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Tubing Specification and Material Selection

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Version history & change log

Version	Issued by	Date	Chapter	Change Log, Comments
Draft	A Hagelaars	17.08.2021	All	Initial Draft
1.0	J. Chang, A. Hagelaars	19.08.2021	All	Editing, review, questions & suggestions
2.0	J. Chang	27.01.2023	All	Editing, publication on YTA Website and PetroWiki

References

ID	Reference	Version / Date	Description
[1]	API Specification 5CT	10th Edition	10th Edition of Specification 5CT, *Casing and Tubing*
[2]	ISO 13680	2020	Petroleum and natural gas industries - Corrosion-resistant alloy seamless tubular products for use as casing, tubing, coupling stock and accessory material
[3]	NACE MR0175/ISO 15156		National Association of Corrosion Engineers: Petroleum and Natural Gas Industries - Materials for use in H2S-containing environments in oil and gas production
[4]	SPE PetroWiki		Article “Casing and Tubing”, revision 10:17, 2 October 2021

Abbreviations

Topic	Denotation	Description
BHT	Bottom Hole Temperature	The temperature of the undisturbed formation at the final depth in a well
CAPEX	Capital Expenditures	
CRA	Corrosion Resistant Alloys	Metals engineered to resist degradation by oxidation or other chemical reactions
CS	Carbon Steel	A steel with carbon content from about 0.05 up to 2.1 percent by weight. The term may also be used in reference to steel which is not stainless steel
DSS	Duplex stainless steel	A grade of stainless steel with metallurgical structure consisting of two phases, austenite (face-centered cubic lattice) and ferrite (body centered cubic lattice) in roughly equal proportions
MSS	Martensitic stainless steels	Ternary alloys of iron, chromium, and carbon that possess a martensitic crystal structure in the hardened condition
OPEX	Operational Expenditures	
SDSS	Super duplex stainless steel	A family of high-performance stainless steels designed with around 25% chromium content in the alloy's makeup
SSC	Sulphide Stress Cracking	A form of hydrogen embrittlement which is a cathodic cracking mechanism

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1 Introduction

Tubing is the normal flow conduit used to transport produced fluids to the surface or injected fluids to the formation. Its use in wells is normally considered a good operating practice.

The use of tubing has several benefits:

- Tubing with the use of a packer allows isolation of the casing from well fluids and deters corrosion damage of the casing;
- It permits better well control because killing fluids can be circulated thus simplifying workovers and enhancing workover results;
- Flow efficiency is typically improved with the use of tubing;
- Multi-completions require tubing to permit individual zone production and operation;
- Furthermore, tubing is required for most artificial lift installations.

Accordingly, governmental rules and regulations often require tubing in every well.

Tubing strings are generally in outside diameter (OD) sizes of 2-3/8” to 4-½” but may be as small as 1.05” or as large as 20”.

The proper selection, design, and installation of tubing string are critical parts of any well completion. Tubing strings must be sized correctly to enable the fluids to flow efficiently or to permit installation of effective artificial lift equipment. A tubing string that is too small causes large friction losses and limits production. It also may severely restrict the type and size of artificial lift equipment. A tubing string that is too large may cause heading and unstable flow, which results in loading up of the well and can complicate workovers. The planned tubing must easily fit inside the installed casing.

When selecting the material, environmental conditions, the projected corrosivity of the well fluids, the minimum and maximum pressures and temperature, safety aspects, and cost-effectiveness must be considered.

The tubing must be designed to meet all stresses and conditions that occur during routine operation of the well and should have an adequate margin for unusual load conditions. It must withstand the stresses caused by tension, burst, and collapse, and it must resist the corrosive action of well fluids throughout the well life. In addition, the tubing must be handled and installed so that the tubing produces the well without failure or without causing undue operating problems.

2 Tubing Standard, Size and Materials

2.1 API and ISO

The American Petroleum Institute (API) developed Specifications, Recommended Practices, and Bulletins for steel tubing that meet the major needs of the oil and gas industry. API documents are reviewed and updated every 5 years. This effort continues, and many of these documents (with modifications) have become International Organisation for Standardisation (ISO) documents.

Currently, API and ISO are the international standards for products intended for worldwide use in the petroleum and natural gas industry.

The specifications for tubing are given in API CT ("API Spec CT") for tubing (10th edition).

API tubing sizes range from ODs of 1.05" to 4½ ". For high-rate wells, tubing larger than 4½" may be beneficial. API and ISO specifications also contain provisions when casing is used as tubing.

2.2 Proprietary

In addition to API steel tubing, there are hostile well conditions that may be better served by other materials. There are proprietary steel grades that do not conform to all aspects of the API specifications but are used in the petroleum-producing industry for resistance to weight-loss corrosion, higher strengths, less susceptibility to sulphide stress cracking (SSC), and wear resistance.

Reservoir fluids flowing through the production tubing are often corrosive, making it necessary to use corrosion resistant alloys (CRA). CRAs contain various quantities of Ni, Mo, Cr, Cu, and other elements for corrosion resistance, making them significantly more expensive than carbon steel (CS), but may prove worthwhile over the lifetime of the well; however, CRA tubing does not always eliminate corrosion and may be incompatible with some completion fluids. ISO 13680 contains information on CRA seamless tubes.

Thermoplastic (fiberglass) tubing has been used successfully in corrosive wells. Most thermoplastic tubing has good tension properties and burst resistance but has relatively small collapse-pressure resistance and poorer wear resistance properties than steel tubing. If temperatures exceed 150°F, a derating service factor may be required.

Other metals and materials have been used as tubing but rarely are used in current oil and gas completions either because of their cost or because of limited applicability.

3 Casing

Casing is also critical to the production of oil and gas and well integrity. It is primarily for structural integrity of the well and typically requires significantly larger diameters and heavier weights than tubing.

While surface, outer, and intermediate casing are used for structural integrity and are not expected to encounter the produced fluids, there is a small section of casing that is exposed to reservoir fluids and should generally be made of the same material as is selected for the tubing. This section is referred to as ‘exposed casing’ or ‘exposed lining’ and is cemented in place for wellbore integrity in some well designs, and/or also perforated and used for production in others.

Figure 1 shows two common well designs: one utilising production casing and the other production liner. While production casing ties back to the surface, production liner is instead suspended from a lower casing section. Both production casing and production liner are used to prevent well collapse and can act as backup containment in the case of a production tubing leak.

Lower-alloy CRAs or carbon steel materials are often chosen as casing to keep costs low. There are carbon steels rated for use in sour conditions and CRAs considered acceptable will vary based on the given environmental conditions. It is a good practice to review casing material for every well design.

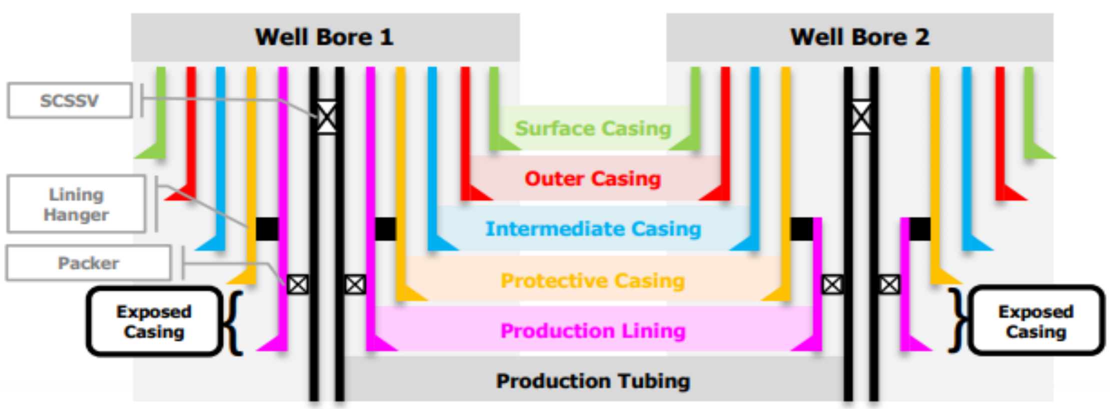

Figure 1: Schematic of Generic Well Bores

Figure 1: Schematic of Generic Well Bores

4 API / ISO Tubing Requirements

API has numerous manufacturing requirements for tubing. The tubing purchaser and designer should be aware of these requirements and of API testing procedures (Ref. API Spec 5CT). All tubing should meet API minimum requirements. In critical wells, the purchaser may want to receive and review the manufacturer’s test results. For tubing used in sour wells (i.e. with H2S content greater than 0.05 psi partial pressure), the specific sour service requirements should be reviewed.

When placing orders for tubing to be manufactured in accordance with API Spec 5CT, the purchaser should consult API Spec 5CT Section 4.

At a minimum, the following requirements should be specified on the purchase order:

- Specification (API/ISO)

- Quantity
- Size designation (OD, normally in inches. Reference: Table C.2 – ISO/API Tubing List in SI unit and Table E.2 – ISO/API Tubing List in Imperial unit)
    - Optimum tubing size depends on type of fluid, fluid flow rate, pressure, temperature and / or type of artificial lift employed (e.g. gas lift, pumps)
- Weight designation, which determines
    - Tensile strength
    - Burst pressure
    - Collapse pressure
- End finish i.e. type of connection, see Section 4.1 (reference Table C.24 Dimensions and masses for standard tubing and tubing threads and Table C.25 in SI unit and Table E.24, E.25 in Imperial unit)
- Tensile and hardness requirements (reference Table C.5 Tensile and hardness requirements in SI unit and Table E.5 in Imperial unit)
- Range length
- Manufacture process and heat treatment (reference Table C.3 Process of manufacture and heat treatment in SI unit and Table E.3 in Imperial unit)
- Seamless or electric weld, see Section 4.2,
- Grade and type, see Section 4.3,
- Composition of the material, see Section 4.4 (reference Table C.4 Chemical composition, mass fraction (%))
- Delivery date, and shipping instructions

4.1 Tubing Connectors / Tubing Joints

API developed specifications for three different connectors for use as tubing joints:

- External-Upset-End tubing and coupling (EUE),
- Non-upset tubing and couplings (NUE), and
- Integral-joint tubing.

API Spec 5CT provides an illustration of API tubing joint connections. All three connections have tapered and round thread forms with either 8 or 10 threads/inch, depending on the size. When casing is used as tubing, long-thread coupling/short-thread coupling and buttress-thread coupling connections can be specified.

The API external-upset-end (EUE) tubing connection is widely used because it is a good, serviceable connection in most wells. The EUE joint has a designed joint strength in tension and pressure strength greater than that of the pipe body and, therefore, is considered a 100% joint efficient connection. For proper lubrication and sealing, the joint requires a good thread compound as outlined in API RP 5A3. To improve the seal performance of API EUE tubing in high-pressure service, a grooved coupling, which accepts non-metallic seal rings, is sometimes used in the coupling (see API Spec. 5CT SR 13). To provide more clearance, API special clearance EUE couplings are available. API EUE joints come in OD sizes of 1.050 to 4.500”.

API non-upset (NUE) tubing is used much less than EUE tubing. The cost of NUE is only slightly less than EUE, and the joint strength is substantially less. The coupling joint diameter of NUE is less than EUE, which offers some advantages when clearance is small. API NUE joints are available in sizes of 1.050 to 4-1/2".

API integral-joint tubing is available in OD sizes of 1.315 to 2.063". API integral-joint tubing has a 10-round form with a joint strength that is less than the body minimum yield, which restricts its use. The small OD of integral-joint tubing permits its use inside larger tubing strings or in wells as unloading or vent strings.

API Spec 5B3 and API RP 5B1 cover threading, gauging, and thread inspection.

4.2 Process of Manufacture

Tubing made to API specifications uses seamless or electric-weld processes. Seamless pipe is defined as a wrought steel tubular product made without a welded seam. It is manufactured by hot-working steel or, if necessary, by subsequently cold-finishing the hot-worked product to produce the desired shape, dimensions, and properties. Because of the nature of the manufacturing, the cross section of the tubing wall area may be slightly eccentric and the tubing slightly oval and not perfectly straight.

Electric-welded pipe has one longitudinal seam formed by electric-resistance or electric-induction welding without the addition of filler metal. The edges to be welded are pressed together mechanically, and the heat for welding is generated by the resistance to flow of electric current. The weld seam of electric welded pipe is heat-treated after welding to a minimum temperature of 1,000°F or processed so that no un-tempered martensite remains. See API Spec. 5CT for exceptions.

Both seamless and electric-weld processes are acceptable for most oil and gas services, but some prefer seamless tubulars for sour service because the electric-weld process may result in a slightly different grain structure near the weld. Such differences are usually eliminated if the electric-weld tubing is heat-treated by the quenched-and-tempered process, which is mandatory for API grades L80, C90, T95, and P110. Couplings usually are made of seamless tubular product of the same grade and type as the pipe.

4.3 API Grades

API standardised several grades of steel that have different chemical content, manufacture processes, and heat treatments and, therefore, different mechanical properties.

API organised these tubing grades into three groups:

- Group 1 for all tubing in grades H40, J55, and N80
- Group 2 for restricted-yield tubing grades L80, C90, and T95
- Group 3 is for high-strength tubing in seamless grade P110

The API grade letter designation was selected arbitrarily to provide a unique name for various steels. Numbers in the grade designation indicate the minimum yield strength of the steel in thousand psi. API defines the yield strength as the tensile stress required to produce a specific total elongation per unit length on a standard test specimen. API Spec. 5CT includes tables listing the manufacture process and heat treatment of API tubing, the chemical requirements, and the API tubing strength and hardness requirements.

4.3.1 API Tubing Grade Guidelines

The following guidelines apply to the use of API tubing grades.

- H40: Although an API grade, H40 is generally not used in tubing sizes because the yield strength is relatively low and the cost saving over J55 is minimal.
- J55: A commonly used grade for most wells when it meets the design criteria. Some operators recommend it be full-length normalised, or normalised and tempered after upsetting when used in carbon dioxide or sour service (ring-worm corrosion problems); however, such heat treatments increase costs. J55 has been the "standard" grade for tubing in most relatively shallow (< 9,000 ft) and low-pressure (< 4,000 psi) wells on land.
- C75: No longer an official API grade and generally not available. It was developed as a higher-strength material for sour service but was replaced by L80 tubing.
- N80: A relatively old grade with essentially open chemical requirements. It is susceptible to H_2S-induced SSC. It is acceptable for sweet oil and gas wells when it meets design conditions. The quenched-and-tempered heat treatment is preferred. The N80 grade is normally less expensive than L80 grades.
- L80: A restricted yield-tubing grade that is available in Type 1, 9Cr, or 13Cr. It is satisfactory for SSC resistance in all conditions but may incur weight-loss corrosion.
    - Type 1: less expensive than 9Cr and 13Cr but more subject to weight-loss corrosion. It is used commonly in many oil and gas fields because of higher strength than J55.
    - Type 9Cr: though popular in the past for CO_2- and mild H_2S-contaminated wells, it has largely been replaced by Type 13Cr.
    - 13Cr has gained popularity because it has good CO_2-induced weight-loss corrosion resistance properties; however, it is more costly. It may not be suitable in sour service environments. Typically, the H_2S partial pressure should be less than 1.5 psi for safe use of L80 13Cr. Users should consult NACE MR-0175.
- C90: A relatively new API grade with two different chemical requirements: Type 1 and Type 2. Only Type 1 is recommended for use in sour service. Typically, this grade must be special ordered; its use has been generally supplanted by T95.
- T95: A high-strength tubular grade that has 2 different chemical requirements, namely Type 1 and Type 2. Only Type 1 is recommended for sour service. T95 is SSC resistant but not weight-loss resistant.
- P110: The old P105 tubing grade, which allowed a normalised and tempered heat treatment, was discontinued, and the casing P110 grade, which is restricted to quench-and-tempered heat treatment, was adopted. This high-strength tubing typically is used in deep sweet oil and gas wells with high pressures. This grade is sensitive to SSC failures unless the temperatures are relatively high (> 175°F). The P110 grade is slightly more expensive than L80 Type 1 but usually less expensive than the C90 and T95 API restricted-yield grades.
- Q125: Although not a specific API tubing grade, users can order Q125 API tubing. Type 1 chemistry is preferred.

4.4 Tubing material selection process

The primary focus of the material selection process is to identify materials which can be safely deployed, and further refined by cost considerations in which capital expenditures (CAPEX) and operational expenditures (OPEX) are balanced to minimise total lifetime cost.

Other considerations such as lead time, quality assurance, and schedule are also factored into the material selection process. General Downhole Material Selection Process Knowledge of a few specific parameters, such as the presence of CO2 or the location, design life, or presence of elemental sulphur, is sufficient to determine whether a CRA is required, but these parameters are not sufficient to determine which CRA should be selected. Unlike carbon steel, CRAs are essentially resistant to corrosion due to CO2 and thus CO2 is the first indicator of whether carbon steel material can be successfully used for the production tubing. CO2 partial pressure (as well as temperature) affects the rate of tubing wall loss and the subsequent frequency of tubing replacement by workover.

This material selection process is illustrated in *Figure 2*.

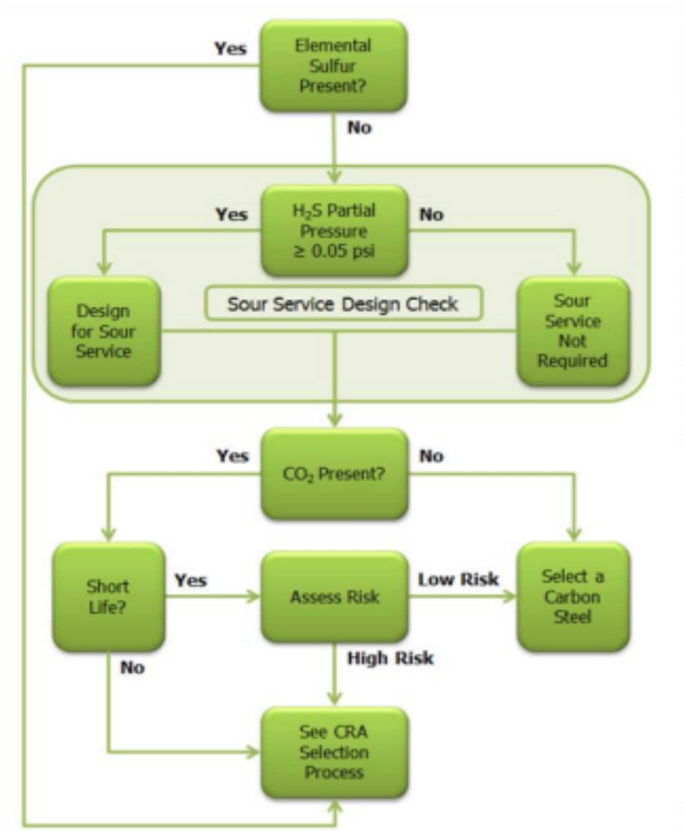

Figure 2: General Material Selection Process

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By this process, carbon steel tubing with downhole corrosion inhibition can often be used in lieu of a CRA, but corrosion inhibition is OPEX intensive and considered a high-risk operation when used offshore. Regardless of offshore location, the presence of elemental sulphur will immediately require the use of CRA tubing due to sulphur's inherent high corrosivity. Ultimately, location is often the most significant driver in materials selection because of the consideration of workover cost.

4.4.1 Corrosion Resistant Alloy selection

CRAs are almost always used for offshore production well tubing due to design life requirements and OPEX associated with workovers. Exposed casing will usually be constructed of the same material as the production tubing, as this material will be exposed to the same corrosive environment as the production tubing.

CRAs can be roughly divided into four categories (families) in order of general ascending corrosion resistance and cost: Martensitic stainless steel (MSS), duplex and super duplex stainless steels (DSS and SDSS), super austenitic stainless steels, and high Nickel Alloys. With the exception of the API 5CT L80 13Cr steel, all other CRA casing and tubing alloys are proprietary.

The CRA family is chosen based the on presence of elemental sulphur and a combination of H2S partial pressure, chloride concentration and temperature. Other environmental parameters are then factored in, along with any specific usage history or available data, and the choice is assessed. Figure 3 shows the CRA family selection process. Detailed material selection will ultimately be determined by parameters associated with the production and shut-in environments: temperature (e.g., bottom hole and shut in), pH, chloride concentration, and H2S partial pressure. The necessity to differentiate between the various temperatures is important. Bottom hole temperature (BHT) is often the most common driver for material selection. However, potential changes in the corrosive nature of produced fluids at the top of the well during shut in, when the well has cooled to the seafloor temperature, may indicate the need for a different material in the upper part of the well. Additional parameters / requirements can necessitate revisiting the materials selection, more relating to schedule, materials properties, and commercial considerations.

While materials can be selected based on the process described, fitness-for-service testing is an acceptable method to prove a material can work in a given environment and is required if no data is available to confirm the alloy is acceptable.

Common fitness-for-service test methods are as follows:

- Specific Corrosion Rate Testing
- Sour Service Compliance Tests
- NACE Method A Cracking Tests
- NACE TM 0177 Method C Tests
- NACE TM 0198 Slow Strain Rate Tensile Tests

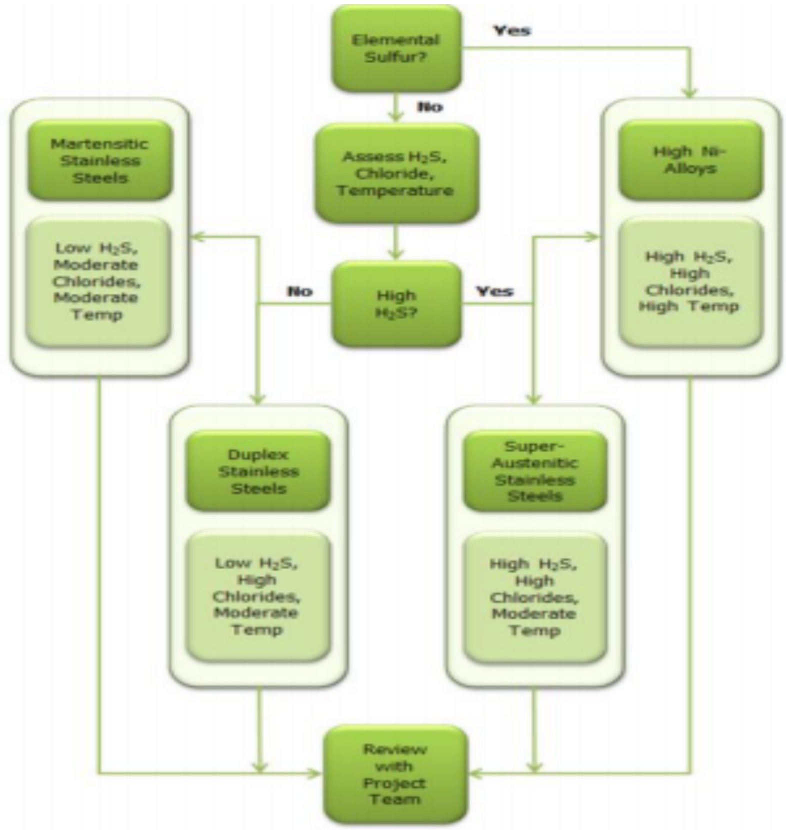

Figure 3: CRA Selection Process

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Appendix 1: ISO 17348:2016 (en)

Petroleum and natural gas industries
Materials selection for high content CO_2 for casing, tubing and downhole equipment

The committee responsible for this document is ISO/TC 67 Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries.

This International Standard gives recommendations and guidelines for materials selection in oil and gas production wells, specifically for high CO2 content gas injection and production systems, as well as for water alternating gas (WAG) injection systems. It is intended to enable responsible parties to carry out materials selection in a consistent manner as a part of the engineering work, based upon a design basis for a particular installation. The main users of this International Standard are oil and gas production companies and engineering contractors. Material manufacturers and equipment suppliers can benefit from using this International Standard for their product development.

Carbon capture and storage (CCS) has been identified as an important technology for achieving a significant reduction in CO2 emissions to the atmosphere.

Many of the technologies and practices that have been developed for CO2 enhanced oil recovery (EOR) can have applicability in CCS projects, assuming that each project design meets its site-specific conditions. The CO2 EOR experiences of the oil and gas industry represent the largest collective base of technical information available on CO2 injection and, as such, provide valuable information for development and implementation of CCS field projects as they move forward.

This International Standard does not provide detailed material requirements and recommendations for manufacturing and testing of equipment. Such information can be found in particular product standards and in manufacturing and testing standards. Other International Standards related to material usage limitations are referred to, e.g. ISO 15156 (all parts) for H2S containing service.

In case of conflict between this International Standard and other international product standards, the requirements of the latter take precedence.

1. Scope

This International Standard provides guidelines and requirements for material selection of both seamless casing and tubing, and downhole equipment for CO2 gas injection and gas production wells with high pressure and high CO2 content environments [higher than 10 % (molar) of CO2 and 1 MPa CO2 partial pressure]. Oil production wells are not covered in this International Standard. This International Standard only considers materials compatibility with the environment.

Guidance is given for the following:

- corrosion evaluation;

- materials selection;
- corrosion control.

This International Standard is aimed at high CO2 content wells, where the threat of low pH and CO2 corrosion is greatest. However, many aspects are equally applicable to environments containing lower CO2 concentrations.

Materials selection is influenced by many factors and synergies and should be performed by either materials or corrosion engineer.

2. Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

- ISO 11960, *Petroleum and natural gas industries — Steel pipes for use as casing or tubing for wells*
- ISO 13680, *Petroleum and natural gas industries — Corrosion-resistant alloy seamless tubes for use as casing, tubing and coupling stock — Technical delivery conditions*
- ISO 15156 (all parts), *Petroleum and natural gas industries — Materials for use in H2S-containing environments in oil and gas production*
- ISO 21457, *Petroleum, petrochemical and natural gas industries — Materials selection and corrosion control for oil and gas production systems*
- ISO 23936-1, *Petroleum, petrochemical and natural gas industries — Non-metallic materials in contact with media related to oil and gas production — Part 1: Thermoplastics*
- ISO 23936-2, *Petroleum, petrochemical and natural gas industries — Non-metallic materials in contact with media related to oil and gas production — Part 2: Elastomers*

API Specification 5CT, 10^{th} Edition Key Changes

On 1^{st} July 2018 API published the 10^{th} Edition of Specification 5CT, Casing and Tubing, and the 7th edition of Technical Report 5C3, Calculating Performance Properties of Pipe Used as Casing or Tubing. These new editions provide technical updates that have reached consensus within API's Subcommittee on Tubular Goods and will now give industry consistent practices in the respective areas of the standards. As part of API's standards develop program, these updates are reflective of API's standards program mission to provide a forum for development of consensus-based industry standards, and technical cooperation to improve the industry's safety performance and competitiveness.

The key changes to highlight for Spec 5CT are:

- Scope to reference RP 5C6 for new requirements for large diameter PSL 2 casing not specifically covered by Spec 5CT (e.g. conductor casing)
- New content on converting USC unit to SI units to be used in stress intensity factor toughness and updates to SSC requirements
- Updated pipe range length requirements for carload shipping
- Update requirements for grade N80 Type 1
- Update requirements for pipe with special end-finish threads
- Updates to how material grades are grouped throughout document
- Eliminate Supplementary Requirement 15 (test certificates) and add new requirements for mill test reports/certifications in its place
- Expand triangle stamp marking requirements
- Add polymer quenching for grade L80
- Update hardness requirement for grades L80, C90, T95 and C110 as result of NACE MR0175
- Delete clause on reducing couplings
- Update requirements for L80 13Cr inside surface preparation
- Expand requirements for NDE personnel certification
- Elimination of grade M65 entirely from the specification
- Updates and clarifications for NACE testing methods as result of updates to NACE's requirements
- Increase casing coupling OD wall thicknesses for 4-1/2, 5 and 5-1/2 inch, and update spec respectively throughout as result, e.g. recalculate weight gain/loss of material
- The key changes to highlight for TR 5C3 are:
- Increase casing coupling OD wall thicknesses for 4-1/2, 5 and 5-1/2 inch, and update TR respectively throughout as result
- Updates to using nominal linear mass in calculations and remove equation for calculating theoretical mass
- Corrective updates to mass steel density and related equations and calculations