Directive 010: Minimum Casing Design Requirements

December 22, 2009

Effective June 17, 2013, the Energy Resources Conservation Board (ERCB) has been succeeded by the Alberta Energy Regulator (AER).

As part of this succession, the title pages of all existing ERCB directives now carry the new AER logo. However, no other changes have been made to the directives, and they continue to have references to the ERCB. As new editions of the directives are issued, these references will be changed.

Some phone numbers in the directives may no longer be valid. Contact AER Inquiries at 1-855-297-8311 or inquiries@aer.ca.

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Directive 010

Revised edition: December 22, 2009

Minimum Casing Design Requirements

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on December 22, 2009.

<original signed by>

Dan McFadyen
Chairman

Contents

1 Overview

1.1 What's New in *Directive 010*

The June 2008 revised edition of ERCB *Directive 010* (formerly *Guide 10*) was developed with input from a technical subcommittee of the Drilling and Completions Committee (DACC) and the ERCB, which reviewed various technical documents containing information on casing design for sweet, sour, and critical sour wells in the Western Canadian Sedimentary Basin (WCSB). In the future, as industry casing design specifications and standards change, the ERCB will consider approving the new standards for use in conjunction with *Directive 010* and will incorporate such changes in subsequent revisions to this directive

The June 2008 edition of *Directive 010* included a grace period up to June 20, 2009, for the use of the existing inventory of materials which do not meet the requirements of Appendix B. Due to the unexpected reduction in drilling activity, changes to the June 20, 2009, grace period for the use of this inventory have become necessary. Technical concerns brought forward by licensees and casing manufacturers regarding a specific requirement in Appendix B have also been addressed. Changes in the December 2009 edition of *Directive 010* include

- amending the grandfathering criteria and extending the grandfathering period beyond June 20, 2009, to address noncompliant materials in regard to Appendix B (Section 1.3.1);
- simplifying the Representative Testing Program (Section 1.3.2); and
- clarifying the use in sour service wells of Industry Recommended Practices (IRP) casing (Section 1.4), the use of casings not defined by American Petroleum Institute (API) 5CT/ISO 11960 specifications (Section 1.5), and revised Appendix B: Materials Requirements for Sour Wells.

This new edition of the directive includes the option to use an Alternative Design Method to allow a licensee to determine the design loads and capabilities of the casing strings and still meet the minimum design factors, which was introduced in the previous edition.

The technical review committee noted that conventional API materials made to API Specification 5CT specifications cannot consistently pass National Association of Corrosion Engineers (NACE) TM0177 sulphide stress cracking (SSC) testing due to manufacturing differences. To address this issue, upgraded design factors and material specifications have been implemented that incorporate the criteria from NACE MR0175/ International Association for Standardization (ISO) 15156 (see Appendix A for all references).

Directive 010 includes

- ~~discussion on compliance and enforcement (Section 1.2);~~
- revisions to the sections on Material Selection (Section 1.3) and Casing Performance Properties (Section 1.5);
- new detailed design and metallurgy criteria for sweet, sour, and critical sour wells, including
  - the Well Category Table (Section 1.4),
  - Appendix B: Material Requirement, which specifies additional sour service (partial pressure [pp] $H_2S \geq 0.3$ kPa.) requirements for materials manufactured according to API 5CT Specification, and
  - when existing casing inventories do not meet the requirements of Appendix B, representative testing is required to ensure satisfactory product performance in sour service environments, as discussed in (Section 1.3.2);
- casing requirements for re-entry wells (Section 1.4), IRP Volume 1 (Section 4), and IRP Volume 6 (Section 5);
- casing wear considerations (Section 1.7);
- other design considerations (e.g., tri-axial, bending, compression, and non-API pipe and connections) (Section 1.8);
- design criteria for
  - using the lesser of connection burst strength or pipe body burst strength (Section 2.2.1),
  - using the lesser of the pipe body yield strength or the joint strength (connection parting strength) (Section 2.2.3), and
  - revised design factors on tension based on connection type (API vs. premium with internal metal-to-metal seal [Section 3.2]);
- a new Alternative Design Method approach (Section 3);
- burst design loads using an assumed or calculated gas gradient (Section 3.2); and
- the following appendices:
  - References, including related ERCB and other applicable publications (Appendix A),
  - Material Requirements (Appendix B),
  - NACE SSC Testing Summary (Appendix C),
  - Definitions as they pertain to this directive (Appendix D),
  - Effects of Tensile Loading on Casing Collapse (Appendix E) (*Directive 015* will be rescinded once this new edition of *Directive 010* is issued), and
  - Alternative Design Method Example (Appendix F).

Licensees must consider all post drilling casing loading, such as fracture stimulation down casing, tubing packer leaks, compressive loading, tri-axial loading, and temperature (see IRP Volume 3: Heavy Oil and Oil Sands Operations, Section 3.1.6, and Appendix E) effects for the life of the well in their casing design.

1.2 Compliance and Enforcement

ERCB requirements are those rules that a licensee has a legal obligation to meet and against which the ERCB may take enforcement action in case of noncompliance. The ERCB's enforcement process is specified in *Directive 019: ERCB Compliance Assurance—Enforcement.*

The requirements in this edition of *Directive 010* are effective on December 22, 2009. All casing ordered prior to the issuance of this directive may be used if it conforms to the design factor requirements in Section 1.3.1. All casing ordered or manufactured after September 22, 2008, must conform to the material requirements in Appendix B.

Licensees must retain records of all supporting data and information used to meet the ERCB minimum casing design requirements for the Simplified and Alternative Design Methods. The licensee must submit information requested by the ERCB within 20 working days.

Directive 010 noncompliance events can be found on the ERCB Web site at www.ercb.ca under Industry Zone: Compliance and Enforcement : ERCB Risk Assessed Noncompliance.

Licensees are reminded that in the event of a well licence transfer or an amalgamation, the new licensee assumes responsibility for meeting all ERCB minimum requirements specified in this directive.

1.3 Material Selection

Licensees must ensure the suitability of casing and pressure-rated casing accessories (e.g., stage tools, external casing packers, in-line centralizers, and float collars) for each specific application for the life of the well. External centralizers, scratchers, and turbolizers are exempt. Unless otherwise specified, any reference to casing includes the casing pipe body and the couplings. Anticipated current and future environments must be considered when selecting casing for use in wells that may encounter hydrogen sulphide (H_2S), or carbon dioxide (CO_2) with H_2S.

Licensees must follow Appendix B to select the proper material specifications for all wells, using partial pressures (pp) of H_2S and CO_2, as well as design factors, to determine the appropriate material specifications. An alternative materials selection process may be used as long as the material meets all the minimum requirements in *Directive 010*. Fit-for-purpose SSC (all casing grades) and hydrogen-induced cracking (HIC; nonquenched and tempered material only) testing may be performed if well conditions result in a situation where *Directive 010*-compliant materials cannot be supplied. Fit-for-purpose testing using actual worst-case environmental wellbore conditions may also be used to qualify materials to higher stress levels, as discussed in Section 1.6.

The partial pressure of each component in the wellbore is equal to the pressure multiplied by its mole fraction in the mixture. For example, a pressure of 30 000 kilopascals (kPa) and a 3 mole % (0.03 mole fraction) H_2S content would have 30 000 kPa x 0.03 = 900 kPa H_2S partial pressure.

Surface casing must be designed for sour service (see Section 1.5) if the licensee intends to drill into a sour zone before setting the next sour service casing string. The casing bowl weld must also be suitable for sour service.

Licensees must maintain casing integrity for the life of the well, including post-abandonment (see *Directive 020: Well Abandonment Guide, Casing pressure testing requirements*).

Corrosion-resistant alloys (CRAs) are specialty materials designed for use in corrosive environments. It is the responsibility of the end user to ensure that the material will perform acceptably in the well environment (see NACE International MR0175/ISO 15156, Part 3: Cracking-resistant CRAs and other alloys).

For IRP materials, licensees must follow the SSC and HIC test procedures, specimen types, loading conditions, and all other acceptance criteria specified in IRP Volume 1, Section 4, for the grade of casing being used. This testing must involve a laboratory experienced with the testing of materials for sour service at elevated pressures.

1.3.1 Materials Not Meeting Requirements of Appendix B

Existing API 5CT/ISO 11960 compliant materials purchased or manufactured prior to September 22, 2008, that do not meet the requirements of Appendix B may be used in drilling of noncritical sour wells providing the following conditions are met:

- if the H_2S concentration is less than 1.00%, the burst design safety factor is 1.30 or greater (increased from the 1.25 minimum for *Directive 010* Appendix B compliant materials), or
- if the H_2S concentration is higher than 1% but less than 5.00%, the burst design safety factor is 1.35 or greater, or
- if the H_2S concentration is greater than or equal to 5.00%, the burst design safety factor is 1.40 or greater, and
- A burst design safety factor of 1.25 shall be used for non-compliant API H40, J55, K55, L80, C90 or T95, if the materials are tested as described in Section 1.3.2.
- Materials not listed in Appendix B must be tested as described in Section 1.3.2 for use in sour wells.

These requirements pertain to both casing and coupling stock.

1.3.2 Representative Testing Program

Materials that do not comply with the requirements of Appendix B can be tested to verify performance in sour service conditions.

API 5CT/ISO 11960 casing and coupling materials must each be tested to the following parameters per heat lot:

- SSC testing—Method A or Method C is sufficient for testing; in accordance with NACE TM0177, the SSC test condition must be either
  - 80% specific minimum yield strength (SMYS) with Solution A Environment, or
  - in accordance with fit-for-purpose testing, as stated in Appendix C.
- HIC testing—for all materials that are not quenched and tempered in accordance with NACE TM0284 and with pass criteria outlined in IRP Volume 1.

1.4 Well Category Table

A well's sour classification is defined by the partial pressure of H_2S, as shown in the table below. Licensees must determine which column their well is under and then select the appropriate recommended casing load conditions, minimum design factors, and material specifications. For reentry wells, an evaluation of the remaining casing wall thickness must be made and the current burst, collapse, and tensile strengths must be recalculated to reconfirm continued compliance with this directive for both existing and future operations.

Well Category Table

	Sweet wells, and sour wells with pp[1] H_2S < 0.3 kPa	**Sour wells with pp $H_2S \geq 0.3$ kPa**	**Critical sour wells[3]**
Recommended loading conditions	*Directive 010* Simplified or Alternative Design Method casing load conditions	*Directive 010* Simplified or Alternative Design Method casing load conditions	IRP Vol. 1, Sec. 4, design criteria[3]
Recommended minimum design factors	*Directive 010* Simplified or Alternative Design Method designs	*Directive 010* Simplified or Alternative Design Method designs	IRP Vol. 1, Sec. 4, design criteria[3]
Material specifications	Material selection as specified in API 5CT or proprietary grades meeting requirements of Section 1.5, paragraph 3	Material selection as specified in Appendix B[2]	Critical sour service specification, as in IRP Vol. 1, Sec. 4

Note: IRP Volume 1, Section 4 Critical Sour Service pipe materials can be used in all wells in Alberta and therefore can be substituted for Appendix B sour service pipe material.

1 Partial pressure (see Appendix D).

2 For Reentry wells, existing materials must meet, as a minimum, API 5CT. Also see *Directive 056: Energy Development Applications and Schedules* for additional requirements.

3 Critical sour wells must be designed in compliance with *Directive 056: Energy Development Applications and Schedules,* IRP Vol. 1, and *Interim Directive (ID) 97-06: Sour Well Licensing and Drilling Requirements*, Section 4.2. The *Directive 010* Alternative Design Method may be used, subject to ERCB approval.

1.5 Casing Performance Properties

Casing must be manufactured to the minimum specifications as defined in API 5CT/ISO 11960. The performance properties of casing must meet or exceed the standards in API Bulletin 5C2.

The casing collapse pressure rating is reduced by axial loading and must be calculated using the current API Bulletin 5C3 standards in conjunction with Appendix E.

Casing not defined by API 5CT/ISO 11960 specifications but meeting the objectives of API 5CT/ISO 11960 manufacturing standards may be used if the manufacturer provides acceptable performance properties, including collapse, burst, and pipe body yield, that meet or exceed the standards in API Bulletin 5C3. Proprietary casing grades must also meet or exceed any applicable API 5CT/ISO 11960 material requirements, such as chemistry, toughness, ductility, hardness, inspection and testing requirements, dimensional tolerances, and other API 5CT/ISO 11960 performance standards. Non-API connections may be used if the minimum design factors are met and applicable material requirements meet or exceed API 5CT/ISO 11960 specifications. The manufacturer must also provide the means by which these performance properties were determined.

Note that API Bulletin 5C3 give guidance to calculate minimum performance properties but may not consider all well operating conditions.

1.6 Burst Design Factor Adjustments

In Section 2: Simplified Method, the minimum burst design factor for sour wells with pp $H_2S \geq 0.3$ kPa has been increased from 1.0 to 1.15 (1.25 for surface casing), based on maximum potential formation pressure. The restricted hoop stress load reduces the susceptibility to SSC.

In Section 3: Alternative Design Method, for sour wells with pp H_2S < 0.3 kPa, SSC is not an issue. Therefore, for practical purposes these wells may be considered sweet wells. For sweet wells, a lower minimum burst design factor of 1.10 may be used, based on maximum potential formation pressure less gas gradient to surface. Wells with pp H_2S of 0.3 kPa or greater are considered sour wells. For sour wells with $0.3 \leq$ pp H_2S < 10 kPa (a pp of H_2S of 0.3 kPa or greater and less than 10 kPa), the minimum burst design factor is 1.20. For sour wells with pp H_2S > 10 kPa, the minimum burst design factor is 1.25. This ensures that the casing hoop stress level in mild sour wells will be less than 83.3 (1/design factor) of its specified minimum yield strength, and in wells with pp H_2S above 10 kPa, the hoop stress level will be less than 80% of SMYS.

Burst design factors for materials used in sour wells may be reduced from the value of 1.25 outlined in the design loading constraints by conducting Fit-for-purpose SSC testing in accordance with NACE TM0177 Method A, Solution A, to a representative load condition. A licensee requesting a reduction in the burst design factor is required to test to an additional 5% stress level or a stress level of 105% (1.05) of the maximum potential material stress.

The load test stress is inversely proportional to the proposed burst design factor: test stress level = (1.05 / minimum burst design factor) x SMYS.

For example, for noncritical sour wells with pp $H_2S \geq 0.3$ kPa, if the burst safety factor is limited to 1.18 due to product availability, the product must be tested to 1.05/1.18 = 0.89, or 89% of the SMYS of the material, instead of the more common 80 to 85% of SMYS.

1.7 Casing Wear Considerations

Casing wear considerations in Subsection 8.141(3) of the *Oil and Gas Conservation Regulations* (*OGCR*) must be taken into account. Casing safety factors must be increased as necessary to maintain the required minimum design factors after consideration of anticipated casing wear. Casing wear can be affected by casing grade, rotating hours, rpm, type of drilling fluid, dogleg severity, inclination, deviated wellbore, tripping frequency, and the types of downhole tools run. Efforts to minimize wear include use of drill pipe conveyed casing wear protectors, use of downhole motors, and drilling fluid additives designed to reduce torque and drag.

Section 12.141 of the *OGCR* requires the licensee to notify the ERCB immediately on detection of a casing leak or failure. Also, if requested by the ERCB, the licensee must provide a report assessing the leak or failure, including a discussion of the cause, duration, damages, proposed remedial program, and measures to prevent future failures (see *Interim Directive [ID] 2003-01*).

1.8 Other Design Considerations

Determination of axial loads must include consideration for additional tension loading (e.g., casing overpull when setting slips, casing pressure testing) or compressive loading (e.g. due to subsequent well operations, such as the installation of a blowout preventer (BOP) stack and subsequent casing and tubing strings), as well as well servicing conditions.

For all directional wells, the licensee must address additional stresses (or loads) caused by bending, regardless of the design method chosen.

Surface casing setting depth must be in accordance with *Directive 008: Surface Casing Depth Minimum Requirements*.

According to Section 6.081 of the *OGCR*, the licensee must not drill beyond a depth of 3600 metres [m] without first setting intermediate casing to ensure well control.

Collapse design must consider uphole formations that contain higher pressures or gradients than those used for the drilling fluid gradient. An example is high pressure/low permeability zones where the drilling fluid gradient is not increased to a fully balanced condition, which eliminates entry of background gas.

The licensee must consider corrosion for the portion of casing subject to long-term exposure to highly corrosive conditions (see API Recommended Practice 5C1: Recommended Practice for Care and Use of Casing and Tubing, Sections 4.8.16 and 5.5.15). Corrosion control may be addressed through appropriate material selection, coatings, environmentally safe corrosion inhibition, cathodic protection, cementing of casing (see *Directive 009: Casing Cementing Minimum Requirements*, DACC's *Primary and Remedial Cementing Guidelines*, and IRP Volume 3: Heavy Oil and Oil Sands Operations, Section 3.1.5), use of tubing and packers, or other engineered options. For external corrosion, see NACE RP0186 Standard (latest edition; see Appendix A for all references).

2 Simplified Method

The Simplified Method is a modification of the design criteria previously specified in *Directive 010* (*Guide 10*), September 1990.

2.1 Surface Casing—Design Factors and Assumptions

Appendix B must be used to select the proper material specifications if the licensee intends to drill into a sour zone before setting the next casing string.

2.1.1 Burst

Design factor = 1.0 for sweet wells or sour wells with pp H_2S < 0.3 kPa.

Design factor = 1.25 for sour wells where the surface casing is potentially exposed to an pp $H_2S \geq 0.3$ kPa.

As a minimum, the casing burst pressure load (kPa) must be no less than 5 times the setting depth (metres true vertical depth [m TVD]) of the next casing string.

2.1.2 Collapse

The collapse design factors and assumptions must be the same as for production casing (Section 2.2.2).

2.1.3 Tension

The tension design factors and assumptions must be the same as for production casing (Section 2.2.3).

2.2 Production Casing—Design Factors and Assumptions

Appendix B must be used to select the proper material specifications for sour wells.

Reentry wells must meet the specifications in the Well Category Table in Section 1.4.

2.2.1 Burst

Design factor = 1.0 for sweet or sour wells with pp $H_2S < 0.3$ kPa.

Design factor = 1.15 for sour wells with pp $H_2S \geq 0.3$ kPa.

No allowance is made for external pressure.

The minimum burst pressure design load that the casing is exposed to must equal the maximum potential formation pressure taken from valid representative offset well data. The casing burst rating must equal or exceed the burst pressure design load times the design factor. In this directive, the design factor is defined as equal to the rating of the tubular divided by the design load on the tubular.

If the maximum potential formation pressure is unknown and not expected to be abnormally overpressured, the minimum burst pressure design load must be equal to an internal pressure gradient of 11 kPa/m times the total depth (m TVD) of the well.

The lesser of the pipe body burst strength or the connection burst strength must be used in the casing minimum burst strength.

If the Simplified Method does not meet the minimum design burst factors, the Alternative Design Method must be applied for burst design.

2.2.2 Collapse

Design factor = 1.0. The casing collapse pressure rating (API Bulletin 5C2) must exceed the external pressure acting on the casing at any given point. No allowance is made for internal pressure, as total evacuation of the casing is assumed.

Axial loading reduces casing collapse pressure rating. The method used to calculate the collapse pressure reduction is outlined in the latest edition of API Bulletin 5C3. The ERCB will continue to accept casing designs where Appendix E has been used to calculate the reduced collapse pressure.

The external pressure acting on the casing is calculated using an external fluid gradient of 12 kPa/m. If the actual drilling fluid gradient is higher than 12 kPa/m, that higher gradient must be used. An acceptable design may be based on a lesser external fluid gradient, but not less than 11 kPa/m, provided that the actual drilling fluid gradient at the time of running casing does not exceed the design gradient.

If the Simplified Method does not meet the minimum design collapse factors, the Alternative Design Method must be applied for collapse design.

2.2.3 Tension

Design factor = 1.6. No allowance is made for buoyancy.

The casing minimum tensile strength must exceed 1.6 times the design tensile load acting on the casing at any given point. The lesser of the pipe body yield strength or the joint strength (connection parting strength) must be considered in the casing minimum tensile strength.

If the Simplified Method does not meet the minimum design tension factors, the Alternative Design Method must be applied for tension design.

2.3 Intermediate Casing—Design Factors and Assumptions

For intermediate casing, the burst, collapse, and tension design factors and assumptions are the same as for production casing (Section 2.2).

2.4 Liners—Design Factors and Assumptions

For liners, the burst, collapse, and tension design factors and assumptions are the same as for production casing (Section 2.2).

The burst and collapse ratings of the preceding casing strings must also meet the requirements for production casing, adjusted for any casing wall thickness reduction.

3 Alternative Design Method

3.1 Introduction

The Alternative Design Method requirements allow the licensee to use a detailed engineering approach to determine the design loads and capabilities of the casing strings. When choosing the Alternative Design Method, the licensee must ensure that the individuals preparing such designs are technically capable and experienced in casing design.

In the event of an ERCB assessment of a casing design, licensees choosing to use the Alternative Design Method must submit supporting data and information, including

1) a detailed wellbore schematic (similar to the STICK drawing example described in Section 11.14 of *Directive 036: Drilling Blowout Prevention Requirements and Procedures*),
2) calculations for each casing string by load type, and
3) any available graphical illustrations of these calculations.

Appendix B must be used to select appropriate materials for sour wells, as discussed in Section 1.3.

Applicants may use an independent engineered design option that determines the loads and capabilities of casing strings in more detail than either the Simplified Method or Alternative Design Method. When an independent engineered option is used, the minimum design factors as listed in *Directive 010* must be met for compliance.

Reentry wells must meet the testing requirements in the Well Category Table in Section 1.4 of *Directive 010*. The casing for reentry wells must also be tested in accordance with *Directive 056: Energy Development Applications and Schedules*, Section 7.10.4. Critical sour reentry wells must also comply with the appropriate sections of the IRP Volume 1: Critical Sour Drilling, Section 4, and IRP Volume 6: Critical Sour Underbalanced Drilling, Section 5.

3.2 Alternative Design Method Tables

3.2.1 Surface Casing

Minimum design factor	Load condition	Internal pressures/fluid	External pressures/fluid
1.0	Collapse	Surface: 0 kPa Fluids: evacuated[1]	Surface: 0 kPa Fluids: mud density at casing point
1.1 1.20[3] 1.25[3] 1.25[4] (IRP Vol. 1, Sec. 4 material)	Burst if pp H_2S < 0.3 kPa Burst if $0.3 \le$ pp H_2S ≤ 10 kPa and pp $CO_2 \le 2000$ kPa Burst if pp H_2S > 10 kPa Burst if pp H_2S $\geq$ 3500 kPa Note: pp H_2S based on maximum internal casing pressure at surface[2]	Surface: the lesser of a) fracture gradient pressure at surface casing shoe: assume minimum 22 kPa/m (unless an actual value is supported by representative offset leak-off test [LOT] data),[2] or b) maximum formation pressure (MFP) in the next hole section less a gas gradient (default is 0.85 x MFP)[2]	Surface: 0 kPa Fluids: 10 kPa/m
1.75 – API connections 1.60 - Premium connections with internal metal to metal seals 1.60 – Pipe body yield strength	Buoyed load tension using the pressure x pipe body area method (see Appendix F)	Surface: 0 kPa Fluids: Mud density at casing point	Surface: 0 kPa Fluids: Mud density at casing point

[1] Evacuated casing in the collapse case may occur in the event of severe lost circulation.
[2] The intent is to have the surface casing burst rating greater than the maximum surface pressure (the lesser of fracture gradient breakdown pressure or formation pressure). This maximum surface pressure is used to calculate the partial pressure of H_2S for selecting the casing minimum burst design factor.
[3] Materials with specifications meeting or exceeding the requirements in Appendix B.
[4] Materials with specifications meeting or exceeding the requirements in IRP Volume 1, Section 4.

3.2.2 Protective Intermediate Casing / Protective Liner

Minimum design factor	Load condition	Internal pressures/fluid	External pressures/fluid
1.0	Collapse	Surface: 0 kPa Fluids: evacuated to at least ½ TVD of next full length casing setting depth, with the lightest mud density after drill-out[1]	Surface: 0 kPa Fluids: mud density at casing/liner setting depth[2]
1.1 1.20[3] 1.25[3] 1.25[4] (IRP Vol. 1, Sec. 4 material)	Burst if pp H_2S < 0.3 kPa Burst if $0.3 \leq$ pp H_2S ≤ 10 kPa and pp $CO_2 \leq 2000$ kPa Burst if pp H_2S > 10 kPa Burst if pp H_2S $\geq$ 3500 kPa	Lesser of a) maximum formation pressure less gas gradient to any depth,[5] or b) fracture gradient pressure at the casing/liner shoe: assume minimum 22 kPa/m less gas gradient to surface, or c) maximum formation pressure x 0.85 for wells with total depth > 1800 m TVD, or d) maximum formation pressure x 0.90 for wells with total depth $\leq$ 1800 m TVD Fluids: Assumed gas gradient	Surface: 0 kPa Fluids: 10 kPa/m gradient
1.75 – API connections 1.60 – Premium connections with internal metal to metal seals 1.60 – Pipe body yield strength	Buoyed load tension using the pressure x pipe body area method (see Appendix F)	Surface: 0 kPa Fluids: Mud density at casing/liner setting depth	Surface: 0 kPa Fluids: mud density at casing/liner setting depth

1 Potential consequences of fully evacuated intermediate casing must be considered.

2 High-pressure low-permeability zones, if known, must be considered when assessing external pressures.

3 Materials with specifications meeting or exceeding the requirements outlined in Appendix B.

4 Materials with specifications meeting or exceeding the requirements outlined in IRP Volume 1, Section 4.

5 The Cullender and Smith method is offered as the standard for the calculation of static bottomhole pressure for this directive. It is applicable to shallow and deep wells, it can be used for sour gases, and with slight modifications it is easily adapted to computer programming. Applicants may use an independent method for the calculation of bottomhole pressures, provided that the method used follows sound engineering principles. (See *Directive 034: Gas Well Testing: Theory and Practice* (3rd edition, 1975), Appendix B.)
As in IRP Volume 1, Section 4 (Fig 1.4.4: Wellhead vs. bottomhole pressure), shut-in tubing pressure is estimated at 85% of bottomhole pressure. Gas gradient is normally calculated by taking 15% (100% - 85%) of formation pressure and dividing by TVD. However, if an actual gas gradient is known (e.g., gas composition, PVT data), that value may be used to determine surface pressure and internal pressure at any depth in the casing string.

3.2.3 Productive Intermediate Casing / Production Casing / Production Liner[1]

Minimum design factor	Load condition	Internal pressures/fluid	External pressures/fluid
1.0	Collapse	Surface: 0 kPa Fluids: evacuated	Surface: 0 kPa Fluids: mud density at casing point[2]
1.1 1.20[4] 1.25[4] 1.25[5] (IRP Vol. 1. Sec. 4 material)	Burst if pp H_2S < 0.3 kPa Burst if $0.3 \leq$ pp H_2S ≤ 10 kPa and pp $CO_2 \leq$ 2000 kPa Burst if pp H_2S > 10 kPa Burst if pp H_2S $\geq$ 3500 kPa	Surface: the lesser of a) maximum formation pressure less gas gradient to any depth[3] b) maximum formation pressure x 0.85 for wells with total depth > 1800 m TVD, or c) maximum formation pressure x 0.90 for wells with total depth ≤ 1800 m TVD and packer fluid column pressure gradient Productive liners: Liner top pressure is equal to or greater than the anticipated maximum formation pressure less methane gradient to liner top and takes into account packer fluid column pressure gradient Postdrilling operations, such as fracturing, must be considered	Surface: 0 kPa Fluids: the lesser of a) 10 kPa/m gradient, or b) known external pore pressure(s) Note: In most cases, the external pressure gradient is balanced by the packer fluid gradient[6]
1.75 – API connections 1.60 - Premium connections with internal metal to metal seals 1.60 – Pipe body yield strength	Buoyed load tension using the pressure x pipe body area method (see Appendix F)	Surface: 0 kPa Fluids: mud density at casing point	Surface: 0 kPa Fluids: mud density at casing point

[1] A productive liner may only be run if the preceding casing string meets the requirements for production casing. Otherwise a full-length casing string must be run in lieu of a liner.
[2] High-pressure, low-permeability zones, if known, must be considered when assessing external pressures.
[3] The Cullender and Smith method is offered as the standard method for the calculation of static bottomhole pressure for this directive. It is applicable to shallow and deep wells, it can be used for sour gases, and with slight modifications it is easily adapted to computer programming. Applicants may use an independent method for the calculation of bottomhole pressures, provided that the method used follows sound engineering principles.
[4] Materials with specifications meeting or exceeding the requirements in Appendix B.
[5] Materials with specifications meeting or exceeding the requirements in IRP Volume 1, Section 4.
[6] The production casing/liner is designed for applied surface pressure on top of a full column of fluid less an external fluid gradient (i.e., net casing burst pressure = applied surface pressure + fluid hydrostatic pressure – external fluid pressure). This also may occur during a packer/tubing leak in a producing well; this case assumes that the leak occurs when a producing well is shut in. *For wells completed with tubing and a packer, the internal casing pressure is the shut-in tubing pressure (SITP) superimposed on a column of packer fluid in the casing/tubing annulus*.

Appendix A References and Suggested Reading

ERCB Publications

Oil and Gas Conservation Act, Oil and Gas Conservation Regulations
Directive 008: Surface Casing Depth Minimum Requirements
Directive 009: Casing Cementing Minimum Requirements
Directive 020: Well Abandonment Guide
Directive 034: Gas Well Testing—Theory and Practice (3rd edition, 1975)
Directive 036: Drilling Blowout Prevention Requirements and Procedures
Directive 056: Energy Development Applications and Schedules
Interim Directive (ID) 97-06: Sour Well Licensing and Drilling Requirements
ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements, 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements, 3) Casing Failure Reporting and Repair Requirements

Other Applicable Publications (latest editions)

Industry Recommended Practices (IRP) Volume 1: Critical Sour Drilling
IRP Volume 3: Heavy Oil and Oil Sands Operations
IRP Volume 6: Critical Sour Underbalanced Drilling

Alberta Recommended Practices (ARP) Volume 2: Completing and Servicing

Drilling and Completion Committee Alberta, Primary and Remedial Cementing Guidelines (April 1995)

National Association of Corrosion Engineers (NACE) MR0175/ISO 15156: Petroleum and natural gas industries—Materials for use in H_2S-containing environments in oil and gas production
NACE RP0186 Standard: Recommended Practice for the Application of Cathodic Protection for Well Casings
NACE Standard TM0177: Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H_2S Environments
NACE Standard TM0284: Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking

American Petroleum Institute (API) Recommended Practice 5C1: Recommended Practice for Care and Use of Casing and Tubing
API Bulletin 5C3: Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties
API Specification 5CT/ISO 11960: Specification for Casing and Tubing

Suggested Reading

NACE Paper # 03105: Development of Recommended Practices for Completing and Producing Critical Sour Gas Wells – Materials Requirements, by Malcolm Hay and Dan Belczewski (NACE Corrosion Conference 2003)

How to Design Casing Strings for Horizontal Wells, by John F. Greenip Jr., Hydril, Houston, Texas, Petroleum Engineer International (December 1989)

The Development of a New High Strength Casing Steel with Improved Hydrogen Sulfide Cracking Resistance for Sour Oil and Gas Well Applications, by George M. Waid and Robert T. Ault, Republic Steel Corporation, Corrosion/79, Paper No. 180 March 1979

Appendix B Material Requirements for Sour Wells — Additional Constraints to API 5CT/ISO 11960

B1. Chemical Requirement—Maximum weight percentages (wt. %) for specific elements

	H-40 or J-55	K-55	L-80 (Type 1)	C-90 (Type 1)	T-95 (Type 1)
C	0.35(4)	0.35(4)	0.32(7)	*	*
Mn	1.35(5)	1.35(5)	1.40(6)	*	*
P	0.020(8)	0.020(8)	0.020(9), (3)	*	*
S	0.015	0.015	0.010(2)	*	*
Ni	*	*	*	0.35	0.35
P+S	0.030	0.030	0.025(1)	0.025	0.025

All elements not specified must comply with API Specification 5CT/ISO 11960.
(1) P+S can be raised to < 0.030% if Cr + Mo > 0.30%, and to < 0.035% if Cr + Mo >0.6%.
(2) S < 0.015% if Cr + Mo > 0.60%.
(3) P may be raised to 0.025% if Cr + Mo > 0.30%
(4) C may be raised to 0.38% if S < 0.010%; C may be raised to 0.40% if S < 0.010% and P < 0.015%.
(5) Mn may be raised to 1.45% if S < 0.010%; Mn may be raised to 1.55% if S < 0.007%.
(6) Mn may be raised to 1.45% if S < 0.007%, Mn may be raised to 1.50% if S < 0.005%
(7) C may be raised to 0.35% if S < 0.005% and P < 0.015%.
(8) P may be raised to 0.025% if S <0.010%
(9) P may be raised to 0.025% if S <0.005%

B2. Tempering Temperature Constraints

L80 Type 1 materials must have a tempering temperature not less than 621°C. All other materials must use minimum tempering temperatures outlined in API Specification 5CT.

Corrosion-resistant alloys (CRAs) are specialty materials designed for use in corrosive environments. It is the responsibility of the end user to ensure that the material can perform acceptably in the well environment. High nickel-based CRAs are expected to perform adequately in the sour conditions that lead the user to this box. Ferritic, martensitic, duplex, and austenitic stainless steels are unlikely to have the necessary SSC resistance for service in these environments (see NACE MR0175/ISO 15156, Part 3: “Cracking-resistant CRAs [corrosion-resistant alloys] and other alloys”).

B3. Hardness Requirements

Rockwell C Scale	L-80 (Type 1)	C-90 (Type 1)	T-95 (Type 1)
Hardness Single Point Reading (max)	22.0	25.4	25.4
Hardness Three Point Average Value (max)	21.0	25.0	25.0

As per frequencies outlined in API Specification 5CT/ISO 11960.

B4. Toughness Requirements (Charpy V-Notch)

Directive 010 compliant materials must meet or exceed the Charpy impact full sized equivalent toughness values outlined in the table below. Charpy impact testing must be conducted in accordance with API 5CT/ISO 11960.

Pipe Body

Test temperature (°C)	Room temperature			0°C		
Joules	H-40	J-55	K-55	L-80 (Type 1)	C-90 (Type 1)	T-95 (Type 1)
Longitudinal (min)	45	60	60	80	100	100
Transverse (min)	30	40	40	55	70	70

.
Note: Lower Charpy V-Notch requirements may be considered when using low temperature testing.

Coupling Stock

Test temperature (^{0}C)	**Room temperature**			**0^0C**		
Joules	H-40	J-55	K-55	L-80 (Type 1)	C-90 (Type 1)	T-95 (Type 1)
Longitudinal (min)	See	48	48	75	90	90
Transverse (min)	Note	32	32	50	70	70

Note: H-40 pipe is normally supplied with grade K-55 couplings and occasionally with grade J-55 couplings.

B5. Box Expanded Connections

Manufacturer/finisher must ensure that the expanded box ends meet minimum *Directive 010* requirements. Procedures pertaining to heat treatment and stress relief must be made available to the ERCB upon request.

Appendix C NACE Sulphide Stress Cracking (SSC) Testing Parameters

In the event that fit-for-purpose SSC testing is required, refer to the following sources for recommendations on testing parameters:

- NACE TM0177
- IRP Volume 1
- Certified NACE testing laboratory

Use of Material Requirements (Appendix B) will assist with the selection of appropriate materials based on partial pressures of H_2S and CO_2.

Appendix D Definitions

Casing: The casing string forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or cross flow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment, such as the drilling blowout preventer (BOP) and downhole production equipment (e.g., production packer). Casing is available in a range of sizes, weights, grades, and materials.

Casing grade: A system of identifying and categorizing the strength of casing materials. The appropriate casing grade for any application typically is based on design loads and the corrosion environment.

Casing point: The depth at which casing is run and cemented. The casing point may be a predetermined depth selected according to geological observations or dictated by problems in the open-hole section.

Design factors: The design factor, as specified in this directive, is the minimum acceptable value. Safety factors must be equal to or greater than the minimum design factors.

Directional wells: Wells where the bending stresses exceed 10% of the SMYS.

Formation (or pore) pressure: The pressure of the fluids within the pores of a reservoir.

Formation (or pore) pressure gradient: The pressure gradient is expressed as kPa/m. This corresponds to the formation (or pore) pressure divided by the true vertical depth of the formation top. The pressure gradient can be expressed as an equivalent mud density, the fluid density required in the wellbore to balance the formation (or pore) pressure.

Fracture gradient: The pressure required to induce fractures in rock divided by depth. In the absence of other data, the default value for casing design is 22 kPa/m.

Fracture pressure: The pressure required to induce fractures at a given depth.

Hydrogen induced cracking (HIC): The development of cracks along the rolling direction of the steel due to the absorption of hydrogen atoms and formation of internal hydrogen gas. The hydrogen is generated by the corrosion of steel in a wet hydrogen sulphide (H_2S) environment.

Intermediate casing: Intermediate casing strings are used to ensure wellbore integrity down to total depth or the next full-length casing point. Intermediate casing strings are set after the surface and before the production casing. For example, the intermediate casing strings may provide protection against caving of weak or abnormally pressured formations and enable the use of drilling fluids of different density necessary for the control of deeper formations to the next casing point.

Joint strength: The joint strength is the connection parting strength (or ultimate strength). The joint strengths of API connections are published in API Bulletin 5C2. For non-API connections, the connection yield and/or ultimate strength may be supplied by the manufacturer. The ultimate strength of non-API connections may be used to meet the minimum tension design factor.

Joule: One joule is the work done, or energy expended, by a force of one newton moving an object one metre along the direction of the force.

Liner: Any string of casing in which the top does not extend to the surface but instead is suspended from inside the previous casing string. The liner can be either protective or productive and must be designed accordingly.

Partial pressure (pp): The partial pressure of each component in a gas mixture is equal to the pressure multiplied by its mole fraction in the mixture. For example: A pressure of 30 000 kPa and a 3 mole % (0.03 mole fraction) H_2S content would have (30 000 kPa x 0.03) = 900 kPa pp H_2S.

Pipe Body Yield Strength (PBYS): The pipe body yield strength is the minimal axial yield strength of the casing tube body. The PBYS is calculated by multiplying the nominal pipe body cross-sectional area by the specified minimum yield strength (SMYS) of the material.

Premium Connections: Non-API connections are sometimes referred to as "premium" connections and are generally used in place of API connections when additional connection performance is required. Premium connections may have one or more enhanced features, such as a modified thread profile and/or a metal to metal seal. Premium connection manufacturers may publish the connection ultimate strength and/or connection yield strength.

Production casing: The last casing string set within a wellbore, which contains the primary completion components. No subsequent drilling operations are conducted after setting production casing; otherwise the string must be designed as productive intermediate casing.

Productive intermediate casing: Productive intermediate casing functions as part of the production string and may be exposed to production fluids. It must meet production casing design criteria suitable for the life of the well.

Protective intermediate casing: Protective intermediate casing cannot be exposed to production fluids after completion; it can only be exposed to drilling or formation fluids while drilling the next hole section(s).

Reservoir: A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids.

Safety factor: The safety factor in this directive is defined as equal to the load rating of the tubular divided by the actual load on the tubular. The calculated safety factors must be equal to or greater than the minimum design factors.

Shut-in tubing pressure (SITP): Shut-in tubing pressure is the producing formation pressure less the gas gradient to surface.

Sour service: Sour service, as specified in *Directive 010*, refers to a partial pressure of H_2S > 0.3 kPa. This value is consistent with NACE MR0175/ISO 15156.

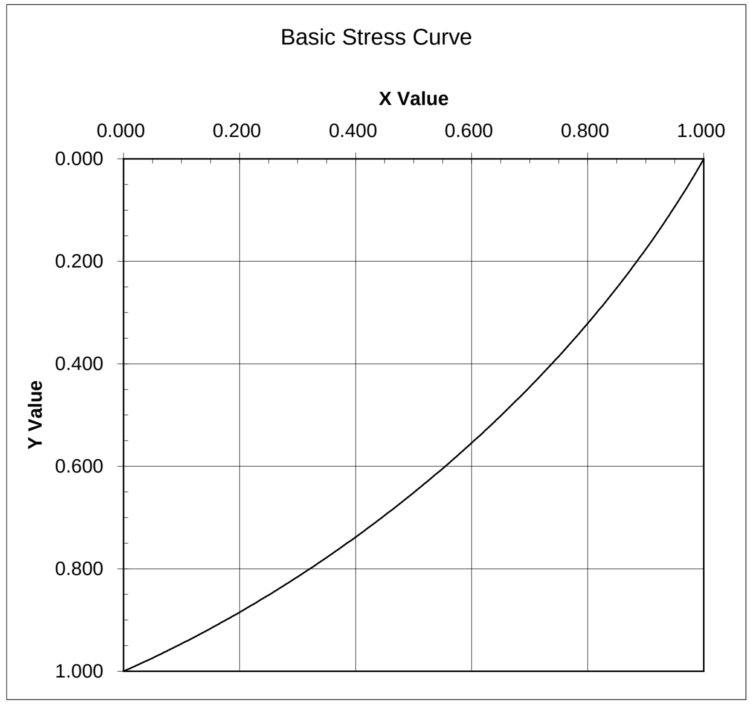
Sulphide stress cracking (SSC): Brittle failure by cracking under the combined tensile stress and corrosion in the presence of water and H_2S.

Surface casing: The first casing string pressure cemented back to surface, which permits installation of blowout preventers for the primary function of well control during the subsequent deepening of the well. It may also provide protection of freshwater aquifers and structural strength, so that the remaining casing strings and surface equipment may be installed.

Appendix E Effects of Tensile Loading on Casing Collapse

(Replaces *Directive 015*)

X	Y	X	Y	X	Y	X	Y
0.000	1.000	0.250	0.851	0.500	0.651	0.750	0.385
0.005	0.997	0.255	0.848	0.505	0.647	0.755	0.379
0.010	0.995	0.260	0.844	0.510	0.642	0.760	0.373
0.015	0.992	0.265	0.841	0.515	0.638	0.765	0.367
0.020	0.990	0.270	0.837	0.520	0.633	0.770	0.360
0.025	0.987	0.275	0.834	0.525	0.628	0.775	0.354
0.030	0.985	0.280	0.830	0.530	0.623	0.780	0.347
0.035	0.982	0.285	0.827	0.535	0.619	0.785	0.341
0.040	0.979	0.290	0.823	0.540	0.614	0.790	0.334
0.045	0.977	0.295	0.819	0.545	0.609	0.795	0.328
0.050	0.974	0.300	0.816	0.550	0.604	0.800	0.321
0.055	0.971	0.305	0.812	0.555	0.599	0.805	0.314
0.060	0.969	0.310	0.808	0.560	0.595	0.810	0.308
0.065	0.966	0.315	0.805	0.565	0.590	0.815	0.301
0.070	0.963	0.320	0.801	0.570	0.585	0.820	0.294
0.075	0.960	0.325	0.797	0.575	0.580	0.825	0.287
0.080	0.958	0.330	0.793	0.580	0.575	0.830	0.280
0.085	0.955	0.335	0.789	0.585	0.570	0.835	0.273
0.090	0.952	0.340	0.786	0.590	0.565	0.840	0.266
0.095	0.949	0.345	0.782	0.595	0.560	0.845	0.259
0.100	0.946	0.350	0.778	0.600	0.554	0.850	0.252
0.105	0.943	0.355	0.774	0.605	0.549	0.855	0.245
0.110	0.940	0.360	0.770	0.610	0.544	0.860	0.237
0.115	0.938	0.365	0.766	0.615	0.539	0.865	0.230
0.120	0.935	0.370	0.762	0.620	0.534	0.870	0.223
0.125	0.932	0.375	0.758	0.625	0.528	0.875	0.215
0.130	0.929	0.380	0.754	0.630	0.523	0.880	0.207
0.135	0.926	0.385	0.750	0.635	0.518	0.885	0.200
0.140	0.923	0.390	0.746	0.640	0.512	0.890	0.192
0.145	0.920	0.395	0.742	0.645	0.507	0.895	0.184
0.150	0.917	0.400	0.738	0.650	0.502	0.900	0.176
0.155	0.913	0.405	0.734	0.655	0.496	0.905	0.169
0.160	0.910	0.410	0.730	0.660	0.491	0.910	0.161
0.165	0.907	0.415	0.726	0.665	0.485	0.915	0.152
0.170	0.904	0.420	0.722	0.670	0.479	0.920	0.144
0.175	0.901	0.425	0.717	0.675	0.474	0.925	0.136
0.180	0.898	0.430	0.713	0.680	0.468	0.930	0.128
0.185	0.895	0.435	0.709	0.685	0.463	0.935	0.119
0.190	0.891	0.440	0.705	0.690	0.457	0.940	0.111
0.195	0.888	0.445	0.700	0.695	0.451	0.945	0.102
0.200	0.885	0.450	0.696	0.700	0.445	0.950	0.093
0.205	0.882	0.455	0.692	0.705	0.439	0.955	0.085
0.210	0.878	0.460	0.687	0.710	0.434	0.960	0.076
0.215	0.875	0.465	0.683	0.715	0.428	0.965	0.067
0.220	0.872	0.470	0.678	0.720	0.422	0.970	0.058
0.225	0.868	0.475	0.674	0.725	0.416	0.975	0.048
0.230	0.865	0.480	0.670	0.730	0.410	0.980	0.039
0.235	0.862	0.485	0.665	0.735	0.404	0.985	0.029
0.240	0.858	0.490	0.660	0.740	0.398	0.990	0.020
0.245	0.855	0.495	0.656	0.745	0.392	0.995	0.010
0.250	0.851	0.500	0.651	0.750	0.385	1.000	0.000



Basic Stress Curve $X^2 + XY + Y^2 = 1$

$$X = \frac{\text{Tensile Load}}{\text{Pipe Body Strength}}$$

$$Y = \frac{\text{Collapse Resistance with Tensile Load}}{\text{Collapse Resistance without Tensile Load}} \quad \text{or } Y = \frac{[(4 - 3X^2)^{1/2} - X]}{2}$$

Example: Calculate the Collapse Resistance of 177.8 mm OD, 34.23 kg/m Grade L-80 casing with 1,000 m of 177.8 mm OD, 38.69 kg/m Grade L-80 casing suspended below

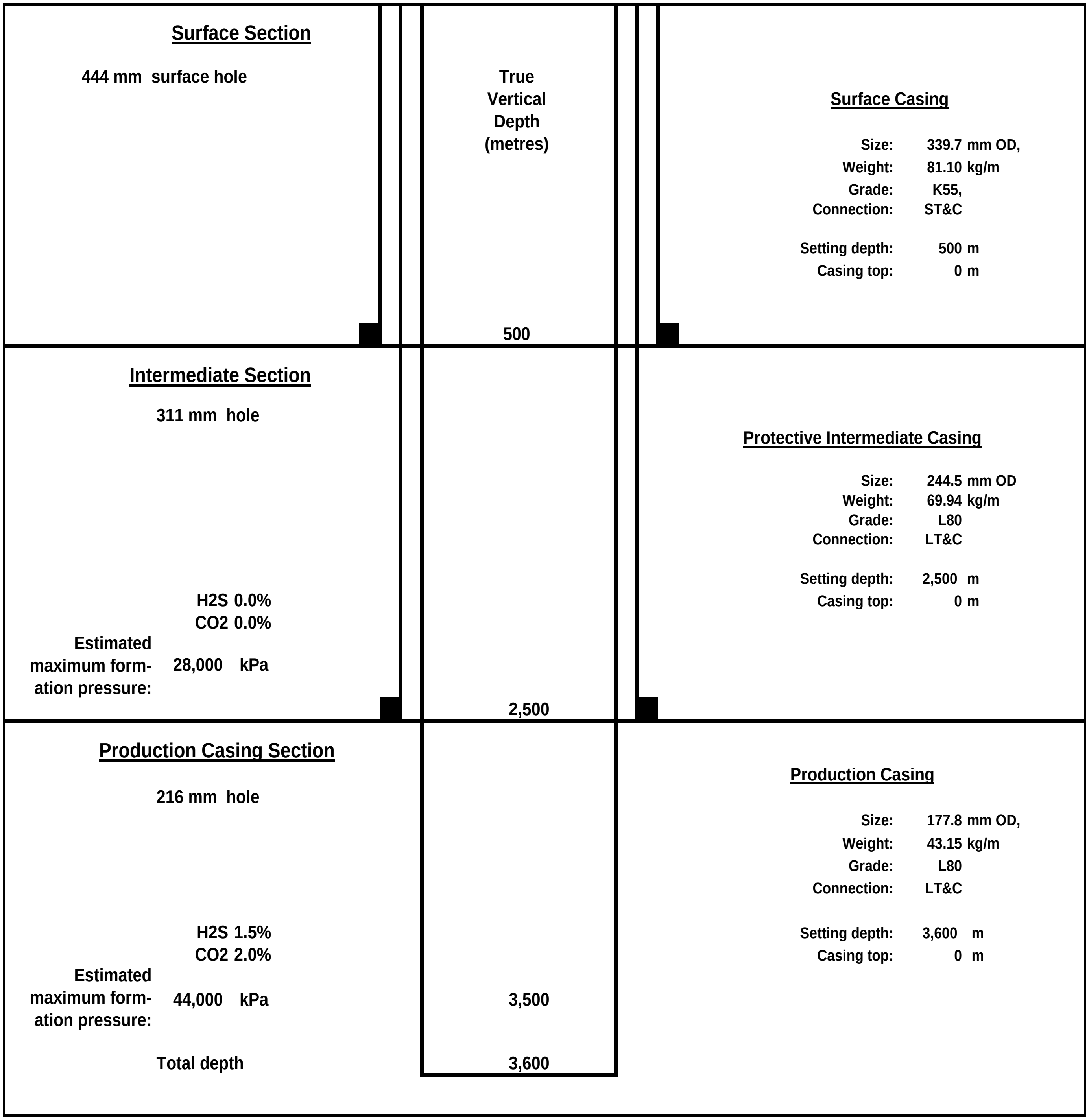
$$X = \frac{\text{Tensile Load}}{\text{Pipe Body Yield Strength}} = \frac{1{,}000 \text{ m} \times 38.69 \text{ kg/m} \times 0.981 \text{ daN/kg}}{236{,}600 \text{ daN}} = 0.160$$

$$Y = \frac{\text{Collapse Resistance with Tensile Load}}{\text{Collapse Resistance without Tensile Load}} = 0.910$$

Collapse Resistance with Tensile Load = 0.910 x 26,400 kPa = 24,000 kPa

Appendix F Alternative Design Method Example

Noncritical Sour Well Example



Appendix F Alternative Design Method Example

Surface Casing (340 mm OD @ 500 m)

Assumptions

Surface casing	339.7	mm OD
Minimum setting depth (Directive 008)	462	m
Planned setting depth	500	m
Mud weight @ 500 m	1100	kg/m^3
Offset press integrity test (PIT) @ 500 m =	22	kPa/m
Next casing depth (m TVD)	2,500	m
Next casing section mud weight	1200	kg/m^3
Max BH pressure prior to next csg depth (MW x Depth x 0.00981)	29,400	kPa
Est max pore pressure	28,000	kPa
Gas gradient	1.80	kPa/m

Next Hole Section

Sweet ?	Yes
H2S	0%
CO2	0%
Critical?	No

Required Minimum Design Factors

	Alternate	Simplified
Collapse	1.00	1.00
Burst	1.10	1.00
Tension (air)		1.60
Tension (buoyed)	1.75	

Load Calculations

1) Collapse @ 500 m = MW x Depth x 0.00981 = 5,400 kPa

2) Burst @ Surface

a) Frac Press @ Csg Shoe = 22 kPa/m x 500 m = 11,000 kPa
(Minimum Value)

b) Surface Pressure = Max Pore Press - Gas Gradient x Casing Depth
= 28,000 kPa - 4,500 kPa = 23,500 kPa

Use Lesser of a) or b) = 11,000 kPa

3) From API 5C2 Select 339.7 mm OD, 81.10 kg/m, K55, ST&C Casing

Collapse Rating = 7,800 kPa — Burst Rating = 18,800 kPa

Joint Strength = 243,300 daN — Pipe Area = 10,008 mm^2
Pipe Body Strength = 379,400 daN — (cross section) 0.0100 m^2

4) Tensile Loads

a) Tension Force = 500 m
x 81.10 kg/m
x 9.81
= 397,776 N or 39,778 daN
(Weight In Air)

b) Compressive Force = 500 m
x 1100 kg/m^3
x 9.81 N/kg
x 0.0100 m^2
= 54,000 N or 5,400 daN
(Buoyancy)

c) Net Tensile Force = 397,776 N
less 54,000 N
343,776 N or 34,378 daN

5)

339.7 mm OD, 81.1 kg/m, K55 ST&C	Calculated Loads Alt Design (A)	Calculated Loads Simpl. (B)	Tubular Rating (C)	Design Factors Alt Design (C) / (A)	Design Factors Simpl. (C) / (B)	Design Factors Minimum Required
Collapse (kPa)	5,400	5,500	7,800	1.44	1.42	1.00
Burst (kPa)		12,500	18,800	x	1.50	1.00
	11,000			1.71	x	1.10
Tension (daN)		39,778	243,300	x	6.12	1.60
	34,378			7.08	x	1.75

6) Check for surface casing compressive loading conditions (Tensile forces using buoyancy)

1) Net tensile force of the protective intermediate (2,500 m of 244.5 mm OD, 69.94 kg/m)	145,759	daN
2) Net tensile force of next string (3,600 m of 177.8 mm OD, 43.15 kg/m prod casing)	127,370	daN
3) Estimated tensile force of tubing string (3,600 m of 88.9 mm OD, 19 kg/m)	67,100	daN
4) Estimated weight of BOP stack and snubbing stack	20,016	daN
Total estimated compressive load on surface casing	**360,245**	daN

Conclude the estimated compressive load is higher than the surface casing joint strength (360.2 kdaN > 243.3 kdaN).

The casing tube body strength is sufficient for external loading but the connection is insufficient. External support mechanisms (i.e. wellhead base plate, etc.) or a stronger connection must be used.

Appendix F Alternative Design Method Example

Protective Intermediate Casing (245 mm OD @ 2,500 m)

Assumptions

Protective intermediate casing	244.5	mm OD
Setting depth (m TVD)	2,500	m
Mud weight @ 2,500 m	1,200	kg/m³
Next casing depth (m TVD)	3,600	m
Next casing section mud weight	1,300	kg/m³
Max BH pressure prior to next csg depth (MW x Depth x 0.00981)	45,900	kPa
Producing zone depth	3,500	m
Est max formation pressure	44,000	kPa
Gas gradient (Based on gas composition)	2.0	kPa/m
Anticipated packer fluid density	1,000	kg/m³
Anticipated fracture gradient at shoe @ 2,500 m =	22	kPa/m

Next Hole Section

		Partial Pressure
Sweet ?	No	
H_2S	1.5%	660 kPa
CO_2	2.0%	880 kPa
Critical?	No	

Material requirements as per Appendix B

Required Minimum Design Factors

	Alternate	Simplified
Collapse	1.00	1.00
Burst	1.25	1.15
Tension (air)		1.60
Tension (buoyed)	1.75	

Load Calculations

1a) External Collapse Load @ 1,800 m = MW x Depth x 0.00981 = 21,200 kPa
(1/2 TVD of next csg)

b) Internal Collapse Load @ 1,800 m = 0 kPa

c) Net Collapse Load @ 1,800 m = 21,200 kPa
(External less Internal)

This collapse situation is a result of lost circulation while drilling the next hole section.
The mud losses cause a fluid level drop to 1/2 TVD of the next full length casing point (not a liner situation).
Potential consequences of fully evacuated intermediate casing was considered and deemed to be of very low risk.
This conservative design ignores the internal support from the gas column above the fluid level;
the lightest mud density, after drill out must be used to provide the minimum internal pressure support below the fluid level.
Therefore, the highest collapse load occurs immediately above the internal fluid level.
All casing from the fluid top to casing shoe shall be designed to at least this collapse design load.
If the fluid density in the next hole section is less than the current density, additional collapse loads will apply below the internal fluid level.

2) Burst @ Surface
Based on lesser of formation pressure at surface, or shoe fracture pressure limitation

a) Surface Pressure = BHP - (Gas Gradient x Production Zone Depth)
= 44,000 kPa - (2 kPa/m x 3,500 m) = 37,000 kPa

b) 44,000 kPa x 0.85 = 37,400 kPa (Use if Gas Gradient unknown & TD > 1800 mTVD)

Choose a) 37,000 kPa (Lesser of (a), or (b))

3) From API 5C2 Select 244.5 mm OD 69.94 kg/m, L80 LT&C Casing

Collapse Rating = 32,700 kPa — Burst Rating = 47,400 kPa

Joint Strength = 397,200 daN — Pipe Area = 8,756 mm²
Pipe Body Strength = 483,100 daN — (cross section) 0.00876 m²

4) Tensile Loads

a) Tension Force = 2,500 m
x 69.94 kg/m
x 9.81
= 1,715,279 N or 171,528 daN

b) Compressive Force = 2,500 m
x 1200 kg/m³
x 9.81
x 0.00876 m²
= 257,692 N or 25,769 daN

c) Net Tensile Force = 1,715,279 N
less 257,692 N
1,457,586 N or 145,759 daN

244.5 mm OD, 69.94 kg/m, L80 LT&C	Calculated Loads Alt Design (A)	Calculated Loads Simpl. (B)	Tubular Rating (C)	Design Factors Alt Design (C) / (A)	Design Factors Simpl. (C) / (B)	Design Factors Minimum Required
Collapse (kPa)	21,200	29,430	32,700	1.54	1.11	1.00
Burst (kPa)		44,000	47,400	x	1.08	1.15
	37,000			1.28	x	1.25
Tension (daN)		171,500	397,200	x	2.32	1.60
	145,800			2.72	x	1.75

Using the alternative design method, the selected pipe is acceptable.
Using the simplified design method, the selected pipe is unacceptable.

Appendix F Alternative Design Method Example

Production Casing Example (178 mm OD @ 3,600 m)

Assumptions

Production casing	177.8	mm OD
Setting depth	3,600	m
Casing top	0	m
Mud weight @ 3,600 m	1,300	kg/m³
Assumed external backup fluid gradient	10	kPa/m
Next casing depth	N/A	m
Next casing section mud weight	N/A	kg/m³
Max BH pressure prior to next csg depth (MW x Depth x 0.00981)	N/A	kPa
Producing zone depth	3,500	m
Est max formation pressure	44,000	kPa
Gas gradient (Based on gas composition)	2.0	kPa/m
Anticipated packer fluid density	1,040	kg/m³
	10.20	kPa/m

Next Hole Section

		Partial Pressure	
Sweet ?	No		
H2S	1.5%	660	kPa
CO2	2%	880	kPa
Critical?	No		

Material requirements as per Appendix B
Material as per IRP Volume 1, Section 4

Required Minimum Design Factors

	Alternate	Simplified
Collapse	1.00	1.00
Burst	1.25	1.15
Tension (air)		1.60
Tension (buoyed)	1.75	

Load Calculations

1) Collapse @ 3,600 m = MW x Depth x 0.00981 = 45,900 kPa

2) Burst

a) Surface Pressure = (BHP - (Gas Gradient x Production Zone Depth))
= (44,000 kPa - (2.0 kPa/m x 3,500 m)) = 37,000 kPa

b) Surface Pressure = (BHP * 0.85)
= 44,000 kPa x 0.85 = 37,400 kPa (Use if Gas Gradient unknown & TD > 1800 mTVD)

Packer Depth BHP - (Gas gradient *Depth) + (Packer Fluid Gradient * Depth) - (Water gradient * Depth) (Depth = 3500 m)
= 37,708 kPa

Use: 37,708 kPa

3) From API 5C2 Select 177.8 mm OD, 43.15 kg/m, L80 LT&C Casing

Collapse Rating = 48,500 kPa   Burst Rating = 56,300 kPa

Joint Strength = 261,100 daN   Pipe Area = 5,451 mm²
Pipe Body Strength = 300,700 daN   (cross section) 0.00545 m²

4) Tensile Loads

a) Tension Force = 3,600 m
x 43.15 kg/m
x 9.81
= 1,523,956 N or 152,396 daN

b) Compressive Force = 3,600 m
x 1300 kg/m³
x 9.81
x 0.00545 m²
= 250,258 N or 25,026 daN

c) Net Tensile Force = 1,523,956 N
less 250,258 N
1,273,698 N or 127,370 daN

177.8 mm OD, 43.15 kg/m, L80 LT&C	Calculated Loads Alt Design (A)	Calculated Loads Simpl. (B)	Tubular Rating (C)	Design Factors Alt Design (C) / (A)	Design Factors Simpl. (C) / (B)	Minimum Required
Collapse (kPa)	45,900	45,900	48,500	1.06	1.06	1.00
Burst (kPa)		44,000	56,300	x	1.28	1.15
	37,708			1.49	x	1.25
Tension (daN)		152,396	261,100	x	1.71	1.60
	127,370			2.05	x	1.75

Therefore, the pipe selected in this example is acceptable.
Since this string design is collapse driven, it can be further optimized by tapering down to a lesser pipe weight pipe in the middle.