DRILLING AND COMPLETION COMMITTEE

# IRP 5 :
# Minimum Wellhead Requirements

An Industry Recommended Practice (IRP)
for the Canadian Oil and Gas Industry

**EDITION: 3**
**SANCTION DATE: June 20, 2018**

CAODC CANADIAN ASSOCIATION OF OILWELL DRILLING CONTRACTORS
CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS Canada's Oil and Natural Gas Producers
EPAC CANADA'S OIL & GAS ENTREPRENEURS™
PSAC working energy Leading Energy Services, Supply, Manufacturing and Innovation

## Copyright/Right to Reproduce



## Disclaimer

This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC).

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in this IRP. However, DACC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication of the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative requirements.

## Availability

This document, as well as future revisions and additions, is available from

Energy Safety Canada
5055 – 11 Street NE
Calgary, Alberta
Canada T2E 8N4
phone: 1-800-667-5557
403-516-8000
email: Safety@EnergySafetyCanada.com
visit: EnergySafetyCanada.com

# Table of Contents

## List of Figures

## List of Tables

# 5.0 Preface

## 5.0.1 Purpose

The IRPs for Minimum Wellhead Requirements are designed to ensure safe and successful control and containment of fluids and pressure from drilling to abandonment. This is only possible when wellhead design, installation, operation and maintenance suit the actual well conditions over the entire life cycle of a well.

## 5.0.2 Audience

The audience for IRP 5 is personnel involved in the planning, design, maintenance and operation of a wellhead.

## 5.0.3 Scope and Limitations

This IRP aligns with and makes reference to API Specification 6A: Specification for Wellhead and Christmas Tree Equipment and API Specification 6A Purchasing Guideline. At time of review, the 20$^{th}$ Edition is the current edition and references are to that edition. Throughout the IRP these documents will be referred to as API 6A and API 6A Purchasing Guideline respectively. Complete reference information is provided in the References section.

API 6A defines a wellhead as “all permanent equipment between the uppermost portion of the surface casing and the tubing head adaptor connection”. IRP 5 adopts a wider and more generic definition of Wellhead Components that also includes components attached to the wellhead to meet well control requirements. This includes all components and related equipment from the top of the outermost casing string up to but excluding the flowline valve. This IRP also considers components managed through the wellhead to the extent they impact wellhead design and operation including fracturing equipment. Drilling and service BOPs are not considered part of the equipment. The IRP refers to Wellhead Components when discussing the equipment relevant to the IRP and Primary Components when referring to API 6A components specifically. Definitions for both are provided in the Definitions section below.

The ultimate function of a wellhead is to contain and control the flow of liquids, gases and solids during the drilling, completion, workover and ongoing operation of the well. A wellhead needs to provide the following:

- A securely sealed surface termination for the various well casing strings.
- Necessary access to annular spaces.
- A means of suspending or installing production tubing and other subsurface equipment required to operate the well.
- A secure platform for installing surface flow control components and other equipment.
- Easy access for well servicing or other interventions.

Well designs and operations continue to evolve so this IRP cannot provide a recommendation for every possible present or future application. Instead, this IRP approaches wellhead requirements from two perspectives:

- An introduction to wellhead components and major variations in wellhead design that are driven by reservoir and well operating considerations and conditions.
- A guide to wellhead implementation, providing recommendations for the following:
    - Assigning responsibilities in wellhead installation, intervention and maintenance.
    - Determining wellhead requirements.
    - Installing and protecting wellheads.
    - Intervention operations.
    - Monitoring and maintaining wellheads, including suspended wells.

This document covers a range of petroleum industry well types including the following:

- Sweet Flowing Wells
- Critical Sour, Sour and Corrosive Wells
- Fracture Trees
- Artificial lift wells
- Other wells that require special considerations with respect to wellhead design (i.e., Injection, Thermal, Cavern and Observation Wells).

Although sour service is covered in this document, IRP 2 Completing and Servicing Critical Sour Wells should be referenced for additional details and requirements.

The IRPs presented here are based on engineering judgement, accepted good practices and experience. The establishment of these minimum requirements does not preclude the need for industry to exercise sound technical judgement in the application and maintenance of wellheads.

The IRP 5 committee does not endorse the use of any particular manufacturer's product. Any descriptions of product types or any schematics of components which may bear resemblance to a specific manufacturer's product are provided strictly in the generic sense.

### 5.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Energy Safety Canada acts as administrator and publisher.

Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP in whole or in part. For details on the IRP creation and revisions process, visit the Energy Safety Canada website at EnergySafetyCanada.com. A complete list of revisions can be found in Appendix A.

### 5.0.5 Sanction

The following organizations have sanctioned this document:

- *Canadian Association of Oilwell Drilling Contractors (CAODC)*
- *Canadian Association of Petroleum Producers (CAPP)*
- *Petroleum Services Association of Canada (PSAC)*
- *Explorers & Producers Association of Canada (EPAC)*

### 5.0.6 Acknowledgements

The following individuals helped develop this edition of IRP 5 through a subcommittee of DACC.

**Table 1 - Development Committee**

| Name | Company | Organization Represented |
|---|---|---|
| Gord Kiteley (Chair) | Suncor | CAPP |
| Neil Beckett | Select Energy Systems Inc. | PSAC |
| Gary Ericson | Saskatchewan Economy | Regulator |
| Keith Farquharson | Steam-Flo Industries Ltd. | PSAC |
| Mason Gao | Conoco Phillips | CAPP |
| Dean Jenkins | Encana | CAPP |
| Steve Jacobson | FMC Technologies Canada Ltd. | PSAC |
| Brad Mandziak | Weir Oil and Gas | PSAC |
| Kyle Niemi | Conoco Phillips | CAPP |
| Patrick Nolan | CNRL | CAPP |
| Jason Ogilvie | Isolation Equipment Services Inc. | PSAC |
| Bill Plaxton | Suncor | CAPP |
| Stephen Pun | Husky Energy | CAPP |
| Pat Webb | Devon Energy | CAPP |
| Matthew Webster | Weir Seaboard | PSAC |
| Maksim Xhaferllari | Alberta Energy Regulator | Regulator |

### 5.0.7 Range of Obligations

Throughout this document the terms ‘must’, ‘shall’, ‘should’, ‘may’ and ‘can’ are used as indicated below:

**Table 2 - Range of Obligation**

| Term | Usage |
|---|---|
| **Must** | A specific or general regulatory and/or legal requirement that must be followed. Statements are bolded for emphasis. |
| **Shall** | An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. Statements are bolded for emphasis. |
| **Should** | A recommendation or action that is advised. |
| **May** | An option or action that is permissible within the limits of the IRP. |
| **Can** | Possibility or capability. |

### 5.0.8 Copyright Permissions

This IRP includes documents or excerpts of documents as follows, for which permission to reproduce has been obtained:

**Table 3 - Copyright Permissions**

| Copyrighted Information | Used in | Permission from |
|---|---|---|
| API Spec 6A Table 2 – Temperature Ratings | Appendix B | API |
| API 6B, Annex G, Table G2 - Pressure Derating of API 6B Flanges at Elevated Temperatures | Appendix B | API |

### 5.0.9 Symbols and Abbreviations

| | |
|---|---|
| **AER** | Alberta Energy Regulator |
| **AOF** | Absolute Open Flow |
| **API** | American Petroleum Institute |
| **ASME** | American Society of Mechanical Engineers |
| **BHP** | Bottomhole Pressure |
| **BOP** | Blowout Preventer |
| **BPV** | Back Pressure Valve |
| **CSA** | Canadian Standards Association |
| **CSS** | Cyclic Steam Stimulation |
| **DACC** | Drilling and Completions Committee |
| **DMDS** | Dimethyldisulphide |
| **EOR** | Enhanced Oil Recovery |
| **ERP** | Emergency Response Plan |
| **ESP** | Electric Submersible Pump |
| **ESPCP** | Electric Submersible Progressing Cavity Pump |
| **FTD** | Final Total Depth |
| **GOR** | Gas/Oil Ratio |
| **$H_2S$** | Hydrogen Sulfide |
| **HAZ** | Heat Affected Zone |
| **HSN** | Highly Saturated Nitrile |
| **IRP** | Industry Recommended Practice |
| **ISO** | International Organization for Standardization |
| **NACE** | National Association of Corrosion Engineers |
| **MPP** | Mid-Point Perforations |
| **MTR** | Mill Test Records |
| **OEM** | Original Equipment Manufacturer |
| **PCP** | Progressing Cavity Pump |
| **PP** | Partial Pressure |
| **PPE** | Personal Protective Equipment |
| **PQR** | Procedure Qualification Record |
| **PSL** | Product Service Level |
| **PWHT** | Post Weld Heat Treatment |
| **RRP** | Reciprocating Rod Pumping |
| **RWP** | Rated Working Pressure |
| **SAGD** | Steam Assisted Gravity Drainage |
| **SCVA** | Surface Casing Vent Assembly |
| **SSC** | Sulphide Stress Cracking |
| **UOM** | Unit of Measure |
| **VR** | Valve Removal |
| **WOR** | Water/Oil Ratio |
| **WPS** | Welding Procedure Specification |
| **WPQR** | Welder Performance Qualification Record |
| **WQTR** | Welder Qualification Test Record |

### 5.0.10 Definitions

The following terms have been defined from an IRP 5 context.

| | |
|---|---|
| **Primary Components** | As defined in API 6A, Primary Components are the tubing head, tubing hanger, tubing head adapter and lower master valve. |
| **Prime Mover** | The source of power for a pump or other device, usually gas engines or electric motors. |
| **Sour Well** | Any well with 0.3 kPa $H_2S$ partial pressure (PP) or greater and not designated as critical sour. |
| **Sweet Flowing Well** | Wells with less than 0.3 kPa $H_2S$ PP that are capable of flowing to surface (natural lift). |
| **Wellhead Components** | API 6A defines a wellhead as “all permanent equipment between the uppermost portion of the surface casing and the tubing head adaptor connection”. IRP 5 adopts a wider and more generic definition that also includes components attached to the wellhead to meet well control requirements. This includes all components and related equipment from the top of the outermost casing string up to but excluding the flowline valve. This IRP will also consider components managed through the wellhead to the extent they impact wellhead design and operation including fracturing equipment. Drilling and service BOPs are not considered part of the equipment. |

### 5.0.11 Background

The earliest wells dug by hand to access shallow, fresh water sources pre-date 5000 BC. Since water levels were often below surface and the water was withdrawn by hand only as required, the wells were lined with wood, stones or bricks to reduce sloughing and contamination and left open to the environment. Early oil wells date back about 1500 years and many were simple pits or excavations. By 1000 AD, drilled depths of over 200 m were achieved and wood (e.g., bamboo) was being used to cap or contain the fluid and pipeline production to where it was needed. The first "modern" wells were drilled in the mid-late 1800s and although these simple wells still were lined with wood, they now were capped by an assortment of fittings. This progression from "open air" to enclosed wellheads reflected the increased utilization of wells and needs to safely manage the resource and contain fluids which were able to flow to surface. Current-day wells have evolved from these modest beginnings. Today’s wells still provide for the unaided (flowing) recovery of fresh water or sweet hydrocarbons from a single, shallow formation. However, they also enable a wide range of operations that include geo-thermal energy, liquid and gas storage, sour production, various types of injections and enhanced recovery of artificially-lifted reserves.

## 5.1 Wellhead Components and Considerations

There are many different well types and operations but wells have the following features in common:

- All wells are lined with steel pipe (casing) to allow unobstructed access to the target reservoir. Up to four casing strings may be installed and each string is cemented in place to mechanically support the pipe and hydraulically isolate the target reservoir from groundwater sources and other formations.
- Most wells also include one or more strings of pipe or tubing to recover or “produce” the reservoir fluids, to inject fluid into the reservoir or to allow other well operations.
- All wells are capped by an assembly of steel pipe and fittings (wellhead). The wellhead’s function is to contain the reservoir or well fluid and to allow safe access to the casing and tubing for the life of the well.

### 5.1.1 Components

The function of the wellhead above the wellbore is fundamentally linked to the function of the various strings of casing and tubing that run down inside the wellbore. Each of the components in Figures 1 and 2 are explained in greater detail after the diagrams.

**Figure 1 - Simplified Diagram of Casing and Tubing**

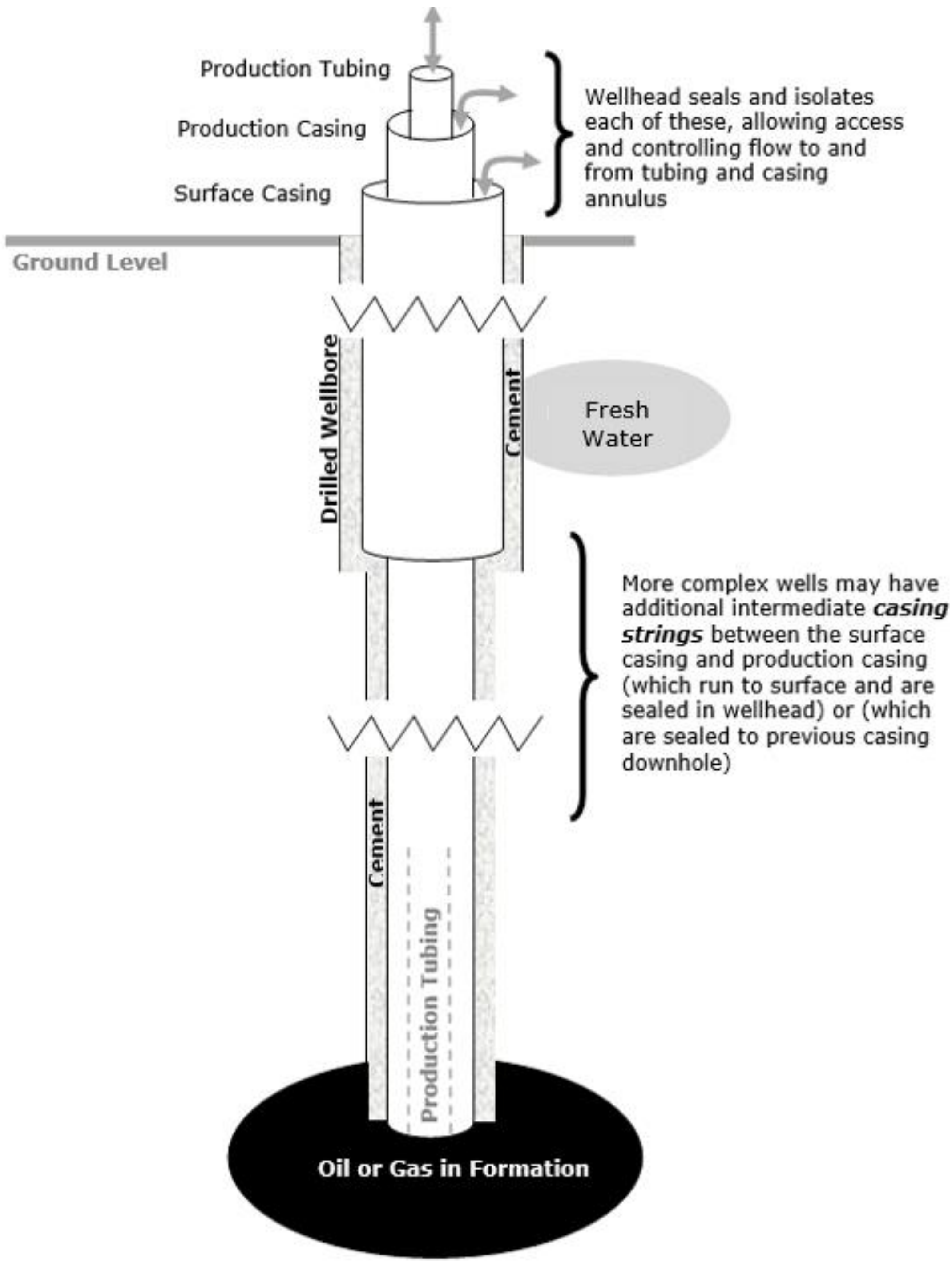
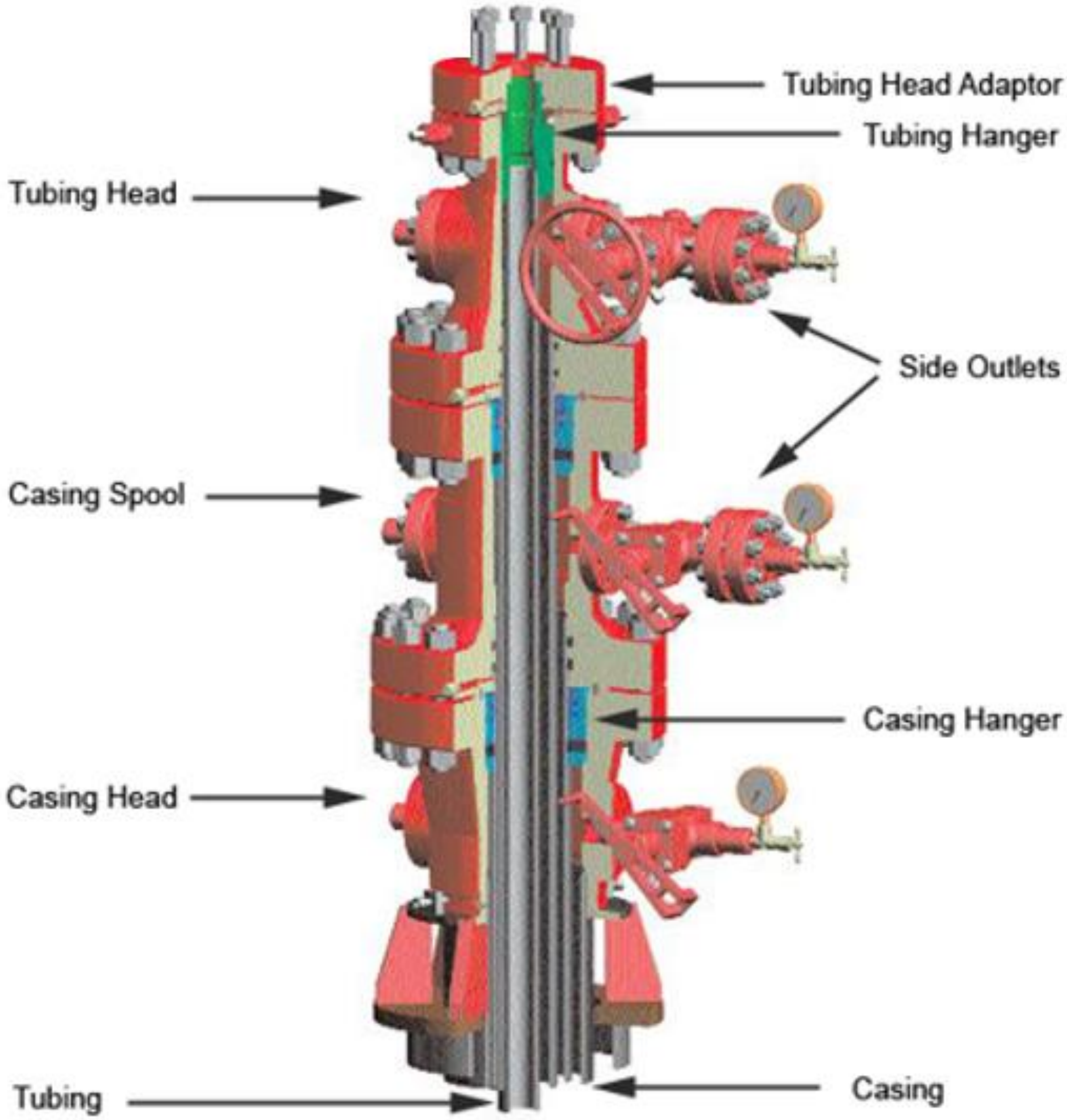


**Figure 2 - Wellhead Basics**



#### 5.1.1.1 Casing

A typical basic well is installed with one or two strings of casing (each cemented into place) plus a short length of conductor pipe (Figure 1).
Conductor pipe is set to prevent sloughing and water influx while drilling through the soft and generally weak material near surface. It may also capture and enable the recirculation of drilling fluid during subsequent drilling operations.

Conductor pipe is:

- typically set at a depth of less than 30 metres,
- cut off at ground level,
- light weight and not used to support any permanent wellhead equipment and
- equipped with a mounted diverter system in the early stages of certain drilling operations that carry a heightened risk of shallow gas kicks.

Surface casing, where required, is installed to isolate the uppermost part of the well and to ensure the integrity of the wellbore while drilling deeper. Once the surface casing is landed the casing is cemented to the borehole wall. The first wellhead components are then attached and begin their function as a well control device.

Surface casing is:

- the foundation of the well, providing the platform on which the wellhead is mounted and securing the existing hole for subsequent drilling,
- easily recognizable as the first and outermost casing string and
- more common in deeper or high pressure wells or where there is a requirement to isolate shallower fresh water from deeper salt water sources or hydrocarbons.

Production casing is set across or on top of the target formation and cemented into place. It is always tied back to surface where wellhead components seal and isolate the annular space between the production casing and the previous casing string. The wellhead offers outlets to access the inside of the production casing.

Production casing is the string through which larger well servicing operations are conducted and the well completion equipment is set. In situations where surface casing is not installed, the production casing will be cemented from final total depth (FTD) to the surface.

Production casing may perform as follows:

- Serve as the platform on which the wellhead is mounted when surface casing is not installed.
- House production tubing or other tubulars and lines run down hole from the wellhead at the surface. This creates an accessible annular space that runs from the wellhead to the target formation.

- Conduct produced fluid to the surface in some cases (e.g., commonly used as the production string for gas in sweet, shallow wells where production tubing may not be used).
- Provide an annulus to vent gases in pumping wells.
- Serve as a conduit for injection purposes in certain cases, most notably steam injections or pressured gas in a gas lift system.

Additional casing strings may be required to isolate intermediate formations (intermediate casing) or to support or provide additional strength for production operations (production liner). These may be found in deep or complex wells or in shallow horizontal wells where a liner may serve as the lower portion of the production casing. These additional strings can be sealed to a previously cemented casing string or cemented and tied back to surface. If tied back to surface, the wellhead is designed to accommodate and support the additional strings.

#### 5.1.1.2 Tubing

In most wells a single tubing string is the main conduit for bringing reservoir fluid to the surface or injecting fluid from the surface into the target formation. Additional tubing strings may be required if the formation has more than one interval being accessed and the fluids from the different intervals need to be kept separate from each other. Multiple tubing strings may also be used when a long reservoir section requires access at two or more locations. Well monitoring equipment or instrumentation may also require additional tubing strings.

Each tubing string is supported from the wellhead and may be free hanging, anchored or sealed against the cemented casing string.

Multiple tubing strings can be run concentrically (each inside the previous tubing) or be in parallel with each string suspended separately.

#### 5.1.1.3 Instrument and Control Lines

Wellheads provide safe, sealed access for small diameter tubing or electric lines that may be installed to monitor well operating conditions, inject chemicals, operate flow control devices or power artificial lift equipment. The wellhead serves to suspend, isolate and support these lines.

#### 5.1.1.4 Types of Wells

Individual wellhead designs can vary significantly based on the types of fluid or other materials handled, the flow velocities, pressures and temperatures encountered. Well production and servicing operations over the entire life cycle of the well also impact design. See 5.1.4 Sweet Flowing Wells, 5.1.5 Critical Sour, Sour and Corrosive Wells, 5.1.7 Artificial Lift Wells and 5.1.8 Other Well Types.

### 5.1.2 Component Requirements Applicable to All Wellheads

In North America, the American Petroleum Institute (API) provides key manufacturing standards for wellhead components. Wellhead components that are certified to API standards carry an API stamp.

Wellhead equipment that meets API 6A is available in the following standard pressure increments:

- 13.8 MPa
- 20.7 MPa
- 34.5 MPa
- 69.0 MPa
- 103.5 MPa
- 138.0 MPa

Standard temperature ratings are defined in Appendix B. Operating ranges are as follows:

- Conventional operations span -60 to 121$^{0}$ C (-75 to -180$^{0}$ F) in 8 ranges (K, L, N, P, S, T, U, V). Equipment can have more than one temperature classification meaning the equipment is suitable for use over the entire range of temperatures covered by these multiple ratings (i.e. a temperature classification of KU means that equipment is good for use over the entire range of -60 to 121°C).
- Elevated temperature operations span -18 to 345$^{0}$ C (0 to 650$^{0}$ F) in 2 ranges (X, Y). Y has the highest temperature rating.

**Note:** Equipment used at elevated temperatures may have de-rated working pressures. Refer to Appendix B and API 6A for more information.

Material Class defines the corrosion resistance required by all components wetted by the retained fluid. The seven material classes range from AA (General service: carbon or low alloy steel) to HH (Sour service: corrosion resistant alloys). All sour service materials must conform to NACE MR0175/ISO 15156. See Appendix B for API Material Requirements.

Product Specification Level (PSL) defines the different levels of technical quality requirements for the wellhead component. PSL 1 is the baseline. PSL 2, PSL 3, PSL 3G and PSL 4 include additional and ever more stringent requirements to confirm component suitability for challenging operations (e.g., high pressure, elevated temperature, sour).

#### 5.1.2.1 Manufacturing Requirements

**IRP** **All wellhead and christmas tree components included in the scope of API 6A must be manufactured in compliance with API 6A and should bear the API monogram.**

**IRP** **Wellhead equipment not included in the scope of API 6A should be designed, manufactured and tested in accordance with the same material specifications and quality assurance procedures, including traceability requirements, as API 6A certified wellhead components at the discretion of the operator.**

#### 5.1.2.2 Salvaged Wellhead Component Requirements

**IRP** **Salvaged wellhead components shall not be reused unless they are restored and certified for the intended service by the Original Equipment Manufacturer (OEM) or an alternate vendor with the same capabilities and expertise as the OEM in regards to the salvaged components.**

**Note:** There may be occasions where casing heads are reused in drilling operations. This type of reuse shall be subject to the IRPs on re-used casing heads (see 5.1.3.1 Casing Head).

#### 5.1.2.3 Rental Equipment

**IRP** **Rented wellhead, christmas tree and fracture tree components that will not become permanent fixtures of the wellhead shall be field inspected for condition prior to reuse.**

**IRP** **Any component that fails field inspection shall not be reused until it is restored and recertified for the intended service.**

**IRP** **Replacement parts or remanufactured equipment and parts should be designed to perform to requirements that meet or exceed the parameters of the intended service.**

#### 5.1.2.4 Pressure Rating Requirements

**IRP The pressure rating on all wellhead components must meet or exceed the maximum anticipated service conditions.**

**IRP The pressure rating of all wellhead equipment not included in API 6A, including all feedthrough components, pack-offs, seals and terminations, shall meet or exceed the maximum anticipated service conditions while in service.**

**Note:** The service conditions of the well may differ over the life of the well. Thermal wellheads for instance undergo periods of high temperature and medium temperature service. The intention of the above statement is to ensure that all wellhead components are rated appropriately for the conditions they will encounter.

**Note:** High temperature operation will de-rate the pressure rating of wellhead components. API 6A provides a guide for temperature-based pressure deration.

**Note:** For new wells, the maximum anticipated bottomhole pressure (BHP) shall be included in these service conditions since well production, injection or servicing operations could result in a full column of dry gas being present from the (open) formation interval to surface. In this case, the full reservoir pressure could be seen at surface.

**Note:** For existing wells where the operating and servicing conditions are well known and a full column of gas cannot occur, the bottomhole pressure does not need to be included in the anticipated service conditions (e.g., wells on artificial lift at lower Gas/Oil Ratio (GOR) or high Water/Oil Ratio (WOR)).

**Note:** In the event that the regulator approved casing of the well has a burst rating that is less than the BHP, operators need to consult with their respective regulators regarding requirements.

**IRP In the event maximum anticipated service conditions change or the actual BHP exceeds wellhead and christmas tree component design, the operator must replace or upgrade the wellhead with appropriate equipment.**

#### 5.1.2.5 Full Bore Access Requirements

IRP Wellhead components should allow full bore access to the casing or tubing to which they are connected.

**Note:** If full bore access is restricted then engineering controls should be in place to maintain well control.

This allows for the setting of full bore tools for the purpose of well control or isolation.

#### 5.1.2.6 Pressure Relief Access on Side Outlets

IRP Side outlets on the wellhead should have pressure relief access (e.g., tapped bull plugs with needle valves).

**Note:** The blind flange opposite the wing valve on a flow cross or tee and side outlets on the casing head are exempt from this recommendation.

### 5.1.3 Basic Components of a Wellhead

A wellhead is made up of a series of components that are connected and sealed in various ways. The key components of a wellhead are covered in the following sections:

- 5.1.3.1 Casing Head
- 5.1.3.2 Casing Spool
- 5.1.3.3 Casing Hangers
- 5.1.3.4 Packoff Flange
- 5.1.3.5 Tubing Head
- 5.1.3.6 Lock Down Screws
- 5.1.3.7 Tubing Hanger
- 5.1.3.8 Tubing Head Adaptor
- 5.1.3.9 Christmas Tree
- 5.1.3.10 Gate Valves
- 5.1.3.11 Coiled Tubing Hangers
- 5.1.3.12 Wellhead Feedthroughs
- 5.1.3.15 Surface Casing Vent Assembly

**Note:** Not every wellhead requires all of these components. The need for each component depends on the type of well, the well completion and expected operation.

This section also covers connections (by type) and seals (by composition and type) (see 5.1.3.13 Connections and 5.1.3.14 Seals).

#### 5.1.3.1 Casing Head

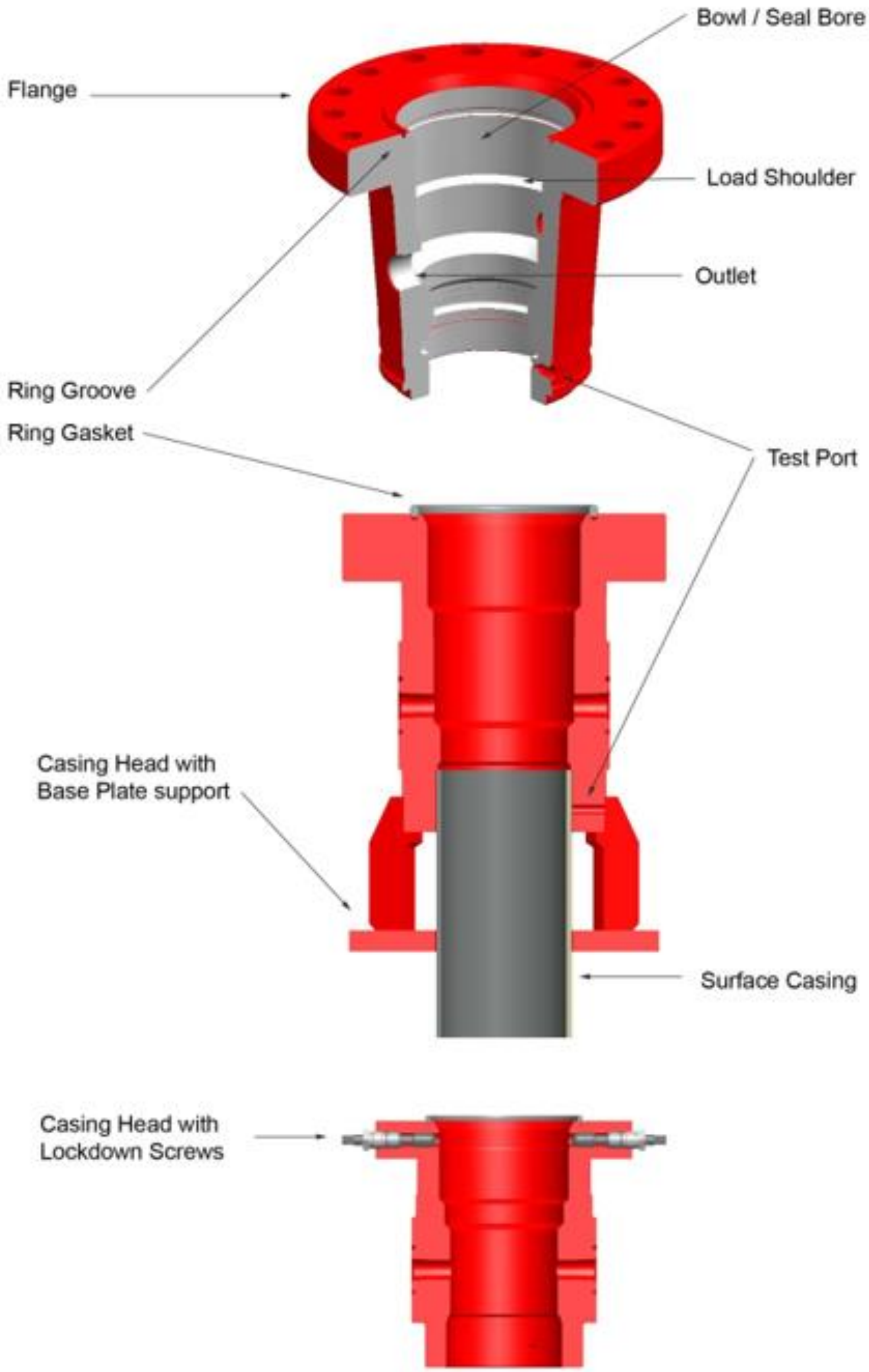
The casing head, also referred to as a casing bowl, is the lowest part of the wellhead assembly (Figure 3). The bottom of the casing head is configured to attach to the casing below (usually the surface casing). The upper inside of the casing head provides a bowl in which the next casing string can be set and sealed (if required). The top of the casing head then connects to the next wellhead component. The method of connecting the casing head to the surface casing below or the next component above is subject to operational and regulatory considerations (see 5.1.3.13 Connections and 5.1.3.14 Seals). A casing head may also be supplied with a landing base plate that takes the weight load off the surface casing and spreads it over the conductor pipe. Access to the annulus between the surface casing and the next casing string is available through side outlets.

The casing head provides the following functionality:

- Isolates the inside of the surface casing from the outside environment.
- Provides a platform for and a means to test the rig BOP stack during drilling operations.
- Supports or transfers the weight of drilling and workover equipment during drilling and well servicing operations.
- Allows the next casing string (i.e., intermediate or production casing) to be suspended or packed off. This is accomplished by setting a casing hanger and seal against the recessed profile machined into the upper inside surface (bowl). The hanger is often held in place by lock down screws. The seal formed against the casing string is called the primary seal.
- Provides access to the surface inner casing annulus for monitoring and fluid return. Access is available through side outlets drilled through the casing head.

One of the side outlets may be converted to a surface casing vent after the well is completed. This can then be used to monitor any flows or pressure build-up of gas, water or hydrocarbon liquids within the surface casing annulus. These flows or pressure build-ups can indicate a failure in the integrity of the inner casing cement, production casing or annular seals that may present an environmental hazard.

**Figure 3 - Casing Heads**



**IRP** **A well with surface casing set must have a surface casing vent installed. This vent must remain on the well until decommissioning.**

**Note:** An exemption to this requirement can only be achieved by contacting the local jurisdictional regulator. See also 5.1.4.3 Low Pressure/Low Risk Gas Wells.

**IRP** **A casing head must have at least one threaded, flanged or studded side outlet with a valve. Regulations may require two outlets with a valve in certain well types.**

Check with the local jurisdictional regulator for mandated requirements on the number of side outlets. In Alberta, Class I-IV wells require one outlet, while Class V-VI require two (AER Directive 36: Drilling Blowout Prevention Requirements and Procedures). British Columbia follows a similar pattern (see the BCOGC Well Drilling Guideline). In Saskatchewan two side outlets are mandatory (see the Saskatchewan Oil and Gas Conservation Regulations).

IRP A wear bushing or sleeve should be inserted into the casing head to protect its inner surfaces from damage for drilling operations in which wear is a concern.

**IRP** **The casing head shall be equipped with a landing base plate that spreads the weight load to the conductor pipe whenever the weight load created by the inner casing string(s), the tubing string(s) and the wellhead could cause the surface casing to fail under compressive loading.**

IRP Any casing head reused in a drilling operation should be inspected and pressure tested between drilling operations.

**Note:** 5.1.2.2 Salvaged Wellhead Component Requirements excludes the use of salvaged or reused casing heads for permanent use unless they are OEM recertified.

**IRP** **Welded casing heads that are reused for temporary operations shall be subjected to a hardness check between each operation to ensure ongoing material integrity and compatibility for additional welding.**

The operator is responsible for conducting a risk review for the hardness required. NACE MR0175/ISO 15156 requirements need to be met for sour wells.

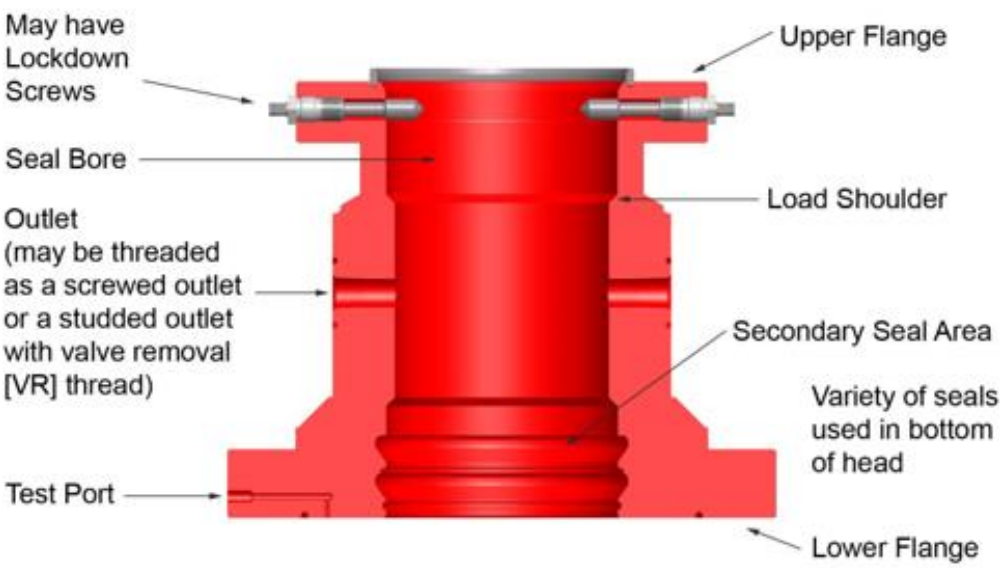
**IRP** **Operators reusing casing heads in temporary operations shall have a written procedure for the tracking and qualified inspection of all used casing heads in order to verify they are fit for purpose.**

#### 5.1.3.2 Casing Spool

If a well includes one or more intermediate casing strings between the surface and production casing, the next component after the casing head is the casing spool (Figure 4).

The bottom of the casing spool mounts on top of a casing head (or previous spool) and the top connects to the next spool or tubing head assembly. The spool is designed so the bottom bowl or counterbore will allow a secondary seal to be set on the previous casing string while the top bowl will hold a casing hanger to suspend and allow a primary seal around the next string of casing. Multiple casing spools may be used, one on top of the other, to hang intermediate casing strings and the final production casing string.

**Figure 4 - Casing Spool**




The casing spool provides the following functionality:

- Allows for a secondary seal on the previous casing string in the counterbore. With a secondary seal in place, flange or hub seals and casing hanger seals are isolated from internal casing pressure.
- Provides a port for pressure testing primary and secondary casing seals and flange connections (see 5.1.3.14.2.2 Primary and Secondary Seals).
- Provides a platform to support, seal and pressure test the BOP during drilling and well servicing operations.
- Provides a load shoulder and controlled bore in the top bowl to support the next casing hanger and enable a primary seal for the next intermediate or production casing.
- Provides annular access for fluid returns or fluid injections and pressure monitoring. Access is available through side outlets drilled in the spool assembly.

**IRP Casing spools with a flanged connection shall provide a test port to enable a pressure test between the primary and secondary seal.**

This test will determine if the seals are holding pressure and confirm that the annulus remains isolated.

#### 5.1.3.3 Casing Hangers

Both casing head and casing spool assemblies may require the use of casing hangers (Figure 5).

Casing hangers attach to the end of a given casing string and suspend and seal the casing string in the top bowl of a casing head or spool. Casing hangers come in two main varieties: slip type and mandrel.

Slip type hangers are installed around the casing after it is run, either before or after the casing is cemented into place. They are also used as a contingency when casing is stuck as they allow the casing to be cut off and set where it sits.

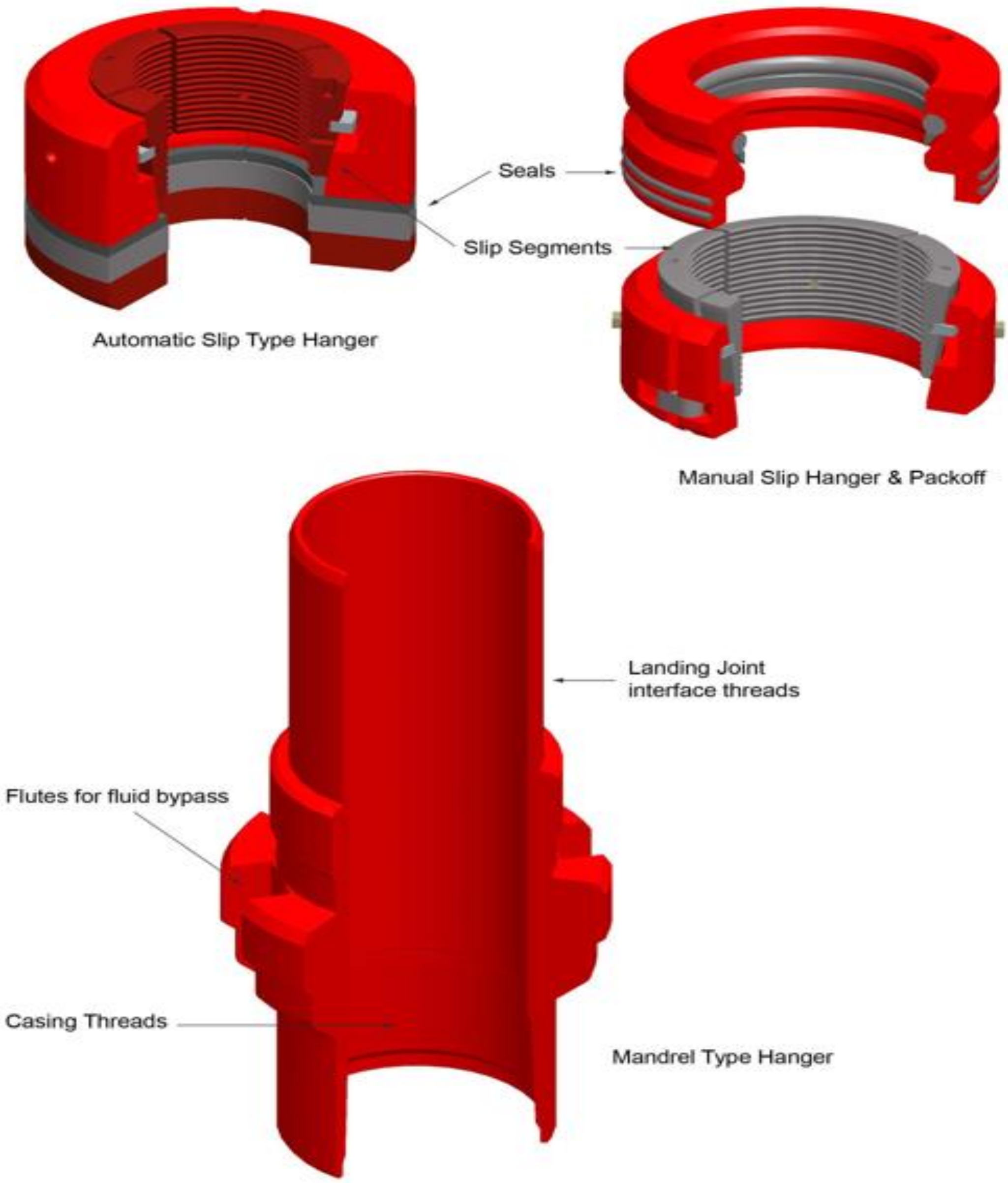
Mandrel type hangers are threaded onto the casing. They provide superior well control when landing the hanger and improve the annular seal. Often mandrel type hangers may be equipped with flutes for fluid bypass. These flutes allow for cement returns to bypass the hanger and return to surface. f this is the case, a separate primary seal is run after cementing.

When a casing hanger is used, shallow intermediate strings are usually suspended from the hanger and then cemented to surface. Longer intermediate and production strings that are not cemented to surface are usually cemented while the casing is suspended in tension from the rig traveling block. After the cement has set for a few hours the traveling block pulls a calculated tension on the casing above the cement and it is at this point the hanger is set in the bowl.

Casing hangers are often called slip and seal hangers (also known as automatic casing hangers) as they are designed with built-in seals. Automatic casing hangers typically require a minimum weight to energize their seal. Consult the OEM for weight requirements. Manual casing hangers (manual slips) may occasionally be run without seals in shallow wells where a primary seal is then installed whenever the BOP is removed.

A hanger may also be held in-place in the upper bowl of a casing head or spool assembly using lock down screws (also called hold-down screws).

**Figure 5 - Casing Hangers**




The casing hanger provides the following functionality:

- Suspends the load of the casing string from the casing head or spool.
- Centers the casing in the head.
- Provides a primary seal against the inside of the casing head and isolates the casing annulus pressure from upper wellhead components.

In the event of a stuck casing, a slip type casing hanger may be required to land the stuck casing.

IRP Slip type casing hangers should be available in operations that are designed for mandrel type casing hangers.

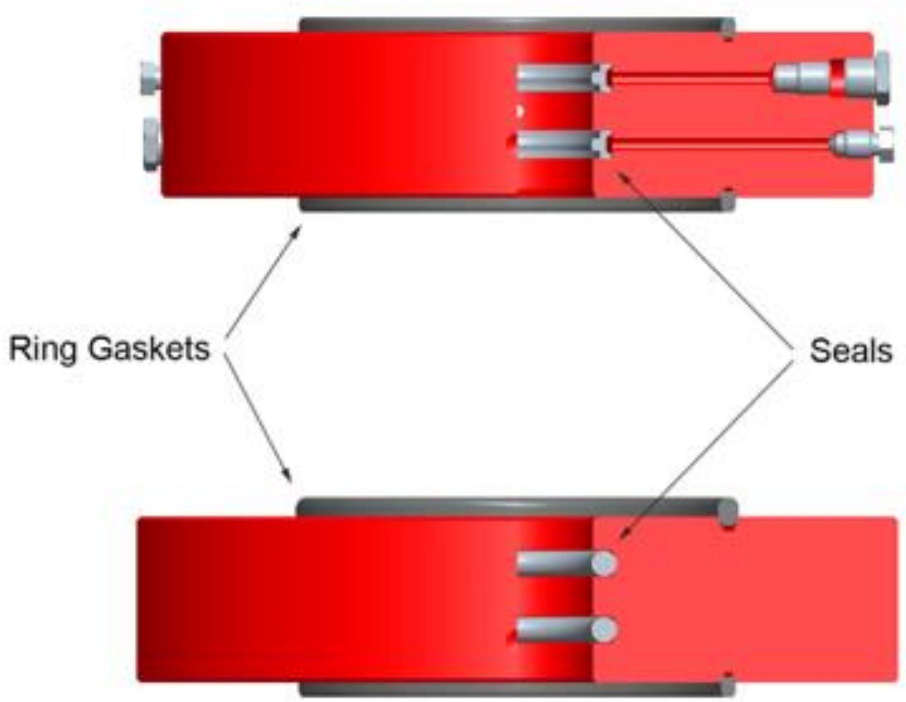
#### 5.1.3.4 Packoff Flange

Packoff flanges (Figure 6) are set above a casing head or spool assembly and sealed against the intermediate or production casing to enable a safe increase in pressure rating between the casing head or spool and any wellhead equipment above the flange (e.g., a tubing head). It is also known as a restricted packoff flange or crossover flange.

API 6A allows for an increase in pressure increments between components. One method to manage increased pressures is to use a packoff flange between wellhead components.

A packoff flange may also be used in temporary operations (e.g., pressure testing primary seals) or as a safety device when drilling out the cement that remains in the shoe joint (or float collar).

**Figure 6 - Packoff Flanges**



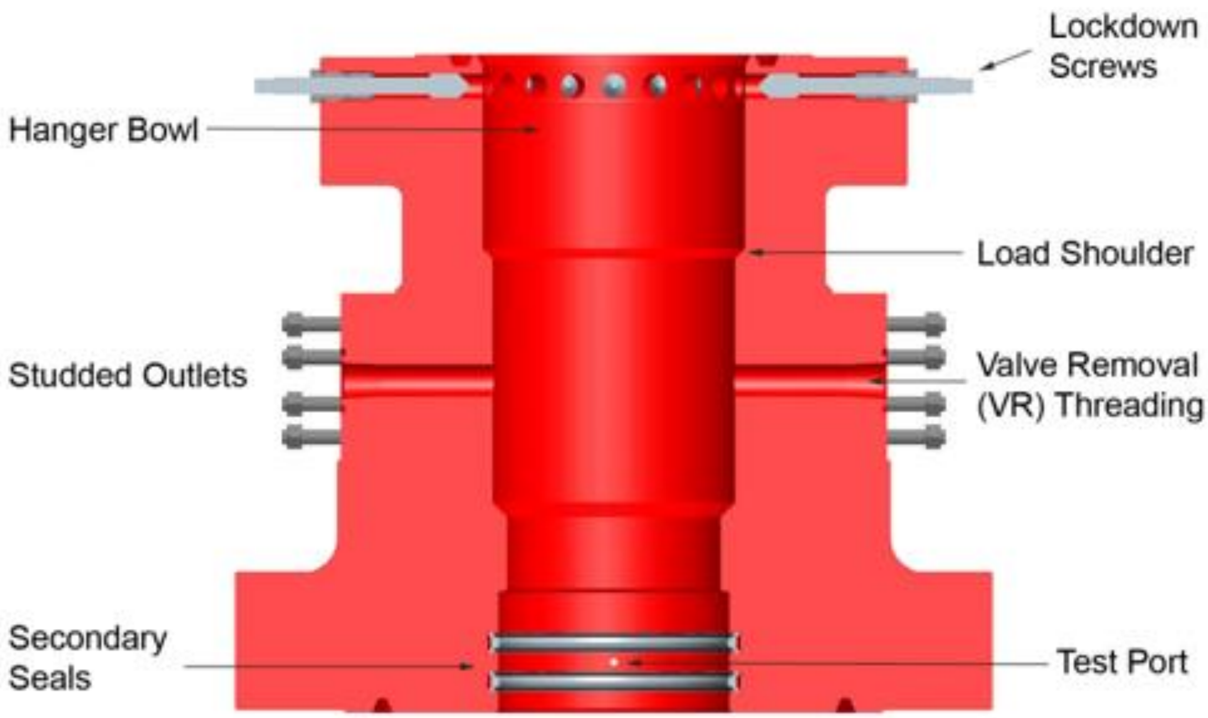

**IRP** **If a packoff flange is used to provide an increase in the API pressure ratings of the equipment it is bolted between, it must meet the requirements of a restricted area packoff as described in 5.1.3.5 Tubing Head. This includes the need for primary and secondary seal ports.**

#### 5.1.3.5 Tubing Head

The tubing head assembly provides a means to suspend and seal the production tubing in the wellhead (Figure 7).

The tubing head is the top spool in the wellhead assembly and is installed after the last casing string is set. The bottom of the tubing spool includes a counterbore that can be used to set a seal against the production casing or casing hanger. The top of the tubing head provides a landing shoulder and a seal bore for landing and enabling a seal to the tubing hanger. Above the tubing head is the tubing head adaptor which provides a transition to the christmas tree (also sometimes referred to as the wellhead top section).

**Figure 7 - Tubing Head**




The tubing head provides the following functionality:

- Enables the suspension of the tubing.
- Allows for sealing of the annulus between the tubing and the production casing.
- Allows access to the annulus between the tubing and production casing (through side outlets).
- Provides the makeup flange for the service rig BOPs during well completions and interventions.
- Provides a bit guide for running the tubing.

Some varieties of tubing heads also provide the following functionality:

- Provides mechanism for locking tubing hanger in place.
- Allows a secondary annulus seal to be set around the top of the production casing or casing hanger.
- Provides access for a test port to test primary and secondary seals.
- Allows for correct orientation of equipment to enable running multiple parallel tubing strings.

Tubing Heads may have an increased pressure rating between the top connection and the bottom connection. API 6A standards allows for an increase in pressure increments. So technically, for example, given proper isolation bolting strength, a 20.7 MPa tubing head assembly could be mounted on a 13.8 MPa casing head or casing spool. This is accomplished by isolating the lower pressure connection by the use of a restricted area packoff.

**IRP If a restricted area packoff is being used, the OEM shall ensure that the connection on the equipment with the lower pressure rating can withstand the loading that will be imparted by the higher pressure connection and equipment.**

The use of a restricted area packoff means that the higher pressures are contained within a smaller (restricted) area than the connection's normal seal diameter (i.e., the ring gasket pitch diameter for R or RX gaskets). This difference in areas reduces the amount of load the high pressure will impart on the low pressure connection and this is what allows for the pressure increase. The OEM must analyze this difference in areas along with any other loading the sealing mechanism may impart on the lower pressure connection and ensure that this connection is of adequate strength.

**IRP Any component providing an increase in API pressure rating shall provide a primary and secondary seal with test port(s).**

**IRP The annulus outlets on the tubing head shall have a pressure rating equal to that of the top connection.**

Lock down screws can be used to support tubing hangers in smaller bores where load shoulder does not exist. For 130 or 103 mm (5-1/8" or 4-1/16") bores, two banks of lock down screws can be used. The lower bank is to support and/or position the hanger and upper bank to retain, support and/or energize the seal.

**IRP Lock down screw position shall be verified prior to running or removing equipment through the tubing head.**

The risk for lock down screw failure increases dramatically in snubbing operations in a tubing head with dual bank lock down screws. The purpose of lock down screws in tubing heads is dependent on design and usage is not universal; however, they are often critical to the load bearing capacity of the head as well as for locating the hanger correctly.

IRP Tubing heads should have the number of turns to engage the hanger stamped near each bank of lock down screws. The operator should consult and follow the OEM's installation procedures.

Refer to 5.1.3.6 Lock Down Screws for more information about lock down screws.

Tubing heads come in the three basic connection configurations shown in Table 4.

**Table 4 - Tubing Head Connection Configurations**

| Top Connection | Bottom Connection | Section | Diagram |
|---|---|---|---|
| Flanged or clamp hub | Flanged or clamp hub | 5.1.3.5.1 | Figure 7 (in 5.1.3.5 above) |
| Flanged | Thread on (for threaded) Weld on (for welded) | 5.1.3.5.2 | Figure 8 |
| Thread on | Thread on (for threaded) Weld on (for welded) | 5.1.3.5.3 | Figure 9 |

Well type and conditions are used to determine which type of tubing head is most appropriate for the operation.

#### 5.1.3.5.1 Top and Bottom Connection Flanged or Clamp Hub

Tubing heads with flanged or clamp hub connections top and bottom may be used in any operation.

IRP Tubing heads with flanged or clamp hub connections top and bottom should be used for operations where pressures are expected to exceed 20.7 MPa or for lower pressures in critical sour applications.

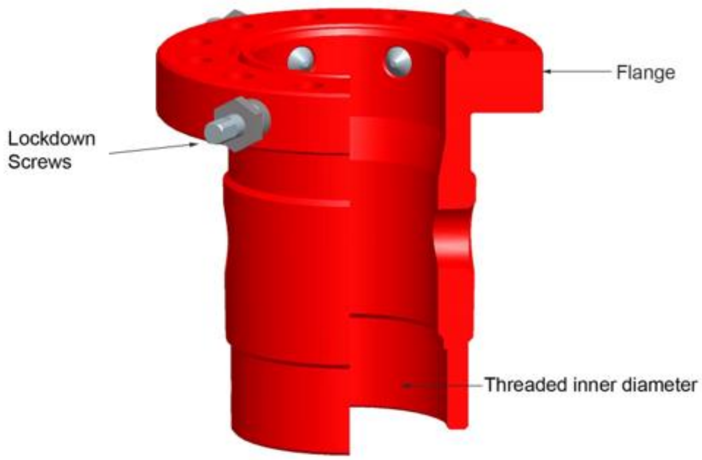
IRP Tubing heads with flanged or clamp hub connections top and bottom should be used for operations where the following conditions exist:

- There is a need to pressure test the annulus between production casing and the previous casing string.
- There is a need to isolate the production casing from any structural loads.
- Replacement of tubing head may be required.
- Multiple casing strings exist.

#### 5.1.3.5.2 Flanged by Threaded or Welded

Flanged top by thread on or weld on tubing heads (Figure 8) may be used in specific low-risk operations. Refer to local jurisdictional regulations for information about where they can be used.

**Figure 8 - Tubing Head Flanged by Threaded or Welded**




IRP Flanged top by welded should be used in thermal operations such as cyclic steam injection (CSS) and steam assisted gravity drainage (SAGD).

The flanged top configuration has advantages over threaded configurations that allow tubing to be run under pressure (e.g., locking screws for tubing hanger retention). Its limitation is that it does not provide a secondary seal on the production casing and therefore no ability to pressure test between the production casing and the previous casing string (usually the surface casing).

#### 5.1.3.5.3 Threaded by Threaded or Welded

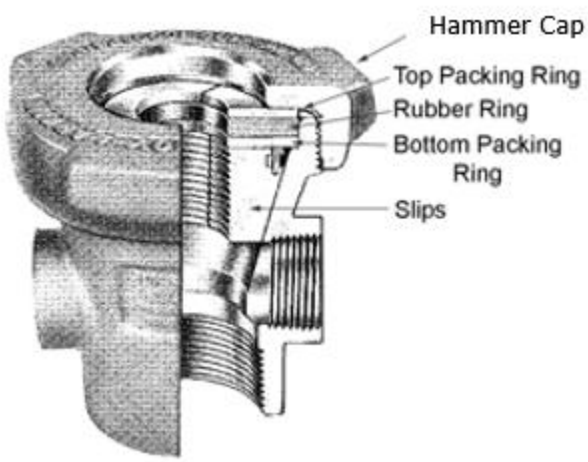
**IRP The use of a tubing head with a threaded hammer cap top shall be limited to low pressure wells not requiring sour service (as per NACE MR0175/ISO 15156).**

With this configuration, the threaded hammer cap locks down the tubing hanger and may energize seals. The hanger will not provide well control without the cap. An adapter will be required to install a BOP. The adapter may be proprietary and not interchangeable with other manufacturers. These designs have historically been rated at working pressures of 10.3 MPa to 20.7 MPa.

IRP Other designs should be used as defined by the manufacturer and should be evaluated for suitability in the specific application. Risks, including tool availability, throughout the life cycle of the well which should be considered.

Threaded by threaded tubing heads can be designed which do not rely on a cap for hanger and seal retention or are intended for specific applications like coiled tubing suspension.

**Figure 9 - Tubing Head Threaded by Threaded or Welded**



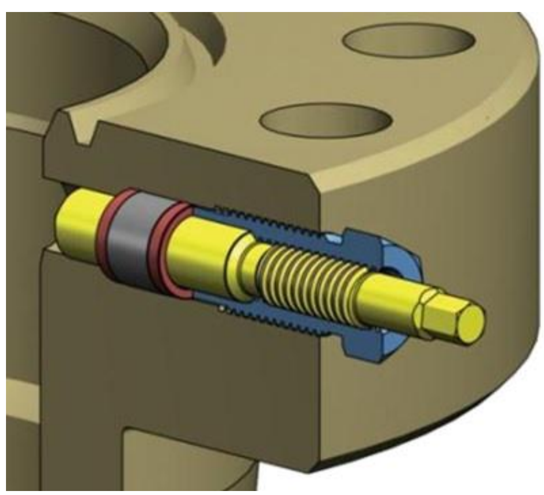

#### 5.1.3.6 Lock Down Screws

Lock down screws are designed to hold down or energize seals on a casing or tubing hanger, packoff and bore protector (or wear bushing) or BOP test plug in the top wellhead bowl. There are many variations in designs and purpose.

There are two common types of lock down screws:

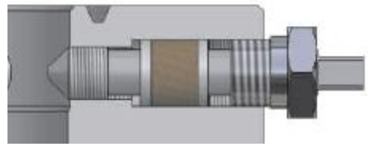
1. Internally Threaded Gland Nut (Figure 10)
2. Threaded Nose Lock Screw (Figure 11)

**Figure 10 - Internally Threaded Gland Nut**



The screw is threaded in the gland nut. The screw thread is located between the packing and the flange outside diameter. The screw thread is not exposed to wellbore fluids

**Figure 11 - Threaded Nose Lock Screw**



The screw is threaded into the tubing/casing head and the thread is located between the wellbore and the packing. The gland nut is used to energize the packing. The screw thread is exposed to wellbore fluids which can impede the function of the lock down screw.

**IRP Manufacturer procedure shall be followed when operating lock down screws.**

The following outlines some general procedures for lock down screws:

- Prior to working on or moving lock down screws, pressure should be isolated and bled off from the hanger cavity using a bleeder tool or alternate method.
- The gland nut should not be backed off to operate the lock down screws.
- All screws should be engaged or backed out equal distances to ensure uniform engagement or opening through the spool.
- Refer to wellhead vendor for proper engagement measurement and torque to apply.
- Engaging or opening sequences should be performed in a cross pattern similar to flange tightening.

Operational steps for removing or landing a hanger while snubbing can be found in IRP 15 Snubbing Operations.

The lock down screw can be ejected from the wellhead if the gland nut is backed out too far while pressure exists.

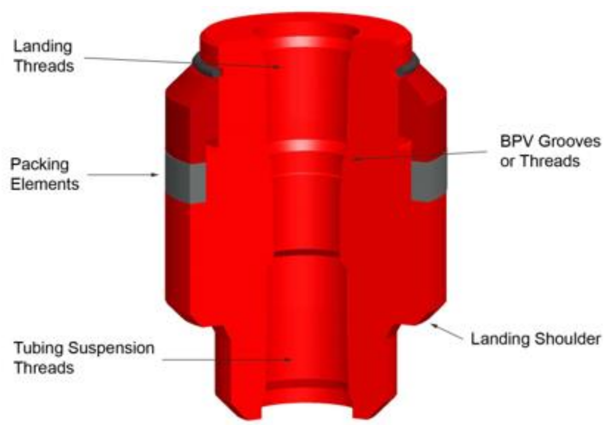
**IRP Personnel shall not stand in the direct path of the lock down screw while operating the lock screw assembly.**

IRP Lock down screws should be able to withstand the dynamic loads from the reciprocating motion of a rod string in artificial lift wells and the torque during the start-up and shut-down of Electric Submersible Pump (ESPs) and Progressing Cavity Pumps (PCPs).

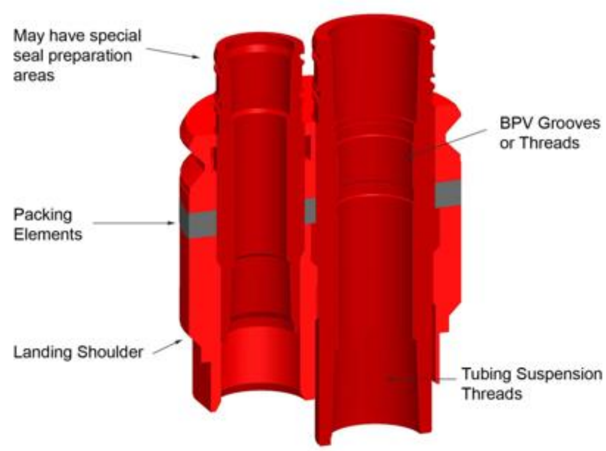
#### 5.1.3.7 Tubing Hanger

A tubing hanger (commonly known as a dog nut) is threaded onto the top of a tubing string and is designed to sit and seal in the tubing head (Figure 12). Usually the tubing hanger is run through the BOP and landed in the top bowl of the tubing head. The top of the tubing hanger provides a profile necessary for the lock screws that secure the hanger in the tubing head. The bottom of the tubing hanger provides a taper that sits on the landing shoulder in the tubing head.

**Figure 12 - Tubing Hangers**




Coupling Style Tubing Hanger




Dual Tubing Hanger

In a simple, single string completion the hanger carries the weight of the tubing and the tubing is “hung in neutral”.

The design of the completion equipment may have an impact on hanger design. Consider that a downhole packer allows the tubing to be set in compression, tension or neutral. Upward (compression) forces may need to be placed on the tubing string during production or injection operations.

The following are situations where this might be considered:

1. When the tubing/casing annulus has to be isolated from the fluid handled (e.g., produced water injection or disposal wells)
2. When different intervals need to be isolated from each other.
3. When gas will be injected to enhance fluid production (i.e., in a gas lift well).

IRP Tubing hanger material grade should be consistent with the production/fracture string material.

**Note:** If a lower grade material tubing hanger is used it will have a lower connection strength than the tubing.

Tubing hangers with seal rings or elastomers provide a seal between the tubing hanger and tubing head below the lock down screws.

Extended neck tubing hangers (Figure 13) allow for a primary and secondary seal on the tubing hanger. In this configuration, a secondary seal packs off inside the tubing head adaptor. As a result, the lock down screws are isolated from the wellbore fluids and the primary and secondary seals can be pressure tested.

Extended neck tubing hangers are required for sour wells and corrosive wells (see 5.1.5 Critical Sour, Sour and Corrosive Wells). Because tubing head components and seals are uniquely exposed to production and injection fluids, special consideration needs to be given to the metallurgy and elastomer seal selection (see Table 8 in 5.1.8.1 Injection or Disposal).

IRP Tubing hangers should come equipped with a profile that enables operator to install a back pressure valve or isolation plug. Risk analysis should be completed if the back pressure valve profile is to be excluded.

Slip type tubing hangers still exist in the field but they may not provide a seal around tubing for adequate well control.

IRP Slip type tubing hangers should not be used in new or retrofit installations.

**Figure 13 - Neck Tubing Hanger**

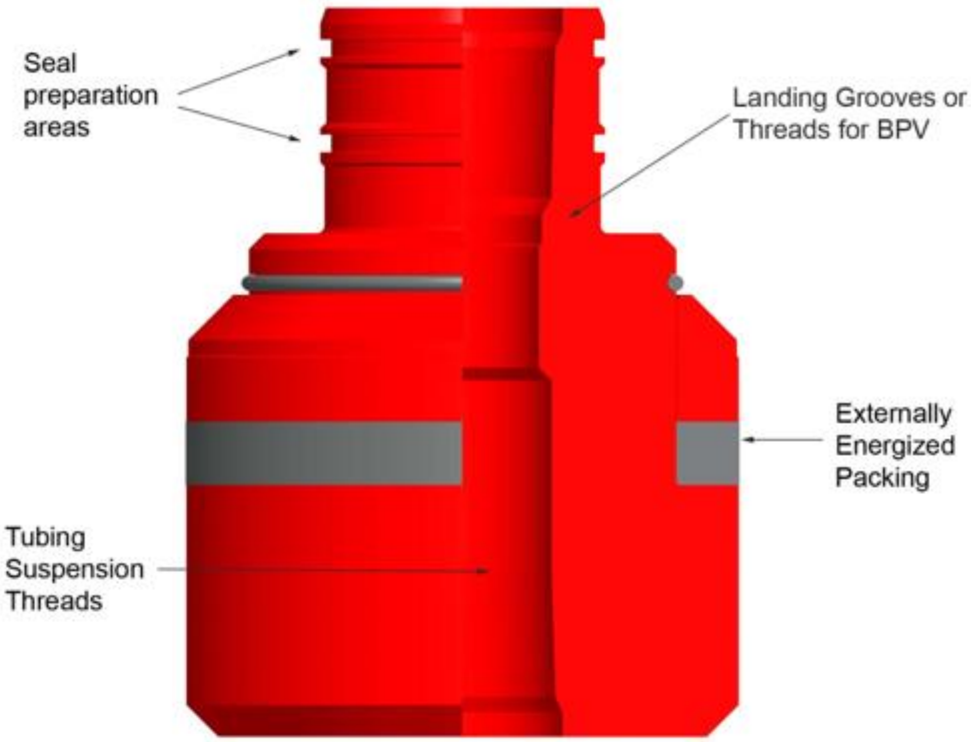
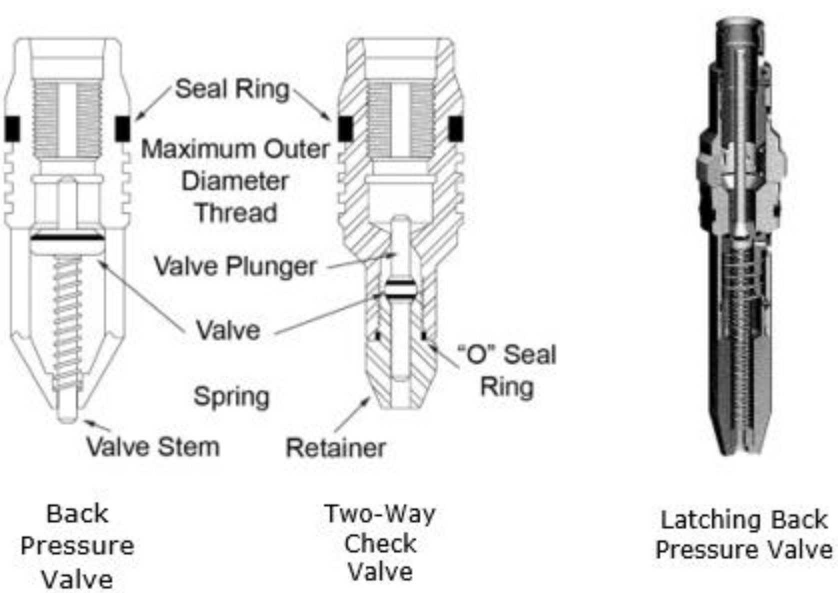



**Figure 14 - Isolation Plugs**



Wellhead isolation plugs are designed to engage into a profile and provide a seal in a tubing or casing hanger. Back pressure valves (BPV) have a check valve that seals pressure from below and allows fluids to be pumped from above. They are used as a barrier to remove, install or maintain equipment above the hanger. A two-way check valve has a valve that will seal from either direction. It is used to test equipment above the hanger. Tools used to install and retrieve both the BPV and the two-way check valve will unseat the check valve allowing pressure to equalize during installation and removal.

#### 5.1.3.8 Tubing Head Adaptor

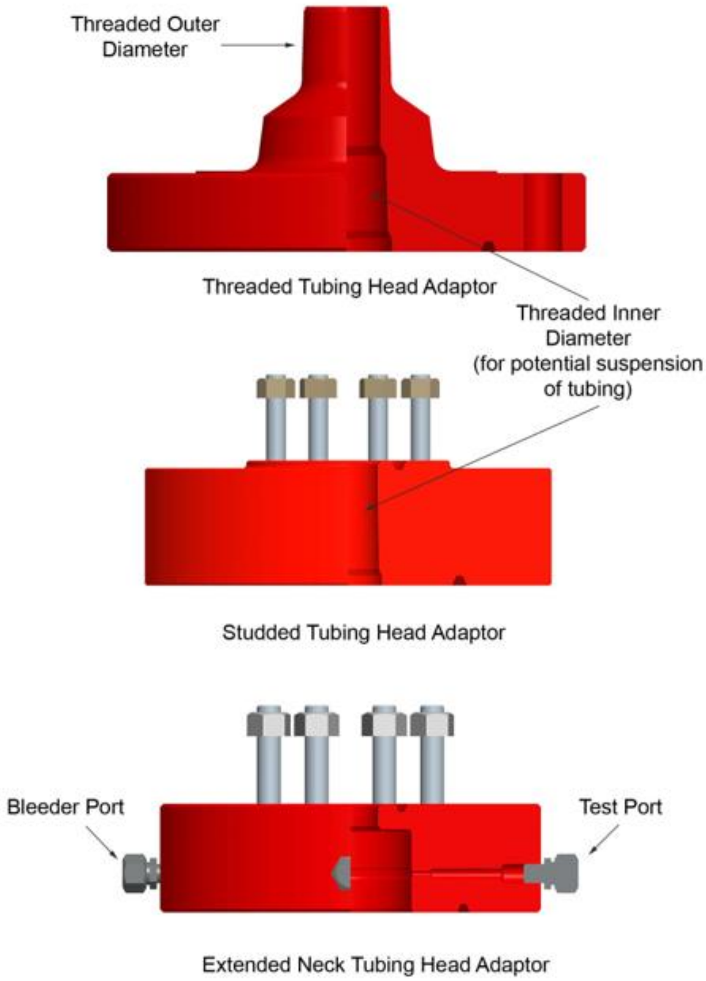
The tubing head adaptor (Figure 15) provides a transition from the tubing head to the christmas tree.

With a tubing hanger that does not have an extended neck interfacing with the tubing head adapter, the bottom of the tubing head adapter, top of the tubing hanger, seal between head and adapter and possibly the lock down screws will be exposed to well fluids.

With an extended neck tubing hanger, the adaptor will provide a secondary seal against the hanger neck. Isolation of seal between the tubing head and adapter and lock down screws from well fluids is provided. The seals also provide means to test the primary and secondary seals on the tubing hanger.

See 5.1.5 Critical Sour, Sour and Corrosive Wells for recommendations on the use of extended neck tubing hangers.

**Figure 15 - Tubing Head Adaptors**




### 5.1.3.9 Christmas Tree

A christmas tree is an assembly of gate valves, chokes and fittings included with the wellhead during well completion (see Figures 16, 17 and 18). The christmas tree provides a means to control the flow of fluids produced from or fluids injected into the well at surface. While christmas trees come in a variety of configurations based on a number of well design and operating considerations, typically the bottom connection of the tree matches the top connection of the tubing head and is generally installed as a unit after production tubing is installed.

**Figure 16 - Christmas Tree for Flowing Well**

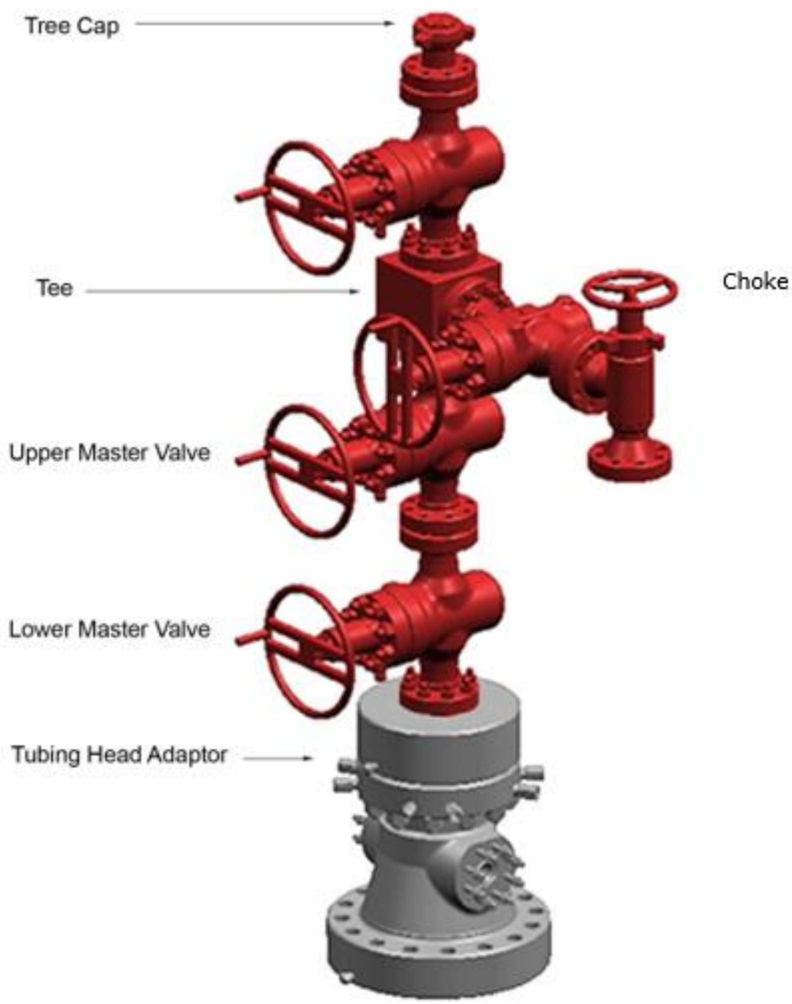


**Figure 17 - Christmas Tree on Rod Pumping Well**

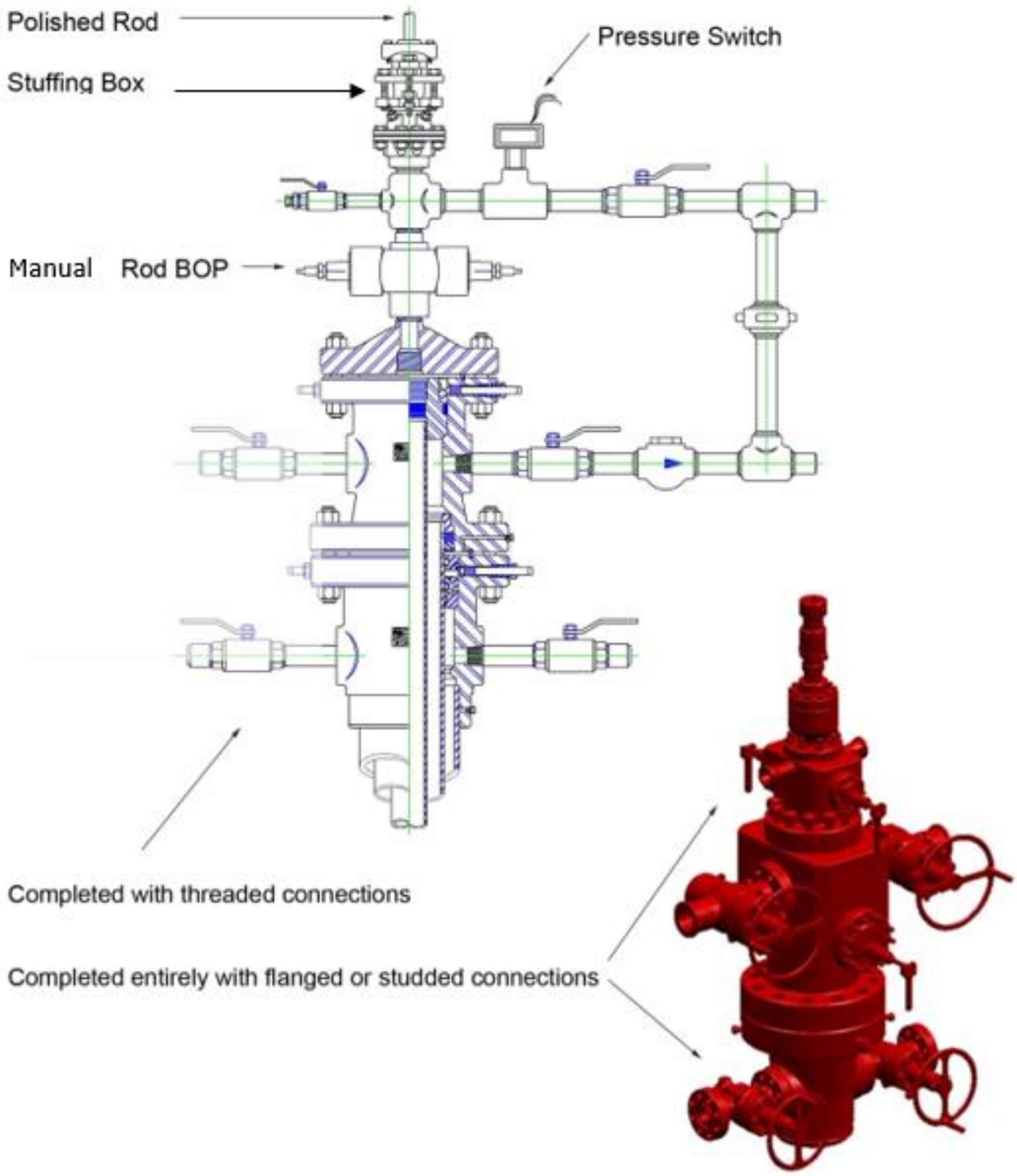
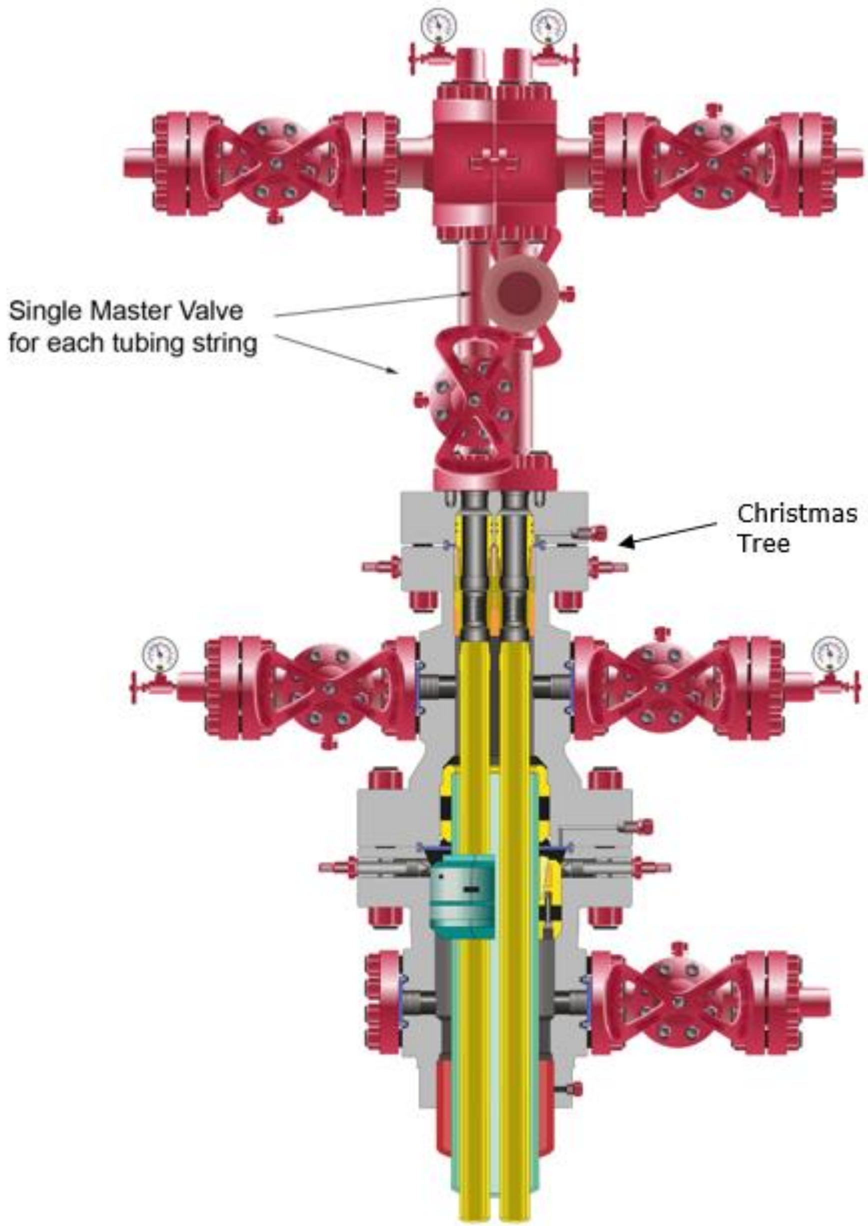


**Figure 18 - Christmas Tree on Dual Completion Well**



Typical christmas tree components on a flowing, gas lift or injector well are shown in Figure 16. These components include the following:

- A minimum of one master valve that will control flows through each tubing string.

**Note:** An additional master valve may be required under certain service conditions and well pressures. In this case the upper valve would typically be used for routine operations while the lower valve provides a barrier in case the upper valve fails or needs to be serviced.

- A tee or cross leading to control valves such as production gate valves, surface safety valves, flow control valves or chokes
- Optionally, a swab valve above the tee that permits vertical access to the tubing.
- A tree cap that might be fitted with a pressure gauge.

The tree cap provides quick access to the tubing bore for bottomhole pressure testing, running down hole equipment, swabbing, paraffin scraping and other through-tubing well work. A tree cap may consist of a bottom hole test adapter which is a tree cap with a top connection providing quick access to the tubing bore and a flange or clamp bottom connection. This type of tree cap must be used in combination with a separate block cross or tee which provides the connection for the flowline. The tree cap may also consist of a flow tee, which combines the tree cap with the tee connection for the flowline into a single piece of equipment. As flow tees are commonly used in lower pressure service, they often have threaded bottom and flowline connections.

**IRP The wellhead shall have a means to relieve pressure underneath the tree cap.**

**IRP The pressure rating of the christmas tree shall meet or exceed the maximum anticipated wellhead shut-in pressure or reservoir pressure, whichever is higher.**

A christmas tree may be modified based on well operating conditions, fluids produced and recovery methods. In the case of an artificial lift well that requires a rod string to run through the christmas tree (e.g., reciprocating rod pumping (RRP) or PCP, see Figure 17), the configuration is adjusted as follows:

- The master valve is either removed or incapacitated to prevent accidental closure.
- A polished rod BOP is added that can seal around the polished rod if required. The polished rod BOP seal ram may be activated either manually or hydraulically.
- A stuffing box is added that provides a seal around the moving polished rod.
- An environmental stuffing box may be included that seals across the tubing bore in the event a polished rod breaks and is pulled or ejected out of the stuffing box. It may be integrated into the stuffing box itself or be installed as a separate component above or below the stuffing box.

IRP Under more demanding operating conditions (e.g., high pressures or corrosive or erosive fluids) a block cross or tee, in conjunction with a bottom hole test adaptor, should be used rather than a combination of flow tee and test adapter for the top fitting on the wellhead.

See 5.2.5.7 Shallow Gas Well Intervention Requirements for bracing requirements for shallow gas well interventions.

#### 5.1.3.10 Gate Valves

Gate valves are on/off pressure control devices designed to be operated in either the fully open or fully closed position. API 6A defines a gate valve as a valve assembly with a gate operating within the body, 90° to the conduit, to effect closure. API 6A gate valves are thru conduit (pass tools), maintain fixed bores and have fixed end to end dimensions for flanged valves. API 6A gate valves can have flanged, threaded or proprietary end connections.
There are two main types of gate valves:

1. Expanding Gate Valve
2. Slab Gate Valve

The expanding gate valve (Figure 19) is also known as the parallel expanding gate valve. The gate assembly is split into two segments (gate and segment), with the stem attached to the gate. As the gate travels from opened to closed, a set of gate springs collapse the gate assembly with slight clearance between the gate and seats. The segment engages a stop at closed or opened position. The gate stop is in the valve bonnet for opened position and at valve body bottom for closed position. The segments with the stem attached continues to travel, sliding on the tapered surface, spreading the gate and segment apart. Tightening the handwheel energizes the seal that is provided between the gate/segment, seats and seat pockets in the body. In this type of valve, the gate must always be wedged at opened or closed. The stem will always be in tension or compression. This valve has a stem injection fitting on the bonnet neck used to mitigate minor stem packing leaks using injectable plastic.

**Figure 19 - Expanding Gate Valve**

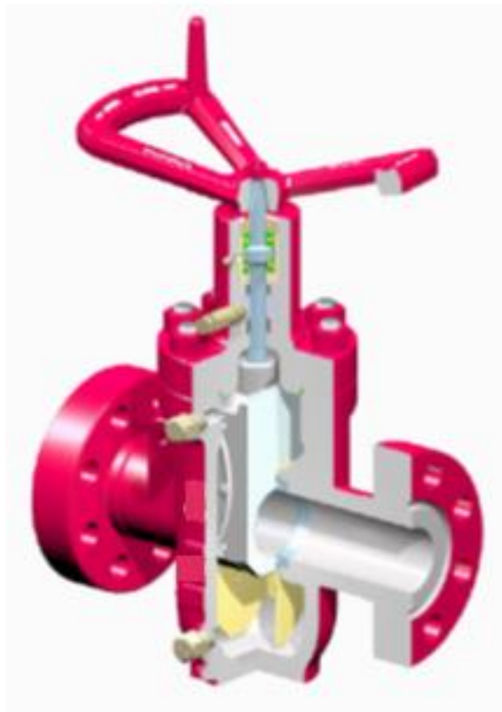


**Table 5 - Valve Positions**

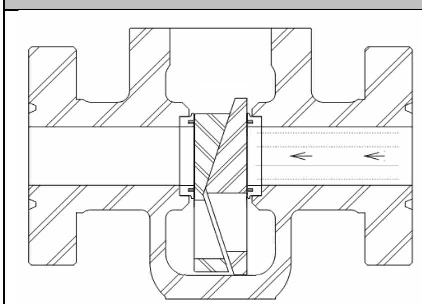
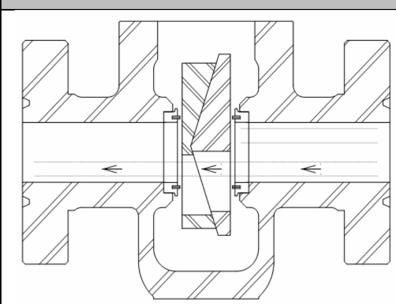
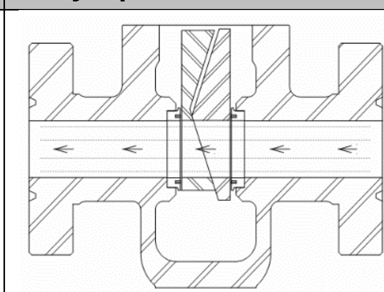
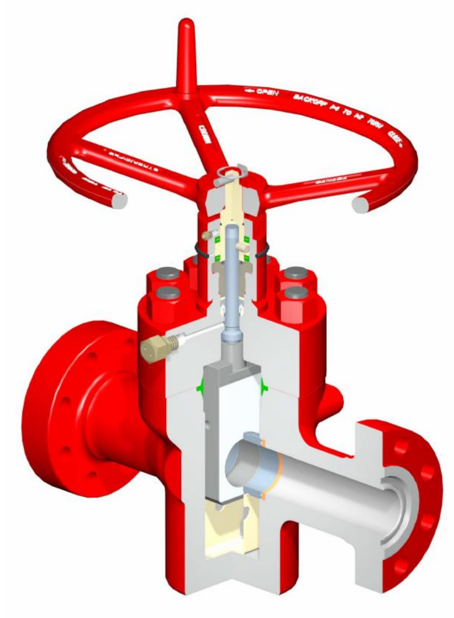
| Sealed Closed | Mid Travel | Fully Open |
|---|---|---|
|  |  |  |
| In the fully closed position, the segment has engaged with the bottom of the body and the gate is wedged downward, expanding the segment and gate so that they form a tight mechanical closure against the upstream and downstream seats. Venting the body cavity pressure will provide, tight shutoff. | During travel towards opening, the gate slides across the wedge angle of the segment, collapsing the assembly so that it travels freely between the seal faces. The gate springs holds the gate and segment in the neutral position. | When the bore in the segment is aligned with the conduit bore, the bonnet prevents further travel and the gate slides across the wedge angle, expanding the gate and the segment, isolating the flow from the body. The preferred flow direction ensures easier operation. |

**Figure 20 - Slab Gate Valve**



The slab gate valve uses a single unit gate, attached to the stem and travels from closed to opened position. Line pressure is used to affect a seal. At either opened or closed position, the gate must be allowed to float freely. Hence the handwheel must be backed off ¼ to ½ turn. The stem will not be stressed except during travel. The seal between gate and seat is provided with pressure from the upstream side, pushing the seat and gate to the downstream seat. There are variations to the slab gate available (e.g., a split gate design where the gate is split into two halves and kept apart by helical springs). The gate/seat seal still follows the slab gate design and handwheel must be backed off.

It is important to distinguish between expanding or slab gate valves. The following are general characteristics of each type of valve but there are valves with other options and configurations available.

The following are generally true of slab gate valves:

- They contain a bonnet cap that is screwed onto the bonnet.
- They have one grease fitting on the bonnet flange face which is used for back seating of the stem and can be used to flush and add grease
- Some valves used in fracturing applications contain extra grease fittings in the body for ease of flush and grease

The following are generally true of expanding gate valves:

- They do not have a bonnet cap.
- They have at least two body grease fittings in line with the stem straddling the bore for mitigating pressure lock, flushing contaminants and adding grease
- They have an injection fitting on the bonnet neck for mitigating minor stem packing leaks with injectable plastic.

Slab gate and split slab gate valves typically back seat on the stem rather than providing an injection fitting. Backseating allows for field replacement of stem packing and stem bearings and shear pin. Expanding gate valves do not have back seat capability.

Valves with two stems are known as balanced stem valves, where pressure across the stem is balanced thereby reducing operating torque.

The following are methods of moving the gate:

- Direct connection to the valve stem with a hand wheel. Hand wheel diameter is usually less than or equal to the end to end dimension to avoid interference.
- Hand wheel on gear operator. This method increases the number of turns and reduce operating torque
- Ball screw. Using ball bearings on a screw tack to reduce friction. Primarily used for large bore fracturing valves and high-pressure gate valves.
- Hydraulic/pneumatic actuators. Using hydraulic or compressed air to move the stem.
- Electric motorized actuators connected to the stem directly and rotate it using an electric motor.

Seat injection fittings can be found in some split gate valves and high pressure expanding gate valves for gate sealant injection to seal between the gate and seat. These fittings are installed along the conduit centerline straddling the stem centerline.

**IRP Valves shall be operated and maintained as per OEM procedures.**

**IRP Operating procedures shall be in place for valves to address, at minimum, the following concerns:**

- **Freezing: Expansion of water (trapped in the body or in the line) due to freezing can cause damage to the valve resulting in valve failure (and potentially a well control event).**
- **Thermal operations (if applicable): expansion of the grease and/or other fluids trapped in the body as it heats up can cause damage to the valve resulting in failure (and potentially a well control event).**

**IRP The slab gate valve shall be opened or closed fully and then backed off ¼ to ½ turn in either closed or opened position unless otherwise specified by OEM.**

**IRP The expanding gate valve shall be opened (counter clockwise) or closed (clockwise) fully and then continue for another ¼ turn unless specified by OEM.**

**IRP Gate Valves shall be used in fully open or fully closed positions. They are not intended to throttle flow.**

**Note:** Flow control valves or chokes can be used to regulate the flow of liquids and gas into or out of a well. While technically these components lie outside the scope of IRP 5, when used correctly, they can optimize recovery and minimize tree and flowline damage caused by erosion and cavitation. Good operating and monitoring procedures are essential. If a choke washes out the wellhead or flowline can erode quickly to the point of failure.

### 5.1.3.11 Coiled Tubing Hangers

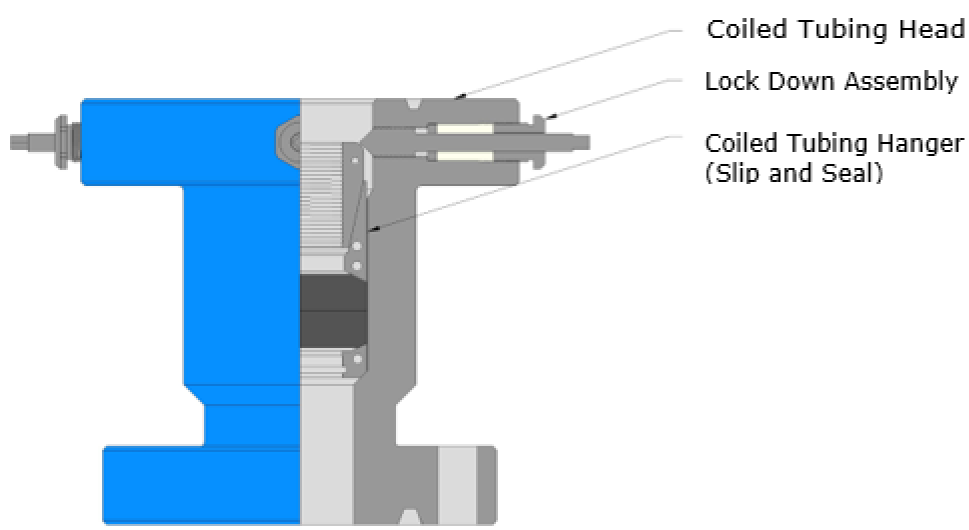
For wells completed using coiled tubing the coiled tubing hanger and head (Figure 21) may be placed above the tubing head (e.g., coiled tubing functioning as a velocity string, instrumentation string or running of small diameter logging tools to evaluate well conditions). Or, depending on its function, it may be hung alongside a tubing string. In some cases the coiled tubing may be hung above the master valve of the christmas tree.

See Figure 47 in 5.1.8.2 Thermal Operations for a thermal wellhead example that includes a coiled tubing configuration.

IRP If coiled tubing runs through a master valve on a christmas tree the master valve handle should be either removed or chained and locked during normal production operations to prevent accidental closure.

**IRP If coiled tubing runs through a master valve on a christmas tree an additional means of well control shall be in place (e.g., a second master valve run above the coiled tubing hanger).**

**Figure 21 - Flanged Coiled Tubing Hanger and Head**




**Note:** The entire assembly is sometimes referred to as a coiled tubing hanger.

### 5.1.3.12 Wellhead Feedthroughs

Wellheads can be designed to accommodate a variety of small diameter strings and lines that are used for a number of purposes. For example, small diameter chemical injection strings are used for corrosion control, de-waxing, scale inhibition, emulsion breaking or viscosity reduction. Subsurface safety control valves (tubing and annular) require lines running through the wellhead. Instrumentation used to monitor downhole pressures and temperatures is also common in some applications.

Feedthroughs present an extra risk in wellhead design as they provide a potential leak path through the wellhead. Feedthroughs need to be carefully considered and alternatives implemented where possible to lower the possibility of leaks.

> **Note:** Feedthroughs, and their associated pack-offs and seals, are covered by the IRP statement in 5.1.2.4 Pressure Rating Requirements.

> **Note:** Rod strings associated with artificial lift have specific IRP requirements covered in section 5.1.7 Artificial Lift Wells.

**IRP Feedthroughs that run through and exit via wellhead equipment shall be sealed and packed off at surface and rated to the working pressure of the wellhead. This applies to both completed and non-completed wellbores.**

IRP Feedthroughs that run through and exit via wellhead equipment should be pressure tested to a value determined by operator’s risk assessment.

> **Note:** Consider this requirement for non-completed wells as conditions can change (e.g., thermal observation wells have been known to leak and cause conditions to change).

**IRP The electric feedthrough connector for an ESP shall provide an electrically grounded, gas-tight seal that is fit for the well’s operating conditions and the surface environment.**

Tubing based feedthroughs present a unique risk to well control.

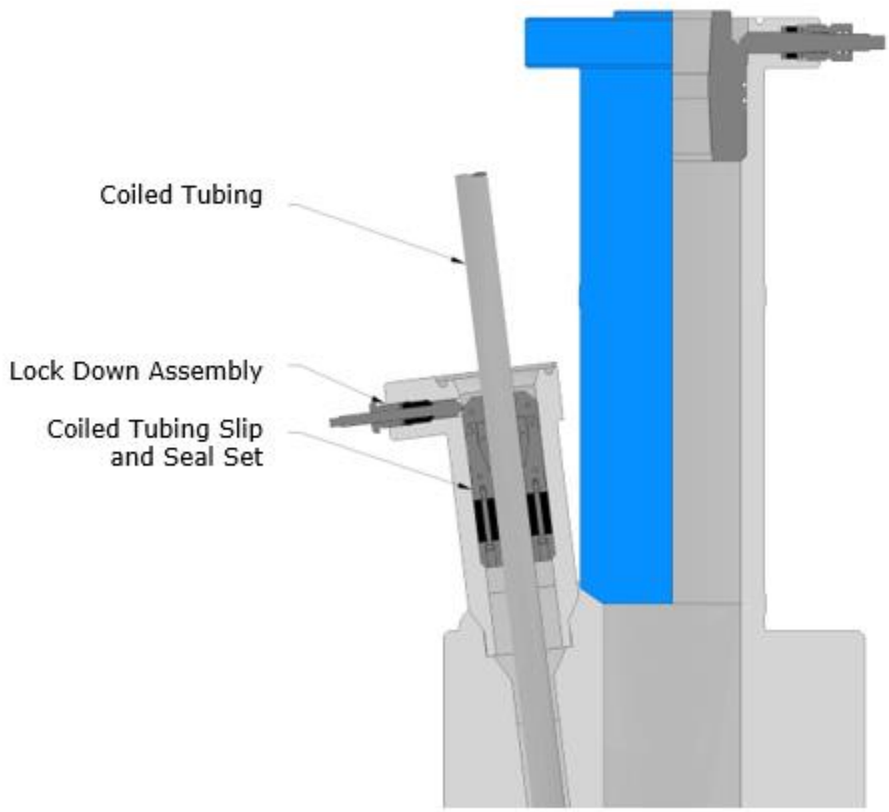
IRP The following should be considered in the design of coiled tubing and capillary tube feedthroughs:

- The packoff and seals between the tube and the wellhead.
- The surface termination of the tube.
- The material characteristics of the tube exposed to the environment.
- Bottomhole pressures (i.e., coiled tubing provides a conduit for bottomhole pressures to come to surface if the coiled tubing fails).

Corrosion of tubing based feedthroughs above the wellhead has been experienced by some operators. The temperatures seen in thermal wells can increase localized corrosion due to condensation above the wellhead.

IRP Proper metallurgy should be implemented to prevent corrosion of tubing strings that feed through wellheads.

**Figure 22 - Coiled Tubing Feedthrough**



#### 5.1.3.13 Connections

Connections provide a secure, leak free joint between wellhead components. The five basic connection types commonly used in wellhead design are discussed in the following sections:

- 5.3.1.13.1 Threaded
- 5.3.1.13.2 Welded
- 5.3.1.13.3 Flanged
- 5.3.1.13.4 Studded
- 5.3.1.13.5 Clamp Hub

There are also other connection types that are less common, such as sliplock connections (see 5.1.3.13.6 Sliplock) and connections unique to coiled tubing (see 5.1.3.13.7 Coiled Tubing Connection Types).

##### 5.1.3.13.1 Threaded

With a threaded connection, components are directly threaded onto the previous component. Threaded connections are used with, but not limited to, the following:

- Casing head to surface casing connections
- Casing head to upper wellhead components
- Side outlets
- Tubing hangers
- Tubing heads
- Adaptors
- Valves
- Flow tees
- Pipe nipples
- Bull plugs
- Pressure and temperature gauges
- Needle valves
- Bottom hole test adapter or fluid sampling port
- Polished Rod BOPs
- Polished Rod Stuffing boxes
- Plunger lift lubricator
- Back pressure valve
- Valve Removal (VR) Plugs
- Erosion (e.g. sand) or corrosion monitoring probes

Threaded connections are typically used only in lower-pressure sweet operations or for smaller diameter pipe or fittings.

**IRP Flanges that are threaded on, even if back welded, shall not be considered an integral flange connection.**

See 5.1.4 Sweet Flowing Wells for a description of conditions under which threaded wellhead components are acceptable and 5.2.3.5.2 Threaded Connections for requirements related to threading procedures.

The following resources can also be referenced:

- For Alberta see the Casing Bowls section of AER Directive 36: Drilling Blowout Prevention Requirements and Procedures.
- API Spec 6A: Specifications for Wellhead and Christmas Tree Equipment
- API RP 5C1: Care and Use of Casing and Tubing
- API RP 5A3: Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements

#### 5.1.3.13.2 Welded

Wellhead equipment can be manufactured using welding. Examples are flanged outlets, spools, tees and crosses. These welds are part of the manufacturing process and governed by API 6A, ASME Section IX and manufacturer’s procedures.

It is difficult to control weld variables in a field environment. This can affect the quality of the weld.

IRP Field welding of wellhead equipment should only be performed for attachments to pipe or casing.

Connections to pipe (typically, but not limited to, well casing) are typically performed using one of three methods: Socket Weld, Slip-on Weld or Butt Weld.

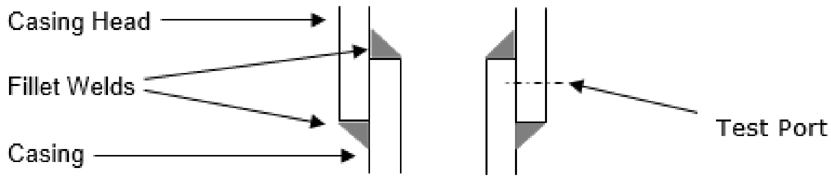
A socket weld involves insertion of pipe into a recessed area of a fitting or flange and fillet welding the exterior surface. Socket welds are typically used for smaller diameter pipe and fittings.

A slip-on weld (Figure 23) is similar to a socket weld with the addition of a fillet weld on the inside of the connection. Slip-on weld connection is the most common means of attaching a casing or tubing head to casing. In this application, a fillet weld is applied to the lower, outside connection where the casing head slips over the casing and to the upper, inside connection where the casing terminates in the casing head. This allows for a test port between the welds to pressure test the sealing integrity of the welds.

IRP Designs using an O-ring in place of the upper weld should not be used.

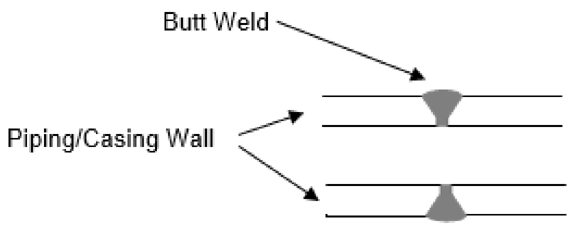
**Note:** The heat input necessary to accomplish a sound weld is likely to compromise the integrity of the O-ring.

**Figure 23 - Example of Slip-On Weld (Cross Section)**




A butt weld (Figure 24) is used in most pipe to pipe welding applications. Two common uses are in joining different lengths of wellhead piping or where a casing extension or repair is required at surface (joining one length of casing to another).

**Figure 24 - Example of Butt Weld (Cross Section)**




The following sections can be referenced for more information:

- See 5.1.4.2 Sweet Flowing Wells Above 13.8 MPa and 5.1.5 Critical Sour, Sour and Corrosive Wells for a description of conditions under which welded casing heads are required.
- See 5.2.3.3 Installation Personnel for requirements related to welding personnel.
- See 5.2.3.5.3 Welded Connections for requirements related to welding procedures.

The following resources can also be referenced:

- For Alberta see the Casing Bowls section of AER Directive 36: Drilling Blowout Prevention Requirements and Procedures.
- API Spec 6A: Specification for Wellhead and Christmas Tree Equipment
- ASME: Boiler and Pressure Vessel Code, Section IX – Welding and Brazing Qualifications
- CSA Z662 Oil & Gas Pipeline Systems
- NACE MR0175/ISO 15156

#### 5.1.3.13.3 Flanged

Flanged connections involve two flanges bolted together on the exterior of the component housing. Each flange has a ring groove and the connection is made up with a ring gasket to enable a seal between the flanges.

Flanged connections can be used in any application. They may be used with the following:

- Casing head to casing spool or BOP stack connections
- Side outlets
- Casing spools
- Spacer spools
- Tubing heads
- Adaptors
- Valves
- Flow tees or crosses
- Bottom hole test adaptors
- BOPs
- Polished rod stuffing boxes
- Plunger lift lubricators

Flanged connections allow for the installation of a test port to meet requirements of pressure testing between primary and secondary seals. Test ports have two types: low pressure and high pressure.

**IRP Test port and gauge connections shall be as follows:**

- **12 mm (1/2 in.) NPT shall be used for pressure tests where the pressure rating is 69.0 MPa or lower.**
- **Type I, II or III test and gauge connection (Autoclave) as defined in API 6A shall be used for pressure tests where the pressure rating is 103.5 MPa or higher**.

**IRP Flanged side outlets on casing heads, casing spools and tubing heads shall have valve removal threading as defined in Table 6 and API 6A to enable the installation and removal of a valve removal plug (see Figure 25).**

**Table 6 - Valve Removal Threading**

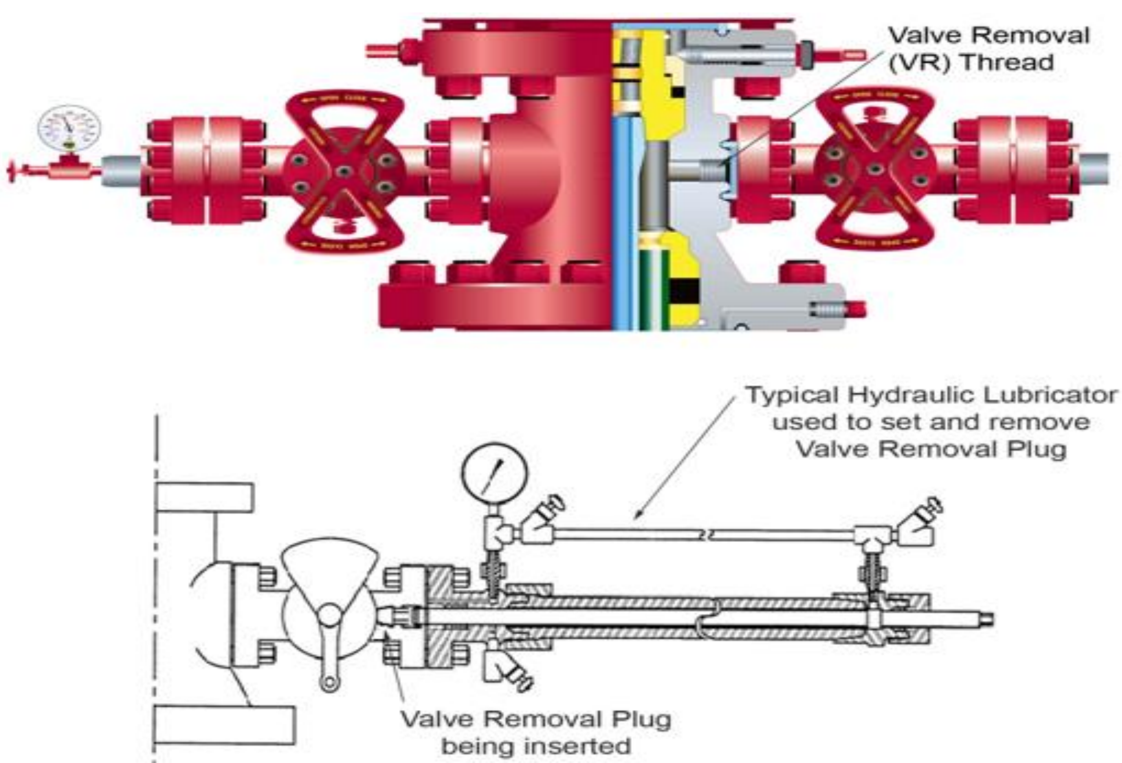
| | Thread Size and Designation | |
|---|---|---|
| **Side Outlet Size** | **≤ 69.0 MPa** | **≥ 103.5 MPa** |
| 46 mm (1-13/16 in.) | 1.660 Line Pipe | 1-¾ - 6 Stub ACME |
| 52 mm (2-1/16 in.) | 1.900 Sharp Vee | 2 - 6 Stub ACME |
| 65 mm (2-9/16 in.) | 2-3/8 Sharp Vee | 2-½ - 6 Stub ACME |
| 78 & 79 mm (3-1/16 and 3-1/8 in.) | 2-7/8 Sharp Vee | 3 - 6 Stub ACME |
| 103 and 105 mm (4 1/16 & 4 1/8 in.) | 3-½ Sharp Vee or no VR Thread | As per manufacturer's specification or no VR thread |
| >105 mm (4-1/8 in.) | As per manufacturer's specification or no VR thread | As per manufacturer's specification or no VR thread |

**Note:** VR thread and plug standards were first introduced into API 6A in the 19th edition 2004. Prior to that, threads were provided according to manufacturer's standards.

IRP Threads should be verified to make sure plug and outlet are compatible prior to installation.

Threads, if present, will be identified beside the outlet with permanent marking.

**Figure 25 - Example of Valve Removal Threading on Side Outlet and Tools**



See 5.1.4.2 Sweet Flowing Wells Above 13.8 MPa and 5.1.5 Critical Sour, Sour and Corrosive Wells for a description of conditions under which flanged, studded, or clamp hub connections are recommended.

See 5.2.3.5.4 Flanged, Studded and Clamp Hub Connections for requirements related to making up flanged connections.

**IRP API 6A Segmented flanges shall not be used for hydrogen sulphide service for material classes DD, EE, FF and HH (see Appendix B for API Material Requirements).**

Segmented flanges defined in API 6A are not for use in sour service. Manufacturers may design proprietary flanges that appear similar to API 6A flanges and are acceptable for use in sour service. Proprietary flanges are designed according to the requirements of other end connectors in API 6A. It is the responsibility of the manufacturer to ensure design is sound.

#### 5.1.3.13.4 Studded

Studded connections involve one component that has studs threaded into its housing and a second component with a flange bolted to the studs. Like flanged connections, studded connections include a ring groove and are made up with a ring gasket to create a seal between the components.

Studded connections may be used with the following:

- Casing head to casing spool or BOP stack connections
- Side outlets
- Casing spools
- Spacer spools
- Tubing heads
- Adaptors
- Valves
- Flow tees or crosses
- BOPs
- Stuffing boxes

Studded connections are typically used in the following operations:

- For pressure ratings at or above 20.7 MPa or higher risk operations.
- In any operations where there are requirements to shorten the height or length of the wellhead components.
- In any operations where there is a need to reduce the bending moment on equipment.

Studded connections allow for the installation of a test port to meet requirements of pressure testing between primary and secondary seals.

**IRP Studded side outlets on casing heads, casing spools and tubing heads shall have valve removal threading as defined in Table 6 and API 6A to enable the installation and removal of a valve removal plug (see Figure 25).**

See 5.1.4.2 Sweet Flowing Wells Above 13.8 MPa and 5.1.5 Critical Sour, Sour and Corrosive Wells for a description of conditions under which flanged, studded or clamp hub connections are required.

See 5.2.3.5.4 Flanged, Studded and Clamp Hub Connections for requirements related to making up studded connections.

#### 5.1.3.13.5 Clamp Hub

A hub is the enlarged end of a wellhead component that will be used to make a connection. With a clamp hub connection, the hubs of the two components being joined are squeezed together over a seal ring or ring gasket and held in-place by a clamp. The two clamp halves wrap around the hub and are bolted to each other to a specified torque to provide the required connection strength and seal rating.

Clamp hub connections may be used with most wellhead components such as the following:

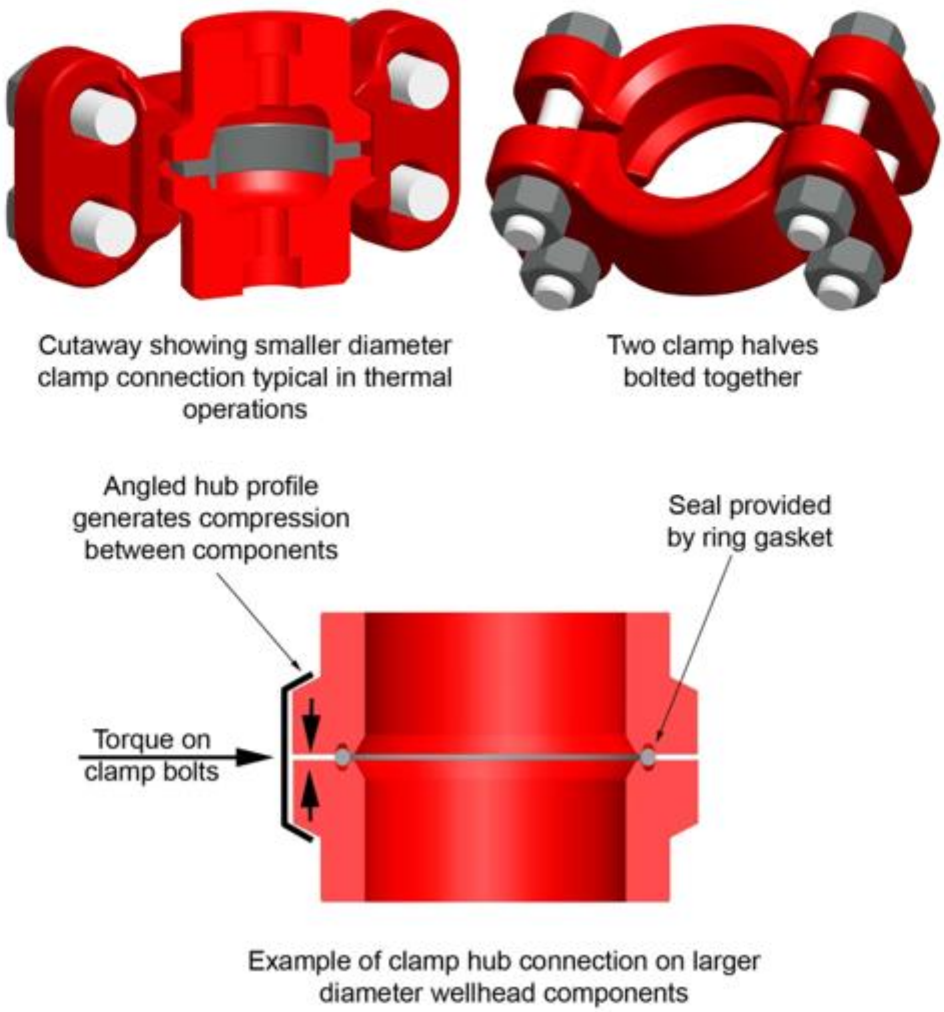
- Casing heads
- BOP stacks
- Casing spools
- Tubing heads
- Adaptors
- Valves
- Chokes
- Flow tees or crosses
- Swivel joints

Clamp hubs are typically used for pressures 13.8 MPa to 138.0 MPa or higher risk operations. Clamp hubs have the following characteristics:

- Superior ability to align and seal wellhead components and piping modules (compared to flanged or studded connections) as small differences in alignment are more easily absorbed by this type of connection.
- Higher fatigue resistance than flanged or studded connections.
- Faster make up time than flanged or studded connections.

Any damage to the face of the hub may compromise the metal to metal seal. Special care is required in any operation where there is potential for this type of damage.

**Figure 26 - Clamp Hub**




See 5.2.3.5.1 Protecting Wellhead Equipment in Transport and On Site for requirements on protecting clamp hub components during transport and while on the lease site.

See 5.1.4.2 Sweet Flowing Wells Above 13.8 MPa and 5.1.5 Critical Sour, Sour and Corrosive Wells for a description of conditions under which flanged, studded or clamp hub connections are required.

See 5.2.3.5.4 Flanged, Studded and Clamp Hub Connections under for requirements related to making up studded connections.

#### 5.1.3.13.6 Sliplock

Sliplock connections (Figure 27) may be used with casing head to casing connections. With a sliplock connection the components are attached by sliding one over the other and engaging slips and seals. Slip segments on the inner diameter of the sliplock hold the casing tight. Seals provide isolation. Both slips and typically seals are energized by studs which are torqued to a prescribed setting provided by the OEM.

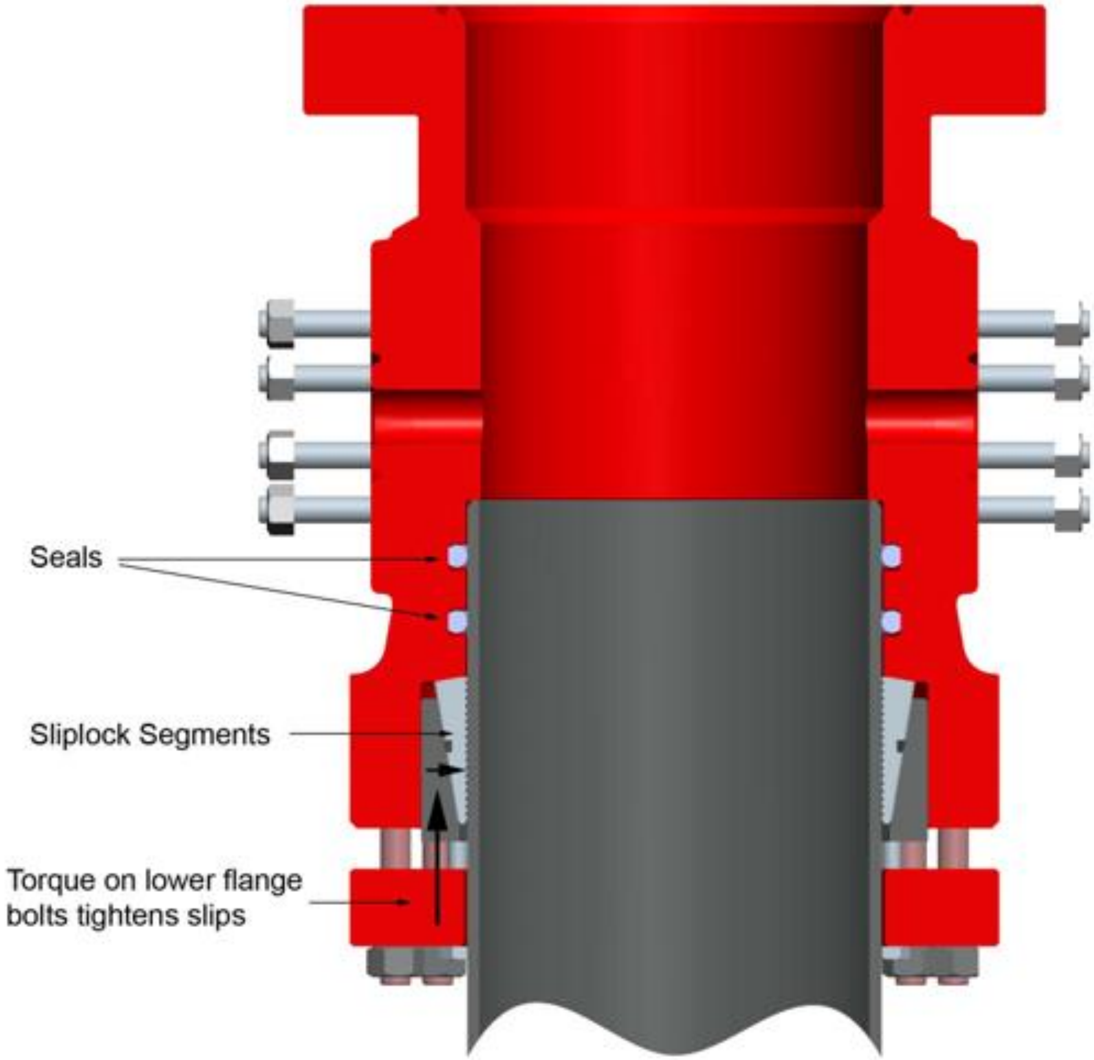
Sliplock connections are typically used in drilling for surface casing or other temporary operations in place of welded or threaded connections as the sliplock provides a faster connection time than either of these other methods. They may be used in observation style wells where the wellbore is not exposed to formation conditions.

**IRP** **If an operator wishes to use a casing head with a sliplock connection for operations with pressures greater than 13.8 MPa or for an extended period of time (e.g., production operations), they shall verify equipment suitability and performance capability. Regulatory approval may be required.**

> **Note:** One of the key concerns to be address is the resiliency of the sliplock seals to all conditions that might be encountered such as formation and drilling pressures, temperatures and fluids, cyclic loading or fatigue and/or adverse conditions such as fire and extreme climates (i.e., very hot or cold).

For Alberta see the Sliplock subsection of the Casing Bowls section of AER Directive 36: Drilling Blowout Prevention Requirements and Procedures.

**Figure 27 - Sliplock Casing Head Example**



#### 5.1.3.13.7 Coiled Tubing Connection Types

Roll-on connectors (Figure 28) may be found in wellheads completed with coiled tubing. The end of the coiled tubing and inner diameter are prepared to ensure a good fit and O-rings might be included to help provide a tight seal. The connector body, with its outer diameter grooves and O-rings, is inserted into the coiled tubing. An installation tool is then applied to crimp the coiled tubing into the connector body grooves. A sleeve may then be slipped over the coiled tubing and threaded onto the connector body. The threaded connector is then attached to the tubing hanger which suspends the coiled tubing in the wellbore.

Roll-on connectors are preferred in shallow gas operations.

In conventional and in situ heavy oil operations, the most common means of landing coiled tubing strings in a wellhead involves slips and seals. If the coil is exposed to the atmosphere there is a risk of corrosion due to condensation.

Coiled tubing may also be attached to a connector body with a welded connection. Other means of attaching coiled tubing include dimple (Figure 29) and grapple connections (Figure 30). Dimple connector uses set screws and grapple connector uses slips to mechanically attach to coiled tubing.

For more information see 5.1.3.11 Coiled Tubing Hangers.

For welded coiled tubing connections see 5.2.3.3 Installation Personnel for requirements related to welding personnel and see 5.2.3.5.3 Welded Connections for requirements related to welding procedures.

**Figure 28 - Roll-On Connector**

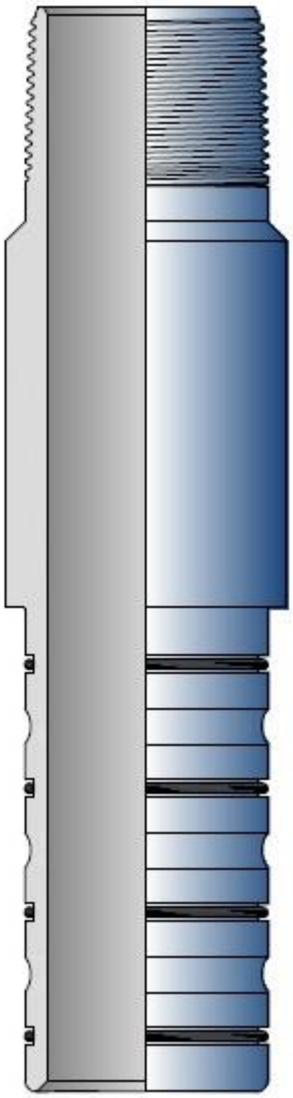


**Figure 29 - Dimple Connector**

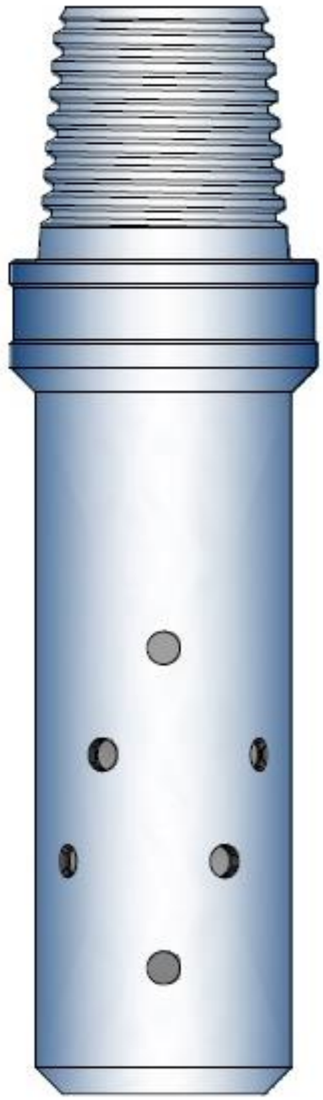
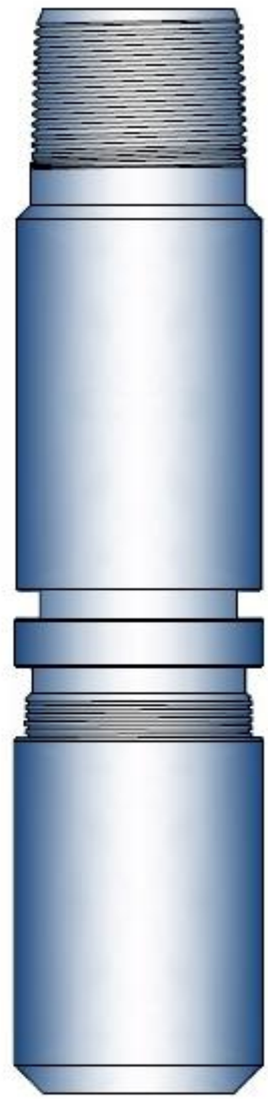


**Figure 30 - Grapple Connector**



#### 5.1.3.14 Seals

Seals are used to hydraulically isolate various tubulars and annuli from one another and to provide well control (i.e., prevent leaking to the environment). Seals also provide isolation between the wellhead and any feedthroughs, including but not limited to: instrumentation, electrical feedthrough equipment and some coiled tubing applications.

> **Note:** Seals are covered in the IRP statement in 5.1.2.4 Pressure Rating Requirements.

IRP Seals should be transported and stored according to OEM specifications.

##### 5.1.3.14.1 Seal Composition

###### 5.1.3.14.1.1 Elastomer and Graphite/Carbon Seals

Sealing components in conventional wells and some thermal wells are typically made from elastomers. Elastomers are designed to operate within a specified temperature range and offer resistance to a specific set of chemical conditions including sour corrosive environments.

Graphite or carbon fibre seals may be used when operating temperatures exceed the service limits of elastomers.

The seal elements (rings) are often installed into recesses or grooves machined into the outer surface of the component or a bushing that seats into the housing (e.g., for secondary seals, tubing or casing hangers or adaptors). Pressure is then applied to energize the seals by setting weight on the seal, mechanically applying pressure or utilizing wellbore pressure.

###### 5.1.3.14.1.2 Metal Seals

Sealing elements (rings) may also be made from metals. Good design and installation practices are essential because it can be difficult to achieve a metal to metal seal that will maintain the required performance through the full range of the well operating conditions. The metal of these sealing components requires sufficient ductility and elasticity to deform under the setting conditions and flex under changing operating conditions in order to maintain the required sealing stress throughout all well operations. This means the metal seal may be softer than the housing it is to be set into so the metal seal does not damage the housing once energized or provide an opportunity for localized corrosion.

###### 5.1.3.14.1.3 Recommendations

**IRP Both elastomer and metal seals shall be chosen ensuring the composition of the seal matches the operating conditions of the well. The seal should be chosen to function over the life of the well. As well conditions or operations change seal integrity will need to be reconfirmed.**

IRP Under dynamic operating conditions, all seals should be maintained and replaced as required.

IRP Elastomer and metal seals should not be reused unless designed for reuse.

See 5.1.7 Artificial Lift Wells (particularly 5.1.7.1 Reciprocating Rod Pump, 5.1.7.4 Electric Submersible Pump) and 5.1.8.1 Injection or Disposal for additional seal-related recommendations.

For additional information refer to the section on Elastomeric Seals in IRP 21: Coiled Tubing Operations.

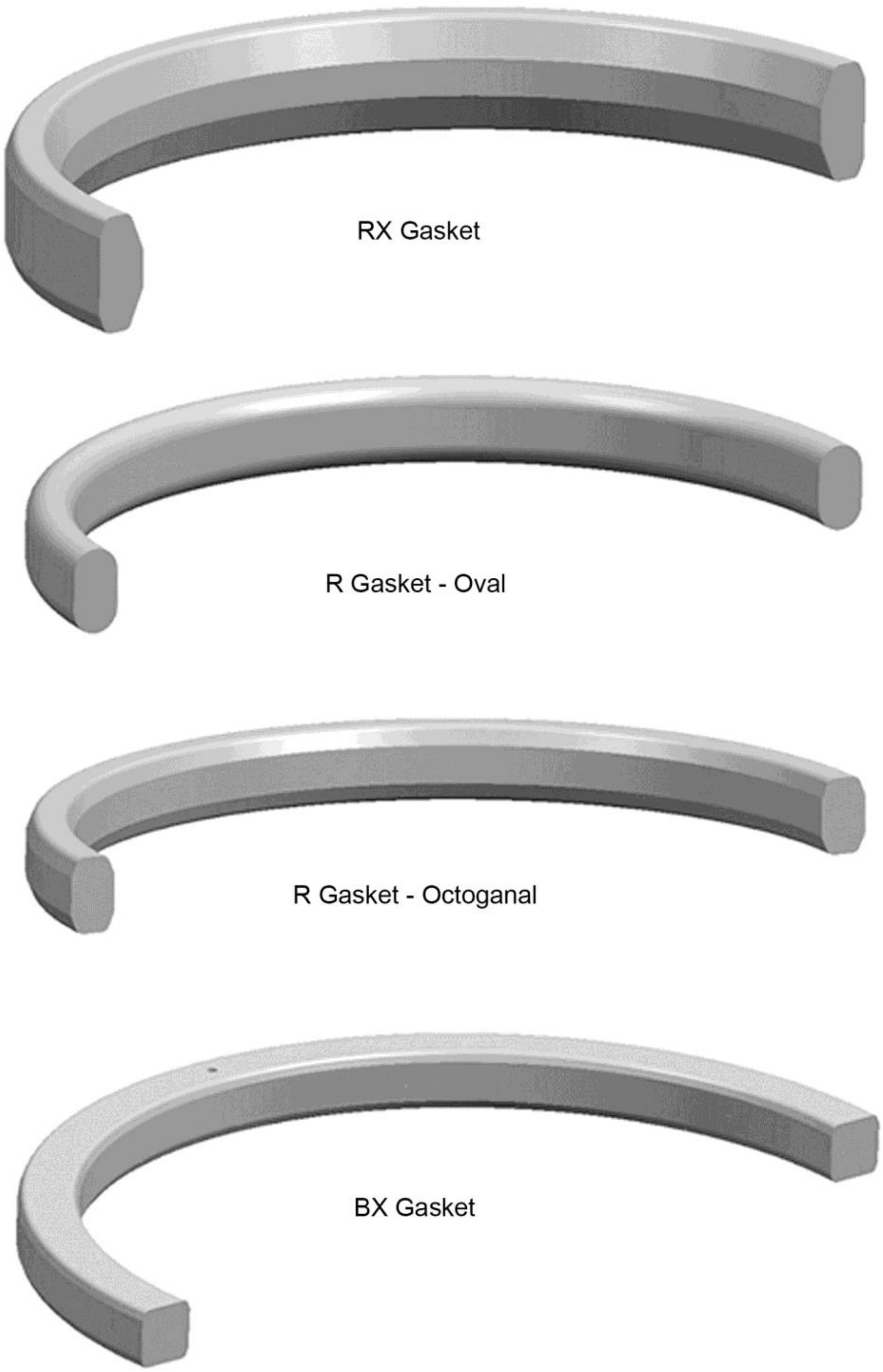
#### 5.1.3.14.2 Seal Types

##### 5.1.3.14.2.1 Ring Gaskets

A ring gasket provides the actual seal in any flanged or studded connection and in some hub clamp connections. The ring gasket is a metal seal designed to fit the grooves on each flange or hub face. As the studs on a flange or clamp are torqued the softer metal of the ring gasket is compressed against and conforms to the harder metal of the face. Each ring gasket carries a rating for the range of pressures, temperatures and corrosive fluids that may be present. There are three basic styles of API approved ring gaskets (see Figure 31):

1. R-style is designed for standard ring joint grooves. R-style includes both oval and octagonal cross sections which are interchangeable in a standard groove.
2. RX-style also fits standard ring grooves. RX ring gaskets have a non-symmetrical cross section resulting in sealing on the OD of the gasket only. This provides a pressure energized self-sealing gasket. A vertical hole in the gasket ensures pressure is balanced.
3. BX-style ring fits only flanges with BX grooves. These flanges are designed to allow face to face contact. BX gaskets also have a pressure balancing hole.
4. R/RX-Style may be used in 13.8-34.5 MPa operations while BX-Style are typically used in any operation above 34.5 MPa.

**Figure 31 - API 6A Metal Ring Gasket Styles**




Ring gaskets are permanently deformed when energized and are designed for single use.

**IRP Ring gaskets shall not be reused for any reason.**

**IRP Ring gaskets shall be chosen to match the known operating conditions of the well and take into account pressure, temperature and fluid exposures. The ring gasket used shall be the one designated for use with the flange type, size and pressure rating.**

**IRP RX or BX ring gaskets shall be used for critical sour operations.**

RX ring gaskets may be preferable for thermal operations. Some operator experience shows that RX gaskets may be more reliable when temperature cycling.

See 5.2.3.5.4 Flanged, Studded and Clamp Hub Connections for recommendations related to the make-up of ring gaskets.

#### 5.1.3.14.2.2 Primary and Secondary Seals

Casing strings (other than the surface casing) that terminate in the wellhead are typically sealed twice. First, a primary seal is set when a casing is suspended by a casing hanger in the top bowl of a casing head or casing spool. This seal isolates the annulus between this casing string and the previous casing string. The casing itself extends into the counterbore of the next wellhead component where a secondary seal can be set. When both a primary and secondary seal are set, the seals and the connection between the two wellhead components can be pressure tested for integrity via a test port. This same principle can be applied to a welded connection between the casing head and surface casing when it is welded both on the top of the casing on the inside of the head and outside on the bottom of the casing head. A test port between the two welds provides a means to pressure test the integrity of the welds.

### 5.1.3.15 Surface Casing Vent Flow Assembly

Wellheads can be equipped with an assembly to isolate and test the annulus between the surface casing and the second string of casing, and allow the annulus to vent freely. This assembly is commonly referred to as a Surface Casing Vent Assembly (SCVA).

**IRP SCVAs must be installed on all newly drilled wells.**

> **Note:** In Alberta a surface casing vent assembly is not required if the well falls under exemption criteria listed in AER Bulletin 2011-35. Refer to local jurisdictional regulations for more information.

Refer to AER Bulletin 2011-35 or local jurisdictional regulation for direction on monitoring surface casing vent flows for wells without a SCVA.

**IRP The surface casing vent must be left open to the atmosphere except during testing (as per Alberta OGCR 6.100 and other local jurisdictional regulations).**

**IRP The SCVA must be a minimum diameter of 50 mm, extend at least 60 cm above ground elevation and terminate so that any flow is directed either in a downward direction or parallel to the ground (as per Alberta OGCR 6.100 and other local jurisdictional regulations).**

**IRP The SCVA must be equipped with a valve.**

**Note:** In Alberta the assembly doesn't need a valve if the anticipated or actual $H_2S$ concentration of the well is less than 5 ppm (as per Alberta OGCR 6.100).

**IRP The designed working pressure of the SCVA must be as per local jurisdictional regulations.**

There two common types of casing vent assemblies are the conventional assembly and the annular packoff.

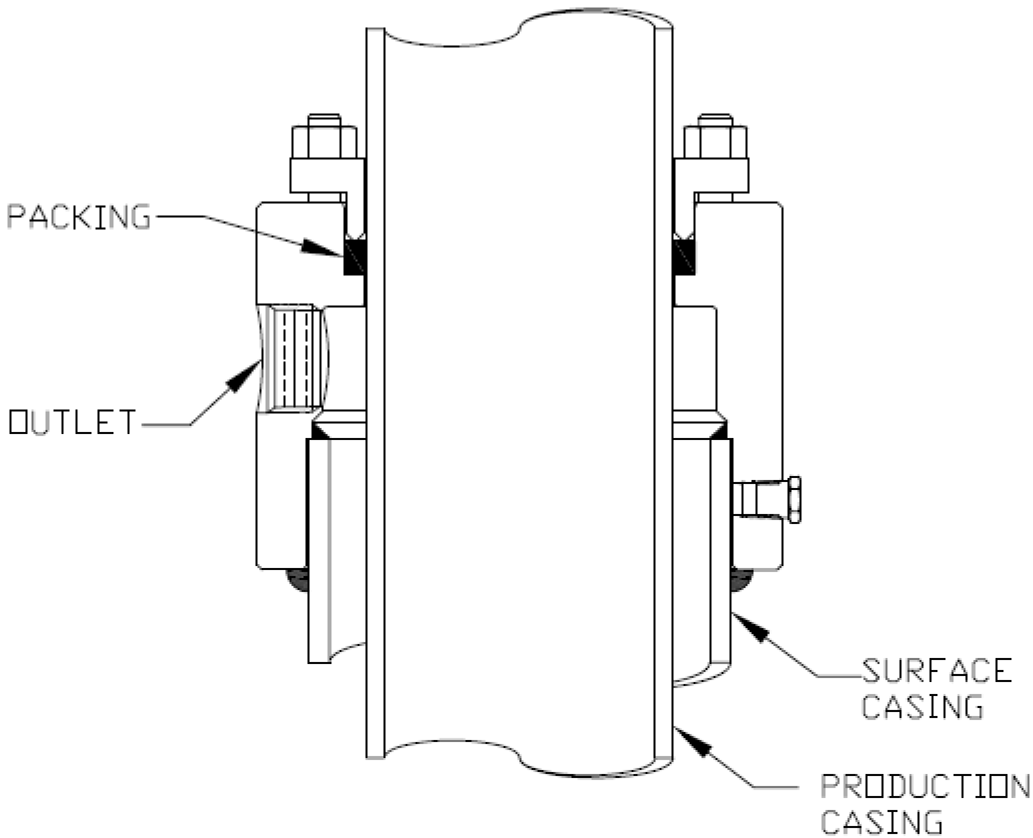
#### 5.1.3.15.1 Conventional Surface Casing Vent Assembly

The conventional surface casing vent assembly is connected to an outlet in the casing bowl and extends above grade for monitoring purposes. Since the casing bowl forms a pressure seal to the surface casing, the SCVA can be used to determine if any flow or pressure exists between the surface casing and the second string of casing.

#### 5.1.3.15.2 Annular Packoff

In applications where high temperature changes are seen on the casing and wellhead it may be desirable to allow differential expansion of the casing strings to reduce the forces seen on the wellhead. This is typically done by installing an annular packoff as seen in Figure 32. The function of the annular packoff is the same as a surface casing vent assembly as described in 5.1.3.15 above.

**Figure 32 - Annular Packoff Assembly**




Casing thermal expansion can be handled in several ways and is not limited to annular packoffs. It is the operator's responsibility to assess whether new technologies meet all the requirements of a SCVA and the risks of thermal service.

A second use of annular packoff assemblies is for observation wells with external instrumentation. The annular packoff allows the instrument leads to be isolated below the wellhead.

Thermal wells with annular packoff assemblies create additional design requirements over conventional SCVA. These need to be considered during initial wellhead design for integrity throughout the life cycle of the well.

Consider the following:

- Fluid expansion in annular space.
- Corrosion of casing close to surface due to elevated temperatures and exposure to ground water.

In thermal wells, water (in liquid form) in the annulus between the surface casing and the second string of casing is heated and causes expansion. Restraining the expansion of this fluid can cause pressure to build past the maximum working pressure (as specified in OGCR 6.100 and/or other local jurisdictional regulations).

The warm up phase is defined as the period in which the well is heated from ambient conditions to over the boiling point of the water in the annulus space.

IRP The operator should allow free expansion of fluid in the annular spaces during warm up phase by ensuring the surface casing vent valve and goose neck are free of obstruction (e.g., ice plug) and are maintained open (as per Alberta OGCR 6.100 and other local jurisdictional regulations).

Packoff assemblies are not always installed on CSS wells due to the operating conditions and corrosion mitigation programs that can be employed. In this scenario, approval from the local jurisdictional regulator is required and an alternate means of testing for SCVF has to be provided.

Corrosion around the annular packoff assembly is possible in thermal wells when there is surface or ground water in the presence of oxygen and elevated temperatures. There is a higher risk to production casing integrity when it is exposed to surface water. The following mitigations may be considered to maintain casing integrity and function of the annular packoff:

- Slope the ground around the wellhead away from the wellhead to limit surface water contact
- Install a shroud around the wellhead if fluid is anticipated to run down onto the top of the annular packoff.
- Terminate the surface casing above ground to allow the packoff assembly to be installed above ground which can largely reduce the ingress of surface water.
- Use corrosion reduction coatings on the surface and production casing close to surface.

**Note:** Elevated temperatures can cause backfill material to adhere to the surface casing. This may cause extensive excavation and labour to remove backfill material before the surface casing can be inspected.

### 5.1.4 Sweet Flowing Wells

Flowing wells rely on reservoir pressure to lift production to surface. Flowing wellheads are typically simple but some may support multiple tubing strings, monitoring lines or control lines. Depending on the type of produced fluids and well completion, production can be up the production casing, production tubing or the tubing-casing annulus.

Sweet, low pressure, low risk wells (e.g., shallow gas) often do not have a tubing string installed.

Each province has different guidelines for sweet or sour wells. For design considerations, such as material selection, the NACE limit is 0.3 kPa $H_2S$ PP.

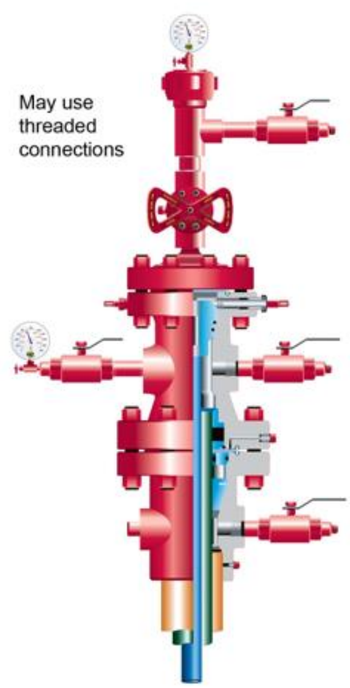
For the purposes of the IRP 5, the threshold between sweet and sour flowing wells is 0.3 kPa $H_2S$ PP. Hence, sweet flowing wells are defined as wells with less than 0.3 kPa $H_2S$ PP that are capable of flowing to surface (natural lift).

#### 5.1.4.1 Sweet Flowing Wells Below 13.8 MPa

**IRP Sweet flowing with a bottomhole pressure at or below 13.8 MPa and that are not expected to face operational pressures above 13.8 MPa over the life of the well shall use connection types that are fit for purpose.**

This may include threaded connections on casing heads and spools.

**Figure 33 - Wellhead for Sweet Flowing Well ≤ 13.8 MPa**

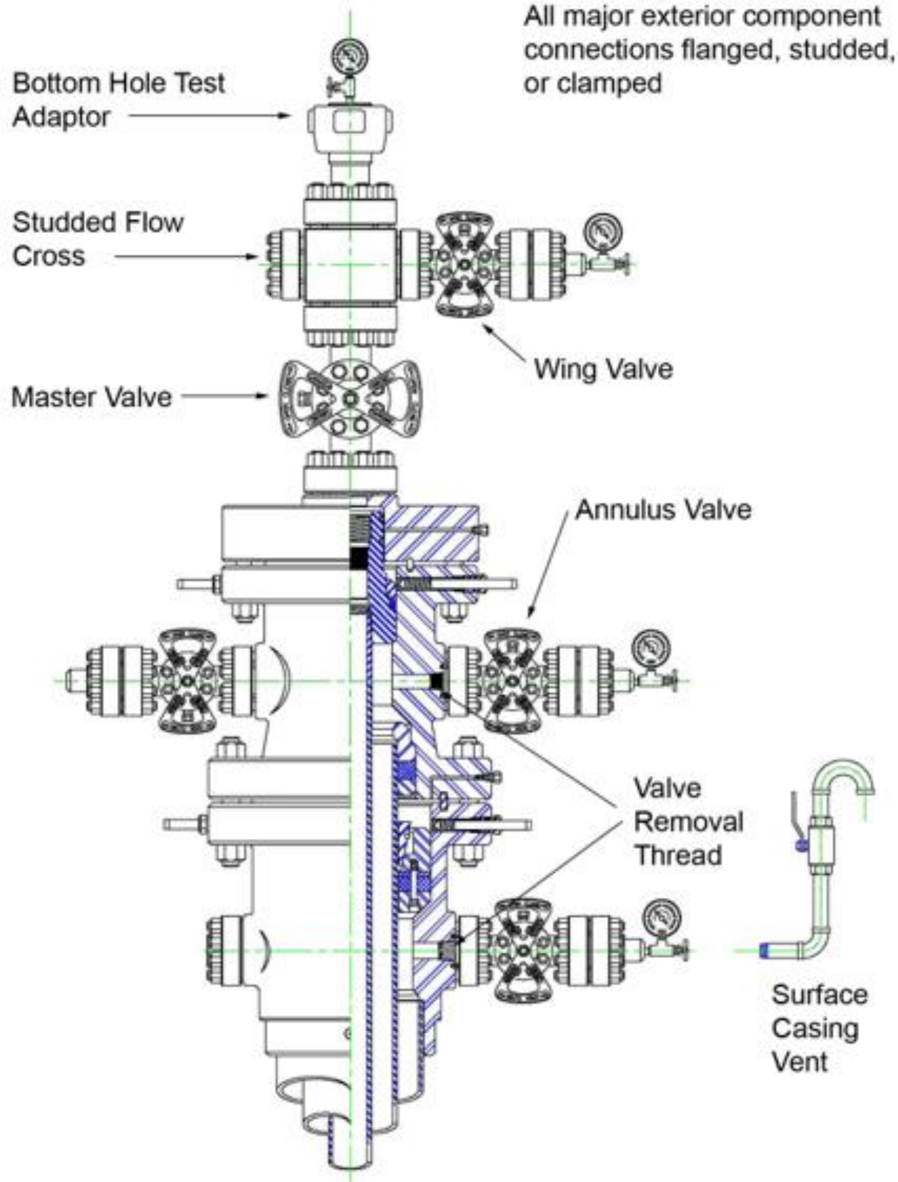



#### 5.1.4.2 Sweet Flowing Well Above 13.8 MPa

**IRP For wellheads on high pressure sweet flowing wells (bottom hole or operational pressure above 13.8 MPa), all major exterior component connections shall be flanged, studded or clamped.**

IRP The API 6A primary components with operational pressures above 103.5 MPa should use PSL 3 or higher.

**Figure 34 - Wellhead for High Pressure Sweet Flowing Well (> 13.8 MPa)**



#### 5.1.4.3 Low Pressure/Low Risk Gas Wells

For the purposes of the following recommendations, a low pressure/low risk well is a well that demonstrates declining production over time and exhibits the following characteristics:

- It is easy to control.
- It presents minimal safety and environmental risk.
- It occurs in an area with a confirmed knowledge of the reservoir and well operating conditions.

These characteristics can be quantified as follows:

- Bottomhole pressure is below 6 MPa.
- Gas deliverability is below 17 $e^3m^3$/d absolute open flow (AOF) @ Midpoint Perforations (MPP).
- Combined ratio (Pressure*Rate) is below 80 (MPa * $e^3m^3$/d).
- No $H_2S$.
- Hydrocarbon liquids are below 30 ml/$m^{3.}$
- Production casing is cemented with good quality cement returns to surface.
- Well density is greater than four wells/three km radius.

This definition is usually applicable in shallow well applications where all formations are below the above BHP criteria. It is not just for depleted production formations.

Low pressure/low risk wells may use a simplified wellhead which consists of a single master valve connected to the casing (see Figure 35).

**IRP The master valve for low pressure/low risk wells shall provide full bore access to the casing and be suitable for expected service conditions.**

IRP A centralizer ring should be installed to stabilize the wellhead if surface casing or conductor pipe is present.

A simplified wellhead such as this will typically consist of a gate valve threaded on to the production casing, a flow tee with a wing valve to the side (to isolate the wellhead from the flow line) and a bleed off valve on the top.

**Figure 35 - Simplified Wellhead for Low Pressure/Low Risk Gas Wells**


A variety of methods may be used to monitor or isolate the annulus between the surface and production casings in areas not prone to vent flows, where good quality cement returns were observed during primary cementing operations and vent flow or gas migration has not been detected around the wellhead.

**IRP All isolation and monitoring methods must adhere to local jurisdictional regulations.**

**IRP A packoff assembly shall be installed if vent flow or gas migration is detected from the production casing to surface casing annulus.**

**Note:** If the vent flow or gas migration is non-serious (as defined by AER ID 2003-01), a company may apply to the appropriate regulator for exemption from the requirement to install a permanent surface casing vent.

A tubing string may be run through the master valve when well flow characteristics deem it necessary. This results in the tubing hanger being installed above the initial master valve.

**IRP If the tubing string is run above the initial master valve there shall be access to the tubing casing annulus.**

A flow tee may be installed below the tubing hanger if the hanger cannot accommodate a port for a casing wing valve.

IRP A full opening (tubing size) valve should be installed below the production flow tee to provide isolation of the tubing string.

### 5.1.5 Critical Sour, Sour and Corrosive Wells

The distinction between sour and critical sour wells is determined by local jurisdictional regulations. The classification of critical sour typically takes into account a number of factors including $H_2S$ release rates and proximity to populated centers. Wellhead requirements for any well deemed to be critical sour can be found in the Wellheads section of IRP 2: Completing and Servicing Critical Sour Wells and are not discussed in this IRP.

For the purpose of wellhead design in IRP 5, sour wells are defined as any well having 0.3 kPa $H_2S$ PP or greater that are not designated as critically sour by local jurisdictional regulation.

Sour wells present three major risks:

1. $H_2S$ is highly toxic even at low concentrations.
2. $H_2S$ is a corrosive product that can degrade both metal and elastomer components in the wellhead.
3. Sulphide Stress Cracking (SSC) can cause mechanical failure of materials.

The higher standard for connections and PSL for sour wells is designed to address these risks. Corrosive factors also need to be considered in the selection of connections and PSLs. The following all present a corrosion hazard:

- $CO_2$ and water
- Salt water
- Aggressive solvents (e.g., Dimethyl disulphide (DMDS))
- Acid (well stimulation)

Where corrosion is aggressive, the higher product standard for sour or critical sour wells may be equally applicable to wells with these or other corrosive fluids.

Damage from $H_2S$ can be accelerated when it is combined with other corrosive fluids. In such cases higher product and safety standards, such as those applied to critical sour wells, may be desirable.

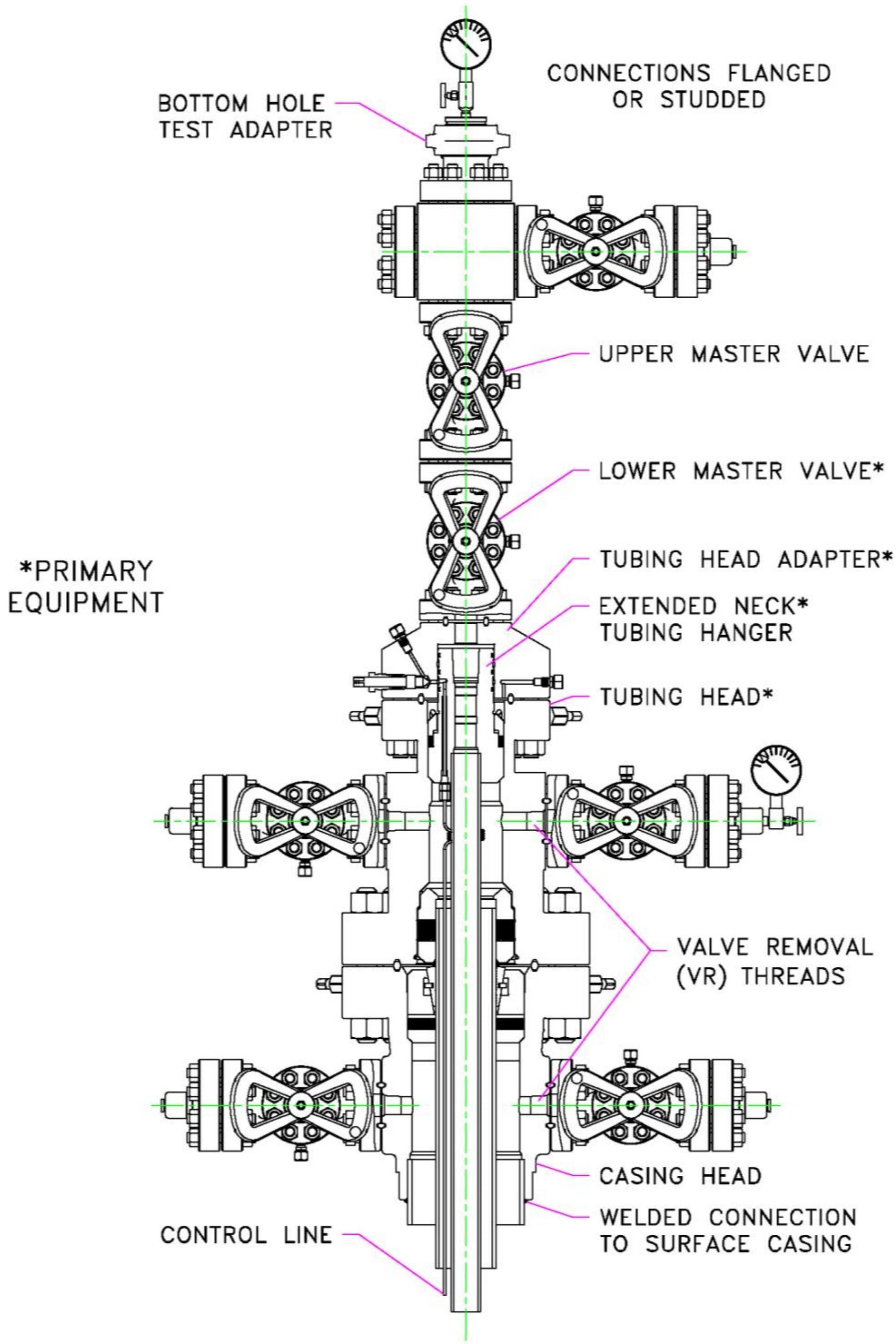
**IRP All wellhead components on sour wells must use appropriate materials as specified by NACE MR0175/ISO 15156 standards (see API 6A Purchasing Guidelines for more information).**

IRP At minimum, all API 6A primary components on sour wells should meet PSL 2 standards. The API 6A recommendation on minimum PSL for primary parts of the wellhead and christmas tree equipment should be followed. Exceptions can be made in low risk scenarios (e.g., low $H_2S$ release ratel).

IRP Wellhead design for any sour well should consider all other characteristics of the produced or injected fluids (e.g., $CO_2$, chlorides, sand, solvents) as well as the rate of production or injection and proximity to environmentally sensitive areas or human populations.

**IRP All major exterior component connections on a sour well, including valves, shall be flanged, studded or clamp hub connections.**

**Figure 36 - Sour Well (Non-Critical) Example**




IRP Extended neck tubing hangers, complete with a back pressure valve (BPV) preparation, should be utilized in sour well completions.

The extended neck with a sealed tubing hanger isolates the produced sour fluids from the top bowl's lock down screw assemblies and ring gasket of the tubing head. Other styles of tubing suspension systems which give the operator the BPV preparation and provide similar protection to the lock down screw assemblies and ring gasket are acceptable (see Figures 13 and 15).

IRP All valves on wellheads on sour wells should be rated for sour service and fit for purpose.

**Note:** The surface casing vent is excluded from this requirement.

**IRP The injection line on a circulating string for sour wells shall be equipped with a check valve.**

**IRP Sour wells must have a minimum of two master valves.**

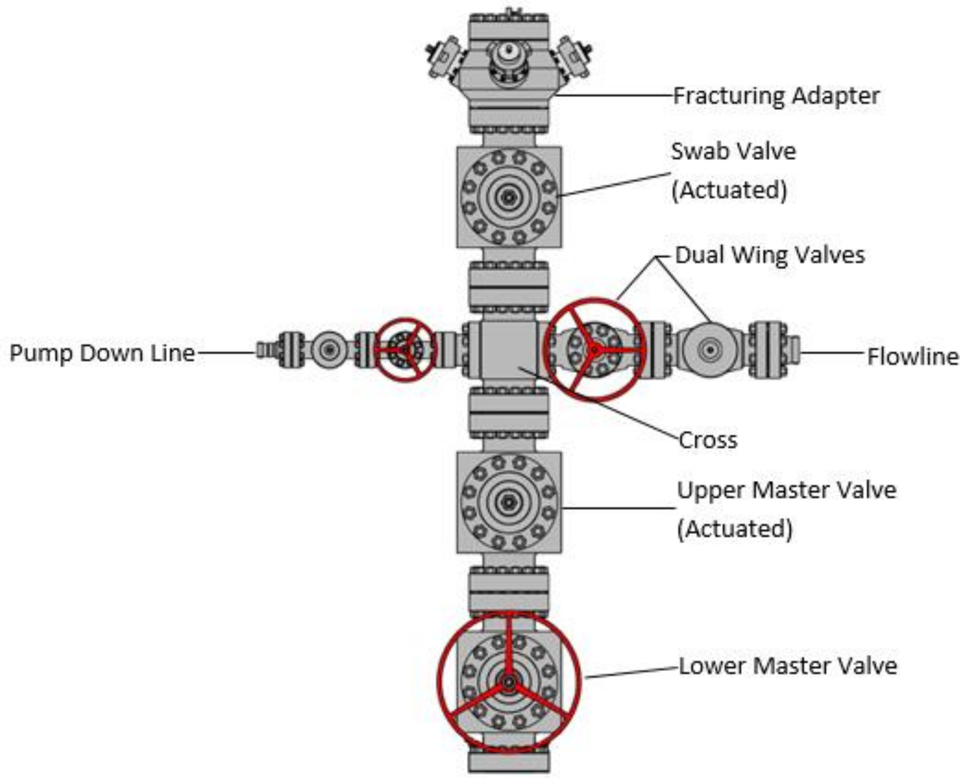
IRP The standards outlined for sour wells (or for critical sour wells in IRP 2: Completing and Servicing Critical Sour Wells) should be considered in the design for any wellheads that will be subject to aggressive corrosive materials in the course of operations over the life of the well.

IRP Wellhead designers should ensure optimal compatibility between wellhead metallurgy and the specific corrosive materials that primary wellhead components and sealing systems will be subjected to in the course of operations over the life of the well.

### 5.1.6 Fracture Trees

The fracture tree is similar to a christmas tree in that it is an assembly of valves and fittings placed above the wellhead. The fracture tree is generally installed as a temporary system and is specifically designed to control the fracture fluid being injected into the well. The tree may also be left in place during initial well flowback operations and the initial well production phase but it is usually replaced by a permanent conventional christmas tree at some point. To accommodate the fracture treatment conditions, fracture trees are usually rated to a higher pressure and often have a larger through bore diameter than the christmas tree that will follow. An example of a fracture tree is shown in Figure 37.

**Figure 37 - Example Fracture Tree**




### 5.1.6.1 Fracture Tree Configuration

For purposes of this IRP, the fracture tree includes only the assembly of valves and fittings from the lowermost valve to the uppermost valve including any wing valves and the fracture adapter (buffalo head or goat head) or cross which the fracturing piping is connected.

IRP The following should be considered for the fracture tree configuration:

- All connections on the fracture tree should consist of flanged, studded or clamp hub connections.
- Hammer unions may be used for inlet and outlet connection to the tree.
- Any tree with a rated working pressure of 69.0 MPa or above should have dual master valves (i.e., an upper and lower master as shown in Figure 37) with the upper master equipped with a double acting actuator.
- A flanged or studded tee or cross should be supplied on the fracture tree to connect the flowline used during flowback operations to the testers.
- Each fracture tree should have at least one wing valve on the flowline to the testers.

- Any fracture tree with a rated working pressure of 69.0 MPa or higher should have dual wing valves on the flowline to the testers if one of the master valves cannot be closed when required (e.g., during coiled tubing fracturing operations the master valves are inoperable when the coiled tubing is across the valves).
- There should be a method of isolating each fracturing inlet line with valves from the fracture tree at all times, including when wireline or coiled tubing may be run into the well. These valves should have integral flanged, studded or clamp hub connections.
- Any fracture tree with a rated working pressure of 69.0 MPa or higher should have a valve between the cross and the fracturing adapter so that any equipment rigged in above this valve can be isolated during flowback. Alternatively, the fracturing inlet line can be supplied with valves.

**IRP The pressure rating of any equipment connected to the fracture tree shall meet or exceed the fracturing pressure unless isolated from the high pressure side.**

For example, flowback equipment is often at a lower rated working pressure than the fracture pressure and needs to be isolated with a valve (or valves) rated to the fracture pressure.

#### 5.1.6.2 Pressure Testing

Pressure testing is a regulatory requirement to assess whether system integrity is adequate to proceed with operations.

**IRP All connections on the fracture tree shall be pressure tested prior to the commencement of fracturing operations.**

IRP All connections on the fracture tree should be field pressure tested to a maximum of the rated working pressure (RWP) of the fracture tree.

**IRP The maximum allowable fracture treatment (operating) pressure shall not exceed 91% of the rated working pressure of the fracture tree.**

As the test pressure is limited to the rated working pressure of the fracture tree this means that the maximum allowable fracture treatment pressure is limited to 91% of the rated working pressure of the fracture tree (Fracturing Pressure=RWP/110%). For example, when a 69.0 MPa RWP fracture tree is used the maximum allowable fracturing treatment pressure would be 62.7 MPa.

#### 5.1.6.3 Erosion Wear

Fracturing fluids can cause erosion of the fracture tree which may lead to equipment failure. The potential for erosion wear needs to be considered in the well and fracture treatment design. Items to consider about erosion wear include the following:

- Velocity
- Pumping rates
- Proppant type and concentration
- Fluid type and whether energized or not
- Metallurgy
- Internal profiles or geometry of the fracture tree and wellhead

Erosion wear can be a concern during flowback operations due to the above factors and reservoir conditions.

#### 5.1.6.4 Valve Operation

If a valve is accidently closed during fracturing operations it can cause all the equipment upstream of this valve to become over pressured, potentially resulting in a failure.

**IRP Operators shall adopt a method to ensure valves on the fracture tree are not functioned or operated at incorrect times.**

Many operators have adopted a communication protocol to avoid this. One example is the “triple handshake” approach in which representatives from the operator, fracturing services company and the service company responsible for the valve operation meet and acknowledge an agreement about valve operation before any valve is operated. This is especially critical on multi-well pads where several simultaneous operations occur in close proximity to each other and that may be interconnected through the use of a fracturing manifold system.

Depending on the design of the valve and actuator, wellbore pressure can cause the inadvertent operation of the valve (either slowly creeping open or closed) if constant hydraulic/pneumatic pressure is not supplied to the actuator.

IRP Valves equipped with actuators should have a means to prevent them from inadvertently opening or closing due to wellbore pressure changes.

The inadvertent operation of the valve can be prevented in several ways such as the use of a specific type of valve (e.g., a balanced stem valve), the use of counter balancing valves on the control system or the use of lock open/closed devices.

#### 5.1.6.5 Connections

The connection between the fracture tree and the wellhead can be subjected to bending loads due to the weight supported by the fracture tree. These loads are normally within the acceptable capacities of the connection. If the load applied is unbalanced, such as when one larger fracturing inlet line tied in horizontally is used, the applied bending load can stress the connection and potentially result in a failure. Unbalanced loads need be adequately supported.

**IRP The loads imparted on the connections to the fracture tree shall not exceed the capacity of the fracture tree connections (as per manufacturer specification).**

#### 5.1.6.6 Post-Fracture

After the fracture treatment is complete, or during maintenance of the fracture tree, the fracture tree or components may need to be removed. Although there should not be any fracturing pressure at this time, there will be wellbore pressure which needs to be contained in order to safely perform this task. A dual barrier well control approach as a redundant means of pressure containment is typically applied, particularly if the wellbore pressure exceeds 34.5 MPa.

**IRP When removing the fracture tree or fracture tree components, dual barriers for well control shall be used if the pressure being contained exceeds 34.5 MPa.**

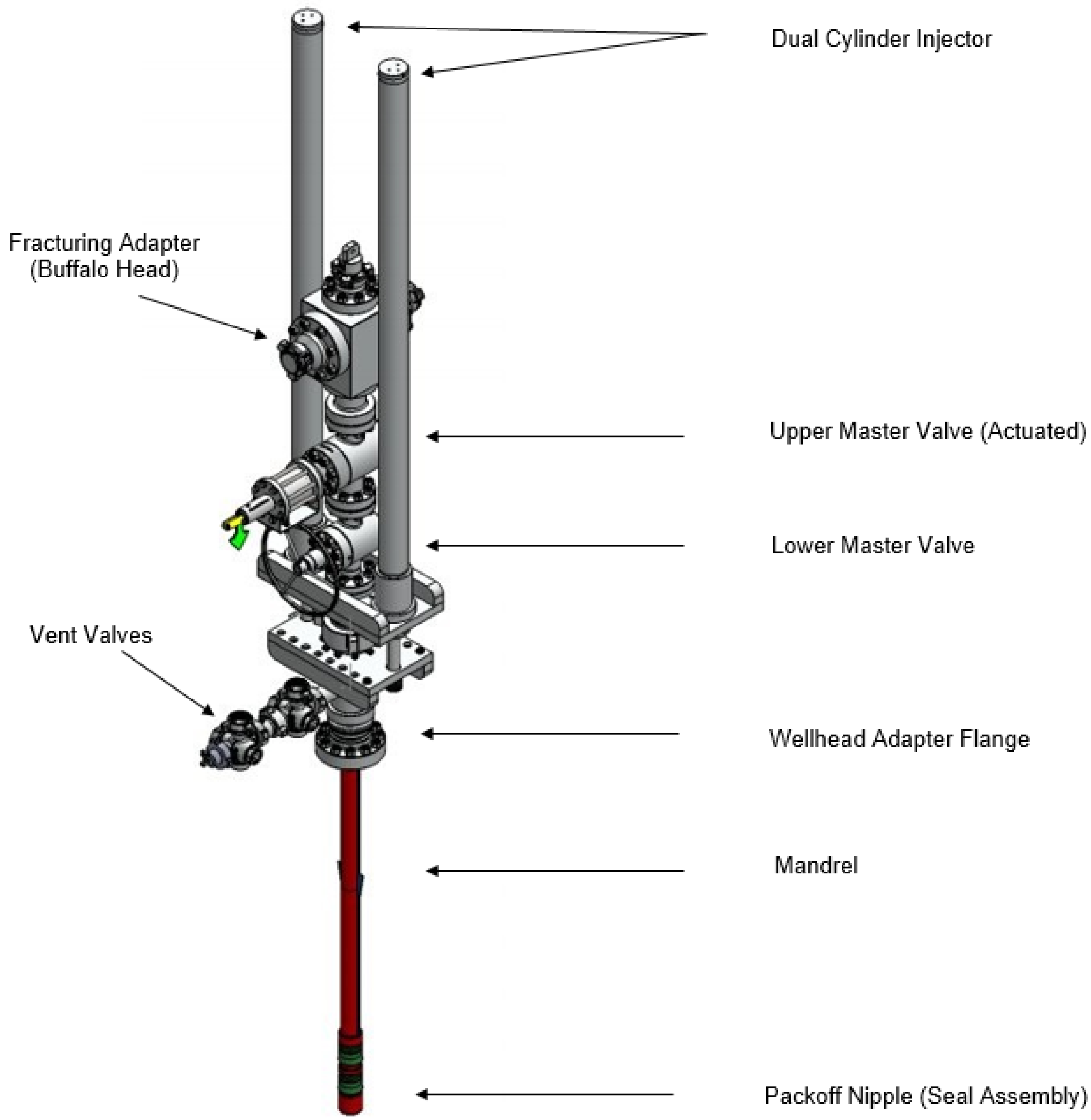
The following are examples of barriers:

- Setting a back pressure valve in the tubing or casing hanger.
- Closing a valve on the wellhead.
- Setting a bridge plug in the wellbore.
- Maintaining a column of fluid of adequate density.

#### 5.1.6.7 Wellhead Isolation Tools

The wellhead isolation tool allows the production wellhead and/or surface wellhead equipment to be isolated from the fracturing process and protect it from fracture treatment pressure, erosion and corrosive fluids. Wellhead isolation tools are used in conjunction with a fracture tree (Figure 38).

**Figure 38 - Wellhead Isolation Tool**




IRP A remote actuated valve or valves should be used with wellhead isolation tools as a means to quickly close and contain the wellhead pressure and prevent damage.

**IRP Vent valves on the isolation tool shall be open during pressure fracture operations to protect the isolated surface wellhead equipment from over-pressurizing.**

#### 5.1.6.8 Additional Fracturing Equipment

Additional surface fracturing equipment can include, but is not limited to, the following:

- Ball Launcher Systems.
- Ball Catcher Assemblies.
- Fracture Adapters (buffalo head or goat head) with coil deflector sleeves.
- Manifold systems for multi-well pad fracturing operations.
- Fracturing piping, valves, flanges and any related accessories.

**IRP The pressure rating of any additional equipment connected to the fracture tree shall meet or exceed the fracturing pressure and be of quality equipment intended to meet the requirements of the fracture as per the OEM operating procedures.**

Refer to the IRP 24 Hazard Register for additional information on wellhead fracture tree related hazards and considerations for hazard management.

### 5.1.7 Artificial Lift Wells

Artificial lift is installed to increase the production rate from flowing wells or enable production at wells that will not flow due to issues such as reservoir depletion, an inadequate inflow pressure or an increased WOR in the produced fluid. Artificial lift may be installed in sweet or sour wells. Consult the wellhead and artificial lift OEMs to ensure all wellhead components are rated for the expected fluid conditions, pressures, temperatures and loads.

The more common types of artificial lift and the wellhead modifications required to enable the safe use of the equipment are summarized in Table 7 and described in more detail in the following sections.

**Table 7 - Common Types of Artificial Lift**

| Type | Description |
|---|---|
| Gas Lift | • The wellhead is modified to allow gas injection and fluid production at the same time.<br>• Often completed with an isolation packer in the tubing/casing annulus (see 5.1.3.6 Tubing Hanger).<br>• Lift gas is injected either into the tubing or the tubing-casing annulus. |
| Electric Submersible Pump (ESP) | • The wellhead includes a pressure-sealing feed-through for the electric power cable that runs from surface to the downhole ESP motor. |
| Reciprocating Rod Pump (RRP) | • A stuffing box and rod blowout preventer are installed to seal around the polished rod that is installed at the top of the rod string.<br>• The wellhead master valve is often not included. |
| Progressing Cavity Pump (PCP) | • Includes the components required by RRP above.<br>• Requires a polished rod BOP and stuffing box. The wellhead also provides the platform on which the PCP drive head and any required electric motors are mounted. |
| Plunger Lift | • Essentially a flowing well with a lubricator/plunger catcher installed on top of the flow cross. |
| Hydraulic (Jet) Pump | • The flowing well wellhead is modified to allow injection of high pressure power fluid to a downhole pump and recovery of the exhausted power fluid and produced reservoir fluid stream(s).<br>• A downhole packer might also be required (see 5.1.3.6 Tubing Hanger).<br>• A switching valve and lubricator are included on top of the flow cross. |

**IRP** **Any artificial lift equipment mounted on the wellhead shall match the requirements of the operating service (e.g., if the wellhead requires flanged connections, the BOP connections or plunger lift assembly shall also be flanged or have at least a comparable rating such as a clamp hub).**

**IRP** **If conditions have changed such that the original wellhead requirements are no longer applicable, the current (not original) conditions shall guide equipment design and selection.**

**Note:** Lift equipment is frequently added later in the life of a well.

#### 5.1.7.1 Gas Lift

A gas lift system enables or enhances well production by injecting high pressure gas into the production fluids to reduce the hydrostatic pressure and improve the ability to flow to surface under natural reservoir pressures. The high pressure lift gas is injected either into the production casing/tubing annulus or the production tubing. It is then introduced to the production fluid through a series of mandrels and valves installed in the production tubing. Produced fluids, with their reduced density, then flow up either the annulus (if the tubing is the conduit for the lift gas) or the tubing (if the annulus is the conduit for the lift gas). A downhole packer is typically included with the completion to avoid injecting gas into the reservoir. Annular gas injection with tubing production is by far the most common completion.

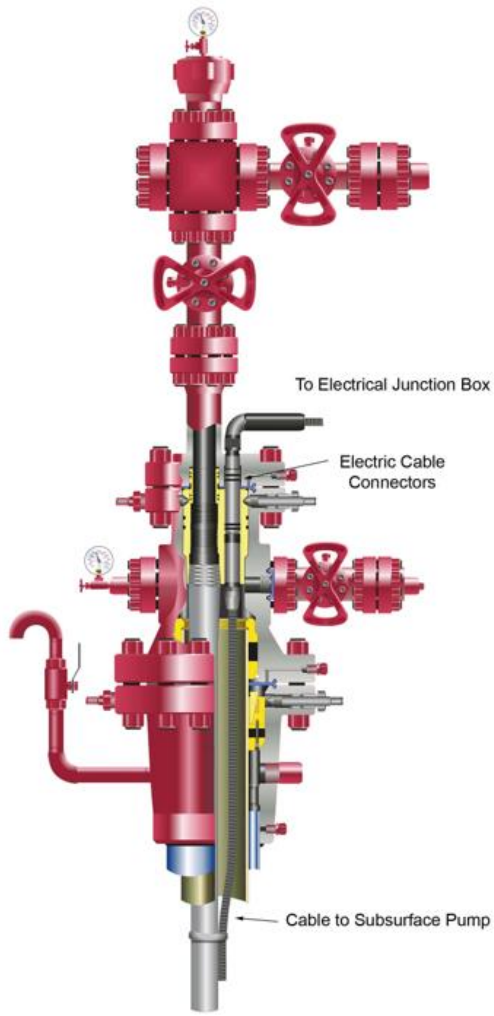
**IRP Wellhead equipment operating with a gas lift system shall be designed to withstand the increased pressures, corrosion and flow conditions resulting from the lift gas.**

#### 5.1.7.2 Electric Submersible Pump

An ESP is installed at the base of the production tubing and the completion might include a downhole packer (see Figure 39). Electric power is supplied to the downhole motor by a cable that is run along the tubing from surface. The high voltage, high amperage power cable is passed through and sealed at the wellhead by a specially engineered electric feedthrough connector.

> **Note:** The feedthrough connector is not designed to carry the weight of the cable. The cable is run with and banded or clamped to the production tubing string. Sufficient slack to avoid landing the cable in tension is required.

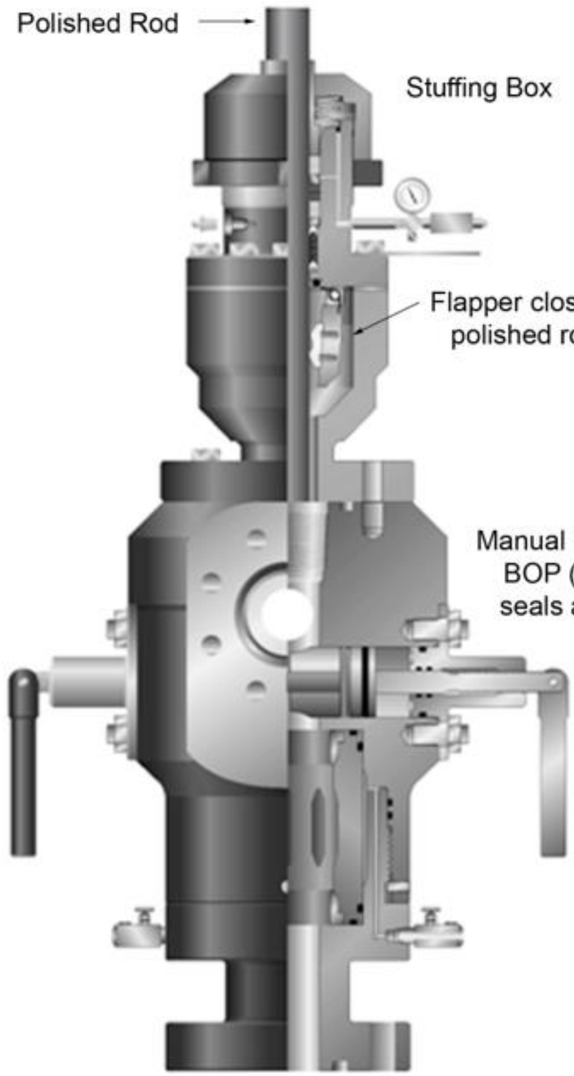
**Figure 39 - Wellhead for Electric Submersible Pump**




#### 5.1.7.3 Reciprocating Rod Pump

A RRP artificial lift system includes a surface drive (usually a pumpjack set behind the well), a rod string and a downhole pump. The rod string connects the surface driver to the downhole pump and is reciprocated vertically to activate the pump and produce the reservoir fluid to surface. The wellhead includes a stuffing box and BOP. The stuffing box provides a dynamic seal against the polished rod. The BOP can be closed off against the rod to seal off the well.

**Figure 40 - Integrated Pollution Control Stuffing Box and BOP**




**IRP All RRP wells shall have a polished rod stuffing box and BOP that are fit for purpose.**

Stuffing box and BOP design and sealing components are to be fit for the type of conditions under which they will be used (e.g., exposure to specific fluids, climate conditions, thermal well conditions, excessive wear in a slanted well or other unique operational wear considerations). See 5.2.6.3 Rod Pumping Well Maintenance for additional recommendations regarding maintenance and replacement of stuffing box sealing components. The rod stuffing box and BOP are outside the scope of API 6A.

IRP All RRP wells should have a pressure switch that automatically shuts down the pump in the event rising pressures exceed a pre-determined limit or a drop in pressure indicates a leak at surface.

**IRP If an isolation valve has been installed below the pressure switch, the isolation valve shall be secured open during operations to ensure the functionality of the pressure switch.**

A pollution control stuffing box (also called an environmental BOP stuffing box) can provide an automatic seal across the wellbore in the event a polished rod breaks and pulls out of the stuffing box.

**IRP The pollution control stuffing box shall be installed on any RRP well capable of flowing to surface in close proximity to human populations or environmentally sensitive areas (refer to local jurisdictional regulations for definitions of close proximity and environmentally sensitive areas).**

IRP The pollution control stuffing box equipment should be installed on any RRP well capable of flowing to surface or on any sour RRP well.

IRP In rod pumping operations on sour wells, consideration should be given to including a master valve that can be used in the event of a rod failure. This is in addition to the polished rod BOP. The master valve handle should be either removed or chained and locked during normal production operations to prevent accidental closure.

IRP In rod pumping operations on sour wells or wells capable of flowing to surface, the use of a dual stage or double ram rod BOP should be considered.

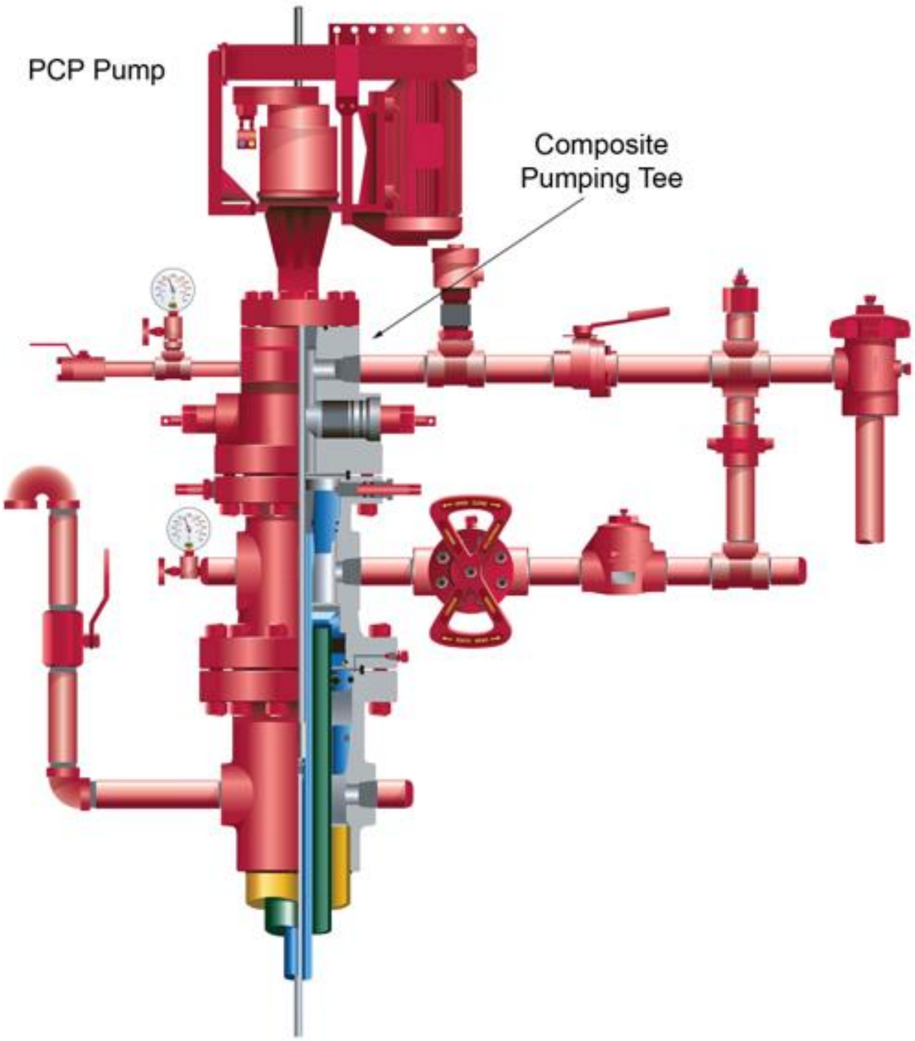
**IRP Operators shall implement a routine maintenance plan that includes a check of stuffing box seals, function tests of the pressure switch (if equipped) and a function check of rod BOP (see 5.2.6.3 Pumping Well Maintenance and 5.2.6.4 Pressure Shut Down System Maintenance).**

#### 5.1.7.4 Progressing Cavity Pump

The PCP artificial lift system also includes a surface drive, rod string and downhole pump but in this technique the rod string is rotated instead of being reciprocated. The PCP drivehead and stuffing box are mounted above the flow cross and, in electrically powered systems, the electric motor also is mounted on or suspended from the wellhead. All RRP IRPs (see 5.1.7.3 above) also apply for surface-driven PCP wells.

> **Note:** There are pumping operations that utilize an Electric Submersible Progressing Cavity Pump (ESPCP). The recommendations for the ESP are more appropriate for this type of pump design.

**Figure 41 - Wellhead for PCP Pump**




**IRP** **In addition to the reciprocating rod pumping IRPs, wellheads accommodating a progressing cavity pump shall be designed with the additional demands of the PCP drivehead taken into consideration.**

IRP Wellheads with a PCP drivehead should be made up with flanged or studded connections to support the additional weight of the motor or drivehead and sustain the vibration, torque and fatigue created by the PCP operation.

#### 5.1.7.5 Plunger Lift

In a plunger lift system (Figure 42) fluids are moved up and out of a well by a plunger that is carried up by natural well pressures. At surface, the arriving plunger is captured in a lubricator, the produced fluid unloaded to the flowline and the plunger released to fall back to the bottom of the well where the unloading cycle repeats.

The major wellhead integrity concern with plunger lift systems is the arrival of the plunger at surface. In normal operations, the force of the incoming plunger is absorbed by the fluid column and springs which stops in the lubricator assembly.

The plunger may fail to capture fluid if well conditions change or the plunger is caught by paraffin, wax, sand, scale or hydrate build-up in the tubing string and fails to drop to the well bottom. When it is subsequently pushed up by well pressure, the plunger may strike the surface assembly with an unexpectedly high velocity and much greater impact force. In extreme circumstances, a plunger arriving at a high velocity without a fluid column may cause equipment damage (wellhead or lubricator failure) and a well control incident.

**IRP Wellhead equipment used with a plunger lift system shall be of a design and function to withstand the unique impact forces that may be encountered during plunger lift operations. This includes the possible impact forces from a plunger that is traveling upwards without a fluid column.**

IRP Plunger lift systems should be designed, and the appropriate timing or pressure setting maintained during operations, to minimize the impact of the plunger’s arrival on the wellhead. Specifically, springs and stops at the top of the plunger lift assembly should effectively absorb the force of the incoming plunger.

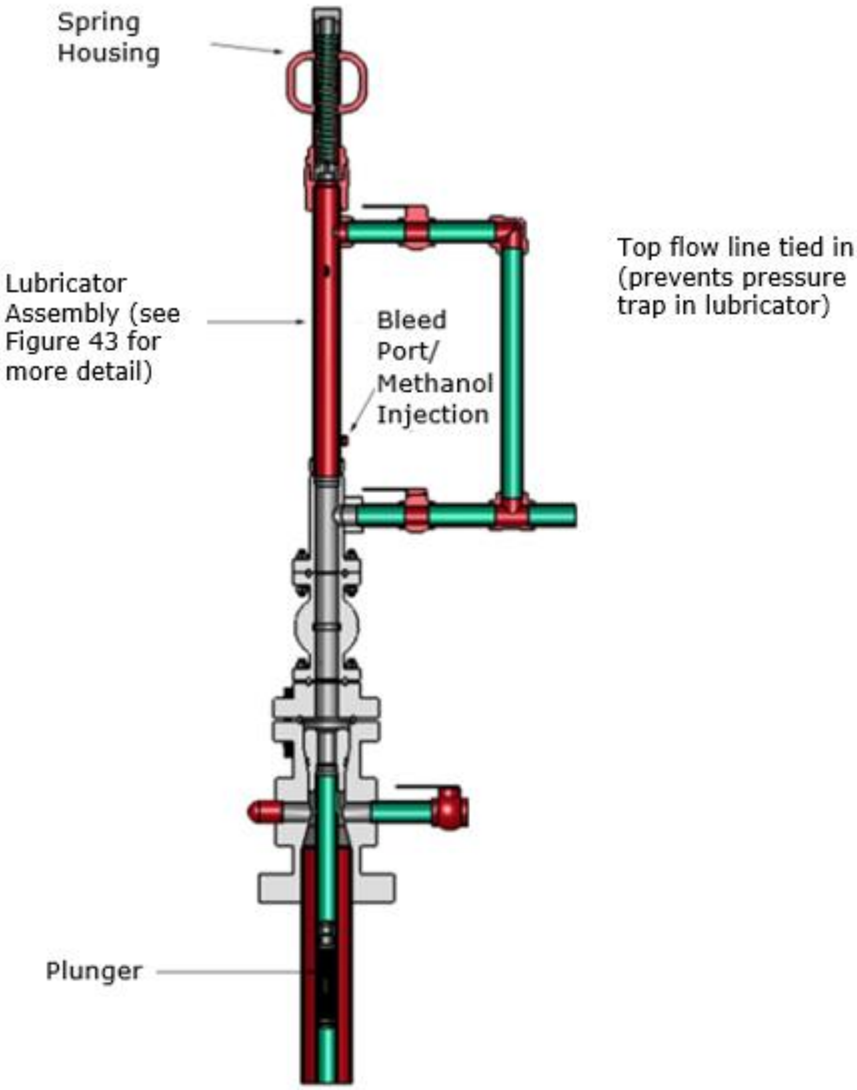
IRP Systems should be in place to prevent ice and hydrates from forming in the plunger lift's lubricator assembly and the spring housing.

If the top flow line on the plunger lift is not tied into the outflow line, ice and debris can build up and trap pressure in the lubricator. Shelters over the wellhead can reduce the risk of freezing.

IRP If swapping out plungers of different weight and/or length, impact forces should be taken into consideration.

Local jurisdictional regulators have several incident reports relating to plunger lift failures. Consult the manufacturer for safe operating procedures.

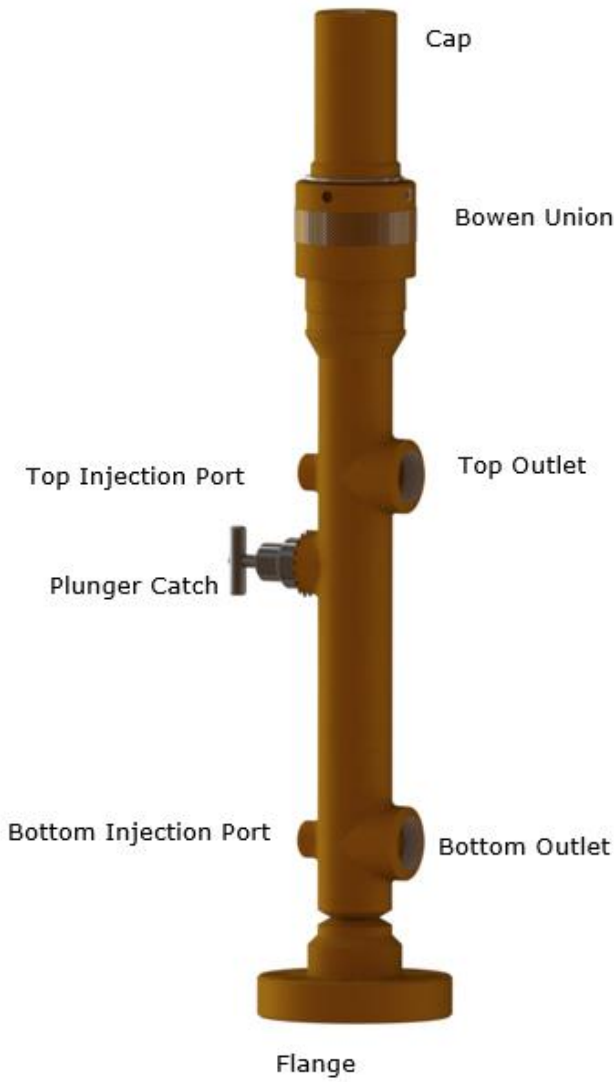
**Figure 42 - Plunger Lift System**




Plunger lift impact and wear can cause loss of well control, particularly with threaded connections between the tubing head adaptor and plunger lift lubricator.

**IRP** **For new installations or conversions to a plunger lift, all christmas tree components, including the lower connection on the plunger lift, shall be flanged or studded. Side outlets are an exception and may be threaded.**

**Figure 43 - Lubricator Assembly**




#### 5.1.7.6 Hydraulic (Jet) Pump

A hydraulic pump is a downhole pump that is driven by pressurized fluid supplied from the surface. Hydraulic pumps come in a variety of designs including jet, piston and turbine pumps.

The simplest design pumps the power fluid down the production tubing and brings the combined power and produced fluid stream to surface through the production casing/tubing annulus. In another configuration where higher pressure or potentially corrosive fluids must not contact the casing, power fluid is pumped down one tubing string and the hydraulic and production fluids brought to surface through a second tubing string. Hydraulic pumps often include downhole packers to avoid injecting fluid into the reservoir. Reciprocating or piston hydraulic pumps typically use three tubulars or conduits since the power fluid, which is re-circulated, must be kept separate from the production fluids to avoid picking up formation fines or other particles which can cause the downhole pump to seize.

Wells completed with a hydraulic pump require a switching valve and lubricator at surface to retrieve the pump.

**IRP** **Wellhead equipment operating with a hydraulic artificial lift system shall be designed to withstand the pressures required to operate the hydraulic pump.**

**IRP** **The lubricator shall include sufficient shock protection to avoid damaging equipment when the downhole pump is surfaced to change components.**

> **Note:** With a hydraulic pump the maximum operating pressure is typically at the surface (power fluid pressure).

**IRP** **The composition of the power fluid and produced fluid shall be considered when selecting wellhead components.**

#### 5.1.7.7 Velocity String

A velocity string is a means of enhancing production by reducing the liquid loading in a well. The velocity string is a small diameter tubular inserted into the production casing or tubing. The reduced diameter results in a higher flow velocity so the liquid can be carried to surface under natural reservoir pressure which reduces the liquid load in the well and improves production. Velocity strings are most often used to de-water low rate gas wells.

Velocity strings can be created with jointed tubing but coiled tubing is more commonly used in this application. The velocity string is typically hung in the tubing head below the master valve in wells with a multiple tubing configuration. A single coiled tubing string may also be hung above and run through the master valve. See 5.1.3.11 Coiled Tubing Hangers for more information.

### 5.1.8 Other Well Types

#### 5.1.8.1 Injection or Disposal

Injection and disposal wells are often configured like flowing wells. Wellheads in these cases may be configured with a tubing string that is isolated from the casing for the injection of fluids or solids. In other cases, material may be injected via the production casing. Once pressured, injection and disposal wells function as a flowing well and must be configured as such. Injection or disposal wells present two areas of concern for wellhead equipment and design: pressure and injection fluid. Structurally, injection and disposal wells are typically identical to wellheads designed for flowing wells.

**IRP** **Existing and new wellheads to be used for injection or disposal purposes shall have an engineering assessment (and, potentially modification) to ensure an adequate pressure rating and the ability to safely handle the injected fluid.**

The assessment of wellhead requirements has to address both pressure and fluid consideration with respect to backflow. Injection can recharge the target zone which flows back the injection and produced fluids at a new and higher pressure. At the same time, the returning fluid is a combination of injected and production fluids with unknown properties. An injected liquid may flow back as a gas (e.g., $CO_2$) carrying higher pressure from the charged formation.

A third consideration with injection wells is temperature, particularly in enhanced oil recovery (EOR) methods that rely on steam injection. For SAGD and CSS recovery methods see 5.1.8.2 Thermal Operations.

**IRP Wellhead components, connections and seals shall be rated to withstand any additional pressures or temperature variations created by injection operations.**

**IRP Wellhead components, particularly elastomer and metal seals, shall be rated to adequately withstand any corrosive or erosive effects created by injected fluids and gases.**

IRP Operators should consider any effects from a combination of injected and produced fluids and gases.

**Figure 44 - Basic Injection Wellhead**

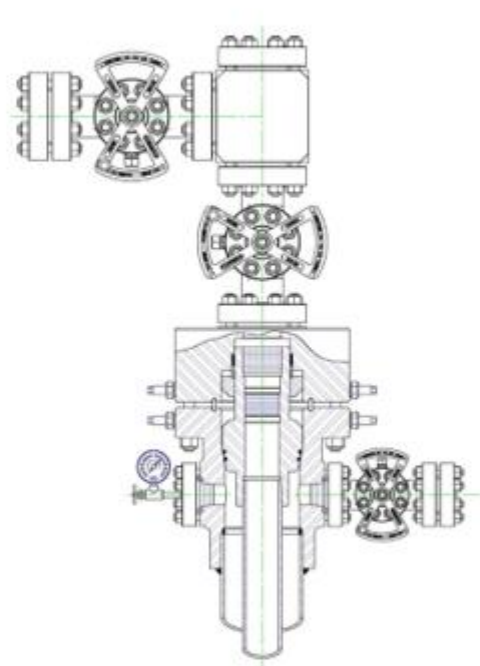


Table 8 lists common examples of injected material.

**Table 8 - Examples of Injection Material**

| Fluid Injected | Anticipated Problems | Considerations/ Material Compatibility |
|---|---|---|
| Sulphur solvents (e.g., DMDS) | Elastomer deterioration | Requires DMDS resistant elastomers or metal to metal seals. |
| $CO_2$ | Metal loss<br>Elastomer deterioration | See API 6A Purchasing Guidelines. |
| $H_2S$ | Metal loss and sulphide cracking<br>Elastomer deterioration | Requires NACE MR0175/ISO 15156 rated metals (see API 6A Purchasing Guidelines). |
| Nitrogen | Introduces extreme temperature variation (cold) | Should ensure seal elastomers can handle the temperature variations created by the introduction of liquid nitrogen. |
| Water (salt or fresh) | Corrosion<br>Scaling | Should account for erosion from turbulence.<br>May require chemical inhibitors (e.g., oxygen scavengers, corrosion and scaling inhibitors), coatings, cladding. |
| Sand or other solids | Erosion<br>Plugging | Should optimize erosional velocity.<br>May require design to minimize or avoid sharp bends, alternate materials or hard surfacing. |
| Hydrocarbons | Seal degradation, waxing, emulsions | Should ensure seal compatibility with hydrocarbon.<br>May require design to deal with viscous, hard to pump fluid |
| Industrial waste | Potentially any of the above depending on waste composition | Should ensure seal and metallurgy compatibility with all potential individual waste components and effects of combining components. |
| Mixed products | May accelerate expected detrimental effects of individual components | Should ensure seal and metallurgy compatibility with all potential individual waste components, components resulting in these breaking down further and the effects of combining components. |

IRP Whenever highly corrosive fluids (e.g., $CO_2$ or acid gas) are going to be continuously injected or stored, the operator should consult with their OEM supplier, review applicable regulation and/or consult with the local jurisdictional regulator on wellhead design criteria.

This is particularly important when injection is to take place in recompleted wells. The designer needs to consider the change of conditions and ensure existing wellhead equipment meets the material requirements of the new operations and is fully fit for purpose.

#### 5.1.8.2 Thermal Operations

Wellhead recommendations for heavy oil/oil sands wells, which utilize a variety of thermal stimulation techniques to enhance oil recovery, are available in IRP 3: In Situ Heavy Oil Operations. These recommendations cover the following topics:

- Designing wellhead for the temperatures and pressures that accompany thermal stimulation.
- Accommodating for the expansion and contraction created by temperature variations.
- Welding requirements and procedures.
- Requirements related to well control devices, surface casing vents, tubing hangers, stuffing boxes on rod pumped wells, pressure shut down devices, BOPs and master valves.

The two basic designs for operations using thermal stimulation techniques are Steam Assisted Gravity Drainage and Cyclic Steam Stimulation.

SAGD production involves twin horizontal wells each with their own wellhead. Low pressure steam, and potentially solvents, are injected into the upper well. This creates a lower viscosity for the heated crude oil or bitumen, allowing it to flow along with the condensed water to the lower production wellbore. Typically, some form of artificial lift (e.g., PCP) is used in the production well to produce the high viscosity fluid and water. Basically, SAGD production requires one well with an injector wellhead designed for steam injection and another with a wellhead designed for a given method of artificial lift.

CSS production involves injecting high pressure steam into the producing formation, allowing for a soaking period and then producing out of the same well, typically first as a flowing well (due to the increased natural pressure from the injected steam) and then by some method of artificial lift. Once production tails off again the cycle of steam/soak/produce is repeated. To complete this process CSS wellheads are adapted for both steam injection and artificial lift. In many cases, CSS wellheads involve a single tubing string that is threaded directly into the tubing bonnet. An integral flow tee/BOP component and high temperature stuffing box are typically mounted above that.

Additional design considerations for thermal wellheads include the need for high temperature seals and pipe swivels or spring hangers to manage expansion and contraction with temperature swings. Produced fluids have a high water vapour load as well as $H_2S$ and $CO_2$ gases. Injected fluids may also include light hydrocarbons to boost recovery. Wellhead equipment may need to be monitored and protected from risk of higher levels of erosion. This may include control of production rates as well as sand or erosion probes.

IRP The use of swivel joints on all connecting pipes should be considered for wellheads where there is the possibility of a bending moment or side loading due to thermal expansion.

**Figure 45 - Integral Flow-Tee BOP**

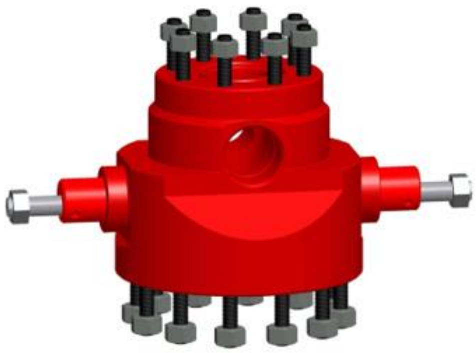


**Figure 46 - Simple Steam Injection Wellhead for SAGD**

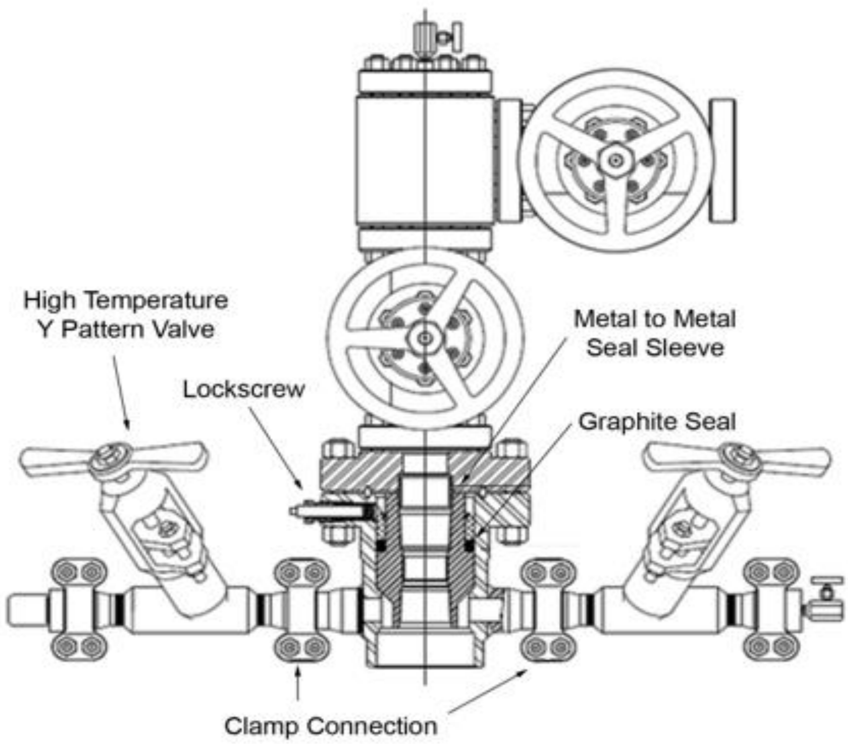


**Figure 47 - Example of SAGD Wellhead for Rod Pumping**

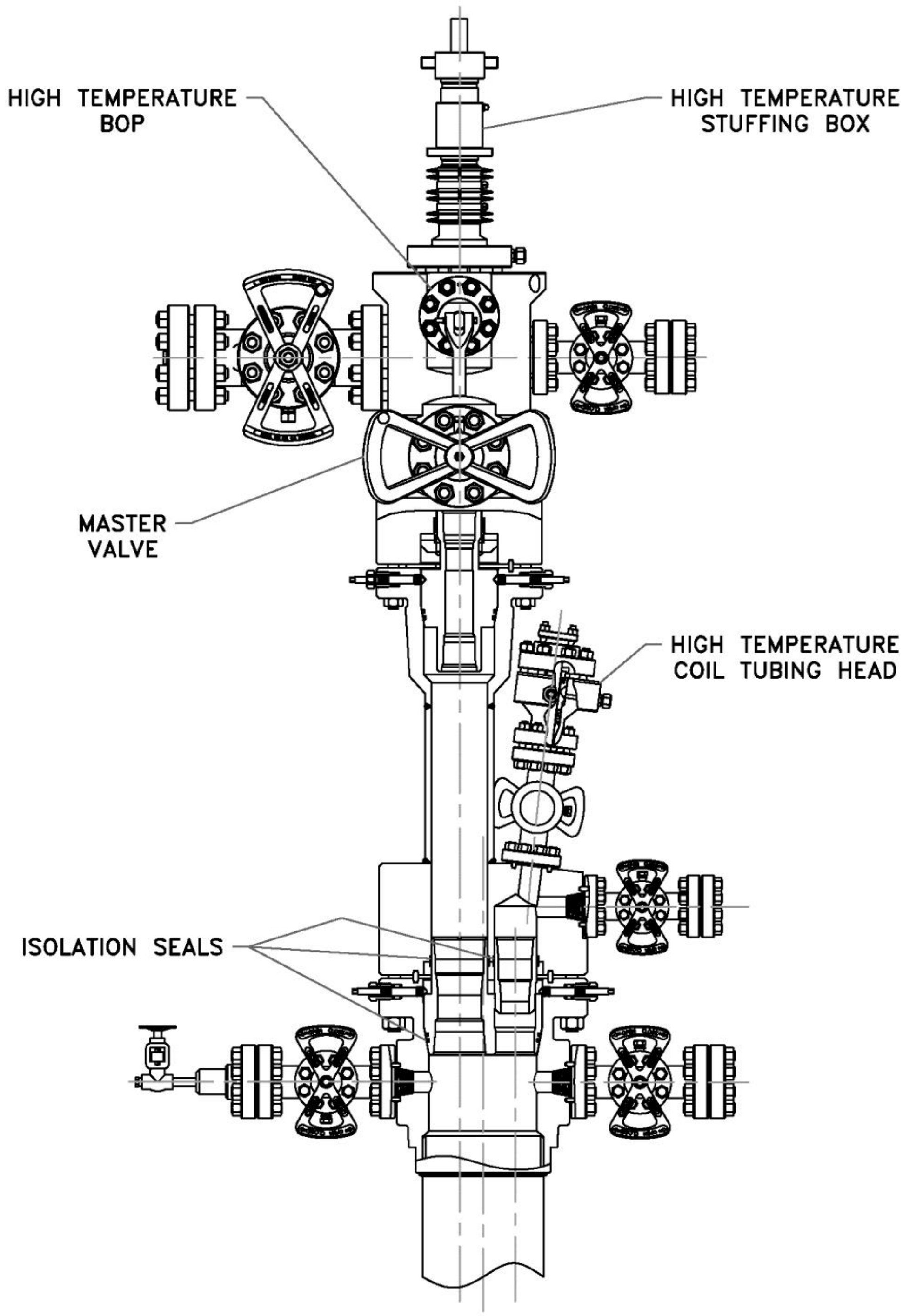
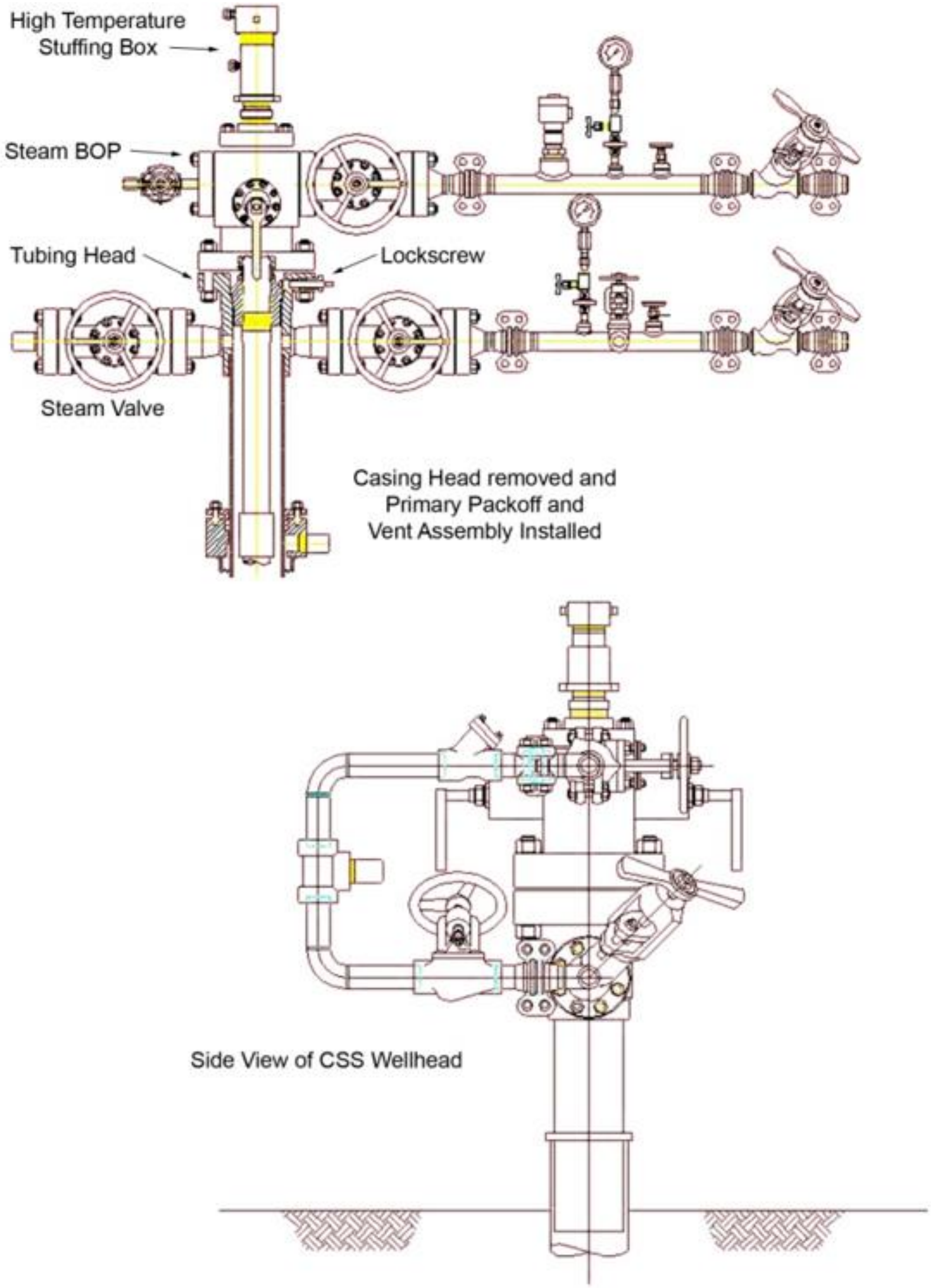


**Figure 48 - Example of CSS Wellhead**



#### 5.1.8.3 Cavern Storage Well

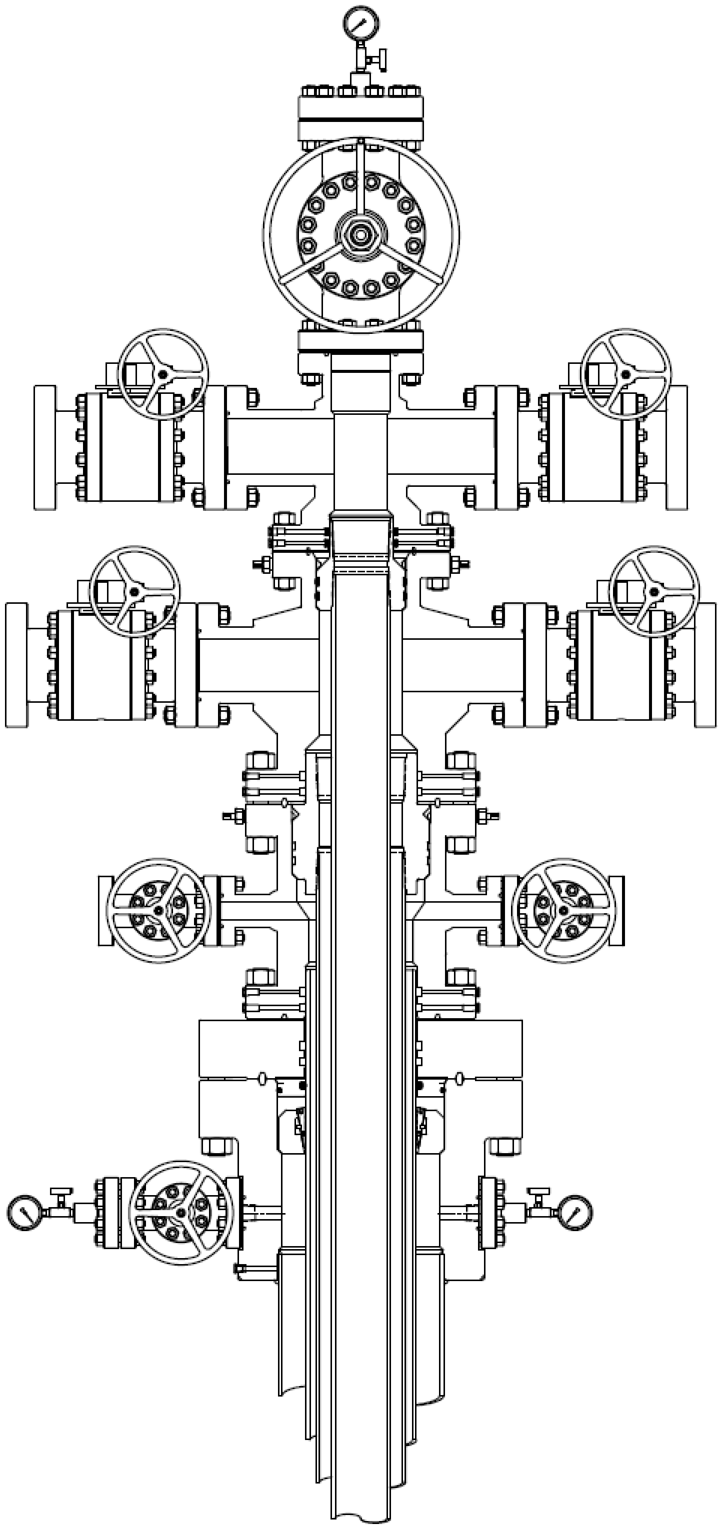
Cavern storage wells are naturally occurring or artificially created underground formations that can typically store large volumes of hydrocarbon gases or liquids. They may use large diameter valves that fall outside the scope of API 6A standards. These valves are covered by pipeline valve standards (i.e., API 6D or CSA Z245).

IRP CSA Z341: Storage of hydrocarbons in underground formations should be consulted during design and implementation of wellheads for cavern storage operations to ensure safe and compliant operations.

**Note:** While API 6D or CSA Z245 rated valves may be necessary in completing cavern storage wells they are not recommended for drilling purposes.

Wellhead design for cavern storage wells needs to consider the type of fluids that will be injected and produced through the wellhead. Separate wellheads may be required for developing and operating the well, particularly where the cavern is developed in a salt formation (see 5.1.8.1. Injection or Disposal).

**Figure 49 - Cavern Storage Wellhead**



### 5.1.8.4 Observation Well

Observation wells can be used to monitor formation conditions or the efficiency of the reservoir depletion process. Depending on their function, observation wells may or may not enter the producing zone and those completed in the overburden might not be exposed to the reservoir in situ or operating environments.

**IRP** **Wellheads on an observation well, including those that do not enter a producing formation, shall be designed for all anticipated conditions and provide for full isolation of the wellbore.**

IRP Monitoring lines of any sort installed in observation wells should be secured with a gas-tight seal.

**IRP** **Electrical lines run into an observation well must meet all electric codes and electric isolation at surface (see 5.1.7.4 Electric Submersible Pump).**

**IRP** **Cables or strings that run through and exit via wellhead equipment shall be sealed and packed off at surface and tested to the working pressure of the wellhead.**

## 5.2 Wellhead Implementation

### 5.2.1 General Responsibilities in Wellhead Implementation

**IRP Operators shall be responsible for the following:**

- **Providing accurate data on well conditions for wellhead design.**
- **Ensuring wellhead components ordered meet all design and regulatory requirements.**
- **Ensuring all required wellhead maintenance is conducted in a timely fashion by competent workers.**
- **Maintaining records of all work carried out on the wellhead for the life of the well.**
- **Conducting a risk assessment of the well and considering revised wellhead requirements whenever the producing character of a well changes (e.g., rising $H_2S$, increased pressure post stimulation, etc.) or operations are adjusted (e.g., interventions, EOR, artificial lift introduced).**
- **Changing out components as required to meet or exceed new conditions.**

**IRP OEMs and OEM suppliers of wellhead components shall be responsible for the following:**

- **Recommending components that meet the design and regulatory requirements communicated by the operator.**
- **Supplying components which meet or exceed design requirements and are free of defect.**
- **Providing detailed handling instructions and required maintenance procedures and schedule.**
- **Providing details of component specifications and history where applicable.**

**IRP Contractors or OEMs that undertake drilling or servicing operations that involve making up all or some portion of the wellhead, dismantling wellhead components or maintaining wellhead components shall be responsible for the following:**

- **Carrying out installation and maintenance according to the OEM's instructions and with the use of the appropriate equipment.**
- **Providing the operator with a record of work conducted and the condition of the components.**
- **Returning used components for the operator to inspect, test or forward to the OEM as necessary when replacing parts.**

### 5.2.3 Determining Wellhead Requirements

Wellhead selection is a task that may be relatively straightforward in some circumstances. In other cases, it may be much more complex and involve consideration of multiple factors. The purpose of the recommendations in this section is to achieve a wellhead that meets minimum requirements for the type of well and operations to be carried out for a given well. Selecting an optimum wellhead for a well may also require broader safety and economic considerations such as the following:

- The overall field development strategy.
- Known changes in production characteristics and fluid composition in a field over time.
- The value of standardization in lowering installation and maintenance costs.
- Short to long term EOR strategies.

#### 5.2.3.1 Required Information Gathering

The first step to ensuring minimum wellhead requirements are met is careful and thorough information gathering by the operator. Wellhead OEM suppliers will typically require operators to complete a data sheet as part of the ordering process. The data sheet will capture most of the critical factors to be considered in wellhead component selection. To accurately and successfully complete the data sheet there are several tasks that have to be completed.

**IRP Operators shall ensure that the following tasks have been completed and the results factored into wellhead design before selecting wellhead equipment:**

- **Identify well type**
- **Identify and calculate pressures and pressure variation**
- **Confirm temperatures (surface, bottom hole and external)**
- **Assess any other ambient conditions**
- **Provide fluid analysis**
- **Identify stimulation/intervention requirements**
- **Evaluate well life cycle**
- **Identify environmental concerns**
- **Confirm functionality of wellhead for drilling, well servicing and all well operations**

##### 5.2.3.1.1.1 Identify and Calculate Pressures and Pressure variation

BHP determines wellhead component requirements when there are no additional wellhead pressures created by artificial lift or well intervention techniques (see 5.1.1 Components). BHP can be accurately predicted in more developed and well-known oil and gas fields. In exploration contexts where formation pressures are harder to predict, wellheads need to be designed to accommodate the uncertainty in pressures.

IRP Any stepping down in component pressure specifications from one component to the next should only be done where there is certainty about pressure requirements and full pressure containment.

**Note:** Anticipated wellhead pressure can be considered equal to BHP for any well that unloads to gas at any point.

#### 5.2.3.1.2 Confirm Temperatures

Highs and lows as well as the degree of temperature variation in surface, bottomhole and external temperatures will affect wellhead design, composition and especially seal selection. Note any risks related to the range and speed of temperature shifts (e.g., start up or loss of steam in winter conditions in CSS wells). These risks need to be communicated to the OEM supplier (see 5.1.8.1 Injection or Disposal and 5.1.8.2 Thermal Operations).

It is critical to consider and account for cold weather in the equipment selection process. Refer to Appendix B for descriptions of the API Temperature Classifications and more information about derating API 6B flanges with temperature.

**IRP Wellhead components shall be temperature rated to -46°C/-50°F (API Temperature Classification N, L or K) in any area in which temperatures are expected to fall below -29°C (-20°F).**

**IRP Wellhead components shall be temperature rated to -60°C/-75°F (API Temperature Classification K) in any area in which temperatures are expected to fall below -46°C (-50°F).**

IRP Operators should confirm with the OEM supplier that the wellhead equipment will be fit for purpose for thermal operations where standard classifications for temperature ranges may not be applicable.

IRP Operators should consult with the OEM supplier to ensure that elastomer seals are fit for purpose given the potential for cold temperature operations.

#### 5.2.3.1.3 Provide Fluid analysis

Fluid analysis can be used to appropriately select wellhead materials but a fluid analysis is not available for a new field. Wellhead design needs to consider the safe handling of the possible composition of the produced fluids. Make estimates based on the geological prognosis.

It is critical that the presence and release rates of $H_2S$ be documented in the fluid analysis. Other information to include is as follows:

- The presence of other corrosive or erosive components
- The API gravity for oil
- The gas composition

- The gas-oil ratio
- Fluid viscosity
- The presence of produced water, its salinity and specific gravity
- The potential for scale or asphaltene deposits, corrosion or emulsions

#### 5.2.3.1.4 Identify Stimulation/Intervention Requirements

If it is already known or likely that particular stimulation or intervention techniques will be applied to a well, the pressures, temperatures and/or injected materials should be documented in advance and the wellhead designed accordingly. For instance, a fracturing operation that introduces both high pressures and an erosive product (e.g., sand) should be accounted for in the wellhead design. A monthly acid treatment would create other requirements.

If the likelihood of particular types of stimulation or intervention techniques is somewhat less certain, there will likely be an economic evaluation to determine if designing for these in the present is more cost effective than replacing components at a subsequent date.

#### 5.2.3.1.5 Evaluate Well Life Cycle

The more accurately the entire life cycle of the well can be defined in advance, the better the likelihood of choosing a wellhead that will meet the operational and economic requirements over its lifetime.

It is important to consider predictable changes in well operating strategies or reservoir depletion methods that will

- alter well operating pressure,
- alter injected or produced fluids or
- might affect $H_2S$ release rates.

Optimal wellheads take into account current and future well characteristics and consider safety and cost over the entire life cycle of the well and wellhead.

#### 5.2.3.1.6 Identify Environmental Concerns

Heightened environmental concerns may require overdesign of the wellhead as an additional precautionary measure.

Environmental concerns may include the proximity to the following:

- Human populations
- Designated or known environmentally sensitive areas
- Surface water
- Domestic livestock operations

IRP Exceeding minimum wellhead design criteria and components should be considered for wellheads in any areas with heightened environmental sensitivity (e.g., due to proximity to human population or the natural environment such as parks, groundwater sources or designated bodies of water).

For example, the heightened design specifications for sour or critical sour may be appropriate in a scenario where any hydrocarbon release to atmosphere could produce significant environmental risk or harm. Other considerations may include increased redundancies, emergency shut down devices and online monitoring.

Consult with the local jurisdictional regulator about any environmental concerns in the plan.

##### 5.2.3.1.7 Confirm Configuration and Functionality of Wellhead

Consider the configuration and functionality of the wellhead in the well design to ensure adequate stakeholder engagement. Items to consider include rig floor height, surface casing height, valve orientation, etc.

#### 5.2.3.2 Transmitting Required Data for Wellhead Design

IRP The OEM/OEM supplier and operator should discuss and be in agreement on all the information provided on the OEM data sheet.

IRP The operator should ensure that the relative quality of the available well data and their risk assessment of the well are shared with the OEM/OEM supplier. See API 6A Purchasing Guidelines.

IRP The operator should retain the original information provided to the OEM/OEM supplier and a list of the components ordered for the life of the wellhead.

#### 5.2.3.3 Competency Requirements for Wellhead Design

IRP The selection and configuration of wellhead components should be done by or under the direction of a competent individual who has a good understanding of the proper application of wellhead components.

### 5.2.4 Wellhead Installation

#### 5.2.4.1 Contractor Competency and Compliance

**IRP Operators shall ensure that contractors selected to install wellheads are competent in the installation of the selected wellhead and install the wellhead in a manner that is compliant with all local jurisdictional regulations.**

For more information about contractor selection see the Energy Safety Canada Guideline on Contractor Management Systems, in particular Step Three: Conduct Contractor Pre-Qualification and Selection.

**IRP Contractors shall ensure the employees who provide wellhead services are competent in the installation of the selected wellhead and are compliant with all local jurisdictional regulations.**

#### 5.2.4.2 Pre-Spud Meeting

IRP Personnel involved in the planning and execution of a wellhead installation should fully discuss the operation in a pre-spud meeting before wellhead installation operations commence.

IRP The pre-spud meeting should, at minimum, cover the following:

- A review of safety regulations and legislation (e.g., PPE, required tickets, radios, etc.).
- Emergency Response Plan (ERP) awareness, understanding and application.
- The assignment and scheduling of on-site hazard assessments.
- Wellhead equipment, installation equipment and installation procedures.
- Coordination between all contractors involved in the procedures.

**Note:** Future operational difficulties can be avoided if there is stakeholder buy in on the details of the final wellhead configuration required for subsequent operations. For instance, operating companies should inform drilling and wellhead installation companies of the ideal height for surface casing and the location and orientation of wing valves and the surface casing vent.

#### 5.2.4.3 Installation Personnel

Selecting the right personnel for installation tasks is critical. The safe operation of a well for the entire life cycle of the well is dependent on wellhead integrity so installation personnel need to be competent and follow the plan. Working around a well during wellhead installation procedures also presents unique hazards to the installation personnel that need to be recognized and mitigated.

**IRP Wellhead installation procedures shall only be carried out by, or under the direct supervision of, competent and capable personnel who are knowledgeable, experienced and trained in the installation of the specific wellhead components being used in a given operation.**

**IRP All wellhead service companies must have in place and adhere to a fatigue management system that is in compliance with all federal and provincial regulations.**

#### 5.2.4.4 Welders

Personnel who provide field welding require qualifications specific to that task.

**IRP Any field welding of pressure containing wellhead components must be performed by a welder certified by the local authority to undertake pressure welding.**

The local authorities for Welder certification in Western Canada are as follows:

- The Alberta Boiler Safety Association (ABSA)
- The Technical Safety Association of Saskatchewan (TSASK)
- The Manitoba Office of the Fire Commissioner
- The British Columbia Safety Authority (BCSA)

**IRP Welders shall be qualified in accordance with ASME Section IX to weld the applicable materials with a valid Welder Performance Qualification Record (WPQR).**

**Note:** The WPQR is evidence that a welder is capable of welding specific materials using a defined process.

IRP Companies contracted to provide welding personnel and services should have a documented quality assurance program.

### 5.2.4.5 Installation Procedures

#### 5.2.4.5.1 Protecting Wellhead Equipment in Transport and On Site

**IRP** **In consultation with the OEM, the operator and all contractors involved with wellhead implementation shall ensure connecting surfaces on all wellhead components are protected from damage during transport, while stored on the lease site and during installation procedures. This includes threading, flange faces, adjoining and side face on clamp hub connections etc.**

#### 5.2.4.5.2 Threaded Connections

Threaded connections are governed by API standards. API stamped threaded components have a standardized length and type of thread machined onto the connections points of the equipment.

Threaded connections can fail for the following reasons:

- Inadequate torque
- Cross-threading
- Over-tightening
- Thread damage
- Mismatched thread types
- Debris/lack of cleanliness

Wellhead connections are critical to wellhead integrity. The aim of the recommended practices in this section aim to minimize the possibility of threaded connection failures on wellheads.

IRP All parties involved in ordering, supplying and/or using threaded wellhead components should ensure the thread types on the wellhead components are capable of handling the total loads that will be carried by the threaded connections. The total initial load and any subsequent loads on a threaded connection should not create thread compression and deformation.

**IRP** **Threaded wellhead connections shall only be made up by trained and experienced personnel. These connections can be made by a less experienced individual for training purposes if done under the direct supervision of someone trained and experienced in making up threaded wellhead connections.**

**IRP** **The individual responsible for making up the threaded connection shall perform the following tasks prior to making up the connection:**

- **Inspect all threads for damage and cleanliness (including ice buildup). Components showing evidence of corrosion or any defects on the threads should not be used.**

- **Ensure there are fully matching threads on a given connection (i.e., identical thread type/form and size).**

**Note:** Wellhead components may be manufactured with different thread forms and/or step in the same component.

- **Ensure the thread compound (pipe dope) is applied as per the manufacturer's recommendation and that the compound used will provide an appropriate seal under the expected operating conditions.**

IRP The following procedures should be used when making up a threaded connection:

- Make the initial connection by hand to prevent cross threading and hand tighten.
- Use a wrench to fully tighten the connection.

**Note:** Torque should be applied by means appropriate for the connection. API RP 5C1 has torque values.

#### 5.2.4.5.3 Welded Connections

When joining parts by welding both base materials and filler metal is melted to form the joint. Changes to the materials occur during this process. It is important to implement controls to ensure the welding is sound.

##### 5.2.4.5.3.1 Welding Procedure Specification

A Welding Procedure Specification (WPS) is a document which describes in detail the required welding variables to assure repeatability.

**IRP A procedure (WPS) shall be written and qualified in accordance with ASME Section IX requirements.**

IRP The completed WPS should be submitted to the local jurisdictional pressure vessel authority or a Professional Engineer for review and approval.

**IRP For sour service, NACE MR0175/ISO 15156 requirements shall be incorporated into the WPS.**

IRP A separate WPS should be developed for each grade of casing.

#### 5.2.4.5.3.2 Procedure Qualification Record

A Procedure Qualification Record (PQR) is a record of welding variables used to produce an acceptable test weld and the results of tests conducted to qualify a Welding Procedure Specification

**IRP Welding PQR shall be included as part of the WPS.**

**IRP The weld procedure shall be qualified in accordance with ASME Section IX and API 6A requirements.**

**IRP For sour service, NACE MR0175/ISO 15156 requirements shall be incorporated into the qualification. This includes post weld heat treatment (PWHT).**

IRP Yield strength testing should be reported during tensile testing of the PQR.

**IRP Mill test records (MTR) for the materials used for qualification shall be included as part of the PQR.**

**IRP When PWHT is specified in the WPS, the PWHT shall be completed.**

#### 5.2.4.5.3.3 Material Requirements

IRP Casing provided for welding should comply with AER Directive 10: Minimum Casing Design Requirements and the requirements of the WPS.

**IRP For sour service, electrodes must have less than one percent nickel content when welding carbon steel and low alloy steel parts (as per NACE).**

Casing may not be able to maintain mechanical properties following a PWHT cycle. Consider establishing controls to ensure that the mechanical properties of the casing are within design requirements following welding and heat treatment (e.g., use the pipe specified in AER Directive 10). This can be addressed by testing pipe before and after heat treatment.

IRP The temperature at which the PWHT is conducted should not be less than 14°C (25°F) below the final heat treatment temperature of the casing head.

IRP The PWHT temperature should not exceed the final heat treatment temperature of the casing head less 14°C (25°F).

Heat treatment above the final heat treatment of the head will change its mechanical properties. A PWHT temperature variance of no more than 14°C (25°F) from the set point is common heat treatment practice.

#### 5.2.4.5.3.4 General Welding Requirements

**IRP Prior to welding the welder and the site owner/representative shall confirm the following:**

- **Valid WPS and PQR are present.**
- **Valid welder qualifications (WPQR) are present**
- **Electrodes used are in compliance with the WPS.**
- **Lighting is adequate if welding is performed in darkness (i.e. after sunset).**
- **Work area is adequately protected from the elements such as wind, moisture and dust.**
- **Counter weights, ground clamps and other temporary attachments are not welded to the pipe or fittings**
- **Drilling fluid level is lowered to at least 600 mm (2 ft.) below the weld line for casing bowls.**
- **When PWHT is specified in the WPS, PWHT equipment is on-site and ready for use.**

**IRP The welder shall confirm the following prior to welding:**

- **Electrodes are properly stored and handled for protection from dirt and moisture.**
- **Work pieces are cleaned and free of moisture, dirt and grease.**
- **Visual examination of welding surfaces and surrounding areas confirms that they are free of indications that could negatively impact the weld.**

**IRP The site owner/representative shall confirm the following prior to welding:**

- **The MTRs for the materials being welded are reviewed and approved against WPS requirements.**
- **Equipment is provided to move, manipulate and position the casing head for proper fit-up.**

**IRP Preheat shall be as follows:**

- **Applied according to the WPS.**
- **Not performed with an Oxy-acetylene torch (acceptable methods include electric resistance, induction or open flame).**
- **Monitored using crayons, thermocouple or pyrometer.**
- **Applied to a minimum distance of 100 mm (4 in.) on either side of the weld area with special attention given to thicker sections of the casing bowl to ensure uniform pre-heating.**

**IRP During welding the following shall apply:**

- **Monitor interpass temperature and maintain within minimum and maximum temperatures in the WPS.**
- **Cover the work pieces with heat insulation blankets for controlled cooling if the interruption is for a prolonged period. Pre-heat temperature established before welding resumes.**

**IRP At completion of welding the following shall apply:**

- **Slow cool to 150°C (300°F) using heat insulation blankets.**
- **Do not use cooling accelerants (e.g., water, fans, etc.).**
- **Do not perform Non-Destructive Examination (NDE) until the weld has cooled.**

**IRP PWHT shall be as follows:**

- **Use uniform and controlled heating throughout the required cycle.**
- **Do not use open flame.**
- **Remove plugs (bull and line pipe) and any other components that cannot withstand the PWHT temperatures prior to heat treatment.**

IRP American Welding Society D10.10 Recommended Practices for Local Heating of Welds in Piping and Tubing should be followed for all field PWHT.

#### 5.2.4.5.3.5 Inspection, Testing and NDE

**IRP Pressure testing, at minimum, shall be performed on all welds. Other testing shall be as deemed appropriate by the end user based on a risk analysis of the well.**

**IRP Pressure testing shall be done with water or nitrogen. Grease or oil are not to be used.**

The following Inspection types may be implemented:

- Magnetic particle inspection (MPI)

**Note:** Wet fluorescent is preferred.

- Liquid penetrant inspection (LPI)
- Radiographic testing (RT)
- Ultrasonic testing (UT)
- Hardness Testing of weld, base metal and heat affected zone (HAZ) when accessible.

#### 5.2.4.5.3.6 Field Welding Records

**IRP Documentation of the welding and associated tests performed shall be recorded and filed for easy retrieval.**

IRP The record should include the following:

- Welder name
- Welder's pressure weld certification
- WPQR
- Date of weldment
- Location of well
- WPS used
- Pre-heat temperature
- Start times for pre-weld heating and actual welding
- Post-heat time and temperature
- Completion times for welding and post-weld heating
- Hardness test record
- Pressure test record
- Non-destructive test reports
- Record of the repair of any defects found during examination of the welds
- Casing MTR
- Casing head or other wellhead component material MTR
- Welding rod material
- Ambient temperatures and conditions

#### 5.2.4.5.4 Flanged, Studded and Clamp Hub Connections

**IRP Contractors or individuals involved in assembling a flanged, studded or clamp hub connections shall use the following procedures:**

- **Ensure the ring groove is clean and dry. The ring gasket and ring groove should never be greased. Light lubrication is acceptable**
- **Inspect the ring groove for visual damage.**
  - **Minor scratches shall be repaired.**
  - **Minor scratch repair may be done in the field with an emery cloth.**
  - **More significant damage shall be returned to the OEM for repair or replacement.**

- **Use only new ring gaskets.**
- **Use only use new or inspected studs and/or nuts.**
- **Tighten nuts as per the pattern recommended by the OEM.**
- **Follow the torque requirements for studs and/or nuts provided by the OEM/OEM supplier.**
- **Ensure the studs extend far enough for full engagement with the nut.**

#### 5.2.4.6 Pressure Testing Connections and Seals

**IRP As connections and seals are completed during wellhead installation, every connection and seal shall be tested to the lessor of**

- **the wellhead's API pressure rating or**
- **the burst/collapse pressure rating of the casing or tubing exposed to the pressure test.**

**IRP The pressure testing of wellhead connections, seals and components is to be performed by competent personnel that are knowledgeable, experienced and trained in the pressure testing of the specific wellhead components being used in a given operation. Pressure testing carried out by less knowledgeable or less experienced personnel for training purposes shall be under the immediate supervision of an individual with the required knowledge, experience and training.**

IRP Nitrogen should be considered for pressure testing thermal wellheads.

The use of any water-based fluid could result in damage associated with freezing or boiling. Mineral oils and similar fluids are prone to degradation with lengthy exposure to high temperature. This can lead to issues such as difficulty lifting tubing hanger from tubing head during a workover (a known problem in industry).

#### 5.2.4.7 Installation Considerations

Optimal wellhead design and installation needs to take into account the final configuration of the wellhead and all flow lines or components connected to the wellhead.

IRP Surface casing should be set and/or cut off at a height that ensures optimal overall height for the completed wellhead and its connected flow lines and, where required, to allow access to the surface casing vent.

Installing equipment or flow lines that attach to a wellhead can create additional load on the wellhead.

**IRP Mitigations shall be considered to handle the additional loads created by equipment or flow lines that attach to the wellhead.**

Steps to consider include, but are not limited to, the following:

- Support any flow riser in the bottom of the ditch in a manner that prevents settling of the riser after backfilling. Settling of flow line risers after tie in can generate abnormal loading on a wellhead resulting in the creation of stress points. This is of particular concern if the wellhead contains a tubing head adapter with a threaded connection to which a rod BOP or master valve is attached. The pin connection is necessarily thin to achieve full bore access to the tubing string. This pin connection becomes a stress point if an abnormal load on the wellhead occurs due to settling of the flow line riser. This condition is accentuated if corrosion is a factor.

- Support and secure any equipment connected to the wellhead in a manner that minimizes the stress applied to the wellhead (e.g., snubbing equipment, coiled tubing injectors, artificial lift systems, injection flow lines, movement of wellhead due to thermal variations, etc.). This is a particularly important consideration with slanted wells.

See 5.2.5.7 Shallow Gas Intervention Requirements for recommendations on bracing for 114 mm (4½ in.) gate valves.

#### 5.2.4.8 Post-Installation Requirements

**IRP Documentation on the components installed and the installation procedures shall be created immediately upon completion of any wellhead installation procedure.**

IRP Individuals or contractors providing wellhead installation services should participate in the documentation process and the operator should ensure these records remain secure and accessible for the life of the well (as per the responsibilities outlined in 5.2.1 General Responsibilities in Wellhead Implementation).

### 5.2.5 Wellhead Protection

**IRP All wellheads shall be conspicuously marked or fenced such that they are visible in all seasons and display the signage and warning symbols required by local regulations.**

IRP Vegetation should be controlled in the immediate vicinity of the wellhead to ensure it remains visible.

IRP The operator of the well should ensure that no farm or other vehicles operate within a three metre radius of the wellhead, except for vehicles specifically required to do so as part of an operation being performed on the well (e.g., a completion, workover or well servicing operation).

**Note:** This does not apply when wellheads are below ground level and/or protected specifically to accommodate vehicles in close proximity.

**Note:** Industry records indicate that a significant number of wellhead failures occur as a result of impact with vehicles. The major sources of these incidents are farm equipment and contractor’s equipment operated too close to wellheads. In some cases, low profile wellhead designs with protective posts and fencing to prevent impact by machinery may allow for a small footprint.

### 5.2.6 Wellhead Intervention

The processes and procedures required for a successful wellhead intervention vary based on the nature of the operation. The following recommendations are designed to be broadly applicable to any operation involving the dismantling and make-up of all or part of an existing wellhead.

#### 5.2.6.1 On-site Audit

**IRP Operators shall perform an on-site audit of the wellsite, prior to completing an intervention plan or commencing any well intervention operation. The audit shall include confirmation of the wellhead equipment present, wellhead condition and wellsite assessment.**

#### 5.2.6.2 Intervention Plan

IRP Operating companies should create an intervention plan prior to commencing any well intervention operation. This includes applying any necessary engineering and/or OEM expertise to any reworking of the wellhead.

IRP The same recommendations identified in 5.2.2 Determining Wellhead Requirements should be applied to an intervention plan. Intervention planning should include an information gathering phase (including the on-site audit), transmission of well information, discussion of wellhead requirements with the OEM/OEM supplier and ensuring the competency of the individual selecting and configuring the revised wellhead.

IRP The intervention plan should be distributed to all companies involved in the wellhead intervention prior to commencing any well intervention operations.

#### 5.2.6.3 Contractor Competency and Compliance

**IRP Operators shall ensure the contractors who provide wellhead intervention services are competent in the dismantling and make-up of the wellhead on site and are compliant with all local jurisdictional regulations.**

See the Energy Safety Canada Contractor Management Systems Guideline, particularly Step Three: Conduct Contractor Pre-Qualification and Selection, for more information.

#### 5.2.6.4 Pre-Intervention Meeting

IRP Personnel involved in the planning and execution of wellhead intervention should meet prior to the commencement of wellhead intervention operations to fully discuss the operation. This meeting should include the following:

- A review of safety regulations and legislation (e.g., PPE, required tickets, radios, etc.).
- ERP awareness, understanding and application.
- Assignment and scheduling of on-site hazard assessments.
- Review of any changes in well conditions from previous operations (based on the on-site audit).
- Wellhead equipment, installation equipment and intervention procedures.
- Coordination of all contractors involved in the procedures.

**Note:** See 5.2.1 General Responsibilities in Wellhead Implementation for a high level breakdown of responsibilities for operators, contractors and OEM/OEM suppliers.

#### 5.2.6.5 Dismantling Procedures

**IRP The well shall be isolated in a secure manner before any wellhead dismantling begins.**

Well characteristics and operational considerations may impact the method selected to secure the well.

**IRP When installing a BOP stack, a pressure test to BHP shall be performed on the connection between the BOP stack and the wellhead prior to commencing further operations.**

IRP The following inspection procedures should be followed in dismantling wellhead components:

- Inspect studs and nuts that will be reused.
- Visually inspect all exposed inner surfaces for signs of erosion, corrosion, cracking, pitting, bending and deformation.
- Visually inspect all threading for compression, galling, corrosion or cross-threading.
- Visually inspect other critical surfaces such as flange faces.
- Report all negative findings to the operator and document any decisions reached regarding the findings (e.g., further testing, part replacement, no further action).
- Label and securely store all equipment that will be reused being sure to protect threading, flange faces and critical clamp hub surfaces.
- Immediately discard components that should not be reused (e.g., ring gaskets or other seals).
- Drain water from components if there is a chance of it freezing.

#### 5.2.6.6 Make Up Procedures

**IRP The same recommendations in 5.2.3.5 Installation Procedures shall be applied to wellhead make up during wellhead interventions.**

IRP Any seal exposed in an intervention operation should be replaced.

**Note:** It is good operational practice to have additional replacement parts on hand during wellhead intervention operations.

#### 5.2.6.7 Shallow Gas Well Intervention Requirements

**IRP Shallow gas wells that utilize a gate valve shall use a bracing system during a well workover to avoid damaging or breaking the valve as a result of any bending movement. This applies equally to shallow gas wells with or without casing heads.**

Wells with a casing head left on can use a bracing system that attaches to the surface casing head and extends to the top of the valve.

Wells with the casing head removed can use a split base plate that attaches to the existing surface casing and extends to the top of the valve.

#### 5.2.6.8 Post-Intervention Requirements

**IRP Documentation about the procedures carried out, including the components removed and installed, shall be created immediately upon completion of any wellhead intervention.**

IRP Individuals or contractors providing wellhead intervention services should participate in the documentation process and the operator should ensure these records remain secure and accessible for the life of the well (as per the responsibilities outlined in 5.2.1 General Responsibilities in Wellhead Implementation).

### 5.2.7 Monitoring and Maintenance

The following two situations have the possibility of valve bonnet studs stretching:

1. Water is present in the gate valve cavity and it freezes causing expansion.
2. Water or grease expanding during thermal start up or cycling.

These can be mitigated with proper maintenance including the following:

- Proper valve greasing.
- Inspection of the studs and gap between valve bonnet and body.
- Correct application of lockout procedures in thermal operations.

#### 5.2.7.1 Documented Maintenance Schedule and Procedure

**IRP All operators shall have a documented maintenance schedule and procedure.**

IRP The maintenance schedule and procedure should include, but not be limited to, the following:

- Visual inspection and leak detection
- Greasing and function testing valves twice a year

**Note:** Fracturing operations may require more frequent greasing

IRP All maintenance activities should be fully documented.

#### 5.2.7.2 Wellhead Pressure Testing

IRP Pressure testing of all wellhead seals and connections should be carried out during any intervention operation. This is in addition to the required testing of any new seals and connections made up as part of the intervention itself.

For example, on a low to medium risk well pressure testing once every five years may be sufficient. For a high risk well this may be as frequently as annually. See AER Directive 13: Suspension Requirements for Wells for well classifications for more information.

#### 5.2.7.3 Rod Pumping Well Maintenance

The stuffing boxes, polished rod BOPs and pressure switch components of rod pumping wells have unique maintenance requirements.

IRP Operators should consult the OEM/OEM supplier of rod pumping well components and create a maintenance schedule and procedure based on their recommendations.

IRP Stuffing box sealing components should be inspected and replaced in accordance with the OEM's recommended schedule.

IRP Operators should consult with the OEM to ensure that stuffing box sealing components are still fit for purpose if operating conditions change (e.g., if the nature of the operation will create excessive wear on the stuffing box then sealing components will have to be changed more often).

The OEM may also provide advice on components that should be stocked and available at all times for ongoing maintenance purposes.

**IRP The stuffing box components shall be inspected if a leak occurs. Stuffing box components shall be replaced if routine maintenance cannot stop the leak or the components are in any way damaged.**

**IRP The sealing elements of a polished rod BOP shall be chosen, installed, maintained and replaced in accordance with the manufacturer's recommendations.**

This is important given that the elements in a polished rod BOP will deteriorate with time (depending on operating conditions). Failing to follow the OEM's guidelines on testing may damage the elements, particularly during cold weather operations.

#### 5.2.7.4 Pressure Shut Down System Maintenance

Pressure shut down systems are critical to the safe operation of pumping wells. They may fail to function as required if they are not regularly maintained and tested, particularly when used in a sour environment.

IRP Pressure shut down devices on pumping wells should, at minimum, be function tested monthly on all wells classified as sour and once every two months on all wells classified as sweet.

IRP Function testing of pressure shut down devices should be incorporated into the operator’s documented maintenance schedule and procedure and captured in the documentation of maintenance activities.

**IRP Any isolation valve that has been installed below the pressure valve shall be secured in the open position during normal operations.**

**Note:** Isolation valves below the pressure switch are installed in order to facilitate easier calibration, maintenance or replacement of the pressure switch. These can be locked or car sealed to prevent accidental closure.

**IRP A pumping well shall not be shut in from a remote flowline location without first shutting down the prime mover at the well site except in an emergency.**

**Note:** If a pumping well is shut in from a remote flowline location, such as at a battery or satellite facility, the operator is depending on the pressure switch to shut down the pump. If the pressure switch fails and the pump keeps operating and building pressure, human safety is compromised and there is a real threat of equipment and environmental damage.

IRP In injection operations the pressure shut down system should be strategically placed and calibrated to ensure protection of the lowest rated pressure equipment in the system.

**Note:** In an injection scenario, the injection plant may produce pressures beyond the specifications of either the pipeline or the wellhead. If the pipeline represents the weakest link, automatic shut-down systems should function on the plant side of the pipeline not at the wellhead.

### 5.2.8 Wellhead Requirements for Suspended Wells

**IRP Operators must consult local jurisdictional regulations for all wellhead requirements related to suspended wells.**

AER Directive 13: Suspension Requirements for Wells outlines requirements for Alberta. It calls for inspections annually, every three years or every five years based on the method of suspending the well and the well type.

Back to table of contents

# Appendix A: Revision Log

Edition 1 of IRP 5 was sanctioned in June 2002.

Edition 2 incorporated a full industry review and was sanctioned in November 2011.

Edition 3 incorporates a full industry review with emphasis on adding thermal and fracturing information. For this edition the document was converted to the current DACC template and style and underwent a complete editorial review. Table 9 summarizes the changes in this edition. Edition 3 was sanctioned in June 2018.

**Table 9 - Edition 3 Revision Summary**

| Section | Remarks/Changes |
|---|---|
| IRP General Updates | • Document converted to current DACC template.<br>• Complete editorial review for conversion to template and current DACC Style guide. Specifically, IRP formatting (Must, Shall, Should) and active voice with clear, concise writing. Updates to references and hyperlinks. This required review of many ‘‘may’ IRP statements from the original IRP and decision about whether they were actually an IRP statement or just general direction.<br>• Add fracturing and thermal information.<br>• Align document with current industry practices and API standards.<br>• Update definitions and acronyms.<br>• Updated many of the diagrams.<br>• Added metric UOM, removing psi from pressure<br>• Removed original Appendix B Flange and Ring dimensions as more current information is available online<br>• Replaced original Appendix B Trim Selection with more current material selection chart from API 6A now in Appendix B<br>• Updated the API 6A temperature chart originally in Appendix C, moved it to Appendix B and added API 6B chart of flange deratings to Appendix B<br>• Removed original Appendix D of ERCB D13 Well Suspension Requirements as more current information is available online from AER website. IRP not just requires consultation of local jurisdictional regulations.<br>• Created some risk register entries to be submitted for IRP24 to cover off fracturing items raised during this review of IRP5. |
| 5.0 Preface<br>5.1 Wellhead Components and Considerations | • Moved background from original document to Preface (5.0.11) section and as introduction to 5.1.<br>• Removed chart of well types as it was incomplete and referenced incorrect sections. Table of contents is better suited for this. Information relating to specific well types was transferred to applicable section in the document. |

| Section | Remarks/Changes |
|---|---|
| 5.1.2 Component Requirements Applicable to All Wellheads | • Removed 207 MPa pressure increment as is no longer part of API 6A.<br>• Updated IRPs around monogramming to be consistent with industry practices.<br>• Added ability to use alternate vendor for salvaged component verification (5.1.2.2).<br>• Added a new section dealing with practices for rental equipment (5.1.2.3).<br>• Added an IRP about pressure requirements for non-API 6A equipment (5.1.2.4).<br>• Full Bore Access Requirements updated to reflect current industry practices (5.1.2.5).<br>• Updated IRP regarding pressure relief access on side outlets from shall to should. |
| 5.1.3 Basic Components of a Wellhead | • Updated Packoff Flange recommendations to reflect current industry practices and standards (5.1.3.4).<br>• Updated Tubing Head recommendations to reflect current industry practices and standards (5.1.3.5) including lock down screw and packoff information.<br>• Added section for practices for Lock Down Screws (5.1.3.6).<br>• Update Christmas Tree section to include information about valves and tree caps (5.1.9).<br>• Created new section for practices specifically related to Gate Valves (5.1.10) based on incident reports of failures from the AER.<br>• Moved Coiled Tubing from original section 5.1.6.8 to this list as 5.1.3.11 Coiled Tubing Hangers.<br>• Added a new section for practices for Wellhead Feedthroughs (5.1.3.12).<br>• Updated welded connections section (5.1.3.13.2) to match current industry standards.<br>• Added valve removal practices for Flanged (5.1.3.13.3) and Studded (5.1.3.13.4) connections.<br>• Updated pressure ratings for connections to align with current version of API 6A.<br>• Updated coiled tubing connection types to include roll-on, dimple and grapple connectors with diagrams (5.1.3.13.7).<br>• Updated seal requirements (5.1.3.14)<br>• Added new section for practices for Surface Casing Vent Assemblies (5.1.3.15). |
| 5.1.4 Sweet Flowing Wells | • Clarified definition of sweet<br>• Reviewed all requirements. |
| 5.1.5 Critical Sour, Sour and Corrosive Wells | • Reviewed all requirements. |
| 5.1.6 Fracture Trees | • Added new section to discuss practices around fracturing equipment. |

| Section | Remarks/Changes |
|---|---|
| 5.1.7 Artificial Lift Wells | • Updated to organize subsection in same order as the table of common types of artificial lift for consistency.<br>• Detailed review and update of practices around plunger lift (5.1.7.5) to address failures as reported to the AER. |
| 5.1.8 Other Well Types | • Moved original section 5.1.8.6 Environmentally sensitive areas and 5.1.8.7 Cold Climate Considerations to 5.2.2.1.6 Identify Environmental Concerns and 5.2.2.1.2 Confirm Temperatures. |
| 5.2.3 Wellhead Installation | • Updated welding personnel requirements (5.2.3.3 and 5.2.3.4).<br>• Updated procedures for welded connections (5.2.3.5).<br>• Added IRP recommending Nitrogen for pressure testing thermal wellheads (5.2.3.6). |
| 5.2.4 Wellhead Protection | • Updated exceptions to IRP statement to be more general instead of referencing military maneuvers and irrigation. |
| 5.2.6 Monitoring and Maintenance | • Added information about and mitigations for valve bonnet stud stretching.<br>• Removed section on weld repair of threaded components as committee felt this was poor practice.<br>• Changed first IRP in 5.2.6.4 about testing frequency from shall to should based on industry feedback. |
| 5.2.7 Wellhead Requirements for Suspended Wells | • Removed everything except IRP requiring consultation with local jurisdictional regulations (removed Appendix that was copy of AER Directive 13 as well). |
| Original Appendix A: Flange/Ring Dimensions | • Removed as more current information is available online. |
| Original Appendix B: Trim Selection Chart | • Replaced with API Material Requirements chart in Appendix B. |
| Original Appendix C: API 6A Table 2 – Temperature Rating | • Updated with current API information in Appendix B. |
| Original Appendix D: Table 1 from ERCB Directive 0123: Suspension Requirements for Wells | • Removed as AER Directive 13 is available online for most current information and reference to this appendix (5.2.7) now only says to consult local jurisdictional regulations. |

Back to table of contents

# Appendix B: API Tables

### API Material Requirements

This table is taken from API 6A. In API 6A it is Table 3.

**Table 10 - API 6A Material Requirements**

| Material Class | Minimum Material Requirements | |
|---|---|---|
| | **Body, Bonnet and Outlet Connections** | **Pressure-Controlling Parts, Stems and Mandrel Hangers** |
| AA General Service | Carbon or low-alloy steel | Carbon or low-alloy steel |
| BB General Service | Carbon or low-alloy steel | Stainless steel |
| CC General Service | Stainless steel | Stainless steel |
| DD Sour Service[1] | Carbon or low-alloy steel[2] | Carbon or low-alloy steel[3] |
| EE Sour Service[2] | Carbon or low-alloy steel[3] | Stainless steel[3] |
| FF Sour Service[2] | Stainless steel[3] | Stainless steel[3] |
| HH Sour Service[2] | CRAs[334] | CRAs[345] |

[1] As defined by ISO 15156 (all parts (NACE MR0175, see Clause 2).

[2] In accordance with ISO 15156 (all parts) (NACE MR0175, see Clause 2).

[3] CRA required on retained fluid wetted surfaces only. CRA cladding of low-alloy or stainless steel is permitted (see 6.5.1.2.2.a).

[4] CRA as defined in Clause 3; ISO 15156 (all parts) (NACE MR0175, see Clause 2) definition of CRA does not apply.

**API Temperature Ratings**

This table is taken from API 6A. In API 6A it is Table 2.

**Table 11 - API Temperature Ratings**

| Temperature Classification | Operating range | | | |
|---|---|---|---|---|
| | ˚C | | ˚F | |
| | min. | max. | min. | max. |
| K | -60 | 82 | -75 | 180 |
| L | -46 | 82 | -50 | 180 |
| N | -46 | 60 | -50 | 140 |
| P | -29 | 82 | -20 | 180 |
| S | -18 | 60 | 0 | 140 |
| T | -18 | 82 | 0 | 180 |
| U | -18 | 121 | 35 | 250 |
| V | 2 | 121 | 35 | 250 |
| X | -18 | 180 | 0 | 350 |
| Y | -18 | 345 | 0 | 650 |

**Pressure Derating of API 6B Flanges at Elevated Temperatures**

As per API 6A, equipment used at temperatures in excess of 121°C, may need to have its Rated Working Pressure (RWP) derated to account for a loss in material strength at these temperatures. An engineering analysis can be done to determine the allowable pressure of the equipment at these temperatures, or in lieu of this analysis, the RWP of the API 6B Flanged connections can be derated as per the Table 14 below. This table is taken from API 6A, Annex G, Table G.2.

**Table 12 - Pressure Derating of API 6B Flanges at Elevated Temperatures**

| Pressure Rating for Classes K to U (MPa) | Derated Pressure (MPa) | |
|---|---|---|
| | Temperature Class X | Temperature Class Y |
| 13.8 | 13.1 | 9.9 |
| 20.7 | 19.7 | 14.8 |
| 34.5 | 32.8 | 24.7 |

# Appendix C: References

### AER References

Available from www.aer.ca:

- Directive 010: Minimum Casing Design Requirements
- Directive 013: Suspension Requirements for Wells
- Directive 036: Drilling Blowout Prevention Requirements and Procedures
- Directive 056: Energy Development Applications and Schedules

### API References

- API Spec 6A: Specification for Wellhead and Christmas Tree Equipment, twentieth edition. 2010.
- API Purchasing Guideline API Specification 6A 20th Edition, October 2010. R1 20120429.
- API RP 5C1: Recommended Practice for Care and Use of Casing and Tubing, eighteenth edition. 2015.
- API RP 5A3: Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements, third edition. 2015.

### DACC References

Available from EnergySafetyCanada.com:

- IRP Volume #2 - Completing and Servicing Critical Sour Wells
- IRP Volume #3 - In Situ Heavy Oil Operations
- IRP Volume #21 - Coiled Tubing Operations
- IRP Volume #24 – Fracture Stimulation (includes IRP 24 Hazard register)

### Energy Safety Canada References

Available from EnergySafetyCanada.com:

- Contractor Management Systems Guideline

### Other References

- ASME Boiler and Pressure Vessel Code
- CSA Z341 Series-10: Storage of hydrocarbons in underground formations. 2014.
- NACE MR0175/ISO 15156: Petroleum and natural gas industries - Materials for use in $H_2S$-containing environments in oil and gas production. 2015.