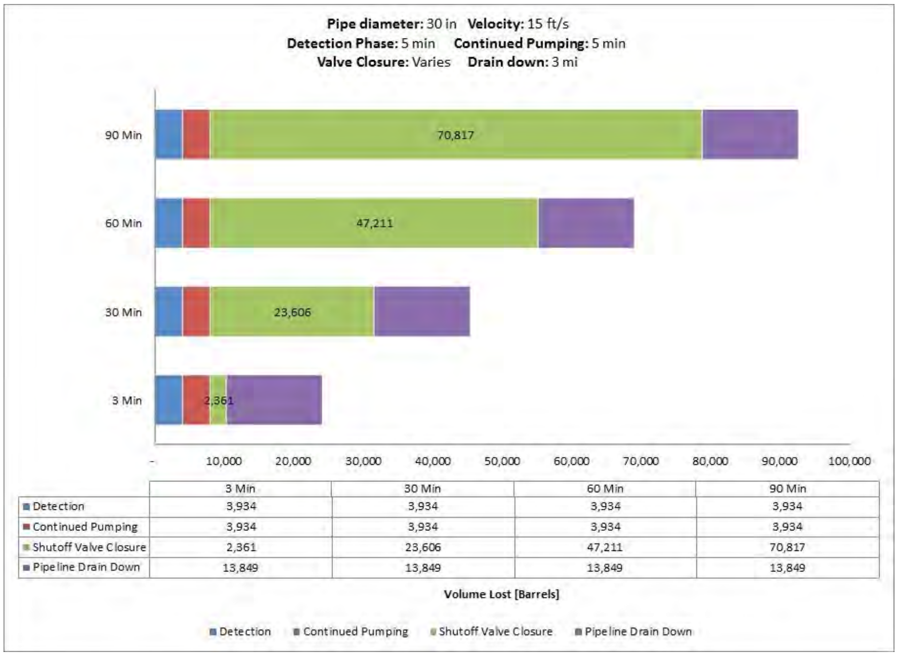
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

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



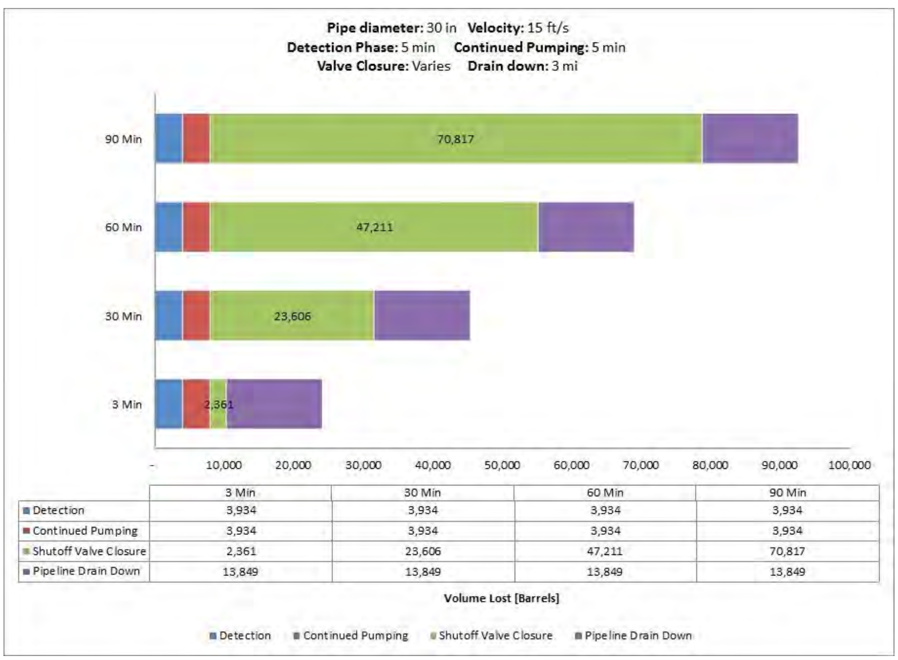
	3 Min	30 Min	60 Min	90 Min
Detection	3,934	3,934	3,934	3,934
Continued Pumping	3,934	3,934	3,934	3,934
Shutoff Valve Closure	2,361	23,606	47,211	70,817
Pipeline Drain Down	13,849	13,849	13,849	13,849

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.

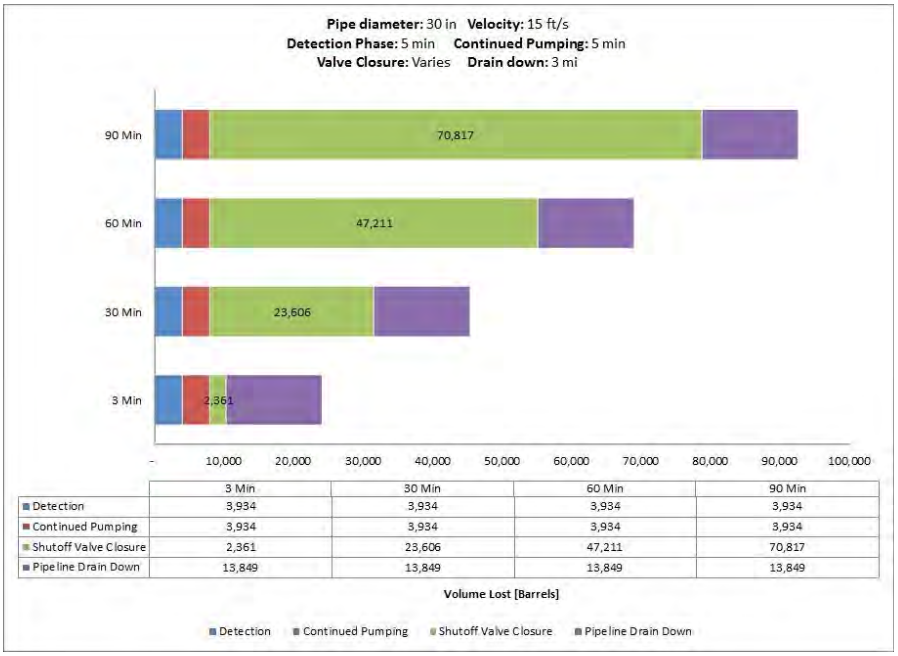


Fig. A-179. 30 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

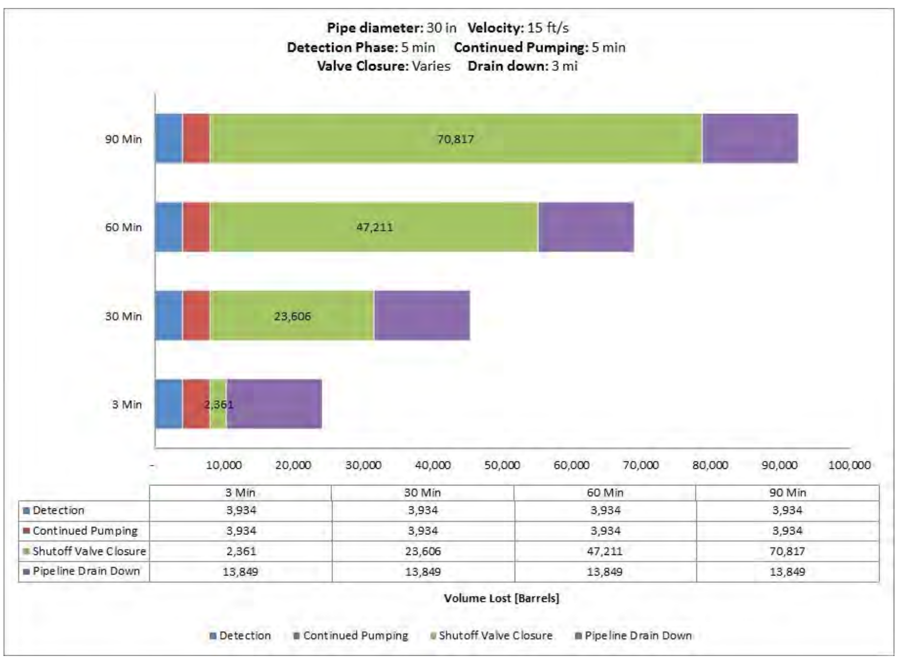
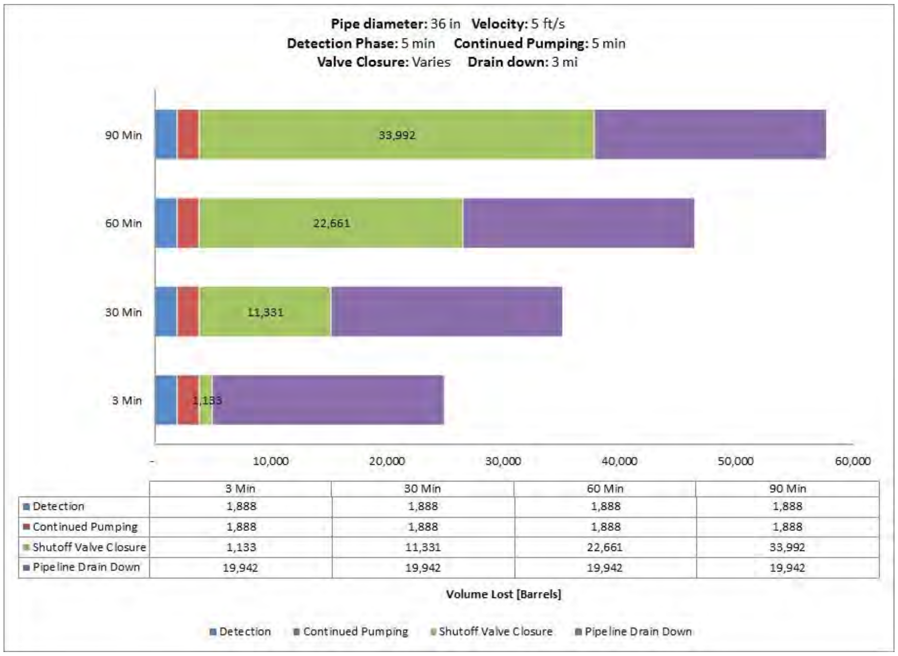
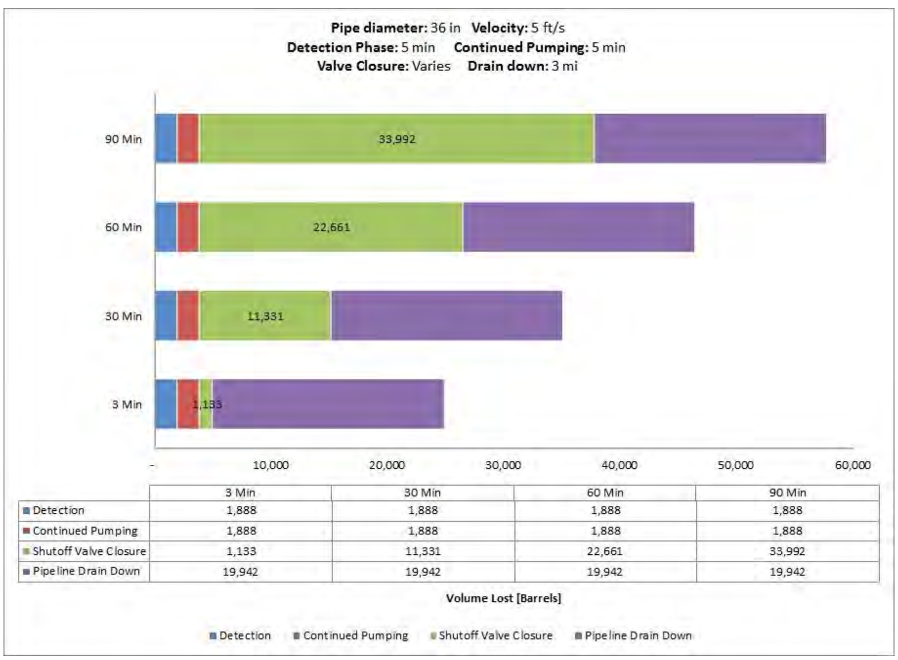


Fig. A-180. 30 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



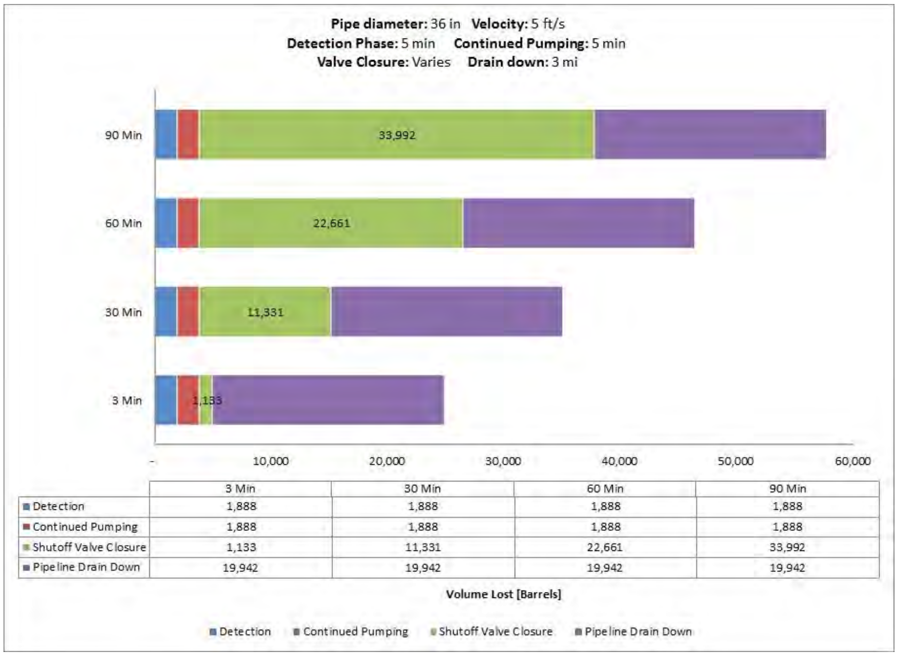
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



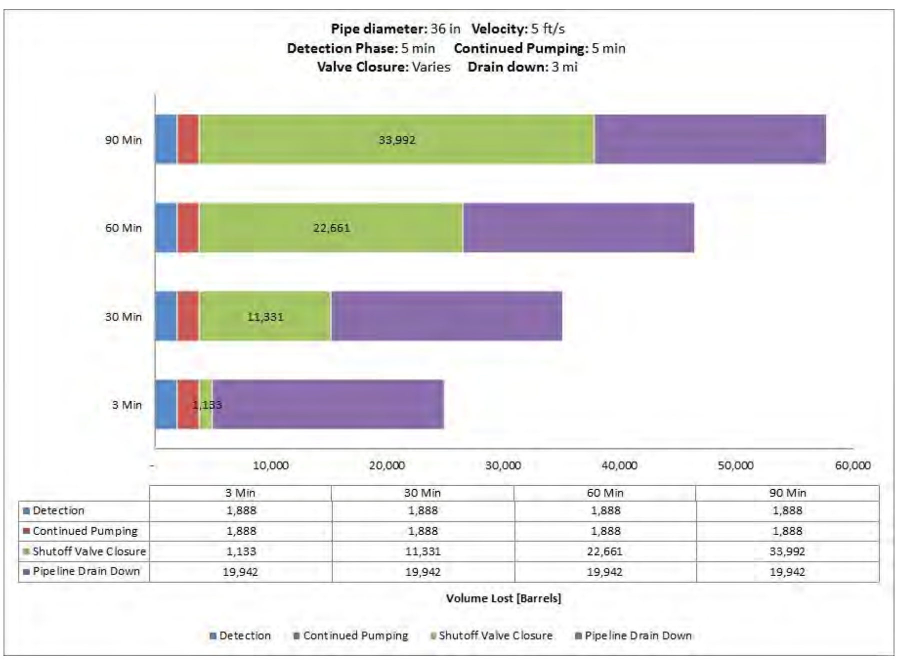
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



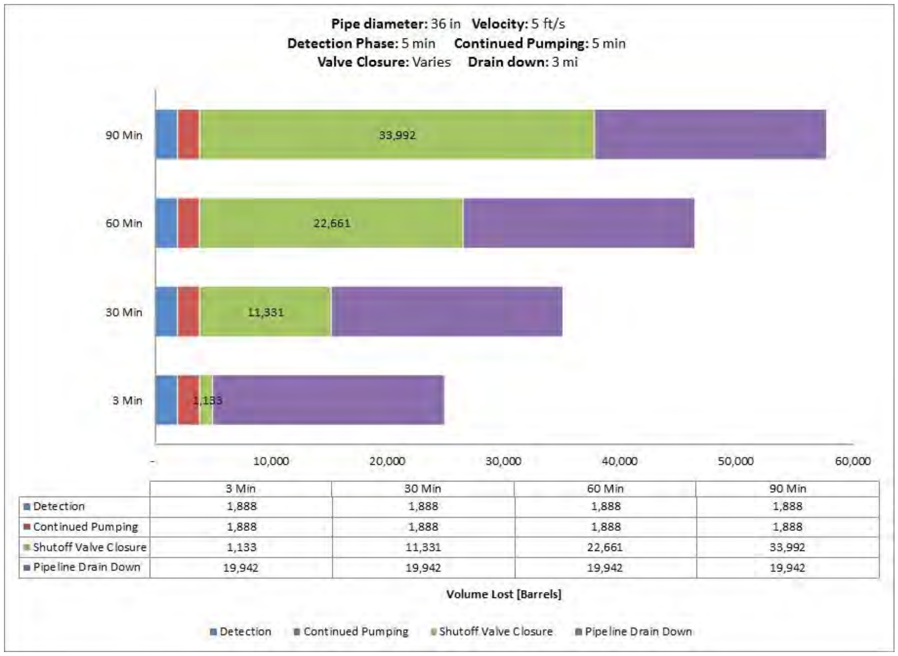
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



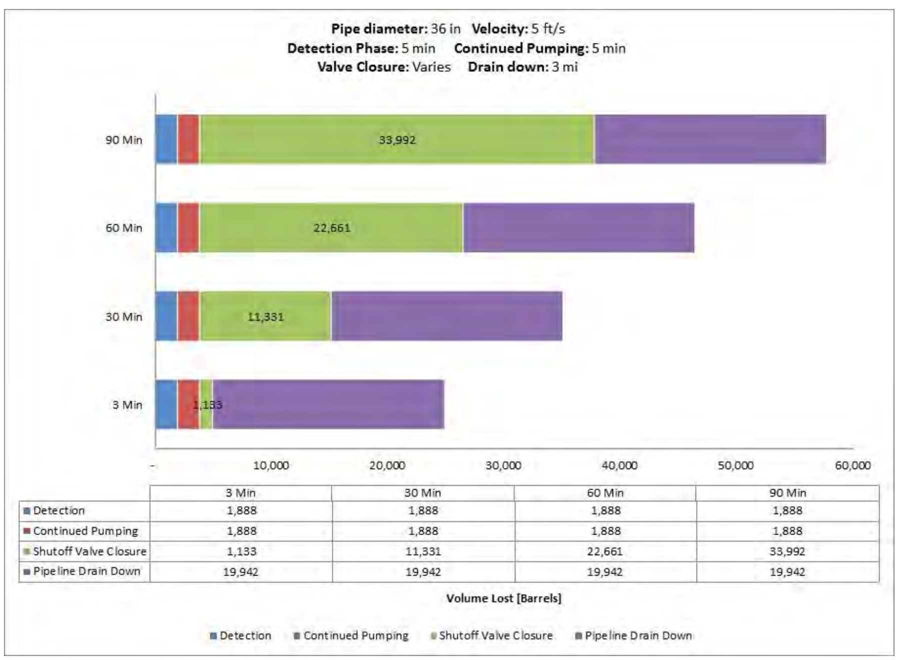
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



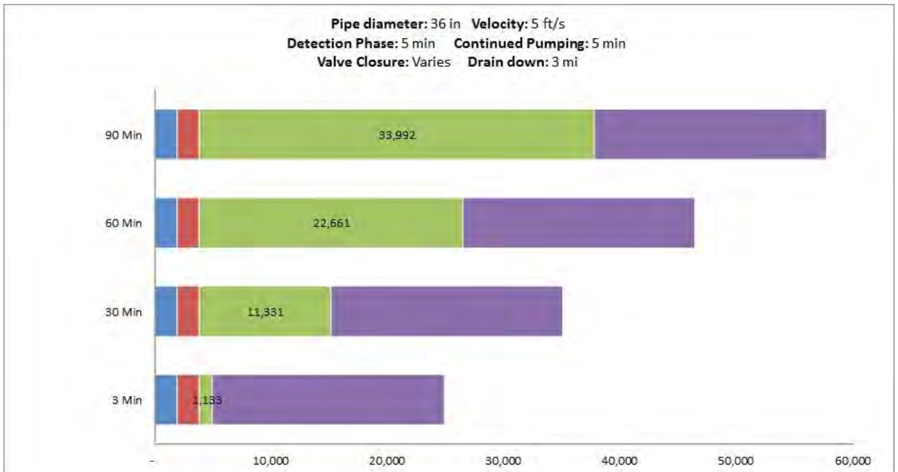
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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

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

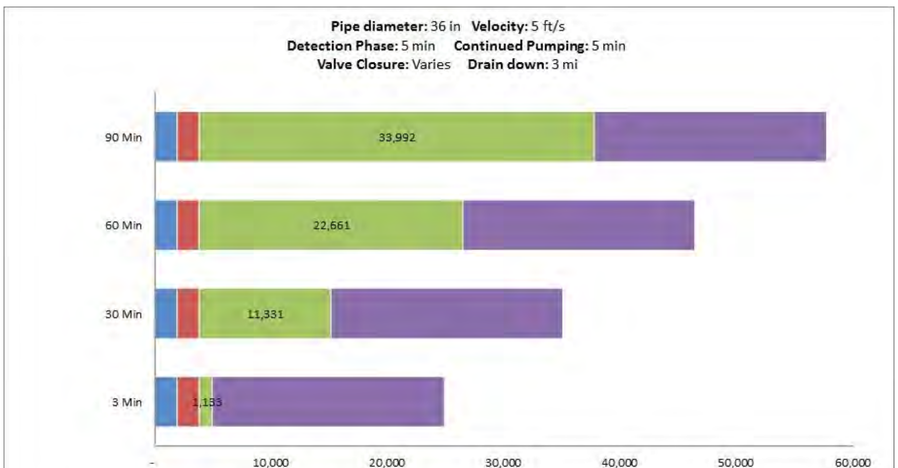


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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.

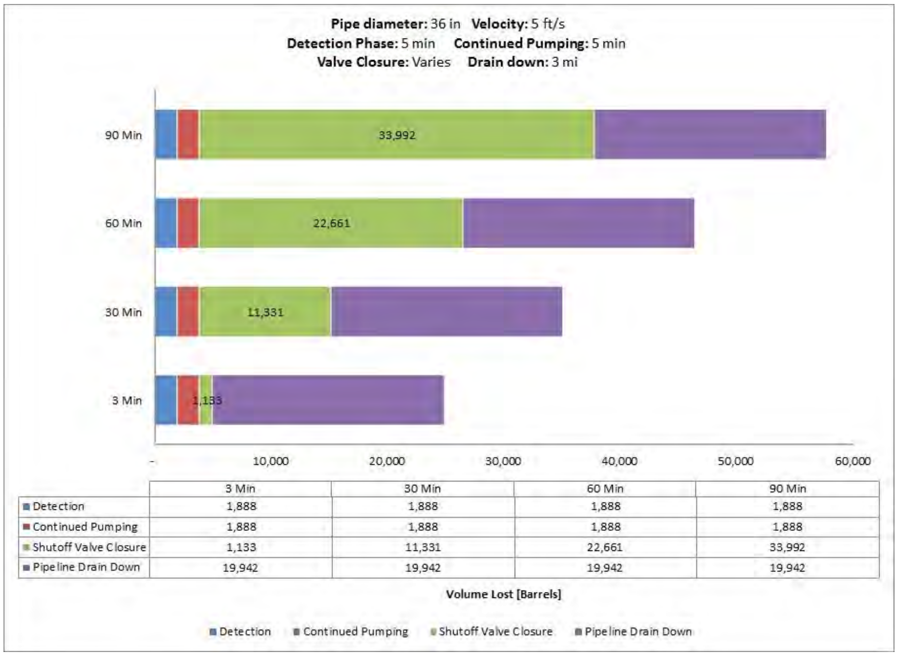


	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

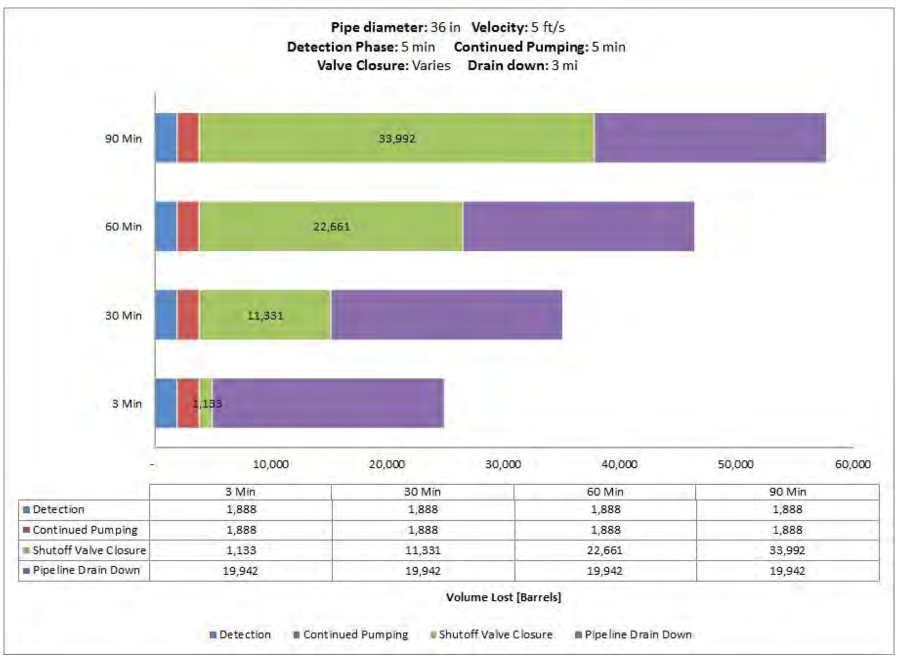
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



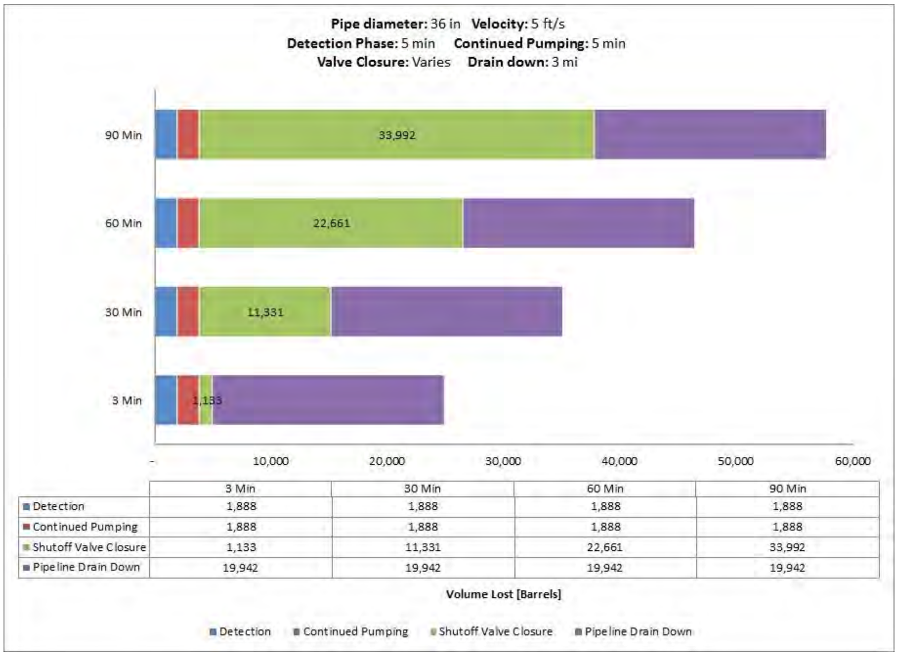
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



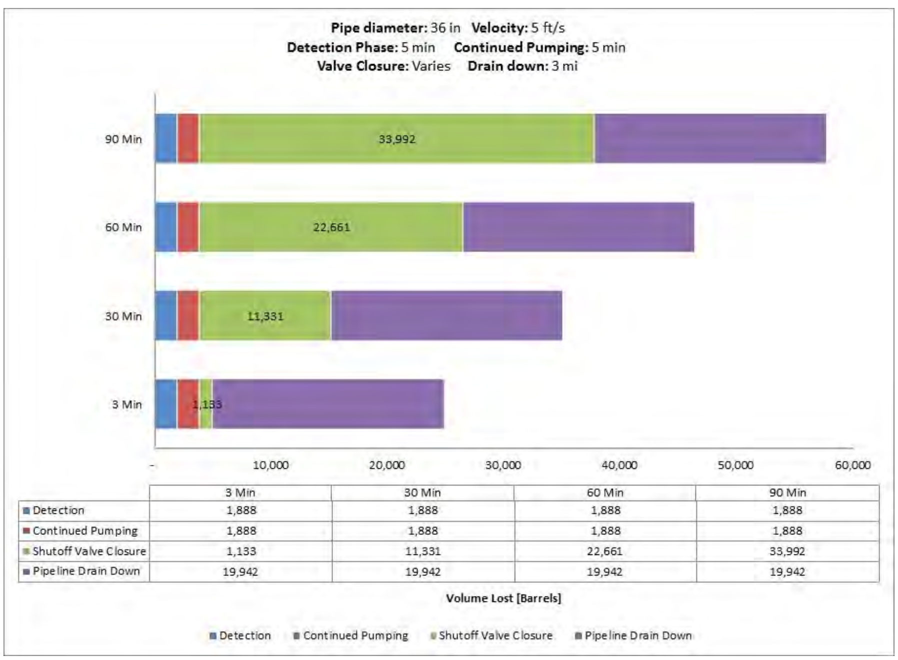
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



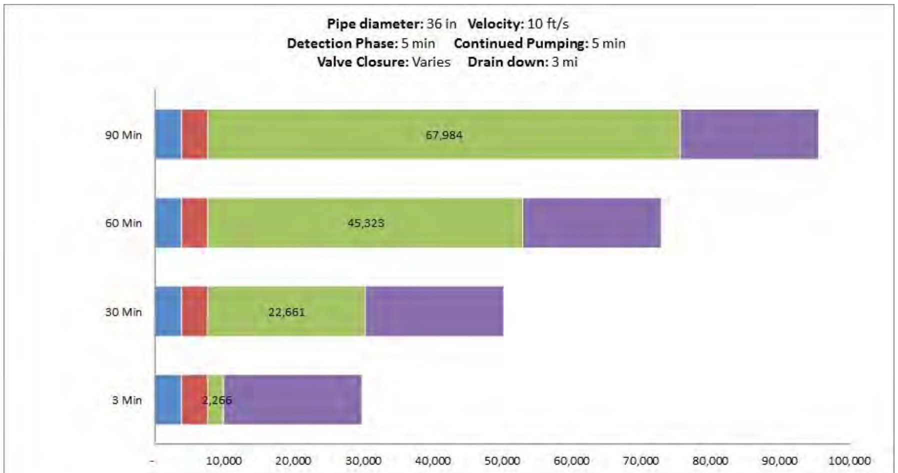
	3 Min	30 Min	60 Min	90 Min
Detection	1,888	1,888	1,888	1,888
Continued Pumping	1,888	1,888	1,888	1,888
Shutoff Valve Closure	1,133	11,331	22,661	33,992
Pipeline Drain Down	19,942	19,942	19,942	19,942

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.

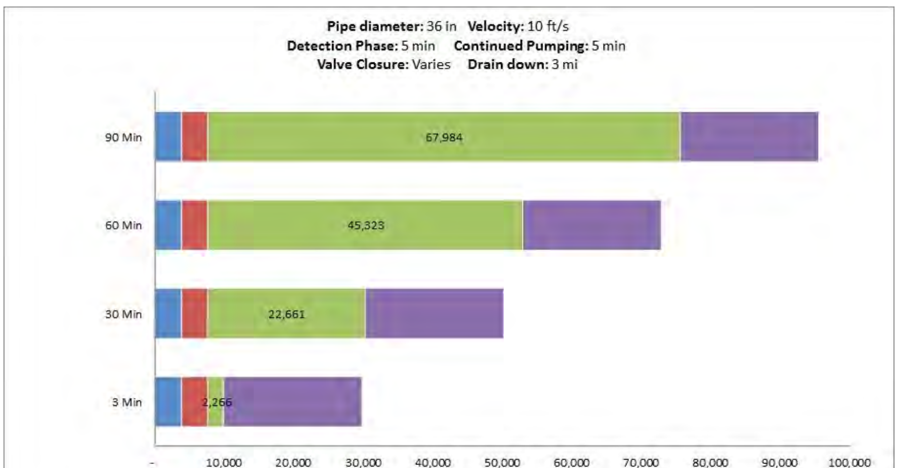


	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

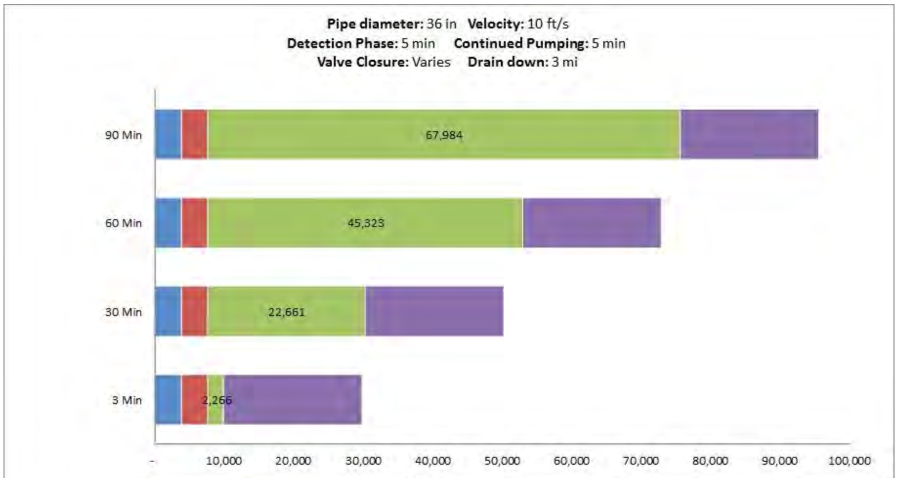


	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

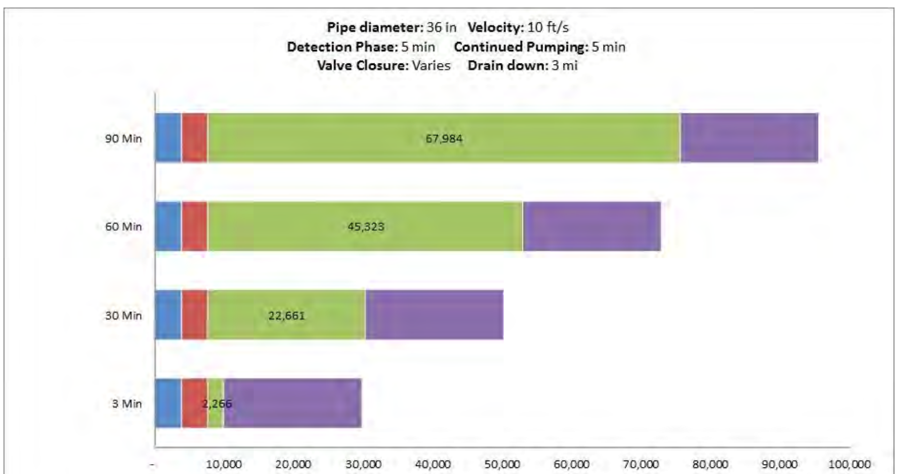
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



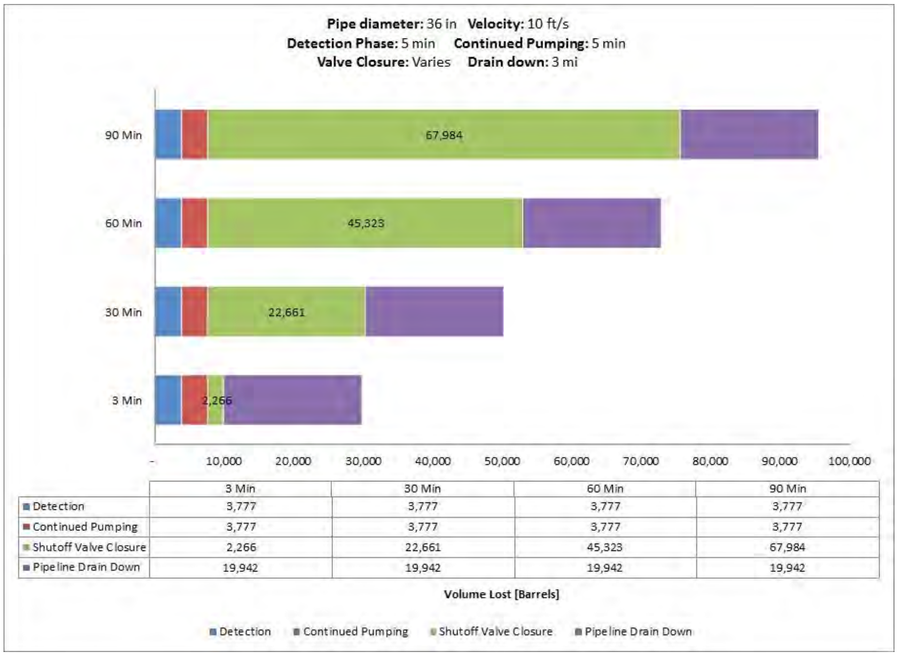
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



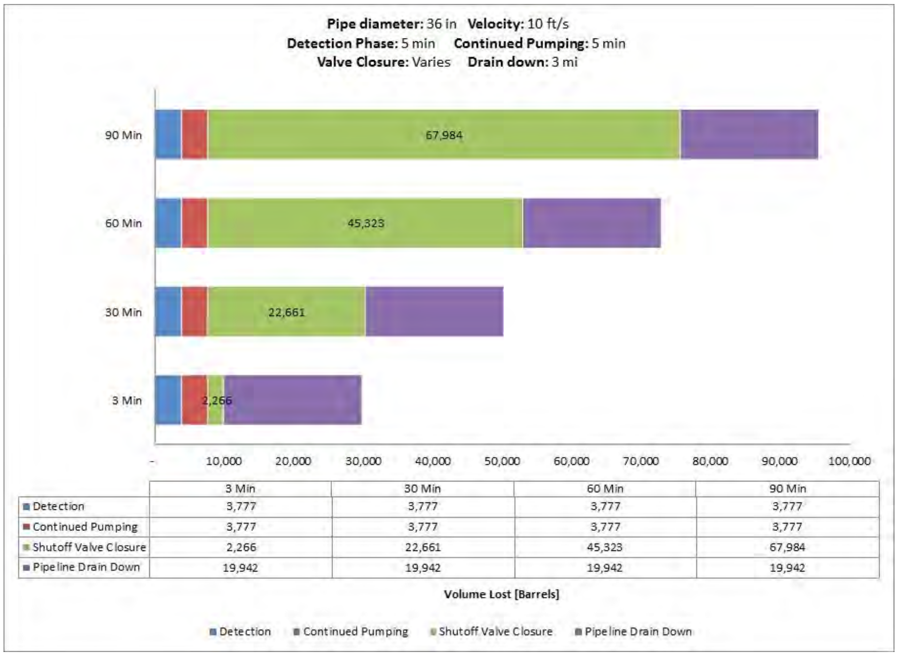
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



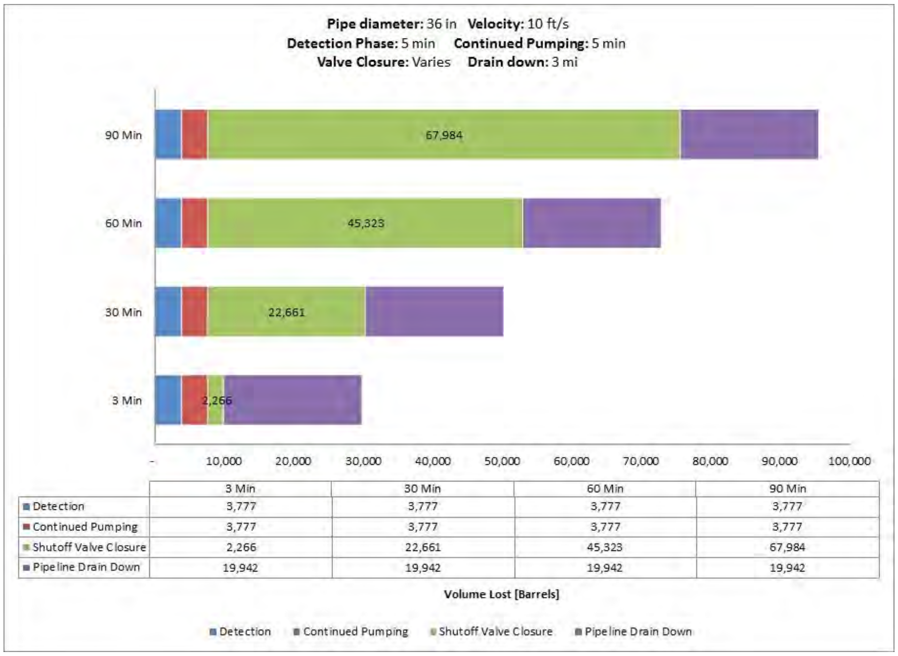
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



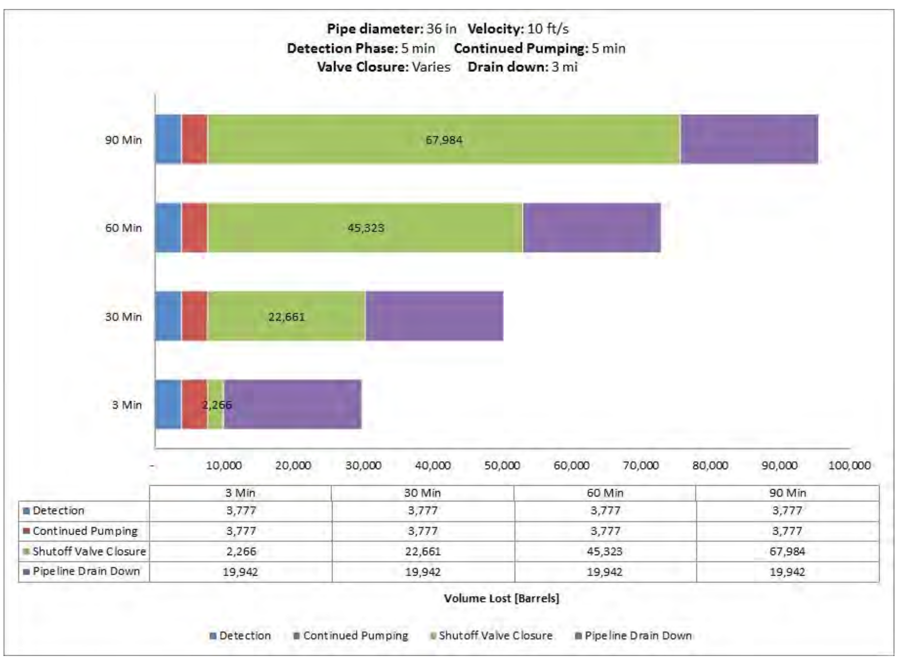
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



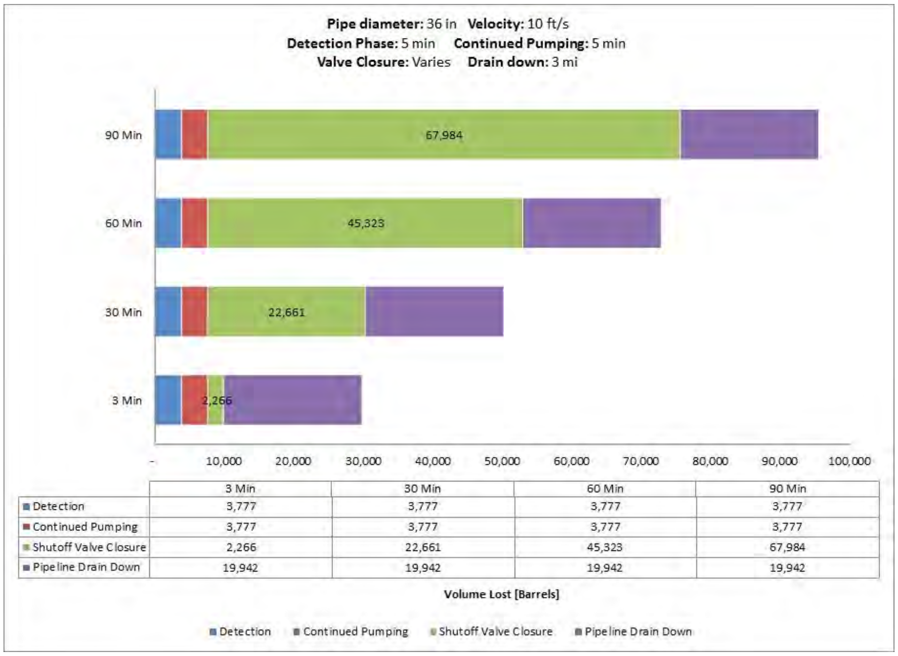
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



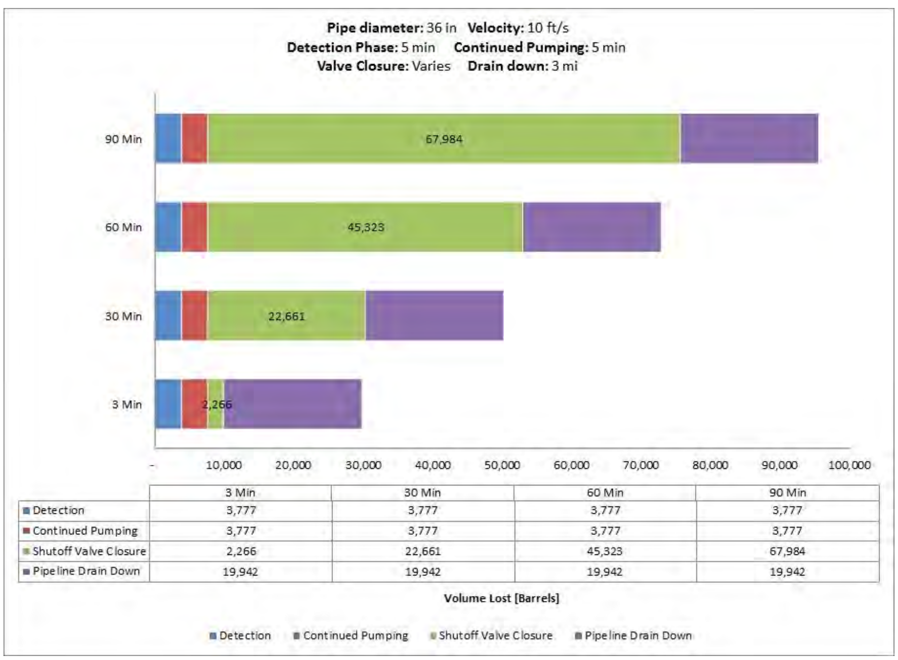
	3 Min	30 Min	60 Min	90 Min
Detection	3,777	3,777	3,777	3,777
Continued Pumping	3,777	3,777	3,777	3,777
Shutoff Valve Closure	2,266	22,661	45,323	67,984
Pipeline Drain Down	19,942	19,942	19,942	19,942

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.

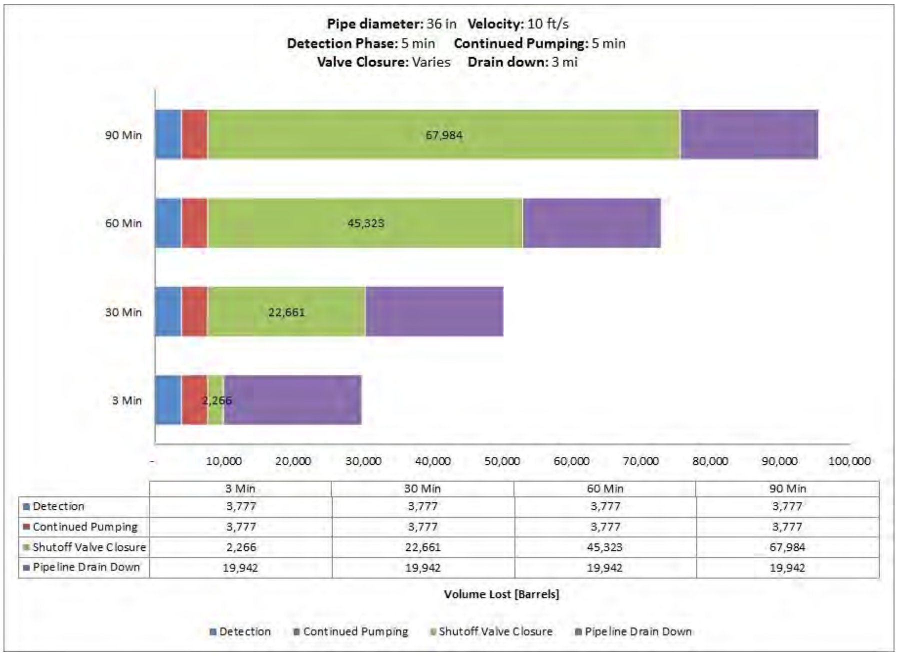


Fig. A-203. 36 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 500 Feet Elevation Change.

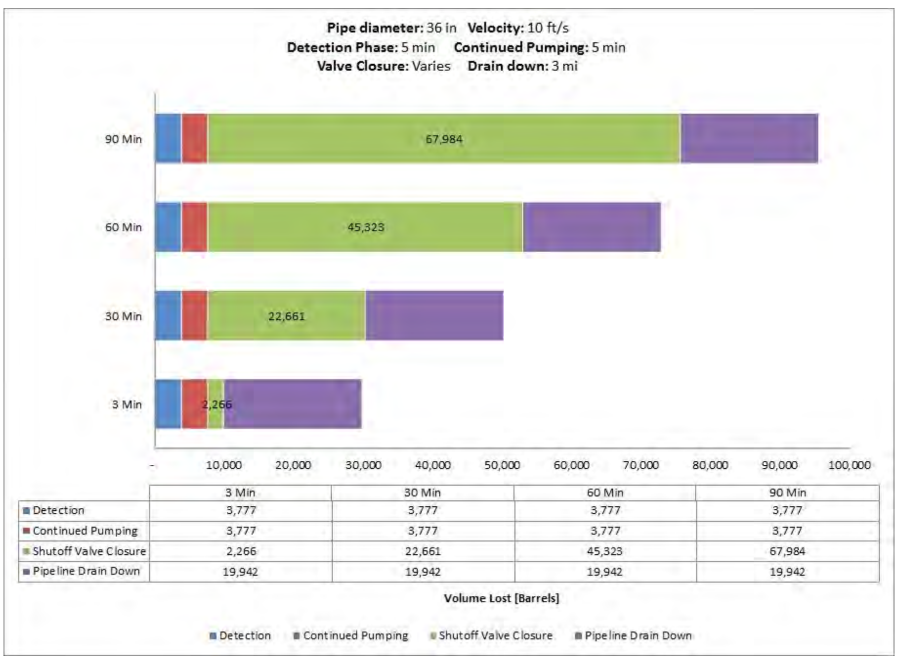
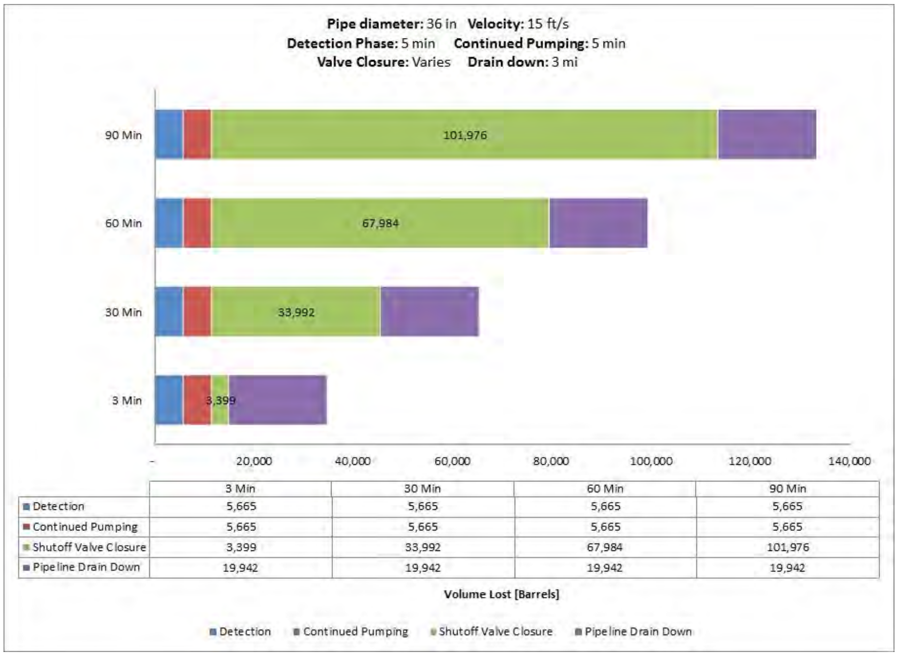
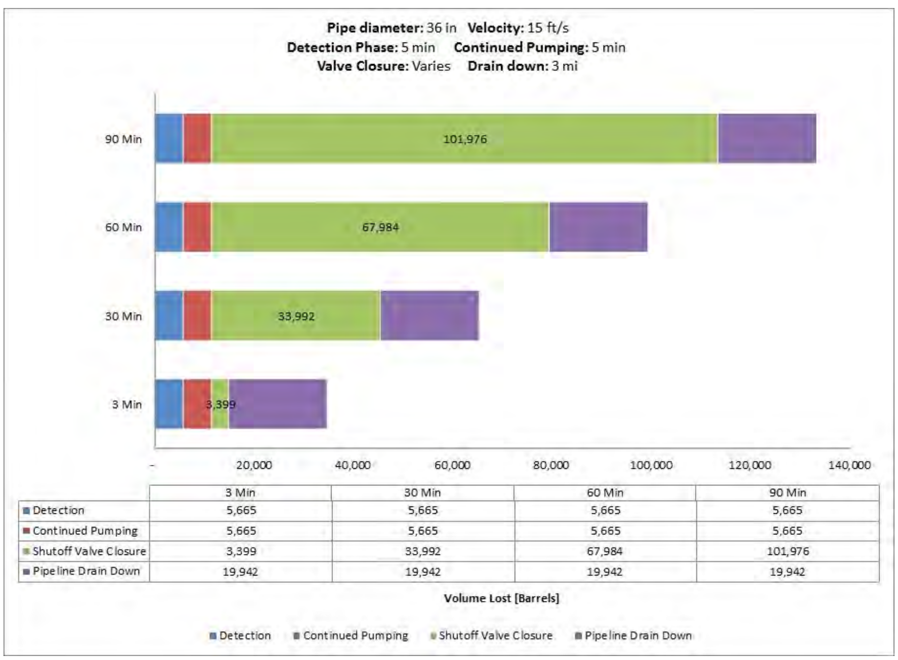


Fig. A-204. 36 Inch Pipe Diameter, 10 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.



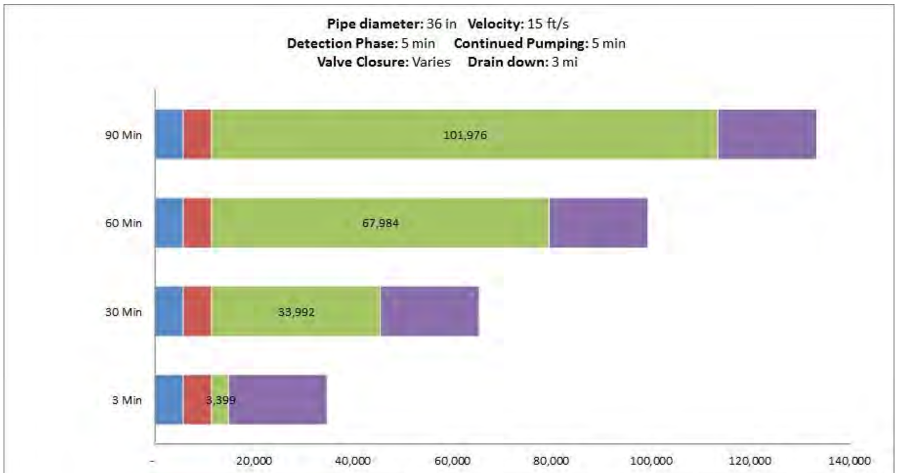
	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Fig. A-205. 36 Inch Pipe Diameter, 15 ft/s, 400 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-206. 36 Inch Pipe Diameter, 15 ft/s, 400 psi MAOP, 500 Feet Elevation Change.

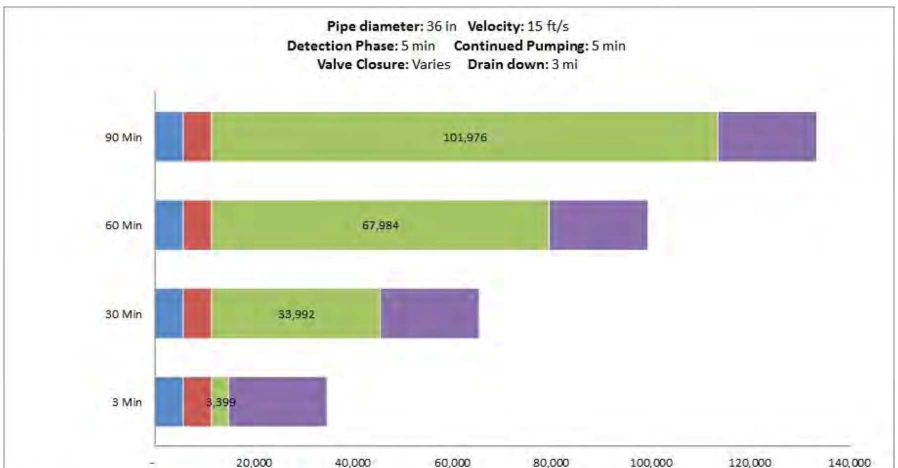


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

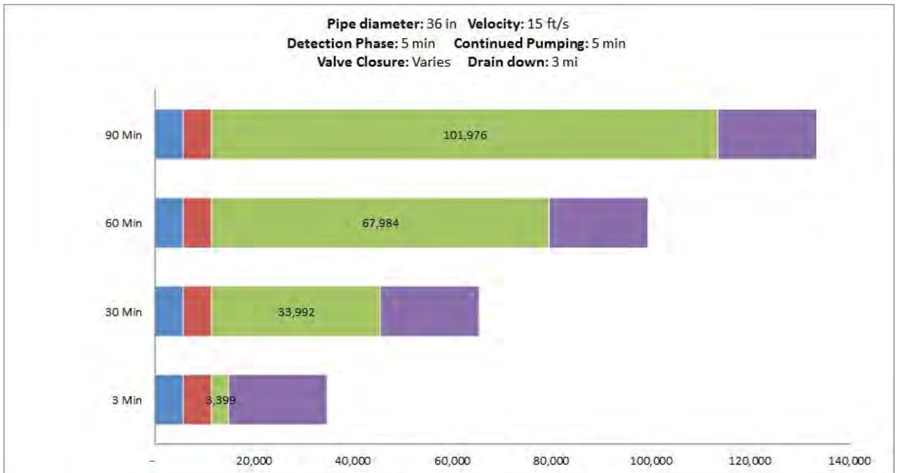


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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

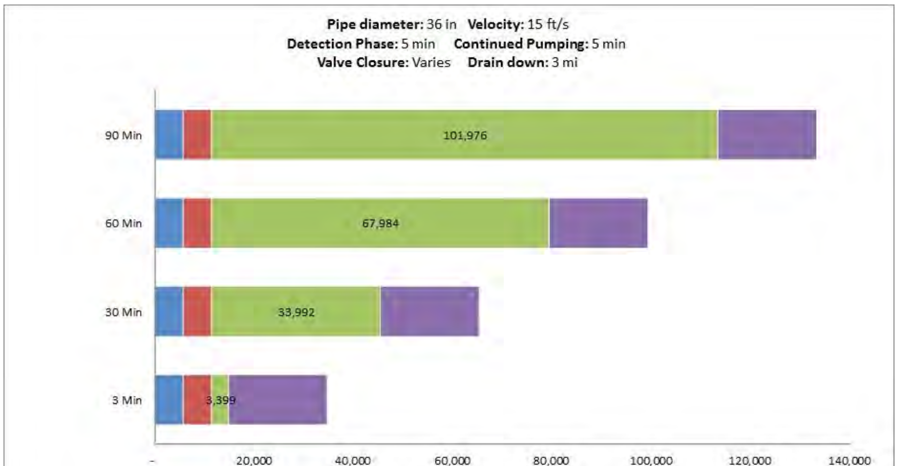


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

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.

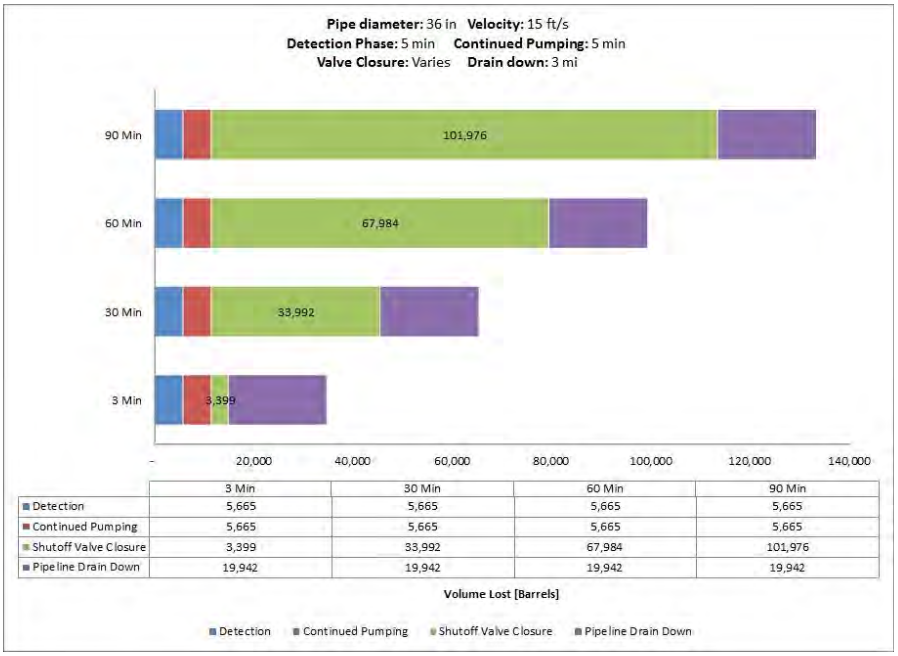


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

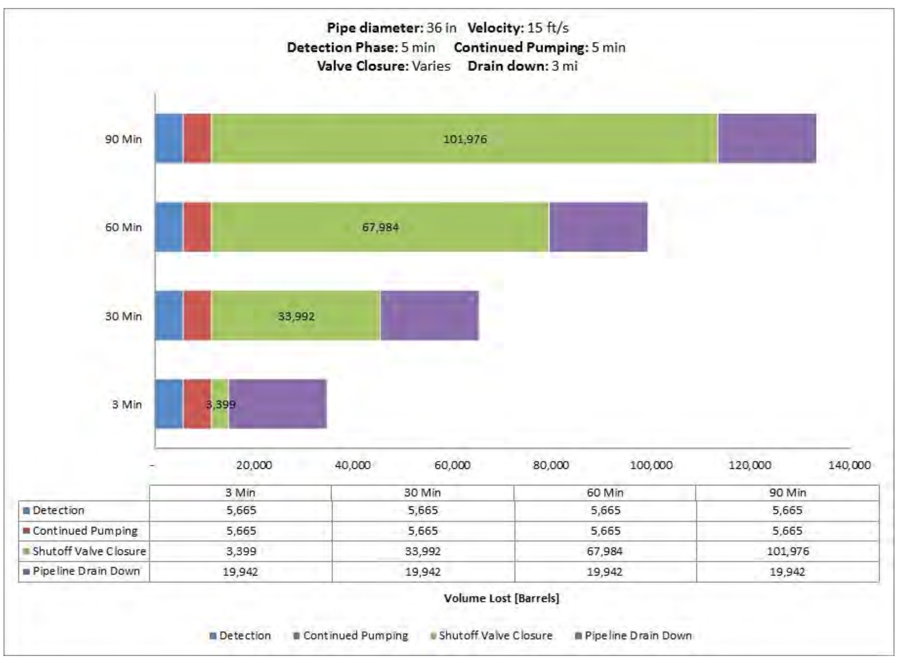
Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

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



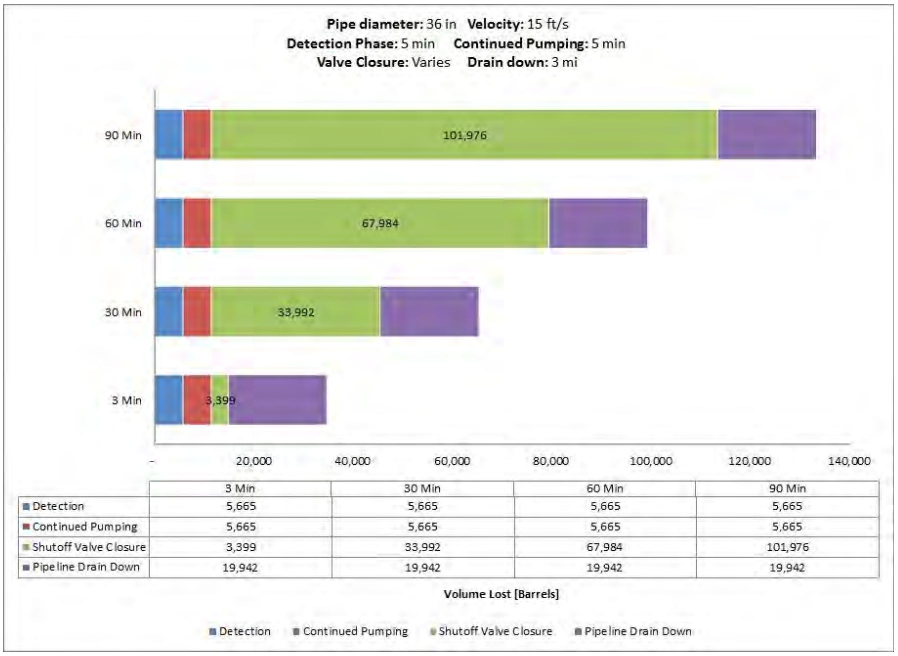
	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



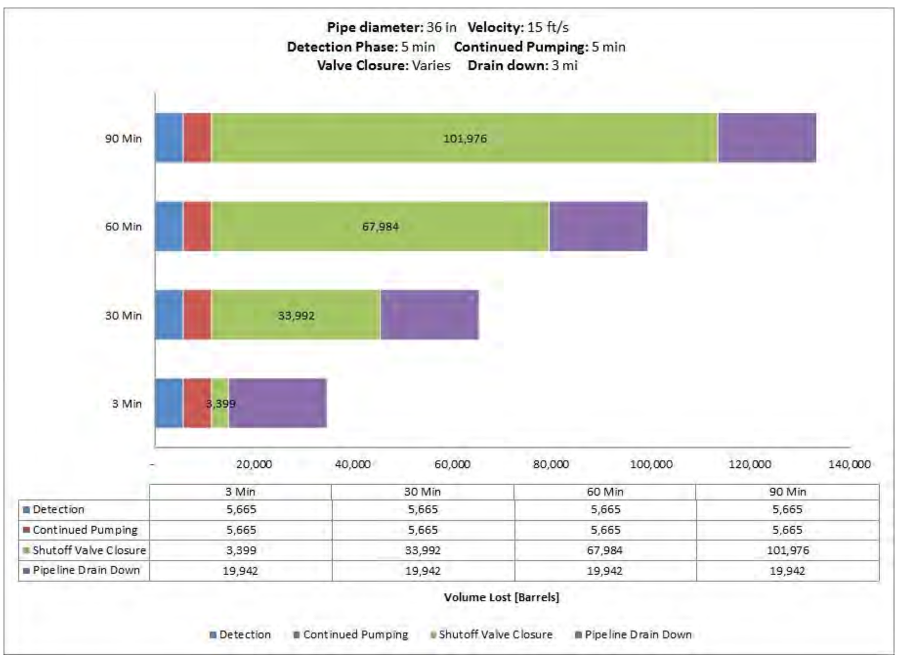
	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

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



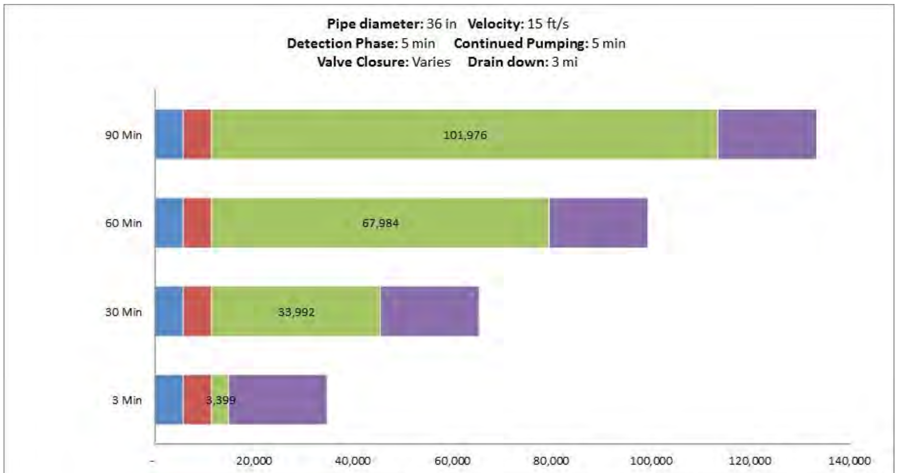
	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

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

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

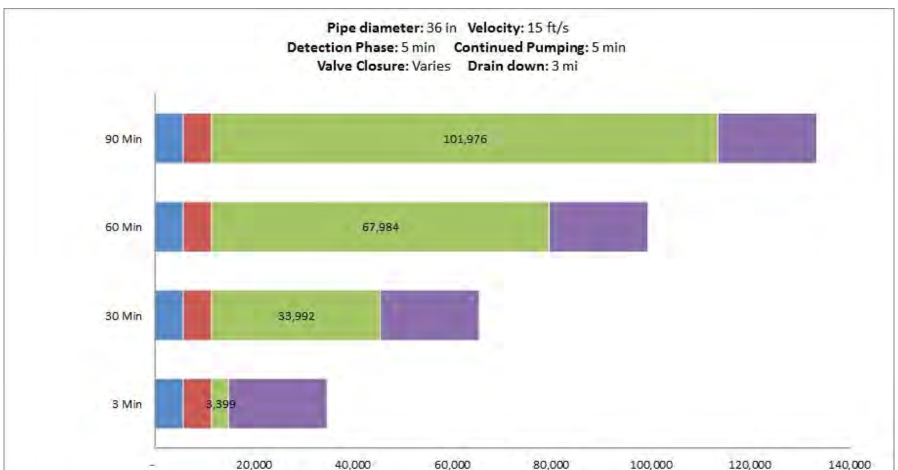


	3 Min	30 Min	60 Min	90 Min
Detection	5,665	5,665	5,665	5,665
Continued Pumping	5,665	5,665	5,665	5,665
Shutoff Valve Closure	3,399	33,992	67,984	101,976
Pipeline Drain Down	19,942	19,942	19,942	19,942

Volume Lost [Barrels]

Detection Continued Pumping Shutoff Valve Closure Pipeline Drain Down

Fig. A-215. 36 Inch Pipe Diameter, 15 ft/s, 1480 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-216. 36 Inch Pipe Diameter, 15 ft/s, 1480 psi MAOP, 1000 Feet Elevation Change.