

Recommended Practice for Movement in In-service Pipelines

API RECOMMENDED PRACTICE 1117
THIRD EDITION, JULY 2008

ERRATA 1, DECEMBER 2008
ERRATA 2, AUGUST 2009

REAFFIRMED, NOVEMBER 2013



AMERICAN PETROLEUM INSTITUTE

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Pipeline Segment

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Foreword

The few pipeline failures that have followed movement operations demonstrate the need for an industry recommended practice on movement of pipelines. A movement operation increases the longitudinal stress in the segment of the pipeline being moved. In most cases this additional stress has caused no significant problems. In 1978, however, a propane pipeline failed after being moved while in service. Although the movement may not have contributed to the failure, the incident demonstrated the need for uniform guidelines to ensure that the movement of an in-service pipeline is done with reasonable safety. Consequently, the American Society of Mechanical Engineers, the American Petroleum Institute, and the Office of Pipeline Safety Regulation of the U.S. Department of Transportation jointly sponsored a study to establish guidelines for safely moving pipelines without taking them out of service. After the release of the "Guidelines for Lowering Pipelines While in Service" by authors at the Battelle Columbus Laboratories, the American Petroleum Institute solicited qualified engineers responsible for the design, construction, and operation of petroleum pipelines to review the Battelle work and other available work and to prepare an industry recommended practice on the safe lowering and/or raising of in-service pipelines.

The purpose of this recommended practice is to address the criteria, methods, values, and recommendations that should be considered in the design and execution of practical and safe pipeline-movement operations. However, it is impossible to foresee all possible pipeline-movement situations or circumstances. This recommended practice is to be used as a guide for moving pipelines while they remain in service. It is not a rigid standard.

This recommended practice is not intended to be an endorsement of moving pipelines as a method for addressing the safety of an existing pipeline at a new road crossing, railroad crossing, foreign utility crossing, or any other crossing. It is merely intended to provide guidance to pipeline operators and contractors who choose the alternative of moving.

This recommended practice has been revised to reflect that the methodology used in moving pipelines can be used for other pipeline movement operations.

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Recommended Practice for Movement of In-service Pipelines

1 Scope

This recommended practice covers the design, execution, inspection, and safety of a pipeline-lowering or other movement operation conducted while the pipeline is in service. (In this document, the terms lowering and movement can be used interchangeably.) This recommended practice presents general guidelines for conducting a pipeline-movement operation without taking the pipeline out of service. It also presents equations for estimating the induced stresses. To promote the safety of the movement operation, it describes stress limits and procedures. Additionally, it outlines recommendations to protect the pipeline against damage. The practicality and safety of trench types, support systems, and lowering or other methods are considered. Inspection procedures and limitations are presented.

The calculations in this recommended practice are based on methods developed from elastic free deflection theory to determine induced stresses and deflection profiles. Other calculation methods such as finite element analysis may be used instead. See the publications listed in Section 2 and the bibliography.

1.1 Applications

This recommended practice applies to onshore steel pipelines. Moving in-service pipelines can be a safe, cost-effective means of relocating a pipeline without loss of service. The recommendations presented in this recommended practice should be applicable to any lowering or other movement of existing pipelines that is undertaken either to accommodate new roads, railroads, foreign utilities, ditches, or creeks or to accommodate any condition for which moving the pipeline is the chosen alternative.

1.2 Exceptions

The recommendations in this document should not be applied retroactively to pipelines that were moved prior to the effective date of this recommended practice. Also, these recommendations should not be applied to movement due to mining or natural subsidence. The movement of pipelines with attached appurtenances is beyond the scope of this recommended practice.

The following pipelines were not considered in developing the methods, criteria, values, and recommendations presented in this document:

- a) offshore pipelines;
- b) pipelines with valves, flanges, fittings, concrete coatings, or attached appurtenances in the section to be moved;
- c) pipelines joined by oxyacetylene welds, mechanical joints, or girth welds of known poor quality (unless welds are reinforced by full encirclement sleeves or other acceptable means).

1.3 Safety Considerations

Caution—The recommendations in this document promote safety under conditions normally encountered in the pipeline industry. Requirements for abnormal or unusual conditions are not specified, and some details of engineering and construction are not provided. All movements of in-service pipelines should comply with applicable safety standards.

1.4 Conventions

In this document, each equation term is defined in Annex A and beneath the first equation that uses it. Also, negative values for stress indicate compressive stress and positive values indicate tensile stress.

2 Normative References

API Standard 1104, *Welding of Pipelines and Related Facilities*

AISC M016 ¹, *Manual of Steel Construction*

ASME B31.4 ², *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*

ASME B31.8, *Gas Transmission & Distribution Piping Systems*

OSHA 29 ³, *Code of Federal Regulations Part 1926—Construction Industry Regulations*

DOT 49 ⁴, *Code of Federal Regulations Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards*

DOT 49, *Code of Federal Regulations Part 195—Transportation of Hazardous Liquids by Pipeline*

3 Definitions

3.1

existing longitudinal stress

Longitudinal stress in the pipe before its movement, excluding residual stress in girth welds and in bends.

3.2

free deflection

Design method that calculates bending stress in the pipe using elastic structural design methods.

3.3

in-service pipeline

Pipeline containing a hazardous fluid and is operating at normal flow conditions.

3.4

lowering (moving)

The controlled displacement of a pipeline segment without cutting the pipeline.

3.5

minimum trench length

Minimum longitudinal distance required to move a portion of a pipeline a certain distance without exceeding its longitudinal stress limits.

3.6

pipe bend

A permanent inelastic deflection of a pipe.

3.7

slack

Condition of a pipeline with neither longitudinal stress nor compressive longitudinal stress.

3.8

total longitudinal stress

Longitudinal stress in a portion of a pipeline during or after its movement.

¹ American Institute of Steel Construction, One East Wacker Drive, Suite 700, Chicago, Illinois 60601, www.aisc.org.

² ASME International, 3 Park Avenue, New York, New York 10016, www.asme.org.

³ Occupational Safety & Health Administration, 200 Constitution Avenue, NW, Washington, D.C. 20210, www.osha.gov.

⁴ U.S. Department of Transportation, 1200 New Jersey Avenue, S.E., Washington, D.C. 20590, www.dot.gov.

4 Design

4.1 Design Considerations

4.1.1 General

This subsection describes design methods for estimating the longitudinal stress in a pipe due to the pressure, temperature, bending, elongation, and initial conditions that would be involved in any particular pipeline-movement operation covered by this recommended practice. It also considers mechanical influences and various loadings.

4.1.2 Total Longitudinal Stress

The total longitudinal stress in the pipe can be estimated with the following equation:

$$S_L = S_E + S_B + S_S \quad (1)$$

where

S_L is the total longitudinal stress in the pipe, in psi;

S_E is the existing longitudinal stress in the pipe, in psi;

S_B is the longitudinal stress in the pipe due to bending caused by the movement operation, in psi;

S_S is the longitudinal stress in the pipe due to its elongation caused by the movement operation, in psi.

4.1.3 Longitudinal Tensile Stress Due to Internal Pressure

The longitudinal tensile stress in the pipe due to internal pressure may be estimated with the following equation:

$$S_P = PD \frac{\mu}{2t} \quad (2)$$

where

S_P is the longitudinal tensile stress in the pipe due to internal pressure, in psi;

P is the maximum internal operating pressure of the pipe, in psi;

D is the outside diameter of the pipe, in inches;

μ is Poisson's Ratio for steel, 0.3;

t is the nominal wall thickness of the pipe, in inches.

4.1.4 Longitudinal Tensile Stress Due to Temperature Change

The longitudinal tensile stress in the pipe due to a change in its temperature may be estimated with the following equation:

$$S_r = E\alpha(T_1 - T_2) \quad (3)$$

where

S_r is the longitudinal tensile stress in the pipe due to a change in its temperature, in psi;

E is the modulus of elasticity of steel 29×10^6 psi;

α is the linear coefficient of thermal expansion of steel, 6.5×10^{-6} in. per in. per °F;

T_1 is the temperature of the pipe at the time of the installation, in °F;

T_2 is the operating temperature of the pipe at the time of the movement, in °F.

If the pipe's temperature at installation time is not known, it should be reasonably estimated.

4.1.5 Longitudinal Flexural Stress Due to Existing Elastic Curvature

When a pipeline is laid to conform elastically to a given trench profile, the pipeline will experience induced flexural stress in amounts proportional to its curvature. In hilly terrain, where slopes are unstable, or where soils are subject to frost heave or liquefaction, the pipeline is likely to experience stress of unpredictable and varying magnitude. This stress (S_C , see 4.1.6) can range from near-yield-strength levels in tension to near-buckling levels in compression. This existing stress should be considered prior to a movement operation.

4.1.6 Existing Longitudinal Stress

The existing longitudinal stress in a pipeline will normally be in the range of –10,000 psi to +20,000 psi. In flat or gently rolling terrain where soils are not subject to frost heave or liquefaction, the pipeline will experience only the longitudinal tensile stress due to internal pressure and temperature as discussed in 4.1.3 and 4.1.4 and the flexural stress to the extent that is elastically curved as discussed in 4.1.5.

The existing longitudinal stress in the pipe may be estimated with the following equation:

$$S_E = S_P + S_r + S_C \quad (4)$$

where

S_C is the longitudinal stress in the pipe due to existing elastic curvature, in psi.

4.1.7 Longitudinal Stress Due to Bending

The longitudinal stress in the pipe due to bending may be estimated with the following equation:

$$S_B = \frac{\omega_T L_I^2}{12S} \quad (5)$$

where

ω_T is the net uniformly distributed load required to achieve the desired mid-span vertical deflection of the pipe (Δ) [not the full weight of the pipe and fluid (see Annex B)], in lb/in.;

L_I is the minimum trench length required to reach the mid-span vertical deflection of the pipe (Δ), in inches;

S is the elastic section modulus of the pipe, in in.³.

4.1.8 Longitudinal Stress Due to Elongation

The longitudinal stress in the pipe due to elongation caused by the movement operation may be estimated with the following equation:

$$S_S = 2.67E \left[\frac{\Delta}{L} \right]^2 \quad (6)$$

where

Δ is the mid-span deflection of the pipe, in ft;

L is the minimum trench length required to reach the mid-span deflection of the pipe (Δ), in ft.

The effects of this stress may be offset by an elastic compressive stress existing in the pipeline prior to the moving because of slack.

4.1.9 Dynamic Effects

Dynamic effects due to impact, vibration, earthquake, subsidence of other potential dynamic load beyond the control of the pipeline operator should be considered in the design of movement operations. Dynamic loads from reconditioning, rehabilitation and any other dynamic or temporary loading under the pipeline operator's control should be considered in the design of the operation.

4.1.10 Previous Movements

The effects of previous movements should be considered in the design of movement operations.

4.2 Design Criteria

4.2.1 General

This subsection defines methodology and outlines criteria and minimum values that may be used in the design of pipeline-movement operations.

4.2.2 Total Longitudinal Stress Limit

A total longitudinal stress limit should be established for the movement operation. This stress level is the specified minimum yield strength of the line pipe to be moved (SMYS) modified by a design factor (FD) determined by the pipeline operator. The design factor takes into account the condition and operating history of the pipeline and any applicable codes and regulations. Normally, it is most influenced by the condition of the girth welds.

4.2.3 Available Longitudinal Bending Stress

The longitudinal stress available for bending may be estimated with the following equation:

$$S_A = F_D SMYS - S_E - S_S \quad (7)$$

where

S_A is the longitudinal stress available for bending, in psi;

F_D is the design factor;

$SMYS$ is the specified minimum yield strength of the pipe, in psi.

4.2.4 Trench Length

The minimum trench length required to achieve a particular mid-span deflection of the pipe without exceeding the longitudinal stress limit can be determined with the following equation, based on elastic free deflection theory, which treats the pipe as a single-span beam that is fixed at both ends and that has a uniformly distributed load (see Figure 1):

$$L = \sqrt{\left[\frac{(3.87 \times 10^7) D \Delta + (7.74 \times 10^7) \Delta^2}{F_D SMYS - S_E} \right]} \quad (8)$$

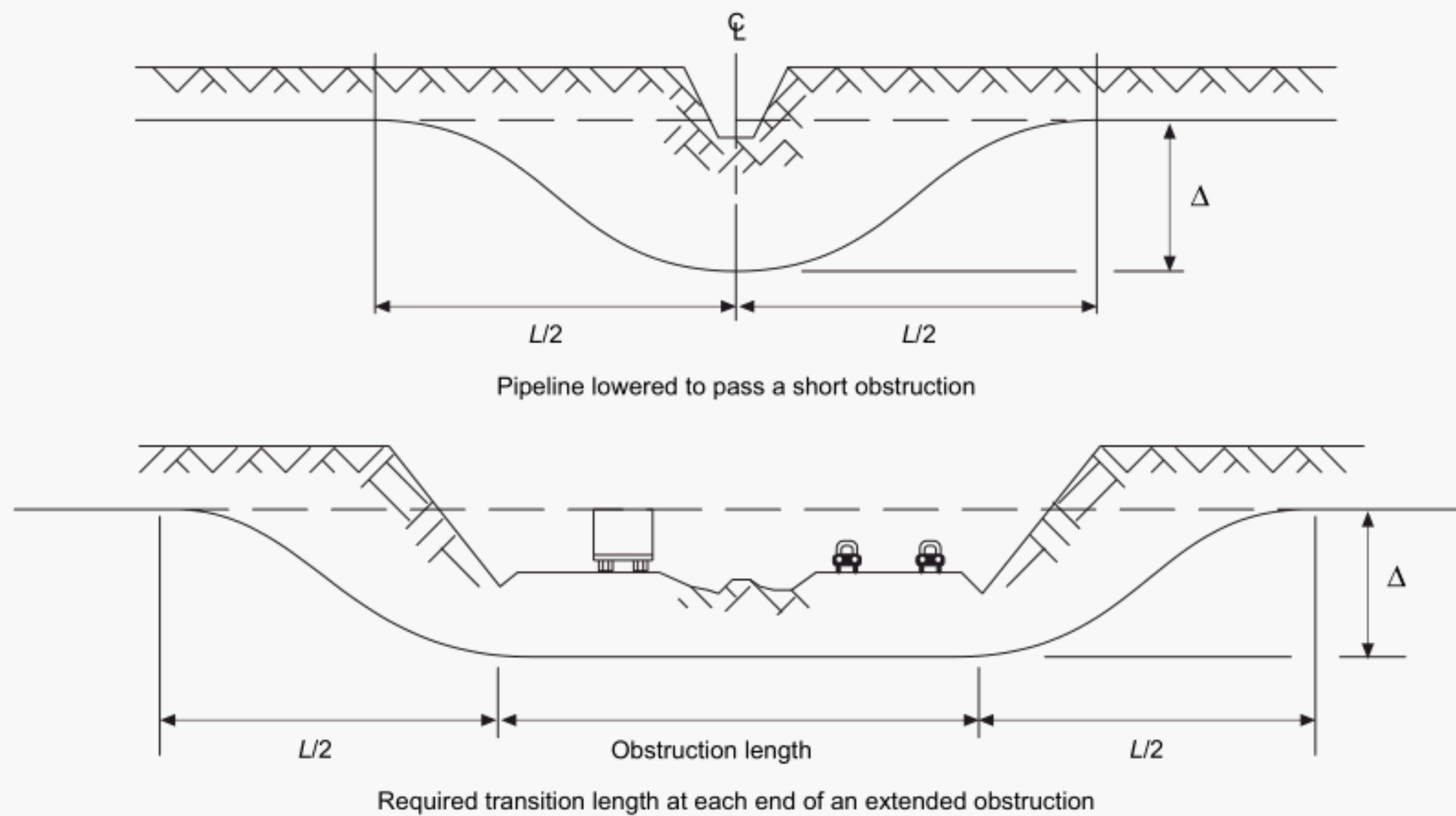


Figure 1—Application of the Minimum Trench Length (L)

4.2.5 Trench (or Displacement) Profile

A profile for the moved portion of the pipeline should be designed to minimize induced bending stress concentrations (see Figure 2). Therefore, to obtain acceptable longitudinal stress distribution due to bending, the deflection at any point along the trench profile can be determined with the following equation:

$$\Delta_x = \frac{16x^2\Delta(L-x)^2}{L^4} \quad (9)$$

where

Δ_x is the vertical deflection of the pipe at distance x , in ft;

x is the distance along the length of the trench from the starting point of the pipe deflection, in ft.

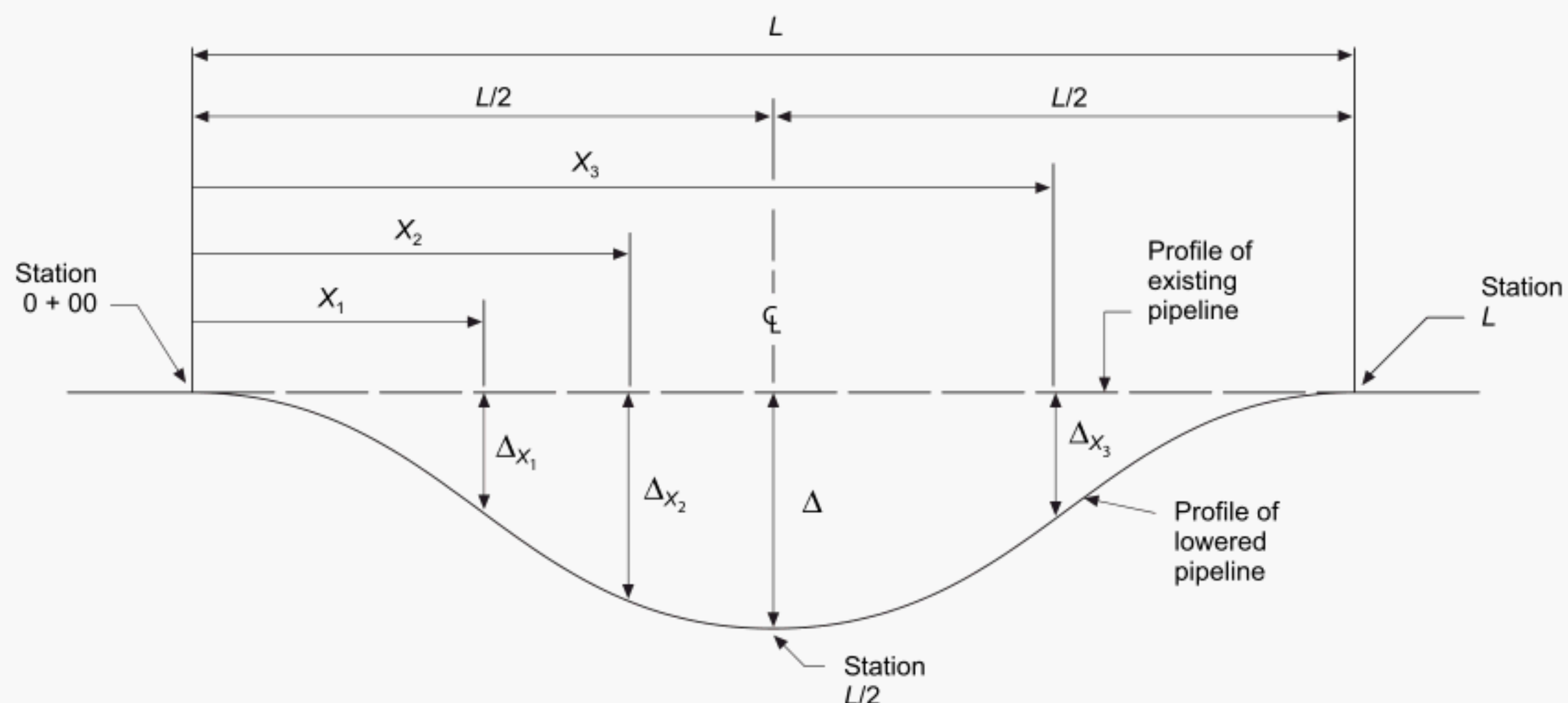


Figure 2—Preferred Trench Profile of the General Lowering

4.3 Support Spacing

Based on a four-span, uniformly loaded beam, the maximum free span between supports can be determined with the following equation:

$$L_s = \sqrt[4]{\frac{0.0286 S_A (D^4 - d^4)}{D^3 - 0.8724 d^2 D}} \quad (10)$$

where

L_s is the maximum free span between pipe supports, in ft;

d is the inside diameter of the pipe, in inches.

4.4 A Sample Problem and Its Solution

The following is a step-by-step solution of a sample problem using the guidelines in this recommended practice for determining the minimum trench length required for the desired deflection of the pipe, the preferred trench profile, and the maximum free span between supports.

The following information is known:

- a) pipeline size is 12.75 in. O.D. by 0.250 in. W.T.—therefore, $D = 12.75$ in., $t = 0.250$ in., and $d = 12.25$ in.;
- b) pipe material is API 5L Grade X42—therefore, SMYS = 42,000 psi;
- c) desired vertical deflection of the pipe $\Delta = 5$ ft;
- d) maximum operating pressure $P = 1000$ psi;
- e) installation temperature of pipe $T_1 = 100^\circ\text{F}$;
- f) operating temperature $T_2 = 30^\circ\text{F}$;
- g) the pipeline is under favorable conditions and has a favorable operating history—therefore, design factor $F_D = 0.90$.

Step 1: With Equation (2), determine the longitudinal stress in the pipe due to internal pressure.

$$\begin{aligned} S_p &= \frac{PD\mu}{2t} \\ &= \frac{1000(12.75)(0.3)}{2(0.250)} \\ &= 7650 \text{ psi} \end{aligned}$$

Step 2: With Equation (3), determine the longitudinal stress in the pipe due to temperature.

$$\begin{aligned} S_r &= E\alpha (T_1 - T_2) \\ &= (29 \times 10^6)(6.5 \times 10^{-6})(100 - 30) \\ &= 13,195 \text{ psi (tension)} \end{aligned}$$

Step 3: With Equation (4), determine the existing longitudinal stress in the pipe, assuming that the longitudinal stress due to existing elastic curvature is equal to zero.

$$\begin{aligned}
 S_E &= S_P + S_r + S_C \\
 &= 7650 + 13,195 + 0 \\
 &= 20,845 \text{ psi}
 \end{aligned}$$

Step 4: With Equation (8), determine the minimum trench length required to reach the desired vertical deflection of the pipe and remain within the longitudinal stress limits.

$$\begin{aligned}
 L &= \sqrt{\left[\frac{(3.87 \times 10^7) D \Delta + (7.74 \times 10^7) \Delta^2}{F_D SYMS - S_E} \right]} \\
 &= \sqrt{\frac{3.87(10^7)(12.75)(5) + 7.74(10^7)(5^2)}{0.9(42,000) - (20,845)}}
 \end{aligned}$$

08 | $= 510 \text{ ft}$

The minimum trench length required to achieve the desired vertical deflection of 5 ft and remain within the longitudinal stress limits is 510 ft.

Step 5: With Equation (9), determine the preferred trench profile.

$$\begin{aligned}
 \Delta_x &= \frac{16x^2 \Delta (L - x)^2}{L^4} \\
 &= \frac{80x^2 (510 - x)^2}{6.765 \times 10^{10}}
 \end{aligned}$$

Table 1 illustrates the results of using this equation to calculate the vertical deflection in the preferred trench profile at intervals of 25 ft. Figure 3 illustrates the minimum trench length and the preferred trench profile.

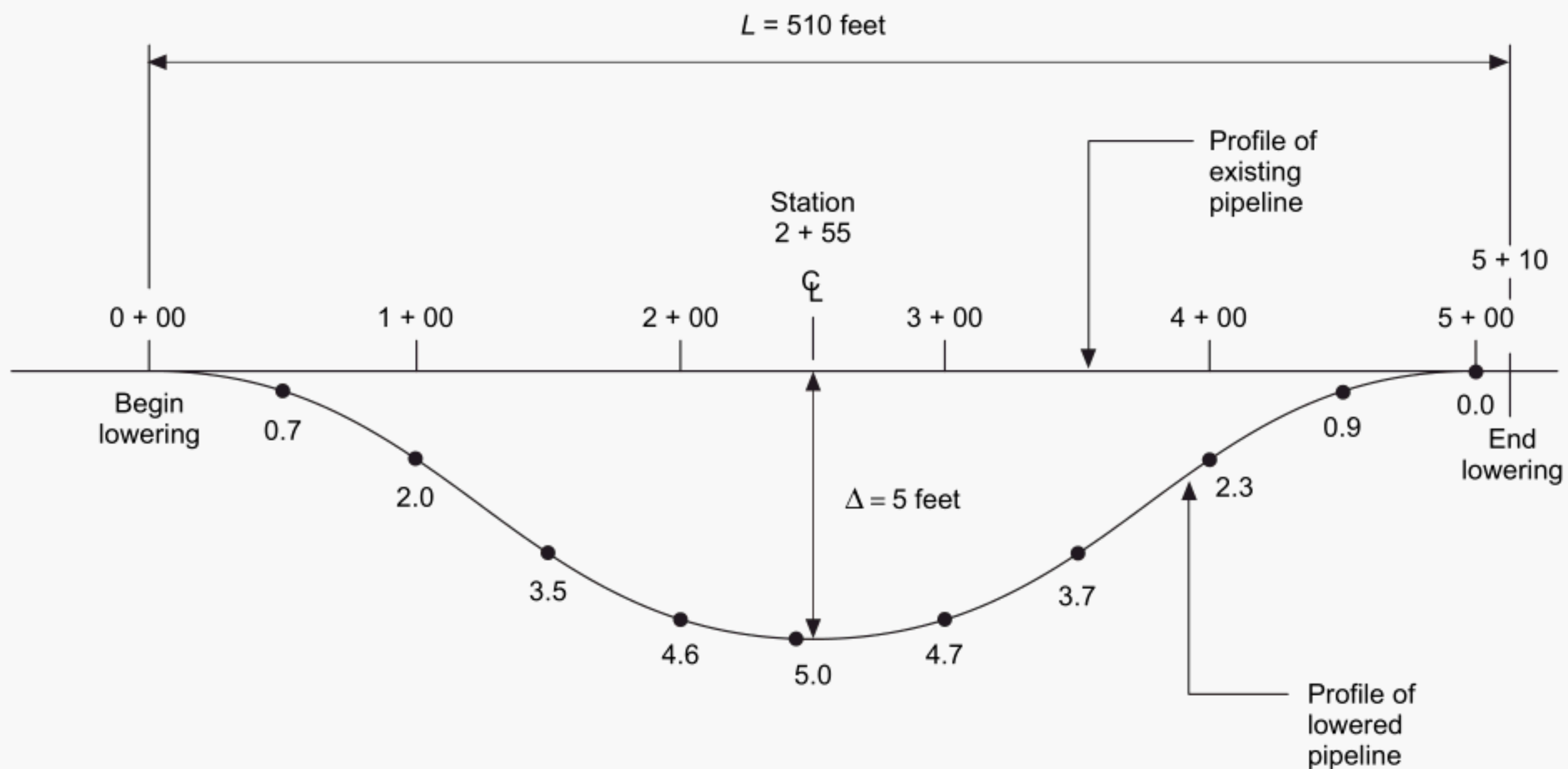


Figure 3—Preferred Trench Profile of a Sample Lowering

Table 1—Some Vertical Deflections (Δ_x) in the Preferred Trench Profile of a Sample Movement

Station x	Deflection Δ_x	Comment
0 + 00	0.0	Beginning of movement
0 + 25	0.2	
0 + 50	0.7	
0 + 75	1.3	
1 + 00	2.0	
1 + 25	2.7	
1 + 50	3.5	
1 + 75	4.1	
2 + 00	4.6	
2 + 25	4.9	
2 + 50	5.0	Midpoint of movement
2 + 55	5.0	
2 + 75	4.9	
3 + 00	4.7	
3 + 25	4.3	
3 + 50	3.7	
3 + 75	3.0	
4 + 00	2.3	
4 + 25	1.5	
4 + 50	0.9	
4 + 75	0.3	
5 + 00	0.0	Minimum length for movement
5 + 10	0.0	

NOTE The deflection Δ_x is measured in ft. The first part of station x is measured in hundreds of ft, and the second part is measured in ft.

Step 6: With Equations (6), (7), and (10), determine the maximum allowable support spacing.

$$S_s = 2.67E \left[\frac{\Delta}{L} \right]^2$$

$$= 2.67(29 \times 10^6) \left[\frac{5}{510} \right]^2$$

$$= 7442 \text{ psi}$$

$$S_A = F_D SMYS - S_E - S_s$$

$$= 0.9(42,000) - 20,845 - 7442$$

$$= 9513 \text{ psi}$$

$$L_s = \sqrt{\frac{0.0286(S_A)[(D)^4 - (d)^4]}{(D^3 - 0.8724(d)^2 D)}}$$

$$L_s = \sqrt{\frac{0.0286(9513)[(12.75)^4 - (12.25)^4]}{(12.75)^3 - 0.8724(12.25)^2(12.75)}}$$

$$= 51.3 \text{ ft}$$

Conclusion: The minimum trench length required to achieve the desired 5-ft vertical deflection of the pipe is 510 ft. The pipeline must be supported every 51.3 ft.

5 Procedure Considerations

5.1 General

A pipeline-moving project has three steps, which are to be performed in the following order:

- a) project planning;
- b) the actual work of ditching, moving, backfilling, and cleanup; and
- c) documentation to meet pipeline-operator and regulatory requirements.

Each of the consideration discussed in this section should be taken into account in at least one of these steps.

5.2 Safety Precautions

Caution—For safety, the cautions and recommendations described in 5.2.2 through 5.2.7 should be considered and followed.

5.2.1 General

5.2.2 Internal Operating Pressure

Prior to the pipe movement, the internal operating pressure of the pipeline should be reduced in accordance with the pipeline operators' procedures and applicable regulations.

5.2.3 Pipeline Location

Prior to planning and excavation, the location of the pipeline, including its depth, should be determined.

5.2.4 Other Underground Facilities

Prior to planning and excavation, efforts should be made to determine whether underground facilities may be encountered and, if so, where the facilities are located. The construction area should be checked for utility markers and other evidence of underground facilities. If available, state or local "One Call" systems should be accessed. Otherwise, operators of such underground facilities should be contacted directly so they may locate and mark their facilities. All contacts should be documented.

5.2.5 Girth Weld Inspection

If available, pipe mill test reports and welding inspection records should be reviewed. In addition, consideration should be given to the visual and nondestructive inspection of girth welds once the pipeline is exposed and prior to movement should be considered.

5.2.6 Attached Appurtenances

Attachments to the pipeline such as fittings or valves may affect the pipeline movement. Their effect on the movement should be considered. The movement of pipelines with attached appurtenances is beyond the scope of this recommended practice (see 1.2).

5.2.7 Excavation Safety

Excavation presents some unique safety considerations. It should be performed in accordance with the pipeline operators' procedures and applicable safety regulations. Refer to OSHA trenching and excavation regulations.

5.3 Terrain

Terrain refers primarily to the profile of the ground where the pipeline is located. Terrain affects a pipeline movement primarily by influencing the length of the trench required to move the pipeline.

In flat or gently rolling terrain, a pipeline is often laid by elastically conforming it to the terrain profile. In this case, the movement should be executed to minimize additional stress in the pipeline.

Caution—In flat or gently rolling terrain, to limit additional stress and ensure the safe movement of the pipeline, it may be necessary to excavate a longer trench than that required by the trench length equation.

In mountainous or hilly terrain, the pipeline may have permanent overbends or sag bends. In such cases, the physical profile for the moved pipeline should incorporate these bends. Movement operations on the pipeline should be executed to prevent the alteration of these bends.

Caution—To maintain safe conditions in difficult terrain such as that found in mountains and hills, movement operations should be treated as special cases and may require a detailed engineering analysis and the use of specialized construction techniques.

5.4 Soil

The soil type may determine the cross-sectional shape of the excavation and how the pipeline will be handled over the ditch.

5.5 Other Considerations

Caution—All pipeline movement projects should be executed with caution. If the pipeline is in tension and little or no slack is available, the movement will subject the pipe to additional stress due to the weight of the pipe, the weight of the fluid in it, and to seasonal temperature changes. Particular care should be taken in older pipelines in which the pipe connections may be mechanically weak.

For pipelines of known low toughness, additional consideration should be given before pipeline movement operations.

5.6 Trenching Requirements

The pipeline excavation should be performed so as to reduce the chances of damage to the pipeline coating system. If necessary, the ditch should be padded before moving the pipeline. The bottom of the completed trench should conform to the design profile for the moved pipeline.

5.7 Supports

5.7.1 Control of Unintended Movement

Changes to the pipe longitudinal stress in the pipe may cause unintended movement. Such changes in stress may result from residual stress or temperature changes in the pipeline. To control such movement, the pipeline should be properly supported and laterally restrained.

5.7.2 Point Loading

Points for supporting or lifting the pipeline should not be at or near girth welds. The spacing of lift or support points should ensure that stress limitations are not exceeded.

5.7.3 Soil Bearing Capacities

The soil bearing capacities for equipment and temporary supports should be considered.

5.7.4 Pipeline-supporting Methods

Figures 4 through 7 illustrate some pipeline-supporting methods.

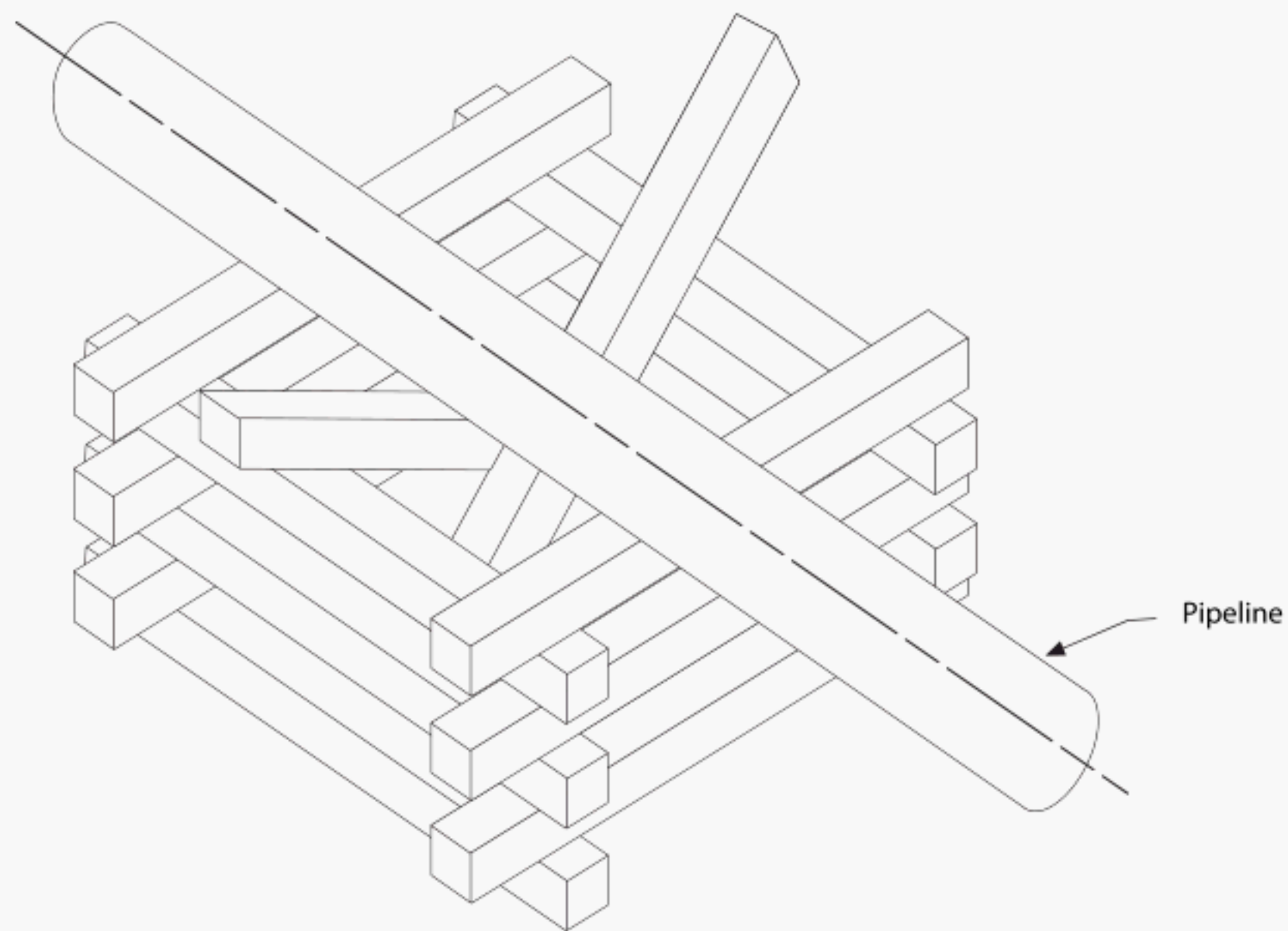


Figure 4—Pig Pen Method of Pipeline Support

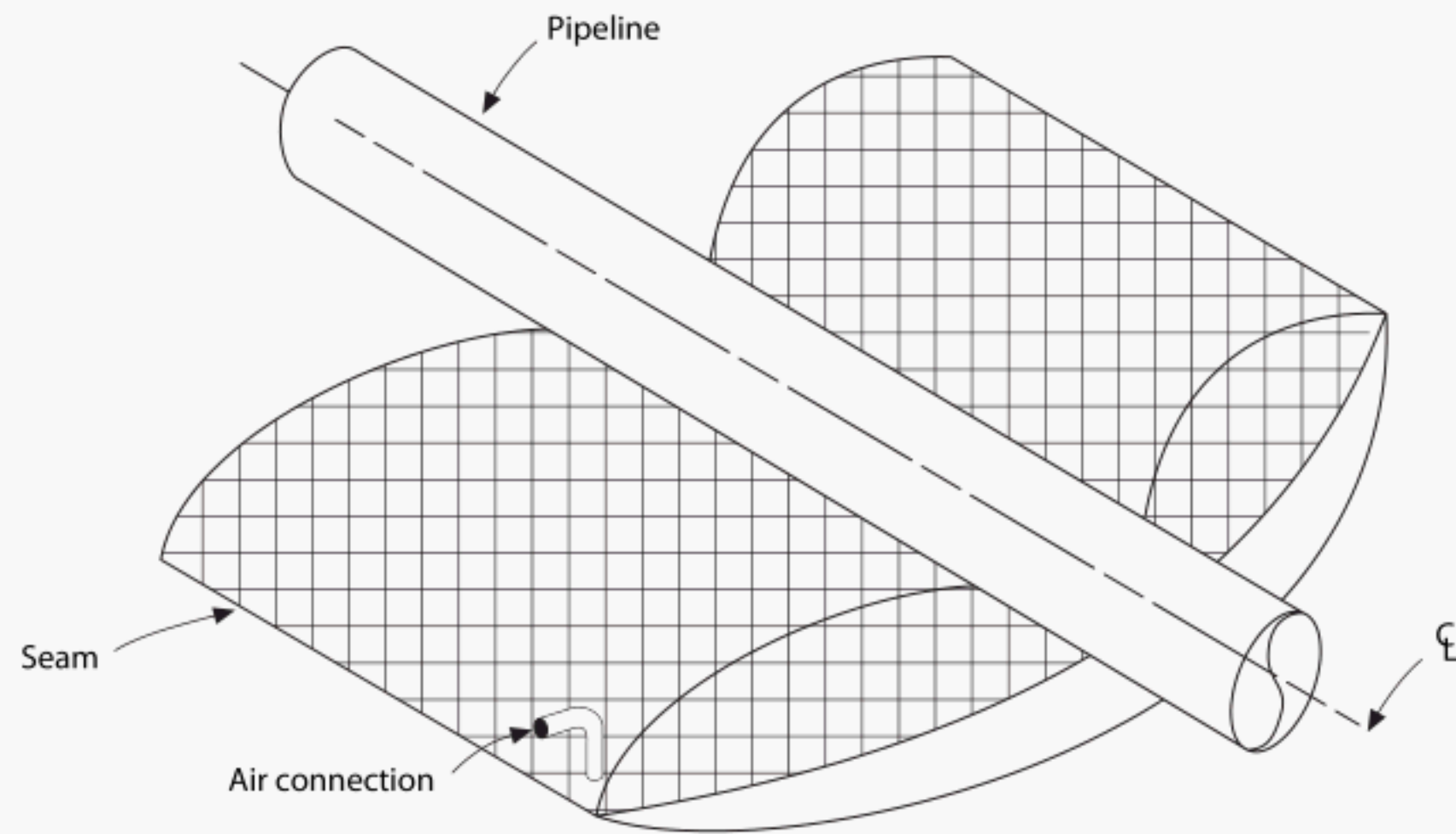


Figure 5—Air Bag Method of Pipeline Support

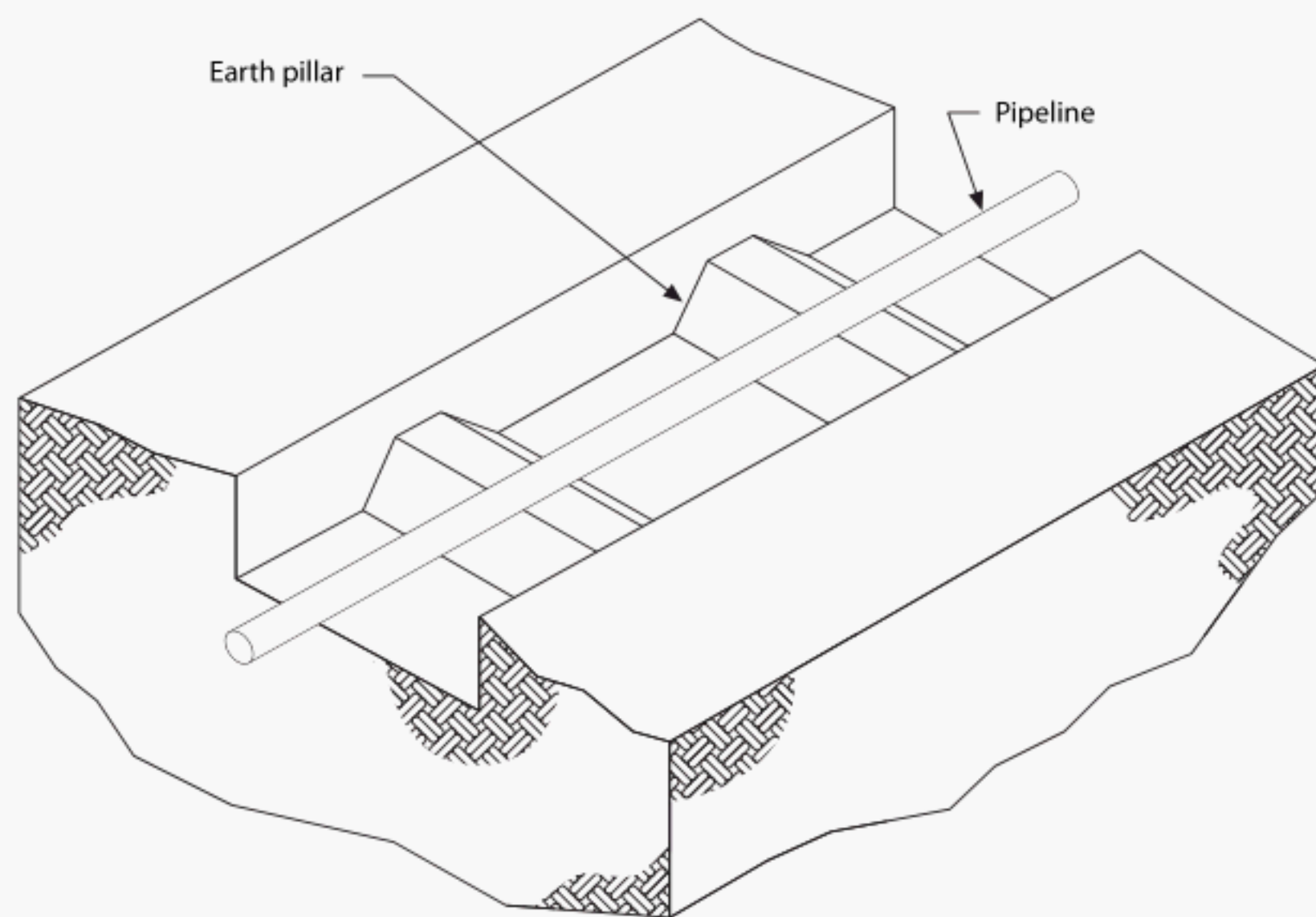


Figure 6—Earth Pillar Method of Pipeline Support

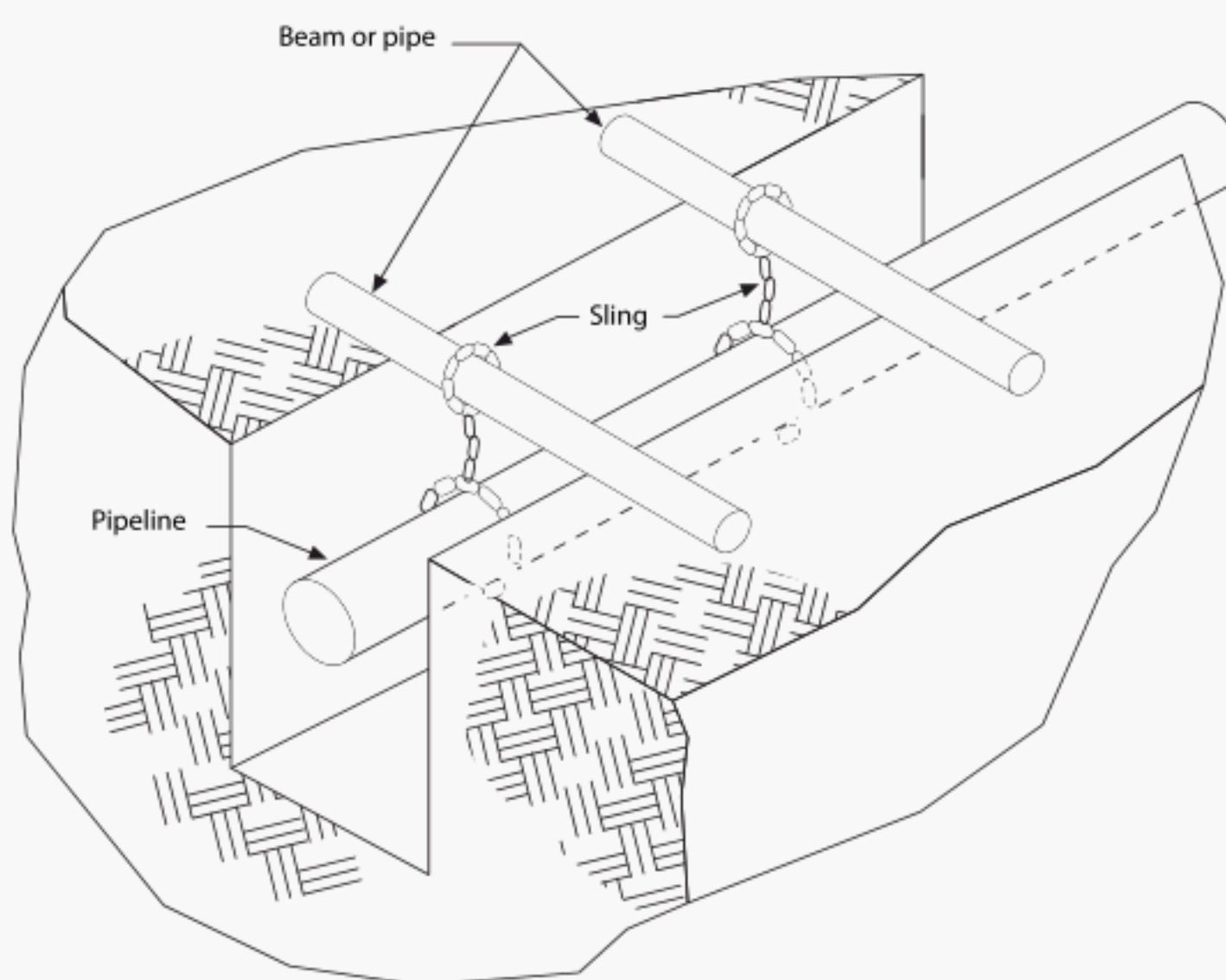


Figure 7—Sling Method of Pipeline Support

5.7.5 Pipeline-movement Methods

Figure 8 through Figure 10 illustrate some pipeline-movement methods. The differential heights of adjacent supports during the movement operation should be controlled so that at no time during the movement does the elastic curvature of the pipeline exceed the expected final elastic curvature of the pipeline due to the movement.

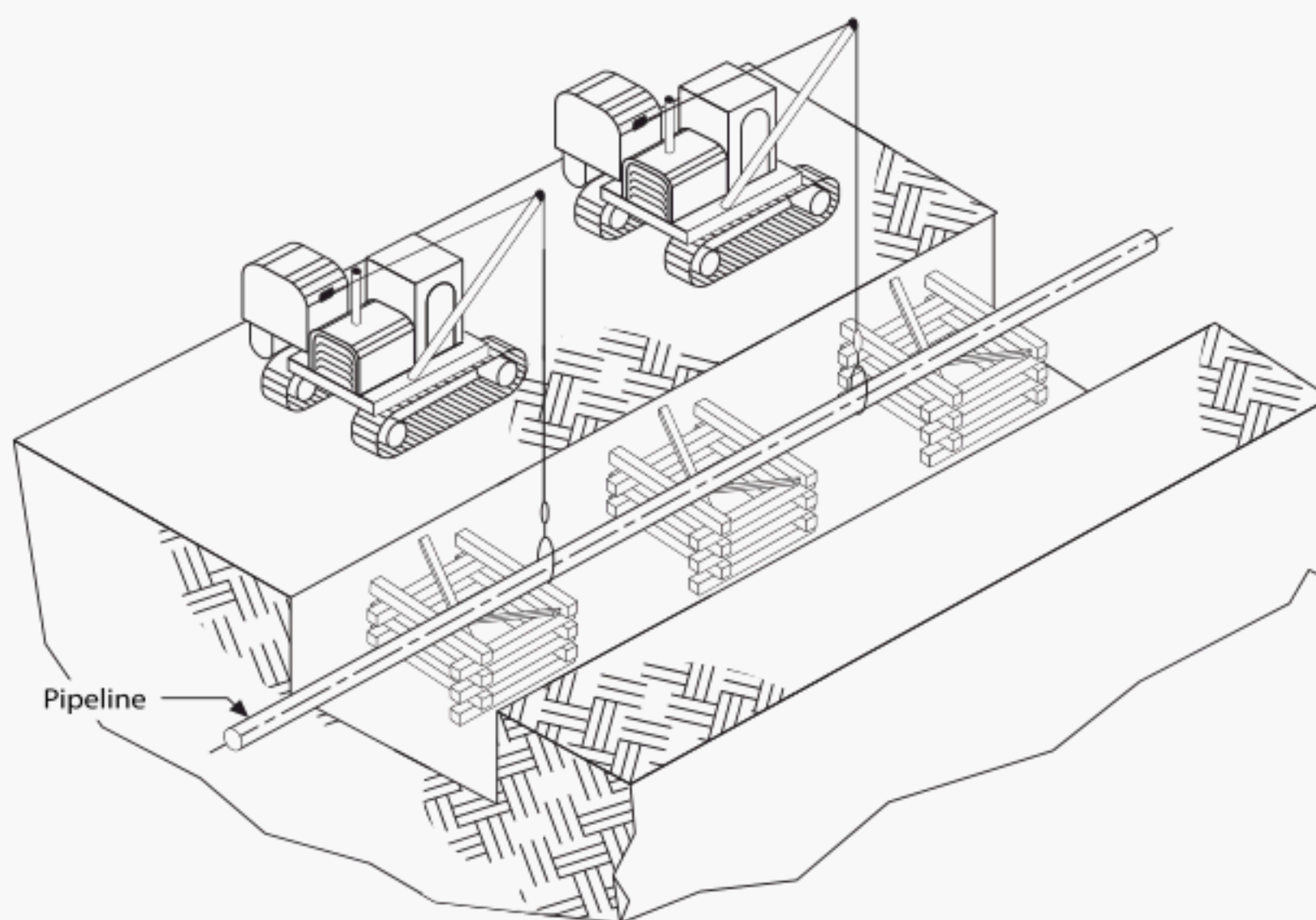


Figure 8—Pipeline-movement Method Using Two Side Booms

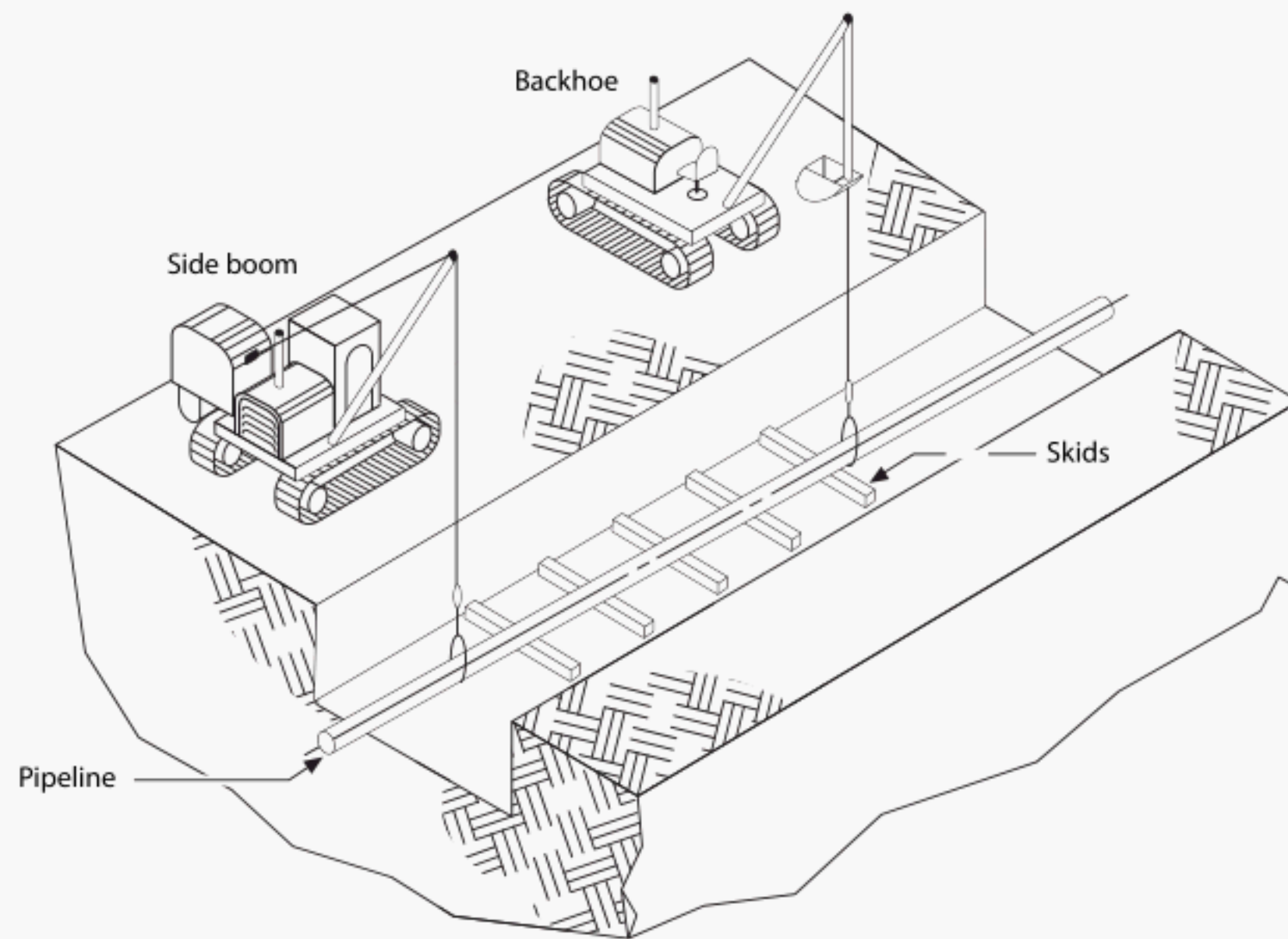


Figure 9—Pipeline-movement Method Using One Side Boom and One Backhoe

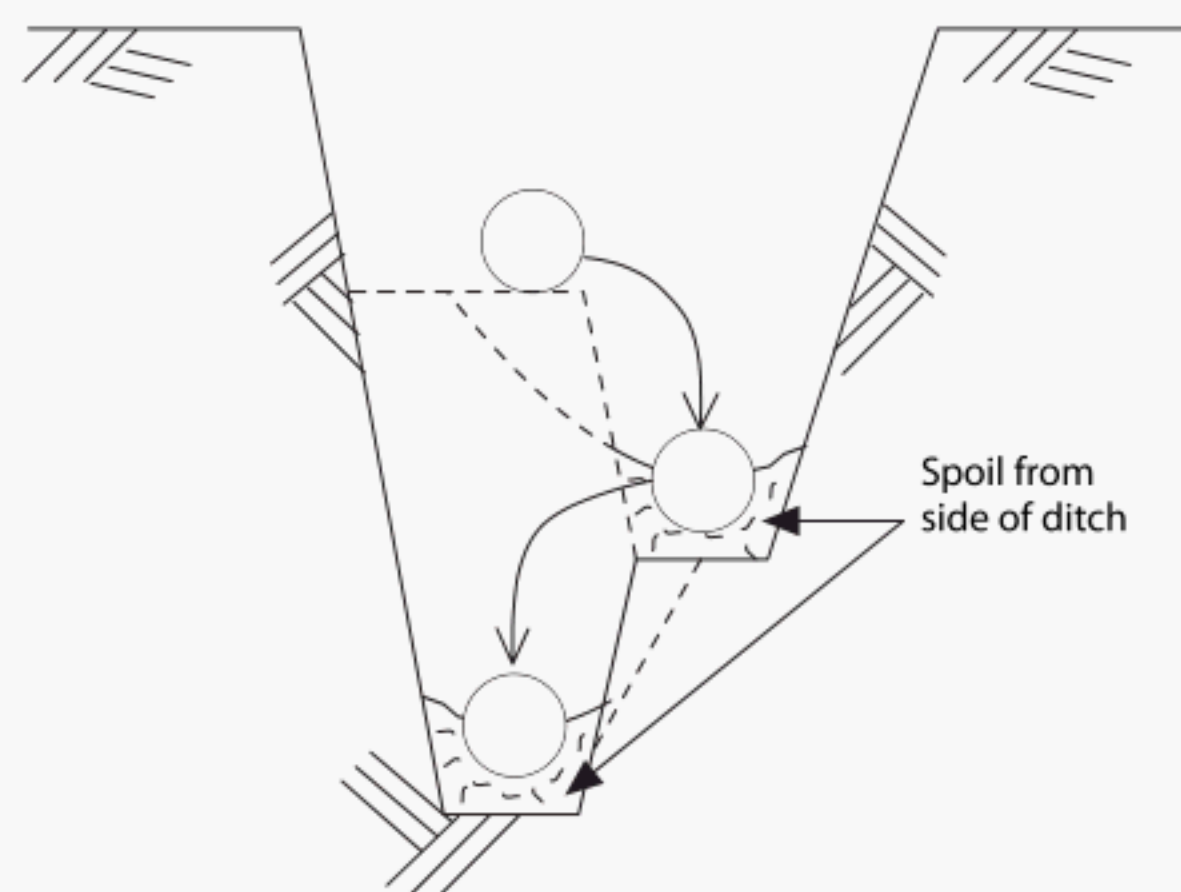


Figure 10—Pipeline-movement Method in Which Pipe is Slide into Ditch

6 Inspection

6.1 General

Prior to the execution of the pipeline movement, the exposed portion of the pipeline should be given a thorough overall visual inspection. A record should then be made of the inspection.

6.2 Girth Welds

Girth welds identified by 5.2.5 as requiring visual inspection should be visually inspected.

Caution—Pipe movement cannot be controlled once started.

NOTE Successive steps may be required.

6.3 Inspection for External Corrosion

The pipeline should be inspected for evidence of external corrosion. The disposition of any pipe with corrosion should be carried out in accordance with the pipeline operators' procedures and applicable regulations.

6.4 Inspection for Mechanical Damage

The pipeline should be inspected for mechanical damage. Imperfections and defects should be handled in accordance with the pipeline operators' procedures and applicable regulations.

6.5 External Coating

6.5.1 Inspection

The coating should be inspected both before and after a movement.

6.5.2 Repair Method

Any holidays (discontinuities) in the coating should be repaired using a system compatible with the existing coating. Loose or disbonded coating should be removed and replaced in accordance with the pipeline operators' procedures and applicable regulations.

7 Cleanup

7.1 General

Caution—Backfilling and restoration should be performed as described in 7.2 and 7.3 so as not to damage the pipe or its coating.

7.2 Backfilling

In backfilling, the use of rock shields or adequate padding should be considered. The backfill next to the pipeline should be free from rocks and other hard objects. Pipeline stress can be reduced in backfilling by ensuring that the pipe is flat on the trench bottom and is padded well with sand or good fill dirt, if necessary. No trash should be allowed to get into the ditch. In areas such as streets, driveways, and parking lots, extra compaction may be required.

7.3 Surface Restoration

After backfilling is completed, right-of-way contours should be restored to the original grade, the backfill material should be crowned over the excavation for soil settling, and appropriate water diversions should be installed to prevent washout of the excavation.

8 Documentation and Records

8.1 General

Adequate documentation and records of each pipeline movement project should be created and retained so that any subsequent operation on the pipeline at the movement site can take into account the adjustments made there. Movement records should be retained for the life of the pipeline.

8.2 Alignment Sheets

Line-moving projects should be posted to alignment sheets as soon as practicable. At a minimum, the posting reference should indicate where the details of the design and the “as-built” information can be found.

8.3 Files

Files should have the following information:

- a) The reason for moving the pipe.
- b) The condition of the pipe.
- c) The condition of the coating.
- d) The pipeline designation.
- e) The pipeline location.
- f) Any design calculations.
- g) The “as-built” plan and profile record.
- h) The dates that work was done.
- i) An observation of pipe behavior during movement.
- j) The pressure during movement.
- k) The name of the on-site representative.
- l) Record of posting to alignment sheets.
- m) The locations of adjacent structures and boundaries such as the following:
 - 1) other pipelines;
 - 2) roads;

- 3) buildings;
- 4) fences;
- 5) property lines;
- 6) rights-of-way;
- 7) aboveground utility structures; and
- 8) underground utility structures.

Annex A

Nomenclature

Symbol	Description	Value/Units
α	linear coefficient of thermal expansion of steel	6.5×10^{-6} in. per in. per °F
Δ	mid-span vertical deflection of the pipe	ft
Δ_x	vertical deflection of the pipe at distance x	ft
d	inside diameter of the pipe	in.
D	outside diameter of the pipe	in.
E	modulus of elasticity of steel	29×10^6 psi
F_D	design factor	—
L	minimum trench length required to reach the mid-span vertical deflection of the pipe (Δ)	ft
L_I	minimum trench length required to reach the mid-span vertical deflection of the pipe (Δ)	in.
L_S	maximum free span between pipe supports	ft
μ	Poisson's Ratio for steel	0.3
P	maximum internal operating pressure of the pipe	psi
S	elastic section modulus of the pipe	in. ³
S_A	longitudinal stress available for bending	psi
S_B	longitudinal stress in the pipe due to bending caused by the lowering operation	psi
S_C	longitudinal stress in the pipe due to existing elastic curvature	psi
S_E	existing longitudinal stress in the pipe	psi
S_L	total longitudinal stress in the pipe	psi
$SMYS$	specified minimum yield strength of the pipe	psi
S_P	longitudinal tensile stress in the pipe due to internal pressure	psi
S_S	longitudinal stress in the pipe due to its elongation caused by the moving operation	psi
S_r	longitudinal tensile stress in the pipe due to a change in its temperature	psi
t	nominal wall thickness of the pipe	in.
T_1	temperature of the pipe at the time of the installation	°F
T_2	operating temperature of the pipe at the time of the movement	°F
ω_T	desired mid-span vertical deflection of the pipe (Δ) [not the full weight of the pipe and fluid (see Annex B)]	lb/in.
x	distance along the length of the trench from the starting point of the pipe deflection	ft

Annex B

Derivation of the Equation for Longitudinal Stress Due to Bending and of the Equation for Trench Length

Equation (8), the trench length equation, and Equation (5), the equation for longitudinal stress in the pipe due to bending, are derived from AISC beam diagram 15 (see AISC M016) for a single-span, fixed-end, uniformly loaded beam. The desired pipe deflection (Δ_I) is set equal to the mid-span deflection of a fixed-end beam and used to determine the net load (ω_T) on the beam (pipe) required to cause this deflection. The length (L_I) of the beam in which the bending stress (S_B) due to the desired deflection is equal to the stress (S_A) available for bending is then determined.

NOTE All AISC dimensions are in inches.

Setting the desired deflection (Δ_I) of the pipe equal to the maximum deflection of a fixed-end beam

$$\Delta_I = \frac{\omega_T L_I^4}{384EI}$$

where

I is moment of inertia, in in.⁴.

Rearranging to solve for ω_T

$$\omega_T = \frac{384EI\Delta_I}{L_I^4}$$

The maximum moment in a fixed-end beam occurs at the ends as follows:

$$M = \frac{w_T L_I^2}{12}$$

where

M is the maximum moment in a fixed-end beam, in in.-lb.

The bending stress in the beam (pipe) at its outer surface is

$$S_B = \frac{MC}{I}$$
$$= \frac{M}{S}$$

where

C is the distance from neutral axis to outside surface of beam, in inches.

Therefore, as expressed in Equation (5), the equation for longitudinal stress in the pipe due to bending.

$$S_B = \frac{\omega_T L_I^2}{12S}$$

As shown in Equation (7)

$$S_A = F_D SMYS - S_E - S_S$$

Equation (6) implies that

$$S_S = 2.67E \frac{\Delta_I^2}{L_I^2}$$

Setting S_B equal to S_A and substituting for S_S

$$\frac{\omega_T L_I^2}{12S} = F_D SMYS - S_E - 2.67E \frac{\Delta_I^2}{L_I^2}$$

Substituting for w_T

$$\frac{384EI\Delta_I}{12S L_I^2} = F_D SMYS - S_E - 2.67E \frac{\Delta_I^2}{L_I^2}$$

Simplifying and solving for L_I^2

$$\begin{aligned} \frac{384EI\Delta_I}{12S} &= L_I^2 (F_D SMYS - S_E) - 2.67E \Delta_I^2 \\ L_I^2 &= \frac{\frac{32EI\Delta_I}{S} + 2.67E \Delta_I^2}{F_D SMYS - S_E} \end{aligned}$$

For a hollow circular pipe (see AISC M016)

$$S = 0.098175 \left(\frac{D^4 - d^4}{D} \right)$$

$$I = 0.049087 (D^4 - d^4)$$

$$E = 29 \times 10^6 \text{ psi}$$

Substituting for S , I , and E

$$\begin{aligned} L_I^2 &= \frac{\frac{32(29 \times 10^6)(0.049087)(D^4 - d^4)\Delta_I}{0.098175 \left(\frac{D^4 - d^4}{D} \right)}}{F_D SMYS - S_E} \\ &+ \frac{2.67(29 \times 10^6)\Delta_I^2}{F_D SMYS - S_E} \\ &= \frac{(4.64 \times 10^8)D\Delta_I + (7.74 \times 10^7)\Delta_I^2}{F_D SMYS - S_E} \end{aligned}$$

and

$$L_I = \sqrt{\frac{(4.64 \times 10^8)D\Delta_I + (7.74 \times 10^7)\Delta_I^2}{F_D SMYS - S_E}}$$

Converting to ft, the units used for L in this document

$$L = \sqrt{\frac{(3.87 \times 10^7)D\Delta + (7.74 \times 10^7)\Delta^2}{F_D SMYS - S_E}}$$

Annex C

Derivation of Trench Profile Equation

Equation (9), the equation for the deflection of the pipe at any point along the trench profile, is derived from AISC beam diagram 15 (see AISC M016), assuming that the beam is fixed at both ends, that the loads are uniformly distributed, and that the units of measure are consistent.

$$\Delta_x = \frac{\omega_T x^2 (L - x)^2}{24 E I} \quad (C.1)$$

Setting the desired deflection of the pipe (Δ) equal to the maximum (mid-span) deflection of a fixed-end beam

$$\Delta = \frac{\omega_T L^4}{384 E I} \quad (C.2)$$

Rearranging to solve for ω_T

$$\omega_T = \frac{384 E I \Delta}{L^4} \quad (C.3)$$

Substitution of the right-hand side of the above equation for ω_T in Equation (C.1) and simplification of the resulting equation show that

$$\begin{aligned} \Delta_x &= \frac{384 E I \Delta x^2 (L - x)^2}{24 E I L^4} \\ &= \frac{16 x^2 \Delta (L - x)^2}{L^4} \end{aligned} \quad (C.4)$$

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Annex D

Derivation of Equation for Longitudinal Stress Due to Elongation

Equation (6), the equation that estimates the longitudinal stress in the pipe due to elongation, is based on the fact that for any given horizontal distance (see Figure D.1), the arc length of a circular curve is greater than the length of the corresponding horizontal line segment.

For any one of the four circular-curve segments of the moved pipe (see Figure D.2), the elongation (δ) is the difference in length due to stretching.

$$\delta = A - l \quad (D.1)$$

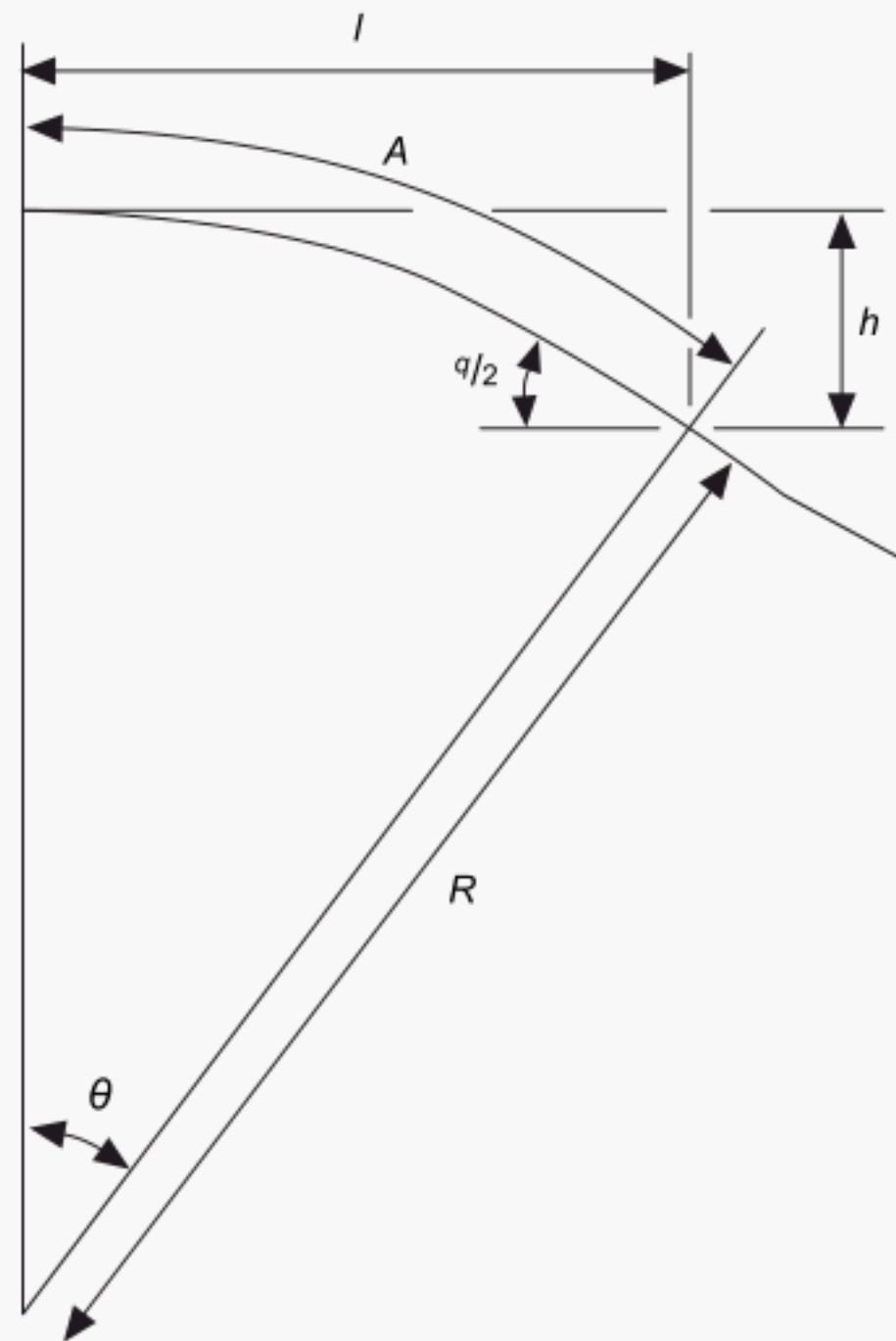


Figure D.1—Arc Length (A) of a Circular Curve

where

δ is the difference in length of the pipe segment due to stretching caused by movement;

A is the arc length of a circular curve representing the pipe segment in its final position, after movement;

l is the original length of the pipe segment, before movement.

The strain (ϵ) on the pipe due to its elongation is the difference in length divided by the original length.

$$\epsilon = \frac{\delta}{l} \quad (D.2)$$

where

ϵ is the strain on the pipe due to its elongation.

Trigonometry indicates that for angles in radians

$$A = R\theta$$

$$l = R \sin \theta = R \left(\theta - \frac{\theta^3}{3!} + \frac{\theta^5}{5!} - \dots \right)$$

where

R is the radius of curvature;

θ is the arc angle, in radians.

For small angles

$$l \cong R \left[\theta - \frac{\theta^3}{6} \right]$$

Substituting and simplifying

$$\begin{aligned} \delta &= A - l = R\theta - R \left[\theta - \frac{\theta^3}{6} \right] \\ &= \frac{R\theta^3}{6} \end{aligned} \tag{D.3}$$

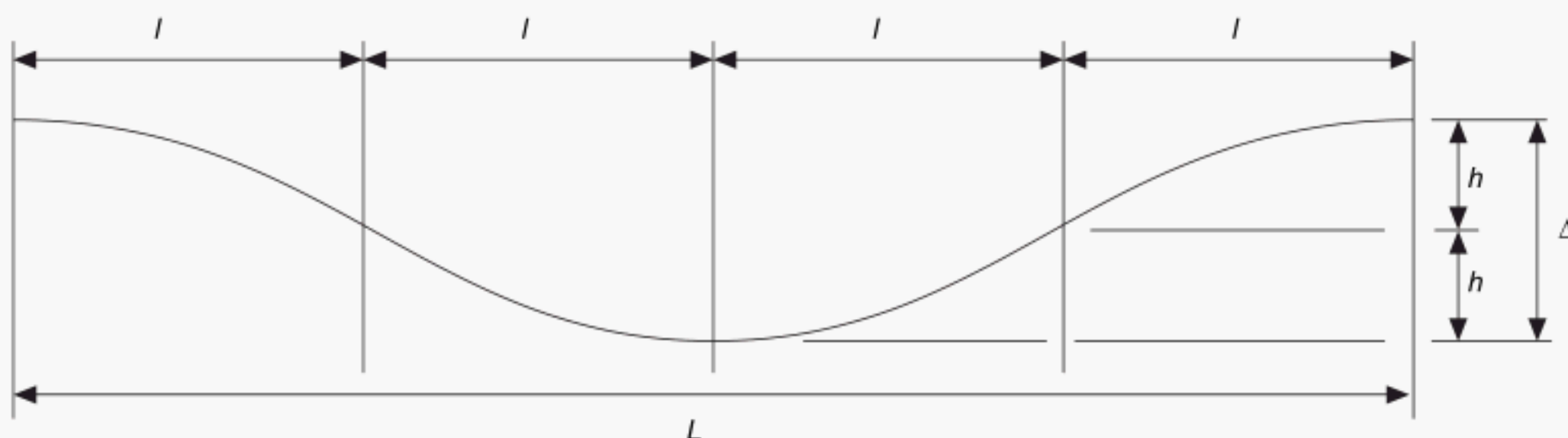


Figure D.2—The Four Circular-curve Segments in the Preferred Trench Profile of the General Movement

In general

$$\frac{h}{l} = \tan\left(\frac{\theta}{2}\right) \tag{D.4}$$

where

h is the deflection.

Since for small angles

$$\tan\left(\frac{\theta}{2}\right) \cong \frac{\theta}{2}$$

therefore

$$\theta = \frac{2h}{l} \tag{D.5}$$

Since

$$l = R \sin \theta \quad (\text{D.6})$$

therefore, for small angles

$$l \cong R \theta$$

Substitution of the right-hand side of the second line of Equation (D.3) for δ in Equation (D.2), reduction of $R\theta$ in the resulting equation to l in accordance with the above equation, and simplification show that

$$\begin{aligned} \varepsilon = \frac{\delta}{l} &= \frac{\left[\frac{R\theta^3}{6} \right]}{l} = \frac{[R \theta \theta^2]}{6l} = \frac{l\theta^2}{6l} = \frac{\left[l \left(\frac{2h}{l} \right)^2 \right]}{6l} \\ &= \frac{2}{3} \left(\frac{h}{l} \right)^2 \end{aligned} \quad (\text{D.7})$$

Since there are four circular-curve segments in each lowering (see Figure D.2)

$$\begin{aligned} L &= 4l \\ l &= \frac{L}{4} \\ l^2 &= \frac{L^2}{16} \end{aligned} \quad (\text{D.8})$$

As Figures D.1 and D.2 indicate

$$\begin{aligned} \Delta &= 2h \\ h &= \frac{\Delta}{2} \\ h^2 &= \frac{\Delta^2}{4} \end{aligned} \quad (\text{D.9})$$

Rewriting the above equation for ε in terms of Δ and L

$$\begin{aligned} \varepsilon &= \frac{2}{3} \left(\frac{h^2}{l^2} \right) = \frac{2}{3} \left(\frac{\Delta^2}{4} \right) \left(\frac{16}{L^2} \right) = \frac{8}{3} \left(\frac{\Delta^2}{L^2} \right) \\ &= 2.67 \left(\frac{\Delta}{L} \right)^2 \end{aligned} \quad (\text{D.10})$$

Since, by definition

$$S_s = \varepsilon E \quad (\text{D.11})$$

therefore, the stress in the pipe due to its elongation is

$$S_s = 2.67 E \left(\frac{\Delta}{L} \right)^2 \quad (\text{D.12})$$

Annex E

Derivation of Equation for Maximum Free Span Between Pipe Supports

Equation (10), the equation for the maximum free span between pipe supports, is derived from AISC beam diagram 39 (see AISC M016), which is for a continuous beam with four equal spans that are loaded.

NOTE All dimensions are in inches.

$$\begin{aligned} M_{\text{Max}} &= 0.1071 W L_{S_I}^2 \\ &= S_A S \end{aligned}$$

where

$L_{S_I}^2$ is the maximum free span between pipe supports, in inches;

M_{MAX} is the maximum moment, in in.-lb;

W is the full weight of water-filled pipe, in lb/in.

For a hollow circular pipe

$$S = 0.098175 \left(\frac{D^4 - d^4}{D} \right)$$

Substitution yields

$$M_{\text{MAX}} = S_A \left[0.098175 \left(\frac{D^4 - d^4}{D} \right) \right]$$

$$0.1071 W L_{S_I}^2 = S_A \left[0.098175 \left(\frac{D^4 - d^4}{D} \right) \right]$$

Solving for $L_{S_I}^2$

$$L_{S_I}^2 = \frac{S_A \left[0.098175 \left(\frac{D^4 - d^4}{D} \right) \right]}{0.1071 W}$$

Since

$$W = \rho_{\text{steel}} A_{\text{pipe}} + \rho_{\text{water}} A_{\text{water}}$$

where

ρ_{steel} is the density of steel, 0.283 lb/in.³;

ρ_{water} is the density of water, 0.0361 lb/in.³;

A_{pipe} is the cross-sectional area of steel pipe, in in.²;

A_{water} is the cross-sectional area of water in filled pipe, in in.².

and

$$A_{\text{pipe}} = \frac{\pi}{4}(D^2 - d^2)$$

$$A_{\text{water}} = \frac{\pi}{4}(d^2)$$

therefore

$$\begin{aligned} W &= \frac{\pi}{4}[\rho_{\text{steel}}(D^2 - d^2) + (\rho_{\text{water}}d^2)] \\ &= \frac{\pi}{4}[(\rho_{\text{steel}}D^2) - (\rho_{\text{steel}}d^2) + (\rho_{\text{water}}d^2)] \\ &= \frac{\pi}{4}[(\rho_{\text{steel}}D^2) + (\rho_{\text{water}} - \rho_{\text{steel}})d^2] \\ &= \frac{\pi}{4}[0.283D^2 - 0.2469d^2] \end{aligned}$$

Substituting for W

$$L_{S_I}^2 = \frac{S_A \left[0.098175 \left(\frac{D^4 - d^4}{D} \right) \right]}{0.1071 \left(\frac{\pi}{4} \right) [0.283D^2 - 0.2469d^2]}$$

Since

$$0.1071 \left(\frac{\pi}{4} \right) = 0.084116$$

therefore

$$\begin{aligned} L_{S_I}^2 &= \frac{S_A [1.16714(D^4 - d^4)]}{0.238D[D^2 - 0.8724d^2]} \\ &= \frac{4.1242S_A(D^4 - d^4)}{D[D^2 - 0.8724d^2]} \\ &= \frac{4.1242S_A(D^4 - d^4)}{D^3 - 0.8724Dd^2} \end{aligned}$$

and

$$L_{S_I}^2 = \sqrt{\frac{4.1242S_A(D^4 - d^4)}{D^3 - 0.8724Dd^2}}$$

Converting to ft, the units used for L_S in this RP

$$L_{S_I}^2 = \sqrt{\frac{0.0286S_A(D^4 - d^4)}{D^3 - 0.8724Dd^2}}$$

Annex F

Equations

Equation	No. Description, in Units
$S_L = S_E + S_B + S_S$	[1] total longitudinal stress in the pipe, in psi
$S_P = P D \frac{\mu}{2t}$	[2] longitudinal tensile stress in the pipe due to internal pressure, in psi
$S_r = E\alpha(T_1 - T_2)$	[3] longitudinal tensile stress in the pipe due to a change in its temperature, in psi
$S_E = S_P + S_r + S_C$	[4] existing longitudinal stress in the pipe, in psi
$S_B = \frac{\omega_T L_I^2}{12S}$	[5] longitudinal stress in pipe due to bending caused by the movement operation, in psi
$S_S = 2.67E \left[\frac{\Delta}{L} \right]^2$	[6] longitudinal stress in pipe due to elongation caused by the movement operation, in psi
$S_A = F_D SMYS - S_E - S_S$	[7] longitudinal stress available for bending, in psi
$L = \sqrt{\frac{[(3.87 \times 10^7) D \Delta + (7.74 \times 10^7) \Delta^2]}{F_D SMYS - S_E}}$	[8] minimum trench length required to reach the mid-span vertical deflection of the pipe (Δ), in ft
$\Delta_x = \frac{16x\Delta(L-x)^2}{L^4}$	[9] vertical deflection of the pipe at distance x , in ft
$L_S = \sqrt{\frac{[0.0286 S_A (D^4 - d^4)]}{D^3 - 0.8724 d^2 D}}$	[10] maximum free span between pipe supports, in ft
$S_C =$ longitudinal stress in the pipe due to existing curvature	— longitudinal stress in the pipe due to existing elastic curvature, in psi

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Date of Issue: August 2009

Affected Publication: API Recommended Practice 1117, *Recommended Practice for Movement of In-service Pipelines*, 3rd Edition, July 2008

ERRATA 1 & 2

This errata corrects editorial errors in the 3rd Edition of API RP 1117.

Page 25, Figure D.1, change:

q

to

θ

The change listed below was issued with Errata 1 (December 2008).

Page 8, Step 4, change:

= 20,845 psi

to

= 510 ft



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