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UNITED STATES DISTRICT COURT

EASTERN DISTRICT OF CALIFORNIA, FRESNO DIVISION

DUHN OIL TOOL, INC.,

Plaintiff/Counterclaim-Defendant,

vs.

COOPER CAMERON CORPORATION,

Defendant/Counterclaim-Plaintiff.

CASE NO. 1:05-CV-01411-OWW-GSA

Honorable Oliver W. Wanger

PLAINTIFF DUHN OIL TOOL, INC.'S THIRD AMENDED COMPLAINT; DEMAND FOR JURY TRIAL

Trial Date: November 29, 2010

I. INTRODUCTION

1. This is an action for patent infringement in violation of the patent laws of the United States, 35 U.S.C. § 1, *et seq*. This court has jurisdiction under 28 U.S.C. § 1338(a). Venue is proper under 28 U.S.C. §§ 1391(b) and (c), and 1400(b).

II. THE PARTIES

2. Plaintiff, Duhn Oil Tool, Inc., is a corporation organized and existing under the laws of the State of California having a principal place of business at 3912 Gilmore Avenue, Bakersfield, California.

3. On information and belief, Defendant Cooper Cameron Corporation is a corporation organized and existing under the laws of the State of Texas having a principal place of business at 1333 West Loop South, Houston, Texas.

III. FACTUAL BACKGROUND

4. For over fifty years, Plaintiff has served the oil industry through the design and manufacture of quality completion products. Plaintiff's products are sold throughout the United States.

5. On February 19, 2003, Plaintiff filed an application with the United States Patent and Trademark Office to obtain a patent for a wellhead isolation tool and a wellhead assembly incorporating such a tool. The application was filed in the names of Robert K. Meek and Rex E. Duhn, and was assigned to Plaintiff. The application matured into United States Patent No. 6,920,925 entitled "Wellhead Isolation Tool" ("the '925 Patent") and issued on July 26, 2005. A copy of the '925 Patent is attached hereto as Exhibit "A".

6. Defendant, by itself or in concert with others, manufactured, used, offered for sale, sold, and continues to manufacture, use, offer for sale and/or sell in this district and elsewhere in the United States, products which infringe the '925 Patent, literally and/or pursuant to the Doctrine of Equivalents, and/or by otherwise contributing to infringement or inducing others to directly infringe the '925 Patent.

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7. When Plaintiff initiated this action against Defendant on or about November 5, 2005, Defendant was manufacturing, using, installing, selling, renting, and/or offering to sell and/or rent an infringing product referred to as its "Old Style" design. Plaintiff's and Defendant's infringement and non-infringement experts, respectively, have both confirmed in discovery that this "Old Style" design infringes the '925 Patent as it meets all the claim limitations of the '925 Patent. In that regard, the Cameron frac "Old Style" mandrel has the structures for creating a "dual load path" where axial forces are reacted through two connected flanges. One of the load paths uses the tubing-head flange with tubing-head lockscrews, while the other path uses Cameron's spinner flange with load ring.

8. Defendant has induced infringement and continues to induce infringement by providing manuals and training regarding Cameron's "Old Style" frac to third parties, to knowingly induce them to infringe the '925 patent. Cameron has identified several third party fracing companies, well owners, customers, and other service providers that either use or install Cameron's frac mandrels. Cameron induced infringement of the '925 patent by training or encouraging them to directly infringe by installing or using Cameron's frac mandrel. By way of example, Cameron manuals have an express step that instructs the installer to tighten the lower tubing-head lockscrews. When the installers tighten in the lower lockscrews, they enable a second path for the axial forces, thereby creating a "dual load path," and directly infringing the Duhn '925 patent. A copy of one such manual is attached as Exhibit "B". Once the installer directly infringes, then other parties, such as the fracing service company and the owner of the wellsite, will also directly infringe the '925 patent through their continued use of the infringing wellhead device.

9. Defendant has contributed to infringement and continues to contribute to infringement by providing the Cameron "Old Style" frac mandrel. Cameron's frac mandrels have no substantial non-infringing use, so third parties directly infringe by their use or installation of Cameron's frac mandrel. When the installers tighten in the

lower lockscrews, this enables a second path for the axial forces, thereby creating a "dual load path" so that the installers directly infringe the Duhn '925 patent. Once the installer directly infringes, then other parties, such as the fracing service company and the owner of the wellsite will also directly infringe the '925 patent through their use of the infringing wellhead device.

10. Defendant continuously made, used, sold, and offered for sale the "Old Style" design, and/or contributed to or induced others to infringe, until about August 2007, when Defendant attempted to work around infringement by introducing a "New Style" design. In the "New Style" design, Defendant merely widened the groove of the frac mandrel where the lock screws set. The "New Style" retains all of the same infringing structures as Defendant's "Old Style," including lockscrews that could be tightened to engage the surface of the frac mandrel. In that regard, the Cameron "New Style" frac mandrel has the structures for creating a "dual load path" where axial forces are reacted through two connected flanges. One of the load paths uses the tubing-head flange with tubing-head lockscrews, while the other path uses Cameron's spinner flange with load ring.

11. Defendant has induced infringement and continues to induce infringement by providing manuals and training regarding Cameron's "New Style" frac to third parties, to knowingly induce them to infringe the '925 patent. Cameron has identified several third party fracing companies, well owners, customers, and other service providers that either use or install Cameron's frac mandrels. Cameron induced infringement of the '925 patent by training or encouraging them to directly infringe by installing or using Cameron's frac mandrel. By way of example, Cameron manuals have an express step that instructs the installer to tighten the lower tubing-head lockscrews. When the installers tighten in the lower lockscrews, they enable a second path for the axial forces, thereby creating a "dual load path," and directly infringing the Duhn '925 patent. A copy of one such manual is attached as Exhibit "B". Once the installer directly infringes, then other parties, such as the fracing

service company and the owner of the wellsite, will also directly infringe the '925 patent through their continued use of the infringing wellhead device. Photographs of "New Style" frac mandrels and other documentary evidence establish the existence of indentations, indicating that the "New Style" mandrels have been used with the lower lockscrews engaged.

12. Defendant has contributed to infringement and continues to contribute to infringement by providing the Cameron "New Style" frac mandrel. Cameron's frac mandrels have no substantial non-infringing use, so third parties directly infringe by their use or installation of Cameron's frac mandrel. When the installers tighten in the lower lockscrews, this enables a second path for the axial forces, thereby creating a "dual load path" so that the installers directly infringe the Duhn '925 patent. Once the installer directly infringes, then other parties, such as the fracing service company and the owner of the wellsite will also directly infringe the '925 patent through their use of the infringing wellhead device. Photographs of "New Style" frac mandrels and other documentary evidence establish the existence of indentations, indicating that the "New Style" mandrels have been used with the lower lockscrews engaged.

13. In November 2007, Defendant re-introduced its "Original" design in a second attempt to avoid infringement. Defendant's "Original" design preceded its infringing "Old Style" design. The "Original" design is identical to Defendant's "Old Style" and "New Style" designs, except there is no groove on the frac mandrel where the lockscrews set. The lockscrews for the "Original" design, however, still set into the outer surface of the frac mandrel, as confirmed during discovery. In that regard, the Cameron "Original" design frac mandrel has the structures for creating a "dual load path" where axial forces are reacted through two connected flanges. One of the load paths uses the tubing-head flange with tubing-head lockscrews, while the other path uses Cameron's spinner flange with load ring.

14. Defendant has induced infringement and continues to induce infringement by providing manuals and training regarding Cameron's "Original"

design frac to third parties, to knowingly induce them to infringe the ‘925 patent. Cameron has identified several third party fracing companies, well owners, customers, and other service providers that either use or install Cameron's frac mandrels. Cameron induced infringement of the ‘925 patent by training or encouraging them to directly infringe by installing or using Cameron's frac mandrel. By way of example, Cameron manuals have an express step that instructs the installer to tighten the lower tubing head lockscrews. When the installers tighten in the lower lockscrews, they enable a second path for the axial forces, thereby creating a “dual load path,” and directly infringing the Duhn ‘925 patent. A copy of one such manual is attached as Exhibit “B”. Once the installer directly infringes, then other parties, such as the fracing service company and the owner of the wellsite, will also directly infringe the ‘925 patent through their continued use of the infringing wellhead device. Photographs of “Original” design frac mandrels and other documentary evidence establish the existence of indentations, indicating that the “Original” design mandrels have been used with the lower lockscrews engaged.

15. Defendant has contributed to infringement and continues to contribute to infringement by providing the Cameron “Original” design frac mandrel. Cameron's frac mandrels have no substantial non-infringing use, so third parties directly infringe by their use or installation of Cameron’s frac mandrel. When the installers tighten in the lower lockscrews, this enables a second path for the axial forces, thereby creating a “dual load path” so that the installers directly infringe the Duhn ‘925 patent. Once the installer directly infringes, then other parties, such as the fracing service company and the owner of the wellsite will also directly infringe the ‘925 patent through their use of the infringing wellhead device. Photographs of “Original” design frac mandrels and other documentary evidence establish the existence of indentations, indicating that the “Original” design mandrels have been used with the lower lockscrews engaged.

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16. Both Plaintiff's own infringement expert and Defendant's witnesses confirmed that Defendant's "New Style" and "Original" designs (collectively "new designs") infringe the '925 Patent. For instance, Plaintiff's expert maintains that Defendant's new designs contain all the structures claimed by the '925 Patent, including the "wherein" clause limitation. Similarly, Defendant's own senior principal engineer admitted that the lockscrews on these new designs indented the frac mandrel when they were torqued into the frac mandrel and that they will react a sheer force. He also admitted that the lockscrews of the new designs were tightened during fracing to act like set screws to prevent the frac mandrel from rotating and dancing.

17. Since introduction of Defendant's new designs in August 2007, Defendant has significantly misrepresented that its new designs do not infringe the '925 Patent. Defendant has falsely asserted that the lockscrews of these new designs do not engage the frac mandrel and that the new designs are not capable of meeting the claim limitations of the '925 Patent. To the contrary, Defendant has been fully aware that the lockscrews on these new designs are torqued-in during fracing and that the new designs are capable of meeting the "wherein" clause of the '925 Patent. Defendant, for example, sent a reminder bulletin to its employees a year after introduction of its new designs, in or about August 21, 2008. In this reminder bulletin, Defendant expressly acknowledges that its installers continued to torque the lockscrews into the new design frac mandrels, thereby infringing the '925 Patent.

18. Despite knowing that its New Style and Original designs continued to infringe the '925 Patent, Defendant continues to make, sell, rent, use, and offer to sell/rent its infringing new designs literally and/or pursuant to the Doctrine of Equivalents, and/or by otherwise contributing to infringement or inducing others to directly infringe the '925 Patent. Even after the introduction of the New Designs, Defendant's "Old Style" continues to infringe the '925 patent due to Defendant's continuing to contribute to or induce others to infringe the '925 patent.

19. Defendant knew or should have known that its New Style and Original designs were installed in an infringing configuration. On or about September 24, 2008 and November 6, 2008, Plaintiff inspected several of Defendant's "New Style" and "Original" designs at Defendant's storage facilities in Grand Junction, Colorado and Longview, Texas. These inspections revealed blatant indentations and deformations caused by lockscrews still being tightened against the frac mandrels of Defendant's new designs. Defendant knew, or it was clearly obvious to Defendant, that its new designs continued to infringe the '925 Patent.

20. Defendant's continued manufacture, sale, rental, use, and/or offer to sell/rent its infringing "New Style" and "Original" designs, either directly or by otherwise contributing to infringement or inducing others to directly infringe the '925 Patent is deliberate and reckless, and a complete disregard of Plaintiff's patent rights.

IV. PATENT INFRINGEMENT

21. Duhn Oil Tool realleges and incorporates herein paragraphs 1 through 20 of this complaint.

22. By its aforesaid acts, Defendant has violated and continues to violate 35 U.S.C. § 271 by its infringement of the '925 Patent by making, using, selling, and/or offering to sell products or devices that embody or otherwise practice one or more claims of the '925 patent, literally and/or pursuant to the Doctrine of Equivalents, and/or by otherwise contributing to infringement or inducing others to directly infringe the '925 Patent. The infringing products or devices include the "Old Style," "New Style," and "Original Design" frac mandel systems.

23. The acts of infringement of Defendant will continue unless enjoined by this Court.

24. Plaintiff is being damaged by Defendant's infringement of the '925 Patent and is being and will continue to be irreparably damaged unless Defendant's infringement is enjoined by this Court. Plaintiff does not have an adequate remedy at law.

25. As a result of Defendant's infringement of the '925 Patent, Plaintiff has been damaged, and its business and property rights will continue to be damaged, and is entitled to recover damages for such injuries pursuant to 35 U.S.C. § 284 in an amount to be determined at trial.

26 Defendant's acts of infringement regarding Defendant's New Style and Original designs are deliberate and willful, thereby rendering this an exceptional case pursuant to 35 U.S.C. §§ 284 and 285.

V. PRAYER FOR RELIEF

WHEREFORE, Plaintiff demands judgment against Defendant as follows:

1. That this Court adjudge and declare:

a. That it has jurisdiction over the parties and of the subject matter of this action;

b. That United States Patent No. 6,920,925 is valid and is owned by Plaintiff;

c. That Defendant has committed acts of infringement of the '925 Patent by its manufacture, use, sale, rental, offers to sell/rent and/or by indirectly inducing or contributing to the infringement by third parties; and

d. That Defendant's acts of infringement since August 2007 have been willful;

2. That Defendant, its agents, representatives, employees, assigns and suppliers, and alls persons acting in concert or in privity with any of them be preliminarily and permanently enjoined from making, using, offering for sale or rental, selling, renting, or importing the inventions of the '925 Patent;

3. That Defendant be required by mandatory injunction to deliver to Plaintiff for destruction any and all products in Defendant's possession, custody, or control embodying the patented invention as well as any promotional literature therefor;

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4. That Plaintiff be awarded damages caused by the acts of patent infringement of the Defendant in an amount sufficient to compensate Plaintiff for the infringement;

5. That Plaintiff be awarded enhanced damages since August 2007 in connection with Defendant's activities regarding its New Style and Original Design mandrels, in accordance with 35 U.S.C. § 284 and in view of Defendant's willful infringement;

6. That Plaintiff be awarded prejudgment interest on infringement damages;

7. That Plaintiff have and recover its costs in this action, including its attorneys' fees; and

8. That Plaintiff have such other and further relief as the court may deem just and proper.

DEMAND FOR JURY TRIAL

Plaintiff hereby demands a trial by jury on the issue of whether Defendant's infringement is willful.

DATED: June 8, 2010

Respectfully submitted,

THOMAS WHITELAW & TYLER LLP

By: /s/ James M. Whitelaw
JAMES M. WHITELAW
Attorneys for Plaintiff/Counterclaim-Defendant DUHN OIL TOOL, INC.

EXHIBIT A

US006920925B2

(12) **United States Patent**
Duhn et al.

(10) Patent No.: **US 6,920,925 B2**
(45) Date of Patent: **Jul. 26, 2005**

(54) **WELLHEAD ISOLATION TOOL**

(75) Inventors: Rex E. Duhn, Bakersfield, CA (US); Robert K. Meek, Bakersfield, CA (US)

(73) Assignee: Duhn Oil Tool, Inc., Bakersfield, CA (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days.

(21) Appl. No.: 10/369,070

(22) Filed: Feb. 19, 2003

(65) **Prior Publication Data**

US 2003/0221823 A1 Dec. 4, 2003

Related U.S. Application Data

(60) Provisional application No. 60/357,939, filed on Feb. 19, 2002.

(51) Int. Cl.[7] E21B 33/03

(52) U.S. Cl. 166/75.13; 166/75.14; 166/96.1; 166/93.1; 166/379

(58) Field of Search 166/75.13, 75.14, 166/379, 96.1, 93.1

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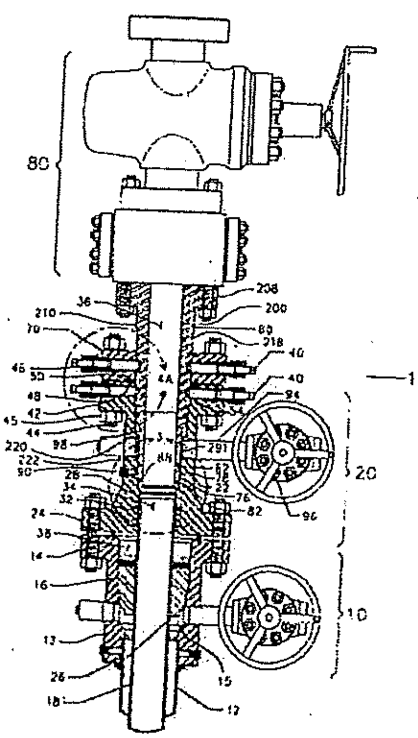
Primary Examiner—David Bagnell
Assistant Examiner—Shane Bomar
(74) *Attorney, Agent, or Firm*—Christie, Parker & Hale, LLP

(57) **ABSTRACT**

A wellhead isolation tool and a wellhead assembly incorporating such a tool are provided. The wellhead assembly has an annular assembly coupled to a well. The annular assembly may include a casing head coupled to the well and a tubing head mounted over the casing head. The wellhead isolation tool is suspended in the annular assembly. The wellhead isolation tool has a first end portion extending above the annular assembly and a second end portion below the first end portion within the annular assembly. A production casing suspended in the annular assembly and is aligned with the wellhead isolation tool.

88 Claims, 7 Drawing Sheets



EX. A PG. 11

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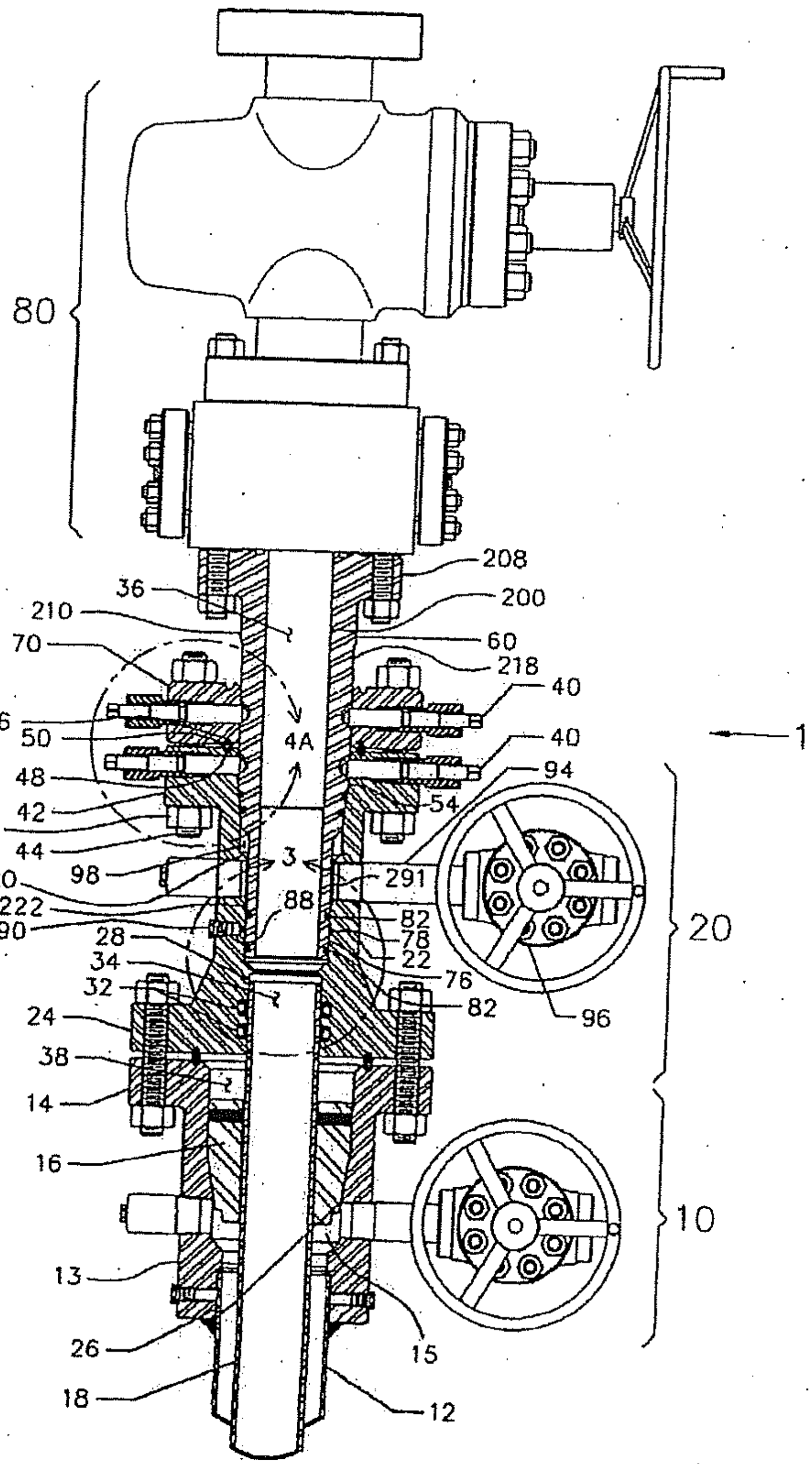
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FIG. 1

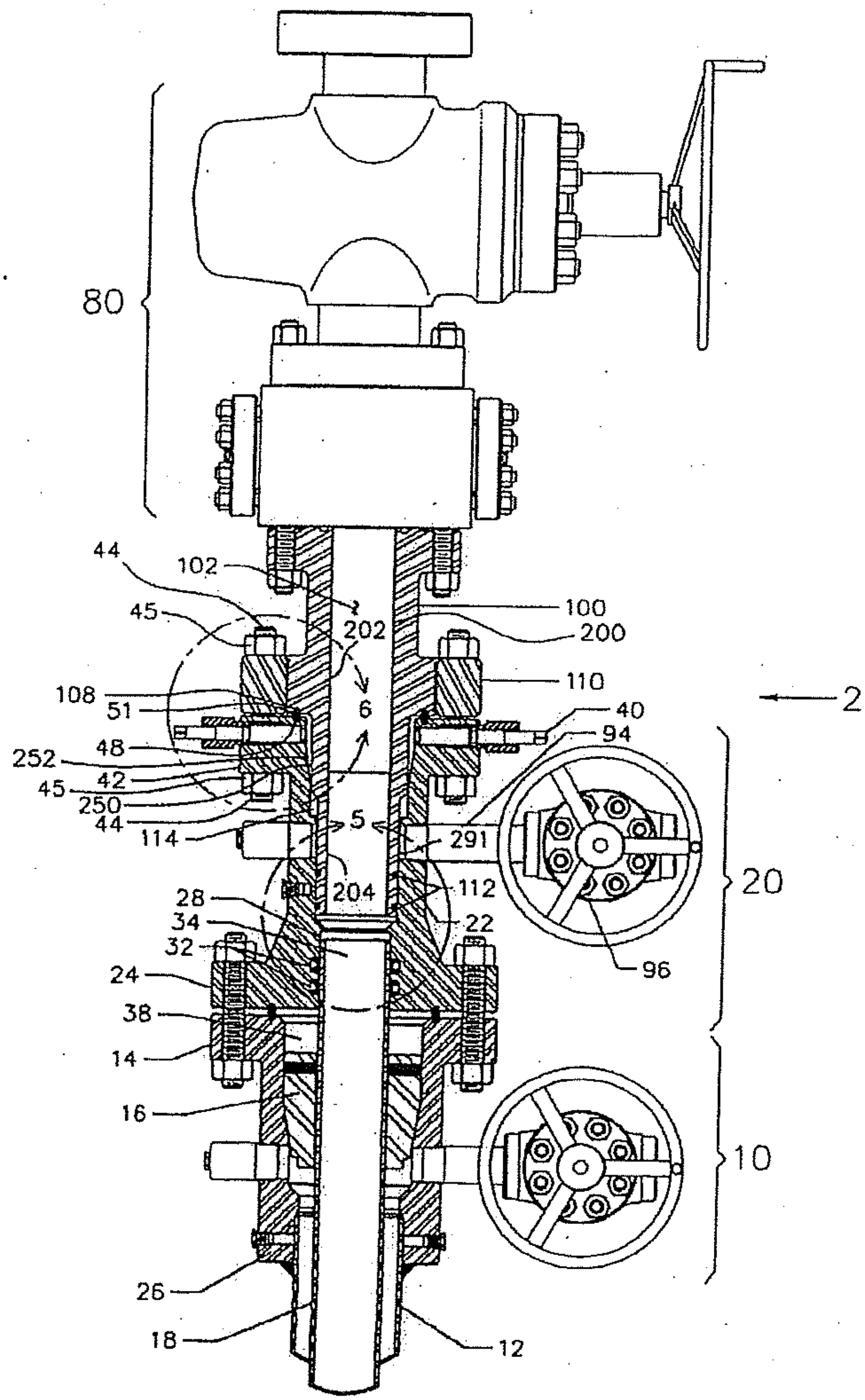

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FIG. 2

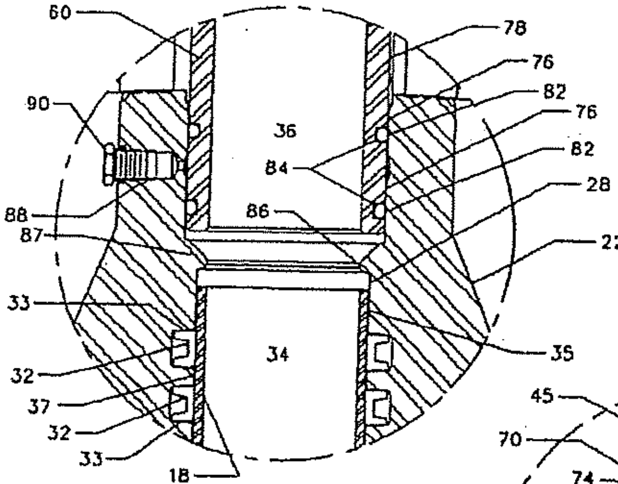

FIG. 3

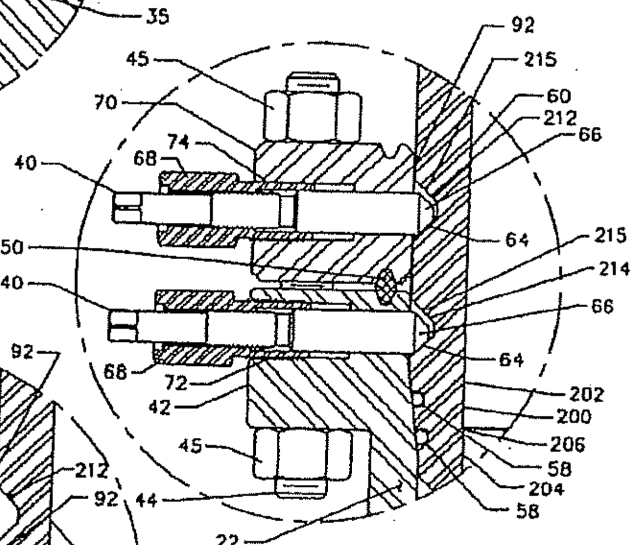

FIG. 4A

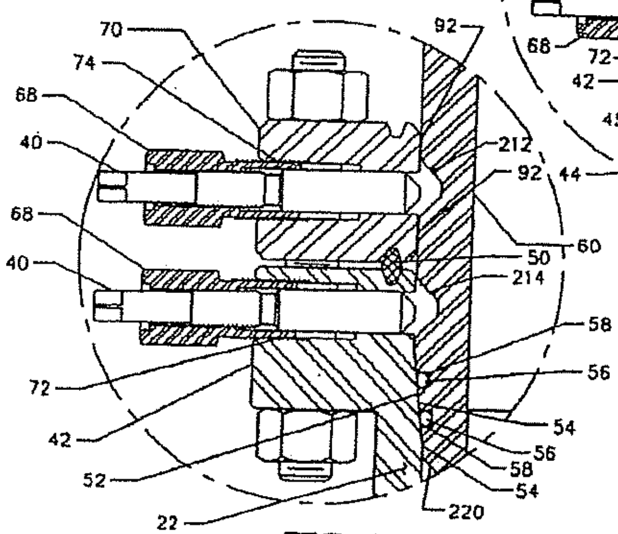

FIG. 4B

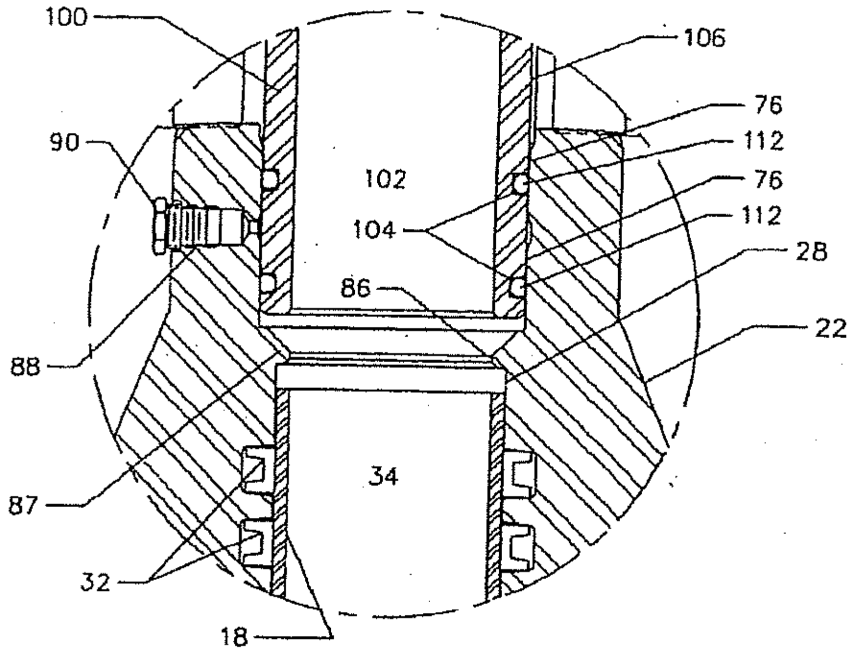
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FIG. 5

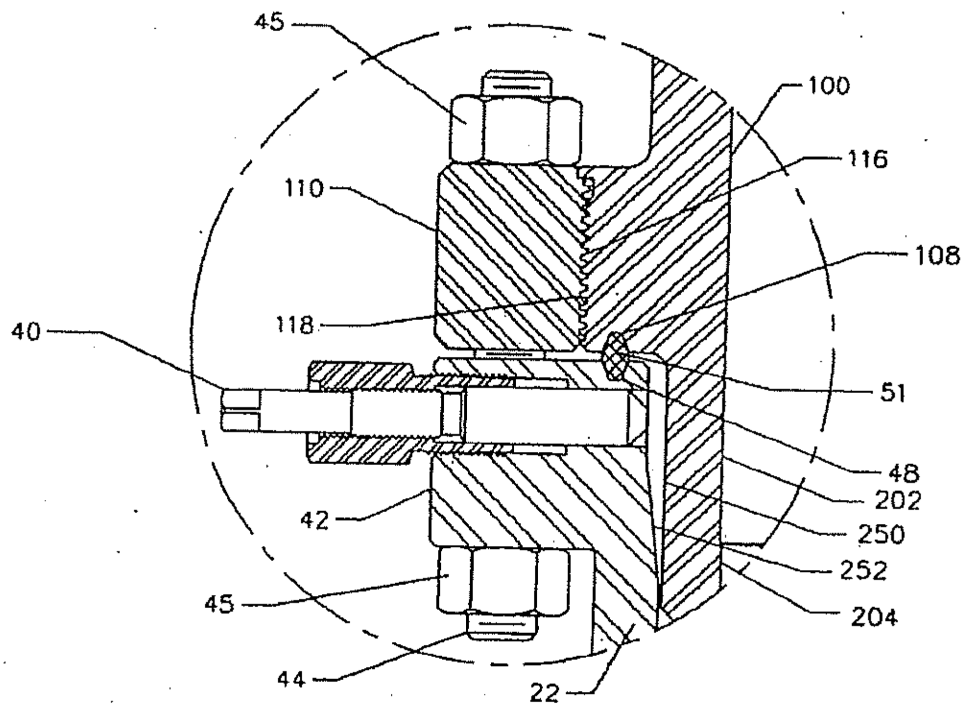
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FIG. 6

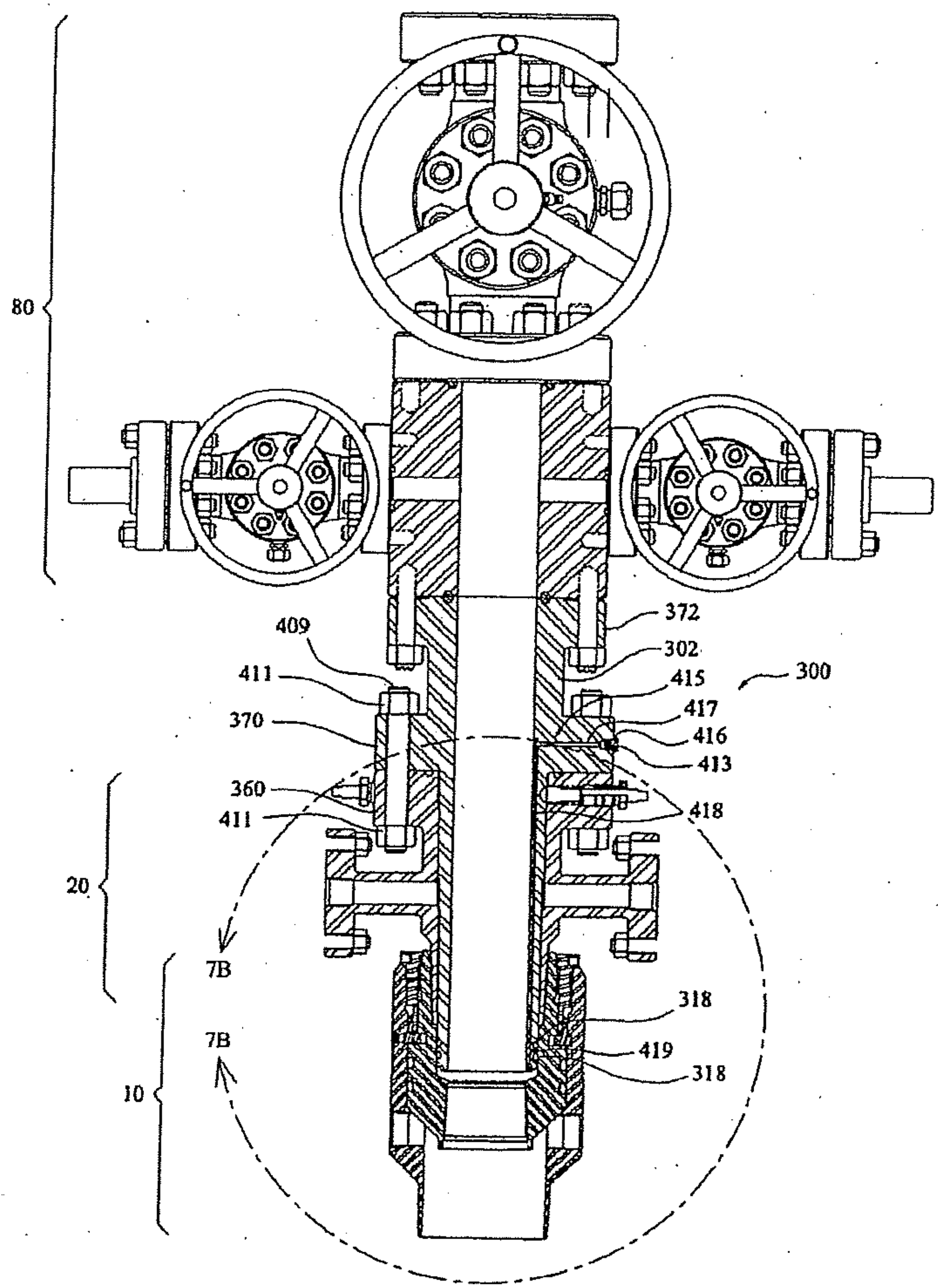
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FIG. 7A

FIG. 7B

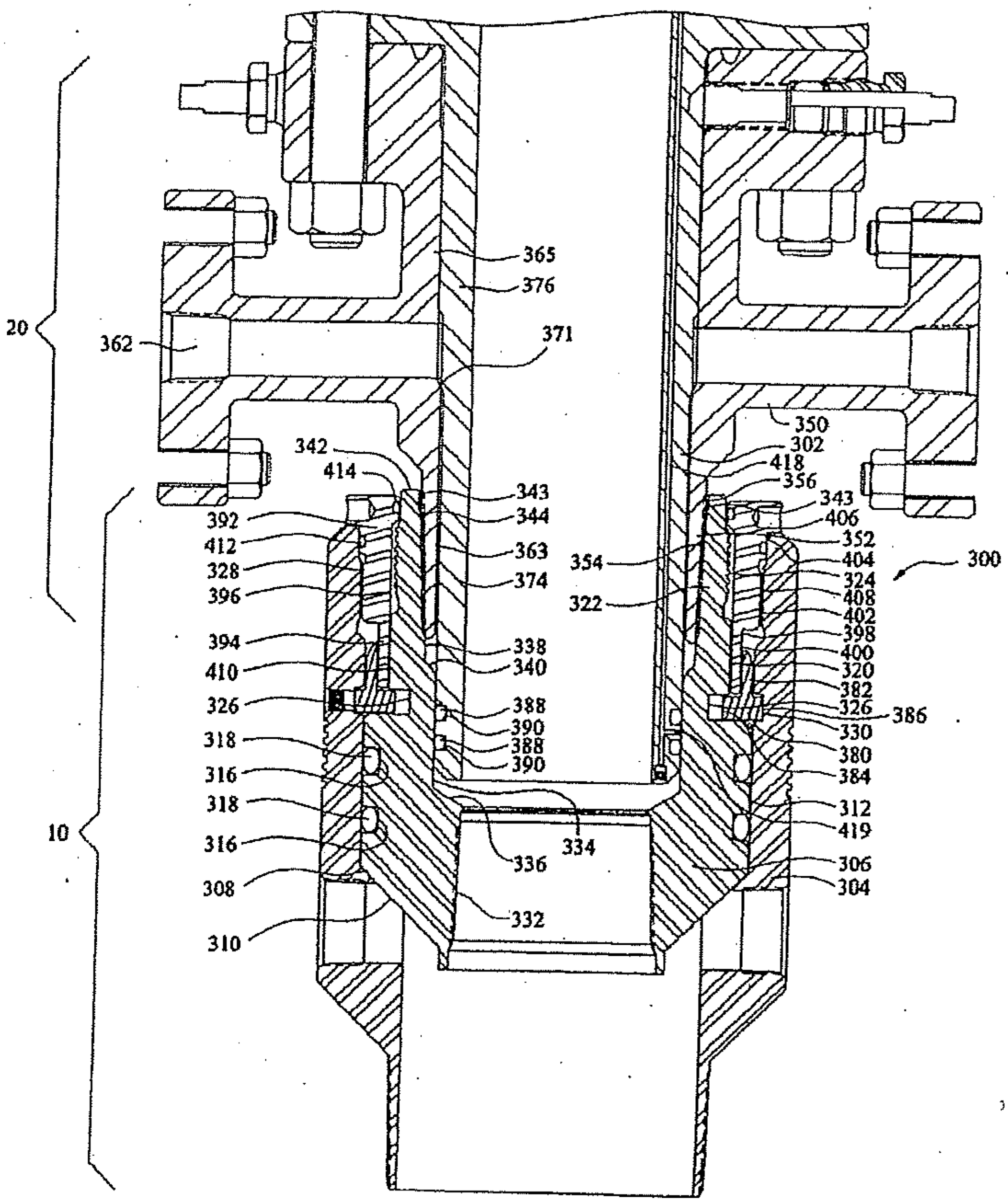
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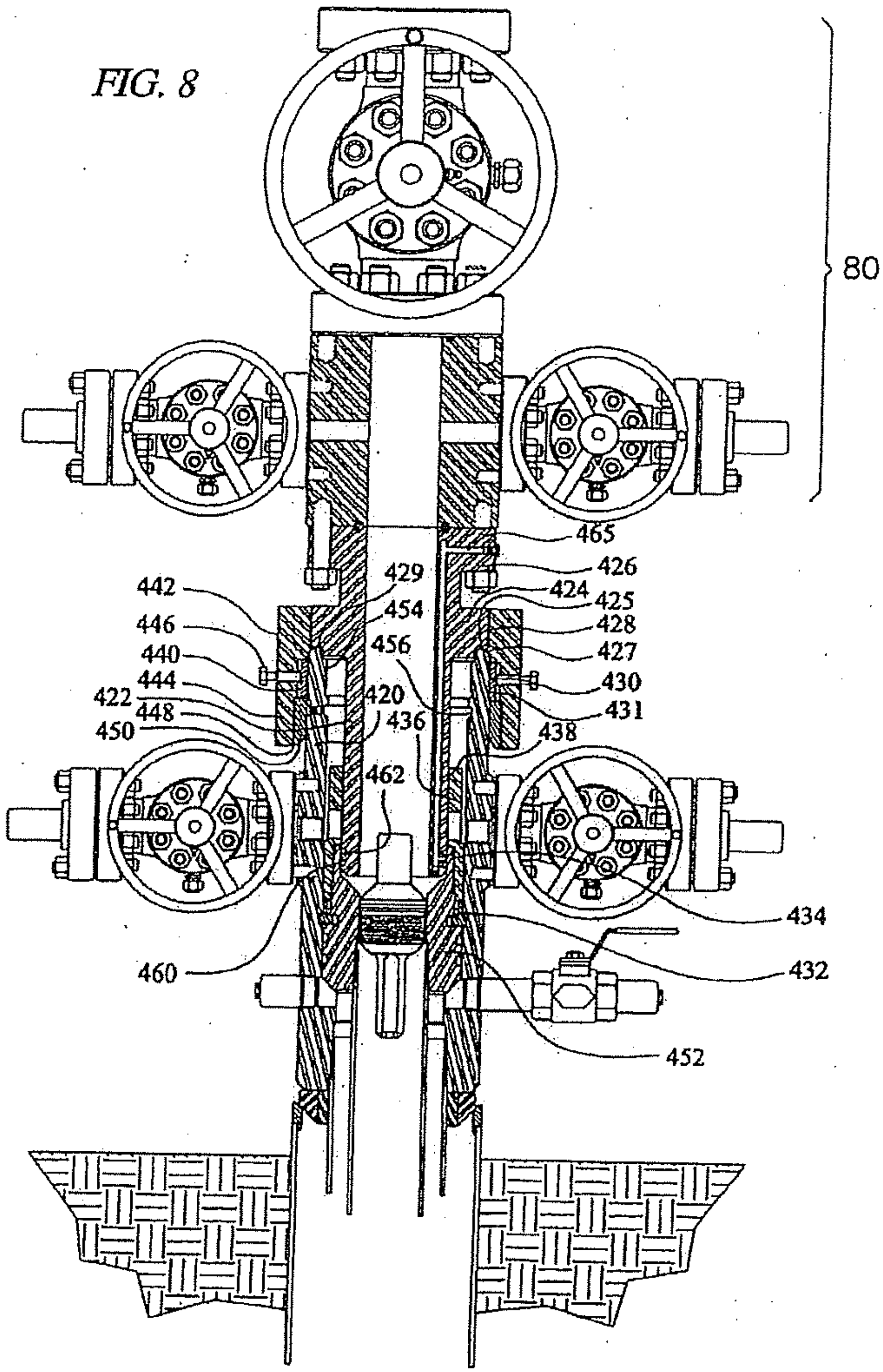
FIG. 8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WELLHEAD ISOLATION TOOL

CROSS-REFERENCED TO RELATED APPLICATION

This application claims priority and is based upon Provisional Application No. 60/357,939, filed on Feb. 19, 2002, the contents of which are fully incorporated herein by reference.

BACKGROUND OF THE INVENTION

The present invention relates to wellhead equipment, and to a wellhead tool for isolating wellhead equipment from the extreme pressures and abrasive materials used in oil and gas well stimulation.

Oil and gas wells often require remedial actions in order to enhance production of hydrocarbons from the producing zones of subterranean formations. These actions include a process called fracturing whereby fluids are pumped into the formation at high pressures in order to break up the product bearing zone. This is done to increase the flow of the product to the well bore where it is collected and retrieved. Abrasive materials, such as sand or bauxite, called propates are also pumped into the fractures created in the formation to prop the fractures open allowing an increase in product flow. These procedures are a normal part of placing a new well into production and are common in older wells as the formation near the well bore begins to dry up. These procedures may also be required in older wells that tend to collapse in the subterranean zone as product is depleted in order to maintain open flow paths to the well bore.

The surface wellhead equipment is usually rated to handle the anticipated pressures that might be produced by the well when it first enters production. However, the pressures encountered during the fracturing process are normally considerably higher than those of the producing well. For the sake of economy, it is desirable to have equipment on the well rated for the normal pressures to be encountered. In order to safely fracture the well then, a means must be provided whereby the elevated pressures are safely contained and means must also be provided to control the well pressures. It is common in the industry to accomplish these requirements by using a 'stinger' that is rated for the pressures to be encountered. The 'stinger' reaches through the wellhead and into the tubing or casing through which the fracturing process is to be communicated to the producing subterranean zone. The 'stinger' also commonly extends through a blow out preventer (BOP) that has been placed on the top of the wellhead to control well pressures. Therefore, the 'stinger', by its nature, has a reduced bore which typically restricts the flow into the well during the fracturing process. Additionally, the placement of the BOP on the wellhead requires substantial ancillary equipment due to its size and weight.

It would, therefore, be desirable to have a product which does not restrict the flow into a well during fracturing and a method of fracturing whereby fracturing may be safely performed, the wellhead equipment can be protected from excessive pressures and abrasives and the unwieldy BOP equipment can be eliminated without requiring the expense of upgrading the pressure rating of the wellhead equipment. It would also be desirable to maintain an upper profile within the wellhead that would allow the use of standard equipment for the suspension of production tubulars upon final completion of the well.

SUMMARY OF THE INVENTION

The present invention is directed to a wellhead isolation tool and to a wellhead assembly incorporating the same. The

present invention in an exemplary embodiment provides for a wellhead isolation tool, also referred to as a "frac mandrel" that cooperates with a relatively low pressure wellhead to accommodate the elevated pressures encountered during the fracturing process by taking advantage of the heavier material cross-section present in the lower end of wellhead equipment and by isolating the weaker upper portions of the wellhead from high fracturing pressures. Said tool provides a full diameter access into the well bore, thus enhancing the fracturing process, and may be used with common high pressure valves to provide well pressure control. The invention further provides for retention of standard profiles within the upper portion of the wellhead allowing the use of standard tubing hangers to support production tubing within the completed well.

In an exemplary embodiment of the invention, a wellhead device is provided that is operable with a conventional high pressure valve for controlling well pressure having at least one string of tubulars. The wellhead device consists of a wellhead body member and a cooperating wellhead isolation tool.

A wellhead body member is provided with an internal through bore communicating with the upper end of a string of tubulars. The lower end of the wellhead body member may be provided with a means to threadedly engage the tubulars, be welded to the tubulars, or slipped over the tubulars and otherwise sealed. The upper end of wellhead body member may be provided with a flanged connection or otherwise furnished with an alternative means of connecting completion equipment, and is further provided with an internal through bore preparation, known in the art as a bowl, to allow suspension of production tubulars. An intermediate connection or connections, either threaded or studded flange, is provided within the wall of the wellhead body member affecting a transverse access port to the annular area between the wellhead body member and the production tubulars. A through bore preparation of the wellhead body member is provided between the transverse access port and lower end tubular accommodation that cooperates with lower end and seals of the wellhead isolation tool. The upper flanged end of the wellhead body member is provided with a plurality of radial threaded ports. Said radial ports are provided with cooperating threaded devices, commonly referred to as lock screws, for the purpose of retaining equipment within the upper bowl of the wellhead body member. The quantity of these lock screws is determined by the pressure rating of the wellhead body member in combination with other parameters.

The exemplary embodiment wellhead isolation tool, is provided with a through bore that equals the through bore of the wellhead tubulars, thus maximizing flow characteristics through the tool. The upper end of the wellhead isolation tool is provided with a flange rated to accommodate fracturing pressures and suitable for the installation of equipment pertinent to the fracturing process. The outer surface of the lower end of wellhead isolation tool cooperates with the lower bore preparation of the wellhead body member and is equipped with a pair of seals that provide isolation of the through bore of the wellhead isolation tool from the upper bore area of the wellhead body member. A radial threaded port is provided in the wall of the wellhead body member in such a location as to provide a means to test the effectiveness of the isolation seals of the wellhead isolation tool after it is installed in the wellhead body member.

In a first exemplary embodiment, the mediate portion of the wellhead isolation tool is provided with an external profile that cooperates with the upper bowl profile of the wellhead body member to establish the proper vertical positioning of the wellhead isolation tool. The outside periphery of this embodiment of the wellhead isolation tool is provided with a pair of grooves formed in the shape of a truncated "V". The resulting lower conic surface of the lowermost "V" groove cooperates with frustroconical ends of the lock screws when the lock screws are threaded into place through their cooperating ports in the flange of the upper end of the wellhead body member to affect retention of the wellhead isolation tool within the wellhead body member. In order to provide the additional strength required to adequately retain the wellhead isolation tool within the wellhead body member, an additional flange, known in the art as a secondary tie down flange, is provided that cooperates with the upper flange of the wellhead body member by a plurality of bolts or studs installed through matching holes machined in the flanges. This additional flange is also provided with a plurality of radial threaded ports in which cooperating lock screws are installed to provide additional retention capacity of the wellhead isolation tool. The frustroconical ends of the latter lock screws cooperate with the lower conic surface of the uppermost "V" groove provided in the wellhead isolation tool to provide the additional strength required to adequately retain the wellhead isolation tool within the wellhead body member. It will be recognized that the additional flange could be furnished as an integral part of the wellhead isolation tool.

In another exemplary embodiment of the wellhead isolation tool, the mediate portion of the tool is provided with an external profile that acts independently from the upper bowl profile of the wellhead body member and with a mounting flange that is threadedly connected to the wellhead solation tool. This allows the wellhead isolation tool to be more universal in its application. The lower end configuration of the second version of the wellhead isolation tool is the same as in the first exemplary embodiment and seals within the cooperating bore of the wellhead body member. As in the first exemplary embodiment, the mounting flange may be provided as an integral part of the wellhead isolation tool.

In another exemplary embodiment of the wellhead isolation tool of the present invention, the wellhead isolation tool penetrates a tubing head and a mandrel casing hanger which is seated within a casing head. A portion of the tubing head also penetrates the mandrel casing hanger. A latch and a top nut are used to retain mandrel casing hanger in the tubing head. The wellhead isolation tool seals at its lower end against the mandrel casing hanger.

In yet a further exemplary embodiment, the wellhead isolation tool penetrates a combination tubing head/casing head and seals against a casing hanger which is seated within the tubing head/casing head combination. The casing hanger is retained within the tubing head/casing head combination by a latch and a top nut. The wellhead isolation tool seals at its lower end against the casing hanger. The top nut used with any of the aforementioned embodiments can have an expanded upper portion for the landing of additional wellhead equipment.

These and other features and advantages will be become apparent from the appended drawings and detailed description.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a partial cross-sectional view of a typical wellhead with an exemplary embodiment wellhead isolation tool of the present invention and a fracturing tree assembly.

FIG. 2 is a partial cross-sectional view of a typical wellhead with another exemplary embodiment wellhead isolation tool of the present invention and a fracturing tree assembly.

FIG. 3 is an enlarged cross-sectional view encircled by arrow 3—3 in FIG. 1.

FIG. 4A is an enlarged cross-sectional view encircled by arrow 4A—4A in FIG. 1.

FIG. 4B is the same view as FIG. 4A with the cooperating lock screws shown in a retracted position.

FIG. 5 is an enlarged cross-sectional view of the section encircled by arrow 5—5 in FIG. 2.

FIG. 6 is an enlarged cross-sectional view of the section encircled by arrow 6—6 in FIG. 2.

FIG. 7A is a partial cross-sectional view of an exemplary embodiment wellhead incorporating an exemplary embodiment wellhead isolation tool of the present invention.

FIG. 7B is an enlarged cross-sectional view of the area encircled by arrow 7B—7B in FIG. 7A;

FIG. 8 is a partial cross-sectional view of another exemplary embodiment wellhead incorporating another exemplary embodiment wellhead isolation tool of the present invention.

DESCRIPTION OF EXEMPLARY EMBODIMENTS OF THE INVENTION

Referring now to the drawings and, particularly, to FIG. 1, a representation of an exemplary embodiment wellhead assembly 1 of the present invention is illustrated. The exemplary embodiment wellhead assembly 1 includes a lower housing assembly 10 also referred to herein as a casing head assembly; an upper assembly 80 also referred to herein as a fracturing tree; an intermediate body member assembly 20 also referred to herein as a tubing head assembly; and a wellhead isolation tool or member 60, which is an elongate annular member, also referred to herein as a frac mandrel. It will be recognized by those skilled in the art that there may be differing configurations of wellhead assembly 1. The casing head assembly includes a casing head 13 defining a well bore 15. The lower end 26 of casing head 13 is connected and sealed to surface casing 12 either by a welded connection as shown or by other means such as a threaded connection (not shown).

The tubing head assembly 20 includes a body member referred to herein as the "tubing head" 22. The upper end 14 of casing head 13 cooperates with a lower end 24 of body member 22 whether by a flanged connection as shown or by other means. A production casing 18 is suspended within the well bore 15 by hanger 16. The upper end of production casing 18 extends into the body member and cooperates with the lower bore preparation 28 of body member 22. The juncture of production casing 18 and lower bore preparation 28 is sealed by seals 32. The seals 32 which may be standard or specially molded seals. In an exemplary embodiment, the seals are self energizing seals such as for example O-ring, T-seal or S-seal types of seals. Self-energizing seals do not need excessive mechanical forces for forming a seal.

Grooves 33 may be formed on the inner surface 35 of the body member 22 to accommodate the seals 32, as shown in FIG. 3, so that the seals seal against an outer surface 37 of the production casing 18 and the grooves 33. In this regard, the seals 32 prevent the communication of pressure contained within the production casing inner bore 34 to the cavity 38 defined in the upper portion of the well bore 15 of the casing head 13. In an alternative exemplary embodiment not shown, grooves may be formed on the outer surface 37 of the production casing 18 to accommodate the seals 32. With this embodiment, the seals seal against the inner surface 35 of the body member. In further alternate exemplary embodiments, other seals or methods of sealing may be used to prevent the communication of pressure contained within the production casing inner bore 34 to cavity 38 defined in the upper portion of the well bore 15 of the casing head 13.

It will be recognized by those skilled in the art that the production casing 18 may also be threadedly suspended within the casing head 13 by what is known in the art as an extended neck mandrel hanger (not shown) whereby the extended neck of said mandrel hanger cooperates with the lower cylindrical bore preparation 28 of body member 22 in same manner as the upper end of production casing 18 and whose juncture with lower cylindrical bore preparation 28 of body member 22 is sealed in the same manner as previously described.

In the exemplary embodiment shown in FIG. 1, the body member 22 includes an upper flange 42. A secondary flange 70 is installed on the upper flange 42 of body member utilizing a plurality of studs 44 and nuts 45. A spacer 50 cooperates with a groove 46 in secondary flange 70 and a groove 48 in the upper flange 42 of body member 22 in order to maintain concentricity between secondary flange 70 and upper flange 42.

Now referring to FIGS. 4A and 4B, lock screws 40 having frustum-conical ends 66 threadedly cooperate with retainer nuts 68 which, in turn, threadedly cooperate with radial threaded ports 72 in upper flange 42 of body member 22 and radial threaded ports 74 in secondary flange 70. The lock screws 40 may be threadedly retracted to allow unrestricted access through bore 92 defined through the secondary flange 70 as for example shown in FIG. 4B.

With the lock screw retracted, an exemplary embodiment wellhead isolation tool 60 is installed through cylindrical bore 92 in secondary flange 70 and into the body member 22. The exemplary embodiment wellhead isolation tool shown in FIG. 1 is a generally elongated annular member having an inner surface 200 having a first section 202 having a first diameter and a second section 204 extending below the first section and having diameter smaller than that of the first section (FIG. 4A). Consequently, a shoulder 206 is defined between the two sections as for example shown in FIG. 4A.

A radial flange 208 extends from an upper end of the wellhead isolation tool and provides an interface for connecting the upper assembly or fracturing tree 80 as shown in FIG. 1. A first annular groove 212 is formed over a second annular groove 214 on an outer surface 210 of the wellhead isolation tool, as for example shown in FIGS. 4A and 4B. In cross-section the grooves are frustum-conical, i.e, they have an upper tapering surface 215 and a lower tapering surface 64 as shown in FIG. 4B. In an alternate embodiments, instead of the grooves 212, 214, a first set of depressions (not shown) is formed over as second set of depressions (not shown) on the outer surface of the wellhead isolation tool. Each set of depressions is radially arranged around the outer surface of the wellhead isolation tool. These depressions also have a frustum-conical cross-sectional shape.

The outer surface 210 of the well head isolation tool has an upper tapering portion 54 tapering from a larger diameter upper portion 218 to a smaller diameter lower portion 222. A lower tapering portion 220 extends below the upper tapering portion 54, tapering the outer surface of the wellhead isolation tool to a smaller diameter lower portion 222.

When the wellhead isolation tool is fitted into the body member through the secondary flange 70, the upper outer surface tapering portion 54 of the wellhead isolation tool mates with a complementary tapering inner surface portion 52 of the body member 22 as shown in FIG. 4B. A seal is provided between the wellhead isolation tool and the body member 22. The seal may be provided using seals 56, as for example self energizing seals such as for example O-ring, T-seal and S-seal type seals fitted in grooves 58 formed on the upper tapering portion 54 of the outer surface of the wellhead isolation tool. In an alternate embodiment not shown, the seals are fitted in grooves on the tapering inner surface portion of the body member. When the upper outer surface tapering portion of the wellhead isolation tool is mated with the tapering inner surface portion of the body member, the lock screws 40 penetrating the secondary flange 70 are aligned with the upper groove 212 formed on the wellhead isolation tool outer surface and the lock screws 40 penetrating the upper flange 42 of the body member 22 are aligned with lower groove 214 formed on the outer surface of the wellhead isolation tool. In an alternate embodiment, the mandrel may have to be rotated such that the lock screws 40 penetrating the secondary flange are aligned with a first set of depressions (not shown) formed on the wellhead isolation tool outer surface and the lock screws 40 penetrating the upper flange of the body member 22 are aligned with a second set depressions (not shown) formed on the outer surface of the wellhead isolation tool.

Now referring to FIG. 4A, lock screws 40 are threadedly inserted so that their frustum conical ends 66 engage the lower tapering surfaces 64 of their respective grooves 212, 214 formed on the outer surface of the exemplary wellhead isolation too), 60 thereby, retaining the wellhead isolation tool 60 within body member 22. With this embodiment, excess loads on the wellhead isolation tool 60 not absorbed by lock screws 40 installed in upper flange 42 are absorbed by lock screws 40 installed in secondary flange 70 and redistributed through studs 44 and nuts 45 to upper flange 42.

Now referring to FIG. 3, with the wellhead isolation tool 60 installed in the body member 22, the outer cylindrical surface 78 of the wellhead isolation tool lower portion 222 cooperates with inner surface 76 of the body member 22. Seals 82 are installed in grooves 84 formed in outer surface 78 of the wellhead isolation tool and cooperate with surfaces 76 to effect a seal between the body member 22 and the wellhead isolation tool 60. In an exemplary embodiment, the seals are self energizing seals such as for example O-ring, T-seal or S-seal types of seals. Alternatively, the seals may be fitted in the grooves formed on in the inner surface 76 of the body member. Pipe port 88 is radially formed through body member 22 and provides access for testing seals 82 prior to placing the wellhead isolation tool 60 in service. Subsequent to testing, pipe port 88 is sealed in an exemplary embodiment with pipe plug 90. Testing may be accomplished by applying air pressure through the pipe port 88 and monitoring the pressure for a decrease. A decrease in pressure of a predetermined amount over a predetermined time period may be indicative of seal leakage.

Cylindrical bores 34, 36 and 86 defined through the production casing 18, the exemplary embodiment wellhead isolation tool 60, and through an annular lip portion 87 the body member 22, respectively, are in an exemplary embodiment as shown in FIG. 3 equal in diameter thus providing an unrestricted passageway for fracturing materials and/or downhole tools.

Referring again to FIG. 1, valve 96 is connected to body member 22 by pipe nipple 94. Valve 96 may also be connected to the body member 22 by a flanged or studded outlet preparation. Valve 96 may then be opened during the fracturing process to bleed high pressures from cavity 98 in the event of leakage past seals 82.

FIG. 2 shows another exemplary embodiment wellhead assembly 2 consisting of a lower housing assembly 10 also referred to herein as a casing head assembly; an upper assembly 80 also referred to herein as a fracturing tree; an intermediate body member assembly 20 also referred to herein as a body member assembly; and another exemplary embodiment wellhead isolation tool 100 also referred to herein as a wellhead isolation tool. It will be recognized by those practiced in the art that there may be differing configurations of wellhead assembly 2. Since the exemplary embodiment shown in FIG. 2 incorporates many of the same elements as the exemplary embodiment shown in FIG. 1, the same references numerals are used in both figures for the same elements. For convenience only the differences from the exemplary embodiment shown in FIG. 1 are described for illustrating the exemplary embodiment of FIG. 2.

Now referring to FIG. 6, a secondary flange 110 is provided in an exemplary embodiment with threads 118, preferably ACME threads, on its inner cylindrical surface that cooperate with threads 116, also in an exemplary embodiment preferably ACME, on the outer cylindrical surface of wellhead isolation tool 100. In an alternate exemplary embodiment, secondary flange 110 may be incorporated as an integral part of wellhead isolation tool 100. However, the assembled tool may be produced more economically with a threaded on secondary flange 110 as for example shown in FIG. 6. The assembly of secondary flange 110 and wellhead isolation tool 100 is coupled to on the upper flange 42 of body member 22 utilizing a plurality of studs 44 and nuts 45. A standard sealing gasket 51 cooperates with a groove 108 formed in the wellhead isolation tool 100 and groove 48 in the upper flange 42 of body member 22 in order to maintain concentricity and a seal between wellhead isolation tool 100 and upper flange 42. With this embodiment, excess loads on the wellhead isolation tool 100 are transmitted to the flange 110 and redistributed through studs 44 and nuts 45 to upper flange 42.

Now referring to FIG. 5, with the wellhead isolation tool 100 installed in body member 22, outer surface 106 of wellhead isolation tool 100 cooperates with cylindrical bore surface 76 of body member 22. Seals 112 installed in grooves 104 machined in outer surface 106 of wellhead isolation tool 100 cooperate with surfaces 76 to effect a seal between body member 22 and wellhead isolation tool 100. Alternatively, the seals are fitted in grooves formed on the inner bore surface 76 of body member 22 and cooperate with the outer surface 106 of the wellhead isolation tool. In the exemplary embodiment, the seals are self energizing seals as for example O-ring, T-seal and S-seal type seals. Other sealing schemes known in the art may also be used in lieu or in combination with the sealing schemes described herein.

As with the embodiment, shown in FIG. 1, pipe port 88 radially formed through body member 22 provides access for testing seals 112 prior to placing wellhead isolation tool 100 in service. Subsequent to testing, pipe port 88 is sealed with pipe plug 90. Cylindrical bores 34, 102 and 86 formed through the production casing 18, through the exemplary embodiment wellhead isolation tool 100, and through the annular lip portion on 87 of the body member 22, respectively, are in an exemplary embodiment equal in diameter thus providing an unrestricted passageway for fracturing materials and/or downhole tools.

Referring again to FIG. 2, valve 96 is connected to body member 22 by pipe nipple 94. Alternatively, the valve 96 may also be connected to body member 22 by a flanged or studded outlet preparation. Valve 96 may then be opened during the fracturing process to bleed high pressures from cavity 114 in the event of leakage past seals 112.

While the wellhead isolation tool has been described with having an upper tapering portion 54 formed on its outer surface which mates with a complementary tapering inner surface 52 of the body member 22, an alternate exemplary embodiment of the wellhead isolation tool does not have a tapering outer surface mating with the tapering inner surface portion 52 of the body member. With the alternate exemplary embodiment wellhead isolation tool, as for example shown in FIG. 2, the wellhead isolation tool has an outer surface 250 which mates with an inner surface 252 of the body member which extends below the tapering inner surface portion 52 of the body member 22. Features of the exemplary embodiment wellhead isolation tool shown in FIG. 1 can interchanged with features of the exemplary embodiment wellhead isolation tool shown in FIG. 2. For example, instead of being coupled to a threaded secondary flange 110, the exemplary embodiment isolation tool may be coupled to the secondary flange 70 in the way shown in relation to the exemplary embodiment wellhead isolation tool shown in FIG. 1.

With any of the aforementioned embodiments, the diameter of the tubing head inner surface 291 (shown in FIGS. 1 and 2) immediately above the area where the lower portion of the wellhead isolation tool seals against the inner surface head of the tubing head is greater than the diameter of the inner surface of the tubing head against which the wellhead isolation tool seals and is greater than the outer surface diameter of the lower portion of the wellhead isolation tool. In this regard, the wellhead isolation tool with seals 32 can be slid into and seal against the body member of the tubing head assembly without being caught.

A further exemplary embodiment assembly 300 comprising a further exemplary embodiment wellhead isolation tool or frac mandrel 302, includes a lower housing assembly 10 also referred to herein as a casing head assembly, an upper assembly 80 also referred to herein as a fracturing tree, and intermediate body assembly 20 also referred to herein as a tubing head assembly, and the intermediate wellhead isolation tool 302 also referred to herein as a frac mandrel, as shown in FIGS.7A and 7B. The casing head assembly includes a casing head 304 into which is seated a mandrel casing hanger 306. The casing head 304 has an internal annular tapering surface 308 on which is seated a complementary outer tapering surface 310 of the mandrel casing hanger. The tapering outer surface 310 of the mandrel casing hanger defines a lower portion of the mandrel casing hanger. Above the tapering outer surface of the mandrel casing hanger extends a first cylindrical outer surface 312 which mates with a cylindrical inner surface of the casing head 304. One or more annular grooves, as for example two annular grooves 316 are defined in the first cylindrical outer surface 312 of the mandrel casing hanger and accommodate seals 318. In the alternative, the grooves may be formed on the inner surface of the casing head port for accommodating the seals.

The mandrel casing hanger 306 has a second cylindrical outer surface 320 extending above the first cylindrical outer surface 312 having a diameter smaller than the diameter of the first cylindrical outer surface. A third cylindrical outer surface 322 extends from the second cylindrical outer surface and has a diameter slightly smaller than the outer surface diameter of the second cylindrical outer surface. External threads 324 may be formed on the outer surface of the third cylindrical surface of the mandrel casing hanger.

An outer annular groove 326 is formed at the juncture between the first and second cylindrical outer surfaces of the mandrel casing hanger. Internal threads 328 are formed at the upper end of the inner surface of the casing head. An annular groove 330 is formed in the inner surface of the mandrel casing head.

The inner surface of the madrel casing hanger has three major sections. A first inner surface section 332 at the lower end which may be a tapering surface, as for example shown in FIG. 7B. A second inner surface 334 extends from the first inner surface section 332. In the exemplary embodiment shown in FIG. 7B, a tapering annular surface 336 adjoins the first inner surface to the second major inner surface. A third inner surface 338 extends from the second inner surface. An annular tapering surface 340 adjoins the third inner surface to the second inner surface. An upper end 342 of the third inner surface of the mandrel casing hanger increases in diameter forming a counterbore 343 and a tapered thread 344.

Body member 350 also known as a tubing head of the tubing head assembly 20 has a lower cylindrical portion 352 having an outer surface which in the exemplary embodiment threadedly cooperates with inner surface 354 of the third inner surface section of the mandrel casing hanger. A protrusion 356 is defined in an upper end of the lower cylindrical section of the body member 350 for mating with the counterbore 343 formed at the upper end of the third inner surface of the mandrel casing hanger. The body member 350 has an upper flange 360 and ports 362. The inner surface of the body member is a generally cylindrical and includes a first section 363 extending to the lower end of the body member. In the exemplary embodiment shown in FIGS. 7A and 7B, the first section extends from the ports 362. A second section 365 extends above the ports 362 and has an outer diameter slightly greater than that of the first section.

The wellhead isolation tool has a first external flange 370 for mating with the flange 360 of the body member of the tubing head assembly. A second flange 372 is formed at the upper end of the wellhead isolation tool for mating with the upper assembly 80. A generally cylindrical section extends below the first flange 370 of the wellhead isolation tool. The generally cylindrical section has a first lower section 374 having an outer surface diameter equal or slightly smaller than the inner surface diameter of the first inner surface section of the body member of the tubing head assembly. A second section 376 of the wellhead isolation tool cylindrical section extending above the first lower section 374 has an outer surface diameter slightly smaller than the inner surface diameter of the second section 365 of the body member 350 and greater than the outer surface diameter of the first lower section 374. Consequently, an annular shoulder 371 is defined between the two outer surface sections of the wellhead isolation tool cylindrical section. The well head isolation tool is fitted within the cylindrical opening of the body member of the tubing head assembly such that the flange 370 of the wellhead isolation tool mates with the flange 360 of the body member 350. When that occurs, the annular shoulder 371 defined between the two outer surface sections of the cylindrical section of the wellhead isolation tool mates with the portion of the first section inner surface 363 of the body member 350.

Prior to installing the mandrel casing hanger into the casing head, a spring loaded latch ring 380 is fitted in the outer groove 326 of the mandrel casing hanger. The spring loaded latch ring has a generally upside down "T" shape in cross section comprising a vertical portion 382 and a first horizontal portion 384 for sliding into the outer annular groove 326 formed on the mandrel casing hanger. A second horizontal portion 386 extends from the other side of the vertical portion opposite the first horizontal portion.

The spring loaded latch ring is mounted on the mandrel casing hanger such that its first horizontal portion 384 is fitted into the external groove 326 formed in the mandrel casing hanger. The spring loaded latch ring biases against the outer surface of the mandrel casing hanger. When fitted into the external annular groove 326 formed in the mandrel casing hanger, the outer most surface of the second horizontal portion 386 of the latch ring has a diameter no greater than the diameter of the first outer surface section 312 of the mandrel casing hanger. In this regard, the mandrel casing hanger with the spring loaded latch ring can be slipped into the casing head so that the tapering outer surface 310 of the mandrel casing hanger can sit on the tapering inner surface portion 308 of the casing head.

In the exemplary embodiment, once the mandrel casing hanger is seated onto the casing head, the body member 350 of the tubing head assembly is fitted within the casing head such that the lower section of the outer surface of the body member threads on the third section inner surface of the mandrel casing hanger such that the protrusion 356 formed on the outer surface of the body member is mated within the counterbore 343 formed on the upper end of the third section inner surface of the mandrel casing hanger. The wellhead isolation tool is then fitted with its cylindrical section within the body member 350 such that the flange 370 of the wellhead isolation tool mates with the flange 360 of the body member. When this occurs, the annular shoulder 371 formed on the cylindrical section of the wellhead isolation tool mates with the first section 363 of the inner surface of the body member 350. Similarly, the lower outer surface section of the cylindrical section of the wellhead isolation tool mates with the inner surface second section 334 of the mandrel casing hanger. Seals 388 are provided in grooves formed 390 on the outer surface of the lower section of the cylindrical section of the wellhead isolation tool to mate with the second section inner surface of the mandrel casing hanger. In the alternative, the seals may be positioned in grooves formed on the second section inner surface of the mandrel casing hanger. In the exemplary embodiment, the seals are self-energizing seals, as for example, O-ring, T-seal or S-seal type seals.

A top nut 392 is fitted between the mandrel casing hanger upper end portion and the upper end of the casing head. More specifically, the top nut has a generally cylindrical inner surface section having a first diameter portion 394 above which extends a second portion 396 having a diameter greater than the diameter of the first portion. The outer surface 398 of the top nut has four sections. A first section 400 extending from the lower end of the top nut having a first diameter. A second section 402 extending above the first section having a second diameter greater than the first diameter. A third section 404 extending from the second section having a third diameter greater than the second diameter. And a fourth section 406 extending from the third section having a fourth diameter greater than the third diameter and greater than the inner surface diameter of the upper end of the mandrel casing hanger. Threads 408 are formed on the outer surface of the second section 402 of the top nut for threading onto the internal threads 328 formed on the inner surface of the upper end of the mandrel casing head. The top nut first and second outer surface sections are aligned with the first inner surface section of the top nut. In this regard, a leg 410 is defined extending at the lower end of the top nut.

The top nut is threaded on the inner surface of the casing head. As the top nut moves down on the casing head, the leg 410 of the top nut engages the vertical portion 382 of the spring loaded latch ring, moving the spring loaded latch ring radially outwards against the latch ring spring force such that the second horizontal portion 386 of the latch ring slides into the groove 330 formed on the inner surface of the casing head while the first horizontal portion remains within the groove 326 formed on the outer surface of the mandrel casing head. In this regard, the spring loaded latch ring along with the top nut retain the mandrel casing hanger within the casing head.

A seal 412 is formed on the third outer surface section of the top nut for sealing against the casing head. In the alternative the seal may be formed on the casing head for sealing against the third section of the top nut. A seal 414 is also formed on the second section inner surface of the top nut for sealing against the outer surface of the mandrel casing hanger. In the alternative, the seal may be formed on the outer surface of the casing hanger for sealing against the second section of the inner surface of the top nut.

To check the seal between the outer surface of the lower section of the cylindrical section of the wellhead isolation tool and the inner surface of the mandrel casing hanger, a port 416 is defined radially through the flange 370 of the wellhead isolation tool. The port provides access to a passage 415 having a first portion 417 radially extending through the flange 370, a second portion 418 extending axially along the cylindrical section of the wellhead isolation tool, and a third portion 419 extending radially outward to a location between the seals 388 formed between the lower section of the wellhead isolation tool and the mandrel casing hanger. Pressure, such as air pressure, may be applied to port 416 to test the integrity of the seals 388. After testing the port 416 is plugged with a pipe plug 413.

With any of the aforementioned exemplary embodiment wellhead isolation tools, a passage such as the passage 415 shown in FIG. 7A, may be provided through the body of the wellhead isolation to allow for testing the seals or between the seals at the lower end of the wellhead isolation tool from a location on the wellhead isolation tool remote from such seals.

The upper assembly is secured on the wellhead isolation tool using methods well known in the art such as bolts and nuts. Similarly, an exemplary embodiment wellhead isolation tool is mounted on the tubing head assembly using bolts 409 and nuts 411.

In another exemplary embodiment assembly of the present invention shown in FIG. 8, a combination tubing head/casing head body member 420 is used instead of a separate tubing head and casing head. Alternatively, an elongated tubing head body member coupled to a casing head may be used. In the exemplary embodiment shown in FIG. 8, the body member is coupled to the wellhead. A wellhead isolation tool 422 used with this embodiment comprises an intermediate flange 424 located below a flange 426 interfacing with the upper assembly 80. An annular step 425 is formed on the lower outer periphery of the intermediate flange. When the wellhead isolation tool 422 is fitted in the body member 420, the annular step 425 formed on the intermediate flange seats on an end surface 427 of the body member. A seal 429 is fitted in a groove formed on the annular step seals against the body member 420. Alternatively the groove accommodating the seal may be formed on the body member 420 for sealing against the annular step 425. Outer threads 428 are formed on the outer surface of the intermediate flange 424. When fitted into the body member 420, the intermediate flange 424 sits on an end portion of the body member 420. External grooves 430 are formed on the outer surface near an upper end of the body member defining wickers. In an alternate embodiment threads may be formed on the outer surface near the upper end of the body member.

With this exemplary embodiment, a mandrel casing hanger 452 is mated and locked against the body member 420 using a spring loaded latch ring 432 in combination with a top nut 434 in the same manner as described in relation to the exemplary embodiment shown in FIGS. 7A and 7B. However, the top nut 434 has an extended portion 436 defining an upper surface 438 allowing for the landing of additional wellhead structure as necessary. For example, another hanger (not shown) may be landed on the upper surface 438. In another exemplary embodiment, internal threads 454 are formed on the inner surface of the body member to thread with external threads formed in a second top nut which along with a spring latch ring that is accommodated in groove 456 formed on the inner surface of the body member 420 can secure any additional wellhead structure such as second mandrel seated on the top of the extended portion of top nut 434.

Once the wellhead isolation tool 422 is seated on the body member 420, a segmented lock ring 440 is mated with the wickers 430 formed on the outer surface of the body member. Complementary wickers 431 are formed on the inner surface of the segmented lock ring and intermesh with the wickers 430 on the outer surface of the body member. In an alternate embodiment, the segmented lock ring may be threaded to a thread formed on the outer surface of the body member. An annular nut 442 is then threaded on the threads 428 formed on the outer surface of the intermediate flange 424 of the wellhead isolation tool. The annular flange has a portion 444 that extends over and surrounds the segmented lock ring. Fasteners 446 are threaded through the annular nut and apply pressure against the segmented locking ring 440 locking the portion of the annular nut relative to the segmented lock ring.

An internal thread 448 is formed on the lower inner surface of the annular nut 442. A lock nut 450 is threaded onto the internal thread 448 of the annular nut and is sandwiched between the body member 420 and the annular nut 442. In the exemplary embodiment shown in FIG. 8, the lock nut 450 is threaded until it engages the segmented locking ring 440. Consequently, the wellhead isolation tool 422 is retained in place seated on the body member 420.

Seals 460 are formed between a lower portion of the wellhead isolation tool 422 and an inner surface of the hanger 452. This is accomplished by fitting seals 460 in grooves 462 formed on the outer surface of the wellhead isolation tool 422 for sealing against the inner surface of hanger 452. Alternatively the seals may be fitted in grooves formed on the inner surface of the hanger 452 for sealing against the outer surface of the wellhead isolation tool. To check the seal between the outer surface of the wellhead isolation tool 422 and the inner surface of the hanger 452, a port 465 is defined through the flange 426 of the wellhead isolation tool and down along the well head isolation tool to a location between the seals 460 formed between the wellhead isolation tool and the hanger 452.

The inner surface of the mandrel casing hanger has three major sections. A first inner surface section 332 at the lower end which may be a tapering surface, as for example shown in FIG. 7B. A second inner surface 334 extends from the first inner surface section 332. In the exemplary embodiment shown in FIG. 7B, a tapering annular surface 336 adjoins the first inner surface to the second major inner surface. A third inner surface 338 extends from the second inner surface. An annular tapering surface 340 adjoins the third inner surface to the second inner surface. An upper end 342 of the third inner surface of the mandrel casing hanger increases in diameter forming a counterbore 343 and a tapered thread 344.

With any of the aforementioned embodiment, one or more seals may be used to provide the appropriate sealing. Moreover, any of the aforementioned embodiment wellhead isolation tools and assemblies provide advantages in that they isolate the wellhead or tubing head body from pressures of refraction in process while at the same time allowing the use of a valve instead of a BOP when forming the upper assembly 80. In addition, by providing a seal at the bottom portion of the wellhead isolation tool, each of the wellhead isolation exemplary embodiment tools of the present invention isolate the higher pressures to the lower sections of the tubing head or tubing head/casing head combination which tend to be heavier sections and can better withstand the pressure loads. Furthermore, they allow for multiple fracturing processes and allow the wellhead isolation tool to be used in multiple wells without having to use a BOP between fracturing processes from wellhead to wellhead. Consequently, multiple BOPs are not required when fracturing multiple wells.

The wellhead isolation tools of the present invention as well as the wellhead assemblies used in combination with the wellhead tools of the present invention including, among other things, the tubing heads and casing heads may be formed from steel, steel alloys and/or stainless steel. These parts may be formed by various well known methods such as casting, forging and/or machining.

While the present invention will be described in connection with the depicted exemplary embodiments, it will be understood that such description is not intended to limit the invention only to those embodiments, since changes and modifications may be made therein which are within the full intended scope of this invention as hereinafter claimed.

What is claimed is:

1. A wellhead assembly comprising:

a casing;

a first tubular member mounted over the casing;

a first tubular member flange extending from the first tubular member;

a generally elongate annular member suspended in the first tubular member, said annular member having a first end portion extending above the first tubular member and a second end portion below the first end portion;

a secondary flange extending from the elongate annular member;

a plurality of fasteners fastening the secondary flange to the first tubular member flange; and

a production tubular member aligned with the elongate annular member, wherein an axial force acts on the generally elongate annular member and is reacted in both the first tubular member flange and the secondary flange.

2. A wellhead assembly as recited in claim 1 wherein the first tubular member comprises an inner surface having an annular lip, wherein said annular lip extends between the elongate annular member second end portion and a portion of the production tubular member.

3. A wellhead assembly as recited in claim 2 wherein said annular lip extends radially inward defining an opening having a first diameter, wherein the elongate annular member first end portion comprises an inner surface having a second diameter and wherein the portion of the production tubular member comprises an inner surface having a third diameter, wherein said first, second and third diameters are equal.

4. A wellhead assembly as recited in claim 1 further comprising a seal between the elongate annular member second end portion and the first tubular member.

5. A wellhead assembly as recited in claim 4 wherein the seal is between the elongate annular member second end portion and a first inner surface section of the first tubular member, wherein the first tubular member comprises a second inner surface section immediately above and concentric with the first inner surface section, said second inner surface section having a diameter greater than the first inner surface section.

6. A wellhead assembly as recited in claim 4 further comprising a second seal between the elongate annular member second end portion and the first tubular member.

7. A wellhead assembly as recited in claim 6 wherein the seals are self energizing seals.

8. A wellhead assembly as recited in claim 6 further comprising a port through the first tubular member providing access to the elongate annular member at a location between the seals.

9. A wellhead assembly as recited in claim 6 further comprising a passage through the elongate annular member providing access to an inner surface of the elongate annular member at a location between the seals from a remote location on the outer surface of the elongate annular member.

10. A wellhead assembly as recited in claim 4 further comprising a fracturing tree mounted over the generally elongate annular member.

11. A wellhead assembly as recited in claim 4 further comprising a BOP mounted over the generally elongate annular member.

12. A wellhead assembly as recited in claim 4 wherein the secondary flange is separate from the elongate annular member.

13. A wellhead assembly as recited in claim 12 further comprising:

at least one lower depression formed on the elongate annular member outer surface;

at least one upper depression formed on the elongate annular member outer surface above the lower depression;

a first plurality lock screws each radially threaded through the first tubular member flange and engaging the at least one lower depression; and

a second plurality of lock screws each radially threaded through the secondary flange and engaging the at least one upper depression, wherein the secondary flange is fastened to the first tubular member flange.

14. A wellhead assembly as recited in claim 13 wherein the elongate annular member comprises an outer surface portion between the first and second ends and below the at least one lower depression, said outer surface portion tapering from a larger diameter to a smaller diameter in a direction toward the second end, wherein the first tubular member comprises a tapering inner surface portion complementary to the inner tapering outer surface portion of the elongate annular member, and wherein the outer tapering surface portion of the elongate annular member seals against the tapering inner surface portion of the first tubular member.

15. A wellhead assembly as recited in claim 14 further comprising a seal between the outer tapering surface portion of the elongate annular member and the tapering inner surface portion of the first tubular member.

16. A wellhead assembly as recited in claim 12 further comprising a plurality lock screws each radially threaded through the first tubular member flange and engaging at least a depression formed on the elongate annular member outer surface, wherein the elongate annular member further comprises a threaded outer surface portion, and wherein the secondary flange is an annular, flange threaded on the elongate annular member threaded outer surface portion.

17. A wellhead assembly as recited in claim 16 wherein the elongate annular member comprises an intermediate flange, and wherein the elongate annular member threaded outer surface portion is formed on the outer surface of the intermediate flange.

18. A wellhead assembly as recited in claim 4 wherein the elongate annular member comprises an outer surface portion between the first and second ends, wherein the first tubular member comprises a tapering inner surface portion tapering from a larger diameter section to smaller diameter section in a direction toward the casing, wherein when suspended in the first tubular member, a portion of a section of the outer surface of the elongate annular member mates with the smaller diameter inner surface section of the first tubular member and a portion of the section of the outer surface of the elongate annular member is surrounded by the tapering inner surface portion of the first tubular member defining a gap between said tapering inner surface portion and said portion of the section of the outer surface of the elongate annular member surrounded by said tapering inner surface portion, and wherein said portion of the section of the outer surface of the elongate annular member is located below said first tubular member flange when said elongate annular member is suspended in said first tubular member flange.

19. A wellhead assembly as recited in claim 4 further comprising:

a plurality lock screws each radially threaded through the first tubular member flange and engaging at least a depression formed on the elongate annular member outer surface, wherein the elongate annular member flange is fastened to the first tubular member flange.

20. A wellhead assembly as recited in claim 1 wherein the elongate annular member comprises an outer surface portion between the first and second ends tapering form a larger diameter to a smaller diameter in a direction toward the second end, wherein the first tubular member comprises a tapering inner surface portion complementary to the inner tapering outer surface portion of the elongate annular member, and wherein the outer tapering surface portion of the elongate annular member seals against the tapering inner surface portion of the first tubular member.

21. A wellhead assembly as recited in claim 20 further comprising a seal between the outer tapering surface portion of the elongate annular member and the tapering inner surface portion of the first tubular member.

22. A wellhead assembly as recited in claim 1 wherein the elongate annular member comprises an outer surface portion between the first and second ends, wherein the first tubular member comprises a tapering inner surface portion tapering from a larger diameter section to smaller diameter section in a direction toward the casing, wherein when suspended in the first tubular member, a portion of a section of the outer surface of the elongate annular member mates with the smaller diameter inner surface section of the first tubular member and a portion of the section of the outer surface of the elongate annular member is surrounded by the tapering inner surface portion of the first tubular member defining a gap between said tapering inner surface portion and said portion of the section of the outer surface of the elongate annular member surrounded by said tapering inner surface portion.

23. A wellhead assembly as recited in claim 1 wherein a portion of the first tubular member extends within a casing head coupled to the casing, the wellhead assembly further comprising:

an annular hanger suspended in the first tubular member, wherein an annular gap is defined between an outer surface of the first tubular member and an inner surface of the casing head, wherein said annular hanger has a first inner surface section and a second inner surface section below the first inner surface section, wherein the second inner surface section has a diameter smaller than the first inner surface section, and wherein the second end portion of the elongate annular member extends to the first inner surface section of the annular hanger;

a first annular groove formed on the outer surface of the hanger and aligned with a second annular groove formed on the inner surface of the first tubular member when the hanger is suspended in the first tubular member, wherein the annular gap extends to said aligned grooves;

a spring loaded latch, wherein in cross-section the spring loaded latch comprises a first section extending opposite a second section and a third section extending from and transvesely to said first and second sections and fitted within the annular gap, wherein the latch can move from a first position where at least a portion of the first section of the latch is within the first annular groove and at least a portion of the second section of the latch is within the second annular groove to a second position where the first section of the latch is not within the first annular groove and at least a portion of the second section of the latch is within the second annular groove, wherein the latch is spring loaded to the second position; and

a top nut having an first section, and a second section extending below the first section wherein the first section comprises an outer surface having a diameter greater than an outer surface of the top nut second section, and wherein the top nut is fitted within the annular gap causing the top nut second section to engage the third section of the spring latch and move the spring latch to the first position.

24. A wellhead assembly as recited in claim 23 wherein the top nut further comprises third section extending above the first section and surrounding the elongate annular member, said top nut third section having an end surface providing a landing for other wellhead equipment.

25. A wellhead assembly as recited in claim 23 wherein the top nut first section is threaded on the outer surface of the hanger.

26. A wellhead assembly as recited in claim 25 wherein the annular hanger is sandwiched between the top nut first section and the, elongate annular member.

27. A wellhead assembly as recited in claim 23 further comprising a seal between the second end portion of the elongate annular member and the first inner surface section of the annular hanger.

28. A wellhead assembly as recited in claim 1 wherein the first tubular member is a tubing head.

29. A wellhead assembly as recited in claim 1 wherein an end of the elongate annular member is aligned with and

faces an end of the production tubular member, wherein an inner surface diameter of said end of said elongate annular member is about equal to an inner surface diameter of said end of said production tubular member.

30. A wellhead assembly as recited in claim 1 wherein the first tubular member flange and the secondary flange are fastened together.

31. A wellhead assembly as recited in claim 1 further comprising:

at least one lower depression formed on the elongate annular member outer surface;

at least one upper depression formed on the elongate annular member outer surface above the lower depression;

a first plurality lock screws each radially threaded through the first tubular member flange and engaging the at least one lower depression; and

a second plurality of lock screws each radially threaded through the secondary flange and engaging the at least one upper depression and coupling the secondary flange to the generally elongate annular member, wherein the secondary flange is fastened to the first tubular member flange, and wherein the secondary flange is separate from the generally elongate annular member.

32. A wellhead assembly as recited in claim 1 further comprising a first plurality lock screws each radially threaded through one of said first tubular member flange and secondary flange and engaging the generally elongate annular member, wherein the other of said first tubular member flange and secondary flange is threaded on the generally elongate annular member, wherein the secondary flange is fastened to the first tubular member flange, and wherein the secondary flange is separate from the generally elongate annular member.

33. A wellhead assembly as recited in claim 32 wherein the lock screws are threaded through the first tubular member flange and wherein the secondary flange is threaded on the generally elongate annular member.

34. A wellhead assembly as recited in claim 1 further comprising a third flange extending from the generally elongate annular member spaced apart from the secondary flange.

35. A wellhead assembly as recited in claim 1 wherein the generally elongate annular member second end is located within the first tubular member.

36. A wellhead assembly as recited in claim 1 wherein the secondary flange is separate from the generally elongate member.

37. A wellhead assembly comprising:

a casing;

a first tubular member mounted over the casing, the first tubular member comprising a flange and a tapering inner surface portion tapering from a larger diameter section to a smaller diameter section in a direction toward the casing;

a generally elongate annular member suspended in the first tubular member, said annular member having a first end portion extending above the first tubular member and a second end portion below the first end portion within the first tubular member, wherein the elongate annular member comprises an outer surface portion between the first and second ends, wherein a portion of a section of the outer surface of the elongate annular member mates with the smaller diameter inner surface section of the first tubular member and a portion of the section of the outer surface of the elongate annular member is surrounded by the tapering inner surface portion of the first tubular member defining a gap between said tapering inner surface portion and said portion of the section of the outer surface of the elongate annular member surrounded by said tapering inner surface portion, and wherein said portion of the section of the outer surface of the elongate annular member is located below said first tubular member flange when said elongate annular member is suspended in said first tubular member flange;

a second flange extending from the generally elongate annular member; and

a production tubular member aligned with the elongate annular member, wherein an axial force acts on the generally elongate annular member and is reacted in both the first tubular member flange and the second flange.

38. A wellhead assembly as recited in claim 37 further comprising:

a plurality lock screws each radially threaded through the first tubular member flange and engaging at least a depression formed on the elongate annular member outer surface, wherein the elongate annular member flange is fastened to the first tubular member flange.

39. A wellhead assembly as recited in claim 37 further comprising a seal between the elongate annular member second end portion and the first tubular member.

40. A wellhead assembly as recited in claim 39 further comprising a second seal between the elongate annular member second end portion and the first tubular member.

41. A wellhead assembly as recited in claim 40 wherein the seals are self energizing seals.

42. A wellhead assembly as recited in claim 40 further comprising a port through the first tubular member providing access to the elongate annular member at a location between the seals.

43. A wellhead assembly as recited in claim 40 further comprising a passage through the elongate annular member providing access to an inner surface of the elongate annular member at location between the seals from a remote location on the outer surface of the elongate annular member.

44. A wellhead assembly as recited in claim 37 wherein the first tubular member is a tubing head.

45. A wellhead assembly as recited in claim 37 wherein an end of the elongate annular member is aligned with and faces an end of the production tubular member, wherein an inner surface diameter of said end of said elongate annular member is about equal to an inner surface diameter of said end of said production tubular member.

46. A wellhead assembly as recited in claim 37 wherein the first tubular member flange and the second flange are fastened together.

47. A wellhead assembly as recited in claim 37 further comprising:

at least one lower depression formed on the elongate annular member outer surface;

at least one upper depression formed on the elongate annular member outer surface above the lower depression;

a first plurality lock screws each radially threaded through the first tubular member flange and engaging the at least one lower depression; and

a second plurality of lock screws each radially threaded through the second flange and engaging the at least one upper depression and coupling the secondary flange to the generally elongate annular member, wherein the second flange is fastened to the first tubular member flange, and wherein the second flange is separate from the generally elongate annular member.

48. A wellhead assembly as recited in claim **37** further comprising a first plurality lock screws each radially threaded through one of said first tubular member flange and second flange and engaging the generally elongate annular member, wherein the other of said first tubular member flange and second flange is threaded on the generally elongate annular member, wherein the second flange is fastened to the first tubular member flange, and wherein the second flange is separate from the generally elongate annular member.

49. A wellhead assembly as recited in claim **48** wherein the lock screws are threaded through the first tubular member flange and wherein the second flange is threaded on the generally elongate annular member.

50. A wellhead assembly as recited in claim **37** further comprising a third flange extending from the generally elongate annular member spaced apart from the second flange.

51. A wellhead assembly as recited in claim **37** wherein the second flange is separate from the generally elongate annular member.

52. A wellhead assembly comprising:

a casing;

a first tubular member mounted over the casing;

a generally elongate annular member suspended in the first tubular member, said annular member having a first end portion extending above the first tubular member and a second end portion below the first end portion within the first tubular member;

a production tubular member aligned with the elongate annular member;

an annular nut coupled to the elongate annular member and surrounding an upper end of the first tubular member;

a locking ring coupled to the first tubular member and surrounded by the annular nut; and

a lock nut coupled to the annular nut at a location below the locking ring, wherein the lock nut has an inner surface having a diameter and wherein the locking ring has an outer surface having a diameter wherein the diameter of the of the lock nut inner surface is smaller than the diameter of the locking ring outer surface.

53. A wellhead assembly as recited in claim **52** further comprising a seal between the elongate annular member second end portion and the first tubular member.

54. A wellhead assembly as recited in claim **53** wherein the elongate annular member comprises a flange and wherein the annular nut is threaded on the elongate annular member flange.

55. A wellhead assembly as recited in claim **54** wherein an annular shoulder is formed on the elongate annular member flange accommodating an end portion of the first tubular member.

56. A wellhead assembly as recited in claim **54** wherein the lock nut is threaded to the inner surface of the annular nut.

57. A wellhead assembly as recited in claim **52** wherein the locking ring is a segmented ring having wickers on an inner surface interfacing with wickers formed on the first tubular member.

58. A wellhead assembly as recited in claim **57** further comprising a plurality of push screws radially threaded though the annular nut and engaging the outer surface of the locking ring for urging the locking ring against the first tubular member.

59. A wellhead assembly as recited in claim **52** wherein a portion of the first tubular member extends within a casing head coupled to the casing, the wellhead assembly further comprising:

an annular hanger suspended in the casing head, wherein an annular gap is defined between an outer surface of the hanger and an inner surface of the casing head, wherein said annular hanger comprises an inner surface having an upper inner surface section, an intermediate inner surface section below the upper inner surface section and a lower inner surface section below the intermediate inner surface section, wherein the intermediate inner surface section has a diameter smaller than the upper inner surface section, and wherein the lower inner surface section has a diameter smaller than the intermediate inner surface section, wherein the first tubular member comprises a lower section within the upper inner surface section of the annular hanger and wherein the second end portion of the elongate annular member extends to the intermediate inner surface section of the annular hanger sandwiching a portion of the first tubular member lower section between the outer surface of the elongate annular member and the upper inner surface of the annular hanger;

a first annular groove formed on the outer surface of the hanger and aligned with a second annular groove formed on the inner surface of the casing head when the hanger is suspended in the casing head, wherein the annular gap extends to said aligned grooves;

a spring loaded latch, wherein in cross-section the spring loaded latch comprises a first section extending opposite a second section and a third section extending from and transvesely to said first and second sections and fitted within the annular gap, wherein the latch can move from a first position where at least a portion of the first section of the latch is within the first annular groove and at least a portion of the second section of the latch is within the second annular groove to a second position where the first section of the latch is not within the first annular groove and at least a portion of the second section of the latch is within the second annular groove, wherein the latch is spring loaded to the second position; and

a top nut having an upper section and a lower section wherein the upper section comprises an outer surface having a diameter greater than an outer surface of the top nut lower section, and wherein the top nut is fitted within the annular gap causing the top nut lower section to engage the third section of the spring latch and move the spring latch to the first position.

60. A wellhead assembly as recited in claim **59** wherein the top nut upper section is threaded on the inner surface of casing head.

61. A wellhead assembly as recited in claim **60** wherein annular hanger is sandwiched between the top nut upper section and the elongate annular member.

62. A wellhead assembly as recited in claim **59** further comprising a seal between the elongate annular member second end portion and the intermediate inner surface section of the annular hanger.

63. A wellhead assembly as recited in claim **62** further comprising:

a second seal between the elongate annular member second end portion and the inner surface of the annular hanger; and an access path from an outer surface portion of the elongate annular member to an inner surface of the elongate annular member between the two seals.

64. A wellhead assembly as recited in claim 63 wherein the two seals are self energizing seals.

65. A wellhead assembly as recited in claim 52 wherein the first tubular member is a tubing head.

66. A wellhead assembly as recited in claim 52 wherein an end of the elongate annular member is aligned with and faces an end of the production tubular member, wherein an inner surface diameter of said end of said elongate annular member is about equal to an inner surface diameter of said end of said production tubular member.

67. A wellhead assembly comprising:

an annular head;

a generally elongate annular member suspended in the head, said annular member having an upper end portion extending above the head and a lower end portion within the head;

a production tubular member aligned with the elongate annular member;

an annular nut coupled to the elongate annular member and surrounding an upper end of the head;

a locking ring coupled to the head and surrounded by the annular nut; and

a lock nut coupled to the annular nut at a location below the locking ring, wherein the lock nut has an inner surface having a diameter and wherein the locking ring has an outer surface having a diameter wherein the diameter of the of the lock nut inner surface is smaller than the diameter of the locking ring outer surface.

68. A wellhead assembly as recited in claim 67 further comprising:

an annular hanger suspended in the head below the upper end of the head, wherein an annular gap is defined between an outer surface of the annular hanger and an inner surface of the head, wherein said annular hanger has an upper inner surface section and a lower inner surface section below the upper inner surface section, wherein the lower inner surface section has a diameter smaller than the upper inner surface section, and wherein the second end portion of the elongate annular member extends to the upper inner surface section of the annular hanger;

a first annular groove formed on the outer surface of the hanger and aligned with a second annular groove formed on the inner surface of the head when the hanger is suspended in the head, wherein the annular gap extends to said aligned grooves;

a spring loaded latch, wherein in cross-section the spring loaded latch comprises a first section extending opposite a second section and a third section extending from and transversely to said first and second sections and fitted within the annular gap, wherein the latch can move from a first position where at least a portion of the first section of the latch is within the first annular groove and at least a portion of the second section of the latch is within the second annular groove to a second position where the first section of the latch is not within the first annular groove and at least a portion of the second section of the latch is within the second annular groove, wherein the latch is spring loaded to the second position; and

a top nut having an first section and a second section extending below the first section wherein the first section comprises an outer surface having a diameter greater than an outer surface of the top nut second section, and wherein the top nut is fitted within the annular gap causing the top nut second section to engage the third section of the spring latch and move the spring latch to the first position.

69. A wellhead assembly as recited in claim 68 wherein the top nut further comprises third section extending above the first section and surrounding the elongate annular member, said top nut third section having an end surface providing a landing for other wellhead equipment.

70. A wellhead assembly as recited in claim 68 wherein the top nut first section is threaded on the outer surface of the hanger.

71. A wellhead assembly as recited in claim 70 wherein at least a portion of the annular hanger is sandwiched between the top nut first section and the elongate annular member.

72. A wellhead assembly as recited in claim 68 further comprising a seal between the second end portion of the elongate annular member and the annular hanger.

73. A wellhead assembly as recited in claim 72 further comprising:

a second seal between the elongate annular member second end portion and the annular hanger; and

an access path from an outer surface portion of the elongate annular member to an inner surface of the elongate annular member between the two seals.

74. A wellhead assembly as recited in claim 73 wherein the two seals are self energizing seals.

75. A wellhead assembly as recited in claim 67 wherein the head comprises a tubing head mounted over a casing head.

76. A wellhead assembly as recited in claim 67 wherein an end of the elongate annular member is aligned with and faces an end of the production tubular member, wherein an inner surface diameter of said end of said elongate annular member is about equal to an inner surface diameter of said end of said production tubular member.

77. A wellhead assembly comprising:

wellhead member;

a first tubular member mounted over the wellhead member;

a first flange extending from the first tubular member;

a generally elongate annular member suspended in the first tubular member;

a second flange extending from the generally elongate annular member;

a production tubular member aligned with the elongate annular member, wherein an end of the elongate annular member is aligned with the production tubular member, wherein an axial force acts on the generally elongate annular member and is reacted in both the first and second flanges; and

a plurality lock screws each radially threaded through one of said first flange and second flange and engaging the generally elongate annular member, wherein the other of said first flange and second flange is threaded on the generally elongate annular member, wherein the second flange is fastened to the first flange, and wherein the second flange is separate from the generally elongate annular member.

78. A wellhead assembly as recited in claim 77 wherein the inner surface diameter of said end of said elongate annular member is equal to the inner surface diameter of said end of said production tubular member.

79. A wellhead assembly as recited in claim 77 wherein the wellhead member is a casing head.

80. A wellhead assembly as recited in claim 77 wherein the elongate annular member is a frac mandrel.

81. A wellhead assembly as recited in claim 77 wherein the first and second flanges are fastened together.

82. A wellhead assembly as recited in claim 77 further comprising a third flange extending from the generally elongate annular member spaced apart from the second flange.

83. A wellhead assembly comprising:

a casing;

a first tubular member mounted over the casing;

a first tubular member flange extending from the first tubular member;

a generally elongate annular member suspended in the first tubular member, said annular member having a first end portion extending above the first tubular member and a second end portion below the first end portion within the first tubular member;

a secondary flange extending from the elongate annular member;

a plurality of fasteners fastening the secondary flange to the first tubular member flange;

a production tubular member aligned with the elongate annular member;

a first seal between the elongate annular member second end portion and the first tubular member;

at least one lower depression formed on the elongate annular member outer surface;

at least one upper depression formed on the elongate annular member outer surface above the lower depression;

a first plurality lock screws each radially threaded through the first tubular member flange and engaging the at least one lower depression;

a second plurality of lock screws each radially threaded through the secondary flange and engaging the at least one upper depression, wherein the secondary flange is fastened to the first tubular member flange, and wherein the secondary flange is separate from the elongate annular member; and

a second seal between the outer tapering surface portion of the elongate annular member and the tapering inner surface portion of the first tubular member, wherein the elongate annular member comprises an outer surface portion between the first and second ends and below the at least one lower depression, said outer surface portion tapering from a larger diameter to a smaller diameter in a direction toward the second end, wherein the first tubular member comprises a tapering inner surface portion complementary to the inner tapering outer surface portion of the elongate annular member, and wherein the outer tapering surface portion of the elongate annular member seats against the tapering inner surface portion of the first tubular member.

84. A wellhead assembly comprising:

a casing;

a first tubular member mounted over the casing;

a first tubular member flange extending from the first tubular member;

a generally elongate annular member suspended in the first tubular member, said annular member having a first end portion extending above the first tubular member and a second end portion below the first end portion within the first tubular member, said elongate annular member further comprising a threaded outer surface portion;

a secondary annular flange threaded on the elongate annular member threaded outer surface portion a secondary annular flange threaded on the elongate annular member threaded outer portion, wherein the secondary annular flange is separate from the elongate annular member;

a plurality of fasteners fastening the secondary flange to the first tubular member flange;

a production tubular member aligned with the elongate annular member;

a seal between the elongate annular member second end portion and the first tubular member; and

a plurality lock screws each radially threaded through the first tubular member flange and engaging at least a depression formed on the elongate annular member outer surface.

85. A wellhead assembly as recited in claim 84 wherein the elongate annular member comprises an intermediate flange, and wherein the elongate annular member threaded outer surface portion is formed on the outer surface of the intermediate flange.

86. A wellhead assembly comprising:

wellhead member;

a first tubular member mounted over the wellhead member;

a first flange extending from the first tubular member;

a generally elongate annular member suspended in the first tubular member;

a second flange extending from the generally elongate annular member;

a production tubular member aligned with the elongate annular member, wherein an end of the elongate annular member is aligned with the production tubular member, wherein an axial force acts on the generally elongate annular member and is reacted in both the first and second flanges;

at least one lower depression formed on the elongate annular member outer surface;

at least one upper depression formed on the elongate annular member outer surface above the lower depression;

a first plurality lock screws each radially threaded through the first flange and engaging the at least one lower depression; and

a second plurality of lock screws each radially threaded through the second flange and engaging the at least one upper depression and coupling the secondary flange to the generally elongate annular member, wherein the second flange is fastened to the first flange, and wherein the second flange is separate from the generally elongate annular member.

87. A wellhead assembly as recited in claim 86 wherein the lock screws are threaded through the first flange and wherein the second flange is threaded on the generally elongate annular member.

88. A wellhead assembly as recited in claim 86 further comprising a third flange extending from the generally elongate annular member spaced apart from the second flange.

* * * * *

EXHIBIT B

CAMERON

EnCana Oil and Gas Inc.

North Piceance

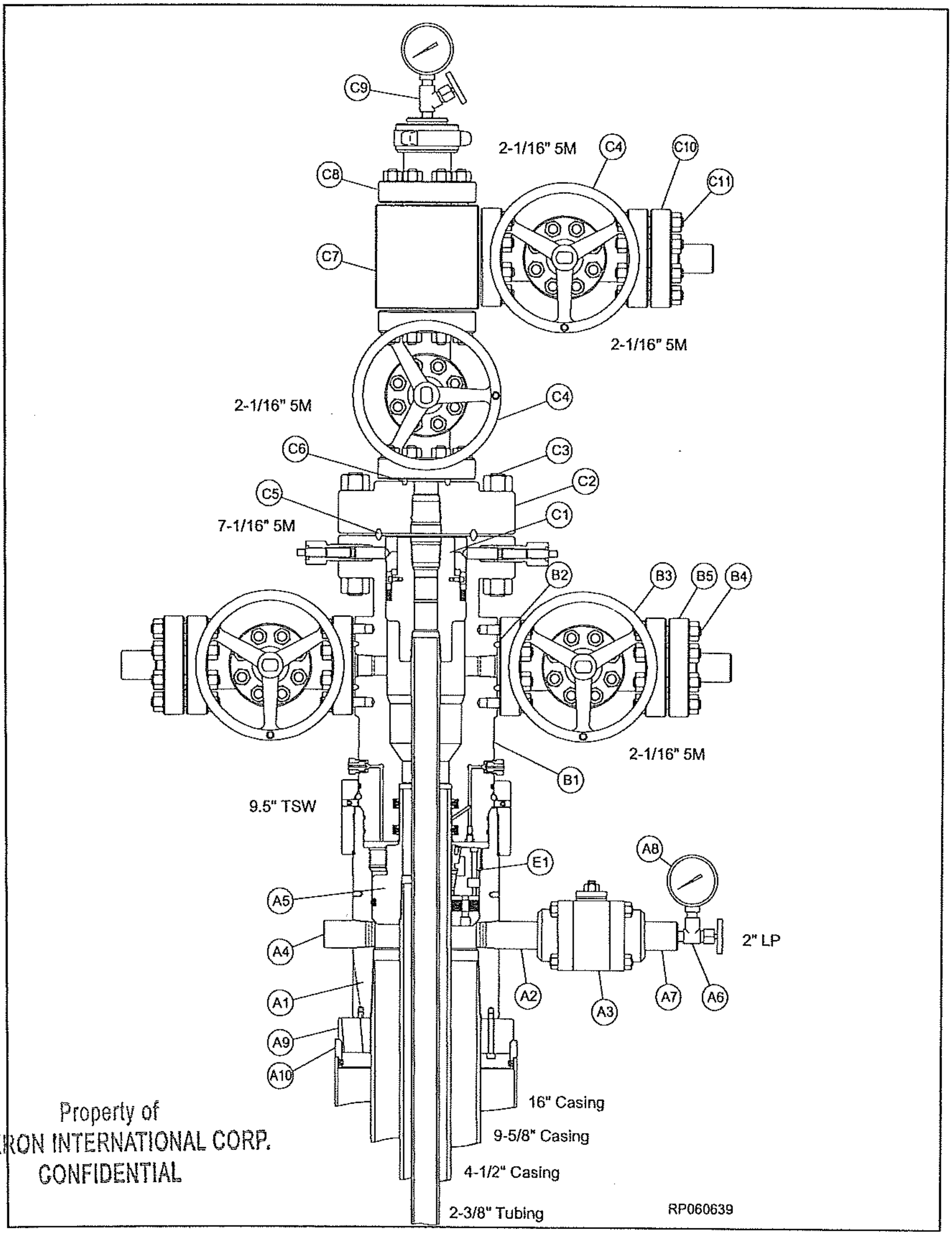
TSW '9.5' Installation Procedure

Surface Systems Publication RP1116 Rev1
June 5, 2006

This document alone does not qualify an individual to Install/Run the Equipment. This document is created and provided as a reference for Qualified Cameron Service Personnel and does not cover all scenarios that may occur.

Table of Contents

System Drawing



RP1116 **Rev1** Page 4	**TSW '9.5'** 16" x 9-5/8" X 4-1/2" x 2-3/8" 5M Houston, Texas	CAMERON

Bill of Materials

CASING HEAD ASSEMBLY

Item	Qty	Description
A1	1	Csg Hd, 9.5" TSW w/ IC bowl x 9-5/8" casing thrd btm w/ two 2" lpo's Part# 2253695-01-01
A2	1	Nipple, 2" lp x 6" lg Part# 021013-12
A3	1	Ball Valve, manual, 2" lp Part# 2191252-01
A4	1	Bull Plug, 2" lp x 3-3/4" lg Part# 006994-04
A5	1	Casing Hanger, TSW, 9.5" x 4-1/2" Part# 2253732-01-01
A6	1	Needle valve, 1/2" NPT 10M Part# 006818-23
A7	1	Bull Plug 2" lp x 1/2" NPT Part# 007481-01
A8	1	Pressure gauge, 0-3M Part# Y52100-00300691
A9	1	Landing Ring for 9.5 TSW to land in 16" casing Part# 2254869-01-01
A10	1	Load Ring for 16" Casing Part# 2247706-02-01

TUBING SPOOL ASSEMBLY

Item	Qty	Description
B1	1	Tubing Spool, C, 7-1/16" 5M x 9.5" TSW, w/ two 2-1/16" 5M sso's and double T seal btm prep for 4-1/2" casing Part# 2253841-01-01
B2	4	Ring Gasket, R-24, PSL4 Part# 702001-24-02
B3	2	Gate Valve, manual, NW, 2-1/16" 5M, flanged ends Part# 9C-10317037
B4	16	Stud w/ two nuts, 7/8" x 6" lg Part# Y51201-20220201
B5	2	Comp. Flg, 2-1/16" 5M x 2" lp Part# 142362-01-03-02

CHRISTMAS TREE ASSEMBLY

Item	Qty	Description
C1	1	Tubing Hgr, Type TC-1A-BPV, 7" Nom. x 2-3/8" Tubing, 2" Type "H" BPV Prep Part# 2736260-01
C2	1	Adapter Hanger Flg C2P, 7-1/16" 5M x 2-1/16" 5M, 2-3/8" Mod. Tubing thd Part# 2133883-01-01
C3	12	Stud w/two Nuts 1-3/8" x 10-3/4" lg Part# Y51201-20921701
C4	2	Gate Valve, manual, NW 2-1/16" 5M flanged ends Part# 9C-10317037
C5	1	Ring Gasket R-46 PSL4 Part# 702001-46-02
C6	4	Ring Gasket R-24 PSL4 Part# 702001-24-02
C7	1	Tee, all studded, 2-1/16" 5M x 2-1/16" 5M x 2-1/16" 5M Part# 257564-01-03-01
C8	1	Tree Cap, 2-1/16" 5M X 2-3/8" tubing thd Part# 271029-07-01
C9	1	Needle valve, 1/2" NPT 10M Part# 007482-40
C10	1	Companion Flange, 2-1/16" 5M x 2" LP Part# 142362-01-03-02
C11	8	Stud w/two nuts, 7/8" x 6" lg Part# Y51201-20220201

FRAC EQUIPMENT

Item	Qty	Description
D1	1	Frac Mandrel, 4-1/16" 10M flanged top with 7-1/16" 5M spinner flange Part# 2216158-01
D2	1	Gate Valve, manual, FLS-R, 4-1/16" 10M, flanged

EMERGENCY

Item	Qty	Description
E1	1	Casing Hanger, IC-2, 9.5" x 4-1/2" Part# 2253822-01-01

RECOMMENDED SERVICE TOOLS

Item	Qty	Description
ST1	1	Riser Adptr for 16" casing w/ double WQ seals Part# 2222933-04
ST2	1	Casing Head Running Tool, 9-5/8" casing thread box top x 9.875" running thread Part# 2253824-01
ST3	1	BOP Adapter, 11" 5M flg top x threaded ring bottom Part# 2253837-01-01
ST4	1	Combo Tool, 9.5" x 4-1/2" IF box top and btm Part# 2253775-01
ST5	1	Wear Bushing, IC, 9.5" x 8.91" bore x 24.50" long w/ j-slot top Part# 2253748-01-01
ST6	1	Casing Hanger Running Tool; 9.5", 4-1/2" casing box top x 7" running thread bottom Part# 2236167-05

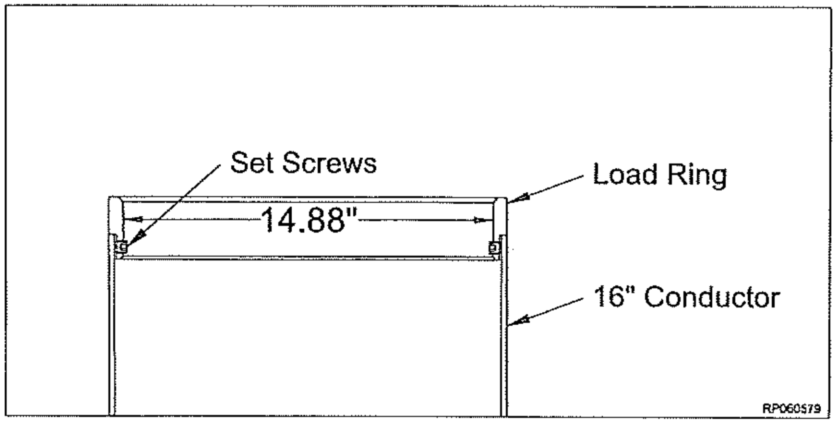
Stage 1 — 16" Casing

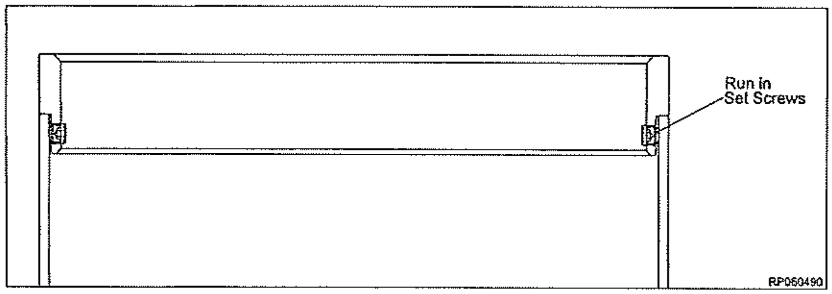
Install the Load Ring

1. Run the 16" Conductor as required.
2. Cut the 16" Conductor at the required height to allow for proper installation of the Load Ring and Drilling Adapter.

NOTE: The cut on the 16" conductor should be square and only a slight bevel should be ground on the OD edge, no larger than 1/8" x 45 deg, to allow it to pass the WQ seals.

3. Examine the ***Load Ring (A10)***. Verify the following:
   - bore is clean and free of debris.
   - set screws are properly installed and undamaged.
4. Orient the Load ring with set screws down.
5. Carefully land the load ring onto the 16" conductor.
6. Run in the load ring set screws inside the 16" conductor to install the Load Ring.
7. Cement the casing as required.





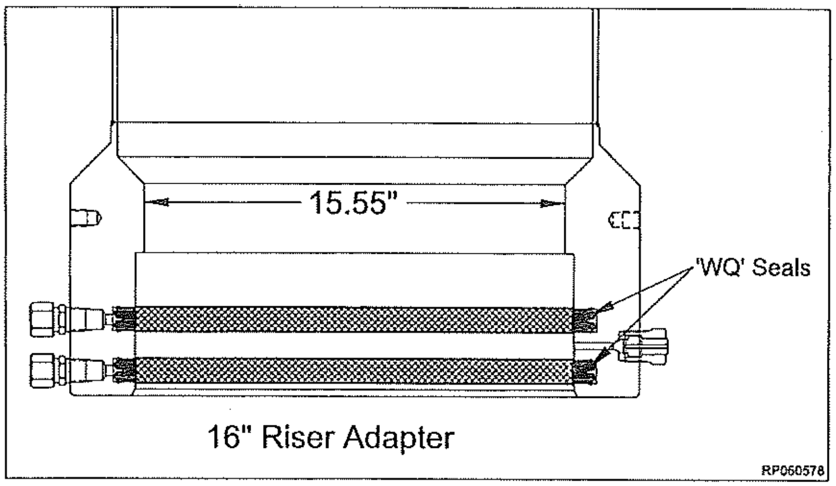
Stage 1 — 16" Casing

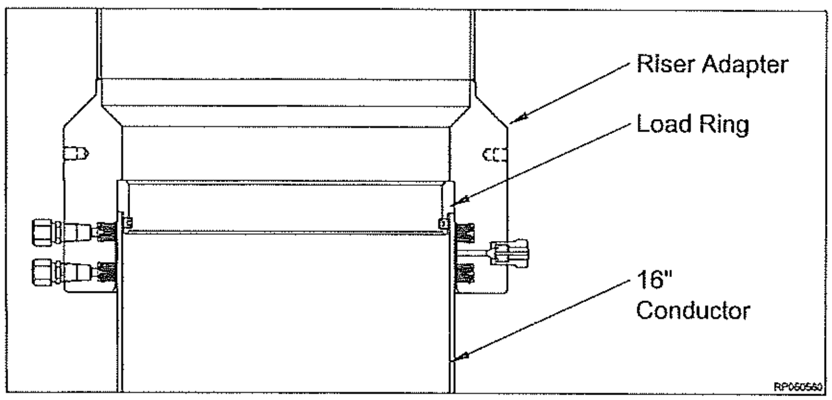
Install the Riser Adapter

1. Examine the ***Riser Adapter (Item ST1).*** Verify the following:
   - bore is clean and free of debris
   - WQ seals are properly installed and undamaged
2. Orient the Adapter as illustrated.
3. Wipe the ID of the WQ seals with a light coat of oil.

WARNING: Excessive oil may prevent a positive seal from forming.

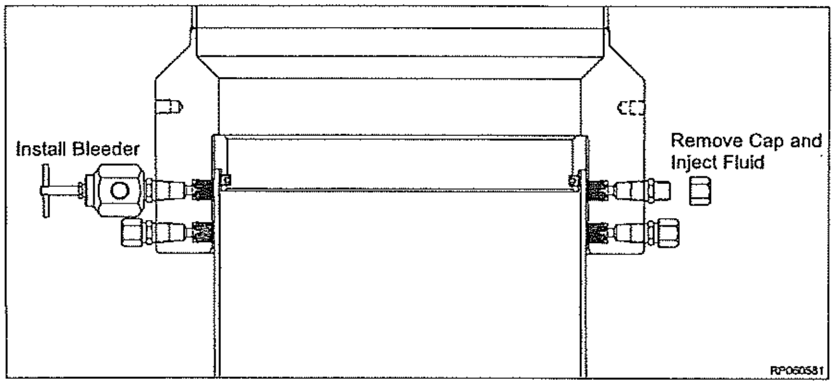
4. Carefully slide the Adapter over the 16" conductor until it lands on the ***Load Ring (A10)***.





Stage 1 — 16" Casing

Energize the WQ Seals

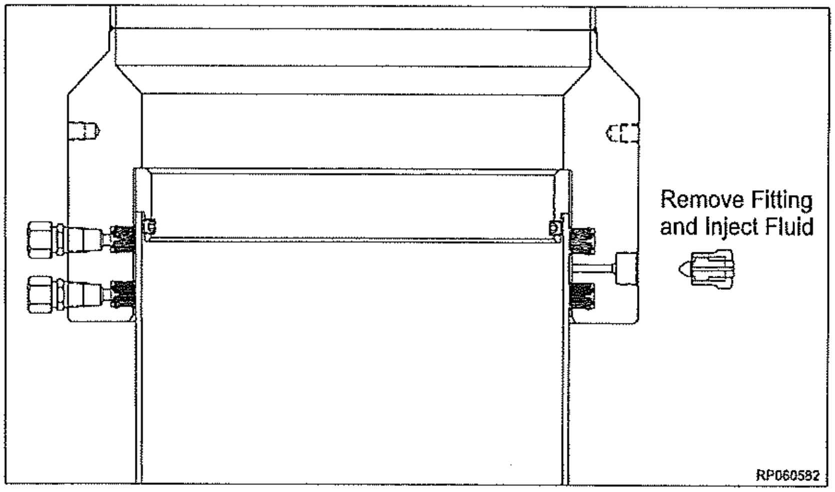


1. Locate the ports on the Adapter for energizing the upper WQ seal and remove the dust cap from each fitting.
2. Install a grease pump to one fitting and remove the opposite fitting.
3. Inject grease into the seal until a continuous stream flows from opposite port.
4. Reinstall the fitting and continue to inject fluid to ***80% of the casing collapse maximum.***
5. Hold and monitor the injection pressure until it has stabilized.
6. Once the pressure has stabilized, carefully bleed off the pump pressure.
7. Remove the grease pump and replace the dust cap.
8. Repeat this procedure for the lower WQ seal.

Stage 1 — 16" Casing

Test Between the Seals

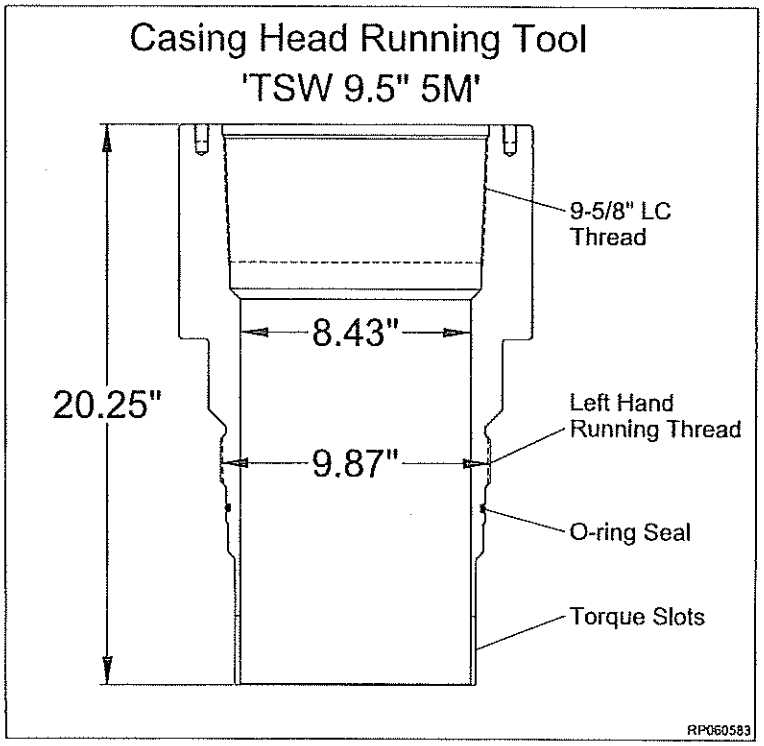
1. Locate the port for testing between the seals and remove the fitting.
2. Install a test pump and inject test fluid to **80% of casing collapse maximum.**
3. Hold and monitor the test pressure for 15 minutes or as required by the drilling supervisor.
4. Once a satisfactory test is achieved, carefully bleed off the test pressure and remove the test pump.
5. Reinstall the fitting.

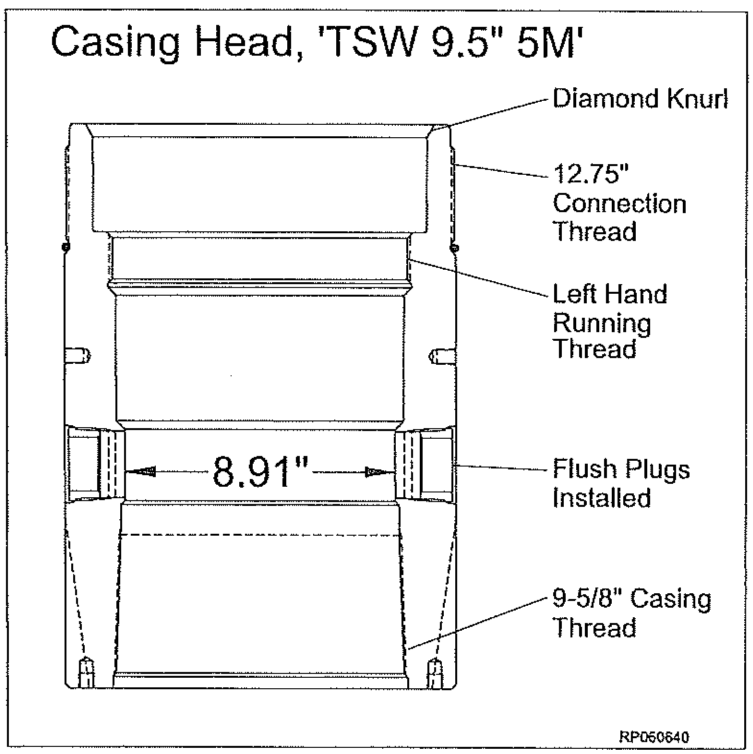


Stage 2 — 9-5/8" Casing

Install the Casing Head

1. Run the 9-5/8" casing and space out as required.
2. Examine the ***Casing Head Running Tool (Item ST2).*** Verify the following:
   - bore is clean and free of debris
   - all threads are clean and undamaged
   - o-ring seal is clean and undamaged
3. Make up a landing joint to the top of the Tool.
4. Examine the ***Casing Head (Item A1).*** Verify the following:
   - bore is clean and free of debris
   - casing hanger seal area is clean and undamaged
   - all threads are clean and undamaged
   - all peripheral equipment is intact and undamaged
5. Remove the outlet equipment of the Casing Head and install 2" line pipe flush fitting plugs into the outlets.





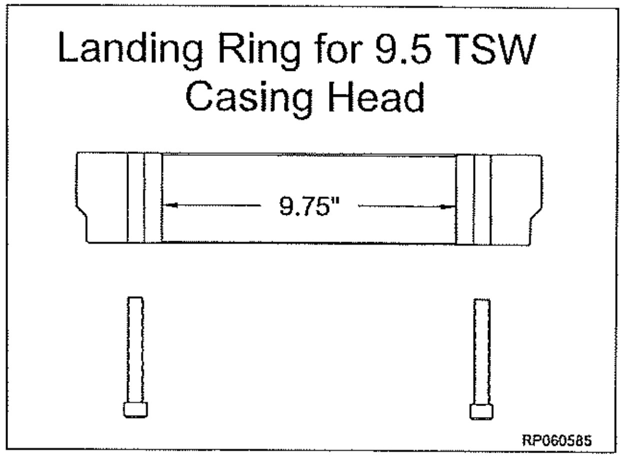
Stage 2 — 9-5/8" Casing

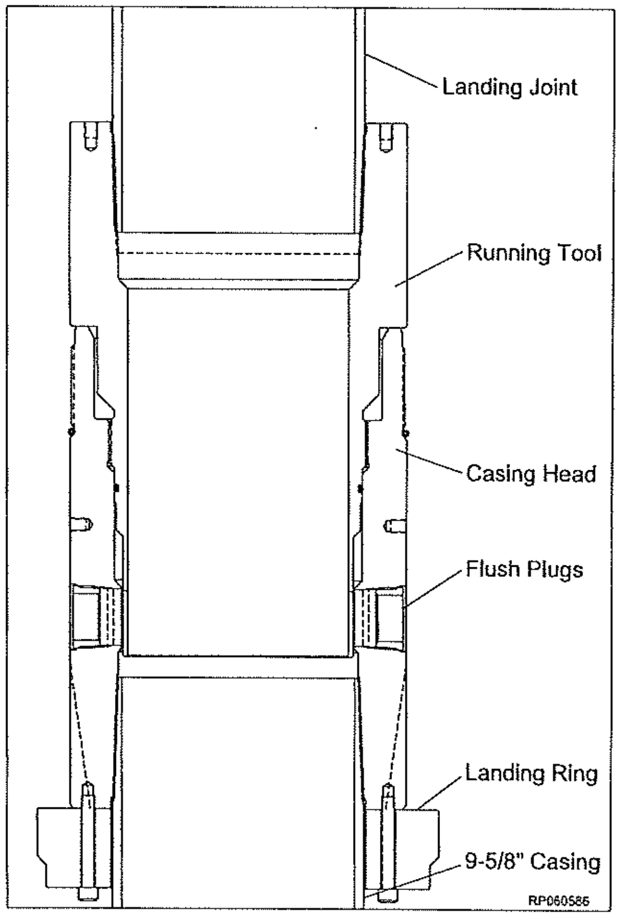
6. Examine the ***Landing Ring (A9).***
7. Install Landing Ring to bottom of Casing Head.
8. Wipe the o-ring of the Tool and the running threads of both Casing Head and Tool with a light coat of oil.

WARNING: Excessive oil may prevent a positive seal from forming.

---

9. Lower the tool into the casing head until the running threads make contact. Turn the tool first to the right until thread jump is felt. Then make up the connection with left hand rotation to a positive stop.
10. Carefully lower the Head onto the 9-5/8" casing and make up to the thread manufacturers recommended optimum torque per rig procedure.





Stage 2 — 9-5/8" Casing

11. Release the casing from the floor slips, and carefully lower the Casing Head through the diverter and Drilling Adapter.

NOTE: Protect the OD threads on the Casing Head during handling.

12. Carefully land the Landing Ring ***(A9)*** onto the Load Ring ***(A10)*** and slack off all weight.

13. Cement the casing as required.

NOTE: Cement returns may be taken through the flow by slots in the Landing Ring.

14. Rotate the landing joint to the right to remove the Running Tool from the Casing Head.

15. Retrieve the Tool and remove from the landing joint.

16. Clean, grease and store the Tool as required.

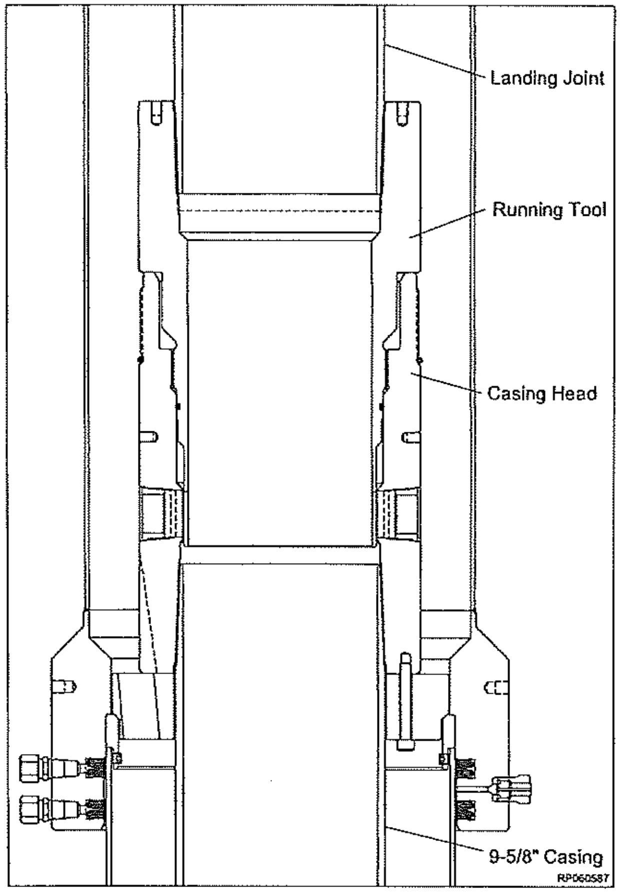
17. Install a bleeder tool to the upper then the lower fittings of the Riser Adapter and vent all trapped pressure.

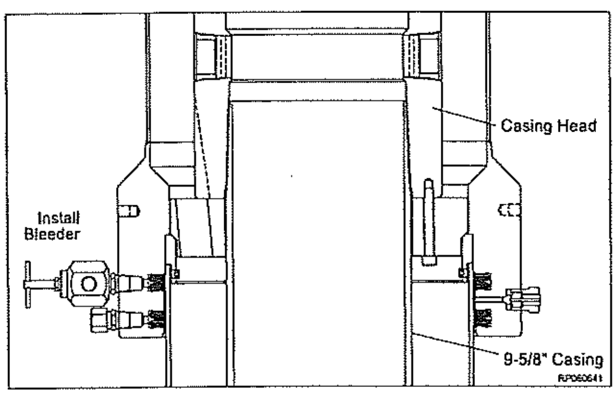
18. The Drilling Adapter may now be stripped over the Casing Head.

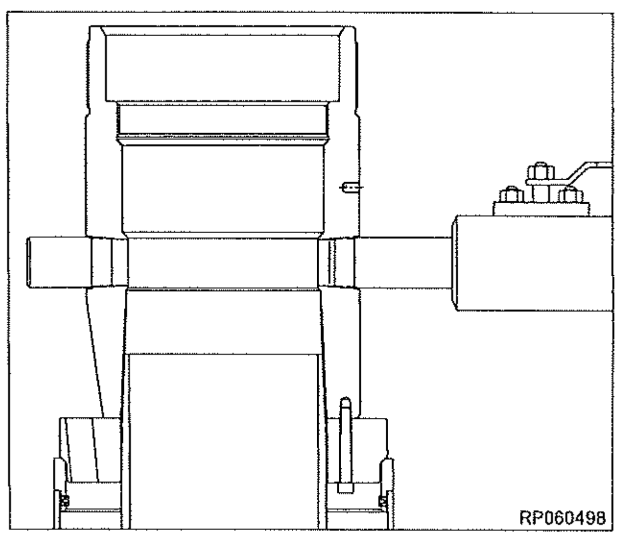
19. Once the Drilling Adapter is removed, remove the four fittings for injecting fluid into the WQ seals and replace them with 1/2" pipe plugs.

20. Clean, grease and store the Adapter as required.

21. Remove flush plugs and install outlet equipment.







Stage 2 — 9-5/8" Casing

Install the Bop Adapter

NOTE: The BOP Adapter may be made up to the BOP offline in an effort to save time.

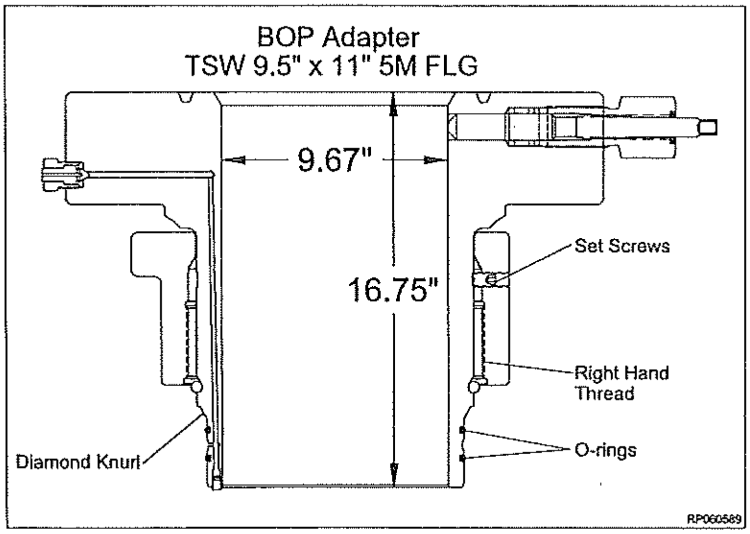
1. Examine the ***BOP Adapter (Item ST3).*** Verify the following:
   - bore is clean and free of debris
   - all threads and seal areas are clean and undamaged
   - o-rings are properly installed and undamaged
   - threaded ring is properly retained in the highest position by two set screws
2. Orient the BOP Adapter with the flange up.
3. Wipe the o-rings and threads of the BOP Adapter with a light coat of oil.

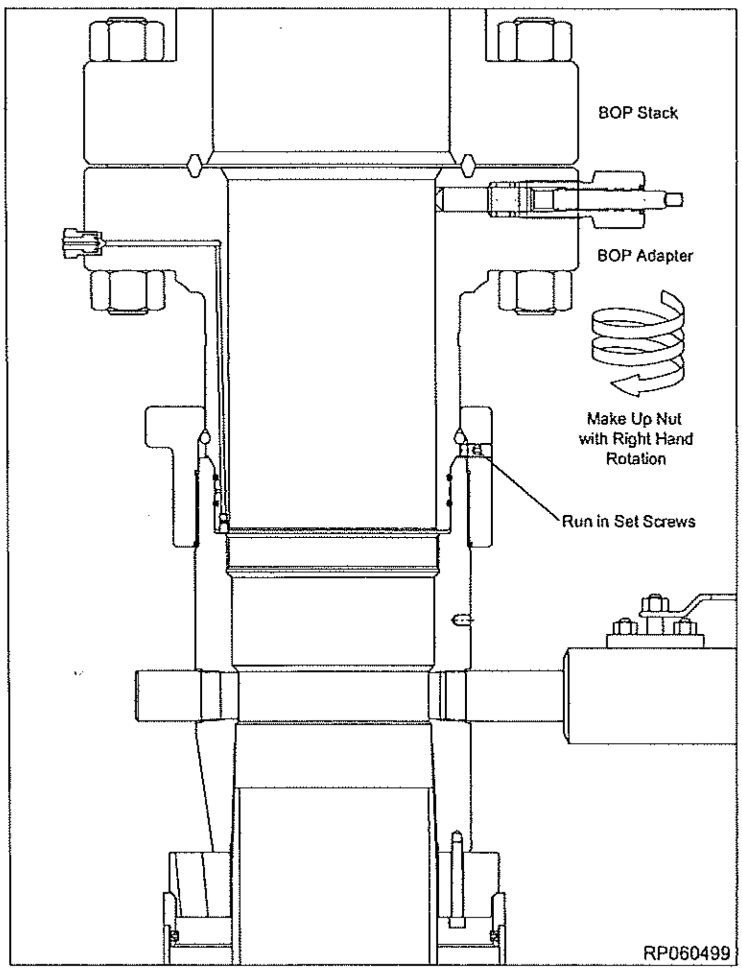
WARNING: Excessive oil may prevent a positive seal from forming.

4. Carefully lower the Adapter onto the Casing Head.
5. Release the setscrews and make up the threaded ring to the external mating threads of the Head with right hand rotation to a positive stop. Should be approximately 11 turns.

WARNING: Be sure setscrews are run out flush with the OD of the threaded ring or they may hit the top of the casing head and prevent proper thread engagement.

6. Retighten the set screws.

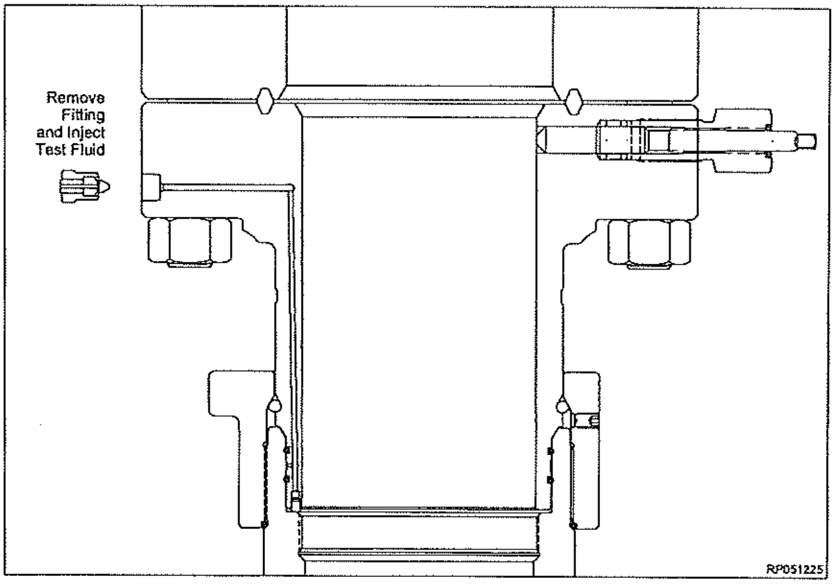




Stage 2 — 9-5/8" Casing

Test the Connection

1. Locate the port on the flange of the BOP Adapter labeled TEST and remove the 9/16" autoclave from the port.
2. Install a test pump and gauge to the fitting for testing the connection.
3. Pump test fluid in the void to ***5000 psi.***
4. Hold and monitor test pressure for fifteen minutes or as required by the Drilling Supervisor.
5. Once a satisfactory test has been achieved, carefully bleed off the test pressure and remove the test pump.
6. Replace the fitting.



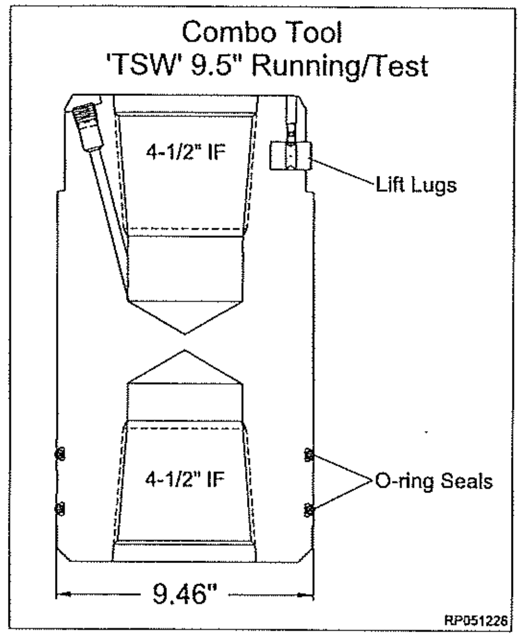
Stage 3 — 4-1/2" Casing

Testing the BOP Stack

Immediately after making up the BOP stack and periodically during the drilling of the hole for the next casing string, the BOP stack (connections and rams) must be tested.

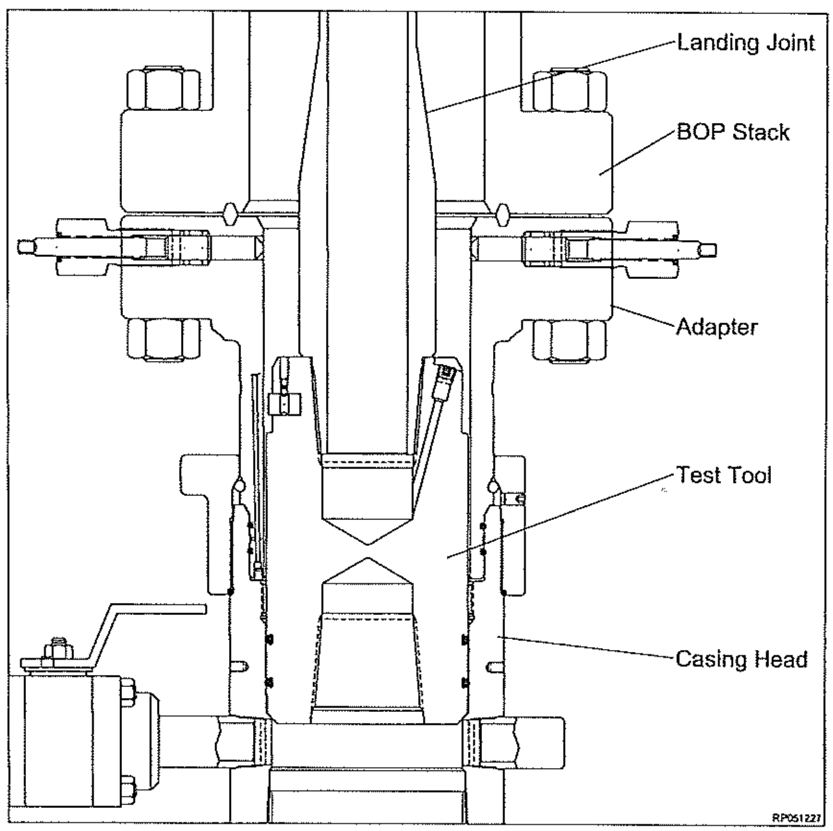
1. Examine the ***Combination Tool (Item ST4).*** Verify the following:
   - o-ring seals are in place and undamaged
   - 1/2" pipe plug is installed, if required
   - all threads are clean and undamaged
2. Orient the Tool with elastomer down and lift lugs up.
3. Make up a joint of drill pipe to the top of the Tool.
4. Wipe the o-ring seals of the Tool with a coat of light oil.

WARNING: Ensure the **elastomer is down** and the **lift lugs are up.**



5. Open the annulus valve of the Head, and drain fluid to land the Tester.
6. Slowly lower the Tool through the BOP until it lands on the load shoulder in the Casing head
7. Close the BOP rams on the drill pipe and test to ***5000 psi maximum.***
8. Monitor the annulus valve for signs of pressure.
9. After a satisfactory test is achieved, release pressure, close the outlet valve and open the rams.
10. Remove as much fluid from the BOP stack as possible.
11. Retrieve the Test Plug slowly to avoid damage to the seal.

NOTE: It may be necessary to open the annulus valve when starting to retrieve the Test Plug to relieve any vacuum that may occur.

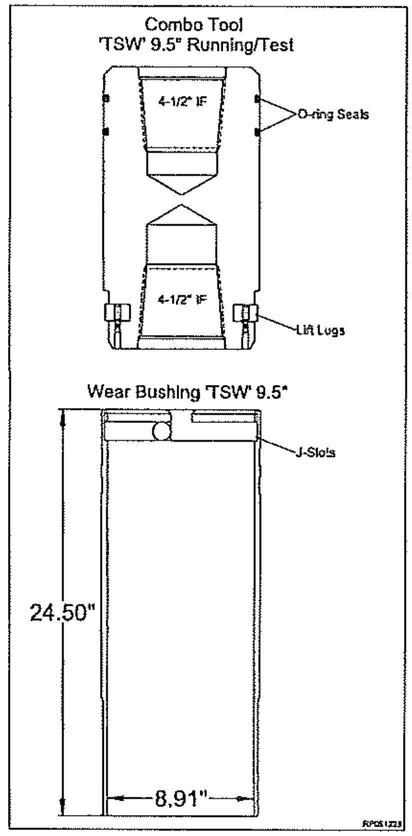


Stage 3 — 4-1/2" Casing

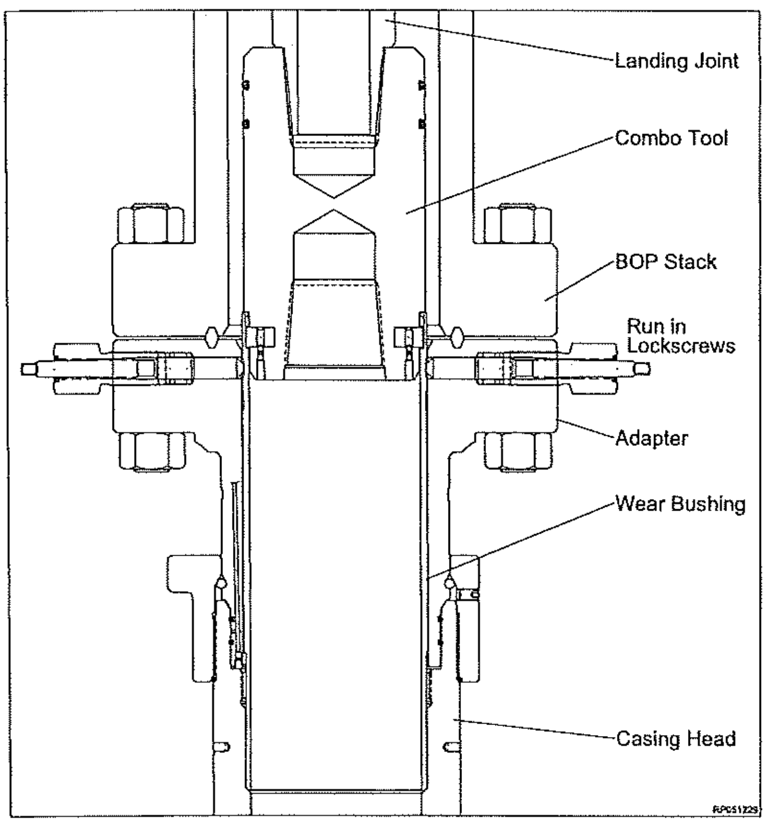
WARNING: Always use a Wear Bushing while drilling to protect the load shoulder and seal area from damage by the drill bit or rotating drill pipe. The Wear Bushing **must be retrieved** prior to running the casing.

Run the Wear Bushing Before Drilling

1. Examine the ***Combination Tool (Item ST4).*** Verify the following:
   - o-ring seals are in place and undamaged
   - lift lugs are intact and undamaged
   - all threads are clean and undamaged
2. Orient the Tool with the lift lugs down and the elastomer up.
3. Make up a joint of drill pipe to the top of the Tool.
4. Examine the ***Wear Bushing (Item ST5).*** Verify the following:
   - bore is clean and free of debris
   - stop lugs are properly installed
   - J-slots are clean and free of debris



WARNING: Make sure the **lift lugs are down** and the **elastomer is up** when latching into the Wear Bushing.



5. Ensure the lockscrews of the Drilling Adapter are fully retracted from the bore.
6. Lower the Tool into the Wear Bushing and rotate the drill pipe 1/4 turn clockwise.
7. Slowly lower the Test Plug/Wear Bushing Assembly through the BOP until it lands on the load shoulder of the Casing Head.
8. Run in two lockscrews of the Drilling Adapter 180 degrees apart to approximately 50 ft lbs.

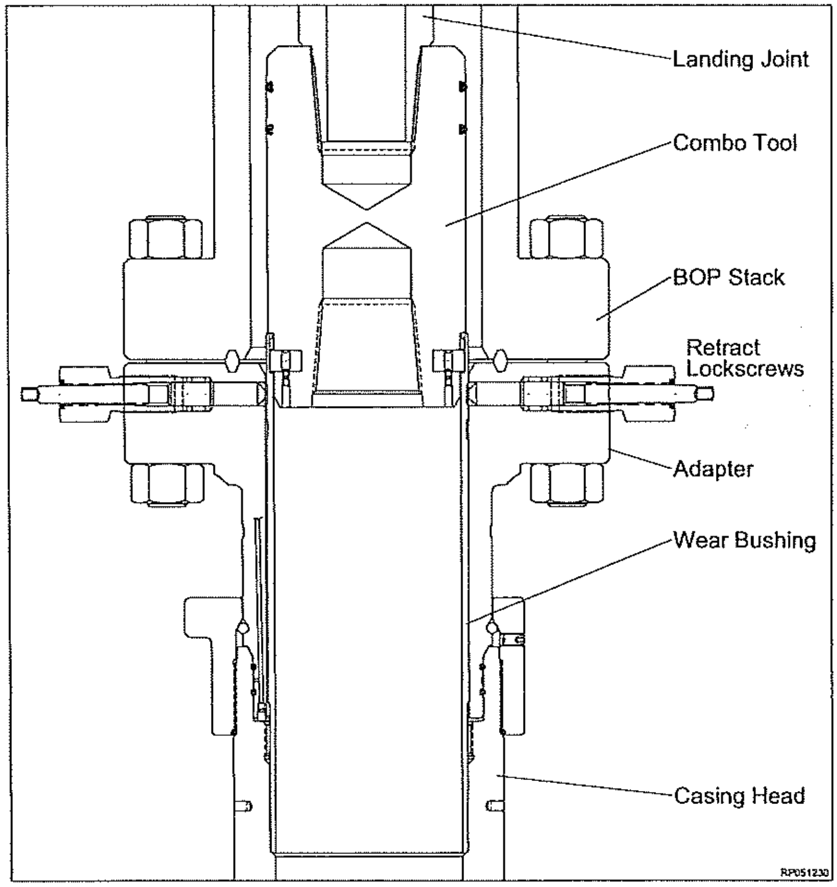
NOTE: Tighten lockscrews in alternating fashion until contact is made with Wear Bushing OD.

9. Disengage the Tool from the Wear Bushing by rotating the drill pipe counterclockwise 1/4 turn and lifting straight up.
10. Drill as required.

Stage 3 — 4-1/2" Casing

Retrieve the Wear Bushing After Drilling

1. Make up the Tool to the drill pipe with the lift lugs down and the elastomer up.
2. Slowly lower the Tool into the Wear Bushing.
3. Rotate the Tool clockwise until the drill pipe drops approximately 2". This indicates the lugs have aligned with the Wear Bushing slots.
4. Rotate clockwise 1/4 turn to fully engage the lugs in the Wear Bushing.
5. Retract the lockscrews of the Drilling Adapter from the bore.
6. Slowly retrieve the Wear Bushing and remove it and the Tool from the drill string.
7. Clean, grease and store the Tool and Wear Bushing.

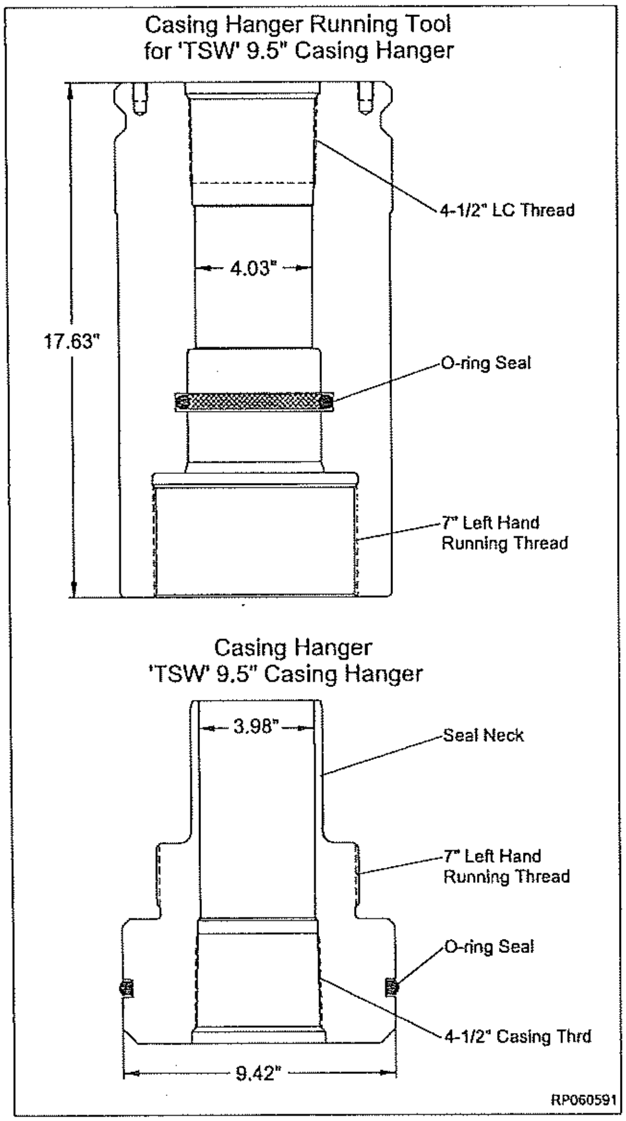


Stage 3 — 4-1/2" Casing

Hang Off the Casing

NOTE: In the event the 4-1/2" casing should become stuck, and the mandrel hanger is unable to be used, refer to the emergency 4-1/2" casing in the back of this procedure.

1. Run the 4-1/2" casing and space out appropriately.
2. Hang off the last joint of casing to be run in the floor slips at height that will enable easy handling and make up of the hanger and landing joint.
3. Examine the ***Running Tool (Item ST6).*** Verify the following:
   - bore is clean and free of debris
   - all threads are clean and undamaged
   - internal seal is properly installed and undamaged
4. Orient the Running Tool with the stub acme running threads down.
5. Examine the ***Casing Hanger (Item A5).*** Verify the following:
   - bore is clean and free of debris
   - all threads are clean and undamaged
   - OD seal is properly installed and undamaged
6. Orient the Hanger with the OD seal down.



Stage 3 — 4-1/2" Casing

7. Ensure the lockscrews of the Drilling Adapter are fully retracted from the bore.
8. Lift the Hanger above the casing hung off in the floor.
9. Lower the hanger onto the casing until the threads make contact.

NOTE: When making up the Hanger to the casing do not use the seal neck area for back up.

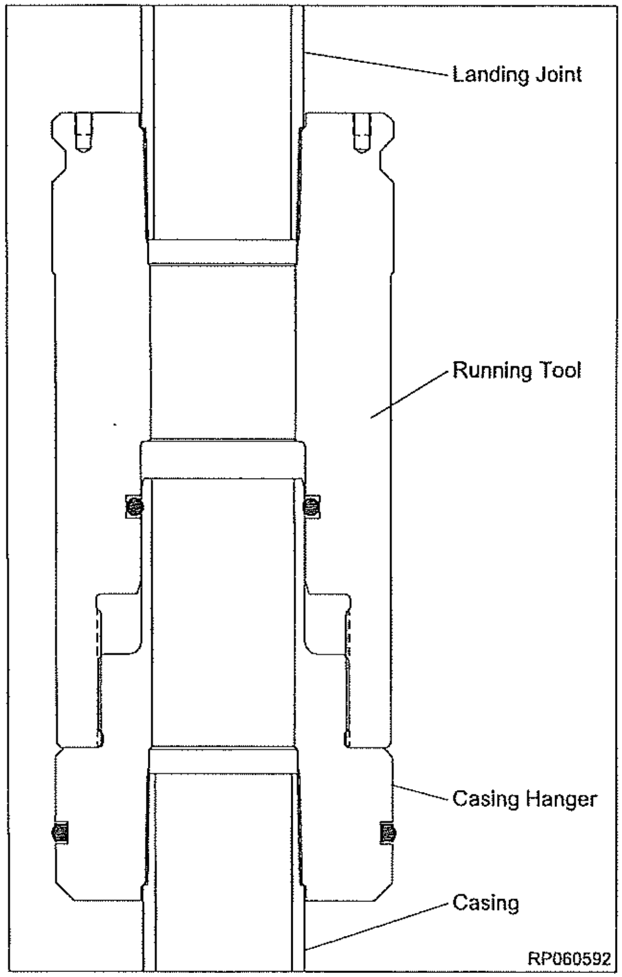
10. While balancing the weight, rotate the assembly to the left until the thread 'jump' can be felt then to the right to the thread manufacturer's recommended optimum torque.
11. Make up a joint of casing to the top of the Running Tool.
12. Wipe the running threads of both the Tool and the Hanger and also the seal of the Tool with a light oil or grease.

WARNING: Excessive oil or grease may prevent a positive seal from forming.

13. Lift and suspend the Tool over the Hanger.
14. Lower the Tool onto the Hanger until the mating threads make contact.
15. While balancing the weight, rotate the Tool to the right until the thread 'jump' can be felt then to the left to a positive stop. Approximately 7 turns.

WARNING: DO NOT Torque the connection.

16. Back the tool off 1/2 turn to the right to keep the threads from binding up.



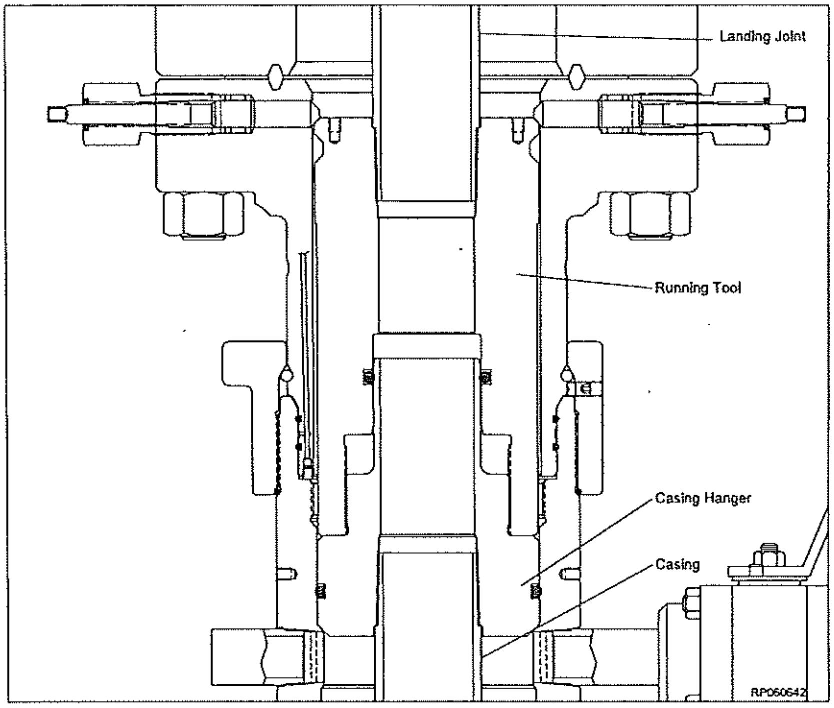
Stage 3 — 4-1/2" Casing

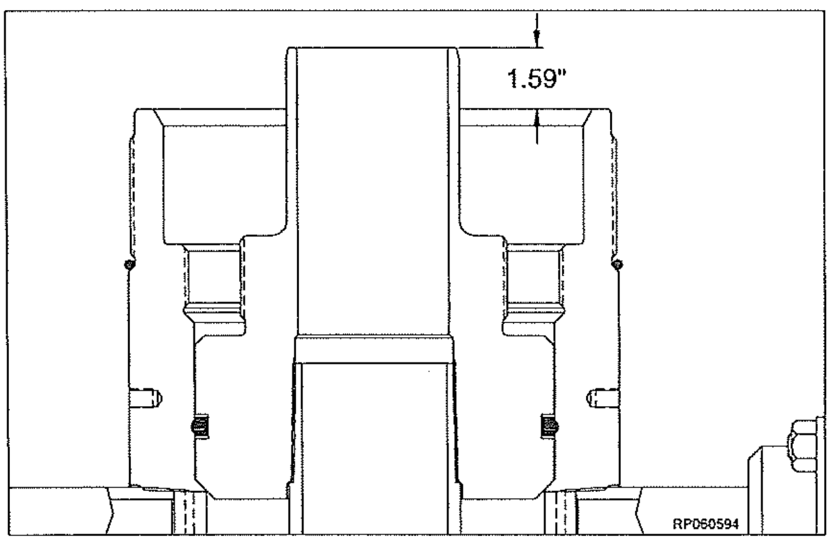
17. Wipe the OD seal of the Hanger with a light oil or grease.

WARNING: Excessive oil or grease may prevent a positive seal from forming.

18. Open the side outlet valve on the casing head, release the casing from the floor slips and lower it into the well, tallying the casing as it is lowered, until the Hanger lands on the load shoulder of the Casing Head.
19. Run in the lockscrews of the Drilling Adapter to approximately 50 ft lbs.
20. Close the BOP rams on the drill pipe and test to 5,000 psi maximum.
21. Monitor the open valve for signs of pressure.
22. After a satisfactory test, release pressure, close the annulus valve and open the BOP rams.
23. Remove as much fluid from the BOP stack as possible.
24. Cement the casing as required. Taking returns through the side outlet in the casing head.
25. Fully retract the lockscrews.
26. Release the Tool from the Hanger by rotating the Tool to the right.
27. Retrieve the Tool to the rig floor.
28. Clean, grease and store the Tool.
29. With the well safe and under control remove the BOP stack at the BOP Adapter.

NOTE: Be sure to disengage the setscrews flush w/the OD of the hold down ring.

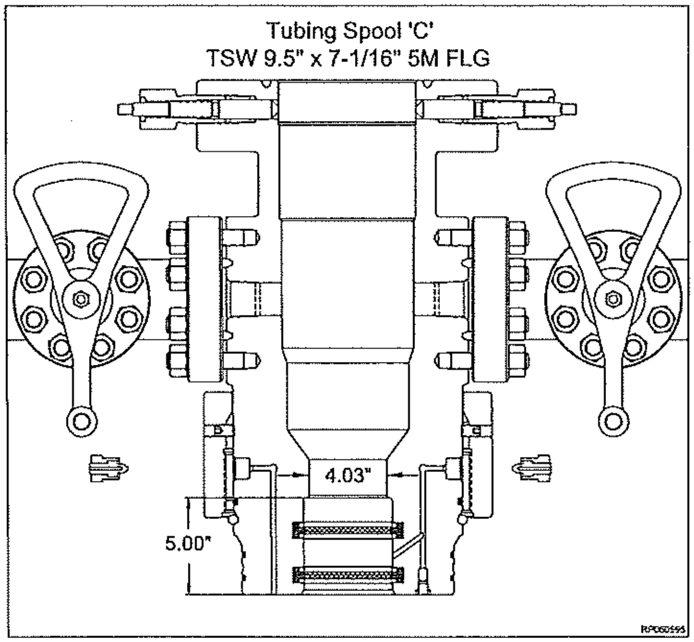




Stage 3 — 4-1/2" Casing

Install the Tubing Spool

1. Examine the ***Tubing Spool (Item B1).*** Verify the following:
   - bore is clean and free of debris
   - T seals and o-rings are properly installed and undamaged
   - ring grooves and seal areas are clean and undamaged
   - peripheral equipment is intact and undamaged
   - all threads are clean and undamaged
   - Autoclave ports are removed to allow the threaded ring to be held high, and to prevent Hydraulic Lock.
   - threaded ring is properly retained in the highest position by two set screws



NOTE: To Minimize Time needed to Pressure Test Connection, pre-fill the void area with test fluid up to the top of the Running Thread of the Casing Hanger.

2. Orient the Spool with the Hold down ring down.
3. Wipe the T seals, o-rings, the OD of the casing hanger, and threads of the threaded ring with light oil.

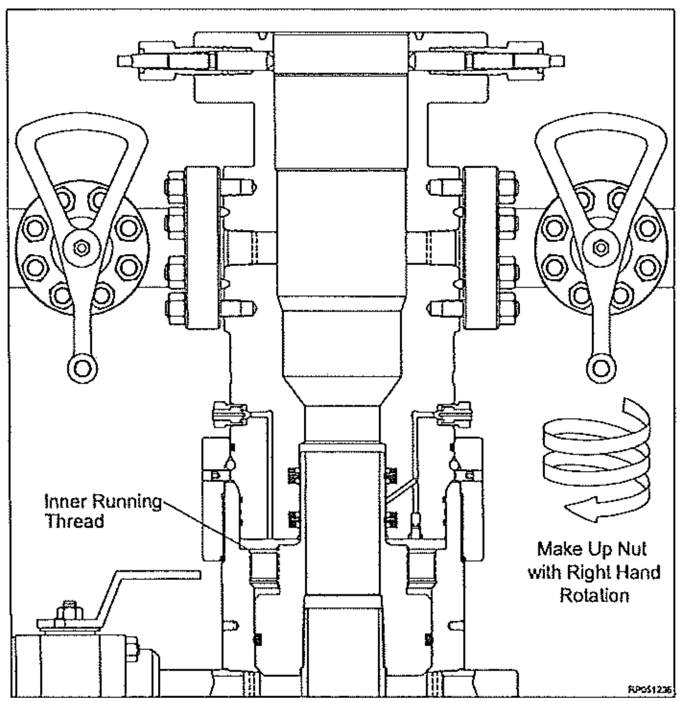
WARNING: Excessive oil may prevent a positive seal from forming.

4. Lift and suspend the Spool over the Casing hanger, ensuring the threaded ring is held high.
5. Carefully lower the Spool over the casing hanger aligning the bottom of the Spool with the bore of the Casing Head.

WARNING: Do Not damage the T seals or o-rings or their sealing ability will be impaired.

6. Once the Tubing Spool is properly landed, release the setscrews and make up the threaded ring to the OD threads of the Head with right hand rotation to approximately 300 ft lbs.

WARNING: Be sure setscrews are run out flush with the OD of the threaded ring or they may hit the top of the casing head and prevent proper thread engagement.



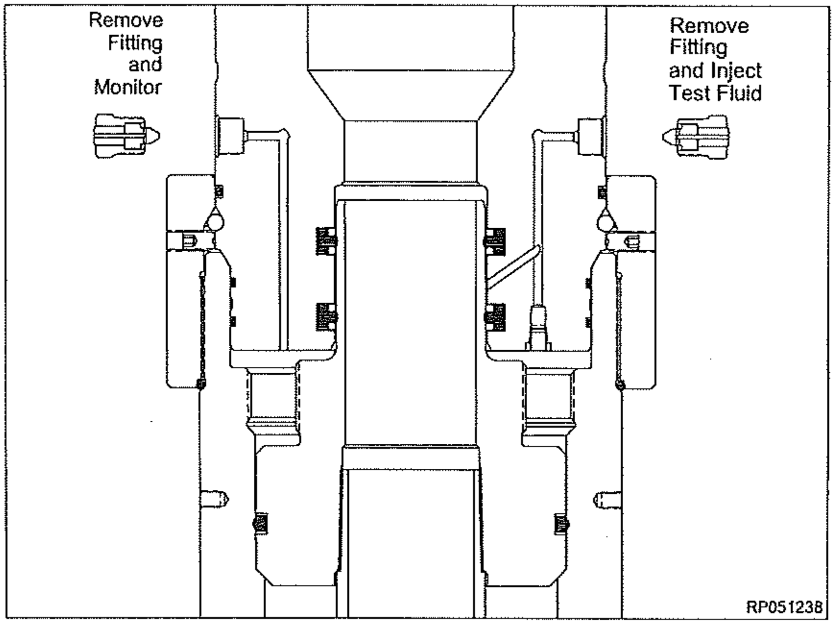
7. Retighten the set screws.
8. Reinstall autoclave fittings.

Stage 3 — 4-1/2" Casing

Test Between the Seals

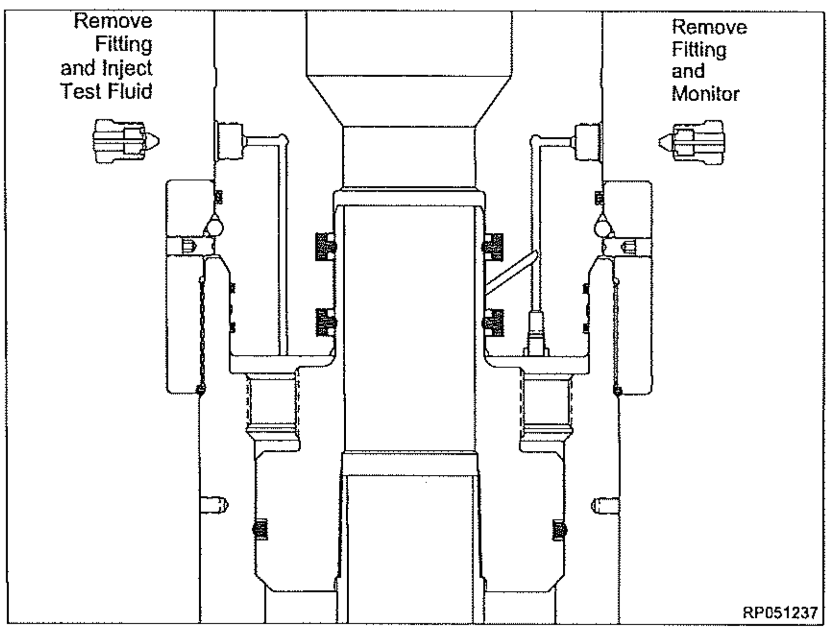
1. Locate the ports on the Spool and remove the fittings.
2. Install a test pump to the test port marked for testing between the seals and inject test fluid to ***10000 psi or 80% of casing collapse — whichever is less.***
3. Monitor the open port on the Spool for signs of leakage.
4. Hold and monitor the test pressure for fifteen minutes or as required by the Drilling Supervisor.
5. Once a satisfactory test is achieved, carefully bleed off the test pressure and remove the test pump.

NOTE: Do not reinstall the fittings.



Test the Connection

1. Install the test pump to the port on the Spool for testing the connection and inject test fluid to ***5000 psi or 80% of casing collapse — whichever is less.***
2. Monitor the seal testing port on the Tubing Spool for signs of leakage.
3. Hold and monitor test pressure for fifteen minutes or as required by Drilling Supervisor.
4. Once a satisfactory test is achieved, carefully bleed off the test pressure and remove the test pump.
5. Reinstall the fittings in the Spool.



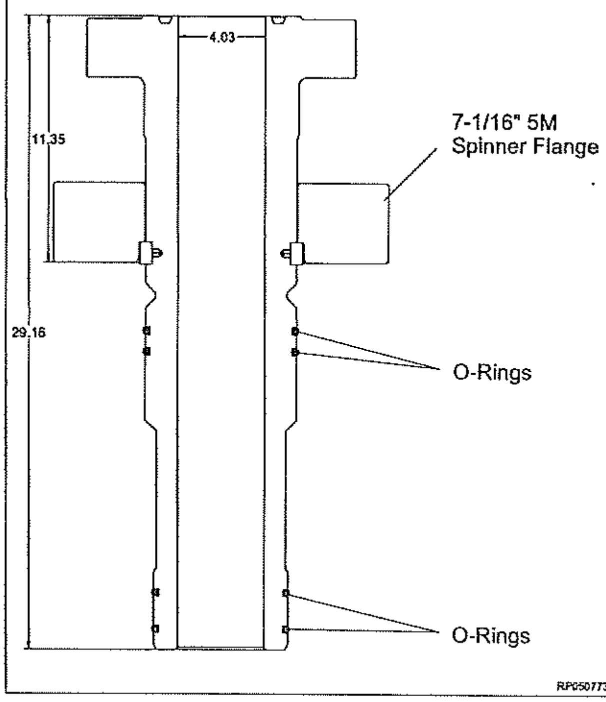
Stage 4 — Frac System

Frac the Well

1. Examine the Frac Mandrel Assembly. Verify the following:
   - bore is clean and free of debris
   - all seals on the ***Frac Mandrel (Item D1)*** are properly installed and undamaged
2. Orient the Assembly as illustrated.

NOTE: Prior to Shipment Frac valves may be installed onto the Mandrel Assembly.

FRAC Mandrel Prepped for 'C' Bowl
7-1/16" 5M x 4-1/16" 10M



Stage 4 — Frac System

3. Wipe the seals of the Mandrel with a light coat of oil.

WARNING: Excessive oil may prevent a proper seal from forming.

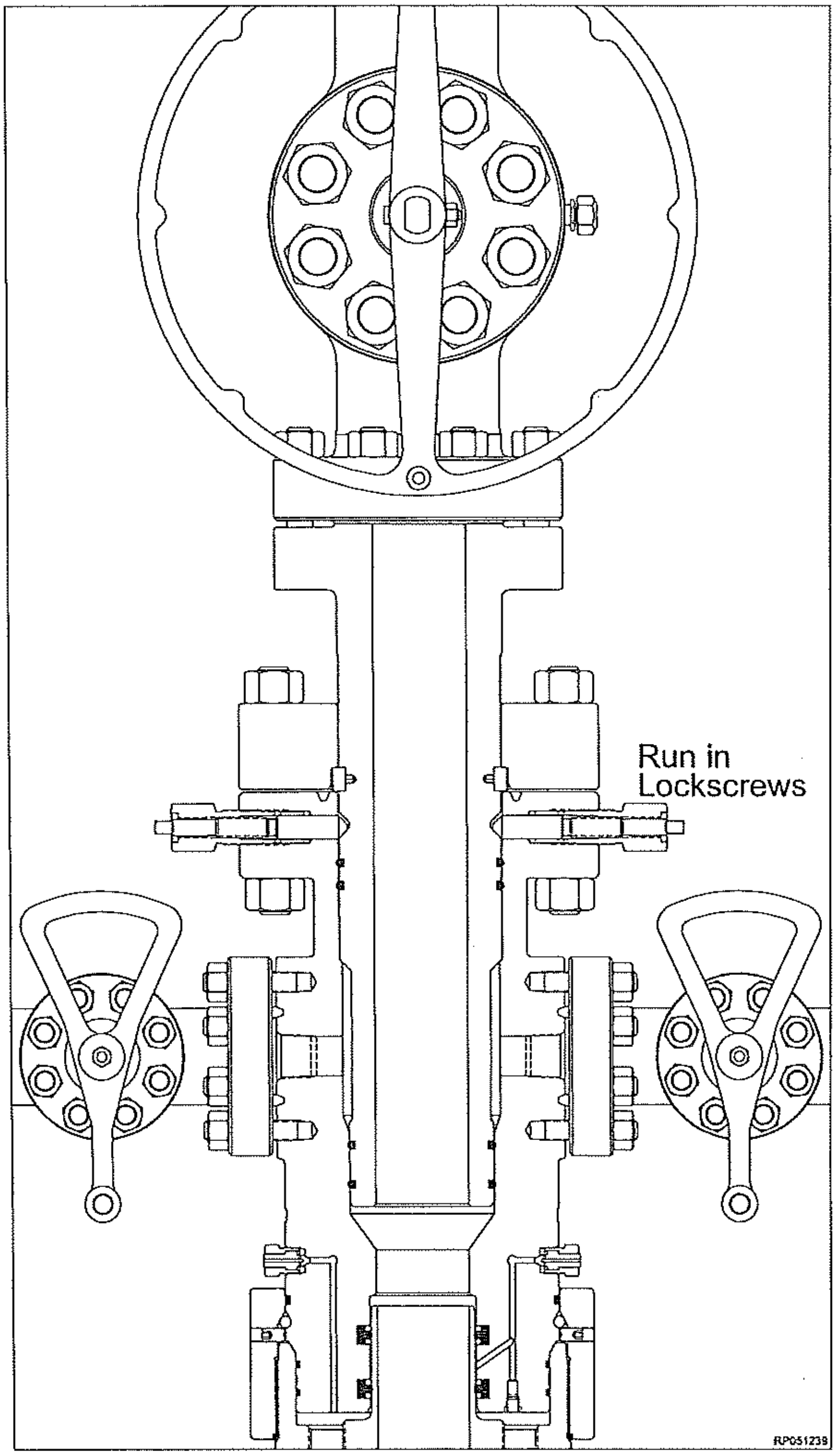
4. Install the ***Studs with only one nut*** into the spinner flange. Due to potential interference with the outlets.

NOTE: These studs must be installed prior to landing the mandrel.

5. Open the outlet valve of the Spool and ensure the bore is clean.
6. Ensure the lockscrews of the Tubing Spool are fully retracted from the bore.
7. Carefully lower the Mandrel into the bore of the Spool ensuring the studs in the spinner flange align with the bolt holes in the Spool.

WARNING: Do not damage the ID of the Spool or the Seals of the Mandrel.

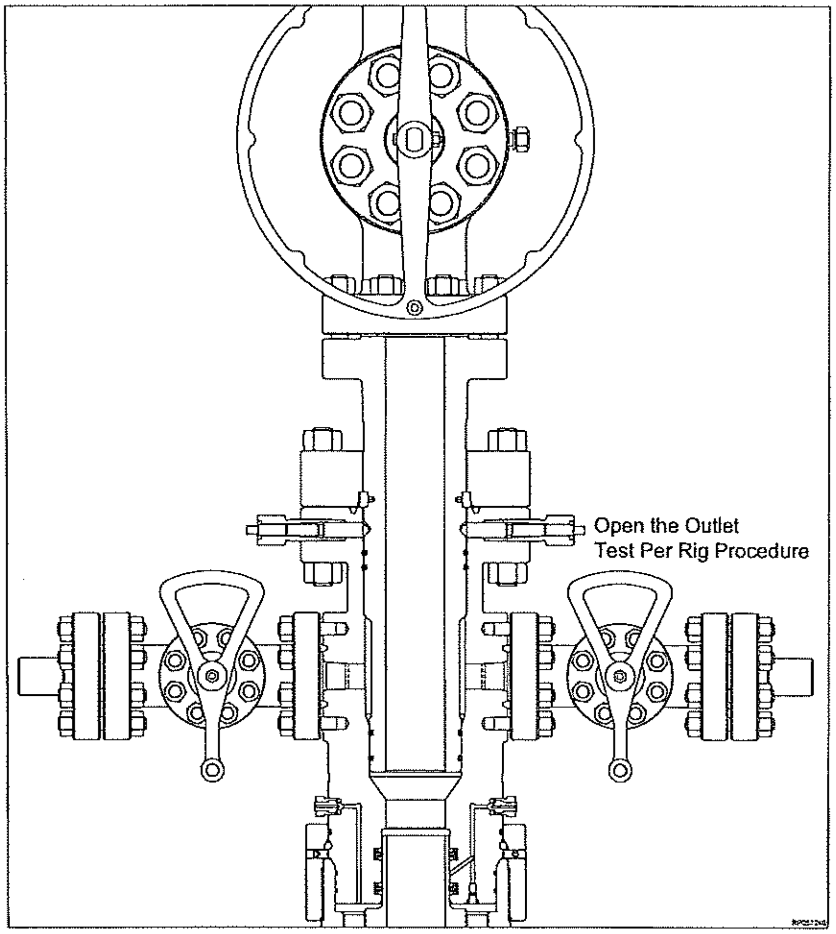
8. Install the second nut onto the studs in the spinner flange.
9. Orient the Tree Assembly per the Company Representatives requirements.
10. Make up the spinner flange to the Spool by tightening the studs and nuts in an alternating cross fashion.
11. Run in all lockscrews in an alternating cross fashion to approximately 200 ft lbs.



Stage 4 — Frac System

Test the Seals of the Frac Mandrel

1. Ensure the outlet valve on the Spool is fully open.
2. Test between the seals of the mandrel to ***5,000 psi maximum*** through the open outlet per rig procedure.
3. Hold and monitor the test pressure for 15 minutes or as required by the Company Representative.
4. Once a satisfactory test is achieved, carefully bleed off all test pressure.
5. The outlet valves should remain open during frac operations if pressure is to exceed ***5,000 psi.***
6. Crack open both the ***5,000 psi*** connection test fitting and the ***10,000 psi*** seal test fitting during Frac operations.
7. After Frac operations are complete tighten both fittings.



Stage 4 — Frac System

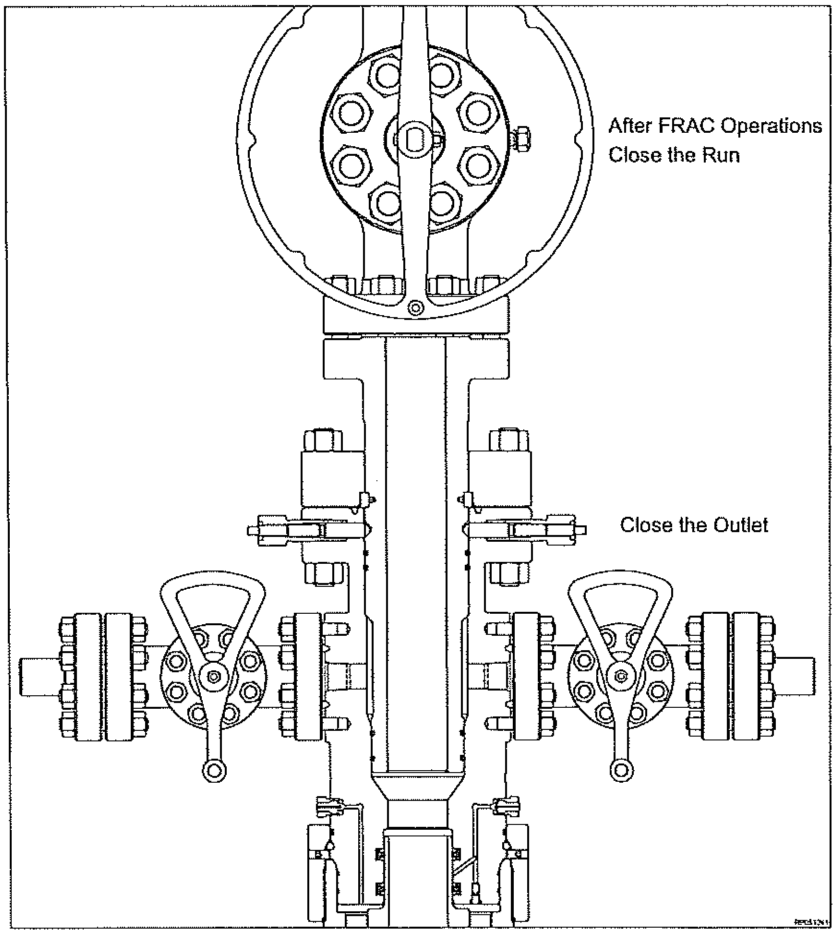
8. Ensure the necessary valves of the Tree are fully open or fully closed, as required.
9. Rig up frac equipment.
10. Frac the Well as required.
11. Once Frac operations are complete, close the lower master valve.
12. Monitor the valve for signs of leakage.
13. Once the well is safe and under control the connection between the lower master valve and the cross may be broken and the upper portion of the tree removed.
14. Once all fracing operations are complete and the well is safe and under control, open the master valve(s) ensuring there is no pressure on the well.
15. Fully retract the lockscrews.
16. Remove the bottom nut from the studs in the spinner flange.
17. Carefully remove the Frac Mandrel from the Spool.

WARNING: Do not damage the ID of the Spool.

18. Install the BOP stack immediately.
19. Inspect the Mandrel and valve for abnormal signs of wear.

NOTE: Any abnormal wear should be reported immediately.

20. Clean, grease and store the equipment as required.

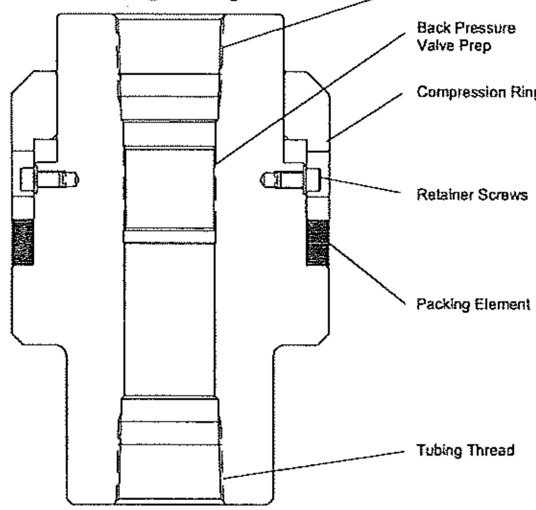


Stage 5 — 2-3/8" Tubing

Install the Tubing Hanger

1. Run the tubing as required and space out appropriately.
2. Examine the ***Tubing Hanger(Item C1).*** Verify the following:
   - bore is clean and free of debris
   - threads are clean and undamaged
   - packing element is properly installed and undamaged
   - compression ring is properly installed, moves freely and is properly retained
3. Orient the Hanger as illustrated.

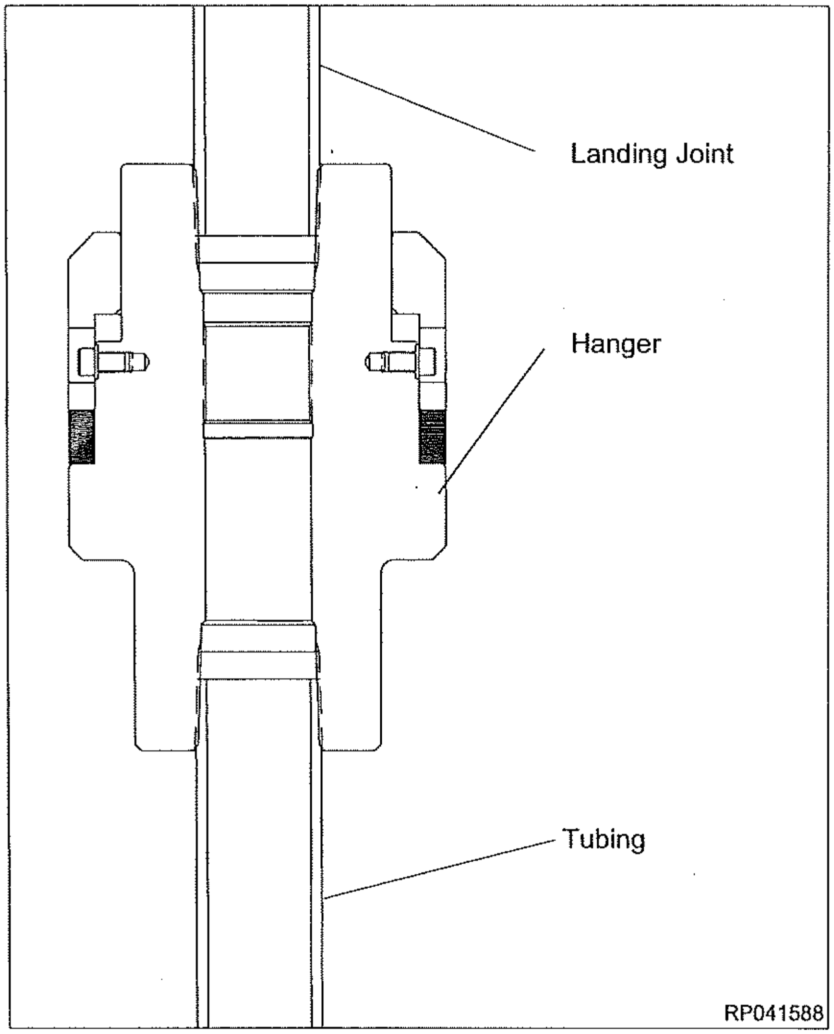
NOTE: Measure the distance from the face of the Tubing Spool flange to the rig floor. This will allow for an accurate measurement ensuring the Hanger is properly landed.



Stage 5 — 2-3/8" Tubing

4. Install the Hanger onto the tubing in the rig floor and tighten to the thread manufacturer's recommended optimum torque.
5. Make up a landing joint to the top of the Hanger and tighten to the thread manufacturer's recommended shoulder torque.
6. Wipe the packing element with a light coat of oil.

WARNING: Excessive oil may prevent a positive seal from forming.

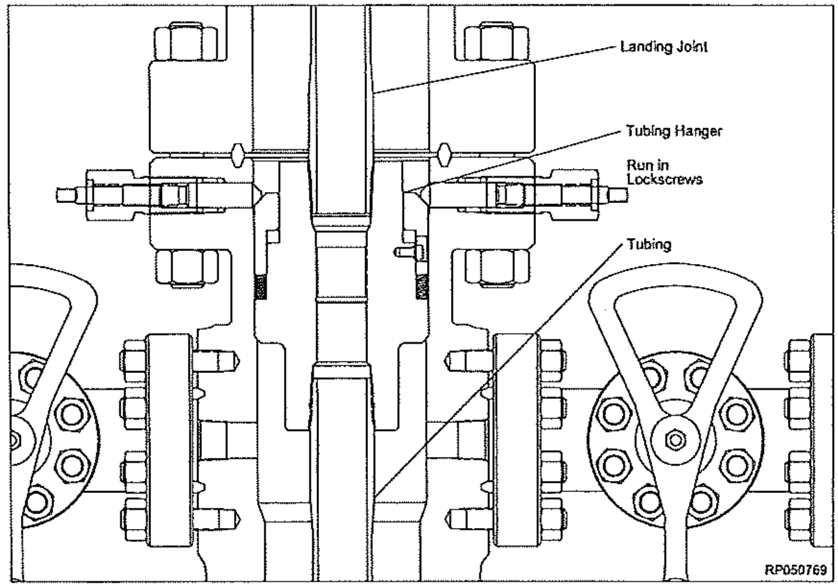


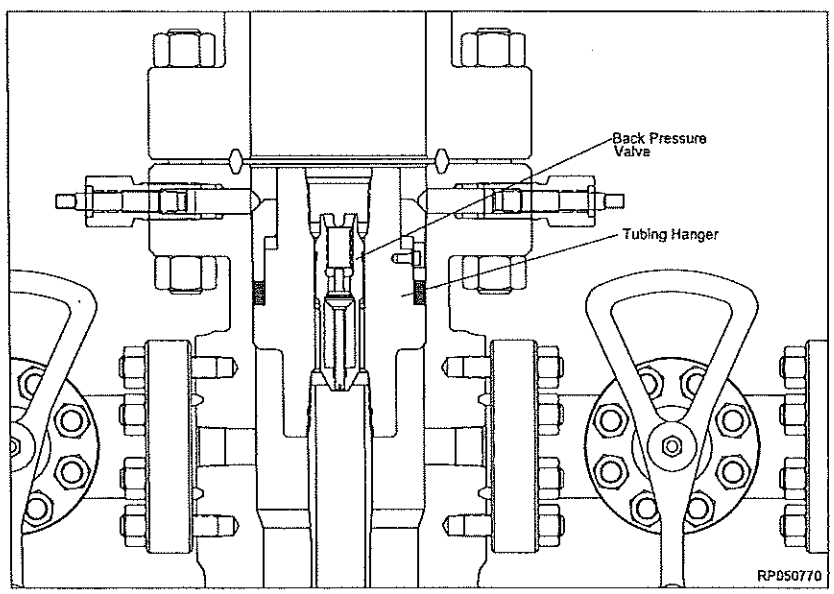
Stage 5 — 2-3/8" Tubing

7. Release the tubing from the floor slips and lower the hanger slowly into the bowl of the tubing spool.

NOTE: When the Hanger is properly landed, the distance measured from the flange face to the rig floor will be equal to the distance the Hanger travels as it is lowered into the well plus the distance from the flange face to the top of the load shoulder in the Spool, approximately 7".

8. With the Hanger properly landed, run in all of the lockscrews in an alternating cross fashion to 200 ft lbs.
9. Close the outlet valve of the Tubing Spool.
10. Remove the landing joint.
11. With the well safe and under control, the BOP stack may be removed.

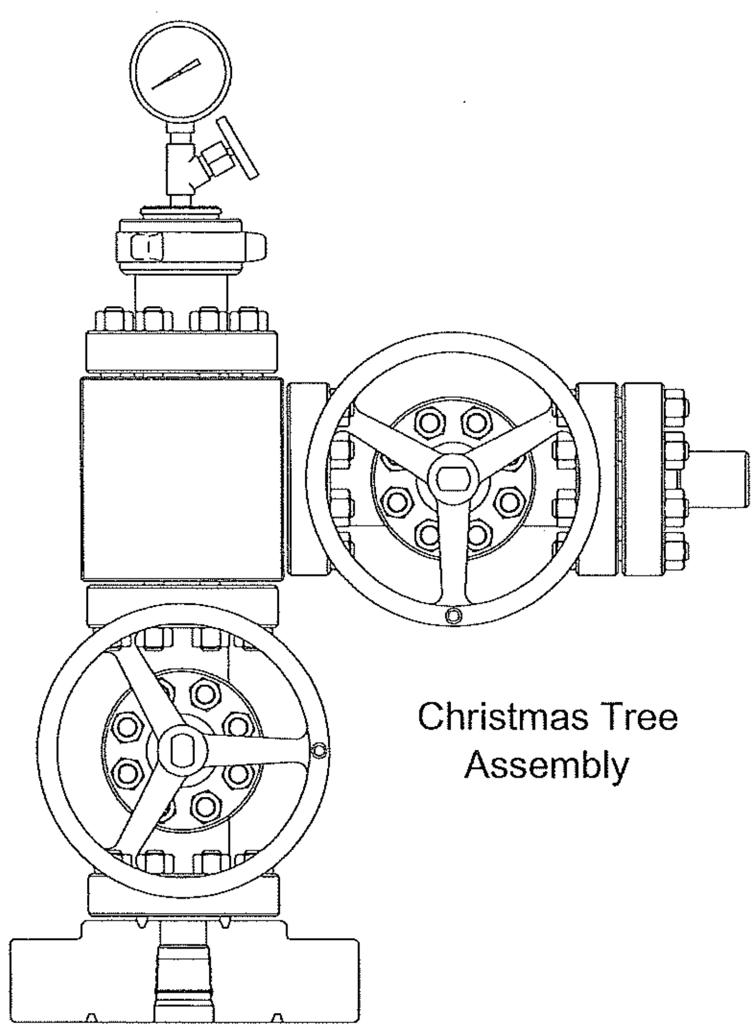




Stage 6 — Christmas Tree Completion

Install the Christmas Tree

1. Examine the ***Christmas Tree Assembly.*** Verify the following:
   - bore is clean and free of debris
   - seal pocket is clean and undamaged
2. Orient the Tree as illustrated.
3. Clean the mating ring grooves of the tubing spool and adapter.
4. Wipe the seal neck of the tubing hanger and the seal pocket of the adapter with a light coat of oil.
5. Place a new ***R-46 Ring Gasket (Item C5)*** into the gasket prep of the tubing spool.
6. Fill the void area above the body of the tubing hanger with clean hydraulic fluid.
7. Lower the Christmas Tree onto the tubing spool, and tighten with the studs and nuts provided in an alternating cross pattern.



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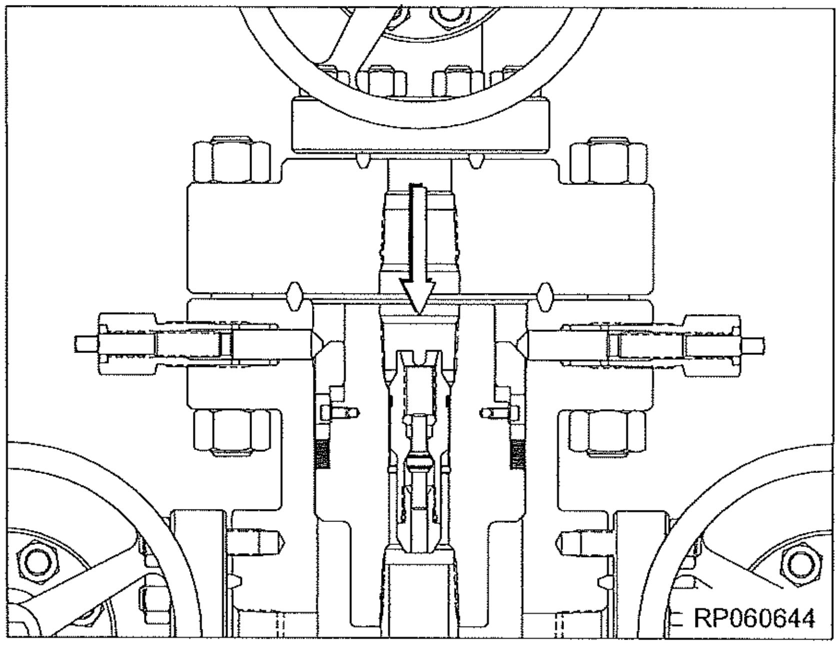
Stage 6 — Christmas Tree Completion

Test the Connection

1. Replace the BPV with a Two-Way Check valve to test the connection.
2. Test through the bore of the tree to ***5000 psi max.*** and hold for fifteen minutes or as required by the Drilling Supervisor.
3. Once a satisfactory test is achieved bleed off all test pressure, and remove the Two-Way Check.

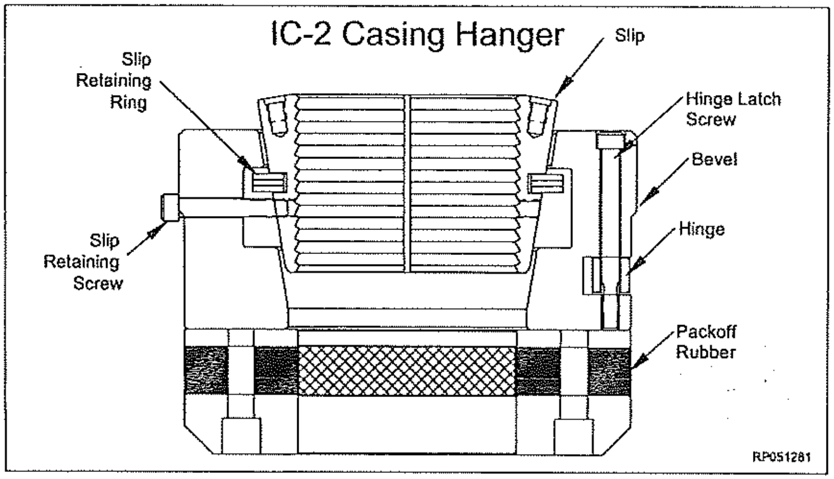


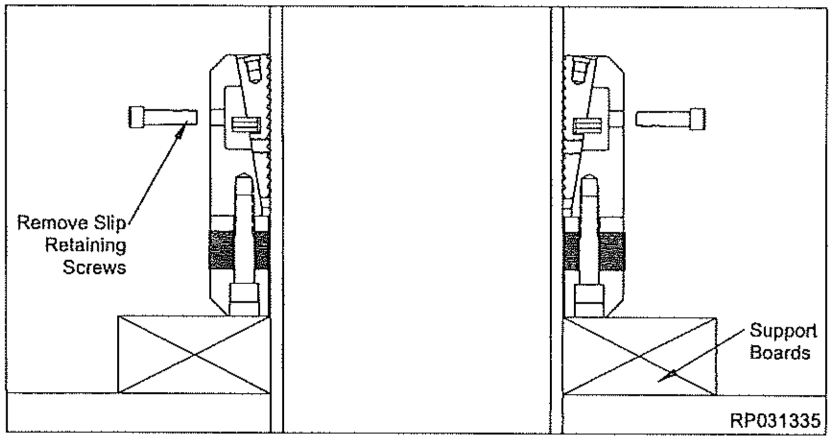
Emergency — 4-1/2" Casing

Hang off the Casing

NOTE: Since the IC-2 Casing Hanger is an automatic, weight energized Hanger, it is necessary to ensure there is adequate casing weight to create an annular seal.

1. Run the casing through the BOP to the required depth and cement the hole as required.
2. Drain the Casing Head bowl through its side outlet.
3. There are two methods used to install the Casing Hanger:
   - from the rig floor through a full opening BOP stack, provided no casing collars are between the rig floor and the Head
   - underneath the BOP stack, provided the well is safe and under control. This option allows the Hanger bowl to be inspected and thoroughly washed prior to the Hanger Installation.
4. Examine the ***IC-2 Casing Hanger (Item E1).*** Verify the following:
   - the packoff rubber is clean and undamaged
   - all screws are in place and intact
   - slips are intact, clean, and undamaged
   - seal element is not compressed beyond the OD of the Hanger
   - the bevel on the OD of the upper body, this helps distinguish from 9" & 9.5" casing hangers
5. Remove the latch screw to open the Hanger.
6. Place two boards against the casing to support the Hanger.





7. Wrap the Hanger around the casing and replace the latch screws.
8. Verify that the seal element is not compressed beyond the OD of the Hanger. If it is, loosen the cap screws in the bottom of the Hanger. The seal **MUST NOT BE COMPRESSED** prior to slacking off casing weight onto the Hanger.
9. Remove the slip retaining screws.
10. Grease the Hanger body and packoff rubber.

Emergency — 4-1/2" Casing

11. Remove the boards and carefully lower the Hanger into the Casing Head, using a cat-line to center the casing, if necessary.

12. When the Hanger is down, pull tension on the casing to the desired hanging weight + 1-1/2" then slack off.

NOTE: Approximately 56,000 lb ft is needed to set 4-1/2" packoff.

NOTE: A sharp decrease on the weight indicator will signify that the Hanger has taken weight and at what point.

13. Retract the setscrews in the threaded ring.

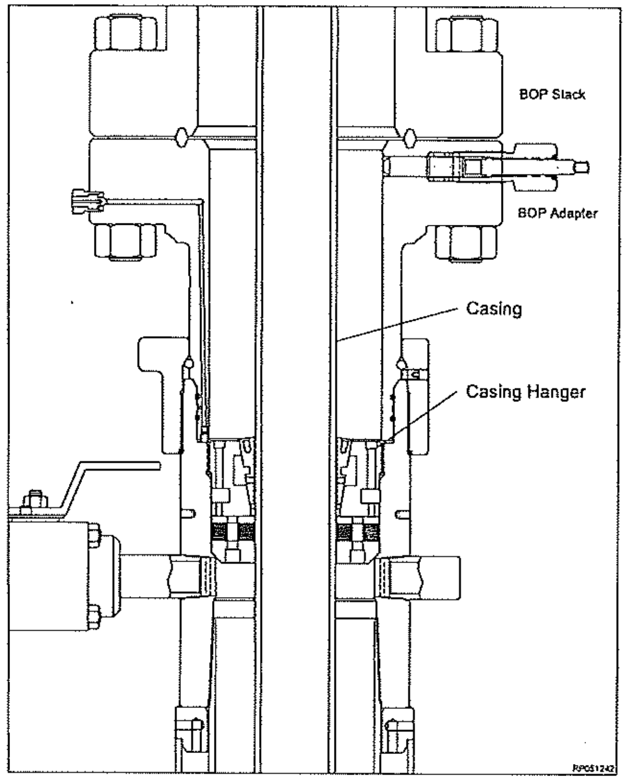
14. Rotate the threaded ring of the BOP Adapter to the left to fully disengage the Drilling Adapter. Move the BOP and excess casing out of the way.

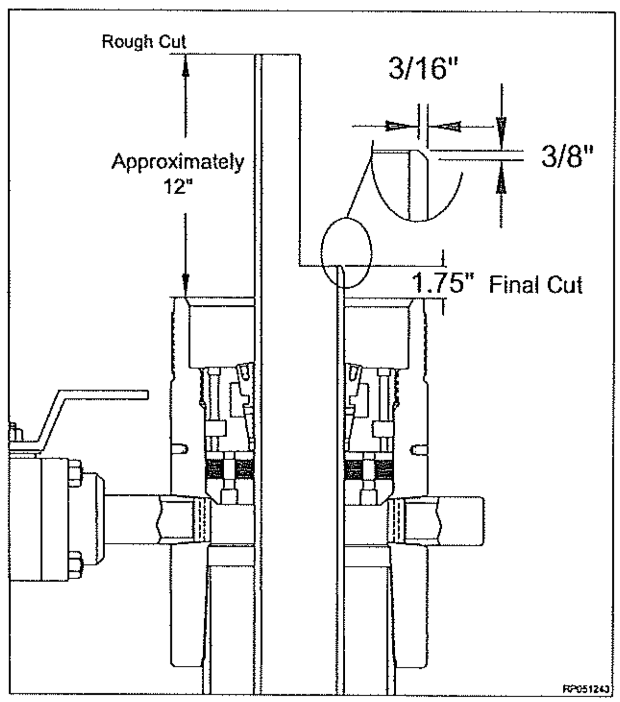
15. Rough cut the casing at 12" above the Head.

NOTE: Always physically measure the exact cutoff height by measuring the bottom bore of the next component to be installed and subtract 1/4" from this dimension, prior to making the final cutoff.

16. Final cut the casing at 1-3/4" ±1/8" above the top of the Head. Place a 3/8" x 3/16" bevel on the casing stub and remove all burrs and sharp edges.

NOTE: The ID edge of the casing may be ground slightly to allow drill pipe and casing collars to pass smoothly.





Stud Torque Chart

Recommended Torques in Foot Pounds for Flange Bolting for 105K Studs				
Bolt Diameter (inches)	Threads Per Inch (1/in)	Tension F (lbf)	Torque F=0.07 (Ft lbf)	Torque F=0.13 (Ft lbf)
.500	13	7,450	35	59
.625	11	11,865	68	115
.750	10	17,559	118	200
.875	9	24,241	188	319
1.00		31,802	279	474
1.125		41,499	401	686
1.25		52,484	553	953
1.375		64,759	739	1,281
1.50		78,322	962	1,677
1.625	8	93,173	1,226	2,146
1.75		109,313	1,534	2,696
1.875		126,741	1,890	3,332
2.00		145,458	2,297	4,061
2.25		186,758	3,276	5,822
2.50		233,212	4,500	8,030

Stud Torque Chart

Recommended Torques in Foot Pounds for Flange Bolting for 80K Studs				
Bolt Diameter (inches)	Threads Per Inch (1/in)	Tension F (lbf)	Torque F=0.07 (Ft lbf)	Torque F=0.13 (Ft lbf)
.500	13	5,676	27	45
.625	11	9,040	52	88
.750	10	13,378	90	153
.875	9	18,469	143	243
1.00	8	24,230	213	361
1.125		31,618	305	523
1.25		39,988	421	726
1.375		49,340	563	976
1.50		59,674	733	1278
1.625		70,989	934	1635
1.75		83,286	1,169	2,054
1.875		96,565	1,440	2,539
2.00		110,825	1,750	3,094
2.25		142,292	2,496	4,436
2.50		177,685	3,429	6,118

"N" Style Lockscrew Torque Chart

N Style Lockscrew Torque Values for Elastomer Seal Hangers

Flange Size	Pressure Rating (psi)	Torque Value (ft lbs)
4-1/16"	10,000	300
	15,000	
7-1/16"	2000	200
	3000	
	5000	
	10,000	300
	15,000	
	20,000	500
9"	2000	250
	3000	
	5000	350
	10,000	400
	15,000	500
	20,000	600
11""	2000	250
	3000	
	5000	350
	10,000	400
	15,000	

N Style Lockscrew Torque Values for Elastomer Seal Hangers

Flange Size	Pressure Rating (psi)	Torque Value (ft lbs)
13-5/8"	2000	250
	3000	
	5000	400
	10,000	
	15,000	500
16-3/4"	2000	250
	3000	
	5000	400
	10,000	
18-3/4"	5000	
	10,000	
20-3/4"	3000	250
21-1/4"	2000	
	5000	350
	10,000	400

Revision History

RP1116 Revision History				
Rev.	Description	Prepared by:	Reviewed by:	Date Released:
01	Initial Release. 300318390 Houston Surface Systems Engineering	Maria Contreras	Jesse Carlilne	June 5, 2006