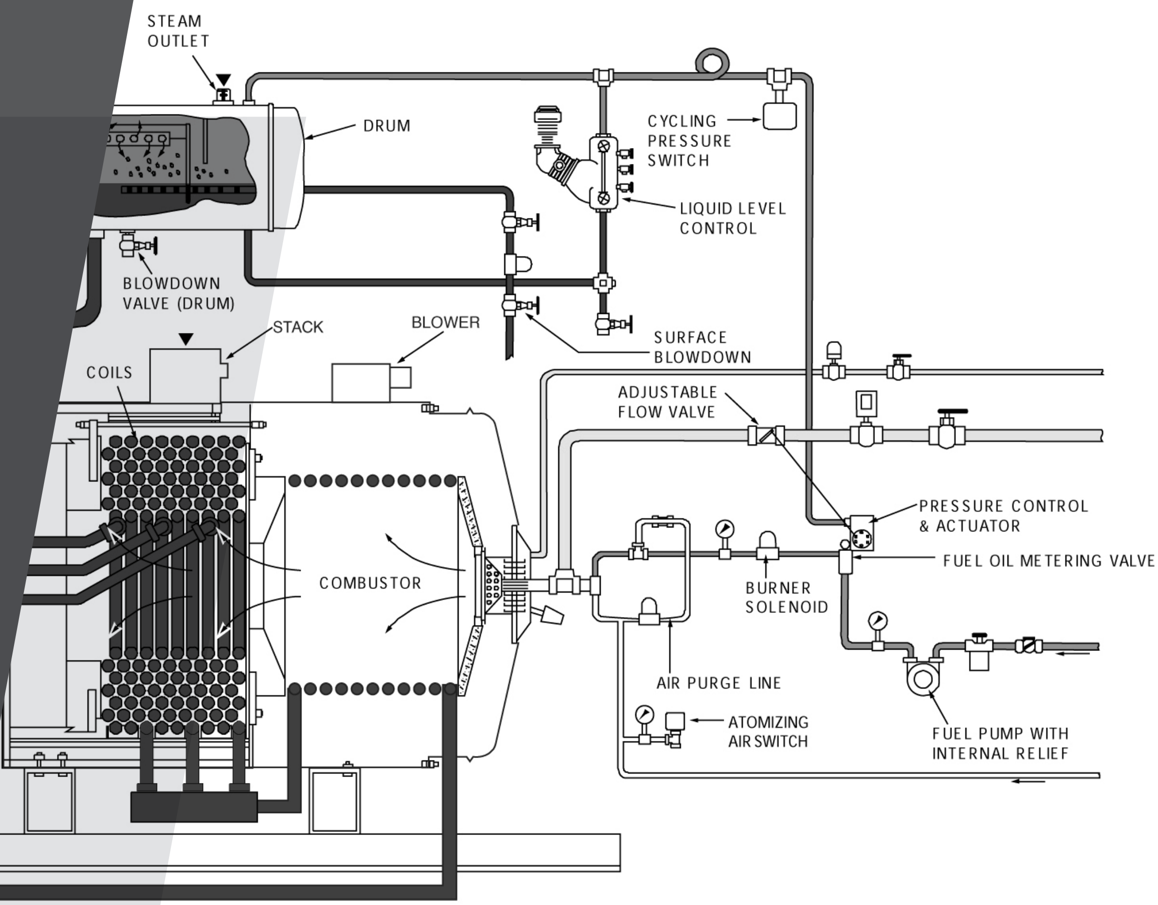
STEAM GENERATORS

CIRCULATIC® STEAM GENERATORS

INSTALLATION MANUAL



VAPOR POWER INTERNATIONAL

551 S. County Line Rd. Franklin Park, IL 60131
P: 630.694.5500 F: 630.694.2230 VaporPower.com

CIRCULATIC

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1.0 INTRODUCTION

1.1 The Vapor Power Circulatic is a forced circulation packaged watertube boiler that employs a low volume water coil as the heat exchange element. Its axis and the axis of the combustion system is positioned horizontally. The entire boiler assembly is mounted on a structural steel skid. All operating components and safety controls required by the governing body which has jurisdiction over the boiler installation (e.g. ASME, CGA, F.M., I.R.I., NFPA, et al) are provided on the Circulatic assembly. Electrical wiring, fire testing and factory adjustments are complete.

1.2 This manual contains many helpful suggestions and recommendations for the proper installation of piping, wiring, stack arrangements, and various other factors that should be considered for a good installation. A well planned installation is essential to achieve maximum efficiency, ease of maintenance, and extended service life from the boiler. Figure 30 (page 67/68) illustrates a typical boiler installation of a unit that may be fired with either gas or oil.

1.3 IN ORDER TO PREVENT DAMAGE THAT MAY OCCUR FROM FREEZING, STORE UNITS INDOORS IN A HEATED ENVIRONMENT WHERE TEMPERATURES REMAIN ABOVE FREEZING AT ALL TIMES.

2.0 LIFTING AND HANDLING

2.1 One of the more important steps of the installation is the careful handling of the boiler as it is moved to the installation site. Careless and rough handling can damage many components that would then impair the operation of the unit or its appearance. Vapor Power recommends that experienced riggers handle the packaged unit.

2.2 Inspect the boiler upon its arrival and make any claims for damage to the carrier within the allowable time limit. Vapor Power is not responsible for damage caused in transit. Inspect the boiler again after the riggers have moved it into place so that any damage claims may be filed against them at this time. Notify Vapor Power immediately should a part be damaged so that a replacement can be obtained before start up.

CAUTION

If the boiler has timbers fastened across the skids do not remove them until the boiler is in place permanently.

2.3 Table 1 lists the various basic Circulatic boiler models, their approximate maximum shipping weights, and their approximate floor loadings. These weights do not include auxiliary equipment.

Table 1. Approximate Shipping Weights

Model Size (BHP)	Floor Load (wet) (Lbs./Sq.Ft.)	Approximate Shipping Weight (Lbs.)
75	125	5,300
100	126	5,800
150	148	7,700
200	169	9,800
250	173	11,900
300	173	11,900
350	180	13,000
400	197	15,500
450	198	17,500
500	190	18,300
600	270	36,000

2.4 Boilers are built on a fabricated steel skid. BHP sizes up to and including 500 BHP have an optional two-piece skid that may be separated, and certain piping items and accessories removed, to reduce clearance width if space restrictions are encountered. BHP size 600 is constructed on a one-piece skid only. Any Circulatic boiler may be lifted and/or moved by transporting it with an overhead crane, a forklift truck, or by rollers (or dollies) across a level floor. Never raise the boiler from one corner only; be sure it is always raised evenly. When lifting one end only, both corners should be raised uniformly.

2.5 LIFTING BY CRANE

Figure 1 illustrates a method of attaching a sling for lifting the boiler from a single point. For boiler sizes up to and including 450 BHP, holes, 2-1/2 inches in diameter, are provided on each end of the boiler skid for the insertion of lifting bars to which slings may be attached. Vapor Power recommends that the lifting bars be a minimum of 2-1/4 inches diameter and extend beyond the boiler skid a sufficient length so that slings do not apply stress to piping, the boiler casing, controls or accessories. Use spreader bars to prevent damage to the boiler when lifting. Apply collars or other type retainers to prevent the slings from slipping over the ends of the lifting bars.

For 500 and 600 BHP sizes, lifting eyes are provided that are removable when the installation is complete. Some riggers prefer to use two cranes for lifting, one attached to each end of the boiler.

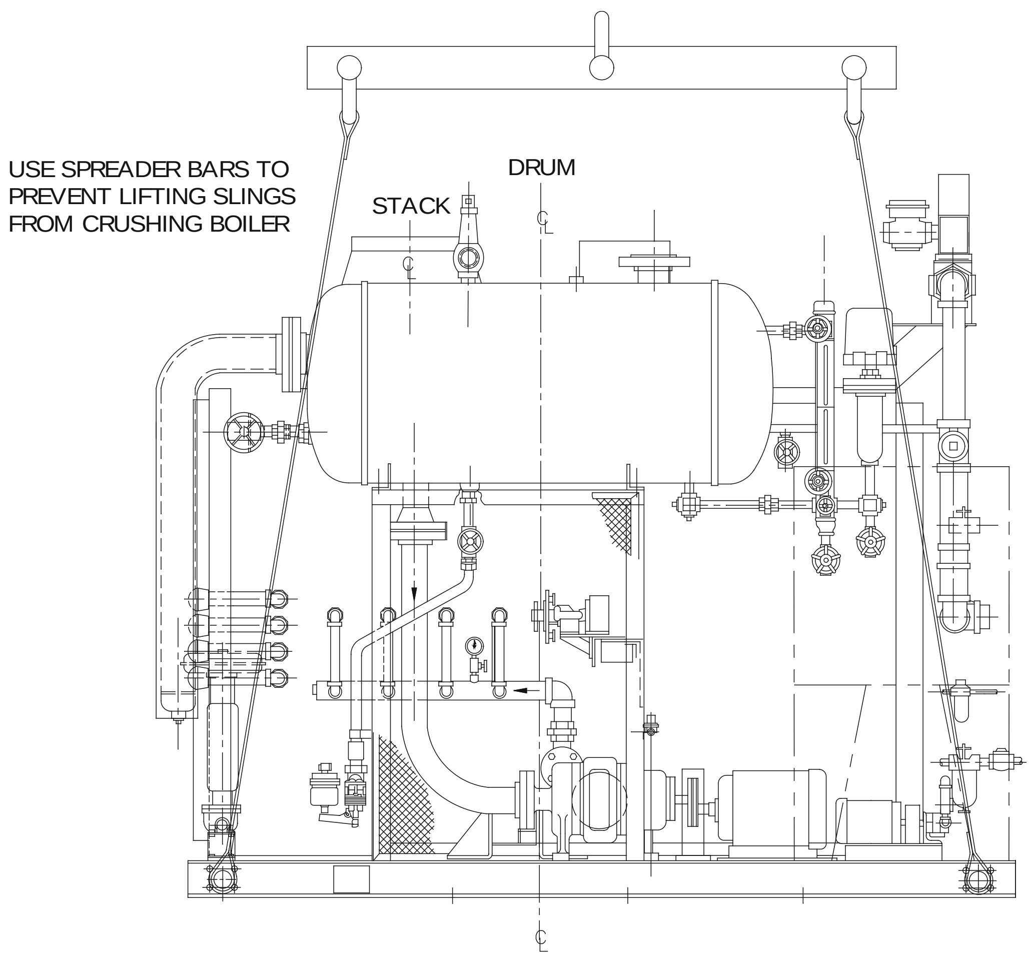


Figure 1. Lifting by Crane

2.6 LIFTING BY FORKLIFT

Figure 2 illustrates how lifting forks may be inserted under the fabricated skid to lift boilers up to and including 500 BHP size. Five inches of clearance are provided for insertion of the forks. The boiler may be lifted from either end but forks inserted from the end opposite the burner is the most preferable. Forks should be at least eight feet long and adequate strength to lift the boiler (see Table 1). Vapor transports the boiler through its shop using a heavy duty pallet truck that lifts both ends of its forks uniformly.

Due to the length and weight of the 600 BHP size lifting by a single forklift is usually impractical. Two forklifts (or pallet trucks) may be used with forks inserted from each end.

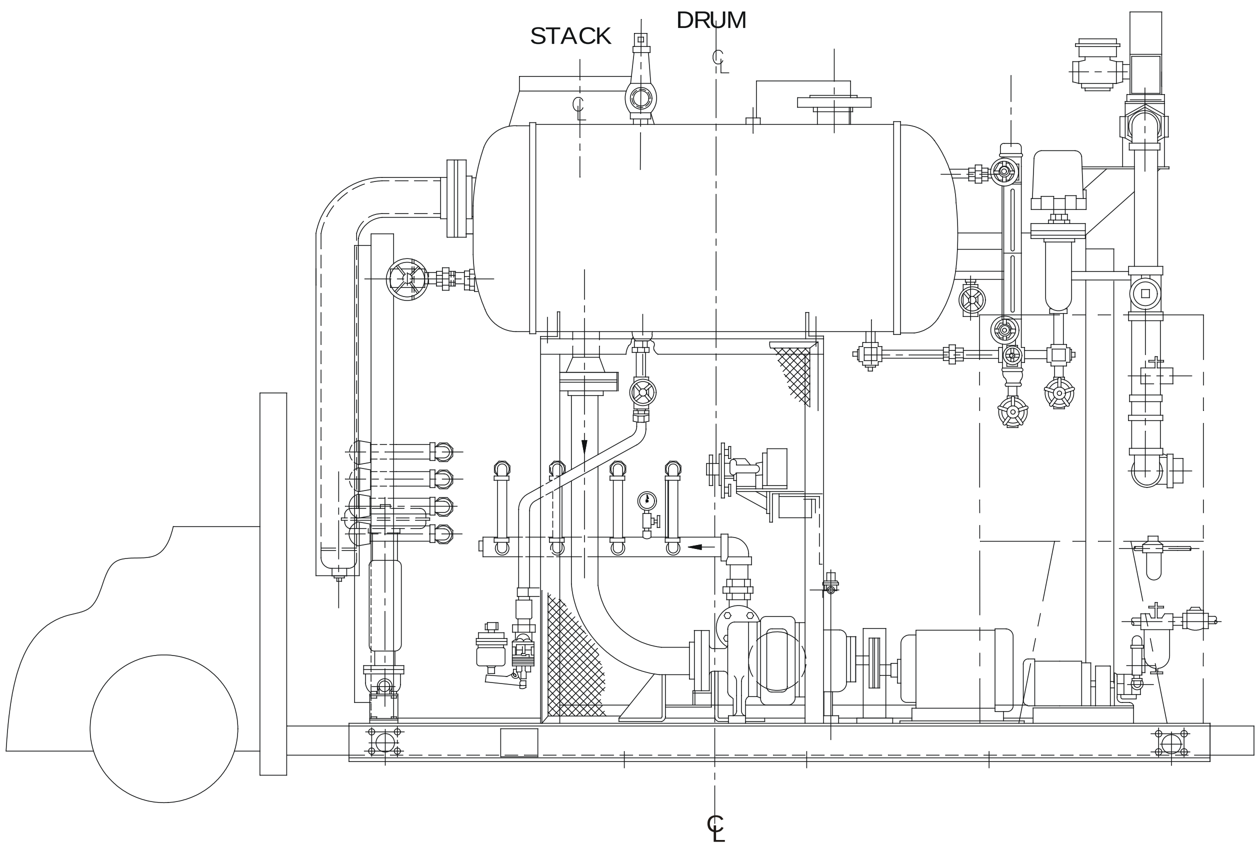


Figure 2. Lifting by Forklift

2.7 TRANSPORTING BY ROLLERS

Figure 3 illustrates how rollers may be placed to move the boiler from one location to another across a level floor. Vapor Power recommends that at least four rollers be used, a minimum of 2 inches diameter, spaced equidistantly along the boiler skid length.

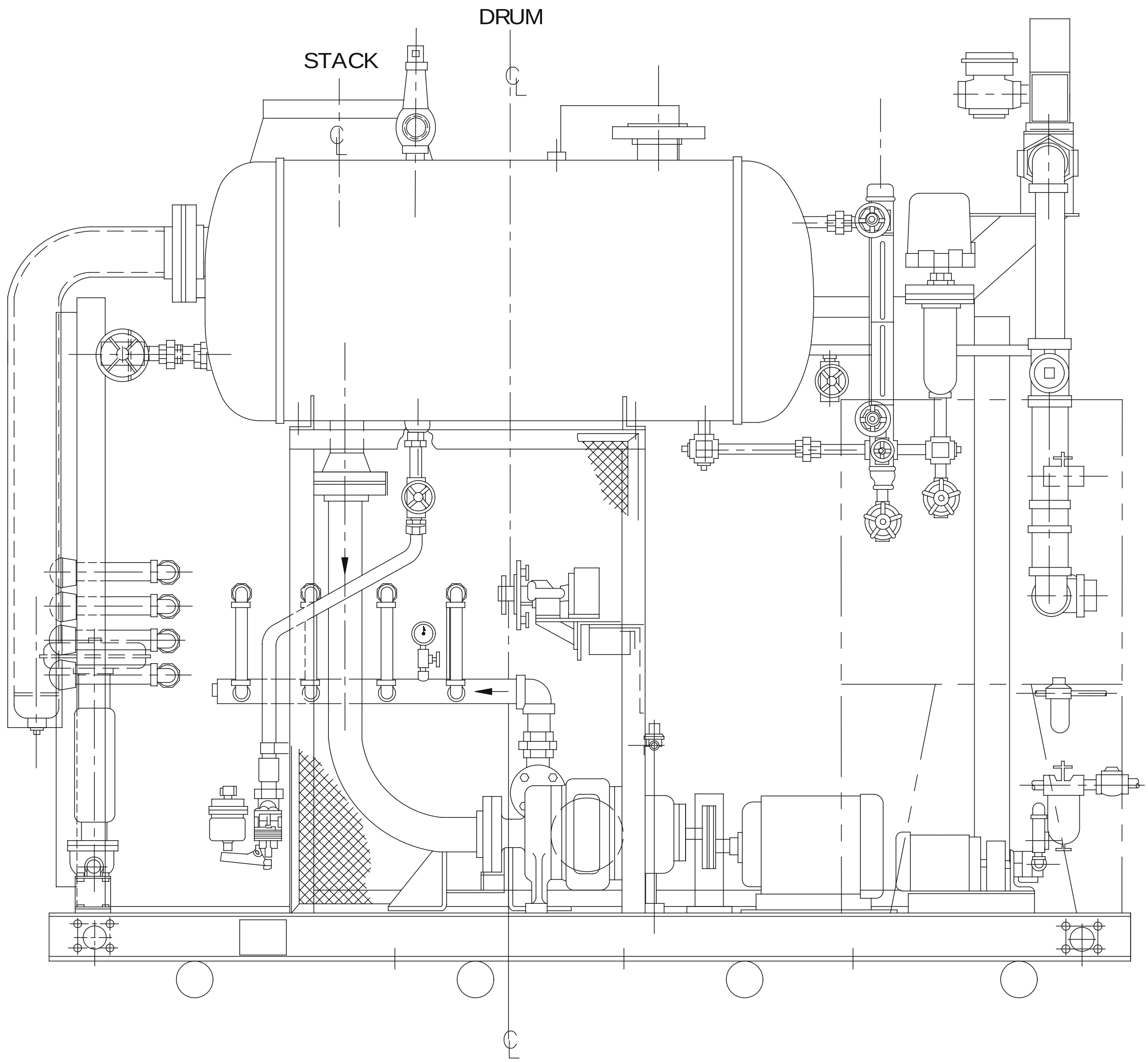


Figure 3. Transporting by Rollers

3.0 INSTALLATION

3.1 Local authorities and your insurance company have jurisdiction over the installation of the boiler, related equipment and stack. They should be consulted before the installation is started, and any permits needed should be obtained.

3.2 Many insurance companies require boiler installations to be in accordance with the National Fire Protection Association (NFPA). Listed below are two of the applicable standards.

3.2.1 NFPA STANDARD NO. 54, NATIONAL FUEL GAS CODE

3.2.2 NFPA STANDARD NO. 31, INSTALLATION OF OIL-BURNING EQUIPMENT

3.2.3 Other applicable standards should be consulted as necessary. These may be determined by contacting the NFPA office in Quincy, MA 02269.

3.3 Installations in Canada must comply with Canadian Gas Association (CSA) Codes listed for oil, natural gas or propane appliances or equipment. Applicable Provincial Regulations should be carefully followed in all cases. As noted in paragraph 3.1, authorities having jurisdiction should be consulted before installations are started. Listed below are two applicable standards.

3.3.1 Gas equipment must be installed in accordance with current CSA standard CAN1-B149 “Installation Codes for Gas Burning Appliances and Equipment”.

3.3.2 Oil equipment must be installed per current Canadian Standards Association (C.S.A.) standard B139 “Installation Code for Oil Burning Equipment”.

3.4 Consult your gas supplier regarding inlet gas pressure and capacity (CFM).

3.5 The contractor/installer should identify all emergency gas, oil and electrical shut off devices upon completion of the installation.

4.0 MOUNTING

4.1 No special masonry support is necessary except to keep the boiler level. The boiler is mounted on a heavy structural steel base but <u>MUST BE LEVEL</u>. If necessary, level the boiler with shims and grout with stiff cement. Make sure the base is in contact with floor at all points. The floor loading will be approximately as indicated in Table 1. Check your building specifications for the permissible floor loading.

4.2 Secure the boiler with bolts through the mounting holes in the skid. Bolts should be no larger than 3/4" diameter to allow for tolerances in the mounting hole and bolt locations.

4.3 The boiler must be mounted on a floor of noncombustible material that is pitched toward a sewer to provide for drainage.

4.4 Some customers prefer to elevate the boiler as additional protection from drainage or to facilitate installation. A concrete pad (see Figure 1) approximately four inches thick is the usual practice in such instances.

5.0 CLEARANCES

5.1 Table 2, as illustrated by Figure 4, gives the dimensions Vapor Power considers as minimum to provide reasonable accessibility for maintenance work on the heating surfaces; removal of burners and combustion components; replacing working parts; and for adjusting, cleaning, and lubricating parts which require attention.

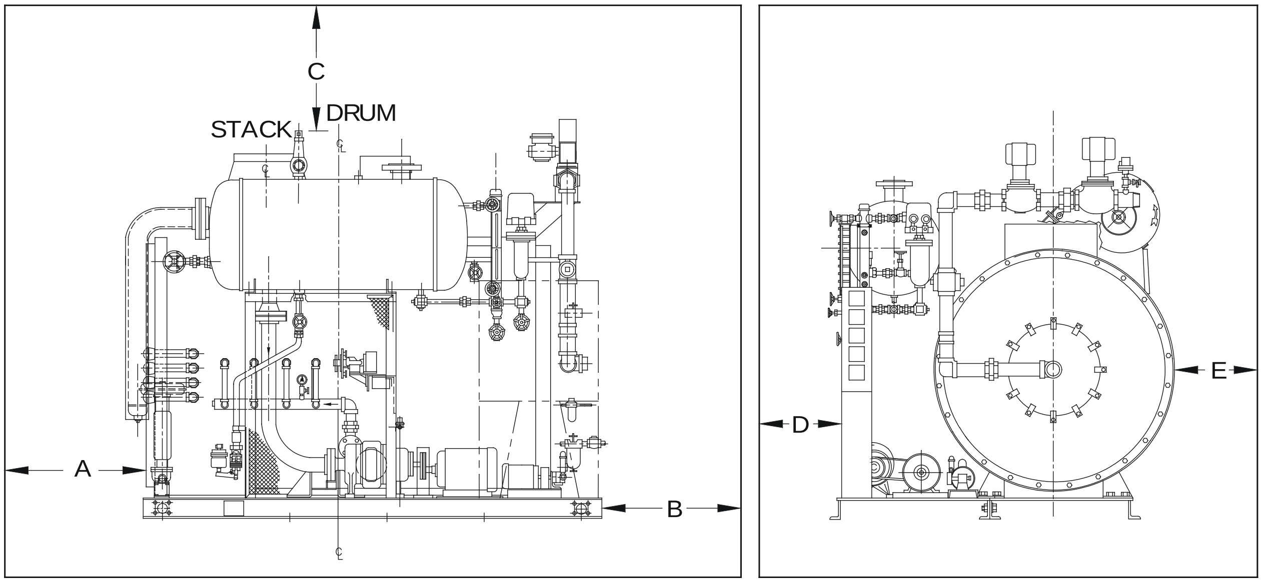


Figure 4. Boiler Clearance Dimensions

Table 2. Clearance Dimensions

<table>
<tr><th rowspan="2">Model Size
(BHP)</th><th>A</th><th>B</th><th>C</th><th>D*</th><th>E*</th></tr>
<tr><th colspan="5">Inches</th></tr>
<tr><td>75
100
150</td><td>48</td><td rowspan="2">48</td><td rowspan="2">48</td><td rowspan="2">36</td><td>12</td></tr>
<tr><td>200
250
300
350
400
450
500
600</td><td>60</td><td>36</td></tr>
<tr><td colspan="6">* 48 inches when area is used as an aisle</td></tr>
</table>

5.2 The authority having jurisdiction over the boiler installation to determine acceptability may be Federal, state, local or insurance company. Any of these organizations may base their acceptance on compliance with the standards of the National Fire Protection Association (NFPA). In the absence of other standards Vapor Power recommends clearance spacings as presented in NFPA standard No. 31, Installation of Oil-Burning Equipment. Where the jurisdiction standards are in conflict with Table 2 the variance should always be on the side for safety.

6.0 COMBUSTION AND VENTILATION AIR REQUIREMENTS

6.1 Table 3 lists the minimum combustion air requirements per boiler.

Table 3. Minimum Air Requirements

Model Size (BHP)	Combustion Air Required (SCFM)
75	665
100	887
150	1328
200	1758
250	2213
300	2663
350	3112
400	3600
450	4050
500	4250
600	5100

6.2 The boiler room must be properly ventilated. Lack of adequate combustion air will result in smoke and sooted heat transfer surfaces. Accumulation of hot air (125°F max.) near the boiler can cause overload elements to trip, relay malfunctions and other component failures that will disrupt the operation of the boiler(s).

6.3 Some building codes, e.g. the National Fire Protection Association (NFPA) specify the number and size of air supply vent openings required, depending upon the type of fuel used and the type of enclosure in which the boiler is to be located. Before installing the boiler the authority having jurisdiction over the installation should be consulted. In the absence of a jurisdictional authority, Vapor Power recommends that the requirements of NFPA be met.

6.4 Some jurisdictional authorities may approve the use of blowers to supply sufficient air to the boiler room in lieu of ventilation openings. If the air supply is dependent upon a blower, an interlock switch should be provided to prevent the boiler from firing if the blower fails.

6.5 When the boiler enclosure room contains exhaust fans, the size of vent openings, or the air makeup blower, must be increased to compensate for the cubic feet per minute of air being exhausted. The increase will be dependent upon the capacity of the fans.

6.6 A method of heating the boiler room, water piping, and the system equipment should be provided in the event the boiler is shut down and the ambient temperatures are below freezing.

7.0 STACK INSTALLATION

7.1 The Vapor Circulatic boiler has a forced draft combustion system that is supplied by its own blower; therefore the stack installation does not need to add draft through the boiler. However, the boiler blower is not designed to overcome positive stack pressures; therefore, the stack should be of sufficient size to provide free discharge of exhaust gases without back pressure.

7.2 Ideally, stack draft at the boiler outlet should be maintained at 0 to –.05 inches of water column at all boiler firing rates. Stack draft should not be more negative than –0.3 in. W.C. when the boiler is operating at high fire and the stack temperature has reached a steady value.

7.3 In areas where unusually high draft conditions prevail a method of reducing the draft is necessary. An orifice, barometric damper or adjustable damper must then be installed in the exhaust stack to reduce the draft to the limits indicated in paragraph 7.2.

7.4 The ideal draft regulator is an electric or hydraulic automatic positioning type. These regulators maintain a constant draft on the boiler under all variances of boiler firing rates and atmospheric conditions. The next best draft regulator is a barometric damper which is in common use in many boiler installations. When it is necessary to increase draft from what is available the height of the stack must be increased or an induced draft fan installed in the exhaust system.

7.5 If more than one boiler is to be connected to a single main stack, the cross sectional area of the main stack must be equal to, or greater than, the sum of the areas of all connecting stacks. See Table 4 for the stack requirements of the various model sizes of boilers.

Table 4. Stack Requirements

Model Size (BHP)	Stack Diameter (In. O.D.)	Stack Area (Sq. In.)
75	12	111
100	14	151
150	16	198
200	18	251
250	20	310
300	24	448
350	24	448
400	26	530
450	28	615
500	28	615
600	32	798

7.6 The best stack installation is one that is supported independent of the boiler and run straight up to the outside with drainage provided at the bottom. The boiler connecting stack is then brought into the main stack not less than 45° above horizontal. All stacks should be at least 5 feet above any wind obstructions and not less than 10 feet above the roof (see Figure 5). The next best stack installation is one which is vertical directly up from the boiler that is supported independent of the boiler also.

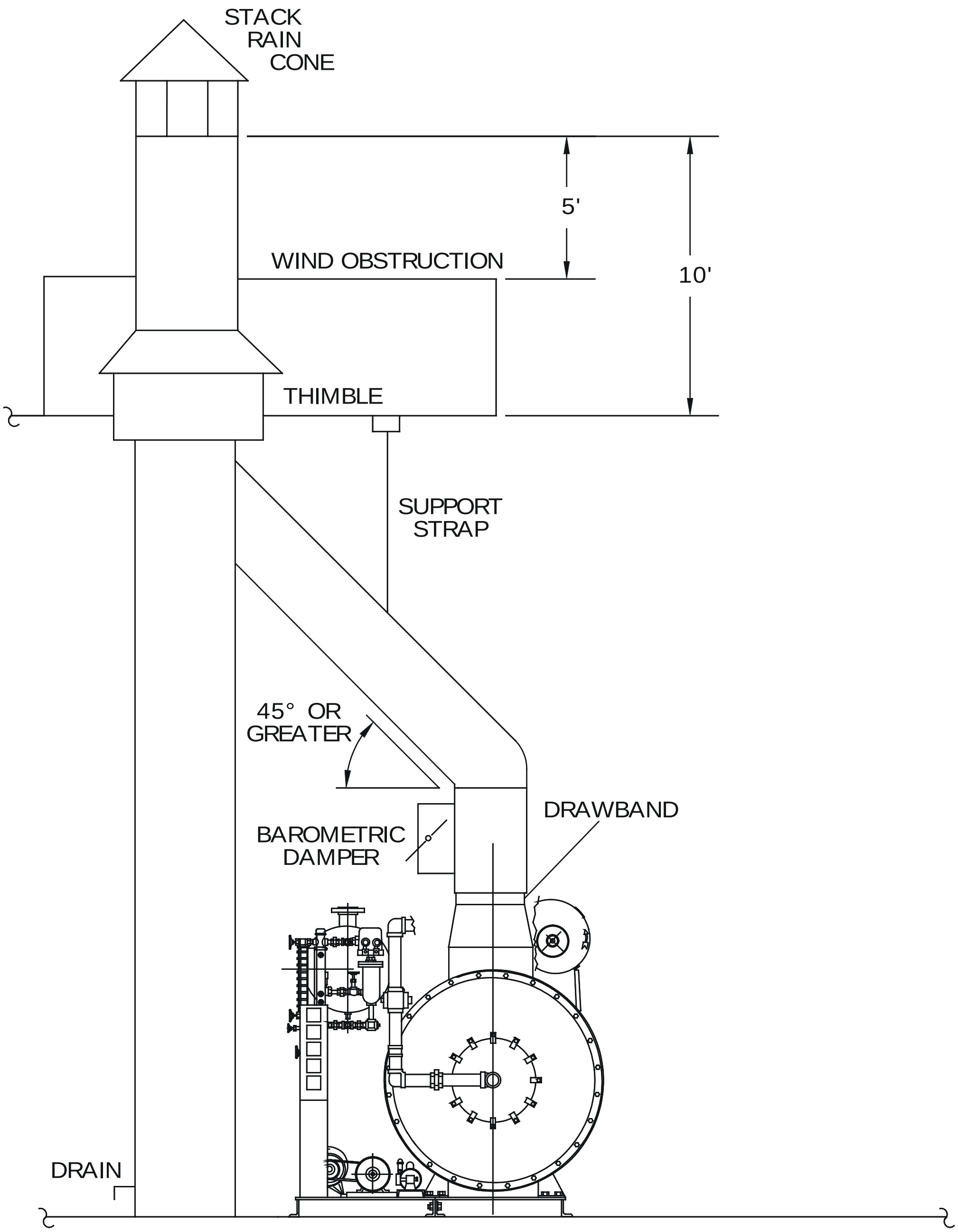


Figure 5. Recommended Stack Installation

7.7 Some Building Codes, e.g. National Fire Protection Association (NFPA) and/or Canadian Standards Association (CSA) and/or others, require that where a metal stack passes through a combustible roof such roof shall be guarded by a metal sleeve or thimble of their specific dimensions. In the absence of any jurisdictional requirements Vapor Power recommends that such a thimble be used that extends not less than nine inches above and below the roof and provide not less than eighteen inches clearance on all sides of the stack. (See Figure 6.)

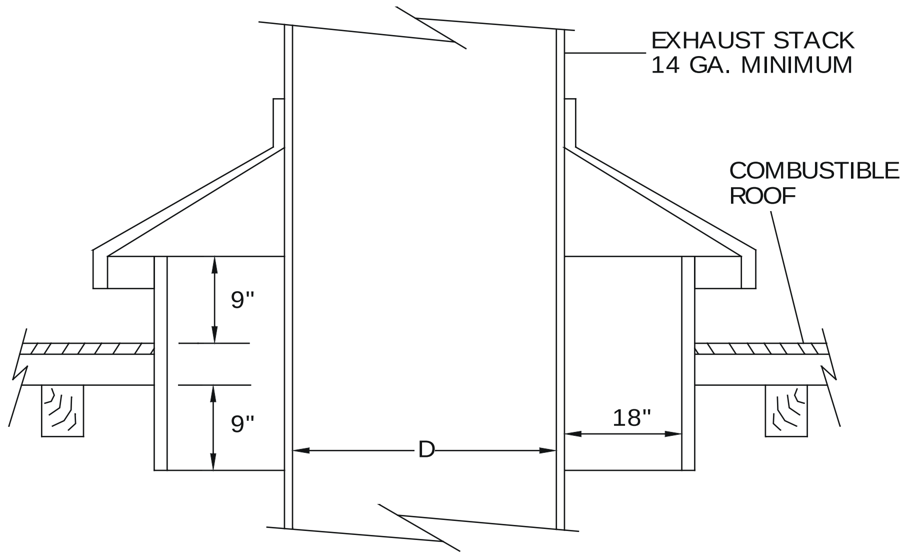


Figure 6. Exhaust Stack Installation Through Combustible Roof

7.8 Horizontal runs in the stack, when necessary should be pitched up 1/4 inch per foot, and the diameter of the pipe should be increased 5% over the preceding pipe diameter at each 10 foot interval in the horizontal run. A 10% increase in pipe diameter over the preceding diameter must be made at each elbow. (See Figure 7.) Horizontal runs should be provided with a clean out door. Round stacks and breeching are preferred.

7.9 The stack should be designed with the required bracing, or hangers to be self-supporting. (See Figure 5.) A section of the stack should be removable to permit inspection for corrosion and soot buildup. An inspection door or panel may be inserted if removal of a section of the stack will be difficult. The minimum recommended material thickness for stacks and breeching is 14 gauge.

7.10 The stack should be protected against down drafts, back drafts, and rain with a simple flat or cone-shaped cap. (See Figure 8.) Make sure the area between the cap and stack is at least equal to the area of the stack. Protect all steel work from corrosion.

7.11 In cold climate regions and/or regions of high humidity, a shutoff damper must be installed in each stack. When closed, the shutoff damper will prevent the boiler coils from freezing or sweating by outside air that is drawn into the boiler when it is shutdown. This is applicable to a boiler installation with multiple stacks or an installation with a single stack in a building with depressed atmospheric pressure.

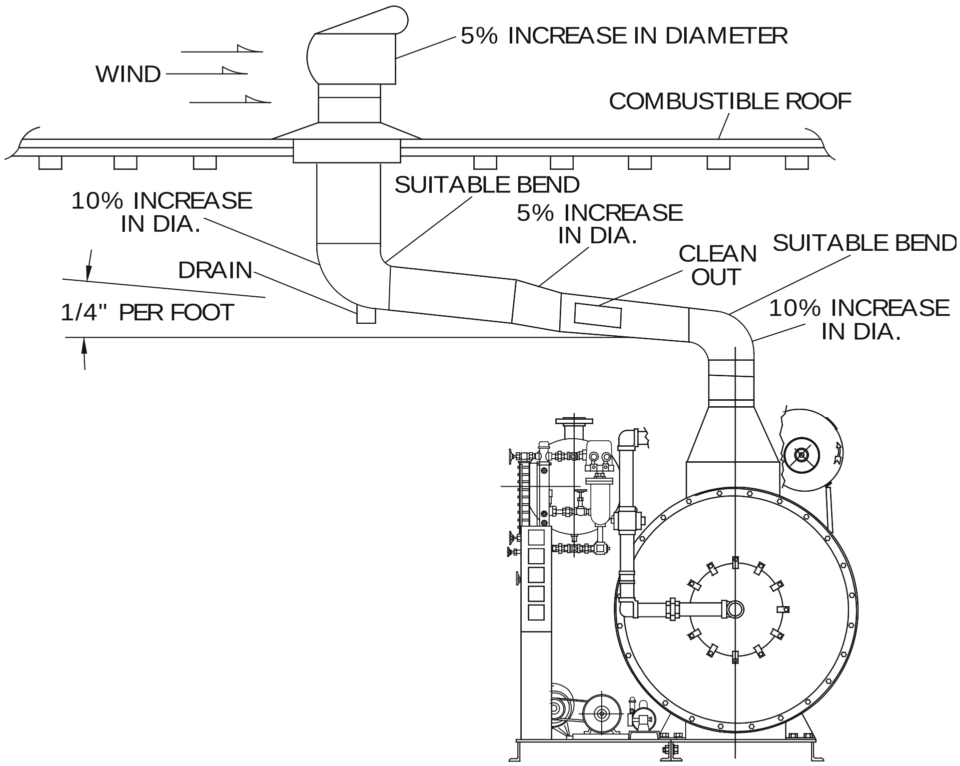


Figure 7. Stack Installation with Horizontal Run

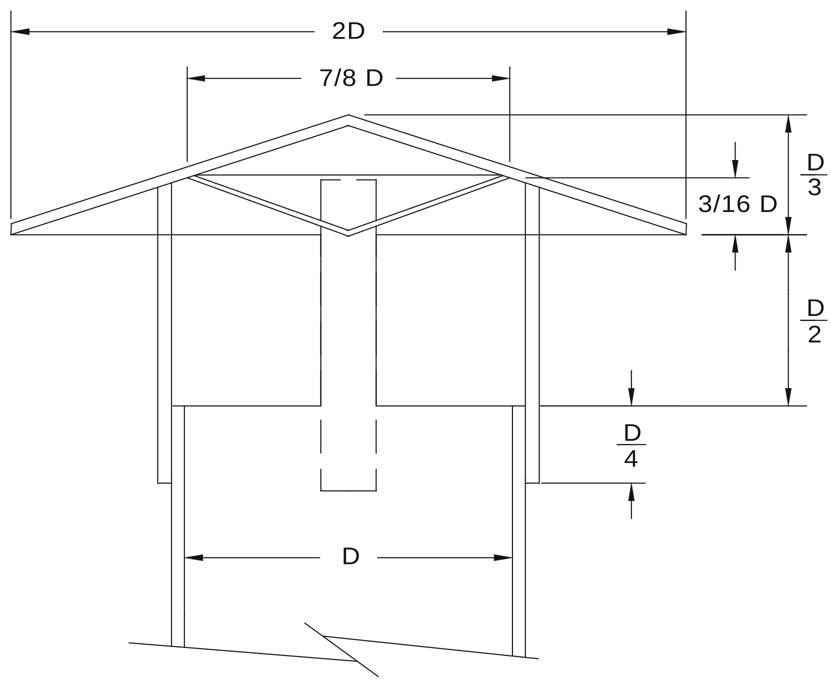


Figure 8. Stack Rain Cone

8.0 STEAM OUTPUT

8.1 An adequate supply of water must be available to operate the boiler. Table 5 indicates the equivalent evaporation rates of various boiler models rated from and at 212°F.

Table 5. Equivalent Evaporation

Model Size (BHP)	Evaporation Lbs./Hr. (From and at 212°F)
75	2,580
100	3,450
150	5,175
200	6,900
250	8,625
300	10,350
350	12,075
400	13,800
450	15,525
500	17,250
600	20,700

8.2 Actual evaporation rates or steam output, depend upon the feedwater (water entering the boiler) temperature and the boiler operating pressure. To determine your actual evaporation refer to Figure 9 and follow the example below.

If you have a 300 BHP boiler operating at 100 psig with 200°F feedwater, enter Figure 9 at the 100 psig point and proceed upward until that grid intersects the curve for 200°F feedwater. Read the scale at left which indicates an actual evaporation of 32.8 pounds of steam per boiler horsepower. Multiplying by 300 BHP equals 9840 pounds of steam. This means that the actual evaporation for a 300 BHP boiler operating at 100 psig is 9840 pounds of steam per hour when the feedwater temperature is 200°F.

FACTORS OF EVAPORATION

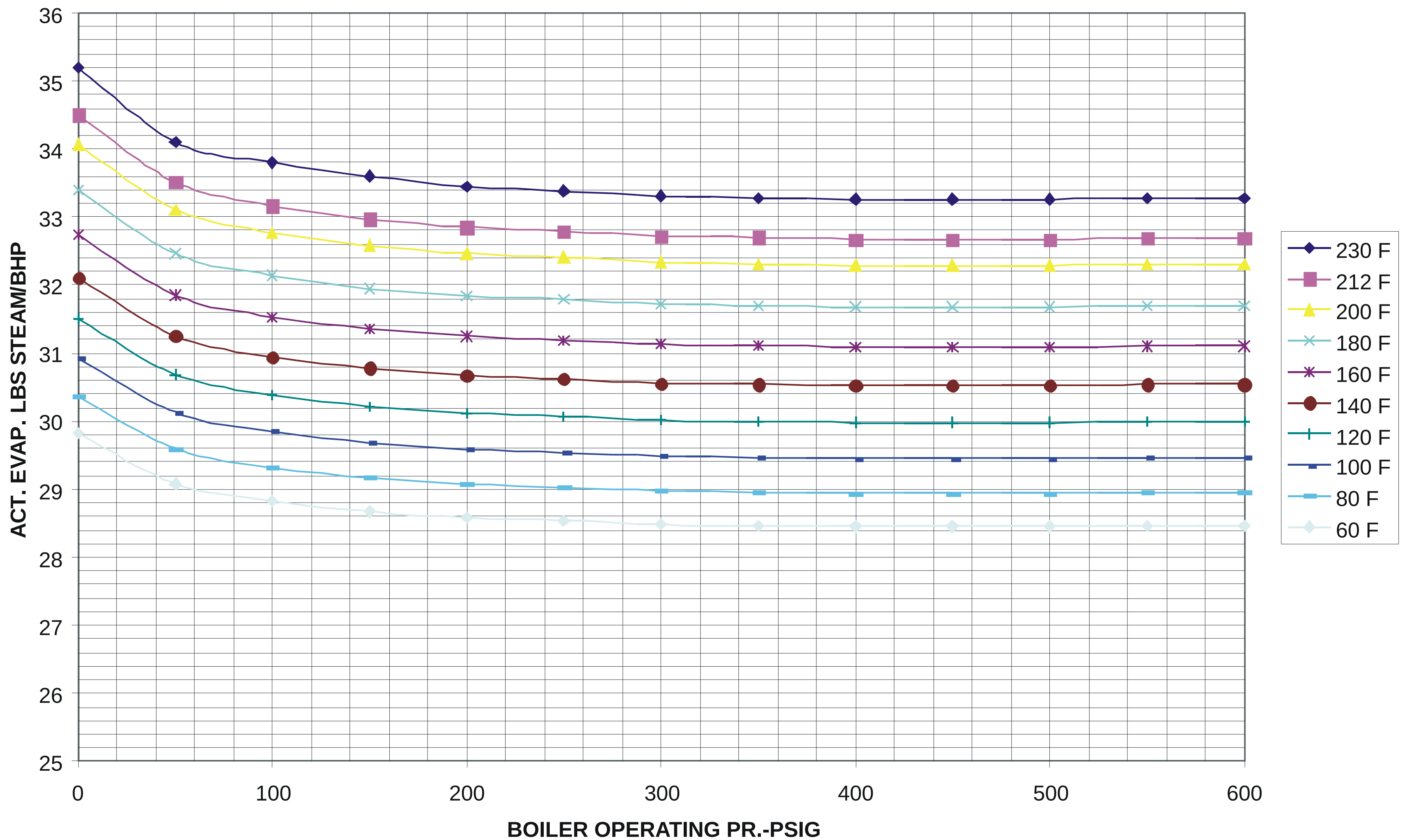


Figure 9. Factors of Evaporation

9.0 FEEDWATER SYSTEM

9.1 FEEDWATER SUPPLY

9.1.1 The boiler feedwater pump must not be directly connected to a city water main or to any apparatus that is directly connected to a water main. The feedwater pump should be connected to a deaerator or a supply make-up tank that will serve as a reservoir for system condensate return, chemical treatment, bypass return and makeup water.

9.1.2 The best method for handling boiler feedwater is a well designed deaerator. The next best method is a well designed feedwater tank such as is illustrated in Figure 10.

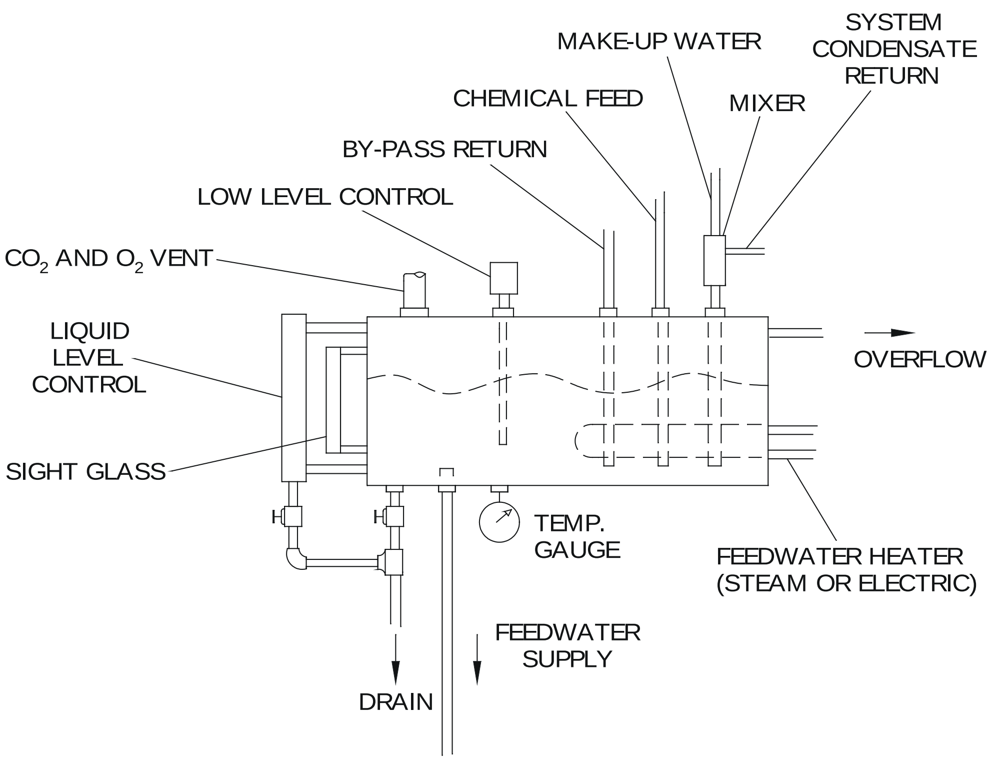


Figure 10. Water Tank Installation

For either a deaerator or a simple feedwater tank the reservoir should be large enough to provide a sufficient quantity of water for approximately ten to twenty minutes of operation when little or no condensate is being returned from the system. The reservoir should also be large enough to accommodate a quantity of system condensate being returned after a boiler and/or system shutdown, plus the expansion that occurs on startup when the feedwater is heated. Table 6 indicates the recommended feedwater reserve quantities at twenty minutes storage and feedwater tank capacities for the different boiler sizes.

Table 6. Recommended Feedwater Reserves & Tank Sizes

Model Size (BHP)	Feedwater Reserve Quantities (U.S. Gallons)	Feedwater Tank Size (U.S. Gallons)
75	100	210
100	140	210
150	210	430
200	275	510
250	350	580
300	420	760
350	490	970
400	560	970
450	630	1250
500	700	1320
600	840	1500

9.1.3 A feedwater pump is necessary to make up the water in the Circulatic boiler drum/separator that has been evaporated. A multi-staged centrifugal pump is the usual preferred choice for this application although a regenerative turbine pump is often used. With proper sizing, piping, and valving a single pump may supply more than one boiler at one time. The pump should be installed as close as possible to the deaerator or makeup tank where piping losses least affect the NPSHA (Net Positive Suction Head Available) to the pump. The suction piping should be at least as large as the pump inlet with one isolation gate valve and as few fittings as possible. Figure 11 and Figure 12 illustrate feedwater pump arrangements schematically.

9.1.4 Feedwater pumps for Vapor Circulatic boilers are sized in the range of <u>2 to 2-1/2</u> times the evaporation rate of the boiler. Use of "general rules" for the sizing of feedwater pumps for other types of boilers runs the risk of unsatisfactory operation for the Circulatic boiler.

9.1.5 When selecting feedwater pump(s) for your installation, consult the latest or current edition and addenda of the ASME Boiler and Pressure Vessel Code as well as local and city codes. Section I, Power Boilers, of the ASME Code, for example, currently requires that the source of feeding shall be capable of supplying water to the boiler at a pressure of 3% higher than the highest setting of any safety valve on the boiler. Vapor Power recommends this as good practice to follow in the absence of any jurisdictional requirements to the contrary. Table 7 (see page 24) lists the approximate evaporation rate for each model boiler, the required feedwater pump capacity range and the heads required at the boiler connection for various boiler operating pressures.

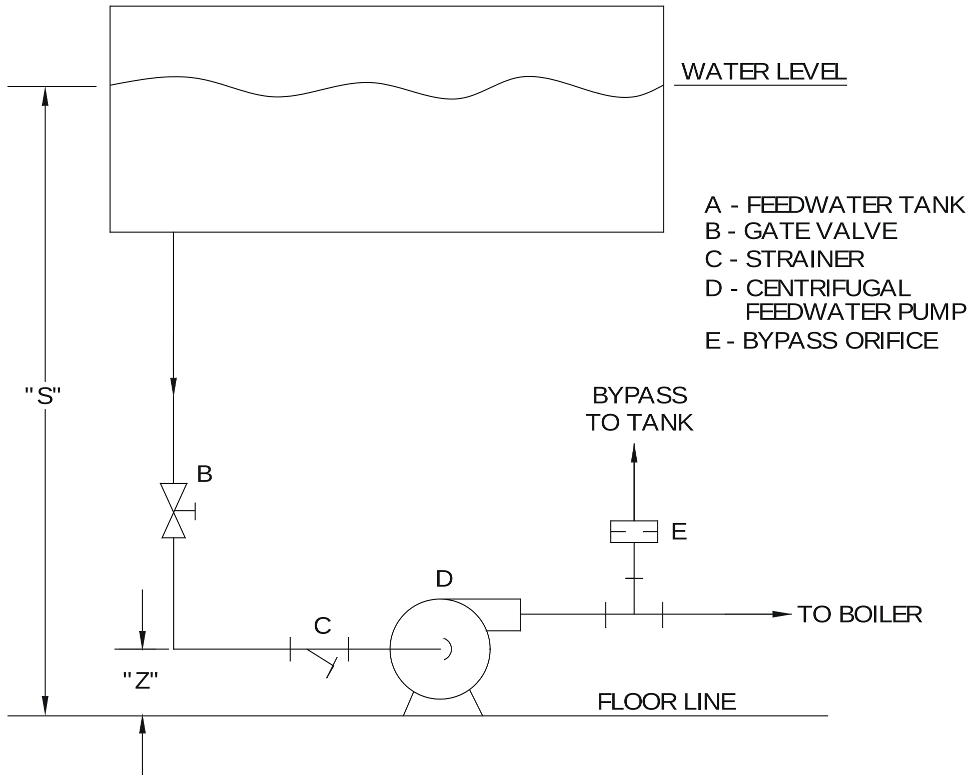


Figure 11. Centrifugal Pump Installation

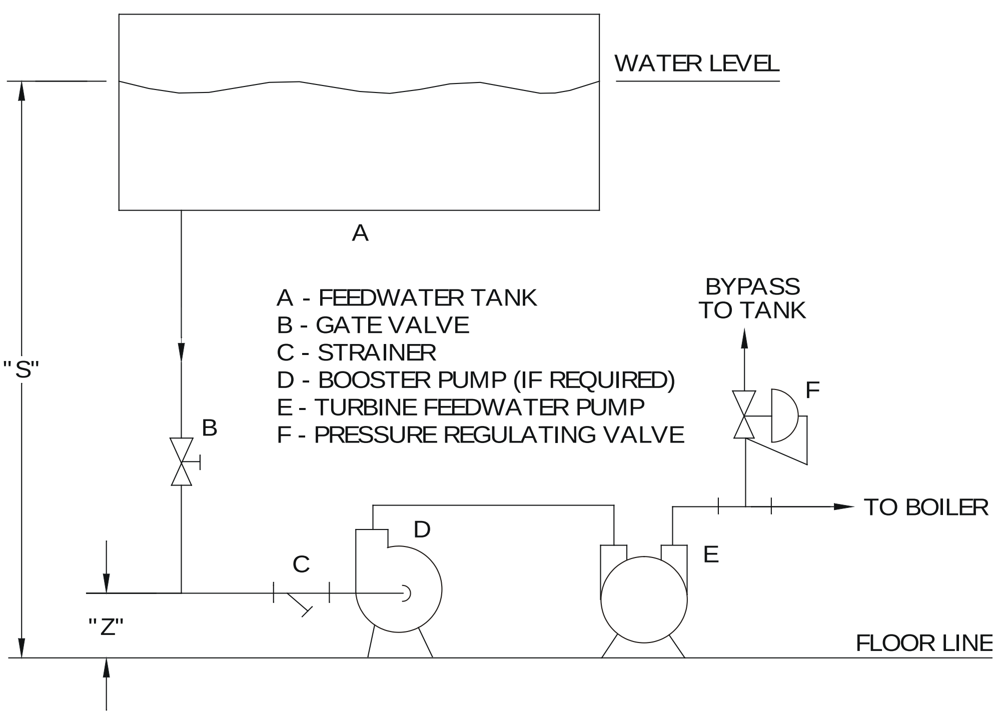


Figure 12. Turbine Pump Installation

9.1.6 To illustrate the use of Table 7 see the following example:

Assume a centrifugal feedwater pump for a 150 BHP Circulatic, operating at 135 psig steam with safety valve set at 150 psig. The feedwater supply will be from a vented tank (see Figure 13) with water temperature at 210°F. Using a sheet of graph paper plot points A, B, C, D & E described as follows and as shown on Figure 13. The pump curve exceeds the requirement of point "A" and crosses line "D-E" at approximately 28.5 GPM @ 418 ft. which is within the desired flow range.

Point "A": 1.03 x Safety valve set pressure = 372 feet of water at an evaporation rate of 10 GPM.

NOTE

For safety valve settings not listed interpolation is required.

Point "B": The minimum flow of 20 GPM at minimum head of 382 ft of water.

Point "C": The maximum flow of 25 GPM at maximum head of 387 ft of water.

Draw a straight line between points "B" and "C". This line represents the boiler pressure requirements over and above 150 psig at the boiler inlet connection.

Other factors to consider in the feedwater pump selection process include the following:

Piping Losses: As indicated in Figure 11 and Figure 12, the feedwater pump is located near the feedwater reservoir in order to keep the pump suction line as short as possible. Piping from the pump to the boiler may then be long with many fittings. The resulting piping losses must be added to the pressure requirements of Table 7. We will assume a pressure drop of approximately 10 PSI (24 ft of water) between the pump and boiler at 20 GPM and 38 feet of water at 25 GPM. These values are added to Point "B" and Point "C" respectively.

Bypass Flow: A centrifugal pump has the ability to operate at "shut off" (zero GPM) for short periods of time. However, operation at "shut off" causes the water temperature in the pump volute to increase quite rapidly as it absorbs the energy supplied by the pump motor, the result of which may damage the pump or cause unsatisfactory operation. Therefore, most pump manufacturers recommend a bypass orifice that allows some flow at all times back to the feedwater supply reservoir.

For this example an orifice will be sized to pass 5 GPM back to the feedwater reservoir at 450 ft. This will hold the temperature rise to what this particular pump manufacturer has recommended as maximum allowable. When the pump is operating at point “E”, approximately 5 GPM must be added for the orifice. This value is also added to points "B” and "C” as indicated by:

<u>Point “D”</u>: Minimum flow of 25 GPM at a head of 406 feet of water

<u>Point “E”</u>: Maximum flow of 30 GPM at a head of 425 feet of water

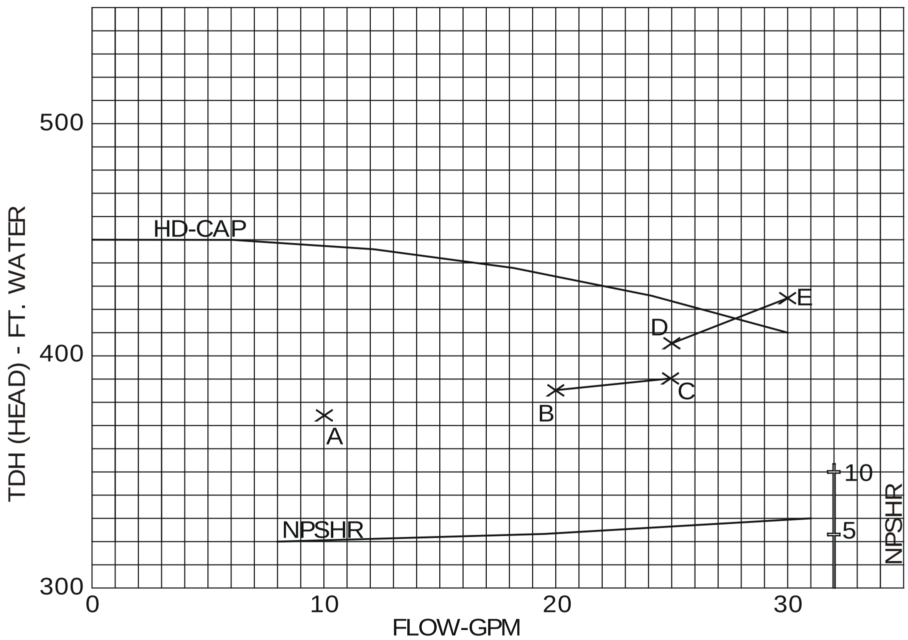


Figure 13. Centrifugal Pump Selection

Table 7. Feedwater Pump Requirements

Model Size (BHP)	Equiv. Evap. (US GPM) (1)	Req'd Feed Water Flow (US GPM)	Oper Press. (PSIG)	S.V. Set (PSIG)	1.03 X S.V. Set (Ft. HD.) (1) (2)	Feedwater Pressure Req'd at the Boiler (3)			
						Minimum Flow (2)		Maximum Flow (2)	
						PSIG	Ft. Water	PSIG	Ft. WATER
			13	15	37	20	47	22	53
			50	55	136	61	146	64	152
75	5	10 - 13	100	110	273	118	283	120	289
			135	150	372	159	382	162	388
			200	220	546	231	556	234	562
			225	250	620	262	630	264	636
			13	15	37	24	56	27	64
			50	55	136	65	155	68	163
100	7	14 - 17	100	110	273	122`	292	125	300
			135	150	372	163	391	166	399
			200	220	546	235	565	238	573
			225	250	620	266	639	269	647
			13	15	37	20	47	22	52
			50	55	136	61	146	63	151
150	10	20 - 25	100	110	273	118	283	120	288
			135	150	372	159	382	161	387
			200	220	546	231	556	233	561
			225	250	620	262	630	264	635
			13	15	37	24	56	27	64
			50	55	136	65	155	68	163
			100	110	273	122	292	125	300
			135	150	372	163	391	166	399
200	14	28 - 34	200	220	546	235	565	238	573
			225	250	620	266	639	269	647
			300	330	819	348	838	352	846
			400	440	1092	462	1111	465	1119
			475	530	1315	554	1334	557	1342
			13	15	37	24	56	27	65
			50	55	136	65	155	68	164
			100	110	273	122	292	125	301
			135	150	372	163	391	166	400
250	17	34 - 42	200	220	546	235	565	239	574
			225	250	620	266	639	269	648
			300	330	819	348	838	352	847
			400	440	1092	462	1111	465	1120
			475	530	1315	554	1334	558	1343
			13	15	37	22	52	25	59
			50	55	136	63	151	66	158
			100	110	273	120	288	123	295
			135	150	372	161	387	164	394
300	21	42 – 52	200	220	546	233	561	236	568
			225	250	620	264	635	267	642
			300	330	819	347	834	350	841
			400	440	1092	460	1107	463	1114
			475	530	1315	552	1330	555	1337
			13	15	37	24	56	28	66
			50	55	136	65	155	69	165
			100	110	273	122	292	126	302
			135	150	372	163	391	167	401
350	25	49 – 60	200	220	546	235	565	239	575
			225	250	620	266	639	270	649
			300	330	819	348	838	352	848
			400	440	1092	462	1111	466	1121
			475	530	1315	554	1334	558	1344
			13	15	37	24	56	28	66
			50	55	136	65	155	69	165
			100	110	273	122	292	126	302
			135	150	372	163	391	167	401
400	28	56 – 70	200	220	546	235	565	239	575
			225	250	620	266	639	270	649
			300	330	819	348	838	352	848
			400	440	1092	462	1111	466	1121
			475	530	1315	554	1334	558	1344

Table 7. Feedwater Pump Requirements (Continued)

Model Size (BHP)	Equiv. Evap. (US GPM) (1)	Req'd Feed Water Flow (US GPM)	Oper Press. (PSIG)	S.V. Set (PSIG)	1.03 X S.V. Set (Ft. HD.) (1) (2)	Feedwater Pressure Req'd at the Boiler (3) Minimum Flow (2) PSIG	Minimum Flow (2) Ft. Water	Maximum Flow (2) PSIG	Maximum Flow (2) Ft. Water
450	32	64 – 80	13	15	37	24	56	28	66
			50	55	136	65	155	69	165
			100	110	273	122	292	126	302
			135	150	372	163	391	167	401
			200	220	546	235	565	239	575
			225	250	620	266	639	270	649
			300	330	819	348	838	352	848
			400	440	1092	462	1111	466	1121
			475	530	1315	554	1334	558	1344
500	35	70 – 88	13	15	37	23	55	28	66
			50	55	136	64	154	69	165
			100	110	273	121	291	126	302
			135	150	372	162	390	167	401
			200	220	546	234	564	239	575
			225	250	620	265	638	270	649
			300	330	819	348	837	352	848
			400	440	1092	461	1110	466	1121
			475	530	1315	554	1333	558	1344
600	42	84 – 105	13	15	37	23	55	27	65
			50	55	136	64	154	68	164
			100	110	273	121	291	125	301
			135	150	372	162	390	166	400
			200	220	546	234	564	239	574
			225	250	620	265	638	269	648
			300	330	819	348	837	352	847
			400	440	1092	461	1110	465	1120
			475	530	1315	554	1333	558	1343

NOTE 1: Head and flow rate needed to meet ASME requirement.

NOTE 2: Head in "Feet of Water" based on SP. GR. of 0.9588 (@ 210°F).

NOTE 3: Piping head losses between feedwater pump and boiler connection plus any other resistance to flow must be added to values shown.

9.1.7 For an alternate example, a regenerative turbine is assumed to be the preferred choice of a feedwater pump. Using a sheet of graph paper plot points A, B & C as described in paragraph 9.1.6 and as shown on Figure 14.

We will also need to consider piping losses as in paragraph 9.1.6 and add these values to points "B" and "C" as indicated by:

Point "Dt": Minimum flow of 20 GPM at a head of 406 feet of water.

Point "Et": Maximum flow of 25 GPM at a head of 425 feet of water.

The illustrated turbine pump curve for this example crosses line "Dt – Et" at 24.5 GPM and 422 feet of head, which is above and to the right of point "A" and within the required flow range.

Turbine pumps, unlike centrifugal pumps do not have the ability to operate at "shut off" (zero GPM). Therefore, as the boiler modulating feedwater valve closes and less feedwater is required, a bypass relief valve (see Figure 12), i.e. pressure regulating valve, must be actuated to avoid exceeding the maximum head allowed for the pump. For this example a bypass relief valve was chosen to start opening at 450 feet of head (point "F"), a value that is both above and to the right of point "A" and above point "Et". As less flow is required by the boiler, the operating point on the pump curve backs up to point "G" where the bypass relief valve is fully open and all water is bypassed back to the feedwater reservoir. The value of point "G" (545 feet of water) is less than the maximum allowable head for the pump.

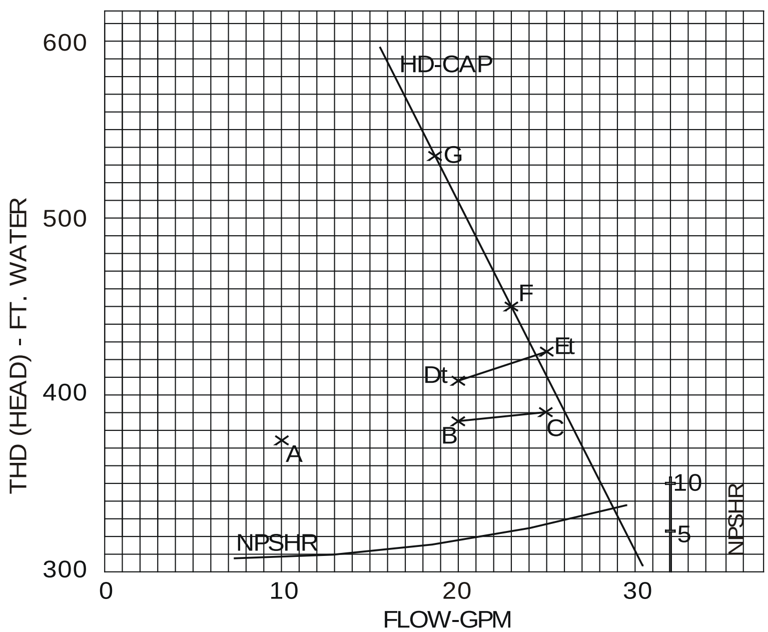


Figure 14. Turbine Pump Selection

9.1.8 Pump cavitation is a very important issue to address in a feedwater pump installation. When cavitation occurs the effect on the pump is a reduction in capacity and pressure and noisy operation. Also, cavities of vapor formed in the pump suction move to regions of higher pressure where they collapse, or implode, with such force that metal is removed from the pump casing and impeller and will eventually destroy the pump. Pump cavitation will occur when the absolute pressure of the pump suction is less than the vapor pressure of the liquid being pumped. It is the responsibility of the customer or installer to provide the necessary energy, through a proper installation, to overcome feedwater pump suction piping losses so that the pump net pressure at the suction is positive or, that the pump receives more than its NPSHR (Net Positive Suction Head Required). The NPSHA (Net Positive Suction Head Available) of a system must always be greater than the pump NPSHR in order to avoid cavitation.

9.1.9 Vapor Power recommends that the feedwater pumps for Circulatic boilers have an NPSHR as low as economically possible. The energy to overcome piping losses and provide the NPSHR normally comes from an elevated feedwater supply reservoir and/or a separate charging (booster) pump which has an inherently lower NPSHR than the main feedwater pump. The elevation of the feedwater tank (reservoir) or, more importantly, the height of the water level can be determined by the following formula and the illustration of feedwater pump arrangements in Figure 11 and Figure 12 (see page 21).

$$S = NPSHR + S.F. - \left[\frac{(P + Pa - Pvp)\ 2.31}{S.G.}\right] + \text{Ƶ} + hf$$

Where:

NPSHR	=	Required Net Positive Suction Head, Feet. (as specified by the pump manufacturer).
S.F.	=	Safety Factor, 2 feet.
S.G.	=	Specific Gravity of the feedwater at the temperature it is to be pumped.
P	=	Pressure on the surface of the feedwater, PSIG. (P = 0) when the feedwater tank is vented to atmosphere.
Pa	=	Atmospheric pressure, PSIA. (Pa = 14.7 PSI at sea level and decreases with altitude).
Pvp	=	Vapor pressure of the feedwater at the temperature it is to be pumped, PSIA (this is the absolute pressure corresponding to the saturated temperature in tables for thermodynamic properties of steam.)
Ƶ	=	Distance from the surface of the floor where the feedwater or booster pump is mounted to the center line of the pump shaft, Feet.
hf	=	All friction losses in the suction system piping up to the pump inlet in feet of head loss (this can be determined from standard friction loss charts).
S	=	Vertical distance from the surface of the floor where the feedwater or booster pump is mounted to the surface of the feedwater, Feet.

9.1.10 Following the example of paragraph 9.1.6 for a centrifugal pump, the illustrated pump has a suction size of 1-1/2" NPS. Suction piping is 1-1/2" NPS schedule 4'0 with 1-1/2" NPS valve and fittings having an equivalent length of straight pipe of 45 feet. Calculate the value of "S" (see Figure 11) when:

NPSHR	=	6.0 feet @ 30 GPM (see Figure 13).
S.F.	=	2 feet
S.G.	=	0.958 (for 210°F water)
P	=	0 PSIG (vented tank)
Pa	=	14.7 PSI
Pvp	=	14.12 PSIA (for 210°F water)
hf	≅	3.2 feet (from piping loss charts for equivalent length of pipe)
Ƶ	=	0.34 feet (4-1/8 inches)

$$S = 6.0 + 2.0. - \left[\frac{(0 + 14.7 - 14.12)\ 2.31}{0.958}\right] + 0.52 + 3.2$$

$$S = 10.14 \text{ feet}$$

The minimum water level of the feedwater tank should be 10-1/2 feet above the pump floor. If it is not possible or practical to mount the tank at the calculated elevation it will be necessary to select a pump with a lower NPSHR, reduce piping losses by increasing the pipe size or purchase a booster pump with an inherently lower NPSHR (see Figure 12).

9.1.11 For comparison the value of "S" for a turbine pump, assuming a 2-1/2" NPS pump inlet with 2-1/2" NPS piping, valve, and fittings for an equivalent length of 45 feet is:

NPSHR	=	5.0 feet @ 24.5 GPM (see Figure 14).
S.F.	=	2.0 feet
S.G.	=	0.958 (for 210°F water)
P	=	0 PSIG (vented tank)
Pa	=	14.7 PSIA
Pvp	=	14.12 PSIA (for 210°F water)
hf	≅	0.5 feet (from piping loss charts for equivalent length of pipe)
Ƶ	=	0.52 feet (6-1/4 inches)

$$S = 5.0 + 2.0. - \left[\frac{(0 + 14.7 - 14.12)\ 2.31}{0.958}\right] + 0.52 + 0.5$$

$$S = 6.6 \text{ feet}$$

The minimum water level of the feedwater tank should be 7 feet above the pump floor in this example.

9.2 FEEDWATER TREATMENT

9.2.1 Every boiler made today is subject to premature failure if its feedwater is not properly treated for scale and corrosion prevention. The boiler manufacturer cannot be held accountable for the adverse results of scale or corrosion; it is the responsibility of the boiler owner/user to see that the feedwater to the boiler is continuously free of scale formers and corrosion potentials. Vapor Power recommends that a reliable water treatment company be consulted before the boiler is installed. The treatment and program should be based entirely on a complete analysis of the raw water and the needs of the boiler and the user system.

9.2.2 Boiler feedwater treatment has two main functions: the first being prevention of scale on the inside of the boiler tubing walls (heat exchanger); the second being the prevention of corrosion of the tubing walls, other boiler parts, and the user system. Although prevention of scale is important, its presence is easily detectable. Many types of scale can be removed by acid washing. The exceptions will be discussed in later paragraphs of this bulletin. Corrosion is the "silent killer". Corrosion cells can be present with no external evidence until actual failure occurs.

9.2.3 General aspects of water treatment and a water treatment program will be discussed in the following paragraphs. Vapor Power will specify only water properties that experience has shown to be necessary; the more complex conditions are left to the water chemist after a review of the raw water analysis.

9.2.4 A daily log should be set up and maintained to show the important properties of the boiler waters as a result of a specified water treatment. The water treatment company and user need to be responsible for periodically examining the log for correct procedures and acceptable water conditions. (See Figures 15 and 16 for sample log sheets.)

9.3 PREVENTION OF SCALE FORMATION

9.3.1 Prevention of scale formation begins with the selection of the proper method for removing the scale forming ingredients of the raw water. For normally encountered water, a sodium zeolite softener has proven to be one of the better methods of removing calcium and magnesium hardness, the two principle scale formers. Water hardness indicates the amount of calcium and magnesium scale formers. They form scale with carbonates ($Ca\ CO_3$), the hydroxides ($Mg\ OH_2$), the sulfates ($Ca\ SO_4$), and the silicates ($Ca\ Si\ O_2$). Their removal eliminates these types of scale formation. The sodium zeolite softener also slightly raises the alkalinity (pH) in the softened water which helps to protect the system from corrosion.

COMPANY______________________ LOCATION_______________________ BOILER TYPE_____________________ STARTUP DATE___________________

BOILER NO.	UNITS							
DATE / TIME	------	/	/	/	/	/	/	/
TIMER	HRS.							
DATA TAKEN BY	------							
SERVO PIN NO.	------							
WATER PUMP PRESS.	PSIG	/	/	/	/	/	/	/
STEAM PRESS PANEL/HEADER	PGIS	/	/	/	/	/	/	/
COIL TEMP 1/2	ºF	/	/	/	/	/	/	/
COIL TEMP 3/4	ºF	/	/	/	/	/	/	/
COIL TEMP 5/6	ºF	/	/	/	/	/	/	/
FUEL NOZZLE PRESS.	IN W.C. OR PSI							
AIR BOX PRESS.	IN W.C.							
ATOM. AIR PRESS.	PSI							
STACK TEMP.	ºF							
FEED WATER TEMP.	ºF							
H_2O PUMP SPEED/ BLOWER SPEED	RPM	/	/	/	/	/	/	/
MAKE UP WATER METER READING	GAL							
BOILER BLOWDOWN	SEC/MIN	/	/	/	/	/	/	/
PROBLEMS or COMMENTS / ADJUSTMENTS								

Figure 15. Daily Boiler Log

DAILY LOG OF WATER CONDITIONS AT ________________________ IN ______________ BOILER START ____________________
WATER TREATMENT CO.__________________________ TYPE CHEMICALS __________ DATE START ____________________
COMMENTS____

WATER OUT OF SOFTNERS

DATE/TIME/BY	UNITS	LIMITS	/ /	/ /	/ /	/ /	/ /	/ /
SOFT NO./pH	------	------ / 7-8	/	/	/	/	/	/
CHLORIDE	PPM C1	equal to raw water						
HARDNESS	PPM $CaCO_3$	0						

BOILER FEEDWATER

BOILER NO.	------	------						
FEEDWATER TEMP	ºF	200-210						
OXYGEN	PPM O_2	0.0						
SULFITE	PPM SO_3	15-30						
HARDNESS	PPM $CaCO_3$	0-Trace						
PHOSPHATE	PPM PO_4	10-30						
pH	------	9-10.0						
TDS	PPM	850						
SILICA	PPM SiO_2	0-6						

WATER INTO BOILER COILS (DRUM WATER)

HARDNESS	PPM $CaCO_3$	0-Trace						
PHOSPHATE	PPM PO_4	30-40						
pH	------	10-11						
'P' ALKALINITY	PPM $CaCO_3$	150-300						
'M' ALKALINITY	PPM $CaCO_3$	300-600						
SULFITE	PPM SO_3	25-50						
TDS	PPM	8500						
DISSOLVED IRON	PPM Fe	0-.2						
SILICA	PPM SiO_2	0-55						

CONDENSATE RETURN WATER

TDS	PPM	0-15						
pH	------	7.5-8.5						
DISSOLVED IRON	PPM Fe	0-.2						

Figure 16. Boiler Water Treatment Log

9.3.2 Water softener size is determined by the amount of hardness to be removed, the required flow rate, the total flow desired between regenerations, and the use factor. The latter must be taken into account if operation were to be 24 hours per day for five to seven days per week. Twin softeners may be necessary so that one can be regenerating while the other is handling the water load. A water treatment chemist will factor all these items into softener sizing calculations along with the raw water analysis.

9.3.3 Silica can form a very troublesome scale that is nearly impossible to remove. If dissolved silica appears in the raw water analysis the use of a demineralizer may be warranted. Your water treatment chemist is best suited to make this determination and to advise about proper demineralizer sizing.

9.3.4 Dissolved iron also forms a scale which must be taken into account. Similar to the other scales, it forms in the hottest region of the boiler heat exchanger tubing. Like silicate and calcium sulfate, it cannot be readily removed once formed. Again, the water treatment chemist can pass judgement on whether the amount present warrants either treatment for reduction or removal. A demineralizer will remove the iron ion from the raw water as well as other ions, e.g. calcium, magnesium, sulfate, chloride, nitrate, silica, etc.

NOTE

Dissolved iron may be entering the boiler feedwater supply in large amounts also with improperly treated return condensate. Checks should be made periodically on this water source especially if its pH is below 8.

9.3.5 Chemical treatment is added to the feedwater to take care of small amounts of hardness that may pass through the softeners or demineralizer. Some examples of this treatment are phosphates, carbonates, chelants, polymers, or combinations of these. Once more, your water treatment chemist can best advise the method compatible with the boiler and system. Chemical treatment without softening or demineralizing is not satisfactory.

9.4 PREVENTION OF BOILER CORROSION

9.4.1 Two gases, dissolved oxygen (O_2) and dissolved carbon dioxide (CO_2), must be eliminated from the feedwater to prevent oxygen corrosion and acidic corrosion (low pH). The best method of accomplishing this elimination is with a well designed de-aerator. The next best thing is a well-designed feedwater tank or condensate receiver. Well-designed de-aerators are available from several commercial sources.

9.4.2 Dissolved oxygen is a corrosion accelerant that must be completely removed. The solubility of oxygen in water decreases with temperature. Therefore, the de-aerator or feedwater tank must heat the boiler feedwater and be vented so that gases driven off can easily escape to the atmosphere. Even at a temperature of 210°F the solubility of oxygen in water is such that some oxygen will remain in solution. (See the oxygen solubility chart in Figure 17). The remaining oxygen must be removed by using an oxygen scavenger. The scavenger must be added to the feedwater tank or de-aerator at a point where it can intercept the remaining dissolved oxygen and have sufficient "residence time" (preferably in the tank) to react. The effect of the scavenger is judged by the residual amount remaining in the boiler feedwater. However, excess scavenger and dissolved oxygen have been known to coexist when residence time is not sufficient. If all dissolved oxygen is not removed in the boiler feedwater it will be driven off within the boiler when the water temperature is increased to the point where dissolved oxygen solubility is zero. At this point oxygen corrosion cells are established which quickly promote the boiler wetted part failure.

9.4.3 Sodium sulfite is the most common oxygen scavenger used in boiler feedwater treatment but has its limits of application. It contributes to total dissolved solids (TDS) and creates sulfates with oxygen (a scale former, see paragraph 9.3.1). Catalyzed sodium sulfite is preferred over uncatalyzed sodium sulfite because the added catalyst greatly speeds the reaction with dissolved oxygen.

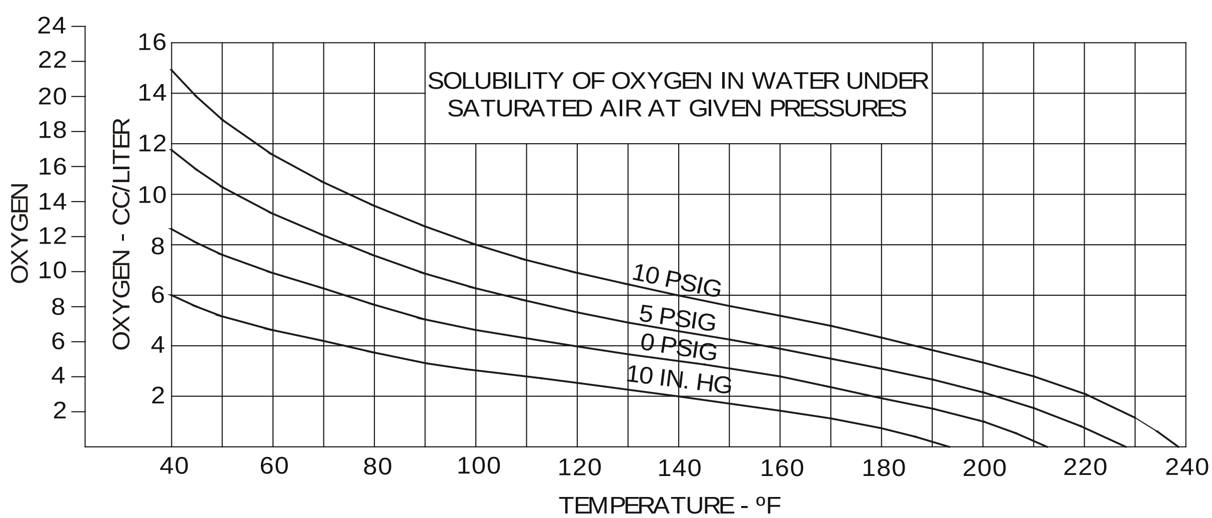


Figure 17. Oxygen Solubility

9.4.4 Hydrazine, once a widely used volatile oxygen scavenger that did not add TDS to the boiler feedwater, is a known carcinogen; hence, its use is not recommended. As a alternate, some of the larger, widely known water treatment companies have developed proprietary compounds that are either volatile or non-volatile oxygen scavengers as the situation may warrant.

9.4.5 Oxygen scavengers may be either volatile or non-volatile. The volatile scavenger not only scavenges oxygen in the feedwater system and boiler, it also provides corrosion protection in the condensate system. Non-volatile oxygen scavengers do not provide corrosion protection to the condensate system leaving this action dependent entirely upon the addition of neutralizing amines.

9.4.6 Acidic corrosion can occur when the boiler feedwater pH is low (7.0 is neutral). If a demineralizer is used in the treatment system the resultant water is slightly acidic and “hungry” to combine with whatever free ions are available from the material it contacts. Sodium zeolite softener water on the other hand leaves the water with a slight alkalinity. In either case it is most often necessary to add a caustic in order to get the feedwater alkalinity within the pH range of 9.0 – 10.0

9.4.7 Caustic soda (Na OH) or soda ash ($Na_2 CO_3$) added to the boiler feedwater are two common ways of increasing the feedwater pH. The caustic soda raises the pH immediately by simply combing with the water to increase the OH anion according to the following chemical equation:

$$Na\,OH + H_2O \Leftarrow Na\,OH + HOH$$

Soda ash requires heat in order to create the OH anion such as in the following chemical equation:

$$Na_2 CO_3 + H_2O \overset{HEAT}{\Leftarrow} CO_2 + 2Na\,OH$$

Formation of CO_2 gas is the undesirable side effect of the soda ash reaction. Depending upon the temperature and residence time in the feedwater tank the reaction may take place in the boiler heat exchanger instead. The CO_2 gas would then find its way into the condensate system where it would combine with the water to form an acidic corrosion agent.

9.4.8 Neutralizing or filming amines are normally required as a protection for the condensate system against corrosion. Volatile amines added to the feedwater tank may be driven off with other gases such as the dissolved oxygen and carbon dioxide; hence, these should be entered downstream of the feedwater tank.

9.5 WATER SAMPLING

9.5.1 Raw water, of course, is the most important sample and analysis. This must be done before any water treatment can be prescribed. Check this water at least once a year thereafter to see if it is changing.

9.5.2 Softened (or deionized) water sampling and analysis checks the softener (or deionizer) operation before a malfunction causes the feedwater to be loaded with either scale formers or water high in chlorides. Chlorides greater than the raw water amount indicates that the softener regeneration cycle has not been properly completed.

9.5.3 Water about to enter the boiler coils is the most important water relative to the **boiler**. The program for water treatment must be established or modified based upon an analysis of this water. When obtaining water samples for testing, water from a connection to the boiler circulating pump outlet manifold is the most representative. Sample water may be taken from the water column also. Take the sample before the blowdown period after flushing out the sampling line. A cooling coil must be used to prevent flashing. Figure 18 illustrates typical pump piping for obtaining water samples.

9.5.4 Where a continuous blowdown line is used, the sample may be obtained from this line after making sure the line is running free. Samples must not be taken from a "dead end" water line. Bottom blowdown lines must be avoided for sampling purposes since the concentration of dissolved solids is not consistent or representative at these points.

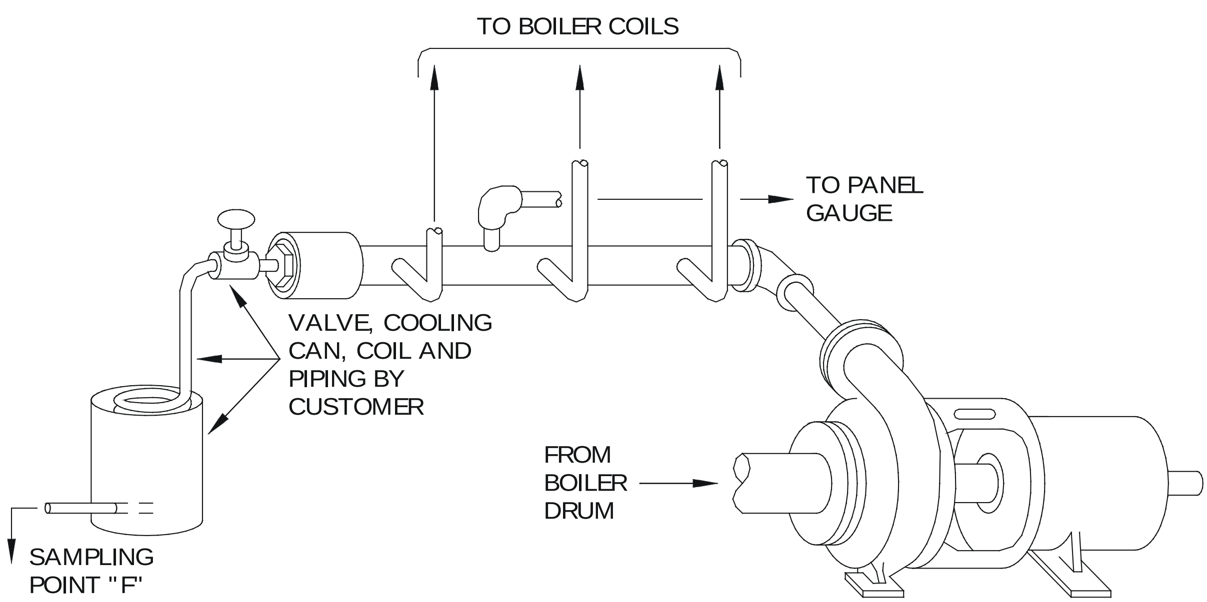


Figure 18. Typical Pump Piping

9.5.5 Return condensate is the most important water relative to the **system load**. If it has low pH or high dissolved iron, corrosion is taking place. If the total dissolved solids are high, carryover may be taking place. Also the system may be leaking process material into the condensate line.

9.6 WATER ANALYSIS

9.6.1 Specific water properties that Vapor Power is certain are required are listed in the following tables of preferred ranges. (See Tables 8, 9, and 10). Other, or more complex, conditions should be referred to your water treatment chemist for resolution.

Table 8. Boiler Feedwater Requirements

Water Property	Preferred Range
Feedwater Temp.	200 - 210ºF
Total Hardness ($CaCO_3$)	0.0 ppm
pH	9 - 10
Carbon Dioxide (CO_2)	0 ppm
Oxygen (O_2)	0 ppm
Oxygen Scavenger (as Sulfite, SO_3)	15 – 30 ppm
Total Dissolved Solids	Less than 850 ppm
Silica (SiO_2)	Less than 5.5 ppm
Carbon Dioxide (CO_2)	0 ppm

Table 9. Boiler Coils Water (Drum Water) Requirements

Water Property	Preferred Range
Total Hardness ($CaCO_3$)	0.0 ppm
pH	10 – 11
Sulfate (as SO_4)	Less than 50 ppm
Total Alkalinity (“M”) ($CaCO_3$)	300 – 600 ppm
Oxygen Scavenger (as Sulfite, SO3)	25 – 50 ppm
Total Dissolved Solids	Less than 8500 ppm
Silica (SiO_2)	Less than 5.5 ppm
Iron (Dissolved)	Less than 0.2 ppm

Table 10. Condensate Return Water Requirements

Water Property	Preferred Range
Total Dissolved Solids	Less than 15 ppm
pH	7.5 – 8.5
Iron (Dissolved)	Less than 0.2 ppm

9.6.2 Dissolved oxygen, without reservations, should be zero. Correspondingly, there should be an excess of the oxygen scavenger, the amount of excess dependent upon the "residence time" that is available for the scavenger to react with the oxygen. Excess sulfite, for example, has been known to coexist with dissolved oxygen when both are measured at the boiler feedwater inlet. Normally, however, excess sulfite should range from 15 – 30 ppm.

9.6.3 Dissolved carbon dioxide should also be zero. If not removed in the feedwater tank or deaerator it will combine with hydrogen to form carbonic acid, a corrosion accelerator, either in the boiler or the condensate system.

9.6.4 Alkalinity in the feedwater protects the boiler from acidic corrosion. It also slows the action of any oxygen that may not have been removed by feedwater heating and oxygen scavenging. On the other hand, if the water becomes too alkaline (pH greater than 12) in the boiler drum, caustic embrittlement can take place. Threads in threaded connections can be destroyed with resultant steam leaks. Vapor Power believes the feedwater pH should be between 9.0 and 10.0 with 9.5 as the preferred target level. The complexity of alkalinity is another place for a water treatment chemist to contribute expertise since the performance of some water treatment compounds may be affected by alkalinity levels. Phosphates, for example, tend to get "sticky" at a pH level below 9.6.

9.6.5 Desired hardness is zero. Temporary hardness for 1 or 2 days of up to 5 ppm can be tolerated with correct after treatment, e.g. phosphates.

9.6.6 Total dissolved solids (TDS) should be kept as low as practically possible. Satisfactory operation has been achieved with TDS values as great as 850 ppm in the inlet boiler feedwater; however, the lower the better. A practical value should be no more than 350 to 400 ppm.

9.6.7 Dissolved silica can be tolerated in small amounts and kept from precipitating out in the boiler coils by control of other properties, i.e. zero calcium, zero magnesium, and high alkalinity (pH) in combination with some proprietary water treatment compounds. Higher boiler operating pressures reduce the amount of dissolved silica that can be kept in solution with chemical treatment.

9.6.8 Dissolved iron may enter the boiler feedwater from either the raw feedwater, the system return condensate or as a total of both. Vapor has a preferred range of 0 – 0.2 ppm in the water entering the boiler coils. Some water treatment companies list 3 ppm of dissolved iron as possibly being harmful. Others allow more or less depending upon their experience with this material. If dissolved iron is entering the boiler feedwater via the system condensate then the condensate should be treated to control corrosion. Lignins have been used as treatment to keep the iron from precipitating out in the boiler coils.

9.7 TESTING WATER SAMPLES

9.7.1 Tests performed daily on water samples need not be a time consuming process. Many economical kits are available on the market to aid in making this a quick and simple procedure. The consulting water treatment chemist may be able to recommend the kits required.

9.7.2 The Dearborn Chemical Company in the Chicago, Illinois area is one manufacturer of individual test kits. Among the kits available are those listed below:

9.7.2.1 Hardness Test Set

9.7.2.2 Sulfite Test Set

9.7.2.3 Total Dissolved Solids Test Set

9.7.2.4 pH Reading Set

10.0 FUEL SUPPLY

10.1 GAS FIRED BOILERS

10.1.1 Vapor Power Circulatic boilers can accommodate various gas supply pressures. The gas train for boiler is sized according to the gas supply pressure the customer has available at the boiler. Gas flow requirements for the various model size boilers are listed in Table 11. Gas train sizes are based on 2 psi supply pressure.

Table 11. Boiler Natural Gas Requirements

Model Size (BHP)	High Fire Gas Flow Req'd. (SCFH)*	Customer Main Gas Connection (NPT) (Inch)
75	3,138	2
100	4,188	2
150	6,281	2
200	8,375	3
250	10,463	3
300	12,563	3
350	14,656	3
400	16,750	3
450	18,844	3
500	20,938	3
600	25,125	3
* Based upon a heating value of 1000 BTU/SCF		
NOTE 1: Gas flow required will change with the BTU heating content of the gas. NOTE 2: Consult your gas regulator supplier (Reliance, Fisher, Maxitrol or equivalent) for the size and type required for your specific application.		

10.1.2 The size of the gas line to the boiler is determined by the gas pressure from the local supplier, the volume of gas flow to the boiler in standard cubic feet per hour (SCFH), and the resistance of the pipe and fittings to the gas flow. Your local gas supplier can help to determine the proper size of piping required.

10.1.3 If the boiler facility main line gas pressure, when regulated, is less than 2 PSI consult Vapor Power, as it may be possible that the available gas pressure is adequate if certain changes to the boiler are made. In instances where the gas pressure is inadequate it may be necessary to install a gas booster. For such requirements experience indicates that a lobe-type, positive displacement booster having a built-in bypass valve produces the best results. Install the booster as close to the boiler as possible.

NOTE

Due to heat of compression it is best to cycle the booster off when the boiler burner cycles off.

10.1.4 When obtaining a gas regulator, specify data from Table 11 for the model size of boiler, the main gas line pressure and standard trim for natural gas (0.60 specific gravity). Regulators need to be adjustable above and below 2 PSI (or other indicated regulated pressure). Also another important feature is turndown. The boiler burners have turndown capability of at least 8:1 from high fire to low fire – the regulator should be able to match that capability. A separate main burner gas regulator is required for each boiler when multiple boiler installations are made.

10.1.5 The selected gas regulator(s) may be installed anywhere between the meter and the boiler, but must be located upstream of gas line safety equipment. Wherever the regulator is located it must be capable of supplying the required pressure at the boiler connection. Two regulators in series may be required if gas pressure is over 10 PSI in order to obtain accurate regulation and to meet local codes.

10.1.6 Some regulators may require a downstream sensor line in order to provide accurate pressure regulation. When a sensor line is required the connection must be at least five pipe diameters of straight pipe downstream of the regulator and two pipe diameters upstream from any valve, elbow or other restriction. Figure 19 illustrates a gas pressure regulator installation where two regulators are required.

10.1.7 There are several organizations and/or insurance companies that may have jurisdiction over a boiler installation. Their objectives are to reduce the probabilities of a boiler fuel explosion by providing guidelines for a system of instrumentation, interlocks and control valves. Figure 20 illustrates a typical gas supply system for a boiler. However, the illustrated system may not reflect the unique or special considerations of specific jurisdictions and does not supplant current Federal, state, and local regulations.

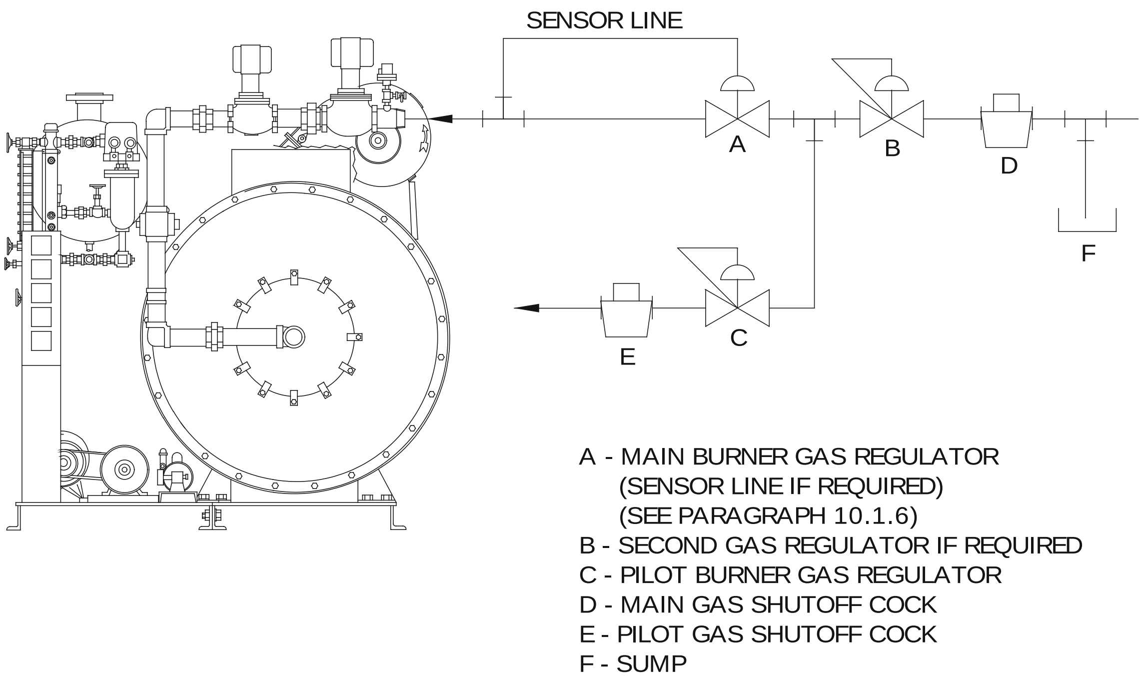
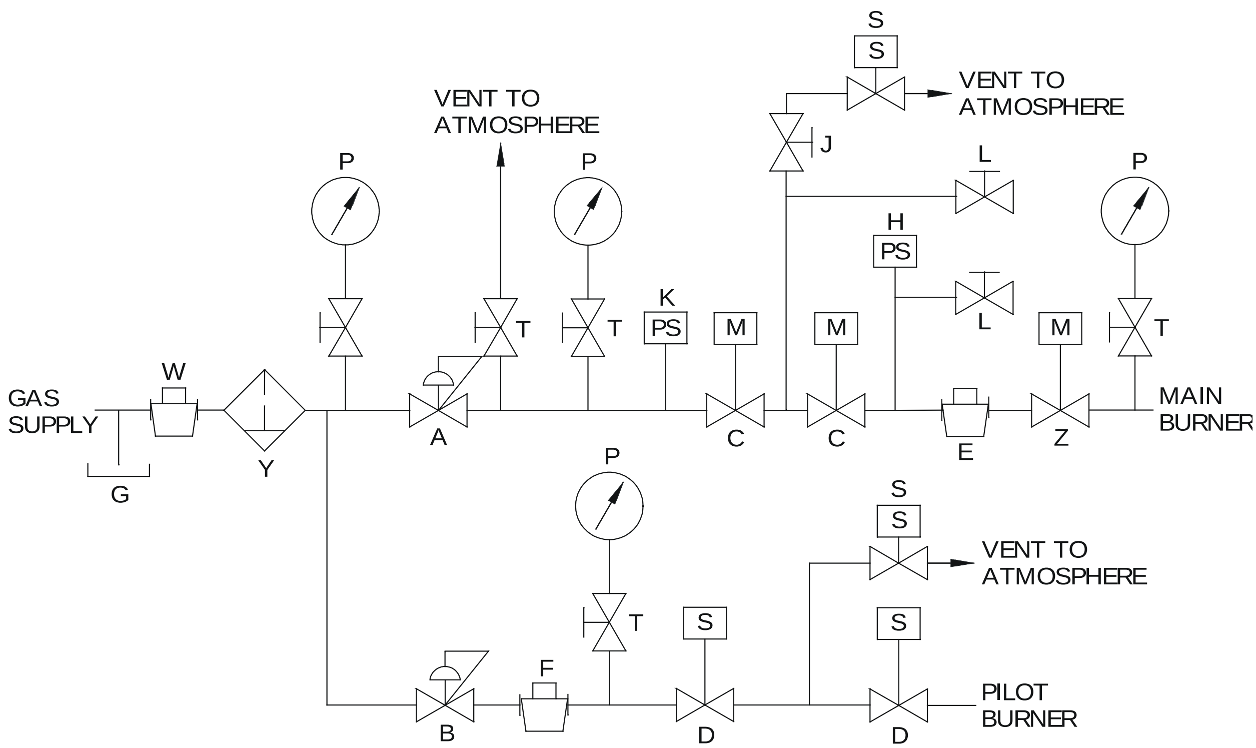


Figure 19. Gas Regulator Installation (For Two Regulators)

10.1.8 Figure 20 indicates several points that vent gas in normal operation. These points must be piped to a safe location outside the boiler enclosure. In addition, items such as regulators and pressure switches may have vent connections provided in case of a diaphragm or element failure. These vent connections should also be piped outside to a safe location.



A - MAIN BURNER GAS REGULATOR
B - PILOT BURNER GAS REGULATOR
* C - SAFETY SHUTOFF VALVE (CLOSED POSITION INTERLOCK WHEN REQ'D)
** D - SAFETY SHUTOFF VALVE (PILOT)
E - MANUAL SHUTOFF COCK (MAIN BURNER)
* F - MANUAL SHUTOFF COCK (PILOT)
G - DRIP LEG (SUMP)
* H - HIGH GAS PRESSURE SWITCH
J - VENT LINE MANUAL SHUTOFF VALVE (SEALED OPEN)
* K - LOW GAS PRESSURE SWITCH
L - LEAKAGE TEST CONNECTION
P - PRESSURE GAUGE
S - VENT VALVE (NORMALLY OPEN, DE-ENERGIZED)
T - MANUAL SHUTOFF VALVE
W - MAIN GAS SHUTOFF COCK
Y - GAS STRAINER
* Z - GAS FLOW CONTROL VALVE

* STANDARD BOILER EQUIPMENT
**1 VALVE IS STANDARD BOILER EOUIPMENT

Figure 20. Typical Gas Supply System

10.2 OIL FIRED BOILERS (DISTILLATE)

10.2.1 Fuel consumption requirements of No. 2 distillate fuel oil for the various model size boilers are shown in Table 12.

Table 12. Boiler Fuel Requirements

Model Size (BHP)	Fuel Consumption @ Rated Output (U.S. GAL/HR)*	Fuel Pump Capacity (U.S. GAL/HR)	Supply Line (Inch IPS)	Return Line (Inch IPS)
75	22	174	1	3/4
100	29.3			
150	44			
200	58.7			
250	73.3			
300	88			
350	102.7			
400	117.3			
450	132			
500	146.7	216	1-1/4	1
600	176	252		
* Based upon a heating value of 140,000 BTU/US GAL				
NOTE: Fuel consumption rate will change with the BTU heating content of the fuel.				

10.2.2 Circulatic boiler sizes 75 BHP through 450 BHP share the same size fuel oil pump in the interests of standardization. This pump delivers a constant rate of 174 U.S. gallons per hour despite the amount burned. Line sizes indicated in Table 12 cover only a single boiler installation with lines not longer than 100 feet in length. For longer lines a corresponding increase in pipe size must be made to compensate for the pipe restriction due to length.

10.2.3 The return line should always be piped back to the supply tank and never to the suction side of the fuel pump. Return line back pressure should not exceed 10 psig at the boiler, which includes the static head pressure if the fuel tank is elevated.

CAUTION

Do not put more than 25 psig to the inlet of the boiler fuel pump. Pressure over 25 psig will damage the fuel pump seal. Do not operate fuel pump without oil or it will be damaged.

10.2.4 If the dynamic suction lift (static suction lift + friction loss of pipe and fittings) exceeds 15 feet of water at the customer connection to the boiler it will be necessary to install a fuel transfer pump. The pump must be located between the main tank and customer connection to the boiler and have a capacity equal to the boiler fuel pump capacity. (See paragraphs 10.2.8, 10.2.9, & 10.2.10 for multiple unit installation).

10.2.5 Some customers prefer to remotely install the boiler fuel pump (and pressure regulating valve) as a method of overcoming the suction lift problem. This practice is acceptable provided a check valve is installed in the pump discharge line to the boiler as close to the pump as possible.

10.2.6 Use only gate valves or ball valves in the fuel piping lines to minimize resistance in the fuel piping system.

10.2.7 Local codes and ordinances may dictate the capacity, design, and location of fuel oil supply tanks. Where such codes and ordinances to not exist Vapor Power recommends the specifications and practices of the National Fire Protection Association (NFPA) Standard 31, Installation of Oil-Burning Equipment, be adopted. Before selecting the size of your oil storage tank check with your fuel oil supplier to find the most economical and convenient quantities in which to order, as it could be a major factor in determining the tank size along with the requirements of the local jurisdiction.

10.2.8 Where there is a multiple unit installation drawing fuel from a common tank, and all boilers are located beyond the boiler fuel pump suction lift capability, a common booster supply pump feeding fuel into a “loop” can reduce piping and other equipment requirements. Two types of “loop” arrangement have been used successfully for multiple unit installations. Before making a final selection the advantages of operation of one versus the economies of the other should be considered.

10.2.9 “OPEN” LOOP ARRANGEMENT

10.2.9.1 Figure 21 illustrates the use of an “open” loop in a multiple heater installation. A booster pump situated near the fuel tank draws fuel from the tank and forces it through a line leading to the units. The unit fuel pump draws fuel from this line and returns what is not burned to a system line that returns to the fuel tank. A fixed restriction at the remote end of the supply line, usually in the form of a U-shaped standpipe, provides a positive head for the inlet of the boiler fuel pumps.

10.2.9.2 The advantage of an “open” loop vs. a “closed” loop is that air entrapment problems are less likely to occur on initial start-up or following maintenance that require fuel line connections to be broken. Any air in the lines can be forced into the system return line and vented through the fuel tank vent. The disadvantage is that the booster pump and fuel lines must be sized for a greater capacity.

10.2.9.3 When selecting a booster pump for an "open" loop installation, choose a positive displacement type having a capacity equal to, or up to 25% greater than, the combined capacity of the boiler fuel pumps.

Example: The boiler fuel pump used on a 300 BHP Circulatic boiler has a capacity of 174 GPH. Therefore, the booster pump capacity for a dual unit installation should be a minimum of 348 GPH; for a four unit installation, 696 GPH, etc.

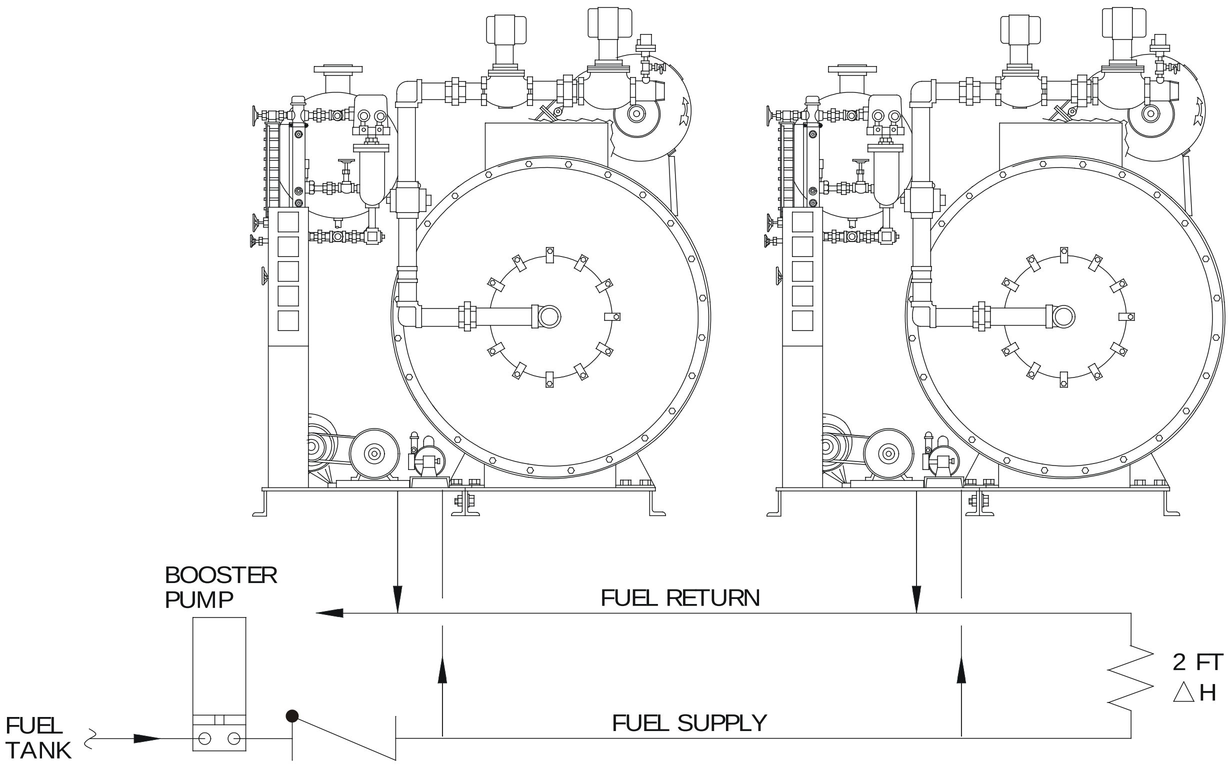


Figure 21. "Open" Loop Fuel Oil Piping Arrangement

10.2.10 "CLOSED" LOOP ARRANGEMENT

10.2.10.1 Figure 22 illustrates the use of a "closed" loop in a multiple heater installation. A booster pump situated near the fuel tank draws fuel from the tank and forces it through a line leading to the boilers. The boiler fuel pump draws fuel from this line and returns what is not burned to the line that leads to the next boiler. A return line to the tank carries what fuel is not required to satisfy burning requirements. A fixed restriction at the remote end of the supply line, usually in the form of a U-shaped standpipe provides a positive head for the inlet of the boiler fuel pumps.

10.2.10.2 The advantage of a "closed" loop vs. an "open" loop is that the booster pump capacity need be sufficient only for the burning requirements of the boilers. Consequently fuel lines for the system may be smaller. The disadvantage is that air entrapment in the system is difficult to eliminate and may be passed along to cause a problem with a boiler downstream in the system.

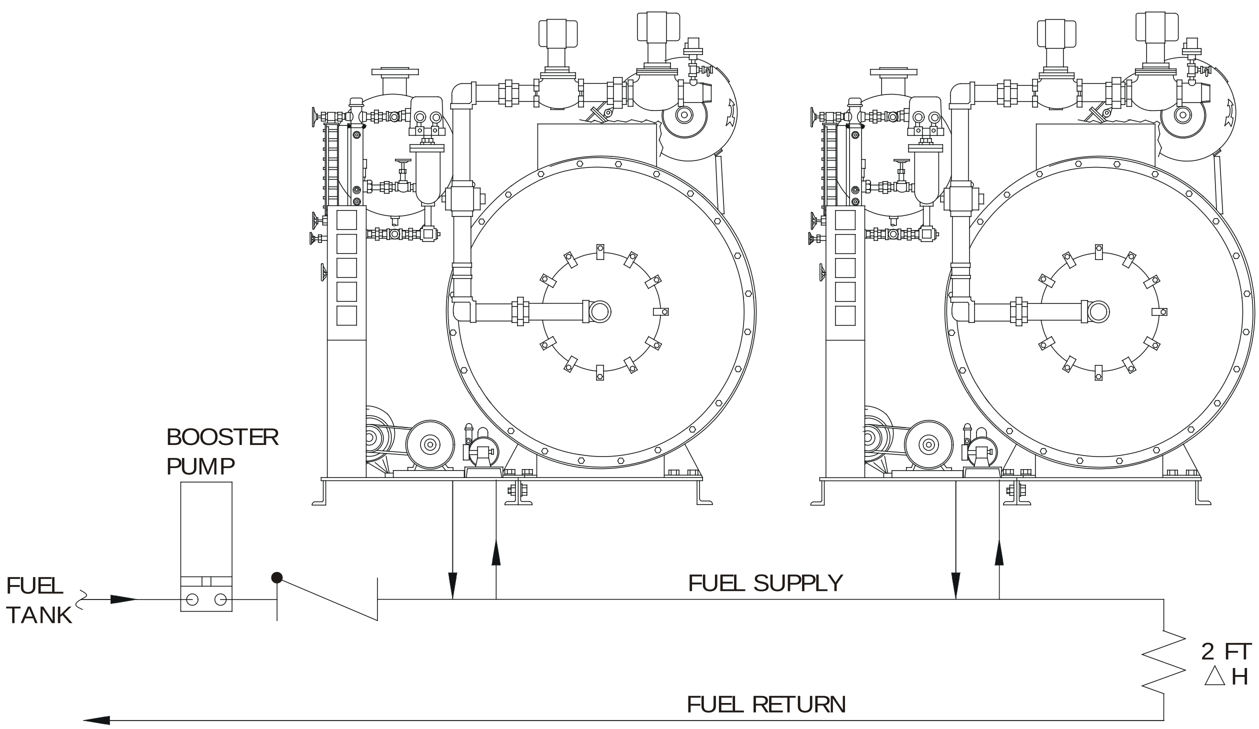


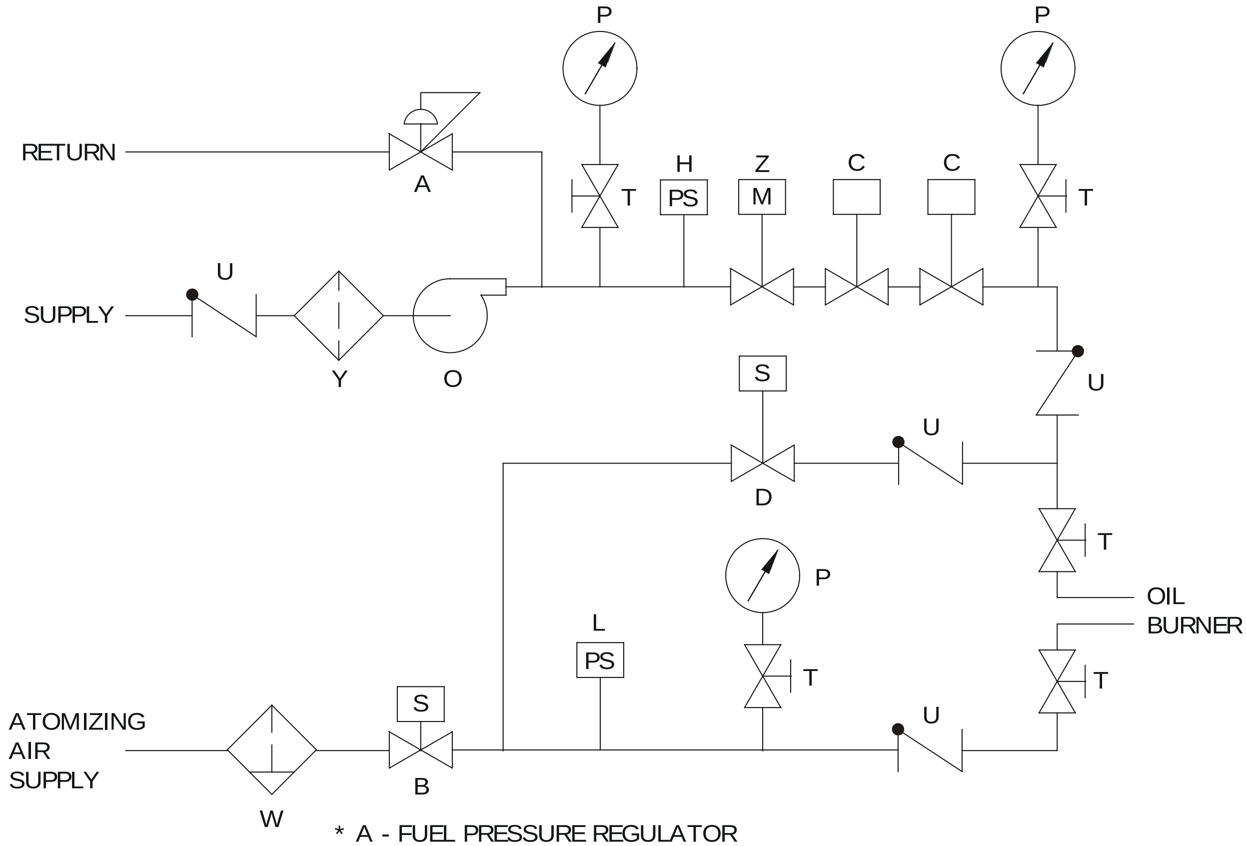
Figure 22. "Closed" Loop Fuel Oil Piping Arrangement

10.2.10.3 When selecting a booster pump for a “closed” loop installation, choose a positive displacement type having a capacity equal to, or up to 25% greater than, the combined maximum burning requirements of the boilers.

Example: A model 300 BHP Circulatic boiler has a maximum fuel burning capacity of 88 GPH. Therefore, the booster pump capacity for a dual unit installation should be a minimum of 220 GPH; for a four unit installation, 440 GPH, etc.

10.2.11 It is important to remember that both the supply and return lines in the fuel system are required to carry the maximum capacity of the booster pump. The supply line should be large enough so that an adequate fuel supply at the remote end of the installation will not result in excessive pressures at the boiler closest to the booster pump. Ordinary pressures at the fuel pump inlet should not exceed 5 PSI although higher pressures can be tolerated if necessary (see paragraph 10.2.3). The fuel return line should be large enough so that the back pressure at any one unit should not exceed 10 PSI which includes the static head pressure if the fuel tank is elevated; ideally there should be no back pressure.

10.2.12 There are several organizations and/or insurance companies that may have jurisdiction over an oil-burning boiler installation. Their objectives, as they are with gas-burning installations, are to reduce the probabilities of a boiler fuel explosion by providing guidelines for a system of instrumentation, interlocks and control valves. Figure 23 illustrates a typical fuel oil supply system for a boiler. The illustrated system may not reflect the unique or special considerations of specific jurisdictions and does not supplant current Federal, state, and local regulations.



* A - FUEL PRESSURE REGULATOR
B - ATOMIZING AIR SHUTOFF SOLENOID VALVE (NC)
* C - SAFETY SHUTOFF VALVE (NC)
* D - FUEL OIL NOZZLE PURGE SHUTOFF SOLENOID VALVE (NO)
* H - LOW FUEL OIL PRESSURE SWITCH
* L - LOW ATOMIZING AIR PRESSURE SWITCH
* O - FUEL OIL PUMP
* P - PRESSURE GAUGE
T - MANUAL SHUTOFF VALVE
* U - CHECK VALVE
W - ATOMIZING AIR FILTER - REGULATOR
Y - FUEL OIL FILTER / STRAINER
* Z - OIL FLOW CONTROL VALVE

* STANDARD BOILER EOUIPMENT

Figure 23. Typical Oil and Atomizing Air Supply System (Distillate)

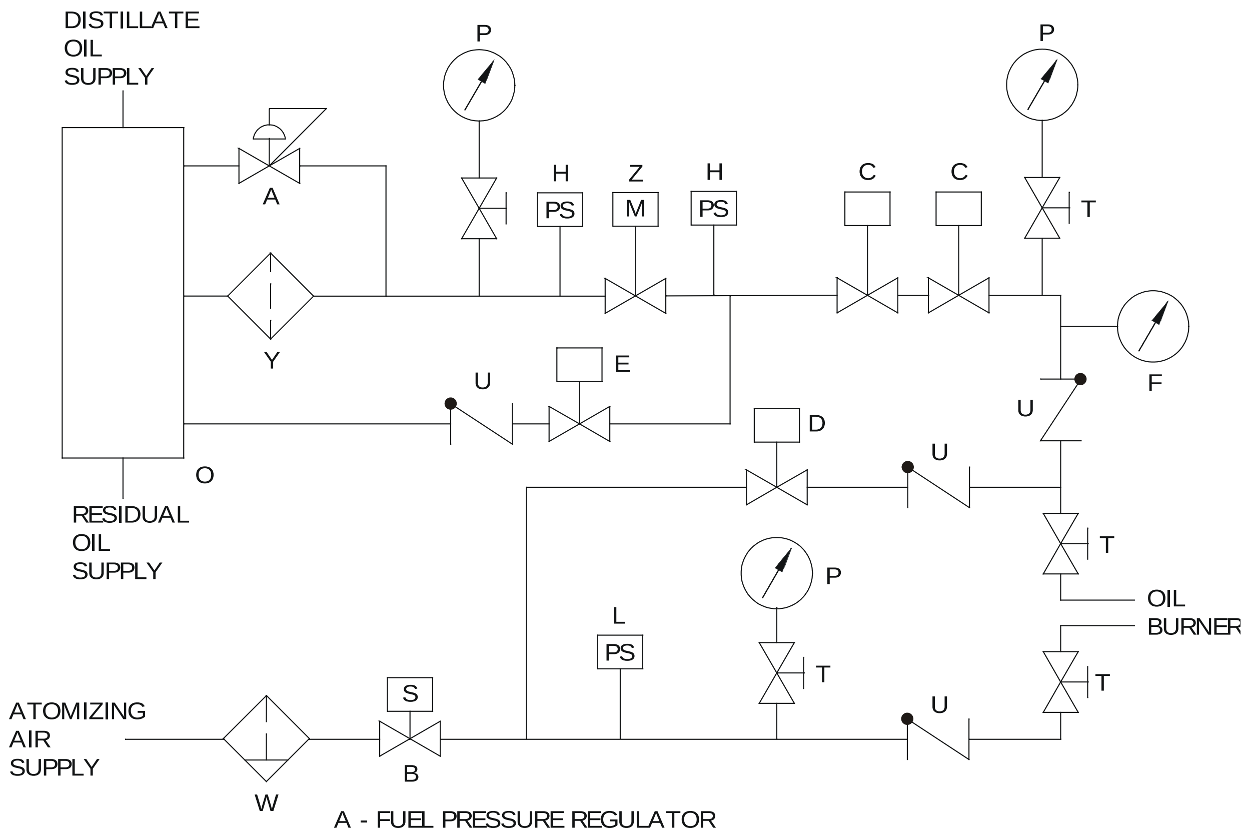
10.3 OIL FIRED BOILERS (RESIDUAL)

10.3.1 Residual fuel oils are available in many grades and qualities. Vapor Power recommends that these residual fuel oils be centrifuged and filtered prior to being supplied to the boiler. These practices will prevent unburnables from entering the boiler and fouling the flue passages in the boiler coils.

10.3.2 Circulatic boilers require fuel oil viscosity at the burner not to exceed 90 - 100 SSU for proper combustion. More viscous grades will require preheating, usually by a preheater skid mounted as close to the boiler as conveniently possible.

10.3.3 Residual fuel oils become very viscous when cooled to room temperature. Some become unpumpable at a temperature below 100ºF. Therefore it is important that the residual oils not be allowed to cool and become solid within the fuel carrying lines of the boiler and preheater skid when the boiler is shutdown. Changing the fuel source supply at the boiler preheater skid inlet to No. 2 fuel oil (distillate) a few minutes before shutdown will purge the system and facilitate the next startup.

10.3.4 Figure 24 illustrates a typical oil supply system for a boiler using residual fuel oil.



A - FUEL PRESSURE REGULATOR
B - ATOMIZING AIR SHUTOFF SOLENOID VALVE
* C - SAFETY SHUTOFF VALVE (NC)
* D - FUEL OIL NOZZLE PURGE SHUTOFF SOLENOID VALVE (NO)
* E - OIL RECIRCULATION VALVE (NO)
* F - OIL TEMPERATURE GAUGE
* G - LOW OIL TEMPERATURE SWITCH
* H - LOW OIL PRESSURE SWITCH
* L - LOW ATOMIZING AIR PRESSURE SWITCH
O - FUEL OIL PREHEATER SKID
* P - PRESSURE GAUGE
T - MANUAL SHUTOFF VALVE
* U - CHECK VALVE
W - ATOMIZING AIR FILTER - REGULATOR
* Y - FUEL OIL FILTER / STRAINER
* Z - OIL FLOW CONTROL VALVE

* STANDARD BOILER EOUIPMENT

Figure 24. Typical Oil and Atomizing Air Supply System (Residual)

11.0 PILOT BURNER GAS REQUIREMENTS

11.1 Natural gas pilots are standard equipment on all Vapor Power boilers fired with oil, natural gas or combination oil/gas fuel. Liquid petroleum gas (LPG) may also be used for pilots. However, in some applications, oil fired boilers are direct spark ignited and, therefore, not fitted with gas pilot burners.

11.2 Natural gas pilots require a regulated 4 inches W.C. supply pressure to the boiler connection. LPG pilots require 11 inches W.C. Pilot burners are orificed so that pilot burner consumption is no more than 40,000 BTUH. An independent gas regulator is required for the pilot burner. Its source of supply may come from anywhere after the gas meter but must be upstream of the main gas regulator. Figures 19 and 20 illustrate a gas pressure regulator installation. A separate pilot burner gas regulator is required for each boiler when multiple boiler installations are made.

11.3 All boilers for C.S.A. certification are equipped with an interrupted spark ignited pilot burner only. The pilot fuel <u>MUST BE</u> natural gas or propane when the main burner is gas fired. Butane or manufactured gas are other possible choices when the main burner is fired with oil.

11.4 Each C.S.A. certified boiler will require use of a pilot gas regulator that is C.S.A. certified.

12.0 COMPRESSED AIR REQUIREMENTS

12.1 INSTRUMENT AIR

12.1.1 A source of clean, dry air is required to operate the feedwater level control on the Circulatic boiler. Air should be supplied at a minimum of 20 PSIG at the boiler connection. Consumption varies but 0.5 SCFM is the expected value for most installations. Other devices that may require use of instrument quality air should be considered.

12.2 ATOMIZING AIR

12.2.1 Compressed air for fuel atomization is required if your boiler is oil fired, or combination oil/gas fired. Table 13 indicates the pressure and cubic feet per minute of free air required for your particular model.

Table 13. Fuel Atomizing Air Requirements

Model Size (BHP)	Air Flow Required (SCFM)	Air Pressure Required at High Fire (PSIG)
75	9.0	20
100	9.0	20
150	9.0	20
200	10.0	20
250	11.0	20
300	11.0	20
350	12.0	25
400	20.0	30
450	20.0	30
500	23.0	30
600	23.0	30

13.0 POWER SUPPLY REQUIREMENTS

13.1 Vapor Power Circulatic boilers are wired at the factory in compliance with the applicable sections of the National Fire Protection Association (NFPA) Standard No. 70, National Electric Code, using Underwriters Laboratories (UL) listed components as a minimum. Specific safety equipment will comply with the requirements of the jurisdictional authority as well (e.g. FM).

13.2 In the absence of jurisdictional authority Vapor Power recommends that all electrical connections between the boiler and the building wiring comply with the requirements of NFPA 70. In Canada, the equipment must be wired and electrically grounded in accordance with the operative edition of the Canadian Standards Association (C.S.A.) Standard C22.1-Canadian Electrical Code, Part 1.

13.3 Whether required by the jurisdictional authority or not, Vapor Power recommends the use of a remote fuseable disconnect switch for the main power supply to each boiler in the installation. No other load should be connected to this switch.

13.4 Table 14 indicates the different horsepower size drive motors that are normally used for Circulatic boilers. Contact the Vapor Power Group of Vapor Power for confirmation of motor sizes before committing to a final design for the installation.

Table 14. Drive Motors* and Boiler Feeder Line Sizes

<table>
<tr><th rowspan="2">Model Size (BHP)</th><th rowspan="2">Recirculating Pump (HP)</th><th rowspan="2">Blower (HP)</th><th rowspan="2">Fuel Pump (HP)</th><th colspan="3">Minimum AWG Line Size (Copper Wire) (See Note)</th></tr>
<tr><th>208/240V</th><th>480V</th><th>600V</th></tr>
<tr><td>75</td><td colspan="2" rowspan="3">7 1/2
7 1/2
10</td><td rowspan="9">1/3
* *</td><td>10</td><td>14</td><td>14</td></tr>
<tr><td>100</td><td>10</td><td>14</td><td>14</td></tr>
<tr><td>150</td><td>8</td><td>14</td><td>14</td></tr>
<tr><td>200</td><td>10</td><td>10</td><td>6</td><td>8</td><td>12</td></tr>
<tr><td>250</td><td>10</td><td>10</td><td>6</td><td>8</td><td>12</td></tr>
<tr><td>300</td><td>10</td><td>10</td><td>6</td><td>8</td><td>12</td></tr>
<tr><td>350</td><td>15</td><td>15</td><td>3</td><td>8</td><td>10</td></tr>
<tr><td>400</td><td>20</td><td>20</td><td>3</td><td>8</td><td>10</td></tr>
<tr><td>450</td><td>20</td><td>20</td><td>3</td><td>8</td><td>10</td></tr>
<tr><td>500</td><td>20</td><td>20</td><td>3/4</td><td>1</td><td>6</td><td>8</td></tr>
<tr><td>600</td><td>20</td><td>25</td><td>3/4</td><td>1</td><td>6</td><td>8</td></tr>
<tr><td colspan="7">* Do not use unless confirmed by Vapor Power.
** Single phase, 120 VAC motor. All other motors used are three phase. 60 HZ is assumed also.</td></tr>
<tr><td colspan="7">NOTE: Wire sizes in Table 14 are based on a 90ºC temperature rated conductor with not more than three current conductors in a cable or raceway based on a 30ºC ambient for line lengths not to exceed 150 feet. Other wire sizes may be required with other types of insulation or ambient temperature. As line lengths increase corresponding wire size increases may be necessary to prevent excessive voltage drop.</td></tr>
</table>

13.5 Nominal values are assigned to a circuit or system for the purpose of designating its voltage class, e.g. 120/240, 480 and 600 volts. The actual voltage at which a circuit operates can vary from the nominal within a range that still allows the equipment to operate satisfactorily. Voltage designations such as 110V and 115V belong to the 120V class, 220V and 230V belong to the 240V class, 440V and 460V belong to the 480V class, and 550V and 575V belong to the 600V class, etc. For the purpose of computing conductor sizes the nominal (class) values for voltage are used.

13.6 In order to have proper fusing in the remote main power disconnect switch, the running draw and the locked-rotor draw (starting) electrical loads must be determined. Modern energy efficient motors (lower I^2R losses) have significant differences from the older, more common motors, i.e. they have higher locked-rotor currents and may even have higher full-load currents. Therefore, when use of "energy efficient" motors are being considered the entire boiler electrical installation must be evaluated for code(s) compliance with those characteristics. Table 15 indicates kVA draws for the various models of Circulatic boilers assuming "energy efficient" motors are used.

Table 15. kVA Draw for Circulatic Boilers

<table>
<tr><th rowspan="2">Model
Size
(BHP)</th><th rowspan="2">Recirculating
Pump
(HP)</th><th rowspan="2">Blower
(HP)</th><th rowspan="2">Fuel
Pump
(HP)</th><th colspan="2">208V, 230V, 460V, 575V</th></tr>
<tr><th>Running Draw
(KVA)
(See Note 1)</th><th>Locked-Rotor Draw
(KVA)
(See Note 2)</th></tr>
<tr><td>75</td><td colspan="2" rowspan="3">7 1/2
7 1/2
10</td><td rowspan="9">1/3
*</td><td>9.5</td><td>73.5</td></tr>
<tr><td>100</td><td>9.5</td><td>73.5</td></tr>
<tr><td>150</td><td>11.9</td><td>90.4</td></tr>
<tr><td>200</td><td>10</td><td>10</td><td>23.0</td><td>180.0</td></tr>
<tr><td>250</td><td>10</td><td>10</td><td>23.0</td><td>180.0</td></tr>
<tr><td>300</td><td>10</td><td>10</td><td>23.0</td><td>180.0</td></tr>
<tr><td>350</td><td>15</td><td>15</td><td>34.2</td><td>269.7</td></tr>
<tr><td>400</td><td>20</td><td>20</td><td>45.6</td><td>359.6</td></tr>
<tr><td>450</td><td>20</td><td>20</td><td>45.6</td><td>359.6</td></tr>
<tr><td>500</td><td>20</td><td>20</td><td>3/4</td><td>45.0</td><td>360.5</td></tr>
<tr><td>600</td><td>20</td><td>25</td><td>3/4</td><td>51.3</td><td>411.3</td></tr>
<tr><td colspan="6">* Single phase, 120 VAC motor. All other motors used are three phase. 60 HZ is assumed also.</td></tr>
<tr><td colspan="6">NOTE 1: All values shown include 0.75 KVA for control panel draw.
NOTE 2: For boilers with two motors KVA values shown assume all motors are started simultaneously. However, Vapor Power designs its control circuits so that there is a delay in starting the two main drive motors in order to avoid the large locked-rotor inrush.</td></tr>
</table>

13.7 KVA may be converted to ampacity by use of the following formula:

$$\text{AMPS} = \frac{\text{KVA} \times 1000}{1.73 \times \text{VOLTS}}$$

Where: KVA is the value from Table 15 for the boiler model being installed.
VOLTS is the voltage supply at the installation.

13.8 It is important for Circulatic boilers to have their control panels grounded. This ground connection is in addition to equipment ground that is made for the service supply conductors. Vapor Power provides a 5/16-18 lug in each control panel for this purpose. In the absence of requirements of the local jurisdiction Vapor Power recommends that the size of this ground conductor be not less than No. 14 AWG copper wire.

14.0 COOLING WATER REQUIREMENTS

14.1 An external source of cooling water is required to cool the shaft seal of the Circulatic boiler water recirculating pump. These shaft seals may be either a packed stuffing box or a rotating mechanical type seal for boilers up to and including 250 PSI Maximum Working Pressure (MWP). In most cases, boilers having greater than 250 PSI MWP will use pumps with a mechanical type shaft seal. Excessive heat is an enemy to extended life for both types of seals.

14.2 Stuffing box cooling has flow rates related to the temperature of the fluid being pumped, in this case water at the saturation temperature of the boiler operating pressure. For installation planning purposes Figure 25 indicates some expected stuffing box cooling data based on cooling water inlet temperature of 70ºF.

14.3 Vapor Power recommends that cooling water flow be maintained so that the temperature out of the stuffing box does not exceed 175ºF. Higher cooling water temperature promotes more rapid scaling within the pump cooling water jacket and therefore a loss of cooling efficiency. Higher cooling water flow rates and a lower cooling water temperature will not harm the pump. However, the maximum allowable pressure in the pump stuffing box jacket is 125 PSI.

14.4 Referring to Figure 25, a boiler operating at 225 PSI (approx. 400ºF saturation temperature) will require up to 3 GPM cooling water at 70ºF in order to limit the outlet temperature to 175ºF.

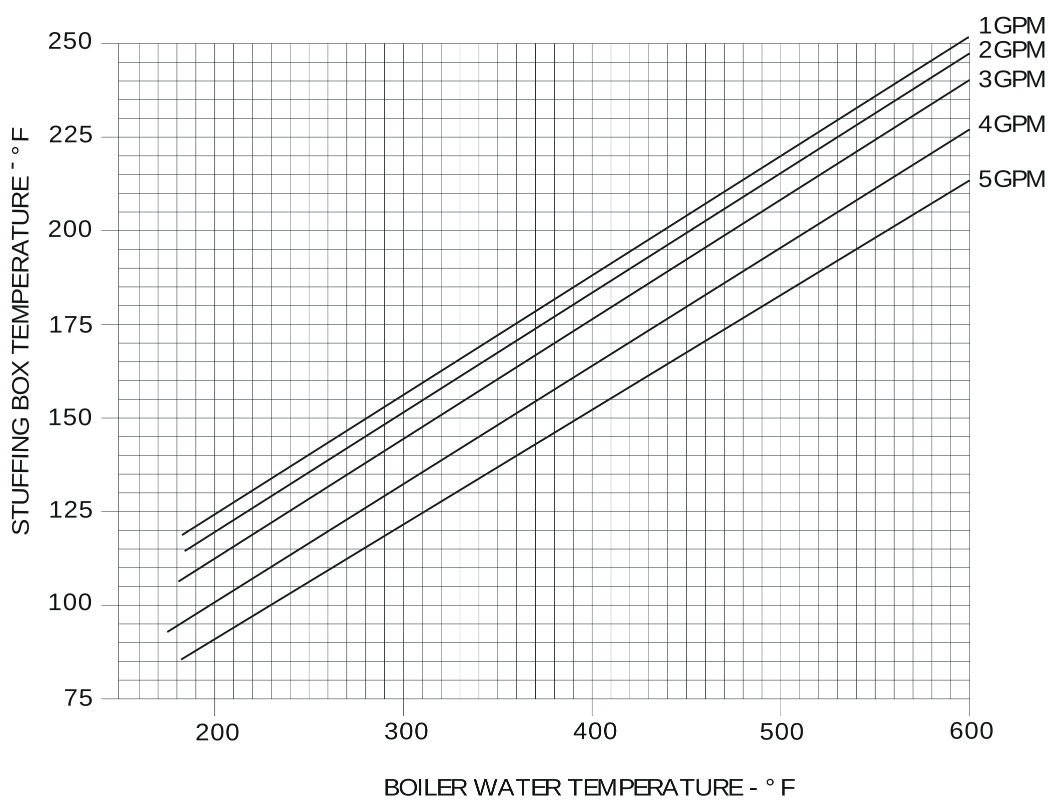


Figure 25. Cooling Water Requirements

14.5 Solids, dissolved and undissolved, in the boiler water being pumped are an enemy to extended life of the mechanical type seal as well as excessive heat. An optional seal flush system is often used for pumps with mechanical seals such as, or similar to, the arrangement illustrated in Figure 26. Water (approximately ½ GPM) is taken from the boiler inlet manifold (recirculating pump outlet) and sent through a heat exchanger. Cooling water to the shell side of the heat exchanger cools the boiler water to a temperature of 160º - 175ºF. The boiler water is then filtered and sent to the seal chamber connection on the pump. This water flushes out the seal chamber as well as cools the seal faces as it again enters the pump suction.

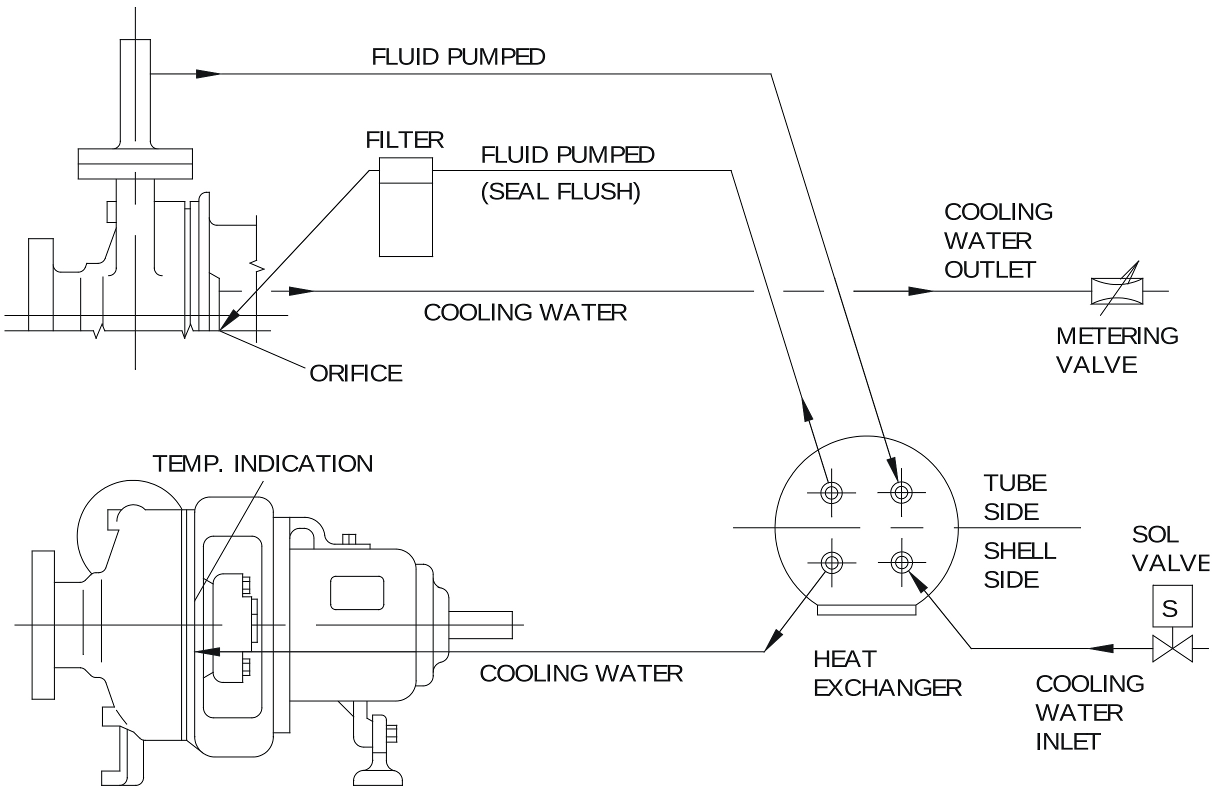


Figure 26. Seal Flush Piping Arrangement

14.6 The external cooling water exits the shell side of the heat exchanger and enters the pump stuffing box jacket. Cooling water from the jacket then goes to an open drain, or in some cases a facility for reclamation that allows the cooling water to be recirculated.

14.7 The recirculating pump cooling water inlet line may contain a manual shut off valve or an automatic shut off valve (see Figure 26) wired to the boiler control panel. Metering of the cooling water must be done on the outlet line.

14.8 Pump manufacturers alert users that it is hazardous to personnel to operate the pump without pumpage or without cooling water. Vapor Power concurs by including the following notification.

WARNING

COOLING WATER MUST BE ALLOWED TO FLOW ANYTIME THE PUMP IS RUNNING. CLOSING INLET OR OUTLET VALVES IN THE COOLING WATER LINES UNDER OPERATING CONDITIONS MAY CAUSE WATER IN THE COOLING JACKETS TO REACH HIGH PRESSURE AND LEAD TO RUPTURE OF THE COMPONENTS THAT IS EXTREMELY HAZARDOUS TO PERSONNEL.

14.9 Softened water for pump cooling should be used for best results. Less scale buildup within the cooling jacket and thus better heat transfer between the stuffing box and cooling water can be expected if treated water is used for cooling.

15.0 STEAM PIPING

15.1 Steam service lines may be sized either by pressure drop or the velocity of steam within them. A reasonable maximum for velocity is generally considered to be approximately 7200 - 7500 feet per minute (120 - 125 feet per second). Higher velocities, up to 12,000 feet per minute, have been used in installations where noise is not a problem and erosion of piping and fittings from water droplets moving at high speed can be ignored. Steam velocity may be calculated by the following formula.

$$V = \frac{2.4Q\,\bar{V}}{A}$$

Where: V = velocity in feet per minute
Q = steam flow in lbs/hr
$\bar{V}$ = specific volume of steam at the flowing pressure in cubic feet/lb
A = internal area of the pipe in square inches

15.2 Vapor Power designs its boilers so that boiler outlet nozzle steam velocity does not exceed 7500 feet per minute at the rated Maximum Working Pressure (MWP). Therefore, it is recommended your steam service line should be as large, or larger than, the outlet connection on the boiler. Long runs of pipe should be checked to see that pressure drops are not too high. The specific volume of steam increases as the flowing pressure decreases so downstream velocity will increase if pipe size is not increased.

15.3 Table 16 lists the boiler steam outlet nozzle sizes for the various models of Circulatic boilers. The sizes indicated are standards for a specific maximum working pressure design and may not be the optimum for the desired operating pressure. Consider the following example:

A 300 BHP Circulatic boiler of 150 PSI MWP has a steam outlet size of 4" NPS x 300 # ANSI flange. However, it is desired to operate this boiler at 50 PSIG. Using the formula in paragraph 15.1 calculate the velocity of the steam.

$$V = \frac{2.4\,Q\,\bar{V}}{A} = \frac{2.4 \times 10{,}350 \times 6.653}{12.73} = 12{,}982 \text{ FPM}$$

Where: Q = 10,350 lbs/hr steam output capacity of a 300 BHP boiler from and at 212ºF
$\bar{V}$ = 6.653 cubic feet per pound for steam at 50 PSIG
A = 12.73 square inches cross sectional area for a 4" NPS X Sch 40 pipe

The velocity calculated, 12,982 feet per minute, exceeds what many consider good design practice. If this velocity is considered to be unacceptable for the application a larger steam outlet size is necessary. Contact the Vapor Power Group of Vapor Power regarding the availability of a special design.

Table 16. Boiler Steam Connection Sizes

Model Size (BHP)	Boiler Design Max. Working Pressure (PSI)	Steam Outlet
75 & 100	15	6" x 150# ANSI Flange
	150	2-1/2 Inch Coupling
	250	2-1/2 Inch Coupling
150	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
200	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
	530	4" x 300# ANSI Flange
250	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
	530	4" x 300# ANSI Flange
300	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
	530	4" x 300# ANSI Flange
350	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
	530	4" x 300# ANSI Flange
400	15	10" x 150# ANSI Flange
	150	4" x 300# ANSI Flange
	250	4" x 300# ANSI Flange
	530	4" x 300# ANSI Flange
450	15	14" x 150# ANSI Flange
	150	6" x 300# ANSI Flange
	250	6" x 300# ANSI Flange
	530	6" x 300# ANSI Flange
500	15	14" x 150# ANSI Flange
	150	6" x 300# ANSI Flange
	250	6" x 300# ANSI Flange
	530	6" x 300# ANSI Flange
600	15	14" x 150# ANSI Flange
	150	6" x 300# ANSI Flange
	250	6" x 300# ANSI Flange
	530	6" x 300# ANSI Flange

15.4 Larger steam headers, if used, or steam reservoirs, will act as a steam accumulator to compensate for a rapid pressure drop due to a sudden demand for steam, or pressure surge when the steam user is abruptly shut off.

15.5 Most of the United States have adopted, or enacted into law, a uniform pressure vessel code, i.e. the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Beyond the limits of the boiler proper, technical and administrative responsibility falls under ASME Code ANSI B31. Cities and other jurisdictions may have requirements that enhance or are different from the ASME. These codes should be reviewed thoroughly regarding use of stop valves and/or check valves at the boiler outlet for both single unit or multiple unit installations.

15.6 Where multiple boilers are installed, the steam lines should be sized to carry the total steam flow and should be adequate to handle the system equipment involved.

15.7 Steam lines should be insulated to conserve heat and to protect personnel from possible burns.

15.8 Where condensate may collect in the steam lines, traps should be installed to prevent "water logging" the system.

15.9 All steam piping must be properly secured and anchored to prevent any strains on equipment and boiler connections.

15.10 To enable the boiler to be tested (combustion adjustment, etc.), it is necessary that provisions be made for discharge of steam that the system cannot accommodate. This is usually done by connecting a blowoff line from the boiler outlet piping to the atmosphere.

15.10.1 The blowoff line should be large enough to relieve the full boiler output at the lowest operating pressure. The end of the line should discharge to a point of maximum safety.

15.10.2 A shutoff valve that can be used to throttle the boiler discharge must be installed in the blowoff line at a point that is easily accessible.

16.0 SAFETY VALVE PIPING

16.1 Individual discharge pipes must be installed to carry away the blowoff from each safety valve. Support these pipes to prevent any stress upon the safety valve.

16.2 Discharge pipes must not be rigidly connected to safety valves. Clearances should be provided to allow for expansion. A drip pan elbow installed similar to the illustration in Figure 27 will provide clearances and also prevent the accumulation of steam condensate from flooding the safety valve outlet and subsequently freezing or otherwise restricting flow. The drain must discharge to an open sewer. Do Not connect to blowdown piping.

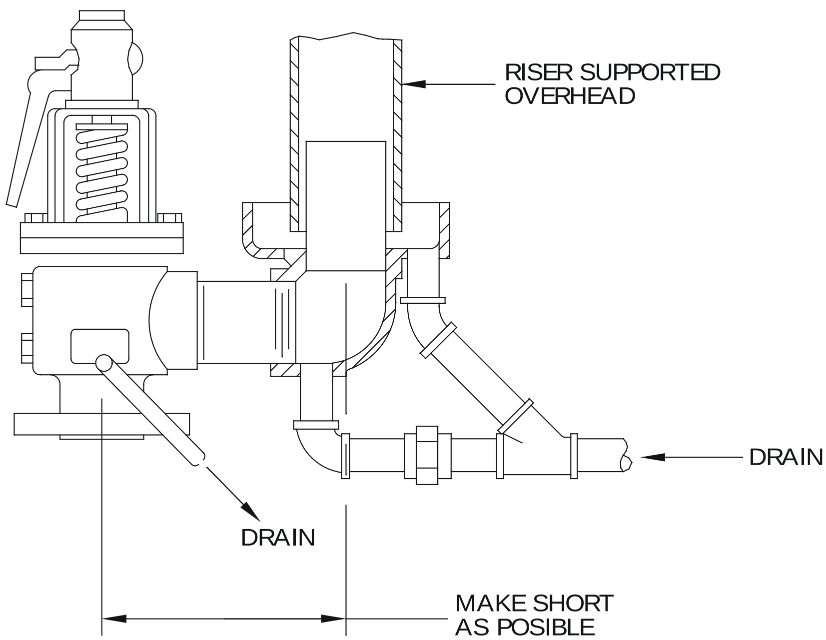


Figure 27. Typical Safety Valve Piping

16.3 Safety valve discharge pipes must have an unobstructed path, that is, no valves or series of pipe fittings between the safety valve and the atmosphere. Also, the discharge pipe shall not be smaller than the safety valve outlet.

16.4 Locate all safety valve discharges so that they clear all working areas and platforms. Usually the discharge pipe is installed to exit vertically.

16.5 Do not install a discharge pipe to exit horizontally if it contains any bends or elbows.

17.0 BLOWDOWNS

17.1 BOTTOM BLOWDOWN (DRUM)

17.1.1 The Circulatic boiler separator drum is equipped with a 1 inch NPT blowdown connection for blowing out sludge deposits that accumulate in the bottom. It is important to remove these deposits periodically as otherwise the total dissolved solids will increase beyond the amount recommended for satisfactory boiler operation. The ASME Code requires a bottom blowdown.

17.1.2 Local codes and ordinances may require that the blowdown be piped into a receiver tank or a blowdown separator. The boiler installer should determine details of what is required.

17.1.3 When piping the drum blowdown, the line size should be at least as large as the drum connection. Use a minimum number of fittings to keep the line restriction as low as possible.

17.1.4 The size of the blowdown receiver should be determined by the amount of blowdown from the boiler. Blowdown rates depend upon local raw water properties, the amount of makeup water needed, the condition of the system return condensate, and the amount of feedwater treatment chemicals added and so cannot be predicted precisely. However, blowdown rates over 10% of the boiler evaporation rate are usually considered excessive.

17.1.5 The boiler may be equipped, optionally, with an automatically operated drum blowdown valve using either pneumatic or hydraulic (oil or water) pressure. Pneumatically operated valves require a pressure of 20 psig minimum to 150 psig maximum for operation. Hydraulically operated valves require a pressure of 40 psig minimum to 150 psig maximum. With either method the operating fluid temperature must not exceed 175ºF. Some of the more commonly used pressure sources for oil fired boilers are the atomizing air source for pneumatically operated valves and fuel oil pressure for hydraulically operated valves. House line water pressure 40 psig or over may also be used.

17.2 SURFACE BLOWDOWN (DRUM)

17.2.1 The Circulatic drum/separator can, as optional equipment, be piped with a surface blowdown connection. The surface blowdown lance is located approximately 1” below the operating water level. When the drum water conditions indicate accumulations of grease, scum, light dissolved solids, or a high pH buildup, surface blowdown in addition to bottom blowdown is recommended.

17.2.2 Figure 28 illustrates a method of piping for simultaneous surface and bottom blowdown.

17.2.3 In some installations the proportion of required surface blowdown to bottom blowdown may be large enough so that water is wasted from frequent simultaneous blowdowns. When this occurs the surface blowdown may be piped directly to the blowdown receiver as illustrated in Figure 29 and the flow throttled so that surface blowdown is continuous.

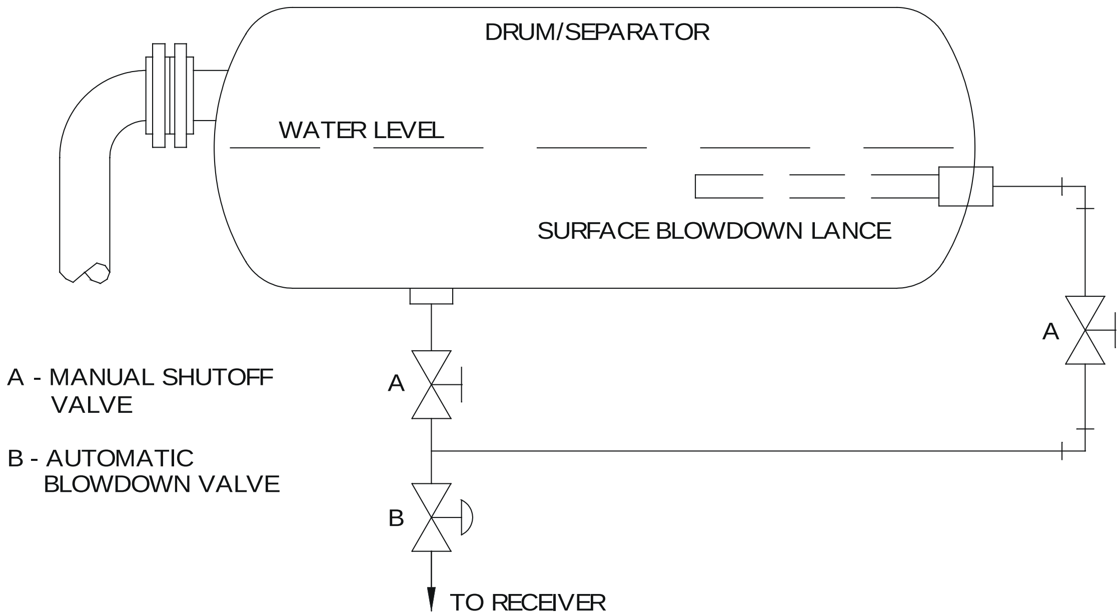


Figure 28. Simultaneous Surface and Bottom Blowdown Arrangement

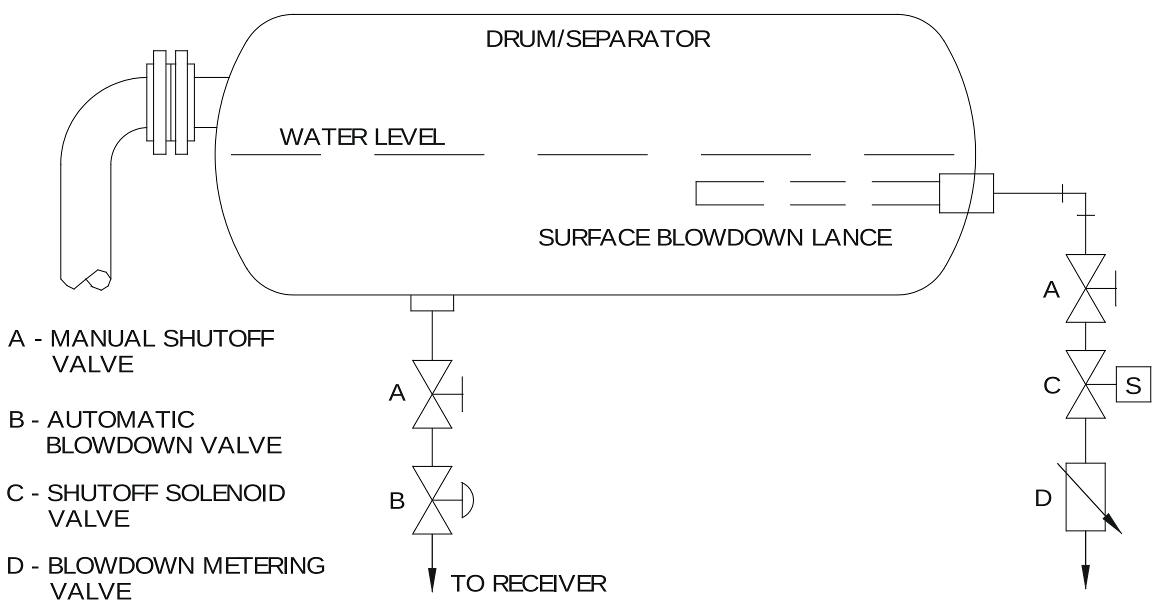


Figure 29. Piping Arrangement for Continuous Surface Blowdown

17.2.4 If the boiler installation is large or has multiple units, and depending upon the amount of blowdown required, it may be economical to install some method of heat recovery from the blowdown water with the continuous blowdown system. Savings from the heat recovery will soon equal the initial cost of the recovery system if the blowdown quantity is large.

17.3 WATER LEVEL CONTROL BLOWDOWN

17.3.1 The Circulatic boiler has a 1 inch NPT gate valve connected to the bottom of all water level controls for blowdown purposes. Water level controls must be blown down to dispose of any sludge or sediment as accumulation may impair the operation.

17.3.2 Water level control blowdowns should also be piped to a condensate receiver.

17.3.3 The frequency and amount of blowdown required for water level controls is also affected by water conditions. However, unless otherwise indicated by local codes affecting your installation, water level controls are usually blown down at least once in each eight hour shift.

18.0 NEW UNIT STORAGE

18.1 Should your new Vapor Power boiler arrive on the job site before the system is ready to accept it, place it in a protected area. It <u>should not</u> be located in an area where workmen will climb on it or can bump into it with heavy equipment.

18.2 As discussed in paragraph 2.2, uncrate and inspect the unit for damage in transit or unloading. Once inspected, the unit should be recovered. Tie the covering down to prevent it from blowing off. This will protect the unit from dirt and possible pilferage.

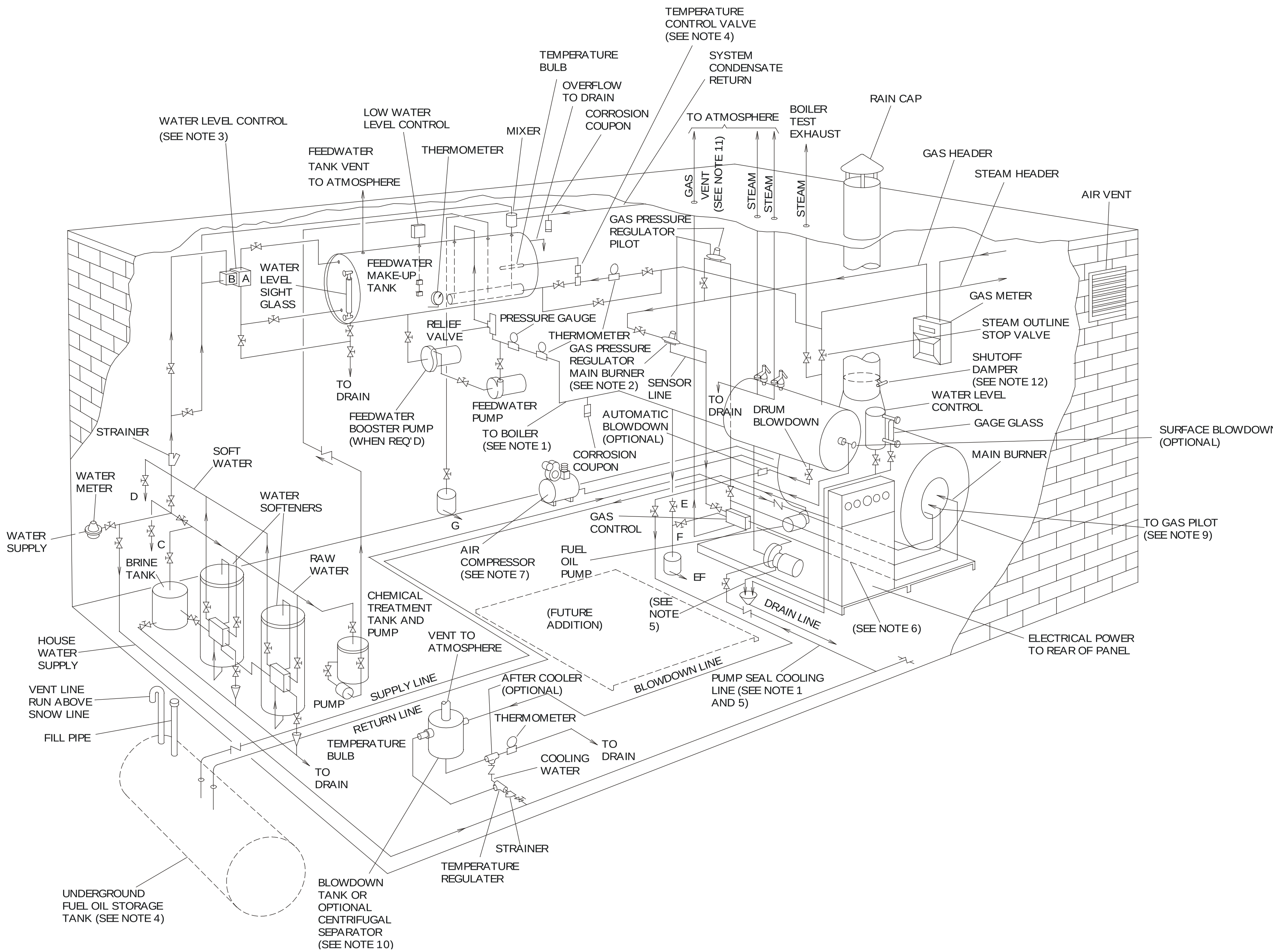


Figure 30. Typical Boiler Installation (Sheet 1 of 2)

NOTES:

1. CONNECTION LOCATIONS ON THIS DRAWING ARE SHOWN PICTORIALLY. FOR ACTUAL LOCATIONS REFER TO CUSTOMER CONNECTION DRAWING FOR BOILER.

2. GAS PRESSURE REGULATION SHOULD BE LOCATED AT LEAST 12 DIAMETERS FROM ANY ELBOW. IF A PRESSURE SENSOR LINE IS USED, IT SHOULD BE LOCATED AT LEAST 10 DIAMETERS DOWNSTREAM OF MAIN REGULATOR AND AT LEAST 5 DIAMETERS UPSTREAM FROM ANY RESTRICTION. (VALVE, TEE, ETC.)

3. WATER LEVEL CONTROL (A) MAY BE MECHANICAL OR ELECTRICAL. IF ELECTRICAL, PART “A” WILL BE A SWITCH MECHANISM AND PART “B” WILL BE AN ELECTRICALLY OPERATED WATER ADMISSION.

4. FOR DE-AERATION OF THE FEEDWATER, IT SHOULD BE HEATED TO ~200ºF BY THE RETURN SYSTEM OR FEEDWATER HEATER SHOULD BE SUPPLIED.

5. THE CIRCULATING PUMP IS EQUIPPED WITH A WATER JACKET AND REQUIRES A SUPPLY AND DRAIN LINE. (SEE SECTION 14)

6. WHEN FM OR FIA CONTROLS ARE SPECIFIED, SEE BOILER PIPING DIAGRAM FOR PIPING DETAILS.

7. COMPRESSED AIR IS REQUIRED FOR FUEL ATOMIZATION WHEN UNIT IS OIL FIRED OR WHEN USED FOR AUTOMATIC PNEUMATIC BLOWDOWN.

8. FUEL OIL STORAGE TANK AND PIPING MUST BE INSTALLED IN COMPLIANCE WITH LOCAL CODES. KEEP CHECK VALVE IN SUCTION LINE.

9. GAS PILOT IS STANDARD ON ALL UNITS. LPG MAY BE USED ON STRAIGHT OIL-FIRED UNITS.

10. CENTRIFUGAL SEPARATOR MAY BE USED INSTEAD OF BLOWDOWN TANK. AFTER-COOLER WITH TEMPERATURE CONTROLLED WATER ADMISSION VALVE. STRAINER, CHECK VALVE, AND THERMOMETER ARE ALSO OPTIONAL EQUIPMENT.

11. INDIVIDUAL VENT LINES ARE RECOMMENDED. WHEN LINES ARE MANIFOLDED, PIPE AREA MUST BE EQUAL TO OR LARGER THAN SUM OF AREAS OF INDIVIDUAL VENT PIPES.

12. DAMPER SHOULD BE INSTALLED IN COLD CLIMATES TO PREVENT COILS FROM BEING FROZEN BY COLD AIR DRAWN IN WHEN BOILER IS SHUT DOWN.

13. RECOMMENDED LOCATIONS FOR WATER SAMPLING (SEE SECTION 9.2) ARE:

    C. RAW WATER
    D. SOFT WATER
    E. BOILER FEED*
    F. INLET MANIFOLD* (SEE FIGURE 8)
    G. CONDENSATE RETURN*
    * THESE POINTS MUST BE COOLED TO CONDENSE VAPOR

Figure 30. Typical Boiler Installation (Sheet 2 of 2)