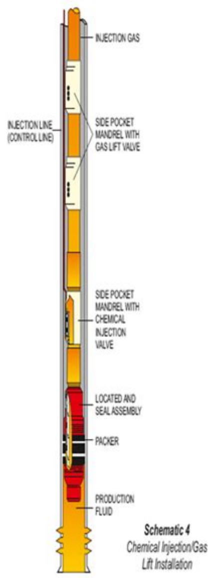
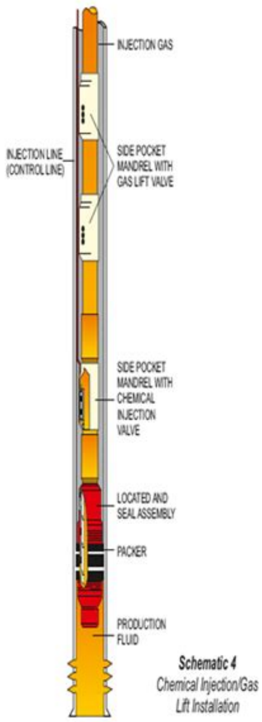

INJECTION GAS
INJECTION LINE (CONTROL LINE)
SIDE POCKET MANDREL WITH GAS LIFT VALVE
SIDE POCKET MANDREL WITH CHEMICAL INJECTION VALVE
LOCATED AND SEAL ASSEMBLY
PACKER
PRODUCTION FLUID
Schematic 4
Chemical Injection/Gas Lift Installation

Book Descriptions:

Completion design manual eni



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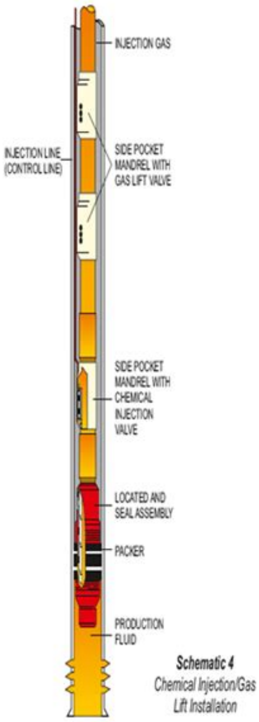
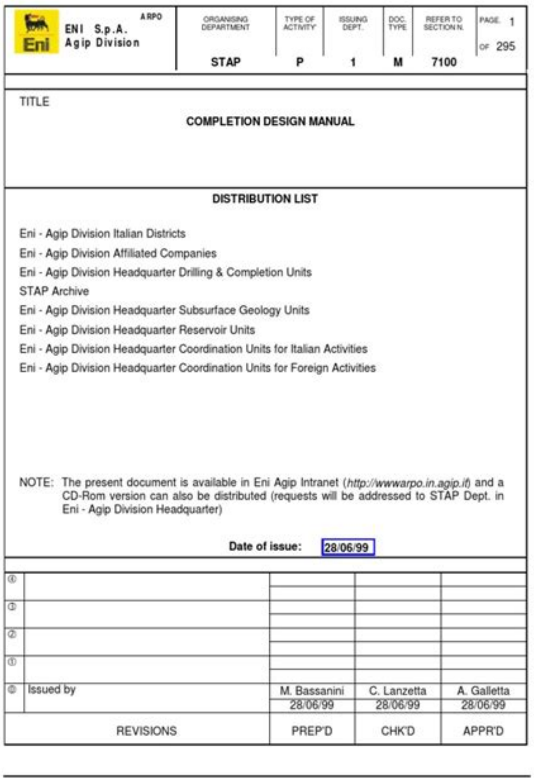


For instance, the decision on the well architecture may subsequently be changed due to the availability of well servicing or workover techniques. This does not mean that the process is sequential and many decisions can be made from studies and analysis run in parallel. The activities in each phase are illustrated in figure 1.a, figure 1.b and figure 1.c. The conceptual design process guides the engineers through analysis and key questions to be considered. During this phase, the user will resolve many of the dilemmas, raised by the interrelated decisions, at an early time. The final conceptual design will be used as the basis for the detailed design process. The conceptual design process begins at the field appraisal stage when a Statement Of Requirements SOR of the completion is produced. It is essential that this is an accurate statement including all the foreseen requirements, as it has a fundamental effect on the field final design and development. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 9 OF 295 REVISION STAPP1M7100 0 As more information is gleamed from further development wells and as conditions change, the statement of requirements need to reviewed and altered to modify the conceptual design for future wells. Provide adequate maintenance and surveillance programmes. Be as simple as possible to increase reliability. Provide adequate safety in accordance with legislative or company requirements and industry common practices. Be as flexible as possible for future operational changes in well function. In conjunction with other wells, effectively contribute to the whole development plan reservoir plan. Achieve the optimum production rates reliably at the lowest capital and operating costs. These may be summarised as to safely provide maximum long term profitability. This, however, in reality is not simple and many critical decisions are needed to balance long term and short term cash flow and sometimes compromises are made.http://www.FlashPointIP.com/fckupload/eye-camera-ps3-manual.xml



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	STAP	P	1	M	7100	

TITLE

COMPLETION DESIGN MANUAL

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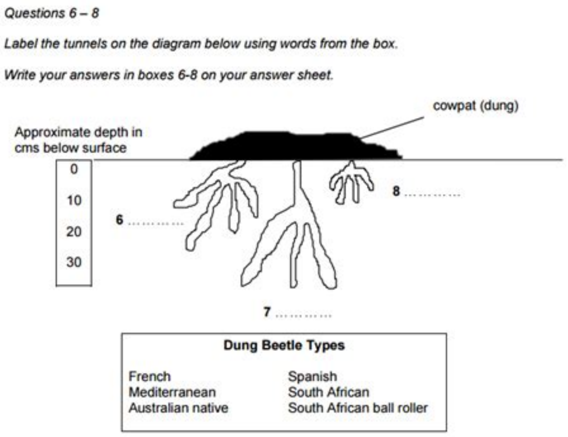
	REVISIONS	PREP'D	CHK'D	APPR'D

An expensive completion may derive more long term profit than a low cost completion but the initial capital costs will be higher Refer to figure 1.d. Figure 1.D Completion Design Versus Profitability ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 13 OF 295 REVISION STAPP1M7100 0 On the other hand if the data available is not accurate, the estimate of some well performance and characteristics throughout the life of the well may be wrong and early workover or well intervention operations will impact on well profitability. Reservoir and geoscience groups often have to set plans and objectives for the field on well performance based on limited information, in the early stages, but are not concerned about production problems, well maintenance or detailed operations. 1.3. FUNCTIONS OF A COMPLETION The main function of a completion is to produce hydrocarbons to surface or deliver injection fluids to formations. This is its primary function, however a completion must also satisfy a great many other functions required for safety, optimising production, servicing, pressure monitoring and reservoir maintenance. Protecting the casing from corrosion attack by well fluids. Preventing hydrocarbon escape if there is a surface leak. Inhibiting scale or corrosion. Producing single or multiple zones. Perforating underbalanced or overbalanced. Permanent downhole pressure monitoring. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 14 OF 295 REVISION STAPP1M7100 2. RESERVOIR CONSIDERATIONS 2.1. INTRODUCTION 0 Oil and gas wells are expensive faucets that enable production of petroleum reservoirs or allow injection of fluids into an oil or gas reservoir. As pointed out in section 1.1, a completion conceptual design must take into account all the well objectives to produce the optimum design to maximise profitability. Most commercial reservoirs have sandstone, limestone or dolomite rocks, however some reservoirs even occur fractured shale. 2.2.2.

Permeability Permeability is a measure of the ability of which fluid can move through the interconnected pore spaces of the rock. Many rocks such as clays, shales, chalk, anhydrite and some highly cemented sandstones are impervious to movement of water, oil or gas even although they may be quite porous. Darcy, a French engineer, working with water filters, developed the first relationship which described the flow through porous rock which is still used today. Darcy's Law states that the rate of flow through a given rock varies directly with permeability measure of the continuity of interconnected pore spaces and the pressure applied, and varies inversely with the viscosity of the fluid flowing. In a rock having a permeability of 1 Darcy, 1cc of a 1cp viscosity fluid will flow each second 2 through a portion of rock 1cm in length and having a crosssection of 1cm, if the pressure across the rock is 1 atmosphere. Relative permeability represents the ease at which one fluid flows through connecting pore spaces in the presence of other fluids, in comparison to the ease that it would flow if there was no other fluid. If reservoir pressure is allowed to decline, some lighter components of the oil will evolve as gas in the pore spaces. Flow of oil is reduced but gas saturation is too small for it to flow through the pores. If pressures to continue to decline, gas saturation continues to increase and at some point equilibrium gas saturation gas begins to flow and the oil rate is further reduced. With further increases in gas saturation, the gas rate continues to increase and less oil flows through the pores until finally only gas flows. Significant oil may still occupy the pores but cannot be recovered by primary production means as the permeability to oil has dropped to zero. This same principle governs the flow of oil in the presence of water. The saturation of each fluid present affects the ease of fluid movement or relative permeability.



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The gasoil or wateroil relative permeability relationships of a particular reservoir rock depend on the configurations of the rock pore spaces and the wetting characteristics of the fluids and rock surfaces. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 16 OF 295 REVISION STAPP1M7100 0 Where two or more fluids are present, the permeability in eq. 2.b represents the permeability of the rock to the desired fluid. This means that the grains of the rock matrix are coated with a film of water permitting hydrocarbons to fill the centre of the pore spaces. The productivity of oil in this condition is maximised. Although it is extremely difficult to determine wettability of cores due to the cutting and preparing specimens for laboratory testing which alters the wettability characteristics, it is not important as this characteristic is included in the permeability measurements. However, it is important when completing or servicing the well in that any foreign substance which may come into contact with the rock may alter its wettability characteristic and reduce the relative permeability to hydrocarbon fluids and cause emulsion which may block flow. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division REVISION STAPP1M7100 2.2.5. 17 OF 295 0 Fluid Distribution The distribution of fluids vertically in the reservoir is very important as the relative amounts of oil, gas and water present at a particular level determines the fluids that produced by a well completed at that level and also influence the relative rates of fluid production. In rock the capillary forces, which are related to water wettability, work to change the normal sharp interfaces between the fluids separated by density. Relative permeability permits both water and oil to flow within the transition zone. Above the transition zone, only oil will flow in an oilwater system. Connate water is related to permeability and pore channels in lower rocks are generally smaller.

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For a given height, the capillary pressure in two different pore sizes will be the same, therefore the water film between the water and the oil will have the same curvature, hence more oil will be contained in larger pore spaces. The nature and thickness of the transition zones between the water and oil, oil and gas, and water and gas are influenced by several factors uniformity, permeability, wettability, surface tension and the relative density differences between the fluids. In lower permeability sands, the transition zones will be thicker than in higher permeability sands. Due to the greater density difference between gas and oil as compared to oil and water, the transition zone between the oil and gas is not as thick as the transition zone between oil and water. A well completed in the transition zone will be expected to produce both oil and water, depending on the saturations of each fluid present at the completion level. figure 2.a summarises oil, water and gas saturation in a typical homogeneous rock example. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 18 OF 295 REVISION STAPP1M7100 0 Figure 2.A Example Fluid Distribution in a Uniform Sand Reservoir Containing Connate Water, Oil and Gas Cap 2.2.6. Fluid Flow In The Reservoir Oil has little natural ability to produce itself into the wellbore. It is produced principally by pressure inherent in gas dissolved in oil, in associated free gas caps, or in associated aquifers. Pressure Distribution Around the Wellbore Pressure distribution in the reservoir and factors which influence it are of great of significance in interpreting well production trends caused by pressure characteristics. Pressure distribution around a producing oil well completed in a homogeneous zone will gradually drop from the reservoir pressure some distance from the wellbore until closer to the wellbore where it will decline quite sharply.

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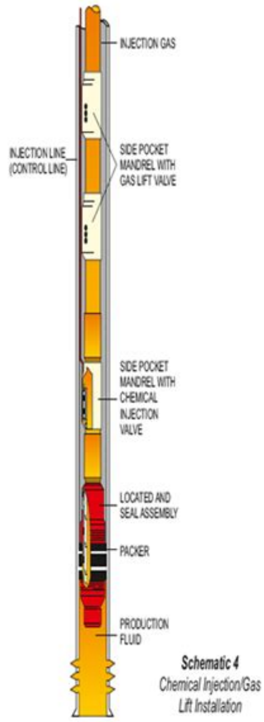

The wellhead pressure will be much lower due to the influence of hydrostatic pressure and tubing frictional effects. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 19 OF 295 REVISION STAPP1M7100 0 In a radial flow situation, where fluids move towards the well from all directions, most of the pressure drop in the reservoir occurs fairly close to the wellbore. As shown in figure 2.b, in a uniform sand, the pressure drop across the last 15ft of the formation surrounding the wellbore is about one half of the total pressure drop from the well to a point 500ft away in the reservoir. Obviously flow velocities increase tremendously as fluid approaches the wellbore. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 20 OF 295 REVISION STAPP1M7100 0 Figure 2.C Units For Darcy’s Law Equation For nonhomogeneous zones, which is the usual case, permeablities must be averaged for flow through parallel layers of differing permeabilities. In cases where there may be sand problems and a gravel pack is used, the tunnels are packed with gravel to hold the formation in place, which will cause a restriction. Flow through perforating tunnels is linear rather radial and Darcy’s equation must be corrected as turbulent flow usually exists. Experiments have shown that pressure drop through gravel filled perforations compared with uncorrected linear flow Darcy’s Law calculations is substantial as shown in figure 2.f below. Curve A indicates that plugging with even high permeability 1 Darcy sand gives a large pressure drop. Actual test data with very high permeability sand, curve B, proves turbulent flow results in higher pressure drop than Darcy’s Law calculations, curve C, predict. Investigators have provided turbulence correction factors which can be applied to Darcy’s equation to permit calculation of pressure drop through perforating tunnels. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 22 OF 295 REVISION STAPP1M7100 0 Figure 2.

F Pressure Drop Versus Flow Rate Through Perforation Causes Of Low Flowing BottomHole Pressure In a well with uniform sand and fluid conditions, two factors may cause low flowing bottomhole pressures. These are permeability and producing rate. With low permeability or excessive rate of production, pressure drawdown will be appreciable higher than normal thus reducing flowing bottomhole pressures and causing the well to be placed on artificial lift if higher productions rates are necessary. Low permeability is often caused by damage close to the wellbore through drilling, completion or intervention operations. This is particularly detrimental as the effect close to the wellbore is greatly magnified. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 23 OF 295 REVISION STAPP1M7100 0 The existence of damage can be calculated by well test results analysing the pressure buildup periods. Flow profiling may highlight zones, in an otherwise productive interval, which are not contributing to the total flow. Noncontributing zones are likely to have been damaged. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division REVISION STAPP1M7100 2.2.7. 24 OF 295 0 Effects Of Reservoir Characteristics Reservoir Drive Mechanisms In an oil reservoir, primary production results from existing pressure in the reservoir. Most reservoirs in actuality produce by a combination of all three mechanisms. In a dissolved gas reservoir, the source of pressure is principally the liberation and expansion of gas from the oil phase as pressure is reduced. A gas drive reservoir's primary pressure source is the expansion of a gas cap over the oil zone. A water drive reservoir's principle pressure source is an external water hydrostatic pressure communicated to below the oil zone. The effect of the drive mechanism on the producing characteristics must be evaluated in the completion design process, and also for later recompletions, to systematically recover reservoir hydrocarbons. figure 2.

g and figure 2.h, show typical reservoir pressures versus production trends and gasoil ratio production trends for the three basic drive mechanisms. In a dissolved gas drive reservoir without any artificial pressure maintenance technique, pressure declines rapidly, gasoil ratio peaks rapidly and then declines rapidly, and primary oil recovery is relatively low. Recompleting would not reduce the gasoil ratio. In a gas cap drive reservoir, pressure declines less rapidly and gasoil ratios increase as the gas cap expands into the upstructure well completion intervals. Well intervention or recompletion to shutoff upstructure intervals may control the gasoil ratio, therefore lose pressure less rapidly. Water drive reservoirs pressure remains high and gasoil ratios are lower but downstructure well intervals quickly begin to produce water. This is controlled by well interventions or recompletions to shutoff the water production or the well is shutin. Gradually even the upstructure wells will water out to maximise oil recovery. Obviously many factors must be considered in developing a reservoir, however the main factors concentrate on the reservoir itself and the procedure used to exploit hydrocarbon recovery. Well spacing, or well location, is fundamental and the cost of time, labour and materials consumed in the drilling are largely nonrecoverable, therefore if development drilling proceeds on the basis of close spacing before the drive mechanism is identified, the investment will have already been made. This does not usually present an insurmountable problem as a field of any considerable size will require a minimum number of wells to be drilled in any case to define the reservoir, i.e. establish the detailed geological picture regarding zone continuity and locate oilwater and gasoil contacts.

By careful planning when enough information is gained to determine the well locations, these can be drilled at the appropriate spacing to maximise recovery with the least amount of wells. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 25 OF 295 REVISION STAPP1M7100 0 Many case histories are available to show problems resulting from reservoir development without having sufficient information about the stratigraphy of the reservoir. Figure 2.G Reservoir Pressure Trends For Various Drive Mechanisms Figure 2.H GasOil Ratios Trends For Various Drive Mechanisms ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 26 OF 295 REVISION STAPP1M7100 0 With regard to drive mechanisms, some general statements can be made Dissolved gas drive reservoirs Well completions in reservoirs with low structural relief can be made in a regularly spaced pattern throughout the reservoir and, provided the rock is stratified, can be set low in the reservoir bed. A regular spacing can also be used for dissolved gas reservoirs with high angle of dip. Again the completion intervals should be structurally low because of the angle of dip and the exact subsurface location would vary with well location on the structure. In this scenario it would be expected that oil recovery would be greater with the minimum well investment as the oil will drain downstructure through time. If this is recognised after drilling begins, the well locations must be changed quickly to take full advantage of the situation. Due to the low recovery by the primary drive mechanism, some means of secondary recovery will almost certainly be required at some point in life of the reservoir and the initial well completion design should take this into account. Gas cap drive reservoirs Wells are generally spaced on a regular pattern where the sand is thick, dip angle is low and gas cap is completely underlayed by oil.

Again completion intervals should be low in the structure to permit the gas cap to grow for maximum recovery and minimum gas production. Like the dissolved gas drive reservoir, the wells in thin sands with a high angle of dip is likely to be more efficiently controlled by having the completion irregularly spaced and low to conform to the shape of the reservoir. Regular spacing would place many completions too near the gasoil contact. Such reservoirs are common where multiple this sands are found on a single structure and the oil column is only a fraction of the total productive relief. Water drive reservoirs Wells can be spaced on a regular pattern on a thick sand and low angle of dip. Completion intervals should be selected high on the structure to permit long production life while oil is displaced up to the completion intervals by invading water from below. A water reservoir in a thin sand with high angle of dip may best be developed with irregular well spacing because of the structural characteristics. Regular spacing of the wells may cause early water production and possible early abandonment in conjunction with reducing the drive effectiveness through excessive water production. Significant levels of water production are unavoidable in later field life when maximising production rates. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division REVISION STAPP1M7100 2.2.8. 27 OF 295 0 Reservoir Homogeneity The general procedures, as described in the previous section is to complete water drive reservoirs high and for dissolved gas drive reservoir low on the structure to obtain an adequate number of wells without excess. However this is only practical if the reservoir is uniform. Most sandstone reservoirs were originally laid down as stratified layers of varying porosity and permeability. Similar assumptions can be made for carbonate and even reef type reservoirs which results in reservoirs of a highly stratified nature.

Fluids from such reservoirs will flow through the various layers at different restrictions to flow and often there are impervious beds between the layers so that fluid cannot flow between the bed to bed. If the reservoir is stratified, either by shale breaks or by variations in permeability, it will probably be necessary to stagger the completion intervals in various members of the reservoir to be sure that each is drained properly. Vertical staggering of the completion can be effected during development to obtain proportionate depletion of the various strata. Additional distribution of intervals in the various members can then be made during later well interventions on the basis of data obtained, experience and operating conditions. To maximise recovery, intervals should be produced independently wherever practical usually determined by economics. Completions with more than one zone are termed multizone completions and are required for long completion intervals for obtaining sufficient volumes of production. Figure 2.I Irregular Water Encroachment and Breakthrough ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 28 OF 295 REVISION STAPP1M7100 0 Figure 2.J High GOR Production by Encroachment of Gas 2.3. HYDROCARBON DATA The practical approach to the study of reservoir fluid behaviour is to anticipate pressure and temperature changes in the reservoir and at surface during production, and to measure, by laboratory tests, the changes occurring in the reservoir samples. The results of these tests then provide the basic fluid data for estimates of fluid recovery by various methods of reservoir operations and also to estimate reservoir parameters through transient pressure testing. Two general methods are used to obtain samples of reservoir oil for laboratory examination purposes, by means of subsurface samplers and by obtaining surface samples of separator liquid and gas.

The surface samples are then recombined in the laboratory in proportions equal the gasoil ratio measured at the separator during well testing. Information concerning the characteristics and behaviour of gas needed for gas reservoirs, depends upon the type of gas and the nature of the problem. If retrograde condensation is involved, it may require numerous tests and measurements. If the gas is wet with no retrograde condensation, or if dry gas, the information is less complex. 2.3.1. Oil Property Correlation Several generalisations of oil sample data are available to permit correlations of oil properties to be made refer to the Compant Well Test Manual for sampling techniques. The process of this analysis is shown in figure 2.k which requires continuous repetition during field life to account for changing conditions. The inflow performance relationship IPR provides the flow potential of the reservoir into the wellbore against the resistance to flow of the formation and near wellbore region. The theoretical IPR is an idealistic assumption of flow performance without pressure drop due to skin effect in the near wellbore region and governed only by the size, shape and permeability of the producing zone and the properties of the produced fluids. The basic theory of this is described in this section along with some simplified IPR relationships from observed field data. Flow behaviour in the near wellbore region may cause a dramatic effect on the IPR curve which results in greatly reduced flow capability. This is characterised by a damaged IPR curve and the amount of damage or skin effect, is mainly caused by the drilling and completion practices. Good drilling and completion practices can or may minimise this damage allowing use of the idealised IPR curve to be used for completion design.

Some completion designs to deal with reservoir conditions, such as gravel packs for unconsolidated sands, will also cause reduced IPR curves which must be anticipated during the design phase. Two phase flow, velocity effects in gas wells, high rate or high GOR oil wells, in undamaged near wellbore regions also reduce the IPR curve. Alternatively, stimulation procedures which can provide a negative skin are desirable as this increases production. Once the IPR is completed, the outflow performance can be determined which takes into consideration the relationship between the surface flowrate and pressure drop in the tubing. The prediction of this relationship is complicated by the nature of multiphase fluid flow. Hence, analysis of the outflow performance requires predictions of phase behaviour, effective fluid density, friction losses and flowing temperatures. The results of the outflow performance analysis are usually produced graphically depicting how bottom hole flowing pressure BHFP, or pump intake pressure, varies with flowrate against a fixed backpressure which is normally the wellhead or separator pressure. ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division REVISION STAPP1M7100 2.4.1. 31 OF 295 0 Inflow Perfomance This section addresses the fundamental principles of inflow performance for oil and gas wells. The use of IPRs generated from reservoir simulation models is also described as is the technique for the applications of the various techniques for predicting inflow performance. Essentially the less data which is available, the more appropriate it is to use theoretical radial flow equation. As more data becomes available, an empirical expression can be validated and applied, however for larger projects, reservoir simulation is usually employed. With a straight line IPR, the flow rate is directionally proportional to the drawdown. The linear relationship can be substantiated from theoretical arguments for a single incompressible fluid i.e.

above the bubble point. However, it has been verified that the straight line approach also provides the accuracy needed for well performance calculations in situations which exceed the theoretical basis, e.g. low drawdowns and damaged wells. In situations which allow the use of a straight line IPR, the constant of proportionality is termed the productivity index PI. Before this the well produces under transient conditions, as in most well tests, result in higher estimates of productivity than when under stabilised conditions. Productivity Index, J, also needs to be treated with caution as Production Engineers and Reservoir Engineers assume different basis for J. Production Engineers relate J to gross liquid production oil and water whereas Reservoir Engineers relate it to oil productivity. J can be calculated directly from bottomhole gauges in well test results or estimated pressures from simulation studies. As water saturation increases, Ko obviously decreases and as does Jo. Damaged wells with positive skins have straight line IPRs with PIs less than the ideal PI. Straight line IPRs with PIs greater than the ideal are typical of wells with negative skin such as when they have been stimulated, have natural fractures or are highly deviated. The PI is very useful for describing the potential of various wells as it combines all rock and fluid properties as well as geometrical issues in a single constant making it unnecessary to consider these properties individually. Figure 2.M Effect of Damage And Fractures on a Well's PI ARPO IDENTIFICATION CODE PAGE ENI S.p.A. Agip Division 34 OF 295 REVISION STAPP1M7100 0 Oil Well Vogel's Two Phase Flow IPR The previous straight line IPR does not hold with two phase flow gas and liquid in the reservoir.