Introduction

Tubulars are selected for the specific conditions anticipated in a given well. The anticipated production flow rates and economics of the well determine tubing size, which then determines the necessary size of each previous hole and tubular. Once the tubular size and setting depths are determined, the wall thickness and grade of material are then chosen by the well designer to ensure the strength is adequate for the expected loads. Material grade is also selected to ensure it is appropriate for the fluids the tubular will encounter; corrosion resistant alloys (CRA) may be required in some environments such as CO2 or H2S. Finally, tubular connections are selected based on dimensional needs, load capacity, and gas-vs-liquid sealability.

This chapter discusses types of casing and tubing; OCTG manufacturing, labeling and specifications; corrosion; API casing grades; transportation and handling; storage; and running procedures.

Pipe types

There are two basic types of pipes used in oil and gas exploration and production and standardized by the American Petroleum Institute (API) and the International Standards Organization (ISO).

For in-well services (i.e., below the wellhead oil country tubular goods [OCTG]):

- Casing: API 5CT/ISO 11960 with API 5B/ISO 10422 for threads;
- Tubing: API 5CT/ISO 11960 with API 5B/ISO 10422 for threads.

Per API, the specification differences between casing and tubing are:

- Length of the drift mandrel: 6 in. or 12 in. for casing and 42 in. for tubing;
- Joint strength calculation method: Minimum tensile strength for casing, and minimum yield strength for tubing.

This chapter specifically covers casing and tubing. For information on drill pipe, heavyweight drill pipe and drill collars, please refer to the separate chapter Drillstring of the IADC Drilling Manual, 12th edition. For additional advice on drillpipe practices, refer to the separate chapter on Drilling Practices.

Types of casing and tubing

Drive, structural and conductor casing

The main purpose of this first string of pipe is to protect unconsolidated shallow formations from erosion by drilling fluids. Additional functions of the first casing string include:

- Allows for installation of a full mud circulation system, when formations are sufficiently stable;
- Guides the drill string and subsequent casing into the hole;
- Can form a part of the piling system offshore for a wellhead jacket or piled platform. In subsea wells the conductor may form an integral part of the structural support for the wellhead system;
- Provide centralization for the inner casing strings, which limits potential buckling of subsequent casing strings;
- Minimize shallow lost returns;
- Provides a mount in onshore applications for a diverter system that would be used in the event of an unexpected shallow influx.

Conductor casings can be driven or jetted to depth or, alternatively, run into a predrilled or jetted hole and cemented.

Surface casing

Surface casing is installed to:

- Prevent poorly consolidated shallow formations from sloughing into the hole;
- Enable full mud circulation;
- Protect fresh water sands from contamination by drilling mud;
- Provide protection against hydrocarbons found at shallow depths;
- Provide initial support for the blowout preventers;
- Provide kick resistance for deeper drilling;
- Support the wellhead system and all subsequent casing strings.

The surface casing string is typically cemented to the surface or seabed. it is usually the first casing on which blowout preventers are installed. The amount of protection provided against internal pressure will only be as effective as the formation strength at the casing shoe.

Intermediate casing

Intermediate casing is used to ensure there is adequate blowout protection for deeper drilling and to isolate formations that could cause drilling problems. The first intermediate string is typically the first casing providing full blowout protection. An intermediate casing string is nearly always set in the transition zone associated with the onset of significant overpressures. If the well could encounter severe lost circulation zone(s), intermediate casing would normally be set in a competent formation below the loss zone.

Intermediate casing can also be used to case off any known hydrocarbon-bearing intervals as a contingency against the possibility of encountering lost circulation, with attendant well control problems. An intermediate string may also be set simply to reduce the overall cost of drilling and completing the well by isolating intervals that have caused me-

chanical problems in the past. Intermediate casing may be required to isolate:

- Swelling clays and shale that can result in tight hole and key seats;
- Brittle caving shale or weak zones prone to washout and creation of persistent on bottom fill;
- Salt intervals;
- Chemically active formations that can upset mud chemistry;
- Over-pressured permeable formations;
- Hole sections that are used to deviate the wellbore;
- High permeability sand(s);
- Partly-depleted reservoirs that could cause differential sticking.

A good well designer should plan to combine as many of these objectives as possible when selecting a single casing point. A liner may be used instead of a full intermediate casing string and difficult wells may actually contain several intermediate casings and/or liners.

Drilling liners

A drilling liner is essentially a string of intermediate casing that does not extend all the way to surface. It is hung off in or above the previous casing shoe and is usually cemented over its entire length to ensure it seals within the previous casing string. In many subsea well designs, the liner is partially cemented around the shoe, and a liner lap packer is used to seal the liner top. This is necessary when the fracture gradient cannot withstand the equivalent circulating density resulting from the pressure drops associated with cementing the entire liner.

Drilling liners may be installed to:

- Increase shoe strength to allow further mud density increases;
- Isolate troublesome zones;
- Satisfy rig tension load limitations;
- Minimize the length of reduced hole diameter to overcome possible adverse effects on drilling hydraulics and the size of drill pipe that can be used;
- Save money compared to running a full string.

There are a number of disadvantages to installing liners:

- Difficulty obtaining a quality cement job;
- Risk of liner running equipment being cemented in the hole;
- The liner lap represents a potential source of influx and typically must be isolated by a retrievable bridge plug if it is necessary to remove the blowout preventer stack;
- The lap must be tested with both positive and negative pressure and remedial action taken if it fails to perform.

Production casing and tiebacks

Production casing is the conduit through which the well will be completed, produced and controlled throughout its life. On exploration wells, this life may amount to only a very short testing period, but on most development wells it will span many years, during which multiple repairs and recompletions might be performed. Production casing should be designed to retain its integrity throughout its life. In most cases, production casing must provide full pressure redundancy to the tubing, isolate the productive intervals, facilitate proper reservoir maintenance and/or prevent the influx of undesired fluids.

The size of the production casing is selected to accommodate the optimum method of completion and production, along with:

- Well flow potential, i.e., tubing size;
- Possibility of a multiple tubing string completion;
- Space required for downhole equipment, such as safety valves, artificial lift equipment, etc.;
- Potential well servicing and recompletion requirements;
- Adequate annular clearances to permit circulation at reasonable rates and pressures.

It is also possible that the production casing itself could be used as production tubing to maximize well deliverability (casing flow), to minimize the pressure losses during fracture stimulations, for continuous or batch chemical injection or for lift gas.

Tubing

The pipe centered in the annulus of an oil and/or gas well through which the hydrocarbons flow to the surface from the formation is called tubing. It is important to size tubing properly. If too small, production will be restricted, limiting the profitability of the well. However, tubing that is too large can reduce fluid velocity and allow for build up of produced water that can kill the well. Large tubing will also affect the economics of the project, adding to the cost of the overall well design.

OCTG materials

For OCTG, material "type" describes the composition of the steel used in manufacturing of the pipe, which impacts resistance to various types of corrosion. The type of material for OCTG must be appropriate for the corrosiveness of the operating environment. The six material types for OCTG are shown in **Table CT-1**.

Manufacturing methods

OCTG pipe is manufactured by either a welded or seamless process.

- Welded tubulars are generally large diameter with relatively thin walls, suitable for structural pipe, conductors, surface casing, and marine risers. Welded

Table CT-1: The six materials used for OCTG manufacture

Material Name	Governing specification	Application
Carbon steels	API 5CT/ ISO 11960	Non-corrosive wells Sour service without CO_2
13% Cr Martensitic	API 5CT/ ISO 11960	Sweet corrosion (CO_2)
Super 13 Martensitic	API 5CRA/ ISO13680 Group1	Sweet corrosion (CO_2) and temperature
22% Cr or 25% duplex or super duplex	API 5CRA/ ISO13680 Group 2	Sour service + CO_2
28% Cr Austenitic (Fe base alloys)	API 5CRA/ ISO13680 Group 3	Highly corrosive: Fit for purpose testing
Alloy 825, G3, C276. Nickel base alloys	API 5CRA/ ISO13680 Group 4	Extremely corrosive: Fit-for-purpose testing

pipe is sometimes used for other applications such as intermediate casing, production casing, and tubing, though these applications are less common, especially in the smaller diameters. Welded pipes have generally good dimensional properties and are generally less expensive but have limitations:

- Prohibited for API 5CRA tubulars;
- Not suitable to 13 Cr;
- Not suitable to sour service. Only accepted for L80, forbidden when higher strength properties are required;
- Prohibited for couplings and accessories, per API 5CT;
- Limited wall thickness because of weld limitation in wall.

- Seamless pipe is suitable for all types of material and grades, and is preferred when well conditions are severe. Per API 5CRA, all CRA tubulars are seamless. Because of manufacturing limitations, seamless pipe is generally only available in diameters of 18 in. or less.

Seamless tube manufacturing

There are multiple seamless steel-tube manufacturing processes that originated at the end of the 19th century. These include:

- Continuous mandrel rolling process and push bench process: 21-178 mm (0.8-7.0 in.);
  - Continuous mandrel rolling process: 7 to 9 tandem rolling stands continuously mill and elongate the hollow shell of the tube over a floating mandrel bar to produce a final tube. Starting material is generally round rolled billets. First the material is heated, then pierced to produce a hallow shell. At this point the piece is elongated anywhere from 2 to 4 times its initial length. Finally the shell is rolled out in the continuous rolling mill to produce a continuous tube;
  - Push Bench: First billets are heated to rolling temperature, and then moved through the cylindrical dies of a piercing press, where they become thick-walled pierced billets (a.k.a., "hollow") closed at one end. Later the hollows are stretched using a 3-roll elongator, thereby leveling the wall thickness. Once elongated the hollow is moved to a push bench, where a mandrel is inserted and it passes through a series of rollers. The hollow passes roller to roller, resulting in smaller wall thicknesses. Finally a hot saw removes the closed end from the hollow.

- Multi-stand plug mill (MPM) with controlled floating mandrel and plug mill: 140-406 mm (5½-16 in.);
  - MPMs and Plug Mills: In Plug mills a solid round (billet) is used. It is uniformly heated in the rotary hearth heating furnace and then pierced by a piercer. The pierced billet or hollow shell is roll-reduced in outside diameter and wall thickness. The rolled tube simultaneously burnished inside and outside by a reeling machine. The reeled tube is then sized by a sizing mill to the specified dimensions. From this step the tube goes through a straightener. This process completes the hot working of the tube. The tube (referred to as a mother tube) becomes a finished product after finishing and inspection.

- Cross-roll Piercing and Pilger rolling process: 250-660 mm (10-26.0 in.);
  - Cross-roll Piercing and Pilgering Stand: Piercing a solid billet with two or three profiled working rolls rotating in the same direction is the basis of the cross –roll pilgering process. Once it is completed the thick-walled hollow shell is rolled through a pilgering process to produce the finished pipe.

