

Directive 010

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Minimum Casing Design Requirements

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1 Introduction

1.1 Purpose of This Directive

This directive sets out the minimum requirements for casing design in accordance with section 6.070 of the *Oil and Gas Conservation Rules*, section 23 of the *Geothermal Resource Development Rules*, and section 27 of the *Brine-Hosted Mineral Resource Development Rules*.

This directive was developed with input from a technical subcommittee of the Drilling and Completions Committee and the Alberta Energy Regulator's (AER's) predecessor (the Energy Resources Conservation Board [ERCB]), which reviewed various technical documents containing information on casing design for sweet, sour, and critical sour wells in the Western Canadian Sedimentary Basin.

 Licensees must consider all postdrilling casing loading, such as fracture stimulation down casing, tubing packer leaks, compressive loading, triaxial loading, and temperature (see *IRP Volume 3*, section 3.1.6, and appendix 5) effects for the life of the well in their casing design.

1.2 AER Requirements

Following AER requirements is mandatory for the responsible duty holder as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The

term "must" indicates a requirement, while terms such as "should," "recommends," and "expects" indicate a recommended practice.

1.3 What's New in the Directive

This directive now also applies to brine-hosted mineral resource development. References to the *Brine-Hosted Mineral Resource Development Rules* and other appropriate references to brine-hosted mineral resource development have been made.

1.4 Compliance

All casing ordered prior to the release of the December 22, 2009, edition of *Directive 010* may be used if it conforms to the design factor requirements in section 1.5.1.

- 2) All casing ordered or manufactured after September 22, 2008, must conform to the material requirements in appendix 2.
- 3) Licensees must retain records of all supporting data and information used to meet the AER minimum casing design requirements for the simplified and alternative design methods.
- 4) The licensee must submit information requested by the AER within 20 working days.

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

1.5 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.

- 5) Anticipated current and future environments must be considered when selecting casing for use in wells that may encounter hydrogen sulphide (H₂S), or carbon dioxide (CO₂) with H₂S.
- 6) Licensees must follow appendix 2 to select the proper material specifications for all wells, using partial pressures (pp) of H₂S and CO₂, 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 1.8.

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) H₂S content would have 30 000 kPa \times 0.03 = 900 kPa H₂S partial pressure.

- 7) Surface casing must be designed for sour service (see section 1.7) if the licensee intends to drill into a sour zone before setting the next sour service casing string.
- 8) The casing bowl weld must also be suitable for sour service.
- 9) Licensees must maintain casing integrity for the life of the well, including post-abandonment (see *Directive 020: Well Abandonment*, 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 National Association of Corrosion Engineers [NACE] MR0175/ISO 15156, Part 3: Cracking-resistant CRAs and other alloys).

- 10) 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.
- 11) This testing must involve a laboratory experienced with the testing of materials for sour service at elevated pressures.

1.5.1 Materials Not Meeting Requirements of Appendix 2

- 12) Existing API 5CT/ISO 11960 compliant materials purchased or manufactured prior to September 22, 2008, that do not meet the requirements of appendix 2 may only be used in drilling of noncritical sour wells if one of the following conditions is met:
 - a) If the H₂S concentration is less than 1.00%, the burst design safety factor must be 1.30 or greater (increased from the 1.25 minimum for *Directive 010* appendix 2 compliant materials).
 - b) If the H₂S concentration is higher than 1% but less than 5.00%, the burst design safety factor must be 1.35 or greater.
 - c) If the H₂S concentration is greater than or equal to 5.00%, the burst design safety factor must be 1.40 or greater.
- 13) A burst design safety factor of 1.25 must be used for noncompliant API H40, J55, K55, L80, C90, or T95 if the materials are tested as described in section 1.5.2.

 Materials not listed in appendix 2 must be tested as described in section 1.5.2 for use in sour wells.

These requirements pertain to both casing and coupling stock.

1.5.2 Representative Testing Program

Materials that do not comply with the requirements of appendix 2 can be tested to verify performance in sour service conditions.

- 15) API 5CT/ISO 11960 casing and coupling materials must each be tested to the following parameters per heat lot:
 - a) SSC testing—Method A or Method C is sufficient for testing; in accordance with NACE TM0177, the SSC test condition must be either
 - i) 80% specific minimum yield strength (SMYS) with Solution A Environment, or
 - ii) in accordance with fit-for-purpose testing, as stated in appendix 3.
 - b) HIC testing—for all materials that are not quenched and tempered in accordance with NACE Standard TM0284 and with pass criteria outlined in *IRP Volume 1*.

1.6 Well Category Table

A well's sour classification is defined by the partial pressure of H₂S, as shown in the table below.

- 16) Licensees must determine which column their well is under and then select the appropriate recommended casing load conditions, minimum design factors, and material specifications.
- 17) 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.

	Sweet wells, and sour wells with partial pressure H ₂ S < 0.3 kPa	Sour wells with partial pressure H₂S <u>></u> 0.3 kPa	Critical sour wells ¹
Recommended loading conditions	<i>Directive 010</i> simplified or alternative design method casing load conditions	<i>Directive 010</i> simplified or alternative design method casing load conditions	<i>IRP Vol. 1</i> , sec. 4, design criteria ¹
Recommended minimum design factors	<i>Directive 010</i> simplified or alternative design method designs	<i>Directive 010</i> simplified or alternative design method designs	<i>IRP Vol. 1</i> , sec. 4, design criteria ¹

Well category table

	Sweet wells, and sour wells with partial pressure H ₂ S < 0.3 kPa	Sour wells with partial pressure H₂S <u>> 0</u> .3 kPa	Critical sour wells ¹
Material specifications	Material selection as specified in API 5CT or proprietary grades meeting requirements of <i>Directive 010</i> , section 1.7	Material selection as specified in appendix 2 ²	Critical sour service specification, as in <i>IRP</i> <i>Vol. 1</i> , 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 2 sour service pipe material.

¹ Critical sour wells must be designed in compliance with Directive 056, IRP Vol. 1, and Directive 036: Drilling Blowout Prevention Requirements and Procedures. The Directive 010 alternative design method may be used, subject to AER approval.

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.

1.7 Casing Performance Properties

- Casing must be manufactured to the minimum specifications as defined in API 5CT/ISO 11960.
- 19) The performance properties of casing must meet or exceed the standards in API Bulletin 5C2.
- 20) 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 5.

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*.

21) 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.

22) 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.

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1.8 Burst Design Factor Adjustments

In section 2, "Simplified Method," the minimum burst design factor for sour wells with pp $H_2S \ge 0.3$ 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 H₂S <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 H₂S of 0.3 kPa or greater are considered sour wells. For sour wells with $0.3 \le pp$ H₂S <10 kPa (pp of H₂S of 0.3 kPa or greater and less than 10 kPa), the minimum burst design factor is 1.20. For sour wells with pp H₂S >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 H₂S 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.

- 23) A licensee requesting a reduction in the burst design factor must 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 = $(1.05 / \text{minimum burst design factor}) \times \text{SMYS}$.

For example, for noncritical sour wells with pp $H_2S \ge 0.3$ 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.

1.9 Casing Wear Considerations

- 24) Casing wear considerations must be taken into account.
- 25) 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 AER immediately on detection of a casing leak or failure.

26) Also, if requested by the AER, 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 *Directive 087: Well Integrity Management*).

1.10 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.

- 27) For all directional wells, the licensee must address additional stresses (or loads) caused by bending, regardless of the design method chosen.
- 28) 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.

- 29) 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.
- 30) 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 1 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

31) Appendix 2 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 a pp $H_2S \ge 0.3$ kPa.

32) 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

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

2.1.3 Tension

34) 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

- 35) Appendix 2 must be used to select the proper material specifications for sour wells.
- 36) Reentry wells must meet the specifications in the Well Category Table in section 1.6.

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 $H_2S \ge 0.3$ kPa.

No allowance is made for external pressure.

37) 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.

- 38) 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.
- 39) The lesser of the pipe body burst strength or the connection burst strength must be used in the casing minimum burst strength.
- 40) 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.

41) 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 AER will continue to accept casing designs where appendix 5 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.

- 42) 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.
- 43) 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.

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

46) 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).

47) 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.

- 48) When choosing the alternative design method, the licensee must ensure that the individuals preparing such designs are technically capable and experienced in casing design.
- 49) In the event of an AER assessment of a casing design, licensees choosing to use the alternative design method must submit supporting data and information, including
 - a) a detailed wellbore schematic (similar to the STICK drawing example described in section 11.14 of *Directive 036: Drilling Blowout Prevention Requirements and Procedures*),
 - b) calculations for each casing string by load type, and
 - c) any available graphical illustrations of these calculations.
- 50) Appendix 2 must be used to select appropriate materials for sour wells, as discussed in section 1.5.

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.

- 51) When an independent engineered option is used, the minimum design factors as listed in this directive must be met.
- 52) Reentry wells must meet the testing requirements in the Well Category Table in section 1.6.

- 53) The casing for reentry wells must also be tested in accordance with Directive 056, section 7.7.5.
- 54) Critical sour reentry wells must also comply with the appropriate sections of *IRP Volume 1*, section 4, and *IRP Volume 6*, section 5.

3.2 Alternative Design Method Tables

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	Burst if pp H ₂ S <0.3 kPa	Surface: the lesser of a) fracture gradient pressure at surface casing shoe:	Surface: 0 kPa Fluids: 10 kPa/m
1.20 ³	Burst if 0.3 ≤ pp H₂S ≤10 kPa and pp CO₂ <u><</u> 2000 kPa	assume minimum 22 kPa/m (unless an actual value is supported by representative offset leak-off test [LOT]	
1.25 ³	Burst if pp H ₂ S >10 kPa	data), ² or b) maximum formation pressure (MFP) in the next hole section less a gas gradient (default is 0.85 ×	
1.25 ⁴ (<i>IRP Vol. 1</i> , sec. 4 material)	Burst if pp H ₂ S \geq 3500 kPa Note: pp H ₂ S based on maximum internal casing pressure at surface ²	MFP) ²	
1.75 – API connections	Buoyed load tension using the pressure x pipe body area method	Surface: 0 kPa Fluids: Mud density at casing point	Surface: 0 kPa Fluids: Mud density at
1.60 – Premium connections with internal metal to metal seals	(see appendix 6)	point	ousing point
1.60 – Pipe body yield strength			

3.2.1 Surface Casing

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 H₂S for selecting the casing minimum burst design factor.

³ Materials with specifications meeting or exceeding the requirements in appendix 2.

⁴ Materials with specifications meeting or exceeding the requirements in *IRP Volume 1*, section 4.

Minimum design factor	Load condition	Internal pressures/fluid	External pressures/fluid
1.0	Collapse	Surface: 0 kPa	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	Fluids: mud density at casing/liner setting depth ²
1.1	Burst if pp H ₂ S	Lesser of	Surface: 0 kPa
	<0.3 kPa	a) maximum formation pressure less gas gradient	Fluids: 10 kPa/m gradient
1.20 ³	Burst if	to any depth, ⁵ or	
	0.3 ≤ pp H₂S ≤10 kPa and pp CO₂ <u><</u> 2000 kPa	 b) fracture gradient pressure at the casing/liner shoe: assume minimum 22 kPa/m less gas gradient to surface, 	
1.25 ³	Burst if pp H₂S >10 kPa	or c) maximum formation pressure × 0.85 for wells with total depth >1800 m TVD, or	
1.25 ⁴ (<i>IRP Vol. 1</i> , Sec. 4 material)	Burst if pp H₂S ≥3500 kPa	d) maximum formation pressure × 0.90 for wells with total depth <u>≤</u> 1800 m TVD Fluids: Assumed gas gradient	
1.75 – API connections	Buoyed load tension using the	Surface: 0 kPa Fluids: Mud density at	Surface: 0 kPa Fluids: mud density at
1.60 – Premium connections with internal metal to metal seals	body area method (see appendix 6)	casing/liner setting depth	casing/liner setting depth
1.60 – Pipe body yield strength			

3.2.2 Protective Intermediate Casing / Protective Liner

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 2.

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 (figure 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.

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	Burst if pp H₂S <0.3 kPa	Surface: the lesser of a) maximum formation pressure less gas gradient to any depth ³	Surface: 0 kPa Fluids: the lesser of a) 10 kPa/m gradient,
1.20 ⁴	Burst if 0.3 ≤ pp H₂S ≤10 kPa and pp CO₂ <u><</u> 2000 kPa	 b) maximum formation pressure × 0.85 for wells with total depth > 1800 m TVD, or c) maximum formation pressure × 0.90 for wells with 	or b) known external pore pressure(s)
1.25 ⁴	Burst if pp H₂S >10 kPa	total depth ≤1800 m TVD and packer fluid column pressure gradient	external pressure gradient is balanced by the packer fluid gradient ⁶
1.25 ⁵ (IRP Vol. 1. Sec. 4 material)	Burst if pp H₂S <u>></u> 3500 kPa	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	
1.75 – API connections	Buoyed load tension using the pressure × pipe body area	Surface: 0 kPa Fluids: mud density at casing point	Surface: 0 kPa Fluids: mud density at casing point
1.60 - Premium connections with internal metal to metal seals	method (see appendix 6)		
1.60 – Pipe body yield strength			

3.2.3 Productive Intermediate Casing / Production Casing / Production Liner¹

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 2.

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 1 References

AER Publications

Directive 008: Surface Casing Depth Minimum Requirements Directive 009: Casing Cementing Minimum Requirements Directive 020: Well Abandonment Directive 034: Theory and Practice of the Testing of Gas Wells (3rd edition, 1975) Directive 036: Drilling Blowout Prevention Requirements and Procedures Directive 056: Energy Development Applications and Schedules Directive 087: Well Integrity Management Directive 089: Geothermal Resource Development Directive 090: Brine-Hosted Mineral Resource Development

Other Applicable Publications

Oil and Gas Conservation Act
Oil and Gas Conservation Rules
Geothermal Resource Development Act
Geothermal Resource Development Rules
Mineral Resource Development Act
Brine-Hosted Mineral Resource Development Rules
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 (DACC), Primary and Remedial Cementing Guidelines (April 1995)
National Association of Corrosion Engineers (NACE)
NACE MR0175/ISO 15156: Petroleum and natural gas industries—Materials for use in

H₂S-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)

API Recommended Practice 5C1: Recommended Practice for Care and Use of Casing and Tubing

API Bulletin 5C2: Performance Properties of Casing and Tubing

API Bulletin 5C3: Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties

API Specification 5CT/ISO 11960: Casing and Tubing

Appendix 2 Material Requirements for Sour Wells – Additional Constraints to API 5CT/ISO 11960

	H-40 or J-55	K-55	L-80 (Type 1)	C-90 (Type 1)	T-95 (Type 1)
С	0.35 ⁽⁴⁾	0.35 ⁽⁴⁾	0.32 ⁽⁷⁾	*	*
Mn	1.35 ⁽⁵⁾	1.35 ⁽⁵⁾	1.40 ⁽⁶⁾	*	*
Р	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

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

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%

Tempering Temperature Constraints

55) 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").

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.

Toughness Requirements (Charpy V-Notch)

56) *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 (°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)	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.

Box Expanded Connections

Manufacturer/finisher must ensure that the expanded box ends meet minimum *Directive 010* requirements.

57) Procedures pertaining to heat treatment and stress relief must be made available to the AER upon request.

Appendix 3 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 Standard TM0177
- IRP Volume 1
- certified NACE testing laboratory

Use of material requirements (appendix 2) will assist with the selection of appropriate materials based on partial pressures of H₂S and CO₂.

Appendix 4 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 factor	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 well	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 <i>API Bulletin 5C2</i> . 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 ₂ S content would have $(30\ 000\ \text{kPa} \times 0.03) = 900\ \text{kPa}$ pp H ₂ S.
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	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 <i>Directive 010</i> , 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 $\rm H_2S$.
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 5 Effects of Tensile Loading on Casing Collapse

Х	Y	х	Y	х	Y	Х	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	0.005	0.260	0.844	0.510	0.642	0.760	0 373
0.015	0.000	0.200	0.044	0.515	0.629	0.765	0.267
0.015	0.992	0.200	0.041	0.515	0.000	0.705	0.307
0.020	0.990	0.270	0.837	0.520	0.033	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
0.070	0.000	0.330	0.703	0.580	0.575	0.830	0.280
0.000	0.000	0.335	0.780	0.585	0.570	0.000	0.200
0.000	0.050	0.000	0.705	0.500	0.575	0.000	0.270
0.030	0.002	0.340	0.700	0.530	0.505	0.040	0.200
0.095	0.949	0.345	0.702	0.595	0.560	0.045	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 4 1 0	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	0.007	0.420	0.722	0.670	0.100	0.010	0.102
0.170	0.004	0.425	0.722	0.070	0.473	0.320	0.144
0.175	0.001	0.420	0.717	0.075	0.474	0.320	0.100
0.100	0.090	0.430	0.713	0.000	0.400	0.930	0.120
0.100	0.095	0.435	0.709	0.000	0.403	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



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

Appendix 6 Example of Alternative Design Method



Noncritical Sour Well Example

Surface Casing (340 mm OD @ 500 m)

Assumptions

								Next Hole S	ection	
Surface casing	1			339.7	mm OD			Sweet ?	Yes	
Minimum settir	ng depth (Directive 00	08)		462	m			H2S	0%	
Planned setting	g depth			500	m			CO2	0%	
Mud weight @	500 m			1100	kg/m³			Critical?	No	
Offset press in	tegrity test (PIT) @	5	500 m =	22	kPa/m			Required M	inimum De	esign Factors
Next casing de	epth (m TVD)			2,500	m				Alternate	Simplified
Next casing se	ction mud weight			1200	kg/m³			Collapse	1.00	1.00
Max BH pressu	ure prior to next csg d	lepth		29,400	kPa			Burst	1.10	1.00
(MW x Depth :	x 0.00981)							Tension (air)		1.60
Est max pore p	oressure			28,000	kPa		Ter	nsion (buoyed)	1.75	
Gas gradient				1.80	kPa/m					
Load Calcula	ations									
	1) Collapse @		500 m =	MW x Dept	th x 0.00981 =	5,400) kPa			
	2) Burst @ Surface									
	, .	a) Fra	ac Press (@ Csg Sho	be =	22 kPa/m x	500 m =	11,000	kPa	
						(Minimum Valu	ue)			
		b) Su	urface Pre	ssure = Ma	ax Pore Press - 0	Gas Gradient x (Casing Depth			
						= 28,000) kPa -	4,500	kPa =	23,500 kPa
					accor of a) or b)	- 11.000	k Po			
				Use Le	esser of a) of b)	= 11,000	Лкра			
	3) From API 5C2 Se	lect	339.7	mm OD,	81.10 kg/m,	K55,	ST&C	Casing		
	С	ollapse F	Rating =	7,800	kPa	В	urst Rating =	18,800	kPa	
		Joint Str	rength =	243,300	daN		Pipe Area =	10,008	mm²	
	Pipe	Body Str	rength =	379,400	daN	(•	cross section)	0.0100	m²	
	Tensile Loads									
		a)	Tensic	on Force =	50	0 m				
				х	81.1	0 kg/m				
				х	<u>9.8</u>	<u>1</u>				
				=	397,77	5 Nor	39,778	daN		
				_			(Weight In A	Air)		
		b) Co	ompressiv	/e Force =	50) m				
				х	110	0 kg/m³				
				х	9.8	1 N/Kg				
				х	0.010	<u>)</u> m²	5 400			
				=	54,000	JNOr	5,400	daN		
			Net Tene	ila Faraa -	207 77	2 11	(Buoyancy)			
		C)	Net rens	lie Force =	597,770					
				less	54,00	<u>J</u> IN				
					343,770	6 Nor	34,378	daN		
		1							1	
	339.7 mm OI	D, (Calculate	d Loads	Tubular	г	Design Facto	rs		
5)	81.1 kg/m, Ks	55 Al	t Desian	Simpl.	Rating	Alt Design	Simpl.	Minimum		
-,	ST&C		(A)	(B)	(C)	(C) / (A)	(C) / (B)	Required		
			\ /	1 - /	(-)		<u> </u>	1	1	
	Collapse (kPa	a)	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	х	1.10	I	
									I	
	Tension (daN	I)		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.

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

	Ass	um	ptio	ns
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Assumptions	<u>.</u>							
						Next Hole S	ection	
Protective inte	ermediate casing		244.5	mm OD		Sweet ?	No	Partial Pressure
Setting depth	(m TVD)		2,500	m		H2S	1.5%	660 kPa
Mud weight @	2,500 m		1,200	kg/m³		CO2	2.0%	880 kPa
				-		Critical?	No	
						Material requ	irements a	s per Appendix B
Next casing de	epth (m TVD)		3,600	m				
Next casing se	ection mud weight		1,300	kg/m³				
Max BH press	ure prior to next csg depth		45,900	kPa		Required Mi	inimum De	sign Factors
(MW x Depth	x 0.00981)		-			•	Alternate	Simplified
Producing zon	e depth		3,500	m		Collapse	1.00	1.00
Est max forma	ation pressure		44,000	kPa		Burst	1.25	1.15
Gas gradient			2.0	kPa/m		Tension (air)		1.60
(Based on ga	s composition)				Ten	sion (buoved)	1.75	
Anticipated pa	cker fluid density		1.000	kg/m³		() /		
Anticipated fra	acture gradient at shoe @	2,500 m =	22	kPa/m				
Load Calcula	tions							
1a) Ex	ternal Collapse Load @ (1/2 TVD of next csg)	1,800	m = MW :	x Depth x 0.00981 =	21,200	kPa		
b)	Internal Collapse Load @	1,800 m =	0	kPa				
c)	Net Collapse Load @ (External less Internal)	1,800 m =	21,200	kPa				

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.

3)

4)

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

а)	Surface Press	ure = BHP - =	(Gas Gradient x I 44,000 kPa - (Production 2 kPa/m	Zone Depth) x 3,500	m) =	37,000 kPa
b)		44,000	kPa x 0.85 =	37,40	0 kPa	(Use if Gas	Gradient unknown & TD > 1800 mTVD)
		Choose a)	37,000	kPa	(Lesser of (a	a), or (b))	
From API 5C2 Select	244.5	mm OD	69.94 kg/m,	L80	LT&C	Casing	
Colla	apse Rating =	32,700	kPa	I	Burst Rating =	47,400	kPa
Jo Pipe Bo	int Strength = dy Strength =	397,200 483,100	daN daN		Pipe Area = (cross section)	8,756 0.00876	mm² m²
Tensile Loads a)	Tens	ion Force = x x	2,500 69.94 9.81	m kg/m			
		=	1,715,279	N or	171,528	daN	
b)	Compress	ive Force = x x	2,500 1200 9.81	m kg/m³			
		x =	<u>0.00876</u> 257,692	m² N or	25,769	daN	
c)	Net Ten	sile Force = less	1,715,279 257,692	N N			
			1,457,586	N or	145,759	daN	
244.5 mm OD, 69.94 kg/m, L80 LT&C	Calculate Alt Design	d Loads Simpl.	Tubular Rating	Alt Desig	Design Factor n Simpl.	rs Minimum Required	
Collapse (kPa)	21,200	29,430	32,700	1.54	1.11	1.00	
Burst (kPa)	37,000	44,000	47,400	x 1.28	1.08 x	1.15 1.25	
Tension (daN)	145,800	171,500	397,200	x 2.72	2.32 x	1.60 1.75	

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

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

Assumptions

							Next Hole	Section			
Production of	casing		177.8	8 mm OD			Sweet ?	No	Partial Pro	essure	
Setting dept	h		3,600	m			H2S	1.5%	660	kPa	
Casing top			C) m			CO2	2%	880	kPa	
Mud weight	@ 3,600 m		1,300	kg/m³			Critical?	No			
Assumed ex	kternal backup fluid grad	dient	10) kPa/m			Material rec	quirements a	as per App	endix B	
							Material as	per IRP Vol	lume 1, Se	ction 4	
Next casing	depth		N/A	m							
Next casing	section mud weight		N/A	kg/m³			Required N	Minimum D	esign Fact	tors	
Max BH pres	ssure prior to next csg of	depth	N/A	kPa				Alternate	Simplified	1	
(MW x Dep	th x 0.00981)						Collapse	1.00	1.00		
Producing zo	one depth		3,500	m			Burst	1.25	1.15		
Est max forr	mation pressure		44,000	kPa		1	Fension (air)		1.60		
Gas gradien	nt		2.0	kPa/m		Tensi	on (buoyed)	1.75			
(Based on g	gas composition)		4.040								
Anticipated p	packer fluid density		1,040	kg/m³							
			10.20) kPa/m							
Load Calcu	llations										
1) (2 600	m - MM/	v Donth v O	00001 -	45 000	kDo				
1) (Collapse @	3,600	m = ww	x Depin x U	.00981 =	45,900	кра				
2) 6	Buret										
2) L	a) Surface	Prossura -		as Gradient v	Production	Zone Denth))					
	a) Surface	= (44 000	kPa - (2 0 kPa/r	2010 Deptil))	m))=	37 000	kPa		
		- (44,000	Ki a - (2.0 11 4/1	11 X 0,000	,) –	07,000	Να		
	b) Surface	Pressure =	(BHP * 0.8	5)							
	s) canace		=	44.000	kPa x 0.8	5 = 37.400	kPa	(Use if Ga	s Gradient	unknown & TD > 1800	mTVD)
				,		,		、 -			,
F	Packer Depth	BHP - (Gas	gradient *D	Depth) + (Pack	er Fluid Gr	adient * Depth)	- (Water gra	adient * Dep	th)	(Depth = 3500 m)	
			=	37,708	kPa				,		
			Use	: 37,708	kPa						
3) F	From API 5C2 Select	177.8	mm OD,	43.15 kg/m,	L80	LT&C	Casing				
	Collaps	se Rating =	48,500	kPa		Burst Rating =	56,300	kPa			
		<u>.</u>	004 400			D : 4		2			
	Joint	Strength =	261,100) daN		Pipe Area =	5,451	mm²			
	Pipe Body	Strength =	300,700) daN		(cross section)	0.00545	m²			
4) 7	Tanaila Laada										
4) 1	rensile Loads	Tanai		2 600							
	a)	Iensi	on Force =	3,600	m Lun (m						
			X	43.15	s kg/m						
			×	4 500 050	- N	150 206	deN				
			-	1,525,950	IN OF	152,590	uan				
	b)	Compressi	ve Force -	3 600	m						
	5)	Compressi	ve i oice -	/ 1300	ka/m ³						
			Ŷ	v 9.81	rg/m						
			· · · · · · · · · · · · · · · · · · ·	0 00545	m ²						
			=	250 258	Nor	25 026	daN				
				200,200		20,020					
	c)	Net Tens	sile Force =	1,523,956	Ν						
	,		less	250,258	Ν						
				1,273.698	N or	127.370	daN				
				,,							
Г								1			
	177.8 mm OD,	Calculate	ed Loads	Tubular		Design Factor	s				
4	43.15 kg/m, L80 LT&C	Alt Design	Simpl.	Rating	Alt Desig	gn Simpl.	Minimum				
		(A)	(B)	(C)	(C) / (A	A) (C) / (B)	Required	J			
Г								1			
	Collapse (kPa)	45,900	45,900	48,500	1.06	1.06	1.00				

 127,370

 Therefore, the pipe selected in this example is acceptable.

37,708

44,000

152,396

56,300

261,100

Burst (kPa)

Tension (daN)

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

х

1.49

x 2.05 1.28

х

1.71

х

1.15

1.25 1.60

1.75