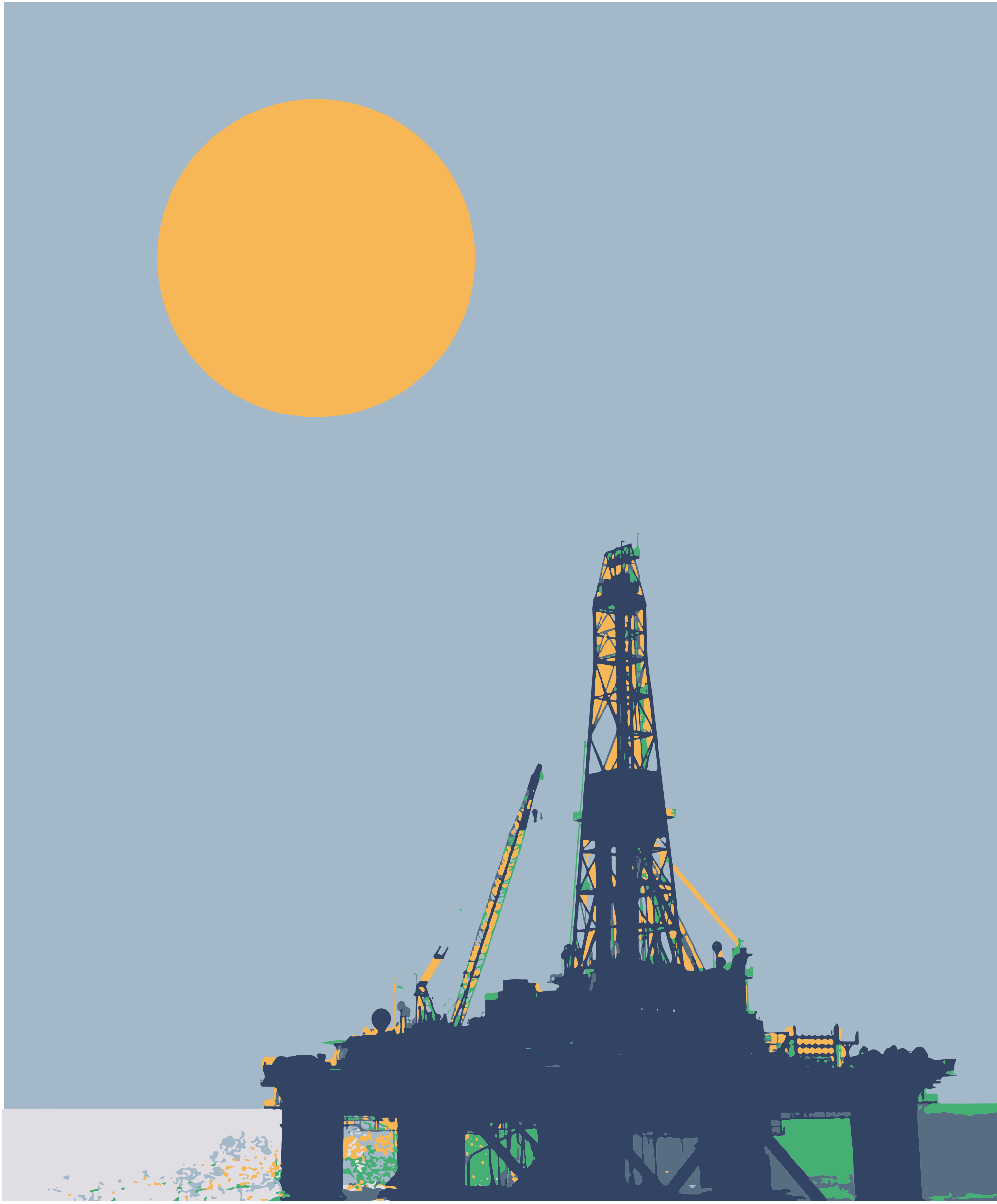
MÁSTER EN INGENIERÍA
DE PETRÓLEO Y GAS
OIL & GAS ENGINEERING MASTER'S DEGREE



COURSE DE3:
DRILLING ENGINEERING

COURSE DE3.1
BASIC DRILLING TECHNIQUES

Doc E: Casing, cementing and completion

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Mining Technology Innovative Lab

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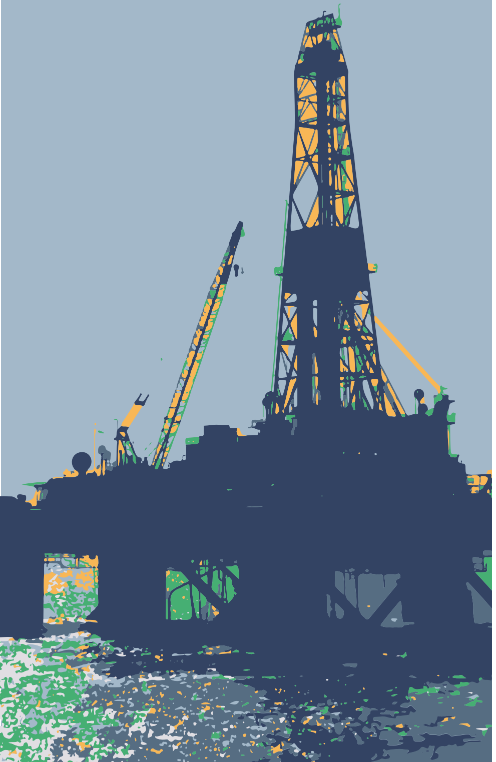

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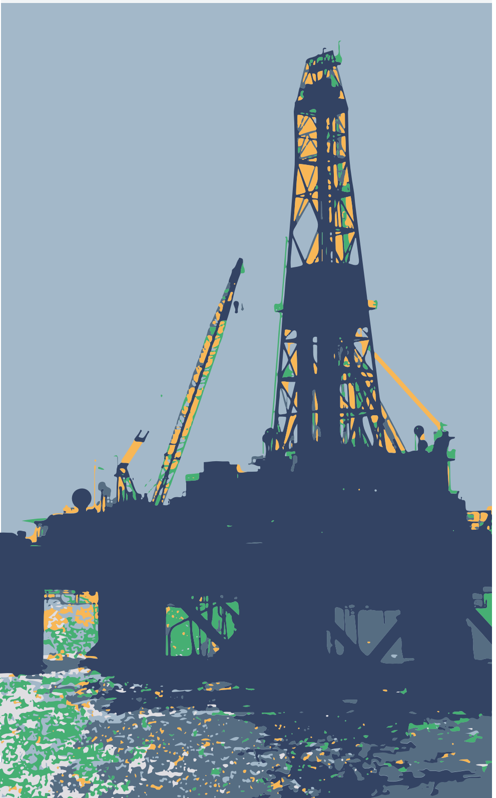


1.
Casing design and installation.

Introduction

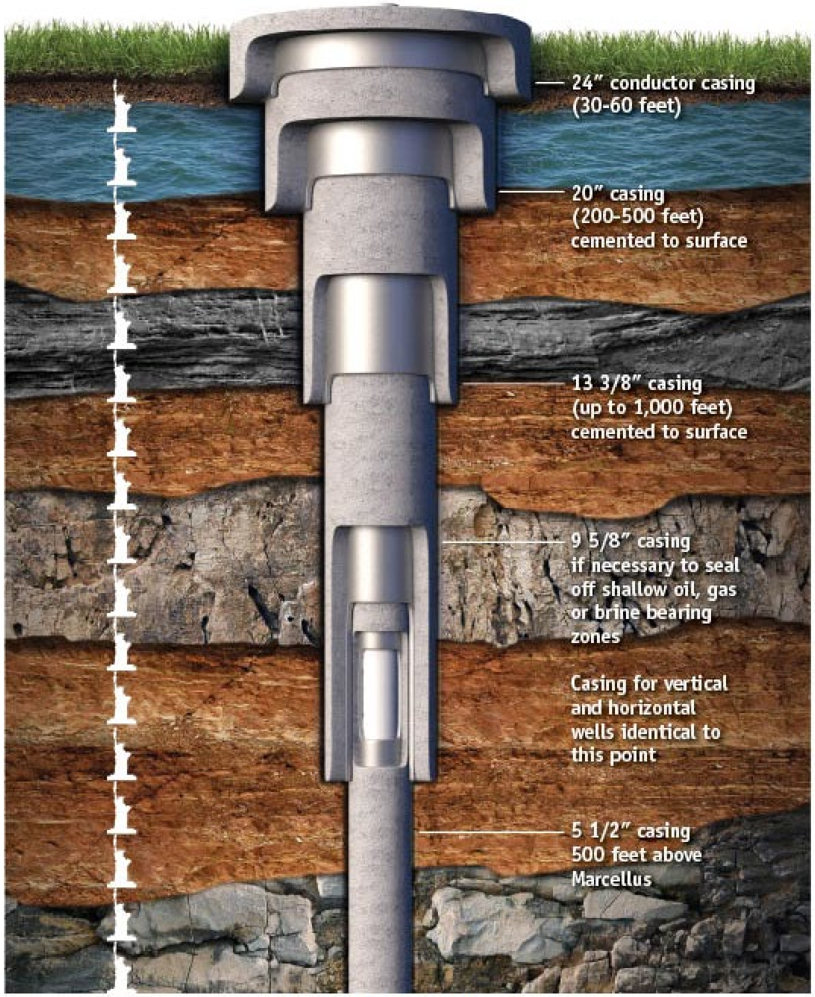
- Casing and tubing strings are the main parts of the well construction.

- All wells drilled for the purpose of oil/gas production (or injecting materials into underground formations) must be cased with material with sufficient strength and functionality.

Introduction

- Casing is the major structural component of a well.

- Casing is needed to:
  - Maintain borehole stability.
  - Prevent contamination of water sands.
  - Isolate water from producing formations.
  - Control well pressures during drilling, production, and workover operations.



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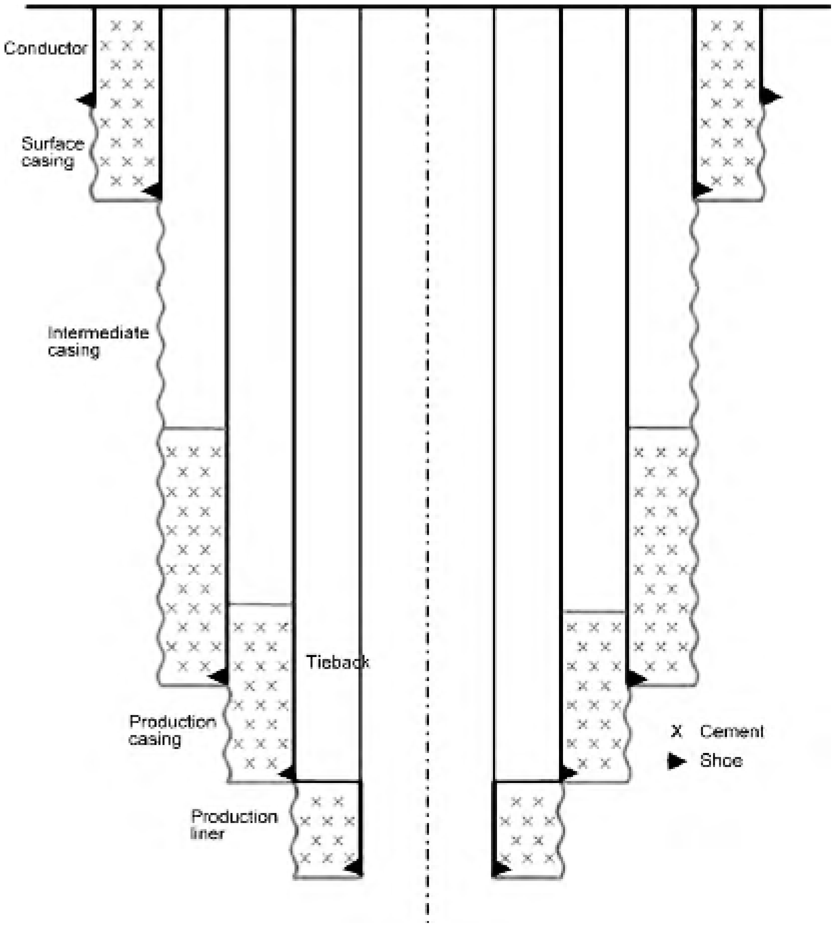
Introduction

- Casing provides locations for the installation of blowout preventers, wellhead equipment, production packers, and production tubing.

- **The cost of casing is a major part of the overall well cost, so selection of casing size, grade, connectors, and setting depth is a primary engineering and economic consideration.**

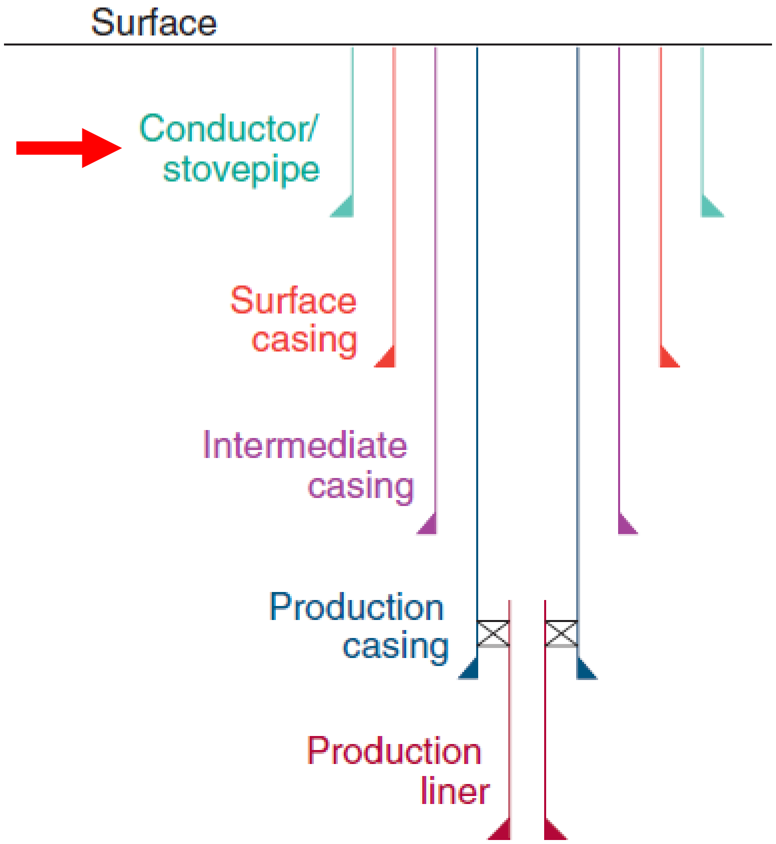
Casing Strings

- There are six basic types of casing strings:
  - Conductor Casing.
  - Surface Casing.
  - Intermediate Casing.
  - Production Casing.
  - Liner.
  - Tieback String.



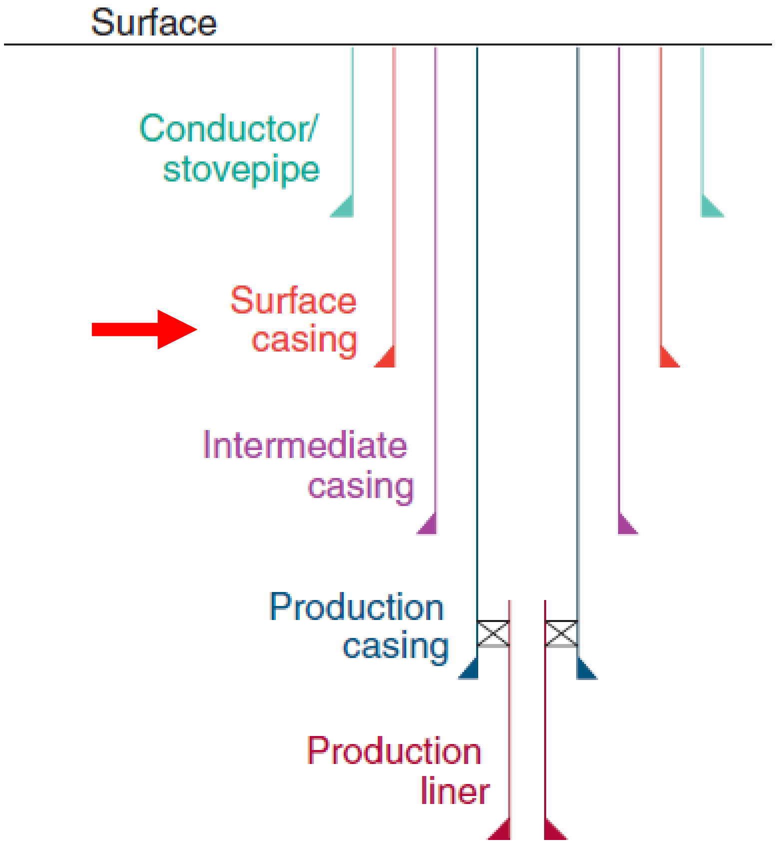
Casing Strings

- **Conductor Casing.**
  - Conductor casing is the first string set below the structural casing.
  - The conductor isolates unconsolidated formations and water sands and protects against shallow gas.
  - This is usually the string onto which the casing head is installed.
  - A diverter or a blowout prevention (BOP) stack may be installed onto this string.
  - When cemented, this string is typically cemented to the surface or to the mudline in offshore wells.



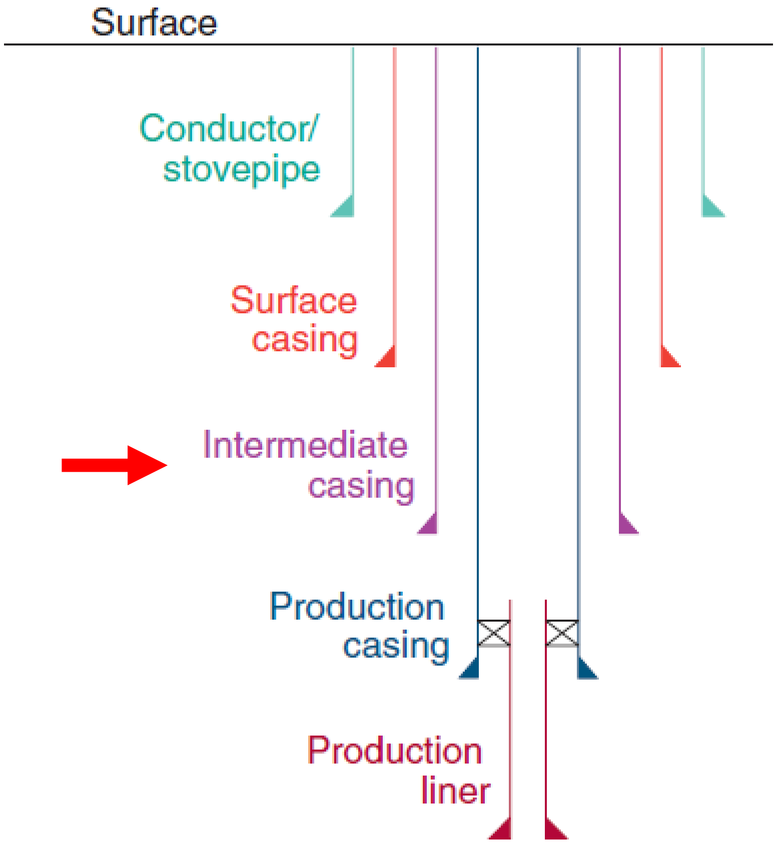
Casing Strings

- **Surface Casing.**
  - Surface casing is set to provide blowout protection, isolate water sands, and prevent lost circulation.
  - It also often provides adequate shoe strength to drill into high-pressure transition zones.
  - In deviated wells, the surface casing may cover the build section to prevent keyseating of the formation during deeper drilling.
  - This string is typically cemented to the surface or to the mudline in offshore wells.



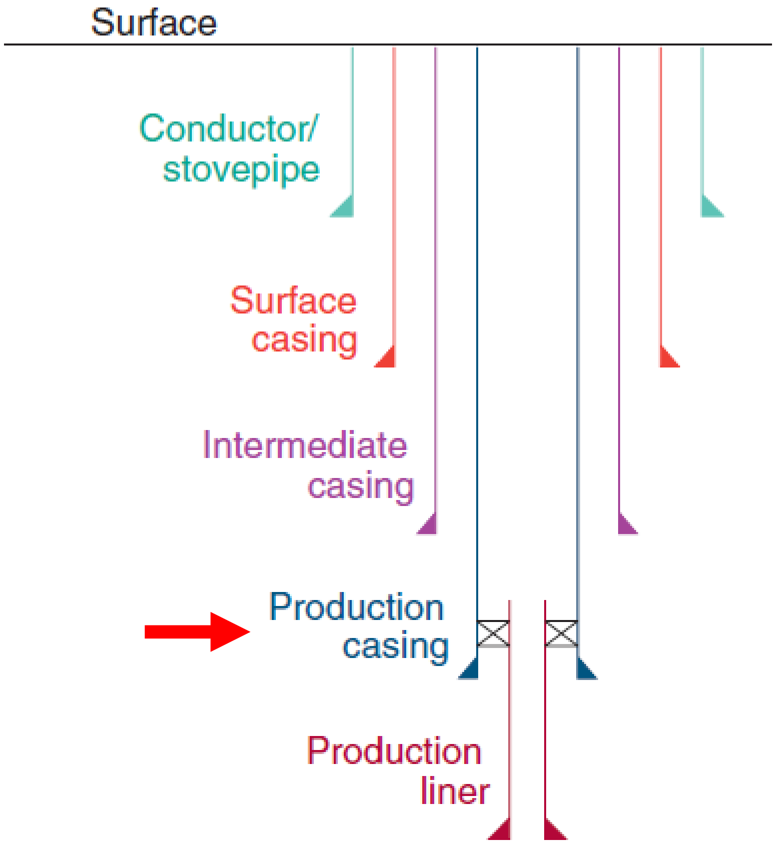
Casing Strings

- **Intermediate Casing.**
  - Intermediate casing is set to isolate unstable hole sections, lost-circulation zones, low-pressure zones, and production zones.
  - It is often set in the transition zone from normal to abnormal pressure. The casing cement top must isolate any hydrocarbon zones.
  - Some wells require multiple intermediate strings.
  - Some intermediate strings may also be production strings if a liner is run beneath them.



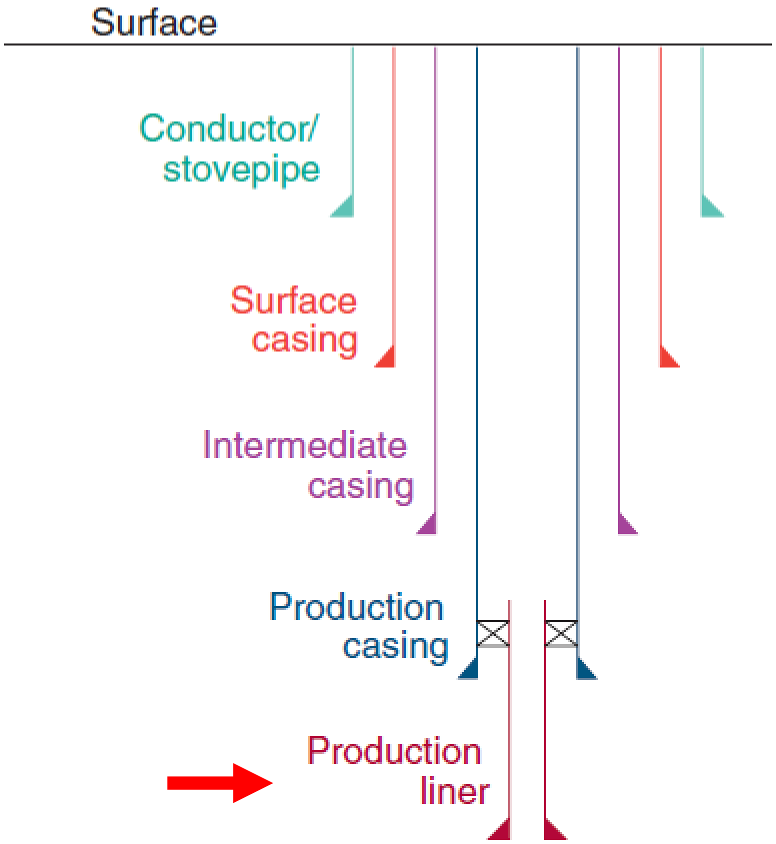
Casing Strings

- **Production Casing.**
  - Production casing is used to isolate production zones and contain formation pressures in the event of a tubing leak.
  - It may also be exposed to injection pressures from fracture jobs, downcasing, gas lift, or the injection of inhibitor oil.
  - A good primary cement job is very critical for this string..



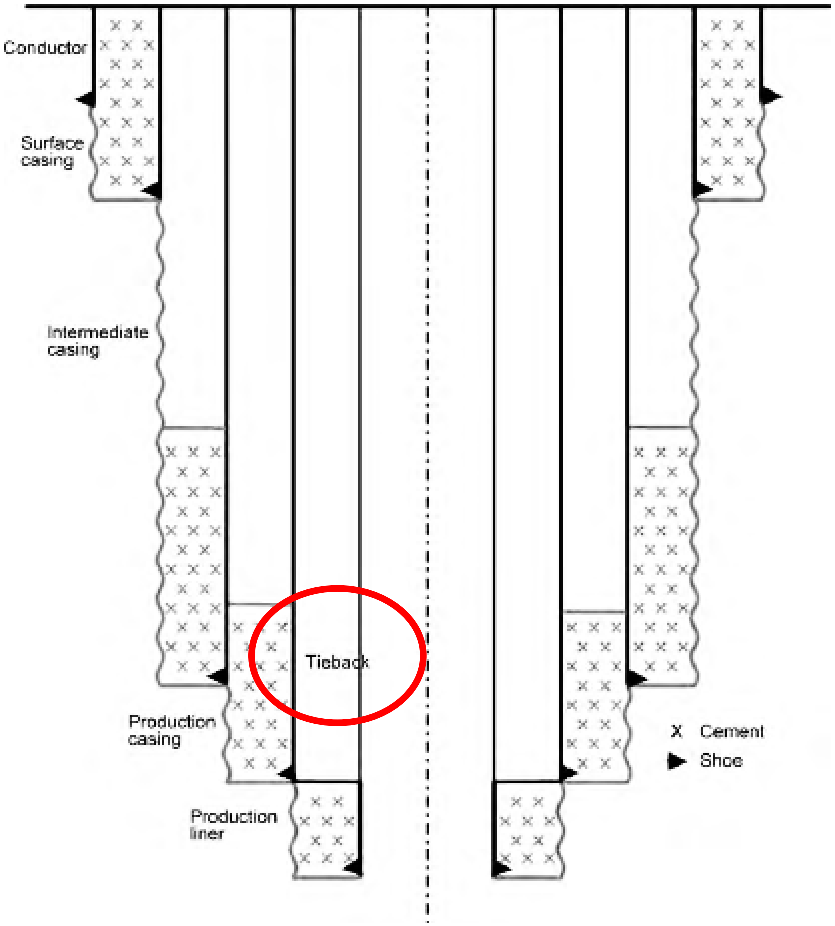
Casing Strings

- **Liner.**
  - Liner is a casing string that does not extend back to the wellhead but instead is hung from another casing string.
  - Liners are used instead of full casing strings to reduce cost, improve hydraulic performance when drilling deeper, allow the use of larger tubing above the liner top, and not represent a tension limitation for a rig.
  - Liners can be either an intermediate or a production string. Liners are typically cemented over their entire length.



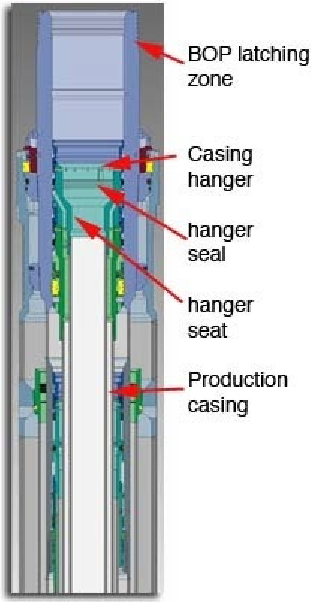
Casing Strings

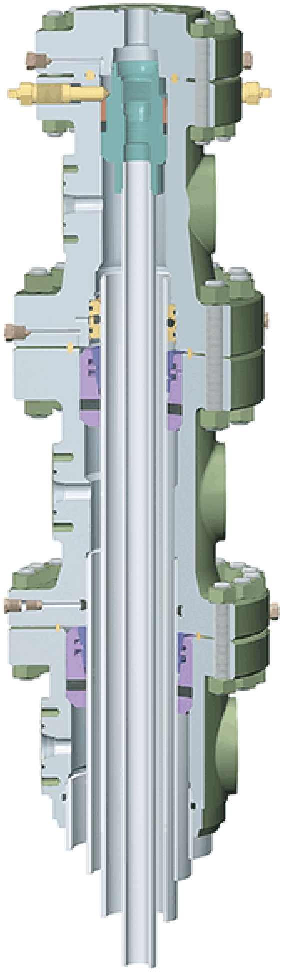
- **Tieback String.**
  - Tieback string is a casing string that provides additional pressure integrity from the liner top to the wellhead.
  - An intermediate tieback is used to isolate a casing string that cannot withstand possible pressure loads if drilling is continued (usually because of excessive wear or higher than anticipated pressures).
  - Similarly, a production tieback isolates an intermediate string from production loads.
  - Tiebacks can be uncemented or partially cemented.

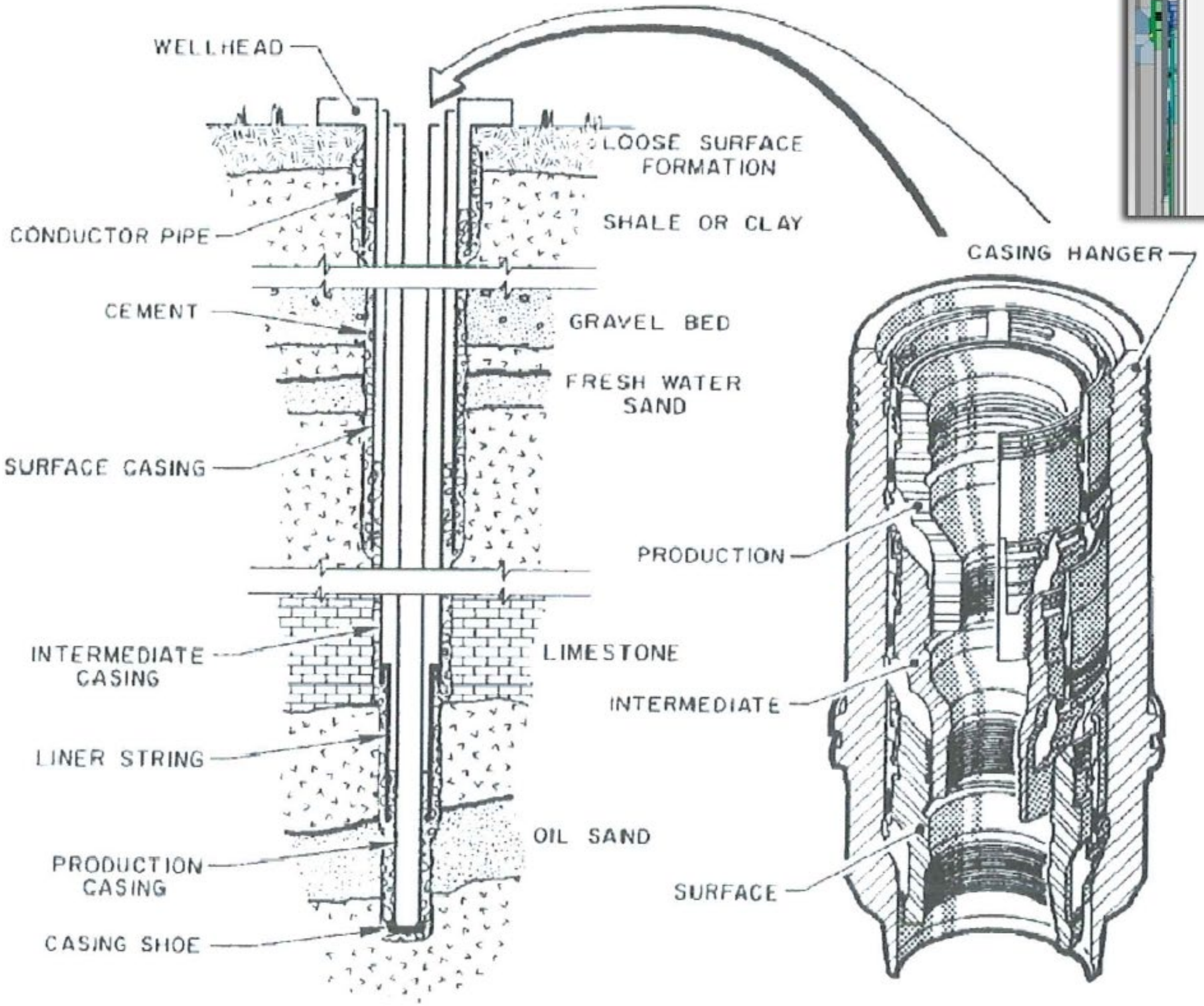


Tubing

- Tubing is the conduit through which oil and gas are brought from the producing formations to the field surface facilities for processing.
- Tubing must be adequately strong to resist loads and deformations associated with production and workovers.
- Further, tubing must be sized to support the expected rates of production of oil and gas:
  - Clearly, tubing that is too small restricts production and subsequent economic performance of the well.
  - Tubing that is too large, however, may have an economic impact beyond the cost of the tubing string itself because the tubing size will influence the overall casing design of the well.


BOP latching zone
Casing hanger
hanger seal
hanger seat
Production casing




WELLHEAD
LOOSE SURFACE FORMATION
CONDUCTOR PIPE
SHALE OR CLAY
CEMENT
GRAVEL BED
FRESH WATER SAND
SURFACE CASING
INTERMEDIATE CASING
LIMESTONE
LINER STRING
OIL SAND
PRODUCTION CASING
CASING SHOE
CASING HANGER
PRODUCTION
INTERMEDIATE
SURFACE

Properties of Casing and Tubing

- The American Petroleum Inst. (API) has formed standards for oil/gas casing that are accepted in most countries by oil and service companies.
- Casing is classified according to five properties:
  - The manner of manufacture.
  - Steel grade.
  - Type of joints.
  - Length range.
  - Wall thickness (unit weight).

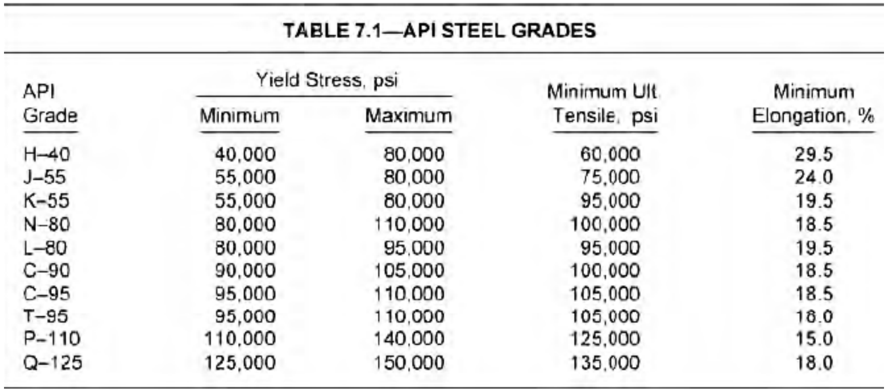


TABLE 7.1—API STEEL GRADES

API Grade	Yield Stress, psi Minimum	Yield Stress, psi Maximum	Minimum Ult. Tensile, psi	Minimum Elongation, %
H–40	40,000	80,000	60,000	29.5
J–55	55,000	80,000	75,000	24.0
K–55	55,000	80,000	95,000	19.5
N–80	80,000	110,000	100,000	18.5
L–80	80,000	95,000	95,000	19.5
C–90	90,000	105,000	100,000	18.5
C–95	95,000	110,000	105,000	18.5
T–95	95,000	110,000	105,000	18.0
P–110	110,000	140,000	125,000	15.0
Q–125	125,000	150,000	135,000	18.0

Properties of Casing and Tubing

- Almost without exception, casing is manufactured of mild (0.3 carbon) steel, normalized with small amounts of manganese. Strength can also be increased with quenching and tempering.
- API has adopted a casing “grade” designation to define the strength of casing steels.
- This designation consists of a grade letter followed by a number, which designates the minimum yield strength of the steel in ksi (103 psi)

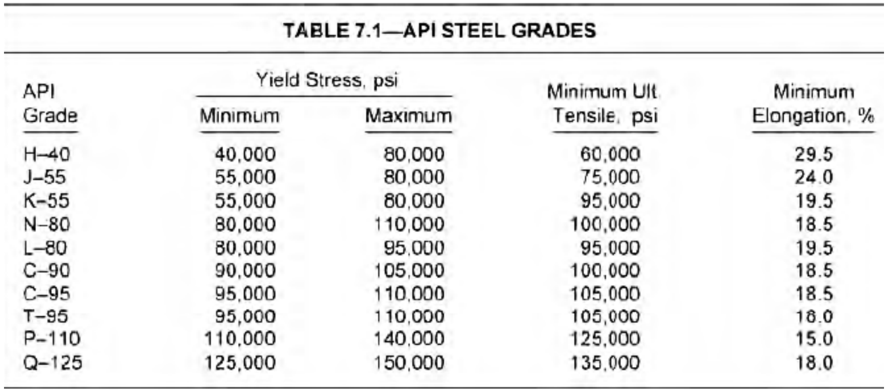


TABLE 7.1—API STEEL GRADES

API Grade	Yield Stress, psi		Minimum Ult. Tensile, psi	Minimum Elongation, %
	Minimum	Maximum		
H–40	40,000	80,000	60,000	29.5
J–55	55,000	80,000	75,000	24.0
K–55	55,000	80,000	95,000	19.5
N–80	80,000	110,000	100,000	18.5
L–80	80,000	95,000	95,000	19.5
C–90	90,000	105,000	100,000	18.5
C–95	95,000	110,000	105,000	18.5
T–95	95,000	110,000	105,000	18.0
P–110	110,000	140,000	125,000	15.0
Q–125	125,000	150,000	135,000	18.0

Properties of Casing and Tubing

- The yield strength, for these purposes, is defined as the tensile stress required to produce a total elongation of 0,5 % of the length.
- However, the case of P–110 casing is an exception where yield is defined as the tensile stress required to produce a total elongation of 0.6% of the length.
- There are also proprietary steel grades widely used in the industry, which do not conform to API specifications.
- These steel grades are often used in special applications requiring high strength or resistance to hydrogen sulfide cracking.

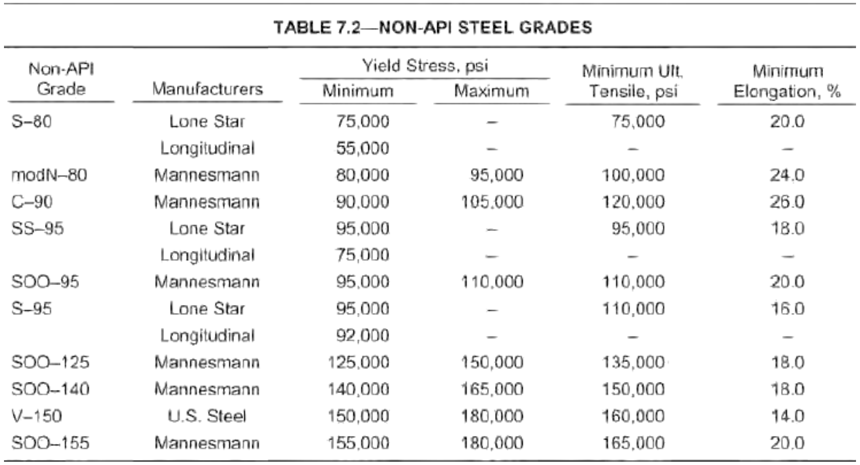


TABLE 7.2—NON-API STEEL GRADES

Non-API Grade	Manufacturers	Yield Stress, psi Minimum	Yield Stress, psi Maximum	Minimum Ult. Tensile, psi	Minimum Elongation, %
S–80	Lone Star	75,000	–	75,000	20.0
	Longitudinal	55,000	–	–	–
modN–80	Mannesmann	80,000	95,000	100,000	24.0
C–90	Mannesmann	90,000	105,000	120,000	26.0
SS–95	Lone Star	95,000	–	95,000	18.0
	Longitudinal	75,000	–	–	–
SOO–95	Mannesmann	95,000	110,000	110,000	20.0
S–95	Lone Star	95,000	–	110,000	16.0
	Longitudinal	92,000	–	–	–
SOO–125	Mannesmann	125,000	150,000	135,000	18.0
SOO–140	Mannesmann	140,000	165,000	150,000	18.0
V–150	U.S. Steel	150,000	180,000	160,000	14.0
SOO–155	Mannesmann	155,000	180,000	165,000	20.0

Casing Design

- To design a casing string, one must know information as follows:
  - Purpose of the well.
  - The geological cross section.
  - Available casing and bit sizes.
  - Cementing and drilling practices
  - Rig performance
  - Safety and environmental regulations.
- To arrive at the optimal solution, the design engineer must consider casing as a part of a whole drilling system.

Casing Design

- **Design objetives**
  - The engineer responsible for developing the well plan and casing design is faced with a number of tasks that can be briefly characterized.
    - Ensure the well's mechanical integrity by providing a design basis that accounts for all the anticipated loads that can be encountered during the life of the well.
    - Design strings to minimize well costs over the life of the well.
    - Provide clear documentation of the design basis to operational personnel at the well site.
  - This will help prevent exceeding the design envelope by application of loads not considered in the original design.

Casing Design

- **Design objectives**
  - While the intention is to provide reliable well construction at a minimum cost, at times failures occur.
  - Most documented failures occur because the pipe was exposed to loads for which it was not designed. These failures are called “off-design” failures. “On-design” failures are rather rare. This implies that casing-design practices are mostly conservative.
  - Many failures occur at connections. This implies that either field makeup practices are not adequate or the connection design basis is not consistent with the pipe-body design basis.

Casing Design. Design Method

- **Phases of Design Process.** The design process can be divided into two distinct phases.
- ***Preliminary Design.***
  - Typically the largest opportunities for saving money are present while performing this task. This design phase includes:
    - Data gathering and interpretation
    - Determination of casing shoe depths and number of strings
    - Selection of hole and casing sizes
    - Mudweight design
    - Directional design.
  - The quality of the gathered data will have a large impact on the appropriate choice of casing sizes and shoe depths and whether the casing design objective is successfully met.

Casing Design. Design Method

- **Phases of Design Process.** The design process can be divided into two distinct phases.
- ***Detailed Design.***
  - The detailed design phase includes:
    - Selection of pipe weights and grades for each casing string.
    - Connection selection.
  - The selection process consists of comparing pipe ratings with design loads and applying minimum acceptable safety standards (i.e., design factors).
  - A cost-effective design meets all the design criteria with the least expensive available pipe.

Casing Design. Required Information

- The items listed next are a checklist, which is provided to aid the well planners/casing designers in both the preliminary and detailed design.
  - Formation properties:
    - Pore pressure
    - Formation fracture pressure.
    - Formation strength (borehole failure).
    - Temperature profile
    - Location of squeezing salt and shale zones.
    - Location of permeable zones.
    - Chemical stability/sensitive shales (mud type and exposure time).
    - Lost-circulation zones, shallow gas.
    - Location of freshwater sands.
    - Presence of H2S and/or CO2.

Casing Design. Required Information

- Directional data:
    - Surface location.
    - Geologic target(s)
    - Well interference data.
- Minimum diameter requirements:
    - Minimum hole size required to meet drilling and production objectives.
    - Logging tool OD.
    - Tubing size(s).
    - Packer and related equipment requirements.
    - Subsurface safety valve OD (offshore well).
    - Completion requirements.

Casing Design. Required Information

- Production data:
  - Packer-fluid density.
  - Produced-fluid composition.
  - Worst-case loads that might occur during completion, production, and workover operations.
- Other:
  - Available inventory.
  - Regulatory requirements
  - Rig equipment limitations.

Casing Design. Preliminary Design

- The purpose of preliminary design is to establish casing and corresponding drill-bit sizes, casing setting depths and, consequently, the number of casing strings.
- Casing program (well plan) is obtained as a result of preliminary design. Casing program design is accomplished in three major steps. First, mud program is prepared; second, the casing sizes and corresponding drillbit sizes are determined; and next, the setting depths of individual casing strings are found.
- **Mud Program.** The most important mud program parameter used in casing design is the “mud weight.”.
    - The complete mud program is determined from: pore pressure; formation strength (fracture and borehole stability); lithology; hole cleaning and cuttings transport capability; potential formation damage, stability problems, and drilling rate; formation evaluation requirement; and environmental and regulatory requirements.

Casing Design. Preliminary Design

- **Hole and Pipe Diameters.** Hole and casing diameters are based on the following requirements.
  - ***Production.*** The production equipment requirements include tubing; subsurface safety valve; submersible pump and gas lift mandrel size; completion requirements (e.g., gravel packing); and weighing the benefits of increased tubing performance of larger tubing against the higher cost of larger casing over the life of the well.
  - ***Evaluation.*** Evaluation requirements include logging interpretation and tool diameters.
  - ***Drilling.*** Drilling requirements include a minimum bit diameter for adequate directional control and drilling performance; available downhole equipment; rig specifications; and available BOP equipment.
    - These requirements normally impact the final hole or casing diameter. Because of this, casing sizes should be determined from the inside outward starting from the bottom of the hole.

Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
    - ***Drilling***
        - Commonly used sizes that will p

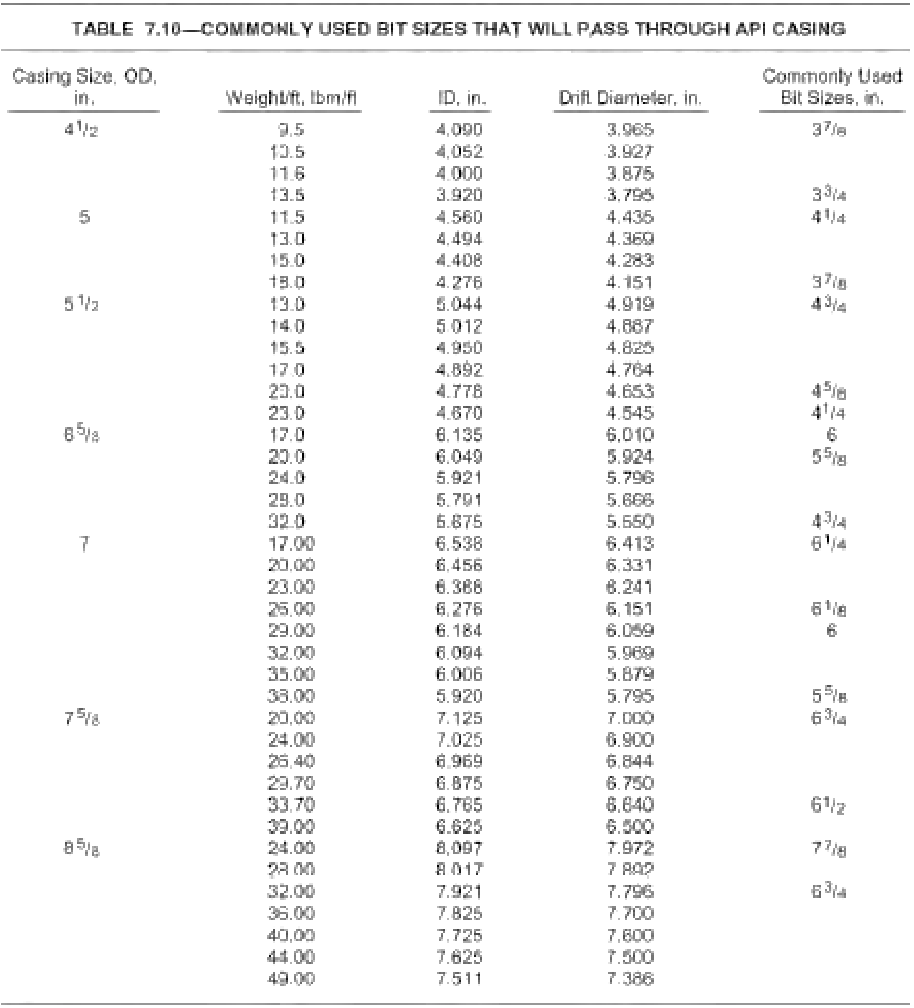


TABLE 7.10—COMMONLY USED BIT SIZES THAT WILL PASS THROUGH API CASING

Casing Size, OD, in.	Weight/ft, lbm/ft	ID, in.	Drift Diameter, in.	Commonly Used Bit Sizes, in.
4 1/2	9.5	4.090	3.965	3 7/8
	10.5	4.052	3.927	
	11.6	4.000	3.875	
	13.5	3.920	3.795	3 3/4
5	11.5	4.560	4.435	4 1/4
	13.0	4.494	4.369	
	15.0	4.408	4.283	
	18.0	4.276	4.151	3 7/8
5 1/2	13.0	5.044	4.919	4 3/4
	14.0	5.012	4.887	
	15.5	4.950	4.825	
	17.0	4.892	4.764	
	20.0	4.778	4.653	4 5/8
	23.0	4.670	4.545	4 1/4
6 5/8	17.0	6.135	6.010	6
	20.0	6.049	5.924	5 5/8
	24.0	5.921	5.796	
	28.0	5.791	5.666	
	32.0	5.675	5.550	4 3/4
7	17.00	6.538	6.413	6 1/4
	20.00	6.456	6.331	
	23.00	6.366	6.241	
	26.00	6.276	6.151	6 1/8
	29.00	6.184	6.059	6
	32.00	6.094	5.969	
	35.00	6.006	5.879	
	38.00	5.920	5.795	5 5/8
7 5/8	20.00	7.125	7.000	6 3/4
	24.00	7.025	6.900	
	26.40	6.969	6.844	
	29.70	6.875	6.750	
	33.70	6.765	6.640	6 1/2
	39.00	6.625	6.500	
8 5/8	24.00	8.097	7.972	7 7/8
	28.00	8.017	7.892	
	32.00	7.921	7.796	6 3/4
	36.00	7.825	7.700	
	40.00	7.725	7.600	
	44.00	7.625	7.500	
	49.00	7.511	7.386	

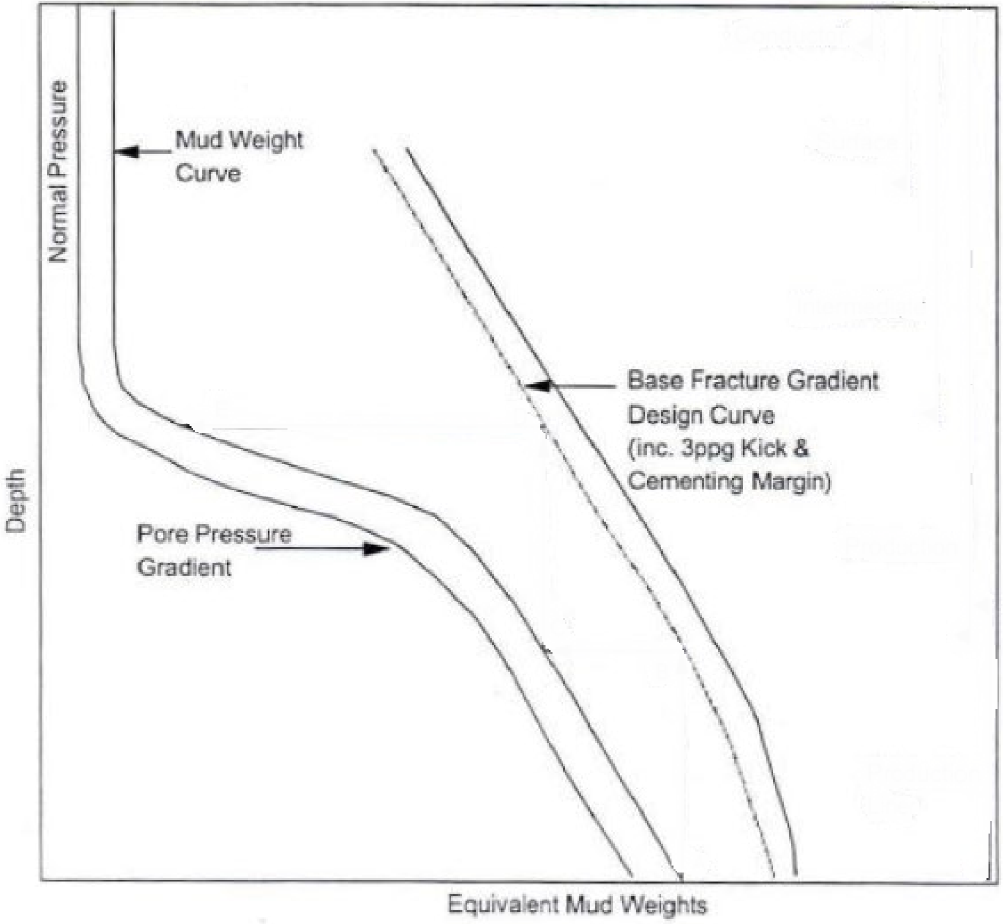
Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
  - ***Drilling***
    - Design sequence:
      1. Based upon reservoir inflow and tubing intake performance, proper tubing size is selected.
      2. The required production casing size is determined considering completion requirements.
      3. The diameter of the drill bit is selected for drilling the production section of the hole considering drilling and cementing stipulations.
      4. One must determine the smallest casing through which the drill bit will pass, and the process is repeated. Large cost savings are possible by becoming more aggressive (using smaller clearances) during this portion of the preliminary design phase. This has been one of the principal motivations in the increased popularity of slimhole drilling.

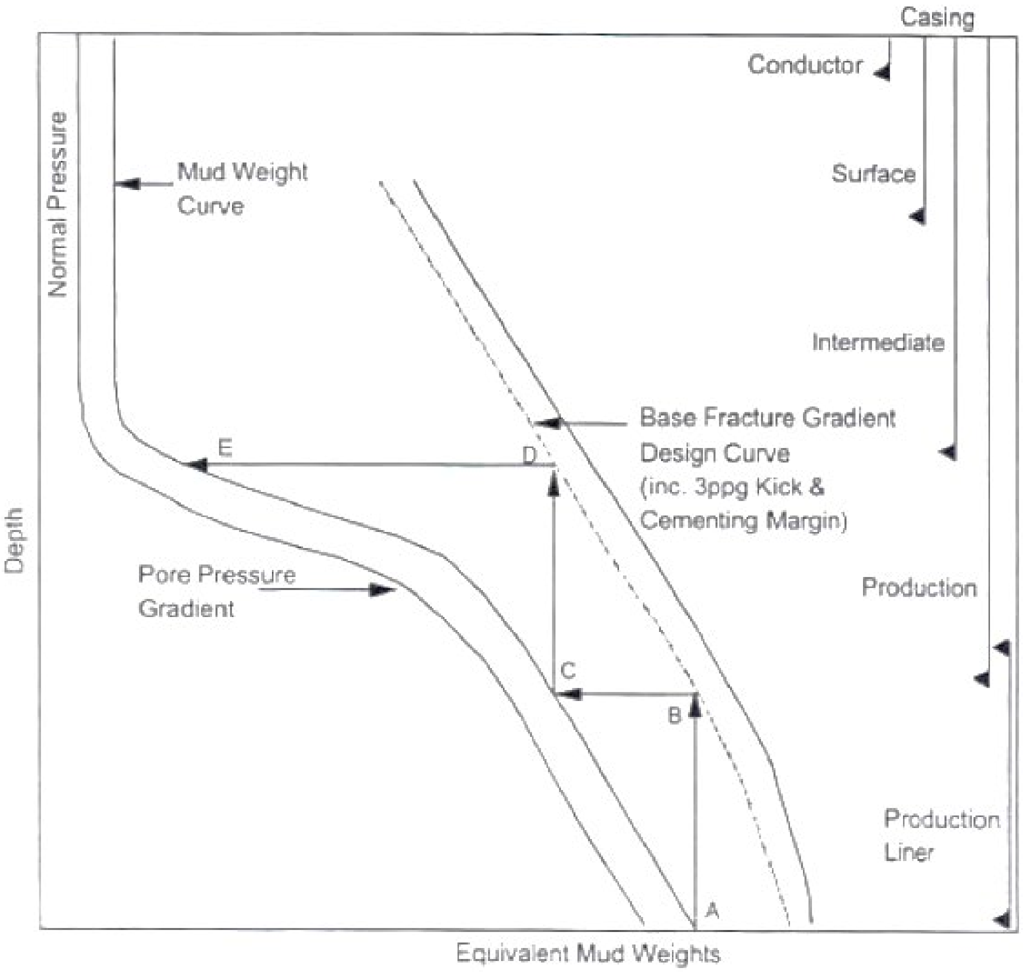
Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
- ***Casing Shoe Depths and the Number of Strings.*** Following the selection of drillbit and casing sizes, the setting depth of individual casing strings must be determined. In conventional rotary drilling operations, the setting depths are determined principally by the mud weight and the fracture gradient, which is sometimes called a well plan.
- Equivalent mud weight (EMW) is pressure divided by true vertical depth and converted to units of lbm/gal. EMW equals actual mud weight when the fluid column is uniform and static. First, pore and fracture gradient lines must be drawn on a well-depth vs. EMW chart.
- Next, safety margins are introduced, and broken lines are drawn, which establish the design ranges. The offset from the predicted pore pressure and fracture gradient nominally accounts for kick tolerance and the increased equivalent circulating density (ECD) during drilling.

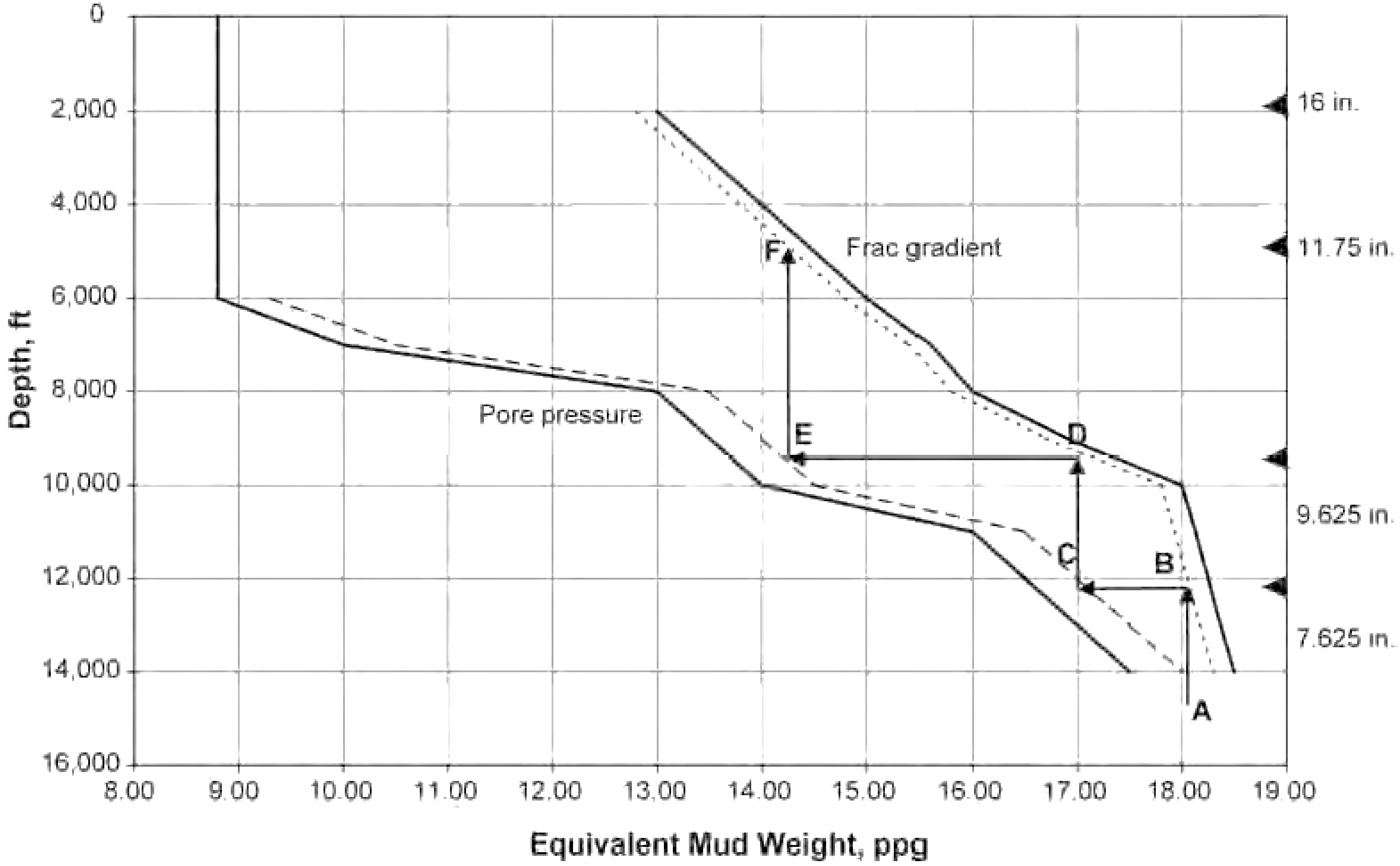
Casing Design. Preliminary Design



Casing Design. Preliminary Design



Casing Design. Preliminary Design



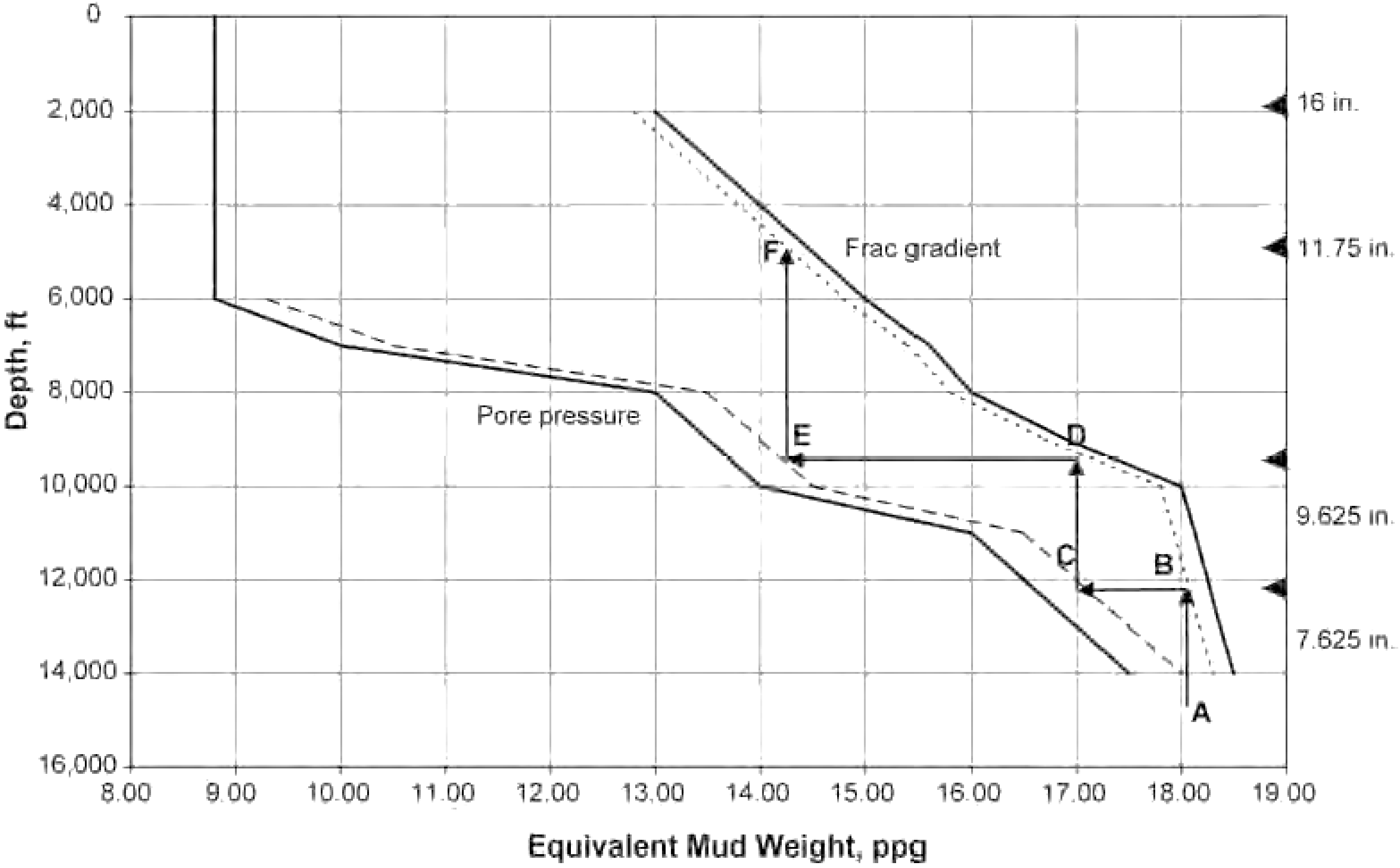
Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
- ***Casing Shoe Depths and the Number of Strings.***

  There are two possible ways to estimate setting depths from this figure.

  - **Bottom-Up Design.**
    - This is the standard method for casing seat selection.
    - From Point A in (the highest mud weight required at the total depth), draw a vertical line upward to Point B. A protective 7⅝-in. casing string must be set at 12,000 ft, corresponding to Point B, to enable safe drilling on the section AB.
    - To determine the setting depth of the next casing, draw a horizontal line BC and then a vertical line CD. In such a manner, Point D is determined for setting the 9⅝-in. casing at 9,500 ft. The procedure is repeated for other casing strings, usually until a specified surface casing depth is reached.

Casing Design. Preliminary Design



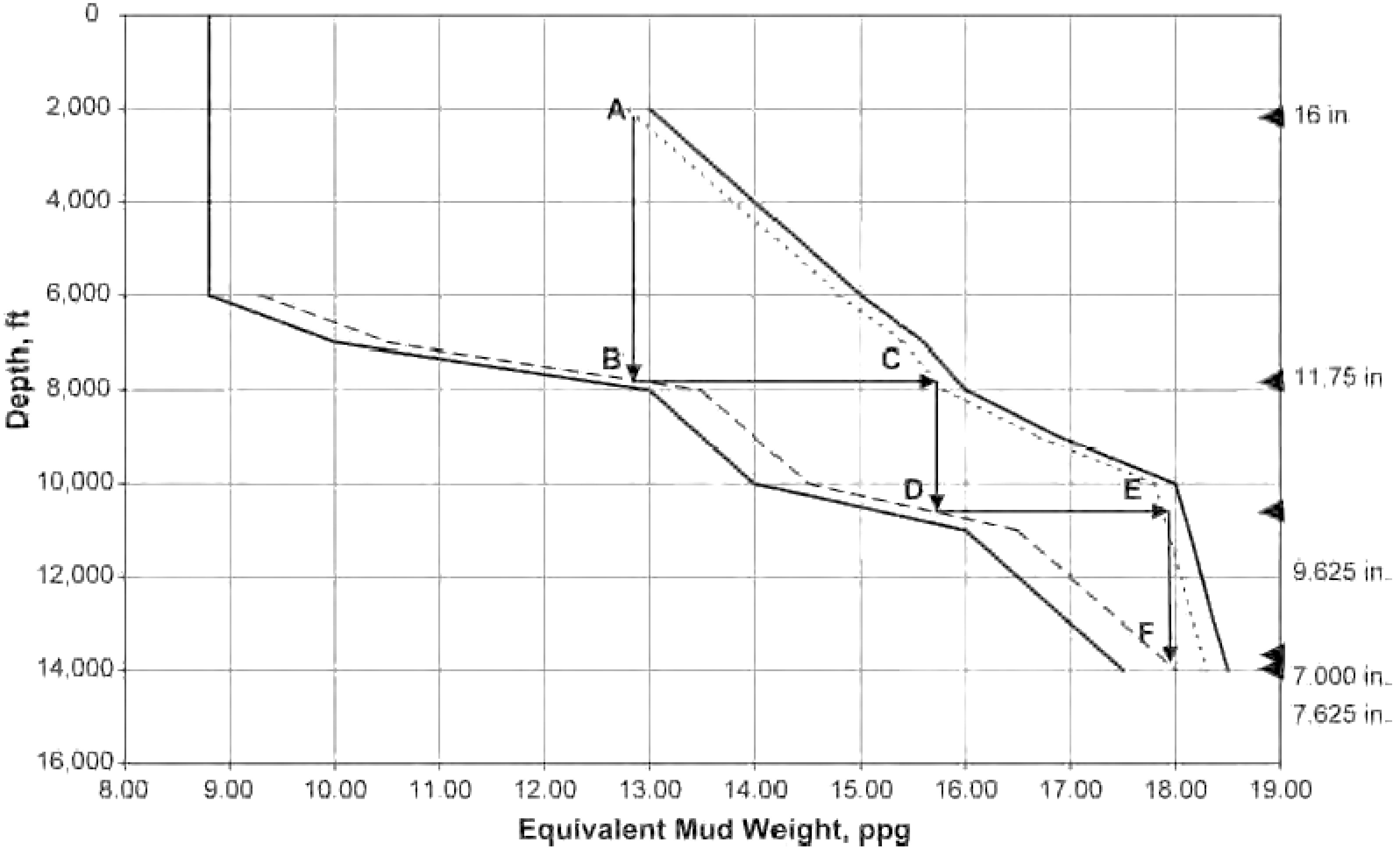
Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
- ***Casing Shoe Depths and the Number of Strings.***

  There are two possible ways to estimate setting depths from this figure.

  - **Top-Down Design.**
    - From the setting depth of the 16-in. surface casing (here assumed to be at 2,000 ft), draw a vertical line from the fracture gradient dotted line, Point A, to the pore pressure dashed line, Point B. This establishes the setting point of the 11¾-in. casing at about 9,800 ft. Draw a horizontal line from Point B to the intersection with the dotted frac gradient line at Point C; then, draw a vertical line to Point D at the pore pressure curve intersection. This establishes the 9⅝-in. casing setting depth.
    - This process is repeated until bottom hole is reached.

Casing Design. Preliminary Design



Casing Design. Preliminary Design

- **Hole and Pipe Diameters.**
- ***Casing Shoe Depths and the Number of Strings.***
  - There are several things to observe about these two methods:
    - They do not necessarily give the same setting depths.
    - They do not necessarily give the same number of strings.
    - In the top-down design, the bottomhole pressure is missed by a slight amount that requires a short 7-in. liner section. This slight error can be fixed by resetting the surface casing depth.
    - The top-down method is more like actually drilling a well, in which the casing is set when necessary to protect the previous casing shoe. This analysis can help anticipate the need for additional strings, given that the pore pressure and fracture gradient curves have some uncertainty associated with them.

Casing Design. Preliminary Design

- **TOC Depths.**
  - TOC (Top of cement) depths for each casing string should be selected in the preliminary design phase because this selection will influence axial load distributions and external pressure profiles used during the detailed design phase.
  - TOC depths are typically based on zonal isolation; regulatory requirements; prior shoe depths; formation strength; buckling; and annular pressure buildup in subsea wells.
  - Buckling calculations are not performed until the detailed design phase. Hence, the TOC depth may be adjusted, as a result of the buckling analysis, to help reduce buckling in some cases.

Casing Design. Preliminary Design

- **Directional Plan.**
  - For casing design purposes, establishing a directional plan consists of <u>determining the wellpath</u> from the surface to the geological targets.
  - The directional plan influences all aspects of casing design including mud weight and mud chemistry selection for hole stability, shoe seat selection, casing axial load profiles, casing wear, bending stresses, and buckling.
  - It is based on factors that include geological targets; surface location; interference from other wellbores; torque and drag considerations; casing wear considerations; bottomhole assembly and drill-bit performance in the local geological setting.
  - To account for the variance from the planned build, drop, and turn rates, which occur because of the BHAs (Bottom hole assembly) used and operational practices employed, higher doglegs are often superimposed over the wellbore.
  - This increases the calculated bending stress in the detailed design phase.

Casing Design. Detailed Design

- **Load Cases.**
    - In order to select appropriate weights, grades, and connections during the detailed design phase using sound engineering judgment, design criteria must be established.
    - These criteria normally consist of load cases and their corresponding design factors that are compared to pipe ratings. Load cases are typically placed into categories that include burst loads; drilling loads; production loads; collapse loads; axial loads; running and cementing loads; and service loads.

Casing Design. Detailed Design

- **Design Factors.**
  - In order to make a direct graphical comparison between the load case and the pipe's rating, the DF must be considered.

$$\mathrm{DF} = SF_{\mathrm{min}} \leq SF = \frac{\text{pipe rating}}{\text{applied load}}$$

  - where
    - DF = design factor (the minimum acceptable safety factor), and
    - SF = safety factor.
  - It follows that

$$\mathrm{DF} \times (\text{applied load}) \leq \text{pipe rating}$$

  - Hence, by multiplying the load by the DF, a direct comparison can be made with the pipe rating. As long as the rating is greater than or equal to the modified load (which we will call the design load), the design criteria have been satisfied.

Casing Design. Detailed Design

- **Other Considerations.**
  - After performing a design based on burst, collapse and axial considerations, an initial design is achieved.
  - Before a final design is reached, design issues (connection selection, wear, and corrosion) must be addressed.
  - In addition, other considerations can also be included in the design.
  - These considerations are triaxial stresses because of combined loading (e.g., ballooning and thermal effects) - this is often called “service life analysis”; other temperature effects; and buckling.

Casing Design. Detailed Design

- **Selection of casing weight, grade and couplings**
  - After establishing the number of casing strings required to complete a hole, their respective setting depths and the outside diameters, one must select the nominal weight, steel grade, and couplings of each of these strings.
  - In practice, each casing string is designed to withstand the maximal load that is anticipated during casing landing, drilling, and production operations.
  - Often, it is not possible to predict the tensile, collapse, and burst loads during the life of the casing. For example, drilling fluid left in the annulus between the casing and the drilled hole deteriorates with time. Consequently, the pressure gradient may be reduced to that of salt water which can lead to a significant increase in burst pressure.
  - The casing design, therefore, proceeds on the basis of the worst anticipated loading conditions throughout the life of the well.

Casing selection criteria

- The main criteria for casing selection are:
  - **Collapse load**: originates from the hydrostatic pressure of drilling fluid, cement slurry outside the casing and later on by ‘moving formations’, for example salt.
  - **Burst load**: this is the internal pressure the casing will be exposed to during operations.
  - **Tension load**: caused by the string weight during running in; it will be highest at the top joints.
  - **Corrosion service**: carbon dioxide (CO2) or hydrogen sulphide (H2S) in formation fluids will cause rapid corrosion of standard carbon steel and therefore special steel may be required.
  - **Buckling resistance**: the load exerted on the casing if under compression.

Pipe Strength

- To design a reliable casing string, it is necessary to know the strength of pipe under different load conditions.
- The most important <u>mechanical properties</u> of casing and tubing are:
    - Burst strength.
    - Collapse resistance.
    - Tensile strength.

Pipe Strength

- **Burst strength.**
  - Burst pressure conditions occur during well control operations, integrity tests, and squeeze cementing.
  - The burst strength of the pipe body is determined by the internal yield pressure formula:

$$P_B = 0.0875 \left[\frac{2Y_p t}{D}\right]$$

  - where
    - P_B = minimum burst pressure, psi,
    - Y_p = minimum yield strength, psi,
    - t = nominal wall thickness, in.,
    - D = nominal outside pipe diameter, in.
- This equation, commonly known as the Barlow equation, calculates the internal pressure at which the tangential (or hoop) stress at the inner wall of the pipe reaches the yield strength (YS) of the material.

Pipe Strength

- **Collapse Strength.**
  - If external pressure exceeds internal pressure, the casing is subjected to collapse.
  - Such conditions may exist during cementing operations or well evacuation.
  - Collapse strength is primarily a function of the material's yield strength and its slenderness ratio, *D/t*.
  - The collapse strength criteria consist of four collapse regimes determined by yield strength and D/t.
    - Yield Strength Collapse.
    - Plastic Collapse.
    - Transition Collapse.
    - Elastic Collapse.

  - Most oilfield tubulars experience collapse in the "plastic" and "transition" regimes.

Pipe Strength

- **Collapse Strength.** *Yield Strength Collapse.*
  - For thick wall pipes ($D/t < 15\pm$), the tangential stress exceeds the yield strength of the material before a collapse instability failure occurs.

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

  - Nominal dimensions are used in the collapse equations.

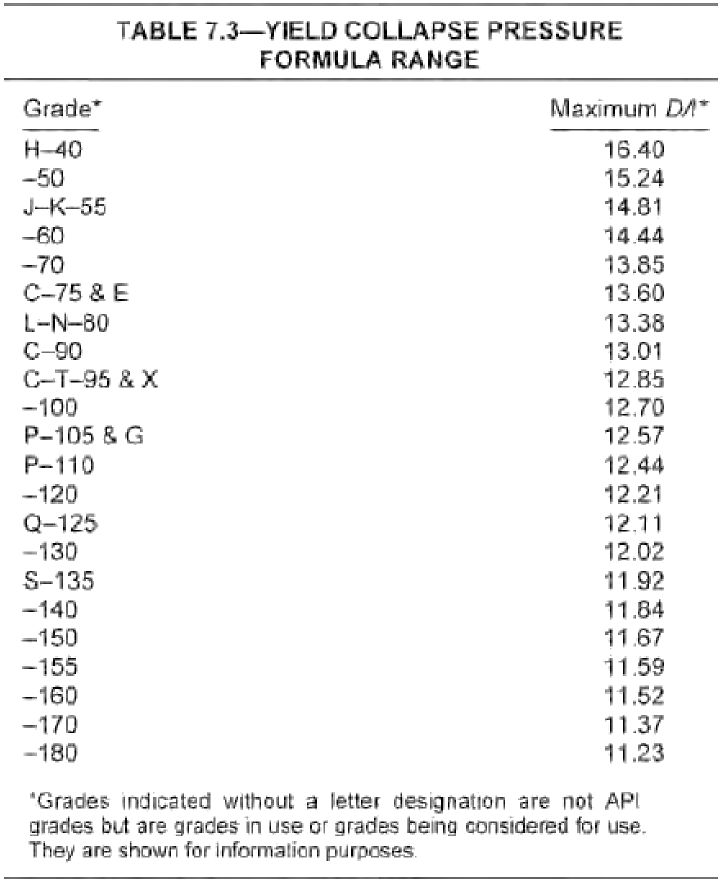


TABLE 7.3—YIELD COLLAPSE PRESSURE FORMULA RANGE

Grade*	Maximum D/t*
H–40	16.40
–50	15.24
J–K–55	14.81
–60	14.44
–70	13.85
C–75 & E	13.60
L–N–80	13.38
C–90	13.01
C–T–95 & X	12.85
–100	12.70
P–105 & G	12.57
P–110	12.44
–120	12.21
Q–125	12.11
–130	12.02
S–135	11.92
–140	11.84
–150	11.67
–155	11.59
–160	11.52
–170	11.37
–180	11.23

*Grades indicated without a letter designation are not API grades but are grades in use or grades being considered for use. They are shown for information purposes.

Pipe Strength

- **Collapse Strength.** *Plastic Collapse.*
  - Plastic collapse is based on empirical data from 2,488 tests of K-55, N-80, and P-110 seamless casing. No analytic expression has been derived that accurately models collapse behavior in this regime.
  - Regression analysis results in a 95% confidence level that 99.5% of all pipes manufactured to API specifications will fail at a collapse pressure higher than the plastic collapse pressure.

Pipe Strength

- **Collapse Strength.** *Plastic Collapse.*
  - The minimum collapse pressure for the plastic range of collapse is calculated by:

$$P_p = Y_p\left[\frac{A}{D/t} - B\right] - C$$

  - The factors *A, B,* and *C* and applicable *D/t* range for the plastic collapse formula are shown in Table.

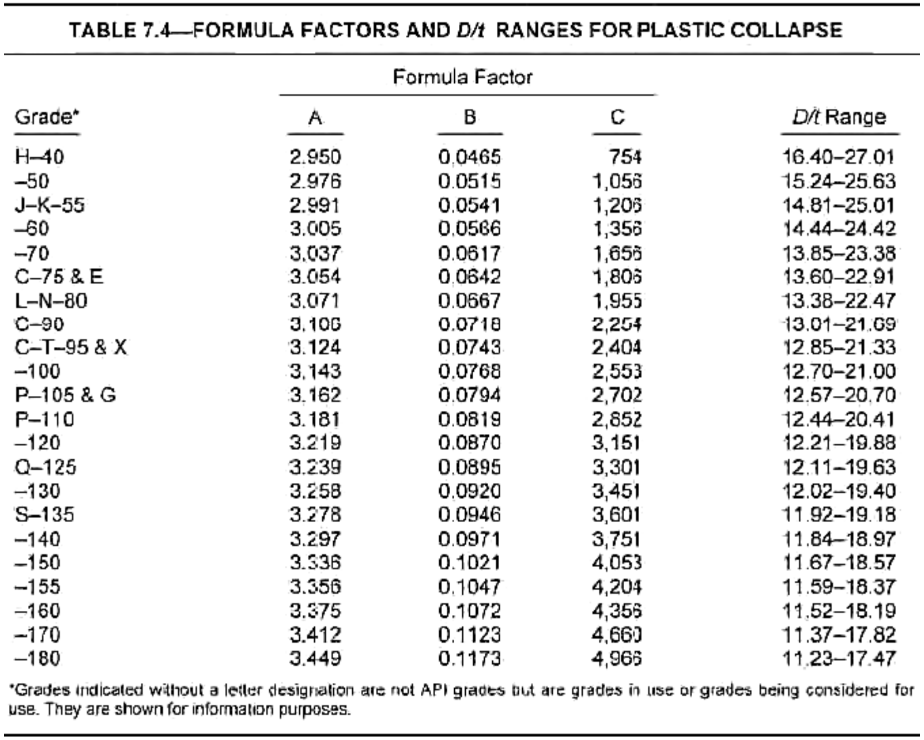


TABLE 7.4—FORMULA FACTORS AND *D/t* RANGES FOR PLASTIC COLLAPSE

Grade*	Formula Factor A	Formula Factor B	Formula Factor C	*D/t* Range
H–40	2.950	0.0465	754	16.40–27.01
–50	2.976	0.0515	1,056	15.24–25.63
J–K–55	2.991	0.0541	1,206	14.81–25.01
–60	3.005	0.0566	1,356	14.44–24.42
–70	3.037	0.0617	1,656	13.85–23.38
C–75 & E	3.054	0.0642	1,806	13.60–22.91
L–N–80	3.071	0.0667	1,955	13.38–22.47
C–90	3.106	0.0718	2,254	13.01–21.69
C–T–95 & X	3.124	0.0743	2,404	12.85–21.33
–100	3.143	0.0768	2,553	12.70–21.00
P–105 & G	3.162	0.0794	2,702	12.57–20.70
P–110	3.181	0.0819	2,852	12.44–20.41
–120	3.219	0.0870	3,151	12.21–19.88
Q–125	3.239	0.0895	3,301	12.11–19.63
–130	3.258	0.0920	3,451	12.02–19.40
S–135	3.278	0.0946	3,601	11.92–19.18
–140	3.297	0.0971	3,751	11.84–18.97
–150	3.336	0.1021	4,053	11.67–18.57
–155	3.356	0.1047	4,204	11.59–18.37
–160	3.375	0.1072	4,356	11.52–18.19
–170	3.412	0.1123	4,660	11.37–17.82
–180	3.449	0.1173	4,966	11.23–17.47

*Grades indicated without a letter designation are not API grades but are grades in use or grades being considered for use. They are shown for information purposes.

Pipe Strength

- **Collapse Strength.** *Transition Collapse.*
  - Transition collapse is obtained by a numerical curve fit between the plastic and elastic regimes. The minimum collapse pressure for the plastic-to-elastic transition zone, *PT*, is calculated with the equation:

$$P_T = Y_p\left[\frac{F}{D/t} - G\right]$$

  - The factors *F* and *G* and applicable *D/t* range for the transition collapse pressure formula, are shown in Table.

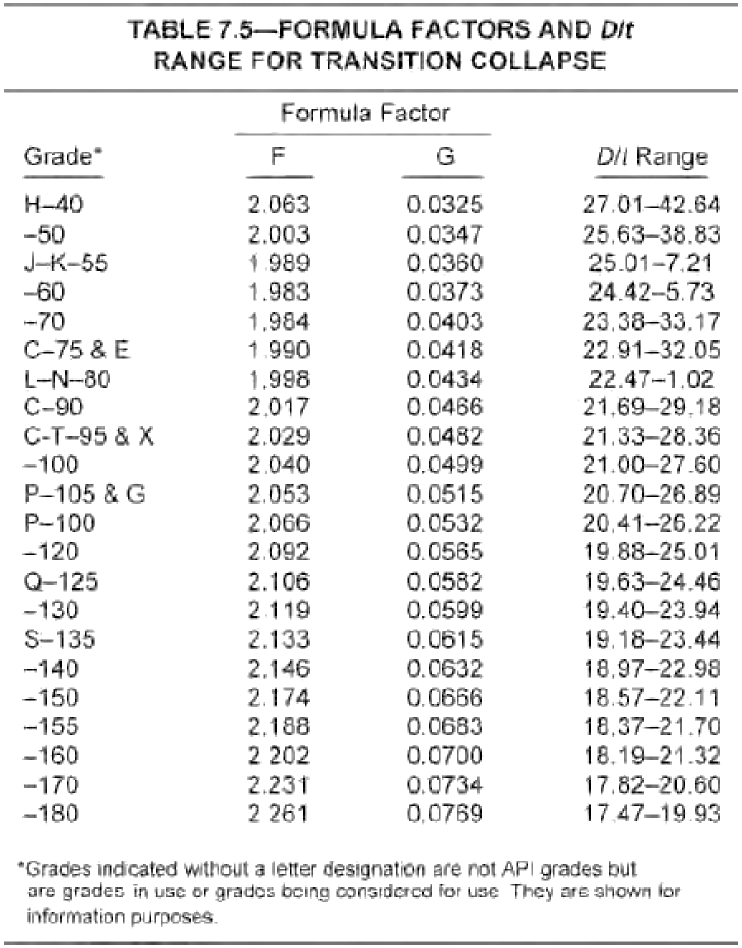


TABLE 7.5—FORMULA FACTORS AND *D/t* RANGE FOR TRANSITION COLLAPSE

Grade*	Formula Factor F	Formula Factor G	*D/t* Range
H–40	2.063	0.0325	27.01–42.64
–50	2.003	0.0347	25.63–38.83
J–K–55	1.989	0.0360	25.01–7.21
–60	1.983	0.0373	24.42–5.73
–70	1.984	0.0403	23.38–33.17
C–75 & E	1.990	0.0418	22.91–32.05
L–N–80	1.998	0.0434	22.47–1.02
C–90	2.017	0.0466	21.69–29.18
C-T–95 & X	2.029	0.0482	21.33–28.36
–100	2.040	0.0499	21.00–27.60
P–105 & G	2.053	0.0515	20.70–26.89
P–100	2.066	0.0532	20.41–26.22
–120	2.092	0.0565	19.88–25.01
Q–125	2.106	0.0582	19.63–24.46
–130	2.119	0.0599	19.40–23.94
S–135	2.133	0.0615	19.18–23.44
–140	2.146	0.0632	18.97–22.98
–150	2.174	0.0666	18.57–22.11
–155	2.188	0.0683	18.37–21.70
–160	2.202	0.0700	18.19–21.32
–170	2.231	0.0734	17.82–20.60
–180	2.261	0.0769	17.47–19.93

*Grades indicated without a letter designation are not API grades but are grades in use or grades being considered for use. They are shown for information purposes.

Pipe Strength

- **Collapse Strength.** *Elastic Collapse.*
  - Elastic Collapse is based on theoretical elastic instability failure; this criterion is independent of yield strength and applicable to thin-wall pipe (*D*/*t* > 25±).
  - The minimum collapse pressure for the elastic range of collapse is calculated with this equation:

$$P_E = \frac{46.95 \times 10^6}{(D/t)[(D/t) - 1]^2}$$

  - The applicable *D*/*t* range for elastic collapse is shown in Table

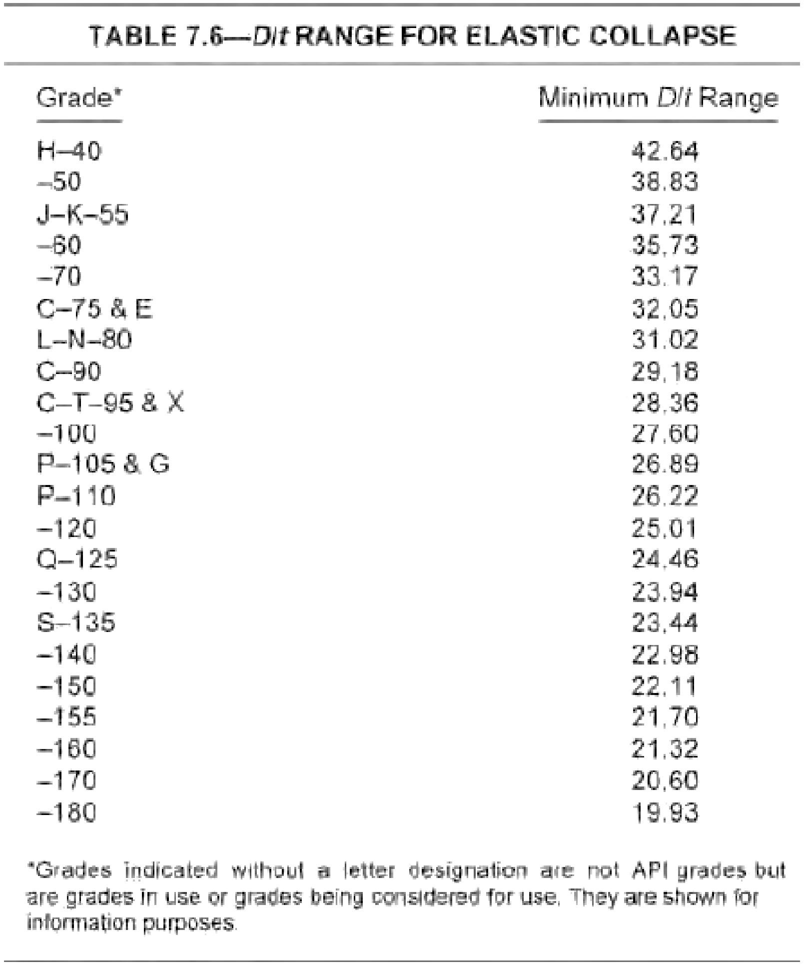


TABLE 7.6—*D/t* RANGE FOR ELASTIC COLLAPSE

Grade*	Minimum *D/t* Range
H–40	42.64
–50	38.83
J–K–55	37.21
–60	35.73
–70	33.17
C–75 & E	32.05
L–N–80	31.02
C–90	29.18
C–T–95 & X	28.36
–100	27.60
P–105 & G	26.89
P–110	26.22
–120	25.01
Q–125	24.46
–130	23.94
S–135	23.44
–140	22.98
–150	22.11
–155	21.70
–160	21.32
–170	20.60
–180	19.93

*Grades indicated without a letter designation are not API grades but are grades in use or grades being considered for use. They are shown for information purposes.

Pipe Strength

- **Axial Strength.**
  - The axial strength of the pipe body is determined by the pipe body yield strength formula:

$$F_y = \frac{\pi}{4}\left(D^2 - d^2\right)Y_p$$

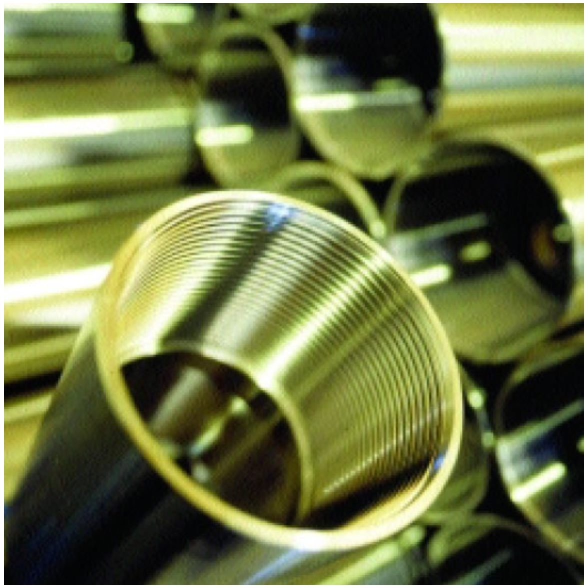
  - where
    - F_y = pipe body axial strength (units of force)
    - Y_p = minimum yield strength
    - D = nominal outer diameter
    - d = nominal inner diameter.
  - Axial strength is the product of the cross-sectional area (based on nominal dimensions) and the yield strength

Pipe Strength

- **Combined Stress Effects.**
  - All the pipe-strength equations previously given are based on a uniaxial stress state.
  - This idealized situation never occurs in oilfield applications because pipe in a wellbore is always subjected to combined loading conditions.
  - The fundamental basis of casing design is that if stresses in the pipe wall exceed the yield strength of the material, a failure condition exists.
  - Hence, the yield strength is a measure of the maximum allowable stress. To evaluate the pipe strength under combined loading conditions, the uniaxial yield strength is compared to the yielding condition.

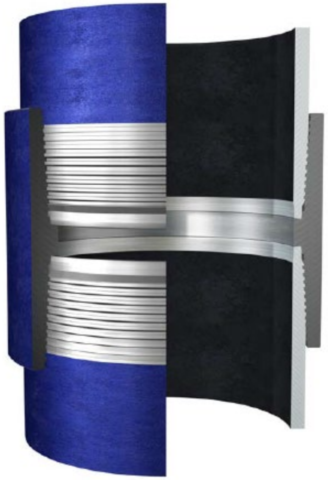
API Connection Ratings

- While a number of joint connections are available, the API recognizes three basic types:
    - Coupling with rounded thread (long or short)
    - Coupling with asymmetrical trapezoidal thread buttress
    - Extreme-line casing with trapezoidal thread without coupling.
- Threads are used as mechanical means to hold the neighboring joints together during axial tension or compression.
- For all casing sizes, the threads are not intended to be leak resistant when made up



Connection Failures

- Most casing failures occur at connections.
- These failures can be attributed to:
    - improper design or exposure to loads exceeding the rated capacity
    - failure to comply with makeup requirements
    - failure to meet manufacturing tolerances
    - damage during storage and handling
    - damage during production operations (corrosion, wear, etc.).



Connection Failures

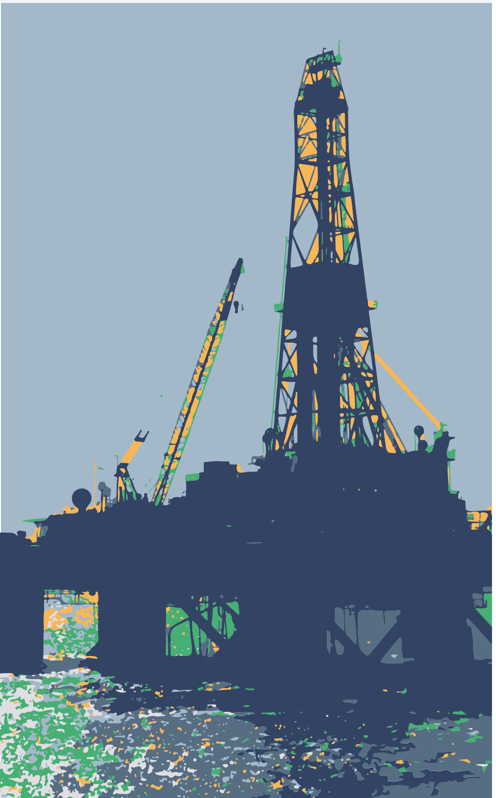
- Connection failure can be classified broadly as: leakage; structural failure; galling during makeup; yielding because of internal pressure; jump-out under tensile load; fracture under tensile load; failure because of excessive torque during makeup or subsequent operations.
- Avoiding connection failure is not only dependent upon selection of the correct connection but is strongly influenced by other factors, which include manufacturing tolerances; storage (storage thread compound and thread protector); transportation (thread protector and handling procedures); and running procedures (selection of thread compound, application of thread compound, and adherence to correct makeup specifications and procedures).
- The overall mechanical integrity of a correctly designed casing string is dependent upon a quality assurance program that ensures damaged connections are not used and that operations personnel adhere to the appropriate running procedures.

Connection Design Limits

- The design limits of a connection are not only dependent upon its geometry and material properties but are influenced by surface treatment; phosphating; metal plating (copper, tin, or zinc); bead blasting; thread compound; makeup torque; use of a resilient seal ring (many companies do not recommend this practice); fluid to which connection is exposed (mud, clear brine, or gas); temperature and pressure cycling; and large doglegs (e.g., medium- or short-radius horizontal wells).

Loads on Casing and Tubing Strings

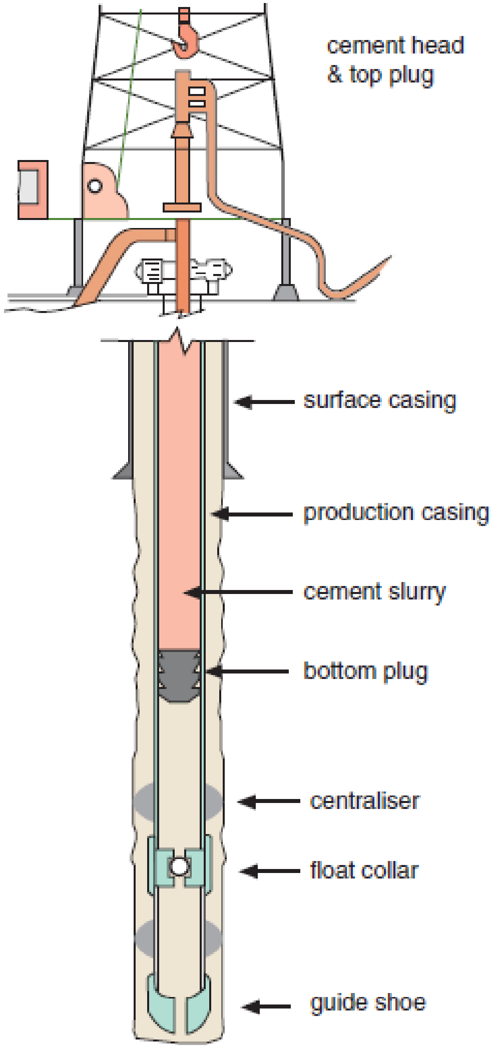
- In order to evaluate a given casing design, a set of loads is necessary. Casing loads result from running the casing, cementing the casing, subsequent drilling operations, production and well workover operations. Casing loads are principally pressure loads, mechanical loads, and thermal loads.
- Pressure loads are produced by fluids within the casing, cement and fluids outside the casing, pressures imposed at the surface by drilling and workover operations, and pressures imposed by the formation during drilling and production.
- Mechanical loads are associated with casing hanging weight, shock loads during running, packer loads during production and workovers, and hanger loads.
- Temperature changes and resulting thermal expansion loads are induced in casing by drilling, production, and workovers, and these loads might cause buckling (bending stress) loads in uncemented intervals.



2.
Cementing.

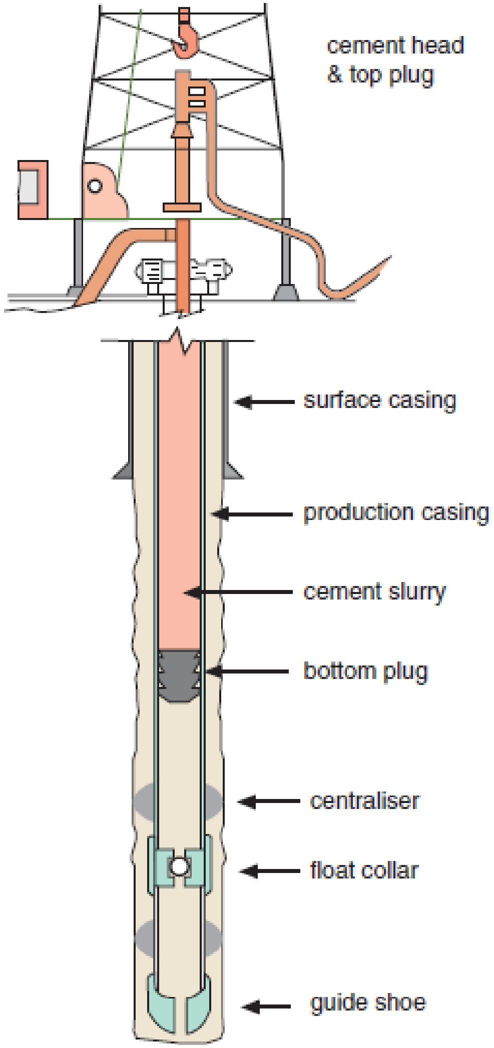
Cementing

- Running casing is the process by which 40 ft sections of steel pipe are screwed together on the rig floor and lowered into the hole.
- The bottom two joints will contain a guide shoe, a protective cap which facilitates the downward entry of the casing string through the borehole.
- Inside the guide shoe is a one-way valve which will open when cement/mud is pumped down the casing and is displaced upwards on the outside of the string.
- The valve is necessary because at the end of the cementing process the column of cement slurry filling the annulus will be heavier than the mud inside the casing and 'U tubing' would occur without it.

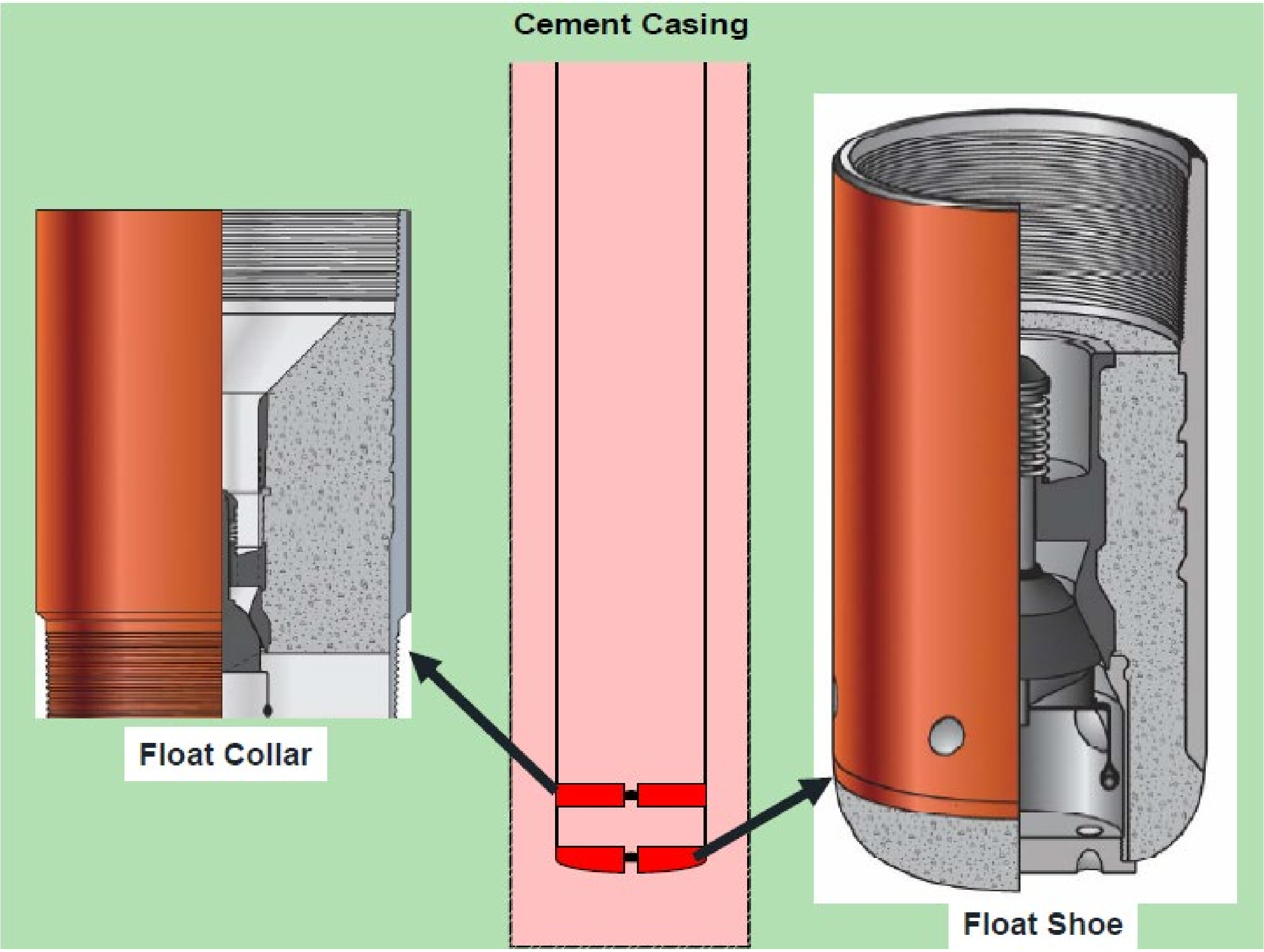


Cementing

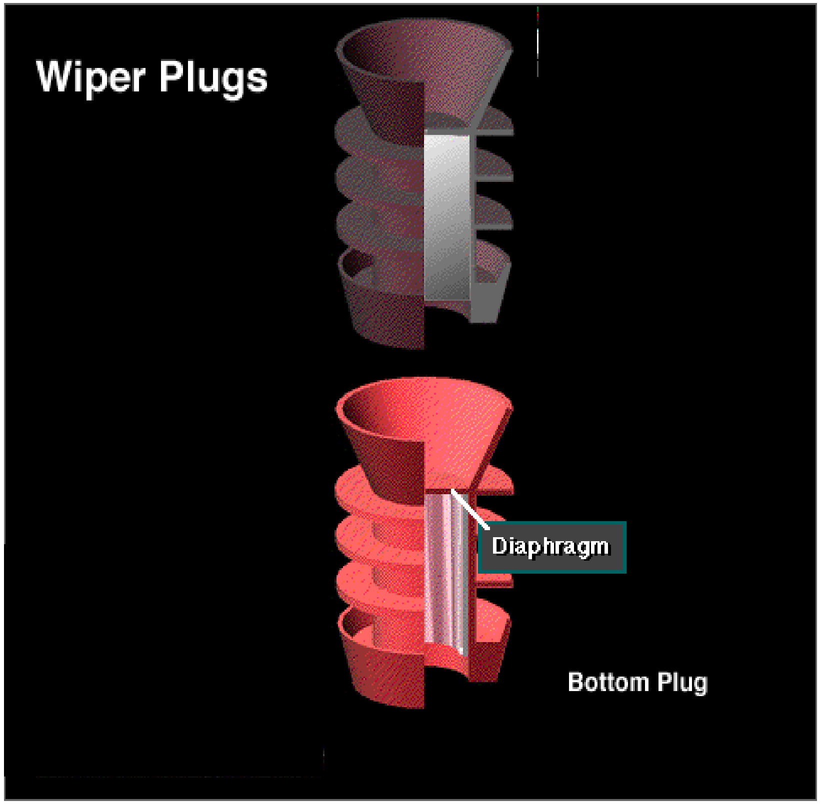
- To provide a second barrier in the string, a float collar is inserted in the joint above the guide shoe. The float collar also catches the bottom plug and top plug, between which the cement slurry is placed. The slurry of cement is pumped down between the two rubber seals (plugs).
- Their function is to prevent contamination of the cement with drilling fluid which would cause a bad cement bond between borehole wall and casing.
- Once the bottom plug bumps into the float collar, it ruptures and the cement slurry is pushed down through the guide shoe and upwards outside the casing.
- Thus, the annulus between casing and borehole wall is filled with cement.



Cementing

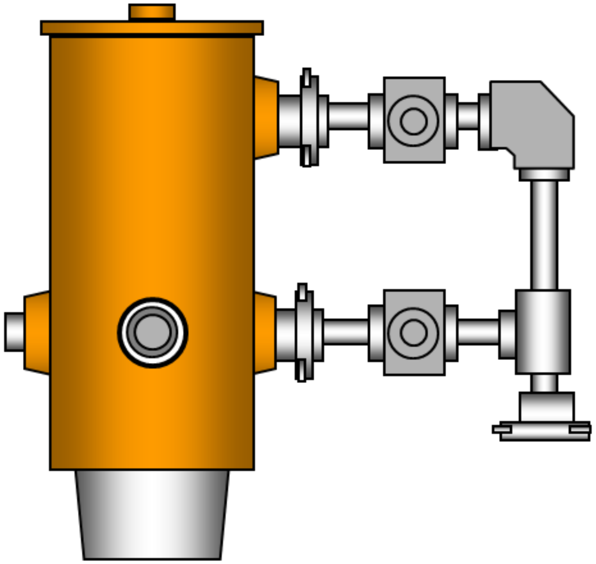


Cementing

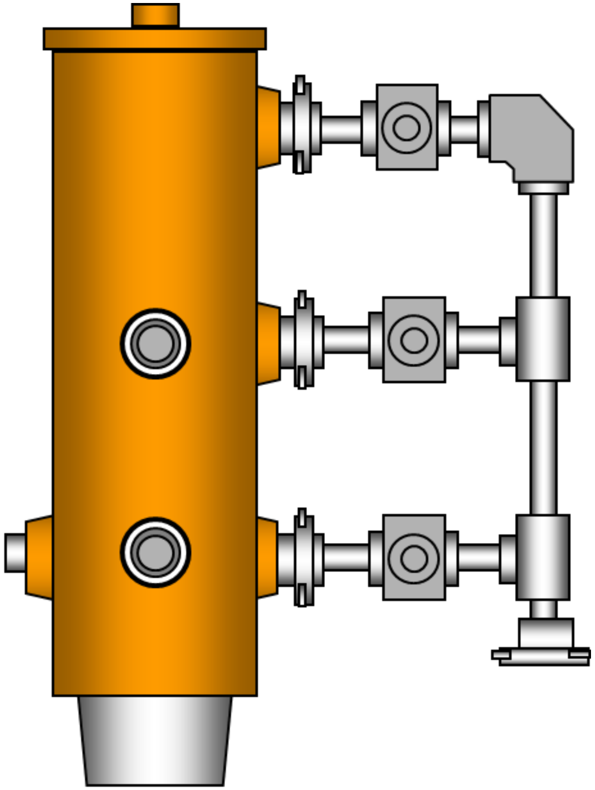


Cementing

- **Surface Equipment;**
    - Conventional Cement Head.



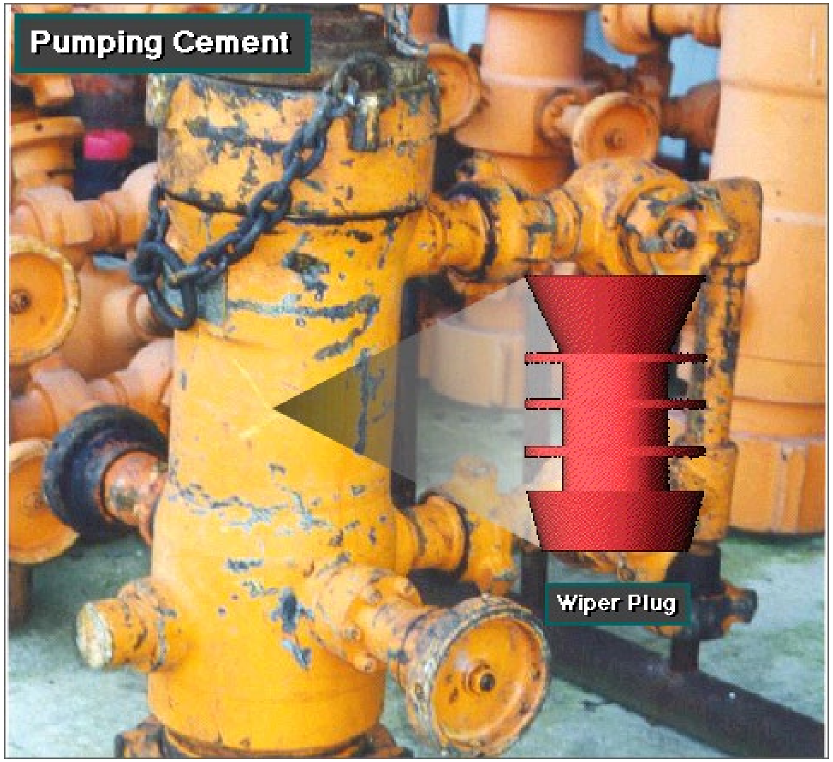
Single Plug Cement Head



Double Plug Cement Head

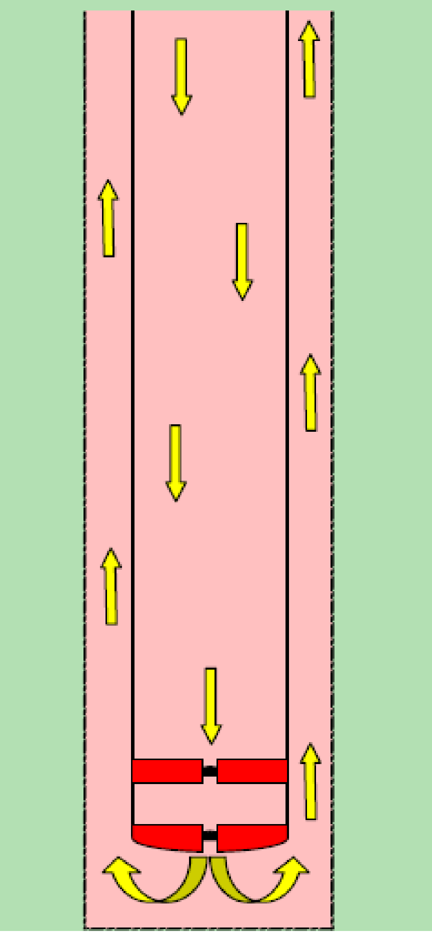
Cementing

- **Surface Equipment;**
  - Conventional Cement Head.

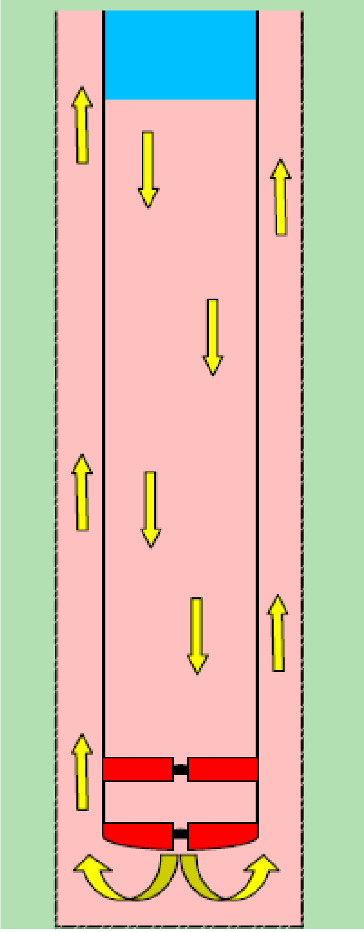


Cementing

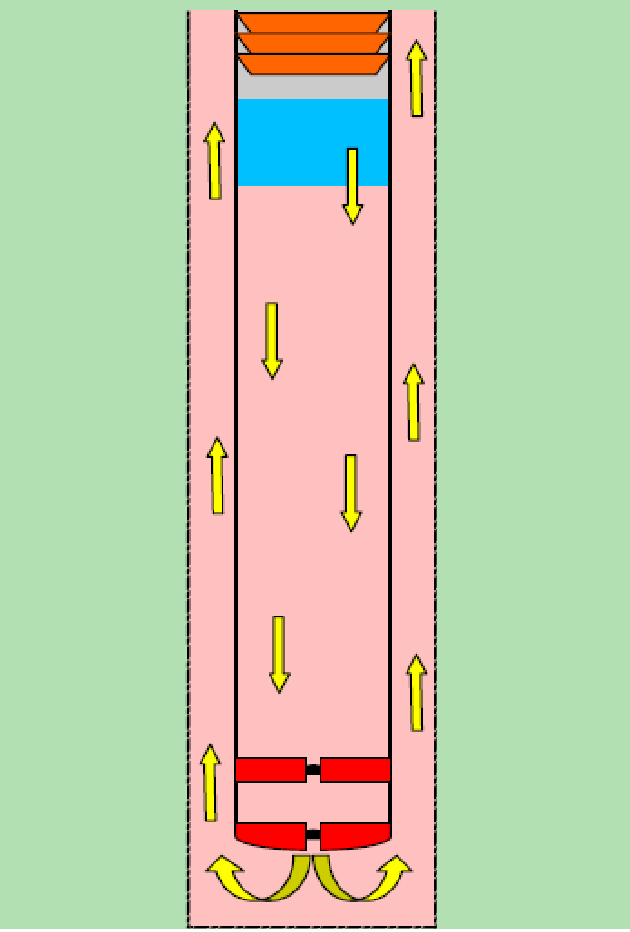
Circulating to condition mud



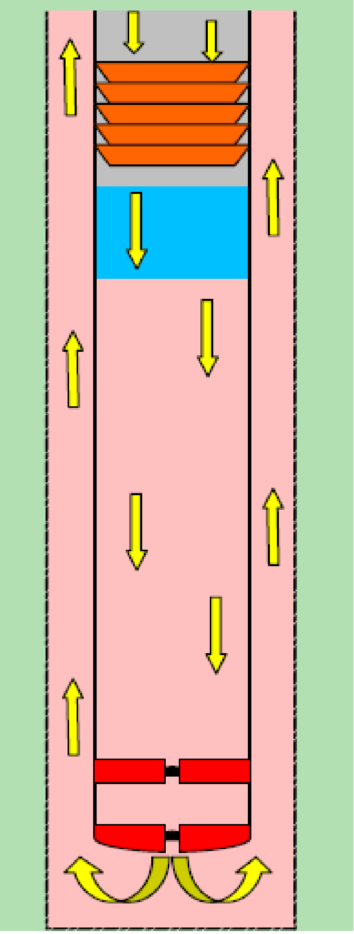
Pumping Spacer Ahead



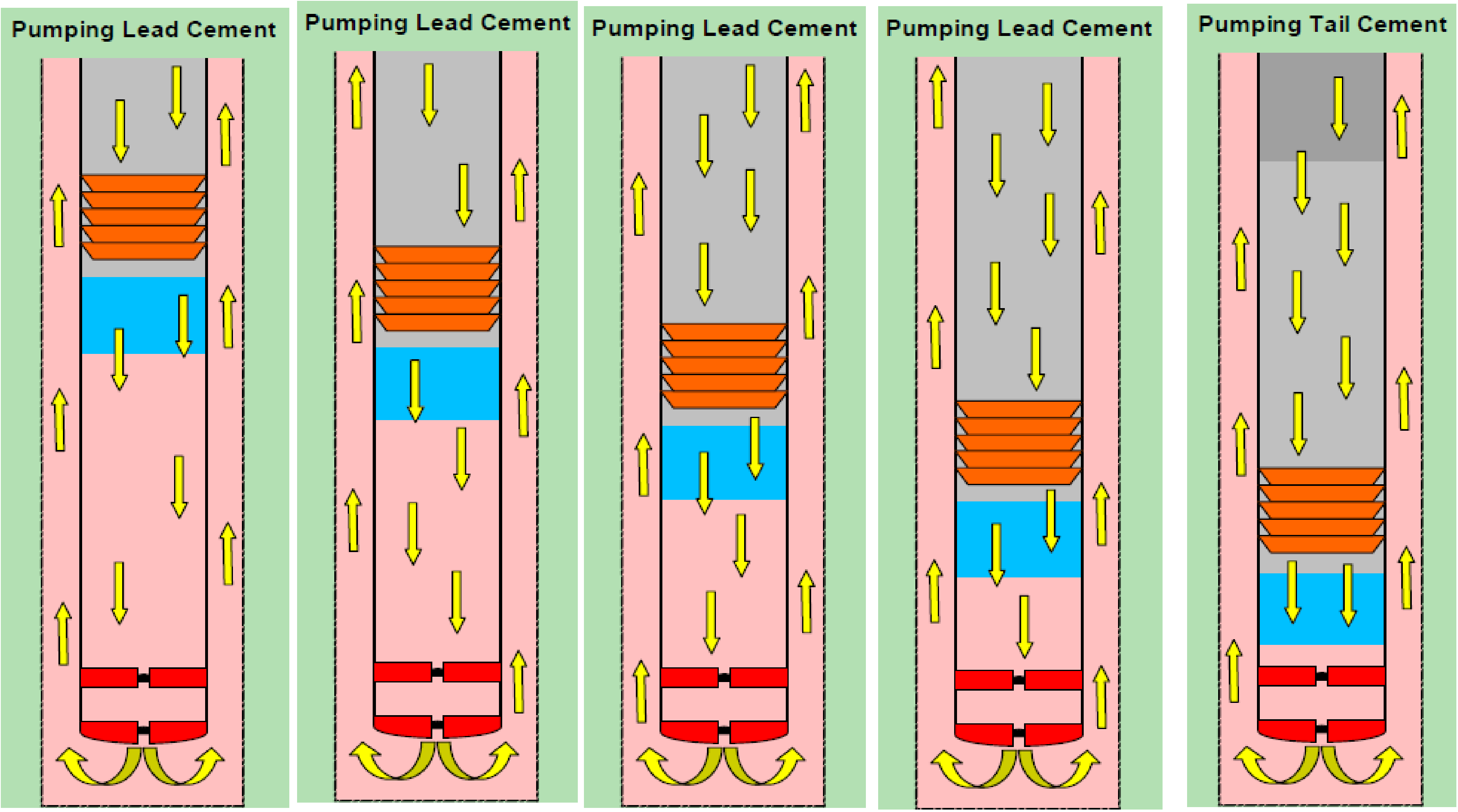
Pumping Lead Cement & drop bottom plug



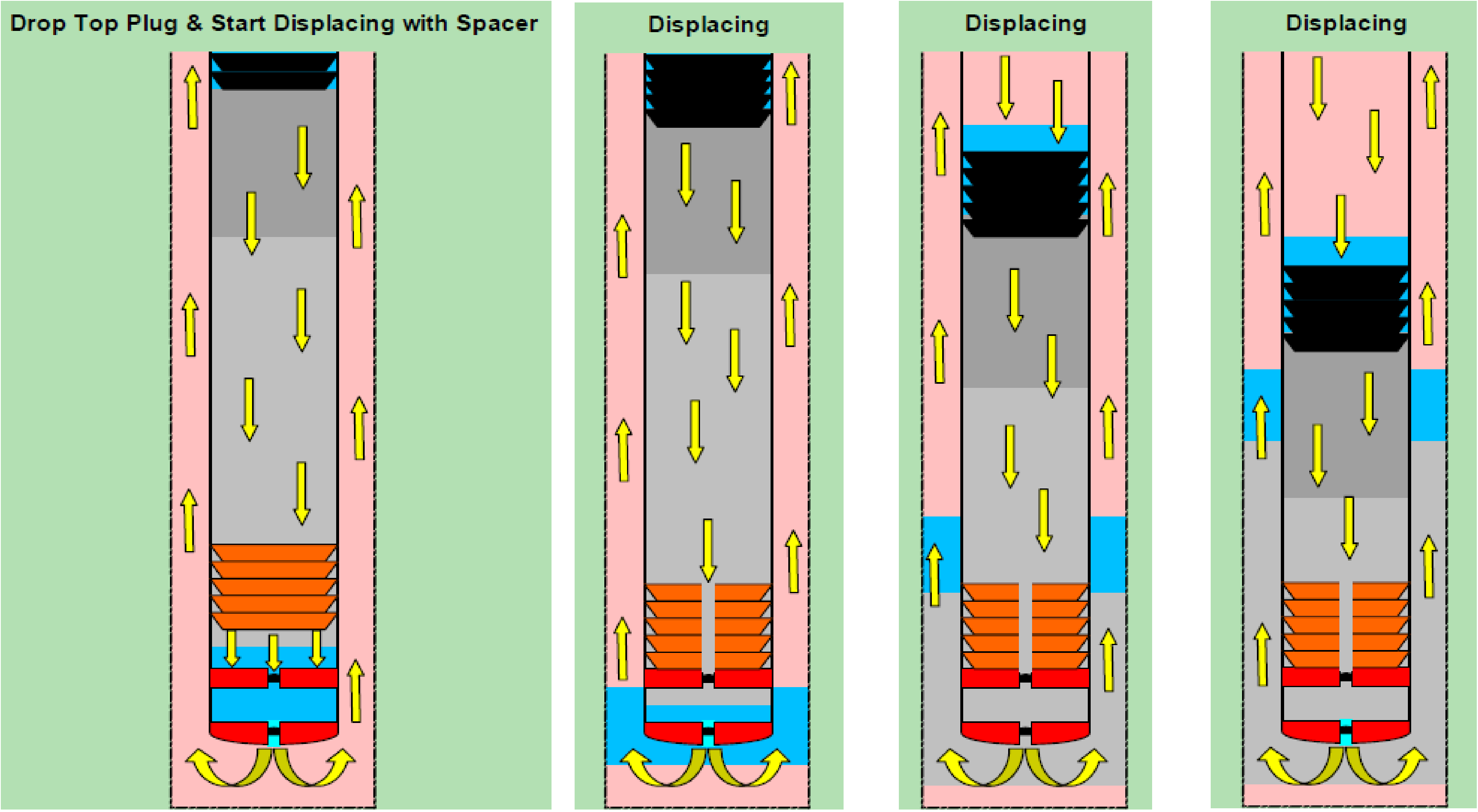
Pumping Lead Cement



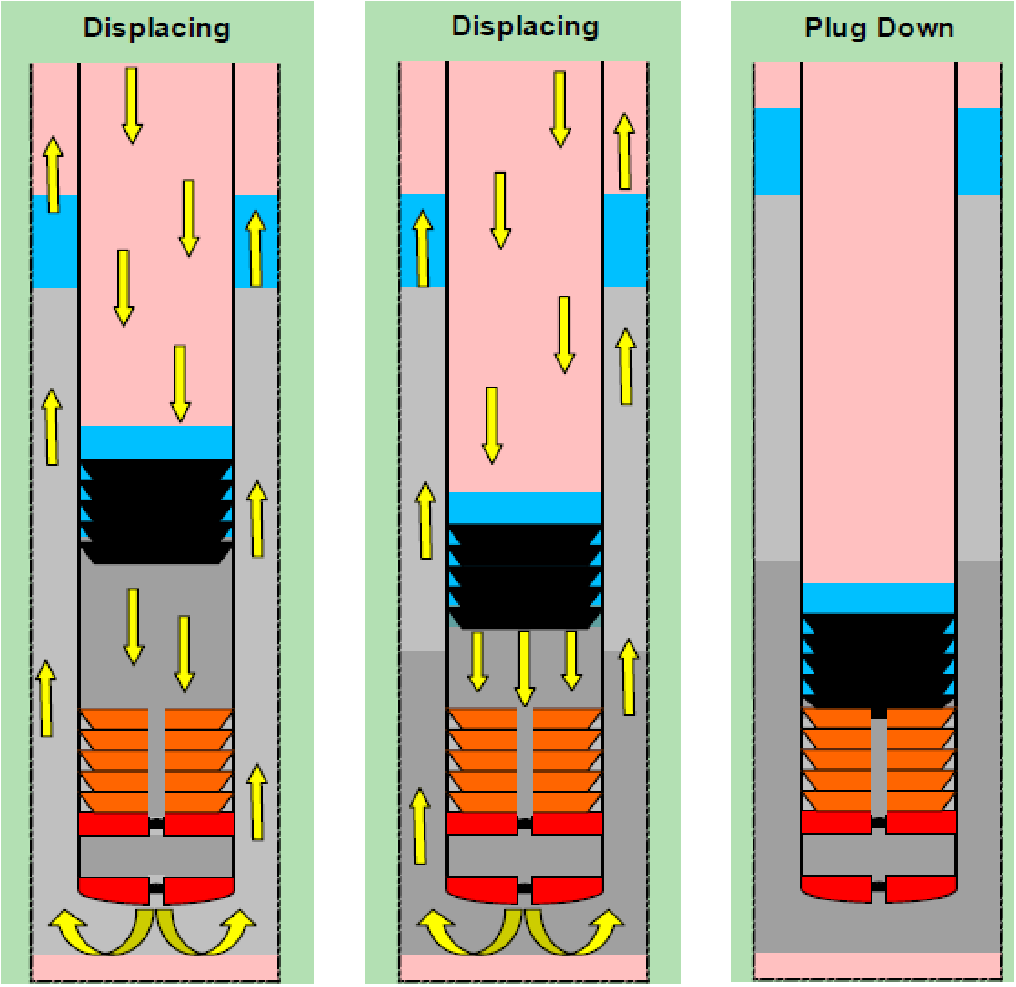
Cementing


Pumping Lead Cement
Pumping Lead Cement
Pumping Lead Cement
Pumping Lead Cement
Pumping Tail Cement

Cementing

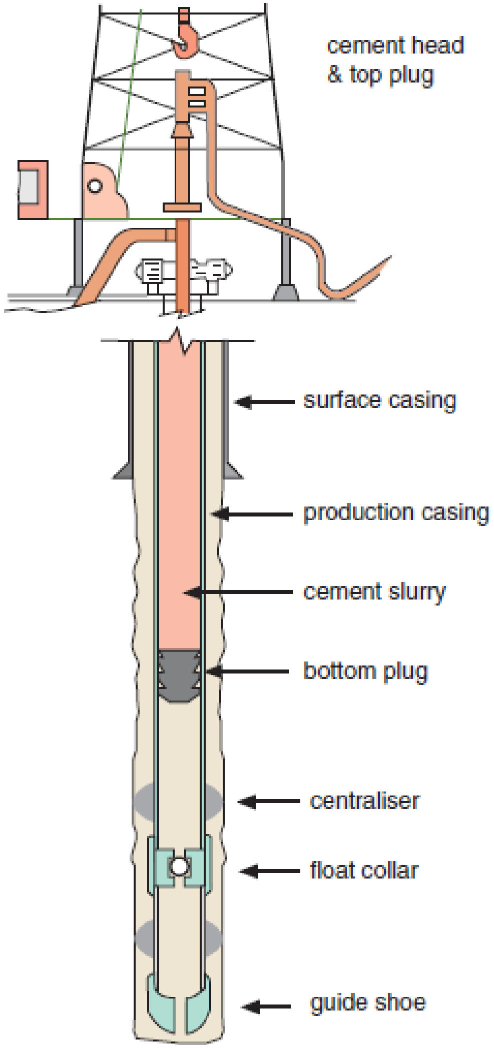

Drop Top Plug & Start Displacing with Spacer
Displacing
Displacing
Displacing

Cementing



Cementing

- The success of a cement job depends partly on the velocities of the cement slurry in the annulus. A high pump rate will result in turbulent flow which results in a better bond than the slower, laminar flow.
- The cement has to be placed evenly around each casing joint. This becomes more difficult with increasing deviation angle since the casing joints will tend to lie on the lower side of the borehole preventing cement slurry entering between casing and borehole wall. To avoid this happening, steel springs or centralisers are placed at intervals outside the string to centralise the casing in the borehole.
- Once the cementation has been completed, the rig will ‘wait on cement’ (WOC), that is wait until the cement hardens prior to running in with a new assembly to drill out the plugs, float collar and shoe, all of which are made of easily drillable materials..

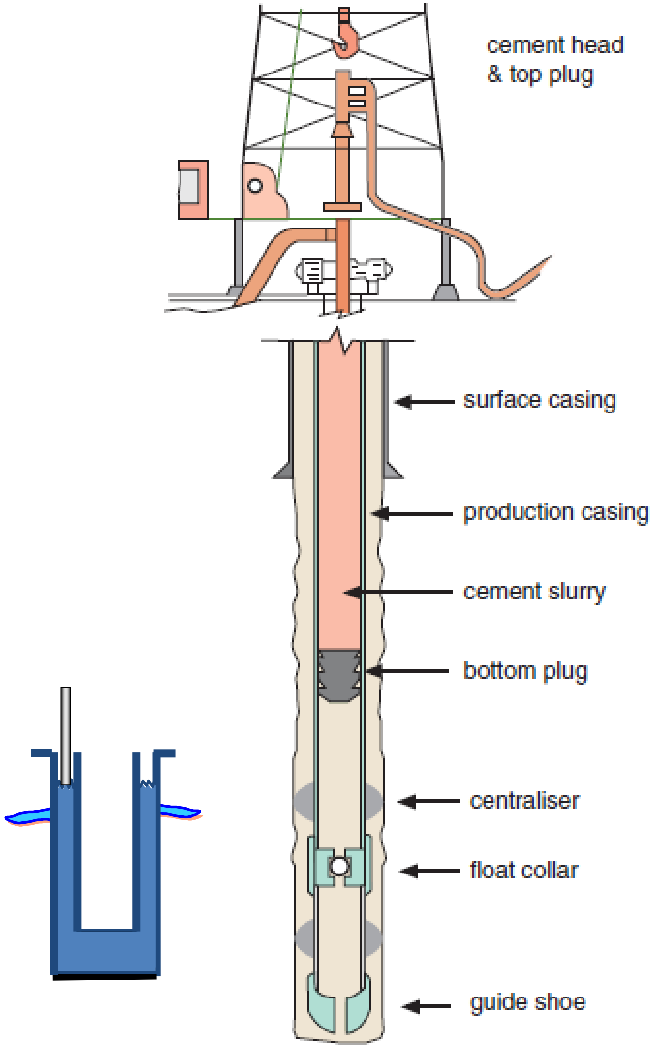


Cementing

- The process described so far is called **primary cementation**, the main purpose of which is:
    - To bond the casing to the formation and thereby support the borehole wall
    - Prevent the casing from buckling in critical sections
    - Separate the different zones behind the casing and thereby prevent fluid movement between permeable formations
    - Seal off troublesome horizons such as lost circulation zones.

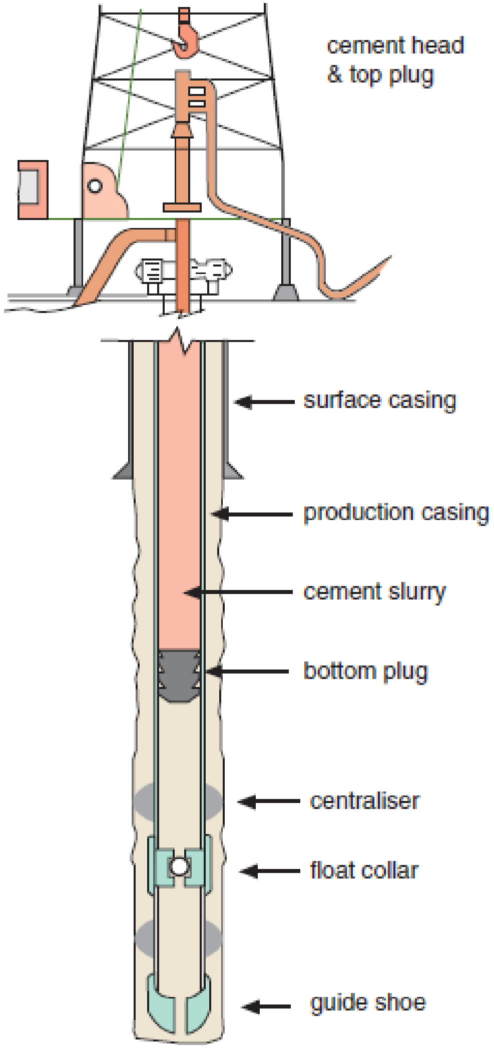
Note:

- Outside cementing is used to bring cement to Surface, but it is limited to 250 - 300 ft of depth. It is also used when high friction pressures exist, and Non-standard Connections are mounted.



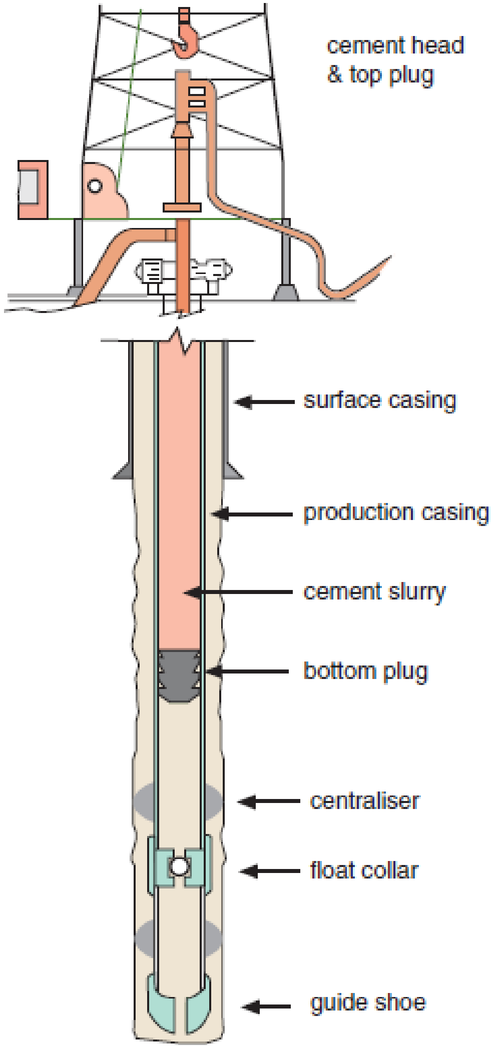
Cementing

- Sometimes primary cementations are not successful, for instance if the cement volume has been wrongly calculated, if cement is lost into the formation or if the cement has been contaminated with drilling fluids.
- In this case, a remedial or **secondary cementation** is required.
- This may necessitate perforating the casing at a given depth and then pumping cement through the perforations.
- A similar technique may also be applied later in the well's life to seal off perforations through which communication with the formation has become undesirable, for instance if water breakthrough has occurred (squeeze cementation).
- Plug back cementations, that is cement placement inside the casing and across the perforations may be required prior to sidetracking a well or in the course of decommissioning.



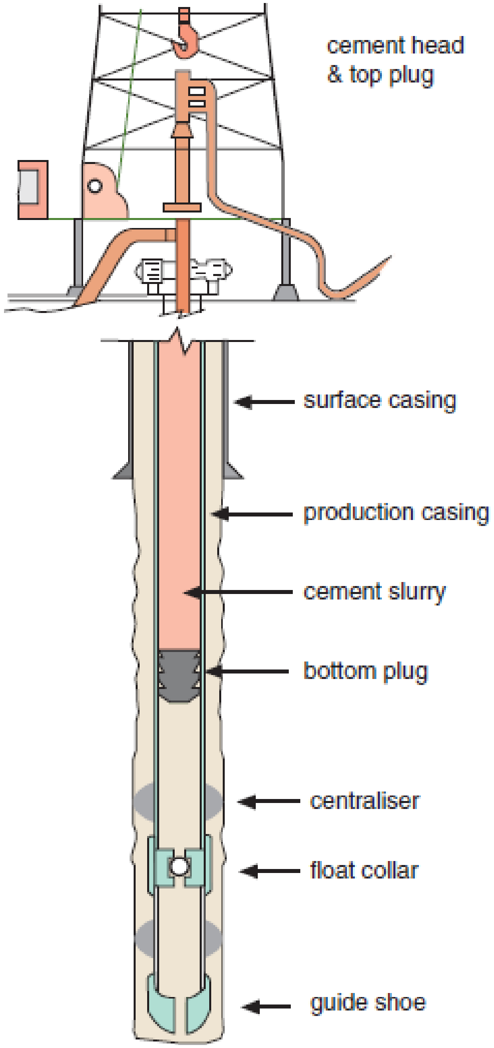
Cementing

- The chemistry of cement slurries is complex. Additives will be used to ensure the slurry remains pumpable long enough at the prevailing downhole pressures and temperatures but sets (hardens) quickly enough to avoid unnecessary delays in the drilling of the next hole section.
- The cement also has to attain sufficient compressive strength to withstand the forces exerted by the formation over time.
- A spacer fluid is often pumped ahead of the slurry to clean the borehole of mudcake and thereby achieve a better cement bond between formation and cement.



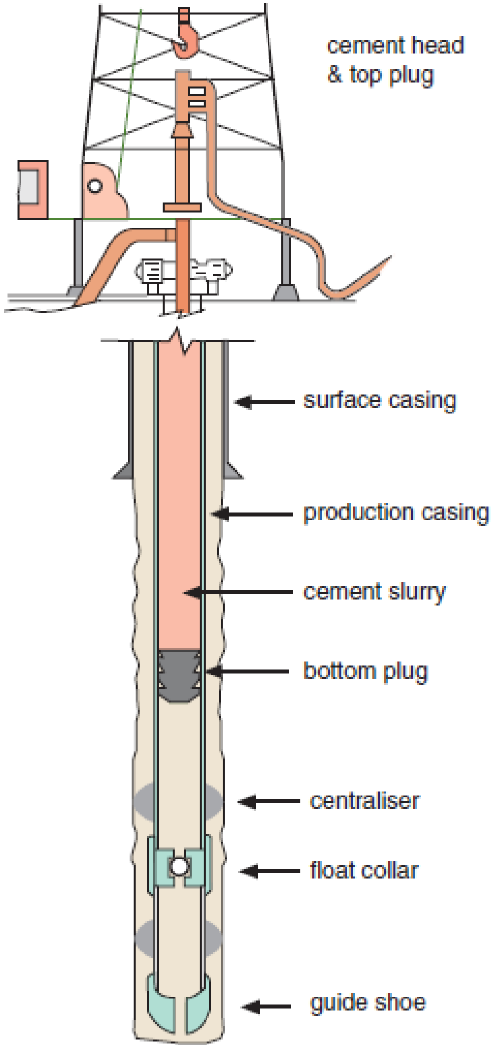
Cementing

- API has identified classes for neat Portland cement.
- The criteria used by API is based on the degree of the fineness of the cement particles.
  - **Class A**: Intended for use from surface to 6000 ft, when special properties are not required.
  - **Class B**: Intended for use from surface to 6000 ft, when condition require moderate to high sulfate resistance.
  - **Class C**: Intended for use from surface to 6000 ft, when conditions require high early strength.
  - **Class D**: Intended for use from 6000 to 10000 ft, under conditions of moderately high temperatures and pressures.
  - **Class E**: Intended for use from 10000 to 14000 ft, under conditions of high temperatures and pressures.



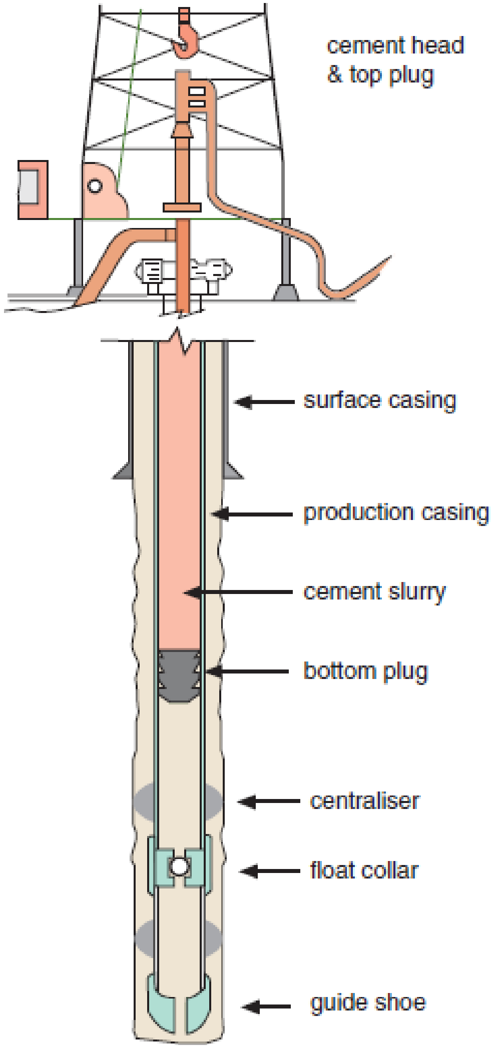
Cementing

- **Class F:** Intended for use from 10000 to 14000 ft, under conditions of extremely high temperatures and pressures.
- **Class G:** Intended for use from surface to 8000 ft, it can be used with retarders and accelerators to cover a wide range of well depths and temperature.
- **Class Geotherm:** This is not an API, but it is basically a class G with silica flour. In order to withstand; high temperature, pressure wells.
- **Class H**: Intended for use from surface to 8000 ft, can be accelerated or retarded to cover a wide range of well depths and temperature.
- **Class J**: Intended for use as manufactured from 12000 to 16000 ft and can be accelerated or retarded.



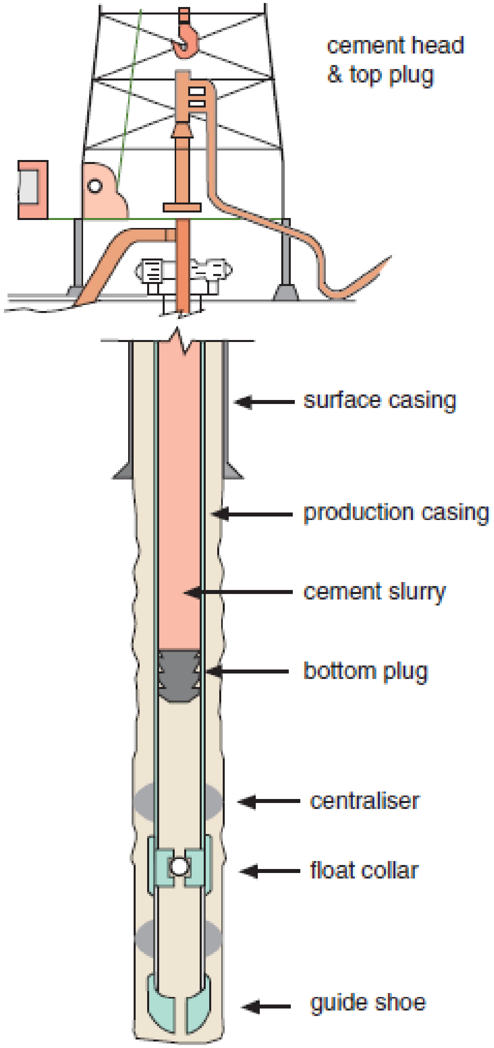
Cementing

- The properties vary according to the objectives of the cement job. Thus for casing job the cement must:
  - Yield a slurry of given density while still exhibiting desired slurry properties,
  - Be easily mixed and pumped,
  - Meet optimum rheological properties required for mud removal,
  - Maintain both physical and chemical characteristics during placement,
  - Be impermeable to annular gas, if present while setting.



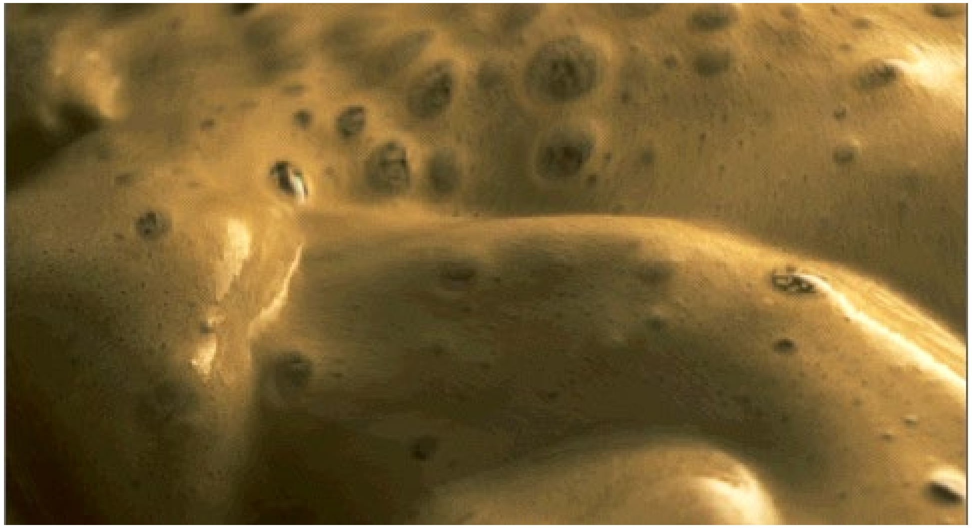
Cementing

- After placement, cementing should:
    - Develop strength quickly,
    - Develop sufficient strength in the long term,
    - Develop casing and formation bond strength,
    - Have as low permeability as possible,
    - Maintain quality even under severe temperature and pressure.
- The properties that are measured to determine a particular job design are categorized as:
    - Cement Slurry Properties,
    - Set Cement Properties.
- The properties of the cement will vary from one well to another and will be determined by the characteristics of the well.



Cementing

- **Cement Slurry Properties**
  - Water Cement Ratio
  - Slurry Density
  - Fluid Loss Control
  - Slurry Rheology
  - Pumping Time
  - Compressive Strength
  - Cement Bonding



- **Additives**
  - Cement additives can be classified as follows

    Accelerators, Retarders, Fluid loss additives,
    Dispersants, Extenders, Weighting agents,
    Lost circulation additives, Special additives

Cementing

- **Cement Slurry Properties**
  - ***Water Cement Ratio:***
    - Define the minimum and maximum boundaries of water content in slurry,
    - The minimum being the water necessary to maintain the cement pumpable,
    - The specific definition being 100 BC (Bearden Unit) consistency,
    - The maximum being the water limit beyond which particles will not remain in suspension until the cement has set. The specification being 3.5 ml of free water after the cement has stood for 2 hours,
    - Exceeding the maximum ratio will cause pockets of free water to form and reduce the strength of set cement.

Cementing

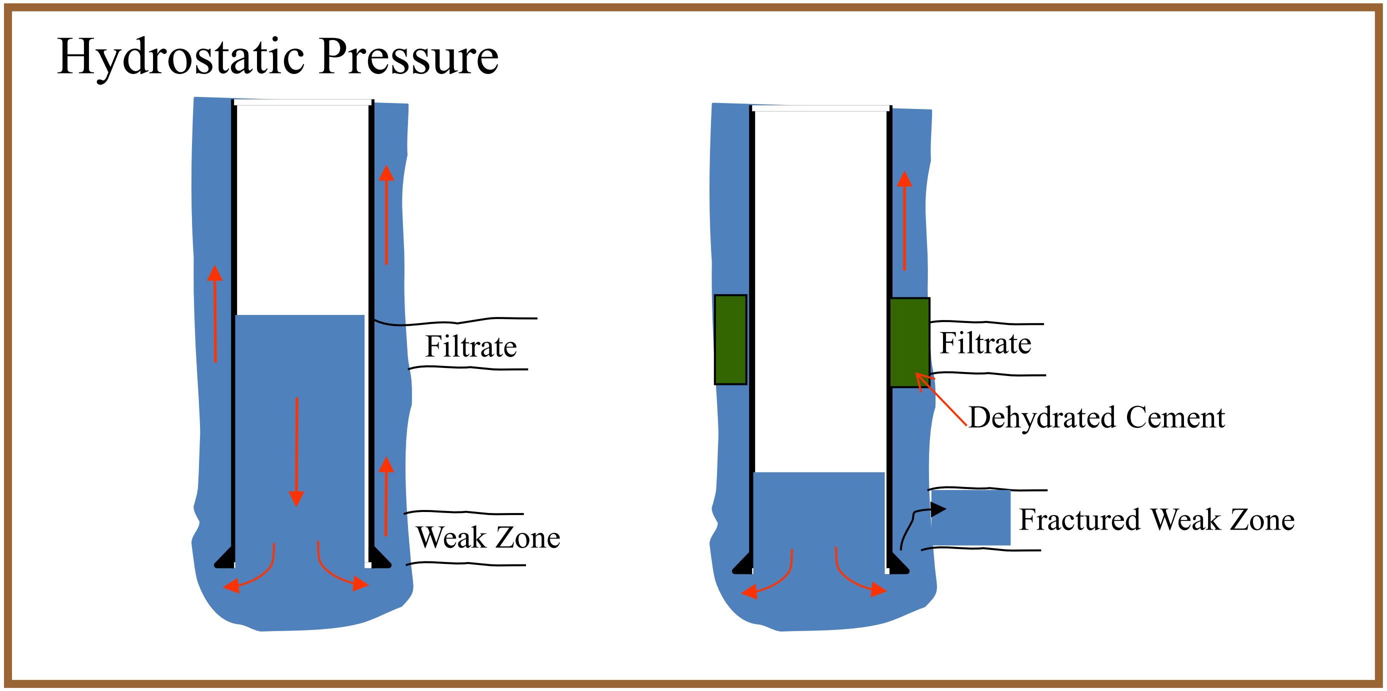
- **Cement Slurry Properties**
  - ***Slurry Density:***
    - Measured in PPG or Kg/l, and is governed by the maximum and minimum water cement ratio,
    - Specific well conditions may require the use of lighter or heavier cements,
    - Lower density slurries may be obtained by using lightning materials such as Pozzolans etc,
    - Higher density slurries may be obtained by using water content below the minimum acceptable. In such cases pumpability is achieved by using dispersants to increase fluidity.

Cementing

- **Cement Slurry Properties**
  - ***Fluid Loss Control:***
    - Variation in water content will affect many characteristics such as thickening time, rheology and compressive strength,
    - Thus a neat slurry placed over a permeable formation will lose filtrate resulting in dehydration of the slurry and decrease in the pumpability,
    - Flash setting may occur due to rapid dehydration,
    - Loss circulation may occur due to an increase in friction pressure,
    - Final compressive strength maybe reduced due to lack of hydration.
  - Some typical fluid loss values are:
    - For normal uncontrolled neat cement; 800/1000 ml/ 1000 psi for 30 min,
    - For cementing casing; 100/200 ml/ 1000 psi for 30 min,
    - For cementing liners; 50/100 ml/ 1000 psi for 30 min,

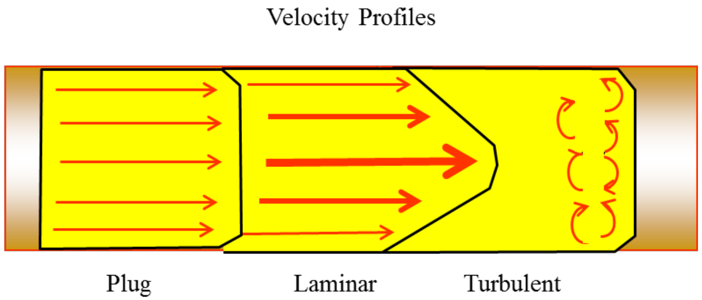
Cementing

- **Cement Slurry Properties**
  - ***Fluid Loss Control:***
    - Flash setting due to dehydration followed by fracturing of lower zone due to increased frictional losses;



Cementing

- **Cement Slurry Properties**
  - ***Slurry Rheology:***
    - The rheological parameters govern the slurries ability to flow with respect to:
      - Pressure loss characteristics,
      - Flow through small opening and vugs,
      - Mud removal capability.
    - Studies have shown that properties that exhibit flat profiles tend to maintain separation of different fluids,
    - Turbulent and plug flow traditionally are preferred over laminar flow.



Cementing

- **Cement Slurry Properties**
  - ***Pumping Time:***
    - Defines the time for which a slurry can be pumped.
    - A slurry must be fluid for as long as it takes to place it and then must set as soon as possible after pumping to limit the waiting on cement time.
    - API defines the thickening time as the time for a slurry to achieve 100 BC. Cement operators normally assume a 50% contingency on pumping time to design their thickening time specification.
    - Accelerators and retarders are used to increase or decrease a slurries pumping time.
  - ***Compressive Strength;***
    - This property is required for:
      - Securing and supporting the casing,
      - Withstanding the shock loading of drilling and perforating,
      - Supporting hydraulic pressures without fracturing,
      - Withstanding the load of tectonic forces such as salt zone

Cementing

- **Additives**
  - **Accelerators**
    - Accelerators generally work to decrease the thickening time and build early compressive strength,
    - Basically there are three types:
      - Calcium chloride,
      - Sodium chloride,
      - Sea water.
    - Accelerators are used to reduce Wait on Cement (WOC), such as in surface casing and shallow wells, particularly when low temperature is involved.

Cementing

- **Additives**
  - **Accelerators**
    - ***Calcium Chloride:***
      - CaCl2, is the most common, effective and economical accelerator,
      - It is always acts as an accelerator, regardless of the concentration used,
      - The usual dosage is 2 to 4 %.
    - ***Sodium Chloride:***
      - NaCl, is not a very efficient accelerator and should be used only when CaCl2 is not available,
      - 10% will accelerate cement slurry, 20% will ac as a retarder.
    - ***Sea Water:***
      - Sea water is used extensively for mixing cement slurries on offshore locations,
      - It contains up to 2.5% of chloride, which ac as cement accelerator,

Cementing

- **Additives**
  - **Retarders**
    - These are Chemicals used to delay cement setting time, in order to allow enough time for proper slurry placement.
    - Following are some of the retarders:
      - Sodium chloride:
        - Good retarder when mix water is saturated with salt,
      - Lignosulfonates:
        - These are chemical compounds derived from wood pulp,
        - They used over a range of 0.1 to 1.5% BWOC.
      - Cellulose Derivatives:
        - Their main function is a fluid loss additives, by which they maintain a constant water to solids ratio in cement slurries,
        - They have the ability to retard cement.

Cementing

- **Additives**
  - **Dispersants**
    - These help maintain a uniform distribution of components in a slurry and result in maintaining flow properties.
    - They are used to:
      - Induce turbulent flow,
      - Reduce water content and therefore increase the compressive strength of the slurry, typically in plug jobs and can be used with adding weighting agents
      - For fluid loss control.

Cementing

- **Additives**
  - **Extenders;**
    - Extenders are used for one of the following reasons:
      - Decrease slurry density to reduce the hydrostatic pressure during cementing job,
      - Increase slurry yield (cuft of slurry per sack of cement) and hence decrease the overall cost,
    - They are classified as following:
      - Water-based:
      - Clays, chemical extenders (Bentonite).
    - Lightweight Aggregates:
      - Pozzolans, Gilsonite, expand Perlite
    - Ultra-Lightweight Systems:
      - Nitrogen, Litefil micorspheres.

Cementing

- **Additives**
  - **Weighting Agents**
    - These are chemicals used to increase the cement slurry density,
    - They should meet the following requirements:
      - High specific gravity,
      - Larger particle size. If small sizes, they increase viscosity,
      - Low water absorption,
      - Availability and acceptable cost.
    - Examples of weighting agents are:
      - Barite,
      - Ilmenite (iron-titanium oxide)
      - Hematite (iron oxide).

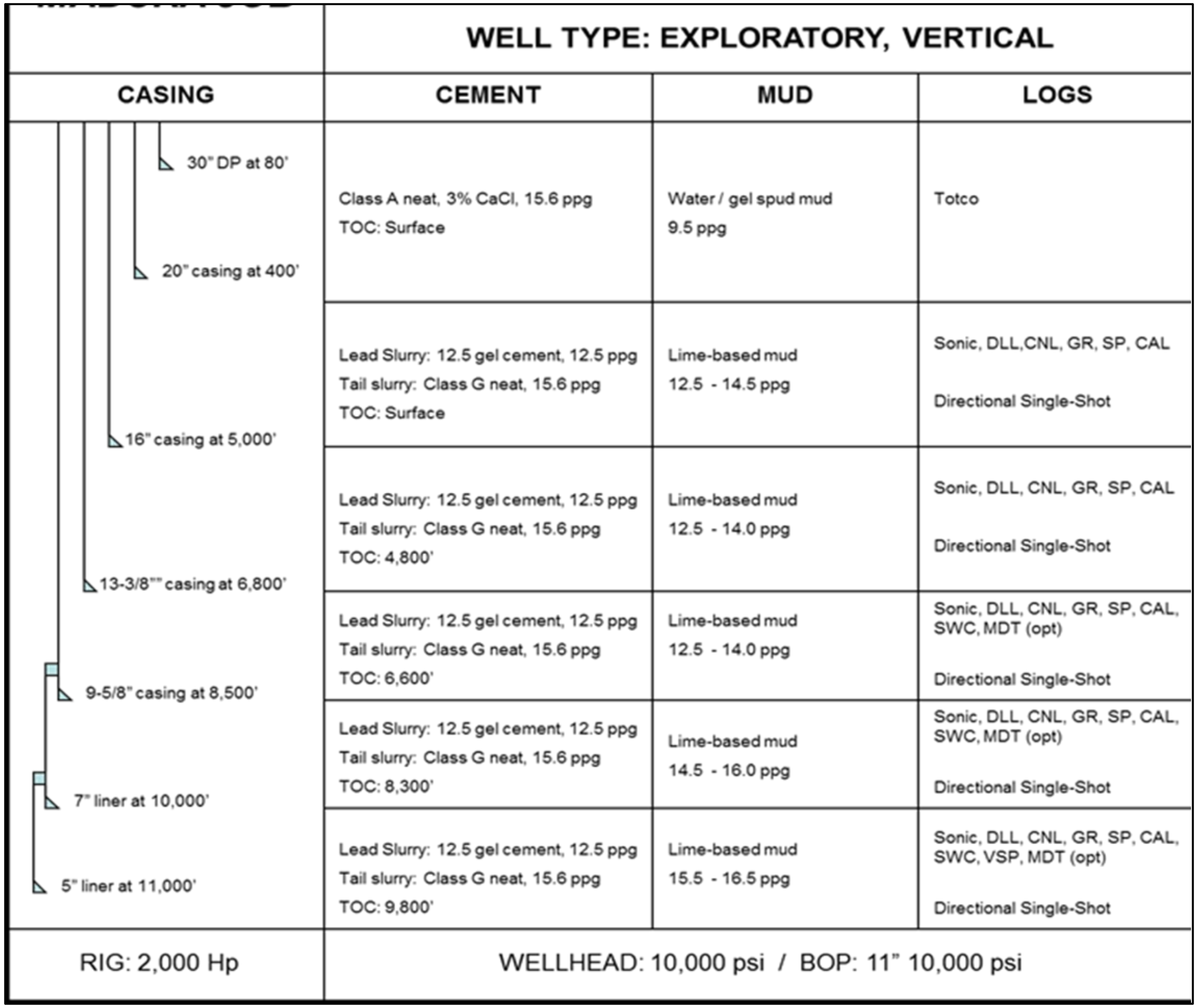
Cementing

- **Additives**
  - **Lost Circulation Materials (LCM);**
    - They help to combat lost circulation. They can do so by:
      - Preventing the occurrence of induced fractures,
      - Curing lost circulation by forming a low permeability bridge across the opening,
    - Some of the LCMs are:
      - Granular,
      - Flake,
      - Fibrous.

Cementing

- **Additives**
  - **Special Additives**
    - Some of these additives are as follows:
      - Thixotropic:
        - This term describe a system that becomes a fluid under conditions of shear. This type is useful in lost circulation zone.
      - Defoaming:
        - These are additives that remove foam from the cement slurry, they could be found as antifoam or defoamer.
      - Strength Retrogression Prevention Agents:
        - Silica sand products are used to prevent such problem.
      - Gas Channeling:
        - This associated with the loss of hydrostatic pressure during dehydration process.

Cementing



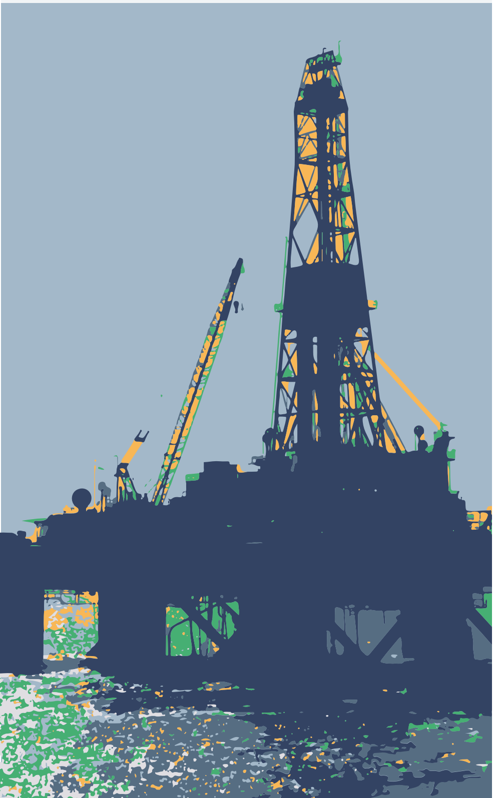
	WELL TYPE: EXPLORATORY, VERTICAL		
CASING	CEMENT	MUD	LOGS
30" DP at 80' 20" casing at 400'	Class A neat, 3% CaCl, 15.6 ppg TOC: Surface	Water / gel spud mud 9.5 ppg	Totco
16" casing at 5,000'	Lead Slurry: 12.5 gel cement, 12.5 ppg Tail slurry: Class G neat, 15.6 ppg TOC: Surface	Lime-based mud 12.5 - 14.5 ppg	Sonic, DLL,CNL, GR, SP, CAL Directional Single-Shot
13-3/8"" casing at 6,800'	Lead Slurry: 12.5 gel cement, 12.5 ppg Tail slurry: Class G neat, 15.6 ppg TOC: 4,800'	Lime-based mud 12.5 - 14.0 ppg	Sonic, DLL, CNL, GR, SP, CAL Directional Single-Shot
9-5/8" casing at 8,500'	Lead Slurry: 12.5 gel cement, 12.5 ppg Tail slurry: Class G neat, 15.6 ppg TOC: 6,600'	Lime-based mud 12.5 - 14.0 ppg	Sonic, DLL, CNL, GR, SP, CAL, SWC, MDT (opt) Directional Single-Shot
7" liner at 10,000'	Lead Slurry: 12.5 gel cement, 12.5 ppg Tail slurry: Class G neat, 15.6 ppg TOC: 8,300'	Lime-based mud 14.5 - 16.0 ppg	Sonic, DLL, CNL, GR, SP, CAL, SWC, MDT (opt) Directional Single-Shot
5" liner at 11,000'	Lead Slurry: 12.5 gel cement, 12.5 ppg Tail slurry: Class G neat, 15.6 ppg TOC: 9,800'	Lime-based mud 15.5 - 16.5 ppg	Sonic, DLL, CNL, GR, SP, CAL, SWC, VSP, MDT (opt) Directional Single-Shot
RIG: 2,000 Hp	WELLHEAD: 10,000 psi / BOP: 11" 10,000 psi		

Cementing


HALLIBURTON
RCM IIIr
RED TIGER
RED TIGER
HALLIBURTON
USDOT
Houston, TX
KENWORTH

Cementing

Cementing



3.
Well completion.

Well Completion

- The completion of the well is the process of terminating it, so that it is ready to produce oil or natural gas. In essence, it consists in deciding the characteristics of the entries to the well from the oil-producing formation.

- There are numerous types of completion:
  - **Open hole completions.** They are the most basic type and are used only in really competent formations in which there are no undermining. They consist in putting the casing directly into formation, leaving open the end of the pipe, without any protection
  - **Conventional perforated completions:** It consist in enter directly the production casing through the formation. The walls of the production casing are perforated with small holes all along that stretch, allowing hydrocarbons to flow through them, while the casing brings enough resistance face to the formation. Formerly perforating gun technique was used to open these holes with projectiles through the casing and cementing. Nowadays companies use the jet perforating technique, consisting of small charges electrically initiated that are introduced into the well and that, once being initiated, cause tiny holes through the formation, similar to the one of the cannonade.

- **Sand exclusion completions:** They are designed for production in areas of the site that contain large amounts of sand, allowing the flow of natural gas or oil into the well but avoiding the entrance of sand through the screens or filters. Both types of barriers can be used either in "open hole" type completions or perforated.
- **Permanent completions:** In this case the completion and the "wellhead", are assembled and installed at the same time. For this reason, the installation of the casing, the execution of the cementing, drilling, and other completion works are made with small diameter tools to ensure the permanent nature of the completion. The completion of a well in this mode can make very significant savings in costs when compared to other types.
- **Multiple zone completion:** It consists in a completion of the well that ensures that two or more formations of hydrocarbons can be extracted simultaneously without mixing them. It is the case, for example, of a well that is drilled through several formations, or when horizontal developments are made to achieve a more efficient exploitation of the deposit. In order to keep separated different completions, hard rubber separators instruments are used.
- **Drainhole completions:** They are a form of horizontal drilling that are radially to the well and within the formation from a vertical well, in order to produce a drainage of hydrocarbons into the well. It is more used in oil wells than in natural gas.

Completion components

- **Drain hole completions:** They are a form of horizontal drilling that are radially to the well and within the formation from a vertical well, in order to produce a drainage of hydrocarbons into the well. It is more used in oil wells than in natural gas.
- **Wellhead:** It is the fundamental equipment for the control of pressure in surface and from which hangs the casing pipes and connects to the BOP (blowout preventer) or the "Christmas tree“.
- **Christmas Tree:** It is the main assembly of valves that controls the flow from the well to the processing plant or, where appropriate, controls the injection well pressure. It allows access to make interventions in the well.
- **Tubing hanger:** This component is located at the top of the wellhead and is the main support of the production tubing.
- **Production tubing:** It is the main conduit for the transport of hydrocarbons from the reservoir to surface (or of the injection fluid) when that is the purpose of the well. It runs from the tubing hanger located above the head, to a point just above the section of production.

- **Downhole safety valve (DHSV):** This component is considered as the last resort for the protection of the surface against an uncontrolled release of hydrocarbons. It is a cylindrical valve with a closing mechanism installed in the production tubing and that is kept open by a hydraulic circuit of high pressure that comes from the surface by a line of 6.35 mm diameter (14”). This high pressure is opposed to the reservoir pressure and allows the flow of hydrocarbon. The valve will close if the umbilical high pressure circuit is cut or damaged or even the wellhead or the Christams tree are destroyed.
- **Annular safety valve:** In wells with gas impulsion capability, many operators consider prudent to install a valve that isolates the annulus for the same reason that a DHSV may be required to prevent the risk from uncontrolled gas leak.
- **Side pocket mandrel**: It consists in a system that contains a pocket along side of the main duct which goes welded or machined to it. It has a diameter of 1 or 1”½ and is designed to contain a gas impulsion valve that allows the gas that could be trapped in the annulus, be injected back into the main duct of production.
- **Electrical submersible pump:** Used for artificial lift to the surface when the reservoir pressure is insufficient.

- **Landing nipple**: It is a component made of a short section of heavy tubing and a mechanized inner surface which provides a sealed area and a profile of closure. This element is inserted into the majority of completions at predetermined intervals to allow the installation of flow control devices. There are three types of devices: no-go nipples, selective-landing nipples and ported or safety-valve nipples.
- **Sliding sleeve:** It has an hydraulically or mechanical device to allow the communication between the tubing and the annular tubing. They are often used in wells with multiple deposits to regulate flows from different areas.
- **Production packer: It** isolates the space between the tubing and the inner casing and the bottom of the well in order to prevent that the formation fluids could flow to all along the casing and damage it. It is usually placed near the foot of the tubing, which is close to the area of production.
- **Downhole gauges:** It is an electronic or optical fiber that allows a continuous monitoring of the pressure and temperature at the bottom of the well. The transmission of signals can be done through a duct outside the tubing or acoustically through the walls of the tubing.
- **Perforated joint:** It is a stretch of perforated pipe that it situated below the packer as alternate entry point for the reservoir fluids in case that the shoe is locked for any reason.

- **Formation isolation valve:** Located at the end of the completion, it allows a bidirectional isolation of the formation. It is not widely used and often present failures.
- **Centralizer:** In very deviated wells, it allows to keep the pipes in the center of the well.
- **Wireline entry guide:** This component is installed at the end of the tubing, called the shoe, and is aimed to facilitate the withdrawal of wireline elements providing a surface that allows the tool to re-enter the tubing without getting stuck.