Directional Drilling Introduction

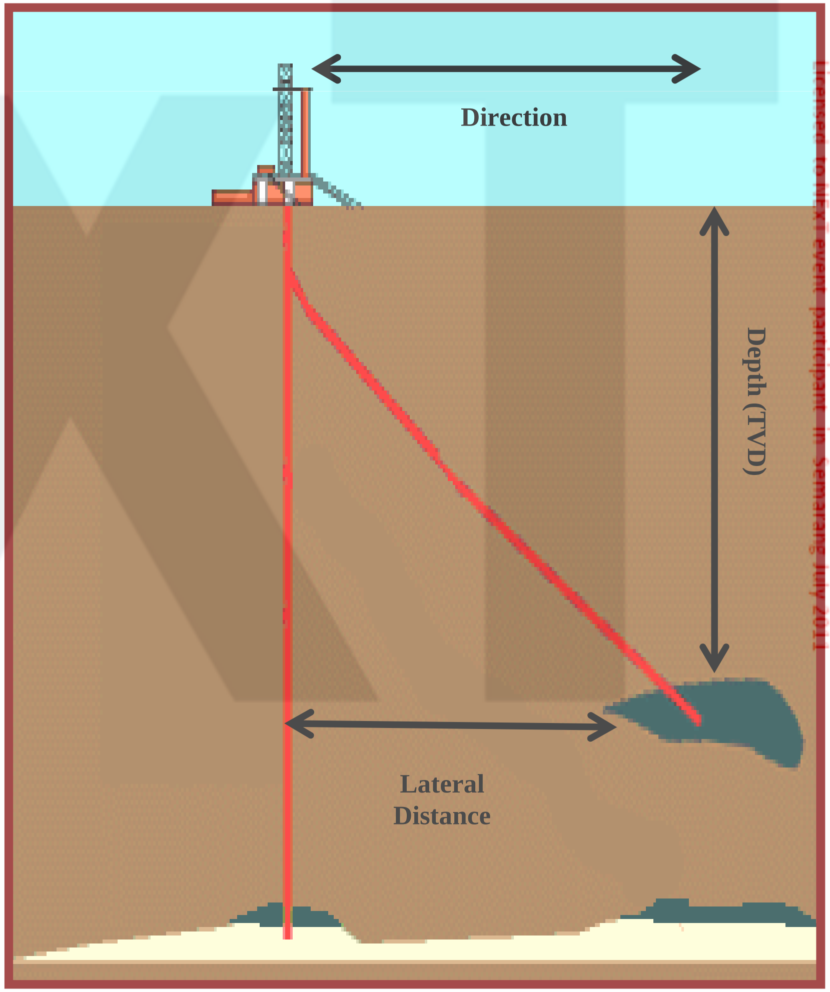
Outline of Directional Drilling Course

- Introduction
- General Terminology
- Coordinate Systems
- Surveying (including MWD)
- Well Plots
- Pathway Design
- Buoyancy and Drillstring Weight Calculations
- BHA Design Considerations
- Drillstring Design Matters
- Well Cleaning Considerations

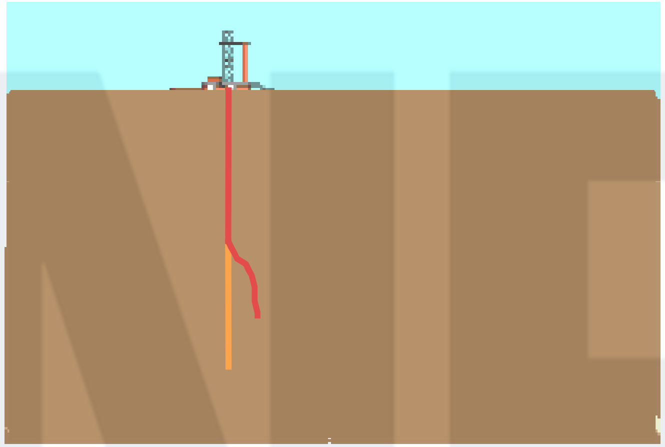
Directional Drilling

Introduction;

- Directional Drilling is the science of deviating a well bore along a planned course to a subsurface target whose location is a given lateral distance, depth and direction from the surface.



Applications of Directional Drilling



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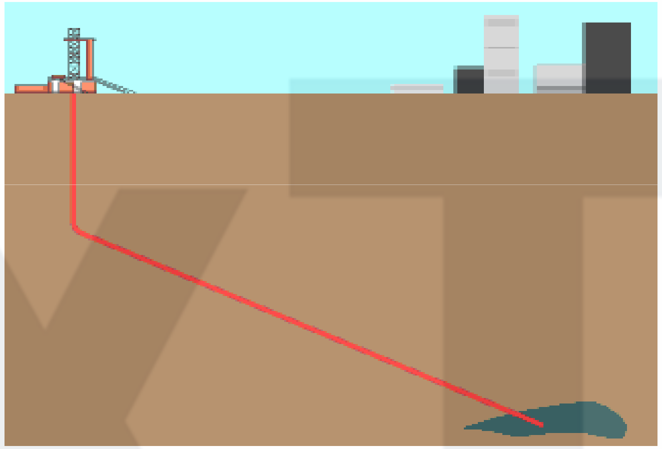
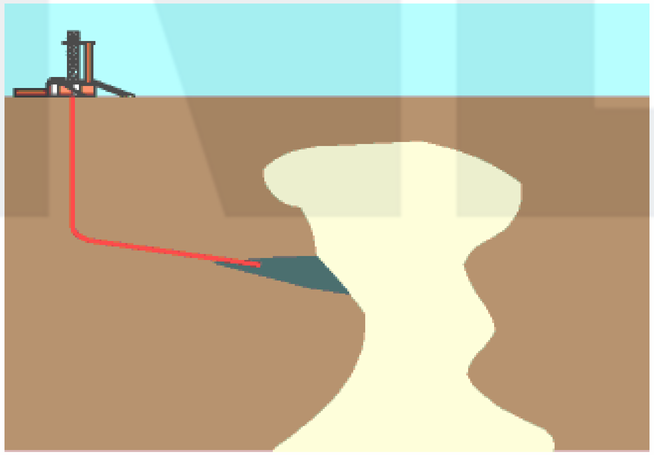
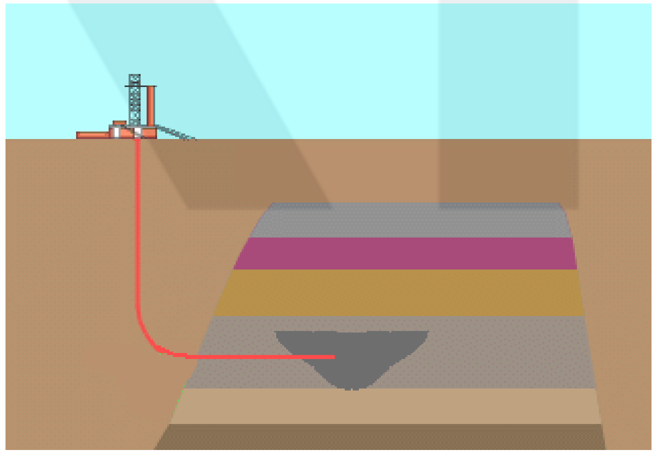


Inaccessible Locations

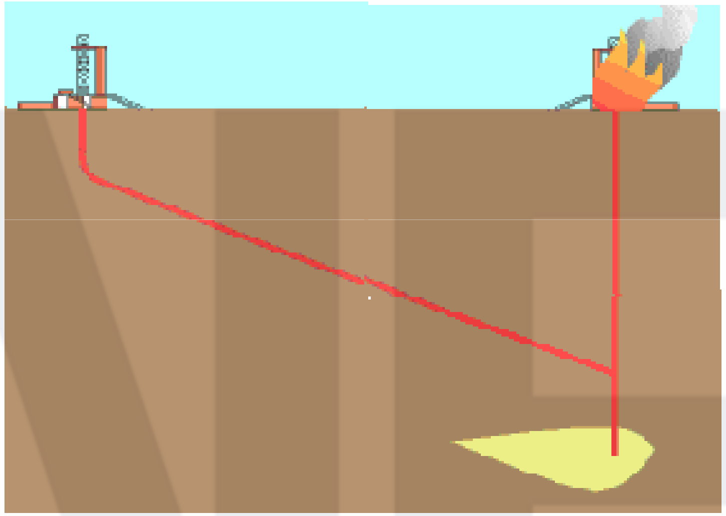


Salt Dome Drilling

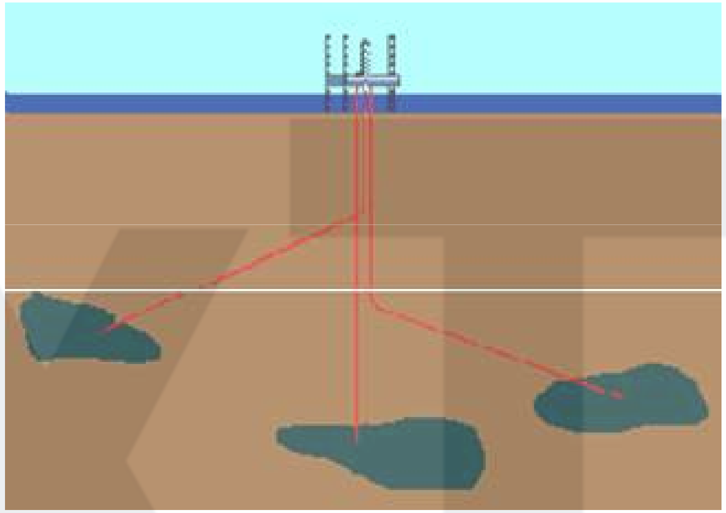


Fault Controlling

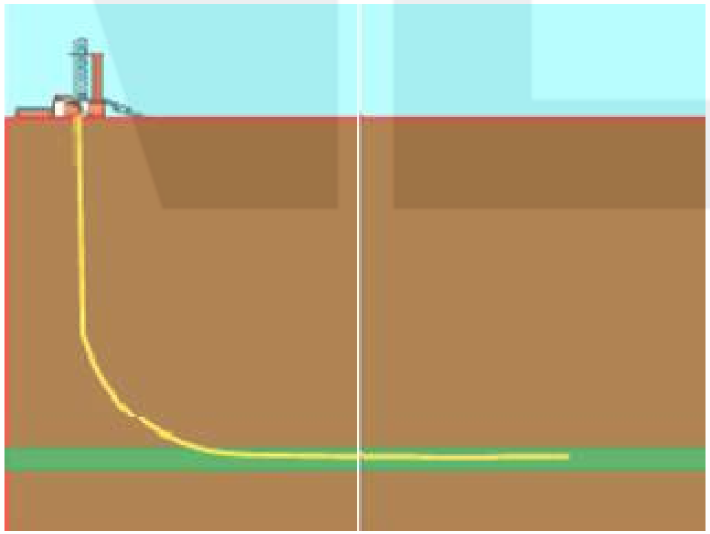
Applications of Directional Drilling



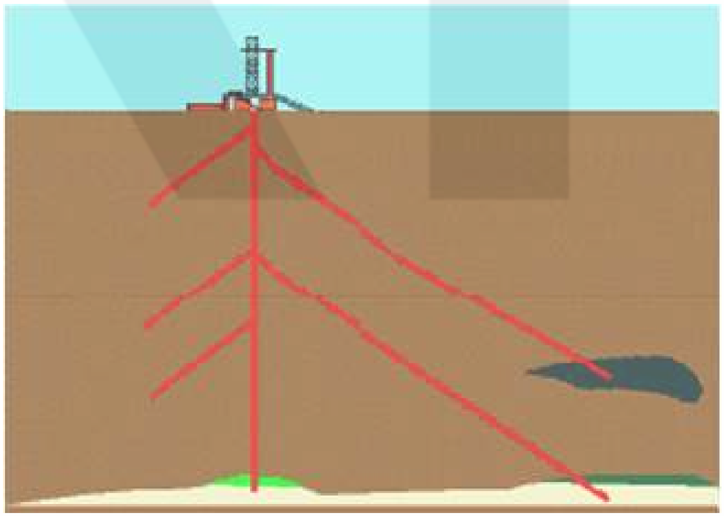
Relief Well



Platform



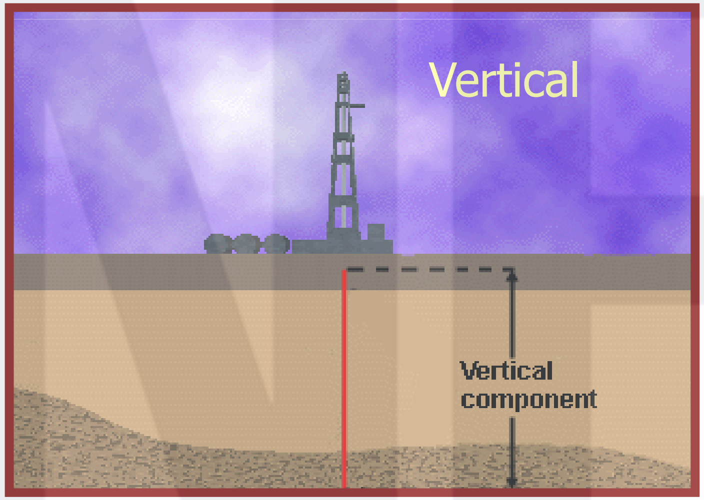
Drainage

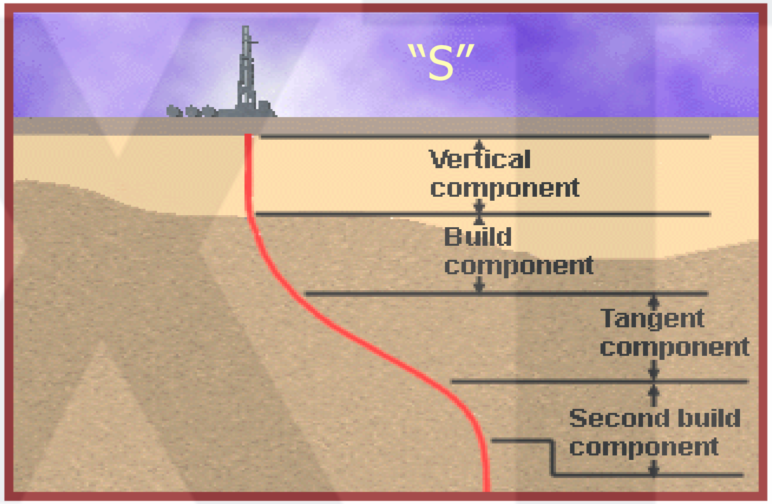


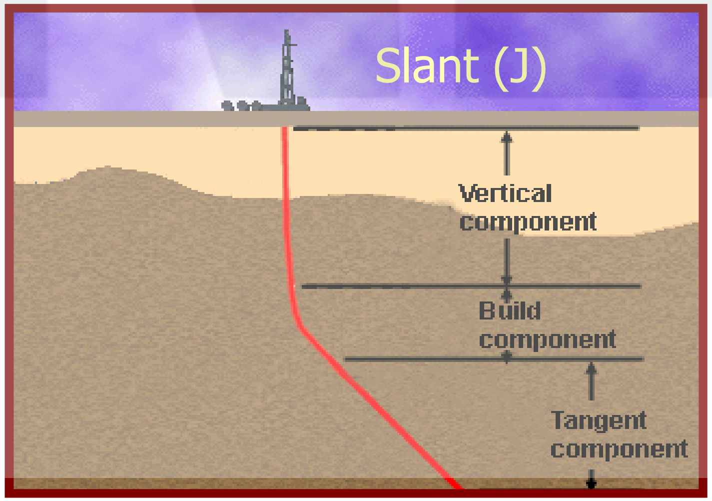
Multilaterals

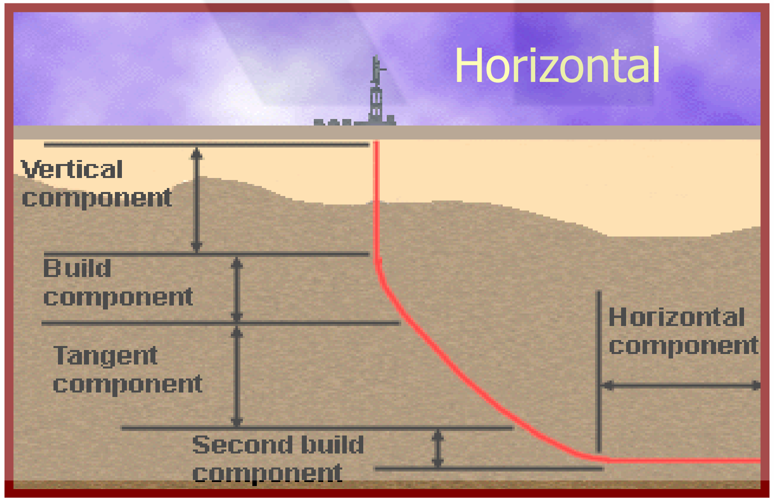
Directional Drilling

- Well Types:









Directional Drilling

Methods

- Background:
  - – The techniques began with the use of devices such as:
    - Whipstock
    - Jetting
    - Motor and bent sub
    - BHA to control inclination in tangent section
    - Wireline steering tool to orient and survey
  - – These tools were limited to specific applications, and were sometimes unreliable or unpredictable

Directional Drilling

Wellbore Survey

- Why are surveys required?
  - Satisfy regulatory agencies
  - Stay within lease boundaries or limits
  - Construct accurate subsurface maps
  - Determine location and control wellbore path
  - Reach a target by steering

Directional Drilling

Advancements

- Current Technology:
  - Steerable mud motors
  - MWD
  - LWD
  - Rotary steerable systems
  - These tools, in combination, can be used to direct or redirect well profiles without changing the BHA and have enabled the drilling of extended reach, horizontal and multi lateral wells.

What is MWD?

- MWD (Measurement While Drilling) tools provide real-time or immediate recording and transmission to the surface of downhole data related to bit operating conditions and directional information.
- Advantage of MWD tools over other methods of acquiring similar data is time, more frequent measurement, and reduction in risk of pipe sticking while the drillstring is motionless
- A variety of MWD services are available - the most common is the steering tool application, which provides a continuous or near continuous reading of drift angle, azimuth and tool face for directional drilling.

What is LWD?

- LWD (Logging-While-Drilling) is similar to MWD in that it is designed to provide a real-time or immediate recording and sometimes transmission to the surface of downhole formation evaluation data
- A variety of LWD services are available - the most common is the resistivity application, which provides qualitative formation evaluation information about the formation penetrated. Sonic, gamma ray, neutron density, caliper, annular pressure and other parameters may be measured

What are Rotary Steerable Systems (RSS)?

A Rotary Steerable System (RSS) is a combination of motor and stabilizer arrangement that allows surface rotation of the drill pipe while keeping the bit orientation fixed.

- May use specialized stabilizer (push to steer)
- May use specialized bit directing technology (point to steer)

What is Geosteering?

A technique whereby real time or near real time rock property and well path information is used to help guide the well in a desired position within a geologic strata or elevation.

- Uses MWD, LWD and RSS to guide well.
- A geologic model or earth model is fundamental to the well design
- Allows placement within the reservoir to optimize production and extend usability of well.

Current Directional Drilling Technology Limits

- Longest horizontal section (>86°) in excess of 26,700 feet (8150 mtr)
- Motor run in excess of 610 hours
- Longest Extended Reach well 29,796 feet (9082m) measured depth. Lateral reach 24,911 feet (7593m). (SPE 98945-MS)
- Shortest measured length from vertical to horizontal 35 feet TVD. (SPE 35244-PA)

Directional Drilling Limitations

- Torque and Drag
- Hole cleaning
- Depth with heat for motors and MWD/LWD equipment
- Not enough near bit technology available
- Air drilling with motors and MWD/LWD
- Steering in less than 5ft TVD thick producing zones.

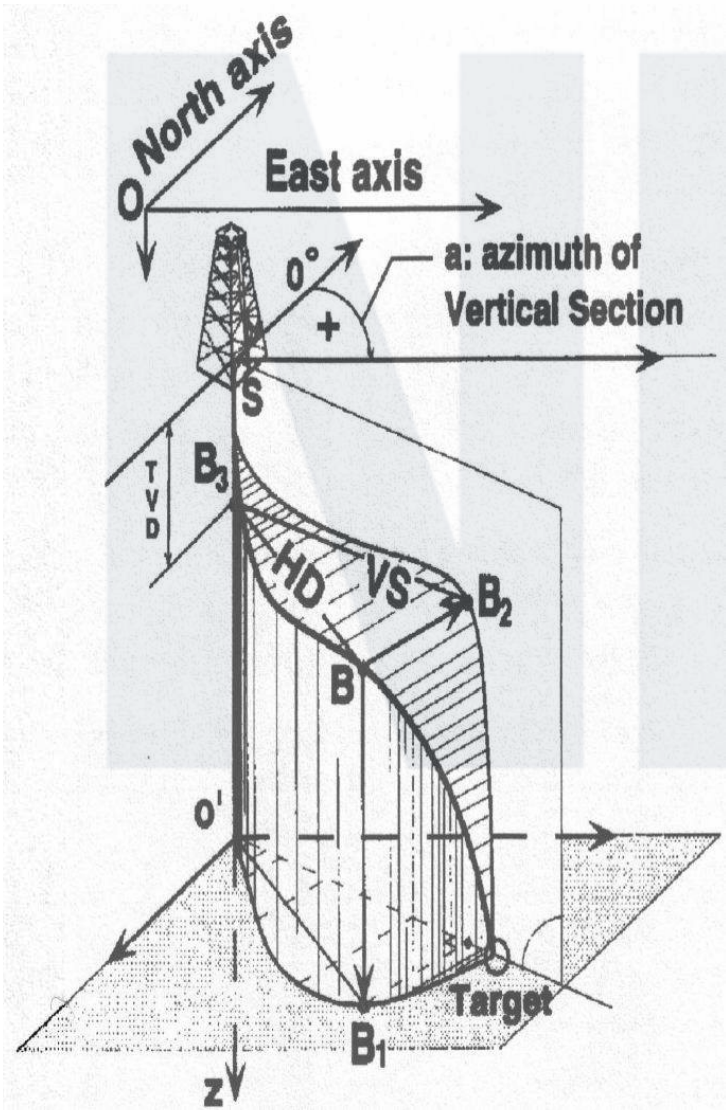
Well Bore Surveying Calculation Methods

Wellbore Surveying Calculation Methods

Lecture Objectives:

1. Describe the difference between the two methods most commonly used to calculate a directional survey; and state which method is most commonly used.
2. Demonstrate the conversion between “rectangular” and “polar” coordinates.
3. Demonstrate how to transform quadrant to azimuth readings and reverse.
4. Demonstrate how to plot directional surveys on a conventional plot (plan view and vertical section).

Terms Used in Survey Calculations



Well reference point "**O**".

Surface location reference point "**S**."

Survey - measurement of the inclination, azimuth, and depth of a station in the borehole.

Vertical section plane – a vertical plane on which the surface and target or point of interest lay.

Azimuth - "**Azm**" indicator "**a**:"- Direction of a course measured in a clockwise direction from 0°- 360° referred to North; also bearing.

Inclination - "**Inc**" angle in degrees from vertical.

Measured Depth - "**MD**" – Distance between two points measured along the well path.

True Vertical Depth - "**TVD**" – Distance from "**S**" to "**O**" The actual vertical depth of an inclined wellbore.

Horizontal displacement - "**HD**" – For points "**B_3**" and "**B**" it is the distance from "**O**" to "**B_1**" on the horizontal plane.

Horizontal section – Distance between two points in the well projected onto a horizontal plane.

Vertical section – "**VS**" - Distance from "**B_3**" to "**B_2**" A projection of the borehole into a vertical plane parallel to the course bearing or azimuth and scaled with vertical depth.

Dog Leg Severity – "**DLS**", change in angle and/or direction over a standard distance, commonly 100 feet or 30 meters.

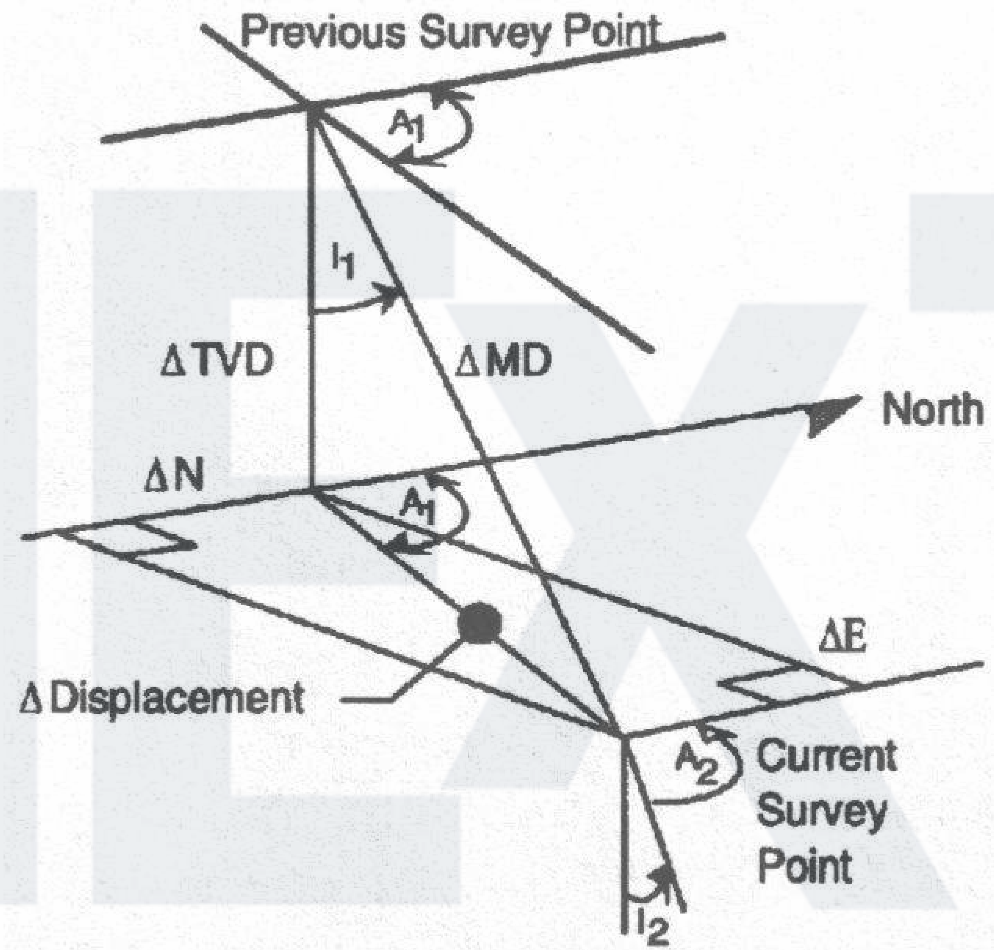
KB/RKB – Rig Kelly Bushing. A point of reference from the known ground level.

Survey Calculation Methods

A number of survey calculation methods have been used in directional drilling. Of these only four have widespread use.

- Tangential - Assumes a straight line
- Average Angle - Assumes an average line
- Radius of Curvature - Assumes a smooth curved line
- Minimum Curvature - Assumes smooth curved line with a dog leg ratio factor

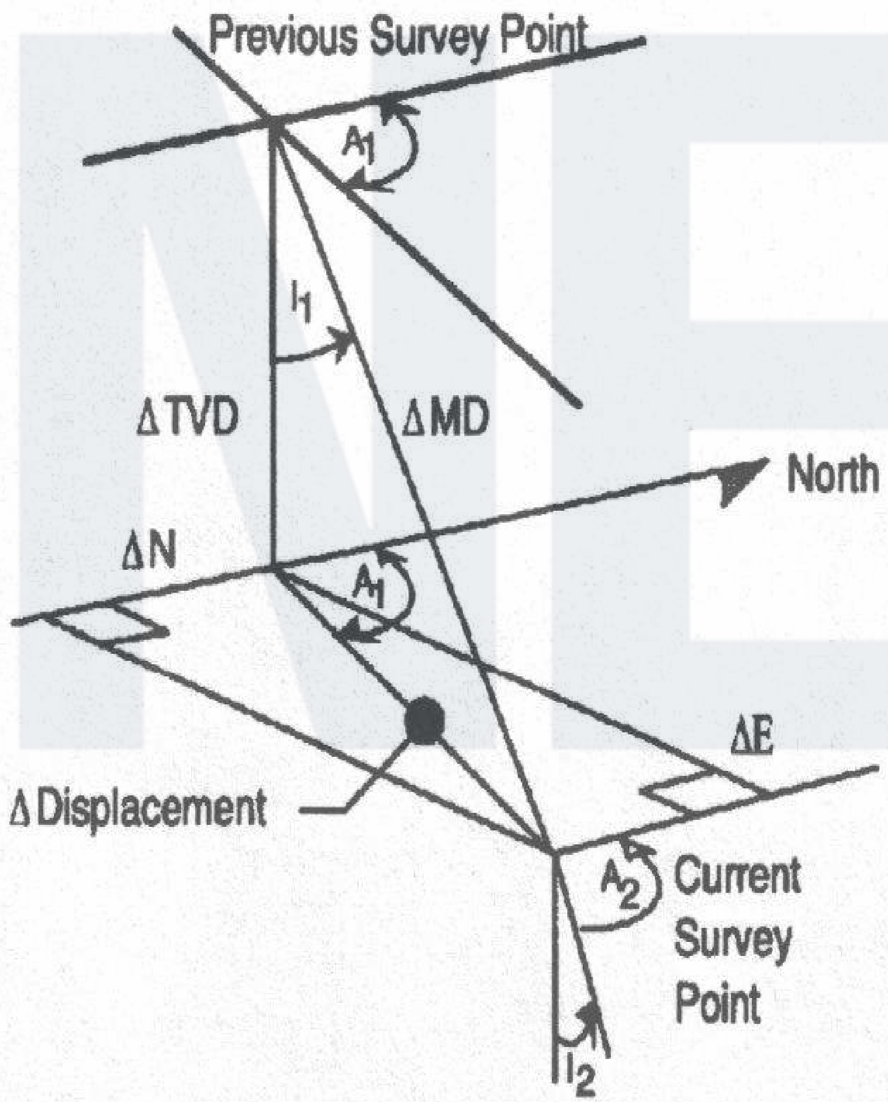
Tangential Method



Use only the inclination and direction of the previous survey to calculate the current survey location.

TVD	= MD x Cos Inclination
Displacement	= MD x Sin Inclination
North	= Displacement x Cos Azimuth
East	= Displacement x Sin Azimuth

Tangential Method



Exercise:

Inc = 20 deg

Azm = 50 deg

MD = 100 feet

TVD = MD x Cos Incl

100 x Cos20 = 94 ft

DISPL = MD x Sin Incl

100 x Sin20 = 34.2 ft

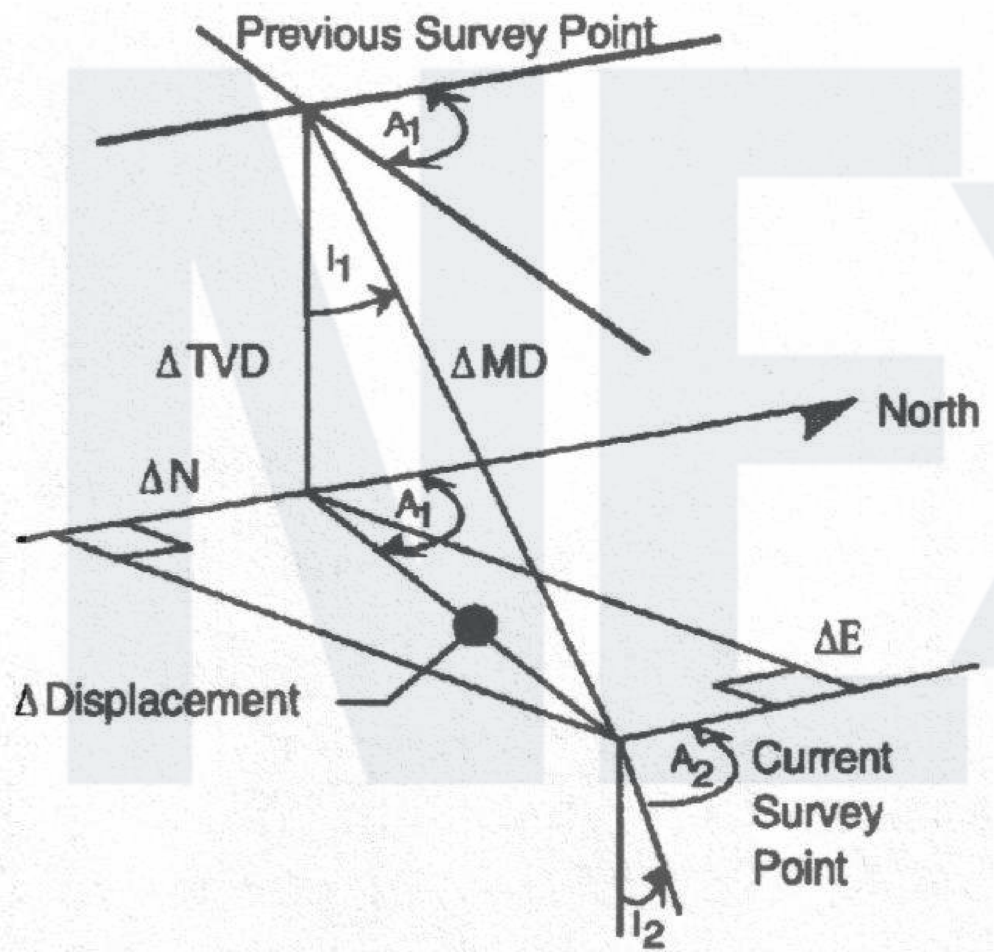
North = DISPL x Cos Az

34.2 x Cos50 = 22 ft

East = DISPL x Sin Az

34.2 x Sin50 = 26.2 ft

Average Angle Method



$$\Delta \text{ North} = \Delta \text{ MD} \cdot \sin\left[\frac{I_1 + I_2}{2}\right] \cdot \cos\left[\frac{A_1 + A_2}{2}\right]$$

$$\Delta \text{ East} = \Delta \text{ MD} \cdot \sin\left[\frac{I_1 + I_2}{2}\right] \cdot \sin\left[\frac{A_1 + A_2}{2}\right]$$

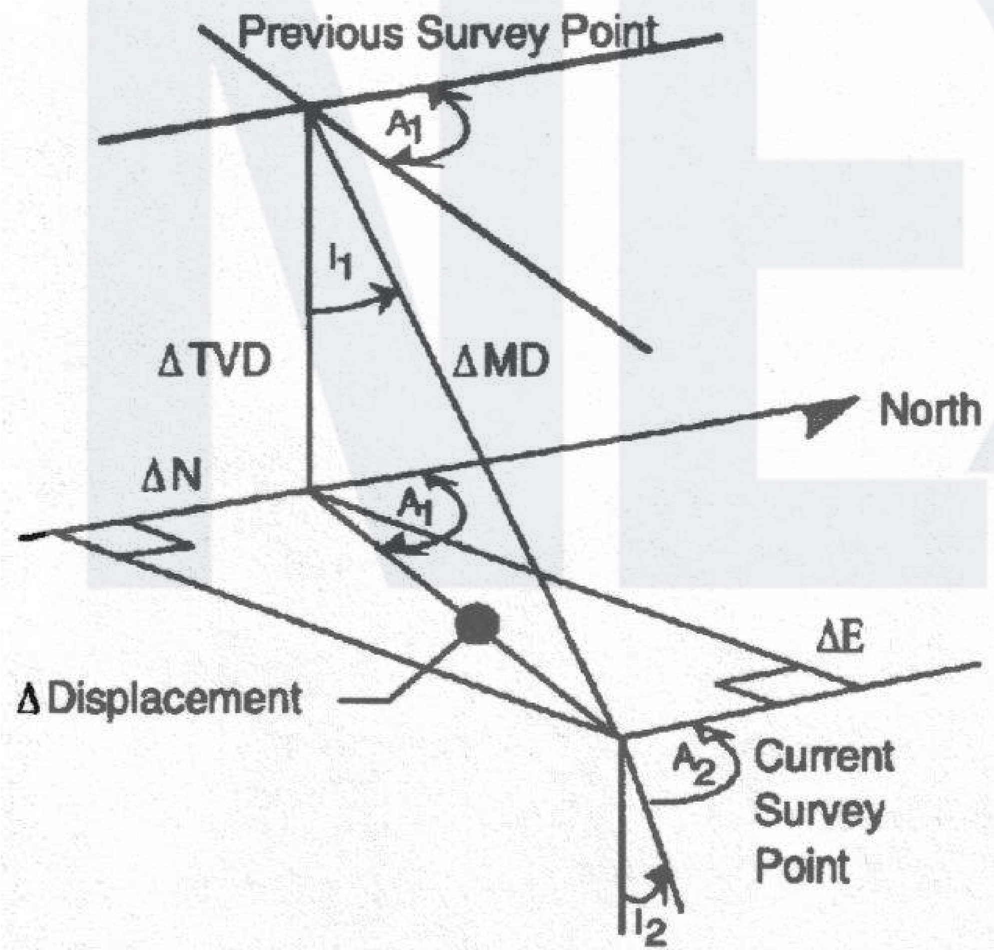
$$\Delta \text{ Vertical Depth} = \Delta \text{ MD} \cdot \cos\left[\frac{I_1 + I_2}{2}\right]$$

$$\text{Course Displacement} = \Delta \text{ MD} \cdot \sin\left[\frac{I_1 + I_2}{2}\right]$$

The Average Angle method uses the arithmetic average of the inclination and azimuth at the two survey stations and performs the same calculations as the tangential method.

Average Angle Method - EXERCISE

$Inc_1 = 20$ deg $Az_1 = 50$ $Inc_2 = 22$ deg $Az_2 = 55$ MD = 100 ft



$$\Delta \text{North} = \Delta MD \cdot \sin\left[\frac{I_1 + I_2}{2}\right] \cdot \cos\left[\frac{A_1 + A_2}{2}\right]$$

$$\Delta \text{East} = \Delta MD \cdot \sin\left[\frac{I_1 + I_2}{2}\right] \cdot \sin\left[\frac{A_1 + A_2}{2}\right]$$

$$\Delta \text{Vertical Depth} = \Delta MD \cdot \cos\left[\frac{I_1 + I_2}{2}\right]$$

$$\text{Course Displacement} = \Delta MD \cdot \sin\left[\frac{I_1 + I_2}{2}\right]$$

Average Angle Method EXERCISE Solution

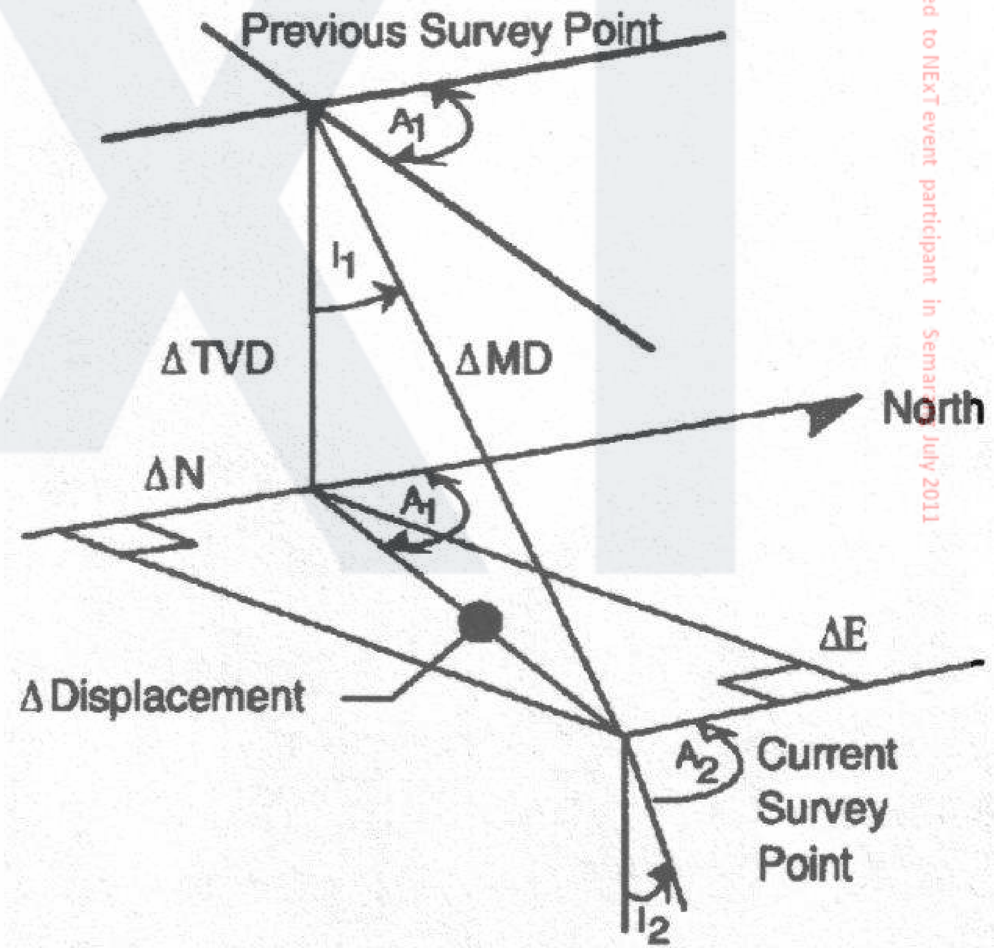
Inc_1 = 20 deg Az_1 = 50 Inc_2 = 22 deg Az_2 = 55   MD = 100 ft

N = 100 x Sin (42/2) x Cos (105/2) = 21.8 ft

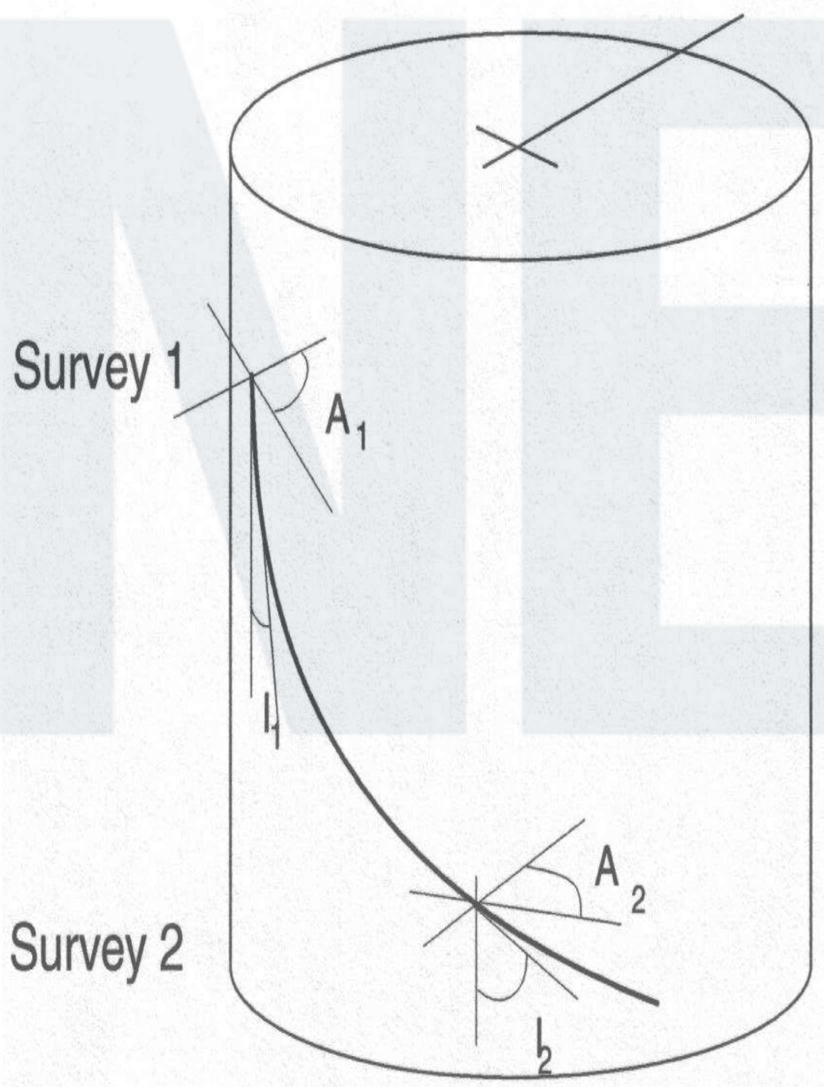
E = 100 x Sin (42/2) x Sin (105/2) = 28.4 ft

Vertical Depth = 100 x Cos (42/2) = 93.4 ft

Horizontal Displ. = 100 x Sin (42/2) = 35.8 ft

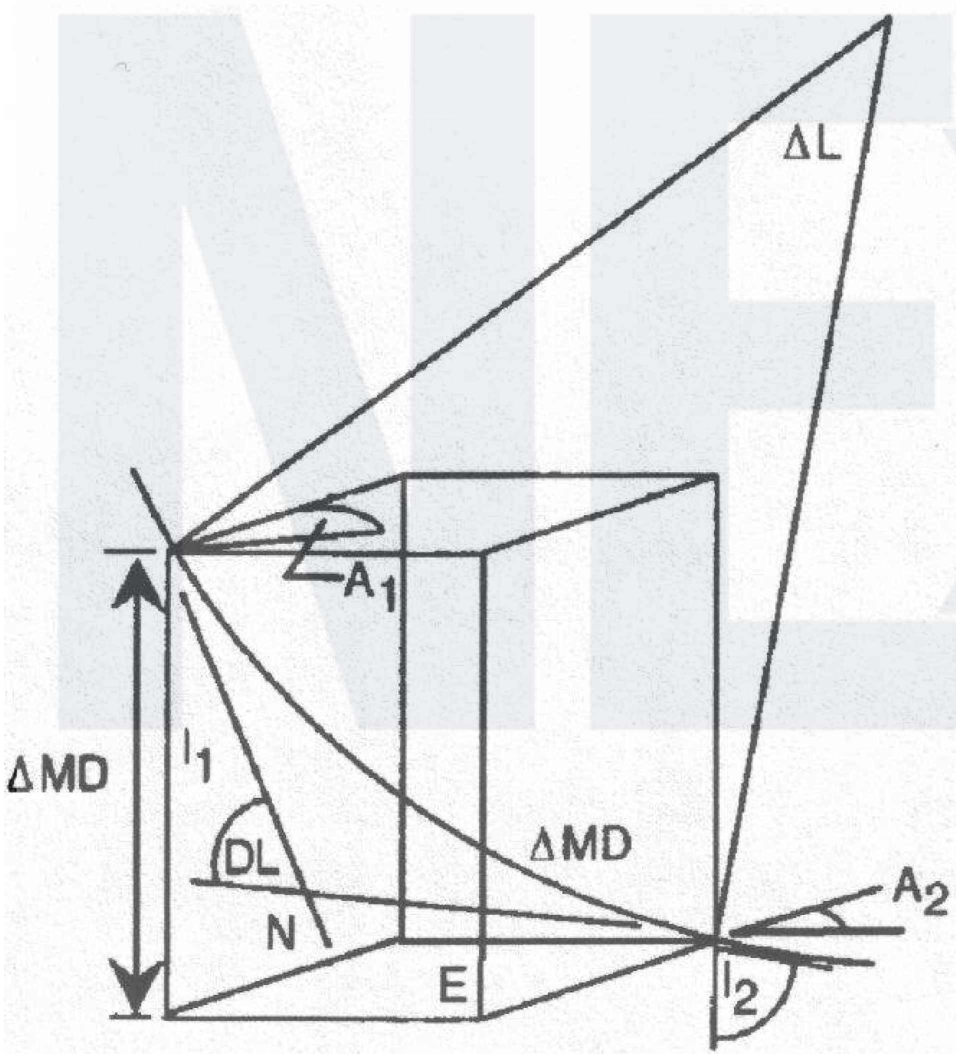


Radius of Curvature Method



- The well path is assumed to be a smooth curve that can be fit to the surface of a cylinder.
- The well is curved at a specific radius in both the vertical and the horizontal plane.
- This method is more accurate on long survey intervals and is able to handle greater angle changes.

Minimum Curvature Method



- Fits the well path on the surface of a sphere of a particular radius using a method similar to the radius of curvature but using a ratio factor which is defined by the curvature of the well bore section.
- This method is the most accurate one and the industry standard.

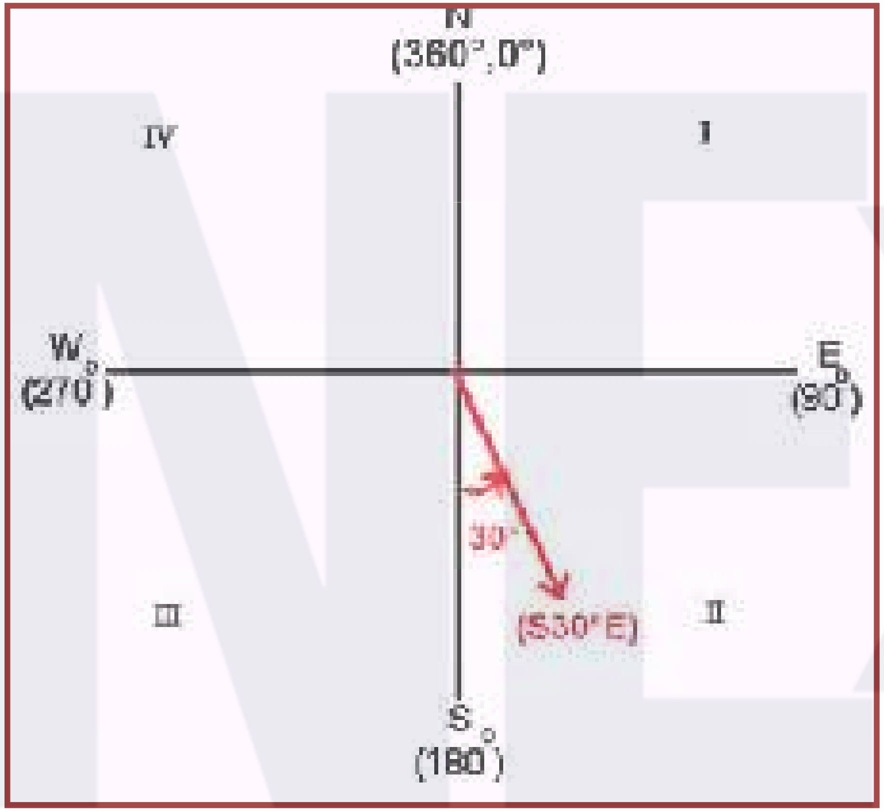
For additional information on the minimum curvature method and formulas refer to *SPE Journal Dec 1972*, pgs 474-88 or "*Applied Drilling Engineering, SPE Textbook Series Vol. 2*," pgs 364 - 366

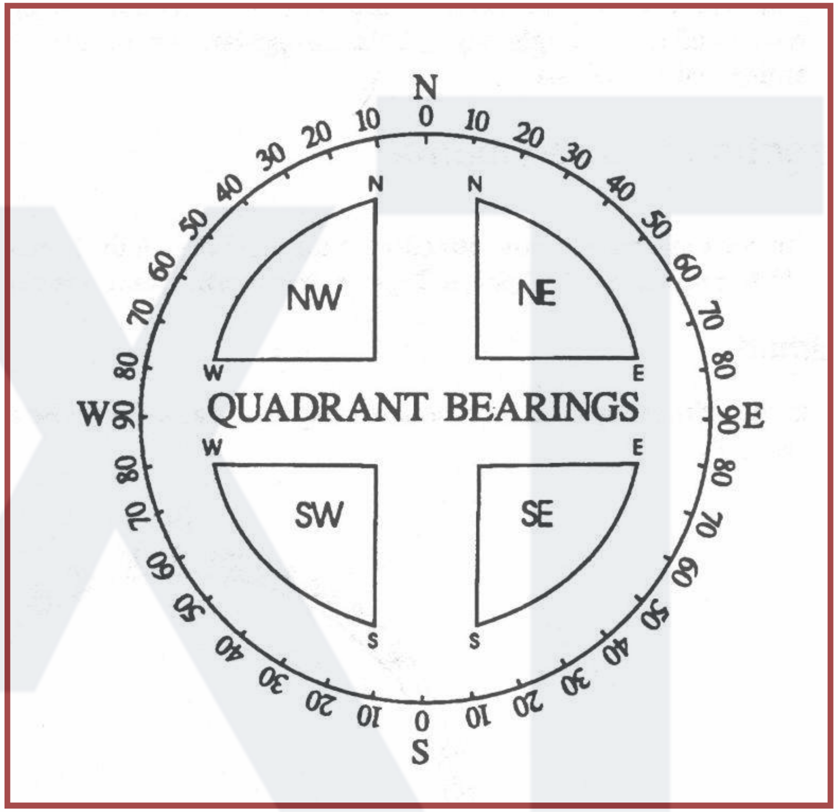
Relative Accuracy of the Different Methods

- Assuming a theoretical well drilled due North (no direction change), from 0 to 2000’ MD, with a build rate of 3°/100’, and survey stations every 100’, we can calculate the relative accuracy of the various methods. This well path is a smooth curve in the vertical plane.
- Compared to the “actual” TVD of 1653.99’ and North displacement of 954.93’, we find the following:

Calculation Method	Error on TVD (ft)	Error on Displacement (ft)
Tangential	-25.38	+43.09
Average Angle	+0.19	+0.11
Radius of Curvature	0.00	0.00
Minimum Curvature	0.00	0.00

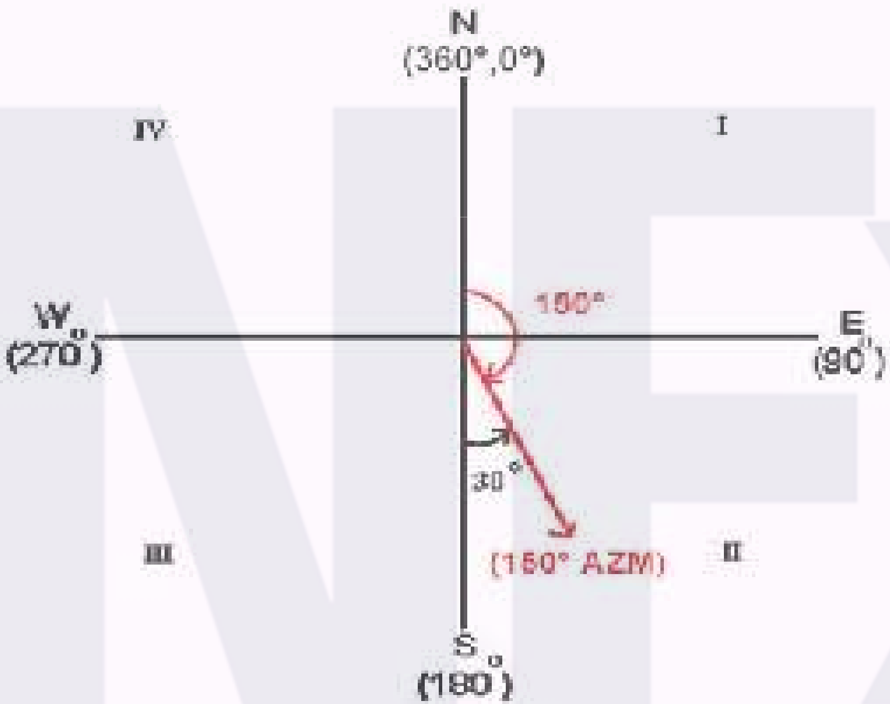
Compass Quadrant Direction

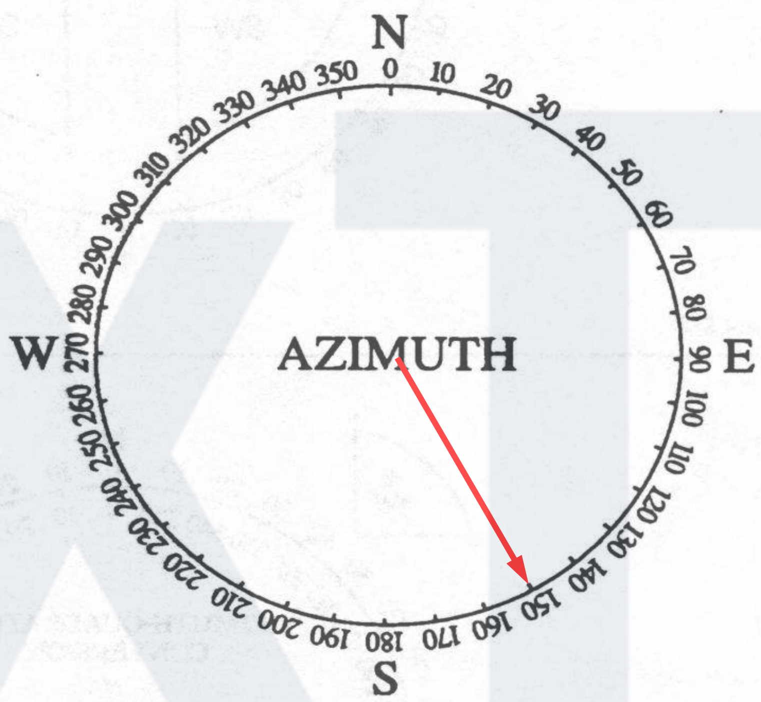




- The four quadrants are normally expressed as NE, SE, SW and NW.
- Originate the reading from north or south; then move toward the east or west in a positive or increasing angle.
- The graphic shows an example quadrant direction of S30°E.

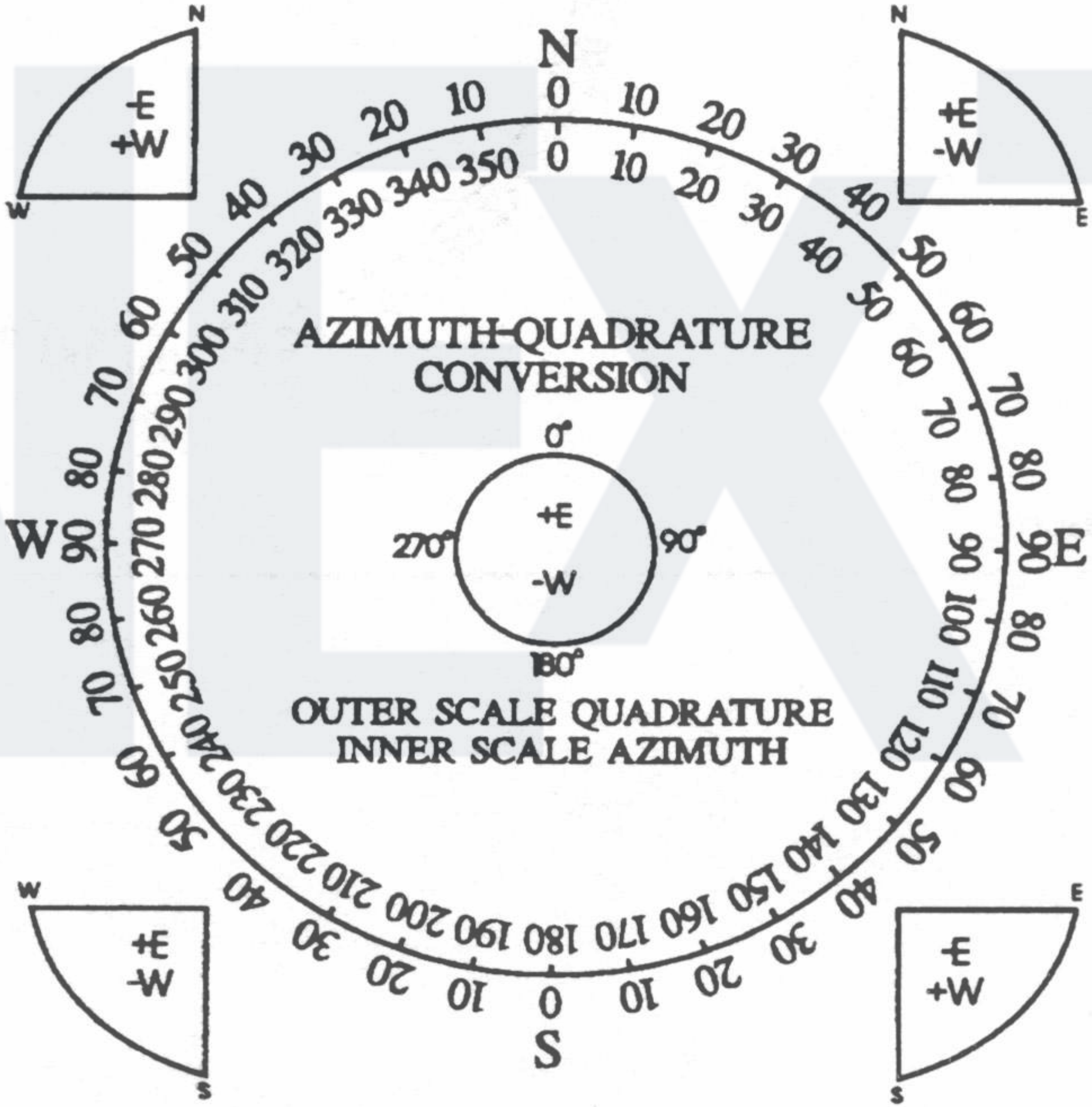
Azimuth Direction





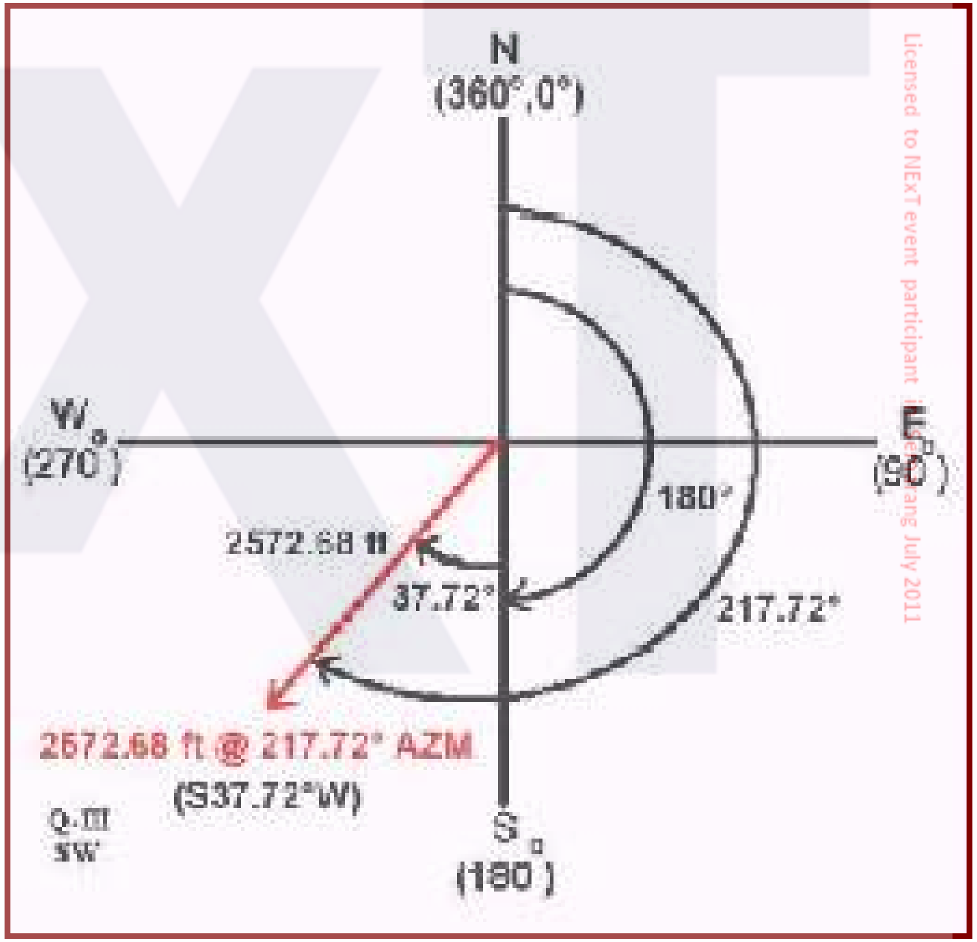
- The azimuth system uses directions ranging from 0° to 360°. The direction is reported from North at 0° in a positive or clockwise direction.
- A direction of 0° or 360° refers to North; 90° refers to East; 180° refers to South; and 270° refers to West.
- The graphic shows an example azimuth direction of 150° AZM.

Compass Quadrant and Azimuth Relationships



Polar and Rectangular Coordinates

- The polar coordinate of a point is defined by a distance and a direction relative to North (azimuth).
- The rectangular coordinate of a point is given in feet or meters with a direction of North/South and East/West.



Dogleg

Dogleg:

Commonly a dogleg is referred as a particularly crooked place in a wellbore where the trajectory of the wellbore in three-dimensional space changes rapidly. While a dogleg is sometimes created intentionally by directional drillers, the term more commonly refers to a section of the hole that changes direction faster than anticipated or desired, usually with harmful side effects. In surveying wellbore trajectories, a standard calculation of dogleg severity (DLS) is made, usually expressed in two-dimensional degrees per 100 feet [degrees per 30 m] of wellbore length.

Dogleg Severity

Lubinski Formula for Dogleg Severity

$$DLS = \frac{d}{\Delta MD} 2 \sin^{-1} \sqrt{\left\{ \left[\left(\sin \frac{\Delta I}{2} \right)^2 + \left(\sin \frac{\Delta A}{2} \right)^2 \times \sin I_1 \times \sin I_2 \right] \right\}}$$

Where:

d = 100 feet or 30 meter, depending on measurement system

ΔMD = course length, MD between 2 survey points

ΔI = change in inclination from survey point 1 to survey point 2

ΔA = change in azimuth from survey point 1 to survey point 2

I_1 and I_2 are inclinations at survey point 1 and survey point 2

Partial Horizontal Survey Sheet - Example

Survey Report-

OPERATOR:	ABC oil and Gas	START:	
WELL:	Example Well # 1	FINISH:	
LOCATION:	Somewhere county, Texas		

PROPOSED DIRECTION: 234.42

MIN. CURVATURE CALCULATIONS

SUR NUM	MD ft	INCL. °	AZM. °	TVD ft	N-S ft	E-W ft	SECT. ft	DLS °/100 ft
Tie-in	0.00	0.00	0.00	0.00	-265.31	35.19	125.79	0.00
KOP	1304.00	2.70	355.20	1303.52	-234.70	32.62	110.05	0.21
1	1334.00	2.90	270.70	1333.49	-233.98	31.80	110.30	12.56
2	1365.00	7.50	246.90	1364.36	-234.77	29.15	112.90	16.08
3	1396.00	12.50	244.60	1394.88	-237.00	24.26	118.19	16.18
4	1427.00	17.40	247.00	1424.82	-240.26	16.96	126.02	15.93
5	1457.00	21.20	249.20	1453.13	-243.94	7.75	135.64	12.89
6	1487.00	24.80	254.00	1480.74	-247.60	-3.37	146.82	13.52
7	1518.00	28.80	257.90	1508.41	-250.96	-16.93	159.80	14.09
8	1549.00	32.70	258.80	1535.05	-254.15	-32.45	174.28	12.67
9	1580.00	36.60	262.00	1560.55	-257.06	-49.82	190.11	13.88
10	1627.00	43.80	262.00	1596.42	-261.28	-79.84	216.98	15.32
11	1659.00	50.40	261.50	1618.19	-264.65	-103.03	237.79	20.66
12	1691.00	58.00	260.10	1636.90	-268.81	-128.63	261.03	24.01
13	1722.00	61.60	260.00	1652.49	-273.44	-155.01	285.18	11.62
14	1753.00	64.00	260.30	1666.66	-278.16	-182.17	310.02	7.79
15	1785.00	66.60	260.40	1680.03	-283.03	-210.83	336.16	8.13
16	1817.00	71.00	260.50	1691.60	-287.98	-240.25	362.96	13.75
17	1849.00	73.90	260.10	1701.24	-293.12	-270.32	390.41	9.14
18	1881.00	78.30	261.10	1708.93	-298.19	-300.96	418.27	14.08
19	1912.00	83.40	261.10	1713.86	-302.92	-331.18	445.61	16.45
20	1944.00	85.50	262.00	1716.95	-307.60	-362.69	473.95	7.13
21	1976.00	84.60	258.50	1719.72	-313.00	-394.10	502.64	11.25
22	2008.00	84.10	253.60	1722.87	-320.67	-425.00	532.23	15.32
23	2040.00	84.70	248.40	1725.99	-331.04	-455.10	562.74	16.28
24	2072.00	86.70	244.30	1728.39	-343.84	-484.32	593.96	14.22
25	2104.00	91.90	243.20	1728.78	-357.98	-513.01	625.52	16.61
26	2135.00	92.10	245.00	1727.70	-371.52	-540.87	656.06	5.84
27	2166.00	89.10	242.50	1727.38	-385.22	-568.67	686.64	12.60
28	2198.00	88.20	241.50	1728.13	-400.24	-596.92	718.35	4.20
29	2230.00	90.40	240.80	1728.52	-415.68	-624.94	750.12	7.21
30	2262.00	91.60	239.30	1727.96	-431.65	-652.66	781.96	6.00
31	2294.00	91.80	238.30	1727.01	-448.22	-680.02	813.85	3.19
32	2325.00	91.60	237.50	1726.09	-464.69	-706.27	844.78	2.66
33	2357.00	90.50	236.20	1725.51	-482.18	-733.06	876.75	5.32
34	2390.00	90.30	235.30	1725.28	-500.76	-760.33	909.74	2.79
35	2422.00	91.00	234.80	1724.91	-519.09	-786.56	941.73	2.69
36	2453.00	90.50	235.60	1724.51	-536.78	-812.01	972.73	3.04

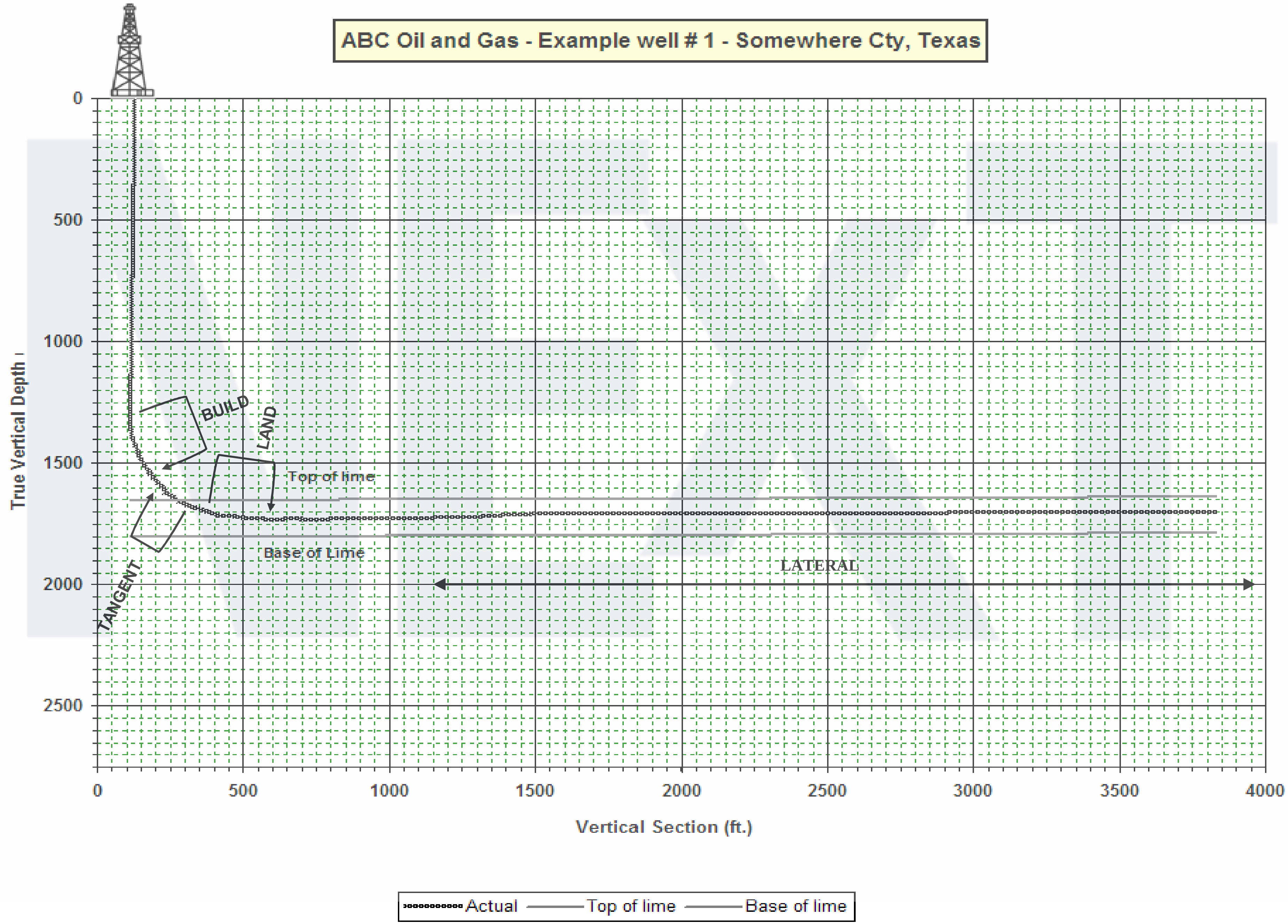
BUILD

TANGENT

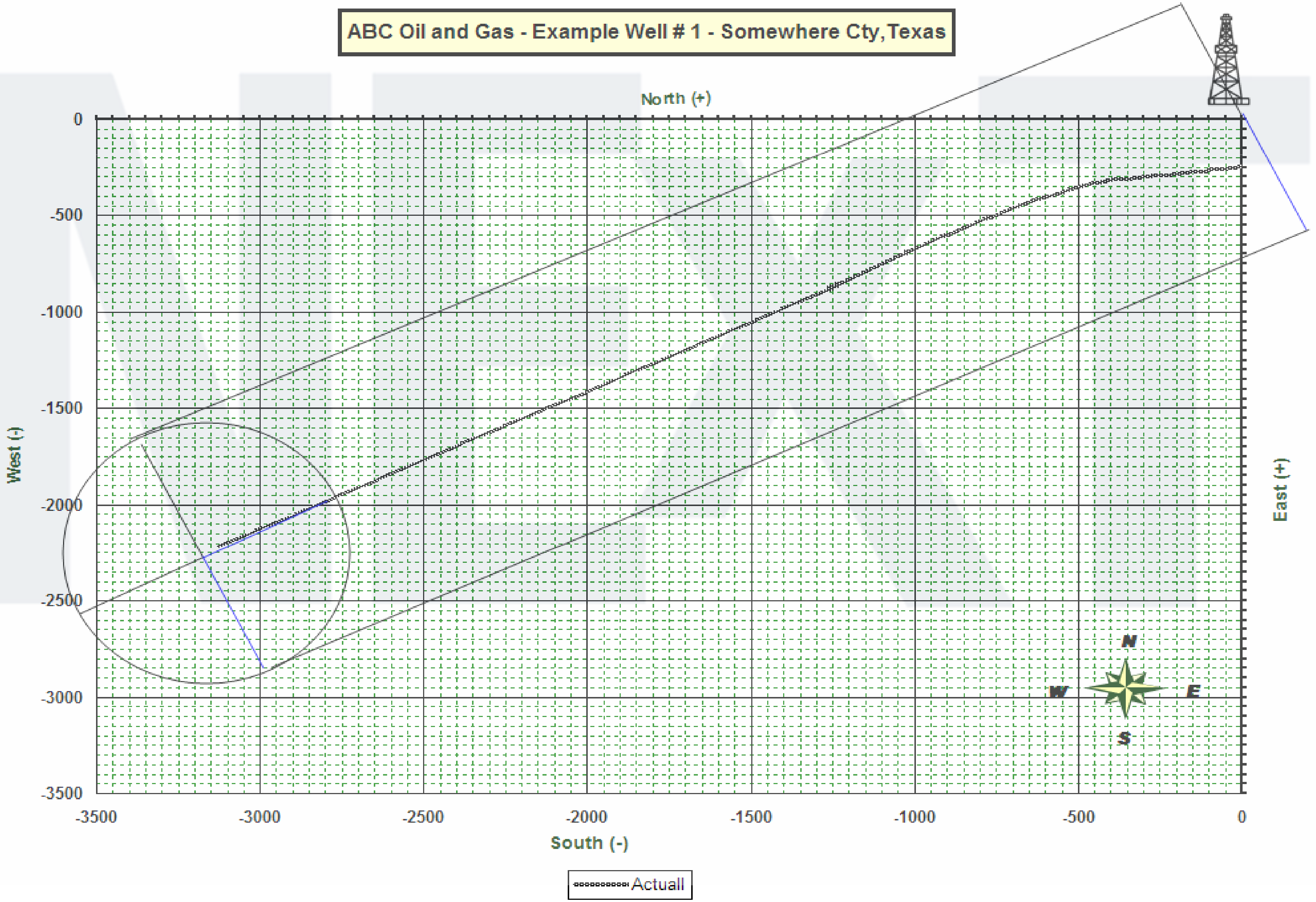
BUILD TO LAND

LATERAL

Vertical Plane View - Example



Horizontal Plane View - Example



Terminology -

- Azimuth: Direction of a course measured in a clockwise direction from 0°-360° referred to North; also bearing.
- Build Angle: The act of increasing the inclination of the drilled hole; the rate of change (degrees/100 ft) of the increasing angle in the hole.
- Course Length: The difference in measured depth or actual hole length from one station to another.
- Departure: Horizontal displacement of one station from another in an east or west direction.
- Displacement: The lateral distance from the surface location to the last survey point.
- Dogleg Severity: A measure of the amount of change in the inclination and/or direction of a borehole, usually expressed in degrees per 100 feet or 30 meters of course length.

Terminology -

- Horizontal Displacement: The distance between any two points that are projected onto a horizontal plane.
- Inclination: The angle in degrees, taken at one or at several points of variation, from the vertical as revealed by a deviation survey; sometimes called the angle of deviation.
- Kick-off-point: The position in the well bore where the inclination of the hole is first purposely increased.
- Departure: Similar to Horizontal Displacement, a straight line in a horizontal plane containing the survey station of interest and the vertical projection of the surface location on the same horizontal plane. At TD the Departure and Closure are the same. See Closure.
- Closure: A straight line, in a horizontal plane containing the end of the well (TD) and the vertical projection of the surface location on the same horizontal plane.
- Measured Depth: Actual length of the wellbore from its surface location to any specified station.
- Quadrant Bearing: An azimuth angle measured from north or south in the direction of east or west.

Terminology -

- Survey Data Sheet: Commonly called the calculation sheet. A paper form on which to tabulate the data and results of calculations of a wellbore survey.
- Tangent: The borehole inclination and direction are maintained constant.
- True North: The direction from any geographical location on the earth's surface to the north geometric pole.
- True Vertical Depth (TVD): The actual vertical depth of an inclined wellbore.
- Walk: The tendency of a well bore to deviate in the horizontal plane; generally thought to be caused by the bit rotating into the side of the hole and/or the nature of the formation to "push" the bit.

Wellbore Surveying Calculation Methods

By now, you should be able to :

1. Describe the difference between the two most commonly used methods of calculating a directional survey; and state which is more commonly used today.
2. Demonstrate the conversion between "rectangular" and "polar" coordinates .
3. Demonstrate how to transform quadrant to azimuth readings and reverse.
4. Demonstrate how to plot directional surveys on a conventional plot (plan view and vertical section).

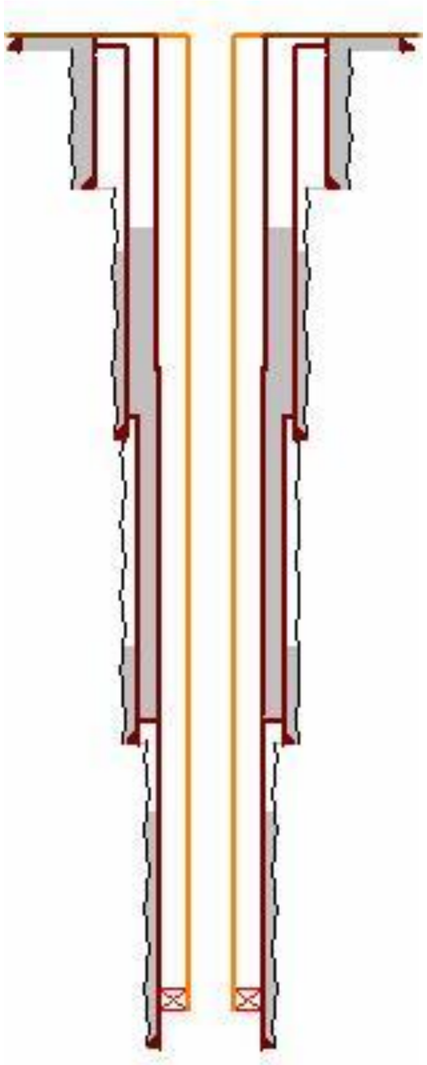
NExT Drilling Technology

Tubing and Casing Design

DR-TC2-NXT02380

Course Overview

- Casing Manufacturing
- HPHT and Sour Service
- API Specifications
- Stress/Strain Theory
- Casing Design Objectives
- Mechanical Design
- Casing Seat Selection
- Kick Tolerance
- Pressure Testing
- Design Documentation
- Procurement and Design Impact
- Design Examples and Practice



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Introduction to Casing Design

Agenda Day 1:

- Casing Materials/Properties
- API Specifications
- Non-API Grades/Specifications
- Mechanics of Materials
- Metallurgy/Manufacturing
- Inspection/NDT
- Exercises

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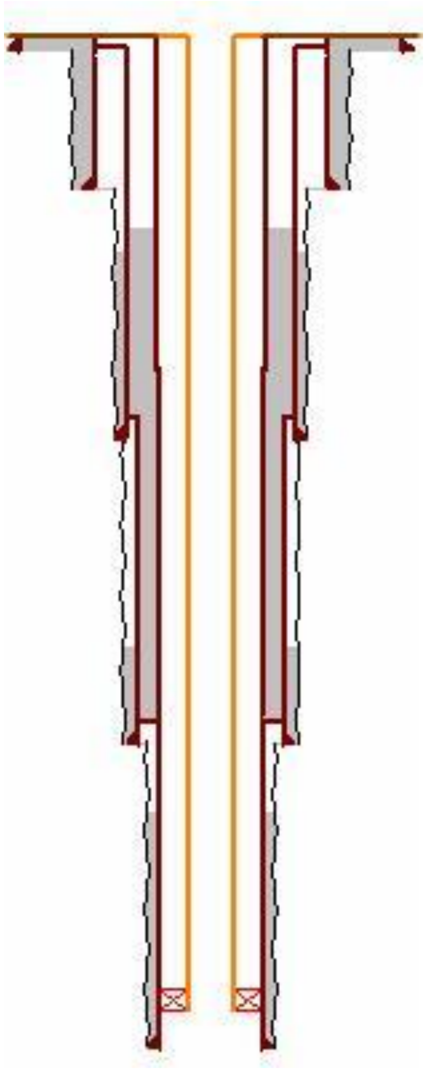
Purpose of String Design

- Ensure mechanical integrity of all strings for well's productive life.
- Provide safe string designs, optimized for cost.
- Provide operational documentation of design loads.



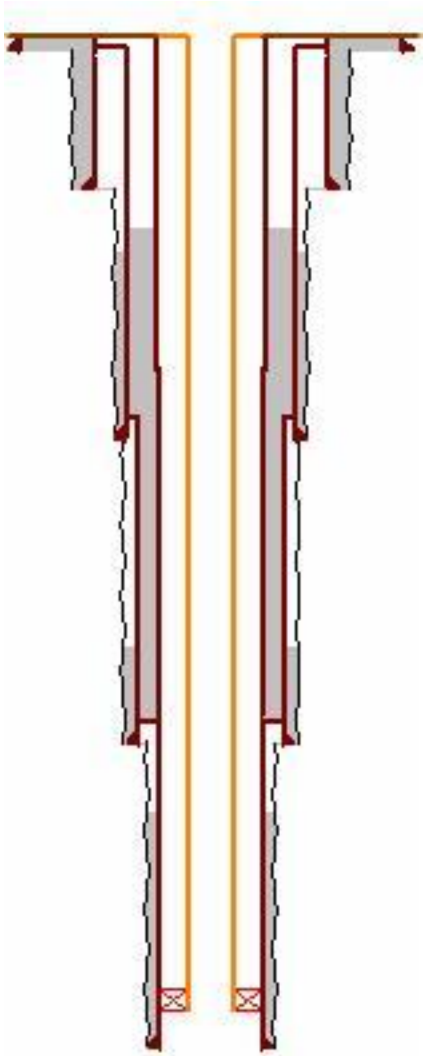
Nomenclature

CASING DEFINITION:

The tubular strings in a well that comprise the structural elements. Generally, cemented in place.

TUBING DEFINITION:

The tubular string in a well that comprise the flow conduit. Generally, replaceable.



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Oil Country Tubular Goods

In-Well Service – Below the wellhead

- Steel and Alloy Pipe
  - Casing
    - API Spec 5CT w/ API Std 5B for threads
    - API Spec 5L for large diameter >16”
  - Tubing
    - API Spec 5CT w/ API Std 5B for threads
  - Drill Pipe
    - API Spec 5D w/ API Spec 7 for tool joints

Material Aspects

Casing and tubing products are identified by four labels:

- Size
- Weight
- Grade
- End Finish

For example: 9-5/8” 47.00 #/ft P-110 BTC

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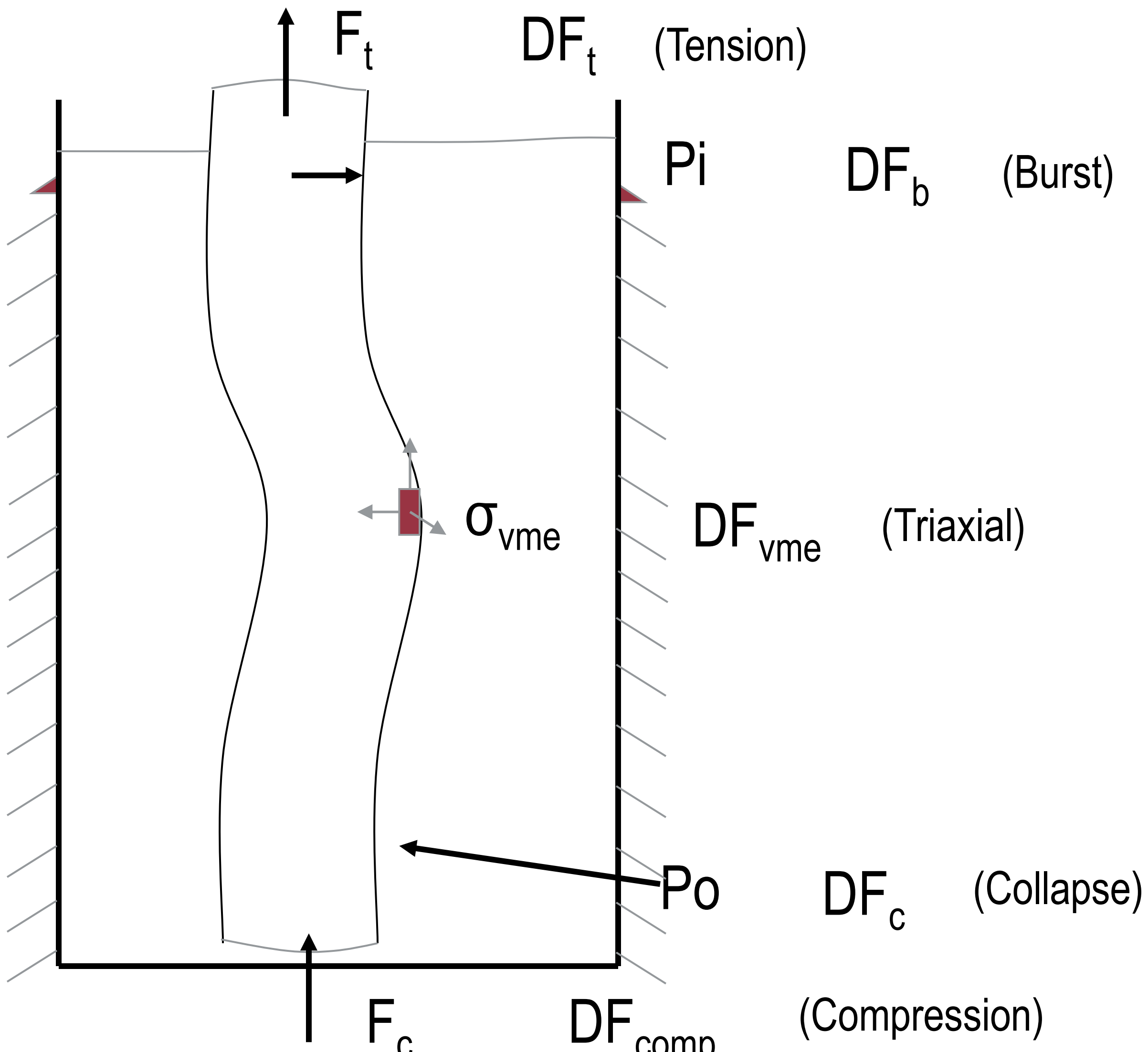
Pipe Material Grades (API)

Grade	Total Elongation at Yield (%)
H-40, J-55, K-55, L-80, N-80, C-90, C-95, T-95	0.50
P-110	0.60
Q-125	0.65

Design Parameters



Mechanical Properties

- Minimum Yield Strength
- Maximum Yield Strength
- Minimum Tensile Strength
- Minimum Elongation
- Proportional Limit
- Elastic Limit
- Minimum Charpy V-Notch
- Absorbed Energy Requirements

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API Design Documents

- API 5C3/ISO-TR-10400 – Performance
- API 5CT/ISO-11960 – Pipe Spec.
- API 5L – Line Pipe
- API 5B/ISO-10422 – API Connections
- NACE MR0175/ISO-15156 – Sour Service

Non API Grades

Why Do We Have Non API Grades:

- Sour Service Requirements – C110
- Low Temperature Service
- High Collapse Materials – TCA HC Q-125

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SOME BASICS

Stress-Strain

Engineering Definitions

- Stress
- Strain
- Modulus of Elasticity
- Hooke's Law
- Poisson's Ratio

Stress Formula

$$Stress = \frac{Force}{Area}$$

$$\sigma = \frac{\mathrm{F}}{\mathrm{A_p}}$$

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Stress Formula

$$Stress = \frac{Force\ (lbf)}{Area\ (sq.in.)} = \frac{lbf}{in^2} = psi$$

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Strain Formula

$$\text{Strain} = \frac{\text{Length Change}}{\text{Original Length}}$$

$$\varepsilon = \frac{\Delta L}{L}$$

NExT

Strain Formula

$$\text{Strain} = \frac{\text{Length Change}}{\text{Original Length}} = \frac{\text{in}}{\text{in}}$$

Hooke's Law

$$\sigma = \mathrm{E}\varepsilon$$

Stress is proportional to strain

E is the proportionality constant called Young's Modulus

Poisson's Ratio

$$\upsilon = \frac{\varepsilon_r}{\varepsilon_a}$$

ε_r = radial (sometimes referred to as transverse) strain

ε_a = axial strain

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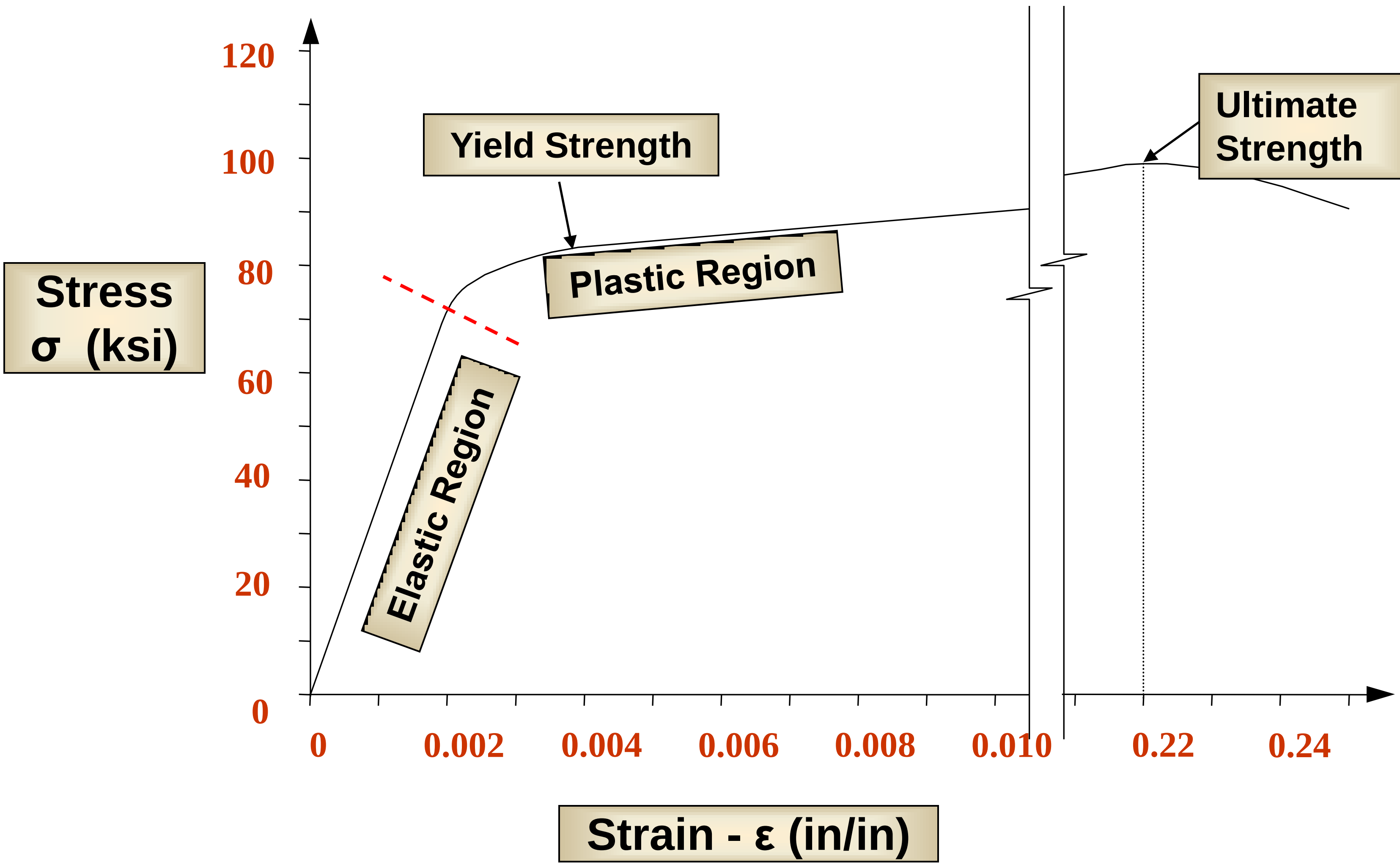
Stress Strain Curve



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Material Strength

- **Yield Strength**

  The stress beyond which the material will permanently deform.

- **Ultimate (Tensile Strength**

  The stress required to part the material

Material Strength

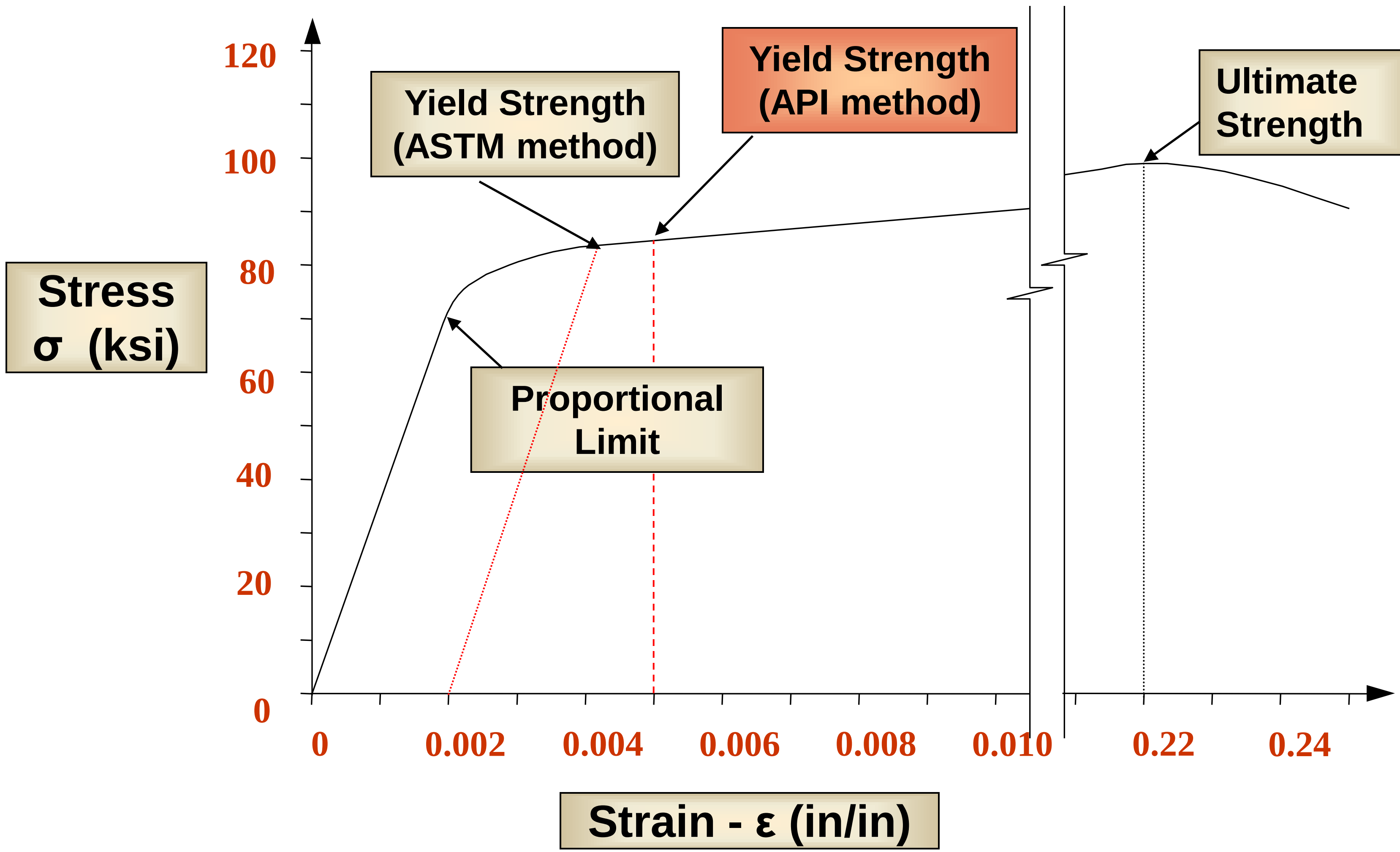
- **Elastic Region**

  At stress below yield, the material will return to its original shape after the load is removed.

- **Plastic Region**

  At stress above yield (and below ultimate) the material is permanently deformed after the load has been removed.

Stress-Strain Curve



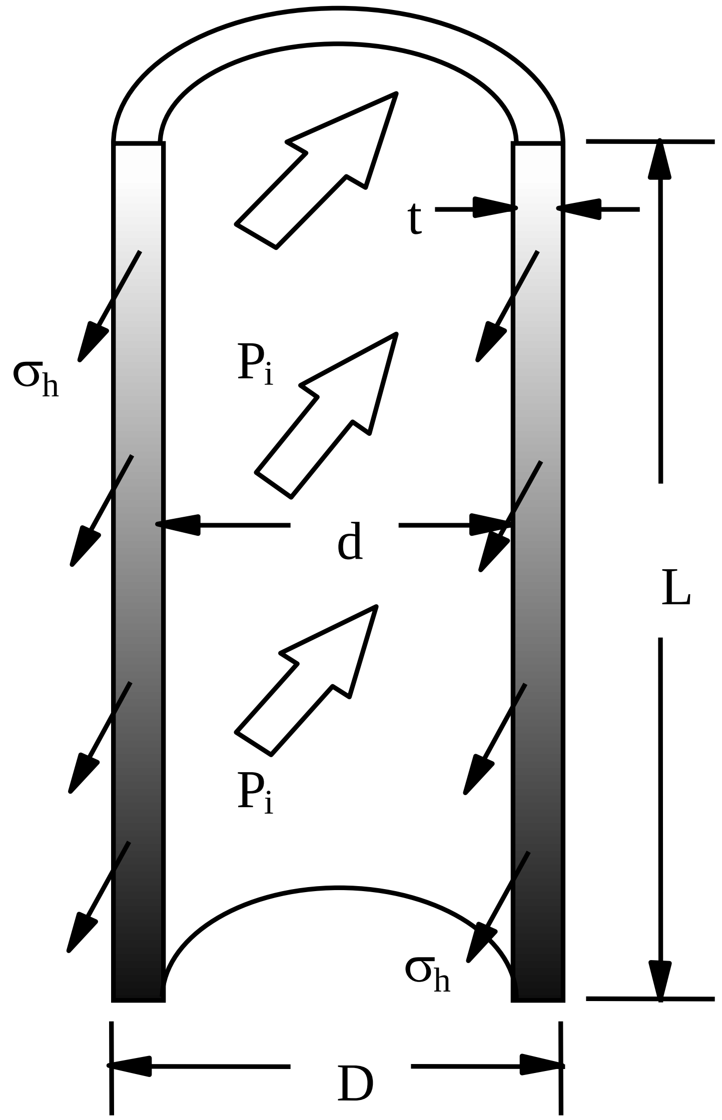
Minimum Internal Yield

Minimum Internal Yield Pressure

(Burst)

Onset of yielding of the internal wall.

NOT RUPTURE



Minimum Internal Yield

Barlow equation for thin wall cylinders:

$$P_i(d)(L) = \sigma_h(2)(t)(L)$$

Solving for internal pressure:

$$P_i = \frac{2\sigma_h t}{d}$$

The pressure which causes yield is:

$$P_y = \frac{2Y_p t}{d}$$

P_i = inside pressure, d = outside diameter, L = arbitrary length,

t = wall thickness, σ_h = hoop stress, P_y = yield pressure Y_p = yield stress

Minimum Internal Yield Pressure

minimum specified yield

nominal wall thickness

minimum specified wall

$$P_y = 0.875\left[\frac{2Y_p t}{D}\right]$$

nominal OD

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Estimated Rupture Pressure

ultimate strength

nominal OD

$$P_r = U_p \ln\left(\frac{D}{d}\right)$$

nominal ID

Based on Tresca

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Internal Yield - Coupling

Minimum Internal Yield Rating for STC, LTC and BTC API Couplings:

$$P = Y_c \left(\frac{W - d_1}{W} \right)$$

Y_c = coupling yield strength (psi)

W = coupling outside diameter (round to the nearest 0.001 in.)

d_1 = diameter at the root of the coupling thread at the end of the pipe in the power tight position (round to the nearest 0.001 in.)

(see next slide for formula to calculate d))

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Internal Yield - Coupling

For LTC and STC Casing and Tubing:

$$d_1 = E_1 - (L_1 + A)T + H - 2S_m$$

E_1= pitch diameter at hand tight plane (in)

L_1 = length, from pipe end to hand tight plane (in)

A = hand tight standoff (in)

T = taper (0.0625 in/in for STC and LTC)

H = 0.10825 in. for 8 TPI S_{rn} = 0.017 in. for 8 TPI

For BTC Casing:

$$d_1 = E_7 - (L_7 + I)T + .062$$

For BTC casing:

E_7= pitch diameter (in) L_7 = length of perfect threads (in)

I = specified in API as a function of diameter

– either 0.40, 0.50 or 0.375 in.

T = taper (0.0625 in/in for 4-$^{1}/_{2}$ to 13-$^{3}/_{8}$, 0.0833 in/in for larger diameter)

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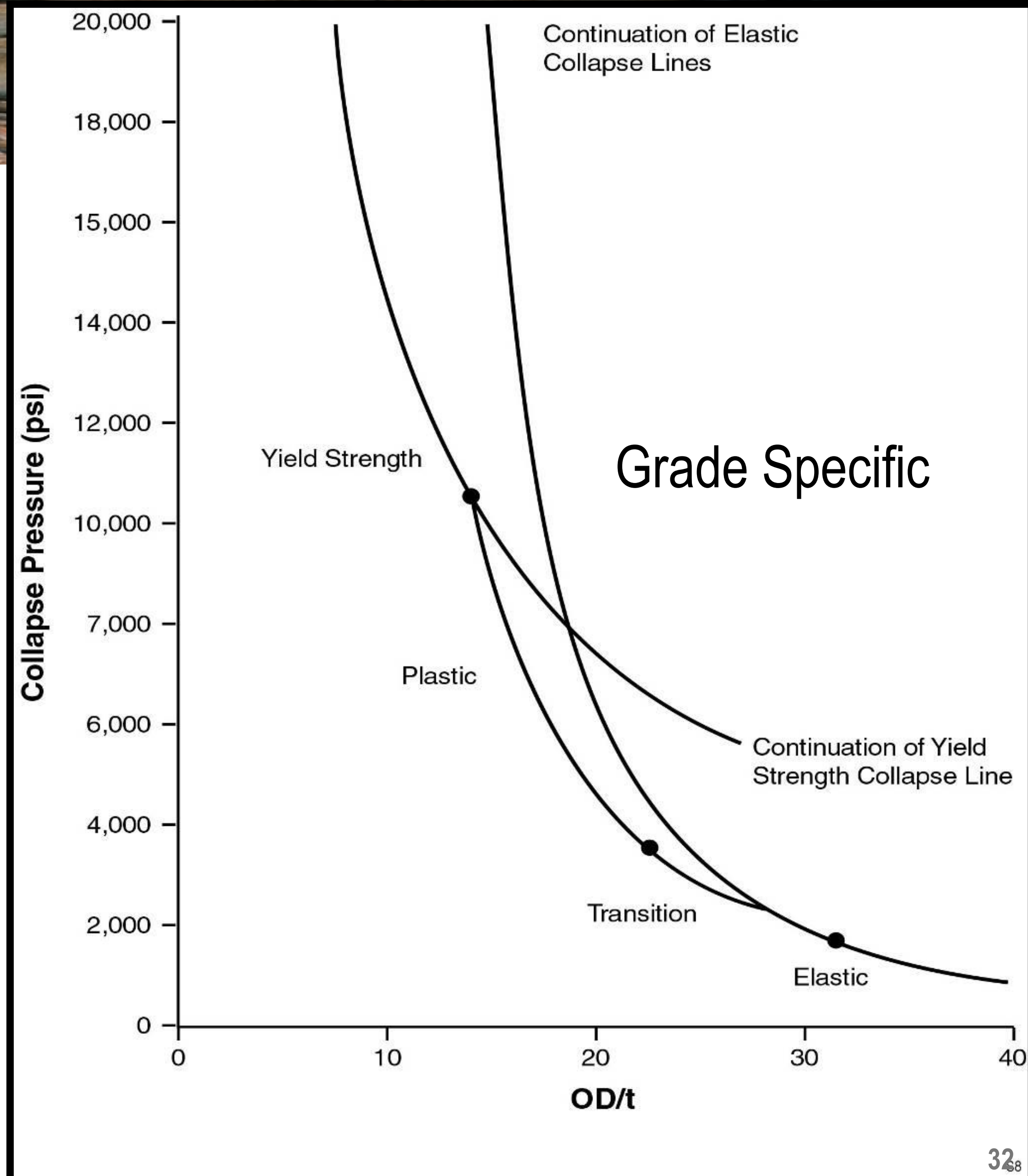
Collapse

Introduction and Background:

- Actual collapse varies
- Collapse reflects D/t, grade, heat treatment and stress due to manufacture
- Studies and failure tests
- Current ratings from studies 1960'S to present
- Current investigations by both ISO and API
- API Bulletin 5C3 collapse ratings

Collapse vs. D/t

- Yield
- Plastic
- Transition
- Elastic



Developed by API

API Collapse Pressure

Function of:

- Pipe OD to Wall Thickness Ratio (D/t)
- Yield Strength
- Axial Stress
- Internal Pressure
- Ovality
- Eccentricity
- Residual Stress
- Modulus of Elasticity
- Poisson's Ratio
- Stress-Strain Curve Shape

Not part of the traditional API collapse equations.

NExT

Yield Collapse

$$P_{c,Y_p} = 2Y_{pa}\left[\frac{(D/t)-1}{(D/t)^2}\right]$$

For Low D/t Ratio Pipe

3.5" 12.95 lb/ft P110

NExT

Plastic Collapse

$$P_{c,P} = Y_{pa}\left[\frac{A}{D/t} - B\right] - C$$

For Moderate D/t Ratio Pipe
7" 32 lb/ft T95

Refer to API RP5C3 for values of A, B and C – formulas are on next slide

NExT

Factors A B and C

$$A = 2.8762 + 0.10679 \times 10^{-5} \times Y_{pa} + 0.21301 \times 10^{-10} \times Y_{pa}^{2} - 0.53132 \times 10^{-16} \times Y_{pa}^{3}$$

$$B = 0.026233 + 0.50609 \times 10^{-6} \times Y_{pa}$$

$$C = -465.93 + 0.030867 \times Y_{pa} - 0.10483 \times 10^{-7} \times Y_{pa}^{2} + 0.36989 \times 10^{-13} \times Y_{pa}^{3}$$

Values for selected yield strength is as follows:

Grade	A	B	C
K-55	2.991	0.0541	1206
N-80	3.071	0.0667	1955
P-110	3.181	0.0819	2852

Transition Collapse

$$P_{c,T} = Y_{pa}\left[\frac{F}{D/t} - G\right]$$

For High D/t Ratio Pipe
13.375" 72 lb/ft N80

Refer to API RP5C3 for values of F and G – formulas are on next slide

NExT

Factors F and G

The factors F and G are calculated as follows:

$$F = \frac{46.95 \bullet 10^{6} \left[\dfrac{3\, B/A}{2 + (B/A)} \right]^{3}}{Y_{pa} \left[\dfrac{3\, B/A}{2 + (B/A)} - (B/A) \right] \left[1 - \dfrac{3\, B/A}{2 + (B/A)} \right]^{2}}$$

$$G = FB/A$$

NExT

Elastic Collapse

$$P_{C,E} = \frac{46.95\,x10^{6}}{(D/t)\left[(D/t)-1\right]^{2}}$$

For Very High D/t Ratio Pipe

16" 84 lb/ft N80

High Collapse Pipe

Collapse Resistance is a function of:

- The average D/t ratio in cross-section
- The API yield strength of the material
- The shape of the stress/strain curve
- The ovality of the pipe
- The residual stresses in the material
- The eccentricity of the pipe wall
- Modulus of elasticity and Poisson's ratio

Collapse With Axial Load

An axial load affects the resistance of the pipe to collapse.

Collapse With Axial Load

$$Y_{pa} = \{[1 - 0.75(\sigma_a / Y_p)^2]^{1/2} - 0.5(\sigma_a / Y_p)\}Y_p$$

Y_{pa} = Yield strength available for collapse.

The more tension the less collapse strength.

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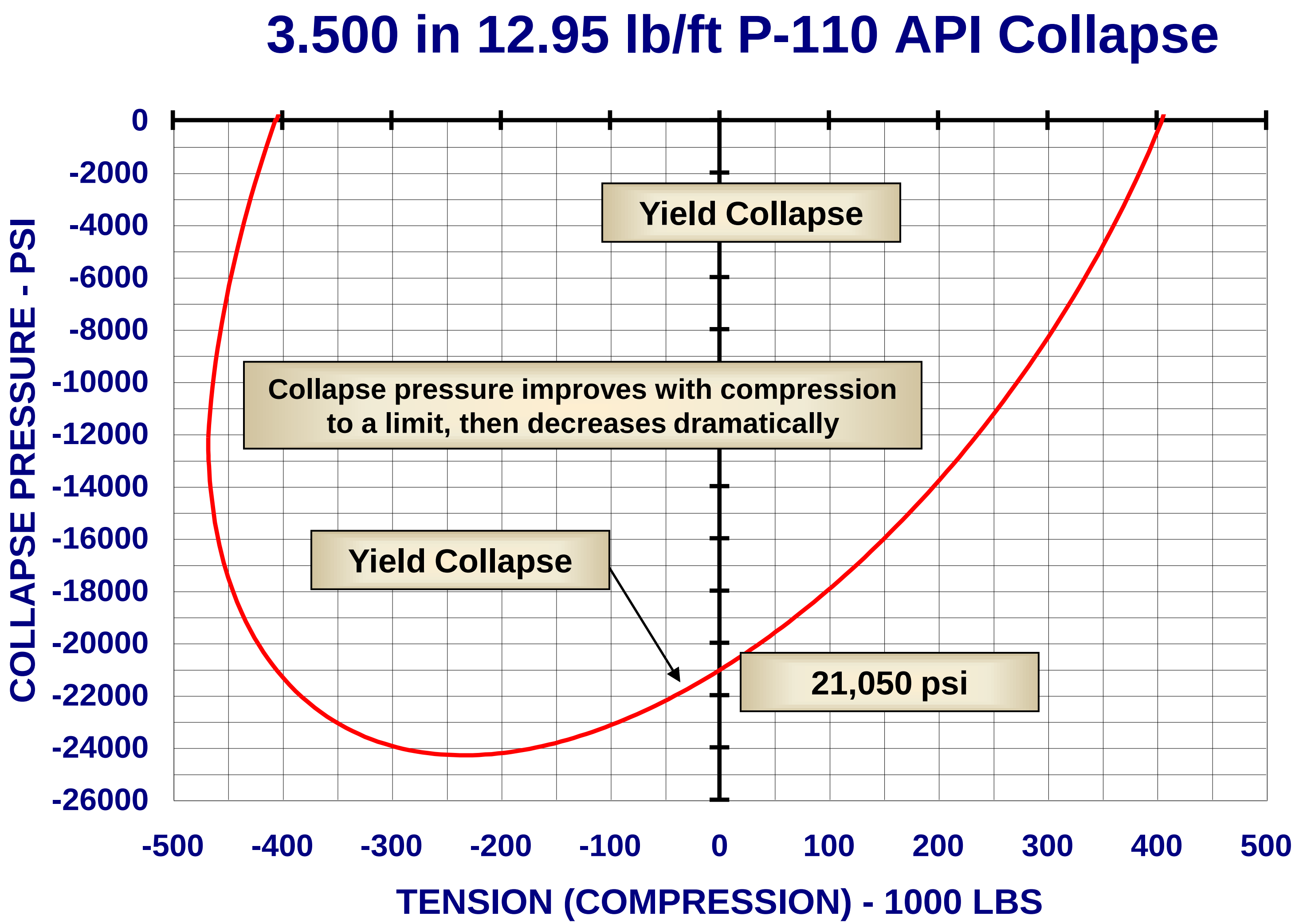
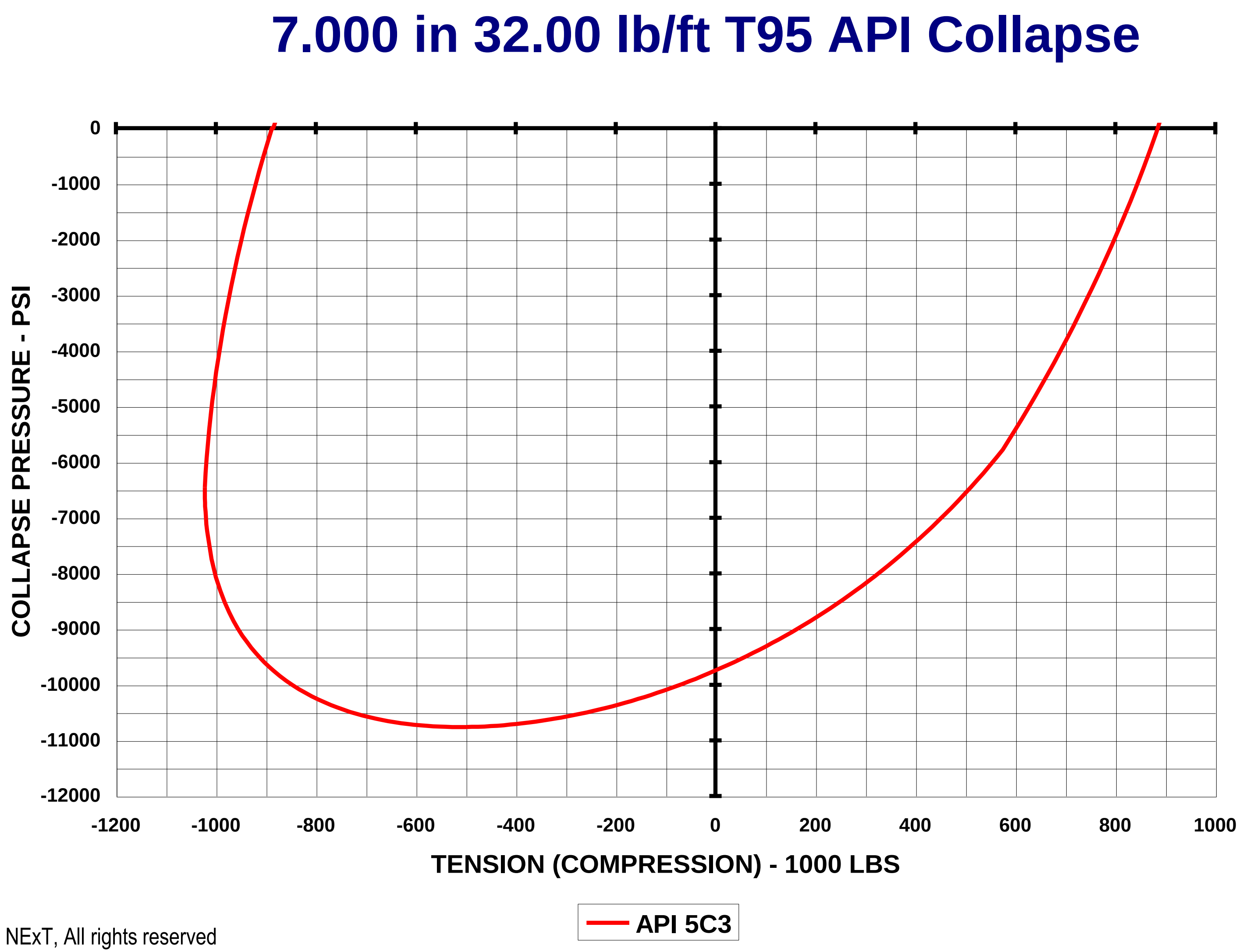
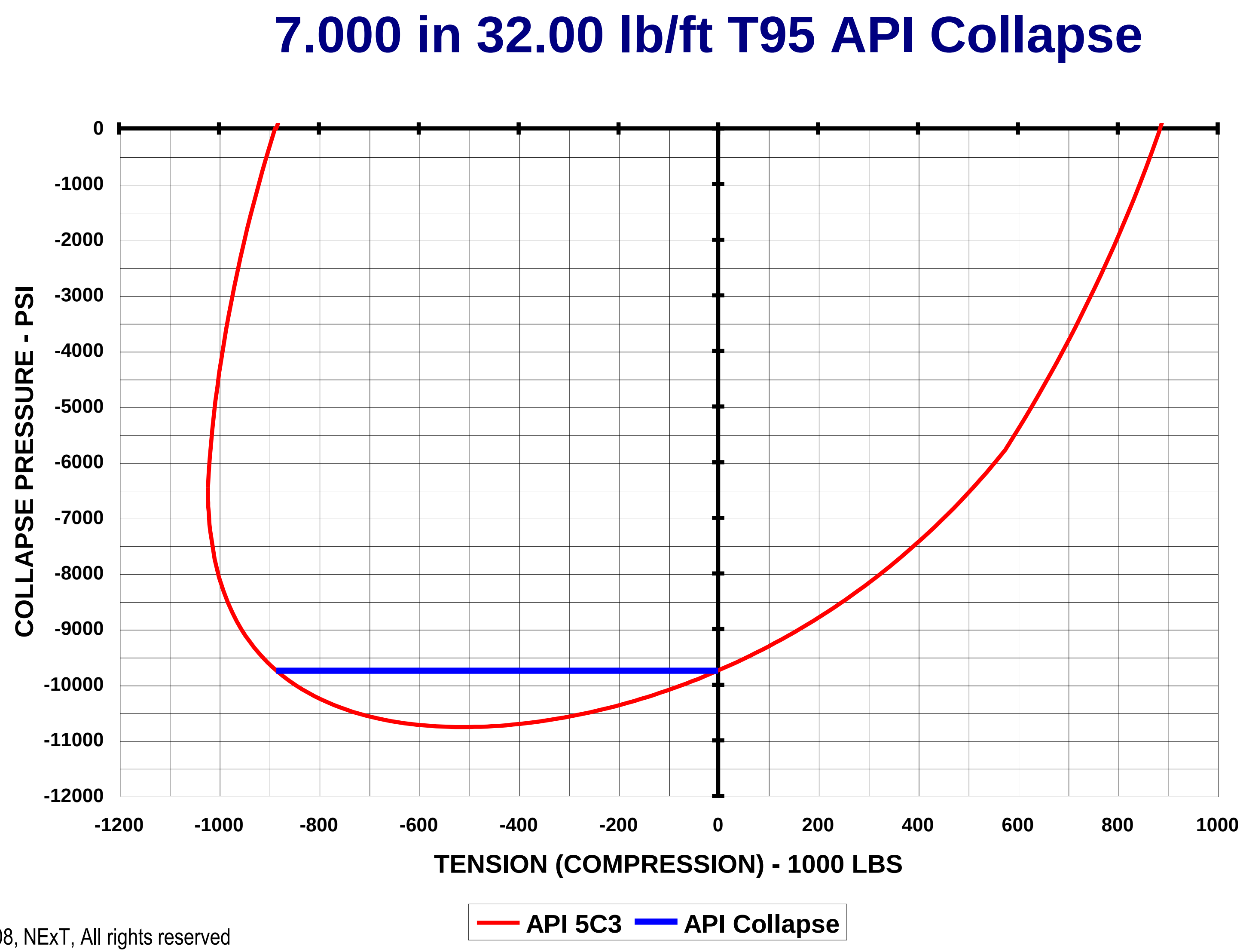
Collapse With Axial Load



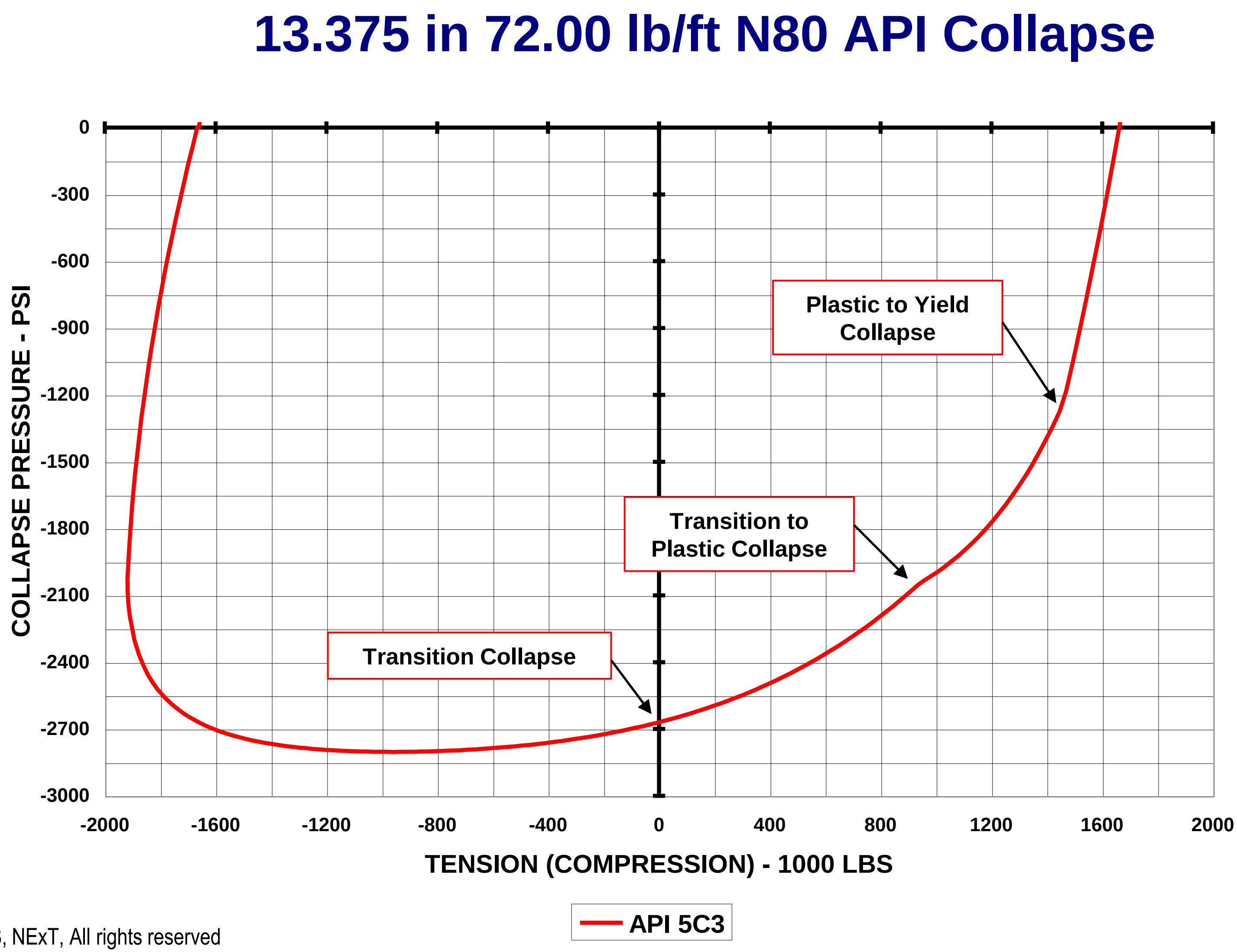
Collapse With Axial Load



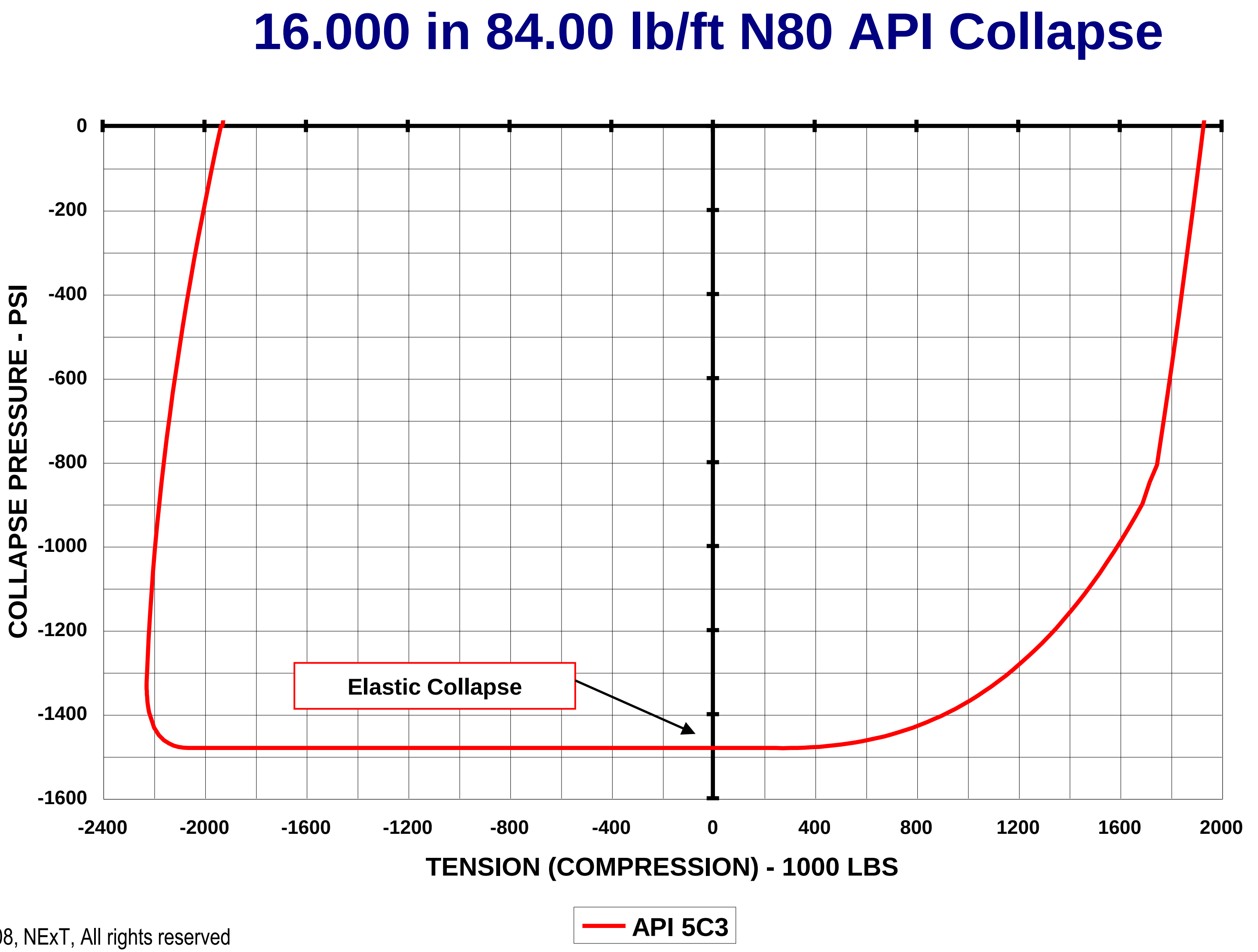
Collapse With Axial Load



Collapse With Axial Load



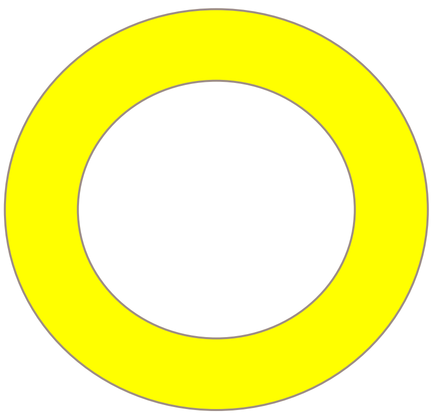
Collapse With Axial Load



Collapse With Internal Pressure

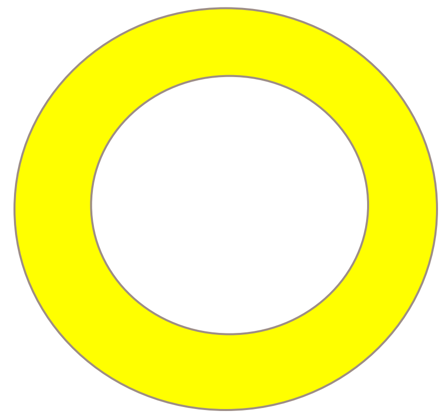
The collapse capabilities are different for these two cases.

Case A



P_o = 10,000 psi
P_i = 0 psi

Case B



P_o = 11,000 psi
P_i = 1,000 psi

Collapse With Internal Pressure

API:

P_e = equivalent collapse pressure

$$P_e = P_o - (1 - 2/(D/t))P_i$$

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Collapse With Internal Pressure

$$P_e = P_o - (1 - 2/(D/t))P_i$$

For D/t = 10:

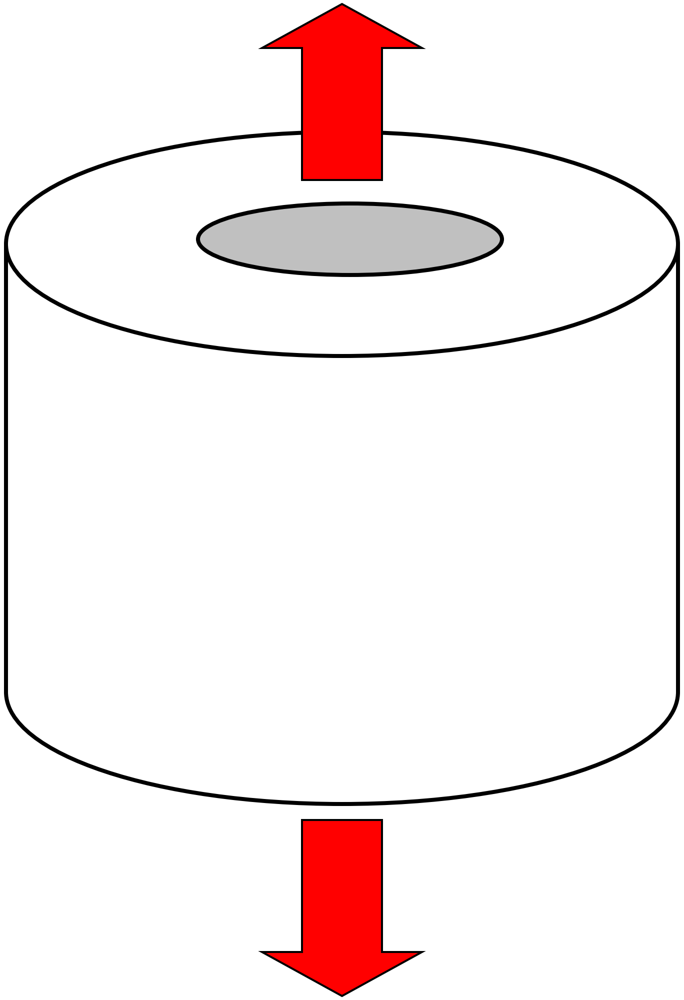
Case A:

P_e = 10000 - (1 – 2/10) 0 = 10,000 psi

Case B:

P_e = 11000 – (1 - 2/10) 1000 = 10,200 psi

Tension Strength



$$P_{pb} = A_p Y_p$$

P_{pb} = (pipe) body yield strength, lbf

Tension Strength

API tension strength formulas use:

- Minimum Specified Yield Strength
- Nominal Pipe Body OD
- Nominal Pipe Body Wall Thickness

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Compression Strength

API does not rate pipe in compression or bending.

Tension Strength

API 8 Round STC & LTC

$$P_{pin} = 0.95 A_{jp} U_p$$

Pin Fracture

P_{pin} = minimum joint strength

A_{jp} = cross-sectional area under last perfect thread,

U_p = minimum ultimate strength

NExT

Tension Strength

API 8 Round STC & LTC

$$P_j = 0.95\, A_{jp}\, L \left[\frac{0.75 D^{-0.59} U_p}{0.5L + 0.14D} + \frac{Y_p}{L + 0.14D} \right]$$

Pin Jump-Out

P_j = minimum joint strength

A_{jp} = cross-sectional area under last perfect thread,

U_p = minimum ultimate strength

D = outside diameter

Y_p = minimum yield strength

L = engaged thread length

NExT

Tension Strength

API BTC

$$P_{pin} = 0.95\, A_{jp} U_p \left[1.008 - 0.0396 \left(1.083 - \frac{Y_p}{U_p} \right) D \right]$$

Pin Fracture

NExT

Tension Strength

API STC, LTC, & BTC

$$P_c = 0.95\, A_c U_c$$

Coupling Thread Fracture

NExT

Tension Strength

API Body Yield - Tension

$$P_{body} = A_p Y_p$$

Tension Strength

API tension strength formulas use:

- Minimum Specified Ultimate Strength
- Minimum Specified Yield Strength
- Nominal Pipe Body Diameters
- Nominal Coupling Diameters

Compression Strength

Body Yield - Compression

$$P_{body} = A_p Y_p$$

Compression Strength

API Connections:

API does not rate connections in compression or bending.

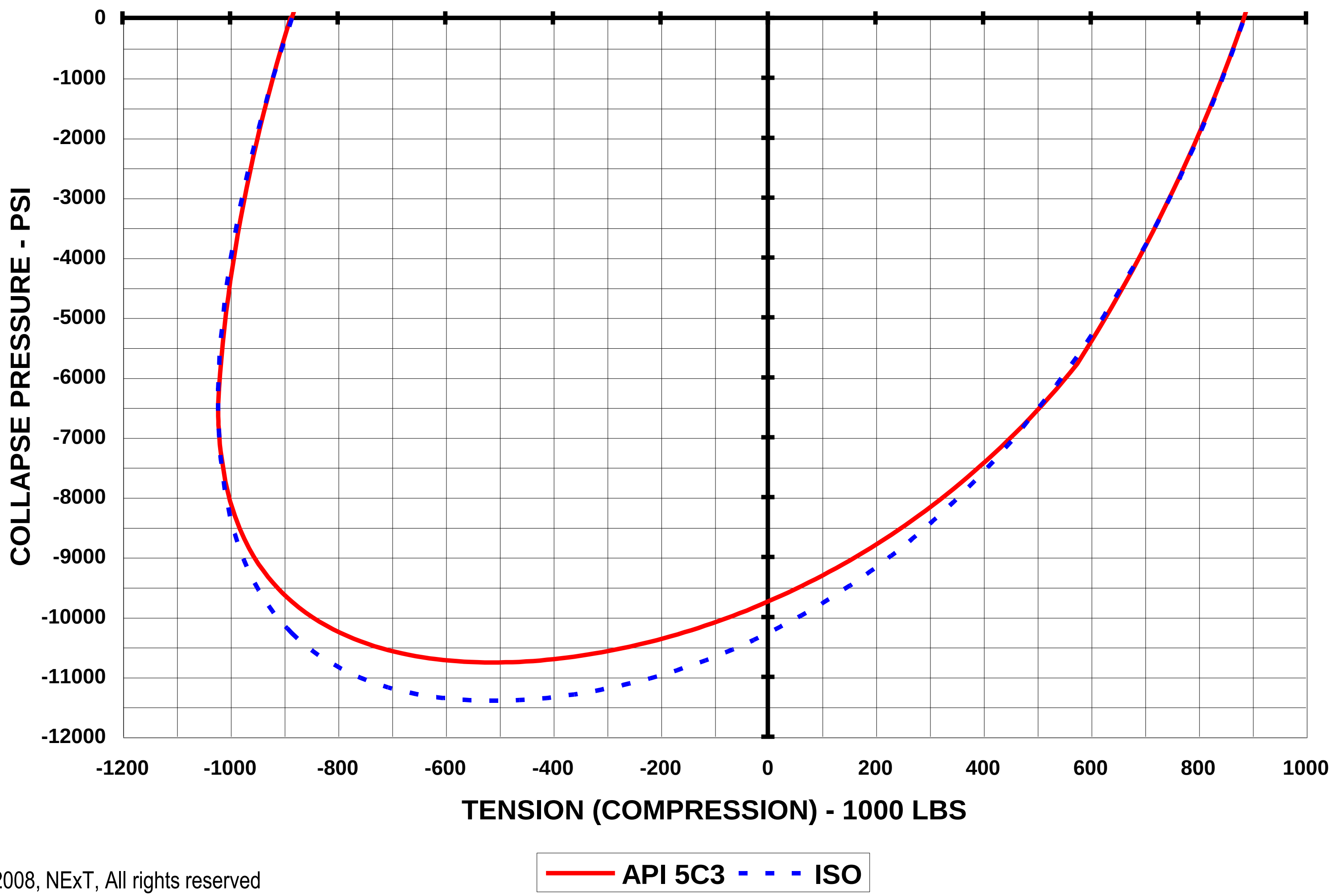
ISO 10400 Collapse Pressure

Function of:

- Pipe OD to Wall Thickness Ratio (D/t)
- Yield Strength
- Axial Stress
- Internal Pressure
- Ovality
- Eccentricity
- Residual Stress
- Modulus of Elasticity
- Poisson's Ratio
- Stress-Strain Curve Shape

ISO 10400 Collapse Pressure

7.000 in 32.00 lb/ft T95 Collapse Comparison



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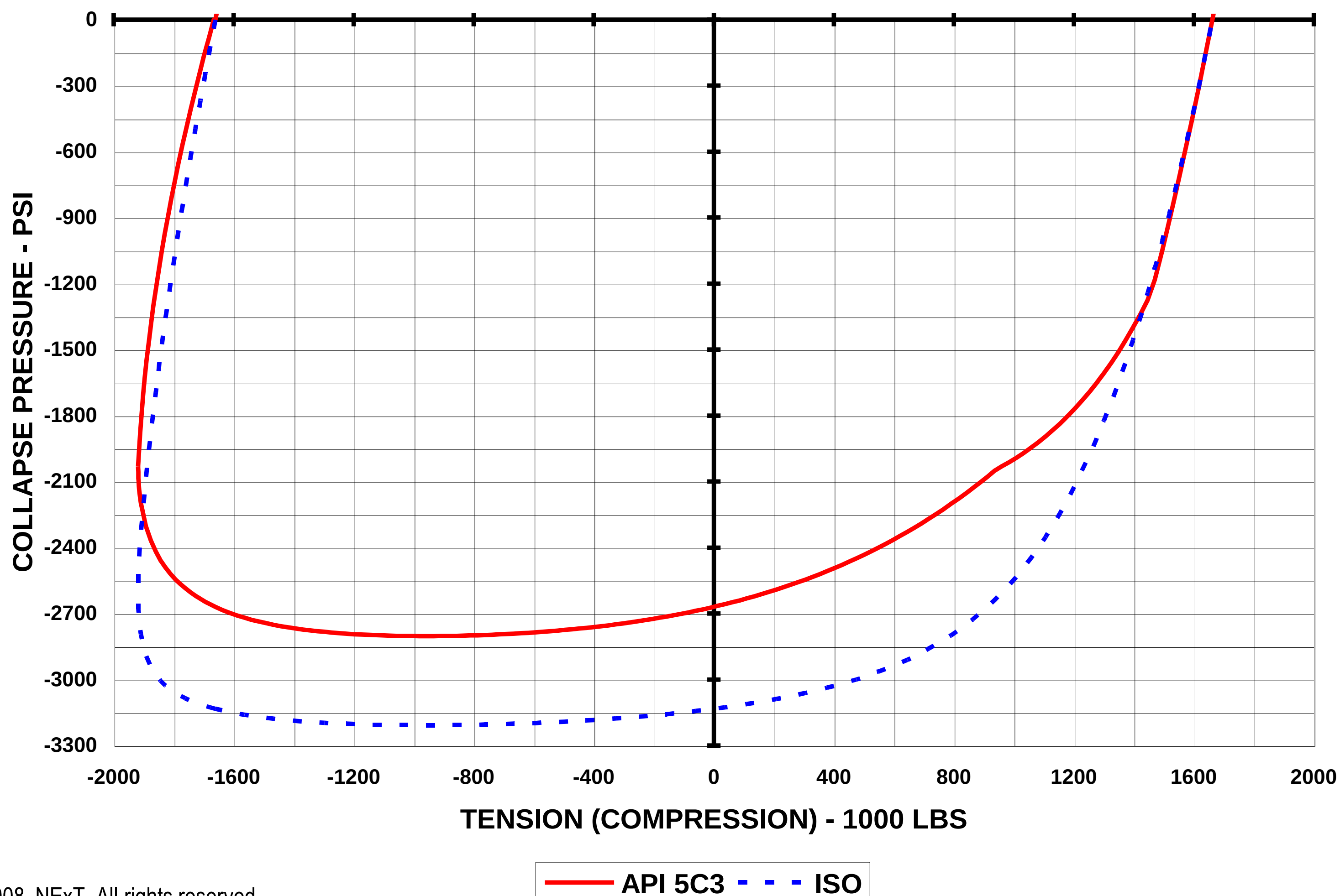
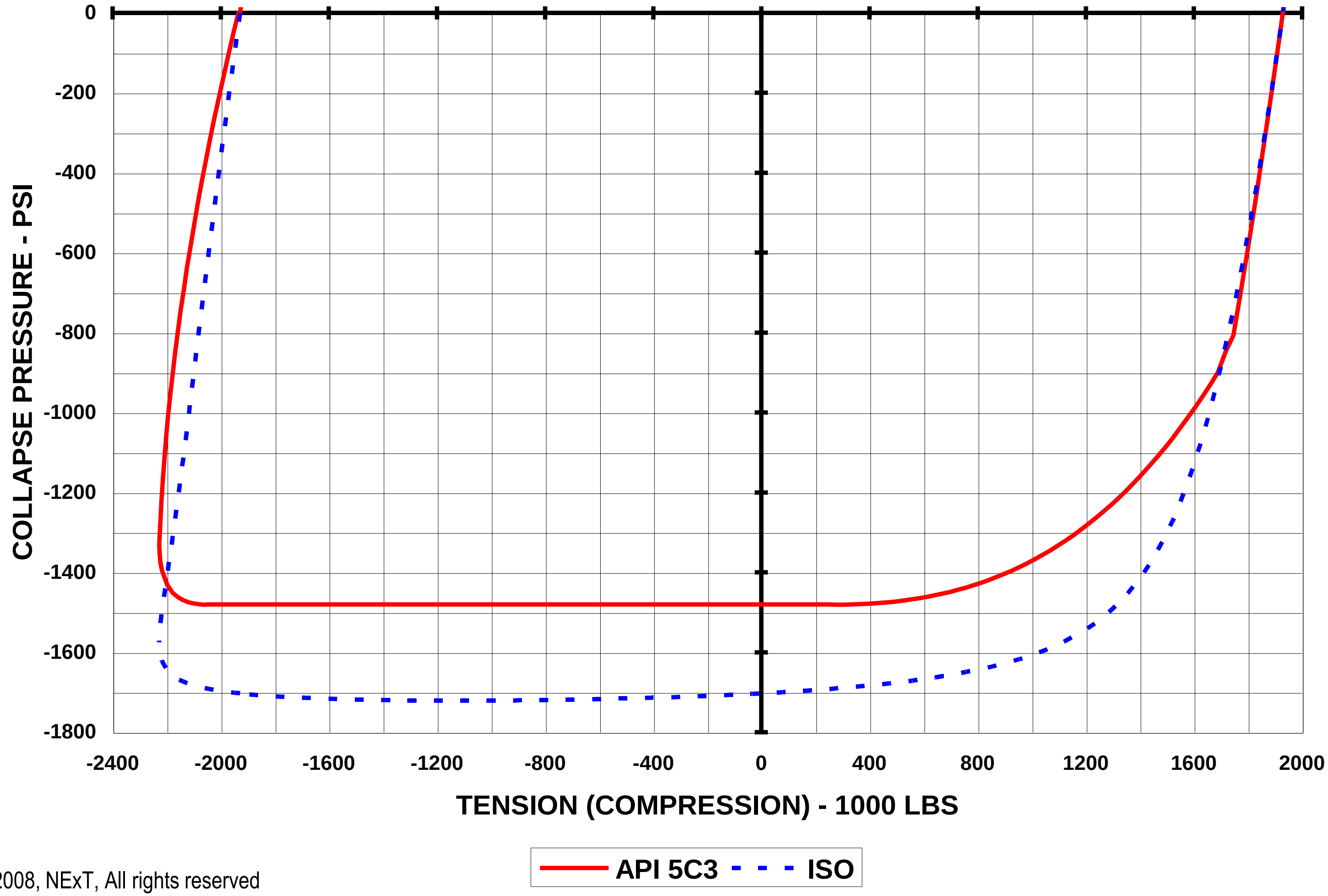
ISO 10400 Collapse Pressure

13.375 in 72.00 lb/ft N80 Collapse Comparison



ISO 10400 Collapse Pressure

16.000 in 84.00 lb/ft N80 Collapse Comparison



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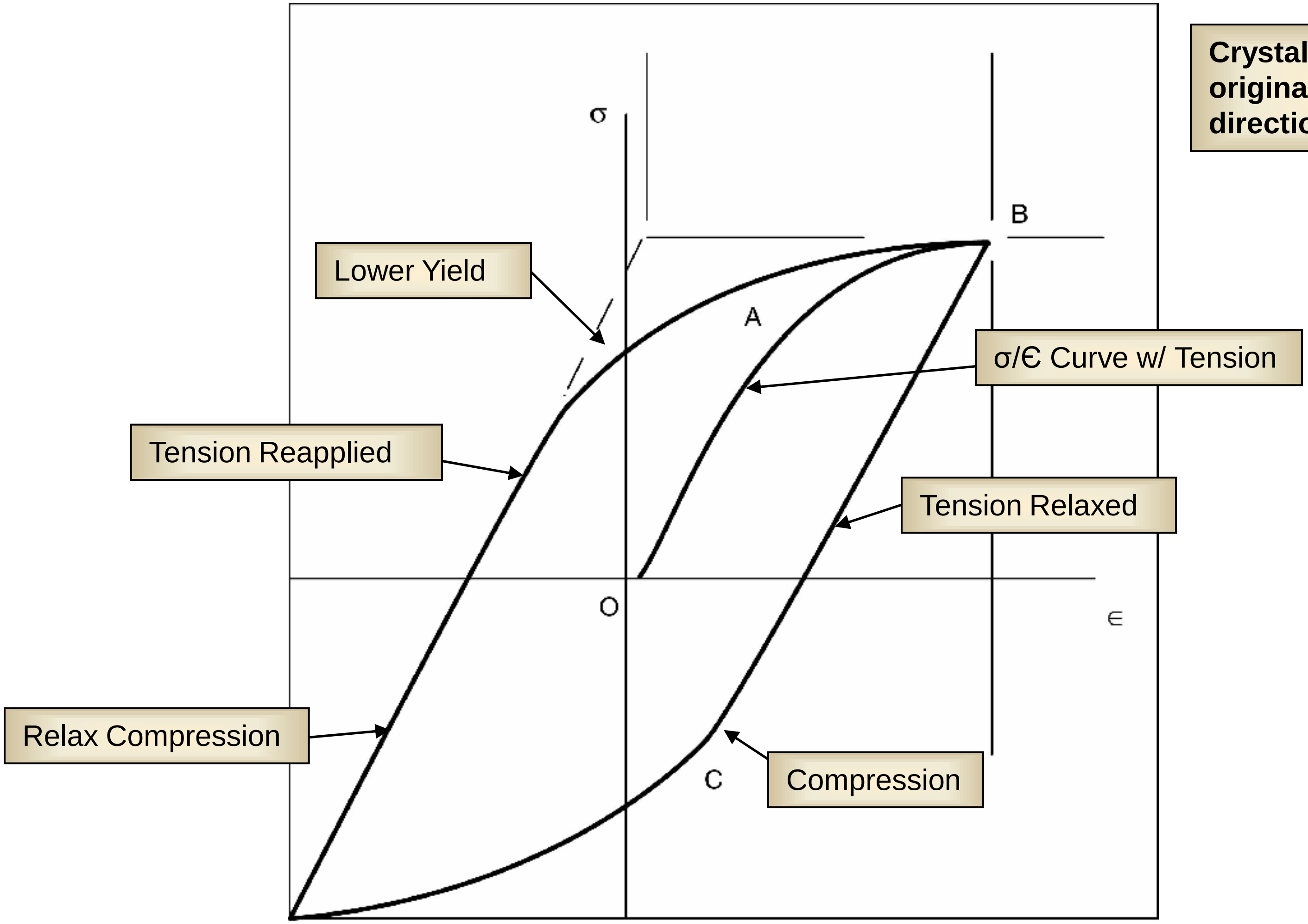
Material Density

ALLOY	DENSITY (lb/in3)	RATIO TO CARBON STEEL
Steel	0.283	1.000
Cr13	0.280	0.989
Duplex	0.289	1.021
Austenitic	0.290	1.025
Ni-3Mo	0.294	1.039
Ni-6Mo	0.300	1.060
C-276	0.321	1.134

Baushinger Effect



Crystals align w/ original tension direction (plastic)

The phenomenon by which plastic deformation increases yield strength in the direction of plastic flow and decreases it in other directions.

NExT

API Grades Manufacture and Heat Treatment

Table E.4—Process of manufacture and heat treatment

Group	Grade	Type	Manufacturing process [a]	Heat treatment	Tempering temperature min. °F
1	*2*	*3*	*4*	*5*	*6*
1	H40		S or EW	None	
	J55		S or EW	None [b]	
	K55		S or EW	None [b]	
	N80	1	S or EW	[c]	
	N80	Q	S or EW	Q&T	
2	M65		S or EW	[d]	
	L80	1	S or EW	Q&T	1050
	L80	9Cr	S	Q&T [e]	1100
	L80	13Cr	S	Q&T [e]	1100
	C90	1	S	Q&T	1150
	C90	2	S	Q&T	1150
	C95		S or EW	Q&T	1000
	T95	1	S	Q&T	1200
	T95	2	S	Q&T	1200
3	P110		S or EW [f,g]	Q&T	
4	Q125	1	S or EW [g]	Q&T	
	Q125	2	S or EW [g]	Q&T	
	Q125	3	S or EW [g]	Q&T	
	Q125	4	S or EW [g]	Q&T	

[a] S = seamless process; EW = electric-welded process.

[b] Full length normalized (N), normalized and tempered (N&T), or quenched and tempered (Q&T), at the manufacturer's option or as specified on the purchase agreement.

[c] Full length normalized or normalized and tempered at the manufacturer's option.

[d] All pipe shall be full body heat-treated. Full length normalized (N), normalized and tempered (N&T), or quenched and tempered (Q&T), at the manufacturer's option or as specified on the purchase agreement.

[e] Type 9Cr and 13Cr may be air-quenched.

[f] Special chemical requirements for electric-welded P110 casing are specified in Table E.5.

[g] Special requirements unique to electric-welded P110 and Q125 are specified in A.5 (SR11).

Tensile and Hardness Requirements

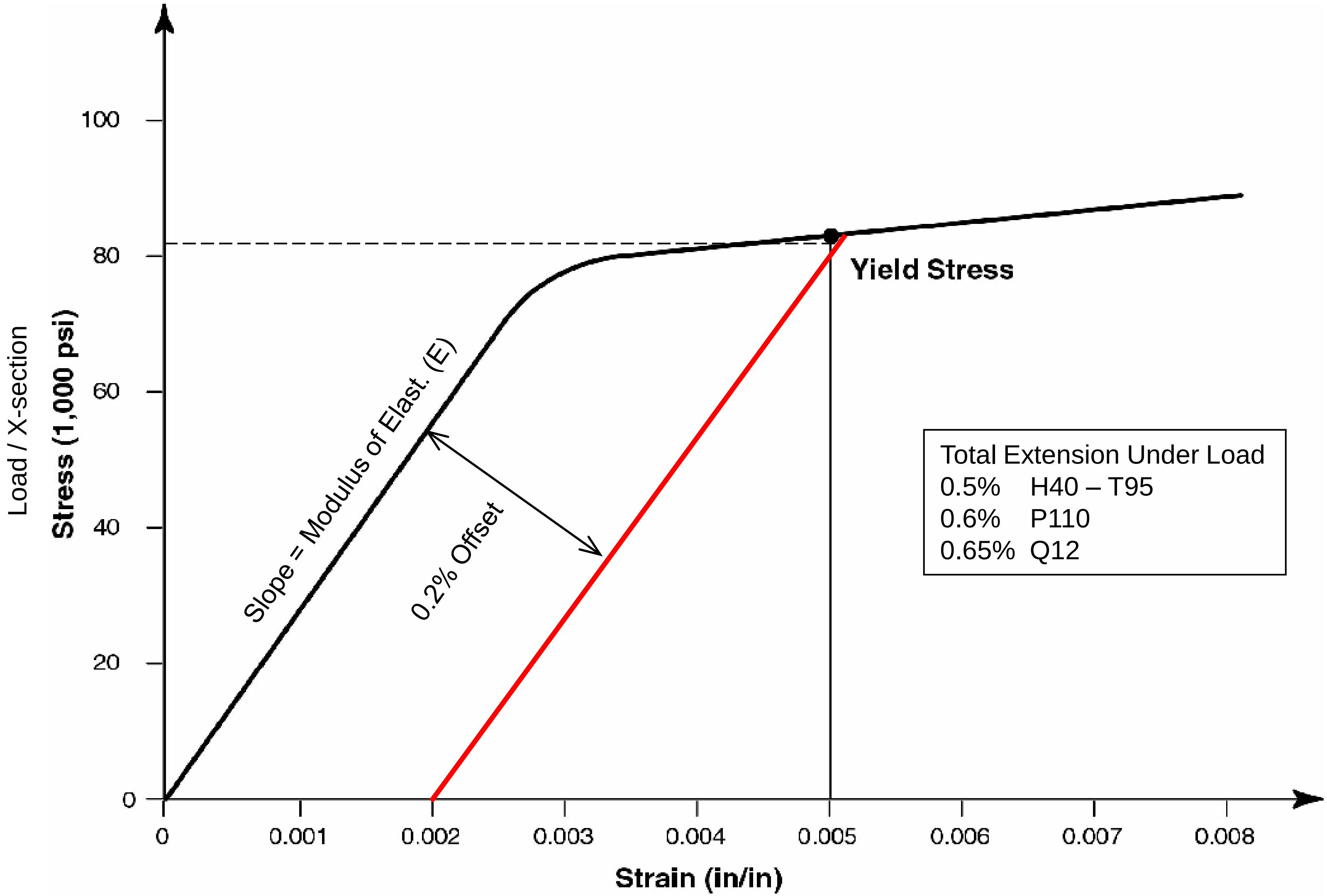
Table E.6—Tensile and hardness requirements

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/HBS	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	0.500 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		0.500 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

Stress Strain Curve-Yield Stress API and ASTM

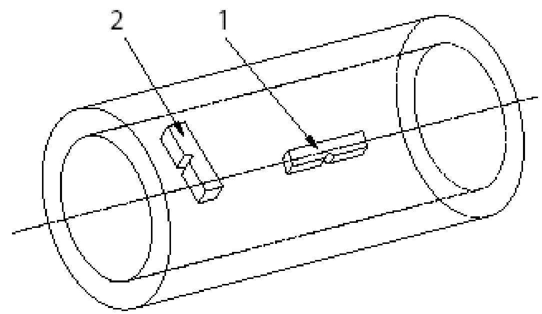


Total Extension Under Load
0.5% H40 – T95
0.6% P110
0.65% Q12

Change in Length

Toughness

Charpy Specimens



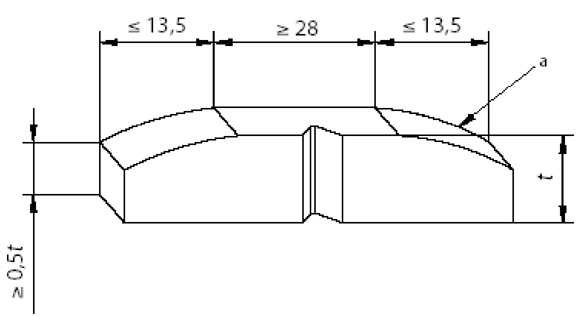
All impact test specimens shall be 10 mm x 10 mm if possible.
The notch shall be oriented perpendicular to the axis of the tube (normal to the tube surface).

Key

1 Longitudinal specimen
2 Transverse specimen

Figure D.12—Impact test specimen orientation

Dimensions in millimetres



Toughness indicator, ability to resist crack propagation.

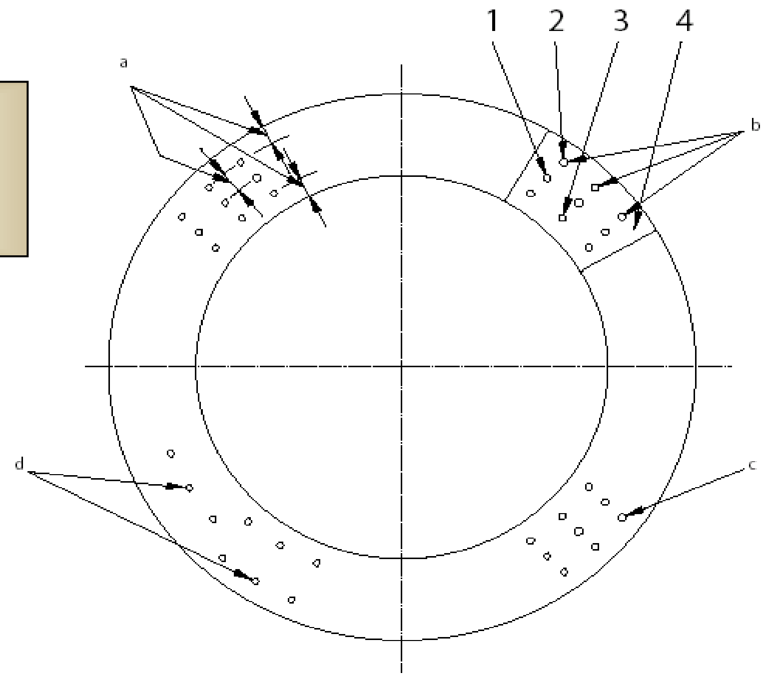
a Outside diameter curvature.

Figure D.13—Charpy specimen dimensions

Hardness Test

Through Wall
Hardness Test

Methods to Achieve:
Avoid Other Impressions
Avoid Edge



Key

1 Impression at mid-wall location

2 Impression at OD location

3 Impression at ID location

4 Hardness impression test block

a An error may result if an indentation is spaced closer than 2 1/2 diameters from its centre to the edge of the specimen or 3 diameters from another indentation measured centre-to-centre.

b Average of Rockwell hardness readings is called a value .

c Rockwell hardness impression data are called readings .

d Alternate spacing of rows permitted for thin-wall pipe.

Figure D.11—Through-wall hardness test

Chemical Composition

Table C.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	—	1,00	0,25 [b]	0,75	—	1,20	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		1,00	—	0,75	—	1,20	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 % maximum 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 17,78 mm.
[c] The carbon content for C95 may be increased up to 0,55 % maximum if the product is oil-quenched.
[d] The molybdenum content for T95 Type 1 may be decreased to 0,15 % minimum if the wall thickness is less than 17,78 mm.
[e] For EW Grade P110 the phosphorus content shall be 0,020 % maximum and the sulfur content 0,010 % maximum.
NL = no limit. Elements shown shall be reported in product analysis.

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Heat Treat

Table E.4—Process of manufacture and heat treatment

Group	Grade	Type	Manufacturing process [a]	Heat treatment	Tempering temperature min. °F
1	*2*	*3*	*4*	*5*	*6*
1	H40		S or EW	None	
	J55		S or EW	None [b]	
	K55		S or EW	None [b]	
	N80	1	S or EW	[c]	
	N80	Q	S or EW	Q&T	
2	M65		S or EW	[d]	
	L80	1	S or EW	Q&T	1050
	L80	9Cr	S	Q&T [e]	1100
	L80	13Cr	S	Q&T [e]	1100
	C90	1	S	Q&T	1150
	C90	2	S	Q&T	1150
	C95		S or EW	Q&T	1000
	T95	1	S	Q&T	1200
	T95	2	S	Q&T	1200
3	P110		S or EW [f,g]	Q&T	
4	Q125	1	S or EW [g]	Q&T	
	Q125	2	S or EW [g]	Q&T	
	Q125	3	S or EW [g]	Q&T	
	Q125	4	S or EW [g]	Q&T	

[a] S = seamless process; EW = electric-welded process.

[b] Full length normalized (N), normalized and tempered (N&T), or quenched and tempered (Q&T), at the manufacturer's option or as specified on the purchase agreement.

[c] Full length normalized or normalized and tempered at the manufacturer's option.

[d] All pipe shall be full body heat-treated. Full length normalized (N), normalized and tempered (N&T), or quenched and tempered (Q&T), at the manufacturer's option or as specified on the purchase agreement.

[e] Type 9Cr and 13Cr may be air-quenched.

[f] Special chemical requirements for electric-welded P110 casing are specified in Table E.5.

[g] Special requirements unique to electric-welded P110 and Q125 are specified in A.5 (SR11).

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Tensile and Hardness

Sour Service Materials

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/HBS	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	0.500 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		0.500 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

NExT

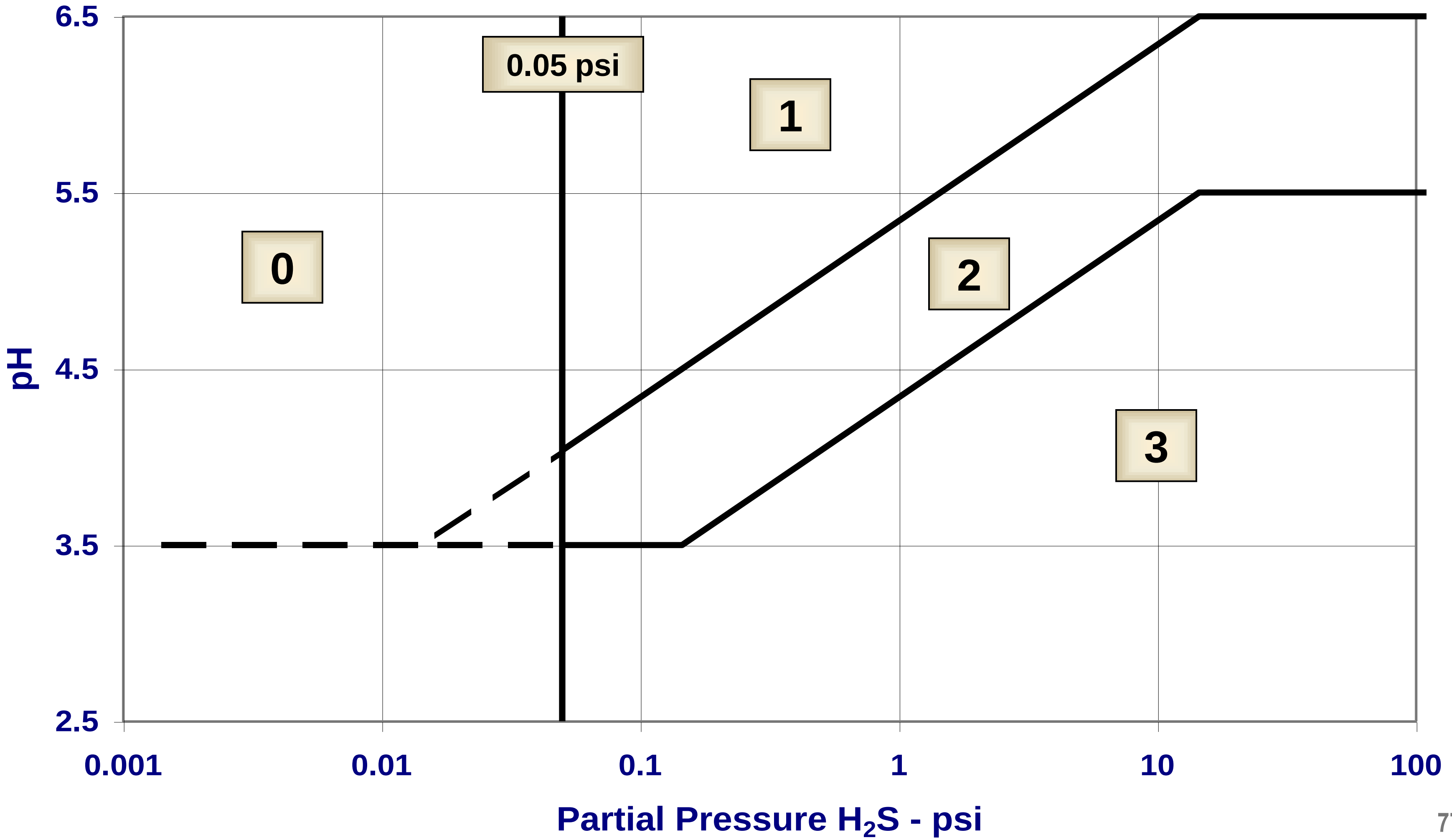
Sour Service

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.			

Sour Service

Figure 1 - ISO 15156



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Practical Hints for CRA

Components continued:

- Free Sulfur can occur as low as 4-5% H_2S. Extremely severe to CRA
- Acid stimulation fluids: carefully evaluate inhibitors
- Completion fluids: Attempt to use low density single salt brines. Certain fluids can be very aggressive in CO_2 environment. Try to avoid Zinc Bromides.
- Scale: some scales can be beneficial

Inspection

- Electromagnetic
- Ultrasonic
- Gamma Ray
- Eddy Current
- Magnetic Particle
- Pressure Test
- Full Length Drift

Well Site Visual Inspections

- Pipe Body
- Drift (Rabbit)
- Thread
- Couplings

Exercises

- Minimum Internal Yield (MIYP)
- Yield Strength Collapse
- Plastic Collapse
- Transition Collapse
- Elastic Collapse

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Exercise

Stress/Strain Exercise

You are looking at a stress-strain curve from a tension test just pulled on casing considered for your well. Find the following information from the attached stress-strain curve (see attached):

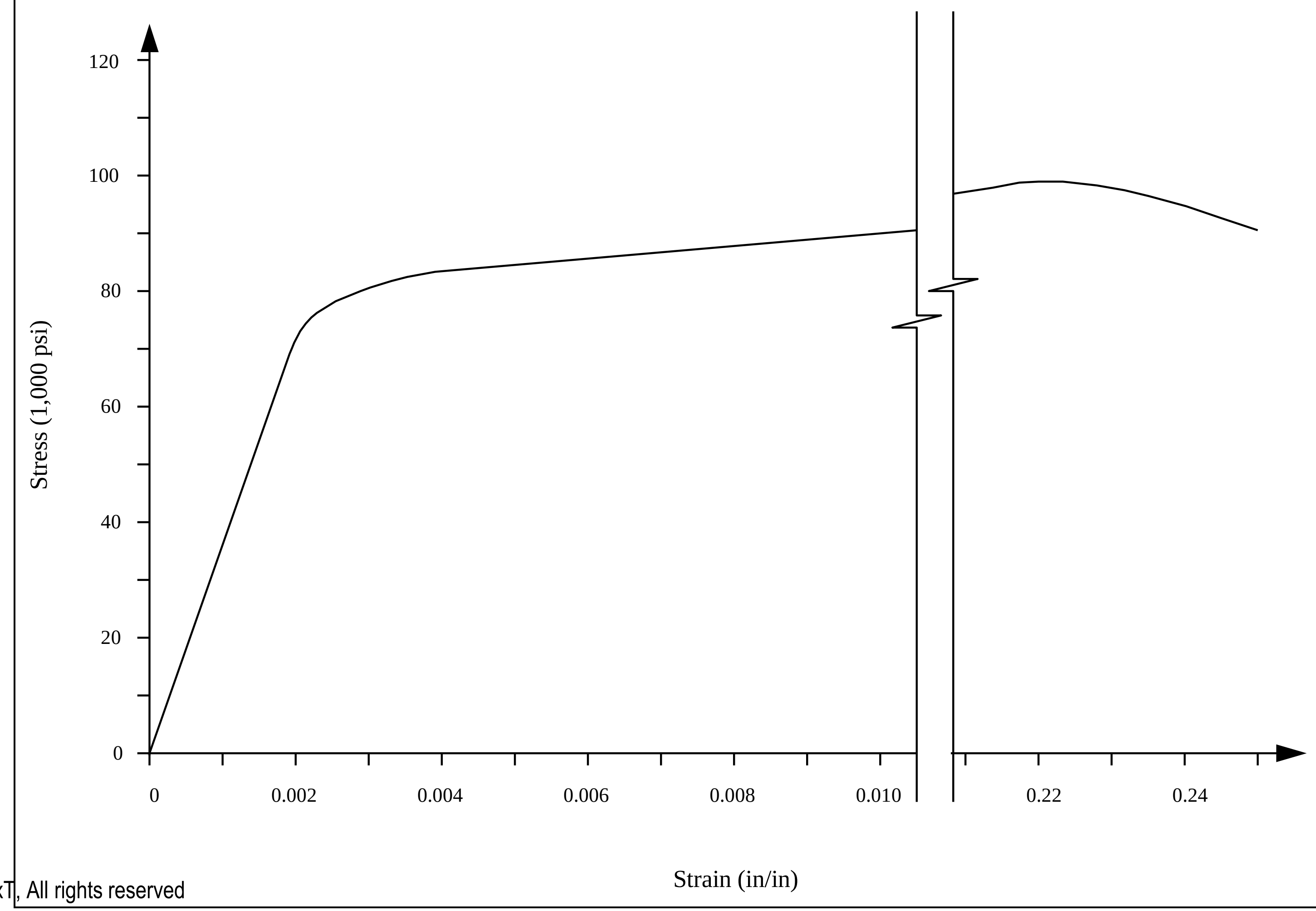
a) Elastic limit = ____________________ psi.

b) Yield point (per ASTM method) = ______________________ psi.

c) Yield point (per API method) = ______________________ psi.

d) Ultimate strength = _____________________ psi.

Exercise



NExT

NExT Drilling Well Planning and Design

Tubing and Casing Design

Two

Well Planning and Design

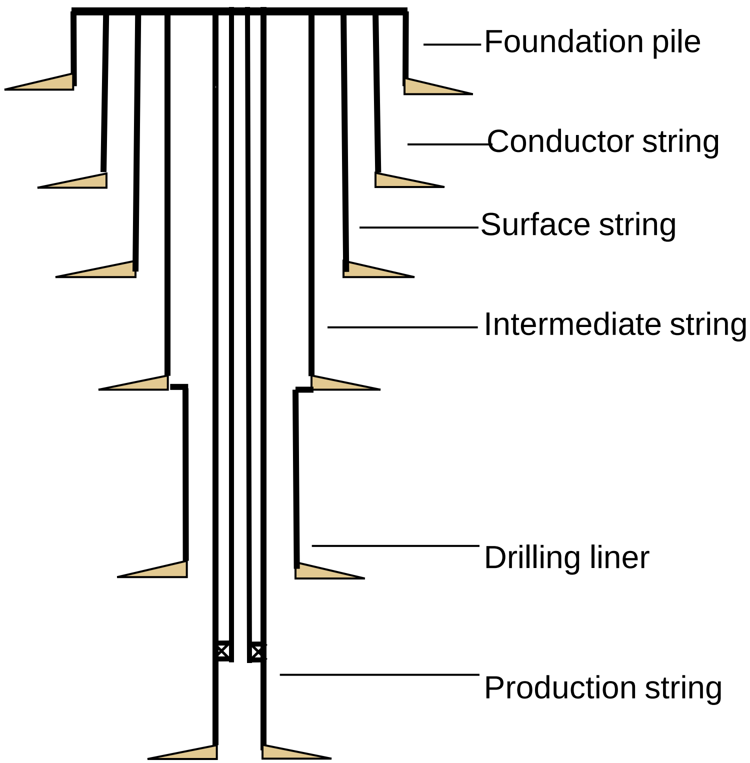
Agenda Day 2:

- Objectives of Casing Design
- Casing Design Concepts
- Tri-Axial Design Principles
- Other Considerations
- Exercises

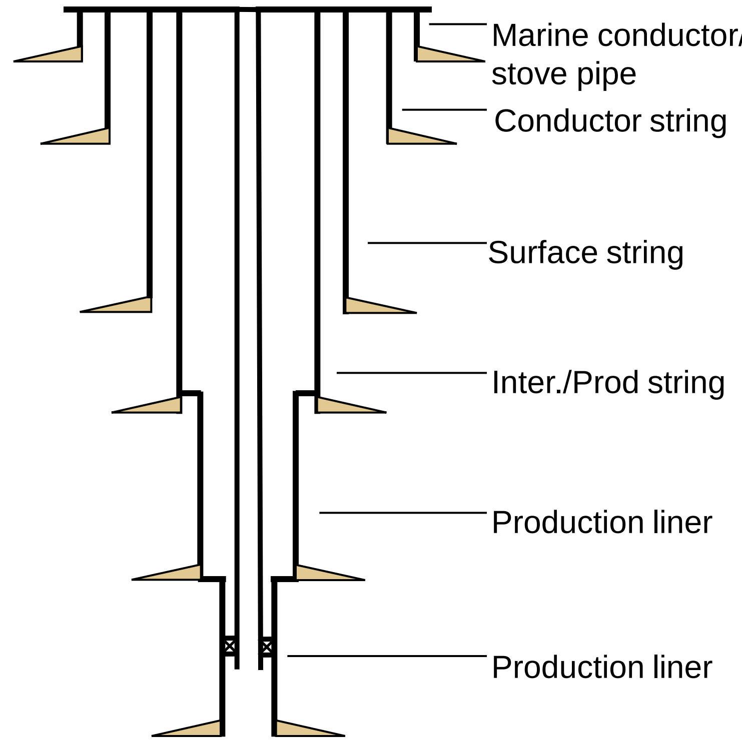
NExT

Well Types

Subsea well



Offshore platform
or land well



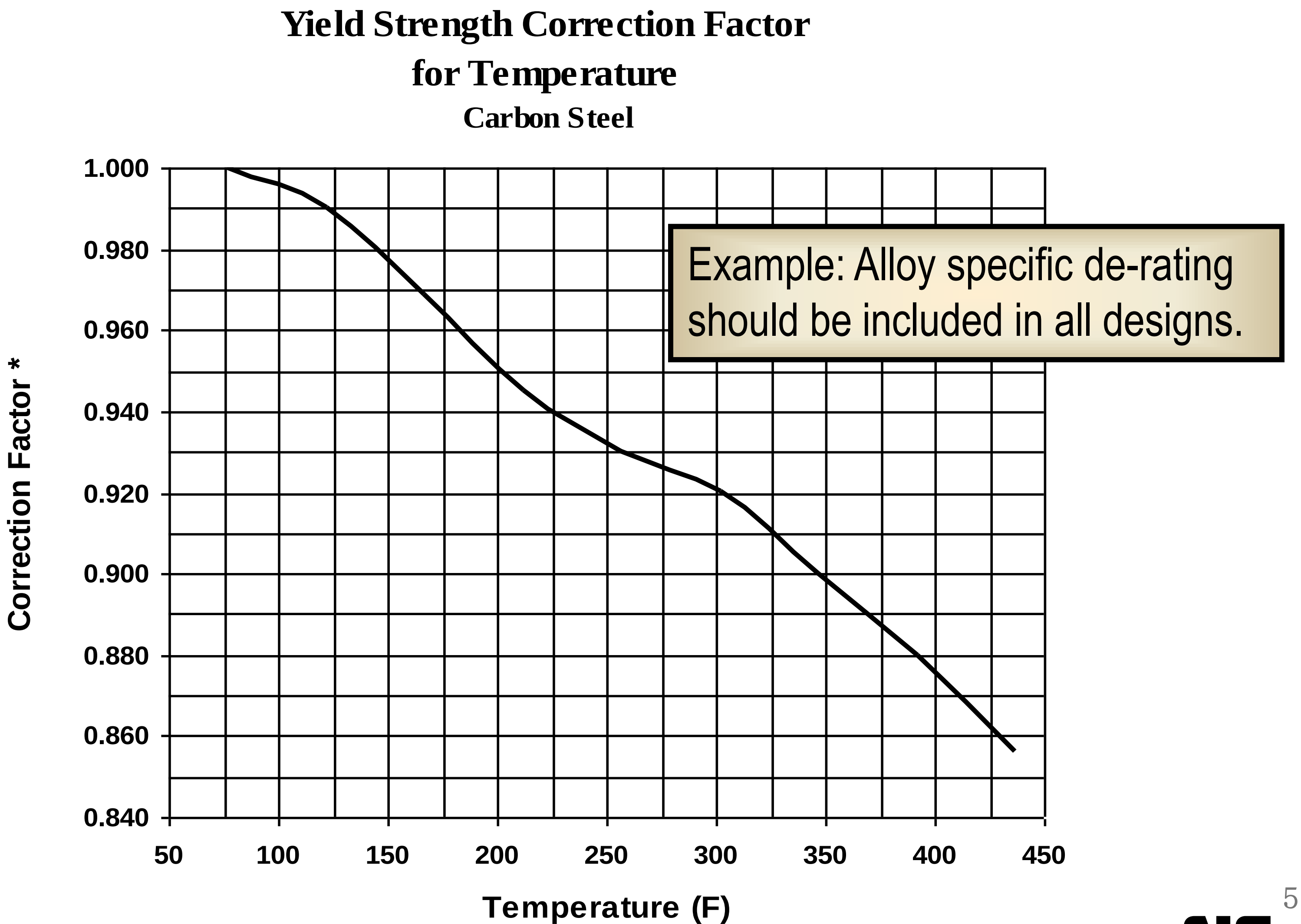
Design Cautions

- YIELD STRENGTH TEMPERATURE DERATION
  Yield strength reduces with temperature
  IMPORTANT DESIGN ELEMENT

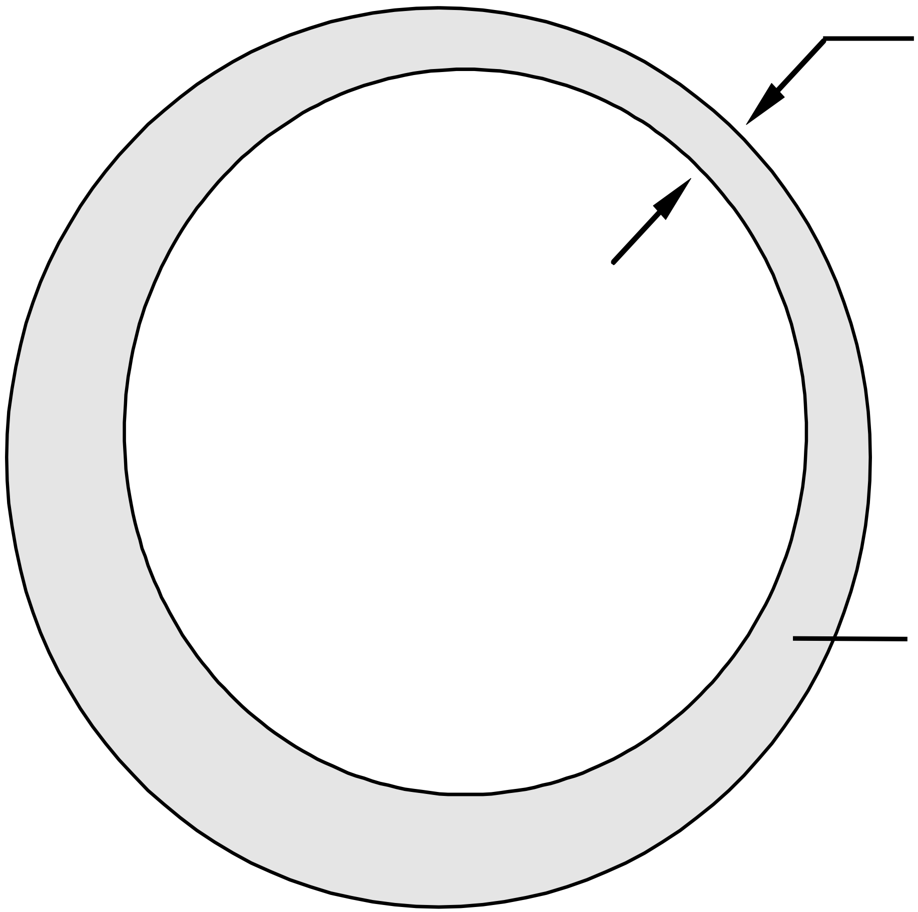
- REDUCED PIPE WALL - Eccentricity

- CASING WEAR – Can greatly reduce performance properties, i.e. MIYP and collapse

Yield Correction Factor



Reduced Wall



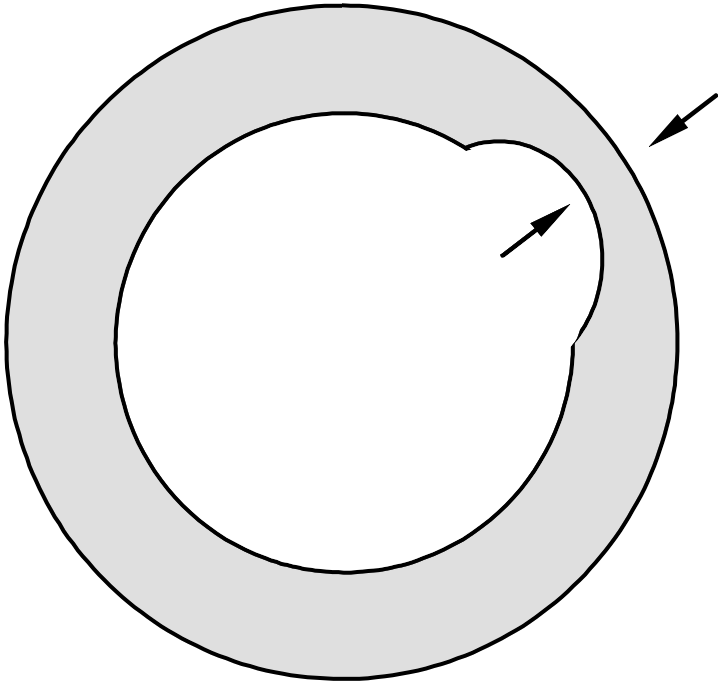
87.5% of specified wall thickness.

Min. wall used for MIYP
Nominal used for collapse

Pipe cross-sectional area remains constant even when the thick-ness is non-uniform due to eccentricity.

NExT

Casing Wear



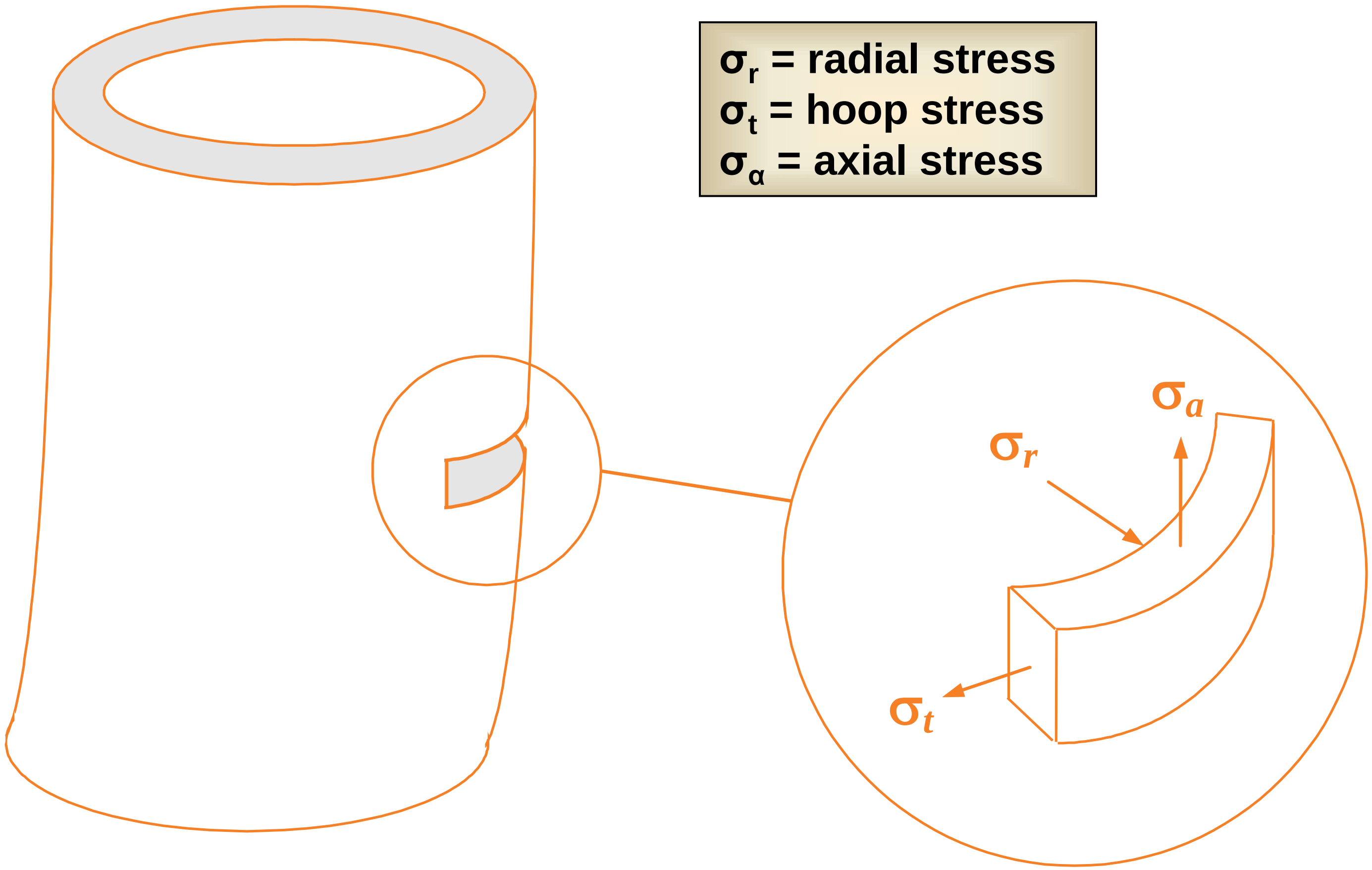
Local wear will have a large effect on the burst and collapse resistance of the pipe but will reduce the overall cross-sectional area only nominally. This will result in only a small reduction in the axial rating.

Triaxial Design Principles

- Tangential and radial stresses are calculated using the Lamé equations for thick wall cylinders.
- Axial loads are considered to be evenly distributed.
- Tangential stress is greatest on the I.D.
- Tangential stress formula is modified to account for allowed (API) minimum wall, I.e., 0.875

Triaxial Design

σ_r = radial stress
σ_t = hoop stress
σ_α = axial stress



Triaxial Design

- The tangential (hoop) stresses are calculated with the Lamè thick wall cylinder equation as follows:

- For the Pipe Outside Diameter:

$$\sigma_{t,o} = \frac{2P_iA_i - P_o(A_o + A_i)}{A_o - A_i}$$

NExT

Triaxial Design

- The axial stress is calculated as follows:

$$\sigma_a = F_a / A_p$$

- Radial stress is the magnitude of the pressure inside and out:

$$\begin{array}{ll} \text{Outside} & \sigma_r = -P_o \\ \text{Inside} & \sigma_r = -P_i \end{array}$$

NExT

Triaxial Design

- The tangential (hoop) stresses are calculated with the Lamè thick wall cylinder equation as follows:

- For the Pipe Inside Diameter:

$$\sigma_{t,i} = \frac{P_i\ (A_o + A_i) - 2P_o\, A_o}{A_o - A_i}$$

NExT

Triaxial Design

- Shear stress can be determined by:

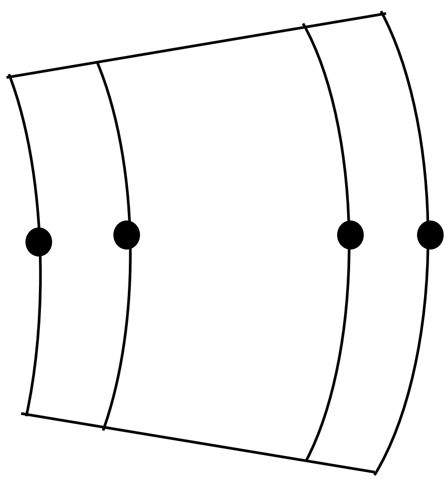
$$\tau = \frac{\pi}{32}(\mathrm{D}^4 - \mathrm{d}^4)\ \text{(hollow tube)}$$

- Then the equivalent triaxial (VME) stress without bending is:

$$\sigma_{vme} = \{0.5[(\sigma_\mathrm{a} - \sigma_\mathrm{t})^2 + (\sigma_\mathrm{t} - \sigma_\mathrm{r})^2 + (\sigma_\mathrm{r} - \sigma_\mathrm{a})^2]\}^{1/2}$$

VME Stresses with Bending

Bending causes ***compressive*** stress at ID



Bending causes ***tensile*** stress at OD

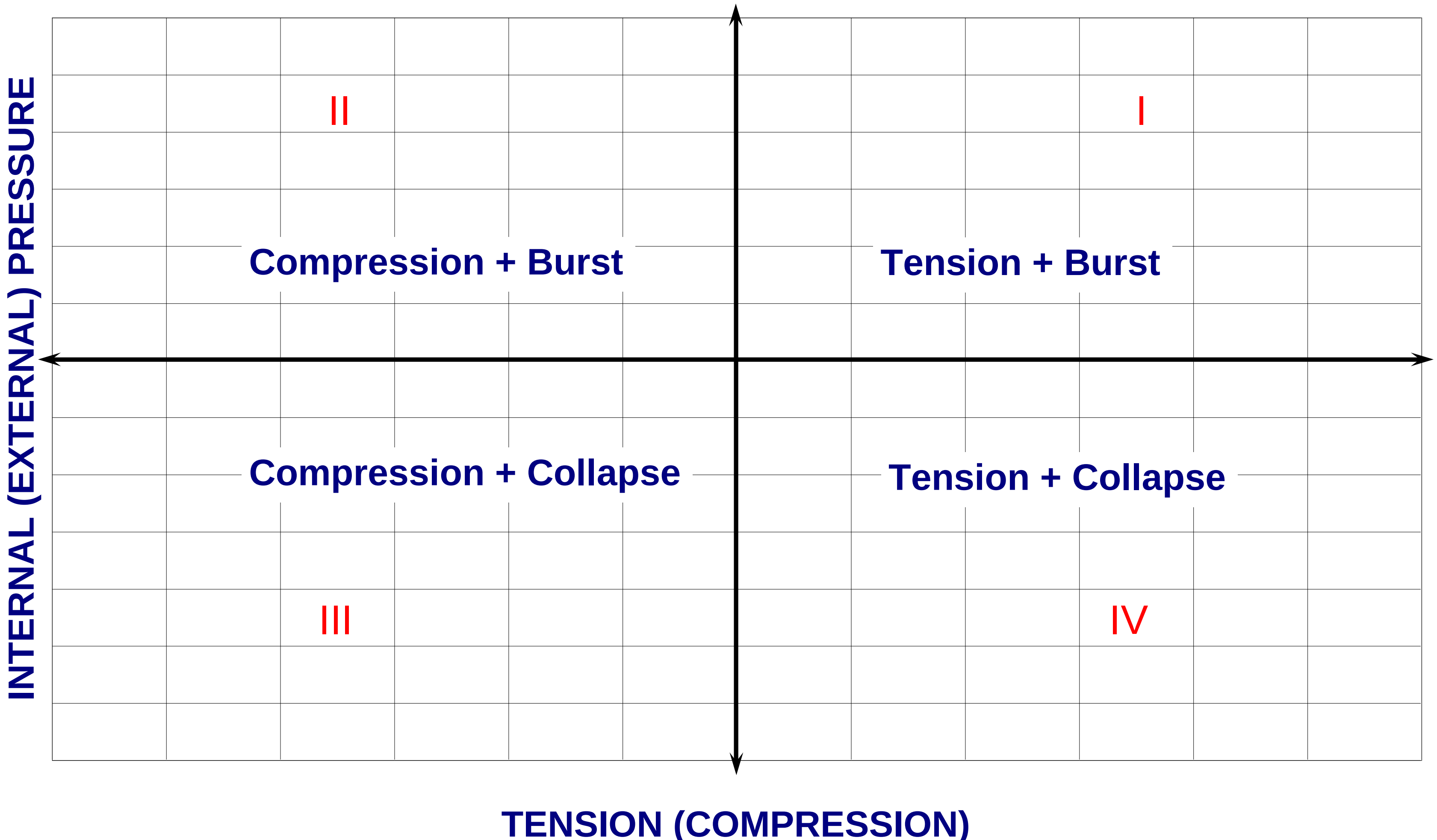
Triaxial Design

- The recommended procedure to calculate the peak VME stress in casing or tubing subjected to bending moments is as follows:

1. Calculate the radial and tangential stresses on the pipe body inside and outside diameters using Lamé's equations.
2. Calculate the axial stress due to the axial force acting on the pipe.
3. Calculate the bending stresses on the pipe body inside and outside diameters.
4. Calculate the VME stress at the inside and outside surfaces at the inside and outside of the bend.
5. Superimpose the axial stress due to bending on the axial stress from the axial force acting on the pipe. For one side of the pipe, the bending stress is positive or tensile, and on the other side the bending stress is negative or compressive.
6. Bending creates a higher stress at the OD of the pipe than at the ID. For a conservative simplification of triaxial calculations the bending stress at the OD can be taken to act across the wall. Triaxial equivalent stress calculations can thus be made for the ID only, simplifying the process. This moderately conservative approximation introduces less than 2% error in casing and 3% error in tubing.

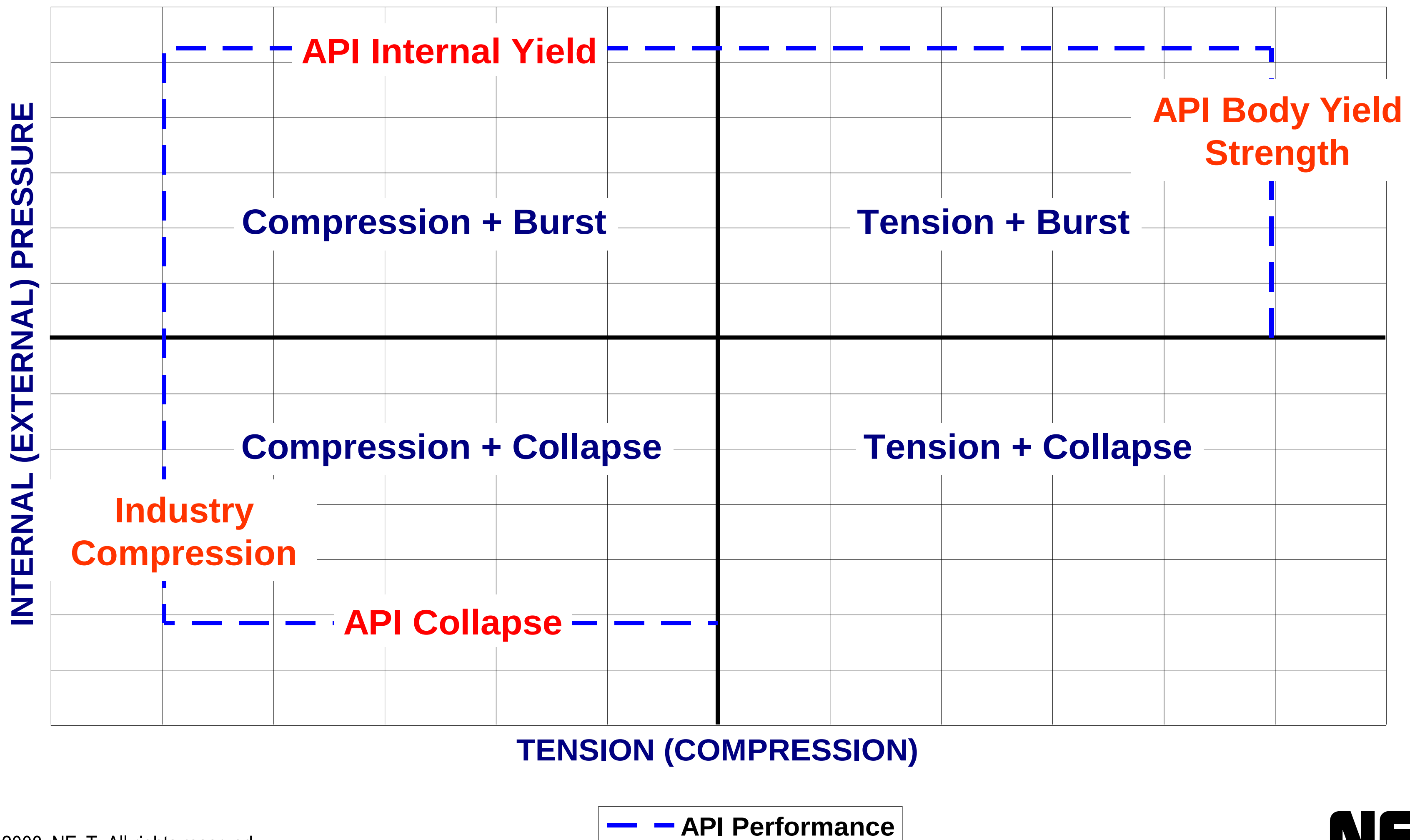
Triaxial Design

Pipe Body Performance



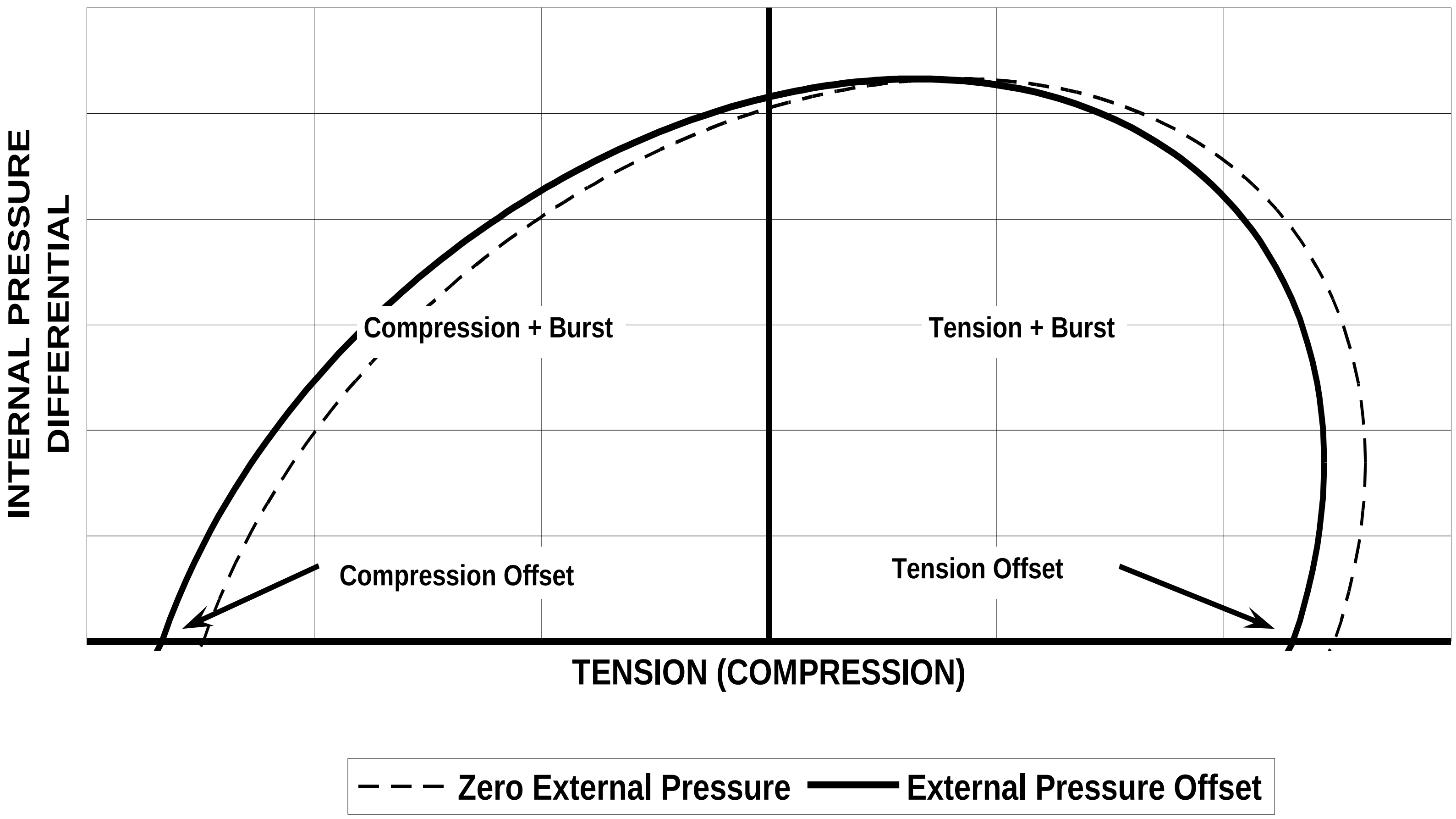
Triaxial Design

API 5C3 Pipe Body Performance



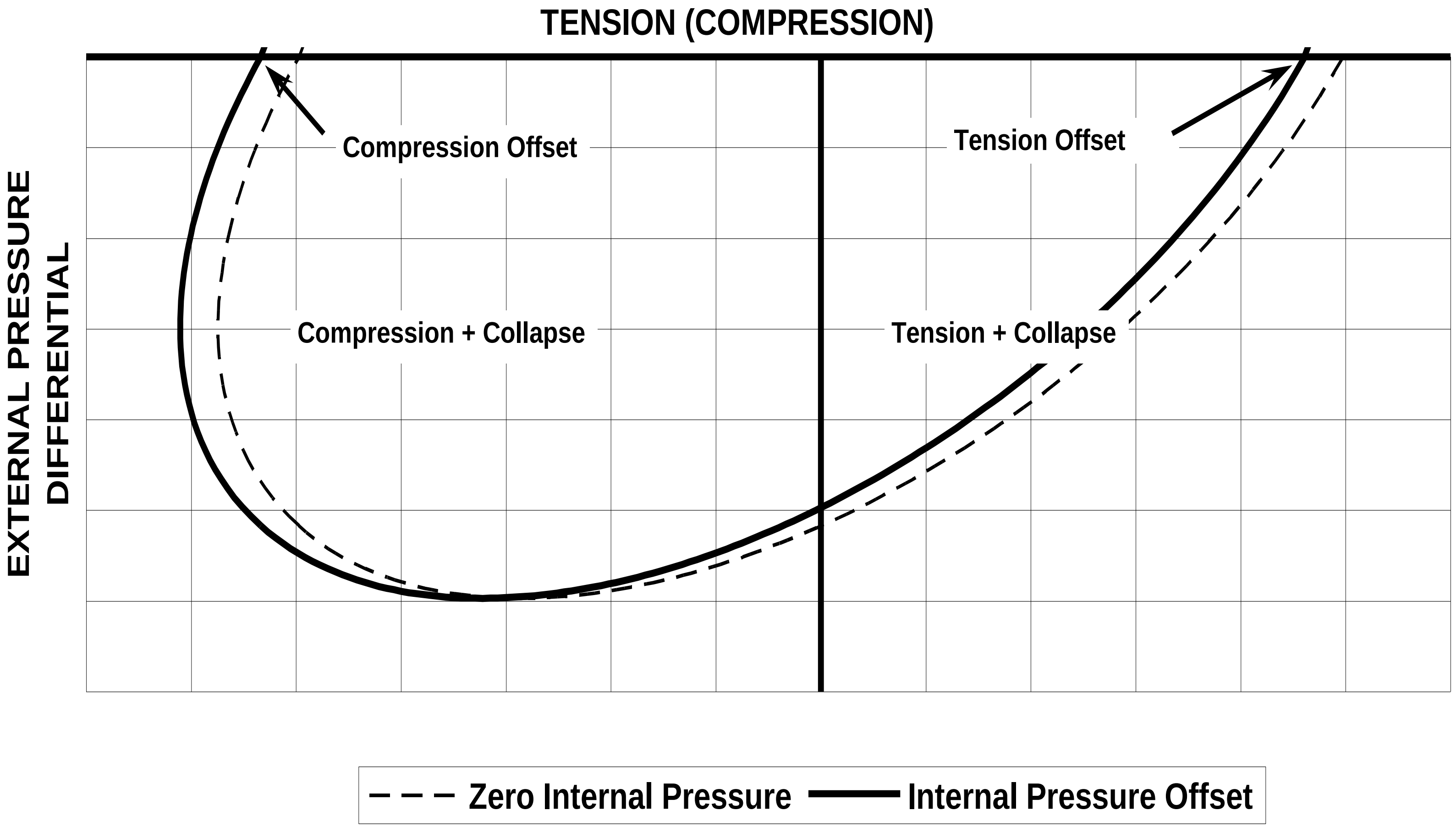
NExT

Triaxial Design



NExT

Triaxial Design



Triaxial Design without Bending

Hencky-von Mises Yield Theory

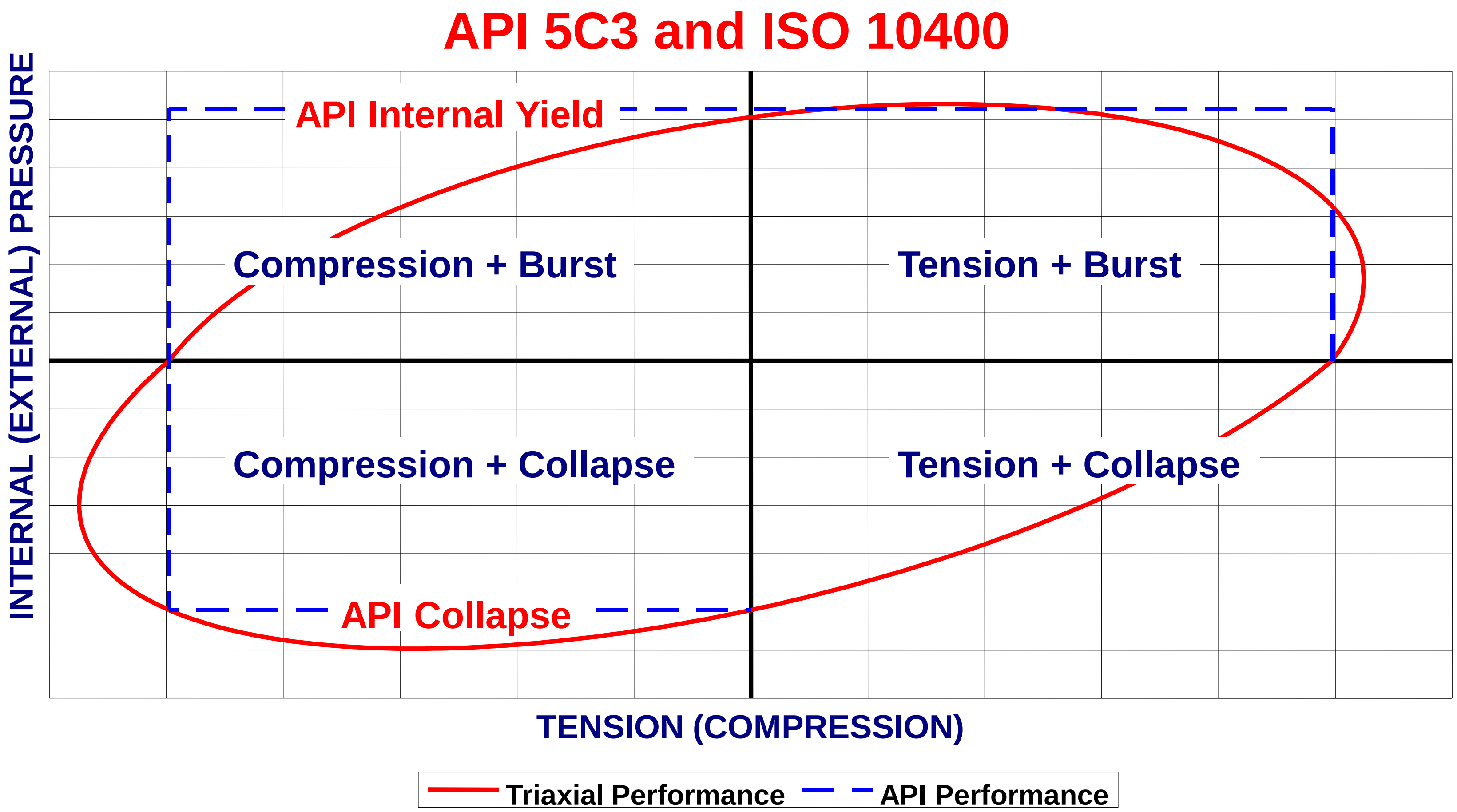
$$Y_p \geq \sigma_{VME} = \frac{1}{\sqrt{2}}\left[(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2\right]^{1/2}$$

For Cylinders:

$$\sigma_{VME} = \frac{1}{\sqrt{2}}\left[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2\right]^{1/2}$$

NExT

Triaxial Design (Pipe Body Performance)

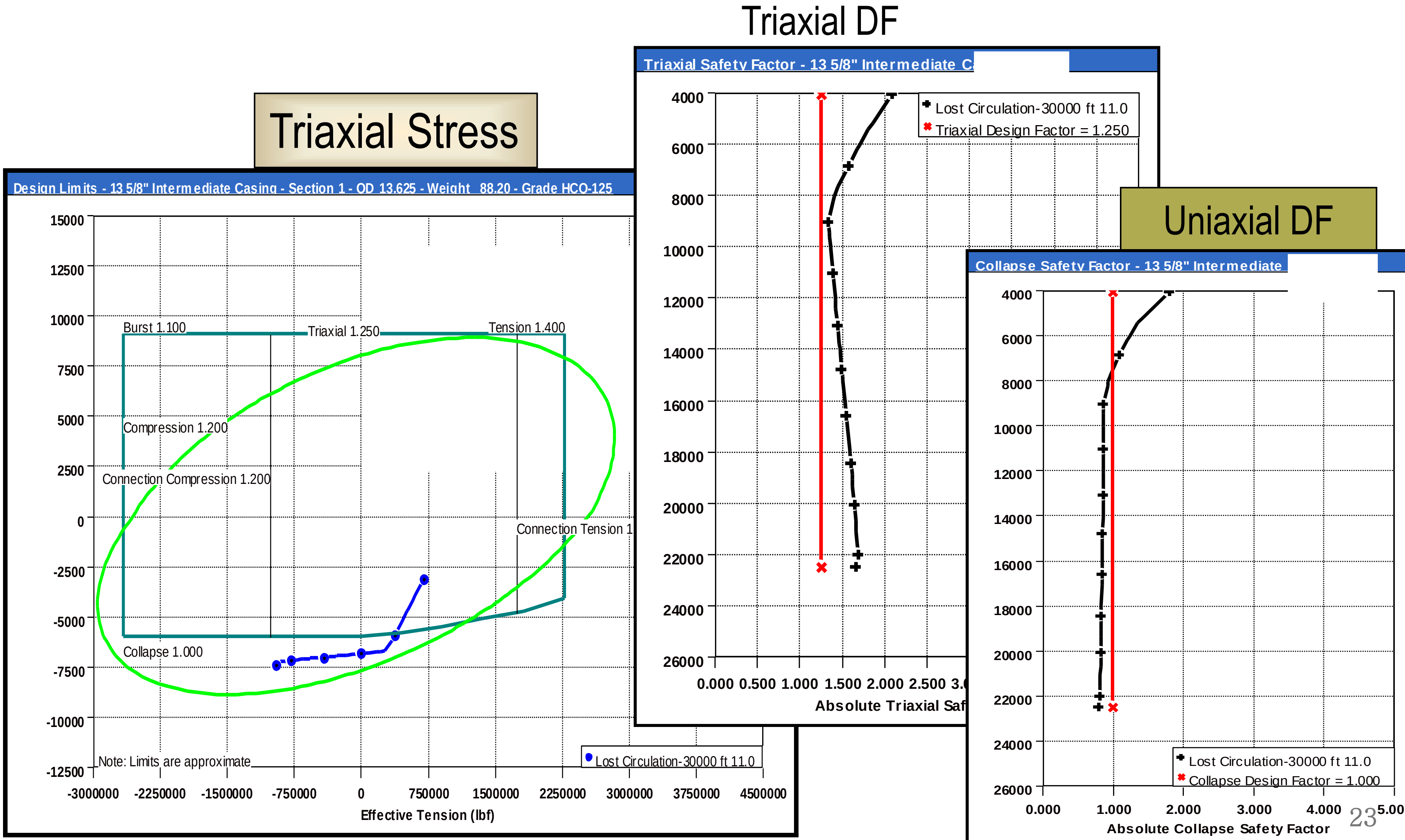


Triaxial Design

- When a casing and tubing string meets triaxial design criteria but does not satisfy uniaxial criteria, engineering judgment should be applied.
- When a casing and tubing string design does not meet triaxial criteria but satisfies uniaxial criteria, triaxial criteria governs and should be used.

NExT

Triaxial DF vs. Uniaxial DF



NExT

Corrosion

Corrosion

Corrosion can have a major detrimental effect on the mechanical integrity of tubing and casing systems and must be considered in the design. Corrosion can attack the pipe in two ways:

- Metal loss will reduce the wall thickness of the casing or tubing and lead to a corresponding reduction in its load resistance.
- The pipe material can be damaged with little or no reduction in wall thickness to an extent that it can no longer withstand operating loads, i.e. stress cracking.

NExT

Corrosion

Two primary corrosion systems in OCTG –

- ***Metal Loss*** – a general loss of pipe material that may take the form of pitting or occur over a broad surface of the pipe.
- ***Sulfide Stress Cracking (SSC)*** – an imperceptible attack of the microstructure that produces catastrophic failure.

Corrosion Environment

CO_2 Partial Pressure

H_2S Partial Pressure

pH

Chloride Content

Bicarbonate Content

Flow Velocity

Condensate

Temperature

Water

NExT

Corrosion Resistance

Steel

- Chemistry
- Microstructure
- Hardness
- Strength

  CO_2 Partial Pressure

  H_2S Partial Pressure

  pH

  Water

Liquid Hydrocarbons

Inhibitors

Temperature

Pressure

Flow Stream Velocity

Amount of Chlorides

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Sulfide Stress Cracking

Pipe Steel

- Strength & Hardness
- Chemistry
- Heat Treatment
- Cold Work/Stress Relief
- Microstructure

- pH
- H_2S Partial Pressure
- Total Tensile Stress
- Temperature
- Exposure Duration
- Other Elements in Flow Stream

Sulfide Stress Cracking

The Probability of SSC Increases with:

- Increasing H_2S Partial Pressure
- Increasing Steel Hardness and Strength
- Increasing Tensile Stress
- Increasing Exposure Duration
- Decreasing Percent Martensite
- Decreasing pH
- Decreasing Temperature

Sulfide Stress Cracking

Pipe Steel

- Strength & Hardness
- Chemistry
- Heat Treatment
- Cold Work/Stress Relief
- Microstructure

- pH
- H_2S Partial Pressure
- Total Tensile Stress
- Temperature
- Exposure Duration
- Other Elements in Flow Stream

NExT

Chemistry Increases SSC Resistance

Alloying Elements to Use

- Molybdenum
- Vanadium
- Niobium
- Chromium
- Titanium

Chemistry Decreases SSC Resistance

Alloying Elements to Avoid

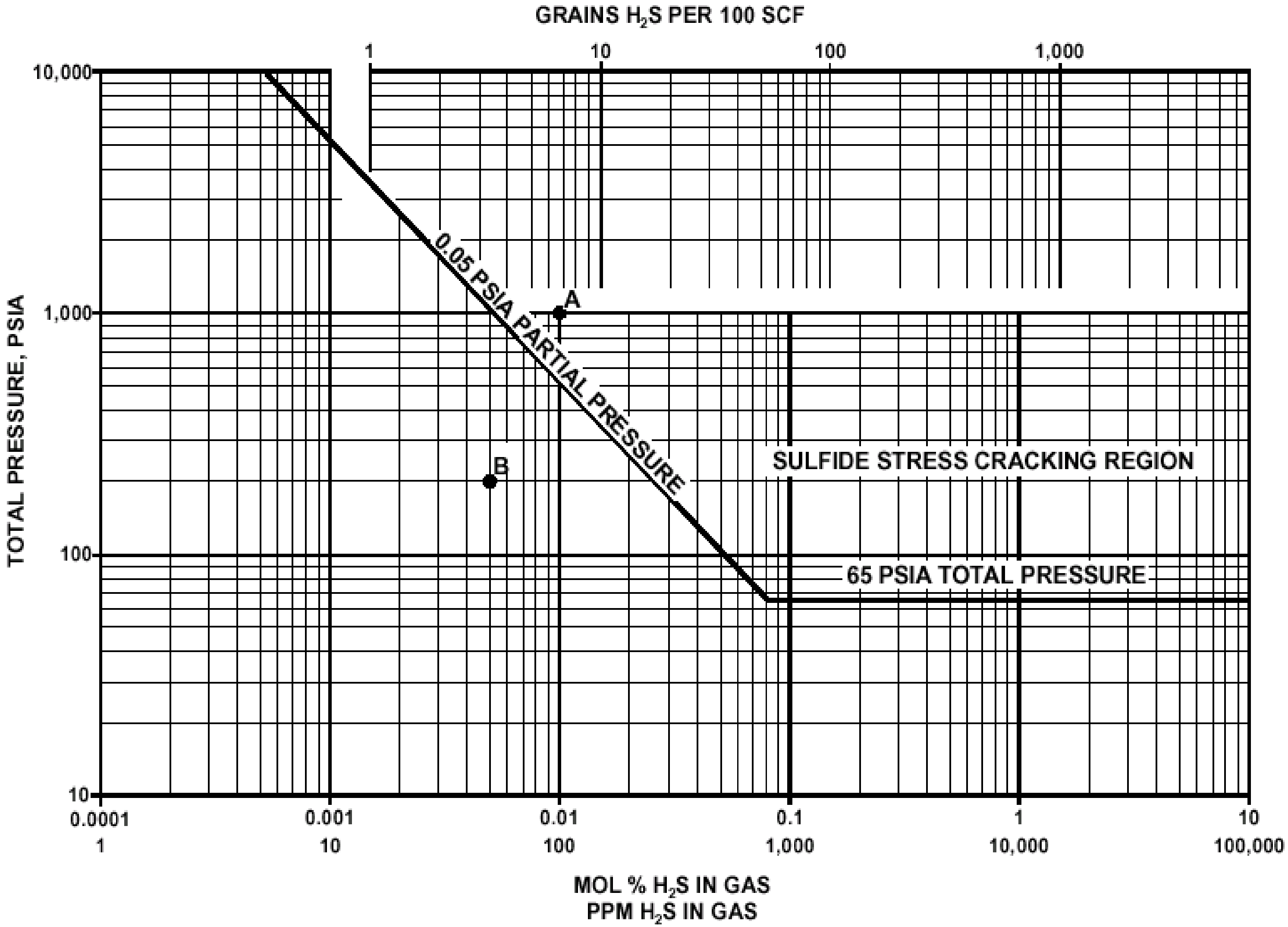
- Manganese
- Silicon
- Sulfur
- Phosphorous

NExT

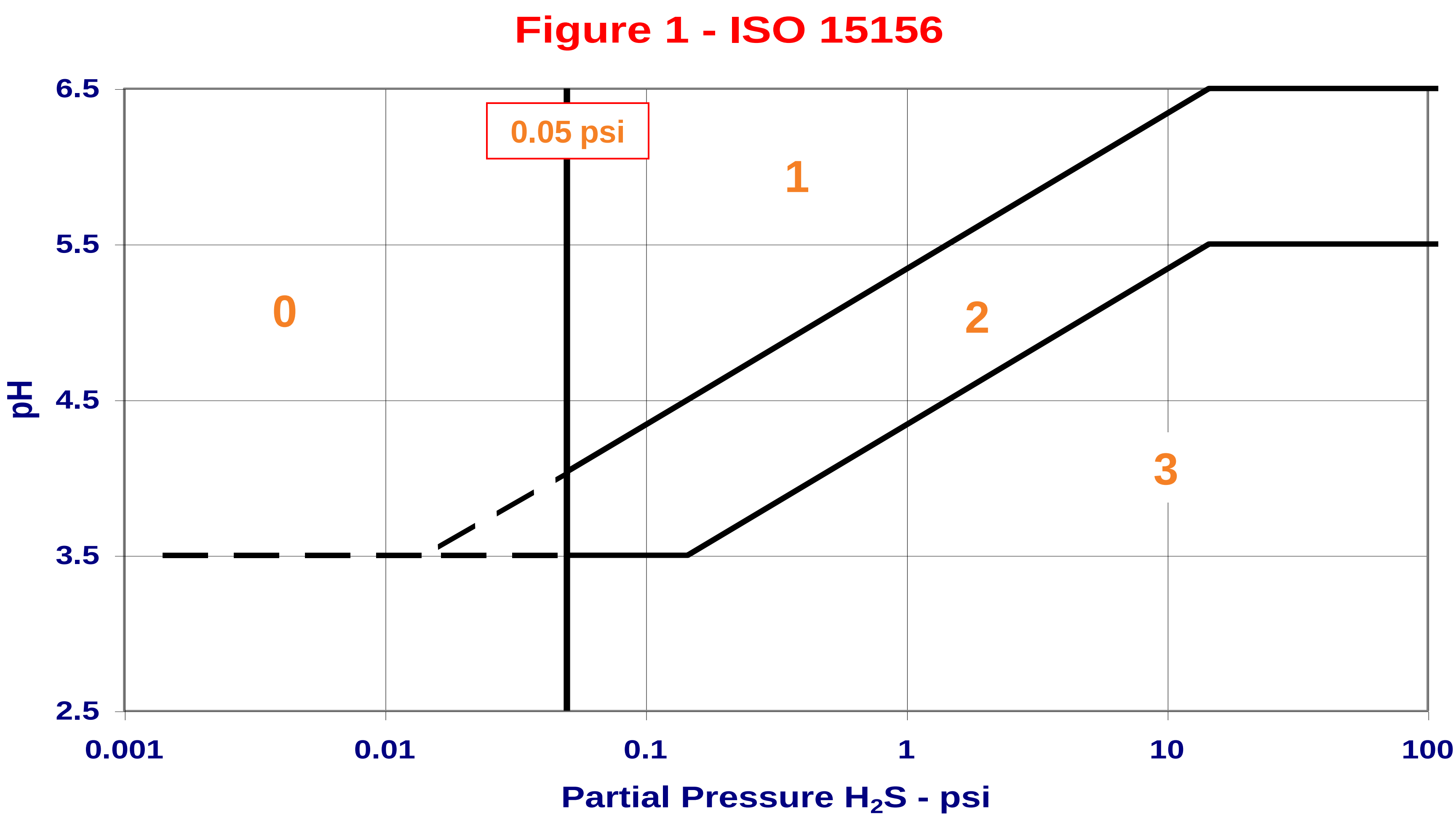
Heat Treat

The Probability of SSC Increases with Decreasing Percent Martensite, i.e. ***Heat Treating is Critical***

NACE MR0175 Properties



NACE MR0175 Properties



NACE MR0175 Properties

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.

Temperature Effect

The probability of SSC increases with decreasing temperature.

From NACE Standard MR0175:

- For all well temperatures – J-55, K-55, M-65, L-80 Type 1, C-90 Type 1, and T-95 Type 1
- For T > 150°F - N-80 (Q&T), C-95, T-95 Type 2
- For T > 175°F - N-80, P-110
- For T > 225°F - Q-125 Type 1

SSC Material Guideline

- Use Type 1 for C-90, T-95, and Q-125.
- Do not use 135 ksi yield strength and higher steel for sour service.
- Evaluate temperature predictions when using a grade not suitable for all well temperatures.

NExT

Corrosion Resistant Alloys (CRA)

Benefit:

- CORROSION RESISTANCE
- VELOCITY ENHANCEMENTS

Detriment:

- HIGHER COST

NExT

Practical Hints for CRA

Components that define the severity of the environment:

- Partial Pressure H_2S (ppm * psi)
- Partial Pressure CO_2 (mol% * psi)
- Chloride content
- Produced water rate
- Produced condensate/oil rate
- Bicarbonate content HCO_3
- Bottom hole temperature
- pH
- Flow velocity

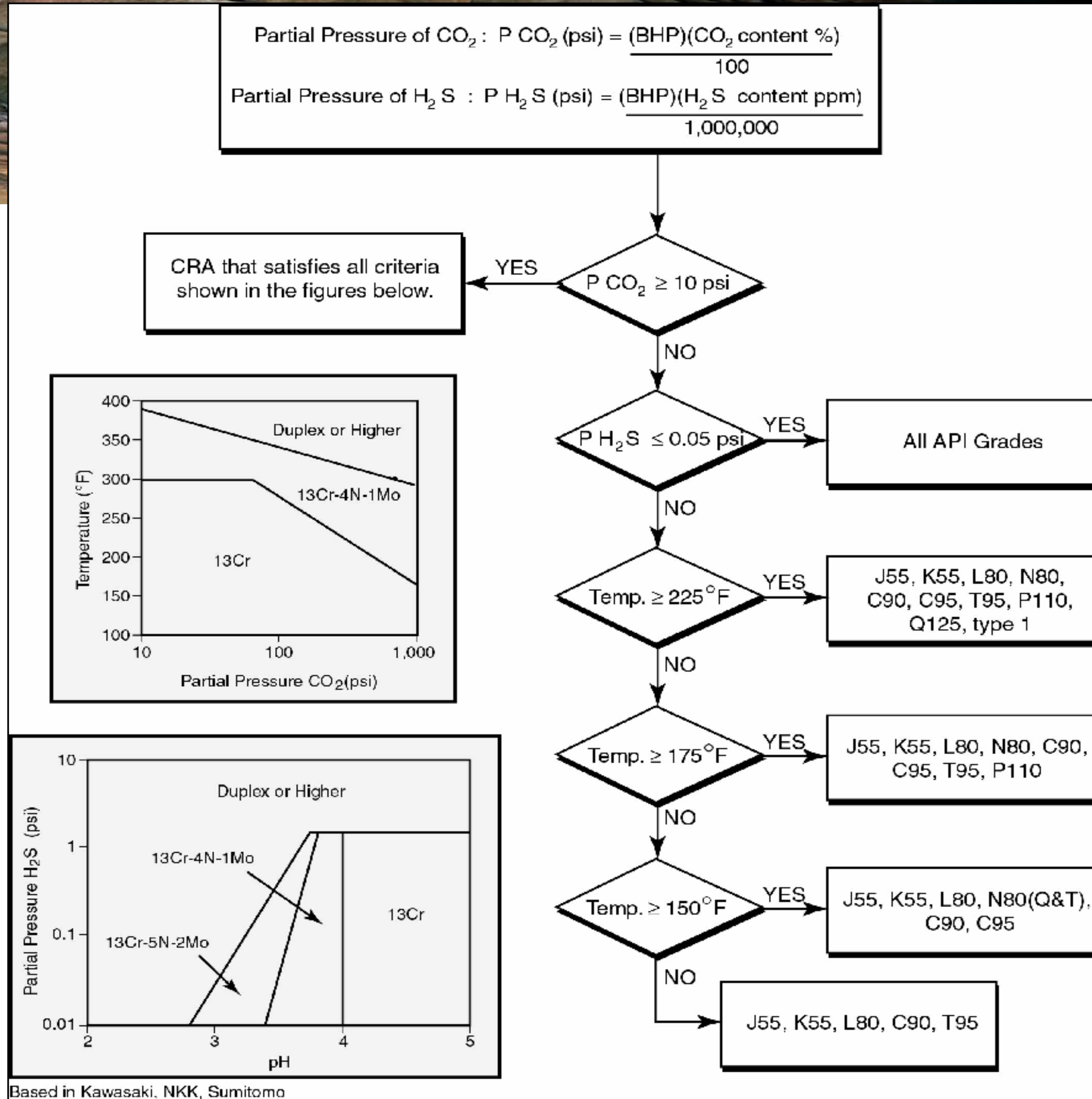
Practical Hints for CRA

Components continued:

- Free sulfur can occur as low as 4-5% H_2S. Extremely severe to CRA
- Acid stimulation fluids: carefully evaluate inhibitors
- Completion fluids: Attempt to use low density single salt brines. Certain fluids can be very aggressive in CO_2 environment. Try to avoid Zinc Bromides.
- Scale: some scales can be beneficial

Basic CRA Guide

Example



Note: A metallurgist should be consulted for specific material applications.

SSC Example

What is the highest API grade suitable for a gas well with shut-in pressure 10,000 psi and 10 PPM H_2S?

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- What is the highest API grade suitable for a gas well with shut-in pressure 10,000 psi and 10 PPM H_2S?

- Step 1 – is the environment sour? The partial pressure is 0.00001 (.001%) * 10000 psi = 0.1 psi > 0.05 psia – thus a sour environment.

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SSC Example

- What is the highest API grade suitable for a gas well with shut-in pressure 10,000 psi and 10 PPM H_2S?
- Step 1 – is the environment sour? The partial pressure is 0.00001 (.001%) * 10,000 psi = 0.1 psi > 0.05 psia – thus a sour environment.
- Step 2 – From Table Slide 37, having no indication of temperature, the highest strength available for all well temperatures is T-95 Type 1.

Common SSC Grades

Tubing -

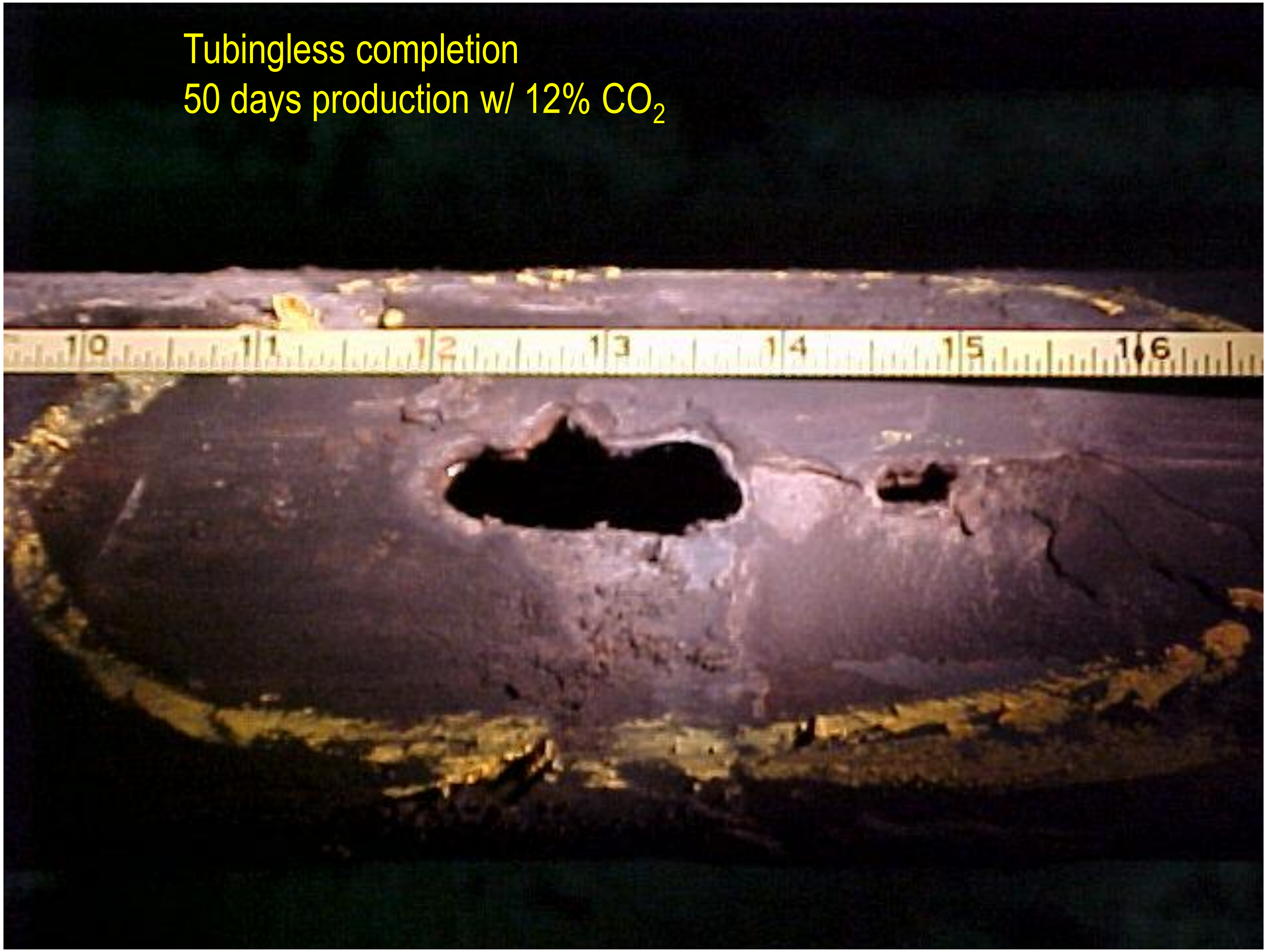
- J-55 and L-80 at all temperatures.
- P-110 at temperatures greater than 175°F.

Casing -

- K-55, L-80, T-95 Type 1 at all temperatures.
- P-110 at temperatures greater than 175°F.
- Q-125 Type 1 at temperatures greater than 225°F.

Failures and Fatigue

3-1/2 12.95 L80 Failure



4-1/2 13.50 P110 LTC Failure

Swollen Joint

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4-1/2 13.50 P110 LTC Failure

Pipe Body Failure
from Pressure Test

4-1/2 15.10 P110 LTC Failure

Coupling Failure
high hoop stress due to poor makeup.

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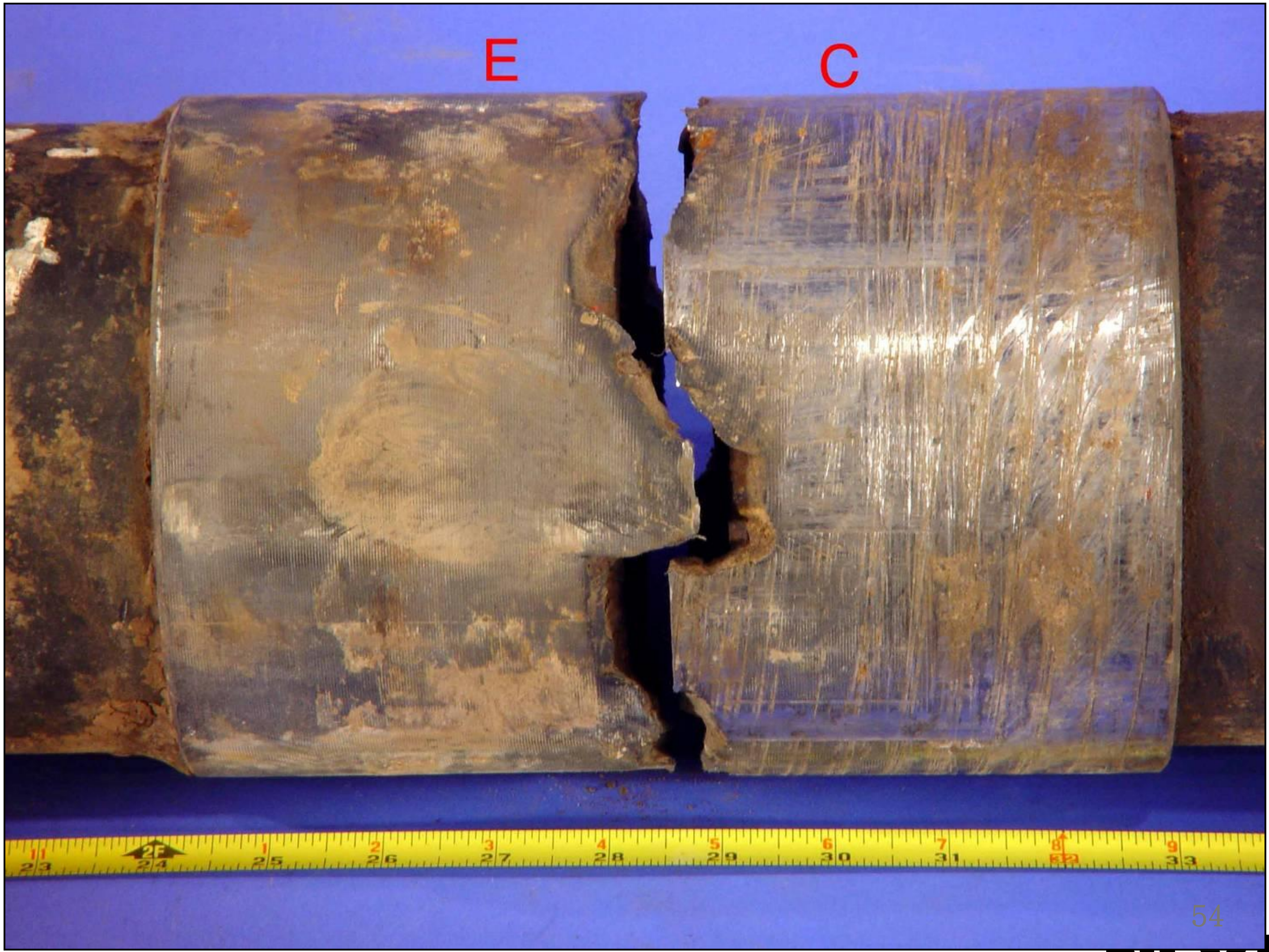
4-1/2 11.60 N80 LTC Failure

Pipe Body Failure from Pressure Test

5-1/2 23 P110 LTC Failure

Fatigue cracking in thread roots from multiple stimulations



Additional Design Considerations

Buckling

- Buckling-induced bending stresses contribute to the overall triaxial stress state of casing and tubing, possibly causing the pipe to yield and permanently corkscrew.
- In casing strings, drilling inside buckled pipe can cause wear that would not occur in non-buckled pipe. Tubing that is buckled under static shut-in conditions may prevent passage of through-tubing work-over or logging tools.

Critical Buckling Cases

- ***Drilling beneath intermediate casing*** – casing that has been hung-off with low tension or compression at the cement top can buckle during subsequent drilling operations and lead to excessive wear on the casing.
- ***Setting a liner on bottom*** – setting a liner on bottom rather than hanging it off with a liner hanger can cause buckled casing.
- ***Tubing static shut-in*** - high pressure can buckle a tubing string that is free to float at the packer and prevent free passage of tools
- ***Stimulation*** - high injection pressure plus piston effects can create buckling in the lower section of the tubing string.

Buckling

BUCKLING PREDICTION:

The Fictitious Force:

$$F_{fict} = A_o P_o - A_i P_i$$

Two factors that influence tubing buckling are axial force and pressure.

Buckling

The ***fictitious force*** is combined with the axial force to form an ***effective force***.

$$\boxed{F_{eff} = F_a + A_O P_O - A_I P_I}$$

A positive F_{eff} indicates no buckling. A negative F_{eff} indicates buckling may occur if the magnitude of the critical F_{crit} required to initiate buckling is exceeded.

Buckling

Critical Force to initiate buckling for both free and fixed ends:

$$F_{crit} = -1.94\left(EIw_{eff}^{2}\right)^{\frac{1}{3}}$$

FREE ENDS

$$F_{crit} = -3.5\left(EIw_{eff}^{2}\right)^{\frac{1}{3}}$$

FIXED ENDS

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Buckling

Critical Force to initiate sinusoidal buckling in an inclined well is given as:

$$F_{crit} = -\sqrt{\frac{4EIw_{eff}\sin\phi}{r_c}}$$

Where the effective weight (w_{eff}) of the string is given by:

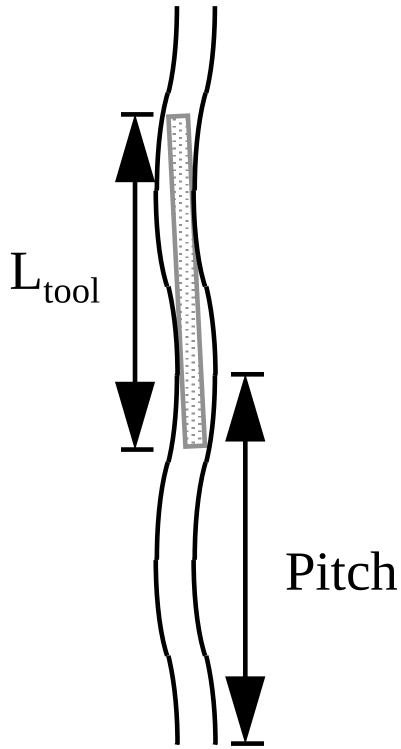
$$w_{eff} = \rho_{st}A_p + \rho_i A_i - \rho_o A_o$$

NExT

Buckling

- The ***neutral point*** is defined as the depth where the effective force is zero.
- In almost every case, this is not the same as the point of zero axial force.
- Above the neutral point, the tubular is buckled.

Buckling



Pitch, Dogleg and Tool Passage