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16. ABSTRACT

Underground natural gas pipeline leakages at roadway crossings result in jeopardizing safety, incur huge costs for repair, disrupt traffic operations and create environmental hazard situations. In 2018, there were 632 pipeline incidents in the United States with reported costs in economic damages of almost $900 million. These costs were more than previous three years of cumulative costs of damages resulting from pipeline incidents in the country. While fatalities were limited to those from gas pipeline leakages, injuries were the highest from all previous five years of pipeline incident data reported in the nation. Significant number of incidents in 2018 resulted from excavation damages (namely, operator/contractor excavation damage, previous damage due to excavation or third-party excavation damage) and other outside force damage to pipelines. Thus, one of the primary focus of this research was to identify engineering practices that have been adopted across various states of the nation to protect gas pipelines from incidents that lead to leakages. Specific focus is on evaluating pipeline protection with encasement, from excavation related damages. The research approach consisted of obtaining information related to encasement by identifying reliable sources through web searches and gathering details on practices for casing pipelines at roadway crossings.

Data for analyzing pipeline incidents were obtained primarily from the Pipeline and Hazardous Materials Safety Administration (PHMSA) – which is a United States Department of Transportation agency. The data resource from the PHMSA for the years from 2010 to 2018 was mainly used to compile information on excavation damages.

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Encasement Research: Effective Utility Encasement Criteria and Methods

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California Department of Transportation

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EXECUTIVE SUMMARY

Underground natural gas pipeline leakages at roadway crossings result in jeopardizing safety, incur huge costs for repair, disrupt traffic operations and create environmental hazard situations. In 2018, there were 632 pipeline incidents in the United States with reported costs in economic damages of almost $900 million. These costs were more than previous three years of cumulative costs of damages resulting from pipeline incidents in the country. While fatalities were limited to those from gas pipeline leakages, injuries were the highest from all previous five years of pipeline incident data reported in the nation. Significant number of incidents in 2018 resulted from excavation damages (namely, operator/contractor excavation damage, previous damage due to excavation or third-party excavation damage) and other outside force damage to pipelines. Thus, one of the primary focus of this research was to identify engineering practices that have been adopted across various states of the nation to protect gas pipelines from incidents that lead to leakages. Specific focus is on evaluating pipeline protection with encasement, from excavation related damages. The research approach consisted of obtaining information related to encasement by identifying reliable sources through web searches and gathering details on practices for casing pipelines at roadway crossings.

Data for analyzing pipeline incidents were obtained primarily from the Pipeline and Hazardous Materials Safety Administration (PHMSA) – which is a United States Department of Transportation agency. The data resource from the PHMSA for the years from 2010 to 2018 was mainly used to compile information on excavation damages.

Data analysis showed that Texas had the largest length of gas transmission pipelines. Louisiana ranked second and California ranked fourth in terms of total miles of gas transmission lines. California had the largest total miles of gas distribution network, followed by Texas. Texas also had the highest total miles of pipeline for hazardous liquid, followed by Louisiana. California ranked sixth in terms of total miles of hazardous liquid pipelines.

Pipeline incident analysis showed that Hawaii had the highest total number of excavation-related incidents per mile for gas transmission lines, followed by Wisconsin. California ranked ninth in terms of excavation-related incidents per mile. Incorrect Operation (which is partly associated with excavation damage) were the highest in New Jersey for incidents per mile, and California was the second highest in such incidents. For gas distribution, excavation-related incidents per mile was the highest for Hawaii, followed by Louisiana. California ranked fifth in incident per mile in this category. For hazardous liquid, Hawaii again ranked the highest for incidents per mile due to excavation-related damages, followed by Delaware. California ranked sixth for these incidents per mile for hazardous liquid. For incidents per mile due to incorrect operations, Maryland ranked the highest - only marginally ahead of New Jersey. California ranked eleventh in terms of incidents per mile due to incorrect operations under the hazardous liquid category.

Additional analysis showed that for majority of excavation-related incidents that occurred in California, the affected pipelines were buried at depths of cover in the range 20 inches to 37 inches. Most other states studied in this research for underground pipeline incidents showed similar range of depths of cover for the number of excavation-related incidents. One of the reasons identified for a high frequency of excavation incidents at these depths of cover was that most of the pipelines were required to be buried at least 30 to 36 inches depth of cover.

When noting any protection that were provided to the incident affected pipelines, analysis of data from 2010 to 2018 showed that none of the pipelines involved in excavation accidents were cased for either the gas transmission or hazardous liquid lines. Both the gas transmission and hazardous liquid pipelines are identified as high pressure pipelines. For pipelines that reported leaks and were cased, corrosion damage or damage that was incurred during installation were noted to be the primary cause. There was only one incident reported to a cased gas distribution pipeline in 2016 under a public street pavement in Kansas due to excavation damage.

Research findings also show that encasement (or casing) can serve to protect pipelines from excavation damages. However, there are pros and cons associated with casing. Advantages of casing include protecting the pipeline from surrounding adverse soil conditions during construction or pipeline installations – particularly against damage from rocky subsurface soil. Leaking gases or fluids can be dissipated and collected using casings at the end points of the casing such as drainage way, venting points, or right-of-way line. However, issues with casing arise when the leakage of gas to the surface occurs. It is problematic to detect the leakage of the pipe underneath the roadway inside the casing if the soil surrounding the pipeline is a clay-textured soil. Other disadvantages of casing arise when the pipeline outside the casing deflects and settles if fill inside bore pits at the casing ends is not sufficiently compacted during installation – thus the pipeline comes in contact to the casing pipe. In addition, highway widening becomes difficult at locations if there are horizontal and vertical bends in the pipeline which run through casings. However, research suggests that the pros of casing the pipeline against external/accidental damage outweighs the cons. This is because data analysis on incidents showed that damages to uncased pipes have resulted in high number of fatalities and injuries, which might have been prevented with encasement.

Alternatives to casings can be provided if the carrier pipe has the same level of protection as a casing would provide - such as installation of single box-culvert-like structure around utility lines. There are established standards for protecting pipelines. ASME/ANSI B31.8 Gas Transmission and Distribution Piping Systems and the ASME/ANSI B31.4 Pipeline Transmission Systems for Liquid Hydrocarbons and Other Liquids provide directions and relevant standards to protecting underground pipes. Code of Federal Regulations (CFR) that provide minimum Federal safety standards for the transportation by pipeline are 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline, and 49 CFR Part 195, Transportation of Liquids by Pipeline.

Trenchless technologies are used to replace gas transmission/distribution pipes that show signs of leakage. Commonly used technologies consist of pipe eating, pipe bursting, and pipe pulling. Pipe bursting is considered to be more applicable across a wide variety of utility types that carry petroleum or hazardous liquids. Basic cost difference associated with installation of a 300-ft long 6-inch cased pipe is higher than a similar sized uncased pipe installation by approximately $39,000.

Pipeline encasement for states such as California, Alabama, Arkansas, Connecticut, Maryland, Virginia and Wyoming require all high-pressure utility pipes to be encased at crossings- however, these states permit uncased crossings of such pipes if the carrier pipe is buried beyond a minimum depth of cover and is of material and design type that supports highway plus any superimposed load. Typical encasement material in consists of steel, reinforced concrete pipe and high-density polyethylene (HDPE). Jack and bore is commonly used installation method for encasement throughout the nation.

Leakages for underground storage tank (UST) which are in the right-of-way can also cause disruption to traffic. Common leak detection techniques for UST consist of interstitial monitoring, automatic tank gauging system, vapor monitoring, groundwater monitoring, statistical inventory reconciliation, manual tank gauging, and continuous in-tank leak detection. UST operators are entrusted with monitoring any leakages from these tanks by conducting a periodic inspection.

In an effort to avoid accidents during construction, several key states such as Alaska, Utah and Virginia use procedures to identify and resolve utility conflicts with highways. A recent pilot exercise was carried out for the identification of utility conflicts and solutions under the SHRP 2 R15B Products at the Maryland State Highway Administration. One of the tools used in the pilot program was the use of a utility conflict matrix (UCM) which enables users to organize, track, and manage the conflicts. UCM provides a much accurate and complete information about utilities that might be in conflict with the project.

In summary, in order to avoid utility conflicts and relocations, Federal Highway Administration (FHWA) encourages implementation of strategies at various stages of the development of highway projects. Strategies at the planning stage consist of forming Utility Coordinating Councils, One-Call Notification, detailed utility information using Subsurface Utility Engineering (SUE), utility agreements, electronic document delivery, cost sharing, joint project agreements, context sensitive design, locating utilities next to ROW line, joint trenching/utility corridors, utility tunnels, use of subways for dry lines, and removal of abandoned lines. These strategies need to be studied in-depth for their implementation in various states across the country to understand if they resulted in any reduction in frequency of excavation-related damages to underground utility pipelines.

1. INTRODUCTION

Encasing utilities dates to 1800s when first cast iron pipes were used in history and protected against corrosion using cement-line. In 1928, coating compounds were in use to coat pipe and protect it from corrosion (Pipeline Knowledge & Development, 2011). For improved durability, in 1942, prestressed concrete cylinder pipe was first manufactured with a thin steel ring encased in concrete for storm sewer lines and water mains. Concrete cylinders are still manufactured today for these purposes.

Early pipeline systems were installed with waterworks in Philadelphia in 1802 (Lygo, 2018). The installations were built with brick and mortar. In 1821, William Hart—known as the “father of natural gas”— piped the gas through hollow logs to nearby houses in the northeastern United States (Wylie, 2018). Around the same time, the wooden pipe or log pipe were installed in the United States - from Philadelphia to Portland, Oregon. Clay pipes became popular in the 1900s, however, these pipes were very heavy and were mainly installed in cities which had local supply of clay. The first accident that was recorded with gas pipeline was in March 1860, when a "gasometer" exploded during a fire at New Orleans, Louisiana (Daily Herald, 1860). The incident resulted in two fatalities leading to death of two men.

2. PIPELINE EXCAVATION ACCIDENTS VIS-À-VIS ENCASEMENT NEEDS

Compilation of Incidents due to Excavation Accidents or Excavation Damage

Data collection involved online searches, reports and other documentations from reliable public agency websites. Data for pipeline incidents that have occurred across various states of the country have been analyzed using information from the Pipeline and Hazardous Materials Safety Administration (Data and Statistics - PHMSA, 2018). Although, the team referred to other online content (published and unpublished) for collecting information on excavation-related incidents, none seemed to meet the quality of information provided by the PHMSA. Excavation damages were attributed to four sub-causes that were identified in the PHMSA incident data logs as follows:

(i) Excavation damage, with the following incident cause subtypes:
    (a) operator /contractor excavation damage
    (b) previous damage due to excavation
    (c) third party excavation damage

(ii) Incorrect operation, with the following incident cause subtypes:
    (a) damage by operator or operator’s contractor
    (b) other incorrect operation

Table 1 presents information on data collected and their sources that have been used to compile incidents due to excavation accidents. Table 2 outlines the standard approach that was adopted to compile information for underground excavation incidents with communication and cable lines, waterlines, underground power lines and sanitary sewer lines. None of the incidents (fatal or non-fatal) that have occurred in the past could be attributed to damage to a pipeline due to excavation for the underground communication and cable lines, waterlines, underground power lines, or sanitary sewer lines. On the other hand, several incidents have been reported due to excavation incidents under the gas transmission, gas distribution and hazardous liquid transportation categories- which, therefore, were the only ones reported in the research findings. Thus, with specific focus on excavation related incidents only, the data analyzed under the following pipeline system type categories were covered: (i) Gas Transmission (ii) Gas Distribution (iii) Hazardous Liquid (including crude oil, refined petroleum product, etc., and (iv) Liquefied Natural Gas (LNG). Amongst the four pipeline system types, protection carried out for gas transmission pipelines was the primary focus in this research since these are high-priority pipelines that have a higher likelihood of conflicting with highway right-of-way at crossings.

Table 1: Summary of information available on data resources used in research

	TRANSPORTED PRODUCT TYPE					
DATA CATEGORY	GAS TRANSMISSION	GAS DISTRIBUTION	HAZARDOUS LIQUID	LIQUIFIED NATURAL GAS	PRESSURIZED WATER AND SEWER PIPELINES	HIGH-VOLTAGE ELECTRIC SUPPLY LINES
Incident Data	1970 – 2018 (except 1985)	1986 – 2018	1986 – 2018	2011 – 2018	1984 – 2014	1984 – 2014
Encasement Information	2010 – 2018	2010 – 2018	2010 – 2018	Limited/No information	Limited/No information	Limited/No information
Encasement Material (if cased)	Limited/No information	Limited/No information	Limited/No information	Limited/No information	Limited/No information	Limited/No information
Pipe Material	1970 – 2018 (except 1985)	1986 – 2018	2010 – 2018	Limited/No information	Limited/No information	Limited/No information
Excavation Damage and Incorrect Operation	1970 – 2018 (except 1985)	1986 – 2018	2010 – 2018	2011 – 2018	Limited/No information	Limited/No information
Depth of Cover	1970 – 2018 (except 1985)	2010 – 2018	2002 – 2018	Limited/No information	Limited/No information	Limited/No information
Cost of Damage	1986 – 2018	1986 – 2018	1986 – 2018	2011 – 2018	Limited/No information	Limited/No information
Installation Method	1986 – 2018	1986 – 2018	1986 – 2018	Limited/No information	Limited/No information	Limited/No information
Liquid Release	2010 – 2018	2010 – 2018	1986 – 2018	Data not reported	Limited/No information	Limited/No information
Primary Data Source(s), Reference(s)	Pipeline and Hazardous Materials Safety Administration (PHMSA)	Pipeline and Hazardous Materials Safety Administration	Pipeline and Hazardous Materials Safety Administration	Pipeline and Hazardous Materials Safety Administration	Occupational Safety and Health Administration (OSHA)	Occupational Safety and Health Administration (OSHA)

Note: ‘Limited/No information’ means information is incomplete or not useful to draw meaningful or technically sound conclusions for ‘EXCAVATION INCIDENTS’

Table 2: Approach adopted for historical incident counts from other utility types from Occupational Safety and Health Administration (OSHA)

TRANSPORTED PRODUCT TYPE	APPROACH USED FOR SEARCHING INCIDENT INFORMATION	COUNT OF EXCAVATION ACCIDENTS RESULTING IN FATALITIES OR INCIDENTS REPORTED (INCIDENTS PER MILE)	DATA SOURCE/REFERENCE
Underground communication and cable lines	SIC* used: 4813, 4841 4813: Telephone Communications, Except Radiotelephone 4841: Cable and Other Pay Television Services Keyword(s) used for search: excavation, dig-in, underground, soil, encasement, cased, uncased, damage, construction	0	1984 – 2018 Fatality and Catastrophe Investigation Summaries, Occupational Safety and Health Administration (OSHA)
Waterlines	SIC used: 4941 4941: Water Supply Keyword(s) used for search: excavation, dig-in, underground, soil, encasement, cased, uncased, damage, construction	0	
Underground power lines	SIC used: 4911 4911: Electric Services Keyword(s) used for search: excavation, dig-in, underground, soil, encasement, cased, uncased, damage, construction	0	
Sanitary sewer lines	SIC used: 4952 4952: Sewerage Systems Keyword(s) used for search: excavation, dig-in, underground, soil, encasement, cased, uncased, damage, construction	0	

* SIC stands for Standard Industrial Classification

Incident Summary from Excavation Damages

Based on the narrative provided in the PHMSA incident data logs, there was no record of third-party damage that caused damage to encasement and gas carrier pipe at the same time. Table 3 presents the total count of incidents that occurred due to excavation and only one incident in Kansas occurred that was with an encased Gas Distribution pipeline, rest of the excavation incidents were with uncased pipelines. None of the incidents that had occurred in the past that were with Liquified Natural Gas pipeline due to excavation damage and did not figure in Table 3.

Table 3: Compilation of excavation-related pipeline damages across various pipeline system types

	Gas Transmission		**Gas Distribution**		**Hazardous Liquid**	
State	**Excavation Damage**	**Incorrect operation**	**Excavation Damage**	**Incorrect operation**	**Excavation Damage**	**Incorrect operation**
AK	8	0	7	0	1	2
AL	21	0	29	3	9	0
AR	125	0	16	0	12	3
AZ	24	0	39	5	3	2
CA	220	3	160	5	74	12
CO	64	0	39	3	15	5
CT	2	0	5	2	1	0
DE	7	0	8	1	1	0
FL	26	0	20	1	6	0
GA	18	0	43	6	4	5
HI	3	0	3	0	4	0
IA	36	0	11	2	22	14
ID	8	0	3	0	1	1
IL	45	0	55	5	37	12
IN	42	0	43	3	8	7
KS	95	0	32	2	60	18
KY	101	1	21	3	3	1
LA	136	0	101	6	35	27
MA	9	0	29	3	1	0

MD	4	0	24	5	4	4
ME	4	0	2	0	0	0
MI	28	1	68	8	7	2
MN	36	0	25	4	17	7
MO	15	0	44	2	19	6
MS	55	0	12	0	9	0
MT	29	0	10	0	11	3
NC	36	0	24	2	3	3
ND	13	0	3	0	15	4
NE	65	0	11	4	15	4
NH	5	0	2	0	0	0
NJ	13	1	27	4	6	6
NM	45	0	24	0	29	6
NV	14	0	21	1	1	1
NY	31	0	51	5	8	4
OH	101	0	52	3	22	7
OK	311	0	31	3	100	27
OR	7	0	9	1	4	0
PA	71	0	73	8	21	8
RI	7	0	5	0	0	0
SC	93	0	9	0	4	4
SD	2	0	9	0	4	1
TN	20	0	28	2	12	1
TX	606	0	282	6	268	100
UT	22	0	12	1	4	2
VA	10	0	30	5	9	1
VT	2	0	0	0	0	0
WA	12	0	20	1	6	1
WI	276	0	24	1	6	3

WV	84	0	11	0	1	0
WY	14	0	6	1	21	5

An in-depth analysis was carried out to develop an understanding of incident counts per mile due to excavation-related pipeline damage. Table 4 provides summary of significant incidents due to excavation damage from the period for which data were available- as noted in Table 1 earlier. Note that there were no data on excavation-related incidents attributed to liquified natural gas, and hence the incident summary from the latter was not included in Table 4.

It is evident from the data compilation in Table 4, Texas had the largest total length of gas transmission pipelines. Louisiana ranked second and California ranked fourth in terms of total miles of gas transmission lines. California had the largest total miles of gas distribution network, followed by Texas. Texas had the highest total miles of pipeline for hazardous liquid, followed by Louisiana. California ranked 6th in terms of total miles of hazardous liquid pipelines.

Hawaii had the highest total number of excavation-related incidents per mile for gas transmission lines, followed by Wisconsin. California ranked 9th in terms of excavation-related incidents per mile. Incorrect Operation (which are partly associated with excavation damages) were the highest in New Jersey for incidents per mile, followed by California. For gas distribution, excavation-related incidents per mile was the highest for Hawaii, followed by Louisiana. California ranked 5th in the same incident per mile category.

For hazardous liquids, Hawaii again ranked the highest for incidents per mile due to excavation-related damages, followed by Delaware. California ranked sixth for these incidents per mile for hazardous liquid. For incidents per mile due to incorrect operations, Maryland ranked one only marginally ahead of New Jersey. California ranked 11th in terms of incidents per mile due to incorrect operations under the Hazardous Liquid category.

Maps are also shown in Figs. A1 to A6 under Appendix to show the spatial distribution of these incidents per mile.

Table 4: Compilation of excavation incidents for various pipeline system types

State	**Miles of Gas Transmission Pipeline**	**Miles of Gas Distribution Pipeline**	**Miles of Hazardous Liquids Pipeline**	**Number of Incidents per mile**					
				Gas Transmission		**Gas Distribution**		**Hazardous Liquids (appendix shows specific number of incidents due to crude oil, petroleum products etc.)**	
				Excavation Damage	**Incorrect Operation**	**Excavation Damage**	**Incorrect Operation**	**Excavation Damage**	**Incorrect Operation**
AK	857	3204	1168	0.009	0	0.002	0	0.001	0.002
AL	6681	30723	1736	0.003	0	0.001	0	0.005	0
AR	7394	20227	1974	0.017	0	0.001	0	0.006	0.002
AZ	6682	24374	582	0.004	0	0.002	0	0.005	0.003
CA	**11929**	**105149**	**7140**	**0.018**	**0.251**	**0.002**	**0**	**0.01**	**0.002**
CO	7852	34962	3796	0.008	0	0.001	0	0.004	0.001
CT	574	7888	102	0.003	0	0.001	0	0.01	0
DE	331	3019	42	0.021	0	0.003	0	**0.024**	0
FL	5054	27343	469	0.005	0	0.001	0	0.013	0
GA	4638	44080	2114	0.004	0	0.001	0	0.002	0.002
HI	23	613	95	**0.133**	0	**0.005**	0	0.042	0
IA	8331	18026	4526	0.004	0	0.001	0	0.005	0.003

ID	1506	8227	717	0.005	0	0	0	0.001	0.001
IL	9386	61453	7974	0.005	0	0.001	0	0.005	0.002
IN	5459	40519	3914	0.008	0	0.001	0	0.002	0.002
KS	13933	22218	11370	0.007	0	0.001	0	0.005	0.002
KY	6855	18088	920	0.015	0.146	0.001	0	0.003	0.001
LA	**24459**	26649	**12454**	0.006	0	**0.004**	0	0.003	0.002
MA	1072	21398	66	0.008	0	0.001	0	0.015	0
MD	978	14669	343	0.004	0	0.002	0	0.012	**0.012**
ME	476	992	269	0.008	0	0.002	0	0	0
MI	8750	57441	3413	0.003	0.114	0.001	0	0.002	0.001
MN	5505	31051	4954	0.007	0	0.001	0	0.003	0.001
MO	4598	27357	5014	0.003	0	0.002	0	0.004	0.001
MS	10433	16576	3694	0.005	0	0.001	0	0.002	0
MT	3888	6995	3443	0.007	0	0.001	0	0.003	0.001
NC	4138	29823	1129	0.009	0	0.001	0	0.003	0.003
ND	2434	3348	3985	0.005	0	0.001	0	0.004	0.001
NE	5861	12729	2817	0.011	0	0.001	0	0.005	0.001
NH	251	1915	71	0.02	0	0.001	0	0	0
NJ	1515	34203	625	0.009	**0.66**	0.001	0	0.01	**0.01**
NM	6494	13693	6485	0.007	0	0.002	0	0.004	0.001
NV	1974	9911	240	0.007	0	0.002	0	0.004	0.004

NY	4503	48374	1141	0.007	0	0.001	0	0.007	0.004
OH	9886	56986	4348	0.01	0	0.001	0	0.005	0.002
OK	11788	25896	12357	0.026	0	0.001	0	0.008	0.002
OR	2485	15576	416	0.003	0	0.001	0	0.01	0
PA	9761	47820	2942	0.007	0	0.002	0	0.007	0.003
SC	2787	21400	805	0.033	0	0	0	0.005	0.005
SD	1564	4691	867	0.001	0	0.002	0	0.005	0.001
TN	4987	38749	1210	0.004	0	0.001	0	0.01	0.001
TX	**45974**	**103289**	58155	0.013	0	0.003	0	0.005	0.002
UT	3101	17331	1646	0.007	0	0.001	0	0.002	0.001
VA	3101	21098	1101	0.003	0	0.001	0	0.008	0.001
VT	80	763	117	0.025	0	0	0	0	0
WA	1935	22269	802	0.006	0	0.001	0	0.007	0.001
WI	4521	38554	2536	0.061	0	0.001	0	0.002	0.001
WV	3791	10686	290	0.022	0	0.001	0	0.003	0
WY	6878	5139	7034	0.002	0	0.001	0	0.003	0.001

Fatalities and injuries

California and Texas had the largest number of fatalities and injuries due to excavation-related incidents for Gas Transmission and Hazardous Liquid transport (see Table 5). Most of the states had a higher number of injuries compared to fatalities under Gas Distribution category. Gas Distribution pipeline systems operate under medium to low-pressure compared to Gas Transmission and Hazardous Liquid transport – thus fatalities could be lower compared to Gas Distribution. There were no fatalities reported for Liquified Natural Gas due to excavation damage and hence, were not included in Table 5.

Table 5: Compilation of fatalities and injuries for various pipeline systems

State	**Gas Transmission**		**Gas Distribution**		**Hazardous Liquid**	
	Total Fatalities	Total Injuries	Total Fatalities	Total Injuries	Total Fatalities	Total Injuries
AK	0	0	0	3	0	0
AL	1	3	1	11	0	0
AR	8	18	0	5	0	0
AZ	1	1	2	11	0	0
CA	34	36	3	23	7	35
CO	5	6	1	31	0	7
CT	0	0	0	1	0	0
DE	0	0	0	4	0	0
FL	1	3	2	11	0	0
GA	4	4	3	25	1	1
HI	0	0	0	3	0	0
IA	8	11	0	3	1	6
ID	0	0	0	1	0	0
IL	5	8	4	27	0	1
IN	0	1	7	18	0	2
KS	3	5	1	15	0	1
KY	5	7	0	5	0	0
LA	5	9	0	20	3	7
MA	0	2	1	5	0	0

MD	0	0	1	4	0	0
ME	0	0	0	0	0	0
MI	3	6	4	16	0	1
MN	3	3	7	21	0	2
MO	0	0	4	9	0	3
MS	1	4	8	3	0	1
MT	0	1	1	6	0	0
NC	4	4	2	28	0	3
ND	5	6	0	0	0	0
NE	1	4	1	7	0	1
NH	0	0	0	0	0	0
NJ	2	4	7	25	0	0
NM	3	7	1	6	0	0
NV	1	1	1	7	0	3
NY	4	1	2	29	0	0
OH	5	6	3	22	0	6
OK	8	9	0	9	1	2
OR	0	0	0	4	0	0
PA	2	10	2	38	0	2
RI	0	0	0	0	0	0
SC	0	0	0	0	0	0
SD	0	0	0	6	0	0
TN	1	2	0	2	0	0
TX	34	54	1	16	7	27
UT	0	0	7	71	0	4
VA	0	0	3	2	0	2
VT	0	0	1	6	0	0
WA	0	0	0	0	0	0
WI	1	1	0	1	0	0

WV	2	3	7	20	0	0
WY	0	3	0	0	0	3

Incident Cost Analysis

Cost analysis was based on the following damage considerations:

$50,000 or more in total costs, measured in 1984 dollars – this is required as per PHMSA. (Note: This is as per Amdt. CFR 191-5, 49 FR 18960, May 3, 1984 when an incident was classified as significant based on property damages of $50,000 or more in 1984. See the following link for the amendment ->> https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/pdmpublic_incident_page_allrpt.pdf).

Therefore, costs have been converted to current year costs and presented under Table 6. New Jersey ranked the highest, followed by California and Louisiana, in terms of total costs due to excavation-related damages. Liquified Natural Gas pipelines did not have any incident due to excavation and hence, were not included in Table 6.

Table 6: Costs associated with excavation-related damages across the states

	Pipeline System			**Total Cost in Year 2018 Dollars**
State	**Gas Transmission**	**Gas Distribution**	**Hazardous Liquid**	
AK	$2,874,144	$378,372	$597,301	$3,849,817
AL	$582,815	$1,688,584	$1,672,113	$3,943,512
AR	$716,061	$1,747,198	$1,843,035	$4,306,294
AZ	$330,249	$7,431,661	$777,254	$8,539,164
CA	$7,494,117	$18,261,345	$33,928,744	**$59,684,206**
CO	$907,991	$16,081,117	$3,242,513	$20,231,621
CT	$0	$325,880	$281,602	$607,482
DE	$0	$1,056,097	$773,982	$1,830,079
FL	$796,277	$1,361,170	$6,139,659	$8,297,106
GA	$1,290,580	$8,273,460	$2,751,930	$12,315,970
HI	$0	$807,644	$811,904	$1,619,548
IA	$280,754	$287,063	$11,295,773	$11,863,590
ID	$138,112	$1,796,514	$113,779	$2,048,405
IL	$914,932	$18,646,895	$12,676,218	$32,238,045
IN	$1,419,012	$5,280,431	$3,942,285	$10,641,728
KS	$773,277	$3,075,613	$7,655,117	$11,504,007

KY	$1,086,698	$1,745,699	$1,430,925	$4,263,322
LA	$3,062,784	$1,538,670	$46,039,437	**$50,640,891**
MA	$762,126	$4,387,985	$291,863	$5,441,974
MD	$296,351	$5,594,638	$6,299,907	$12,190,896
ME	$0	$404,828	$0	$404,828
MI	$1,521,996	$11,569,778	$1,975,995	$15,067,769
MN	$283,804	$10,391,668	$7,511,173	$18,186,645
MO	$173,305	$26,264,851	$21,374,382	$47,812,538
MS	$119,814	$1,131,108	$1,562,438	$2,813,360
MT	$1,077,674	$1,299,683	$2,401,698	$4,779,055
NC	$4,202,755	$2,231,563	$396,679	$6,830,997
ND	$35,322	$12,397	$3,516,572	$3,564,291
NE	$1,495,285	$6,269,041	$6,794,060	$14,558,386
NH	$0	$779,994	$0	$779,994
NJ	$38,734,194	$25,416,700	$4,117,904	**$68,268,798**
NM	$1,278,660	$2,235,250	$2,269,539	$5,783,449
NV	$915,160	$3,624,944	$605,072	$5,145,176
NY	$540,131	$31,400,265	$7,471,359	$39,411,755
OH	$1,318,133	$15,294,057	$27,938,348	$44,550,538

OK	$1,581,431	$2,929,230	$31,131,749	$35,642,410
OR	$0	$17,727,983	$4,318,130	$22,046,113
PA	$462,509	$15,742,171	$11,846,380	$28,051,060
SC	$0	$161,690	$597,301	$758,991
SD	$0	$757,905	$1,672,113	$2,430,018
TN	$289,963	$2,752,339	$1,843,035	$4,885,337
TX	$14,262,036	$11,369,852	$777,254	$26,409,142
UT	$0	$1,379,261	$33,928,744	$35,308,005
VA	$644,288	$3,794,269	$3,242,513	$7,681,070
VT	$0	$0	$281,602	$281,602
WA	$44,196	$2,007,527	$773,982	$2,825,705
WI	$277,060	$4,856,702	$6,139,659	$11,273,421
WV	$1,018,726	$382,697	$2,751,930	$4,153,353
WY	$74,007	$458,287	$811,904	$1,344,198

Liquid Release

Compilation of quantity of highly volatile liquids released were mainly gathered from Hazardous Liquid transportation pipeline incidents. Quantity in terms of highly volatile liquid releases of 5 barrels or more, or other liquid releases of 50 barrels or more and liquid releases causing an unintentional fire or explosion are compiled state-wise in Table 7. Note that the barrels of liquid release were attributed only resulting from excavation accidents. Texas ranked the highest in terms of total volatile liquids released followed by Oklahoma. California had the sixth highest number of barrels of liquid release from excavation-related incidents among all the states.

Table 7: Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more

State	Highly Volatile Liquid Released mainly Hazardous Liquids (in barrels)
AK	59
AL	1562
AR	7855
AZ	3696
CA	**51542**
CO	43780
CT	145
FL	2127
GA	5808
HI	1030
IA	19578
ID	789
IL	83090
IN	7633
KS	67510
KY	12806
LA	100676
MA	138
MD	3185
MI	1457
MN	39271
MO	36378
MS	5495
MT	14790
NC	2768
ND	41342
NE	20773
NJ	3219
NM	34786
NV	345
NY	4736
OH	32085
OK	**131058**
OR	1939
PA	24079
SC	24574
SD	3472
TN	15716
TX	**411853**
UT	16257
VA	14919
WA	3476
WI	15773
WY	20295

Depth of Cover in Excavation-related Incidents

The charts in Figs. 1 – 6 show counts of incidents with respect to various depth of cover at which the incidents have occurred for various pipeline systems. It is evident from these charts that majority of excavation-related incidents occurred at depths of cover between 20” to 37” in California and in all the states of the nation. Note that these observations have been made based on historical data obtained and analyzed from incidents reported on PHMSA between 1970 -2018 for gas transmission pipelines and between 2010-2018 for gas distribution pipelines.

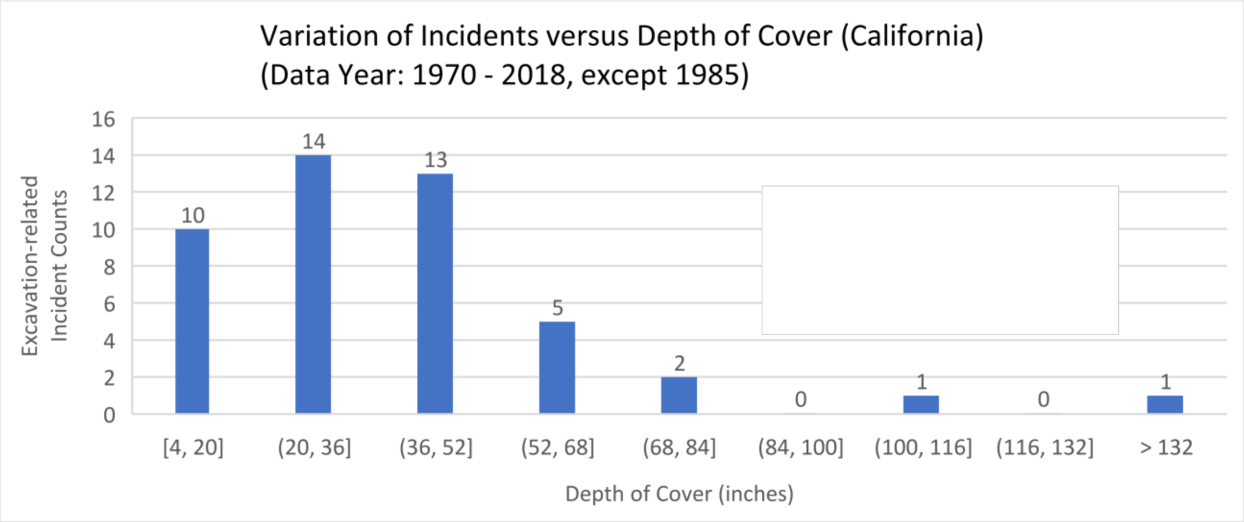


Figure 1: Distribution of incidents for depth of cover for Gas Transmission pipelines in California

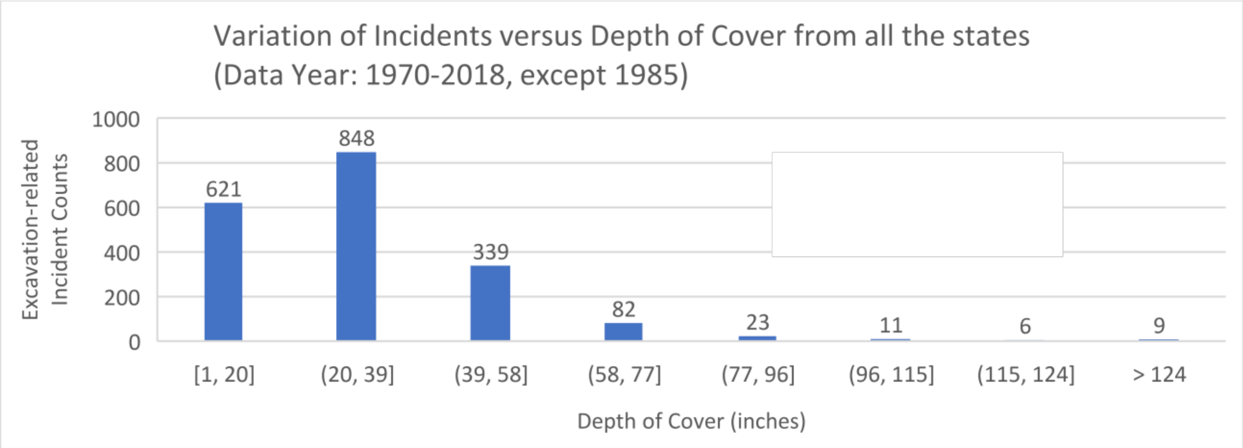


Figure 2: Distribution of incidents for depth of cover for Gas Transmission pipelines from all the states

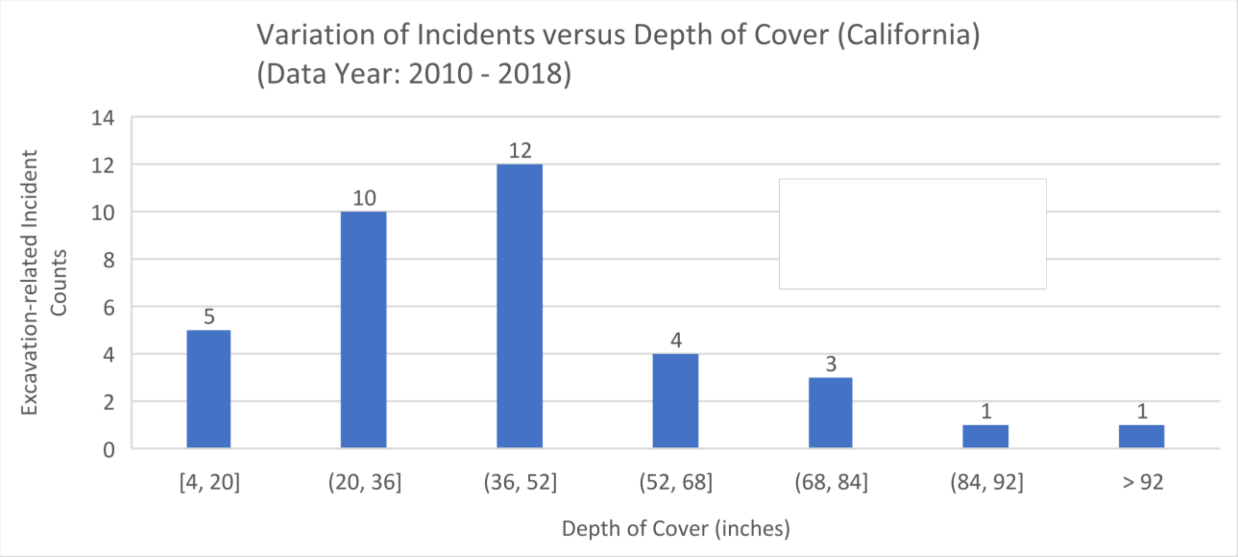


Figure 3: Distribution of incidents for depth of cover for Gas Distribution pipelines in California

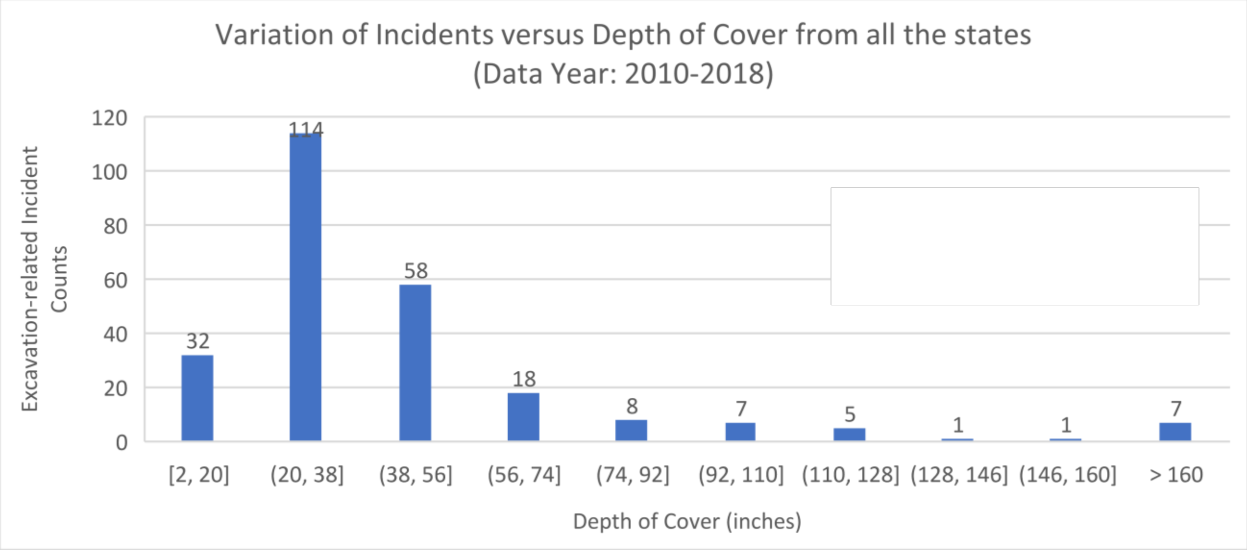


Figure 4: Distribution of incidents for depth of cover for Gas Distribution pipelines from all the states

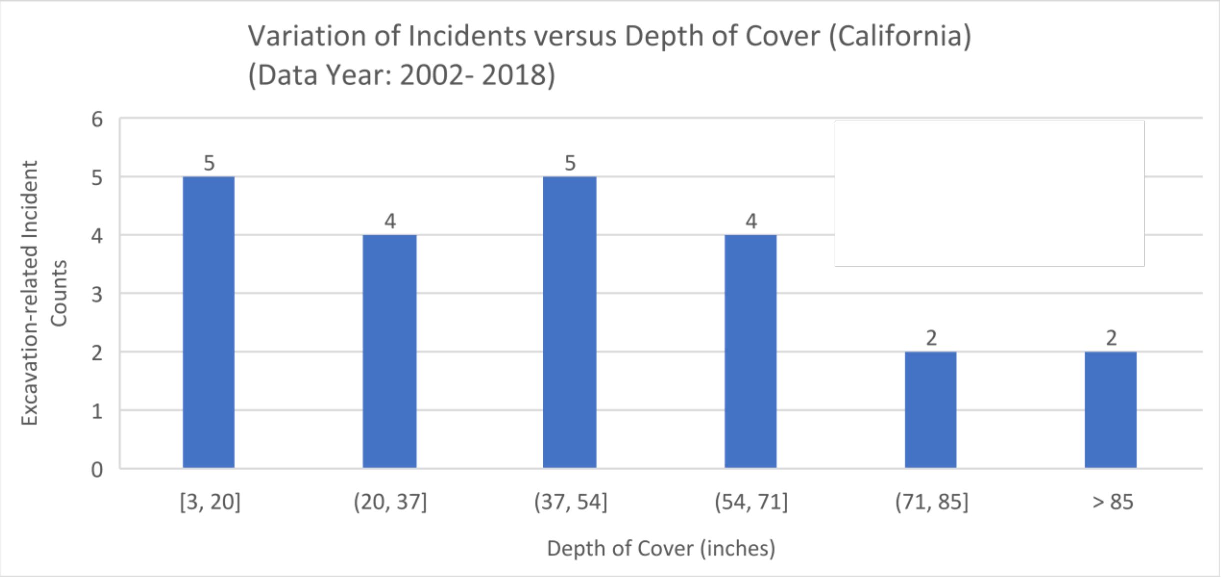


Figure 5: Distribution of incidents for depth of cover for Hazardous Liquid pipelines in California

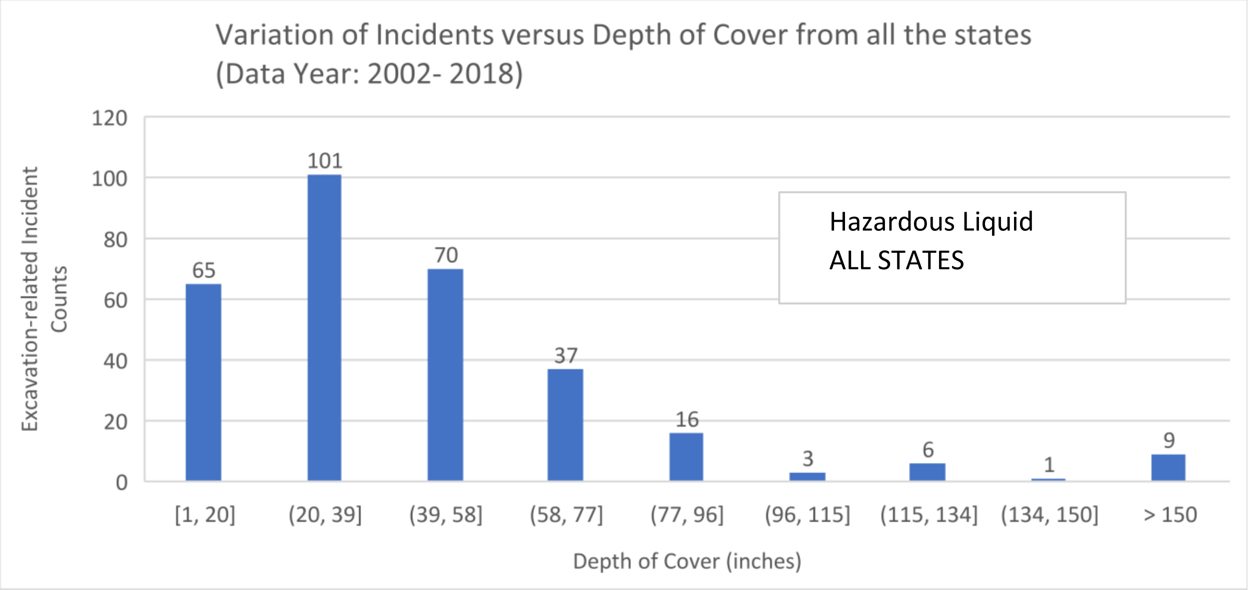


Figure 6: Distribution of incidents for depth of cover for Hazardous Liquid excavation incidents from all the states

Encasement Information

Analysis of underground pipeline incident data from 2010 to 2018 showed that almost none of the pipelines involved in excavation accidents were 'cased' for Gas Transmission or Hazardous Liquid – which are high pressure pipelines. Pipelines that were noted as cased and involved in leakages were due to corrosion damage or damage that was incurred during installation. There was only one incident reported to a cased Gas Distribution pipeline in 2016 under a public street pavement in Kansas due to excavation damage. The pipeline was struck due to lack of information of the location of the gas carrying pipe. The pipeline material was steel, was 4" in diameter and the depth of cover was 144". The pipeline was struck during directional drilling to install a fiber optics line. No information was provided on the encasement material.

Casings – Pros and Cons

There are number of pros and cons associated with casing a pipeline at the crossings which are

Pros

The advantages for the encasement of pipeline crossings include the following:

1. Casings are used to protect the pipeline from external damage – especially during any construction or maintenance activities.
2. Casings protect the pipeline from surrounding adverse soil conditions during construction – particularly against damage from rocky subsurface soil.
3. Insertion, replacement, removal, or maintenance of carrier pipe can be easily carried out -especially where trenching needs to be avoided.
4. Leaking gases or fluids can be dissipated and collected using casings at the end points of the casing such as drainage way, venting points, or right-of-way line.

Cons

There are several cons which have been identified in literature on the use of casing for carrier pipe. These are divided into two categories for classification purposes, i.e. cons due to – (A) Construction-related activity and (B) Material related (NCHRP Project Report 20-7):

Construction-related:

1. Often insulators stack together at the end of a casing.
2. The pipeline outside the casing can deflect and settle if fill inside bore pits at the casing ends is not sufficiently compacted during installation – thus the pipeline comes in contact to the casing pipe.

3. Highway widening becomes difficult at locations if there are horizontal and vertical bends in the pipeline which run through casings.
4. Visually inspecting a carrier within the casing is impossible, and hence, any damage to carrier pipe goes undetected.

Material-related:

1. Defects in the casing cross section can sometimes cause the carrier to bind inside the casing.
2. Sometimes water enters a casing through defective end seals, casing joints, or external vents– this increases the corrosion potential of the pipeline, and finally

Cased Installations - Remarks

The pros of casing the pipeline against external/accidental damage outweighs the cons. This is because damages to uncased pipes have resulted in high number of fatalities and injuries. Leakages in cased carrier pipes, whether due to wrong construction practices or material defects, have often been detected and fixed causing minimal fatalities or injuries or traffic closures.

In addition, adopting best practices in construction methodologies and choice of high-quality casing material can often eliminate most cons – particularly those that are constructed-related as follows:

1. Crossing failure: This can result due to improper installation and inspection procedures or insufficient clearance between pipe and casing (see Fig. 7)
2. Excessive force is often applied to drive the carrier through its casing. This could cause damage to the carrier pipe or casing insulators or both. Or, result in irregular casing line or grade and displacement at casing joints.
3. During construction or after construction, lack of separation between a carrier and casing can result in metal-to-metal contact between the carrier and casing. This can cause short circuit in the cathodic protection system and drains protective current from the remaining pipeline resulting in an increase in the corrosion potential at the point of contact between carrier and casing.

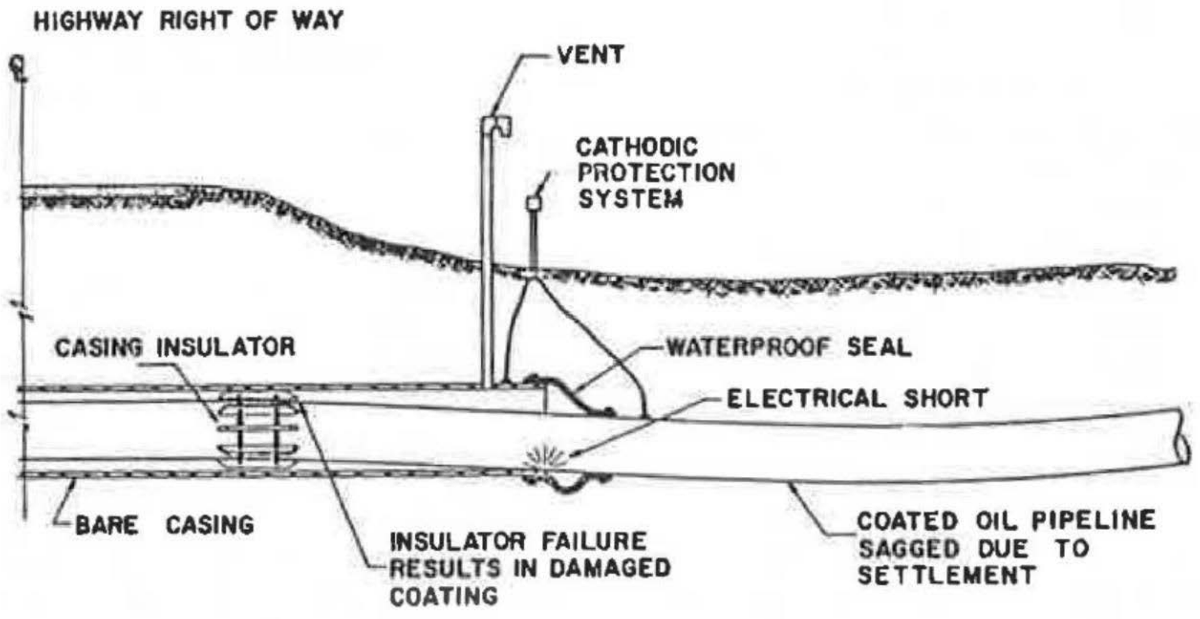


Figure 7: Crossing failure
(Source: NCHRP 20-7, Task 22)

Uncased Pipelines – Pros and Cons

Pros and cons associated with uncased pipe installation at the crossings are as follows:

Pros

Pros of an uncased pipe installation consist of the following:

1. Uncasing a pipe can prevent its corrosion potential that often result due to casing coming in contact with the carrier pipe
2. Improper installation of pipe is not a worry with uncased pipes.
3. Inspecting a pipe without casing is easier, and
4. Managing insulators that are often required with casing is not a concern.

Cons:

Cons of an uncased underground carrier pipe includes the following:

1. The uncased carrier pipe is exposed to external damage. This could lead to result fatalities and injuries without any forewarning.
2. Surrounding soil conditions, especially rocky soils, can directly erode or dent the uncased carrier pipe.

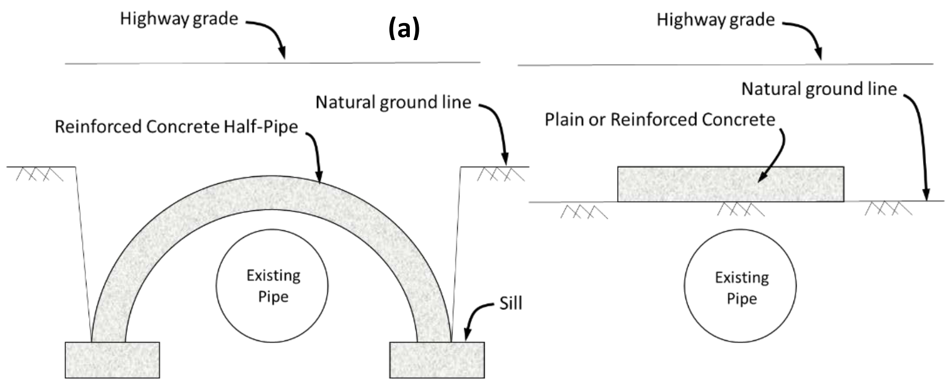
3. Detection of the leakage point under a pavement surface from an uncased carrier pipe can be problematic, especially if the surrounding soil is clay, and
4. Replacement of uncased pipe is often difficult, and sometimes it is cost effective to completely abandon the leaking pipe and install a new one.

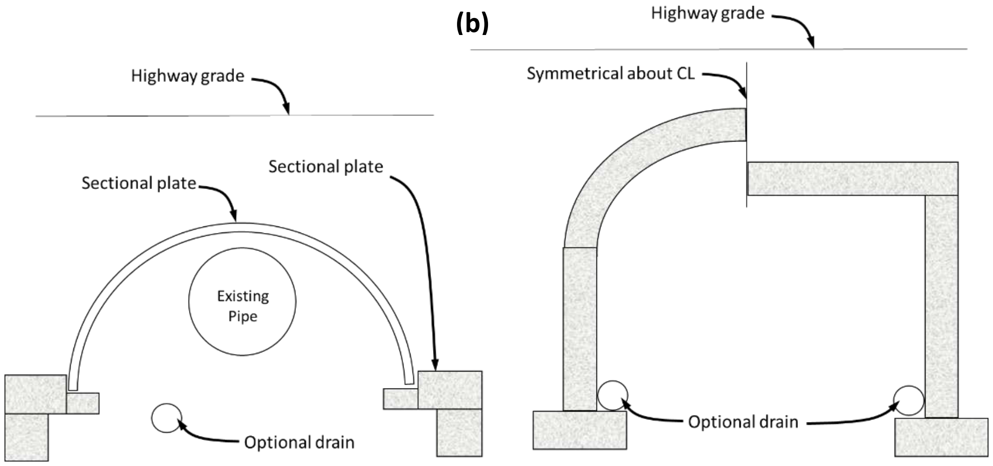
Uncased Installations - Remarks

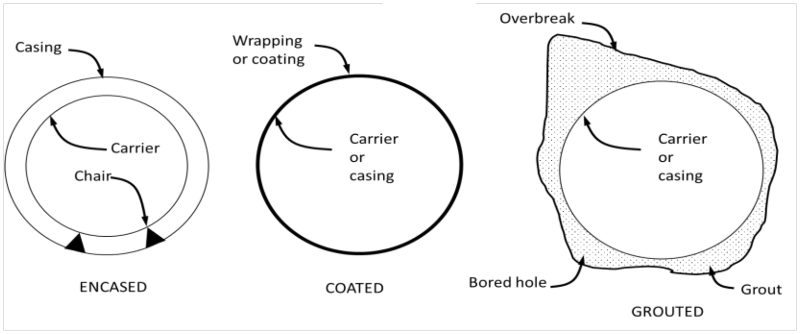
Uncased pipelines are vulnerable to accidental damage during construction activities. Despite the pros, uncased pipelines can also be damaged during their installations. With uncased pipes, the damage can often go undetected until any leakage occurs at later times. This could require increased frequency of inspection and maintenance for the uncased pipeline. However, choice of high-quality standard carrier pipe material can prevent damages that could occur to uncased pipes during their installation.

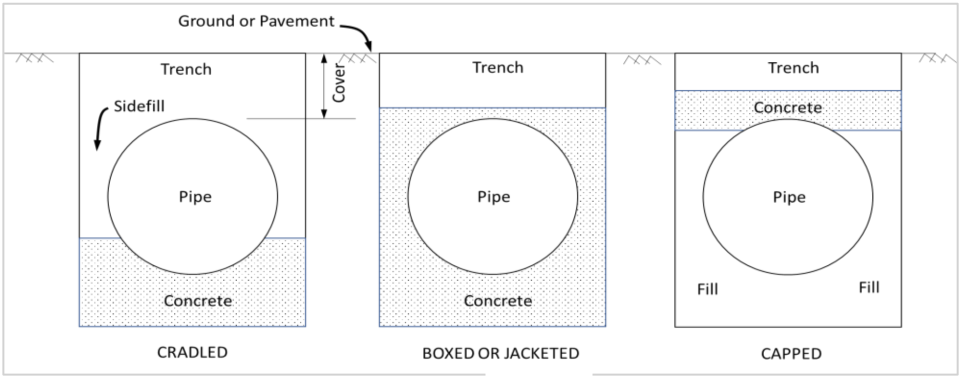
Alternatives to Casing

There are alternatives to casing a pipeline which often ensure the same level of protection to the carrier pipe and eliminates most of the cons listed above. For example, a single box-culvert-like structure can be used (see Fig. 8). In specific, protection to the carrier can be ensured using encasement with half pipe and floating slab, plate arch protection, monolithic arch or box, and protection using encasement with plate arch and monolith arch or other types of mechanical protection for underground utility crossings as shown in Fig. 8.









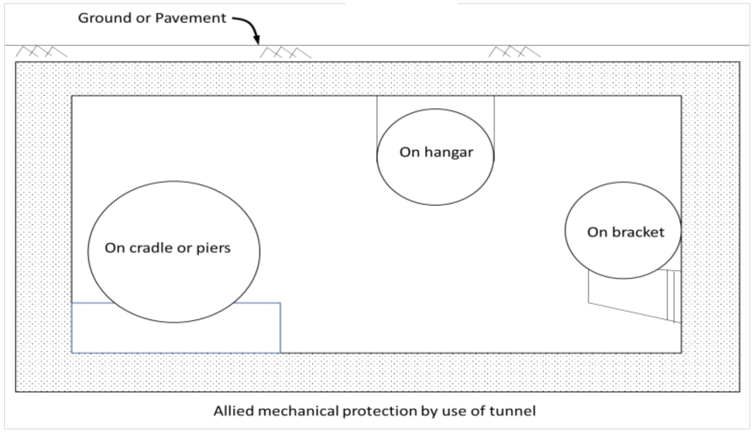


Figure 8: Alternative methods of protecting a pipeline (Image Source: AASHTO, 2005)

(a) half pipe and floating slab,

(b) plate arch protection, monolithic arch or box, and protection using encasement with plate arch and monolith arch.

(c), (d) and (e) – other mechanical protections

3. CURRENT ENCASEMENT STANDARDS FOR PIPELINE SAFETY

The following references have been used to document findings of this section:

I. References to existing standards on gas transmissions provided by the standard developing organizations such as the American Society of Mechanical Engineers (ASME) and the American National Standards Institute (ANSI).
II. Federal encasement requirements and guidelines, and
III. Regulations/guidelines with respect to encasement requirements in six key states covering California, Missouri, Alabama, Iowa, Virginia and Texas.

Utility and Organizational Standards

Based literature reviews from publicly available reports, open access manuals and publications, it was noted that most utility companies operating in California did not post online guidelines that are being followed for encasement requirements.

ASME/ANSI B31.8-2018 Gas Transmission and Distribution Piping Systems and the ASME/ANSI B31.4 Pipeline Transmission Systems for Liquid Hydrocarbons and Other Liquids provide directions and relevant standards to protecting pipes. ASME/ANSI B31.8-2018 sets forth engineering requirements deemed necessary for the safe design and construction of pressure piping and includes provisions for protecting pipelines from external and internal corrosion. ASME B31.4 prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of liquid pipeline systems.

Code of Federal Regulations (CFR)

The minimum Federal safety standards for transportation by pipeline are 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline, and 49 CFR Part 195, Transportation of Liquids by Pipeline. Neither of these regulations require that casings be used. However, Section 195.256, Crossing of railroads and highways, of the liquid regulations requires such crossings be installed to adequately withstand the dynamic forces exerted by anticipated traffic loads. Section 192.103 of the gas regulations requires that all pipelines be designed with sufficient wall thickness or must be installed with adequate protection to withstand anticipated external pressures and loads. Section 192.323, Casing, sets forth the requirements for casings if they are used on a gas transmission line or main under a railroad or highway (Office of Pipeline Safety Operations, 2018; 49 CFR 192.323).

American Association of State Highway and Transportation Officials (AASHTO)

AASHTO 2005 “A Guide for Accommodating Utilities within Highway Right-of-Way” states that the need for casing of pressurized carrier pipes and carriers of materials that are flammable, corrosive, expansive, energized, or unstable should be determined by the transportation agency. Further casings should be considered for the following conditions:

1. Crossings of freeways, expressways, and other controlled access highways and at other locations where it is necessary to avoid trenched construction.

2. As protection for carrier pipe from external loads or shock either during or after construction of the highway.

   - "Jacked or bored installations of coated carrier pipes should be encased. Exceptions may be made where assurance can be provided against damage to the protective coating."

   - "On uncased construction the carrier shall conform to the material and design requirements of utility industry and governmental codes and standards. In addition, the carrier pipe should be designed to support the load of the highway plus superimposed loads thereon when the pipe is operated under all ranges of pressure from maximum internal to zero pressure. Such installations should employ a higher factor of safety in the design, construction, and testing than would normally be required for cased construction."

   - "Uncased crossing of welded steel pipelines which carry flammable, corrosive, expansive, energized, or unstable materials, particularly if carried at high pressure or potential, maybe permitted, provided additional protective measures are taken in lieu of encasement. Such measures would employ a higher factor of safety in the location, design, construction, and testing of the uncased-carrier pipe, including such features as increased depth of cover, thicker wall pipe, radiograph testing of welds, hydrostatic testing, coating and wrapping, and cathodic protection."

Regulations/guidelines from Key States

Alabama

ALDOT Utilities Manual (ALDOT, 2018) and a report by Lindly et al. (2015) highlights that the encasements are required on interstates and on all roadways "unless otherwise exempted" or "unless a utility obtains approvals to forego encasement," which require a variance request. Steel lines greater than 2 inches must be encased. Exceptions to policy on encasement include:

i. Higher factor of safety in design, construction, and testing
ii. Welded steel pipe
iii. Thicker walled pipe
iv. Radiographic testing of welds
v. Hydrostatic testing
vi. Coating and wrapping
vii. Protective concrete slabs under ditch lines
viii. Cathodic protection, and
ix. P.E. certification that design, construction, and testing provide safety at least equal to a cased crossing.

California

Guidance on encasement is provided in Chapter 600 Utilities Permits, Encroachment Permits Manual, which states that the utility facilities must comply with the following encasement and protection requirements:

1. Types of facilities requiring encasement or protection:

   a. High priority utilities (mentioned in Table 8) are required to be encased on both conventional and access-controlled highway right-of-way, when installed either longitudinal or transverse to highway.

      - An exception to this policy may be allowed for the installation of Uncased High-Pressure Natural Gas Pipelines when in compliance with the TR-0158 Special Provisions.
      - Service laterals are exempt from encasement requirement.

   b. Additionally, pressurized liquid carrier facilities are required to be encased on both conventional and access-controlled highway right-of-way when installed either longitudinal or transverse to highway.

      - Service laterals are exempt from encasement requirement.

   c. Additionally, for all transverse crossings, placement of multiple pipes or ducts, regardless of diameters are required to be encased on both conventional and access-controlled highway right-of-way.

   d. Consider encasement of carriers that are exempt from encasement, when these possibilities exist:
      - When under embankments of 10 feet or more.
      - Appreciable settlement of supporting ground.
      - When detrimental subsidence of the ground under a fill is anticipated. In such cases, a sleeve 6 inches larger than the outside diameter of the pipe is recommended.
      - Damage to protective pipe coatings during jacking.
      - A corrosion protective coating and/or cathodic protection may be required due to corrosive environments or when California Public Utilities Commission (CPUC) requires cathodic protection. (Corrosive environments can deteriorate steel and cement mortar. Check cathodic protection requirements with headquarters Structures Design, Electrical, Mechanical, Water and Waste Water Branch.)
      - Cracking of mortar coating during jacking or boring operations.
      - Corrosion of field-coated joints.
      - Existing electrical and communication lines under an embankment of 10 feet or more.

The information on encasement requirements outlined above for High Priority Utilities have been summarized in Table 8.

Table 8: Encasement for High Priority Utilities

			Natural gas pipelines greater than 6 inches in diameter, or with normal operating pressures greater than 60 psig	*Petroleum Pipelines*	*Pressurized sanitary sewer pipelines*	*High-voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60 kV*	*Hazardous materials pipelines that are potentially harmful to workers or the public if damaged*
Installation Method	Bore and Jack	*Freeway*	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***
		Conventional	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***
	Directional Drilling	*Freeway*	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***
		Conventional	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***
	Trenching	*Freeway*	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***
		Conventional	***Encase***	***Encase***	***Encase***	***Encase***	***Encase***

Iowa

Iowa Administrative Code states that pipe or casing shall be installed with at least 1 foot of separation from any other pipe or wire in the right-of-way (Iowa Administrative Code, 2018). A pipeline carrying natural gas at an operating pressure of greater than 60 pounds per square inch, liquid petroleum products, ammonia, chlorine or other hazardous or corrosive products shall be encased from right-of-way line to right-of-way line (Iowa DOT, 2018).

Encasement of a pipeline carrying a product listed above is not required if the pipeline meets all the following requirements and the utility owner certifies as a part of the permit that these requirements are met for the pipeline:

- It is welded steel pipeline.
- It is cathodically protected.
- It is coated in accordance with accepted industry standards.
- It complies with federal, state and local requirements and meets accepted industry standards regarding wall thickness and operating stress levels.

Missouri

Engineering Policy Guide states that for Major Routes (Interstate System or Other Freeways, With Controlled and Normal Access Right of Way), underground utility crossings will be continuously encased under through roadways, the median, ramps and shoulder areas with the casing extending to the toe of the fill slopes or to the ditch line [6]. Encasement will be required under high type outer roadways. However, exceptions may be made for encasement for the following:

i) Natural gas distribution pipe (nominal 6-inch diameter maximum) of polyethylene (PE) plastic, traceable, installed by a horizontal bore method at a minimum depth of 72 in. under ditches and roadways, constructed in accordance with and meeting applicable material requirements.

ii) Non-fiber communication or electric cables installed in ducts

iii) Welded steel pipelines carrying gaseous or liquid petroleum products - provided they are cathodically protected against corrosion, triple-coated in accordance with accepted pipeline construction standards, and meet applicable material requirements

iv) Gas service connections of steel or copper, protected and constructed in accordance with and meeting applicable material requirements

v) Water service connections and crossings of copper 2-inch inside diameter or less, and meeting applicable material requirements.

Texas

Texas Administrative Code (TAC) under SUBCHAPTER C. UTILITY ACCOMMODATION states the following on encasement (Texas Administrative Code, 2018):

A. Underground utility facilities crossing the highway shall be encased in the interest of safety, protection of the utility, protection of the highway, and for access to the utility facility. Casing shall consist of a pipe or other separate structure around and outside the carrier line. The utility must demonstrate that the casing will be adequate for the expected loads and stresses.

B. Casing pipe shall be steel, concrete, or plastic pipe as approved by the district, except that if horizontal directional drilling is used to place the casing, high-density polyethylene (HDPE) pipe must be used in place of plastic pipe.

C. Encasement may be of metallic or non-metallic material. Encasement material shall be designed to support the load of the highway and superimposed loads thereon, including that of construction machinery. The strength of the encasement material shall equal or exceed structural requirements for drainage culverts and it shall be composed of material of satisfactory durability for conditions to which it may be subjected. The length of any encasement under the roadway shall be provided from top of backslope to top of backslope for cut sections, five feet beyond the toe of slope for fill sections, and five feet beyond the face of the curb for curb sections. These lengths of encasement include areas under center medians and outer separations.

Virginia

Virginia Administrative Code 24VAC30-151-370. Encasement Requirements states the following (Virginia Administrative Code Title 24, 2018):

A. Encasement pipe shall be required where it is necessary to avoid trenched construction, to protect carrier pipe from external loads or shock, or to convey leaking fluids or gases away from the areas directly beneath the traveled way if the utility has less than minimal cover; is near footings of bridges, utilities or other highway structures; crosses unstable ground; or is near other locations where hazardous conditions may exist. Encasements crossing nonlimited access rights-of-way shall extend a suitable distance beyond the slope for side ditches and beyond the back of curb in curbed sections. The district administrator's designee may require encasement pipe even if an installation meets industry standards for non-encasement.

Casing pipe shall be sealed at the ends with approved material to prevent flowing water and debris from entering the annular space between the casing and the carrier. All necessary appurtenances such as vents and markers shall be included.

B. Uncased crossings of welded steel pipelines carrying transmittants that are flammable, corrosive, expansive, energized, or unstable, particularly if carried at high pressure, may be permitted subject to the following conditions:

   1. The applicant provides supporting data documenting that its proposed installation meets or exceeds industry standards for uncased crossings,

   2. The applicant provides supporting data documenting that the pipeline will support the anticipated load generated by highway traffic, and

   3. All uncased pipeline crossings that fail must be relocated a minimum of 36 inches to either side of the failure. The failed line shall then be filled with grout and plugged at both ends.

4. PIPELINE LEAKAGES AND GAS MIGRATION IN SOIL MEDIA

This section documents information on natural gas leakages from pipeline network across the nation and in California. The focus are the causes that result in these leakages, highlighting key researches of soil migration from pipeline leakage, and encasement information of the pipelines for observed leakage incidents.

Cover Requirements

Underground natural gas transmission and distribution pipelines are usually buried at a depth of at least 3-4 ft below – with a minimum of at least 24 inches (610 millimeters) of cover - though there are some exceptions to this minimum cover requirement. Depending on the location classification, as shown in Table 9, the minimum cover is provided by the Code of Federal Regulations (CFR) under Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards (49 CFR 192, 2018).

Table 9: Minimum soil cover for underground transmission pipelines (CFR 192.327, 2018)

Location Type*	**Minimum Depth of Cover** (in inches)	
	Normal soil	**Consolidated rock**
Class 1 locations	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

*Class locations mentioned in Table 9 are defined as per (CFR 192.5, 2018) in Appendix.

Historical Pipeline Leakages

Literature search on pipeline emission surveys revealed that natural gas leaks have occurred mainly due to aging of pipes after their underground installation (Beusse et al., 2014; Jackson et al., 2013). Data from Pipeline Incident 20 Year Trends of Pipeline and Hazardous Materials Safety Administration (PHMSA) substantiate these findings as most of the underground pipeline leakages (both for transmission and distribution) occurred for those installed in the years before 1980 (see chart in Figs. 9 and 10). Research shows that, globally, aged pipelines made of cast iron or unprotected/uncased steel often leak due to causes such as earth movement, breakdown of joints and corrosion of unprotected steel, and graphitization (i.e., natural degrading to softer elements over time) (Deepagoda et al., 2016). In the United States, most of the underground leakages from gas transmission or distribution pipelines into the soil have occurred due to external corrosion, environmental cracking, excavation damage by operator’s contractor, equipment not installed properly, construction, installation or fabrication-related, failure of equipment body (except compression), vessel plate or other material, other incorrect operation (PHMSA, 2018).

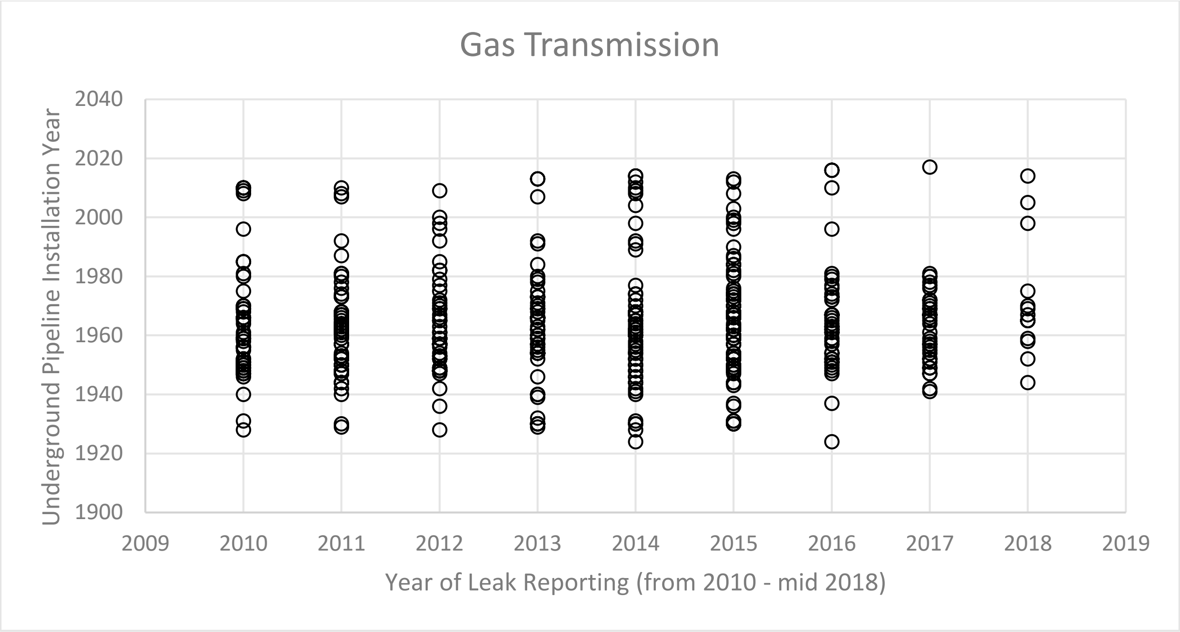


Figure 9: Cumulative variation in number of underground/under soil gas transmission pipeline leaks with respect to their installation year in all the states (Source: PHMSA, 2018)

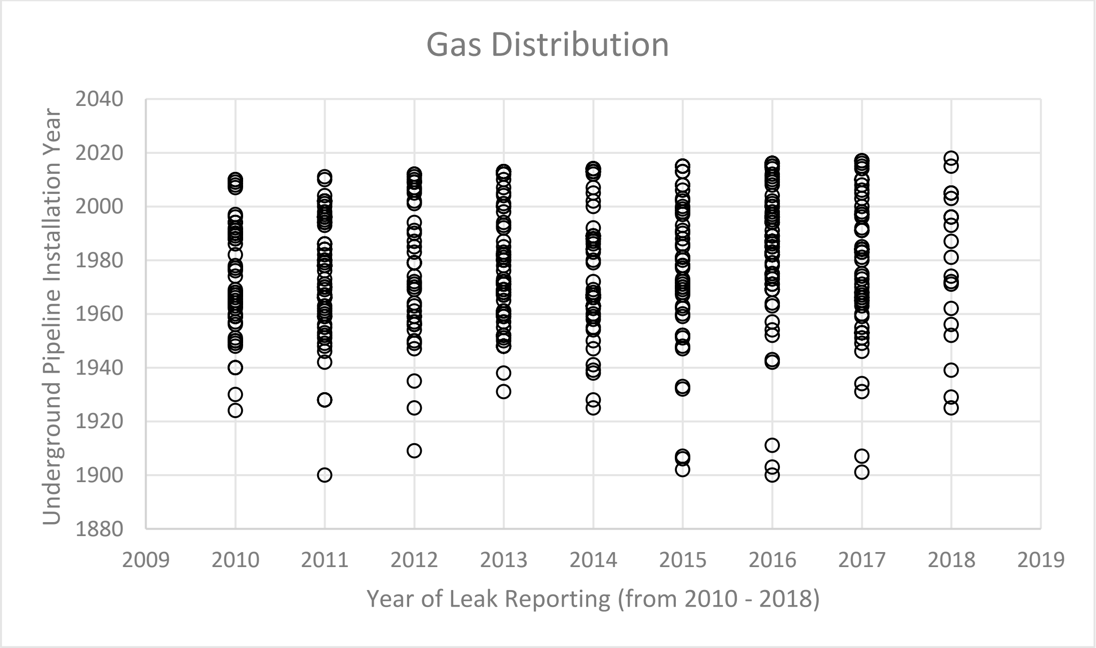


Figure 10: Cumulative variation in number of underground/under soil gas distribution pipeline leaks with respect to their installation year in all the states (Data Source: PHMSA, 2018)

The data in Table 10 shows cumulative counts of gas transmission and distribution leakages for all the states from 2010 to 2018.

Table 10: Gas transmission and distribution pipeline leakage data from 2010 to mid-2018 from all the states

Year	Frequency of Pipeline Leakages for Gas Transmission	Frequency of Pipeline Leakages for Gas Distribution
2010	50	58
2011	58	67
2012	49	50
2013	51	66
2014	59	56
2015	69	59
2016	40	73
2017	36	62
2018	14	28
Total	**426**	**519**

Analysis of top-ten causes for underground pipeline leakages across the country from 2010 to mid-2018 showed that the leaks have been mainly attributed due to excavation damage by third party, construction-, installation-, or fabrication-related, and from corrosions of the pipelines (whether external or internal). This is shown in the Tables 11 and 12 based on data derived from the PHMSA.

Table 11: Compilation of causes for underground gas transmission pipeline leakage across the country from 2010 to 2018

Top-ten Reasons for Pipeline Leakage in Gas Transmission Lines	Number of Leakages Recorded
Excavation damage by third party	89
Construction-, installation-, or fabrication-related	64
External corrosion	51
Internal corrosion	43
Original manufacturing-related (not girth weld or other welds formed in the field)	24
Environmental cracking-related	18
Excavation damage by operator's contractor (second party)	18
Previous damage due to excavation activity	14
Threaded connection/coupling failure	14
Non-threaded connection failure	12

Table 12: Compilation of causes for underground gas distribution pipeline leakage across the country from 2010 to 2018

Top-ten Reasons for Pipeline Leakage in Gas Distribution Lines	Number of Leakages Recorded
Excavation damage by third party	219
Other outside force damage	35
Other incorrect operation	22
Electrical arcing from other equipment or facility	17
Excavation damage by operator's contractor (second party)	15
External corrosion	15
Body of pipe	11

Previous damage due to excavation activity	11
Damage by car, truck, or other motorized vehicle/equipment not engaged in excavation	10
Excavation Damage by Operator (First Party)	9

Within California, there have been a total of 47 gas transmission pipeline leaks recorded from 2010 to mid-2018 (with top-five leakage causes shown in Table 13). Similarly, there were 70 gas distribution pipeline leakages, out of which top-five causes have been shown in Table 14. The various causes of these underground pipeline leakages in California include excavation damage by third party, construction-, installation- or fabrication-related, environmental cracking-related, external corrosion, among others.

Table 13: Top-five causes of underground gas transmission pipeline leakages in California from 2010 to 2018

Cause of Leakage in California for Gas Transmission Lines	Number of Leakages Recorded from 2010 - 2018
Excavation damage by third party	25
External corrosion	4
Other incorrect operation	3
Construction-, installation-, or fabrication-related	2
Environmental cracking-related	2

Table 14:Top-five causes of underground gas distribution pipeline leakages in California from 2010 to 2018.

Cause of Leakage in California for Gas Distribution Lines	Number of Leakages Recorded from 2010 - 2018
Excavation damage by third party	30
Other outside force damage	9
Electrical arcing from other equipment or facility	6
Excavation damage by operator (first party)	5
Body of pipe	3

Pipeline Leakages and Depth of Cover

Data analyses from 2010 to 2018 of underground pipeline leakages (for gas transmission and distribution) across the country shows that most of the leakages occurred for pipelines with depth of cover varying between 30 to 60 inches (see chart in Fig. 11). In California, the depth of cover between 4 in. to 108 in. have been noted to be problematic, with the highest number of leakages (both for gas transmission and distribution pipelines) mainly occurring at depths of cover in the range of 30 to 60 inches. This is similar to what has been found for underground pipes in other states of the nation (see charts in Figs. 11 to 13).

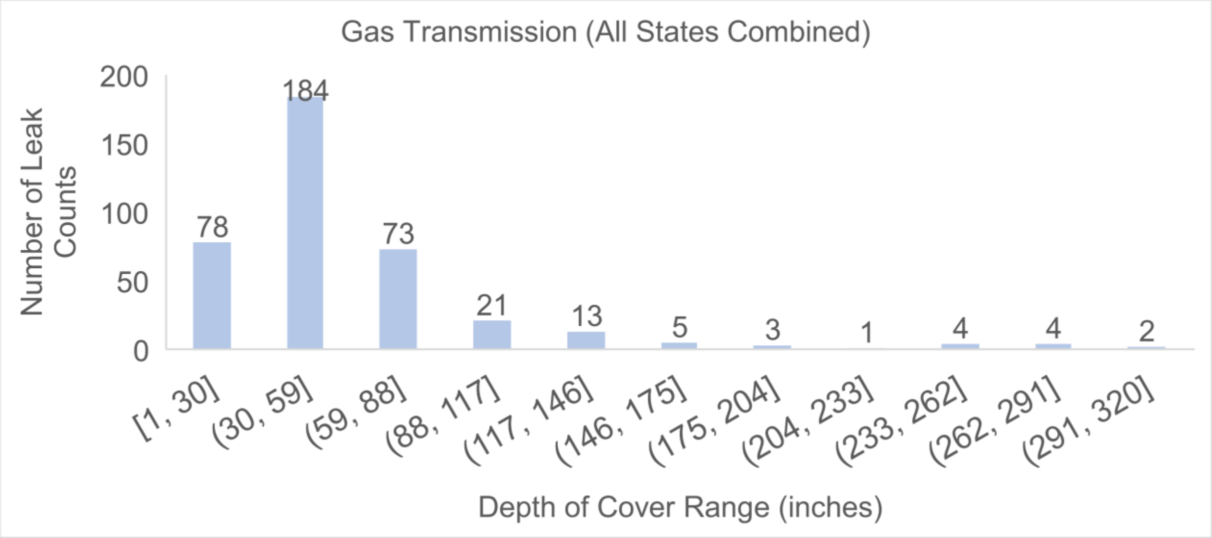


Figure 11: Frequency of underground gas transmission pipeline leakages versus depth of cover for year 2010 to mid-2018 in all the states

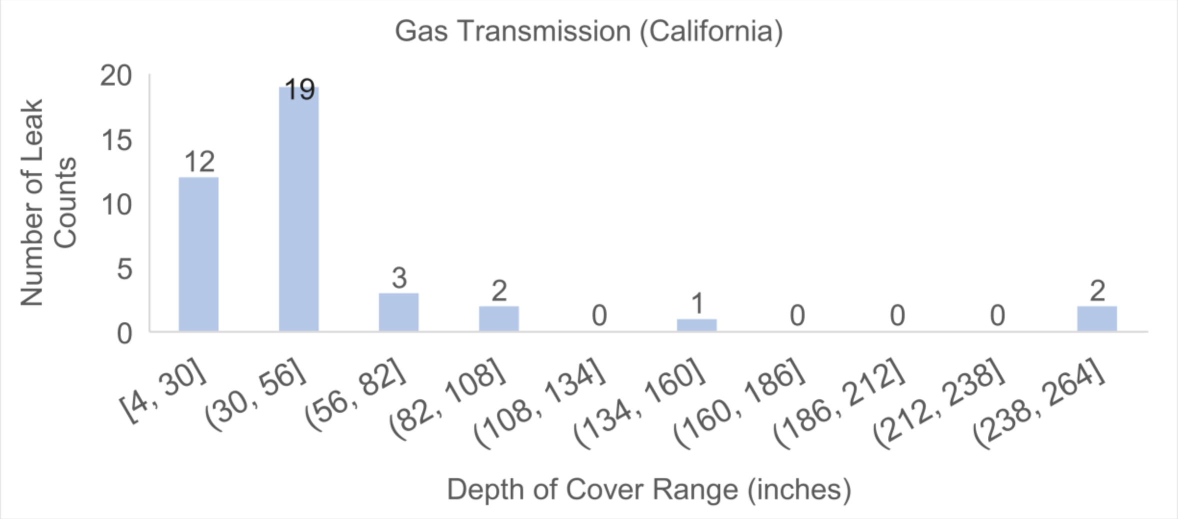


Figure 12: Frequency of underground gas transmission pipeline leakages versus depth of cover for year 2010 to mid-2018 in California

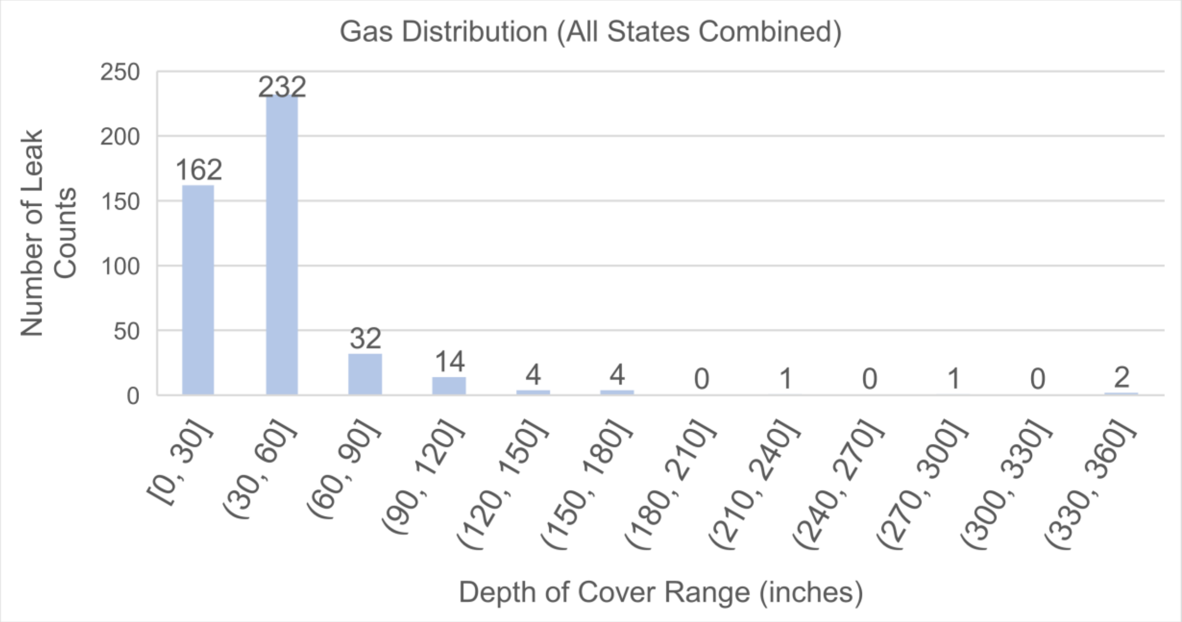


Figure 13: Frequency of underground gas distribution pipeline leakages versus depth of cover for year 2010 to mid-2018 in all the states

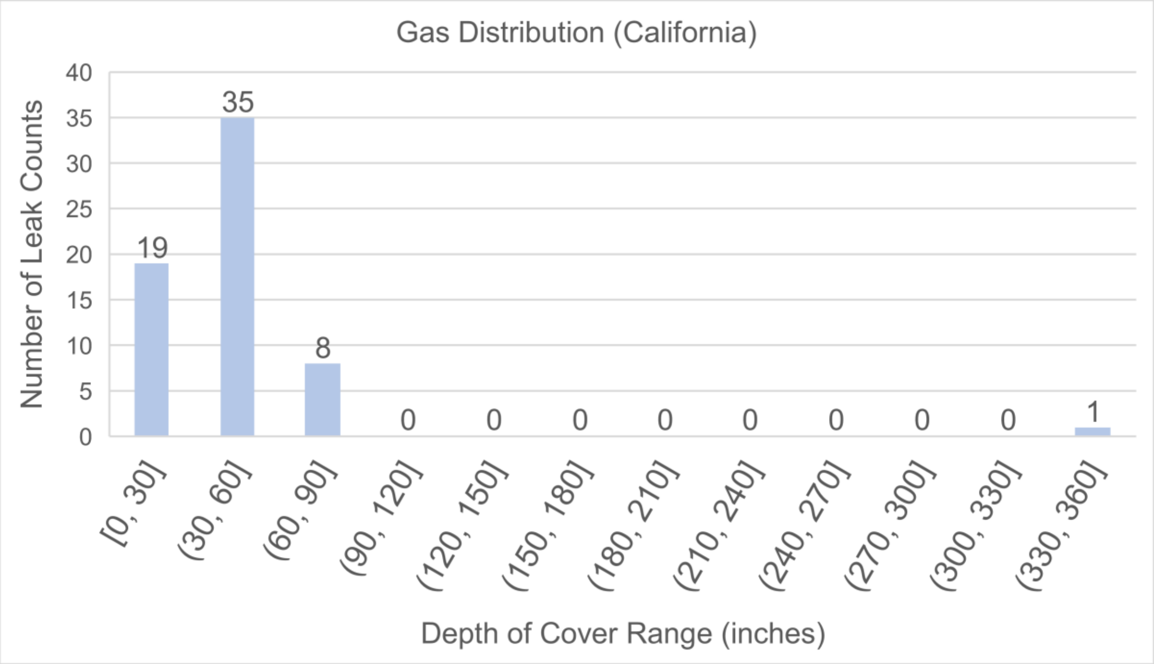


Figure 14: Frequency of underground gas distribution pipeline leakages versus depth of cover for year 2010 to mid-2018 in California

The chart in Fig. 15 and Fig. 16 shows the respective percentage distribution of underground gas transmission and distribution pipeline leakage causes with respect to the depth of cover. The data used has been used for pipeline incidents that occurred between 2010 to 2018. The distribution has been divided with respect to the following depth of cover (in inches) categories: 1-30, 31 – 60, 61 – 90, 91 – 120, 121 – 150, 151 – 180, 181 – 210, 211 – 240, 241 – 270 and greater than 270 inches. The two charts show the percentage of leakages has been highest for the range of 31 to 60 inches of depth of cover. Within California, depth of cover less than 60 inches has the highest probability of showing leakage due to excavation (see Fig. 17 and 18).

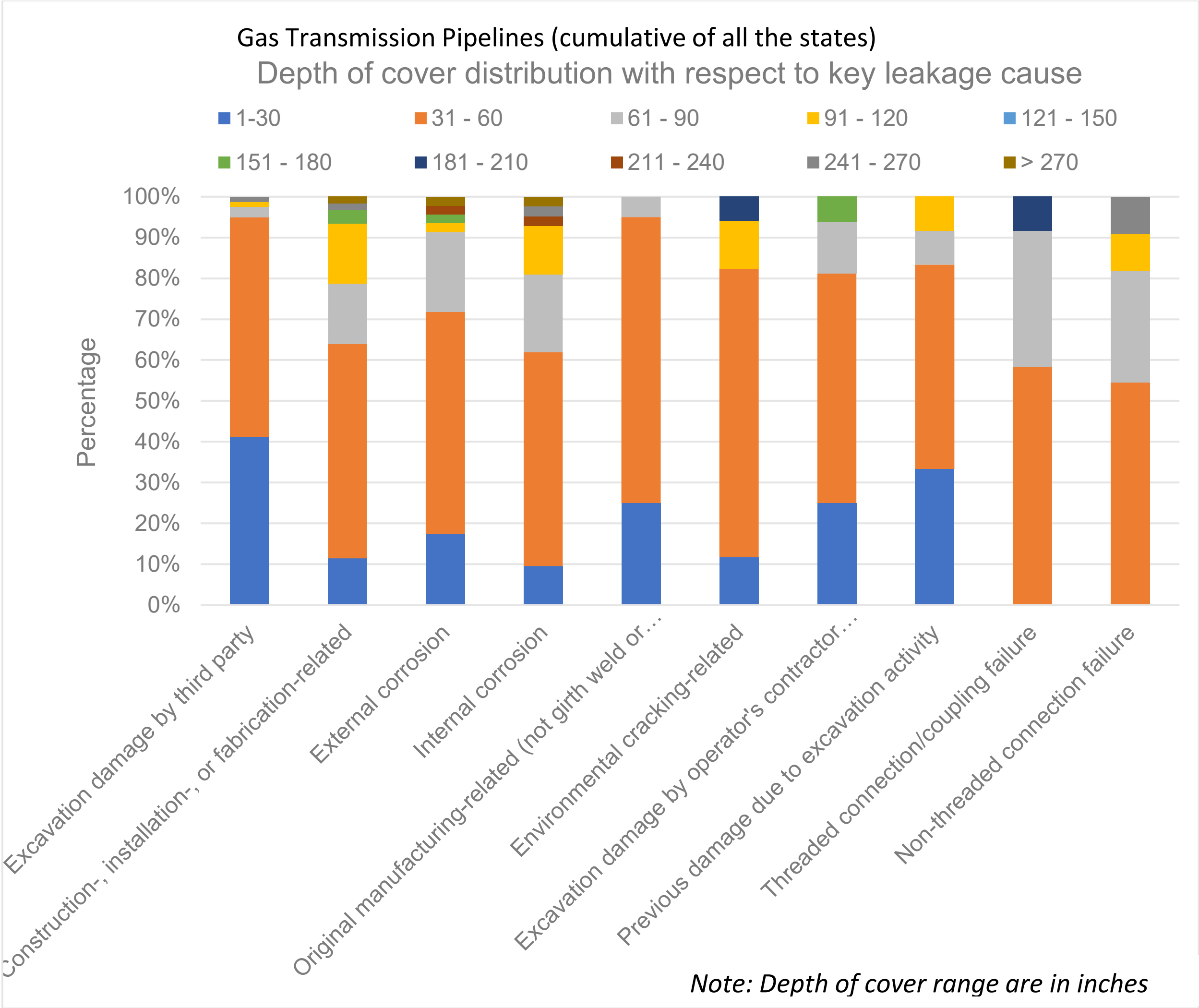


Figure 15: Year 2010 to 2018 percentage distribution of depth of cover versus leakage causes for Gas Transmission pipelines from all the states.

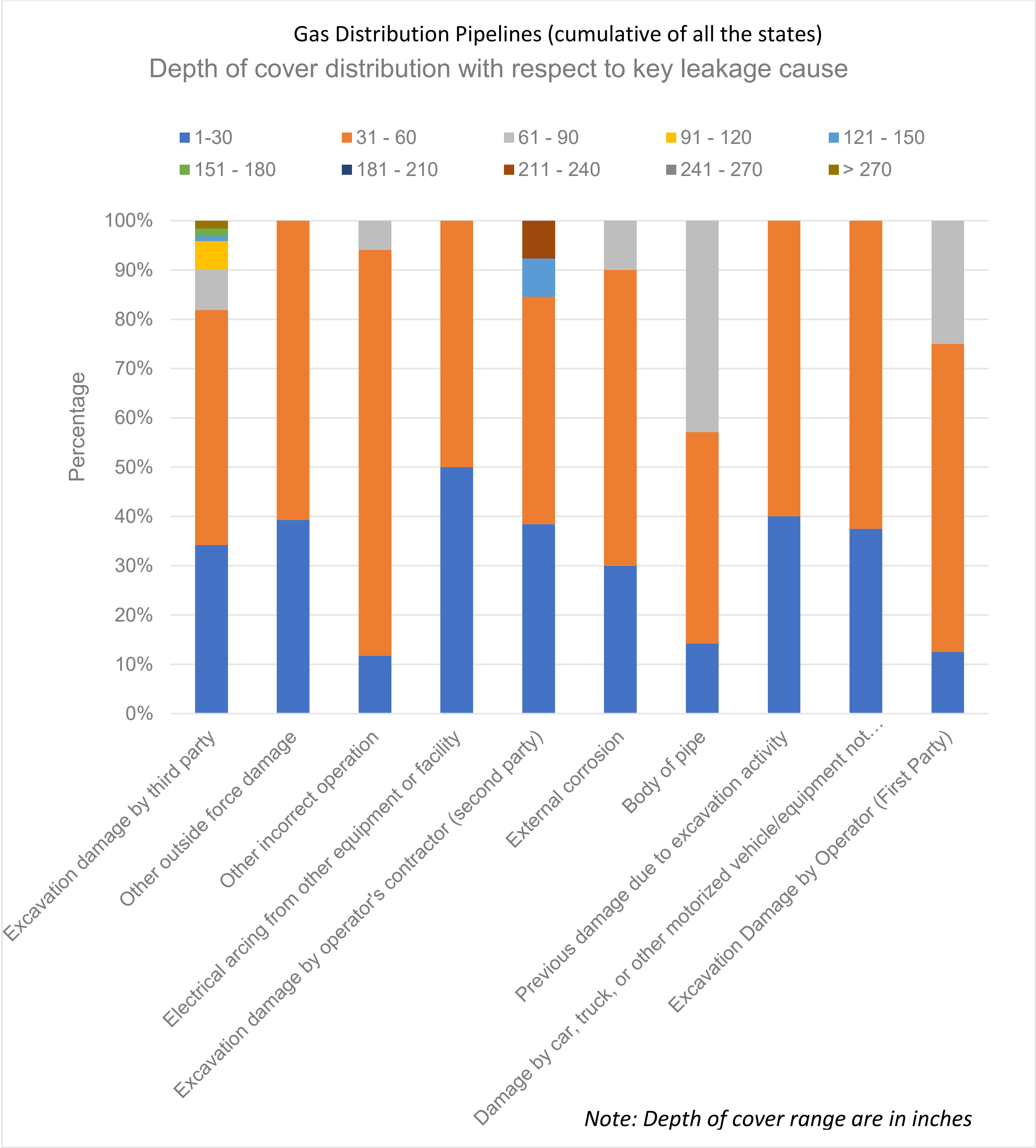


Figure 16: Year 2010 to 2018 percentage distribution of depth of cover versus leakage causes for Gas Distribution pipelines from all the states.

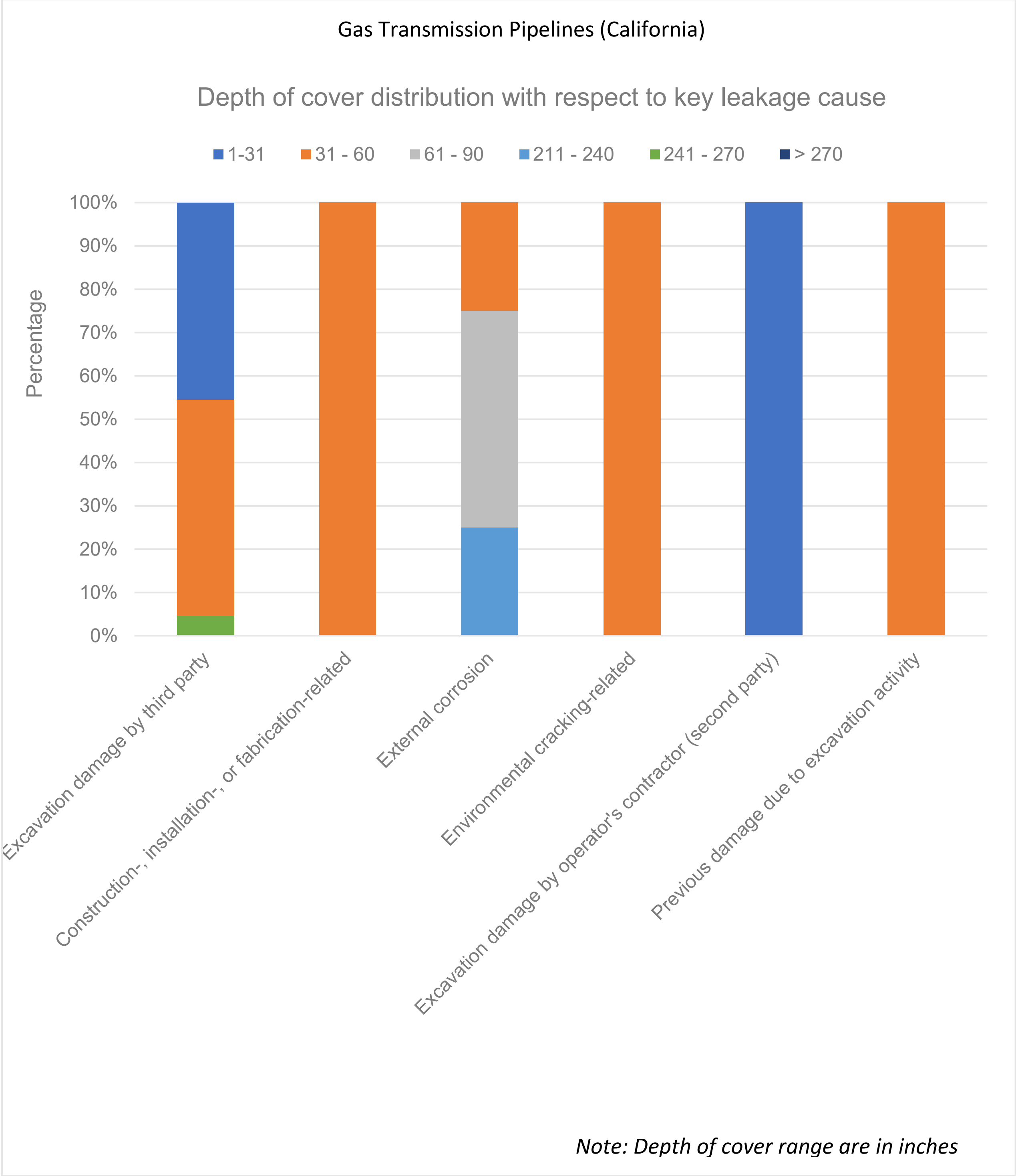


Figure 17: Year 2010 to 2018 percentage distribution of depth of cover versus leakage causes for Gas Transmission pipelines in California.

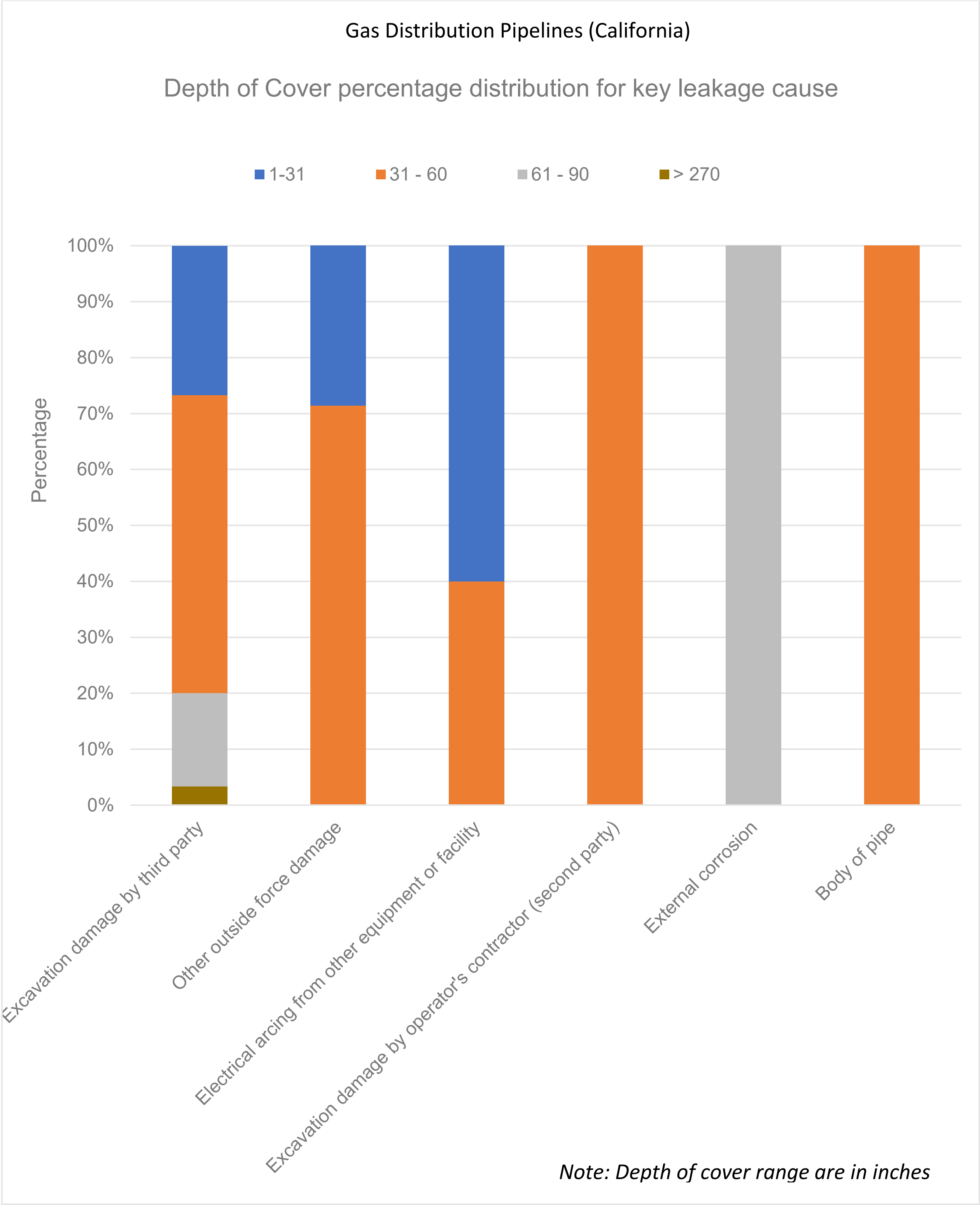


Figure 18: Year 2010 to 2018 percentage distribution of depth of cover versus leakage causes for Gas Distribution pipelines in California.

Gas Migration in Soil Media

Detection methods deployed for natural gas leakages have been broadly divided into three categories based on degree of intervention needed from a human: automated (e.g. fiber optic or cable sensors), semi-automated (e.g. statistical or digital signal processing methods) and manual (e.g. thermal imagers or LIDAR devices) (Murvay and Silea, 2012). Based on the study of Deepagoda et. al (2016), wind as compared to temperature, has been found to have a strong impact on surface concentration of natural gas under various saturation and soil-texture conditions. High temperature and high wind conditions at the surface expedite the subsurface moisture dynamics and a decreasing surface natural gas concentration was observed with increasing wind speed.

Okamoto and Gomi (2011) discuss the concept of ‘advection’ and ‘diffusion’ with respect to underground gas leakage and gas migration to the soil surface. Gas migration due to underground leakage is transferred across the soil by the process known as “advection” and “diffusion” in the pores of soil particles. While “advection” is transfer as a result of the average movement of fluid, and when the emission due to leakage stops, the flow also stops, “diffusion” is caused by the diffusion of gas molecules in the air in the pores between soil particles. Thus, although leakage stops, diffusion continues as it is the molecular motion due to differences in concentration.

Underground migration of natural gas has got significant attention in research through experiments carried out under controlled environment. For example, Okamoto and Gomi (2011) investigate underground diffusion of natural gas (consisting of methane with specific 0.56 and propane with specific gravity 0.49) as it migrates to the surface with the set-up as shown in Fig. 19. The soil used was sand, covered with crushed stone and then asphalt - thus, simulating the leakage of underground pipelines through soil environment. The objective of the full-scale experiment was to capture study the behavior of underground pipeline gas leakage, diffusion range and time. Further, an analytical model was constructed to simulate the diffusion behavior and verified with results of the full-scale experiments. The leakage pressure used in the experiment was 0.2 kPa, location of leakage was 1.2 m (3.93 ft) below ground and the groundwater level is 2.9 m (9.51 ft) below ground.

For the set-up shown in Fig.19, the gas concentration is found to be high and vertically asymmetric about the point of leakage for the spread of methane and propone as shown in Fig. 20a and Fig. 20b, respectively. The gases are not allowed to diffuse through the surface due to the presence of asphalt - this process is similar to natural gas leakage from a pipeline (whether cased or uncased) present underneath asphalt roadway. It is noted from Figs. 20a and 20b, that the gas with a lower specific gravity spreads downward and gas with a higher specific gravity spreads upward – defying the usual tendency of a gas with a lower specific gravity which usually distributes upward and gas with a higher specific gravity distributes downward. Both pressure and concentration are high in the zone close to the point of leakage. Advection and diffusion lead to concentric spread of the gas around this leakage point.

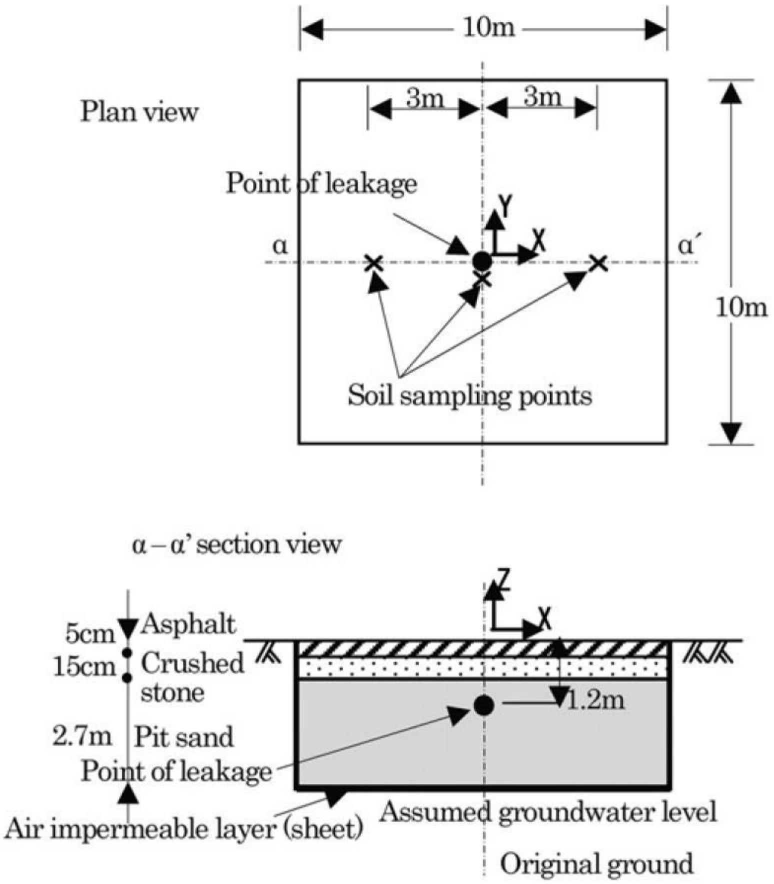
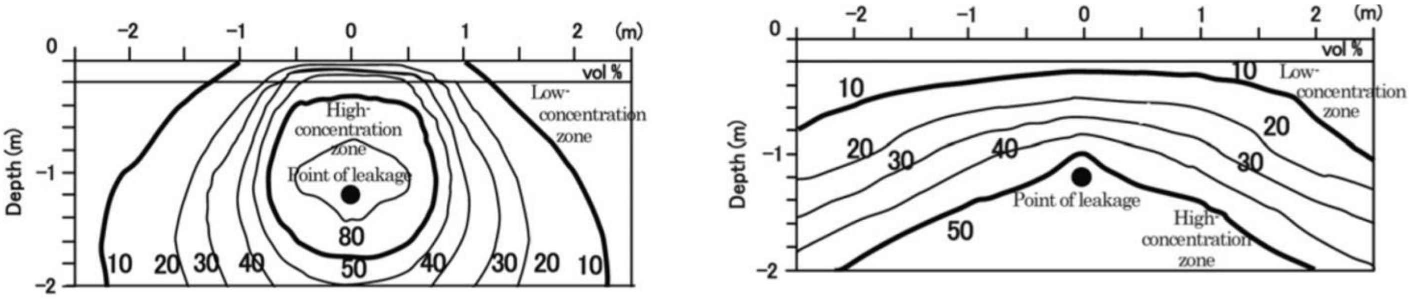


Figure 19: Set-up for estimating natural gas migration due to point of leakage (Source: Okamoto and Gomi, 2011)



20(a)

20(b)

Figure 20: Migration profile of (a) methane and (b) propane through soil profile covered by asphalt cover (Source: Okamoto and Gomi, 2011)

In practice, backfilling of trenches during pipeline installation is carried out by compacting with soil materials that create a low-permeability zone around the pipeline. If the excavated area for laying the pipe has rocky formations, a high-permeability around the pipe is maintained by filling the trench with broken rocks. The differences in filling-up the trench with variable soil types often affects the migration of natural gas after a leakage has occurred in the buried pipeline. Research shows that the extent and magnitude of leak into the surrounding soil type depends on the pressure with which the liquid in carried through the pipeline – which typically varies between high-pressure (~3500–9600 kPa) to low-pressure (1.5–2000 kPa) conditions (Deepagoda et al., 2016). Leak detections with high-pressure pipelines are often easier and can be fixed, when compared to pipelines that operate at low-pressures.

Factors such as the depth of the pipeline, soil properties, soil moisture and gas composition greatly influence the gas migration within the soil. The spread of the leakage surrounding the pipeline has been noted to vary broadly in the range of 6.5 – 33 ft in length (Okamoto and Gomi, 2011; Yan et al., 2015). Transport and migration of natural gas (predominantly consisting of methane) in soil depends on soil heterogeneity, moisture, temperature, and pressure gradients (Poulsen et al., 2003). Migration of natural gas in clay soil texture type is somewhat irregular in shape and varies with respect to migration in normal soil environment (such as sand) in the form of an inverted cone as the sketch in Fig. 21 shows. The variability in migration is due to low-permeability of clay as compared to that of a homogenous soil system of sand which has a high permeability (Ho and Webb, 2006).

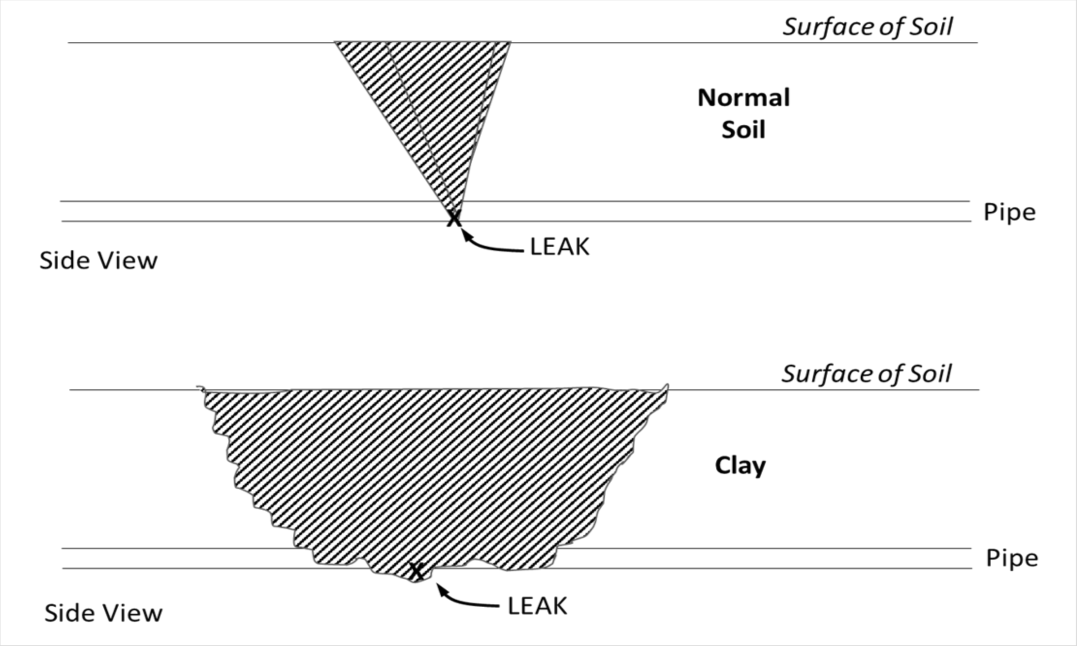


Figure 21: Path of natural gas leakage propagation as it travels through the soils (Source: Texas Gas Association, 2018)

Key laboratory-based studies have been conducted that have investigated methane migration in soil media (consisting of dry sand) in one-dimensional column such as those conducted by Hibi et al. (2009). The gas concentrations were measured at selected points along the column experimental apparatus. Costanza-Robinson and Brusseau (2002) carried out gas phase miscible displacement experiments to quantitatively investigate the advective and dispersive contributions to methane transport in unsaturated porous media – consisting of clay, silt and sand. The purpose was to measure dispersivity values with the use of a tracer compound (containing methane) and of the soil water content. Dispersion coefficients and retardation factors were obtained by fitting breakthrough curves for advection and dispersion through the experimental study. The dispersivities of gas phase transport in the porous media consisting of clay, silt and sand were found to be methane dependent at the highest soil water contents.

In one of the latest researches, Felice et. al (2018) simulated shallow methane generation with a controlled subsurface methane release. There were four main objectives of the study - (i) characterize subsurface methane migration and transformation from a controlled field release at shallow depths, including the areal extent of the methane plume (ii) measure the lag time for methane oxidation to begin (iii) determine the fraction of subsurface methane reaching the atmosphere; and (iv) measure seasonal variability and identify environmental controls of methane migration. The simulation assumed that "biological methane oxidation would begin within several days of introducing methane to the soil and that this biological activity would limit the efflux of methane to the atmosphere". Another hypothesis was also investigated - "methane migration would be tied to soil moisture, with decreased efflux during wet periods." The set-up for the experiment by Felice et. al is shown in Fig. 21. The set-up used for this experiment conducted at a field site was located in the Putah Creek Riparian Reserve, approximately 2.25 km south of the University of California campus at Davis. The site had a measured texture of silt loam in the upper 0.25 m of soil and from approximately 0.95 to 1.5 m below ground surface, the maximum depth of monitoring. The site was instrumented with an array of narrow-diameter, custom-built, stainless steel drive points installed at 0.5, 1.0, and 1.5 m below ground surface to allow gas injection and sampling of soil gas. Table 15 shows the injection periods involving methane and other tracer gases during the experiment. Site precipitation events and volumetric soil water content measured at the site are shown in Fig. 22. Soil gas profiles from the low- and high-rate injection periods are shown in Fig. 23.

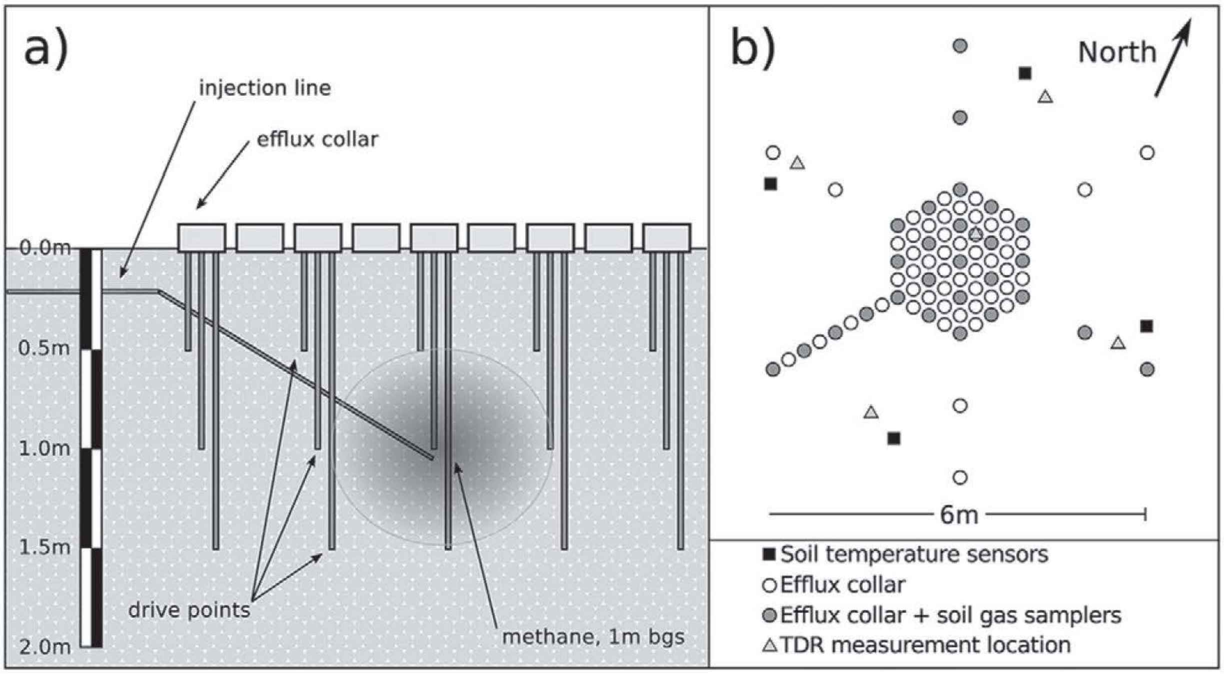
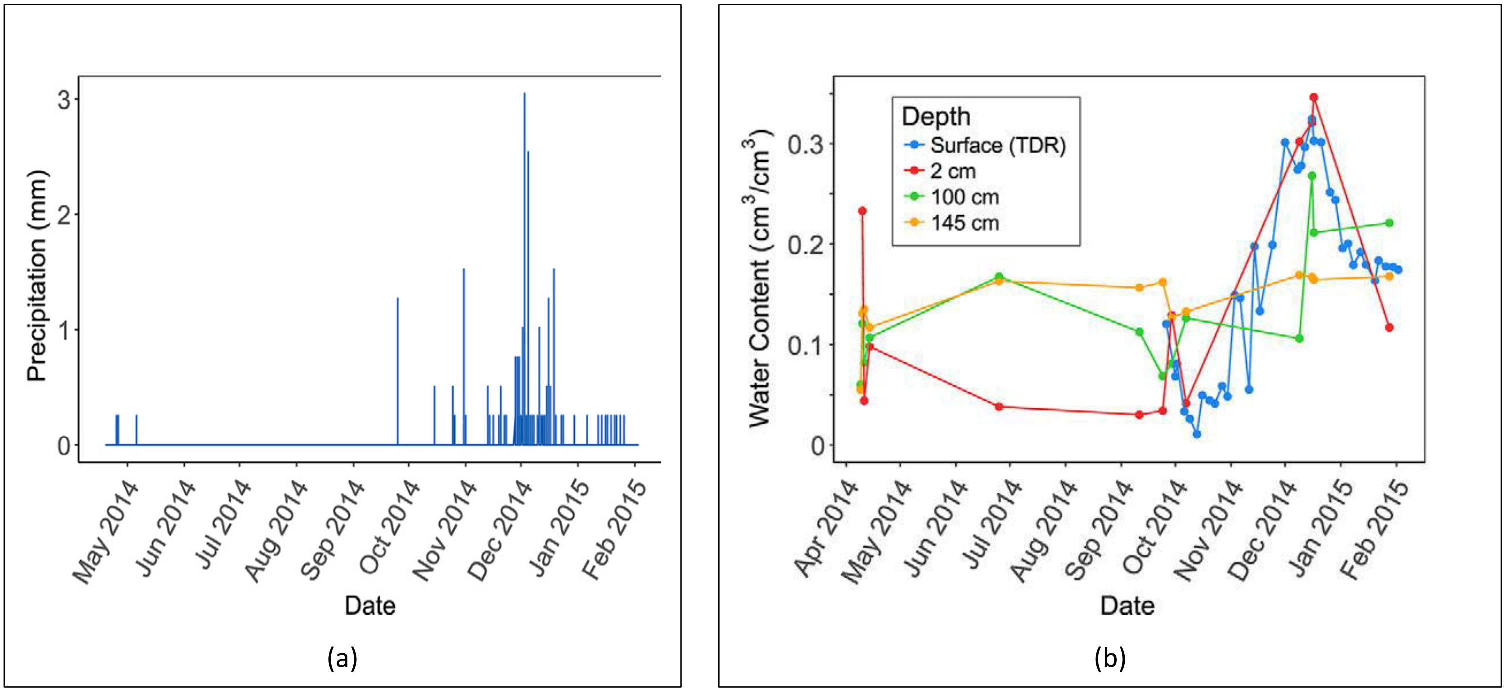


Figure 22: a) Vertical cross-section, and b) plan view schematics of the methane injection and monitoring network

Table 15: Methane injection periods and composition of injected gas throughout the experiment. The gas mixture was injected at a target rate of 1000 mLd-1 during all injection periods with methane (CH4), neon (Ne) and difluoroethane (DFE).

Injection period	Gas composition	Injection dates	Injection duration d
First low-rate CH_4 injection	25% CH_4, 75% Ne	7–22 July 2014	15
First high-rate CH_4 injection	100% CH_4	23 July–19 Sept. 2014	58
Second low-rate CH_4 injection	25% CH_4, 75% Ne	19 Sept.–17 Oct. 2014	28
Second high-rate CH_4 injection	100% CH_4	17 Oct. 2014–3 Feb. 2015	109
Conservative tracer injection	100% 1,1-DFE†	3–27 Feb. 2015	24
CH_4/tracer co-injection	50% CH_4, 50% 1,1-DFE	27 Feb.–13 Mar. 2015	14
CH_4/CH_4–oxidation inhibitor co-injection	50% CH_4, 50% ethene	13–23 Mar. 2015	10

† DFE, difluoroethane.



(a)

(b)

Figure 23: (a) Precipitation events at the site, and (b) Volumetric soil water content measured at the site

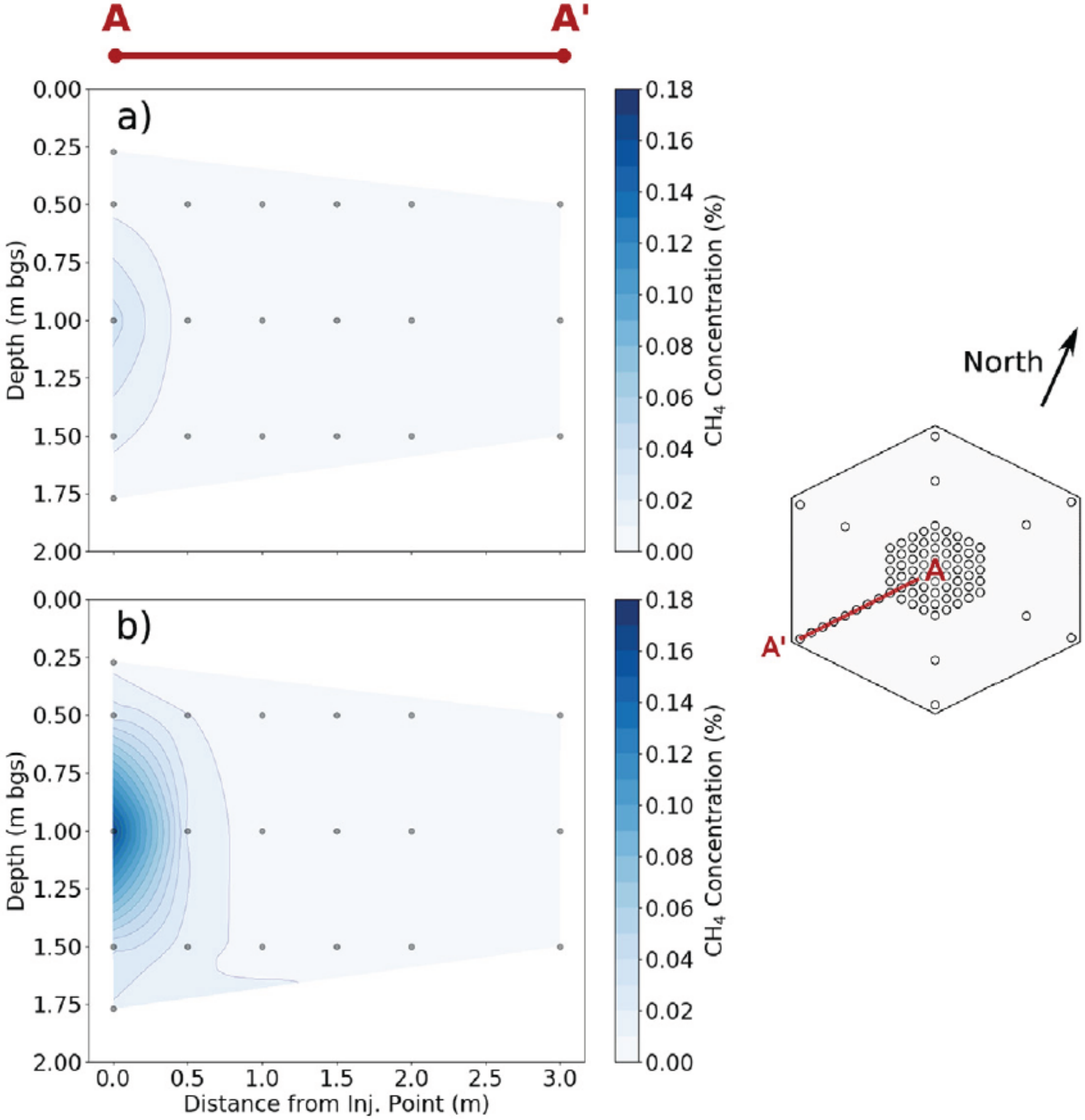


Figure 24: Soil gas profiles during the second (a) 25% (8 Oct. 2017) and (b) 100% (23 Oct. 2017) methane injection periods. Circles represent sampling points

Based on recordings of the monitoring points used in this experiment, it was noted that methane migration was very rapid after the start of its injection. The soil gas profiles from the low- and high-rate injection periods are shown in Fig. 24. It was also noted that methane efflux was highest directly above the injection point - with rates decreasing radially (see Fig. 25). In conclusion, methane was detected at the soil surface (mainly silt) as far as 1 m from the injection point within 1 day of beginning injection and reached steady state within 3 day of beginning injection or changing the injection mix. Methane efflux was highest directly above the injection point, with rates decreasing radially as shown in Fig. 25. In the figure shown, negative efflux indicates net consumption of methane by the soil, and positive efflux indicates net emissions of methane to the atmosphere. Sampling points were represented by circles.

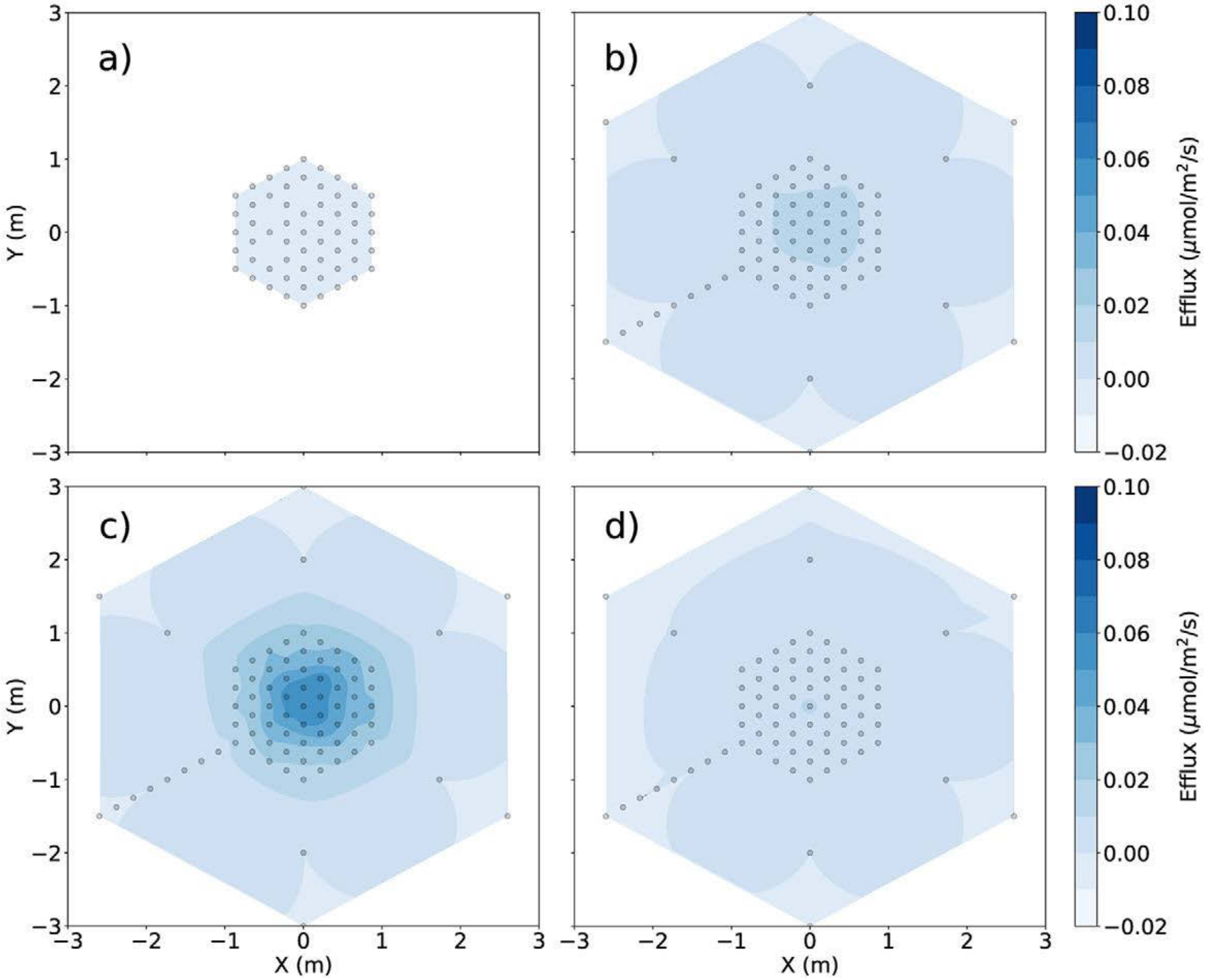


Figure 25: Contour plots of efflux snapshots taken (a) prior to the start of methane injection (30 Apr. 2014), (b) during 25% methane injection (8 Oct. 2014), (c) during 100% methane injection (11 Sept. 2014), and (d) during 100% methane injection following a per period of precipitation and declining efflux (15 Jan. 2015).

Cased/Uncased Pipeline Leakages in California

One of the several causes of pipeline leakages in California has been the external corrosion of aged pipes (note here that the leakage is not due to excavation damage, as has been extensively discussed before). The spatial location of leakages in California from 2010 to 2018 has been shown in Fig. 26 and Fig. 27 for gas transmission and distribution pipelines, respectively. Tables 16 and 17 shows the compilation of gas transmission and distribution leaks for reporting year, information on installation year of the pipe, cased/uncased pipe, soil texture at leak location and depth of cover (in inches).

In the years from 2010 to 2018, there have been only THREE instances of pipeline leakages in California from pipes that were encased. The leakage that had occurred from an encased pipeline in 2011 under pavement and another that had occurred under a railroad crossing. All other underground leakages detected in California during 2010 - 2018 period was not found to be cased. For the leakage detected with encased pipe under roadway crossing, PG&E personnel discovered gas readings at the casing vents for a 20-inch casing surrounding 16-inch steel gas transmission line. PG&E crews excavated the pipe and casing on both sides of the roadway with the purpose to identify the location of the leak. However, the source of the leak was not detected at either side of the roadway but appeared to be located somewhere under the roadway. Due to the location of the leak, it was not feasible to attempt to repair the leak and therefore, a new pipe to be installed under the roadway was proposed and replaced the leaking pipe.

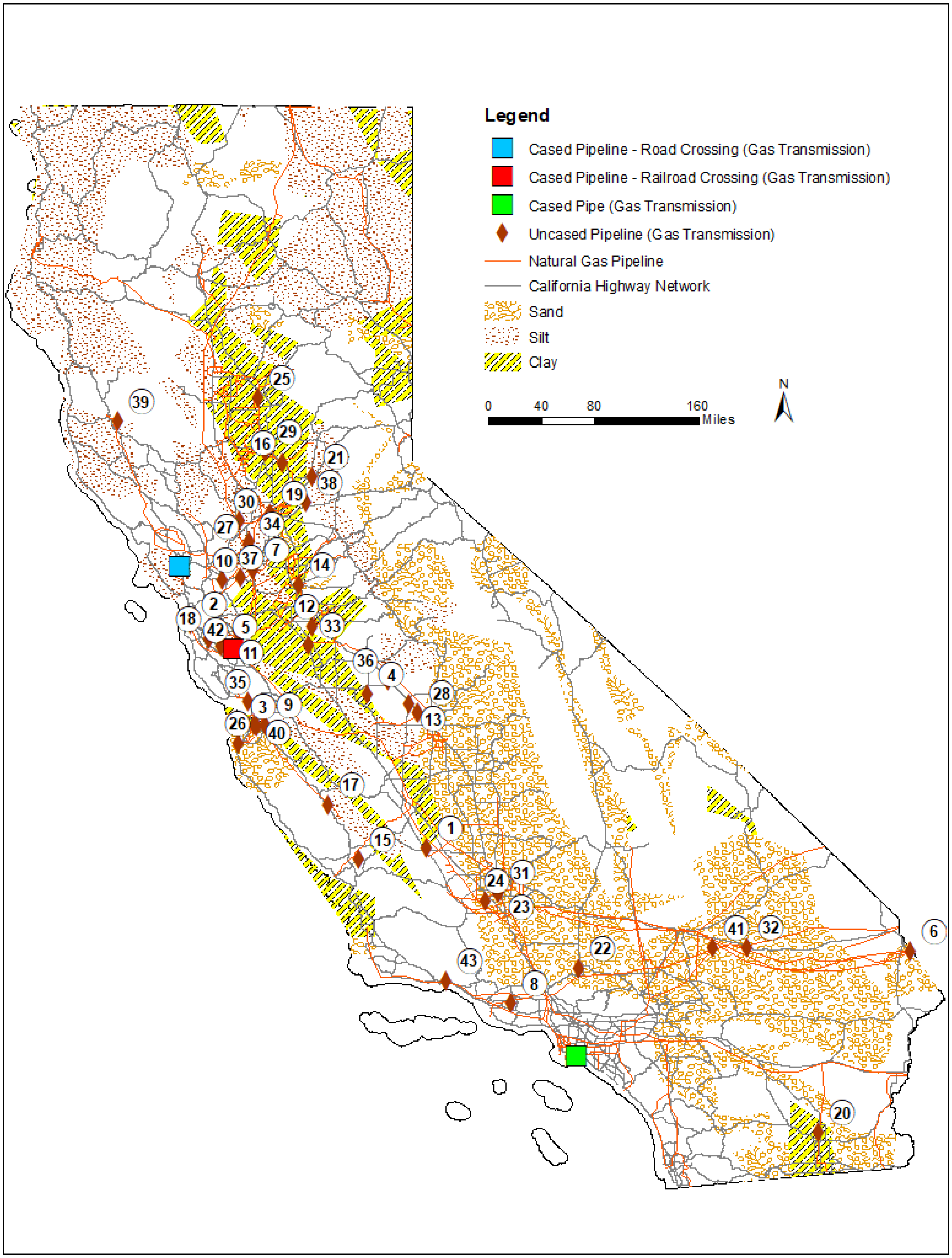


Figure 26: Spatial distribution of gas transmission pipeline leaks across California (Soil Information Data Source: California Soil Resource Lab, 2018)

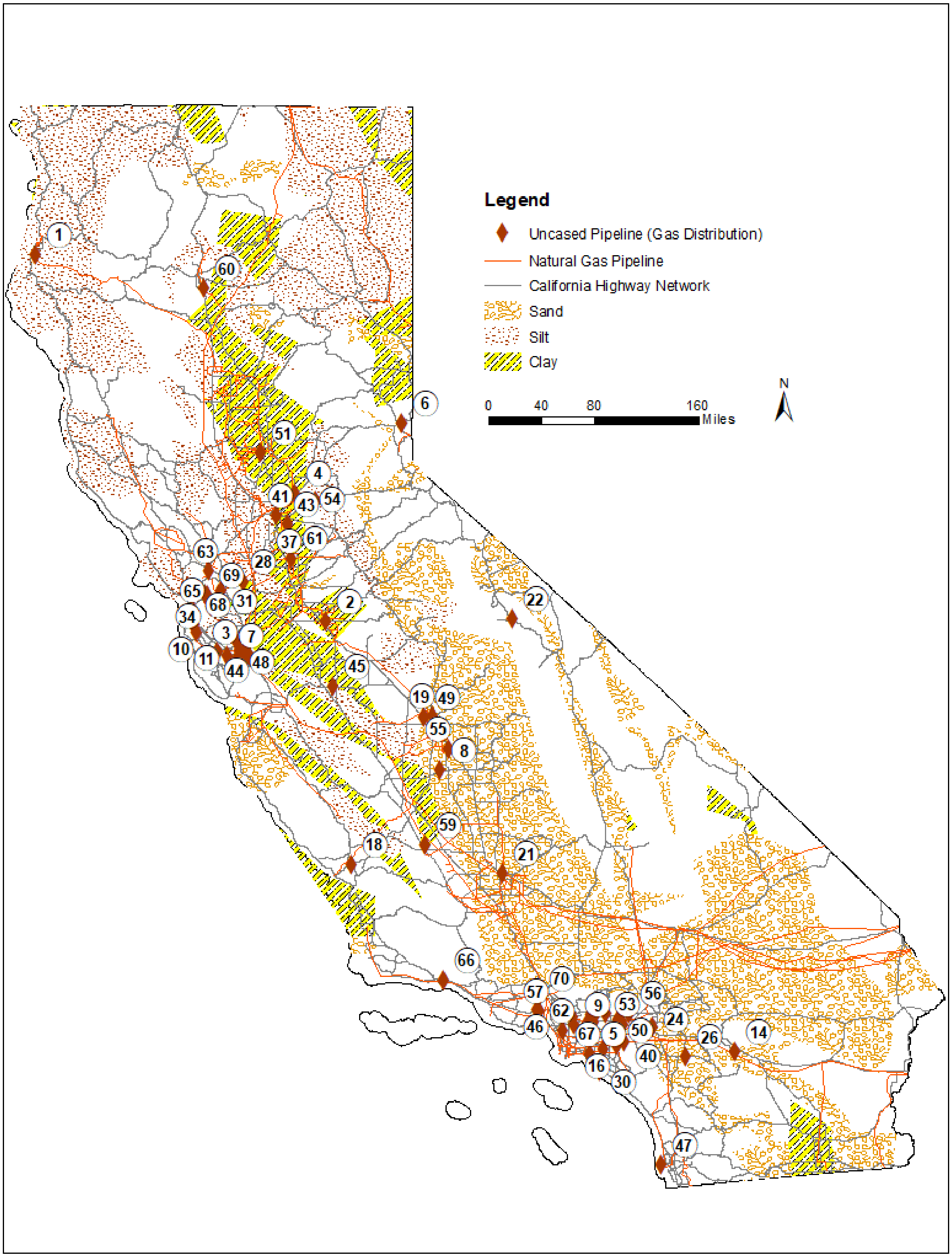


Figure 27: Spatial distribution of gas distribution pipeline leaks across California

Table 16: Compilation of underground/under soil natural gas transmission pipeline leakage in California (2010- 2018) (Data Source: PHMSA, 2018)

Leak Detection No.	Leakage Reporting Year	Pipeline Installation Year	Cased/Uncased	Predominant Soil Texture at Leak Location	Depth of Cover (in.)
1	2011 *(External Corrosion)*	1961	Cased *(Roadway Crossing, Under Pavement)*	Silt	240
2	2014 *(External Corrosion)*	1944	Cased *(Railroad Crossing)*	Silt, Clay	66
3	2010	1966	Cased	Sand	12
1	2010	1931	Uncased	Clay	NA
2	2010	1956	Uncased	Silt, Clay	NA
3	2010	1952	Uncased	Clay	29
4	2010	1985	Uncased	Sand	NA
5	2011	1980	Uncased	Clay	NA
6	2011	1957	Uncased	Sand	NA
7	2011	1942	Uncased	Clay	39
8	2011	1944	Uncased	Sand	18
9	2011	1930	Uncased	Silt, Clay	20
10	2012	NA	Uncased	Silt	72
11	2012	1936	Uncased	Silt, Clay	NA
12	2012	1947	Uncased	Clay	NA
13	2012	1965	Uncased	Sand	10
14	2012	1985	Uncased	Clay	54
15	2013	1932	Uncased	Silt, Clay	32
16	2013	1955	Uncased	Clay	56

17	2013	1957	Uncased	Silt, Clay	18
18	2014	2014	Uncased	Silt, Clay	138
19	2014	1991	Uncased	Clay, Sand	60
20	2014	1948	Uncased	Clay	40
21	2014	1962	Uncased	Clay, Sand	30
22	2014	2004	Uncased	Sand	55
23	2014	1954	Uncased	Sand	54
24	2014	1955	Uncased	Sand	48
25	2014	1928	Uncased	Clay	84
26	2015	1959	Uncased	Sand	30
27	2015	1937	Uncased	Silt, Clay	4
28	2015	1962	Uncased	Sand	45
29	2015	1943	Uncased	Clay	52
30	2015	1949	Uncased	Silt, Clay	39
31	2015	1954	Uncased	Sand	36
32	2016	1950	Uncased	Sand	36
33	2016	1972	Uncased	Silt	42
34	2016	1937	Uncased	Clay	48
35	2016	NA	Uncased	Silt	22
36	2016	1962	Uncased	Clay	36
37	2017	1952	Uncased	Silt, Clay	35
38	2017	2017	Uncased	Clay	NA
39	2017	1972	Uncased	Silt	48
40	2017	1966	Uncased	Silt	30
41	2017	1957	Uncased	Sand	40
42	2017	NA	Uncased	Silt, Clay	24
43	2018	1965	Uncased	Sand	102

Table 17: Compilation of underground/under soil natural gas distribution pipeline leakage in California (2010- 2018) (Data Source: PHMSA, 2018)

Leak Detection No.	Leakage Reporting Year	Pipeline Installation Year	Cased/Uncased	Predominant Soil Texture at Leak Location	Depth of Cover (in.)
1	2010	NA	Uncased	Silt	30
2	2010	NA	Uncased	Clay, Sand	12
3	2010	1967	Uncased	Silt	6
4	2010	NA	Uncased	Clay	NA
5	2011	1959	Uncased	Sand	48
6	2011	1996	Uncased	Clay, Sand	36
7	2011	1973	Uncased	Silt	NA
8	2011	1966	Uncased	Sand	12
9	2012	1979	Uncased	Sand	NA
10	2012	2011	Uncased	Silt	NA
11	2012	NA	Uncased	Silt	NA
12	2012	2012	Uncased	Silt	NA
13	2012	1959	Uncased	Sand	42
14	2012	1979	Uncased	Sand	34
15	2012	2002	Uncased	Sand	37
16	2012	1979	Uncased	Sand	NA
17	2013	1987	Uncased	Silt	18
18	2013	1952	Uncased	Clay	21
19	2013	1950	Uncased	Sand	87
20	2013	NA	Uncased	Silt	75
21	2013	1938	Uncased	Sand	4
22	2013	NA	Uncased	Sand	30
23	2013	2001	Uncased	Clay	31

24	2013	1960	Uncased	Sand	40
25	2013	1967	Uncased	Sand	32
26	2014	1947	Uncased	Sand	19
27	2014	1959	Uncased	Sand	45
28	2014	2005	Uncased	Silt	36
29	2014	1986	Uncased	Silt	28
30	2014	1966	Uncased	Sand	40
31	2014	1954	Uncased	Silt	35
32	2014	1966	Uncased	Silt	66
33	2014	1988	Uncased	Silt	63
34	2014	1989	Uncased	Silt	66
35	2015	NA	Uncased	Silt	48
36	2015	1947	Uncased	Sand	36
37	2015	2008	Uncased	Clay	42
38	2015	1948	Uncased	Sand	48
39	2015	2006	Uncased	Sand	64
40	2015	1980	Uncased	Sand	80
41	2015	NA	Uncased	Clay	32
42	2016	1954	Uncased	Silt	NA
43	2016	2008	Uncased	Clay	48
44	2016	NA	Uncased	Silt	84
45	2016	1989	Uncased	Clay	NA
46	2016	1982	Uncased	Sand	45
47	2016	1942	Uncased	Sand	36
48	2016	NA	Uncased	Silt	36
49	2016	2016	Uncased	Sand	348
50	2016	1975	Uncased	Sand	44

51	2017	1974	Uncased	Clay	55
52	2017	1953	Uncased	Sand	18
53	2017	1983	Uncased	Sand	36
54	2017	NA	Uncased	Clay	NA
55	2017	1992	Uncased	Sand	48
56	2017	1983	Uncased	Sand	36
57	2017	1966	Uncased	Sand	20
58	2017	NA	Uncased	Silt	40
59	2017	1931	Uncased	Clay, Sand	8
60	2017	1973	Uncased	Silt, Clay	60
61	2017	1946	Uncased	Clay	24
62	2017	1951	Uncased	Sand	NA
63	2017	NA	Uncased	Silt	49
64	2017	1984	Uncased	Silt	48
65	2017	NA	Uncased	Silt	NA
66	2018	1939	Uncased	Sand	36
67	2018	1925	Uncased	Sand	46
68	2018	1996	Uncased	Silt	40
69	2018	NA	Uncased	Silt	36
70	2018	1987	Uncased	Sand	40

A summary of findings on leakages at roadway crossings (under pavement or under soil which are near the crossings), along with depth of cover information, has been presented in Table 18.

Table 18: Summary of cased and uncased natural gas pipeline leakage incidents at roadway crossings for various states of the nation (data source PHMSA: 2010 - 2018)

State	Road Crossing (Under Pavement, Under Soil)	Cased/Uncased	Depth of Cover (inches)	Comments
CA	Under pavement	Cased	240	There was a 20-inch casing surrounding 16-inch steel gas transmission line. The pipe and casing on both sides of the roadway was excavated. The source of the leak was not at either side of the roadway but appeared to be located somewhere under the roadway. It was difficult to repair the leak and a new pipe was installed under the roadway to replace the leaking pipe.
CA	Under pavement	Uncased	264	The 20-inch gas steel transmission line was struck while performing directional boring
CO	Exposed due to excavation	Uncased	12	Third party excavator damaged a gas transmission line due to lack of information
GA	Under soil	Uncased	11	The damage to gas transmission line was on a dirt road and the damaged pipe portion was replaced. Permission was not obtained before the grading activity.
GA	Under soil	Uncased	48	Unpaved road was involved in the incident. The road grader made a 2in x 1in puncture in the 3- inch uncased pipeline. There was no one-call notification made prior to the activity.

IL	Under pavement	Uncased	70	Leak caused by erosion from the water and sandy soil.
KS	Under pavement	Bored/drilled	288	Pipe was installed by pulling through a horizontal directional drilling hole and pipe did not contain abrasion resistant coating. The hole had been bored through solid rock and external corrosion caused by damage to coatings during install, by scraping the sides of the bore hole. *A 16" pipe was pulled into the existing 20" line as a replacement at the road crossing and the existing line was used as a casing.*
LA	Under soil	Uncased	8	Pipeline was struck by a road contractor cleaning the roadway ditch.
MN	Under soil	Uncased	30	The pipe failure was due to environmental cracking which occurred in a localized hard spot in the pipe wall.
MO	Under pavement		156	The pipe was damaged during installation when it was pulled through the bore hole exposing the exterior of the steel pipe to the effects of "tenting" and atmospheric corrosion.
MS	Under soil	Uncased	24	There was a failure of a rubber seal.
NC	Under soil	Uncased		Contractor bored into the side of the line.
NJ	Under pavement	Bored/drilled	48	The rock underneath the pipe was the cause of a small crack where the leak initiated.

NM	Other	Uncased	6	Grader had punctured the pipeline.
NM	Exposed due to excavation	Uncased	10	A road grader scraped the pipeline with the blade. The operator did not call the state’s one-call notification center for a locate request.
NV	Under soil	Uncased	156	The puncture occurred in the pipeline due to a tool not operated properly.
OH	Under soil	Cased	48	The crack in the pipe originated during the welding process at the time of original construction.
OH	Under pavement	Cased	93	The external corrosion resulted in the pipe coating damage under the rubber casing isolator, and the coating damage likely occurred during installation of the casing. *Filling the annular space between the carrier pipe and the casing with a dielectric material removes the corrosive environment and can prevent corrosion from occurring.* Filling of this casing could have prevented this leak.
PA	Exposed due to excavation	Cased	144	Removing a portion of road casing encircling the 30-inch carrier pipe caused the pinhole leak.
TX	Under pavement	Cased	240	External corrosion was the cause and it was discovered that the vent pipe was detached from the casing.
TX	Under soil	Bored/drilled		A boring unit by a subcontractor had damaged an underground gas pipeline.

TX	Under soil	Uncased	120	A boring activity struct the line and the third-party excavator did not contact the operator prior to exposing the active pipeline.
TX	Under pavement	Cased	60	Product was detected venting from the casing vent pipe. No confirmation was made for the cause of the release due to location of the crossing at navigation street. A new horizontal directional drilling was installed with a new pipe and the leaking pipeline segment was purged, cut and capped on both sides of the crossing.
WI	Under soil	Cased	120	Natural gas appeared to be blowing from vent casings on both sides of the road. Approximately 60-feet of new tested, coated pipe was installed with an open cut on the road.

5. TRENCHLESS TECHNOLOGIES FOR UNDERGROUND PIPELINE REPLACEMENT

Background

In practice, trenchless techniques are divided into three categories: trenchless inspection techniques, new construction or installation and trenchless rehabilitation (Ezeokonkwo and Nwoji, 2014; ISTT, 2018). Trenchless construction methods (TCM) are used to install new underground utility pipe and involve limited amount of surface disruption. Trenchless rehabilitation refers to extending the design life of a pipe by replacing, upgrading or renovating the existing pipeline system. The flowchart in Fig. 28 illustrates various subdivisions of these methods.

Based on the literature reviews conducted on Pipe Eating, Pipe Bursting (Pneumatic, Hydraulic, Rod Pulling, Splitting), Pipe Pulling, Close Fit Lining (Die drawing, Rolldown, Deformed pipe, Service pipe liner), Continuous Sliplining, Cured in place pipe, Discrete Sliplining, Ferrocement, Live Insertion, Segmental Lining, Spiral Lining, Spray Lining (Cement Mortar, Epoxy resin, Polymeric), Reinforced Cementitious, Air Scouring, Chemical Stabilization, Flushing, Jetting, Localized Repair (Joint Sealing, Patch, Pointing, Rerounding, Robotic), Pigging, and Pressure Scraping. Cured-in-Place Pipe-Lining (CIPP) is another trenchless sewer repair method that requires little or no digging (Cured-in-Place Pipe-Lining, 2019). This is a pipe rehabilitation technique in which sewer pipe several hundred feet long can be repaired in a short time. The process consists of inserting a flexible liner inside the old pipe and the liner is inflated to press the inside pipe wall firmly. Using heat exposure or ultraviolet light the liner is then hardened inside of the old pipe. However, only Pipe eating, Pipe bursting and Pipe pulling are used as trenchless technologies for pipeline replacement – rest all are used for renovation of underground gas pipes. Table 19 describes the three commonly used trenchless technologies and they are applicable for pipe replacement. Sliplining is usually not used for pipe replacement, however, in this process plastic pipe (HDPE) or PVC sections are joined by fusion welding outside of the pipe to be rehabilitated, and then the pipe is pulled into place as one solid liner (CHAPTER 16, TRENCHLESS TECHNOLOGY, ODOT, 2019).

Pipe Replacement Trenchless Techniques

Tables 19 and 20 provide a summary of findings on key characteristics of popular trenchless technologies.

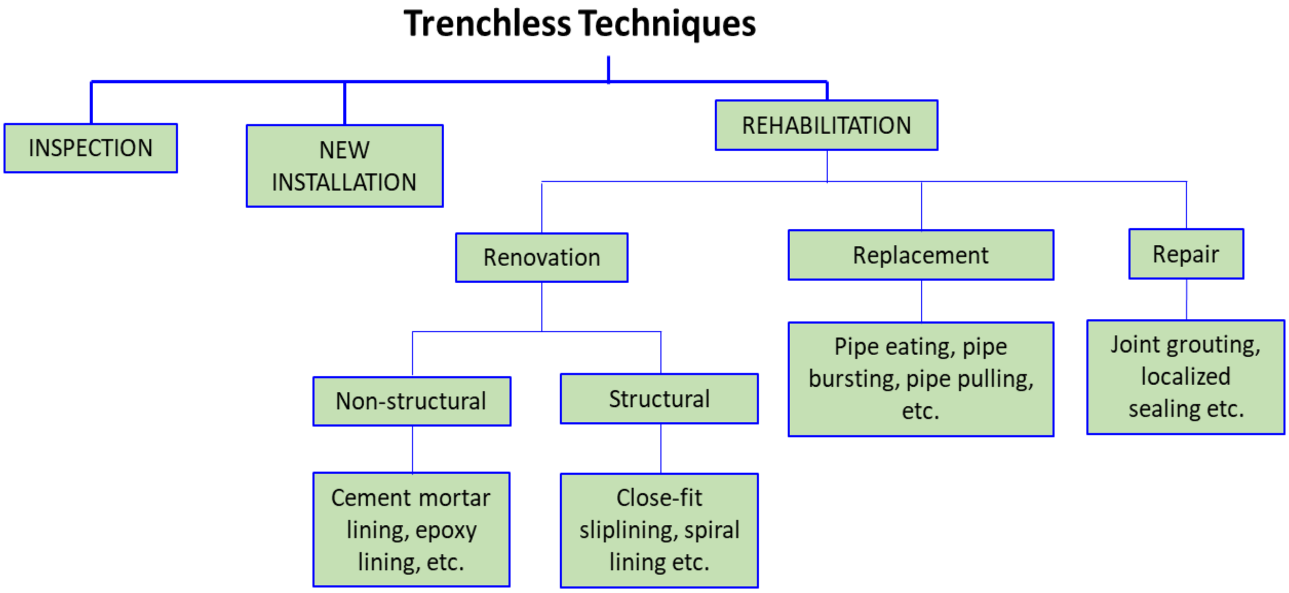


Figure 28: Trenchless techniques (ISTT, 2018)

Table 19: Trenchless techniques for replacement of underground pipes

Trenchless Technique	**Description**
Pipe Eating	• Pipe eating is the process in which it crushes the existing or the old pipe by the tunneling machine as the new pipe is jacked into place (see Fig. 29). [*Manual for Controlling and Reducing the Frequency of Pavement Utility Cuts, FHWA, 2018*] • Used for the replacement of clayware, concrete, asbestos cement, and reinforced concrete pipes. • This technique is suited for large diameter pipes and in situations where the heave caused by expansive upsizing could damage the surface. • Pipe eating is usually helpful when the pipe to be replaced is deep enough, the pipe route and location is complex – such as presence of trees and the amount of spoil it might create (Groundforce, 2019). Thus, pipe eating would not be used if it caused damage to the roadway.

Pipe Bursting	• Pipe bursting is a method of using a bursting tool (expander) as it moves through the existing pipeline by application of radial forces to break open or to split the pipe. (Manual for Controlling and Reducing the Frequency of Pavement Utility Cuts, FHWA, 2018). • Pipe bursting are generally used to replace the same size pipes; however, this technique can also be used to install a larger diameter pipes over the old smaller pipes. • During this process, a thin-walled sleeve is pulled (made of either push-fit PVC pipe or butt-fused polyethylene) into the bore directly behind a spreader (see Fig. 30). • There are four common types of pipe bursting techniques: pneumatic, hydraulic, rod pulling and splitting. Pipe bursting is used primarily when the pipe material is PVC or some similar material that is brittle in nature. Specific to California (ENCROACHMENT PERMITS, CALTRANS, 2019): • Pipe Bursting operations generally are only performed by the owning utility when they have exceeded the operating capacity of their existing facilities. In most cases pipe bursting allows the utility owners the advantage of upgrading their existing facilities by up to 50%. • On installations of diameters 12” or greater it is necessary to establish a survey-grid line and establish the existing elevation points over the existing area of installation. • A soil analysis should be required and review of the information to identify any locations of difficulty, density, water table, changes in soil formation that could present or create greater friction resistance. Other information can be requested based on following considerations: ○ The ratio of the proposed upgrade to determine difficulty, generally up to 25% increase in diameter is common. An increase of 25% - 50% is considered challenging, and an increase of 50% or greater is considered experimental. ○ The existing depth of cover, “rule of thumb” depth of cover should be at least 10 times the difference in the upgrade of the existing diameter to be burst. ○ Whether or not the existing line has been viewed by video, do not allow line to be burst blind.

	o Is this proposed line straight or are there bends in the line? o If bends are existing in the line, the location of the bend will have to be excavated and new pits re-established at those locations. o Require that the contractor provide a list of equipment to be on site to handle an emergency, in the event that bypass pumping is required to maintain the existing service in the event of a problem. o As to what method will be utilized (static, pneumatic, burst and jack, or hydraulic).
Pipe Pulling	• Pipe pulling is the process in which a new pipe is attached to the old pipe and pulled into the ground as the old pipe is pulled out utilizing the route of the existing pipe (see Fig. 31). (Trenchlessmedia, 2018) • In this technique, the need for further excavation and soil removal is prevented. • The technique is useful for small diameter piping mainly because for large diameter pipes would require high capacity cables/chain, large size towing heads, and equipment with very high pulling capacities to extract the pipe out. Depending on how the soil conditions are, pulling large diameter pipes could involve more careful monitoring during the process and could lead to uneven alignment of the new pipe and might not be cost effective – as compare to other available trenchless pipe replacement methods.

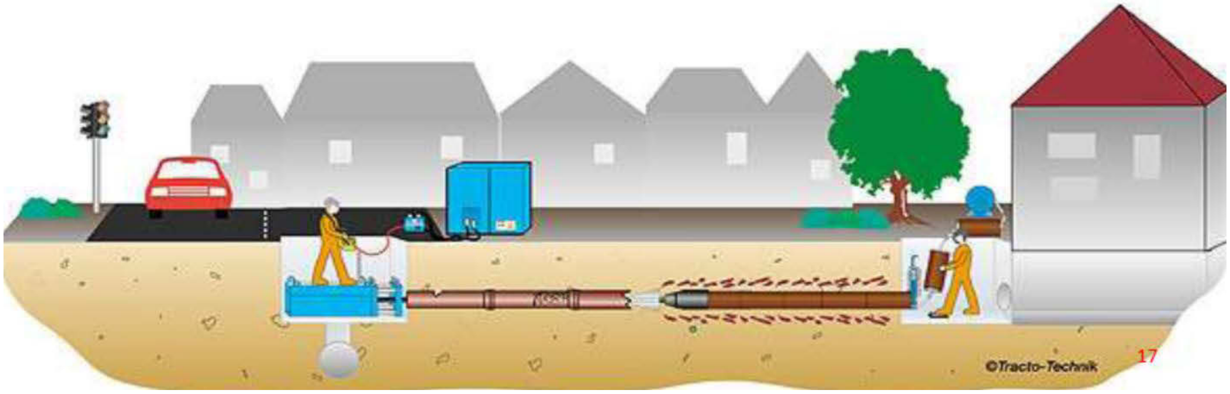


Figure 29: Pipe eating (Source: Tracto-Technik, 2018)

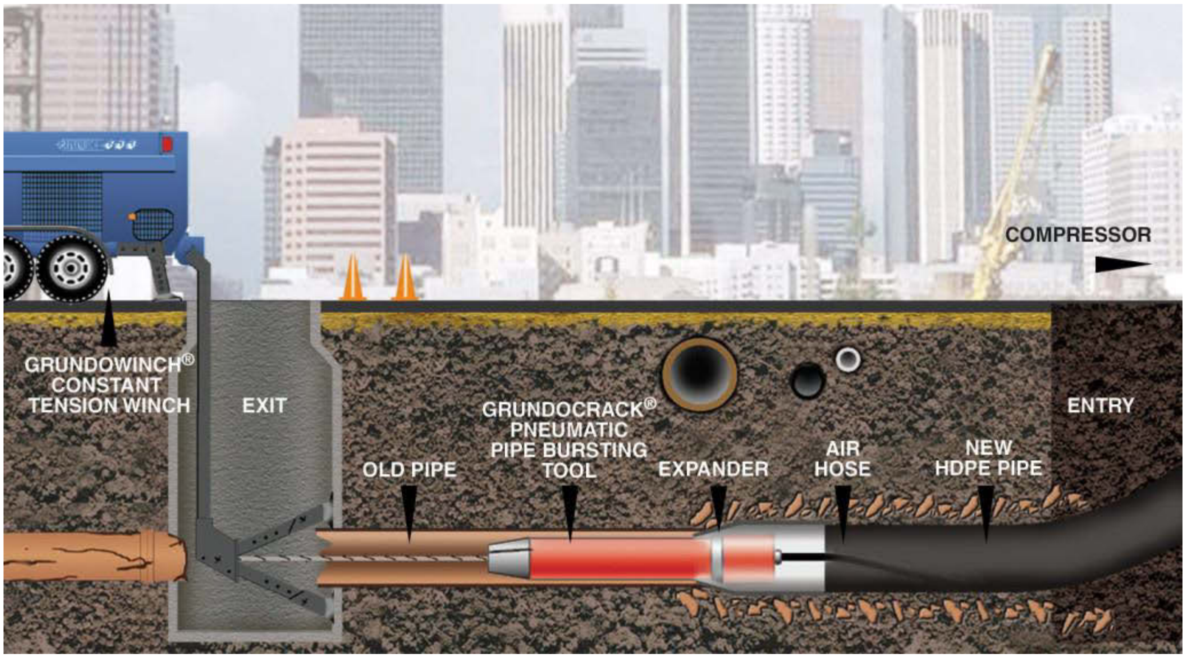


Figure 30: Pipe bursting (Source: TT Technologies, 2018)

Figure 31: Pipe pulling (Source: Terra, Trenchless Technologies, 2018)

Table 20: Summary of findings of popular trenchless technologies

Method Description	*Types of Equipment*	*Suitable Soil Type*	*Range of Application*			*Excavation Cost*	*Traffic Management Needs?*	*Policy on pipe removal and abandonment*
			Depth	*Length*	*Diameter*			
Pipe Eating (Stein, 2001)	*Tunneling machine*	*Clay, Silt, Sand and loose Granite*	*Exact information could not be found*	*Usually less than 820 ft*	*Less than 73”*	*Variable and depends on factors described separately in later sections*	*No disturbance to traffic*	*Information not available for California or other states on policy of removal or abandonment of pipes Table 19*
Pipe Bursting (IPR Information Packet, 2018)	*A bursting tool with expander*	*Clay, Silt and Sand*	*Less than 12 ft depending on routine, and could be greater than 18 ft for difficult to extremely difficulty project design classifications*	*Less than 350 for routine design and could be greater than 450 ft for difficult to extremely difficult design classifications*	*6” to 48”*	*Variable and depends on factors described separately in later sections*	*No disturbance to traffic (see footnote[1])*	*Explained separately in Table 19*
Pipe Pulling (Trenchlessmedia, 2018)	*A pipe pulling tail piece, a clamp and clamp adapter*	*Clay, Silt and Sand*	*Exact information could not be found*	*Typically, 50 ft*	*Smaller diameter pipe size (usually less than 6”)*	*Variable and depends on factors described separately in later sections*	*No disturbance to traffic*	*Information not available for California or other states on policy of removal or abandonment on pipes*

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[1] Both pipe eating and pipe bursting are trenchless methods that cause minimal to no traffic disturbance. This is also the reason behind deployment of such pipeline replacement techniques. Impact from the heave gets dissipated radially along the surrounding soil that and the fragments from the older pipe facilitate this dissipation. In addition, the heave/force of pull is distributed along the pipeline direction and is under certain depths to cause any impactful damage to the roadway or pavement. Only if this method is repeated too frequently might result in transferring the underground disturbances to the roadway surface.

Cost Components for Trenchless Techniques

Costs associated with trenchless technologies are variable, depend on type of soil, depth and extent (length) of the trenchless technique used and can be divided into six general categories as follows (*Manual for Controlling and Reducing the Frequency of Pavement Utility Cuts, FHWA, 2018*):

1. *Capital cost of equipment*: Capital cost include drilling rig, boring unit, impact mole, cutting head, jacking unit, control cabin, spoil removal system, power unit, directional control and detection device, and other equipment used for a trenchless method.
2. *Operating cost*: These costs comprise equipment set-up, operation and labor costs.
3. *Site investigation*: Several factors influence site investigation costs comprising soil conditions, ground water conditions, water table location, and location of existing utilities and other obstacles.
4. *Excavation cost*: These costs are incurred during excavation and all procedures related to replacement of pipes.
5. *Traffic management*: These are costs incurred with use of equipment that require use of traffic control devices for the travel lanes of highways or streets.
6. *Product pipe cost*

Cost Estimate of Installing a Pipe with and without Encasement

Labor and machine costs associated with installation of a single pipe – whether for a carrier pipe or a casing pipe – are practically the same during construction (NCHRP 20-7, 248). For Auger Boring where line and grade are not critical, the cost is \$5-6 per inch of pipe diameter per foot of pipe, and where line and grade are critical the cost rises to \$6-9 per inch of pipe diameter per foot of pipe (costs based on year 2018 dollar values).

For a 300 ft pipe, the labor and machine costs for casing would be \$9,000 (=\$5×6×300) to \$16,200 (=\$9×6×300) to bore a 6-inch diameter pipe. Other cost estimates to insert a 6-inch steel pipe in the casing is shown in Table 21. With the cost of casing using an 8-inch steel pipe being \$130 per feet (Source: Galloup, Pipe and Tube, 2019), a 300 ft pipe casing material would cost \$39,000.

Table 21: Estimated costs to insert a 6-inch steel pipe in a casing (NCHRP 20-7 (248))

Description	QTY.	Unit Cost	Units	Total Project Cost
Material				
6-inch diameter Steel Pipe	300.00	$29.50	feet	$8,850
Casing Spacers	26.00	$206.50	Each	$5,369
Casing End Seals	2.00	$147.50	Each	$296
Vents	2.00	$59.00		$118
Filling	5.00	$236.00		$1,180
Miscellaneous items (taxes, freight, etc., 15%)				$2,360
Pipe Contractor Labor				
Contract Labor-Boring Crew -6" Carrier Installation (4 Man Crew Day Rate 8 hr Days-for 3 days)	96.00	$118	Hr.	$11,328
Install and Paint Vents	15.00	$118	Hr.	$1,770
Miscellaneous (inspection, etc.)				$2,478
Grand Total				**$33,748**

Thus, total costs for installation of a **300-ft length of a 6-inch pipe with an encasement** would be between **$81,748** (=$33,748 + $9,000 + $39,000) to **$88,948** (=$33,748 + $16,200 + $39,000).

The cost of installation of the same **300-ft length 6-inch pipe without casing** would be **$42,748** to **$49,948**. However, the cost of installation of a carrier pipe without casing might become higher due to higher material costs and a larger pipe wall thickness and additional coating protection needed for jacking it in the soil. A quantified estimate for the cost without casing is provided in Table 22. The cost is found to be in the range of **$127,076** (=$118,076+ $9,000) to **$134,276** (=$118,076+ $16,200).

Table 22: Estimated costs to high-quality 6-inch steel pipe without casing

(Note: costs do not include the jacking cost)

Description	QTY.	Unit Cost	Units	Total Project Cost
Material				
6-inch diameter Steel Pipe	300.00	$333.80*	feet	$100,140
Miscellaneous items (taxes, freight, etc., 15%)				$2,360
Pipe Contractor Labor				
Contract Labor-Boring Crew -6" Carrier Installation (4 Man Crew Day Rate 8 hr Days-for 3 days)	96.00	$118	Hr.	$11,328
Install and Paint Vents	15.00	$118	Hr.	$1,770
Miscellaneous (inspection, etc.)				$2,478
Grand Total				**$118,076**

* *6" Seamless Pipe Schedule 80s, Stainless Steel 316/316L ASTM A312 ASME SA312 suitable for gas transmission without encasing (Source: Pipingnow.com)*

Trenchless technologies have been preferred methods for utility pipe replacements, especially at crossings. Table 23 outlines the application of Pipe Eating, Pipe Bursting (Pneumatic, Rod Pulling, and Splitting) and Pipe Pulling methods for specific utility types. These utility types consist of : Natural gas pipelines greater than 6 inches in diameter, or with normal operating pressures greater than 60 psig, Petroleum Pipelines, Pressurized sanitary sewer pipelines High-voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60 kV and hazardous materials pipelines that are potentially harmful to workers or the public if damaged.

Table 23: Trenchless techniques for pipe replacement applicable for specific utility types

(Primary Source: *Manual for Controlling and Reducing the Frequency of Pavement Utility Cuts, FHWA, 2018*)

Method Description	*Natural gas pipelines greater than 6 inches in diameter, or with normal operating pressures greater than 60 psig*	*Petroleum Pipelines*	*Pressurized sanitary sewer pipelines*	*High-voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60 kV*	*Hazardous materials pipelines that are potentially harmful to workers or the public if damaged*
	(Pipe material type: Steel or Plastic pipes[1])	*(Pipe material type: Carbon steel pipes[2])*	*(Pipe material type: Ductile iron Pipe, Polyvinyl chloride (PVC), or High-Density Polyethylene (HDPE))[3]*	*(Pipe material type: Concrete covers[4])*	*(Pipe material type: Carbon steel pipes[2])*
Pipe Eating	NO	NO	YES	NO	NO
Pipe Bursting (Pneumatic, Rod Pulling, and Splitting)	YES	YES	YES (only Pneumatic)	YES	YES
Pipe Pulling (smaller diameter pipes)	NO	NO	NO	YES	NO

[1] 49 CFR Part 192; [2] 49 CFR §195.8; [3] Standards and Specifications, Sacramento Area Sewer District, 2013; [4] Undergrounding high voltage electricity transmission lines, National Grid, 2015.

6. ENCASEMENT REQUIREMENTS FOR SUBSURFACE UTILITY INSTALLATIONS

Encasement Dimensions

In this section, documentation is provided on findings on encasement dimensions and specifications for some key states for which the information was readily available through online web searches and reliable sources.

California dimensions for casing diameter, thickness and minimum depth of cover are found to be similar to other states that were included in this research.

Details for state-specific information on casing are provided through tabulated information in the next section.

Findings from Key States – Alabama, California, Iowa, Massachusetts, New Hampshire, Oregon and Texas.

States for which the information on encasement dimensions on were readily available using web searches have been compiled in Table 24. States show similarities in pipe dimensions and depth of cover requirement for underground pipe and encasement. The only exception is for encasement requirement in New Hampshire which has a lower minimum pipe wall thickness as compared to other states researched and documented in Table 24.

Table 24: Dimensions of welded steel encasement pipe

State	**Pipe Diameter (inches)**	**Minimum Pipe Wall Thickness (inches)**		**Minimum Depth of Cover (inches)***
Alabama	Less than 4	> 0.068 and < 0.237		30
	4 to 12	0.188		
	>12 to 24	0.250		
	>24	0.375		
California		Pipe length less than 150 ft	Pipe length over 150 ft	48
	6 to 28	0.250	0.250	
	30 to 38	0.375	0.500	
	40 to 60	0.500	0.750	
	62 to 72	0.750	0.750	
Iowa	6-14	0.188		48 inches (electrical cable) 36 inches (communication
	16	0.188		
	18	0.250		
	20	0.250		
	22	0.250		

	24	0.281	cables, freeway right-of-way) 30 inches (communication cable) 36 inches (underground facilities)
	26	0.281	
	28	0.312	
	30	0.312	
	32	0.312	
	34	0.312	
	36	0.344	
	38	0.344	
	40	0.344	
	42	0.344	
	44	0.344	
	46	0.344	
	48	0.344	
Massachusetts	12 to 28	0.250	24
	30 to 34	0.375	
	36 to 60	0.500	
New Hampshire	12 to 18	0.060	30 to 60
	24 to 30	0.075	
	36	0.105	
Oregon	4-18	0.250	30
	12-84	0.500	
	36-144	1.000	
Texas	4-24	0.250	24 to 48
	25-42	0.375	
	43-60	0.500	

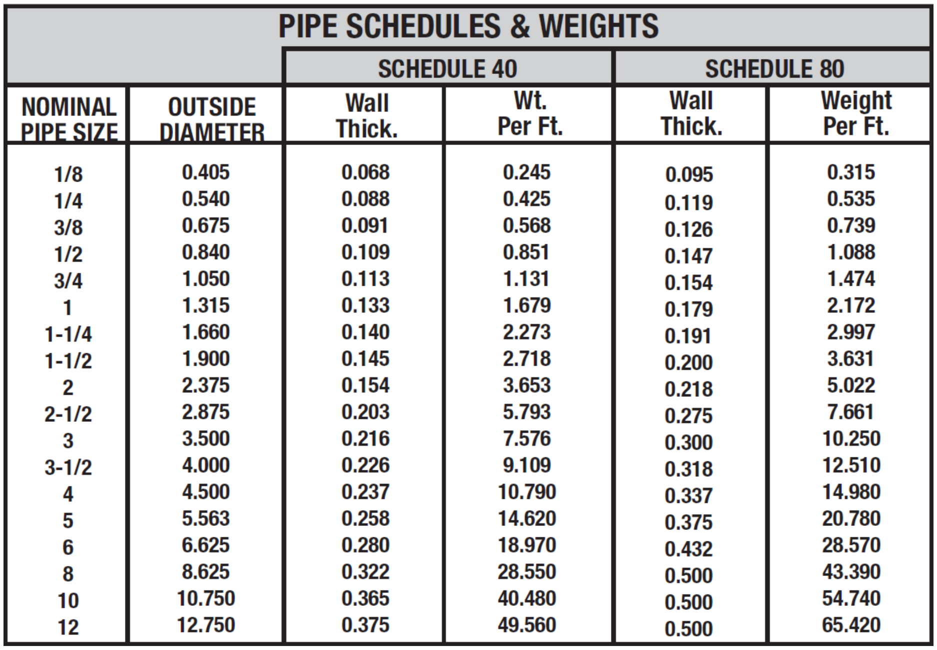
** Depth of cover are reported from several other states under Table 30*

For the states in Table 24, “49 CFR § 195.248 - Cover over buried pipeline” governs the federal requirement. Resources used for compiling findings from the states in Table 24 are as follows:

ALABAMA

1. From: STANDARD SPECIFICATIONS FOR HIGHWAY CONSTRUCTION, ALABAMA DEPARTMENT OF TRANSPORTATION, accessed on February 2, 2019 and ALDOT Utilities Manual.
2. Pipe schedules relate to thickness of the wall of the pipes (see Table 25 for reference). The units are in inches. Schedule 40 and 80 are standard pipe classification numbers that determine the diameter of a pipe.

Table 25: Pipe schedule reference (Metal Supermarkets, 2013)



PIPE SCHEDULES & WEIGHTS					
		SCHEDULE 40		SCHEDULE 80	
NOMINAL PIPE SIZE	OUTSIDE DIAMETER	Wall Thick.	Wt. Per Ft.	Wall Thick.	Weight Per Ft.
1/8	0.405	0.068	0.245	0.095	0.315
1/4	0.540	0.088	0.425	0.119	0.535
3/8	0.675	0.091	0.568	0.126	0.739
1/2	0.840	0.109	0.851	0.147	1.088
3/4	1.050	0.113	1.131	0.154	1.474
1	1.315	0.133	1.679	0.179	2.172
1-1/4	1.660	0.140	2.273	0.191	2.997
1-1/2	1.900	0.145	2.718	0.200	3.631
2	2.375	0.154	3.653	0.218	5.022
2-1/2	2.875	0.203	5.793	0.275	7.661
3	3.500	0.216	7.576	0.300	10.250
3-1/2	4.000	0.226	9.109	0.318	12.510
4	4.500	0.237	10.790	0.337	14.980
5	5.563	0.258	14.620	0.375	20.780
6	6.625	0.280	18.970	0.432	28.570
8	8.625	0.322	28.550	0.500	43.390
10	10.750	0.365	40.480	0.500	54.740
12	12.750	0.375	49.560	0.500	65.420

CALIFORNIA

1. Chapter 600 – Utility Permits (rev 6/2018), Encroachment Permits Manual, Caltrans, 2018.

IOWA

1. From Iowa DOT Office of Design, Casing Pipe 2009

MASSACHUSETTS

1. MassDOT Utility Accommodation Policy on State Highway Right of Way, May 2013.

NEW HAMPSHIRE

1. From 2006 NHDOT Standard Specifications, Section 603 – Culverts and Storm Drains. Depth of cover differs between 30” or 60” depending on use of pipe (high/medium/low pressure gas, water lines, sanitary sewer lines, etc.). As per New Hampshire DOT, High Pressure Gas and Liquid Petroleum Lines has pressure greater than 100 psi, and Medium and Low Pressure Gas Lines <100 psi.

OREGON

1. From Oregon Standard Specifications for Construction 2018. Uses corrugated metal pipes as minimum, smooth iron/steel pipe used for pressure pipe. Size follows ASTM A760 Type III

TEXAS

1. Chapter 21 – RIGHT OF WAY, Texas Department of Transportation, Texas Administrative Code, 2018.

VIRGINIA

1. 2018 Supplement to the 2016 VDOT Road and Bridge Specifications.

WASHINGTON

1. Utilities Manual, Washington State Department of Transportation, 2019.

Summary of State Dot Encasement Policy at Crossings

The following Table 26 presents a summary of findings on encasement provisions from various states.

Table 26: Summary of State DOT Encasement Policy at Crossings

(Source: Modified based on Draft NCHRP Project 20-07, Task 248)

State DOT	Encasement Requirement	Alternative Requirements of Uncased Carrier Pipe
Alabama DOT	- Uncased crossing are permitted as per the alternative requirements. - Utility may file a request to forgo encasement.	- Conform to the material and design requirements of appropriate utility and governmental codes, - Carrier pipe designed to support the load of the highway plus any superimposed loads,

		- Installation employs a higher factor of safety in the design, construction, and testing.
Arkansas State Highway & Transportation Department	- Utilities may be encased or uncased.	- Provide sufficient strength to withstand the internal design pressure and loads, - Greater depth of cover (minimum of 4 feet), - Increased wall thickness/higher strength steel, - Adequate coating and wrapping, - Radiograph testing of welds and hydrostatic testing, - Cathodic protection, - As per Title 49 CFR, Part 192, or Part 195.
Arizona DOT	- Does not include specific requirements with respect to encasement for gas and liquid pipelines.	- No alternative requirements for uncased pipes are listed.
California DOT	High priority utilities, pressurized liquid carrier facilities and all transverse crossings are required to be encased on both conventional and access-controlled right-of-way. Other details of the encasement requirement or exceptions are documented at the end of this table.	- The crossing is designed in accordance with Title 49, Part 192, and/or the California Public Utilities Commission, - Uncased gas carrier pipeline designed for a Class 3 Location, as per CFR - Title 49, Part 192, - The crossing is adequately identified by signs, - Provide as-built drawings.
Colorado DOT	- The utility shall utilize casing pipe for buried facilities when necessary.	- No alternative requirements for uncased pipes are listed.
Connecticut DOT	- Casing may be omitted as per owner and designer certification as per the alternative requirements shown in table.	- The highway is not a limited access highway, - Design is in accordance with all applicable Pipeline Safety Regulations, - The pipeline is cathodically protected, and the use of a

		casing could cause loss of that protection, - The pipeline is coated in accordance with accepted industry standards, - Installed at a depth that failure of the carrier pipe would not cause damage to the highway structure.
Florida DOT	- In limited access crossing, welded steel gas or liquid petroleum pipes may be installed without encasement.	- Pipelines conform with 49 CFR, Part 192 or 195, - Pipeline designed to withstand internal design pressures and the superimposed loads of the transportation facility.
Georgia DOT	- All facilities carrying hazardous materials or under pressure shall be cased. - Uncased crossings of welded steel pipelines transmitting gas or liquid petroleum may be permitted.	- Conform to 49 CFR, Part 192 or Part 195, as applicable.
Idaho DOT	- Casing shall not used where the utility company advises against it and when the utility company provides additional protective measures as listed in the table.	- Higher factor of safety in design, - Thicker wall pipe, - Radiograph testing of welds & Hydrostatic testing, - Adequate coating and wrapping, - Cathodic protection.
Illinois DOT	- Encasement may be eliminated under the requirements listed in the table. - In conventional highways, encasement not required for crossing of 60 psi or less,	- Extra heavy pipe is used, - Cathodic protection of the pipe is provided, - If encasement maintenance may not disturb the right-of-way.
Indiana DOT	- May be encased and non-encased.	- Only welded steel lines with adequate corrosion protection may be used for non-encased crossings, - Must provide sufficient strength to withstand loads.

Iowa DOT	- A natural gas or hazardous liquids pipeline at pressure greater than 60 psi shall be encased unless casing meets the listed requirements.	- It is welded steel & cathodically protected, - It is coated in accordance with standards, - It complies with federal, state and local requirements regarding wall thickness and operating stress levels.
Kansas DOT	- Lines carrying high pressure natural gas, liquid or other hazardous or corrosive products need not be cased if they meet the listed conditions.	- Welded steel and cathodically protected, - Coated in accordance with accepted standards, - Wall thickness is thick enough to meet requirements of the Federal Regulations, - Designed for operating stress levels in accordance with Federal Pipeline Safety Regulations.
Commonwealth of Kentucky Transportation Cabinet	Encasement required except when it is not feasible or special design is considered	- Cathodically protected carrier pipe, - Oversized pipe that is coated and wrapped with extra wall thickness, - Pipes of 2 inches or less when 30 inches below ground and designed according to specifications.
Louisiana DOT	- Utility company has a choice of cased or uncased crossing.	- 5-ft cover below the roadway and 3-ft below ditches or drainage structures. - Both highway and utility officials are satisfied that the lines are structurally and operationally safe in a case by case basis. - Protection, in the form of a concrete slab or other acceptable method in vulnerable locations - Markers must be installed - Repairs will not be allowed if it necessitates open cutting the roadway.

Main DOT	- Casing shall be used under bridge approach. Department determines casing requirement needs in a case-by-case basis.	- No specific requirements for uncased crossings are listed.
Maryland DOT	- Crossing either through sleeves or conduits or by the use of thicker wall.	- Uncased pipe wall thickness is increased to the next higher standard or for steel pipe have a design factor 20% lower than that required to obtain the higher yield strength.
Minnesota DOT	- The Commissioner will determine the need for casing of pressurized carrier pipes. - Crossings may be installed without a casing, normally in trenched construction.	Exceptions may be made where assurance can be provided against damage to the protective coating.
New York State DOT	- The carrier pipe shall be placed inside a casing pipe where trenchless installation impractical. The design of casing shall not diminish the desired level of cathodic protection. - Uncased carrier pipes are permitted if they conform to the listed requirements.	- Industry standards and applicable codes, - Designed to withstand all applied and/or superimposed, - Design shall include increased pipe wall thickness, adequate wrapping, coating or other treatment to protect against corrosion and telltale to indicate pipe corrosion, - Pipe design shall be site specific, based on field investigation.
North Carolina DOT	- In freeways, crossing permitted without encasement if installed prior to or during construction. - In other roads, without encasement in bored installations for pipe 6 inches or less.	- The utility shall demonstrate to the satisfaction of the Manager of Right-of Way or State Design Services Engineer that the installation method for an uncased crossing is such that the bored hole is never left unsupported.
Ohio DOT	Casing is required for pipes less than 16 inch if internal pressure is larger than 30% Specified Minimum Yield Strength (SMYS).	- Pipes larger than 16 inch must comply with CFR 192, - The department reserves the right to require casing or an alternative,

		- Casing required for any pipe size near MSE walls and foundations.
Oklahoma DOT	Crossing with or without casing according to provisions.	- Design according to standards, - Min depth of 48 inches of cover, - Place identification markers.
Tennessee DOT	Maybe installed without using an encasement pipe if conditions are satisfied.	- Wall thickness of carrier pipe, coating and wrapping, welds and cathodic protection shall be in accordance with Standards and codes - Where soil conditions permit the installation of the carrier pipe at a depth with minimum cover or greater without damage to its protective coating.
Texas DOT	- Where encasement is not employed, the utility shall show that the welded steel carrier pipe will provide sufficient strength. - Additional protective measures are as listed in the alternative requirements.	- Heavier wall thickness, higher Factor of Safety, - Adequate coating and wrapping, - Cathodic protection, - Use of Barlow's formula regarding allowable pressure, - Wall thickness according to 49 CFR 192.105.
Utah DOT	Use casing for all pipes carrying hazardous materials except as required by Federal regulations.	- Where Federal regulations including 49 CFR Part 192 require, UDOT will allow the use of heavy wall, extra strength pipe approved by UDOT Region Director or his authorized representative.
Virginia DOT	- Uncased crossings of welded steel pipelines pressure may be permitted.	- The applicant provides supporting data documenting that their proposed installation meets or exceeds all federal requirements,

		- The applicant provides supporting data documenting that the pipeline will support the anticipated load, - All un-encased pipeline crossings that fail must be relocated a minimum of 36 inches to either side of the failure. The failed line shall then be filled with grout and plugged at both ends.
Washington DOT	- Casing shall not be required for pipelines carrying natural gas. - Casing is required for pressurized carrier pipes, other than natural gas.	- Pipelines conveying natural gas which meet the design, installation and cathodic protection provisions of 49 CFR Part 192 and chapter 480-93WAC.
West Virginia DOT	- All pipelines crossing under paved State highways must be placed in a casing. - Casing will not be required if it meets alternative conditions.	- 1-1/4 inches or less diameter copper or steel pipe. - Plastic pipe, meeting requirements of ASTM, - Pipe, including but not limited to steel; cast iron; ductile iron; rigid plastic, and concrete, all in a thickness capable of sustaining live and dead load requirements of the Division of Highways. - Under unpaved roads unless otherwise directed by the District Engineer or his authorized representative.
Wyoming DOT	Cased or non-cased pipes. Casing is not required if it meets requirements.	- If the carrier pipe is of heavy wall thickness and line is cathodically protected, - Comply with most current provisions of Federal and State regulations, - Minimum depth of cover 120 inches for transmission

		lines and 36 inches for distribution lines or additional protection.

State Specific Encasement for High Priority Utilities

In this section, documentation is provided on findings of any encasement recommendations for utilities (whether high-priority or other utility types). The findings have been compared with California with some key states in Table 27. The requirements for encasement for utilities in California has been found to be similar with the encasement requirements for other key-states in the nation. The key states are those for which encasement information was readily available from reliable public agency websites (such as state-specific department of transportation (DOT) websites).

Table 27: Encasement for utilities (findings from some key-states)

State Name	*Encasement Required for High Priority Utility Types?*	*Comments*
Alabama	Yes	**Alabama:** Encasement is required for all utilities unless exempt from the manual or obtains approval to forego it. Uncased carrier pipes at crossings without encasements should have a higher factor of safety in the design, construction, and testing of the uncased carrier pipe.
California	Yes	In accordance with Caltrans's Project Development Procedures Manual, all new high priority utilities (See section 603.1, Encroachment Permits Manual) and pressurized fluid carrier facilities are required to be encased within both conventional and access-controlled right-of-way for both longitudinal and transverse installations. However, exceptions for encasement are allowed as per (i) "Exception to Policy - Uncased High-pressure Natural Gas Pipelines" (see Appendix H)" – states that the carrier pipeline is designed as per 49 CFR 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, (ii) minimum depth of cover is 7 ft 6 inches, and at no time the minimum depth of cover is less than 42 inches, (iii) reinforced

		concrete structure is provided under the pavement to protect the pipe, (iv) uncased carrier pipeline, as a minimum, be designed for Class 3 Location (as per 49 CFR 192), (v) existence of the crossing is adequately identified by signing at the right-of-way line, and (vi) pipeline owner provides a certified letter that the pipeline was installed properly and in accordance with the permit plans.
Iowa	Yes	**Iowa:** Encasement is required unless it meets specific requirements: (1) welded steel pipeline, (2) cathodically protected, (3) coated in accordance with accepted industry standards, (4) complies with federal, state and local requirements and meets accepted industry standards regarding wall thickness and operating stress levels.
Massachusetts	Yes	**Massachusetts:** Encasement is not required unless using jacked/boring installations or has less than minimum cover.
New Hampshire	Yes	**New Hampshire:** Encasement is required when installed by jacking or boring pits.
Oregon	Yes	**Oregon:** Does not state whether encasement is required but has standards when encasement is utilized.
Texas	Yes	**Texas:** Encasement shall be utilized for interest of safety and protection of the utility and highway, and access to the utility. At each end of the casing, it shall be opened or vented to prevent possible buildup of pressure and to detect leakages. Requests for exceptions are considered only where the utility shows that extreme hardship or unusual conditions provide justification.

Virginia	Yes	**Virginia:** Encasement is required if a utility has less than minimal cover, near footings or bridges, utilities or other highway structures, crosses unstable ground, or is near other locations where hazardous conditions may exist. Minimum depth is 36 inches.

Encasement Requirement for Key States

In this section, documentation is provided on findings on highway facilities that might not require encasement or encasement requirement could be waived for any utility types – under freeways, conventional roads or other facilities such as ramps, tunnels etc. The findings have been compared with California with some key states in Table 28. Key states are those for which the findings were readily available from reliable public agency websites (such as state-specific DOTs) and identified using web searches. When compared to policies in other key states, California has more rigorous encasement requirement under freeways and conventional roads. For other facilities such as ramps and tunnels, encasement is required with access control for California. However, there was not many key states that have a defined policy on encasement for ramps and tunnels.

Table 28: Encasement 'required' (R), 'waived' (W), 'not recommended' (NR) or 'not available' (NA) for various highway facilities. (here table entries are shown for example purposes only from one of many literatures that team reviewed)

State	*Freeway/ Expressway*	*Conventional*	*Other facilities with/without access control (such as ramps, tunnels, park-n-ride etc.)*	*Additional Information*
Alabama	***R***	***NA***	***W***	Installations at bridges and tunnels are rare and will be handled on an individual basis as a special case.
California	***R***	***R***	***R (with access control)***	In accordance with Caltrans's Project Development Procedures Manual, all new high priority utilities (See section 603.1, Encroachment Permits Manual) and pressurized fluid carrier facilities are required to be encased within both conventional and access-controlled right-of-way for both longitudinal and transverse installations.

Iowa	***R***	***NA***	***NR***	Encasement is required unless it meets specific requirements: (1) welded steel pipeline, (2) cathodically protected, (3) coated in accordance with accepted industry standards, (4) complies with federal, state and local requirements and meets accepted industry standards regarding wall thickness and operating stress levels. For prohibitions on longitudinal occupancy, no utility facility is allowed in or on a structure carrying a freeway roadway or ramp, except for freeway border brides.
Massachusetts	***R***	***NA***	***NA***	Additional details could not be found using web searches
Missouri	***R***	***R***	***NA***	Encasement is required for all underground utility crossings under the roadways
New Hampshire	***R***	***NA***	***R***	Encasement is mandatory for bridge approaches, freeways, interchange ramps, and railroad crossings.
Oregon	***W***	***NA***	***NR***	Encasement is only allowed between the freeway access control line and the freeway right-of-way lines.
Texas	***R/W***	***NA***	***NA***	Encasement may be waived if the line is of welded steel construction and is protected from corrosion by cathodic protective measures or cold tar epoxy wrapping, and the utility

				signs a written agreement that the pavement will not be cut for pipeline repairs at any time in the future.
Virginia	***R***	***NA***	***NA***	Encasement is required if a utility has less than minimal cover, near footings or bridges, utilities or other highway structures, crosses unstable ground, or is near other locations where hazardous conditions may exist. Minimum depth is 36 inches.

Encasement for Longitudinal Installations

In this section, documentation is provided on findings if encasements are required for longitudinal installation of utility lines. The findings indicate that most states do not have requirements for encasement of longitudinal installations, except for few. These few states provide basic information on encasement but not exclusively for longitudinal installations. The findings from these states is provided below in Table 29:

Table 29: Longitudinal encasement for various highway facilities.

State	*High Priority Utility Types or Other Utility Types*	*Additional Information*
Alabama	***Required*** (only if pipelines have potential to become vulnerable)	Suitable bridging, concrete slabs or other appropriate measures to be used to protect existing uncased pipelines in their location make them vulnerable to damage from highway construction or maintenance operations. For underground electric power and communication lines, encasement is required for less than minimum prescribed depth of cover (24”), if the cable facilities is near the footings of bridges or other highway structures or where there may be hazard. No other specific information was found for encasement requirement for other utility specific longitudinal installations.
California	***General Information***	Caltrans adopted the American Association of State Highway and Transportation Officials (AASHTO) October 2005 documents: A Policy on the Accommodation of Utilities Within Freeway Right-of-Way, and A Guide for Accommodating Utilities Within Highway Right-of-Way. Consideration should be given to encasement or other suitable protection for any pipeline (a) with less than minimum cover, (b) near footings of bridges or other highway structures or across unstable or subsiding ground, (c) near other locations where hazardous conditions may

		exist, or (d) on a structure that crosses an environmentally sensitive waterway or other natural area.
New Hampshire	***General Guidance***	General guidance was provided on encasement – such as encasements are to be avoided (if possible) for installations of pipelines that are close to footings of bridges and retaining walls, at cross drains where flow of water, drift or stream bed flow may be obstructed; in a wet or rocky terrain. However, no specific information was provided on encasement for utility specific longitudinal installations.
Washington	***Not Required***	For any utility type, encasements requirements typically do not apply to longitudinal installations.

Utility Steel Encasement Pipe Standards for Key States

In this section, documentation is provided on findings related to encasement material specifications, soil and types in which encasements might vary, minimum depths of cover, and any installation method required. It was found that only few states specify ASTM, AWWA requirements. States that do have requirements of steel encasement require ASTM A139 or ASTM A53. California's encasement of utilities is adopted from AASHTO 2005 –A Guide for Accommodating Utilities Within Highway Right-of-Way. The guide allows the use of concrete encasement (or as a means for mechanical protection) of utility pipelines. Other findings under this section is documented in Table 30.

Table 30: Compilation of utility encasement pipe characteristics and soil types with recommended depths

State Name	*List of Encasement Pipe Material Types* *(steel, concrete etc. with ASTM, AWWA, AASHTO details)*	*Soil Types and Conditions*	*Minimum Recommended Depths* *(in inches)*	*Suitable Installation Method(s)*
Alabama	Steel ASTM A53, Grade B; ASTM A252, Grade 2)	Information not available	30”	Trenchless installations recommended and as per 49 CFR 192
Arizona	A thick 6 ft concrete slab to be provided on each side of the pipeline trench. No specific reference made to ASTM, AWWA etc.	Information not available	60” (high pressure gas or volatile fluids) 48” (low pressure gas or volatile fluids)	Dry boring method (no water use)
Arkansas	Casing to be composed of	Information not available	36”	Dry boring method (no water use)

	satisfactory durability No specific reference made to ASTM, AWWA etc.			
California	No specific reference made to ASTM, AWWA etc.	Information not available	42”	Jacking and boring (49 CFR 192 and CPUC General Orders No. 112-F: Design, construction, testing, maintenance and operation of utility gas gathering, transmission and distribution piping systems)
Colorado	A concrete cap minimum 4 inches in thickness. Concrete encasement minimum 2 inches on all sides Encasement in 0.25 inch wall thickness steel conduit	Information not available	No specific mention of minimum depth of cover	Trenchless installations recommended

	No specific reference made to ASTM, AWWA etc.			
Connecticut	Material should be of satisfactory durability. No specific reference made to ASTM, AWWA etc.	Information not available	36”	No specific mention of installation method
Florida	All casing pipe materials to comply with industry standard No specific reference made to ASTM, AWWA etc.	Information not available	No specific mention of minimum depth of cover	No specific mention of installation method
Georgia	Encasement pipe to have the strength equal to or exceeding the carrier pipe. No specific reference made to ASTM, AWWA etc.	Information not available	120” (under pavement surface of interstate and limited access roads) 48” (under pavement surface of all other highways) 36” (under other surface)	No specific mention of installation method

Idaho	Material should be of satisfactory durability. No specific reference made to ASTM, AWWA etc.	Information not available	60” (for interstate) 48 (other locations within 20 ft of edge of roadway) 36 (other highways and roads)	Jacking and boring
Illinois	No specific reference made to ASTM, AWWA etc.	Information not available	30 “	Jacking and boring
Indiana	Material should be of satisfactory durability. No specific reference made to ASTM, AWWA etc.	Information not available	29.5” (59 inches for high pressure gas and liquid petroleum lines, encased)	No specific mention of installation method

Iowa	No specific reference made to ASTM, AWWA etc.	Information not available	48” (electrical cable) 36(communication cables, freeway right-of-way) 30” (communication cable) 36” (underground facilities)	No specific mention of installation method
Kansas	No specific reference made to ASTM, AWWA etc.	Information not available	No specific mention of minimum depth of cover	Jacking and boring (dry boring, use of water not permitted)
Kentucky	Concrete, steel, or iron pipe. No specific reference made to ASTM, AWWA etc.	Information not available	30” (under roadways) 18” (other locations)	No specific mention of installation method
Louisiana	No specific reference made to ASTM, AWWA etc.	Information not available	60” (roadway) 36” (below ditches or drainage)	No specific mention of installation method
New York	Casing pipe shall be the same as for carrier pipe.	Information not available	No specific information available on	Trenchless installation

	Steel pipe: ASTM A-139, Grade B or equal, 35,000 minimum yield strength Reinforced concrete pipe: ASTM C-76		minimum depth of cover	(jacking and boring)
North Carolina	Encasement pipe shall be equal or greater strength as required by the Department on highway drainage pipe. No specific reference made to ASTM, AWWA etc.	Information not available	No specific information available on minimum depth of cover	No specific mention of installation method
Ohio	Any material permitted by the ODOT No specific reference made to ASTM, AWWA etc.	Information not available	48” (under pavement surfaces, water lines) 36” (under pavement surfaces, other facilities)	No specific mention of installation method
Oklahoma	No specific reference made	Information not available	48”	Jacking and boring

	to ASTM, AWWA etc.			
Oregon	No specific reference made to ASTM, AWWA etc.	Information not available	30”	Jacking and boring
Tennessee	No specific reference made to ASTM, AWWA etc.	Information not available	30” (under highway, cased) 36” (under highway, uncased)	Jacking and boring
Texas	Steel encasement (low and high pressure gas lines) Steel casing pipe should have a minimum yield strength of 35,000 psi. Steel casing should meet ASTM A-36, ASTM A-568, ASTM A-135, ASTM A-139, or other approved equal.	Information not available	18” (under pavement, low pressure lines) 24” (outside pavement, low pressure lines) 30” (uncased, outside pavement, low pressure lines) 36” (longitudinal installations, low pressure lines) 18” or one-half diameter of the pipe (encased, under pavement structures for	No specific mention of installation method

			high- pressure lines) 30” (encased, line outside pavement structure) 36” (uncased sections of pipelines, high-pressure lines, outside pavement structures) 60” (uncased, under pavement surface, high-pressure lines) 48” (uncased, outside pavement, high-pressure lines) 48” (longitudinal placement)	
Virginia	Steel encasement shall conform to ASTM A139 or ASTM A53	Information not available	36”	No specific mention of installation method
Wyoming	Complies with federal and state laws.	Information not available	120” (uncased, gas transmission line, below	No specific mention of

	No specific reference made to ASTM, AWWA etc.		pavement surface) 36” (uncased, gas gathering and distribution lines) 48” (uncase, liquified petroleum gas lines)	installation method

Encasement Material and Design for High Priority Utility Product Type

In this section, documentation is provided on findings related to encasement design specifications for various product types such as encasement material, design size, yield strength, size and joint connection, and end treatment. The focus has been on high-priority utility (such as high-pressure natural gas) since the information on end treatment were not found from authentic sources for other utility types.

An itemized summary of these findings are as follows (Sources used: Draft NCHRP Project 20 – 07, 248; 49 CFR § 192.187 - Vaults: Sealing, venting, and ventilation; NACE, Standard Recommended Practice, Steel-Cased Pipeline Practice, NACE Standard RP0200-2000):

- If there is a possibility of water entering the casing, the ends must be sealed.
- If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of the Specified Minimum Yield Strength (SMYS).
- If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.
- Some states such as Connecticut, Iowa, Indiana and Maine require all sealed casings to be vented.
- The casing vents should be capped with devices that control and significantly limit the exchange of air inside the casing system.

- The end seal is a dielectric material and assists in preventing water and soil ingress.

- The selection of the appropriate end seal depends on the position of the carrier at the end of the casing. Most watertight seals, such as modular mechanical seals, require that the carrier pipe be positioned in the center of the casing, whereas most rubber boots allow for some amount of off-centered positioning.

- End seal should be compatible with casing fill material.

- Air communication test should be conducted in accordance with manufacture recommendations to ensure positive air flow between the fill and discharge vents prior to filling.

- Other details specific to California for high-priority utility lines is outlined in Table 31.

Table 31: California encasement-specific details on end treatment

Utility Type	*Encasement Material (steel, concrete etc.)*	*Design Size* *(ASTM, AWS*, AASHTO, standards etc.)*	*Yield Strength (in psi)*	*Size and Joint Connection* *(outside diameter, wall thickness etc.)*	*End Treatment (such as seal wrap around, seamless, brick and cement etc.)*
High Priority Utility Product Type (such as pressurized natural gas pipelines)	**Steel** (Source: Caltrans - Encroachment Permit Manual) **Reinforced Concrete Pipe** (RCP) in compliance of State Standard Specifications is an acceptable carrier for	A sleeve should have an inside diameter that is 4 inches larger than the outside diameter of the carrier pipe. The minimum wall thickness required for steel encasements is based on lengths and	N/A	Pipe joints must be watertight under pressure and foreseeable conditions of expansion, contraction, and settlement. Recommended joint sealants include rubber, neoprene, and similar synthetic	Encasement ends must be plugged with un-grouted bricks or other suitable material approved by the DOT representative (Caltrans). Casing pipe should be sealed at the ends with an approved flexible material to prevent flowing water and debris

	storm drain gravity flow or non-pressure flow. RCP when installed by Bore & Jack shall have rubber gaskets at the joints, and holes for the grouting of voids left by jacking operations. **High Density Polyethylene** (HDPE) is acceptable when the method of Horizontal Directional Drilling is used to install the encasement	diameters of pipes 200 mm (8 in.) in diameter and larger, the diameter of the casing should be a minimum of 100 mm (4 in.) larger than that of the carrier pipe. For pipelines smaller than 200 mm (8 in.) in diameter, the diameter of the casing is normally a minimum of 50 mm (2 in.) larger than that of the carrier pipe		products. Mortar, grout, or other portland cement materials are not allowed as joint sealants.	from entering the annular space between the casing and the carrier. Vent pipes should be installed at both ends of a casing, one on top of the casing at the high elevation end and one on the bottom of the casing at the low elevation end. The casing vent hole should be at least one-half the diameter of the vent pipe (25 mm or 1 in. minimum). The casing vent pipe should be minimum of 50 mm or 2 in. in diameter

Encasement Installation Methods

In this section, documentation is provided on findings related to specifications for encasement installation methods. Jack and bore has been widely used for casing installation. The information on the bedding material, material grading and lining and coating for suitable installation methods of casing is compiled in Table 32.

Table 32: Information on casing installation using jack and bore method

Installation Method	*Bedding Material* *(ASTM, AASHTO Class I, II or III)*	*Material Grading (recommendations by AASHTO)*	*Linings and Coatings for Jack and Bore* *(Recommendations by AWWA, AASHTO, ASTM, NACE)*
Jack and Bore	For Gas Pipe Sand Bedding or Electric Conduit Sand Bedding: Material should be free of rock, ice, clay, organic matter or other objectionable material. The material should conform to the following standards. ASTM C136: Standard Test Method for Sieve Analysis of Fine and Coarse Aggregates Sand Equivalent per ASTM D2419 - Standard Test Method for Sand Equivalent Value of Soils and Fine Aggregate: 25 minimum Plasticity Index per ASTM D4318 - Standard Test Methods for Liquid Limit,	AASHTO Section 30 limits the maximum particle size for bedding material to 1.25 in. However, this is for high density pipe material.	Steel casing sections are connected by welding and the weld should conform to American Water Works Association (AWWA) C206 - Field Welding of Steel Water Pipe. Steel pipe casing should conform to the requirements of ASTM A283 - Standard Specification for Low and Intermediate Tensile Strength Carbon Steel Plates, Grade B, C, or D. All joints are welded. All welding is performed in accordance with AWWA C206 - Field

	Plastic Limit, and Plasticity Index of Soils: Non-plastic Moisture - Density per ASTM D1557 - Standard Test Methods for Laboratory Compaction Characteristics of Soil Using Modified Effort: Maximum +2% of optimum, Minimum - 5% of optimum Any gas pipe sand bedding material retained on a #4 sieve, shall not contain angular material as described in ASTM D2488 - Standard Practice for Description and Identification of Soils.		Welding of Steel Water Pipe. Coating for steel casing in generally not required. A recommended type of coating for steel pipes is mill applied Fusion Bonded Epoxy.

Encasement alternatives, Underground Storage Tank and Leakage Monitoring

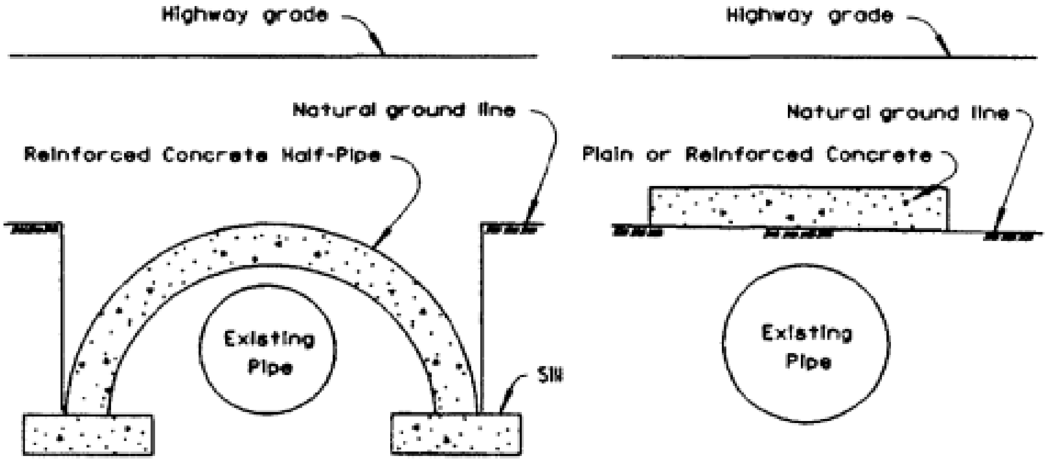
In this section, documentation is provided on findings related to alternatives to encasement and other related research questions which are as follows:

1. **Are there alternatives to encasement that provide the same level or better protection from dig-in accidents?**

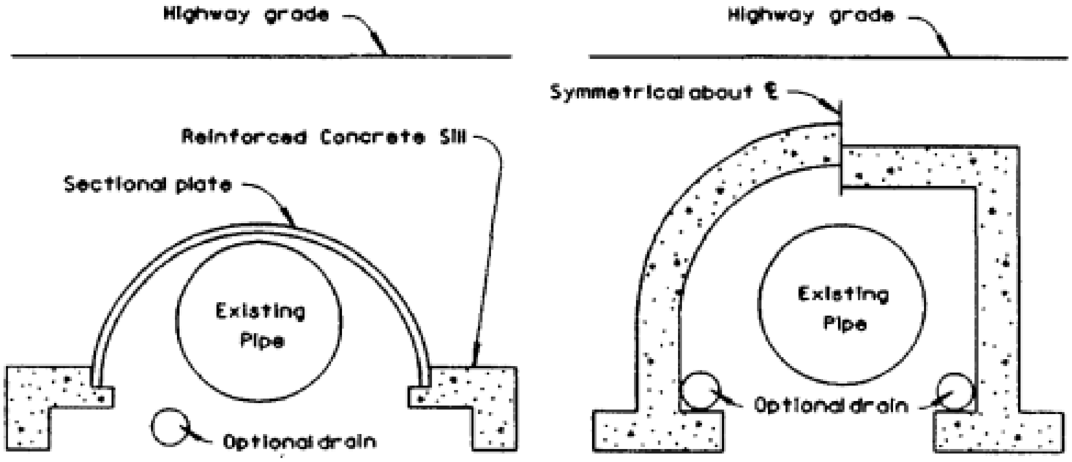
   There are three possible ways in which protection against dig-in/excavation accidents can be provided:

   a. *Subsurface Utility Engineering (SUE), Quality Level (QL) –D*: QL-D can be provided as a forewarning in case a pipeline is encountered during excavation. This information should be provided as the alternative through some sort of sign in case pipeline information wasn't obtained beforehand. However, this QL –D info should lead to a higher QL for accurate information regarding existing utility design.

   b. *Concrete Slabs*: The guidance is provided in *AASHTO 2005 - A Guide for Accommodating Utilities Within Highway Right-of-Way*. Designs for concrete slabs depend on location/project. but there are also places that manufacture the slabs as well (often referred to as utility and pipe protection slabs, see Fig. 1).



(a) HALF PIPE PROTECTION (b) FLOATING SLAB PROTECTION



(c) PLATE ARCH PROTECTION (d) MONOLITHIC ARCH OR BOX

Figure 32: Examples of protection of existing utility lines under a highway (Source: AASHTO 2005)

c. *Pipeline Markers*: Pipeline markers are used above ground along the ROW where the pipeline intersects a highway/street/railway/etc. The markers not only give warning to the existing pipeline but also identify the product transported in the line, the name of the pipeline operator, and a contact number.

2. **Since one of our goals is secondary containment (like a double walled fuel tank), do we need to include leak detection? What type of leak detection? Do we need to require this system in state right of way? How is it monitored? By who? Frequency? Are relief valves required? How often, spacing, height, size?**

Underground Storage Tank

a. For context, double walled fuel tanks are tanks that have an inner and outer wall with spacing in between. This spacing may also be used as secondary containment depending on the material used for the outer wall. These underground storage tanks (USTs) typically have leak detection systems.
b. Leak detection is needed if piping is “within 1,000 feet of any existing community water system or potable drinking water” (Source: Secondary Containment for Underground Storage Tank Systems - 2005 Energy Policy Act). With the leak detections, line leak detection may be included (this is for connected underground piping to the UST).
c. California UST Regulations from the California Water Boards**:** In Article 4, Section 2643 (p49), California uses the automatic tank gauge, statistical inventory reconciliation plus tank integrity testing, and continuous in-tank leak detection. Other methods may be used if they are checked and in compliance with the State Water Board. All UST facilities are inspected annually.

A summary of leak detection techniques for UST is compiled in Table 33.

Table 33: Leak detection types, right-of-way and other leak monitoring part details

	Leak Detection Type (such as interstitial monitoring, automatic tank gauging systems, vapor monitoring etc.)	*Right-of-way needed (Yes/No)*	*Personnel Designated for Monitoring*	*Frequency of Monitor**	*Relief Valve Details (spacing, height, size)*
1	Interstitial monitoring	No	UST Operator	Periodically/ Continuously	General details have been provided separately However, no information was
2	Automatic tank gauging system	No	UST Operator	Periodically/ Continuously	
3	Vapor monitoring	Yes	UST Operator	Monthly/ Every 14 days	

4	Groundwater monitoring	Yes	UST Operator	Monthly/ Every 14 days	found available to report through online web searches on specific details such as spacing, height or size of the relief valves for UST)
5	Statistical inventory reconciliation	No	UST Operator	Monthly	
6	Manual tank gauging	No	UST Operator	Monthly	
7	Continuous in-tank leak detection	No	UST Operator	Continuously	

**Note: All data are compiled and tested monthly to ensure operability and serviceability*.

Relief Valve**:** A pressure relief valve is characterized by gradual opening or closing generally proportional to the increase or decrease in pressure. Relevant codes and standards are provided by the American Petroleum Institute (API) are on the functioning and selection of these valves. These specific codes are as follows:

1. ANSI/API Recommended Practice 520 Part I, Sizing and Selection. This API design manual is widely used for sizing of relief valves on both liquid and gas filled vessels: (a) liquid vessels - paragraphs 5 and 6, and (b) gas filled vessels - Appendix D-3. This RP covers only vessels above 15 psig. Each relief valve has its own design issues and special considerations.

2. API Standard 527: specifies methods for determining the seat tightness of metal- and soft-seated pressure relief valves and defines the maximum acceptable leakage rates with metal-seated valves or soft-seated valves for nominal pipe sizes.

Other findings

- The pressure-relief device should normally be placed close to the protected equipment so that the inlet pressure losses to the device are within the allowable limits. (API Recommended Practice 520)

- If a series of valves are present, small orifice valve is recommended to be placed at lower set pressure and installed upstream of the other valves (Safety and Relief Valves, Leslie Controls, LLC.).

- The pressure-relief valve should not exceed 3 percent of the set pressure of the valve. (API Recommended Practice 520)

- Pressure-relief valves should be mounted in a vertical upright position

Interstitial Monitoring: There are liquid sensors installed in the space between the inner and outer wall of a UST system. This detection is best used in heavy rainfall areas.

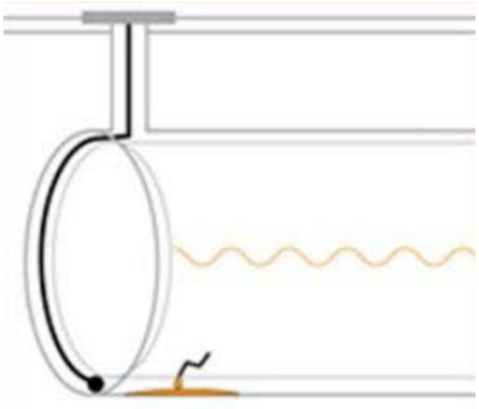


Figure 33: Secondary containment with interstitial monitoring

(Source: U.S. Environmental Protection Agency's Office of Underground Storage Tanks:)

Automatic tank gauging system (ATG) This monitors the temperature and level of fuel in the UST. It is installed inside the tank and wired to a monitor.

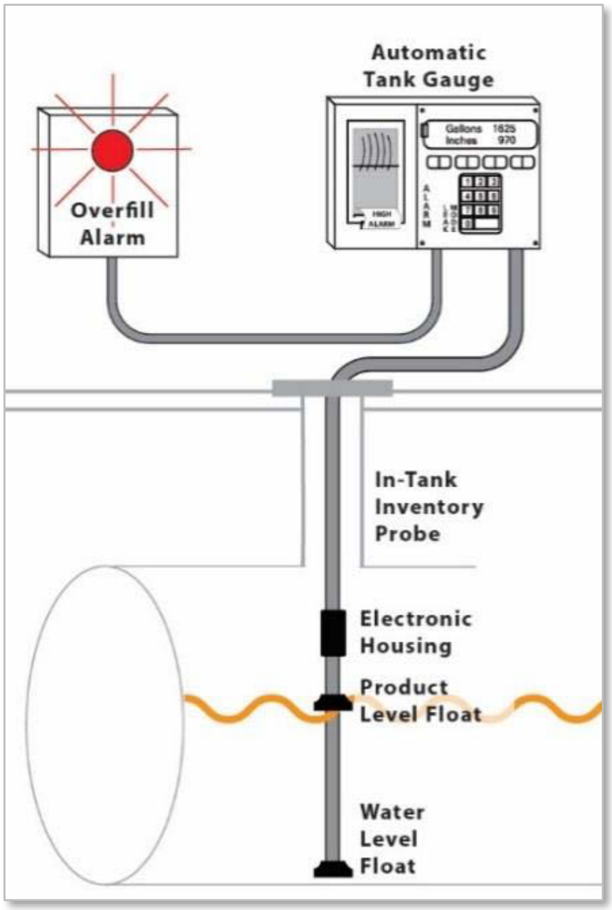


Figure 34: Automatic tank gauging system

(Source: U.S. Environmental Protection Agency's Office of Underground Storage Tanks[2])

Vapor monitoring: The vapor monitoring measures either the product fumes in the soil around the UST or special tracer chemicals added to the UST, which escape in order to check for a leak. This also has monitoring wells.

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[2] https://www.epa.gov/sites/production/files/2016-05/documents/stot_5-2-16_final_508.pdf

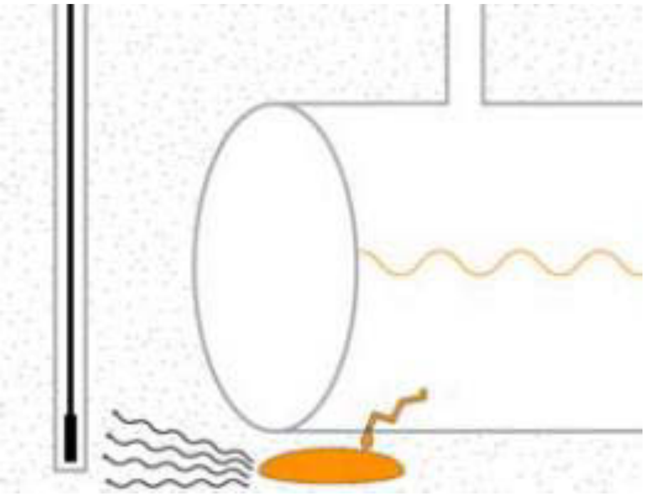

Figure 35: Vapor monitoring

(Source: U.S. Environmental Protection Agency's Office of Underground Storage Tanks)

Groundwater monitoring: The groundwater monitoring senses the presence of liquid product floating on the groundwater and requires groundwater monitoring wells installed near the tanks along the piping. This method cannot be used where the water table is more than 20 feet below the surface.

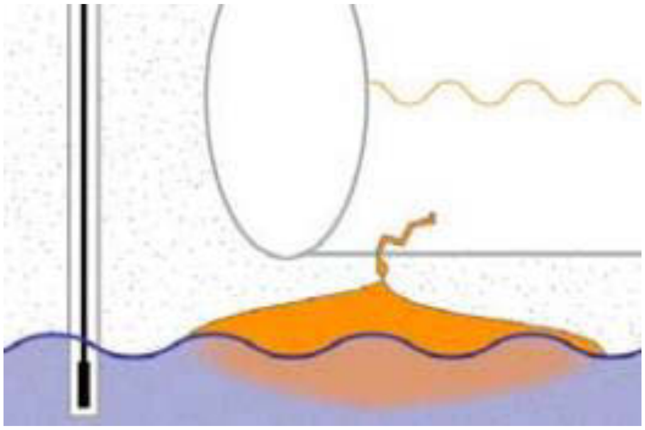

Figure 36: Groundwater monitoring

(Source: U.S. Environmental Protection Agency's Office of Underground Storage Tanks)

Statistical inventory reconciliation (SIR): The SIR uses computer software to analyze any inconsistencies in the data to indicate a leak.

Manual tank gauging: The manual tank gauging requires the UST to be out of service for 36 hours to measure the start and end readings to see if any changes occur.

Table 34: Test standards for manual tank gauging

(Source: U.S. Environmental Protection Agency's Office of Underground Storage Tanks)

Tank Size	Minimum Duration of Test	Weekly Standard (1 test)	Monthly Standard (4-test average)
Up to 550 gallons	36 hours	10 gallons	5 gallons
551-1,000 gallons **(when tank diameter is 64")**	44 hours	9 gallons	4 gallons
551-1,000 gallons **(when tank diameter is 48")**	58 hours	12 gallons	6 gallons
551-1,000 gallons **(also requires periodic tank tightness testing)**	36 hours	13 gallons	7 gallons
1,001-2,000 gallons **(also requires periodic tank tightness testing)**	36 hours	26 gallons	13 gallons

Continuous in-tank leak detection (CITLD): The CITLD encompasses all statistically based methods where the system will gather measurements uninterrupted. Continuous ATG and SIR fall under this category.

7. CONCLUDING REMARKS

Casing is normally provided for pipes at crossings (roadway, railroad, or water) to avert any accidents due to excavation damages and to support surface loads due to traffic. An analysis of a ‘cased’ versus an ‘uncased’ gas transmission pipeline leakage from 2010 to 2018 across the United States showed that majority of the leaks were due to excavation damage to pipes that were uncased, and these damages were done outside the highway right of way. In some situations, leakages resulted from the damage to the pipe that was done originally during their installation process and was not noticed before encasing. Excavation accidents with pipes also occurred due to lack of information of an existing pipeline or not using one-call request before the excavation activity. Based on the observation from the available data, having an encased pipeline would have prevented damage to pipelines or reduced severity of the incidents during excavation accidents.

Several studies show that the path taken by the natural gas to migrate to the soil surface after leakage is complex – especially, if the soil has a high clay texture content. In California, several pipeline leakages have been noted in the past from regions where clay is a predominant soil type. External corrosion has also been widely reported to be the cause of these pipeline leakages in California – often during installation of the pipe. Current technologies exist that can detect underground leakages, however, detection of source of these leakages through a ruptured point on a pipe is often difficult and involves digging, removal of the encasement and sometimes even complete abandoning of the leaking pipe. This is usually done to expedite the replacement of the pipe, restore gas transportation, and save costs. There was an leakage incident reported in Texas by an operator in which a leaking pipe was completely abandoned due to difficulty in accessing buried pipe underneath a pavement.

Trenchless technologies such as pipe bursting has been one of the preferred methods for utility pipe replacements at roadway crossings. Trenchless technologies, in general, are commonly used for replacing natural gas pipelines greater than 6 inches in diameter, pipelines with operating pressures greater than 60 psig, petroleum pipelines, pressurized sanitary sewer pipelines, high-voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60 kV and hazardous materials pipelines that are potentially harmful to workers or the public if damaged.

With the goal to avoid accidents with utility lines during excavation or construction activities in the highway right-of-way, many states such as Alaska, Utah and Virginia use procedures right in the beginning of any construction activity to identify and resolve utility conflicts. A recent pilot exercise was carried out for the dentification of utility conflicts and solutions under the SHRP 2 R15B Products at the Maryland State Highway Administration (SHRP 2 R15B, 2015). This was being achieved by using a much accurate and complete information about utilities that might conflict with the alignment of the project. One of the most popular tools explored under the pilot program was the use of a utility conflict matrix (UTM) which enables users to organize, track, and manage the conflicts.

Federal Highway Administration (FHWA) encourages implementation of strategies at various stages of the development of a highway project to avoid utility relocations (Avoiding Utility Relocations, FHWA 2019). These consist of the following:

I. Planning Strategies (such as forming Utility Coordinating Councils, One-Call Notification, detailed utility information using Subsurface Utility Engineering (SUE), utility agreements, electronic document delivery, cost sharing, joint project agreements, context sensitive design, locate next to ROW line, joint trenching / utility corridors, utility tunnels, use of subways for dry lines, and removal of abandoned lines)
II. Design Strategies and Alternatives (SUE - Quality of Level B)
III. Geometric and Alignment Changes - Geometric and alignment changes for roadway can be done at the planning stage or very early in the design stage
IV. Drainage Changes as per the geometry of the roadway
V. Structural Changes, and
VI. Slopes / Retaining Walls / Barriers

Future research could investigate the success of one or more of the above listed strategies adopted by various State DOTs across the nation. Particularly, identifying those strategies that are cost effective, accepted as state-of-the-practice by utility operators and could eventually reduce accidents associated with pipelines in the state highway right-of-way in California.

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APPENDIX

Incident Summaries

The incident narratives have been compiled based on year 2010-2018 gas transmission pipeline incidents data obtained from the Pipeline and Hazardous Materials Safety Administration (PHMSA)3. The incident summaries are arranged in chronological order.

1. INCIDENT #1

Incident Year	2010
Location (State)	Georgia
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	On September 21, 2010, a Grady county public works motor grader damaged southern natural gas company's 6” south Grady pipeline causing a gas release at 811 psig. The location was at a dirt road, Hopkins Road, in Grady county, GA. The motor grader operator was injured on his right side due to debris from the gas release. He was treated at the Grady county hospital and released within 4 hours. No fire occurred. 911 emergency responders included the Grady county ema and the Calvary volunteer fire department who secured the area. 9.628 miles of pipeline was isolated and depressurized. Evaluation of the damage to the pipeline revealed a 6” x 2” cut into the pipe. A 2” section of pipe was replaced, and the line was returned to service at 7:00 p.m. EDT the same day. The motor grader operator did not contact the one call center prior to the grading activity. The pipeline was marked with 49 CFR 192 markers on both sides of the dirt road. The operator was pulling the ditches on the north side of the road, which is the only side of the road that the county maintains in this area. The grader operator stated that he lifted his blade and thought he was past the pipeline when he lowered his blade. The blade was lowered directly on top of the pipeline, near the north side marker, resulting in the damage to the pipe and the subsequent gas release.

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3 Pipeline and Hazardous Materials Safety Administration (PHMSA), United States Department of Transportation, accessed on January 12, 2019. https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

2. INCIDENT #2

Incident Year	2010
Location (State)	Illinois
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Other Outside Force Damage
Narrative	On the morning of November 30, 2010 at 0620 the fire chief from the city of Madison called Mississippi River Transmission (MRT) system control to report a gas leak at the intersection of Washington Ave. and Race St. MRT's system controller notified field personnel and our first responders arrived on the scene at 0650. There was a water leak at this site also and could not be immediately confirmed that it was a gas leak. The inlet block valve was closed. The downstream block valve was also closed. Based on monitored line pressure, it was confirmed that there was leaking gas on the pipeline. MRT's contractor brought in a 6" water pump to remove the water and to excavate the area of the leak. The water company was called to the scene and they denied that they had a leak. There was also a lift station drainage line in this area. It was shut off. After not making much progress in the water removal, the water company was called again. They arrived and confirmed that they did have a leak. The water line was shutoff and excavation was started once the water was removed. A 4 bolt leak clamp was installed on the gas line to seal off the leak caused by erosion from the water and sandy soil. Positive pressure was maintained on the pipeline to prevent water from entering the pipe. The line was blown down to prepare for repairs at a later date. The water company finished their leak repairs at a later date. Water was continuously pump from the area next two days. MRT's contract welders started fabricating the replacement pipe and fittings at the Columbia measuring station. Later, the pipe and fittings were transported to the contractors welding shop to finish the fabrication and X-ray. At the leak site there was more excavation done and a 20 ft. section of pipe was removed. Foreman plugs were installed in the ends of the pipe to prevent anything from entering the pipeline. An 8 hour hydrotest was performed on the new pipe and fitting as well. After passing the x-ray, the last weld was blasted and

	recoated. The line was purged, loaded, and placed back in service.

3. INCIDENT #3

Incident Year	2011
Location (State)	Ohio
Road Crossing	Yes
Cased/Uncased	Cased
Cause	Material Failure of Pipe or Weld
Narrative	Gas control personnel for Tennessee Gas Pipeline (TGP) noticed pressure drops relative to its pipeline in valve section 214 downstream of Carrollton compressor station and near the town of Hanoverton, OH around 10:30 pm EST on February 10, 2011. Shortly thereafter, TGP received a report from a local landowner of a fire some 11,000 feet north of valve 214 in line 4. Upon responding, field personnel verified that a rupture had occurred in line 4 where it crosses McKay Road in Columbiana County, OH. There was no formal evacuation of residents although emergency responders did advise some to leave their homes as a precautionary measure (TGP was not involved in any evacuation). Post-incident root cause analysis revealed the failure occurred as a result of tensile overload on a pre-existing hydrogen assisted crack in the underbed of the girth weld. The crack originated during the welding process at the time of original construction. The tensile overload was the result of a number of interacting stressors including but not limited to thermal contraction stresses. The pipeline has been repaired, purged, and loaded with natural gas to a pressure of 491 psig.

4. INCIDENT #4

Incident Year	2011
Location (State)	New Mexico
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	El Paso Natural Gas (EPNG) company was notified on August 16, 2011, by the New Mexico State Police of a natural gas release at McKinley County Road 57. EPNG gas control confirmed a rapid pressure drop in the EPNG 4" 2207 line and dispatched field personnel to the scene. A McKinley County road grader had punctured the pipeline but there was no fire or explosion and no injuries nor fatalities. EPNG personnel isolated the pipeline and repaired it by cutting in a new cylinder of pipe. The pipeline was successfully placed back into service on the evening of the 16th.

5. INCIDENT #5

Incident Year	2011
Location (State)	California
Road Crossing	Yes
Cased/Uncased	Cased
Cause	External Corrosion
Narrative	On the morning of September 19, 2011, PG&E personnel discovered gas readings at the casing vents for a 20-inch casing surrounding 16-inch steel gas transmission line I-21g under Redwood Boulevard, south of Atherton Avenue in Novato. PG&E crews excavated the pipe and casing on both sides of the roadway in an attempt to identify the location of the leak. Unfortunately, the source of the leak was not at either side of the roadway but appeared to be located somewhere under the roadway. Due to the location of the leak it is not feasible to attempt to repair the leak. A new pipe was installed under the roadway to replace the leaking pipe. Plans are also being developed for the removal of the old pipe to facilitate the root cause analysis of the leak. PG&E will

	provide the results of the root cause analysis to the CPUC upon completion of the analysis. There were no injuries or fatalities as a result of this incident. Damages are expected to exceed $50,000 following further evaluation on September 20, 2011, after which the DOT was notified. This incident initially became reportable when San Francisco major media tv Channel 5 was observed on scene at 1845 hours.

6. INCIDENT #6

Incident Year	2011
Location (State)	Texas
Road Crossing	Yes
Cased/Uncased	Cased
Cause	External Corrosion
Narrative	At 8:00 pm on December 13, 2011, Center Point Energy called the control center notifying them of a gas odor at Hwy 3 and Brookglen drive in Houston, TX. The control center called the operations on call person to respond. Local operations personnel discovered an LEL around a 10-foot area of the intersection of Highway 3 and Brookglen drive. Emergency response procedures were initiated and at the request of the TPC plant, a controlled shutdown was coordinated which allowed them to get another supplier online before the pipeline was shut down and isolated. A portable flare was brought out to flare down the pipeline. The pipeline was purged and inerted with nitrogen. Excavation of the release site was started on December 15, 2011 and the damaged section of pipe was identified in the afternoon located approximately 20 feet inside the casing under Brookglen drive. It was decided to repair the pipeline by excavating both ends of the casing and replacing the entire pipe section inside it. The installation of the certified replacement pipe was completed on December 18, 2011 and the pipeline was returned to service on December 20, 2011. No further remediation or repairs were necessary. Analysis of the damaged area of the pipe determined the cause to be external corrosion due to being shorted to the casing. During excavation it was discovered that the

	vent pipe was detached from the casing. New casing vents were installed on both sides of the casing.

7. INCIDENT #7

Incident Year	2012
Location (State)	Missouri
Road Crossing	Yes
Cased/Uncased	Unknown
Cause	External Corrosion
Narrative	Field installed shrink sleeve was damaged and unbonded during installation when the pipe was pulled through the bore hole exposing the exterior of the steel pipe to the effects of "tenting" and atmospheric corrosion.

8. INCIDENT #8

Incident Year	2012
Location (State)	New Jersey
Road Crossing	Yes
Cased/Uncased	Bored/Drilled (uncased)
Cause	Previous Mechanical Damage Not Related to Excavation
Narrative	Operator employees and third-party contractors were on site of an anomaly investigation dig, operator employees were removing soil around the pipeline when operator employees smelled an odor coming from the anomaly pie. The pipeline was taken out of service and an investigation was initiated. The results of the leak investigation showed a dent on the pipe due to a rock underneath the pipe. The rock underneath the pipe was the cause of a small crack where the leak initiated. The pipe anomaly segment was cutout and replaced with new pipe.

9. INCIDENT #9

Incident Year	2013
Location (State)	Texas
Road Crossing	Yes
Cased/Uncased	Bored/Drilled (information on whether there was a casing, or no casing for the impacted pipeline was not provided in the narrative. However, the incident occurred due to a boring activity to the underground gas pipeline at the crossing)
Cause	Excavation Damage by Third Party
Narrative	At approximately 11:38 on Wednesday March 13, 2013, Texas Gas Service received an emergency call of a hit line. The call was received from W. Military Hwy, McAllen. A Texas Gas Service first responder arrived at 12:26 and noticed that there were fire department personnel on site and that Military Hwy was closed to traffic. He also noticed damage to the roadway. Further investigation revealed that a boring unit operated by Hernandez Utilities, subcontractor for Mastec, had damaged an underground gas pipeline. Due to the proximity of another pipeline in the area, Texas Gas Service was uncertain if the damaged gas pipeline was a 10" transmission line operated by Texas gas service. To determine if the damaged pipeline was Texas Gas Service's personnel isolated the damaged portion of the 10" transmission line via operating 2 manual valves and monitored the gas pressure within the isolated section. It was then determined that the damaged pipeline was the Texas Gas Service pipeline. The leakage was controlled by isolating the segment. Skillets were installed to the valve site for additional safety to prevent any possible leak through with the shutdown completed. The roadway was then reopened.

10. INCIDENT #10

Incident Year	2013
Location (State)	Wisconsin
Road Crossing	Yes
Cased/Uncased	Cased
Cause	Material Failure of Pipe or Weld
Narrative	On April 23, 2013, at approximately 04:27 Northern Natural Gas Company's Omaha operations communications center received a call reporting that there appeared to be blowing natural gas 1/2 mile south of county road on Steele Valley Road. It was indicated that emergency responders were on-site and that they had blocked off a section of the road. Further, that there were no residences in the immediate area. A representative from Midwest Natural Gas called to confirm that natural gas appeared to be blowing from vent casings on both sides of the road. The location is approximately four miles west of the town of Mondovi, Wisconsin. Northern Company Employees were dispatched to the site and a gas management plan was developed to reduce pressure on the pipeline to approximately 520-550 psig from a typical 795 psig. Pressure was reduced by pinching block valves and letting customer usage pull the pressure down on the line then closely monitoring. Emergency stopple and bypass piping was brought on-site tested and placed in-service. Michels Construction, a contractor, assisted with excavation activities on both side of the road. Upon completion of excavation a crack in a piping girth weld was found on the underside (six o'clock position) which went entirely through the pipe, the crack was approximately 4 ½ inches long and one sixteenth of an inch wide. The Steele County Road department was contacted and agreed that Northern could open cut the road for installing new tested pipe. Northern would be responsible for restoration of the road and hard surfacing. Approximately 60-feet of new tested, coated pipe was installed. There were no injuries, no fire, no evacuations and no loss of service to customers. The pipe with the cracked girth weld was sent to an outside metallurgical laboratory for

	analysis. A metallurgical analysis was completed with findings that the pipe at both girth welds examined were found to exhibit misalignment and appear to be distorted. Extraneous welding wire was noted protruding from the internal portions of the weld. The crack was found to be 6-inches long and in the lower quadrant of the weld "necking down", typical of ductile overloading fracturing, was noted in the pipe on the internal surface of the cracked area. In the laboratory's opinion, the crack was caused by bending forces, as shown by the distortion of the pipe at the girth weld. Black deposits along both sides of the crack at the outside surface showed that a crack approximately 0.025 inches deep preceded final separation. Final separation initiated at the preexisting crack and final separation was by ductile overload.

11. INCIDENT #11

Incident Year	2013
Location (State)	Pennsylvania
Road Crossing	Yes
Cased/Uncased	Cased
Cause	Damage by Operator or Operator's Contractor Not Related to Excavation and Not Due to Motorized Vehicle/Equipment Damage
Narrative	A spectra energy welder was removing a portion of road casing encircling the 30-inch carrier pipe using a hot cut method when a pin hole leak occurred due to the torch coming in contact with the carrier pipe. Natural gas was released through the pin hole.

12. INCIDENT #12

Incident Year	2014
Location (State)	Minnesota
Road Crossing	Yes

Cased/Uncased	Uncased
Cause	Material Failure of Pipe or Weld
Narrative	The Viking gas transmission pipeline ruptured and ignited at approximately 0618 hours on May 26, 2014. Gas control dispatched Viking operations personnel. The rupture was verified by on site Viking personnel at 0647 hours. Local law enforcement and fire departments responded and isolated the area from traffic. There were no injuries or deaths. PHMSA was notified of the incident. The segment of pipe where the failure occurred was completely isolated. The communities of Warren and Argyle lost natural gas service impacting approximately 900 customers. On May 28, 2014, the pipeline segment was repaired and restored to 80 percent of the operating pressure at the time of failure. The ruptured pipe segment was sent to Kiefner and Associates in Ohio for failure analysis. Metallurgical testing determined that the failure was due to environmental (hydrogen induced) cracking which occurred in a localized (3.5 inches x 4.4 inches) hard spot (30-46 rc) in the pipe wall.

13. INCIDENT #13

Incident Year	2014
Location (State)	North Carolina
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	Contractor called for clearances. Facilities were located. Since it was a high-pressure facility a standby was scheduled. Contractor elected to proceed the day before the scheduled standby and elected to cross the line without exposing it. Contractor bored into the side of the line. Operator responded with make safe, repair, restoration of service and cleanup activities as required. Operator notified national response center at time of incident due to preliminary report of an injury. There was no reportable injury. Operator did not file incident report at the time because it was not believed any other reporting criteria was met. During calculation of property damages in order to bill

	contractor, operator discovered total property damage did exceed the $50,000 reporting threshold.

14. INCIDENT #14

Incident Year	2014
Location (State)	Kansas
Road Crossing	Yes
Cased/Uncased	Unknown
Cause	External Corrosion
Narrative	On 8/12/2014 at 01:15 SSC operations were dispatched through a Kansas one-call ticket. At 02:59 on 8/12/2014 SSC operator contacted gas control notifying of a possible leak on a SSC line. The leak was at the I-35 and 67th Street exit where SSC and KGS had lines located. KGS completed their excavation at 16:34 on 8/12/2014. KGS stated the gas detection was stronger as they moved closer to the SSC line. SSC operations began excavation after this determination. SSC began blow-down to determine ownership of the leak at 19:37 on 8/12/2014. SSC operations completed the blowdown and confirmed the leak at 09:03 on 8/13/2014. SSC continued to excavate the area to try and determine the location of the leak. At 16:21 on 8/13/2014 the pipe was uncovered, and it was determined that the leak was believed to be under the I-35 roadway. At this time the National Response Center was notified based on the expected repair cost to exceed $50,000. Due to location and lack of workspace this pipe could not be removed to investigate the leak. SSC determined the pipe was installed by pulling through an HDD hole and pipe did not contain abrasion resistant coating. The hole had been bored through solid rock. SSC believes external corrosion caused by damage to coating during install, by scraping the sides of the bore hole, to be the most likely cause of the leak. SSC is researching any similarly installed pipe to determine whether other leaks can occur and what SSC can do to eliminate these possible threats. SSC has completed the replacement of the road crossing by pulling a 16" pipe into the existing 20" line. The existing line will be used as a casing. The replacement was completed on 9/3/2014. The line was purged,

	packed, and back in service on 9/5/2014. All repairs to the I-35 ramp and r/w were done.

15. INCIDENT #15

Incident Year	2014
Location (State)	Ohio
Road Crossing	Yes
Cased/Uncased	Cased
Cause	External corrosion
Narrative	On October 15, 2014, a contractor employed by Columbia Gas Transmission, LLC (Columbia) was working on a near-by project, when he detected the odor of natural gas. Upon further investigations, a casing vent was tested for evidence of a non-hazardous natural gas leak inside a casing. Operations personnel were notified to assist in securing the site pending further assessment and necessary safety measures. The segment was isolated by Columbia personnel and the line was blown down. Hence, the site was secured. Upon further investigation, a decision was made to replace the casing and the pipe with a pipe. Upon removal of the pipe, an external corrosion pit with 100 percent wall penetration was determined to be the cause of the unintended natural gas release. The corrosion pit was approximately 3.75 inches inside of the north end of the casing at the 5 o'clock position when facing north. The pit was at a location of damaged or missing coating. The damaged coating was located under the rubber casing isolator. Both rubber isolators and wooden centralizers were observed to be in use upon removal of the casing. However, the carrier pipe was not centered through the casing. Water marks were observed on both the carrier pipe and on the casing, indicating that the casing seals had been compromised and, at times, water had been present in the annular space. Water flowed out of the south side of the casing when the south side casing seal was exposed. No known soil conditions or measured potential readings commonly associated with microbiologically influenced corrosion or cathodic protection interference were observed.

	1. The external corrosion pit occurred as a result of corrosion at the site of coating damage under the rubber casing isolator on the north side of the casing. 2. The coating damage likely occurred during installation of the casing or during a subsequent excavation of the casing ends. The wooden centralizers caused and/or exacerbated the coating damage. 3. The placement of the casing isolator over the area of damaged coating did not isolate the exposed steel from eventual electrolyte intrusion. With water being present between the casing seal and the pipe, atmospheric and crevice corrosion pitted the pipe to cause the leak. 4. The introduction of water as an electrolyte to the exposed steel created a localized corrosion cell under the rubber casing isolator. External corrosion occurred when the non-level casing filled with water completely to the north (high) side of the road and atmospheric corrosion occurred when the casing was not completely filled. 5. During the time when the casing was completely filled with water, the rubber casing isolator shielded the exposed steel from cathodic protection current that could have mitigated the corrosion cell during that time. During the time when atmospheric corrosion was occurring, only re-coating the exposed steel or maintaining dry conditions inside the casing could have mitigated the corrosion cell. Key lessons learned/corrective measures: 1) the nature and location of the corrosion pit that caused the leak makes it difficult, if not impossible, to detect during typical, non-excavation casing potential or short tests. Because the corrosion occurred in an electrically shielded area, the only reliable method for detection is the use of in-line inspection tools. 2) there were no indicators for a low pipe-to-soil potential measurements for the pipeline in the area going back to 2008. Likewise, no casing-to-soil potential measurements indicated short testing was needed. 3) filling the annular space between the carrier pipe and the casing with a dielectric material removes the corrosive

	environment and can prevent corrosion from occurring. Filling of this casing could have prevented this leak.

16. INCIDENT #16

Incident Year	2014
Location (State)	Georgia
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	On November 6, 2014, southern natural gas line 34 (Nashville line) was struck by a road grader where it crosses Bradford Rd in Berrien County, GA. The road grader was being run by a Berrien county road crew who had failed to make a one-call notification. Bradford road is unpaved at this location, and the pipeline is uncased. The road grader made a 2 in x 1 in puncture in the 3-inch pipeline. The first notification of the incident came as a call from a nearby landowner to gas control. Gas control immediately called operations. The first person arrived at the upstream tap valve and had the valve shut within 5 minutes. There were two road graders, one cutting the ditch and a second grader following behind and grading the road. The first grader that was cutting the ditch is the grader that stuck the pipeline. There were pipeline markers on either side of Bradford Road.

17. INCIDENT #17

Incident Year	2015
Location (State)	Mississippi
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Equipment Failure

Narrative	The rubber seal on an underground split sleeve clamp failed resulting in leak.

18. INCIDENT #18

Incident Year	2015
Location (State)	Texas
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	Third party excavator had called in, and accurate locates were performed. The third party excavator did not contact the operator prior to exposing the active pipeline. The excavator exposed an abandoned section of 16" pipe, they assumed it to be active. The excavator did not contact the operator to confirm if the line was active or not. During the boring process, the active 12" line was struck. The 12" line was 8.5 feet below the abandoned 16" line.

19. INCIDENT #19

Incident Year	2015
Location (State)	Colorado
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	On April 13 a third-party excavator damaged a 8” transmission line near the town of Saguache, CO. The excavator was performing drainage work for the county road, and no locate ticket was requested. The incident was identified by SCADA controllers, and the line was isolated by manually-operated

	mainline valves. There were no injuries and the gas did not ignite.

20. INCIDENT #20

Incident Year	2015
Location (State)	Louisiana
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	Gulf South Pipeline, LP experienced a pipeline failure as the result of third-party damage. Pipeline was struck by a Parish Road Contractor cleaning the roadway ditch. No one-call was made by the road contractor. No injuries were incurred.

21. INCIDENT #21

Incident Year	2015
Location (State)	Texas
Road Crossing	Yes
Cased/Uncased	Cased
Cause	Other Incident Cause
Narrative	At 08:05 am on 10/30/2015, operations discovered a minor natural gas leak on line at the navigation street crossing in Corpus Christi. The leak was discovered while conducting an annual gas leakage survey; product was detected venting from the casing vent pipe. Enterprise determined that the leak was reportable based on the expected cost to repair or replace the segment of pipeline. Operations isolated the pipeline segment and purged the pipeline. The leaking segment was purged, cut and capped on both sides of the crossing. A new HDD was

	installed, and the pipeline was returned to service. The old segment could not be exposed to confirm the cause of the release due to location of the crossing at navigation street.

22. INCIDENT #22

Incident Year	2015
Location (State)	Nevada
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Other Outside Force Damage
Narrative	On November 21, 2015, the 8-inch Carson lateral was punctured on the south side of Mica Drive at US-395 during an in-line inspection (ILI) tool run. The puncture occurred at a drop section containing 45-degree elbows installed in 1987 as part of a relocation for the construction of Mica Drive. An investigation on the cause of the incident has been completed and it was determined that during the ILI of the Carson lateral, the leading eye of the MFL tool struck the inside of the 45-degree elbow and caused a puncture in the pipeline. Company employees and contractors were stationed at the segment isolation valves as part of the ILI procedure allowing for a rapid response and shutdown of the pipeline as part of the isolation plan. Public and private property damage includes six vehicles and a landscape retaining wall as a result of the blowing dirt and rocks. The magnetic flux leakage ILI tool was also damaged.

23. INCIDENT #23

Incident Year	2016
Location (State)	New Mexico
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party

Narrative	A road grader scraped the pipeline with the blade and gouged a hole approximately 6" x 9". Grader operator did not call the NM one-call notification center for a locate request.

24. INCIDENT #24

Incident Year	2018
Location (State)	California
Road Crossing	Yes
Cased/Uncased	Uncased
Cause	Excavation Damage by Third Party
Narrative	On March 7, 2018 at approximately 10:43 am, a third-party subcontractor struck a 20-inch gas steel transmission line while performing directional boring. This resulted in an escape of gas. Crews responded and were able to control the gas through closing valves at nearby regulator stations. There were no injuries that resulted from this incident. Investigation revealed that prior to the incident, the third-party subcontractor had a USA ticket. The line had been properly marked by an SDG&E contractor. At the time of the incident, the third-party subcontractor did not have a valid USA ticket for the excavation activities performed. In addition, the third-party subcontractor failed to request a stand-by from d SDG&E which is required when excavating near high pressure gas facilities. This incident was reported to DOT and CPUC due to estimated damage amount exceeding $50,000.

Class Location Definitions

1. A Class 1 location is: (i) An offshore area; or (ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

2. A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

3. A Class 3 location is: (i) Any class location unit that has 46 or more buildings intended for human occupancy; or (ii) An area where the pipeline lies within 100 yards (91

meters) 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.)

4. A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

Data Compilation – Pipeline Incidents per Mile

Table A1: Incident per mile for various Hazardous Liquid types

State	Hazardous Liquid Type				
	Crude Oil	Petroleum Products	Highly Volatile Liquids	Liquid CO_2	Biofuel
AK	0.002	0.001	0.000	0.000	0.000
AL	0.001	0.008	0.000	0.000	0.000
AR	0.003	0.008	0.000	0.000	0.000
AZ	0.001	0.004	0.000	0.000	0.000
CA	0.044	0.039	0.000	0.000	0.000
CO	0.001	0.009	0.000	0.000	0.000
CT	0.000	0.001	0.000	0.000	0.000
DE	0.000	0.000	0.000	0.000	0.000
FL	0.001	0.004	0.000	0.000	0.000
GA	0.000	0.007	0.000	0.000	0.000
HI	0.000	0.002	0.000	0.000	0.000
IA	0.001	0.014	0.000	0.000	0.000
ID	0.000	0.002	0.000	0.000	0.000
IL	0.009	0.023	0.000	0.000	0.000
IN	0.002	0.012	0.000	0.000	0.000
KS	0.015	0.028	0.000	0.000	0.000

KY	0.002	0.002	0.000	0.000	0.000
LA	0.035	0.013	0.001	0.000	0.000
MA	0.000	0.002	0.000	0.000	0.000
MD	0.000	0.007	0.000	0.000	0.000
ME	0.000	0.000	0.000	0.000	0.000
MI	0.003	0.003	0.000	0.000	0.000
MN	0.006	0.013	0.000	0.000	0.000
MO	0.004	0.012	0.000	0.000	0.000
MS	0.006	0.003	0.000	0.000	0.000
MT	0.003	0.009	0.000	0.000	0.000
NC	0.000	0.006	0.000	0.000	0.000
ND	0.011	0.006	0.000	0.000	0.000
NE	0.000	0.012	0.000	0.000	0.000
NH	0.000	0.000	0.000	0.000	0.000
NJ	0.000	0.010	0.000	0.000	0.000
NM	0.013	0.008	0.000	0.000	0.000
NV	0.000	0.002	0.000	0.000	0.000
NY	0.000	0.009	0.000	0.000	0.000
OH	0.004	0.019	0.000	0.000	0.000
OK	0.061	0.030	0.000	0.001	0.000
OR	0.000	0.003	0.000	0.000	0.000
PA	0.000	0.023	0.000	0.000	0.000
SC	0.000	0.006	0.000	0.000	0.000
SD	0.000	0.003	0.000	0.000	0.000
TN	0.001	0.009	0.000	0.000	0.000
TX	0.162	0.083	0.000	0.001	0.000
UT	0.003	0.000	0.000	0.000	0.000

VA	0.000	0.009	0.000	0.000	0.000
VT	0.000	0.000	0.000	0.000	0.000
WA	0.002	0.004	0.000	0.000	0.000
WI	0.000	0.007	0.000	0.000	0.000
WV	0.001	0.000	0.000	0.000	0.000
WY	0.017	0.006	0.000	0.000	0.000

Spatial Location and Counts of Historical Pipeline Incidents

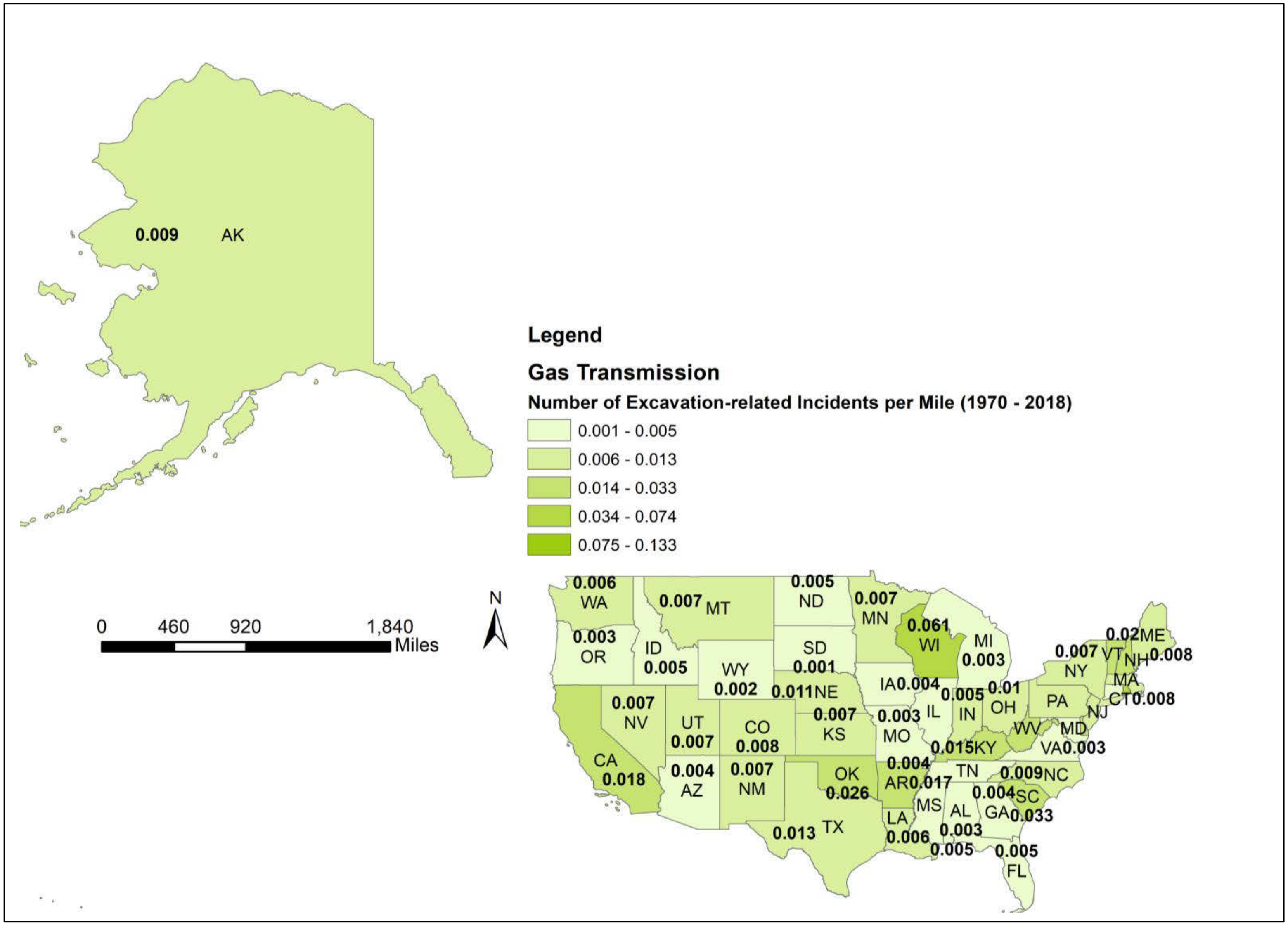

Figure A1: Spatial distribution of incidents (excavation-related) per mile of Gas Transmission pipelines

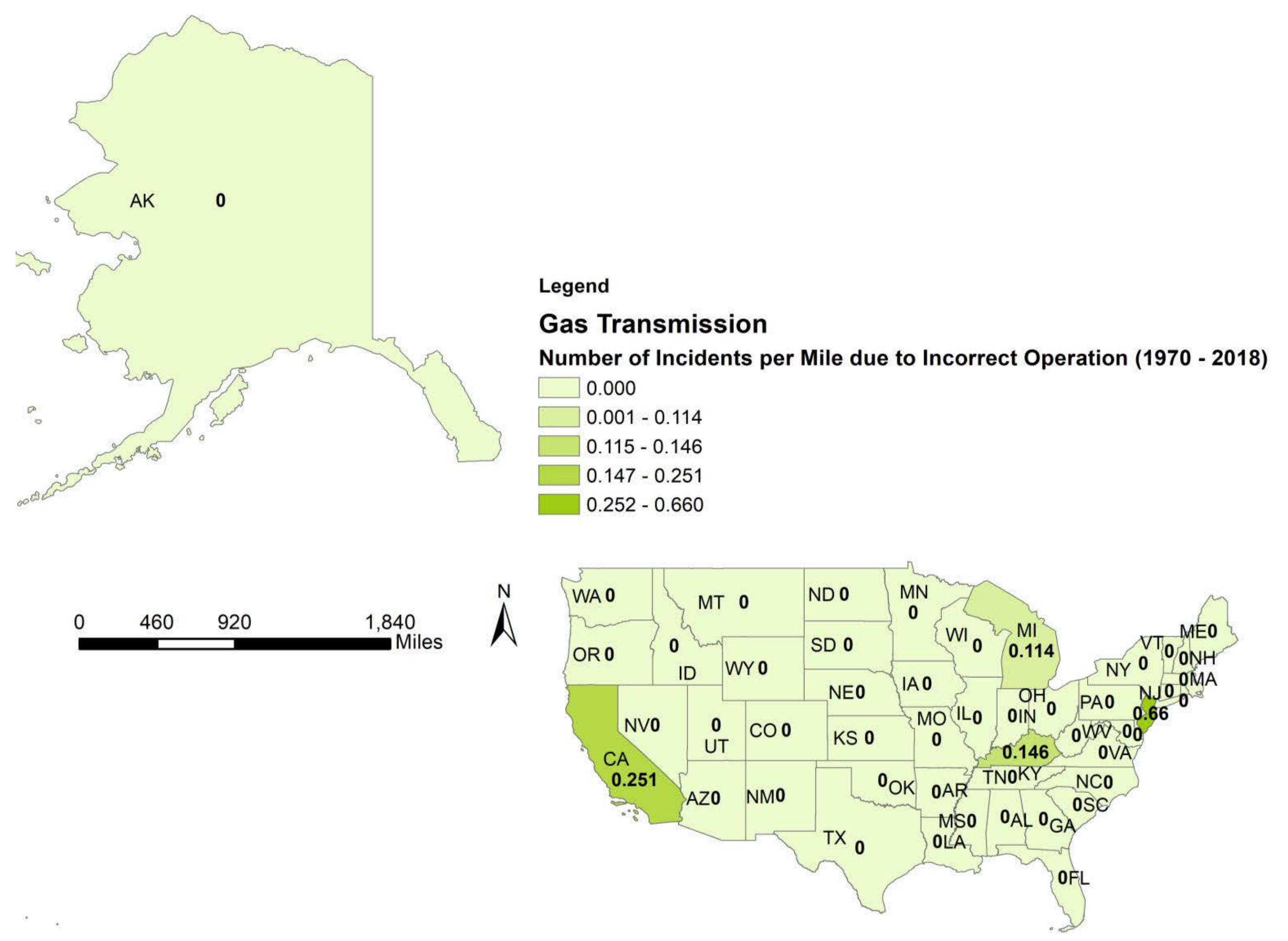

Figure A2: Spatial distribution of incidents per mile due to incorrect operations of Gas Transmission pipelines

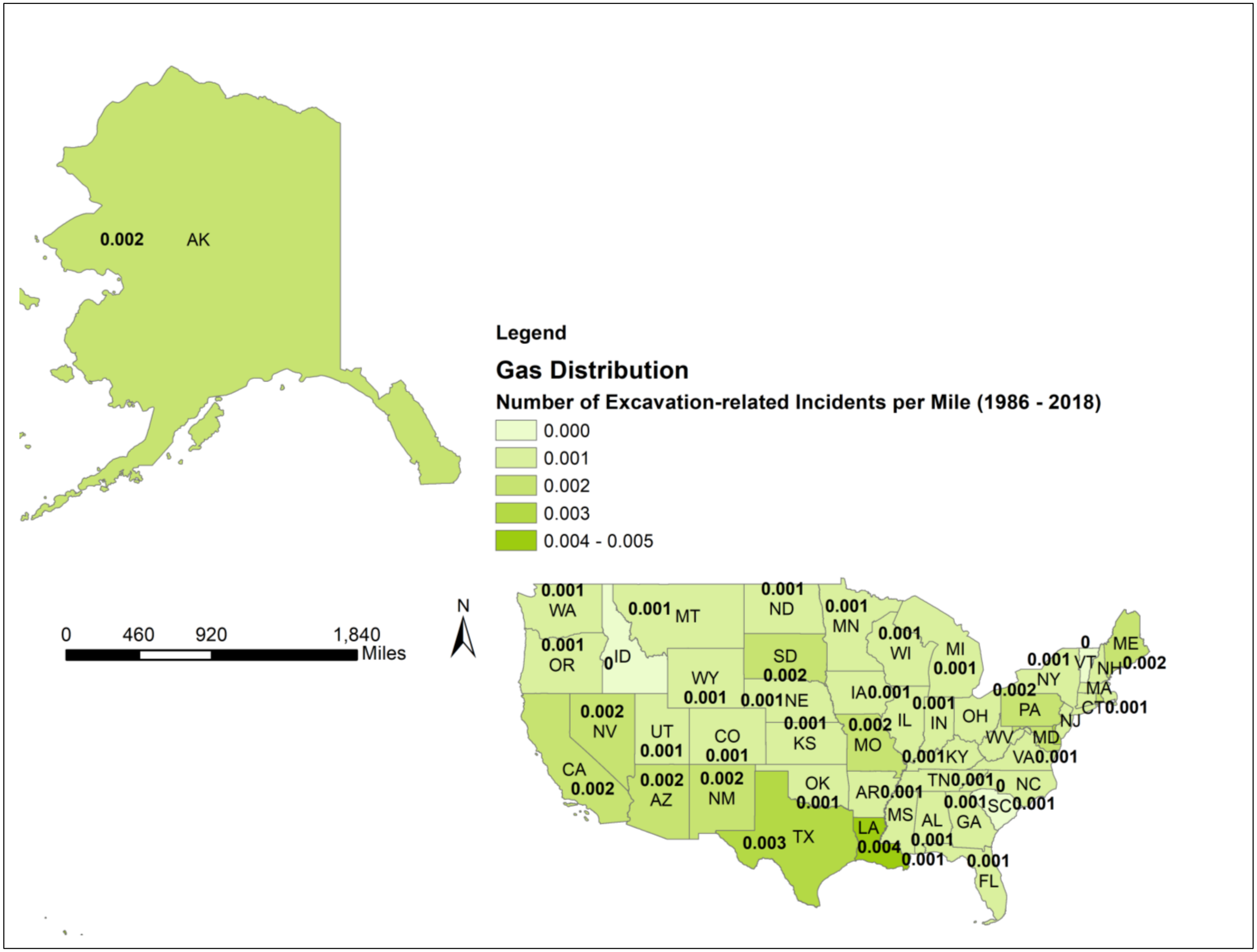

Figure A3: Spatial distribution of incidents (excavation-related) per mile of Gas Distribution pipelines

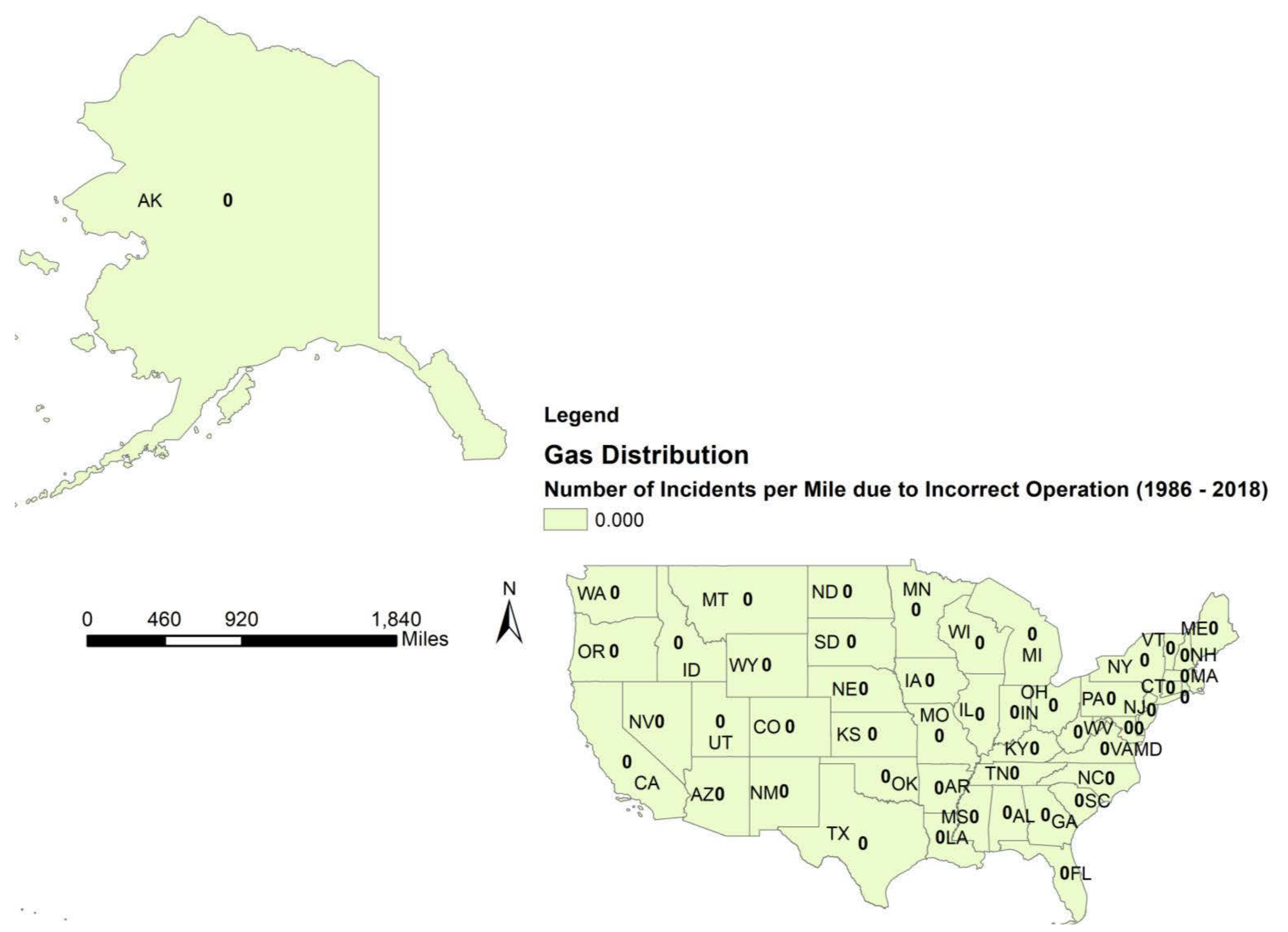

Figure A4: Spatial distribution of incidents per mile due to incorrect operations of Gas Distribution pipelines

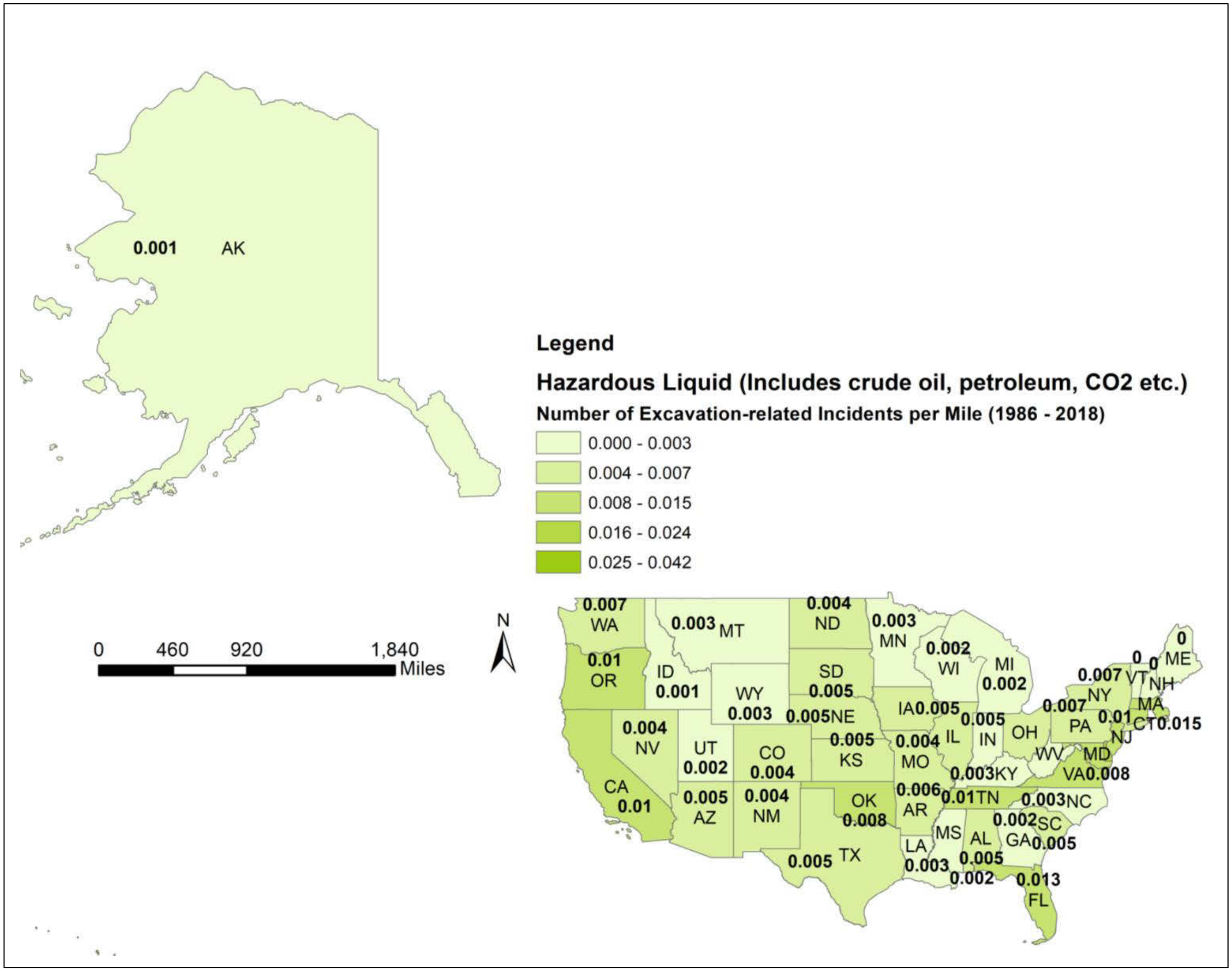

Figure A5: Spatial distribution of incidents (excavation-related) per mile of Hazardous Liquid pipelines

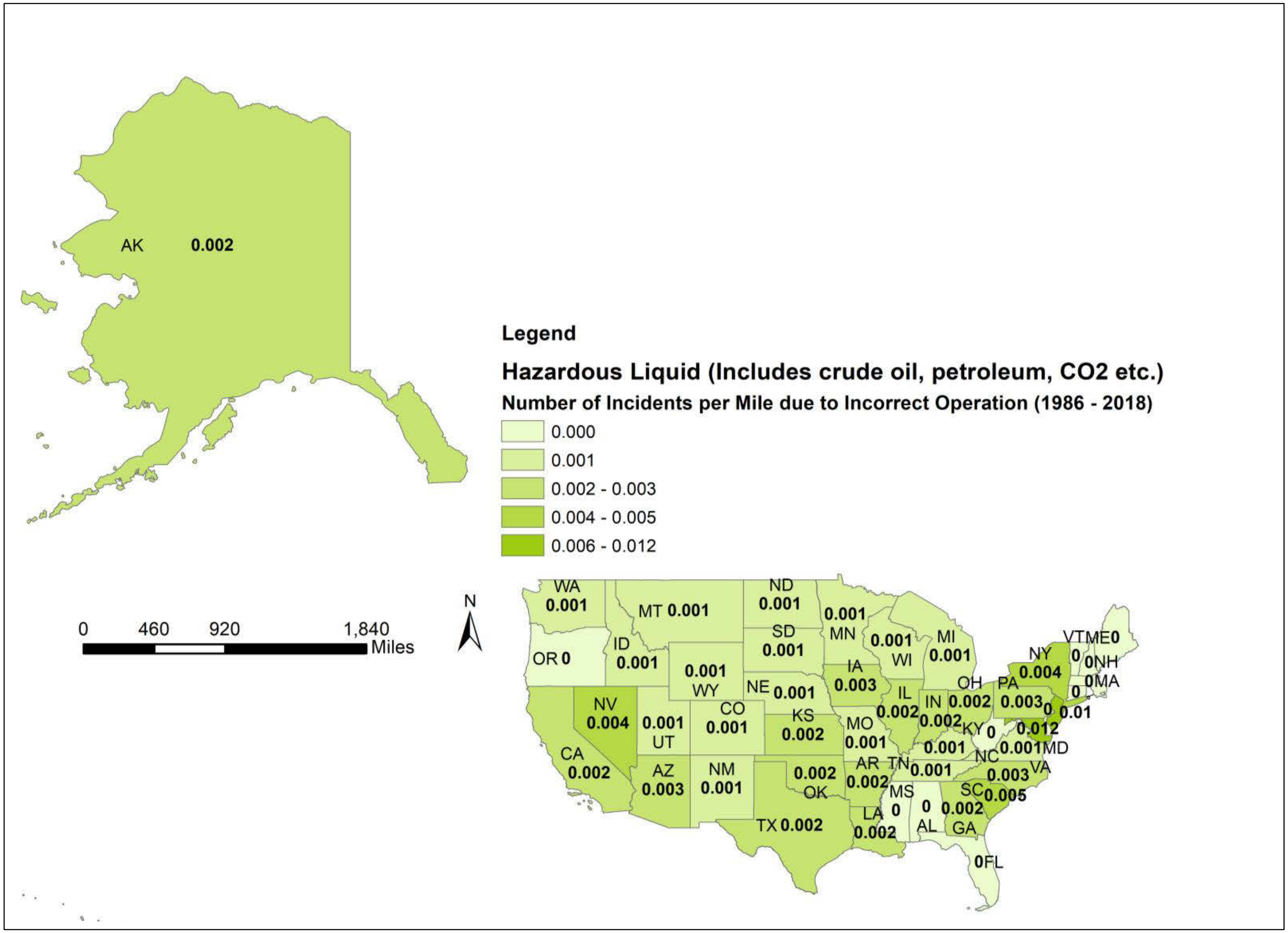

Figure A6: Spatial distribution of incidents per mile due to incorrect operation of Hazardous Liquid pipelines