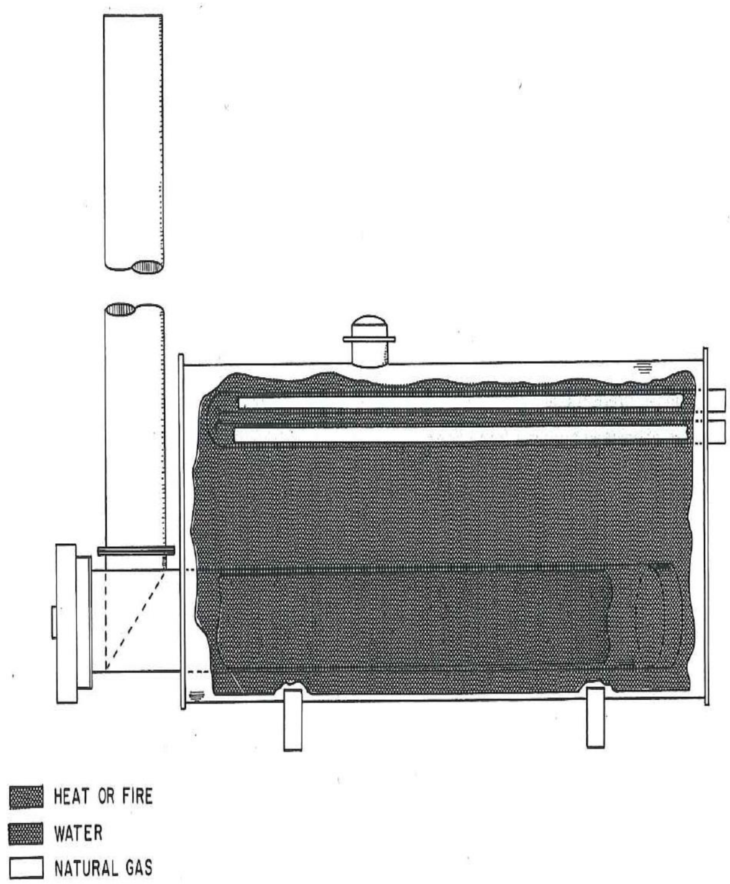
WATER BATH INDIRECT HEATER



WATER BATH INDIRECT HEATER

HOW IT WORKS:

Fuel gas is burned within the horizontal "U"-shaped firebox immersed in the lower portion of the .water bath.· Heat released by the burning fuel gas is quickly transmitted through the firebox wall to the water bath, maintaining it at the desired temperature. A horizontal oriented "U" fire tube is used in this example and illustration. This orientation would require a much larger water bath shell than if the "U" fire tube were oriented in the vertical position, therefore justifying the horizontal firetube.

The process fluid to be heated (well stream, natural gas, oil, water, etc.) is conducted through the flow coil of the heater that is immersed in the upper portion of the water bath. Heat is transmitted from the hot water bath surrounding the flow coil through the tube-wall to the fluid inside the flow coil.

The heater temperature controller maintains the water bath temperature at the desired level by controlling the firebox fuel gas supply. A temperature of 190 ºF is considered the desired optimum at which the bath of this type of heater should operate. At temperatures above 190 ºF, water loss can be expected to increase and be excessive. A water bath temperature of 190 ºF provides the designer with the temperature to use in

Mean Temperature Difference (MTD) calculations for an optimized coil selection. Heaters in service can be - and should be - operated at water bath temperatures less than 190 ^{o}F when inlet condition and/or outlet temperature requirements allow for this.

Operating the bath temperature at the minimum temperature required to give natural gas hydrate protection in either the pipeline or separator not only saves fuel, but provides maximum liquid recovery in the downstream equipment because it eliminates the possible formation of hydrates and the process upsets that they cause.

Standard Components and Accessories[1]:

1 - Flanged cylindrical heater shell
1 - Removable "U"-bend type firebox w/cover plate
1 - Firebox stack
1 - Removable wellstream flow coil with cover plate.
    Coil connections are either screwed or beveled for welding.
1 - Fuel gas preheat coil;
1 - High efficiency burner w/pilot light
1 - Fuel gas manifold (pre-piped in shop) with:
    1 - Low pressure strainer and drain valve
    1 - Main fuel gas line block valve
    1 - Pilot gas block valve
    1 - 2" Dial face 0-60 psig pressure gauge with isolating valve
    1 - Lot of pipe, pipe fittings, copper tubing and tubing fittings for hookup
1 - Thermostat
1 - Diaphragm operated fuel gas control valve
1 - 3" Dial face thermometer, 20-240 °F
1 - Low pressure fuel gas regulator
1 - 8" Vapor conservation, pressure/vacuum vent valve for shell fill connection
Paint: One coat of standard primer and one coat of aluminum

Optional Accessories and Design Features - Extra Price:

Smith Industries Flame Arrestor
Smith Industries Down-draft Diverter
Smith Industries Stack Arrestor
Fisher 630 "Big Joe" Regulator
Fisher 620 Regulator
High bath temperature shutdown thermostat
Diaphragm operated fuel shut-down valve
Energy conserving shop-installed fiberglass shell insulation with aluminum jacketing and vapor barrier;
Fuel gas "Safe Trap" with internal high level safety shut down valve;
Pilot flame-out safety shut down control;

[1] This listing is subject to change without notice.

Short nose chokes (fixed orifice, manual hand wheel, or pilot and diaphragm operated);
Long nose adjustable choke (manual hand wheel, or pilot and diaphragm operated);
Special well stream coils of required size, including multi-pass and working pressures in excess of 10,000 psig. Connections may be flanged, beveled for welding, screwed, or special end.
Shop-installed choke and piping tie-across between coil passes;
Welded-in (non-removable) flow coils and/or fireboxes;
Structural steel skid and shop skid-mounting;
Special paints and coatings.

The natural gas standard conditions identified in this document as Scf or Scfd are those established by the NGPSA and measured at 60 ºF and 14.696 psia.

Sizing Water Bath Indirect Heaters

Several general design considerations should be reviewed before proceeding to the sizing problem, as they can have an appreciable effect upon the final heater selection. These considerations are as follows:

1. Natural gas hydrate formation in a produced natural gas stream;
2. Joule-Thomson Effect (temperature drop verses pressure drop);
3. Choke valve type and installation;
4. Use of antifreeze compounds (glycols);
5. Use of corrosion inhibitors;
6. Use of energy-saving shell insulation.

Some of these are involved only with natural gas heating problems; i.e., natural gas hydrates and the Joule-Thomson Effect. The others can apply also to crude oil heating problems.

Natural Gas Hydrates

Natural gas hydrate formation is a phenomenon that is encountered with high-pressure well streams and causes freeze-up and line-plugging at temperatures well above 32° F. Hydrates are very similar to snow in appearance. Research on the subject has resulted in the publication of **Chart No. 1** for predicting when hydrates can occur. In addition, the following guidelines are given:

1. The wellstream must have free-water present and in contact with the natural gas before hydrates can form.
2. The wellstream must be near the predicted hydrate formation temperature for a given pressure.

A methane hydrate, also called a methane **clathrate** (CH_4•$5.75H_2O$) or ($4CH_4$•$23H_2O$), is a solid clathrate compound (more specifically, a clathrate hydrate) in which a large amount of methane is trapped within a crystal structure of water, forming a solid very similar to water ice. Methane clathrates (hydrates) are commonly formed during natural gas production operations, when liquid water is condensed in the presence of methane at high pressure. It is known that larger hydrocarbon molecules like ethane and propane can also form hydrates, although longer molecules (butanes, pentanes) cannot fit into the water cage structure and tend to destabilize the formation of hydrates. Once formed, hydrates can block pipeline and processing equipment.

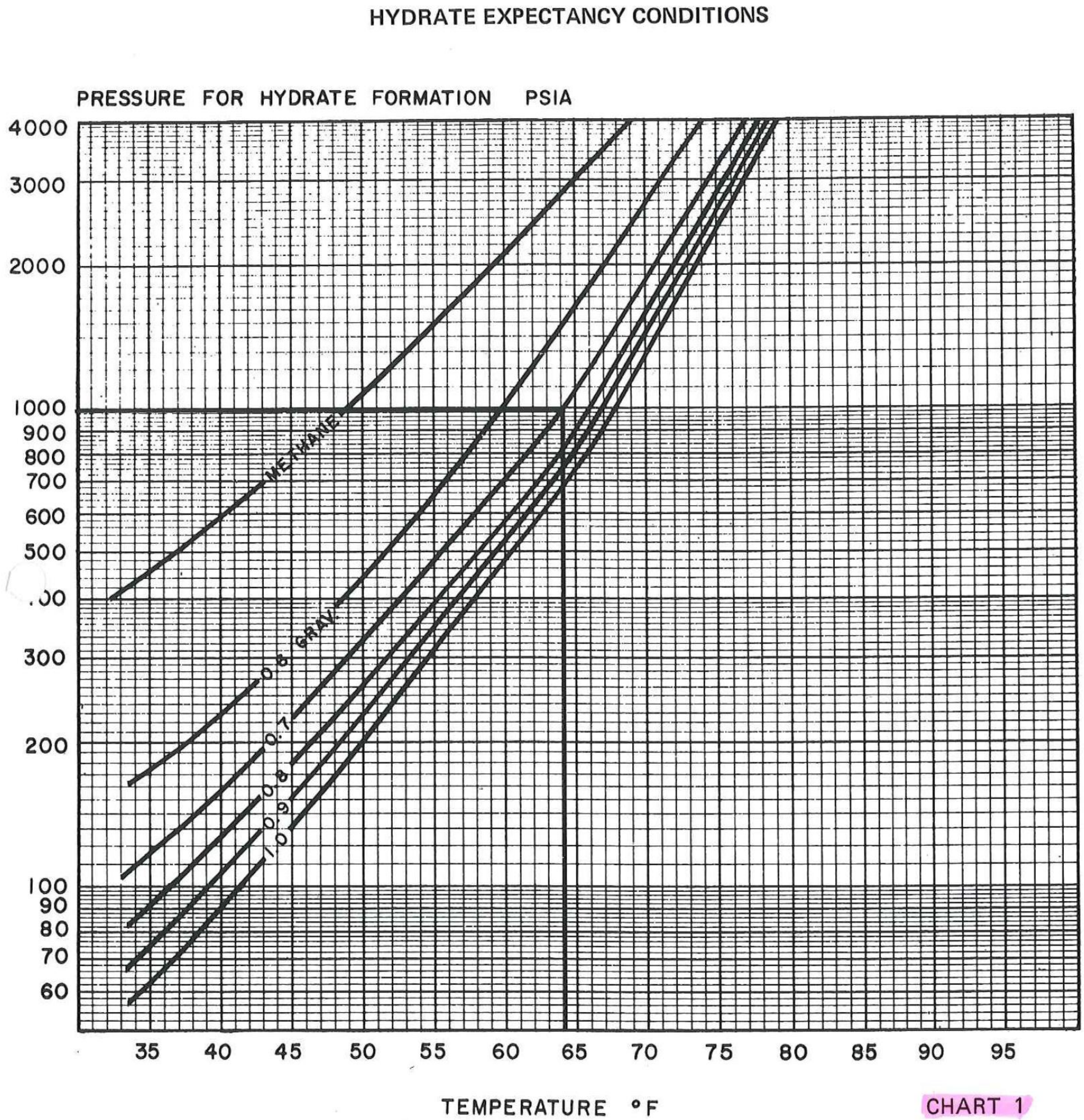
The average methane clathrate hydrate composition is 1 mole of methane for every 5.75 moles of water. The observed density is around 0.9 g/cm^3. For one mole of methane, which has a molar mass of about 16.043 g, we have 5.75 moles of water, with a molar mass of about 18.015 g, so together for each mole of methane the clathrate complex has a mass of 16.043 g + (5.75 × 18.015) g ≈ 119.631 g. The fractional contribution of methane to the mass is then equal to 16.043 g/119.631 g ≈ 0.1341. The density is around 0.9 g/cm^3.

Chart No. 1 is the result of investigating several hundred natural gas streams and is generally considered to be representative of most wellstreams encountered in field operations. However, there are known instances where hydrates have been encountered at temperatures as much as 10 ºF above and below those predicted by this chart. Therefore, the temperature predicted by **Chart No. 1** should be modified by known wellstream behavior, if available.

Natural gas hydrates are particularly troublesome in pipelines and gas process equipment. They can cause flow stoppage, reduce line capacity, and cause physical damage. Slugs of gas hydrates moving through a pipeline at normal gas velocities can produce high impact forces on valves, orifice plates, strainers, and other equipment that impede their movement. Hydrate slugs traveling from the line into scrubbers, separators, and compressors can likewise cause serious internal structural damage. Therefore, natural gas hydrates must be avoided to maintain expected design flow conditions. Each sizing problem should have both the inlet and outlet conditions checked, using **Chart No. 1** to approximate when hydrates may be expected.

Joule-Thomson Effect

Another phenomena encountered with high pressure natural gas well streams is the Joule-Thomson Effect. A reduction in wellstream temperature occurs when the wellstream pressure is rapidly reduced, such as when the wellstream passes through a choke valve or specially designed control valve. This is referred to as the Joule-Thomson Effect or auto-refrigeration effect. It is probable that in the act of reducing the high pressure gas to sales line pressure, this effect will lower the wellstream temperature into the region of hydrate formation. Each application must be reviewed to determine the Joule-Thomson Effect. **Chart No. 2** is a plot of the expected decrease in temperature due to pressure reduction for an average wellstream with 10 barrels of liquid per MMScf passing through the choke valve. The temperature downstream of a choke can be predicted with reasonable accuracy using the upstream temperature, the initial pressure, and the final pressure. If the wellstream has more than 10 bbls/MMScf, the temperature drop across the choke due to pressure reduction should be reduced 5 ºF for each additional 10 bbl/MMScf. Conversely, if the wellstream has no liquid passing through the choke, the temperature drop should be increased 5 ºF.

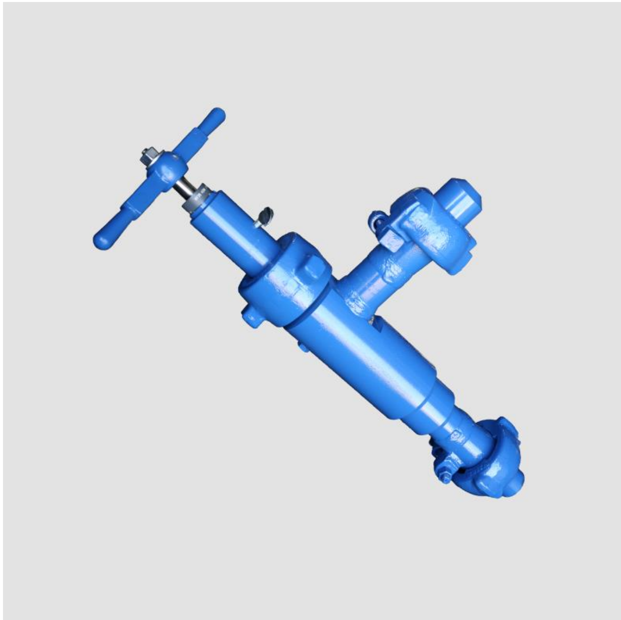


Hydrate Formation Conditions. Purpose: To predict the temperature below which hydrates will form, where sufficient liquid water is present.

Choke Valve Installation

Choke valves are specially designed valves for handling high differential pressures across the seat and stem. They are manufactured in two basic types, differentiated from each other by the body style:

(1) The "Long-Nose Choke" or long body style; and
(2) The "Tee Type Wing Valve" or short body pattern.



The "Long-Nose Choke" Valve

The "Tee Type Wing Valve"

The long-nose choke was developed for use with the water bath indirect heater. The long body extension between the side inlet and the bottom outlet allows a portion of the choke to be immersed into the hot water bath. This places the seat of the choke where it is warmed by the hot water bath, keeping hydrates melted-out of the choke. The "Tee Type Wing Valve", or short body pattern choke, is normally the choke used on wellheads, on inlet lines to separators, and on heater coil outlets, etc. with this choke, the wellstream must be preheated sufficiently to prevent formation of hydrates immediately downstream of the choke; otherwise, problems will be encountered with hydrate-plugging and freeze-up.

The location of the pressure reducing choke will affect the selection of the flow coil. If the inlet gas pressure is 2,000 psig or less, it is normally advantageous to install the choke on the inlet of the heater which results in a lower gas temperature in the flow coil. This takes advantage of a larger temperature differential between the gas and the hot water bath. The coil area is inversely proportional to the mean temperature difference. Mean temperature difference is the logarithmic average temperature between the water bath and the inlet and outlet temperatures of the process stream. Therefore, the required area would be less than if the pressure reduction were taken on the heater outlet. See the comparison on natural gas heating for a typical problem. Use **Chart No. 3** for Mean Temperature Difference (MTD) determination.

TEMPERATURE DROP VS. PRESSURE DROP

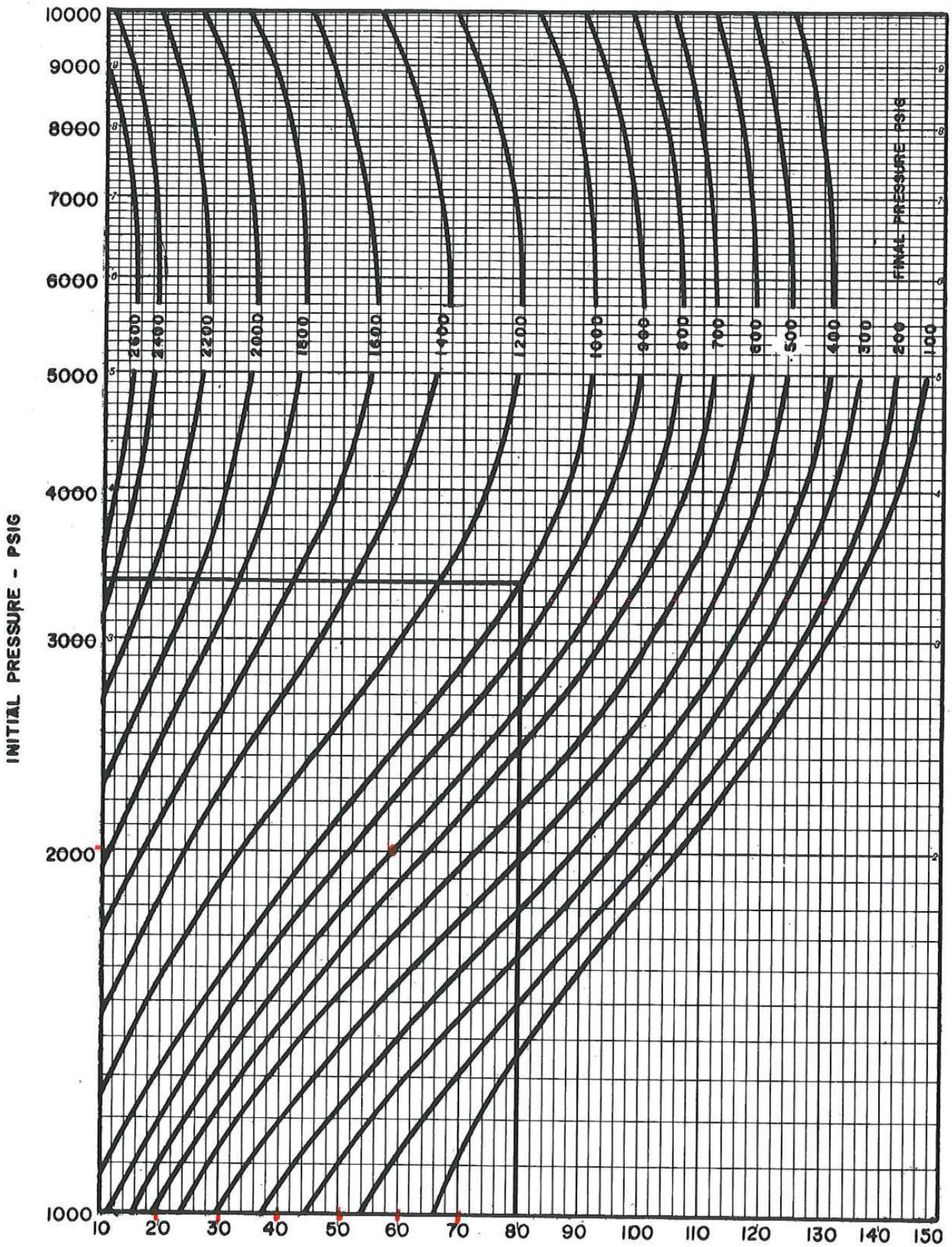
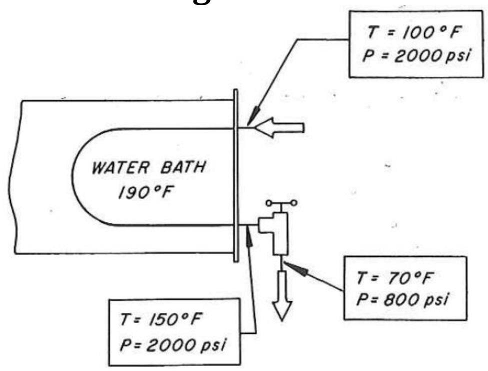


CHART 2

Determination of the required coil area for a Water Bath Indirect Heater

Inlet Conditions	Outlet Conditions
4 MMScfd of 0.7 Sp. Gr. Natural Gas	4 MMScfd of 0.7 Sp. Gr. Natural Gas
2,000 psig and 100 ºF	800 psig and 70 ºF

Example 1 - With the pressure reducing choke installed on the coil outlet



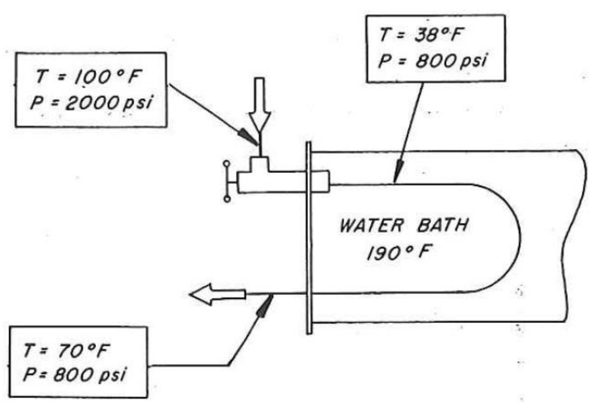
ΔT_1 = 190º - 100º = 90 ºF
ΔT_2 = 190º - 150º = 40 ºF
MTD = 62 ºF

Q = 176,667 Btu/hr with 2" Xtra Heavy flow coil

U = 102

$$A = \frac{Q}{U(MTD)} = \frac{176{,}667}{102(62)} = 27.9\ ft^2\ coil\ area\ required$$

Example 2 - With the pressure reducing choke installed on the coil inlet



ΔT_1 = 190º - 38º = 152 ºF
ΔT_2 = 190º - 70º = 120 ºF

MTD = 137 ºF

Q = 176,667 Btu/hr with 2” Xtra Heavy flow coil

U = 100

$$A = \frac{Q}{U(MTD)} = \frac{176{,}667}{100(137)} = 12.9\ ft^2\ coil\ area\ required$$

The coil heat transfer area required using the choke on the inlet is less than half that required with the choke on the coil outlet. Additional cost savings can be achieved by using a lower pressure-rated coil downstream of the choke valve. In the example problem, a 2” standard weight coil could be substituted for the 2” Xtra heavy coil.

The area required with the choke on the inlet is less than half that required with the choke on the coil outlet. Additional cost savings can be achieved by using a lower pressure-rated coil downstream of the choke. In the example problem, a 2” standard weight coil could be substituted for the 2” Xtra Heavy coil.

When the inlet gas pressure is in excess of 2,000 psig, it is normally necessary to preheat the wellstream ahead of the pressure reducing choke valve. The flow coil, in this case, would be a split or double-pass coil with two inlets and two outlets extending through the cover plate. The long-nose choke is installed on the inlet to the second pass. The outlet of the first pass is piped to the side connection or inlet of the choke valve. There are two advantages to this arrangement:

1. A larger MTD is utilized to keep the surface area smaller; and
2. The cost can be reduced by using a lower working pressure pipe for the second pass.

The previous examples provide some insight as to the effect that choke placement can have on the coil selection.

Antifreeze Additives in the Water Bath

It is quite common to put antifreeze compounds in water bath heaters to prevent physical damage to the unit in the event of pilot light, burner, or fuel system failure. The dependability of the controls and accessories furnished by many manufacturers is excellent, but this does not rule out the possibility of a malfunction. Ethylene glycol is the most prevalent antifreeze in use today. The maximum concentration should never be higher than 50% glycol by volume. However, the use of ethylene glycol must be considered when sizing the coil because the increased viscosity and change in other bath properties results in a lower over-all heat transfer coefficient commonly called “U”. for a 50% volume glycol solution, the “U” factor can be reduced as much as 20%. This requires a proportional increase in surface area of the coil with the same bath temperature. There is one compensating advantage: the bath temperature can be raised to 220 ºF (at sea level) without boiling taking place. The higher available MTD partially offsets the reduction in heat transfer coefficient.

Corrosion Inhibitors

Most ethylene glycol solutions marketed today contain corrosion inhibitors. The corrosion inhibitor should be replaced annually. Heaters containing only fresh water should have a corrosion inhibitor added on an annual basis. The pH should be periodically checked to keep it in the neutral or slightly basic range (pH of 7 or 9). There are a number of compounds which may be used as corrosion inhibitors. Manufacturers will recommend a suitable compound upon request. Corrosion inhibitors do not influence the sizing or selection of the flow coil. They aid in reducing scaling and maintaining a clean transfer surface on both the firebox and the coil. This will prolong the life of the heater.

Energy-Saving Shell Insulation

The present-day emphasis on energy conservation and its relatively high price has created new interest in insulating heater shells efficiently to conserve fuel and lower operating costs. Heat losses from a water bath indirect heater are normally estimated as equal to 10% of the required process heat. In northern regions and higher elevations, the loss can be as high as 20% of the process heat. Insulating the shell with 1½ inches of a dense fiberglass blanket and covering it with an aluminum jacket with a vapor barrier can reduce this loss to less than 1% of the required process heat. This amounts to an appreciable savings in operating cost. Lease operators are encouraged to insulate their units.

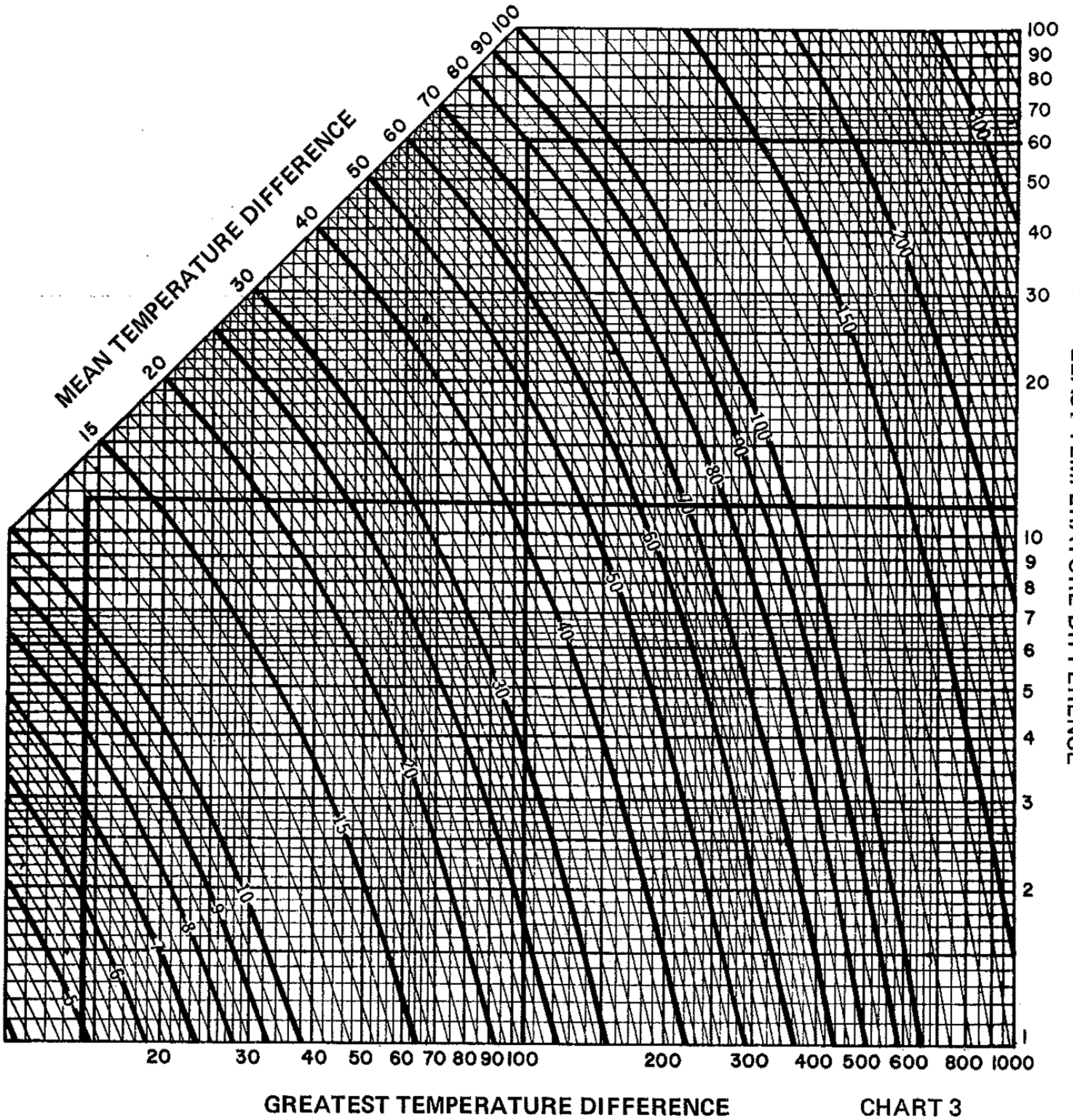


CHART 3

NOTE: For points larger than shown on chart multiply Greatest and Least Temperature Difference shown on chart by 10 and resulting Mean Temperature Difference by 10 (Example shown refers to problem beginning page B-17.)

Sizing Procedure for Natural Gas Heating

The sizing procedure for natural gas heating is divided into three basic steps:

1. Determination of the firebox capacity;
2. Determination of the flow coil heat transfer area; and
3. Determination of the flow coil pressure drop.

The information developed from these parts is used to make the final heater recommendation for the process. An example is presented to illustrate the methods and the charts used in each of these parts:

EXAMPLE

It is desired to select an indirect heater for the following gas well flowing service:

Natural gas flow rate =	4.0 MMScfd
Flowing pressure =	3,350 psig
Shut-in pressure =	4,500 psig
Flowing temperature =	85 ºF
Heater outlet pressure =	1,000 psig

Note: the gas temperature may be considerably less at start-up, affecting the operating efficiency temporarily.

Determination of Firebox Capacity

Determination of the required firebox capacity (the process heat load) is necessary in order to identify which of the standard heater sizes will satisfy the requirement. This provides the designer with a specific firebox and shell combination and a group of standard coils to consider.

Two preliminary steps are performed before proceeding with the actual calculation of the process heat load. The first step is to examine the inlet and outlet conditions and to determine where hydrates may be expected. The second step is to determine the temperature drop expected as a result of the choking or pressure reduction. It is advisable to check the inlet condition for hydrate expectancy. The wellstream in the example enters at 85 ºF. this is 10 ºF above the hydrate expectancy temperature (75 ºF) corresponding to 3,350 psig on **Chart No.1**. the inlet condition is therefore satisfactory.

1 The heater outlet gas temperature must be high enough to prevent any hydrate formation in the flowing natural gas. Refer to the hydrate expectancy chart (**Chart 1**) and note that for 0.7 Specific Gravity natural gas at 1,000 psig hydrates can be expected to form at 64 ºF.

The heater outlet temperature must therefore be above 64 ºF. Note: 10 ºF is added to allow for possible deviation in the wellstream's behavior from the average.

2 The gas temperature drop due to pressure reduction is found from **Chart 2**. Note that with an initial pressure of 3,350 psig and a final pressure of 1,000 psig the temperature drop is 80 ºF. This means that with 85 ºF inlet to the choke valve, the temperature after the choke would be (85 - 80) = 5 ºF.

In order to avoid this low temperature immediately after the choke, the heater coil will be split into a coil up-stream of the choke valve and a coil down-stream of the choke valve. For practical purposes, the temperature of the stream before choking will be raised to 130 ºF. (With water bath temperature of 190 ºF maximum, 130 ºF is within 60 ºF of the bath temperature and any closer approach will result in a very large up-stream coil.)

3 **Charts Numbers 4**, **5**, & **6** are used in calculating the process heat load or the firebox capacity. These are enthalpy or heat-content charts and are provided for three specific gravities of natural gas. Since the natural gas in this example has a specific gravity of 0.7, **Chart No. 5** will be used. The examination of steps 1 and 2 above resulted in the selection of a split coil in which the gas will be preheated to 130 ºF at 3,350 psig, passed through a choke valve where the pressure will be reduced to approximately 1,000 psig, and then heated above the hydrate temperature to 74 ºF. Each part of the coil is treated as a separate part of the problem. The required heat loads are found from **Chart No. 5** as follows:

(a) **Up-stream Coil Section:**
Enter the chart from the left at 3,350 psig and move to the right to the coil inlet temperature of 85 ºF (point 1). Move vertically downward and read the corresponding enthalpy of 5.18 Btu/Scf. Repeat this operation by moving horizontally along the 3,350 psig line to the choke valve inlet temperature of 130 ºF (point 2). Move vertically downward to read the corresponding enthalpy of 7.05 Btu/Scf. The upstream coil section heat load (Q_1) can be calculated as follows:

$$Q_1 = (H_2 - H_1)\frac{4{,}000{,}000\ Scfd}{24} = (7.05 - 5.18)\frac{4{,}000{,}000}{24} = 311{,}666\ Btu/hr$$

Where,

H_1 = Enthalpy at point 1
H_2 = Enthalpy at point 2

(b) **The process of choking (or "throttling")** is, for all practical purposes, a thermodynamic, constant enthalpy process that can be visually represented by the vertical line between point 2 and point 3. The basic assumption is that the movement of natural gas takes place so rapidly there is no heat lost or gained in passing through the choke valve seat. Therefore, the heat content of the gas ahead of the choke valve seat equals that of the gas immediately downstream of the seat. In other words, $H_2 = H_3$.

(c) **Coil section downstream of the choke:**
Enter **Chart No. 5** at 1,000 psig and more horizontally until intersecting the vertical line drawn downward from point 2. (Enthalpy = 7.05 Btu/Scf = H_3) Continue horizontally along the 1,000 psig line until you reach 74 ºF (point 4). Move vertically downward and read the corresponding coil outlet enthalpy of 8.16 Btu/Scf = H_4. The downstream coil heat load (Q_2) can then be calculated as follows:

$$Q_2 = (H_4 - H_3)\frac{4{,}000{,}000\ Scfd}{24} = (8.16 - 7.05)\frac{4{,}000{,}000}{24} = 185{,}000\ Btu/hr$$

Note: $H_2 = H_3 = 7.05$ Btu/Scf

(d) **Atmospheric heat losses from un-insulated heater shell:**

Process heat load = $Q_1 + Q_2$ = 311,666 + 185,000 = 496,666 Btu/hr

Heat losses for an un-insulated shell are estimated at 10% of process heat load.

Heat loss = (496,666) (0.1) = **49,666 Btu/hr = Q_S**

Note: Insulated shell heat loss = 4,967 Btu/hr approximately

(e) **Total heat load or required firebox capacity:**

$Q_{Total} = Q_1 + Q_2 + Q_S$ = 311,666 + 185,000 + 49,666 = **546,333 Btu/hr**

Select a standard heater size having a firebox capacity greater than the total heat load. From the **standard heater size table**, select the **750,000 Btu/hr heater** for further consideration.

Determination of the Flow Coil Heat Transfer Area:

(4) Minimum coil areas are now found as follows:

$$A = \frac{Q}{U(MTD)}$$

Where,

A = Pipe heat transfer area, ft^2
Q = Heat transferred, Btu/hr
U = Overall Heat Transfer Coefficient, Btu/hr-ft^2-ºF
MTD = Log Mean Temperature Difference, ºF

This example is solved with the aid of charts and tables which reduces the calculations to a minimum. These charts do not include the presence of liquid in the gas or when a substance changes phase; i.e., gas condenses to liquid or liquid vaporizes. For streams containing more than 10 barrels of liquid per million standard cubic feet of gas, it is suggested that a manufacturer's Engineering Department determine the size of the required unit.

(a) **Up-stream Section**

"U" is obtained from **Chart 7**, first noting that for 4,500 psig shut-in pressure, a 2" XXtra Heavy coil is required.

Enter **Chart 7** at 4 MMScfd, read vertically to the intersection with 2" XXtra Heavy pipe, then read horizontally to the intersection with 3,350 psig line, then follow up to read **U = 128 Btu/hr-ft^2-ºF**.

The MTD is obtained from **Chart 3**[2], assuming a maximum bath temperature of 190 ºF.

Where,

GTD = Greatest Temperature Difference (Abscissa) = Water bath temperature minus the initial gas temperature = 190 - 85 = **105 ºF**

LTD = Least Temperature Difference (Ordinate) = Water bath temperature minus the final gas temperature = 190 - 130 = **60 ºF**

Applying GTD = 105 ºF and LTD = 60 ºF to the chart, the **MTD = 80 ºF**.

Now, solving the heat transfer equation:

Up-stream section coil area = (311,666)/(128 x 80) = **30.4 ft^2**

(b) **Down-stream section (solving as above)**

U = 116 Btu/hr-ft^2-ºF at 1,000 psig
MTD = 127 ºF

GTD = (190-50) = 140 ºF &
LTD = (190-74) = 116 ºF

Down-stream section coil area = 185,000/(116 x 127) = 12.6 ft^2

Therefore minimum total coil area = (30.4 ft^2) + (12.6 ft^2) = **43 ft^2**

[2] The MTD chart is logarithmic. Arithmetic averaging of the temperature differences can be used for approximating coil sizes if an MTD chart is not available.

(5) **Heater Selection**
In all cases select an indirect heater that has a Btu rating and coil area greater than the calculated values. The indirect heater selected must have a coil area greater than 43 ft^2 and a firebox rating greater than 546, 333 Btu/hr. therefore, the 750,000 heater with 10 tubes of XXtra Heavy coil is selected from **Table 1** on standard heater coils since the Btu rating and coil area is greater than the calculated requirements.

The coil will be split 6 & 4 to give 34.8 ft^2 in the section up-stream of choke and 23.2 ft^2 in the down-stream section. (Note: Each coil section must have an even number of passes)

Determination of Estimated Flow Coil Pressure Drop

The pressure drop may be estimated from nominal coil length given in **Table 2** and from pressure drop **Chart 8**.

> Equivalent coil length = 114 (from **Table 2**) x 1.3 (factor for return bends) = 148.2 ft for the 10 passes, or 14.82 ft/pass.

The up-stream coil, with 6 passes, has 88.92 ft of flow coil. The pressure drop is approximately 6.2 psi/100 ft or 5.5 psi (6.2 x 0.8892).

The down-stream coil with 4 passes has 59.28 ft of flow coil. The pressure drop is approximately 15 psi/100 ft or 8.9 psi (15 x 0.5928).

Final Heater Selection and Specifications:

The heater selected, as a result of the above calculations, is a 750,000 Btu/hr indirect heater with a 10-tube, 2" XXtra Heavy flow coil, split 6/4; a long nose choke installed on the inlet to the second pass; and interconnecting piping between the outlet of the first coil and the inlet of the choke.

The coil could be manufactured for this example with 2" XXtra Heavy pipe in the first pass and 2" Xtra Heavy pipe in the second pass. Provisions must be taken to prevent the full wellhead pressure (4,500 psig) from being exerted on the 2" Xtra Heavy pass. This can be accomplished by using a pressure controller to monitor the coil immediately downstream of the choke valve. The pressure controller would be used to actuate a diaphragm-controlled shut-in valve or diaphragm-actuated long-nose choke to isolate the 2" Xtra Heavy pass from the high pressure.

Since the calculated heat load of an insulated heater is 501,633 Btu/hr, it may be possible to use a smaller heater; i.e., 500,000 Btu/hr, depending on actual field conditions and user preference.

Sizing Procedures for Oil Heaters

The sizing procedure for heating crude oil is similar to that for natural gas, although the actual calculations are more complicated. The method presented is a simplified procedure which is sufficiently accurate for normal field application.

The following information is required to properly select an indirect heater for oil heating:

1 Quantity of oil, water, and gas in the wellstream
2 Specific Gravity of the oil, water, and gas
3 Oil viscosity in SSu or Centistokes at 100 ºF
4 Inlet and outlet temperature in ºF
5 Inlet pressure and allowable pressure drop through the heater coil, in psi

Information that is not available must be either estimated or assumed, based upon knowledge of other production in the general area. Heater sizing should be checked when correct information becomes available.

The charts in this document are based upon the assumption that crude oil wellstreams have only minimal quantities of gas when entering the heater flow coil. Gas released by the heating process actually improves the heat transfer coefficient; therefore, this basic assumption results in conservative sizing. Applications for crude oil wellstream with appreciable quantities of gas generally with gas-oil ratio of 100 ft^3 per barrel or higher, should be referred to the manufacturer's engineering department for sizing.

The sizing procedure for crude oil heating is done in three parts. The charts to be used are **Charts 3**, **9**, **10**, and **11**. The table on available standard coils is to be used also. The coils shown are those that handle about 90% of the gas heating applications; however, other coils are available for specific requirements.

Crude Oil Heater Sizing Example

It is desired to select an Indirect Heater for the following service:

- Crude oil flow rate = 2,400 barrels/day with 20% water included
- Oil Specific Gravity = 30 ºAPI
- Oil viscosity = 55 SSU at 100 ºF
- Inlet pressure = 1,500 psig
- Inlet temperature = 50 ºF
- Outlet temperature = 100 ºF
- Oil Characterization Factor = 11.8

(Note: The wellstream originates from an oil and gas separator and enters the heater with only a small quantity of entrained gas)

Determination of Firebox Capacity
Refer to **Chart No. 9**

(1) **Crude oil specific heat value**
a. Average temperature in the flowcoil (T_{avg})

$$T_{Avg} = (T_{in} + T_{out})/2 = (50 + 100)/2 = 75\ ^{o}F$$

b. Using the inset specific heat graph on **Chart No. 9**:

T_{Avg} = 75 ºF and crude oil is 30 ºAPI

$C_P = 0.46$

(2) **Wellstream heat load:**
Enter Chart No. 9 on the left side at 2,400 Bpd crude flow rate. Move to the right horizontally to intersect with the 20% volume water line. Move vertically downward to the 50 ºF temperature-rise line. (Wellstream enters at 50 ºF and leaves at 100 ºF for a 50 ºF rise in temperature). At this intersection move again horizontally to the right until intersecting a 30 ºAPI oil gravity line. Then move downward again until intersecting the specific heat lines at approximately 0.46. move horizontally to the right and read the wellstream heat load in MMBtu/hr. In this case, the heat load is 890,000 Btu/hr.

$$\mathbf{Q_1 = 890{,}000\ Btu/hr}$$

(3) **Estimate the shell heat losses, Q_S**
Heat loss to the atmosphere for un-insulated heaters is approximately 10% of process heat load.

$$Q_S = 890{,}000 \times 0.10 = \mathbf{89{,}000\ Btu/hr}$$

(4) **Total heat load or required firebox capacity**:

$$Q_T = Q_1 + Q_S = 890{,}000 + 89{,}000 = \mathbf{979{,}000\ Btu/hr}$$

Select a standard heater size having a firebox capacity greater than the total heat load. Select a 1,000,000 Btu/hr heater for the process.

Determination of the Flow Coil Heat Transfer Area

Minimum coil areas are found by using **Chart No. 10** for determining the overall heat transfer coefficient "U", **Chart No. 3** for the MTD, and the previously determined process heat load Q_1. This information is inserted into the equation below to obtain the required flow coil heat transfer area.

$$A = \frac{Q}{U(MTD)}$$

Where,

A = Pipe heat transfer area, ft^2
Q = Heat transferred, Btu/hr
U = Overall Heat Transfer Coefficient, Btu/hr-ft^2-ºF
MTD = Log Mean Temperature Difference, ºF

(1) **Determine Pipe Coil Size:**
Refer to **Table 2** for coils available for a 1,000,000 Btu/hr heater. The table lists both 2" and 3" size coils. It may be necessary to try both sizes of pipe because of the pressure drop. Try the 12-tube 2" Xtra Heavy coil with 93.4 ft^2 of coil area, and 166 lineal feet of pipe in the coil.

(2) **Determine the Over-all Heat Transfer Coefficient:**
Chart No. 10 is a nomograph with a turning line in the middle.

a. Locate the flow rate on the left vertical line of the chart and draw a line from 2,400 Bpd through the 2" Xtra Heavy mark on the second vertical line (labeled "Pipe size"). Extend this line until it intersects the turning line.

b. Locate the crude oil viscosity (55 SSU at 100 ºF) on the right hand side vertical line (labeled "viscosity"). Lay a straight-edge on the chart and draw a line intersecting both the 55 SSU point and the previously located intersection on the turning line. Where this line intersects the "U" factor line, read the Overall Heat Transfer Coefficient value. The "U" factor is 79 Btu/hr-ft^2-ºF.

(3) **Determine the Mean Termperature Difference:**

GTD = (190-50) = 140 ºF
LTD = (190-100) = 90 ºF

From **Chart No. 3**, MTD = 112 ºF

A = Q_1/(U x MTD) = 890,000/(79 x 112) = **100.6 ft^2 required**

Table 2 lists the 12-2 Xtra Heavy coil with only 93.4 ft^2 of area, while the example needs 100.6 ft^2. By proportion, it can be determined that a 14-2 Xtra Heavy coil can be placed in a 1,000,000 Btu/hr heater shell, or whether a larger shell would be required. The manufacturer's engineering department should be contacted for this information and recommendations. (Note: The engineering department confirmed that a 14-2 Xtra Heavy coil can be placed in a 1,000,000 Btu/hr indirect heater shell - but it is not in stock.)

Determination of the Estimated Flow Coil Pressure Drop

Pressure drop is not specified; therefore, the amount of pressure drop will be estimated and provided to the customer for his consideration. Use **Chart No. 11** for this item.

(1) Calculate the crude oil flow rate in Barrels/hour:
Crude oil hourly flow rate = 2400/24 = 100 Barrels/hr

(2) Enter **Chart No. 11** at 100 Bbl/hr and move to the right until intersecting the 2" Xtra Heavy line. Move vertically downward to the bottom of the chart and read pressure drop: 9.2 psi/100 ft

(3) Move to the inset correction factor chart to find the viscosity correction factor of 30 ºAPI oil having a viscosity of 55 SSU at 100 F. The viscosity correction factor = 0.75.

Corrected Pressure = (9.2) (0.75) = 6.9 psi/100 ft

(4) Calculate the estimated pressure drop for a 14-tube 2" Xtra Heavy coil:

a. Calculate the equivalent lineal feet in a 14-2 Xtra Heavy coil.
12-2 Xtra Heavy coil has 166 lineal feet. By proportion, the 14" coil has
(166) (14/12) = 193.7 lineal feet

b. Apply the return bend factor to the coil.
A 14-2 Xtra Heavy coil has (193.7) (1.3) = **251.7 equivalent lineal feet**

c. Calculate the developed pressure drop:

$$\Delta P = (6.9/100)\ (251.7) = 17.4 \text{ psi}$$

The 14-tube 2" Xtra Heavy coil is satisfactory.

Final Heater Selection

A 1,000,000 Btu/hr indirect heater with a 14-2 Xtra Heavy flow coil having a pressure drop of 17.4 psi could be recommended; however, the coil working pressure of 3,372 psig is considerably above the wellstream flowing pressure of 1,500 psig. A coil of 2" standard weight pipe would be adequate since its working pressure is 2,363 psig. The engineering department should be contacted for information on a 14-tube 2" Standard weight coil. In either instance, the coil would have to be fabricated as a "special" since it is not a stock item. The 2" Standard weight coil costs less than the 2" Xtra Heavy coil, thereby reducing the capital investment. (However, the versatility of the Xtra Heavy coil for use on other locations may offset the additional capital investment required.)

Insulation of the heater shell is recommended as an extra price item because it offers a fuel savings of approximately 1,900 Scfd

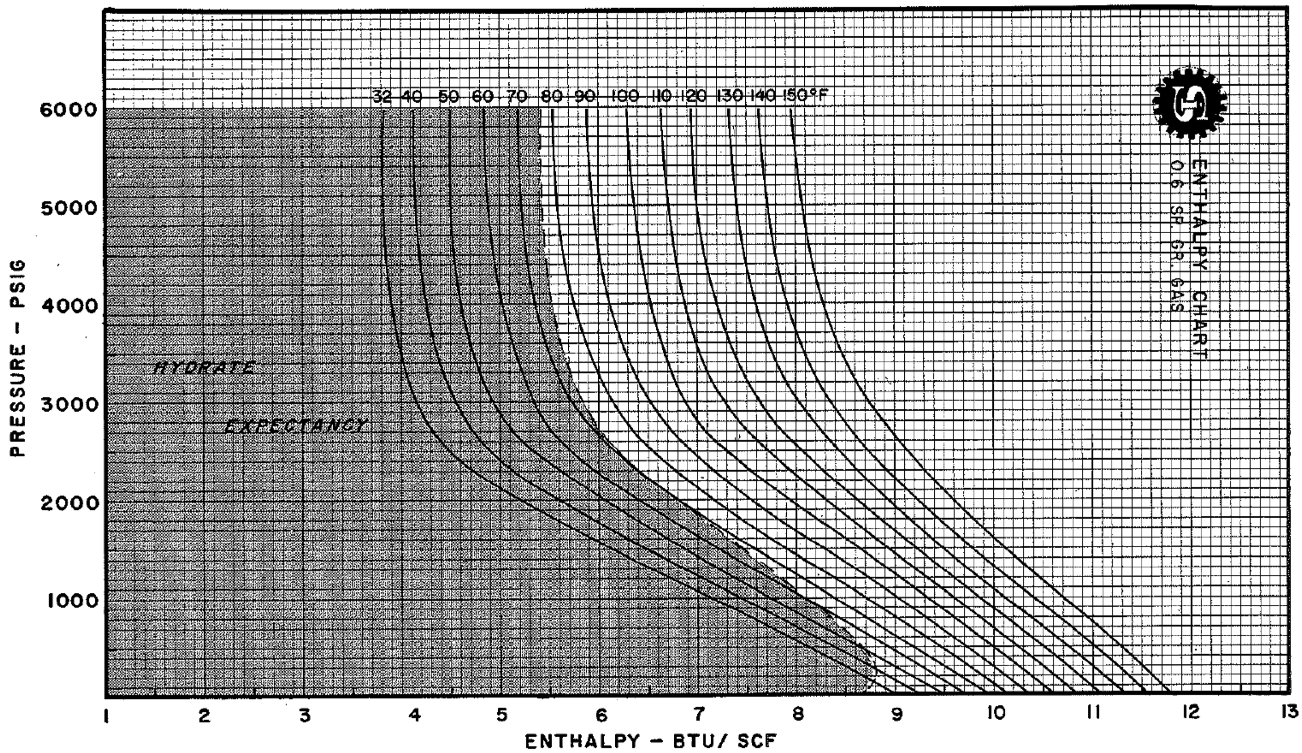


CHART 4

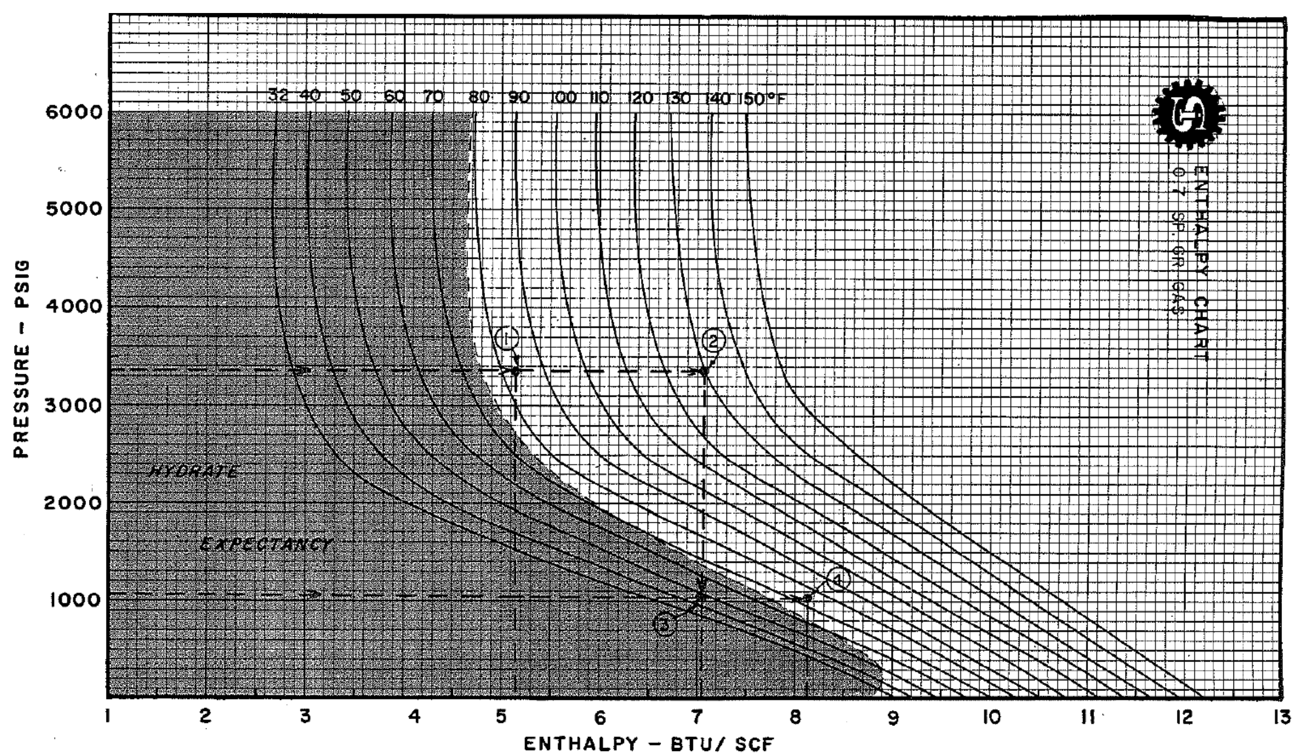


CHART 5

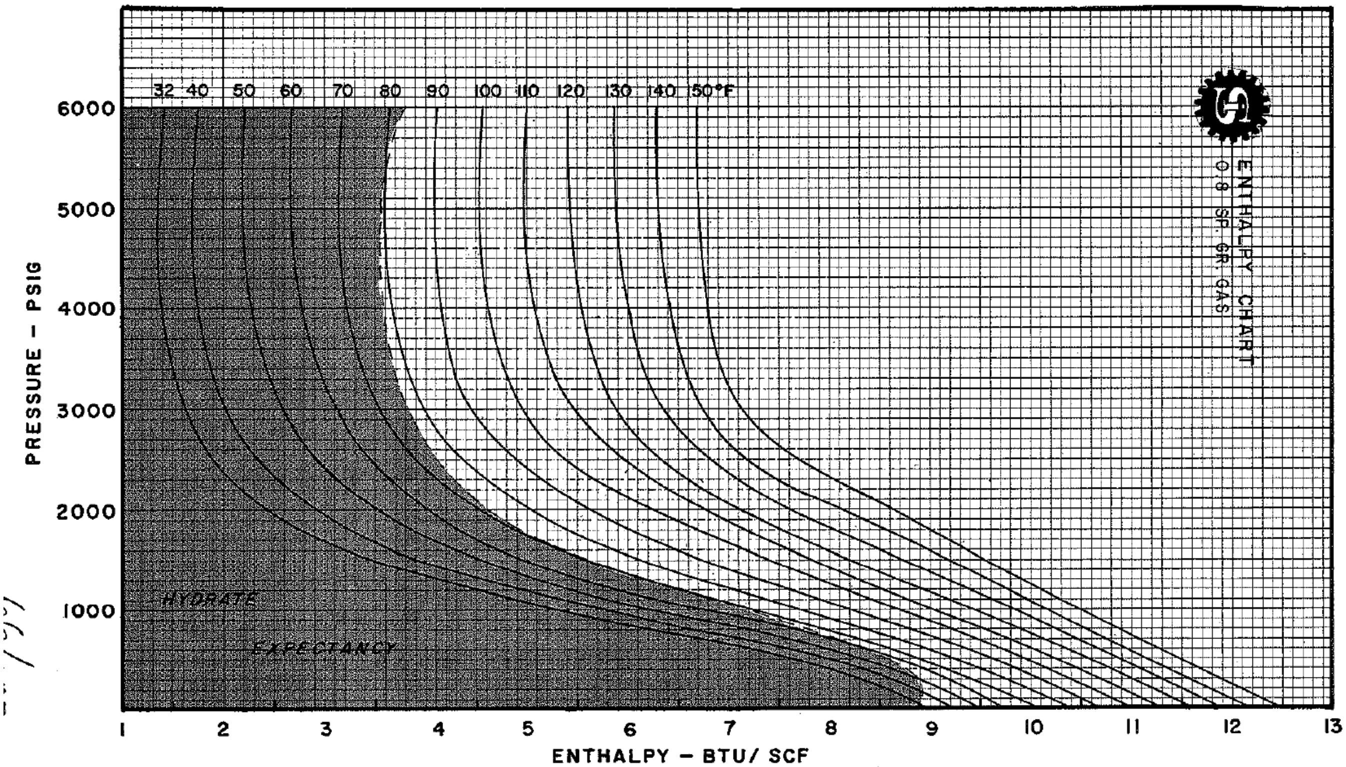

32 40 50 60 70 80 90 100 110 120 130 140 150°F
ENTHALPY CHART
0.8 SP. GR. GAS
PRESSURE – PSIG
6000
5000
4000
3000
2000
1000
HYDRATE
EXPECTANCY
1 2 3 4 5 6 7 8 9 10 11 12 13
ENTHALPY – BTU/ SCF

CHART 6

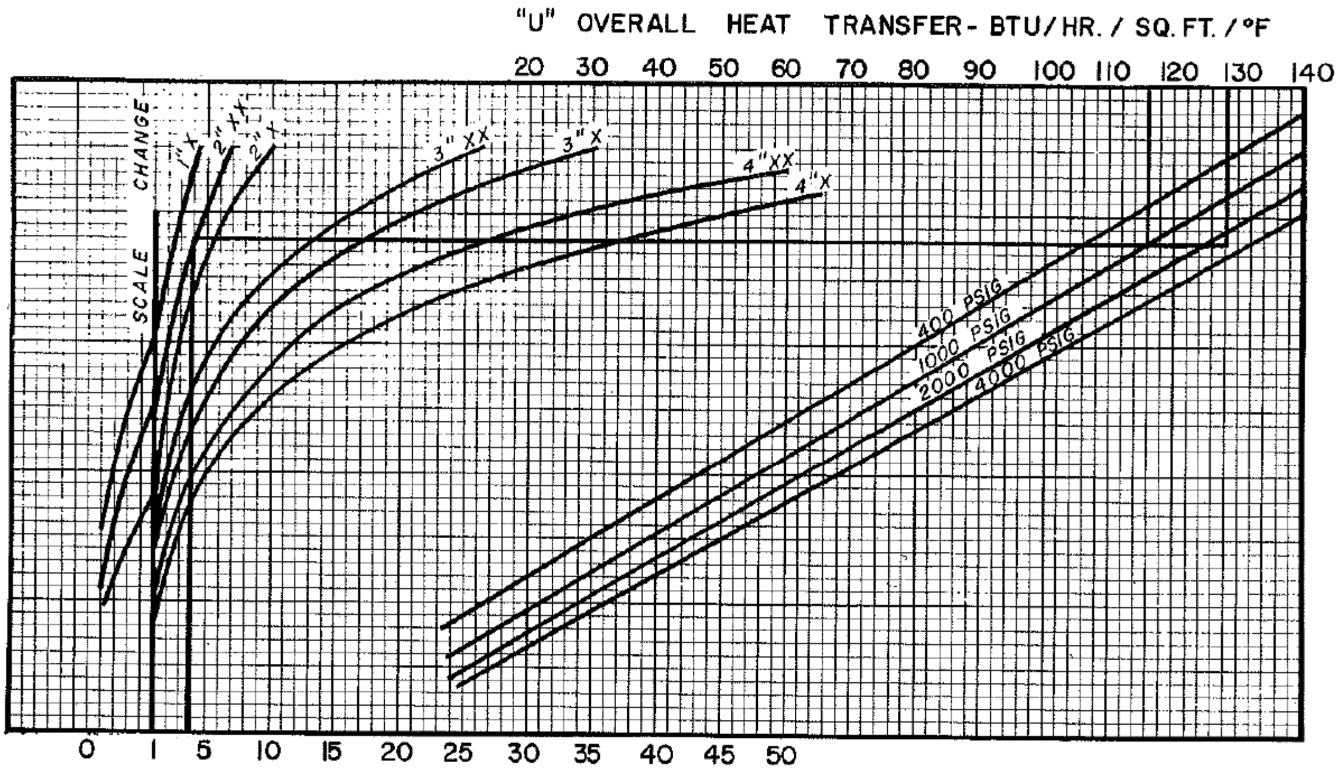


CHART 7

PRESSURE DROP VS. COIL SIZE

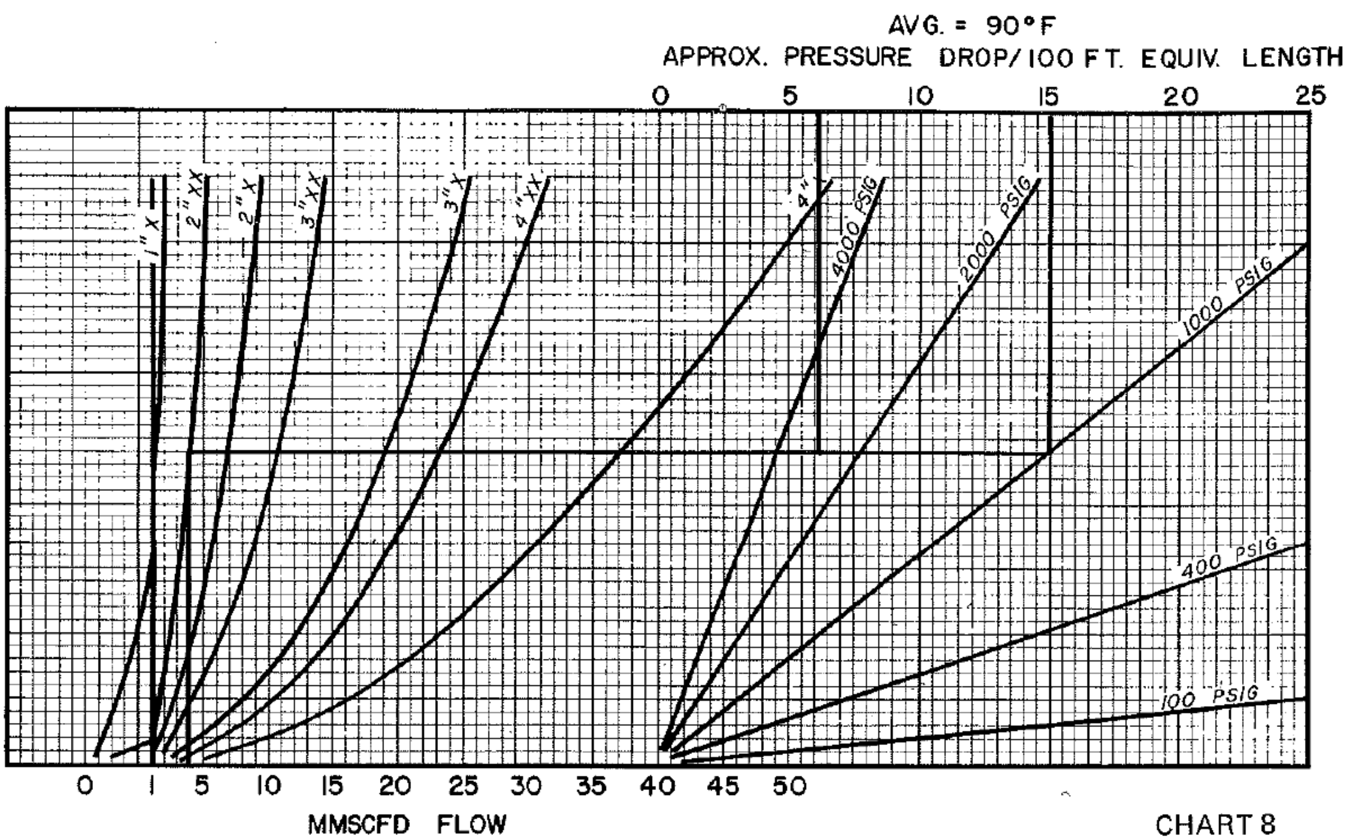
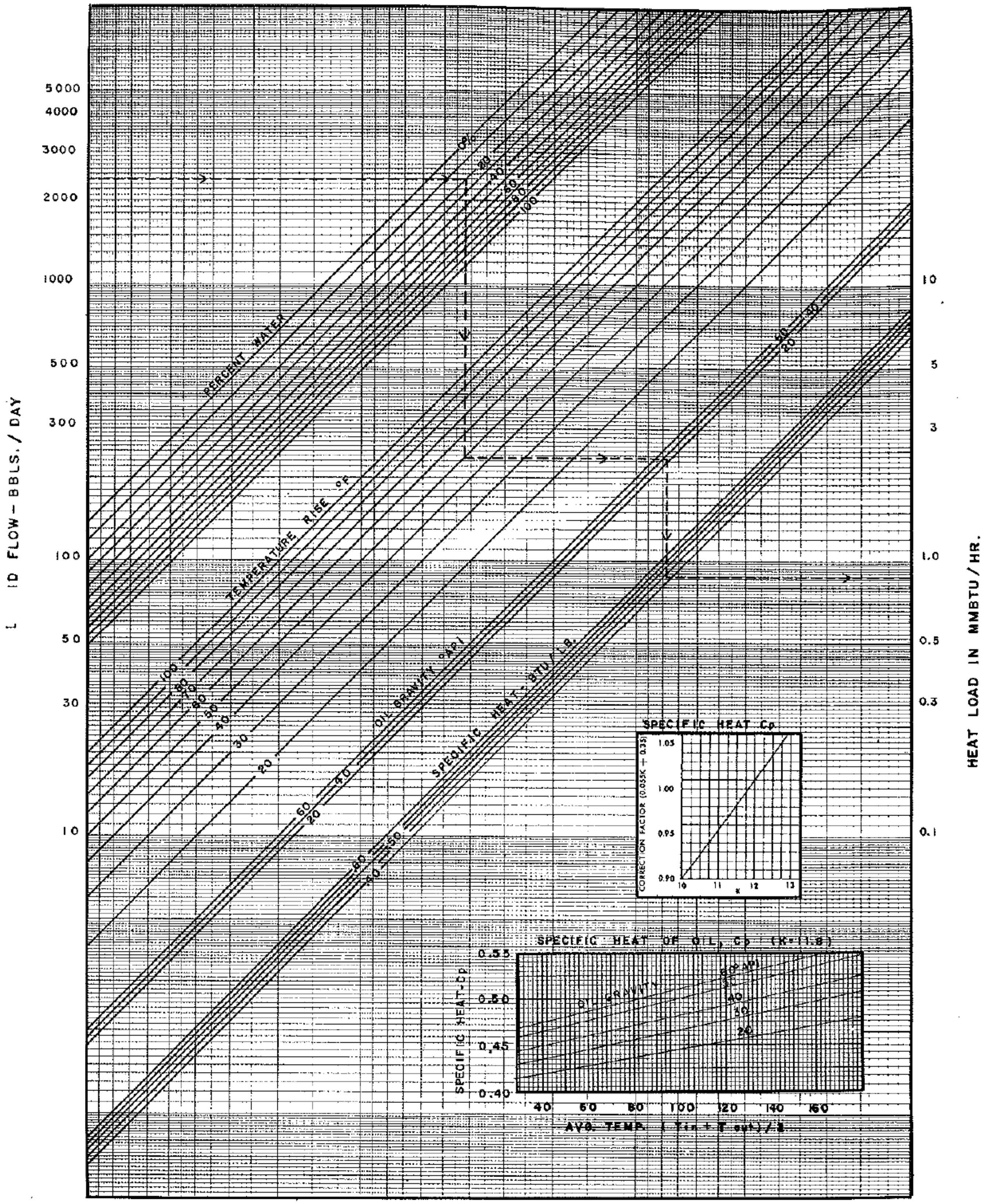
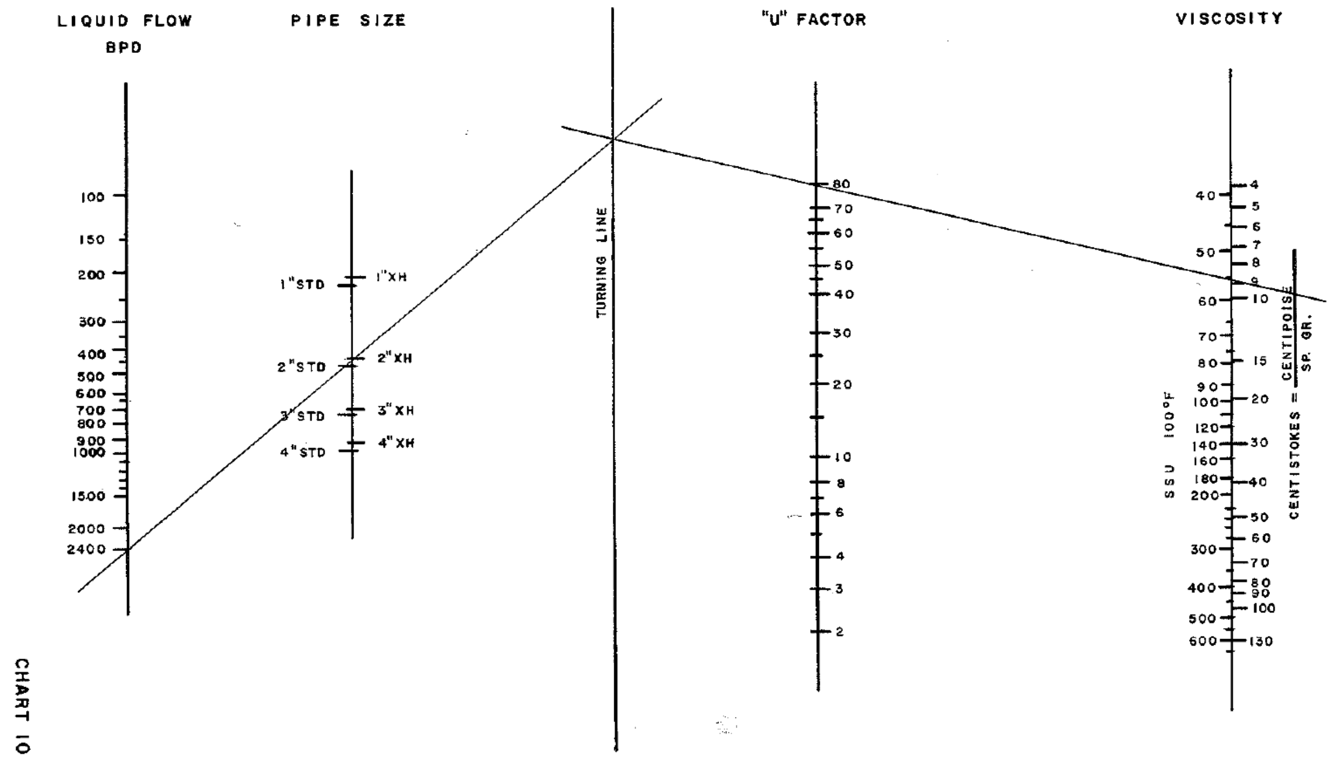


CHART 8



OIL HEATING— SIZING CHART

HEAT LOAD CALCULATION — OIL HEATING CHART 9

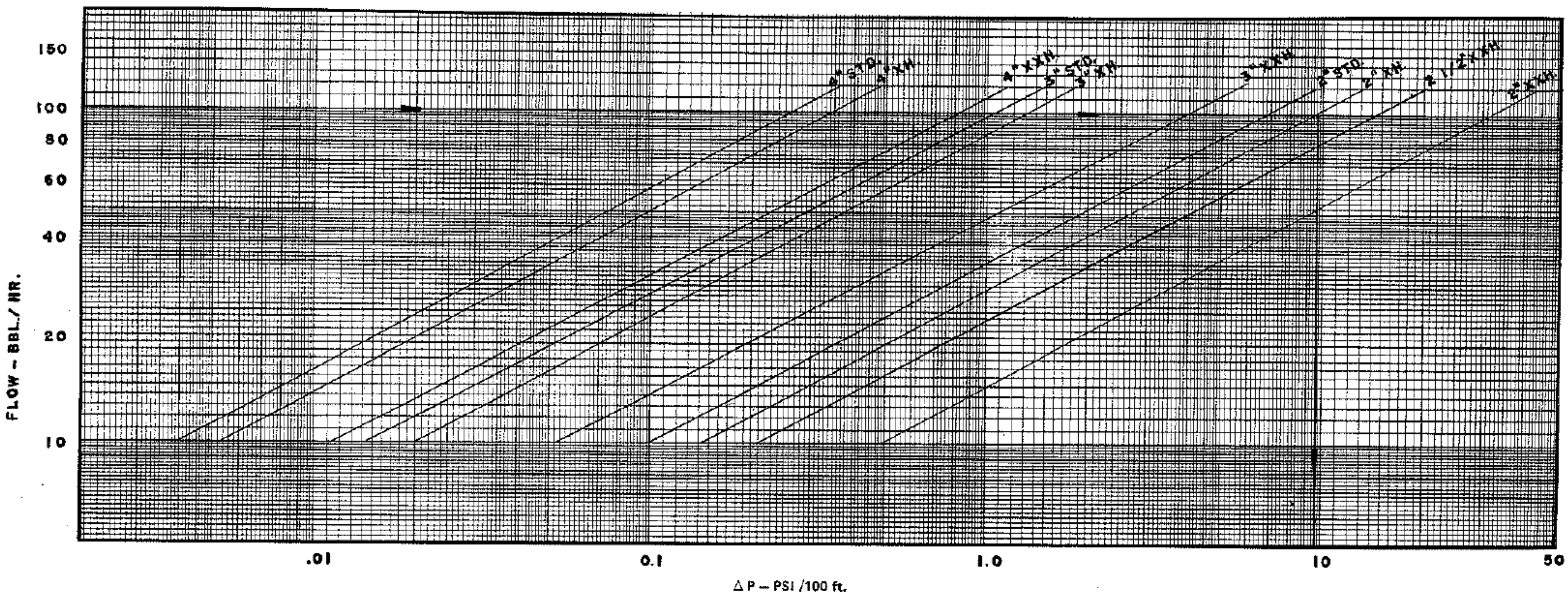


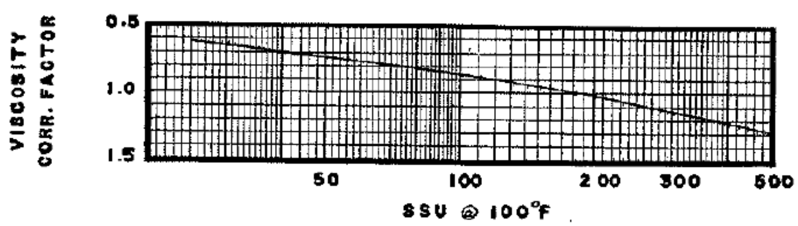
"U" VALUES FOR OIL HEATING

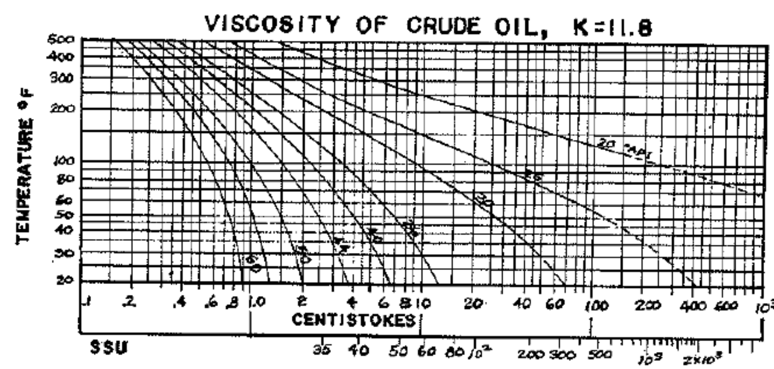
CHART 10

PRESSURE DROP CHART – OIL HEATING

Chart 11



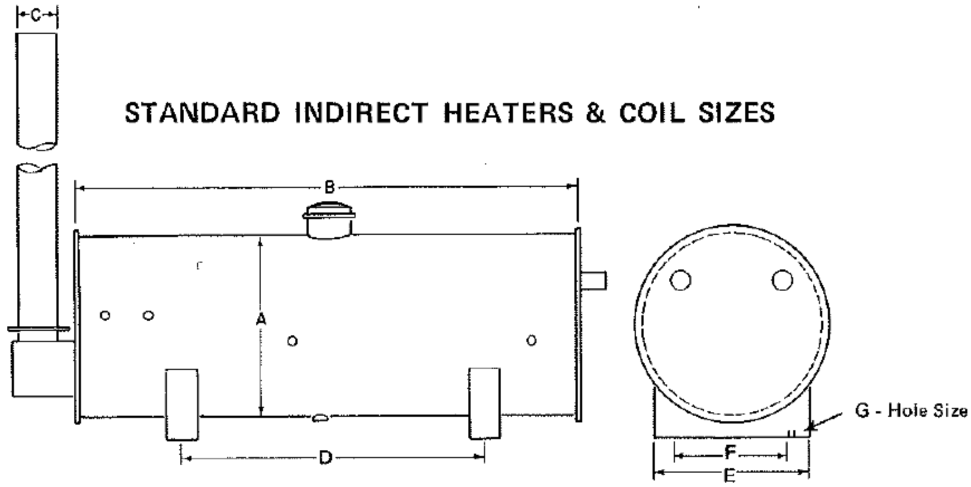




PRE-FABRICATED STOCK COILS*

HEATER SIZE	NO. & SIZE TUBE	PASSES	COIL W.P. PSI	MEAN COIL AREA SQ. FT.
250,000	8-2"XH	Single Pass	3372	29.5
500,000	8-2"XH	Single Pass	3372	42.6
500,000	8-2"XH	Double Pass	3372	42.6
500,000	8-2"XXH	Double Pass	6747	38.3
750,000	10-2"XXH	Double Pass	6747	58.0
1,000,000	12-2"XXH	Double Pass	6747	85.9

*Subject to change without notice.
OTHER COMBINATIONS OF COIL SIZE, PASSES, W.P. AND MEAN AREA AVAILABLE.



STANDARD INDIRECT HEATERS & COIL SIZES

NOMINAL DIMENSIONAL DATA

Heater	A	B	C	D	E	F	G
BTU HR	Ft. In.	Ft. In.	Ft. In.	Ft. In.	Ft. In.	Ft. In.	In. only
250,000	2'-0"	7'-6"	0'-8"	5'-6"	1'-0"	1'-5"	3/4"
500,000	2'-6"	10'-0"	0'-10"	6'-0"	1'-9"	1'-5"	11/16"
750,000	3'-0"	12'-0"	0'-12"	6'-0"	2'-2"	1'-10"	11/16"
1,000,000	3'-6"	14'-4"	1'-2"	11'-0"	3'-0"	2'-4"	3/4"
1,500,000	4'-0"	17'-6"	1'-4"	12'-6"	3'-6"	3'-0"	3/4"
2,000,000	5'-0"	20'-0"	1'-8"	12'-6"	4'-4"	3'-0"	7/8"

SPECIFICATIONS

Heater Furnace Input BTU/HR	Shell Size O.D. x Lgt.	Std. No. & Size Tubes	Coil W.P. PSI	Std. Mean Coil Area Sq. Ft.	Approx. Coil Lin. Ft.	Water Fill Vol: Bbls.	Shipping Weight Pounds
250,000	24" x 7'6"	8-2"XH	3372	29.5	54	2.9	1,400
250,000	24" x 7'6"	8-2"XXH	6747	26.5	54	2.9	1,610
500,000	30" x 10'0"	8-2"XH	3372	42.6	76	6.0	2,210
500,000	30" x 10'0"	8-2"XXH	6747	38.3	76	6.0	2,510
750,000	36" x 12'0"	10-2"XH	3372	64.4	114	10.5	2,875
750,000	36" x 12'0"	10-2"XXH	6747	58.0	114	10.5	3,325
750,000	36" x 12'0"	6-3"XH	3150	59.4	70.9	10.3	3,030
750,000	36" x 12'0"	6-3"XXH	6300	58.8	70.9	10.3	3,615
1,000,000	42" x 14'4"	12-2"XH	3372	93.4	166	17.9	4,060
1,000,000	42" x 14'4"	12-2"XXH	6747	85.9	166	17.9	4,725
1,000,000	42" x 14'4"	8-3"XH	3150	94.8	113.2	17.5	4,390
1,000,000	42" x 14'4"	8-3"XXH	6300	85.9	113.2	17.5	5,335
1,500,000	48" x 17'6"	14-2"XH	3372	134.0	237	28.7	5,650
1,500,000	48" x 17'6"	14-2"XXH	6747	120.5	237	28.7	6,600
1,500,000	48" x 17'6"	10-3"XH	3150	145.0	173.1	28.0	6,235
1,500,000	48" x 17'6"	10-3"XXH	6300	131.4	173.1	28.0	7,675
2,000,000	60" x 20'0"	16-2"XH	3372	175.7	311	51.8	10,110
2,000,000	60" x 20'0"	16-2"XXH	6747	158.0	311	51.8	11,360
2,000,000	60" x 20'0"	10-3"XH	3150	165.9	198.1	51.2	10,580
2,000,000	60" x 20'0"	10-3"XXH	6300	150.4	198.1	51.2	12,240

*Subject to change without notice. Other combinations are available.