DESIGN OF SURFACE FACILITIES FOR A RESERVOIR FLUID

THESIS

SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENT FOR THE AWARD OF THE DEGREE OF

MASTER OF TECHNOLOGY

(Gas Engineering)

SUBMITTED BY

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DEHRADUN

MAY 2010

CANDIDATE'S DECLARATION

I hereby declare that the work which is being presented in the thesis entitled "DESIGN OF SURFACE FECILITIES FOR A RESERVOIR FLUID" by "SARATH CHANDRA KANDULA" in partial fulfillment of requirements for the award of degree of M. Tech. (Gas Engineering) submitted in the Department of Chemical Engineering at UNIVERSITY OF PETROLEUM & ENERGY STUDIES, DEHRADUN is an authentic record of my own work carried out under the supervision of Asst Prof. CH. VARA PRASAD. The matter presented in this thesis has not been submitted by me in any other University / Institute for the award of M. Tech Degree. *Due to the confidentiality of data, the original name, location and identity of the data has been changed.*

K. Sarath

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This is to certify that the above statement made by the candidate is correct to the best of my/our knowledge

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The M.Tech Viva–Voce Examination of Sarath Chandra Kandula has been held on 08-05-10 and accepted.

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This is to certify that the project work entitled "DESIGN OF SURFACE FACILITIES FOR A RESERVOIR FLUID" being submitted by Mr. SARATH CHANDRA KANDULA (R030308016), in partial fulfillment of the requirement for the award of the degree of Master of Technology [Gas Engineering] in University of Petroleum and Energy Studies-Dehradun, is a bonafide project work carried out by him under my guidance.

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ABSTRACT

With the advent of new technology, oil industry started developing high pressure reservoirs which are mostly offshore in nature, but this pressure will decline with respect to time which has to be considered for the design of surface equipments which makes the design complicated.

Mostly of the reservoirs don't produce an appreciable amount of water content at the early stages, but the surface facility designer has to consider the future water flux for separation. Now a days the pipe line gas specification are becoming very typical particularly in case of water content and these all lead to a complication in the design of surface facilities in order to meet the industry requirement.

With these complications, optimization of production operations is considered as a major factor to achieve required production rates at an economical production costs.

Considering the above problems prevailing in the industry, I aimed at designing surface facilities of particular reservoir fluid.

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NOMENCLATURE

A	choke area
B_g	gas formation volume factor
B_o	oil formation volume factor
C_t	total compressibility
C_D	chokes discharge co-efficient
D_n	non Darcy co-efficient
D	diameter of separator
d_I	choke inner diameter
d_2	tubing inner diameter
f_F	fanning friction factor
F_f	moody friction factor
g	acceleration due to gravity
g_g	unit conversion factor
H	height of separator
h	pay zone thickness
k	specific heat ratio
k_i	liquid vapour equilibrium ratio
K	permeability
MW_i	molecular weight of component
MW_a^l	apparent molecular weight of liquid
MW_a^v	apparent molecular weight of vapor
n_l	no of moles of fluid in liquid phase
n_v	no of moles of fluid in vapor phase
N_{RE}	Reynolds number

P_{ci}	critical pressure of component
P_{pc}	pseudo critical pressure
P_{wf}	flowing bottom hole pressure
P_i	reservoir pressure
P_{hf}	flowing head pressure
P_{outlet}	chokeoutletpressure
ΔP	pressure drop at choke
Q	deliverability of reservoir
r_w	well bore radius
r_e	drainage radius
R_s	gas solubility
S	skin factor
T_{ci}	critical temperature of component
T_{pc}	pseudo critical temperature
T_{wf}	flowing bottom hole temperature
T_i	reservoir temperature
T_{hf}	flowing head temperature
T_{outlet}	choke out let temperature
T_b	boiling point temperature
U	fluid velocity
V_L	liquid phase volume
V_{VS}	vapor phase volume
y_i	mole fraction
Z	gas compressibility factor
$\square_o$	Specific gravity of oil

$\square_g$	Specific gravity of gas
μ	Viscosity
μ_l	corrected gas viscosity
μ_g	gas viscosity
μ_o	oil viscosity
ρ_o	density of oil
ρ_g	density of gas
Φ	porosity

TABLE OF CONTENTS

LIST OF FIGURES

TABLE OF CONTENTS

CHAPTER-1

1. INTRODUCTION

The job of a production facility is to separate the well stream into three components, typically called "phases" (oil, gas, and water), and process these phases into some marketable product(s) or dispose of them in an environmentally acceptable manner. In mechanical devices called "separators" gas is flashed from the liquids and "free water" is separated from the oil. These step's remove enough light hydrocarbons to produce a stable crude oil with the volatility meet sales criteria. The gas that is separated must be compressed and treated for sales. Compression is typically done by engine-driven reciprocating compressors. Large integral reciprocating compressors are also used. The separated gas is saturated with water vapor and must be dehydrated to an acceptable level (normally less than 7 Ib/MMscf). Usually this is done in a glycol dehydrator.

Dry glycol is pumped to the large vertical contact tower where it strips the gas of its water vapor. The wet glycol then flows through a separator to the large horizontal re boiler where it is heated and the water boiled off as steam. In some locations it may be necessary to remove the heavier hydrocarbons to lower the hydrocarbon dew point. Contaminants such as H2S and

CO2 may be present at levels higher than those acceptable to the gas purchaser. If this is the case, then additional equipment will be necessary to "sweeten" the gas. The oil and emulsion from the separators must be treated to remove water. Most oil contracts specify a maximum percent of basic sediment and water (BS and W) that can be in the crude. This will typically vary from 0.5% to 3% depending on location. Some refineries have a limit on salt content in the crude, which may require several stages of dilution with fresh water and subsequent treating to remove the water. Typical salt limits are 10 to 25 pounds of salt per thousand barrels.

These can be either horizontal or vertical in configuration and are distinguished by the fire tube, air intakes, and exhausts that are clearly visible. Teeters can be built without fire tubes, which make them, look very much like separators. Oil treating can also be done by settling or in gun barrel tanks, which have either external or internal gas boots.

Production facilities must also accommodate accurate measuring and sampling of the crude oil. This can be done automatically with a Lease Automatic Custody Transfer (LACT) unit or by gauging in a calibrated tank.

1.1 PRODUCTION OPERATIONS INVOLVED

A company with a successful discovery, which is large enough to motivate a field development, is usually required to apply for a production license from the resource owner. Thus, the exploration license is converted to a production license. This usually requires a submission of a field development plan containing, among others, a time schedule from project start to first oil, information on production levels, field development method and environmental impact. When the field development plan is sanctioned by the resource owner, the work towards first oil production starts.

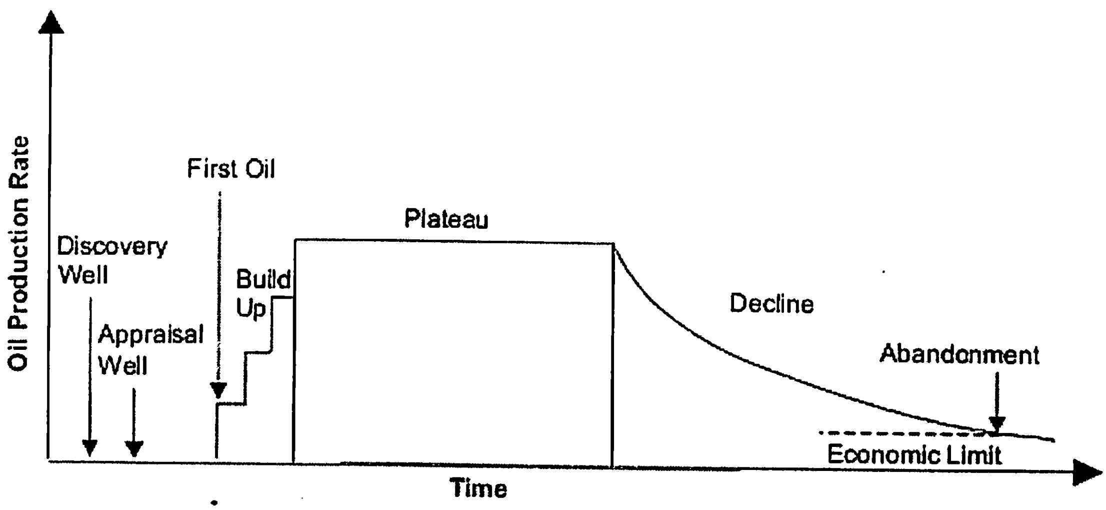

Figure-1: well production curve

The period from the start of continuous production until the field abandonment, is referred to as the development and production phase. After first oil there is a build up phase with the aim of reaching the designed plateau production. The production profile is to a large extent dependent on the characteristics of the reservoir and its fluids, such as pressure and permeability. Moreover, it also governs the design of the production system used to get the produced fluids from the reservoir to the surface.

The production system can be divided into five parts.

1. Reservoir
2. Wellbore
3. Production conduit (tubing)
4. Surface installations (wellhead, Christmas tree, flow line and choke)
5. Separator

An unproduced reservoir contains fluids (oil and/or gas and/or water) in the pore space, usually at high pressure. When a well is drilled into the reservoir, the stored energy in the compressed fluids allows the fluid to flow toward the wellbore. As long as the pressure in the reservoir will lift the fluids to the surface, the well is natural flowing. In addition to pressure, the flow is governed by the viscosity of the oil (μ) and the properties of the following reservoir parameters: permeability (k), porosity (φ), and pore compressibility (c).

At some point during the production time, the pressure declines to a level where the fluids cannot reach the surface. In this case, supporting energy must be supplied by some kind of pump and the well is said to be artificial lift operated. The reservoir fluid then flow through the production tubing and reaches the surface equipment.

The wellhead is an equipment assembly placed on top of a well to safeguard against uncontrolled flow of oil and/or gas, i.e. a blow-out. On top of the wellhead is a so called Christmas tree, an assembly of pipes and valves where the produced fluids leave the well and enter the flow line.

A choke is installed on the flow line to provide stable conditions before the separator. In the separator, the produced fluids are separated to each phase and then stored, sold or used. The production results in a pressure depletion process in the reservoir. This is a dynamic process and the fluid remaining in the reservoir will change both in terms of its volume, flow properties and in some cases its composition. The response of the reservoir is to compensate for the produced fluids by compaction of the reservoir rock and/or expansion of any of the fluids present in the reservoir or underlying water bearing rocks, so called aquifers. The compensation of the withdrawn fluids is the reservoir drive mechanism and it has certain typical performance characteristics in terms of:

- Ultimate recovery factor
- Pressure decline rate
- Gas-oil ratio (GOR)
- Water production

CHAPTER-2

2. PRODUCTION SYSTEMS

2.1 RESERVOIR

A reservoir is formed of one or more subsurface rock formations containing liquid and gaseous hydrocarbons, of sedimentary origin with very few exceptions. The reservoir rock is pours and permeable, and the structure is bounded by impermeable barriers which trap the hydrocarbons reservoirs. The vertical arrangement of the fluid in the structure is governed by gravitational force. Figure 1 shows a across-section of atypical hydrocarbon reservoir.

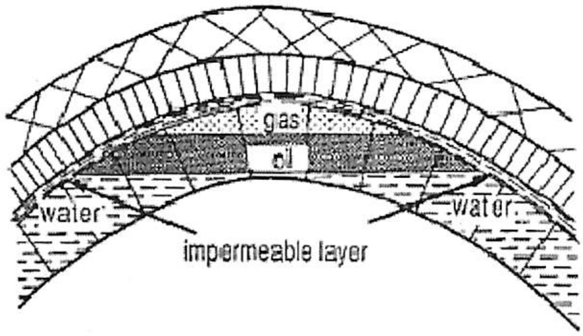

Figure-2: reservoir

The reserve from the reservoir can be extracted by different drive mechanisms' these drives are occurred depending on the formation of the reservoir. Below is a short description of each of the reservoir drive mechanisms

2.1.1 VOLUMETRIC EXPANSION DRIVE

The simplest form of reservoir drive occurs when the reservoir pressure is above the oil's bubble point, the oil is under saturated. The removal of oil from the reservoir is compensated by expansion of the oil left in place, i.e. the pressure drops. As long as the reservoir pressure is above the bubble point, the expansion of the oil is the only drive mechanism. Continued production will eventually lead the pressure to drop to a level below the bubble point. Only a small percentage of the oil in place is recovered by volumetric expansion drive.

2.1.2 SOLUTION GAS DRIVE

The production of a reservoir where the pressure is below the oil's bubble point will result in gas bubbles coming out of solution. As the pressure drop continues, both the gas and oil phases will expand in the reservoir which is the drive mechanism for the reservoir. Gas will come out of solution everywhere in the reservoir where the pressure is below the bubble point. However, the gas will be concentrated in low pressure areas such as close to the wellbore. A rapid decline in the reservoir pressure is usually observed. The GOR will increase rapidly as soon as the gas saturation allows free gas to move to the wellbore. If the vertical permeability is good, a secondary gas cap can be built up due to gravitational forces. The ultimate recovery factor varies from 5 to 30 per cent, which suggests that a lot of oil is left in the reservoir. Consequently, solution gas drive reservoirs are good candidates for secondary recovery methods.

2.1.3 GAS CAP EXPANSION DRIVE

In a reservoir where both oil and gas zones exist, i.e. the reservoir pressure is equal to or below the bubble point of the Oil, gas will migrate upwards to form a gas cap. The production will result in an expansion of the gas cap and expansion of the solution gas as it is liberated. The pressure decline will in general be slow, due to the expansion capacity of the gas cap. However, this depends on the size of the gas cap and its relative size to the oil volume. A steady increase in the GOR is usually observed. The recovery factor for a gas cap reservoir can be expected to be in the interval 20 to 40 per cent.

2.1.4 INFLUX WATER DRIVE

It is common that reservoirs are bounded by aquifers. Their size compared to the oil volume varies from very large to negligible. When oil is removed from the reservoir during production, the water from the aquifer moves into the pore space which previously was occupied by oil and in this way replace the oil. If the aquifer is large compared to the oil volume the pressure decline is usually very gradual. As production continues the oil-water level (OWL) will gradually rise. However, it is only in very uniform reservoirs the OWL will raise in an even way. The water will eventually reach a producing zone and cause water break-through and consequently, production of both oil and water. The fluid production is often stable but with increasing part water and decreasing part oil during the lifetime, i.e. the water cut increases. If there is a drop in pressure, the drop is slow and thus the GOR in water drive reservoirs is usually stable. The recovery factor is very high, according to Ahmed (2001) up to 75 per cent while Selley (1998) has it to 60 per cent.

2.1.5 COMPACTION DRIVE

The pressure depletion caused by fluid production from a reservoir will in some cases be compensated by a compaction of the reservoir due to the overburden of the overlying layers. To some limited extent, compaction is present in all reservoirs, but usually with no measurable effects. For example, the giant Ekofisk oil field in the Norwegian part of the North Sea is an example where the reservoir compaction was measured in meters.

2.1.6 COMBINATION DRIVE

The most common type of reservoir drive is a combination of the drive mechanisms mentioned above. The combination of free gas and an aquifer is most encountered. The response to production of oil is less predictable in a combination drive reservoir.

2.2 WELL BORE

When a well is drilled the fluid will attain the kinetic energy due to the difference in the pressure between reservoir and the surface and an accumulation of the reserve will accrue at the bottom of the well this will allow the fluid to flow up to the surface.

The recovery of oil from any of the reservoir drive mechanisms is called primary oil recovery. Secondary recovery, on the other hand, is when a fluid is injected into the reservoir in order to increase production and recovery. Below is a short description of each of the recovery mechanisms.

2.2.1 PRIMARY RECOVERY

During the primary recovery stage, reservoir drive comes from a number of natural mechanisms. These include: natural water displacing oil upward into the well, expansion of the natural gas at the top of the reservoir, expansion of gas initially dissolved in the crude oil, and gravity drainage resulting from the movement of oil within the reservoir from the upper to the lower parts where the wells are located. Recovery factor during the primary recovery stage is typically 5-15%. While the underground pressure in the oil reservoir is sufficient to force the oil to the surface all that is necessary is to place a complex arrangement of valves on the well head to connect the well to a pipeline network for storage and processing.

2.2.2 SECONDARY RECOVERY

Over the lifetime of the well the pressure will fall, and at some point there will be insufficient underground pressure to force the oil to the surface. After natural reservoir drive diminishes, secondary recovery methods are applied. They rely on the supply of external energy into the reservoir in the form of injecting fluids to increase reservoir pressure, hence replacing or increasing the natural reservoir drive with an artificial drive. Sometimes pumps, such as beam pumps and electrical submersible pumps (ESPs), are used to bring the oil to the surface. Other secondary recovery techniques increase the reservoir's pressure by water injection, natural gas reinjection and gas lift, which inject air, carbon dioxide or some other gas into the reservoir. Typical recovery factor from water-flood operations is about 30%, depending on the properties of oil and the characteristics of the reservoir rock. On average, the recovery factor after primary and secondary oil recovery operations is between 30 and 50%.

2.2.3 TERTIARY RECOVERY

Tertiary oil recovery reduces the oil's viscosity to increase oil production. Thermally enhanced oil recovery methods (TEOR) are tertiary recovery techniques that heat the oil and make it easier to extract. Steam injection is the most common form of TEOR, and is often done with a cogeneration plant. In this type of cogeneration plant, a gas turbine is used to generate electricity and the waste heat is used to produce steam, which is then injected into the reservoir. This form of recovery is used extensively to increase oil production in the San Joaquin Valley, which has very heavy oil, yet accounts for 10% of the United States' oil production. In-situ burning is another form of TEOR, but instead of steam, some of the oil is burned to heat the surrounding oil. Occasionally, detergents are also used to decrease oil viscosity as a tertiary oil recovery method. Another method to reduce viscosity is carbon dioxide flooding. Tertiary recovery allows another 5% to 15% of the reservoir's oil to be recovered. Tertiary recovery begins when secondary oil recovery isn't enough to continue adequate production, but only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the current price of crude oil. When prices are high, previously unprofitable wells are brought back into production and when they are low, production is curtailed.

2.3 PRODUCTION CONDUCT

Most oil wells produce reservoir fluids through tubing strings. This is mainly because tubing strings provide good sealing performance and allow the use of gas expansion to lift oil. Gas wells produce gas through tubing strings to reduce liquid loading problems. Tubing strings are designed considering tension, collapse, and burst loads under various well operating conditions to prevent loss of tubing string integrity including mechanical failure and deformation due to excessive stresses and buckling. The API defines ''tubing size'' using nominal diameter and weight (per foot). The nominal diameter is based on the internal diameter of tubing body. The weight of tubing determines the tubing outer diameter. Steel grades of tubing are designated to H-40, J-55, C-75, L-80, N-80, C-90, and P-105, where the digits represent the minimum yield strength in 1,000 psi.

2.4 SURFACE INSTALLATIONS

Various combinations of well head, charismas tree, and choke are installed to control the flow of the fluid coming from the reservoir. The main purpose of this equipment installation is to control the flow and to protect the reservoir from getting damaged by uncontrolled flow of fluid which results in the damage of the wellbore due to water drive and sand accumulation at wellbore.

These problems can be overcome by applying the back pressure on the wellbore by using choke and other installations at the surface of the well. The main equipment used to achieve the controlled flow is.

- Wellhead
- Charismas tree
- Choke

2.4.1 WELLHEAD

The main purpose of a wellhead is to provide a pressure barrier connecting the casing strings that run from the bottom of the hole sections to the surface pressure control equipment.

A wellhead serves numerous functions. Some of these are:

- Means of casing suspension. (Casing is the permanently installed pipe used to line the well hole for pressure containment, collapse prevention, etc.)
- Means of casing pressure isolation when multiple casing strings are used
- Means of attaching a blowout preventer during drilling
- Means of attaching a tree for well control during production, injection, or other operations
- Means of well access
- Means of pump attachment
- Means of tubing suspension (Tubing is removable pipe installed in the well)

The basic requirements for materials, dimensions, test procedures and pressure ratings for wellheads and wellhead equipment are defined on API Spec 6A: Specification for Wellhead and Christmas Tree Equipment. Wellheads are cemented in place and are generally permanently kept in place, although in exploration wells they may be recovered for use again.

2.4.2 CHARISMAS TREE

This is the main assembly of valves that controls flow from the well to the process plant (or the other way round for injection wells) and allows access for chemical squeezes and well interventions.

The typical accruement of a charismas tree are shown in the figure-3

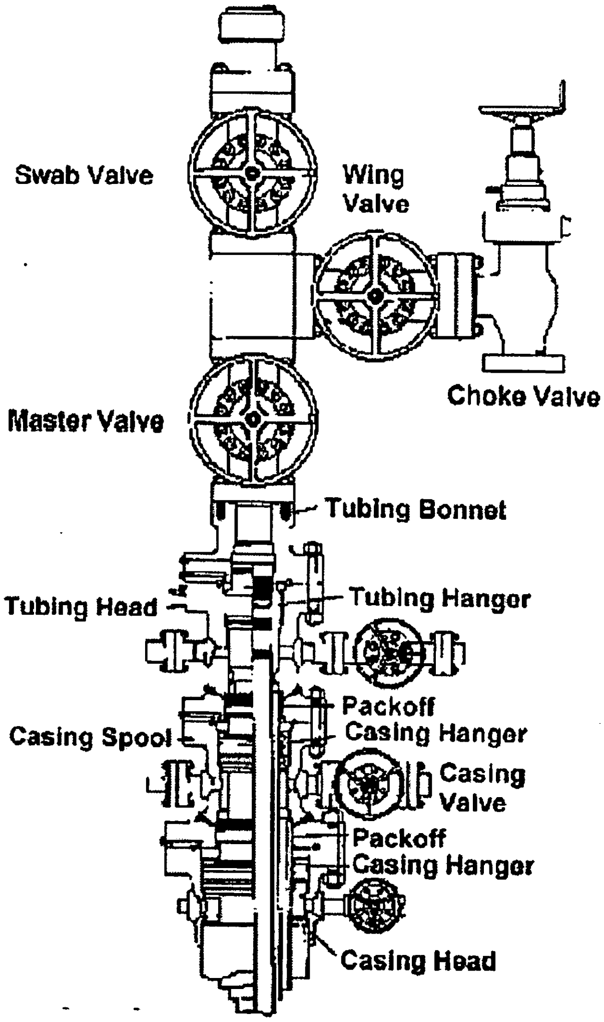

Figure-3: charismas' tree

2.4.3 CHOKE

Wellhead chokes are used to limit production rates for regulations, protect surface equipment from slugging, avoid sand problems due to high drawdown, and control flow rate to avoid water or gas coning. Two types of wellhead chokes are used. They are

Positive (fixed) chokes

Adjustable chokes.

Placing a choke at the wellhead means fixing the wellhead pressure and, thus, the flowing bottom-hole pressure and production rate. Pressure equations for gas flow through a choke are derived based on an isentropic process. This is because there is no time for heat to transfer and the friction loss is negligible at chokes. In addition to the concern of pressure drop across the chokes, temperature drop associated with choke flow is also an important issue for pure gas wells, because hydrates may form that may plug flow lines.

2.5 SEPARATOR

At the high pressure existing at the bottom of the producing well, crude oil contains great quantities of dissolved gases. When crude oil is brought to the surface, it is at a much lower pressure. Consequently, the gases that were dissolved in it at the higher pressure tend to come out from the liquid. Some means must be provided to separate the gas from oil without losing too much oil.

In general, well effluents flowing from producing wells come out in two phases: vapor and liquid under a relatively high pressure. The fluid emerges as a mixture of crude oil and gas that is partly free and partly in solution. Fluid pressure should be lowered and its velocity should be reduced in order to separate the oil and obtain it in a stable form. This is usually done by admitting the well fluid into a gas–oil separator plant (GOSP) through which the pressure of the gas–oil mixture is successively reduced to atmospheric pressure in a few stages.

Upon decreasing the pressure in the GOSP, some of the lighter and more valuable hydrocarbon components that belong to oil will be unavoidably lost along with the gas into the vapor phase. This puts the gas–oil separation step as the initial one in the series of field treatment operations of crude oil. Here, the primary objective is to allow most of the gas to free itself from these valuable hydrocarbons, hence increasing the recovery of crude oil.

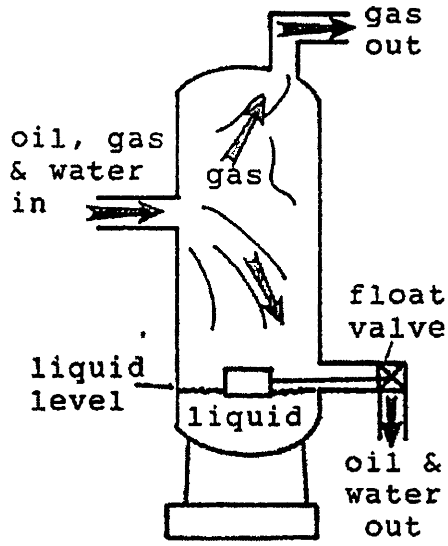

Figure-4 two phase separator

Compression of advantages and disadvantages of all three types of the separator

Condition	Horizontal	vertical	sphear
efficiency of separator	1	2	3
stabilization of separated fluid	1	2	3
adaptability of varying conditions	1	2	3
flexibility of operation	2	1	3
Capacity	1	2	3
cost per unit capacity	1	2	3
ability to handle foreign material	3	1	2
adaptability to portable use	1	2	3
space required for installation	1	3	2
vertical plane	1	3	2
horizontal plane	3	1	2
ease of installation	2	3	1
ease of inspection and maintenance	1	3	2

Table-1comparision of seperators

CHAPTER-3

3. CASE STUDY

The well is situated in the SAR-1 reservoir. The reservoir is silt stone with intercalation of shale, gray in color, moderately hard with specks of mica and carbonaceous matter. The matrix porosity is about 14% to 18.5% and absolute permeability of rock varies between 1to 4 md as estimated from core sample of well.

Initial testing of the well is done by installing an EPS system and the following parameters are calculated.

Before designing the facilities required, the analysis of the reservoir is to be done and the actual current situation of the reservoir has to be determined and from the reservoir conditions that are obtained from this study has been considered for the design of the surface facilities design.

3.1 WELL DETAILS

Reservoir data

Reservoir pressure	205.9 Kg/cm^2
Reservoir temperature	110 ^0C
Effective permeability	0.35 md
Average porosity	15 %
API gravity	44.5
Skin factor	1.26
GOR	570 v/v
Drainage radius	1000 ft
Well radius	0.125 m
Pay zone thickness	25 m
Productivity index	$0.028M^3/d/kg/cm^2$
Well depth	1768.5m

Reservoir fluid composition:

Component	Mole fraction
C_1	0.6599
C_2	0.0869
C_3	0.0591
$i\text{-}C_4$	0.0239
$n\text{-}C_4$	0.0278
$i\text{-}C_5$	0.0157
C_6	0.181
C_7	0.0601
N_2	0.0194
Co_2	0.0121
H_2S	0.0058

Well profile

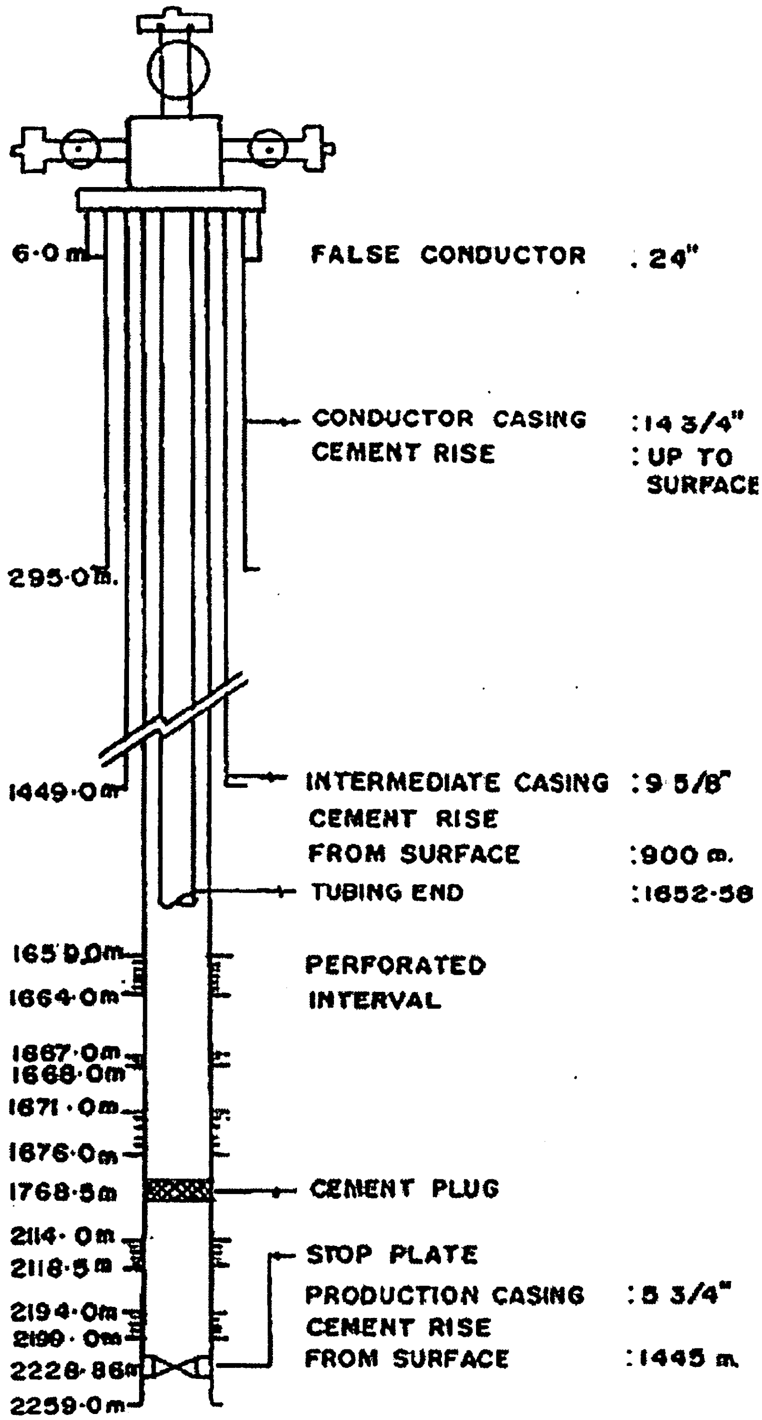

Figure-6 Well profile.

3.2 DETERMINATION OF RESERVOIR CHARACTERISTICS

From the above details of the reservoir the present situation of the reservoir such as bottom hole pressure, well head pressure, size of choke, well fluid condition and operating pressure and temperatures of the systems to be designed are determined.

3.2.1 GAS PROPERTIES CALCULATION AT RESERVOIR CONDITIONS

Gas Composition (mol-fraction)		
C_1	=	0.6599
C_2	=	0.0869
C_3	=	0.0591
i-C_4	=	0.0239
n-C_4	=	0.0278
i-C_5	=	0.0112
n-C_5	=	0.0157
C_6	=	0.181
C_{7+}	=	0.0601
N_2	=	0.0194
CO_2	=	0.0121
H_2S	=	0.0058
Check Σ	=	1

Pressure (psia)	2927.89
Temperature (degF)	230
Temperature (degR)	690

3.2.1 SPECIFIC GRAVITY

Gas-specific gravity (yg) is defined as the ratio of the apparent molecular weights of a natural gas to that of air, itself a mixture of gases. The molecular weight of air is usually taken as equal to 28.97 (approximately 79% nitrogen and 21% oxygen)

Calculation of specific gravity-

Compound	y_i	MW_i	y_iMW_i	p_{ci} (psia)	y_ip_{ci} (psia)	T_{ci}, (°R)	y_iT_{ci} (°R)
C_1	0.6599	16.04	10.584	673	444.112	344	227.005
C_2	0.0869	30.07	2.613	709	61.612	550	47.795
C_3	0.0591	44.1	2.606	618	36.523	666	39.360
i-C_4	0.0239	58.12	1.389	530	12.667	733	17.518
n-C_4	0.0279	58.12	1.615	551	15.317	766	21.294
i-C_5	0.0157	72.15	1.132	482	7.567	830	13.031
n-C_5	0.0112	72.15	0.808	485	5.432	847	9.486
C_6	0.0181	86.18	1.559	434	7.855	915	16.561
C_{7+}	0.0601	114.23	6.865	361	21.70	1024	62
N_2	0.0194	28.02	0.543	226.9	4.403	492	9.544
CO_2	0.0121	44.01	0.532	1073	12.983	548	6.630
H_2S	0.0058	34.08	0.197	672.4	3.897	1306	7.574
Σ=	1	Σ=	30.448	Σ=	634.069	Σ=	447.346

Apparent Mol wt	=	30.448	
Pseudo Critical P	=	634.069	psia

Pseudo Critical T	=	4477.346	deg R
Gas Specific Gravity	=	1.05104	

Oil Specific Gravity:

$$\square = \frac{141.4}{131.5+API}$$

Specific gravity of oil	0.8039

3.2.2 VISCOSITY

Gas viscosity is a measure of the resistance to flow exerted by the gas. Dynamic viscosity (jug) in centipoises (cp) is usually used in the natural Engineering. Gas viscosity is very often estimated with charts or correlations developed based on the charts. The gas viscosity correlation of Carr, Kobayashi, and Burrows (1954) involves a two-step procedure which is executed bellow. The gas viscosity at reservoir temperature and a pressure is estimated as follows.

Calculation of viscosity:

Using correlations developed by Carr, Kobayashi, and Burrows (1954) for viscosity.

Pseudo critical pressure:

$$P_{pc}=678 - 50(\square_g - 0.5) - 206.7y_{N_2} + 440y_{CO_2} + 606.7y_{H_2S}$$

Pseudo critical pressure(psia):	697.164

Pseudo critical temperature:

$$T_{pc}=326 + 315.7(\square_g - 0.5) - 240y_{N_2} - 83.3y_{CO_2} + 133.3y_{H_2S}$$

Pseudo critical temperature(R):	345.357

Uncorrected gas viscosity:

$$\mu_{1HC} = 8.188*10^{-3} - 6.15*10^{-3}\log(\Box_g) + (1.709*10^{-5} - 2.062*10^{-6}*\Box_g)*T_{deg\,F}$$

Uncorrected gas viscosity at 14.7 psia:	0.0127

N_2 correction for gas viscosity at 14.7 psia:

$$\mu_{1N_2} = \{9.59*10^{-3} + 8.48*10^{-3}\log(\Box_g)\}*y_{N_2}$$

N_2 correction for gas viscosity at 14.7 psia:	0.0008

CO_2 correction for gas viscosity at 14.7 psia:

$$\mu_{1CO_2} = \{6.24*10^{-3} + 9.08*10^{-3}\log(\Box_g)\}*y_{CO_2}$$

CO_2 correction for gas viscosity at 14.7 psia:	0.000363

H_2S correction for gas viscosity at 14.7 psia:

$$\mu_{1H_2S} = \{3.73*10^{-3} + 8.49*10^{-3}\log(\Box_g)\}*y_{H_2S}$$

H_2S correction for gas viscosity at 14.7 psia:	4.28E-05

Corrected gas viscosity (cp) at 14.7 psia (μ_1):

$$\mu_1 = \mu_{1HC} + \mu_{1N_2} + \mu_{1CO_2} + \mu_{1H_2S}$$

Corrected gas viscosity at 14.7 psia (μ_1):	0.01325

Pseudo-reduced pressure:

$$P_{p_r} = \frac{P}{P_{p_c}}$$

Pseudo-reduced pressure:	14.3438

Pseudo-reduced temperature:

$$T_{p_r} = \frac{T}{T_{p_c}}$$

Pseudo-reduced temperature:	1.85

Gas viscosity μ_g is given as:

$$\mu_r = ln\left\{\frac{\mu_g}{\mu_1} * T_{pr}\right\}$$

$$= a_0 + a_1 P_{pr} + a_2 P_{pr}^2 + a_3 P_{pr}^3 + T_{pr}(a_4 + a_5 P_{pr} + a_6 P_{pr}^2 + a_7 P_{pr}^3) + T_{pr}^2(a_8 + a_9 P_{pr} + a_{10} P_{pr}^2 + a_{11} P_{pr}^3) + T_{pr}^3(a_{12} + a_{13} P_{pr} + a_{14} P_{pr}^2 + a_{15} P_{pr}^3)$$

$a_0 =$	-2.462	$a_8 =$	-0.7933
$a_1 =$	2.97	$a_9 =$	1.396
$a_2 =$	-0.2862	$a_{10} =$	-0.1491
$a_3 =$	0.008054	$a_{11} =$	0.00441
$a_4 =$	2.808	$a_{12} =$	0.08393
$a_5 =$	-3.498	$a_{13} =$	-0.1864
$a_6 =$	0.3603	$a_{14} =$	0.02033
$a_7 =$	-0.01044	$a_{15} =$	-0.00061

$\ln((\mu_g/\mu_1)*T_{pr}) =$	1.6016

$\mu_g =$	0.035	centi-poise

Viscosity of oil:

$$\mu_{o=}\mu_{ob} + 0.001(p - p_b)\left(0.024\mu_{ob}{}^{1.6} + 0.38\mu_{ob}^{0.56}\right)$$

Where

$$\mu_{0d=(0.32+\left(\frac{1.8*10^7}{API}\right)\left(\frac{360}{t+200}\right)^A}$$

$$A = 10^{(0.43+(\frac{8.330}{API})}$$

$$a = Rs(2.2 * 10^7 R_s - 7.4 * 10^{-4})$$

$$b = \frac{0.68}{10^c} + \frac{0.25}{10^d} + \frac{0.062}{10^a}$$

$$c = 8.62 * 10^{-5} R_s$$

$$d = 1.10 * 10^{-3} R_s$$

And

$$e = 3.74 * 10^{-3} R_s$$

A	4.1418
A	-0.1674
B	0.7901
C	0.02103
D	0.2684
E	0.9152
μ_{ob}	0,3602
Viscosity of oil	0,90729

3.2.3 GAS COMPRESABILITY FACTOR

Gas compressibility factor is also called as “deviation factor” or “Z-factor.” Its value reflects how much the real gas deviates from the ideal gas at a given pressure and temperature. Gas compressibility factor can be determined on the basis of measurements of PVT laboratories. For a given amount of gas, if temperature is kept consistent and volume is measured at 14.7 Psia and an elevated pressure P1,Z-factor can be determined with the following formula.

Calculation of Z-factor:

Using correlations developed by Brills and Beggs (1974) for compressibility factor.

$$z = A + \left(\frac{1-A}{e^B}\right) + CP_{Pr}^{D}$$

$$A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.10$$

A	=	0.1677

$$B = (0.62 - 0.23T_{pr})P_{pr} + \left\{\frac{0.066}{T_{pr} - 0.86} - 0.037\right\} P_{pr}^2 + \frac{0.32P_{pr}^6}{10^E}$$

B	=	0.3861

$$C = 0.132 - 0.32\log(T_{pr})$$

C	=	0.11086

$$D = 10^F$$

D	=	0.9713

$$E = 9(T_{pr} - 1)$$

E	=	1.4774

$$F = 0.3106 - 0.49T_{pr} + 0.182T_{pr}^2$$

F	=	-0.0126

$$z = A + \left(\frac{1 - A}{e^B}\right) + CP_{Pr}^D$$

z-factor	=	0.82038

3.2.4 FORMATION VOLUME FACTOR

Formation volume factor is defined as the ratio of volume of the fluid at reservoir conditions to the ratio of fluid volume at standard conditions.

Formation volume factor of gas

$$B_g = 0.0283 \frac{zT}{p}$$

B_g	0.00182

Formation volume factor of oil

$$B_g = 0.9757 + 0.00012 * \left(GOR \left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + (1.25 * T)\right)^{1.2}$$

B_o	1.2172

3.2.5 DENSITY

Because natural gas is compressible, its density depends upon pressure and temperature. Gas density can be calculated from gas law for real gas with good accuracy.

Gas density-

$$\rho_o = \frac{2.7\gamma_g P}{zT}$$

Oil density-

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{0.972 + 0.000147\left(R_s\sqrt{\frac{\gamma_g}{\gamma_0}} + 1.25t\right)^{1.175}}$$

Density of gas	44.0345
Density of oil	40.7970

3.2.6 FLOWING BOTTOM HOLE PRESSURE

During transient flow, the developing pressure funnel is small relative to the reservoir size. Therefore the reservoir acts like an infinitely large reservoir from transient pressure analysis point of view. Assuming single phase floe in the reservoir, several analytical solutions have been developed for describing transient flow behaviours. They are available from classic text books such as Dake. A consistent rate solution expressed is frequently used in production engineering.

$$P_{wf} = P_i - \left(\frac{162.6 q B_o \mu_o}{kh}\right) * \left(\log t + \log\frac{k}{\emptyset \mu_0 c_t r_w^2} - 3.23 + 0.87S\right)$$

Bottom hole pressure	2452.541 Psia

3.2.7 DELIVERABILITY OF RESERVOIR

Reservoir deliverability is defined as the oil or gas production rate achievable from reservoir at a given bottom-hole pressure. It is a major factor affecting well deliverability. Reservoir deliverability determines types of completion and artificial lift methods to be used. A thorough knowledge of reservoir productivity is essential for production engineers. Reservoir deliverability depends on several factors including the following:

- Reservoir pressure.
- Pay zone thickness and permeability.
- Reservoir boundary type and distance.
- Wellbore radius.
- Reservoir fluid properties.
- Near-wellbore condition.
- Reservoir relative permeability.

Reservoir deliverability can be mathematically modeled on the basis of flow regimes such as transient flow, steady state flow, and pseudo–steady state flow. An analytical relation between bottom-hole pressure and production rate can be formulated for a given flow regime. The relation is called ''inflow performance relationship'' (IPR).

The general equation used to determine the deliverability of the reservoir for above 2000psia bottom hole pressures is considered as.

$$q = \frac{kh\left(p^2 - {p_{wf}}^2\right)}{1424\mu ZT\left(\ln\left(\frac{0.472r_e}{r_w}\right) + s + Dq\right)}$$

For pressures above 3000psia

$$q = \frac{kh\left(p - p_{wf}\right)}{141.2 * 10^3 B_g\mu\left(\ln\left(\frac{0.472r_e}{r_w}\right) + s + Dq\right)}$$

Where

$$D = \frac{FKh}{1422T}$$

$$F = 3.161 * 10^{-12}\left(\frac{\beta T \gamma_g}{\mu_g h^2 r_w}\right)$$

$$\beta = 1.88 * 10^{-10} K^{-1.47} \phi^{-0.53}$$

<u>Calculation of well deliverability</u>: The deliverability of the reservoir is calculated using the Excell sheet as follows.

Input data:

Effective permeability to gas:	0.35	Md
Pay zone thickness:	82	Ft
Equivalent drainage radius:	1000	Ft
Wellbore radius:	0.406	Ft
Darcy skin factor:	1.26	
Non-Darcy coefficient:	9.07679630E-25	d/Mscf
Reservoir pressure:	2927.898	Psia
BHP	2510.307	Psia
AVG PRESS	2719.1025	PSIA
Temperature:	230	F
Specific Gravity	0.749623	
The average gas viscosity:	0.035	Cp
Z-factor	8.5700000E-01	

Solution:

CAL OF NON DARCY COEEFICIENT

K	0.35000
Ø	0.15000
B	0.00000
F	0.00000
D	0.00000

CAL OF COMPRESSIBILITY

Ppc	665.58764
Tpc	400.95510
Ppr	4.08527
Tpr	1.72089
A	0.47985
B	0.63320
C	0.06473
D	0.98971
E	5.58171
F	-0.00449
Z	0.87573

B_g =	0.001187227	rb/SCF
p_{wf} (psia)	q (Mscf/d)	
	p^2 - Approach	p - Approach
1000	127.82	122.78007

Initially the deliverability is assumed as zero and the obtained values are consider for the next iteration until the value become consistent and final value is taken as deliverability of the reservoir.

Deliverability using p^2- Approach	127.82mmscfd
Deliverability using p - Approach	122.78mmscfd

3.2.8 WELLHEAD PRESSURE

The above deliverability has gives the achievable oil production at well bore. However, the achievable oil production rate from a well is determined by wellhead pressure and the flow performance of production string that is, tubing, casing, or both. The flow performance of production string depends on geometries of the production string and properties of fluids being produced. Thus the pressure drop in the tubing is calculated an considering single phase flow in the tubing and the pressure at the well head is determined from the difference of the bottom hole pressure and the pressure drop occurred.

Pressure drop in the tubing is given as

$$\Delta P = \frac{g}{g_c}\rho\Delta Z + \frac{\rho}{2g_c}\Delta u^2 + \frac{2f_f\rho u^2 L}{g_c D}$$

Where

Elevation increase

$$\Delta Z = \cos\alpha L$$

Fluid velocity

$$u = \frac{4q}{\pi D^2}$$

Moody friction factor – F_f is taken from Darcy-Wiesbach friction factor diagram.

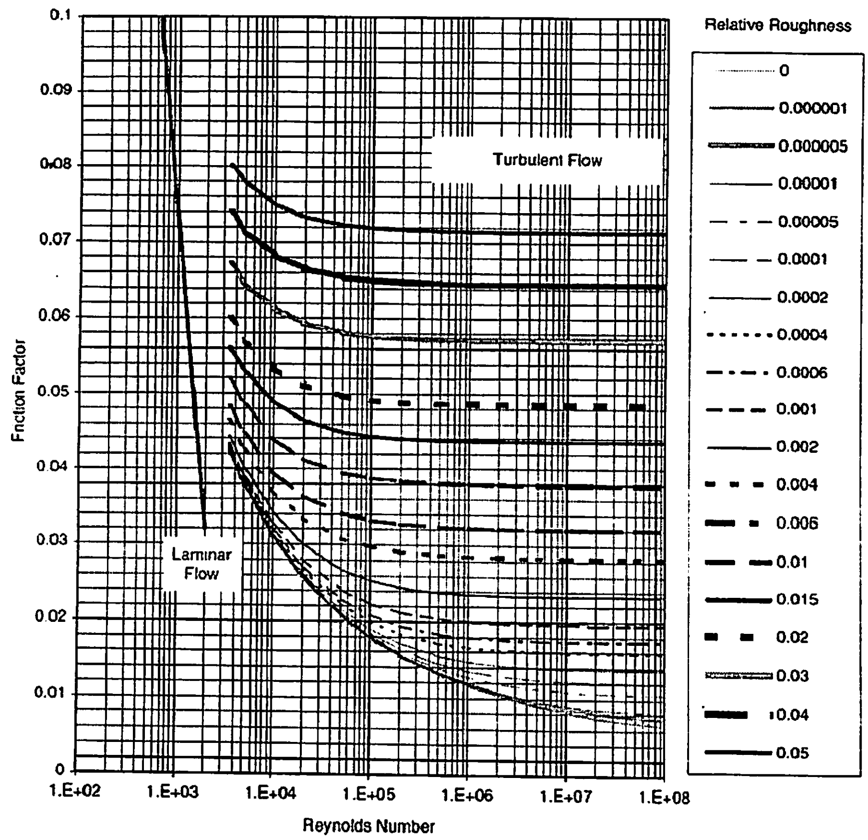

Figure-6 moody friction factor

Fanning friction factor

$$f_F = \frac{moody\ friction\ factor}{4}$$

Calculation of well head pressure:

Inputs:

Deliverability	122.78	Mscf/d
API gravity	44.5	Deg
Viscosity	0.035	
Tubing	3 1/2"	Inch
tubing inner dia	3.548	Mm

Inclination	0	Deg
relative roughness	0.001	
well depth	5421.84	Ft
specific gravity	0.8039	
oil density	40.801	

Solution:

elevation increase	5421.84
fluid velocity	0.00014381
Reynolds no	10633.0715
moody friction factor	0.022
Gravitational acceleration	32.17
fanning friction factor	0.0055
pressure drop	221216.494

Thus well head pressure is calculated as

$$p_{hf} = p_{wf} - \Delta P$$

Well head pressure 1003.7653psia

3.2.9 CHOKE PERFORMANCE

Wellhead chokes are used to limit production rates for regulations, protect surface equipment from slugging, avoid sand problems due to high drawdown, and control flow rate to avoid water or gas coning. Two types of wellhead chokes are used. They are

- Positive (fixed) chokes
- Adjustable chokes.

Placing a choke at the wellhead means fixing the wellhead pressure and, thus, the flowing bottom-hole pressure and production rate. Pressure equations for gas flow through a choke are derived based on an isentropic process. This is because there is no time for heat to transfer and the friction loss is negligible at chokes. In addition to the concern of pressure drop across the chokes, temperature drop associated with choke flow is also an important issue for pure gas wells, because hydrates may form that may plug flow lines.

Calculation of choke performance:

Inputs		
WHP	1003.765	Psia
K	1.4	
choke dia	0.1181	In
pipe dia	3.548	In
Viscosity	0.035	Cp
Deliverability	122.787	scf/d
Density	40.801	

Pressure of the fluid coming out of the choke is determined using the following equation

$$\frac{P_{outlet}}{P_{up}} = \left(\frac{2}{K+1}\right)^{\frac{K}{K+1}}$$

Choke out let pressure	530.270psia

Using this choke out let pressure the flow rate for different choke sizes has been calculated and the choke with maximum flow rate is considered for further calculations. The calculation is as follows.

$$q = C_D A \sqrt{\frac{2g_c \Delta P}{\rho}}$$

Where

$$C_D = \frac{d_2}{d_1} + \frac{0.3167}{\left(\frac{d_2}{d_1}\right)^{0.6}} + 0.025(\log(N_{Re})) - 4$$

$$N_{Re} = 1.48 * \frac{\left(\frac{q}{5.615}\right)}{\mu d_2}\rho$$

Solution

choke diameter	C_D	N_{Re}	choke outlet pressure	flow rate
0.1181	2.51186693	319460.531	530.2707686	963.622898
0.1574	2.13337078	239696.879	530.2707686	1453.73915
0.1968	1.88432403	191708.784	530.2707686	2007.31931

Thus the maximum flow rate of 2007.319mmscfd with a choke diameter of 5mm is considered for the determination of suitable separator calculation.

3.2.10 FLASH CALCULASTION

Based on the composition of well stream fluid, the quality of products from each stage of separatiбn can be predicted by flash calculations, assuming phase equilibriums are reached in the separators. This requires the knowledge of equilibrium ratio it is defined as.

$$k_i = \frac{y_i}{x_i}$$

Calculation:

The determination of flash calculation involves the iteration of no of moles of fluid in the liquid phase which is used to determine the no of moles of vapor which are used to determine the volumes of liquid and gas phases and gas oil ratio. Thus an excel sheet is created to determine the required results. The calculation is as follows.

Input Data:	
Pressure:	530
Temperature:	113
Specific gravity of stock tank oil:	0.80
Specific gravity of solution gas:	1.05

Gas solubility (R_s):	500

Compound	Mole Fraction (z_i)
C_1	0.6599
C_2	0.0869
C_3	0.0591
i-C_4	0.0239
n-C_4	0.0278
i-C_5	0.0157
n-C_5	0.0112
C_6	0.0181
C_{7+}	0.0601
N_2	0.0194
CO_2	0.0121
H_2S	0.0058

Solution:

Step-1

Calculation of mole fractions

The mole fraction is determined using the equation.

$$k_i = \frac{1}{P}10^{a+cf_i}$$

Where

$$a = 1.2 + 4.5 * 10^{-4}p + 1.5 * 10^{-9}P^2$$

$$c = 0.89 - 1.7 * 10^{-4}p - 3.5 * 10^{-8}P^2$$

$$f_i = b_i\left(\frac{1}{T_{bi}} - \frac{1}{T}\right)$$

a =	1.439043641
c =	0.790012415
n =	8.99593328

Solution

Compound	MWi	ziMWi	pci (psia)	zipci	Tci	ziTci	b (oR)	TB (oR)	F	ki
C1	16.040	10.585	673.000	444.113	344.000	227.006	365.787	94.000	3.253	19.250
C2	30.070	2.613	709.000	61.612	550.000	47.795	1923.321	303.000	2.991	11.953
C3	44.100	2.606	618.000	36.524	666.000	39.361	3093.040	416.000	2.037	2.108
i-C4	58.120	1.389	530.000	12.667	733.000	17.519	3589.837	471.000	1.357	0.611
n-C4	58.120	1.616	551.000	15.318	766.000	21.295	3748.958	491.000	1.093	0.378
i-C5	72.150	1.133	482.000	7.567	830.000	13.031	4190.957	542.000	0.418	0.111
n-C5	72.150	0.808	485.000	5.432	847.000	9.486	4369.229	557.000	0.219	0.077
C6	86.180	1.560	434.000	7.855	915.000	16.562	4826.606	610.000	-0.511	0.020
C7+	114.230	6.865	361.000	21.696	1024.000	61.542	7571.129	760.827	-3.262	0.000
N2	28.020	0.544	226.900	4.402	492.000	9.545	329.866	109.000	2.451	4.473
CO2	44.010	0.533	1073.000	12.983	548.000	6.631	910.139	194.000	3.103	14.656
H2S	34.080	0.198	672.400	3.900	1306.000	7.575	1253.686	331.000	1.600	0.951
	MWa =	30.449	ppc =	634.069	Tpc =	477.346				

Step -2

Calculation of no of moles of fluid in gas and liquid phases.

With the obtained values of K_i no of moles of vapor is assumed and no of moles of liquid is found until the sum of booth the phases equal to zero.

n_v =	0.8883		
Compound	z_i	k_i	$z_i(k_i-1)/[n_v(k_i-1)+1]$
C_1	0.6599	19.2503	0.6997
C_2	0.0869	11.9532	0.0887
C_3	0.0591	2.1085	0.0330
i-C_4	0.0239	0.6115	-0.0142
n-C_4	0.0278	0.3782	-0.0386
i-C_5	0.0157	0.1109	-0.0664
n-C_5	0.0112	0.0772	-0.0573
C_6	0.0181	0.0205	-0.1365
C_{7+}	0.0601	0.0001	-0.5372
N_2	0.0194	4.4726	0.0165
CO_2	0.0121	14.6556	0.0126
H_2S	0.0058	0.9512	-0.0003
Total			0.0000
n_L =	0.1117		

Step -3

Calculation of apparent macular weight

Compound	x_i	y_i	x_iMW_i	y_iMW_i
C_1	0.0383	0.7381	0.6150	11.8388
C_2	0.0081	0.0968	0.2435	2.9111
C_3	0.0298	0.0628	1.3132	2.7690
i-C_4	0.0365	0.0223	2.1210	1.2970
n-C_4	0.0621	0.0235	3.6089	1.3650
i-C_5	0.0747	0.0083	5.3873	0.5976
n-C_5	0.0621	0.0048	4.4819	0.3460
C_6	0.1393	0.0029	12.0078	0.2457
C_{7+}	0.5373	0.0001	61.3778	0.0084
N_2	0.0047	0.0212	0.1331	0.5952
CO_2	0.0009	0.0135	0.0406	0.5944
H_2S	0.0061	0.0058	0.2066	0.1965

Step -4

Calculations of required parameters.

Apparent molecular weight of liquid

$$MW_a^l = \sum_{i=1}^{N_c} x_i MW_i$$

Apparent molecular weight of vapor

$$MW_a^v = \sum_{i=1}^{N_c} y_i MW_i$$

Density of liquid

$$\rho_v = \frac{MW_a^v P}{ZRT}$$

Density of fluid

$$\rho_l = \frac{62.4\rho_o + 0.0136R_s\rho_g}{0.972 + 0.000147\left(R_s\sqrt{\frac{\rho_g}{\gamma_o}} + 1.25(T-460)\right)^{1.175}}$$

Volume of vapor phase

$$V_{vsc} = \frac{zn_vRT_{sc}}{P_{sc}}$$

Volume of liquid phase

$$V_L = \frac{n_L MW_a^l}{\rho_l}$$

Apparent molecular weight of liquid phase:	91.53672058	
Apparent molecular weight of vapor phase:	22.76479472	
Specific gravity of liquid phase:	0.704927293	water =1
Specific gravity of vapor phase:	0.784992922	air = 1
Input vapor phase z-factor:	0.8203	
Density of liquid phase:	43.98746306	lbm/ft3
Density of vapor phase:	2.391111808	lbm/ft3
Volume of liquid phase:	0.041408211	bbl
Volume of vapor phase:	276.5689603	scf
GOR:	6679.084914	scf/bbl
API gravity of liquid phase:	69.22992133	

3.3 RESULT OF THE RESERVOIR ANALYSIS

From the above analysis the details of the reservoir are obtained as follows.

reservoir pressure	2927.898	Psia
reservoir temperature	230	F
bottom hole pressure	2418.68988	Psia
casing head pressure	2495.491	Psia
tubing size	3 ½	Inch
choke size	0.1181	Inch
total flow rate from the well	963.622898	bbl/d
volume of liquid phase	0.04140821	Bbl
volume of vapor phase	276.56896	Scf

3.4 TWO PHASE SEPERATOR

Separation of well stream gas from free liquids is the first and most critical stage of field-processing operations. Composition of the fluid mixture determines what type and size of separator is required. However, pressure is another key factor affecting selection of separators. Separators are also used in other locations such as upstream and downstream of compressors, dehydration units, and gas sweetening units. At these locations, separators are referred to as scrubbers, knockouts, and free liquid knockouts. All these vessels are used for the same purpose: to separate free liquids from the gas stream.

Separators should be designed to perform the following basic functions:

- cause a primary-phase separation of the mostly liquid hydrocarbons from the gas stream
- refine the primary separation by further removing most of the entrained liquid mist from the gas
- refine the separation by further removing the entrained gas from the liquid stream
- discharge the separated gas and liquid from the vessel and ensure that no re-entrainment of one into the other occurs

FACTORS AFFECTING SEPARATION

- Gas and liquid flow rates (minimum, average, and peak)
- Operating and design pressures and temperatures
- Surging or slugging tendencies of the feed streams
- Physical properties of the fluids such as density and compressibility
- Designed degree of separation (e.g., removing 100% of particles greater than 10 microns)
- Presence of impurities (paraffin, sand, scale, etc.)
- Foaming tendencies of the crude oil
- Corrosive tendencies of the liquids or gas

Sizing of separator:

In vertical separators, a minimum diameter must be maintained to allow liquid drops to separate from the vertically moving gas. The liquid retention time requirement specifies a combination of diameter and liquid volume height. Any diameter greater than minimum required diameter for gas capacity can be chosen.

Different combination of height and diameter are considered and the capacity is calculated for each of them and suitable one is selected among them which is suitable for the requirements using Excel sheet.

Solution:

INPUT		
PARAMETER	VALUE	UNIT
GAS FLOW RATE	5.409990676	MMscfd
GAS SPECIFIC GRAVITY	1.051041836	
CONDENSATE FLOW RATE	150	bbl/ MMscf
CONDENSATE GRAVITY	69	API
OPERATING PRESSURE	530	PSIG
OPERATING TEMP	113	FAREN

Gas capacity:

$$q_{st} = \frac{2.4D^2H_p}{z(T+460)}\sqrt{\frac{\rho_L - \rho_g}{\rho_g}}$$

Liquid capacity:

$$q_L = \frac{1440V_L}{t}$$

diameter	Height	V_L	empirical factor	retention time	Liquid capacity	Gas capacity
16	5	0.27	0.205	1	388.8	0.0066416
16	7.5	0.41	0.205	1	590.4	0.0066416
16	10	0.51	0.205	1	734.4	0.0066416
20	5	0.44	0.205	1	633.6	0.01037749
20	7.5	0.65	0.205	1	936	0.0103775
20	10	0.82	0.205	1	1180.8	0.01037749
24	5	0.66	0.205	1	950.4	0.01494359
24	7.5	0.97	0.205	1	1396.8	0.01494359
24	10	1.21	0.205	1	1742.4	0.01494359
30	7.5	1.13	0.205	1	1627.2	0.02334936
30	10	1.64	0.205	1	2361.6	0.02334936
30	15	2.02	0.205	1	2908.8	0.02334936
36	7.5	2.47	0.205	1	3556.8	0.03362308
36	10	3.02	0.205	1	4348.8	0.03362308
36	15	4.13	0.205	1	5947.2	0.03362308
42	7.5	3.53	0.205	1	5083.2	0.04576475
42	10	4.29	0.205	1	6177.6	0.04576475

42	15	5.8	0.205	1	8352	0.04576475
48	7.5	4.81	0.205	1	6926.4	0.05977437
48	10	5.8	0.205	1	8352	0.05977437
48	15	7.79	0.205	1	11217.6	0.05977437
54	7.5	6.33	0.205	1	9115.2	0.07565194
54	10	7.6	0.205	1	10944	0.07565194
54	15	10.12	0.205	1	14572.8	0.07565194
60	7.5	8.08	0.205	1	11635.2	0.09339745
60	10	9.63	0.205	1	13867.2	0.09339745
60	15	12.73	0.205	1	18331.2	0.09339745
60	20	15.31	0.205	1	22046.4	0.09339745

From the above table separate with 20*7-1/2 dimensions is suitable for the gas capacity of the well deliverability

The specifications of the separator is as follows

capacity of tank	450 m3/d
no of vents	2
vent size	4"
air entering flow rate	1120
air emptying flow rate	1220

3.5 STORAGE TANK

Oil that is free of impurities to the extent that it will meet pipeline specifications is referred to as clean oil or pipeline oil. It is oil from the separator, FWKO, heater-theatre, or gun barrel, depending upon the type of treating necessary to obtain the clean fuel. The pipeline oil goes from the treating facilities to the storage facilities, known as stoke tank.

The number and size of the stock tank depends on the volume of the oil produced per day, the method of selling the oil to the pipeline, and how frequently and at what rate oil is taken by the company

The separation, treating and storage facilities are commonly referred as tank battery. The two basic types of stock tanks are bolted steel and welded steel. Bolted steel stock tanks are normally 500 barrels or larger and are assembled on location. Welded steel stock tanks ranges from 90 barrels to several thousand barrels. Welded tanks up to 400 barrels in capacity are shop-welded and are transported as a complete unit to the tank battery site. Large tanks are welded on site. Welded tanks can be internally coated to protect them from corrosion. Bolted tanks offer the option of internal lining or galvanizing construction for protection against corrosion.

Design of storage system:

For the design pf the storage system following assumptions are made

- Tank capacity is taken for three days production capacity of the well.
- Unloading of tank is done for every one week.
- Flow rate to the tank is considered to be maximum flow rate from the separator.
- 4" vent is taken considered for the breathing.

And the calculations are as follows

Inputs	
tank capacity	2808 bbl/d
filling flow rate	39 bbl/h

Emptying flow rate	39 bbl/h
Solution	
thermal breathing flow rate	
for 2808 from the table-1 of thermal breathing	
emptying	84.3
Filling	50.6
total venting flow rate	
Emptying	121.74
Filling	89.99
number of vents	
for 4" vents	
negative pressure	25mm of wc
over pressure	50mm of wc
allowable air flow rate	
Emptying	1220
Filling	1120
maximum flow rate	
Emptying	1168.361702
Filling	1019.811881
thus two 4" vents are chosen	

Thus the specifications of the storage tank is given as follows

specifications of tank	
capacity of tank	450 m3/d
no of vents	2
vent size	4"
air entering flow rate	1120
air emptying flow rate	1220

The thermal breathing flow rates are taken from the following table-1

tank capacity	Inbreathing	Out breathing	
		flash pt>37.8^{0}c	flash pt<37.8^{0}c
10	1.69	1.01	1.69
20	3.37	2.02	3.37
100	16.9	10.1	16.7
200	33.7	20.1	33.7
300	50.6	30.3	50.6
500	84.3	50.6	84.3
700	118	70.8	118
1000	169	101	169
1500	253	152	253
2000	337	202	337
3000	506	303	506

3180	647	388	647
4000	787	472	896
5000	896	537	1003
6000	1003	602	1077
7000	1077	646	1136
8000	1136	682	1210
9000	1210	726	1345
10000	1345	807	1480
12000	1480	888	1615
14000	1615	969	1745
16000	1745	1047	1877
18000	1877	1126	2179
20000	2179	1307	2495
25000	2495	1378	2562
30000	2564	1497	2991

Table-2 Thermal breathing

CHAPTER-4

4. CONCLUSION

From the preliminary study cried on the reservoir the following characteristics are determined.

reservoir pressure	2927.898	Psia
reservoir temperature	230	F.
bottom hole pressure	2418.68988	Psia
casing head pressure	2495.491	Psia
tubing size	3 ½	Inch
choke size	0.1181	Inch
total flow rate from the well	963.622898	bbl/d
volume of liquid phase	0.04140821	Bbl
volume of vapor phase	276.56896	Scf

For the above reservoir conditions of the reservoir the following surface facilities are recommended.

Separator		
Diameter	20	In
Height	7.5	In
operating Pressure	530	Psia
operating Temperature	113	^{o}F

storage tank		
capacity of tank	450	m3/d
no of vents	2	
vent size	4"	Inch
air entering flow rate	963.6229	
air emptying flow rate	0.1181	
filling flow rate	39	bbl/h
Emptying flow rate	39	bbl/h

4.1 LAYOUT

The layout of the surface facilities is as follows:

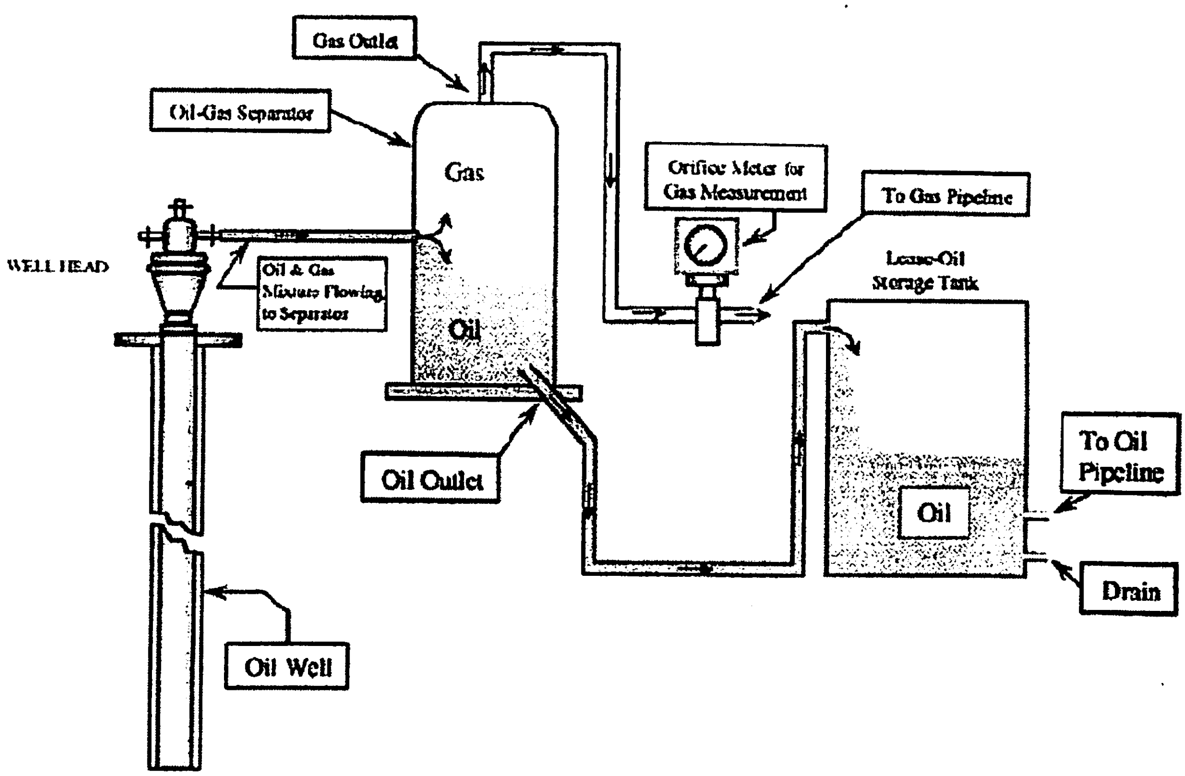

Figure-7 layout of surface facilites

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