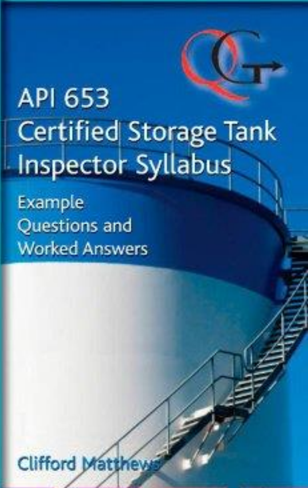
WOODHEAD PUBLISHING LIMITED

A QUICK GUIDE

API 653 Certified Storage Tank Inspector Syllabus

Example Questions and Worked Answers

Clifford Matthews



WP

A Quick Guide to API 653 Certified Storage Tank Inspector Syllabus

A Quick Guide to

API 653 Certified Storage Tank Inspector Syllabus

Example Questions and Worked Answers

Clifford Matthews

Series editor: Clifford Matthews

Matthews Engineering Training Limited
www.matthews-training.co.uk

ASME PRESS

WOODHEAD PUBLISHING LIMITED

Oxford Cambridge New Delhi

Published by Woodhead Publishing Limited, 80 High Street, Sawston, Cambridge CB22 3HJ, UK
www.woodheadpublishing.com
and
Matthews Engineering Training Limited
www.matthews-training.co.uk

Woodhead Publishing India Private Limited, G-2, Vardaan House, 7/28 Ansari Road, Daryaganj, New Delhi – 110002, India

Published in North America by the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990, USA
www.asme.org

First published 2011, Woodhead Publishing Limited and Matthews Engineering Training Limited

British Library Cataloguing in Publication Data
A catalogue record for this book is available from the British Library.

Library of Congress Cataloging in Publication Data
A catalog record for this book is available from the Library of Congress.

Woodhead Publishing ISBN 978-1-84569-756-3 (print)
Woodhead Publishing ISBN 978-0-85709-527-5 (online)
ASME ISBN 978-0-7918-5980-3
ASME Order No. 859803

Typeset by Data Standards Ltd, Frome, Somerset, UK
Printed in the United Kingdom by Henry Ling Limited

Contents

The Quick Guide Series

The *Quick Guide* data books are intended as simplified, easily accessed references to a range of technical subjects. The initial books in the series were published by The Institution of Mechanical Engineers (Professional Engineering Publishing Ltd), written by the series editor Cliff Matthews. The series is now being extended to cover an increasing range of technical subjects by Matthews Engineering Training Ltd.

The concept of the Matthews *Quick Guides* is to provide condensed technical information on complex technical subjects in a pocket book format. Coverage includes the various regulations, codes and standards relevant to the subject. These can be difficult to understand in their full form, so the *Quick Guides* try to pick out the key points and explain them in straightforward terms. This of course means that each guide can only cover the main points of its subject – it is not always possible to explain everything in great depth. For this reason, the *Quick Guides* should only be taken as that – a quick guide – rather than a detailed treatise on the subject.

Where subject matter has statutory significance, e.g. statutory regulation and reference technical codes and standards, then these guides do not claim to be a full interpretation of the statutory requirements. In reality, even regulations themselves do not really have this full status – many points can only be interpreted in a court of law. The objective of the *Quick Guides* is therefore to provide information that will add to the clarity of the picture rather than produce new subject matter or interpretations that will confuse you even further.

If you have any comments on this book, or you have any suggestions for other books you would like to see in the

Quick Guides series, contact us through our website: www.matthews-training.co.uk

Special thanks are due to Helen Hughes for her diligent work in typing the manuscript for this book.

Cliff Matthews
Series Editor

How to Use This Book

This book is a 'Quick Guide' to the API 653 Certified Storage Tank Inspector examination syllabus, formally called the 'body of knowledge' (BOK) by API. It is intended to be of use to readers who:

- intend to study and sit for the formal API 653 Individual Certification Program (ICP) examination or
- have a general interest in the content of API 653 and its associated API/ASME codes, as they are applied to the in-service inspection of atmospheric storage tanks.

The book covers all the codes listed in the API 653 BOK (the so-called 'effectivity list'), but only the content that is covered in the body of knowledge. Note that in some cases (e.g. API 650 *Welded Tanks for Oil Storage*) this represents only a small percentage of the full code content. In addition, the content of individual chapters of this book is chosen to reflect those topics that crop up frequently in the API 653 ICP examination. Surprisingly, some long-standing parts of the API 653 BOK have appeared very infrequently, or not at all, in recent examinations.

While this book is intended to be useful as a summary, remember that it cannot be a full replacement for a programme of study of the necessary codes. The book does not cover the entire API 653 ICP body of knowledge, but you should find it useful as a pre-training course study guide or as pre-examination revision following a training course itself. It is very difficult, perhaps almost impossible, to learn enough to pass the exam using only individual reading of this book.

This quick guide is structured into chapters – each addressing separate parts of the API 653 BOK. A central idea of the chapters is that they contain self-test questions to help you understand the content of the codes. These are as important as the chapter text itself – it is a well-proven fact that you retain more information by actively searching (either mentally or physically) for an answer to a question than by the more passive activity of simply reading through passages or tables of text.

Most of the chapters can stand alone as summaries of individual codes, with the exception of the typical open-book examination questions in Chapter 17 that contain cumulative content from all of the previous chapters. It therefore makes sense to leave these until last.

Code references dates

The API 653 ICP programme runs twice per year with examinations held in March and September. Each examination sitting is considered as a separate event with the examination content being linked to a pre-published code 'effectivity list' and body of knowledge. While the body of knowledge does not change much, the effectivity list is continually updated as new addenda or editions of each code come into play. Note that a code edition normally only enters the API 653 effectivity list twelve months after it has been issued. This allows time for any major errors to be found and corrected.

In writing this *Quick Guide* it has been necessary to set a reference date for the code editions used. We have used the effectivity list for the September 2011 examinations. Hence all the references used to specific code sections and clauses will refer to the code editions/revisions mentioned in that effectivity list. A summary of these is provided in the Appendix.

In many cases the numbering of code clauses remains unchanged over many code revisions, so this book should be of some use for several years into the future. There are subtle differences in the way that API and ASME, as separate organizations, change the organization of their clause numbering systems to incorporate technical updates and changes as they occur – but they are hardly worth worrying about.

Important note: the role of API

API have not sponsored, participated or been involved in the compilation of this book in any way. API do not issue past ICP examination papers, or details of their question banks to any training provider, anywhere.

API codes are published documents, which anyone is allowed to interpret in any way they wish. Our interpretations in this book are built up from a record of running successful API 510/570/653 training programmes in which we have achieved a first-time pass rate of 90 % + . It is worth noting that most training providers either do not know what their delegates' pass rate is or don't publish it if they do. API sometimes publish pass rate statistics – check their website www.api.org and see if they do, and what they are.

Appendix

Publications Effectivity Sheet For API 653 Exam Administration: 21 September 2011

Listed below are the effective editions of the publications required for the API 653, Aboveground Storage Tank Inspector Examination for the date shown above.

- **API Recommended Practice 571,** *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry, First Edition, December 2003*. IHS Product code **API CERT 653_571** (includes only the portions specified below)

ATTENTION: Only the following mechanisms to be included:

4.2.7 – Brittle Fracture
4.2.16 – Mechanical Fatigue
4.3.2 – Atmospheric Corrosion
4.3.3 – Corrosion under insulation (CUI)
4.3.8 – Microbiologically Induced Corrosion (MIC)
4.3.9 – Soil Corrosion
4.3.10 – Caustic Corrosion
4.5.1 – Chloride Stress Corrosion Cracking (Cl-SCC)
4.5.3 – Caustic Stress Corrosion Cracking (Caustic Embrittlement)
5.1.1.11 – Sulfuric Acid Corrosion

- **API Recommended Practice 575**, *Inspection of Atmospheric and Low-Pressure Storage Tanks*, Second Edition, May 2005. IHS Product Code **API CERT 575**
- **API Recommended Practice 577** – *Welding Inspection and Metallurgy,* First Edition, October 2004. IHS Product Code **API CERT 577**
- **API Standard 650**, *Welded Steel Tanks for Oil Storage*, Eleventh Edition, June 2007 **with Addendum 1 (Nov 2008) and Addendum 2 (Nov 2009).** IHS Product Code **API CERT 650**

- **API Recommended Practice 651**, *Cathodic Protection of Aboveground Petroleum Storage Tanks*, Third Edition, January 2007. IHS Product Code **API CERT 651**
- **API Recommended Practice 652**, *Lining of Aboveground Petroleum Storage Tank Bottoms,* Third Edition, October 2005. IHS Product Code **API CERT 652**
- **API Standard 653**, *Tank Inspection, Repair, Alteration, and Reconstruction*, Fourth Edition, April 2009. IHS Product Code **API CERT 653**
- **American Society of Mechanical Engineers (ASME)**, *Boiler and Pressure Vessel Code,* 2007 edition with 2008 Addendum **and 2009 Addendum.**
    - i. ASME Section V, *Nondestructive Examination, Articles 1, 2, 6, 7 and* ***23 (section SE-797 only)***
    - ii. Section IX, *Welding and Brazing Qualifications (**Section QW only**)*

IHS Product Code for the ASME package **API CERT 653 ASME**. Package includes **only** the above excerpts necessary for the exam.

API and ASME publications may be ordered through IHS Documents at 00(1)-303-397-7956 or 800-854-7179. Product codes are listed above. Orders may also be faxed to 303-397-2740. More information is available at http://www.ihs.com. API members are eligible for a 30% discount on all API documents; exam candidates are eligible for a 20% discount on all API documents. When calling to order, please identify yourself as an exam candidate and/or API member. **Prices quoted will reflect the applicable discounts.** No discounts will be made for ASME documents.

Note: API and ASME publications are copyrighted material. Photocopies of API and ASME publications are not permitted. CD-ROM versions of the API documents are issued quarterly by Information Handling Services and are allowed. Be sure to check your CD-ROM against the editions noted on this sheet.

Chapter 1

Interpreting API and ASME Codes

It would help if things were different, but passing any API Inspector Certification Programme (ICP) examination is, unfortunately, all about interpreting codes. As with any other written form of words, codes are open to interpretation. To complicate the issue further, different forms of interpretation exist between code types; API and ASME are separate organizations so their codes are structured differently, and written in quite different styles.

1.1 Codes and the real world

Both API and ASME codes are meant to apply to the real world, but in significantly different ways. The difficulty comes when, in using these codes in the context of the API ICP examinations, it is necessary to distil both approaches down to a single style of ICP examination question (always of multiple choice, single-answer format).

1.2 ASME construction codes

ASME construction codes (only sections V and IX are included in the API 653 ICP body of knowledge) represent the art of the possible, rather than the ultimate in fitness-for-service (FFS) criteria or technical perfection. They share the common feature that they are written entirely from a new construction viewpoint and hence are relevant up to the point of handover or putting into use of a piece of equipment. Strictly, they are not written with in-service inspection or repair in mind. This linking with the restricted activity of new construction means that these codes can be prescriptive, sharp-edged and in most cases fairly definitive about the technical requirements that they set. It is difficult to agree that their content is not black and white, even if you do not agree with the technical requirements or acceptance criteria, etc. that they impose.

Do not make the mistake of confusing the definitive requirements of construction codes as being the formal arbiter of FFS. It is technically possible, in fact commonplace, to use an item safely that is outside code requirements as long as its integrity is demonstrated by a recognized FFS assessment method.

1.3 API inspection codes

API inspection codes (e.g. API 653) and their supporting recommended practice document (API RP 575: *Guidelines and Methods for Inspection of Existing Atmospheric and Low Pressure Storage Tanks*) are very different. Recommended practice (RP) documents are not formal codes and so do not share the prescriptive and 'black and white' approach of construction codes.

There are three reasons for this:

- They are based around accumulated expertise from a *wide variety* of tank applications and situations.
- The technical areas that they address (corrosion, equipment lifetimes, etc.) can be diverse and uncertain.
- They deal with technical *opinion*, as well as fact.

Taken together, these make for technical documents that are more of a technical way of looking at the world than a solution, unique or otherwise, to a technical problem. In such a situation you can expect *opinion* to predominate.

Like other trade associations and institutions, API (and ASME) operate using a structure of technical committees. It is committees that decide the scope of codes, call for content, review submissions and review the pros and cons of what should be included in their content. It follows therefore that the content and flavour of the finalized code documents are the product of committees. The output of committees is no secret – they produce fairly well-informed opinion based on an accumulation of experience, tempered, so as not to appear too opinionated or controversial, by having the technical edges taken off. Within these constraints there is no doubt that API codes do provide sound and fairly balanced technical opinion. Do not be surprised, however, if this opinion does not necessarily match your own.

1.3.1 Terminology

API and ASME documents use terminology that occasionally differs from that used in European and other codes. Non-destructive examination (NDE), for example, is normally referred to as non-destructive testing (NDT) in Europe and API work on the concept that an operative who performs NDE is known as the *examiner* rather than the term *technician* used in other countries. Most of the differences are not particularly significant in a technical sense – they just take a little getting used to.

In occasional cases, meanings can differ *between* ASME and API. This is actually less of an issue in the API 653 ICP than in the other ICPs because, unlike pressure vessels, the construction code for tanks is an API one: API 650. In general however, API codes benefit from their principle of having a separate section (see API 653 section 3) containing definitions. These definitions are selective rather than complete (try to find an accurate explanation of the difference between the terms *approve* and *authorize*, for example).

Questions from the ICP examination papers are based solely on the terminology and definitions understood by the referenced codes. That is the end of the matter.

1.3.2 Calculations

Historically, both API and ASME codes were based on the United States Customary System (USCS) family of units. There are practical differences between this and the European SI system of units.

SI is a consistent system of units, in which equations are expressed using a combination of *base* units. For example, a generic hoop stress equation broadly applicable to pressure vessels or tank shells is

$$\text{Stress (S)} = \frac{\text{pressure}\,(p) \times \text{diameter}\,(d)}{2 \times \text{thickness}\,(t)}$$

In SI units all the parameters would be stated in their base units, i.e.

Stress: N/m^2 (Pa)
Pressure: N/m^2 (Pa)
Diameter: m
Thickness: m

Compare this with the USCS system in which parameters may be expressed in several different 'base' units, combined with a multiplying factor. For example the equation for determining the minimum allowable corroded shell thickness of storage tanks is

$$t_{\min} = \frac{2.6(H-1)DG}{SE}$$

- where $t_{\min}$ is in inches;
- fill height (H) is in feet;
- tank diameter (D) is in feet.

G is specific gravity, S is allowable stress and E is joint efficiency. Note how, instead of stating dimensions in a single base unit (e.g. inches) the dimensions are stated in the most convenient dimension for measurement, i.e. shell thickness in inches and tank diameter and fill height in feet. Remember that:

- This gives the same answer; the difference is simply in the method of expression.
- In many cases this can be easier to use than the more rigorous SI system – it avoids awkward exponential (10^6, 10^{-6}, etc.) factors that have to be written in and subsequently cancelled out.
- The written terms tend to be smaller and more convenient.

1.3.3 Trends in code units

Until fairly recently, ASME and API codes were written exclusively in USCS units. The trend is increasing, however, to develop them to express all units in dual terms USCS (SI), i.e. the USCS term followed by the SI term in brackets. Note the results of this trend:

- Not all codes have been converted at once; there is an inevitable process of progressive change.
- ASME and API, being different organizations, will inevitably introduce their changes at different rates, as their codes are revised and updated to their own schedules.
- Unit conversions bring with them the problem of *rounding errors*. The USCS system, unlike the SI system, has never adapted well to a consistent system of rounding (e.g. to one, two or three significant figures) so errors do creep in.

The results of all these is a small but significant effect on the form of examination questions used in the ICP examination and a few more opportunities for errors of expression, calculation and rounding to creep in. On balance, ICP examination questions seem to respond better to being treated using pure USCS units (for which they were intended). They do not respond particularly well to SI units, which can cause problems with conversion factors and rounding errors.

1.4 Code revisions

Both API and ASME review and amend their codes on a regular basis. There are various differences in their approaches but the basic idea is that a code undergoes several addenda additions to the existing edition, before being reissued as a new edition. Timescales vary – some change regularly and others hardly at all.

Owing to the complexity of the interlinking and cross-referencing between codes (particularly referencing *from* API *to* ASME codes) occasional mismatches may exist temporarily. Mismatches are usually minor and unlikely to cause any problems in interpreting the codes.

It is rare that code revisions are very dramatic; think of them more as a general process of updating and correction. On occasion, fundamental changes are made to material allowable stresses (specified in ASME II-D), as a result of experience with material test results, failures or advances in manufacturing processes.

1.5 Code illustrations

The philosophy on figures and illustrations differs significantly between ASME and API codes as follows:

- *ASME codes*, being construction-based, contain numerous engineering-drawing style figures and tables. Their content is designed to be precise, leading to clear engineering interpretation.
- *API codes* are often not heavily illustrated, relying more on text. For storage tanks, however, the situation is a little different. Both API 653 and its partner recommended practice API RP 575 contain quite a lot of figures, tables and photographs. This makes them easier to read than, for example, the equivalent API codes for pipework or pressure vessels.
- *API recommended practice (RP) documents* are better illustrated than their associated API codes but tend to be less formal and rigorous in their approach. This makes sense, as they are intended to be used as technical information documents rather than strict codes, as such. API RP 575 is a typical example containing photographs, tables and drawings (sketch format) of a fairly detailed nature. In some cases this can actually make RP documents more practically *useful* than codes.

1.6 New construction versus repair activity

This is one of the more difficult areas to understand when dealing with ASME and API codes. One difficulty comes from the fact that, although ASME V (NDE) and ASME IX (welder qualifications) were written exclusively from the viewpoint of new construction, they are both referred to by API 653 in the context of in-service *repair* and, to a lesser extent, re-rating. The main problem with storage tanks, however, is competition *between* API codes, as both the construction code API 650 and the in-service inspection code API 653 are of course both API documents

The ground rules (set by API) to manage this potential contradiction are as follows (see Fig. 1.1).

- For *new tank construction*, API 650 is used – API 653 plays no part.
- For *tank repair*, API 653 is the 'driving' code. In areas where it references 'the construction code' (e.g. API 650), then this is followed *when it can be* (because API 653 has no content that contradicts it).

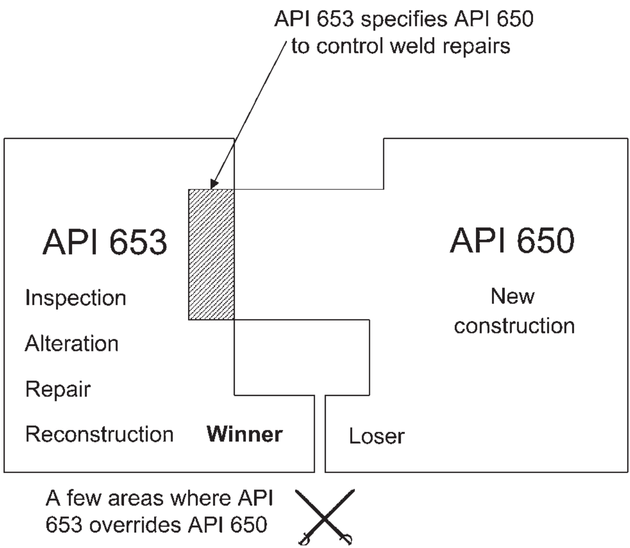


Figure 1.1 New construction versus repair

- For *tank repair* activities where API 653 and API 650 contradict, then API 653 takes priority. Remember that these contradictions are to some extent false – they only exist because API 653 is dealing with on-site repairs, while API 650 was not written with that in mind. Three areas where this is an issue are:
  - some types of repair weld specification (material, fillet size, electrode size, etc.);
  - decisions on whether a tank requires pressure testing;
  - assumptions on material strength and impact test requirements.
- For *tank reconstruction* (cutting a tank up and reassembling it somewhere else) API 653 is, strictly, the driving code, so if there were any contradictions between API 653 and API 650, then API 653 would take priority. In practice, API 653 actively cross-refers to API 650 in most areas, so the problem rarely exists.

1.7 Conclusion: interpreting API and ASME codes

In summary, then, the API and ASME set of codes are a fairly comprehensive technical resource, with direct application to plant and equipment used in the petroleum industry. They are perhaps far from perfect but, in reality, are much more comprehensive and technically consistent than many others. Most national trade associations and institutions do not have any in-service inspection codes *at all*, so industry has to rely on a fragmented collection from overseas sources or nothing at all.

The API ICP scheme relies on these ASME and API codes for its selection of subject matter (the so-called 'body of knowledge'), multiple exam questions and their answers. One of the difficulties is shoe-horning the different approaches and styles of the ASME codes (V and IX) into the same style of questions and answers that fall out of the relevant API documents (in the case of the API 653 ICP these are API 651, 652, 575, 650 and 653). Figure 1.2 shows the situation. It

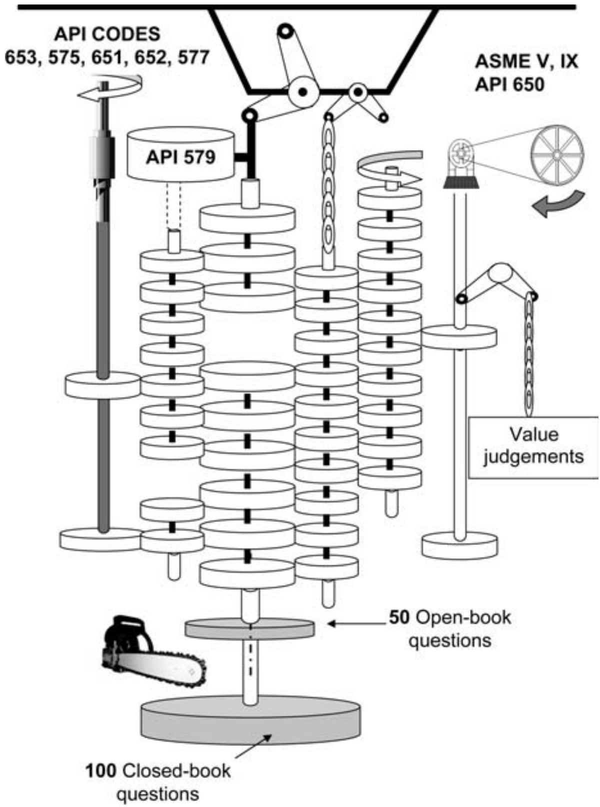


Figure 1.2 Codes in, questions out

reads differently, of course, depending on whether you are looking for reasons for difference or seeking some justification for similarity. You can see the effect of this in the style of many of the examination questions and their 'correct' answers.

Difficulties apart, there is no question that the API ICP examinations are all about understanding and interpreting the relevant ASME and API codes. Remember, again, that while these codes are based on engineering experience, do not expect that this experience necessarily has to coincide with your own. Accumulated experience is incredibly wide and complex, and yours is only a small part of it.

Chapter 2

An Introduction to API 653: 2009 and its Related Codes

API codes, and the way in which they are written, are an acquired taste. As with all tastes that develop over time, some people eventually acquire it, some pretend to (because it sounds good) and others do not, but just put up with it. API codes are written from the viewpoint of the US refinery industry, so if you are not in the US refinery industry you may find some of the concepts and terminology different. In particular, the system of personnel responsibilities (what the inspector has responsibility for) bears little resemblance to the way that things work in many tank operator companies in the UK and Europe.

This chapter is about learning to become familiar with the layout and contents of API 653. It forms a vital preliminary stage that will ultimately help you understand not only the content of API 653 but also its cross-references to the other relevant API and ASME codes.

API 653 is divided into 13 sections (sections 1 to 13) and nine annexes followed by a large group of figures and 12 tables. Even when taken together, these are not sufficient to specify fully a methodology for the inspection, repair and alteration and reconstruction of storage tanks. To accomplish this, other information and guidance has to be drawn from the other codes included in the API 653 body of knowledge (BOK). Figure 2.1 shows how all these codes work together

So that we can start to build up your familiarity with API 653, we are going to look at some of the definitions that form its basis. We can start to identify these by looking at the API 653 contents/index page. This is laid out broadly as shown in Fig. 2.1.

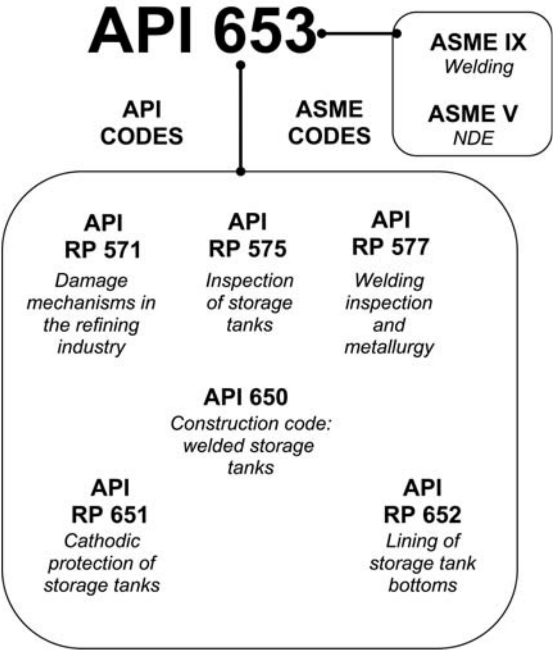


Figure 2.1 The API 653 body of knowledge (BOK) codes

2.1 Section 1: scope

This is a very short (one-page) part of the code. Unlike some other API codes (and earlier versions of this one), this section does not give a list of types of tanks that are specifically included or excluded from the coverage of API 653. The main emphasis is on the principle that API 653 can be used in relation to tanks that were built to the construction code API 650, or *any other tank construction code* (e.g. BS 2654).

Note also how the fitness-for-service (US terminology for fitness-for-purpose) document API RP 579 is cross-referenced for the source of more detailed assessment procedures than are given in API 653. As with all the API Certified

1 SCOPE
- 1.1 Introduction
- 1.2 Compliance with this standard
- 1.3 Jurisdiction
- 1.4 Safe working practices

2 REFERENCES

3 DEFINITIONS

Read through these sections at this stage

4 SUITABILITY FOR SERVICE
- 4.1 General
- 4.2 Tank roof evaluation
- 4.3 Tank shell evaluation
- 4.4 Tank bottom evaluation
- 4.5 Tank foundation evaluation

This section is basically about the techniques of evaluating corroded tanks

5 BRITTLE FRACTURE CONSIDERATIONS
- 5.1 General
- 5.2 Basic considerations
- 5.3 Assessment procedure

6 INSPECTION
- 6.1 General
- 6.2 Inspection frequency considerations
- 6.3 Inspection from the outside of the tank
- 6.4 Internal inspection
- 6.5 Alternative to internal inspection to determine bottom thickness
- 6.6 Preparatory work for internal inspection
- 6.7 Inspection checklists
- 6.8 Records
- 6.9 Reports
- 6.10 NDE

7 MATERIALS
- 7.1 General
- 7.2 New materials
- 7.3 Original materials for reconstructed tanks
- 7.4 Welding consumables

8 DESIGN CONSIDERATIONS FOR RECONSTRUCTED TANKS
- 8.1 General
- 8.2 New weld joints
- 8.3 Existing weld joints
- 8.4 Shell design
- 8.5 Shell penetrations
- 8.6 Wind girders and shell stability
- 8.7 Roofs
- 8.8 Seismic design

9 TANK REPAIR AND ALTERATION
- 9.1 General
- 9.2 Removal and replacement of shell plate material
- 9.3 Shell repairs using lap-welded plates
- 9.4 Repair of defects in shell-plate material
- 9.5 Alteration of tank shells to change shell height
- 9.6 Repair of defective welds
- 9.7 Repair of shell penetrations
- 9.8 Addition of existing shell penetrations
- 9.9 Alteration of existing shell penetrations
- 9.10 Repair of tank bottoms
- 9.11 Repair of fixed roofs

Note how many of these subjects relate to tanks that, as the result of inspection findings, have to be repaired or reconstructed ... it is a continuing theme throughout the document

Figure 2.2 The contents of API 653

9 TANK REPAIR AND ALTERATION (CONTINUED)

9.12 Floating roofs
9.13 Repair/replacement of floating roof perimeter seals
9.14 Hot taps

10 DISMANTLING AND CONSTRUCTION
10.1 General
10.2 Cleaning and gas-freeing
10.3 Dismantling methods
10.4 Reconstructions
10.5 Dimensional tolerances

A lot of this section is to do with acceptable weld sizes and dimensional tolerances

11 WELDING
11.1 Welding qualifications
11.2 Identification and records
11.3 Alternatives to PWHT

12 EXAMINATION AND TESTING
12.1 NDE
12.2 Radiographs
12.3 Hydrostatic testing
12.4 Leak tests
12.5 Measured settlement during hydrostatic testing

An important section covering NDE and hydrotesting

13 MARKING AND RECORD KEEPING
13.1 Nameplates
13.2 Record keeping
13.3 Certification

ANNEX B is an important one. Have a look at figures showing acceptable levels of tank bottom settlement (possible open-book exam questions)

APPENDICES
- ANNEX A PAST API EDITIONS
- **ANNEX B EVALUATION OF TANK BOTTOM SETTLEMENT**
- ANNEX C CHECKLISTS FOR TANK INSPECTION
- ANNEX D AUTHORIZED INSPECTOR CERTIFICATION
- ANNEX E (BLANK)
- ANNEX F NDE REQUIREMENTS SUMMARY
- ANNEX G QUALIFICATION OF TANK BOTTOM EXAM PROCEDURES/PERSONNEL
- ANNEX H SIMILAR SERVICE ASSESSMENT
- ANNEX S AUSTENITIC STAINLESS STEEL STORAGE TANKS

FIGURES

A long list of figures, many of which contain engineering data on defect measurement and repair

Note how there is a lot of information in these figures that can form the basis of examination questions (particularly open-book ones).

Figure 2.2 The contents of API 653 (continued)

Inspector examination scopes, the actual content of API 579 is not in the exam syllabus; you just need to know of its existence, and broadly what it covers.

Section 1.2: compliance

The overriding principle of this section is identifying the party with the ultimate responsibility for compliance with API 653 as the user/owner of the storage tanks (not the API-certified inspector). There is an inference in this section that all other involved parties should have responsibilities for their own actions, but the overriding responsibility still lies with the user/owner. Again, this is a principle common to all the API in-service inspection codes.

Section 1.4: safe working practices

Strictly, API codes are not health and safety (H&S) documents. There does seem to be a trend, however, as new editions are published, to cross-reference various H&S documents that have an influence in various 'jurisdictions' in the USA or related API documents that contain H&S information.

Note how this section references API 2015 (safe entry to tanks), API 2016 (entering and cleaning tanks) and API 2217A (work in confined spaces). They also appear in the list of referenced codes shown in section 2 of API 653. Questions on H&S requirements often appear in the closed-book section of the API exam paper. They are invariably of a fairly general nature and relate mainly to avoiding the danger of confined spaces or explosive atmospheres in empty tanks.

2.2 Section 3: definitions

This section of API 653 is smaller than the equivalent one in API 570 or API 510. Although it has been expanded in this latest 2009 edition of the code, it contains fewer technical definitions than is usual, mainly because a lot of the technical details on storage tank subjects are presented in API 575, rather than in API 653 itself. We will look at the content and major technical points of API 575 later.

There are a few specific definitions listed in API 653 that you need to understand at this stage.

Section 3.1: alteration

An *alteration* is defined in API 653 as any work on a tank that *changes its physical dimensions or configuration*. Note how this is a much broader definition than in API 510/570 where an alteration is more specifically defined as a change that takes a component outside the documented design criteria of its design code. There is probably no hidden reason behind the differences in approach (other than they were written by different people).

This definition leads on to one of the main thrusts of the content of API 653 – that of tank *repair and reconstruction*. The whole concept behind API 653 seems to be that a storage tank inspector is going to spend their life looking at tanks that resemble rust-buckets and need imminent repair to stop them leaking or falling down. This would suggest that some probably do.

Section 3.3: authorized inspection agency

Again, this can be a bit confusing. The four definitions (a to d) shown in API 653 relate to the situation in the USA, where the authorized inspection agency has some kind of legal jurisdiction, although the situation varies between states. Note this term *jurisdiction* used throughout API codes and remember that it was written with the various states of the USA in mind.

The UK situation is completely different, as control of major accident hazards (COMAH) and other H&S legislation form the statutory requirement. For atmospheric storage tanks, the nearest match to the 'authorized inspection agency' in the UK is probably the Health and Safety Executive (HSE). It is different with pressure equipment, where the Pressure System Safety Regulations (PSSRs) and their 'Competent Person' inspection body occupy the nearest role to the 'authorized inspection agency' position.

Section 3.4: authorized inspector

This refers to the USA situation where, in many states, storage tank inspectors *have to be* certified to API 653. There is no such legal requirement in the UK (but don't tell anyone). Assume, for this book, that the authorized inspector is someone who has passed the API 653 certification exam and can therefore perform competently the storage tank inspection duties covered by API 653.

Note this difference to other API codes:

- API 653 is noticeably different to API 510 (vessels) and 570 (pipework) in that it does not spend lots of time trying to list the numerous responsibilities of the authorized inspector. This may be because API are trying to make their codes more relevant to non-US situations where the responsibilities are different. Instead, API 653 concentrates much more on the *technical aspects* of tank inspections. This is good news, because this is what codes are supposed to be for. No one consults the stultified content of codes when working out job descriptions or contract wording.

Figure 2.3 summarizes how API 653 sees the duties and responsibilities of the tank owner/user and API-certified tank inspector.

Section 3.7: change in service

Changes in service of storage tanks are perfectly allowable under the requirements of API 653, as long as code compliance is maintained. In the USA, the API-authorized inspector is responsible for accepting changes of service, once he is happy with the results of thickness checks, change of process conditions, etc. In the UK way of working, this is unlikely to be carried out by a single person (although, in theory, the API 653 qualification should qualify an inspector to do it).

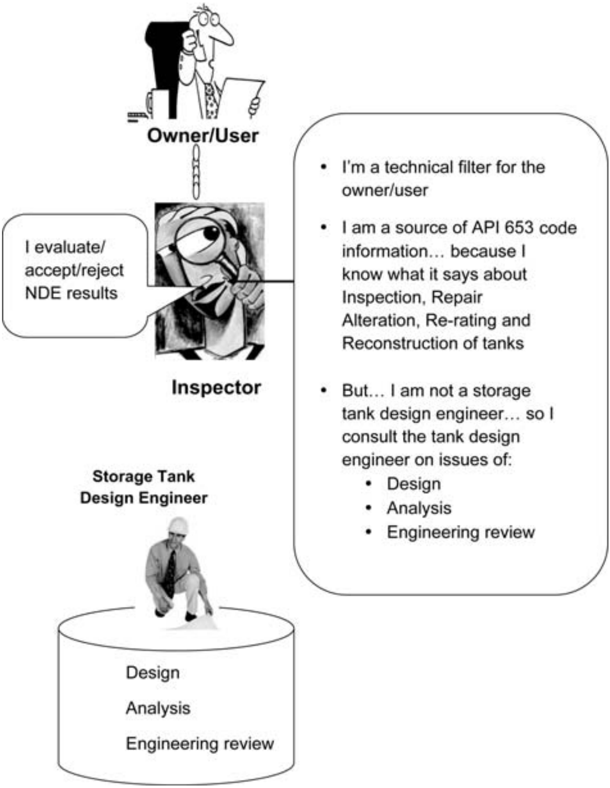


Figure 2.3 Roles and duties

Section 3.19: owner/operator

This section appears in many of the API codes. Sometimes it refers to the owner/user, rather than owner/operator. The overriding principle is that the API-certified storage tank inspector is responsible to the owner/user for confirming that the requirements of API 653 have been met. You will see this as a recurring theme throughout this code (and there will almost certainly be examination questions on it).

Section 3.23: reconstruction organization

Surprisingly, API 653 exerts little control on who is allowed to carry out repairs to storage tanks. Contrast this to the API approach on pressure vessels, where organizations that hold an ASME 'code stamp' (certificate of authorization) are seen as the main participants.

Section 3.24: repair

API 653 places great importance on the activities of repair and reconstruction of storage tanks. To this end, definition 3.24 specifies four broad definitions of repair activities. These are:

- Replacement of bits of tank roof, shell or bottom
- Re-levelling and/or jacking of bits of a tank
- Adding reinforcement plates to existing shell penetrations
- Repairing defects by grinding-out and welding

The key aspects of this are not the repair activities themselves (they are fairly obvious), but what happens after the repair is completed. Look back to API 653 definition 3.2 '*as-built standard*' and read what it says. Three things should become apparent:

- In the USA, great emphasis is obviously placed on what edition of the code a tank was built to (originally) and repaired to (after it has developed rust-bucket status). This is not necessarily of such interest in other countries but API and ASME codes clearly revolve around it.
- The main US code for both construction and repair is actually API 650, rather than 653.You can see this from the list of revisions in API 653 Annex A. Note how API 650 was preceded by the older code API 12C. In the most recent edition of API 653 it is clear that API are keen to recognize other tank construction codes, as well as API 650. This explains the use of the generic term 'as-built standard' instead of assuming that all tanks have to be built to API 650.
- It is possible for a repaired tank to be rated to several

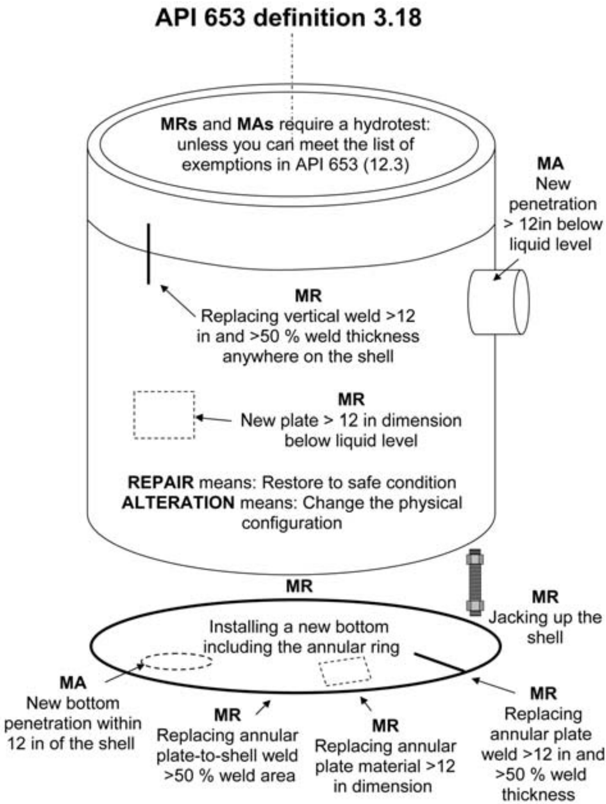


Figure 2.4 API 653 definitions of major repairs (MR) and major alterations (MA)

separate construction code editions, one for the original construction and one for the re-rating, each time it is repaired or altered. Note the sections of definition 3.2 where it says this. Note also the statements in the section where it gives the situation if the original code edition, or the actual construction date, are not known.

Section 3.18: major alteration/repair

As a related section to section 3.24, section 3.18 specifies what API 653 considers a *major* alteration/repair. These definitions have some implications as to the applicability of other sections in the code. Figure 2.4 summarizes the eight definitions.

Section 3.21: recognized toughness

This rather strangely titled definition is in recognition of a link to section 5 of API 653 which covers the avoidance of brittle fracture in storage tanks (both new and repaired). Brittle fracture at low ambient temperature is one of the few catastrophic failure mechanisms that can affect storage tanks so API 653 contains quite a bit of content aimed at avoiding it. It is purely a function of material choice, so mitigation measures are fairly predictable. We will see these covered later in API 653 section 5 and API 571.

Now try these introductory questions on the scope and definitions of API 653: 2009. The answers are in the back of this book.

2.3 API 653 scope and definitions: practice questions

Q1. API 653: scope

Which of these vessels is *specifically* excluded from the requirements of API 653?

(a) A storage tank built to API 12C ☐
(b) A storage tank built to API 650 ☐
(c) A storage tank built to BS 2654 ☐
(d) None, API 653 can be used for all of them ☐

Q2. API 653: conflict of codes

If there is a conflict of technical requirements between API 650 (construction) and API 653 on activities that must be carried out on an in-service tank, what actions would you take?

(a) Follow API 650 ☐
(b) Follow API 653 ☐
(c) Use API 579 instead ☐
(d) Use API 2217A instead ☐

Q3. API 653: responsibilities for compliance

Who has the ultimate responsibility for compliance with API 653?

(a) The company that inspects it (one of the options in API 653 section 3.4) ☐
(b) The API authorized inspector (API 653 definition 3.5) ☐
(c) The owner/operator ☐
(d) All of the above share the responsibility ☐

Q4. API 653: safe working practices

What does API 2016 cover?

(a) Procedures for safe hot tapping ☐
(b) Preparing tank bottoms for hot work ☐
(c) Recommended practice for entering and cleaning tanks ☐
(d) Safe venting of tanks ☐

Q5. API 653: alterations

Which of these is classed as an *alteration* to a storage tank?

(a) Work necessary to restore a tank to a safe condition ☐
(b) Removal and replacement of a tank roof ☐
(c) Changes to the shape of a tank roof ☐
(d) All of the above ☐

Q6. API 653: authorized inspector

In regions of API jurisdiction, can an authorized inspector be an individual (self-employed) person?

(a) Yes, without restriction ☐
(b) Yes, as long as they work under the owner/operator's programme/controls ☐

(c) Yes, as long as they do not work under the control of the owner/operator ☐
(d) No, it is prohibited ☐

Q7. API 653: authorized inspector certification

How many years of storage tank inspection or inspection supervision experience must an applicant with a degree in engineering or technology have in order to satisfy API acceptance criteria?

(a) 5 years ☐
(b) 3 years ☐
(c) 2 years ☐
(d) 1 year ☐

Q8. API 653: inspector recertification

How often must an API 653-certified vessel inspector who is actively involved in tank inspections be 'recertified' by API?

(a) Every year ☐
(b) Every 3 years ☐
(c) Every 5 years ☐
(d) It depends on how many individual tanks they have inspected ☐

Q9. API 653: inspector recertification

An inspector achieved API 653 certification 3 years ago but has only been actively engaged in tank inspections for 25 % of his time over the past 3 years. What does this inspector have to do to achieve his 3-yearly recertification?

(a) Sit a full recertification examination covering the whole API 653 syllabus ☐
(b) Sit an on-line examination covering recent code revisions only ☐
(c) Just apply for recertification without any exam ☐
(d) Both (b) and (c) above ☐

Q10. API 653: inspector recertification

How often does an API 653-authorized inspector who has been actively engaged in tank inspections for 50 % of his time have to sit the on-line test covering revisions to the codes relevant to their authorization?

(a) It is not necessary as they have been 'actively engaged' for enough time ☐

(b) Every 3 years ☐
(c) Every 5 years ☐
(d) Every 6 years ☐

Chapter 3

An Introduction to API RP 575

This chapter is about learning to become familiar with the layout and contents of API RP 575: *Guidelines and Methods for Inspection of Existing Atmospheric and Low-Pressure Storage Tanks*. API RP 575 is a well-established document (it has only recently changed from its first edition to the current 2005 2nd edition) with its roots in earlier documents published by the American refining industry. It is more a technical *guide document* rather than a code, as such, but it performs a useful function in supporting the content of API 653.

Note the following five points about API RP 575.

3.1 Scope

It has a *very wide scope* (evidenced by its title), which specifically includes all types of atmospheric and low pressure tanks. This wide scope is evident once you start to read the content; it refers to all types of storage tanks and the design features, inspection methods and damage mechanisms that go with them.

3.1.1 Damage mechanisms

API 575 introduces various *corrosion and degradation mechanisms*. As expected, these are heavily biased towards the refining industry with continued emphasis on petroleum-related corrosion mechanisms and cracking. In general, although it provides a description and discussions on corrosion, API RP 575 acts only as an introduction to these corrosion mechanisms, leaving most of the detail to be covered in API RP 571.

3.1.2 Equipment

It is *downstream oil industry orientated* (not surprising as it is an API document). Its main reference is to the downstream oil sector, a term commonly used to refer to the part of the industry involved in the refining, selling and distribution of products derived from crude oil (gas, petrol, diesel, etc.).

The types of equipment covered by the code can therefore include oil refineries, petrochemical plants, petroleum products distributors, retail outlets and natural gas distribution companies. These can involve thousands of products such as gasoline, diesel, jet fuel, heating oil, asphalt, lubricants, synthetic rubber, plastics, fertilizers, antifreeze, pesticides, pharmaceuticals, natural gas, propane and many others.

3.1.3 Related codes

API RP 575 refers to a lot of *related codes* that are not in the API 653 exam BOK. Examples are the out-of-print API 12 series and multiple documents in the API 300 series, API RP 307, 315, 322, etc., and others; see API 575 section 2 on page 1 of the document. These provide technical details on specific subjects and problems. Do not worry about these referenced documents; you need to know that they exist but you do not need to study them for the API 653 examination.

3.1.4 Exam content

API 575 *is all text and technical descriptions*, accompanied by explanatory photographs of a fairly general nature. It contains few calculations. The only calculations it does contain of any significance are the ones on corrosion rates and inspection periods in section 6. These are important but will be covered later in API 653. In practice, most examination questions about API 575 in the API 653 certification exam are *closed book*. The downside to this is that API 575 contains several thousand separate technical facts, giving a large scope for the choice of exam questions.

All this means that you need to develop a working familiarity with the technical content of API 575 treating it as essential background knowledge for the API 653 syllabus, rather than as a separate 'standalone' code in itself. We will look at some of the more important areas as we work through the document.

3.2 API 575 sections 1 and 2: scope and references

These sections are little more than general information on where the document sits in relation to other API publications. Note however the reference to the older (superseded) API 12A and 12C specifications. There are obviously storage tanks still around that were made to these codes, rather than API 650 and 620: the codes that replaced them.

3.3 API 575 section 3: definitions

API 575 section 3 bears a startling resemblance to the equivalent section in API 653. This is a feature of API codes in general; there is repetition between them, although hopefully no (or, at least, not much) actual contradiction. Most of the definitions in this section (alteration/repair/reconstruction, etc.) are exactly the same as given in API 653 and therefore do not need further study. There are, however, a couple of new ones.

Definition 3.3: atmospheric pressure

This used to feature in API 653 but has recently been taken out of several parts of the code. The important point is how it defines an atmospheric tank as one that is actually designed to withstand an internal pressure of up to 2.5 psi (18 kPa) gauge pressure (i.e. above atmospheric).

Definition 3.8: examiner

This is a concept that features in API 570 and 510 for pipes and vessels but is mysteriously absent from API 653, appearing, instead, here in API 575. Do not confuse this as anything to do with the examiner who oversees the API certification exams. This is the API terminology for the NDT technician who provides the NDT results for evaluation by the API-qualified storage tank inspector. API recognizes the NDT technician as a separate entity from the API-authorized storage tank inspector.

API codes (in fact most American-based codes) refer to NDT (the European term) as NDE (non-destructive examination), so expect to see this used throughout the API 653 examination. Other countries' codes are not actually prohibited, but are not mentioned either. Welcome to America.

API codes only really recognize US NDE qualifications, hence the reference to SNT-TC-1A, etc., qualifications for NDE 'examiners' (that term again).

Definition 3.13: reconstruction

The term *reconstruction* means dismantling a tank and then reassembling it on a new site. Visualize a large tank on the back of a 48-wheel trailer holding you up on the motorway and you get the picture. Do not confuse this with tank *repair* (definition 3.15), which does not involve moving the tank to a new site.

All the other definitions are the same (more or less) as in API 653 and are nothing to get excited about, unless you have a particularly low excitement threshold.

3.4 API 575 section 4: types of storage tanks

Although it looks fairly complicated, API 575 section 4 only covers two generic types of storage tank: atmospheric tanks and low pressure tanks. The definitions are simple:

- *Atmospheric tanks* (API 650) are designed to a gauge pressure of $\leq 2\frac{1}{2}$ psi.
- *Low pressure tanks* (API 620) are designed to a gauge pressure of $2\frac{1}{2} - 15$ psi.

Most of the API examination questions will be about the atmospheric type of tanks since API 620 is (strictly) not in the BOK.

Note in API 575 section (4.2.2) the definition of *vapour pressure*. This is defined as the pressure existing on the surface of a confined liquid caused by the vapours given off by the liquid. It is the value of this vapour pressure that determines whether a fluid can be stored in an atmospheric tank or requires a (low) pressurized tank.

Section 4.2.3: types of atmospheric storage tank roofs

Atmospheric tank designs are differentiated mainly by their type of roof. There are several different designs of shell (flanged, ribbed, spiral-wound, etc.) but they are not covered in the scope of API 575. The two main generic types are *fixed roof and floating roof*. Floating roofs are used when there is a need to avoid the accumulation of flammable/explosive vapours in the space above the fluid.

Look at section 4.2.3 and highlight the main points of the descriptions of the following roof types:

- Fixed cone roof
- (Fixed) umbrella roof
- (Fixed) dome roof
- Pan-type (floating) roof
- Pontoon (floating) roof
- Double-deck (floating) roof

Have a look also at the type that has a floating roof, but with an additional fixed roof above it (Fig. 13 of API 575). This is to isolate the floating roof from the weather and/or to ensure that particularly hazardous vapours are not released into the atmosphere. Two other (fairly rare) atmospheric types are the breather type and balloon type (Fig. 15)

Section 4 also shows various types of seals that are used on floating roof tanks (see the figures in section 4). These are fairly straightforward and do not give great scope for exam questions.

Section 4.3: low pressure storage tanks

Low pressure tanks do not form a major part of the API 653 syllabus and they are not covered in much detail in API 575. Note the few significant points about them, however, in section 4.3.2:

- They are constructed to API 620, not API 650.
- They are necessary when the vapour pressure of the stored fluid exceeds the $2\frac{1}{2}$ psi limit of API 650-type atmospheric tanks. Volatile products such as light crude, some petrol

products and liquid oxygen/nitrogen fall into this category.

There are various designs, some of them quite elaborate domed shapes, but many are now made spherical, as this is the best shape for retaining pressure and they are not too difficult to make.

Have a look at the various figures in API 575, highlighting the design features of storage tanks.

Now try these questions on types of tanks and their construction features.

3.5 API RP 575: practice questions

Q1. API 575: construction standards

Which of the following old specifications covered riveted atmospheric storage tanks?

(a) API 12A ☐
(b) API 12B ☐
(c) API 12C ☐
(d) API 12D ☐

Q2. API 575: use of atmospheric tanks

Which of the following fluids would *not* be suitable for being held in an atmospheric tank?

(a) Heavy oil ☐
(b) Gas oil (kerosene) ☐
(c) Water ☐
(d) Liquid oxygen ☐

Q3. API 575: atmospheric storage tank roofs

What type of fixed roof does not need supporting rafters/columns, etc.?

(a) Double roof type ☐
(b) Geodesic dome type ☐
(c) Breather type ☐
(d) Pan type ☐

Q4. API 575: atmospheric storage tank roofs

Which of these is not a floating roof design?

(a) Pan type ☐

(b) Pontoon type ☐
(c) Double-deck type ☐
(d) Lifter type ☐

Q5. API 575: atmospheric storage tank roofs
Why do some floating-roof tanks have an additional dome roof on the top?

(a) To keep the rain out ☐
(b) To decrease the vapour pressure of the stored product ☐
(c) To increase the vapour pressure of the stored product ☐
(d) Both (a) and b) above ☐

Q6. API 575: atmospheric storage tank roofs
What kind of floating-roof seal may be filled with foam?

(a) A mechanical seal ☐
(b) A tube seal ☐
(c) A counterweight seal ☐
(d) None of the above ☐

Q7. API 575: atmospheric storage tank roofs
What is the purpose of using a breather-type roof?

(a) To help the floating roof move without 'vapour-locking' ☐
(b) To reduce vapour pressure and avoid the need for a pressurized tank ☐
(c) To provide expansion space for vapours ☐
(d) To enable vapours to be safely vented to atmosphere ☐

Q8. API 575: low pressure storage tanks
Which code covers the venting of low pressure tanks?

(a) API 650 ☐
(b) API 2000 ☐
(c) API 12B ☐
(d) API 12D ☐

Q9. API 575: storage tank design pressure
What is the maximum design gauge pressure of an API 650 tank?

(a) Atmospheric pressure ☐
(b) $2\frac{1}{2}$ psi ☐
(c) 103 kPa ☐
(d) 15 psi ☐

Q10. API 575: storage tank design pressure

What is the maximum design gauge pressure of an API 620 tank?

(a) Atmospheric pressure ☐
(b) $2\frac{1}{2}$ psi ☐
(c) 18 kPa ☐
(d) 15 psi ☐

CHAPTER 4

Reasons for Inspection: Damage Mechanisms

First of all, what exactly *is* the point of tank inspections? Granted, some leak or catch fire, and there are no doubt a small number of major failures, but the everyday world is not exactly full of catastrophic tank disasters.

On the face of it, API codes are quite clear on the subject – their objective is to achieve tank *integrity* (it says so in API 653 section 1). Integrity must surely mean *structural integrity*, i.e. the avoidance of catastrophic failure or major collapse leading to total loss of the tank contents.

All right. What about leaks? Clearly, leaks are undesirable and published codes have quite a bit to say about avoiding them. API 575 starts the ball rolling in its section 5: *Reasons for inspection and causes of deterioration*. It mentions the objective of avoiding holes in all areas of a tank, to avoid the risk of hazards from flammable leaks or environmental pollution. The situation elsewhere in the codes is not quite so straightforward – it is a long-standing principle of API codes that fairly deep isolated pits are unlikely to lead to structural failure. For tanks, this is balanced by API 653's approach to repairs; patch plates, flush insert repairs or hot taps are really no problem as far as API 653 is concerned, so leaks from isolated pitting can be repaired if or when they occur.

4.1 The approach to damage mechanisms (DMs)

API 653 and its associated codes have a well thought-out approach to DMs. It is better organized than equivalent pipework and vessel codes; a little less fragmented and hence easier to understand. In essence, most of the information on DMs has been relegated out of API 653 into API 571 *Damage Mechanisms*. Awkwardly, quite a lot of the introductory information remains in API 575. These relatively short sections are a frequent source of exam questions, many taken word-for-word from the rather dense narrative paragraphs. It is fair to say that the key points don't exactly jump out of the pages at you. Let's see what they are.

4.2 API 575 section 5: reasons for inspection

API 575 takes a logical approach to this:

- Section 5.2 identifies *corrosion* as the prime cause of deterioration of tanks. This is then subdivided into section 5.2.1 *external corrosion* and Section 5.2.2 *internal corrosion*.
- For external corrosion, the emphasis is heavily on corrosion of the tank bottom being the main problem. This fits with the overall approach of API 653. External shell corrosion is not covered in detail in API 575 section 5.2.1. API 653 deals with that in detail later.
- For internal corrosion, API 575 section 5.2.2 simply reinforces the idea that it is the tank product that generally causes the corrosion. It also mentions bottom sediment and water (BS&W) – a common examination question.
- Section 5.4 is about leaks, cracks and mechanical deterioration, i.e. just about anything that is not classed as corrosion. Note these API value judgement points that appear in this section:
  - The most critical place for crack-like flaws is at the shell-to-bottom weld, owing to the high stresses.
  - Settlement underneath the tank bottom caused by freezing and thawing can trap water and cause bottom corrosion.
- Section 5.5 is about auxiliary equipment such as tank vents, drains, structural steelwork and ladders. It mainly cross-references annex C in API 653 – a long checklist of tank inspection items. This is a very comprehensive checklist, but thankfully next to impossible to use as the subject of multichoice examination questions.

4.2.1 Similar service

Once you start to consider the reasons for inspecting (or conversely, not inspecting) a tank, the issue of *similar service* raises its head. There is no great difficulty about the principle – it simply means that instead of going to all the trouble of measuring the corrosion rate of a tank, you just assume it is the same as that already determined from another tank in similar service. This is a great idea, as long as you actually believe it.

This idea of similar service is growing in acceptance in the API codes – API 653: 2009 now contains a complete new Annex H about it, and there is also a simpler introduction in API 575 Annex B. We will look at this in detail later; just remember for the moment that it can be used as the justification for *not* inspecting a tank, rather than the justification for inspecting it.

4.2.2 Reasons for inspection

Both API 575 and 653 infer that the condition of a tank bottom is mainly what drives the need for inspection. They don't exclude the shell and roof but, on balance, it is the corrosion of bottoms that causes the problems. API RP 651: *Cathodic Protection* takes a similar view, concentrating mainly on the soil side with its differential aeration and resulting corrosion currents.

In API 575, discussion of the reasons for inspection soon give way to the actual techniques of inspection, and their frequency. Sections 7.2 and 7.3 cover external inspection and section 7.4 internal inspections. API 653 explains the reasons for inspection in various fragments of sections 4 and 6 but is fairly resolute at not going into specific technical details of damage mechanisms. This makes sense – API 571 deals exclusively with DMs (corrosion-based and other types) and is a much better way of presenting them than a piecemeal coverage in API 653. As it develops, API 653 maintains its reputation as a set of good practical engineering guidelines rather than a corrosion handbook.

4.2.3 The link with API 571 damage mechanisms

API exam question setters seem to like API 571. Divided into neat packages of damage mechanisms, each package contains a fairly logical structure of description, appearance, critical factors, affected equipment, inspection and mitigation for each DM in turn. This stuff is just made for exam questions; either closed-book questions on subjects requiring a bit of reasoning or open-book questions based on little more than the verbatim wording with the odd paraphrase thrown in for good measure.

In terms of extent, the API 653 BOK contains only a few of the full range of DMs contained in API 571. This reflects the fact that storage tanks are less likely to see such a wide variety of DMs as refinery vessels or pipework, which can come into contact with high temperatures, aggressive catalysts, sour (H_2S) fluids and similar.

Remember the background to API 653 – it exists to anticipate, monitor and ultimately repair the effects of the DMs that attack tanks, so API 571 will always remain a key part of the BOK, and a well-used source of exam questions.

4.3 API 571: introduction

API 571 was added some years ago to the BOK for the API examinations and replaces what used to be included in an old group of documents dating from the 1960s entitled *IRE* (*Inspection of Refinery Equipment*). The first point to note is that the API 571 sections covered in the API 653 ICP exam syllabus are only an extract of ten DMs from the full version of API 571.

4.3.1 The ten damage mechanisms

Your API 653 exam copy of API 571 contains (among other things) descriptions of ten damage mechanisms. Here they are in Fig. 4.1.

Remember that these are all DMs that are found in the petrochemical/refining industry (because that is what API 571 is about), so they may or may not be found in other

1. Brittle fracture
2. Mechanical fatigue
3. Atmospheric corrosion
4. Corrosion under insulation (CUI)
5. Microbiological-induced corrosion (MIC)
6. Soil corrosion
7. Caustic corrosion
8. Chloride stress corrosion cracking (SCC)
9. Caustic SCC (caustic embrittlement)
10. Sulphuric acid corrosion

Figure 4.1 The ten tank damage mechanisms from API 571

industries. Some, such as brittle fracture and fatigue, are commonly found in non-refinery plant whereas others, such as sulphuric acid corrosion and microbiological-induced corrosion (MIC), are more common in tanks containing petroleum products. In reality, storage tank farms are rarely just limited to refinery products so the boundaries are less well defined than for pressure vessels and pipework.

4.3.2 Are these DMs in some kind of precise logical order?

Yes, more or less. The list contains a mixture of corrosion and non-corrosion DMs, some of which affect plain carbon steels more than alloy or stainless steels and vice versa. There are also various subdivisions and a bit of repetition thrown in for good measure. None of this is worth worrying about, as the order in which they appear is not important.

In order to make the DMs easier to remember you can think of them as being separated into three groups. There is no code significance in this rearrangement at all; it is simply to make them easier to remember. Figure 4.2 shows the revised order.

One important feature of API 571 is that it describes each DM in some detail, with the text for each one subdivided into

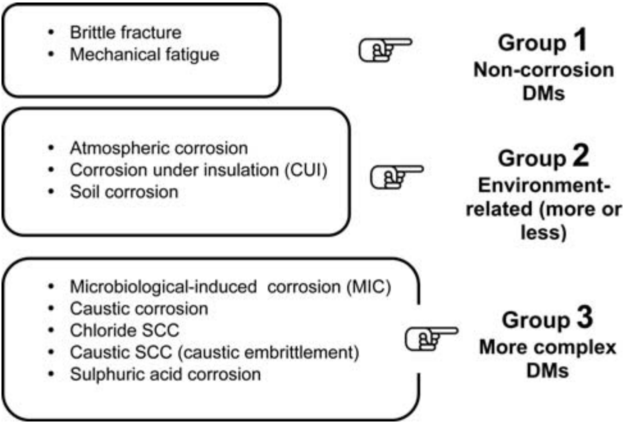


Figure 4.2 Tank damage mechanisms: the revised order

*six subsections***.** Figure 4.3 shows the subsections and the order in which they appear.

These six subsections are *important* as they form the subject matter from which the API examination questions are taken. As there are no calculations in API 571 and only a few tables of detailed information, you can expect most of the API examination questions to be *closed book*, i.e. a test of your understanding and short-term memory of the DMs. The questions could come from any of the six subsections as shown in Fig. 4.3.

4.4 The first group of DMs

Figures 4.4 and 4.5 relate to the first two DMs extracted from API 571: brittle fracture and mechanical fatigue. Note that these are not corrosion mechanisms but *damage mechanisms*, with a mechanical basis. When looking through these figures, try to cross-reference them to the content of the relevant sections of API 571.

REMEMBER THE WAY THAT API 571 COVERS EACH OF THE DAMAGE MECHANISMS

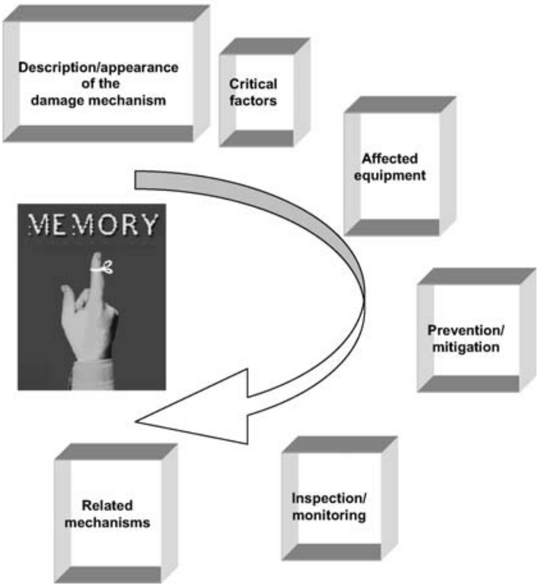


Figure 4.3 API 571 coverage of DMs

Caused by hydro-testing and/or operating below the Charpy impact transition temperature

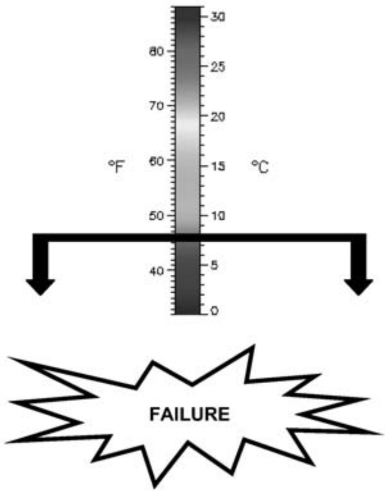


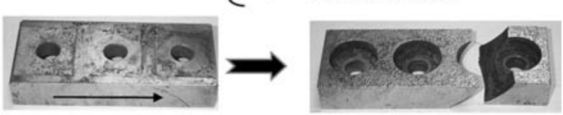
Figure 4.4 Brittle fracture

MECHANICAL FATIGUE

The result of cyclic stresses caused by mechanical loadings

Common around stress concentrations

- Changes of section
- Keyways
- Rough welds
- Thread notches



Fatigue crack in progress

Propagation to failure

Figure 4.5 Mechanical fatigue

Now try this first set of self-test questions covering the first two DMs.

4.5 API 571 practice questions (set 1)

Q1. API 571: brittle fracture

Which of these is a description of brittle fracture?

(a) Sudden rapid fracture of a material with plastic deformation ☐
(b) Sudden rapid fracture of a material without plastic deformation ☐
(c) Unexpected failure as a result of cyclic stress ☐
(d) Fracture caused by reaction with sulphur compounds ☐

Q2. API 571: brittle fracture: affected materials

Which of these storage tank construction materials are particularly susceptible to brittle fracture?

(a) Plain carbon and high alloy steels ☐
(b) Plain carbon, low alloy and 300 series stainless steels ☐
(c) Plain carbon, low alloy and 400 series stainless steels ☐
(d) High temperature resistant steels ☐

Q3. API 571: brittle fracture: critical factors

At what temperature is brittle fracture of a storage tank most likely to occur?

(a) Temperatures above 400 °C ☐
(b) Temperatures above the Charpy impact transition temperature ☐
(c) Temperatures below the Charpy impact transition temperature ☐
(d) In the range 20–110 °C ☐

Q4. API 571: brittle fracture

Which of these activities is *unlikely* to result in a high risk of brittle fracture of a storage tank?

(a) Repeated hydrotesting above the Charpy impact transition temperature ☐
(b) Initial hydrotesting at low ambient temperatures ☐
(c) Commissioning of thin-walled tanks ☐
(d) Autorefrigeration events in low pressure tanks ☐

Q5. API 571: brittle fracture: prevention/mitigation

What type of material change will *reduce* the risk of brittle fracture?

(a) Use a material with lower toughness ☐
(b) Use a material with lower impact strength ☐
(c) Use a material with a higher ductility ☐
(d) Use a thicker material section ☐

Q6. API 571: brittle fracture: appearance

Cracks resulting from brittle fracture will most likely be predominantly:

(a) Branched ☐
(b) Straight and non-branching ☐
(c) Intergranular ☐
(d) Accompanied by localized necking around the crack ☐

Q7. API 571: mechanical fatigue: description

What is mechanical fatigue?

(a) The result of excessive temperatures ☐
(b) The result of temperature-induced corrosion ☐
(c) The result of high stresses caused by high temperatures ☐
(d) The result of cyclic stresses caused by dynamic loadings ☐

Q8. API 571: mechanical fatigue: critical factors

As a practical rule, resistance to mechanical fatigue is mainly determined by what aspect of a piece of equipment?

(a) Its design ☐
(b) Its operation ☐
(c) The material microstructure ☐
(d) The material's heat treatment ☐

Q9. API 571: mechanical fatigue: appearance

What will a fracture face of a component that has failed by mechanical fatigue most likely exhibit?

(a) Fine branching cracks ☐
(b) Dagger-shaped lines ☐
(c) Beach marks ☐
(d) Chevron marks ☐

Q10. API 571: prevention/mitigation

Mechanical fatigue cracking is best avoided by:

(a) Specifying long weld leg lengths ☐
(b) Blending weld toes ☐
(c) Keeping temperature cycling to a minimum ☐
(d) Using a high strength material ☐

4.6 The second group of DMs

Figures 4.6 to 4.8 relate to the second group of DMs: atmospheric corrosion, CUI and soil corrosion. Note how these DMs tend to be related to the environment outside the

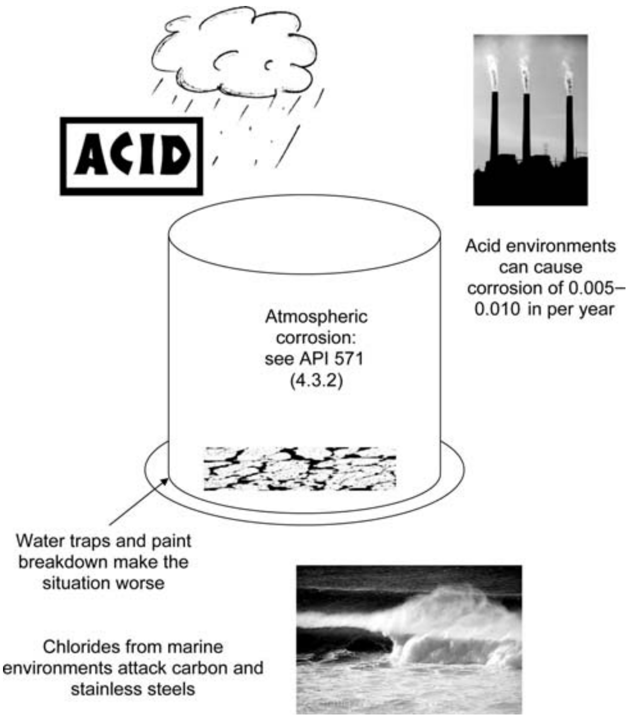


Figure 4.6 Atmospheric corrosion

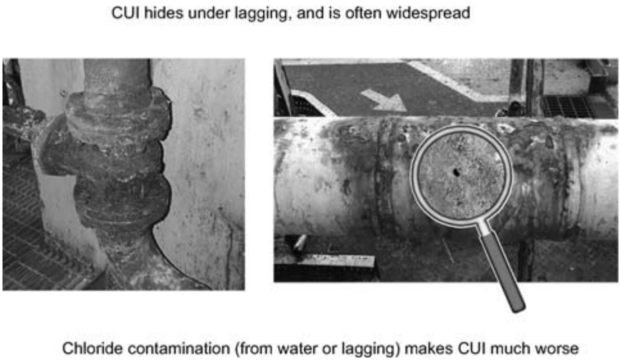


Figure 4.7 Corrosion under insulation (CUI)

Figure 4.8 Soil corrosion

storage tank. Remember to identify the six separate subsections in the text for each DM.

Try these practice questions.

4.7 API 571 practice questions (set 2)

Q1. API 571: atmospheric corrosion

Atmospheric corrosion is primarily caused by:

(a) Wind ☐
(b) Water ☐
(c) Acid rain ☐

(d) Daily or seasonal temperature cycles ☐

Q2. API 571: atmospheric corrosion

As a practical rule, atmospheric corrosion:

(a) Only occurs under insulation ☐
(b) May be localized or general (widespread) ☐
(c) Is generally localized ☐
(d) Is generally widespread ☐

Q3. API 571: atmospheric corrosion: critical factors

A typical atmospheric corrosion rate in mils (1 mil = 0.001 inch) per year (mpy) of steel in an inland location with moderate precipitation and humidity is:

(a) 1–3 mpy ☐
(b) 5–10 mpy ☐
(c) 10–20 mpy ☐
(d) 50–100 mpy ☐

Q4. API 571: CUI: critical factors

Which of these metal temperature ranges will result in the most severe CUI?

(a) 0–51 °C ☐
(b) 100–121 °C ☐
(c) 0 to −10 °C ☐
(d) 250+ °C ☐

Q5. API 571: CUI: appearance

Which other corrosion mechanism often accompanies CUI in 300 series stainless steels?

(a) HTHA (high-temperature hydrogen attack) ☐
(b) Erosion–corrosion ☐
(c) Dewpoint corrosion ☐
(d) SCC ☐

Q6. API 571: CUI: affected equipment

Which area of a lagged storage tank shell would you say could be particularly susceptible to CUI?

(a) Around nozzles ☐
(b) Around lagging support rings and wind girders ☐
(c) Near the product fill line ☐
(d) On the windward side ☐

Q7. API 571: CUI: appearance

Once lagging has been removed from an unpainted tank structure, CUI normally looks like:

(a) Deep gouges ☐
(b) Bulges ☐
(c) Loose flaky scale ☐
(d) White or grey deposit ☐

Q8. API 571: CUI: prevention/mitigation

Which of these actions may reduce the severity of CUI on a lagged storage tank?

(a) Adding additional layers of insulation ☐
(b) Using calcium silicate insulation ☐
(c) Using mineral wool insulation ☐
(d) Using closed cell foam glass insulation ☐

Q9. API 571: CUI: mitigation

CUI conditions can be identified on an in-use lagged storage tank using:

(a) Neutron backscatter ☐
(b) X-ray fluorescence ☐
(c) Laser techniques ☐
(d) Phased array ☐

Q10. API 571: CUI: critical factors

Which of these can make storage tank CUI worse?

(a) Elevated tank temperatures above 200 °C ☐
(b) Airborne contaminants ☐
(c) Sunshine ☐
(d) Low temperatures below 10 °C ☐

Q11. API 571: soil corrosion

What is the main parameter measured to assess the corrosivity of a soil underneath a storage tank?

(a) Acidity ☐
(b) Alkalinity ☐
(c) Density ☐
(d) Resistivity ☐

Q12. API 571: soil corrosion: appearance

What would you expect the result of soil corrosion to look like?

(a) Branched and dagger-shaped cracks ☐
(b) Isolated, large and deep individual pits ☐
(c) Straight cracks ☐
(d) External corrosion with wall thinning and pitting ☐

Q13. API 571: soil corrosion: protection

Which of these would be used to *reduce* the amount of soil corrosion of a storage tank?

(a) Caustic protection ☐
(b) Cathodic protection ☐
(c) Anodic protection ☐
(d) More post-weld heat treatment ☐

Q14. API 571: soil corrosion: critical factors

What effect does metal temperature have on the rate of soil corrosion?

(a) None ☐
(b) The corrosion rate increases with temperature ☐
(c) The corrosion rate decreases with temperature ☐
(d) There will be minimal soil corrosion below 0 °C ☐

Q15. API 571: soil corrosion: critical factors

Which of these areas would you expect to suffer the worst soil corrosion?

(a) Soil-to-air interfaces ☐
(b) Any areas in contact with soil of pH 7 ☐
(c) Areas where the soil has recently been disturbed ☐
(d) Areas in contact with soil that has plants or moss growing in it ☐

4.8 The third group of API 571 DMs

Now look through Figs 4.9 to 4.12 covering the final group of five DMs: MIC, caustic corrosion, chloride SCC, caustic SCC and sulphuric acid corrosion. These relate predominantly to corrosive conditions on the product side (i.e. inside) of a tank. Again, remember to identify the six separate subsections in the text for each DM, trying to anticipate the type of examination questions that could result from the content.

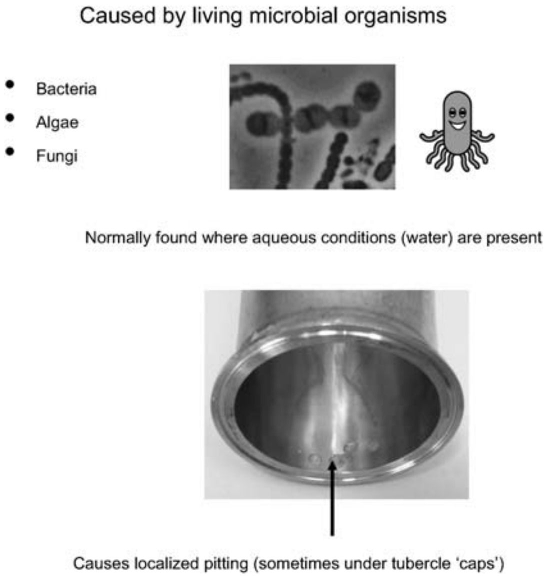


Figure 4.9 Microbial-induced corrosion (MIC)

4.8.1 Finally: specific DMs of API 652

For historical reasons the ten DMs extracted into the BOK from API 571 exclude one of the most important ones, corrosion caused by sulphate reducing bacteria (SRB). Discussion of this is hidden away in API RP 652: *Lining of Above Ground Storage Tank Bottoms*. All of this code is included in the BOK so SRBs need to be added to the DMs considered from API 571. API 652 section 4.5 provides a detailed, if slightly contradictory, explanation of the effect of SRBs. They are basically a facilitation mechanism for concentration cell pitting rather than a separate DM by themselves.

Figure 4.13 summarizes the situation. Read this figure as a clue to the content of API exam questions rather than a detailed technical treatise on the subject. Look carefully at

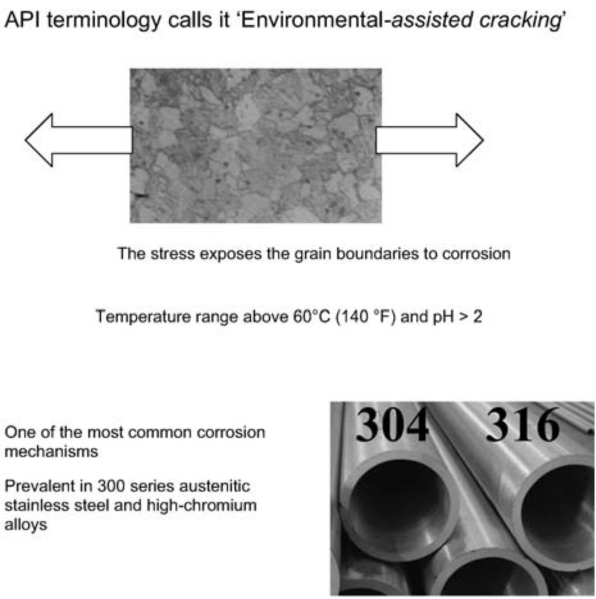


Figure 4.10 Chloride stress corrosion cracking (SCC)

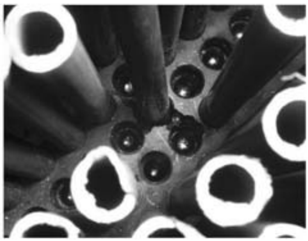
the form of words used – and do not be surprised if they pop up as exam questions.

Now attempt the final set of self-test questions covering these DMs (start on p. 53).

A specialist type of stress corrosion cracking caused by alkaline conditions. The worst offenders are:

- Caustic potash (KOH)
- Sodium hydroxide (NaOH)

Caustic attack in a heat exchanger tubesheet



Typically found in H_2S removal units and acid neutralization units

Figure 4.11 Caustic stress corrosion cracking (SCC)

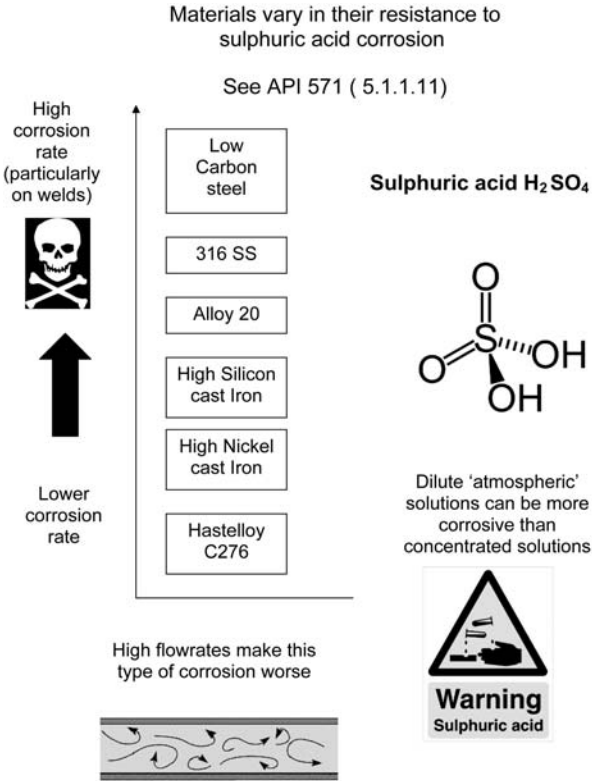
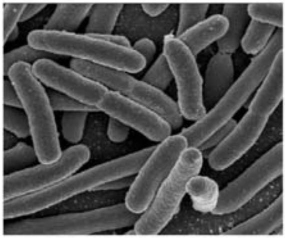


Figure 4.12 Sulphuric acid corrosion (SCC)

Sulphate reducing bacteria (SRB)

These are described in API 652 section 4.5



Some good 'exam question points' about SRB

SRB mainly attack **tank bottoms**

The bacteria form **colonies**, causing local anaerobic conditions

SRB convert sulphates to **sulphides**, which are corrosive to steel

They cause pitting by a **concentration cell** mechanism

Figure 4.13 Sulphate reducing bacteria (SRB): some key points

4.9 API 571 practice questions (set 3)

Q1. API 571: MIC: description

MIC is caused by the corrosive effects of:

(a) Living organisms ☐
(b) The degradation of organisms after they have died ☐
(c) Organisms reacting with sulphur ☐
(d) Organisms reacting with chlorides ☐

Q2. API 571: MIC: appearance

What does MIC typically look like?

(a) Uniform wall thinning with a 'sparkling' corroded surface ☐
(b) Localized pitting under deposits ☐
(c) Smooth longitudinal grooving ☐
(d) A dry flaky appearance ☐

Q3. API 571: MIC: critical factors

Under what pH values does MIC occur?

(a) Almost any pH 0–12 ☐
(b) Mainly pH 1–6 (acidic) ☐
(c) Mainly pH 8–12 (alkaline) ☐
(d) Mainly pH 5–7 ☐

Q4. API 571: MIC: critical factors

What is the maximum temperature under which you would expect MIC to occur?

(a) 60 °C ☐
(b) 113 °C ☐
(c) 175 °C ☐
(d) 250 °C ☐

Q5. API 571: MIC: prevention

MIC is best controlled by:

(a) Reducing flow velocities ☐
(b) Recirculating the system with water ☐
(c) Chemical dosing ☐
(d) Lagging the system to keep the temperature up ☐

Q6. API 571: description of chloride SCC

Chloride SCC is also called (in API terminology):

(a) Embrittlement cracking ☐

(b) Environmental cracking ☐
(c) Brittle fracture ☐
(d) Chevron cracking ☐

Q7. API 571: SCC: affected materials
Chloride SCC is known to particularly attack what type of tank construction material?

(a) Low carbon steels ☐
(b) Low alloy steels ☐
(c) Austenitic stainless steels (300 series) ☐
(d) Older, low grade steel (common in riveted tanks) ☐

Q8. API 571: SCC: critical factors
What is the lower limit of chloride content at which chloride SCC stops occurring?

(a) There is no lower limit ☐
(b) 100 ppm ☐
(c) 10 ppm ☐
(d) 1 ppm ☐

Q9. API 571: SCC: critical factors
What is the temperature above which chloride SCC becomes more likely under chloride process conditions?

(a) Above 0 °F ☐
(b) Above 60 °F ☐
(c) Above 110 °F ☐
(d) Above 140 °F ☐

Q10. API 571: chloride SCC: appearance
What kind of corrosion deposit is normally seen on the surface of a material suffering from chloride SCC?

(a) White powdery deposit ☐
(b) Small blisters or pits (may be hiding under paint) ☐
(c) Iron oxide (rust) ☐
(d) None ☐

Q11. API 571: chloride SCC: inspection
Which of these techniques is best able to find chloride SCC?

(a) RT (radiographic testing) ☐
(b) UT (ultrasonic testing) ☐
(c) PT (penetrant testing) ☐
(d) MT (magnetic testing) ☐

Q12. API 571: chloride SCC: morphology

What shape are chloride SCC cracks?

(a) Dagger-shaped ☐
(b) Fine and branching ☐
(c) Stepwise (like a series of steps) ☐
(d) Zigzag, starting from stress concentrations or sharp edges ☐

Q13. API 571: caustic SCC

Caustic SCC in storage tanks is also called:

(a) Acidic SCC ☐
(b) Caustic embrittlement ☐
(c) Caustic grooving ☐
(d) Caustic oxidation ☐

Q14. API 571: caustic SCC location

Caustic SCC is particularly common around which locations in storage tanks?

(a) Non-post-weld heat-treated welds ☐
(b) Post-weld heat-treated welds in thick section materials ☐
(c) Annular ring-to-bottom lap welds ☐
(d) Nozzle and manway welds ☐

Q15. API 571: caustic SCC: critical factors

Caustic SCC can be caused at caustic concentrations of:

(a) Any concentration; there is no safe lower limit ☐
(b) 0.1–1 ppm caustic ☐
(c) 1–10 ppm caustic ☐
(d) 50–100 ppm caustic ☐

Q16. API 571: caustic SCC: appearance

Caustic SCC cracks have a greater tendency to propagate:

(a) Parallel to a weld ☐
(b) Across a weld (transverse) ☐
(c) Along the liquid–air interface in a storage tank ☐
(d) In a direction roughly at 45 degrees from the weld line ☐

Q17. API 571: sulphuric acid corrosion: affected materials

Which of these tank fittings construction materials would be most resistant to sulphuric acid corrosion?

(a) High silicon cast iron ☐
(b) 316 stainless steel ☐
(c) Low carbon steel ☐
(d) Carbon–manganese steel ☐

Q18. API 571: sulphuric acid corrosion: critical factors

Which of these sulphuric acid conditions will result in the worst corrosion of a tank construction material?

(a) Low acid concentrations ☐
(b) High acid concentrations ☐
(c) High acid concentrations plus low flow velocity ☐
(d) High acid concentrations plus high flow velocity ☐

Q19. API 571: sulphuric acid corrosion: prevention

Which of these actions will reduce the effect of corrosion in a system susceptible to sulphuric acid corrosion?

(a) Washing with demineralized water ☐
(b) Washing with a caustic solution ☐
(c) Draining the system and drying it with warm air ☐
(d) Abrading the surface to remove the oxide film ☐

Q20. API 571: sulphuric acid corrosion: affected equipment

If a storage tank with trace heating contains a sulphuric acid rich product, where would you expect the worst corrosion to occur?

(a) The roof ☐
(b) The floor ☐
(c) Underneath the floor ☐
(d) Halfway up the shell ☐

CHAPTER 5

Inspection Practices and Frequency

This chapter is about code recommendations on how to inspect a tank and how often you should do it. They are of course separate subjects and the two codes that address them, API 653 and API 575, approach them from slightly different viewpoints. API 653 divides inspections into different types and addresses inspection interval (or frequency) in its section 6. It also introduces the way in which a tank inspection interval can be based around a risk-based inspection (RBI) assessment. It seems to like this idea. The baton then passes across to API 575 section 7, which confirms the method of corrosion rate calculation and then launches into a detailed methodology of how to inspect the various parts of a tank inside and outside, when it is in or out of service. This API RP 575 section is a major source of exam questions (open and closed book) and, looking objectively, gives excellent experienced-based guidance on how to inspect tanks.

We will look at these relevant sections of API 653 and API RP 575 in turn.

5.1 API 653 section 6: inspection

First the good news about section 6. A lot of information about what to inspect during a tank inspection has been separated out into API 653 Annex C – a hugely detailed inspection checklist of nearly 20 pages. Its content is excellent but the good news is that it is next to impossible to transform such checklist data into multiple choice exam questions. This goes for all checklists – you just cannot get many API-style exam questions out of them, no matter how hard you try.

The remaining content of API 653 section 6 is logically structured, if a little unbalanced. Figure 5.1 shows its breakdown. Note the way in which it divides inspection into four discrete types, routine external, full external, ultrasonic testing (UT) thickness and interval. As you can

6.2 Inspection frequency consideration

6.3 External tank inspection
- Routine
- Full External

6.4 Internal tank inspection
- Objectives
- First inspection interval
- Following inspection intervals
- RBI:POF/COF factors

Note the difference (new to API 653:2009)

6.5 Alternatives to internal inspection of the bottom

6.6 Preparatory work for internal inspection

6.7 Inspection checklist

6.8 Records

6.9 Reports

6.10 NDE

Remember that API 653 section 6 only covers **WHAT TO DO.** To see **HOW TO EVALUATE** the inspection results, you have to go to API 653 section 4: *suitability for service*

Figure 5.1 The contents of API 653 section 6: inspection

see from Fig. 5.1, the main technical content of section 6 is about putting limits on the intervals for internal inspections. This has changed significantly since the previous edition of API 653. The main points are now:

- There are different maximum intervals for the first internal inspection after putting into service, and subsequent ones.
- Both sets are, loosely, RBI-based.
- First inspection intervals range from 12 to 25 years (6.4.2.1). This is shorter than those for subsequent intervals which extend from 20 to 30 years (6.4.2.2).

Figure 5.2 shows the idea. Note the story behind the allowable spread of these intervals. In both categories the existence of a release prevention barrier (RPB), i.e. a bund or some similar method to contain spills, allows a significantly longer interval to be used. There is nothing particularly earth-shattering about this – it simply reflects the fact that an

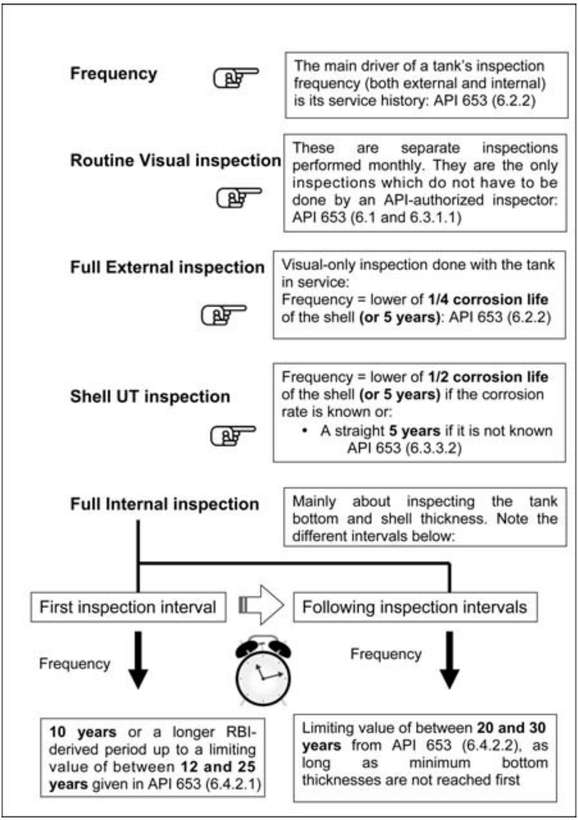


Figure 5.2 The API 653 tank inspection types

RPB reduces the consequences of failure (COF) if the tank leaks.

Note two other key points:

- Viscous substances such as tar are classed as low risk products and are exempted from both the 'maximum' interval tables (it says so in 6.4.2.6).
- Section 6.4.2.5(c) explains how to adapt these maximum interval tables (newly introduced into API 653: 2009 edition remember) to tanks where different RBI-based intervals have been set before 2009. Figure 5.3 shows how this works. Read this in conjunction with section 6.4.2.5(c) and you should not find it too difficult.

5.2 API 653 section 6: view of RBI

API 653 section 6 does not go into huge detail on RBI. It accepts and supports the activity, as long as it follows the good-sense guidelines mentioned in 6.4.2.4. These are:

- The RBI has been carried out to the guidance of API RP 580 with systematic attention given to both probability and consequences of failure (POF and COF).
- It was performed by a knowledgeable group.
- The assessment (and conclusions presumably) were approved by an API-authorized inspector and a storage tank engineer.
- It has been reassessed after all failures or service changes, and at least every 10 years to make sure it is still relevant.

These points are fundamental to API code views on RBI, so watch out for them in exam questions – open or closed book.

5.2.1 Any there other possible exam questions on RBI?

Yes. The two new individual checklists on probability (called likelihood) factor (6.4.2.4.1) and consequence (6.4.2.4.2) are good, but difficult to turn into multichoice exam questions. More likely are questions that check your appreciation of which factors should be in which list, to test if you really

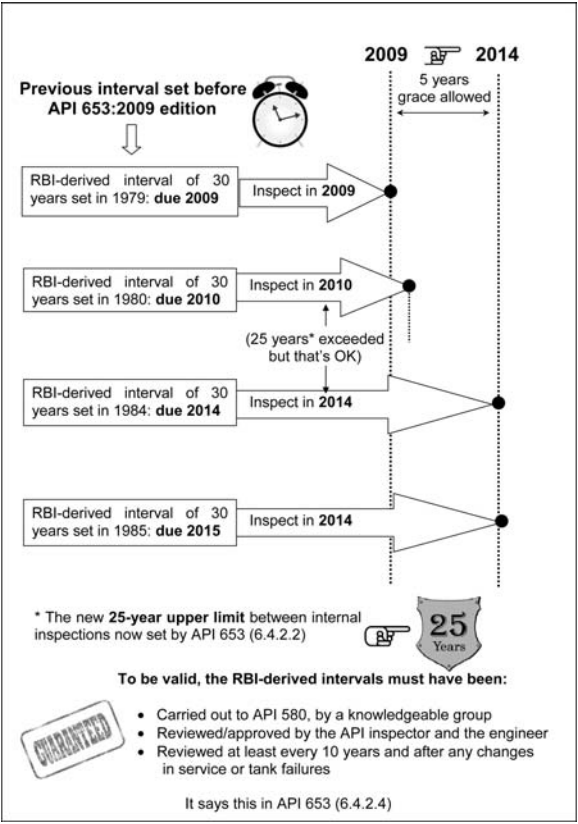


Figure 5.3 Dealing with historical inspection intervals

understand the fundamental difference between POF and COF. These are generally straightforward; just watch out for the occasional convoluted wording or questions phrased as a negative: e.g. which of the following factors does *not* have an effect on POF? Watch out for these awkward 'not questions' in all API ICP exams (you will not be disappointed).

5.2.2 Reports and recommendations (section 6.9)

Owners/users have an ongoing battle getting tank inspectors to write sufficiently detailed inspection reports. Many are short on detail, carefully indecisive in their conclusions and diplomatically vacant about what should be done next. API 653 section 6.9.2 (another newly added section) is an attempt to improve this. Look at what it requires:

- Inspection reports must recommend repairs and/or future monitoring, and give reasons why (6.9.3.1).
- They must give the maximum next inspection interval and show where it comes from (by corrosion rate calculation or reference to API 653 clauses).

However, note that the precise repair scope and timing is the responsibility of the owner/user. Figure 5.4 shows this in a visual way.

5.3 API 575 section 6: inspection frequency and scheduling

Do not expect anything new on inspection frequency in API RP 575; it just cross-refers to API 653, as you would expect. It does, however, add the requirement for the monthly routine inspection. Note also the suggestion made in API 575 (6.1) that external inspection be carried out after unusual events such as:

- Obvious settlement
- High winds, rain or lightning
- Seismic movements

Of these, seismic events are perhaps the most important, particularly on floating roof tanks. Any ground movement at all can cause the tank shell to distort, particularly near the top, causing a floating roof to stick.

5.3.1 Corrosion rate

All API in-service inspection codes place great importance on determining a corrosion rate. This is covered in section 6.2 of

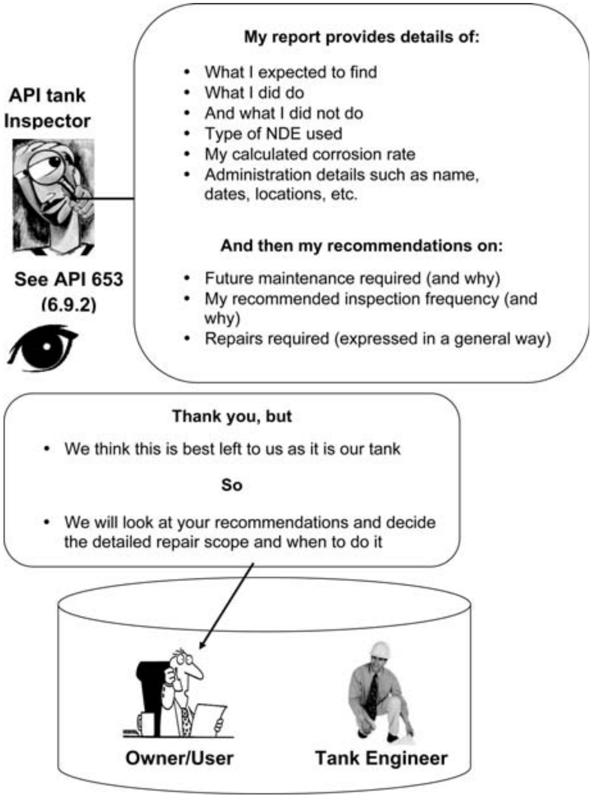


Figure 5.4 Inspection reports and recommendations

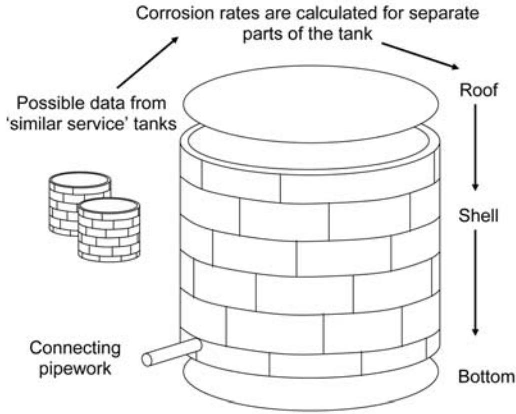
API RP 575. It is not repeated in API 653, but it is needed to be able to work to API 653, as it governs the life of a tank. Determining an accurate corrosion rate is not easy – tank components normally corrode at different rates and there can be big differences *within* a component. In tank floors, areas around heating coils, drain sumps and the shell-to-floor weld can have dramatically different (normally higher) corrosion rates than areas only 100–200 mm away. Shells, similarly, are likely to corrode more quickly around the product/air interface, or at the top if vapours are corrosive, or at the bottom if the product is such to encourage a corrosive water layer here.

With externally lagged tanks the situation is worse because CUI almost never happens uniformly. You can expect to find more seriously corroded areas around water traps such as wind-girders or, more randomly, wherever the cladding allows rain water in, ensuring that the lagging material remains wet.

Practicalities apart, API RP 575 (6.2) takes a fairly simplistic view of the corrosion rate, assuming it is real, predictable and conveniently uniform and linear, for any particular product service. Figure 5.5 shows the situation – the calculations are fairly simple. Remember that for exam questions these can be done in either USCS or SI units, but you would be well advised to use USCS (inches) units if you want to avoid conversion and rounding errors.

5.3.2 Changing corrosion rate

API exam questions like to check whether you appreciate that corrosion rates do not necessarily remain constant through time. This is particularly important for multiproduct storage tank farms, which may contain many different types of product during their life. The idea of a changing corrosion rate is shown in API RP 575 Fig. 32 with the long-winded title, *Hypothetical Corrosion Rate Curve for the Top Course of a Storage Tank*. There is nothing difficult about this figure; it just has its axes oriented in a rather bizarre way. To understand it, simply turn the page 90 degrees anticlockwise and it will all make sense – with the years on the horizontal axis and shell thickness on the vertical axis. Remember that the idea is all a little hypothetical, but you can expect real exam questions about it. Figure 5.6 shows a better interpretation of this idea.



$$\text{Corrosion rate}^* = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{No. of years } (N) \text{ between the readings}}$$

Units can be expressed as: in/yr, 'mils' (0.001 in/yr or mm/yr

*Corrosion rate may be a short-term or long-term rate, depending on the time (N) between the readings. There is no formal definition of how many years means 'long term'

Two objectives of calculating a corrosion rate:

☞ It determines the (theoretical) remaining life of the tank, i.e. the time taken to reach the minimum allowable thickness: t_{min}

☞ It allows an inspection interval (frequency) to be set to see how things are going

Figure 5.5 Corrosion rate: a simple concept

5.4 API RP 575: inspection practices

Whereas API 653 is a little thin on actual tank inspection practice, API RP 575 is full of information. Packed into dense narrative passages (not the easiest to read) are hundreds of valid points and instructions on how to inspect a tank. There is some very good information here, built up by an army of unknown inspection warriors over many years.

Firstly, look at the structure. Figure 5.7 shows how the

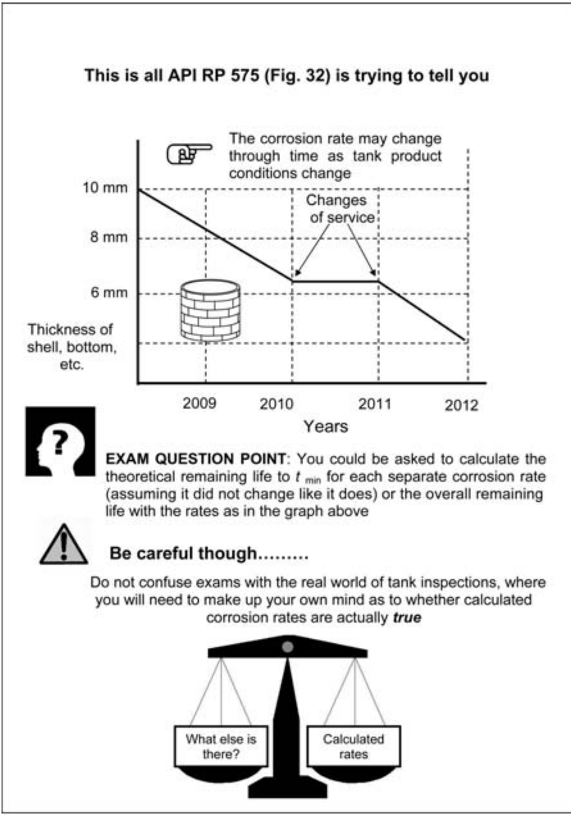
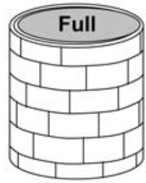


Figure 5.6 Changing corrosion rate

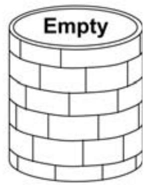
chapter breaks down into the three main inspection types: (7.2) external (tank in-service), (7.3) external (tank out-of-service) and (7.4) internal (empty and out-of-service). To save repetition a lot of the information relevant to all three types is included in the first section 7.1. You can expect about 10 % of the API exam questions to come from this section (some

7.1 Preparation

7.2 External inspection of in-service tank
- 7.2.1 Ladders and stairways
- 7.2.2 Platforms and walkways
- 7.2.3 Foundations
- 7.2.4 Anchor bolts



7.3 External inspection of out-of-service tank
- 7.3.1 Bottom
- 7.3.2 External pipes
- 7.3.3 Roof
- 7.3.4 Valves
- 7.3.5 Auxiliary equipment



7.4 Internal inspection
- 7.4.4 Bottom
- 7.4.5 Shell
- 7.4.6 Leak testing
- 7.4.7 Linings
- 7.4.8 Roof and structural members
- 7.4.9 Internal equipment

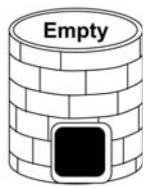


Figure 5.7 Methods of inspection: what is in API RP 575 (section 7)

picked out of the text word-for-word) so we will look at each of these sections in turn.

5.4.1 Preparation for inspection (7.1)

There are two aspects to this: safety aspects and tools for inspection. The safety aspects of storage tank entry are of course based on statutory codes and rules applicable to the USA. Requirements will be different in other countries although the principles will be much the same, being based

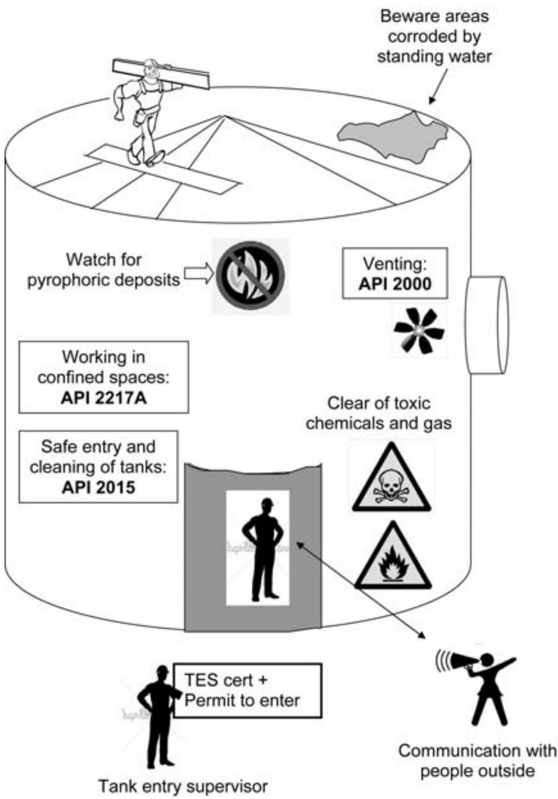


Figure 5.8 Tank inspection: safety precautions: API RP 575 (7.1)

on experience and common sense. Figure 5.8 summarizes the major points that pop up as exam questions.

Inspection *tools* is a strange subject for exam questions, but there are a few common exam questions built around them. Their mention is also scattered about other subsections of section 7.1. Figure 5.9 picks out the main points. Note that there is a separate API individual certificate programme

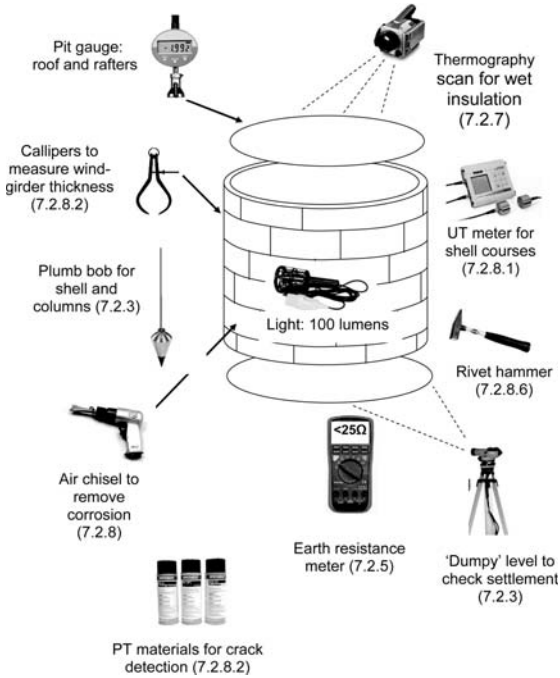


Figure 5.9a Tank inspection tools

(ICP) for tank entry supervisors (TES). This is entirely based on US legislation and so has limited applicability in other countries.

5.4.2 External inspection of an in-service tank (7.2)

Section 7.2 provides a fairly well-structured list of items to check during an external inspection of a tank that is still in use.

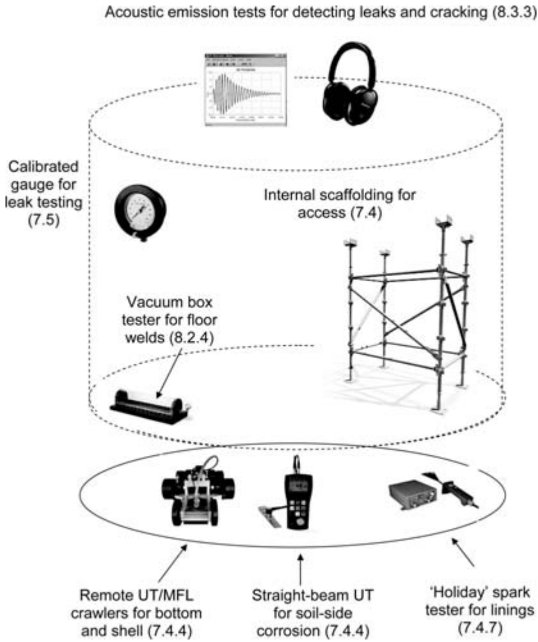


Figure 5.9b Tank inspection tools (continued)

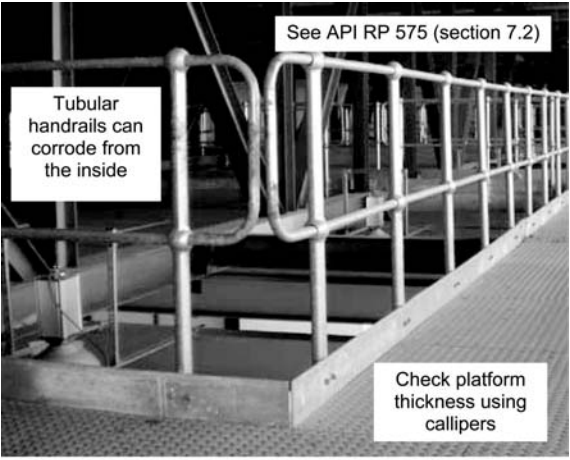
5.4.3 Ladders, platforms, walkway inspection (7.2.1–7.2.2)

Figure 5.10 shows points to check on ladders, platforms and walkways. On tanks situated in dirty or corrosive environments (steelworks for example) these components present a bigger personal safety risk than the tank itself, so they are important inspection items. Do not expect a lot of exam questions on them though – the answers would be too obvious to make a good exam question.

5.4.4 Foundation inspection (7.2.3)

Note the two important points here:

- Foundation settlement causes floor settlement – a subject



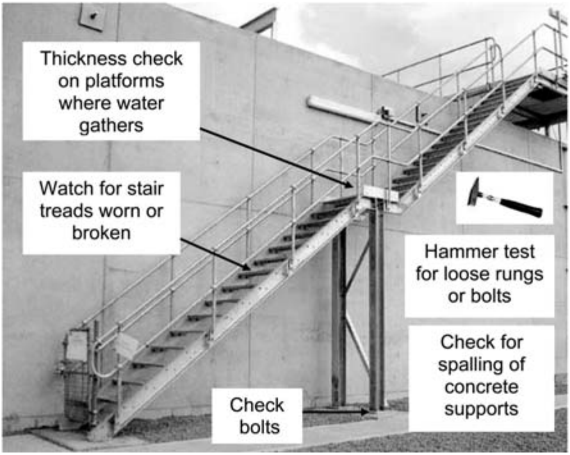


Figure 5.10 External inspections: ladders, platforms and walkways

covered not in API RP 575 but in API 653 Annex B. We will look at this in detail later.
- Check the mastic seal between the bottom of a tank and its foundation. If the joint is unsealed, water will get in and corrode the bottom.

5.4.5 Anchor bolts and earth connections (7.2.4–7.2.5)

There are a few straightforward points here that occasionally appear as rather uninspiring exam questions:

- A simple hammer test on anchor bolts can show if they are loose or heavily corroded (if they break).
- Tank earthing ('grounding') connections should be visually checked for corrosion where they enter the soil. Watch for the exam question that asks what the maximum earth resistance should be (the answer is 25 ohms).

5.4.6 Tank shell inspection (7.2.8)

The main content of API RP 575 section 7.2 is in here. A lot of effort goes into inspecting tanks shells as they are easily accessible, even though it is still often the tank bottom that governs the tank life. Both this and later sections 7.3 and 7.4 contain information about tank inspection, much of which is related to finding shell plate thickness using some types of UT measurement. Figure 5.11 shows the key points.

5.4.7 Shell UT thickness checks

The key point about shell UT thickness readings is that there must be sufficient accurate readings available to feed the evaluation calculation that we will look at later, in API 653 section 6. Five points per corroded (vertical) plane are required as an absolute minimum for any averaging calculation. For light or fairly regular corrosion this can often be achieved by individual UT (pulse-echo) thickness gauge readings. If the corrosion is more widespread, or serious, then full scanning is normally required, of individual shell plates or the entire shell. It all depends on the severity.

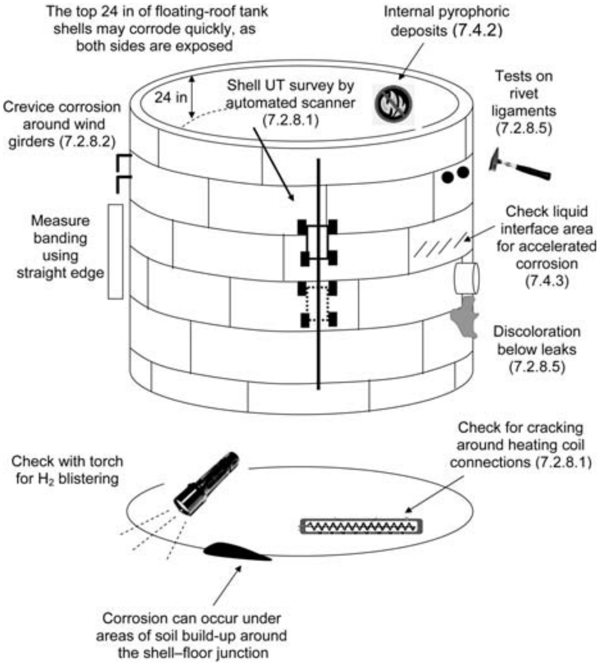


Figure 5.11 Tank shell inspection: general points from API RP 575 (7.2, 7.3, 7.6)

API RP 575 seems to favour full scanning (also called 'corrosion mapping'). Scanning techniques themselves are not part of the API 653 BOK; you just need to know that it exists and what it does.

The recommended periodicity of shell UT thickness checks is an interesting one. API 653 sees UT thickness checking as being a totally separate activity from a tank external inspection, even though, in reality, it will often be carried out at the same time. It sets a maximum periodicity of:

- Periodicity of shell UT thickness checking = half the remaining corrosion life (to a maximum of 15 years).

This is a popular examination question. Expect it to come up almost every time.

5.4.8 Tank bottom inspection (7.4)

Unless you have access to robotic equipment, most tank floor inspections are carried out during the internal inspection programme after the tank has been emptied and cleaned. The bottom is normally inspected last, for safety reasons, after the condition of the roof and shell have been confirmed. Tank bottom problems divide squarely into two: soil-side and product-side. In older tanks laid on a soil or rubble base, soil-side problems are often the worst. Soil-side galvanic and/or crevice corrosion is notoriously unpredictable and localized, and often remains hidden until it is serious enough to cause leakage or serious structural problems.

The extent of floor inspection tends to be decided by the level of test equipment available. Simple pulse-echo UT meters can check for soil-side thinning in selected areas but is a hit-and-miss affair at best. Floor scanning equipment using ultrasonic or magnetic floor leakage (MFL) gives much more reliable coverage, and more detailed UT can be done on areas of concern that have been found.

From an API examination question perspective, there are a few technical points that are worth remembering:

- Statistical analysis of scanning results can be done on data samples of 0.2–10 % of the bottom area. Its anyone's guess where the 0.2 % figure came from.
- Statistical analysis is less reliable once significant corrosion (usually soil-side) has actually been detected. If this happens 100 % scanning is the best.
- Bottom corrosion is made worse by bottom settlement. API 653 Annex B covers settlement in detail. We will look at this later in chapter 6 of this book.

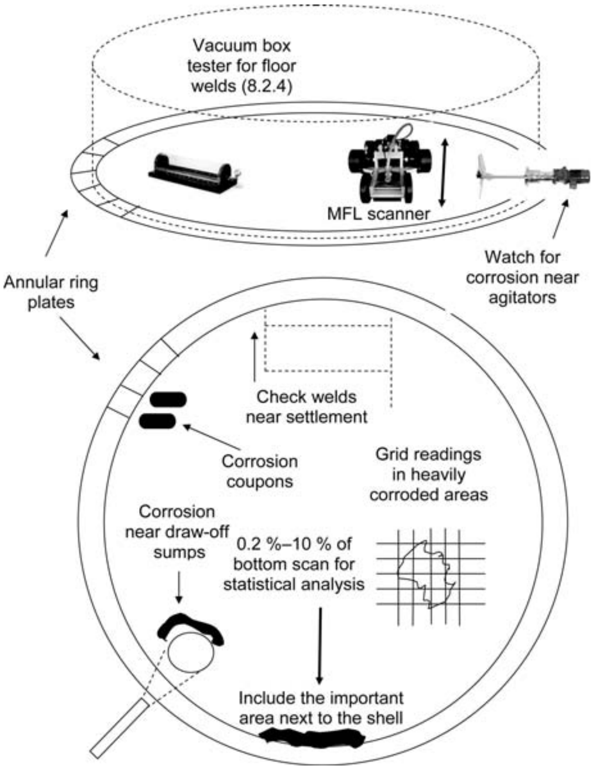


Figure 5.12 Tank floor inspections: API RP 575 (7.4.4)

Figure 5.12 shows some other key points for floor inspection. They are all good exam question material.

5.4.9 Tank roof inspection (7.4.8)

The inspection of a tank roof can be split into those activities applicable to fixed and floating roof tanks. Before inspecting either, note the general safety points outlined in Fig. 5.13.

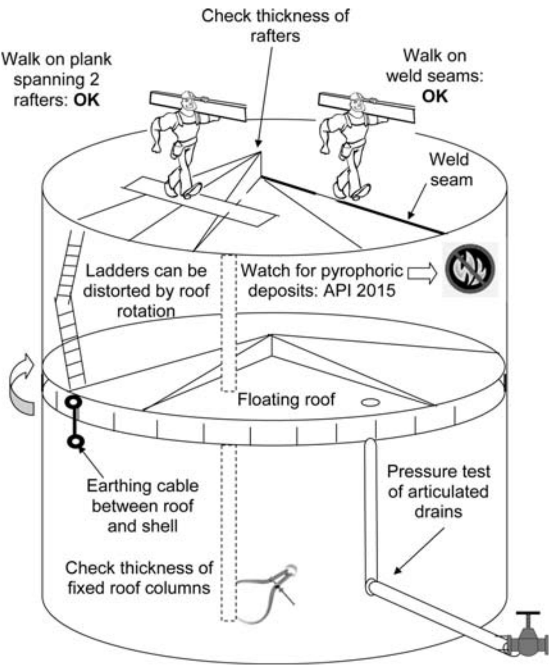


Figure 5.13 Tank roof inspection: API RP 575 (7.2.5)

5.4.10 Fixed roof inspection

Figure 5.13 shows some areas of inspection on a fixed roof tank. Most are to do with thickness checking, normally just by a simple pulse-echo UT meter, pit gauge or calipers. The following points regularly appear as exam questions:

- Structural members, rafters and columns can corrode from both sides, resulting in a high (double) corrosion rate.
- Corrosion is normally more serious in dents or depressions where rainwater has been standing.
- Evaluation of roof corrosion is not covered in API RP

575. It is covered by API 653 section 6 so we will look at it later in chapter 6 of this book.

5.4.11 Floating roof inspection

Floating roofs have more problems than fixed roofs. They have a more involved structure (so corrode more) and are complicated by seals and articulated drain arrangements. These suffer from mechanical problems (sticking, distortion or broken parts) as well as corrosion. Figure 5.13 shows some points; see also the detailed checklists in API 653 Annex C.

5.4.12 Inspection of auxiliary equipment (7.10)

Auxiliary equipment fitted to tanks (connected pipework, valves, drains, flame arrestors, level gauges and similar) are responsible for their fair share of problems and inspection findings. They do not fit particularly well into the API exam questions about inspection practices however. Surprisingly, they appear more often as questions linked to the design aspects of API 650: the tank construction code. The questions are not particularly difficult and relate mainly to a few specific drawings of design features.

Now try these practice questions.

5.5 API 653: inspection intervals: practice questions

Q1. API 653: tank inspection intervals

Fundamentally, under the API methodology, how are the inspection intervals (both internal and external) for storage tanks decided?

(a) They are based on the tables in API 653 ☐
(b) They are based on local legislation ('jurisdiction') ☐
(c) They are based on the results of previous service history ☐
(d) They are based on the results of a mandatory RBI analysis ☐

Q2. API 653: tank external inspection intervals

What is the maximum period that API 653 specifies for an *external* inspection by an API-authorized tank inspector?

(a) There is not one (it can vary depending on history, RBI results, etc.) ☐
(b) 5 years or $\frac{1}{2}$ of the remaining corrosion life ☐
(c) 5 years or $\frac{1}{4}$ of the remaining corrosion life ☐
(d) 10 years or $\frac{1}{2}$ of the remaining corrosion life ☐

Q3. API 653: shell UT inspection intervals

What is the maximum period that API 653 specifies for UT thickness checking of the shell if the corrosion rate is not known?

(a) There is not one (it can vary depending on history, RBI results, etc.) ☐
(b) 1 year ☐
(c) 2 years ☐
(d) 5 years ☐

Q4. API 653: shell UT inspection intervals

What is the maximum period that API 653 specifies for UT thickness checking of the shell when the corrosion rate is known and has been validated within the past 5 years?

(a) 5 years ☐
(b) 15 years or $\frac{1}{2}$ of the remaining corrosion life ☐
(c) 5 years or $\frac{1}{4}$ of the remaining corrosion life ☐
(d) 10 years or $\frac{1}{4}$ of the remaining corrosion life ☐

Q5. API 653: tank internal inspection intervals

Which part of the tank normally 'controls' the internal inspection interval?

(a) The bottom ☐
(b) The lower courses of the shell ☐
(c) The fluid interface areas of the shell ☐
(d) The condition of the tank nozzle-to-shell welds ☐

Q6. API 653: initial internal inspection intervals

What is the maximum period that API 653 specifies for the first internal inspection interval if a formal documented RBI evaluation has not been carried out?

(a) 10 years ☐
(b) 20 years ☐

(c) $\frac{1}{2}$ corrosion life if the corrosion rate is known, 20 years if it is not ☐
(d) $\frac{1}{2}$ corrosion life if the corrosion rate is known, 10 years if it is not ☐

Q7. API 653: following inspection intervals

What is the absolute maximum internal inspection interval for a tank containing oil (following the initial one) under any scenario?

(a) 20 years ☐
(b) 25 years ☐
(c) 30 years ☐
(d) There is not one ☐

Q8. API 653: interval exemptions

Tanks containing which of these products are exempt from API 653 maximum internal inspection intervals?

(a) Light distillate ☐
(b) Asphalt ☐
(c) Crude oil ☐
(d) Toxic substances ☐

Q9. API 653: repair recommendations

Whose job is it to provide repair recommendations for tanks?

(a) The examiner ☐
(b) The inspector ☐
(c) The owner/operator ☐
(d) All of the above ☐

Q10. API 653: NDE qualifications

Examiners doing NDE of tanks must be qualified according to the requirements of:

(a) API 650 ☐
(b) API 653 Appendix D ☐
(c) ASME V ☐
(d) ASME IX ☐

CHAPTER 6

Evaluation of Corroded Tanks

6.1 Introduction

Most of the calculations in API 653 reside in section 4: *Suitability for Service*. This is about what to do with tanks that are corroded or damaged in some way. It provides practical methods of determining whether a corroded tank complies with the well-established requirements of API 653, giving a viewpoint on whether it is safe for continued use.

For both practical and API 653 exam purposes it is important to understand the relationship between three codes involved in calculations of tank integrity: API 653, API 650 and API 579. Figure 6.1 shows the situation. API 650 is a pure construction code so its calculations and the parameters

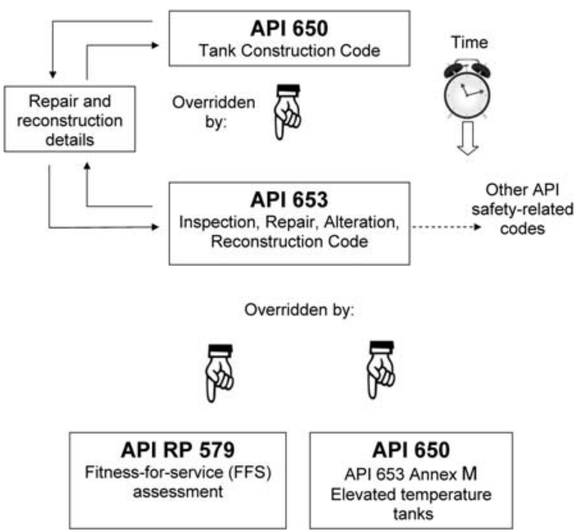


Figure 6.1 Relationships between tank assessment codes

they use are for *new tanks*. You can think of the objective of API 650 as being to produce a tank that will successfully pass its initial hydrostatic test, before being put into service. At this point, its job is done and API 653 takes over.

In dealing with in-service tanks that have undergone some degradation, API 653 *overrides* some of the integrity-related requirements of API 650. You can think of API 653 in three ways:

- As an 'out-of-design code' assessment.
- As a more realistic assessment, based on the realities of tank operation in use.
- As a less conservative assessment, using up some of the margins hidden away in the design code that are not required, once it has passed its initial hydrostatic test.

All of these are correct, in their own way. A common technical thread running through all three, however, is the way that API 653 sees the issue of tank failure. Although not entirely unconcerned with leaks and environmental issues, the calculation routines of API 653 centre mainly around the objective of preventing structural failure and collapse of the tank. Leaks are undesirable, but they can be contained and/or repaired. This same priority is shown by other API in-service inspection codes, and those from other bodies also, so it is probably correct.

In practice it is easily possible for a tank with heavy and unsightly corrosion to pass an API 653 calculation assessment. Some people would therefore offer the view that API 653 is more interested in integrity rather than cosmetic appearance. If a tank fails the corrosion evaluation methods in API 653 the question of what to do gets wider. The options are:

- Repair it to API 653/650.
- Rerate it (by lowering the fill height of the tank) to API 653.
- Do a fitness-for-service (FFS) assessment to API 579.

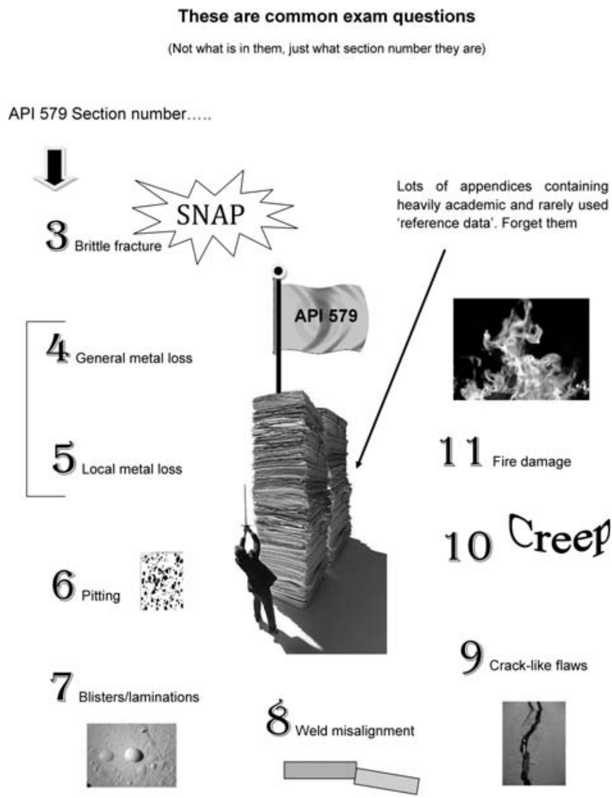


Figure 6.2 The section numbers of API 579

Looking at Fig. 6.2 you can see the context of API 579. It is a large detailed document containing many sections of detailed assessment methods for corrosion, bulging, weld problems and various other damage mechanisms that can affect tanks. Its use is not limited to tanks, but it fits well with the mechanical characteristics of atmospheric tanks of straightforward construction. An API 579 assessment is an out of (design) code assessment so, as such, carries an element of risk and even technical controversy, even though its methods are fairly robust and well-proven.

The detailed context of API 579 is, thankfully, not included in the API 653 exam body of knowledge. We will therefore concentrate on the evaluation methods of API 653 section 4: *Suitability for Service*.

6.1.1 The anticipated failure mechanisms

The evaluation methodologies of API 653 section 4 are almost exclusively concerned with preventing ductile failure. This is the main failure mode of corroded tanks in service. Do not confuse this with the competing mechanism of brittle fracture – related to material properties at low temperatures. This is primarily of interest for new tanks under hydrotest and is covered in a different section of API 653 (section 5).

6.2 The contents of API 653 section 4: suitability for service

Figure 6.3 shows the breakdown of the content of section 4: *Suitability for Service* and its partner Annex B: *Evaluation of Bottom Settlement*. Taken together, these provide good coverage on how to assess a corroded or damaged tank. Remember the key points about the calculation methods employed:

- They are based on the design calculations of the tank construction code API 650 but include various *overrides*.
- Areas in which API 653 clauses override the design requirements of API 650 are a fertile source of exam questions, as they are at the centre of the actual idea of API 653.
- Only the simpler parts of Annex B: *Evaluation of Bottom Settlement* ever appear as exam questions. Some of the topics listed in the BOK never appear.

6.3 Tank roof evaluation

This comprises little more than a list of checkpoints. A few that arise as exam questions are:

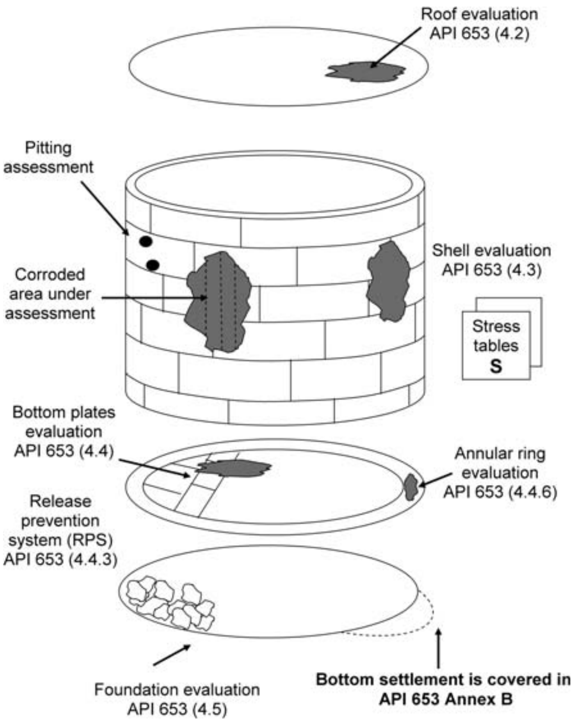


Figure 6.3 Tank evaluation: the breakdown of API 653 section 4

- Roof plates containing holes must be repaired or replaced.
- Roof plates corroded to an average thickness of less than 0.09 in in any 100 in^2 must also be repaired or replaced.

Note also these related safety points from API RP 575 (2.9):

- When walking on a tank roof it is safer to walk *on* the weld seams than between them.

- If planks are used as roof walkways they must span at least two rafters.
- Watch out for blocked roof drains. Corrosion tends to be worse where water gathers in pools.
- Tank vent valves fitted on the roof need to be checked for blockage.

There are generally no calculation questions related to roofs in the exam.

6.4 Shell evaluation

Evaluation of corroded shells is a major part of the API 653 body of knowledge. There are enough variations on the method to make for a fairly wide choice of exam questions. It also combines a useful group of principles that, in themselves, also turn up regularly in exam questions. Figure 6.4 shows these principles and we will look at them individually now.

6.4.1 Material strength

For tanks, this is straightforward. Construction steels are divided into well-established designations ('grades'), each of which has a minimum specified yield strength (S_Y) and ultimate tensile strength S_T (sometimes just abbreviated to Y and T). Remember that these are the minimum values the material has to meet to qualify for its designated grade – in practice it will almost certainly be stronger. Now look at Fig. 6.5, to see how these strength values are actually incorporated into tank design and repair.

Look at the principles highlighted in this figure. Although the rated yield (Y) and ultimate tensile strength (T) for any material are fixed, the percentage of this strength that is used to decide the value of allowable stress (S) to be used in the calculations varies depending on four things:

1. Whether it is a new-build/reconstructed tank or an existing one being assessed in its corroded condition.
2. Will the tank (in the future) only see its (lighter than water) petroleum product or will it be filled with water during a hydrotest?

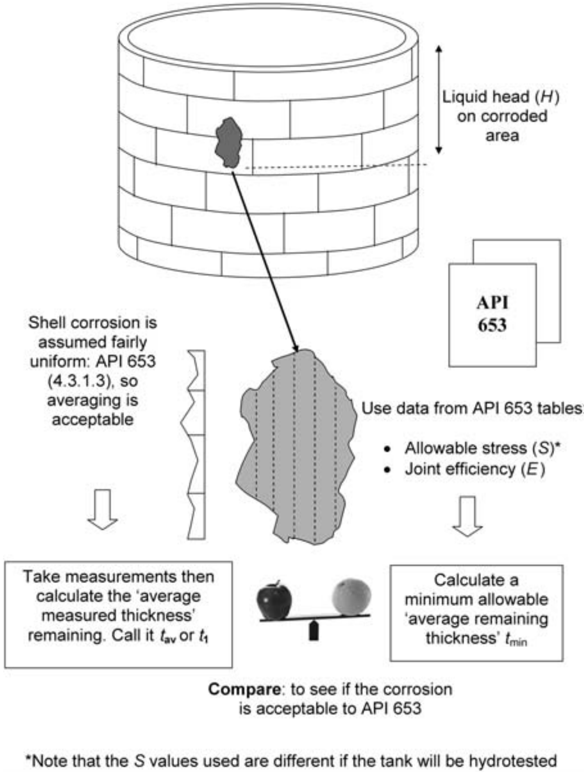


Figure 6.4 Tank shell evaluation: the principles

3. The location of the actual shell course under consideration.
4. Whether it is an elevated temperature tank, designed for operation above 200 °F (for low carbon steel).

Referring to the table in Fig. 6.5 you can see how these parameters all affect the allowable stress value to be used. Note the key principles involved in deciding the *S* value:

A material has a code-specified value of :
- Yield Y and Tensile strength T

The allowable stress used in calculations is then a percentage of these values, depending on the application: as below

The allowable S value is higher for in-service assessment of corroded tanks (by accepting a lower margin in order to keep the tank in service)

Application	Allowable *'product stress'* S if no hydrotest is planned		Allowable *'hydro stress'* S if a hydrotest is planned	
New or reconstructed tank: API 650 Table 5-2 applies	The lower of **0.66Y or 0.4T**		The lower of **0.75Y or 0.43T**	
Corrosion/repair assessment: API 653 Table 4-1 applies	Lower 2 courses	Upper courses	Lower 2 courses	Upper courses
	The lower of **0.8Y or 0.43T**	The lower of **0.88Y or 0.472T**	The lower of **0.88Y or 0.472T**	The lower of **0.9Y or 0.519T**

Note also how the allowable S value also rises to accommodate a hydrotest

Note how for corroded/repaired tanks, API 653 accepts a higher stress in the upper courses, whereas for new or reconstructed tanks, API 650 treats all courses the same

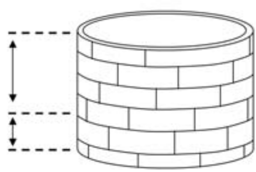


Figure 6.5 Tank shell material strengths

- It is normally the *lowest* of a percentage of Y (yield) or T (tensile) strength. There is no fixed rule as to which takes priority; you have to calculate both options and use the lowest value.
- A higher S value is allowed if a tank is to be hydrotested. This is acceptable on the basis that the tank shell will only see the increased stress *once,* so any increased risk is small.
- A higher S value is allowed for existing tanks (API 653)

than for new or reconstructed tanks (to API 650). Again, a little more risk is acceptable with an existing tank because it has proved itself by passing its original hydrotest and has not fallen down since.

- For existing tanks *only*, a higher S value is allowed in the upper areas of the shell than in the bottom two courses. This is because the upper courses are under less stress from the product weight, so are a bit less important from an integrity point of view.
- If a tank is likely to see elevated temperatures (above 200 $^{\circ}$F) then a bit of extra caution is required. This takes the form of a stress reduction factor to allow for the fact that materials get weaker as temperature rises.

6.4.2 The principle of stress averaging

The stress on a tank shell is very simple. It is almost entirely pure hoop stress acting on the vertical plane, attempting to split the tank open from top to bottom. Simplistically, for an uncorroded tank, the hoop stress is calculated using the simple formula below:

$$\text{Hoop stress } S = \frac{Pd}{2tE}$$

or rearranging to express it in terms of minimum required thickness (t)

$$t = \frac{Pd}{2SE}$$

where

p = pressure (from the head of liquid)
d = diameter of the tank
S = allowable stress
E = weld joint efficiency (a type of safety factor)

Using this equation it is easy to find the stress (S) or minimum required thickness (t) at any vertical position in the tank shell. The difficulty comes when you start to apply this

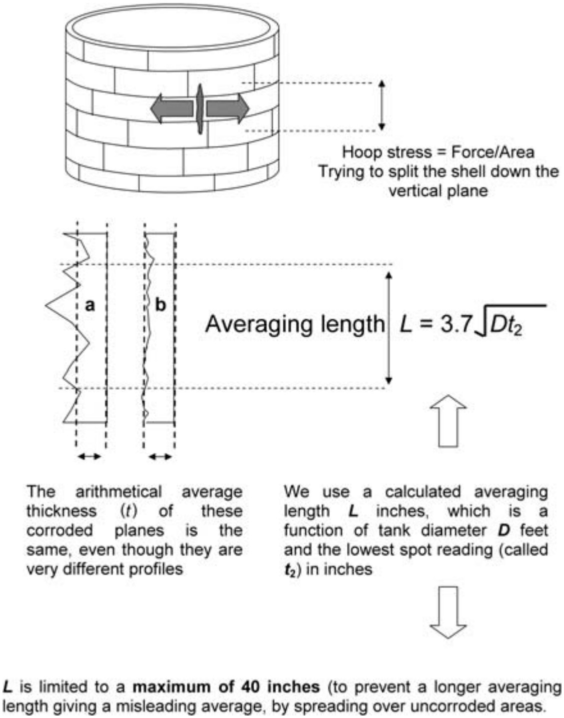


Figure 6.6 Tank hoop stress and averaging

to a tank shell that is corroded along the vertical plane. Figure 6.6 shows the situation. In an uncorroded shell plate of uniform thickness the hoop stress is resisted by the uniform 'thickness' area of the plate and averaging is not an issue. Once the plate is corroded then the area resisting the hoop stress starts to vary from place to place; thinner areas of plate have less area to resist the force so the hoop stress value is higher. Some method is therefore needed to decide how to deal with this varying stress level.

The problem of averaging

The danger with simple arithmetic averages is that they can be misleading. Look at the two examples in Fig. 6.6. Profile (a) is clearly more likely to fail than profile (b) but both have the same calculated arithmetic average.

API 653 attempts to neutralize this weakness by defining a *calculated averaging length*. This gives a length over which it is assumed (simplistically) that the hoop stresses on a corroded plane 'average themselves out'. Figure 6.6 shows the calculation. Note how it is related to tank diameter (D) and minimum (spot) wall thickness (called, rather confusingly, t_2), and how the square root sign reduces the sensitivity of L to large changes in D and t_2.

6.4.3 Weld joint efficiency (*E*)

Weld joint efficiency (symbol E) is a concept found in several API and ASME codes. Crudely, it acts as a design margin that increases the minimum required shell thickness. In other design codes, joint efficiency is affected by the weld location, its configuration (single groove, double groove, etc.), amount of NDE and a more general, somewhat hidden, consideration of construction 'quality'. For storage tanks the situation is simpler, being mainly governed by the design code and year edition to which it is built. You can see this in Table 4-2 of API 653.

Is joint efficiency (E) real?

Yes, as long as you think of it in the following way:

- E is mainly for use in new tank design. Its purpose is to make sure a tank is strong enough to pass its initial hydrotest.
- Once a tank is corroding in use its E is still relevant, however; if the corrosion is not near a weld it can be ignored (by making $E = 1$). This is a low-risk assumption acceptable to API 653.

Figure 6.7 summarizes the joint efficiency information contained in API 653 Table 4-2. Note how E is much lower

Standard	Edition	Joint type	Joint efficiency *E*	Applicability/limits
API 650	7th ed (1980–present)	Butt	1.0	Basic standard
			0.85	Appendix A spot RT
			0.7	Appendix A no RT
	1st–6th ed (1961–1978)		0.85	Basic standard
			1.0	Appendices D and G
API 12C	14th–15th ed (1957–1958)	Butt	0.85	
	3rd–13th ed (1940–1956)	Lap[a]	0.75	3/8 in max *t*
		Butt[c]	0.85	
	1st–2nd ed (1936–1939)	Lap[a]	0.7	7/16 in max *t*
		Lap[b]	0.5+*k*/5[e]	1/4 in max *t*
		Butt[c]	0.85	
Unknown	?	Lap[a]	0.7	7/16 in max *t*
		Lap[b]	0.5+*k*/5[e]	1/4 in max *t*
		Butt	0.7	
		Lap[d]	0.35	

[a]Full double lap weld.
[b]Full fillet weld with at least 25 % intermittent full fillet on opposite side.
[c]Single butt-welded joint with backing bar.
[d]Single lap welded only.
[e]*k* = percentage of intermittent weld (in decimal form, e.g 40 % = 0.4).

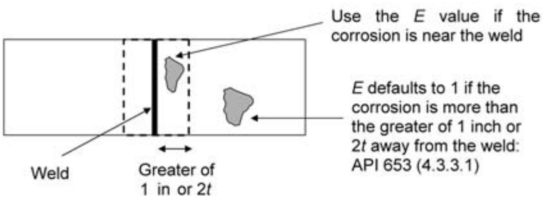


Figure 6.7 Shell joint efficiencies *E*

for tanks built to older design codes. This reflects the uncertainties and variability of material control and uncertain manufactured 'quality' prevalent in earlier times.

Joint efficiency for riveted shells

There are a lot of older riveted tanks still in use in the USA, so you can expect a couple of API exam questions about them. The principles are fairly straightforward:

- For corroded areas near riveted seams, E varies from 0.45 to 0.92; the latter for a total of 12 rows of rivets (6 either side of the joint centreline). See API 653 Table 4-3.
- As with welded seams, if corrosion is located well clear (6 inches away) from the nearest rivets the joint efficiency can be relaxed to $E = 1$.

6.4.4 Hydrostatic head consideration

An atmospheric storage tank shell is a good example of a very straightforward stress regime. If we conveniently ignore wind loading, the tensile stress on any point of the shell (at least above the bottom few inches where it meets the bottom annular plate) is an almost pure example of hoop stress. In turn, this hoop stress at any vertical location is directly proportional to the height of liquid (h) above it. We can see this from the hydrostatic head equation:

$$\text{Pressure} = \text{liquid density } (\rho) \times \text{gravity } (g) \times \text{height } (h)$$

$$\text{Units: } P\left(\mathrm{N/m^2}\right) = \frac{\mathrm{kg}}{\mathrm{m^3}} \times \frac{\mathrm{m}}{\mathrm{s^2}} \times \mathrm{m}$$

Substituting from Newton's law:

$$\text{Force} = \text{mass} \times \text{acceleration}$$

$$\mathrm{N} = \frac{\mathrm{kg\,m}}{\mathrm{s^2}} \text{ gives } \mathrm{kg} = \frac{\mathrm{N\,s^2}}{\mathrm{m}}$$

Therefore

$$P\left(\mathrm{N/m^2}\right) = \frac{\mathrm{N}}{\mathrm{m} \times \mathrm{m^3}} \times \mathrm{m} \times \mathrm{m} = \mathrm{N/m^2}$$

For a tank shell of uniform plate thickness over its full height, the hoop stress varies directly with height, as shown in Fig. 6.8. This will also apply if we just consider a single shell course. In practice, shell plate thickness normally

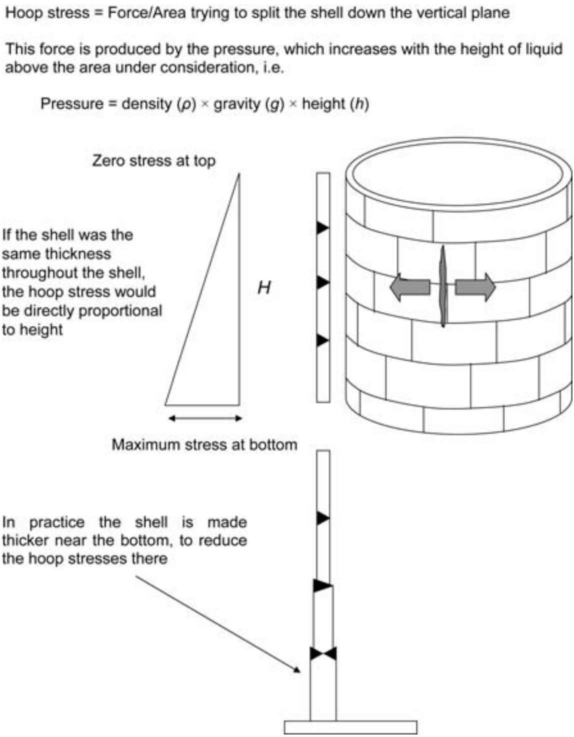


Figure 6.8 Hoop stress and height

increases from top to bottom, modifying the situation slightly.

In assessing corroded shell plates, API 653 uses simple adaptations of the hoop stress equation. This changes slightly in practice although, importantly, not in principle, depending on the amount of corrosion in the specific plate course being considered. This can be explained by referring to it as the so-called ‘one-foot rule’.

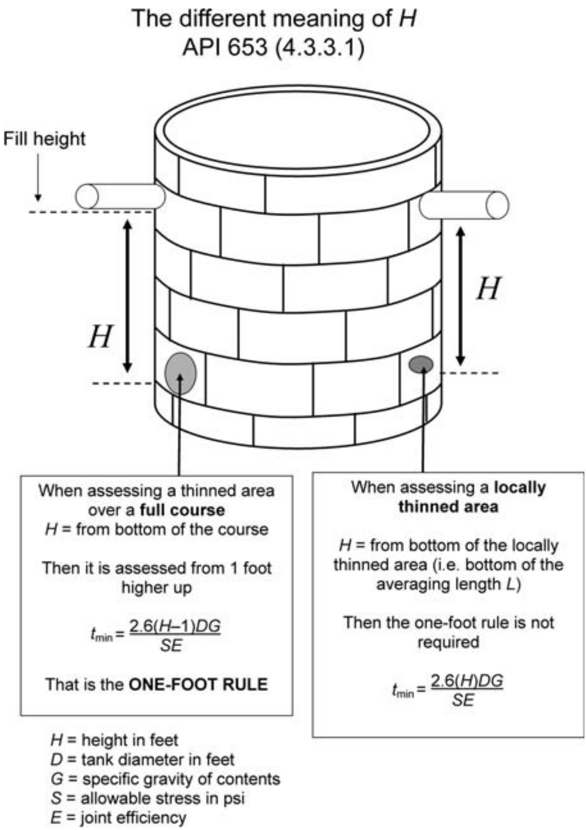


Figure 6.9 The one-foot rule

6.4.5 The one-foot rule

Figure 6.9 shows the equation to be used to calculate the minimum acceptable thickness. There are two options:

- The corroded area is sufficiently large to warrant conducting the assessment of a *full shell course plate*.
- The corroded area is much more *localized within a plate*.

Note the difference between the equations used; they differ only by their use of either the term (H) or ($H - 1$) within the equation (hence the one-foot rule name). In practice, it can be difficult to decide exactly which to use, as people's opinions will vary on whether a corroded patch is extensive enough to warrant a full course assessment or not. For API 653 examination purposes the question will tell you which assessment to use. Looking at the example in Fig. 6.9 you can also anticipate that the answers obtained from both methods do not vary by very much, particularly for larger tanks. The same principle is used when rerating tanks or calculating a safe full height for a tank that has a corroded shell.

6.4.6 What do we do about pitting?

In the world of API, pitting is seen as a very different thing to wall thinning. Although they may (and generally do) occur together, they are seen as separate for assessment purposes. The principles of dealing with pitting are common to several API in-service inspection codes. The points listed below summarize the approach of API 653 (4.3.2.2) to pitting:

- As a matter of principle, *widely scattered* pits in a tank shell can be ignored. This is because they are unlikely to result in structural failure of the tank.
- The definition of *widely scattered* is (practically at least) defined by the content of Fig 6.10 taken from API 653 Fig. 4-2. Note the reference to 2 inches in 8 inches – cumulative lengths of pitting greater than this are considered too concentrated to be isolated and so must be assessed as a corroded area instead. Strangely, no depth of this pitting is defined – so pitting is pitting.
- To restrict the allowable depth of pits, API 653 (4.3.2.2a) prohibits any pit from being so deep that it leaves less than 50 % of the calculated t_{min} for that location in the shell. In assessing this, make sure to add any future corrosion allowance (the amount that may suddenly or gradually disappear before the next scheduled inspection).

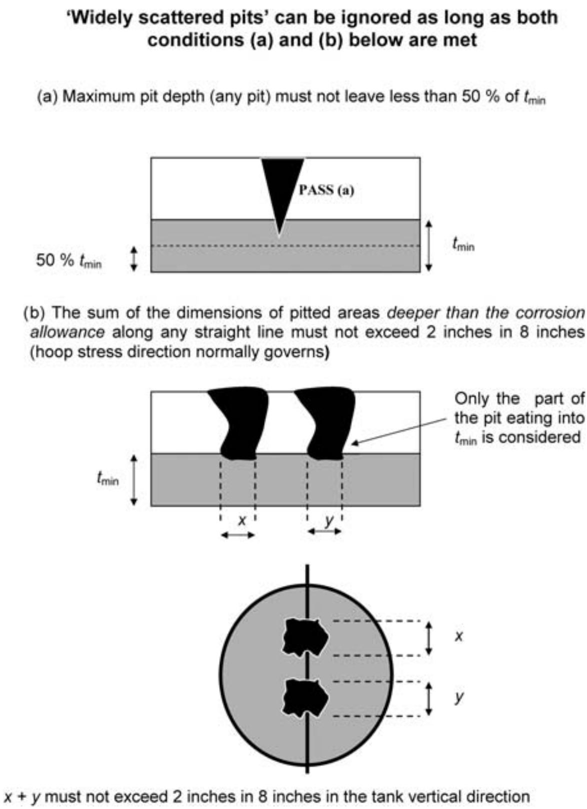


Figure 6.10 Pitting evaluation: API 653 (4.3.2.2 b)

The end result of applying these criteria to pitting is either that it can be ignored or that it is serious enough to be treated as a corroded area, using the main corrosion assessment method. We will look at this next.

6.4.7 Corrosion assessment – the big principle

Figure 6.11 shows the big principle of API corrosion assessment. This appears, with minor variations, in most API assessment codes for tanks, vessels and pipework and in API 579 – the advanced fitness-for-service (FFS) code relevant to them all. Note the key issues:

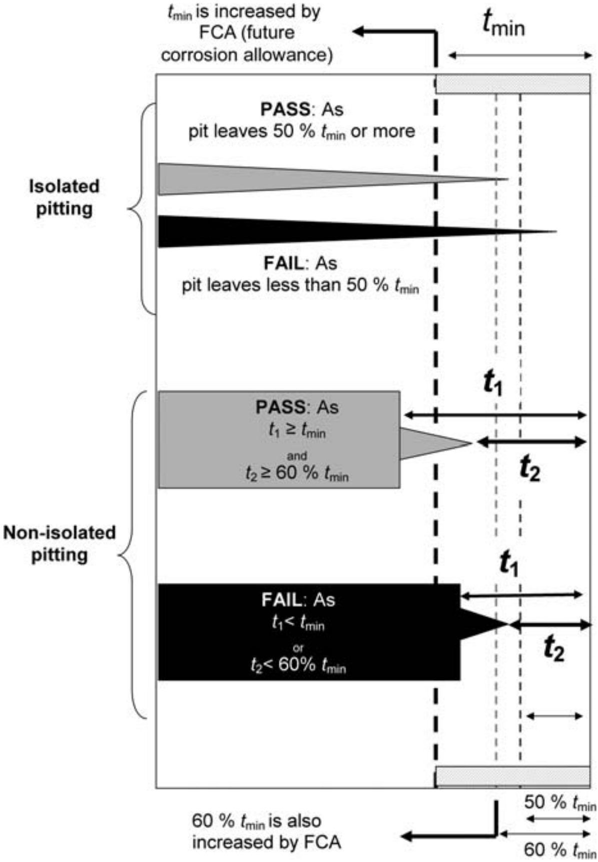


Figure 6.11 API 653 (4.3.2.1e) pitting assessment

- It is a double-barrelled assessment.

  meaning

- There are two separate assessments, and you have to pass both to be acceptable.

  and

- One assessment relates to the *average thinning* (on the assumption that this is what causes failure).
- The other assessment relates to the *thinnest 'spot' reading* (as long as it is not isolated pitting of course), under the assumption that this is what is going to cause the problems.

Looked at individually, each of these assessments is perfectly capable of providing a misleading picture of the integrity of the shell. Taken together, however (when you have to pass both), they provide a much better and balanced assessment.

Figure 6.12 shows a sample (simplified) shell assessment.

6.5 API 653 (4.4): tank bottom evaluation

Tank bottoms cause most of the problems with the integrity of storage tanks. Over time, they are likely to suffer from a variety of problems of settlement, corrosion or even cracking, leading to leaks. API 653 provides a full list of causes of bottom failure in section 4.4.2. Figure 6.13 shows the major causes; note how most of them relate, either directly or indirectly, to corrosion of some sort.

6.5.1 Release prevention systems (RPSs)

API 653 (4.4.3) goes into some detail about so-called release prevention systems (RPSs). This generic term refers to any method (either a physical feature or an *action* that can assist in maintaining the integrity of the tank bottom, i.e. preventing a leak from *happening*) They are:

- Internal inspection of the tank bottom
- A leak detection system

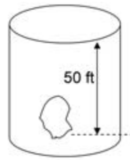
A 100 ft diameter tank has a corroded patch as shown

H = height (feet) from the bottom of the assessment length L to the maximum design liquid level = 50 ft

G = specific gravity of the contents = 0.9

S = max allowable stress in psi (0.8Y for lower 2 courses) = 0.8 x 35 000 psi = 28 000 psi

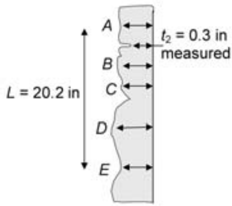
E = joint efficiency E = 1



Work out the average thickness t_{av}
$t_{av}=(A+B+C+D+E)/5$
$t_{av}=(0.4+0.35+0.31+0.45+0.42)/5$
$t_{av}=0.386$ in

t_2 = minimum 'spot' thickness anywhere on the corroded patch

Corroded profile



QUESTION: Is it safe for use at full fill height?

Calculate maximum averaging length (L) = $3.7\sqrt{(Dt_2)}$ = $3.7\sqrt{100 \times 0.3}$ = 20.2 in

Compare t_{av} with the minimum allowable thickness as calculated by the formula:
$$\text{Min } t_{av} = \frac{2.6\,(H-1)\,D\,G}{SE} = \frac{2.6(50-1)100 \times 0.9}{28\,000 \times 1} = 0.41 \text{ in}$$
As the actual measured t_{av} (0.386 in) is **smaller than** the minimum t_{av} required (0.386 in) this is **unacceptable**. The tank must be repaired or the fill height H reduced

Figure 6.12 Typical (simplified) shell assessment

- Leak testing (to find problems in advance)
- Cathodic protection of the underside of the tank bottom
- Internal lining of the tank bottom

API 653 (4.4.3) does not go so far as recommending which of these is likely to be the best method – it simply reports that they exist, with a brief description of what they are. Do not expect lots of exam questions on this.

In contrast to RPSs, release prevention barriers (RPBs) are used to contain or otherwise mitigate a bottom leak once it

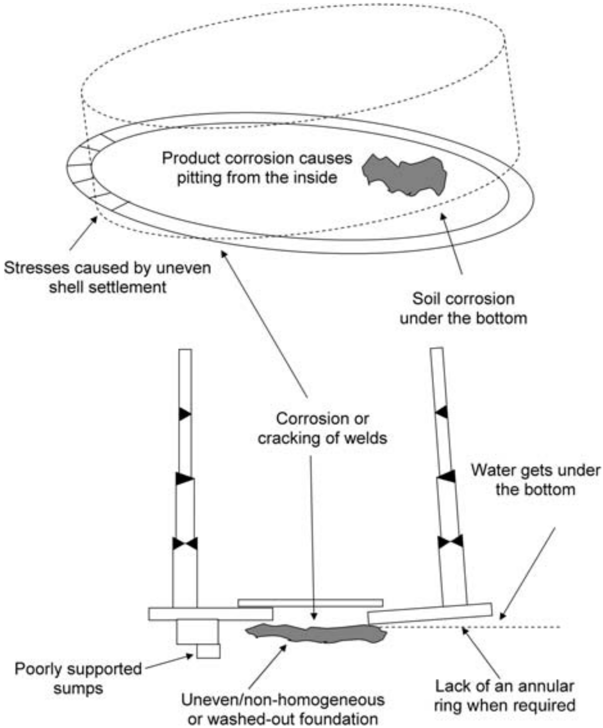


Figure 6.13 Causes of tank bottom failure: API 653 (4.4.2)

has happened. Tank bunds, earthwork liners and drainage channels are the classic RPBs. There is a lot more detail in API 650 appendices I1 and I2, which are in the API 653 BOK.

6.5.2 Bottom evaluation – general principles

Tank bottom evaluation is subdivided into the three main elements that make up the tank bottom.

- The bottom plates themselves (4.4.5) are the main plates, normally overlapped and lap welded inside the tank.

- The annular ring (4.4.6) is a thicker ring of fairly narrow plates, butt welded together in an annulus located under (and welded to) the lower shell plate course. The annular ring therefore supports almost all of the steelwork weight of the shell and its attachments. Older tanks may not always have this thicker annular ring but most modern ones do.
- The critical zone is not a separate set of floor plates but simply the annular area extending 3 inches inward from the shell, all round the tank. You can think of it as just a particular critical region of the annular ring. It appears in API 653 (4.4.5.4) and the definition section (3.10).

Not all of the technical points in these sections of API 653 get universal agreement. Some tank codes from other countries take different views on the risk of operating with quite thin bottom plates and annular rings, and so prefer to specify a greater minimum acceptable corroded thickness in preference to relying on an RPS/RPB as a last line of defence. Differences of opinion apart, API 653 does provide consistent and easy-to-follow acceptance levels, which many tank operators follow quite successfully.

6.5.3 Bottom plate minimum thickness API 653 (4.4.5) and Table 4-4

This is one of the more difficult equations of API 653 to understand. There is nothing wrong with the principles behind it; it is simply written using odd symbols and in a strange way. Part of the problem comes from the fact that it tries to incorporate scenarios in which a bottom may have already been repaired and/or have had a lining applied to arrest corrosion before it is assessed.

Note a key point about this equation, which we will call the *MRT equation*:

- *The 'MRT' equation just tells you how to calculate the remaining thickness of the bottom plates at the next* *inspection. It does not actually give you a minimum acceptable value. That is given in API 653 Table 4-4.*

Here is what the equation in 4.4.5.1 looks like, with some slightly simplified English:

$$MRT = \left(\text{minimum of } RT_{bc} \text{ or } RT_{ip}\right) - O_r\,(StP_r + UP_r)$$

where

MRT = thickness of bottom plates at the next inspection.
O_r = interval to next inspection (years)
RT_{bc} = minimum remaining thickness left after considering (soil side) bottom corrosion
RT_{ip} = minimum remaining thickness after considering internal (product-side) corrosion
StP_r = product-side corrosion rate
UP_r = soil-side corrosion rate

If you can fight your way through the confusing wording (and ignore all the stuff on repairs which may or may not have been done) this actually makes reasonable sense. It simply says:

- MRT = current thickness – (time to next inspection × corrosion rate)

Qualify this by the following couple of points and you can see the equation for what it really is – a complicated way of expressing a simple idea:

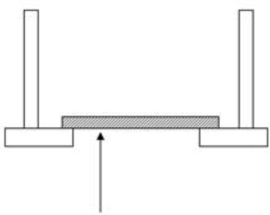
- The corrosion rate consists of the internal corrosion rate plus the external corrosion rate (as the tank bottom has an inside and an outside).
- If the tank has an internal lining, just assume that the *internal* corrosion rate = 0.
- If this tank has cathodic protection (CP), just assume that the *external* corrosion rate = 0.
- If either the internal or external surfaces have been

repaired, the original corrosion rate that necessitated the repairs must be assumed to be still in force, unless you have evidence that it has changed (e.g. gone to zero if a lining has been applied after the repairs).

6.5.4 Minimum acceptable bottom plate thickness

Once you have calculated the remaining bottom thickness at the next inspection, the idea is that you then compare the results with Table 4-4 (reproduced in Fig. 6.14). This allows a basic minimum thickness of 0.1 in (2.5 mm), but can be reduced to half that (0.05 in or 1.25 mm) if the tank has either an internal lining or some method of containment to catch leaks if they do occur. These thicknesses are quite low,

This refers to the main bottom plates *inside* the annular ring



Minimum thickness of bottom plate at next inspection	Tank bottom/ foundation design
0.1 in	No means for detecting and containing bottom leakage
0.05 in	Fitted with means for detecting and containing bottom leakage
0.05 in	Bottom lining >0.05 in thick to API 652

From API 653 (Table 4-4)

Figure 6.14 Bottom plate minimum thickness: from API 653 Table 4-4

and of course can be overruled either way by an RBI assessment.

6.5.5 What about the critical zone?

The 3 in wide critical zone (defined in API 653 definition 3.10 remember) may be either part of the annular ring (if the tank has one) or the bottom plate, if it does not. Figure 6.15 shows this specific requirement, a hybrid limit of the lower of:

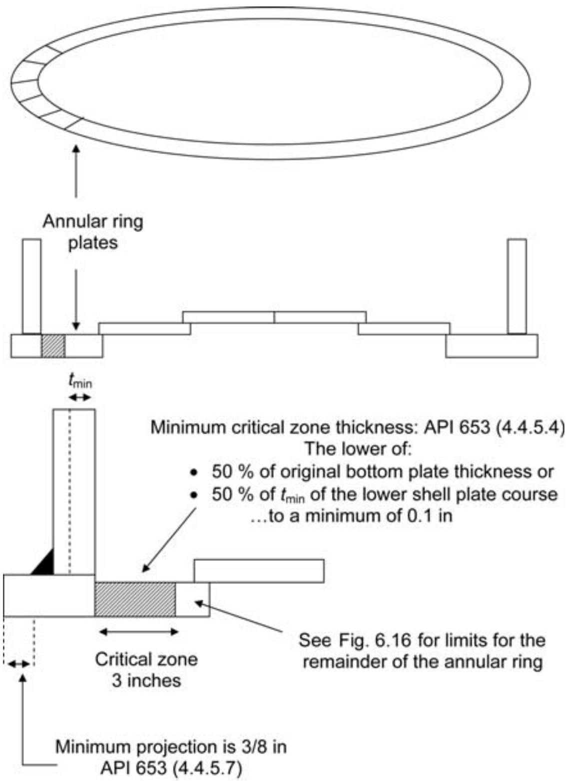


Figure 6.15 Tank bottom limits: critical zone API 653 (4.4.5.4)

- 50 % of *actual* original bottom thickness (excluding any corrosion allowance)

  or

- 50 % of t_{min} of the lower-shell plate course

  but

- It must not be less than 0.1 in (2.5 mm), excluding isolated pitting as usual.

If the tank does have an annular ring, then this restriction on the minimum thickness of the critical zone still applies; it just falls within the annular ring rather than the bottom plates.

6.5.6 Minimum thickness of the annular plate ring (4.4.6)

The minimum acceptable thickness of the annular ring needs to be greater than that of the bottom plates, as it is under more stress from supporting the weight of the shell (plus sometimes bending from foundation settlement or other sources). The thicknesses are shown in API 653 Table 4-5 and summarized in Fig. 6.16. Note how three additional factors (that did not affect the main bottom plates) come into play:

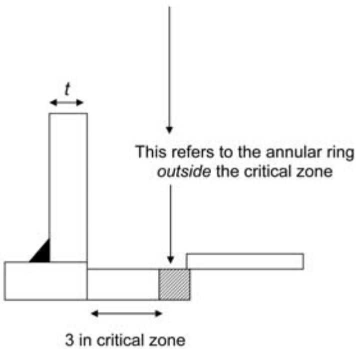
- The thickness of the first shell course
- The actual 'product' stress in the first shell course
- Whether or not the specific gravity of the product is greater than 1 (heavier than fresh water)

Owing to the fact that the condition of a tank bottom is one of the most important life-limiting factors and the main reason for actually doing internal inspections, the above subjects appear regularly as both open- and closed-book exam questions. The calculations are normally straightforward and you can see some typical examples at the end of this chapter.

6.6 Foundation evaluation: API 653 (4.5)

This short section situated at the end of section 4 contains a few general points on the condition of concrete foundations

Plate thickness of first shell course (in)	Stress in first shell course (psi) calculated from $S = [2.34D(H\text{-}1)] / t$			
	<24 300 psi	<27 000 psi	<29 700 psi	<32 400 psi
$t \leq 0.75$	**0.17 in**	**0.2 in**	**0.23 in**	**0.3 in**
$0.75 < t \leq 1$	**0.17 in**	**0.22 in**	**0.31 in**	**0.38 in**
$1 < t \leq 1.25$	**0.17 in**	**0.26 in**	**0.38 in**	**0.48 in**
$1.25 < t \leq 1.5$	**0.22 in**	**0.34 in**	**0.47 in**	**0.59 in**
$t > 1.5$	**0.27 in**	**0.4 in**	**0.53 in**	**0.68 in**
Thicknesses in inches				



From API 653 (Table 4-5)

Figure 6.16 Bottom limits: annular ring API 653 Table 4-5

but nothing about the main foundation-induced problem, which is that of *settlement*. This is physical movement of part of or all of the foundations, causing stresses and distortion of the tank structure above it. This is covered in API 653 Annex B, which we will look at next. Although physically separated in different parts of the code, section 4: *Suitability for Service* and Annex B: *Evaluation of Tank Bottom Settlement* are closely related to each other and should be considered together when assessing tank bottoms.

6.7 Bottom settlement: API 653 Annex B

Exactly how much of Annex B is in the API 653 examination body of knowledge (BOK) is open to some interpretation. This annex contains a lot of quite detailed information that maps well on to the way that tank settlement assessments are actually done in the field. Some of it, however, is far too complicated to be suitable for the API 653 exam. The BOK partly addresses this by mentioning a few exclusions, but at first reading it is not particularly easy to translate this into which part of Annex B you need, or need not, study.

Fortunately, the reality is fairly straightforward – most of the content of Annex B does not appear as exam questions, either because it is too complicated or it does not fit well into the multichoice exam question format. This means that there are generally fewer settlement-related questions than perhaps you might expect, given its importance. They are mainly predictable open-book questions and not too difficult. We will look at the most popular subjects and then at some simple questions at the end of this chapter.

Annex B is set out along fairly logical guidelines as follows:

- The different types of bottom settlement, categorized predominantly by the way that they affect the shell. The types are uniform, planar and differential.
- Measurement of various types of bottom settlement. The three clear types included in the BOK are:
  - Edge settlement (B-2.3)
  - Bottom settlement near the shell
  - Bottom settlement remote from the shell nearer the centre of the tank floor.
- Evaluation of the types of settlement against acceptable limits, given in the form of graphs or simple linear formulae.
- Decisions based on the results of the evaluation about performing additional NDE or repair. Details of the repairs themselves are not included in Annex B-2, as they are fully covered in API 653 section 9.

6.7.1 Types of settlement

The problem with storage tanks is that they are structures that have little rigidity. Most have no cross-bracings supporting the shell, leaving only the hoop strength of the thin shell to support the load exerted by the product liquid. Even the margins in material thickness are small, compared to those used in pressure vessels and pipework. To make things worse many older tanks were built on either simple rubble foundations or low quality concrete.

The result is that when tanks move (or 'settle') on their foundations, the uniform hoop stress regime in the shell is soon disturbed, leading to unpredictable stresses, strains and distortion. This can soon lead to cracking and leaks, or, in extreme cases, collapse of the tank. To try and avoid this tank owners should take regular measurements of tank settlements over time.

Distortion of a tank shell involves a rather complicated three-dimensional geometry that is not easy to measure, or even describe in simple terms. Measurement and analysis is therefore generally left to specialist contractors. Quite a bit of API 653 Annex B is devoted to describing these specialist techniques – the good news is that they are not really included in the BOK, and are too complicated to appear in the form of API exam questions. For exam purposes, you can think of the types of tank settlement as being simplied into three separate components as follows (see Fig. 6.17):

- *Uniform settlement*. This is 'sinking' of the tank perfectly vertically downwards, with no tilting, twisting, buckling or any other type of distortion whatsoever. It rarely happens exactly like this in practice, but you can think of it as one of the components of any real settlement pattern.
- *Planar tilt*. You can think of this as the tank shell and bottom assembly simply tilting over to one side. Again, it does this in a perfectly even and uniform manner – the shell remains perfectly circular without it buckling or kinking. Owing to the tilting there is a small, usually insignificant, increase in vertical liquid height, and therefore in the hoop stress at the bottom of the shell. Looking at Fig. 6.17 you can see how the shape of a uniformally tilted tank can be represented by a perfect cosine wave.

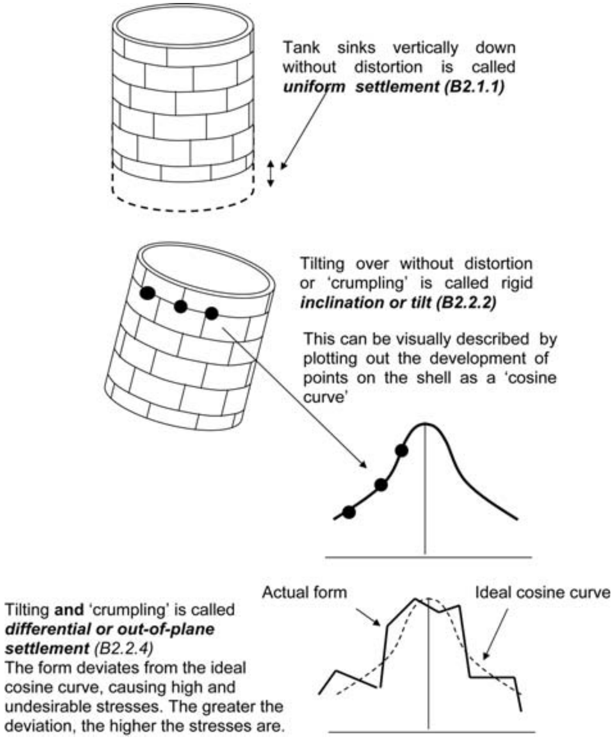


Figure 6.17 Tank settlement: API 653 Annex Fig B-3

- *Non-planar differential settlement*. This is the one that causes the real problems in use. The fact that a tank is a very thin shell structure means that as it settles and tilts, it nearly always distorts as well. This causes extra shell stresses, sticking of floating roofs and breakage of support columns, girders and connecting nozzles and pipework.

Is non-planar differential settlement in the exam?
Probably not. Quite a lot of API 653 Annex B is devoted to the measurement and description of differential settlement. It

is done by measuring the difference between the actual shape of the settled tank compared to that of the planar-tilted ideal cosine curve. The greater the difference, the greater is the differential distortion and the larger the resulting stresses. You can see the principle explained in API 653 (2.2.4) and Figs B-4 and B-5 – described as the 'least-squares fit method'. Fortunately, this is far too complicated to make an API exam question so the calculation will not appear in the exam. You can maybe expect a question on the principles of tilting and distortion and their effects but no calculations.

To repeat: you do not need to learn the specific details and equations of 'out-of-plane' differential settlement. They will not be in the closed-book exam.

6.7.2 Edge settlement

The various types of tank settlement that we have just looked at are not, in themselves, the problem. It is their distortion effects that are important. API 653 Annex B-2 divides these into two separate situations – settlement distortion under, or very near, the edge of the tank ('edge settlement') and that well away from the edge nearer the centre of the tank ('bottom settlement'). Unlike shell distortions, these are easy to assess using simple graphs and calculations, and so appear in the API 653 BOK. Expect one or two exam questions to appear on this subject, but no more.

Edge settlement is when the tank bottom settles sharply around the edge of the tank often caused by 'washout' or crumbling of foundations. Looking at Fig. 6.18 (see also Fig. B-6 in API 653) you can see how this results in sharp deformations of both the bottom and shell steelwork, causing serious bending stresses. The API 653 Annex B assessment uses a simple ratio of the (vertical) length of edge settlement to its length (in the tank radial direction). It then divides this into two separate scenarios as follows:

- If the edge settlement is an area where the tank bottom

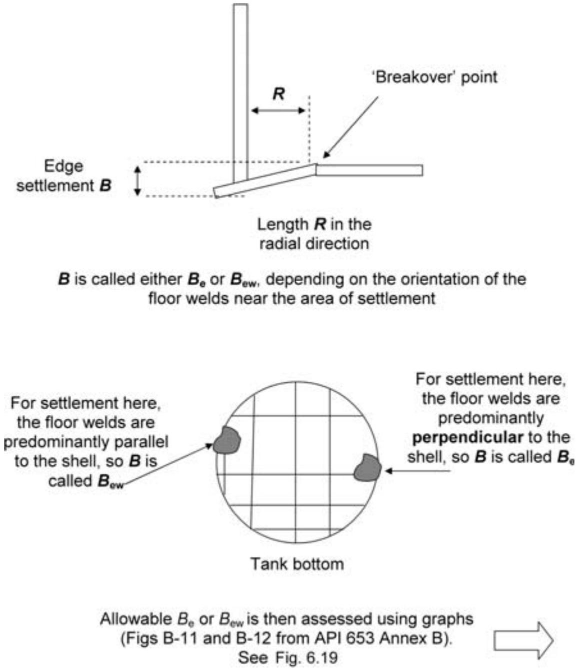


Figure 6.18 Tank bottom edge settlement: (API 653 Annex B-2.3)

plate welds run near-*parallel* ($\pm 20^{o}$) to the shell, the extent of edge settlement is called B_{ew}.

- If the edge settlement is in an area where the tank bottom plate welds run near-*perpendicular* ($\pm 20^{o}$) to the shell, the extent of edge settlement is called B_e.

Note how both of the above cases refer to the vertical amount of settlement (B); they are simply renamed B_{ew} or B_e, depending on which way the local tank bottom plate welds are orientated.

Assessment against the edge settlement graphs

Once the edge settlement measurements are available, the assessment is easy. Figure 6.19 summarizes the content of API 653 Figs B-11 and B-12.

To use the graph, simply enter the graph on the horizontal axis with the measured radius (*R*) of the settled area. Remember that this is not actually a true radius, as such, but the length of the settled area measured in the tank radial

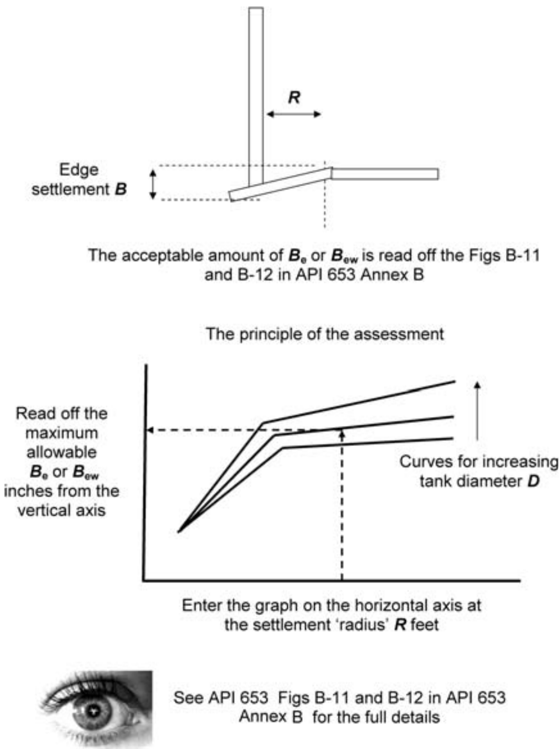


Figure 6.19 Edge settlement assessment: API 653 B-11 and B-12

direction. Then, using the relevant curve for the tank diameter in question, read off B_{ew} (or B_e) from the vertical axis. This is the maximum allowed dimension of B_{ew} (or B_e) acceptable to API 653. Any more than this needs repair or further specialized evaluation.

API 653 exam papers do not like to contain a lot of figures or graphs, so exam questions tend to be limited to code clauses that do not require use of the graphs. Note the following key points:

- B_{ew}, when bottom welds are ($\pm 20^o$) parallel to the shell, is more conservative than B_e so it is normal to do this assessment first (B-2.3.4).
- When B_{ew} or B_e are $\geq 75\,\%$ of their limit (and larger than 2 in) the welds in the region should be inspected with PT/MT to check for cracking (API 653 Figs B-11 and B-12).
- Any bottom plate exhibiting a strain (permanent plastic deformation) of more the 2–3 % should be replaced (B-4.2).
- The settlement graphs were originally developed for $\frac{1}{4}$ in thick tank bottoms but can also be applied with reasonable accuracy for thicknesses between $\frac{5}{16}$ in and $\frac{3}{8}$ in.
- In general, settlement occurs fairly slowly over the first few years of service (B-3.4.5).
- Watch out for the edge settlement clause B-3.4.6 (a to d). There are possible exam questions in here.

6.7.3 Bottom settlement

Remember that this is assessed differently depending on whether the settlement is near the shell or further away, towards the centre. The methods are very similar, using a simple equation based on the depth (B_B) of the settlement (bulge) compared to its radius (R). Figure 6.20 shows the situation. Note how the simple linear graph in API 653 Fig. B-10 contains absolutely nothing new; it is simply the equation $B_B = 0.37R$ shown in a different way.

As with edge settlement, the limits of bottom settlement

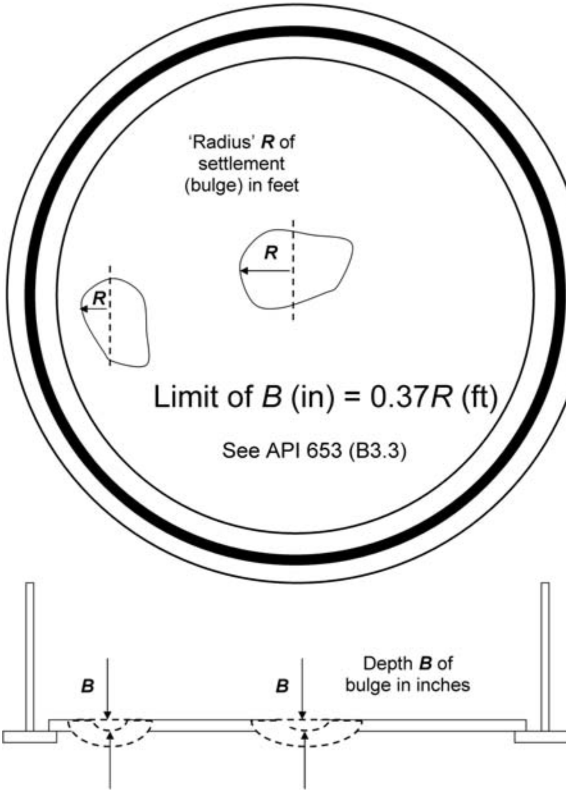


Figure 6.20 Assessing bottom bulges: API 653 B-2.4 and B-2.5

are there to prevent the floor plates being bent too sharply, which would cause risk of cracking of the lap welds. It may still be technically possible to operate the tank with a settlement in excess of these limits, but an engineer's assessment would be required.

As bottom settlement limits can be determined without using graphs (i.e. using the $B_B = 0.37R$ equation) this subject can appear as an (open-book) exam question.

The presentation in the code is a little confusing, mainly because the combination of equations and graphs (meaning exactly the same) makes this subject more complicated than it actually is.

Figure 6.21 gives a summary of code formulae used in a tank evaluation. Now try these practice questions.

6.8 API 653 section 4: evaluation: practice questions (set 1)

Q1. API 653: isolated pitting

> How many pits of less than half the minimum required wall thickness, each of 0.25 in diameter, are allowed in an 8 in vertical line of corrosion on a tank?

(a) 4 pits ☐
(b) 8 pits ☐
(c) 10 pits ☐
(d) 16 pits ☐

Q2. API 653: joint efficiencies (unknown construction standard)

What is the weld joint efficiency factor for a tank built in 1950 with a single butt welded joint with a 'back-up bar'? The construction standard is not known.

(a) 1.0 ☐
(b) 0.85 ☐
(c) 0.7 ☐
(d) 0.35 ☐

Q3. API 653: allowable stress *S*

If the yield strength (Y) of a material of construction is 35 000 psi and the tensile strength (T) is 60 000 psi, what is the value of the maximum allowable stress for the *bottom two courses* of a tank made of this material?

(a) 25 740 psi ☐
(b) 28 000 psi ☐
(c) 35 000 psi ☐
(d) 30 680 psi ☐

(*Questions continued on p. 123*)

TO FIND	EXISTING WELDED TANKS	EXISTING RIVETED TANKS	RECONSTRUCTED TANKS
ALLOWABLE STRESS VALUES *S*	**API 653, 4.3.3.1** **API 650 Table 3-2** Table 4-1 in API 653 gives allowable **product stresses** and **hydrostatic** test stresses for all courses	**API 653, 4.3.4.1** Use $S = 21\,000$ lbf/in^2 for any riveted tanks	**API 653 8.4.2 and 8.4.3 also API 650 Table 5-2** *S* values come directly from product or hydro values listed in Table 5-2 of API 650 If unknown material, for product stress use the smaller of 2/3 yield or 2/5 UTS If unknown material, for hydro stress: 3/4 yield or 3/7 UTS.
JOINT EFFICIENCY *E*	**API 653, 4.3.3.1 and Table 4-2** Read joint efficiency directly from Table 4-2 If at least 1 in or 2 times the thickness of the shell plate away from the weld, *E* is always 1.0 (see 4.3.3.1)	**API 653, 4.3.4.1 and Table 4-3** Read *E* directly from Table 4-3 If at least 6 in away from the rivet joint, *E* is always 1.0	**API 653, 8.4.5 and Table 4-2, also API 650, 5.6.3.2** For tanks de-seamed, *E* is 1.0 (all new welds) For tanks with existing welds left in, *E* is the lowest allowed in API 653, Table 4-2

t_{min} of shell	**API 653, 4.3.3.1(a) and (b)** $t_{min} = \frac{2.6D(H-1)G}{SE}$ This is used when determining the minimum acceptable thickness for an entire shell course $t_{min} = \frac{2.6DHG}{SE}$ This formula is used when determining the minimum thickness for any other portions of a shell course (such as a locally thinned area) Remember to add corrosion allowance	SAME AS WELDED	**API 650, 5.6.3.2** Product: $t = \frac{2.6D(H-1)G}{S} + CA$ Hydro: $t = \frac{2.6D(H-1)G}{S}$ If tank is not de-seamed, formulae become: Product: $t = \frac{2.6D(H-1)G}{SE} + CA$ Hydro: $t = \frac{2.6D(H-1)G}{SE}$

Figure 6.21 Tank evaluation; summary of formulae (continues overleaf)

TO FIND	EXISTING WELDED TANKS	EXISTING RIVETED TANKS	RECONSTRUCTED TANKS
To find allowable product fill height:	(a) $H = \frac{SEt}{2.6DG} + 1$ The formula shown in (a) above is used when determining the maximum acceptable product fill height for an entire shell course (b) $H = \frac{SEt}{2.6DG}$ The formula shown in (b) above is used when determining the maximum acceptable product fill height for any other portions of a shell course (such as a locally thinned area of any other location of interest)	(a) $H = \frac{SEt}{2.6DG} + 1$ The formula shown in (a) above is used when determining the maximum acceptable product fill height for an entire shell course (b) $H = \frac{SEt}{2.6DG}$ The formula shown in (b) above is used when determining the maximum acceptable product fill height for any other portions of a shell course (e.g a locally thinned area)	

To find allowable/required hydrostatic test height:	API 653, 4.3.3.1, 4.3.3.2(a)(b),	API 653, 4.3.3.1, 4.3.3.2(a)(b), 4.3.4.1 and 4.3.4.2	API 650, 5.6.3.2 Formula given in problem
	$^{*}H_t = \frac{S_t E t_{min}}{2.6DG} + 1$	$^{*}H_t = \frac{S_t E t_{min}}{2.6DG} + 1$	$^{*}H_t = \frac{S_t E t_{min}}{2.6DG} + 1$
	Height in feet, from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course	Height in feet, from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course	Height in feet, from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course t = *actual* thickness of plate determined by inspection Thickness measurements must be taken within 180 days of reconstruction
	$^{*}H_t = \frac{S_t E t_{min}}{2.6DG}$	$^{*}H_t = \frac{S_t E t_{min}}{2.6DG}$	
	Height in feet from the bottom of L for the most severely thinned area in each shell course or from the lowest point within any other location of interest to the hydrostatic test height t_{min} = *actual* thickness of plate determined by inspection S_t may be found directly in API 653, Table 4-1 or as follows: $S_t = 0.88Y$ or $0.472T$ for 1st or 2nd courses $S_t = 0.9Y$ or $0.519T$ for all other courses Y and T are found in Table 4-1 of API 653 or in Table 3-2 in API 650	Height in feet from the bottom of L for the most severely thinned area in each shell course or from the lowest point within any other location of interest to the hydrostatic test height t_{min} = *actual* thickness of plate determined by inspection. S_t may be found directly in API 653, Table 4-1. This provides that S or S_t is = 21 000 lbf/in^2	

Figure 6.21 (continued)

TO FIND	EXISTING WELDED TANKS	EXISTING RIVETED TANKS	RECONSTRUCTED TANKS
To find L – maximum vertical length of corrosion averaging	**API 653, 4.3.2.1** $L = 3.7\sqrt{Dt_2}$ Dt_2 = lowest thickness in area under consideration (not including pits)	**API 653, 4.3.2.1** $L = 3.7\sqrt{Dt_2}$ Dt_2 = lowest thickness in area under consideration (not including pits)	**API 653, 4.3.2.1** $L = 3.7\sqrt{Dt_2}$ Dt_2 = lowest thickness in area under consideration (not including pits)
To find minimum annular plate thickness	**API 653, Table 4-4** Product specific gravity is less than 1.0 Stress in first shell course $S = \frac{2.34D(H-1)}{t}$ **API 650, Table 5-1** Product specific gravity is 1.0 or greater than 1.0 Stress in first shell course $S = \frac{2.6D(H-1)}{t}$ From this, enter applicable table at shell thickness, coincide this to calculate stress, read thickness directly from the table	**API 653, Table 4-4** **API 650, Table 3-1** Product specific gravity is less than 1.0 Stress in first shell course $S = \frac{2.34D(H-1)}{t}$ **API 650, Table 5-1** Product specific gravity is 1.0 or greater than 1.0 Stress in first shell course $S = \frac{2.6D(H-1)}{t}$ From this, enter applicable table at shell thickness, coincide this to calculated stress, read thickness directly from the table	**API 650, Table 5-1** Stress in first shell course $S = \frac{2.6D(H-1)}{t}$ From this, enter applicable table at shell thickness, coincide this to calculated stress, read thickness directly from the table

To find inspection intervals	**API 653, 6.3.2.1** * External inspection interval Ext Insp Int $= \dfrac{RCA}{4N}$ or 5 years (whichever is less) **API 653, 6.3.3.2(a)** * Ultrasonic inspection interval 5 years maximum if the corrosion rate is unknown UT Insp Int $= \dfrac{RCA}{2N}$ or 15 years (whichever is less)	**API 653, 6.3.2.1** * External Inspection Interval Ext Insp Int $= \dfrac{RCA}{4N}$ or 5 years (whichever is less) **API 653, 6.3.3.2(a)** * Ultrasonic Inspection Interval 5 years maximum if the corrosion rate is unknown UT Insp Int $= \dfrac{RCA}{2N}$ or 15 years (whichever is less)	**API 653, 6.3.2.1** * External Inspection Interval Ext Insp Int $= \dfrac{RCA}{4N}$ or 5 years (whichever is less) **API 653, 6.3.3.2(a)** * Ultrasonic Inspection Interval 5 years maximum if the corrosion rate is unknown UT Insp Int $= \dfrac{RCA}{2N}$ or 15 years (whichever is less)
To find plumbness of tank	N/A	N/A	**API 653, 10.5.2** $P = \dfrac{\text{height (ft)} \times 12}{100} \leq 5\,\text{in}$ $P =$ maximum out-of-plumb, with a maximum of 5 inches allowed, in all cases

Figure 6.21 (continued)

TO FIND	EXISTING WELDED TANKS	EXISTING RIVETED TANKS	RECONSTRUCTED TANKS
To find maximum height of bulge or settlement in tank bottom	**API 653, B.3.3** $B_B = 0.37R$ Note: R is always in feet and B_B is in inches	**API 653, B3.3** $B_B = 0.37R$ Note: R is always in feet and B_B is in inches	**N/A**
To find distance between a hot tap and existing nozzles	**API 653, 9.14.3.1** Minimum spacing $= \sqrt{RT}$ R = tank shell radius in inches T = tank shell thickness in inches	**API 653, 9.14.3.1** Minimum spacing $= \sqrt{RT}$ R = tank shell radius in inches T = tank shell thickness in inches	**N/A**

Figure 6.21 (continued)

Q4. API 653: allowable stress for unspecified steel

What is the design strength of unspecified steel used in the top courses of a storage tank?

(a) 24 000 psi ☐
(b) 23 595 psi ☐
(c) 26 400 psi ☐
(d) 25 960 psi ☐

Q5. API 653: calculation of averaging length

The minimum shell thickness t_2 (exclusive of isolated pits) in a tank of 100 ft diameter is measured at 0.375 in. What is the critical length over which the thickness readings should be averaged out?

(a) 138.75 in ☐
(b) 22.65 in ☐
(c) 6.12 in ☐
(d) 10 in ☐

Q6. API 653: calculation of minimum acceptable shell thickness

A tank has the following dimensions:

Nominal tank diameter	150 ft
Total height of tank	30 ft
Maximum fill height	30 ft
Number of courses equally spaced	5
Specific gravity of contents	0.85
Construction code	API 650 basic standard 5th edition
Material of construction	A283 C

What is the minimum acceptable thickness t_{min} for the bottom course? Use the 'full course' equation $t_{min} = 2.6(H-1)DG/SE$

(a) 0.48 in ☐
(b) 0.35 in ☐
(c) 0.25 in ☐
(d) 0.75 in ☐

Q7. API 653: hydrotest height (entire course consideration)

An API 12C 15th edition tank of diameter 150 ft has a bottom course made of A285C. The measured minimum average thickness for the *entire bottom course* is 0.2 in. What is the maximum allowable fill height for hydrotesting this tank?

(a) 10.5 ft ☐
(b) 12.3 ft ☐
(c) 15.4 ft ☐
(d) 20.6 ft ☐

Q8. API 653: calculation of allowable t_2 (including corrosion allowance)

A tank has an average minimum measured thickness (t_1) of 0.5 in and has a design corrosion allowance of 0.125 in.What is the minimum allowable individual thickness (t_2) of a corroded area anywhere, excluding any isolated pitting?

(a) 0.3 in ☐
(b) 0.125 in ☐
(c) 0.25 in ☐
(d) 0.425 in ☐

Q9. API 653: bottom annular plate thickness

If the stress in the first course of a tank is 26 000 psi and the course is $\frac{1}{2}$ in thick, what is the minimum thickness for the bottom annular plate?

(a) 0.17 in ☐
(b) 0.2 in ☐
(c) 0.27 in ☐
(d) 0.34 in ☐

Q10. API 653: hydrotest fill height for a complete tank

A tank is constructed to an unknown code but all the joints are butt welded. It is 120 ft in diameter and the material of construction is an unknown low carbon steel. There is *localized corrosion* on the bottom course and the minimum thickness is 0.25 in. What is the maximum fill height for hydrotesting the complete tank?

(a) 9.8 ft ☐
(b) 10.4 ft ☐

(c) 12.5 ft ☐
(d) 14.6 ft ☐

6.9 API 653 appendix B: tank bottom settlement: practice questions (set 2)

Q1. API 653: types of settlement

Shell settlement can be made up of three types. What are they?

(a) Rigid tilt, planar tilt and bottom settlement ☐
(b) Out-of-plane settlement, differential settlement and rigid tilt ☐
(c) Uniform settlement, differential settlement and planar tilt ☐
(d) Shell, annular ring and bottom plate settlement ☐

Q2. API 653: types of settlement

Which of these *does not* induce stresses in the tank structure (but may in the connections)?

(a) Uniform settlement ☐
(b) Out-of-plane settlement, differential settlement ☐
(c) Planar tilt ☐
(d) Both (a) and (c) above ☐

Q3. API 653: shell settlement

What shape does differential settlement follow?

(a) A tangent curve ☐
b) A straight tilt ☐
c) A cosine curve ☐
d) None of the above ☐

Q4. API 653: maximum allowable deflection

Maximum allowable out-of-plane deflection *S* (ft) is given by the equation:

$$S \leqslant \left(L^2 \times Y \times 11\right)/[2(E \times H)]$$

where

L = arc length (ft) between measurement points = 20 ft
Y = yield strength (psi) = 20 000 psi
E = Young's modulus (psi) = 24 × 106 psi
H = tank height (ft) = 50 ft

What is the maximum allowable out-of-plane deflection *S*?

(a) 0.25 in ☐
(b) 0.44 in ☐
(c) 0.65 in ☐
(d) 1.2 in ☐

Q5. API 653: shell settlement

In general, when is most settlement presumed to have occurred for (say) a 10-year-old tank that is showing settlement?

(a) Immediately after the initial hydrotest before putting into service ☐
(b) In the first few years of service ☐
(c) Approximately evenly over the tank's life to date ☐
(d) In the most recent years as foundation washout, etc., gets worse ☐

Q6. API 653: edge settlement repairs

It is acceptable to repair the bottom-to-shell weld without further investigation by an experienced engineer as long as the actual settlement is not greater than:

(a) 20 % of the maximum allowable settlement ☐
(b) 50 % of the bottom plate thickness ☐
(c) 50 % of the maximum allowable settlement ☐
(d) 100 % of the maximum allowable, as long as there are no cracks ☐

Q7. API 653: measured edge settlement

A tank which when new has the centre of its bottom lower than its edges is called a:

(a) Cone-up type ☐
(b) Cone-down type ☐
(c) Elephant's foot type ☐
(d) Inclined-bottom type ☐

Q8. API 653: settlement

What is the 'least squares fit' method all about?

(a) Determining an accurate reading for roof distortion ☐
(b) Determining an accurate measurement of floor bulges ☐
(c) Determining the size and shape of floor plates for optimum fit ☐
(d) Determining an accurate reading for settlement ☐

Q9. API 653: settlement

What can be caused by rigid (planar) tilt?

(a) Bulges in the tank floor ☐
(b) Differential edge settlement ☐
(c) A sticking floating roof ☐
(d) All of the above ☐

Q10. API 653: settlement

A lack of circularity at the top of a tank is typically a feature of:

(a) Planar tilt ☐
(b) Out-of-plane settlement ☐
(c) Uniform settlement ☐
(d) Cosine or sine curve settlement ☐

Chapter 7

API 650: Tank Design

7.1 Reminder: the API 653 body of knowledge (BOK)

Strictly, the API 653 BOK and examination are about the in-service life of storage tanks, i.e. that period after construction when relevant approvals and certification requirements have been completed. This is the same philosophy as the other two major ICPs: API 510 (vessels) and API 570 (pipework). The practical situation is a bit different. Whereas API 653 provides good coverage of inspection, repair, alteration and reconstruction (its title) it only contains a limited amount of technical data on shell and nozzle design. This is often needed for alteration and (particularly) reconstruction; hence there is a need for the BOK to fall back on the new tank construction code: API 650.

7.1.1 How much of API 650 is in the API 653 BOK?

This depends on how you look at it. API 650 is a good code, full of technical details. Its 400+ pages divide roughly 50:50 between the body of the code (sections 1 to 10) and a long procession of appendices (A to X) (see Fig. 7.1). It would be next to impossible to learn all of this volume of material. The API published BOK is not particularly useful in helping you decide which bits of API 650 you need to learn. The necessary information is there, but it does not exactly jump out of the page at you. To confuse the matter, part of it lists what is *not* in the BOK and then lists exclusions from these exclusions. Fortunately, the situation is simpler than it appears. Look at these guidance points:

- Almost all of the exam questions sourced from API 650 appear in the *open-book* section of the exam. They have to, if you think about it, or candidates would need to learn all

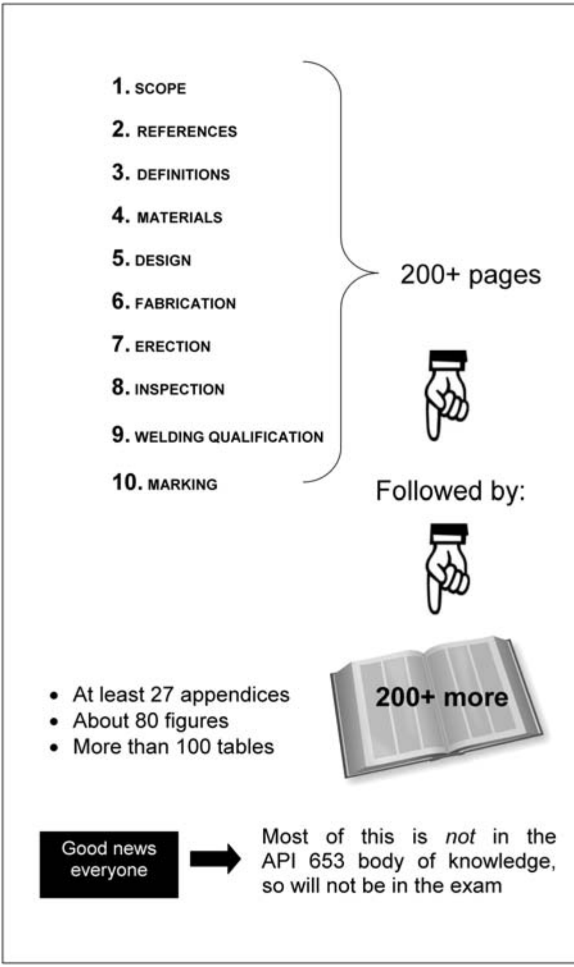


Figure 7.1 The contents of API 650 11th edition: tank construction code

of API 650, 400 + pages, most of which is fairly peripheral to the API 653 BOK.

- Exam questions tend to be chosen from a few selected areas of API 650. They are surprisingly predictable – most are about:
  - Toughness requirements of materials
  - Allowable stresses in shell material and the resulting shell thickness
  - Arrangement and dimensions of shell nozzles/connections (particularly welds), roof fittings or foundations
  - A few specific bits in the appendices about elevated temperature tanks, stainless steel tanks or floating roofs.

Figures 7.2 and 7.3 below summarize the situation. Taken together these two figures show almost all of the exam question subjects that are sourced from API 650. Remember:

- They are likely to be open-book questions.
- The questions will either be about reconstructed tanks (API 653 section 10) or specifically mention *new* tanks.
- There will be little technical interpretation involved – it is simply a case of picking bits of information from arrangement drawings or tables.

To help you anticipate the questions that can appear in the exam, we will look at the technical aspects in turn. Remember, again, that there is no great technical depth to the exam question content. Getting the correct answer is simply a matter of knowing where to look in the main sections or few relevant appendices of API 650.

7.2 API 650: material allowable stresses

We first saw this idea back in Chapter 6 of this book. All feasible shell materials are allocated an allowable stress value *S*, which is then used in a simple equation to calculate the minimum required thickness. There are two possible options

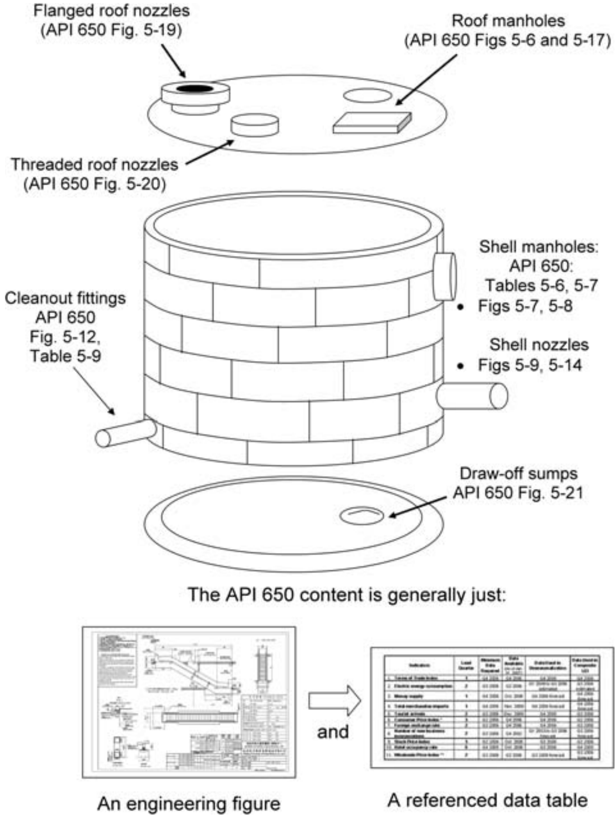


Figure 7.2 API 650 BOK content (1)

to choose from for each material – a slightly higher *S* value being used if the tank is to be hydrotested.

For calculating t_{min} for corroded existing tanks the table of *S* values in API 653 Table 4-1 is used. This makes sense as the tank is already built and no new shell components are being added. For new or reconstructed tanks, however (reconstruction is treated the same as a new build), Table 5-2 (a or b)

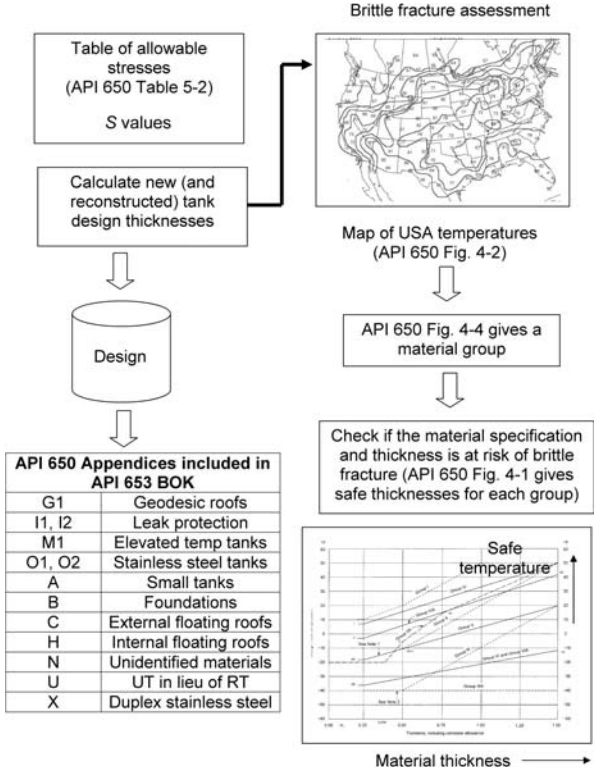


Figure 7.3 API 650 BOK content (2)

of API 650 is used. This contains much the same range of material in a similar format to Table 4-1 of API 653 but the *values are different*.

7.2.1 Why do API 653 and 650 have different allowable stress (*S*) values?

Simply because they are different scenarios. API 650 is for new build, when the objective is to specify an *S* value that allows for a certain ‘factor of safety’. API 653 then takes over for the assessment of corroded tanks where the objective is to keep the tank in operation. It does this by using up some of the margin that was previously provided by the API 650 *S* value. Hence the *S* values in API 653 Table 4-1 are higher, by about 10–20 %, depending on the material.

Here it is again, so you do not get confused:

- API 650 Table 5-2 contains *S* values to be used for new build or reconstructed tank calculations. The figures come from the percentages of yield (*Y*) and tensile (*T*) values specified by API 650 (5.6.2.1), i.e. 66 % *Y* or 40 % *T*, whichever is less. They are the same for all shell courses.
- API 653 Table 4-1 contains *S* values to be used for the assessment of existing corroded tanks. The figures come from the higher percentages of yield (*Y*) and tensile (*T*) values specified by API 653 (4.3.3.1). They are the smaller of 80 % *Y* or 42.9 % *T* for the lower two shell courses and the smaller of 88 % Y or 47.2 % *T* for all the other courses.
- Look back at Fig. 6.5 of this book and you can see this comparison expressed in a table.

Figure 7.4 shows how both API 650 and 653 present this *S* data. Most API 653 exams contain questions that require you to pick out *S* values from one of these tables, so just use this guideline:

- If the question refers to the evaluation of existing corroded tanks, use the *S* values from API 653 (Table 4-1) and note which shell courses are referred to

    but

- If the question mentions reconstructed or newbuild tanks, use the *S* values from API 650 (Table 5-2)

    and always

- Watch for whether the question mentions a hydrotest or not, as that will affect the values to use.

The API 650 format: API 650 Table 5-2
-For new and reconstructed tanks-

Material	Grade	Thickness	Min Y (psi)	Min T (psi)	Product stress (psi): all courses	Hydro stress (psi): all courses
A 283	C	All	30 000	55 000	20 000	22 500
No provision for unknown material						

Note how the allowable S values are **higher** for in-service assessment of corroded tanks (by accepting a lower margin in order to keep the tank in service)

The API 653 format: API 653 Table 4-1
-For in-service existing tanks-

Material grade	Min Y (psi)	Min T (psi)	Product stress (psi)		Hydro stress (psi)	
			Lower 2 courses	Other courses	Lower 2 courses	Other courses
A293-C	30 000	55 000	23 600	26 000	26 000	27 000
Unknown	30 000	55 000	23 600	26 000	26 000	27 000

Remember these figures are derived from the equations below (and then rounded up for convenience)

Application	Product stress		Hydro stress	
New or reconstructed tank: API 650	The lower of $0.66Y$ or $0.4T$		The lower of $0.75Y$ or $0.43T$	
Corrosion/repair assessment: API 653	Lower 2 courses	Upper courses	Lower 2 courses	Upper courses
	The lower of $0.8Y$ or $0.43T$	The lower of $0.88Y$ or $0.472T$	The lower of $0.88Y$ or $0.472T$	The lower of $0.9Y$ or $0.519T$

Figure 7.4 *S* values from API 650 and 653

7.3 API 650: material toughness requirements

As well as strength, API codes are always concerned with material toughness. It is toughness (not ductility), that provides the resistance to brittle fracture either during hydrotest or in cold conditions. API 653 section 5 has its own crude assessment of the risk of brittle fracture during hydrotest but API 650 covers it in more detail for use at the newbuild or reconstruction stage.

In common with most other API (and ASME) codes, API 650 uses a straightforward routine for assessing toughness. It is based on the premise that some combinations of material, thickness and minimum design temperature do not require impact testing because previous experience dictates that there will be no problem with brittle fracture; i.e. toughness is adequate. Conversely, if the material/thickness/temperature combination does not meet the necessary threshold levels, then impact testing is required to test whether the material has sufficient toughness or not. Impact (Charpy) specimens are tested in groups of three specimens and the results compared with minimum single and average reading requirements given in a table in the code.

The API 650 method (see Fig 7.5 below) is set out in section 4 of the code and is as follows:

- Step 1. For a given material, identify its group number (I to VI) from API 650 Table 4-4(a or b). Be careful to note if the material is 'killed' and/or normalized as this can affect its group. Watch out for information given in the notes at the bottom of the table also.
- Step 2. For a given location in the USA determine the lowest one day mean (average) temperature (LODMAT) from the map in API 650 Fig. 4-2.
- Step 3. Go to the graphs in API 650 Fig. 4-1 and plot the LODMAT temperature against the thickness of the material in question, then compare it with the line on the graph for the current material group.
- Step 4. If the plot point on the API 650 Fig. 4-1 graph falls *above* the line for the material group, impact tests are not needed as brittle fracture is not considered likely.
- Step 5. If the plot point on the Fig. 4-1 graph falls *below* the line for the material group then the material must be impact tested to see whether it has adequate toughness or not. The acceptance values are shown in Table 4-5 of API 650 and range from 20 to 68 J (15–50 ft-lb) depending on material group, thickness and the orientation of the

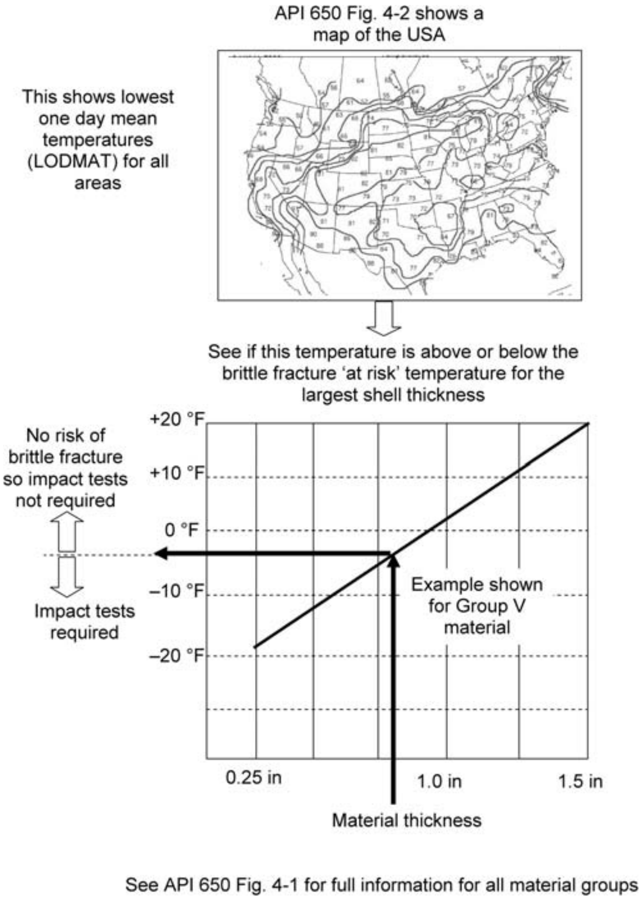


Figure 7.5 API 650 brittle fracture assessment

specimen taken from the parent metal plate. All test results are calculated from the average of three test specimens.

7.4 Tank component arrangement and sizes

The second API 650 topic that is included in the API 653 BOK covers acceptable material/weld sizes and arrangements for some of the major tank components. As a construction code, API 650 contains a lot of detailed technical requirements about how to attach nozzles and other fittings to the shell, roof and bottom. There are several thousand of these requirements, compressed into a family of full-page arrangement drawings, many further qualified by referenced tables of data. These tables mainly cover material thickness, pipe schedules, minimum weld sizes and such like. Fortunately, not all are in the API 653 BOK. The main ones that are included are:

- Shell manholes API 650 Fig. 5-7 and Tables 5-3 to 5-5
- Shell nozzles API 650 Fig. 5-8 and Tables 5-6 to 5-9
- Shell nozzles near weld seams API 650 Fig. 5-14
- Minimum spacing of welds API 650 Fig. 5-9
- Shell connections flush with the bottom API 650 Fig. 5-14
- Draw-off sumps API 650 Fig. 5-21 and Table 5-16
- Clean-out fittings API 650 Fig. 5-12 and Table 5-9
- Roof manholes API 650 Fig. 5-6 and Table 5-13
- Roof rectangular hatches API 650 Fig. 5-17
- Flanged roof nozzles API 650 Fig. 5-19
- Threaded roof nozzles API 650 Fig 5-20

7.5 Some tips on exam questions

The API 653 examination frequently contains questions taken from the long list of figures and tables above. There are normally only a handful, however, and the exam questions that can be asked are constrained by:

- The exam questions do not reproduce drawings from API 650, so they have to rely on text or data tables to get their questions.
- It is surprisingly difficult to ask a question, in text form, about something on a drawing *unless* it is kept very simple. Questions are commonly therefore about material thick-

ness, weld size or some angle or other that can be picked out of one of the API 650 figures without too much chance of misinterpretation.

7.6 Finally: bits and pieces from the API 650 appendices

Very little of the content of all the API 650 appendices ever appears in the API 653 exam. There is far too much of it, most of which is of little practical necessity to API 653 storage tank inspection. Picking through the published API body of knowledge (BOK) reveals the few bits of the appendices that are included:

Appendix	A:	Optional design small tank
	B:	Tank foundations
	C:	External floating roofs
	H:	Internal floating roofs
	N:	Unidentified materials
	U:	UT in lieu of RT
	X:	Duplex stainless steel tanks

Appendix	G1 (only):	Geodesic dome roof
	I1, I2 (only):	Underfloor leak protection
	M1 (only):	Elevated temperature tanks
	O1, O2 (only):	Under-bottom connections
	S1 (only):	Stainless steel tanks

It is difficult to see any great underlying pattern in this selection. The good news is that they are not a major source of exam questions – perhaps one or two from the 50 open-book questions in the exam. They are nearly always very straightforward – as long as you can find the correct appendix, you should be able to pick out the answer. Figure 7.6 shows some points from these appendices that make good subjects for exam questions.

App G Geodesic dome roofs	• Usually made of aluminium (G-1) • Max design temperature 200 °F
App I Undertank leak detection	• A release prevention barrier (RPB) is recommended for new construction • Drain pipe fitted through concrete ringwalls (Fig. I-1)
App M Elevated temperature tanks	• Design temperature range 200–500 °F (93–260 °C)
App C External floating roofs	• Bonding (grounding) shunts fitted to the uppermost seal (C.3.1.6)
App H Internal floating roofs	• Movable hatches and fittings must be electrically bonded to the internal floating roof to avoid sparking when opening (H.4.1.6)
App U UT in lieu of RT	• UT of welds must extend the lower of 1 in or 1 x material thickness (U.3.1) either side of the weld

Figure 7.6 Some useful BOK points from the API 650 appendices

Chapter 8

Tank Non-destructive Examination

Non-destructive examination (NDE) of storage tanks is a subject of direct relevance to tank inspections. Although an API inspector would rarely perform NDE themselves (the NDE technician or API-termed 'examiner' does that) it is the role of the inspector to specify the scope, check the technique, and evaluate the results. In the context of the API 653 ICP, NDE questions form a sizeable chunk of the body of knowledge (BOK) and appear, fairly predictably, as exam questions of several sorts.

Let us start with these points about the NDE coverage of API 653:

- The NDE content of API 653 nearly all relates to tank *repairs*.
- The requirements supplement the fuller coverage in the tank construction code API 650. They are necessary to fill in the gaps, as API 650 is about new construction, so does not cover in-service repairs.
- There are two, almost completely separate, parts to storage tank NDE. The techniques and technical details (covered in ASME V), and scope or extent of NDE that is required, which is found in API 653 itself.
- The NDE content of API 653 is separated into two parts. More than 90 % is found in section 12: *Examination and Testing,* catalogued by *area* of the tank. This is then summarized by techniques (VT, PT, UT, etc.) in Annex F: *NDE Requirements Summary* near the back of the code.

Figure 8.1 below summarizes the situation. Note how strictly (as clearly stated in API 653 (12.1.1.1)) the source code for NDE compliance is actually the new construction code API 650. In practice, this tends mainly to influence tanks that are being reconstructed (cut up and reassembled somewhere else), as these are effectively treated as if they are new-build

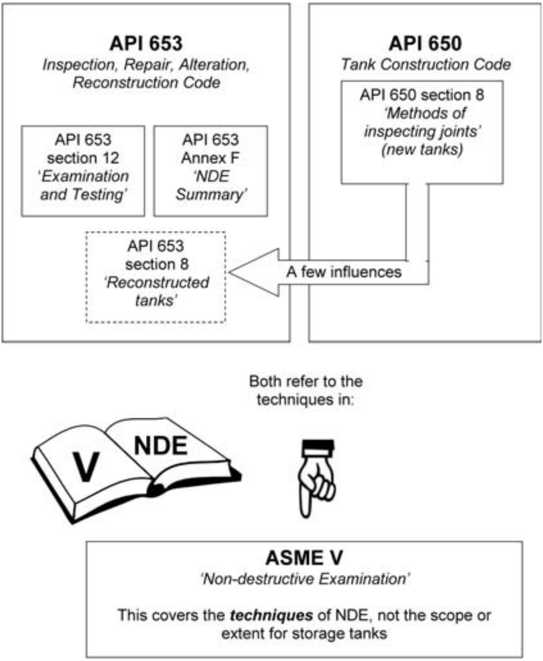


Figure 8.1 The tank NDE scope of API 653 and 650

tanks. In most practical in-service inspection/repair/alteration scenarios the relevant NDE requirements are not fully covered in API 650, and API 653 steps in to take over (and take priority).

8.1 The ideas behind API 653 section 12: examination and testing

Although API 653 section 12.1 is set out as a long list of uninspiring '100 % NDE' text clauses (with no diagrams) the overall technical ideas behind it are quite straightforward.

- *Visual inspection*. Almost all welding activity requires visual testing (VT) at stages before, during and after the welding.
- *Crack detection*. Completed fillet welds (patches, reinforcing plates, etc.) are checked for cracks by PT/MT, as well as the usual VT.
- *Butt welds*. Used for shell insert patches, plate replacement and similar, these require volumetric NDE to check for cracks and other defects inside the weld.
- *Parent material*. This will be welded and must be free of defects. The main scenarios are:
  – After removal of attachments: visual/PT/MT for surface cracks (12.1.4.1, 12.1.2.2, 12.1.8.2, etc.)
  – Before welding penetrations: shell requires UT for laminations (12.1.2.1, 12.1.8.1).
  – After grinding out of defects and backgouging the cavities: need visual/PT/MT for surface cracks (12.1.3.1).

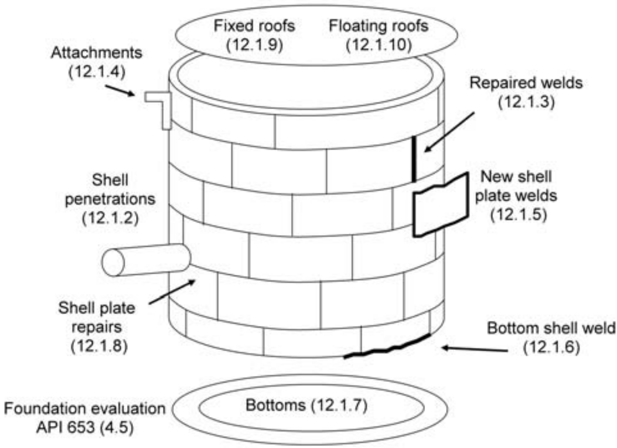
These fairly general points actually consume quite a lot of the text clauses of API 653 section 12.1. It is probably easier to remember their principles (have a look at Figs 8.2 and 8.3) than the fragmented way they are set out in section 12.1. Remember that they are also repeated in API 653 Annex F.

8.2 Weld leak testing

API 653 section 12 explains four methods of leak testing in repaired/new welds. The purpose of these is to make sure there are no leak paths existing through the welds that would cause a leak when the tank is put into service. Note two important points about these tests:

- They are in addition to the usual VT/PT/MT surface crack detection used on (mainly fillet) welds.
- They are designed to be more searching than the hydrostatic test. Water is notoriously poor at finding its way through tight or staggered cracks, and will often not

These are the NDE-related sections from API 653 section 12: *Examination and Testing*



NDE Summaries in API 653 Annex F	
F.2	Visual inspection (all areas)
F.3	PT/UT (mainly before and after weld repairs)
F.4	Lamination checks before weld repairs
F.5	Vacuum box testing
F.6	Tracer gas testing
F.7	Diesel oil 'wicking' test
F.8	Air leak test
F.9	RT (mainly about insert plates or as an alternative to UT)
Remember these are all related to tank repairs and alterations	

Figure 8.2 API 653: NDE content

show leaks that are easily detectable using more searching methods.

API 653 section 12 is quite careful in the way in which it recommends each of the techniques for the application to which it is best suited. The way in which this is presented in the code text does not exactly make it jump out at you, but it

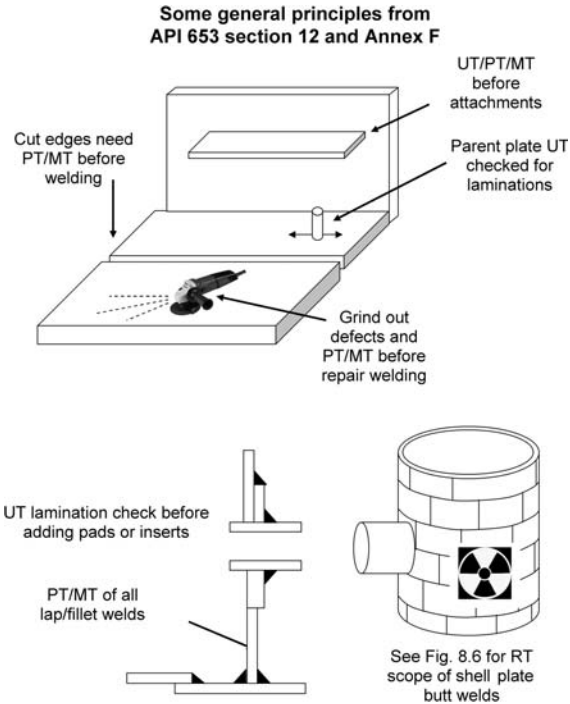


Figure 8.3 Some general principles of tank repair/NDE

is there. Figure 8.4 shows the idea and Fig. 8.5 shows the techniques in more detail.

8.2.1 Vacuum box testing (F5)

This is done using a right-angled box surrounded by rubber seals. It is placed over repair welds and a vacuum drawn inside the box. Any air leaking in through weld cracks soon shows up as an increase in pressure. See API 650 (8.6.1) for procedure details.

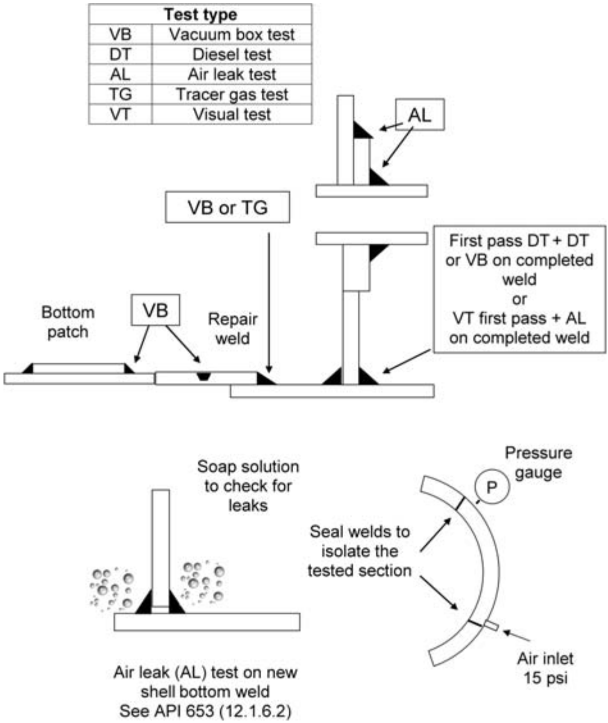


Figure 8.4 Weld testing methods

8.2.2 Diesel oil 'wicking' test (F7)

API 650 sees this as an *alternative* to a vacuum box test. Section 12.1.6 is a good example – it specifies either a vacuum box *or* diesel oil test on a completed shell-to-bottom fillet weld. This works by simply painting diesel oil on to one side of a weld and seeing if, over a minimum period of 4 hours, it creeps through to the other side by capillary 'wicking' action though penetrating cracks or other defects. Spreading chalk or similar powder on the weld helps show when the diesel oil is creeping through.

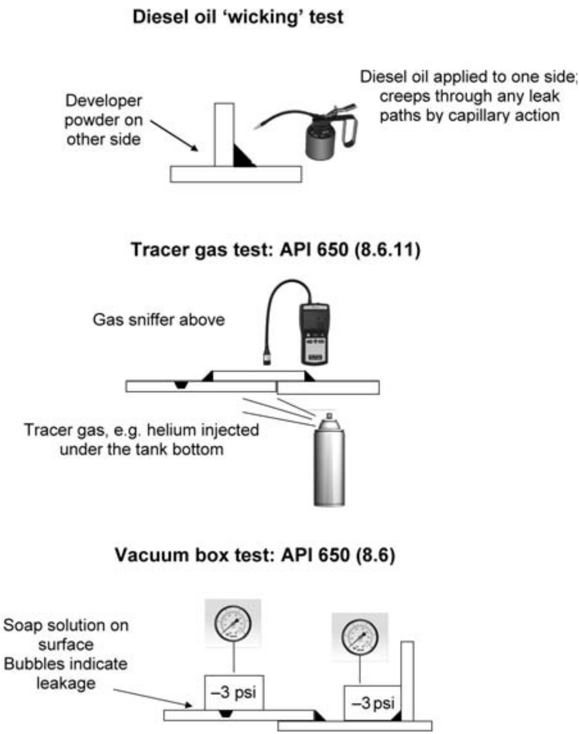


Figure 8.5 Weld leak testing techniques

8.2.3 Tracer gas testing (F6)

This is an extra-sensitive technique (again, an alternative to vacuum box testing) which can be used on new tank bottom welds. The gas (usually helium) is inserted under the tank bottom and sniffer detectors used to detect any leakage through to the top surface. Owing to the difficulty of constraining the gas to one side of the weld, this technique is normally only used for tank bottoms. It is such a sensitive technique that it can be very difficult to get welds totally leak-free.

8.2.4 Air leak testing (F8)

The main purpose of this test is for testing new nozzles/shell penetrations when they are fitted with reinforcing (compensation) pads. Air is introduced between the two plates, hence testing whether there are any leak paths in the fillet weld(s). Threaded air connection/bleed nipple holes are installed for this purpose.

As a special case the air test can be used as an alternative to diesel oil testing of the first pass of a new (or repaired) shell-to-bottom fillet weld. Figure 8.4 shows the details – note how weld 'blockages' need to be installed to isolate the area under test and how the air entry point and pressure sensing points must be at opposite ends of the part of the annulus being tested.

8.2.5 Weld radiography

API and ASME codes have long preferred RT to other volumetric methods such as shear-wave (angle probe) UT. This is probably partly because of the fact that RT gives a permanent record and partly for historical reasons, rather then necessarily its effectiveness in finding defects. In reality, doing RT on a plant where repairs are being carried out can be awkward owing to health and safety requirements so many operators prefer UT. In recent years, API codes have become more open to replacement of RT with UT, although their equivalent (ASME and API) construction codes have been slower to follow.

Fundamentally, the RT required by API 653 section 12 starts with that specified in API 650. Note where it says this in API 653 (12.2.1). This is then supplemented (added to) by the clauses of API 653 (12.2) – catering for repair and replacement activities that are not covered by API 650 (which is only about new construction). While the code clauses are not particularly memorable, the principle makes sense – site repair welds are rarely done under optimum conditions, so extra RT is a good idea to find any defects that may be caused as a result.

8.3 How much RT does API 650 require?

It all depends on the thickness of the shell. API 650 section 8.1.2: *Number and Location of Radiographs* sets out three scenarios: for shell plate material up to 10 mm, 10 mm to 25 mm and above 25 mm thick. It differentiates between vertical, horizontal and intersections and shows the requirements fairly clearly in the code Fig 8-1.

For shells up to 10 mm thick in particular, the requirements are not that obvious, i.e.:

- For vertical welds: one spot RT in the first 10 ft and in each 100 ft thereafter, 25 % of which need to be at intersections.

  and

- For horizontal welds: one spot RT in the first 10 ft and in each 200 ft thereafter.

Look at API 650 Fig 8-1 for the full details.

8.4 How much RT does API 653 require?

You can be excused for being a little confused about this. While straightforward in concept, the clauses API 653 (12.2.1.1) to (12.2.1.6) look a bit daunting. To simplify it, think of shell plate welds as being of the following types:

- 'New construction' type welds: i.e. new welds between new plates. This is exactly the same as new construction, so just follow API 650 (8.1.2) as API 653 has no additional requirements.
- 'Repair' welds. These may be between either new-to-existing plates or existing-to-existing plates. Treat these as repair welds (with a higher risk), so they need some additional RT.

8.4.1 Key point – the difference between new plates and replacement plates

Do not get confused by this one:

- 12.2.1.1 to 12.2.1.4 are about the situation where new shell plates are installed in a shell, to replace corroded ones. Figure 8.6 covers this scenario.
- 12.2.1.6 and its subsection. This is about when plates are cut out to provide *access doors* (to allow work to be carried out inside the tank) and then rewelded up afterwards.

Figure 8.7 below shows this situation. Note how one less vertical weld RT shot is required than when fitting a new shell plate (i.e. 12.2.1.1b).

For thicker materials >1 in the additional chance of defects means that full RT is required on vertical seams. In some cases, it is easier to cut out circular access doors than rectangular ones. This only requires 1 RT shot (see 12.2.1.6.1) unless, again, it is more than 1 in thick, when full RT is required.

Figure 8.8 shows what to do about reconstructed tanks.

8.4.2 What about exam questions?

It is easy to get overly excited about exam questions on RT. Surprisingly there are generally not that many about the required scope of RT for the multiple possible permutations of vertical, horizontal, intersection, new and repaired welds. One or two pop up in the open-book question section, typically one from API 650 and one from API 653. More common are questions from ASME V article 2 and API 577. These are of a more generic nature and often less technically rigorous than you might expect.

8.4.3 NDE procedures and qualifications

API codes (and their ICP exams) are littered with stuff about who needs to be qualified to what level and which procedures they should be working to. NDE activities are no exception.

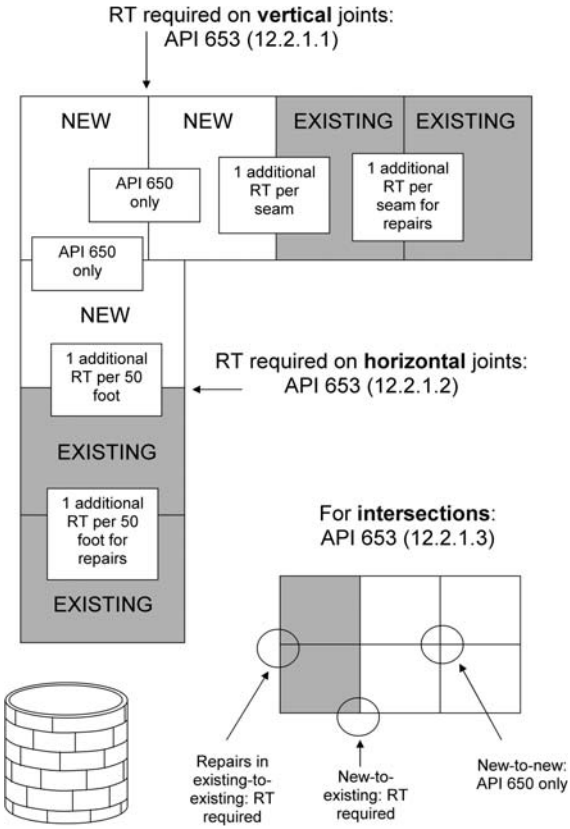


Figure 8.6 RT of shell plate repairs

These statements reflect a fairly consistent API view of the inspection world, but there is absolutely no reason why they should fit *your* situation.

API 653 Annex F provides the best summary of this information. Note how all NDE scopes from other chapters

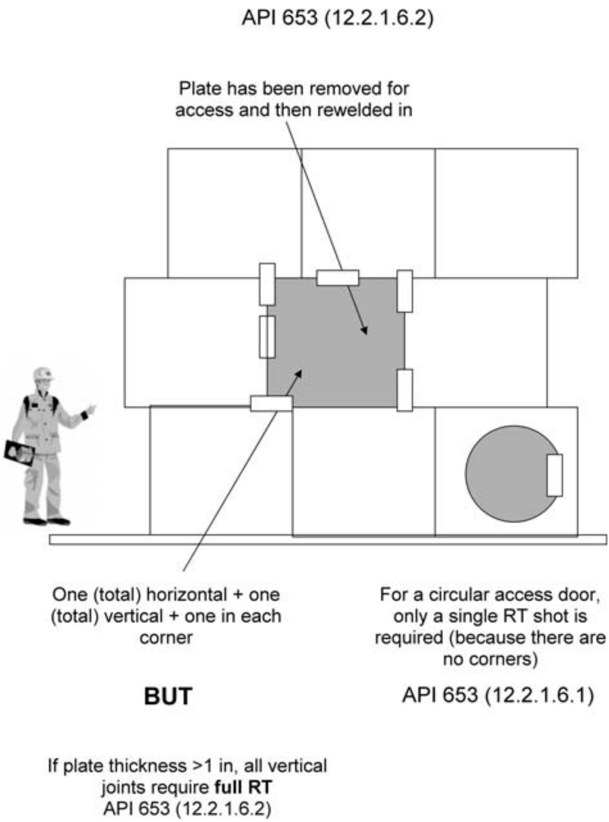


Figure 8.7 RT of access door sheets

are compiled together at the end of each subsection. Figure 8.9 is another way of presenting this.

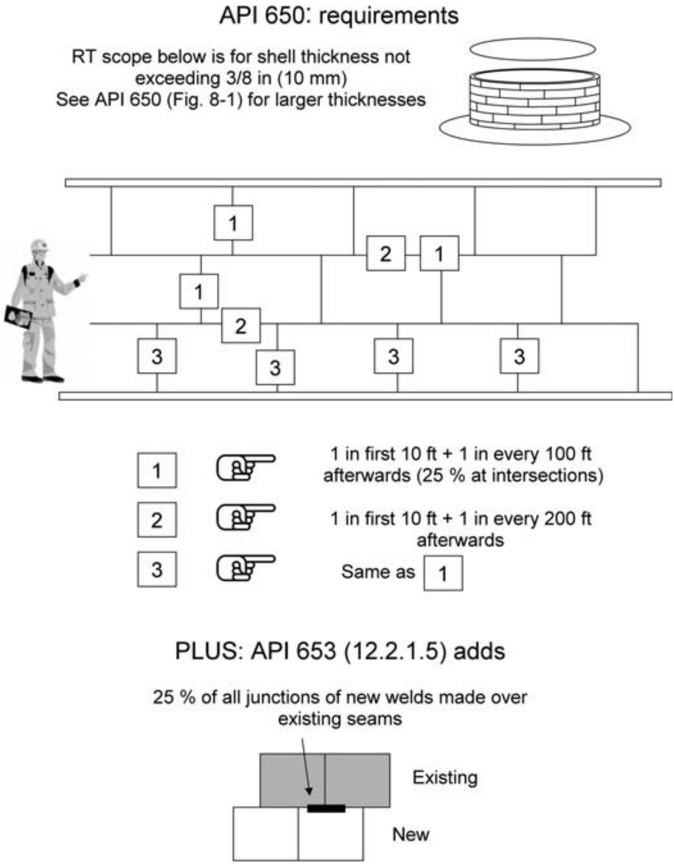


Figure 8.8 RT of reconstructed tanks

NDE STANDARDS REQUIREMENTS: API 653 ANNEX F			
Technique	Acceptance standard	Operator qualifications required	Procedure requirements
Visual F.2	650 (8.5)	None	None
MT F.3	ASME V Art 7	650 (8.2.3)	ASME V Art 7
PT F.3	ASME V Art 6	650 (8.2.3)	ASME V Art 6
UT F.4	As agreed 650 (8.3.2.5)	SNT-TC-1A L1/L2/L3	ASME V Art 4
Vacuum box F.5	-	650 (8.6.4) Eyesight	650 (8.6) 3 psi
Tracer gas F.6	-	None	An agreed procedure
Diesel test F.7	-	None	None
Air leak F.8	-	None	650 (7.3.5)
RT F.9	ASME VIII UW-51(b)	SNT-TC-1A L1/L2/L3	ASME V Art 2

Figure 8.9 NDE procedure requirements

Now try these practice questions.

8.5 Tank NDE: practice questions

Q1. API 653: shell penetrations

What NDE must always be carried out before adding a hot tap connection to a shell plate?

(a) RT or UT of the immediate area affected for laminations ☐
(b) UT of the immediate area affected for laminations ☐
(c) PT or MT of the immediate area ☐
(d) RT only of the immediate area and new welds ☐

Q2. API 653: shell penetrations

A hot tap connection to a shell plate has been examined by PT. Under what circumstances should the use of UT or fluorescent MT also be considered?

(a) When PT has detected a surface breaking flaw ☐
(b) When the shell plate is > $\frac{1}{2}$ inch and toughness is unknown ☐
(c) When the weld is subjected to fatigue stresses ☐
(d) All of the above ☐

Q3. API 653: shell penetrations

What NDE is required on the completed welds of stress relieved assemblies?

(a) MT or PT after stress relief, but before hydrostatic testing ☐
(b) MT or PT after hydrostatic testing ☐
(c) MT or PT before stress relief and UT or RT after hydrostatic testing ☐
(d) MT or PT before stress relief and after hydrostatic testing ☐

Q4. API 653: repaired weld flaws

What is the minimum level of NDE required on a completed butt weld repair?

(a) RT or UT of the full repair length ☐
(b) RT or UT of 50 % of the full butt weld length ☐
(c) PT or MT of the full repair length ☐
(d) 'Spot' RT or UT ☐

Q5. API 653: temporary and permanent shell attachments

How must completed permanent attachment welds be examined?

(a) By VT and MT or PT ☐
(b) By VT only ☐
(c) By VT if a shell to bottom weld or MT for any other type ☐
(d) Both (a) and (c) ☐

Q6. API 653: shell to bottom weld

A welded-on patch plate is to be placed over a shell to bottom weld. If the plate will cover 16 inches of the bottom weld, what length of shell to bottom plate weld needs to be inspected before the patch is applied?

(a) 12 inches ☐
(b) 16 inches ☐
(c) 24 inches ☐
(d) 28 inches ☐

Q7. API 653: bottoms

In addition to PT or MT, what testing is required for areas of bottom plates repaired by welding?

(a) VT ☐
(b) MT or PT ☐
(c) VT plus vacuum box and solution or tracer gas and detector ☐
(d) Vacuum box and solution or tracer gas and detector ☐

Q8. API 653: number and location of radiographs

A new shell plate has been welded into an existing tank. The RT requirement is in accordance with API 650. What additional radiography will be required?

(a) One radiograph at each intersection ☐
(b) One additional radiograph for each vertical joint ☐
(c) One additional radiograph for each 50 feet of horizontal weld ☐
(d) All of the above ☐

Q9. API 653: acceptance criteria for existing shell plate welds

An intersection between a new and old weld contains defects unacceptable to the new standard. The defects are, however, acceptable to the original construction standard. Must they be repaired?

(a) Yes, if the defects are in the new weld ☐
(b) Yes, if the defects are in the old weld ☐
(c) No, they do not need repair ☐
(d) It is at the inspector's discretion ☐

Q10. API 653: marking and identification of radiographs

What does the letter R mean on a weld radiograph?

(a) The weld needs to be re-shot ☐
(b) The weld has been re-shot ☐
(c) The weld has been repaired ☐
(d) The RT has been carried out with gamma radiography ☐

Chapter 9

Tank Repairs and Alterations

Overall, a lot of the storage tanks in the world are in a bit of a mess. Here are the reasons why:

- *Poor maintenance*. Tanks are easily forgotten when allocating maintenance budgets to higher priority parts of a plant. They are often seen as being less process-critical. Access is also difficult – external inspection/maintenance requires scaffolding or mobile cranes.
- *Long lifetimes*. It is not unusual for tanks to be 50 or more years old.
- *Multiproduct use*. Changing process conditions leads to unpredictable (frequently unknown) corrosion rates.
- *Construction standards*. Although tank construction codes (particularly recent ones) are technically consistent in themselves, tanks are hardly high technology items. Most are made from corrosion-prone low carbon steel. They are simple utilitarian fabrications, rather than cutting-edge engineering structures, which is reflected in their low price.
- *Environmental conditions*. A lot of tanks are situated in dirty or marine environments. Once the external painting starts to break down, corrosion occurs quickly. It is worse if the external surfaces are lagged.

The result of all this is that most storage tanks end up needing a lot of repairs during their lifetime. These can range from small patches or replacement plate inserts through to replacing complete tank bottoms, shell courses (or ‘strakes’) or roofs. Some of these do little for the cosmetic appearance of the tank, but are perfectly technically viable – and cheaper than buying a new tank.

9.1 Repairs or alterations?

API in-service inspection codes are well known for their differentiation between *repairs* and *alterations*. They contain the definitive opinion that repairs and alteration are fundamentally different things. The rationale behind this is:

- Alterations involve some kind of 'new' design aspect (for the tank in question) that needs to be considered. Repairs do not.
- Because of the 'new design' aspect of alterations, technical details need to be approved and the work authorized to proceed by someone with the necessary knowledge. API-certified inspectors are not always expected to have this knowledge. Some higher technical authority (a qualified 'engineer') has to have the final word.

Fortunately API 653 is more logical than some other codes as to the difference between repair and alterations. This is then qualified by dividing each into 'major' or 'non-major' categories, i.e. major repairs and major alterations. Note that the code does not actually classify the opposite of *major* repair or alteration as *minor* or *ordinary*. It just infers that they are 'not major'. Wonderful.

Here are the key points:

A *repair* (non-major) is an activity used to fix some corrosion or similar problem to return a tank to a safe operating condition. Nothing is added and there is no significant design implication (API 653 definition 3.2.4).

A *major repair* is a repair (as above), but of a type specifically stated in API 653 definition 3.18, i.e.:

- Removing and then replacing a shell plate of longest dimension more than 12 in situated below liquid level.
- Removing and then replacing annular ring material with the longest dimension more than 12 in.
- Removing and then replacing more than 12 in of a vertical shell plate weld or annular plate ring radial weld located anywhere in the tank.

- Removing and replacing a significant amount (>50 % of weld) of the shell-to-bottom/ring weld.
- Jacking up the tank shell to renew the complete tank bottom.

An *alteration* (non-major) is some change or addition that changes the tank's physical dimension or configuration (definition 3.1).

A *major alteration* is an alteration (as above) that specifically involves:

- Installing a new shell penetration >NPS 12 below the design liquid level (NPS is nominal pipe size).
- Installing a new bottom penetration within 12 in of the shell.

Figure 9.1 shows the situation in pictorial form. Once you have accepted the principle of this repair versus alteration differentiation then the major versus non-major split fits in fairly naturally with the integrity implications of the activity. Repairs or alterations designed as *major* have a higher risk of leak or failure consequences if not done correctly. Figure 9.2 shows the responsibilities for approvals and the hydrotest requirements.

9.2 Hydrotest requirements

API 653's view is that 'non-major' repairs or alterations are not important enough to warrant a mandatory hydrotest. Owners/users can of course perform one if they wish but it is not a code requirement. For major repairs or alteration then a hydrotest is required by section 12.3.1b of API 653. Even this, however, can be overridden by either:

- An FFS assessment (API 653 section 12.3.2.7) – the exact type of which remains undefined.
- Complying with the relevant exemption clauses chosen from API 653 sections 12.3.2.3 to 12.3.2.7. This is a rather long list but, in summary, simply says that the major repairs/alteration meet the requirements of:

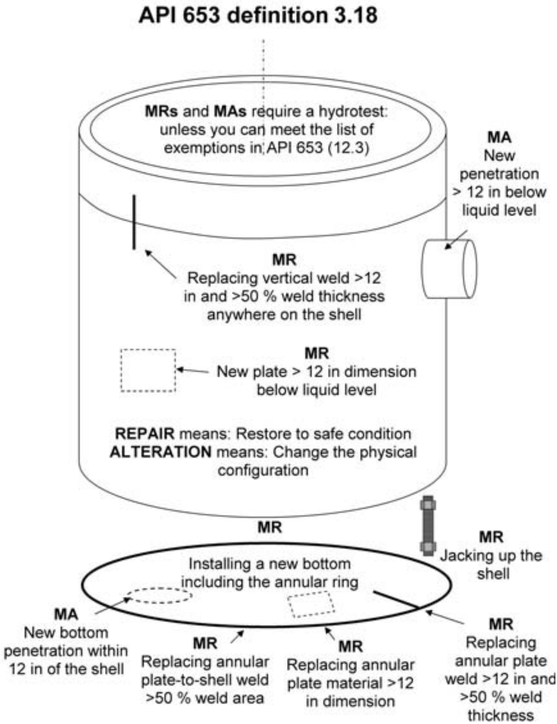


Figure 9.1 Major repairs (MR) and major alterations (MA): API 653

- Correct materials (with sufficient toughness)
- Qualified weld procedures
- Low hoop stress ($\leq$7 ksi)
- Good weld quality

Putting aside the minutiae of code clauses for the moment, you can see that API 653 does not actually impose a mandatory hydrotest for any repairs or alterations at all. It is

Remember that these are API 653's view of the world; they may, or may not, match your experience, or ways of working in real storage tank organizations

ACTIVITY	APPROVAL/ AUTHORIZATION TO START WORK	DESIGNATE HOLD POINTS	APPROVAL AND HOLD POINTS ON COMPLETION OF WORK	HYDROTEST?
Repair	I or E: API 653 (9.1.3)	I	I or E	Not required
Major repair	I or E	I	I or E	Required; but a list of exemptions available: API 653 (12.3.2.11b)
Alteration	E	I	I or E	Not required
Major alteration	E	I	I or E	Required; but a list of exemptions available: API 653 (12.3.2.11b)

- I: API Authorized Inspector
- E: Storage Tank Engineer

See API 653 (definition 3.18) for the explanation of major/non-major repairs and alterations

Figure 9.2 Approval and hydrotest requirements

mandatory for dismantled and reconstructed tanks (see API 653 section 12.3.1a) because this is similar to new construction activity. It therefore has to comply with the construction code API 650 as if it were a new tank, required to prove its integrity before use.

9.3 Repair and alterations – practical requirements

Section 9: *Tank Repair and Alterations* is one of the longest sections of API 653. From an API exam perspective also, the subject is important; repair and alteration-related topics can form up to 30–35 % of the total haul of exam questions. Most of these have a practical engineering aspect to them involving design, welding, testing or responsibilities rather than any deeply theoretical considerations.

Figure 9.3 shows the breakdown of the section. Note how it divides logically into activities involving shell plates,

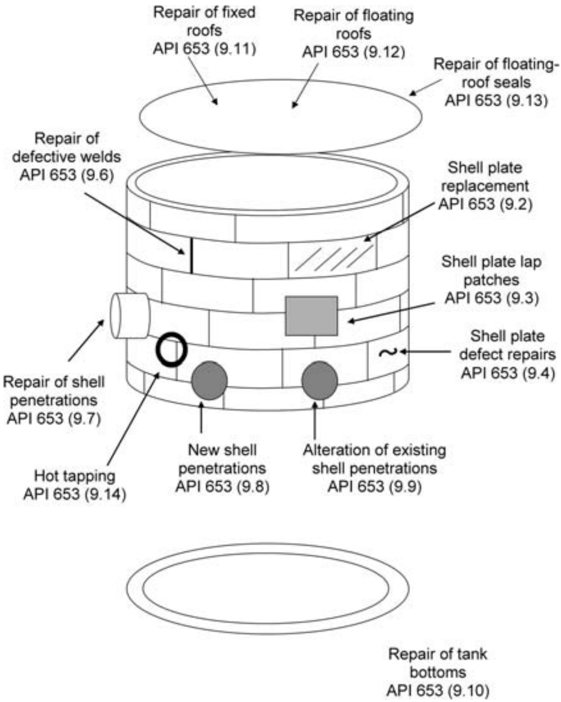


Figure 9.3 Tank repairs: the breakdown of API 653 section 9

penetrations (i.e. nozzles), bottoms and roofs. Detailed technical requirements cover all these areas – related to either repairs or alterations, as applicable. Throughout the sections, some common principles apply:

- Minimum and maximum repair sizes and thickness
- Allowable repair location
- Weld locations, types and sizes
- Methods of avoiding local hardness, leading to cracking and brittle fracture

We will look at these in turn, concentrating on those areas that feature heavily in the API exam questions.

9.3.1 Are these repairs temporary or permanent?

They are all permanent. Unlike pressure vessels, where some types of repairs have to be considered as temporary, storage tanks can be permanently repaired using fillet-welded 'lap' patches. They may not look particularly attractive, but they provide perfectly adequate strength and integrity against leaks. Non-welded repairs such as epoxy filler, wraps, clamps, etc., do not feature significantly in API 653 – there are a few references in API 575 but little technical detail. Welded repairs are clearly preferred, where possible.

9.3.2 The basics of code compliance

Fundamentally, tank repairs and alterations have to comply with the tank construction code API 650. Practically, however, API 650 does not cover most repair configurations, so API 653 section 9 takes over with the required technical detail. The principles are similar, although API 653 allows extra leeway in some areas, to allow for the realities of site fabrication work.

9.4 Repair of shell plates

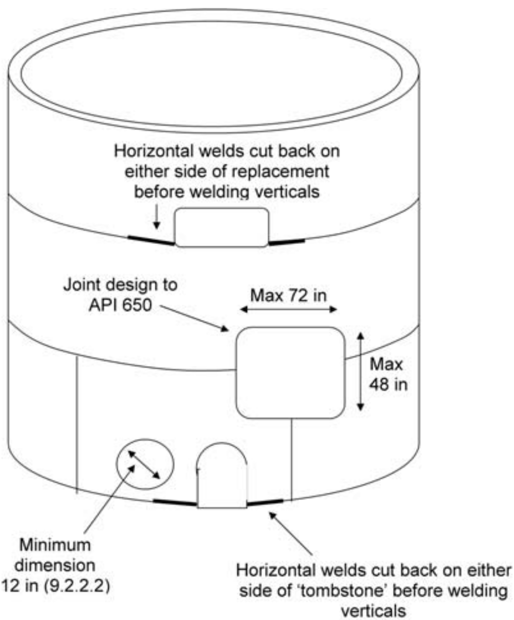
Repair of shell plates comprises two types:

- *Replacement plates*, where plates are cut out, normally because of corrosion, and a new replacement 'insert' plate is butt-welded in its place. These are covered in API 653 section 9.2.
- *Lap-welded patch plate (API 653 section 9.3)*. Here, a plate is fillet (lap)-welded over the top of a corroded (not cracked) area to restore the thickness and strength of the tank shell.

Both of these types are considered permanent repairs and the code clauses specify limitations on plate size and shape, allowable weld locations and design features related to them.

Engineering details of replacement shell plates are shown in API 653 Fig. 9-1. The main details of this are reproduced in Fig. 9.4 here – note the additional annotations taken from the subsections of API 653 (9.2).

API 653 section 9.3 covers similar restrictions for lap-welded patch plates. There is no code figure for this – all the requirements are listed in the multiple subsections of 9.3. Figure 9.5 below summarizes the main requirements – note the limits on minimum and maximum overlap and the similar size restrictions to those for butt-welded replacement (insert) patches. Lamination checks of the parent plate before welding are important – UT checks for parent plate laminations are therefore required by API 653 (9.3.1a).



See API 653 (Fig. 9-1) for full details

Figure 9.4 Replacement shell plates: API 653 section 9.2 and Fig. 9-1

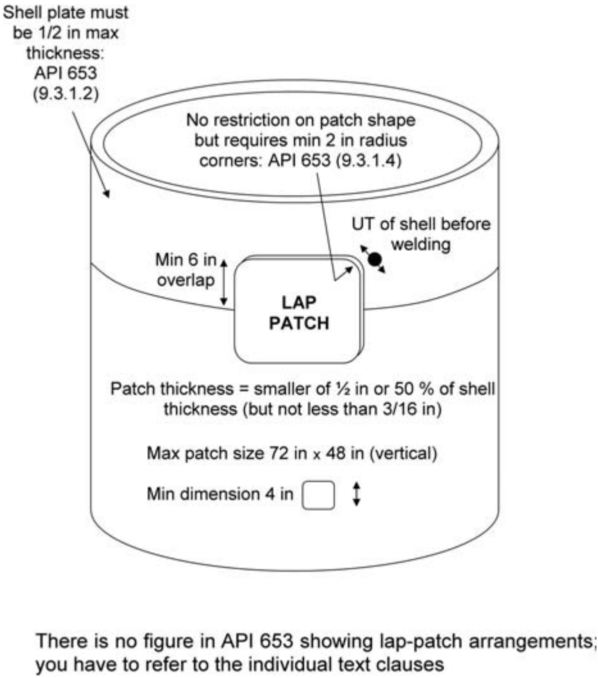


Figure 9.5 Shell lap patches: API 653 section 9.3

9.4.1 Repairing shell plate defects (9.6)

It is much easier to repair defective welds on shell plates *in situ* than to replace them or apply a lap-welded patch plate. As long as the minimum required plate thickness is maintained, corroded areas can be blended by grinding or blended and weld-repaired as need be. The requirements are fairly commonsense:

- Cracks, lack of fusion and slag must be ground out completely before rewelding.
- Excessive undercut in excess of API 650 limits needs to be removed by blending and rewelding if required (for plate

≤13 mm it is maximum 0.4 mm on vertical welds and 0.8 mm on horizontal welds).

- Weld arc strikes must be removed as they cause stress concentrations.

9.5 Shell penetrations

There are three main things you can do with tank shell penetrations (nozzles or access manholes)

- Repair them (9.7)
- Replace or add new penetrations (9.8)
- Alter existing penetrations (9.9)

9.5.1 Repair of penetrations (9.7)

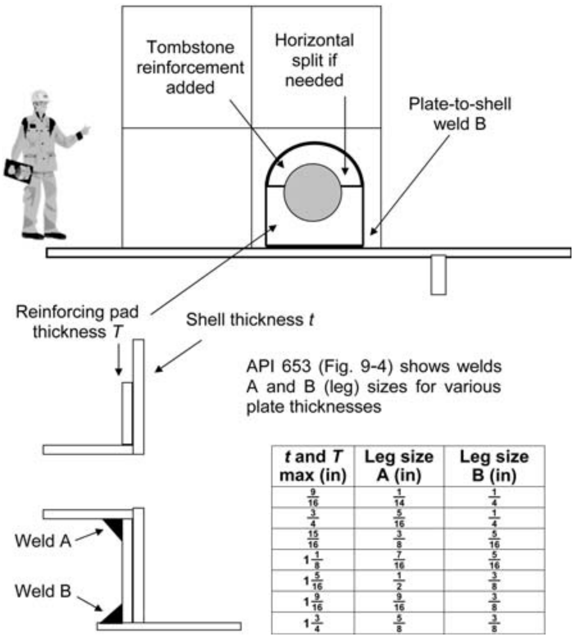
This is generally about adding of reinforcing (compensation) plates to existing nozzles. The reasons for needing to do this would be:

- An increase in tank maximum fill height or product specific gravity, meaning that existing nozzles near the bottom of the shell require additional compensation.
- The shell around existing nozzles is corroded (on either the inside or outside of the tank), so shell strength in that region needs to be restored.

Figure 9.6 shows the main technical requirements of adding these reinforcing plates to existing nozzles. Note the 'tombstone' plate fitted when the nozzle or manway is near the bottom of the tank (which they usually are). As you can see from the figure, the main issue is the minimum fillet weld (leg) size between the bottom of the tombstone plate and the bottom annular ring. Note how the nozzle-to-reinforcing plate weld is the same for the tombstone plate as for a reinforcing plate that does not extend all the way to the floor. The plate-to-floor weld is smaller.

Watch out for open-book exam questions about this section of the code – particularly about the optional horizontally split reinforcing plate and the positioning of the vent/tell-tale holes.

See API 653 (Fig. 9-4)



t and *T* max (in)	Leg size A (in)	Leg size B (in)
$\frac{9}{16}$	$\frac{1}{14}$	$\frac{1}{4}$
$\frac{3}{4}$	$\frac{5}{16}$	$\frac{1}{4}$
$\frac{15}{16}$	$\frac{3}{8}$	$\frac{5}{16}$
$1\frac{1}{8}$	$\frac{7}{16}$	$\frac{5}{16}$
$1\frac{5}{16}$	$\frac{1}{2}$	$\frac{3}{8}$
$1\frac{9}{16}$	$\frac{9}{16}$	$\frac{3}{8}$
$1\frac{3}{4}$	$\frac{5}{8}$	$\frac{3}{8}$

Figure 9.6 Adding reinforcement to existing nozzles

9.5.2 Alteration of existing shell penetrations (9.9)

This is about the effects of installing an additional tank bottom on top of an existing corroded one. The additional bottom is normally added either directly on or an inch or two above the existing one, with a layer of cushioning material such as sand or crushed stone in between the two. This causes the new bottom-to-shell weld to be raised up nearer the lowest shell nozzles reinforcing plate, frequently reducing the weld spacing to below the minimum distance required. Section 9.9 gives three solutions to this:

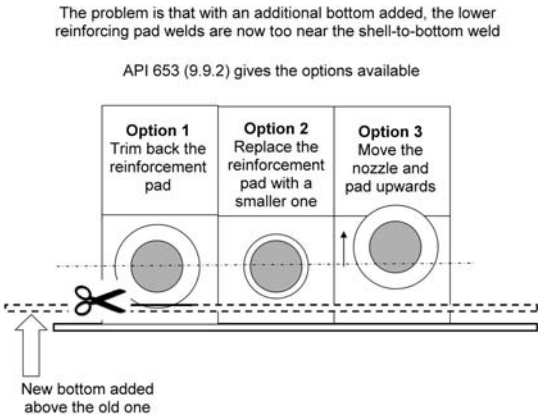


Figure 9.7 Altering existing penetrations

- Trim the bottom of the existing nozzle reinforcing plate, as long as there is still adequate reinforcement available (as per the API 650 calculation, section 9.9.2.1).
- Remove the existing reinforcing plate and replace with a new one (9.9.2.2). Sometimes it is possible to just replace the bottom half, leaving the top half in place.
- Move the offending nozzle and its reinforcing plate upwards, increasing the spacing to the shell-to-bottom weld.

Figure 9.7 summarizes these three methods. As most of the technical detail is about weld spacing and sizes, these are normally only suitable for open-book exam questions. It is difficult to construct sensible closed-book exam questions from this topic.

9.6 Adding an additional bottom through an existing tombstone plate (9.9.4)

API 653 (9.9.4) is, arguably, a special case, where an additional bottom is added through an existing tombstone reinforcing plate. This is a rather complex new code section –

a bit too involved for more than the occasional open-book exam question. The basic idea (see Fig. 9-6 of API 653) is that the lower edge of the tombstone plate is cut and bevelled to allow it to be welded into the new fillet weld added between the existing shell plate and the new bottom. This is then 'backed up' with an additional fillet weld on that.

9.7 Repair of tank bottoms

Tank bottoms can corrode from either the product side or soil side, so bottom repairs are a common occurrence, particularly on old, multiproduct tanks without cathodic protection.

Similar to shells, bottoms can be permanently repaired using individual fillet-welded lap patch plates. Alternatively, if corrosion is very widespread, a complete new bottom can be fitted, usually directly on top of the existing one, unless there is some pressing reason for removing it.

9.7.1 Patch plate bottom repairs

API 653 Fig. 9-9 contains all the necessary information about what you can and can not do when doing bottom patch plate repairs. Figure 9.8 below shows some of the major points. Note how:

- Minimum patch plate dimension is either 6 in or 12 in, depending on whether it overlaps an existing seam (9.10.1.1b).
- Patch plates may be almost any shape or maximum size.
- Minimum spacing distances have to be met to avoid HAZ interaction causing local hardening and cracking problems.
- Special restrictions apply in the critical zone (the annular area extending 3 in in from the shell).

9.7.2 Repairs in the critical zone

The critical zone (API 653 definition 3.10) is the annular area of the tank bottom extending 3 in in from the shell. For tanks fitted with an annular ring, the critical zone is part of the

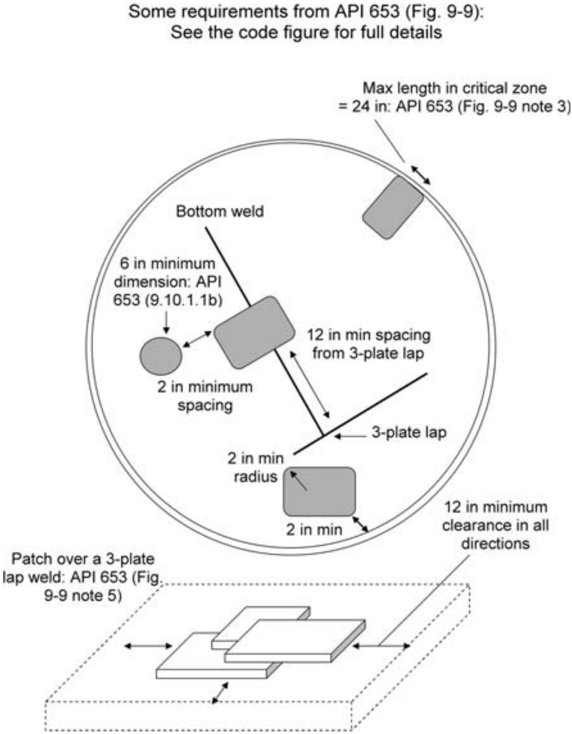


Figure 9.8 Patch plate bottom repairs

annular ring, but generally not all of it. The reason for separately identifying the critical zone is that it sees high bending stresses if foundation washout or distortion causes edge settlement. This bending would have a tendency to tear apart the shell-to-bottom fillet welds, as they have little strength. Stresses increase with small radial lengths and large vertical deflections, so repair restrictions are put in place to limit this.

Figure 9.9 shows typical restrictions on patch repairs.

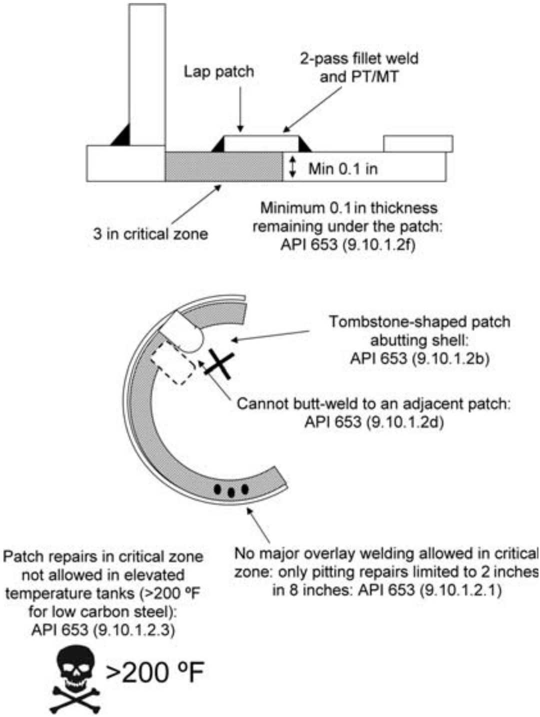


Figure 9.9 Patch plate repairs in the critical zone

9.7.3 Repairing pitting in the critical zone (9.10.1.6)

Pitting can be repaired by overlay welding as long as the parent material underneath is not less than 0.1 in thick. The usual 2 in in 8 in cumulative maximum applies (the definition of isolated pitting), but in this case the plane in which this is calculated is on an arc parallel to the shell. This is the plane on which shear stress acts on the bottom plate if there is any foundation washout around the tank or circumference.

9.7.4 Replacement of tank bottom (9.10.2)

Full bottom replacement is a major exercise, used when the tank bottom is so severely corroded that wholesale replacement is the most practical option. This section really refers to replacing all the bottom plates, but while leaving the annular ring (with its critical zone) in place. Figure 9.10 shows the idea.

Note how Fig. 9.10 shows the definition of this activity as a *repair*, not a major repair or an alteration. In a fit of logic, API 653 definition 3.18(f) says:

- *Replacement of a tank bottom is not classed as 'replacement*

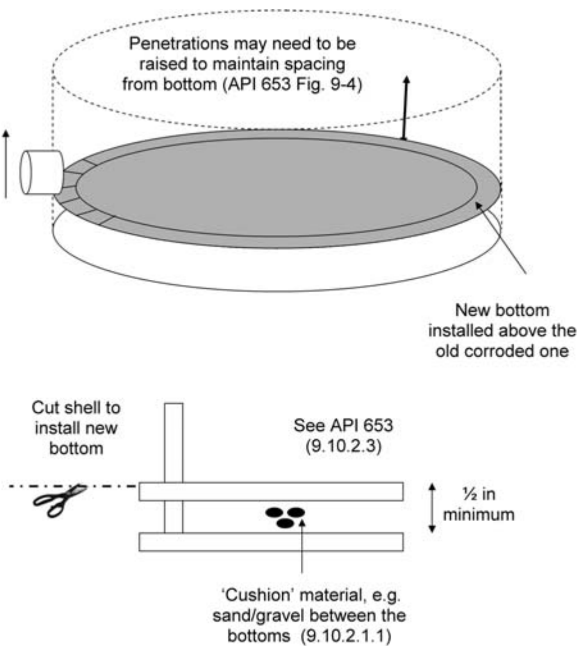


Figure 9.10 Replacing the tank bottom

of a tank bottom' if the annular ring remains unaffected. You may need to read that again.

This means that it is classed as a straightforward repair without the requirement for a post-repair hydrotest.

Replacement of the tank bottom is predominately an exercise in complying with the construction code API 650. There is also a list of API 653 requirements (in 9.6.2) that override this, as they specifically refer to repairs. They are:

- Sand/gravel cushion material is required between the existing and new floors (9.10.2.1.1).
- Penetrations may need to be raised to maintain minimum spacings above the bottom-to-shell weld (9.10.2.1.4 and 9.10.2.4).

For convenience, the activity of 'replacing a tank bottom' is normally done while leaving the existing bottom in place. API 653 sections 9.10.2.1.1 to 9.10.2.1.5 specifically cover this scenario, as the most popular option.

9.8 Repair of tank roofs

The repair of tank roofs is a fairly straightforward exercise, as long as you comply with the construction code requirements of API 650. API 653 does not have many preferences or overrides. This is probably more to do with the fact that tank roofs are little more than a simple plate structure under little stress, than any great technical philosophy. Looking at API 650 section 5.10: *Roofs* and appendix F you can see that they contain three types of information:

- Calculation equations (which are not in the API 653 BOK).
- Cross-references to other sections of API 650 (which are also not included in the BOK).
- Limiting physical dimensions (minimum thickness, etc.) of roof plates and supporting components.

This self-limits the topics that appear as API 653 exam questions. A few questions appear about minimum thickness of roof plates or the roof-to-shell junctions, but they rarely extend further than that. You can expect these to be open-book questions – easily picked out from section 10 of API 650. You can see some examples at the end of this chapter and Fig. 9.11 shows some corresponding points.

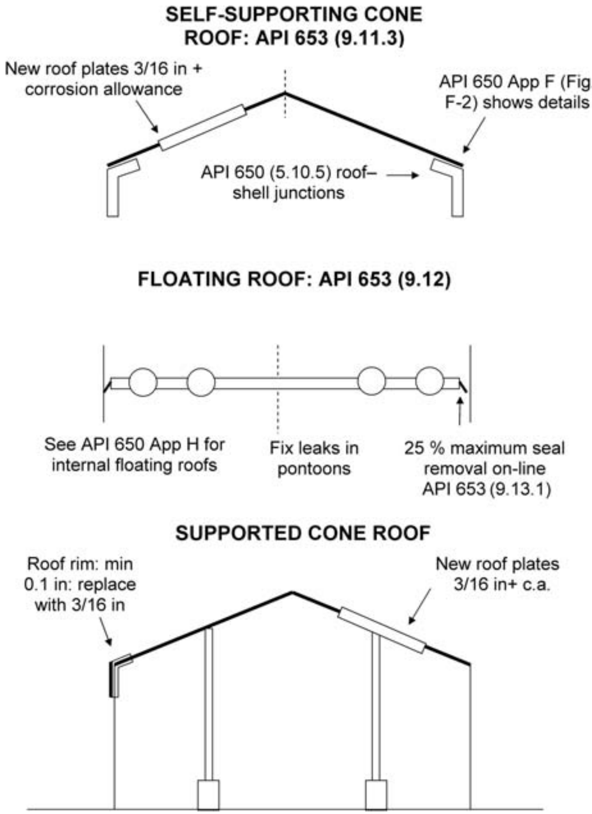


Figure 9.11 Repairs to roofs: API 653 (9.11–9.13) and API 650 (5.10)

9.9 Hot tapping: API 653 (9.14)

'Hot tapping' is the term given to cutting a new nozzle penetration into a tank when it still contains the product at its storage temperature (it does not need to be 'hot'). This is a much quicker and less troublesome method than emptying and cleaning the tank in order to add the new penetration. It is a common procedure, normally performed without any mishaps, and also in pipelines and vessels, as well as storage tanks.

This API 653 section is a common source of exam questions. The hot tapping activity has specific requirements in nozzle reinforcement, weld size and testing in order to ensure that the design is strong enough and is completed without leaks or weld cracking. Note some key points about hot tapping a storage tank shell:

- Hot tapping is always an *alteration* rather than a repair, as it changes the physical configuration of the tanks (API 653 definition 3.1).
- If the new penetration is larger than NPS 12 then it becomes a *major alteration*, as hot taps are always installed below the liquid level (definition 3.18c).
- Materials and stresses must be chosen to *avoid brittle fracture*.
- The main issue during the installation is to *avoid weld cracking*, leading to leaks or fracture. This requires limitations to be placed on weld electrode type, weld spacings and weld joint type and size.

Figure 9.12 below shows how the hot tapping procedure is done. Note the steps of the operation:

1 The new flanged nozzle is welded to the tank shell, followed by the reinforcing (compensation) pad.
2 A valve is bolted to the flange and the tapping machine mounted on the other side of the flange (so the machine is isolated from the tank by the valve). The tapping machine

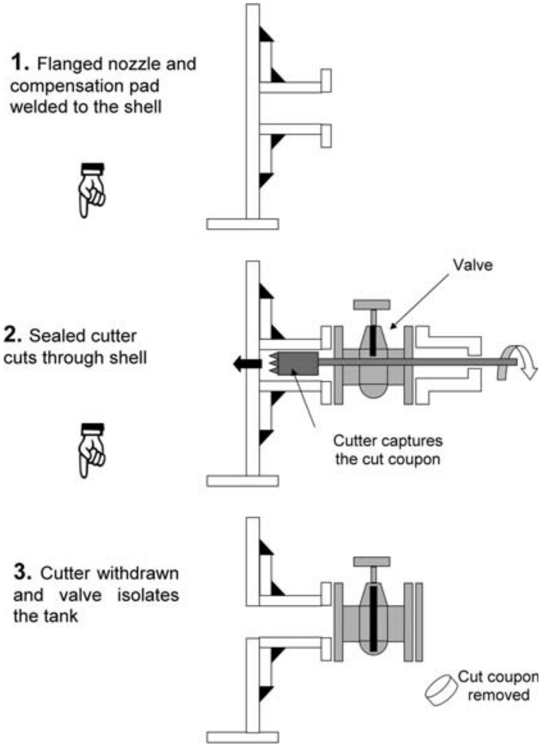


Figure 9.12 The hot tapping procedure: API 653 (9.14)

is fitted with glands, completely sealing the cutter and its driveshaft inside the fluid boundaries.

3 The valve is opened and the cutting head traverses through the valve, cutting the opening in the tank. A pilot drill and 'catch wire' arrangement holds on to the cut coupon, preventing it falling into the tank.

4 When the cut is complete the cutting head is retracted back through the valve, which is then closed, isolating the liquid so the cutting machine can be removed.

9.9.1 API RP 2201

API Recommended Practice RP 2201: *Procedures for Welding or Hot Tapping on Equipment in Service* is a detailed document covering the subject of hot tapping. It is very comprehensive, but the good news is that its content is not in the API 653 exam body of knowledge, so you do not need to study it. Knowledge of its existence, however, *is* an exam topic, as it is mentioned in the reference section of several of the API 653 subject codes.

9.9.2 API 653 (9.14) hot tapping requirements

This code section provides a good example of what API codes do best. Instead of bothering with too much technical detail of procedure, it just gets straight to those points that will have an influence on the integrity of the hot tapping penetration. This section 9.14 is valid examination question material. Most are open-book topics, but there are also several points of technical principle that make valid closed-book questions

Figure 9.13 summarizes some key points. A lot of it centres around the requirement that hot-tapped nozzles require a reinforcement plate, which must be made from sufficiently tough material and then meet well-defined sizing and weld requirements. Penetration position is defined by the fact that it must be a minimum 3 feet below the liquid level (9.14.1.2) but not see sufficient static head pressure to cause a hoop stress of more than 7000 psi (9.14.1.1(4)).

Note how Fig. 9.13 summarizes key points of API 653 Fig. 9-10. This is a good concise figure summarizing a lot of technical detail, and a well-established source of API 653 examination questions.

9.10 Tank repair and alteration – other requirements

Remember that API 653 section 9 does not cover *all* the requirements of tank repair and alteration. Repair and alteration are fundamentally API 650 construction code

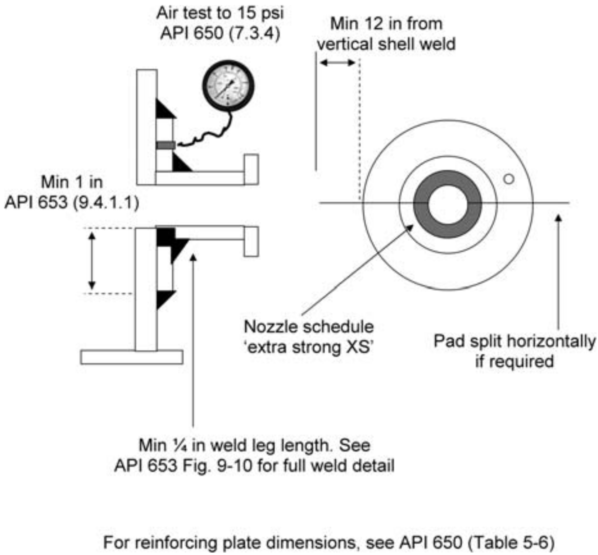


Figure 9.13 Hot tapping detail (see API 653 Fig. 9-10)

activities with the requirements of API 653 added to them, to cover the practical aspects of site work. This should become clearer when we look at the subject of tank reconstruction in Chapter 10. This is almost a purely API 650-based activity, treating the reconstruction as the same as building a new tank from scratch.

For the procedural aspects of welding and NDE of tank repair and alteration, ASME V, IX and API 577 provide more detail than API 653 itself. These therefore provide the source of exam questions of a more generic nature, e.g. related to other types of repair/alteration as well as hot tapping. We will cover them in separate chapters of this book. Exam questions tend to be fairly polarized, however, concentrating on one or the other, because that is how the questions are compiled.

Now try these practice questions.

9.11 Repair and alterations: practice questions

Q1. API 653: repair of defects in shell plate material

Which of the following is not an acceptable method of repairing a corroded area on a shell plate that is at its minimum design thickness?

(a) Grinding out the corroded area to a smooth contour ☐
(b) Applying a lap-welded patch plate over the defective region ☐
(c) Repairing the defective region with weld metal ☐
(d) Replacing the corroded region with a butt-welded insert plate ☐

Q2. API 653: repair of defective welds

Which of the following imperfections must *always* be repaired?

(a) Existing weld reinforcement in excess of API 650 acceptance criteria ☐
(b) Existing weld undercut ☐
(c) Arc strikes either in or adjacent to welded joints ☐
(d) All of the above ☐

Q3. API 653: addition or replacement of shell penetrations

A new nozzle is to be installed in an existing shell. The nozzle is 4 in NPS. The shell is $\frac{5}{8}$ in thick and does not meet the current design metal temperature criteria. How must the nozzle be installed?

(a) With a butt-welded insert plate with a minimum diameter of 16 in ☐
(b) With a butt-welded insert plate with a minimum diameter of 8 in ☐
(c) With a butt-welded insert plate with a minimum diameter of 6 in ☐
(d) A nozzle cannot be installed under these circumstances ☐

Q4. API 653: addition or replacement of shell penetrations

A new nozzle is to be installed in an existing shell. The nozzle is 1 in NPS. The shell is $\frac{3}{8}$ in thick. How must the nozzle be installed?

(a) It can be installed directly into the shell ☐
(b) A nozzle cannot be installed under these circumstances ☐

(c) With a butt-welded insert plate with a minimum diameter of 2 in ☐
(d) With a butt-welded insert plate with a minimum diameter of 13 in ☐

Q5. API 653: repairing tank bottoms

A welded-on patch plate has been used to repair a defect within the critical zone on the tank bottom. Which of the following situations would be unacceptable?

(a) The patch plate is $\frac{5}{16}$ in thick ☐
(b) The bottom plate at the perimeter weld is $\frac{1}{5}$ in thick ☐
(c) The plate perimeter weld has two weld passes ☐
(d) The patch plate is tombstone shaped and within 6 in of the shell ☐

Q6. API 653: repairing tank bottoms

A welded-on patch plate is not permitted in the critical zone of tanks operating at what temperature?

(a) There is no stated temperature restriction ☐
(b) 100 °F for carbon steel and 200 °F for stainless steel ☐
(c) 100 °C for carbon steel and 100 °F for stainless steel ☐
(d) 200 °F for carbon steel and 100 °F for stainless steel ☐

Q7. API 653: replacement of entire tank bottom

A tank has its entire bottom replaced. Existing shell penetrations may not require raising if the tank material has a yield strength as follows:

(a) $\leq$50 000 lbf/in^2 ☐
(b) $>$50 000 lbf/in^2 ☐
(c) $\leq$100 000 lbf/in^2 ☐
(d) $>$100 000 lbf/in^2 ☐

Q8. API 653: repair of fixed roofs

What is the minimum allowable thickness of new roof plates?

(a) $\frac{1}{4}$ in ☐
(b) $\frac{1}{4}$ in plus corrosion allowance ☐
(c) $\frac{3}{16}$ in plus corrosion allowance ☐
(d) $\frac{5}{16}$ in plus corrosion allowance ☐

Q9. API 653: hot taps

Which of the following statements are true concerning hot taps?

(a) They can only be done on tanks that do not need heat treatment ☐
(b) They cannot be carried out on tanks of unknown toughness ☐
(c) They cannot be used for openings greater than 4 in diameter ☐
(d) Hot taps fitted to the roof must be approved by the design engineer ☐

Q10. API 653: hot taps

What is the minimum height of liquid required above the hot tap location during hot tapping?

(a) 12 in ☐
(b) 8 in ☐
(c) 3 feet ☐
(d) 5 feet ☐

Q11. API 653: minimum weld spacings

What is the minimum spacing in any direction between a hot tap weld and adjacent nozzles in a tank 300 ft in diameter and 0.5 in thick?

(a) 21 in ☐
(b) 30 in ☐
(c) 36 in ☐
(d) 42 in ☐

Q12. API 653: replacement shell plates

Which of the following statements are true when replacing entire shell plates or full height segments?

(a) Vertical welds can be cut and re-welded in contravention of the spacing requirements in API 653 Fig. 9-1 ☐
(b) Horizontal welds can be cut and re-welded ☐
(c) Horizontal welds must be cut at least 6 in beyond the new vertical weld ☐
(d) Horizontal joints must be welded prior to vertical joints ☐

Q13. API 653: shell repairs using lap-welded patches

Lap-welded patches must have rounded corners. What size corner radius should be used?

(a) 1 inch maximum ☐
(b) 1 inch minimum ☐
(c) 2 inches maximum ☐
(d) 2 inches minimum ☐

Q14. API 653: NDE requirements

As well as section 12, is there is a summary list of the NDE requirements of API 653 hidden away?

(a) Annex B ☐
(b) Annex F ☐
(c) Annex G ☐
(d) Annex H ☐

Chapter 10

Tank Reconstruction

Strangely at odds with the sensible idea that a storage tank can be heavily repaired throughout its life lies the subject of tank *reconstruction*. This is the wholesale dismantling of a tank into a large number of transportable pieces and then reassembling them somewhere else, on a completely different site. Opinions differ on whether this is all worth the bother. It is a labour intensive exercise and many countries with high labour rates would not find it economic – it would be cheaper to build a new one.

Technical practicality plays a part in the decision – it can be physically awkward getting the disassembled parts to fit, particularly for larger tanks. The state of corrosion can also cause problems – additional corrosion is often discovered during disassembly, requiring repairs before reassembly of the parts. Old, large tanks are the biggest risk.

Notwithstanding the practical and cost uncertainties, tank reconstruction is clearly a viable option in those countries that do it, so it is a long-standing part of API 653, with specific technical principles. It is also a valid topic for API 653 exam questions.

10.1 Code requirements for tank reconstruction

Unlike repairs, tank reconstruction is considered a 'build as new' activity. In most cases this turns into a 'build better than new' activity as one of the fundamental requirements is that reconstruction activities must be done to the 'current applicable standard', i.e. the code edition relevant to when it is reconstructed, not the old one to which it was originally built. This applies only to all *new* material, components, welding and NDE used during the reconstruction. Existing materials, components and welds that are not reworked can remain as they are, to the as-built standard. Figure 10.1 summarizes the situation.

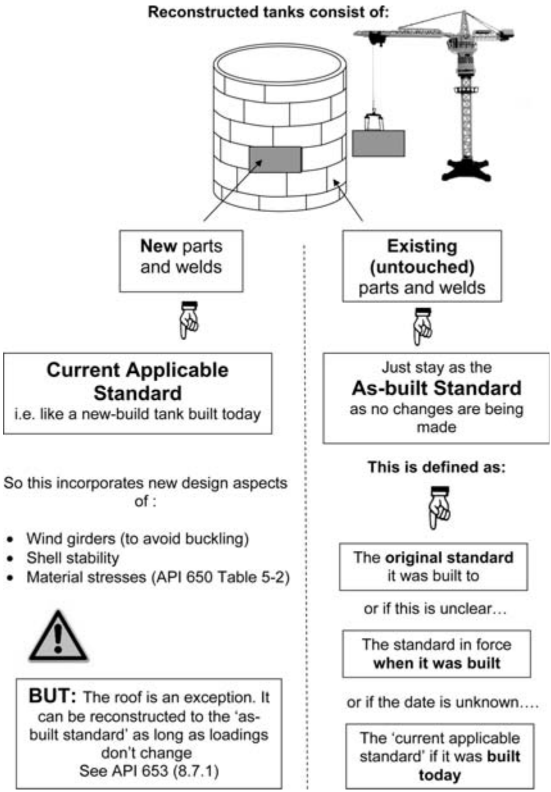


Figure 10.1 Reconstructed tanks: which code?

The main code requirements for reconstruction are found in three places:

- Section 8 of API 653 covers *design consideration for reconstruction tanks*. This is a one-page section setting out the relevant code-compliance requirements as described above.
- API 653 section 10: *Dismantling and Reconstruction* is a

longer section covering the procedures of dismantling the tank and putting it back together again. The dismantling bits (10.3) are unique to API 653 because they are not covered in the construction code. The reconstruction requirements (10.4) are practical additions to the construction code (API 650) – mainly about welding acceptance criteria and broad dimensional tolerances for the rebuilt tank.

- API 650, the construction code itself, contains the most detailed information. This drives the technical detail of the reconstruction, reinforcing the principle that reconstruction is a new-build activity rather than a repair or alteration one. There are other non-API construction codes, which is why API 653 is careful to refer to the construction codes in generic terms rather than exclusively to API 650. Such niceties do not extend to the API exam – construction code questions will all be about API 650.

10.2 Reconstruction responsibilities

API 653 does not make such a well-defined split between the meaning of the words *approval* and *authorization*, as do API 510 or API 570 relating to pressure vessels and pipework. The inherent meanings of the words (as decided by API), however, are the same, as follows:

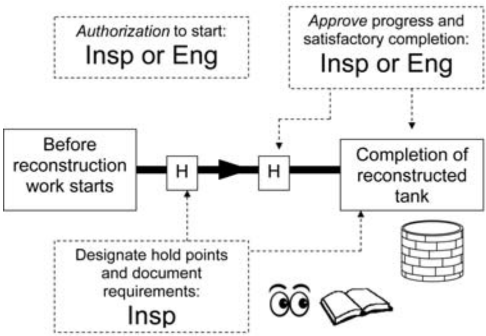
- *Approval* means approval of a design procedure method or way of doing something, independent of whether the activity has started or not. It can also apply to accepting some work or activity that has finished (i.e. agreeing it has been done properly).
- *Authorization* means authorizing an activity *to start*.

You can see these words in action in API 653 (10.1.4), although they are not defined for you. One long-standing controversial area of API ICP exams is the large number of questions about personnel responsibilities and their relevance to inspection practice outside the USA. Like them or not, Fig. 10.2 shows what they are for tank reconstruction. Note

APPROVAL: Meaning review of *what is to be done*
API 653 (10.1.4)

AUTHORIZATION: Meaning OK for work to proceed
API 653 (10.1.3)

- Insp = Inspector
- Eng = Engineer



Note how the Inspector can deal with these alone (because there are no design implications, and it is what inspectors **do**)

Figure 10.2 Reconstruction responsibilities

how the API inspector alone can approve not only hold points and the extent of the completed tank document package but also authorize reconstruction work to start and approve its completion. The tank engineer therefore has no *mandatory* role in reconstruction. That is all there is about reconstruction responsibilities in API 653.

10.3 API 653 section 10: structure

Section 10 is split logically into dismantling (10.3) and reconstruction (10.4) activities. These subsections provide parallel coverage for the main components of the tank: bottom, shell and roof. The main issue of both dismantling and reconstruction is the objective of avoiding cracking in the reconstructed tank welds. The first part of achieving this is to ensure that parts of old existing welds are not left in place to interfere with new reconstruction welds causing local carbide concentrations and the risk of cracking. Much of section 10.3 is centred around this objective. Note particularly how:

- *Bottom plates* must be cut a minimum of 2 in away from existing bottom seam welds (10.3.2.1) and $\frac{1}{2}$ in away from the shell-to-bottom fillet weld (API 653 Fig. 10-1).
- If the *entire tank bottom* is to be reused it must be cut a minimum of 12 in from the shell-to-floor junction, leaving the shell with the remaining part of the bottom still intact (API 653 10.3.2.2b and Fig. 10-1).
- *Shell plates* must be cut a minimum of 6 in away from existing shell seam welds (10.3.3.1c) and $\frac{1}{2}$ in up from the shell-to-bottom fillet weld (Fig. 10-1 again).
- *Roof plates* must be cut a minimum of 2 in away from existing roof seam welds.

Figure 10.3 summarizes the content of API 653 Fig. 10-1 and some of its referenced sections. This is a common source of open-book exam questions. It is difficult to write an awkward question on this – so they are normally straightforward, just requiring you to read various minimum dimensions from the code Fig. 10-1. Easy.

10.4 Reconstruction (10.4 and 10.5)

This is simply a case of welding the cut parts back together again in a way that avoids brittle fracture, cracks or other integrity-threatening defects (10.4). In addition the completed tank has to meet a set of dimensional tolerances (10.5) on inclination (plumbness), roundness, peaking and banding in order that it does not suffer from excessive 'out of design' stresses in use.

Given that tank reconstruction is essentially a new construction activity, these sections of API 653 section 10 are based on the straight requirements of API 650, with a few

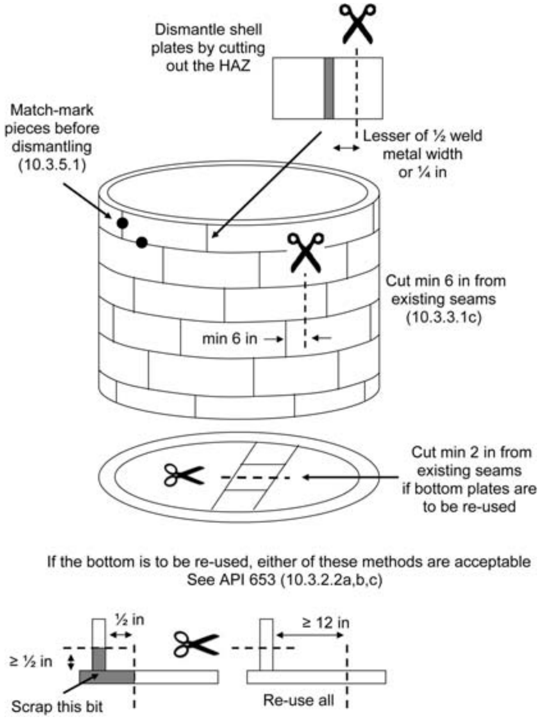


Figure 10.3 Tank dismantling options: API 653 (10.3)

additional practical aspects thrown in for good measure. Salient points are:

- Weld spacings have to be maintained with a minimum $5t$ stagger on shell plate vertical joints (10.4.2.1).
- Preheat of weld joints is necessary in cold climates. The preheat temperature depends on thickness (10.4.2.3):
  - Below 0 °F, no welding is allowed.
  - 0 °F to 32 °F on thickness > 1 in, preheat to 140 °F.
  - Thickness > $1\frac{1}{2}$ in, preheat to 200 °F (10.4.4.3).
- Weld maximum undercut (as per API 650) and reinforce-

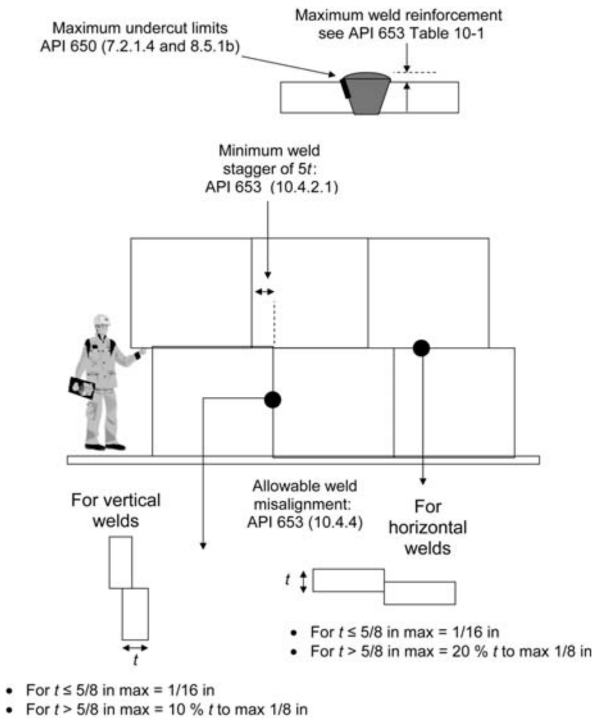


Figure 10.4 Some important reconstruction requirements

ment limits (API 653 Table 10-1) apply. This is to avoid stress concentrations and crack initiation points.

Figure 10.4 above summarizes some of these important points. Note how they are mainly about the shell plates.

10.4.1 Use of low hydrogen welding rods

Most API codes are in agreement that whenever welding is carried out under any type of non-optimum conditions (e.g. on site), it is best to use low hydrogen welding rods. This minimizes the risk of cracking, caused by hydrogen molecules expanding in small discontinuities (such as grain boundaries) and progressively weakening the structure. Couple this with heating and cooling and you get cracks. Both API 571 and 577 (both in the API 653 body of knowledge) address hydrogen cracking and its prevention, so the subject almost always appears as (several) exam questions in one form or another.

Figure 10.5 shows the major issues relating to avoiding hydrogen cracking. Note how these are taken not only from API 653 section 10: *Reconstruction* but also from section 11: *Welding*.

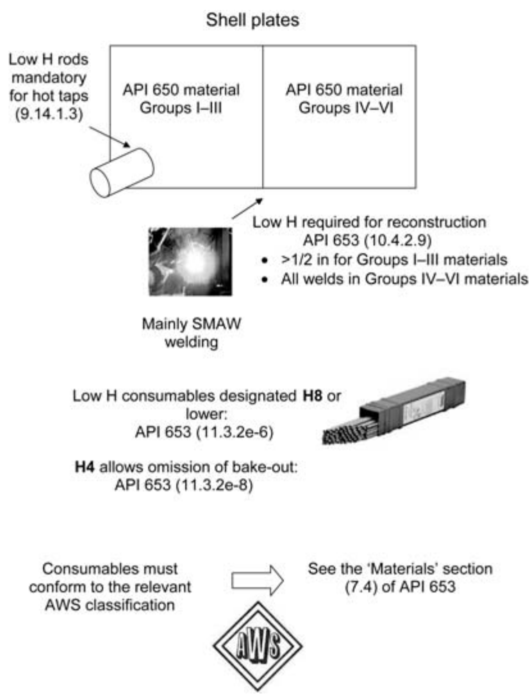


Figure 10.5 The importance of low hydrogen welding rods

10.4.2 Reconstructed tank dimensional tolerances in API 653 (10.5)

In engineering terms, atmospheric storage tanks are large, rather floppy structures that do not take well to dimensional inaccuracies. The activity of reconstructing accurately an old tank after dismantling it can be difficult – it may be a slightly different size due to cutting, rejection of old weld seams, etc., and the old plates are frequently distorted, damaged during transport, or weakened by corrosion. The main problems usually occur with the shell. Excessive shell distortion has two effects:

- *Sticking roofs*. Shells usually distort more near the top of the tank. This causes floating roofs to either stick or leak past the seals, letting vapour out and rain in.
- *Excessive stress*. Tank shells are designed to the simple hoop membrane stress equation, which works on the assumption that the shell is round and of uniform (plane) section over its height, within certain tolerances. Any distortion that takes a shell outside this idealized shape causes stress to rise, indeterminately. This gives an increased risk of failure at almost any area of stress concentration, such as weld undercut or excessive weld cap convexity. API 650 (10.5) sets dimensional tolerances to try and avoid these problems.

10.4.3 Foundation tolerances

Uneven foundations will cause distortion in an otherwise accurate shell. Tolerances are specified by API 653 (9.10.5.6), depending on whether the foundations include a concrete ringwall (an annular concrete foundation ring on which the shell sits).

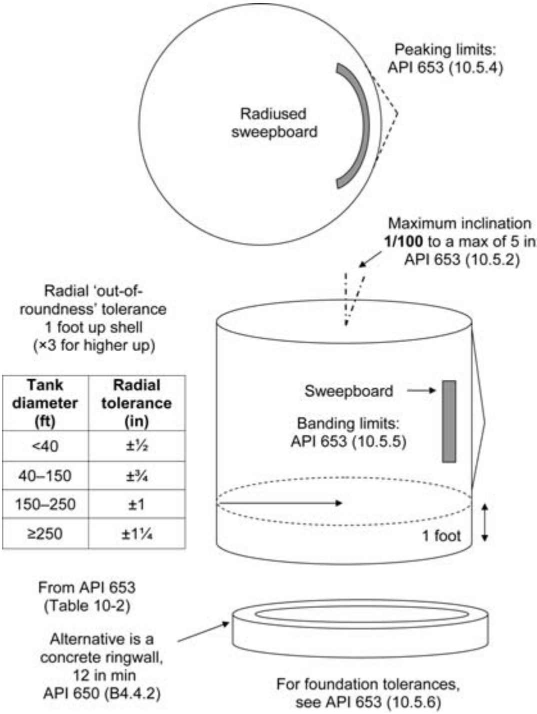
10.4.4 Shell tolerances

There are four of these: plumbness, roundness, peaking and banding. All can cause problems if excessive, and things get worse if they act together.

- *Plumbness* (10.5.2) is simply inclination or out-of-verticality. The limit is 1 in 100 to a maximum of 5 inches (see 10.5.2.1).
- *Out-of-roundness* (10.5.3) is the measured deviation of the shell shape from a true circle. Simplistically it is the difference between the minimum and maximum measured diameter. It causes bending stresses, which are not allowed for a simple hoop (membrane) stress design theory. As out-of-roundness (OOR) generally gets worse higher up the tank, it is measured in two places: 1 foot above the bottom as a reference and then higher up as required.
- *Peaking*. This is distortion along the longitudinal (vertical) weld in the shell. It is mainly initiated by material rolling and/or welding stresses during new construction. Occasionally it can get worse in service.
- *Banding*. Banding is similar to peaking but involves distortion around the circumferential (horizontal) shell welds rather than the vertical ones. It is less common and almost always the result of construction (or repair/alteration/reconstruction) inaccuracies.

Figure 10.6 shows the tolerances allowed for these features in reconstructed tanks. Being large-dimension related, they require specialized equipment to measure accurately. The usual method is via laser measuring equipment, although API 653 refers to the older, but still effective, method of using plumblines and long 'sweepboards' made out of light wooden planks or aluminium strips.

The dimensional tolerances above are checked *before* the hydrostatic test on a reconstructed tank (10.5.1.2). Remember that tank reconstruction is the only situation after new construction where a hydrostatic test is truly *mandatory* to comply with API 653 – look back to API 653 section 12 and you can see it specified in 12.3.1a. Settlement measurements are also taken as per API 653 section 12.5 if there is any doubt about the strength or rigidity of the tank foundations.



Tank diameter (ft)	Radial tolerance (in)
<40	±½
40–150	±¾
150–250	±1
≥250	±1¼

Figure 10.6 Tolerances for reconstructed tanks

10.4.5 Tank reconstruction: API 653 versus API 650

Fundamentally, tank reconstruction is considered a new-build activity. Remember that all new welding activity is treated as exactly that, as if it were being done on a completely new tank – with the requirement to follow the construction code API 650. In its role as an in-service code, however, API 653 is allowed several overrides to cater for site practicalities, while still providing a tank of sufficient structural integrity.

10.4.6 Reconstruction and other related codes

For the purposes of the API 653 examination (and practically as well), other codes also play their part in reconstruction activities. NDE is covered by ASME V and welding qualifications by ASME IX. Exam questions are rarely detailed enough to examine these links in any great depth – they are more likely to be either an API 653-specific question about reconstruction design or procedures, or very generic questions (unrelated to specific new-build/repair/alteration/reconstruction activities) picked verbatim out of the wording of ASME V or IX, not both.

Now try these practice questions.

10.5 API 653 section 10: dismantling and reconstruction: practice questions

Q1. API 653: dismantling – bottoms

The bottom is being removed from a storage tank and the plates are to be re-used. What would be an acceptable method(s) of removing the plates?

(a) Grinding out existing lap welds ☐
(b) Cutting alongside but at least 2 inches away from existing welds ☐
(c) De-seaming existing lap welds ☐
(d) All of the above ☐

Q2. API 653: dismantling – shells

The shell of a storage tank is being dismantled and the plates are to be re-used. What would be an acceptable method(s) of removing the plates if the shell thickness is $\frac{3}{4}$ in?

(a) Cut through the horizontal and vertical welds ☐
(b) Cut out the welds and heat affected zones ☐
(c) Cut alongside but at least 2 inches away from existing welds ☐
(d) All of the above ☐

Q3. API 653: dismantling – roofs

The roof is being removed from a storage tank and the plates are to be re-used. What would be an acceptable method(s) of removing the plates?

(a) Grinding out existing lap welds ☐
(b) Cutting alongside but at least $\frac{1}{2}$ inch away from existing welds ☐
(c) Cutting along butt welds ☐
(d) All of the above ☐

Q4. API 653: reconstruction – welding

A tank is being reconstructed. What is the minimum offset allowed between vertical joints in adjacent courses?

(a) $5t$, where t is the plate thickness of the thicker course ☐
(b) $5t$, where t is the plate thickness of the thinner course ☐
(c) 6 in ☐
(d) Either (a) or (b) ☐

Q5. API 653: reconstruction – welding

Under what circumstances is welding prohibited when reconstructing a tank?

(a) When the surfaces to be welded are wet from rain, ice or snow ☐
(b) During periods of high winds without shelter ☐
(c) When the base metal temperature is below 0 °F ☐
(d) Any of the above ☐

Q6. API 653: reconstruction – welding

What are the maximum smooth undercut limits for welds?

(a) $\frac{1}{64}$ in for vertical seams and $\frac{1}{32}$ in for horizontal seams ☐
(b) $\frac{1}{32}$ in for vertical seams and $\frac{1}{64}$ in for horizontal seams ☐
(c) 10 % t (where t = plate thickness) ☐
(d) $\frac{1}{64}$ in for vertical seams and $\frac{1}{64}$ in for horizontal seams ☐

Q7. API 653: reconstruction – welding

What is the maximum reinforcement height permitted on each side of the plate on a vertical butt weld in $\frac{1}{2}$ in thick plate material?

(a) $\frac{1}{64}$ in ☐
(b) $\frac{1}{32}$ in ☐
(c) $\frac{1}{16}$ in ☐

(d) $\frac{3}{32}$ in ☐

Q8. API 653: reconstruction – shells

A tank with a shell thickness $> 1\frac{1}{2}$ in requires welding with a multipass welding procedure. What special restriction(s) would be placed on this welding?

(a) No weld pass must exceed $\frac{1}{2}$ in ☐
(b) The vertical weld pass must not exceed $\frac{1}{2}$ in ☐
(c) A minimum preheat temperature of 200 °F is required ☐
(d) Welds must be single-pass ☐

Q9. API 653: reconstruction – plumbness

What is the maximum out-of-plumbness permitted in a reconstructed tank?

(a) 1 in 100 with a maximum of 5 in ☐
(b) 1in 50 with a maximum of 2 in ☐
(c) 1 in 200 with a maximum of 10 in ☐
(d) 1 degree from the vertical with a maximum of 5 in ☐

Q10. API 653: reconstruction – peaking

What is the maximum peaking allowed?

(a) $\frac{1}{2}$ in using a horizontal sweepboard 36 in long ☐
(b) 1 in using a horizontal sweepboard 36 in long ☐
(c) $\frac{1}{2}$ in using a vertical sweepboard 36 in long ☐
(d) 1 in using a vertical sweepboard 36 in long ☐

Chapter 11

Hydrostatic Testing and Brittle Fracture

API inspection codes in general have a strange love–hate relationship with hydrotesting. Storage tanks are no exception – on one hand API 653 explains how and when it *should* be done, but this is followed up by a long list of valid scenarios for exemption. Unlike pressure equipment items, the underlying message is that (excluding new or fully reconstructed tanks) a hydrotest on a storage tank is something that you *choose* to do, rather then being forced to do so by API 653.

11.1 What is the subject about?

Code coverage and API exam questions are in surprising agreement on their coverage of hydrotesting. They are concerned with:

- *WHY* you would want to do a hydrotest.
- *WHEN* it is necessary (and when you do not need to bother).
- *HOW* the test is done, once you have decided to do it.

Hydrotesting fits well into the API exam question mix because of the way that coverage is spread around several of the codes in the API 653 body of knowledge (BOK). It is covered in API 653 (12.3), API 650 (7.3.6) and also has links to the brittle fracture section of API 571. The following list of hydrotest-related subjects can be shoe-horned into exam question format:

- *Allowable stress (S) levels*. A tank scheduled for hydrotest must have a higher allowable *S* value than one which is not, to accommodate the increase in hoop stress caused by the water compared to its normal oil product (see Fig. 6.5 of this book).

- *Responsibilities*, i.e. who decides if a hydrotest is required in various repair/alteration scenarios.
- *Exemptions*, and when they are allowed. This fits together with the question of responsibilities and who decides what.

There are enough basic principles, specific code clauses and data tables here to feed both open- and closed-book-style exam questions. That is why they regularly appear.

11.2 Why? The objectives of a hydrotest

Neither API 653 nor API 650 go into much detail but, simplistically, a hydrotest is:

- A code test for leaks

  and

- A strength test (of sorts)

  plus

- A chance for brittle fracture and excessive foundation settlement to happen, if they are going to.

It can never be a full test of fitness for service, because in reality there are lots of defects and problems that a hydrotest will not discover. Water is not good at finding its way through very fine cracks, for example, and welds in some locations can contain huge internal defects without the remotest chance that they will result in structural collapse of the tank during a static-head-only hydrotest. This is well understood, which is why API 653 section 12 lists hydrotest as only one type of NDE, among all the other (ASME V) techniques used.

Perhaps the most agreed objective of hydrotesting a tank is to check for excessive foundation settlement on tanks laid directly on a soil, sand or rubble base, i.e. without a full concrete base, or at least a concrete ringwall installed under the shell.

11.3 When is a hydrotest required?

This is straightforward.

- A hydrotest is only *mandatory* for:
  - A newbuild tank: API 650 (7.3.6)
  - A reconstructed tank: API 653 (12.3.1)
- A hydrotest is required for a tank that has undergone major repairs or major alterations (API 653 definition 3.18) but it can be exempted if:
  - Firstly it has been agreed by a tank design engineer and the owner/user (12.3.2.2a and b).

    and then, either

  - It passes an FFP (fitness-for-purpose) assessment.

    or

  - It meets a quite long list (nearly two pages of API 653 (12.3.2.3) to (12.3.2.6)) of criteria relating to material, type, thickness, stress and weld location.
- For non-major repairs or alterations, a hydrotest is not required. It actually says this in API 653 (12.3.3.1).

Excluding new-build and reconstructed tanks then, where a hydrotest is mandatory, the answer to whether a hydrotest is required after a repair or alteration simply hinges on whether the repair or alteration is *major* or not, according to API 653 definition 3.18. If it is major then it requires a test unless it can qualify for any of the exemption routes above.

11.3.1 Why would you want to find an excuse not to hydrotest?

Because it requires a large amount of treated water, which then has to be legally disposed of, meeting environmental standards, etc. It takes a lot of time, is expensive and the tank may have to be cleaned and dried out afterwards. Coupled with this it is only a partial test of fitness for service of a tank and other NDE techniques are better at finding fine defects.

This goes a long way to explain why API 653 allows exemption in many cases.

11.4 Avoiding brittle fracture

API 653 does not set out to be a textbook on brittle fracture – it does not even warrant a separate mention in the definitions section 3. That is fine, because the mechanisms of brittle fracture are more than adequately explained in API 571 along with its appearance, prevention and mitigation options. What API 653 (section 5) does do is set out a well-rehearsed methodology of preventing the specific occurrence of brittle fracture on storage tanks. In many cases this is set against a scenario of the tank or its operating condition having changed in some way with the potential of increasing the risk of brittle fracture, causing wholesale fracture of the shell, with the release of all the contents.

11.4.1 What causes increased risk of brittle fracture?

Four things:

- *Brittle material*. Many cheaply produced materials lack toughness (tough is the opposite of brittle). This is actually *the result of* low ductility (because ductility and toughness are not precisely the same thing).
- *Thickness*. The thicker a material section is, the more brittle (less tough) it is. Strange but true. Lots of textbooks will explain this to you if you need to know why.
- *Temperature*. Simple steels get more brittle as they get colder. Effects vary with the specific material but 7–10 °C is used as a rough benchmark for a temperature below which brittle fracture (rather than ductile failure) may become a risk.
- *Stress*. All failures need to be caused by stress of some sort. Brittle fracture is more likely at higher stresses. Simplistically, dynamic impact-induced stresses are the worst although more statically induced membrane stresses can also cause it, particularly during fast product filling or unexpected wind or seismic loadings.

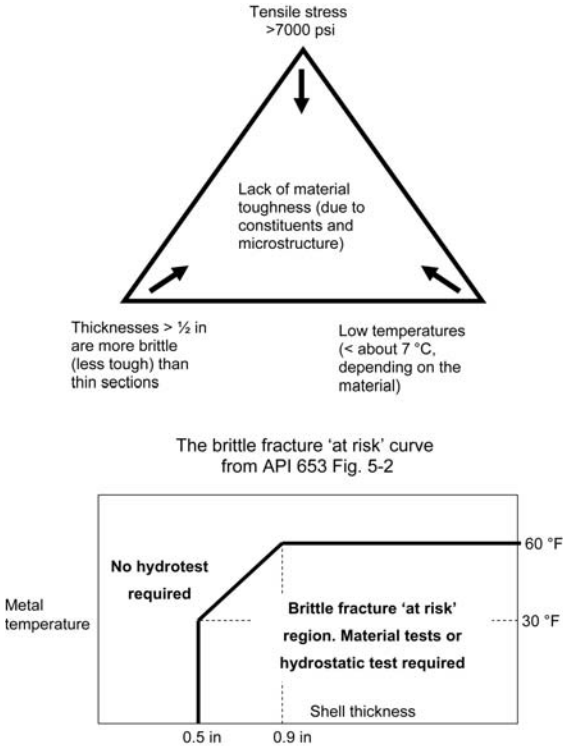


Figure 11.1 The reasons for brittle fracture

These four factors can act singly or in combination (see Fig. 11.1) so measures need to be in place to restrict them all, to keep the chance of brittle fracture low.

11.4.2 When does API 653 section 5 worry about brittle fracture?

API 653's views owe more to accumulated experience and intuition than advanced metallurgical theory – proven or otherwise. Clause 5.2.2 sets out four scenarios where it may happen and then the rest of section 5 goes on to describe a methodology to assess which you have. It is best to accept API's view of this, whether you think it is oversimplified or not, because it forms the basis of their exam questions. API 653 (5.2.2) says that you should be worried about the risk of brittle fracture if a tank is being:

- Hydrotested for the first time.
- Filled for the first time in cold weather.
- Changed to a service (product, site environment or both) where it will see a lower temperature than previously.
- Repaired, altered, or reconstructed.

Conversely, if a tank is not in one of these four scenarios it is reasonable to expect that the risk of brittle fracture is minimal.

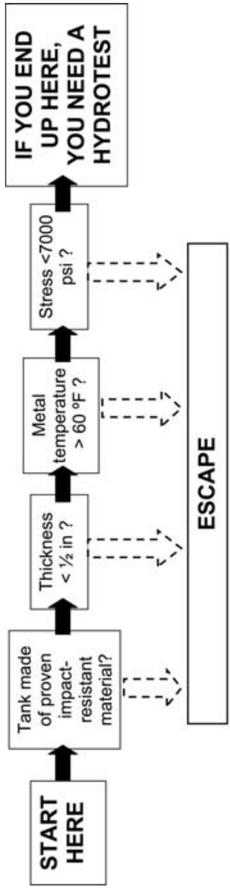
11.4.3 If there is a risk, what do you do?

Easy, do a hydrotest. If the tank passes without fracture, then its 'brittle fracture integrity' is proven and the problem has effectively gone away, *even if* the remainder of the scenario conditions are still there. Now you can see the main purpose of API 653 section 5 – to provide a methodology to decide whether or not you need to do an 'enforced' hydrotest, to prove a tank's resistance to brittle fracture.

11.5 Is a hydrotest needed? API 653 flowchart (Fig. 5-1)

In common with many other API documents, API 653 expresses decision-making activities in the form a flowchart (see API 653 Fig. 5-1). You either like flowcharts or you do not. This one is very easy – it just looks complicated on first viewing – see Fig. 11.2 here which is a simplified version. The full API 653 Fig. 5-1 version has 11 steps, each of which is actually explained in the text of section 5.3.

Starting on the left of the flowchart, the objective is to spend as little time on the flowchart as possible by taking the *first possible exemption* from doing a hydrotest that you can.



If you can meet ***any one*** of these requirements, you can escape from the flowchart, and so do not need to do a hydrotest

See API 653 Fig. 5-1 for the full flowchart

Figure 11.2 The 'hydrotest exemption' flowchart

Failure is indicated by being unable to escape from the flowchart before arriving in disgrace at the right-hand end, where the only real practical option is to do the hydrotest, to prove that brittle fracture will not occur. The exemptions available in the flowchart are all based on API code experience – and support the idea that there is no advantage to be gained from doing a hydrotest if you really do not need to.

If you prefer things to be presented another way, then the list below shows all the exemptions. So there is *no need* to do a hydrotest if you can meet *any one* (not all) of the following criteria:

- The tank was built to API 650 7th edition or later, so the material will be sufficiently tough (non-brittle).

  or

- It has already been hydrotested, and did not fail then.

  or

- The shell plate is $\frac{1}{2}$ inch thick or less.

  or

- It will not see temperatures lower than 60 °F.

  or

- It will not see hoop stresses greater than 7000 psi.

  or

- The material is shown as exempt (by API 653 Fig. 5-2 if the grade is unknown or API 650 Fig. 4-1 if the grade is known). If you look at this figure in API 650 (see chapter 7) you will see how some grades of steel can keep their tough (non-brittle) characteristics down to beyond −30 °F, but you need to be able to confirm that the material grade is the correct one.

  or

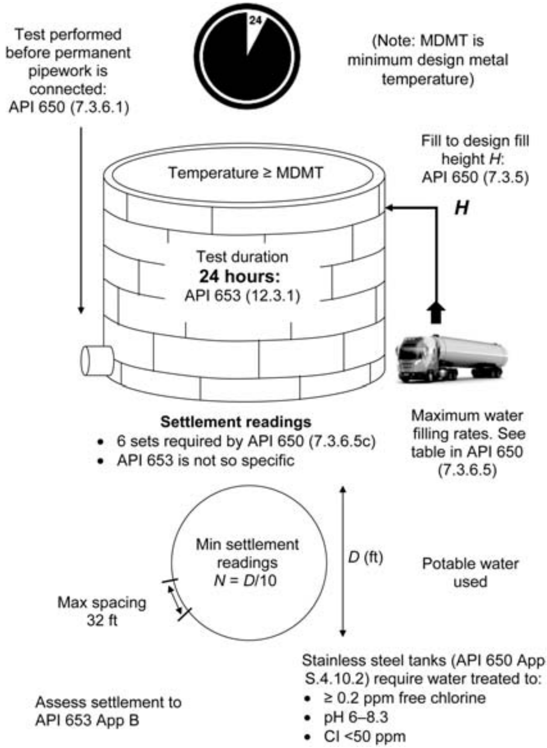


Figure 11.3 Tank hydrotesting

- The tank has already been proven safe, when full at the lowest one day mean average temperature (LODMAT) for the geographical area where it is located (see API 650 Fig. 4-2).

If a tank cannot meet any one of the above criteria, you need to do a hydrotest. Figure 11.3 shows some important technical and procedural points.

11.5.1 Exam questions?

Yes. The API 653 exam regularly contain questions on both the generic API 571 aspects of brittle fracture and the tank-specific aspects from API 653 and 650 explained above. Expect both open- and closed-book variants. The split may appear a bit random, but the questions themselves are normally fairly straightforward.

Now try these practice questions.

11.6 API 653: hydrotesting: practice questions

Q1. API 653: hydrostatic testing

What is the duration of a full hydrostatic test?

(a) 4 hours ☐
(b) 8 hours ☐
(c) 12 hours ☐
(d) 24 hours ☐

Q2. API 653: hydrostatic testing

API 653 specifies that a full hydrostatic test is required for a tank that has undergone 'major repairs or major alterations'. Which of the activities below is classed as a 'major repair or major alteration' on a 150 ft diameter tank?

(a) Removing and replacing the complete bottom-to-shell weld ☐
(b) Installing 4 new bottom plates near the centre of the tank ☐
(c) Installing a new NPS 12 nozzle below the liquid level ☐
(d) Installing a new NPS 14 nozzle above the liquid level ☐

Q3. API 653: hydrostatic testing

Which of these activities is likely to require a full hydrostatic test on an existing (not new) tank made of unknown low carbon steel with a shell and roof thickness of 0.7 in?

(a) Full replacement of the roof ☐
(b) Increase of the service temperature from 40 °F to 65 °F ☐
(c) Decrease of the service temperature from 65 °F to 40 °F ☐
(d) Repair to the roof-to-shell welds ☐

Q4. API 653: hydrostatic test exemption

As a guiding principle, can experienced tank design engineers (employed by the owner/user) override the requirement for a hydrostatic test on an existing tank that has had major repairs and alterations and that API 653 suggests should be tested?

(a) Yes ☐
(b) No, not under any circumstances ☐
(c) Yes, as long as the tank was built to API 650 ☐
(d) It is open to interpretation; the code is unclear ☐

Q5. API 653: hydrostatic test: limiting stress in the repair area

Section 12.3.2.3.3 contains a formula for calculating the stress during a hydrotest (to see if it exceeds 7 ksi).What is the difference between this formula and the one in the 'evaluation' section of API 653?

(a) None ☐
(b) The formula in 4.3.3.1b calculates the height *H* in a different way ☐
(c) The formula in 4.3.3.1b assumes a full plate course; 12.3.2.2.3 does not ☐
(d) None of the above are correct ☐

Q6. API 653: shell repair for hydrostatic test exemption

If you want to claim exemption from a hydrotest after repair, the material around the repair area (not the repair plates themselves) must:

(a) Be impact tested, irrespective of the tank design temperature ☐
(b) Meet API 650 7th edition or later ☐
(c) Fall within the 'safe use' region of Fig. 5-2 ☐
(d) None of the above are correct ☐

Q7. API 653: leak test

What is the objective of a leak test as defined in API 653 section 12.4?

(a) To test the fillet welds on nozzle reinforcing pads ☐
(b) To replace the hydrostatic test for badly corroded tanks ☐
(c) To check for roof leaks ☐

(d) To check for bottom leaks ☐

Q8. API 653: measuring settlement during the hydrotest

How many settlement measurement points are required during a hydrotest (API 653 section 12.5.1.2), compared to the 'out-of-service' requirement specified in API 653 appendix B?

(a) You need more during the hydrotest ☐
(b) You need fewer during the hydrotest ☐
(c) The difference depends on the tank diameter ☐
(d) They are the same ☐

Q9. API 653: settlement points

How many inspection points are required to carry out an internal survey for a very large tank 280 ft in diameter?

(a) 32 points ☐
(b) 28 points ☐
(c) 36 points ☐
(d) 45 points ☐

Q10. API 653: objective of the hydrostatic test

Which of these is not a major objective of a tank hydrostatic test?

(a) Check for brittle fracture ☐
(b) Check for creep failure ☐
(c) Check for shell distortion ☐
(d) Check for foundation settlement ☐

Chapter 12

Tank Linings: API RP 652

12.1 Introduction

This chapter is about learning to become familiar with the layout and contents of API RP 652: *Lining of Above-ground Storage Tanks*. Similar to API RP 651, API 652 is a well-established document (recently issued in its 3rd edition: 2005). As a short code, it supplies supplementary technical information suitable mainly for open-book examination questions. Similar to the other short code in the syllabus, it is more a technical *guide document* than a true code, but it performs a function in supporting the content of API 653. It contains useful technical information on the lining of tank bottoms to minimize the effects of corrosion. API 652 is one of those API documents that, in each revision, seems to *grow* in technical detail, rather than keeping the scope constant and just making a few paragraph amendments, as many codes do.

Note the following five points about API 652:

Point 1. Tank bottoms can be lined on the inside or outside (i.e. the bottom surface). This is mentioned in a couple of places in the document but perhaps not made particularly clear.

Point 2. API 652 covers linings that are either applied to new tanks or retrofitted to old ones, normally to try to stop future corrosion where significant corrosion has already been found. It introduces both thin- and thick-film linings, but does not go into a lot of technical detail about the chemical and mechanical properties of the linings themselves. This is because lining materials are incredibly varied (there are hundreds of different proprietary ones, each specified by its own manufacturer's data sheet) so it would be next to impossible to produce any meaningful generic information that would apply to all of them.

Point 3. Although very relevant to the API 653 body of knowledge, API 652 contains little information on inspection itself. It concentrates more on describing the need for tank bottom linings, their properties and how they can fail. Within this scope, however, lies a lot of technical information points suitable for use as closed-book exam questions.

Point 4. In the few areas that API 652 does contain information related to the inspection of linings (and, more importantly, the preparation of the surface before lining), it cross-references various related US codes. The main ones are from:

- SSPC (The Steel Structures Painting Council)
- NACE (The National Association of Corrosion Engineers)

While most oil/gas/petrochemical inspectors have heard of NACE codes, the SSPC ones are less familiar outside the US. These SSPC codes deal with metal surface cleaning, shot blast and surface finish grades. Most European countries use the Swedish standard SIS 055966 instead (the source of the SA shot blast surface finish grades).

Point 5. Like API 651, API 652 discusses corrosion mechanisms, specifically of the tank floors, so you can expect some crossover with the coverage of API 571 *damage mechanisms*. Note, however, that the corrosion discussed in API 652 is mainly related to the internal surfaces of the tank bottom, rather than the external galvanic corrosion described in more detail in API 571.

Finally, API 651 is *mainly text and technical descriptions*, accompanied by a few tables of a fairly general nature. It contains no calculations relevant to exam questions but does contain a few quantitative facts and figures that are worth remembering. API examinations have an annoying habit of using questions that test candidates' short-term memory of facts and figures that appear in the codes. Watch out for these as you read through this code.

12.2 Linings and their problems, problems, problems

Inspectors soon become familiar with the application and inspection of linings and the problems that they bring. If you have never inspected linings, or been involved with them at all, you can give yourself a head start by reading the following commentary.

12.2.1 What are they?

The linings we are talking about here are mainly of the epoxy or rubber-based types, not loose steel linings, welded 'buttered' linings or anything like that. They are used on new tanks to try and stop corrosion, and on old tanks that are badly corroded, either because they were not lined in the first place or because the original lining has fallen off.

12.2.2 So what's the problem?

The problem is that linings love to fall off. Overall, perhaps almost 50 % of new linings fall off and do not reach their design life, and that includes those that were reasonably well applied and inspected. If you consider those that were not well chosen, applied, inspected or whatever, then *most* of them fall off. All of each lining does not fall off of course, only bits of it... annoyingly small bits clinging to (or supposed to be clinging to) rough welds, bits of spatter, sharp corners, etc. This leaves small unprotected areas of parent material.

Small unprotected areas are good news for the corrosion, which sees each one as an opportunity to produce a pinhole, the rate of corrosion being greatly accelerated by the small area. At the same time, it nibbles away at the not-very-well bonded lining on either side of the pinhole and starts to peel this back; the corrosion creeps underneath and the hole gets bigger. The incredibly unsurprising end result is that the parent metal corrodes through and everyone gets together in a big meeting to discuss why the lining failed. Works every time.

All is not finished yet . . . we can reline it (they say).

Yes, you can reline tank or vessel surfaces successfully, either by piecemeal repairs or complete relining. You can also line vessels that were not lined originally and have already suffered, corrosion. The problem is that more than 50 % of the linings (relinings that is) fail due to either poor preparation or for a new reason. Here it is:

- To retrospectively line a corroded item, you have to get the surface *totally clean of soluble salts* and similar contaminants. It is no good just shotblasting the surface; it has to be chemically clean as well. This is always difficult, as, by definition, any surface that is corroded has probably been exposed to salts in some form.

12.2.3 The conclusion

The conclusion is simply that getting linings to perform well on tank or vessel surfaces *is difficult*. Although the linings themselves, like paints, are the results of a lot of expensive development and testing, and are generally of high quality, the practice of their pre-preparation and application is not always of such a high standard. The result is that many fail well before their design life and some components require continual relining throughout their life to keep corrosion to a manageable level.

12.3 So where does API 652 fit in?

If you were to put together a document to try to address the problems described above you would have to:

- List the problems that cause linings to fail.
- Decide ways to minimize them, particularly relating to pre-cleaning and application.
- Specify some basic guidance on lining choice and types.
- Ensure QA procedures and record systems were put in place to check the job was done properly.

- Recommend regular inspections.

Eventually, after consulting various people and bodies (and listening to shiny presentations from lining technical sales teams), you would end up with something that looks surprisingly like API 652.

12.3.1 The contents of API 652

Figure 12.1 shows the contents list of API 652. It is a short document of 15–16 pages providing a fairly generic introduction to the subject of tank linings. It contains mainly text and tables with a few figures. There are no calculations. The chapter headings are in a logical order, starting with explaining why bottom linings are required and then progressing through lining selection, surface preparation, application, inspection and repair.

1.	Scope	Usual API code preliminary information
2.	References	
3.	Definition	
4.	Corrosion mechanism	
5.	The need for tank bottom linings	
6.	Lining selection	
7.	Surface preparation	
8.	Lining application	
9.	Quality control inspection	
10.	Evaluation and repairs of existing linings	
11.	Maximizing lining service life	
12.	Safety	

Figure 12.1 The contents of API 652

12.3.2 API 652 section 3: definitions

There are a few definitions here that are specific to US and API codes in particular. Watch out for them in exam questions:

- *An anchor pattern* (API 652 definition 3.4) is the strange name given to a surface profile (or roughness) before the lining is applied. It is achieved by shotblasting and looks absolutely nothing like an anchor.
- *A thick-film lining* (definition 3.33) is one with a dry film thickness (dft) of 20 mils (0.020 in) or 0.51 mm or greater. These are frequently epoxy-based, have multiple coats or are reinforced with glass-fibre-reinforced polymer (GRP) fibres.
- *A thin-film lining* (definition 3.33) is one with a dft of less than 0.020 in (0.51 mm).
- A lot of chemical-based names appear in the definition list: adduct, amine, bisphenol-A-polyester, copolymer, isophthalic polyester, polyamide, phenolic and a few others. Do not worry too much about these – their definitions say what they are, and they generally only appear in open-book questions (and then not very often).

12.3.3 API 652 section 4: corrosion mechanism

For historical reasons, API 652 contains descriptions of a few of the corrosion mechanisms that can give rise to the need for a bottom lining in the first place. These supplement the more detailed descriptions provided in the main damage mechanism code API 571. There is nothing that contradicts API 571, just one or two additional points that are expressed in a slightly different way. It lists:

- Chemical corrosion
- Concentration cell (crevice) corrosion under deposits or mill scale
- Galvanic cell corrosion
- Sulphate-reducing bacteria (SRB) corrosion
- Erosion/corrosion

- Fretting (rubbing) corrosion

Of these, SRB corrosion contains the most detail (API 652 (4.5)). It is caused by bacteria colonies depositing on the steel, resulting in concentration cell pitting or chemical attack caused by the reduction of sulphate to sulphide. This is a common mechanism found on petroleum tank bottoms and the lower shell area.

12.3.4 API 652 (section 6): tank bottom lining selection

This is a long section for API 652, containing a lot of generic information about the suitability, advantages and disadvantages of the three main types of lining: thin-film, thick-film unreinforced and thick-film reinforced. There is information contained in here suitable for both open- and closed-book exam questions. Figure 12.2 shows a summary of some of the more useful points, expressed in the form of a table. Remember that all this is mainly with reference to linings applied to the inside (product-side) of the tank bottom. Shells can be lined also, but API 652 is predominately about bottom linings, as its title suggests.

Remember that API 652 only provides generic information. There are several hundred proprietary coating system products available. These differ a lot in chemical content, longevity and price. Manufacturer's datasheets for these products are freely available and contain excellent technical detail.

12.3.5 Preparation and application

Surface preparation by blasting is a critical part of the lining application procedure. Figure 12.3 shows the details. The required level is SSPC SP-5 'white metal' finish, with the lower 'near-white metal' level SSPC SP-10 being acceptable in some situations. Equally as important is cleaning to remove surface containments, typically chemicals, common on items that have been in use in a contaminated environment. This is done using a combination of chemical cleaning,

Lining type	Thickness	Materials	Temperature range	Advantages	Limitations	Common applications
Thin film	dft <0.020 in (0.51 mm)	Epoxy or copolymer resins e.g. • Phenolic • Amine • Polyamide API 652 (Table 1)	120–220 °F (49–104 °C) API 652 (Table 1)	• Better for new, smooth surfaces • Good flexibility • Allow MFL floor scanning	• Poor for corroded surfaces • Susceptible to damage • May require multiple coats • Can require 'holiday test' repairs	• Water and light petroleum products • Non-erosive service conditions
Thick-film unreinforced	dft ≥0.02 in (0.51 mm)	Epoxy or polyester compounds	140–220 °F (60–104 °C) API 652 (Table 2)	• Better on corroded bottoms • Fast curing (<24 h) • Few repairs required	• Requires spray application • Can crack on flexible plates	• New or old tanks • Crude oil or petroleum distillates
Thick-film reinforced	0.020–0.030 in resin coat + GRP mat + 0.025–0.03 in resin coat + Final resin (gel) coat	Strengthened with chopped glass fibres or matting	140–220 °F (60–104 °C) API 652 (Table 2)	• Better on heavily corroded bottoms • Can bridge over perforations	• May crack in highly stressed areas • MFL (magnetic flux leakage) can be difficult	• Tanks in bad condition • Crude oil or petroleum distillates • Erosive conditions

Figure 12.2 Tank bottom lining selection

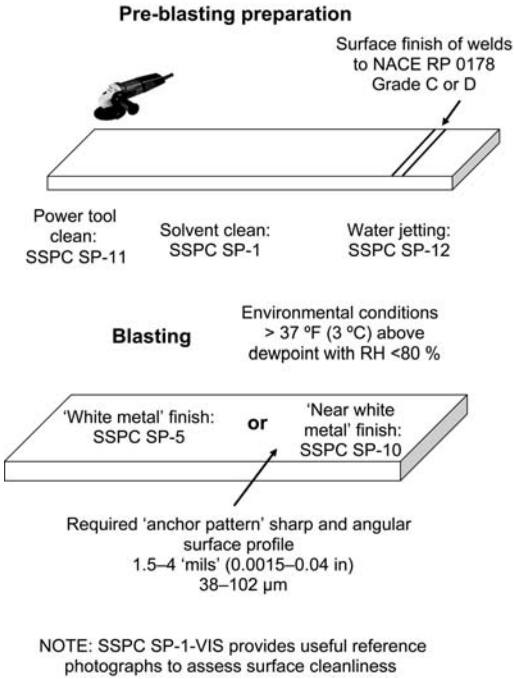


Figure 12.3 Surface preparation

steam cleaning and rinsing with demineralized water. Note the following important points:

- Blasting should not be performed if the temperature of the steel surface is less than 37 °F (3 °C) above dewpoint or if the relative humidity is greater than 80 %.
- The profile 'anchor' pattern required is typically 0.0015–0.04 in (38–102 μm) and should be sharp and angular.

Following on from surface preparation, API 652 (8.2–8.5) gives guidelines for the lining application process. These are useful practical points as linings are prone to peeling off in early service if they are not applied properly. Note the following, which are valid points for either open- or closed-book exam questions:

- Excess lining thickness, as well as insufficient thickness, can cause failure of linings (8.5).
- Curing times and temperatures must be in compliance with the lining manufacturer's datasheets (8.5).
- Wet film thickness (wft) can be checked during application to standard ASTM D4414.
- After drying, dry film thickness (dft) can be checked to standard SSPC PA2.

12.3.6 Testing of existing linings (API 652 section 10)

All newly applied and existing linings require visual examination to check for pinholes and areas of obvious low or excessive coverage. The most common procedure is the spark ('holiday') test. Figure 12.4 shows the details. A high voltage is applied between the parent metal under the lining and a wire brush or sponge passed over the top surface of the dry lining. Any pinhole or discontinuity in the lining (known mysteriously as a 'holiday') causes current to flow, resulting in a visible blue spark and audible alarm.

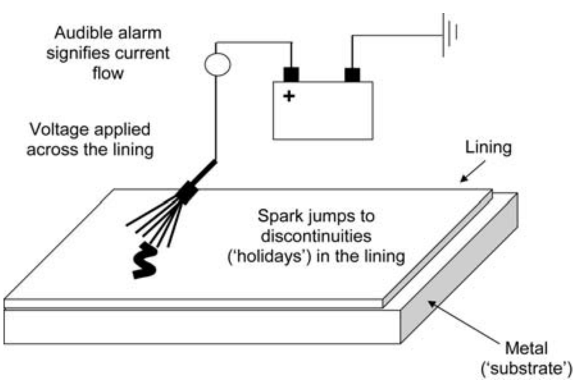


Figure 12.4 Holiday (spark) testing of linings

Thin-film lining tests normally use a low voltage (67.5 V) supply and a wet sponge detection technique. Thick-film reinforced linings can use as high as 20 kV. The lining manufacturer's datasheet will specify the correct voltage to be used. Insufficient voltage will not detect fine pinholes, whereas excessive voltage may actually break down weak areas of lining, causing additional discontinuities that were not there before.

Controversially, API 652 (10.5e) says that holiday testing is typically not recommended for linings that have been in previous service 'since the pressure of moisture in the film can cause damage when exposed to the voltage'. Some lining manufacturers believe their lining specification have superseded this problem – but they do not write the API exam questions.

12.4 European surface preparation standards

In Europe, most industries use grades of metal shotblasting preparation based on the Swedish standard SIS 055900. This specifies the 'SA' shot blast grades, of which the most commonly used are:

- *Grade SA-3*. A pure 'white' finish (a near-perfect blasted finish with no tarnish or staining).
- *Grade SA-2½*. An 'almost perfect' blasted finish, but one that allows a minor tarnish or stained appearance. This grade SA-2½ is the most common grade specified for preparation for painting and linings. It is much easier and cheaper to achieve than grade SA-3, which would be uneconomic for most utility steelwork, tanks and vessels.
- *Grade SA-2*. A 'thorough blast finish' that still has significant surface staining and contamination. This is considered a slightly substandard surface finish that is not suitable as a base for paints or linings.
- *Grade SA-1*. A 'light blast cleaning' that still has significant surface staining and contamination. This is

considered a poor quality surface finish that is not suitable as a base for paints or linings.

API codes do not use these grades. Instead, they use those grades specified by the US Society for Protective Coatings (formerly the Steel Structures Painting Council), known generically as the ***SSPC grades***. These work to the same principles but instead of an SA grade, they are given as an SP grade. The conversions are broadly as follows:

SA grade (used in Europe)	SSPC SP grade (used by API codes and in the USA)
SA-3 White metal finish	SP-5
SA-$2\frac{1}{2}$	SP-10
SA-2	
SA-1	
No equivalent	Power tool cleaning to bare metal SP-11
No equivalent	Water-jetted finish before relining SP-12
No equivalent	Solvent-cleaned finish SP-1

Section 7 of API 652 specifies the surface grades required for preparation prior to lining. Note how they compare to the grades, and their European comparisons shown above. These comparisons are shown for understanding only; API exams will only mention the SSPC SP grades, not the European SA grades.

Now try these practice questions.

12.5 Tank linings: practice questions

Q1. API 652: galvanic cell corrosion

You are supervising the construction of a new storage tank with an unlined bottom and you want to reduce the chances of corrosion. Which one of these alternative activities would you specify?

(a) Shot blast the mill scale from the underside of the tank bottom ☐

(b) Shot blast the mill scale from the topside of the tank bottom ☐
(c) 'Weather' the steel plates outside to increase the thickness of mill scale ☐
(d) Prepare the plate surface to NACE No. 10 SSPC-PA-6 ☐

Q2. API 652: SRB

You have a petroleum product tank that has known SRB corrosion mechanisms occurring in it. Which of these actions should you *not* take?

(a) Drain the tank regularly to get rid of water ☐
(b) Check the steam-heating coils for leaks ☐
(c) Increase the inspection period so as not to disturb the iron sulphide layer ☐
(d) Decrease the inspection period and disturb the internals more often ☐

Q3. API 652: need for bottom linings

Which of these tanks is most likely to respond *best* to lining of the tank bottom?

(a) One with rubble and sand foundations ☐
(b) A large flexible tank with foundation washout under the tank base ☐
(c) A small rigid tank on a concrete base ☐
(d) A floating-roof tank that is regularly completely emptied and filled ☐

Q4. API 652: thin-film bottom linings

A relatively new and lightly corroded tank contains crude oil at 150 °F. It is decided to clean it out and line it to give it a long life (25+ years). Which of these linings would you choose?

(a) Thick-film reinforced vinyl ester ☐
(b) Thick-film unreinforced vinyl ester ☐
(c) Thin-film reinforced epoxy/amine ☐
(d) Thin-film unreinforced epoxy/amine ☐

Q5. API 652: thick-film linings

A tank lined with thin-film lining has suffered lining failure and the tank floor is now quite heavily pitted, corroded and grooved. It has been fully prepared and is now ready for relining. Which of the following would you choose to give the best future performance?

(a) Thick-film reinforced ☐
(b) Thick-film unreinforced ☐
(c) Thin-film reinforced ☐
(d) Thin-film unreinforced ☐

Q6. API 652: thick-film linings

Which of these is the greatest disadvantage of thick-film reinforced linings when applied to large, old tanks with old foundations, and probably suffering from many years of water contamination?

(a) It cannot be applied thick enough ☐
(b) It is prone to cracking ☐
(c) It is prone to SRB ☐
(d) It cannot be applied thin enough to fill the pits and hollows ☐

Q7. API 652: surface preparation

Which lining activity requires the best surface finish and cleaning preparation?

(a) Lining of new tanks, because of mill scale ☐
(b) Lining of old tanks, because of salt contamination ☐
(c) Lining of old tanks, because of the rough surface profile (pitting) ☐
(d) They are all the same ☐

Q8. API 652: lining conditions

What are the environmental requirements for lining application?

(a) 5 °C above dewpoint and relative humidity <90 % ☐
(b) 3 °C above dewpoint and relative humidity <80 % ☐
(c) 3 °F above dewpoint and relative humidity <80 % ☐
(d) 3 °C above dewpoint and relative humidity <90 % ☐

Q9. API 652: inspection parameters

Which one of these is ***not*** the purpose of a holiday test?

(a) To check for pinholes ☐
(b) To check for lining adhesion ☐
(c) To check for discontinuities ☐
(d) To check for very thin areas of lining ☐

Q10. API 652: topcoating an existing lining

How should you prepare an existing, well-adhered lining for a new topcoat?

(a) Prepare it to SSPC-10 ☐
(b) Prepare it to SSPC-5 ☐
(c) Grind off the top surface with power tools to ASTM D 2583 ☐
(d) Just brush-blast it ☐

Chapter 13

Introduction to Welding/API RP 577

13.1 Module introduction

The purpose of this chapter is to ensure you can recognize the main welding processes that may be specified by the welding documentation requirements of ASME IX. The API exam will include questions in which you have to assess a Weld Procedure Specification (WPS) and its corresponding Procedure Qualification Record (PQR). As the codes used for API certification are all American you need to get into the habit of using American terminology for the welding processes and the process parameters.

This module will also introduce you to the API RP 577 *Welding Inspection and Metallurgy* in your code document package. This document has only recently been added to the API examination syllabus. As a Recommended Practice (RP) document, it contains technical descriptions and instruction, rather than truly prescriptive requirements.

13.2 Welding processes

There are four main welding processes that you have to learn about:

- Shielded metal arc welding (SMAW)
- Gas tungsten arc welding (GTAW)
- Gas metal arc welding (GMAW)
- Submerged arc welding (SAW)

The process(es) that will form the basis of the WPS and PQR questions in the API exam will almost certainly be chosen from these.

The sample WPS and PQR forms given in the non-mandatory appendix B of ASME IX (the form layout is not strictly within the API 653 examination syllabus, but we will discuss it later) *only* contain the information for qualifying these processes.

13.2.1 Shielded metal arc welding (SMAW)

This is the most commonly used technique. There is a wide choice of electrodes, metal and fluxes, allowing application to different welding conditions. The gas shield is evolved from the flux, preventing oxidation of the molten metal pool (Fig. 13.1). An electric arc is then struck between a coated electrode and the workpiece. SMAW is a manual process as the electrode voltage and travel speed are controlled by the welder. It has a constant current characteristic.

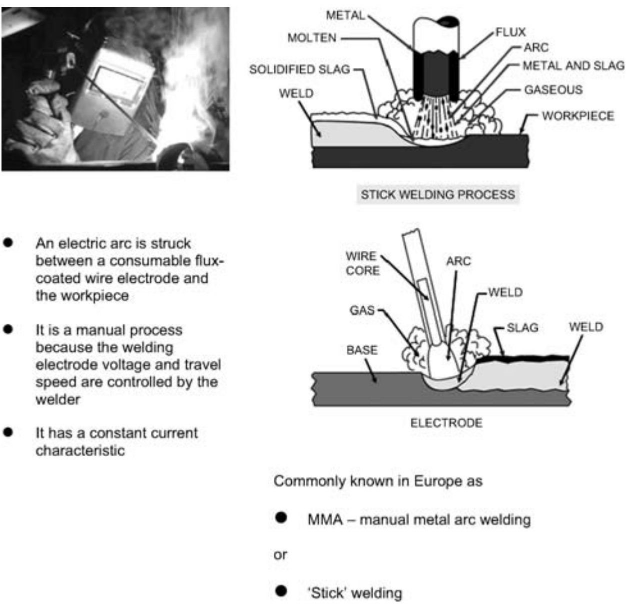


Figure 13.1 The shielded metal arc welding (SMAW) process

13.2.2 Metal inert gas (GMAW)

In this process, electrode metal is fused directly into the molten pool. The electrode is therefore consumed, being fed from a motorized reel down the centre of the welding torch (Fig. 13.2). GMAW is known as a semi-automatic process as the welding electrode voltage is controlled by the machine.

Tungsten inert gas (GTAW)

This uses a similar inert gas shield to GMAW but the tungsten electrode is not consumed. Filler metal is provided from a separate rod fed automatically into the molten pool (Fig. 13.3). GTAW is another manual process as the welding electrode voltage and travel speed are controlled by the welder.

Submerged arc welding (SAW)

In SAW, instead of using shielding gas, the arc and weld zone are completely submerged under a blanket of granulated flux (Fig. 13.4). A continuous wire electrode is fed into the weld. This is a common process for welding structural carbon or carbon–manganese steelwork. It is usually automatic with

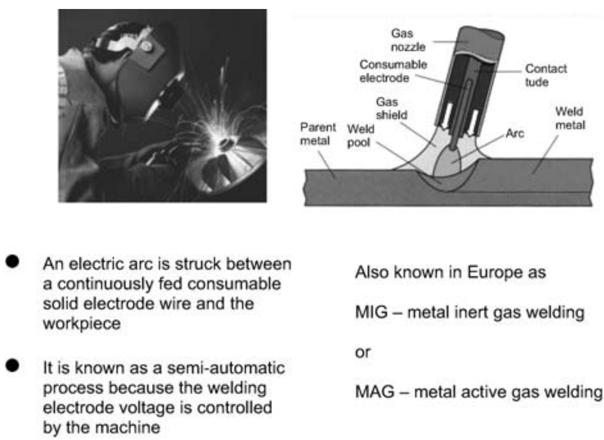


Figure 13.2 The gas metal arc welding (GMAW) process

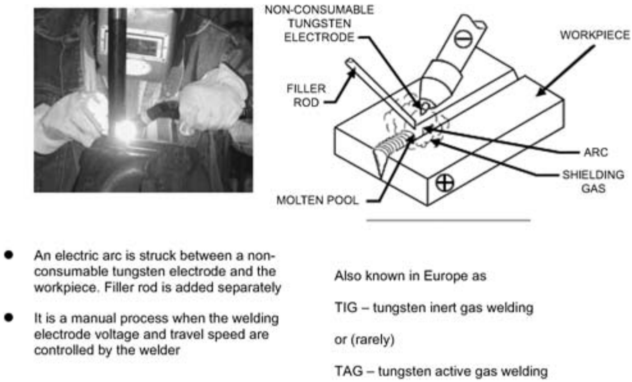


Figure 13.3 The gas tungsten arc welding (GTAW) process

the welding head being mounted on a traversing machine. Long continuous welds are possible with this technique.

Flux-cored arc welding (FCAW)

FCAW is similar to the GMAW process, but uses a continuous hollow electrode filled with flux, which produces the shielding gas (Fig. 13.5). The advantage of the technique is that it can be used for outdoor welding, as the gas shield is less susceptible to draughts.

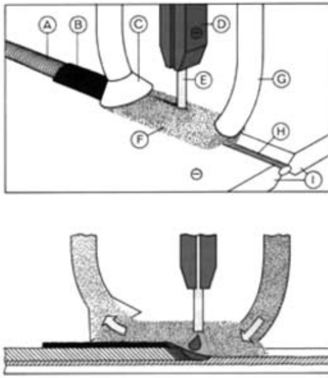
13.3 Welding consumables

An important area of the main welding processes is that of weld *consumables*. We can break these down into the following three main areas:

- Filler (wires, rods, flux-coated electrodes)
- Flux (granular fluxes)
- Gas (shielding, trailing or backing)

There are always questions in the API examination about weld consumables.

Figures 13.6 to 13.11 show basic information about the main welding processes and their consumables.



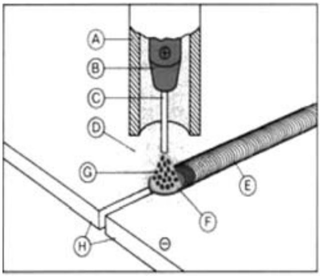
Schematic representation of submerged arc welding

A Finished weld *F Flux*
B Slag *G Flux supply*
C Powder removal *H Root bead*
D Electrode holder *I Parent metal*
E Filler wire

- An electric arc is struck between a reel-fed continuous consumable electrode wire and the work with the arc protected underneath a flux blanket

- It can be a semi-automatic, mechanized or automated process

Figure 13.4 The submerged arc welding (SAW) process



In FCAW the filler wire contains a flux. This protects the weld from the atmosphere by coating it in a slag (similar to SAW)

A Gas cup
B Electrode holder
C Filler wire
D Shielding gas
E Finished weld
F Weld pool
G Arc
H Parent metal

Figure 13.5 The flux cored arc welding (FCAW) process

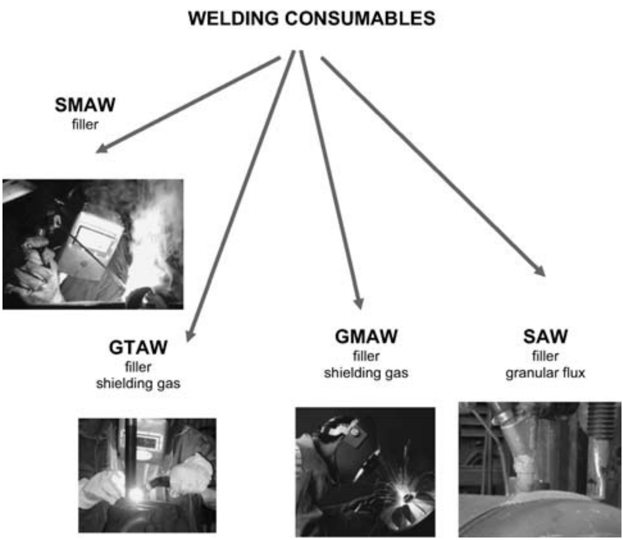


Figure 13.6 Welding consumables

TYPES

- Basic: for low-hydrogen applications
- Rutile: for general purpose applications
- Cellulosic: for stovepipe (vertical down) applications

FILLER
Flux-coated electrodes

Figure 13.7 SMAW consumables

The American Welding Society (AWS) have a welding electrode identification system (see API 577 section 7.4 and appendix A). This is the system for SMAW electrodes

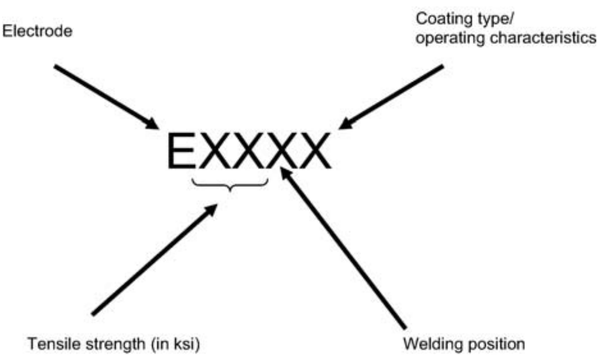


Figure 13.8 SMAW consumables identification

FILLER:
Solid rods or wire

SHIELDING GAS:
Argon, helium or mixtures

Figure 13.9 GTAW consumables

FILLER:
Solid wire supplied on reels

SHIELDING GAS:
Inert gases – argon , helium, or mixtures. Active gases – carbon dioxide (CO_2) or Ar/CO_2 mixtures

Figure 13.10 GMAW consumables

Figure 13.11 SAW consumables

Now try these two sets of familiarization questions about the welding processes and their consumables.

13.4 Welding process familiarization questions

Q1. API 577 section 5.2

How is fusion obtained using the SMAW process?

(a) An arc is struck between a consumable flux-coated electrode and the work
(b) An arc is struck between a non-consumable electrode and the work
(c) The work is bombarded with a stream of electrons and protons
(d) An arc is struck between a reel-fed flux-coated electrode and the work

Q2. API 577 section 5.1

Which of the following is not an arc welding process?

(a) SMAW
(b) STAW
(c) GMAW
(d) GTAW

Q3. API 577 section 5.3

How is fusion obtained using the GTAW process?

(a) An arc is struck between a consumable flux-coated electrode and the work

(b) An arc is struck between a non-consumable tungsten electrode and the work ☐
(c) The work is bombarded with a stream of electrons and protons ☐
(d) An arc is struck between a reel-fed flux-coated electrode and the work ☐

Q4. API 577 section 5.3
How is the arc protected from contaminants in GTAW?

(a) By the use of a shielding gas ☐
(b) By the decomposition of a flux ☐
(c) The arc is covered beneath a fused or agglomerated flux blanket ☐
(d) All of the above methods can be used ☐

Q5. API 577 section 5.4
How is fusion obtained using the GMAW process?

(a) An arc is struck between a consumable flux-coated electrode and the work ☐
(b) An arc is struck between a non-consumable electrode and the work ☐
(c) The work is bombarded with a stream of electrons and protons ☐
(d) An arc is struck between a continuous consumable electrode and the work ☐

Q6. API 577 section 5.4
Which of the following are modes of metal transfer in GMAW?

(a) Globular transfer ☐
(b) Short-circuiting transfer ☐
(c) Spray transfer ☐
(d) All of the above ☐

Q7. API 577 section 5.6
How is the arc shielded in the SAW process?

(a) By an inert shielding gas ☐
(b) By an active shielding gas ☐
(c) It is underneath a blanket of granulated flux ☐
(d) The welding is carried out underwater ☐

Q8. API 577 section 5.6

SAW stands for:

(a) Shielded arc welding ☐
(b) Stud arc welding ☐
(c) Submerged arc welding ☐
(d) Standard arc welding ☐

Q9. API 577 sections 5.3 and 3.7

Which of the following processes can weld *autogenously*?

(a) SMAW ☐
(b) GTAW ☐
(c) GMAW ☐
(d) SAW ☐

Q10. API 577 section 5.3.1

Which of the following is a commonly accepted advantage of the GTAW process?

(a) It has a high deposition rate ☐
(b) It has the best control of the weld pool of any of the arc processes ☐
(c) It is less sensitive to wind and draughts than other processes ☐
(d) It is very tolerant of contaminants on the filler or base metal ☐

13.5 Welding consumables familiarization questions

Q1.

In a SMAW electrode classified as E7018 what does the 70 refer to?

(a) A tensile strength of 70 ksi ☐
(b) A yield strength of 70 ksi ☐
(c) A toughness of 70 J at 20 °C ☐
(d) None of the above ☐

Q2.

Which of the following does not produce a layer of slag on the weld metal?

(a) SMAW ☐
(b) GTAW ☐
(c) SAW ☐

(d) FCAW ☐

Q3.
Which processes use a shielding gas?

(a) SMAW and SAW ☐
(b) GMAW and GTAW ☐
(c) GMAW, SAW and GTAW ☐
(d) GTAW and SMAW ☐

Q4.
What type of flux is used to weld a low hydrogen application with SAW?

(a) Agglomerated ☐
(b) Fused ☐
(c) Rutile ☐
(d) Any of the above ☐

Q5.
What shielding gases can be used in GTAW?

(a) Argon ☐
(b) CO_2 ☐
(c) Argon/CO_2 mixtures ☐
(d) All of the above ☐

Q6.
Which process does not use bare wire electrodes?

(a) GTAW ☐
(b) SAW ☐
(c) GMAW ☐
(d) SMAW ☐

Q7.
Which type of SMAW electrode would be used for low hydrogen applications?

(a) Rutile ☐
(b) Cellulosic ☐
(c) Basic ☐
(d) Reduced hydrogen cellulosic ☐

Q8.
In an E7018 electrode, what does the 1 refer to?

(a) Type of flux coating ☐

(b) It can be used with AC or DC ☐
(c) The positional capability ☐
(d) It is for use with DC only ☐

Q9.
Which of the following processes requires filler rods to be added by hand?

(a) SMAW ☐
(b) GTAW ☐
(c) GMAW ☐
(d) SAW ☐

Q10.
Which of the following processes uses filler supplied on a reel?

(a) GTAW ☐
(b) SAW ☐
(c) GMAW ☐
(d) Both (b) and (c) ☐

Chapter 14

Welding Qualifications and ASME IX

14.1 Module introduction

The purpose of this chapter is to familiarize you with the principles and requirements of welding qualification documentation. These are the Weld Procedure Specification (WPS), Procedure Qualification Record (PQR) and Welder Performance Qualification (WPQ). The secondary purpose is to define the essential, non-essential and supplementary essential variables used in qualifying WPSs.

ASME section IX is a part of the ASME Boiler Pressure Vessel code that contains the rules for qualifying welding procedures and welders. It is also used to qualify welders and procedures for welding to ASME VIII.

14.1.1 Weld procedure documentation: which code to follow?

API 650 and 653 require that repair organizations must use welders and welding procedures qualified to ASME IX and maintain records of the welding procedures and welder performance qualifications. ASME IX article II states that each Manufacturer and Contractor shall prepare written Welding Procedure Specifications (WPSs) and a Procedure Qualification Record (PQR), as defined in section QW-200.2.

14.2 Formulating the qualification requirements

The actions to be taken by the manufacturer to qualify a WPS and welder are done in the following order (see Fig. 14.1):

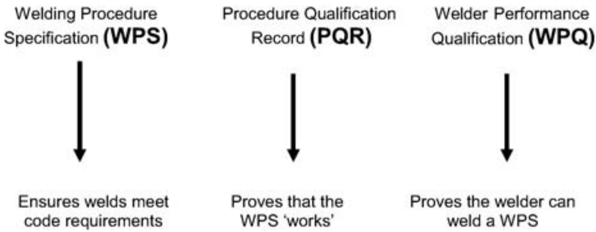


Figure 14.1 Formulating the qualification requirements

Step 1: qualify the WPS

- A preliminary WPS (this is an unsigned and unauthorized document) is prepared specifying ranges of essential variables, supplementary variables (if required) and non-essential variables required for the welding process to be used.
- The required numbers of test coupons are welded and the ranges of essential variables used recorded on the PQR.
- Any required non-destructive testing and/or mechanical testing is carried out and the results recorded in the PQR.
- If all the above are satisfactory then the WPS is qualified using the documented information on the PQR as proof that the WPS works.

The WPS (see Fig. 14.2) is signed and authorized by the manufacturer for use in production.

Step 2: qualify the welder. The next step is to qualify the *welder* by having him weld a test coupon to a qualified WPS. The essential variables used, tests and results are noted and the ranges qualified on a Welder Performance Qualification (WPQ) (see Fig. 14.3).

Note that ASME IX does not require the use of preheat or PWHT (post weld heat treatment) on the welder test coupon. This is because it is the skill of the welder and his ability to follow a procedure that is being tested. The pre- and PWHT are not required because the mechanical properties of the joint have already been determined during qualification of the WPS.

ASME IX QW 482 WPS format:

Company Name ______ MET Ltd ______ By: ______ S. Hughes ______
Welding Procedure Specification No __ SMAW-1 ____ Date __ 01/04/2006_ Supporting PQR No __ SMAW-1_
Revision No ______ 0 ______ Date __ 01/04/06 ____

Welding Process(es) ______ SMAW ______ Type(s) ______ Manual ______
Automatic, Manual, machine or Semi Automatic

JOINTS (QW-402)

Details

Joint Design ______ Single Vee Butt ______
Backing (Yes) ______ (No) ____ X ______
Backing Material (Type) ______
Refer to both backing and retainers

See production drawing

☐ Metal ☐ Nonfusing Metal

☐ Nonmetallic ☐ Other

Sketches, Production Drawings, Weld Symbols or Written Description should show the general arrangement of the parts to be welded. Where applicable, the root spacing and the details of weld groove may be specified. At the option of the manufacturer, sketches may be attached to illustrate joint design, weld layers and bead sequence, eg for notch toughness procedures, for multiple process procedures etc

BASE METALS (QW-403)

P-No. ____ 1 ______ Group No. ____ 2 ______ to P-No. ____ 1 ______ Group No. ____ 2 ______
OR
Specification type and grade ______
to
Specification type and grade ______
OR
Chemical Analysis and Mechanical properties ______
to
Chemical Analysis and Mechanical properties ______

Thickness Range:
Base Metal: Groove __ 1/16" – 2" ______ Fillet ______
Pipe Diameter range: Groove __ All ______ Fillet ______ All ______
Other ______

FILLER METALS (QW-404) Each base metal-filler metal combination should be recorded individually

Spec. No (SFA)	SFA 5.1		
AWS No Class)	E7016		
F No	6		
A-No	4		
Size of filler metals	All		
Weld Metal			
Thickness range			
Groove	All		
Fillet	All		
Electrode-Flux (Class)	N/A		
Flux Trade Name	N/A		
Consumable Insert	N/A		
Other			

Figure 14.2a WPS format

ASME IX QW 482 (Back)

WPS No _SMAW-1___ Rev ___0___

POSITIONS (QW-405)

Position(s) of Groove ____________

Welding Progression: Up ______ Down ______

Position(s) of Fillet ____________

PREHEAT (QW-406)

Rate
Preheat Temp. Min ____________

Interpass Temp. Max ____________

Preheat Maintenance ____________
(Continuous or special heating , where applicable, should be recorded)

POSTWELD HEAT TREATMENT (QW-407)

Temperature Range

Time Range

GAS (QW-408)

	Gas(es)	Percent composition (Mixture)	Flow
Shielding			
Trailing			
Backing			

ELECTRICAL CHARACTERISTICS (QW-409)
Current AC or DC ____________ Polarity ____________
Amps (Range) ____________ Volts (Range) ____________
(Amps and volts range should be recorded for each electrode size,position, and thickness, etc. this information may be listed in a tabular form similar to that shown below).

Tungsten Electrode Size and Type____________
(Pure Tungsten, 2% Thoriated, etc)
Mode of Metal Transfer for GMAW ____________
(Spray arc, short circuiting arc, etc)
Electrode Wire feed speed range ____________

TECHNIQUE (QW-410)
String or Weave Bead ____________
Orifice or Gas Cup Size ____________
Initial and Interpass Cleaning (Brushing, Grinding, etc) ____________

Method of Back Gouging ____________
Oscillation ____________
Contact Tube to Work Distance ____________
Multiple or Single Pass (per side) ____________
Multiple or Single Electrodes ____________
Travel Speed (Range) ____________
Peening ____________
Other ____________

Weld Layer(s)	Process	Filler Metal		Current		Volt range	Travel Speed Range	Other (remarks, comments, hot wire addition, technique, torch angle etc)
		Class	Diameter	Type Polarity	Amp Range			

Figure 14.2b WPS format

QW 483 PQR format

Company Name ____________________

Procedure Qualification Record No. ____________________ Date __________

WPS No ____________________

Welding Process(es) ____________________

Types (Manual, Automatic, Semi-Auto)

JOINTS (QW-402)

Groove Design of Test Coupon

(For combination qualifications, the deposited weld metal thickness that shall be recorded for each filler metal or process used)

BASE METALS (QW-403)
Material spec. __________
Type or Grade __________
P-No __________ to P-No __________
Thickness of test coupon __________
Diameter of test coupon __________
Other __________

POSTWELD HEAT TREATMENT (QW-407)
Temperature __________
Time __________
Other __________

GAS (QW-408)

	Percent composition		
	Gas(es)	(Mixture)	Flow Rate
Trailing	None		
Backing	None		
Backing	None		

FILLER METALS (QW-404)
SFA Specification __________
AWS Classification __________
Filler metal F-No __________
Weld Metal Analysis A-No __________
Size of Filler Metal __________
Other __________
Weld Metal Thickness __________

ELECTRICAL CHARACTERISTICS (QW-409)
Current __________
Polarity __________
Amps __________ Volts __________
Tungsten Electrode Size __________
Other __________

POSITIONS (QW-405)
Position of Groove __________
Welding Progression (Uphill, Downhill) __________
Other __________

PREHEAT (QW-406)
Preheat Temp. __________
Interpass Temp. __________
Other __________

TECHNIQUE (QW-410)
Travel Speed __________
String or Weave Bead __________
Oscillation __________
Multiple or Single Pass (per side) __________
Single or Multiple Electrodes __________
Other __________

Figure 14.3a PQR format

QW 483 PQR (Back)

PQR No. __SMAW-1

TENSILE TEST (QW-150)

Specimen No	Width	Thickness	Area	Ultimate Total load lb	Ultimate Unit Stress psi	Type of Failure & Location

GUIDED- BEND TESTS (QW-160)

Type and Figure No	Result

TOUGHNESS TESTS (QW-170)

Specimen No	Notch Location	Specimen Size	Test Temp	Impact Values			Drop Weight Break (Y/N)
				Ft-lb	% Shear	Mils	

Comments ______________________________

FILLET WELD TEST (QW-180)

Result – Satisfactory? : Yes____ No _____ Penetration into Parent Metal? : Yes____ No _____

Macro – Results ______________________________

OTHER TESTS

Type of Test ______________________________

Deposit Analysis ______________________________

Other ______________________________

Welder's Name ____________________Clock No. ___________ Stamp No. _________

Tests conducted by: ______________________Laboratory Test No.______________

We certify that the statements in this record are correct and that the tests welds were prepared, welded, and tested in accordance with the requirements of Section IX of the ASME Code.

Manufacturer ____________________

Date ____________________ By ____________________

(Detail of record of tests are illustrative only and may be modified to conform to the type and number of tests required by the Code.)

Figure 14.3b PQR format

14.2.1 WPSs and PQRs: ASME IX section QW-250

We will now look at the ASME IX code rules covering WPSs and PQRs. The code section splits the variables into three groups:

- Essential variables
- Non-essential variables
- Supplementary variables

These are listed on the WPS for each welding process. ASME IX section QW-250 lists the variables that must be specified on the WPS and PQR for each process. Note how this is a very long section of the code, consisting mainly of tables covering the different welding processes. There are subtle differences between the approaches to each process, but the guiding principles as to what is an essential, non-essential and supplementary variable are much the same.

14.2.2 ASME IX welding documentation formats

The main welding documents specified in ASME IX have examples in non-mandatory appendix B section QW-482. Strangely, these are not included in the API 653 exam code document package but fortunately two of them, the WPS and PQR, are repeated in API 577 (have a look at them in API 577 appendix C). Remember that the actual format of the procedure sheets is not mandatory, as long as the necessary information is included.

The other two that are in ASME IX non-mandatory appendix B (the WPQ and Standard Weld Procedure Specification (SWPS)) are not given in API 577 and are therefore a bit peripheral to the API 653 exam syllabus.

14.3 Welding documentation reviews: the exam questions

The main thrust of the API 653 ASME IX questions is based on the requirement to review a WPS and its qualifying PQR, so these are the documents that you must become familiar with. The review will be subject to the following limitations (to make it simpler for you):

- The WPS and its supporting PQR will contain only *one* welding process.
- The welding process will be SMAW or SAW and will have only one filler metal.
- The base material P group number will be limited to P1 only.

Base materials are assigned P-numbers in ASME IX to reduce the amount of procedure qualifications required. The P-number is based on material characteristics like weldability and mechanical properties. S-numbers are the same idea as P-numbers but deal with piping materials from ASME B31.3.

14.3.1 WPS/PQR review questions in the exam

The API 653 certification exam requires candidates to review a WPS and its supporting PQR. The format of these will be based on the sample documents contained in annex B of ASME IX. Remember that this annex B is not contained in your code document package; instead, you have to look at the formats in API 577 appendix B, where they *are* shown (they are exactly the same).

The WPS/PQR documents are designed to cover the parameters/variables requirements of the SMAW, GTAW, GMAW and SAW welding processes. The open-book questions on these documents in the API exam, however, only contain *one* of those welding processes. This means that there will be areas on the WPS and PQR documents that will be left unaddressed, depending on what process is used. For example, if GTAW welding is *not* specified then the details of tungsten electrode size and type will not be required on the WPS/PQR.

In the exam questions, you will need to understand the variables to enable you to determine if they have been correctly addressed in the WPS and PQR for any given process.

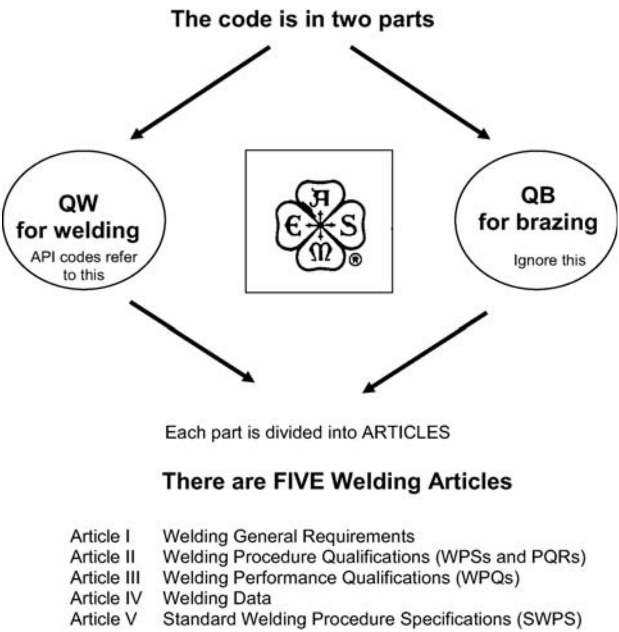


Figure 14.4 The ASME IX numbering system

14.3.2 Code cross-references

One area of ASME IX that some people find confusing is the numbering and cross-referencing of paragraphs that takes place throughout the code. Figure 14.4 explains how the ASME IX numbering system works.

14.4 ASME IX article I

Article I contains less technical ‘meat’ than some of the following articles (particularly articles II and IV). It is more a collection of general statements than a schedule of firm technical requirements. What it does do, however, is cross-reference a lot of other clauses (particularly in article IV), which is where the more detailed technical requirements are contained.

From the API exam viewpoint, most of the questions that can be asked about article I are:

- More suitable to closed-book questions than open-book ones
- Fairly general and 'commonsense' in nature

Don't ignore the content of article I. Read the following summaries through carefully but treat article I more as a lead-in to the other articles, rather than an end in itself.

Section QW-100.1
This section tells you five things, all of which you have met before. There should be nothing new to you here. They are:

- A Weld Procedure Specification (WPS) has to be qualified (by a PQR) by the manufacturer or contractor to determine that a weldment meets its required mechanical properties.
- The WPS specifies the conditions under which welding is performed and these are called welding 'variables'.
- The WPS must address the essential and non-essential variables for each welding process used in production.
- The WPS must address the supplementary essential variables if notch toughness testing is required by other code sections.
- A Procedure Qualification Record (PQR) will document the welding history of the WPS test coupon and record the results of any testing required.

Section QW-100.2
A welder qualification (i.e. the WPQ) is to determine a welder's ability to deposit sound weld metal or a welding operator's mechanical ability to operate machine welding equipment.

14.5 Section QW-140 types and purposes of tests and examinations

Section QW-141: mechanical tests

Mechanical tests used in procedure or performance qualification are as follows:

- *QW-141.1: tension tests* (see Fig. 14.5). Tension tests are used to determine the strength of groove weld joints.
- *QW-141.2: guided-bend tests* (see Fig. 14.6). Guided-bend tests are used to determine the degree of soundness and ductility of groove-weld joints.
- *QW-141.3: fillet-weld tests.* Fillet weld tests are used to

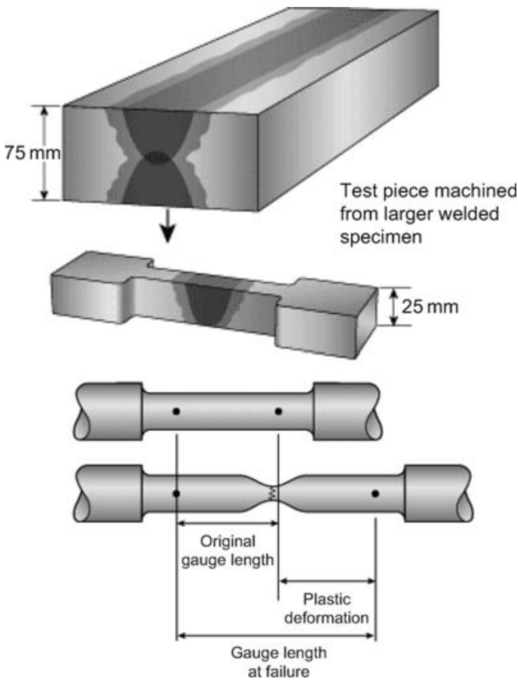


Figure 14.5 Tension tests

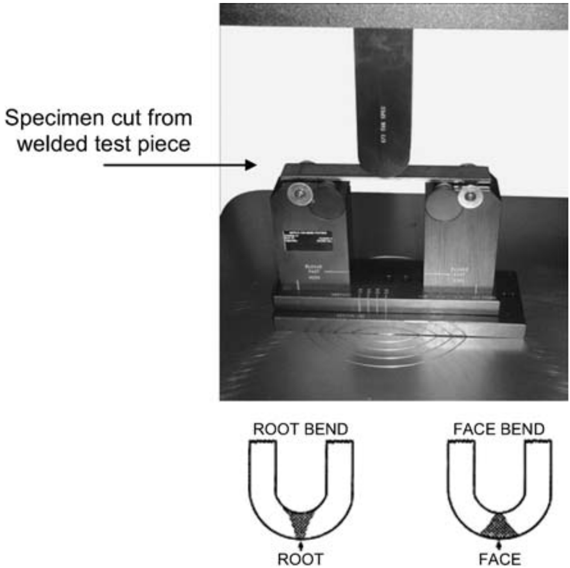


Figure 14.6 Guided bend tests

determine the size, contour and degree of soundness of fillet welds.

- *QW-141.4: notch-toughness tests*. Tests are used to determine the notch toughness of the weldment.

14.6 ASME IX article II

Article II contains hard information about the content of the WPS and PQRs and how they fit together. In common with article I, it cross-references other clauses (particularly in article IV). From the API examination viewpoint there is much more information in here that can form the basis of open-book questions, i.e. about the reviewing of WPS and PQR. ASME IX article II is therefore at the core of the API examination requirements.

Section QW-200: general
This gives lists of (fairly straightforward) requirements for the WPS and PQR:

- *QW-200.1* covers the WPS. It makes fairly general 'principle' points that you need to understand (but not remember word-for-word).
- *QW-200.2* covers the PQR again. It makes fairly general 'principle' points that you need to understand (but not remember word-for-word).
- *QW-200.3: P-numbers*. P-numbers are assigned to base metals to reduce the number of welding procedure qualifications required. For steel and steel alloys, *group* numbers are assigned additionally to P-numbers for the purpose of procedure qualification where notch-toughness requirements are specified.

Now try these familiarization questions, using ASME IX articles I and II to find the answers.

14.7 ASME IX articles I and II familiarization questions

Q1. ASME IX section QW-153: acceptance criteria – tension tests

Which of the following is a true statement on the acceptance criteria of tensile tests?

(a) They must never fail below the UTS of the base material ☐
(b) They must fail in the base material. ☐
(c) They must not fail more than 5 % below the minimum UTS of the base material ☐
(d) They must fail in the weld metal otherwise they are discounted ☐

Q2. ASME IX section QW-200 PQR

A PQR is defined as?

(a) A record supporting a WPS ☐
(b) A record of the welding data used to weld a test coupon ☐

(c) A Procedure Qualification Record ☐
(d) A Provisional Qualification Record ☐

Q3. ASME IX section QW-200.2 (b)
Who certifies the accuracy of a PQR?

(a) The Authorized Inspector before it can be used ☐
(b) The Manufacturer or his designated subcontractor ☐
(c) An independent third-party organization ☐
(d) Only the Manufacturer or Contractor ☐

Q4. ASME IX section QW-200.3
What is a P-number?

(a) A number assigned to base metals ☐
(b) A procedure unique number ☐
(c) A number used to group similar filler material types ☐
(d) A unique number designed to group ferrous materials ☐

Q5. ASME IX section QW-200.3
What does the assignment of a group number to a P-number indicate?

(a) The base material is non-ferrous ☐
(b) Post-weld heat treatment will be required ☐
(c) The base material is a steel or steel alloy ☐
(d) Notch toughness requirements are mandatory ☐

Q6. ASME IX section QW-202.2 types of test required
What types of mechanical tests are required to qualify a WPS on full penetration groove welds with no notch toughness requirement?

(a) Tension tests and guided bend tests ☐
(b) Tensile tests and impact tests ☐
(c) Tensile, impact and nick break tests ☐
(d) Tension, side bend and macro tests ☐

Q7. ASME IX section QW-251.1
The ‘brief of variables’ listed in tables QW-252 to QW-265 reference the variables required for each welding process. Where can the complete list of variables be found?

(a) In ASME B31.3 ☐
(b) In ASME IX article IV ☐
(c) In API 510 ☐
(d) In ASME IX article V ☐

Q8. ASME IX section QW-251.2

What is the purpose of giving base materials a P-number?

(a) It makes identification easier ☐
(b) It reduces the number of welding procedure qualifications required ☐
(c) It shows they are in pipe form ☐
(d) It indicates the number of positions it can be welded in ☐

Q9. ASME IX section QW-251.2

A welder performance test is qualified using base material with an S-number. Which of the following statements is true?

(a) Qualification using an S-number qualifies corresponding S-number materials only ☐
(b) Qualification using an S-number qualifies corresponding F-number materials ☐
(c) Qualification using an S-number qualifies corresponding P-number materials only ☐
(d) Qualification using an S-number qualifies *both* P-number and S-number materials ☐

Q10. ASME IX section QW-253

Which of the following would definitely not be a variable consideration for the SMAW process?

(a) Filler materials ☐
(b) Electrical characteristics ☐
(c) Gas ☐
(d) PWHT ☐

14.8 ASME IX article III

Remember that WPQs are specific to the *welder*. While the content of this article is in the API 653 syllabus it is fair to say that it commands less importance than articles II (WPSs and PQRs and their relevant QW-482 and QW-483 format forms) and article IV (welding data).

Section QW-300.1

This article lists the welding processes separately, with the essential variables that apply to welder and welding operator performance qualifications. The welder qualification is limited by the essential variables listed in QW-350, and defined in article IV *Welding data*, for each welding process. A welder or welding operator may be qualified by radiography of a test coupon or his initial production welding, or by bend tests taken from a test coupon.

Look at these tables below and mark them with post-it notes:

- Table QW-353 gives SMAW essential variables for welder qualification.
- Table QW-354 gives SAW essential variables for welder qualification.
- Table QW-355 gives GMAW essential variables for welder qualification.
- Table QW-356 gives GTAW essential variables for welder qualification.

Section QW-351: variables for welders (general)
A welder needs to be requalified whenever a change is made in one or more of the essential variables listed for each welding process. The limits of deposited weld metal thickness for which a welder will be qualified are dependent upon the thickness of the weld deposited with each welding process, exclusive of any weld reinforcement.

In production welds, welders may not deposit a thickness greater than that for which they are qualified.

14.9 ASME IX article IV

Article IV contains core data about the welding variables themselves. Whereas article II summarizes which variables are essential/non-essential/supplementary for the main welding processes, the content of article IV explains what the variables actually *are*. Note how variables are subdivided into *procedure* and *performance* aspects.

Section QW-401: general
Each welding variable described in this article is applicable as an essential, supplemental essential or non-essential variable for procedure qualification when referenced in QW-250 for

each specific welding process. Note that a change from one welding process to another welding process is an essential variable and requires requalification.

Section QW-401.1: essential variable (procedure)
This is defined as a change in a welding condition that will affect the mechanical properties (other than notch toughness) of the weldment (for example, change in P-number, welding process, filler metal, electrode, preheat or post-weld heat treatment, etc.).

Section QW-401.2: essential variable (performance)
A change in a welding condition that will affect the ability of a welder to deposit sound weld metal (such as a change in welding process, electrode F-number, deletion of backing, technique, etc.).

Section QW-401.3: supplemental essential variable (procedure)
A change in a welding condition that will affect the notch-toughness properties of a weldment (e.g. change in welding process, uphill or downhill vertical welding, heat input, preheat or PWHT, etc.).

Section QW-401.4: non-essential variable (procedure)
A change in a welding condition that will not affect the mechanical properties of a weldment (such as joint design, method of back-gouging or cleaning, etc.).

Section QW-401.5
The welding data include the welding variables grouped as follows:

- QW-402 joints
- QW-403 base metals
- QW-404 filler metal
- QW-405 position
- QW-406 preheat
- QW-407 post-weld heat treatment

- QW-408 gas
- QW-409 electrical characteristics
- QW-410 technique

Section QW-420.1: P-numbers

P-numbers are groupings of base materials of similar properties and usability. This grouping of materials allows a reduction in the number of PQRs required. Ferrous P-number metals are assigned a group number if notch toughness is a consideration.

Section QW-420.2: S-numbers (non-mandatory)

S-numbers are similar to P-numbers but are used on materials not included within ASME BPV code material specifications (section II). There is no mandatory requirement that S-numbers have to be used, but they often are. Note these two key points:

- For WPS a P-number qualifies the same S-number but not vice versa.
- For WPQ a P-number qualifies the same S-number and vice versa.

Section QW-430: F-numbers

The F-number grouping of electrodes and welding rods is based essentially on their usability characteristics. This grouping is made to reduce the number of welding procedure and performance qualifications, where this can logically be done.

Section QW-432.1

Steel and steel alloys utilize F-1 to F-6 and are the most commonly used ones.

Section QW-492: definitions

QW-492 contains a list of definitions of the common terms relating to welding and brazing that are used in ASME IX.

Try these ASME IX articles III and IV familiarization questions. You will need to refer to your code to find the answers.

14.10 ASME IX articles III and IV familiarization questions

Q1. ASME IX section QW-300

What does ASME IX article III contain?

(a) Welding Performance Qualification requirements ☐
(b) A list of welding processes with essential variables applying to WPQ ☐
(c) Welder qualification renewals ☐
(d) All of the above ☐

Q2. ASME IX section QW-300.1

What methods can be used to qualify a welder?

(a) By visual and bend tests taken from a test coupon ☐
(b) By visual and radiography of a test coupon or his initial production weld ☐
(c) By visual, macro and fracture test ☐
(d) Any of the above can be used depending on joint type ☐

Q3. ASME IX section QW-301.3

What must a manufacturer or contractor *not* assign to a qualified welder to enable his work to be identified?

(a) An identifying number ☐
(b) An identifying letter ☐
(c) An identifying symbol ☐
(d) Any of the above can be assigned ☐

Q4. ASME IX section QW-302.2

If a welder is qualified by radiography, what is the minimum length of coupon required?

(a) 12 inches (300 mm) ☐
(b) 6 inches (150 mm) ☐
(c) 3 inches (75 mm) ☐
(d) 10 inches (250 mm) ☐

Q5. ASME IX section QW-302.4

What areas of a pipe test coupon require visual inspection for a WPQ?

(a) Inside and outside of the entire circumference ☐

(b) Only outside the surface if radiography is to be used ☐
(c) Only the weld metal on the face and root ☐
(d) Visual inspection is not required for pipe coupons ☐

Q6. ASME IX section QW-304

For a WPQ, which of the following welding processes can *not* have groove welds qualified by radiography?

(a) GMAW (short-circuiting transfer mode) ☐
(b) GTAW ☐
(c) GMAW (globular transfer mode) ☐
(d) They can all be qualified by radiography ☐

Q7. ASME IX section QW-322

How long does a welder's performance qualification last if he has not been involved in production welds using the qualified welding process?

(a) 6 months ☐
(b) 2 years ☐
(c) 3 months ☐
(d) 6 weeks ☐

Q8. ASME IX section QW-402 joints

A welder qualified in a single welded groove weld with backing must requalify if:

(a) He must now weld without backing ☐
(b) The backing material has a nominal change in its composition ☐
(c) There is an increase in the fit-up gap beyond that originally qualified ☐
(d) Any of the above occur ☐

Q9. ASME IX section QW-409.8

What process requires the electrode wire feed speed range to be specified?

(a) SMAW ☐
(b) SAW ☐
(c) GMAW ☐
(d) This term is not used in ASME IX ☐

Q10. ASME IX section QW-416

Which of the following variables would not be included in a WPQ?

(a) Preheat ☐
(b) PWHT ☐
(c) Technique ☐
(d) All of them ☐

14.11 The ASME IX review methodology

One of the major parts of all the API in-service inspection examinations is the topic of weld procedure documentation review. In addition to various ‘closed-book’ questions about welding processes and techniques, the exams always include a group of ‘open-book’ questions centred around the activity of checking a Weld Procedure Specification (WPS) and Procedure Qualification Record (PQR).

Note the two governing principles of API examination questions on this subject:

- The PQR and WPS used in exam examples will only contain one welding process and filler material.
- You need only consider essential and non-essential variables (you can ignore supplementary variables).

The basic review methodology is divided into five steps (see Fig. 14.7). Note the following points to remember as you go through the checklist steps of Fig. 14.7:

- The welding *process* is an *essential* variable and for the API 653 exam will be limited to SMAW or SAW only.
- Non-essential variables do not have to be recorded in the PQR (but may be at the manufacturer’s discretion) and must be addressed in the WPS.
- Information on the PQR will be *actual values* used whereas the WPS may contain a *range* (e.g. the base metal *actual* thickness shown in a PQR may be $\frac{1}{2}$ in, while the base metal thickness *range* in the WPS may be $\frac{3}{16}$ in–1 in).
- The process variables listed in tables QW-252 to QW-265

STEP 1: variables table

- Find the relevant 'brief of variables' table in article II of ASME IX for the specified welding process (for example QW-253 for SMAW). This table shows the relevant essential and non-essential variables for the welding process.

STEP 2: PQR check

- Check that the 'editorial' information at the beginning and at the end of the PQR form is filled in.
- Check that all the relevant **essential** variables are addressed on the PQR and highlight any that are not.

STEP 3: WPS check

- Check that the editorial information at the beginning of the WPS form is filled in and agrees with the information on the PQR.
- Check that all the relevant **essential** variables are addressed on the WPS and highlight any that are not.
- Check that all the relevant **non-essential** variables are addressed on the WPS and highlight any that are not.

STEP 4: range of qualification

- Check that the **range of qualification** for each **essential variable** addressed in the PQR is correct and has been correctly stated on the WPS.

STEP 5: number of tensile and bend tests

- Check that the correct type and number of tensile and bend tests have been carried out and recorded on the PQR.
- Check that the tensile/bend test results are correct.

Figure 14.7 The ASME IX WPS/PQR review methodology

are referred to as the 'brief of variables' and must *not* be used on their own. You *must* refer to the full variable requirements referenced in ASME IX article IV otherwise you will soon find yourself in trouble.

- The base material will be P1 only for the API 653 exam (base materials are assigned P-numbers in ASME IX to reduce the amount of procedure qualifications required).

14.12 ASME IX WPS/PQR review: worked example

The following WPS/PQR is for an SMAW process and contains typical information that would be included in an exam question. Work through the example and then try the questions at the end to see if you have understood the method.

Figures 14.8 and 14.9 show the WPS and PQR for an SMAW process. Typical questions are given, followed by their answer and explanation.

WPS

Company Name ____ MET Ltd ____ By: ____ S. Hughes ____
Welding Procedure Specification No __ SMAW-1 ____ Date __ 01/04/2006 _ Supporting PQR No __ SMAW-1 _
Revision No ____ 0 ____ Date __ 01/04/06 ____

Welding Process(es) ____ SMAW ____ Type(s) ____ Manual ____
Automatic, Manual, machine or Semi Automatic

JOINTS (QW-402)

Details

Joint Design ____ Single Vee Butt ____
Backing (Yes) ____ (No) ____ X ____ See production drawing
Backing Material (Type) ____
Refer to both backing and retainers

☐ Metal ☐ Nonfusing Metal

☐ Nonmetallic ☐ Other

Sketches, Production Drawings, Weld Symbols or Written Description should show the general arrangement of the parts to be welded. Where applicable, the root spacing and the details of weld groove may be specified.At the option of the manufacturer, sketches may be attached to illustrate joint design, weld layers and bead sequence, eg for notch toughness procedures, for multiple process procedures etc

BASE METALS (QW-403)

P-No. ____ 1 ____ Group No. ____ 2 ____ to P-No. ____ 1 ____ Group No. ____ 2 ____
OR
Specification type and grade ____
to
Specification type and grade ____
OR
Chemical Analysis and Mechanical properties ____
to
Chemical Analysis and Mechanical properties ____

Thickness Range:
Base Metal: Groove __ 1/16" – 2" ____ Fillet ____
Pipe Diameter range: Groove __ All ____ Fillet ____ All ____
Other ____

FILLER METALS (QW-404) Each base metal-filler metal combination should be recorded individually

Spec. No (SFA)	SFA 5.1		
AWS No Class)	E7016		
F No	6		
A-No	4		
Size of filler metals	All		
Weld Metal			
Thickness range			
Groove	All		
Fillet	All		
Electrode-Flux (Class)	N/A		
Flux Trade Name	N/A		
Consumable Insert	N/A		
Other			

Figure 14.8a SMAW worked example (WPS)

WPS(Back)

WPS No _SMAW-1___ Rev ___0___

POSITIONS (QW-405)
Position(s) of Groove ________All________
Welding Progression: Up __Yes_ Down __Yes__
Position(s) of Fillet _________All____________

POSTWELD HEAT TREATMENT (QW407)
Temperature Range ___None____________
Time Range ___None____________

PREHEAT (QW-406)

Rate
Preheat Temp. Min ______None____________

Interpass Temp. Max _____None____________

Preheat Maintenance _______None______________

(Continuous or special heating , where applicable, should be recorded)

GAS (QW-408)

	Gas(es)	Percent composition (Mixture)	Flow
Shielding	None		
Trailing	None		
Backing	None		

ELECTRICAL CHARACTERISTICS (QW-409)
Current AC or DC ______DC_______________ Polarity____Reverse________
Amps (Range) ______110-120_______________ Volts (Range) ___12-20______
(Amps and volts range should be recorded for each electrode size,position, and thickness, etc. this information may be listed in a tabular form similar to that shown below).

Tungsten Electrode Size and Type ___________N/A________________________
(Pure Tungsten, 2% Thoriated, etc)
Mode of Metal Transfer for GMAW ________N/A________________________
(Spray arc, short circuiting arc, etc)
Electrode Wire feed speed range ___________N/A________________________

TECHNIQUE (QW-410)
String or Weave Bead ______________Both____________________________
Orifice or Gas Cup Size ______________N/A____________________________
Initial and Interpass Cleaning (Brushing, Grinding, etc)______Brushing, grinding______________

Method of Back Gouging ____________None____________________________
Oscillation
________________________N/A________________________
Contact Tube to Work Distance ________N/A____________________________
Multiple or Single Pass (per side) _____Multiple pass – no pass greater than ¼"________________
Multiple or Single Electrodes _________Multiple____________________________
Travel Speed (Range) _______________10 IPM____________________________
Peening
___________________________Allowed____________________________
Other ____

Weld Layer(s)	Process	Filler Metal Class	Filler Metal Diameter	Current Type Polarity	Current Amp Range	Volt range	Travel Speed Range	Other (remarks, comments, hot wire addition, technique, torch angle etc)

Figure 14.8b SMAW worked example (WPS)

PQR

Company Name__________MET Ltd__________

Procedure Qualification Record No. _____SMAW-1__________ Date____19/03/06___

WPS No______SMAW-1__________

Welding Process(es)_____SMAW__________

Types (Manual, Automatic, Semi-Auto)____Manual__________

JOINTS (QW-402)

Single Vee Groove, 60 degree included angle. No backing

Groove Design of Test Coupon

(For combination qualifications, the deposited weld metal thickness that shall be recorded for each filler metal or process used)

BASE METALS (QW-403) Material spec._____SA672_____ Type or Grade_____B70_____ P-No_____1_____ to P-No_____1_____ Thickness of test coupon_____1"___ Diameter of test coupon_____36"___ Other_____	**POSTWELD HEAT TREATMENT (QW-407)** Temperature _None_____ Time_____None_____ Other_____ **GAS (QW-408)** Percent composition Gas(es) (Mixture) Flow Rate Trailing _None__ ____ ____ Backing _None__ ____ ____ Backing _None__ ____ ____
FILLER METALS (QW-404) SFA Specification____5.1__ AWS Classification___E7018__ Filler metal F-No_____4__ Weld Metal Analysis A-No__1__ Size of Filler Metal____1/8"__ Other_____ Weld Metal Thickness____1"__	**ELECTRICAL CHARACTERISTICS (QW-409)** Current____Direct_____ Polarity____Reverse_____ Amps____100____Volts____10____ Tungsten Electrode Size____N/A____ Other_____
POSITIONS (QW-405) Position of Groove____3G____ Welding Progression (Uphill, Downhill)____ Other_____ **PREHEAT (QW-406)** Preheat Temp.____200°F____ Interpass Temp.____650°F____ Other_____	**TECHNIQUE (QW-410)** Travel Speed_____25 IPM____ String or Weave Bead____String____ Oscillation____N/A____ Multiple or Single Pass (per side)__multiple___ Single or Multiple Electrodes____Single____ Other_____

Figure 14.9a SMAW worked example (PQR)

PQR (Back)

PQR No. __SMAW-1

TENSILE TEST (QW-150)

Specimen No	Width	Thickness	Area	Ultimate Total load lb	Ultimate Unit Stress psi	Type of Failure & Location
T-1	0.750	0.985	0.7387	54100	73236	BF/WM
T-2	0.751	0.975	0.6253	40000	63969	BF/WM

GUIDED- BEND TESTS (QW-160)

Type and Figure No	Result
QW-462.2- FACE	Opening 1/16" long –Acceptable
QW-462.2- ROOT	Acceptable

TOUGHNESS TESTS (QW-170)

Specimen No	Notch Location	Specimen Size	Test Temp	Impact Values			Drop Weight Break (Y/N)
				Ft-lb	% Shear	Mils	

Comments ____

FILLET WELD TEST (QW-180)

Result – Satisfactory? : Yes____ No _____ Penetration into Parent Metal? : Yes_____ No _____

Macro – Results ____

OTHER TESTS

Type of Test ____

Deposit Analysis ____

Other ____

Welder's Name __Richard Easton__________ Clock No. ____________ Stamp No.__RE2_____

Tests conducted by: __LAB Ltd___________ Laboratory Test No. ___LAB01___________

We certify that the statements in this record are correct and that the tests welds were prepared, welded, and tested in accordance with the requirements of Section IX of the ASME Code.

Manufacturer ______MET Ltd______________

Date_______19/03/06______________ By ________S Hughes__

Figure 14.9b SMAW worked example (PQR)

Step 1: variables table

Q1. (WPS). The base metal thickness range shown on the WPS:

(a) Is correct ☐
(b) Is wrong – it should be $\frac{1}{16}$ in–$1\frac{1}{2}$ in ☐
(c) Is wrong – it should be $\frac{3}{16}$ in–2 in (QW-451.1) ☐
(d) Is wrong – it should be $\frac{3}{8}$ in–1 in ☐

The welding process is SMAW; therefore the brief of variables used will be those in table QW-253. Look at table QW-253 and check the brief of variables for base metals (QW-403). Note that QW-403.8 specifies that 'change' of thickness T qualified as an essential variable and therefore the base material thickness must be addressed on the PQR. When we read QW-403.8 in section IV we see that it refers us to QW-451 for the thickness range qualified. Thus:

- The PQR tells us under base metals (QW-403) the coupon thickness $T = 1$ inch.
- QW-451.1 tells us that for a test coupon of thickness $\frac{3}{4}$–$1\frac{1}{2}$ inch the base material range qualified on the WPS is $\frac{3}{16}$ inch to $2T$ (therefore $2T = 2$ inches).

*The correct answer must therefore be **(c)**.*

Q2. (WPS). The deposited weld metal thickness:

(a) Is correct ☐
(b) Is wrong – it should be 'unlimited' ☐
(c) Is wrong – it should be 8 in maximum ☐
(d) Is wrong – it should be 2 in maximum (QW-451.1) ☐

Look at table QW-253 and note how QW-404.30 'change in deposited weld metal thickness *t*' is an essential variable (and refers to QW-451 for the maximum thickness qualified); therefore weld metal thickness must be addressed in the PQR. Thus:

- PQR under QW-404 filler states weld metal thickness $t = 1$ inch.

- QW-451 states if $t \geq \frac{3}{4}$ in then maximum qualified weld metal thickness $= 2T$ where $T =$ base metal thickness.

The correct answer must therefore be ***(d)****.*

Q3. (WPS): check of consumable type. The electrode change from E7018 on the PQR to E7016 on the WPS:

(a) Is acceptable (QW-432) ☐
(b) Is unacceptable – it can only be an E7018 on the WPS ☐
(c) Is acceptable – provided the electrode is an E7016 A1 ☐
(d) Is unacceptable – the only alternative electrode is an E6010 ☐

Note how QW-404.4 shows that a change in F-number from table QW-432 is an essential variable. This is addressed on the PQR, which shows the E7018 electrode as an F-4. Table QW-432 and the WPS both show the E7016 electrode is also an F-4.

The correct answer must therefore be ***(a)****.*

Q4. (WPS): preheat check. The preheat should read:

(a) 60 °F minimum ☐
(b) 100 °F minimum ☐
(c) 250 °F minimum ☐
(d) 300 °F minimum ☐

QW-406.1 shows that a decrease of preheat > 100 °F (55 °C) is defined as an essential variable.

The PQR shows a preheat of 200 °F, which means the minimum shown on the WPS must be 100 °F and not 'none' as shown.

The correct answer must therefore be ***(b)****.*

Q5. (PQR): Check tensile test results. The tension tests results are:

(a) Acceptable ☐
(b) Unacceptable – not enough specimens ☐
(c) Unacceptable – UTS does not meet ASME IX (QW-422) or 70 ksi ☐
(d) Unacceptable – specimen width is incorrect ☐

Note how the tensile test part of the PQR directs you to QW-150. On reading this section you will notice that it directs you to the tension test acceptance criteria in QW-153. This says that the minimum procedure qualification tensile values are found in table QW/QB-422. Checking through the figures for material SA-672 grade B70 shows a minimum specified tensile value of 70 ksi (70 000 psi) but the PQR specimen T-2 shows a UTS value of 63 969 psi.

*The correct answer must therefore be **(c)**.*

Q6. (PQR). The bend test results are:

(a) Acceptable ☐
(b) Unacceptable – defect size greater than permitted ☐
(c) Unacceptable – wrong type and number of specimens (QW-450) ☐
(d) Unacceptable – incorrect figure number – should be QW-463.2 ☐

The PQR directs you to QW-160 for bend tests. For API exam purposes the bend tests will be *transverse* tests. Note these important sections covering bend tests:

- QW-163 gives acceptance criteria for bend tests.
- QW-451 contains PQR thickness limits and test specimen requirements.
- QW-463.2 refers to performance qualifications.

Check of acceptance criteria

From QW-163, the $\frac{1}{16}$ inch defect is acceptable so answer (b) is incorrect. QW-463.2 refers to *performance qualifications* so answer (d) is incorrect.

Check of test specimen requirements

QW-451 contains the PQR thickness limits and test specimen requirements. Consulting this, we can see that for this material thickness (1 in) there is a requirement for *four side bend* tests.

*Therefore the correct answer is **(c)**.*

Q7. (PQR): validation of PQRs. To be 'code legal' the PQR must be:

(a) Certified (QW-201) ☐
(b) Notarized ☐
(c) Authorized ☐
(d) Witnessed ☐

The requirements for certifying of PQRs are clearly shown in QW-201. Note how it says *'the manufacturer or contractor shall certify that he has qualified . . .'*

*The correct answer must therefore be **(a)**.*

Q8. (WPS/PQR): check if variables shown on WPS/ PQR. Essential variable QW-403.9 has been:

(a) Correctly addressed on the WPS ☐
(b) Incorrectly addressed on the WPS ☐
(c) Not addressed on the PQR ☐
(d) Both (b) and (c) ☐

Note how QW-253 defines QW-403.9 '*t*-pass' as an essential variable. It must therefore be included on the PQR *and* WPS. Note how in the example it has been addressed on the WPS (under the QW-410 technique) but has not been addressed on the PQR.

*The correct answer must therefore be **(d)**.*

Q9. (PQR): variables shown on WPS/PQR. The position of the groove weld is:

(a) Acceptable as shown ☐
(b) Unacceptable – it is an essential variable not addressed ☐
(c) Unacceptable – position shown is not for pipe (QW-461.4) ☐
(d) Both (b) and (c) ☐

Remember that weld positions are shown in QW-461. They are not an essential variable however, so the weld position is not required to be addressed on the PQR. If it is (optionally) shown on the PQR it needs to be checked to make sure it is correct. In this case the position shown refers to the test position of the plate, rather than the pipe.

*The correct answer must therefore be **(c)**.*

Q10. (PQR/WPS): variables. The PQR shows 'string beads but WPS shows 'both' string and weave beads. This is:

(a) Unacceptable – does not meet code requirements ☐
(b) Acceptable – meets code requirements (non-essential variable QW-200.1c) ☐
(c) Acceptable – if string beads are only used on the root ☐
(d) Acceptable – if weave beads are only used on the cap ☐

For SMAW, the type of weld bead used is not specified under QW-410 as an essential variable. This means it is a *non-essential* variable and is not required in the PQR (but remember it can be included by choice). QW-200.1c permits changes to non-essential variables of a WPS as long as it is recorded. It is therefore acceptable to specify a string bead in the PQR but record it as 'string and weave' in the WPS.

*The correct answer must therefore be **(b)**.*

Chapter 15

Cathodic Protection: API RP 651

This chapter is about learning to become familiar with the layout and contents of API RP 651: *Cathodic Protection of Above-ground Storage Tanks*. This is the main source of information on cathodic protection of tank bottoms included in the API 653 BOK.

15.1 Cathodic protection – what's it all about?

Cathodic protection (CP) is about protecting the *soil side* of a tank bottom from corrosion. Although modern tanks tend to be constructed on concrete bases, many older ones were laid directly on soil or rubble bases, so the underside of their floors are in permanent contact with the soil. Depending on its make-up, conductivity and suchlike, corrosion currents pass between the soil and the floor, a galvanic cell is set up and the floor corrodes away. This type of corrosion can be quite aggressive and widespread, and of course is hidden away under the floor where it cannot be seen. The first clue of its existence is generally a leakage of the tank contents into the surrounding soil, causing all manner of problems.

API 653 is well aware of the need to minimize underfloor corrosion. The latest edition places limits on the timing of the first internal inspection of a new tank (see API 653 section 6.4.2.1) and allows a longer maximum interval if CP is fitted, particularly in conjunction with an internal lining protecting the product side as well. The inference is that a CP system can therefore reduce the probability of failure (POF) when carrying out an RBI assessment of a tank. Similarly, API 653 refers to CP as an example of a release prevention system (RPS) – a generic term used for any measure used to preserve tank integrity, particularly of the floor (see API 653 clause 4.4.3).

API 575, being an older publication, sticks to a few well-established references to CP. It is raised as an issue to consider if you are trying to decide the bottom corrosion rate by 'similar service' extrapolation rather than by actual measurement. Whether or not CP is installed will obviously have a large effect on whether similar service assumptions are valid or just a fanciful way of justifying fewer inspections.

Apart from that, there is a mention of tunnelling under the bottom to assess soil-side corrosion (yes, its allowed, see API 575 (section 7.3.1)), a reminder to include CP when replacing tank bottoms, and that is about all. From this you can see that almost all of the relevant information on CP is delegated over to API 651.

API 651 is a well-established but short document (now on its 3rd edition: 2007). As a short code, it supplies supplementary technical information suitable mainly for open-book examination questions. Similar to the other short document in the BOK (API 652: *Lining of Tank Bottoms*) it is more of a technical guide document rather than a code as such, but it performs a useful function in supporting the content of API 653.

Note the following points about API 651:

- *Scope*. It has a narrow scope (evidenced by its title), which is specifically about the cathodic protection (CP) of above-ground tanks. In addition, the technical information that it provides is at a 'general knowledge' level. There is little that is new or innovative about this subject.
- *Exam BOK*. Not all sections of the code are actually included in the API 653 BOK. The sections that are covered are those that describe the more general aspects of CP. They are:
  - Sections 1 to 6
  - Section 8
  - Section 11

  Those sections that describe the technical detail of CP systems (API 651 sections 7, 9 and 10) are specifically *excluded* from the BOK, so you can cross them out in your code.

- *Definitions*. It contains a good few specific terminology and definitions (most of which are defined in the 'definitions' section 3). There is nothing particularly difficult about the terms used, once you have read through them. Most are general engineering knowledge or commonsense.
- *Related codes*. Similar to most of the other codes in the API 653 exam BOK, section 2 of API 651 refers to a lot of *related codes* that are not actually in the BOK. The main ones are a long list of specific API RP documents covering various detailed aspects of cathodic protection (RP 1632, RP-01-69, RP-01-77 and others). Once again, do not worry about these referenced documents; you need to know that they exist but will not need them for the API 653 examination.
- *Damage mechanisms*. API 651 is based on the avoidance of galvanic corrosion mechanisms, so can therefore expect some crossover with the content of API 571: *Damage Mechanisms*. There are a few minor differences in terminology, but no direct contradictions as such. In fact, API 571 contains much more technical detail about galvanic corrosion than API 651, which is more focused on its avoidance, rather than describing the mechanisms in great technical detail.

On a general note, API 651 consists mainly of text and technical descriptions, accompanied by explanatory photographs of a general nature. It contains no calculations relevant to exam questions. In recent API 653 exams, many of the questions about API 651 have been found in the closed-book part of the exam, so you do need to develop a working familiarity with the technical content of API 651 in order to prepare for these questions. We will look at some of the more important areas as we work through this chapter.

15.2 The content of API 651

15.2.1 API 651 sections 1 and 2: *Scope and References*

These sections contain little more than general information on where the document sits in relation to other API publications. Note, however, the reference to the older (superseded) API specifications, and the list of ones covering the more specialized aspects of cathodic protection (which are not in the 653 BOK).

15.2.2 API 651 section 3: *Definitions*

This is a long section, compared to the length of API 651 itself. It also contains more important definitions than are often found in this area of API codes, so you need to give this section a bit of attention. Note the following definitions as potential exam questions:

- Coke breeze, backfill, liner and membrane
- Tank pad and tank cushion
- Groundbed and shallow-anode groundbed
- Structure-to-structure and structure-to-electrolyte voltage

Note *this important one*:

- The difference between an anode and a cathode (and which one corrodes)

Figure 15.1 summarizes some of the terminology used in API 651.

15.2.3 API 651 section 4: *Corrosion of Above-ground Steel Storage Tanks*

This section covers how and why storage tanks corrode.

The galvanic corrosion mechanism (API 651 section 4.1.1)

Although the text does not mention it specifically, just about all corrosion in the world involves galvanic corrosion cells of one type or another. This section breaks the description of the cell into four parts (a, b, c, d). Note the following points, where they appear in the text:

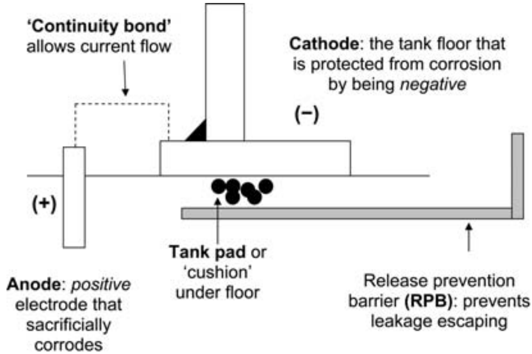


Figure 15.1 Tank cathodic protection: API 653 terminology

- It is the *anode* that corrodes, as the base metal goes into solution.
- The cathode protects the anode (you can think of it like that), and no corrosion takes place at the cathode.
- The objective of CP is therefore to make the tank cathodic, so it will not corrode. It does, of course, have to be cathodic to *something*, so a sacrificial anode is used for this.

Note the point in 4.1.1d, which infers the fact that tank bottoms may actually suffer galvanic corrosion cells on both their external surface *and* internal surfaces.

API 651 sections 4.1.2–4.1.5

These sections contain quite a few little hidden points that you can expect to appear as exam questions. Note the following:

- Pitting corrosion has a smaller number of (larger) corrosion cells than general corrosion. Definitions of pitting appear regularly as exam questions. Someone, somewhere, obviously thinks that knowing this makes you a good tank inspector.
- Minute differences in alloying elements, contaminants and

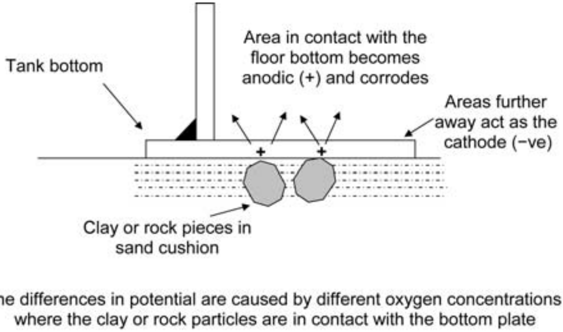


Figure 15.2 Oxygen concentration cells

variations in the electrolyte (the soil) can result in uneven potentials, so starting off a corrosion cell. In practice, this means that these cells can start almost anywhere, and you have no way of predicting where that might be.

- Areas of low oxygen concentrations become anodic (the part that corrodes).
- Note the content of API 651 Fig. 2 (there is potential for exam questions in there) . . . you can see the idea in Fig. 15.2 here.

Corrosion mechanisms (API 651 section 4.2)

The important fact in section 4.2.1 is the part that stray currents (particularly DC ones) play in contributing to galvanic corrosion of storage tanks. Note where they come from; earthed (API call it *grounded*) DC power systems are often unrelated to the storage tank under consideration.

Section 4.2.2 contains the key technical definitions of galvanic corrosion. It is well worth learning the various technical points in this section; it contains at least four points that can form closed-book exam questions. Find these points by looking for the answers in your code (all in API 651 section 4.2.2) to these four questions:

1 Which way does current flow in a corrosion cell?

2 If a stainless steel tank is connected to a plain carbon steel tank, which one becomes the anode and corrodes?
3 In the above example, where in the tank will the worst corrosion actually occur, and why?
4 By inference, what two things most commonly govern the corrosion rate above?

Internal corrosion (API 651 section 4.3)

Note the content of this section about the possibility of corrosion occurring *inside* a tank bottom, not just on the outside (underneath). The list of six factors that influence the severity of corrosion are worth noting. The last one (temperature) was only added in the latest edition of API 651; it was not there before. Note also the cross-reference to API 652, which also mentions corrosion mechanisms (as does API 571).

15.3 Determination of the need for cathodic protection (API 651 section 5)

The first key points in this section occur in 5.1.3. This introduces the fact that pure hydrocarbons are not particularly corrosive and it is the presence of contaminants (water, etc.) that is the trigger for the corrosion of internal tank surfaces. For external corrosion, note the statement in 5.1.4 confirming that the tank bottom plays the role of the cathode and in order to install cathodic protection of the tank bottom it needs to be possible to pass a current between the tank bottom and a sacrificial anode situated in the ground external to the tank.

15.3.1 Tank pad and soil conditions (API 651 section 5.3)

This section contains some important points that come up regularly as examination questions. Here are the main ones:

- The cushion material (note the terminology) under the tank can have an important effect on how well a CP system works.

- Fine-grained cushion material is best as large-grained particles can result in differential aeration, encouraging pitting of the tank bottom.
- High soil resistivity (resistance) is best (see API 651 Table 1) as it minimizes corrosion activity. Expect exam questions to ask you about the numbers in this table.
- The need to check the resistance of surrounding soil, to see if there is any chance of contamination of a good, high resistance foundation layer.

15.3.2 Different types of tank cushion (foundation)

API 651 sections 5.3.2 to 5.3.7 introduce six different types of tank cushion as follows:

- Sand pad
- Continuous concrete pad
- Crushed limestone or clamshell pad
- Oiled-sand pad
- Continuous asphalt pad
- Native soil pad

Of these, almost all modern tanks (excluding perhaps some constructed in remote desert areas) are made using continuous concrete slab cushions. Section 5.3.3 discusses the use of a stable, properly prepared subsoil, free-draining concrete pad design and the fact that CP systems may not be sufficient to control corrosion, if these are not properly complied with. Figure 15.3 should help you understand these better.

The alternative (non-concrete) types of tank base are best considered in terms of their *disadvantages*. Salient points are:

- For soil bases, pH must be checked to see if it is corrosive.
- Clean-sand bases do not eliminate the need for CP.
- Oiled sand may actually reduce the effectiveness of CP due to the higher resistance of the oiled sand (even though the oil may reduce corrosion in other ways).

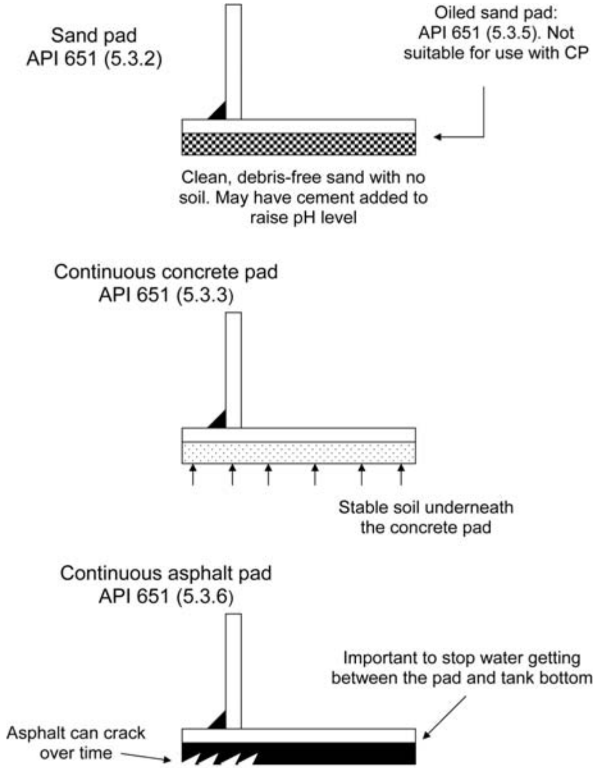


Figure 15.3 Types of tank pad

15.3.3 Release prevention barriers (RPBs): API 651 section 5.4.3

Secondary containment is a way of controlling the accidental escape of the stored product, thereby reducing the chance of contamination due to leaks and spills. The three main methods in use are a liquid-tight tank dyke (or bund), a double bottom tank design and an impervious (thick plastic sheet) membrane underneath the tank foundation. The main content of API 651 section 5.4.3 is to emphasize that these RPBs can prevent the use of effective CP and, in some cases, produce conditions that actually accelerate the corrosion of the tank bottom.

15.3.4 Methods of CP for corrosion control (API 651 section 6)

This is straightforward enough. There are only two methods:

- Galvanic (or passive) method involving non-energized electrodes
- Active (impressed current) method

Section 6.2.1 explains the use of zinc or magnesium cast or ribbon anodes, buried underneath and/or around the tank and the resulting limitations (low anti-corrosion potential, restricted to low resistance soils, more useful for small tanks, etc.).

The more useful impressed current CP system is explained in section 6.3. API 651 Fig. 6 shows how it works. Note how the current direction travels from the buried anode to the tank (cathode and negative). Note also how these CP systems work off direct current (DC), usually provided by a rectifier powered by an alternating current (AC) source. This is good source material for exam questions. Note the materials identified in section 6.3.5 that the CP anodes are frequently made from – another good closed-book examination question.

Remember that you do not need API 651 section 7: *Design of CP Systems* as it is not in the exam BOK.

15.4 Criteria for cathodic protection (API 651 section 8)

This is a short section. It is included (perhaps) in the syllabus because it contains some quantitative (number) values that can be used as exam questions. For adequate protection, a tank must be *850 mV cathodic (negative)* with the CP applied. This is with respect to a reference electrode contacting the electrolyte (soil) around the tank. It is important to read section 8.3: *Measurement Techniques*. It is a bit complicated but do not worry too much about the detail. The main points are:

- The important measurement is the tank-to-soil protection potential.
- The protection potential is measured with the CP current applied.
- Correction is needed for IR (voltage) drops in the soil.
- Notice what reference electrodes can be made of (API 651 Table 3).

Remember to cross out section 9 of API 651: *Impressed Current Systems* and section 10: *Interference Currents*. They are not in the API 653 exam BOK.

15.5 Operation and maintenance of CP systems (API 651 section 11)

This section is largely commonsense; however, it contains important exam question information. The best way to retain this information is to read through the section and find the answers yourself to the following questions:

1. Should a tank be full or empty when doing a bottom-to-electrode potential check . . . and why?
2. What is *breakout piping* (check back in section 3: *Definitions*)? What safety precautions should you specifically take before separating joints if a CP system has been in use?
3. How often are periodic CP surveys recommended to ensure the system is still working correctly?
4. How often should the impressed current sources be checked?
5. What does API 651 section 11.4.7 recommend for the retention times for CP records?

Now try these self-test questions covering the content of API 651.

15.6 API 651: cathodic protection: practice questions

Q1. API 651: corrosion of tanks

In a galvanic corrosion cell, positive metal ions are produced where?

(a) At the anode ☐
(b) At the cathode ☐
(c) From the electrolyte ☐
(d) All of the above ☐

Q2. API 651: types of corrosion

Large individual corrosion cells caused (for example) by differential aeration of the tank floor cushion (base) are most likely to cause what type of corrosion of the tank floor?

(a) Overall general wall thinning (probably serious) ☐
(b) Environmental cracking (SCC) ☐
(c) Stray current-induced corrosion ☐
(d) Pitting ☐

Q3. API 651: types of corrosion

Which of these is most likely (according to API 651) to cause differences in potential, leading to the formation of galvanic corrosion cells?

(a) The temperature effects of welding ☐
(b) Differing oxygen concentrations ☐
(c) A clay-rich electrolyte ☐
(d) An alkaline electrolyte ☐

Q4. API 651: stray current corrosion

Where do stray currents come from?

(a) Generators ☐
(b) Overhead power lines ☐
(c) Electric railways ☐
(d) All of the above ☐

Q5. API 651: internal corrosion

Which of these criteria is *least likely* to influence the severity of internal corrosion in a storage tank containing a refined petroleum product?

(a) Foundation material ☐
(b) Dissolved gases in the product ☐

(c) pH of the product ☐
(d) Conductivity of the product ☐

Q6. API 651: internal corrosion

On balance, which of these corrosion mechanisms is *least likely* to affect a plain carbon steel tank?

(a) Pitting ☐
(b) Environmental cracking ☐
(c) General wall-thinning corrosion ☐
(d) Anodic attack ☐

Q7. API 651: soil conditions

A foundation soil with a resistance (resistivity) of 20 000 ohms is considered:

(a) Very corrosive ☐
(b) Moderately corrosive ☐
(c) Mildly corrosive ☐
(d) Fairly uncorrosive ☐

Q8. API 651: sand pad conditions

Which of these soil conditions is considered very corrosive?

(a) pH 6 and 2000 ppm sulphates ☐
(b) pH 3 and 1000 ppm sulphates ☐
(c) pH 7 and 500 ppm chlorides ☐
(d) All of the above ☐

Q9. API 651: CP systems

Which one of these statements is *most correct*? (Yes, these are awkward questions.)

(a) The objective of any CP system is to make the tank bottom anodic ☐
(b) The objective of a passive CP system is to make the tank bottom cathodic ☐
(c) Anodes are more negative than the cathode and so corrode away ☐
(d) Impressed current CP works better with AC than DC. ☐

Q10. API 651: criteria for cathodic protection

Which one of these conditions will give the best protection of a storage tank from galvanic corrosion?

(a) The tank is at the same potential as the soil surrounding it ☐

(b) The tank is 850 mV more anodic than the soil surrounding it ☐
(c) The tank is 850 mV more positive than the soil surrounding it ☐
(d) The tank is 850 mV more negative than the soil surrounding it ☐

Chapter 16

The NDE Requirements of ASME V

16.1 Introduction

This chapter is to familiarize you with the specific NDE requirements contained in ASME V. API 650 references ASME V as the supporting code but only articles 1, 2, 6, 7 and 23 are required for use in the API 653 examination.

These articles of ASME V provide the main detail of the NDE techniques that are referred to in many of the API codes. Note that it is only the *body* of the articles that are included in the API examinations; the additional (mandatory and non-mandatory) appendices that some of the articles have are not examinable. We will now look at each of the articles 1, 2, 6, 7 and 23 in turn.

16.2 ASME V article 1: general requirements

Article 1 does little more than set the general scene for the other articles that follow. It covers the general requirement for documentation procedures, equipment calibration and records, etc., but does not go into technique-specific detail. Note how the subsections are annotated with T-numbers (as opposed to I-numbers used for the appendices).

Manufacturer versus repairer

One thing that you may find confusing in these articles is the continued reference to *The Manufacturer*. Remember that ASME V is really a code intended for new manufacture. We are using it in its API 653 context, i.e. when it is used to cover repairs. In this context, you can think of The Manufacturer as *The Repairer*.

Table A-110: imperfections and types of NDE method

This table lists imperfections in materials, components and welds and the suggested NDE methods capable of detecting them. Note how it uses the terminology *imperfection* ...

some of the other codes would refer to these as discontinuities or indications (yes, it is confusing). Note that table A-110 is divided into three types of imperfection:

- Service-induced imperfections
- Welding imperfections
- Product form

We are mostly concerned with the service-induced imperfections and welding imperfections because our NDE techniques are to be used with API 653, which deals with in-service inspections and welding repairs.

The NDE methods in table A-110 are divided into those that are capable of finding imperfections that are:

- Open to the surface only
- Open to the surface or slightly subsurface
- Located anywhere through the thickness examined

Note how article 1 provides very basic background information only. The main requirements appear in the other articles, so API examination questions on the actual content of article 1 are generally fairly rare. If they do appear they will probably be closed book, with a very general theme.

16.3 ASME V article 2: radiographic examination

ASME V article 2 covers some of the specifics of radiographic testing techniques. Note that it does not cover anything to do with the *extent* of RT on storage tanks, i.e. how many radiographs to take or where to do them (we have seen previously that these are covered in API 650 and 653).

Most of article 2 is actually taken up by details of image quality indicators (IQIs) or penetrameters, and parameters such as radiographic density, geometric unsharpness and similar detailed matters. While this is all fairly specialized, it is fair to say that the subject matter lends itself more to open-book exam questions rather than closed-book 'memory' types of questions.

T-210: scope

This explains that article 2 is used in conjunction with the general requirements of article 1 for the examination of materials including castings and welds.

Note that there are seven mandatory appendices detailing the requirements for other product-specific, technique-specific and application-specific procedures. Apart from appendix V, which is a glossary of terms, do not spend time studying these appendices. Just look at the titles and be aware they exist. The same applies to the three non-mandatory appendices.

T-224: radiograph identification

Radiographs have to contain unique traceable permanent identification, along with the identity of the manufacturer and date of radiograph. The information need not be an image that actually appears on the radiograph itself (i.e. it could be from an indelible marker pen) but usually is.

T-276: IQI (image quality indicator) selection

T-276.1: material

IQIs have to be selected from either the same alloy material group or an alloy material group or grade with less radiation absorption than the material being radiographed.

Remember that the IQI gives an indication of how 'sensitive' a radiograph is. The idea is that the smallest wire visible will equate to the smallest imperfection size that will be visible on the radiograph.

T-276.2: size of IQI to be used (see Fig. 16.1)

Table T-276 specifies IQI selection for various material thickness ranges. It gives the designated hole size (for hole type IQIs) and the essential wire (for wire type IQIs) when the IQI is placed on either the source side or film side of the weld. Note that the situation differs slightly depending on whether the weld has reinforcement (i.e. a weld cap) or not.

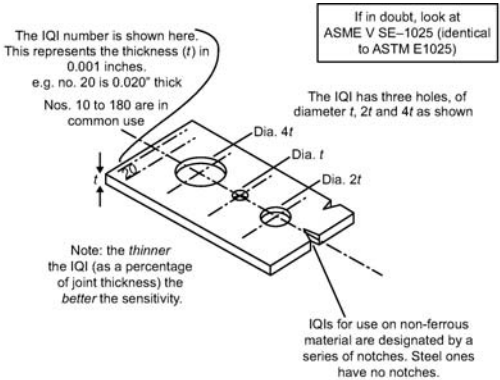


Image quality designation is expressed as (*X*)-(*Y*)*t*:
(*X*) is the IQI thickness (*t*) expressed as a percentage of the joint thickness
(*Y*)(*t*) is the hole that must be visible

IQI designation	*Sensitivity*	*Visible hole**
1–2*t*	1	2*t*
2–1*t*	1.4	1*t*
2–2*t*	2.0	2*t*
2–4*t*	2.8	4*t*
4–2*t*	4.0	2*t*

* The hole that must be visible in order to ensure the sensitivity level shown

T-277.1 ARTICLE 2 — RADIOGRAPHIC EXAMINATION T-277.2

TABLE T-276
IQI SELECTION

Nominal Single-Wall Material Thickness Range		IQI			
		Source Side		Film Side	
in.	mm	Hole-Type Designation	Wire-Type Essential Wire	Hole-Type Designation	Wire-Type Essential Wire
Up to 0.25, incl.	Up to 6.4, incl.	12	5	10	4
Over 0.25 through 0.375	Over 6.4 through 9.5	15	6	12	5
Over 0.375 through 0.50	Over 9.5 through 12.7	17	7	15	6
Over 0.50 through 0.75	Over 12.7 through 19.0	20	8	17	7
Over 0.75 through 1.00	Over 19.0 through 25.4	25	9	20	8
Over 1.00 through 1.50	Over 25.4 through 38.1	30	10	25	9
Over 1.50 through 2.00	Over 38.1 through 50.8	35	11	30	10
Over 2.00 through 2.50	Over 50.8 through 63.5	40	12	35	11
Over 2.50 through 4.00	Over 63.5 through 101.6	50	13	40	12
Over 4.00 through 6.00	Over 101.6 through 152.4	60	14	50	13
Over 6.00 through 8.00	Over 152.4 through 203.2	80	16	60	14
Over 8.00 through 10.00	Over 203.2 through 254.0	100	17	80	16
Over 10.00 through 12.00	Over 254.0 through 304.8	120	18	100	17
Over 12.00 through 16.00	Over 304.8 through 406.4	160	20	120	18
Over 16.00 through 20.00	Over 406.4 through 508.0	200	21	160	20

Figure 16.1 IQI selection

T-277: use of IQIs to monitor radiographic examination

T-277.1: placement of IQIs

For the best results, IQIs are placed on the *source side* (i.e. nearest the radiographic source) of the part being examined. If inaccessibility prevents hand-placing the IQI on the source side, *it can be placed on the film side* in contact with the part being examined. If this is done, a lead letter 'F' must be placed adjacent to or on the IQI to show it is on the film side. This will show up on the film.

IQI location for welds. Hole type IQIs can be placed adjacent to or on the weld. Wire IQIs are placed on the weld so that the length of the wires is perpendicular to the length of the weld. The identification number(s) and, when used, the lead letter 'F' must not be in the area of interest, except where the geometric configuration of the component makes it impractical.

T-277.2: number of IQIs to be used

At least one IQI image must appear on *each radiograph* (except in some special cases). If the radiographic density requirements are met by using more than one IQI, one must be placed in the lightest area and the other in the darkest area of interest. The idea of this is that the intervening areas are then considered as having acceptable density (a sort of interpolation).

T-280: evaluation of radiographs (Fig. 16.2)

This section gives some quite detailed 'quality' requirements designed to make sure that the radiographs are readable and interpreted correctly.

T-282: radiographic density

These are specific requirements that are based on very well-established requirements used throughout the NDE industry. It gives numerical values of *density* (a specific measured parameter) that have to be met for a film to be considered acceptable.

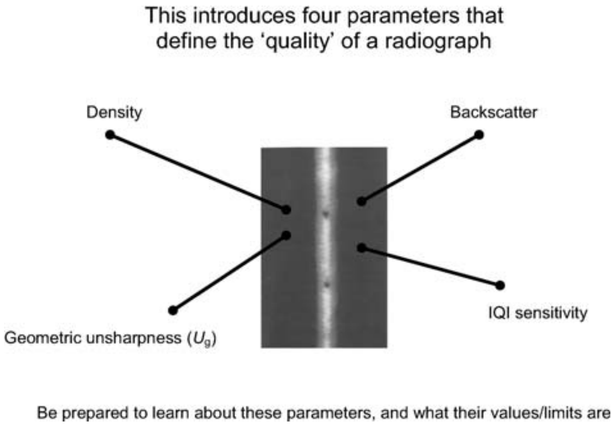


Figure 16.2 Evaluation of radiographs

T-282.1: density limitations

This specifies acceptable density limits as follows:

- Single film with X-ray source: density = 1.8 to 4.0
- Single film with gamma-ray source: density = 2.0 to 4.0
- Multiple films: density = 0.3 to 4.0

A tolerance of 0.05 in density is allowed for variations between densitometer readings.

T-283: IQI sensitivity

T-283.1: required sensitivity

In order for a radiograph to be deemed 'sensitive enough' to show the defects of a required size, the following things must be visible when viewing the film:

- For a hole type IQI: the designated hole IQI image and the 2T hole
- For a wire type IQI: the designated wire
- IQI identifying numbers and letters

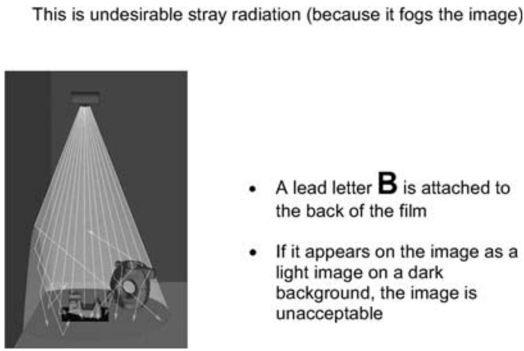


Figure 16.3 Backscatter gives an unclear image

T-284: excessive backscatter
Backscatter is a term given to the effect of scattering of the X or gamma rays, leading to an unclear image.

If a light image of the lead symbol ‘B’ appears on a darker background on the radiograph, protection from backscatter is insufficient and the radiograph is unacceptable. A dark image of ‘B’ on a lighter background is acceptable (Fig. 16.3).

T-285: geometric unsharpness limitations
Geometric unsharpness is a numerical value related to the ‘fuzziness’ of a radiographic image, i.e. an indistinct ‘penumbra’ area around the outside of the image. It is represented by a parameter U_g (unsharpness due to geometry) calculated from the specimen-to-film distance, focal spot size, etc.

Article 2 section T-285 specifies that geometric unsharpness (U_g) of a radiograph shall not exceed the following:

Material thickness, in (mm)	**U_g Maximum, in (mm)**
Under 2 (50.8)	0.020 (0.51)
2 through 3 (50.8–76.2)	0.030 (0.76)
Over 3 through 4 (76.2–101.6)	0.040 (1.02)
Greater than 4 (101.6)	0.070 (1.78)

In all cases, material thickness is defined as the thickness on which the IQI is chosen.

16.4 ASME V article 6: penetrant testing (PT)

T-620: general
This article of ASME V explains the principle of penetrant testing (PT). We have already covered much of this in API 577, but ASME V article 6 adds some more formal detail.

T-642: surface preparation before doing PT
Surfaces can be in the as-welded, as-rolled, as-cast or as-forged condition and may be prepared by grinding, machining or other methods as necessary to prevent surface irregularities masking indications. The area of interest, and adjacent surfaces within 1 inch (25 mm), need to be prepared and degreased so that indications open to the surface are not obscured.

T-651: the PT techniques themselves
Article 6 recognizes *three penetrant processes*:

- Water washable
- Post-emulsifying (not water based but will wash off with water)
- Solvent removable

The three processes are used in combination with the *two penetrant types* (visible or fluorescent), resulting in a total of six liquid penetrant techniques.

T-652: PT techniques for standard temperatures
For a standard PT technique, the temperature of the penetrant and the surface of the part to be processed must be between 50 °F (10 °C) and 125 °F (52 °C) throughout the examination period. Local heating or cooling is permitted to maintain this temperature range.

T-670: the PT examination technique (see Fig. 16.4)

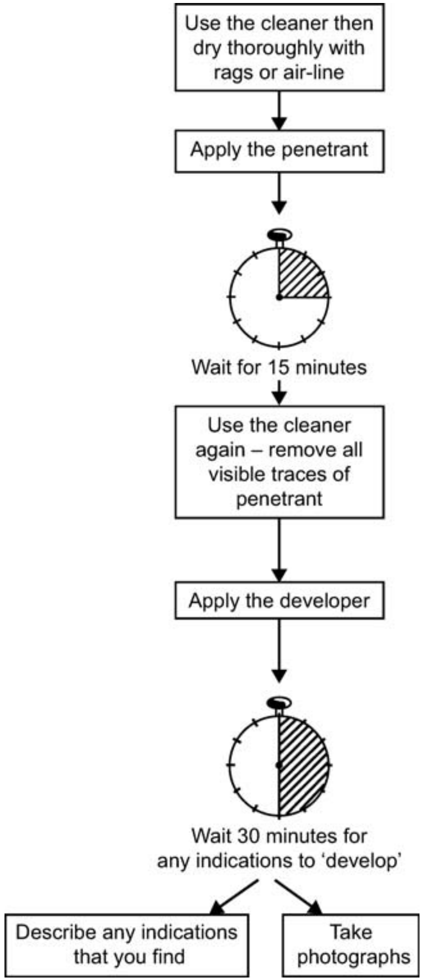


Figure 16.4 PT examination technique

T-671: penetrant application

Penetrant may be applied by any suitable means, such as dipping, brushing or spraying. If the penetrant is applied by spraying using compressed-air type apparatus, filters have to be placed on the upstream side near the air inlet to stop contamination of the penetrant by oil, water, dirt or sediment that may have collected in the lines.

T-672: penetration time

Penetration time is critical. The minimum penetration time must be as required in table T-672 or as qualified by demonstration for specific applications.

Note: While it is always a good idea to follow the manufacturers' instructions regarding use and dwell times for their penetrant materials, table T-672 lays down *minimum* dwell times for the penetrant and developer. These are the minimum values that would form the basis of any exam questions based on ASME V.

T-676: interpretation of PT results

T-676.1: final interpretation

Final interpretation of the PT results has to be made within 10 to 60 minutes after the developer has dried. If bleed-out does not alter the examination results, longer periods are permitted. If the surface to be examined is too large to complete the examination within the prescribed or established time, the examination should be performed in increments.

This is simply saying: *inspect within 10–60 minutes*. A longer time can be used if you expect very fine imperfections. Very large surfaces can be split into sections.

T-676.2: characterizing indication(s)

Deciding (called *characterizing* in ASME-speak) the types of discontinuities can be difficult if the penetrant diffuses excessively into the developer. If this condition occurs, close observation of the formation of indications during application of the developer may assist in characterizing and determining the extent of the indications; i.e. the shape of deep indications can be masked by heavy leaching out of the penetrant, so it is advisable to start the examination of the part as soon as the developer is applied.

T-676.4: fluorescent penetrants

With fluorescent penetrants, the process is essentially the same as for colour contrast, but the examination is performed using an ultraviolet light, sometimes called *black light*. This is performed as follows:

(a) It is performed in a darkened area.
(b) The examiner must be in the darkened area for at least 5 minutes prior to performing the examination to enable his or her eyes to adapt to dark viewing. He or she must not wear photosensitive glasses or lenses.
(c) Warm up the black light for a minimum of 5 min prior to use and measure the intensity of the ultraviolet light emitted. Check that the filters and reflectors are clean and undamaged.
(d) Measure the black light intensity with a black lightmeter. A minimum of 1000 $\mu W/cm^2$ on the surface of the part being examined is required. The black light intensity must be re-verified at least once every 8 hours, whenever the workstation is changed or whenever the bulb is changed.

T-680: evaluation of PT indications

Indications are evaluated using the relevant code acceptance criteria (e.g. API 650 for tanks). Remember that ASME V does not give acceptance criteria. Be aware that false indications may be caused by localized surface irregularities. Broad areas of fluorescence or pigmentation can mask defects and must be cleaned and re-examined.

Now try these familiarization questions on ASME V articles 1, 2 and 6.

16.5 ASME V articles 1, 2 and 6: familiarization questions

Q1. ASME section V article 2: radiography T-223

When performing a radiograph, where is the 'backscatter indicator' lead letter 'B' placed?

(a) On the front of the film holder ☐
(b) On the outside surface of the pipe ☐
(c) On the internal surface of the pipe ☐
(d) On the back of the film holder ☐

Q2. ASME section V article 2: radiography T-277.1 (d)

Wire IQIs must be placed so that they are:

(a) At 45° to the weld length ☐
(b) Parallel to the weld metal's length ☐
(c) Perpendicular to the weld metal's longitudinal axis but not across the weld ☐
(d) Perpendicular to the weld metal's longitudinal axis and across the weld ☐

Q3. ASME section V article 6: penetrant testing T-620

Liquid penetrant testing can be used to detect:

(a) Subsurface laminations ☐
(b) Internal flaws ☐
(c) Surface and slightly subsurface discontinuities ☐
(d) Surface breaking discontinuities ☐

Q4. ASME section V article 1: T-150

When an examination to the requirements of section V is required by a code such as API 650 the responsibility for establishing NDE procedures lies with:

(a) The inspector ☐
(b) The examiner ☐
(c) The user's quality department ☐
(d) The installer, fabricator or manufacturer/repairer ☐

Q5. ASME section V article 6: penetrant testing mandatory appendix II

Penetrant materials must be checked for which of the following contaminants when used on austenitic stainless steels?

(a) Chlorine and sulphur content ☐

(b) Fluorine and sulphur content ☐
(c) Fluorine and chlorine content ☐
(d) Fluorine, chlorine and sulphur content ☐

16.6 ASME V article 7: magnetic testing (MT)

Similar to the previous article 6 covering penetrant testing, this article 7 of ASME V explains the technical principle of magnetic testing (MT). As with PT, we have already covered much of this in API 577, but article 7 adds more formal detail. Remember again that it is not component specific; it deals with the MT techniques themselves, not the *extent* of MT you have to do on a storage tank.

T-720: general

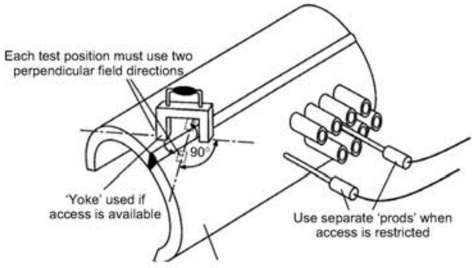
MT methods are used to detect cracks and other discontinuities on or near the surfaces of ferromagnetic materials. It involves magnetizing an area to be examined, then applying ferromagnetic particles to the surface, where they form patterns where the cracks and other discontinuities cause distortions in the normal magnetic field.

Maximum sensitivity is achieved when linear discontinuities are orientated *perpendicular to the lines of magnetic flux*. For optimum effectiveness in detecting all types of discontinuities, each area should therefore be examined at least *twice*, with the lines of flux during one examination approximately perpendicular to the lines of flux during the other; i.e. you need two field directions to do the test properly.

T-750: the MT techniques (see Fig. 16.5)

One or more of the following five magnetization techniques can be used:

(a) Prod technique
(b) Longitudinal magnetization technique
(c) Circular magnetization technique
(d) Yoke technique
(e) Multidirectional magnetization technique



MT prod and yoke methods

Figure 16.5 MT examination technique

The API examination will be based on the prod or yoke techniques (i.e. (a) or (d) above), so these are the only ones we will consider. The others can be ignored for exam purposes.

T-752: the MT prod technique

T-752.1: the magnetizing procedure

Magnetization is accomplished by pressing portable prod type electrical contacts against the surface in the area to be examined. To avoid arcing, a remote control switch, which may be built into the prod handles, must be provided to allow the current to be turned on *after* the prods have been properly positioned.

T-752.3: prod spacing

Prod spacing must not exceed 8 in (203 mm). Shorter spacing may be used to accommodate the geometric limitations of the area being examined or to increase the sensitivity, but prod spacings of less than 3 in (76 mm) are usually not practical due to 'banding' of the magnetic particles around the prods. The prod tips must be kept clean and dressed (to give good contact).

T-755: the MT yoke technique
This method must only be used (either with AC or DC electromagnetic yokes or permanent magnet yokes) to detect discontinuities that are *surface breaking* on the component.

T-764.1: magnetic field strength
When doing an MT test, the applied magnetic field must have sufficient strength to produce satisfactory indications, but it must not be so strong that it causes the masking of relevant indications by non-relevant accumulations of magnetic particles. Factors that influence the required field strength include:

- Size, shape and material permeability of the part
- The magnetization technique
- Coatings
- The method of particle application
- The type and location of discontinuities to be detected

Magnetic field strength can be verified by using one or more of the following three methods:

- Method 1: T-764.1.1: pie-shaped magnetic particle field indicator
- Method 2: T-764.1.2: artificial flaw shims
- Method 3: T-764.1.3 hall effect tangential-field probe

T-773: methods of MT examination (dry and wet)
Remember the different types of MT technique. The ferromagnetic particles used as an examination medium can be either *wet* or *dry*, and may be either fluorescent or colour contrast:

- For dry particles the magnetizing current *remains on* while the examination medium is being applied and excess of the examination medium is removed. Remove the excess particles with a light air stream from a bulb, syringe or air hose (see T-776).
- For wet particles the magnetizing current will be *turned on*

after applying the particles. Wet particles from aerosol spray cans may be applied before and/or after magnetization. Wet particles can be applied during magnetization as long as they are not applied with sufficient velocity to dislodge accumulated particles.

T-780: evaluation of defects found during MT
As with the other NDE techniques described in ASME V, defects and indications are evaluated using the relevant code acceptance criteria (e.g. API 650). Be aware that false indications may be caused by localized surface irregularities. Broad areas of particle accumulation can mask relevant indications and must be cleaned and re-examined.

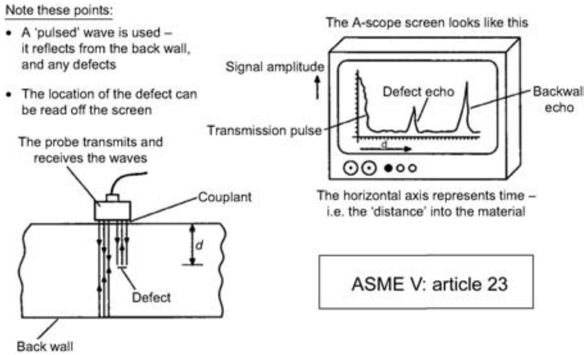
16.7 ASME V article 23: ultrasonic thickness checking

In the ASME V code, this goes by the grand title of *Standard Practice for Measuring Thickness by Manual Ultrasonic Pulse-Echo Contact Method: section SE-797.2*. This makes it sound much more complicated than it actually is. Strangely, it contains some quite detailed technical requirements comprising approximately seven pages of text and diagrams at a level that would be appropriate to a UT qualification exam. The underlying principles, however, remain fairly straightforward. We will look at these as broadly as we can, with the objective of picking out the major points that may appear as closed-book questions in the API examinations.

The scope of article 23, section SE-797

This technique is for measuring the thickness of any material in which ultrasonic waves will propagate at a constant velocity and from which back reflections can be obtained and resolved. It utilizes the *contact pulse echo method* at a material temperature not to exceed 200 °F (93 °C). Measurements are made from one side of the object, without requiring access to the rear surface.

The idea is that you measure the velocity of sound in the



It simply uses the time it takes a pulsed sound wave to pass through a material to give a measure of its thickness

Figure 16.6 UT thickness checking

material and the time taken for the ultrasonic pulse to reach the back wall and return (see Fig. 16.6). Halving the result gives the thickness of the material.

Summary of practice

Material thickness (T), when measured by the pulse-echo ultrasonic method, is a product of the velocity of sound in the material and one half the transit time (round trip) through the material. The simple formula is:

$$T = Vt/2$$

where

T = thickness
V = velocity
t = transit time

Thickness-checking equipment

Thickness-measurement instruments are divided into three groups:

Flaw detectors with CRT readouts. These display time/amplitude information in an *A-scan* presentation (we saw this method in a previous module). Thickness is measured by reading the distance between the zero-corrected initial pulse and first-returned echo (back reflection), or between multiple back reflection echoes, on a calibrated base-line of a CRT. The base-line of the CRT should be adjusted to read the desired thickness increments.

Flaw detectors with CRT and direct thickness readout. These are a combination pulse ultrasound flaw detection instrument with a CRT and additional circuitry that provides digital thickness information. The material thickness can be electronically measured and presented on a digital readout. The CRT provides a check on the validity of the electronic measurement by revealing measurement variables, such as internal discontinuities, or echo-strength variations, which might result in inaccurate readings.

Direct thickness readout meters. Thickness readout instruments are modified versions of the pulse-echo instrument. The elapsed time between the initial pulse and the first echo or between multiple echoes is converted into a meter or digital readout. The instruments are designed for measurement and direct numerical readout of specific ranges of thickness and materials.

Standardization blocks

Article 23 goes into great detail about different types of 'search units'. Much of this is too complicated to warrant too much attention. Note the following important points.

Section 7.2.2.1: calibration (or standardization) blocks

Two 'calibration' blocks should be used: one approximately the *maximum* thickness that the thickness meter will be measuring and the other the *minimum* thickness.

Thicknesses of materials at high temperatures up to about 540 °C (1000 °F) can be measured with specially designed instruments with high-temperature compensation. A rule of thumb is as follows:

- A thickness meter reads 1 % too high for every 55 °C (100 °F) above the temperature at which it was calibrated. This correction is an average one for many types of steel. Other corrections would have to be determined empirically for other materials.
- **An example**. If a thickness meter was calibrated on a piece of similar material at 20 °C (68 °F), and if the reading was obtained with a surface temperature of 460 °C (860 °F), the apparent reading should be reduced by 8 %.

Now try these familiarization questions covering ASME V articles 7 and 23 (article 9 questions are too easy).

16.8 ASME V articles 7 and 23: familiarization questions

Q1. ASME section V article 7: magnetic particle testing T-720

Magnetic particle testing can be used to find:

(a) Surface and near-surface discontinuities in all materials ☐
(b) Surface and near-surface discontinuities in ferromagnetic materials ☐
(c) Surface and near-surface discontinuities in all metallic materials ☐
(d) Surface breaking discontinuities only ☐

Q2. ASME section V article 7: magnetic particle testing T-720

During an MT procedure, maximum sensitivity for finding discontinuities will be achieved if:

(a) The lines of magnetic flux are perpendicular to a linear discontinuity ☐
(b) The lines of magnetic flux are perpendicular to a volumetric discontinuity ☐
(c) The lines of magnetic flux are parallel to a linear discontinuity ☐
(d) The lines of magnetic flux are parallel to a volumetric discontinuity ☐

Q3. ASME section V article 7: magnetic particle testing T-741.1 (b)
Surfaces must be cleaned of all extraneous matter prior to magnetic testing. How far back must adjacent surfaces to the area of interest be cleaned?

(a) At least 2 inches ☐
(b) At least $\frac{1}{2}$ inch ☐
(c) Cleaning is not required on adjacent surfaces ☐
(d) At least 1 inch ☐

Q4. ASME section V article 7: magnetic particle testing T-741.1 (d)
According to ASME V,what is the maximum coating thickness permitted on an area to be examined by MT?

(a) 50 μm ☐
(b) No coating is permitted ☐
(c) 40 μm ☐
(d) An actual value is not specified ☐

Q5. ASME section V article 7: magnetic particle testing T-764.1
Which of the following methods can verify the adequacy of magnetic field strength?

(a) A pie-shaped magnetic particle field indicator ☐
(b) Artificial flaw shims ☐
(c) A gaussmeter and Hall effect tangential-field probe ☐
(d) They can all be used ☐

Q6. ASME section V article 7: magnetic particle testing T-762(c)
What is the lifting power required of a DC electromagnet or permanent magnet yoke?

(a) 40 lb at the maximum pole spacing that will be used ☐
(b) 40 lb at the minimum pole spacing that will be used ☐
(c) 18.1 lb at the maximum pole spacing that will be used ☐
(d) 18.1 lb at the minimum pole spacing that will be used ☐

Q7. ASME section V article 7: magnetic particle testing T-752.2

Which types of magnetizing current can be used with the prod technique?

(a) AC or DC ☐
(b) DC or rectified ☐
(c) DC only ☐
(d) They can all be used ☐

Q8. ASME section V article 7: magnetic particle testing T-752.3

What is the maximum prod spacing permitted by ASME V?

(a) It depends on the current being used ☐
(b) There is no maximum specified in ASME codes ☐
(c) 8 inches ☐
(d) 6 inches ☐

Q9. ASME section V article 7: magnetic particle testing T-755.1

What is the best description of the limitations of yoke techniques?

(a) They must only be used for detecting surface breaking discontinuities ☐
(b) They can also be used for detecting subsurface discontinuities ☐
(c) Only AC electromagnetic yokes will detect subsurface discontinuities ☐
(d) They will detect linear defects in austenitic stainless steels ☐

Q10. ASME section V article 7: magnetic particle testing, appendix 1

Which MT technique is specified in ASME article 7 mandatory appendix 1 to be used to test coated ferritic materials?

(a) AC electromagnet ☐
(b) DC electromagnet ☐
(c) Permanent magnet ☐
(d) AC or DC prods ☐

Q11. ASME section V article 23: ultrasonic thickness testing, section 5.1

UT thickness checking using standard equipment is used for temperatures up to:

(a) 93 °F ☐
(b) 200 °F ☐
(c) 150 °F ☐
(d) 150 °C ☐

Q12. ASME section V article 23: ultrasonic thickness testing, section 8.5

Special ultrasonic thickness measurement equipment can be used at high temperatures. If the equipment is calibrated at ambient temperature, the apparent thickness reading displayed at an elevated temperature should be:

(a) Reduced by 1 % per 55 °F ☐
(b) Increased by 1 % per 55 °F ☐
(c) Increased by 1 % per 100 °F ☐
(d) Reduced by 1 % per 100 °F ☐

Chapter 17

Thirty Open-book Sample Questions

Q1. Atmospheric corrosion

As a practical rule, atmospheric corrosion:

(a) Only occurs under insulation ☐
(b) May be localized or general (widespread) ☐
(c) Is generally localized ☐
(d) Is generally widespread ☐

Q2. Repair of defective welds

Which of the following imperfections must *always* be repaired?

(a) Existing weld reinforcement in excess of API 650 acceptance criteria ☐
(b) Existing weld undercut ☐
(c) Arc strikes either in or adjacent to welded joints ☐
(d) All of the above ☐

Q3. Isolated pitting

How many pits of less than half the minimum required wall thickness, each of 0.25 in diameter are allowed in an 8 in vertical line of corrosion on a tank?

(a) 4 pits ☐
(b) 8 pits ☐
(c) 10 pits ☐
(d) 16 pits ☐

Q4. Calculation of test stress: upper courses

A shell material on an existing tank has a yield strength of 32 000 psi and UTS of 60 000 psi. What is the maximum allowable hydrostatic test stress for the material for use in the upper courses?

(a) 32 000 psi ☐
(b) 28 160 psi ☐
(c) 28 800 psi ☐
(d) 31 140 psi ☐

Q5. API 653: reconstruction: underbead cracking

When welding attachments to API 650 groups IV, IVA, V or VI materials, care must be taken to avoid:

(a) Underbead cracking ☐
(b) Reduced tensile strength ☐
(c) Distortion ☐
(d) All of the above ☐

Q6. Hot taps

Which of the following statements is true concerning hot taps?

(a) They can only be carried out on tanks that do not need heat treatment ☐
(b) They cannot be carried out on tanks of unknown toughness ☐
(c) They cannot be used for openings greater than 4 in diameter ☐
(d) Hot taps fitted to the roof must be approved by the design engineer ☐

Q7. Brittle fracture risk

What is the maximum thickness of shell plate material of a tank designed for a temperature of 50 °F before a hydrotest is required?

(a) $\frac{3}{8}$ inch ☐
(b) 0.5 inch ☐
(c) 0.71 inch ☐
(d) 0.9 inch ☐

Q8. Corrosion of a vertical weld

What is the minimum remaining thickness allowed in a corroded area located on a vertical weld in a tank built in 1980?

(a) $\frac{1}{10}$ inch ☐
(b) 50 % of normal thickness ☐
(c) $\frac{3}{16}$ inch ☐
(d) $\frac{5}{8}$ inch ☐

Q9. RT of shell repairs

A 12 in long repair is made to a tank shell vertical butt weld. How much of the repair requires radiography after the repair?

(a) None of it ☐
(b) 6 in ☐

(c) 6 in starting at one end of the repair ☐
(d) 12 in ☐

Q10. *E* value for shell assessment

When evaluating the retirement thickness of a $\frac{3}{8}$ inch shell plate in which the corrosion is 1 in away from a weld but the material is unknown, the value used for joint efficiency (*E*) shall be:

(a) 0.7 ☐
(b) 0.75 ☐
(c) 0.85 ☐
(d) 1 ☐

Q11. Welder qualifications

A welder is qualified in vertical downhill welding for an SMAW procedure. If an inspector finds this welder welding vertically uphill, what should the inspector do?

(a) Accept the weld if it meets the visual acceptance requirements ☐
(b) Reject the weld ☐
(c) Allow uphill welding as it is better ☐
(d) Accept the weld then requalify the welder for an uphill procedure ☐

Q12. Repair and alterations of storage tanks

Which of these activities is defined as a major repair/major alteration of a storage tank? In none of these activities is the foundation of the tank disturbed

(a) Installing a new NPS 10 nozzle below the liquid level ☐
(b) Jacking up the tank shell for floor repairs ☐
(c) Installing a new bottom excluding the annular ring ☐
(d) Installing a new bottom penetration near the centre of the tank ☐

Q13. Operation at elevated temperatures

A tank made to API 650 of unknown low carbon steel is designed to operate at an elevated temperature of 300 °F. What is the correct allowable stress value that should be used in the calculations for the lower courses?

(a) 24 000 psi ☐
(b) 30 000 psi ☐
(c) 28 360 psi ☐
(d) 21 120 psi ☐

Q14. Bottom annular plate thickness

If the stress in the first course of a tank is 26 000 psi and the course is $\frac{1}{2}$ in thick, what is the minimum allowable thickness for the bottom annular plate?

(a) 0.17 in ☐
(b) 0.2 in ☐
(c) 0.27 in ☐
(d) 0.34 in ☐

Q15. API 653: repairing tank bottoms

What is the minimum size permitted for a welded-on patch plate on a tank bottom?

(a) 6 inches ☐
(b) 8 inches ☐
(c) 10 inches ☐
(d) 12 inches ☐

Q16. MT temperature limitations

The maximum surface temperature for dry magnetic particle testing of weldments is:

(a) Set by the manufacturer of the examination medium ☐
(b) 250 °F ☐
(c) Limited by the permeability of the magnetic particles ☐
(d) 600 °F ☐

Q17. Edge settlement repairs

For tanks that show excessive edge settlement, which plates should be replaced, rather than repaired?

(a) Plates containing welds ☐
(b) Plates showing more than 2–3 % plastic strain ☐
(c) Plates that have not been tested with MT ☐
(d) Plates adjoining the shell ☐

Q18. Subsequent inspection periods

Following an inspection, a tank has been subjected to an RBI assessment. The maximum allowable internal inspection period allowed is:

(a) 10 years ☐
(b) 20 years ☐
(c) 25 years ☐
(d) Unlimited, i.e. whatever the RBI assessment concludes ☐

Q19. Chloride SCC temperatures

Chloride SCC of 300-series stainless steel occurs above a metal temperature of about:

(a) 100 °F (38 °C) ☐
(b) 140 °F (60 °C) ☐
(c) 180 °F (82 °C) ☐
(d) 212 °F (100 °C) ☐

Q20. Minimum thickness of annular ring

The minimum allowable thickness of a tank annular ring is:

(a) 0.1 in ☐
(b) 0.17 in ☐
(c) 0.1875 in ☐
(d) 0.375 in ☐

Q21. Addition or replacement of shell penetrations

A new nozzle is to be installed in an existing shell. The nozzle is 1 in NPS and the shell is $\frac{3}{8}$ in thick. How must the nozzle be installed?

(a) It can be installed directly into the shell ☐
(b) A nozzle cannot be installed under these circumstances ☐
(c) With a butt-welded insert plate with a minimum diameter of 2 in ☐
(d) With a butt-welded insert plate with a minimum diameter of 13 in ☐

Q22. Acceptable future life with a known corrosion rate

A 50-year-old riveted oil tank has the following data:

- Diameter = 115 ft and height = 50 ft
- Oil density = 875 kg/m3
- Material: unknown
- Rivet arrangement: double-row lap jointed
- Shell lower course has thinned from 1.3 in to 1.0 in since new

When should the next UT shell thickness checks be done?

(a) Now ☐
(b) In approximately 4 years ☐
(c) In approximately 8 years ☐

(d) In 15 years ☐

Q23. CUI prevention/mitigation

Which of these would significantly reduce the risk of the occurrence of CUI on a 316 stainless steel tank component system fitted with standard mineral wool lagging?

(a) Change the pipe material to a 304 stainless steel ☐
(b) Change to a calcium silicate lagging material ☐
(c) Shotblast the pipe surface and re-lag ☐
(d) Change to low chloride lagging material ☐

Q24. Shell evaluation formula

A freshwater tank has the following data:

- Diameter = 100 feet
- Height = 30 feet
- Allowable stress in lower shell course = 24.8 ksi
- Joint efficiency E = 0.8

What is the minimum allowable (corroded) thickness of the lower shell plate course (ignore isolated pitting)?

(a) 0.28 in ☐
(b) 0.38 in ☐
(c) 0.48 in ☐
(d) None of the above ☐

Q25. Floor repairs using lap patches

A lap patch has been used to effect a permanent repair of the floor plate of a storage tank. The repair procedure shows that the patch crosses an existing floor seam weld and that the weld on the lap patch running parallel to the floor seam is 2 inches from it. What should the inspector do?

(a) Accept it ☐
(b) Reject it ☐
(c) Accept it if the material has a stress of <30 ksi ☐
(d) Accept it if the material has a stress of <28 ksi ☐

Q26. Maximum settlement B_α at angle α to the tank shell

An API inspector is inspecting a 100 foot diameter storage tank and discovers an approximately circular area of settlement near the tank shell 3.5 in 'deep' extending from the tank shell, about 4 feet towards the tank centre. The existing welds in the floor are at 25° from the tank centreline. What should the inspector do?

(a) Reject it ☐
(b) Accept it ☐
(c) Accept it if the tank has a height of less than 80 feet ☐
(d) Accept it if the tank has a height of less than 100 feet ☐

Q27. Measuring settlement during a hydrotest

How many settlement measurement points are required during a hydrotest, compared to the 'out-of-service' requirement specified in API 653 appendix B?

(a) You need more during the hydrotest ☐
(b) You need fewer during the hydrotest ☐
(c) The difference depends on the tank diameter ☐
(d) They are the same ☐

Q28. API 653: settlement points

How many inspection points around the circumference are required to carry out a survey for a very large tank 280 ft in diameter?

(a) 32 points ☐
(b) 28 points ☐
(c) 36 points ☐
(d) 45 points ☐

Q29. API 650: methods of inspecting joints

What is the maximum difference in design thickness that API 650 allows between plates classed as the same thickness for radiographic purposes?

(a) 1 mm ☐
(b) 2 mm ☐
(c) 3 mm ☐
(d) 4 mm ☐

Q30. API 650: methods of inspecting joints

What is the minimum length of weld (remote from intersections) that must be shown on a radiograph?

(a) 2 in ☐
(b) 3 in ☐
(c) 6 in ☐
(d) None of the above ☐

Chapter 18

Answers

18.1 Familiarization question answers

Chapter 2	Practice questions	Introduction to API 653
Question	Answer	Section
1	d	653 (1.1.3)
2	b	653 (1.1.2)
3	c	653 (1.2)
4	c	653 (1.4 and 2)
5	c	653 (3.1)
6	d	653 (3.4)
7	d	653 (Annex D)
8	b	653 (Annex D2.2)
9	c	653 (Annex D5.2)
10	d	653 (Annex D)
Chapter 3	Practice questions	API 575
Question	Answer	Section
1	a	575 (4.2.1)
2	d	575 (4.2.2)
3	b	575 (4.2.3)
4	d	575 (4.2.3)
5	a	575 (4.2.3)
6	b	575 (4.2.3)
7	c	575 (4.2.3)
8	b	575 (4.3)
9	b	575 (4.3)
10	d	575 (4.3)
Chapter 4	Practice questions	Damage mechanism API 571 Set 1
Question	Answer	Section
1	b	571 (4.2.7.1)
2	c	571 (4.2.7.2)
3	c	571 (4.2.7.3)
4	a	571 (4.2.7.4)
5	c	571 (4.2.7.6)
6	b	571 (4.2.7.5)

7	d	571 (4.2.16.1)
8	a	571 (4.2.16.3)
9	c	571 (4.2.16.5)
10	b	571 (4.2.16.6)
		Set 2
1	b	571 (4.3.2.1)
2	b	571 (4.3.2)
3	a	571 (4.3.2.3)
4	b	571 (4.3.3.3)
5	d	571 (4.3.3.6)
6	b	571 (4.3.3.5)
7	c	571 (4.3.3.6)
8	d	571 (4.3.3.7)
9	a	571(4.3.3.7)
10	b	571 (4.3.3.3)
11	d	571 (4.3.9)
12	d	571 (4.3.9.5)
13	b	571 (4.3.9.6)
14	b	571 (4.3.9.3)
15	a	571 (4.3.9.3)
		Set 3
1	b	571 (4.3.8.1)
2	b	571 (4.3.8.5)
3	a	571 (4.3.8.3)
4	b	571 (4.3.8.3)
5	c	571 (4.3.8.6)
6	b	571 (4.5.1.1)
7	c	571 (4.5.1.2)
8	a	571 (4.5.1.3)
9	d	571 (4.5.1.3)
10	d	571 (4.5.1.5)
11	c	571 (4.5.1.7)
12	b	571 (4.5.1.8)
13	b	571 (4.5.3.1)
14	a	571 (4.5.3.1)
15	d	571 (4.5.3.3)
16	a	571 (4.5.3.5)
17	a	571 (5.1.1.11.2)
18	c	571 (5.1.1.11.3)
19	b	571 (5.1.1.11.6)
20	b	571 (5.1.1.11.4)

Chapter 5	Practice questions	Inspection practices and frequency API 653
Question	Answer	Section
1	c	653 (6.2.2)
2	c	653 (6.3.2)
3	d	653 (6.3.3.2)
4	b	653 (6.3.3.2)
5	a	653 (6.4.1.1)
6	a	653 (6.4.2.1)
7	c	653 (6.4.2.2)
8	b	653(6.4.2.6)
9	b	653(6.9.3.1)
10	a	653 (6.10)

Chapter 6	Practice questions	Evaluation API 653 Set 1
Question	Answer	Section
1	b	653 (4.3.2.2) Fig. 4-2
2	c	653 (Table 4-2)
3	a	653 (4.3.3.1)
4	d	653 (4.3.3.1) Table 4-1
5	b	653 (4.3.2.1)
6	a	653 (4.3.3.1a) Tables 4-1, 4-2
7	b	653 (4.3.3.2) Tables 4-1, 4-2
8	d	653 (4.3.2.1(ii))
9	b	653 (Table 4-4)
10	d	653 (4.3.3.2b) Tables 4-1, 4-2
		Bottom settlement evaluation API 653 Set 2
1	c	653 (Annex B2.2)
2	a	653 (Annex B2.2)
3	d	653 (Fig. B-3)
4	b	653 (Annex B.3.2)
5	b	653 (Annex B.3.4.5)
6	c	653 (B.3.4.7)
7	b	653 (Fig. B-7)
8	d	653 (Annex B2.2.4)

9	c	653 (Annex B2.2.4)
10	b	653 (Annex B2.2.3)
Chapter 8 Question	Practice questions Answer	Tank NDE Section
1	b	653 (12.1.2.1)
2	b	653 (12.1.2.3)
3	a	653 (12.1.2.4)
4	a	653 (12.1.3)
5	a	653 (12.1.4.1–12.1.4.2)
6	d	653 (12.1.6.3)
7	c	653 (12.1.7.3)
8	d	653 (12.2.1)
9	a	653 (12.2.2)
10	c	653 (12.2.3.2)
Chapter 9 Question	Practice questions Answer	Repair and alteration Section
1	a	653 (9.4)
2	c	653 (9.6.5)
3	a	653 (9.8.6)
4	a	653 (9.8.6)
5	a	653 (9.10.1.2)
6	d	653 (9.10.1.2.3)
7	a	653 (9.10.2.7)
8	c	653 (9.11.2)
9	a	653 (9.14.1.1)
10	c	653 (9.14.1.2)
11	b	653 (9.14.3)
12	b	653 (9.2.2.2)
13	d	653 (9.3.1.4)
14	b	653 App
Chapter 10 Question	Practice questions Answer	Dismantling and reconstruction Section
1	d	653 (10.3.2.1)
2	b	653 (10.3.3.1)
3	a	653 (10.3.4.1)
4	a	653 (10.4.2.1)
5	d	653 (10.4.2.3)
6	a	653 (10.4.2.5)
7	d	653 (10.4.2.6, Table 10-1)
8	c	653 (10.4.4.3)

9	a	653 (10.5.2.1)
10	a	653 (10.5.4)
Chapter 11	Practice Questions	Hydrostatic testing and brittle fracture
Question	Answer	Section
1	d	653 (12.3.1)
2	a	653 (12.3.1 and definition 3.18)
3	c	653 (12.3.1 and Fig. 5-2)
4	a	653 (12.3.2)
5	d	653 (12.3.2.3.3)
6	d	653 (12.3.2.3.3)
7	a	653 (12.4)
8	d	653 (12.5)
9	b	653 (12.5.1.2)
10	b	653 (12.3)
Chapter 12	Practice questions	API 652: linings
Question	Answers	Section
1	b	652 (4.4)
2	c	652 (4.5)
3	c	652 (5)
4	d	652 (6.2)
5	a	652 (6.3)
6	b	652 (6.3.1)
7	d	652 (7)
8	b	652 (8.3)
9	b	652 (9)
10	d	652 (10.6.3)
Chapter 13	Practice questions	API 577: welding process
Question	Answer	Section 5
1	a	577 (5.2)
2	b	577 (5.1)
3	b	577 (5.3)
4	a	577 (5.3)
5	d	577 (5.4)
6	d	577 (5.4)
7	c	577 (5.6)
8	c	577 (5.6)
9	b	577 (5.3 + 3.7)
10	b	577 (5.3.1)

Chapter 13 Question	Practice questions Answer	
1	a	
2	b	
3	b	API 577: welding consumables
4	a	
5	a	
6	d	
7	c	
8	c	
9	b	
10	d	
Chapter 14 Question	**Practice questions Answer**	
1	c	
2	b	
3	d	
4	a	ASME IX articles I and II
5	c	
6	a	
7	b	
8	b	
9	d	
10	c	
1	d	
2	d	
3	d	
4	b	
5	a	ASME IX articles III and IV
6	a	
7	a	
8	a	
9	c	
10	d	
Chapter 15	**Practice questions**	**API 651: Cathodic protection**
Question	Answer	Section
1	a	651 (4.1.1)
2	d	651 (4.1.2)
3	b	651 (4.1.4)
4	d	651 (4.2.1)
5	a	651 (4.3)

6	b	651 (4.3)
7	d	651 (5.3)
8	b	651 (5.3.2.1)
9	b	651 (6.2)
10	d	651 (8)
Chapter 16 Question	Practice questions Answer	
1	d	
2	d	ASME V articles 1, 2 and 6
3	d	
4	d	
5	c	
1	b	
2	a	
3	d	
4	d	
5	d	ASME V articles 7 and 23
6	a	
7	b	
8	c	
9	a	
10	a	
11	b	
12	d	

18.2 Answers to open-book sample questions

Q1. Ans (b)
API 571 (4.3.2)

Q2. Ans (c)
API 653 (9.6)

Q3. Ans (b)
API 653 (4.3.2.2 Fig. 4-2). Sum of dimension <2 in in 8 in vertical 8×0.25 in diameter $= 2$ in.

Q4. Ans (c)
For the upper courses, API 653 (4.3.3.2) states you should use:

$$St = \text{lesser of } 0.9Y \text{ or } 0.519T$$

$$St = \text{lesser of } 0.9 \times 32\,000 = 28\,800 \text{ psi or } 0.519 \times 60\,000 = 31140 \text{ psi}$$

Hence Ans is 28 800 psi.

Q5. Ans (a)
Question from API 653 (10.4.2.10) and also in API 650. These group materials have a tendency to brittleness; hence *underbead cracking* are the key words in the question.

Q6. Ans (a)
API 653 (9.14)

Q7. Ans (c)
API 653 (Fig. 5-2). The thickness corresponding to 50 °F is 0.71 in.

Q8. Ans (a)
As no code or joint efficiency are given the answer is the 0.1 in minimum from API 653 (4.3.3.1).

Q9. Ans (d)
API 653 (12.1.3.2) says that butt weld repairs require RT or UT over their full length.

Q10. Ans (d)
API 653 (4.3.3.1) says that the required distance away from the weld is the greater of 1 in or $2 \times$ plate thickness, i.e. 1 in away.

Q11. Ans (b)
ASME IX QW405.3 and QW405.4(c).

Q12. Ans (b)
API 653 (12.3.1.2) and definition 3.23.

Q13. Ans (d)
From API 653 (4.3.10.1) and 650 Fig. M-1

For unknown material assume $Y = 30\,000$ psi

$S = 0.8Y$ for all courses

From API 650 Table M-1, yield strength reduction factor at 300 °F = 0.88

So $30\,000 \times 0.8 \times 0.88 = 21\,120$ psi.

Q14. Ans (b)
API 653 Table 4-4, so answer is 0.20 in.

Q15. Ans (a)
API 653 (9.10.1.1b)

Q16. Ans (a)
In ASME V, Article 7, Table T-721, there is an essential variable listing if the surface temperature is outside the temperature range recommended by the manufacturer.

Q17. Ans (b)
API 653 (B-4.2). Other answers are incorrect.

Q18. Ans (c)
From the table in API 653 (6.4.2.2) it has had RBI and hence the maximum period allowed is 25 years. There is no mention of a release prevention barrier in the question.

Q19. Ans (b)
API 570 gives a range of 140–400 °F in the CUI section (5.5.6.1). Also confirmed in API 571 (4.5.3.2), which says that SCC starts from 140 °F.

Q20. Ans (b)

API 653 (Table 4.4) shows that the annular ring in thicker than the 0.1 in applicable for the rest of the tank; 0.1875 in is $\frac{3}{16}$ in and 0.375 is $\frac{3}{8}$ in (incorrect answer).

Q21. Ans (a)

API 653 (9.8.6)

Q22. Ans (a)

Combined API 653 (4.3.3) and 653 (6.4.2) inspection period limits.

Using the equation for 'full course' (in the absence of any contradictory information).

Assuming full fill height $H = 60$ ft

SG = 0.875

Allowable stress for lower courses for unknown material for a riveted tank = 21 000 psi (Table 4-1)

Joint efficiency from Table 4-3 for riveted joint = 0.6 (2 row lap joint)

Acceptable $t = [2.6(H–1)\ DG/SE]$

$t = [2.6 \times 49 \times 115 \times 0.875)/(21\,000 \times 0.6)]$

Required $t = [12\,819.62/12\,600] = 1.017$ in

Corrosion rate = 0.3 in/50 years = 0.006 in/yr (not required)

Amount of excess material left = 1 in – 1.017 in = nothing left ... so must inspect it now.

Q23. Ans (a)

API 571 (4.3.3.6)

Q24. Ans (b)

API 653 (4.3.3.1)

Using $t_{min} = 2.6\ (H–1)\ DG/SE = 2.6 \times (30 - 1) \times 100 \times 1/(24\,800 \times 0.8)$

Using $t_{min} = 7540/19\ 840 = 0.38$ in.

Q25. Ans (a)

API 653 Fig. 9-5 (see note 4) allows lap patches for floor plates where the spacing from an existing weld is 2 in min.

Q26. Ans (b)

Using API 653 (B-3.4.4)

Maximum allowable settlement at arbitrary angle α is B_α

$B_\alpha = B_e - (B_e - B_{ew}) \sin \alpha$ so we need the maximum allowable values of B_e and B_{ew}

Determine maximum B_{ew} from Fig. B-10. For diameter = 100 ft and radius of settled area of 4 feet this gives maximum $B_{ew} = 4.25$ in

Determine maximum B_e from Fig. B-11. For diameter = 100 ft and radius of settled area of 4 feet this gives maximum $B_e = 5.1$ in

Now apply $B_\alpha = B_e - (B_e - B_{ew}) \sin \alpha$, where $\alpha = 25^\circ$ from the tank centerline

$B_\alpha = 5.1-(5.1-4.25) \sin 25^\circ$

$B_\alpha = 5.1-(0.85)\ 0.4226$

$B_\alpha = 5.1- 0.359 = 4.74$ in (answer). This is the maximum allowable settlement at this angle so 3.5 in is within limits (accept).

Q27. Ans (d)

API 653 (12.5)

Q28. Ans (b)

API 653 (12.5.1.2)

Number of points = $D/10$ to a maximum of 32 feet

For a 280 ft tank, circumference = 880 feet

$D/10$ gives $N = 28$ points and these would be spaced at $880/28 = 31.4$ feet, so answer is 28 points.

Q29. Ans (c)

API 650 (6.1)

Q30. Ans (c)

API 650 (6.1.2.8)

Index