Natural Gas Engineering
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Module No # 02
Lecture No # 06
Nodal Analysis

Hello everyone and welcome to the third of week 2 in first two lectures of this week we learnt about natural gas properties and this third lecture in the part of natural gas production we will try to understand how the rock properties can be estimated and how they are going to influence the production of natural gas.

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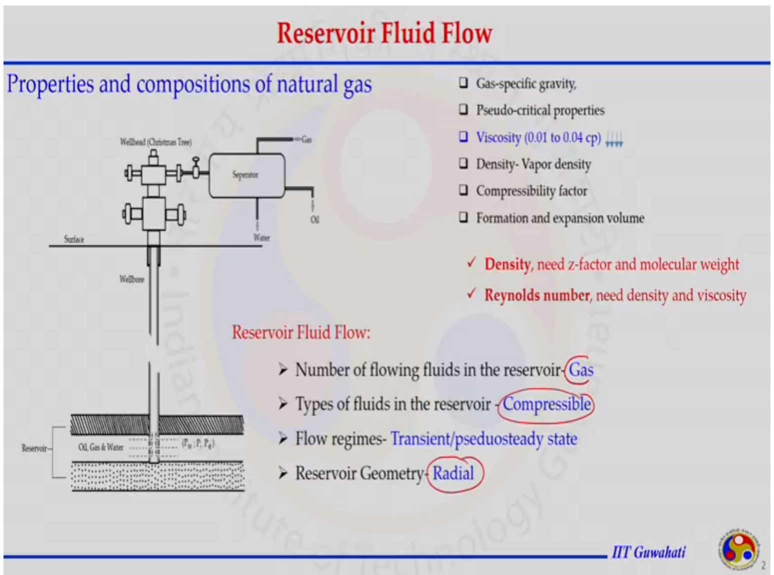

So let us see what we gone through in the last two classes compressively in the summarize that he natural gas which is being produce from the reservoir to surface and there it is getting refined and further it is transported the properties of natural gas need to be estimated because natural gas is compressible in nature compressibility nature also changes with temperature thus it is important to understand how these properties can be estimated at different temperature and pressure those will help us to design the equipment and facilities and maximum utilization facilities to process and transport the natural gas.

So we had learnt about several properties in summary it is specific gravity pseudo critical properties important one is viscosity. Viscosity of natural gas is very low compared to oil and water is in the magnitude of 0.012, 0.04 centipoise density compressibility factor and properties those relate the change in volume under one condition to another condition formation volume factor and expansion factor.

And these are inter related properties like density need compressibility factor and later on you will see the Reynolds number density viscosity. So the reservoir fluid hat is getting produced from the formation domain that is porous in nature several factor are responsible for the production of fluid that is the number of flowing fluid in the reservoir. The fluid like gas, oil, water or represent what quantity they are present.

So in our case we are having the gas when we deal about the natural gas alone we assume like it is just 100% natural gas 100% saturation of the natural gas or the reservoir is saturated 100% with the gas only that we assume otherwise the number of flowing fluid affect the production. Types of fluid in the reservoir what is the nature of the fluid it is compressible, incompressible how the properties are getting changed and the flow resume that is transient condition or pseudo condition those are responsible to for the production.

So in earlier time when the production is started it the production value under transient time and later accept to pseudo steady state case. A reservoir geometry like fluid is happening in axial direction like in a radial direction is spherical semi spherical. So altogether it is not only the fluid properties those are important understanding the reservoir formation it is behavior for the production fluid is also important to be understood.

And in that case we are going to learn some of the properties of reservoir those are related to natural gas engineering either could be several other terminology or the definition and other that aspects the reservoir those should be understood by the reservoir engineer in particular those are dealing with the while reservoir or the condensate reservoir.

But in our case as I mentioned here we are assuming it is compressible in nature we are in the transient is pseudo steady state conditions when the natural gas is being produced and the flow is happening under the radial condition we will say all these things coming weeks when we are going to setup the mathematical expression for how the fluid is flowing from reservoir to wellbore.

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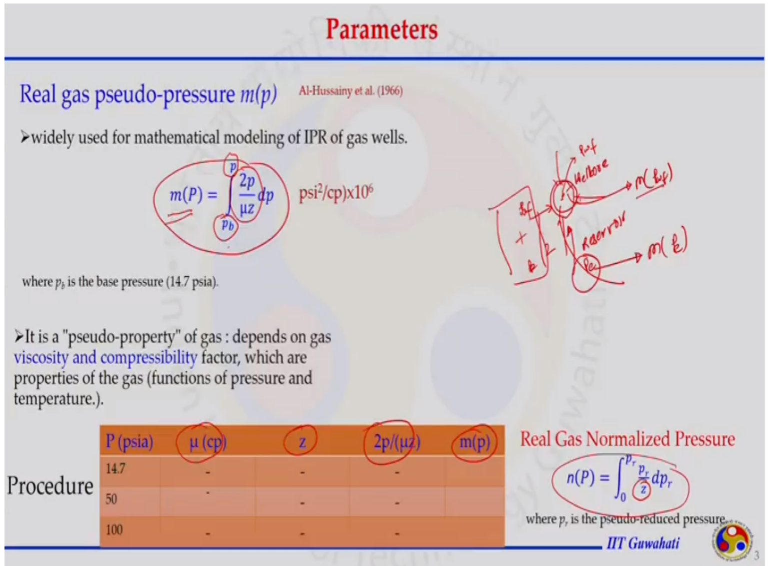

In this regard let us see some of the parameters those help us to understand how the properties of natural gas are going to be change with the condition as well as how to represent those changes in the mathematical expression to understand the gas production. So the parameter that we are going to use is a real gas to do pressure denoted as mp it is widely used for mathematical modeling of IPR of gas well.

That is said the fluid flow assuming it is happening in a radial direction in all the reservoir corner to well bore this is our wellbore and this is reservoir. From this reservoir the fluid is travelling because of the pressure radiant and use see here he pressure is very here the reservoir pressure as well as pressure is high here relatively reservoir as well as pressure is high here but relatively reservoir pressure it is low value and the different could be 500 psi or it could be 1000 psi it could be more also.

So when the fluid or the gas is flowing from high pressure to low pressure region we have taken the example of radial the gas is going through several domain several zones where the pressure and temperature conditions are different. So the reservoir pressure changes from PE to PWF that is responsible for the gas flow we can assume the reservoir is isothermal with respect to temperature that changes in the temperature changes is not that much with that could be assume for the pressure that could not be assume like this because the flow is happening because of pressure gradient only.

And when fluid is flowing from reservoir to wellbore it is going through several pressure zones and had each point when the fluid is having the experience of different condition the properties of fluid will change especially the viscosity and compressibility factor there is one parameters pseudo pressure that is say when the fluid is happening different conditions to pass through one point to the other point in the long term in the form of 2p / Mu z.

Where the effect of viscosity and compressibility can be combined and interrogated from pb2 to p to represent all these changes are happening. And that is give us like a flexibility or a very approximation tool that says any changes are happening could be represented in this form. One of the simplest way could be we can just say the average pressure could be used evaluate the viscosity and compressibility factor.

So for example the pressure is PWF here and P here we can take the average of this and after taking the average of this we can evaluate compressibility and viscosity at that pressure but that is not going to represent the changes the gas is facing throughout this production process. So the pseudo real pressure that is got lot of acknowledgement in developing the inflow performance relationship where the lumping these Mu and z can allow us to account the changes in these lump parameters because of the pressure.

It is a pseudo properties of the gas because if depends on the gas viscosity and compressibility factor. Well compressibility and viscosity both are the function of pressure and temperature. That is this properties is called the pseudo pressure properties how to calculate that so if we see we can prepare a table or the procedure can be explained like this when we are having a pressure the if you see here the lower limit of this integral sign is PV that is any base pressure we can take atmospheric pressure as base pressure that is 14.7 psia we can integrate this to the pressure of interest. So for example I want to know the mp value here the wellbore condition that will be mp wf.

If I want to know at the reservoir condition pe here I need to know will be mpe so to know the value of this pseudo pressure at mp at a particular what we can do we can divide the ahh pressure change from base pressure to the pressure interest in small segment. S small segment we have are having the integration by the (()) (09:08) rule will be more accurate and at each pressure we can calculate the viscosity compressibility factor and this parameter lump parameter 2p / Mu z and then by doing the trapezoidal rule we can calculate mp.

Knowing this we can also how the mp is changing with respect to pressure so at a particular point when we are having a different pressure we can represent the changes of pressure for Viscosity and compressibility in this mp form. Another parameter similar to mp is np that is called the gas normalize pressure this is with respect to reduce pressure and only the compressibility factor is accounted for the change it is assumed the viscosity we will be deal separately.

But how the changes are happening in compressibility for the pressure range from 0 to reduce pressure or the pressure of the interest can be accounted with the help of this expression mp. But this is not use widely in gas industry the more important mp the more important is you will see we are developing the relationship for IPR curve. We will see how mp makes the job easy however it needs the computational technique any excel programmer mat lab program or any mathematical program that can integrate the function 2p / Mu z from pv to pressure of interest.

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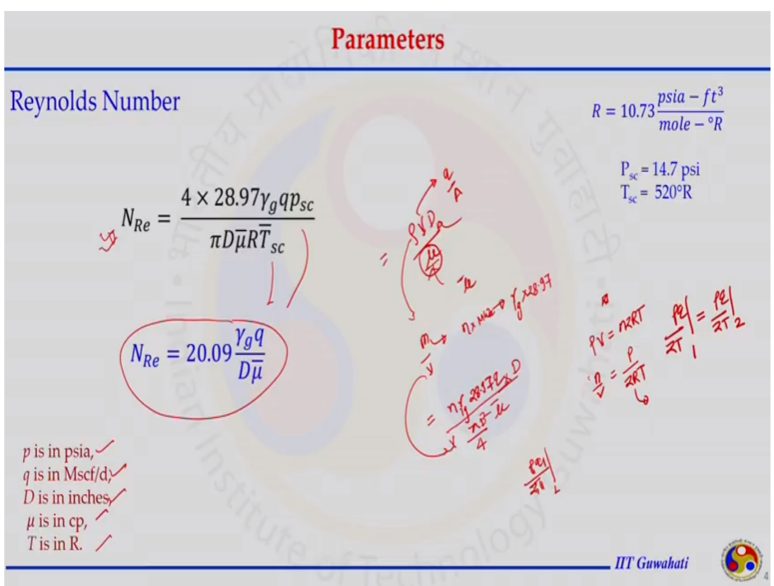

Another parameter that we will have the frequently when we are transporting the natural gas through the pipeline not only during the transportation volume production also when the fluid reach wellbore bottom part it travels from wellbore bottom to well head and it the long distances travelled the parameter that comes into picture is Reynolds number.

The Reynolds number is the ratio of inertial force to viscos forces but in mathematical sense it is written as rho pd / Mu rho is the viscosity of the fluid which is being fluid v is the velocity which is actually apparent velocity that can be written flow rate per unit area. Volumetric flow rate per unit area d is the diameter of the pipe and Mu is the viscosity of the fluid. So in case of natural gas production when we are having natural gas is being produced from this wellbore or being transported to through the pipeline we know the diameter of the pipe.

The viscosity term we know it depends on the pressure so viscosity can be evaluated average condition. So we can write this Mu 1 that means we can evaluate viscosity at average temperature and average pressure condition using the correlation given or discuss in the last lecture. This rho the density of the gas we know density m / v the m is mass of the gas that can be written in the form of number of moles of that gas molecular weight that is again the apparent molecular weight because natural gas is a mixture and this apparent molecular weight can be converted into specific gravity multiply by the molecular weight of the air that is 28.97.

So we can convert this if you write this here we are going to get here the rho that is replaced by n gamma z 28.97 we can replace this v / q divided by a. a is the area of the pipe cross sectional area of the pipe that we can say Pie d square / 4 then d is here and divided by viscosity that is evaluated under the average condition. Now what we can do this volume will also be here this is v so by the real gas law we know pv = nzRT.

So we can write n / v = p / zRT we know R is the gas constant the value is known to us 10.73 in the US field unit system or 8.314 in a second unit system. So depend the unit system has been if we represent all of those we are going get this expression here one more analysis one more correlation that is p1q1 z1T1 at one condition so pq zT at condition 1 = pqzT at condition 2 we can use this standard condition pressure and temperature in this expression.

If we write here we are going to get the Reynolds number in this form and you see Reynolds number in this form called gamma g. So we need to know the composition of the gases the q production rate under standard condition standard pressure, standard temperature diameter of the team and viscosity. So the Reynolds number when the fluid is being flown also going to change with the temperature and pressure with the gas is going to experience and the Reynolds number is very important when we are flowing through the pipeline we understand the flow is under terminate condition or under the laminar condition.

It determines the friction factor the roughness of the pipe is used with the help of Reynolds with the help of friction factor value. So Reynolds number itself a function of temperature and pressure if we put the standard condition of temperature and pressure we are going to get this expression here. It is very important again the coefficient numerical coefficient appearing in Reynolds number or any other term depend on the unit system has been chosen.

So here p is shown in the psi Q is in Mscf per day D is in inches that should be remembered that should not be repeat but it is in inches, Mu is the centipoise and temperature it is in the absolute system degree ranking. So knowing as much as accurately the fluid property will allow us to calculate the accurate Reynolds number and that accurately measure the accurate Reynolds number and that accurately measure calculation of Reynolds number will allow us to calculate the friction factor and this is very important parameter that we will we use in very frequently.

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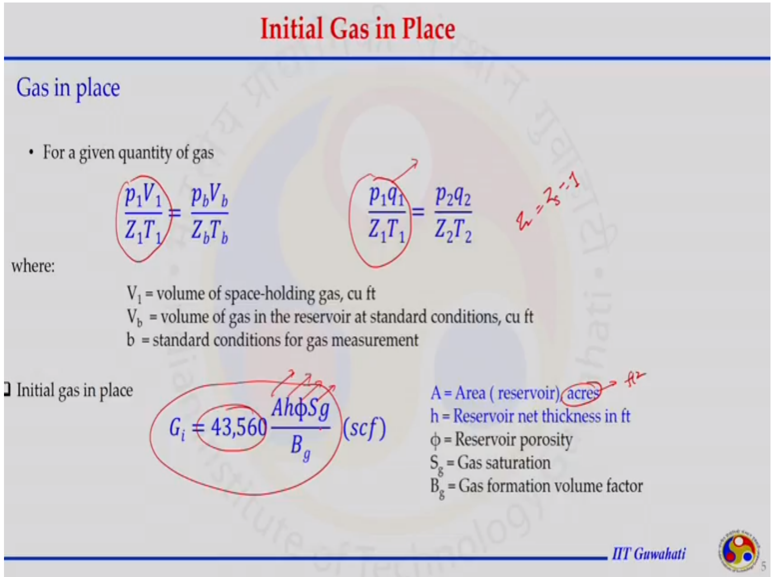

Another things knowing the properties of gas we can also estimate gas in place as I already mentioned previously like the pvZT when R is constant gas constant that can be taken out. So at a particular temperature pressure condition or volume condition one set of the data can be transferred to another set of the data using the real gas law and that with respect to base we can convert any data set to the base condition or to standard condition as we use during the calculation of Reynolds number.

Similarly we can also express the same thing with respect to the flex also p1q1z1T1 = p2q2 / z2T2 under the standard condition we assume z2 as a z2 at standard condition is 1. So we assume the natural gas under standard condition will behave as the ideal so initial gas in place can be calculated with the help of this expression VG the volume of the gas under standard condition to reservoir condition.

So we know the VG value we can use this expression and can find out how much gas reserve is available in a particular reservoir domain. And you are using it will depend on A this is area reservoir area in the unit of A curves and in the numerical coefficient we are seeing here is 43560 this is a conversion of = ft square we convert this acre to ft square we are going to get this 43560 numerical value for the multiplication part.

h is the page on thickness or the net thickness through with the fluid is travelling from the reservoir to wellbore fe is the porosity and Sg is the gas saturation. So here you will see when we are using the knowledge of the gas properties to estimate the gas reserve or gas in place of the reservoir we also need to understand several terms those are related to reservoir. So in the further slides we are going to understand more about the reservoir and its properties those are related to natural gas production.

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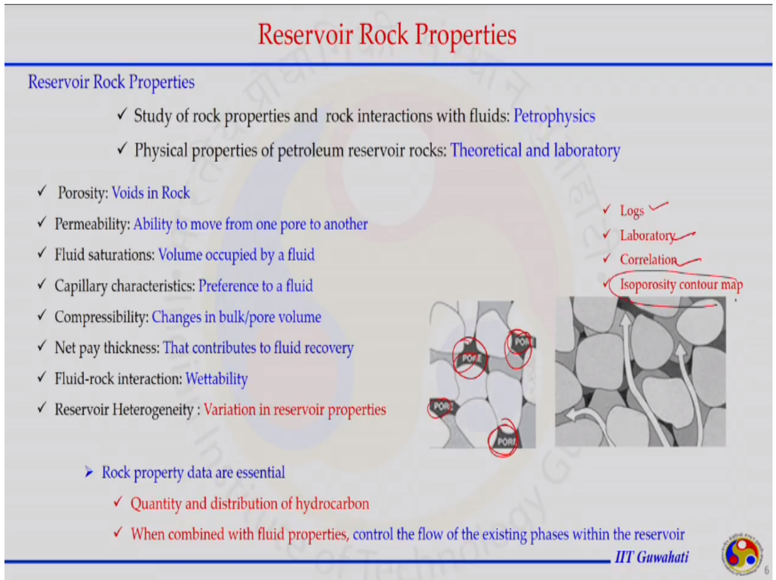

So reservoir rock properties are very important because they provide the information or the knowledge about the gas is or the fluid is available in the reservoir domain or not how much is the how much volume of the particular phase is available and they also allow us to design and implement the gas or fluid production (()) (18:34) from the reservoir. So the reservoir rock property study comes under the head of petro physics that accounts for the study of properties and rock interaction with fluid.

So within the reservoir we are having the rock and fluid the rock can be out of different types depends on the formation is composed of it could be just a lose sand or unconsolidated sands or it could be very tightly packed sand stone, lime stone kind of the reservoir it depends on the geological time scale the other parameter those we are not going to cover in this we just going to understand the properties those are related to natural gas production.

So the petro physics includes the study of rock properties and the interaction with the fluid these physical properties of petroleum reservoir can be estimated either theoretically or perform in the laboratory experiment. The important properties can be counted as porosity that is the boiled in the rocks the rock that appears like it has no porous or it as no place to be in the form of void but yes it is having significant void is depend on the size of those void is.

So every rock is having the porosity that may vary from 2% to volume percent to 40%, 50% like the unconsolidated sand is having very high porosity while the tightly packed shell are having very low porosity. That porosity actually depends on several factors so here I have listed some of the properties those are related to natural gas production like the porosity, permeability fluid saturation, capillary characteristics, compressibility, net pay thickness, fluid rock interaction, reservoir heterogeneity.

And all this properties are in one way or other way or going to the included in the natural gas production study important properties are porosity and permeability. Porosity accounts for the wide in rock permeability it is ability to move from one port to another port. So the permeability actually decide the fluid or the hydro carbon or the gas available in the reservoir is recoverable or not as it can be seen in this pictures.

The ports are there so this are the pores those ports may be connected or may not be connected the gas may be stored here but that may be recoverable or not recoverable that is determined by the permeability of that rock. So if it is permeable then only it is recoverable other properties like fluid saturation those or like which part of the rock is occupied by the gas and which part is occupied by the oil and when both oil, gas as well as water all phases are available in a pore domain in the reservoir in one place how they are going to occupy the places in the pore region is determined by the fluid saturation.

Every properties could be important like net pay thickness that continuous this is the thickness of the reservoir that contributes to fluid recovery. So reservoir like it is a very big area where we are having a wellbore perforated and in this reservoir for example this is the porous region where fluid is accumulated we want to produce the fluid when we are injecting our wellbore at the bottom of the wellbore we perforate.

We create the holes in that wellbore bottom part and the fluid travels assuming it is a radial flow the radially fluid travels from all the direction towards the wellbore and only a part of the wellbore that was that is actually allowing the fluid to travel is a net pay thickness. In fact the fluid may be available in large area or in the large height that can be excess for the production that is called the gross page on thickness for the net page on thickness is the thickness through which the fluid is coming to wellbore.

Fluid rock interaction like wettability that is also effect reservoir heterogeneity, variation in reservoir properties. So the reservoir properties like porosity, permeability, saturation compressibility, page on thickness all they vary from location to location and the heterogeneity should accounted when we are going to understand comprehensively.

How the reservoir property and how the reservoir domain is going to contribute towards the recoverable hydro carbon production. The rock property data are essential because they quantify and also calculate the distribution of the hydro carbon in the rock when these properties are combined with fluid properties they control the flow of the adjusting phases within the reservoir.

So assuming reservoir is having while gas and water how they are going to be produce determine by the rock properties as well as fluid properties and the reservoir properties can be estimated either by the locks performing the experiment in the laboratory using some establish correlation or some maps those are available it is very tedious job it is very completed job knowing the entire reservoir spectrum how the porosity, permeability, fluid saturation are distributed so sometimes it those are calculated either on average basis based on the experience and some other parameter correlation are used to correct the properties.

We are not going to detail of that but one by one we will try to understand more detail about some of the important properties here.

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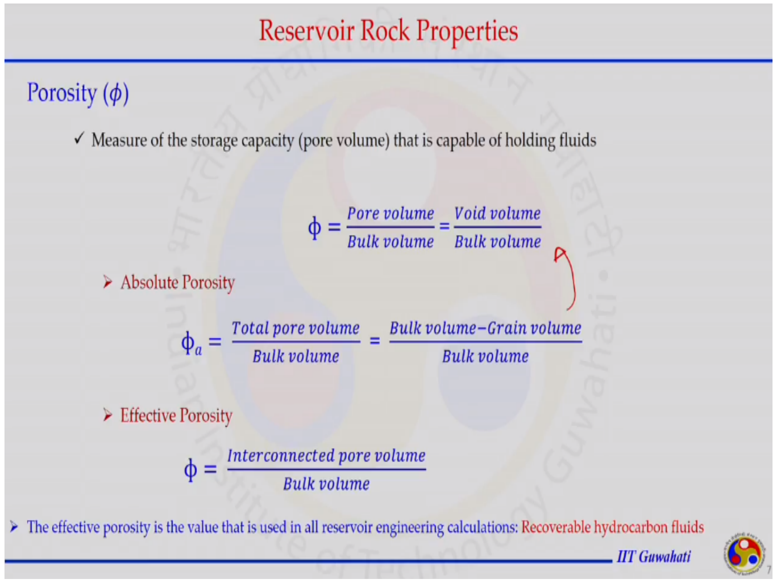

Like the porosity measure of the storage capacity so reservoir is having several voids that voids could be in the range of just 2% or less than 2% to 40% or 60% of the total volume of the rock but only the volume that is can accommodate the fluid or the pore volume contributes towards the porosity so the porosity by mathematical definition it is the pore volume divided by bulk volume.

So for example we are having one core (()) (25:13) example and that is having certain height and certain diameter we can calculate the bulk volume of that core but this is not pore volume. Pore volume is something when we are using the pores of the core sample to store some fluid or the fluid is stored in that core sample that can used to calculate the porosity of the core sample so the porosity is pore volume divided by bulk volume.

Pore volume is also known as a wide volume so the definition comes us wide volume by bulk volume porosity further classified or defined in two other important set of terminology absolute porosity that is represented by fe that is total power volume divided by bulk volume and he bulk volume – grain volume is the total pore volume.

So this obsolete porosity definition is similar to what is the general porosity definition thus simply says the total pore volume available within the domain of study divided by the bulk volume is obsolete porosity well effective porosity simply says the volume that is available or the void that is available in the bulk volume is not going to contribute the recovery of the hydro carbon or production it is only the interconnected pore volume.

So the pore volume those are interconnected can be used to calculate the effective porosity by definition comes out as a ratio of interconnected pore volume to bulk volume. We will see with the one of the example how this absolute porosity and effective porosity can be calculated but in more of the engineering application that is reservoir engineer application this is the effective porosity that is used because effective porosity is something that is actually account for the recoverable hydro carbon.

There might be plenty of hydro carbon available in the reservoir domain but only those are recoverable those are found in the connecting pores are recoverable.

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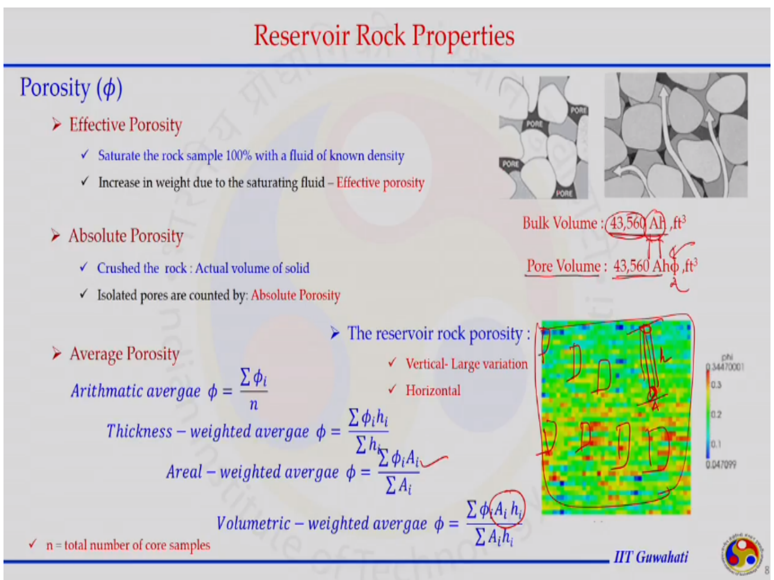

The effective porosity as it is shown in this picture again this is these are the pores and this is this are pores and this is which are the pores which are connected will contribute for the production.so let us take an example we are having one sample core samples (()) (27:36) certain diameter and certain height h is the height if this is a core and this is some area cross sectional area is A.

So we know the dimensions of the core we can calculate the bulk volume now this core is saturated with the fluid of non- property none density what we can we are saturating this

100% so what we will come to know the pores those are connected the fluid or the fluid of none density can travel to only those connected zones so we can calculate the weight increase of this pores sample when it was 100% saturated with the fluid of non-properties. The Increase in the weight is because of the effective porosity which is available in this core club.

So we can calculate the effective porosity another definition absolute porosity so assume like this core sample is crushed and when we are crushing it we just destroy the connected and non-connected terminology we just simply said this is sample after crushing it this is a sample which is having grain volume or the volume occupied by the rock only we can calculate the actual volume of solid.

So we crush it mix it we destroy the connecting nodes also so we are going to get actual volume of this solid knowing the actual volume of the solid and the bulk volume that was already there before crushing it we can calculate the obsolete porosity of this and that obsolete porosity simply because the isolated pores are counted. So the pores which were not accessible before or also counted in this and that this the obsolete porosity here an example is shown.

So for example this is (()) (29:40) area of the reservoir is know we can calculate the bulk volume A and h is the area h is the height and this is the numerical coefficient because of converting acre into ft square pore volume is simply this volume multiply by the porosity so by knowing the porosity we can always calculate the pore volume or connecting pore volume here the pore this is effective porosity. The reservoir rock porosity varies all the direction but equivalent horizontally it varies more than the horizontal section.

In fact even in **a** at location to location the value various the node those are connected just here may not be connected just next one inch or one feet away. So in a large domain of like (()) (30:34) reason there are large variation in the porosity value with respect to location that is can be classified as a vertical porosity variation or the horizontal variation and this pictures simply shows like how the porosity is distributed in some domain for that what can be done we can calculate the average porosity of the interest domain or the reservoir of interest.

That average can be calculated in several form first mathematical average we can classify that several zones with vertically, horizontal either small segments and we can say the porosity of different region number of samples we are having we can just simply sum the porosity of different core samples divided by the number of core samples. Number of core samples means for example this is our reservoir domain in a 2D manner we are collecting a sample from a different location the core sample estimating the porosity of each we can just take the arithmetic average.

Other way could be taken as weighed average porosity in that case we know the porosity changes with sample to sample we can just weight with the height similarly we can with the area or by the volume is again Ai hi. AI hi is the volume of core i which is having area Ai and the height hi. So the variation can accounted by using any one of the formula and that represent the average value of the porosity.

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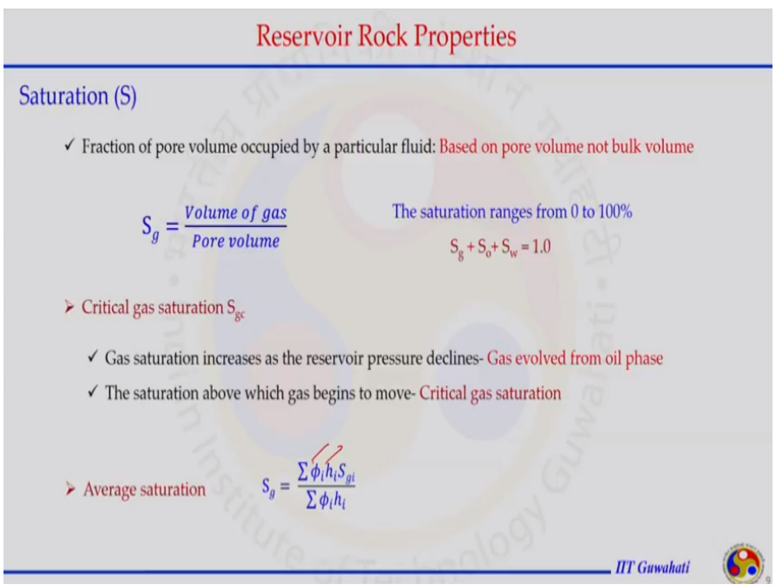

Another properties is saturation so the void is those are available those are connecting void is the reservoir are filled by fluid those fluids could be water, oil and gas. So the saturation of oil, gas and water is just a fraction of pore volume occupied by the particular fluid so if it is occupied by a gas the volume of gas divided pore volume is the saturation of the gas. Similarly can be explained for the oil So that is volume of the pore occupied by the oil divided by the pore volume.

Similar for the water the volume of the pore or the void as occupied by the water divided by the pore volume is the saturation of the water. So this saturation can range from 0 to 100 % for example in a reservoir domain there is a no gas available only the oil and water then this gas saturation is 0 when the area is just having single phase then gas phase the gas saturation is 100%. So this saturation can range from 0 to 100% the saturation of each phase that is available gas, oil, water the summation = 1.

Critical gas saturation another important parameter that determines like the condition ever which gas beings to move and any fluid begins to move when the fluid move its critical saturation then only it is start to move gas saturation increases as the reservoir pressure decline. So what exactly the definition of critical gas saturation is when we are having the two phase gas and liquid because of the pressure decline is happening in the reservoir gas comes out oil of the oil phase and the gas saturation increase.

And when the gas saturation reaches critical condition just gas start to move the average value of the gas saturation can be calculated in the waited form like it is weighed with the porosity as well as page on thickness Phi i and hi. Similarly it can be estimated for the oil and water.

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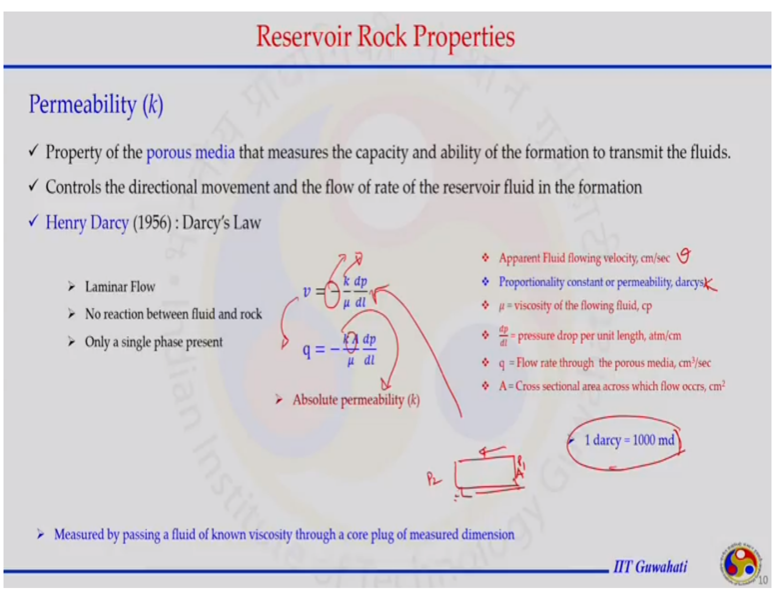

Permeability it is the property of the porous media that measure the capacity availability of formation to transmit the fluid. So it is kind of the property of the rock that says the fluid can be pass can be travel from one location to other location or not it controls the direct movement of the flows if the permeability is in the X direction only the fluid will travel only in X direction not in Y in this direction or any particular direction where the permeability is there where the fluid will travel otherwise not.

So it control the directional movement and the fluid rate of the reservoir fluid in the formation the permeability is defined by Henry Darcy in 1956 when he was performing the laboratory experiment under the laminar flow condition when there was not reaction happening and only single phase was present he had develop a correlation that says the apparent velocity is proportional to pressure gradients and inversely proportional to viscosity of fluid.

And the proportionally constant came out as K and that K is permeability of the availability of the rock that says the fluid can travel with that particular velocity that can be converted the apparent velocity can be converted into flow rate. So velocity = qya so area we got on the right and side the minus sign simply says the strength decrease when pressure increase or other way when pressure decreases length increases that is why we are having the negative terms here.

Important is this expression is only under the condition of laminar flow no fluid and rock interaction and only single phase is present and in our case when we are having the natural gas flow in the reservoir in the radial direction when there is no reaction is happening only gas phase is being flowed under the laminar condition we can perfectly use Henry Darcy to account for that.

Here the permeability that we get is the obsolete permeability we can understand the permeability later on. So here the apparent fluid flow velocity is v the unit is meter per second it could be one unit system here I had mentioned in the CGS system proportionality constant of permeability in Darcy Mu is viscosity of the flowing fluid this is k that is forget to mention the pressure gradient per unit length this flow rate and centimeter q per second is cross sectional area across which flow occurs and all together we get with the help of this expression we can get the Darcy permeability and then 1 Darcy is 1000 milli Darcy.

So this permeability measured by passing a fluid of non-viscosity through a core plug of major dimension. So for example we are having a core we know the dimension the cross sectional area the length of that core here and flowing because of that pressure gradient p1 is higher than p2 we will flow in this direction and when we are collecting the flex at the outlet establishing the relationship of the Darcy law the proportionality constant we are going to get is permeability and the permeability is absolute permeability.

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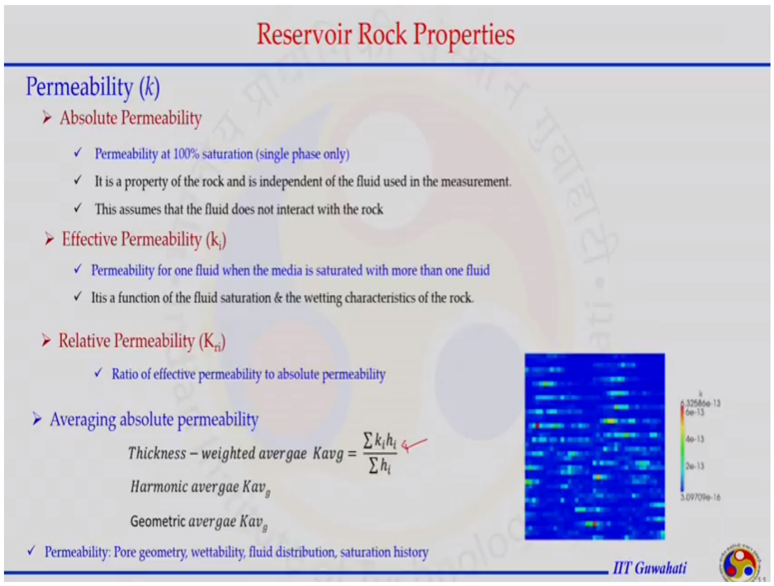

This is the permeability can again be the obsolete permeability when we consider only one phase or one single phase is present in the system it means the permeability and 100% saturation of that fluid it is a property of the rock and it is independent of the fluid using the measurement under the 100% saturation it just becomes the property of rock means how interconnecting pores are available in the log this assume that the fluid does not interact with the rock.

So all these are the conditions of Henry Darcy effective permeability when the reservoir is having more than 1 fluid there is a competition of which one will travel which will get the preference from the reservoir to flow from one point to another point and that is where the effective permeability is into picture and says the permeability of the fluid A and other fluid B and C are present in the domain.

It is a function of the fluid saturation and the wetting characteristic of the rock so which phase is more having the wettability and non-wettability towards the rock will affect the effective permeability. Relative permeability is another term that is often used in the reservoir calculation that is the ratio of effective permeability to absolute permeability.

Permeability depends again on the pore geometry what type of the pores they are connected not connected wettability means the interaction between the fluid and rock and the fluid distribution like how man phases of the fluid are present and how they are distributed gas is on the top or it is dissolve in the oil and the saturation history similar to porosity permeability distribution is also there because the pores are may be connected here and just one feet and next distance they are not connected.

So the porosity like porosity permeability is also having the distribution across the all these direction X, Y, Z and again the like the porosity average absolute permeability can be calculated mathematically average the permeability. So for example first one is like arithmetic average we can also go with the harmonic average and geometric average the adjustment representation taking different form of mathematically form will be used to calculate the permeability is just like we are having the reservoir or let us say we are having some domain of 2D.

Let us say and we are having different zone of different permeability we can consider the flow is happening from bottom to top or top to bottom and the because of different permeability of each layer fluid will travel differently to know the effective to know the average absolute permeability we can average out the permeability of each section and that can be done to calculate the average absolute permeability.

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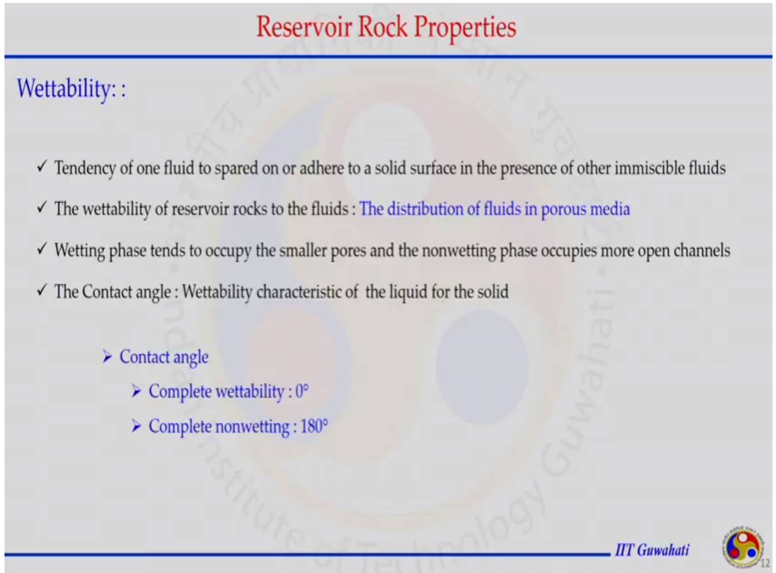

Another important properties is wettability is mostly used in the production of oil is more important than the gases the tendencies of one fluid to spread on or added to a solid surface in the presence of others immiscible fluid when two immiscible fluid are in the pores or in the determine or in the contact of rock which one is having more tendency to add or spread on the surface on the rock is measured by the wettability.

The wettability of reservoir rock to be fluid it shows the distribution of fluid in pores media so which is having more affinity towards the rock it will go towards the rock other going on the other side and it is measured in the measured in form the contact angle that characteristic of the liquid for the solid if the contact angle is 0 it means complete wettability the oil the fluid is having complete wettability means it added or it is stick to the surface of the rock when the angle is 180 degree means it is complete non waiting situation.

So with the help of wettability we can understand which fluid is having the access to the enter in the pore or coming out of the pore reason depend on the wettability behavior of that fluid available with respect to rock.

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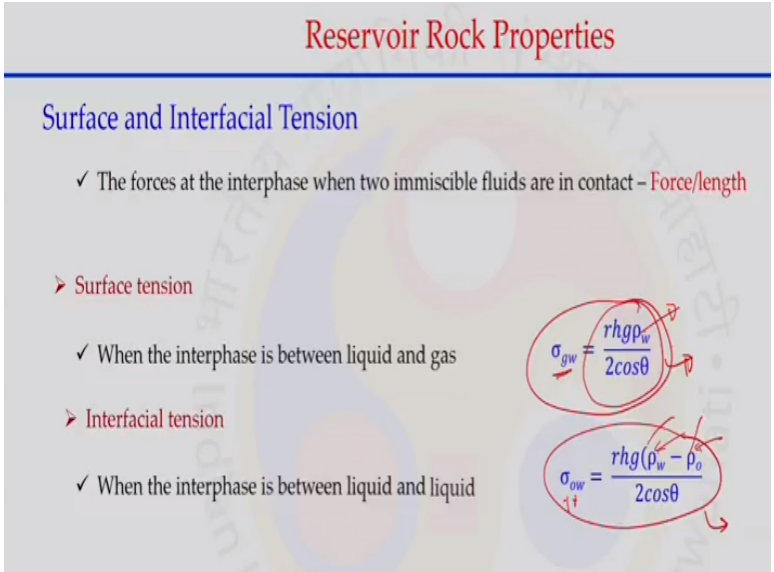

Other definition is are surface tension interfacial tension often comes the forces at the interfaces at the fluid or two immiscible fluid are in contact this is measured in force per length surface tension is between the liquid and gas while the interfacial tension when the two immiscible liquids are in the contact this expression can be obtained simply by equalizing the surface tension force at the interface by the gravity forces and when we do that that thing we can get the expression for this surface tension and expression for the interfacial tension.

And those depends on the density of the faces here in the surface tension case we are having for the water this is gas water system where we assume the density of the gas is negligible we are going to read this expression when in the gas of two liquid when we having oil and water the density of both the cases are going to come some are going to come to the magnetic expression where account for the forces those are acting in the interphase.

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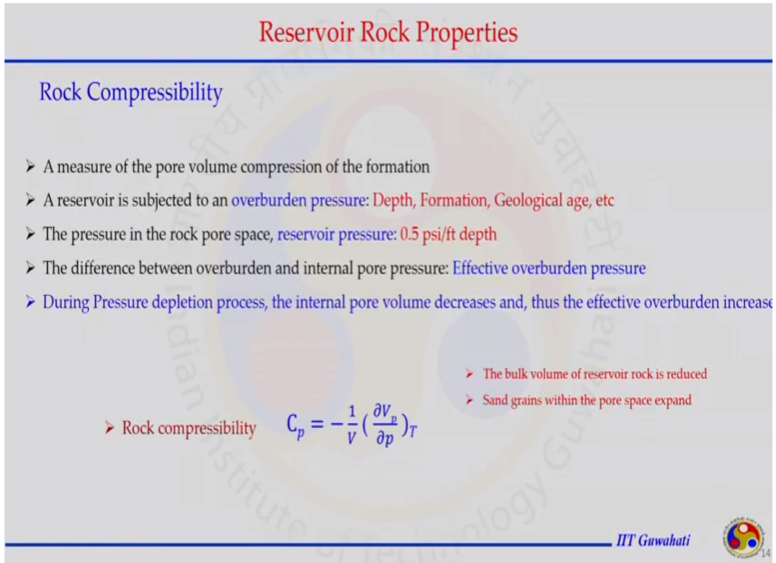

Rock compressibility like the fluid compressibility rock compressibility also becomes important when we talk about the pore volume available in the reservoir to be occupied where the fluid as we know we go down the reservoir is subjected to an over burden pressure. So it is assume like when we are going down 1 psi pressure should increase because of the pore volume is available.

It is just 0.5 psi per feet depth because the rock does not the pores in the rock does not experience the over pressure burden pressure comes in the completely the difference in the over burden pressure and internal pore pressure is called effective over burden pressure. During pressure depreciation process when we start producing the fluid form the reservoir the internal pore volume decreases.

When the internal pore volume decreasing effective over burden pressure increases and when this process happens the bulk volume of reservoir rock is reduced and sand grain with in the pore is this start expanding and because of this two things the pore volume for the bulk volume available in the reservoir as well as the pore volume both gets change and the properties those are responsible those are depend on the bulk volume of the reservoir also get influenced.

Mathematically the core rock compressibility is defined as change in volume with respect to pressure at isothermal condition divided by the initial volume. So any change in volume with respect to pressure divided by the initial volume is the rock compressibility because of the over burden when we are going to a different depth the over burden pressure will be different when we production the pressure internal pore volume pressure will also be different with the time and thus the rock compressibility will also be different.

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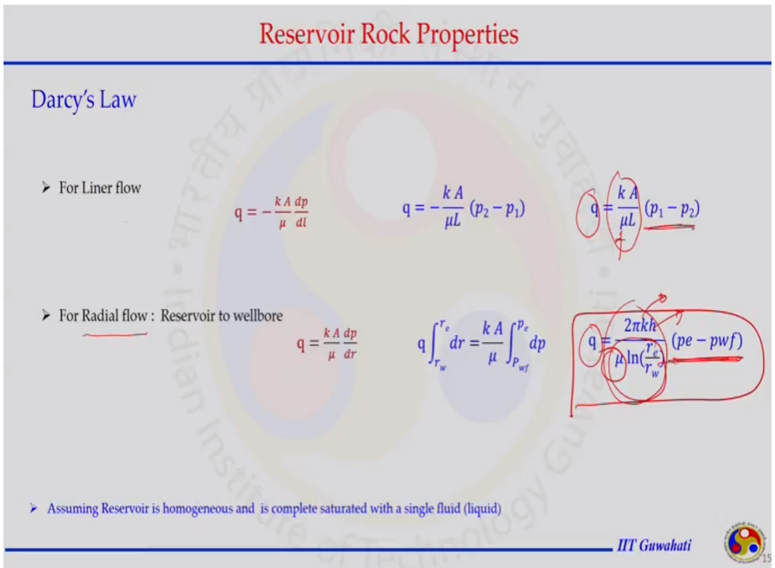

Another application of Darcy law that is we will be using when the flow is happening from the reservoir domain to wellbore than can happen under the linear condition or in a radial condition. Radial condition when we are having reservoir to well bore is happening from all the direction radially linear flow when we are having some experimental setup or the reservoir domain in such a way when the flow is happening in only one direction linearly.

Here we are having fluid and this is just travelling towards one direction two get the production value is we can use the understanding of the Darcy law to establish the relationship how the flow will happen because of the pressure gradient and both the cases under the linear flow or the radial flow we are having q as a function of another pressure draw down p1 – p2 is the linear and reservoir – wellbore pressure here with other properties like here.

Several assumption has been made here like the viscosity is not changing the q is also constant reservoir is homogenous most of the properties like the permeability is not changing with respect to direction in the reservoir we will see the application of Darcy law when we will be developing the relationship from the IPR we will get almost this kind of the expression that says how the q flugs is related to the pressure brought down the radius of well bore and reservoir viscosity of the gas which is being produced k is permeability and h is the page on thickness.

So using the Darcy law again we will be emphasis Darcy law is applicable only for laminar flow condition when there is no interaction between the fluid and rock is happening and only one phase is present either gas or line or water. In our case we are going to the gas flow is happening radial direction from reservoir to well bore.

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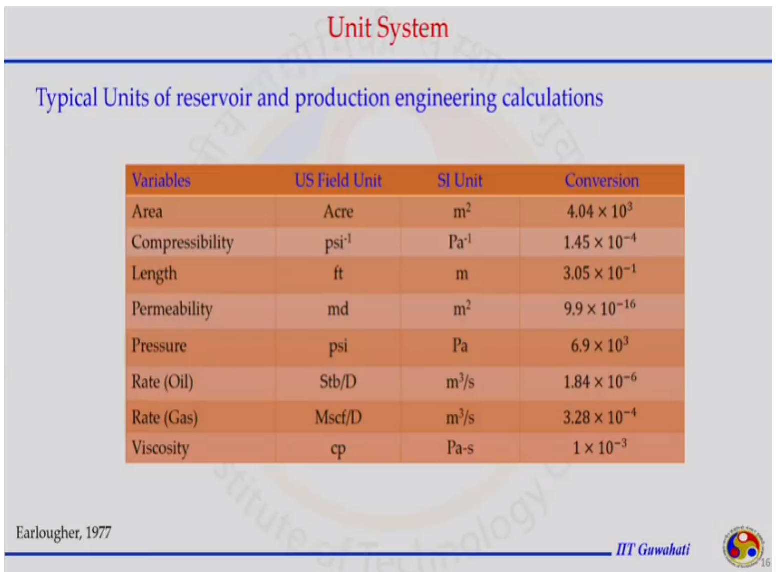

In summary the fluid properties there are several fluid properties influence the performance of any particular process or particular equipment thus to understand the performance or designing of the equipment or understanding the production system we need to measure the properties of natural gas and those properties changes with the condition like temperature and pressure and composition.

Similar way understanding of reservoir rock is also important especially when we are having the objective of knowing the gas in place and what maximum rate gas can be produced from the reservoir and all these calculation if we see we are having several parameters those are appearing like the Reynolds number the value of numerical coefficient of Reynolds number depends on the unit system chosen for each parameter involved in the value of numerical coefficient of Reynolds number depends on the unit system chosen for each parameter involved in the calculation of Reynolds number.

Similarly when we are having the expression for gas in place we are having the area page on thickness, porosity when we are having the Darcy law we are having the permeability there page on thickness there, pressure there, viscosity there it becomes very important to understand how to convert from one unit system to other unit system. The dealing with the reservoir calculation done in US field unit system here I have summarizes small table that is taken from one of the reference that says from US field unit system how to convert into SI system or the reverse.

So for example the area in US field unit system it is given in acre while in the SI unit system it is meter square so the conversion should be applied similarly for the other especially for this gas production system where it is in US field unit system it is Mscf per day while in SI unit it is meter cube per second and permeability in US field unit system it is milli Darcy while in SI unit system it is meter square you can prepare you compressive list for all the calculation or for all the conversion those will be appearing in several calculations.

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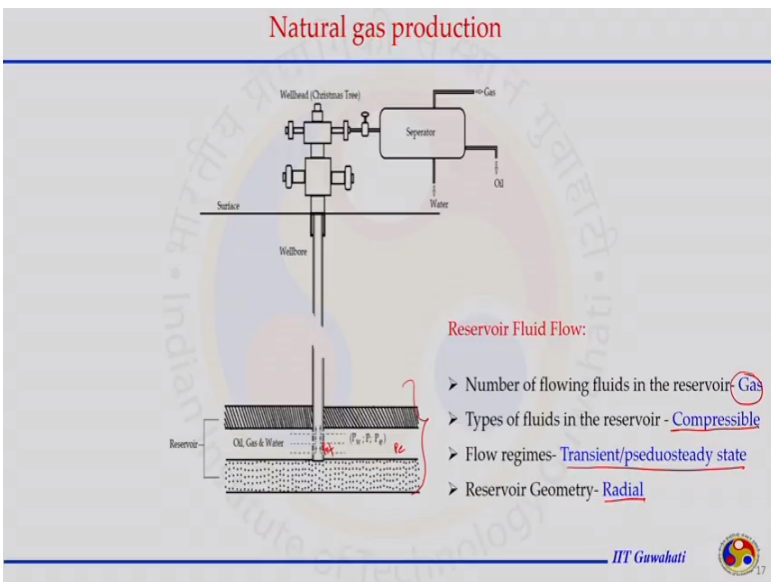

With this I think we are ready to understand natural gas production where we are having the identified well location the reservoir location where the gas well can be drilled and the production can be started. So in the next week we are going to establish the relationship for this segment IPR inflow performance relationship where the fluid will be travelling from all the direction or radially towards the wellbore the pressure PWF is lesser than the reservoir pressure that is the driving force for the fluid to travel.

And in our case of the natural gas production system we are going to assume only single phase is project some amount of the water, some amount of the oil, some amount of the sand particle may be present but we will treat them as negligible awe are going to assume our gas is compressible in nature and establish the relationship for the pseudo steady state condition and transient condition.

I already mentioned the flow we will consider under the radial conditions so with this understanding we will go to establish the IPR relation next week thank you very much for listening the video.