Well Planning

Before initial operations are started on any well, a plan should be constructed that will take the well from initial drilling to plug and abandonment. There are a series of steps and operations that go into completing a successful well. Many of these are interconnected, and the expense of a well in today's market requires that consideration be given to efficient economical planning.

The method of planning is the same, regardless of the use of the well. Planning starts with cooperation and information exchange between explorers, drillers, completions and operations engineers and foremen, partner companies, service companies, equipment providers, and government regulatory officials. The information gathered in this step often prevents expensive misunderstandings that would occur during the drilling or completion of the well or disastrous environmental problems that could result from improperly executed operations. Each of the functional operations in well service involves specialists. Too often these specialists do not have a good knowledge of the operation of other parts of the industry, and the effects that their specific actions will have on the other operations of a well.

One of the first basic needs in today's environment is to prevent pollution. There is a need to isolate all usable waters from contamination during the drilling, completion, or producing process. This step requires careful design and a concerted effort on the application side. The requirements include casing that will withstand pressure and the corrosive atmospheres that will be experienced during the life of a well, even if a sweet well turns slightly sour. It also requires consideration of cement placement and elimination of any possible means of migration of fluids through or around the borehole.

The expected use of a well, whether it be observation, production, injection, or a multiple purpose well, will influence where the well is placed, how large the casing is, and what corrosive service ratings will be required. It should be remembered that many wells serve more than one purpose during their lives.

The reservoir conditions will obviously affect the completions. The factors that are most known in this area are temperature and pressure. However, fluids, viscosity, corrosiveness of the fluids, and even the rate of fluid production become very important. Factors which are not always considered include the tendency for formation of scales, emulsions, paraffins, and asphaltenes. It is very possible by modification of the tubing string or the incorporation of special coatings to almost completely prevent many scale problems.

The rate of fluid production is the main factor in selection of the casing size. Expectations of a very high rate well cannot be met with small casing. Problems such as this are often in direct contrast to efforts to reduce well costs by using a small casing string or a small tubing string. Although initial savings in these areas can easily be made, the long-term benefits of the well weigh in heavily for larger tubulars. There are also alternatives to conventional tubing and casing strings such as monobore completions, velocity strings, tailpipe extensions, and the use of coiled tubing for rapidly run and retrieved tubing strings.

The amount of service needed during the life of a well certainly has an influence on the topside connections and the location of the wellhead itself. For sweet gas wells with very low liquid production, remote wellheads or subsea wellheads in offshore fields make very good sense. These wells would only be good where well intervention was at a minimum.
Perhaps one of the most difficult parts to effectively plan are multiple layered reservoirs. In this problem area, there is a need to process all of the reservoirs without permitting crossflow from one zone to another. Obviously, individual wells could be used to isolate each zone. However, the expense of drilling and completion are usually too high to make this a viable alternative, except in the highest rate producing areas. Other methods of effectively producing multiple reservoirs or layered reservoirs include a variety of techniques, such as tubing selectives, multiple completions, and sequenced production of reservoirs. Commingling of zones should be done when permitted by pressures and reactants that may form by mixing waters or oils of various zones.

Physical well design parameters should have been dictated by the expected producing behavior of the well. Sizes of tubing and casing are set before the drilling bit selection process. During the tubular design, the use of pup joints (short joints of casing to improve depth control of perforating and other operations), nipple locations, and the use of special equipment in a string, such as subsurface safety valves that require larger casing, are needed early in the design phase of the well. In most cases, it is advisable to minimize the number of restrictions in a producing string to make sure needed tools can pass through the string and to prevent deposits that are often caused downstream of a flow restriction.

Cementing operations should be carefully planned and applied to eliminate channeling of fluid. Too often it is assumed that the primary cement job will be a failure before the job is even pumped. This type of thinking leads to a haphazard placement of cement and a self-fulfilling prophecy requiring expensive squeeze cementing. It has been shown in a number of tests that proper quality control and attention to detail can result in effective primary cementing jobs.

Perforating planning is an area that could definitely use attention during both planning and application. A variety of processes and tools are available from underbalanced to extreme overbalanced perforating and from wireline perforating to tubing conveyed perforating. Perforating expense can run from a few thousand dollars to over one hundred thousand dollars, depending on the needs of the well and the care with which it is designed. Expensive techniques are by no means always needed.

The type of artificial lift that will be used on the well should have been decided long before the well was drilled. A number of artificial lift methods are available: gas lift, beam lift, plunger, jet lift, progressive cavity pumps, electric submersible, and natural flow. Of these lift methods, beam lift, gas lift, and electric submersible pumps probably make up at least 98% of the artificial lift cases. Many wells that are on natural flow early in their life have to be artificially lifted as pressures decline or as fluid volumes increase to the point where gas drive and natural gas lift are no longer sufficient. The ability to change lift methods as fluid volumes increase or decrease is required for well operation optimization. If the casing and packer are designed with a conversion in mind, the switch of lift systems is easy.

Some formations have special needs, such as sand control. When the strength of the formation is not adequate to prevent sand grains from being dislodged by the drag forces encountered in production, then special completion techniques are needed to prevent the sand from entering the wellbore. A number of techniques have been tried, with resin consolidation of the sand and gravel packing being the primary control mechanisms. The real concern in most sand control jobs is not what type of control, but whether sand control is needed and when it is needed. The factors that cause sand movement change during the lift of the well. Some wells that will not experience sand production until after water breakthrough are gravel packed from initial completion. This is a large initial expense that can, in some cases, be delayed. Produced fluids including oil, gas, water and returning injected fluids are all readable fluids. In addition, the well is a reactor when these fluids are moved through the well path. Conditions within this "reactor" include temperature, pressure, pressure drop and other factors such as metallurgy and clearances within the structure of the well. When the well flow path from formation to tank battery is correctly designed for the flow of a particular fluid, the detrimental reactions are very few. But when the well design is not suited to the particular fluids that must be produced, a "problem well" is often created. Produced fluids are a reactant-rich "soup" composed of natural surfactants in both the oil and the water, free and dissolved salts, hydrocarbons with carbon chain links from C_1 to C_{60}, dissolved and free mineral and hydrocarbon gases, bacteria, micelles, and over 20 possible combinations of emulsions, foams, froths, and dispersions controlled and stabilized by such things as pH, viscosity, internal phase concentration, and surface energy. When an upset occurs, the panic that ensues usually requires a quick fix. When the tank battery goes down because of a tank of "bad" oil (oil with a higher than allowable water content), chemical treating is usually required as an emergency procedure to reduce the water content and return the well to production. The total chemical approach may be short-sighted in some instances, particularly when production upset symptoms are treated in a cyclic manner. The best approach often requires an understanding of the individual reactants and their relationship to both each other and their flow path environment. Often problem wells will yield improvements only when physical changes are made in the well design. Numerous instances are available that show chronic production upset problems being eliminated when physical changes were made to the well architecture.

An understanding of production chemistry is a critical factor in designing the downhole and surface equipment that makes up the well's system. The approaches that must be used are much the same as initial design; however, the knowledge that liquid and gas volumes, relative amounts and pressure will change over the life of a project. Thus, some flexibility must be built in to achieve a low maintenance well system.

In general, several steps are followed when evaluating and/or designing a well system.

1. Most emulsions, including emulsions, sludges, froths, foams and dispersions, are most troublesome because of energy input and a stabilizing mechanism. By eliminating one or both of these two factors, a significant decrease can be attained in problems with phase separation. The lift system and pressure drops within the flowing system are the chief inputs of energy into an emulsion.

2. Upsets following acidizing or any type of chemical treating may be severe and are generally based either on a solid material added with the chemical injection or by a variance in pH which affects the

behavior of natural surfactants. Tracking and controlling pH can often be a significant factor in eliminating problems with upsets.

3. Production of solids from a well creates problems with emulsion stabilization, solids abrasion and all types of fluid separation. Where possible, flow of solids should be identified and the source minimized.

The lift system must be designed for the expected rate after a stimulation and must take into account the recovery of the stimulation load fluid plus the method with which it commonly flows back. The most severe problems in these areas generally include hydraulic fracturing and acidizing. Once an acid job has begun to flow back, the pH may drop, significantly affecting the amount of corrosion during the load fluid recovery stage. Jobs involving proppant fracturing often give problems because of proppant flowback in the produced fluids during the initial stage of fluid flow.

In old wells and in marginal wells there is probably no stronger need than that of consideration of produced water control. Water comes in as a response to low pressure caused by hydrocarbon production. There may be many scenarios of water production. In some cases water drives the hydrocarbons toward the wellbore. If you shutoff the water, you will reduce the hydrocarbon production volume. In other cases leaks through bad cement, corroded casing, or through fractures can flood the well with extraneous water. In these cases a water control treatment is often useful. Where bottom water drive is severe, horizontal wells have often been used to successfully produce hydrocarbon without severe water production problems. Each of these possibilities can be addressed in the initial well plan.

Control of corrosion is needed throughout the life of the wells. In many applications the well will have a very low corrosivity when first drilled, but the corrosion rate will go up significantly during the life of a well. In many wells, the original casing lasts 20 or more years before leaks are detected. Repair may bring temporary relief, but leaks may often return within a few months. Special inhibitor programs are needed as well conditions change.

Formation damage has been mentioned in earlier paragraphs, and it is well to remember that formation damage may recur during the life of the well. The most prevalent times for formation damage occurrence are during workovers and when pressure declines or water from a floodfront causes precipitation of either organic or inorganic components in the formation or in the tubing string. Modeling can often show a trend of formation damage and its effects, but the actual occurrence of formation damage can probably not be adequately predicted by any model without very exacting knowledge of well behavior.

The occurrence of formation damage or drilling of a formation that is lower permeability than expected may require stimulations. Stimulations, including fracturing, acidizing, heat, and solvents, can be applied on almost any well provided that the support equipment and the tubulars will allow the techniques to be implemented. If formation damage or stimulation need can be adequately forecasted early In the life of the well then cost reduction is often possible.

For projects where enhanced recovery is envisioned, well placement and spacing become critical. In these applications the use of horizontal wells, deviated wells, and vertical wells are necessary to adequately process and sweep the reservoir. It is unfortunate that we know enough about reservoir to adequately place wells only when the reservoir is nearing depletion. With new techniques however, such as well-to-well seismic and 3D seismic, improved mapping of the reservoir if possible. This type **of** investigation may also yield additional pay zones and how those pay zones can be accessed.

Every well that is ever drilled will require plug and abandonment. The techniques for plugging abandonment and the rules are many and varied. The underlying objective however is very plain. Wells should be plugged in a manner in which the fluids that are in the reservoirs will stay isolated. This need for isolation should be an overriding concern in any completion planning and must be accounted for when processes such as fracturing or well placement are considered.