ASME B31G-2012
(Revision of ASME B31G-2009)

Manual for Determining the Remaining Strength of Corroded Pipelines

Supplement to ASME B31 Code for Pressure Piping

AN AMERICAN NATIONAL STANDARD

The American Society of
Mechanical Engineers

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Three Park Avenue • New York, NY • 10016 USA

Date of Issuance: October 24, 2012

The next edition of this Manual is scheduled for publication in 2015.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Manual. Periodically certain actions of the ASME B31 Committee may be published as Code Cases. Code Cases and interpretations are published on the ASME Web site under the Committee Pages at http://cstools.asme.org/ as they are issued.

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This Manual was developed under procedures accredited as meeting the criteria for American National Standards. The Standards Committee that approved the Manual was balanced to assure that individuals from competent and concerned interests have had an opportunity to participate. The proposed Manual was made available for public review and comment that provides an opportunity for additional public input from industry, academia, regulatory agencies, and the public-at-large.

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FOREWORD

It has been recognized within the pipeline industry that some sections of high-pressure pipelines, particularly those with long service histories, may experience corrosion. It has also been recognized, through theoretical analysis, scientific research and testing, and industry operating experience, that some amount of metal loss due to corrosion can be tolerated without impairing the ability of the pipeline to operate safely. In 1984, ASME published the first edition of the B31G Manual for Determining the Remaining Strength of Corroded Pipelines. The B31G document provided pipeline operators with a simplified evaluation method based on the results of analysis and tests. The application of B31G has enabled pipeline operators to reliably determine safe operating pressure levels for pipe affected by corrosion, and to determine whether repairs are necessary in order to continue operating safely.

B31G continued to be reissued by ASME with only minor revisions over time, although other corrosion evaluation methods had evolved since B31G's initial publication. A majority of these other methods are based on the same theoretical model from which the original B31G method was derived, but may offer some refinement in accuracy. Subsequently, an effort was undertaken to update the B31G document to recognize certain other corrosion evaluation methods that have proven sound and that have seen successful use in the pipeline industry. Incorporation of these other methods into a recognized Code document provides the pipeline operator or other user with a formalized framework within which to use such methodologies, as well as a wider range of codified technical options with which to make an evaluation. The 2009 revision of B31G reflected those objectives.

The 2012 edition of B31G was approved by the American National Standards Institute (ANSI) on September 20, 2012.

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Code for Pressure Piping

(The following is the roster of the Committee at the time of approval of this Standard.)

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General. ASME Standards are developed and maintained with the intent to represent the consensus of concerned interests. As such, users of this Standard may interact with the Committee by requesting interpretations, proposing revisions, and attending Committee meetings. Correspondence should be addressed to:

Secretary, B31 Standards Committee
The American Society of Mechanical Engineers
Three Park Avenue
New York, NY 10016-5990

Proposing Revisions. Revisions are made periodically to the Standard to incorporate changes that appear necessary or desirable, as demonstrated by the experience gained from the application of the Standard. Approved revisions will be published periodically.

The Committee welcomes proposals for revisions to this Standard. Such proposals should be as specific as possible, citing the paragraph number(s), the proposed wording, and a detailed description of the reasons for the proposal, including any pertinent documentation.

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Requests for Cases shall provide a Statement of Need and Background Information. The request should identify the standard, the paragraph, figure or table number(s), and be written as a Question and Reply in the same format as existing Cases. Requests for Cases should also indicate the applicable edition(s) of the standard to which the proposed Case applies.

Interpretations. Upon request, the B31 Standards Committee will render an interpretation of any requirement of the Standard. Interpretations can only be rendered in response to a written request sent to the Secretary of the B31 Standards Committee.

The request for an interpretation should be clear and unambiguous. It is further recommended that the inquirer submit his/her request in the following format:

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry.
Edition:	Cite the applicable edition of the Standard for which the interpretation is being requested.
Question:	Phrase the question as a request for an interpretation of a specific requirement suitable for general understanding and use, not as a request for an approval of a proprietary design or situation. The inquirer may also include any plans or drawings that are necessary to explain the question; however, they should not contain proprietary names or information.

Requests that are not in this format may be rewritten in the appropriate format by the Committee prior to being answered, which may inadvertently change the intent of the original request.

ASME procedures provide for reconsideration of any interpretation when or if additional information that might affect an interpretation is available. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME Committee or Subcommittee. ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity.

Attending Committee Meetings. The B31 Standards Committee regularly holds meetings, which are open to the public. Persons wishing to attend any meeting should contact the Secretary of the B31 Standards Committee.

ASME B31G-2012
SUMMARY OF CHANGES

Following approval by the B31 Committee and ASME, and after public review, ASME B31G-2012 was approved by the American National Standards Institute on September 20, 2012.

Changes given below are identified on the pages by a margin note, **(12)**, placed next to the affected area.

Page	*Location*	*Change*
2	1.5	In the nomenclature, definition of P_F revised
7	2.3	First sentence revised
9	Table 3-1	In eighth column, second entry revised
	Table 3-1M	In eighth column, second entry revised
10	Table 3-2	In fifth column, second entry revised
11	Table 3-2M	In fifth column, second entry revised
14	Table 3-4	In second column, first entry revised
15	Table 3-4M	In second column, first entry revised
22	Table 3-8	In third column, first entry revised
23	Table 3-8M	In third column, first entry revised

SPECIAL NOTES:

The interpretations to ASME B31G are included in this edition as a separate section for the user's convenience.

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MANUAL FOR DETERMINING THE REMAINING STRENGTH OF CORRODED PIPELINES

1 INTRODUCTION

1.1 Scope

This document is intended solely for the purpose of providing guidance in the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems within the scope of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL. Where the term *pipeline* is used, it may also be read to apply to piping or pipe conforming to the acceptable applications and within the technical limitations discussed below.

1.2 Acceptable Applications

The application of this document is limited to the evaluation of wall loss in metal pipe within the following limitations:

(a) metal loss in pipelines located belowground, aboveground, or offshore

(b) metal loss due to external or internal corrosion

(c) metal loss produced by grinding where used to completely remove mechanical damage, cracks, arc burns, manufacturing defects, or other defects from the pipe surface

(d) metal loss in field bends, induction bends, and elbows

(e) metal loss that incidentally affects longitudinal or helical electric seam welds or circumferential electric welds of sound quality and having ductile characteristics, provided workmanship flaws are not present in sufficiently close proximity to interact with the metal loss

(f) metal loss of any depth with respect to the pipe wall, except that due consideration shall be given to the accuracy of measurements and effective corrosion rates when the depth of metal loss exceeds 80% of the actual pipe wall dimension

(g) metal loss in new pipe where allowed by the applicable code of construction

(h) metal loss in pipe material having ductile fracture initiation characteristics [see paras. 1.7(e) and (f)] unless using a Level 3 assessment in accordance with paras. 2.2(b) and 2.4

(i) metal loss in pipe operating at temperatures above ambient within the range of operating temperature recognized by the governing standard, and provided material strength properties at temperature are considered

(j) metal loss in pipe operating at any level of allowable design hoop stress [see paras. 1.4(a) and (b) for additional considerations]

(k) metal loss in pipe where internal pressure is the primary loading [see paras. 1.4(c) and (d) for additional considerations]

1.3 Exclusions

This document does not apply to the following:

(a) crack-like defects or mechanical surface damage not completely removed to a smooth contour by grinding

(b) metal loss in indentations or buckles resulting in radial distortion of the pipe wall larger than 6% of the pipe outside diameter, unless a Level 3 assessment is performed in accordance with para. 2.4

(c) grooving corrosion, selective corrosion, or preferential corrosion affecting pipe seams or girth welds

(d) metal loss in fittings other than bends or elbows

(e) metal loss affecting material having brittle fracture initiation characteristics [see paras. 1.7(e) and (f)] unless a Level 3 assessment is performed in accordance with para. 2.4

(f) pipe operating at temperatures outside the range of operating temperature recognized by the governing standard or operating at temperatures in the creep range

1.4 Additional Considerations

The user is cautioned that additional considerations may apply in certain situations, described below.

(a) Pipe operating at low hoop stress levels due to internal pressure (e.g., less than 25% of SMYS) may be perforated by corrosion without inducing structural material failure. The methods and criteria provided herein do not address failure by perforation.

(b) Pipe affected by general corrosion of the pipe wall (i.e., corrosion-caused wall loss over the entire pipe surface) effectively operates at a greater hoop stress than

the nominal hoop stress based on the original wall dimension. Evaluation of individual deep pits within a generally corroded area should account for the effect of wall loss due to general corrosion.

(c) Under conditions normally encountered in buried pipelines, the hoop stress due to internal pressure is the largest stress and will govern the mode of failure. High longitudinal stresses in tension acting on metal loss having a significant circumferential extent, in unrestrained piping, could change the failure mode from longitudinal to circumferential. The methods and criteria provided herein do not address circumferential failure due to high longitudinal tensile stresses. For such situations, the user should refer to a more comprehensive fitness-for-purpose guidance document, such as API 579-1/ ASME FFS-1–2007, Fitness-for-Service.

(d) Metal loss having a significant circumferential extent and acted on by high longitudinal stresses in compression could be susceptible to wrinkling or buckling. Also, the combination of hoop stress due to internal pressure and longitudinal compression could interact to lower the failure pressure in the metal loss area. The methods and criteria provided herein do not address buckling or wrinkling, or interaction of hoop stress with longitudinal compressive stresses. For such situations, the user should refer to a more comprehensive fitness-for-purpose guidance document, such as API 579-1/ ASME FFS-1.

(12) 1.5 Nomenclature

A = local area of metal loss in the longitudinal plane
A_C = cross-sectional area of Charpy impact specimen
A_0 = local original metal area = Lt
C_V = Charpy V-notched impact absorbed energy
D = specified outside diameter of the pipe
d = depth of the metal loss
E = elastic modulus of steel
L = length of the metal loss
L_e = effective length = $L(\pi/4)$
M = bulging stress magnification factor
$MAOP$ = maximum allowable operating pressure
MOP = maximum operating pressure
P_F = estimated failure pressure = $2S_F t/D$
P_O = operating pressure, may equal MAOP or MOP
P_S = safe operating pressure = P_F/SF
S_F = estimated failure stress level
S_{flow} = flow stress, defined in para. 1.7(b)
S_O = hoop stress at the operating pressure, calculated as $P_O D/2t$
S_{UT} = specified ultimate tensile strength at temperature, may equal SMTS
S_{YT} = specified yield strength at temperature, may equal SMYS
SF = safety factor
$SMTS$ = specified minimum tensile strength at ambient conditions
$SMYS$ = specified minimum yield strength at ambient conditions
t = pipe wall thickness
z = L^2/Dt
z_e = L_e^2/Dt

1.6 Analysis Level

The user may choose to conduct a Level 0, Level 1, Level 2, or Level 3 analysis, depending on the quantity and quality of data available with which to perform an evaluation, and on the desired degree of refinement of the analysis.

(a) A Level 0 evaluation is one that relies on the tables of allowable defect length and depth found in section 3. These tables are carried over without change from earlier editions of ASME B31G and have been supplemented by the addition of tables in metric units. It is intended that a Level 0 evaluation be conducted in the field without the need for performing detailed calculations.

(b) A Level 1 evaluation is a simple calculation that relies on single measurements of the maximum depth and axial extent of metal loss. It is intended that a Level 1 evaluation be conducted in the field by an engineer, corrosion technician, coating inspector, or other individual having appropriate training. A Level 1 evaluation is also suitable for use in prioritizing metal-loss anomalies identified by inline inspection.

(c) A Level 2 evaluation is one that incorporates a greater level of detail than a Level 1 evaluation in order to produce a more accurate estimate of the failure pressure. It typically relies on detailed measurements of the corroded surface profile, accounting for the actual distribution of metal loss, and involves repetitive computations that may be facilitated by the use of computer software or spreadsheets. It is intended that a Level 2 evaluation be conducted by an engineer or technician having appropriate training. A Level 2 evaluation may be suitable for use in prioritizing metal-loss anomalies identified by high-resolution inline inspection.

(d) A Level 3 evaluation is a detailed analysis of a specific flaw in accordance with a user-defined methodology, with full justification for loadings, boundary conditions, material properties, and failure criteria. It is intended that a Level 3 evaluation be conducted by a technical specialist having appropriate expertise in the subject of fitness-for-service assessment.

1.7 Material Properties and Other Data

(a) Specified minimum material properties shall be used when conducting Level 0, Level 1, or Level 2 evaluations for the purpose of determining the need for a repair. Actual material properties from mill test reports (MTRs) or laboratory testing, if known with sufficient

confidence to warrant their usage, may be used with Level 3 evaluations. Statistical representations of material properties may be used with Levels 1, 2, or 3 for purpose of establishing a probability of failure; however, the details of such analyses are outside the scope of this document.

(b) Flow stress is a concept relevant to fracture mechanics and is used in the Level 1, Level 2, and Level 3 evaluations. It is not a property specified in a material grade or finished product standard. Research indicates that it may be defined variously as given below.

(1) S_{flow} for plain carbon steel operating at temperatures below 250°F (120°C) may be defined by $S_{flow} = 1.1 \times \text{SMYS}$. S_{flow} shall not exceed SMTS.

(2) S_{flow} for plain carbon and low-alloy steel having SMYS not in excess of 70 ksi (483 MPa) and operating at temperatures below 250°F (120°C) may be defined by $S_{flow} = \text{SMYS} + 10$ ksi (69 MPa). S_{flow} shall not exceed SMTS.

(3) S_{flow} for plain carbon and low-alloy steel having SMYS not in excess of 80 ksi (551 MPa) may be defined by $S_{flow} = (S_{YT} + S_{UT})/2$, where S_{YT} and S_{UT} are specified at the operating temperature in accordance with the ASME Boiler and Pressure Vessel Code, Section II, Part D; applicable pipe product specification; or room temperature strength multiplied by the temperature derating factor specified by the applicable construction code. Linear interpolation of strength values is allowed between listed temperatures.

(c) This document does not prescribe which definition for flow stress should be used where more than one definition applies. Where more than one definition applies, the various definitions produce acceptable though not necessarily identical results when used with any given evaluation method. It is noted that S_{flow} was defined as 1.1 × SMYS in previous editions of B31G. This definition remains an inherent element of the Level 0 assessment and is recommended with the Level 1 assessment performed in accordance with para. 2.2(a).

(d) Only the specified nominal wall thickness shall be used for the uncorroded wall thickness when conducting a Level 0 evaluation. If known with confidence, the actual uncorroded wall thickness may be used with a Level 1, Level 2, or Level 3 evaluation, with a suitable adjustment of the hoop stress due to internal pressure.

(e) Pipe body material may be considered to have adequate ductile fracture initiation properties for purposes of this Standard if the material operates at a temperature no colder than 100°F (55°C) below the temperature at which 85% shear appearance is observed in a Charpy V-notched impact test.

(f) Electric resistance welded (ERW) seams that have been subjected to a normalizing heat treatment, single and double submerged arc welded seams, and girth welds made using the shielded metal arc, gas metal arc, flux cored arc, and submerged arc processes (manual or automated, and in any combination) are considered to have adequate ductile fracture initiation properties for purposes of this Standard. Other seam and weld types shall be investigated to establish fracture properties before applying methods described herein to metal loss affecting such welds. Consideration shall be given to the disposition of workmanship flaws or manufacturing flaws within a weld or seam that could interact with metal loss due to corrosion.

(g) Some operating conditions, such as low-temperature service, or long-term exposure to sour environments or to very high temperatures, could adversely affect the ductility and fracture toughness properties of some materials. It is the user's responsibility to consider such conditions where necessary before applying methods described herein.

1.8 Evaluation Procedure

Evaluations shall be carried out in accordance with the procedures described in section 2. In addition, the following considerations apply:

(a) Units may be in any self-consistent system. It is the responsibility of the user to determine unitary conversion factors as may be required.

(b) This document makes no recommendation as to which evaluation level and evaluation method to select. All methods described herein have been demonstrated to provide reliable and conservative results when they are applied correctly and within stated limitations. Not all methods give identical numerical results or consistent degrees of conservatism. It is the pipeline operator's responsibility to select an evaluation method, based on experience and judgment, that is consistent with its operating procedures.

(c) Original source reference documents for each methodology are cited. Further references may be found in other documents available in the public domain. While each method can be applied as presented, source documents may provide additional information to the user. The user should consider referring to applicable sources as necessary in order to best implement a given method.

(d) Other evaluation methods may evolve or come into use which were not contemplated by this document. It is not the intention of this document to prohibit their use, but the user of such methods shall be able to demonstrate that the objective of a safe and reliable assessment of metal loss can be achieved.

1.9 Safety Factors and the Meaning of Acceptance

A flaw or anomaly is considered acceptable where the computed failure stress is equal to or greater than the hoop stress at the operating pressure multiplied by a suitable safety factor. There is no single safety factor that is suitable for all types of pipeline construction, for all modes of pipeline operation, or for all types of flaws or anomalies.

This document recommends a minimum safety factor equal to the ratio of the minimum hydrostatic test pressure required for the given type of pipeline construction to the MAOP or MOP, but usually not less than 1.25. Larger factors of safety may be appropriate in some cases, e.g., in locations of greater risk to the public or the environment. Lesser factors of safety may be justified in some circumstances, e.g., for limited periods of time, or where additional procedures are in place to limit modes of operation, or in a remote location having reduced consequences of failure. In establishing the safety factor for a given pipeline segment, the pipeline operator shall give consideration to the accuracy of corrosion depth and length measurements, rates of corrosion growth, the characteristics of the pipe, the reliability of surge control or excess pressure limiting methods, and the presence of external factors that affect risk.

When evaluating anomalies identified by inline inspection, use of larger factors of safety will result in smaller flaws being left in service following field investigation and pipeline repairs. This can increase the reassessment interval to the next inline inspection.

1.10 Software

The use of commercial or proprietary computer software packages, as well as purpose-written programs or spreadsheets, can greatly facilitate Level 1 evaluations, and is practically a necessity for conducting thorough Level 2 and Level 3 evaluations. It is the user's responsibility to verify the accuracy and reliability of all software and spreadsheets, and to train personnel in their correct usage.

Validation of software should include documented evidence that correct results are obtained over the full range of parameters that could reasonably be expected to occur when making evaluations. The following document summarizes the results of burst tests and service failures of line pipe affected by corrosion or artificial metal loss, and which have previously been used for the purpose of validating the evaluation methods presented herein: Kiefner, J. F., Vieth, P. H., and Roytman, I., "Continued Validation of RSTRENG," PRCI Catalog No. L51749, Contract PR 218-9304, Dec. 20, 1996.

Validation may be demonstrated by comparison of calculated results against published benchmark test data such as that found in the above reference, or against results produced by another recognized evaluation method that have been calculated in accordance with this Standard.

Validation of third-party software should also demonstrate that adequate checks or warnings are produced when parameters fall outside ranges that will ensure correct results.

1.11 Accuracy

Consideration should be given to the accuracy of recorded flaw sizes, particularly where indirect methods are used to locate and size the flaws. Methods accounting for uncertainty in indirectly sized flaws include increasing the flaw dimension in order to account for detection tool error, or statistical analysis of the probable flaw sizes or risk of failure.

Metal-loss corrosion anomalies indicated by inline inspection may be evaluated by a Level 1 or Level 2 evaluation method. The user is cautioned against overstating the precision of evaluations applied with flaw dimensions indicated by inline inspection without adequate calibration or verification of actual flaw sizes by investigations carried out in the field.

1.12 Flaw Interaction

The methods described herein are suitable for evaluating isolated areas of metal loss. Corrosion may occur such that multiple areas of metal loss are closely spaced longitudinally or transversely. If spaced sufficiently closely, the metal loss areas may interact so as to result in failure at a lower pressure than would be expected based on an analysis of the separate flaws. The following guideline is suggested with reference to Fig. 1.12-1, based on limited testing and analysis:

(a) Flaws are considered interacting if they are spaced longitudinally or circumferentially from each other within a distance of 3 times the wall thickness ($3t$). Interacting flaws should be evaluated as a single flaw combined from all interacting flaws.

(b) Flaws are considered noninteracting if spaced outside of the above dimensions. Noninteracting flaws should be evaluated as separate flaws.

Care should be exercised when grouping or clustering anomalies indicated by inline inspection for purposes of evaluating interaction during the prioritization process. Consideration should be given to minimum thresholds of metal loss for reliable detection and sizing, minimum thresholds for reporting, and the expected mode of coating failure (e.g., localized failure versus disbondment over large areas). Methods employed for clustering of inline inspection anomalies should be validated by field verification of actual flaw dimensions and spacing.

1.13 Flaw Orientation

Corrosion caused by disbondment of continuous wrapped coatings may exhibit a helical pattern. If the helical pattern lies at an angle less than 45 deg to the pipe axis, the overall length of the corroded area indicated as L_1 in Fig. 1.13-1 shall be considered in the evaluation. If the helical pattern lies at an angle of 45 deg or greater to the pipe axis, it is sufficient to consider the most severe longitudinal section through the corroded area having a length L_2 in Fig. 1.13-1.

Corrosion may occur with a circumferential orientation, e.g., adjacent to a girth weld. It shall be evaluated for safe operating pressure as with corrosion having a helical angle greater than 45 deg to the pipe axis. Evaluation of the circumferential extent of corrosion subject

Fig. 1.12-1 Corrosion Pit Interaction Distances

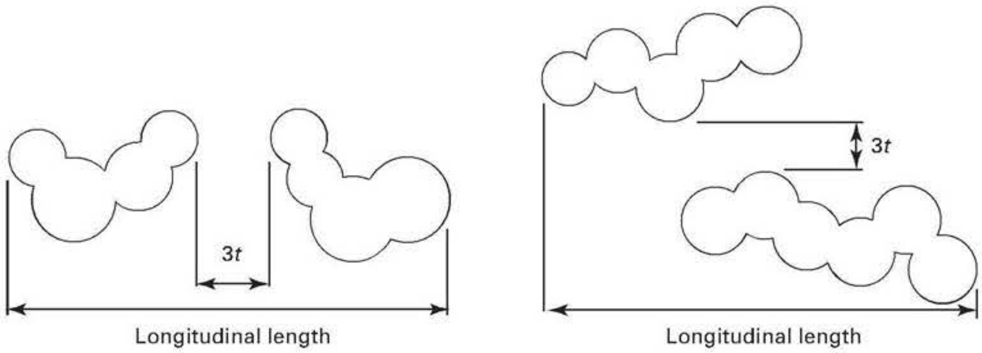
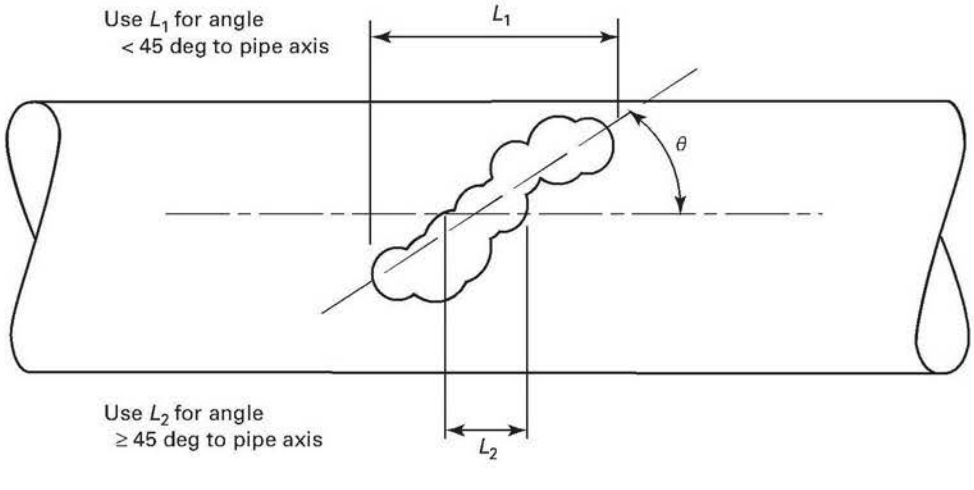


Fig. 1.13-1 Helically Oriented Corrosion Pattern



to high axial pipe stresses is outside the scope of this document. For such situations, the user should refer to a more comprehensive fitness-for-purpose guidance document, such as API 579-1/ASME FFS-1.

2 EVALUATION METHODS

2.1 Level 0 Evaluation

Tables of allowable length of corrosion are found in section 3. The tables are carried over without change from previous editions of B31G and have been supplemented by the addition of tables in metric units. They were calculated from the equations for a Level 1 evaluation in accordance with the original B31G methodology. They provide a ready reference of maximum corrosion lengths for a range of pipe sizes and depths of corrosion. The tables may be used to determine the maximum allowable longitudinal extent of a contiguous area of corrosion or an interacting cluster of metal loss areas.

Evaluations shall be carried out consistent with the procedure described in the following steps:

Step 1. Determine pipe diameter and nominal wall thickness from appropriate records or direct measurement of the pipe.

Step 2. Determine applicable pipe material properties from appropriate records.

Step 3. Clean the corroded pipe surface to bare metal. Care should be taken when cleaning corroded areas of a pressurized pipe.

Step 4. Measure the maximum depth of the corroded area, d, and longitudinal extent of the corroded area, L, as shown in Fig. 2.1-1.

Step 5. Locate the table corresponding to the size of the pipe, D.

Step 6. In the table, locate the row showing a depth equal to the measured maximum depth of the corroded area. If the exact measured value is not listed, choose the row showing the next greater depth.

Step 7. Read across to the column showing the wall thickness of the pipe. If the nominal wall thickness is not listed, use the column for the next thinner wall. The value, L, found at the intersection of the wall thickness column and the depth row is the maximum allowable longitudinal extent of such a corroded area.

Step 8. The metal loss area on the pipe is acceptable if its measured length, L, does not exceed the value of L given in the table.

The tables produce results that may be more conservative than those obtained by performing a Level 1, Level 2, or Level 3 analysis, particularly for operating hoop stress levels less than 72% of SMYS, and also for very long corroded areas. Therefore, the tables may show that a given corroded area is unsuitable for the current operating pressure, while the use of equations given below may show that it is acceptable.

The tables were designed to provide a minimum factor of safety of 1.39 for pipelines operating with a hoop stress of 72% of SMYS. Application of the tables to the evaluation of corrosion in pipelines operating at hoop stress levels greater than 72% of SMYS will result in a factor of safety that is proportionately less.

2.2 Level 1 Evaluation

Level 1 evaluations shall be carried out consistent with the procedure described in the following steps:

Step 1. Determine pipe diameter and nominal wall thickness from appropriate records or direct measurement of the pipe.

Step 2. Clean the corroded pipe surface to bare metal. Care should be taken when cleaning corroded areas of a pressurized pipe.

Step 3. Measure the maximum depth of the corroded area, d, and longitudinal extent of the corroded area, L, as shown in Fig. 2.1-1.

Step 4. Determine applicable pipe material properties from appropriate records.

Step 5. Select an evaluation method and calculate the estimated failure stress, S_F.

Step 6. Define an acceptable safety factor, SF.

Step 7. Compare S_F to $SF \times S_O$.

Step 8. The flaw is acceptable where S_F is equal to or greater than $SF \times S_O$, or where P_F is equal to or greater than $SF \times P_O$.

If the flaw is unacceptable based on Step 8 above, the pressure can be reduced such that it is less than P_F/SF.

(a) Original B31G

$$M = (1 + 0.8z)^{1/2}$$

For $z \leq 20$,

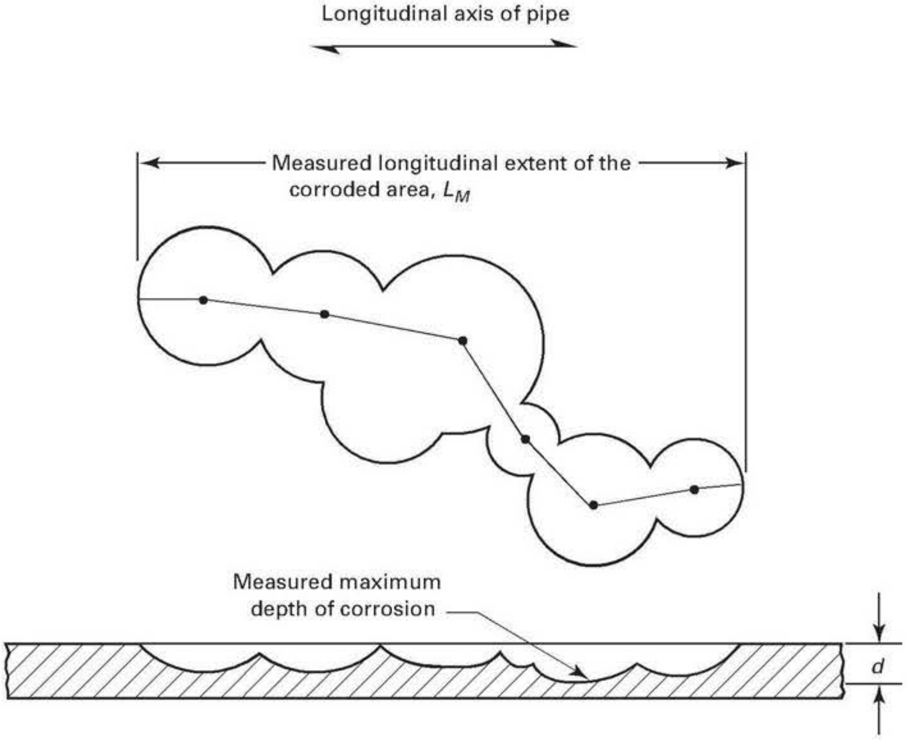
$$S_F = S_{\text{flow}} \left[\frac{1 - \frac{2}{3}(d/t)}{1 - \frac{2}{3}(d/t)/M} \right]$$

For $z > 20$,

$$S_F = S_{\text{flow}}(1 - d/t)$$

Note that previous editions of B31G incorporated a definition for flow stress of $S_{\text{flow}} = 1.1 \times \text{SMYS}$. For consistency in comparison to results obtained from evaluations performed to an earlier edition, use of the same definition for flow stress is recommended.

Fig. 2.1-1 Corrosion Parameters Used in Analysis



[References: ANSI/ASME B31G-1984 and ASME B31G-1991.]

(b) Modified B31G. For $z \leq 50$,

$$M = (1 + 0.6275z - 0.003375z^2)^{1/2}$$

For $z > 50$,

$$M = 0.032z + 3.3$$

$$S_F = S_{\text{flow}} \left[\frac{1 - 0.85(d/t)}{1 - 0.85(d/t)/M} \right]$$

[References: (1) Kiefner, J. F., and Vieth, P. H., "Project PR3-805: A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," AGA Catalog No. L51609, Dec. 22, 1989; (2) Kiefner, J. F., and Vieth, P. H., "New Method Corrects Criterion for Evaluating Corroded Pipe," Oil & Gas Journal, Aug. 6 and Aug. 20, 1990.]

(c) API 579 Level 1. The "API 579 Level 1" assessment, when reduced to its simplest form, is of a similar format to the other Level 1 methods presented herein, and therefore qualifies as a Level 1 assessment for purposes of meeting the requirements of this document.

(12) 2.3 Level 2 Evaluation

Level 2 evaluations are performed using what is known as the Effective Area Method. Level 2 evaluations shall be carried out using a procedure similar to the ten steps described for Level 1, except that the Effective Area Method generally requires several measurements of the depth of corrosion or remaining wall thickness throughout the corroded area. The Effective Area Method is expressed as follows:

$$S_F = S_{\text{flow}} \left[\frac{1 - A/A_0}{1 - (A/A_0)/M} \right]$$

The Effective Area Method evaluates, by iteration, all possible combinations of local metal loss, A, with respect to original material, A_0. It requires for input a detailed longitudinal distribution or profile of metal loss. The detailed profile is established by obtaining several measurements of metal loss or remaining wall thickness throughout the metal loss area. Such measurements may be arranged in a grid pattern, or may follow a "river bottom" path through the deepest areas of metal loss. Increments of measurement need not be uniform, subject to limitations of application software. If using a grid pattern, the analysis must be repeated along each meridian to establish the governing solution. For a corroded profile defined by n measurements of depth of corrosion including the end points at nominally full wall thickness, $n!/2(n-2)!$ iterations are required to examine all possible combinations of local metal loss with respect to surrounding remaining material. The local solution resulting in the lowest calculated failure stress shall govern.

Owing to its iterative nature, it is a practical necessity to use a computer program or other algorithmic approach (e.g., a spreadsheet) in order to carry out an evaluation using the Effective Area Method.

The "API 579 Level 2" assessment, when reduced to its simplest form, is equivalent to the Effective Area Method presented herein, and therefore qualifies as a Level 2 assessment for purposes of meeting the requirements of this document. Refer to API 579-1/ASME FFS-1 for detailed instructions.

[References: Same as in para. 2.2(b).]

2.4 Level 3 Evaluation

A Level 3 evaluation typically involves a detailed analysis, such as a finite element analysis of the corroded region. The analysis should accurately consider or account for all factors that could affect the accuracy of results, including loadings including internal pressure and external forces; boundary conditions and constraints; ovality, deformations, misalignments, and discontinuities; material stress–strain characteristics; and effects of the flaw on the overall distribution of loads and stresses. A failure criterion should be developed that considers the strain capacity or fracture resistance characteristics of the material. Similar issues should be considered in developing a suitable safety factor as were described for a Level 1 or Level 2 analysis.

3 TABLES OF ALLOWABLE LENGTH OF CORROSION

The following are applicable to Tables 3-1 through 3-12M:

(a) Metal loss having a maximum depth of 10% of the nominal pipe wall thickness or less is not limited as to allowable length.

(b) Metal loss having a maximum depth exceeding 80% of the nominal pipe wall thickness shall not be evaluated using the tables of allowable length.

Table 3-1 Values of L for Pipe Sizes $\geq$ NPS 2 and $<$ NPS 6 (12)

Depth, d, in.	Wall Thickness, t, in.							
	0.083	0.109	0.125	0.141	0.154	0.172	0.188	0.218
0.01	1.99	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.02	0.92	1.94	2.44	2.59	2.71	2.86	2.99	No limit
0.03	0.53	0.85	1.13	1.51	1.94	2.86	2.99	3.22
0.04	0.39	0.60	0.75	0.93	1.11	1.40	1.74	2.74
0.05	0.31	0.47	0.58	0.70	0.82	1.00	1.18	1.62
0.06	0.25	0.39	0.48	0.58	0.66	0.79	0.92	1.21
0.07	...	0.33	0.41	0.49	0.56	0.67	0.77	0.99
0.08	...	0.28	0.35	0.43	0.49	0.58	0.67	0.84
0.09	...	...	0.31	0.38	0.43	0.51	0.59	0.74
0.10	...	...	0.27	0.33	0.39	0.46	0.53	0.66
0.11	...	...	...	0.30	0.35	0.41	0.48	0.60
0.12	...	...	...	...	0.31	0.38	0.43	0.55
0.13	...	...	...	...	...	0.34	0.40	0.50
0.14	...	...	...	...	...	...	0.37	0.46
0.15	...	...	...	...	...	...	0.34	0.43
0.16	...	...	...	...	...	...	...	0.40
0.17	...	...	...	...	...	...	...	0.37

Table 3-1M Values of L for Pipe Sizes $\geq$ 60 mm and $<$ 168 mm O.D. (12)

Depth, d, mm	Wall Thickness, t, mm							
	2.1	2.8	3.2	3.6	3.9	4.4	4.8	5.5
0.3	50.5	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.5	23.2	49.1	62.0	65.8	68.8	72.7	76.0	No limit
0.8	13.4	21.7	28.7	38.3	49.2	72.7	76.0	81.9
1.0	9.8	15.1	19.0	23.7	28.1	35.6	44.2	69.5
1.3	7.8	11.9	14.7	17.9	20.8	25.3	29.9	41.1
1.5	6.4	9.8	12.1	14.6	16.8	20.1	23.4	30.7
1.8	...	8.3	10.3	12.4	14.3	17.0	19.5	25.0
2.0	...	7.2	9.0	10.8	12.4	14.7	16.9	21.4
2.3	...	...	7.9	9.5	11.0	13.0	14.9	18.8
2.5	...	...	6.9	8.5	9.8	11.6	13.4	16.8
2.8	...	...	...	7.6	8.8	10.5	12.1	15.2
3.0	...	...	...	...	8.0	9.6	11.0	13.9
3.3	...	...	...	...	...	8.7	10.1	12.8
3.6	...	...	...	...	...	...	9.3	11.8
3.8	...	...	...	...	...	...	8.5	10.9
4.1	...	...	...	...	...	...	...	10.2
4.3	...	...	...	...	...	...	...	9.5

(12)

Table 3-2 Values of L for Pipe Sizes $\geq$ NPS 6 and $<$ NPS 10

Depth, *d*, in.	Wall Thickness, *t*, in.							
	0.083	0.125	0.156	0.188	0.203	0.219	0.250	0.312
0.01	3.32	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.02	1.53	4.08	4.55	5.00	No limit	No limit	No limit	No limit
0.03	0.88	1.89	3.37	5.00	5.20	5.40	5.77	No limit
0.04	0.65	1.25	1.90	2.91	3.61	4.65	5.77	6.44
0.05	0.51	0.97	1.40	1.97	2.30	2.73	3.86	6.44
0.06	0.42	0.80	1.13	1.54	1.77	2.04	2.67	4.77
0.07	...	0.68	0.96	1.29	1.46	1.66	2.11	3.37
0.08	...	0.59	0.83	1.11	1.25	1.42	1.77	2.68
0.09	...	0.52	0.74	0.98	1.10	1.24	1.54	2.26
0.10	...	0.46	0.66	0.88	0.99	1.11	1.37	1.97
0.11	...	...	0.59	0.80	0.90	1.01	1.24	1.76
0.12	...	...	0.54	0.73	0.82	0.92	1.13	1.60
0.13	...	...	...	0.66	0.75	0.85	1.04	1.46
0.14	...	...	...	0.61	0.69	0.78	0.96	1.35
0.15	...	...	...	0.56	0.64	0.72	0.89	1.26
0.16	...	...	...	...	0.59	0.67	0.83	1.18
0.17	...	...	...	...	...	0.63	0.78	1.10
0.18	...	...	...	...	...	...	0.73	1.04
0.19	...	...	...	...	...	...	0.69	0.98
0.20	...	...	...	...	...	...	0.65	0.93
0.21	...	...	...	...	...	...	...	0.88
0.22	...	...	...	...	...	...	...	0.84
0.23	...	...	...	...	...	...	...	0.80
0.24	...	...	...	...	...	...	...	0.76

Table 3-2M Values of *L* for Pipe Sizes ≥ 168 mm and < 273 mm O.D. (12)

Depth, *d*, mm	Wall Thickness, *t*, mm 2.1	3.2	4.0	4.8	5.2	5.6	6.4	7.9
0.3	84.4	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.5	38.8	103.6	115.7	127.0	No limit	No limit	No limit	No limit
0.8	22.4	48.0	85.6	127.0	132.0	137.1	146.4	No limit
1.0	16.4	31.8	48.1	73.8	91.6	118.1	146.4	163.6
1.3	13.0	24.6	35.5	50.0	58.5	69.3	98.0	163.6
1.5	10.7	20.3	28.7	39.1	44.9	51.7	67.8	121.1
1.8	...	17.3	24.3	32.6	37.1	42.2	53.6	85.5
2.0	...	15.0	21.1	28.2	31.9	36.0	45.0	68.1
2.3	...	13.1	18.7	24.9	28.1	31.6	39.1	57.4
2.5	...	11.6	16.7	22.3	25.1	28.3	34.8	50.2
2.8	...	...	15.0	20.2	22.8	25.6	31.4	44.8
3.0	...	...	13.6	18.4	20.8	23.4	28.7	40.6
3.3	...	...	...	16.9	19.1	21.5	26.4	37.2
3.6	...	...	...	15.5	17.6	19.8	24.4	34.4
3.8	...	...	...	14.3	16.3	18.4	22.7	32.0
4.1	...	...	...	...	15.1	17.1	21.2	29.9
4.3	...	...	...	...	...	15.9	19.8	28.0
4.6	...	...	...	...	...	...	18.6	26.4
4.8	...	...	...	...	...	...	17.5	25.0
5.1	...	...	...	...	...	...	16.4	23.6
5.3	...	...	...	...	...	...	...	22.4
5.6	...	...	...	...	...	...	...	21.3
5.8	...	...	...	...	...	...	...	20.2
6.1	...	...	...	...	...	...	...	19.2

Table 3-3 Values of L for Pipe Sizes $\geq$ NPS 10 and $<$ NPS 16

Depth, d, in.	Wall Thickness, t, in.							
	0.156	0.219	0.250	0.307	0.344	0.365	0.438	0.500
0.02	5.80	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.03	4.29	6.87	7.34	No limit	No limit	No limit	No limit	No limit
0.04	2.41	5.92	7.34	8.14	8.62	8.87	No limit	No limit
0.05	1.78	3.48	4.91	8.14	8.62	8.87	9.72	10.39
0.06	1.44	2.59	3.40	5.77	8.62	8.87	9.72	10.39
0.07	1.22	2.11	2.69	4.13	5.53	6.62	9.72	10.39
0.08	1.06	1.81	2.26	3.30	4.22	4.85	8.37	10.39
0.09	0.94	1.59	1.96	2.80	3.48	3.93	6.10	9.38
0.10	0.84	1.42	1.74	2.45	2.99	3.35	4.92	6.95
0.11	0.75	1.28	1.57	2.19	2.65	2.94	4.18	5.64
0.12	0.68	1.17	1.44	1.98	2.39	2.64	3.67	4.81
0.13	...	1.08	1.32	1.82	2.18	2.40	3.29	4.23
0.14	...	1.00	1.22	1.68	2.01	2.21	2.99	3.80
0.15	...	0.92	1.14	1.56	1.86	2.05	2.75	3.46
0.16	...	0.86	1.06	1.46	1.74	1.91	2.55	3.19
0.17	...	0.80	0.99	1.37	1.64	1.79	2.39	2.97
0.18	...	...	0.93	1.29	1.54	1.69	2.24	2.77
0.19	...	...	0.88	1.22	1.46	1.60	2.12	2.61
0.20	...	...	0.82	1.15	1.38	1.51	2.00	2.47
0.21	...	...	...	1.09	1.31	1.44	1.90	2.34
0.22	...	...	...	1.04	1.25	1.37	1.81	2.23
0.23	...	...	...	0.99	1.19	1.30	1.73	2.12
0.24	...	...	...	0.94	1.13	1.25	1.66	2.03
0.25	...	...	...	...	1.08	1.19	1.59	1.95
0.26	...	...	...	...	1.03	1.14	1.52	1.87
0.27	...	...	...	...	0.99	1.09	1.46	1.80
0.28	...	...	...	...	...	1.05	1.41	1.73
0.29	...	...	...	...	...	1.00	1.35	1.67
0.30	...	...	...	...	...	...	1.31	1.61
0.31	...	...	...	...	...	...	1.26	1.55
0.32	...	...	...	...	...	...	1.21	1.50
0.33	...	...	...	...	...	...	1.17	1.45
0.34	...	...	...	...	...	...	1.13	1.41
0.35	...	...	...	...	...	...	1.09	1.36
0.36	...	...	...	...	...	...	...	1.32
0.37	...	...	...	...	...	...	...	1.28
0.38	...	...	...	...	...	...	...	1.24
0.39	...	...	...	...	...	...	...	1.20
0.40	...	...	...	...	...	...	...	1.16

Table 3-3M Values of *L* for Pipe Sizes ≥ 273 mm and < 406 mm O.D.

Depth, *d*, mm	Wall Thickness, *t*, mm							
	4.0	5.6	6.4	7.8	8.7	9.3	11.1	12.7
0.5	147.4	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.8	109.1	174.6	186.5	No limit	No limit	No limit	No limit	No limit
1.0	61.3	150.4	186.5	206.7	218.8	225.4	No limit	No limit
1.3	45.2	88.3	124.8	206.7	218.8	225.4	246.9	263.8
1.5	36.5	65.9	86.4	146.6	218.8	225.4	246.9	263.8
1.8	30.9	53.7	68.2	104.8	140.5	168.1	246.9	263.8
2.0	26.9	45.9	57.3	83.9	107.1	123.3	212.7	263.8
2.3	23.8	40.3	49.8	71.0	88.3	99.8	155.0	238.4
2.5	21.3	36.0	44.3	62.1	76.0	85.0	124.9	176.5
2.8	19.2	32.6	40.0	55.5	67.3	74.7	106.1	143.3
3.0	17.3	29.8	36.5	50.4	60.6	67.0	93.1	122.2
3.3	...	27.4	33.6	46.2	55.3	61.0	83.5	107.5
3.6	...	25.3	31.1	42.7	51.0	56.1	76.0	96.5
3.8	...	23.4	28.9	39.7	47.4	52.0	69.9	87.9
4.1	...	21.8	27.0	37.1	44.2	48.5	64.9	81.0
4.3	...	20.3	25.2	34.8	41.5	45.5	60.6	75.3
4.6	...	...	23.7	32.8	39.1	42.9	56.9	70.5
4.8	...	...	22.2	31.0	37.0	40.5	53.7	66.3
5.1	...	...	20.9	29.3	35.1	38.4	50.9	62.7
5.3	...	...	...	27.8	33.3	36.5	48.4	59.4
5.6	...	...	...	26.4	31.7	34.8	46.1	56.6
5.8	...	...	...	25.1	30.2	33.1	44.0	54.0
6.1	...	...	...	23.8	28.8	31.7	42.1	51.6
6.4	...	...	...	...	27.5	30.3	40.3	49.5
6.6	...	...	...	...	26.3	29.0	38.7	47.5
6.9	...	...	...	...	25.1	27.7	37.2	45.7
7.1	...	...	...	...	...	26.6	35.7	44.0
7.4	...	...	...	...	...	25.5	34.4	42.4
7.6	...	...	...	...	...	...	33.2	40.9
7.9	...	...	...	...	...	...	32.0	39.5
8.1	...	...	...	...	...	...	30.8	38.1
8.4	...	...	...	...	...	...	29.7	36.9
8.6	...	...	...	...	...	...	28.7	35.7
8.9	...	...	...	...	...	...	27.7	34.6
9.1	...	...	...	...	...	...	...	33.5
9.4	...	...	...	...	...	...	...	32.4
9.7	...	...	...	...	...	...	...	31.4
9.9	...	...	...	...	...	...	...	30.5
10.2	...	...	...	...	...	...	...	29.6

(12)

Table 3-4 Values of *L* for Pipe Sizes ≥ NPS 16 and < NPS 20

Depth, *d*, in.	Wall Thickness, *t*, in. 0.188	0.250	0.312	0.344	0.375	0.438	0.500	0.625
0.02	7.77	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.03	7.77	8.96	No limit	No limit	No limit	No limit	No limit	No limit
0.04	4.52	8.96	10.01	10.51	10.97	No limit	No limit	No limit
0.05	3.06	6.00	10.01	10.51	10.97	11.86	12.67	No limit
0.06	2.39	4.15	7.41	10.51	10.97	11.86	12.67	No limit
0.07	2.00	3.28	5.23	6.75	8.84	11.86	12.67	14.17
0.08	1.73	2.75	4.17	5.14	6.34	10.21	12.67	14.17
0.09	1.52	2.39	3.51	4.24	5.08	7.44	11.45	14.17
0.10	1.37	2.13	3.07	3.65	4.30	6.00	8.48	14.17
0.11	1.24	1.92	2.74	3.23	3.77	5.10	6.88	13.85
0.12	1.13	1.75	2.48	2.91	3.37	4.47	5.87	10.53
0.13	1.03	1.61	2.27	2.66	3.06	4.01	5.16	8.65
0.14	0.95	1.49	2.10	2.45	2.81	3.65	4.63	7.43
0.15	0.87	1.39	1.96	2.28	2.61	3.36	4.22	6.56
0.16	...	1.30	1.83	2.13	2.43	3.12	3.89	5.91
0.17	...	1.21	1.72	1.99	2.28	2.91	3.62	5.40
0.18	...	1.14	1.62	1.88	2.15	2.74	3.38	4.99
0.19	...	1.07	1.53	1.78	2.03	2.58	3.18	4.64
0.20	...	1.00	1.44	1.68	1.92	2.45	3.01	4.35
0.21	...	...	1.37	1.60	1.83	2.32	2.85	4.10
0.22	...	...	1.30	1.52	1.74	2.21	2.72	3.88
0.23	...	...	1.24	1.45	1.66	2.11	2.59	3.69
0.24	...	...	1.18	1.38	1.59	2.02	2.48	3.52
0.25	...	...	...	1.32	1.52	1.94	2.38	3.36
0.26	...	...	...	1.26	1.45	1.86	2.28	3.22
0.27	...	...	...	1.21	1.39	1.79	2.19	3.10
0.28	...	...	...	...	1.34	1.72	2.11	2.98
0.29	...	...	...	...	1.28	1.65	2.03	2.87
0.30	...	...	...	...	1.23	1.59	1.96	2.77
0.31	...	...	...	...	...	1.53	1.90	2.68
0.32	...	...	...	...	...	1.48	1.83	2.59
0.33	...	...	...	...	...	1.43	1.77	2.51
0.34	...	...	...	...	...	1.38	1.71	2.43
0.35	...	...	...	...	...	1.33	1.66	2.36
0.36	...	...	...	...	...	...	1.61	2.29
0.37	...	...	...	...	...	...	1.56	2.23
0.38	...	...	...	...	...	...	1.51	2.16
0.39	...	...	...	...	...	...	1.46	2.11
0.40	...	...	...	...	...	...	1.42	2.05
0.41	...	...	...	...	...	...	...	1.99
0.42	...	...	...	...	...	...	...	1.94
0.43	...	...	...	...	...	...	...	1.89
0.44	...	...	...	...	...	...	...	1.84
0.45	...	...	...	...	...	...	...	1.80
0.46	...	...	...	...	...	...	...	1.75
0.47	...	...	...	...	...	...	...	1.71
0.48	...	...	...	...	...	...	...	1.67
0.49	...	...	...	...	...	...	...	1.63
0.50	...	...	...	...	...	...	...	1.59

Table 3-4M Values of *L* for Pipe Sizes ≥ 406 mm and < 508 mm O.D. (12)

Depth, *d*, mm	Wall Thickness, *t*, mm							
	4.8	6.4	7.9	8.7	9.5	11.1	12.7	15.9
0.5	197.4	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.8	197.4	227.6	No limit	No limit	No limit	No limit	No limit	No limit
1.0	114.8	227.6	254.2	267.0	278.7	No limit	No limit	No limit
1.3	77.7	152.3	254.2	267.0	278.7	301.2	321.9	No limit
1.5	60.8	105.4	188.2	267.0	278.7	301.2	321.9	No limit
1.8	50.7	83.2	132.9	171.4	224.5	301.2	321.9	359.8
2.0	43.8	69.9	105.8	130.6	161.2	259.5	321.9	359.8
2.3	38.7	60.8	89.3	107.7	129.1	189.1	290.8	359.8
2.5	34.7	54.1	77.9	92.8	109.3	152.4	215.4	359.8
2.8	31.4	48.8	69.6	82.1	95.7	129.5	174.8	351.8
3.0	28.6	44.5	63.0	73.9	85.6	113.6	149.1	267.5
3.3	26.2	41.0	57.8	67.5	77.8	101.8	131.1	219.8
3.6	24.1	37.9	53.4	62.2	71.4	92.7	117.7	188.7
3.8	22.2	35.3	49.7	57.8	66.2	85.3	107.3	166.7
4.1	...	32.9	46.4	54.0	61.7	79.1	98.9	150.1
4.3	...	30.8	43.6	50.7	57.9	73.9	91.9	137.1
4.6	...	28.9	41.1	47.7	54.5	69.5	86.0	126.6
4.8	...	27.1	38.8	45.1	51.5	65.6	80.9	117.9
5.1	...	25.5	36.7	42.8	48.9	62.1	76.4	110.5
5.3	...	...	34.8	40.6	46.4	59.0	72.5	104.2
5.6	...	...	33.0	38.6	44.2	56.2	69.0	98.6
5.8	...	...	31.4	36.8	42.2	53.7	65.8	93.7
6.1	...	...	29.9	35.1	40.3	51.3	63.0	89.4
6.4	...	...	...	33.5	38.6	49.2	60.3	85.5
6.6	...	...	...	32.0	36.9	47.2	57.9	81.9
6.9	...	...	...	30.6	35.4	45.4	55.7	78.7
7.1	...	...	...	...	33.9	43.6	53.6	75.7
7.4	...	...	...	...	32.5	42.0	51.7	72.9
7.6	...	...	...	...	31.2	40.4	49.9	70.4
7.9	...	...	...	...	...	39.0	48.2	68.0
8.1	...	...	...	...	...	37.6	46.5	65.8
8.4	...	...	...	...	...	36.3	45.0	63.7
8.6	...	...	...	...	...	35.0	43.6	61.8
8.9	...	...	...	...	...	33.8	42.2	60.0
9.1	...	...	...	...	...	...	40.9	58.2
9.4	...	...	...	...	...	...	39.6	56.6
9.7	...	...	...	...	...	...	38.4	55.0
9.9	...	...	...	...	...	...	37.2	53.5
10.2	...	...	...	...	...	...	36.1	52.0
10.4	...	...	...	...	...	...	...	50.7
10.7	...	...	...	...	...	...	...	49.3
10.9	...	...	...	...	...	...	...	48.1
11.2	...	...	...	...	...	...	...	46.9
11.4	...	...	...	...	...	...	...	45.7
11.7	...	...	...	...	...	...	...	44.5
11.9	...	...	...	...	...	...	...	43.4
12.2	...	...	...	...	...	...	...	42.4
12.4	...	...	...	...	...	...	...	41.3
12.7	...	...	...	...	...	...	...	40.3

Table 3-5 Values of *L* for Pipe Sizes ≥ NPS 20 and < NPS 24

Depth, *d*, in.	Wall Thickness, *t*, in.							
	0.219	0.250	0.344	0.406	0.469	0.500	0.562	0.625
0.03	9.38	10.02	No limit	No limit	No limit	No limit	No limit	No limit
0.04	8.08	10.02	11.75	No limit	No limit	No limit	No limit	No limit
0.05	4.74	6.70	11.75	12.77	13.72	14.17	No limit	No limit
0.06	3.54	4.64	11.75	12.77	13.72	14.17	15.02	No limit
0.07	2.88	3.66	7.54	12.77	13.72	14.17	15.02	15.84
0.08	2.46	3.08	5.75	8.86	13.72	14.17	15.02	15.84
0.09	2.16	2.68	4.74	6.83	10.21	12.80	15.02	15.84
0.10	1.93	2.38	4.08	5.66	7.94	9.48	14.12	15.84
0.11	1.75	2.15	3.61	4.89	6.61	7.69	10.61	15.49
0.12	1.60	1.96	3.26	4.34	5.73	6.56	8.67	11.77
0.13	1.47	1.80	2.97	3.92	5.09	5.77	7.42	9.67
0.14	1.36	1.67	2.74	3.58	4.60	5.18	6.54	8.31
0.15	1.26	1.55	2.54	3.31	4.22	4.72	5.88	7.34
0.16	1.17	1.45	2.38	3.08	3.90	4.35	5.37	6.61
0.17	1.09	1.36	2.23	2.89	3.64	4.04	4.95	6.04
0.18	...	1.27	2.10	2.72	3.41	3.78	4.61	5.57
0.19	...	1.19	1.99	2.56	3.21	3.56	4.32	5.19
0.20	...	1.12	1.88	2.43	3.04	3.36	4.07	4.87
0.21	...	...	1.79	2.31	2.89	3.19	3.85	4.59
0.22	...	...	1.70	2.20	2.75	3.04	3.65	4.34
0.23	...	...	1.62	2.10	2.63	2.90	3.48	4.13
0.24	...	...	1.55	2.01	2.51	2.77	3.32	3.93
0.25	...	...	1.48	1.92	2.41	2.66	3.18	3.76
0.26	...	...	1.41	1.84	2.31	2.55	3.05	3.61
0.27	...	...	1.35	1.77	2.22	2.45	2.94	3.46
0.28	...	...	...	1.70	2.14	2.36	2.83	3.33
0.29	...	...	...	1.64	2.06	2.27	2.73	3.21
0.30	...	...	...	1.57	1.99	2.19	2.63	3.10
0.31	...	...	...	1.51	1.92	2.12	2.54	2.99
0.32	...	...	...	1.46	1.85	2.05	2.46	2.90
0.33	...	...	...	...	1.79	1.98	2.38	2.81
0.34	...	...	...	...	1.73	1.92	2.31	2.72
0.35	...	...	...	...	1.67	1.86	2.24	2.64
0.36	...	...	...	...	1.62	1.80	2.17	2.56
0.37	...	...	...	...	1.56	1.74	2.11	2.49
0.38	...	...	...	...	...	1.69	2.05	2.42
0.39	...	...	...	...	...	1.64	1.99	2.35
0.40	...	...	...	...	...	1.59	1.93	2.29
0.41	...	...	...	...	...	...	1.88	2.23
0.42	...	...	...	...	...	...	1.83	2.17
0.43	...	...	...	...	...	...	1.78	2.12
0.44	...	...	...	...	...	...	1.73	2.06
0.45	...	...	...	...	...	...	...	2.01
0.46	...	...	...	...	...	...	...	1.96
0.47	...	...	...	...	...	...	...	1.91
0.48	...	...	...	...	...	...	...	1.86
0.49	...	...	...	...	...	...	...	1.82
0.50	...	...	...	...	...	...	...	1.78

Table 3-5M Values of *L* for Pipe Sizes ≥ 508 mm and < 610 mm O.D.

Depth, *d*, mm	Wall Thickness, *t*, mm							
	5.6	6.4	8.7	10.3	11.9	12.7	14.3	15.9
0.8	238.1	254.4	No limit	No limit	No limit	No limit	No limit	No limit
1.0	205.1	254.4	298.5	No limit	No limit	No limit	No limit	No limit
1.3	120.5	170.3	298.5	324.3	348.5	359.8	No limit	No limit
1.5	89.8	117.8	298.5	324.3	348.5	359.8	381.5	No limit
1.8	73.3	93.1	191.6	324.3	348.5	359.8	381.5	402.3
2.0	62.6	78.2	146.0	225.2	348.5	359.8	381.5	402.3
2.3	54.9	68.0	120.4	173.5	259.5	325.1	381.5	402.3
2.5	49.1	60.4	103.7	143.8	201.7	240.8	358.6	402.3
2.8	44.4	54.6	91.8	124.3	168.0	195.4	269.5	393.4
3.0	40.6	49.8	82.7	110.2	145.5	166.7	220.2	299.1
3.3	37.3	45.8	75.5	99.5	129.3	146.6	188.5	245.7
3.6	34.5	42.4	69.6	91.0	116.9	131.6	166.1	211.0
3.8	32.0	39.4	64.6	84.1	107.1	119.9	149.4	186.3
4.1	29.7	36.8	60.4	78.3	99.1	110.5	136.4	167.8
4.3	27.7	34.4	56.6	73.3	92.4	102.7	125.8	153.3
4.6	...	32.3	53.4	69.0	86.6	96.1	117.1	141.6
4.8	...	30.3	50.5	65.1	81.6	90.4	109.6	131.8
5.1	...	28.5	47.8	61.7	77.2	85.5	103.3	123.6
5.3	...	...	45.4	58.7	73.3	81.1	97.7	116.5
5.6	...	...	43.2	55.9	69.8	77.1	92.8	110.3
5.8	...	...	41.2	53.4	66.7	73.6	88.4	104.8
6.1	...	...	39.3	51.0	63.8	70.4	84.4	99.9
6.4	...	...	37.5	48.9	61.1	67.5	80.9	95.5
6.6	...	...	35.8	46.9	58.7	64.8	77.6	91.6
6.9	...	...	34.2	45.0	56.4	62.3	74.6	88.0
7.1	...	...	...	43.2	54.3	60.0	71.8	84.6
7.4	...	...	...	41.5	52.3	57.8	69.2	81.6
7.6	...	...	...	39.9	50.4	55.8	66.8	78.7
7.9	...	...	...	38.4	48.7	53.8	64.6	76.1
8.1	...	...	...	37.0	47.0	52.0	62.5	73.6
8.4	...	...	...	...	45.4	50.3	60.5	71.3
8.6	...	...	...	...	43.9	48.7	58.6	69.1
8.9	...	...	...	...	42.4	47.2	56.8	67.0
9.1	...	...	...	...	41.1	45.7	55.1	65.1
9.4	...	...	...	...	39.7	44.3	53.5	63.2
9.7	...	...	...	...	...	42.9	52.0	61.5
9.9	...	...	...	...	...	41.6	50.5	59.8
10.2	...	...	...	...	...	40.3	49.1	58.2
10.4	...	...	...	...	...	...	47.7	56.6
10.7	...	...	...	...	...	...	46.4	55.2
10.9	...	...	...	...	...	...	45.1	53.7
11.2	...	...	...	...	...	...	43.9	52.4
11.4	...	...	...	...	...	...	...	51.1
11.7	...	...	...	...	...	...	...	49.8
11.9	...	...	...	...	...	...	...	48.6
12.2	...	...	...	...	...	...	...	47.4
12.4	...	...	...	...	...	...	...	46.2
12.7	...	...	...	...	...	...	...	45.1

Table 3-6 Values of L for Pipe Sizes $\geq$ NPS 24 and $<$ NPS 30

Depth, d, in.	Wall Thickness, t, in.							
	0.250	0.312	0.375	0.438	0.469	0.500	0.562	0.625
0.03	10.97	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.04	10.97	12.26	13.44	No limit	No limit	No limit	No limit	No limit
0.05	7.34	12.26	13.44	14.53	15.03	15.52	No limit	No limit
0.06	5.08	9.07	13.44	14.53	15.03	15.52	16.45	No limit
0.07	4.01	6.41	10.83	14.53	15.03	15.52	16.45	17.35
0.08	3.37	5.10	7.77	12.51	15.03	15.52	16.45	17.35
0.09	2.93	4.30	6.22	9.12	11.19	14.02	16.45	17.35
0.10	2.61	3.76	5.27	7.35	8.70	10.38	15.47	17.35
0.11	2.35	3.35	4.61	6.24	7.24	8.43	11.62	16.96
0.12	2.15	3.04	4.13	5.48	6.28	7.19	9.50	12.90
0.13	1.98	2.79	3.75	4.91	5.58	6.32	8.13	10.60
0.14	1.83	2.57	3.45	4.47	5.04	5.68	7.17	9.10
0.15	1.70	2.39	3.19	4.11	4.62	5.17	6.44	8.04
0.16	1.59	2.24	2.98	3.82	4.27	4.77	5.88	7.24
0.17	1.49	2.10	2.79	3.57	3.98	4.43	5.43	6.61
0.18	1.39	1.98	2.63	3.35	3.74	4.15	5.05	6.11
0.19	1.31	1.87	2.49	3.16	3.52	3.90	4.73	5.69
0.20	1.23	1.77	2.36	2.99	3.33	3.69	4.45	5.33
0.21	...	1.68	2.24	2.85	3.16	3.50	4.21	5.02
0.22	...	1.59	2.13	2.71	3.01	3.33	4.00	4.76
0.23	...	1.51	2.03	2.59	2.88	3.17	3.81	4.52
0.24	...	1.44	1.94	2.48	2.75	3.04	3.64	4.31
0.25	...	...	1.86	2.37	2.64	2.91	3.49	4.12
0.26	...	...	1.78	2.28	2.53	2.79	3.35	3.95
0.27	...	...	1.71	2.19	2.43	2.69	3.22	3.79
0.28	...	...	1.64	2.10	2.34	2.59	3.10	3.65
0.29	...	...	1.57	2.02	2.26	2.49	2.99	3.52
0.30	...	...	1.51	1.95	2.17	2.40	2.88	3.39
0.31	...	...	...	1.88	2.10	2.32	2.78	3.28
0.32	...	...	...	1.81	2.03	2.24	2.69	3.17
0.33	...	...	...	1.75	1.96	2.17	2.61	3.07
0.34	...	...	...	1.69	1.89	2.10	2.53	2.98
0.35	...	...	...	1.63	1.83	2.03	2.45	2.89
0.36	...	...	...	...	1.77	1.97	2.38	2.81
0.37	...	...	...	...	1.71	1.91	2.31	2.73
0.38	...	...	...	...	...	1.85	2.24	2.65
0.39	...	...	...	...	...	1.79	2.18	2.58
0.40	...	...	...	...	...	1.74	2.12	2.51
0.41	...	...	...	...	...	...	2.06	2.44
0.42	...	...	...	...	...	...	2.00	2.38
0.43	...	...	...	...	...	...	1.95	2.32
0.44	...	...	...	...	...	...	1.89	2.26
0.45	...	...	...	...	...	...	...	2.20
0.46	...	...	...	...	...	...	...	2.15
0.47	...	...	...	...	...	...	...	2.09
0.48	...	...	...	...	...	...	...	2.04
0.49	...	...	...	...	...	...	...	1.99
0.50	...	...	...	...	...	...	...	1.94

Table 3-6M Values of L for Pipe Sizes $\geq$ 610 mm and < 762 mm O.D.

Depth, *d*, mm	Wall Thickness, *t*, mm							
	6.4	7.9	9.5	11.1	11.9	12.7	14.3	15.9
0.8	278.7	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.0	278.7	311.4	341.4	No limit	No limit	No limit	No limit	No limit
1.3	186.5	311.4	341.4	368.9	381.8	394.2	No limit	No limit
1.5	129.1	230.5	341.4	368.9	381.8	394.2	417.9	No limit
1.8	102.0	162.8	275.0	368.9	381.8	394.2	417.9	440.7
2.0	85.6	129.6	197.4	317.8	381.8	394.2	417.9	440.7
2.3	74.5	109.3	158.1	231.6	284.2	356.2	417.9	440.7
2.5	66.2	95.5	133.9	186.7	221.0	263.8	392.9	440.7
2.8	59.8	85.2	117.2	158.6	184.0	214.1	295.2	430.9
3.0	54.5	77.2	104.9	139.1	159.4	182.6	241.2	327.6
3.3	50.2	70.8	95.3	124.7	141.6	160.6	206.5	269.1
3.6	46.4	65.4	87.5	113.5	128.1	144.2	182.0	231.1
3.8	43.2	60.8	81.1	104.4	117.3	131.4	163.7	204.1
4.1	40.3	56.9	75.6	96.9	108.5	121.1	149.4	183.8
4.3	37.7	53.4	70.9	90.6	101.2	112.5	137.8	167.9
4.6	35.4	50.3	66.8	85.1	94.9	105.3	128.2	155.1
4.8	33.2	47.5	63.1	80.3	89.4	99.1	120.1	144.4
5.1	31.2	44.9	59.8	76.1	84.6	93.6	113.1	135.4
5.3	...	42.6	56.9	72.3	80.4	88.8	107.0	127.6
5.6	...	40.5	54.2	68.8	76.5	84.5	101.6	120.8
5.8	...	38.5	51.7	65.7	73.0	80.6	96.8	114.8
6.1	...	36.6	49.4	62.9	69.9	77.1	92.5	109.5
6.4	...	...	47.2	60.3	67.0	73.9	88.6	104.7
6.6	...	...	45.2	57.8	64.3	71.0	85.0	100.3
6.9	...	...	43.3	55.5	61.8	68.2	81.7	96.3
7.1	...	...	41.5	53.4	59.5	65.7	78.7	92.7
7.4	...	...	39.9	51.4	57.3	63.3	75.8	89.3
7.6	...	...	38.3	49.5	55.2	61.1	73.2	86.2
7.9	...	...	...	47.7	53.3	59.0	70.7	83.3
8.1	...	...	...	46.1	51.5	57.0	68.4	80.6
8.4	...	...	...	44.4	49.7	55.1	66.2	78.1
8.6	...	...	...	42.9	48.1	53.3	64.2	75.7
8.9	...	...	...	41.4	46.5	51.7	62.2	73.4
9.1	...	...	...	...	45.0	50.0	60.4	71.3
9.4	...	...	...	...	43.5	48.5	58.6	69.3
9.7	...	...	...	...	...	47.0	56.9	67.3
9.9	...	...	...	...	...	45.6	55.3	65.5
10.2	...	...	...	...	...	44.2	53.7	63.7
10.4	...	...	...	...	...	...	52.2	62.0
10.7	...	...	...	...	...	...	50.8	60.4
10.9	...	...	...	...	...	...	49.4	58.9
11.2	...	...	...	...	...	...	48.1	57.4
11.4	...	...	...	...	...	...	...	55.9
11.7	...	...	...	...	...	...	...	54.5
11.9	...	...	...	...	...	...	...	53.2
12.2	...	...	...	...	...	...	...	51.9
12.4	...	...	...	...	...	...	...	50.6
12.7	...	...	...	...	...	...	...	49.4

Table 3-7 Values of *L* for Pipe Sizes ≥ NPS 30 and < NPS 36

Depth, *d*, in.	Wall Thickness, *t*, in.						
	0.250	0.312	0.375	0.438	0.500	0.625	0.688
0.03	12.27	No limit	No limit	No limit	No limit	No limit	No limit
0.04	12.27	13.71	15.03	No limit	No limit	No limit	No limit
0.05	8.21	13.71	15.03	16.24	17.35	No limit	No limit
0.06	5.68	10.14	15.03	16.24	17.35	No limit	No limit
0.07	4.49	7.17	12.10	16.24	17.35	19.40	20.35
0.08	3.77	5.70	8.69	13.99	17.35	19.40	20.35
0.09	3.28	4.81	6.96	10.19	15.68	19.40	20.35
0.10	2.91	4.20	5.89	8.22	11.61	19.40	20.35
0.11	2.63	3.75	5.16	6.98	9.42	18.97	20.35
0.12	2.40	3.40	4.62	6.12	8.04	14.42	20.35
0.13	2.21	3.11	4.19	5.49	7.07	11.85	15.82
0.14	2.04	2.88	3.85	5.00	6.35	10.17	13.07
0.15	1.90	2.68	3.57	4.60	5.78	8.98	11.25
0.16	1.77	2.50	3.33	4.27	5.33	8.09	9.96
0.17	1.66	2.35	3.12	3.99	4.95	7.39	8.98
0.18	1.56	2.21	2.94	3.75	4.63	6.83	8.21
0.19	1.46	2.09	2.78	3.53	4.36	6.36	7.59
0.20	1.38	1.98	2.63	3.35	4.12	5.96	7.07
0.21	...	1.88	2.50	3.18	3.91	5.62	6.63
0.22	...	1.78	2.38	3.03	3.72	5.32	6.26
0.23	...	1.69	2.27	2.89	3.55	5.05	5.93
0.24	...	1.61	2.17	2.77	3.39	4.82	5.64
0.25	...	...	2.08	2.65	3.25	4.61	5.38
0.26	...	...	1.99	2.54	3.12	4.42	5.15
0.27	...	...	1.91	2.44	3.00	4.24	4.94
0.28	...	...	1.83	2.35	2.89	4.08	4.74
0.29	...	...	1.75	2.26	2.79	3.93	4.57
0.30	...	...	1.68	2.18	2.69	3.80	4.41
0.31	...	...	...	2.10	2.60	3.67	4.26
0.32	...	...	...	2.03	2.51	3.55	4.12
0.33	...	...	...	1.96	2.43	3.44	3.99
0.34	...	...	...	1.89	2.35	3.33	3.86
0.35	...	...	...	1.82	2.27	3.23	3.75
0.36	...	...	...	...	2.20	3.14	3.64
0.37	...	...	...	...	2.13	3.05	3.54
0.38	...	...	...	...	2.07	2.96	3.44
0.39	...	...	...	...	2.01	2.88	3.35
0.40	...	...	...	...	1.94	2.81	3.26
0.41	...	...	...	...	...	2.73	3.18
0.42	...	...	...	...	...	2.66	3.10
0.43	...	...	...	...	...	2.59	3.02
0.44	...	...	...	...	...	2.53	2.95
0.45	...	...	...	...	...	2.46	2.87
0.46	...	...	...	...	...	2.40	2.81
0.47	...	...	...	...	...	2.34	2.74
0.48	...	...	...	...	...	2.28	2.68
0.49	...	...	...	...	...	2.23	2.62
0.50	...	...	...	...	...	2.17	2.56
0.51	...	...	...	...	...	...	2.50
0.52	...	...	...	...	...	...	2.44
0.53	...	...	...	...	...	...	2.39
0.54	...	...	...	...	...	...	2.33
0.55	...	...	...	...	...	...	2.28

Table 3-7M Values of L for Pipe Sizes ≥ 762 mm and < 914 mm O.D.

Depth, d, mm	Wall Thickness, t, mm						
	6.4	7.9	9.5	11.1	12.7	15.9	17.5
0.8	311.6	No limit	No limit	No limit	No limit	No limit	No limit
1.0	311.6	348.1	381.7	No limit	No limit	No limit	No limit
1.3	208.5	348.1	381.7	412.5	440.7	No limit	No limit
1.5	144.3	257.7	381.7	412.5	440.7	No limit	No limit
1.8	114.0	182.0	307.4	412.5	440.7	492.7	517.0
2.0	95.7	144.9	220.7	355.3	440.7	492.7	517.0
2.3	83.2	122.2	176.8	258.9	398.2	492.7	517.0
2.5	74.0	106.7	149.7	208.7	294.9	492.7	517.0
2.8	66.8	95.3	131.0	177.3	239.3	481.8	517.0
3.0	61.0	86.3	117.2	155.6	204.1	366.3	517.0
3.3	56.1	79.1	106.5	139.4	179.5	300.9	401.9
3.6	51.9	73.1	97.8	126.9	161.2	258.4	331.9
3.8	48.3	68.0	90.6	116.8	146.9	228.2	285.8
4.1	45.1	63.6	84.6	108.4	135.4	205.5	252.9
4.3	42.2	59.7	79.3	101.3	125.8	187.8	228.1
4.6	39.6	56.2	74.7	95.1	117.7	173.4	208.6
4.8	37.1	53.1	70.6	89.8	110.8	161.5	192.8
5.1	34.9	50.3	66.9	85.0	104.7	151.3	179.6
5.3	...	47.7	63.6	80.8	99.3	142.7	168.5
5.6	...	45.2	60.6	77.0	94.5	135.1	158.9
5.8	...	43.0	57.8	73.5	90.2	128.4	150.6
6.1	...	40.9	55.2	70.3	86.2	122.4	143.2
6.4	...	...	52.8	67.4	82.6	117.0	136.6
6.6	...	...	50.6	64.6	79.3	112.2	130.7
6.9	...	...	48.4	62.1	76.3	107.7	125.4
7.1	...	...	46.5	59.7	73.4	103.6	120.5
7.4	...	...	44.6	57.5	70.8	99.9	116.0
7.6	...	...	42.8	55.4	68.3	96.4	111.9
7.9	...	...	...	53.4	65.9	93.2	108.1
8.1	...	...	...	51.5	63.7	90.1	104.5
8.4	...	...	...	49.7	61.6	87.3	101.2
8.6	...	...	...	48.0	59.6	84.6	98.1
8.9	...	...	...	46.3	57.7	82.1	95.2
9.1	...	...	...	...	55.9	79.7	92.5
9.4	...	...	...	...	54.2	77.4	89.8
9.7	...	...	...	...	52.5	75.3	87.4
9.9	...	...	...	...	50.9	73.2	85.0
10.2	...	...	...	...	49.4	71.3	82.8
10.4	...	...	...	...	...	69.4	80.7
10.7	...	...	...	...	...	67.6	78.6
10.9	...	...	...	...	...	65.8	76.7
11.2	...	...	...	...	...	64.2	74.8
11.4	...	...	...	...	...	62.5	73.0
11.7	...	...	...	...	...	61.0	71.3
11.9	...	...	...	...	...	59.5	69.6
12.2	...	...	...	...	...	58.0	68.0
12.4	...	...	...	...	...	56.6	66.4
12.7	...	...	...	...	...	55.2	64.9
13.0	...	...	...	...	...	...	63.5
13.2	...	...	...	...	...	...	62.0
13.5	...	...	...	...	...	...	60.6
13.7	...	...	...	...	...	...	59.3
14.0	...	...	...	...	...	...	58.0

(12)

Table 3-8 Values of *L* for Pipe Sizes ≥ NPS 36 and < NPS 42

Depth, *d*, in.	Wall Thickness, *t*, in.							
	0.250	0.281	0.312	0.375	0.406	0.469	0.562	0.688
0.03	13.44	14.25	No limit	No limit	No limit	No limit	No limit	No limit
0.04	13.44	14.25	15.01	16.46	No limit	No limit	No limit	No limit
0.05	8.99	13.40	15.01	16.46	17.13	18.41	No limit	No limit
0.06	6.22	8.22	11.11	16.46	17.13	18.41	20.15	No limit
0.07	4.92	6.21	7.85	13.26	17.13	18.41	20.15	22.30
0.08	4.13	5.09	6.25	9.52	11.89	18.41	20.15	22.30
0.09	3.59	4.37	5.27	7.62	9.16	13.70	20.15	22.30
0.10	3.19	3.86	4.60	6.46	7.60	10.66	18.94	22.30
0.11	2.88	3.47	4.11	5.65	6.56	8.87	14.23	22.30
0.12	2.63	3.15	3.72	5.06	5.82	7.69	11.63	22.30
0.13	2.42	2.90	3.41	4.59	5.26	6.83	9.95	17.33
0.14	2.24	2.68	3.15	4.22	4.81	6.18	8.78	14.31
0.15	2.08	2.50	2.93	3.91	4.44	5.66	7.89	12.33
0.16	1.94	2.33	2.74	3.65	4.13	5.23	7.20	10.91
0.17	1.82	2.19	2.57	3.42	3.87	4.88	6.65	9.84
0.18	1.71	2.06	2.42	3.22	3.64	4.58	6.18	9.00
0.19	1.60	1.94	2.29	3.04	3.44	4.31	5.79	8.31
0.20	1.51	1.83	2.17	2.89	3.26	4.08	5.45	7.75
0.21	...	1.73	2.06	2.74	3.10	3.87	5.16	7.27
0.22	...	1.64	1.95	2.61	2.95	3.69	4.90	6.85
0.23	...	...	1.85	2.49	2.82	3.52	4.67	6.49
0.24	...	...	1.76	2.38	2.70	3.37	4.46	6.18
0.25	...	...	...	2.28	2.58	3.23	4.27	5.89
0.26	...	...	...	2.18	2.48	3.10	4.10	5.64
0.27	...	...	...	2.09	2.38	2.98	3.94	5.41
0.28	...	...	...	2.00	2.28	2.87	3.79	5.20
0.29	...	...	...	1.92	2.19	2.76	3.66	5.00
0.30	...	...	...	1.84	2.11	2.66	3.53	4.83
0.31	...	...	...	...	2.03	2.57	3.41	4.66
0.32	...	...	...	...	1.95	2.48	3.30	4.51
0.33	...	...	...	...	...	2.40	3.19	4.37
0.34	...	...	...	...	...	2.32	3.09	4.23
0.35	...	...	...	...	...	2.24	3.00	4.11
0.36	...	...	...	...	...	2.17	2.91	3.99
0.37	...	...	...	...	...	2.10	2.83	3.87
0.38	...	...	...	...	...	...	2.74	3.77
0.39	...	...	...	...	...	...	2.67	3.67
0.40	...	...	...	...	...	...	2.59	3.57
0.41	...	...	...	...	...	...	2.52	3.48
0.42	...	...	...	...	...	...	2.45	3.39
0.43	...	...	...	...	...	...	2.38	3.31
0.44	...	...	...	...	...	...	2.32	3.23
0.45	...	...	...	...	...	...	...	3.15
0.46	...	...	...	...	...	...	...	3.07
0.47	...	...	...	...	...	...	...	3.00
0.48	...	...	...	...	...	...	...	2.93
0.49	...	...	...	...	...	...	...	2.87
0.50	...	...	...	...	...	...	...	2.80
0.51	...	...	...	...	...	...	...	2.74
0.52	...	...	...	...	...	...	...	2.68
0.53	...	...	...	...	...	...	...	2.62
0.54	...	...	...	...	...	...	...	2.56
0.55	...	...	...	...	...	...	...	2.50

Table 3-8M Values of L for Pipe Sizes $\geq$ 914 mm and $<$ 1 066 mm O.D. (12)

Depth, d, mm	Wall Thickness, t, mm							
	6.4	7.1	7.9	9.5	10.3	11.9	14.3	17.5
0.8	341.4	361.9	No limit	No limit	No limit	No limit	No limit	No limit
1.0	341.4	361.9	381.4	418.1	No limit	No limit	No limit	No limit
1.3	228.4	340.2	381.4	418.1	435.0	467.6	No limit	No limit
1.5	158.1	208.9	282.3	418.1	435.0	467.6	511.8	No limit
1.8	124.9	157.6	199.4	336.8	435.0	467.6	511.8	566.3
2.0	104.9	129.4	158.7	241.7	302.1	467.6	511.8	566.3
2.3	91.2	111.0	133.9	193.6	232.8	348.1	511.8	566.3
2.5	81.1	98.0	116.9	164.0	193.0	270.6	481.2	566.3
2.8	73.2	88.0	104.3	143.5	166.7	225.4	361.6	566.3
3.0	66.8	80.1	94.6	128.4	147.9	195.2	295.4	566.3
3.3	61.4	73.6	86.7	116.7	133.5	173.5	252.9	440.2
3.6	56.9	68.1	80.1	107.2	122.1	156.9	222.9	363.6
3.8	52.9	63.4	74.5	99.3	112.8	143.7	200.5	313.1
4.1	49.4	59.3	69.6	92.6	105.0	132.9	183.0	277.1
4.3	46.2	55.6	65.4	86.9	98.3	123.9	168.8	249.9
4.6	43.3	52.3	61.6	81.8	92.5	116.2	157.0	228.5
4.8	40.7	49.3	58.2	77.3	87.4	109.5	147.1	211.2
5.1	38.3	46.5	55.1	73.3	82.8	103.6	138.5	196.8
5.3	...	44.0	52.2	69.7	78.7	98.4	131.1	184.6
5.6	...	41.6	49.6	66.3	75.0	93.7	124.5	174.1
5.8	...	...	47.1	63.3	71.6	89.5	118.6	164.9
6.1	...	...	44.8	60.5	68.5	85.6	113.3	156.9
6.4	...	...	...	57.8	65.6	82.0	108.5	149.7
6.6	...	...	...	55.4	62.9	78.7	104.1	143.2
6.9	...	...	...	53.1	60.3	75.7	100.1	137.3
7.1	...	...	...	50.9	58.0	72.8	96.3	132.0
7.4	...	...	...	48.8	55.7	70.2	92.9	127.1
7.6	...	...	...	46.9	53.6	67.7	89.6	122.6
7.9	...	...	...	...	51.6	65.3	86.6	118.4
8.1	...	...	...	...	49.7	63.0	83.8	114.5
8.4	...	...	...	...	...	60.9	81.1	110.9
8.6	...	...	...	...	...	58.9	78.6	107.5
8.9	...	...	...	...	...	56.9	76.2	104.3
9.1	...	...	...	...	...	55.1	73.9	101.3
9.4	...	...	...	...	...	53.3	71.8	98.4
9.7	...	...	...	...	...	...	69.7	95.7
9.9	...	...	...	...	...	...	67.7	93.2
10.2	...	...	...	...	...	...	65.8	90.7
10.4	...	...	...	...	...	...	64.0	88.4
10.7	...	...	...	...	...	...	62.2	86.1
10.9	...	...	...	...	...	...	60.5	84.0
11.2	...	...	...	...	...	...	58.9	82.0
11.4	...	...	...	...	...	...	...	80.0
11.7	...	...	...	...	...	...	...	78.1
11.9	...	...	...	...	...	...	...	76.3
12.2	...	...	...	...	...	...	...	74.5
12.4	...	...	...	...	...	...	...	72.8
12.7	...	...	...	...	...	...	...	71.1
13.0	...	...	...	...	...	...	...	69.5
13.2	...	...	...	...	...	...	...	68.0
13.5	...	...	...	...	...	...	...	66.4
13.7	...	...	...	...	...	...	...	65.0
14.0	...	...	...	...	...	...	...	63.5

Table 3-9 Values of *L* for Pipe Sizes ≥ NPS 42 and < NPS 48

Depth, *d*, in.	Wall Thickness, *t*, in. 0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.03	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.04	17.03	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.05	17.03	18.50	19.21	19.88	20.53	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.06	17.03	18.50	19.21	19.88	20.53	21.77	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.07	10.93	18.50	19.21	19.88	20.53	21.77	22.95	24.08	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.08	8.33	12.85	16.55	19.88	20.53	21.77	22.95	24.08	25.14	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.09	6.87	9.90	12.06	14.80	18.55	21.77	22.95	24.08	25.14	26.16	27.16	No limit	No limit	No limit	No limit	No limit	No limit
0.10	5.92	8.21	9.72	11.51	13.74	20.46	22.95	24.08	25.14	26.16	27.16	28.12	29.03	No limit	No limit	No limit	No limit
0.11	5.24	7.09	8.26	9.58	11.15	15.37	22.44	24.08	25.14	26.16	27.16	28.12	29.03	29.92	No limit	No limit	No limit
0.12	4.72	6.29	7.25	8.30	9.51	12.56	17.06	24.08	25.14	26.16	27.16	28.12	29.03	29.92	30.79	31.65	No limit
0.13	4.31	5.68	6.50	7.38	8.36	10.75	14.02	18.72	25.14	26.16	27.16	28.12	29.03	29.92	30.79	31.65	32.46
0.14	3.97	5.19	5.91	6.67	7.51	9.48	12.04	15.46	20.25	26.16	27.16	28.12	29.03	29.92	30.79	31.65	32.46
0.15	3.69	4.80	5.44	6.11	6.84	8.53	10.63	13.32	16.82	21.75	27.16	28.12	29.03	29.92	30.79	31.65	32.46
0.16	3.44	4.47	5.05	5.65	6.31	7.78	9.57	11.78	14.54	18.17	23.31	28.12	29.03	29.92	30.79	31.65	32.46
0.17	3.23	4.18	4.72	5.27	5.86	7.18	8.75	10.63	12.89	15.75	19.56	24.84	29.03	29.92	30.79	31.65	32.46
0.18	3.05	3.93	4.43	4.94	5.48	6.68	8.08	9.72	11.65	14.00	17.00	20.93	26.23	29.92	30.79	31.65	32.46
0.19	2.88	3.72	4.18	4.66	5.16	6.26	7.52	8.98	10.66	12.66	15.14	18.25	22.22	27.60	30.79	31.65	32.46
0.20	2.73	3.52	3.96	4.41	4.88	5.89	7.05	8.37	9.86	11.60	13.71	16.28	19.43	23.48	29.04	31.65	32.46
0.21	2.59	3.35	3.76	4.18	4.63	5.57	6.65	7.85	9.20	10.74	12.58	14.76	17.36	20.59	24.80	30.45	32.46
0.22	2.46	3.19	3.59	3.99	4.40	5.29	6.29	7.40	8.63	10.03	11.65	13.55	15.77	18.44	21.80	26.11	31.74
0.23	2.35	3.05	3.42	3.80	4.20	5.04	5.98	7.01	8.15	9.42	10.88	12.56	14.49	16.77	19.56	23.00	27.32
0.24	2.24	2.91	3.27	3.64	4.02	4.82	5.70	6.67	7.72	8.89	10.23	11.74	13.45	15.43	17.81	20.67	24.13
0.25	2.14	2.79	3.14	3.49	3.85	4.61	5.45	6.36	7.35	8.43	9.66	11.04	12.57	14.33	16.40	18.84	21.72
0.26	2.04	2.67	3.01	3.35	3.70	4.43	5.22	6.09	7.02	8.03	9.17	10.43	11.83	13.40	15.24	17.36	19.82
0.27	1.95	2.57	2.89	3.22	3.55	4.25	5.02	5.84	6.72	7.67	8.73	9.90	11.18	12.62	14.26	16.15	18.29
0.28	. . .	2.46	2.78	3.10	3.42	4.10	4.83	5.61	6.45	7.35	8.34	9.43	10.62	11.93	13.43	15.12	17.02
0.29	. . .	2.37	2.68	2.98	3.30	3.95	4.65	5.40	6.20	7.05	7.99	9.02	10.12	11.34	12.71	14.25	15.95
0.30	. . .	2.28	2.58	2.88	3.18	3.81	4.49	5.21	5.97	6.79	7.68	8.64	9.68	10.81	12.08	13.49	15.03
0.31	. . .	2.19	2.49	2.78	3.07	3.68	4.34	5.04	5.76	6.54	7.39	8.30	9.28	10.34	11.52	12.82	14.24
0.32	. . .	2.11	2.40	2.68	2.97	3.56	4.20	4.87	5.57	6.32	7.13	8.00	8.92	9.92	11.02	12.23	13.54
0.33	. . .	. . .	2.31	2.59	2.87	3.45	4.07	4.72	5.39	6.11	6.88	7.71	8.59	9.53	10.57	11.70	12.92
0.34	. . .	. . .	2.23	2.50	2.78	3.34	3.94	4.57	5.22	5.91	6.66	7.45	8.29	9.18	10.17	11.23	12.37
0.35	. . .	. . .	2.16	2.42	2.69	3.24	3.82	4.43	5.07	5.73	6.45	7.21	8.01	8.87	9.80	10.80	11.87
0.36	. . .	. . .	. . .	2.34	2.61	3.14	3.71	4.31	4.92	5.56	6.26	6.99	7.76	8.57	9.46	10.41	11.42
0.37	. . .	. . .	. . .	2.27	2.52	3.05	3.61	4.19	4.78	5.41	6.07	6.78	7.52	8.30	9.15	10.05	11.01
0.38	. . .	. . .	. . .	. . .	2.45	2.96	3.51	4.07	4.65	5.26	5.90	6.59	7.30	8.05	8.86	9.73	10.64
0.39	. . .	. . .	. . .	. . .	2.37	2.88	3.41	3.96	4.53	5.12	5.74	6.40	7.09	7.81	8.59	9.42	10.29
0.40	. . .	. . .	. . .	. . .	2.30	2.80	3.32	3.86	4.41	4.98	5.59	6.23	6.90	7.59	8.34	9.14	9.97

Table 3-9 Values of L for Pipe Sizes $\geq$ NPS 42 and $<$ NPS 48 (Cont'd)

Depth, d, in.	Wall Thickness, t, in.																
	0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.41	...	...	...	...	...	2.72	3.23	3.76	4.30	4.86	5.45	6.07	6.71	7.39	8.11	8.88	9.67
0.42	...	...	...	...	...	2.65	3.15	3.66	4.19	4.74	5.31	5.92	6.54	7.19	7.89	8.63	9.40
0.43	...	...	...	...	...	2.57	3.07	3.57	4.09	4.62	5.18	5.77	6.38	7.01	7.69	8.40	9.14
0.44	...	...	...	...	...	2.50	2.99	3.49	3.99	4.51	5.06	5.64	6.22	6.84	7.50	8.18	8.90
0.45	...	...	...	...	...	...	2.91	3.40	3.90	4.41	4.95	5.50	6.08	6.68	7.31	7.98	8.67
0.46	...	...	...	...	...	...	2.84	3.32	3.81	4.31	4.83	5.38	5.94	6.52	7.14	7.79	8.46
0.47	...	...	...	...	...	...	2.77	3.24	3.72	4.21	4.73	5.26	5.81	6.38	6.98	7.61	8.25
0.48	...	...	...	...	...	...	2.70	3.17	3.64	4.12	4.62	5.15	5.68	6.24	6.82	7.43	8.06
0.49	...	...	...	...	...	...	2.64	3.09	3.56	4.03	4.52	5.04	5.56	6.10	6.67	7.27	7.88
0.50	...	...	...	...	...	...	2.57	3.02	3.48	3.94	4.43	4.93	5.44	5.97	6.53	7.11	7.71
0.51	...	...	...	...	...	...	...	2.96	3.40	3.86	4.34	4.83	5.33	5.85	6.40	6.96	7.55
0.52	...	...	...	...	...	...	...	2.89	3.33	3.78	4.25	4.73	5.23	5.73	6.27	6.82	7.39
0.53	...	...	...	...	...	...	...	2.83	3.26	3.70	4.17	4.64	5.12	5.62	6.14	6.69	7.24
0.54	...	...	...	...	...	...	...	2.76	3.19	3.63	4.08	4.55	5.02	5.51	6.03	6.56	7.10
0.55	...	...	...	...	...	...	...	2.70	3.12	3.56	4.00	4.46	4.93	5.41	5.91	6.43	6.96
0.56	...	...	...	...	...	...	...	...	3.06	3.49	3.93	4.38	4.84	5.31	5.80	6.31	6.83
0.57	...	...	...	...	...	...	...	...	3.00	3.42	3.85	4.30	4.75	5.21	5.69	6.19	6.70
0.58	...	...	...	...	...	...	...	...	2.94	3.35	3.78	4.22	4.66	5.12	5.59	6.08	6.58
0.59	...	...	...	...	...	...	...	...	2.88	3.29	3.71	4.14	4.58	5.03	5.49	5.98	6.46
0.60	...	...	...	...	...	...	...	...	2.82	3.22	3.64	4.07	4.50	4.94	5.40	5.87	6.35
0.61	...	...	...	...	...	...	...	...	...	3.16	3.58	4.00	4.42	4.85	5.31	5.77	6.24
0.62	...	...	...	...	...	...	...	...	...	3.10	3.51	3.93	4.34	4.77	5.22	5.67	6.14
0.63	...	...	...	...	...	...	...	...	...	3.04	3.45	3.86	4.27	4.69	5.13	5.58	6.04
0.64	...	...	...	...	...	...	...	...	...	2.99	3.39	3.79	4.20	4.61	5.05	5.49	5.94
0.65	...	...	...	...	...	...	...	...	...	...	3.33	3.73	4.13	4.54	4.97	5.40	5.84
0.66	...	...	...	...	...	...	...	...	...	...	3.27	3.66	4.06	4.47	4.89	5.32	5.75
0.67	...	...	...	...	...	...	...	...	...	...	3.21	3.60	3.99	4.39	4.81	5.23	5.66
0.68	...	...	...	...	...	...	...	...	...	...	3.15	3.54	3.93	4.32	4.73	5.15	5.57
0.69	...	...	...	...	...	...	...	...	...	...	3.10	3.48	3.87	4.26	4.66	5.07	5.49
0.70	...	...	...	...	...	...	...	...	...	...	3.04	3.42	3.80	4.19	4.59	5.00	5.41
0.71	...	...	...	...	...	...	...	...	...	...	...	3.37	3.74	4.13	4.52	4.92	5.33
0.72	...	...	...	...	...	...	...	...	...	...	...	3.31	3.69	4.06	4.45	4.85	5.25
0.73	...	...	...	...	...	...	...	...	...	...	...	3.26	3.63	4.00	4.39	4.78	5.18
0.74	...	...	...	...	...	...	...	...	...	...	...	3.21	3.57	3.94	4.32	4.71	5.10
0.75	...	...	...	...	...	...	...	...	...	...	...	3.15	3.52	3.88	4.26	4.64	5.03
0.76	...	...	...	...	...	...	...	...	...	...	...	...	3.46	3.82	4.20	4.58	4.96

Table 3-9 Values of L for Pipe Sizes $\geq$ NPS 42 and $<$ NPS 48 (Cont'd)

Depth,	Wall Thickness, t, in.																
d, in.	0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.77	...	...	...	...	...	...	...	...	...	...	...	...	3.41	3.77	4.14	4.51	4.89
0.78	...	...	...	...	...	...	...	...	...	...	...	...	3.36	3.71	4.08	4.45	4.82
0.79	...	...	...	...	...	...	...	...	...	...	...	...	3.30	3.66	4.02	4.39	4.76
0.80	...	...	...	...	...	...	...	...	...	...	...	...	3.25	3.60	3.96	4.33	4.69
0.81	...	...	...	...	...	...	...	...	...	...	...	...	...	3.55	3.91	4.27	4.63
0.82	...	...	...	...	...	...	...	...	...	...	...	...	...	3.50	3.85	4.21	4.57
0.83	...	...	...	...	...	...	...	...	...	...	...	...	...	3.45	3.80	4.16	4.51
0.84	...	...	...	...	...	...	...	...	...	...	...	...	...	3.40	3.75	4.10	4.45
0.85	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.70	4.05	4.39
0.86	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.65	3.99	4.34
0.87	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.60	3.94	4.28
0.88	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.55	3.89	4.23
0.89	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.50	3.84	4.17
0.90	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.45	3.79	4.12
0.91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.74	4.07
0.92	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.69	4.02
0.93	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.64	3.97
0.94	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.59	3.92
0.95	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.55	3.87
0.96	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.82
0.97	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.77
0.98	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.73
0.99	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.68
1.00	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.64

Table 3-9M Values of L for Pipe Sizes ≥ 1 066 mm and < 1 219 mm O.D.

Depth, d, mm	Wall Thickness, t, mm																
	8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
0.8	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.0	432.5	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.3	432.5	469.9	488.1	505.0	521.5	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.5	432.5	469.9	488.1	505.0	521.5	552.8	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.8	277.7	469.9	488.1	505.0	521.5	552.8	583.0	611.7	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.0	211.6	326.3	420.4	505.0	521.5	552.8	583.0	611.7	638.7	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.3	174.5	251.4	306.4	376.0	471.2	552.8	583.0	611.7	638.7	664.5	689.8	No limit	No limit	No limit	No limit	No limit	No limit
2.5	150.3	208.4	246.9	292.3	348.9	519.7	583.0	611.7	638.7	664.5	689.8	714.2	737.5	No limit	No limit	No limit	No limit
2.8	133.0	180.1	209.8	243.4	283.2	390.5	570.0	611.7	638.7	664.5	689.8	714.2	737.5	760.0	No limit	No limit	No limit
3.0	119.8	159.7	184.1	210.8	241.5	319.1	433.4	611.7	638.7	664.5	689.8	714.2	737.5	760.0	782.2	803.8	No limit
3.3	109.4	144.2	165.0	187.4	212.4	273.1	356.1	475.5	638.7	664.5	689.8	714.2	737.5	760.0	782.2	803.8	824.5
3.6	100.8	131.9	150.1	169.4	190.7	240.8	305.7	392.7	514.4	664.5	689.8	714.2	737.5	760.0	782.2	803.8	824.5
3.8	93.6	121.9	138.1	155.2	173.8	216.6	270.0	338.2	427.3	552.4	689.8	714.2	737.5	760.0	782.2	803.8	824.5
4.1	87.5	113.4	128.2	143.6	160.2	197.6	243.2	299.3	369.3	461.4	592.0	714.2	737.5	760.0	782.2	803.8	824.5
4.3	82.1	106.2	119.8	133.9	148.9	182.3	222.2	269.9	327.5	400.0	496.8	630.8	737.5	760.0	782.2	803.8	824.5
4.6	77.3	99.9	112.6	125.5	139.3	169.6	205.2	246.8	295.8	355.5	431.9	531.7	666.3	760.0	782.2	803.8	824.5
4.8	73.1	94.4	106.2	118.3	131.0	158.9	191.0	228.1	270.8	321.6	384.5	463.5	564.4	701.0	782.2	803.8	824.5
5.1	69.3	89.5	100.6	111.9	123.8	149.6	179.1	212.6	250.5	294.8	348.3	413.4	493.4	596.5	737.6	803.8	824.5
5.3	65.8	85.0	95.6	106.3	117.5	141.6	168.8	199.4	233.6	272.9	319.5	374.9	441.0	523.0	630.0	773.6	824.5
5.6	62.6	81.0	91.1	101.2	111.8	134.4	159.8	188.1	219.3	254.7	296.0	344.2	400.5	468.4	553.8	663.1	806.1
5.8	59.6	77.3	87.0	96.6	106.7	128.1	151.9	178.2	206.9	239.2	276.4	319.1	368.1	425.9	496.7	584.3	693.8
6.1	56.9	74.0	83.2	92.4	102.0	122.4	144.8	169.4	196.2	225.9	259.7	298.2	341.6	391.9	452.3	524.9	612.9
6.4	54.3	70.8	79.7	88.6	97.8	117.2	138.5	161.7	186.7	214.2	245.4	280.4	319.3	363.9	416.5	478.5	551.7
6.6	51.9	67.9	76.5	85.0	93.9	112.4	132.7	154.7	178.2	204.0	232.8	265.0	300.4	340.5	387.0	441.0	503.5
6.9	49.6	65.2	73.5	81.7	90.2	108.1	127.5	148.3	170.6	194.8	221.8	251.5	284.0	320.4	362.3	410.1	464.6
7.1	...	62.6	70.7	78.7	86.9	104.0	122.6	142.6	163.7	186.6	211.9	239.6	269.7	303.1	341.1	384.1	432.3
7.4	...	60.2	68.0	75.8	83.7	100.3	118.2	137.3	157.4	179.1	203.0	229.0	257.1	288.0	322.8	361.8	405.2
7.6	...	57.9	65.5	73.1	80.8	96.8	114.1	132.4	151.7	172.4	195.0	219.5	245.8	274.6	306.8	342.5	381.9
7.9	...	55.7	63.2	70.5	78.0	93.6	110.2	127.9	146.4	166.1	187.7	210.9	235.7	262.6	292.6	325.6	361.7
8.1	...	53.6	60.9	68.1	75.4	90.5	106.6	123.7	141.5	160.4	181.0	203.1	226.5	251.9	279.9	310.7	343.9
8.4	...	...	58.8	65.8	72.9	87.6	103.3	119.8	136.9	155.1	174.8	195.9	218.2	242.2	268.6	297.3	328.2
8.6	...	...	56.7	63.6	70.6	84.9	100.1	116.1	132.7	150.2	169.1	189.3	210.5	233.3	258.2	285.3	314.2
8.9	...	...	54.8	61.5	68.3	82.3	97.1	112.6	128.7	145.6	163.8	183.2	203.5	225.2	248.9	274.4	301.6
9.1	...	...	...	59.5	66.2	79.9	94.3	109.4	125.0	141.3	158.9	177.5	197.0	217.7	240.3	264.5	290.1
9.4	...	...	...	57.6	64.1	77.5	91.6	106.3	121.4	137.3	154.3	172.2	190.9	210.8	232.3	255.4	279.7
9.7	...	...	...	...	62.2	75.3	89.1	103.4	118.1	133.5	150.0	167.3	185.3	204.4	225.0	247.0	270.2
9.9	...	...	...	...	60.3	73.1	86.6	100.6	115.0	129.9	145.9	162.7	180.1	198.5	218.3	239.3	261.4
10.2	...	...	...	...	58.4	71.1	84.3	98.0	112.0	126.5	142.0	158.3	175.1	192.9	211.9	232.1	253.3

Table 3-9M Values of L for Pipe Sizes $\geq$ 1 066 mm and $<$ 1 219 mm O.D. (Cont'd)

Depth, d, mm	Wall Thickness, t, mm 8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
10.4	...	...	...	...	...	69.1	82.1	95.5	109.1	123.3	138.4	154.2	170.5	187.7	206.0	225.5	245.7
10.7	...	...	...	...	...	67.2	79.9	93.0	106.4	120.3	135.0	150.3	166.1	182.7	200.5	219.2	238.7
10.9	...	...	...	...	...	65.4	77.9	90.7	103.8	117.4	131.7	146.6	162.0	178.1	195.3	213.4	232.1
11.2	...	...	...	...	...	63.6	75.9	88.5	101.3	114.6	128.6	143.1	158.1	173.7	190.4	207.9	226.0
11.4	...	...	...	...	...	...	74.0	86.4	99.0	111.9	125.6	139.8	154.4	169.6	185.8	202.7	220.2
11.7	...	...	...	...	...	...	72.2	84.3	96.7	109.4	122.8	136.6	150.9	165.7	181.4	197.8	214.8
11.9	...	...	...	...	...	...	70.4	82.4	94.5	106.9	120.0	133.6	147.5	161.9	177.2	193.2	209.7
12.2	...	...	...	...	...	...	68.6	80.5	92.4	104.6	117.4	130.7	144.3	158.4	173.3	188.8	204.8
12.4	...	...	...	...	...	...	67.0	78.6	90.3	102.3	114.9	127.9	141.2	155.0	169.5	184.7	200.2
12.7	...	...	...	...	...	...	65.3	76.8	88.3	100.2	112.5	125.3	138.3	151.7	165.9	180.7	195.8
13.0	...	...	...	...	...	...	...	75.1	86.4	98.1	110.2	122.7	135.5	148.6	162.5	176.9	191.7
13.2	...	...	...	...	...	...	...	73.4	84.6	96.0	108.0	120.3	132.7	145.6	159.2	173.3	187.7
13.5	...	...	...	...	...	...	...	71.8	82.8	94.1	105.8	117.9	130.1	142.8	156.1	169.8	183.9
13.7	...	...	...	...	...	...	...	70.2	81.1	92.2	103.7	115.6	127.6	140.0	153.0	166.5	180.2
14.0	...	...	...	...	...	...	...	68.6	79.4	90.3	101.7	113.4	125.2	137.4	150.1	163.3	176.8
14.2	...	...	...	...	...	...	...	...	77.7	88.5	99.8	111.2	122.9	134.8	147.3	160.3	173.4
14.5	...	...	...	...	...	...	...	...	76.1	86.8	97.9	109.2	120.6	132.4	144.7	157.3	170.2
14.7	...	...	...	...	...	...	...	...	74.6	85.1	96.0	107.2	118.4	130.0	142.1	154.5	167.1
15.0	...	...	...	...	...	...	...	...	73.1	83.5	94.2	105.2	116.3	127.7	139.6	151.8	164.2
15.2	...	...	...	...	...	...	...	...	71.6	81.9	92.5	103.3	114.3	125.4	137.1	149.1	161.3
15.5	...	...	...	...	...	...	...	...	...	80.3	90.8	101.5	112.3	123.3	134.8	146.6	158.6
15.7	...	...	...	...	...	...	...	...	...	78.8	89.2	99.7	110.3	121.2	132.5	144.1	155.9
16.0	...	...	...	...	...	...	...	...	...	77.3	87.6	98.0	108.5	119.2	130.3	141.8	153.3
16.3	...	...	...	...	...	...	...	...	...	75.8	86.0	96.3	106.6	117.2	128.2	139.4	150.8
16.5	...	...	...	...	...	...	...	...	...	...	84.5	94.7	104.9	115.3	126.1	137.2	148.4
16.8	...	...	...	...	...	...	...	...	...	...	83.0	93.0	103.1	113.4	124.1	135.0	146.1
17.0	...	...	...	...	...	...	...	...	...	...	81.5	91.5	101.4	111.6	122.1	132.9	143.8
17.3	...	...	...	...	...	...	...	...	...	...	80.1	89.9	99.8	109.8	120.2	130.9	141.6
17.5	...	...	...	...	...	...	...	...	...	...	78.7	88.4	98.2	108.1	118.4	128.9	139.4
17.8	...	...	...	...	...	...	...	...	...	...	77.3	87.0	96.6	106.4	116.6	126.9	137.4
18.0	...	...	...	...	...	...	...	...	...	...	...	85.6	95.1	104.8	114.8	125.1	135.3
18.3	...	...	...	...	...	...	...	...	...	...	...	84.1	93.6	103.2	113.1	123.2	133.4
18.5	...	...	...	...	...	...	...	...	...	...	...	82.8	92.1	101.6	111.4	121.4	131.4
18.8	...	...	...	...	...	...	...	...	...	...	...	81.4	90.7	100.1	109.8	119.7	129.6
19.1	...	...	...	...	...	...	...	...	...	...	...	80.1	89.3	98.6	108.2	118.0	127.7
19.3	...	...	...	...	...	...	...	...	...	...	...	...	87.9	97.1	106.6	116.3	126.0

Table 3-9M Values of *L* for Pipe Sizes ≥ 1 066 mm and < 1 219 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm																
	8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
19.6	...	...	...	...	...	...	...	...	...	...	...	...	86.6	95.7	105.1	114.7	124.2
19.8	...	...	...	...	...	...	...	...	...	...	...	...	85.2	94.3	103.6	113.1	122.5
20.1	...	...	...	...	...	...	...	...	...	...	...	...	83.9	92.9	102.1	111.5	120.9
20.3	...	...	...	...	...	...	...	...	...	...	...	...	82.7	91.5	100.7	110.0	119.2
20.6	...	...	...	...	...	...	...	...	...	...	...	...	...	90.2	99.3	108.5	117.6
20.8	...	...	...	...	...	...	...	...	...	...	...	...	...	88.9	97.9	107.0	116.1
21.1	...	...	...	...	...	...	...	...	...	...	...	...	...	87.6	96.5	105.6	114.5
21.3	...	...	...	...	...	...	...	...	...	...	...	...	...	86.4	95.2	104.1	113.1
21.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	93.9	102.8	111.6
21.8	...	...	...	...	...	...	...	...	...	...	...	...	...	...	92.6	101.4	110.1
22.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	91.3	100.1	108.7
22.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	90.1	98.7	107.3
22.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	88.9	97.5	106.0
22.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	87.7	96.2	104.6
23.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	94.9	103.3
23.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	93.7	102.0
23.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	92.5	100.8
23.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	91.3	99.5
24.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	90.1	98.3
24.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	97.1
24.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	95.9
24.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	94.7
25.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	93.5
25.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	92.4

Table 3-10 Values of L for Pipe Sizes $\geq$ NPS 48 and $<$ NPS 52

Depth, d, in.	Wall Thickness, t, in.																
	0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.03	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.04	18.20	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.05	18.20	19.78	20.54	21.26	21.95	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.06	18.20	19.78	20.54	21.26	21.95	23.27	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.07	11.69	19.78	20.54	21.26	21.95	23.27	24.54	25.74	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.08	8.91	13.73	17.69	21.26	21.95	23.27	24.54	25.74	26.88	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.09	7.35	10.58	12.89	15.82	19.83	23.27	24.54	25.74	26.88	27.97	29.03	No limit	No limit	No limit	No limit	No limit	No limit
0.10	6.33	8.77	10.39	12.30	14.69	21.87	24.54	25.74	26.88	27.97	29.03	30.06	31.04	No limit	No limit	No limit	No limit
0.11	5.60	7.58	8.83	10.24	11.92	16.44	23.99	25.74	26.88	27.97	29.03	30.06	31.04	31.99	No limit	No limit	No limit
0.12	5.04	6.72	7.75	8.87	10.16	13.43	18.24	25.74	26.88	27.97	29.03	30.06	31.04	31.99	32.92	33.83	No limit
0.13	4.60	6.07	6.94	7.89	8.94	11.49	14.99	20.01	26.88	27.97	29.03	30.06	31.04	31.99	32.92	33.83	34.70
0.14	4.24	5.55	6.32	7.13	8.03	10.13	12.87	16.53	21.65	27.97	29.03	30.06	31.04	31.99	32.92	33.83	34.70
0.15	3.94	5.13	5.81	6.53	7.32	9.11	11.36	14.23	17.99	23.25	29.03	30.06	31.04	31.99	32.92	33.83	34.70
0.16	3.68	4.77	5.40	6.04	6.74	8.32	10.24	12.60	15.54	19.42	24.92	30.06	31.04	31.99	32.92	33.83	34.70
0.17	3.46	4.47	5.04	5.63	6.27	7.67	9.35	11.36	13.78	16.84	20.91	26.55	31.04	31.99	32.92	33.83	34.70
0.18	3.26	4.21	4.74	5.28	5.86	7.14	8.63	10.39	12.45	14.96	18.18	22.38	28.04	31.99	32.92	33.83	34.70
0.19	3.08	3.97	4.47	4.98	5.52	6.69	8.04	9.60	11.40	13.54	16.18	19.51	23.75	29.51	32.92	33.83	34.70
0.20	2.92	3.77	4.24	4.71	5.21	6.30	7.54	8.95	10.54	12.41	14.66	17.40	20.77	25.10	31.05	33.83	34.70
0.21	2.77	3.58	4.02	4.47	4.94	5.96	7.10	8.39	9.83	11.49	13.45	15.78	18.56	22.01	26.52	32.56	34.70
0.22	2.63	3.41	3.83	4.26	4.71	5.66	6.73	7.91	9.23	10.72	12.46	14.49	16.86	19.71	23.31	27.91	33.93
0.23	2.51	3.26	3.66	4.07	4.49	5.39	6.39	7.50	8.71	10.07	11.63	13.43	15.49	17.93	20.91	24.59	29.20
0.24	2.39	3.11	3.50	3.89	4.29	5.15	6.10	7.13	8.26	9.51	10.93	12.55	14.38	16.49	19.03	22.09	25.80
0.25	2.29	2.98	3.35	3.73	4.12	4.93	5.83	6.80	7.86	9.02	10.33	11.80	13.44	15.32	17.53	20.14	23.22
0.26	2.18	2.86	3.22	3.58	3.95	4.73	5.59	6.51	7.50	8.58	9.80	11.15	12.64	14.33	16.29	18.56	21.19
0.27	2.09	2.74	3.09	3.44	3.80	4.55	5.36	6.24	7.18	8.20	9.33	10.59	11.95	13.49	15.25	17.26	19.55
0.28	...	2.63	2.97	3.31	3.66	4.38	5.16	6.00	6.89	7.85	8.92	10.09	11.35	12.76	14.36	16.17	18.20
0.29	...	2.53	2.86	3.19	3.52	4.22	4.97	5.78	6.63	7.54	8.54	9.64	10.82	12.12	13.59	15.23	17.05
0.30	...	2.44	2.76	3.08	3.40	4.08	4.80	5.57	6.38	7.25	8.21	9.24	10.35	11.56	12.91	14.42	16.07
0.31	...	2.34	2.66	2.97	3.28	3.94	4.64	5.38	6.16	6.99	7.90	8.88	9.92	11.05	12.32	13.71	15.22
0.32	...	2.26	2.56	2.87	3.17	3.81	4.49	5.21	5.95	6.75	7.62	8.55	9.53	10.60	11.78	13.08	14.48
0.33	...	...	2.47	2.77	3.07	3.69	4.35	5.04	5.76	6.53	7.36	8.25	9.18	10.19	11.30	12.51	13.81
0.34	...	...	2.39	2.68	2.97	3.57	4.21	4.89	5.58	6.32	7.12	7.97	8.86	9.82	10.87	12.01	13.22
0.35	...	...	2.31	2.59	2.88	3.46	4.09	4.74	5.42	6.13	6.90	7.71	8.56	9.48	10.47	11.55	12.69
0.36	...	...	...	2.50	2.79	3.36	3.97	4.60	5.26	5.95	6.69	7.47	8.29	9.16	10.11	11.13	12.21

Table 3-10 Values of *L* for Pipe Sizes ≥ NPS 48 and < NPS 52 (Cont'd)

Depth, *d*, in.	Wall Thickness, *t*, in.																
	0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.37	...	...	...	2.42	2.70	3.26	3.86	4.47	5.11	5.78	6.49	7.25	8.04	8.87	9.78	10.75	11.77
0.38	...	...	...	...	2.62	3.17	3.75	4.35	4.97	5.62	6.31	7.04	7.80	8.60	9.47	10.40	11.37
0.39	...	...	...	...	2.54	3.08	3.65	4.23	4.84	5.47	6.14	6.85	7.58	8.35	9.19	10.07	11.00
0.40	...	...	...	...	2.46	2.99	3.55	4.12	4.71	5.33	5.98	6.66	7.37	8.12	8.92	9.77	10.66
0.41	...	...	...	...	...	2.91	3.45	4.02	4.59	5.19	5.83	6.49	7.18	7.90	8.67	9.49	10.34
0.42	...	...	...	...	...	2.83	3.36	3.92	4.48	5.06	5.68	6.33	6.99	7.69	8.44	9.23	10.05
0.43	...	...	...	...	...	2.75	3.28	3.82	4.37	4.94	5.54	6.17	6.82	7.50	8.22	8.98	9.77
0.44	...	...	...	...	...	2.68	3.19	3.73	4.26	4.82	5.41	6.02	6.65	7.31	8.01	8.75	9.51
0.45	...	...	...	...	...	...	3.11	3.64	4.16	4.71	5.29	5.88	6.50	7.14	7.82	8.53	9.27
0.46	...	...	...	...	...	...	3.04	3.55	4.07	4.60	5.17	5.75	6.35	6.97	7.63	8.33	9.04
0.47	...	...	...	...	...	...	2.96	3.47	3.98	4.50	5.05	5.62	6.21	6.82	7.46	8.13	8.82
0.48	...	...	...	...	...	...	2.89	3.39	3.89	4.40	4.94	5.50	6.07	6.67	7.29	7.95	8.62
0.49	...	...	...	...	...	...	2.82	3.31	3.80	4.31	4.84	5.39	5.94	6.52	7.13	7.77	8.43
0.50	...	...	...	...	...	...	2.75	3.23	3.72	4.22	4.74	5.27	5.82	6.39	6.98	7.60	8.24
0.51	...	...	...	...	...	...	...	3.16	3.64	4.13	4.64	5.17	5.70	6.26	6.84	7.45	8.07
0.52	...	...	...	...	...	...	...	3.09	3.56	4.04	4.54	5.06	5.59	6.13	6.70	7.29	7.90
0.53	...	...	...	...	...	...	...	3.02	3.48	3.96	4.45	4.96	5.48	6.01	6.57	7.15	7.74
0.54	...	...	...	...	...	...	...	2.95	3.41	3.88	4.37	4.87	5.37	5.89	6.44	7.01	7.59
0.55	...	...	...	...	...	...	...	2.89	3.34	3.80	4.28	4.77	5.27	5.78	6.32	6.87	7.44
0.56	...	...	...	...	...	...	...	...	3.27	3.73	4.20	4.68	5.17	5.67	6.20	6.75	7.30
0.57	...	...	...	...	...	...	...	...	3.20	3.65	4.12	4.60	5.08	5.57	6.09	6.62	7.16
0.58	...	...	...	...	...	...	...	...	3.14	3.58	4.04	4.51	4.98	5.47	5.98	6.50	7.03
0.59	...	...	...	...	...	...	...	...	3.07	3.51	3.97	4.43	4.90	5.37	5.87	6.39	6.91
0.60	...	...	...	...	...	...	...	...	3.01	3.45	3.89	4.35	4.81	5.28	5.77	6.28	6.79
0.61	...	...	...	...	...	...	...	...	...	3.38	3.82	4.27	4.73	5.19	5.67	6.17	6.67
0.62	...	...	...	...	...	...	...	...	...	3.32	3.75	4.20	4.64	5.10	5.58	6.07	6.56
0.63	...	...	...	...	...	...	...	...	...	3.25	3.69	4.12	4.57	5.02	5.48	5.97	6.45
0.64	...	...	...	...	...	...	...	...	...	3.19	3.62	4.05	4.49	4.93	5.40	5.87	6.35
0.65	...	...	...	...	...	...	...	...	...	...	3.55	3.98	4.41	4.85	5.31	5.77	6.25
0.66	...	...	...	...	...	...	...	...	...	...	3.49	3.92	4.34	4.77	5.22	5.68	6.15

Table 3-10 Values of L for Pipe Sizes $\geq$ NPS 48 and $<$ NPS 52 (Cont'd)

Depth,	Wall Thickness, *t*, in.																
d, in.	0.344	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.67	...	...	...	...	...	...	...	...	...	...	3.43	3.85	4.27	4.70	5.14	5.59	6.05
0.68	...	...	...	...	...	...	...	...	...	...	3.37	3.79	4.20	4.62	5.06	5.51	5.96
0.69	...	...	...	...	...	...	...	...	...	...	3.31	3.72	4.13	4.55	4.98	5.42	5.87
0.70	...	...	...	...	...	...	...	...	...	...	3.25	3.66	4.07	4.48	4.91	5.34	5.78
0.71	...	...	...	...	...	...	...	...	...	...	...	3.60	4.00	4.41	4.83	5.26	5.70
0.72	...	...	...	...	...	...	...	...	...	...	...	3.54	3.94	4.34	4.76	5.19	5.61
0.73	...	...	...	...	...	...	...	...	...	...	...	3.48	3.88	4.28	4.69	5.11	5.53
0.74	...	...	...	...	...	...	...	...	...	...	...	3.43	3.82	4.21	4.62	5.04	5.45
0.75	...	...	...	...	...	...	...	...	...	...	...	3.37	3.76	4.15	4.55	4.96	5.38
0.76	...	...	...	...	...	...	...	...	...	...	...	...	3.70	4.09	4.49	4.89	5.30
0.77	...	...	...	...	...	...	...	...	...	...	...	...	3.64	4.03	4.42	4.83	5.23
0.78	...	...	...	...	...	...	...	...	...	...	...	...	3.59	3.97	4.36	4.76	5.16
0.79	...	...	...	...	...	...	...	...	...	...	...	...	3.53	3.91	4.30	4.69	5.09
0.80	...	...	...	...	...	...	...	...	...	...	...	...	3.48	3.85	4.24	4.63	5.02
0.81	...	...	...	...	...	...	...	...	...	...	...	...	...	3.80	4.18	4.56	4.95
0.82	...	...	...	...	...	...	...	...	...	...	...	...	...	3.74	4.12	4.50	4.89
0.83	...	...	...	...	...	...	...	...	...	...	...	...	...	3.69	4.06	4.44	4.82
0.84	...	...	...	...	...	...	...	...	...	...	...	...	...	3.63	4.01	4.38	4.76
0.85	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.95	4.32	4.70
0.86	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.90	4.27	4.64
0.87	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.84	4.21	4.58
0.88	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.79	4.16	4.52
0.89	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.74	4.10	4.46
0.90	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.69	4.05	4.40

Table 3-10M Values of *L* for Pipe Sizes ≥ 1 219 mm and < 1 320 mm O.D.

Depth, *d*, mm	Wall Thickness, *t*, mm																
	8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
0.8	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.0	462.4	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.3	462.4	502.3	521.8	539.9	557.5	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.5	462.4	502.3	521.8	539.9	557.5	591.0	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.8	296.9	502.3	521.8	539.9	557.5	591.0	623.3	653.9	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.0	226.2	348.8	449.4	539.9	557.5	591.0	623.3	653.9	682.8	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.3	186.6	268.8	327.5	402.0	503.7	591.0	623.3	653.9	682.8	710.4	737.5	No limit	No limit	No limit	No limit	No limit	No limit
2.5	160.7	222.8	264.0	312.5	373.0	555.6	623.3	653.9	682.8	710.4	737.5	763.5	788.4	No limit	No limit	No limit	No limit
2.8	142.2	192.5	224.3	260.2	302.7	417.5	609.4	653.9	682.8	710.4	737.5	763.5	788.4	812.4	No limit	No limit	No limit
3.0	128.1	170.7	196.8	225.4	258.2	341.1	463.3	653.9	682.8	710.4	737.5	763.5	788.4	812.4	836.2	859.3	No limit
3.3	116.9	154.2	176.4	200.3	227.1	292.0	380.6	508.3	682.8	710.4	737.5	763.5	788.4	812.4	836.2	859.3	881.4
3.6	107.8	141.0	160.5	181.1	203.9	257.4	326.8	419.8	549.9	710.4	737.5	763.5	788.4	812.4	836.2	859.3	881.4
3.8	100.1	130.3	147.7	165.9	185.8	231.5	288.7	361.6	456.8	590.5	737.5	763.5	788.4	812.4	836.2	859.3	881.4
4.1	93.5	121.3	137.1	153.5	171.2	211.3	260.0	320.0	394.8	493.3	632.9	763.5	788.4	812.4	836.2	859.3	881.4
4.3	87.8	113.5	128.1	143.1	159.1	194.9	237.5	288.6	350.1	427.7	531.1	674.4	788.4	812.4	836.2	859.3	881.4
4.6	82.7	106.8	120.3	134.2	148.9	181.3	219.3	263.9	316.2	380.1	461.7	568.4	712.3	812.4	836.2	859.3	881.4
4.8	78.2	100.9	113.6	126.5	140.1	169.9	204.2	243.9	289.5	343.8	411.1	495.5	603.3	749.4	836.2	859.3	881.4
5.1	74.1	95.7	107.6	119.7	132.4	160.0	191.4	227.2	267.8	315.1	372.3	442.0	527.5	637.7	788.6	859.3	881.4
5.3	70.3	90.9	102.2	113.6	125.6	151.3	180.4	213.2	249.7	291.7	341.6	400.8	471.4	559.1	673.5	827.0	881.4
5.6	66.9	86.6	97.4	108.2	119.5	143.7	170.8	201.0	234.4	272.3	316.4	368.0	428.1	500.7	592.0	708.9	861.8
5.8	63.8	82.7	93.0	103.3	114.0	136.9	162.4	190.5	221.2	255.7	295.5	341.2	393.5	455.3	531.0	624.6	741.7
6.1	60.8	79.1	88.9	98.8	109.1	130.8	154.8	181.1	209.7	241.5	277.7	318.8	365.1	418.9	483.5	561.2	655.3
6.4	58.1	75.7	85.2	94.7	104.5	125.3	148.0	172.8	199.6	229.0	262.3	299.7	341.4	389.0	445.2	511.5	589.8
6.6	55.5	72.6	81.8	90.9	100.3	120.2	141.9	165.3	190.5	218.0	248.9	283.3	321.1	364.0	413.8	471.5	538.3
6.9	53.0	69.7	78.5	87.4	96.5	115.5	136.3	158.6	182.4	208.3	237.1	268.9	303.7	342.6	387.3	438.4	496.7
7.1	...	66.9	75.5	84.1	92.9	111.2	131.1	152.4	175.0	199.5	226.5	256.2	288.4	324.1	364.7	410.6	462.2
7.4	...	64.3	72.7	81.0	89.5	107.2	126.4	146.8	168.3	191.5	217.0	244.9	274.8	307.9	345.1	386.8	433.1
7.6	...	61.9	70.0	78.1	86.4	103.5	121.9	141.5	162.2	184.3	208.5	234.7	262.8	293.5	328.0	366.2	408.2
7.9	...	59.6	67.5	75.4	83.4	100.0	117.8	136.7	156.5	177.6	200.6	225.5	252.0	280.8	312.8	348.1	386.6
8.1	...	57.3	65.1	72.8	80.6	96.8	114.0	132.2	151.3	171.5	193.5	217.1	242.2	269.3	299.3	332.1	367.7
8.4	...	...	62.8	70.3	78.0	93.7	110.4	128.0	146.4	165.8	186.9	209.4	233.2	258.9	287.1	317.8	350.9
8.6	...	...	60.7	68.0	75.4	90.8	107.0	124.1	141.8	160.6	180.8	202.4	225.1	249.4	276.1	305.0	335.9
8.9	...	...	58.6	65.8	73.0	88.0	103.8	120.4	137.6	155.7	175.1	195.8	217.5	240.7	266.0	293.3	322.4
9.1	...	...	...	63.6	70.8	85.4	100.8	116.9	133.6	151.1	169.9	189.8	210.6	232.8	256.8	282.7	310.2

Table 3-10M Values of *L* for Pipe Sizes ≥ 1 219 mm and < 1 320 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm																
	8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
9.4	. . .	. . .	. . .	61.6	68.6	82.9	97.9	113.7	129.8	146.8	164.9	184.1	204.1	225.4	248.4	273.0	299.0
9.7	. . .	. . .	. . .	. . .	66.5	80.5	95.2	110.5	126.3	142.7	160.3	178.9	198.1	218.5	240.6	264.1	288.8
9.9	. . .	. . .	. . .	. . .	64.4	78.2	92.6	107.6	122.9	138.9	156.0	173.9	192.5	212.2	233.3	255.8	279.4
10.2	. . .	. . .	. . .	. . .	62.5	76.0	90.1	104.7	119.7	135.3	151.9	169.2	187.2	206.2	226.6	248.2	270.7
10.4	. . .	. . .	. . .	. . .	. . .	73.9	87.7	102.0	116.7	131.8	148.0	164.9	182.3	200.6	220.3	241.0	262.7
10.7	. . .	. . .	. . .	. . .	. . .	71.9	85.5	99.5	113.8	128.6	144.3	160.7	177.6	195.4	214.3	234.4	255.2
10.9	. . .	. . .	. . .	. . .	. . .	69.9	83.3	97.0	111.0	125.5	140.8	156.8	173.2	190.4	208.8	228.1	248.2
11.2	. . .	. . .	. . .	. . .	. . .	68.0	81.1	94.6	108.3	122.5	137.5	153.0	169.0	185.7	203.5	222.2	241.6
11.4	. . .	. . .	. . .	. . .	. . .	. . .	79.1	92.4	105.8	119.7	134.3	149.5	165.1	181.3	198.6	216.7	235.4
11.7	. . .	. . .	. . .	. . .	. . .	. . .	77.1	90.2	103.3	116.9	131.2	146.1	161.3	177.1	193.9	211.5	229.6
11.9	. . .	. . .	. . .	. . .	. . .	. . .	75.2	88.0	101.0	114.3	128.3	142.8	157.7	173.1	189.5	206.5	224.1
12.2	. . .	. . .	. . .	. . .	. . .	. . .	73.4	86.0	98.7	111.8	125.5	139.7	154.2	169.3	185.2	201.9	218.9
12.4	. . .	. . .	. . .	. . .	. . .	. . .	71.6	84.0	96.5	109.4	122.9	136.8	151.0	165.7	181.2	197.4	214.0
12.7	. . .	. . .	. . .	. . .	. . .	. . .	69.9	82.1	94.4	107.1	120.3	133.9	147.8	162.2	177.4	193.2	209.3
13.0	. . .	. . .	. . .	. . .	. . .	. . .	. . .	80.3	92.4	104.8	117.8	131.2	144.8	158.9	173.7	189.1	204.9
13.2	. . .	. . .	. . .	. . .	. . .	. . .	. . .	78.5	90.4	102.7	115.4	128.6	141.9	155.7	170.2	185.3	200.6
13.5	. . .	. . .	. . .	. . .	. . .	. . .	. . .	76.7	88.5	100.6	113.1	126.0	139.1	152.6	166.8	181.6	196.6
13.7	. . .	. . .	. . .	. . .	. . .	. . .	. . .	75.0	86.7	98.5	110.9	123.6	136.4	149.7	163.6	178.0	192.7
14.0	. . .	. . .	. . .	. . .	. . .	. . .	. . .	73.4	84.9	96.6	108.7	121.2	133.8	146.9	160.5	174.6	189.0
14.2	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	83.1	94.7	106.6	118.9	131.3	144.1	157.5	171.3	185.4
14.5	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	81.4	92.8	104.6	116.7	128.9	141.5	154.6	168.2	182.0
14.7	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	79.7	91.0	102.6	114.6	126.6	139.0	151.9	165.2	178.7
15.0	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	78.1	89.2	100.7	112.5	124.3	136.5	149.2	162.3	175.5
15.2	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	76.5	87.5	98.9	110.5	122.1	134.1	146.6	159.4	172.5
15.5	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	85.9	97.1	108.5	120.0	131.8	144.1	156.7	169.5
15.7	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	84.2	95.3	106.6	118.0	129.6	141.7	154.1	166.7
16.0	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	82.6	93.6	104.8	116.0	127.4	139.3	151.5	163.9
16.3	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	81.1	91.9	102.9	114.0	125.3	137.0	149.1	161.2
16.5	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	90.3	101.2	112.1	123.2	134.8	146.7	158.7
16.8	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	88.7	99.5	110.3	121.3	132.7	144.4	156.2

Table 3-10M Values of *L* for Pipe Sizes ≥ 1 219 mm and < 1 320 mm O.D. (Cont'd)

Depth,	Wall Thickness, *t*, mm																
d, mm	8.7	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
17.0	...	...	...	...	...	...	...	...	...	...	87.1	97.8	108.5	119.3	130.6	142.1	153.7
17.3	...	...	...	...	...	...	...	...	...	...	85.6	96.2	106.7	117.4	128.5	139.9	151.4
17.5	...	...	...	...	...	...	...	...	...	...	84.1	94.6	105.0	115.6	126.6	137.8	149.1
17.8	...	...	...	...	...	...	...	...	...	...	82.7	93.0	103.3	113.8	124.6	135.7	146.9
18.0	...	...	...	...	...	...	...	...	...	...	...	91.5	101.7	112.0	122.8	133.7	144.7
18.3	...	...	...	...	...	...	...	...	...	...	...	90.0	100.1	110.3	120.9	131.7	142.6
18.5	...	...	...	...	...	...	...	...	...	...	...	88.5	98.5	108.6	119.1	129.8	140.5
18.8	...	...	...	...	...	...	...	...	...	...	...	87.0	97.0	107.0	117.4	127.9	138.5
19.1	...	...	...	...	...	...	...	...	...	...	...	85.6	95.5	105.4	115.7	126.1	136.6
19.3	...	...	...	...	...	...	...	...	...	...	...	...	94.0	103.8	114.0	124.3	134.7
19.6	...	...	...	...	...	...	...	...	...	...	...	...	92.5	102.3	112.4	122.6	132.8
19.8	...	...	...	...	...	...	...	...	...	...	...	...	91.1	100.8	110.7	120.9	131.0
20.1	...	...	...	...	...	...	...	...	...	...	...	...	89.7	99.3	109.2	119.2	129.2
20.3	...	...	...	...	...	...	...	...	...	...	...	...	88.4	97.9	107.6	117.6	127.5
20.6	...	...	...	...	...	...	...	...	...	...	...	...	...	96.4	106.1	115.9	125.8
20.8	...	...	...	...	...	...	...	...	...	...	...	...	...	95.0	104.7	114.4	124.1
21.1	...	...	...	...	...	...	...	...	...	...	...	...	...	93.7	103.2	112.8	122.5
21.3	...	...	...	...	...	...	...	...	...	...	...	...	...	92.3	101.8	111.3	120.9
21.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	100.4	109.8	119.3
21.8	...	...	...	...	...	...	...	...	...	...	...	...	...	...	99.0	108.4	117.8
22.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	97.6	107.0	116.2
22.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	96.3	105.6	114.8
22.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	95.0	104.2	113.3
22.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	93.7	102.8	111.9

Table 3-11 Values of L for Pipe Sizes $\geq$ NPS 52 and $<$ NPS 56

Depth, *d*, in.	Wall Thickness, *t*, in.															
	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.04	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.05	20.58	21.38	22.12	22.84	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.06	20.58	21.38	22.12	22.84	24.22	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.07	20.58	21.38	22.12	22.84	24.22	25.54	26.80	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.08	14.29	18.42	22.12	22.84	24.22	25.54	26.80	27.98	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.09	11.01	13.42	16.47	20.64	24.22	25.54	26.80	27.98	29.11	30.22	No limit	No limit	No limit	No limit	No limit	No limit
0.10	9.13	10.82	12.81	15.28	22.77	25.54	26.80	27.98	29.11	30.22	31.29	29.55	No limit	No limit	No limit	No limit
0.11	7.89	9.19	10.66	12.41	17.11	24.97	26.80	27.98	29.11	30.22	31.29	29.55	33.29	No limit	No limit	No limit
0.12	7.00	8.06	9.24	10.58	13.98	18.99	26.80	27.98	29.11	30.22	31.29	32.31	33.29	34.27	35.21	No limit
0.13	6.32	7.23	8.21	9.31	11.96	15.60	20.83	27.98	29.11	30.22	31.29	32.31	33.29	34.27	35.21	36.12
0.14	5.78	6.58	7.42	8.36	10.55	13.39	17.20	22.54	29.11	30.22	31.29	32.31	33.29	34.27	35.21	36.12
0.15	5.34	6.05	6.80	7.61	9.49	11.83	14.82	18.72	24.20	30.22	31.29	32.31	33.29	34.27	35.21	36.12
0.16	4.97	5.62	6.29	7.02	8.66	10.65	13.11	16.18	20.21	25.93	31.29	32.31	33.29	34.27	35.21	36.12
0.17	4.65	5.25	5.86	6.52	7.99	9.73	11.82	14.35	17.52	21.76	27.63	32.31	33.29	34.27	35.21	36.12
0.18	4.38	4.93	5.50	6.10	7.43	8.99	10.81	12.96	15.58	18.92	23.29	29.19	33.29	34.27	35.21	36.12
0.19	4.14	4.65	5.18	5.74	6.96	8.37	9.99	11.86	14.09	16.85	20.31	24.72	30.71	34.27	35.21	36.12
0.20	3.92	4.41	4.90	5.43	6.56	7.84	9.31	10.97	12.91	15.26	18.11	21.62	26.13	32.31	35.21	36.12
0.21	3.73	4.19	4.66	5.15	6.20	7.39	8.73	10.23	11.95	14.00	16.42	19.32	22.91	27.60	33.89	36.12
0.22	3.55	3.99	4.43	4.90	5.89	7.00	8.24	9.61	11.16	12.97	15.08	17.54	20.52	24.26	29.05	35.31
0.23	3.39	3.81	4.23	4.67	5.61	6.65	7.80	9.07	10.48	12.11	13.98	16.13	18.66	21.76	25.60	30.39
0.24	3.24	3.64	4.05	4.47	5.36	6.34	7.42	8.59	9.89	11.38	13.06	14.96	17.17	19.81	23.00	26.85
0.25	3.10	3.49	3.88	4.28	5.13	6.07	7.08	8.18	9.39	10.75	12.28	13.99	15.94	18.25	20.96	24.17
0.26	2.97	3.35	3.73	4.11	4.92	5.81	6.78	7.81	8.93	10.20	11.61	13.16	14.91	16.95	19.32	22.06
0.27	2.85	3.22	3.58	3.95	4.73	5.58	6.50	7.47	8.53	9.71	11.02	12.44	14.04	15.87	17.97	20.35
0.28	2.74	3.10	3.45	3.81	4.56	5.37	6.25	7.17	8.17	9.28	10.50	11.82	13.28	14.94	16.83	18.94
0.29	2.64	2.98	3.32	3.67	4.39	5.18	6.01	6.90	7.85	8.89	10.03	11.26	12.62	14.14	15.85	17.75
0.30	2.54	2.87	3.20	3.54	4.24	5.00	5.80	6.64	7.55	8.54	9.62	10.77	12.03	13.44	15.01	16.73
0.31	2.44	2.77	3.09	3.42	4.10	4.83	5.60	6.41	7.28	8.22	9.24	10.32	11.51	12.82	14.26	15.84
0.32	2.35	2.67	2.98	3.30	3.97	4.67	5.42	6.20	7.03	7.93	8.90	9.92	11.03	12.26	13.61	15.07
0.33	. . .	2.57	2.88	3.19	3.84	4.52	5.25	6.00	6.80	7.66	8.58	9.56	10.61	11.76	13.02	14.38
0.34	. . .	2.49	2.79	3.09	3.72	4.39	5.09	5.81	6.58	7.41	8.29	9.22	10.22	11.31	12.50	13.76

Table 3-11 Values of *L* for Pipe Sizes ≥ NPS 52 and < NPS 56 (Cont'd)

Depth, *d*, in.	Wall Thickness, *t*, in.															
	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.35	...	2.40	2.69	2.99	3.61	4.26	4.93	5.64	6.38	7.18	8.02	8.91	9.86	10.90	12.02	13.21
0.36	...	...	2.61	2.90	3.50	4.13	4.79	5.47	6.19	6.96	7.78	8.63	9.54	10.52	11.59	12.71
0.37	...	...	2.52	2.81	3.40	4.01	4.66	5.32	6.01	6.76	7.55	8.36	9.24	10.18	11.19	12.25
0.38	...	...	...	2.72	3.30	3.90	4.53	5.17	5.85	6.57	7.33	8.12	8.95	9.86	10.82	11.83
0.39	...	...	...	2.64	3.20	3.80	4.41	5.04	5.69	6.39	7.13	7.89	8.69	9.56	10.48	11.45
0.40	...	...	...	2.56	3.11	3.69	4.29	4.90	5.54	6.22	6.94	7.67	8.45	9.28	10.17	11.09
0.41	...	...	...	...	3.03	3.60	4.18	4.78	5.40	6.06	6.76	7.47	8.22	9.03	9.88	10.76
0.42	...	...	...	...	2.94	3.50	4.08	4.66	5.27	5.91	6.59	7.28	8.01	8.78	9.60	10.46
0.43	...	...	...	...	2.86	3.41	3.97	4.55	5.14	5.77	6.42	7.10	7.80	8.56	9.35	10.17
0.44	...	...	...	...	2.79	3.33	3.88	4.44	5.02	5.63	6.27	6.93	7.61	8.34	9.11	9.90
0.45	...	...	...	...	...	3.24	3.78	4.33	4.90	5.50	6.13	6.76	7.43	8.14	8.88	9.65
0.46	...	...	...	...	...	3.16	3.69	4.23	4.79	5.38	5.99	6.61	7.26	7.95	8.67	9.41
0.47	...	...	...	...	...	3.08	3.61	4.14	4.68	5.26	5.85	6.46	7.09	7.76	8.46	9.18
0.48	...	...	...	...	...	3.01	3.52	4.05	4.58	5.14	5.73	6.32	6.94	7.59	8.27	8.97
0.49	...	...	...	...	...	2.93	3.44	3.96	4.48	5.03	5.60	6.19	6.79	7.43	8.09	8.77
0.50	...	...	...	...	...	2.86	3.37	3.87	4.39	4.93	5.49	6.06	6.65	7.27	7.92	8.58
0.51	...	...	...	...	...	...	3.29	3.79	4.30	4.83	5.38	5.93	6.51	7.12	7.75	8.40
0.52	...	...	...	...	...	...	3.22	3.71	4.21	4.73	5.27	5.81	6.38	6.97	7.59	8.22
0.53	...	...	...	...	...	...	3.14	3.63	4.12	4.64	5.16	5.70	6.25	6.84	7.44	8.06
0.54	...	...	...	...	...	...	3.07	3.55	4.04	4.54	5.06	5.59	6.13	6.70	7.29	7.90
0.55	...	...	...	...	...	...	3.01	3.48	3.96	4.46	4.97	5.48	6.02	6.58	7.16	7.74
0.56	...	...	...	...	...	...	...	3.41	3.88	4.37	4.87	5.38	5.91	6.45	7.02	7.60
0.57	...	...	...	...	...	...	...	3.34	3.80	4.29	4.78	5.28	5.80	6.34	6.89	7.46
0.58	...	...	...	...	...	...	...	3.27	3.73	4.21	4.69	5.19	5.69	6.22	6.77	7.32
0.59	...	...	...	...	...	...	...	3.20	3.66	4.13	4.61	5.10	5.59	6.11	6.65	7.19
0.60	...	...	...	...	...	...	...	3.14	3.59	4.05	4.53	5.01	5.50	6.01	6.53	7.07
0.61	...	...	...	...	...	...	...	...	3.52	3.98	4.45	4.92	5.40	5.90	6.42	6.95
0.62	...	...	...	...	...	...	...	...	3.45	3.91	4.37	4.83	5.31	5.81	6.31	6.83
0.63	...	...	...	...	...	...	...	...	3.39	3.84	4.29	4.75	5.22	5.71	6.21	6.72
0.64	...	...	...	...	...	...	...	...	3.32	3.77	4.22	4.67	5.13	5.62	6.11	6.61
0.65	...	...	...	...	...	...	...	...	...	3.70	4.15	4.59	5.05	5.52	6.01	6.50
0.66	...	...	...	...	...	...	...	...	...	3.63	4.08	4.52	4.97	5.44	5.92	6.40
0.67	...	...	...	...	...	...	...	...	...	3.57	4.01	4.44	4.89	5.35	5.82	6.30
0.68	...	...	...	...	...	...	...	...	...	3.51	3.94	4.37	4.81	5.27	5.73	6.20
0.69	...	...	...	...	...	...	...	...	...	3.45	3.87	4.30	4.74	5.19	5.65	6.11
0.70	...	...	...	...	...	...	...	...	...	3.39	3.81	4.23	4.66	5.11	5.56	6.02

Table 3-11 Values of *L* for Pipe Sizes ≥ NPS 52 and < NPS 56 (Cont'd)

Depth, *d*, in.	Wall Thickness, *t*, in.															
	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.71	...	...	...	...	...	...	...	...	...	...	3.75	4.17	4.59	5.03	5.48	5.93
0.72	...	...	...	...	...	...	...	...	...	...	3.69	4.10	4.52	4.95	5.40	5.84
0.73	...	...	...	...	...	...	...	...	...	...	3.63	4.04	4.45	4.88	5.32	5.76
0.74	...	...	...	...	...	...	...	...	...	...	3.57	3.97	4.38	4.81	5.24	5.68
0.75	...	...	...	...	...	...	...	...	...	...	3.51	3.91	4.32	4.74	5.17	5.60
0.76	...	...	...	...	...	...	...	...	...	...	...	3.85	4.25	4.67	5.09	5.52
0.77	...	...	...	...	...	...	...	...	...	...	...	3.79	4.19	4.60	5.02	5.44
0.78	...	...	...	...	...	...	...	...	...	...	...	3.73	4.13	4.54	4.95	5.37
0.79	...	...	...	...	...	...	...	...	...	...	...	3.68	4.07	4.47	4.88	5.29
0.80	...	...	...	...	...	...	...	...	...	...	...	3.62	4.01	4.41	4.82	5.22
0.81	...	...	...	...	...	...	...	...	...	...	...	...	3.95	4.35	4.75	5.15
0.82	...	...	...	...	...	...	...	...	...	...	...	...	3.89	4.29	4.69	5.08
0.83	...	...	...	...	...	...	...	...	...	...	...	...	3.84	4.23	4.62	5.02
0.84	...	...	...	...	...	...	...	...	...	...	...	...	3.78	4.17	4.56	4.95
0.85	...	...	...	...	...	...	...	...	...	...	...	...	...	4.11	4.50	4.89
0.86	...	...	...	...	...	...	...	...	...	...	...	...	...	4.06	4.44	4.83
0.87	...	...	...	...	...	...	...	...	...	...	...	...	...	4.00	4.38	4.76
0.88	...	...	...	...	...	...	...	...	...	...	...	...	...	3.95	4.33	4.70
0.89	...	...	...	...	...	...	...	...	...	...	...	...	...	3.89	4.27	4.64
0.90	...	...	...	...	...	...	...	...	...	...	...	...	...	3.84	4.21	4.58
0.91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.16	4.53
0.92	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.10	4.47
0.93	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.05	4.41
0.94	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.00	4.36
0.95	...	...	...	...	...	...	...	...	...	...	...	...	...	...	3.95	4.31
0.96	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.25
0.97	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.20
0.98	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.15
0.99	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.10
1.00	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.05

Table 3-11M Values of L for Pipe Sizes $\geq$ 1 320 mm and < 1 422 mm O.D.

Depth,	Wall Thickness, *t*, mm															
d, mm	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
1.0	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.3	522.8	543.1	562.0	580.2	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.5	522.8	543.1	562.0	580.2	615.2	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.8	522.8	543.1	562.0	580.2	615.2	648.7	680.6	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.0	363.1	467.7	562.0	580.2	615.2	648.7	680.6	710.6	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.3	279.7	340.9	418.4	524.3	615.2	648.7	680.6	710.6	739.4	767.6	No limit	No limit	No limit	No limit	No limit	No limit
2.5	231.9	274.8	325.3	388.2	578.3	648.7	680.6	710.6	739.4	767.6	794.7	750.6	No limit	No limit	No limit	No limit
2.8	200.4	233.5	270.8	315.1	434.5	634.3	680.6	710.6	739.4	767.6	794.7	750.6	845.6	No limit	No limit	No limit
3.0	177.7	204.8	234.6	268.7	355.0	482.3	680.6	710.6	739.4	767.6	794.7	820.6	845.6	870.3	894.4	No limit
3.3	160.5	183.6	208.5	236.4	303.9	396.2	529.1	710.6	739.4	767.6	794.7	820.6	845.6	870.3	894.4	917.4
3.6	146.8	167.0	188.5	212.2	267.9	340.2	437.0	572.4	739.4	767.6	794.7	820.6	845.6	870.3	894.4	917.4
3.8	135.6	153.7	172.7	193.4	241.0	300.5	376.3	475.5	614.7	767.6	794.7	820.6	845.6	870.3	894.4	917.4
4.1	126.2	142.7	159.8	178.2	219.9	270.6	333.0	410.9	513.4	658.7	794.7	820.6	845.6	870.3	894.4	917.4
4.3	118.2	133.3	148.9	165.6	202.9	247.2	300.3	364.4	445.1	552.8	701.9	820.6	845.6	870.3	894.4	917.4
4.6	111.2	125.2	139.7	155.0	188.7	228.3	274.6	329.1	395.6	480.6	591.7	741.4	845.6	870.3	894.4	917.4
4.8	105.0	118.2	131.6	145.8	176.8	212.6	253.8	301.3	357.9	427.9	515.8	628.0	780.0	870.3	894.4	917.4
5.1	99.6	112.0	124.6	137.8	166.5	199.3	236.5	278.7	328.0	387.5	460.0	549.0	663.7	820.8	894.4	917.4
5.3	94.6	106.4	118.3	130.7	157.5	187.8	221.9	259.9	303.6	355.5	417.1	490.7	582.0	701.0	860.7	917.4
5.6	90.2	101.3	112.6	124.4	149.6	177.8	209.2	244.0	283.4	329.4	383.0	445.6	521.1	616.2	737.9	897.0
5.8	86.1	96.8	107.5	118.7	142.5	169.0	198.2	230.3	266.2	307.6	355.1	409.6	473.9	552.7	650.1	772.0
6.1	82.3	92.6	102.9	113.5	136.1	161.1	188.5	218.3	251.3	289.0	331.8	380.0	436.1	503.2	584.1	682.0
6.4	78.8	88.7	98.6	108.8	130.4	154.1	179.9	207.7	238.4	273.0	311.9	355.3	404.9	463.4	532.4	613.9
6.6	75.6	85.1	94.6	104.4	125.1	147.7	172.1	198.3	226.9	259.1	294.8	334.3	378.8	430.6	490.7	560.3
6.9	72.5	81.8	91.0	100.4	120.2	141.8	165.1	189.8	216.8	246.8	279.9	316.1	356.6	403.1	456.3	516.9
7.1	69.7	78.6	87.5	96.7	115.8	136.5	158.6	182.2	207.6	235.8	266.6	300.1	337.3	379.6	427.4	481.1
7.4	67.0	75.7	84.3	93.2	111.6	131.5	152.8	175.2	199.3	225.9	254.9	286.1	320.4	359.2	402.6	450.8
7.6	64.4	72.9	81.3	89.9	107.7	126.9	147.3	168.8	191.8	217.0	244.3	273.5	305.5	341.4	381.1	424.9
7.9	62.0	70.3	78.5	86.8	104.1	122.7	142.3	162.9	184.9	208.8	234.7	262.2	292.2	325.6	362.3	402.4
8.1	59.7	67.8	75.8	83.9	100.7	118.7	137.6	157.4	178.5	201.4	226.0	252.0	280.3	311.5	345.7	382.7
8.4	. . .	65.4	73.2	81.1	97.5	114.9	133.3	152.4	172.6	194.5	218.0	242.8	269.4	298.8	330.8	365.2
8.6	. . .	63.1	70.8	78.5	94.5	111.4	129.2	147.6	167.1	188.2	210.6	234.2	259.6	287.3	317.4	349.6

Table 3-11M Values of *L* for Pipe Sizes ≥ 1 320 mm and < 1 422 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm															
	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
8.9	...	60.9	68.4	76.0	91.6	108.1	125.3	143.2	162.0	182.3	203.8	226.4	250.6	276.9	305.3	335.6
9.1	...	...	66.2	73.6	88.9	104.9	121.7	139.0	157.3	176.8	197.5	219.2	242.3	267.3	294.3	322.8
9.4	...	...	64.1	71.4	86.3	101.9	118.3	135.1	152.8	171.7	191.6	212.5	234.6	258.5	284.2	311.2
9.7	...	...	...	69.2	83.8	99.1	115.0	131.4	148.6	166.9	186.2	206.2	227.5	250.4	274.9	300.6
9.9	...	...	...	67.1	81.4	96.4	112.0	127.9	144.6	162.3	181.0	200.4	220.8	242.8	266.3	290.8
10.2	...	...	...	65.0	79.1	93.8	109.0	124.6	140.8	158.1	176.2	194.9	214.6	235.8	258.3	281.8
10.4	...	...	...	...	76.9	91.3	106.2	121.4	137.2	154.0	171.6	189.7	208.8	229.2	250.9	273.4
10.7	...	...	...	...	74.8	88.9	103.5	118.4	133.8	150.2	167.3	184.9	203.3	223.1	243.9	265.6
10.9	...	...	...	...	72.8	86.7	101.0	115.5	130.6	146.5	163.2	180.3	198.2	217.3	237.4	258.3
11.2	...	...	...	...	70.8	84.5	98.5	112.7	127.5	143.1	159.3	175.9	193.3	211.9	231.3	251.5
11.4	...	...	...	...	...	82.3	96.1	110.1	124.5	139.8	155.6	171.8	188.7	206.7	225.6	245.1
11.7	...	...	...	...	...	80.3	93.8	107.6	121.7	136.6	152.0	167.9	184.3	201.8	220.1	239.0
11.9	...	...	...	...	...	78.3	91.6	105.1	119.0	133.6	148.7	164.1	180.2	197.2	215.0	233.3
12.2	...	...	...	...	...	76.4	89.5	102.8	116.4	130.7	145.5	160.5	176.2	192.8	210.1	227.9
12.4	...	...	...	...	...	74.5	87.5	100.5	113.9	127.9	142.4	157.1	172.4	188.6	205.5	222.8
12.7	...	...	...	...	...	72.7	85.5	98.3	111.4	125.2	139.4	153.9	168.8	184.6	201.1	217.9
13.0	...	...	...	...	...	...	83.5	96.2	109.1	122.6	136.6	150.7	165.4	180.8	196.8	213.2
13.2	...	...	...	...	...	...	81.7	94.1	106.9	120.1	133.8	147.7	162.1	177.2	192.8	208.8
13.5	...	...	...	...	...	...	79.8	92.1	104.7	117.7	131.2	144.8	158.9	173.6	189.0	204.6
13.7	...	...	...	...	...	...	78.1	90.2	102.6	115.4	128.6	142.0	155.8	170.3	185.3	200.6
14.0	...	...	...	...	...	...	76.3	88.3	100.5	113.2	126.2	139.3	152.9	167.1	181.7	196.7
14.2	...	...	...	...	...	...	...	86.5	98.5	111.0	123.8	136.7	150.0	163.9	178.3	193.0
14.5	...	...	...	...	...	...	...	84.7	96.6	108.9	121.5	134.2	147.3	161.0	175.1	189.4
14.7	...	...	...	...	...	...	...	83.0	94.7	106.8	119.2	131.8	144.6	158.1	171.9	186.0
15.0	...	...	...	...	...	...	...	81.3	92.9	104.9	117.1	129.4	142.1	155.3	168.9	182.7
15.2	...	...	...	...	...	...	...	79.6	91.1	102.9	115.0	127.1	139.6	152.6	165.9	179.5
15.5	...	...	...	...	...	...	...	...	89.4	101.0	112.9	124.9	137.2	150.0	163.1	176.4
15.7	...	...	...	...	...	...	...	...	87.7	99.2	111.0	122.8	134.9	147.5	160.4	173.5
16.0	...	...	...	...	...	...	...	...	86.0	97.4	109.0	120.7	132.6	145.0	157.7	170.6
16.3	...	...	...	...	...	...	...	...	84.4	95.7	107.2	118.7	130.4	142.6	155.2	167.8
16.5	...	...	...	...	...	...	...	...	...	94.0	105.3	116.7	128.3	140.3	152.7	165.1
16.8	...	...	...	...	...	...	...	...	...	92.3	103.5	114.8	126.2	138.1	150.3	162.5
17.0	...	...	...	...	...	...	...	...	...	90.7	101.8	112.9	124.2	135.9	147.9	160.0
17.3	...	...	...	...	...	...	...	...	...	89.1	100.1	111.1	122.2	133.8	145.6	157.5
17.5	...	...	...	...	...	...	...	...	...	87.6	98.4	109.3	120.3	131.7	143.4	155.2
17.8	...	...	...	...	...	...	...	...	...	86.0	96.8	107.5	118.4	129.7	141.3	152.8

Table 3-11M Values of *L* for Pipe Sizes ≥ 1 320 mm and < 1 422 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm															
	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
18.0	...	...	...	...	...	...	...	...	...	...	95.2	105.8	116.6	127.8	139.2	150.6
18.3	...	...	...	...	...	...	...	...	...	...	93.6	104.1	114.8	125.9	137.1	148.4
18.5	...	...	...	...	...	...	...	...	...	...	92.1	102.5	113.1	124.0	135.1	146.3
18.8	...	...	...	...	...	...	...	...	...	...	90.6	100.9	111.4	122.2	133.2	144.2
19.1	...	...	...	...	...	...	...	...	...	...	89.1	99.4	109.7	120.4	131.2	142.1
19.3	...	...	...	...	...	...	...	...	...	...	...	97.8	108.1	118.6	129.4	140.2
19.6	...	...	...	...	...	...	...	...	...	...	...	96.3	106.5	116.9	127.6	138.2
19.8	...	...	...	...	...	...	...	...	...	...	...	94.8	104.9	115.3	125.8	136.3
20.1	...	...	...	...	...	...	...	...	...	...	...	93.4	103.4	113.6	124.1	134.5
20.3	...	...	...	...	...	...	...	...	...	...	...	92.0	101.9	112.0	122.4	132.7
20.6	...	...	...	...	...	...	...	...	...	...	...	...	100.4	110.5	120.7	130.9
20.8	...	...	...	...	...	...	...	...	...	...	...	...	98.9	108.9	119.0	129.2
21.1	...	...	...	...	...	...	...	...	...	...	...	...	97.5	107.4	117.4	127.5
21.3	...	...	...	...	...	...	...	...	...	...	...	...	96.1	105.9	115.9	125.8
21.6	...	...	...	...	...	...	...	...	...	...	...	...	...	104.5	114.3	124.2
21.8	...	...	...	...	...	...	...	...	...	...	...	...	...	103.0	112.8	122.6
22.1	...	...	...	...	...	...	...	...	...	...	...	...	...	101.6	111.3	121.0
22.4	...	...	...	...	...	...	...	...	...	...	...	...	...	100.2	109.9	119.4
22.6	...	...	...	...	...	...	...	...	...	...	...	...	...	98.9	108.4	117.9
22.9	...	...	...	...	...	...	...	...	...	...	...	...	...	97.5	107.0	116.4
23.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	105.6	115.0
23.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	104.3	113.5
23.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	102.9	112.1
23.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	101.6	110.7
24.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	100.3	109.4
24.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	108.0
24.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	106.7
24.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	105.4
25.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	104.1
25.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	102.8

Table 3-12 Values of L for Pipe Sizes $\geq$ NPS 56 Through NPS 60

Depth, d, in.	Wall Thickness, t, in.															
	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.04	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.05	21.36	22.19	22.96	23.71	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.06	21.36	22.19	22.96	23.71	25.13	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.07	21.36	22.19	22.96	23.71	25.13	26.50	27.81	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.08	14.83	19.11	22.96	23.71	25.13	26.50	27.81	29.03	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
0.09	11.43	13.93	17.09	21.42	25.13	26.50	27.81	29.03	30.21	31.36	No limit	No limit	No limit	No limit	No limit	No limit
0.10	9.48	11.23	13.29	15.86	23.63	26.50	27.81	29.03	30.21	31.36	32.47	33.53	No limit	No limit	No limit	No limit
0.11	8.19	9.54	11.07	12.87	17.75	25.91	27.81	29.03	30.21	31.36	32.47	33.53	34.55	No limit	No limit	No limit
0.12	7.26	8.37	9.59	10.98	14.50	19.70	27.81	29.03	30.21	31.36	32.47	33.53	34.55	35.56	36.54	No limit
0.13	6.56	7.50	8.52	9.66	12.42	16.19	21.62	29.03	30.21	31.36	32.47	33.53	34.55	35.56	36.54	37.48
0.14	6.00	6.82	7.70	8.67	10.95	13.90	17.85	23.39	30.21	31.36	32.47	33.53	34.55	35.56	36.54	37.48
0.15	5.54	6.28	7.06	7.90	9.84	12.28	15.37	19.43	25.11	31.36	32.47	33.53	34.55	35.56	36.54	37.48
0.16	5.16	5.83	6.53	7.28	8.98	11.06	13.61	16.79	20.98	26.91	32.47	33.53	34.55	35.56	36.54	37.48
0.17	4.83	5.45	6.08	6.77	8.29	10.10	12.27	14.89	18.19	22.58	28.68	33.53	34.55	35.56	36.54	37.48
0.18	4.54	5.12	5.71	6.33	7.71	9.33	11.22	13.45	16.16	19.63	24.17	30.29	34.55	35.56	36.54	37.48
0.19	4.29	4.83	5.38	5.96	7.22	8.68	10.37	12.31	14.62	17.48	21.07	25.66	31.87	35.56	36.54	37.48
0.20	4.07	4.57	5.09	5.63	6.80	8.14	9.66	11.39	13.40	15.83	18.79	22.43	27.12	33.53	36.54	37.48
0.21	3.87	4.35	4.83	5.34	6.44	7.67	9.06	10.62	12.41	14.52	17.04	20.05	23.78	28.64	35.17	37.48
0.22	3.68	4.14	4.60	5.08	6.11	7.27	8.55	9.97	11.58	13.46	15.65	18.21	21.29	25.18	30.15	36.65
0.23	3.52	3.95	4.39	4.85	5.82	6.90	8.10	9.41	10.87	12.57	14.51	16.73	19.36	22.58	26.56	31.54
0.24	3.36	3.78	4.20	4.64	5.56	6.58	7.70	8.92	10.27	11.81	13.56	15.53	17.82	20.56	23.86	27.86
0.25	3.22	3.62	4.03	4.44	5.33	6.29	7.35	8.49	9.74	11.16	12.74	14.52	16.54	18.93	21.75	25.08
0.26	3.09	3.48	3.87	4.27	5.11	6.03	7.03	8.10	9.27	10.58	12.05	13.66	15.48	17.59	20.05	22.89
0.27	2.96	3.34	3.72	4.10	4.91	5.79	6.74	7.76	8.86	10.08	11.43	12.91	14.57	16.47	18.64	21.12
0.28	2.85	3.21	3.58	3.95	4.73	5.58	6.48	7.44	8.48	9.63	10.89	12.26	13.78	15.51	17.46	19.65
0.29	2.74	3.09	3.45	3.81	4.56	5.37	6.24	7.16	8.14	9.23	10.41	11.69	13.09	14.68	16.45	18.42
0.30	2.63	2.98	3.32	3.67	4.40	5.19	6.02	6.90	7.84	8.86	9.98	11.18	12.48	13.95	15.57	17.36
0.31	2.53	2.87	3.21	3.55	4.25	5.01	5.81	6.65	7.55	8.53	9.59	10.71	11.94	13.30	14.80	16.44
0.32	2.44	2.77	3.10	3.43	4.11	4.85	5.62	6.43	7.29	8.23	9.23	10.30	11.45	12.73	14.12	15.64
0.33	. . .	2.67	2.99	3.32	3.98	4.70	5.44	6.22	7.05	7.95	8.91	9.92	11.01	12.21	13.52	14.92
0.34	. . .	2.58	2.89	3.21	3.86	4.55	5.28	6.03	6.83	7.69	8.61	9.57	10.61	11.74	12.97	14.28

Table 3-12 Values of L for Pipe Sizes ≥ NPS 56 Through NPS 60 (Cont'd)

Depth,	Wall Thickness, t, in.															
d, in.	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.35	...	2.49	2.80	3.11	3.74	4.42	5.12	5.85	6.62	7.45	8.33	9.25	10.24	11.31	12.47	13.71
0.36	...	...	2.70	3.01	3.63	4.29	4.97	5.68	6.43	7.22	8.07	8.96	9.90	10.92	12.02	13.19
0.37	...	...	2.62	2.92	3.52	4.17	4.83	5.52	6.24	7.01	7.83	8.68	9.58	10.56	11.61	12.72
0.38	...	...	...	2.83	3.42	4.05	4.70	5.37	6.07	6.82	7.61	8.43	9.29	10.23	11.23	12.28
0.39	...	...	...	2.74	3.33	3.94	4.57	5.23	5.91	6.63	7.40	8.19	9.02	9.92	10.88	11.88
0.40	...	...	...	2.66	3.23	3.83	4.45	5.09	5.75	6.46	7.20	7.96	8.77	9.63	10.55	11.51
0.41	...	...	...	...	3.14	3.73	4.34	4.96	5.61	6.29	7.01	7.75	8.53	9.37	10.25	11.17
0.42	...	...	...	...	3.06	3.63	4.23	4.84	5.47	6.14	6.83	7.55	8.31	9.11	9.97	10.85
0.43	...	...	...	...	2.97	3.54	4.13	4.72	5.34	5.99	6.67	7.37	8.10	8.88	9.70	10.55
0.44	...	...	...	...	2.89	3.45	4.02	4.61	5.21	5.85	6.51	7.19	7.90	8.66	9.45	10.27
0.45	...	...	...	...	...	3.36	3.93	4.50	5.09	5.71	6.36	7.02	7.71	8.45	9.22	10.01
0.46	...	...	...	...	...	3.28	3.83	4.39	4.97	5.58	6.21	6.86	7.53	8.25	8.99	9.76
0.47	...	...	...	...	...	3.20	3.74	4.29	4.86	5.46	6.07	6.71	7.36	8.06	8.78	9.53
0.48	...	...	...	...	...	3.12	3.66	4.20	4.75	5.34	5.94	6.56	7.20	7.88	8.58	9.31
0.49	...	...	...	...	...	3.04	3.57	4.11	4.65	5.22	5.82	6.42	7.05	7.71	8.39	9.10
0.50	...	...	...	...	...	2.97	3.49	4.02	4.55	5.12	5.70	6.29	6.90	7.54	8.21	8.90
0.51	...	...	...	...	...	...	3.41	3.93	4.46	5.01	5.58	6.16	6.76	7.39	8.04	8.71
0.52	...	...	...	...	...	...	3.34	3.85	4.37	4.91	5.47	6.03	6.62	7.24	7.88	8.53
0.53	...	...	...	...	...	...	3.26	3.76	4.28	4.81	5.36	5.92	6.49	7.09	7.72	8.36
0.54	...	...	...	...	...	...	3.19	3.69	4.19	4.72	5.26	5.80	6.37	6.96	7.57	8.19
0.55	...	...	...	...	...	...	3.12	3.61	4.11	4.62	5.15	5.69	6.25	6.83	7.43	8.04
0.56	...	...	...	...	...	...	...	3.53	4.02	4.53	5.06	5.59	6.13	6.70	7.29	7.88
0.57	...	...	...	...	...	...	...	3.46	3.95	4.45	4.96	5.48	6.02	6.58	7.15	7.74
0.58	...	...	...	...	...	...	...	3.39	3.87	4.37	4.87	5.38	5.91	6.46	7.02	7.60
0.59	...	...	...	...	...	...	...	3.32	3.79	4.28	4.78	5.29	5.80	6.34	6.90	7.46
0.60	...	...	...	...	...	...	...	3.25	3.72	4.20	4.70	5.19	5.70	6.23	6.78	7.33
0.61	...	...	...	...	...	...	...	...	3.65	4.13	4.61	5.10	5.60	6.13	6.66	7.21
0.62	...	...	...	...	...	...	...	...	3.58	4.05	4.53	5.02	5.51	6.02	6.55	7.09
0.63	...	...	...	...	...	...	...	...	3.51	3.98	4.45	4.93	5.42	5.92	6.44	6.97
0.64	...	...	...	...	...	...	...	...	3.45	3.91	4.38	4.85	5.33	5.83	6.34	6.86
0.65	...	...	...	...	...	...	...	...	...	3.84	4.30	4.77	5.24	5.73	6.24	6.75
0.66	...	...	...	...	...	...	...	...	...	3.77	4.23	4.69	5.16	5.64	6.14	6.64
0.67	...	...	...	...	...	...	...	...	...	3.71	4.16	4.61	5.07	5.55	6.04	6.54
0.68	...	...	...	...	...	...	...	...	...	3.64	4.09	4.54	4.99	5.47	5.95	6.44
0.69	...	...	...	...	...	...	...	...	...	3.58	4.02	4.46	4.92	5.38	5.86	6.34
0.70	...	...	...	...	...	...	...	...	...	3.51	3.95	4.39	4.84	5.30	5.77	6.24

Table 3-12 Values of *L* for Pipe Sizes ≥ NPS 56 Through NPS 60 (Cont'd)

Depth, *d*, in.	Wall Thickness, *t*, in.															
	0.406	0.438	0.469	0.500	0.562	0.625	0.688	0.750	0.812	0.875	0.938	1.000	1.062	1.125	1.188	1.250
0.71	...	...	...	...	...	...	...	...	...	...	3.89	4.32	4.76	5.22	5.69	6.15
0.72	...	...	...	...	...	...	...	...	...	...	3.83	4.26	4.69	5.14	5.60	6.06
0.73	...	...	...	...	...	...	...	...	...	...	3.76	4.19	4.62	5.07	5.52	5.98
0.74	...	...	...	...	...	...	...	...	...	...	3.70	4.12	4.55	4.99	5.44	5.89
0.75	...	...	...	...	...	...	...	...	...	...	3.64	4.06	4.48	4.92	5.36	5.81
0.76	...	...	...	...	...	...	...	...	...	...	...	4.00	4.42	4.85	5.29	5.73
0.77	...	...	...	...	...	...	...	...	...	...	...	3.94	4.35	4.78	5.21	5.65
0.78	...	...	...	...	...	...	...	...	...	...	...	3.87	4.29	4.71	5.14	5.57
0.79	...	...	...	...	...	...	...	...	...	...	...	3.82	4.22	4.64	5.07	5.49
0.80	...	...	...	...	...	...	...	...	...	...	...	3.76	4.16	4.58	5.00	5.42
0.81	...	...	...	...	...	...	...	...	...	...	...	...	4.10	4.51	4.93	5.35
0.82	...	...	...	...	...	...	...	...	...	...	...	...	4.04	4.45	4.86	5.28
0.83	...	...	...	...	...	...	...	...	...	...	...	...	3.98	4.39	4.80	5.21
0.84	...	...	...	...	...	...	...	...	...	...	...	...	3.93	4.33	4.73	5.14
0.85	...	...	...	...	...	...	...	...	...	...	...	...	...	4.27	4.67	5.07
0.86	...	...	...	...	...	...	...	...	...	...	...	...	...	4.21	4.61	5.01
0.87	...	...	...	...	...	...	...	...	...	...	...	...	...	4.15	4.55	4.94
0.88	...	...	...	...	...	...	...	...	...	...	...	...	...	4.10	4.49	4.88
0.89	...	...	...	...	...	...	...	...	...	...	...	...	...	4.04	4.43	4.82
0.90	...	...	...	...	...	...	...	...	...	...	...	...	...	3.99	4.37	4.76
0.91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.32	4.70
0.92	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.26	4.64
0.93	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.20	4.58
0.94	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.15	4.52
0.95	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.10	4.47
0.96	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.41
0.97	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.36
0.98	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.31
0.99	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.25
1.00	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	4.20

Table 3-12M Values of L for Pipe Sizes $\geq$ 1 422 mm Through 1 524 mm O.D.

Depth, *d*, mm	Wall Thickness, *t*, mm 10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
1.0	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.3	542.6	563.6	583.2	602.1	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.5	542.6	563.6	583.2	602.1	638.4	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
1.8	542.6	563.6	583.2	602.1	638.4	673.2	706.3	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.0	376.8	485.4	583.2	602.1	638.4	673.2	706.3	737.5	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
2.3	290.3	353.8	434.2	544.1	638.4	673.2	706.3	737.5	767.3	796.5	No limit	No limit	No limit	No limit	No limit	No limit
2.5	240.7	285.1	337.6	402.9	600.1	673.2	706.3	737.5	767.3	796.5	824.7	851.5	No limit	No limit	No limit	No limit
2.8	207.9	242.3	281.1	327.0	450.9	658.2	706.3	737.5	767.3	796.5	824.7	851.5	877.5	No limit	No limit	No limit
3.0	184.4	212.6	243.5	278.9	368.4	500.5	706.3	737.5	767.3	796.5	824.7	851.5	877.5	903.2	928.1	No limit
3.3	166.5	190.5	216.3	245.3	315.4	411.1	549.1	737.5	767.3	796.5	824.7	851.5	877.5	903.2	928.1	952.1
3.6	152.3	173.3	195.7	220.2	278.0	353.0	453.5	594.0	767.3	796.5	824.7	851.5	877.5	903.2	928.1	952.1
3.8	140.7	159.5	179.2	200.7	250.1	311.8	390.5	493.4	637.9	796.5	824.7	851.5	877.5	903.2	928.1	952.1
4.1	131.0	148.1	165.8	185.0	228.2	280.8	345.6	426.4	532.8	683.6	824.7	851.5	877.5	903.2	928.1	952.1
4.3	122.6	138.3	154.6	171.9	210.5	256.5	311.7	378.1	461.9	573.6	728.4	851.5	877.5	903.2	928.1	952.1
4.6	115.4	130.0	144.9	160.8	195.9	236.9	285.0	341.6	410.5	498.7	614.0	769.4	877.5	903.2	928.1	952.1
4.8	109.0	122.7	136.6	151.3	183.5	220.6	263.4	312.7	371.4	444.0	535.2	651.7	809.5	903.2	928.1	952.1
5.1	103.3	116.2	129.3	143.0	172.8	206.8	245.4	289.2	340.4	402.2	477.4	569.8	688.8	851.7	928.1	952.1
5.3	98.2	110.4	122.7	135.7	163.5	194.9	230.2	269.7	315.1	368.9	432.9	509.2	603.9	727.5	893.2	952.1
5.6	93.6	105.2	116.9	129.1	155.2	184.5	217.1	253.2	294.1	341.8	397.5	462.4	540.8	639.5	765.7	930.8
5.8	89.3	100.4	111.6	123.2	147.9	175.4	205.7	238.9	276.2	319.2	368.5	425.0	491.8	573.6	674.7	801.2
6.1	85.4	96.1	106.7	117.8	141.3	167.2	195.7	226.5	260.8	299.9	344.3	394.4	452.5	522.2	606.2	707.8
6.4	81.8	92.0	102.3	112.9	135.3	159.9	186.7	215.5	247.4	283.3	323.7	368.7	420.2	480.9	552.5	637.0
6.6	78.4	88.3	98.2	108.4	129.8	153.2	178.6	205.8	235.5	268.9	306.0	346.9	393.1	446.9	509.3	581.4
6.9	75.3	84.8	94.4	104.2	124.8	147.2	171.3	197.0	224.9	256.1	290.4	328.0	370.0	418.3	473.6	536.5
7.1	72.3	81.6	90.8	100.3	120.1	141.6	164.6	189.0	215.4	244.7	276.7	311.5	350.0	393.9	443.5	499.2
7.4	69.5	78.5	87.5	96.7	115.8	136.5	158.5	181.8	206.8	234.4	264.5	296.9	332.5	372.8	417.8	467.8
7.6	66.8	75.7	84.4	93.3	111.8	131.7	152.9	175.1	199.0	225.2	253.5	283.8	317.1	354.2	395.5	440.9
7.9	64.3	72.9	81.4	90.1	108.1	127.3	147.7	169.0	191.8	216.7	243.5	272.1	303.3	337.9	376.0	417.6
8.1	61.9	70.3	78.6	87.1	104.5	123.1	142.8	163.4	185.2	209.0	234.5	261.6	290.9	323.2	358.7	397.1
8.4	. . .	67.9	76.0	84.2	101.2	119.3	138.3	158.1	179.1	201.9	226.2	251.9	279.6	310.1	343.3	379.0
8.6	. . .	65.5	73.4	81.5	98.0	115.6	134.1	153.2	173.4	195.3	218.6	243.1	269.4	298.2	329.4	362.8

Table 3-12M Values of *L* for Pipe Sizes ≥ 1 422 mm Through 1 524 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm 10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
8.9	...	63.3	71.0	78.9	95.1	112.2	130.1	148.6	168.2	189.2	211.5	235.0	260.0	287.4	316.8	348.2
9.1	...	...	68.7	76.4	92.2	108.9	126.3	144.3	163.2	183.5	205.0	227.5	251.4	277.4	305.4	335.0
9.4	...	...	66.5	74.1	89.5	105.8	122.8	140.2	158.5	178.2	198.9	220.5	243.4	268.3	294.9	323.0
9.7	...	...	...	71.8	86.9	102.8	119.4	136.4	154.2	173.2	193.2	214.0	236.0	259.8	285.2	312.0
9.9	...	...	...	69.6	84.5	100.0	116.2	132.7	150.0	168.5	187.8	207.9	229.2	252.0	276.3	301.8
10.2	...	...	...	67.5	82.1	97.3	113.1	129.3	146.1	164.0	182.8	202.2	222.7	244.7	268.0	292.4
10.4	...	...	...	...	79.8	94.8	110.2	126.0	142.4	159.8	178.1	196.9	216.7	237.9	260.3	283.7
10.7	...	...	...	...	77.6	92.3	107.4	122.9	138.9	155.8	173.6	191.8	211.0	231.5	253.1	275.6
10.9	...	...	...	...	75.5	89.9	104.8	119.9	135.5	152.1	169.3	187.1	205.7	225.5	246.4	268.1
11.2	...	...	...	...	73.5	87.6	102.2	117.0	132.3	148.5	165.3	182.6	200.6	219.9	240.1	261.0
11.4	...	...	...	...	...	85.4	99.8	114.3	129.2	145.0	161.5	178.3	195.8	214.5	234.1	254.3
11.7	...	...	...	...	...	83.3	97.4	111.6	126.3	141.8	157.8	174.2	191.3	209.4	228.4	248.0
11.9	...	...	...	...	...	81.3	95.1	109.1	123.5	138.6	154.3	170.3	187.0	204.6	223.1	242.1
12.2	...	...	...	...	...	79.3	92.9	106.6	120.8	135.6	150.9	166.6	182.9	200.1	218.0	236.5
12.4	...	...	...	...	...	77.3	90.8	104.3	118.2	132.7	147.7	163.1	179.0	195.7	213.2	231.2
12.7	...	...	...	...	...	75.4	88.7	102.0	115.7	129.9	144.7	159.7	175.2	191.6	208.6	226.1
13.0	...	...	...	...	...	...	86.7	99.8	113.2	127.3	141.7	156.4	171.6	187.6	204.3	221.3
13.2	...	...	...	...	...	...	84.8	97.7	110.9	124.7	138.9	153.3	168.2	183.8	200.1	216.7
13.5	...	...	...	...	...	...	82.9	95.6	108.6	122.2	136.1	150.3	164.9	180.2	196.1	212.3
13.7	...	...	...	...	...	...	81.0	93.6	106.4	119.8	133.5	147.4	161.7	176.7	192.3	208.1
14.0	...	...	...	...	...	...	79.2	91.7	104.3	117.4	130.9	144.6	158.6	173.4	188.6	204.1
14.2	...	...	...	...	...	...	...	89.8	102.2	115.2	128.5	141.9	155.7	170.1	185.1	200.3
14.5	...	...	...	...	...	...	...	87.9	100.2	113.0	126.1	139.3	152.8	167.0	181.7	196.6
14.7	...	...	...	...	...	...	...	86.1	98.3	110.9	123.8	136.7	150.1	164.0	178.4	193.0
15.0	...	...	...	...	...	...	...	84.4	96.4	108.8	121.5	134.3	147.4	161.1	175.3	189.6
15.2	...	...	...	...	...	...	...	82.7	94.5	106.8	119.3	131.9	144.9	158.3	172.2	186.3
15.5	...	...	...	...	...	...	...	...	92.7	104.9	117.2	129.6	142.4	155.6	169.3	183.1
15.7	...	...	...	...	...	...	...	...	91.0	103.0	115.2	127.4	140.0	153.0	166.4	180.0
16.0	...	...	...	...	...	...	...	...	89.3	101.1	113.1	125.2	137.6	150.5	163.7	177.0
16.3	...	...	...	...	...	...	...	...	87.6	99.3	111.2	123.1	135.3	148.0	161.0	174.2
16.5	...	...	...	...	...	...	...	...	...	97.5	109.3	121.1	133.1	145.6	158.4	171.4
16.8	...	...	...	...	...	...	...	...	...	95.8	107.4	119.1	131.0	143.3	155.9	168.7
17.0	...	...	...	...	...	...	...	...	...	94.1	105.6	117.1	128.9	141.0	153.5	166.0
17.3	...	...	...	...	...	...	...	...	...	92.5	103.9	115.2	126.8	138.8	151.1	163.5
17.5	...	...	...	...	...	...	...	...	...	90.9	102.1	113.4	124.8	136.7	148.8	161.0
17.8	...	...	...	...	...	...	...	...	...	89.3	100.4	111.6	122.9	134.6	146.6	158.6

Table 3-12M Values of *L* for Pipe Sizes ≥ 1 422 mm Through 1 524 mm O.D. (Cont'd)

Depth, *d*, mm	Wall Thickness, *t*, mm															
	10.3	11.1	11.9	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	25.4	27.0	28.6	30.2	31.8
18.0	...	...	...	...	...	...	...	...	...	...	98.8	109.8	121.0	132.6	144.4	156.3
18.3	...	...	...	...	...	...	...	...	...	...	97.2	108.1	119.2	130.6	142.3	154.0
18.5	...	...	...	...	...	...	...	...	...	...	95.6	106.4	117.3	128.7	140.2	151.8
18.8	...	...	...	...	...	...	...	...	...	...	94.0	104.7	115.6	126.8	138.2	149.6
19.1	...	...	...	...	...	...	...	...	...	...	92.5	103.1	113.8	124.9	136.2	147.5
19.3	...	...	...	...	...	...	...	...	...	...	...	101.5	112.2	123.1	134.3	145.4
19.6	...	...	...	...	...	...	...	...	...	...	...	100.0	110.5	121.4	132.4	143.4
19.8	...	...	...	...	...	...	...	...	...	...	...	98.4	108.9	119.6	130.5	141.5
20.1	...	...	...	...	...	...	...	...	...	...	...	96.9	107.3	117.9	128.7	139.6
20.3	...	...	...	...	...	...	...	...	...	...	...	95.4	105.7	116.3	127.0	137.7
20.6	...	...	...	...	...	...	...	...	...	...	...	...	104.2	114.6	125.2	135.8
20.8	...	...	...	...	...	...	...	...	...	...	...	...	102.7	113.0	123.5	134.0
21.1	...	...	...	...	...	...	...	...	...	...	...	...	101.2	111.5	121.9	132.3
21.3	...	...	...	...	...	...	...	...	...	...	...	...	99.7	109.9	120.2	130.5
21.6	...	...	...	...	...	...	...	...	...	...	...	...	...	108.4	118.6	128.8
21.8	...	...	...	...	...	...	...	...	...	...	...	...	...	106.9	117.1	127.2
22.1	...	...	...	...	...	...	...	...	...	...	...	...	...	105.5	115.5	125.6
22.4	...	...	...	...	...	...	...	...	...	...	...	...	...	104.0	114.0	124.0
22.6	...	...	...	...	...	...	...	...	...	...	...	...	...	102.6	112.5	122.4
22.9	...	...	...	...	...	...	...	...	...	...	...	...	...	101.2	111.1	120.8
23.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	109.6	119.3
23.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	108.2	117.8
23.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	106.8	116.4
23.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	105.4	114.9
24.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	104.1	113.5
24.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	112.1
24.6	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	110.7
24.9	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	109.4
25.1	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	108.0
25.4	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	106.7

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ASME B31G INTERPRETATIONS VOLUME 1

Replies to Technical Inquiries October 30, 2009 through April 30, 2012

FOREWORD

It has been agreed to publish interpretations issued by the B31 Committee concerning B31G as part of the update service to the Manual. The interpretations have been assigned numbers in chronological order. Each interpretation applies either to the latest Edition at the time of issuance of the interpretation or the Edition stated in the reply. Subsequent revisions to the Manual may have superseded the reply.

These replies are taken verbatim from the original letters, except for a few typographical and editorial corrections made for the purpose of improved clarity. In some instances, a review of the interpretation revealed a need for corrections of a technical nature. In these cases, a revised reply bearing the original interpretation number with the suffix R is presented. In the case where an interpretation is corrected by errata, the original interpretation number with the suffix E is used.

ASME procedures provide for reconsideration of these interpretations when or if additional information is available which the inquirer believes might affect the interpretation. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME committee or subcommittee. As stated in the Statement of Policy in the Code documents, ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity.

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Interpretation: G-1-01

Subject: ASME B31G-2009

Date Issued: September 29, 2011

File: 11-1259

Question (1): When calculating the term $z = L^2/Dt$, is t in this case the corroded pipe wall thickness?

Reply (1): No. Dimension t is the uncorroded pipe wall thickness.

Question (2): When calculating the failure stress (S_F), is t the corroded pipe wall thickness?

Reply (2): Yes.

Question (3): When calculating the hoop stress (S_O or S_h), is t in this case the corroded pipe wall thickness?

Reply (3): No. Dimension t is the uncorroded pipe wall thickness.

Question (4): Does t represent the uncorrroded pipe wall thickness?

Reply (4): Yes.

ASME CODE FOR PRESSURE PIPING, B31

Power Piping	B31.1-2012
Process Piping	B31.3-2010
Tuberías de Proceso	B31.3-2010
Pipeline Transportation Systems for Liquids and Slurries	B31.4-2012
Refrigeration Piping and Heat Transfer Components	B31.5-2010
Gas Transmission and Distribution Piping Systems	B31.8-2010
Managing System Integrity of Gas Pipelines	B31.8S-2010
Gestión de Integridad de Sistemas de Gasoductos	B31.8S-2010
Building Services Piping	B31.9-2011
Slurry Transportation Piping Systems	B31.11-2002
Hydrogen Piping and Pipelines	B31.12-2011
Standard for the Seismic Design and Retrofit of Above-Ground Piping Systems	B31E-2008
Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping	B31G-2012
Standard Test Method for Determining Stress Intensification Factors (*i*-Factors) for Metallic Piping Components	B31J-2008
Pipeline Personnel Qualification	B31Q-2010
Calificación del Personal de Líneas de Tuberías	B31Q-2010
Standard Toughness Requirements for Piping	B31T-2010

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ASME B31G-2012

ISBN 978-0-7918-3448-0

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Ex. II - 32

Cathodic Protection
(Second Edition)

John Morgan

National Association of Corrosion Engineers

Occasionally insulating units are placed in pits or above ground. When they are it is sensible to cover the actual joint, particularly a flanged joint, with a resin glass fiber cover so that it cannot accidentally be short-circuited, say by a metal spanner; on breaking such a bond an incendive spark could easily occur. The problems of interference and other reasons for longitudinal separation of pipelines are given in the chapter of electrolysis and interference.

Modern long distance pipelines are protected over long distances and in many cases there is a limited number of points where power is available. Usually at the end of the pipeline, at a terminal or storage depot, power supplies are available. The pipe is isolated at this point so that cathodic protection can be applied separately and at different levels to the depot itself and to the pipeline. The pipeline potential at the impressed current station will probably have a potential of -1.5 V to copper sulfate to achieve the maximum spread. It would be uneconomical and, in fact, difficult to protect the remainder of the depot to this level. The isolating coupling or, indeed, in many cases two or three isolating couplings, are used to enable these different levels of protection to be used.

Vertical Pipes

Well Casings

Most well casings are constructed of steel tubes joined together to be in good electrical contact. The tubes are coated prior to installation though this coating cannot be relied upon to prevent their corrosion as it will be damaged during installation. At the top of the well one or two larger diameter pipes may be placed concentrically over the well tube and may enclose 10 per cent to 20 per cent of the total depth, the system being shown schematically in Fig. 132. Cathodic protection can be applied to the well casing tubes though only to the outer one where there are a multiplicity of concentric tubes. Because cathodic protection will cause a change in potential between these tubes, the space between them should be grouted with concrete or filled with clean inhibited sand if grouting is impossible.

It is difficult to measure the potential of the well casing though in some cases a half cell could be lowered so as to be outside the bottom of the casing and a potential measurement made relative to this half cell. The potential gradients in the tube metal may be measured by lowering a series of devices which will make metallic contact to the tubes down the well and from these measurements the current flowing in the tubes can be determined. Fig. 133 shows the type of potential variations that would be obtained by such a survey, the practical values varying with the geological strata and with the pipe resistance. A modification of the zero current ammeter similar to that used in pipe surveys could be employed to determine this current directly.

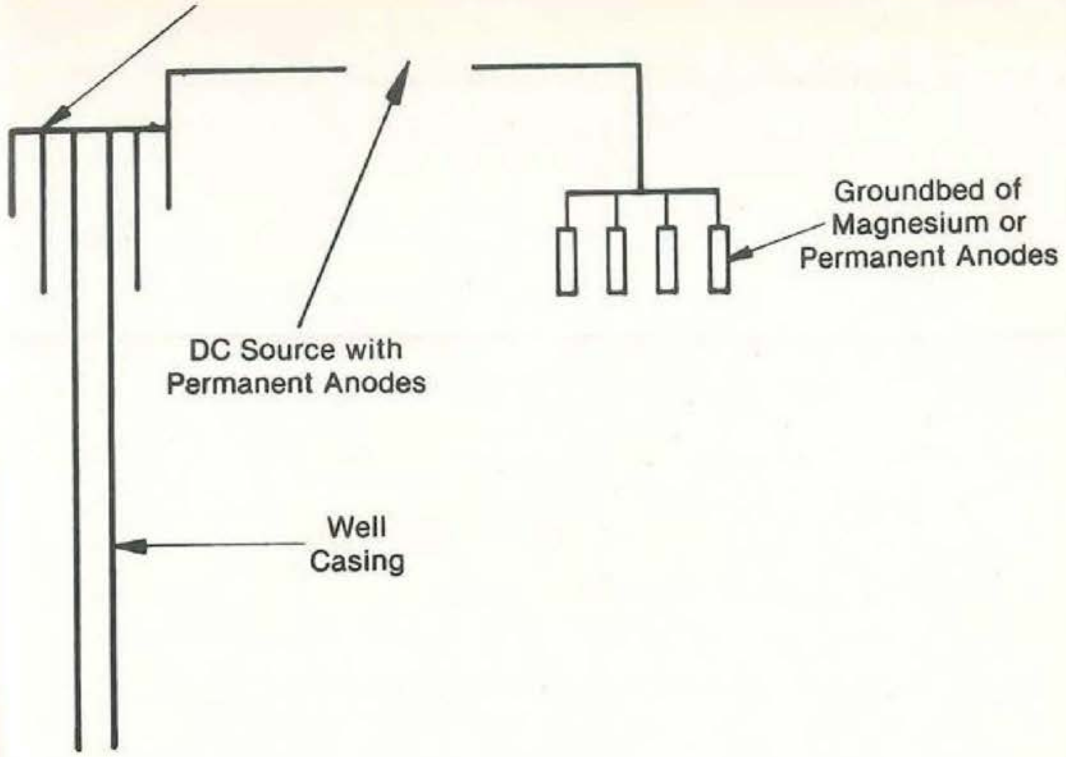

FIGURE 132 - Well casing with cathodic protection anodes.

The well casing will be protected when the metal potential curve indicates that the flow of current in the casing is increasing towards the top of the well as this means that the well must be receiving current and so is cathodic throughout its length. This is used as the criterion of protection.

Alternatively, a plot may be made of the potential against the log of current. There will be a break in the curve and it has been shown that where the curved section becomes a straight line as described earlier the casing will be adequately protected. This technique was developed by Haycock and has proved to be effective in a number of oil fields.

The spread of protection will be governed by the same parameters that affected the spread in a normal pipeline. The lengths of the casing will not be great, a spread of full protection of more than 10,000 ft. will rarely be needed and the current required for protection will usually be less than 15 amp, generally only 2 to 3 amp being sufficient. For isolated wells magnesium can be used, a typical anode installation may be a group of five or six high potential packaged anodes.

There will be an increase in potential at the top of the well, just as there is at the drainage point on the pipeline. In many cases this will detract from the driving potential of low voltage anodes so their use will not generally be possible.

Often the well is connected to a small pipeline or several wells may ex-

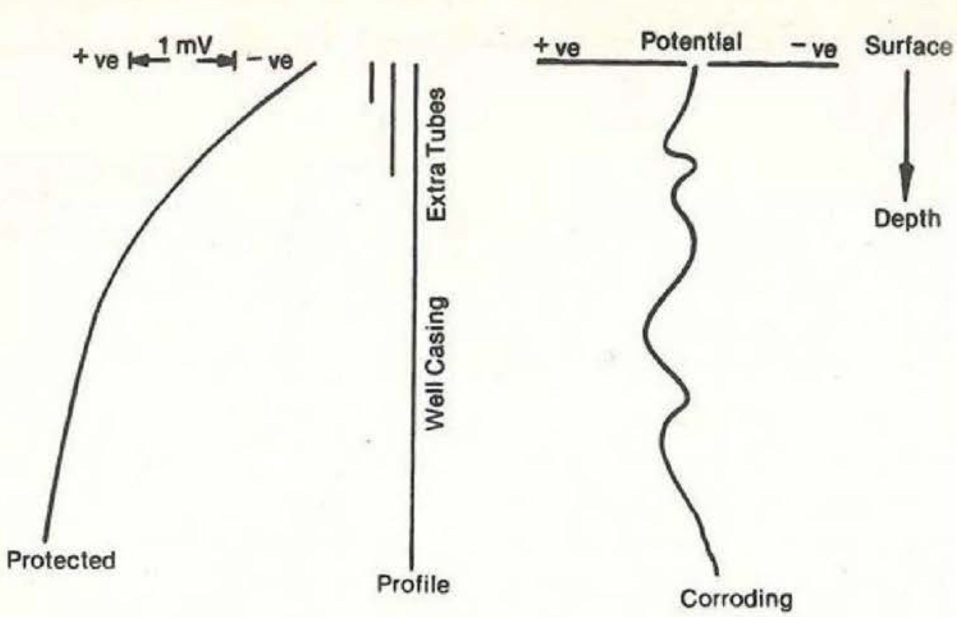

FIGURE 133 - Potentials along well casing.

ist in a group or small field, in which case, providing power is available, an impressed current installation would be preferable. The overprotection at the well head will mean that magnesium anodes, if used to protect a large group of inter-connecting well head piping, will be unattractive. Even with the use of impressed current it might well be that isolation of the wells will prove to be worthwhile. When a gathering line is connected to a well head then both may require an increased protection in order to achieve a spread. Where there are several wells there is unlikely to be any shielding of one well by another as their diameter is very small in comparison with their length.

Some wells have screens at their bottom end and these can be protected by the general system if the screen is in water or a conducting strata as it would be in an artesian well. The inside of the casing or pumps at the lower end will not receive protection by these techniques. Red water, which is often caused by the prolonged contact of the well and pumps, can be prevented by complete cathodic protection of the lower end of the well though this is not achieved from the outside.

Piles

Many buildings nowadays are constructed on steel piles driven some considerable depth into the ground. Often these are used solely to allow a concrete pile to be formed within them and their corrosion is of little consequence. When their corrosion is to be avoided the outside of the piles can be protected cathodically. The piles must be electrically continuous one with another or if not they must be bonded together. It is essential that the bond-

Ex. II - 33

NACE Standard TM0106-2016
Item No. 21248

Reaffirmation 2016-03-20
Revised 2015-02-01
Approved 2006-06-23

Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines

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ABSTRACT

This standard describes types of microorganisms, mechanisms by which MIC occurs, methods of testing for the presence of bacteria, research results, and interpretation of testing results for external surfaces of buried, ferrous-based metal pipelines and related components. Appendixes are included for media specifications (nonmandatory Appendix A), dilution procedures (nonmandatory Appendix B), and site inspection and testing (nonmandatory Appendix C). This standard is maintained Task Group 237.

KEYWORDS

MIC, microorganisms, sampling, MMM, biofilm, bacteria, Archaea

ISBN 1-57590-206-0

Foreword

In NACE standards, the terms shall, must, should, and may are used in accordance with the definitions of these terms in the NACE Publications Style Manual, 4th ed., Paragraph 7.4.1.9. Shall and must are used to state mandatory requirements. The term should is used to state something considered good and is recommended but is not mandatory. The term may is used to state something considered optional.

Microbiologically influenced corrosion (MIC) is corrosion caused by the presence or activity (or both) of microorganisms in biofilms on the surface of the corroding material. Many materials, including most metals and some nonmetals, can be degraded in this manner. Microbiologically mediated reactions can alter both rates and types of electrochemical reactions in a corrosion cell. These reactions influence pitting, crevice corrosion, differential aeration cells, concentration cells, dealloying, and galvanic corrosion. Therefore, MIC investigations require microbiological, chemical, and metallurgical testing for proper diagnosis. The conclusion that MIC has taken place should be based on the preponderance of circumstantial evidence. Microorganisms are often resistant to many control methods and can be a serious external corrosion threat to pipelines.

This NACE standard test method applies to the external surfaces of ferrous-based metal pipeline facilities and describes types of microorganisms, mechanisms by which MIC occurs, methods for sampling, and testing for the presence of microorganisms, research results, and interpretation of testing results. Sections 1 through 4 of this standard discuss the technical aspects of MIC. Sections 5 through 7 discuss field equipment and testing procedures.

This standard is intended for use by pipeline operators, pipeline service providers, government agencies, and any other persons or companies involved in planning or managing pipeline integrity. Portions of Sections 3 and 4 of this standard are excerpted from Peabody's Control of Pipeline Corrosion, Chapter 14—"Microbiologically Influenced Corrosion,"1 and enclosed in quotation marks.

This standard was prepared by Task Group (TG) 237, "Microbiologically Influenced Corrosion on External Surfaces of Buried Pipelines: Detection, Testing, and Evaluation—Standard." It was revised in 2015 by TG 237. TG 237 is administered by Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings," and is sponsored by STG 60, "Corrosion Mechanisms." This standard is issued by NACE International under the auspices of STG 35.

Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines

Figures

Section 1: General

1.1 While the evaluation, monitoring, and mitigation of MIC cannot be prescribed in one particular manner for any given pipeline, this standard describes methodologies by which the appropriate tools and techniques may be selected and practically applied to external surfaces of buried, ferrous-based metal pipelines and related components. The methods presented in this standard represent the general consensus of industry experts in pipeline corrosion and microbiology at the time this standard was published.

1.2 Appendix A (Nonmandatory) provides a site inspection and testing checklist.

1.3 All applicable safety and environmental codes, rules, and regulations must be followed when using this standard.

1.4 The term "pipeline" as used in this standard generally refers to any pipe or component of a pipeline system for which the mechanism of external MIC is of interest to the user of this standard.

Section 2: Definitions

Abiotic: The absence of living organisms, their biological components, or the metabolic activities of living organisms.

Acid-producing bacteria (APB): Aerobic or anaerobic bacteria that produce organic acids as an end product of their metabolism. A few organisms (e.g., Thiobacillus) are also capable of producing mineral acids (typically under aerobic conditions).

Aeration: (1) Exposing to the action of air. (2) Causing air to bubble through. (3) Introducing air into a solution by spraying, stirring, or similar method. (4) Supplying or infusing with air, as in sand or soil. (5) The introduction of air into the pulp in a flotation cell to form air bubbles.

Aerobic: Containing air or free molecular oxygen.

Aerobic microorganism (aerobe): A microorganism that uses oxygen as the final electron acceptor in metabolism.

Anaerobic microorganism (anaerobe) bacteria: A microorganism that does not require oxygen for metabolism.

Archaea: Unicellular microorganisms that are genetically distinct from bacteria and eukaryotes, which often inhabit extreme environmental conditions. *Archaea* include halophiles (microorganisms that may inhabit extremely salty environments), methanogens (microorganisms that produce methane), and thermophiles (microorganisms that can thrive in extremely hot environments). *Archaeoglobus* is a common *Archaea*.

Archaeoglobus: Microorganisms that grow at high temperatures between 60 and 95 °C (140 and 203 °F), with optimal growth at 83 °C (181°F) (ssp. *A. fulgidus* VC-16).2 They are sulfate-reducing *archaea*, coupling the reduction of sulfate to sulfide with the oxidation of many different organic carbon sources, including complex polymers. *Archaeoglobus*species have been isolated from oil reservoirs and production systems; however, this group of microorganisms is normally not measured with current culturing techniques.

Autoclave: A pressurized, steam-heated vessel used for sterilization.

Basal: The minimal level for, or essential for maintenance of vital activities of an organism, such as basal metabolism.

Biofilm: Microbial growth at an interface in which individual cells are bound within a matrix of extracellular polymeric materials.

Biotic: Involving the presence or metabolic activities of living organisms.

Carbohydrate: Any of the group of organic compounds composed of carbon, hydrogen, and oxygen, including sugars, starches, and celluloses.

Cathodic protection (CP): A technique to reduce the corrosion rate of a metal surface by making that surface the cathode of an electrochemical cell.

Coating: (1) A liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film. (2) (In a more general sense) a thin layer of solid material on a surface that provides improved protective, decorative, or functional properties.

Coating system: The complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.)

Culture medium: A sterile solution or other substrate that is formulated to promote the growth of a particular type or group of microorganisms. (Also called growth medium.)

4-,6-diamidino-2-phenylindole (DAPI): A stain for optical microscopy that targets the Deoxyribonucleic acid (DNA) in all (i.e., living and inactive) microbial cells.

Denaturing gradient gel electrophoresis (DGGE): A molecular microbiological method used to profile the most abundant microbial groups in a sample.

Dielectric coating: A coating that does not conduct electricity. For the purposes of this standard, it also inhibits the passage of an electric current relative to the coating's dielectric strength.

Disbondment: The loss of adhesion between a coating and the substrate.

Dissimilatory: Metabolic reactions in which a reductant is used as an electron acceptor and not incorporated into the cell (e.g., dissimilatory sulfate or nitrate reduction); metabolic changes that convert complex molecules into simple ones.

Eukaryotes: Cells having a true nucleus, bound by a double membrane. Prokaryotic cells have no nucleus.

Facultative: Capable of growing either with or without the presence of a specific environmental factor, e.g., oxygen.

Fluorescence in situ hybridization (FISH): A molecular microbiological method used for enumeration of microorganisms. The method is based on gene probes targeting ribosomal Ribonucleic acid (RNA) (16S or 23S rRNA) in microbial cells. Only living and active cells contain sufficient ribosomes that can be detected by FISH. Gene probes consist of two parts: (1) an artificial DNA strand complementary to the ribosomal RNA in the target cell; and (2) a fluorescing molecule covalently attached to the probe that enables observation of the target microorganism in the microscope.

Fungi: Nucleated, usually filamentous, spore-bearing parasitic organisms devoid of chlorophyll, including molds, mildews, smuts, mushrooms, yeast, and others.

Growth: Increase in the quantity of metabolically active protoplasm, accompanied by an increase in cell number, cell size, or both.

Growth medium: See Culture medium.

Heterotrophic: An organism that obtains nourishment from the ingestion and breakdown of organic matter.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Inoculum: A small quantity of microorganisms used to start a new culture.

Inorganic acid: A compound composed of hydrogen and a nonmetal element or radical. They can range from acids of great strength (e.g., hydrochloric acid [HCl] and sulfuric acid [H_2SO_4] to those that are very weak (e.g., boric acid). A substance that yields hydrogen ions (which can act as a proton donor) and the conjugate base ions when dissolved in water. (Also called a mineral acid.)

Isotonic: Having uniform tension of a solution; having the same osmotic pressure as the fluid phase of a cell or tissue.

Metal-oxidizing bacteria: Bacteria (most notably iron and manganese oxidizing bacteria) that derive their energy from oxidizing one oxidation state of a metal to another.

Metal-reducing bacteria (MRB): Bacteria that when in direct contact with solid iron (Fe^{+3}) and manganese (Mn+4) oxides them and produces soluble ions (Fe^{+2} and Mn^{+2}), resulting in dissolution of surface oxides and localized corrosion.[1]

Methanogens: Microorganisms that produce methane as a metabolic byproduct in anoxic (i.e., oxygen-free) conditions. They are classified as *Archaea*, a group quite distinct from bacteria. Some are extremophiles and found in environments such as oil field systems, hot springs, and submarine hydrothermal vents, as well as in the "solid" rock of the Earth's crust, kilometers below the surface. Methanogens are common *Archaea* in oil production systems; however, they are normally not measured with current culturing techniques. Methanogens are involved in MIC by consuming hydrogen at the metal surface and thereby creating a depolarization.

Microaerophilic: Pertaining to those microorganisms requiring free oxygen, but in very low concentration for optimum growth.

Microbiologically influenced corrosion (MIC): Corrosion affected by the presence or activity, or both, of microorganisms. (Note: The microorganisms that are responsible for MIC are typically found in biofilms on the surface of the corroding material. Many materials, including most metals and some nonmetals, can be degraded in this manner.)

Microbe: See *microorganism.*

Microorganism: An organism of microscopic or ultramicroscopic size. Bacteria, *Archaea,* and fungi are microorganisms. Bacteria and *Archaea* are combined and called prokaryotes. Fungi belong to eukaryotes (*Eukarya*).

Mineral acid: See inorganic acid.

Monosaccharide: A carbohydrate that cannot be hydrolyzed to a simpler carbohydrate.

Morphology: A branch of biology that deals with structure and form of an organism at any stage of its life history.

Most probable number method (MPN): A technique that does not rely on quantitative assessment of individual cells; instead, it relies on specific qualitative attributes of the microorganism being counted. The important aspect of MPN methodology is the ability to estimate a microbial population size based on a process-related attribute. The MPN technique estimates microbial population sizes in a liquid substrate. The methodology for the MPN technique is dilution and incubation of replicated cultures across several serial dilution steps.

Motile: Exhibiting or capable of movement.

Organic acid: Weak acid that contains carbon (correctly classified as carboxylic acids because they contain a carboxyl group, -COOH). Organic acids (e.g., formic, acetic, lactic) are the end product of metabolism by a variety of microorganisms. (Also called *short-chain fatty acids.*)

Organism: A complex structure of interdependent and subordinate elements whose relations and properties are largely determined by their function as a whole. (Also see *microorganism.*)

Oxidation-reduction potential: The potential of a reversible oxidation-reduction reaction in a given electrolyte reported on the standard hydrogen electrode scale. (also called *redox potential*)

Permeation: The migration of water from the soil through the coating to the pipe surface by diffusion.

Phosphate buffer: Solution made of dibasic potassium phosphate (K_2HPO_4) and sodium phosphate (Na_2HPO_4).

Pipe-to-soil potential: See *structure-to-electrolyte potential.*

Polymerase chain reaction (PCR): A molecular technique which allows the production of large quantities of a specific DNA from a DNA template using a simple enzymatic reaction without a living organism. A quantitative version of PCR is called quantitative polymerase chain reaction (qPCR).

Polysaccharide: A carbohydrate composed of many monosaccharides.

Prokaryotes: The prokaryotes are divided into two domains: the bacteria and the *Archaea*. *Archaea* were originally thought to live only in inhospitable conditions such as extremes of temperature, pH, and radiation, but have been found in all types of habitats. Sulfate-reducing prokaryotes (SRP) consist of both sulfate-reducing bacteria and sulfate-reducing *Archaea*.

Quantitative polymerase chain reaction (qPCR): A molecular microbiological method used to quantify the total number of microorganisms or a specific genus/species of microorganisms in nearly any type of sample. qPCR can be used for both fluid and solid samples, as well as microorganisms collected via membrane filtration. This method does not underestimate microorganisms that do not grow in culture. This method uses synthetic DNA (called primers) tagged with a fluorescent molecule or synthetic DNA mixed with a DNA intercalating agent (dye) to quantify microorganisms using a modified version of polymerase chain reaction (PCR).

Redox potential (E_h): See *oxidation-reduction potential.*

Ringers solution: An aqueous solution of chlorides that is isotonic to animal tissues.

Sterile: (1) Free of any living microorganisms. (2) Not introducing microorganisms that are foreign to the host body or subject under study.

Structure-to-electrolyte potential: The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Substratum: A solid surface; often refers to a surface colonized by microorganisms.

Sulfate-reducing *Archaea*(SRA): A group of anaerobic *Archaea* that perform dissimilatory reduction of sulfate, resulting in sulfide formation. They are most likely to grow at reservoir conditions (60 to 95 °C [140 to 203 °F]).

Sulfate-reducing bacteria (SRB): A group of anaerobic bacteria that perform dissimilatory reduction of sulfate, resulting in sulfide formation. They grow at a broad range of temperatures.

Sulfate-reducing prokaryotes (SRP): A group of microorganisms that consists of both sulfate-reducing bacteria (SRB) and sulfate-reducing *Archaea*(SRA).

Tenting: A tent-shaped void formed along the girth weld or longitudinal seam-weld reinforcement in a pipe when the external coating is not in continuous intimate contact with the pipe and weld surfaces.

Water leaching: The removal of soluble constituents from a coating by water.

Section 3: Introduction

3.1 MIC is corrosion affected by the presence or activity (or both) of microorganisms in biofilms on the surface of the corroding material. Many materials, including most metals and some nonmetals, can be degraded in this manner. MIC can result from the activities of microorganisms, including bacteria, Archaea, and fungi[1] in biofilms or in the local environment directly in contact with the corroding material.[2] This standard is primarily focused on the effects of bacteria and Archaea. In one survey, Jack et al.[3] reported that MIC was responsible for 27% of the corrosion deposits on the exterior of line pipe. Pope and Morris[4] reported that almost all cases of MIC on external surfaces of coated pipes were associated with disbonded or damaged coatings. The following general statements are commonly accepted regarding microorganisms.[1]

3.1.1 Individual microorganisms are usually small in size (they typically are from 0.2 to 10 µm (8 to 400 µin) in length by up to 2 or 3 µm [80 to 120 µin] in width)—a quality that allows them to penetrate crevices and other areas. Colonies of microorganisms can grow to macroscopic proportions.[1]

3.1.2 Microorganisms may be motile, capable of migrating to more favorable conditions or away from less favorable conditions (e.g., toward food sources or away from toxic materials).

3.1.4 Certain microorganisms can withstand a wide range of temperatures (at least -10 to 99 °C [14 to 210 °F]), pH levels, and oxygen concentrations.[1]

3.1.5 Microorganisms grow in colonies and form biofilms, making survival more likely under adverse conditions.

3.1.6 Under favorable conditions, microorganisms can reproduce very quickly (generation times of 18 min have been reported).[1]

3.1.7 Individual microbial cells can be widely and quickly dispersed by water or other modes, thus the potential for some cells in the population to reach more favorable environments is good.

3.1.8 Many microorganisms can quickly adapt to use a wide variety of different nutrient sources. For example, Pseudomonas fluorescens can use more than 100 different compounds as sole sources of carbon and energy, including sugars, lipids, alcohols, phenols, and organic acids.[1]

3.1.9 Many microorganisms form extracellular polysaccharide materials (capsules or slime layers). The resulting slimes are sticky and trap organisms and debris (food), resist penetration of toxicants, (e.g., biocides or corrosion inhibitors), and hold the cells between the source of the nutrients (the bulk fluid) and the surface.[1]

3.1.10 Many bacteria and fungi produce spores that are resistant to temperature, acids, alcohols, disinfectants, drying, freezing, and other adverse conditions. Spores may remain viable for hundreds of years and germinate on finding favorable conditions. In the natural environment, there is a difference between survival and growth. Microorganisms can withstand long periods of starvation and desiccation. If conditions are alternating wet and dry, microbes may survive dry periods and grow only during the wet periods.

3.1.11 Microorganisms may be resistant to many chemicals (antibiotics, disinfectants, and others) by virtue of their ability to degrade these chemicals or by being impenetrable (because of slime, cell wall, or cell membrane characteristics). Resistance may be easily acquired by mutation or acquisition of a plasmid (essentially by naturally occurring genetic exchange between cells, i.e., genetic engineering in the wild).

3.2 Mechanisms for MIC

MIC typically takes place in the presence of microbial consortia that are comprised of more than one physiological type of microorganism. Depending on the environment, these microbes may include metal-oxidizing bacteria, sulfate-reducing prokaryotes (SRP), acid-producing bacteria (APB), metal-reducing bacteria (MRB), and methanogens that interact in complex ways within the structure of biofilms.[5,6] MIC does not produce a unique form or morphology of corrosion. Instead, MIC can result in pitting, crevice corrosion, underdeposit corrosion (UDC), and dealloying, in addition to galvanic corrosion.

Simply by their presence on a metal surface, microorganisms may set up the proper conditions for pitting or crevice corrosion. Once localized corrosion has been initiated, microbial reactions can maintain suitable conditions (e.g., low oxygen concentration) for continued pit/crevice growth. Under anaerobic reducing conditions, MIC may be observed when there is some mechanism for the removal or transformation of corrosion products (e.g., a transition from stagnation to flow) or the introduction of oxygen to a previously anaerobic environment. The following discussion about individual MIC mechanisms is directly related to carbon steel.[1]

3.2.1 Sulfate Reduction

Sulfate-reducing bacteria (SRB) are a diverse group of anaerobic microorganisms that can be isolated from a variety of subsurface environments. If the aerobic respiration rate within a biofilm is greater than the oxygen diffusion rate during biofilm formation, the metal/biofilm interface can become anaerobic and provide a niche for sulfide production by SRB. The critical thickness of the biofilm required to produce anaerobic conditions depends on the availability of oxygen and the rate of respiration. SRB concentrations may be proportional to sulfate concentrations. The distribution of favorable pH ranges from 6 to 12, although SRB can adapt to other less optimum conditions. SRB grow in soil, fresh water, or salt water under anaerobic conditions.

Many species of SRB have been identified, differing in morphology and in the organic substances that they can metabolize. They have in common the ability to oxidize certain organic substances to organic acids or carbon dioxide by reduction of inorganic sulfate to sulfide. In the absence of oxygen, the metabolic activity of SRB causes accumulation of hydrogen sulfide near metal surfaces. This is particularly evident when metal surfaces are covered with biofilms. The concentration of sulfide is highest near the metal surface.

Iron sulfide forms quickly on carbon steels and covers the surface if both ferrous and sulfide ions are available. Formation of iron sulfide minerals stimulates the cathodic reaction. Once electrical contact is established, a galvanic couple develops with the mild steel surface as an anode, and electron transfer occurs through the iron sulfide. Under conditions such as low ferrous ion concentrations, adherent and temporarily protective films of iron sulfides are formed on the steel surface, with a consequent reduction in corrosion rate.[7,8]

Although SRB are anaerobic in their metabolism, studies by Hardy and Brown demonstrated that the availability of oxygen can increase corrosion in the presence of SRB.[9] They found that the corrosion rates of mild steel in anaerobic cultures of SRB were low (6.74 μm/y [0.265 mpy]), while subsequent exposure to air caused higher corrosion rates (610 μm/y [24 mpy]).

The most prevalent mechanism for the observed corrosion in a study reported by Jack et al.[10] was the formation of a galvanic couple between steel and microbiologically produced iron sulfides. The couple is normally short-lived because the iron sulfide matrix becomes saturated with electrons derived from the corrosion process. In the presence of SRB, however, the corrosion process is perpetuated because SRB removes electrons (in the corrosion process) from the iron sulfide surface. This process may involve the formation of cathodic hydrogen on the iron sulfide or the direct transfer of electrons from the iron sulfide matrix to redox proteins in the bacterial cell wall. Corrosion rates associated with this mechanism were proportional to the amount of iron sulfide in the corrosion cell.

Sulfate-reducing *Archaea* (SRA) are like SRB, obtaining their energy by oxidizing organic compounds or molecular hydrogen (H_2) while reducing sulfates to sulfides, especially to hydrogen sulfide.[11] SRA consist of the genera *Archaeoglobus*. *Archaeoglobus* grow at temperatures in the range of 60 to 95 °C (140 to 203 °F), with optimal growth at 83 °C (181 °F) (ssp. A. fulgidus VC-16).[2] Previously, *Archaeoglobus* species have been isolated from oil reservoirs and oil production systems; however, this group of microorganisms is normally not measured with current culturing techniques. SRA are known to cause the corrosion of iron and steel in oil and gas processing systems by producing iron sulfide.

The formation of H_2S by SRA activity can have profound effects in terms of reservoir souring, health/safety/environmental threats, and materials degradation.

3.2.2 Acid Production

Organic acids are produced by both bacteria and fungi. This process is anaerobic for some microorganisms or aerobic for other microorganisms and fungi. Most final products of APB are short-chained fatty acids (e.g., acetic, formic, and lactic acids). The role of APB in MIC is controversial. Pope et al.[12] proposed that APB produce biogenic organic acids that are directly responsible for corrosion in the absence of SRB. Jack et al.[13] reported that the main role of APB is to provide the environment and nutrients for SRB growth. Other bacterial species can produce aggressive inorganic acids, such as sulfuric acid (H_2SO_4), in aerobic environments. Microorganisms in the soil as well as other environments can locally generate high concentrations of carbon dioxide. The carbon dioxide dissolves in the water, producing carbonic acid. Carbonic acid solution is corrosive to pipeline steels and can lead to general attack, pitting attack, and stress corrosion cracking.[1]

3.2.3 Metal Deposition

3.2.3.1 Microorganisms can also affect corrosion by creating differential aeration cells on the surface of the metal and fixing the location of anodic sites beneath colonies of microorganisms. The organisms most often cited as causing differential aeration cells are those organisms capable of depositing iron and manganese oxides.

3.2.3.2 Iron-oxidizing bacteria produce orange-red tubercles of iron oxides and hydroxides by oxidizing ferrous ions from the bulk medium or the substratum. Iron-depositing bacteria are microaerophilic and may require synergistic associations with other bacteria to maintain low oxygen conditions in their immediate environment. Deposits of cells and metal ions create oxygen concentration cells that effectively exclude oxygen from the area immediately under the deposit and initiate a series of events that individually or collectively are very corrosive.

In an oxygenated environment, the area immediately under individual deposits becomes deprived of oxygen. That area becomes a relatively small anode compared to the large surrounding oxygenated cathode. Cathodic reduction of oxygen can result in an increase in pH of the solution in the vicinity of the metal. The metal forms metal cations at anodic sites. If the metal hydroxide is the thermodynamically stable phase in the solution, the metal ions are hydrolyzed by water, forming hydrogen (H^+) ions. If cathodic and anodic sites are separated from one another, the pH at the anode decreases and that at the cathode increases.

The pH at the anode depends on specific hydrolysis reactions. In addition, chloride (Cl^-) ions from the electrolyte migrate to the anode to neutralize any buildup of charge, forming heavy metal chlorides that are extremely corrosive. Under these circumstances, pitting involves the conventional features of differential aeration, a large cathode-to-anode surface area, and the development of acidity and metallic chlorides. Pit initiation depends on mineral deposition by microorganisms.

3.2.3.3 Manganese oxidation and deposition is coupled to cell growth and metabolism of organic carbon. The reduced form of manganese (Mn^{+2}) is soluble and the oxidized forms (Mn_2O_3, MnOOH, Mn_3O_4, and MnO_2) are insoluble. As a result of microbial action, manganese oxide deposits are formed on buried or submerged materials including metal, stone, glass, and plastic, and can occur in natural waters that have manganese concentrations as low as 10 to 20 ppb. For mild steel corrosion under anodic control, manganese oxides can elevate corrosion current. The current can be significant for biomineralized oxides that provide large mineral surface areas. Given sufficient conductivity, manganese oxide can sometimes serve as a cathode to support corrosion at an oxygen-depleted anode within the deposit.

3.2.4 Metal Reduction

Dissimilatory iron and/or manganese reduction occurs in several microorganisms, including anaerobic and facultative aerobic bacteria. Inhibitor and competition experiments suggest that iron (Fe^{+3}) and manganese (Mn^{+4}) are efficient electron acceptors that are similar to nitrate in redox ability and are capable of out-competing electron acceptors of lower potential, such as sulfate or carbon dioxide.[14]

MRB in direct contact with solid Fe^{+3} and Mn^{+4} oxides produce soluble ions (Fe^{+2} and Mn^{+2}). The result is dissolution of surface oxides and localized corrosion.[1]

3.2.5 Methanogens

Methanogens produce methane as a metabolic by-product in anoxic conditions. They are classified as *Archaea*, a group quite distinct from bacteria.

Methanogens typically thrive in environments in which all electron acceptors other than CO_2 (such as oxygen, nitrate, sulfate, and trivalent iron) have been depleted. They are common in wetlands, where they are responsible for marsh gas, and in the guts of animals such as ruminants and humans. Others are extremophiles, found in environments such as oilfield systems, hot springs, and submarine hydrothermal vents, as well as in the "solid" rock kilometers below the surface of the Earth's crust. Methanogens are common *Archaea* in oil production systems; however, they are normally not measured with current culturing techniques.[15,16]

Methanogens are known to promote MIC in steel and other metal structures by consuming hydrogen formed at the corrosion cathode.[17]

Section 4: External MIC of Pipelines

4.1 Environment

The potential for MIC of buried pipelines is controlled by the availability of nutrients, water, and electron acceptors. Peabody reported data from Harris[18] that indicated soil moisture content and bacterial cell counts were greater in backfill material than in undisturbed earth adjacent to a pipeline. Trench backfill is not as consolidated and allows greater penetration of moisture and increased oxygen diffusion. Anaerobic bacteria thrive in waterlogged, dense soil. Alternating moisture and oxygen concentrations influence the growth of bacterial populations. Despite the numerous mechanisms that one would predict for MIC of buried pipelines, most failures have been attributed to the presence and activities of SRB and APB. In general, sandy soils favor APB; high-clay soils support populations of both kinds of organisms. To protect against all forms of external corrosion and cracking, several coating materials have been used, including coal tar derivatives, asphalts, polyolefin tapes, and fusion-bonded epoxies (FBE). Line pipe has been further protected by CP. Although these are sound measures, MIC can occur in the presence of these preventative measures, if one or both break down or are not properly maintained.[1]

4.2 Coatings

4.2.1 Differing environmental conditions (e.g., soil moisture, microflora, nutrients) in both field surveys and laboratory experiments make it difficult to interpret coatings performance and draw comparisons. Comparisons between field surveys and laboratory experiments must not exceed stated condition limitations. Tenting of coatings along irregularities on the pipe surface, especially at long seam or girth welds, can create gaps between the coating and the pipe surface that fill with groundwater and introduce microorganisms that may create corrosion cells under the disbonded coating. Tape coatings are particularly susceptible to tenting while liquid- or powder-applied coatings are more resistant to this type of failure mechanism. Tenting has been most prevalent in wet high-clay soils on unstable, geologically active slopes that are subject to high service temperatures. The high service temperatures promote coating disbondment. Not all coating materials are affected by soil bacteria under all conditions. Coatings derived from both coal (tars) and petroleum (asphalts) pass some exposure tests and fail others. Materials that, by themselves, show resistance to attack by microorganisms fail when combined or reinforced with other materials.[1]

4.2.2 Jack et al.[10] demonstrated that certain coatings disbond more readily after being exposed to soils containing SRB and APB. Polyethylene (PE) coating damage proceeded linearly with time. PE tape coatings supported higher bacterial counts than extruded PE or FBE, presumably because of the presence of biodegradable adhesive/primer components in the coating system. Susceptibility to disbonding was high with FBE, higher with extruded PE, and highest with PE tape. Two types of coating damage were reported: 1) damage caused by water leaching and 2) damage caused by permeation. Both mechanisms affect intact coatings and coatings around holidays. At existing holidays, damaged FBE coatings experience an increased susceptibility to coating disbondment.

4.2.3 Peabody reported that coal tars, coal-tar epoxies, and coal-tar enamels were immune to disbonding because of activities of microorganisms, which would likely lessen the chances of corrosion, including MIC. Early coatings based on asphalt were subject to oxidation and loss of low-molecular-weight components through biodegradation and biodeterioration, resulting in a permeable, embrittled coating.[3] Pendrys[19] demonstrated that, with time, asphalt could be degraded by microorganisms selected from soil. Harris[18] demonstrated that bacteria commonly found in pipeline soils can degrade asphalt, tape adhesives, kraft paper (expendable once the pipeline is in place), as well as the binders and fillers used in felt pipeline wrappers. The next-generation coatings were based on polyvinyl chloride (PVC) or PE. The PVC tape was unstable in service. Plasticizers constitute up to 50 wt% of a PVC product and can be effectively lost through biodeterioration and water dissolution. PE coatings rely on adhesives to attach the polyolefin layer to the primed steel surface.[1]

4.3 Cathodic Protection

For CP levels more negative than –850 mV (–880 mV to –1,000 mV) polarized vs. a saturated copper/copper sulfate ($Cu/CuSO_4$) reference electrode, it has been demonstrated that bacteria levels, including SRB, can increase in saturated soils, seawater, and marine sediments[1,20-22] so that if the CP is intermittent, MIC can occur at a higher rate than if CP were not previously present.[23] MIC has at least three effects on CP of pipelines.

4.3.1 When microbial activity is present and the coating is compromised, the potential level required to mitigate corrosion is a more negative value. Pope and Morris[4] found that pipeline failures were often in contact with wet clays with little scaling potential, creating a situation in which the demand for CP continues at a high level over long periods of time and in which CP may not be distributed equally over the surface of coating holidays and surrounding disbondments. Microorganisms colonize and initiate corrosion at such sites. Research by Barlo and Berry[24] determined that the current criteria specified in NACE SP0169[25] for CP of buried pipelines (0.85 V versus $Cu/CuSO_4$) were generally valid in concept. However, the critical values for the criteria varied with the environment. Elevated temperature (60 °C [140 °F]), mill scale, and anaerobic bacteria affect CP requirements—100 to 200 mV more cathodic (negative) change in protection potential is required compared to the condition absent those factors.[1]

4.3.2 MIC can increase the kinetics of corrosion reactions, increasing the CP current necessary to achieve a given level of polarization.

4.3.3 Microorganisms can attack certain pipeline coatings, increasing exposed metal surface area and further increasing the CP current used to achieve a given level of polarization. Water intrusion at breaks in the coating may cause corrosion where the remaining dielectric coating may block CP. It should be noted, however, that when sufficient CP levels exist, corrosion is mitigated even in the presence of increased levels of bacteria. The difficulty is determining what is adequate for providing protection in each situation without adversely affecting the coating.[1]

Section 5: Sampling Equipment

5.1 Certain procedures may be used to collect samples.

5.1.1 Typical equipment and supplies should include some or all of the following:

(a) Sterile plastic or glass containers (10 to 125 mL [0.33 to 4.20 oz]).
(b) Sterile plastic sample collection bags.
(c) Sterile metal scalpels.
(d) Sterile cotton or polyester-fiberfill swabs.
(e) Sterile wooden spatulas (tongue depressors).
(f) Sterile 1 to 5 mL (0.03 to 0.1 oz) syringes.
(g) Sterile disposable plastic pipettes.
(h) Sterile latex gloves.
(i) Ice chest with refrigerant.
(j) Digital or film camera.
(k) Magnifying lens (5 to 60x).
(l) Marking pens (for wet surfaces).
(m) Nylon bristle brushes.
(n) Mechanical pit depth gauge.
(o) Labels.
(p) pH paper or meter.
(q) Culture media.
(r) Ultrasonic thickness (UT) meter to measure metal thickness.
(s) Sterile vials of phosphate-buffer solution.
(t) Formaldehyde (36.5%) for fixation on site (for use with DAPI method) or 2% glutaraldehyde as a general fixative.

5.2 Sterile containers must not contain any chemical that inhibits microbial survival. Collection containers may contain sterile phosphate buffer, Ringers solution, or other holding medium for suspension of solid samples. If samples are to be analyzed for chemical composition, they must be maintained separately from samples transferred to a holding medium. Most sampling containers are glass or plastic.

5.2.1 Glass containers should have screw-down caps and must have been sterilized using a combination of pressure and temperature over time (100 kPa [14.5 psig] steam at approximately 121 °C [250 °F] for a minimum of 20 min). Glass containers may be reused many times after cleaning and sterilization.

5.2.2 Plastic containers are usually disposable; however, some can be cleaned and autoclaved. In most cases, plastic sampling containers have rigid walls, but polyethylene flexible-walled containers with closure ties can be used.

5.2.3 Sterile plastic bags provide a lightweight sample container. Plastic bags designed for domestic use are not sterile and must not be used for sample collection.

5.2.4 Sterile, individually wrapped supplies can be purchased from most pharmacies and all scientific supply stores. Sterile bags and tubes are usually ordered in bulk, and the interiors remain sterile until opened.

Section 6: Sampling and Testing Procedures

6.1 Site Inspection

6.1.1 Before excavation of the pipeline, the topography and soil type of the area surrounding the dig should be noted. The site should be photographed both close up and from a distance. The photos should complement one another so that they can be aligned and compared. A ruler should be included in photographs to indicate relative dimensions.

6.1.2 The following measurements provide useful information:

6.1.2.1 Soil resistivity using ASTM(1) G5726 Wenner 4 point or similar method.

6.1.2.2 Pipe-to-soil potential.

6.1.2.3 Redox potential (E_h) as the potential of a platinum electrode using a saturated copper copper-sulfate reference electrode.

6.1.2.4 Soil pH to compare with under-coating pH measurements to determine effectiveness of CP.

6.1.3 Exposure of the pipe should be slow and careful to avoid damage to the pipe and areas of sampling. Soil should be removed from the pipe surface carefully to expose the coating surface. In most cases, products adhering to the coating surface shall not be removed until they are at a laboratory or other suitable location where analyses can be performed. Color photographs of corroded areas and their relationship to the pipe surface should be taken.

6.1.4 The following should be noted and recorded (see checklist in Appendix A):

6.1.4.1 Coating type (e.g., coal tar, asphalt, bitumen, tape, FBE), type of damage (e.g., disbonding, holidays, blistering, seam tenting, cracking, wrinkling, or none), extent of damage (percentage of exposed area), and location (circumferential and longitudinal position on the pipe in relation to weld seams and coating seam, if present).

6.1.4.2 Characteristics of soil: moist, dry, or wet; silt, sand, gravel, rock, or clay; odor; discoloration associated with a buried object; local chemical composition, e.g., presence of salts, cations, anions, such as chlorides, sulfates, carbonates, etc.

6.1.4.3 Relationship of corroded area within overall system: depth, light, engineering design (welds, seams), etc.

6.2 Description of Corrosion Products

6.2.1 Corrosion products: color (brown, black, white, or gray), shape (deposit, nodule, or films), texture, and odor.

6.2.2 The form of any visible corrosion: shapes, sizes, and depths of pits; crevice corrosion; UDC should be noted (See Figure 1).

6.2.3 Any visible biological accumulations in corroded areas: form, color, texture, or odor (e.g., none, earth, rotten eggs, etc.).


Elliptical


Shallow, Parabolic


Deep, Narrow


Grain Attack, Vertical


Undercut


Sub-Surface


Grain Attack, Horizontal

FIGURE 1: Examples of Various Pit Morphologies as Viewed in Cross Section.[27]

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(1) ASTM International (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428.

(2) European Federation of Corrosion (EFC), 1 Carlton House Terrace, London, SW 1Y 5DB, UK.

6.2.4 Chemical testing for sulfides and carbonates.

6.3 Coating Inspection

6.3.1 Once the pipe is exposed, the soil, water, and deposits must be sampled immediately and stored or tested. The coating surrounding the suspected area of corrosion should be carefully removed using a knife or similar instrument. Sample contamination of corrosion with soil or water must be kept to a minimum. Contact with the soil, corrosion product, or film with hands or tools other than sterile implements must be avoided.

6.3.2 Coating inspection for MIC testing purposes must precede any other coating evaluation. Likely areas of active corrosion or MIC should be identified using ILI tools or visual inspection. Damaged coatings should be carefully removed using a sterile scalpel to expose the steel.

6.4 Sample Collection

6.4.1 Whenever possible, a clean working surface should be used, because if proper precautions are not taken, dust or dirt on the working surface or general area can potentially contaminate the inside of sample containers when a sterile sample bottle is uncapped. Ideally, the containers should be handled by gripping the lower part of the bottle, and skin contact with the upper part of the container must be avoided.

6.4.2 If a small volume of liquid is present under the coating, a sample should be taken using a sterile syringe or polyester-fiberfill swab. Both the liquid in the syringe and on the swab may be used for the enumeration of microorganisms as described later. The swab must be stored in a sterile plastic tube until tested.

6.4.3 The pH of any liquid found under the coating should be tested using pH (1 to 14) paper or a meter with a microsensor electrode. The coating should be carefully sliced to a length to allow the test paper to be slipped behind the coating. The coating should be pressed against the pH paper for a few seconds and then lifted. The pH paper may then be removed. The color of the paper in relation to the chart provided with the paper should be noted and recorded. A syringe or pipette should be used to extract a small amount of liquid to measure pH by putting a drop or two of liquid on the microsensor. If possible, the pH of any available groundwater (typically at pipe level) away from the pipe should be determined for reference.

6.4.4 If surface deposits or corrosion products are fragile, they should be scraped from the pipe. Corrosion products must be collected by scraping the area with a sterile scalpel, or swabbing with a sterile polyester-fiberfill swab.

6.4.5 Multiple samples, when present, are typically taken from one or more of the following locations:

6.4.5.1 Undisturbed soil immediately next to the exposed pipe-steel surface or at an area of coating damage.

6.4.5.2 Deposits associated with visual evidence of pipe corrosion, especially those pit contents underneath nodules or tubercules that have been removed and are more likely to be uncontaminated with soil or groundwater. (Note: it should be identified when corrosion samples are known or suspected to be contaminated from outside sources).

6.4.5.3 Scale or biofilm on the steel surface or the backside of the coating.

6.4.5.4 Liquid trapped behind the coating.

6.4.5.5 Fresh, undisturbed soil at pipe depth at least 1 m (3 ft) transverse to the pipe. This location, such as the ditch wall, acts as a reference from which to determine whether the microbial population near the pipe is elevated.

6.4.5.6 Additional samples should be taken from other locations where bacterial activity is suspected and tested.

6.4.5.7 Solid and liquid samples must be placed in clean, sterile, sealed, and carefully labeled containers. The containers should be filled to no more than 60% maximum volume. The bag or tube must be sealed tightly, and the whole bagged sample sealed again within a second plastic bag to reduce the risk of leakage.

6.4.5.8 Sample containers should be labeled with the location of the dig site, sample origin, date, sampling time, and the tests that have been performed on the sample. Extraneous dust, dirt, and debris shall not be introduced into the sample at the time of collection. The interior surfaces of sample containers or any other parts likely to be in direct contact with the sample must not have been directly handled.

6.5 Sample Transport

6.5.1 Changes in detectable numbers and types of microorganisms can occur rapidly after removal of samples from the environment. One should arrive at the corrosion site with all solutions, media, and other necessary materials. If that is not possible, liquids and solids can also be transported to a laboratory or other facility for processing and testing. The major concern in transporting samples for microbiological evaluation is to ensure that microorganisms remain alive and active without multiplication. Sample collection may expose microorganisms to abrupt changes in pressure, temperature, atmosphere, and light, causing redistribution in numbers and types of microorganisms in the original sample.

6.5.2 After collection, samples should be stored in the dark away from temperature extremes. When transit times are less than 6 h, liquid samples can be maintained at the original collection temperature by storing in an insulated container. If the sample has been collected from sources above 30 °C (86 °F), intrinsic heat can maintain the microbial population without significant changes. If the transit time is longer than 6 h, the sample temperature should be lowered to less than 10 °C (50 °F) to restrict growth and competition. A standard method used to control post-sampling shifts in microflora has been to provide a cold-temperature shock by packing ice packs around sample containers to bring the temperature down to within the range of 1 to 4 °C (34 to 39 °F), which reduces microbial activity to a basic survival metabolic mode. Prolonged storage for periods of longer than a few days can cause changes in the microflora and should be avoided.

Section 7: Testing Guidelines

7.1 Field vs. Laboratory Testing

7.1.1 Bacteria, being living organisms, are highly sensitive to changes in their environment (e.g., temperature, salinity, and dissolved gases). Additionally, many chemical species associated with microbial metabolism, such as organic acids or sulfide compounds, can be rapidly oxidized or degraded. Thus, to obtain results that accurately represent pipeline conditions, certain tests relevant to MIC investigation or monitoring must be performed within minutes or hours of sample collection. Historically, this has been one of the factors that resulted in the lack of meaningful data for use in MIC assessment of pipelines because the analytical results may be misleading. Therefore, collecting samples for microbiological analysis should be avoided when pipe and coating have been extensively handled, exposed to atmosphere or sunlight for extended periods of time, or otherwise exposed to conditions where dehydration, extreme temperature changes, or contamination could occur. If such samples are analyzed, the compromising conditions should be documented so they may be taken into consideration when a final evaluation of the data at that site is performed.

7.1.2 As technology has improved, more types of tests and more sophisticated analyses have been made available for use in the field (i.e., near the point where samples are collected). Because indicators of the environmental conditions under which MIC may occur are readily degraded or lost after removal of a sample from the pipeline, a general rule for improving the quality of data is to perform testing on location whenever practical. Proper sample preservation and handling procedures must be followed diligently and consistently in cases in which testing cannot be performed in the field.

7.1.3 Results from both corrosion and microbiological tests should be integrated when evaluating the threat, likelihood, or presence of MIC. Information on both types of tests is provided in Section 7. Many of the test procedures described here are equally useful for evaluating external MIC.

7.2 Microbiological Culture Testing

7.2.1 Although MIC is often attributed to a single type of microorganism, more often the corrosion is caused by the activities of several different organisms that form a community. Microbiological testing of buried pipelines has generally included testing for SRB, APB, general aerobic organisms, general anaerobic organisms, and in some cases, iron-depositing and iron-reducing bacteria. It should be noted that iron-depositing and iron-reducing bacteria are very difficult to grow in culture, and microscopic analysis is more commonly used for detection of these bacteria.

7.2.2 The objective of the microbiological culture techniques described in this standard is to approximate the size of the viable bacterial population in a solid or liquid sample using semi-quantitative estimates, or preferably, the most probable number (MPN) method when sample replication is employed.[28,29] Such estimates are based on the assumption that bacteria are normally distributed in liquids or solids. Microorganisms in solid and liquid environmental samples are usually enmeshed in particulates. Typically, a suspension of solid samples is made in a Ringers solution or phosphate buffer. Particles should be dispersed so that colony forming units are separated to maximize the accuracy of the estimate. Water samples should be mixed by shaking or stirring for 10 to 60 sec just prior to dilution.

7.2.3 To culture microorganisms, a small amount of liquid or a suspension of a solid is added to a solution or solid that contains nutrients. The small sample is called an inoculum, and the nutrient is called the culture or growth medium. There are normally three considerations when growing microorganisms: type of culture medium, incubation temperature, and length of incubation.

7.2.4 The type of medium used to culture microorganisms determines to a large extent the numbers and types of microorganisms that grow. No growth medium can approximate the complexity of a natural environment. Under ideal circumstances, liquid culture provides favorable growth conditions for 1 to 10% of the natural population.[30] Typically, the presence of specific types of organisms is established, and a standard methodology is used so that comparisons can be made. There are no "correct" culture media. A convenient method is to purchase prepared, pre-measured, pre-sterilized media. Test kits also generally include syringes, swabs, and marking pens. Several culture media formulations for various groups of microorganisms are included in NACE Standard TM0194.28

7.2.5 Highly colored samples may sometimes interfere with culture interpretations.

7.3 Microscopy Methods—General

7.3.1 Microscopy is most commonly used to examine liquid or solid samples directly to determine the overall numbers of microorganisms present without regard to their viability or species. The procedure involves placing a few µL of sample on a glass slide, preparing the slide for examination using various staining techniques, and examining the slide with a light microscope at magnifications from approximately 500x to 1,500x. Depending on the method of sample preparation, the detection limit for all microorganisms present in a liquid sample, including viable, nonviable, and dead cells, is approximately 102 to 103 cells per mL. Levels of microorganisms in coastal seawaters are typically > 106 cells per mL. This procedure is typically performed in the laboratory.

7.3.2 Microorganisms structurally consist of lipids and proteins that degrade and break down once the cell dies if the sample is not preserved after collection. Samples collected for microscopy are often preserved (fixed) using a formaldehyde or glutaraldehyde phosphate buffer solution. This type of preservation kills the microorganisms but preserves or fixes the structure of the cell. Fixative solution vials are commercially available. Typically only a few mL of the liquid or solid sample are preserved in the fixative.

7.3.3 One advantage of microscopy is that only a minute amount of sample is required for examination. A surface swab can provide adequate sample material (e.g., when no bulk liquid or solid is present).

7.4 Epifluorescent Microscopy

7.4.1 Epifluorescent microscopy involves treating the sample with a stain that fluoresces when viewed under a specific wavelength of ultraviolet light. This technique helps distinguish microorganisms from debris, or may be used to examine specific cellular structures of microorganisms. Hydrocarbons and some organic materials may interfere with epifluorescent microscopy as they give auto-fluorescence and obscure the signal from the biological material. This procedure is typically performed in the laboratory.

7.4.2 Biological stains such as acridine orange (N,N,N',N'-tetramethylacridine-3,6-diamine), fluorescein isothiocyanate (FITC), and DAPI are used for epifluorescent microscopy. A variety of microbiological test kits are commercially available. Acridine orange is a common nucleic acid stain that permeates cells to interact with DNA and RNA.

7.4.3 Fluorescent probes have been developed to "label" specific groups of microorganisms, or to distinguish live vs. dead cells in a sample. Fluorescent in situ hybridization (FISH) probes are used to identify and quantify certain species and groups of microorganisms. Because FISH labels only microorganisms with a certain content of ribosomal RNA, it is only active cells or cells that have recently been active that are enumerated. Quantitative use of FISH probes is discussed in Paragraph 7.8.2.

7.4.4 The DAPI method quantifies all intact microorganisms containing DNA (both living and inactive cells) in almost any type of liquid sample.[31,32] DAPI is often used in combination with FISH analysis to help distinguish the total cell count from the number of cells that are labeled using the FISH probes. The full DAPI method may be completed in less than half a day in a laboratory. The liquid sample is filtered whereby microorganisms (cells of bacteria, *Archaea*, and fungi) are collected on a filter. These are subsequently stained with a fluorescent dye that binds to the DNA in the cells and then washed to remove excess dye. Cells are manually counted using an epifluorescence microscope. Fluid samples should be fixed in the field with formaldehyde (36%) to a final concentration of 2% in the sample. Adequate sample amounts for this type of testing are 50 to 100 mL (1.6 to 3.40 oz) of fluid depending on the cell density.

7.4.5 Microscopy and biochemical methods have been used for many years, and genetic methods are now becoming available for the detection, quantification, and in some cases identification of microorganisms present at corrosionsites. [33-35]

7.5 Adenosine Triphosphate Photometry (ATP)

7.5.1 ATP, related to energy production and consumption, is present in all living cells. When cells die, however, ATP rapidly degrades. Consequently, the quantity of ATP in field samples is approximately proportional to the number of living microorganisms in that sample. ATP may give an indication of the viable biomass present in living organisms, and may be measured using an enzymatic reaction that generates light when ATP is present. The intensity of the light is measured in a photomultiplier, the output being proportional to the amount of ATP.

7.5.2 Several commercial field test kits are available for ATP quantification. Quantification of ATP typically relies on photometers that measure the amount of light emitted when the ATP within the sample is allowed to react with a particular enzyme. Before the reaction, the sample to be quantified is filtered and treated with gold buffers. These buffers assist in releasing the ATP from the organism so they can react with the enzyme. Finally, the sample and enzyme are combined and analyzed. Advantages of ATP measurement include speed to results (less than 10 min per sample), no underestimation of unculturable organisms, and use in any sample type including produced fluids, oil/emulsions, and solids. ATP measures should be backed up with at least one additional method for more specific quantification of the microorganism (e.g., SRB).

7.6 Hydrogenase Measurements

7.6.1 Hydrogenase is an enzyme produced by bacteria that use hydrogen as an energy source. Testing for the presence of the hydrogenase is one method used to enumerate bacteria populations in corrosion deposits and water samples in the field.

7.6.2 Quantification of bacteria populations using this method first involves extraction of the hydrogenase enzyme from the sample. The extracted enzyme is preserved in a solution that maintains enzyme activity and then placed within a reaction chamber where hydrogen is introduced. The hydrogen is oxidized and a redox indicator color change reveals the presence of the hydrogenase enzyme (refer to NACE Standard TM0194). The reaction typically is not rapid; it can take anywhere from 30 min to 4 h. The reaction time and developed color intensity together are used to measure the relative activity of the enzyme.

7.7 Adenosine Phosphosulfate Reductase (APS)

7.7.1 APS reductase is an enzyme specifically associated with SRB. Measurement of the APS reductase present in a bacterial sample provides an indication of the active SRB concentration. Detection and measurement are based on immunological methods and may be performed using a field kit.

7.7.2 The test involves exposure of the sample to small particles containing antibodies. These particles specifically capture the APS reductase enzyme. The particles, now mixed with APS reductase, are subsequently isolated on a porous membrane and exposed to specific indicator chemicals. Reaction between the particles and chemicals results in a color change that is proportional to the concentration of the APS reductase in the sample.

7.8 Molecular Microbiological Methods (MMM)

7.8.1 MMM, also referred to as genetic methods, are culture-independent approaches that provide direct analysis of samples without the bias introduced by the growth process used during culturing. Because no prior growth of microorganisms is required, MMMs accept very small amounts of any type of sample (liquid, biofilm, solid) with or without live bacteria. After genetic materials are extracted from the sample, assays that are very specific and render a more precise quantification of various types of bacteria than culture tests are performed in the laboratory.[36,37] A comparison of MMMs is shown in Table 1 and Figure 2.

Table 1
Comparison of MMMs[31]

MMM	Method Based On	Living Cells Counted?	Dead Cells Counted?	Quantitative Method?	Information Yielded
DAPI	Microscopy	Yes	Yes	Yes	Total cell counts (live and dead)
FISH	Microscopy	Yes	No	Yes	Total numbers of live bacteria Total numbers of live Archaea Total numbers of live SRB Total numbers of live SRA
DGGE	PCR	Yes	Yes	No	Comparison of populations Identification of abundant microorganisms
qPCR	PCR	Yes	Yes	Yes	Numbers of total bacteria Numbers of total Archaea Numbers of SRB Numbers of SRA Numbers of three groups of methanogens2

7.8.2 Quantitative FISH—quantitative FISH is a MMM in which only living and active cells are stained with a fluorescent dye visible during epifluorescence microscopy. Unlike the DAPI method, FISH probes may be designed to attach only to selected groups of microorganisms (e.g., specific types of SRB or SRA). Therefore, only the specific target microorganisms are visible and may be enumerated during subsequent microscopy. The quantitative FISH method does not underestimate organisms that do not grow in culture. FISH is a microscopy method that uses synthetic oligonucleotides (synthetic DNA) tagged with a fluorescent molecule (dye). Together, the synthetic DNA and the fluorescent molecule are referred to as a probe. The probe is mixed with the bacteria in a fluid sample and the numbers of bacteria (or *Archaea*) that take up the probe and have it hybridize to their rRNA are counted. The quantitative FISH method differentiates active/alive microorganisms from dead microorganisms. A probe may be designed to detect a general population (e.g., total bacteria or total *Archaea*) or a specific genus or species (e.g., *Desulfovibrio desulfuricans*). A given sample is analyzed using several different probes to understand the prokaryotic diversity in a sample, and which types/species of microorganisms are most abundant. The preparation steps for the quantitative FISH method are different from the DAPI method. However, cells stained for the quantitative FISH method are counted in the same manner as in direct bacterial counts (for the DAPI method) in the laboratory. Adequate sample amounts for this type of testing are in the range of 50 to 100 mL (1.6 to 3.40 oz) of fluid depending on the cell density. Samples are filtered onto 0.2 μm

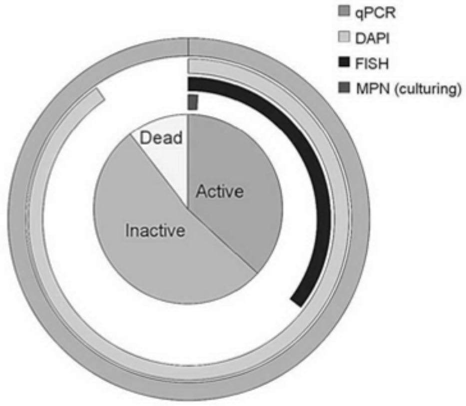

FIGURE 2: An Illustration of the Portions of the Different Pools of Microorganisms (Live, Inactive, and Dead) Typically Present in Samples from the Oil Industry that are Enumerated Using Various MMMs as Compared to the MPN (Culturing) Method. Each of the Methods Indicated is Discussed Further in the Text.[37]

filters. FISH probes are selected to target total bacteria and *Archaea*, as well as specific groups of relevance (e.g., SRB). The samples are inspected by epifluorescence microscopy at 1,000x magnification. The cells stained with each probe are counted and related to the overall number of cells obtained by the DAPI method (see Paragraph 7.4.4).

7.8.3 qPCR—PCR and qPCR is a MMM to amplify a single or few copies of a piece of DNA across several orders of magnitude, generating millions of copies of a particular DNA sequence. The qPCR is an emerging method for enumerating microorganisms in complex environmental samples, particularly in solid samples where epifluorescence microscopy (used for the DAPI method and FISH method) may be difficult to perform because of background interference. The qPCR method enumerates genes rather than individual cells by applying a modified polymerase chain reaction (PCR) method. Like the quantitative FISH method, the qPCR method may be applied to count total cells or specific groups of microorganisms (e.g., SRP or methanogenic *Archaea*).[9,15,38,39] Because qPCR targets the DNA in all prokaryotes, the qPCR method measures living, inactive, and dead microorganisms. qPCR may be used to quantify the total number of microorganisms or a specific genus/species of microorganisms in nearly any type of sample, including produced fluids, oil/emulsion, and solids. The qPCR method does not underestimate organisms that do not grow in culture. qPCR may be done on both fluid and solid samples as well as microorganisms collected via membrane filtration. qPCR uses synthetic DNA (called primers) tagged with a fluorescent molecule or synthetic DNA mixed with a DNA intercalating agent (dye) to quantify organisms using a modified version of the PCR method. Briefly, total prokaryotic DNA is extracted and amplified using primers that target to a conserved region of the bacterial DNA. The region used may make the assay very general (meaning counting total bacteria or *Archaea*), or very specific (meaning counting a single genus or species). Similar to quantitative FISH, the qPCR method may be used to enumerate a very general group of bacteria (i.e., total bacteria or *Archaea*) or very specific organism (e.g., *Desulfovibrio desulfuricans*). Adequate sample amounts for this type of testing are 50 mL (1.7 oz) of fluid, 2.0 to 5 g (0.07 to 0.1 oz) of solid, or a 0.2 or 0.45 µm filter with a minimum of 10 mL (0.30 oz) of fluid passed through it.

7.8.4 DGGE—MMM method based on the PCR method that is used for comparing microbial communities across a number of different samples. During DGGE, genetic material in individual samples is amplified by PCR and subsequently compared by electrophoresis. DGGE is used for identifying dominant groups of microorganisms in individual samples and for evaluating how the microorganisms are distributed between samples.[41-43] DGGE may be performed on any fluid or solid sample, as well as bacteria collected via membrane filtration. Adequate sample amounts for this type of testing are 50 mL (1.7 oz) of fluid, 2 to 5 g (0.07 to 0.1 oz) of solid, or a 0.2 or 0.45 µm filter with a minimum of 10 mL (0.30 oz) of fluid passed through it.

7.9 Organic Acids

Organic acids such as butyric, pyruvic, propionic, and acetic acid are by-products or intermediary species of microbial metabolism. Gas chromatography-mass spectrometry (GC-MS) or high-pressure liquid chromatography (HPLC) are used in the laboratory to identify and quantify organic acid species in properly preserved samples. Organic acids quickly degrade; therefore, samples are preserved by filtration into nitrogen-purged vials and maintained at 4 °C (40 °F) until analysis is performed.

7.10 Chemical Analysis

7.10.1 Corrosion products should be taken from the steel surface, coating, or optimally, from the pit contents underneath a deposit that has been removed. The color and type of sample collected should be noted in each case. Although liquid or corrosion product samples are often limited in volume, when sampled from externally corroded pipe, on-site tests should be performed because significant chemical changes can occur over a short period of time. Additionally, compositional analyses, i.e., anions, cations/metals, and organic acids should be performed in the laboratory.

7.10.2 Field tests on liquids should include pH, total alkalinity, and dissolved hydrogen sulfide. Field tests on solids and corrosion products should include pH and a qualitative analysis for the presence of sulfides and carbonates. Carbonates are present if noticeable bubbling occurs when a drop of dilute hydrochloric acid is placed on a small portion of the corrosion product. Sulfides can be detected by the characteristic odor of rotten eggs or by exposing the acid-treated corrosion product to lead-acetate test paper. A white-to-brown color change occurs in the presence of sulfides. Follow-up testing in the laboratory with more sophisticated analytical equipment (e.g., energy dispersive spectroscopy [EDS], x-ray diffraction [XRD], etc.) to determine the elemental and mineral phases present should be performed to verify field tests. When collecting corrosion product samples from steel surfaces, coating, or pit contents for laboratory analysis, a large enough sample should be taken to enable testing by various methods. Avoid reusing the material from one test method for another test method if multiple tests are performed.

7.11 Pipeline Examination

7.11.1 When examining external surfaces of the exposed pipeline, disbonded coating, corrosion products, soil, and other materials should be removed from the pipe wall using a clean spatula or knife, with care taken not to scratch the metal. Any remaining material should be removed with a clean, dry, stiff brush, e.g., nylon bristle brush. A brush with metal bristles obscures the pit features. In cases when all of the product cannot be removed with this method, a brass bristle brush may be used in the longitudinal direction. The area may subsequently be cleaned with an air blast or an alcohol swab. A shiny metallic surface in the pit suggests the possibility of active corrosion. However, judgment should be used to differentiate this condition from one created by scraping the steel surface with a metallic object, such as the knife or spatula used to clean the surface or to obtain the sample product.

7.11.2 The steel surface shall be inspected for corrosion, and any damage shall be carefully documented. When possible, gauges should be used to measure the pit depths. Also, the length of the corroded area in relation to the circumferential and longitudinal position should be determined. The newly cleaned corroded area should first be examined without magnification. Then, a low-power magnifying lens at 5 to 50x power should be used to examine the detail of the corrosion pits. An example checklist is in Appendix A.

7.12 Analysis of Pipeline Samples

7.12.1 Careful analysis of pipeline samples (pipe sections or components that have been removed from service) may provide useful information regarding internal corrosion mechanisms.

7.12.2 Precautions should be taken to avoid contamination of the external surfaces of the pipeline before, during, and after the pipe section or component is removed from service. If inadvertent alteration of the external surface of the pipeline sample occurs, the nature of the alteration should be noted to aid in correct interpretation of subsequent testing results.

7.12.3 Alteration of pipeline samples can occur as a result of removal efforts, exposing the surface deposits to oxygen, soil, foreign matter, temperature changes, and contamination from handling.

7.12.4 Samples should be collected immediately after the pipe section or component is removed from service (i.e., within minutes when possible). Corrosion products and biofilms can change profoundly on exposure to air, affecting test results.

7.12.5 When samples cannot be collected immediately after a pipe section or component is removed, the external surfaces and deposits may be covered temporarily with new, clean, plastic sheeting to minimize exposure to air until samples are collected. This practice may compromise the condition of the surface samples to an unknown extent, and should be used only when samples cannot be collected immediately.

7.12.6 Culture tests of samples from pipe that has been exposed to air, dehydration, and potential contamination for extended periods of time (i.e., days) should not be relied on for providing useful data.

7.12.7 The internal condition of pipeline samples at the time of removal should be carefully and thoroughly documented; these data are important in the interpretation of both field and laboratory tests. An example checklist is provided in Appendix A.

7.12.8 Field and laboratory tests of pipeline samples for external corrosion analysis should be directed toward characterization of the biological, chemical, and metallurgical conditions present in the pipeline. In particular, distinction should be made between samples collected in corroded areas vs. areas where no corrosion is present.

7.12.9 Corrosion features on the pipeline sample should be protected from further corrosion after removal of the pipeline sample. Microscopic features of corrosion damage are easily lost because of oxidation or improper handling.

7.12.10 Optical microscopy and scanning electron microscopy (SEM) of internal corrosion features may provide useful information regarding the origin and growth of localized corrosion.

7.12.11 Metallographic examination of corroded areas removed from pipeline samples may provide information about the nature of the corrosion relative to the microstructure of the pipeline. Particularly, selective or preferential corrosion of microstructural features may be determined from metallographic examination.

7.12.12 Chemical analysis of microscopic corrosion features using EDS or other microanalytical techniques may provide useful data regarding localized corrosion initiation mechanisms.

7.12.13 Preservation methods, such as in situ histological embedment of biofilms and corrosion products, may yield samples suitable for microscopic examination using fluorescent staining techniques, phase contrast examination of thin sections, and transmission electron microscopy (TEM).

7.12.14 Interpretation of data collected from pipeline samples should be performed as described in Section 8.

7.13 Data and Records Management

All data and information, e.g., sample collection method used, should be documented on field data sheets or in logbooks with permanent ink.

7.14 Inspection Techniques

7.14.1 Inspection data are used to detect and monitor corrosion-related damage. Techniques include visual inspection, ultrasonic testing (UT), radiographic testing (RT), and magnetic flux methods. Inspection may be used for establishing the orientation, distribution, density, size, shape, and extent of external corrosion damage; however, inspection results alone do not establish the presence of MIC. Inspection data should be integrated with other information about the internal environment of the pipeline.

7.14.2 The results of ILI may provide information about the location and severity of external corrosion relative to operating parameters, design, elevation, and other considerations.

7.14.3 An external corrosion direct assessment (ECDA) standard has been published for pipelines in ANSI/NACE SP0502.[43] As for ILI data, ECDA methods provide information about the location and severity of external corrosion relative to pipeline design and operating conditions.

Section 8: Application of Test Methods to Pipelines and Interpretation of Data

8.1 Data Interpretation

8.1.1 Because microorganisms are ubiquitous, the presence of bacteria or other microorganisms does not necessarily indicate a causal relationship with external corrosion observed on a pipeline. In fact, microorganisms can nearly always be cultured from natural environments. Therefore, merely detecting viable bacteria in liquid or solid samples associated with external corrosion does not necessarily prove that MIC has occurred.

8.1.2 To determine the cause of external corrosion, all chemical, microbiological, metallurgical, and operational data about the pipeline site must be examined, integrated, and analyzed. Analytical results from samples obtained in the corroded area should be compared with the results from reference samples taken outside the corroded area.

8.1.3 To determine the presence of external MIC on a pipeline, microbiological, operational, and chemical data must be integrated. Analysis of the data should demonstrate that microorganisms and their activities have provided the predominant influence over the corrosion mechanism present on the pipeline, as opposed to abiotic mechanisms.

8.1.4 Pipeline operators may collect data in support of internal MIC analysis in conjunction with other routine sampling, maintenance, integrity assessment, inspection, and environmental and regulatory compliance activities.

8.1.5 Interpretation of data relative to the assessment or determination of MIC on a pipeline should consider a number of factors that can influence both corrosion and microorganism growth, including: soil type, soil composition, groundwater composition (if present), temperature, coating condition, and cathodicprotection.

8.1.6 Interpretation of data related to bulk phase (macro scale) conditions must be done in consideration of the fact that microorganisms can exist and flourish in microniches. For example, pipelines may experience little or no corrosion damage as a result of a wide range of conditions throughout the majority of the pipeline, yet be affected by MIC in a small area of a specific section of the pipeline because of the unique environment present only at that location.

8.1.7 Because MIC is a complex mechanism that involves electrochemistry, microbiology, corrosion control, pipeline operation and design, as well as engineering and integrity assessment, plans to evaluate MIC of pipelines and analyze data should include input from those with expertise in the respective fields. Pipeline operators should seek input from a multidisciplinary team whenever possible, so as not to emphasize one aspect of science or technology over another.

8.2 Corrosion Damage Investigation

8.2.1 MIC is suggested by increased levels of viable microorganisms associated with pit areas that were uncontaminated by adjacent groundwater or soil, or by microscopic determination of iron and manganese bacteria in corrosion deposits. These are often good indicators of microbial involvement.

8.2.2 To validate MIC as the cause of internal corrosion, the following three conditions must be met:

8.2.2.1 Condition 1—Assuming there is no known or suspected contamination from outside sources, demonstration of increased levels of specific types of viable microorganisms (bacteria or fungi) associated with the corrosion, relative to samples taken outside the corroded area.

8.2.2.2 Condition 2—Chemical indicators that support the microbiological evidence (e.g., elevated levels of sulfide or sulfur in pit deposits from SRB and SRA, or organic acids from APB) are identified in the corroded area.

8.2.2.3 Condition 3—Biotic factors (the presence or activities of living organisms) are identified as the primary contributor to the corrosion damage. The objective of this verification step is to establish that the presence of specific biotic conditions was the predominant contributor to the corrosion observed. The influence of abiotic factors (chemical or physical conditions unrelated to living organisms) on the corrosion mechanism also must be considered in all cases. The nature of the corrosion damage to the pipeline system should be consistent with the nature of the identified microorganism(s) and their by-products, or their physical influence on the formation of corrosion cells. For example, if viable APB or methanogens are concentrated at the corrosion damage relative to the environment, and evidence of their metabolic activity (organic acids) is determined to be associated with the corrosion, the nature of the corrosion damage should be consistent with these observations (e.g., accelerated corrosion damage or pitting beneath biofilms or deposits). This is an important step in the final diagnosis because it is often difficult to discern between the relative contributions of various factors (biotic and abiotic) affecting localized corrosion.

8.3 Corrosion Mitigation

8.3.1 The methods described in this standard may be used to determine the need for, and effectiveness of, mitigation measures for controlling MIC. Specific procedures for mitigating external MIC of pipelines are beyond the scope of this standard.

8.3.2 NACE SP0169 provides general information about methods for controlling external MIC by design, operation, and specific measures, such as coatings and cathodic protection.

8.3.3 The mitigation measures used to control external corrosion of pipelines may be effective for both biotic and abiotic corrosion mechanisms.

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Appendix A
(Nonmandatory)
Site Inspection and Testing

A1.1 A sample checklist used for site inspection and testing is provided in Table A1:

Table A1
Site Inspection and Testing Checklist

Paragraph No.	Inspection Point	Observations
6.1.1	**Observations prior to excavation**	
	General topography of site	
	Soil type	
6.1.2	**Measurements prior to excavation**	
	Soil resistivity	
	Pipe-to-soil potential	
	Close interval survey	
	Current mapping	
	Redox potential	
	Other	
6.1.3	**Observations during excavation**	
	Method of excavation	
	Coating damaged while digging?	
	Soil depth to top of pipe	
	Special features (bend, fitting, etc.)	
	Previous repair area?	
	Observations after excavation	
6.1.4.1	Coating type (coal tar, asphalt, bitumen, tape, wax, epoxy)	
	Nature of coating damage (disbonding, blistering, tenting, cracking, wrinkling)	
	Extent of coating damage (length, circumference, area of pipe exposed)	
	Location of coating damage relative to pipe girth and seam welds, and coating seam if applicable	
	Typical location of coating damage (top, bottom, sides, random)	
	Coating repairs	
	Age of coating	
	Plant or field application	
6.1.4.2	**Soil moisture level**	
	Soil type (silt, sand, gravel, rock, clay, peat, other)	
	Discoloration near pipeline	
	Soil strata depths	
	Running water (spring)	
	Seasonal effects at location	
	Soil or groundwater pH	
	Soil pH around pipeline	
	Note soil samples collected for analysis	

6.1.4.3	**Relationship of corrosion to:**	
	Distance from nearest compressor station	
	Inlets, outlets, taps, fittings	
	Heat sources or temperature change	
	Construction/material changes	
	Recent repairs or damage	
	Power lines	
	Other pipelines or underground facilities	
6.2.1	**Corrosion products/deposits color**	
	Nature of deposits (scale, nodule, film)	
	Deposit texture (hard, soft, friable)	
	Deposit odor	
	Deposit strata (note changes in layers if they exist)	
	Note visual differences between general deposits and localized deposits associated with corrosion	
	Relationship between coating and deposits (e.g., beneath coating, on top of coating, etc.)	
	Calcareous deposits present?	
	Chemical spot testing results	
	Note deposit samples collected for analysis	
	Visible biological accumulations in deposits or on pipe	
	Liquid present beneath coating?	
6.2.2	**Observations of corrosion damage**	
	Nature of corrosion damage	
	Isolated pitting	
	Isolated pitting within areas of general corrosion	
	Linked pitting within areas of general corrosion	
	General metal loss with few deeper pits	
	Etching or general metal loss with no pitting	
	Selective attack at welds	
	Crevice corrosion (at flange joints, mechanical joints)	
	Pit morphology (elliptical, parabolic, narrow, grain attack, subsurface). See Figure 1.	
	Pit features (striations, tunnels, cup shape, pits within pits, undercutting, strata levels, grooves, shiny, dull)	
	Other observations	
	Severity of corrosion:	
	Longitudinal extent	
	Circumferential extent	
	Maximum wall loss	
	Profile of wall loss	
	Maximum/average pit depth	
	Maximum/average pit diameter	
	Pit length vs. pit width	
	Depth/diameter ratio	
	Where is corrosion the most severe?	

6.4	**Samples collected for microbial and chemical analysis**	***Note whether sample was collected and exact location of sample.***
	Soil samples	
	a. Undisturbed soil next to pipe	
	b. Undisturbed soil, bottom of ditch	
	c. Undisturbed soil, ditch wall, pipe elevation	
	d. Soil in contact with coating damage or corrosion	
	Coating/deposit samples	
	a. Disbonded or damaged coating	
	b. Deposits at corrosion sites	
	c. Deposits where no corrosion occurred	
	d. Scale, biofilm, liquids from under coating	
	Corrosion samples	
	a. Corrosion products or nodules	
	b. Material from beneath nodules	
	c. Surface swab of pit contents	
	d. Pipe sample cut-out	
	General information and history	
	Year of installation	
	Pipe diameter and wall thickness	
	Pipe grade and manufacturer	
	Year of CP installation	
	Type of CP system	

NACE INTERNATIONAL

NACE Standard TM0106-2016
Item #00000

ISBN 1-57590-000-0
NACE International

Ex. II - 34

Paper No.
9452

NACE INTERNATIONAL CORROSION 2017 Conference & Expo

Cathodic Protection and MIC - Effects of Local Electrochemistry

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ABSTRACT

Uncertainties are present about the mechanisms of cathodic protection (CP) and its effectiveness to limit or completely stop Microbiologically Influenced Corrosion (MIC). The goal of this research was to improve the understanding of the mechanisms of CP by determining the interactions between corrosion and local chemical parameters, such as pH, under varying CP conditions, both in the absence and presence of MIC.

Electrical resistance (ER) probes, covered with a biofilm of sulphate-reducing microorganisms, were subjected to a series of CP potentials. In some cases MIC could not be stopped by CP, even at very negative potentials. The application of CP potentials resulted in an increase of the pH near the steel surface. In the absence of a biofilm CP could raise the pH above 13, whereas the pH remained below 8 in the presence of an active MIC biofilm. These findings show that MIC biofilms can reduce the effectiveness of CP by maintaining a mild pH, supporting their activity.

Once biofilms have established, it may be very hard or even impossible to stop MIC with CP, irrespective of the potential applied. This suggests that CP strategies should be aimed at preventing MIC biofilms to develop from the start.

Key words: MIC, electrical resistance probe, cathodic protection, biofilm, sulphate-reducers, microsensors, pH, electrochemistry.

INTRODUCTION

Microbiologically influenced corrosion (MIC) has been identified as one of the major causes of failures of underground steel infrastructure. Uncertainties are present about the mechanisms of cathodic protection (CP) and its effectiveness to limit or completely stop MIC. Several different mechanisms for the effect of CP on MIC have been proposed, including formation of alkalinity and electrostatic effects at the metal surface.[1]

To prevent or mitigate corrosion using cathodic protection (CP), the right potential should be applied. A criterion of -0.95 V (vs. Cu-$CuSO_4$) is widely used, but its robustness has been questioned by several authors.[1,2] A crucial factor is the role of environmental conditions and the ensuing electrochemical and microbiological reactions following the application of CP.

Recently, a model was developed which is able to explain mechanisms of cathodic protection and limitations of the current threshold values.[2] In spite of the successful description of corrosion phenomena by this model, some input parameters still remain unclear. The spread resistance is one uncertain parameter. It is determined by soil microstructure and local soil electrolyte chemistry. The latter strongly depends on the applied potential and the resulting electrochemical reaction occurring at the steel surface at a given rate as well as on the coupled mass transport. The combined effects of applied protection current, mass transport and microbial activity in the soil adjacent to a defect are currently not well understood. Especially the role of sulphate-reducing bacteria is unclear: the presence of these bacteria can influence the local environment by affecting pH (most likely by acidification), but also by affecting levels of Fe^{2+} concentration due to formation of precipitates such as iron sulphides. A better understanding of these processes is necessary to understand the occurrence of MIC and the effectiveness of CP.

The goal of this research was to answer the following questions:

- How effective is CP in the absence and presence of Microbiologically Influenced Corrosion (MIC)?
- What factors explain the effectiveness of CP in the absence and presence of MIC?
- What does this mean for CP protection criteria?

In order to answer these questions, we determined the interactions between corrosion and local chemical parameters such as pH under varying CP conditions, in the absence and presence of MIC.

EXPERIMENTAL PROCEDURE

1. Relation between CP and local pH in synthetic solutions

In a first series of experiments the effect of the current density on the pH near a steel surface with a hemispherical shape was investigated in simulated soils. The pH-value at the steel surface was measured with sensors previously described.[3] All experiments were performed in quartz sand. To determine the relation between applied potential and local pH, a probe was used consisting of a platinum wire. The probe's geometry was based on a hemisphere with 1 cm diameter that was subjected to a galvanostatic current (Figure 1). The pH and spread resistance were measured over time until steady state was achieved.

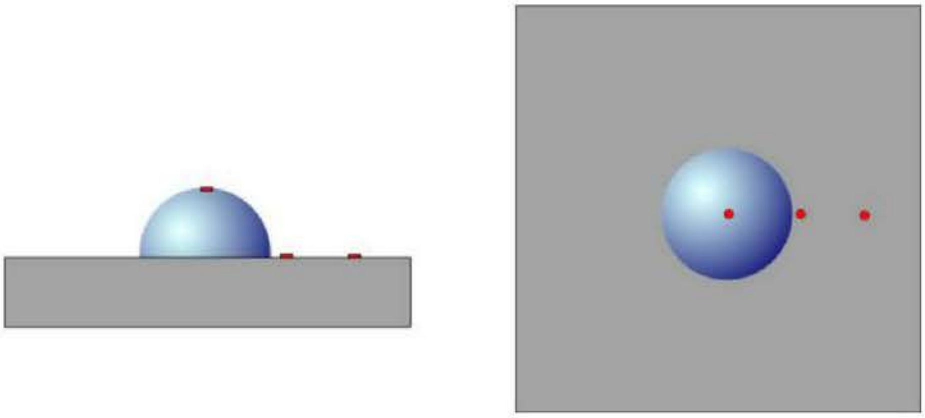

Figure 1: Experimental set-up for measuring the spread resistance and pH as a function of soil condition and current density over time. A steel hemisphere was used as cathode. The locations of pH-sensors are schematically indicated by red dots.

2. Abiotic corrosion and Microbiologically Influenced Corrosion (MIC) in groundwater (laboratory experiments)

To study abiotic corrosion and Microbiologically Influenced Corrosion, a setup was used consisting of and ER probe exposed to groundwater (Figure 2). The ER probes used in these experiments were obtained from Metricorr. These sensors consist of a steel surface which can be exposed to a chosen environment, and a reference steel surface which is not exposed. By measuring electrical resistance the thickness of the steel can be determined over time. Electrical parameters such as DC and AC currents and potentials were measured with a Metricorr[†] logger.

A biofilm of MIC-causing sulphate-reducing microorganisms was grown on the steel surface of an ER probe placed in an anaerobic reactor. For this purpose, a flow of groundwater containing sulphate reducing microorganisms was pumped along the steel surface of the ER probe. Growth of a MIC biofilm was initiated by adding 5 mM Na_2SO_4 to the groundwater reservoir and intermittent doses of 12 mM sodium-D,L-lactate to the reactor. Formation of a MIC biofilm representative of those present in the field is ensured by using groundwater from a location in the North of the Netherlands, where MIC on underground pipelines was reported to occur frequently. Details on the experimental approach and setup were described before.[4]

[†] Trade Name

Figure 2: Left: ER probe in anaerobic reactor containing groundwater; right: close-up of setup for measurement for gradients using microsensors.

With the ER-probe, corrosion rates were measured under various chosen CP values and groundwater conditions, in combination with measurement of electrical DC and AC parameters. In all experiments with CP, the applied potential (imposed voltage) was adjusted with a potentiostat. The corrosion potential on the steel surface of the probe (EDC) was measured with respect to an Ag/AgCl reference electrode. Small scale gradients of pH and redox potential in the biofilm at the steel surface were measured using mini-pH sensors or microsensors mounted in a micromanipulator.

Microsensor measurements

Microsensors were used to measure gradients of pH and redox potential in a MIC biofilm on a micrometer scale, and to determine the effect of CP and groundwater flow on these profiles. For these measurements, either a mini pH sensor was used, or microsensors. The minisensors were from the type WTW SenTix MIC D. The microsensors were obtained from Unisense[†]. The microsensors for redox potential and pH had a tip size of 25 µm.

3. Microbiologically Influenced Corrosion (MIC) in groundwater (field experiments)

Field experiments were performed at a location in the north of the Netherlands. This location was chosen because it is located in an area where external MIC has been discovered on several spots on underground pipelines. The soil parameters of this area are largely determined by the presence of peat. The top layer of a few decimeters consists of humus rich soil and, largely excavated, peat. Underneath is yellow sand. The groundwater level ranges throughout the year from 0,5 to 1,3 meters below ground level.

On the field site 25 groundwater monitoring wells were installed. These consisted of PVC tubes with an external diameter of Ø75 mm and had depths ranging from 1.6 to 3.2 meters below surface level. The deepest of the PVC tubes was provided with a well screen consisting of vertical slits (20 cm x 0.5 mm) to allow the groundwater to flow from the relevant depth into the well. A filter wick was covering the slotted part of the tube. Thus, by inserting the ER (bio)probes in the monitoring wells, it was possible to carry out measurements in the groundwater at a controlled depth and location.

[†] Trade Name

The effect of cathodic protection (CP) on (microbiological) corrosion on the ER probes was studied with the set-up depicted in Figure 3. With a rectifier (Delta ES030-5) a cathodic protection potential was applied between the probe and its environment. A steel anode was located in a nearby ditch. The applied CP potential was measured with an Ag/AgCl reference electrode which was located in the monitoring well adjacent to the probe. A Metricorr logger measured the thickness of the probe, electric potential with respect to the reference cell and current density (DC and AC). Details on the field setup and experimental approach were described before.[4]

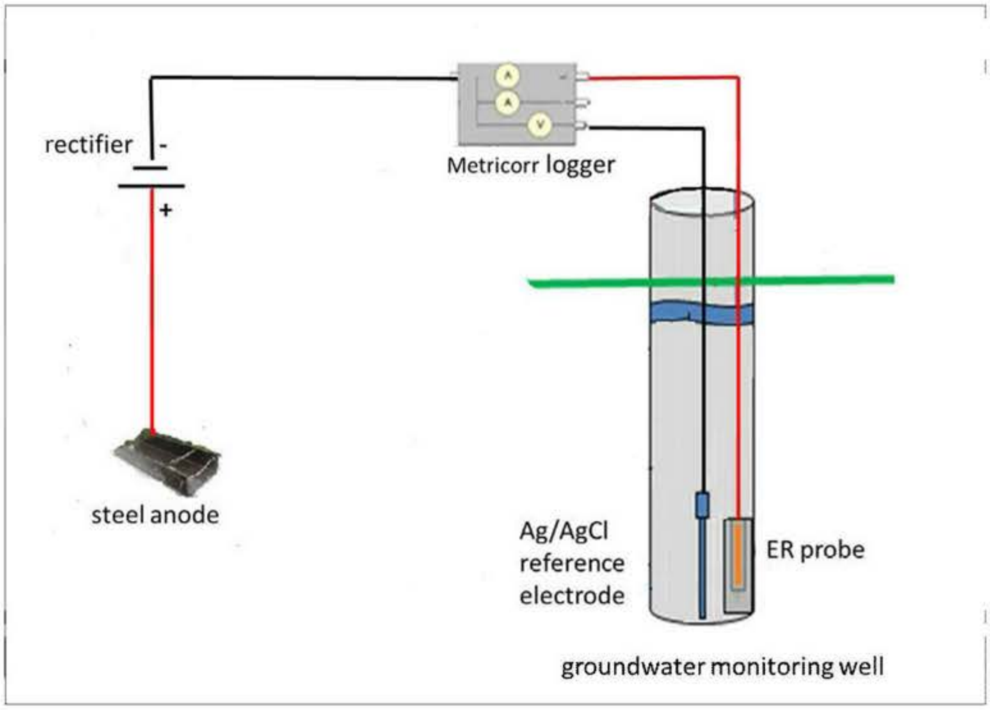

Figure 3: **Experimental set-up to measure interaction between CP and corrosion in the field.**

RESULTS

1. Effects of pH and cathodic protection in well-defined abiotic laboratory media

The results of the measurements of the pH distribution in synthetic soil are shown in Figure 4. After applying the current the pH reached a steady state value within a few hours. After one week, the pH gradient reached several centimeters into soil. At the steel surface the pH-value was in the range of 12.5 or above for current densities of 1 A/m^2 or 10 A/m^2, respectively. Corresponding values of the pH are typical for steel in concrete and are associated with the formation of a stable passive film on the steel surface. This finding is in line with calcareous deposits that are commonly found at coating defects. These deposits often have diameters in the range of several tens of centimeters. Since their formation is controlled by the increase of the pH and the precipitation of calcium carbonate they can be considered as a qualitative measure of the dimension of the increased pH and its extent into the surrounding soil.

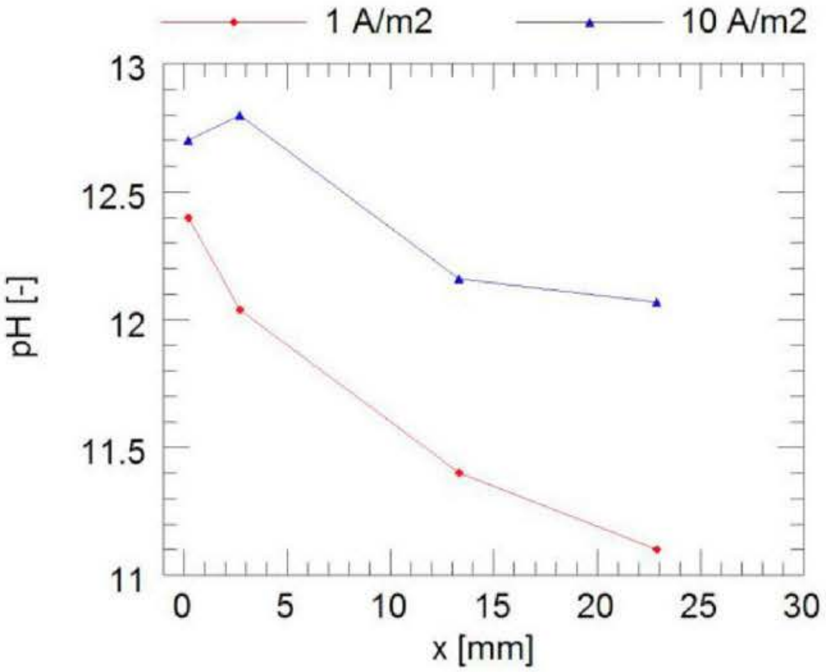

Figure 4: Distribution of the pH into soil after one week of cathodic protection.

2. Cathodic protection, pH and corrosion in groundwater (laboratory experiments)

Effects of CP on abiotic corrosion

Cathodic protection is reported to have a large effect on pH gradients.[5,6] We measured the effect of cathodic protection on pH at the steel surface of ER probes using a pH mini-electrode. The results can be found in Figure 5. A clear effect of imposed voltage on the pH can be seen: with a more negative CP potential, the pH strongly increases (up to pH 14 at -2000 mV). This effect is in accordance with the effects reported in literature.[5,6]

To rule out the potential disturbance of the signal by direct electrical contact between steel surface and pH sensor, the pH minisensor was positioned at a slight distance from the steel surface. The pH value hardly changed by this, indicating that the curves reflect actual pH values. Another test confirming this conclusion was performed by applying the pH indicator phenolphtalein in the medium. This indicator showed a pink colour upon CP. Phenolphtalein is colourless at neutral pH and turns purple in the pH range from 8 to 12, and turns colourless above pH 13. The indicator showed a pink colour upon applying CP. This gives further proof for the pH effects reported in Figure 5. It is also remarkable that the indicator mainly turns pink at the edges of the steel surface, whereas no colour is visible at the centre of the steel surface. This indicates that the pH at the center of the steel surface is higher than 13, which is in line with the measurements in Figure 5.

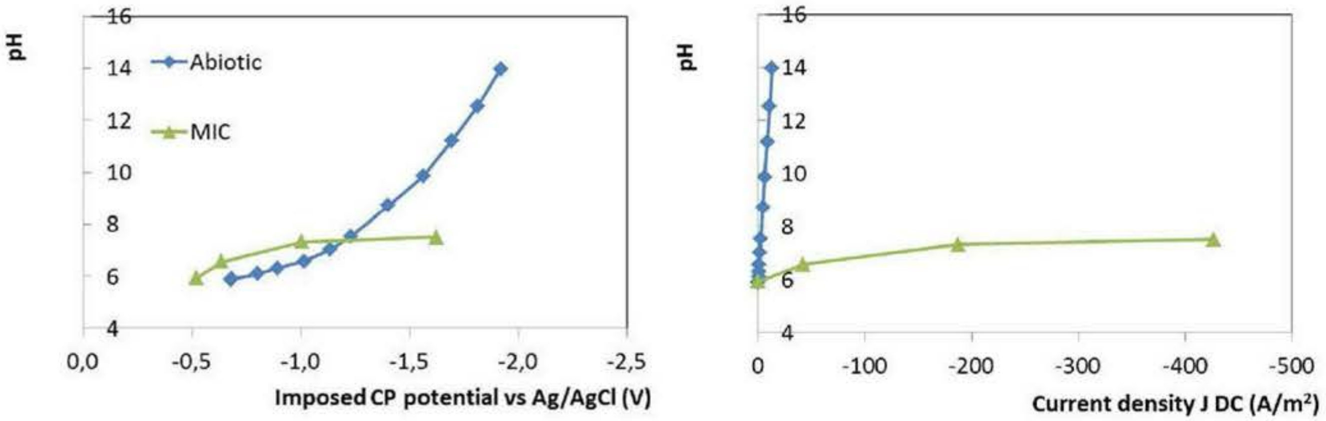

Figure 5: pH upon application of various levels of CP versus applied potential (versus Ag/AgCl) (left) and current density J DC (right) of abiotic ER probe (blue) and MIC ER probe (green).

<u>Effects of CP on Microbiologically Influenced Corrosion (MIC)</u>

The effect of the applied potential of Cathodic Protection (CP) on the MIC rates is presented for two cases (Figure 6 and 7).

In Figure 6, the relative MIC rate is presented compared to the maximally measured MIC rate for this MIC ER probe (in %) as a function of applied CP potential. For this MIC biofilm, the MIC rate gradually decreases with increasing CP potential.

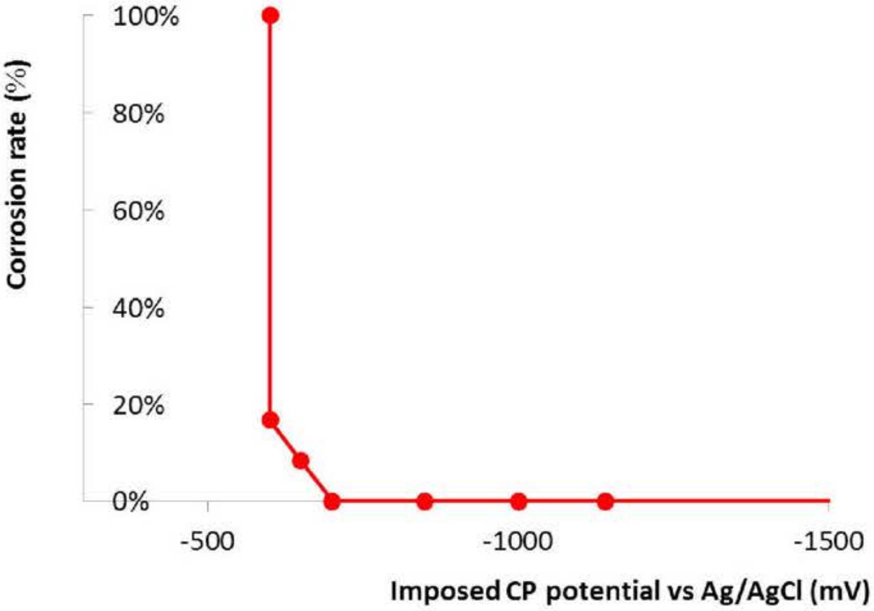

Figure 6: Effect of imposed CP potential on corrosion rate measures using an MIC ER probe, expressed as % compared to the maximal corrosion rate.

For another biofilm however, a different situation was observed (Figure 7). First, the MIC could be stopped completely. However at a later moment, MIC could not be stopped, even at CP potentials as high as -1000 mV vs. Ag/AgCl.

The local pH was measured in the biofilms that could not be stopped corroding by CP (Figure 5). In comparison to abiotic corrosion, a striking difference is visible. Inside the MIC biofilm the pH remained below 7.5, in spite of increasing the CP potential to -1700 mV (Figure 5). Another important observation was that the presence of a biofilm, the current densities are 40 to 100 times higher than current densities in the absence of MIC.

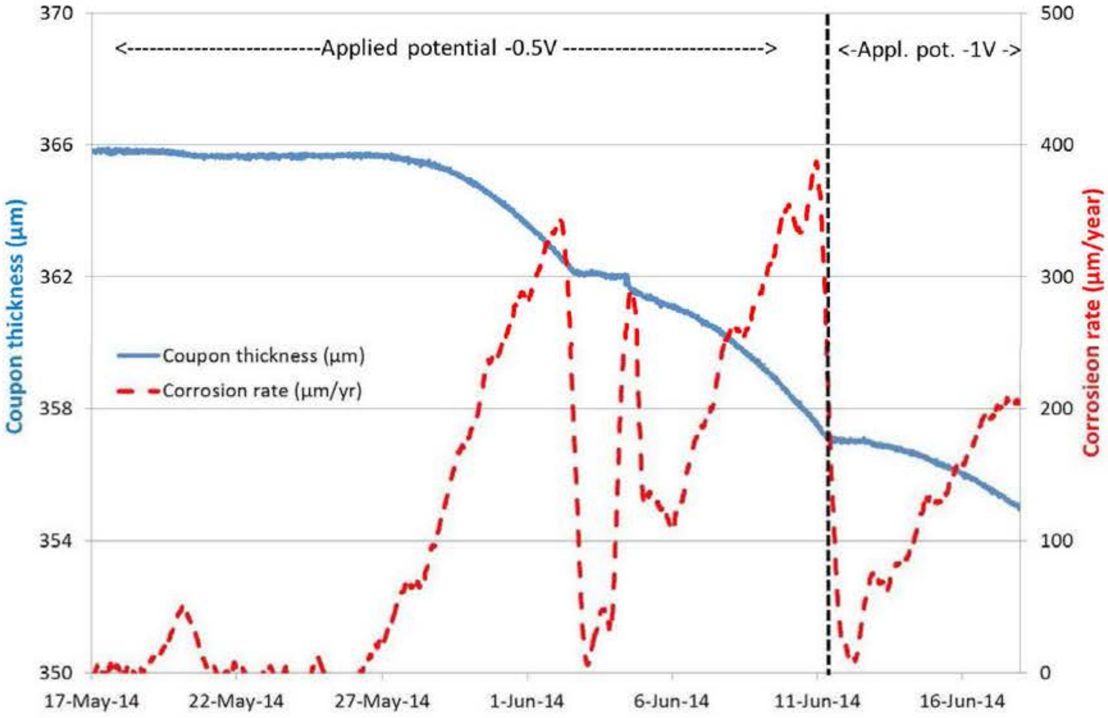

Figure 7: Coupon thickness and corrosion rate measured with fast corroding MIC ER probe.

3. Field experiments

To test the effectiveness of CP in the field, ER bioprobes preloaded with a MIC biofilm in the laboratory were transferred to the field and, after an adaptation time, exposed to a series of CP potentials (Figure 8).

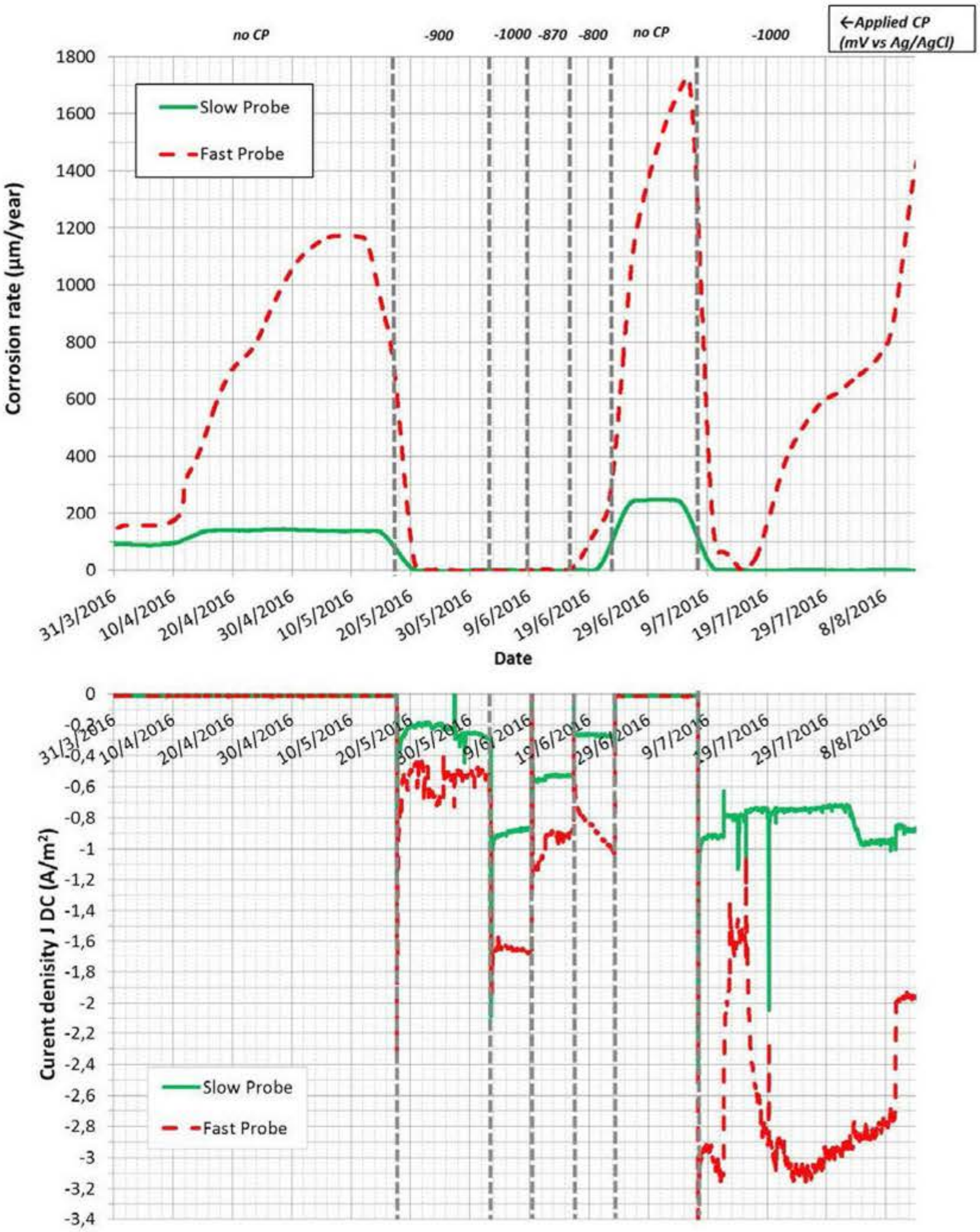

Figure 8: Corrosion rate (top) and current density (bottom) measured for MIC bioprobes in the field over time. Applied CP potentials (vs. Ag/AgCl) indicated at the top of the figure.

On two probes with different grades of microbiological corrosion, different levels of CP were applied, in two series over time. In between the series, no CP was applied. In the first CP series, for both probes the MIC could be stopped completely. The stronger corroding probe needed higher applied values to stop MIC completely (-1000 mV versus -870 mV vs Ag/AgCl). Remarkable is that for both probes, corrosion rates increased after the application of CP, indicating that despite the fact that corrosion stops during the application of CP, the biofilm is becoming more active. In the second CP series, MIC could not be stopped on the fastest corroding probe (red line in Figure 8), even at CP potentials as high as -1000 mV vs. Ag/AgCl. The slower corroding probe (green line), immediately stopped corroding at this applied CP potential. For the faster corroding probe which cannot be stopped with CP, the current densities were about two times higher than those for the slow corroding probe (Figure 8).

CONCLUSIONS

Cathodic Protection (CP) appears to work at least partly via a pH mechanism. In the absence of microorganisms, a clear elevation of the pH near the steel surface is observed. In the presence of MIC, three interesting phenomena were observed:

- MIC can in some cases not be stopped by CP, even in case of very negative applied potentials;
- Within a MIC biofilm, the increase of pH upon CP can be significantly less than in the absence of a MIC biofilm;
- In the presence of a MIC biofilm the DC current upon CP is much higher than in the absence of a biofilm (40-100x).

The exact mechanisms determining this pH-control inside the biofilm remain to be resolved. Some hypotheses are:
1. The microorganisms are able to couple sulphate-reduction to the oxidation of hydrogen (H_2) to protons (H^+). By doing so, the protons taken up from the groundwater to form H_2 at the steel surface exposed to CP are recycled, and thus a potential pH increase is counteracted (Figure 9);
2. The biofilm has a strong chemical pH-buffering capacity, for example related to the presence of iron-sulphide and siderite precipitates, and organic molecules.

One of the most important findings is the suggestion that CP can feed MIC microorganisms at the steel surface by providing them with energy via electrons and/or hydrogen. There are strong indications that, once certain biofilms have established, it is very hard or even impossible to stop them with CP, irrespective of the potential applied. Instead of stopping an already established biofilm, CP strategies should therefore be aimed at preventing MIC biofilms to develop from the start.

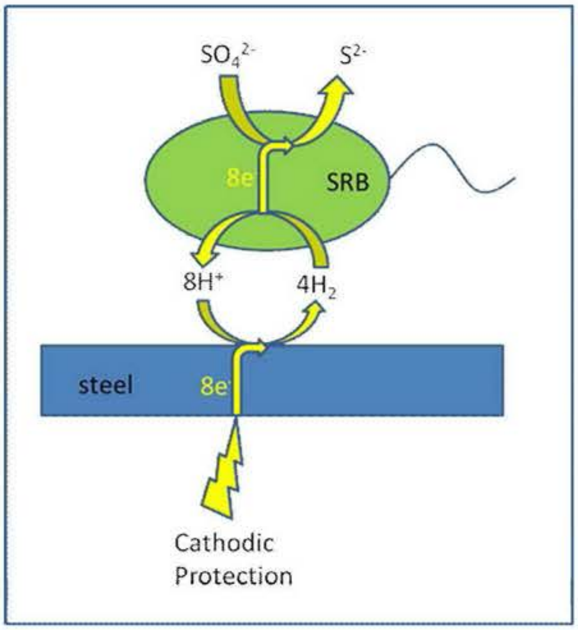

Figure 9: Schematic depiction of potential mechanism of electron coupling of MIC at the steel surface.

ACKNOWLEDGEMENTS

We thank Andre Cinjée, Berthil Slim and David Joos for practical assistance.

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ASM Handbook, Volume 13C: Corrosion: Environments and Industries
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DOI: 10.1361/asmhba0004114

Well Casing External Corrosion and Cathodic Protection

W. Brian Holtsbaum, CC Technologies Canada Ltd.

THE PORTION OF THE WELL OF CONCERN is that portion of the casing in contact with the formation either directly or through a cement barrier. It must be noted that where multiple casing strings are used, only that portion of each casing string in contact with the formation applies to this discussion.

Well Casing Corrosion

The corrosion mechanism will vary depending on the depth and the conditions at various parts of the casing. Gordon et al. (Ref 1) reported corrosion on well casings above a depth of 60 m (200 ft) that was due to oxygen enhanced by chlorides and sulfates in the soil while below that depth corrosion was caused by carbon-dioxide-rich formation water. These conclusions were based on scale analyses, sidewall core analyses, and soil analyses. In addition to these mechanisms, galvanic corrosion (especially if the casing is connected to surface facilities), anaerobic bacteria supported by drilling mud, and stray-current electrolysis are other possible causes of corrosion (Ref 2). Cementing the casing in place helps reduce the corrosion rate but does not eliminate it (Ref 3).

The procedure for predicting the probability and/or rate of corrosion is given in NACE RP0186 (Ref 4) and can be summarized:

1. Study the corrosion history of the well or other wells in the area (Ref 5).
2. Study the downhole environment, including the resistivity logs, different strata, drilling mud, and cement zones.
3. Inspect any casing that has been pulled (Ref 1).
4. Review the results of pressure tests.
5. Review the results of downhole wall thickness tests (Ref 1).
6. Review the results of casing potential profiles (CPP).
7. Review the oil/gas/water well maintenance records.

In a given area, after the first leak has occurred, the subsequent accumulated number of casing leaks often follows a straight-line relationship with time when presented on a semilog plot, that is, the log of the leaks versus time (Ref 5–7). This in effect means that the leak rate is increasing tenfold over equal periods of time. Repairs to the casing will alter this relationship as a repair often replaces several potential leaks; however, the leak rate will not be reduced to a tolerable level until cathodic protection is applied.

As part of many drilling programs it is common practice to pump cement into the annular space between the well borehole and the casing, usually to a point above the producing formation (sometimes from surface to producing formation depth and other times only portions of the casing strings are cemented) to achieve a seal. The cement in newer wells is often brought to the surface. However, in older wells, the cement was only sufficient to achieve a seal from the oil- and/or gas-bearing formation and therefore was brought from the bottom to a specific point along the casing. It should be noted that sections of casing pressed into the formation before cement injection will not necessarily have a cover of cement, or at the most, a very thin layer that is inadequate for corrosion control. Furthermore sections of casing not in the cement will continue to be exposed to the remains of the drilling mud.

The formation of corrosion cells can be:

- Local or pitting
- Between the cement and noncement sections of casing
- Between differential temperature zones
- Between brine formations and relatively inert rock
- Between the well casing and the surface facilities if there is a metallic connection

In addition, corrosive gases from a formation, such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) in an aqueous environment, can cause more aggressive attack.

Direct-current (dc) stray-current interference is another possible source of external corrosion. These may come from other cathodic protection systems, surface welding, or dc operated equipment. Alternating-current (ac) stray current in high current densities can also be a source of corrosion (Ref 8). Stray current accelerates corrosion on the casing if it discharges into the formation when returning to its source.

Detection of Corrosion

The two principal methods for detecting well casing corrosion include metal-loss (corrosion-monitoring) tools and casing current measurement. Both are described in this section.

Metal-Loss Tools

Casing monitoring tools for corrosion consist of three basic types: mechanical tools, electromagnetic tools, and ultrasonic tools (Ref 9).

The mechanical caliper tool is the oldest method where many "fingers" are spaced around a tool mandrel. When the tool is pulled past an anomaly, these fingers either extend into a defect or are pushed in by scale, a dent, or a buckle in the casing.

Electromagnetic tools consist of:

- High-resolution magnetic flux leakage and eddy-current devices
- An "electromagnetic thickness, caliper, and properties measurement" device

The source of magnetic flux comes from the electromagnet (or permanent magnet) in the tool. As the tool moves along the casing, the magnetic flux through the casing wall is constant until it is distorted by a change in the pipe wall thickness. The flux leakage induces current in sensing coils that is related to the penetration of the defect in the casing wall. A uniform thinning of the casing wall may be detected only as a defect at the beginning and end as there may be little change in flux leakage in between. Strictly, a magnetic flux tool cannot discriminate between a defect in the inside or the outside of the casing.

However, by adding a high-frequency eddy current that can be generated in the same tool, which induces a circulating current through the inner skin of the casing wall, discrimination between internal and external defects can be achieved. Sensing coils on the tool then detect the high-frequency field. A metal flaw or loss in the inside of the casing impedes the formation of circulating currents, and the change in this current is a measure of the surface quality and approximate vertical height of the defect. By comparing the defects from the electromagnetic to those obtained from the eddy-current signals in the tool, the external defects can be defined by a process of elimination.

The ultrasonic tool has transducers around the tool that act as both transmitters and receivers of an acoustic signal. The reflected signal is then analyzed for casing thickness, internal diameter, casing wall roughness, and defects. In addition, a cement evaluation can be included.

Tool Limitations. Since each tool has limitations, it may be necessary to run more than one tool depending on the type of flaw expected. In spite of the limitations, these tools can provide a reasonably accurate assessment of the casing metal loss; unfortunately, they can only detect corrosion damage after it has occurred.

Casing Current Measurement

According to Faraday's law (Eq 1), the metal loss due to corrosion is proportional to the dc current and the length of time that it leaves the metal and enters the electrolyte:

$$W = \frac{MtI}{nF} \quad \text{(Eq 1)}$$

where W is weight loss in grams (g); M is the atomic weight in grams (g); t is the time in seconds (s); I is the current in amperes (A); n is the number of electrons transferred per atom of metal consumed in the corrosion reaction; and F is Faraday's constant (96,500 coulombs per gram equivalent weight).

For steel, this equates to a metal loss of 9.1 kg/A-yr (20.1 lb/A-yr). If the current can be measured then the metal loss, as a measure of weight, for a given period of time can be calculated.

An axial current at any point in the casing can be calculated from Ohm's law (Eq 2) by measuring a voltage (microvolt, μV) drop across a known length of casing resistance:

$$I_p = \frac{V_2}{R_p} \quad \text{(Eq 2)}$$

where I_p is the axial current in casing (μA); V_2 is the axial voltage drop between two contact points along the casing pipe (μV); and R_p is the casing pipe wall resistance between the two contact points (Ω).

This voltage measurement is commonly called a casing potential profile (CPP), but the intent is to assess the axial and radial current profile in the casing. By determining an axial current value and direction between consecutive points in the casing, a radial current pickup or discharge can then be predicted in accordance with Kirchoff's current law, which states "the sum of the current at any junction must equal zero." Figure 1 illustrates three possible current measurement scenarios (A, B, and C); in all cases, the junction in Kirchoff's current law is at the center of each scenario.

The anodic or corroding sections of a casing are at the sections of current discharge, while the current pickup areas are cathodic and are not corroding. Scenario A of Fig. 1 shows the axial current increasing from 1.5 to 2.0 A; therefore, there must have been a 0.5 A pickup in between, indicating that this section is cathodic. The current of 2.0 A coming up the casing in scenario B is greater than the 1.5 A that continues up the casing; thus, 0.5 A must have discharged from the section in between the two points, causing this to be anodic or corroding. The current of 1.0 A that is coming downhole at the top of scenario C is in the reverse direction from the 1.5 A coming uphole; therefore, the current coming into the casing section from both ends must discharge from the pipe section somewhere in between. This section is therefore anodic and would be corroding.

By measuring the axial current at regular intervals along the casing, a complete current map along the casing can be obtained as shown in Fig. 2. Such a test is called a casing potential profile (CPP), and the plot in Fig. 2 is called an axial current profile. Both the amount and the direction of current have to be determined to predict a current pickup or discharge. An increasing slope coming uphole (equal to a negative change in depth per change in current going downhole) in Fig. 2 indicates a current pickup (cathodic section), while the reverse slope indicates a current discharge (anodic section). The amount of metal loss can be predicted for a given period of time on the assumption that the relative current will remain the same.

Determination of the amount of current pickup and discharge along the casing in Fig. 2 results in the radial current profile shown in Fig. 3. Referring to Fig. 2, the direction of net current flow at about "85% of depth" is in the downhole direction as it crosses the zero (0) current axis, while the current below that depth is coming uphole. This causes a current discharge centering

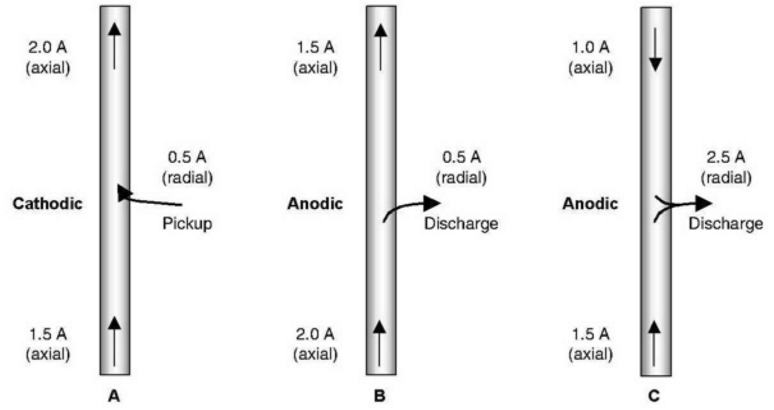


Fig. 1 Example of radial current pickup or discharge from axial current. Refer to the text for a discussion of scenarios A, B, and C.

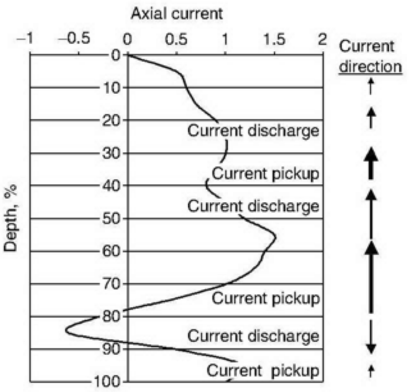


Fig. 2 Example of axial current profile in casing without cathodic protection

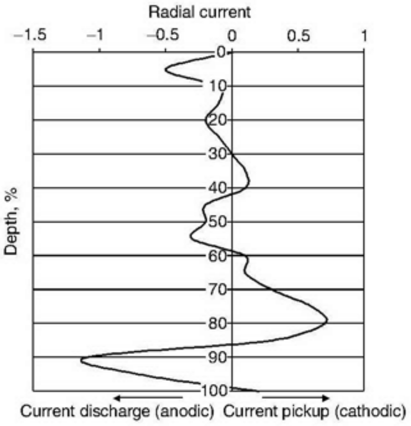


Fig. 3 Calculation of radial current profile from Fig. 2

at about 90% of depth as shown in Fig. 3. This is the same as scenario C in Fig. 1. In a similar fashion, the current at a depth between 0 and 25% and also 40 and 55% of depth is less than the current below, although in the same direction, which is the same as scenario B in Fig. 1. This also indicates a current discharge (anodic) area. The remainder of the casing in this example is picking up current and is cathodic, which fits the condition illustrated by scenario A in Fig. 1.

Limitations and Advantages of Casing Current Measurements. Casing current measurements, are only sensitive enough to measure long-line currents and do not detect local corrosion cells that exist between the spacing of the two contacts.

The advantage of this test is that macrocorrosion can be predicted before it occurs. However, the assumption that the current magnitude and location will stay the same can create a large error. The existence of local corrosion pits will be missed, and these can represent a large amount of the corrosion taking place (Ref 9, 10).

Cathodic Protection of Well Casings

At one time there was a concern that cathodic protection current applied at the surface would not reach the bottom of deeper well casings. Blount and Bolmer (Ref 11) conducted polarization tests with a reference electrode located at the top and the bottom of well casings and concluded that cathodic protection is feasible to a depth of at least 1000 m (3300 ft). Subsequent tests have shown that it is feasible to depths up to at least 3960 m (13,000 ft).

Two methods of determining the amount of cathodic protection current required are described in this section: a casing polarization (*E* log *I*) test and a CPP test. The first test attempts to predict when the casing becomes a polarized electrode, while the second test confirms if an adequate amount of cathodic protection current is being discharged from the anode bed(s) to ensure current is being picked up along the length of the casing being tested.

E log I Test (Tafel Potential)

The *E* log *I* test is a measurement of the polarized casing-to-soil (electrolyte) potential (*E*) compared to the logarithm of different increments of applied current (*I*). The casing-to-soil potential is measured with respect to a remote reference electrode, often a copper/copper-sulfate reference electrode (CSE). "Remote" in this case is a point where the electrical voltage gradient is zero. Polarization is considered to take place at the intersection of the two straight lines as shown at point "A" in Fig. 4. At the intersection of the upper straight line (point "B"), the curve becomes a hydrogen overvoltage curve and obeys the Tafel equation.

In the early years, the point where the two straight lines intersected (Fig. 4, point A) was taken as the current required for the protection of the well casing. This not only gave widely varying results depending on the relative slope of the two lines, but also provided current requirements that were found to be too low to protect the casings. The laboratory and field research of Blount and Bolmer (Ref 11) confirmed that the intersection of the upper portion of the Tafel slope with the curve was the point of corrosion control and proved to yield more consistent results (Fig. 4, point B). This point is normally used to establish a cathodic protection criterion for the casing.

A schematic of a typical *E* log *I* test is shown in Fig. 5. The test is conducted by impressing an increment of current for period of time and then measuring the "instant off" potential when the applied current is briefly interrupted. This process is repeated at increasing increments of current to a point beyond where the Tafel break in a plot between the instant off potential (*E*) and the logarithm of the current (log *I*) occurs (point B in Fig. 4). There has been extensive experimentation both in the laboratory and the field (Ref 11–13) comparing the current increments and the length of time at each increment to allow polarization to occur. The conclusion was that the best results occur when the increments of current and the time intervals between current increases are constant. A sufficient time interval must be established that ensures polarization will be complete before proceeding to the next current value. Although the current increment and time needs to be established for each *E* log *I* test, current increments of 0.5 A and time intervals of 10 min is often a practical combination. The time interval has been reduced to 5 min under certain circumstances where the well polarizes more quickly. It must be noted that too short of time intervals can yield an inaccurate higher current requirement as polarization may not be complete at given current values before the test current is increased incrementally.

Equipment (Fig. 6) can be set to automatically interrupt the current and record casing-to-electrolyte potentials continuously during the current interruption. In this way, the existence of a "spike" can be seen and the appropriate instant off casing-to-soil potential selected for each current interval. Furthermore, the current output

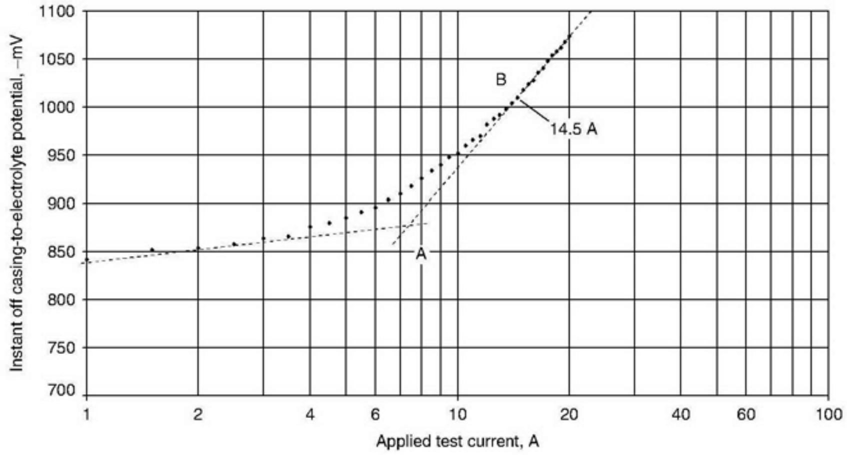


Fig. 4 An example of an *E* log *I* plot. Refer to text for a discussion of points A and B.

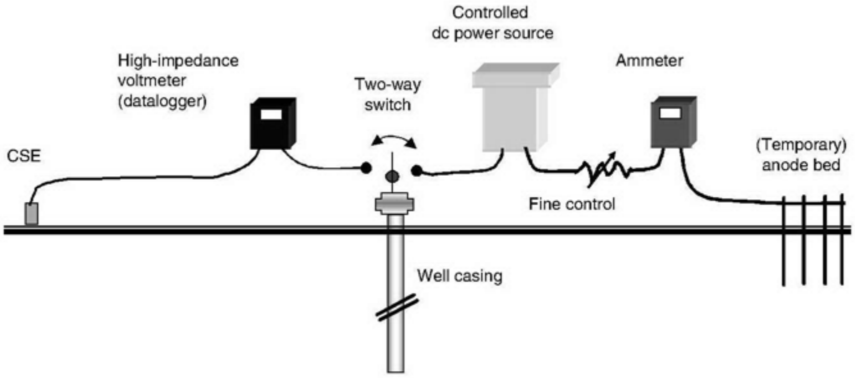


Fig. 5 Basic *E* log *I* test. CSE, copper/copper-sulfate reference electrode; dc, direct current.

can be controlled using silicon-controlled rectifiers (SCRs) to ensure that it remains constant during the test interval and that the desired fine incremental output control can be achieved.

Often a premature ending of the test occurs because the *E* log *I* profile was interpreted incorrectly as having straightened out. This variance is likely due to reactions that are taking place at different times or at different points as the test proceeds. To protect against stopping the test prematurely, a linear plot of *E* versus *I* should be made as the test proceeds to ensure that the test has left a straight-line relationship indicating that polarization is occurring. Often there is an early straight-line segment or the profile starts to leave the linear straight-line relationship only to return to the same slope. These early deviations are false indications as shown by the data from Fig. 4 plotted on a linear profile in Fig. 7. The Tafel break of interest in the *E* log *I* plot is beyond that determined by the linear plot (12.5 A) and becomes the criterion for protection for that well casing, as shown by point B in Fig. 4.

Subsequent *E* log *I* analysis by this method has compared favorably to the current requirement determined by CPP test results provided that the break (Fig. 4, point B) was selected after the straight-line relationship has ended on a linear plot. When this method is not used, an erroneous analysis of the *E* log *I* test can be expected (Ref 14).

Advantages and Limitations. An advantage of the *E* log *I* test is that it can be performed while the well is still in production. However, the casing still should be electrically isolated from all other structures for this test, or at least one must be able to measure the portion of the test current returning from the casing by perhaps using a clamp-on ammeter that can either fit around the wellhead or individually around all of the lines, instrument tubing, and conduit that connects to the well.

One disadvantage of the *E* log *I* test is the concern as to whether the test "sees" the lower part of the casing.

Casing Potential Profile

The CPP test for cathodic protection is similar to that described previously for predicting corrosion from casing current measurements except that now a current pickup is desired at all locations similar to that illustrated in Fig. 1 (scenario A). The casing has to be electrically isolated from all surface structures and the service rig during this test, otherwise the current returning at the wellhead must be measured.

The original CPP tool had two contacts that were 3 m (10 ft) to 7.6 m (25 ft) apart. The tool was stopped at regular intervals for microvolt (μV) measurements. Davies and Sasaki (Ref 13) describe a newer CPP tool (the CPET corrosion-protection evaluation tool) that has four rows of knife contacts that are 0.6 m (2 ft) apart between rows (Fig. 8). Measurements taken between the different rows of contacts include the pipe resistance, a voltage drop (μV_2) between the inner 0.6 m (2 ft) contacts, and another voltage drop (μV_6) across the outer contacts 1.8 m (6 ft) apart.

Pipe (Casing) Resistance Determination. Using a conventional four-pin resistance test (the same test is often used in conjunction with a resistivity measurement), the instrument

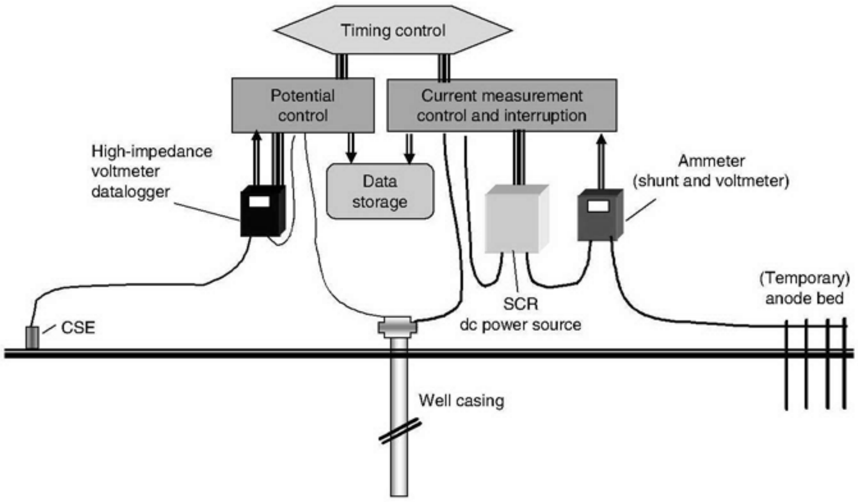


Fig. 6 Automatically controlled *E* log *I* test. CSE, copper/copper-sulfate reference electrode; dc, direct current; SCR, silicon-controlled rectifier

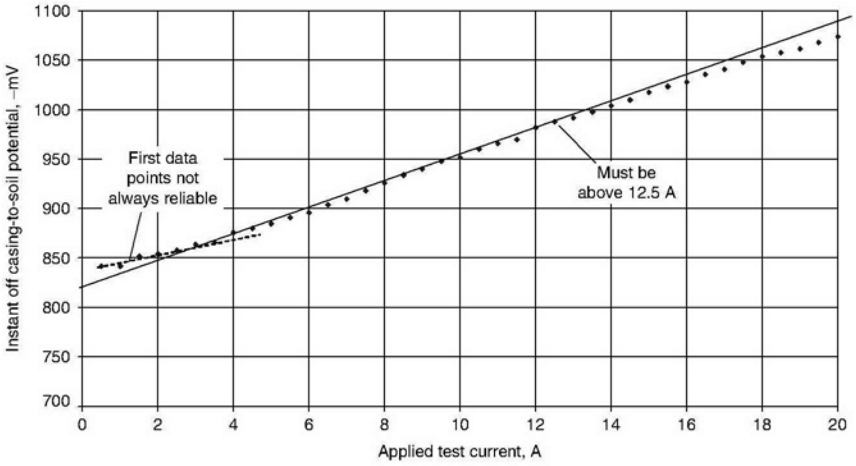


Fig. 7 Linear plot showing where the curve leaves a linear relationship. Tafel point on *E* log *I* must be at a higher current than the point that deviated from a linear straight line in this figure. Data generated from Fig. 4

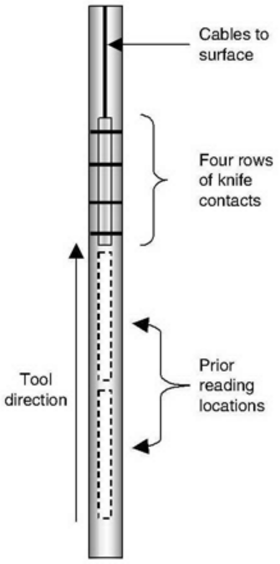


Fig. 8 CPET casing potential profile tool. CPET, corrosion protection evaluation tool

impresses a known current (I_{test}) between the outer contacts and measures the resulting voltage (V_2) across the inner 0.6 m (2 ft) contacts. This then allows the casing resistance between these 0.6 m (2 ft) contacts (R_2) to be calculated by using Ohm's law ($R_2 = V_2/I_{test}$).

Casing Axial Current Determination. Once the pipe resistance for the test point has been determined the axial current can then be calculated by $I_2 = V_2/R_2$. Identical measurements and calculations are made across all other sets of contacts and the results averaged. Normally, the results across the 0.6 m (2 ft) and 1.8 m (6 ft) rows are reported ($I_2 = V_2/R_2$ and $I_6 = V_6/R_6$). The radial current is then calculated between consecutive current measurements noting current direction.

It must be understood that the current in the casing when measured at any given point is the accumulation of all of the current pickup less any discharge on the casing below that point. Also the cathodic protection current direction has to be toward the top of the casing in order to return to the dc power source. Therefore, only when cathodic protection has been successfully applied does a plot of the axial casing current continually increase from the bottom to the top of the casing, thus indicating a continuous current pickup.

Figure 9 illustrates two cathodic protection trials with current applied. From the plots it can be seen that trial 1 did not eliminate all of the anodic areas. Thus, the applied current was increased until the anodic areas were eliminated as indicated by the axial current increasing continuously from the casing bottom to top, trial 2.

Trial 1 in Fig. 9 shows an axial current pickup at all but two sections. One current discharge is at approximately 55% of depth and the other at approximately 85% of depth; both of which are identified by "downward" slopes on the profile. The axial current at 85% of depth is in the downhole direction as it crosses the zero (0) current axis, while the current below is coming uphole. While the axial current at 55% of depth is in the same downward direction, the current above is less than that below, which also indicates a current discharge or an anodic section.

Since this was unsatisfactory, the current was increased for trial 2 (it must be noted that during an actual test, time must be given to ensure a steady state has been achieved after ampere adjustments before another log is run to obtain reliable results). Here, continuous axial current pickup occurred from bottom to top as shown by the positive slope in the accumulated current profile. The total current value established by this test now becomes the criterion for cathodic protection. It should be noted that errors can occur in this measurement due to poor contacts. However, this is the best technology available at the present time to determine the amount of cathodic protection current required to protect a well casing, or a portion of a well casing.

A partial CPET plot is shown in Fig. 10 that illustrates the axial current, radial current, and the casing thickness. The casing thickness is an estimate based on Faraday's law (Eq 1) and the assumption that the radial current discharge has remained the same over time. As a result, the casing thickness estimate may not be a true measure of the wall thickness remaining. Experience has shown that there is often quite a discrepancy between corrosion-prediction losses by this method when compared to actual metal-loss measurements.

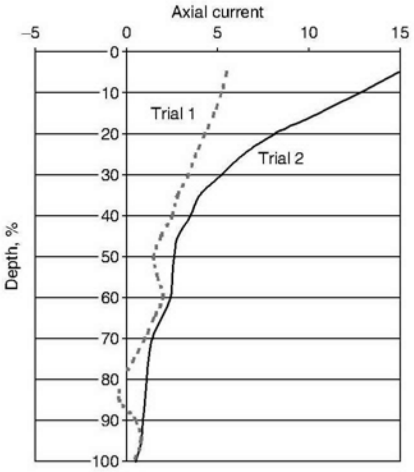


Fig. 9 Sample casing potential profile axial current profile

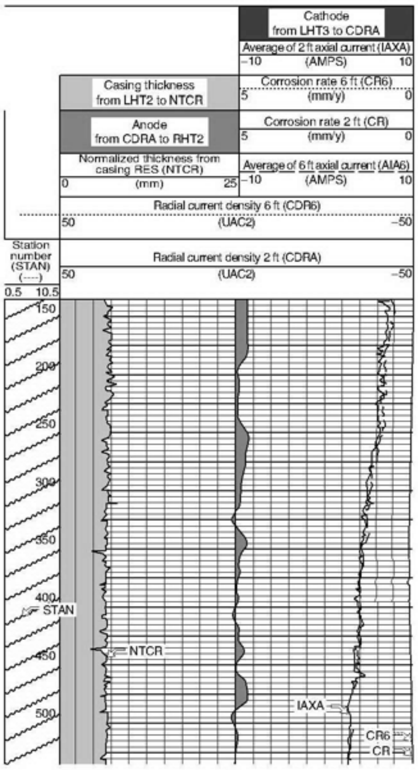


Fig. 10 CPET axial and radial current plot with a conventional rectifier and casing thickness. Total current is 15.3 A.

Factors Influencing the use of CPP Tests. Even though CPP is probably the best means now available to establish the current required for a well casing, it is not often used. The main reasons are associated with the cost of running the tool, both direct and indirect costs. Some of the reasons include:

- In order to run the tool the well has to be taken out of service. This in itself limits the number of potential candidates unless there is a very urgent need to take a well out of service.
- Depending on the fluid in the well bores, many wells will have to be "killed" before the tool can be run.
- In order for the tool to make good contact with the casing, any scale or product buildup on the inside of the casing will have to be cleaned off before the tool is run.
- There are not many CPET tools available worldwide, and the older CPP tool is not available. Coordinating the work is therefore vital to ensure the well and the tool are available at the same time.
- A cathodic protection system: anodes, rectifier (or some other suitable dc power source), cabling, and so forth, must be constructed and operating in advance of the downhole log if the test is to verify a current requirement target.
- If the testing is to determine cathodic protection current requirements, then weeks or even months between runs might be necessary in order to allow a steady state to be achieved between output adjustments.
- Since completion practices for wells in the same producing area can vary significantly, multiple tests on multiple wells may be necessary to arrive at current return criteria that meet all of the well completion variations.

Mathematical Modeling of Total Current Requirement for Well Casing Cathodic Protection

Several mathematical models (Ref 15–19) have been developed to estimate the total current required to protect a well casing by cathodic protection that can be summarized:

- Current density
- An attenuation equation
- A modified attenuation equation
- A computerized equivalent circuit using formation resistivity, nonlinear polarization characteristics, and well casing information

The current density model applies an empirical current density to the surface area of other well casings of similar characteristics to the source of the empirical data to estimate the total current requirement of each well casing. The variations in well depth and completion such as the amount of the casing that was cemented between it and the formation and the quality of the cement can make this approach quite inaccurate. Verification by field tests on typical well casings in a given geographical area is advised.

Attenuation calculations modified from those used on pipelines were applied initially to casings to estimate a potential at a given depth based on the potential change at the surface. The relationship developed by Schremp and Newton (Ref 16) is given by Eq 3 to calculate the potential change at any given depth in the casing with the applied current source being interrupted:

$$e_x = e_o \exp\left[\frac{-1.648.7(r_1)(x_1)(I_1)\exp(-x_1/L_1)}{e_o}\right] \quad \text{(Eq 3)}$$

where e_o is the potential change at wellhead when applied current is momentarily interrupted (mV); e_x is the potential change at depth x_1 from the wellhead (mV); r_1 is the unit resistance of the innermost casing (Ω/m or Ω/ft); x_1 is the distance from wellhead (m or ft); I_1 is the current in the innermost casing (A); and L_1 is the length of innermost casing (m or ft).

A more sophisticated mathematical model was developed by Dabkowski (Ref 17), and a spreadsheet version was developed by Smith et al. (Ref 18).

Casing-to-Anode Separation

The spacing of the anode to the casing can also change the current required for a particular casing as illustrated by data from Blount and Bolmer (Ref 11) plotted in Fig. 11. The current requirement to protect the casing increases if the anode is brought too close to the casing. There is an optimum distance beyond which a further increase in distance is of no benefit. Hamberg et al. (Ref 7) also demonstrated a similar result in offshore well casings.

A comparison of the distribution of current in two similar casings that were 2600 m (8530 ft) (well casing "A") and 2475 m (8120 ft) (well casing "B") deep in the same area but with different casing-to-anode separations is shown in Fig. 12. The excess current being impressed onto the casing near the surface helps provide an understanding of this change in current requirement due to the casing-to-anode separation (Ref 14).

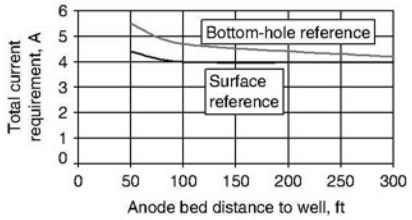


Fig. 11 An example of the change in current requirements with anode to well spacing. Source: Ref 11

Blount and Bolmer (Ref 11) found that the anode bed should be at least 30 m (100 ft) from casings that were on the order of 1220 m (4000 ft) deep. This distance should be increased for deeper wells for optimum performance. The anode bed in either the *E* log *I* or the CPP test should therefore be located at a distance from the well casing similar to where the permanent anode bed will be installed.

Coated Casings

Coatings are available that are durable enough to withstand many of the rigors of a casing installation. Although significant coating damage is expected, Orton et al. (Ref 20) reported that the current requirement of a coated casing with bare couplings and no effort to repair coating damage can be reduced to less than 10% of that of a similar bare casing. A further benefit is that a reduction in the current requirement will also reduce the interference effects on nearby structures and casings as discussed below.

Cathodic Protection Systems

The cathodic protection system for a well casing requires the same consideration as that for a pipeline. There are two types of cathodic protection systems used for well casings and pipelines: sacrificial anode systems and impressed-current systems (see the article "cathodic protection" in Volume 13A for additional information).

Sacrificial Anode Systems. In the early years, a sacrificial anode system was often used for wells where a low current requirement was predicted. Sacrificial anode systems are still appropriate for more shallow wells with a low current requirement.

An impressed-current cathodic protection system is the most common type for well casings due to the amount of current typically required for protection. A separate installation (Fig. 13) is common at each well. If two or more wellheads are in close proximity, interference can result (Ref 21–23).

Power Sources. Where ac power is available, it is likely that a standard or pulse-type rectifier will be used as a dc power source. Otherwise, thermoelectric generators, solar, wind-powered generators, and engine-driven generators are all possible candidates for the dc power source.

Thermoelectric generators (TEG) have a limited power availability; therefore, the anode bed resistance should be kept low to obtain the required current. The available power from a TEG usually peaks at around 0.6 to 1.2 Ω and reduces as the circuit resistance increases. The manufacturer's technical information must be consulted. A clean regulated fuel source such as natural gas or propane is required.

Both solar- and wind-generated power need batteries as a backup power source to provide cathodic protection current when there is either no sun or wind, respectively. The use of solar is

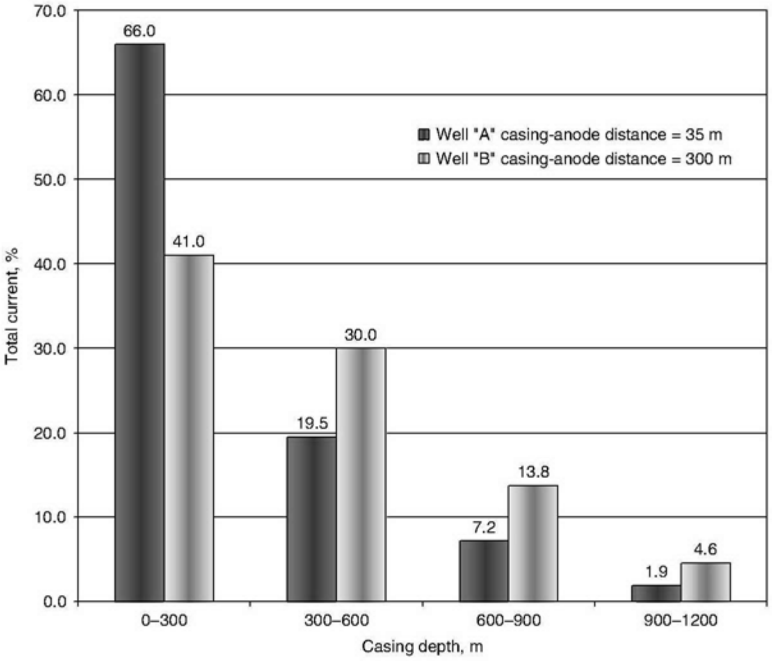


Fig. 12 An actual example of current distribution in similar casings but with different casing-to-anode distances. Source: Ref 18

less popular in the northern regions where there is a lack of sunlight in the winter, and wind power is not appropriate unless the area is historically windy.

Engine-generator systems are best used with an ac generator feeding a rectifier for dc output and control. Maintenance on dc generators has proved to be high in the past, resulting in many outages during the year. Although to a lesser degree than the dc generator, the ac generator also requires maintenance and regular inspections.

Pulse rectifiers provide a high-voltage dc pulse of short duration. The frequency of the pulse may be from 1000 to 5000 Hz, but the duty cycle is normally set in the range of 10 to 15%. Bich and Bauman (Ref 24) reported that total current requirements can be reduced to 50% or less using a pulse rectifier instead of a conventional rectifier, and more current will reach the lower portions of the casing. The improved performance is attributed to the waveform. However, Dabkowski (Ref 25) showed mathematically that the pulse from the rectifiers would attenuate to 0 at 500 to 1000 m (1640 to 3280 ft) from the casing top, suggesting that any improved performance is not due to the pulse. It has been the author's experience that cathodic protection with pulse rectifiers can be achieved down to 80% of the comparable current to a conventional rectifier, but not the significant reduction suggested by Bick and Bauman. Further work needs to be completed to validate any of these claims. The digital instrumentation measuring the pulse rectifier output is another factor in this comparison, as errors can be realized depending on the sampling rate. A major disadvantage of pulse rectifiers is noise interference, especially on communication equipment that may be servicing the well. This can be reduced by locating the pulse rectifier away from the electrical/communication building, not paralleling electrical cables, and using deep anodes.

Regardless of the power source, one negative cable must be connected to the well casing while a second negative cable is often run to the isolated surface facilities to assist in interference mitigation.

The anode bed design and location is largely dictated by the soil layer resistivity and the location of surface facilities and pipelines. If uniform low-resistivity soil conditions exist at a surface location that is sufficiently remote from the casing and other structures, a shallow anode type of anode bed can be used. Where high-resistivity conditions exist at the surface but more suitable strata exist underneath, a deep anode bed would be preferred. The latter anode bed will also tend to reduce interference with surface facilities, as the major portion of the anode gradient exists below pipeline and foundation depth. It must be noted that the same spacing between the casing and anode must be maintained whichever type of anode bed is used, as going deeper does not change the distance between the structures.

The anode bed should be located at an equal or greater distance than the temporary anode bed to the casing that was used during the current requirement test. However, a minimum spacing of 30 m (100 ft) from the well for shallow wells but preferably greater than 50 m (165 ft) should be maintained. The separation between anodes and structures not receiving current will vary depending on the voltage gradients in the soil but should be 100 m (300 ft) or more. Otherwise, provision for interference control discussed below must be considered.

Direct-Current Stray-Current Interference

Stray current can be defined as current in an unintended path. Many sources of current use the earth as part of their electrical circuit. Conductors in the earth such as well casings and pipelines provide opportune parallel paths for current intended for another purpose.

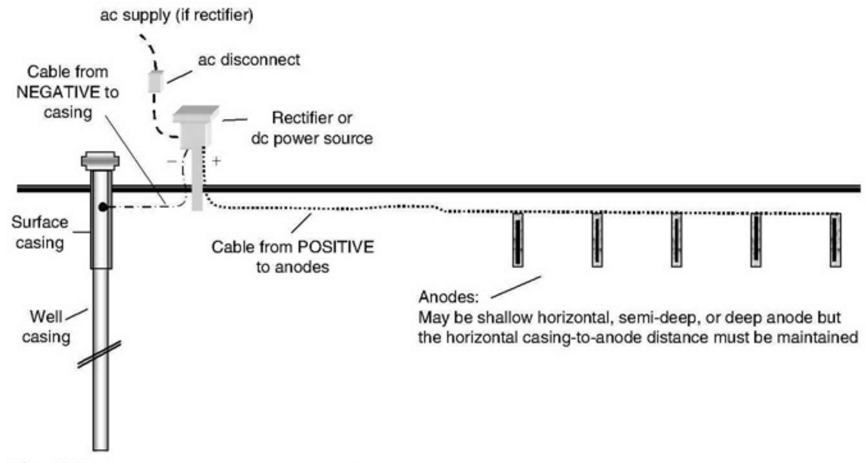


Fig. 13 Typical cathodic protection installation

The area of stray-current pickup is similar to cathodic protection and not of concern. However, the manner by which that current returns to its original source is of concern. Should that current *leave* the casing to enter the soil, the casing in that location is anodic and accelerated corrosion occurs.

Stray-Current Pickup. A stray current may be picked up at the surface, in which case the current must discharge into the soil downhole to return to its source. Alternately, a current discharge near the surface to either facilities near the wellhead or to the surface casing may occur, in which case there will have to be a current pickup downhole. Both cases (Fig. 14) are a cause for concern as there is a current discharge occurring at some point along the casing.

Since an electronegative shift in casing-to-soil potentials occurs with the application of cathodic protection, a stray-current pickup at a lower depth with a discharge near the surface can be detected by an electropositive shift in casing-to-electrolyte potentials, with the reference electrode located near the wellhead, when the foreign dc power source (s) is energized. Conversely, a current pickup at the surface will be detected by an electronegative shift in potentials when the foreign current source comes on. The area of current discharge will then be at a point lower on the casing, and its location would have to be defined by a CPP log, or similar.

Stray-current pickup on pipeline systems away from the well casing can result in a stray-current discharge from the well casing if the two structures are continuous. In these cases, a current pickup is normally close to the anode bed while the discharge is near the wellhead. However, it is conceivable that the current pickup and discharge points can develop at other points, especially if varying coating qualities or vastly differing resistivities exist along the pipeline or casing.

Stray-Current Sources. The stray current may come from a relatively steady-state source such as another cathodic protection system (Ref 21–23) or a high-voltage dc power line ground, or it may come from a dynamic source such as a transit system, welding machines, dc mine equipment or, finally, from telluric current that is a natural source of stray current (Ref 26).

Interference Control. Interference can be controlled by:

- Providing a metallic return path for the stray current
- Moving the offending anode bed or ground
- Adjusting the current distribution in the foreign system
- Installing and/or adjusting a cathodic protection system on the well casing to counter the stray-current effects
- Using common cathodic protection systems (Ref 21)
- Balancing wellhead potentials

A well casing cathodic protection system can also cause interference on surface facilities or pipelines. In this case, a second negative circuit is often provided in the rectifier to both control interference and assist with the protection of the surface facilities or pipelines.

Orton et al. (Ref 20) reported that a coated casing reduced the cathodic protection current requirement to 10% of a bare well casing. This in turn will reduce the tendency for mutual interference of nearby casings.

Isolation of Well Casings

The purpose of isolating a well casing from surface facilities is twofold: (a) it eliminates a macrocorrosion cell between the casing and the surface facilities, and (b) it allows the cathodic protection current distribution to be controlled between the well casing and the surface facilities.

In addition, an isolating feature allows the current impressed on the well casing to be directly measured in the connecting cable. If not isolated, a means of measuring the current return from the casing itself must be established, such as a clamp-on ammeter around the wellhead at the surface, to confirm that the "current" criterion is being met.

From a cathodic protection standpoint, the preferred location for this isolation is at the wellhead. However, some operators locate it a distance away in the event of a fire at the well so that the isolating material does not melt and complicate firefighting procedures. All tubing conduits and pipe supports must also be isolated if they are bypassing the isolating feature.

If the product from the well contains a large amount of brine, there is a risk of "internal" interference. This occurs where current picked up on the opposite side of the isolation uses the brine as a path around the isolation. In such a case, corrosion is seen only on one side of the isolating feature (Fig. 15A).

A "long-path" isolation, which consists of an isolating feature and an internally coated or lined section of pipe (Fig. 15B), can be used to reduce the internal interference. If this is not effective in controlling internal interference, the isolating feature should be omitted.

Commissioning and Monitoring

Inspection. A cathodic protection system must operate continuously to be effective. Regular inspection of the dc power supply to ensure that the required current is being provided in all circuits is necessary throughout the year. A more detailed inspection should be conducted annually. A description of the cathodic protection system operation and the records is given in NACE RP0186 (Ref 4).

Inspections of the dc power source should only be made by persons who are trained and qualified to work on electrical equipment. The use of strict safety practices including lockout/tagout procedures is especially necessary when working

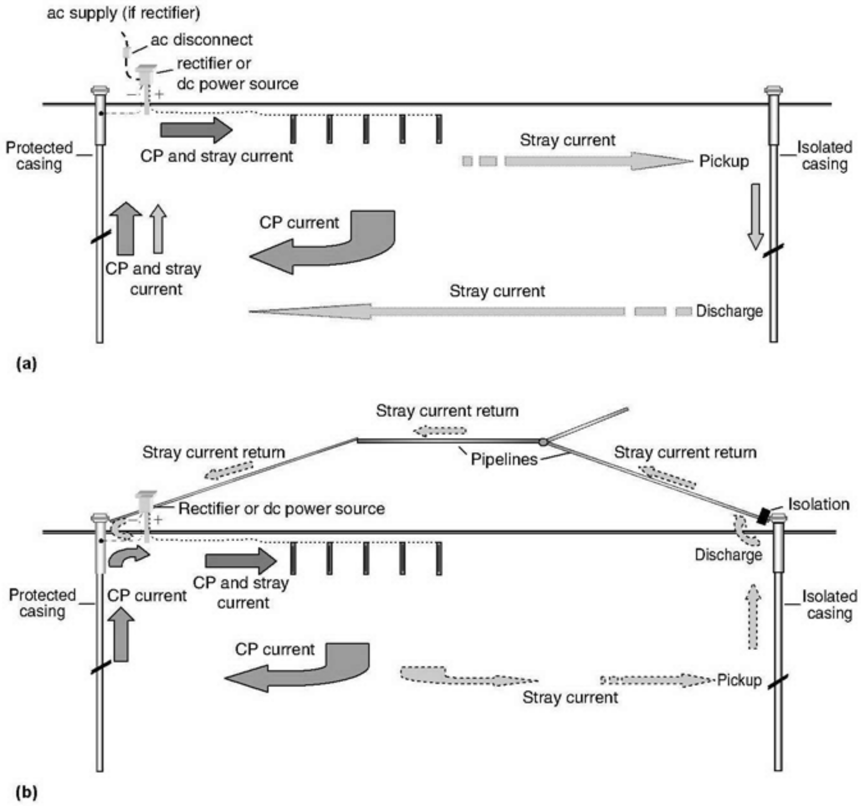
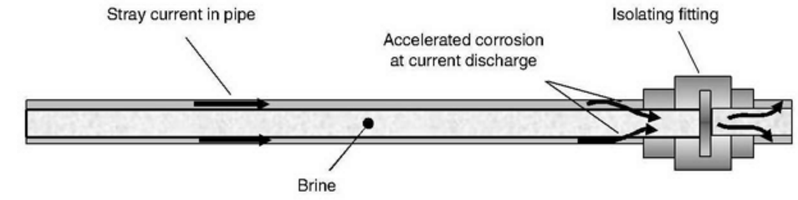
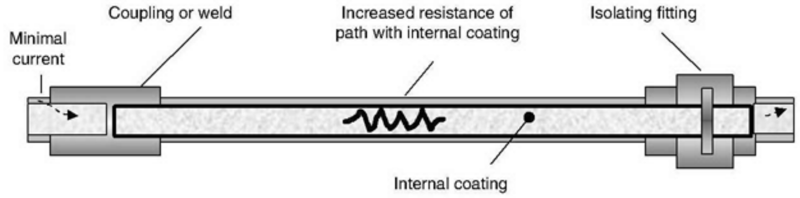


Fig. 14 Direct-current stray-current interference. (a) Stray-current pickup near top with discharge downhole. (b) Stray-current pickup downhole with discharge near top. CP, cathodic protection



(a) Internal stray current interference through brine path across isolating fitting



(b) "Long-path" increases resistance across isolating fitting to reduce stray current

Fig. 15 (a) Internal interference across an isolating feature and (b) reduced by a long-path isolating feature on the rectifiers. The routine readings should include these measurements:

- dc power source current output
- dc power source voltage output
- dc power source adjustment setting (tap setting if applicable)
- dc current in secondary circuits
- dc interference control devices
- Power meter or fuel supply where applicable

The annual inspection should include:

- Completion inspection of the dc power source
  - (a) Calibration of the dc power source current output
  - (b) Calibration of the dc power source voltage output
  - (c) Direct-current power source adjustment setting (tap setting if applicable)
  - (d) Calibration of the dc in secondary circuits
- Measurement of the well-to-electrolyte potential
- Measurement of the surface facility structure-to-electrolyte potentials
- Testing the effectiveness of wellhead isolation, if applicable
- Measurement of the current returning from the casing at the wellhead with a clamp-on ammeter, if there is no isolation
- Confirmation that dc interference control devices are providing the necessary control
- Specialty tests applicable to the specific cathodic protection installation

Corrosion-control records are of paramount importance in an effective corrosion-control program. They will be used to establish a need for enhancements of the corrosion-control program and to ensure that the existing corrosion-control equipment is operating. The records should include but not be limited to:

Historical:

- Well completion data including casing sizes and lengths, cementing information and well total depth
- Corrosion leaks identifying well, depth, internal or external, date of failure compared to date of drilling and/or workover (s)
- Inspections of casing failures and corrosion products
- Electrical well logs (wall thickness, CPP identifying corrosion, and resistivity)
- Coating type and thickness, if applicable
- Drawing of well casing strings and lease equipment and piping
- System map of the field
- Location and type of electrical isolation

Cathodic Protection:

- Current requirement tests (CPP log(s), E log I test(s), and soil resistivity in layers near the surface)
- Design and drawings of cathodic protection installation detailing:
  - (a) Well location
  - (b) Piping and lease facilities
  - (c) dc power source type, rating and location
  - (d) Description of energy supply for dc power source
  - (e) Cable type(s) and location
  - (f) Cable to wellhead and piping connections
  - (g) Anode beds type and location
  - (h) Anode material type, spacing and depth
  - (i) Backfill type and amount
  - (j) Junction box and test station details

Interference Control:

- Records of all tests pertaining to interference on the well from other systems and on other systems from the well cathodic protection system
- List of owners and contacts involved in the interference control program
- Description of the method of interference mitigation, including control devices and target values of current and potential
- If bonds or directional devices are used, the location, type, resistance value, current, and current direction

All records must show the date, the name of the inspector or tester and, if different, the names of those who make recommendations. Any changes in current output must be correlated with other measurements taken.

Cathodic Protection Summary

For new wells, the use of an abrasion-resistant underground coating on those portions of the casing exposed to the strata should be considered as part of a corrosion-control program, as this will greatly reduce the amount of cathodic protection current required for protection. If coating is used, though, a cathodic protection system must be planned and implemented immediately, as a coating alone will concentrate corrosion at the coating holidays.

Prior to applying cathodic protection, a review of the existing well historical data should be made to assess the possibility of corrosion that will cause premature and costly failure repairs. Electrical logging tools, which are reasonably accurate, are available to assess the metal loss that has occurred and to predict the possibility of future corrosion.

Provided the proper amount of current is applied and maintained, cathodic protection of well casings has proved to be an effective means of minimizing corrosion on the casing. The cathodic protection current can be determined by various means; however, two of the more reliable results have to date been with CPP type of testing and polarization tests (E log I). The former test is difficult to perform in that the well has to be taken out of service, which usually results in few candidate wells in an older field. Also it may be necessary to perform multiple tests, with time provided between tests to allow for steady-state conditions to be achieved, which adds to the cost of the test. The E log I test must be correctly analyzed to identify the Tafel point on the profile; otherwise, a current less than that necessary may be defined as the criterion. Another option is to use a mathematical model; however, the validity of this option should be confirmed by tests at the start of the cathodic protection program.

Another factor in designing well casing cathodic protection systems is to remember that the amount of cathodic protection current required is also dependent on the spacing between the casing and the anodes, up to a certain distance, and that distance must be defined for each well. If the anodes are placed within that distance, the current requirement increases. Once a cathodic protection current requirement is established for a temporary anode bed, the same distance or greater should be used in the final cathodic protection design.

Isolation of the casing from other facilities is another important cathodic protection system design consideration. Isolating the well casing from surface facilities is preferred to eliminate the macrocorrosion cell between the casing and these structures without cathodic protection and to provide a means for controlling and measuring the cathodic protection current to the casing. However, if the product inside the isolation contains a large quantity of brine, either a "long-path" isolating fitting should be used to minimize internal interference, or in some cases the isolator may have to be removed entirely.

Generally, cathodic protection systems using conventional rectifiers are designed and installed for the protection of the casings, although pulse rectifiers have also been used. Particular attention has to be placed on the size and the location of the anode bed in order to achieve the required current output for the desired life of the anode bed.

Stray current must also be considered during the cathodic protection system design. Stray-current interference from other dc power sources will accelerate corrosion on the casing if it encourages a current discharge into the formation. A common source is from other cathodic protection systems in the same oil/gas field, but can also come from other sources not related to the oil/gas field. Several methods have been outlined to either avoid or minimize these interference effects. Any stray-current control device must be continuously inspected and maintained.

Detailed records must be kept on the history of the well, electrical logs, casing repairs, and on the operation of the corrosion-control equipment. These records must be able to stand up to future legal scrutiny.

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NACE SP0186-2007
(formerly RP0186-2001)
Item No. 21031

Standard Practice

Application of Cathodic Protection for External Surfaces of Steel Well Casings

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Reaffirmed 2007-03-10
Reaffirmed 2001-09-20
Reaffirmed September 1984
Approved March 1986
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ISBN:1-57590-134-X
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Foreword

Oil and gas wells represent a large capital investment. It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves.

This NACE International standard practice identifies procedures to determine the need for cathodic protection (CP) and the current requirements to achieve CP of well casings associated with oil and gas production and gas storage. It also outlines practices for the design and installation of CP systems and for their operation and maintenance. The purpose of this standard is to ensure more effective prevention of corrosion of well casings by making available reliable information about CP as it relates to well casings. This standard is intended for use by corrosion engineers in oil and gas production, especially those concerned with the CP of steel well casings.

This standard was originally prepared in 1986 by Unit Committee T-1E on Cathodic Protection and Task Group (TG) T-1J-2, a component of Unit Committee T-1J on Storage Wells. It was reaffirmed in 1994 by Unit Committee T-1E, and in 2001 and 2007 by Specific Technology Group (STG) 35 on Pipelines, Tanks, and Well Casings. The STG membership consists of representatives from oil and gas producing and storage companies, equipment manufacturers, consulting firms, and CP service companies. Included in the membership are persons involved in design, consulting, research, construction, maintenance, and manufacturing and supply of materials, all of whom are concerned with the establishment and maintenance of cathodic protection systems used with well casings. This standard is issued by NACE under the auspices of STG 35.

In NACE standards, the terms *shall, must, should,* and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. The term *should* is used to state something considered good and is recommended but is not mandatory. The term *may* is used to state something considered optional.

NACE International

Standard Practice

Application of Cathodic Protection for External Surfaces of Steel Well Casings

Contents

Section 1: General

1.1 This standard presents acknowledged procedures for the control of external corrosion of steel well casings by applying CP. This standard is intended to be a guide for establishing minimum requirements for corrosion control when CP is practical and cost-effective.

1.2 This standard does not designate practices for specific situations. The complexity of some casing spacing, subsurface proximity to other casings, and environmental conditions preclude standardizing the application of CP. Deviation from this standard may be warranted in specific situations, provided those in responsible charge can demonstrate that the objectives expressed in this standard have been achieved.

1.3 This standard does not include corrosion control methods based on chemical control of the environment.

1.4 This standard applies only to well casing exteriors and not to internal corrosion, or to corrosion of other surface or downhole equipment.

1.5 The provisions of this standard should be applied under the direction of competent persons knowledgeable in the physical sciences, principles of engineering, and mathematics. They may have acquired knowledge by professional education and related practical experience and should be qualified to practice corrosion control for well casings by the use of CP. Such persons may be registered professional engineers recognized as being qualified as corrosion specialists in the appropriate fields of corrosion control by NACE International. Their professional activities should include suitable experience in well casing corrosion control practices.

Section 2: Definitions[1]

Alternating Current (AC): Current whose direction changes with time.

Ampere: Unit of current that is one coulomb per second.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

Backfill: Material placed in a hole to fill the space around the anodes, vent pipe, and buried components of a cathodic protection system.

Casing Potential Profile: Voltage (IR) drop and current direction versus casing depth is plotted. Amount of current is determined from the IR drop and casing resistance. (See nonmandatory Appendix A.)

Casing-to-Electrolyte: See *Structure-to-Electrolyte Potential.*

Casing-to-Reference Electrode: See *Structure-to-Electrolyte Potential.*

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic Protection: A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Cement: Cement slurry fills the space between the casing and the sides of the wellbore to a predetermined height above the bottom of the well.

Continuity Bond: A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Counterpoise: A conductor or system of conductors arranged beneath a power line, located on, above, or most frequently, below the surface of the earth and connected to the footings of the towers or poles supporting the power line.

Coupling (or Collar): Well casing joint connector.

Current Density: The current to or from a unit area of an electrode surface.

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(1) Definitions in this section are those presented in the *NACE Glossary of Corrosion-Related Terms* and those that reflect the common usage among practicing corrosion control personnel. In many cases, in the interest of brevity and practicality, the strict scientific definitions are abbreviated or paraphrased.

Deep Groundbed: One or more anodes installed vertically at a nominal depth of 15 m (50 ft) or more below the earth's surface in a drilled hole for the purpose of supplying cathodic protection.

Dielectric Coating: A coating that does not conduct electricity.

Direct Current (DC): Current whose direction does not change with time.

Drainage: Conduction of electric current from an underground or submerged metallic structure by means of a metallic conductor.

E-log-I: A test that indicates the cathodic protection current required by a slope change on the cathodic polarization diagram. (Refer to nonmandatory Appendix B.)

Electrical Isolation: The condition of being electrically separated from other metallic structures or the environment.

Electric Log: A survey taken in the open borehole of a well to determine the lateral formation resistivity.

Electrolyte: A chemical substance containing ions that migrate in an electric field. For the purposes of this standard, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic structure, including the moisture and other chemicals contained therein.

Electroosmotic Effect: The effects of the movements in an electric field of liquid with respect to colloidal particles immobilized in a porous diaphragm or a single capillary tube.

Fault Current: A current that flows from one conductor to ground or to another conductor due to an abnormal connection (including an arc) between the two. A fault current flowing to the ground may be called a ground fault current.

Field: A group of wells in close physical proximity, usually considered a unit when applying cathodic protection. It may be an oil or natural gas production field or a natural gas storage field.

Foreign Structure: Any metallic structure that is not intended as a part of a system under cathodic protection.

Galvanic Anode: A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of cathodic protection.

Gamma Ray Neutron Log: Gamma ray is a measurement of the natural radioactivity of a formation. Neutron log is used for delineation of porous formations. Data are used to identify the formations in the earth.

Groundbed: One or more anodes installed below the earth's surface for the purpose of supplying cathodic protection.

Impressed Current: An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

Instant-Off Potential: The polarized half-cell potential of an electrode taken immediately after the cathodic protection current is stopped, which closely approximates the potential without IR drop (i.e., the polarized potential) when the current was on.

Interference Bond: An intentional metallic connection, between metallic systems in contact with a common electrolyte, designed to control electrical current interchange between the systems.

Intermediate Casing: A string of casing set to protect a section of hole and to allow drilling to continue to a greater depth. Also called protection casing string.

IR Drop: The voltage across a resistance in accordance with Ohm's law.

Isolation: See *Electrical Isolation*.

Lithology: Rock formations traversed by well casing.

Long-Line Current: Current through the earth between an anodic and a cathodic area that returns along an underground metallic structure.

Mutual Interference: An electrical DC interference on a well originating from within the cathodic protection system of several wells and structures, such as several DC power sources for a group of wells.

Native State Potential: The potential with zero groundbed current.

Negative Return: A point of connection between the cathodic protection negative cable and the protected structure.

Ohm: A resistance that passes one ampere of current when a one-volt potential is applied.

Packaged Anode: An anode that, when supplied, is already surrounded by a selected conductive backfill material.

Photovoltaic: Generation of an electromotive force when radiant energy falls on the boundary between two dissimilar materials.

Pipe-to-Soil Potential: See *Structure-to-Electrolyte Potential*.

Polarization: The change from the open-circuit potential as a result of current across the electrode/electrolyte interface. In this standard, polarization is considered to be the change of potential of a metal surface resulting from current to or from an electrolyte.

Potential Profile Log: See *Casing Potential Profile.*

Production Casing: Casing that extends through the surface and intermediate casings, sometimes only to the tip of the zone but almost always through the producing or storing zone.

Rectifier: A device to convert AC power to DC power.

Reference Electrode: An electrode whose open-circuit potential is constant under similar conditions of measurement, which is used for measuring the relative potentials of other electrodes.

Resistivity: (1) The resistance per unit length of a substance with uniform cross section. (2) A measure of the ability of an electrolyte (e.g., soil) to resist the flow of electric charge (e.g., cathodic protection current). Resistivity data are used to design a groundbed for a cathodic protection system.

Right-of-Way: Right of passage, as over another's property.

Self-Interference: See *Mutual Interference.*

Shunt: A precise resistor with known resistance in an electrical circuit used to measure a voltage (IR) drop, which is used to calculate the amount of current in amperes.

Soil Resistivity: A measure of the ability of a soil or formation to conduct electricity expressed in units of ohm-centimeters or ohm-meters. Data are used to design a groundbed for a cathodic protection system.

Structure-to-Electrolyte Potential: The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Structure-to-Structure Potential: The potential difference between metallic structures, or sections of the same structure, in a common electrolyte.

Surface Casing: A casing string extending from the surface to a depth great enough to keep surface waters and loose earth from entering the well.

Surface Groundbed: One or more anodes installed below the earth's surface for the purpose of supplying cathodic protection less than 15 m (50 ft) in depth for the anodes.

Tafel Plot, Tafel Diagram, Tafel Line: A plot of the relationship between the change in potential (E) and the logarithm of the current density (log *i*) of an electrode when it is polarized in both the anodic and cathodic directions from its open-circuit potential.

Tafel Segment: That portion of the Tafel plot that appears as a straight line when current is plotted on the logarithmic scale and potential change is plotted on the linear scale. The beginning of the Tafel segment is that point on the curve at which the current-potential relationship follows the straight line with increasing current increments and deviates from the straight line with decreasing current increments.

Tafel Slope: The slope of the straight-line portion of the E log *i* curve on a Tafel plot. (The straight-line portion usually occurs at more than 50 mV from the open-circuit potential.)

Test Wire: An insulated wire attached to a structure (usually buried) such as a pipeline and brought to a terminal convenient for making electrical tests to evaluate cathodic protection.

Tubing: A pipe inside the production casing through which oil is pumped, or liquid is removed from the natural gas storage zone.

Union (Isolating): See *Electrical Isolation.*

Voltage: An electromotive force, or a difference in electrode potentials expressed in volts.

Well: A steel-cased hole associated with the production and storage of oil or gas.

Wellbore *(also called bore hole)*: A hole drilled into the earth for the installation of a deep groundbed system.

Wellhead: Valves and other aboveground fittings electrically connected to the production, surface, and intermediate casings. May be called a "christmas tree" when referring to oil and natural gas production and storage wells.

Well Casing: See *Production Casing*, *Intermediate Casing*, and *Surface Casing.*

Section 3: Determination of Need for CP

3.1 Introduction

3.1.1 The purpose of this section is to indicate those factors that should be considered in determining whether a well casing requires CP.

3.1.2 Metallic structures in contact with soil or submerged under water are subject to corrosion. Adequate procedures should be adopted to ensure that corrosion is not affecting safe and economical operation of well casings.

3.2 The decisions governing the need for CP of well casings shall be based on data obtained from corrosion surveys, operating records, prior tests with similar systems in similar environments, and on a study of design specifications and engineering, operating, and economic requirements.

3.2.1 The usual procedures for predicting the probability and rate of corrosion of a particular metallic casing system are as follows:

(a) The corrosion history of the well casing in question or of other systems of the same material in the same general area or in similar environments should be studied. The history should include cumulative leak frequency and downhole data obtained from workover (reconditioning) records.

(b) The environment surrounding a well casing should be studied. Once the nature of the environment has been determined, the probable corrosiveness can be estimated by referring to actual corrosion experience on similar well casings in similar environmental conditions. It should be remembered that formation water changes caused by production or injection methods may be contributing factors. One source of environmental data is the formation resistivity logs run on wells being investigated and on surrounding wells.

(c) The casing should be mechanically or electrically inspected for evidence of corrosion. The condition of the casing system should be carefully determined and recorded. (See nonmandatory Appendix C.)

(d) The casing should be inspected to determine whether there are any anodic areas. A well casing potential profile tool is commonly used for these investigations. (See nonmandatory Appendix A.)

(e) Maintenance records detailing leak locations and wall thickness surveys, which can be used as a guide for locating areas of maximum corrosion, should be reviewed.

(f) Statistical treatments of available leak data should be considered.

(g) The results of pressure testing should be reviewed; under certain conditions, this may help determine whether corrosion has occurred.

(h) When the well casing is pulled, it should be visually inspected.

(i) Close communication should be maintained with those responsible for the workover of a well.

3.2.2 Environmental and physical factors governing the need for CP are as follows:

3.2.2.1 The nature or constituents of the product being produced or stored.

3.2.2.2 Location of the well casing system in a sparsely or densely populated area and the frequency of visits by personnel.

3.2.2.3 Location of the well casing system as related to other facilities.

3.2.2.4 Influence of DC sources foreign to the system.

3.2.2.5 The introduction of secondary or tertiary recovery systems, which can sometimes increase corrosion rates on the backside of a well casing.

3.2.3 Economic factors

3.2.3.1 Costs of maintaining the well casing in service for its expected life may include repairing corrosion leaks, reconditioning, or replacing all or portions of the system.

3.2.3.2 In addition to the direct costs that result from corrosion, contingent costs may be incurred. The more common types of contingent costs are:

(a) Public liability claims.

(b) Property damage claims.

(c) Damage to natural facilities, such as municipal or irrigation water supplies, forests, parks, and scenic areas.

(d) Cost of cleanup of product lost to surroundings.

(e) Cost of individual casing workover(s) as related to corrosion leak(s).

(f) Plant shutdown and start-up costs.

(g) Loss of deliverability because of possible permanent formation damage caused by casing leak(s).

(h) Cost of lost product.

(i) Loss of revenue through interruption of service.

(j) Loss of contracts or good will through interruption of service.

(k) Loss of reclamation or salvage value of well casing.

(l) Loss of well casing, rendering well unusable for production or injection purposes.

3.2.3.3 The usual costs for protecting well casings are the costs of installing and operating CP. Other corrosion control costs may include:

(a) Inhibitors and bactericides used in drilling fluids.

(b) Corrosion-resistant materials.

(c) Cement for zones known to be corrosive.

(d) Electrical isolation to limit possible foreign current discharge from casings and to ensure that CP currents are applied to the well casing.

(e) Dielectric coating on the outer surface of casing.

Section 4: Criterion for CP and Current Requirements

4.1 Introduction

4.1.1 The determination of design current requirements depends, in part, on prior experience with similar structures or environments in which the method has been used successfully. The first-time user is strongly urged to consult a person experienced in well casing CP before finalizing a design.

4.1.2 Certain methods have been developed through laboratory experiment, or have been derived empirically by evaluating data from successful CP systems. These methods are presented in Paragraph 4.3 and can be used to assist with the design process; they are not intended to be a comprehensive or limiting list.

4.2 Criterion for CP

4.2.1 The CP current applied to the well casing shall be considered adequate when measurements indicate that a net flow of current to the casing has eliminated all anodic areas.

4.3 Methods of Determining Design Current Requirements

4.3.1 A profile tool is a device used to measure a voltage (IR) drop across a portion of well casing in service by electrically isolating two sets of contacts from each other. The voltage readings are used to indicate the magnitude and direction of the current flow in the casing. Details of the test method and interpretation of the data are given in Appendix A.

4.3.2 Average current density (mA/m^2) may be used to calculate the quantity of CP current required to prevent external corrosion. The current density used should be dictated by the downhole completion practice and formations (e.g., cementing practices, formation resistivities, water salinity, etc.) encountered in a given well. Current densities usually vary from 10 to 200 mA/m^2.

4.3.3 Mathematical modeling may also be used to determine design current requirements. The effect of applied CP current downhole can be calculated from electrical measurements at the wellhead. The applied voltage and current distribution can be calculated as a function of well depth. Usually, a downhole potential criterion is established as the accepted indication of protection. Several calculation methods are available, and others are being developed.

4.3.3.1 One method of mathematical modeling uses a modified attenuation equation. The native state potential is measured and recorded. It also requires well casing data and current drain measurements made after polarization of the well.

4.3.3.2 Another method uses formation resistivity data to establish a potential attenuation curve for a casing to which CP has been applied.

4.3.3.3 A third method models the well casing by a computerized equivalent electrical circuit incorporating resistivity profiles, nonlinear polarization characteristics, and the well casing data.

4.3.4 E-log-I method

4.3.4.1 The principle behind the E-log-I method is that when current is impressed through the earth onto a metallic well casing, the potential between the well casing and reference electrode is shifted.

The potential shift for a given current level depends on the following factors:

(a) The length of time the current is applied.

(b) Current density, which is affected by factors such as well depth, casing sizes, and cement.

(c) Properties of the electrolyte.

4.3.4.2 As increasing levels of current are impressed, polarization begins on the surface of the casing. The E-log-I data are plotted to enable selection of a current level at which polarization begins. (Details of the test method and interpretation of the data are given in Appendix B.)

4.4 Methods of Evaluating Effectiveness

4.4.1 A combination of procedures is always advised for evaluating the effectiveness of CP.

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Section 5: Design of CP Systems for Well Casings

5.1 Introduction

5.1.1 This section presents recommended procedures for designing CP systems that effectively control corrosion of well casings in contact with the earth. The design should satisfy the criterion in Section 4 and be reliable for the intended operating life of the system.

5.1.2 CP for pipelines is considered separately from well protection when applicable.

5.2 Objectives of CP System Design

5.2.1 Enable application of sufficient protective current to the well casings to meet the criterion for CP.

5.2.2 Minimize the stray current to foreign underground structures. (See Section 7.)

5.2.3 Design a groundbed with a lifetime that is commensurate with the required life of the protected structure.

5.2.4 Provide for periodic maintenance of the groundbed.

5.2.5 Provide a power source and groundbed with sufficient capacity to include connecting pipelines and other structures as required.

5.3 Considerations in the Design of CP Systems

5.3.1 CP applied to the well casings and the connecting pipelines and structures may be a source of mutual interference. (Refer to Section 7.)

5.3.2 Electrical grounding procedure requirements should be considered in the CP design.

5.3.3 In designing a CP system for well casings, the following should be considered:

5.3.3.1 Availability of AC power should be determined.

5.3.3.2 The proposed installation site should be investigated for any hazardous conditions.

5.3.3.3 The AC power source for the CP rectifier should be a suitable distance from the well structure to ensure a safe working area.

5.3.3.4 Materials and installation practices that conform to applicable codes (e.g., National Electrical Manufacturers Association [NEMA](2) Standards, National Electrical Code [NEC],(3) and practices of NACE International) should be specified.

5.3.3.5 The CP system should be selected and designed for optimum economies of installation, maintenance, and operation.

5.3.3.6 Materials and installation practices that ensure safe and dependable operation throughout the intended service life of the CP system should be specified.

5.3.3.7 A system for optimum currents should be selected. Excessive current can be detrimental to buried or submerged metallic structures.

5.3.3.8 The current requirement data for pipelines connected to wells should be studied so that the groundbeds may be placed in the proper locations. This allows appropriate distribution of current to wells and pipelines.

5.3.3.9 Electrical interference from foreign sources should be investigated and the results included as a design consideration. (See Section 7.)

5.4 Considerations Influencing Location of Anodes

5.4.1 The anode that will be closest to a well should be placed at a distance determined by testing or accepted empirical means.

5.4.2 Plans for long- and short-term additions or changes in buried physical structures.

5.4.3 Location of pipelines connected to wells.

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(2) National Electrical Manufacturers Association (NEMA), 1300 North 17th Street, Suite 1847, Rosslyn, VA 22209.

(3) National Electrical Code (NEC), National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02269.

5.4.4 Pipelines used as a negative return and those electrically isolated.

5.4.5 Soil resistivity.

5.4.6 Use of surface or deep vertical type of groundbed.

5.4.7 Location of foreign structures.

5.4.8 Placement where likelihood of physical disturbance or damage is minimal.

5.5 Types of CP Systems for Well Casings

5.5.1 Impressed current system

5.5.1.1 Surface groundbed

5.5.1.2 Deep groundbed

5.5.2 Galvanic anode system

5.6 Considerations in the Selection of the Type of CP System

5.6.1 Current requirements

5.6.1.1 The total casing surface area to receive CP, including surface casings and that portion of intermediate and production casing that is to receive protection.

5.6.2 Soil resistivity

5.6.2.1 Resistivity and installation space availability influence the choice of a surface or deep groundbed installation. High-resistivity formations that restrict the flow of current to the casing may necessitate placement of anodes below such formations.

5.6.2.1.1 Resistivity to a 15-m (50-ft) depth for a surface groundbed may be determined by surface measurements or experience.

5.6.2.1.2 Resistivity for depths greater than 15 m (50 ft) for a deep groundbed may be determined by surface measurement, formation resistivity log, or experience.

5.6.3 Future drilling of wells in the area of CP influence.

5.6.4 Future development of the right-of-way area and extensions to the pipeline system connected to wells jointly protected by the same power source and groundbed.

5.6.5 The cost of installation, operation, and maintenance.

5.6.6 Physical space available and condition of land surface for ease of facility installation, ingress, and egress.

5.6.7 Proximity of foreign structures.

5.6.8 Ability to procure easement.

5.6.9 Interference effect.

5.6.10 Power source availability.

5.7 Factors Determining Anode Current Output, Operating Life, and Efficiency

5.7.1 Various anode materials have different rates of deterioration when discharging a given current density from the anode surface in a specific environment. For a given current output, the anode life depends on the anode and backfill materials and the number of anodes in the CP system. Anode performance data may be used to calculate the probable deterioration rate.

5.7.2 The resistance to electrolyte of the anode system may be calculated from available data. Formulas and graphs relating to these factors are available.

5.7.3 The use of a special backfill material with impressed current anodes lengthens their useful life and reduces the effective anode-to-earth electrical resistance. The most common backfill materials are metallurgical coke, calcined petroleum coke, and natural or manufactured graphite.

5.7.4 Entrapment of gas generated by the anodic reaction can impair the ability of the impressed current groundbed to deliver the required current. Suitable provision should be made for venting the anodes, particularly in a deep groundbed. Increasing the number of anodes may reduce gas blockage by reducing current discharge from each anode.

5.7.5 Electroosmotic effects could impair the ability of the impressed current groundbed to deliver the required current. Suitable provisions should be made to ensure adequate moisture around the anodes. Increasing the number of impressed current anodes may reduce electroosmotic effects.

5.7.6 Special applications such as deep groundbeds require careful selection of cables and wires. Refer to NACE SP0572.[1]

5.8 Impressed Current System Design Considerations

5.8.1 Groundbed location and total current required should be determined.

5.8.2 A deep groundbed may be used when lithology prevents equitable distribution of current to the total depth of the well casing. Placing anodes in relatively low-resistivity shallow formations compared with deeper formations may concentrate excessive current on upper portions of the well casing and deprive the deeper portions of sufficient current. Refer to NACE SP0572.

5.8.3 Placement of groundbeds too close to a well casing may prevent flow of sufficient current to a lower depth. Increasing total current may create interference with other wells and structures.

5.8.4 The performance of vertically or horizontally placed anodes can be affected by their spacing. In a soil of a given resistivity, the output of an impressed current groundbed may be improved by increasing the space between anodes, assuming the additional cable resistance is considered.

5.8.5 DC power sources that can be used:

5.8.5.1 Rectifier units to convert AC to DC power.

5.8.5.2 Thermoelectric generators.

5.8.5.3 Photovoltaic power systems.

5.8.5.4 Wind- or power-driven generators or alternators with rectification.

5.9 Galvanic Anode System Design Considerations

5.9.1 Galvanic anodes have limited use for CP of well casings.

5.10 Design Factors in Applying CP to More than One Well

5.10.1 Several wells may be cathodically protected as a group. When applying CP, the wells should be treated as a unit, along with associated pipelines or structures, using one or more power sources and groundbeds. Care must be taken to ensure adequate current distribution throughout the length of each well.

5.10.1.1 Well casings in a group may vary in length.

5.10.1.2 Well spacing may vary.

5.10.1.3 Intermediate casings may vary in length.

5.10.1.4 Wells with identical completion procedures and equal lengths of casing may have different current requirements.

5.10.2 The current requirements and electrical resistances of any connecting pipeline, when used as a negative return to a rectifier, can limit the amount of current reaching the well casings.

5.10.3 If detrimental electrical interference is encountered, each CP system must be designed to counteract the effects.

5.10.4 CP design varies regarding the physical field parameters. The most effective design considers:

5.10.4.1 Total amount of current required for casings and other structures.

5.10.4.2 Soil resistivity for installation of anodes.

5.10.4.3 Location of well casing with respect to pipelines and other structures.

5.10.4.4 The individual current demand of each well.

5.10.5 Typical CP design options

5.10.5.1 One DC power source and one groundbed for one or several wells.

5.10.5.2 One DC power source and more than one groundbed for several wells.

5.10.5.3 More than one DC power source and one groundbed for several wells.

5.10.6 Perimeter or isolated wells may require a separate CP system.

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Section 6: Installation of CP Systems

6.1 Introduction

6.1.1 This section presents recommended procedures for installation of CP systems that achieve protection of the well casing structures when design considerations recommended in Section 5 and Appendix D have been followed.

6.2 Construction Specifications

6.2.1 All construction work performed on CP systems shall be done in accordance with construction drawings and specifications. The construction specifications shall be in accordance with recommended practices in Section 5 and nonmandatory Appendix D.

6.3 Construction Supervision

6.3.1 All construction work performed on CP systems shall be under the supervision of a trained and qualified inspector. It shall be the inspector's function to verify that the installation is made in strict accordance with the drawings and specifications, or that exceptions are made only with the express consent of qualified personnel, when it can be demonstrated that the effectiveness of the system is not impaired. It should also be the inspector's function to verify that construction methods and techniques are in accordance with good practices.

6.3.2 All deviations from construction specifications shall be noted on as-built drawings.

6.4 Galvanic Anodes

6.4.1 Inspection and handling

6.4.1.1 Packaged anodes shall be inspected and steps taken to ensure that the backfill material completely surrounds the anode. The individual container for the backfill material and anode should be intact. If individually packed anodes are supplied in waterproof containers, the containers should be removed before installation. Packaged anodes should be kept dry during storage.

6.4.1.2 The lead wire must be securely connected to the anode. The lead wire should be inspected to ensure that it is not damaged. Care should be taken to avoid damage to insulation and kinking of the lead wire.

6.5 Impressed Current Systems

6.5.1 Inspection and handling

6.5.1.1 The rectifier or other power source shall be inspected to ensure that internal connections are mechanically secure and that no damage is apparent. Rating of the direct current source output should comply with construction specifications. Care should be exercised in handling and installation.

6.5.1.2 Impressed current anodes shall be inspected for conformity to specified anode material and size and length of lead wire, and to ensure that the cap, if used, is secure. Care should be exercised to avoid cracking or damaging anodes during handling and installation.

6.5.1.3 The lead wire shall be inspected carefully for defects in insulation (e.g., cracks, abrasions, or excessive thinning below specified thickness). Care should be taken to avoid damage to insulation in the wire. Defects in the lead wire must be repaired or the anode/wire unit must be rejected.

6.5.1.4 Anode backfill material shall conform to specifications.

6.5.2 Installation provisions

6.5.2.1 The rectifier or other power source should be installed so that the possibility of damage or vandalism is minimized.

6.5.2.2 Wiring to rectifiers shall comply with all local and national electrical codes and requirements of the utility supplying power. An external disconnect switch on AC wiring shall be provided. The rectifier case shall be grounded adequately.

6.5.2.3 Impressed current power supplies should be designed to prevent reverse current flow when the unit is not operational.

6.5.2.4 Impressed current anodes should be installed vertically, horizontally, or in deep holes as indicated in the construction specifications. Backfill material, when specified, should be packed around the anodes, eliminating voids. Care shall be taken to avoid damage to the anode, wire, and wire connection to the anode during installation.

6.5.2.5 The conductor (negative lead wire) to the structure shall be connected as indicated in the specifications. Conductor connections to the power source must be mechanically secure and electrically conductive. Before the power source is energized, it must be verified that the negative conductor is connected to the structure and the positive conductor is connected to the anodes and to the power source output terminals. After the power source is energized, suitable electrical measurements shall be made to verify that these connections are correct.

6.5.2.6 Underground negative lead wire shall be effectively insulated. Bare or ineffectively insulated wire may require a substantial amount of the total protective current.

6.5.2.7 Underground splices on the positive lead cable to anodes shall be kept to a minimum. Connections between cable and conductor from each anode shall be mechanically secure and electrically conductive. If buried or submerged, these connections must be sealed to prevent moisture penetration so that electrical isolation is ensured. If the insulation integrity on the buried or submerged positive lead cable, including splices, is damaged, the cable may corrode and fail prematurely.

6.5.2.8 When specifications call for burial of the anode cable, care must be taken to avoid damage to the insulation. Sufficient slack shall be left in the cable to avoid strain on connections and anode leads caused by settling. Backfill materials used around cables should be free of rocks and foreign materials that might damage the wire insulation when installed in the trench. Cables may be installed by plowing if proper precautions are taken.

6.6 Corrosion Control Test Stations and Bonds

6.6.1 Refer to Section D.5 of Appendix D for design of corrosion control test stations and bonds.

6.7 Isolating the Wellhead from Pipelines and Other Structures

6.7.1 Refer to Section D.2 of Appendix D for design of electrical isolation.

Section 7: Control of Interference Currents

7.1 Introduction

7.1.1 This section presents recommended practices for the detection and mitigation of interference currents.The mechanisms and detrimental effects of interference currents are described.

7.2 Mechanism of Interference Current

7.2.1 Interference current corrosion on a well casing differs from electrochemical corrosion caused by other conditions. The source of the corrosion current is foreign or separate from the affected well. The foreign structure may be electrically bonded to or isolated from the affected well. Interfering currents may enter or leave the casing at several locations along the well casing. The damage from an interference current occurs in the area where the current leaves the well casing and enters the electrolyte.

7.2.2 The severity of interference resulting from stray electrical current depends on several factors:

7.2.2.1 Distance between wells.

7.2.2.2 Location of pipelines with respect to wells.

7.2.2.3 Location of interfering current source.

7.2.2.4 Depth of well casing.

7.2.2.5 Location of highly conductive earth formations.

7.2.2.6 Magnitude of potential gradient in the earth that the affected well penetrates. These gradients are created by current flowing to other structures.

7.2.2.7 Location of electric power line grounding system.

7.2.2.8 Quality and extent of the cementing program on the well casing.

7.2.3 Sources of interference currents:

7.2.3.1 Constant current—Sources that have essentially constant DC output are CP rectifiers, thermoelectric generators, photovoltaic and windmill battery units, etc.

7.2.3.2 Fluctuating current—Typical sources are DC electrified railway systems, mine hauling systems, pumps, welding machines, DC power systems, etc.

7.2.3.3 An interference current may originate in a foreign CP system on nearby wells or pipelines that are electrically isolated from the affected well.

7.2.3.4 Mutual interference current can result from CP applied to other wells in a metallically connected system that includes the affected well.

7.3 Detection of Interference Currents

7.3.1 During well casing CP surveys, personnel should look for electrical changes and facilities that may be a source of interference current.

7.3.1.1 A change in casing-to-electrolyte potential when foreign electrical sources are switched off and on is cause to investigate for downhole well casing interference.

7.3.1.2 Well casing current measurement and downhole well casing potential profiles should be used to assess the presence and magnitude of interference current.

7.3.1.3 The presence of external corrosion and perforation of well casing may be determined by using an electromagnetic thickness measurement tool to find changes in wall thickness.

7.3.2 When interference current is suspected, appropriate tests should be conducted to determine its presence and magnitude. All affected parties shall be notified before tests are performed. (Notification should be channeled through an Underground Corrosion Control Coordinating Committee, where one exists).(4) Any one or a combination of the following procedures can be used to determine the existence or extent of interference:

7.3.2.1 Casing potential changes shall, where practical, be measured with respect to a remote reference electrode. The reference electrode shall be placed beyond the earth gradient field of interfering current. The foreign direct current source should be turned on and off during the test.

7.3.2.2 Change in the magnitude of well casing current should be measured, and the direction of flow should be determined while performing a well casing potential profile. The foreign direct current source should be turned off and on during the test.

7.3.2.3 The variation in current output of the suspected source of interference current should be determined and compared with measurements obtained in Paragraphs 7.3.2.1 and 7.3.2.2. This may require correlation of data with time.

7.4 Methods for Resolving Interference Corrosion Problems

7.4.1 Each interference problem is unique and the solution should be mutually satisfactory to all parties involved.

7.4.2 Mutual interference between well casings may be minimized when wellheads within the electrically connected system are adjusted to equal potential with respect to a remote reference electrode.

7.4.3 The interfering current source should be removed or relocated.

7.4.4 The effect of interference current may be counteracted by adding CP to the affected well.

7.4.5 Mutual interference between wells in a common CP system may be reduced by providing an interference bond, with a current drain regulating device, from the wells to the rectifier.

7.4.5.1 An interference bond of proper resistance should be designed and installed.

7.4.5.2 A current regulating device should be installed in the rectifier cable connected to the wellhead.

7.4.5.3 The current discharge from interfering cathodic rectifiers should be adjusted to eliminate or decrease interference.

7.4.6 The CP groundbed should be relocated.

7.4.7 The design of the CP system should be modified when connecting pipelines (used as negative returns) require a high percentage of the total current for protecting the wells.

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(4) Information on Underground Corrosion Control Coordinating Committees may be available from the Technical Activities Division, 1440 South Creek Drive, Houston, TX 77084-4906 (telephone: +1 281/228-6200). Underground Corrosion Control Coordinating Committees are asked to keep NACE International Headquarters informed of their activities, but records are more current on some of the groups than on others.

7.4.7.1 Rectifiers and groundbed with reduced current output per unit should be added.

7.4.7.2 The dielectric coating of connecting pipelines should be improved to reduce the total required current.

7.5 Methods to Indicate Resolution of Interference

7.5.1 A satisfactory downhole well casing potential profile log indicating current that is adequate to eliminate anodic areas on affected casing should be obtained.

7.5.2 Sufficient CP currents, interpreted from surface test data or empirical calculation, should be applied to affected well casing.

7.5.3 Interference current discharges should be neutralized as determined by applicable criteria.

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Section 8: Operation and Maintenance of CP Systems

8.1 Introduction

8.1.1 The purpose of this section is to designate procedures and practices for energizing and maintaining continuous, effective, and efficient operation of CP systems.

8.1.1.1 Electrical measurements and inspections are necessary to determine that protection has been established according to the applicable criterion and that each part of the CP system is operating properly. Conditions that affect protection may change with time, however, and corresponding changes are required in the CP system to maintain protection. Periodic measurements and inspections shall be made to detect changes in the conditions that affect the CP system. Local conditions may exist in which operating experience indicates that surveys and inspections should be made more frequently than recommended herein.

8.1.1.2 Care should be exercised in selecting the location, number, and type of electrical measurements used to determine the adequacy of CP.

8.2 Tests shall be conducted after each CP system is energized to determine whether the system is satisfying the applicable criterion and is operating efficiently. Tests shall include one or more of the following types of measurements and must relate to the criterion established by this standard.

8.2.1 Casing-to-reference-electrode potential, as applicable.

8.2.2 Calculation technique to estimate CP effectiveness (refer to Paragraph 4.3.3).

8.2.3 Structure-to-structure potential.

8.2.4 Current flow.

8.2.5 Well casing potential profile (refer to Paragraph 4.3.1 and Appendix A).

8.3 Periodic tests are suggested to ensure the continuity of CP; the electrical measurements used in the tests may include one or more of the measurements listed in Paragraph 8.2.

8.4 Inspection and tests of CP facilities should be conducted as follows to ensure their proper operation and maintenance:

8.4.1 All sources of impressed current shall be checked at intervals not to exceed two months. Evidence of proper functioning may include the current output, normal power consumption, a visual or audible signal indicating normal operation, or the satisfactory electrical state of the protected casing.

8.4.2 All impressed current protective facilities should be inspected annually as part of a preventive maintenance program to minimize in-service failure. Inspections may include a check for electrical shorts, ground connections, meter accuracy, efficiency, and circuit resistance.

8.4.3 Reverse current switches, diodes, and inteference bonds, whose failure would jeopardize structure protection, shall be inspected for proper functioning at intervals not to exceed two months.

8.4.4 The effectiveness of electrical isolation fittings and continuity bonds shall be evaluated during periodic testing. This may be accomplished by on-site inspection or by evaluating corrosion test data.

8.5 The test equipment used for obtaining each electrical value shall be of an appropriate type. Instruments and related equipment shall be maintained in good operating condition and checked annually for accuracy.

8.6 Remedial measures shall be taken when periodic tests and inspections indicate that protection is no longer adequate according to applicable criteria. These measures may include:

8.6.1 Repair, replacement, or adjustment of components of CP systems.

8.6.2 Providing supplementary facilities when additional CP is necessary.

8.6.3 Repair, replacement, or adjustment of continuity and interference bonds.

8.6.4 Removal of accidental metallic contacts.

8.6.5 Repair of defective electrical isolation devices.

Section 9: Corrosion Control Records

9.1 Introduction

9.1.1 The purpose of this section is to describe corrosion control records that document in a clear, concise, workable manner the data pertinent to the design, installation, maintenance, and effectiveness of corrosion control measures for well casings.

9.2 Relative to determination of the need for corrosion control, the following should be recorded when applicable:

9.2.1 Information on corrosion leaks (e.g., date, well identity, location).

9.2.2 Electromagnetic casing thickness measurements.

9.2.3 Casing potential profile data.

9.2.4 Coating type applied to external surfaces of casings.

9.3 Relative to structure design, the following should be recorded:

9.3.1 Location and design of wellhead and associated electrical isolation devices.

9.3.2 Design and procedure for isolating or bonding any associated electrical power source grounding system.

9.3.3 Design and location of test leads, bond cables, and other test facilities.

9.3.4 Details of any other corrosion control measures taken.

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9.4 Relative to the design of corrosion control facilities, the following should be recorded:

9.4.1 Results of current requirement tests and how the tests were performed.

9.4.2 Results of soil resistivity surveys at groundbed locations, and where the surveys were made with respect to other wells, pipelines, and structures.

9.4.3 Interference tests and design of interference bonds and drainage switch installations, including:

9.4.3.1 Location of interference source relative to location of wells and other structures.

9.4.3.2 Scheduling of interference tests, correspondence with coordinating committees, coordinating committee minutes, and direct communication with the concerned companies.

9.4.3.3 Record of interference tests conducted, including location of tests, name of company involved, and results.

9.5 Relative to the installation of corrosion control facilities, the following should be recorded:

9.5.1 Installation of CP facilities

9.5.1.1 Impressed current systems

(a) Location and date placed in service.

(b) Type, size, depth, backfill, and spacing of anodes.

(c) Number of anodes.

(d) Location of groundbed anodes with respect to wells, pipelines, and other structures.

(e) Specifications of rectifier or other energy source.

(f) Type(s) and size(s) of buried cable.

9.5.1.2 Galvanic anode systems

(a) Location and date placed in service.

(b) Type, size, backfill, and spacing of anodes.

(c) Number of anodes.

9.5.2 Installation of interference bonds and drainage switches

9.5.2.1 Details of interference bond installation

(a) Locations and names of companies involved.

(b) Resistance value or other pertinent information.

(c) Magnitude and polarity of drainage current.

9.5.2.2 Details of drainage switch installation

(a) Locations and names of companies involved.

(b) Type of switch or equivalent device.

(c) Data showing effective operating adjustment.

9.5.2.3 Details of other remedial measures

9.6 Records of surveys, inspections, and tests set forth in Sections 4, 5, 7, and 8 should be maintained to demonstrate that applicable criteria for interference control and CP have been satisfied.

9.6.1 Current drained from the well casing should be recorded at intervals consistent with company requirements.

9.6.2 Other electrical measurements should be recorded as required to monitor the CP for each well and to satisfy the criterion for CP of the wells.

9.7 Relative to the maintenance of corrosion control facilities, the following information should be recorded:

9.7.1 Maintenance of CP facilities

9.7.1.1 Repair of rectifiers or other DC energy sources.

9.7.1.2 Repair or replacement of anodes, connections, and cable.

9.7.2 Maintenance of interference bonds and drainage switches

9.7.2.1 Repair of interference bonds.

9.7.2.2 Repair of drainage switches or equivalent devices.

9.7.3 Maintenance, repair, and replacement of electrical isolation devices, test leads, and other test facilities.

9.8 Records sufficient to demonstrate the evaluation of the need for and the effectiveness of corrosion control measures should be retained as long as the facility involved remains in service. Other related corrosion control records should be retained for a period that satisfies individual company needs.

References

1. NACE SP0572 (latest revision), "Design, Installation, Operation, and Maintenance of Impressed Current Deep Anode Beds" (Houston, TX: NACE).

2. F.W. Anney, "Electrical Resistivity of Oil-Country Tubular Steels," U.S. Steel Technical Report, March 31, 1971.

3. NACE SP0177 (latest revision), "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems" (Houston, TX: NACE).

4. ANSI/ASME B31.8 (latest revision), "Gas Transmission and Distribution Piping Systems" (New York, NY: ANSI, and New York, NY: ASME).

5. NACE SP0169 (latest revision), "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" (Houston, TX: NACE).

Appendix A—Casing Potential Profile (Nonmandatory)

A.1 Introduction

A.1.1 This appendix describes a typical potential profile tool, its function, and use. Procedures for interpreting data are covered. This appendix supplements Paragraph 4.3.1 of this standard.

A.1.2 The name "casing potential profile" has been widely accepted. The measurement is actually a potential difference, and the plotted data represent a casing potential difference profile. The tool measures a potential difference between two points on the casing as opposed to the potential of a pipe as measured in a pipe-to-soil potential in evaluating pipeline corrosion. The term *potential difference* is used interchangeably with voltage (IR) drop.

A.1.3 A casing potential profile should be performed under the direction of a person qualified by knowledge and experience in this particular endeavor.

A.2 Types of Casing Potential Profile Tools

A.2.1 A typical casing potential profile tool consists of two contacts positioned 3 to 8 m (10 to 26 ft) apart on tubing and separated by an electrical insulator. A wire is attached to each contact and brought to the surface to a voltmeter. The tool is moved along the inside of the casing to take voltage drop measurements as needed. (Refer to Figure A1.)

A.2.2 Some of the contact devices are:

A.2.2.1 Spring-loaded knives that continuously contact the casing while moving up or down. Tension is increased against the casing wall by manipulating the position of knives.

A.2.2.2 "Pipe cutter" wheels permanently tensioned on spreader arms. Wheels continuously ride the casing wall at constant pressure.

A.2.2.3 Spreader arms with contactors that are opened and closed by an electric motor or mechanical means from the ground level. Pressure against the casing wall is adjustable.

A.3 Effect of Electrical Resistance on Data

A.3.1 Variable circuit resistance affects voltage (IR) drop readings. Because the electrical resistance of steel casing is extremely low (in the µ-ohm per m range), the equipment design and procedure used to measure voltage are critical. For example, the voltage measured across approximately 6 m (20 ft) of casing can be in the range of 1 to 5,000 µV. The resistance portion of the electrical circuit consists of the following:

A.3.1.1 The well casing between the profile tool's upper and lower contacts.

A.3.1.2 Other permanent tool fittings and cable and connectors.

A.3.1.3 Contact of the knives to the casing wall at each setting.

A.3.2 Resistance tables for the various casing grades are available.[2] The resistance of the casing for a given API(5) grade changes as downhole temperature increases.

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(5) American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005.

The resistance of the casing can be measured prior to installation.

A.3.3 A voltage (IR) drop measured across a given length of casing and total resistance can be used to calculate the current flow. The resistance value should be corrected for changes caused by temperature and grade of steel.

A.4 Other Influences on the Measured Voltage (IR) Drop

A.4.1 Thermal voltage differences between upper and lower contacts, casing wall, and knives. This is caused by the contacts riding continuously on the casing wall.

A.4.2 Resistance between contacts and casing wall. Foreign material on the casing wall can increase the total resistance and give an erroneous voltage (IR)

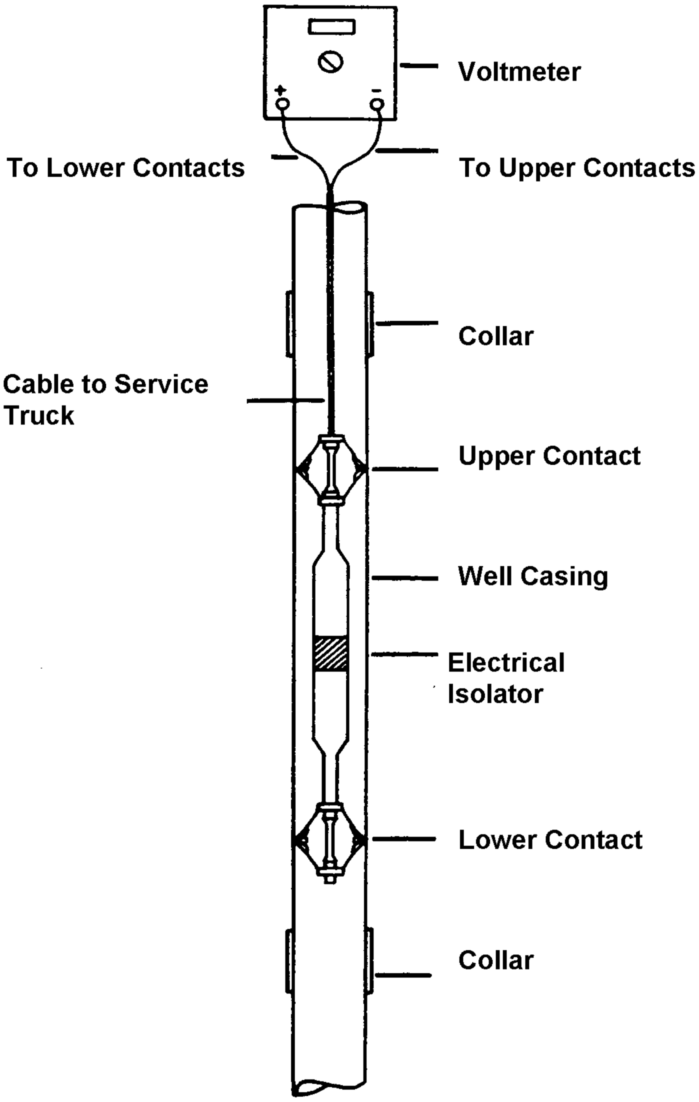

FIGURE A1—Casing Potential Profile Tool

drop reading. Some foreign materials commonly encountered are corrosion products, scale, petroleum deposits, corrosion inhibitors, and moisture.

A.4.3 Ineffective electrical insulation between upper and lower contacts.

A.4.4 Electrically conductive fluid in the casing and in contact with the tool.

A.5 Use of Instruments

A.5.1 Voltmeters with a high impedance and resolution of 1 µV and a short response time are required. They should also have AC rejection and be temperature compensated. Instruments should be calibrated annually.

A.5.2 The accepted procedure is to connect the positive (+) terminal of the voltmeter to the lower contact of the potential tool. A positive reading indicates current flowing up the casing (from positive to negative), and a negative reading indicates current flowing down the casing.

A.5.3 The tool is stopped at a given location in the well casing, and the IR drop readings are repeated, if required, until an acceptable one is obtained. An acceptable reading is one that is consistent with the log and other available data.

A.6 Data Use and Interpretation

A.6.1 A typical example of a casing potential profile plot is shown in Figure A2.

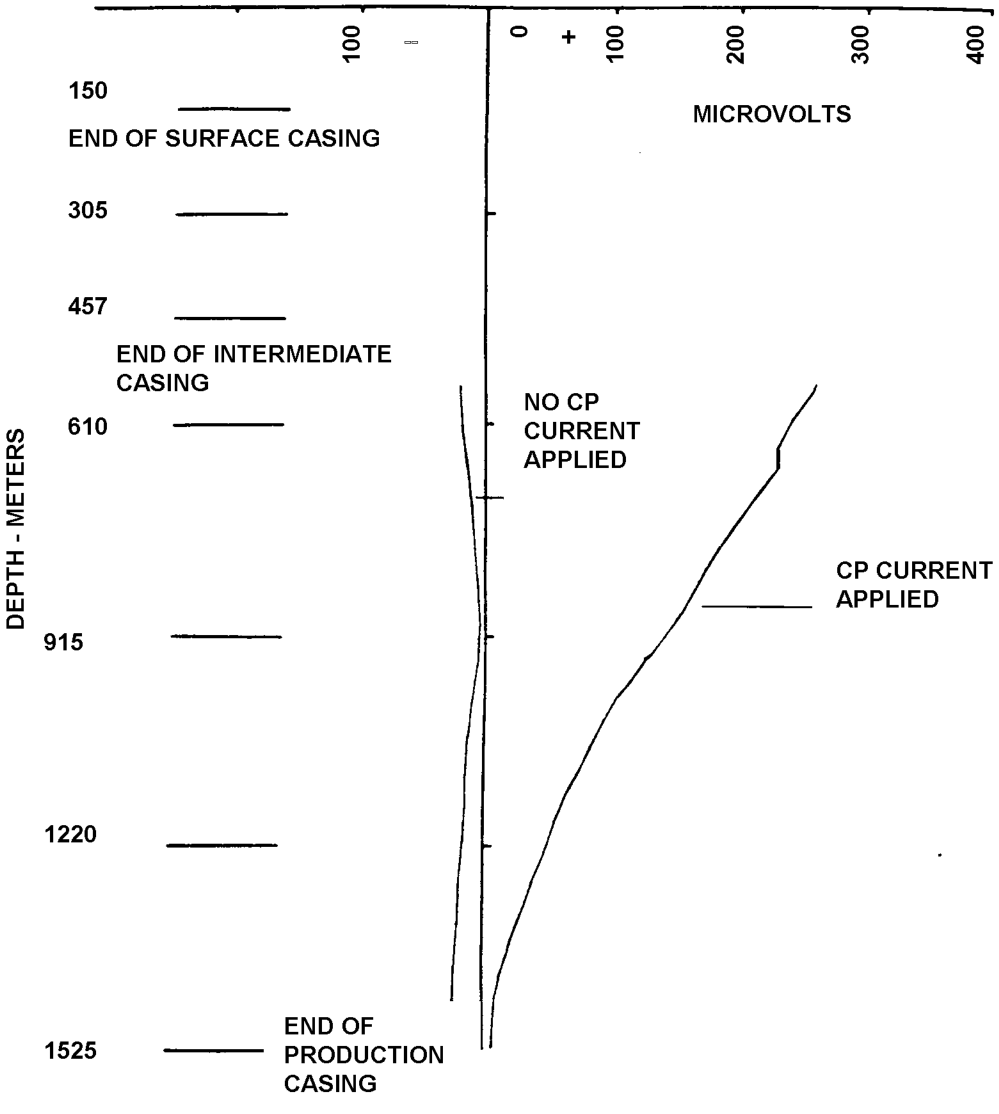

FIGURE A2—Typical Casing Potential Profile Plot

A.6.2 Considerations in interpreting casing potential profile data:

A.6.2.1 Abrupt or inconsistent changes in single readings may indicate poor contact of the tool with the casing wall.

A.6.2.2 Data taken from a production casing shielded by other casing in the well are not necessarily indicative of current gain or discharge from the production casing to the formation.

A.6.2.3 A positive slope of the plotted voltage (IR) drop versus depth normally indicates an increase in the amount of current being picked up by the casing.

A.6.2.4 A negative slope of the voltage (IR) drop normally indicates a discharge of current from the casing.

A.6.2.5 Changes in slope are caused by a change in current or resistance. Resistance changes can be caused by:

(a) Change of wall thickness (e.g., corrosion, manufacturer's tolerance).

(b) Change of API pipe grade.

(c) The bridging of collars by the contacts of the tool.

A.6.2.6 Each voltage (IR) drop reading taken on a section of the casing (typically several meters) measures the long-line current. The local anodic cells are not detectable within the span of the tool. Current pickup is not necessarily uniform along the casing between tool contacts. Therefore, the current density at a given area on the casing may be greater or less than that indicated.

A.6.2.7 Casing potential profile data give a reasonable indication of the amount of current flowing and indicate a direction of current flow. The data cannot be interpreted to determine whether sufficient current is being applied to cancel all corrosion cells.

A.7 Well data for each well can assist in interpreting potential profile readings. These data may include the following:

A.7.1 API grade, diameter, length, and weight of casing joint and its location in the well.

A.7.2 Collar locator, used to facilitate positioning of a casing potential profile tool between collars.

A.7.3 Electromagnetic logs, which help determine changes in wall thickness and grade of casing, and allow evaluation of the inner wall surface condition.

A.7.4 Formation resistivity logs that identify strata that may alter current distribution.

A.7.5 Leak history and repair methods.

A.7.6 Other types of logs for a given well can aid in interpreting casing potential profile data. Refer to Paragraph D.7.4 of Appendix D.

A.8 Interference Testing with the Casing Potential Profile Tool

A.8.1 The casing potential profile tool is valuable when used to determine electrical DC interference. Data obtained pertain only to the conditions prevailing at the time of the test.

Appendix B—E-Log-I Test
(Nonmandatory)

B.1 Introduction

B.1.1 The purpose of this appendix is to outline the procedure for performing an E-log-I test and to give guidelines for interpretation of data. This appendix supplements Paragraph 4.3.4 of this standard.

B.2 General

B.2.1 An E-log-I test should be performed under the direction of a person qualified by knowledge of and experience in this particular endeavor.

B.3 Prerequisites to Performing an E-log-I Test

B.3.1 All buried metallic structures must be electrically isolated from the casing.

B.3.2 The temporary groundbed should be located at a sufficient distance from the well to give optimum current distribution along the well casing. When feasible, it should be placed where permanent bed location is anticipated.

B.3.3 Other buried metallic structures should be located.

B.3.4 Foreign rectifiers or other DC sources that could influence the test should be located.

B.3.5 The locations of high-resistivity strata that make it difficult to force current through underlying formations should be determined.

B.3.6 Placement of the reference electrode should be based on well depth, well spacing, and distance to foreign structures, and it should be beyond the influence of the test groundbed.

B.4 Test Procedure

B.4.1 After the equipment is set up (see Figure B1), the test should be conducted according to the following steps.

B.4.1.1 The "native state" potential, i.e., the potential with zero groundbed current, should be measured and recorded.

B.4.1.2 The test should then be begun by impressing current through the groundbed onto the well casing at the predetermined level (typically 0.1 A, as in Figure B2, for the selected time, typically two or three minutes).

B.4.1.3 At the end of the selected time, the current flow should be interrupted and the potential should be observed. Within a fraction of a second, the potential will drop abruptly. It will then begin a gradual "decay." The potential of interest is that just prior to the start of the decay. This is frequently referred to as the instant-off potential.

B.4.1.4 The current interruption should last no more than two seconds. A higher current should then be applied to the casing at the next predetermined current level. Typically, increments from 0.1 to 2.0 A are used.

B.4.1.5 The current increments should be selected to meet the requirements of individual conditions and to ensure the proper interpretation of the E-log-I test.

B.4.1.6 Time intervals should be consistent throughout the test.

B.5 Interpretation of Test Results

B.5.1 Figure B2 is an example of an E-log-I curve. Casing-electrolyte potentials and current applied are plotted on semilogarithmic scales. The interpretation of the curve is dependent on the experience of the operator. The current required is usually taken at the intersection, point A, or the first point lying on the Tafel segment, point B.

B.5.2 If the E-log-I results have not been verified for a given group of wells, additional testing such as the casing potential profile log should be conducted.

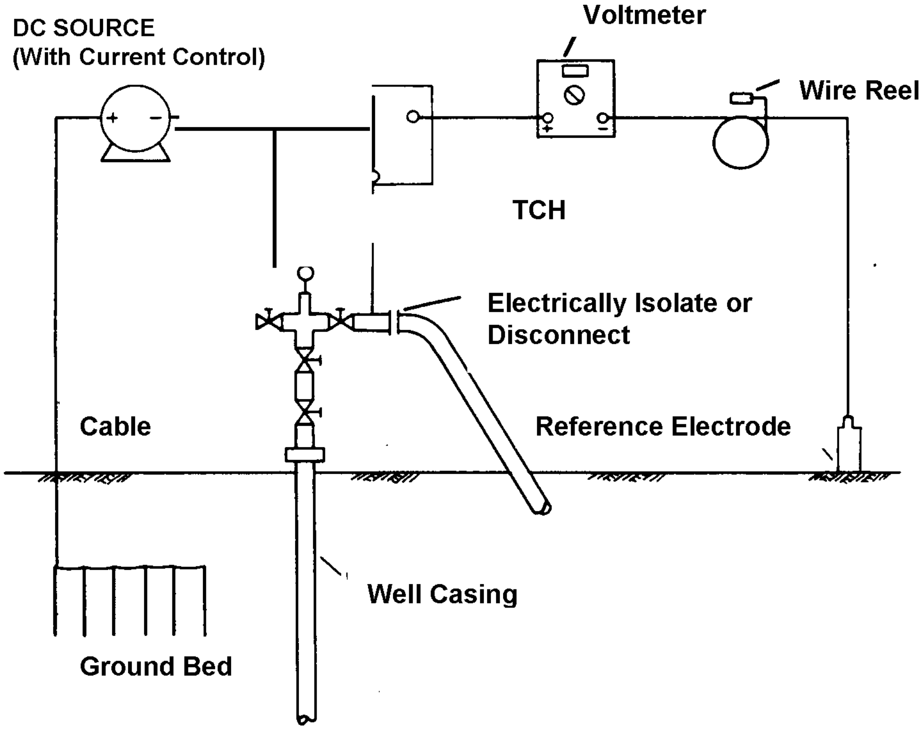

FIGURE B1—Equipment Set-Up for E-Log-I Test

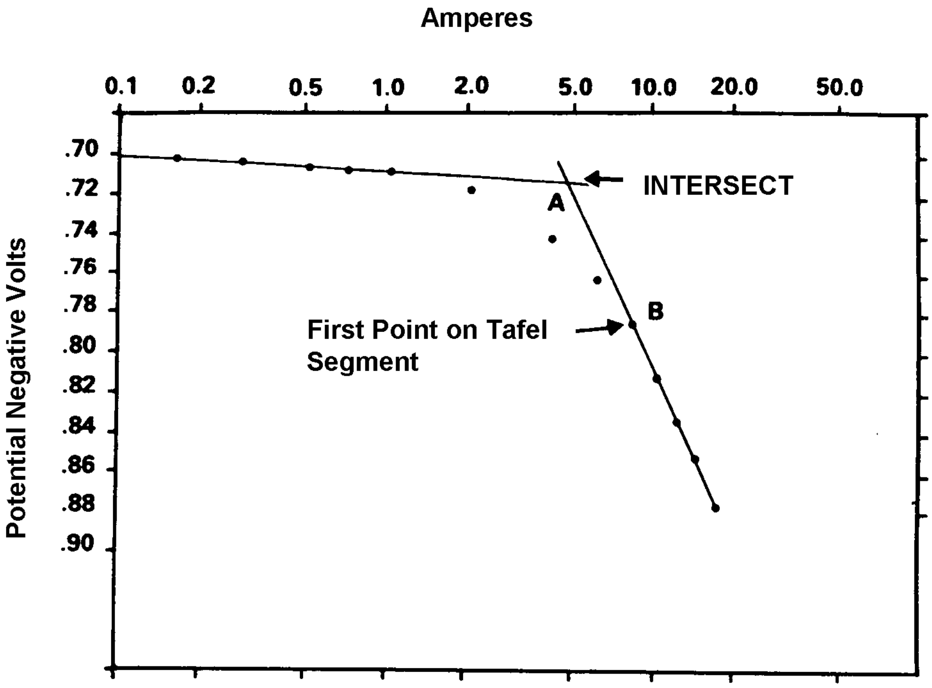

FIGURE B2—Sample E-Log-I Plot

Appendix C—Electromagnetic Casing Inspection Instruments (Nonmandatory)

C.1 Introduction

C.1.1 Subsurface electromagnetic inspection instruments are used to inspect the casing wall for defects. The inspection helps in determining a need to install a CP system or in determining its effectiveness after installation. These instruments fall into two broad categories; one induces an AC electromagnetic field into the casing wall and the other, a DC electromagnetic field into the casing wall. A comparison of these electromagnetic inspection instruments points out the differences in the methods of measurement and the significance of these differences.

C.2 Corrosion Inspection Instruments

C.2.1 The AC inspection instrument derives its signal by detecting the amount of phase shift measured between the low-frequency transmitter coil and the receiver coil. The transmitter coil is energized with a low-frequency AC current, causing an electromagnetic field to be induced into the casing. The field is detected by the receiver coil, usually located 300 to 600 mm (12 to 24 in.) away.

C.2.1.1 The amount of phase shift of the received signal from the transmitter is related to the properties of the casing. These properties are:

(a) Casing weight.

(b) Casing size.

(c) Casing grade, including permeability and conductivity.

(d) Metallic influence outside casing, if inspected casing is inside another casing (e.g., scratchers, centralizers).

C.2.1.2 The predominant response is a result of the change in the casing weight. Because there is an "averaging" effect between the transmitter and receiver coil, there must be significant metal loss (e.g., by corrosion) with respect to normal casing weight to cause a meaningful change in the phase shift.

C.2.1.3 The accuracy is such that a change from one API casing weight to another of the same size casing is detectable. It is responsive to the change in the amount of metal, whether the change is internal or external.

C.2.1.4 Supplementally, a noncontact electronic caliper is usually available for added internal information, and some instruments are also equipped with a set of closely spaced coils to provide uncalibrated indications of small defects.

C.2.2 The DC inspection instrument derives its casing defect signal by detecting a disturbance in an otherwise stable magnetic field within and surrounding the casing wall. The stable magnetic field is induced into the casing wall. A defect such as a corrosion pit causes a field irregularity or "flux leakage" at that point on both sides of the casing wall, whether the defect itself is on the inside or the outside wall of the casing. This disturbance can be created by a single pit, an isolated defect, or by a group of closely located pits, i.e., general corrosion. The instrument sensors detecting the field disturbances are small and are in contact (as close as possible) with the internal circumferential surface of the casing.

C.2.2.1 Signals emitted by these sensors are caused by changes in the field disturbances, which vary because of:

(a) The strength of the induced DC magnetic field.

(b) Defect depth.

(c) Defect shape.

(d) Metallic influence outside casing (e.g., scratchers, centralizers, another casing).

(e) Casing wall thickness.

(f) Casing size.

(g) Casing grade, including permeability and conductivity.

(h) The speed with which the sensor passes the defect.

C.2.2.2 Techniques currently in use utilize the amplitude of the sensor signal. Although casing wall thickness affects the signal amplitude, the sensor does not discern that thickness; the amplitude response is usually calibrated to indicate depth of defect penetration in percent of the total casing wall thickness.

C.2.2.3 Instrument sensitivity is normally limited to defect depths greater than 20% of the casing wall and defect areas greater than 32 mm (1.3 in.) in diameter. Accuracy of the corrosion defect measurement is approximately ±15% of defect depth in ideal single-string conditions when the casing information is known (e.g., weight, grade, etc.)

C.3 The information presented in Table C.1 may be used to determine which instrument is the most effective for certain situations.

C.3.1 Normally, operating conditions for both instruments are for temperatures up to 177°C (351°F), pressures of 100 MPa (14,500 psi), and casing sizes from 110- to 250-mm (4.3- to 9.8-in.) outside diameters. Some instruments can operate in conditions beyond these limits. The performance of either instrument is degraded when run in a multistring casing; however, the DC instrument's operation is less affected.

C.3.2 The running of base logs as soon as possible is recommended for better evaluation of future data.

C.3.3 Clean casing walls result in more reliable inspections.

TABLE C.1—Instrument Effectiveness

Type of Instrument	Detects Casing Collars	Detects Small Defects and Defect Depths	Detects Large Holes in Casing	Detects Casing Weight Change	Detection of Outer Casing String	Detects Parted Casing String	Detects Drill Pipe Wear
AC	Yes	No	Yes	Yes	Yes	Yes	Yes
DC	Yes	Yes	Yes	No	No	Yes	No

Appendix D—Well Completion Design and Other Factors Associated with CP (Nonmandatory)

D.1 Introduction

D.1.1 The purpose of this appendix is to provide accepted corrosion control practices for the design of CP systems for oil production, natural gas production, and natural gas storage wells and associated aboveground facilities. A person qualified to practice corrosion control should be consulted during all phases of well design and installation (see Paragraph 1.5.) These recommendations should not be construed as taking precedence over recognized electrical safety practices. Electrical grounding procedures at the well surface must conform to local, state, and national codes.

D.2 Electrical Isolation

D.2.1 Isolating devices consisting of flange assemblies, prefabricated insulating joints, unions, and couplings should be installed to isolate the well production casing electrically from other wells, associated pipelines, gauge lines, and structures when required to facilitate the application of corrosion control. These devices should be properly rated for temperature, pressure, and dielectric strength. Installation of isolating devices should be avoided in enclosed areas where combustible atmospheres are likely to be present. Typical locations at which electrical insulating devices may be considered are as follows:

D.2.1.1 Where facilities change ownership, e.g., the wellhead.

D.2.1.2 At the junction of bare well casing and associated pipelines and facilities.

D.2.1.3 At the junction of dissimilar metals (to prevent galvanic corrosion).

D.2.2 Isolating devices

D.2.2.1 Inspection and electrical measurements should be performed to ensure that electrical isolation is adequate.

D.2.2.2 Buried isolating devices should be suitably coated or wrapped with insulating material to prevent electrical current transfer through the surrounding soil.

D.2.2.3 Additional or special isolating devices may be needed on pipelines containing conductive fluids.

D.2.3 The need for lightning and fault current protection at isolating devices should be considered. Cable connections from isolating devices to arrestors should be short, direct, and of a size suitable for short-term, high current loading.

D.2.4 When electrical contact would adversely affect CP, well casings should be electrically isolated from supporting pipe stanchions and structures.

D.2.5 When an isolating device is required, proper pressure-rated materials manufactured to perform this function should be used and installed according to manufacturer's recommendations.

D.2.6 As much distance as is practical should separate well casings, associated pipelines, and other facilities from electric transmission tower footings, ground cables, and counterpoise. Regardless of separation, consideration should always be given to lightning and fault current protection of well casings and safety of personnel. (See NACE SP0177.[3])

D.2.7 Plastic fittings used in chemical pump lines must meet electrical and physical requirements.

D.2.8 Isolation of high-temperature natural gas discharge and oil lines requires special design considerations for use of materials.

D.2.9 Nonmetallic isolators should meet specifications for use in buried and aboveground applications, as required.

D.3 Electrical Continuity

D.3.1 Consideration should be given to the electrical properties of screwed casing couplings. To ensure electrical continuity, low-electrical-resistance thread compounds should be used.

D.4 Coatings

D.4.1 A dielectric coating used on a well casing requires a surface that provides a good physical bond between it and the formation or cement to ensure a sealed environment. NOTE: Coatings used on well casings require special dielectric, physical, and chemical qualities, which are beyond the scope of this standard.

D.5 Corrosion Control Test Stations and Bonds

D.5.1 Test stations for potential and current measurements should be provided at the well to facilitate CP testing. Such use may include, but not be limited to, the following:

D.5.1.1 Well production casing.

D.5.1.2 Well surface and intermediate casings.

D.5.1.3 Dehydration, oil pumping, natural gas compressor, and other similar facilities.

D.5.1.4 Foreign metallic pipelines or facilities near the well.

D.5.1.5 Gauge lines.

D.5.2 Test leads should be color coded or otherwise permanently identified. Wire should be installed with slack. Damage to wire insulation should be avoided. Test leads should not be exposed to excessive sunlight. Aboveground test stations are preferred. If test stations are flush with the ground, adequate conductor slack should be provided within the test station to facilitate test connections.

D.5.3 An isolating device can be accommodated by attaching an appropriate test wire and low-resistance current-carrying cable to each side of the device. These cables and wires should be appropriately color coded or labeled and terminated at a convenient location for bonding when needed. Shunts may be used to measure current.

D.5.4 The test station may accommodate current-carrying cable when a pipeline is utilized as the negative return. Current-carrying cable or wire should not be used as a contact for taking casing-to-reference-electrode potentials.

D.5.5 Attachment of test leads and cables to steel well casings and equipment

D.5.5.1 Test leads are usually attached to an aboveground fitting, which is directly connected to the well casing. Soldering or thermit welding may be used to attach wire or cable when heating requirements do not exceed the temperature limit for casing and fittings. NOTE: Care should be taken to ensure that specified temperature limits are not exceeded during thermit welding to prevent damage to the pipe by copper penetration. Consult ANSI(6)/ASME(7) B31.8[4],Paragraph 862.115 on Electrical Connections and Monitoring Points, for additional guidelines on thermit welding. Mechanical connections to flanges and other fittings can be used if they remain secure and maintain low resistance. Refer to NACE SP0169.[5]

D.5.5.2 Attaching test wires directly to the production casing below ground level is beyond the scope of this standard. Special consideration must be given to requirements for cementing and completion procedures.

D.5.6 Coating of test wire attachments

D.5.6.1 All test lead wire and cable should be coated with a direct burial type of electrical isolating material. Attachments to fittings or casings should be coated with a dielectric material. The coating should be compatible with the existing coating on the fitting or casing.

D.6 CP

D.6.1 Refer to Sections 5 and 6 of this standard for the design and installation of CP.

D.7 Information Useful for the Design and Monitoring of a CP System

D.7.1 Well piping system specifications and practices.

D.7.1.1 Total length, size, weight, API grade, and location of each casing string in the well.

D.7.1.2 Electrical resistance of steel casing. Tables are available for various grades and temperatures. (8)

D.7.1.3 Coatings (dielectric)—well casings and connecting pipelines.

D.7.1.4 Cement types and grades, and locations of cemented intervals.

D.7.1.5 Drilling mud—type, inhibitor.

D.7.1.6 Additives to cement or mud.

D.7.1.7 Completion data regarding backfill around casing and the location of cement or other material.

D.7.1.8 Surface well fittings such as valves for access to casing.

D.7.1.9 Locations of metallic scratchers and centralizers.

D.7.1.10 Locations of metallic stress rings.

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(6) American National Standards Institute (ANSI), 1819 L St., NW, Washington, DC 20036.

(7) ASME International (ASME), Three Park Avenue, New York, NY 10016-5990.

(8) Casing resistance data tables available from Manager, Casing Inspection Services, Dresser Atlas, Box 1407, Houston, TX 77251. Tables were based in part on data found in a U.S. Steel Technical Report.[2]

D.7.1.11 Acidizing procedures.

D.7.2 Well and associated pipeline site environments

D.7.2.1 Existing and proposed CP systems.

D.7.2.2 Possible interference sources (see Section 7 of this standard).

D.7.2.3 Surface environmental conditions.

D.7.2.4 Foreign buried metallic structures (including location, ownership, and corrosion control practices).

D.7.2.5 Site accessibility.

D.7.2.6 AC power availability.

D.7.2.7 Status of well's electrical isolation from foreign structures.

D.7.3 Field survey, corrosion test data, and operating experience

D.7.3.1 Electrical resistivity of the electrolyte (soil).

D.7.3.2 Electrical continuity (low resistance is required across well casing threaded couplings).

D.7.3.3 Cumulative leak history.

D.7.3.4 Interference current data.

D.7.4 Well logs used to supplement other test data utilized for design

D.7.4.1 Electromagnetic alternating current and direct current logs (thickness gauge).

D.7.4.2 Electric log—formation resistivity normally available from well completion data.

D.7.4.3 Gamma ray neutron log—determines relative lithology for location of high-resistivity formations.

D.7.4.4 Collar locator log—facilitates other logs such as casing potential profile.

D.7.4.5 Cement bond log or temperature log—indicates where cement is located between well casing and formation.

D.7.4.6 Optical inspection inside casing.

D.7.4.7 Caliper log (mechanical feelers) to determine internal wall thickness change or defects such as corrosion pits.

D.7.4.8 Dual induction resistivity log.

Ex. II - 37

Symposium on Casing Cathodic Protection Theory†

PREFACE

John W. Stout*

The protection of oil-well casing from outside corrosion is of prime importance to the oil industry. Cathodic protection is one method that is being applied on a large scale in several California oil fields to reduce or control outside casing corrosion. This symposium was conceived to briefly describe the theory of casing cathodic protection and to give the industry the benefit of the case histories of four current major casing cathodic protection projects in California

PART 1

FUNDAMENTALS OF CATHODIC PROTECTION AS APPLIED TO OIL-WELL CASING

F. W. Schremp‡

ABSTRACT

This paper presents a review of the processes of corrosion and cathodic protection of oil-well casing Various criteria used for the determination of cathodic current requirements are discussed A comparison also is made of the advantages and limitations of each criterion.

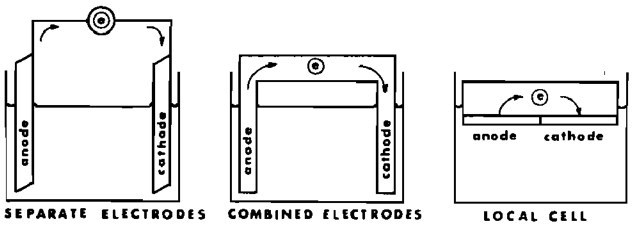
INTRODUCTION

This paper is concerned with the processes of corrosion and cathodic protection of iron in an earth-electrolyte environment. A review of corrosion processes is presented before discussion of cathodic protection because the concepts of cathodic protection are intimately associated with the processes of corrosion Electron flow is used as the convention of current flow throughout the paper Electron flow is opposite to the direction of positive current flow.

Corrosion

Corrosion in an electrolyte is an electrochemical process. Metal goes into solution at anode areas, and a current of electrons flows through the metal and is discharged at cathode areas The amount of current flowing is controlled by the relative areas of anodes and cathodes as well as the potential differences existing between the anodes and cathodes. Potential differences may be caused by surface defects in the metal and/or differential environmental conditions such as variations in electrolyte concentration, pH, and dissolved oxygen content, to name a few.

The corrosion of iron involves the solution of iron at anodic areas and deposition of hydrogen at the cathodic areas. The process goes on in such a way that the electrolyte remains electrically neutral; i e., an equivalent number of positive ions are displaced from the electrolyte for every iron atom dissolved into the electrolyte. Typical iron corrosion reactions are shown in Fig 1.



	ANODE	CATHODE
PRIMARY REACTIONS	$Fe = Fe^{++} + 2e$ metal ion	$2H^+ + 2e = 2H^0$ ions atoms
SECONDARY REACTIONS		$2H^0 + \frac{1}{2}O_2 = H_2O$ atoms liquid $2H^0 = H_2$ atoms gas

$Fe^{++} + \frac{1}{2}O_2 + H_2O = Fe(OH)_2$
ions solid

Fig. 1 (Schremp)—Corrosion Reactions of Iron in an Electrolyte

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*Standard Oil Co of California, Taft, Calif

†Presented at the spring meeting of the Pacific Coast District, Division of Production, Los Angeles, Calif, April 30 and May 1, 1959

‡California Research Corp, La Habra, Calif.

Hydrogen film formation is the primary cathode reaction and tends to limit the corrosion process in two ways *1*, by insulating the iron surface from the electrolyte, and *2*, by increasing the tendency for hydrogen to re-enter solution and thus oppose the tendency for iron to dissolve. Formation of a hydrogen film is called "polarization" and removal is called "depolarization."

A hydrogen film usually is not sufficient to stop corrosion completely because the film may be damaged by the formation and release of hydrogen-gas bubbles or combination of hydrogen with dissolved oxygen. In either case, removal of the hydrogen film permits the corrosion process to continue. In acid solutions, the hydrogen film is destroyed mainly by the formation and release of hydrogen gas In alkaline solutions, the hydrogen combines with dissolved oxygen.

Dissolved iron usually is precipitated as iron hydroxide. If the precipitate falls on the metal surface, it may slow the corrosion process by acting like a protective coating Iron hydroxide also will react with dissolved oxygen to form ferric hydroxide and may reduce the corrosion rate if the supply of dissolved oxygen is limited.

It is apparent from this discussion that corrosion may be controlled if the cathode areas are maintained in a polarized condition and if hydroxide and insoluble reaction products are deposited on the cathode areas Perhaps the most effective way to achieve a polarized condition is to apply a counter current between the metal and the electrolyte sufficient to neutralize the corrosion current and thus prevent the metal from going into solution Application of a counter current is called cathodic protection. Subsequent sections of this paper will be devoted to the discussion of cathodic protection and the criteria that have been developed to implement its use.

Cathodic Protection

Use of a counter current has been called cathodic protection because the corroding metal surface is made the cathode in a cell reaction involving the metal and a sacrificial anode. Such a system is illustrated in Fig. 2

Electrochemically, magnesium is more inclined to dissolve than iron, and as a result electrons are released at the magnesium anode and flow through the external circuit to the steel casing, thereby offsetting the tendency for iron to dissolve. Of course, the fact that a metal is more electronegative than iron; i e., shows a greater tendency to dissolve, does not mean that the metal can be used effectively as a sacrificial anode to prevent the corrosion of iron. Sufficient electrons must be supplied by the anode to satisfy the demands of all the cathode areas on the steel surface High ground resistance and too small a potential difference between the anode and the casing will prevent most metals that are electronegative to iron from being useful as sacrificial anodes.

One way of circumventing the problem of too small a potential difference is to use a rectifier system that can supply large amounts of current and an anode bed made from scrap iron, carbon rods, or Duriron. The rectifier system can then be adjusted to supply the desired amount of current to the casing.

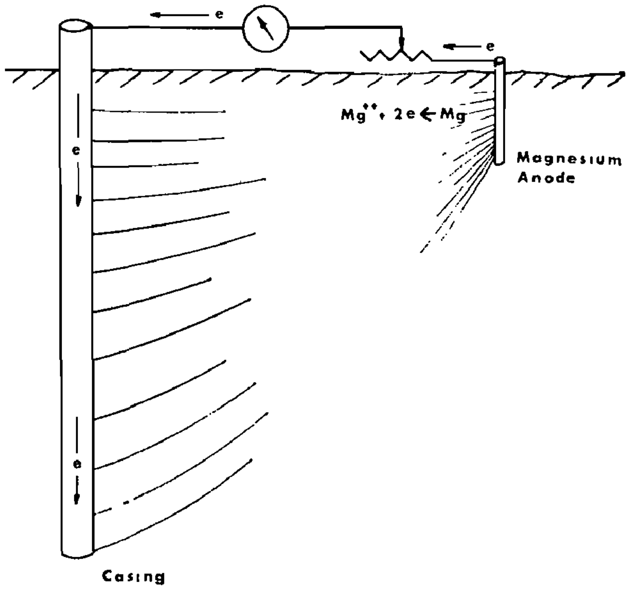

Fig. 2 (Schremp)—Cathodic Protection Using A Sacrificial Anode

Determination of cathodic current requirements for oil-well casings is difficult because direct measurement of corrosion currents is impractical Instead, a number of criteria have been developed that are useful in estimating current requirements Several of the more widely used criteria are discussed in the following section.

Criteria for Current Requirements

Three of the criteria for cathodic current requirements are illustrated by the use of a polarization-potential diagram The diagram of a single anode and cathode cell is shown in Fig 3. Lines E_c-S' and E_a-S are the polarization curves for the cathode and anode, respectively. The point E_c represents the open circuit potential of the cathode area and E_a, the open circuit

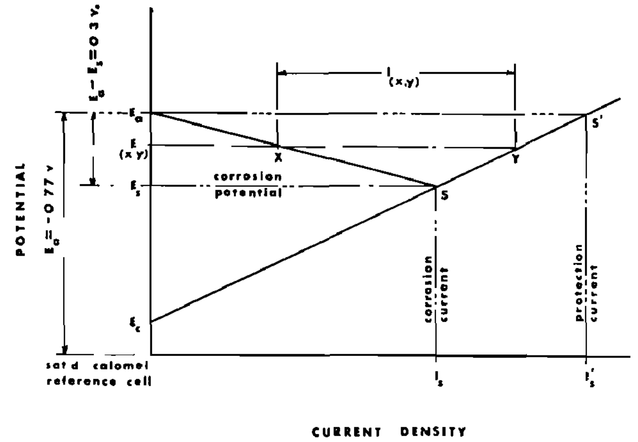

Fig. 3 (Schremp)—Polarization Diagram of a Single Corrosion Cell Illustrating Various Criteria for Cathodic Protection

potential of the anode area Both potentials refer to a saturated calomel half cell Point S defines the corrosion potential E_S and current I_S of the combined cell.

Cathodic-protection theory requires that the cathode potential shift along S-S' toward Y and the anode potential along S-E_a toward X when a counter current is applied to the cell Theory also states that when X reaches E_a, i e , when the polarized potential $E_{(x,y)}$ of the cell equals the open circuit potential E_a of the anode, the anode current is zero and corrosion ceases. Point S', therefore, defines the external current I_S' required to stop corrosion.

Following is a brief discussion of the more widely used criteria.

1. *Pipe-to-soil potential.* According to this criterion, corrosion will stop when the pipe-to-soil potential is equal to the open circuit potential of the anode areas Laboratory work shows that the open circuit anode potential depends upon the activity of ferrous ions in the corrosive environment. Pure iron in equilibrium with a solution of ferrous ions, $Fe(OH)_2$ at pH = 8 3, has a potential of —0.77 volts referred to a saturated calomel half cell, —0 85 volts referred to Cu; $CuSO_4$ Hence, if the pipe-to-soil potential of the casing can be raised to a value of —0.77 volts referred to saturated calomel, corrosion will stop Schweidtfeger and McDorman[1] verified this behavior in a series of experiments involving the corrosion of steel in various soils. Of course, field conditions may affect the potential at which corrosion stops, but the result is to lower the potential requirement The potential criterion of —0 77 volts may, therefore, err on the conservative side Ballou and Schremp[2] have attempted to extend the usefulness of this criterion to oil-well casing by proposing a relationship between down-hole pipe-to-soil behavior and surface measurements Their work indicates that down-hole polarization may be estimated from surface measurements alone

2. *Potential shift.* Field experience has shown that the corrosion potential of steel seldom is more than 0 2 to 0 3 volts below the open circuit potential of the anodic areas This is true because polarization of buried steel is largely under cathodic control Reference to Fig. 3 shows that the first and second criteria are similar because they both depend upon raising the casing potential to the open circuit potential of the anode areas.

3. *Current density* This criterion is based almost entirely upon field experience Pipeline engineers have found that current densities ranging from 0.5 to 20 milliamperes per square foot of exposed pipe surface will prevent corrosion in surroundings ranging from high-resistivity soil to sea water. Current densities in the range of 1½ to 3 milliamperes per square foot appear to be satisfactory for the prevention of casing corrosion.

4. *Break in the polarization potential, log-current curve.* This criterion was first reported by Britton[3] in 1931 and is best explained by the use of polarization diagrams. Polarization under cathodic control is shown in Fig. 4a, and polarization under mixed control, in 4b. Associated with each curve is a plot of the polarization potential-vs -log applied current

Reference to Fig 4a shows that under cathodic control the cell potential is virtually the same as the open circuit potential of the anode area. Application of counter-current to such a system causes no change in the cell potential until a certain minimum current, I_S is exceeded. Application of currents greater than I_S causes the potential to increase. The increase in potential with applied current now obeys the Tafel equation for hydrogen overvoltage. Protective current is indicated by I_S' and corresponds to the break in the *E-vs.-log I* curve

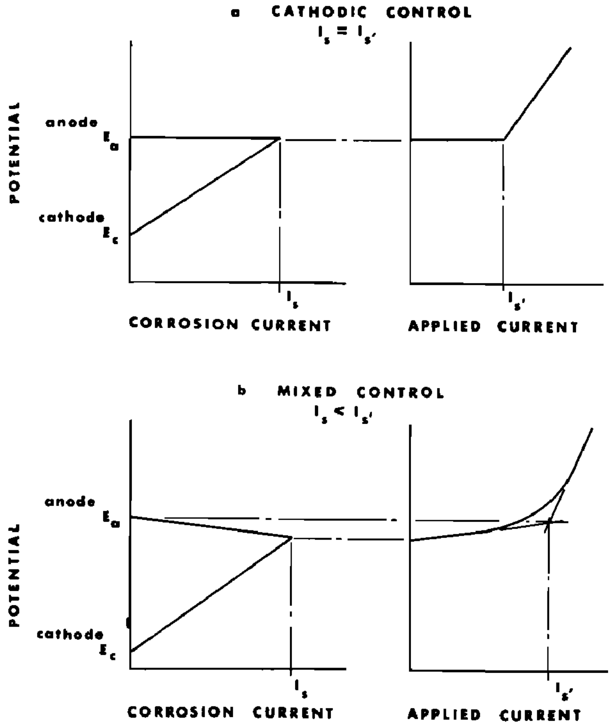

Fig. 4 (Schremp)—Effect of Polarization on Current Requirements

Fig 4b shows that the corrosion current I_S is less than the required protective current I_S'. Polarization behavior under mixed control is different from the behavior under cathodic control because the anode and cathode polarization potentials are not identical functions of the applied current. For low values of applied current, the composite polarization potential increases slightly At higher values of applied current, the slope of the *E-vs.-log I* curve continues to increase Ultimately, values of current are reached that cause the polarization potential to obey the Tafel equation. Mixed control makes difficult the determination of the current required to prevent corrosion One way to determine current from the *E-vs.-log I* curve is to extend the straight-line portions of the curve and use the point of intersection to indicate the proper current.

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[1] References are at the end of Part 1

Eldredge and Haycock[4] studied current requirements under mixed control behavior and found that for oil-well casings a more accurate indication of current is given by the point at which the *E-vs.-log I* curve straightens out and begins to obey the Tafel equation Both the intersection and Eldredge-Haycock criteria are illustrated in Fig 5.

A fifth and final criterion involves the measurement of IR drops along the casing The plot of IR drops vs. well depth is called a potential profile. Inasmuch as the IR drops are a function of the corrosion current flowing in the casing, changes in the slope of the potential profile indicate regions where current is either being picked up or discharged from the casing. Corrosive intervals are indicated by negative slopes on the potential profile. Erasure of negative slopes by the use of counter-current is believed to indicate cessation of corrosion

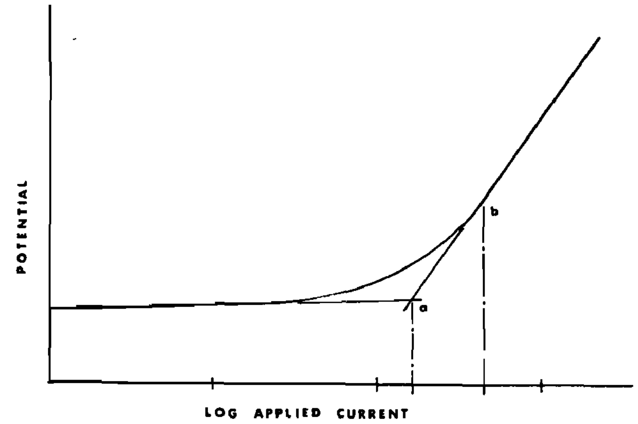

Fig. 5 (Schremp)—Current-potential Curve Showing Two Ways of Estimating Current Requirements

The measurement of potential profiles has been described in detail elsewhere.[5,6,7] For purposes of this paper, the potential-profile logging setup is shown schematically in Fig. 6. An explanatory profile is shown in Fig 7.

Reference to Fig. 7 shows that in region *A*, electrons are flowing from the casing and the slope of the potential profile is positive This indicates a cathodic region. In region *B* the slope is vertical, indicating that current is not entering or leaving the casing Such behavior might result if the casing were cemented through the interval Region *C*, which is anodic, shows a negative slope on the potential profile Electrons are entering the casing and metal is being dissolved. Region *D* is another cathodic area. No mention is made of the direction current flowing in the casing because it has no bearing on the interpretation of the potential profile. The slope of the profile through various intervals is important because it indicates the rate at which electrons enter or leave the casing. Severity of corrosion increases as the negative slope approaches the horizontal.

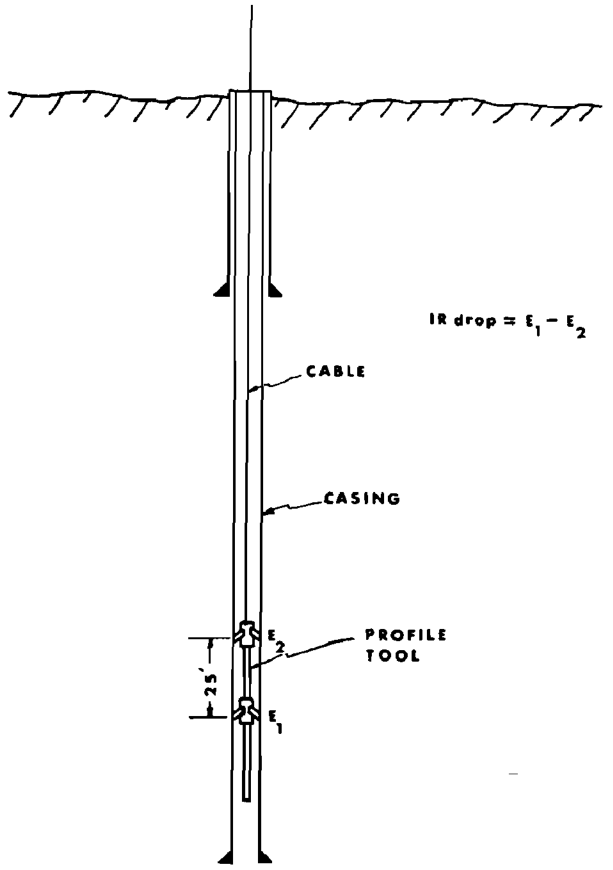

Fig. 6 (Schremp)—Casing-potential Profile Logging Setup

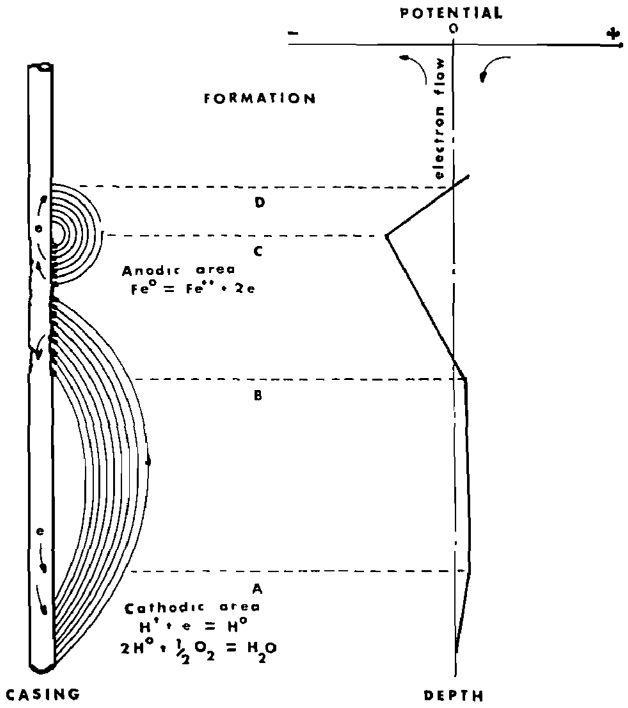

Fig. 7 (Schremp)—Casing-potential Profile

Table 1 (Schremp)

Advantages and Limitations of the Various Criteria Used to Estimate Cathodic Protection Current Requirements

Criterion	Advantages	Limitations
1. Pipe-to-soil potential of —0 85 volts (Cu; $CuSO_4$ reference)	Inexpensive measurement to make If used properly, will give a conservative estimate of current required.	Potential should be measured at the bottom of the casing. Usefulness of Ballou, Schremp-type surface measurements not completely evaluated.
2 Potential shift	Same as *1*.	Depends upon the assumption that the average corrosion potential of steel is 0.2-0 3 volts more cathodic than the open circuit anode potential. Potential shift also should be measured down hole.
3. Current density	Useful in making preliminary estimates of current requirements.	This is only a secondary criterion. Knowledge of cathodic-protection requirements for a given area must be available if reliable estimates are to be made.
4 "Break" in *E-log I* curve	Does not depend upon the open circuit anode potential to arrive at an estimate of current required. Gives a reasonably accurate estimate of current requirements. Relatively inexpensive to use.	Break in *E-log I* curve must be quite distinct if reliable estimates of current requirements are to be made Also, this method will not indicate the amount of current needed to prevent severe local cell action.
5 Potential profile	Indicates the probable location of gross anodic areas. Gives a qualitative picture of gross corrosion on the casing.	Erasure of negative slopes usually results in too low an estimate of cathodic current required. Profile cannot identify local cell action, hence erasure of negative slopes cannot indicate complete protection. Measurements are expensive to make.

SUMMARY

Cathodic protection involves the application of sufficient counter-current to neutralize the corrosion current and prevent iron from going into solution. Five criteria for estimating current requirements were discussed. Perhaps the most widely used criterion is the "break" in the *E-log I* curve Popularity of this criterion probably results from the relative simplicity of measurement. all measurements can be made above ground.

The relative usefulness of each criterion previously discussed is indicated in Table 1

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PART 2

CASING CATHODIC PROTECTION — SAN MIGUELITO FIELD

JACK A. BIREN*

ABSTRACT

Cathodic protection of oil-well casings in the San Miguelito Field has been effective in reducing oil-well casing failures Ten amperes of protective current as determined empirically with potential-profile techniques were recommended to provide protection from "normal" corrosion and from interference from surrounding cathodically protected wells Separate rectifier control and anode beds which serve from 1 to 4 wells are used in the 160 well installations Anode-to-soil resistance has prevented the use of recommended amperage at many wells Most failures have occurred in the first 10 years of well life, indicating a polarizing effect Evaluation cannot be completed until the 10-amp current is applied to all wells However, some protection is afforded at present current levels.

INTRODUCTION

A cathodic-protection installation believed to be the first to include all well casings in an entire oil field was put in operation during February 1956 at Continental's Grubb Lease, Ventura County, California Casing failures which have been attributed to external corrosion began in 1940 and increased logarithmically with time until a total of 29 such failures had occurred prior to completion of the cathodic-protection installation In addition to the loss of two wells and the resultant redrilling of another, the repair costs ranged from $7,557 to $70,956 and averaged $33,200 per well. In five instances where production could be continued by flowing or gas lifting through macaroni inside the tubing, the casings were not repaired These are marginal wells where it has been established that the cost of wash-over work to recover the tubing and packers from the casing is excessive in relation to the indicated reserves.

The record of known and probable failure depths in relation to the top of cement outside the casing as determined by temperature surveys or calculations indicates that in 21 of the 29 wells where casings failed, the holes were found where the casing was *not* cemented In only 4 wells were the holes indicated to be in cemented pipe Holes located partly in cemented pipe and partly in uncemented pipe were found in 2 wells whereas the failure depths have not been pin-pointed in relation to the cement top in the remaining 2 wells. These data, of course, are not an attempt to evaluate the completeness of the cement sheath nor its actual effective top, but do tend to support the theory that a cement coating does give some protection against external casing corrosion.

Determination of Current Requirements

Empirical methods were used to determine the amount of current to be applied to the wells at San Miguelito. In June 1954 a series of potential profiles were run in 4 Grubb Lease wells Three of these wells are situated on one well site with the casing heads less than 20 ft apart.

To determine the interference effect of adjacent wells, a current of 12 amp was applied to one of these wells while a profile was run on another — the two wells being in electric contact only through the ground A definite anodic slope was developed above 1,500 ft but none below that depth This effect was eliminated when all wells in the group were electrically connected at the surface.

A sharp anodic slope was noted in the potential profiles at the base of the surface pipe, which was cause for concern. To minimize the possible corrosion of the casing at this point, it was recommended that a casing centralizer be placed here in all new wells to assure metallic contact at this point.

In all 4 wells surveyed the potential surveys showed a tendency for external corrosion to occur over large areas of the casing These corrosive areas as defined by the profiles corresponded to the location of known failures in two of the surveyed wells No failures had been noted in the other two wells at that time, yet failure did occur in both prior to completion of the cathodic-protection installation.

The application of 3 to 5 amp of protection current was sufficient to remove all the anodic slopes from the profiles of the 4 wells tested. A trial run using 5 amp of impressed current was immediately started on one of the test wells and continued for a period of 6 months. At the end of this period the 7-in. casing was washed over and recovered from 5,200 ft The inspection and tests of the primary solids deposits revealed the following evidences of the effectiveness of the cathodic protection.

1 The corroded areas of the Grubb 61 casing were as predicted by the potential-profile survey.

2. A thin calcareous deposit was found in scattered areas over most of the pipe recovered indicating that cathodic protection was being effective to the depth of casing recovered.

3. The surface pipe effect was not sufficiently severe to prevent the use of cathodic protection

The recovered casing was replaced with a new casing string which was landed with a lead-seal casing bowl set over the stub of the old pipe at 5,200 ft. The new pipe was not cemented. Immediately after landing the

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*Continental Oil Co , Los Angeles, Calif new pipe, a potential profile was run. In contrast to the smooth anodic areas found in the profile of the old pipe, a very erratic series of breaks in the curve was found in this same hole with new pipe and new mud Time is apparently a factor in the establishment of equilibrium conditions within the hole.

Five amperes of impressed current on the new pipe were effective in smoothing out the erratic potential profile. It was concluded at that time that the application of 5 amp should be sufficient to protect each well in the San Miguelito Field. Subsequent interference tests have indicated 10 amp are needed

Application of Cathodic Protection

The cathodic-protection installations for Continental Oil Company's 160 Grubb Lease wells use separate rectifier control and 3 anodes for each well. The selenium rectifiers used at 1 and 2 well installations are rated at 20 volts and 15 amp per well, whereas those for 3 and 4 well installations are rated at 40 volts and 15 amp per well Voltmeters are installed on each rectifier, and ammeters are provided to indicate the current to each well on multiple and single well units alike. All rectifiers are pole mounted.

Each rectifier is connected to an anode bed which has 3 anodes for each well served by the rectifier, i.e., the anode bed for a 3-well installation has 9 anodes Graphite anodes 3 in × 60 in are set 1 ft off bottom inside a 12-in. augered hole back-filled with coke breeze to 1 ft above the anode, then 1 ft of gravel caps the coke breeze and the hole is filled to the surface with dirt. Anode beds are placed at least 150 ft from the wells involved. Care was taken to avoid adjacent wells, pipelines, and other surface structures which might adversely effect the casing-to-earth potentials at depth.

Operational tests include the periodic readings of the voltmeter and ammeters at the rectifiers. Differences and variances in the readings are considered to be indicative of the anode-bed effectiveness and operational problems. It has been noted that in the moist shale areas the recommended current flow is attained at less than rectifier-capacity voltage. However, the sandy soils in other areas afford resistances which have prevented the minimum recommended current from being applied at capacity voltages Relocation of anode beds to areas where they may be wetted and the addition of anodes in some areas are being effected to reduce anode-to-soil resistance. Evidence of rodent damage to the insulating sheath of the buried cathodic-protection cables has been found. The extent of this problem has not been determined to date

Interference tests were run in a well situated on the easterly side of the lease in an area of dense well spacing. Potential profiles were run to a depth of 5,800 ft with several variations of current applications on the test wells and offsetting wells. Eight amperes were sufficient current to remove the anodic slopes from the potential-profile curve with current applied to the surrounding wells An *E-log I* curve run at the time substantiated the 8-amp requirement. It was concluded that an interference or stray-current problem does exist between wells under cathodic protection and those wells in a field either with insufficient protection or with no protection. It was therefore recommended that a minimum of 10 amp should be applied to each well in the field and that necessary revisions be made in the anode beds to achieve the 10 amp per well.

Results of Three Years of Cathodic Protection

In February 1959, the cathodic-protection system at Continental Oil Company's San Miguelito operations completed three years of operation A deflection in the logarithmic-failure curve (Fig 1) at the time cathodic protection was applied would indicate a reduction in the rate of increasing casing failures. The 13 failures which have occurred since application of the protective current include second failures in 3 of the wells while 9 of the troubled wells had less than the recommended protective 10-amp current applied because of operational problems Extrapolation of the failure rate prior to the application of cathodic protection would indicate that 15 additional casing failures might have occurred during these past three years had the current not been applied It is realized, however, that other factors may have been involved in effecting this change. These factors include the following.

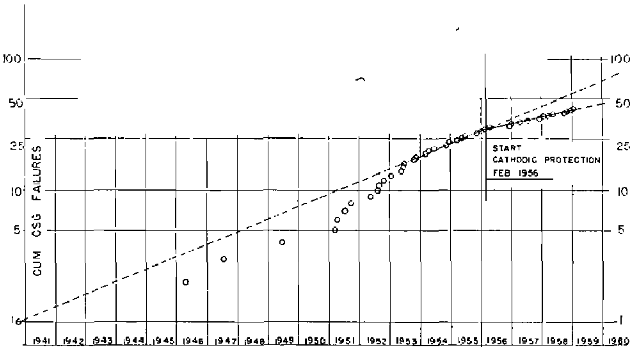

Fig. 1 (Biren)—Casing Failures Vs. Time
Continental Oil Co. — Grubb Lease —
Ventura County, Calif.

1. High well-completion rate during the 10-year period just before starting cathodic protection.
2. Condition and grade of the casing when run.
3. Nature of the drilling fluid.
4. Effect of polarization of the steel-casing surface.
5. Interference or stray currents from the cathodic-protection system itself.

The number of well failures which have occurred in each year of well service is indicated graphically in Fig. 2. It is noted that very few failures have occurred after 9 years of service. This is believed to be the effect of polarization The single failures in the extreme positions, 1st and 12th years, are perhaps indicative of the effect of the grade of casing used. The early failure was in cold-worked S-95 steel while the 12th-year failure was in H-40 steel. Inasmuch as both of the 19th-year failures occurred in wells with lower than

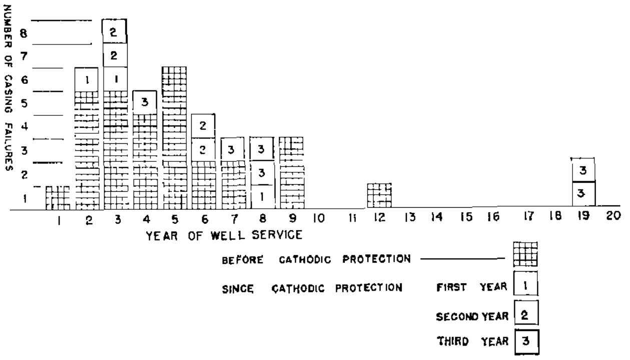

Fig. 2 (Biren)—Casing Failures Vs. Year of Well Service
Continental Oil Co.—Grubb Lease—Ventura County, Calif.

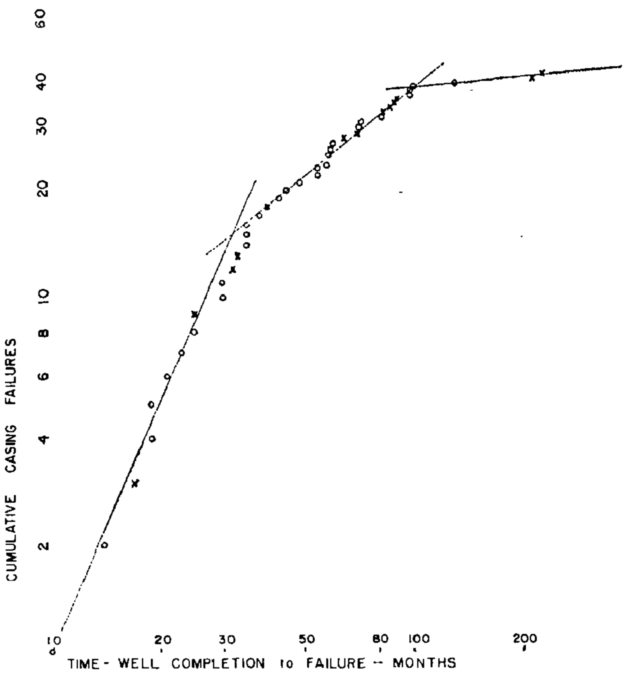

Fig. 3 (Biren)—Casing Failures Vs. Time in Hole
Continental Oil Co.—Grubb Lease—Ventura County, Calif.

recommended protective current, it is suspected that interference may be responsible.

The log-log plot of cumulative well failures vs. time from well completion to failure (Fig. 3) would indicate three phases in the process of failures. It is believed that the middle slope between 32 and 102 months is perhaps the norm, whereas the failures earlier than 32 months occurred either before polarization or because of some pipe defect. The latter failures after 102 months (9 years) are accounted for by the grade of pipe, H-40, which is apparently more resistive to corrosion and failures caused by insufficient protective current or interference.

CONCLUSIONS

A reduction in the rate of increasing oil-well casing failures in the San Miguelito Field has been effected by the application of a cathodic-protection current during the past three years. This reduction has been accomplished despite lower than recommended applied amperages on many wells. In fact, most failures which have occurred since application of the protective current have been in areas where anode-to-soil resistivity has restricted the use of recommended minimum amperages.

Casing polarization or stabilization of electropotential conditions within the casing well-bore annulus has been effective in confining the critical period for external casing corrosion to the first 9 years of well life. Field tests have shown that an interference or stray current problem does exist between wells under cathodic protection and those wells in a field either with insufficient protection or with no protection. The solution of the problem of applying the 10-amp current to those wells in resistive soil areas is necessary before evaluation of the San Miguelito oil-well casing cathodic protection system can be completed.

ACKNOWLEDGMENT

It is the writer's desire to thank the Continental Oil Company for permission to publish this paper and to acknowledge the planning and field work done by J. D. Lung, J. W. Wolfe, Jr., and H. F. Gerckens.

Appreciation is extended also for the use of the unpublished reports on this project by W. D. Greathouse, J. D. Sudbury, and J. E. Landers of Continental Oil Company's Research and Development Department, which were essential to the preparation of this paper.

PART 3

TWO YEARS OF CATHODIC-PROTECTION EXPERIENCE IN THE VENTURA FIELD

B. W. BRADLEY*

ABSTRACT

Cathodic protection was applied to approximately 500 of Shell Oil Company's Ventura oil-well casings in January 1957. Before that time Shell was experiencing in Ventura about 12 casing-corrosion failures per year, and the trend was increasing at about one additional failure per year. During 1957, with cathodic protection applied to approximately 500 wells, only 9 casing-corrosion failures occurred. This was in line with anticipated results. However, continuing study of the problem during that year indicated certain features of the

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*Shell Oil Co., Ventura, Calif.

Ventura cathodic-protection system could cause stray current interference between wells on a given drilling island. The conditions found most troublesome included *1*, grouping of anode beds in low-resistance soil near one well on multiwell drilling islands; *2*, location of anode beds near surface lines; *3*, shorted insulated unions; and *4*, abandoned surface lines. Casing-potential surveys in three wells, which experienced corrosion failures in rapid succession during early 1958, confirmed the need to correct these causes of stray current. Accordingly, all cathodic-protection units were turned off after approximately 18 months of operation as a precautionary measure while the problem was evaluated and corrected. The nine 1957 casing-corrosion failures and 11 in 1958 were below the past failure trend and indicated that some degree of protection was obtained in spite of stray currents during these 18 months of protection and lack of protection during the last 7 months.

By the end of 1958 cathodic-protection equipment in a test block of 46 wells was revised for stray-current control. Casing-potential surveys in 2 wells within the block revealed that cathodic protection can be applied to densely drilled wells without adverse effects of stray currents to that number of wells.

INTRODUCTION

Starting in 1949 efforts were made to control oil-well casing-corrosion failures in the Ventura Field. The various schemes, which included full-string cementing, high pH drilling mud, bactericide in high pH mud, and oil-base mud, were either ineffective or too expensive. During this time the annual number of failures was increasing and it appeared that cathodic protection might be an effective and profitable way to reduce the failure rate. Accordingly, investigations into the use of cathodic protection were begun in early 1955. The results of this work and the method of applying cathodic protection to the Ventura well casings were reported by Kerr[1] in 1957. As stated by Kerr the current potential-curve criterion, plus economic considerations, was used as the basis for selecting current requirements of 27 amp per well.

Kerr's work indicated cathodic protection could be applied satisfactorily to deep oil-well casings, and a test block of 27 wells was placed under protection. However, the casing-failure rate took a decided increase in 1955, as shown in Fig. 1, which indicated an increasing number of failures might be experienced in the coming years. Therefore, Shell undertook a field-wide installation of cathodic protection shortly after completing the test-block work, and before the results could be studied and evaluated. The installation of equipment was completed by January 1957, when 475 well casings were placed under cathodic protection. New wells drilled in 1957 brought the total well casings under protection to about 500 by January 1958.

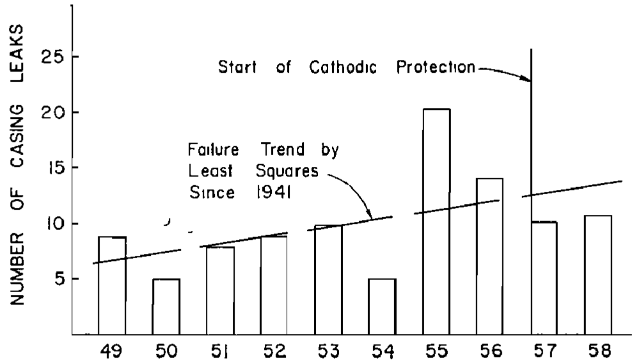

Fig. 1 (Bradley)—Annual Casing Failures — Ventura Field

Ventura Field Topography and Oil-production Facilities

Before discussing the main subject of this report, cathodic-protection stray currents, it is important to first visualize the characteristics of the field. This field is widely known as one of the nation's prolific oil producers due partly to 22 producing reservoirs. To develop these reserves, wells have been drilled into each sand on a given spacing. In localities where two or more sands overlie one another the spacing patterns often result in wells being drilled very near one another, say as close as 50 ft.

The problem of close well spacings is further complicated by the rugged terrain of the area with elevation changes of as much as 300 ft occurring within a horizontal distance as short as 600 ft. Because of the rugged nature of the land, all semi-flat areas are at a premium. Thus, the high density of wells is further squeezed together on drilling islands cut from the hills.

Each of these drilling islands is served by pipelines supplying mud, fuel gas, and water. Additional pipelines for the wells located on each island are flow lines, gas-lift lines, hydraulic-lift oil lines, and in some instances fuel gas and water lines for pumping equipment or well servicing. These lines are buried where they cross the drilling island or lease roads, but are laid on the surface or pipe racks elsewhere. As the result of inevitable changes and continued development, some lines are abandoned in place or covered by many feet of fill dirt.

In summary, on the Shell leases in the Ventura Field, comprising about 1,860 acres, approximately 620 wells have been drilled. This is equivalent to 1 well every 3 acres, which are grouped even closer together on the surface because of the rugged topography of the area.

Indications of Stray Currents

On completion of the installation work, field studies were undertaken in 1957 to check the circuits and to determine the degree of protection being obtained. Several anomalies were observed, but not understood at that time. The first well re-entered to study a wellhead-to-soil potential anomaly (Taylor 430) gave the casing-potential profile shown in Fig. 2 with all wells on the drilling island under protection. (For test

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[1] Reference is at the end of Part 3.

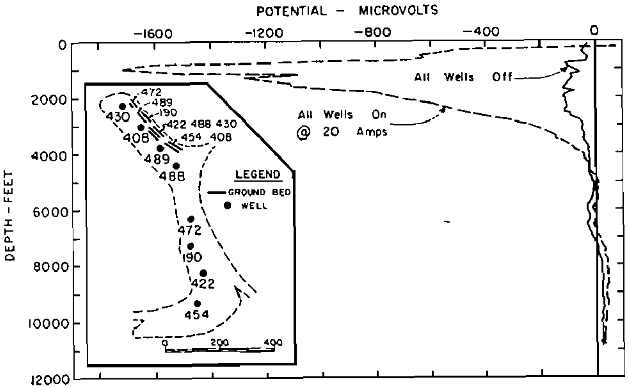

Fig. 2 (Bradley)—Potential Profiles — T-430 Original Anodes

purposes 20-amp protective current was used for all casing-potential surveys.) With Taylor 430 on protection alone a normal profile indicating protection was obtained. Taylor 430 was 1 well on an 8-well island, and as shown in the insert, the anode beds for all wells had been bunched in low-resistant soil near Taylor 430

Grouping of anode beds in this manner had been based on a study of ground-bed sites which revealed that soil type was the predominant factor controlling circuit resistance. Shale outcrops throughout the field provided circuit resistances much smaller than other soils, and had been selected as anode-bed sites in order to save power costs. It was reasoned that because all wells would be under protection, the current would seek out the well casing it was to protect without interfering with protection to other wells The profiles in Taylor 430 showed this was not the case.

It was hypothesized that the bunched anode beds were the major cause of interference Accordingly, the beds were revised to place each bed closer to the well it protected than any other casing, and repeat surveys were conducted. The results of this work are shown in Fig. 3. With all wells on the potential profile indicates a protected profile with somewhat less protection than if Taylor 430 was on protection alone With all wells on the drilling island off, a corroding condition was observed This condition was thought caused by stray current from anode beds protecting wells on adjacent drilling islands, but was of little consequence inasmuch as all cathodic-protection units were to be on all the time.

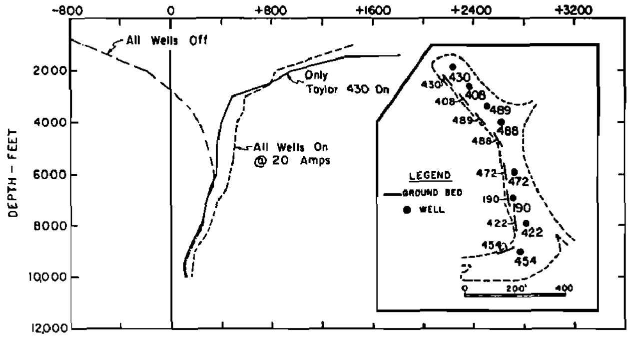

Fig. 3 (Bradley)—Potential Profiles — T-430 Revised Anodes

1957 Activities

Throughout 1957 this problem was studied in the field, and although other situations of poorly located anode beds were found to be causing adverse conditions, none were as severe by wellhead-to-remote soil potential measurements as found at Taylor 430. Each of these cases was corrected as soon as the opportunity presented itself.

During 1957 Shell Oil Company experienced only 9 casing failures attributable to corrosion As shown in Fig. 1, this was 3 failures below the average for the last 4 years, and also 3 failures below the trend line established since 1941. Thus, in spite of the known interference problems, which were being corrected, the failure frequency was down somewhat.

Casing Failures in Early 1958

During the first 4 months of 1958, potential-profile surveys were made in 3 wells while they were being worked over to repair casing leaks. The results of these surveys are discussed individually following

Taylor 397

The potential profile obtained in this well, along with the anode wellhead arrangement on this island, is shown in Fig. 4. Wellhead-to-remote soil potentials taken before re-entering the well indicated what was interpreted as a questionable degree of protection. The flow of current to Taylor 398 could easily have been straying on to and off of Taylor 397 casing as suggested by the potential profile. It was thought at the time that the interfering stray currents were one or a combination of the following

1. Stray current from anode beds on this island
2. Surface-line stray currents from other anode beds; and possibly
3. Stray current from anode beds on nearby drilling islands.

However, with Taylor 397 protected alone (no interfering stray currents from this island or to surrounding islands) protection was still not attained Inasmuch as

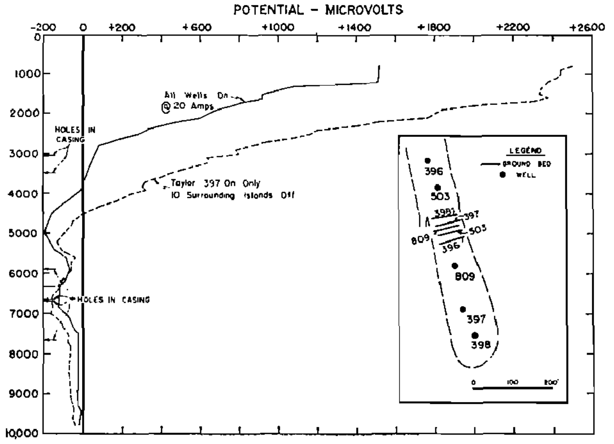

Fig. 4 (Bradley)—Potential Profiles — T-397 Original Anodes

the "on alone" profile was made with practically no chance of interfering stray current, it was assumed that proper protection for some time would be required to overcome the damage. At the time this explanation did not seem too logical, but was the only explanation possible.

Although six holes and a split were found in the casing, the well gave indications of a failure before installation of cathodic protection. Nevertheless, the conditions caused by the arrangement of these beds could contribute corrosion damage to this well casing After revising the anodes on this island, a survey was run in Taylor 809, a neighboring well, which indicated adequate protection was possible with proper anode placement as described later.

Taylor 462

A potential profile was run in this well during a workover to repair a casing leak. Based on the knowledge obtained from the Taylor 430 and Taylor 397 anode and well arrangements, it was suspected that Taylor 462 was being damaged by stray currents created by the situation shown in Fig. 5 Therefore, a few days before re-entering the well a new bed was installed on the Taylor 462 island (see Fig. 6) which should have corrected the situation. However, the profile revealed a condition which apparently was the result of surface-line stray currents and/or the residual effects of damage by the poorly placed anodes. Support for the latter theory was gained when another "on alone" profile, run after leaving the well protected by 35 amp for 15 min, was shifted a marked amount in the protected direction. The influence of stray current from *1*, anodes on surrounding drilling islands and/or *2*, surface-line stray currents is shown by the "both wells off" curve.

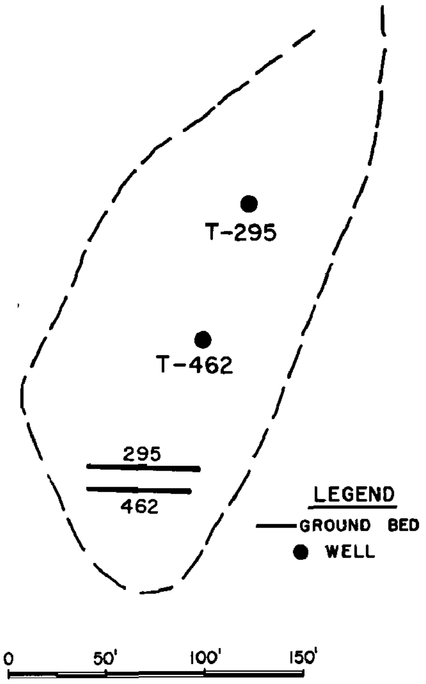

Fig. 5 (Bradley)—Old Position of Ground Beds and Wells — T-462

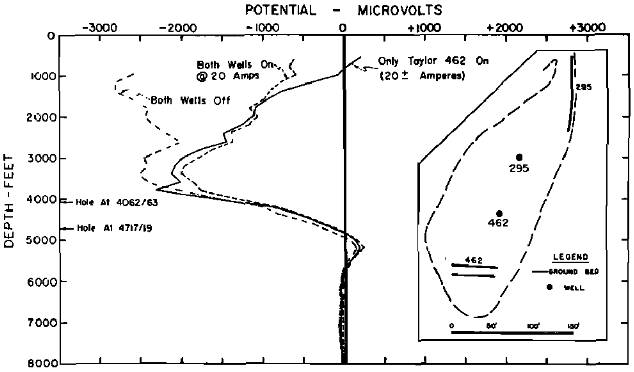

Fig. 6 (Bradley)—Potential Profiles — T-462 New Anodes

Taylor 453

The next casing-potential survey was run in Taylor 453 during a casing-repair workover. Wellhead-to-remote soil potentials on this well gave values thought indicative of protection Although the anodes were poorly located on this island, as shown in Fig 7 insert, there should have been no stray current from this island interfering with protection to Taylor 453. However, two anodic intervals, see Fig. 7, were revealed by the casing-potential profile. When protection to the casings of all wells on Taylor 453 island was turned off, the presence of stray current became evident.

Tests in 46-well Block

These experiences all apparently involved some manifestation of stray current which was neither thoroughly understood nor controlled. In addition to the stray current from poorly placed anodes, it was known that considerable stray current existed on surface lines at this time inasmuch as the work to control these had just begun. Furthermore, there was possibly some stray current flowing directly to these wells from anodes on nearby islands. However, the amount of stray current from each source was unknown.

In view of these conditions it was possible that damage might be occurring to an unknown number of well casings Therefore, it was decided to turn off

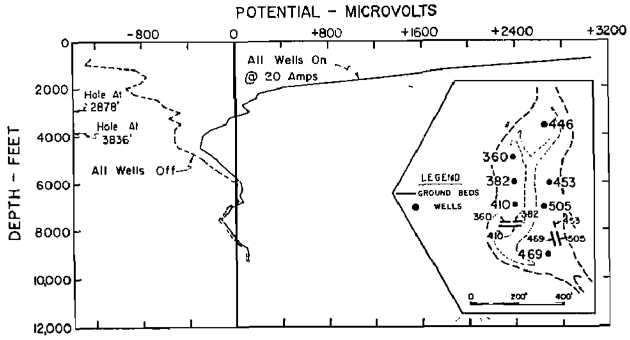

Fig. 7 (Bradley)—Potential Profiles — T-453 Original Anodes

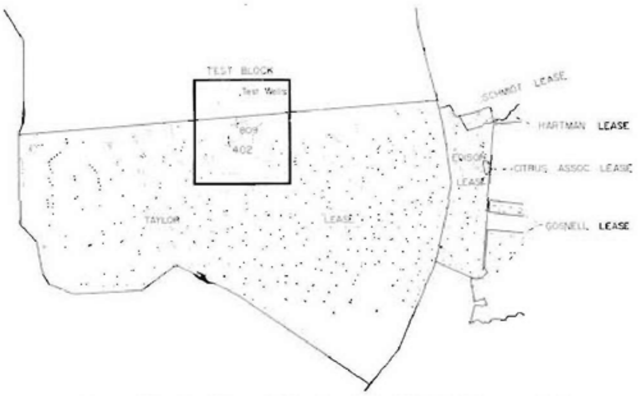

Fig. 8 (Bradley)—Test Block, Shell Wells and Leases

protection to all casings, and to thoroughly evaluate the problem in a selected block of wells. The block selected, see Fig. 8, contained many multi-well islands, large concentrations of surface lines, and two wells in which previous potential surveys had been made.

17-well Test

The first step consisted of revising the equipment to properly protect 17 wells in a group of 5 drilling islands located within the 46-well test block. New anodes were installed so each bed would be nearer the casing it protected than any other casing. The old anodes were left in place for comparative tests. Cables were installed to drain stray current from all surface lines back to the offending rectifiers. The current drained back was measured by permanent shunts, and could be adjusted by changing resistors as shown in Fig. 9 and explained later.

After completing this work a potential survey was run in Taylor 809, a well centrally located on a 5-well island with only the 17 wells under protection. It was also located next to Taylor 397 which was previously reported to have been subjected to stray currents. The first potential profile was made under the original conditions, i.e., old anode beds and no control of surface-line

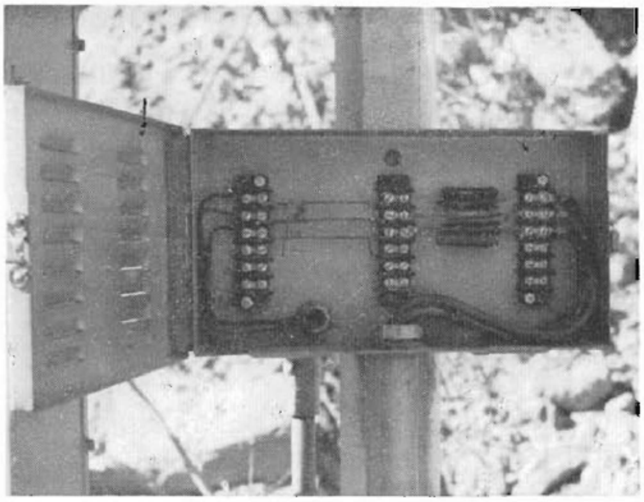

Fig. 9 (Bradley)—Drain Resistors and Shunts — Three-well Island

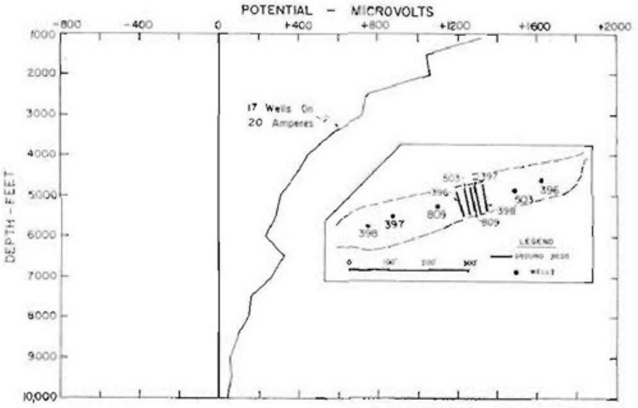

Fig. 10 (Bradley)—Potential Profiles T-809 Old Anodes

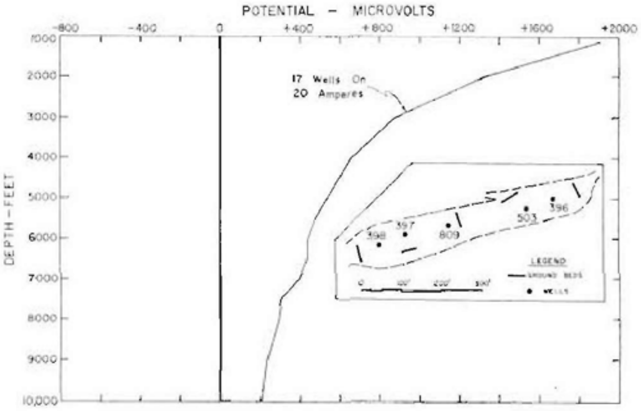

Fig. 11 (Bradley)—Potential Profiles T-809 New Anodes

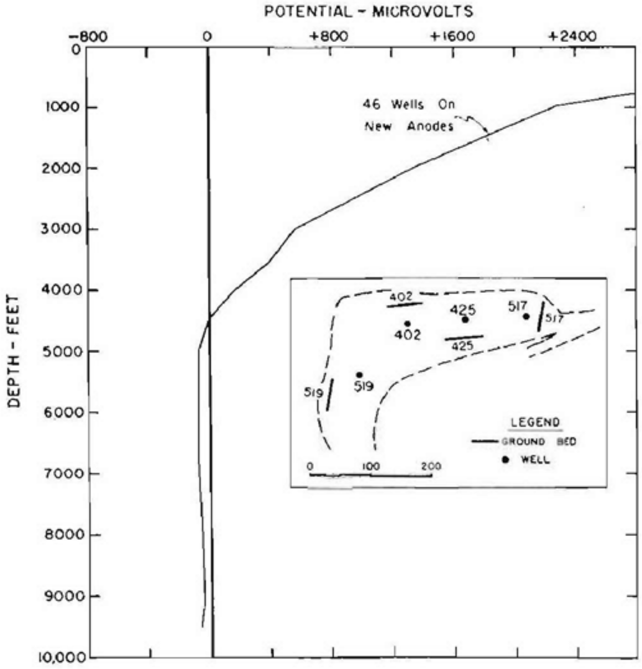

Fig. 12 (Bradley)—Potential Profiles — T-402 New Anodes

stray currents as shown in Fig. 10. Although the apparent anodic interval at 1,500 to 2,000 ft could have been caused by a change in casing weight, the corroding condition at 6,000 to 6,500 ft was caused by stray currents.

All wells were then protected with the new anode beds and no surface-line stray currents. A potential profile indicating satisfactory protection is shown in Fig. 11.

46-well Test

The next step consisted of revising equipment for the remaining wells in the 46-well test block in the manner described previously, and making similar casing potential surveys in a well (Taylor 402) centrally located in the block (see Fig. 8).

Considering the experience in Taylor 809 the first profile was made with all 46 wells protected by new anode beds and surface-line stray current controlled. The surprising results, which revealed the casing to be unprotected below 4,500 ft, are shown in Fig. 12. In the ensuing investigation it was found that this well had been damaged at some time by stray current flowing through a shorted flow-line insulating union. Because the well had never been protected by properly placed anodes, the results of damage had never been overcome. In an attempt to overcome the theorized residual damage (protection had been turned off 5 months at the time) the well was protected overnight by 50 amp. On the following morning a repeat potential survey with all wells under ideal protection at 20 amp gave the results in Fig. 13.

To determine if the indicated protection shown in Fig. 13 resulted from the overnight protection at 50 amp, a repeat profile was made two days later. The results were the same as shown in Fig. 13. During the intervening two days the well was subjected to miscellaneous currents and ideally protected overnight by 20 amp as were all 46 wells.

Observations During Test-block Work

During the revision work in the 46-well test block several significant problems were encountered. These problems and other pertinent observations are summarized following.

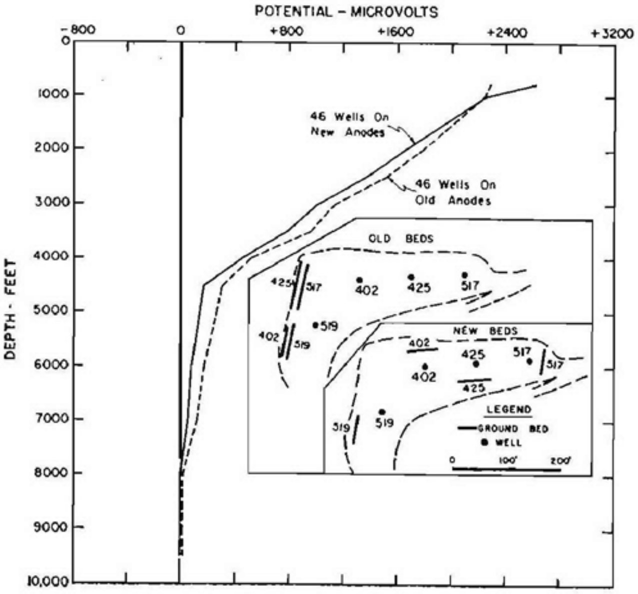

Fig. 13 (Bradley)—Potential Profiles — T-402 Old and New Anodes

1. Surface-line Stray Currents

Theoretically, to control stray currents on surface lines it is necessary to *1,* elevate lines near anodes on wooden blocks; *2,* move anode beds or pipelines when they are located too near each other; and *3,* establish a current-drain connection from each pipeline back to the offending rectifier. However, from a practical viewpoint all pipelines lying together in one group can be treated as one line by electrically bonding them together and providing one drain cable back to the rectifier. It was found in a few instances that some pipelines act like individuals and require separate drain cables for proper stray-current control. On multi-well islands several current-drain cables were usually required to drain current back to each rectifier. Fig. 9 illustrates the rather simple circuits on a 3-well island with a minimum of pipelines to pick up stray current. Fig. 14 illustrates the multiple circuits existing on an 8-well island crossed by numerous pipelines. To arrive at the proper drain current the stray current in each line (or group of lines) was measured under conditions of no-current and full-current output. The resistors were then inserted

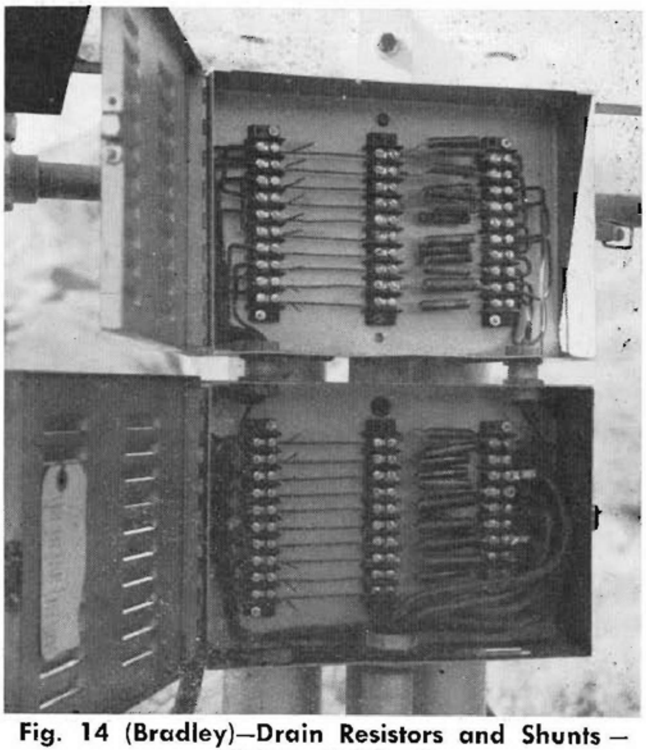

Fig. 14 (Bradley)—Drain Resistors and Shunts — Eight-well Island

Table 1 (Bradley)
Surface-line Stray Currents on Pipelines Leaving 46-well Test Block

Condition	Total Current Leaving Block, Amperes
1. No cathodic protection.	4
2. 45 old anodes on (no control of surface-line stray currents).	157
3. 46 new anodes on (with surface-line stray-current control)	0.8*

*Current entering block

on a trial and error basis until there was less than 0.1 amp of stray current on every line leaving the island.

To obtain some idea of the amount of surface-line stray current that existed under the original and revised conditions, an envelope was drawn around the 46-well area on a map, and the current flowing in the 198 lines that crossed the envelope was measured. The results, which are shown in Table 1, illustrate the severity of the surface-line stray current without control measures.

Fig. 15 illustrates how surface-line stray currents can cause interfering stray currents on well casings. In the assumed case the surface-line stray current corrodes both the surface line and a nearby foreign well casing. However, the surface-line stray current can be controlled by draining the current back to the offending rectifier as previously described. Although this still leaves some stray current to flow directly through the soil to the nearby foreign well, even that can be overcome by placing the foreign well under protection as shown by the protected profiles of Fig. 11 and 13. Although Fig. 15 shows 2 amp of stray current flowing through the soil to the neighboring well and 2 amp of stray current on the flow line, tests have shown that on multi-well islands the surface-line stray current is by far the largest and most significant stray current. For instance, detailed tests on a 5-well island indicate that stray current flowing directly through the soil was about 1.25 amp per anode bed while as much as 5.8 amp per anode bed were leaving the island via the surface pipelines.

To control the surface-line stray currents, illustrated in Fig. 15, and still obtain about 20-amp protection to the casing, it is necessary to increase rectifier output by approximately the amount of current drained from the surface lines. In Fig. 15, it is 2-amp drain or 22-amp rectifier output. This 10-percent increase in current divides itself proportionately to the various parallel circuits. Thus, 16 amp current flowing directly to the well casing is increased 10 percent to 17.6 amp and 2 amp stray current to the nearby well is increased 10 percent to 2.2 amp. Nevertheless, control of the surface-line stray currents reduces the total stray currents attempting to flow onto nearby well casings. An analysis of these circuits is presented in Table 2.

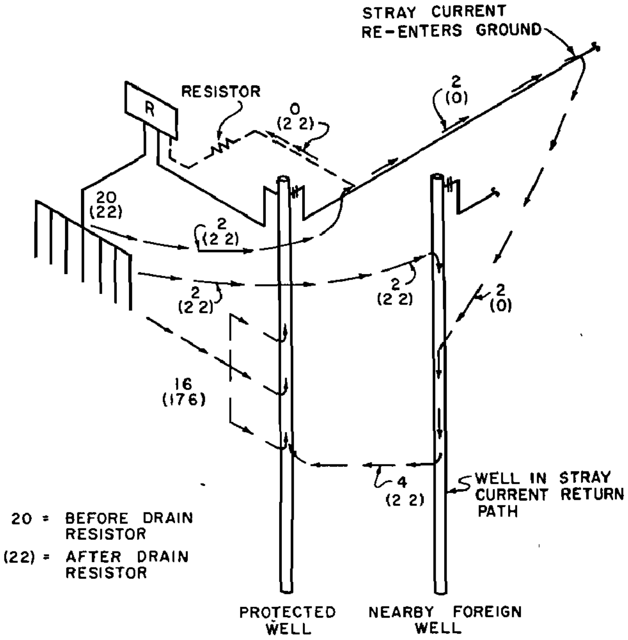

Fig. 15 (Bradley)—Paths of Cathodic-protection Stray Currents

Table 2 (Bradley)
Cathodic-protection Circuit Currents

	Without Drain Resistor	With Drain Resistor
Protected-well Circuit		
Current direct to protected well	16	17.6
Current via stray routes to protected well	4	2.2
Total current protecting well	20	19.8
Current returned by drain resistor from flow line	0	2.2
Rectifier output	20	22.0
Flow-line Circuit		
Corroding stray current	2	0
Foreign-well Circuit		
Corroding current directly through soil	2	2.2
Corroding current from flow lines	2	.0
Total corroding stray currents	4	2.2

2. Abandoned-line Stray Currents

In several instances during the revision work it was impossible to control the surface-line stray current in spite of direct electrical short circuits back to the rectifier from a certain pipeline. This was found to result from pipelines abandoned in place years ago and now located unknown very near the anode beds. Old maps and the memories of old timers were helpful in locating abandoned lines when stray-current conditions typical of such conditions were encountered. These lines were removed to control stray currents.

3. Shorted Insulated Unions

In several cases in which it was initially impossible to control surface-line stray currents by drain resistors, it was discovered that the troublesome lines were flow or gas lines connected to a well without an insulated union or through a shorted union. In such cases the current would flow directly to the well inasmuch as shorted unions provide a very low-resistant path to the well casing which provides an exceptional anode.

CONCLUSIONS

In view of the foregoing tests and analyses it appears that the 46 wells in the test block can be placed under proper cathodic protection. Similar techniques should apply to large groups of densely located wells, although other conditions now unknown might become apparent. It has been shown that proper application of cathodic protection to well casings can only be accomplished by *1*, proper location of the anode beds; and *2*, control of the surface-line stray currents, which often requires *a*, removal of abandoned lines, *b*, adequate insulation of wells from connecting lines; *c*, elevation of lines when near anode beds, and *d*, occasionally moving either the anode bed or pipelines.

ACKNOWLEDGMENT

The author wishes to thank Shell Oil Company for permission to publish this report, and to acknowledge the assistance of F. E. Field in planning and executing the test work, and the tireless efforts of W. W. Salisbury, J. A. Trapasso, and J. J. Walker in gathering the large amount of data required to analyze these problems. In addition, appreciation is extended to L. B. Nelson, Shell Pipe Line Corporation; E. W. Wallace, Shell Oil Company; E. W. Haycock and W. J. Warren, Shell Development Company, for their helpful suggestions concerning the test work.

REFERENCE

[1] Keir, A. W. Cathodic Protection of Casing, Ventura Field, Paper No. 801-33-G, presented at the spring meeting of the Pacific Coast District, Division of Production, American Petroleum Institute, Los Angeles, Calif., May 16 and 17, 1957.

PART 4
CASING CATHODIC PROTECTION EXPERIENCE AT KETTLEMAN HILLS

FRED L. SMALL*

ABSTRACT

Forty-five installations for cathodic protection of well casing have been made at Kettleman Hills since June 1956. This report covers the results of operation, with special emphasis on the correlation of *E-log I* test (determination of wellhead potential vs. the logarithm of the drained current) to indicate current-drain demand with the actual current drain established by usage. Theory and manipulation of the test have been covered in other papers and will not be discussed herein.[1,2,3]

BACKGROUND HISTORY

General

The wells being protected are generally the most valuable wells. They represent a good cross-section of all wells at Kettleman Hills and are scattered throughout the field. The wells have completion dates from 1930 to the present, and represent all producing zones.

There has been no casing failure reported in any of the 45 wells under cathodic protection. Based on experience prior to cathodic protection, two casing failures should have occurred in this group if no cathodic protection had been applied.

Anode Beds

All installations are graphite anode beds with air-cooled rectifiers. Both selenium and silicon-diode rectifiers have been installed; neither appears superior to the other at this time. Each installation was originally designed to serve one well only. However, inasmuch as usage has shown that surplus capacity was available

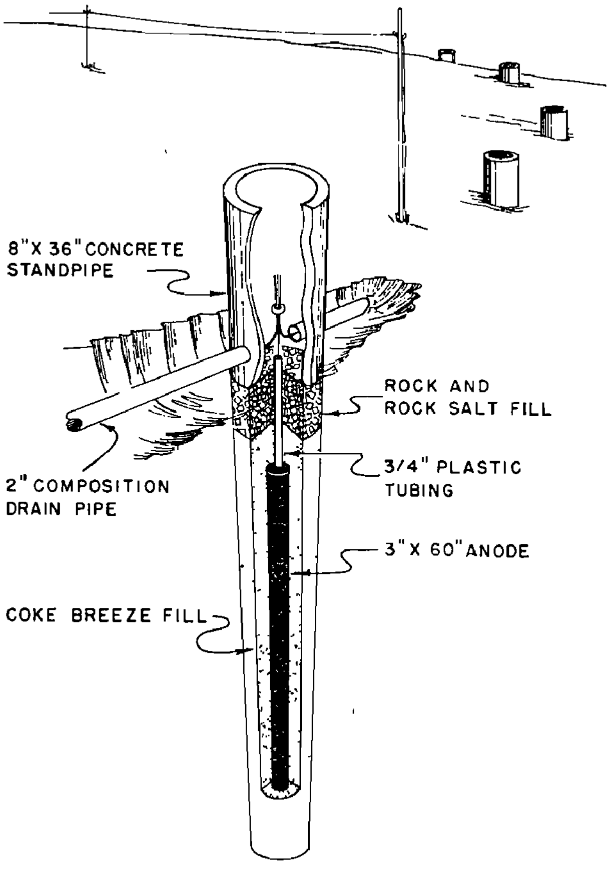

Fig. 1 (Small)—Vertical Anode-bed Installation

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*Standard Oil Co. of California, Western Operations, Inc., Avenal, Calif.

[1] References are at the end of Part 4

at some installations, adjacent wells have been tied in to utilize this excess capacity for partial protection Four such dual installations are now in use, and more will probably be made

The first installations made were with anodes in series, laid in a trench. Much trouble has been experienced with rodents eating the insulation off the buried cable, necessitating many costly repair jobs. All later installations have utilized 3 in. by 60 in graphite anodes installed vertically, in 12-in. diameter by 10-ft deep drilled holes, and packed with coke breeze. The anodes are hooked up in parallel to a header cable protected by 2-in. composition drain pipe. No trouble has been encountered at these installations with rodents Fig 1 shows the general layout of later installations.

Where possible, the anode beds have been located near waste-water sumps or drainage ditches to keep loop resistance down. All other anode beds are watered periodically. Where watering is necessary, salt is added to the water.

PREDICTING CURRENT REQUIRED FOR PROTECTION

Surface-casing to Half-cell Potential

On the basis of a limited number of tests (3), (5), it has been determined that a surface-casing to half-cell potential of —1 00 to —1 02 volts will give a casing to half-cell potential at the bottom of the hole of —0 85 volts or more. Variations undoubtedly occur, but it is believed there are more overprotected wells than underprotected wells in the field

E-log I Curve

The *E-log I* curve of this paper is the "Wellhead Current Potential Curve" of Kerr,[1] "Log Current Potential Curve" of Haycock,[2] and "Null Potential Curve" of Ballou and Schremp[3] Half cell refers to the copper-copper sulfate half cell in common pipeline-protection use.

E-log I tests were made on 33 of the wells. All of the *E-log I* tests were run using a surface or wellhead connection and a half cell located approximately 300 ft from the well. All of the tests were made using the anode bed installed for actual protection A truck-mounted welding generator was used as the power source. Control of the generator output at low amperages is difficult, and a variable rheostat was used in most recent tests

A few pointers on actual testing, picked up by experience, are worthy of mention.

1. Apparatus should be checked out by running a test on a pipeline or unimportant well before being used for critical well testing A final check at the well site, using a water or gas line as the cathode before hooking up to the well, will prevent many poor tests.
2. Approximate amperage desired for each drain point should be predetermined, and the setting marked if possible.
3. An overdrain of current, even of short duration, nullifies the results. If an overdrain occurs during the first part of the test before the curve is reached, the test is probably of no value If an overdrain occurs, the test should be stopped and the well allowed to come back to its original state before the test is made This might take a few hours or several days.
4. Timing is quite important The actual duration of the drain period does not seem to be as important as having each drain period the same. A 4-min. drain period, with 1 min to read and reset, was considered optimum for the work at Kettleman Hills.
5. The "off" potential decays rapidly and must be obtained within a second or two to be of value. Plotting results as they are obtained will enable the operator to preset, approximately, the potentiometer or voltmeter and get more consistent readings

Table 1 gives the *E-log I* predicted drain compared with the actual drain established by use Summarizing this table, there appear to be:

11 tests — good correlation with actual
11 tests — fair correlation with actual.
11 tests — poor correlation with actual

This summary does not look favorable for the *E-log I* prediction However, other factors investigated change the picture considerably.

SOURCES OF ERROR

Insulating Flanges

All insulating flanges of wells to be protected were checked and repaired, where necessary, before running *E-log I* tests or applying protection Toward the latter stages of the survey, an improved method of testing insulating flanges was used (4) This new method and equipment indicated several flanges previously thought to be effective were actually defective

Repairing the defective insulating flanges has lowered the current drain dramatically in some cases. At other wells there has not been much improvement.

Well 8-21J is an example of the benefits obtained by repairing a defective insulating flange. This well had a good *E-log I* curve, with an indicated drain of 18 amp However, after putting it under cathodic protection, a surface casing potential of —1 00 volts could be attained only part of the time with 50-amp drain. The old method of testing insulating flanges showed all to be good With the new instrument, a 3-in. flange showed defective and was replaced in December 1958. The surface-casing potential immediately went to —1 07 volts. Since then, the current drain has been reduced to 35 amp and will probably be cut back more.

There is no way of knowing if defective flanges were shorted at the time of the *E-log I* test or became shorted later.

Effect of Overdrain of Current

The effect of overdrain of current of the *E-log I* test was noted at well 323-21J, where drain of 20 amp for about 1 min was inadvertently made at the start of the first drain period. The drain was stopped and the well allowed to rest about 15 min; then the test was started

Table 1 (Small)
E-Log I Vs. Actual Current Demand

Well No.	Date Installed	*E-Log I* Indicated Demand, Amperes	Actual Current Demand, Amperes	Difference in Amperes, Base-actual	*E-Log I* as Percent of Actual	Correlation[1]	Remarks
First Group							
87-20J	6-56	19	25	— 6	76	Fair	
344-20J	6-56	11	15	— 4	70	Fair	DIF, 12-58[2]
8-21J	6-56	18	35	—17	51	Poor	DIF, 12-58[3]
27-21J	6-56	23	35	—12	66	Poor	
324-35J	6-56	22	30	— 8	73	Poor	DIF, 12-58
32-2P	7-56	30	25	+ 5	120	Fair	DIF, 3-57[4]
36-2P	7-56	17	23	— 6	74	Fair	
343-3P	7-56	21	30	— 9	70	Poor	DIF, 12-58
341-12P	7-56	20	22	— 2	91	Good	
631-12P	7-56	28	25	+ 3	112	Good	
634-12P	7-56	14	15	— 1	93	Good	
642-12P	7-56	15	12	+ 3	125	Good	
E27-7Q	8-56	21	30	— 9	70	Poor	
8-8Q	9-56	25	25	—	100	Good	
36-17Q	9-56	9	13	— 4	66	Fair	DIF — not repaired
E67-17Q	9-56	32	30	+ 2	107	Good	DIF — not repaired
87-17Q	9-56	33	22	+11	150	Poor	
333-18Q	9-56	31	10	+21	210	Poor	
341-18Q	8-56	31	25	+ 6	124	Fair	DIF, 2-57
61-20Q	8-56	34	30	+ 4	113	Fair	
44-21Q	8-56	21	34	—13	62	Poor	DIF[5]
32-27Q	8-56	53	44	+11	121	Fair	DIF, 3-57
Second Group							
36-20J	5-58	45	25	+20	180	Poor	
47-20J	3-58	28	25	+ 3	112	Good	
331-20J	7-58	25	30	— 5	83	Fair	
332-20J	7-58	15	15	—	100	Good	
323-21J[6]	7-58	26	17	+ 9	153	Poor	
343-28J	4-58	36	40	— 4	90	Good	
65-30J[7]	4-58	21	45	—24	47	Poor	
27-34J	3-58	31	25	+ 6	124	Fair	
38-34J	3-58	15	20	— 5	75	Fair	
V32-7Q	3-58	39	40	— 1	97	Good	
632-7Q	12-58	27	27	—	100	Good	DIF, 12-58

Correlation first group	good	6	fair	8	poor	8
Correlation second group	good	5	fair	3	poor	3
Correlation all wells	good	11 tested	fair	11	poor	11

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[1] Good — difference less than 4 amp unless actual demand over 35 amp, then difference 10 percent or less.
Fair — difference 4 to 7 amp incl. unless actual demand over 35 amp, then difference 11 to 20 percent.
Poor — difference over 7 amp

[2] DIF = defective insulating flange — month and year repaired.

[3] 8-21J — before repairing insulating flange, 50 amp would not keep current potential up to —1 00 volt Since repairing, current cut back to 35 amp

[4] 32-3P — required 45 amp before repairing insulating flange.

[5] 44-21Q — repaired insulating flange June 1957 40 amp brought current potential up to —1 00 volt Repaired December 1958, cut to 34 amp, probably will go lower

[6] 323-21J — overdrain of 20 amp at start of test. Discard

[7] 65-30J — loop resistance too high, could not get around bend of curve Probably has defective 6-in. insulating flange. Discard test

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again The original casing to half-cell potential was —0.725 volts. At the start of the test the second time it was —0 764 volts The curve obtained was ragged, and the current drain indicated was 53 percent greater than that determined by operation Fig 2 gives a plot of the curve, along with a curve obtained from a similar well that checked very well with the actual.

There is a good possibility that the other three wells with "poor" correlation and excessively high *E-log I* indicated drain were also subjected to an overdrain during testing

This test points out the importance of avoiding an overdrain of current, especially at the lower amperage readings.

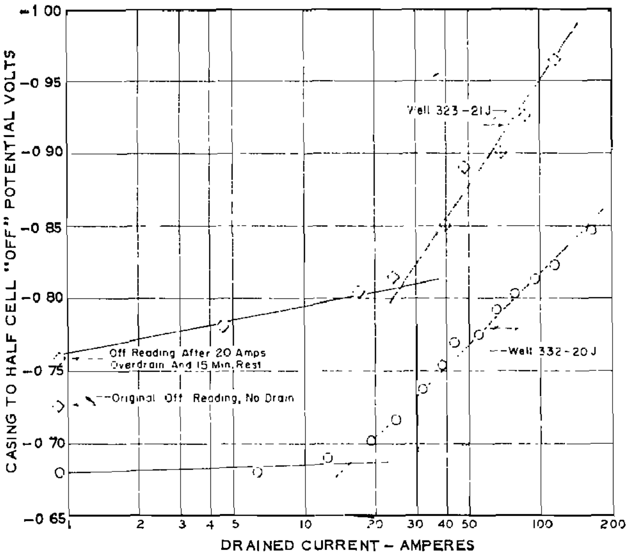

Fig. 2 (Small)—*E-Log I* Curves—Kettleman North Dome Unit

Disregarding the tests made on wells with faulty insulating flanges and the four tests suspected of overdrain, it is possible to come up with a different picture from Table 1.

Well No.	Predicted	Actual	Difference, Amperes	Correlation
87-20J	19	25	— 6	Fair
47-20J	28	25	+ 3	Good
331-20J	25	30	— 5	Fair
332-20J	15	15	—	Good
27-21J	23	35	—12	Poor
343-28J	36	40	— 4	Good
27-34J	31	25	+ 6	Fair
38-34J	15	20	— 5	Fair
36-2P	17	23	— 6	Fair
341-12P	20	22	— 2	Good
631-12P	28	25	+ 3	Good
634-12P	14	15	— 1	Good
642-12P	15	12	+ 3	Good
E27-7Q	21	30	— 9	Poor
V32-7Q	39	40	— 1	Good
8-8Q	25	25	—	Good
61-20Q	34	30	+ 4	Fair

9 — Good correlation = 53 percent
6 — Fair correlation = 35 percent } 88 percent
2 — Poor correlation = 12 percent
Total 17 100 percent

It is believed that with improved technique the accuracy and reliability of the test will be further improved.

Costs of *E-Log I* Tests

With the equipment we have used, two men are necessary to run the test and a third man to operate the welding generator. The actual test time is about 1 hour, 15 min, with another 45 min to set up and move. In addition, about 2 hours or more engineering time are needed to plan the program and interpret results.

The cost (equipment and manpower) of the foregoing test is approximately $50. As mentioned earlier, we have used permanent beds, already installed, for the anode. If it is necessary to install temporary anode beds for the test, the cost will be much higher.

Current Density

Table 2 gives the current drain necessary to give a surface-casing to half-cell potential of —1.00 to —1.02 volts, and the current density in milliamperes per square foot (ma per sq ft) of the exposed casing area which is defined for our purposes as all casing not behind other casing; that is, all casing exposed to formation including that behind cement.

The current density varies from a low of 0 5 ma per sq ft to a high of 2.1 ma per sq ft The average is 1 3 ma per sq ft.

The bare casing area, defined as the exposed area not behind cement, has also been calculated for a few of the newer wells. The current density based on bare casing area varied from 1 3 to 2.5 ma per sq ft.

Casing area would probably have merit in sizing installations if all variable and influencing factors were known However, it is currently not considered a reliable method to size installations at Kettleman Hills

CONCLUSIONS

1. Cathodic protection at Kettleman Hills has reduced the casing-failure rate.

2 The *E-log I* test to indicate current drain from a casing is only 70 percent accurate on the basis of tests tabulated. However, it is believed this rather low accuracy is probably the result of errors of technique and faulty insulation flanges, rather than to a fundamental fault in the test itself. With improved technique, it is believed the test should indicate the actual drain demanded within 10 percent.

3. The test should be a valuable aid in engineering studies aimed at determining the economy of protecting a field or a group of wells.

4. The usefulness of the test in sizing individual installations is something that would depend to some degree on individual circumstances, but to a large degree on the care and preparation devoted to each test.

The Future

Because of the good experience in reducing forecasted casing failures in 45 wells at Kettleman Hills, 100 more wells in this field are being considered for cathodic protection.

The economics of continued use of the *E-log I* method of predicting future cathodic-protection requirements has been carefully considered Because this method is subject to errors, and experience has permitted development of an average requirement, it has been decided to install future anodes and rectifiers of slightly greater capacity than the average current demand found necessary in the present 45 wells being protected cathodically. This plan will save the costs of *E-log I* tests, and will permit any excess capacity to be used to partially protect less economic wells that otherwise would not be protected. If more capacity is needed, additional anodes will be added and the rectifier changed.

Table 2 (Small)
Current Density on Protected Wells

Well No.	Depth, Feet	Current Drain Required, Amperes	Exposed Casing Area, Square Feet	Milliamperes per Square Foot	Bare Casing Area, Square Feet	Milliamperes per Square Foot	Date Insulating Flange Repaired
287-19J	8,060	20	18,689	1.1			
8-20J	8,895	22	23,226	1.0			
36-20J	11,175	25	27,176	0.9			
47-20J	8,105	25	21,120	1.2			
87-20J	8,167	25	21,254	1.2			
331-20J	11,640	30	20,979	1.4	12,181	2.5	
332-20J	11,660	15	21,734	0.7	10,592	1.4	
344-20J	11,386	15	20,117	0.8	10,193	1.3	12-58
8-21J	8,217	35	22,011	1.6			12-58
27-21J	11,450	35	26,738	1.3			
343-28J	11,683	17	21,765	0.8	7,601	2.2	
H-6	10,624	40	21,878	1.8			
65-30J	9,143	40	22,995	1.7			
341-30J	8,265	45	21,980	2.0			
323-21J	10,910	40	22,499	1.8			
83-32J	8,290	35	20,825	1.7			
E72-33J	10,060	30	23,408	1.3			
27-34J	8,043	25	22,736	1.1			
38-34J	8,819	20	24,825	0.8			
324-35J	10,441	30	24,204	1.2			12-58
V45-1P	8,795	40	22,160	1.8			
E32-2P	10,035	25	20,342	1.2			10-57
E36-2P	9,775	23	19,784	1.2			
81-3P	8,032	25	17,928	1.4			
87-3P	7,981	25	26,595	0.9			
343-3P	10,173	30	23,329	1.3			12-58
341-12P	10,300	22	17,790	1.2			
631-12P	8,150	25	17,617	1.4			
634-12P	7,932	15	15,590	1.0			
642-12P	7,997	12	17,414	0.7			
E27-7Q	9,852	30	23,693	1.3			
V32-7Q	9,225	40	27,578	1.5			
V42-7Q	9,250	32	20,265	1.6			12-58
611-7Q	8,941	25	21,700	1.2			
632-7Q	9,170	27	20,525	1.3			12-58
8-8Q	7,992	25	23,162	1.1			
36-17Q	7,725	13	19,329	0.7			not repaired
E67-17Q	10,126	30	24,822	1.2			not repaired
87-17Q	7,925	22	22,042	1.0			
333-18Q	10,940	10	21,735	0.5			
341-18Q	10,010	25	22,809	1.1			2-57
61-20Q	7,095	30	23,250	1.3			
44-21Q	7,519	34	17,239	2.0			6-57 and 12-58
32-27Q	7,795	44	21,013	2.1			3-57
72-27Q	8,040	35	21,678	1.6			12-58

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PART 5

CASING CATHODIC PROTECTION — COALINGA NOSE UNIT PROJECT

C. E. Hedborg*

ABSTRACT

The pipeline criterion of maintaining a minimum pipe-to-soil potential of —850 millivolts relative to a copper-sulfate reference electrode has been used in providing cathodic protection for well casings at the Coalinga Nose Unit A polarization period of 2,000 hours is required for wellhead potentials to reach equilibrium with a 25-amp current. However, short-term test data can be used to predict long-term polarization levels. Down-hole measurement indicates that protection extends to total depth of a 7,000-ft casing. Casing potentials were observed to decline 30 millivolts per 1,000 ft of depth after 42 days drainage time. At 300 days drainage time the decline had decreased to 10 5 millivolts per 1,000 ft.

Criteria for Protection

The pipeline criterion of maintaining a minimum pipe-to-soil potential of —850 millivolts with respect to a saturated copper-sulfate reference electrode has been used in determining well-casing cathodic-protection current requirements at the Coalinga Nose Unit (CNU), Fresno County, California

Current Requirement Tests

Tests to determine the cathodic-protection current requirements were conducted on 10 wells which were selected as being representative of all wells in the field These tests were divided into two parts: a short-term test period of 10 to 24 hours duration followed by a long-term test period of about 6 months duration.

The data obtained from the short-term tests were used as a basis for designing permanent, impressed-current cathodic-protection installations for the 10 test wells. These permanent installations were then operated and observed for about 6 months, following which a program of installing protection installations on all wells of economic value to the unit was started. There are at present 130 wells under protection at the CNU.

During the short-term tests, casing-to-soil potentials were measured only at the well head. Based on work conducted by other companies[1], it was assumed that the casing-to-soil potentials would decrease by 20 millivolts for each 1,000 ft of depth A 7,000-ft well, which is average for the CNU, would therefore require a wellhead potential of —990 millivolts in order to have an indicated potential of —850 millivolts at total depth. Fig 1 shows a schematic diagram of the equipment and circuits used during the tests The anode bed was located from 250 to 300 ft from the well. The reference electrode was placed on the surface of the ground, 300 ft from the well head and in a direction opposite from the anode bed

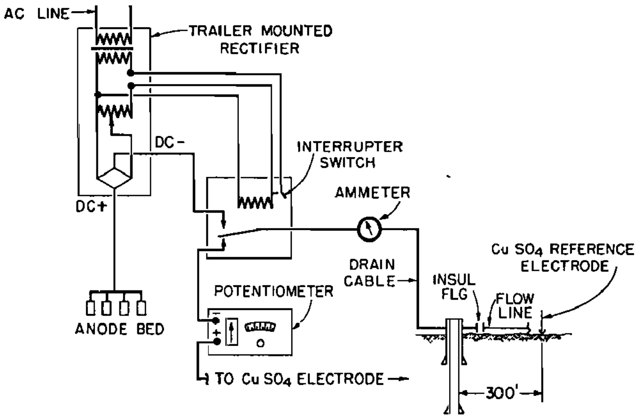

Fig. 1 (Hedborg)—Test Equipment

In order to eliminate the inclusion of ohmic (i e , IR drop) potentials, all casing-potential measurements were taken with the current momentarily interrupted. The circuit shown in Fig. 1 makes possible the measurement of power-off potentials with a minimum drain-current interruption time The results of the short-term tests are shown on Fig 2 In these tests we were trying to determine the current required to produce a power-off potential of —850 millivolts at total depth. As stated earlier, this would require a wellhead potential of —990 millivolts.

As indicated by Fig 2, the casings take an appreciable period of time to respond to electrical drainage.

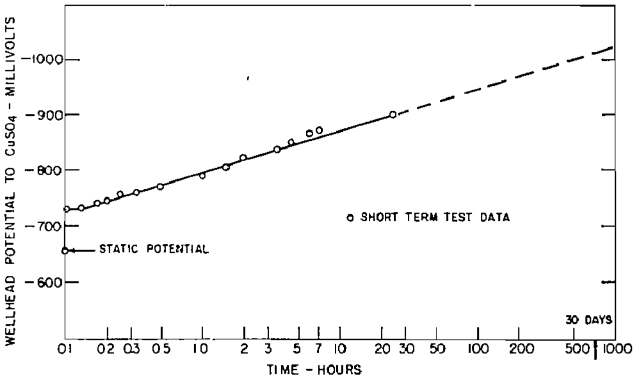

Fig. 2 (Hedborg)—*E-log* Time Curve — 25-amp Drain Potentials are measured with respect to a remote saturated Cu SO_4 reference electrode. All potential measurements made with power momentarily interrupted. All adjacent rectifiers within 2,000 ft shut down during these tests.

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*Union Oil Co of California, Brea, Calif

[1] References are at the end of Part 5

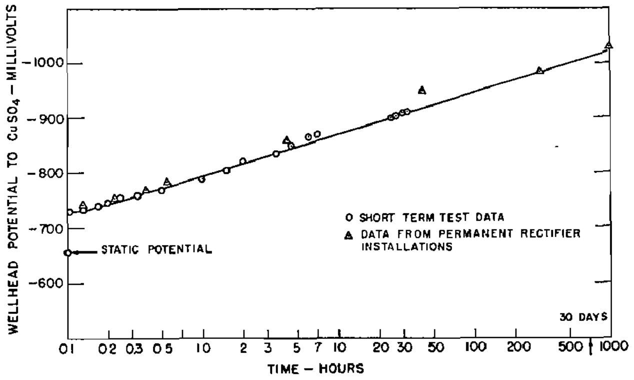

Fig. 3 (Hedborg)—*E-log* Time Curve—25-amp Drain Potentials are measured with respect to a remote saturated Cu SO_4 reference electrode. All potential measurements made with power momentarily interrupted. All adjacent rectifiers within 2,000 ft shut down during these tests.

However, by plotting the short-term test data as potential vs. the logarithm of the drainage time and by extrapolating the resulting curve, it appeared reasonable to assume that a 25-amp drain current would produce the desired wellhead potential in about 30-days time The curve shown on Fig. 2 is typical of all of the wells tested Based on these short-term tests, permanent-rectifier installations having direct-current capacities of 30 amp and 50 volts were installed at the 10 test wells.

Fig 3 shows the *E-log* time curve for the same well shown on Fig. 2 after 1,000 hours at 24 amp It can be seen that the points fell on the curve indicated by the short-term tests. Although not shown on this curve, the wellhead potentials stabilized at about 1,060 millivolts after 2,000 hours drainage time at 24 amp.

A down-hole potential survey was conducted on one of the test wells after it had been on protection for 42 days. This survey consisted of lowering a single-point contacting tool inside the casing and measuring power-off potential differences, for various depth positions, between the casing and a surface reference electrode. The results of this work are shown on Fig. 4. The same type of survey was conducted on another well in the field after it had been under protection for 300 days. The results of this survey are also shown on Fig. 4.

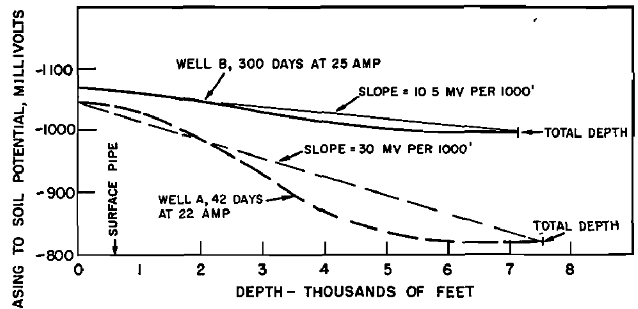

Fig. 4 (Hedborg)—Casing-to-soil Potential Vs. Depth Potentials are measured with respect to a remote saturated Cu SO_4 reference electrode. All potential measurements made with power momentarily interrupted. All adjacent rectifiers within 2,000 ft shut down during these tests.

These two curves show that there has been a considerable reduction in the slope of the attenuation curve The average slope for Well A after 42 days drainage was 30 millivolts per 1,000 ft The slope for Well B after 300 days drainage time was 10 5 millivolts per 1,000 ft The reduced slope of the attenuation curve is, it is believed, the result of a gradual accumulation of calcareous coatings on the casing. The relatively flat slope for Well B probably indicates that an equilibrium condition has been reached The 30-millivolt attenuation figure obtained on Well A indicated that a wellhead potential of —1,060 millivolts was required for the protection of 7,000 ft of casing. A rectifier output of about 25 amp was required to maintain this potential. Up to December 1958, all the rectifiers in the field were operated at this current value. At this time, however, the down-hole survey on Well B indicated that the wells were being overprotected. Gradual reductions in rectifier output are therefore being made so as to yield wellhead potentials that are commensurate with the 10.5-millivolt attenuation figure. At the present writing the amount of current reduction possible has not been accurately established

Results to Date

In order to minimize interference, all anode beds were kept a minimum distance of 200 ft from the nearest surface facility As an additional safeguard, the surface facilities are given partial protection by the application of a 1-amp drain at each protected well. This current is applied by installing a bypass resistor around the flow-line insulating flange. To date, no interference damage has been evidenced

Some failures of silicon-diode rectifier elements have occurred as a result of lightning storms. Most of these failures took place during a storm which the local power company classed as unusually severe. Our present opinion is that these lightning failures do not constitute a serious problem The costs to place a damaged rectifier back in service have averaged $25. This includes material and labor The benefits of the silicon diodes are· *1*, higher conversion efficiency; and *2*, greater resistance to high ambient temperatures Under the conditions prevailing at Coalinga it is believed that these advantages justify the continued use of silicon rectifier elements.

The anode beds are of the graphite-rod type with each rod being installed in a 14-in. diameter, 20-ft. deep hole. The annular space surrounding the 4-in diameter rods was filled with calcined petroleum coke. The installations at Coalinga are all of the single-well type: that is, a separate anode bed and rectifier is installed for each well Anode beds of from 5 to 8 rods were installed at a distance of from 250 to 300 ft from the well head At a few sites it has been necessary to provide facilities for wetting the anode beds in order to reduce contact resistance.

Experience has indicated that there are many ways in which an insulating joint can become inoperative For example, it has been found that the insulation material in certain types of fittings is easily damaged As a result of this, we consider it desirable to make periodic routine checks on all insulating joints in the field. These routine checks have led us to the conclusion that the flange-type insulation joint is the most reliable. A uniform color coding has proved a valuable aid in preventing the accidental bypassing of insulating joints by copper tubing fittings such as on pressure gages, flow meters, etc

CONCLUSIONS

There have been but two casing failures at the CNU during its life. One of these was attributable to external corrosion; this failure occurred on a 14-year-old well. The fact that no additional failures have occurred since protection was first applied in April 1957 is not sufficient evidence to permit drawing of conclusions as to the efficacy of cathodic protection. However, based on theoretical considerations, favorable pipeline experiences, and published data[2] on the results of full-scale field-evaluation tests, we believe cathodic protection to be an effective method of preventing external casing corrosion.

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Ex. II - 38

Understanding How Components Fail

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Library of Congress Catalog Card Number: 84-73304
ISBN: 0-87170-189-8
SAN: 204-7586

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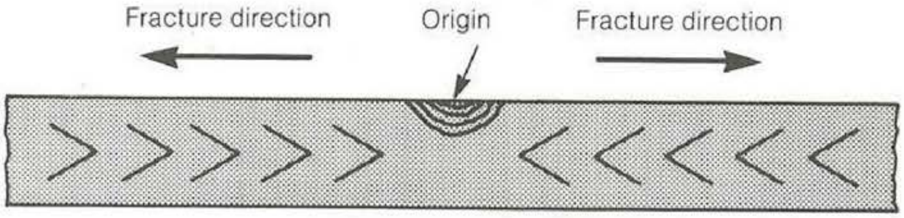

Note the classic chevron or herringbone marks that point toward the origin of the fracture, where there usually is some type of stress concentration, such as a welding defect, fatigue crack, or stress-corrosion crack. The plane of the fracture is always perpendicular to the principal tensile stress that caused the fracture at that location.

Fig. 2. Sketch of pattern of brittle fracture of a normally ductile steel plate, sheet, or flat bar.

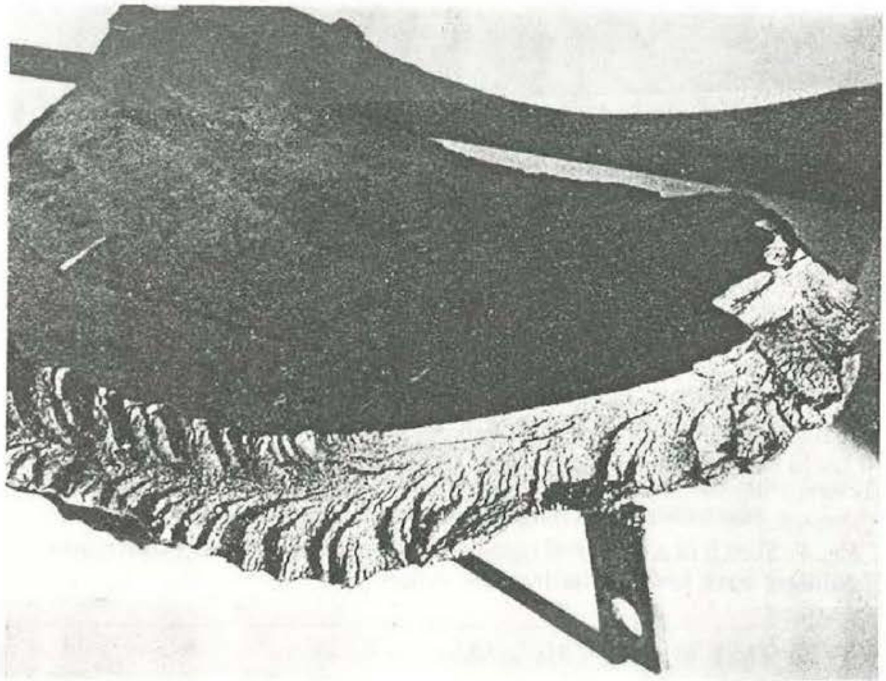

Fig. 3. Fragment of a thick-walled fractured drum. The fracture, which started at the right side of the photo, ran rapidly to the left, resulting in a well-defined chevron pattern. (Ref 10)

sitioned so that it just grazes the projections of the surface texture. See Fig. 2 through 8 for illustrations of these marks.

Brittle fractures of some parts may have a pattern of radial lines, or ridges, emanating from the origin in a fan-like pattern. Again, it may be difficult to perceive the texture of the fracture surface unless the light is carefully controlled. See Fig. 9 through 11.

Brittle fractures of extremely hard, fine-grain metals usually

Ex. II - 39

Interpretation of Temperature Logs in Water- and Gas-injection Wells and Gas-producing Wells[†]

JAMES M. BIRD*

ABSTRACT

The movement of fluids in a bore hole is a problem of interest to petroleum engineers. There are several tools available to detect and record the direction and extent of this movement. The use of temperature surveys for this purpose is the subject of this paper. The general shape of temperature logs in water-injection wells is discussed in the light of the principles of heat transfer involved. The mathematics is evolved to express this relationship, followed by empirical data substantiating the assumptions on which the mathematics is based. The importance of correct field techniques in running this type of survey is emphasized. The reversibility of the concepts developed are demonstrated in analyzing temperature curves in a well flowing water and oil. An analysis of field data is shown. The similarity and differences between a flowing water and oil well and a gas-producing well are demonstrated, with suggestions as to a method of interpreting temperature logs of the latter type.

Temperature Surveys in Water-injection Wells

It is acknowledged that important factors affecting the profitable operation of a water flood are the number of feet of sand being flooded and the rate at which each foot is taking water. Further, it is helpful to know that the intake well is operating mechanically as intended. Such things as ineffective plug-backs, packers, cement jobs, and leaky pipe can be detrimental to the profit-making ability of a water drive. It is hoped that it can be demonstrated here that temperature logs of active intake wells can be an aid to answering questions such as these.

Referring to Fig. 1, let us assume a geothermal gradient defined by Curve 1. If the surface lines are buried and if the water-intake well is a reasonable distance from the pressure plant, we can assume that water enters the well at surface temperature. Imagining that there is an infinite amount of water moving down the pipe, it is evident that a temperature survey run under these conditions would show no change in temperature down to a depth where something less than an infinite amount of water is flowing. Further, it is evident that when a depth is reached where no fluid is moving, the temperature curve must increase to the indigenous subsurface temperature for that particular depth. A hypothetical curve illustrating a temperature log of a well taking an infinite amount of water is illustrated by the dashed curve to the left of Fig. 1. The water must leave the hole in the area of the wall between a point slightly above where the curve leaves the input temperature and where it arrives at the geothermal gradient temperature. Referring to Fig. 1, the water must leave the hole between the depths *A* and *B*. Considering the case of a temperature log of this intake well when it is taking something less than an infinite amount, it is apparent that the resultant curve must lie in the area between the infinite volume curve just discussed and the geothermal gradient or zero volume curve. This area is cross-hatched on Fig. 1. As this finite quantity of water moves down the hole, it tends to increase in temperature as it comes into the presence of a progressively hotter environment as defined by Curve 1. The factors governing the quantity of heat q that is driven into the water can be related by the expression:

$$q = \frac{2\pi k\,(T_E - T_W)\,dh}{\ln \frac{R_e}{R_w}} \qquad (1)$$

wherein:

T_E = the temperature of the earth at the depth in question.

T_W = the temperature of the water.

k = the coefficient of heat conduction.

dh = the differential thickness.

R_e = radius from the center of the bore hole to where T_E exists.

R_w = the well radius.

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* Bird Well Surveys, Bradford, Pa.

[†] Presented at the spring meeting of the Eastern District, Division of Production, White Sulphur Springs, W.Va., June 1954.

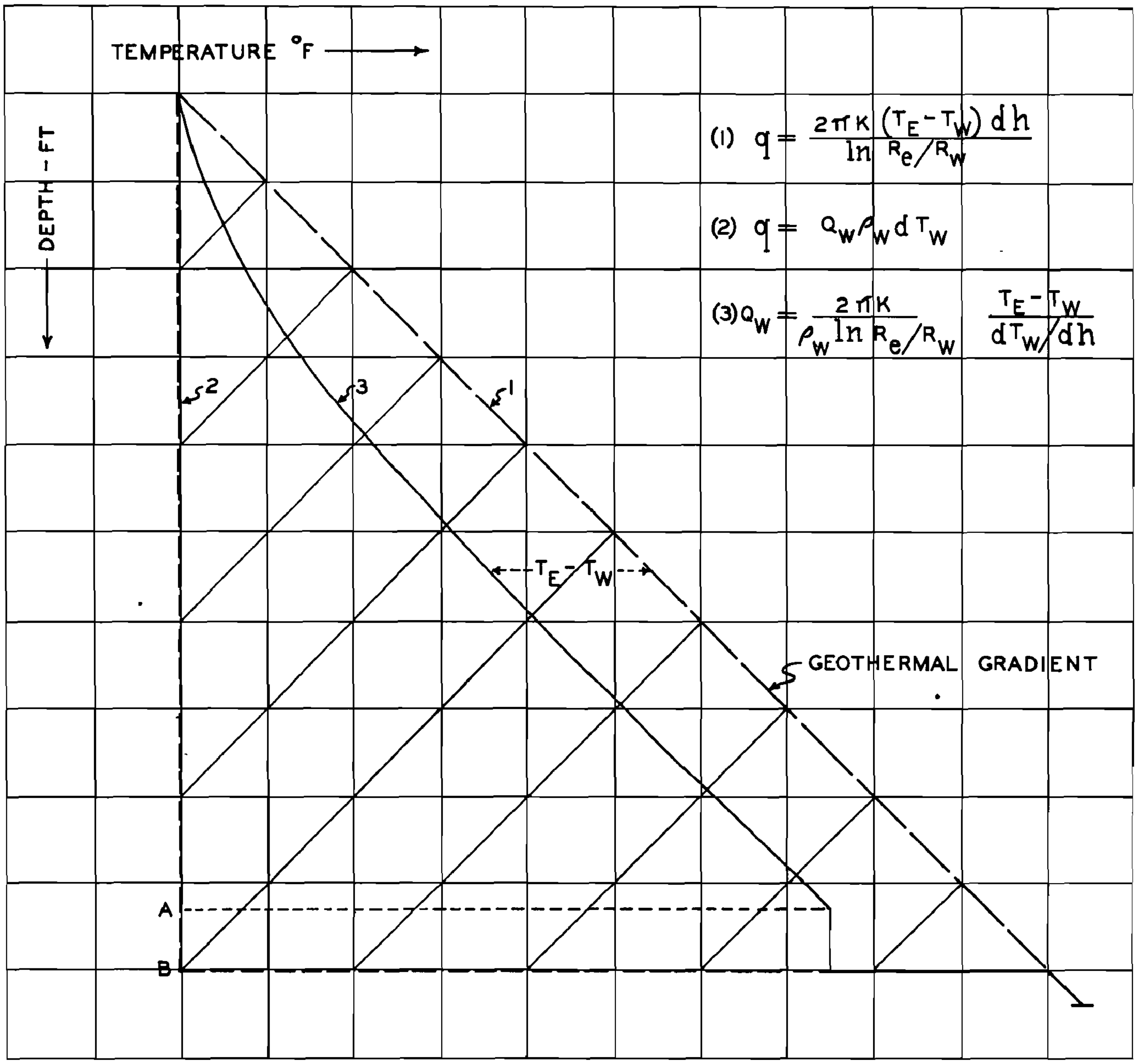

Fig. 1—Theoretical Water-injection Wells

This is true assuming *a*, the heat flow in the angular direction is zero; and *b*, the heat flow in the vertical direction is steady, i.e., as much heat enters below as leaves above in a unit of time. Postulating that everything on the right-hand side of this expression remains constant as the water moves down the hole, it is evident that the value of q depends largely upon the value of $T_E - T_W$. As the water moves down the well, $T_E - T_W$ will increase as the water temperature departs from the geothermal gradient. This greater difference in temperature causes more heat to be driven into the water. The effect of this heat being absorbed by the water is expressed by this relationship:

$$q = Q_W \rho_W dT_W \qquad (2)$$

wherein:

Q_W = barrels of water per day.

ρ_W = density of water.

The resultant shape of the curve is the product of these two effects. The farther the water temperature departs from the temperature of the earth, the more Btu's are driven into the water. So long as the quan-

Table 1

Application of Equations to Published Data and Temperature Surveys

	State	Well-bore Condition	$T_E - T_W$, Deg F.	dt/dh, Deg F. per Ft	Δ	H_2O Volume, Bbl per Day
1	Pa.	H_2O outside 2-in.—2 packers	7.07	0.0131	540	97
2			5.00	0.0170	294	49.5
3			9.2	0.0130	708	108
4	W. Va.	5-in. cemented	13.2	0.0090	1,360	318
5			13.7	0.0080	1,710	275
6			13.2	0.0092	1,435	274
7			11.1	0.0092	1,210	210
8			7.6	0.0081	940	149
9	Pa.	6¼-in. open hole	5.49	0.0110	499	75
10	Pa.	H_2O outside 2-in.	7.5	0.0040	1,875	432
11	N.Y.	H_2O outside 2-in.	6.7	0.172	390	49
12			7.9	0.0140	565	45
13			5.7	0.0190	300	24
14	Ill.	4-in. cemented	11.2	0.0157	714	144
15	Pa.	H_2O outside 2-in. with tail pipe	0.84	0.0130	64	9
16			3.5	0.0085	412	72
17	Pa.	H_2O outside 2-in.	2.48	0.0037	790	128
18			4.6	0.00116	3,960	585
19	Calif.	7-in. cemented—perforated	82.0	0.0015	5,460	900
20			52.0	0.0013	4,020	750
21	Ky.	4-in. cemented	3.91	0.0323	121	24
22	Pa.	H_2O outside 2-in.	9.2	0.0115	800	130
23			8.4	0.0077	1,090	125
24	W. Va.	5-in. cemented	4.5	0.0105	428	45
25			5.6	0.0105	534	88
26			9.8	0.0100	980	250

tity of the water moving down into the well is constant, the absorption of this increased amount of Btu's causes the temperature of the water to increase proportionately. A change in the slope of the temperature curve results from this increased absorption of Btu's. This change in slope is in the direction that brings T_W closer to T_E. Thus the departure of the water temperature from the earth's temperature is self-limiting; and after sufficient depth is reached, the slope of the curve will approach parallelism with the geothermal gradient. One of a family of curves of this type is illustrated by Curve 3, Fig. 1.

Equation (1) relates factors that cause Btu's to be forced into the fluid, and equation (2) shows the effect on the water temperature of the absorption of these Btu's. Equating the two and solving for Q_W we obtain:

$$Q_W = \frac{2\pi k}{\rho_W \ln\frac{R_e}{R_w}} \cdot \frac{T_E - T_W}{\frac{dT_W}{dh}} \tag{3}$$

For constant values of heat conductivity, water density, well-bore radius, and external heat radius, Q_W should plot as a straight line vs. $T_E - T_W/(dT_W/dh)$, which we will call Δ.

To test the practical usefulness of these equations, they were applied to the published work of Sayre and Wertman[1] and T. J. Nowak[2] as well as

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[1] References are at the end of the paper.

temperature profiles run by Bird Well Surveys. Table 1 lists the results and Fig. 2 is the plot of these figures. Points 22 and 23 were taken from Sayre and Wertman, points 19 and 20 from data of T. J. Nowak. It is interesting to note the wide range in intake rates, the variety of pipe sizes, and the geographical distribution. The grouping of the points about a straight line substantiates the hypothesis that *k* remains fairly constant and that when dealing with water-injection wells corrections for *ln* R_e/R_w are not critically necessary. It should be pointed out that the annular space between the pipe and the wall of the earth must be filled with something other than air or gas for proper heat conduction. However, in most cases this space is filled with mud, water, or cement, and this does not present a problem. In all cases these surveys were run in wells that had been

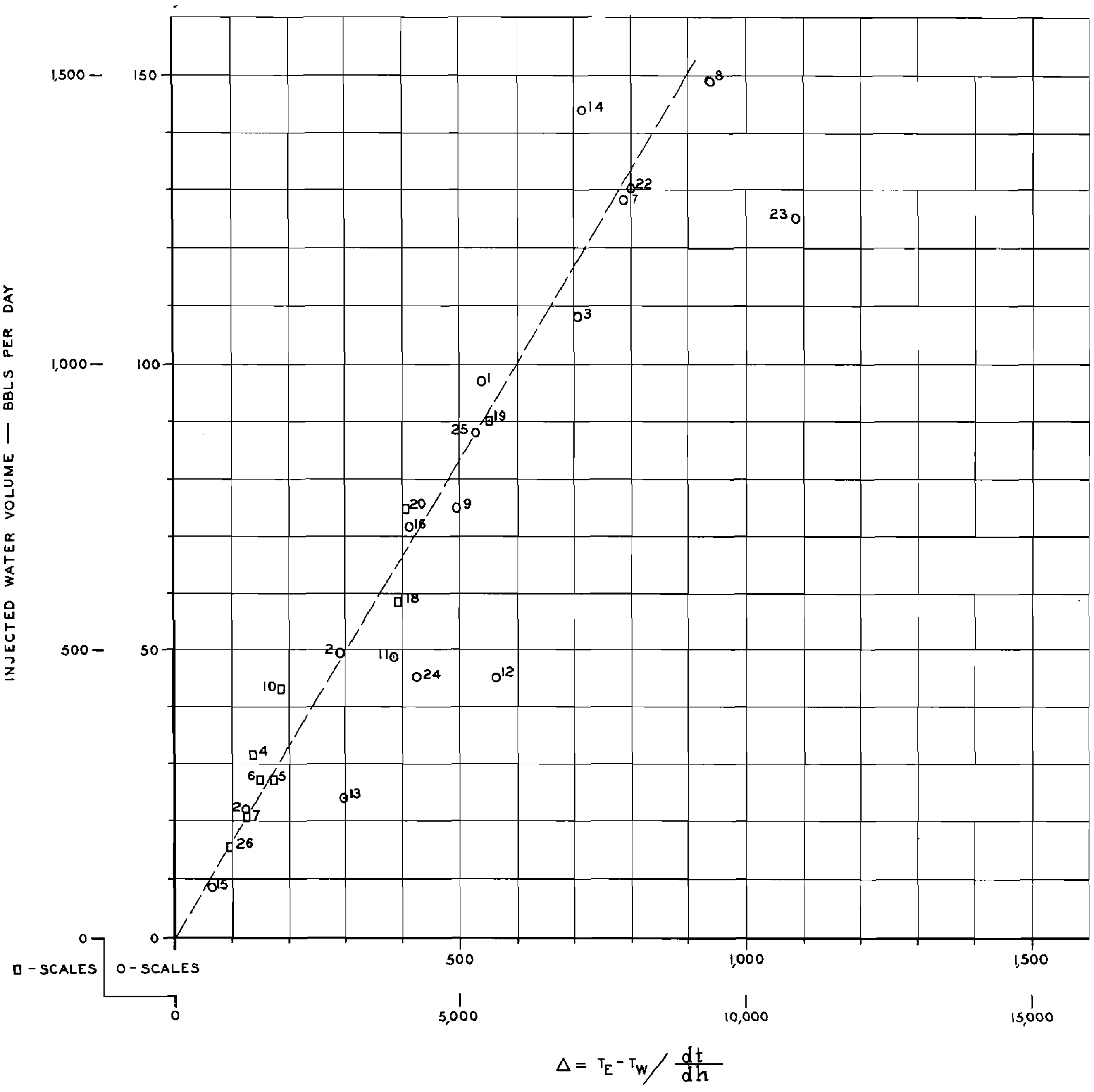

Fig. 2—Plot of Data from Table 1

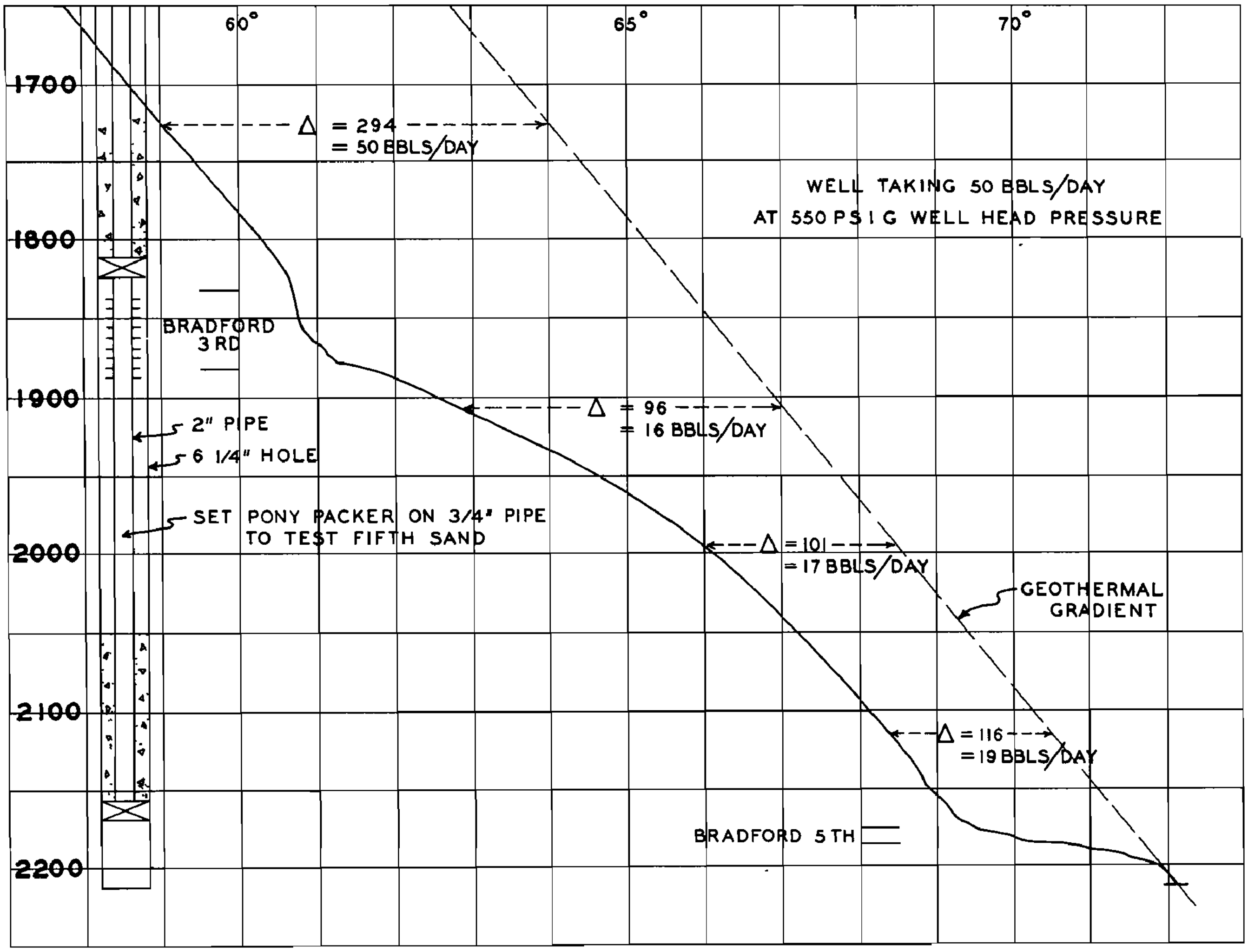

Fig. 3—Water-injection Well

taking a specific quantity of water without interruption for a considerable time prior to making the temperature measurements. Further, these stabilized conditions were not disturbed in making the temperature measurements. Fig. 2 demonstrates that a factor of six to one yields good results in converting Δ into barrels per day.

Going back to Curve 2 of Fig. 1, let us follow the water down the well and see what happens when the water comes to the top of the first zone of permeability. The sand matrix immediately takes on the temperature of the permeating water, and a cold front is formed, which moves back into the sand. Bulletin No. 60 of the Penn State College Mineral Industries Experiment Station, of Greenstein and Preston[3] demonstrates how this wave front is formed and moves through the sand increasing R_e. Therefore, the water that passes on down the hole will not change in temperature in traversing this zone of permeability because this portion of the wall has taken on the temperature of the water itself. At the bottom of the first permeable section less water is flowing down the well, but $T_E - T_W$ is, if anything, slightly larger than it was at the top of the permeability where more water was flowing. This slightly increased amount of heat flowing into less water in unit time causes the slope of the temperature log to become more horizontal. The water temperature rises quickly as it moves down the hole until a new equilibrium is established or until the slope again approximates the geothermal gradient at a new value of $T_E - T_W$. It should be pointed out that it is not necessary for this new equilibrium to be established before taking a new value for Δ. In theory, neglecting changes in R_e, Δ should remain constant at all points along this curve. Any changes in the value of Δ with depth must be in descending order and must reflect the movement of a smaller quantity of water. One other

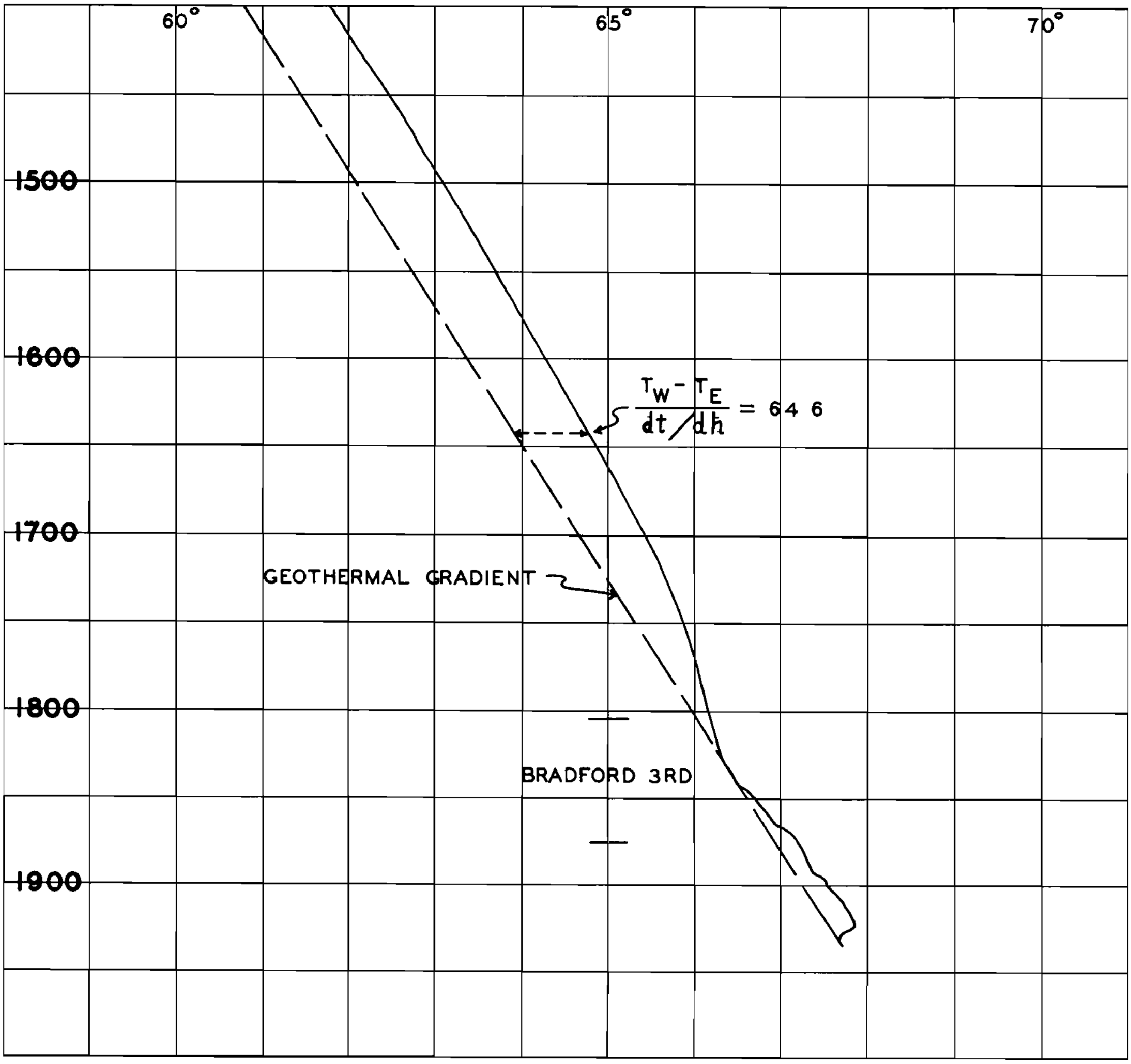

Fig. 4—Flowing Water-flood Well (Open-hole)

aspect of this phenomenon that should be noted is that changes in the diameter of the hole or pipe affect the velocity of the water but do not affect the quantity moving in unit time. From this it would seem that this method is insensitive to variations in the hole diameter. This conclusion is borne out by Table 1.

Fig. 3 is an actual temperature log of an intake well in operation illustrating this reaction. The indigenous earth-temperature curve is obtained by projecting the pocket temperature back up the hole. There are several methods available for picking the proper slope to use in projecting this gradient if no shut-in temperature log is available. If the well is deep enough for the opposing forces governing Δ to reach equilibrium, the slope of the injection temperature curve itself can be used. In lieu of this, a mean surface temperature can be estimated and a constant-slope indigenous earth-temperature curve computed, using the pocket temperature. Assuming this gradient, Δ was computed at various points along the constant injection-temperature curve between the two zones of permeability; Δ changes very little over this depth, and the values correspond to the maximum and minimum intake rates of 19 and 16 bbl per day. Months after completing this survey

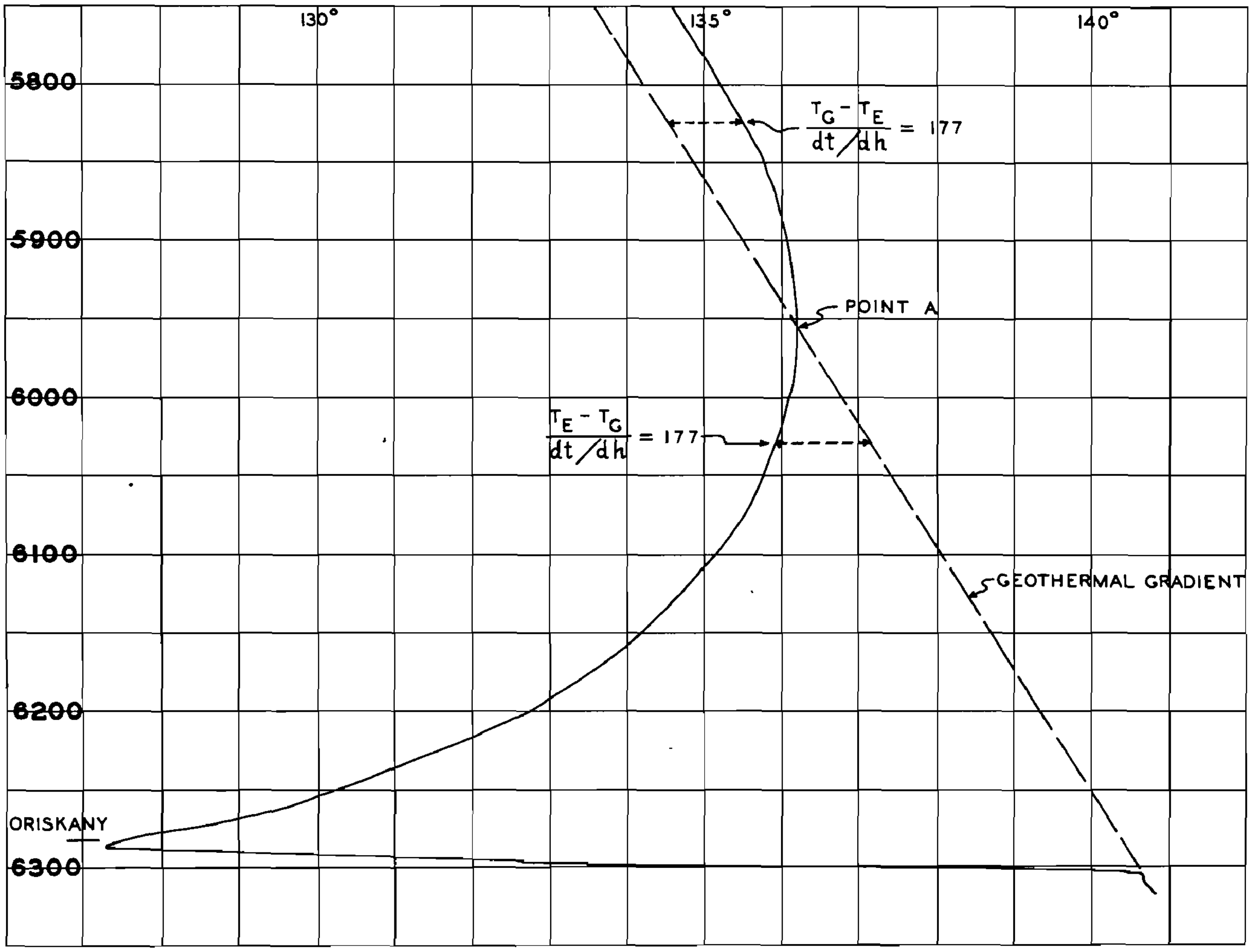

Fig. 5—Producing Gas Well

a small string of pipe with a "pony" packer was run into the well and set in the interval between the two sands; and the lower sand was found to be taking 16 bbl of water a day at the same wellhead pressure that had been established in making the original survey.

Temperature Surveys in a Well Flowing Water and Oil

Let us now consider the case of a flowing well. Presumably, the fluid enters the bore hole at the indigenous formation temperature. This might not be the case in a secondary-recovery project (see reference 1). However, if the distance between intake and outlet wells is great, the fluid temperature will differ only slightly from the indigenous temperature. As the fluid moves up the hole over impervious formations, there will be a tendency for it to be cooled, because of the fact that it is passing progressively cooler formations. The temperature of the water departs from the indigenous temperature, but in doing so causes $T_W - T_E$ to become greater. The larger this differential temperature becomes, the greater the rate of cooling becomes. The same self-limiting phenomenon takes place as was discussed in the case of an injection well, only the process is reversed. After moving up the hole a sufficient distance, the slope of the curve approaches parallelism with the indigenous-temperature curve. Fig. 4 illustrates such a temperature curve. Here again it is necessary that a stabilized flowing condition be established. Points 15 and 16 on Fig. 2 show how points taken from two of this type well fall in line with similar computation taken from an injection well.

Temperature Curve of a Well Flowing Gas

Much effort in the past directed toward interpreting temperature logs of gas-producing wells has revolved around the magnitude of the temperature kick. Attempts to allocate the total volume of gas to two or more gas-producing horizons by using the degree of

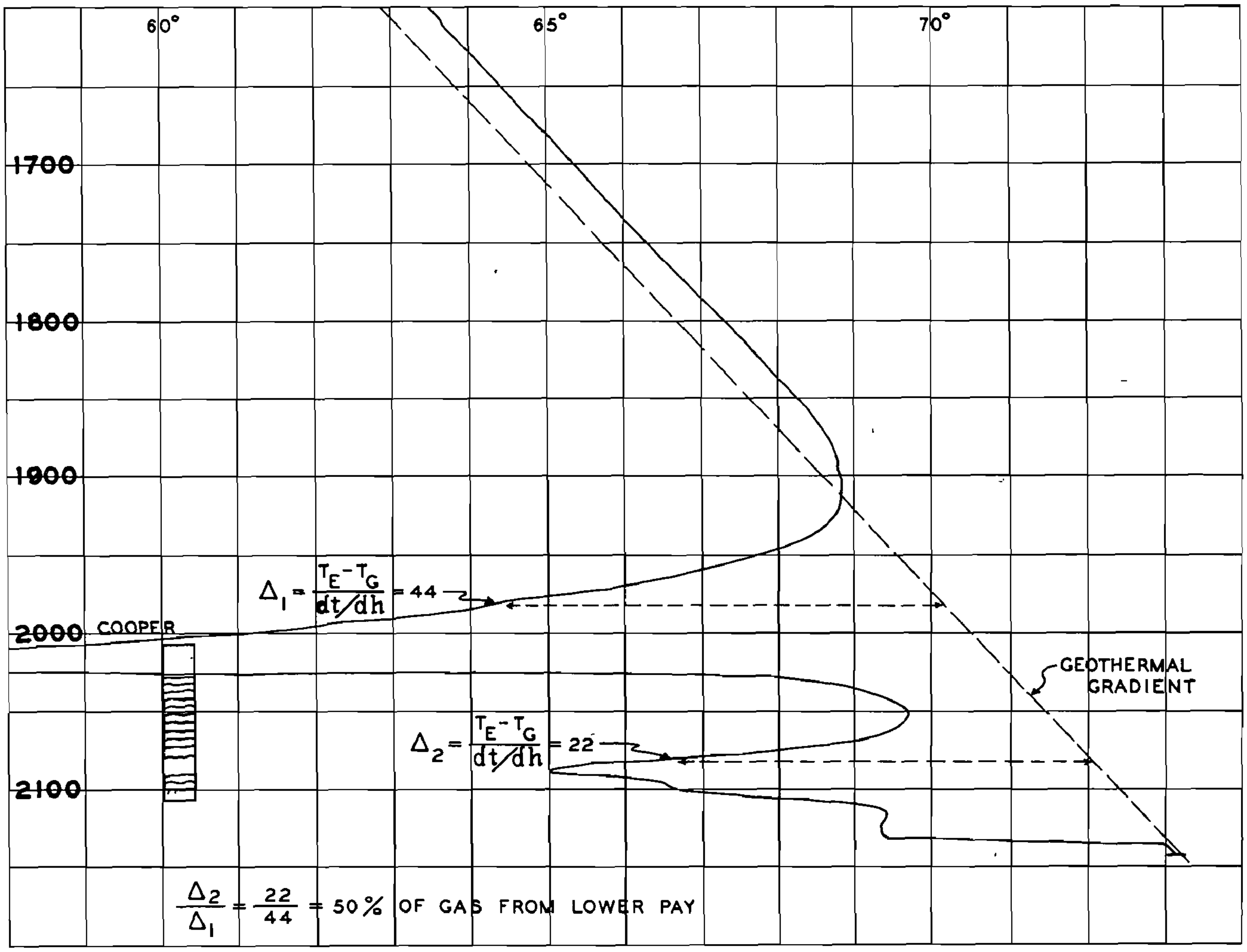

Fig. 6—Producing Gas Well

cooling of the gas in entering the bore hole have generally met with failure because of the nature of this cooling phenomenon. The degree of cooling is dependent upon the pressure drop and upon the type of porosity and its distribution, as well as the volume of gas that is expanding. Applying appropriate values to these variables in order to compute the volume of gas is usually impossible. In an effort to overcome these difficulties the technique discussed previously was applied to a producing gas well.

The gas, in moving into the bore hole, must expand and arrives at a temperature that is less than the indigenous temperature for that depth. In moving up the hole it will warm up. The amount of heat moving into the gas is expressed again by an equation similar to (1), where corrections are made for the efficiency with which heat can be transferred through the gas to itself. The effect of this heat on the temperature of the gas can be expressed by an equation similar to (2), except that a different factor is used for the density and specific heat of the gas depending upon the constituents that make up the gas and the pressure and temperatures involved. The quantity of gas can, nevertheless, be equated with Δ. It is believed that this will be fairly independent of the temperature at which the gas arrived in the hole. As the gas moves up the hole, two things happen. The gas warms up and the indigenous temperature of the earth gets less. Finally there is a point reached where no temperature change takes place. This is marked point A on Fig. 5. It is the place where the temperature curve of the flowing gas crosses the geothermal gradient curve. The temperature curve of the flowing gas must be vertical at point A. I suggest that temperature curves run where this does not seem to be the case are faulty curves caused usually by improper logging speeds or improper conditioning of the well. Above point A the curve is analogous to that of the flowing water well discussed. Fig. 5 illustrates how a projection of the indigenous gradient taken in the pocket of the well passes through point A. It also illustrates that similar values of Δ will be computed on either the heating or cooling side of point A.

Fig. 6 illustrates the application of this method applied to a well with two pays. Δ_2 is computed above the lower pay and Δ_1 above the upper. Δ_1 can be equated with the total production, and Δ_2/Δ_1 will give that proportion being produced by the lower sand. Sufficient empirical data are not available to publish a conversion factor from Δ to cubic feet per day.

CONCLUSIONS

Information as to the direction and amount of fluid that is moving in a bore hole can be derived from a study of a temperature profile of this moving fluid. Knowledge of the indigenous earth temperature is necessary. Success in this interpretation depends further upon making the temperature measurements under steady-state flow conditions. Care must be taken that the temperature measurements recorded are representative of the temperature of the fluid.

ACKNOWLEDGEMENT

Acknowledgement is made of the help of Dr. John Calhoun and Robert Newman of Penn State University. It was their insight into the nature of the basic concepts presented in this paper that made it possible. Further, thanks are extended to all the people of Bird Well Surveys who helped gather this data.

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PAPER
NUMBER **SPE 2965**

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EVALUATION OF GAS STORAGE WELL COMPLETIONS WITH WELL LOGS

By

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This paper was prepared for the 45th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, to be held in Houston, Tex., Oct. 4-7, 1970. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Publication elsewhere after publication in the JOURNAL OF PETROLEUM TECHNOLOGY or the SOCIETY OF PETROLEUM ENGINEERS JOURNAL is usually granted upon request to the Editor of the appropriate journal provided agreement to give proper credit is made.

Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussion may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

ABSTRACT

Many of the problems connected with the underground storage of natural gas, in both aquifer and depleted reservoirs, can be solved by the proper application of modern wireline logging tools.

Well logs are useful in gas storage wells for the location and inventory of gas-bearing zones, determination of levels where gas enters or is produced from the formation, determining well deliverability, and the location of casing leaks as well as points where the pipe is defective due to corrosion. Logs run after the well is completed can help to evaluate the effectiveness of a stimulation process or the mechanical integrity of the completion. Logs run at intervals, as the storage well is produced, can define changes in gas saturation, movement of fluid contacts, and growth of the gas bubble, thus permitting a periodic inventory.

Major changes in injection patterns and withdrawal rates are usually symptoms of problems. Suitable logging programs can help define these problems and indicate the remedial action necessary to bring the field back to maximum efficiency.

The open-hole logs and the logs run immediately after completion provide valuable background information for the interpretation of logs run later in the life of the well. In existing storage fields, where background information is not available, data must be gathered in order to help define the existing problems. A thorough evaluation of the existing subsurface hardware must also be made.

Small-diameter tools and pressure-control systems are available with which most logging operations may be made in either tubing or casing without interrupting the well operation.

Field examples from gas storage projects in several different areas are used to illustrate the interpretation techniques.

EVALUATION OF GAS STORAGE WELL COMPLETIONS WITH WELL LOGS

By

B. A. Smith, and M. R. Neal

INTRODUCTION

The steadily increasing demand for natural gas has created a need for more facilities for storing gas that is produced during the warm season for use during the cold season. A common type of storage facility now in use is the underground gas storage reservoir.

The sizes of the underground storage reservoirs range from relatively small, with only a few wells, to huge reservoirs, with hundreds of wells. Their uses vary from meeting peak demand for a few hours a day in the coldest weather to furnishing most of the gas used in the area during the winter season.

Gas storage reservoirs are of two main types: ***depleted storage reservoirs*** which once contained gas or oil and water, or a combination of all three, and ***aquifer storage reservoirs*** which originally contained only water.

Besides problems common to all wells, there are many which are peculiar to gas storage wells and reservoirs. The problems encountered, and the method of evaluation used, will depend on the type of reservoir. Some of these problems are:

1. Location of zones where gas is stored.
2. Determining where withdrawal gas is coming from or where injected gas is entering the formation.
3. Determining deliverability and ways to improve deliverability.
4. Location of leaks in the casing.
5. Locating corrosion, or zones of weakness in the casing, which may lead to future leaks.
6. Tracing and finding gas lost through leaks.
7. Inventory — or determination of amount of gas in storage.
8. Evaluating stimulation methods and locating zones affected by stimulation.

EVALUATION OF NEW WELL COMPLETIONS

When new gas storage fields are being developed a complete evaluation can eliminate or simplify many of the problems described above. This includes both open-hole formation evaluation before casing is set and cased-hole evaluation of well performance and hardware integrity.

The open-hole programs are necessary for complete interpretation of most subsequent cased-hole logs. A complete open-hole suite might include the Density, Neutron, and Sonic logs for porosity and lithology information, Induction log for saturation, and Microlog for indication of the permeable zones.[1]

The objectives of the initial cased-hole logs should be considered in two groups; evaluation before perforating, and evaluation after perforating.

BEFORE PERFORATING

The cased-hole program before perforating should be designed to furnish:

1. Base Neutron logs for future use in inventory calculations or diagnosis of well problems.
2. Evaluation of cement bonding and zone isolation.
3. Evaluation of integrity of the casing.
4. Depth control.

The base Neutron log and the open-hole logs furnish background information useful in computing the gas inventory from subsequent Neutron logs run later in the life of the well.[2] The base Neutron log is also useful for tying in to formation depths and for locating gas, behind the casing or in thief zones, which has escaped from the storage zone or leaked through the casing.

Base Neutron logs should be run with water in the casing and also with gas or air in the casing. Both are necessary because in a storage well the liquid level in the casing will vary with the injection-withdrawal cycle. In future inventory calculations the "wet" Neutron will be used as a reference below the liquid level and the "dry" Neutron as a reference above.

The base "wet" Neutron log and Cement Bond log should both be run before perforating in order to have the casing full of water to the surface. The base "dry" Neutron log is run after the water has been removed from the casing in preparation for perforating. The well must be evaluated from total depth to surface since casing leaks or thief zones may occur at any level.

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[1] References are at end of paper.

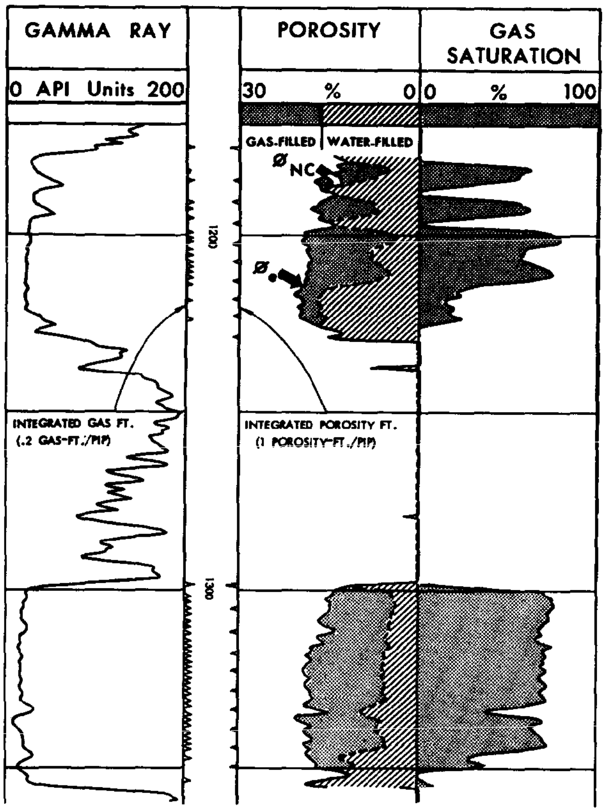

Fig. 1 — Computed log comparing porosity, ϕ_e, from open-hole logs, with porosity, ϕ_{NC}, from the cased-hole Neutron (center), and showing computed gas saturation curve (right).

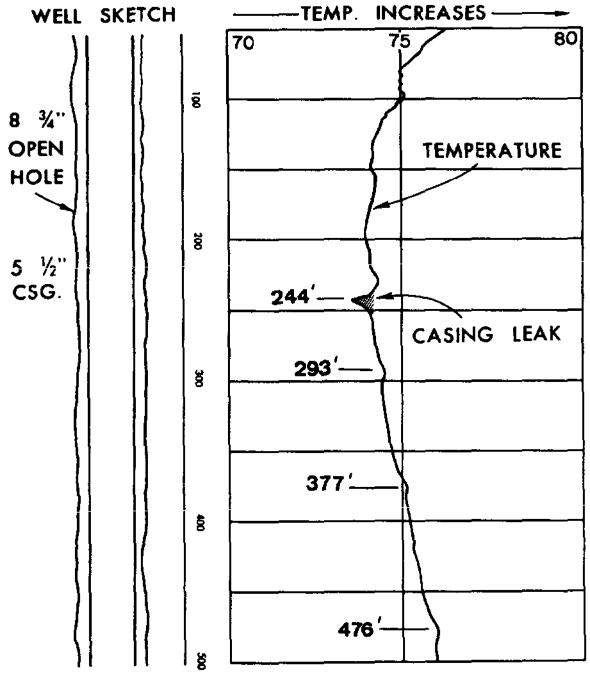

Fig. 2 — Temperature log showing a small casing leak.

Fig. 1 is a presentation of the results which may be derived from the open-hole and cased-hole logs. The Gamma Ray log on the left-hand side (Track 1) shows upper and lower non-shaly zones and a shale bed in between. In Track 2 (center), the fluid-filled porosity, computed from open-hole logs, is the solid curve, and the porosity computed from the cased-hole Neutron log is the dashed curve. The porosity response for the cased-hole Neutron was derived by cross-plotting open-hole porosity data with base Neutron logs run prior to gas injection. Gas saturation, computed from the difference between the two porosities, is presented in Track 3 (right). Integrated porosity-feet is given by the pips on the right side of the depth track, and integrated hydrocarbon-feet by the pips on the left side.

Evaluation of the quality of cement bonding to casing and of zone isolation is done with the Cement Bond Log, an acoustic device.[3] The usefulness of the Cement Bond Log is greatly enhanced by the addition of a VDL log (acoustic wave train log in variable density presentation)[4], which confirms the indications of the Cement Bond Log and reveals the quality of bonding between the cement and formation.

If the pressure test of the casing, made before perforating, indicates casing leaks these may be located with the Temperature log.

Temperature logs can locate gas leaks. They may also be used to detect fluid movements behind casing, thus providing a check on zone isolation. Fig. 2 shows a Temperature log which was used to locate a small leak in a gas storage well before final completion. The anomaly at 244 ft clearly shows the gas leak. Calculations indicated the rate of loss through this leak to be 900 SCF of gas per day at 1000 psig. A casing patch was set over this interval. Further pressure testing indicated the leak was sealed, and the well was completed.

An interesting feature of this log is the presence of heating anomalies shown at 293, 377, and 476 ft. When correlated with open-hole logs, each of these anomalies corresponds to a caved zone. They are probably caused by heat of hydration in the annular cement. This heat is still evident on the log even though the well had been cemented for 65 days.

A Casing Collar log provides convenient depth references for use on subsequent logging or perforating operations in the well. Casing-collar depths may be tied in to formation depths by comparing them with features on cased-hole Gamma Ray or Neutron logs. (For example of Casing Collar log, see Fig. 8.)

AFTER PERFORATING

The cased-hole program after perforating should be designed to:

1. Investigate the effect of perforation and stimulation.

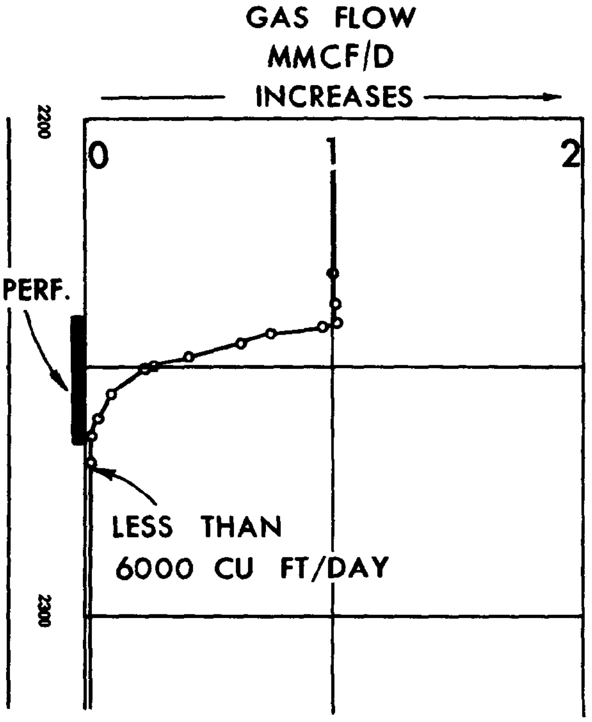

Fig. 3a — Packer Flowmeter log showing gas-injection profile.

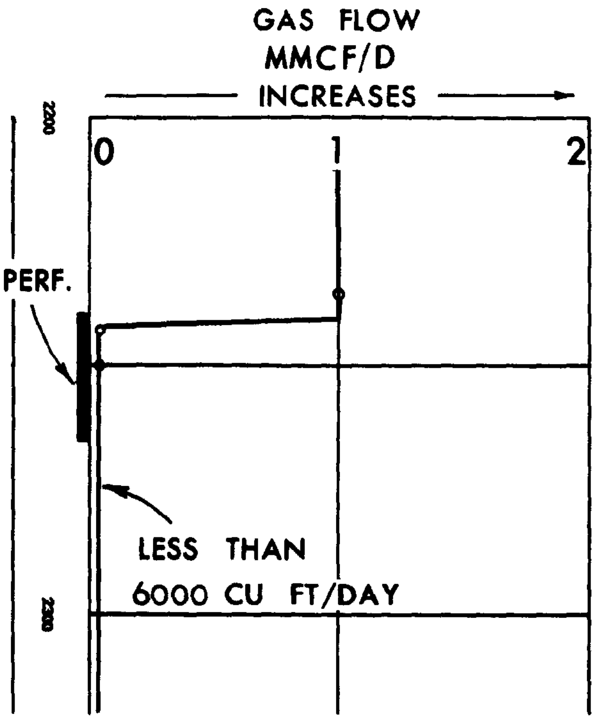

Fig. 3b — Packer Flowmeter log showing most of injected gas is entering through the top two feet of perforations.

2. Assure that the completion is performing as designed.
3. Furnish a reference set of logs for use in studying any future production problems.

A typical set of after-completion logs includes Flowmeter, Gradiomanometer[5], Temperature log, and Pipe Inspection logs. Normally this program will fulfill the three requirements given above.

Perforations, stimulation, and well performance can be evaluated in several ways. Figs. 3a and 3b show profiles of flow rates measured versus depth on Packer Flowmeter surveys run in two offset wells. In Fig. 3a the smooth decrease of flow rate shows distribution of gas injection over the bed, but with most of the gas entering the upper part of the bed. However, Fig. 3b shows that practically all of the injected gas in the adjacent well is entering through the top two feet of the perforations. This could indicate any one of a variety of problems such as ineffective perforations or stimulation, permeable streaks in the formation, skin damage, etc. Further investigation of this zone proved the problem was caused by insufficient injection pressure. Increasing the injection pressure resulted in acceptance of injected gas throughout the perforated interval.

Fig. 4 shows a Continuous Flowmeter log run in a well which had been completed using the "limited-entry" technique. Injection was through the tubing-casing annulus. The log indicates that 55% of the injected gas was entering the formation through the bottom two perforations, although

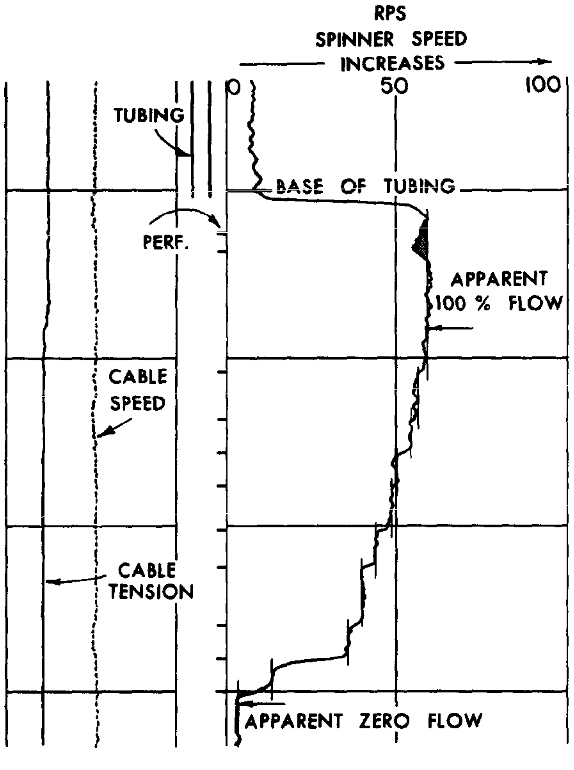

Fig. 4 — Continuous Flowmeter log showing that 55% of injected gas is entering the formation through bottom two perforations.

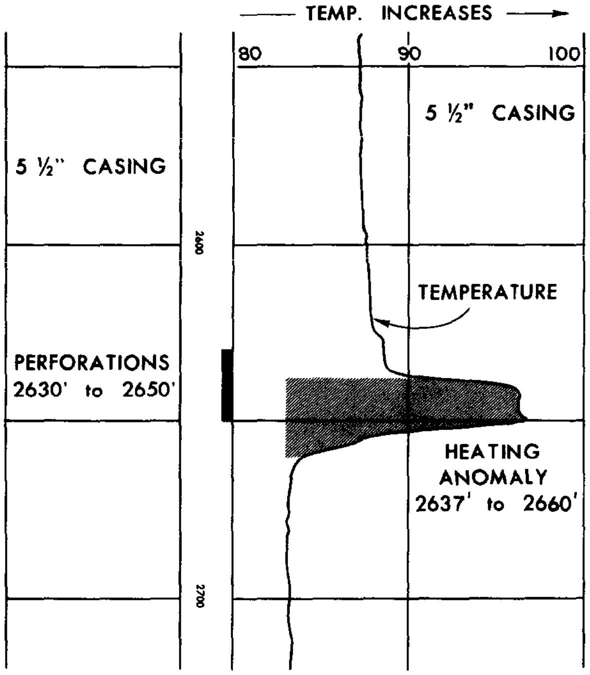

Fig. 5 — Large heating anomaly on Temperature log shows where acid has reacted in formation.

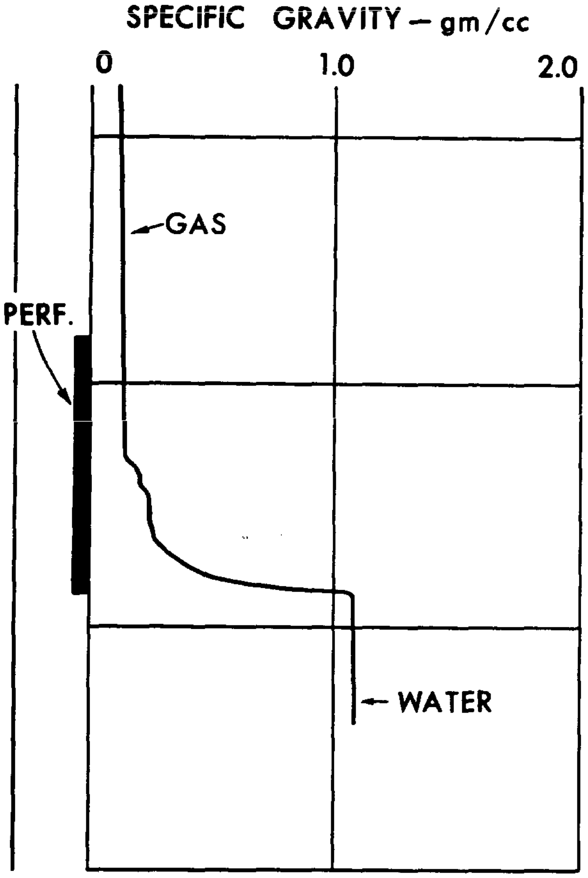

Fig. 6 — A typical Gradiomanometer log.

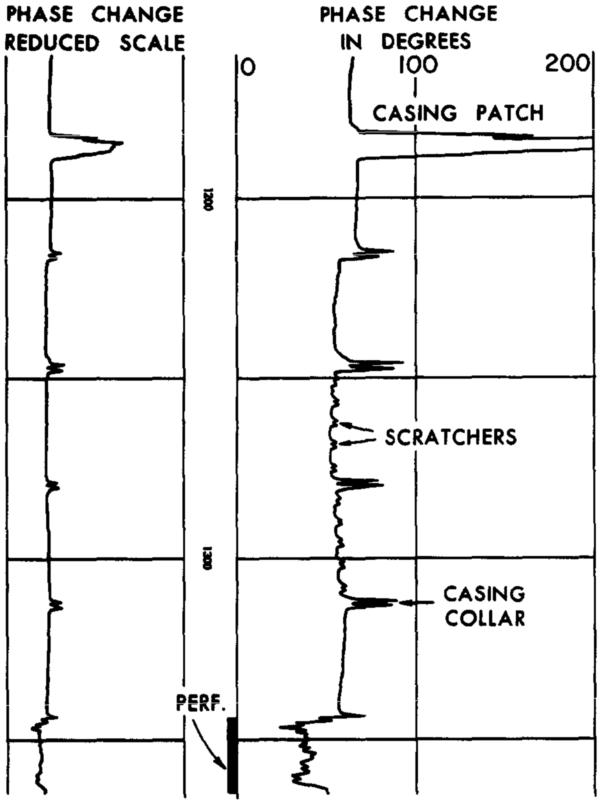

Fig. 7 — Scratchers, casing patch, casing collars, and perforations are apparent on Pipe Inspection log.

some gas is entering each of the other perforations except the top two.

Both Fig. 3b and Fig. 4 are cases of ***new wells*** that did not perform as designed. Both wells required remedial action for efficient operation.

The effects of stimulation may be checked with a Temperature log. Fig. 5 shows a Temperature log run to check the effect of acidizing a carbonate reservoir. The large heating anomaly shows clearly where the acid has reacted in the formation. A similar procedure may be used to detect zones where hydraulic fracturing fluids have entered the formation.[6]

The Temperature and Flowmeter logs supply complementary information. The Flowmeter shows where fluids or stimulation agents enter or leave the casing and the Temperature log shows where these same fluids enter or leave the formation. Both items of information are necessary to evaluate well performance and design remedial action if necessary.

A typical Gradiomanometer log[5] is shown in Fig. 6. This log of hole-fluid density is valuable for indicating the lowest point of gas injection or withdrawal from a formation. This information is necessary when trying to shut off water on the withdrawal cycle and when making studies of water encroachment or water coning.

The final log necessary for the well completion package is the Pipe Inspection log. This log responds to average casing thickness. A typical Pipe Inspection log run in a new well is shown in Fig. 7. Note how clearly casing collars, scratchers, casing patches, perforations, and other variations in the casing makeup are indicated.

The Pipe Inspection log may be run either before or after perforating since the wellbore fluid has no effect on the log. The tool works equally well in gas, air, water or oil.

The primary purpose of the Pipe Inspection log in a new well is to provide a reference for future logs. With a base log for comparison, corrosion can be detected when as little as 3 to 5% of the original casing thickness has been affected. With this early detection it is generally possible to take timely remedial action before any gas is lost.

EVALUATION OF DEPLETED-RESERVOIR STORAGE FIELDS

Many of the fields presently used for, or being converted to, gas storage originally contained gas or oil. These depleted fields make ideal gas storage reservoirs since the two requisites, 1) a porous, permeable formation, and 2) an impermeable cap rock, are already known to exist. Some of the wells in these fields were drilled before the advent of well logging. Records on these old wells (some as old as the 1800's) are meager, and in many cases complete casing records are not available. Depleted fields with few or no records present a different problem than new completions, and a different approach must be used.

Before problems can be defined or remedial action designed, as much information as possible must be gathered on each well. Basically the following questions should be answered:

1. Where are the original casing strings located?
2. Where are the storage zones located?
3. Is there a mechanical problem in the well such as leaks, corrosion, incipient failure of a casing string, etc.?
4. Are there any zones of gas accumulation other than the storage zones?
5. Where is gas entering and leaving the formation?
6. In a water-drive reservoir, where is the fluid level in the wellbore and in the formation at different periods during the injection-withdrawal cycle?

Many of these questions can be answered by running appropriate logs.

A typical logging program for a gas expansion reservoir would include Gamma Ray-Neutron, Cement Top Locator, Temperature, Flowmeter, Caliper, Cement Bond log, and Pipe Inspection log. For a water drive reservoir the Gradiomanometer and possibly a Thermal Neutron Decay Time log should be added.[7, 8]

The Gamma Ray log is used for correlation and definition of formation boundaries. It may also be used to delineate water flows, which exist or have occurred behind casing, by detecting deposits of radioactive scale.[9]

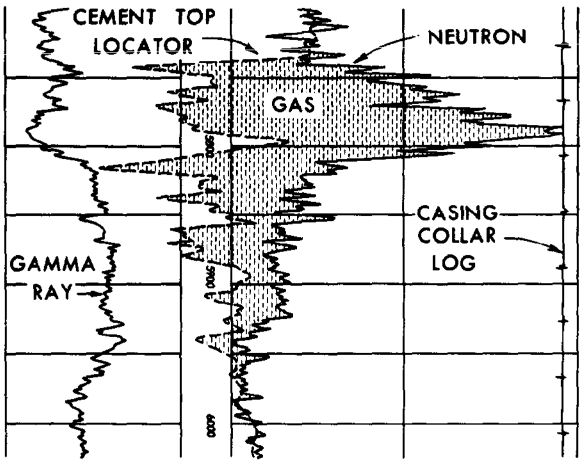

Fig. 8 — Separation between Cement Top Locator log and Neutron log indicates presence of gas.

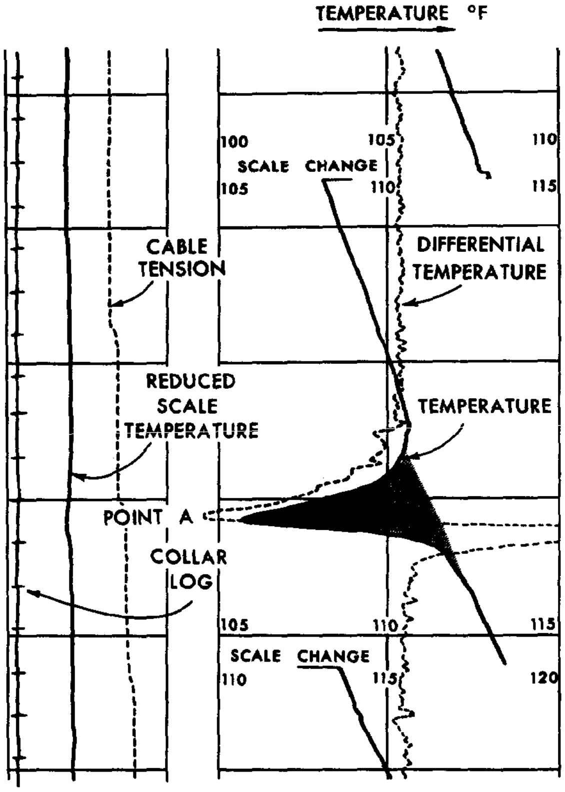

Fig. 9 — Temperature log showing a casing leak at Point A.

The Neutron and Cement Top Locator may be compared to find gas either in open hole or behind casing. In this application, the Cement Top Locator serves as a qualitative cased-hole density log. (Note the indication of gas by separation of curves in Fig. 8.) Without porosity data it is difficult to determine the presence of gas behind casing with only one of these logs. However, a comparison of the two gives positive identification of gas.

The Temperature log is run with the well flowing and rerun at periodic shut-in intervals. Location of zones which have taken injected gas or produced gas are more easily identified from the shut-in runs. These zones will retain their temperature anomaly while the surrounding formations will return to their normal geothermal temperatures. Much information about the well's mechanical condition and the gas-producing zones can be derived from these logs.

Fig. 9, run 48 hours after shut-in, shows a casing leak where 36,000 cu ft/day of gas is escaping. A study of the temperature gradients indicates the gas is coming up the casing to Point A, leaving the wellbore, and continuing up the hole in the casing-formation annulus. Exact points of entry of gas into the formation could not be determined since the original geothermal gradient for this well was not available. However, no gas accumulation zones were noted above Point A, so the lost gas apparently migrates away from the well.

Fig. 10 is a Temperature log which shows a casing leak located several thousand feet above the intended storage formation. Analysis of this log and companion logs indicated this to be a gas accumulation zone which produced gas back into the wellbore during low pressure cycles.

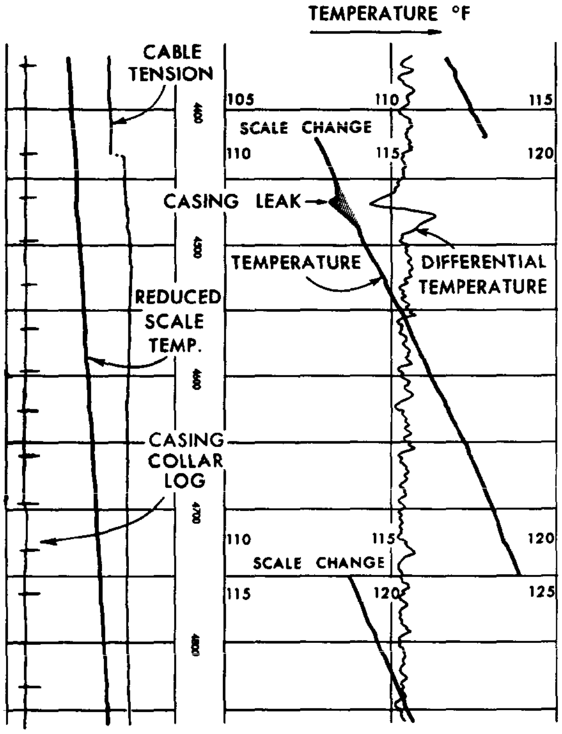

Fig. 10 — A casing leak several thousand feet above the intended storage zone is indicated by Temperature log.

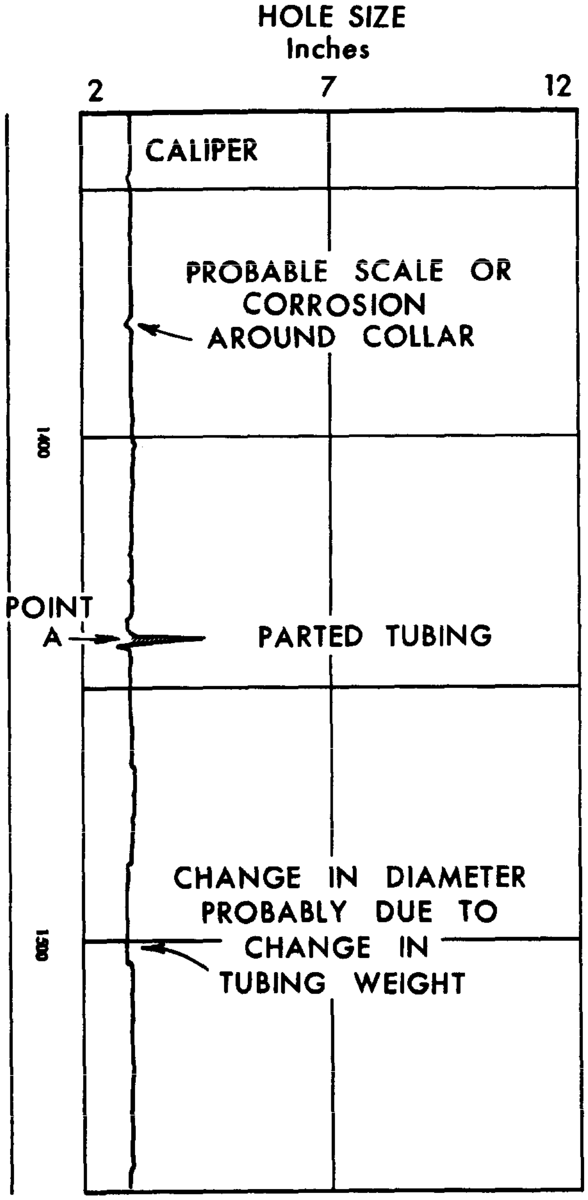

Fig. 11 — Caliper log showing parted tubing at Point A.

Flowmeter logs are run to determine how much gas is flowing and where the gas is entering the borehole. In open-hole completions a Caliper log must be run in order to convert the velocity information from the Continuous Flowmeter to the desired volumetric flow rate information.

In old wells where the records are very poor it is sometimes necessary to run the Caliper even in the casing and tubing to completely analyze well performance. Fig. 11 shows a Caliper which indicates parted tubing at Point A.

The Pipe Inspection log is run to find zones of incipient failure in the casing string. Corrosion, perforations, and other hardware characteristics are pinpointed. For instance, Fig. 12 also indicates excessively thin casing in several sections. One such section is located at Point A. On the basis of this log and the anticipated future casing pressures it was decided to plug and abandon this well. During the plugging operations the casing collapsed. A Caliper log run in the collapsed casing is superimposed over the Pipe Inspection log of Fig. 12. The Caliper indicates the casing to be collapsed at Point A.

The correct program for gathering information on a well is not necessarily limited to the logs described. It should be tailored to the particular well and field conditions being investigated. The reservoir drive system, completion method, casing program, and many other factors must be studied before deciding on a program. One system is to log a few wells and analyze the results. If the desired information is not clear, alter the program and try again. In this manner an optimum program can be established for any set of conditions.

When the information on the well has been secured it is analyzed, and any rework programs are then defined. The well in Fig. 13 has several defects which should be rectified.

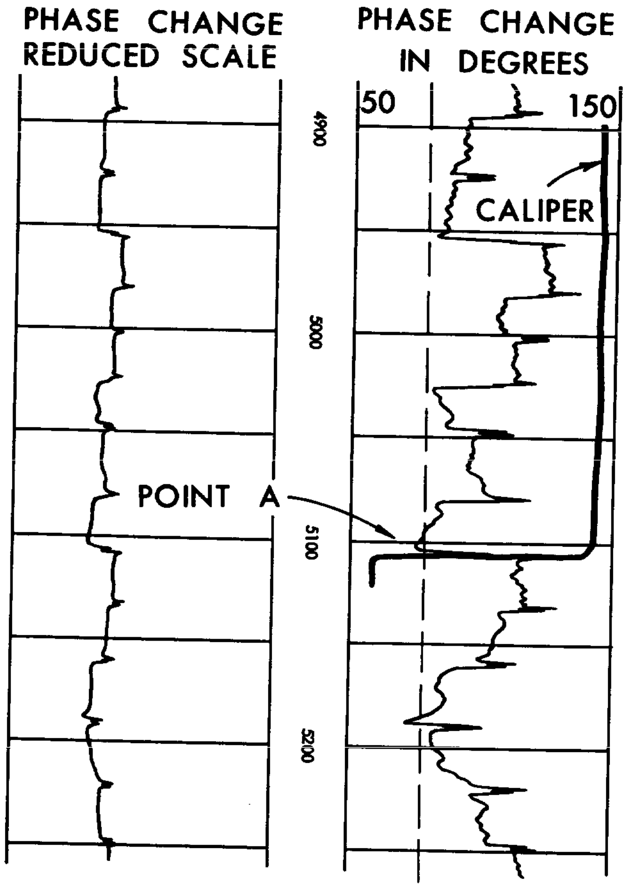

Fig. 12 — Pipe Inspection log shows the casing to be excessively thin at Point A. Subsequent Caliper log shows casing collapsed at that point.

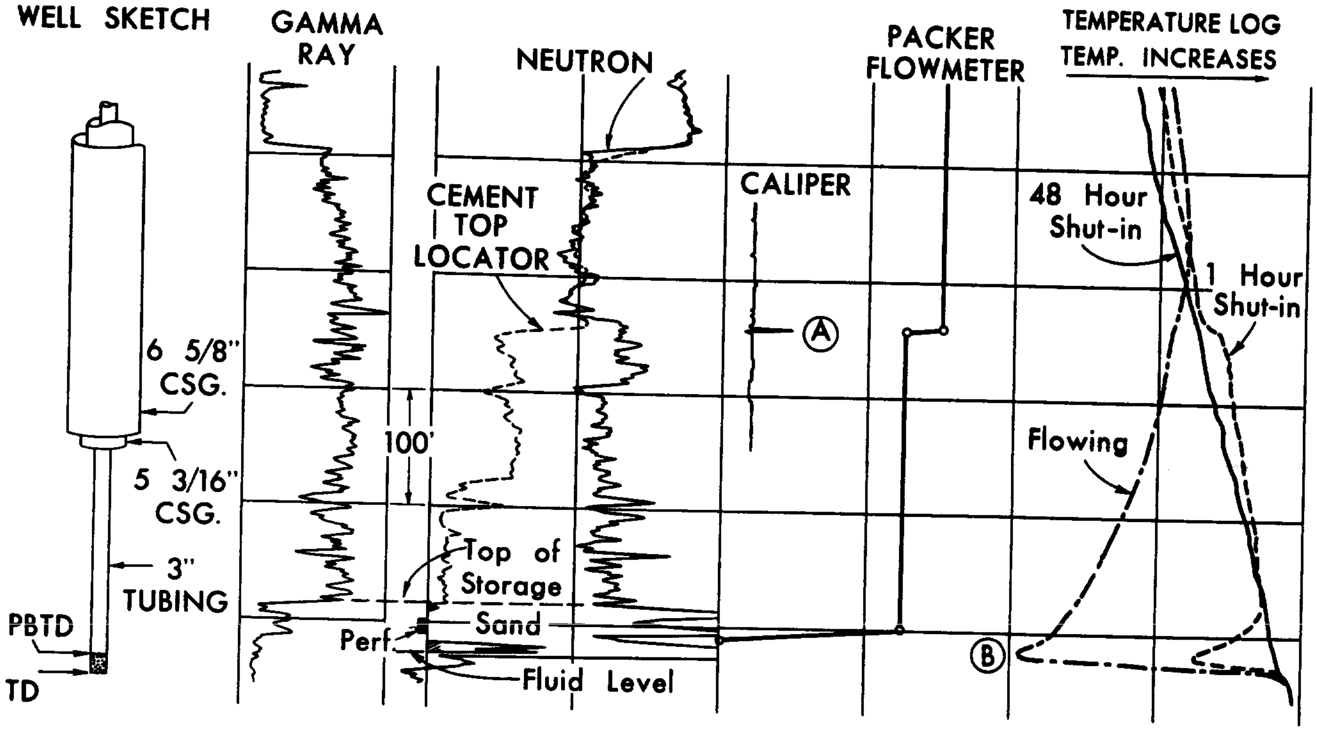

Fig. 13 — Several problems in this well were defined by logs. Caliper and Packer Flowmeter indicate the tubing to be parted at Point A. Temperature log (Point B) indicates gas is being produced from formation below perforated interval.

The parted tubing, indicated by the Caliper and Packer Flowmeter at A, should be replaced. The tubing should be reset and perforated opposite the zone of gas production as indicated by B on the Temperature Log. Because extensive rework would have been necessary for this well it was considered more economical to plug it and drill an offset well.

After necessary rework programs are completed, the same set of after-completion logs described in evaluation of new well completions should be run. These will serve two purposes:

1. To check the effectiveness of reconditioning.
2. To furnish a reference set of logs for analyzing future difficulties.

EVALUATION OF PRODUCTION PROBLEMS

When production problems occur, the logging program must be selected in a different manner than in new-well or depleted-reservoir cases previously discussed. There is no standard logging program which will solve all production problems. Instead, a deliberate step-by-step analysis of the problem must be completed.

The first step is to study all available history on the well such as the drilling and completion records, the open- and cased-hole logs, and the injection-withdrawal records over the life of the well, etc. This information, together with the recent history of problems, will lead to many questions concerning downhole dynamics of the well.

When the study is complete and the questions have been listed, the next step is to decide what log is most likely to answer the important questions. This log should be run and the data again analyzed with the additional information available. If the answers are now clear the remedial work can be planned. If the problem is still not well defined the log to run next must be selected. This process of logging and analysis should be repeated until the production problem is defined.

The following is an example of a production problem which occurred in a new, aquifer storage field. Approximately 40 wells had been completed and gas injection had started. After several short-term tests had been successfully completed, it was decided to make a full-scale withdrawal test.

During the test the gas production from several wells virtually stopped. Since less than 50% of the theoretically available gas had been produced, a solution had to be found.

Four of the wells, which were still producing gas and some water, were chosen to analyze the problem. A well sketch typical of these completions is shown in Fig. 14a.

It was decided to run a Neutron log to determine if there was still gas in the storage zone. Comparison of this log (solid curve of Fig. 14b) with the base Neutron log (not shown) indicated that much gas was still present in the

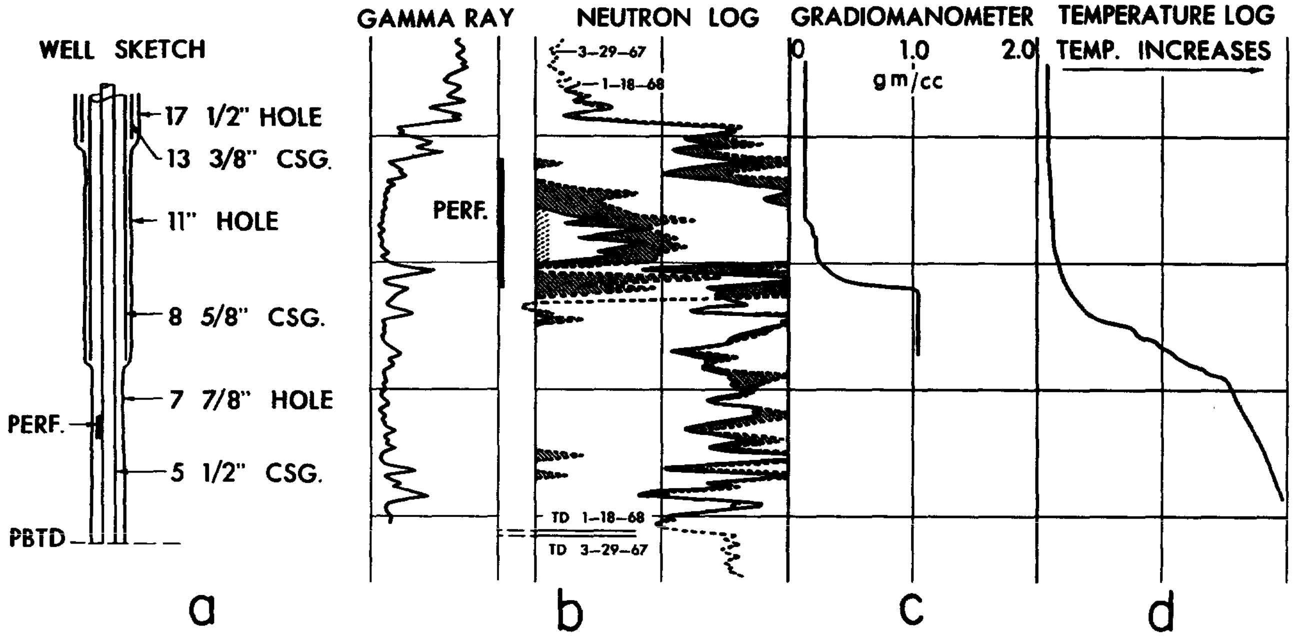

Fig. 14 — Logs run in a storage field that was experiencing production problems. Neutron log indicates gas still present in storage zone. Gradiomanometer shows that some water was being produced from perforations. Temperature log indicates gas production was coming from formations below the perforations.

storage zone, but did show a reduction from the previous Neutron log (dotted curve) run after gas injection. It also indicated that some gas had been produced from zones below the perforated zone.

After this, a Flowmeter and Gradiomanometer were run to determine if all the production was coming from the perforations. The Gradiomanometer, shown in Fig. 14c, showed that the casing was full of water below the bottom of the perforations, and contained gas from there on up. The Flowmeter confirmed this. The original Cement Bond log on this well had indicated good zone isolation.

A Temperature log was run while the well was producing to try to find out why gas production had dropped in the other wells. The log, shown in Fig. 14d, indicated that the formation was being cooled below the perforated zone. This implies a movement of gas from the formation below the perforated zone, and one can conclude that the aquifer below the perforated zone is a much better reservoir for gas storage than the one perforated. With this information, the original permeability information was restudied. It showed the upper 50 feet of the storage formation to have relatively low permeability and porosity. The results of the same logging program performed on all four wells showed the same characteristics. It was therefore defined as a field problem rather than a problem in one or a few wells.

From the data now available it appeared that gas was preferentially flowing from the more permeable sand lower in the formation. The flow was restricted by the low permeability opposite the perforations. Since there was poor communication between the porous, permeable zone and the perforations, there was a rapid decline in pressure, hence in the production, as gas previously injected into the upper zone was produced.

To test this theory two wells were perforated over a 20 foot section below the original perforations and in the more permeable zone. These were not the wells logged, but the wells that were virtually dead in the same field. The results were:

1. Both wells came back on gas naturally without swabbing.
2. Both wells, when they had cleaned up and stabilized, were several hundred percent better than on original tests.

On the basis of these tests the other wells in the field were reperforated with much the same results.

It is important to complete the study of a production problem while the well is still dynamic (producing normally). If the problem continues and finally kills the well, usually little or no information about the cause of the problem can be obtained. There are exceptions, but in general the well must be dynamic to define a production problem.

A case in which the problem was defined after a well had gone to water and died occurred in a small 11-well field. Sev-

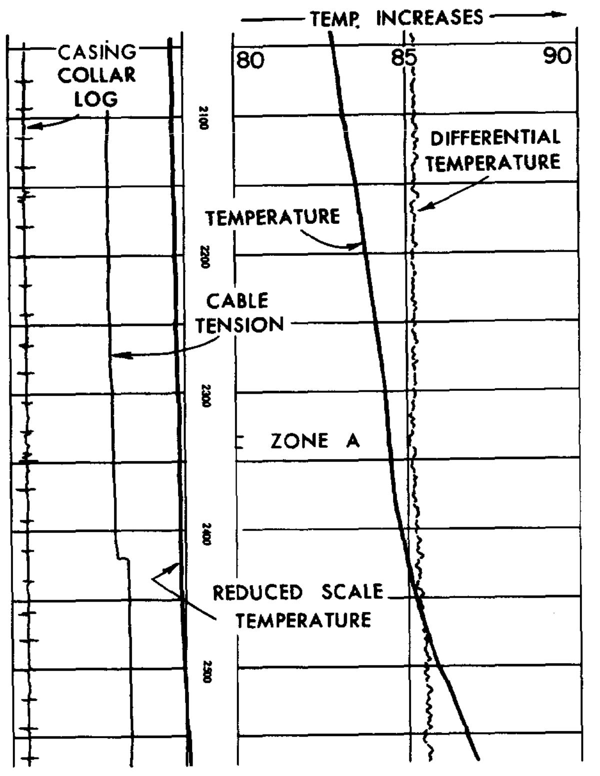

Fig. 15 — Temperature log shows water production from Zone A flowing down to the bottom of the casing and into the wellbore.

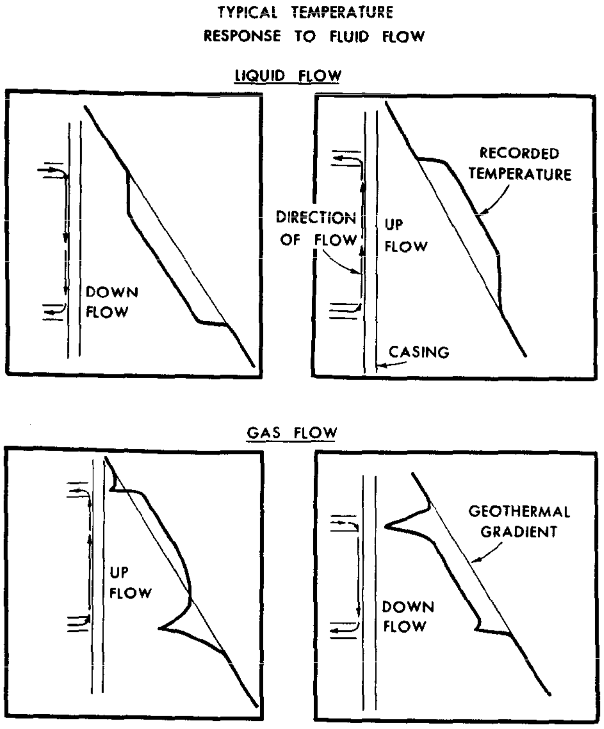

Fig. 16 — Theoretical sketch of Temperature log responses to liquid and gas flow.

eral wells in this field had already been abandoned due to water production.

Consideration was being given to abandoning the field. It was decided to make a final effort to determine if the water was coming from the storage sand or was channeling from a water zone. A decision was made to log one of the dead wells in an attempt to solve the problem.

The water was swabbed to several hundred feet below the static fluid level. While the well was filling again to the static level several Temperature logs were run. One of these logs is shown in Fig. 15.

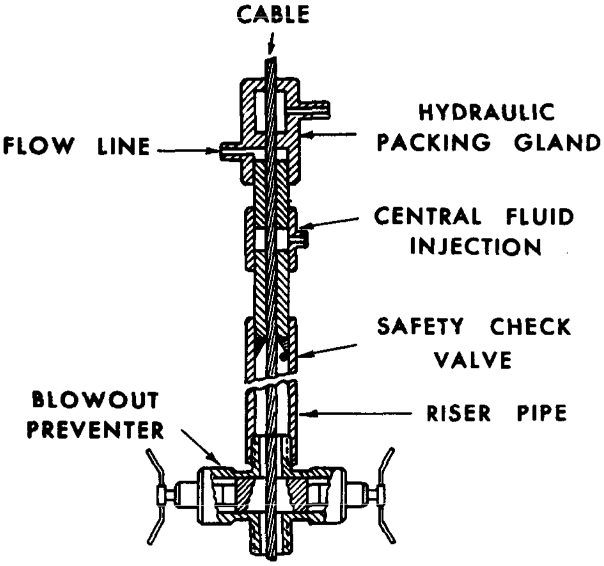

Fig. 17 — High-pressure wellhead control assembly (schematic).

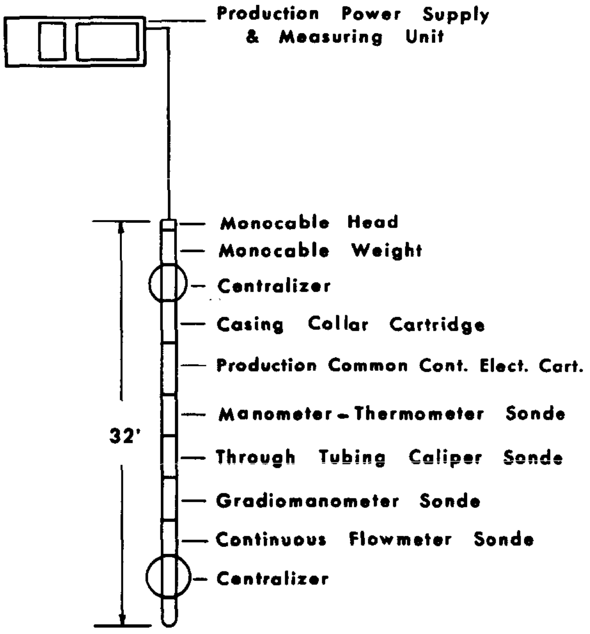

Fig. 18 — Production Combination Tool.

Close examination of the Temperature log reveals the differential curve goes to zero at Zone A. This indicates the temperature gradient was zero at this level. When the flowing fluid is liquid, the temperature curve will be vertical only where fluid leaves the formation.[10] (Compare the theoretical temperature curves for liquid and gas production shown in Fig. 16.) Therefore, water is being produced from Zone A and flowing around the bottom of the casing to the wellbore.

On the basis of this analysis the well was perforated and squeezed between the storage zone and Zone A. The well was then swabbed and put back on the line. It cleaned up, and no more water problems occurred. On the basis of these results, a second well was also squeezed and put back on production with similar success.

DESCRIPTION OF TOOLS AVAILABLE FOR DYNAMIC WELL STUDIES

Ten years ago results such as have been described were impossible for two reasons:

1. Wellhead control equipment had not been developed which could handle even relatively low pressure gas without freezing off at the control head. Even if freeze-off had not been a problem the large amounts of gas escaping made the operation costly and dangerous, and the results questionable.
2. Tools had not been developed for making meaningful dynamic studies of well conditions.

In the last decade these problems have been overcome. Dynamic well control is now possible by use of high pressure

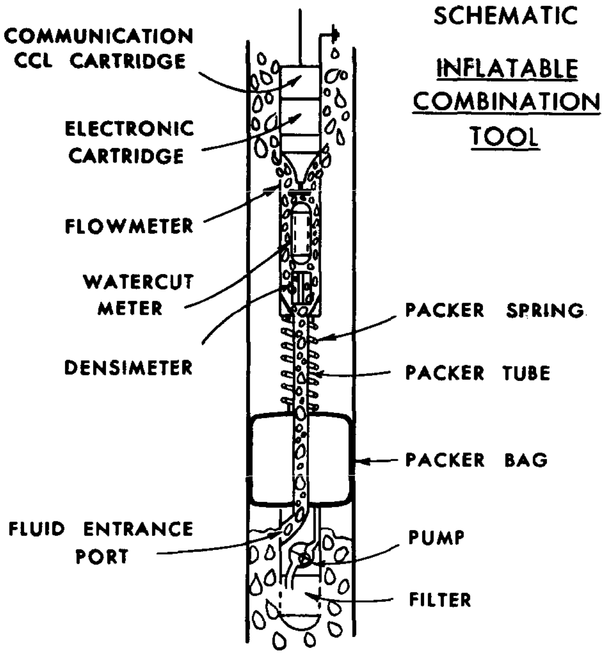

Fig. 19 — Inflatable Combination Tool (schematic).

wellhead control assemblies (Fig. 17). Wellhead control equipment is available which can safely control up to 15,000 psi of wellhead pressure without loss of gas. Since gas loss does not occur, freeze-off is not a problem; there is no danger of fire or explosion, and the results obtained truly represent the dynamics of the well.

The second problem has become overcome by development of tools designed to be used in wells under dynamic conditions. In addition, many of the more familiar services have been redesigned and improved for thru-tubing work.

Two new tools applicable to dynamic studies are the Production Combination Tool[11], and the Inflatable Combination Tool.

The Production Combination Tool (Fig. 18) is designed to make, sequentially, five individual measurements on one trip in the well. These five measurements, each recorded continuously versus depth, are: temperature, pressure, flow rate, hole size, and fluid density. A Casing Collar Log is recorded along with each of the five measurements for positive depth control.

The advantages of running five services on one trip in the hole are many. Probably the most important is the ability to take all measurements under the same well conditions, and in a shorter time.

The Inflatable Combination Tool[5] (Fig. 19) makes level-by-level measurements of flow rate, fluid density, and water cut index. It provides data for the analysis of low-volume multiphase flow. That is, oil, gas and water can be

TABLE I

Tools Available for Evaluation of Well Completions

Tool	Function	Tool Diameter in inches	Minimum Pipe Size (Internal Diameter)
Gamma Ray-Neutron Log	Determine: gas inventory, formation depth and thickness, gas-liquid contacts, lithology, porosity index	$1\frac{11}{16}$ $3\frac{5}{8}$	2-inch tubing
Cement Bond Log	Determine: zone isolation, cement top	$1\frac{11}{16}$ 3.9	2-inch tubing
Thermal Decay Time Log	Locate hydrocarbons behind pipe Evaluate fluid saturations	$1\frac{11}{16}$ $3\frac{5}{8}$	2-inch tubing
Pipe Inspection Log	Locate corrosion damage, Evaluate economic life remaining in casing	$3\frac{1}{4}$ 5	$3\frac{3}{4}$-inch I.D.
Packer Flowmeter	Determine: contribution of each zone to total production or injection, Indicate changes of flow pattern (low flow rates)	$1\frac{11}{16}$ 2	2-inch tubing
Continuous Flowmeter	Determine: contribution of each zone to total production or injection. Indicate changes of flow pattern (high flow rates)	$1\frac{11}{16}$ 2	2-inch tubing
Production Combination Tool	Includes: Continuous Flowmeter, High Resolution Thermometer, Collar Locator, Manometer, and Gradiomanometer	$1\frac{11}{16}$	2-inch tubing
Inflatable Combination Tool	Determine production or injection profiles and identify fluids	$1\frac{11}{16}$ $2\frac{1}{8}$	2-inch tubing
Gradiomanometer	Determine: gas entries, fluid contacts	$1\frac{11}{16}$	2-inch tubing
High Resolution Thermometer	Determine: fluid entries, lowest depth of production or injection. Locate: fluid flow behind pipes, gas leaks. Determine geothermal gradients	$1\frac{11}{16}$	2-inch tubing
Radioactive Tracer	Locate flow of injected fluids behind casing, Determine travel paths of injected fluids	$1\frac{3}{8}$	$1\frac{3}{4}$-inch tubing
Fluid Sampler	Recover a representative volume of wellbore fluids for PVT work	$1\frac{11}{16}$	2-inch tubing
Thru-Tubing Caliper	Determine hole size	$1\frac{11}{16}$	2-inch tubing
Cement Top Locator	Determine apparent density of casing-formation annulus and/or formation	$1\frac{11}{16}$ $3\frac{5}{8}$	2-inch tubing
Casing-Collar Locator	Locate casing collars for depth reference	$1\frac{11}{16}$ $3\frac{5}{8}$	2-inch tubing

differentiated at each depth or station in the hole at flow rates as low as approximately 10 barrels per day. The source of water or oil problems in gas storage wells may therefore be isolated and treated.

Other wireline operations applicable to dynamic well studies are: Gamma Ray-Neutron Log, Cement Top Location Log, Cement Bond Log, Radioactive Tracer Log, Thermal Neutron Decay Time Log, Fluid Sampler, and Pipe Inspection Log.

Most of these tools are available in 1 11/16-inch diameter for thru-tubing work. Table I lists available tools, their uses, and sizes.

CONCLUSIONS

Comprehensive evaluation of gas storage completions requires a coordinated information package. For maximum value, this package must be planned prior to drilling the well and must be tailored to the unique problems associated with gas storage wells.

In depleted gas storage reservoirs such coordinated information packages are usually not available. However, using a well planned data gathering program as a base, many of the problems associated with renovating old depleted fields may be avoided. Those problems which cannot be avoided may be treated before they become disastrous.

When problems with the normal production cycle of the storage well do occur, these problems can usually be isolated and often treated without interrupting well operation.

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ACKNOWLEDGMENT

The authors wish to express their appreciation to the oil companies for releasing the logs used in the examples.

Ex. II – 41

United States
Environmental Protection
Agency

Office of Research and
Development
Washington DC 20460

EPA/600/R-94/124
July 1994

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Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity

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FOREWORD

EPA is charged by Congress to protect the nation's land, air and water systems. Under a mandate of national environmental laws focused on air and water quality, solid waste management and the control of toxic substances, pesticides, noise and radiation, the Agency strives to formulate and implement actions which lead to a compatible balance between human activities and the ability of natural systems to support and nurture life.

The Robert S. Kerr Environmental Research Laboratory is the Agency's center of expertise for investigation of the soil and subsurface environment. Personnel at the Laboratory are responsible for management of research programs to: (a) determine the fate, transport and transformation rates of pollutants in the soil, the unsaturated and saturated zones of the subsurface environment; (b) define the processes to be used in characterizing the soil and subsurface environment as a receptor of pollutants; (c) develop techniques for predicting the effect of pollutants on ground water, soil, and indigenous organisms; and (d) define and demonstrate the applicability and limitations of using natural processes, indigenous to the soil and subsurface environment, for the protection of this resource.

This report presents a discussion of three tools that can be used for determining the mechanical integrity of injection wells. Each tool is unique in its own right and can be applied to specific problems encountered in injection well mechanical integrity determinations. The ability to understand the application of each tool will help to assure that the use of injection wells for disposal of waste will not endanger underground sources of drinking water.

Clinton W. Hall
Director
Robert S. Kerr Environmental Research Laboratory

ABSTRACT

Regulations of the Environmental Protection Agency require that an injection well exhibit both internal and external mechanical integrity. The external mechanical integrity consideration is that there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

Mechanical integrity problems both related and not-related to injection can be investigated using the three logging tools: radioactive tracer, noise and temperature.

The operational principles of each tool are discussed, followed by the principles by which the tools detect flow and examples of the tool being used in such application. Finally, general operational guidelines are outlined to assist the reader in the application of each tool.

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ACKNOWLEDGEMENTS

This report is based on a training session prepared for the United States Environmental Protection Agency and East Central University by Dr. R. M. McKinney (Exxon Production Research–Retired). Many thanks to Pat Powell, Dynamac Corporation, and Carol House, CDSI, for their untiring efforts in putting the manuscript in final form.

Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity

Introduction

This report describes the application of the above logging tools to injection well operation in order to infer the answer to two questions:

(1) Is the injected water entering intervals other than the interval approved for disposal?

(2) Does the presence of the borehole allow crossflow from saltier water formations into underground sources of drinking water?

The problems associated with positive answers to these questions are referred to as related and nonrelated injection well problems, respectively. In actuality, noninjection related problems in one borehole can generally be traced to long standing related problems in other wellbores. For this reason, injection related problems are the first discussed as consideration is given to how each of the three logging tools tells if injected fluid is being confined to the approved interval. This discussion will necessarily entail consideration of proper use of each tool as well as a detailed look at what the survey results mean. The entire field of production logging is somewhat unique in that how one does things is usually more important than what one does.

Once the problem of confinement, or the lack of such, is dealt with, then the use of the tools for noninjection related flows from abnormally pressured into normally pressured zones or from normally pressured into depleted zones will be discussed. The operational procedures and the interpretational guidelines for these situations are not the same as those for demonstrating confinement. In general, the radioactive tracer tool must be replaced by neutron activation tools that create a tracer behind pipe as well as inside pipe. These latter tools are a specialty in their own right and are not discussed in these notes.

The tools are introduced in the same order as listed in the title: Temperature, Radioactive Tracer, and Noise. This ordering recognizes both general utility and level of expertise necessary for effective utilization. A temperature survey has unique features unmatched by any of the other logging tools. Furthermore, it is the least likely to mislead the interpreter provided one is thoroughly trained in its use. To the uninitiated, a temperature survey can, however, be rather perplexing.

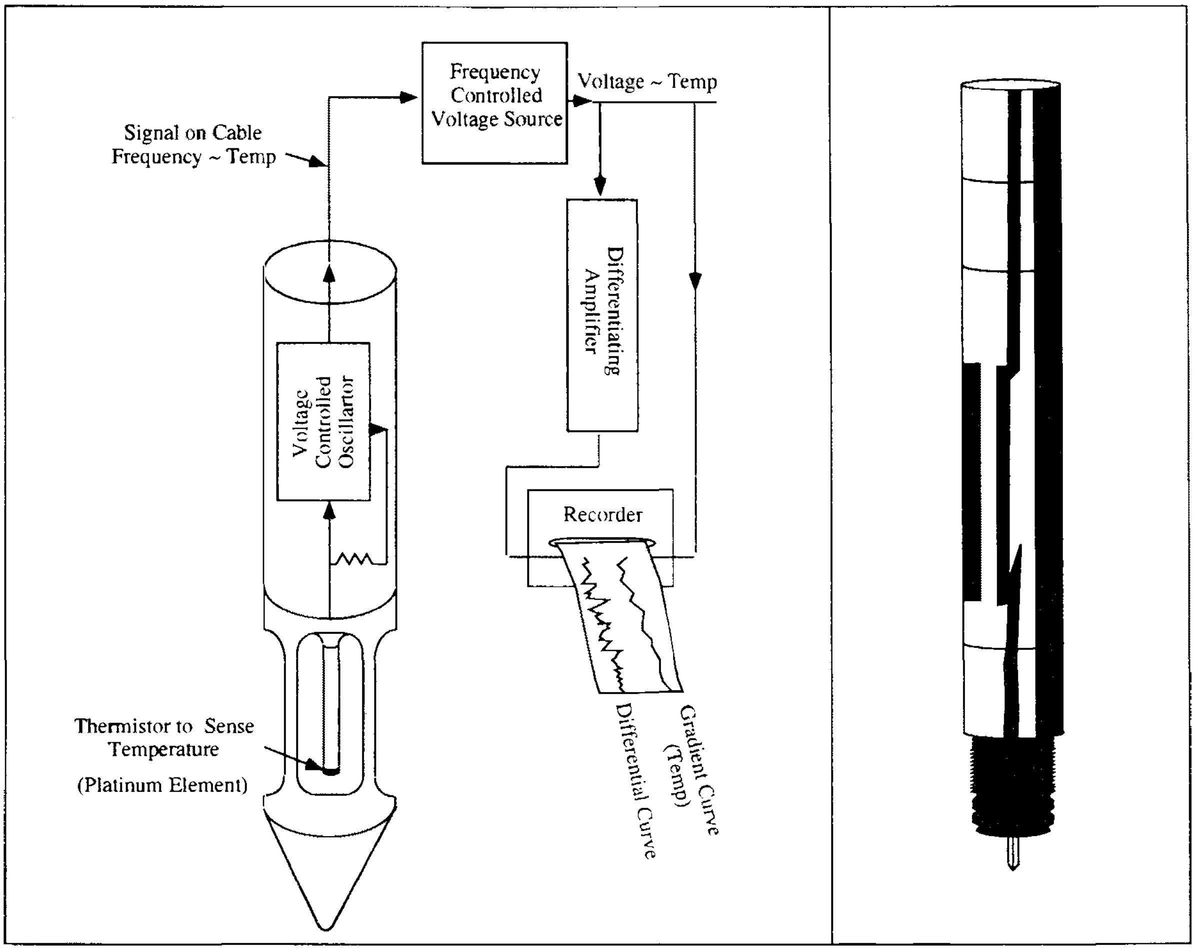
As each tool is introduced, its operational principles are discussed briefly. Next, those principles by which the tool detects flow are given in some detail. This understanding is necessary if the log analyst is to "know what to expect" on the log. This development is then followed by numerous examples in the form of illustrations. Finally, general operational guidelines are attempted now that the reader has a basis to not only appreciate the significance of such but also to recognize their specific limitations.

Temperature Surveys

The temperature logging tool is the oldest of the production surveying instruments. Records of its use to indicate downhole flow dates back into the middle 1930's. These early thermometers were run on "slick" line and recorded downhole, usually on oxide-coated metal charts of the same sort as those found in downhole pressure "bombs." The sensing element in these earliest thermometers was a column of mercury whose expansion or contraction positioned a floating piston to which was attached the "scribing" pen. In time, these sensors were replaced by vapor-pressure type detectors, that is, by bulbs partially filled by a volatile liquid whose vapor pressure increased with temperature. This pressure, in turn, was measured by a bourdon type element already in use in pressure gauges. This latter type of thermometer has survived to the present time and is still in use, mainly for bottomhole temperature measurements. As surveying tools they are cumbersome to use. Not only do they require careful shop calibration but, also, their slow response requires the operator to make stops of 5 to 15 minutes' duration each at those stations selected for temperature measurement. By way of contrast, modern electric wireline thermometers not only have better resolution, but also have sufficiently rapid response time that, at logging speeds of 30 feet per minute, a continuous record can be obtained that parallels true borehole fluid temperature variation with depth and that lags by no more than about one degree Fahrenheit. These are the tools described in this document.

Continuously Recording Thermometers: A schematic of a modern, electric wireline thermometer appears on frame A of Figure 1. A cage, open to wellbore fluid, is located at the bottom of the tool. Contained in this cage is a thermistor that senses the surrounding fluid temperature. The preferred sensor is a platinum element of some sort, either a tiny coil of platinum wire or a platinum-film resistor. Platinum is an ideal temperature sensor because its resistivity is stable and increases linearly with temperature over a wide range. Thus, the tool makes a continuous measurement of the resistance of the thermistor, which, by shop calibration, is directly related to the temperature of the sensor's environment. In actual construction, the thermistor is either one branch of a bridge circuit or has a constant current passed through it. In either case, the voltage drop across the sensor is directly proportional to its resistance. This voltage is used to control the frequency output of a voltage-controlled oscillator, the "spikes" from which are transmitted up the logging cable to be counted at the surface. So long as the pulses (spikes) are of high enough voltage to be detectable at the surface, the tool output is independent of the length (resistance) of logging cable between the tool and the surface recorders.

On analog recording trucks, the transmitted counts per minute are converted to a voltage by a counting circuit and recorded on a pen-and-ink strip-chart recorder as a temperature, or gradient, trace. This is trace 1 on Figure 2, a section of temperature log from a flowing well that produces 1,800 barrels per day (BPD) of liquids most of which is water. The scale in degrees Fahrenheit at the bottom of the log goes with this trace. As frame (A), Figure 1, shows, an amplified trace



(A) Schematic of Tool

(B) Actual Tool

Figure 1. A surface recording, continuous thermometer.

of temperature changes can be generated by the output of a differentiating amplifier whose input is the same voltage that gives the temperature record. The resulting "differential" trace magnifies the changes in slope on the temperature curve and, as is evident from curve 2 on Figure 2, is well worth the additional charge even though no absolute scale is associated with the trace.

When used in the manner illustrated in Figure 2, a temperature survey becomes a high-precision flow survey that has the best vertical resolution of all logging tools. For example, the increase in slope recorded at depth A on the differential trace 2 fixes the bottommost point of production more precisely than the depth scale itself can be established. Depth A can be shifted by no more than the width of the pen mark, ± 1/2 foot. Furthermore, the tool will resolve temperature changes as small as 0.05°F. An excursion of about this size is caused by the small entry at depth C on the log of Figure 2. This is the only flow meter that would detect such a small entry. The large entry at depth B is, of course, quite evident as is the lack of entries from anywhere in the middle set of perforations. The accuracy of the absolute temperature values on Figure 2 depends completely on when and how carefully the tool was last calibrated.

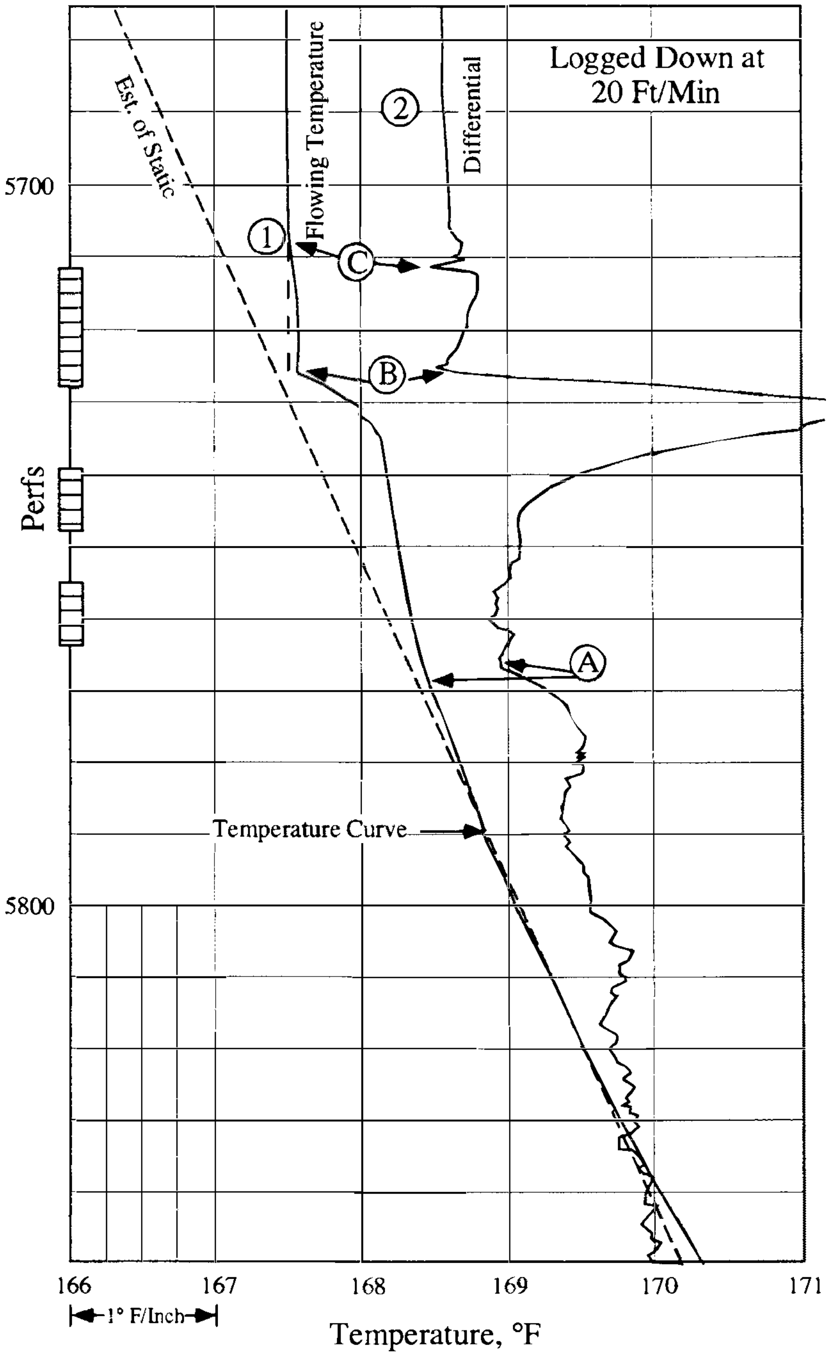
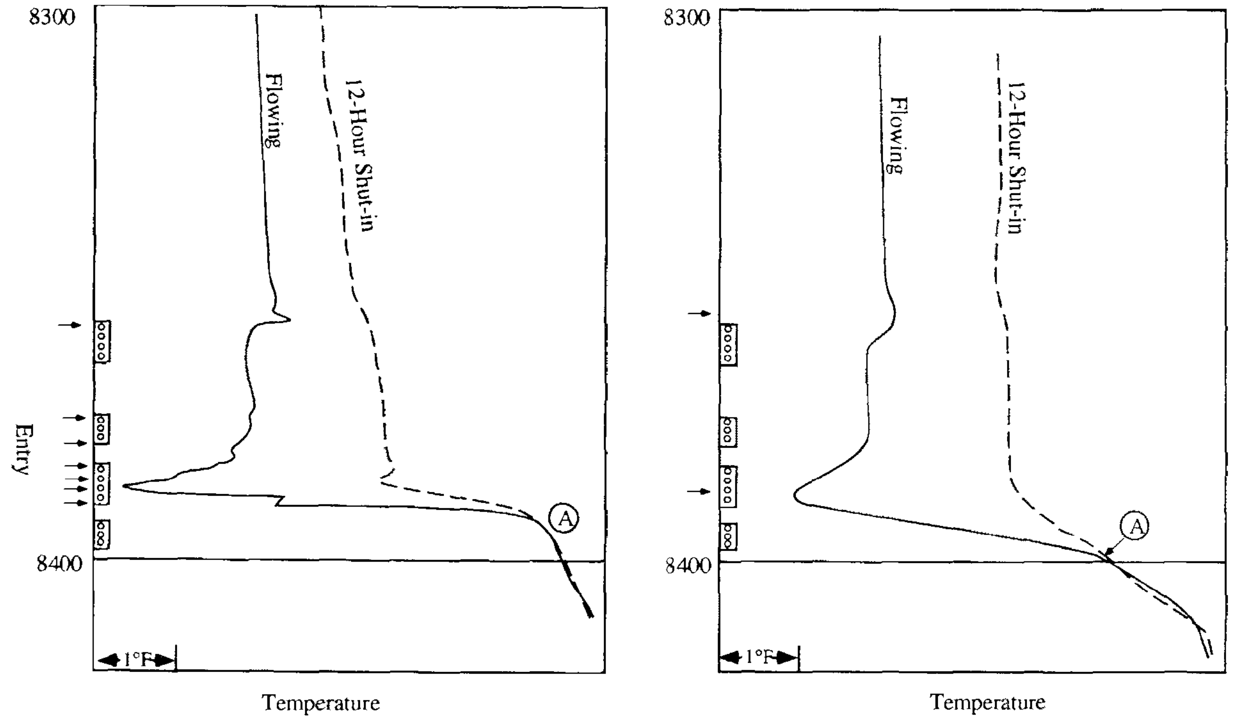


Figure 2. A section of a temperature survey from a well flowing mainly water at 1800 BPD.

On digital logging trucks, the pulses transmitted up the logging cable are processed for tape storage by a binary coded digit unit (BCD). This is essentially a counting device with its own separate clock that is not synchronized with the downhole "clock" or tool. The conversion from pulses per minute to binary coded digits therefore introduces a sampling error that is considerable relative to the resolution of the downhole tool. Before display, this noise is filtered from the record with "suppressor" filters. The resulting degradation in signal quality is evident from a comparison of frames A and B of Figure 3 which show the results of processing the same temperature log by analog and digital panels, respectively.



(A) Analog Panel

(B) Digital Panel with "Suppressor"

Figure 3. Temperature logs from same thermometer in gas well but with processing by two different surface panels.

Tool Specifications: Modem temperature survey tools are designed to function at pressures up to 20,000 PSIG and at temperatures of 350° to 400°F. Special high-temperature tools are also available which extend the operating range up to about 550°F. The combined length of the cage containing the sensor and the barrel containing the electronics is no more than about 4 feet. This short length allows the tool to be run in combination with other surveying instruments. The diameter of commercial tools range from a minimum of 7/8-inch to a maximum of 1 11/16-inch. The small 7/8-inch version is used extensively to survey down the annulus of wells on rod pumps. They are also useful for passing through tight spots in old injection wells. A 1 3/8-inch diameter instrument is the preferred choice for use in 2-inch tubing that contains nipples of various types.

Logging Procedures: Temperature surveys are best run going into the hole with the temperature sensor located as near as possible to the bottom end of the tool string. This allows the sensor to contact fluid that has not been mixed vertically by the passage of the tool and wireline. The tool need not be run with centralizers and the logging speed should not exceed 40 ft/min with 20 to 30 ft/min being preferable. The survey should start at least 100 feet above the zone of interest to allow time for the moving tool to stabilize.

Static Temperature Gradients: The static temperature in a wellbore increases gradually with depth into the well. In most areas of the North American continent, this increase will occur at a rate between 0.5 and 2.5 degrees Fahrenheit for each 100-foot increase in depth, with a value of

1.7°F/100 ft (3°C/100 M) being typical. The major portion of this static gradient results from heat production in the earth's crust by radioactive decay of minerals; consequently, local gradients reflect primarily the relative richness in shale of the subsurface. Typical static gradients in Texas and Louisiana are illustrated on Figure 4. These are all measured in wells that have never undergone injection or production and that have been shut-in for at least one year after completion.

The detailed variations in static gradients are determined by variations in the effective thermal conductivity, *k*, of the combined rock and pore fluids. Typical values for *k* in BTU/Hr-ft^2-(°F/ft) for various earth materials as well as for water, oil and gas are listed in Table 1. As the size of *k* decreases, the size of the static gradient increases, that is, the rate at which temperature increases with depth becomes larger. From this table, one can infer that it is the water content mainly that

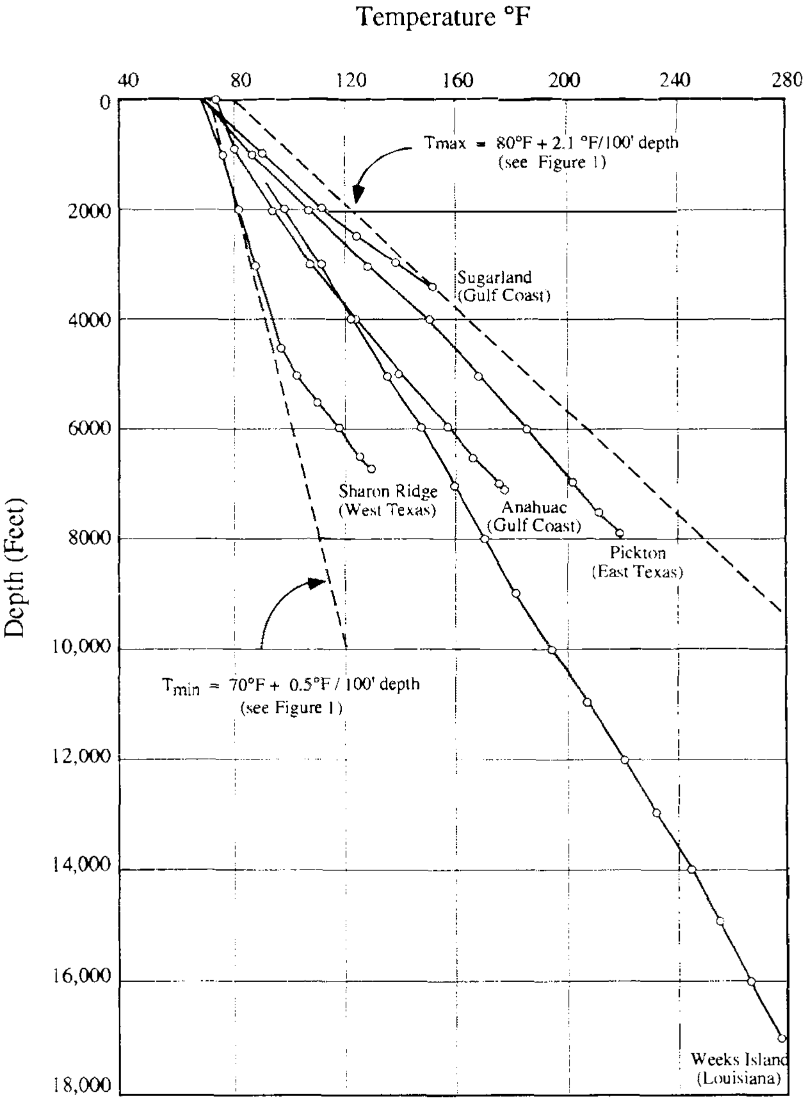


Figure 4. Static temperature gradients in the Texas-Louisiana area.

TABLE 1. HOW LITHOLOGY AFFECTS STATIC THERMAL GRADIENTS (POROUS MATERIALS ARE WATER SATURATED)

Material	Thermal Conductivity, *k* BTU/hr-ft^2 - (°F/ft)	Increasing Geothermal Gradient
Quartzite	13	
Salt	13	
Anhydrite	13	↓
Dolomite	2.5	
Limestone	1.5	
Sandstone	1.5	
Shale	0.9	
Gypsum	0.8	
Cement	0.4	
Water	0.4	
Oil	0.085	
Gas	0.040	

Thermal Conductivity, *k* = Heat Flux/Temperature Gradient

determines the location of a particular lithotype in this ordering. Thus, a shale section, which has high water content, would show a static gradient that is $1.5/0.9 \simeq 1.7$ times larger than that in a clean sand section. Figure 5 shows that this magnitude of variation does indeed show up provided the strata in the sequence are sufficiently thick. The numbers in Table 1 show that non-porous lithologies will exhibit the smallest static gradients. This effect is illustrated on Figure 6, which is a static temperature survey from a well drilled into a salt dome near Sugarland, Texas. The gradient of 2.6°F/100 ft. in the shale above the salt is abnormally high because of the large heat flux upward through the salt "chimney" of high thermal conductivity. The shale gradient is, thus, influenced by factors other than its conductivity and radioactive mineral content.

Non-Static Temperature Gradients: Whenever an injection well is shut-in for logging, the wellbore fluid temperature begins its change towards static conditions. The time required to reach static conditions is generally, however, longer than what can be devoted to logging operations. Consequently, the logging operations will usually take place with the wellbore in a thermally dynamic state, that is, with the wellbore temperature displaced from static temperature. In such a state, the thermal conductivity alone does not control the rate at which a given lithology returns to static temperature. Rather, it is the thermal diffusivity that determines the dynamic rate of change with time in the wellbore. This physical property has the dimensions of length^2/time and is the ratio formed by division of the thermal conductivity, *k*, by the product of density,

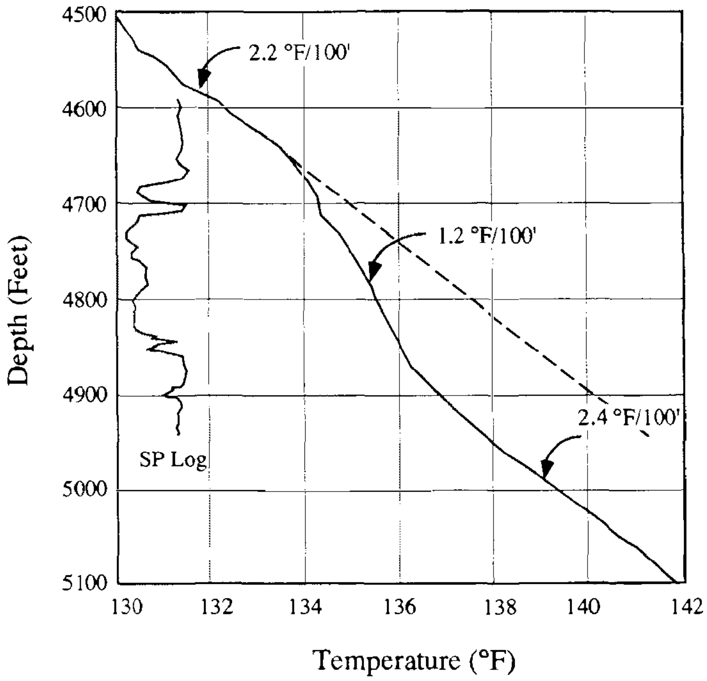


Figure 5. Static temperature gradient variations in a sand-shale sequence.

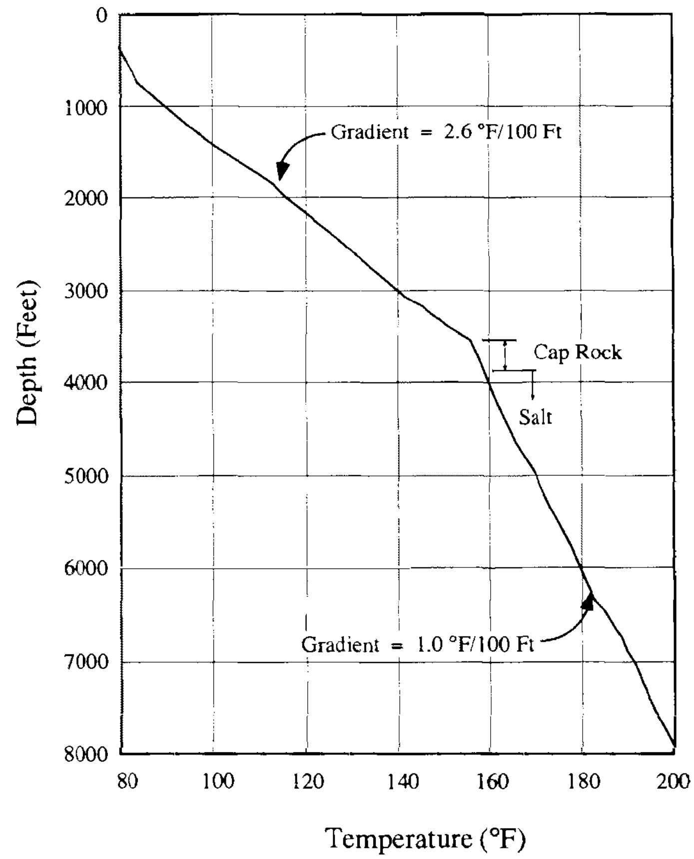


Figure 6. Static temperature survey from a well penetrating a salt dome.

ρ, and specific heat, Cp. The larger the value of thermal diffusivity, the more rapidly will a material return to static temperature once disturbed. Typical values of thermal diffusivity for various lithotypes appear in Table 2. A pattern can be seen generally similar to that evident from Table 1. Namely, shales lag behind other lithotypes in their recovery to static temperature. This, again, is a consequence of the high water content of shales. Conversely, the non-porous, non-hydrated materials recover most rapidly. Figure 7 is a "cartoon" illustrating the influence lithology can exert on temperature surveys run in a well that is returning to static temperature from the cold side. The hardest material, the siltstone, leads all other lithologies in the return to static temperature thereby appearing as a "hot" spot on the surveys. Likewise, the shales lag everything else and appear as "cold" spots. Had the return been from the hot side of static, then the "direction" of anomalies would be the reverse, the siltstone would be the "cold" spot whereas the shales would appear as warmer areas. The main point of Figure 7 is that lithology can add significant character to shut-in temperature surveys from a well that is still considerably disturbed from static conditions. This character will, however, become progressively less severe as shut-in time increases and the wellbore temperature approaches static. This behavior is in contrast to that of a true injection anomaly whose influence will persist even on otherwise static surveys.

TABLE 2. HOW LITHOLOGY AFFECTS DYNAMIC THERMAL EQUILIBRIUM (POROUS MATERIALS ARE WATER SATURATED)

Material	Thermal Diffusivity $\alpha = k/\rho c_p$ ft^2/hr	Increasing Lag Time
Quartzite	0.14	
Salt	0.11	
Anhydrite	0.06	↓
Dolomite	0.07	
Limestone	0.05	
Sandstone	0.05	
Shale	0.03	
Gypsum	0.02	
Cement	0.01	
Gas	0.008	
Water	0.006	
Oil	0.003	

Thermal Diffusivity, α (ft^2/hr), α = Conductivity / Density x Specific Heat

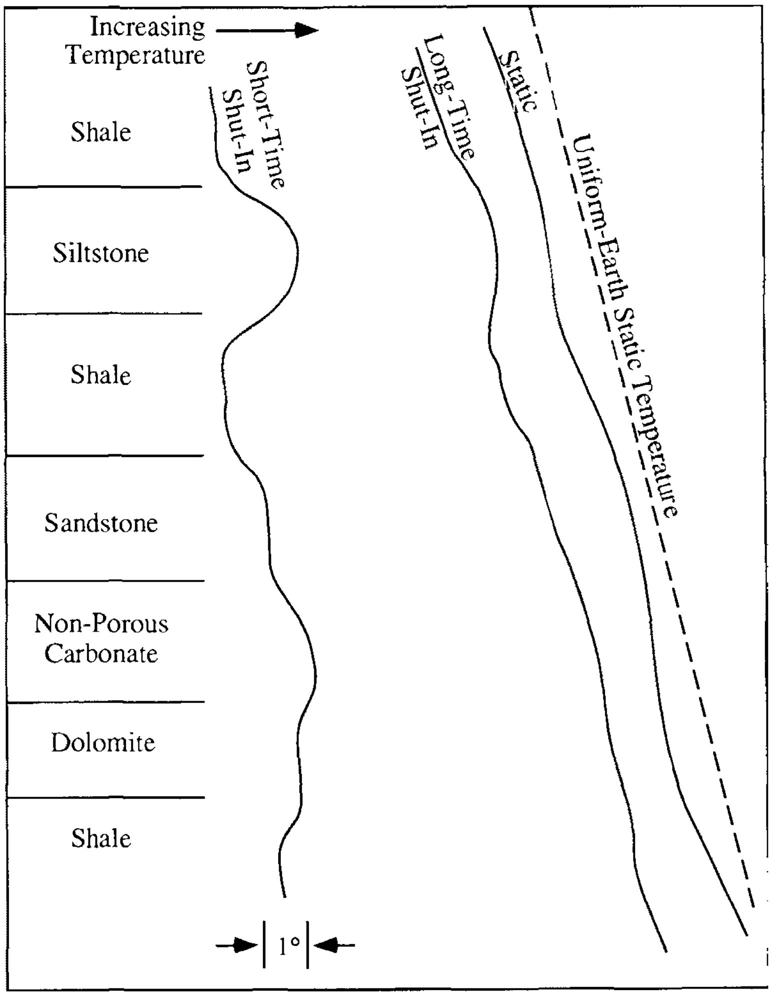
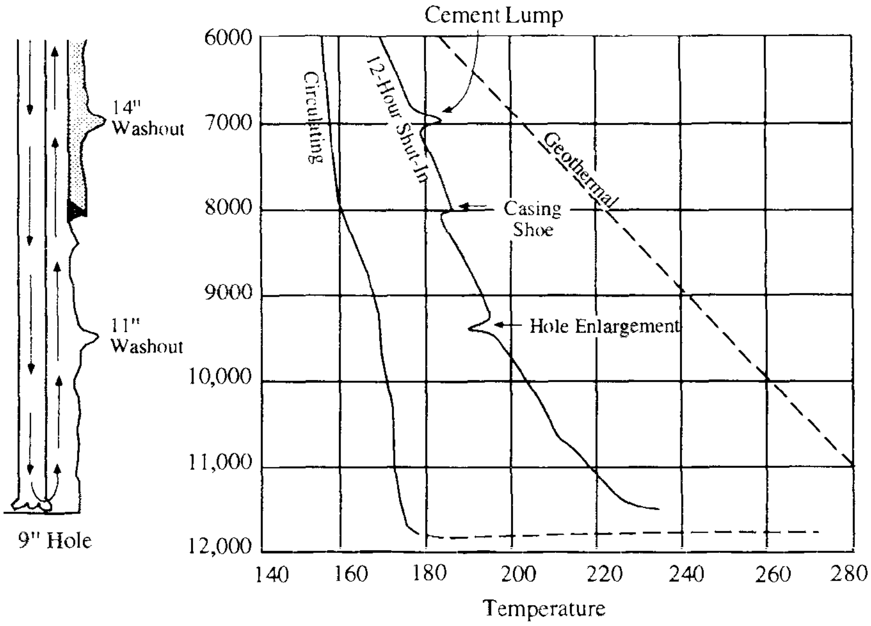


Figure 7. Hypothetical influence of lithology on wellbore temperature warming with time to static conditions.

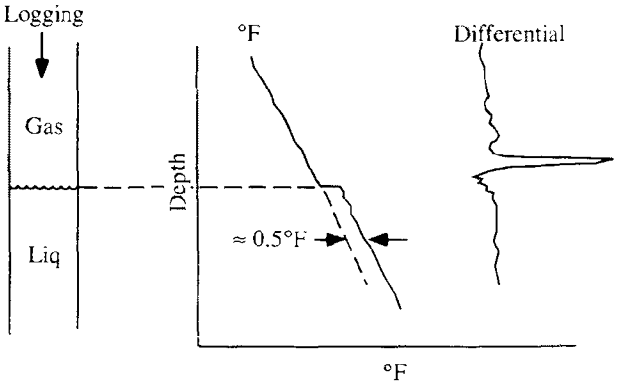
Frame A of Figure 8 shows that details of a well's completion also add character to any shut-in survey made in a non-static wellbore. Usually, those parts of the wellbore that are more insulated will lead the lesser insulated portions in the return to static temperature. This behavior is a consequence of the fact that the formation behind the better insulated parts is less disturbed than is that behind the lesser insulated portions. For example, the behavior of the temperature at the casing shoe on frame A at 8,000 feet is the type usually seen on shut-in surveys. In actuality, the reverse behavior is sometimes seen on very short shut-in surveys on which the better insulation is still preserving the wellbore fluid temperature at values closer to that existing at shut-in. This apparently contradictory behavior is, in fact, the consequence of an exceedingly useful and unique feature of temperature surveys; namely, the "distance into the formation" that is examined can be varied by simply varying the shut-in time.

Like lithology influence, completion influences also die out as the wellbore temperature approaches static. Furthermore, completion effects serve as excellent quality control checks on both the operation of the tool and the sensitivity selected for display.

Frame B of Figure 8 shows an additional feature common to shut-in surveys from shut-in wells that were on injection. This feature is the sudden "catch up" in temperature that occurs when a thermometer first enters a liquid column from gas and is thereby in better thermal contact with its environment. Since the water level is typically within a few hundred feet of the surface in an injection well that "goes on vacuum" when shut-in, the direction that catch-up takes depends on whether ambient air temperature is hotter or cooler than the wellbore liquid. Frame B of Figure 8 illustrates the case of cooler air.



(A) Completion Influences on Temperature



(B) Logging Across a Liquid Level

Figure 8. Wellbore influence on temperature surveys.

Temperature Behavior in Deep Injection Wells: Most saltwater disposal wells inject into zones at least 2,000 feet deep whose static temperature generally exceeds 115°F. The injection therefore cools the wellbore in the vicinity of the injection zone. Once injection is started, the flowing temperatures in the injection "string" quickly settle to a stable value. In fact, by the time that the tubular volume has been displaced three times, the temperature has made 90% of the necessary adjustment to reach its stable value. This rapid stabilization occurs because the heat transfer from the earth through the tubulars and into the moving stream is at a quite low rate, typically in the range of 50 to 200 BTU/hr per foot of wellbore. In the familiar terminology of "air conditioning," this rate of heat exchange is less than 0.02 tons of "conditioning." Consequently, the injected fluid quite literally carries its temperature down with it.

Figure 9 contains three temperature surveys computed for a well on injection at two different rates, 500 and 5,000 BPD. The earth is uniform with a linear gradient of 1.65°F per 100 feet of depth. One-half of the total volumetric rate is injected into porosity at two depths, 6,500 and 7,000 feet, depths B and C respectively. Two inch tubing is set at 5,500 feet, depth A, on a packer in 5 1\2 inch casing. Surveys 1 and 2 compare the profiles for injection at the rate of 500 BPD but with water at two different surface temperatures, 110°F and 80°F, respectively. The

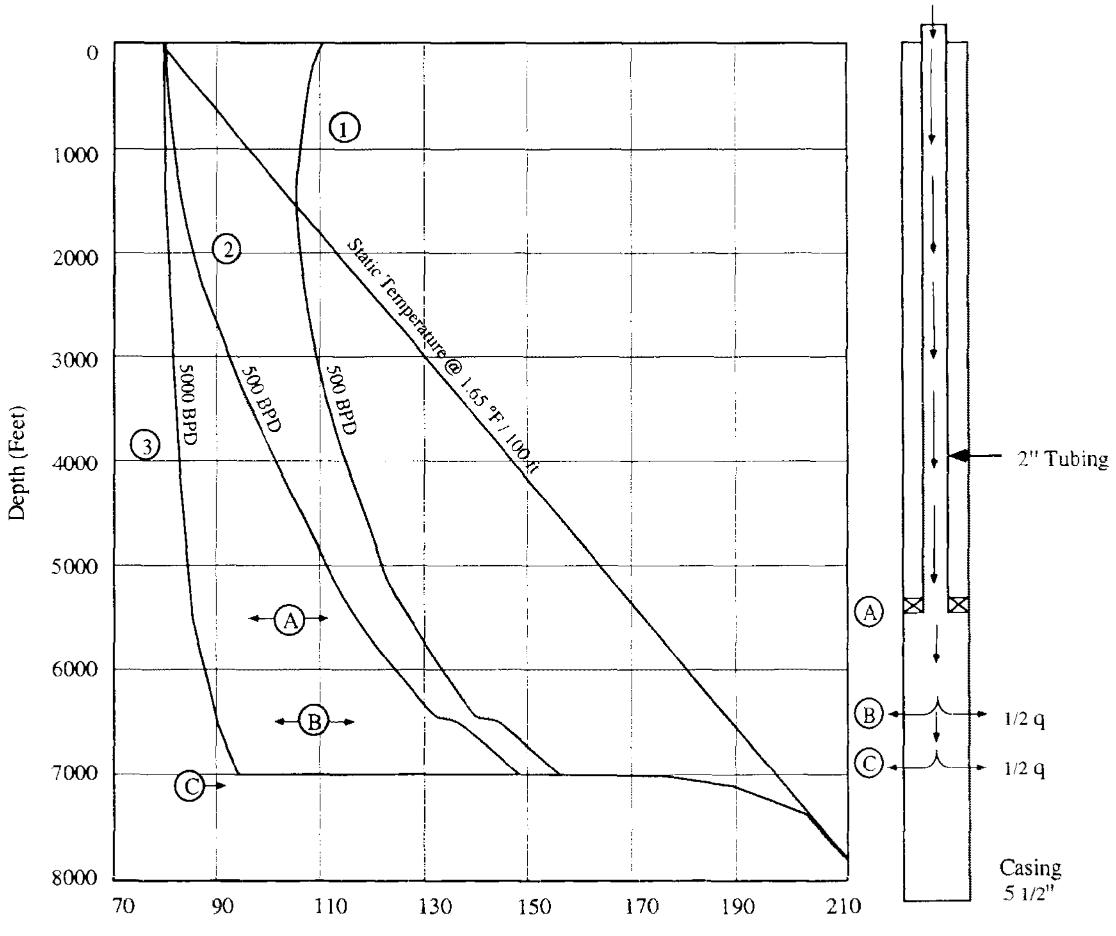


Figure 9. Computed injection temperature profiles for a deep, saltwater disposal well.

latter is static temperature at the surface. If survey 2 is shifted vertically to 1,550 feet, the depth at which survey 1 crosses the static gradient, then the two surveys would overlay each other. Furthermore, surface temperature is seen to have little influence on the profiles at the injection depths. Below the static temperature crossing depth, each profile drops nearly vertically before beginning to bend back towards static. A comparison of surveys 2 and 3 shows that the higher the rate, the more nearly vertical the profile remains. The injection gradient, dt/dz, the rate of temperature change with depth, is therefore inversely related to injection rate. If the injection zones are sufficiently deep, or the injection rate is sufficiently small, each injection profile will become parallel to the static temperature line and be displaced to the cold side by an amount, $\Delta T = T_{static} - T$, that is constant and directly proportional to the injection rate. In fact, if one makes an energy balance on a small length, ΔZ, of wellbore, the following expression for volumetric rate at any depth, Z is obtained:

$$q = \frac{A}{\rho c_p} \times \frac{\Delta T}{\frac{dT}{dZ}}, \qquad (1)$$

$$\Delta T = T_{static} - T_{wellbore},$$

This relationship is illustrated graphically on Figure 10 and is the expression needed for flow profiling. The constant A in Eq.(1) depends upon the size and completion details of the wellbore as well as the relevant thermal properties. At two locations with similar completions in a wellbore, the respective rate/ratio is thus

$$\frac{q_2}{q_1} = \frac{\Delta T_2}{\Delta T_1} \bullet \frac{\left(\frac{dt}{dz}\right)_1}{\left(\frac{dt}{dz}\right)_2} \qquad (2)$$

This expression is very useful. On the computed surveys of Figure 9, the injecting temperature gradients increase slightly below the end of the tubing string at 5,500 feet, depth A. This increased gradient is the result of the increased heat transfer to a unit of fluid at the slower velocity and more intimate contact with the casing. On the more common depth scales of 1-5

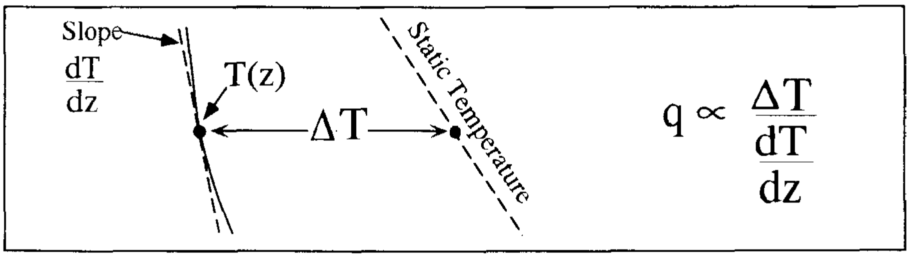


Figure 10. Relationship between temperature profile and rate for an injection well.

inches per 100 feet, this increase is difficult to recognize. As already illustrated on frame A of Figure 8, the completion has more influence on the shut-in surveys.

What is more apparent on the three injecting surveys of Figure 9 is the "catch-up" behavior in temperature that occurs immediately below the topmost loss of fluid into porosity at depth B, 6,500 feet. This sudden increase in slope makes it easy to recognize the location of each injection interval. The "catch-up," of course, results from the decreased amount of mass flow leaving depth B in the wellbore relative to that arriving at B from above. According to equation (1), a decrease in rate q mandates a decrease in the ratio $\Delta T/(dT/dz)$, which below depth B is affected by a small decrease in ΔT and a larger increase in dT/dz. In fact, between depths B and C the rate of temperature increase with depth stabilizes at a value about twice as large as is the value immediately above depth B, only one-half the volumetric injection rate survives the first loss. The final loss from the well is into porosity at 7,000 feet, depth C. Below this deepest point of injection, the temperature begins its final return to static, a process occurring over some 500 feet below C on Figure 9. The exact distance required for this return depends on several things, the amount of temperature displacement from static, the response time of the thermometer, the logging speed, and the length of time the well has been on injection.

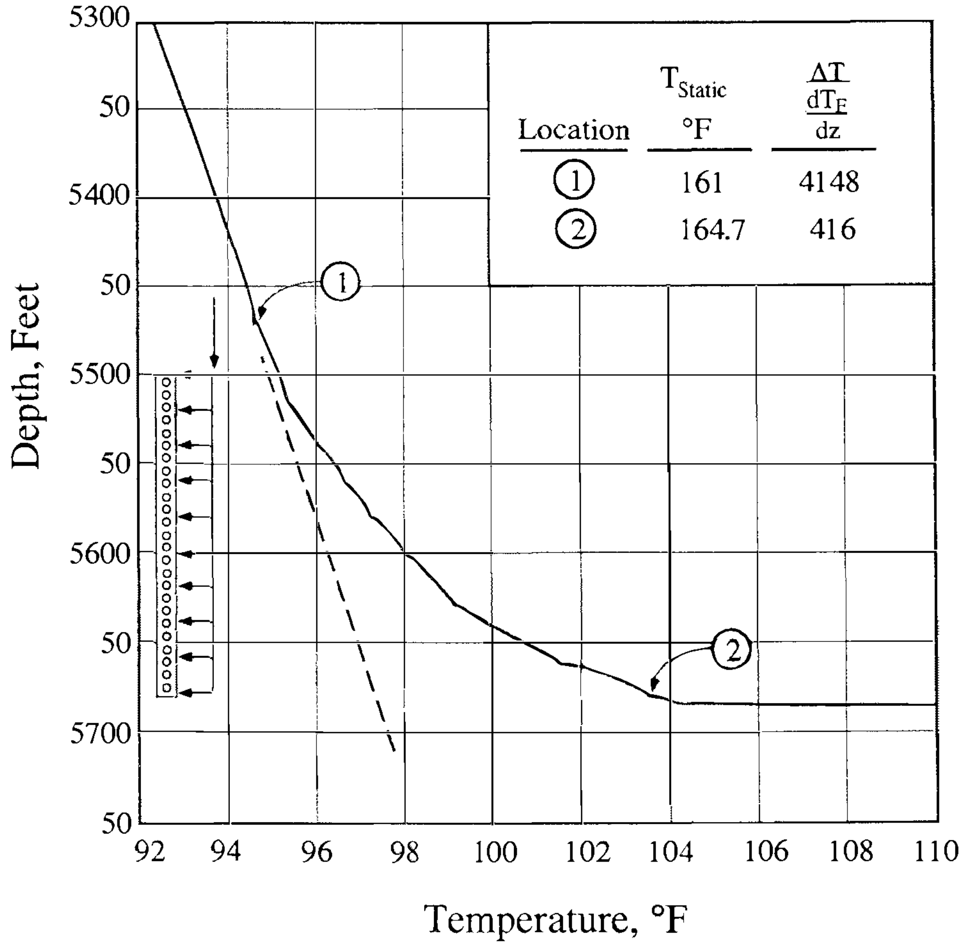


Figure 11. Computed injection profile at 1,000 BPD with equal amounts injected at each of 10 locations.

The injection zones of Figure 9 are mathematical points devoid of interval thickness. On actual logs it is possible to find, within a given interval, the discrete points of injection with much better vertical resolution than is possible with other flowmeters. This idea is illustrated, again by computed example, on Figure 11 that shows an injection zone 175 feet thick that accepts a total volumetric rate of 1,000 BPD with injection occurring in ten equal increments of 100 BPD each at ten, equally-spaced locations. The discrete increases in slope identify the points of injection. This figure also illustrates the application of flow profiling relation expressed by equation (2). The total injection rate is represented by the ratio

$$\frac{\Delta T}{\frac{dT}{dz}} = 4148$$

as calculated at location 1. The injection that survives to the bottom of the perforated interval is represented by the corresponding value of 416, computed for the stable slope at depth 2. This latter value is accordingly only 10% of the former. In theory, similar calculations can be made for each of the ten injection points, but, in fact, some "adjustment" distance is required between exit points for the profiling technique to be valid.

The reader may be puzzled by the fact that on Figure 11 the injection temperature at the deepest exit, the bottom of the perforated interval, is only slightly warmer than that at the topmost exit even though only 10% of the injection reaches the bottom exit. The displacement from static at the top of the perforations is 66°F whereas that at the bottom is ~ 61°F. This seems paradoxical, but actually is not. The total injection rate brings the cold to 5,500 feet at the interval top. Even a small fraction of this rate can travel the remaining 175 feet to the bottom of the interval quickly enough to avoid much warming. It is slope increases that identify losses.

Figure 11 also allows one to perceive the injection profile that would result from that hypothetical situation of uniform injectivity per unit length. This would produce, over the injection interval, a temperature profile that with increasing depth is <u>concave</u> towards static. This behavior is opposite the <u>convex</u> recovery associated with the isolated injection locations depicted on Figure 9. It is this latter type of behavior that will almost without exception be observed on actual temperature surveys.

The above concepts can be applied to the injection profile given on Figure 12. The surveys on this figure come from a well that had been shut-in since the time that a sand-propped, hydraulic fracturing operation had been carried out three weeks earlier. Fracture proppant still filled the wellbore below the bottom of the perforated interval. A base log, survey 1 on Figure 12, was run before the well was further disturbed in any way. This log is regarded as the "static" reference survey even though the cooling residual from the pumping done during fracturing is still evident in the perforated interval three weeks after the fact. After the base log was completed, the thermometer was pulled back up to 8,400 feet and water injection started at a rate of 5,800 BPD. Two hours later the injection logging, survey 2, was started. By the time this run was completed, the well had been on injection for 2 1/2 hours at the 5,800 BPD rate. Approximately 600 barrels of water was pumped during this time, a volume about 530 barrels in excess of the tubular

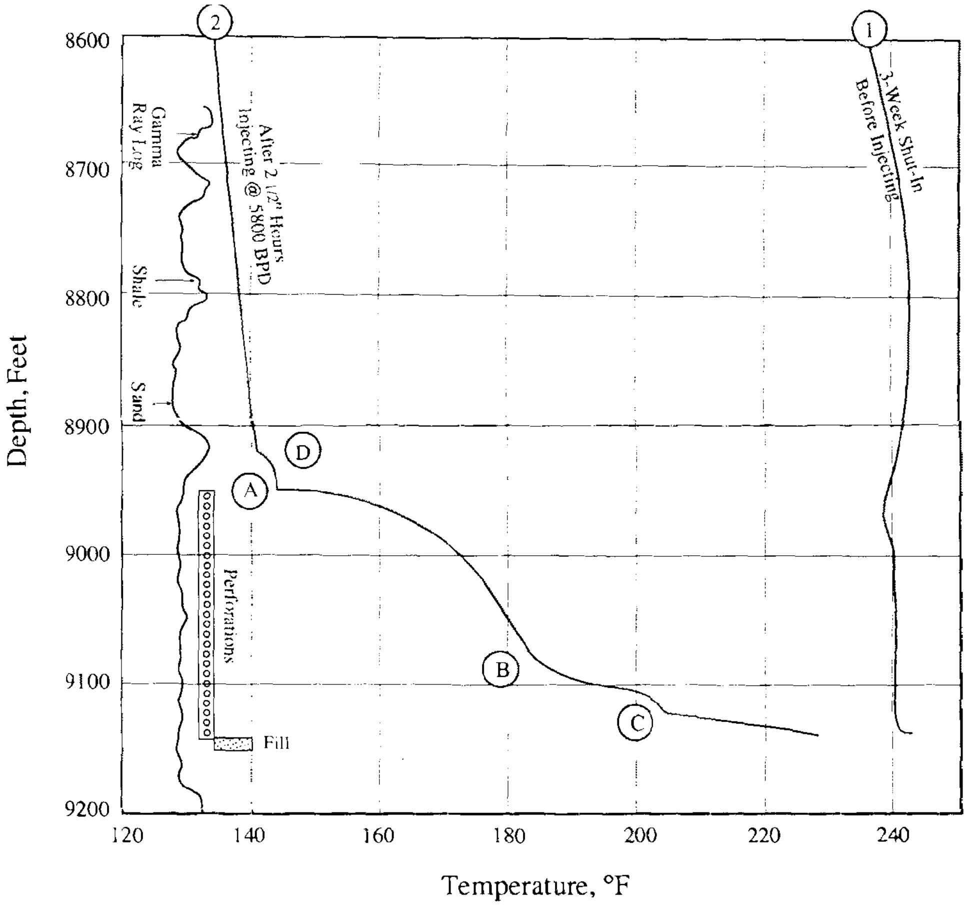


Figure 12. Injection temperature survey on a well that had been hydraulically fractured three weeks earlier.

volume of the well. For the 185-foot perforated interval this is an "overflush" of 530/185 ~ 3 BBLs/ft. Generally, a minimum overflush of 2 BBLs/ft is required to insure that subsequent shut-in surveys reveal the porosity that took the injected water. In this case, however, the injectivity was far from uniform over the 240-foot sand interval that had been fractured. Within the perforated interval, one can identify at most three depths at which fluid is lost from the wellbore into porosity. These are depths A at the top of perforations and depths B and C near the bottom. The sudden change in slope at two of these locations, A and C, identify very localized exits of the type displayed previously on Figure 9. The third, more gradual change in slope at depth B may reflect a twenty or so foot thick interval of relatively uniform injectivity of the sort illustrated on Figure 11. One can also see immediately that the majority of the injected fluid leaves the wellbore at the top of the perforations, depth A. The injecting gradient below this depth stabilizes at a value much larger than that associated with total injection rate, the profile above 8900 feet.

The slope and displacement values necessary for use in equation (2) for flow profiling are set up graphically on Figure 13. Values for the full injection stream are calculated at 8,750 feet, although other locations could have been used on the stable profile. The determination of the

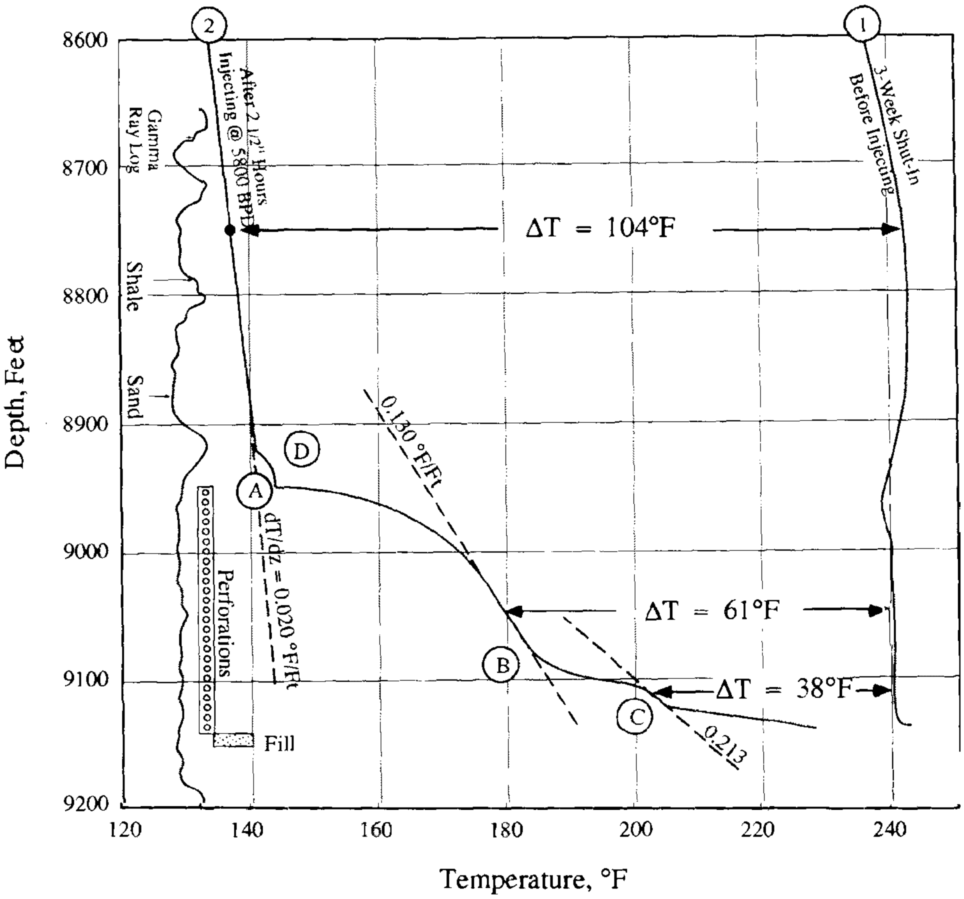


Figure 13. Slopes, dt/dz, and displacements, ΔT, necessary for rate estimations.

displacement ΔT = 104 °F is illustrated on Figure 13 . The slope of the tangent at this depth, the dotted line labeled dT/dz = 0.020 °F/ft, is determined as follows: From 8,600 to 9,100 feet the temperature along the line warms from 133° to 143°F. Thus dT = 143 - 133 = 10 °F over a distance dz = 9,100 - 8,600 = 500 feet, so that

$$\frac{dT}{dz} = \frac{10}{500} = 0.020 \text{ °F/ft.}$$

To estimate the amount of the injection that survives the loss at depth A, a stable section of slope at depth of 9,050 feet is selected. In the section of very rapid change immediately below the loss at A, the slope is influenced by the logging speed and the response characteristics of the tool as well as by the actual rate of temperature change with depth. For this reason, this section is avoided when estimating slopes. Above the deepest loss, depth C, there is insufficient record to provide a slope with much reliability. The value shown on Figure 13 is therefore only a rough estimation.

If the rate of injection into porosity at each of the three depths A, B and C are designated by the symbols q_A, q_B, and q_C, respectively, then the slope and displacement on Figure 13 at 8,750 feet is the result of the total rate, $q_A + q_B + q_C$. Likewise, those at 9,050 feet result from the sum $q_B + q_C$. Finally, the numbers at 9,110 represent q_C alone. These facts are summarized below.

Depth, Feet	Total Flow in Wellbore	Displacement from Static, °F	Injection Gradient, °F/ft
8,750	$q_A + q_B + q_C$	104	0.020
9,050	$q_B + q_C$	61	0.130
9,110	q_C	38	0.213

According to equation (2)

$$\frac{q_B + q_c}{q_A + q_B + q_c} = \frac{61}{104} \times \frac{0.020}{0.130} = 0.09$$

Consequently, only 9% of the total injection survives the first loss at depth A. Some 91% is therefore injected at this depth. Likewise, at depth C,

$$\frac{q_C}{q_A + q_B + q_C} = \frac{38}{104} \times \frac{0.020}{0.213} = 0.03$$

which leaves

$$\frac{q_B}{q_A + q_B + q_C} = 0.09 - 0.03 = 0.06$$

The injectivity profile, thus, is even more non-uniform than one might suspect by a simple visual inspection of Figure 12 alone. Such insight, not precise flow profiles, is the value of the procedure outlined in the above calculations.

A discussion of the apparent loss at 8,920 feet, depth D on Figure 12, is deferred for a subsequent section where behind-pipe flow is introduced. According to the gamma-ray log on the figure, this "loss" is still at the top of the completed zone and, as such, cannot be a loss to sands above.

The injection survey of Figure 12 will be discussed further, but for now additional materials need to be developed. Therefore, focus again on the computed profiles of Figure 9, in particular, survey 2 for injected water at surface temperature. This figure shows only the temperature in the wellbore itself, which at 6,000 feet is, for example, 123 °F. This location is 500 feet above the topmost injection zone. The solid curves on Figure 14 show what happens to the temperature in the formation away from the wellbore as a function of the length of time that the well has been on injection. The recovery from a wellbore temperature of 123 °F to a static value of 179 °F is logarithmic in distance, R, away from the well over most of the disturbed region of the formation. If the well has been on injection for only 2 hours, then most of the recovery to static temperature occurs within 1.5 feet of the wellbore. At a distance of 2.5 feet, the temperature is undisturbed from its static value. Even after 10 years of continuous injection, the resulting temperature disturbance extends for only 350 feet away from the wellbore. This distance, L, away from the wellbore that is disturbed can be estimated from the relation

$$L\,(\text{ft}) = 3.5\sqrt{\alpha t_I}$$

α = Thermal diffusivity, $(\text{ft})^2$ / hr
t_I = Injection time, hours

For example, Figure 14 was computed for $\alpha = 0.05$, a value that according to Table 2 is typical for porous sands or carbonates; consequently, for $t_I = 10$ years = 87,600 hrs:

$$L = 3.5\sqrt{0.05 \times 87{,}600} = 3.5 \times 66 = 230 \text{ ft.}$$

By this distance the temperature on Figure 14 is within 2 °F of static, i.e., over 95 % of the recovery has occurred. The lesson of significance illustrated by the solid curves on Figure 14 is that conduction of heat in the earth is an exceedingly slow process. Energy transport by flow, i.e., by convection, easily outdistances the spread by conduction. This point is illustrated by the dash curves on Figure 14. These show the temperature profiles that would exist if an injection

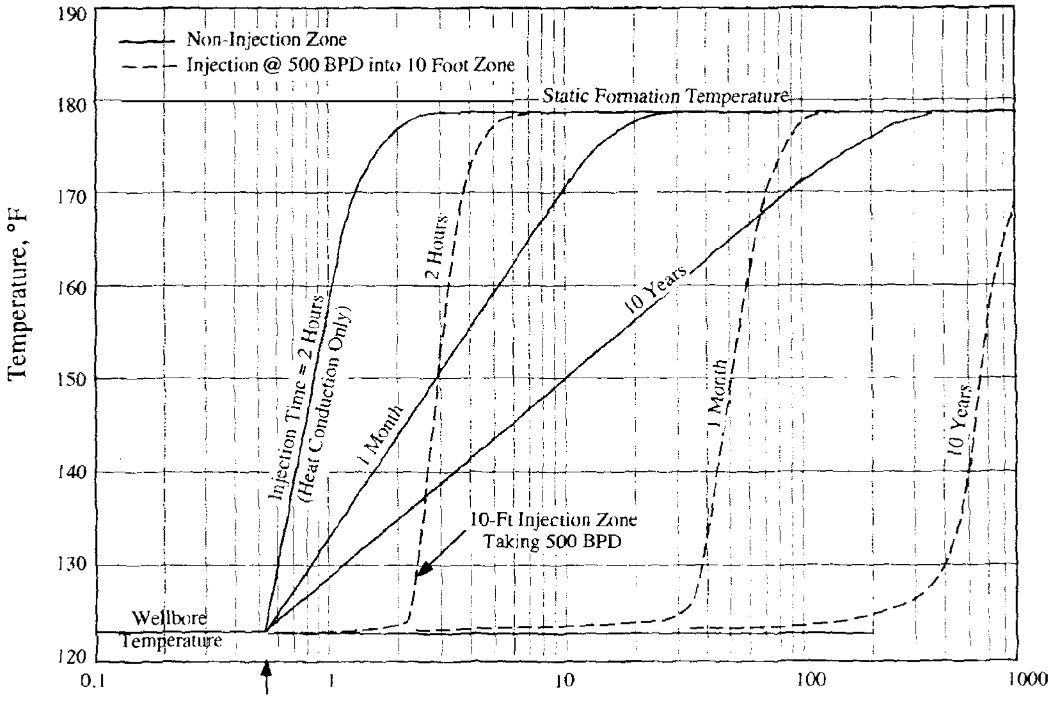


Figure 14. Temperature profile around a well with R_w = 0.54 ft. on injection at a wellbore temperature of 123°F and at 500 BPD rate. Earth is uniform with static temperature of 179°F and with diffusivity of α = 0.05 ft^2/hr.

zone 10 feet thick at this location received 500 barrels of water per day. After only 2-hours' injection, the injection zone has been cooled almost to the injection water temperature for some two feet away from the wellbore, a distance beyond which conduction would have hardly made any disturbance to static temperature. The contrast between the two processes increases with injection time. A very significant consequence of this difference is the attendant difference in rate of temperature recovery in the wellbore with time once an injection well is shut off. Those areas of the wellbore opposite porosity that have received injected fluid will not return to static nearly as quickly as will those areas that have not. In deep injection wells, zones taking water will remain cooler than surrounding areas. This different rate of warm up is illustrated on Figure 15 for the situation described on Figure 14. If, for example, the well is shut-in after 2 hours of continuous injection, then 3 hours later the wellbore fluid temperature opposite a zone free of injection has warmed up to 163 °F from an injection value of 123 °F . This change represents 71% of the total recovery to the static 179 °F. By contrast, the center temperature in the injection zone has just started to warm up. Even after 10 years of injection, a 24-hour shut-in survey will show a 7 °F difference between injection and non-injection locations. The point is: Shut-in temperature surveys are excellent for detection of those porous regions that have stored injected water. The well whose injectivity survey was given in Figure 12 will illustrate this idea.

Figure 16 reproduces those logs already given on Figure 12 and adds five shut-in surveys that were run 1, 3, 6, 12, and 24 hours after the 2 1/2-hour period of injection at 5,800 BPD. The 1-hour shut-in survey is dominated by a phenomenon often seen on wells that have been fractured, intentionally or otherwise. The warm "nose" on the survey between depths A and G is the result

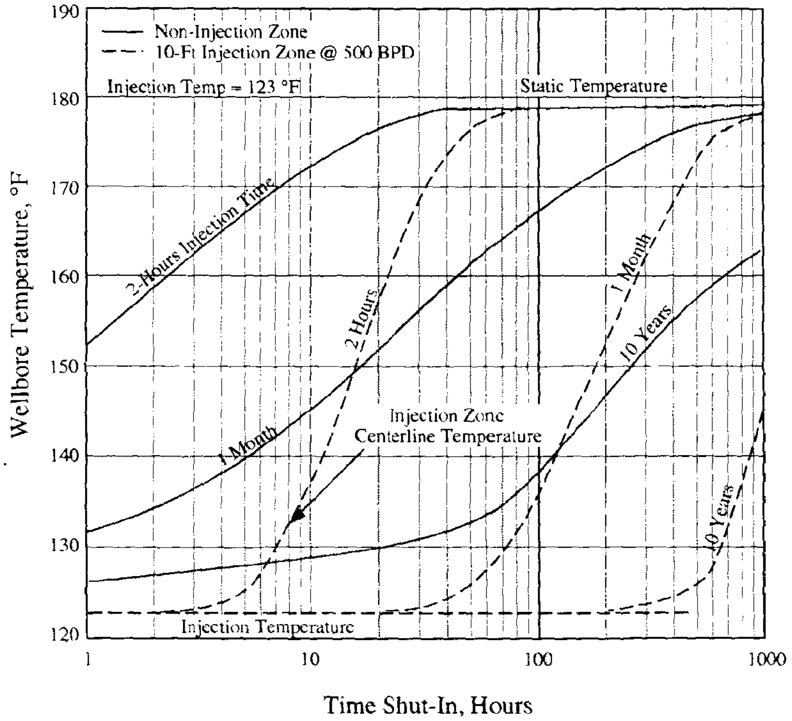


Figure 15. Temperature recovery with time of fluid in wellbore of well in Figure 14.

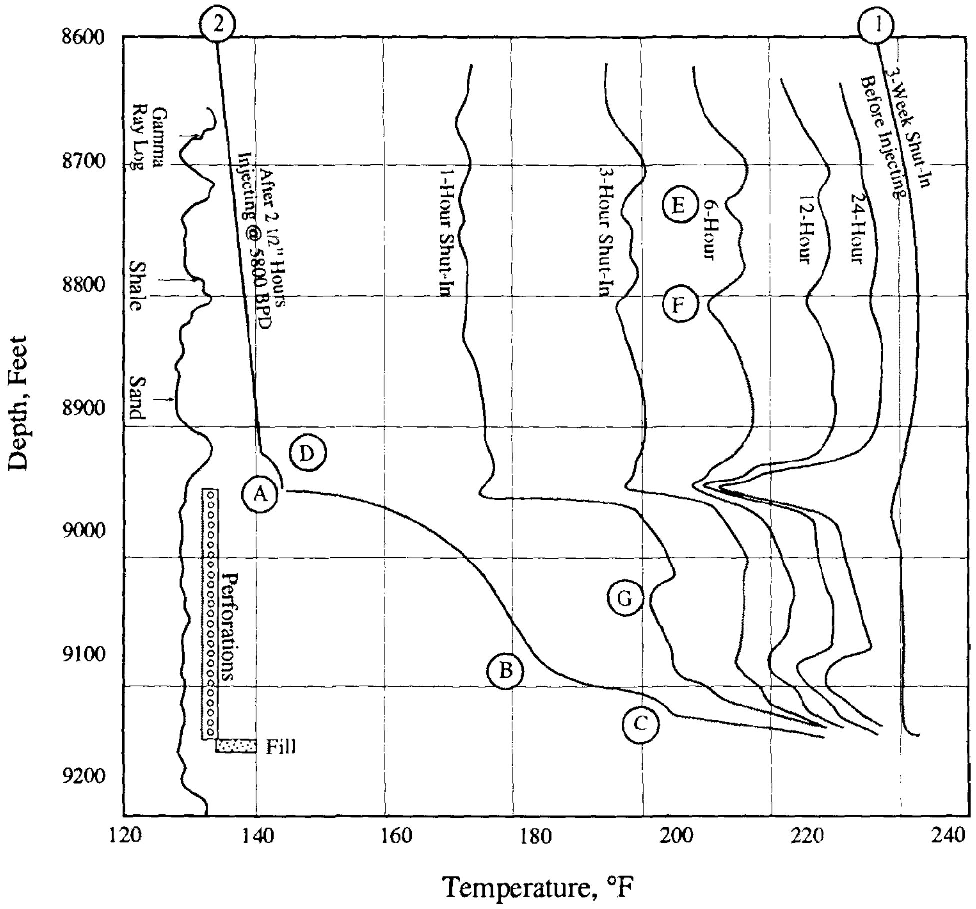


Figure 16. Injecting and subsequent shut-in surveys on a well that was hydraulically fractured three weeks prior.

of flow from one wing of the fracture through the wellbore and into the other wing of the fracture. Injection opens these wings somewhat. The crossflow is then set up by different rates of closure in the two wings. This effect has displaced to the warmer side all the surveys through the perforated interval. However, the 6, 12 and 24-hour records show the same qualitative behavior that was described in the discussion relative to Figures 14 and 15. Namely, cold spots show up at the porous intervals at the depths where fluid was lost from the wellbore, depths A, B, and C. The storage at depth C is hardly noticeable on the 24-hour shut-in survey. This location received only some 3% or 18 barrels of the 604 barrels injected in the 2 1/2 hours, according to the profile from the injecting survey. The behavior at depths B and C on the shut-in runs indicate that the 3% amount may have been an overestimation and that most of the 9% or 54 barrels surviving the first loss at depth A was injected into porosity at depth B. In contrast, the temperature at depth A, the location of porosity that took 550 barrels of the 604 barrels injected, hardly changes in the time elapsed from the 6-hour to the 24-hour surveys. This comparison is proof of the previous assertion that the depth "seen" into the formation increases with time of shut-in. The injected fluid spread farther away from the wellbore at depth A than at the other two depths.

To determine if any of the injected water was lost to sands above the perforated zone, look on the shut-in surveys for cold spots above the "disposal zone." The 3, 6 and 12-hour surveys show definite cooler locations at depths E and F, 8,725 and 8,810 feet, respectively. However, the gamma ray log shows that shales, not sands, are located at these depths. Because of their very low permeability, shales would not take injection in preference to sands. In addition, Figure 7 shows that because of the influence of lithology, shales should show up as cooler regions on shut-in surveys to the cold side of static temperature. One can conclude that no fluid storage areas are seen above the interval of sand that was perforated, thus injection was confined to the proper interval. This conclusion was arrived at in two steps:

(1) The injecting survey showed losses from the wellbore only in the designated interval,

(2) At least two sequential shut-in surveys showed fluid storage only in porosity within the same interval.

The presence of lithology influence on shut-in surveys is obviously time dependent. On Figure 16 the influence is not yet developed on the 1-hour shut-in survey and has almost disappeared on the 24-hour run. However, when present this influence is the most sensitive indicator we have to the absence of flow behind pipe. Some flow will inevitably persist after shut-in by virtue of either pressure in the injection zone or falling liquid level in the wellbore itself. Almost any flow at all will overcome the influence of lithology. This fact can be demonstrated in the following fashion. In the time interval from 1 to 6 hours the wellbore fluid temperature at 8,880 feet, the location of a sand, warms 41°F from 176 °F to 217 °F at an average rate of 41/5 = 8.2 °F/hr. During this same time the shale at 8,810 only warms by 37°F, an average rate of 7.4 °F/hr. The difference in rate of 0.8 °F/hr amounts to a rate of heat transfer to the water contained in 1 foot of 5 1/2-inch wellbore of

$$\dot{q}_H = (\rho C_p V_{5.5}) \text{ x } 0.8 \text{ °F/hr}$$

$$q_H = 62.5 \text{ x } 1 \text{ x } 0.1305 \text{ x } 0.8 = 6.5 \text{ BTU/hr-ft}$$

Any leakage behind pipe that will absorb this amount of energy with negligible rise in temperature will therefore obliterate the lithology influence. The annular volume between 5 1/2-inch casing and 8-inch hole is 0.184 ft^3/ft. If this volume is displaced N times in one hour, then the corresponding volumetric rate is;

$$q = 0.184 \text{ N } ft^3/hr = 0.786 \text{ N BPD}$$

If this flow changes temperatures by no more than, say, 0.1°F over the one-foot length, then the shale excursion at depth F, a change of about 1°F/ft., would be subdued by a factor of ten and thus rendered insignificant. This 0.1 °F/ft would result from a heat transfer rate of

$$q_H \text{(flow)} = \rho C_p q \text{ x } 0.1$$

$$q_H \text{(flow)} = 62.5 \text{ x } 1 \text{ x } 0.184N \text{ x } 0.1 = 1.15 \text{ N } \frac{BTU}{hr\text{-}ft}$$

This energy transfer should equal the amount $q_h = 6.5 \frac{\text{BTU}}{\text{Hr-Ft}}$ resulting from lithology influence. Thus

$$1.15\,N = 6.5,$$

or

$$N = 5.6,$$

which corresponds to a leak rate q = 0.786 N = 4.4 BPD. No other logging tool has a rate resolution this low.

The preceding discussion has demonstrated how confined injection shows up on temperature surveys. In fact, some behind-pipe flow also shows up on Figure 13. The apparent small loss from the wellbore at depth D on the injecting survey results from flow exiting at the top of the perforations and then flowing up behind pipe to the top of the fracture which was stopped by the plastic shale at 8,920 feet. In the crossflow interval AD, the net flow downward is less than it is above D; consequently, the survey records a "loss" at depth D.

This "loss" type of behavior is illustrated on Figure 17 at a thief zone located at 5,600 feet, some 200 feet above the injection zone at 5,800 feet. The curves on this figure were computed for a well on injection at 500 BPD with varying amounts of loss from 0 to 500 BPD by flow behind casing from the perforations upward to the thief zone. A 100% loss shifts the survey back towards static by about one-fifth of the total displacement associated with no loss. From the figure, one can see that the flowing survey itself will show the influence of a loss to a shallower thief zone whenever this loss amounts to at least 20% of the flow inside the pipe.

The injecting survey of Figure 18 illustrates a behind-pipe loss to a higher injection zone whose perforations had been cemented by a "squeeze." At the time the survey was run, the well had been on injection for 4 hours at a rate of 990 BPD. Three apparent losses to porosity are evident on the log at depths 1, 2 and 3. The bottom loss, depth 3, is at the presently completed injection zone; however, the other two losses are located at supposedly squeezed perforations. The most obvious conclusion is that these perforations have "broken down" and are taking part of the injection intended for location 3. On the left side of Figure 18 appear stationary flowmeter readings made with a diverting type flowmeter, a "basket" spinner tool, at four locations A, B, C, and D. The readings at locations A and B are the same; thus, there is no fluid loss from the wellbore at depth 1. The temperature log must therefore be responding to behind-pipe flow. Now, between depths C and D, the spinner does show a loss from the wellbore of an amount of fluid equal to

$$100\left(1 - \frac{7.1}{11.6}\right) = 39\%$$

of the total injection rate. This fluid obviously exits the wellbore at location 2 on the temperature survey. Therefore, the squeezed perforations at ~5,910 feet have broken down. Of the water leaving the wellbore here, part or all then flows behind pipe up to the topmost zone just below 5,800 feet.

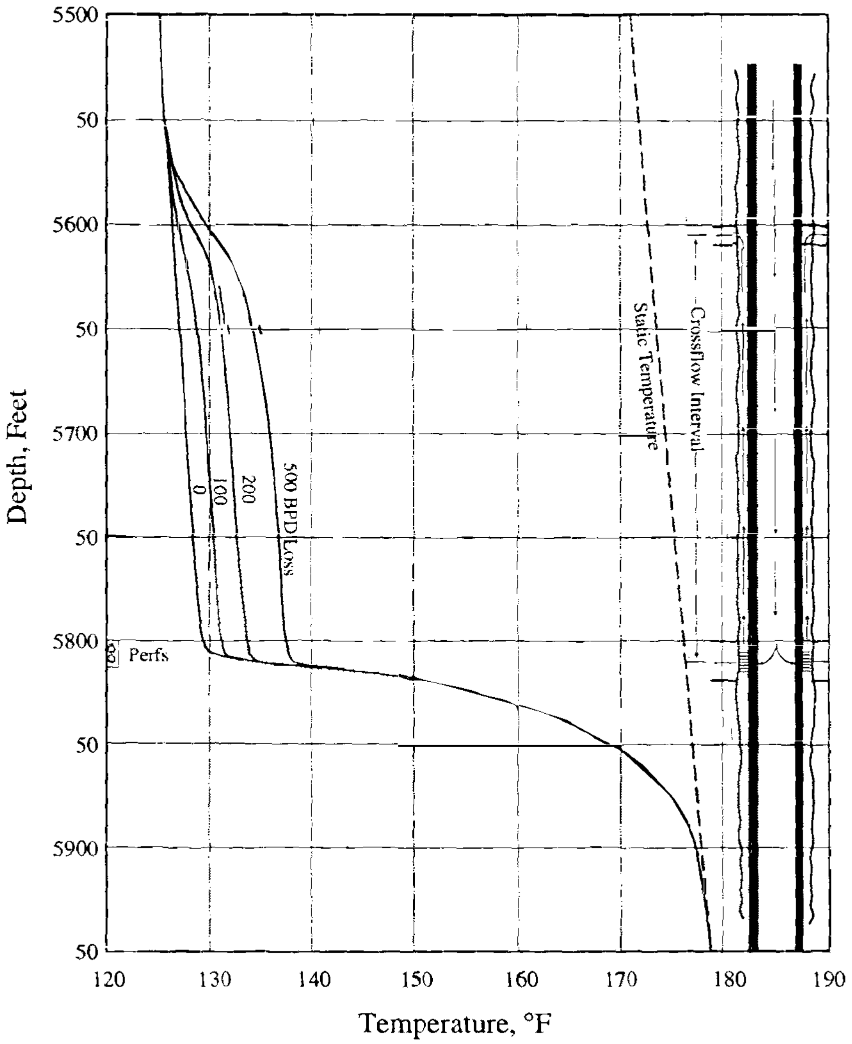


Figure 17. **Temperature surveys computed for a well on injection at 500 BPD with varying amounts of loss behind pipe to thief zone located 200 feet above.**

As might be expected, the shut-in temperature surveys are most sensitive to small losses from injection zones. A leakage rate of one barrel per day into porosity will eventually show up if it persists for a long enough time. Figure 19 shows computed shut-in surveys for the thief zone situation depicted on Figure 17. Each solid curve on Figure 19 is a 6-hour shut-in survey across the thief zone at 5,600 to 5,610 feet and the rates are the behind-pipe losses from the primary injection zone at 5,800 feet. The leak is assumed to have existed at the indicated rate for one month prior to logging. If injection into the well had also been going on for only one month, then the figure shows that a shut-in period of 6-hours would begin to reveal quite small leaks into

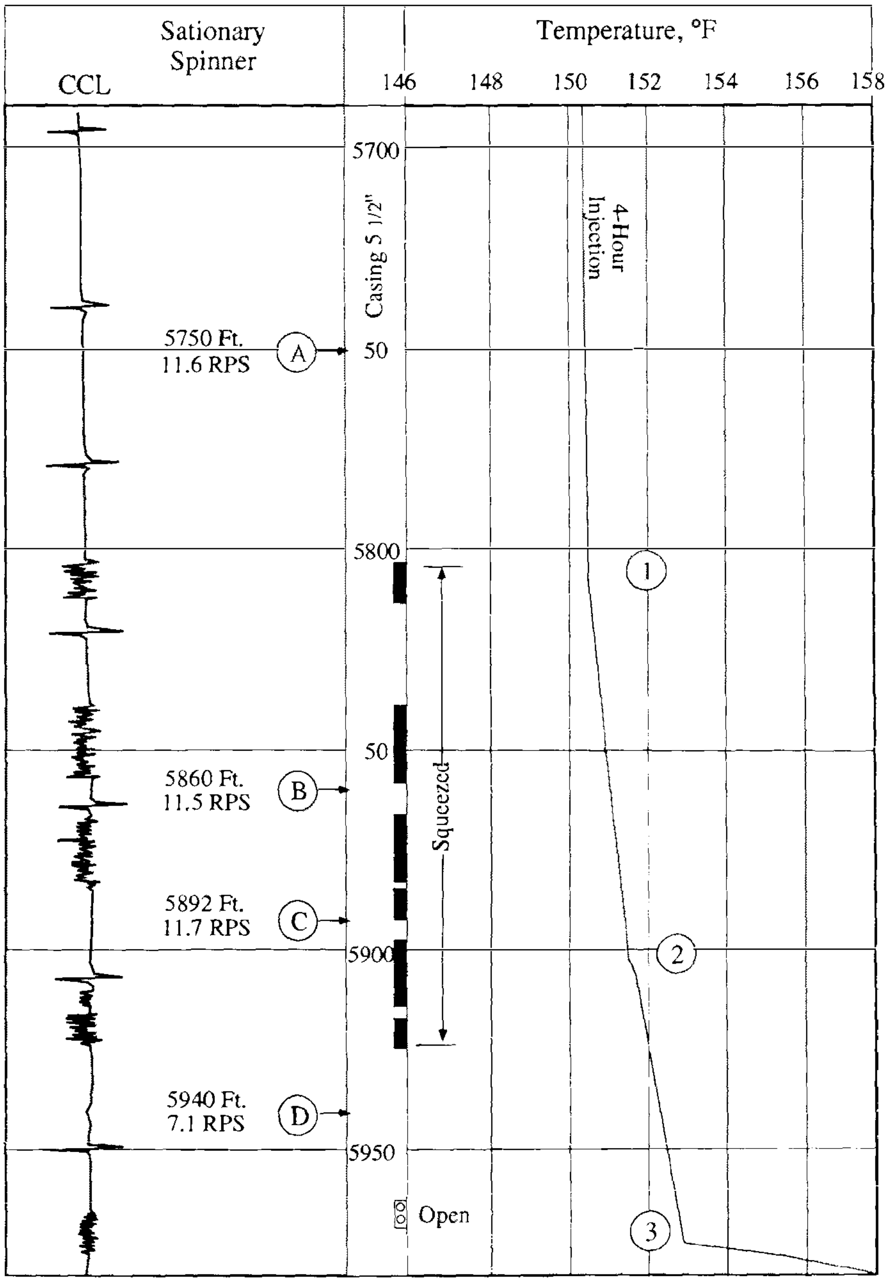


Figure 18. Temperature survey from well on injection at 990 BPD salt water.

storage porosity at 5,600 feet . However, had the well been on injection for a year prior to the development of the leak, then even a 500 BPD leak would have been hidden by the residual conductive cooling from the long period of the flow of cold water past this location in the wellbore. Consequently, in planning the shut-in surveys that are to follow the injecting survey, one must obviously take into account the length of time that a well has been on continuous injection. The shut-in times listed in Table 3 can serve as planning guide provided at least two shut-in surveys are run, one at the beginning of the listed interval and one at the end of the

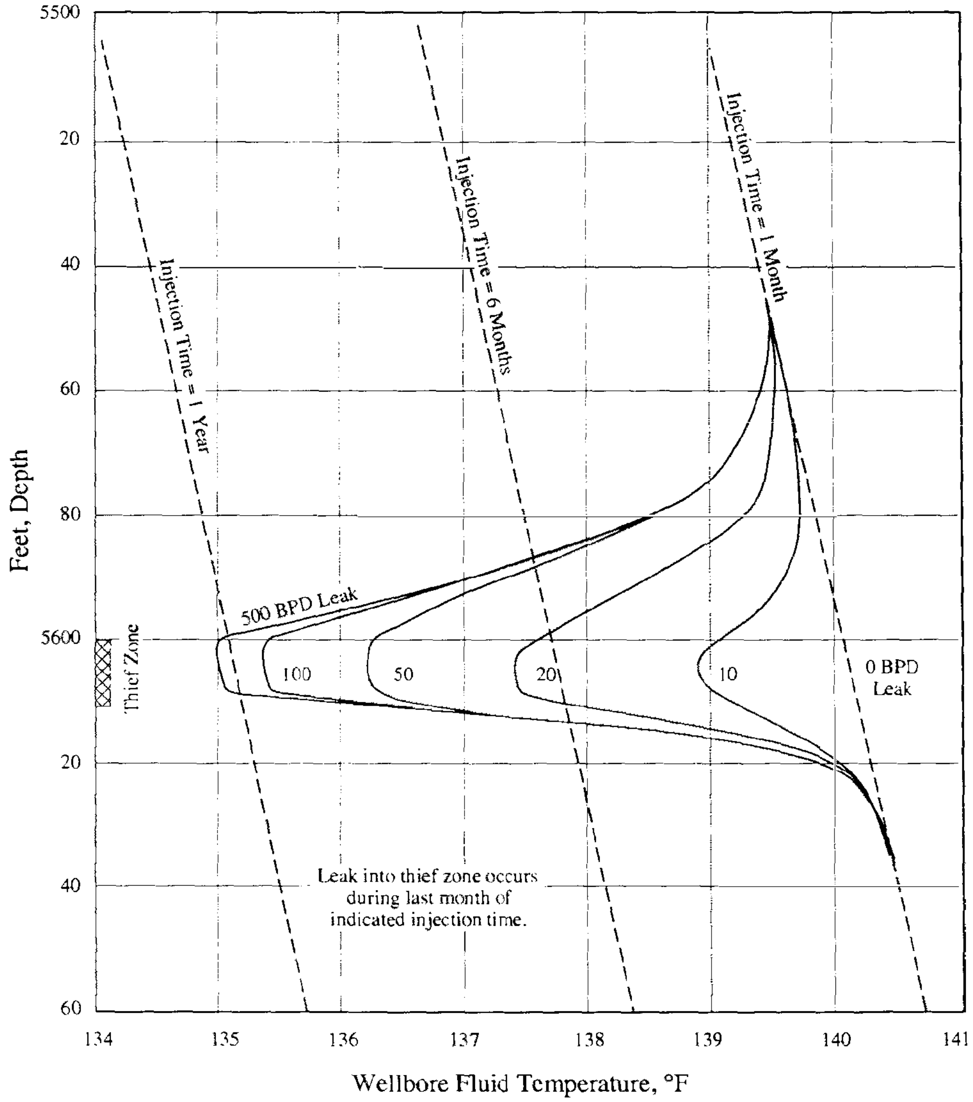


Figure 19. **6-hr shut-in temperature surveys past the thief zone depicted on Figure 17. Computed for a one-month old leak.**

interval. For example, if a well has been on injection for 10 years prior to shut-in, then Figure 15 shows that after 96-hours of shut-in, a section of wellbore opposite a non-injection zone would have warmed from 123°F to 138°F. At this temperature, Figure 19 indicates that a 20 BPD leak would just begin to show up. Consequently, this survey along with one at 192-hours shut-in should not miss the storage porosity. When used according to the guidelines of Table 3, temperature surveys can detect leaks that all the other tools will miss. The use of proper timing of surveys is illustrated by the runs reproduced on Figure 20. These surveys include an injecting run followed by shut-in surveys after 1, 3, 12 and 24 hours, respectively. The well had been on injection at about 500 BPD for nearly one year. All the porous zones indicated on the neutron porosity log are dolomitic developments in limestone. The perforations are into the bottom

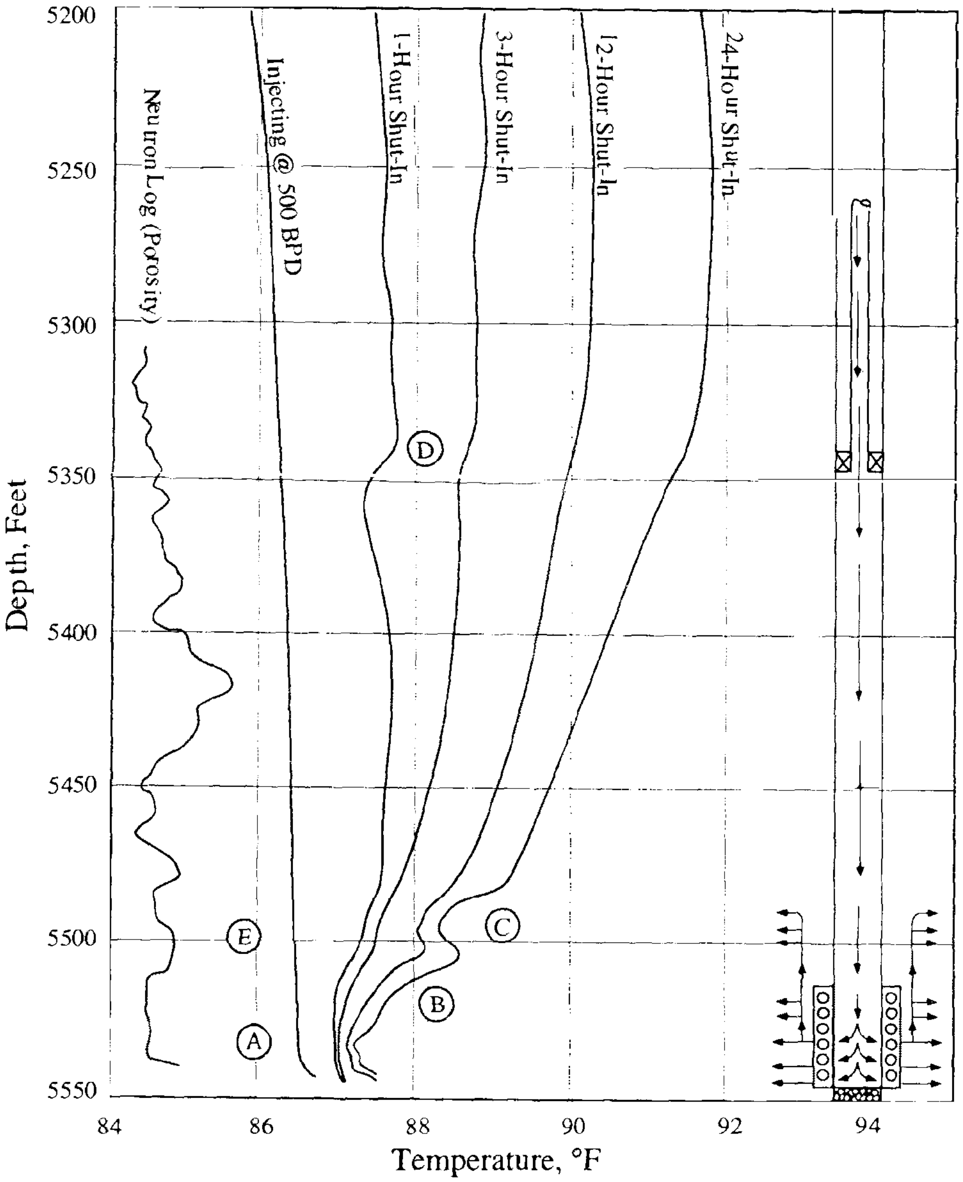


Figure 20. Injecting and shut-in temperature surveys from well on continuous injection at about 500 BPD for almost one year.

member of a lithological unit of lime that extends upwards to 5,150 feet. The injecting survey shows that almost all the currently injected water is leaving the wellbore below depth A at 5,530 feet, which is the bottom 15 feet of the 33-foot perforated interval. There is a slight indication of a "loss" at depth E in the porous member immediately above the disposal zone; however, it is so slight that one would not call it significant. The 1 and 3-hour shut-in surveys show that fluid