Major Project On

Methods of

'Production Casing In the K.G Basin'

Submitted by

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Integrated B.Tech (APE) + MBA (UAM)

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Under the guidance

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Methods of Production Casing In The KG Basin

A thesis submitted in partial fulfilment of the requirements for the Degree of Bachelor of Technology (Applied Petroleum Engineering)

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CERTIFICATE

This is to certify that the project report entitled

Methods of

'Production Casing in the K.G Basin'

BY

Amritha Radhakrishnan

Kadiyala Sri P Janaki

In partial fulfillment for the award of the degree of the Intt B.tech (APE +UAM). It is record of the bonafide work carried out by them under esteemed guidance and supervision of Dr.S.P.Braide Professor COES, UPES and P.T.Rao, Chief Engineer (D) RJY Asset, ONGC.

Solzani 16 May 2011

Signature of Internal guide

Signature of *External Guide*

DECLARATION

We hereby declare that the project work incorporated in this project entitled Methods of '**Production Casing In the K.G Basin**' is originally carried out by us under the guidance of Dr.S.P.Braide in Univesity of Petroleum and Energy Studies & P.T.Rao(Chief Engineer) in ONGC,KG basin during 2010-11. It has not been submitted in part or in full for any Degree of any other universities

Amritha Radhakrishnan (R270307006)

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Methods of

Production Casing In The KG Basin

Abstract of Major Project On

'Methods of Production Casing In the K.G Basin'

The project is the study of methods of Production casing in the Krishna-Godavari (KG) basin. The KG basin is located between latitude 15 to 17.5 degrees north and longitude 80 to 89.5 degrees east along the east coast of India. Casing is a very large diameter pipe which is assembled and inserted into a recently drilled section of a borehole and held in place with cement. The objective of casing is to help the drilling process in several ways including: prevent contamination of fresh water well zones, prevent unstable upper formations from caving-in or forming large caverns, prevent the sticking of the drill string as drilling recommences to greater depths, provides a strong upper foundation for the use of high density drilling fluid to continue drilling deeper etc.

The project mainly concentrates on production casing and need for this. Production casing, alternatively called the 'oil string' or 'long string,' is installed last and is the deepest section of casing in a well. This is the casing that provides a medium from the petroleum-producing formation to the surface of the well. The size of the production casing depends on a number of considerations, including the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later time. For example, if it is expected that the well will be deepened at a later date, then the production casing must be wide enough to allow the passage of a drill bit later on.

This major project focuses in detail on the types of production casing used in the K.G. basin and gives us an understanding on how this part of the production process is varied to meet prevalent conditions. In this we also try to design a production casing and suggest the best grade of tubing to be used.

CONTENTS

LIST OF TABLES

ABBREVIATIONS

API	American Petroleum Institute
BeF	Bending Force
BF	Buoyancy factor
BHP	Bottom Hole Pressure
BOP	Blow Out Preventer
BTC	Buttress Thread Coupling
CF	Cement Force
CSA	Cross Sectional Area
CSG	Casing
CW	Cement Weight
ERCB	Engineering Review Control Board
GTO	Geo Technical Order
IDT	Integrated Device Technology
ISO	International Organization for Standardization
Kpa	Kilopascal
LAT	Latitude
LONG	Longitude
LTC	Long Thread Coupling
MW	Mud Weight
MWE	Mud Weight Equivalent
NACE	National Association of Corrosion Engineer
OGCR	Oil & Gas conservation Regulation

Pb	Bottom Pressure
Ps	Surface Pressure
Psi	Pounds per Square Inch
PT testing	Pressure Temperature testing
RC	Radius of Curvature
SF	Safety Factor
SMYS	Specific Minimum Yield Strength
SSC	Sulphide Stress Corrosion
STC	Short Thread coupling
TD	True Depth
TVD	True Vertical Depth
VSP	Vertical Seismic Profile

CHAPTER-I

INTRODUCTION

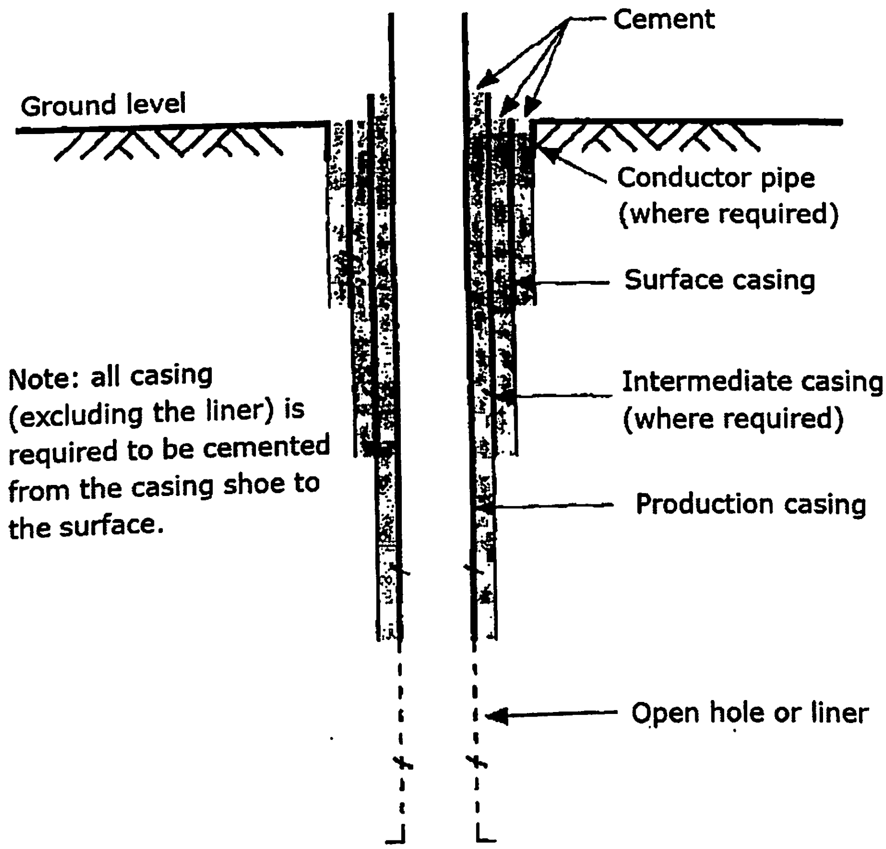
1.1 CASING

Well casing is a very important part of the completed well. In addition to strengthening the well hole, it provides a conduit to allow hydrocarbons to be extracted without intermingling with other fluids and formations found underground. It is also instrumental in preventing blowouts, allowing the formation to be 'sealed' from the top should dangerous pressure levels be reached. Once the casing has been set, and in most cases cemented into place, proper lifting equipment is installed to bring the hydrocarbons from the formation to the surface. After the casing is installed, tubing is inserted inside the casing, running from the opening well at the top to the formation at the bottom. The hydrocarbons that are extracted go up this tubing to the surface. This tubing may also be attached to pumping systems for more efficient extraction, should that be necessary.

Large-diameter pipe lowered into an open hole and cemented in place. The well designer must design casing to withstand a variety of forces, such as collapse, burst, and tensile failure, as well as chemically aggressive brines. Most casing joints are fabricated with male threads on each end, and short-length casing couplings with female threads are used to join the individual joints of casing together, or joints of casing may be fabricated with male threads on one end and female threads on the other. Casing is run to protect fresh water formations, isolate a zone of lost returns or isolate formations with significantly different pressure gradients. The operation during which the casing is put into the wellbore is commonly called "running pipe." Casing is usually manufactured from plain carbon steel that is heat-treated to varying strengths, but may be specially fabricated of stainless steel, aluminum, titanium, fiberglass and other materials.

Casing that is cemented in place aids the drilling process in several ways:

- Prevent contamination of fresh water well zones.
- Prevent unstable upper formations from caving-in and sticking the drill string or forming large caverns.
- Provides a strong upper foundation to use high-density drilling fluid to continue drilling deeper.
- Isolates different zones, that may have different pressures or fluids - known as zonal isolation, in the drilled formations from one another.
- Seals off high pressure zones from the surface, avoiding potential for a blowout
- Prevents fluid loss into or contamination of production zones.
- Provides a smooth internal bore for installing production equipment.



A slightly different metal string, called production tubing, is often used without cement in the smallest casing of a well completion to contain production fluids and convey them to the surface from an underground reservoir.

In the planning stages of a well a drilling engineer, usually with input from geologists and others, will pick strategic depths at which the hole will need to be cased in order for drilling to reach the desired total depth. This decision is often based on subsurface data such as formation pressures, strengths, and makeup, and is balanced against the cost objectives and desired drilling strategy.

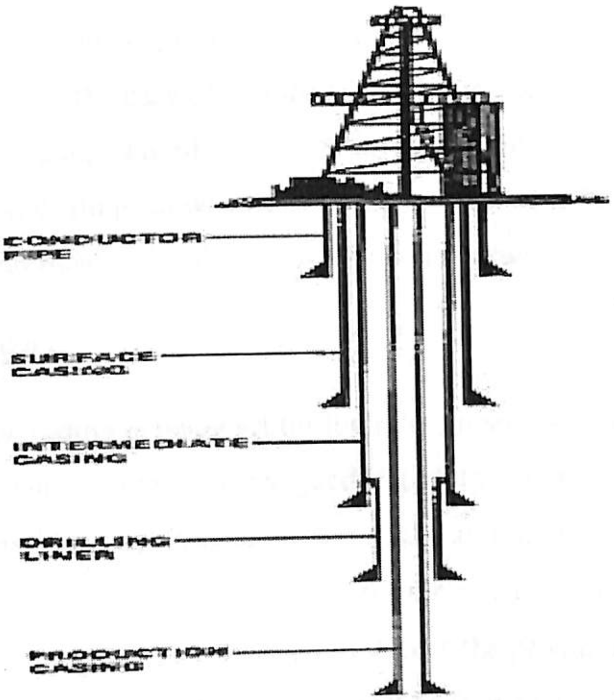
With the casing set depths determined, hole sizes and casing sizes must follow. The hole drilled for each casing string must be large enough to easily fit the casing inside it, allowing room for cement between the outside of the casing and the hole. Also, the inside diameter of the first casing string must be large enough to fit the second bit that will continue drilling. Thus, each casing string will have a subsequently smaller diameter.

The inside diameter of the final casing string (or penultimate one in some instances of a liner completion) must accommodate the production tubing and associated hardware such as packers, gas lift mandrels and subsurface safety valves. Casing design for each size is done by calculating the worst condition that may be faced during drilling and production. Mechanical properties of designed pipes such as collapse resistance, burst pressure, and tensile strength must be sufficient for the worst conditions.

Casing strings are supported by casing hangers that are set in the wellhead, which later will be topped with the Christmas tree. The wellhead usually is installed on top of the first casing string after it has been cemented in place.

1.2 TYPES OF CASING

While drilling, environments like high pressured zones, weak and fractured formations, unconsolidated formations and sloughing shales are often encountered. So wells are drilled and cased in several steps to seal of the trouble some zones and to allow drilling to the total depth. The five general casings used in completion of well are conductor pipe, surface casing, intermediate casing, production casing and liner. These casings are run in different depths and one or two of them may be omitted as per the drilling conditions. They may also be run as liners or with liners.



CONDUCTOR PIPE

It is the outer most casing string. The main use of this casing is to hold back the unconsolidated formations and prevent them from falling into the hole. It is cemented to the surface and is used to support well head equipment and subsequent casings. The conductor pipe is fitted with a diverter system above the flow line outlet where the shallow water or gas flow is expected. So it will prevent the surface blowout. Commonly, a 16 in. pipe is used in shallow wells and 20 in. in deep wells.

SURFACE CASING

The main purposes of the surface casing string are to : hold back unconsolidated shallow formations that can slough into the hole and cause problems, isolate the fresh water bearing formations and prevent their contamination by fluids from deeper formations and to serve as a base on which to set the blowout preventers. Sizes of this casing are in between 7 to 16 in. in diameter with 10 ¾ in. and 13 3/8 in. being most common sizes.

INTERMEDIATE CASING

Intermediate or protective casing are set between production and surface casings. The main use of setting this casing is to case off the formations to prevent the well from being drilled to the total depth. In the case of abnormal formation pressures in the deep sections of the well, this intermediate casing is used to protect formations below the surface casing from the pressures created by the drilling fluids specific weight required to balance the abnormal pore pressures. Generally intermediate casing sizes will be in between 7 in. to 11 ¾ in.

PRODUCTION CASING

The production casing is being set through the prospective productive zones except in the case of open-hole completions. It is designed to resist the maximal shut –inn pressure of the producing formation and may be designed to withstand stimulating pressures during completion and work over operations. It provides protection for the environment at the time of failure of tubing string during production operations and it allows the production tubing for repairing and replacement. Production casing inside diameter will be in between 4 ½ in. to 9 5/8 in. It will be providing additional support for the sub surface equipment and also prevents the casing buckling by cementing far enough above the producing formations.

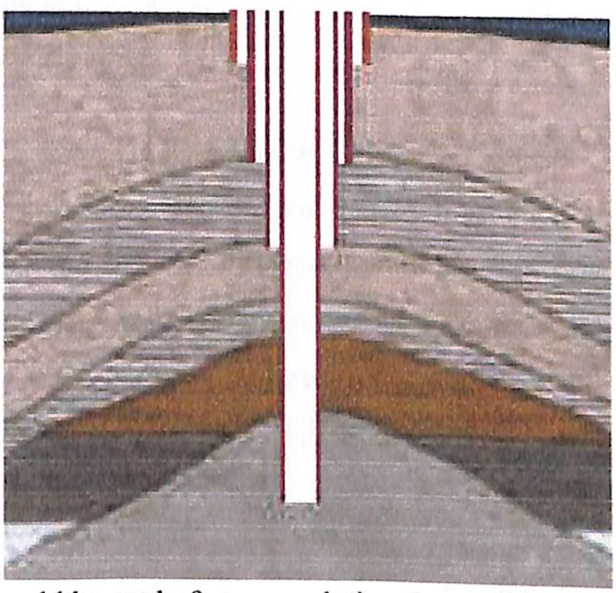
LINERS

Liners are suspended from bottom of the next largest casing string but do not reach the surface usually. They are used to seal off the trouble some sections of the well or through the producing zones for economic reasons. The liner assemblies include drilling liner, production liners, tie back liner, scab liners and scab tie back liner.

1.3 PRODUCTION CASING

Production casing, alternatively called the 'oil string' or 'long string,' is installed last and is the deepest section of casing in a well. This is the casing that provides a conduit from the surface of the well to the petroleum-producing formation. Always production casing is lowered after confirming the hydrocarbon presence in the formation and its depth and thickness.

Most of the times in a well, the presence of pay zones are more than one. In such situations the casing is lowered covering the bottom most zone. The size of the production casing depends on a number of considerations, including the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later time. For example, if it is expected that the well will be deepened at a later date, then the production casing must be wide enough to allow the passage of a drill bit later on.



The final string of casing pipe run in the hole is the production casing. The production casing is used to control the hydrocarbon bearing zones that will be produced. This string of pipe adds structural integrity to the well-bore in the producing zones.

It is necessary to conduct the hydrocarbons to the surface Production casing should be set before completing the well for production. It should be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons.

A calculated volume of cement sufficient to fill the annular space at least five hundred (500) feet above the top of the uppermost hydrocarbon zone should be used. Casings must also be of such quality that they can withstand particularly corrosive media in the well (H_2S, CO_2 etc.), if expected to be exposed to such formations.

This string would normally be the longest string run and may often be cemented in stages so as not to brake down the lower formation. It must also be of sufficient strength that should the production string (s) leak it will contain the formation pressure that will migrate to surface and should be design to cover the expected life span of the well.

If there are indications of inadequate primary cementing (such as lost returns, cement channeling, or mechanical failure of equipment) in the surface, intermediate, or production casing strings, the casings should be evaluate, by pressure testing the casing shoe, running a cement bond log or a cement evaluation tool log, running a temperature survey, or a combination before continuing operations. If the evaluation indicates inadequate cementing, the casing should re-cement and if necessary perforated and squeezed with cement. When a liner is used as production casing, the testing of the seal between the liner top and next larger string must be conducted as in the case of intermediate liners.

Production casing for deep high pressure corrosive environment wells requires special planning. The criteria by which production casing is planning. The criteria by which production casing is chosen for wells shallower than 20,000' is quite different for deeper wells. If the worst case condition for internal pressure is a tubing leak, then the most accurate method of predicting shut-in tubing pressure must be employed. The use of the appropriate restricted yield materials is advisable in many high pressure completion systems, even in areas not normally associated with sulfide stress cracking problems.

Uniaxial design analysis is not sufficient to adequately predict load condition in deep high pressure completion systems. A triaxial stress pressure completion systems. A triaxial stress analysis should be performed to insure the yield strength of the material is greater than the worst case stress condition for the most cost effective size/material combination.
A casing connection that has demonstrated performance under extreme combined loads should be performance under extreme combined loads should be chosen to insure the integrity of the production casing system.

From a safety standpoint, the production casing system is one of the most important aspects of well planning. Less than optimum surface and intermediate casing can sometimes be compensated for by good well control procedures. A production casing failure, however, may have disastrous results in that it normally is not tested until a tubing failure, and serves as the back up protection for such an event. protection for such an event. The proper selection of a production casing system insuring both a technically correct and cost effective solution is an iterative process.

The first step is to predict the load conditions as accurately as possible. The absolute requirement is that the production casing system should maintain integrity during a shut-in tubing leak condition. To this end the use of the most accurate method of predicting shut-in pressures is imperative. An examination of the various methods is offered.

The use of sour service materials is recommended in a high pressure deep completion. Under extreme pressure conditions restricted yield materials may be required, even in areas not normally associated with sulfide stress cracking. The use of industry standard uniaxial design factors may not result in the most technically correct or cost effective solution. An analysis of the three principal stresses will enhance probability that the production casing system exceeds any load conditions it may be subjected to.

Conventional casing connections may not be sufficient for the extreme tensile and internal pressure loads that the production casing system pressure loads that the production casing system may encounter. In order to preserve the integrity of the production casing system, the connections must be designed for extreme combined loads. What would be expected of a connection and some advanced thread concepts to solve these problems are discussed.

Determine the realistic loads

It is imperative that realistic load condition be estimated in order to choose an adequate wall thickness, material and connection to satisfy the requirements of the severe environment.

In a completion utilizing a conventional closed annulus, or packer completion, the worst case loading can occur during a tubing leak. In this case we assume that will essentially have the shut-in tubing pressure acting on the production casing system at the surface. Accurate prediction of expected formation pressure should be used as the starting point in designing production casing.

CHAPTER-II

LITERATURE REVIEW

2.1 CASING SPECIFICATION

Casings are specified according to following

SIZE

Size is specified by outside diameter of the casing pipe. API SPEC-5A furnishes the full details of tolerance on outside diameter and weight. API tolerance on outside diameter for non-upset casings are :to.031 inch for 4" and smaller and :t 0.75% for 4.5" and larger size. The API tolerance on wall thickness is -12.5 %.

NOMINAL WEIGHT

The term nominal weight is primarily used for the purpose of identification of casing type during ordering. It is expressed in ppf or kg/m. Nominal weight is not the exact weight and is approximately equal to the calculated theoretical weight per foot for a 20 feet (6.1 m) length of threaded and coupled casing joint.

PLAIN END WEIGHT

The plain end weight of the casing joint is the weight without the inclusion of thread and coupling. It can be calculated from the following formula:

Wpe = 10.68 (D-t) t ppf

or Wpe = 0.02466 (D-t) t kg/m

Where,

Wpe = Plain end weight (ppf or kg/m)

D = Diameter (inch or mm)

t = Wall thickness (inch or mm)

THREADED AND COUPLED WEIGHT

The threaded and coupled weight is the average weight of a joint including the thread at both ends and a coupling at one end when power tight.It is based on a 20 feet long pipe measured from the outer face of the coupling to the end of the pipe and is calculated from the following formula:

w = 1/20 [wpe { (20- (N1+ 2J)/ 24} + weight of coupling - weight removed in threading two pipe end}

Where,

W = threaded and coupled weight (ppf)

N 1 = coupling length (inch)

J = Distance from end of pipe to centre of coupling in power tight position (inch)

Wpe = Plain end weight.

2.2 GRADE DEFINITION

A standardized measure of casing strength properties, since most oilfield casing is of approximately the same chemistry (typically steal), and differ only in the heat treatment applied, the grading system provides for standardized strength of casing to be manufactured and used in wellbores. The first part of the nomenclature, a letter refers to the tensile strength the second part of the designation, a number ,refers to the minimum yield strength of the metal (after heat treatment) at 1000 psi (6895 kpa).

For example, the casing grade j-55 has minimum yield strength of 55,000 psi (379,211 kpa).The casing grade p-110 designates a higher strength pipe with minimum yield strength of 110,000 psi (758,422 kpa).

Since the well designer is concerned about the pipe yielding under various loading conditions, the casing grade is the number that is used in most calculations. It is also important to note that, in general ,the higher the yield strength, the more susceptible the casing is to sulfide stress cracking. Therefore if H2S is anticipated, the well designer may not be able to use tubular with strength as high as he or she would like.

GRADE OF STEEL

The raw material used for manufacturing of casing has no definite microstructure. The microstructure of steel and mechanical properties can be greatly changed by the addition of special alloys and by heat treatment. Thus, different grades of casing can be manufactured to suit different drilling situations. The number designates the minimum yield strength of that particular grade in thousands of psi. The minimum yield strength is defined as the tensile stress required on a test specimen to produce the following extension under load as determined by an extensometer. In addition to API grades, several other proprietary steel grades called as non-API grades are widely used in oil industry.

Steel grades and Grades

API Steel Grades	Min. Yield Strength (psi)	Min. Tensile Strength (psi)	% Elongation for Min. Yield Strength
H-40	40,000	60,000	0.5
J-55	55,000	75,000	0.5
K-55	55,000	95,000	0.5
C-75	75,000	95,000	0.5
L-80	80,000	95,000	0.5
N-80	80,000	1,00,000	0.5
C-95	95,000	1,05,000	0.5
P-110	1,10,000	1,25,000	0.6
Q-125	1,25,000	1,35,000	0.65

2.3 TYPES OF CONNECTIONS

Most of the casing pipes are connected together by means of couplings. Different type of threads are cut on the ends of the pipes. Depending upon the types of the threads at they ends of casing pipes, they can be specified as under:

API round thread casing

1. Short thread coupling (STC)
2. Long thread coupling (LTC)

   Both STC and LTC have 8 threads per inch cut on them. Strength on LTC couplings is about 30 % more than STC in tension.

API BUTTRESS Thread casing

BTC is capable of transmitting higher axial load than the API 8 round threads. A proper thread compound is used to create leak resistance. Number of threads per inch in BTC threads is 5.

API Extreme Line Casing

In such casings the pipe ends are slightly upset where Box and Pin threads are cut .In addition the box is provided at its bottom with slightly tapered sealing surface against which a mating sealing surface with a slight curvature and extending beyond the threaded pin is pressed under radial stresses during makeup.

The thread profile is trapezoidal. Due to the type of thread and to the special design of sealing surface, the extreme line casing is highly suitable for high service loads. The joint is gas tight and can transmit high axial tensile and compressive loads.Number of threads per inch for extreme line connection is 6 for casing size 4 ½ inch to 7 5/8 inch and 5 for casing size 8 5/2 inch to 10 ¾ inch. A part from the standard API connections mentioned above , several other proprietary connections are in use in the oil industry .

In KG basin, most of the wells are gas bearing wells. The methods of casing for gas and oil bearing wells are almost same except the connection methods. VAM and XL connection casing is mostly used for gas bearing zones and oil and gas bearing zones. In BTC,LTC and STC connections there is a chance of gas leakage(gas cut) from casing into the annulus through shoulder section. XL and VAM connections are gas tight connections hence the leakage will not be there.

VAM Casing Coupling

VAM casing coupling have the thread crust and roots are flat and parallel to the cone. Flanges are 3 degrees to 10 degrees to the vertical of pipe axis. 5 threads per inch are on the axis of pipe. Double metal-metal seals are provided at the pin end by incorporating a reverse shoulder at the internal shoulder, which is persistent to high torque and allows non turbulent flow of fluid.

Metal-metal seals, at the internal shoulders of VAM couplings are affected most by the change in tension and compression in the pipe. When the make up torque is applied, the internal shoulder is locked into coupling. Their by creating tension in the box and compression in the pin. If tensile load is applied to the connection the box will be elongated further and compression in the pin will be reduced to added load. Should the tensile load exceed the critical value, the shoulders may separate.

LENGTH RANGE

Length of casing pipes manufactured is another criterion by which casings are classified. The lengths of casing pipes for different ranges are as under:

RANGE I 16 To 25 Feet

RANGE II 25 To 34 Feet

RANGE III 34 To 46 Feet

2.4 STRENGTH PROPERTIES OF CASING

Casing pipe strength properties are generally specified as :

(1) Yield strength for (a) pipe body and (b) coupling

(2) Collapse strength for pipe body

(3) Burst strength for (a) pipe body, (b) coupling and (c) leak resistance of the connection

YIELD STRENGTH

API yield strength is defined as the tensile stress required to produce a total elongation of 0.65, 0.60 and 0.50 percent of length for 0-125, P-110 and remaining grades respectively. It is customary to quote yield strength of casing while referring to the strength of casing. The most common types of casing joints are threaded on both ends and fitted with a threaded coupling at one end only. The coupling is the box end of the casing joint. The strength of the coupling may be higher or lower than the yield strength of the main body of the casing joint. Hence, manufacturers supply data on both, body and coupling strengths and the minimum of two to be used in casing design calculations, as will be shown later. There are also available integral casing (i.e. without couplings) in which the threads are cut the pipe ends.

COLLAPSE STRENGTH DESIGN

It is defined as the maximum external pressure required to collapse a specimen of casing. Under the action of external pressure and axial tension, a casing cross-section can fail in three possible modes of collapse-elastic collapse, plastic collapse, and failure caused by exceeding the ultimate tensile strength of the material. The transition between the three failure modes is governed by the tube geometry and material properties. These three modes of collapse under external pressure are governed by D/t ratio. It has been observed that for thin tubes (large D/t ratio) collapse failure mode is expected to be elastic. As the D/t ratio decreases or as the pipe becomes thicker I the collapse failure mode changes to plastic (for intermediate D/t ratio) or to ultimate strength (for low value of D/t).

BURST STRENGTH

Burst strength of pipe body is defined as the maximum value of internal pressure that may cause the material of the casing to yield. Minimum burst resistance of casing is calculated by use of Barlow's formula

$$\boxed{p = 0.875\ 2Yp\ t/D}$$

Where,

P = burst pressure (psi)

Vp = minimum yield strength (psi)

D = outside dia of casing (inch)

t = thickness of casing (inch)

The factor 0.875 allows for minimum pipe wall thickness. It makes allowance for a 12.5% variation in wall thickness due to manufacturing tolerance. Burst failure occurs by either rupturing of pipe body failure of coupling or leakage of coupling threads. Hence, API has defined three internal pressure resistance values for casing and the minimum one should be used for calculation. In addition to pipe body burst resistance, the other two resistances are:

(a) Internal yield pressure for coupling.

(b) Internal pressure leak resistance of connection.

Casing design is influenced by:

(a) Loading conditions during drilling and production.

(b) Formation strength at casing shoe.

(c) The degree of deterioration to which the pipe will be subjected during entire life of a well.

2.5 DESIGN CRITERIA

The following are the criteria which must be considered when carrying out detailed casing design:

(1) Axial load

- Axial
- Axial compression

(2) Collapse pressure

(3) Burst pressure

(4) Other loading conditions, if any

Axial Load

✓ AXIAL TENSION

Most axial tension arises from the weight of casing itself. Other tension loadings can arise due to bending, drag, shock loading and pressure testing of casing. Since a number of parameters contribute to tensile loading, the tensile load on the casing should be calculated at the following stages:

1 .When running the pipe

2. When cementing

3. When pressure testing (drilling phase)

Four situations should be considered and a safety factor evaluated for each one of them.

Situation 1. Common force plus a shock loading when running

Situation 2. Common force plus an overpull when running

Situation 3. Common force plus a weight of cement force when cementing

Situation 4. Common force plus a pressure test in the drilling phase

The highlighted terms are explained in more detail below. Common force is a combination of the weight of the casing string less the buoyancy force in the minimum mud weight envisaged plus the bending force.

(i) Weight of the casing (W)

$$\boxed{W = Wn \times L \text{ kg-f}}$$

where,

Wn = casing nominal weight in kg/m

L = casing length in m

(ii) Buoyancy force (BF) is an upward force acting on the bottom of the casing string. True vertical depths must be used in a directional well. Any composite strings with different internal diameters must be considered separately.

$$\boxed{SF = MW \times CSA \times U\ 10 \text{ kgf}}$$

where,

MW = mud weight in gm/cc

CSA = cross sectional area in sq. cm ,

L = casing length in m.

iii) Bending force (BeF) is a force acting in tension on the outside of the pipe and compressive force on the inside. It will be caused by any deviations in the well, resulting from side-tracks, build-ups and drop-offs or from sagging of casing caused by lack of centralisation or washouts. Bending calculations must be redone if a well has to be side- tracked around a fish.

BeF = 29 x RC x D x Wn kgf

where,

RC= radius of curvature in deg/30 m

D = outside diameter of pipe in inch

Wn = casing nominal weight in ppf

Shock loading is exerted on the casing string because of:

(1) Sudden deceleration force, for example if the spider accidently closes or the slips are 'kicked-in' on moving pipe or the pipe hits a bridge / ledge.

(2) Sudden acceleration force, such as picking the pipe out of the slips or if the casing momentarily hangs up on a ledge then slips off it.

Any of the above will cause a stress wave to be created, which travels through the casing at the speed of sound. Magnitude of shock load can be calculated by the following formula

Shock loading = 1.55 x 103 x V x Wn kgf

where,

V = peak velocity while running inm/sec

Wn = nominal weight of casing in ppf

Overpull contignecy of 1,00,000 Ibs (45.45 T) Is normally incorporated. This is not exactly a design factor but a function of the hole conditions.

Cement force (CF), a worst case situation is assumed as follows: the mud weight in the annulus is the lowest envisaged for the section; the inside of the casing is full of cement slurry , with mud above; the shoe instantaneously plugs off just as the cement reaches it and the pressure rises to a value of say 100 kg/cm2 before the pumps are shut down. It is appreciated that the cement will be 'running away' at this point with no positive displacement pressure being exerted.

CF=(CW -MW) x L + 100] x A kgf

where,

CW = cement weight in gm/cc.

MW = mud weight in gm/cc

L = length over which CW & MW act in m

A = internal area of the casing in cm2

Pressure testing will be performed on the casing as the plugs are bumped and later on in the well depending on operational conditions. The actual test pressure will depend on:

* The rated burst strength of the casing.
* The well head pressure rating.
* The BOP stack pressure rating.
* The maximum anticipated surface

AXIAL COMPRESSION

Collapse pressure originates from the mud column behind the casing. Since mud hydrostatic pressure increases with depth, collapse pressure will be maximum at bottom and zero at top. When a casing is subjected to a collapse pressure due to mud hydrostatic pressure from outside, it is called collapse Load. The internal pressure (due to any reason) is called back up. The difference between the collapse and Internal pressure is termed as resultant. Resultant is the net pressure which is actually acting on the casing. If the casing is designed in collapse as total empty from inside, it is known as dry design. In this case back up equals to zero. Normally a surface casing is designed dry an intermediate casing is designed partially empty assuming that the casing shoe will be able to withstand minimum of native fluid column.

BURST PRESSURE

Compressional effects occur in casing due to temperature effects in landed casing and because of the weight of other inner casing strings which are supported by the outer strings. So far as compression loads are concerned, wells fall into one of three categories:

(1) Land wells and subsea wells

(2) Platform wells with surface wellheads

(3) Mudline suspension wells

In land wells, if the outer casing is cemented all the way to surface it will be able to support all the expected compressional loads. If, however, it is not cemented to surface, then there is danger of buckling due to the compressive loads. In platform wells, with surface wellheads, there is a free standing part of the casing equivalent to the water depth plus air gap plus height to the wellhead deck. Buckling can occur on this free standing section. To prevent buckling, the outermost casing must be well centralised within the conductor and designed to be strong enough to withstand the likely buckling forces. With mudline suspension wells, used mostly on jack-up wells, the weight of the casing is hung off at the seabed. The tieback string which link the seabed wellhead with the surface equipment on the jack up rigs is however, subject to buckling. During drilling operations, in most of the cases, the temperature effect is so slight that it can be ignored. However, during the production phase, the compressive loads on the production string must be considered.

COLLAPSE PRESSURE

Collapse pressure originates from the mud column behind the casing. Since mud hydrostatic pressure increases with depth, collapse pressure will be maximum at bottom and zero at top. When a casing is subjected to a collapse pressure due to mud hydrostatic pressure from outside, it is called collapse Load. The internal pressure (due to any reason) is called back up. The difference between the collapse and Internal pressure is termed as resultant. Resultant is the net pressure which is actually acting on the casing. If the casing is designed in collapse as total empty from inside, it is known as dry design. In this case back up equals to zero. Normally a surface casing is designed dry and intermediate casing is designed partially empty assuming that the casing shoe will be able to withstand minimum of native fluid column.

BURST PRESSURE

The burst criterion in casing design is normally based on the maximum internal pressure resulting from a kick during drilling of the next hole section. For added safety in some cases, it is also assumed that influx fluid will displace the entire mud, thereby subjecting the inside of the casing to the bursting effects of formation pressure. The "load", "back up" and resultant concept is also applied here with a difference that load in burst will be internal pressure, back up will be external pressure.

Other Loadings

Other loadings that may develop in the casing include:

(1) Bending with tong during make up.
(2) Pullout off the joint and slip crushing.
(3) Corrosion and fatigue failure.
(4) Pipe wear due to running wire line tools and drill string assembly in deviated and dog-legged holes.
(5) Additional loadings arising from treatment operations like acidizing, hydrofracturing, cement squeezing etc. Additional loadings cannot be determined directly and, it is assumed that they are taken care by the Safety Factors

Safety Factors

Casing design is not an exact technique because of the uncertainities in determining the actual loadings and also because of change in casing properties with time resulting from corrosion and wear. A Design Factor is used to allow for such uncertainities and to ensure that the rated performance of the casing is always greater than the expected resultant loading. In other words, casing strength is down-rated by a chosen safety factor. Every organisation has its own policy of safety factors. Most commonly used design factors for casing design are :

Collapse 0.85 -1.125

Burst 1.00 -1.10

Tension 1.60 -1.80

Safety factors can be defined as the ratio between rated capacity of casing and the actual load.

SF collapse = (Rated collapse resistance of casing) / (Actual resultant collapse pressure)

SF burst = (Rated burst rating of casing) / (Actual resultant burst pressure)

SF tension = Rated yield strength (pipe body or Joint whichever is minimum) / Actual resultant tensile load

BIAXIAL EFFECTS

Burst and collapse resistances of casing are altered when the pipe is under tension or compression load. These changes may, but do not neccessarily, apply to connectors. Coupling manufacturers should be consulted in stringent operating conditions. The qualitative changes in pipe resistance are as follows:

Types of Load	Result
Tension	Collapse – Decrease Burst - Increase
Compression	Collapse – Increase Burst - Decrease

An easy and faster way of finding the quantitative effect of axial tension on collapse resistance is by referring to the collapse curve factors.

2.6 DIFFERENT DESIGN APPROACHES

Casing design becomes more critical as the well depth and formation pressure increase. It is imperative that realistic load condition be estimated in order to select suitable casing to satisfy the requirements of the environment. The main step is to predict the load conditions as accurately as possible.

The maximum load concept method or its modified version analyse expected drilling problems and the casing is designed to withstand the expected loads. The design procedure is flexible enough to meet most demanding drilling and completion conditions. A brief summary of production casing design approaches has been given in Table. The selection of a particular approach should depend upon individual well data.

LOAD ASSUMPTIONS IN DIFFERENT DESIGN APPROACHES: PRODUCTION CASING

Load	**Conventional**	**Maximum Load conpect Approach A**	**Apporach B**
Burst	**Internal pressure** During production the well is full with gas, there by subjecting the casing to bottom hole pressure **Back-Up** Saline water in the casing annulus	**Internal Pressure** During production the well is full with formation fluid, thereby subjecting the casing to bottom hole pressure **Back- up** Same as conventional Approach	**Internal Pressure** Same as conventional Approach **Back –Up** Same as conventional Approach.
Collapse	External Pressure The casing annulus is full with the mud in which it was lowered. Back-up Casing is considered "dry" from inside due to the possibility of the well being put on artificial lift and plugged perforation.	External Pressure Same as Conventional Approach. Back-up Same as Conventional Approach.	External Pressure Same as Conventional Approach. Back-up Same as Conventional Approach.
Tension	Buoyancy is neglected	Buoyancy is considered	Buoyancy is considered

2.7 GUIDE LINES FOR CASING DESIGN

Unfortunately, a standard set of casing design guidelines can not be used for all types of casing string run into a well. Various drilling and geological conditions require modifications to the casing design guidelines. With this in mind, following general guidelines are given for design of different casing strings.

Casing Performance Properties

Casing must be manufactured to the minimum specifications as defined in API 5CT/ISO 11960. The performance properties of casing must meet or exceed the standards in API Bulletin 5C2. The casing collapse pressure rating is reduced by axial loading and must be calculated using the current API Bulletin 5C3 standards in conjunction with Appendix E. Casing not defined by API 5CT/ISO 11960 specifications but meeting the objectives of API 5CT/ISO 11960 manufacturing standards may be used if the manufacturer provides acceptable performance properties, including collapse, burst, and pipe body yield, that meet or exceed the standards in API Bulletin 5C3. Proprietary casing grades must also meet or exceed any applicable API 5CT/ISO 11960 material requirements, such as chemistry, toughness, ductility, hardness, inspection and testing requirements, dimensional tolerances, and other API 5CT/ISO 11960 performance standards. Non-API connections may be used if the minimum design factors are met and applicable material requirements meet or exceed API 5CT/ISO 11960 specifications. The manufacturer must also provide the means by which these performance properties were determined.

Note that API Bulletin 5C3 give guidance to calculate minimum performance properties but may not consider all well operating conditions.

Burst Design Factor Adjustments

In Section 2: Simplified Method, the minimum burst design factor for sour wells with pp $H_2S \geq 0.3$ kPa has been increased from 1.0 to 1.15 (1.25 for surface casing), based on maximum potential formation pressure. The restricted hoop stress load reduces the susceptibility to SSC. In Section 3: Alternative Design Method, for sour wells with pp $H_2S < 0.3$ kPa, SSC is not an issue. Therefore, for practical purposes these wells may be considered sweet wells. For sweet wells, a lower minimum burst design factor of 1.10 may be used, based on maximum potential formation pressure less gas gradient to surface. Wells with pp H_2S of 0.3 kPa or greater are considered sour wells. For sour wells with $0.3 \leq$ pp $H_2S < 10$ kPa (a pp of H_2S of 0.3 kPa or greater and less than 10 kPa), the minimum burst design factor is 1.20. For sour wells with pp $H_2S > 10$ kPa, the minimum burst design factor is 1.25. This ensures that the casing hoop stress level in mild sour wells will be less than 83.3 (1/design factor) of its specified minimum yield strength, and in wells with pp H_2S above 10 kPa, the hoop stress level will be less than 80% of SMYS.

Burst design factors for materials used in sour wells may be reduced from the value of 1.25 outlined in the design loading constraints by conducting Fit-for-purpose SSC testing in accordance with NACE TM0177 Method A, Solution A, to a representative load condition. A licensee requesting a reduction in the burst design factor is required to test to an additional 5% stress level or a stress level of 105% (1.05) of the maximum potential material stress. The load test stress is inversely proportional to the proposed burst design factor: test stress level = (1.05 / minimum burst design factor) x SMYS. For example, for noncritical sour wells with pp $H_2S \geq 0.3$ kPa, if the burst safety factor is limited to 1.18 due to product availability, the product must be tested to 1.05/1.18 = 0.89, or 89% of the SMYS of the material, instead of the more common 80 to 85% of SMYS.

Casing Wear Considerations

Casing wear considerations in Subsection 8.141(3) of the *Oil and Gas Conservation Regulations* (*OGCR*) must be taken into account. Casing safety factors must be increased as necessary to maintain the required minimum design factors after consideration of anticipated casing wear. Casing wear can be affected by casing grade, rotating hours, rpm, type of drilling fluid, dogleg severity, inclination, deviated wellbore, tripping frequency, and the types of downhole tools run. Efforts to minimize wear include use of drill pipe conveyed casing wear protectors, use of downhole motors, and drilling fluid additives designed to reduce torque and drag. Section 12.141 of the *OGCR* requires the licensee to notify the ERCB immediately on detection of a casing leak or failure. Also, if requested by the ERCB, the licensee must provide a report assessing the leak or failure, including a discussion of the cause, duration, damages, proposed remedial program, and measures to prevent future failures.

Other Design Considerations

Determination of axial loads must include consideration for additional tension loading (e.g., casing overpull when setting slips, casing pressure testing) or compressive loading (e.g. due to subsequent well operations, such as the installation of a blowout preventer (BOP) stack and subsequent casing and tubing strings), as well as well servicing conditions. For all directional wells, the licensee must address additional stresses (or loads) caused by bending, regardless of the design method chosen.

According to this, the licensee must not drill beyond a depth of 3600 metres [m] without first setting intermediate casing to ensure well control. Collapse design must consider uphole formations that contain higher pressures or gradients than those used for the drilling fluid gradient. An example is high pressure/low permeability zones where the drilling fluid gradient is not increased to a fully balanced condition, which eliminates entry of background gas.

The licensee must consider corrosion for the portion of casing subject to long-term exposure to highly corrosive conditions Corrosion control may be addressed through appropriate material selection, coatings, environmentally safe corrosion inhibition, cathodic protection, cementing of casing , use of tubing and packers, or other engineered options.

CHAPTER-III

CASING DESIGN CALCUALTIONS

3.1 DATA REQUIRED FOR DESIGN

The main component in developing the casing design for a well is GTO (Geo Technical Order) . This should be completed before a well plan and the design of casing will be done by the following information.

- Type of well
- Location-onshore, offshore (water depth), objective depth etc.
- Geological information- formation tops, faults, structures maps etc.
- Pore pressure, fracture pressure and temperature profile.
- Directional well plan
- Offset well data- casing schemes geological tie-in, operational problems, mud weights etc
- Hazards- shallow gas, faults etc.
- Evaluation requirements.
- Hydrocarbon compositions- gas or oil, corrosion considerations.
- Anticipated producing life of well and future well intervention.
- Tubing and downhole completion components sizes.
- Annulus communications, bleed off and monitoring policy, particularly for development wells.
- Constraints- license block or lease line restrictions.

3.2 CASING DESIGN PRINCIPLES

Vertical setting depth of casing = CSD

Vertical TD of next hole = TD

Formation pressure at next TD = P¦

Mud weight to drill hole for current casing = pm

Mud weight to drill hole for next casing = pm1

3.3 COLLAPSE CALCULATIONS

Complete evacuation in production casing is virtually impossible, because during lost circulation, the fluid column inside the casing will drop to a height such that the remaining fluid inside the casing just balances the formation pressure of the thief zone. Predicting the depth of the thief zone in practice is difficult. Using the TD of the next hole section represents the worst case situation and this depth should normally be used.

Assuming that the thief zone is at the casing seat, then:

External pressure at shoe = $CSD\ x0.465$

Internal pressure at shoe = $L\ x\ pm1x0.052$

Where:

pm = density of mud in which casing was run (ppg)

$pm1$ = mud density used to drill next hole (ppg)

pf = formation density of thief zone, (psi/ft) (or pg)

(assume = 0.465 psi/ft for most designs)

L = length of mud column inside the casing

L = CSD * 0.465 / .052 * $pm1$

Depth to top of mud column = $CSD - L$

collapse point will have to be calculated.

Collapse pressure, C = external pressure - internal pressure

1 Point (at surface)

C1 = Zero

3.4 PRELIMINARY BURST CALCULATIONS

The burst loads on the casing should be evaluated to ensure the internal yield resistance of the pipe is not exceeded. Fluids on the outside of the casing (back-up) supply a hydrostatic pressure that helps resist pipe burst. The net burst pressure is the resultant.

The following situations should be considered during the drilling and production phases for burst design:

- Well influx and kick circulation
- Cementing
- Pressure testing
- Stimulation
- Testing
- Near surface tubing leak
- Injection

The most important part of the string for burst design is the uppermost section. If failure does occur then the design should ensure that it occurs near the bottom of the string. Although tension considerations influence the design of the top part of the casing, burst is the governing design factor.

For the production casing, The worst case occurs when gas leaks from the top of the production tubing to the casing. The gas pressure will be transmitted through the packer fluid from the surface to the casing shoe .

Burst pressure = Internal pressure - External pressure

Burst at surface = $(B1) = Pf - G \times CSD$

(or the maximum anticipated surface pressure - whichever is the greater)

Burst at shoe = $(B2) = B1 + 0.052\, pp \times CSD - CSD \times 0.465$

Where:

G = gradient of gas (usually 0.1 psi/ft)

Pf = formation pressure at production casing seat (psi)

pp = density of completion (or packer) fluid (ppg)

0.465 = the density of backup fluid outside the casing to represent the worst case (psi/ft)

Note: if a production packer is set above the casing shoe depth, then the packer depth should be used in the above calculation rather than *CSD*. The casing below the packer will not be subjected to the burst loading.

3.5 TENSILE CALCULATION

The total tensional load at any time is the sum of forces due to:

· The weight of the casing in air

· Buoyancy

· Bending

· Drag or shock loading (whichever is the greater)

· Casing test pressures

In addition, the design must take account of drag or shock loading when running or reciprocating the string.The design factor will vary if either all of the potential tension forces are calculated or simply hanging weight is used.

After each section of casing is selected during burst and collapse calculations, the top section is checked to be certain that it meets tensile strength requirements. If the casing is too weak, a change should be made to provide sufficient strength for least cost. This should normally be via the following method:

· A more efficient connection

· Higher grade of steel

· Higher weight of steel/foot

As with all casing design considerations, the final selection can be heavily influenced by available pipe, warehouse stock or buyback agreements from suppliers.

The following forces must be considered:

1 Buoyant weight of casing (based on true vertical projection of the casing length) (positive force).

2 *Bending force* = 63 *WN* x *OD* x q

WN = weight of casing/ft (positive force)

q = dogleg severity, degrees/100 ft

3 *Shock load (max)* = 3200 *x WN*

(Use 1500 *x WN* in situation where casing is run slowly)

4 Drag force (approx equal to 100,000 lbf) (positive force)

Because the calculation of drag force is complex and requires an accurate knowledge of the friction factor between the casing and hole, shock load calculations will in most cases suffice.

Caution

Both shock and drag forces are only applicable when the casing is run in hole. In fact, the drag force reduces the casing forces when running in hole and increases them when pulling out. However, despite the fact that the casing operation is a oneway job (running in), there are many occasions when a need arises for moving casing up the hole, e.g. to reciprocate casing or to pull out of hole due to tight hole. Hence, the extreme case should always be considered for casing selection.

Selection Based on Tension

If all safety factors are equal or above 1.6, proceed to the next step. If the safety factor is less than 1.6, which usually occurs near the top of the hole, replace the chosen weight with the heaviest weight in the string and repeat the calculations. If the safety factor is still less than 1.6, a heavier casing may be required.

Once again, ensure that the safety factor in tension during pressure testing is >1.6.

S.F. = Yield strength / tensile forces during pressure testing

Where:

Buoyancy factor (BF) = (1-Mud Weight, ppg

Steel density, ppg)

Steel density = 65.44 ppg

WN = Weight of casing per foot

q = Dogleg severity, (degrees/100 ft)

Yield Strength: The lowest of the body or joint strength should be used.

CHAPTER-IV

KG BASIN

The Krishna Godavari Basin is located on the east coast of Indian Peninsula extending over an area of 41, 000 sq km in both onshore and offshore besides the deltas of Krishna Godavari Rivers. This basin comprise of sediments ranging in age from Lower Permian to Recent. The major part of the basin is buried under alluvium. The basaltic rocks are sporadically cropping out in this basin.

KG Basin originated in three stages of rifting .The protenozoic proto –rift (NW-SE) accommodated purana group of sediments. This was followed by Gonodawana rifting. The drifting was accompanied by Southeasterly tilting of the basin.

History of KG Basin and Rajahmundry Asset

1) Geological surveys initiated in 1959. Geophysical surveys initiated in 1960.

2) First Onland well Narsapur-1 in 1979. First Offshore well G-1-1 in 1980 (water depth 250 m).

3) Deepest Onland well : Bhavadevarapalli-1 (5001 m)

   Deepest Offshore well : GS-11-1 (4611 m).

4) Maximum pressure gradient recorded: 2.1 MWE in Tatipaka-1

   Maximum BHT recorded: 187°c in Amalapuram-1.

5) Onland commercial production of Gas started in 1988.

6) Offshore production started in 2001.

7) Oil Production started in the year 1988.

8) Commissioned a Mini Refinery in September 2001 first of its kind in the fulfilling the requirement of HSD for both Rajahmundry and Karaikal Assets

9) Uniqueness of Rajahmundry Asset is Operating in Onshore as well as Offshore. Upstream as well as Downstream sector. Largest Gas Producing Asset (Onshore).

4.1 BASINAL AREA

- ONLAND : 28000 Sq.km
- OFFSHORE : 24000 Sq.km
- DEEP WATER : 18000 Sq.km

The Infrastructure Available at Rajahmundry Asset/KG Basin

Installations	: - 18
Onshore Drilling Rigs	: - 7
Work over Rigs	: - 1
Offshore Drilling Rigs	: - 1 (Jack-Up) and 4 (Floater)
	Sagar Bhushan deployed since 21.07.2005

Fig: 1- KG-Basin Map

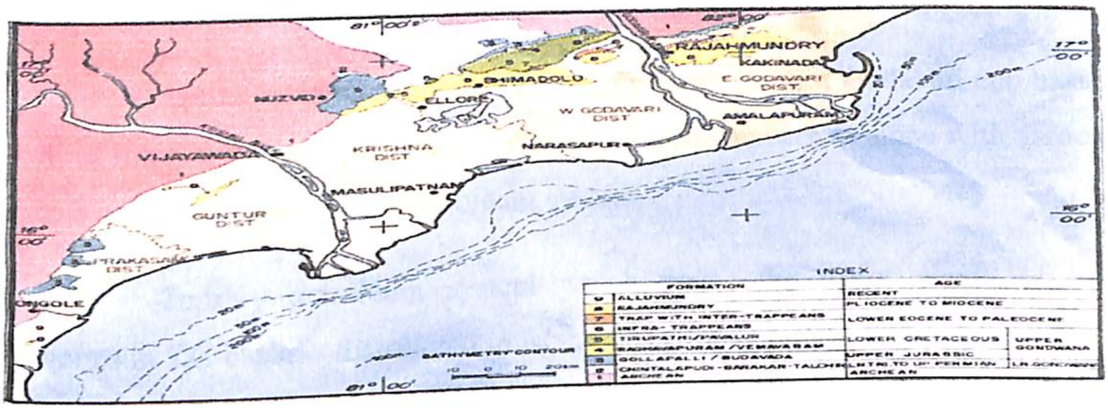


Fig: - Geological Map of KG-Basin

4.2 SUB –DIVISIONS OF KG BASIN

KG-Basin is classified into 3 types, namely

1) Krishna 2) West-Godavari 3) East-Godavari

4.3 MAJOR GAS FIELDS

Mandapeta, endumuru, Tatipaka, Pasarlapudi & Ponnamanda fields Adavipalem and Kesnapalli west fields in East Godavari sub basin

Kaikaluru, Lingala fields in West Godavari sub-basin

4.4 MAJOR OIL FIELDS

Ravva fields in the offshore part of the basin.

Kesnapalli west and Lingala in the onland part of the basin

4.5 HYDROCARBON FINDS IN KG BASIN

The older Permian–Triassic petroleum system produces gas in Mandapeta area. The gas is in post maturity stage indicating the significance of metagenesis. The gas is rich in methane and inferred to have originated from carbonaceous source rocks of Kommugudem formation.

Late Jurassic to early cretaceous petroleum system is provided by kaikaluru, EM-1 and MW-1A. The condensates of kaikaliru-16, kaikaluru -17 and gases from kaikaluru-12 and EM -1 and MW -1A represent this petroleum system.

Aptian-albian petroleum system is present in west Godavari sub basin in general .the oil of lingala, suryaraopeta and condensate from penumedum alone with associated gasses are some of the examples of the petroleum system.

Tertiary petroleum system which forms the major chunk of hydrocarbons discoveries in KG basin is distributed in island area, Amalapuram area and most of the offshore areas.

Vadaparru and palakollu shale's have been identified as the main sores for the hydrocarbons reserves

CHAPTER-V

CASE STUDIES

5.1 CASE STUDY 1

Designing of production casing For the locations likely to be drilled at KG Basing, ONGC, Rajahmundry.

GENERAL DATA :–

1	LOCATION/ FIELD	KOPPARRU / WEST GODAVARI
2	WELL NAME	KPR-AA
3	WELL CATEGORY	EXPLORATORY TEST 'B'
4	CO-ORDINATES	RELEASED: LAT: 16° 28' 26.33" LONG: 81° 38' 44.32"
5	WELL OBJECTIVES	Eocene Sequence 1 & 2.
6	TOTAL DEPTH	2700 M TVD / 2765 M MD
7	NEAR BY WELLS	MY-1, 2 & WPKAA

DRILLING REMARKS IN G.T.O. :–

1. The well is designed as per the geological parameters given in GTO.
2. The casing shoe depths and drilling technical data are tentative and subject to modification based on actual drilling conditions while drilling and as per the requirement of the well to complete the same safely and successfully to TD.
3. while drilling of the well if sand(soft) formations encountered at casing shoe depths (as per GTO), few more meters may be drilled further so that casing shoe can be positioned in relatively harder formation for a better shoe strength.
4. All recommendations given in safe drilling practices are to be adhered to.
5. All surface equipments are to be installed and tested as per IDT guidelines.

6. During drilling of well for achieving better results the drilling parameters may be optimized / use of standard drilling practices, if required (ie. In reference to actual well requirements).
7. Kick Off depth : 225 M and Drift of 325± 25 to be achieved around 1300 m in 229 ±12° in 'S' profile assuming no loss zones in the directional phase.
8. Micro monitoring of drilling & mud parameters are required while drilling in 12 ¼" & 8 ½" phases for any abnormal pressure, gain/loss situations.
9. Open hole /Cased hole VSP to be decided as per feasibility depending on actual well conditions.
10. Proper care has to be taken while drilling through limestone beds to avoid any induced losses.
11. All drilling time calculations are based on performance incentive calculations. Logging times are indicative and Coring / VSP times not included in time calculations.

ANTICIPATED STRATIGRAPHY

INTERVAL (M) TVD	AGE	FORMATION
0000-1015	Miocene-Pliocene	Narsapur clay stone & Younger
1015-1320	Oligocene – Upr Eocene	Matsyapuri SST
1320-1685	Middle Eocene	Bhimanapalli LST
1685-2000	Lower Eocene	Upper Pasarlapudi
2000-2155	Lower Eocene	Lower Pasarlapudi
2155-2700	Paleocene	Palakollu shale

WELL DATA

❖ PORE PRESSURE DATA

DEPTH INTERVALS (M) TVD	MWE (SG)	MAX. PRESSURE (Kg/Cm2)	PSI
0000-1685	1.00	168.50	2396
1685-2700	1.15	310.50	4415

❖ FRACTURE GRADIENT OF NEAR BY WELL

WELL	DEPTH (M)	MWE	REMARKS
WKPAA	507	1.28	
	1770	1.28	LOT
	2632	1.77	PIT
MYAA	204	1.30	SIT
	1409	1.35	PIT
	2595	1.94	PIT

❖ DIRECTIONAL DATA

KOP: 225 M, HD of 325 ± 25 M efforts to achieve in direction of 229°±12° in 'S' profile at 1300 M (TVD).

❖ FORMATION DIP

GENTLE

❖ ANTICIPATED TEMPERATURE GRADIENT

DEPTH (M)	TEMP(0° C)
2700	109° (Overall temp grad of 3°C/100 m)

❖ POTENTIAL WELL PROBLEM

26”	NIL
17 ½”	NIL
12 ¼”	Monitoring of well condition through drilling and mud parameters is required while drilling through H/C shows given in G.T.O.
8 ½”	

❖ EXPECTED HYDROCARBON SHOW (M) TVD:-

1320, 1685, 1730, 1880, 2000, 2155, 2250, 2490, 2650 M.

❖ TESTING DATA OF NEAR BY WELL DATA–WPKAA

Object	Depth	PT Results
I	3317-3313	W/F Feeble gas 0 psi.
II	3015-12, 3007-04, 3002-2999 & 2989-87	W/F Feeble gas 0 psi.

MYAA: Dry & abandoned.

DRILLING SPECIFICATIONS

❖ HOLE SECTIONS

HOLE	CSG SIZE	DEPTH (M) TVD (MD)	CSG SETTING
26”	20”	200	Surface Casing
17 ½”	13 3/8”	1200 (1265)	Intermediate Casing

12 ¼"	9 5/8"	2100 (2165)	Intermediate Casing
8 ½"	7"	2700 (2765)	Production Casing

❖ **CASING PROGRAMME**

SIZE	SETTING DEPTH (TVD/MD) (M)	WEIGHT (PPF)	GRADE	CONN.
20"	200	94	J-55	UDT
13 3/8"	1200 (1265)	68	J-55	BTC
9 5/8"	2100 (2165)	47	N-80	BTC

Production casing design for well KPR-AA

Final Depth: 2700 m

Formation Pressure gradient: 1.15 MWE

Production Casing Size required: 7"

Expected Hydrocarbons: Gas with associated fluids.

Assumption: Design consideration taken only for gas as the fluid passing through the production casing.

Considering the Conventional Method,

BURST Calculations:

Considering the casing, filled with gas.

Bottom Hole Pressure (at 2700m) = 1.15 * 2700 / 10

= 310.5 kg/cm2

Gas column weight = 0.65 * 2700 / 10

= 175.5 kg /cm2 (Gas sp.gravity = 0.65)

surface pressure = BHP – Gas column wt.

= 310.5- 175.5

= 135 kg/cm2

General safety factor for Burst = 1.10

Therefore Burst Pressure = 310.5 * 1.10

= 341.5 kg/ cm2

considering the performance of 7" casing from API tables.

Since 7''casing size is required, except K-55,26 ppf all other grade casings meets the requirements for burst.

Availability of 7" casing obtained from the ONGC RJY stores and data is as follows:

1	26 ppf	N-80	XL	6000 m
2	29 ppf	P-110	XL	5000 m
3	29 ppf	N-80	BTC	3500 m
4	32 ppf	N-80	BTC	6800 m

Taking consideration of cost factor from the available inventory 26 ppf N-80 is cheaper than other casings. Also the type of connection is XL which well suits for gas wells.

<u>Checking for tension:-</u>

Casing weight = 26 ppf

= 38.7 kg/ m

Total weight = 38.7 * 2700

= 104490 kg

Let us consider total loss situation for lowering (which is the worst scenario)

Buoyancy = 0

From the tables,

7", 26 ppf , N-80 yield strength = 274545

joint strength for XL connection = 291264

Since yield strength is less than joint strength in this case safety factor is calculated with respect to yield strength

Therefore, safety factor = 274545/ 104490

= 2.627

The general safety factor considering for tension is 1.80

Therefore, 7" 26ppf N-80 XL which is preferred for lowering is verified and safe for tension

<u>Collapse</u>

Lets us consider, while lowering the casing inside is dry, due to possibility of well being put on artificial lift and plugged perforation

However , from outside saline water always exists

Therefore collapse pressure at surface = 0

Collapse pressure at the shoe (2700m)= 1.03*2700/10

= 278.1 kg/cm2 (sp.gravity of saline water = 1.03)

From the performance properties of casing from API tables , 7" 26ppf N-80 XL collapse pressure is 381 kg/cm2

therefore safety factor = 381/278.1

= 1.37

general consideration for the collapse safety factor is 1.125

here 1.37(calculated) > 1.125(general)

therefore the preferred casing is verified .

5.2 CASE STUDY 2

Designing of production casing For the locations likely to be drilled at KG Basing, ONGC, Rajahmundry.

GENERAL DATA :–

1	LOCATION/FIELD	MALLESWARAM / KRISHNA DISTRICT
2	WELL NAME	MSAA
3	WELL CATEGORY	EXPLORATORY TEST 'B'
4	CO-ORDINATES	RELEASED: LAT: 16° 21' 30.02" N LONG: 81° 17' 06.80"E
5	WELL OBJECTIVES	Primary: Sands in Syn-Rift (NDG Fm) Secondary: High Amplitude with in RGP shale fm
6	TOTAL DEPTH	4100 M TVD / Basement
7	NEAR BY WELLS	CP-1, PR-1A, NG-2

DRILLING REMARKS IN G.T.O. :-

12. The well is designed as per the geological parameters given in GTO.
13. The casing shoe depths and drilling technical data are tentative and subject to modification based on actual drilling conditions while drilling and as per the requirement of the well to complete the same safely and successfully to TD.
14. while drilling of the well if sand(soft) formations encountered at casing shoe depths (as per GTO), few more meters may be drilled further so that casing shoe can be positioned in relatively harder formation for a better shoe strength.
15. All recommendations given in safe drilling practices are to be adhered to.
16. All surface equipments are to be installed and tested as per IDT guidelines.
17. During drilling of well for achieving better results the drilling parameters may be optimized / use of standard drilling practices, if required (ie. In reference to actual well requirements).
18. Open hole /Cased hole VSP to be decided as per feasibility depending on actual well conditions.
19. 7" liner / 7" casing to be decided as per actual well requirement during drilling. If 7" Liner requirement exists then 11"-10m tubing spool is to be hooked up.
20. Also if 7" production liner is to be lowered then connection for the 9 5/8" casing (as production casing) to be of premium connection.
21. Micro monitoring of drilling & mud parameters are required while drilling in 17 ½", 12 ¼" & 8 ½" phases for any abnormal pressure, gain/loss situations.
22. Proper care has to be taken while drilling through limestone beds to avoid any induced losses
23. All drilling time calculations are based on performance incentive calculations. Logging times are indicative and Coring / VSP times not included in time calculations.

ANTICIPATED STRATIGRAPHY :–

INTERVAL(M) TVD	AGE	FORMATION
0000-0787	Eocene & Younger	Narsapur Claystone
0787-1500	Eocene & Younger	Nimmakurru Sandstone
1500-1605	Paleocene	Razole
1605-2325	Upr Cretaceous	Tirupati Sand stone
2325-3665	Upr-Lower cretaceous	RGP Shale form
3665-4100(+)	Lr Cretaceous-Upr Jurassic	NDG Shale form

WELL DATA :–

- **PORE PRESSURE DATA**

DEPTH INTERVALS (M) TVD	EMW (SG)	MAX. PRESSURE (Kg/Cm2)	PSI
0000-0700	1.05	74	1045
0700-1600	1.10	176	2503
1600-2300	1.20	276	3925
2300-3000	1.30	390	5546
3000-3400	1.40	476	6769
3400-3600	1.55	558	7935
3600-4100	1.70	697	9911

- **FRACTURE GRADIENT OF NEAR BY WELL**

WELL	DEPTH (M)	E.M.W	REMARKS
PR-1A	182	1.18	PIT
	1231	1.31	LOT
	1812	1.32	LOT
	2612	1.80	LOT
	2777	1.82	LOT
	2729	1.81	LOT
	3540	2.05	PIT
NG-2	304	1.345	LOT
	1710	1.40	LOT
	3200	1.80	LOT

- **DIRECTIONAL DATA**

Nil, Being Vertical Well.

- **FORMATION DIP**

GENTLE

- **ANTICIPATED TEMPERATURE GRADIENT**

DEPTH (M)	TEMP(0° C)
4100	168° (Overall temp gradient 3.38° C/100 M)

❖ POTENTIAL WELL PROBLEM

26"	NIL
17 ½"	NIL
12 ¼"	Monitoring of every drilling and mud parameters required while drilling through H/C shows given in G.T.O.
8 ½"	

❖ EXPECTED HYDROCARBON SHOW (M) TVD:-

2325, 3300, 3450, 3665, 3680, 3750, 3850, 3900, 4000 & 4050 M.

❖ TESTING DATA OF NEAR BY WELL DATA

NG-2

Obj	Interval	Remarks
I	4050-4047, 4042-4035 & 4032-4029	No influx even after compr apply
II	3909-3904	No influx/activity even on N2 apply
III	3862.5-3861, 3853.5-3852,3838-3836.5	W/f F/gas at 0 psi on N2 apply

DRILLING SPECIFICATIONS :-

❖ HOLE SECTIONS

HOLE	CSG SIZE	DEPTH (M) (TVD/MD)	CSG SETTING
26"	20"/18 5/8"	600	Surface Casing
17 ½"	13 3/8"	2000	Intermediate Casing
12 ¼"	9 5/8"	3350	Intermediate Casing

❖ CASING PROGRAMME

SIZE	SETTING DEPTH (TVD/MD) (M)	WEIGHT (PPF)	GRADE	CONN.
20"/18 5/8"	600	133/87.5	J-55	OMEGA
13 3/8"	2000	68	P-110	BTC
9 5/8"	3350	47/53.5	P-110/Q-125	BTC
7"	4100	29	P-110	XL/Premium

Production casing design for well MSAA

Final Depth : 4100m

Formation Pressure gradient : 1.70 MWE

Casing Size required : 7''

Expected Hydrocarbons : Gas with associated fluids

Assumption : Design consideration taken only for gas as the fluid passing through the production casing.

Considering the Conventional Method,

<u>BURST Calculations :</u>

Considering the casing, filled with gas.

Bottom Hole Pressure (at 4100m) = 1.7 * 4100 / 10

= 697 kg/cm2

Gas column weight = 0.65 * 4100/ 10

= 266.5 kg /cm2 (Gas sp.gravity = 0.65)

surface pressure = BHP – Gas column wt.

= 697- 266.5

= 430.5 kg/cm2

General safety factor for Burst = 1.10

Therefore Burst Pressure = 697 * 1.10

= 766.7 kg/ cm2

Considering the performance of 7''casing from API tables.

Since 7 " casing size is required, except 26 ppf – K- 55 ,L – 80 , C – 95, 29 ppf – L -80 , C- 95, all the casings meets the requirements for burst.

Availability of 7" casing obtained from the ONGC RJY stores and data is as follows:

1	29 ppf	P-110	XL	5000 m
2	32 ppf	C-95	BTC	6800 m
3	32 ppf	P-110	BTC	7000 m

Taking consideration of cost factor from the available inventory 29 ppf P-110 is cheaper than other casings. Also the type of connection is XL which well suits for gas wells.

Checking for tension:-

Casing weight = 29 ppf

= 43.16 kg/ m

Total weight = 43.16 * 4100

= 176956 kg

let us consider total loss situation for lowering

buoyancy = 0

From the tables,

7", 29 ppf , P -110 yield strength = 422273

joint strength for XL connection = 410000

Since yield strength is greater than joint strength in this case safety factor is calculated with respect to joint strength

Therefore, safety factor = 410000/ 176956

= 2.3

The general safety factor considering for tension is 1.80

Therefore, 7" 29 ppf P -110 XL which is preferred for lowering is verified and safe for tension

Collapse

Lets us consider, while lowering the casing inside is dry, due to possibility of well being put on artificial lift and plugged perforation

However , from outside saline water always exists

Therefore collapse pressure at surface = 0

Collapse pressure at the shoe (4100m)= 1.03*4100/10

= 422.3 kg/cm2 (sp.gravity of saline water = 1.03)

From the performance properties of casing from API tables , 7" 29 ppf P – 110 XL collapse pressure is 599 kg/cm2

therefore safety factor = 599/422.3

= 1.41

general consideration for the collapse safety factor is 1.125

here 1.41(calculated) > 1.125(general)

therefore the preferred casing is verified

CHAPTER-VI

CONCLUSION

Casing design is a procedure of stress analysis which is used to produce a pressure vessel which can with stand a variety of external, internal, thermal and self weight loading. It is the key part and integral part of the total well design process. The ideal casing design of any well is that which is most economic over the entire life of the well without compromising environment and safety.

We analyzed that the production casing is being set through the prospective productive zones except in the case of open-hole completions. It is designed to resist the maximal shut –inn pressure of the producing formation and may be designed to withstand stimulating pressures during completion and work over operations. It provides protection for the environment at the time of failure of tubing string during production operations and it allows the production tubing for repairing and replacement. Production casing inside diameter will be in between 4 ½ in. to 9 5/8 in. It will be providing additional support for the sub surface equipment and also prevents the casing buckling by cementing far enough above the producing formations.

We designed production casing for 2 wells located in KG basin. It was mentioned in the given wells data that the casing should be a 7 " casing. As per the availability in the ONGC store and considering the economics 26 ppf N-80 XL and 29ppf P-110 XL were satisfying the requirements of the well-KPR-AA and Well MSAA respectively.

CHAPTER-VII

CASING CHARTS

Performance Properties of API casings

SIZE O.D.	WT. T&C	GRADE	COLLAPSE PRESSURE	BURST PRESSURE ROUND	BURST PRESSURE BUTT.	PIPE YIELD STRENGTH	JOINT TENSILE STRENGTH ROUND SHORT	ROUND LONG	BUTT.	X-LINE
in	ppf (kg/m)		psi (kg/cm²)	psi (kg/cm²)	psi (kg/cm²)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)
4 1/2"	9.5 (14.14)	K-55	3310 (233)	4380 (308)	—	152000 (69091)	112000 (50909)	—	—	—
	10.5 (15.63)	K-55	4010 (269)	4790 (337)	4790 (337)	166000 (75455)	146000 (66364)	—	249000 (113182)	—
	11.6 (17.26)	K-55	4960 (349)	5350 (377)	5350 (377)	184000 (83636)	170000 (77273)	180000 (81818)	277000 (125909)	—
		L-80	6350 (447)	7780 (548)	7780 (548)	267000 (121364)	—	212000 (96364)	291000 (132273)	—
		C-95	7010 (494)	9240 (651)	9240 (651)	317000 (144091)	—	234000 (106364)	325000 (147727)	—
		P-110	7560 (532)	10690 (753)	10690 (753)	367000 (166818)	—	279000 (126818)	385000 (175000)	—
	13.5 (20.09)	L-80	8540 (601)	9020 (635)	9020 (635)	307000 (139545)	—	257000 (116818)	334000 (151818)	—
		C-95	9650 (680)	10710 (754)	10710 (754)	364000 (165455)	—	284000 (129091)	374000 (170000)	—
		P-110	10670 (751)	12410 (874)	12410 (874)	422000 (191818)	—	338000 (153636)	443000 (201364)	—
	15.1 (22.47)	P-110	14320 (1008)	14420 (1015)	13460 (948)	485000 (220455)	—	406000 (184545)	509000 (231364)	—
		K-55	3060 (215)	4240 (299)	—	182000 (82727)	147000 (66818)	—	—	—
	13 (19.35)	K-55	4140 (292)	4870 (343)	4870 (343)	208000 (94545)	186000 (84545)	201000 (91364)	309000 (140455)	—
	15 (22.32)	K-55	5550 (391)	5700 (401)	5700 (401)	241000 (109545)	228000 (103636)	246000 (111818)	359000 (163182)	416000 (189091)
		L-80	7250 (511)	8290 (584)	8290 (584)	350000 (159091)	—	295000 (134091)	379000 (172273)	416000 (189091)
		C-95	8090 (570)	9840 (693)	9840 (693)	416000 (189091)	—	326000 (148182)	424000 (192727)	459000 (208636)
		P-110	8830 (622)	11400 (803)	11400 (803)	481000 (218636)	—	388000 (176364)	503000 (228636)	547000 (248636)
	18 (26.79)	L-80	10490 (739)	10140 (714)	9910 (698)	422000 (191818)	—	376000 (170909)	457000 (207727)	446000 (202727)
		C-95	12010 (846)	12040 (848)	11770 (829)	501000 (227727)	—	416000 (189091)	512000 (232727)	493000 (224091)
		P-110	13450 (947)	13940 (982)	13620 (959)	580000 (263636)	—	495000 (225000)	606000 (275455)	587000 (266818)

R.4.1 PERFORMANCE PROPERTIES OF API CASINGS (Contd.)

SIZE O.D.	WT. T&C	GRADE	COLLAPSE PRESSURE	BURST PRESSURE ROUND	BURST PRESSURE BUTT.	PIPE YIELD STRENGTH	JOINT TENSILE STRENGTH ROUND SHORT	JOINT TENSILE STRENGTH ROUND LONG	BUTT.	X-LINE
in	ppf (kg/m)		psi (kg/cm²)	psi (kg/cm²)	psi (kg/cm²)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)
5 1/2"	14 (20.83)	K-55	3120 (220)	4270 (301)	—	222000 (100909)	189000 (85909)	—	—	—
	15.5 (23.11)	K-55	4040 (285)	4810 (339)	4810 (339)	248000 (112727)	222000 (100909)	239000 (108636)	366000 (166364)	429000 (195000)
	17 (25.30)	K-55	4910 (346)	5320 (375)	5320 (375)	273000 (124091)	252000 (114545)	272000 (123636)	402000 (182727)	471000 (214091)
		L-80	6280 (442)	7740 (545)	7740 (545)	397000 (180455)	—	338000 (153636)	428000 (194545)	471000 (214091)
		C-95	6930 (488)	9190 (647)	9190 (647)	471000 (214091)	—	374000 (170000)	480000 (218182)	521000 (236818)
		P-110	7460 (525)	10640 (749)	10640 (749)	546000 (248182)	—	445000 (202273)	568000 (258182)	620000 (281818)
	20 (29.75)	L-80	8830 (622)	9190 (647)	9190 (647)	466000 (211818)	—	416000 (189091)	503000 (228636)	497000 (225909)
		C-95	10000 (704)	10910 (768)	10910 (768)	554000 (251818)	—	460000 (209091)	563000 (255909)	549000 (249545)
		P-110	11080 (780)	12640 (890)	12640 (890)	641000 (291364)	—	548000 (249091)	667000 (303182)	654000 (297273)
	23 (34.23)	L-80	11160 (786)	10560 (744)	10560 (744)	530000 (240909)	—	489000 (222273)	550000 (250000)	549000 (249545)
		C-95	12820 (910)	12540 (883)	12540 (883)	630000 (286364)	—	540000 (245455)	608000 (276364)	606000 (275455)
		P-110	14520 (1023)	14520 (1023)	14520 (1023)	729000 (331364)	—	643000 (292273)	724000 (329091)	722000 (328182)
6 5/8"	20 (29.76)	K-55	2970 (209)	4180 (294)	4180 (294)	315000 (143182)	287000 (121984)	290000 (131818)	—	—
	24 (35.72)	K-55	4560 (321)	5110 (360)	5110 (360)	382000 (173636)	342000 (155455)	372000 (169091)	548000 (249091)	605000 (275000)
		L-80	5760 (406)	7440 (524)	7440 (524)	555000 (252273)	—	473000 (215000)	592000 (269091)	605000 (275000)
		C-95	6290 (443)	8830 (622)	8830 (622)	659000 (299545)	—	546000 (248182)	665000 (302273)	668000 (303636)
		P-110	6710 (473)	10230 (720)	10280 (720)	763000 (346818)	—	641000 (291364)	786000 (357273)	796000 (361818)
	28 (41.67)	L-80	8170 (575)	8810 (620)	8810 (620)	651000 (295909)	—	576000 (261818)	693000 (315000)	648000 (294545)
		C-95	9200 (648)	10460 (737)	10460 (737)	773000 (351364)	—	665000 (302273)	780000 (354545)	716000 (325455)
		P-110	10140 (714)	12120 (854)	12120 (854)	895000 (406818)	—	781000 (355000)	922000 (419091)	852000 (387273)

SIZE O.D.	WT. T&C	GRADE	COLLAPSE PRESSURE	BURST PRESSURE ROUND	BURST PRESSURE BUTT.	PIPE YIELD STRENGTH				
in	ppf (kg/m)		psi (kg/cm²)	psi (kg/cm²)	psi (kg/cm²)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)
6 5/8"	32 (47.62)	L-80	10320 (727)	10040 (707)	9820 (692)	734000 (333636)	—	666000 (302727)	783000 (355909)	717000 (325909)
		C-95	11800 (831)	11920 (839)	11660 (817)	872000 (396364)	—	769000 (349545)	880000 (400000)	793000 (360455)
		P-110	13200 (930)	13800 (972)	13500 (951)	1009000 (458636)	—	904000 (410909)	1040000 (472727)	944000 (429091)
7"	26 (38.69)	K-55	4320 (304)	4980 (351)	4980 (351)	415000 (188636)	364000 (165455)	401000 (182273)	592000 (269091)	641000 (291364)
		N-80	5410 (381)	7240 (510)	7240 (510)	604000 (274545)	—	511000 (232273)	641000 (291364)	641000 (291364)
		C-95	5870 (413)	8600 (606)	8600 (606)	717000 (325909)	—	593000 (269545)	722000 (328182)	709000 (322273)
	29 (43.16)	N-80	7020 (494)	8160 (575)	8160 (575)	676000 (307273)	—	587000 (266818)	718000 (326364)	685000 (311364)
		C-95	7820 (551)	9690 (682)	9690 (682)	803000 (365000)	—	683000 (310455)	808000 (367273)	757000 (344091)
		P-110	8510 (599)	11220 (790)	11220 (790)	929000 (422273)	—	797000 (362273)	955000 (434091)	902000 (410000)
	32 (47.62)	L-80	8600 (606)	9060 (638)	8460 (596)	745000 (338636)	—	661000 (300455)	791000 (359545)	850000 (386364)
		C-95	9730 (685)	10760 (758)	10050 (708)	885000 (402273)	—	768000 (349091)	891000 (405000)	841000 (382273)
		P-110	10760 (758)	12460 (877)	11640 (820)	1025000 (465909)	—	897000 (407727)	1053000 (478636)	1002000 (455455)
	35 (52.09)	L-80	10180 (717)	9960 (701)	8460 (596)	814000 (370000)	—	734000 (333636)	833000 (378636)	850000 (386364)
		C-95	11640 (820)	11830 (833)	10050 (708)	966000 (439091)	—	853000 (387727)	920000 (418182)	940000 (427273)
		P-110	13010 (916)	13700 (965)	11640 (820)	1119000 (508636)	—	996000 (452727)	1096000 (498182)	1118000 (508182)
	29.7 (44.20)	L-80	4790 (337)	6890 (485)	6890 (485)	683000 (310455)	—	566000 (257273)	721000 (327727)	700000 (318182)
		C-95	5120 (361)	8180 (576)	8180 (576)	811000 (368636)	—	659000 (299545)	813000 (369545)	774000 (351818)
		P-110	5340 (376)	9470 (667)	9470 (667)	940000 (427273)	—	769000 (349545)	960000 (436364)	922000 (419091)
	33.7 (50.15)	L-80	6560 (462)	7900 (556)	7900 (556)	778000 (353636)	—	664000 (301818)	820000 (372727)	766000 (348182)
		C-95	7260 (511)	9380 (661)	9380 (661)	923000 (419545)	—	772000 (350909)	925000 (420455)	846000 (384545)
		P-110	7850 (553)	10860 (765)	10860 (765)	1069000 (485909)	—	901000 (409545)	1093000 (496818)	1008000 (458182)

R.4.1 PERFORMANCE PROPERTIES OF API CASINGS (Contd.)

SIZE O.D.	WT. T&C	GRADE	COLLAPSE PRESSURE	BURST PRESSURE ROUND	BURST PRESSURE BUTT.	PIPE YIELD STRENGTH	JOINT TENSILE STRENGTH ROUND SHORT	JOINT TENSILE STRENGTH ROUND LONG	JOINT TENSILE STRENGTH BUTT.	JOINT TENSILE STRENGTH X-LINE
in	ppf (kg/m)		psi (kg/cm^2)	psi (kg/cm^2)	psi (kg/cm^2)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)
$7\,^5/_8$"	39 (58.04)	L-80	8810 (620)	9180 (646)	9180 (646)	895000 (406818)	—	786000 (357273)	945000 (429545)	851000 (386818)
		C-95	9980 (703)	10900 (768)	10900 (768)	1063000 (483182)	—	914000 (415455)	1065000 (484091)	941000 (427727)
		P-110	11060 (779)	12620 (889)	12620 (889)	1231000 (559545)	—	1066000 (484545)	1258000 (571818)	1120000 (509091)
	42.8 (63.69)	C-75	10240 (721)	9670 (681)	9190 (647)	935000 (425000)	—	852000 (387273)	1035000 (470455)	—
		L-80	10810 (761)	10320 (727)	9790 (689)	998000 (453636)	—	892000 (405455)	1053000 (478636)	—
		C-95	12400 (873)	12250 (863)	11620 (818)	1185000 (538636)	—	1037000 (471364)	1187000 (539545)	—
		P-110	13910 (980)	14190 (1000)	13460 (948)	1372000 (623636)	—	1210000 (550000)	1402000 (637273)	—
	47.1 (70.09)	C-75	11290 (795)	10760 (758)	9190 (647)	1031000 (468636)	—	953000 (433182)	1140000 (518182)	—
		L-80	12040 (848)	11480 (808)	9790 (689)	1100000 (500000)	—	997000 (453182)	1160000 (527273)	—
		C-95	14300 (1007)	13630 (960)	11620 (818)	1306000 (593636)	—	1159000 (526818)	1300000 (590909)	—
		P-110	16550 (1165)	15780 (1111)	13460 (948)	1512000 (687273)	—	1353000 (615000)	1545000 (702273)	—
$9\,^5/_8$"	43.5 (64.75)	L-80	3810 (268)	6330 (446)	6330 (446)	1005000 (456818)	—	813000 (369545)	1038000 (471818)	975000 (443182)
		C-95	4130 (291)	7510 (529)	7510 (529)	1193000 (542273)	—	948000 (430909)	1178000 (535455)	1078000 (490000)
		P-110	4430 (312)	8700 (613)	8700 (613)	1381000 (627727)	—	1106000 (502727)	1388000 (630909)	1283000 (583182)
	47 (69.95)	L-80	4750 (335)	6870 (484)	6870 (484)	1086000 (493636)	—	893000 (405909)	1122000 (510000)	1032000 (469091)
		C-95	5080 (358)	8150 (574)	8150 (574)	1289000 (585909)	—	1040000 (472727)	1273000 (578636)	1411000 (641364)
		P-110	5310 (374)	9440 (665)	9440 (665)	1493000 (678636)	—	1213000 (551364)	1500000 (681818)	1358000 (617273)
	53.5 (79.62)	L-80	6620 (466)	7930 (558)	7930 (558)	1244000 (565455)	—	1047000 (475909)	1286000 (584545)	1173000 (533182)
		C-95	7330 (516)	9410 (663)	9410 (663)	1477000 (671364)	—	1220000 (554545)	1458000 (662727)	1297000 (589545)
		P-110	7930 (558)	10900 (768)	10900 (768)	1710000 (777273)	—	1422000 (646364)	1718000 (780909)	1544000 (701818)

R.4.1 PERFORMANCE PROPERTIES OF API CASINGS (Contd.).

SIZE O.D.	WT. T&C	GRADE	COLLAPSE PRESSURE	BURST PRESSURE		PIPE YIELD STRENGTH	JOINT TENSILE STRENGTH			
				ROUND	BUTT.		ROUND SHORT	ROUND LONG	BUTT.	X-LINE
in	ppf (kg/m)		psi (kg/cm²)	psi (kg/cm²)	psi (kg/cm²)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)	lbs (kgs)
10 3/4"	45.5 (67.71)	K-55	2090 (147)	3580 (252)	3580 (252)	715000 (325000)	528000 (240000)	—	931000 (423182)	1236000 (561818)
	51 (75.90)	K-55	2700 (190)	4030 (284)	4030 (284)	801000 (364091)	606000 (275455)	—	1043000 (474091)	1383000 (628636)
		L-80	3220 (227)	5860 (413)	5860 (413)	1165000 (529545)	794000 (360909)	—	1190000 (540909)	1383000 (628636)
		C-95	3490 (246)	6960 (490)	6960 (490)	1383000 (628636)	927000 (421364)	—	1354000 (615455)	1529000 (695000)
		P-110	3870 (258)	8060 (568)	8060 (568)	1602000 (728182)	1080000 (490909)	—	1594000 (724545)	1820000 (827273)
	55.8 (83.04)	L-80	4020 (243)	6450 (454)	6450 (454)	1276000 (580000)	884000 (401818)	—	1303000 (592273)	1515000 (688636)
		C-95	4300 (303)	7660 (539)	7660 (539)	1515000 (688636)	1092000 (469091)	—	1483000 (674091)	1675000 (761364)
		P-110	4630 (326)	8860 (624)	8860 (624)	1754000 (797273)	1203000 (546818)	—	1745000 (793182)	1993000 (90591)
13 3/8"	61 (90.78)	K-55	1540 (108)	3090 (218)	3090 (218)	962000 (437273)	633000 (287727)	—	1169000 (531364)	—
	68 (101.20)	K-55	1950 (137)	3450 (243)	3450 (243)	1069000 (485909)	718000 (326364)	—	1300000 (590909)	—
	72 (107.15)	L-80	2670 (188)	5380 (379)	5380 (379)	1661000 (755000)	1029000 (467727)	—	1650000 (750000)	—
		C-95	2820 (199)	6390 (450)	6390 (450)	1973000 (896818)	1204000 (547273)	—	1893000 (860455)	—
20"	94 (139.89)	K-55	520 (37)	2110 (149)	2110 (149)	1480000 (672727)	824000 (374545)	955000 (434091)	1479000 (672273)	—
	106.1 (157.90)	K-55	770 (54)	2410 (170)	2410 (170)	1685000 (765909)	960000 (436364)	1113000 (505909)	1683000 (765000)	— —
	133 (197.93)	K-55	1500 (106)	3060 (215)	3060 (215)	2125000 (965909)	1253000 (569545)	1453000 (660455)	2123000 (965000)	—

CHAPTER-VIII

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