Production Casing Design Considerations

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Agenda

- Introduction
- Casing Design Factors
- Casing Design Loads
- Pipe Performance
- Materials Selection
- Casing Connections
- Stimulation

Introduction

Three Major Responsibilities when Performing Casing and Tubing Design:

- Ensure the well’s mechanical integrity.
- Optimize well costs.
- Provide operations personnel with maximum allowable loads.

Info Needed for Casing Design

- Mud weights
- Formation pressures
- Frack gradients
- Casing seats
- Casing sizes
- Directional plans
- Cement program
- Temperature profiles
- Base frack fluid, proppant type, and max proppant concentration
- Max anticipated frack surface pressure
- Produced fluid composition

Casing Design Factors

Load Cases

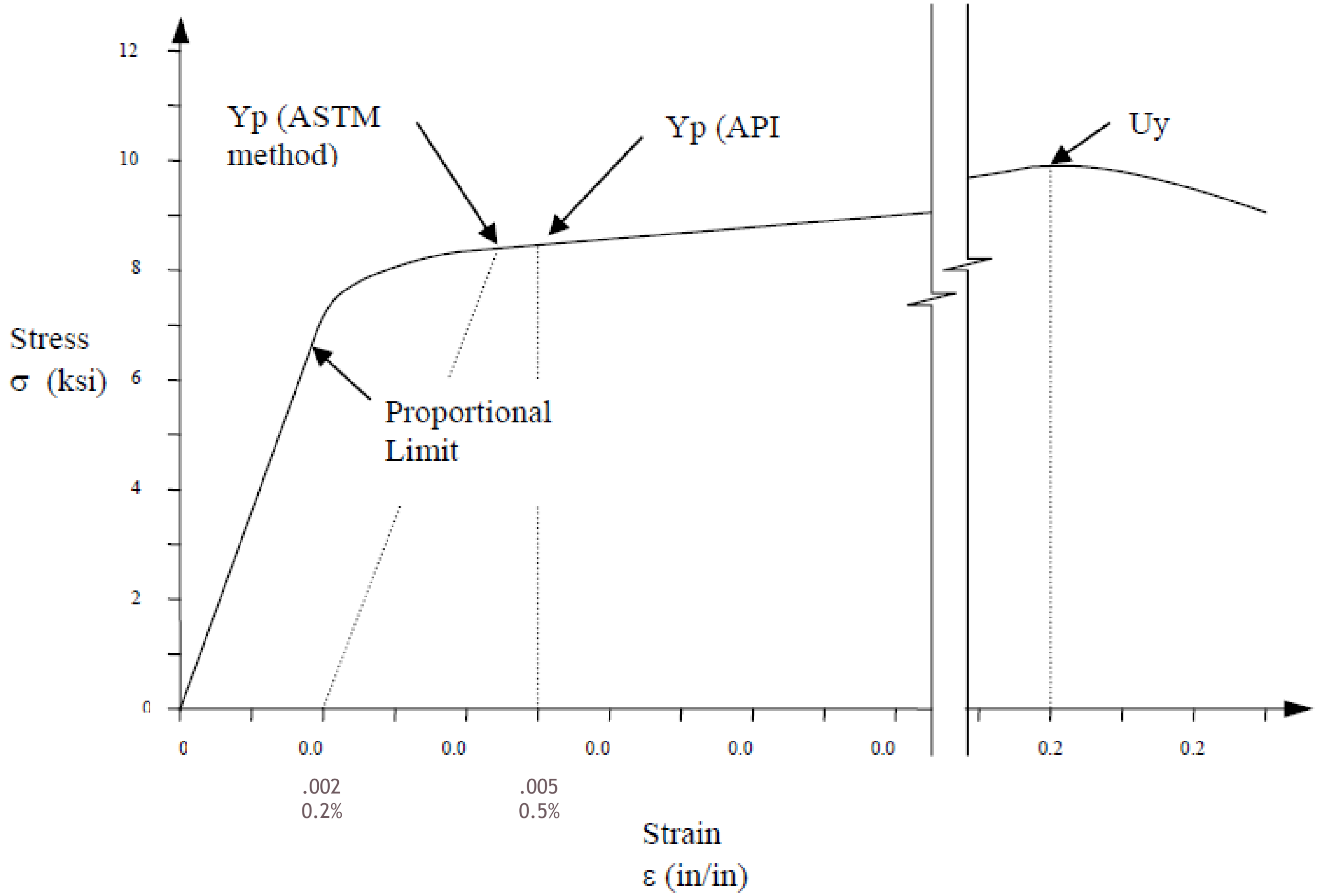
- Dividing the pipe rating by a corresponding load results in a design factor. If the design factor is greater than the minimum acceptable design factor, then the pipe is acceptable for use with that load.

$$\mathrm{DF} = \frac{\text{pipe rating}}{\text{planned load}} \geq \mathrm{DF}_{\min}$$

Devon Minimum Casing Design Factors

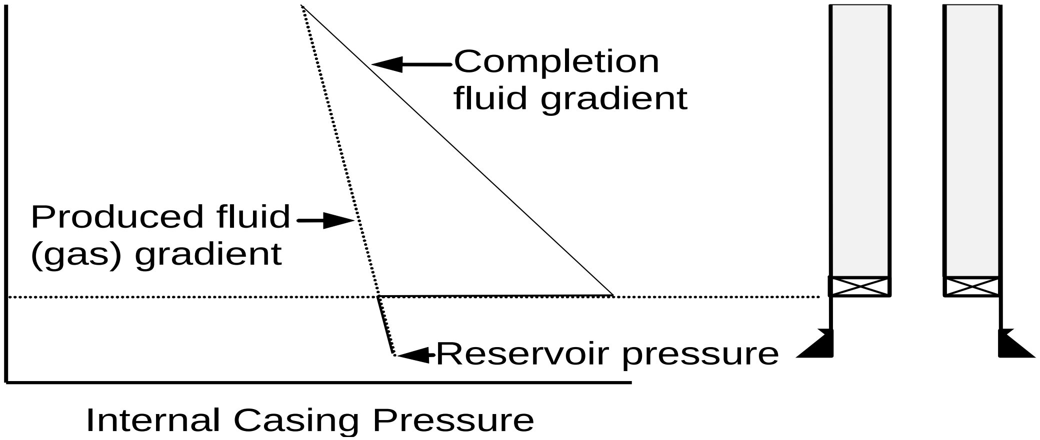
Internal Yield (Burst)	1.25	(1.1 if SICP < 5,000 psi)
Collapse	1.1	
Tension	1.4	Based on yield strength
Compression	1.2	
Von Mises Triaxial	1.25	

Yield Strength vs Ultimate Strength



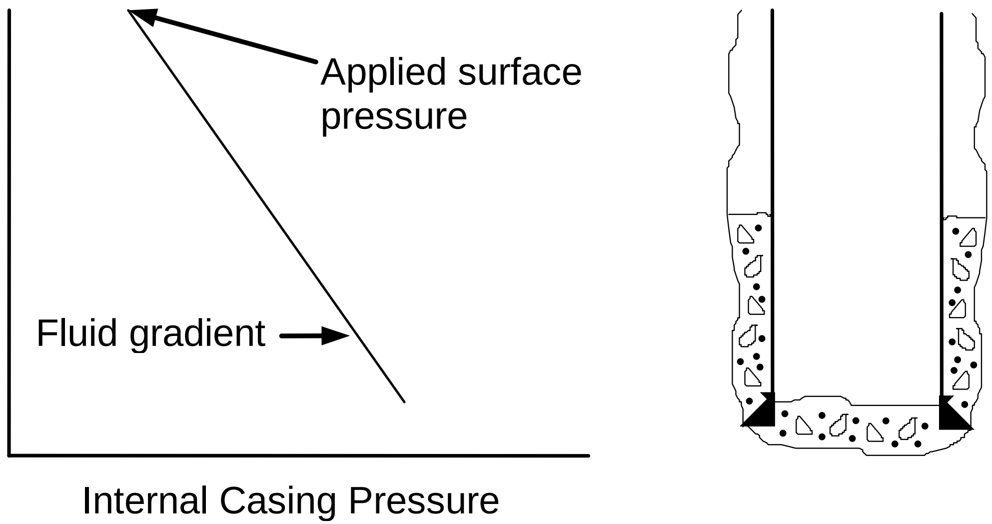
Casing Design Loads

Tubing Leak



- This load case represents a high surface pressure on top of the completion fluid created by a tubing leak near the surface. Surface pressure is based on a gas gradient extending upward from the reservoir. Tubing leaks are evaluated with both static and flowing temperature profiles.

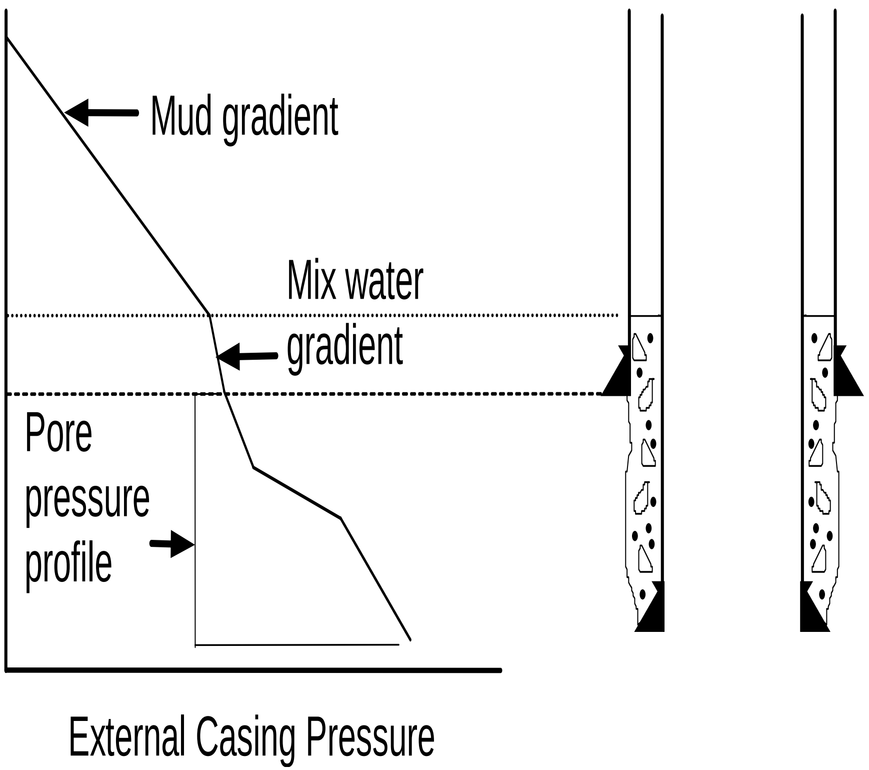
Injection Down Casing



- This load case applies to wells that experience high pressure injection operations such as a fracing down casing. The load case models a surface pressure applied to a static fluid column. This is analogous to a screen-out during a frac job.

External Pressure Profile for Burst Cases

- The external pressure profile used for the standard burst load cases:
- Full mud gradient or deteriorated mud from the surface to the TOC.
- Cement mix-water gradient from the TOC to the outer casing shoe (typically 8.3 to 8.6 ppg).
- Pore pressure profile from the outer casing shoe to the base of the production casing.



Production Casing Collapse Loads

- **Full Evacuation**
  - This load case applies to severely depleted reservoirs or a large drawdown due to low permeability or plugged perforations.
  - It assumes zero pressure on the inside of the pipe (such as fill over perfs and the well pressure blown down).
  - The external pressure used is the mud gradient from surface to the casing bottom.

Pipe Performance

Internal Yield Strength

- Internal yield pressure is calculated from the Barlow Equation per API Bulletin 5C3

- $P = 0.875 * [2*Y_p*T]/D$

- P= Internal yield pressure (psi)
- Y_p = Yield strength of the pipe (example P110 is 110,000 psi)
- T = nominal wall thickness (inches)
- D = nominal OD of pipe (inches)

- Per API the calculated number is rounded to the nearest 10 psi.

- The 0.875 factor represents the allowable manufacturer's tolerance of minus 12.5% on wall thickness per API specifications.

Internal Yield Strength Example Calculation

- 5.5” 23# P110 pipe has an ID of 4.67”
- wall thickness = [5.500 - 4.670] / 2 = 0.415 inches
- $P = 0.875 * [2*Y_p*T]/D$
- P = 0.875 * [2 * 110,000 * 0.415] / 5.5 = 14,525 $\simeq$ 14,520 psi
- Internal yield strength per cement manual = 14,520 psi

Collapse Pressure Calculation

- Is based on four different equations based on the D/t ratio and the yield strength of the pipe
- Plastic collapse is based on a statistical regression analysis on empirical data from 2488 tests
- More information is in API Bulletin 5C3

Axial Strength (Pipe Body)

- Axial strength of pipe body is calculated from the formula below:

- $F_y = (\pi/4) * (D^2 - d^2)\ Y_p$

- F_y = Tension strength (lbs. rounded to the nearest 1,000)
- Y_p = Yield strength of pipe (psi)
- D = OD of pipe (inches)
- d = ID of pipe (inches)

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Joint Strength of Connection

- Calculations for joint strength of different API connections is found in API Bulletin 5C3.
- Joint strength of API connections is based on the ultimate strength and not the yield strength.
- Most (but not all) premium or proprietary connections are based on the yield strength of the connection.

Materials Selection

API Spec 5CT

Specification for Casing and Tubing

API Specification 5CT
Eighth Edition, July 1, 2005

ISO 11960:2004, Petroleum and natural gas industries—Steel pipes for use as casing or tubing for wells

EFFECTIVE DATE: JANUARY 1, 2006

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Mechanical Properties

API Specification 5CT / ISO 11960

Table E.6 — Tensile and hardness requirements

Group	Grade	Type	Total elongation under load	Yield strength ksi		Tensile strength min.	Hardness [a] max.		Specified wall thickness	Allowable hardness variation [b]
			%	min.	max.	ksi	HRC	HBW	in	HRC
1	2	3	4	5	6	7	8	9	10	11
1	H40	—	0.5	40	80	60	—	—	—	—
	J55	—	0.5	55	80	75	—	—	—	—
	K55	—	0.5	55	80	95	—	—	—	—
	N80	1	0.5	80	110	100	—	—	—	—
	N80	Q	0.5	80	110	100	—	—	—	—
2	M65	—	0.5	65	85	85	22	235	—	—
	L80	1	0.5	80	95	95	23	241	—	—
	L80	9Cr	0.5	80	95	95	23	241	—	—
	L80	13Cr	0.5	80	95	95	23	241	—	—
	C90	1, 2	0.5	90	105	100	25.4	255	⩽ 0.500	3.0
	C90	1, 2	0.5	90	105	100	25.4	255	0.501 to 0.749	4.0
	C90	1, 2	0.5	90	105	100	25.4	255	0.750 to 0.999	5.0
	C90	1, 2	0.5	90	105	100	25.4	255	⩾ 1.000	6.0
	C95	—	0.5	95	110	105	—	—	—	—
	T95	1, 2	0.5	95	110	105	25.4	255	⩽ 0.500	3.0
	T95	1, 2	0.5	95	110	105	25.4	255	0.501 to 0.749	4.0
	T95	1, 2	0.5	95	110	105	25.4	255	0.750 to 0.999	5.0
	T95	1, 2	0.5	95	110	105	25.4	255	⩾ 1.000	6.0
3	P110	—	0.6	110	140	125	—	—	—	—
4	Q125	—	0.65	125	150	135	b	—	⩽ 0.500	3.0
	Q125	—	0.65	125	150	135	b	—	0.501 to 0.749	4.0
	Q125	—	0.65	125	150	135	b	—	⩾ 0.750	5.0

[a] In case of dispute, laboratory Rockwell C hardness testing shall be used as the referee method.

[b] No hardness limits are specified, but the maximum variation is restricted as a manufacturing control in accordance with 7.8 and 7.9.

Chemical Requirements

API Specification 5CT / ISO 11960

Table E.5 — Chemical composition, mass fraction (%)

Group	Grade	Type	C		Mn		Mo		Cr		Ni	Cu	P	S	Si
			min.	max.	min.	max.	min.	max.	min.	max.	max.	max.	max.	max.	max.
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*
1	H40	—	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
	J55	—	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
	K55	—	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
	N80	1	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
	N80	Q	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
2	M65	—	—	—	—	—	—	—	—	—	—	—	0.030	0.030	—
	L80	1	—	0.43 [a]	—	1.90	—	—	—	—	0.25	0.35	0.030	0.030	0.45
	L80	9Cr	—	0.15	0.30	0.60	0.90	1.10	8.00	10.0	0.50	0.25	0.020	0.010	1.00
	L80	13Cr	0.15	0.22	0.25	1.00	—	—	12.0	14.0	0.50	0.25	0.020	0.010	1.00
	C90	1	—	0.35	—	1.20	0.25 [b]	0.85	—	1.50	0.99	—	0.020	0.010	—
	C90	2	—	0.50	—	1.90	—	NL	—	NL	0.99	—	0.030	0.010	—
	C95	—	—	0.45 [c]	—	1.90	—	—	—	—	—	—	0.030	0.030	0.45
	T95	1	—	0.35	—	1.20	0.25 [d]	0.85	0.40	1.50	0.99	—	0.020	0.010	—
	T95	2	—	0.50	—	1.90	—	—	—	—	0.99	—	0.030	0.010	—
3	P110	[e]	—	—	—	—	—	—	—	—	—	—	0.030 [e]	0.030 [e]	—
4	Q125	1	—	0.35		1.35	—	0.85	—	1.50	0.99	—	0.020	0.010	—
	Q125	2	—	0.35	—	1.00	—	NL	—	NL	0.99	—	0.020	0.020	—
	Q125	3	—	0.50	—	1.90	—	NL	—	NL	0.99	—	0.030	0.010	—
	Q125	4	—	0.50	—	1.90	—	NL	—	NL	0.99	—	0.030	0.020	—

a The carbon content for L80 may be increased up to 0.50 % max. if the product is oil-quenched.

b The molybdenum content for Grade C90 Type 1 has no minimum tolerance if the wall thickness is less than 0.700 in.

c The carbon content for C95 may be increased up to 0.55 % max. if the product is oil-quenched.

d The molybdenum content for T95 Type 1 may be decreased to 0.15 % min. if the wall thickness is less than 0.700 in.

e For EW Grade P110, the phosphorus content shall be 0.020 % max. and the sulfur content 0.010 % max.

NL = no limit. Elements shown shall be reported in product analysis.

Definition of Sour Service per NACE MR0175 / ISO 15156

- H_2S exceeds 0.05 psia partial pressure
- Partial pressure = (ppm H_2S)*(well pressure)/1,000,000
- Total pressure exceeds 65 psia for a gas well or 265 psi for an oil well

Selecting Tubulars for Sour Service (per NACE MR0175)

Table A.3 — Environmental conditions for which grades of casing and tubing are acceptable

For all temperatures	For ≥ 65 °C (150 °F)	For ≥ 80 °C (175 °F)	For ≥ 107 °C (225 °F)
ISO 11960[a] grades: H40 J55 K55 M65 L80 type 1 C90 type 1 T95 type 1	ISO 11960[a] grades: N80 type Q C95	ISO 11960[a] grades: N80 P110	ISO 11960[a] grade: Q125[b]
Proprietary grades as described in A.2.2.3.3	Proprietary Q & T grades with 760 MPa (110 ksi) or less maximum yield strength Casings and tubulars made of Cr-Mo low alloy steels as described in A.2.2.3.2.	Proprietary Q & T grades with 965 MPa (140 ksi) or less maximum yield strength	

Temperatures given are minimum allowable service temperatures with respect to SSC.

Low temperature toughness (impact resistance) is not considered, equipment users shall determine requirements separately.

a For the purposes of this provision, API 5CT is equivalent to ISO 11960:2001.

b Types 1 and 2 based on Q & T, Cr-Mo chemistry to 1 036 MPa (150 ksi) maximum yield strength. C-Mn steels are not acceptable.

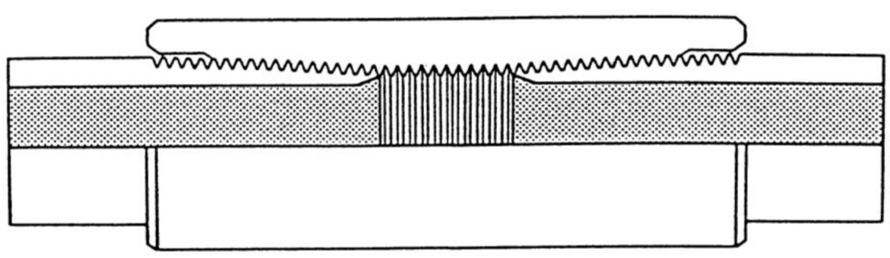
Casing Connections

Connections

- Connections represent less than 3% of the pipe length
- More than 90% of pipe failures occur in the connection
- Connections represent 10%-50% of the total tubular costs

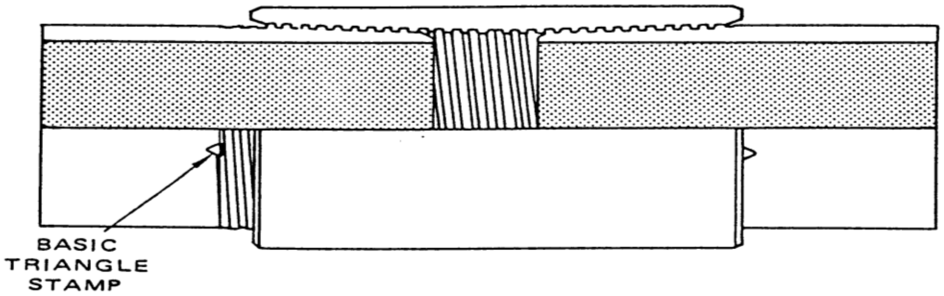
API Connections

- STC
  - 8 threads per inch
  - Threads have rounded crests and roots
- LTC –
  - 8 threads per inch
  - Threads have rounded crests and roots
  - Thread section is longer so has better sealability and tensile strength than STC



API Connections

- Buttress
  - 5 threads per inch
  - Not symmetric for the load and stab flanks



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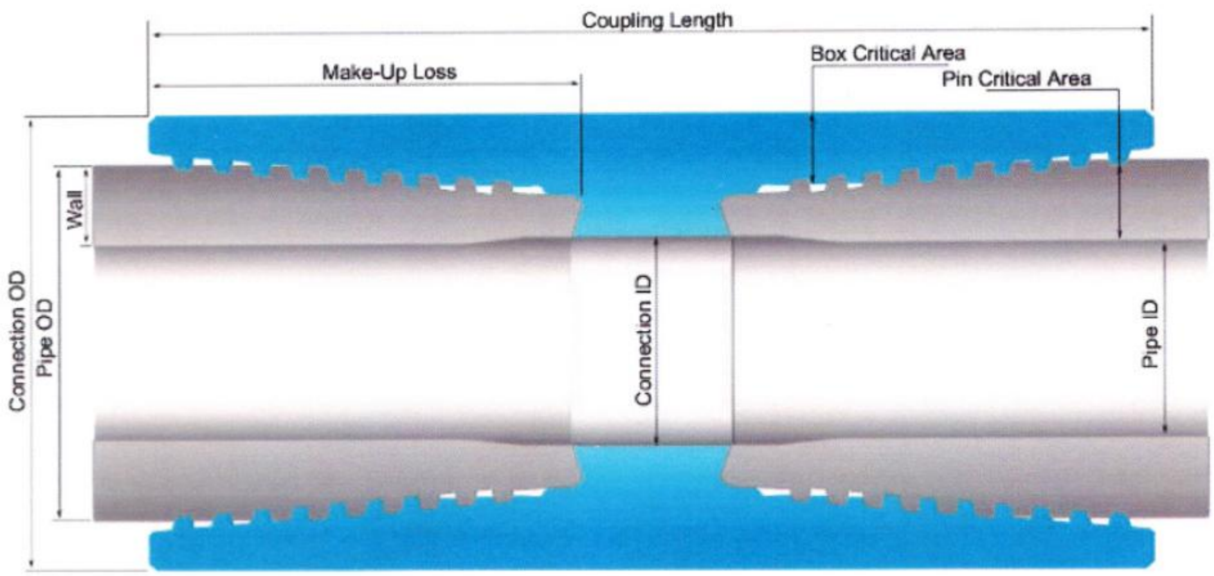
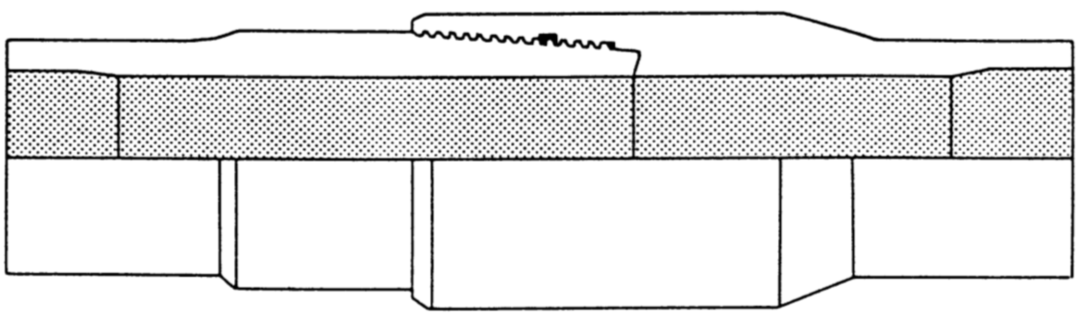
Metal-to-Metal Seal Thread and Coupled (MTC)

- Generally have burst, collapse, and tension ratings equal to the pipe body



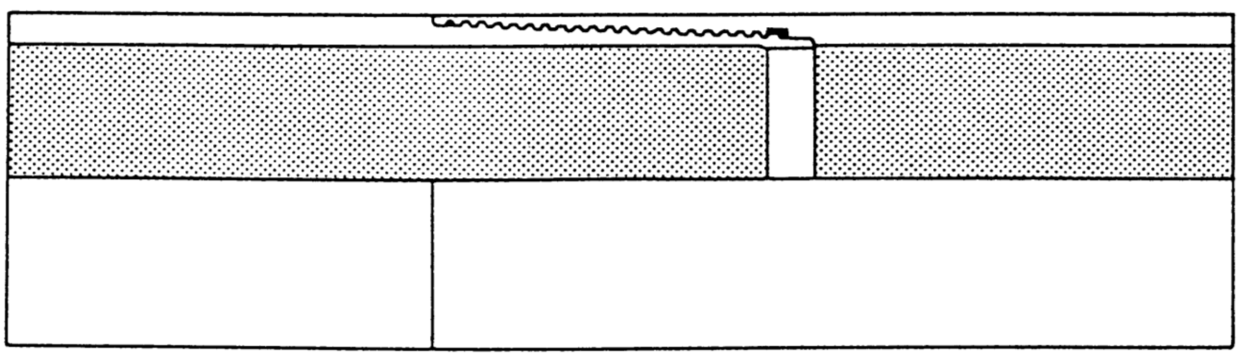
Integral Joint Connection (IJ)

- Half the leak paths of thread and coupled connections
- Connection OD significantly smaller than coupled connections
- 70 to 80% of pipe body strength in tension



Flush Joint Connection (FJ)

- Connection OD is same (within 2%) as pipe body
- 45 to 60% of pipe body strength in tension



Tensile Strength of Connections

- Joint strength of API connections is based on ultimate strength
- Most (but not all) premium connections are based on yield strength

Stimulation

Stimulation Considerations

- Design for screen out conditions at maximum sand concentration
  - (max pressure at max sand concentration)

- Cooling affects tension

- Ballooning from internal frack pressure affects tension

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Thank You.

Production Casing Design Considerations

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The statements made during the workshop do not represent the views or opinions of EPA. The claims made by participants have not been verified or endorsed by EPA.

This abstract presents information to consider in the design of a safe and effective production casing string for well production and also as a conduit for a fracture stimulation. The presentation discusses casing design factors and casing design loads. Pipe performance is discussed as well as material selection. A description of the various types of casing connections is given. Also, additional considerations that should be addressed if the well will be hydraulically fractured down casing are discussed.

There are three major requirements to be considered in designing production casing:

1) Ensure the well's mechanical integrity
2) Optimize well costs
3) Provide operations personnel with the maximum allowable loads

Many factors enter into the production casing design. These include the mud weights required to drill the well and balance the formation pressures, the fracture gradients, casing seat depths, casing sizes, the directional plan, the cement program and the temperature profiles. Also, the type of fracture fluid and proppant to be used, maximum proppant concentration, and the calculation for the maximum anticipated hydraulic fracture surface pressure should be considered. The types, composition, and volumes of the anticipated production must also be considered. This information is used to determine the planned loads over the life of the well.

Once these expected loads are determined, the pipe selection can be made that will meet or exceed the minimum design factors required by the designer. The design factor is the pipe rating divided by the anticipated load. This design factor must meet or exceed the minimum design factor that the designer has set. Most pipe ratings are based on the yield strength of the pipe. To determine the yield strength of a given material, a specimen is machined and put into a load cell where tension is pulled and the strain measured on the sample until it fails. A stress-strain curve is then generated. The yield strength using the API method is defined as the stress at a strain of 0.5% elongation. This yield strength is less than the ultimate strength of the sample.

There are two main design cases for internal yield pressure of production casing. One is modeled with a tubing leak near the surface with the shut-in tubing pressure added to the packer fluid weight as an internal load. The shut-in tubing pressure is estimated from the bottom hole pressure minus the weight of the gas in the tubing. The weight of the gas in the tubing is calculated both at static and at flowing temperatures (sometimes called a hot shut-in)

The other internal yield pressure case is injection down casing such as during a hydraulic fracture stimulation. The internal pressure is modeled by the applied surface pressure and the fluid gradient based on the fluid being pumped. This is analogous to a hydraulic fracture screen-out downhole since fluid friction down the casing is not subtracted from the internal pressure profile. The external casing pressure profile is modeled with the mud gradient from surface to the top of cement. Then the gradient from the cement mix water from that point to the outer casing shoe. From the outer casing shoe to total depth (TD), the external pressure profile is the pore pressure profile.

Production casing collapse loads assumes zero pressure on the inside of the pipe and a final mud weight gradient on the outside of the casing.

Rated internal yield pressure of casing is calculated using the Barlow Equation below:

- $P = 0.875 * [2*Yp*T]/D$
- P= internal yield pressure or burst strength (psi)
- Yp = yield strength of the pipe (example P110 is 110,000 psi)
- T = nominal wall thickness (inches)
- D = nominal outer diameter of pipe (inches)

Per API, the calculated number is rounded to the nearest 10 psi. The 0.875 factor in the above equation represents the allowable manufacturer's tolerance of minus 12.5% on wall thickness per API specifications.

Collapse ratings on API tubulars are derived from four different equations based on the outside diameter / thickness ratio and the yield strength of the pipe.

Axial strength of the pipe body is calculated from the formula below:

- $Fy = (\pi/4) * (D2 - d2)\ Yp$
- Fy = tension strength (lbs. rounded to the nearest 1,000)
- Yp = yield strength of pipe (psi)
- D = OD of pipe (inches)
- d = ID of pipe (inches)

Calculations for joint strength can be found in API bulletin 5C3. Published joint strength of API connections is based on the ultimate strength of the pipe and not the yield strength. Most, but not all premium connections are based on the yield strength of the connection.

API Spec 5CT is the Specification for Casing and Tubing. The different grades of API pipe specify a minimum and maximum yield strength. A maximum hardness is also specified from grades designed for sour service.

The chemical composition of the different grades of API casing is also specified. Grades designed to work in sour service have more stringent chemical requirements.

Sour service is defined by the National Association of Corrosion Engineers or NACE, as an environment where the partial pressure of H_2S exceed 0.05 psia. The total pressure must also exceed 65 psia for a gas well and 265 psia for an oil well. The NACE standard MR0175 and the ISO standard 15156 specify material to be used in sour service. In summary, API casing grades H40, J55, K55, M65, L80, C90 and T95 are good for all temperatures. N80 is good above 150 degrees F, P110 is good above 175 degrees F and Q125 is good above 225 degrees F.

Casing connections represent less than 3% of the pipe length yet account for more than 90% of pipe failures. Also, the connection represents 10% to 50% of the total tubular cost.

API connections STC (short thread and coupled) and LTC (long thread and coupled) each have 8 threads per inch and have rounded crests and roots. On LTC, the tread section is longer so it will have better sealability and tensile strength than STC.

A buttress connection is another API connection that has 5 threads per inch. It is not symmetric for the load and stab flanks.

There are several types of premium connections available, but most fall into one of the following categories:

A metal to metal seal thread and coupled connection generally has the internal yield, collapse, and tension ratings equal to the pipe body.

An integral joint connection has half the leak paths of thread and coupled connections. Also, the connection outer diameter (OD) is significantly smaller than a coupled connection. It also features a metal to metal seal. The joint strength of an integral joint connection is usually 70 to 80% of the pipe body.

A flush joint connection is approximately the same OD as the pipe body. Its joint strength is usually only 45 to 60 % of the pipe body strength in tension.

Prior to the hydraulic fracturing of a well, the maximum allowable surface fracture pressure must be calculated. The fluid gradients inside and outside the pipe are needed to make this calculation. Not only must the burst (internal yield) pressure of the pipe be considered when making this calculation but also the effect of the internal hydraulic fracturing pressure and hydraulic fracture injection rate on tension. The internal pressure during the hydraulic fracture causes a ballooning effect on the production casing that adds to the tension load. During the fracture, the production casing is cooled[2] by the injection of fracture fluids, which also adds to

[2] Fracture fluids stored at the surface will be near surface temperature, which is generally a much cooler temperature than the bottom hole temperature.

the tension load of the production casing. These additional tension loads must be taken into consideration when determining the maximum allowable hydraulic fracture pressure.