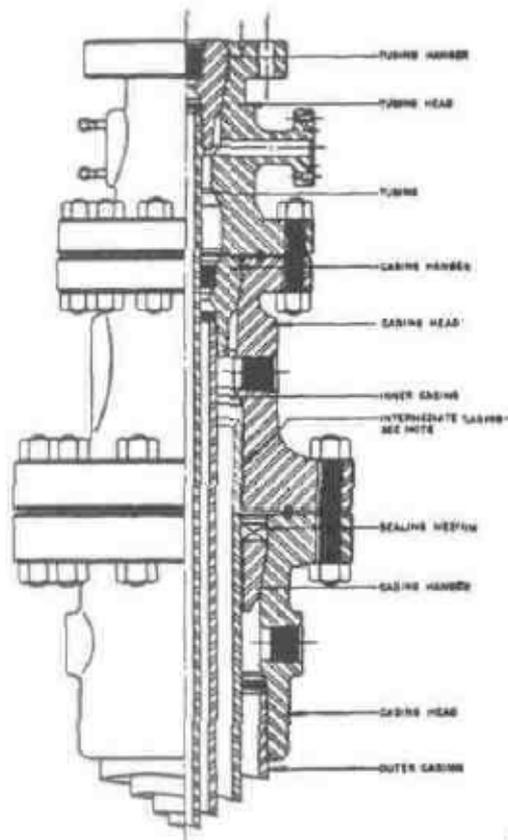


Chapter 5: Well Heads, Chokes and SSSVs

Wellheads

Wellheads are the connection point for the tubulars and the surface flow lines as well as being the surface pressure control point in almost any well operation. They are rated for working pressures of 2000 psi to 15,000 psi (or greater). They must be selected to meet the pressure, temperature, corrosion, and production compatibility requirements of the well. There are three sections of a wellhead, and each serves a function in the completion of a well.¹ The outermost cemented casing string, usually either the conductor pipe or the surface string, is fitted with a slip type or threaded casing head. The head, Figure 5.1, also called a well head flange, supports the BOPs during drilling and the rest of the well head during production. A port on the side of the head allows communication with the annulus when another casing string is run. For all additional casing strings, a casing spool is used. The spool has a flange at each end. The flange diameter, bolt pattern and seal assembly are a function of the spool size range and the pressure rating. When specifying well head equipment, all pieces should be rated for the same pressure. The tubing is hung and isolated in a tubing spool. The tubing is "spaced out" to come to the right height for the seal assembly by the use of pup joints (short pieces of tubing). Annulus communication is provided in the ports on the side of the spools.



(Kastor, 1972)

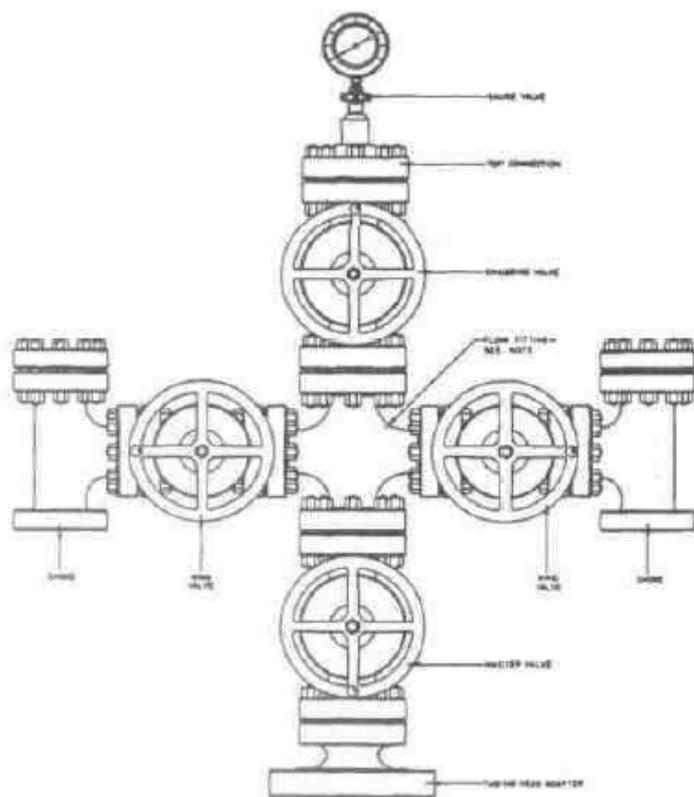
Figure 5.1: Wellhead assembly showing casing and tubing hangers. The casing head is screwed or welded to the conductor or surface string.

Each spool has alignment screws for aligning the tubular in the center of the spool. Alignment is critical since each flange connection (bolt hole alignment) depends on the last casing being in the center of the spool below it.

Multiple tubing strings can be accommodated by special heads. These head designs depend on isolation seals in the well head and multiple tubing spools. Setting the tubing and casing strings in tension is a common practice to offset the effects of buckling created by tubing expansion when hot fluids are produced.

The seal between each section is a single metal ring that fits in grooves in the top and base of connecting spool sections. The pressure to seat these metal-to-metal seals is provided by compression when the section flanges are bolted together. Oil is applied to the seals before bolting down the flanges. Various methods and devices for sealing have been tested for seals. Elastomers are subject to attack by solvents² and temperature cycling.³ Metal to metal seals are the most common, especially in severe service areas. In sour gas (hydrogen sulfide) areas, special metals are often needed for wellheads.⁴

The final section of the wellhead is the familiar "Christmas tree" arrangement of control valves. The tree sits on top of the tubing hanger spool and holds the valves used in well operation, Figure 5.2. The master valve is a full opening valve that is the main surface control point for access to the tubulars. It is always fully open when the well is producing or when a workover is in progress. The working pressure rating of the master valve must be sufficient to handle full wellhead pressure. If a valve or fitting in the upper part of the tree must be replaced, the master valve can be closed without killing the well (for all wells with a clear tubing, i.e., no rods). On very high pressure ($P_s > 5000$ psi) or hazardous wells, there may be two master valves; a backup for insurance against leaks in the main valve. The wing valve (often two valves) are mounted immediately above the master valve in a separate spool. Produced fluids leave the wellhead at the wing valve connection. The purpose of multiple wing valves is to allow changing of chokes or flow line repair without interrupting well flow. The swabbing or lubricator valve is mounted above the wing valve and is used to open the well to entry by a tool string. A schematic of the wellhead and tubulars is shown in Figure 5.3.



(Kastor, 1972)

Figure 5.2: "Christmas Tree" valve assembly for surface well control. On high pressure or sour gas wells,

The choke is the only device used to limit the production of flowing fluids. Using a valve, such as the wing valve or master valve, to limit fluid flow would allow fluid flow (possibly with solids) to cross the sealing surface of the valve. This could lead to erosion and a leaking master valve and would require killing the well to replace the valve.

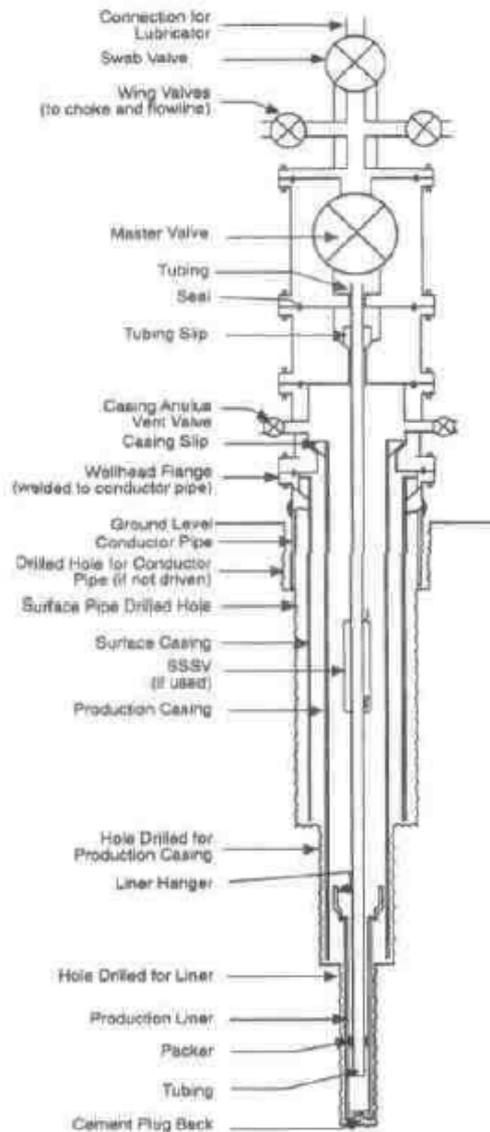


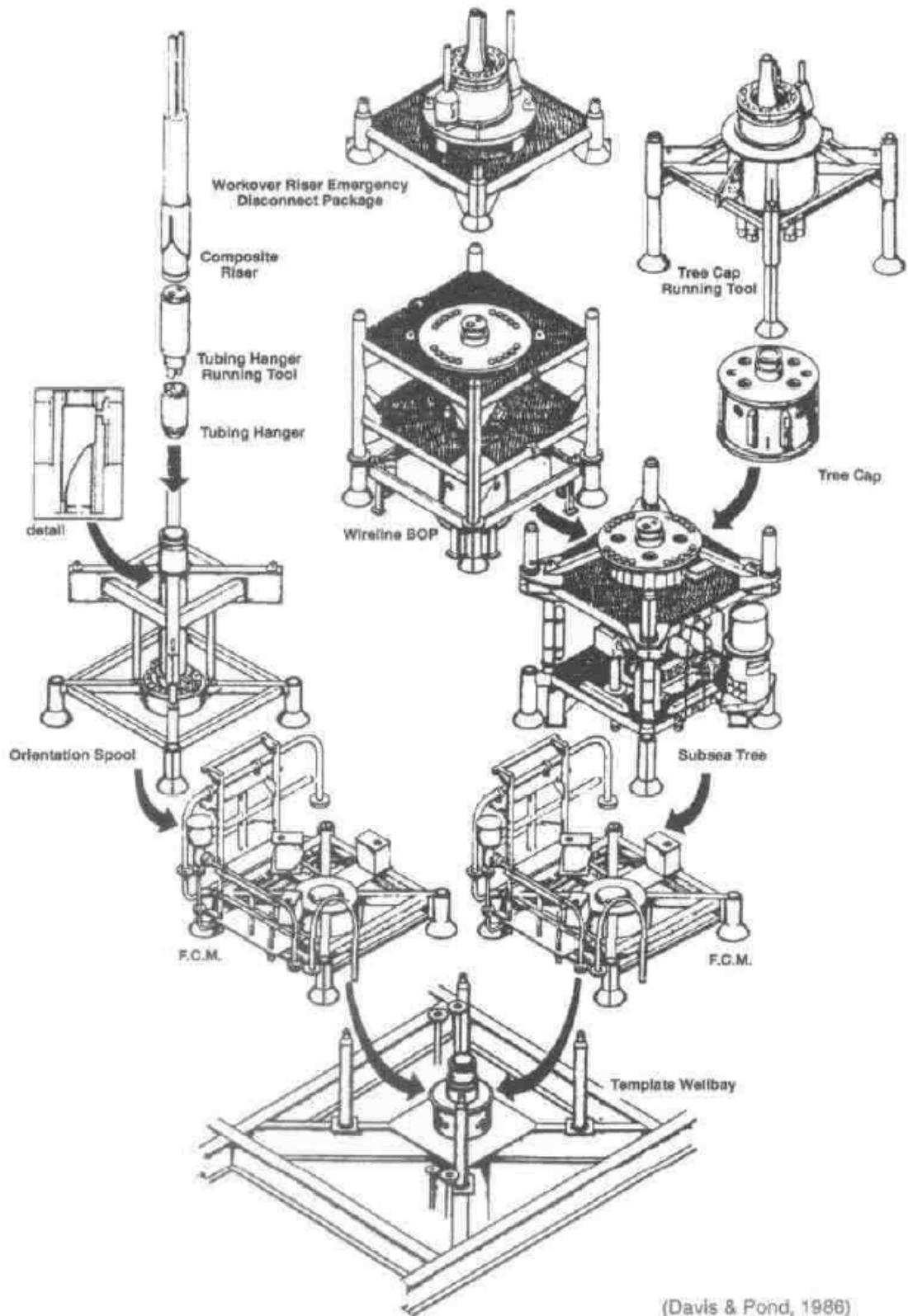
Figure 5.3: A rough schematic of a completed well with normal hardware.

A connection on top of the swabbing valve can be used to mount a lubricator. A lubricator is a pressure rated tube that allows a tool string to be lowered into the well, even while the well is flowing. One end of the lubricator is attached to the swabbing valve and the other contains a seal assembly that seals against the wireline that is used to run the tool. Since the lubricator stands straight up to allow the tool string to drop into the well, the length of the lubricator (and the length of the tool string) is controlled by the length of lubricator tube that can be safely supported by the equipment on location. A more detailed discussion of the lubricator will be given in the chapter covering wireline techniques.

Subsea Wellheads

A special type of well head is involved in a subsea well. In subsea wells, the wellhead sits on the ocean's bottom at depths from less than a hundred feet to over 2500 ft. Access is much more difficult than in a surface well, thus subsea completions require a well to be low maintenance, usually a sweet gas or flowing oil well. The wellheads for these wells must be self contained units with controls that can be manipulated by remote action at the well head by a ROT (remotely operated tool), by diver or by ROV (remotely operated vehicle). Almost all subsea operations, including drilling, begin after a template is installed on the ocean floor. The template serves as a locator for almost all tools used to drill, complete and workover the well. A schematic of the template and several workover and completion "tools" are shown in Figure 5.4. The modular work devices in the figure are characteristic of a surface wireline assisted operations. The

production well head that fits into the template must provide the same solid connection to the well as all land based well. Because of the remote or diver operation, however, appearances are vastly different than a surface well. Replaceable components of the wellhead such as valves and chokes are often equipped with guide bars to assist in remote replacement.



(Davis & Pond, 1986)

Figure 5.4: A subsea template and assorted workover and completion tools.

Coiled Tubing Well Heads

The use of coiled tubing for recompletion and even initial completion of some wells requires the use of special hangers or even complete wellheads that are designed especially for coiled tubing. Coiled tubing is being used in place of conventional tubing in some wells to minimize rig cost or to avoid killing the well to run tubing. Because of the lack of connections, coiled tubing can be run through stripping rubber seals in the BOP or through a standard stripper head. Hanging the tubing off in the wellhead requires slips; and, in live well workovers, these can be attached to the tubing and snubbed through the BOP stack to the slip bowl portion of the wellhead, or the slips can be made a part of the wellhead and activated from outside.

Coiled tubing completions may incorporate well ore bolt-on components or may be completely spool-able including gas lift valves, SSSVs and packers.

Examples of a hanger element are shown in Figure 5.5 and 5.6. These heads require a setting point below the master valve for a workover where the wellhead is nipped down. For low cost recomple-tions where the existing tubing and wellhead will not be removed, the coiled tubing is set through the existing master valve with the coiled tubing hanger and a new master valve set above the old master valve. Success of the coiled tubing completions and recompletions has been good when the tubing is sized correctly for the well condition.

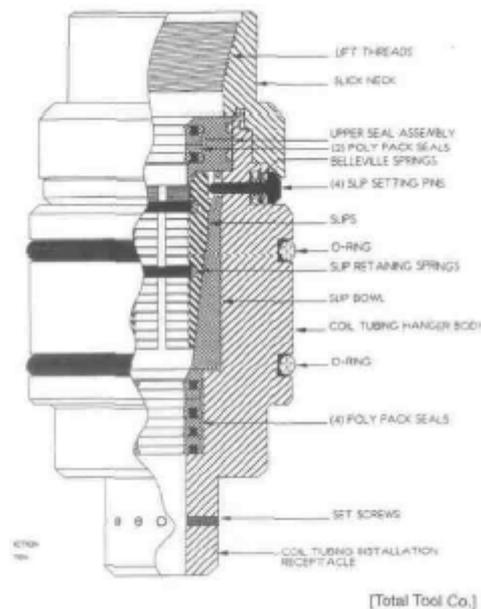


Figure 5.5: Coiled Tubing Hanger

Hydrate Control in Coiled Tubing Completions

Coiled tubing offers very good opportunities for recompletion or even initial completion of some wells, however, coiled tubing is particularly susceptible to collapse and compaction from production forces if an ice plug or hydrate plug forms either in the tubing or around the tubing. Problems in some operations where ice plugs have formed in the annulus during flow have caused sufficient force to collapse and compact coiled tubing to the point where 30-40 ft of coiled tubing are compressed into an area only 5 or 6 ft long. The only way to prevent ice plugs is either to control the rate of the gas flow so that the temperature drop during gas expansion does not create ice plugs or to inject a freeze inhibitor below the hydrate point to totally inhibit the formation of the ice.

COILED TUBING HANGER

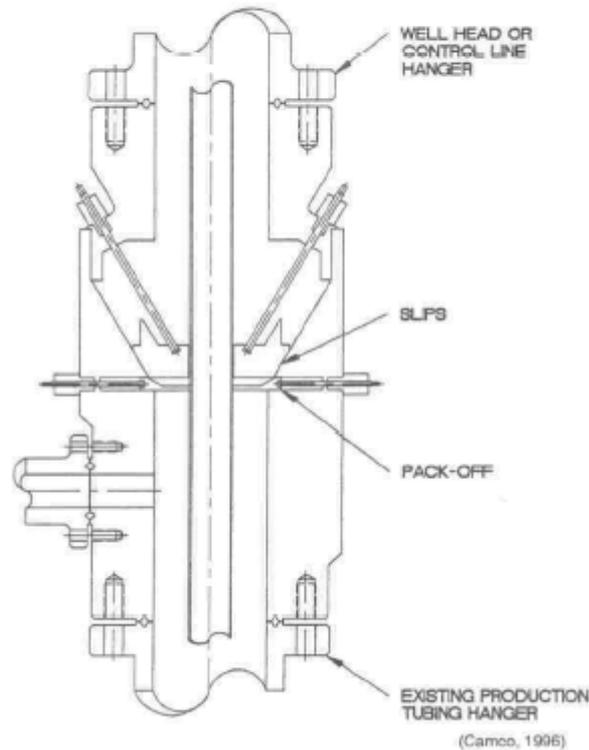


Figure 5.6: Coiled Tubing Hanger.

Example: Wellhead configuration - For a gas producing formation at 9600 ft with a reservoir pressure gradient of 0.55 psi/ft, what is the minimum wellhead equipment pressure rating (in psi) needed to cover production or fracture stimulation with an 8.5 lb/gal frac fluid, when fracturing the zone at 9600-11000. The friction pressure down the 4-1/2 in., 12.6 lb/ft, N-80 work string (packer set at 9300 ft) during the frac will be 75 psi/1000 ft of tubing length. During production flow the friction pressure is 10 psi/1000 ft. Shut in during production will be with a full column of gas (0.1 psi/ft). Standard safety factor for well head working pressure is 80% of rated capacity.

Solution: Calculate highest possible surface pressure.

1. Max producing pressure (shut in with gas column) = $(9600 \times (0.55 - 0.1)) = 4320$ psi

Don't use the friction pressure on producing since the worst production surface pressure case is static with gas in the tubing.

2. Max fracture stimulation surface pressure = $(0.83 \times 9600) - (9600 \times (8.5 \times 0.052)) + (9.3 \times 75)$ (7968 psi) D (4243 psi) + (698 psi) = 4423 psi

Minimum wellhead pressure rating $4423/0.8 = 5529$ psi

Chokes

Chokes hold a backpressure on a flowing well to make better use of the gas for natural gas lift and to control the bottomhole pressure for recovery reasons. In vertical pipe flow, the gas expands rapidly with decreasing hydrostatic head and the liquid moves in slugs through the tubing. The potential gas lift energy is rapidly lost and liquids fall back and begin to accumulate over the perforations. Accumulating liquids hold a back pressure on the formation. If enough liquids accumulate, the well may "die" and quit flowing. A choke holds back pressure by restricting the flow opening at the well head. Back pressure restricts the uncontrolled expansion and rise of the gas and thus helps keep the gas dispersed in the liquids on the way up the tubing. Chokes may be variable or have a set opening, Figure 5.7. The set openings, often called "beans," are short flow tubes. They are graduated in 64ths of an inch. Common flow sizes are about 8 through more than 20 (in 64ths) for small to moderate rate gas wells. Liquid producers and high rate gas wells use 20+ choke settings. The size of the choke needed depends on reservoir pressure, tubing size,

amount of gas, and amount and density of liquids. Variable chokes may use an increasing width slot design that allows quick resetting. They are useful on well cleanups following stimulation where choke size can vary over the course of a single day from 4/64ths to over 40. They are also used where periodic liquid unloading necessitates frequent choke size changes.

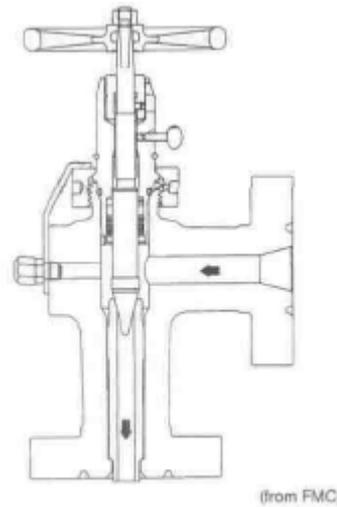


Figure 5.7: One form of adjustable choke.

Solids in the produced fluids are the major source of failures for chokes. Abrasion from sand, scale, ice, corrosion particles and other solids can cut out the choke restriction and cause the well to load up with fluids and die. Choke abrasion from solids and cavitation is increased when large pressure drops are taken. In these situations, choke life is often measured in minutes. For better performance at high pressure drops, take the drop in stages across three or more choke sets in series. The problem is with gas expansion; as gas goes from 5000 psi to atmospheric pressure, the gas expands 340 fold, with a similar increase in velocity. The same pressure drop, taken in series from 5000 to 3000, from 3000 to 500 and 800 to atmospheric results in gas volume (and velocity) increases of 136 fold (5000 psi to 3000 psi), 150 fold (3000 psi to 800 psi) and 54 fold (500 psi to atmospheric). The 340 fold total drop is the same, but the velocity increase across any one choke is significantly reduced.

Subsurface Safety Valves

When a well head is damaged, through accident or even terrorist incident, the fluids from a producing well can continue to flow, creating pollution and safety problems. One solution to the wild well potential is the use of safety valves. Safety valves are used to automatically halt the flow of fluid from a well in the event that the surface equipment of the well is damaged. Safety valves located at the surface are surface safety valves (SSVs) and those located below the wellhead are subsurface safety valves (SSSVs). SSVs are located above the master valve and below the choke and/or beyond the choke on the production line. SSSVs are located in the tubing string below the ground or mud line. Together, the surface safety valves and subsurface safety valves form a redundant system of fail-safe valves. The valves are designed to be fail-safe; they are designed in a normally closed position. Opening of the valves requires application of a pressure to the valve to hold the valve open. When the pressure is lost, all safety valves close automatically. Safety valves are typically used offshore, in environmentally sensitive areas and in some remote locations on unattended wells.

Any requirement for a subsurface safety valve and the depth of the valve below the wellhead depends upon the application and local government requirements. In offshore U.S., SSSVs are required and the subsurface safety valve is usually set in the tubing string 100 ft or more below the mud line. In the event of an accident or disaster, in which the wellhead equipment is partially or completely damaged or removed, the valves will shut in the wells and prevent pollution and fire.

The pressure that keeps the safety valves open is supplied by a small pump in a hydraulic-controlled panel on the surface platform.¹² The pump is an automatic hydraulic supply unit, powered usually by clean gas pressure. The pump supplies the control line with a 7 lb/gal clean hydraulic oil at a set pressure. Other types of actuation systems that have been tried for control of the SSSVs include differential flowing pressure,¹⁰ electric downhole solenoid,¹¹ velocity actuated,⁹ gas,¹³ electromagnetic wave control (directed through the sediments)¹⁴⁻¹⁵ and through loss of tension in the tubing string.

The earliest valves were designed to close if the well flow reached some maximum rate and were used almost exclusively offshore. The idea behind the design was that the valve would close if the platform was damaged in a storm. The problem with this type of downhole "flow sensitive" control, was that the valves were continually in need of resizing as the well's production capacity declined (reservoir depleted). The maximum rate trigger-mechanism was also a nuisance when high rate flow of gas was needed to meet market demand or when liquid slugged through the tubing. SSSV control is now almost exclusively from the surface via a small hydraulic control line on the outside of the tubing. If the pressure supply is interrupted, the valves closes automatically.

The valve sealing mechanism varies with manufacturer and the age and type of the valve. Most SSSVs use either a flapper valve or a ball valve with the current favorite being the flapper. The seat and flapper unit are protected from the well stream by a spring opposed sleeve that slides through the open flapper and isolates both the seat and the flapper. The sleeve is held in place by the hydraulic control pressure. The flapper assembly may be elastomer seal, metal-to-metal or a mixture of the two systems. Metal-to-metal seal units can be built for pressures in excess of 25000 psi. Ball valve units are equipped with spring loaded mechanisms that rotate the throat out of the well stream when the hydraulic opening pressure is removed. Examples of flapper and ball valves are shown in Figure 5.8. Other types of seal mechanisms have also been tried.



Figure 5.8: Examples of ball valves (above, Otis) and flapper (left, Camco).

The two conveyance types of subsurface safety valves are tubing retrievable and wireline retrievable. Tubing retrievable valves are run as part of the tubing string (the valve body is made up as part of the string) whereas wireline retrievable valves can be run and retrieved from a profile set in the tubing string. In the U.S., the tubing retrievable valves are almost twice as popular as the wireline retrievable valves, while in non-U.S. areas, the wireline valves are more popular than the tubing retrievables. The reasons for the popularity differences are found in personal preferences, workover cost differences and, to some extent, in regulations regarding well operation. The benefits of the tubing retrievable valve is that it has a fully opening bore, with very little obstruction to the flowing fluids. One disadvantage is that if there is a problem with the valve, the tubing must be pulled to the depth of the valve for service. This requires use of a rig; a large cost for many remote platforms. The tubing retrievable valves also require a relatively large upper casing section because of large valve body. The large outer body diameter (over 7 in. for a 4-1/2 in. bore valve) is necessitated by the flapper, spring and pressure equalization equipment within the valve. The wireline retrievable subsurface safety valve can be replaced by wireline without pulling the well, but it restricts the opening through which fluids may flow. The flow restriction for this type of valve may reduce 4-1/2 in. tubing to about a 1-1/2 in. bore over the 5 to 6 ft length of the valve. For most wells, this is not a severe restriction over a very short length. In wells that produce paraffin or scale, however, this flow restriction, especially near the top of the tubing may serve as the site for solids deposition and promote rapid valve failure. In wells that produce sand, any restriction may be a site for abrasion. In wells that do not precipitate or produce solids, the valves are often a good choice, especially in areas where well deliverability rate is critical and time consuming workovers (such as pulling the string to replace a tubing retrievable SSSV) must be avoided. Wireline retrievable valves must be set in a special profile that is made up as part of the string. The profile seat is connected to the same type of external control line that is used

for the tubing retrievable valve. A set of seals on the outside of the wireline valve isolates the hydraulic pressure port in the profile and allows a connection to the valve control mechanism. If the valve fails or malfunctions, the wireline unit can be removed and replaced by a low cost wireline operation with minimum productivity interruption.

Safety valve failures are rare but have been documented. When a valve fails to close, it is classified as a failure. When a valve fails to open, it is classified as a malfunction. The difference between the two labels comes from the design intent of the valve. Since the valve is designed to close when surface control pressure is lost, a failure is failure to close. Either event is troublesome.

One study on the reliability of SSSVs, showed the valves to have a failure rate that was on the order of 0.8 to 2.3% in normal operations.¹⁶ One of the biggest reasons for SSSV failure (of valves tested) is plugging of the sealing mechanism with paraffin, scale, produced sand, ice and other solids.^{8,23-25} It is very important to operate the valves periodically so debris can be removed from the assembly and that valve's internal mechanism can be lubricated. This operation is known as "exercising" the valve and is recommended to be done once per month. To exercise the valve, the wing vent is usually closed to shut the well in and the safety valve is open and closed several times. Merely releasing and restoring the hydraulic pressure at the surface will not confirm that the valve has actually closed. After the hydraulic control pressure is released, a few hundred psi can be bled off the tubing at the surface. If the pressure does not come back to initial shut-in pressure, then the valve is sealing. The amount of pressure that needs to be bled off at the surface depends of what seat material is in the valve. Elastomer seals are tested at about 500 psi while metal-to-metal seals are usually tested at least 500 to over 1000 psi. The recommended test pressure is available from the valve manufacturer. A regular maintenance schedule may be a legal requirement of operation.¹⁶⁻¹⁹

Reliability of the valves is very good if precautions are taken on regularly "exercising" the control mechanism. All of the 36 wells on the ill-fated Piper Alpha platform in the North Sea were equipped with SSSVs as per regulations. After the platform was destroyed, the fire was caused by the uncontrolled volume of produced gas in the pipeline (nearest shutoff was reportedly 1-1/2 miles away). The fire-fighting crew reported only minor leaks from tubing of the shut-in wells. In Kuwait, ten wells of the 700+ that had well heads damaged or destroyed were reportedly equipped with SSSVs. The valves prevented fires on those wells.

Opening the valve, either on initial well startup or after shut-in to check valve operation should follow a set of simple rules. To prevent valve damage, the pressure on both sides of the valve must be equalized. If the valve is a flapper design, the pressure is best equalized by pumping down the tubing to open the valve. If the unit is a ball valve, it may have to be opened by activation of the hydraulic pressure control unit. Flapper valves can also be opened by hydraulic actuator pressure. With either system, if the valve must be opened by the hydraulic mechanism, the differential pressure across the valve must be equalized before valve opening to prevent valve damage. Pressure equalization is accomplished with internal baffles that allow controlled flow of gas or liquid through the a part of the valve body. After pressure above and below the valve is equalized, the valve can easily be opened. If the valve is opened with a differential pressure across the valve, the fluid flow across the seal may cause erosion of the valve face.

An additional element of consideration for SSSVs is the construction material. Since they are directly in the flow stream, the SSSVs must be designed to withstand operational corrosion or erosion forces. Construction materials of corrosion resistant metals such as Incolloy or Hastelloy are common.

Selection of the type of SSSV depends on well conditions.⁷ Included in the considerations are legal requirements, depth of placement, pollution standards, dual strings,^{20,21} subsea wellhead,²² casing size near surface, presence of kill strings, annular flow, cost of workovers, frequency of workovers, type of workovers, deliverability obligations and the cost of the valve. When these and other variables such as pressure, setting depth, and temperature are considered, a decision can generally be made by examining the requirements and behavior of the available equipment.⁸

Setting depth of a valve depends on the ability of that valve to close in the event of an accident. The SSSV is rated with a closing pressure, F_c . If the control line pressure drops below F_c the valve closes, shutting in the well. The F_c value effectively limits how deep the valve can be set since either control line hydrostatic fluid pressure or annular fluid hydrostatic (in the event of a control line break) could keep the valve open if the fluid hydrostatic exceeded the SSSV closing pressure. A simple formula translates the closing pressure rating into maximum set depth.

$$\text{Max Set Depth} = \frac{F_c - F_s}{MHFG}$$

Set Depth = maximum set depth of SSSV

F_c = closing pressure rating of SSSV

F_s = a safety factor, $F_s = 0.15 F_g$, usual minimum is 75 psi.

MHFG= maximum hydraulic fluid gradient.

In the case of the valve with $F_c = 350$ psi, an empty (unpressured annulus) and a 7 lb/gal hydraulic oil, the set depth is:

$$\text{Max Set Depth} = \frac{350 \text{ psi} - 75 \text{ psi}}{0.364 \text{ psi/ft}} = 755 \text{ ft}$$

The 0.364 psi/ft is the gradient of 7 lb/gal fluid and 75 psi was used because $F_g = 0.15 \times 350 = 53$ psi.

If the annulus is liquid filled (or gas under pressure), the MHFG that would be used is the maximum gradient produced at the SSSV. For example, a 15 lb/gal packer fluid in the annulus would change the maximum setting depth for the same spring to:

$$\text{Max Set Depth} = \frac{350 \text{ psi} - 75 \text{ psi}}{0.78 \text{ psi/ft}} = 352 \text{ ft}$$

Example: An offshore platform uses a SSSV, set at 450 ft below the mud line (ocean floor). The water depth is 300 ft and the platform is 75 ft above the sea surface. The hydraulic fluid used for valve operation has a density of 8.4 lb/gal. Sea water density is 8.5 lb/gal. The annulus of the well is filled with inhibited sea water (8.5 lb/gal). What is the minimum flapper closure pressure (F_c) needed (in psi) for operation under all environments including loss of the control line at the downhole valve. $F_s = 75$ psi

Solution: Set Depth = [$F_c D F_s$] / MHFG, $F_c = [\text{Set Depth} \times \text{MHFG}] + F_s$ There

are two possible hydraulic fluid and set depth combinations:

1. at operating conditions, set depth = 450 + 300 + 75 = 825 ft, The hydraulic density » (8.4×0.052) = 0.437 psi/ft for this condition.
2. at "disaster" conditions (loss of control line at valve) set depth = 450 + 300 = 750 ft, (note that the air gas is not use D and fluid now is sea water). The hydraulic fluid density = $8.5 \times 0.052 = 0.442$ for this condition.

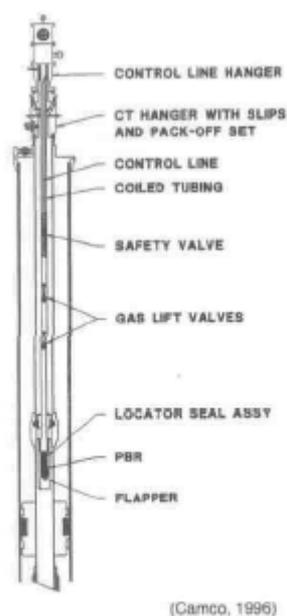
Condition 1, $F_c = (825 \times 0.437) + 75 = 436$ psi Condition

2, $F_c = (750 \times 0.442) + 75 = 407$ psi

The minimum flapper closure pressure needed is 436 psi

The other safety valve path that must be considered is the annular area. Annular safety control is necessary in areas that require SSSV isolation where the annular area is or could become a flow path. The annular pressure control systems that are currently on the market are packer type devices that use an applied hydraulic force to hold the annular flow channels open. All of these devices serve as a hanger so that the tubing suspension is maintained regardless of wellhead damage. Hanging significant tubing weight from these devices causes significant problems because of potential casing deformation. Two approaches have helped cure this problem. The packer slip assembly has been enlarged in one model to spread out the load. in the other approach, a casing profile is run in the casing string and the tubing hanger is set in the profile.

A special case in subsurface safety valves is the coiled tubing completion, Figure 5.9. This completion, all completely spoolable onto a coiled tubing reel can be more easily pulled in the event of a workover.



(Camco, 1996)
 Figure 5.9 A coiled tubing completion with a subsurface safety valve.

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