STEAM JET EJECTORS

The operating principle of a steam jet ejector is that the pressure energy in the motive steam is converted into velocity energy in the nozzle, and, this high velocity jet of steam entrains the vapor or gas being pumped. The resulting mixture, at the resulting velocity, enters the diffuser where this velocity energy is converted to pressure energy so that the pressure of the mixture at the ejector discharge is substantially higher than the pressure in the suction chamber.

An ejector stage has operating limitations on the compression attainable and will operate efficiently only up to a definite maximum ratio of compression. The ratio of compression is the absolute discharge pressure divided by the absolute suction pressure.

For greater ratios of compression than can be attained in a single ejector stage, two or more stages can be arranged to operate in series. This assembly consitutes a multi-stage ejector.

An ejector stage is inherently a constant capacity device. The capacity is a function of the physical proportions of the diffuser.

To obtain variation in capacity, two or more ejectors, either single or multi-stage, can be arranged to operate in parallel, each series constituting an element of a multiple element ejector. This arrangement permits the operation of the number of elements needed for the required capacity, as each element is capable of completely compressing a portion of the total capacity.

Ejectors are generally categorized into one of four basic types: single-stage, multi-stage non-condensing, multi-stage condensing and multi-stage with both condensing and non-condensing stages.

Single-stage ejectors are the simplest and most commonly used construction. They are generally recommended for pressures from atmospheric to

2" Hg. Abs. Single-stage units discharge at or near atmospheric pressure.

Multi-stage non-condensing ejectors are used where it is necessary to produce lower suction pressures. Steam consumption in these units is relatively high as each successive stage is required to handle the load and motive steam of the stage ahead of it. These designs are frequently used where a low first cost is more frequent than operating economy, for intermittent use or for applications where water is not available.

Multi-stage condensing ejectors are available in two or more stages. An inter-condenser of either the surface or direct-contact (barometric) type is used between the stages to condense the steam from the preceding stage and reduce the load. This design is generally recommended for suction pressures from 4.0" Hg. Abs. to 3 mm Hg. Abs. in two-stage designs; from 25 mm Hg. Abs. to 1.5 mm Hg. Abs. in three-stage designs. See Figure 7 for a more complete breakdown of suction pressure range versus ejector scheme.

For handling large amounts of condensable vapors, the first stage "booster" is usually followed by a condenser which is in turn followed by a two-stage ejector to compress non-condensables to atmospheric pressure. When condensable loads are small or nonexistent, only one inter-condenser following the second stage may be used. Three-stage non-condensing units use relatively large quantities of motivating steam and are not generally recommended.

Some designs incorporate the use of an after-condenser to condense the atmospheric stage motive steam. Where surface type inter- and after-condensers are used the condensate for the main condenser can be pumped through the inter-condenser and after-condenser as cooling water. This permits returning heat of the ejector steam to the boiler.

Basic Construction

Ejectors are composed of three basic parts: steam nozzle, mixing section and diffuser section. Figure I illustrates a typical ejector. A high pressure motivating fluid (M_a) enters at 1, expands through the converging-diverging nozzle to 2. The suction fluid (M_b) enters at 3, mixes with the motivating fluid in the mixing chamber 4. Both M_a and M_b are then recompressed through the diffuser to 5. Figures II and III show the pressure, velocity, and thermal changes for a typical ejector using high pressure steam as the motivating fluid and saturated vapor as the suction fluid.

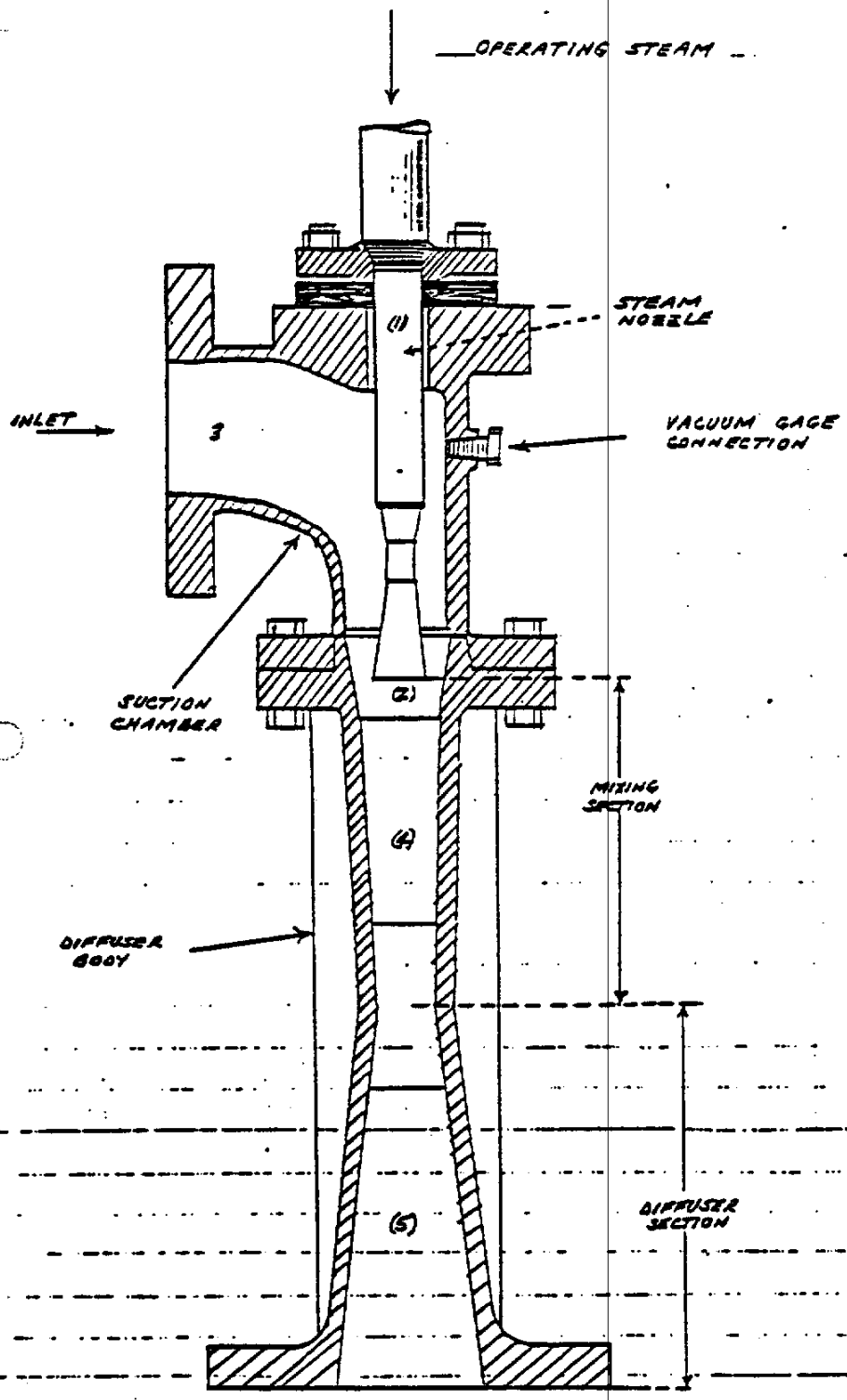

OPERATING STEAM
STEAM NOZZLE
(1)
INLET
3
VACUUM GAGE CONNECTION
SUCTION CHAMBER
(2)
MIXING SECTION
(4)
DIFFUSER BODY
DIFFUSER SECTION
(5)

FIGURE I

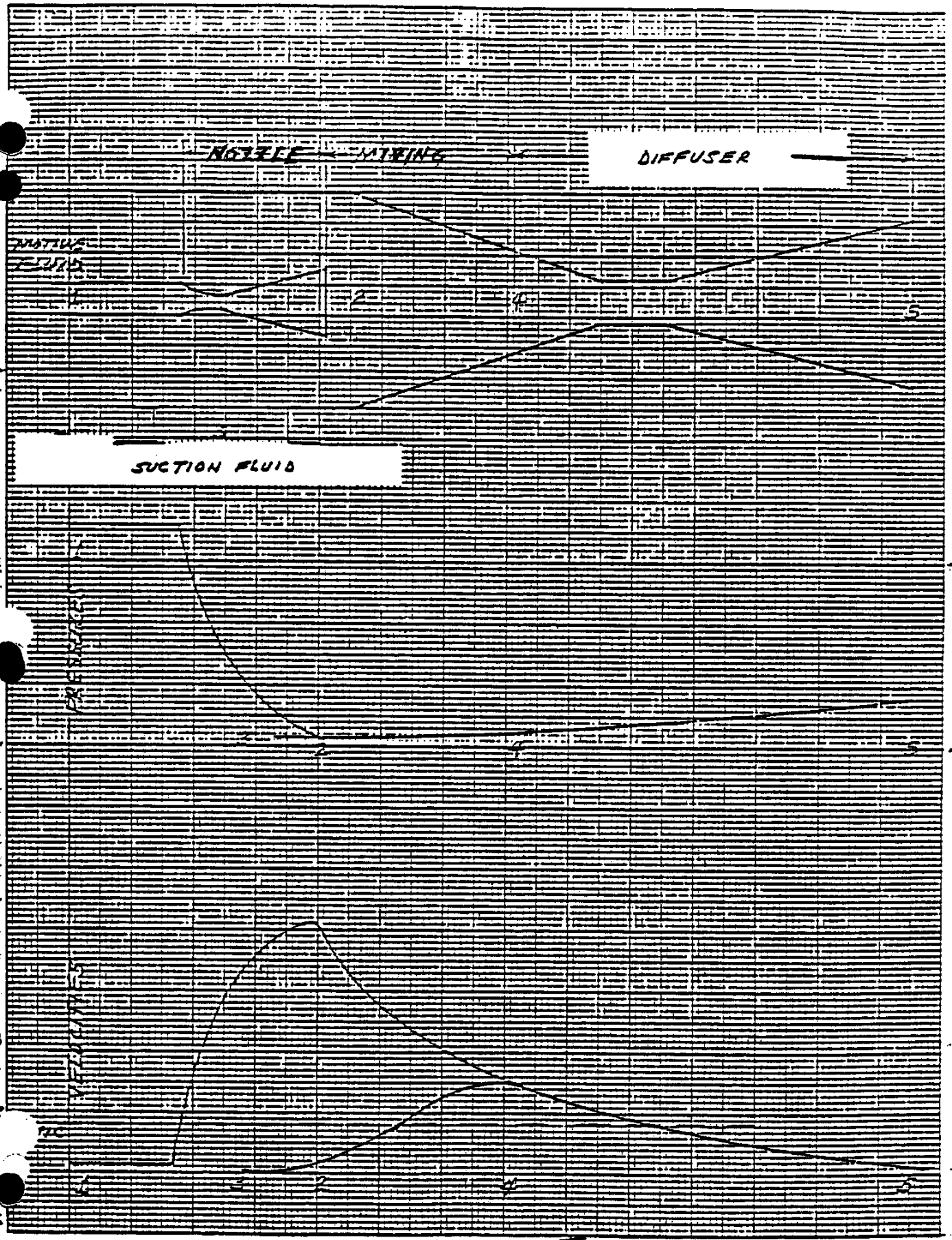

NOZZLE
MIXING
DIFFUSER
MOTIVE FLUID
SUCTION FLUID
PRESSURE
VELOCITY
1
2
4
5

FIGURE II

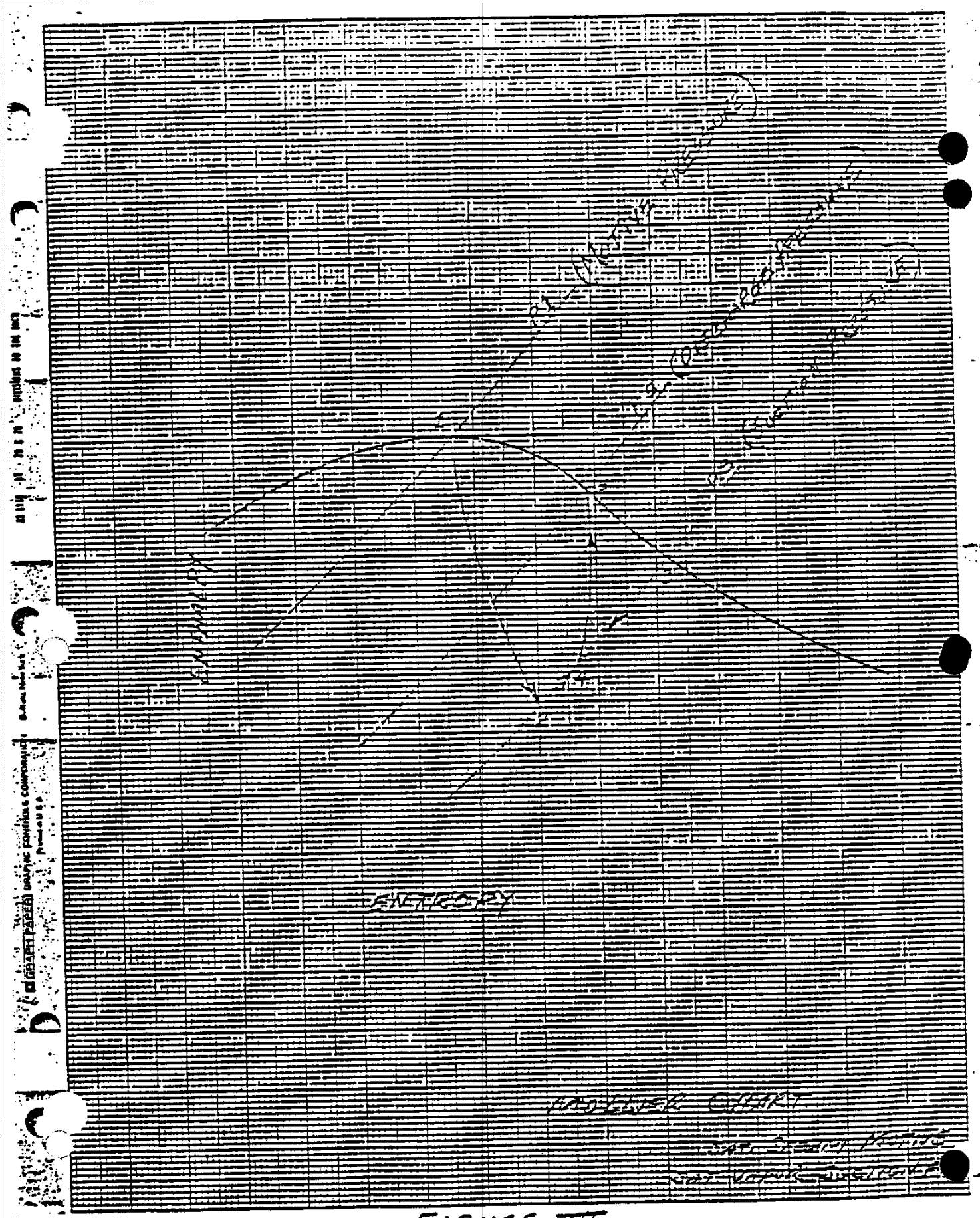
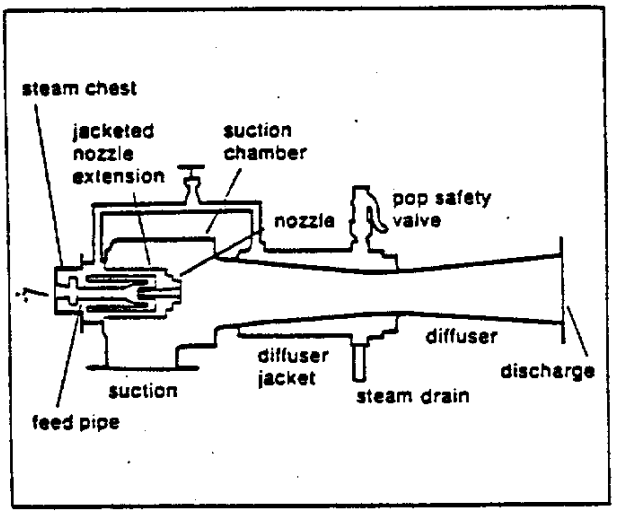
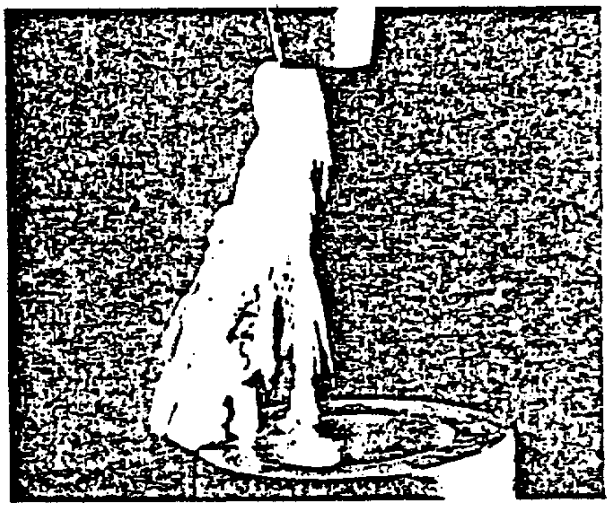
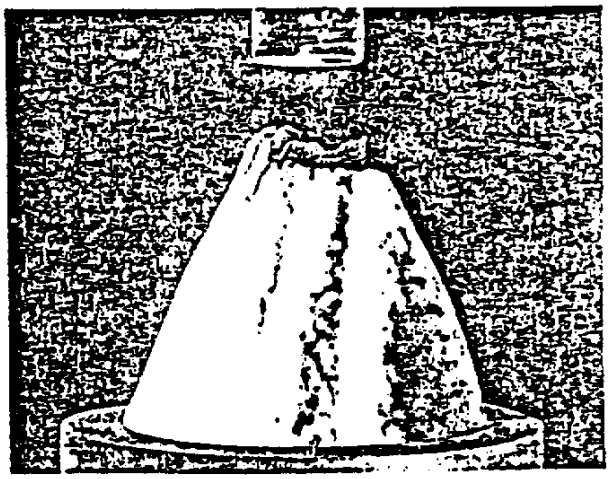


FIGURE III





Ice formation on a steam-jet ejector nozzle.



The same equipment shown above but with heated nozzle.

steam jacketing

Expansion of motive steam through the ejector nozzle is almost isentropic; as a result, temperature of steam exiting from the nozzle is usually quite low. Where the suction pressure of an ejector falls below 4- to 5-mm Hg abs, this temperature is sufficiently below 32 F to freeze moisture in the suction gas and part of motive steam, thus forming an irregular cone of ice between nozzle and diffuser. This obstruction will affect ejector stability between 5-mm pressure and shutoff (no load). If the nozzle tip and inlet diffuser section are heated to prevent ice from building up, satisfactory operation at all pressures can be obtained. Usual way to do this is to steam-jacket the nozzle and diffuser. Typical jacketed nozzle and diffuser are illustrated above.

Steam-jacketed nozzles and diffusers are furnished as standard equipment on all Worthington ejectors designed to operate below 4-mm.

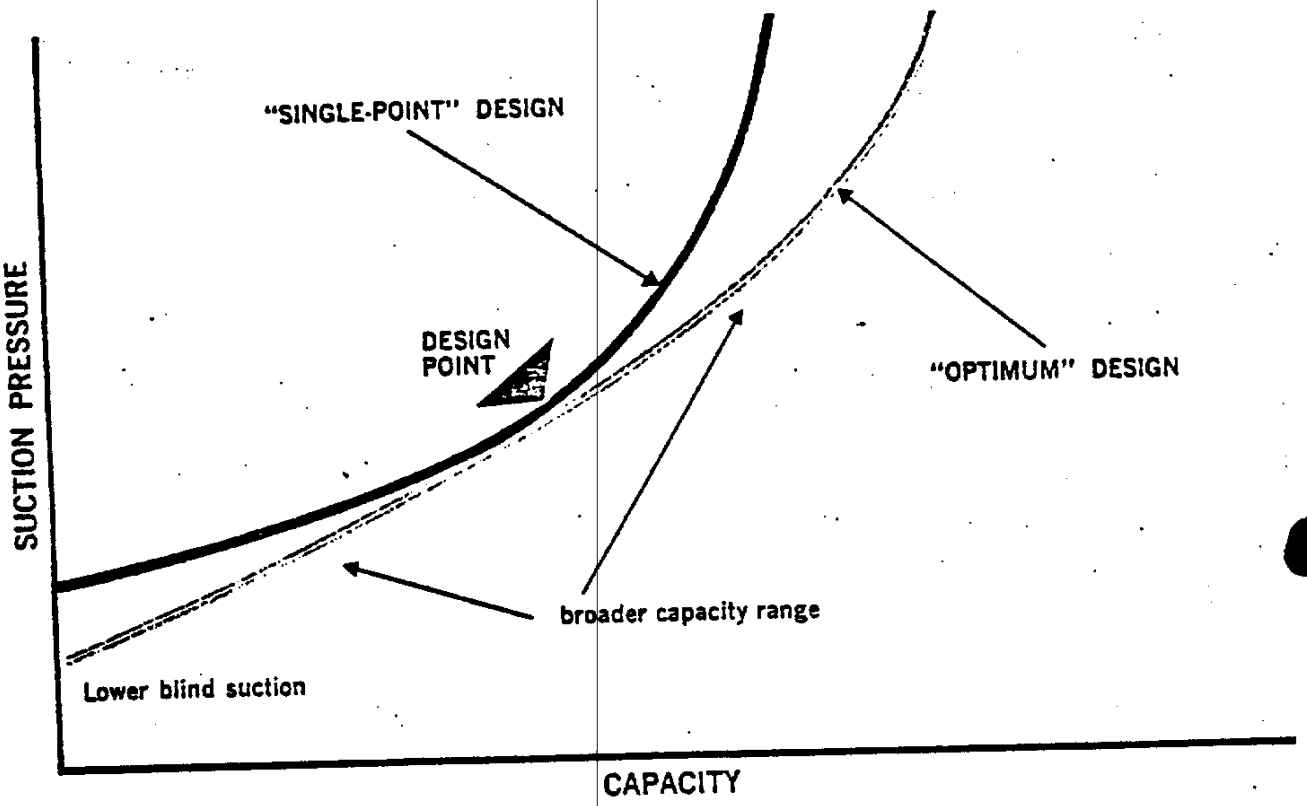

"SINGLE-POINT" DESIGN
DESIGN POINT
"OPTIMUM" DESIGN
broader capacity range
Lower blind suction
SUCTION PRESSURE
CAPACITY

FIGURE II

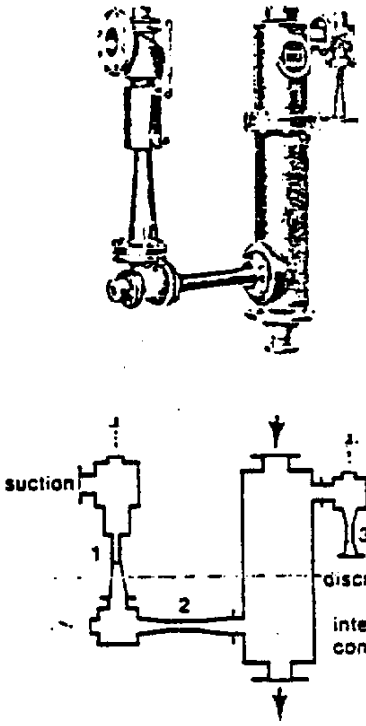


Figure 1X

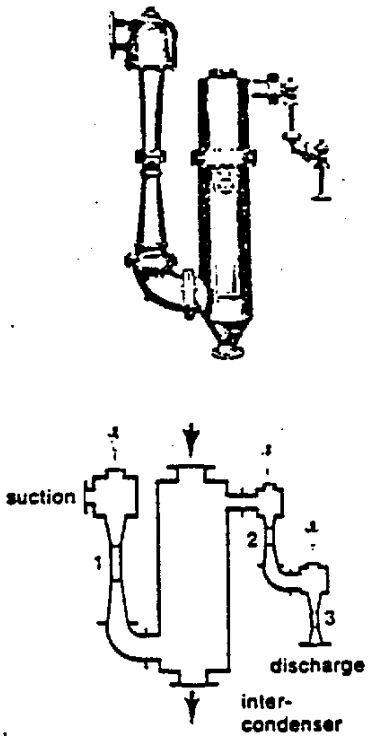


Figure 2X

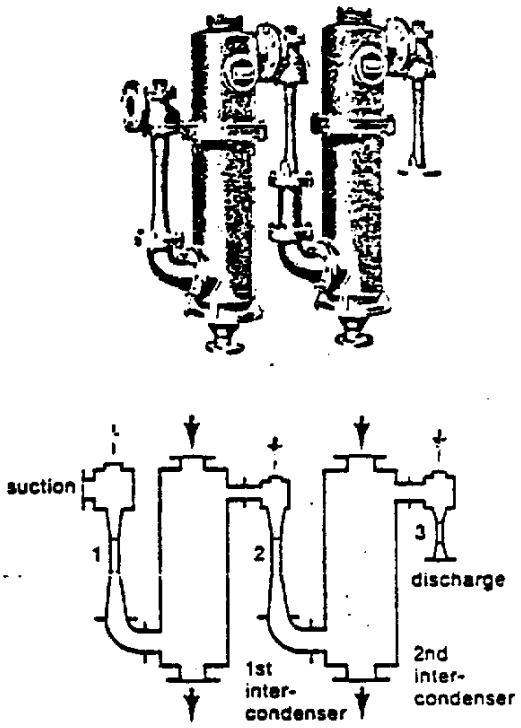


Figure 3X

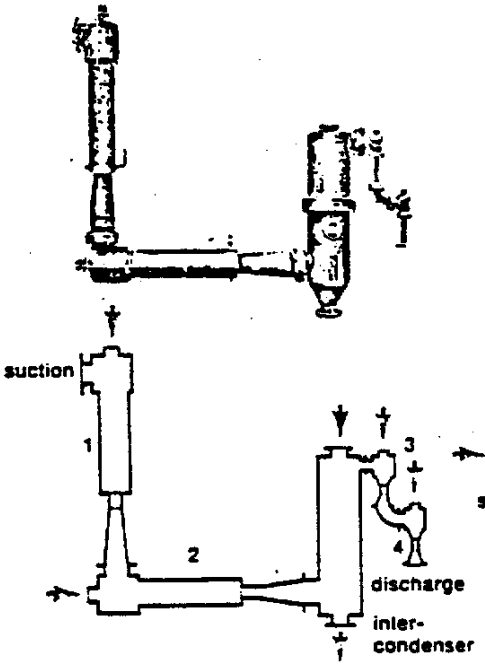


Figure 4X

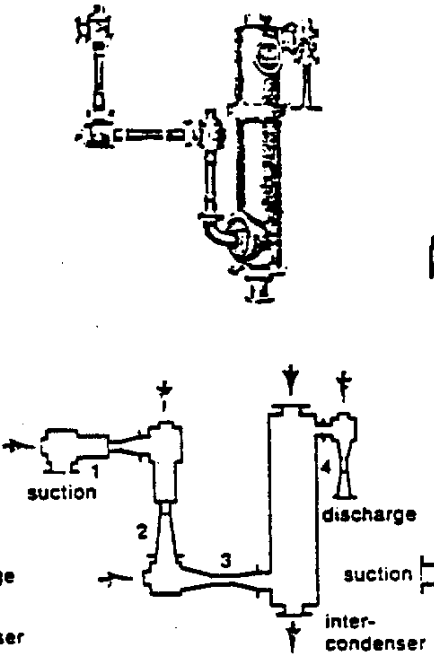


Figure 5X

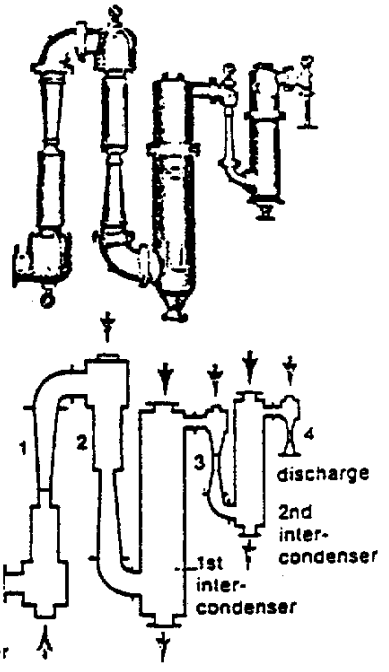


Figure 6 X

FIGURE VII

(PRESSURE RANGES IN mm H_2O ABS)



Fig. 2
(45-200)

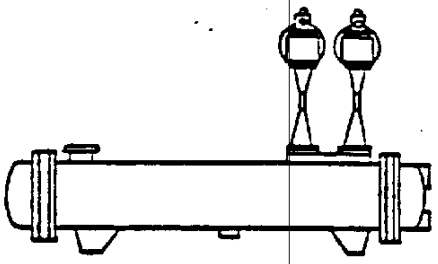


Fig. 3

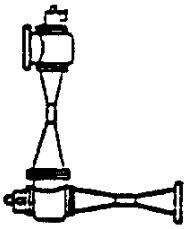


Fig. 4 (4-100)

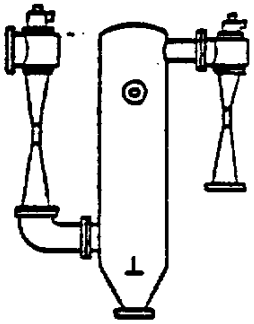


Fig. 5 (3-200)

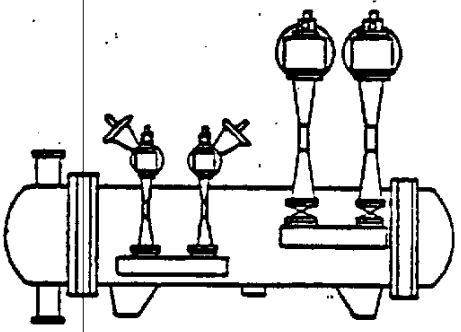


Fig. 6

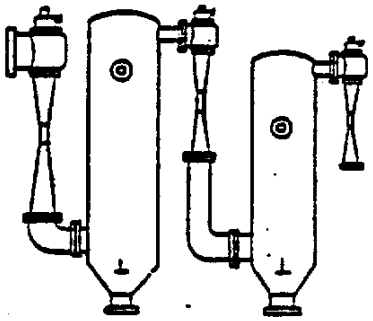


Fig. 7 (1.5-40)

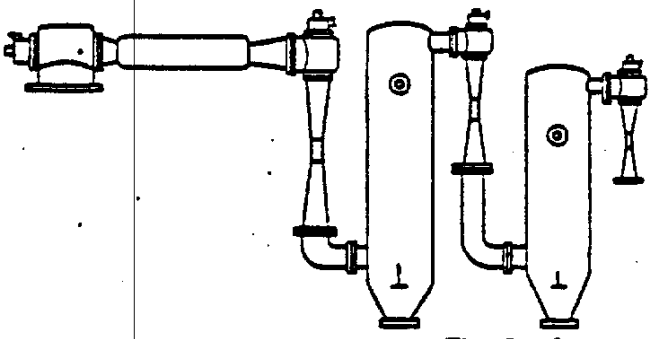


Fig. 8 (0.15-5)

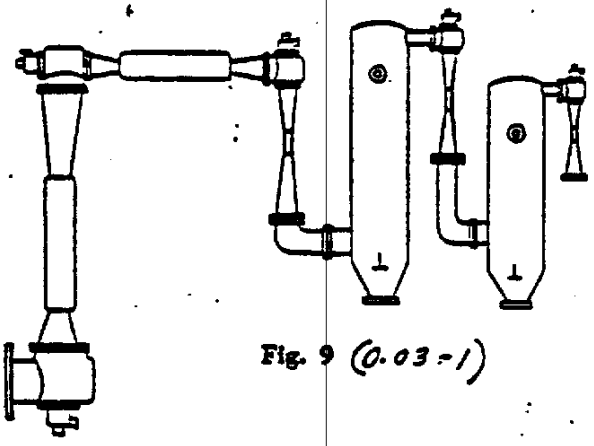
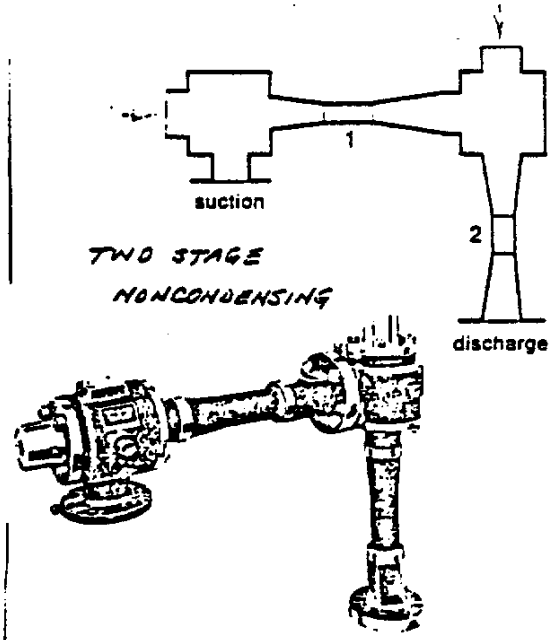


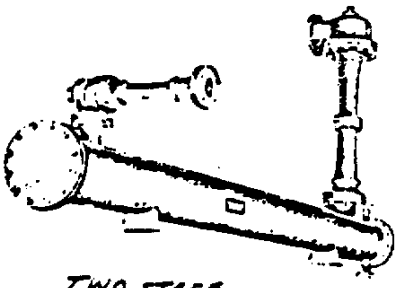
Fig. 9 (0.03-1)

COMMON TYPES OF EJECTOR UNITS

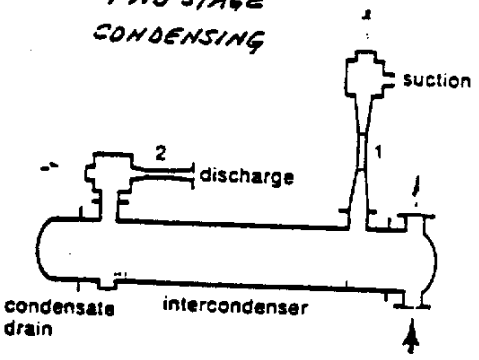
FIGURE V

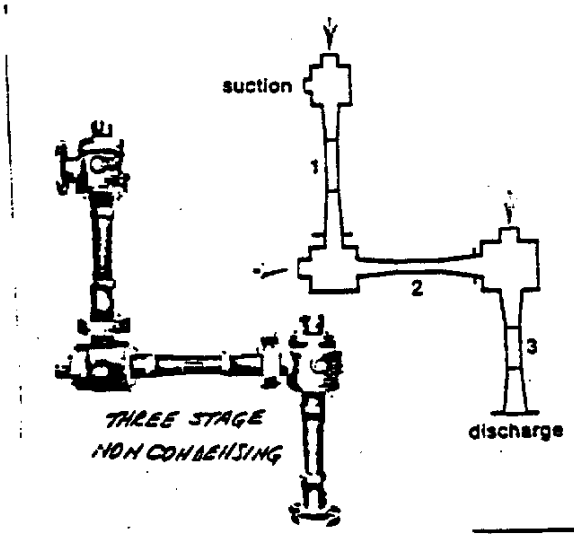


TWO STAGE
NONCONDENSING



TWO STAGE
CONDENSING





THREE STAGE
NON CONDENSING

FIGURE VI

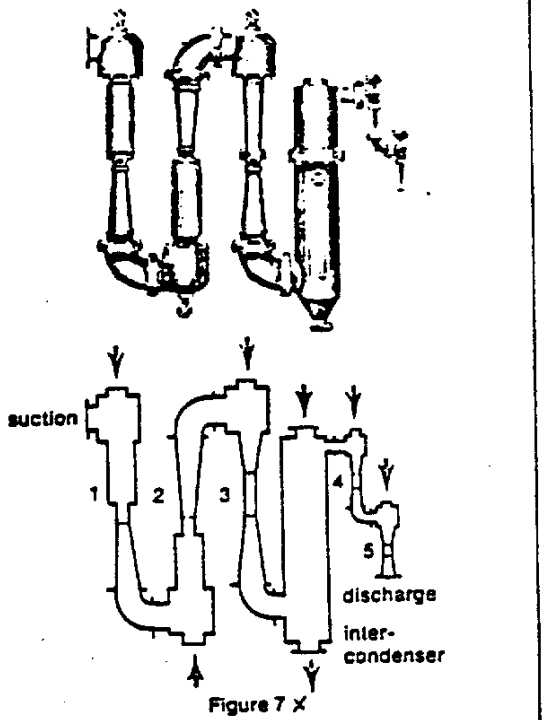


Figure 7 X

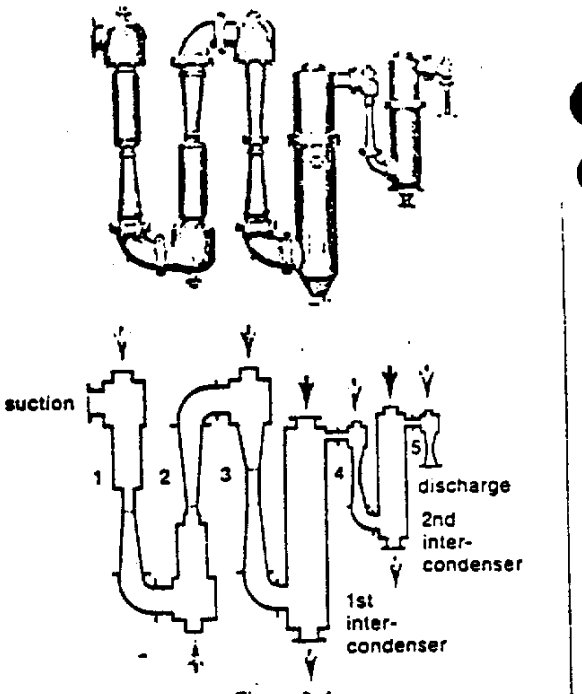


Figure 8 X

14

FIGURE VIII

Figure IX - three stage unit where an intercondenser after the first stage is not justified by the steam savings in the second stage. The scheme is also used where the suction pressure and temperature of available cooling water cannot efficiently produce a pressure for condensation in one stage of compression.

Figure 2X - three stage unit where the load to the ejector contains a large quantity of vapor that can be condensed economically after one compression stage. Since the second and third stage are directly coupled, the total noncondensibles would have to be relatively small to make this a good selection.

Figure 3X - three stage totally condensing units are especially effective in achieving maximum steam economy.

Figure 4X - four stage unit where rates of condensible to noncondensible vapors is large. Where this arrangement is used the noncondensible quantity load is small, permitting the use of a two stage noncondensing "tail".

Figure 5X - four stage unit where very small loads, mostly noncondensibles, are to be handled.

Figure 6X - four stage unit most commonly used. The load is large and the use of two intercondensers is economically feasible.

Figure 7X - five stage unit where the noncondensible quantity is low enough to permit a two stage noncondensing fourth and fifth stage arrangement.

Figure 8X - five stage unit, used when noncondensible load is sufficiently large to require an intercondenser between fourth and fifth stages.

Ejector Efficiency

There are many published and accepted formulae to express ejector efficiency. The usual concept of efficiency involves a comparison of energy output to energy input. A ratio of this sort is of little value in the selection and design of ejectors. Since ejectors approach a theoretically isentropic process, it is convenient to express overall efficiency as a function of entrainment efficiency.

The capacity (#/Hr.) of an ejector handling other than saturated vapor is a function of the fluid's molecular weight and temperature. The higher the molecular weight of a fluid, the greater the ejector suction capacity, assuming equal motivating quantities. Conversely, the ejector will handle less of lower molecular weight fluids. For example, a steam ejector will handle approximately 23% more free dry air than it will water vapor. The reverse of this is true where suction fluid temperatures are concerned. The ejector will handle less fluid as the temperature of that fluid increases.

An ejector represents what is referred to as single point design. That it, its design will be optimum at a single set of conditions. Ejector designs can be classified either as critical or non-critical. Critical design means that the fluid velocity in the diffuser throat is sonic. In non-critical units the fluid velocity is sub-sonic. A steam ejector is of critical design when the suction pressure is lower than approximately 55% of the discharge pressure (approximately 2:1 compression ratio). Ejectors designed in the critical range are sensitive to operating conditions other than those the unit was designed for. The table on the following sheet illustrates how these changes in operation can affect ejector performance.

EFFECT OF OPERATIONAL CHANGES ON CRITICAL FLOW EJECTOR PERFORMANCE

Motive Steam Pressure	Discharge Pressure	Non-condensible Load	Suction Pressure	Suction Capacity
Constant	Constant	Increases	Increases	See note 1
Constant	Constant	Decreases	Decreases	See note 1
Increases	Constant	Constant	See note 2	See note 2
Decreases	Constant	Constant	See note 3	See note 3
Constant	Increases	Constant	See note 3	See note 3
Constant	Decreases	Constant	No Change	No Change

Note 1. Suction capacity will increase or decrease to balance the non-condensible load at the higher or lower suction pressure, within the stability range of the ejector(s).

Note 2. As a general rule, a slight decrease in capacity occurs if motive steam pressure is increased above the design pressure, particularly for single stage and multi-stage non-condensing units. Hence, the suction pressure will rise to the point where suction capacity balances the non-condensible load.

Note 3. Suction capacity decreases slightly at first, and then rapidly as the "breaking pressure" is reached. At this point the ejector system becomes unstable. Suction pressure rises slightly at first, and then rapidly after the "breaking pressure" is reached. Note that "breaking pressure" applies to both a lower than design motive steam pressure and a higher than design discharge pressure.

In an ejector whose motivating fluid is steam, the quality of the high pressure steam has an effect on the operation of the unit. Most units are designed to use dry and saturated high pressure steam as a motive fluid. If the quality of the steam decreases below 98%, a gradual increase in the suction pressure and decrease of suction capacity is experienced. This phenomenon will be particularly noticed in units designed for high compression ratios $\frac{\text{(Discharge Pressure)}}{\text{(Suction Pressure)}}$ or $\frac{P_5}{P_3}$ and even more so in multi-stage units.

Staging Ejectors

Lower suction pressures are obtained by staging of the jets. Figure IV illustrates the design suction pressures and relative steam consumption for various stages.

Ejector staging can be divided into condensing units and non-condensing units. The usual method of staging is to use a vapor condenser between the stages. Condensers are used to condense out all of the motivating steam plus the suction water vapor from the first stage, allowing only saturated non-condensables to pass on to the following stages. The size and type of condenser used in a function of the air-vapor ratios, cooling water temperatures available, steam and water costs, and contaminants in the first stage suction vapor.

The term non-condensing is used where a stage discharges directly into the following stage. As explained before, steam consumption in this type of unit is higher because the second stage must handle all of the motivating steam plus the suction capacity from the first stage. Non-condensing units are used where the inter-stage pressure is lower than could be obtained with the temperature of cooling water available, such as in four, five and six stage units.

Two and three stage non-condensing units are used where first cost and

installation cost out-weigh consideration of steam comsumption. Two-stage non-condensing units are used as primers and evacuators. A two-stage non-condensing unit uses approximately 100% more steam than a two-stage condensing unit, but when used as an evacuator its priming time is only approximately 20% longer. This is due to the oversizing of the final or atmospheric stage.

Ejector Ratings

Ejectors are rated on the weight flow of gas compressed, rather than on volume flow as is usual with other compressor types. Ratings are expressed in lb/hr of the gas or gas mixture handled. Steam (or other motive medium) is also stated in lb/hr.

Normally, manufacturers' basic ratings are on the weight rate of "equivalent air", which is air at 14.7 PSIA and 70°F and containing normal atmospheric moisture. The user must specify the desired capacity in such terms that equivalent air can be calculated and the best ejector can be selected.

Capacities desired are preferably specified in one of three ways:

1. Lb/hr of a saturated air-water vapor mixture (AVM);
2. Lb/hr of a superheated air-water vapor mixture; and,
3. Lb/hr of a mixture of gases either including or excluding water vapor.

The proportion of air to vapor in (1) is known and no further information is needed for conversion to equivalent air.

In (2), it is mandatory that the relative weights of air and vapor be specified, otherwise it is impossible to determine the MW and equivalent air.

Method (3) requires that a complete analysis of the gas be given or that the user specify the average molecular weight. The analysis may be on a volumetric (molar) or a weight ratio basis.

One of the major problems in ejector selection is that information given is often insufficient to permit accurate evaluation of MW.

Conversion from specified lb/hr to equivalent air is based on two conversion curves involving "entrainment ratios". These curves (Fig. XI and XII were established by tests run under the auspices of the Heat Exchange Institute and are accepted and used by all ejector manufacturers. Two conversion steps are involved, the first being based on molecular weight and the second on gas inlet temperature. These apply to each individual ejector as a single-stage basic element.

Molecular Weight entrainment ratio is the ratio of the total weight of inlet gas that can be handled to the total weight of equivalent 70°F air that would be handled under the same conditions.

Temperature entrainment ratio is the ratio of the total equivalent weight of air (or water vapor) at actual temperature that can be handled to the weight of equivalent air or water vapor at 70°F that would be handled. Dry gas and steam (water vapor) must be separately converted for temperature and totaled.

Entrainment ratios are divisors to obtain lb/hr equivalent air when lb/hr of the gas handled (and its water vapor component) are known.

Obtain Equivalent Air

The formula for obtaining equivalent air for any gas or gas mixture whether containing water vapor or dry is given below.

$$\text{Equivalent air} = \frac{\text{lb/hr Dry Gas}}{\text{MWER} \times \text{TER}_g} + \frac{\text{lb/hr Water Vapor}}{0.81 \times \text{TER}_v}$$

MWER is molecular Weight entrainment ratio Fig. XI
TER_g is temperature entrainment ratio for dry gas Fig. XII
0.81 is molecular weight entrainment ratio for water vapor (MW = 18).
TER_v is temperature entrainment ratio for water vapor Fig. XII

In the case of a dry gas, only the left hand part of the equation applies. For an air-water vapor mixture first obtain the percent air in the mixture and obtain the overall entrainment ratio from Figures. This can be applied as a divisor directly to the total lb/hr of mixture to obtain the total equivalent air.

Although the user has little need to utilize the equivalent air rating, it has been presented to assist in picturing the effects of gas composition, average molecular weight, and gas temperature on the capacity of a given ejector and to call attention to information in the manufacturer must have to make a satisfactory selection.

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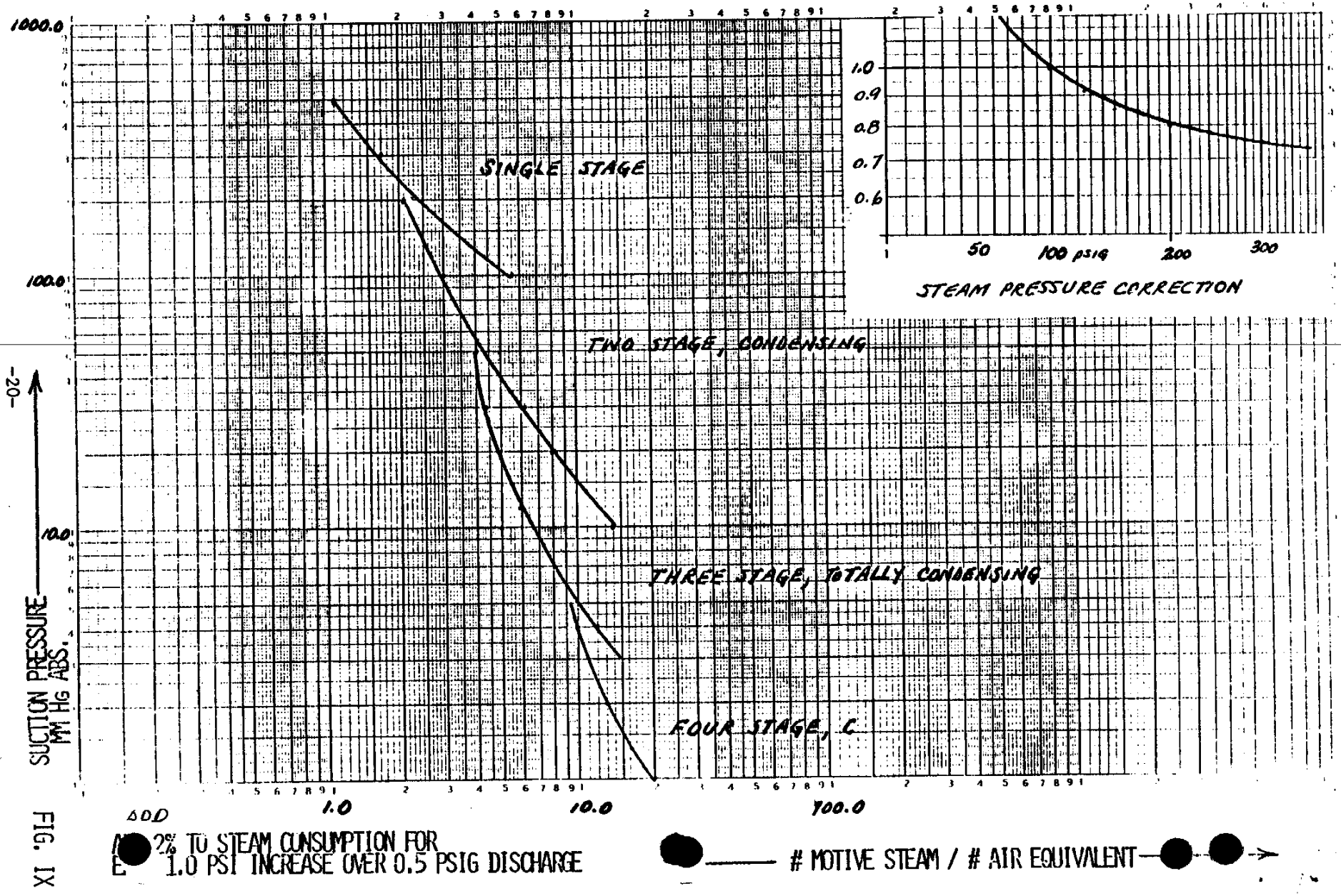


FIG. XI

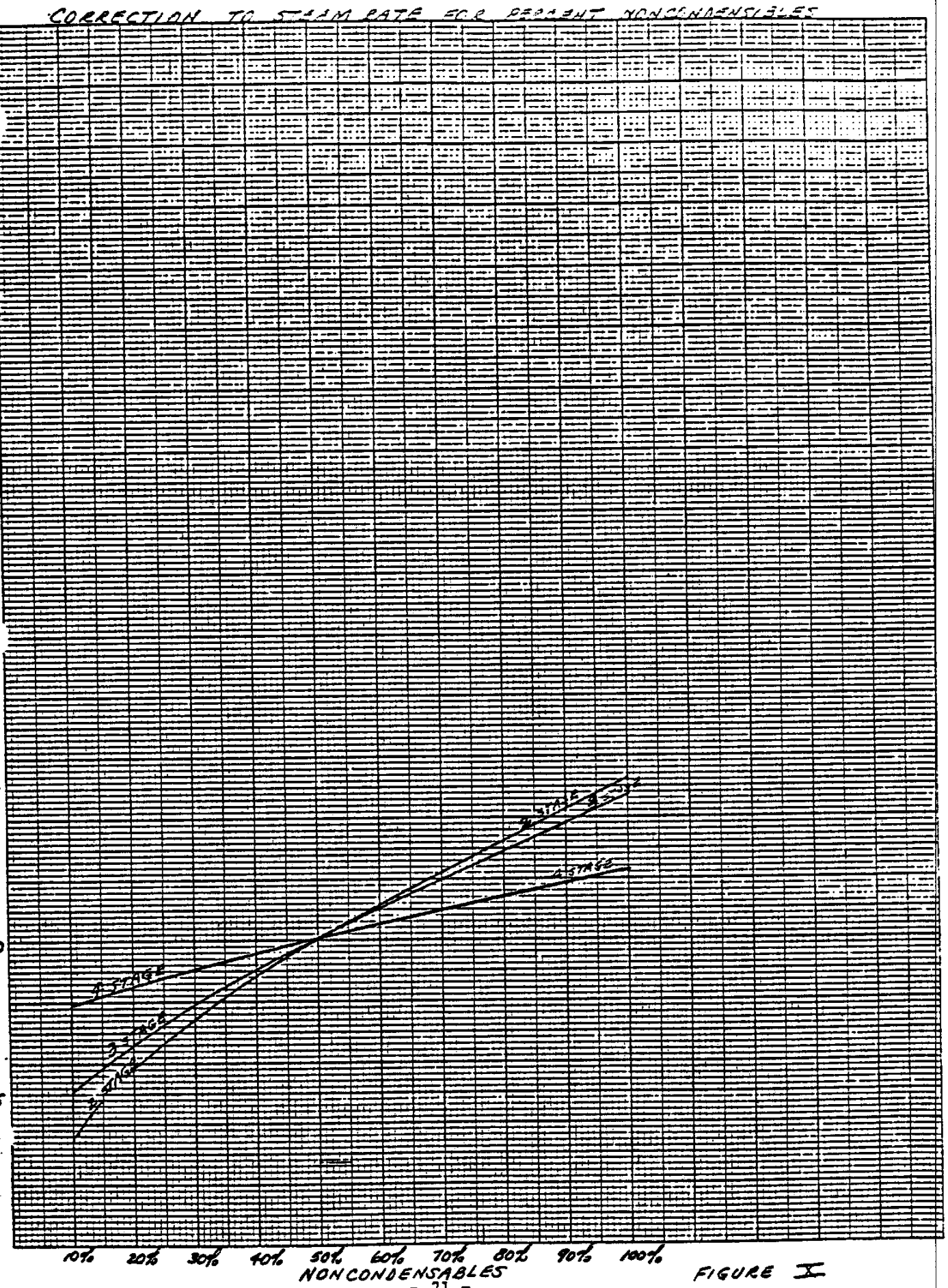
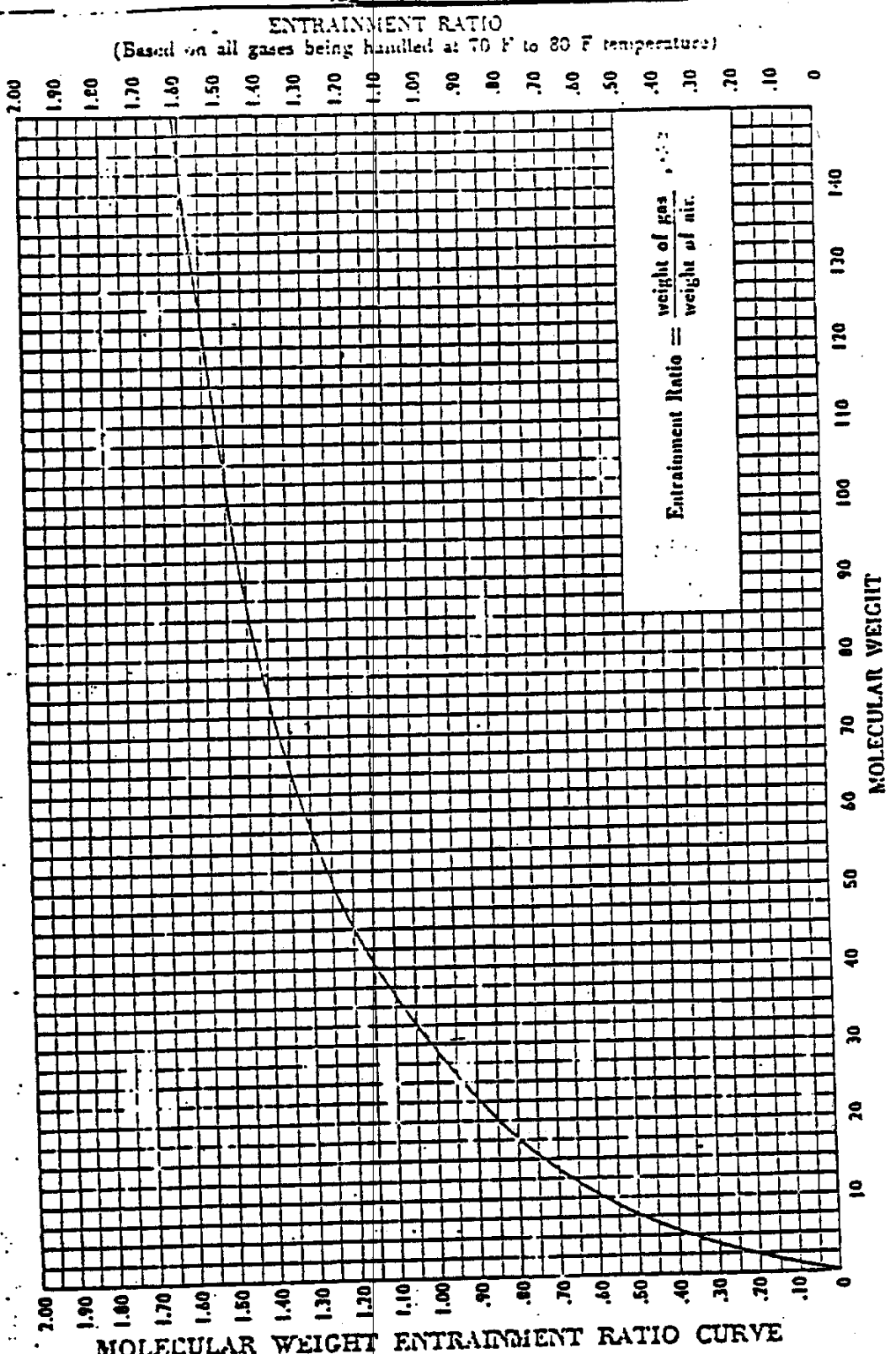
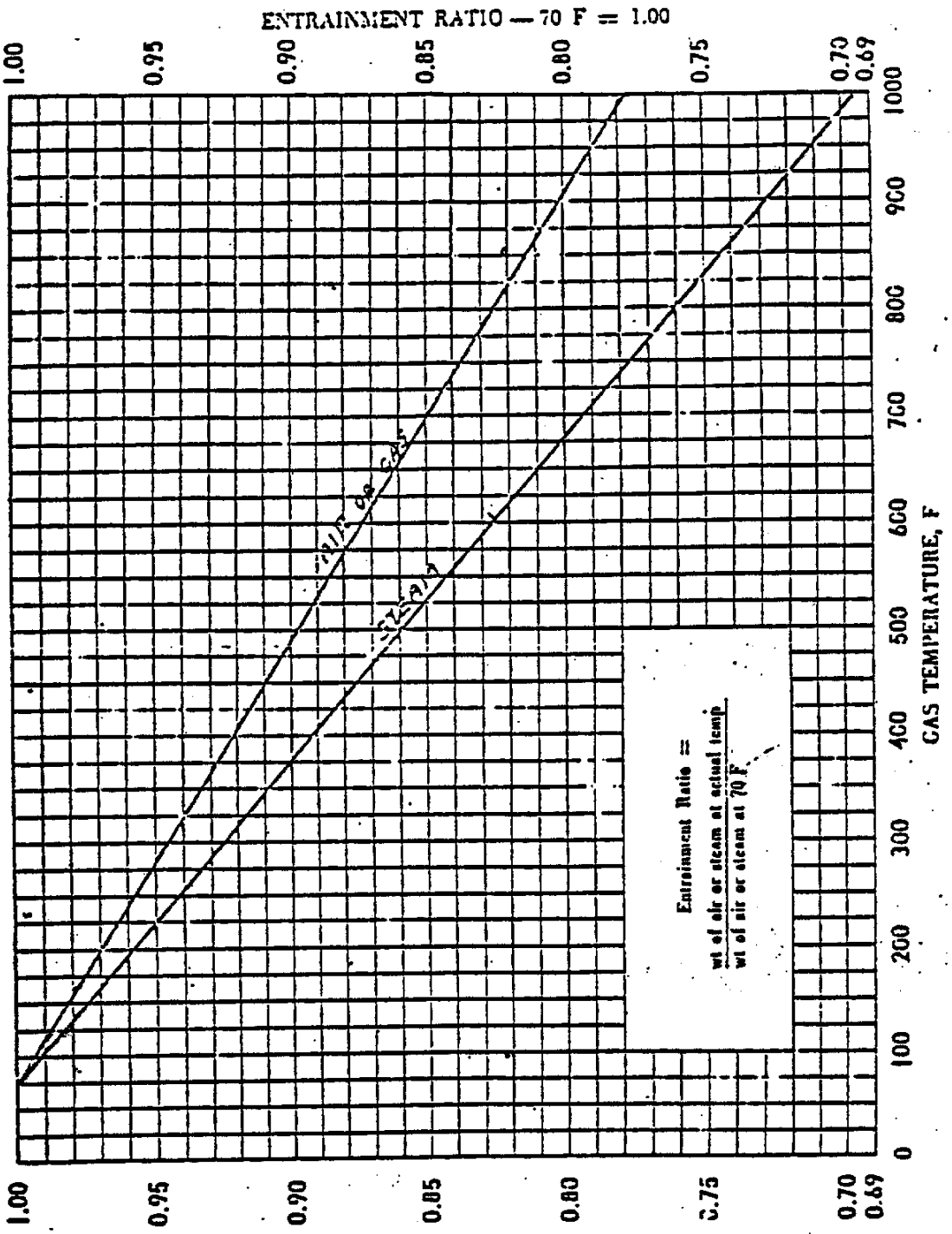

CORRECTION TO STEAM RATE FOR PERCENT NONCONDENSABLES
CORRECTION MULTIPLIER
1.5
1.0
0.5
4 STAGE
3 STAGE
2 STAGE
4.5 STAGE
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
NONCONDENSABLES

FIGURE X



MOLECULAR WEIGHT ENTRAINMENT RATIO CURVE

FIGURE XI



TEMPERATURE ENTRAINMENT RATIO CURVE

FIGURE XII

Effect of MW and Temperature

Fig. XIII is a typical performance curve of a single stage ejector showing what happens to ejector performance with changes in the characteristics of the gas being handled. In this example, motive steam flow is held constant. Referring first to the equivalent air (MW 29) curve in the left hand group, it can be seen that for every ejector there is a definite relation between absolute suction pressure and capacity. The right hand curve shows the maximum stable operating discharge pressure obtainable with the particular ejector with a specified steam pressure and varying capacities.

Fig. XIV also shows the effect on the capacity (lb/hr) of changes in MW of the gas handled. It will be noted that the higher the MW the greater the total weight this ejector will handle. There will be no appreciable change in the maximum discharge pressure, however, when the gas composition varies.

Fig. XIV shows similarly the effect of suction gas temperatures above the 70°F reference value.

Fig. XIII and XIV are on a dry-gas basis. Inclusion of water vapor with the gas would lower the top curve on Fig. XIII and raise the two bottom curves because of its effect on average MW. It would also lower the 400 and 800°F curves on Fig. XIV because of the reduced entrainment ratio for the water vapor component.

Conversely, what these curves indicate is that for a given total lb/hr of gas, (1) the lower the molecular weight, the greater the lb/hr of steam required and the larger the ejector; and, (2) the higher the gas temperature, the greater the steam quantity required and the larger the ejector.

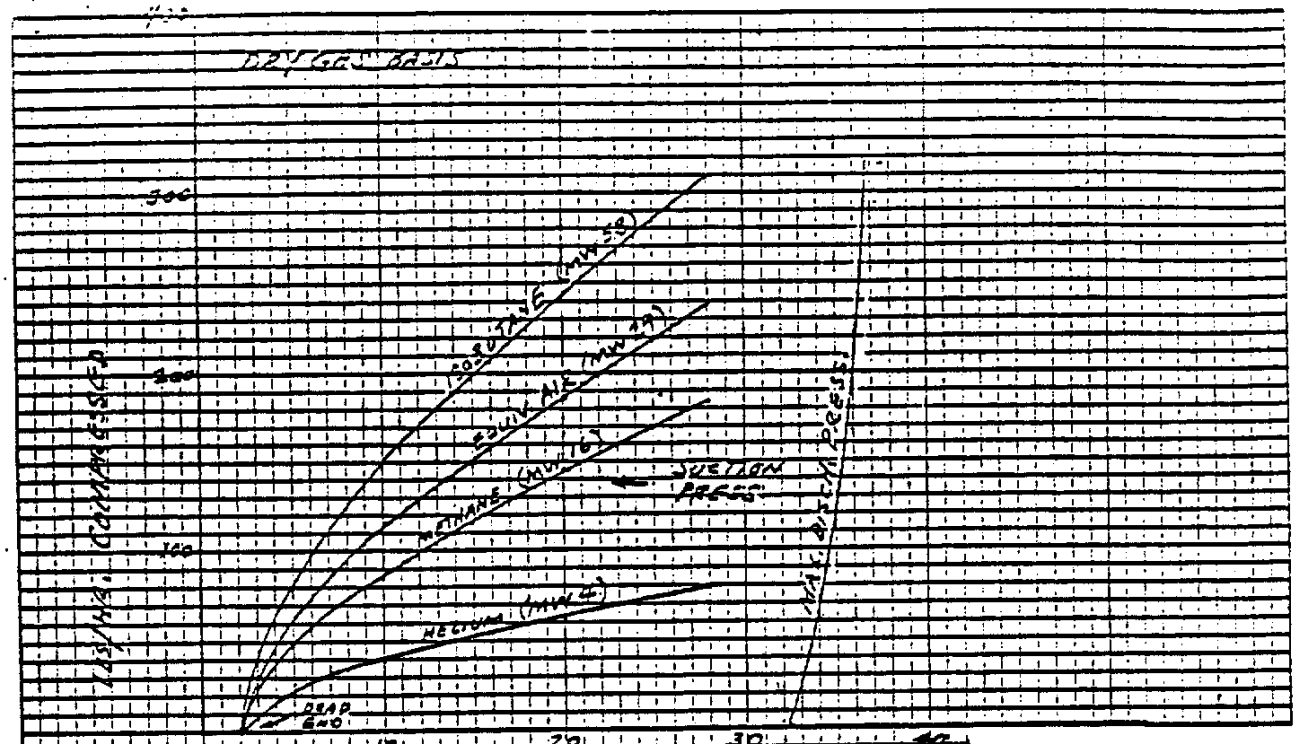


FIGURE VIII

TYPICAL FIELD CALIBRATION CURVE SHOWING THE EFFECT OF CHANGES IN MOL WT. (DRY GAS BASIS ONLY)

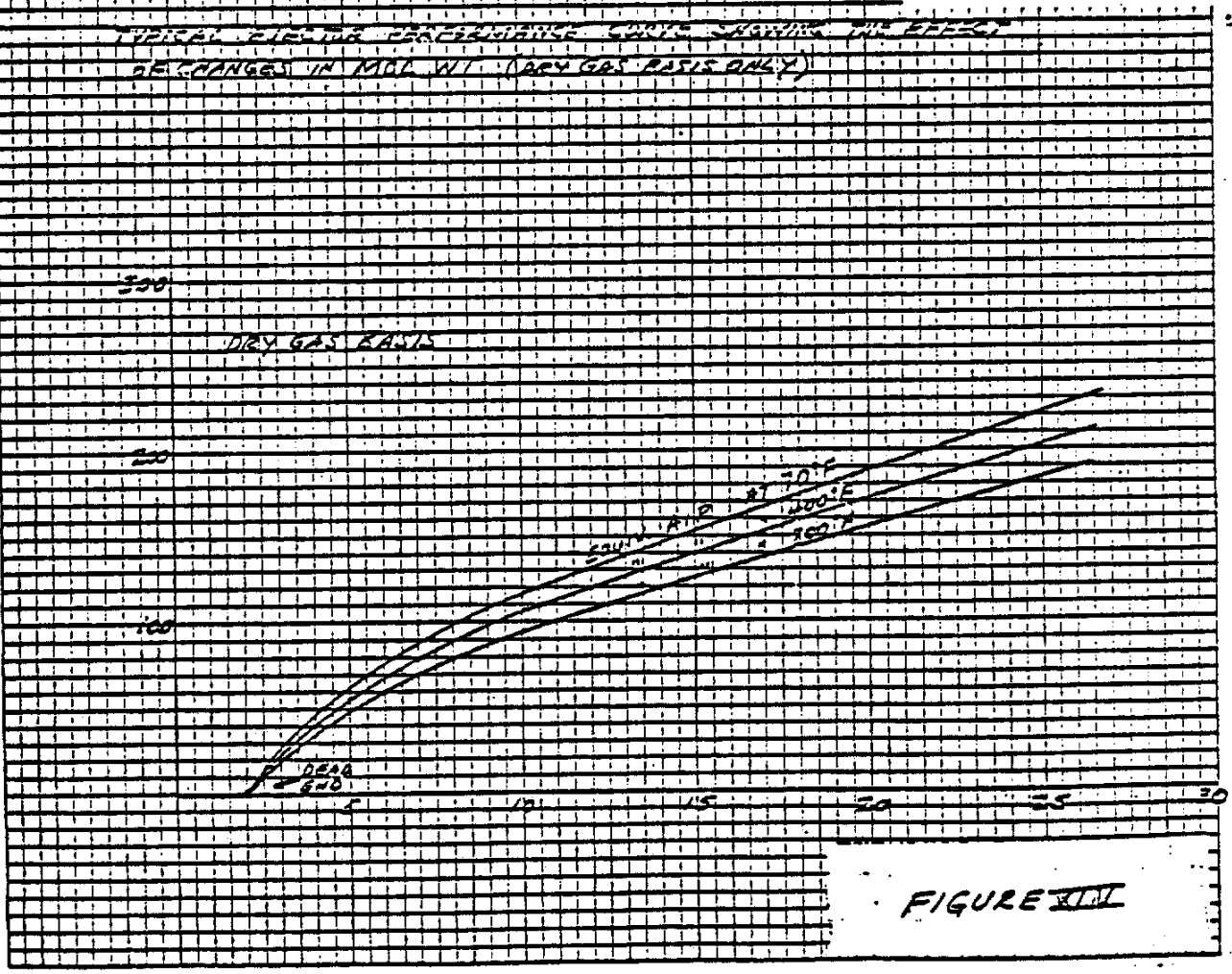
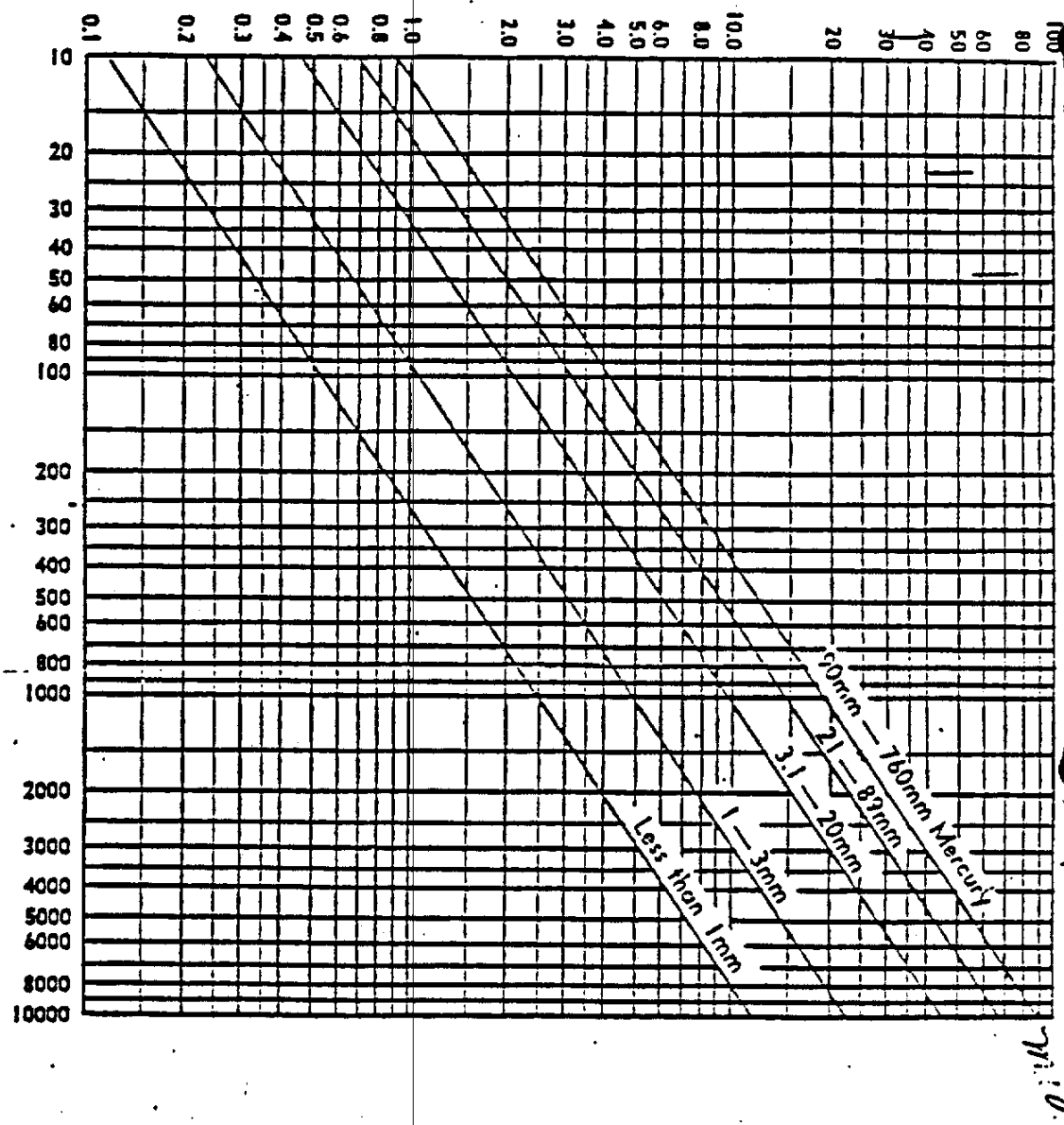


FIGURE IX

MAXIMUM AIR LEAKAGE—POUNDS ~~PER~~ HOUR



MAXIMUM AIR LEAKAGE VALUES

FOR COMMERCIALLY TIGHT SYSTEMS

FIGURE XV

AIR LEAKAGE IN VACUUM SYSTEMS

E-59. Drop Test

The air leakage in an existing vacuum system may be determined by a drop test. This test is based on the fact that air leaks into the system at a constant rate as long as pressure within the system is less than 0.53 times atmospheric pressure (about 15 in. Hg absolute). It is usually run with the system empty but with all agitators and other moving equipment in operation to duplicate leakage through seals and glands. Test should be run with the system at normal atmospheric temperature and the system should be free of any liquids.

Procedure:

1. Evacuate system to about 5 in. Hg absolute using available ejector.
2. Close off isolating valve between system and ejector; then close steam supply to ejector.
3. Record elapsed time for pressure in system to rise from one observed pressure to a higher observed pressure. If leakage is low, a rise of one or two inches may take a long enough time to give an accurate estimate of leakage. However, do not permit pressure to rise above 15 in. Hg absolute.
4. Knowing system volume, initial and final pressure and elapsed time, the total leakage rate into system may be calculated from the equation:

$$\text{Leakage (lbs per hour)} = \frac{0.15 \times \text{Volume (cu. ft.)} \times \text{Pressure Rise (in. Hg)}}{\text{Time (minutes)}} \qquad (8)$$

Example:

V = Volume, cubic feet = 300 cu ft

p_1 = Initial pressure in system, inches Hg absolute = 5 in. Hg abs

p_2 = Final pressure in system, inches Hg absolute = 9 in. Hg abs

T = Time, minutes = 6.5 min

$$\text{leakage} = \frac{0.15 \times 300 \times (9-5)}{6.5}$$

$$= 27.7 \text{ lbs per hr}$$

5. In order to prove tightness of the isolating valve between system and ejector, the test should be repeated with the ejector operating. If the isolating valve is tight, the total calculated leakage for both tests will be identical. If the isolating valve is not tight, the two values will be different by an amount equal to the leakage through the valve plus the air removed by the ejector under the pressure conditions existing across the leaking valve. For reliable tests of air leakage using the drop test, leakage through isolating valve in closed position should be proven negligible.

Development of Equation:

Let: l = Leakage rate, lbs per hour

W_1 = Weight of air in system at initial pressure, lbs

W_2 = Weight of air in system at final pressure, lbs

T = Time, minutes

0.075 = Weight of air, lbs per cubic feet at 30 in. Hg abs, 70 F

60 = Minutes per hour

p_1 = Initial pressure in system, in. Hg abs

p_2 = Final pressure in system, in. Hg abs

30 = Standard atmospheric pressure (30 in. Hg abs)

$$l = (W_2 - W_1)\frac{60}{T}$$

$$W_1 = 0.075V \times \frac{p_1}{30}$$

$$W_2 = 0.075V \times \frac{p_2}{30}$$

$$W_2 - W_1 = \frac{0.075V}{30}(p_2 - p_1)$$

$$l = \frac{0.075V}{30}(p_2 - p_1)\frac{60}{T}$$

$$l = 0.15\frac{V}{T}(p_2 - p_1) \qquad (8)$$

Inspection of equation (8) shows that absolute pressure at start and finish of test need not be known (as long as final pressure is not above 15 inches Hg absolute). Only the pressure rise need be known. Therefore, the test may be run using a reliable vacuum gauge or mercury column without correction for barometer pressure.

E-60. Air Meters

If the air ejector serving the vacuum system is provided with a surface aftercondenser, the total noncondensable gases handled by the ejector can be measured by means of a suitable air meter installed at the air outlet connection. The total gas load will consist of air leakage into the system plus noncondensable gases generated in the process plus air released from condensing water, if a direct contact condenser is used ahead of the ejector. Air meters are generally of two types:

1. Variable area type with constant pressure drop
2. Fixed area type with variable pressure drop, such as a nozzle with water manometer for measuring head.

When using air meters, all the air shall be directed through the meter. Also, for accurate determination of air leakage, the temperature of the saturated air must be measured and suitable corrections made to meter readings to correct for mixture density and for percentage of air in the mixture.

E-61. Other Tests

Following installation, every complete vacuum system should be hydrostatically tested to locate and eliminate any points of leakage at flanged connections, valves, etc. On large installations, where hydrostatic testing becomes impractical, another type of testing for leaks may be employed. Here the vacuum system is filled with compressed air and a tracer of a halogen gas such as "Freon-12". The location of leaks can be quickly determined by passing the probe of an electronic leak detector over points where leakage can occur. In place of the electronic detector, a propane burning torch, adjusted for a soft blue flame which turns green in contact with the nonflammable "Freon", may be used.

E-62. Commercially Tight Systems

For a vacuum system to be considered commercially tight, the air leakage should not exceed values shown in Figure 42. The maximum air leakage values shown for the five absolute pressure ranges are for a vacuum system without any agitator. For a system with agitator, having ordinary commercial shaft seal, a reasonable amount of maintenance will keep shaft leakage down to 5 lbs per hour. With special high vacuum seal and good maintenance, shaft leakage can be kept to a negligible amount.

E-63. Selecting Ejector Capacity

The values of maximum air leakage should not be used for selecting capacity of the ejector equipment. It is recommended that the design capacity of the ejector be equal to double the maximum estimated air leakage to which should be added the noncondensable gases produced in the process and any associated condensable vapors. For the recommended capacity of ejectors to serve the condensers of prime movers, see the Heat Exchange Institute Standards for Steam Surface Condensers and Standards for Direct Contact Barometric and Low Level Condensers, current edition.

Discharge Pressure

Any single stage ejector will operate stably at a given motive steam pressure and capacity against an increasing discharge pressure up to the breaking pressure. At this point, the gas flow will stop or fluctuate. The ejector becomes unstable. If the discharge pressure is reduced slowly, the ejector will resume stable operation at a lower back pressure level. This is the recovery pressure and is known in the industry as maximum discharge pressure. The maximum pressure required at the ejector discharge flange must be known by the manufacturer from the specifications so that he can supply an ejector that will have a stable operating range equal to or exceeding this maximum.

Changes in Steam Flow

Changes in an ejector's motive steam flow may be made by altering the size of the motive steam nozzle, or by changing the steam pressure.

A change by the first method alters the ejector characteristic, especially as regards compression ratio. If a simultaneous change is made in the nozzle pressure so that the steam flow (lb/hr) through the nozzle remains unchanged, there is little or no change in the ejector characteristic curve.

- Changes in steam pressure (and flow) with a fixed steam nozzle do not appreciably alter the suction pressure curve, but do produce a higher or lower discharge pressure, as the motive steam pressure increases or decreases within narrow limits. If steam pressure is increased too far above design, the excessive steam flow will choke the ejector throat and gas capacity will be materially reduced.

With superheated steam, any increase in superheat at constant pressure will have an effect opposite to a pressure increase. That is, an increase in temperature will lower the discharge pressure due to the reduced weight

of steam flow.

The reduction of discharge pressure by changes in motive steam conditions can cause the ejector to break and become unstable. This consideration is not really that significant from a practical standpoint. It would take a rather outstanding increase in the amount of superheat (above that specified for design) to reduce steam flow rate through the ejector nozzle to the point where ejector discharge pressure might fall to the "break" point.

Every ejector specification must show and the ejector must be designed for the lowest obtainable steam pressure and the highest obtainable superheat at the steam nozzle. This is important if the ejector is to stay on the line at all times and have the required capacity even with the most unfavorable steam conditions.

Multi-stage Ejector Design

Although it is sometimes possible to use a compression ratio higher than 15 in one stage, the highest practical stage-compression ratio is usually about 10, and most stages have a lower compression ratio for steam economy. *If the desired overall compression ratio cannot be achieved economically in a single stage, it is necessary to use a multi-stage ejector. A multi-stage ejector has two or more stages operating in series to perform the total compression job. By convention, the stages in a multi-stage ejector are numbered consecutively, starting with the stage having the lowest suction pressure.

If a multi-stage ejector has no condensers between its stages, the steam requirements of successive stages will increase geometrically. Each successive stage must handle not only the load gas, but also the motive steam from all prior stages.

It is possible to reduce the steam requirement of a multi-stage ejector by placing condensers between stages. Each condenser removes most of the

*In a multi-stage condensing unit, as the percent condensables increases, the highest practical compression ratio decreases to about 6 to 1.

steam and other condensible vapors from the total vapor load to the subsequent stage. As an example of the steam saved by using intercondensers, at 10 mm Hg absolute, a two-stage air ejector with intercondenser requires only one-fourth the steam needed by a two-stage non-condensing ejector.

Control

In some vacuum systems, it is only necessary to keep the system pressure at or below the design pressure. But in many systems it is necessary to control the pressure closely. Several methods are described in the published literature. Any one of three control methods may be used: (1) loading the ejector with a controlled flow of noncondensable or condensable gas; (2) throttling the flow of gases from the system to the ejector; or (3) installing parallel ejectors - total capacity = design load.

Control by Adding Gas Load

Perhaps the most generally appropriate method of controlling the system is by admitting clean nitrogen through a controlled valve into the line connecting the ejector to the process system.

The nitrogen satisfies two requirements of the typical ejector and process-condenser combination.

First, it supplements the actual load from the process system to equal the load required by the ejector at the desired operating pressure.

Second, it provides a quick supply of noncondensable gases required by the process condenser to operate in the usual part-load condition. Because the condenser usually is oversized for the required heat-transfer service, noncondensable gases must be accumulated in the condenser, effectively masking enough heat-transfer area to raise the condensing temperature and pressure to the desired level.

Nitrogen is usually safe to use as a control gas because it is inert to most systems and will not form an explosive mixture with the process

vapors.

However, if atmospheric air can be tolerated in the process system, it should be used in preference to expensive nitrogen. The air inlet may be screened or filtered to prevent obstruction of the control valve by dirt or insects.

If water vapor can be tolerated in the process condenser, the system pressure may be controlled by using load vapor obtained from the ejector discharge. This control method has two advantages over the above methods.

First, it reduces the usage of makeup noncondensable gas almost to zero, which is important if the non-condensable gas is expensive.

Second, it reduces the final vent flow to a minimum, proportional to the actual air leakage in the system. This may reduce significantly the loss of volatile condensable product vapor. If an aftercondenser is not used, and the last stage is vented to the air, the plume of steam will provide a direct visual indication of the magnitude of the air leakage in the system.

Writing the Specifications

The general objective in sizing and selecting an ejector is to minimize the total costs of removing the noncondensable gases which accumulate in a vacuum process system. Careful development of the ejector specifications will help in attaining that objective. An oversize ejector will cost more initially, and may use unnecessarily large quantities of steam and cooling water. But if an ejector is undersized, frequent monitoring of air leaks is required to avoid costly upsets.

To be complete, a specification must describe the pumping job, the utilities available to perform the work, the mechanical design requirements and materials of construction, and the economic objective.

Pumping Job

The specifications must describe the quantity of each significant component in the vapor load; the physical properties which determine its behavior in the stages and condenser; the suction (inlet) conditions; the discharge pressure, and the range over which stable operation is required.

Vapor Load

Up to four components may be present in the vapor load to a steam-jet air ejector: (1) air, (2) noncondensable gases, (3) condensable vapors, and (4) water vapor. The flow of each significant component of the design load should be given separately in pounds per hour.

Air Leakage

Air leakage is present in all subatmospheric pressure systems of conventional design. The amount of air leakage is a function of the system design construction and method of operation, and increases as imperfections develop. Imperfections include packing on valve stems and pump and agitator shafts, flanged and screwed connections, and defects in the process-systems walls.

To achieve commercially tight construction, it is necessary to design for minimum air leakage in low-pressure systems. This means fewer and tighter flanged and screwed connections, fewer packed valve stems and pump shafts, and avoidance or sparing use of gas blowback for the instrument systems.

To visualize the degree of tightness which must be maintained in a vacuum system, it may be noted that 10 lb/hr of air leakage represents an accumulation of air leaks equivalent to a 1/10-in.-diameter, rounded-entrance, critical-flow orifice metering atmospheric air into a vacuum system.

It is well to make a preliminary size and cost estimate of the vacuum system required. One method to do this is to calculate the total vapor load

to each ejector stage, estimate the steam requirements of each stage, then check the cooling-water usage and the design of the surface condensers, if desired.

Steam Usage

The first step is to convert the total specified process vapor load to a standardized basis, (W_a) lb/hr of equivalent dry air at 70°F, in the manner described in the HEI Standards. The basic steam rate may be obtained from Fig. IV and corrected for the actual steam pressure by a steam-usage multiplier also obtained from Fig. IV.

For 1 psig discharge pressure or stability at no load, add about 17% to the steam usage at the last stage.

The vapor load to the ejector stage following an intercondenser is calculated using the condenser-outlet vapor temperature.

Small quantities of a condensable vapor which has a low vapor pressure and is soluble in water will usually condense almost completely in the first intercondenser.

A typical application problem is attached to show the several choices required dependent on relative costs of utilities and sizes of system and loads involved. The figures are approximate and are to illustrate the various steps involved in the selection and sizing by the ejector manufacturers. This also gives the user a basis for preliminary design of this equipment and expected utilities (steam and cooling water) requirement.

OPERATION AND MAINTENANCE

Since steam jet ejectors have no moving parts, operation and maintenance problems should be negligible.

Assuming the equipment has been specified correctly, satisfactory operation of an ejector system will depend upon, (1) correct installation, (2) correct utilities, and (3) periodic inspection.

Installation

A single stage, or multi-stage non-condensing ejector system can be in any convenient location. A condensing system will either require a baro-barometric leg or a pump or trap for condensate removal. When using barometric condensers, it is common practice to use a barometric leg. A barometric leg necessarily requires that the vacuum equipment be located above ground level. The height required depends upon the absolute pressure at the condenser. High vacuum systems will usually require a minimum height of 34 feet. The barometric leg should discharge to a properly designed hotwell. There must be enough volume of water above the discharge of the barometric leg to keep the discharge submerged during start-up. The required volume can easily be calculated, if the diameter of the barometric leg is known.

If a pump is used to remove condensate, or a combination of condensate and condensing water, the pump manufacturer must be advised of the absolute pressure condition at the suction of the pump, and the discharge head required.

In many cases vacuum traps or receivers can be used to remove condensate. Traps and receivers may be considered, if the system is small and utilizes surface type condensers.

Once the ejector system has been located, consideration must be given to three of four connections: suction connection, discharge connection, steam connections, and in most cases water connections.

The suction line should be the same diameter as the suction connection of the ejector system and should be as short and as straight as practical. A maximum velocity of 250-300 feet per second is recommended.

The discharge line should be the same diameter as the discharge of the ejector system. Ejector systems are normally designed to discharge at 0.5 psig. If this pressure is exceeded, the system will not operate properly. Therefore, it is important to design the discharge line to keep pressure below 0.5 psig, or to inform the manufacturers of an anticipated higher discharge pressure. Many ejectors discharge to the atmosphere directly. Others discharge to condenser hotwells or after-condensers. If the discharge is submerged in the hotwell, the maximum submergence should be 1 foot to avoid surpassing 0.5 psig. In all cases discharge pressures should be carefully considered.

Since dry steam is a basic requirement for good performance and maintenance, installation of steam lines is extremely important. Steam mains should be well trapped. The steam piping to the ejector system should come off the top of the main line. A good velocity is around 100 feet per second. In most cases a steam separator and steam strainer are recommended. If the strainer is used, it should be upstream of the separator. Steam lines and separators should be completely insulated. A steam pressure gauge (compound type is recommended) should be located as close to the ejector system as possible.

Since precondensers and intercondensers operate under vacuum, water pressure at the inlet of barometric condensers is not critical. Sufficient pressure differential should be available for control of water flow. A pressure of 5 psig is normally considered sufficient. Water pressure should remain fairly constant, since wide fluctuations will cause changes in water flow with resultant changes in condenser pressures. If surface condensers are used, sufficient pressure must be available to overcome pressure drop through the condensers.

Maximum allowable pressure drop through surface condensers is usually specified by the customer before design. For divided water boxes, use a low (about 4 ft/second) velocity so that when you are reduced to half the box the velocity doesn't exceed 8 feet per second.

Utilities

The basic utilities with which we are involved, are steam and water. For efficient design, it is necessary to know minimum steam pressure at the steam inlet to the ejector system and maximum condensing water temperature.

Under critical flow design lowering of steam pressure below design pressure will cause the system to break down completely. Under noncritical flow conditions steam pressure below design will result in a loss of capacity and a resultant loss of vacuum. The use of steam pressure above design will not improve performance and, if the steam pressure is considerably higher than design, performance will be adversely affected, due to the throats of the system being overloaded. The steam supply to an ejector system must be dry. Wet steam will cause poor performance and, in addition, will erode the internals of the system, causing further loss of performance. A well designated steam separator and trap assembly will correct a wet steam condition. If the steam supply is superheated, this condition should be considered before final design. Significant superheat will change the design of nozzles and throats. If a significant superheat condition is not known before design, steam nozzles and throats will be undersized.

Maximum water temperature must be given before design of the condensing type ejector system. The absolute pressure at the condensers is dependent on the water temperature rise and water flow. The capacity of the stage following the condenser is dependent upon temperature of saturated air which, in turn, is dependent upon incoming water temperature. In order to maintain proper condenser pressures, design water temperature should not be exceeded. The quality of water used is not extremely important in the design of barometric condensers. The better barometric condensers are non-plugging and are not affected by sludge. Any solid large enough to clog the inlet

or outlet would naturally cause severe problems. Surface condensers' water quality must be considered before design. Fouling factors are normally determined and specified by the customer.

Inspection

Periodic inspection of the internals of ejector systems is highly recommended. The frequency of inspection will depend upon the type of service and quality of steam supply. A unit used on corrosive or erosive service will certainly be inspected more often than a unit in non-corrosive service. A good rule of thumb is to inspect the ejector system whenever related equipment is inspected.

Critical dimensions of an ejector system can be obtained for the manufacturer. A visual check, however, is all that is normally required. If steam nozzles and diffusers are smooth and round, and erosion or corrosion is not indicated, replacement of parts is not required. Pitting, etching, or wire drawing, if noticed by the naked eye, will affect performance and call for replacement. Spare steam nozzles and diffusers should be kept in stock for small systems up to 6" suction. Above this size, it is usually recommended steam nozzles be kept as spares.

Trouble-Shooting

Steam jet vacuum equipment is highly efficient and trouble-free. As with any equipment in erosive or corrosive service, breakdowns beyond control may occur. Knowledge of correct procedures for locating trouble will save time and valuable product.

Unsatisfactory performance of an ejector system can be caused by external or internal causes. Unsatisfactory performance can also be classified as sudden or gradual. The gradual loss of vacuum will normally suggest external causes. Since it is easier to check external causes of trouble, all possible external causes should be checked first.

External Causes of Trouble

1. Low steam pressure
2. Wet steam
3. High water temperature or insufficient water flow
4. Entrained air in condenser water
5. High discharge pressure
6. Fluctuating water pressure
7. Change in load - excessive air leakage

Let us assume that a multi-stage system has lost vacuum. The possible external causes are quickly checked and are found trouble-free. We must now look for internal causes of trouble.

Internal Causes of Trouble

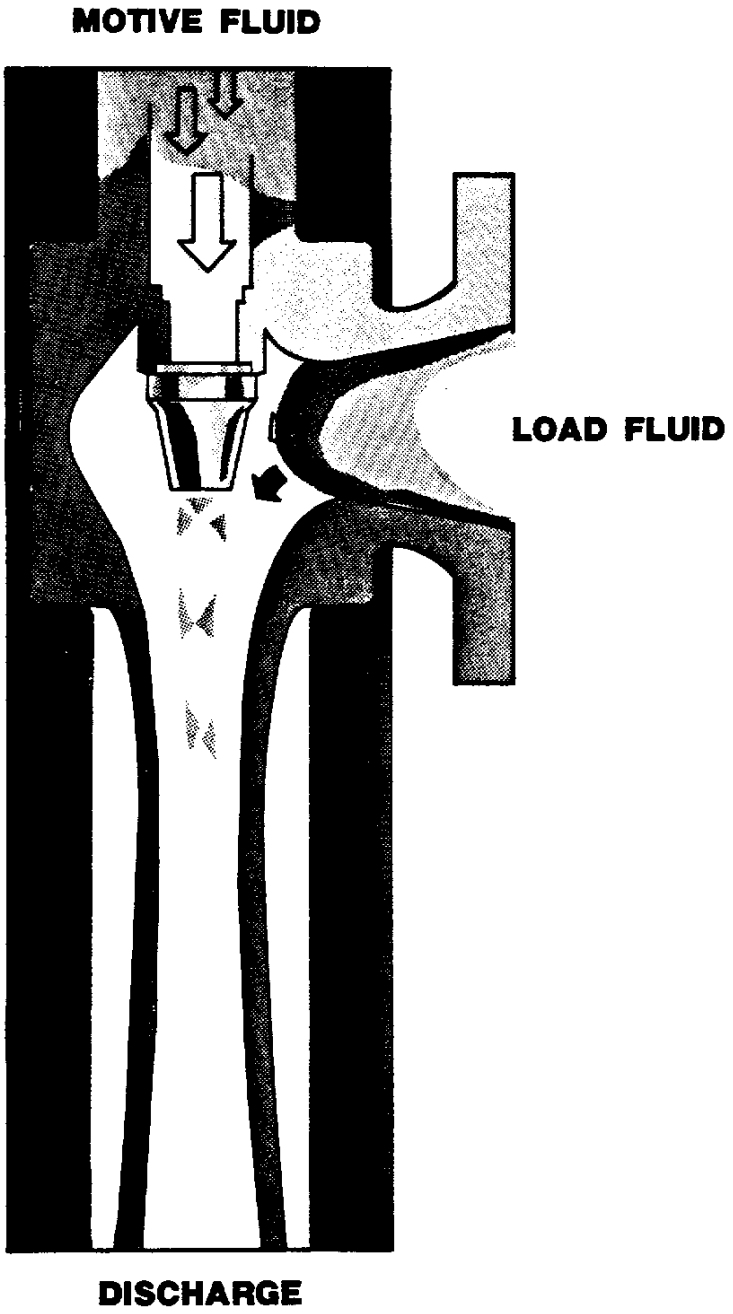
1. Eroded or corroded parts, particularly nozzles and diffusers
2. Clogged nozzles, diffusers and strainers
3. Leaks in steam chests
4. Clogged or fouled water supply
5. Clogged water discharge
6. Excessive leakage - cracked or worn parts
7. Intercondenser water nozzle eroded.

In order to reduce the amount of disassembly we will check by stages. Since stages ahead of the Z (or final) stage will not work unless the Z stage is working properly, we must check the Z stage first.

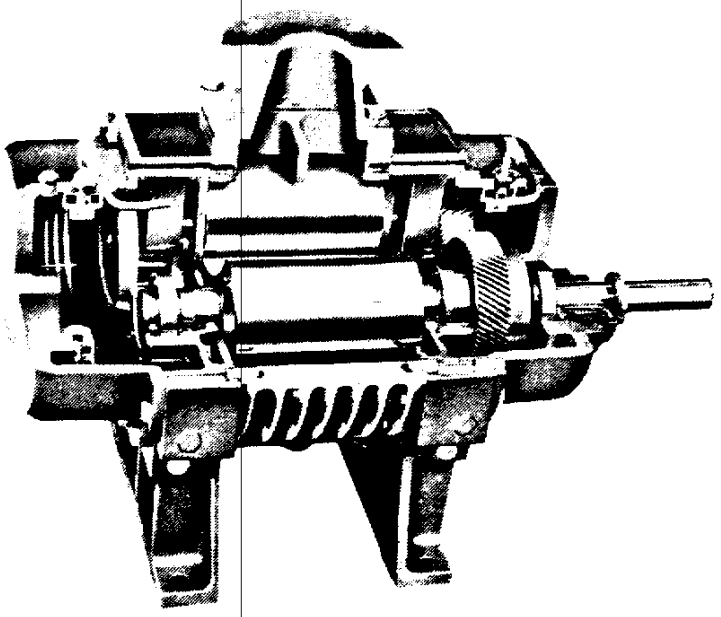
The discharge of the Z stage should be checked visually and audibly. Is water coming out of the discharge? If so, the condenser ahead of the Z stage is flooding. Can a popping noise be heard? If so, the Z stage is not performing properly. Since the majority of ejector problems are found in the Z stage, a simple performance check should be made. The suction

flange should be blanked off, and the pressure read at the suction of the Z stage with a mercury absolute gauge. If the suction pressure is above design no load pressure, the Z stage should be disassembled and inspected carefully for clogged or eroded nozzles and diffusers. The steam chest should be carefully checked for indications of steam leakage, particularly around the steam nozzle connection. If erosion or corrosion is in evidence, it is quite likely that the diffusers and nozzles of preceding stages are in poor condition. The preceding stages, therefore, should be checked and parts replaced, if needed. If the Z stage check out properly, preceding condensers and stages should be checked in reverse order, i.e., Y stage, X stage, W stage . Correct interstage pressures can be found in the manufacturer's instruction book, or from the engineering department.

It is, of course, necessary that accurate instruments be used in checking an ejector system. Steam pressure gauges should be calibrated periodically. Compound steam pressure gauges are recommended, since they are not damaged when subject to vacuum. Thermometers must be accurate, since interstage condenser pressures are dependent upon inlet and discharge water temperatures. The type of vacuum gauges used depends upon degree of vacuum. A mercury absolute gauge is usually satisfactory for single, two-stage and three-stage systems. More sophisticated gauges are required for four, five and six-stage systems.

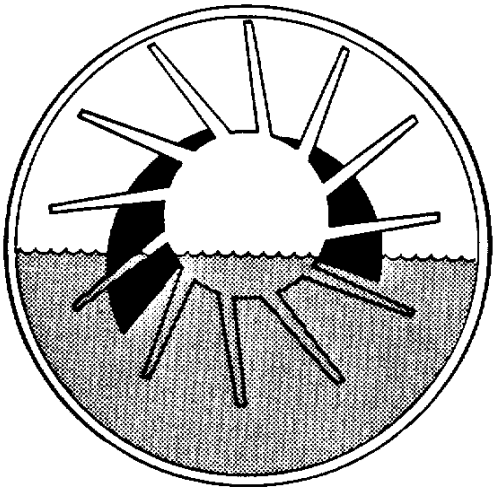

MOTIVE FLUID
LOAD FLUID
DISCHARGE

LOBE TYPE POSITIVE DISPLACEMENT VACUUM PUMP



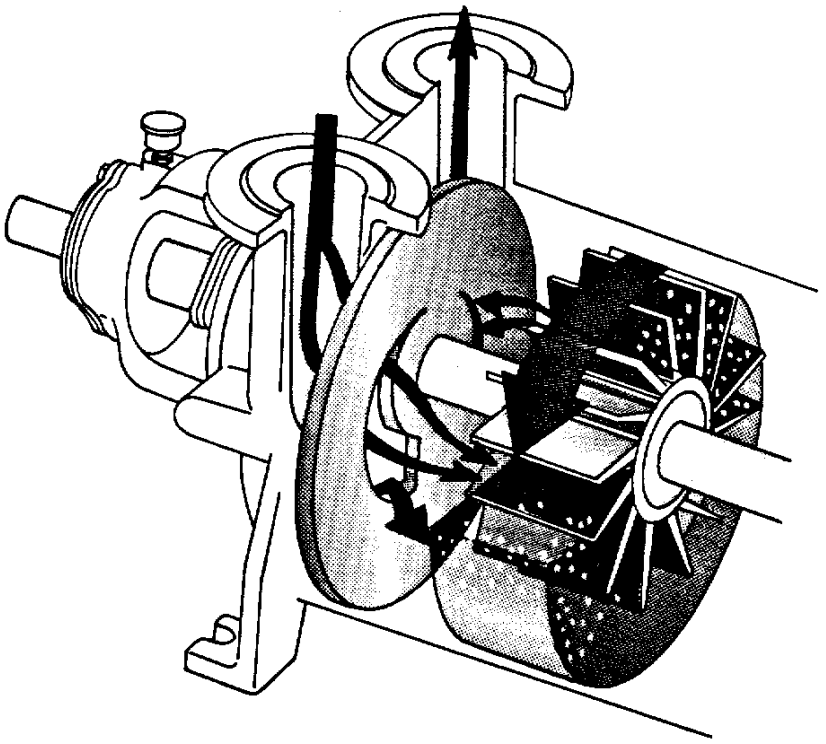
UOP 650-17

LIQUID RING PUMP OPERATION



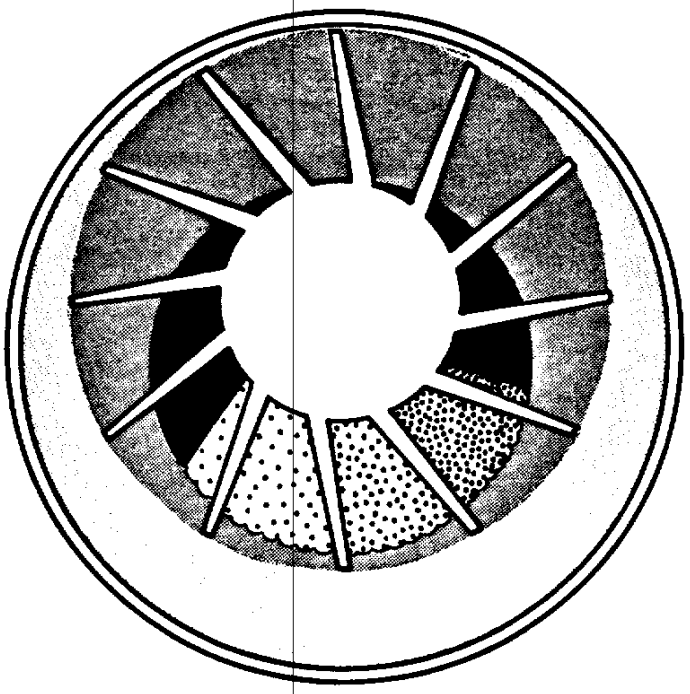
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RUIDO DE SECO
AGUA O HIDROCARBURO



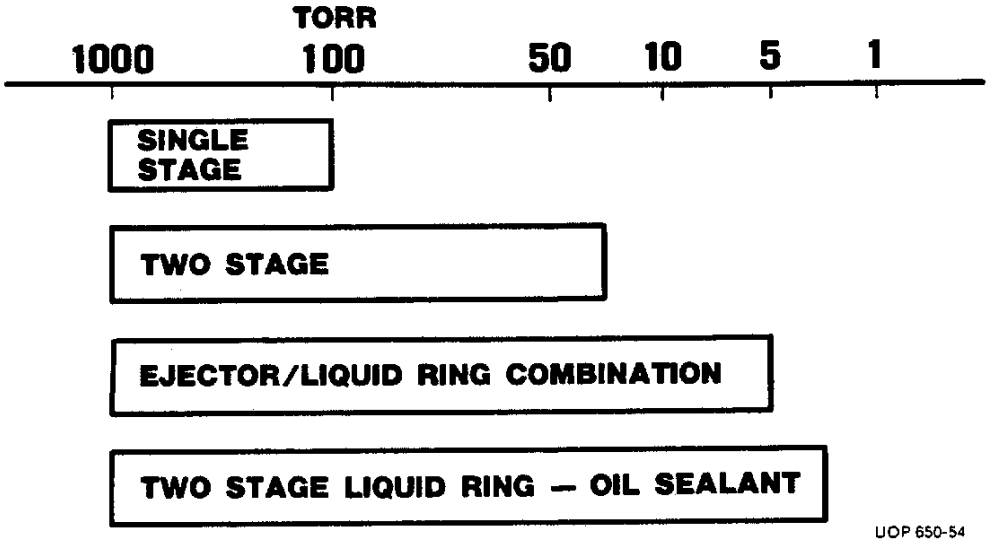
UOP 650-25

LIQUID RING



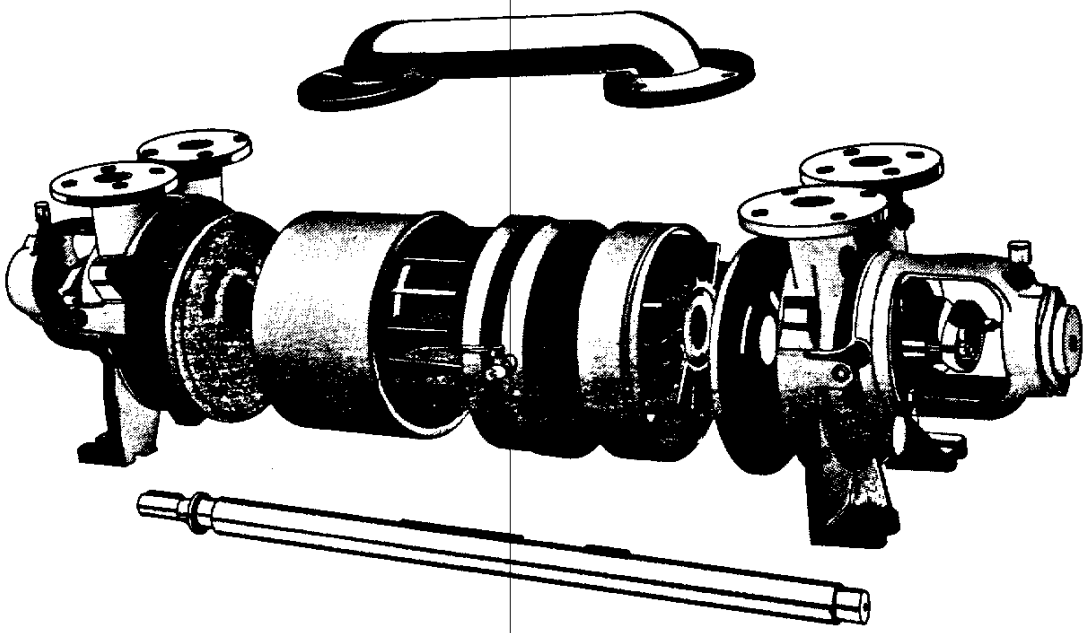
UOP 650-26

LIQUID RING PUMP PRESSURE RANGE



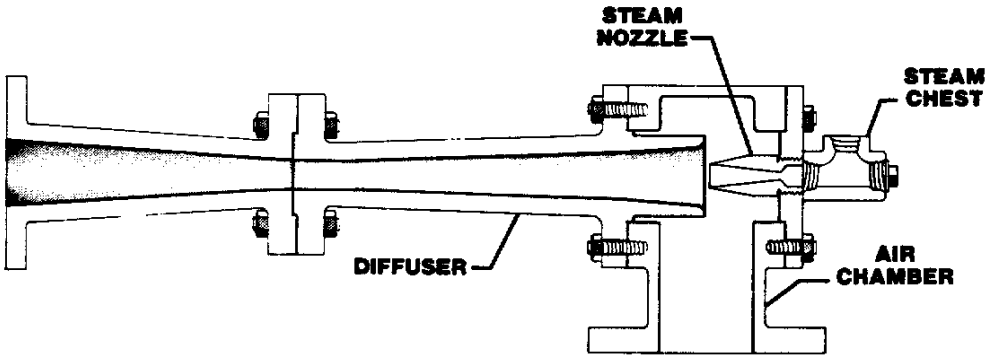
UOP 650-54

LIQUID RING VACUUM PUMP



UOP 650-16

STEAM JET EJECTOR



UOP 650-56

ADVANTAGES OF EJECTORS OVER OTHER TYPES OF VACUUM PUMPS

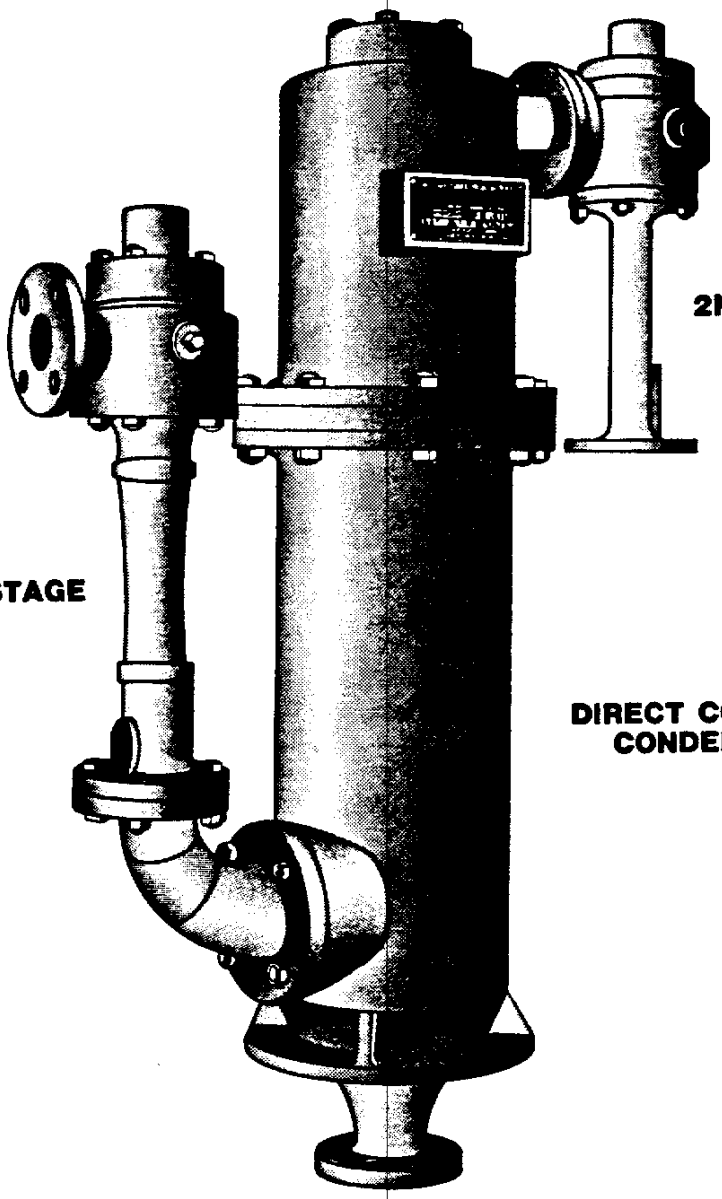
1. LOW FIRST COST
2. ECONOMY OF OPERATION
3. SIMPLICITY
4. COMPACTNESS
5. DURABILITY
6. DEPENDABILITY
7. LOW INSTALLATION COST
8. LOW MAINTENANCE COST

EJECTORS CAN HANDLE CORROSIVE, TOXIC FLUIDS . . .

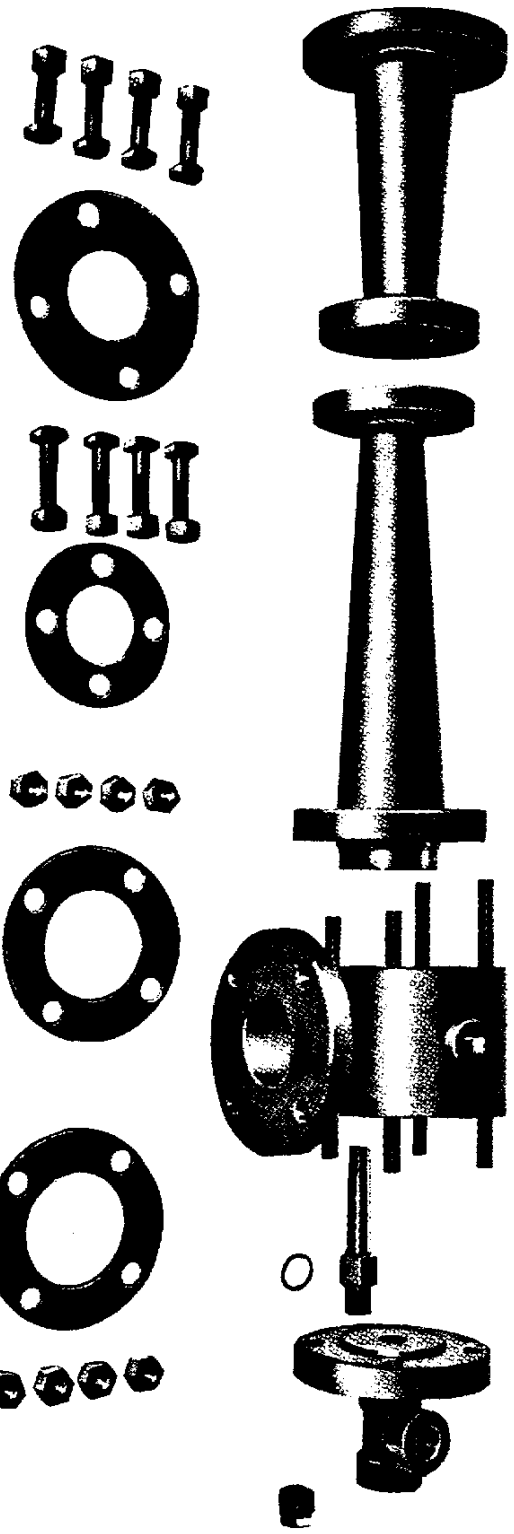


UOP 650-21

TWO STAGE CONDENSING WITH DIRECT CONTACT INTERCONDENSER

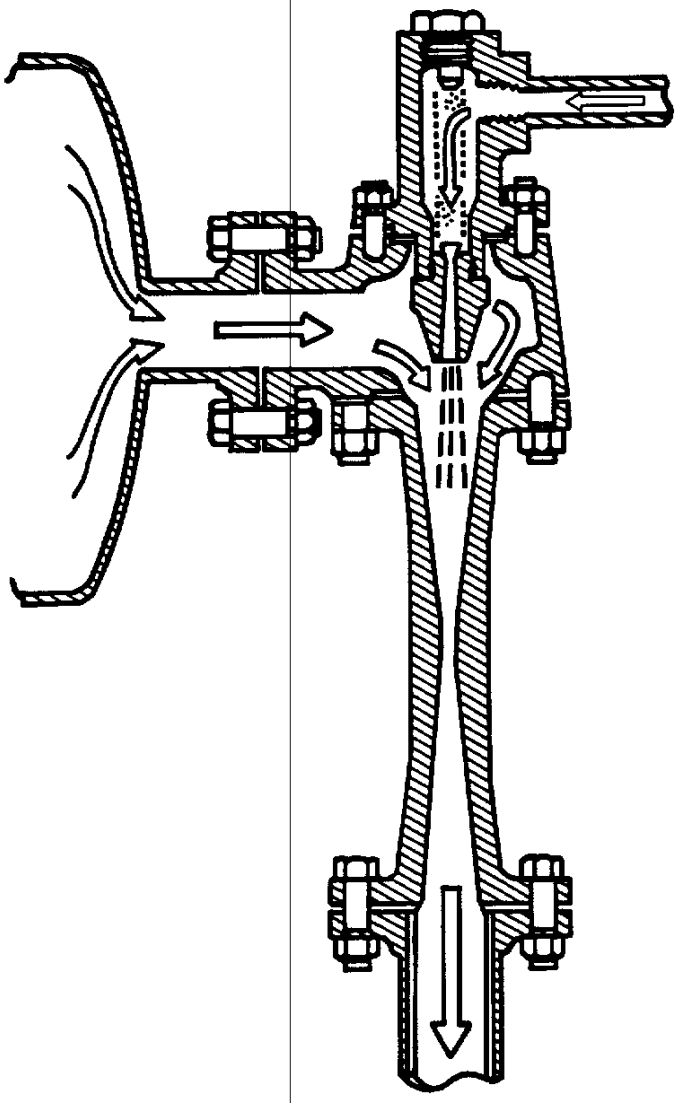


UOP 650-19



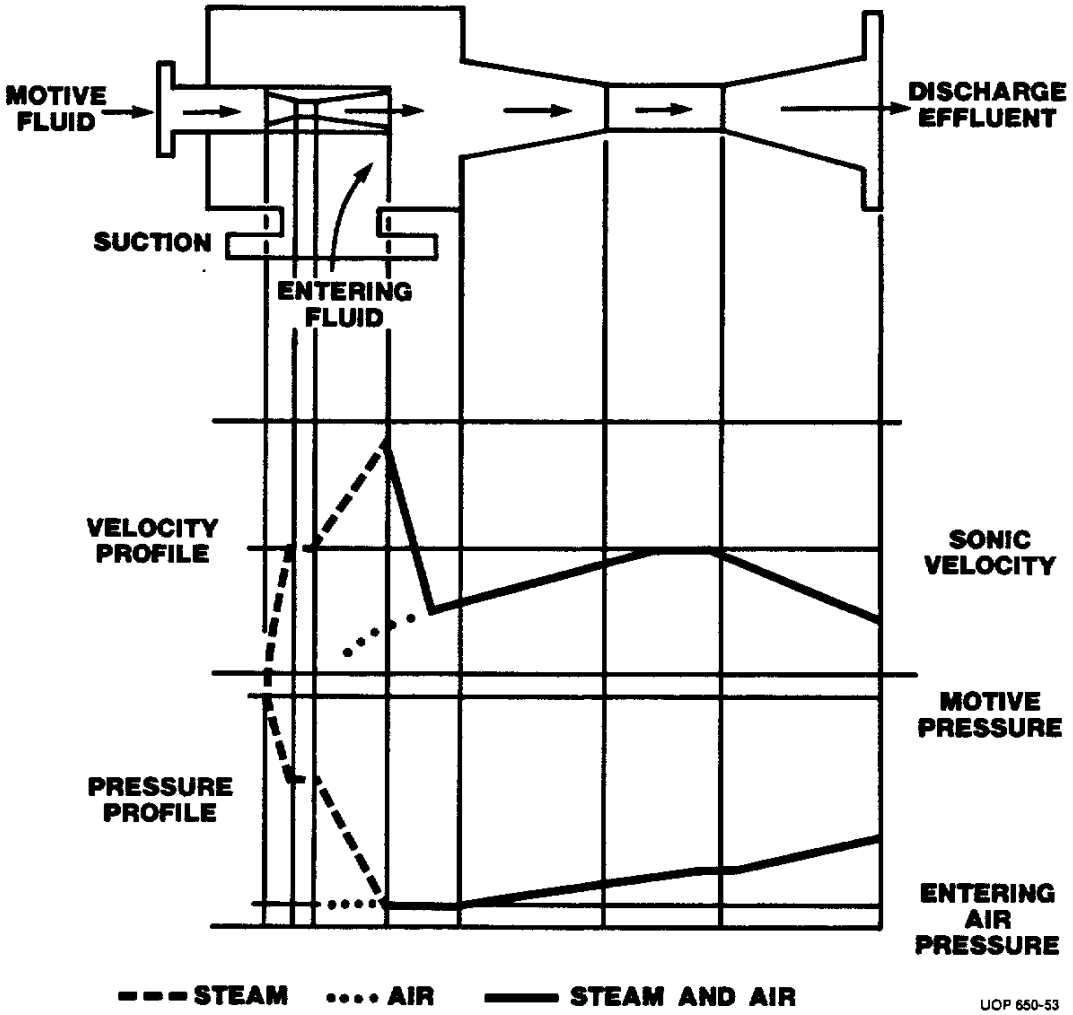
UOP 650-29

EJECTOR OPERATION

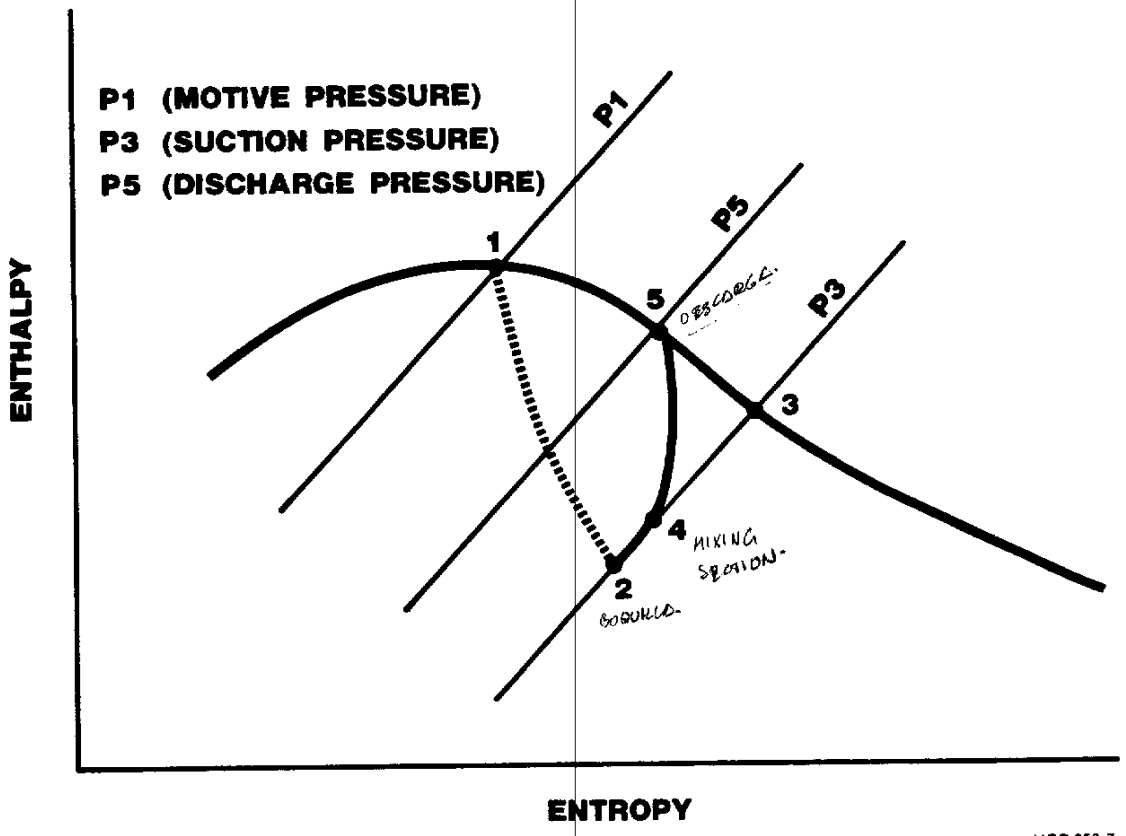


UOP 650-28

EJECTOR CHARACTERISTICS



MOLLIER CHART
SATURATED STEAM MOTIVE AND VAPOR SUCTION FLUID



UOP 650-7

A CRITICAL DESIGN INDICATES THAT THE VELOCITY IN THE MIXING SECTION OF THE EJECTOR IS SUPERSONIC . . .

A CRITICAL DESIGN —

- **HAS A STANDING WAVE**
- **HAS A RELATIVELY NARROW RANGE OF OPERATION**
- **IS SENSITIVE TO THE LOCATION OF THE NOZZLE RELATIVE TO THE DIFFUSER AND THE DIFFUSER GEOMETRY** (CAMBIOS EN GROSOR DEL EMPAQUE PUEDE CAMBIAR EFICIENCIA)
- **IS USED FOR MOST PROCESS APPLICATIONS**

UOP 650-24

STAGE COMPRESSION RATIO =

$$\frac{\text{EJECTOR DISCHARGE FLUID ABSOLUTE PRESSURE}}{\text{EJECTOR LOAD FLUID ABSOLUTE PRESSURE}}$$

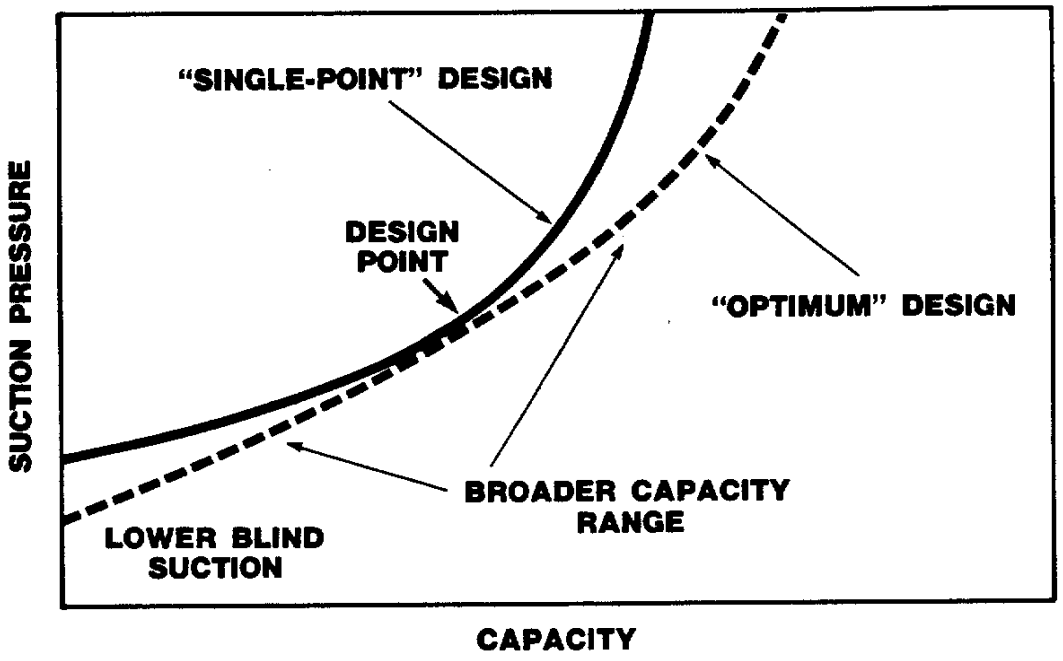
IF STAGE COMPRESSION RATIO IS

≳2.0 NON CRITICAL DESIGN

≲2.0 CRITICAL DESIGN

UOP 650-32

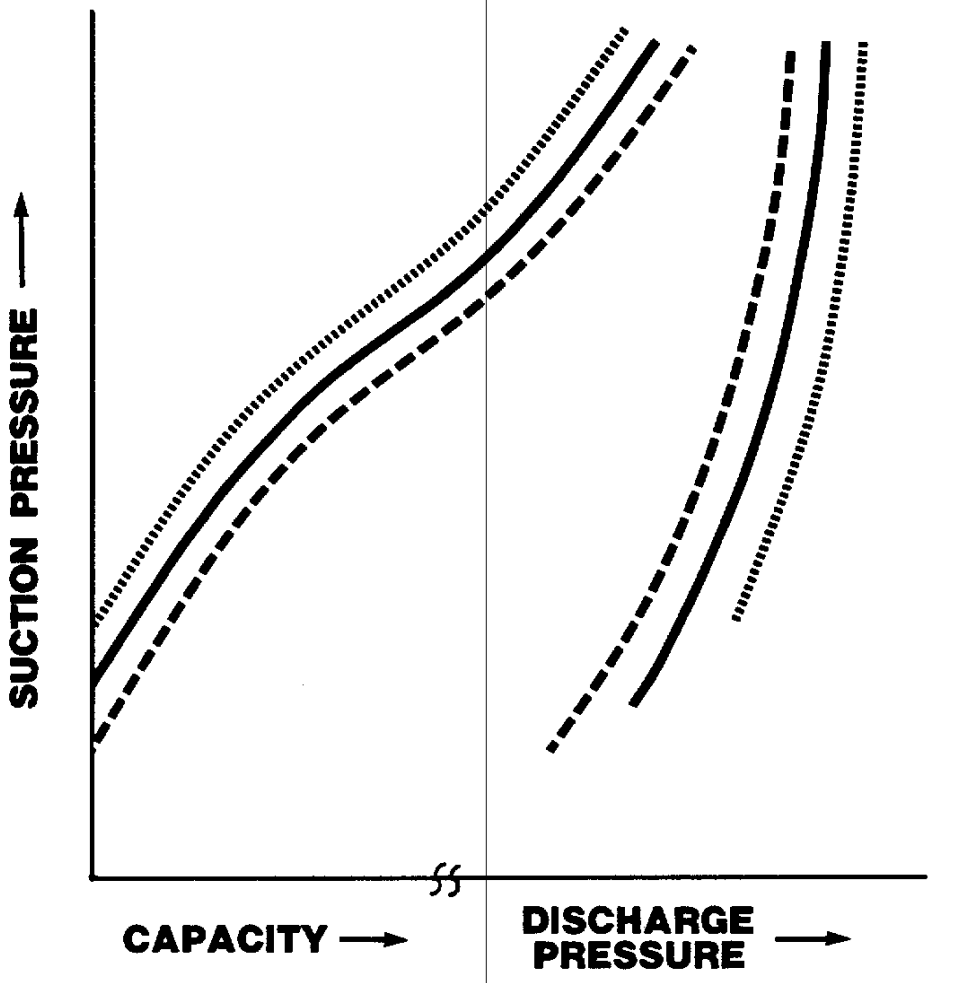
EJECTOR PERFORMANCE CURVE



UOP 650-27

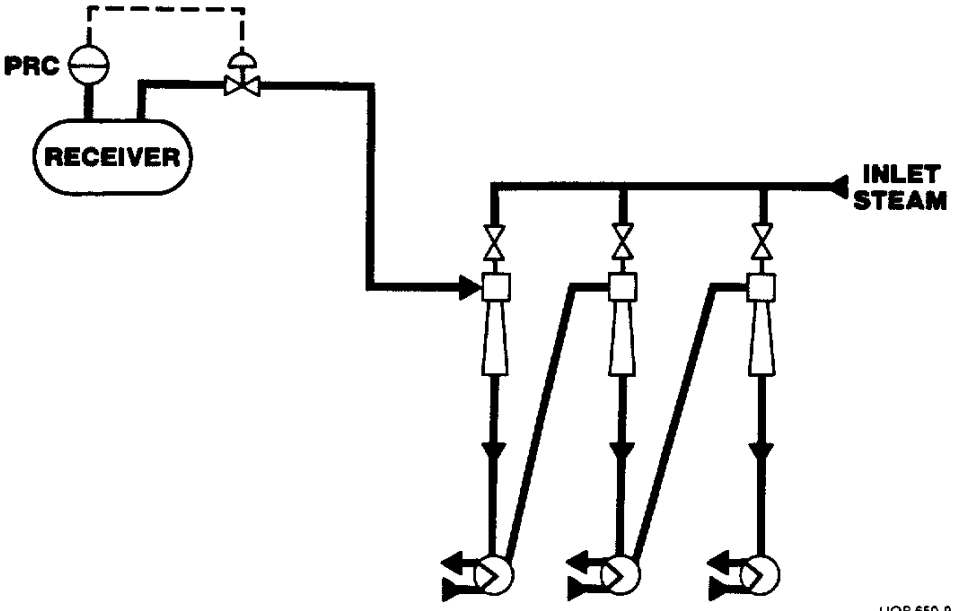
SON DISEÑADOS PARA UN FLUJO DETERMINADO DE VAPOR

EFFECT OF NOZZLE POSITION ON PERF. CURVE



UOP 650-56

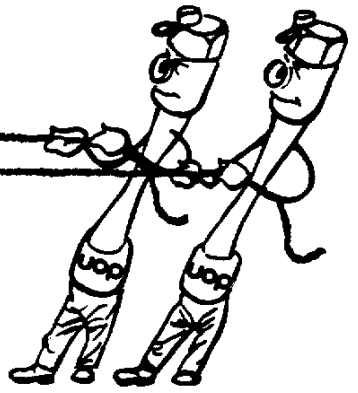
CONTROL BY THROTTLING INLET VAPOR LINE



UOP 650-9

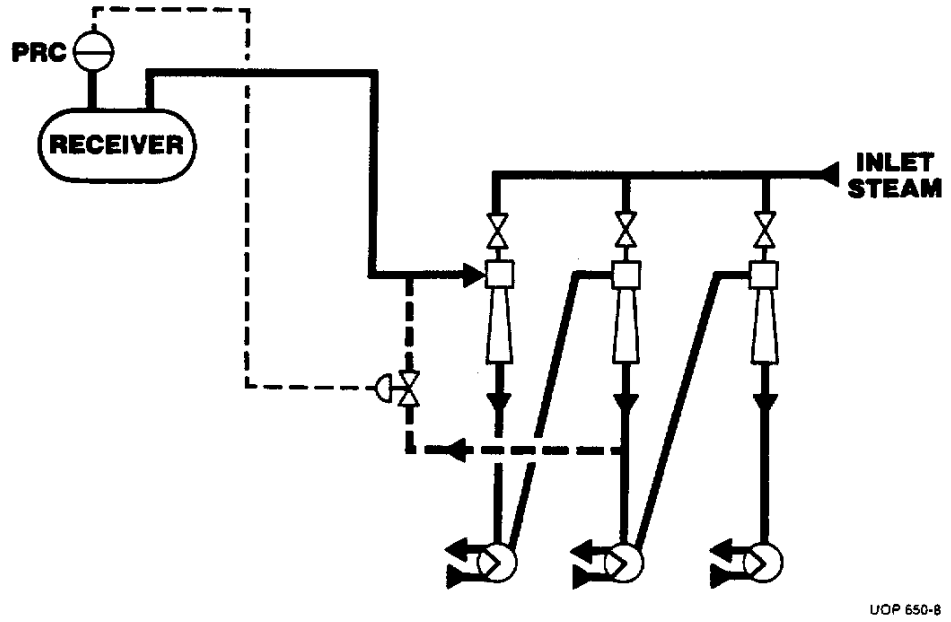
BETTER CORRECTED
SO UTILIZES POOR CORRECTION HAS ERROR

EJECTORS OPERATE IN PARALLEL FOR STEP TYPE CONTROL AND FOR SPARING . . .



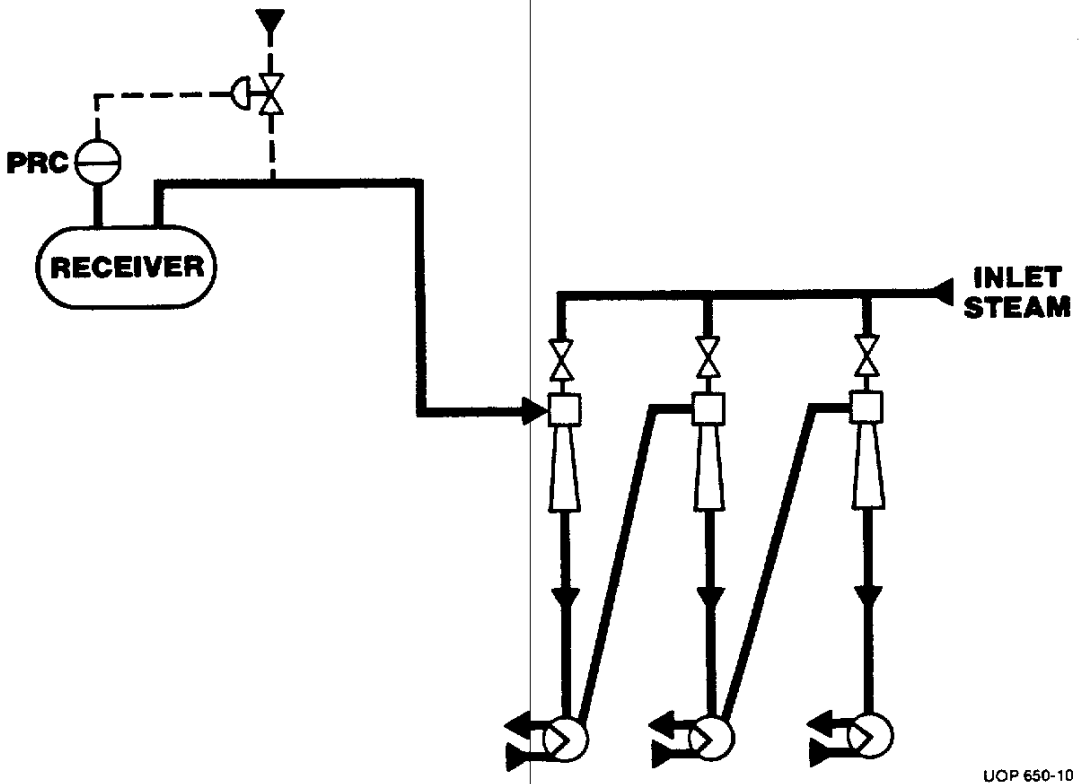
UOP 650-23

CONTROL BY RECYCLING INTERSTAGE FLOW BACK TO SUCTION



RECYCLED VS MATERIAL
SE UTILIZES ONTEC ORC CONDENSOR
FOR MONITOR (2 RECYCLE) CONDENSORS
& NO CONDENSERS

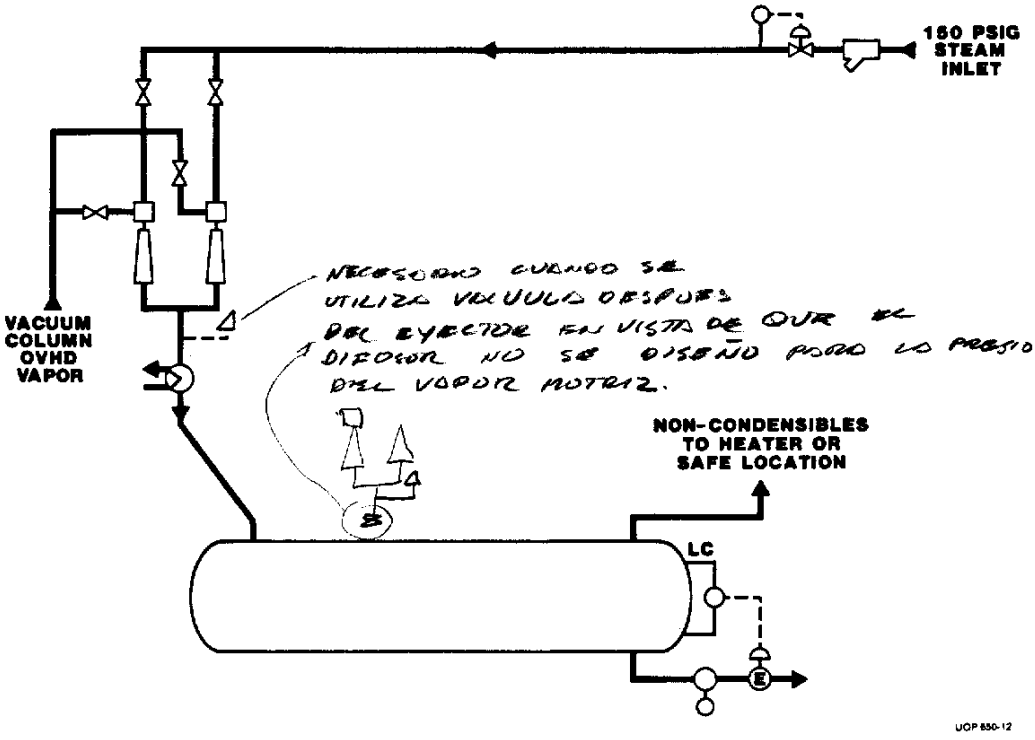
CONTROL BY ADDITIONAL LOAD GAS THROTTLING



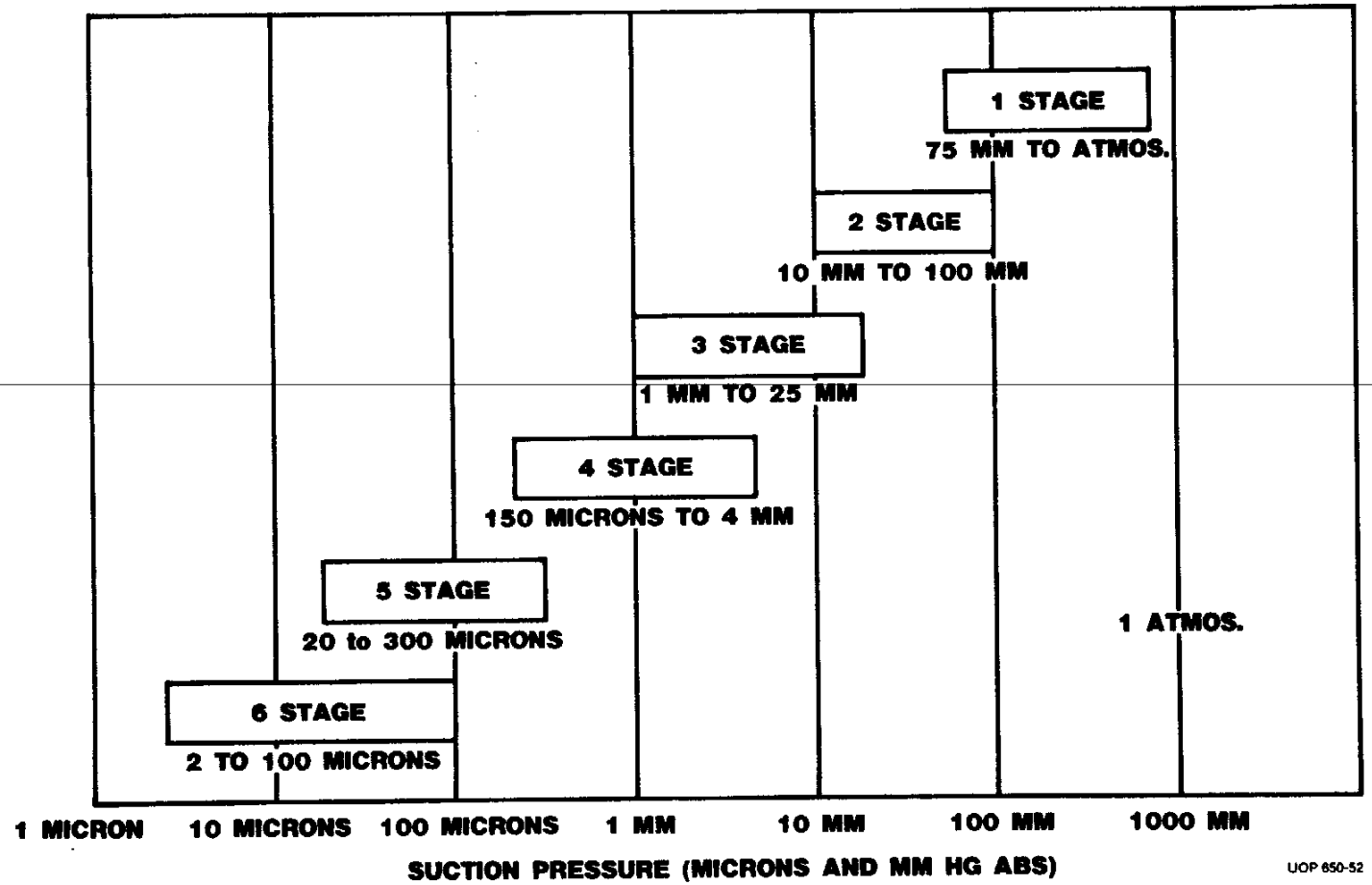
UOP 650-10

UTILIZA EXTRA CAPACIDAD Y GAS

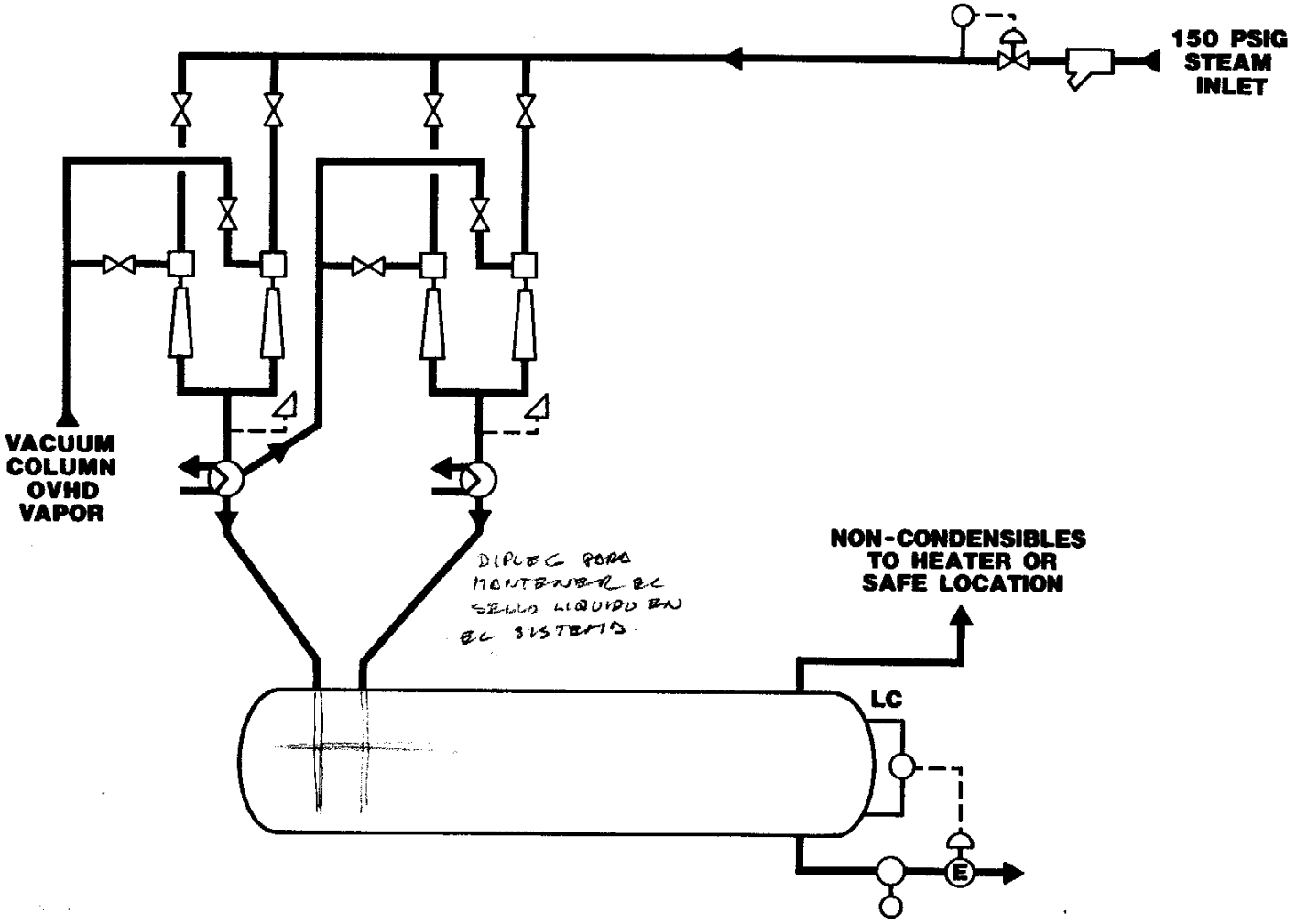
SINGLE STAGE ~ 50-75 MM HG ABS



EJECTOR APPLICATION INFORMATION

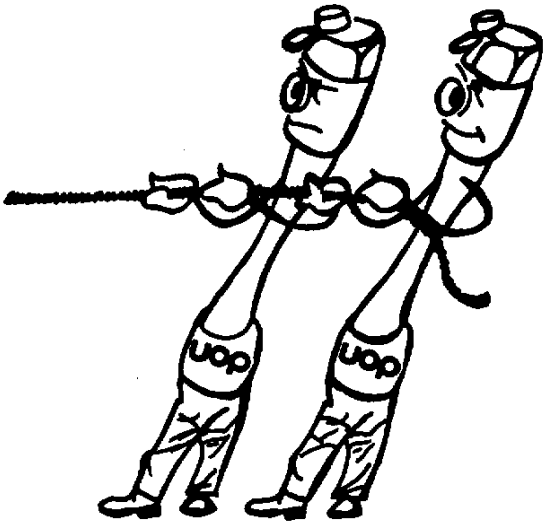


TWO STAGE~10-100MM HG ABS



UOP 650-13

EJECTORS IN SERIES GIVE INCREASED COMPRESSION RATIO CAPABILITY . . .



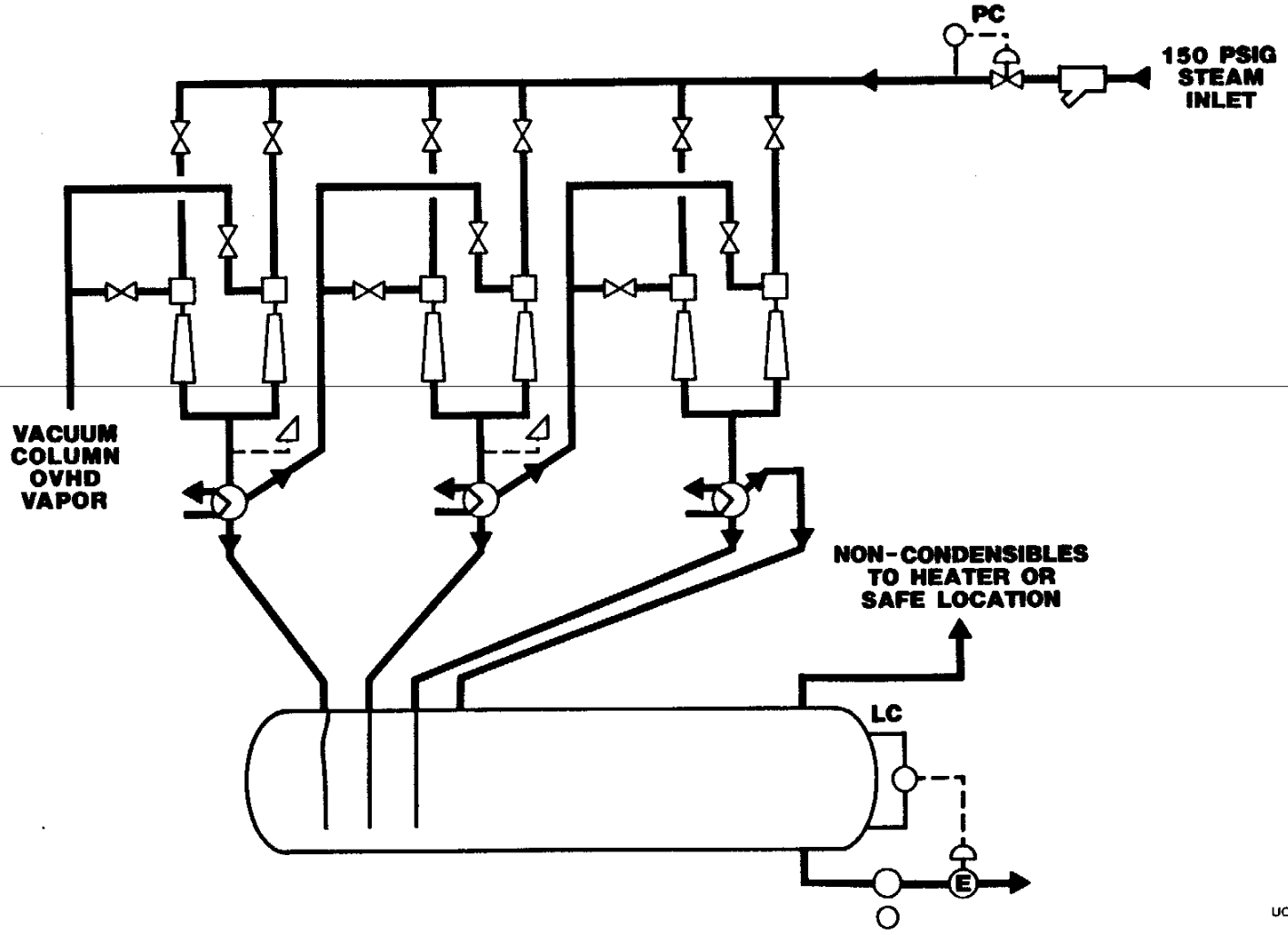
UOP 650-20



SOMETIMES A BOOSTER STAGE IS USED FOR HIGH COMPRESSION RATIOS . . .

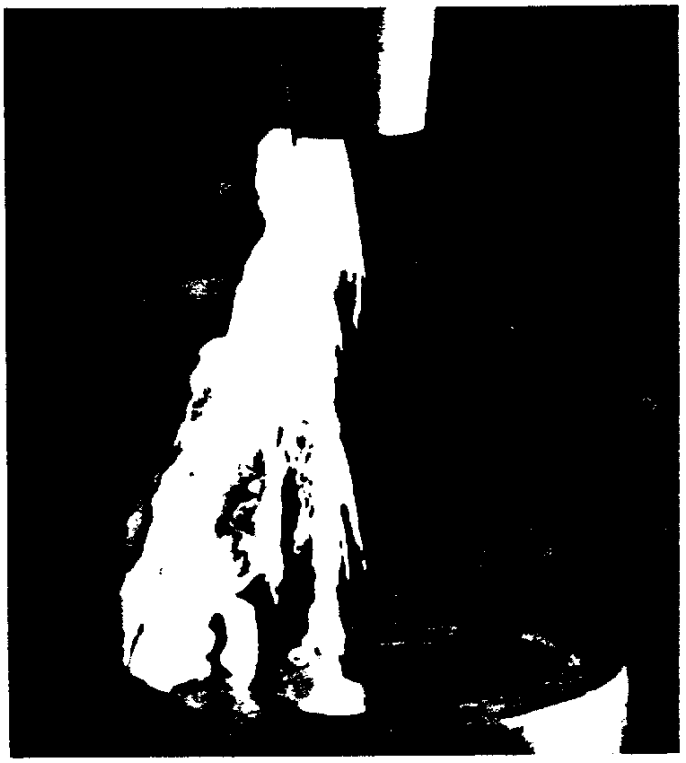
UOP 650-22

THREE STAGE~1-25 MM HG ABS



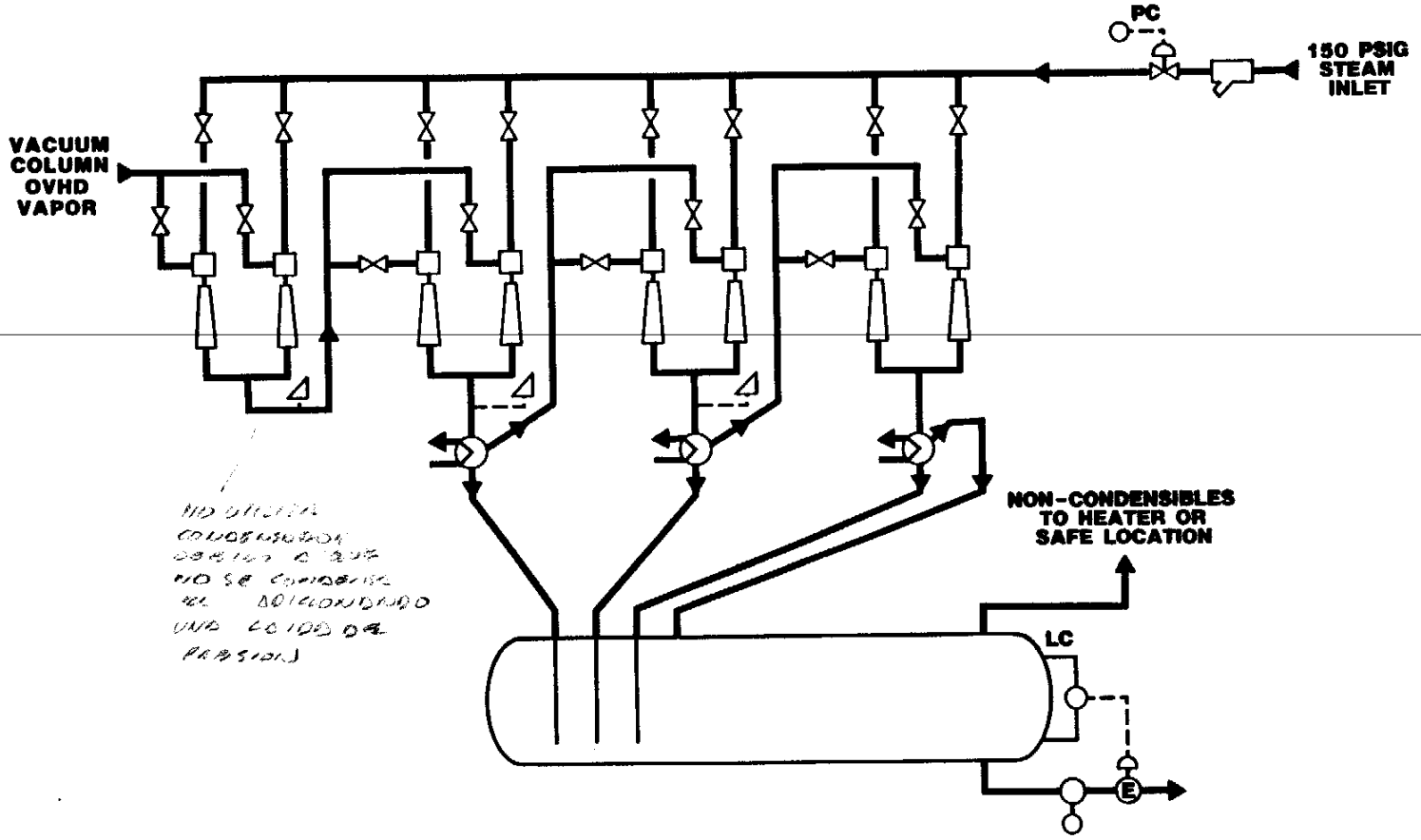
UOP 650-14

FOR SUCTION PRESSURE BELOW 4 TO 5 MM HG ABS ICE WILL FORM ON STEAM-JET EJECTOR NOZZLE



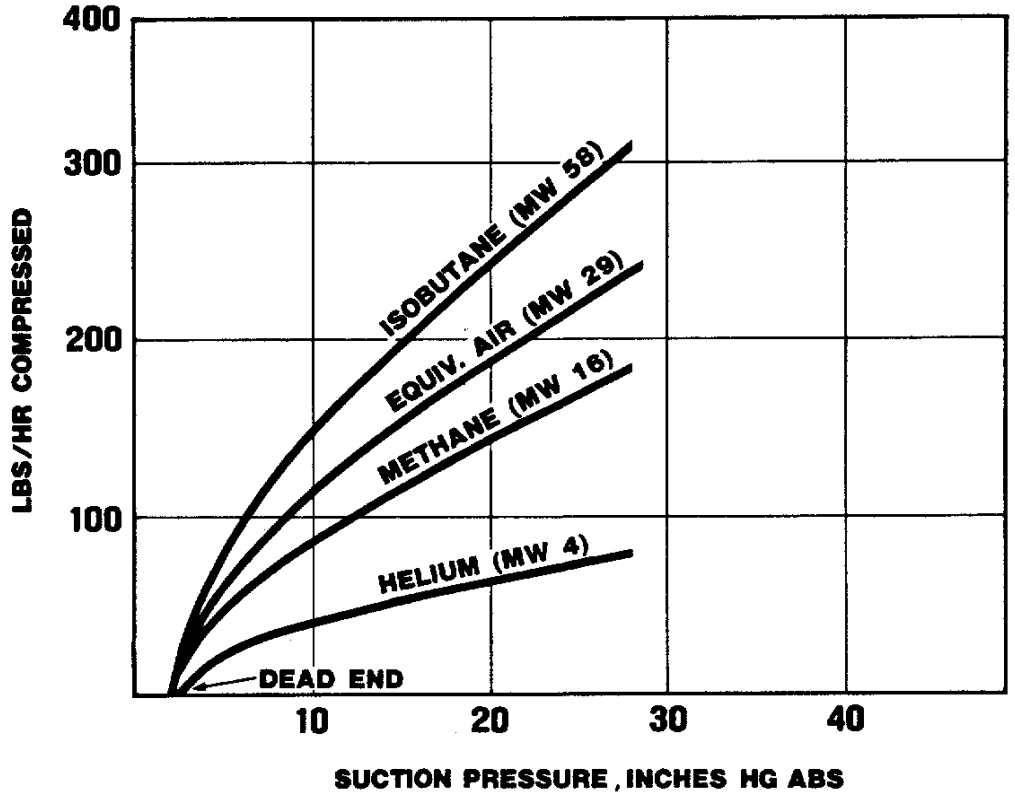
UOP 650-18

FOUR STAGE ~ 150 MICRONS — 4 MM HG ABS
(1 MICRON = 1/1000 MM)

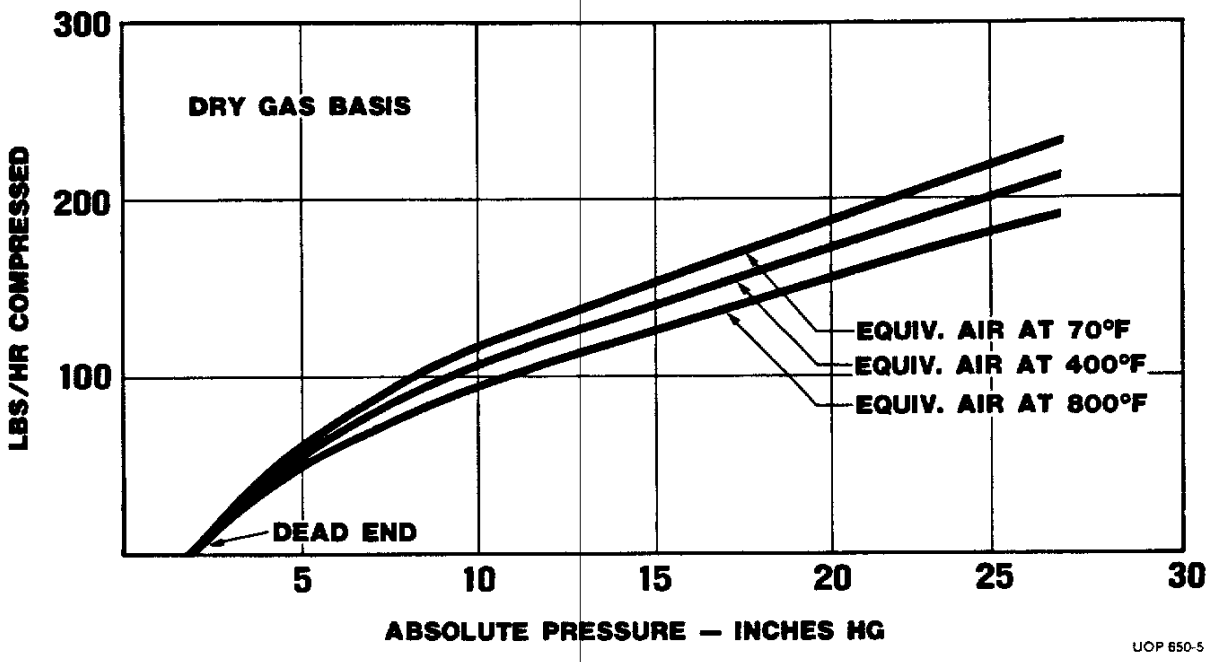


UOP 650-15

EJECTOR PERFORMANCE CURVE SHOWING THE EFFECT OF CHANGES IN MOL WT



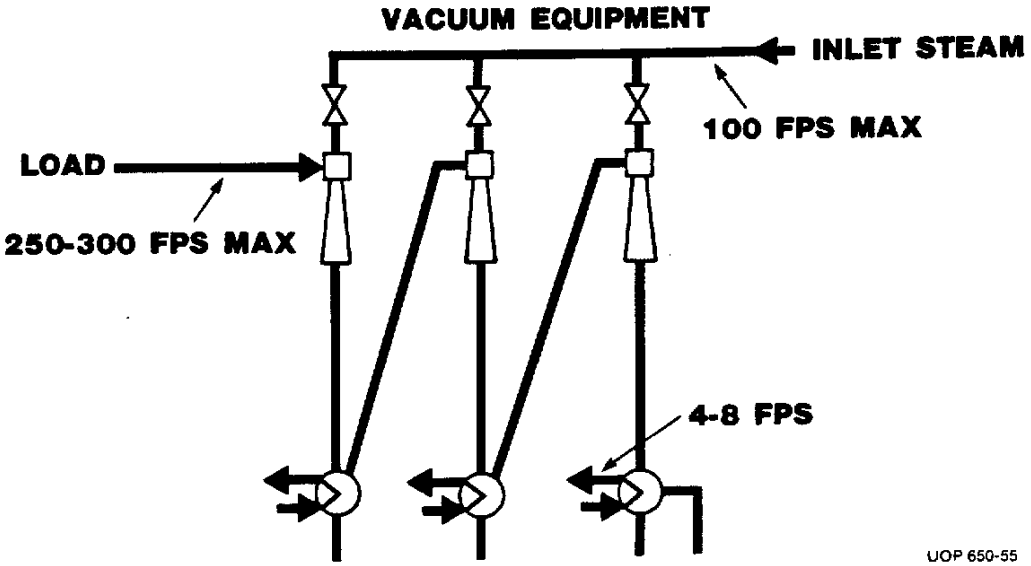
UOP 650-4



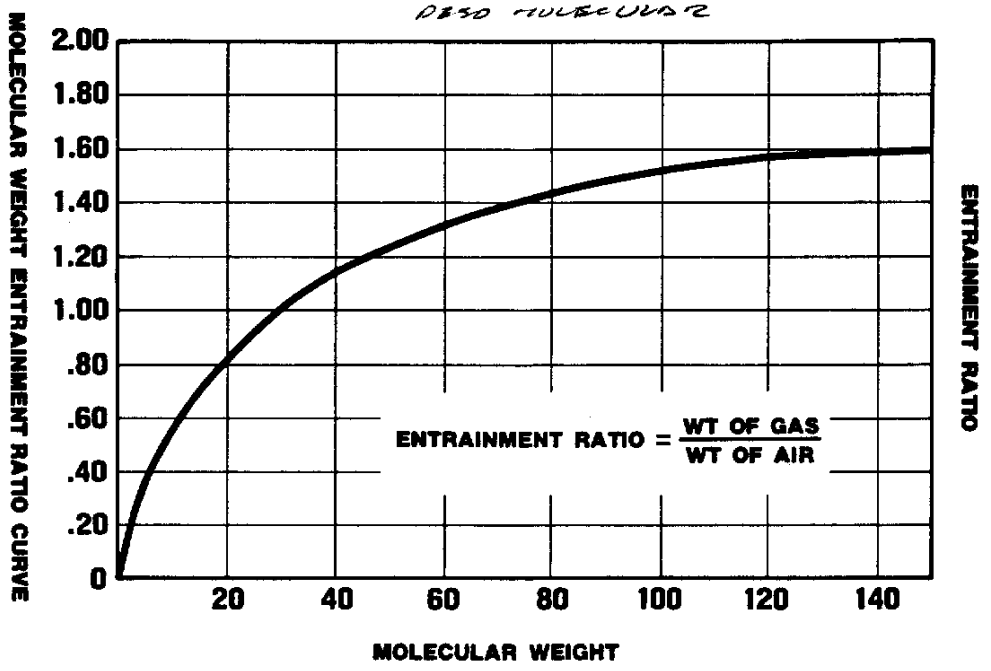
UOP 650-5

EFECTO DE LA TEMPERATURA

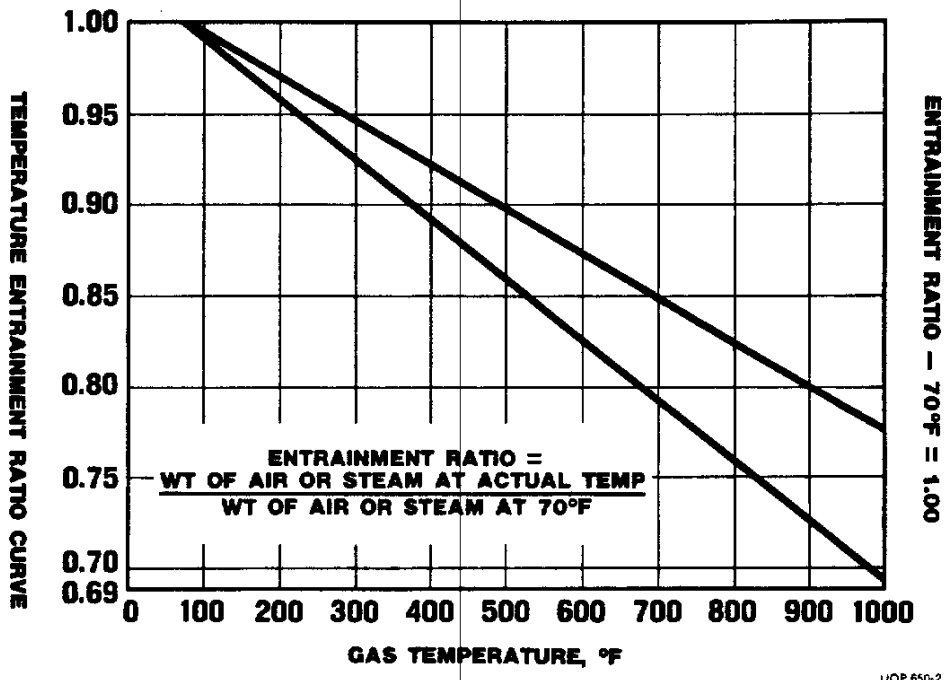
DESIGN PARAMETERS



FACTOR DE CORRECCION PARA PESO MOLECULAR

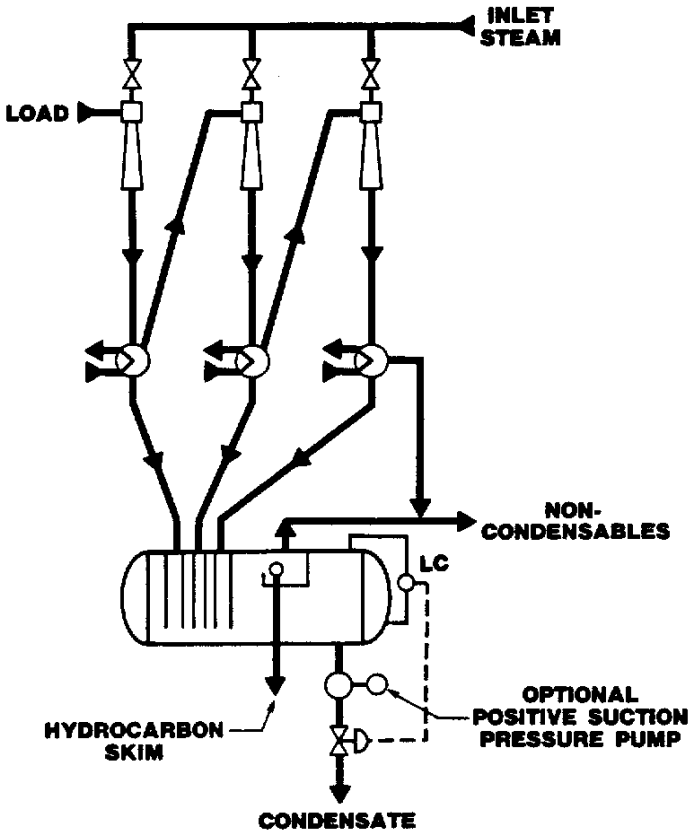


UOP 650-3



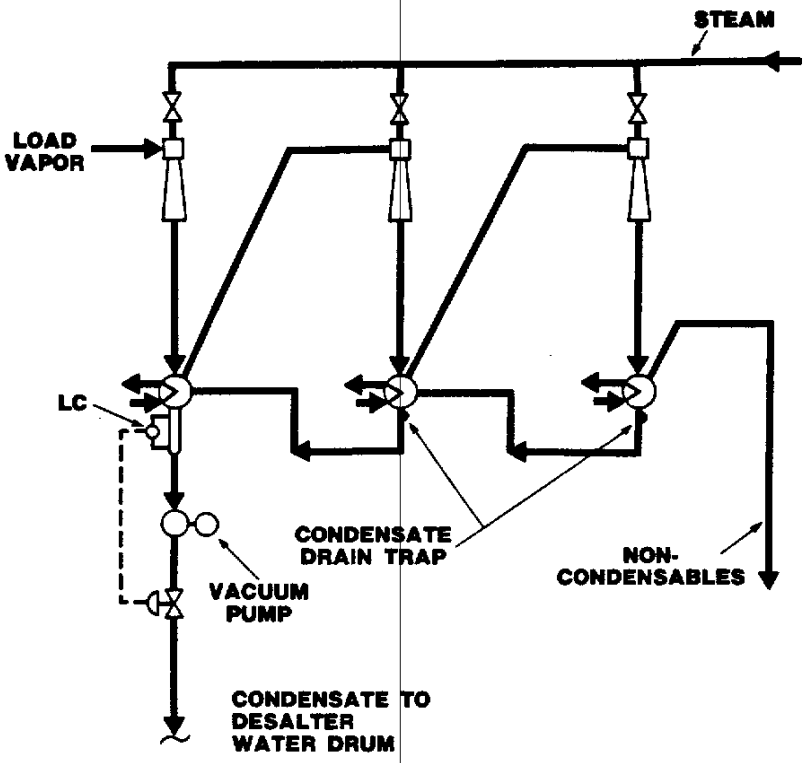
FACTOR OF CORRECTION FOR VAPOR
& AIR & GAS FLUID MIXTURE

CONDENSATE REMOVAL USING HOT WELL AND ELEVATED CONDENSERS



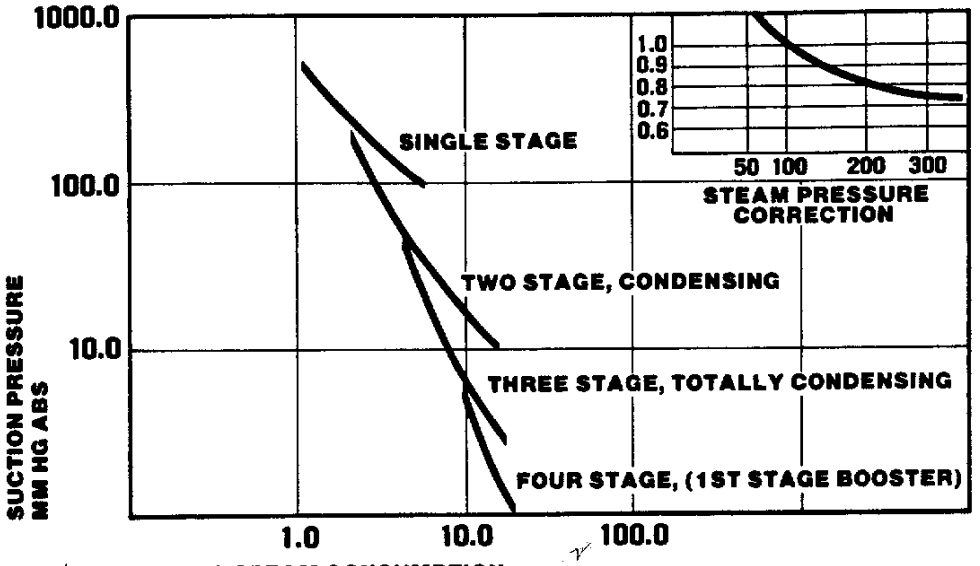
UOP 650-6

CONDENSATE REMOVAL UTILIZING A PUMP



UOP 650-57

STEAM JET EJECTOR CONSUMPTION CHART



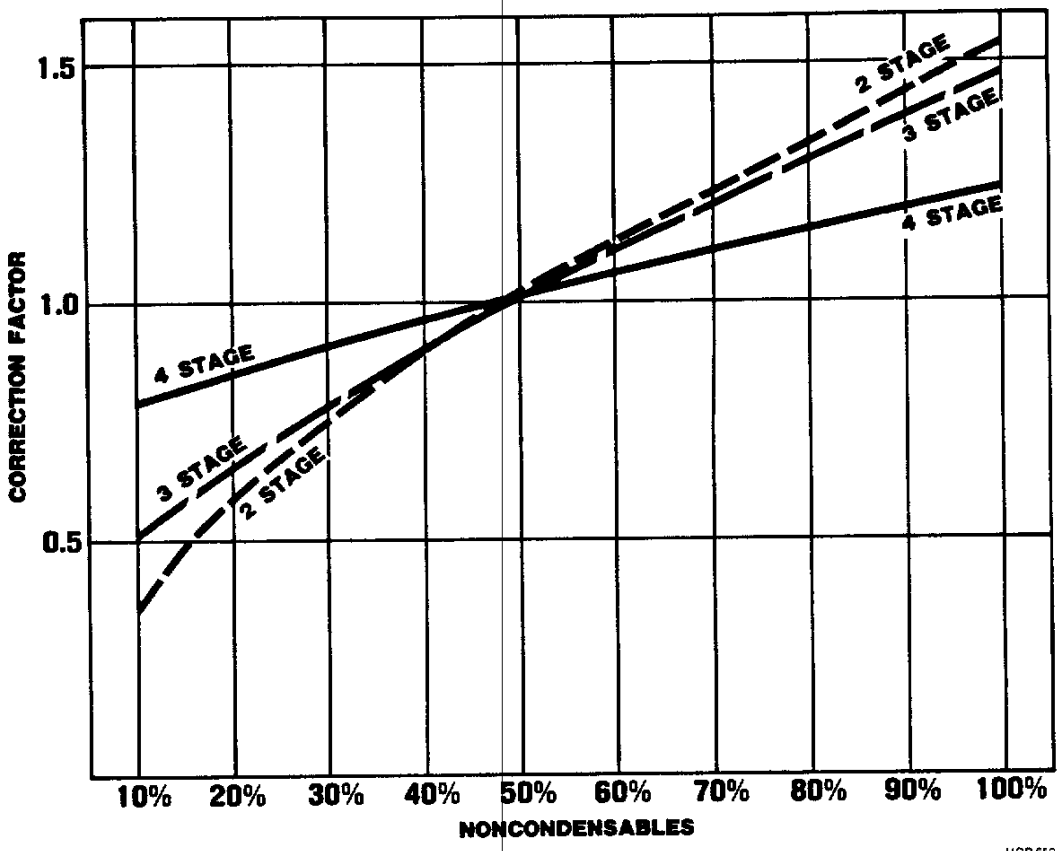
Ex
DISCH
PSI

	K = FACTOR.
14.7 → 15.2	1.0
15.7	1.02
16.7	1.04

$$GPM\ C.W = \frac{(DUTY)\ BTU/HR}{(8.33\ \#/GAL)(1.3\ BTU/\#\ ^\circ F)(60\ MIN/HR)(C.W\ RISE\ ^\circ F)\ 0.3}$$

0.3 asumo que utilizo el 80% de la elevacion de temperatura.

CORRECTION TO STEAM RATE FOR PERCENT NONCONDENSIBLES



UOP 650

STEAM JET EJECTORS

DESIGN ENGINEERING SEMINAR

M. J. WILCOX

SAMPLE PROBLEM I

INFORMATION REQUIRED

SUCTION VAPOR	MOLE WT.	#/HR
NONCONDENSABLES	30	600
STEAM	18	1000
CONDENSABLES	100	1000

INLET STEAM — 125 psig, dry & SATURATED

SUCTION TEMPERATURE — 260°F

SUCTION PRESSURE — 12 mm Hg ABSOLUTE

FROM VAPOR PRESSURE CURVE

60% OF 100 MW CONDENSED IN FIRST INTERCOND
20% OF 100 MW CONDENSED IN SECOND INTERCONDENS.
20% OF 100 MW CONDENSED IN AFTERCONDENSER

LATENT HEAT OF CONDENSABLES - 250 BTU/#

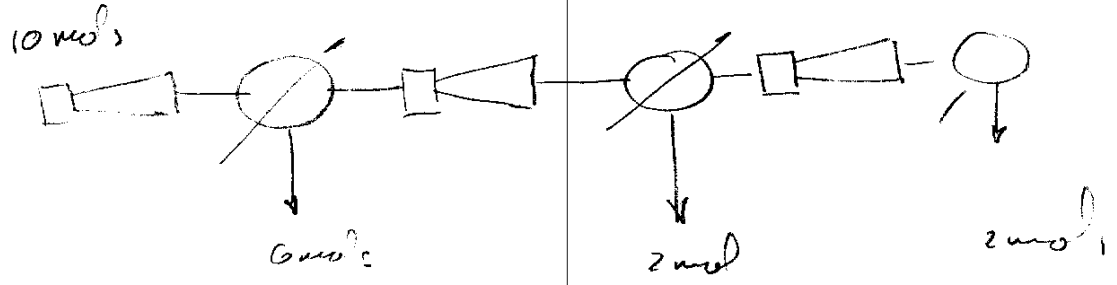
DISCHARGE PRESSURE - 1.5 PSIG = 14.7 + 1.5 = 16.2 PSIA

ELEVATION - SEA LEVEL

COOLING WATER - 90 → 120°F

1. ESTIMATE REQUIRED UTILITIES FOR A THREE STAGE TOTALLY CONDENSI SYSTEM.

2. PERFORM A "STAGE ANALYSIS" ON THE FIRST STAGE.


10 mol's
6 mol's
2 mol
2 mol

PART (I.)

AIR EQUIVALENT LOAD

1 #/HR	2 MW		3 MW CORR FIG VI PAG 32	4 TEMP CORR FIG VII PAG 23		5 * AIR EQUIV.
600	30	(NONCOND)	1.0	0.957	600x 1/1.0 x 0.95+	627
1000	18	(STEAM)	0.81	0.940		1313
1000	100	(COND)	1.50	0.957		697
						2637 #/HR

* 5 = 1/(3 x 4).

% NONCONDENSABLES = $\frac{800^*}{2600}$ = 30.8%

*600 # OF 30 MOL WT + (.20)(1000) OF 100 MW (SINCE 20% IS NONCOND IN EJECTOR

BASIC STEAM RATE (FIG IX) = 5.9 # steam / # equiv. air
PARA 12 MM DBS SUCTION PRESS

MULTIPLIER DUE TO 16.2 PSIA DISCH = 1.02 (FIG IX)
0.02 PER 1 PSI ADIABATIC
SOME 0.5 PSIG.

STEAM PRESSURE CORRECTION FACTOR = 0.92 (FIG IX)
FIG IX RECORD

NONCONDENSABLE CORRECTION FACTOR = 0.80 (FIG X)
PARA 30% NO COND Y 3 STAGES

ESTIMATED TOTAL STEAM MOTIVE LOAD = (5.9)(1.02)(0.92)(0.80)(2637) = 11680 #/HR

ESTIMATED COOLING WATER REQUIREMENT

(1193 - 78) BTU/# (11680) #/HR (MOTIVE STEAM) = 13.02 MM BTU/HR
(1178 - 78) BTU/# (1000) #/HR (LOAD STEAM) = 1.10 MM BTU/HR
(250) BTU/# (1000) #/HR (COND HEAT) = 0.25 MM BTU/HR
14.37 MM BTU/HR

GPM = (DUTY) BTU/HR / (8.33 #/GAL)(1. BTU/#°F)(60 MIN/HR)(C.W RISE °F)

$\frac{(14.37)(10^6)\ BTU/HR}{500\ (\Delta T = 20)}$ = 958 gpm COOLING WATER (THEORY)

PART (2.)

*STEAM EQUIVALENT LOAD

#/HR	MW	MW CORRECTION	TEMP. CORR	STEAM EQ.
600	30	1.25	0.967	502
1000	16	1.0	0.94	1064
1000	100	1.85	0.967	565
				2131 #/HR

SELECT FIRST STAGE DISCHARGE PRESSURE - SEE NOTE 1

→ 67 mm Hg ABS

MOTIVE TO LOAD RATIO = 1.9 (FROM ATTACHED CURVE)

STEAM PRESSURE CORRECTION FACTOR = 1.08 (FROM ATTACHED CURVE)

FIRST STAGE MOTIVE = (2131) (1.9) (1.08) = 4373 #/HR

FIRST STAGE INTERCONDENSER

INLET PRESSURE - 67 mm Hg ABS

OUTLET PRESSURE - 64 mm Hg ABS

*DIFFERENTIAL - 3 mm Hg - WHERE THE ROUTING IS SHORT AND DIRECT 5% (PRESSURE LEVEL) IS SUFFICIENT ESTIMATE FOR EXCHANGER AND PIPING DROP

*THIS EXAMPLE ILLUSTRATES A SLIGHTLY DIFFERENT APPROACH IN THAT IT USES "STEAM EQUIVALENT" RATHER THAN THE MORE USUAL "AIR EQUIVALENT"

PART (2.)

STEAM - $\frac{5373}{18}$ = 298.5

CONDENSABLES - $\frac{1000}{100}$ = 10

NONCONDENSABLES - $\frac{600}{30}$ = 20

328.5 TOTAL MOLS

PARTIAL PRESSURE OF WATER IN DISCHARGE VAPOR

$(298.5/328.5)(67)$ = 60.9 mm Hg A, 107 °F

SELECT A TEMPERATURE RISE - SEE NOTE 2

→ 12 °F

SATURATION TEMPERATURE
(OUTLET VAPOR TEMPERATURE) → 97 °F - SEE NOTE 3

REMEMBER THAT THERE ARE TWO SECTIONS TO THE INTERCONDENSER, THE MAIN OR CONDENSING SECTION WHICH THE EJECTOR DISCHARGE VAPOR CONTACTS AND PASSES THROUGH FIRST, AND THEN THE VAPOR COOLING SECTION OR SECONDARY SECTION WHERE THE 107 °F NONCONDENSABLES FROM THE INITIAL CONDENSATION ARE COOLED TO 97 °F, "WRINGING OUT" A LITTLE MORE WATER. THE COOLING WATER TO THE CONDENSER PASSES THRU THE SECONDARY SECTION FIRST SINCE THE NEED FOR THE LOWEST TEMPERATURE COOLANT IS THERE.

CALCULATE CARRYOVER

VAPOR PRESSURE OF WATER VAPOR AT 97 °F = 44.8 TORR (mm Hg ABS)
VAPOR PRESSURE OF CONDENSABLE VAPOR - UNKNOWN, [redacted]
VAPOR PRESSURE OF NONCONDENSABLE VAPOR - UNKNOWN

[redacted]

PART (2)

CARRYOVER OF CONDENSABLES = (4 MOLS)(100) = 400 #/HR OF 100 MW CARRYOVER

X = MOLS OF WATER VAPOR OUT

$$\frac{X}{44.8} = \frac{20+4}{(64-44.8)}$$

$X = 56$

(X)(18) = 1008 #/HR WATER VAPOR CARRY OVER

THEREFORE LOAD TO SECOND STAGE EJECTOR IS:

600 #/HR OF 30 MW NONCONDENSABLE VAPOR
1008 #/HR " OF WATER VAPOR
400 #/HR OF 100 MW CONDENSIBLE VAPOR

ESTIMATED HEAT REMOVED IN FIRST STAGE INTERCONDENSER IS:

(1193 - 78) BTU/# (4373) + (1178 - 78)(1000) - (1105)(1008) + (250)(1000 - 400)

$= 4.88 \times 10^6 + 1.1 \times 10^6 - 1.11 \times 10^6 + 0.15 \times 10^6 = 5.02 \times 10^6$ BTU/HR

EJECTORS

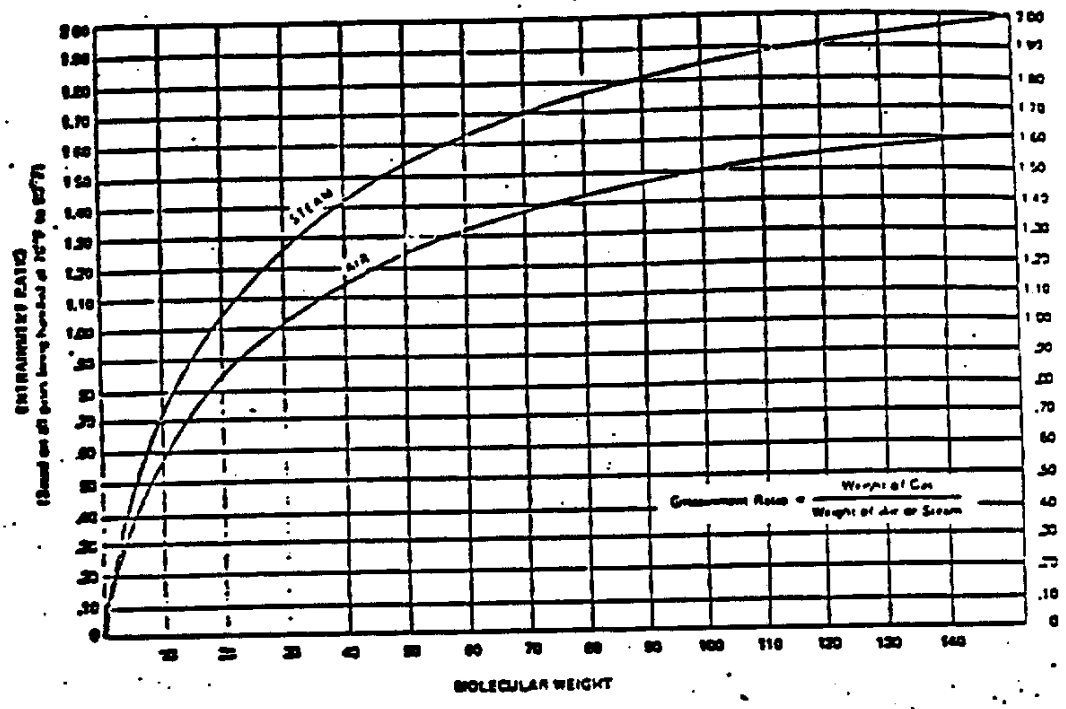
Course "Y"

NOTES

1.) Discharge pressure of ejectors which is also inlet pressure to condensers is a variable which is determined by % Non-cond., water temperature, motive to load ratio and utility values. Finding the discharge pressure is a trial and error calculation. A good starting point is to use equal compression ranges for each ejector. The best compression range for the first stage will decrease from "equal" as the % of condensables in the load increases or until the water temperature sets the lowest limit. To accurately calculate the system several discharge pressures should be tried for each ejector.

2.) Temperature rise is affected by water temperature, utility costs, allowable pressure drop, condensing temperature and other special factors such as minimum velocity. The best rise is determined by trial and error. the most economical selection is normally to use the water in series. A good starting point is to use the total allowable temperature rise divided by the number of condensers. This will be the best if the load is all noncondensable. If the load has water vapor present then the temperature rise in the first condenser will be larger. It is normally best to use all of the allowable temperature rise but if the load has a high percentage of water vapor this does not hold true.

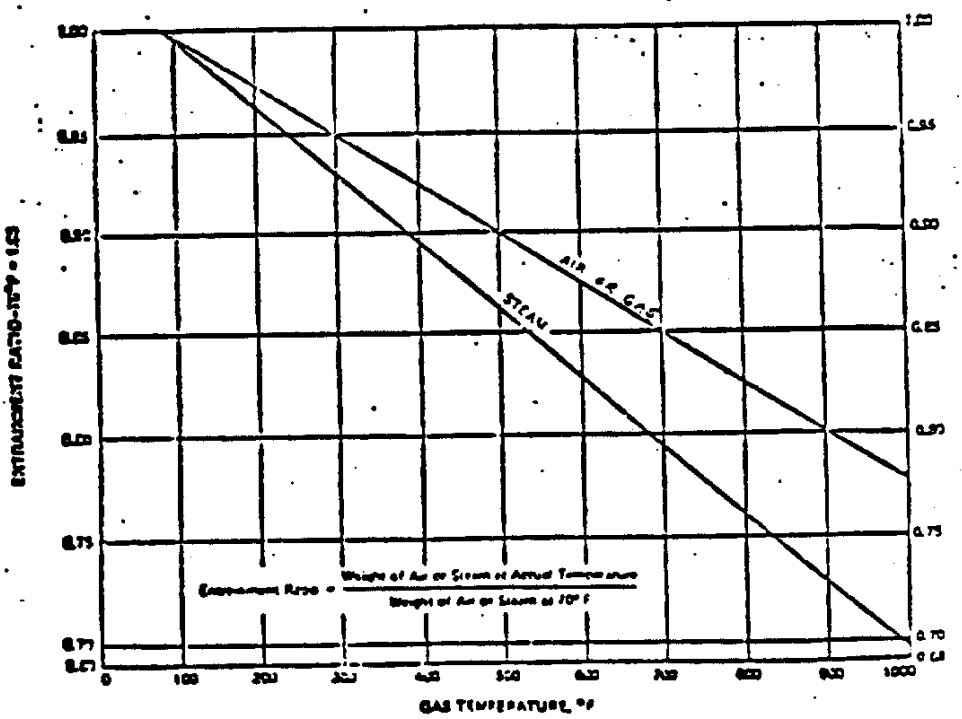
3.) Saturation Temperature. For large (26"ϕ or larger) units use (water inlet plus (0.6 x temp. rise) or 7°F. min) for units with removable bundles and use (water inlet plus (0.5 x temp. rise) or 5°F. min) for units with fixed tubesheets. For small units (under 26"ϕ) that are multi pass use same as above except use 10°F. min. approach.



Source: Heat Exchange Institute, "Standards for Steam Jet Ejectors," adapted from Figure 11.

FIGURE A-1

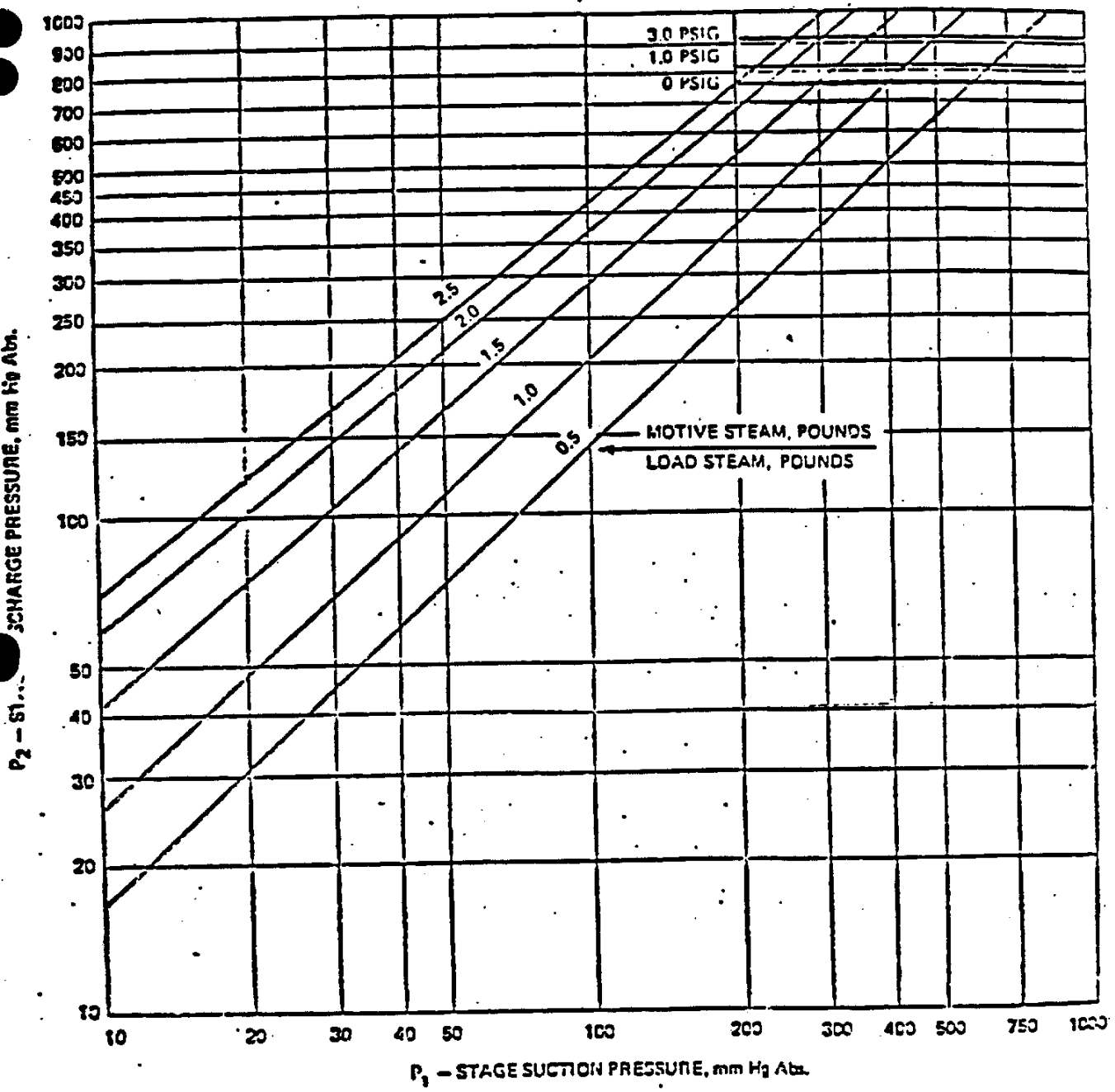
MOLECULAR WEIGHT ENTRAINMENT RATIO CURVE



Source: Heat Exchange Institute, "Standards for Steam Jet Ejectors," Figure 10.

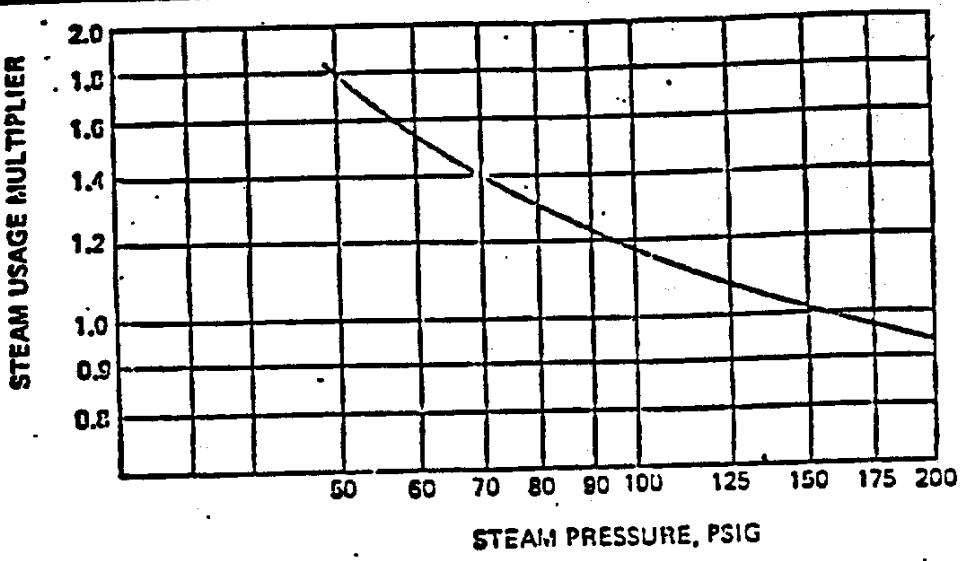
FIGURE A-2

TEMPERATURE ENTRAINMENT RATIO CURVE



SOURCE: Graham Manufacturing Co., Inc.

FIGURE A-3
EJECTOR STAGE STEAM REQUIREMENT



SOURCE: Graham Manufacturing Co., Inc.

FIGURE A-4

CORRECTION FOR MOTIVE STEAM PRESSURE

SAMPLE PROBLEM II

SUCTION VAPOR:	MW	#/HR
NONCONDENSABLES INCLUDING AIR	31	2500
STEAM	18	1500

SUCTION TEMPERATURE: 120°F

SUCTION PRESSURE REQUIRED: 30 MM HgA

ATMOSPHERIC PRESSURE: 14.7 PSIA

MOTIVE STEAM: 150 PSIG @ 416°F (50°F SUPERHEAT)

COOLING WATER: 85°F → 120°F

LAST STAGE EXHAUST PRESSURE - 1.0 PSIG (15.7 PSIA = 812 MM HgA

(1) COMPUTE EQUIVALENT AIR. (USE EQUIVALENT AIR EQUATION ON PAGE 18 AND FIGURES XI & XII.

(2) COMPUTE STEAM CONSUMPTION FOR TWO STAGE CONDENSING AND THREE STAGE CONDENSING. IF DISCHARGE PRESSURE WERE 2 PSIG INSTEAD OF 1 PSIG, WHAT WOULD ADDITIONAL STEAM CONSUMPTION BE?

(3) WHAT IS APPROXIMATE COMPRESSION RATIO PER STAGE FOR TWO AND THREE STAGE SYSTEMS WITH THE 1.0 PSIG DISCHARGE FROM THE AFTERCOOLER? (HINT: ASSUME 5% Δ P THRU INTER AND AFTER CONDENSERS AND EQUALIZE COMPRESSION RATIOS.)

(4) AN ENGINEER SUGGESTS USING A FOUR STAGE TOTALLY CONDENSING UNIT TO COMPRESS 100% STEAM FROM 10 MM HgA TO 0.5 PSIG (786 MM HgA). HIS COOLING WATER IS 120°F → 140°F. HE PLANS ON HAVING INTER-CONDENSERS AFTER EACH STAGE WITH NO AFTERCONDENSER. HIS PROPOSED DISCHARGE PRESSURES FOR EACH STAGE ARE:

1st - 30 MM HgA
2nd - 90 MM HgA
3rd - 270 MM HgA
4th - 786 MM HgA

PLEASE COMMENT ON HIS PROPOSAL.

(5) FOR THE RIGOROUS EXAMPLE I WE REVIEWED, THE CALCULATED WATER VAPOR CARRYOVER WAS DETERMINED FOR A 97°F OUTLET VAPOR TEMPERATURE. WHAT WOULD BE THE INCREASE IN THAT AMOUNT IF THE TEMPERATURE WERE INCREASED 1 F°?

I

EQUIV. AIR

#/HR	MW	MW CORR	TEMP CORR	DIR EQ.
2500	31	1.02	0.999	2453.
1500	18	0.81	0.886	2090.
				4544 #/HR.

II STEAM COMPSUMPTION

2 STAGES 30 MM Hg Δ. 3 STAGES

6.2 # STEAM/# EQ AIR 4.8 LBS VAP/# EQ AIR.

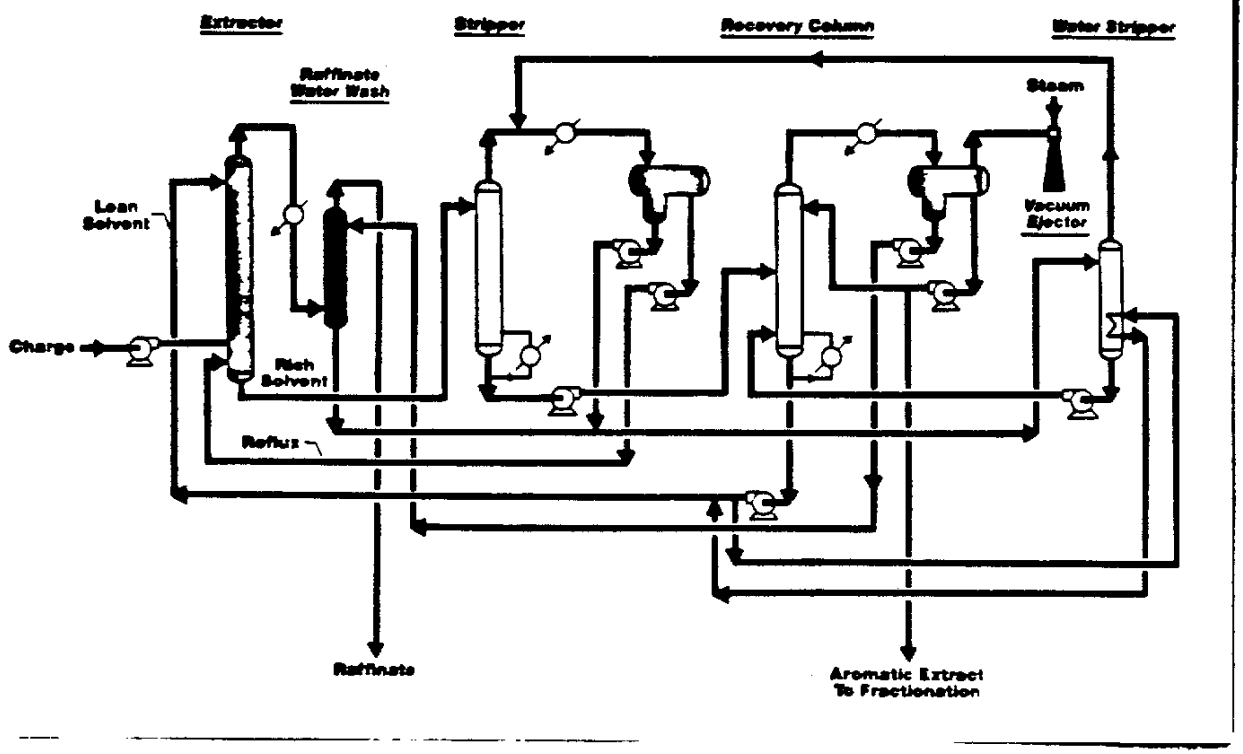
MULTIPLICATION 1.01.

STEAM PRESS CORR 0.9.

NON COND

% NO COND

COMPARISON OF STEAM JET EJECTOR VERSUS LIQUID RING VACUUM PUMP ON A SULFOLANE PROCESS UNIT



DUTY

	MOL WT	#/hour
AROMATIC HYDROCARBON VAPORS	98.7	187
AIR	29.1	150
WATER VAPOR	18.0	33

SUCTION PRESSURE	220 mm Hg Abs
SUCTION TEMPERATURE	100 °F
DISCHARGE PRESSURE	16.2 psiA (1.5 psiG)
INLET STEAM	150 psiG ($4.00 per 1000 lbs)
COOLING WATER ΔT	10 F° (5¢ per 1000 gallons)

EJECTOR SELECTION: SINGLE STAGE, CONDENSING

1. CALCULATE STEAM RATE

AIR EQUIVALENT LOAD = $\frac{187}{(0.99)(.99)} + \frac{150}{(.99)} + \frac{33}{(.81)(.99)} = 319$ #/hr (370 #/hr actual)

STEAM RATE = (BASIC STEAM RATE) x (DISCH PRESS CORR) x (STM PRESS CORR)

= (2.2) x (1.02) x (0.87) = 1.95 $\frac{\text{lbs motive stm}}{\text{lb air equiv}}$

ESTIMATED TOTAL STEAM CONSUMPTION = (1.95) (319) = 622 #/hr

COST OF STEAM PER YEAR = (622) x $\frac{\$4.00}{1000}$ x 24 x 365 = $21,800

ESTIMATED COOLING WATER CONSUMPTION = $\frac{(\sim(1195 - 68\ \text{BTU/lb})\,622 + (280\ \text{BTU/lb})(187)}{500\ (10°\ \text{rise})}$

= 150 gpm

COST OF COOLING WATER = $\frac{150 \times 60 \times 24 \times 365 \times \$.05}{1000} = \$3942$

TOTAL UTILITY COST PER YEAR = $25742

ESTIMATED TOTAL INSTALLED COST OF EJECTOR SYSTEM = $20,000

LIQUID RING VACUUM PUMP -

TOTAL MOLS per HOUR 8.88
lbs per HOUR 370

	mol%
HCBN	21.3
AIR	58.0
WATER VAPOR	20.7
mol weight	41.6

SCFM 56.3
ACFM 209

220 mm Hg A
2.63 inches Hg VAC

VACUUM PUMP SELECTION CL 302
EST. 1300 RPM
12.5 Hp
7 GPM SEAL WATER
16 GPM C.W.

ELECTRICAL COST @ 5¢/KW hr = $ 4084 per year
COOLING WATER COST @ 5¢/1000 gal = $420 / year

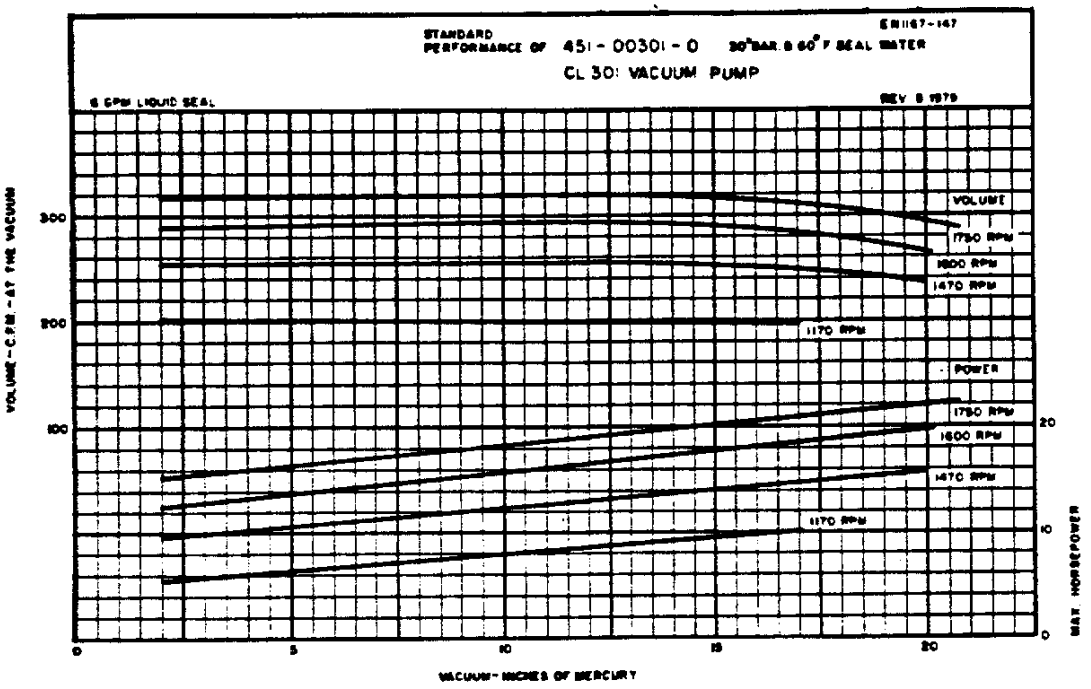
TOTAL UTILITY COST PER YEAR $4504
ESTIMATED TOTAL INSTALLED COST OF LRVP SYSTEM $20,000

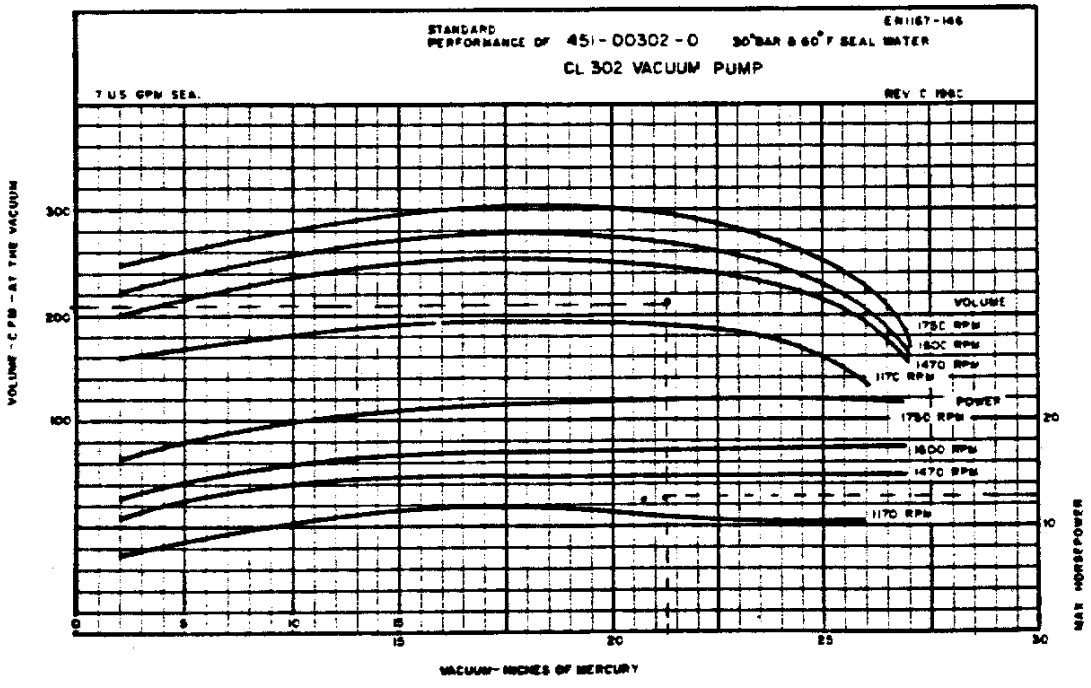
SIMPLE PAYOUT ANALYSIS

INSTALLED Δ $20,000
UTILITY Δ $2238

CONCLUSION: LRVP PAYS OUT IN 11.3 MONTHS BASED ON:
1) 5¢/KW hr 2) $4.00/1000 LB STM 3) 5¢/1000 gal cooling water 4) EST. COSTS ARE

PUMPS – SERIES 300





SAMPLE PROBLEM II

(1)

#/HR	MW	MW CORRECTION	TEMP. CORRECTION	AIR EQUIV.
2500	31	1.02	0.990	2476
1500	18	0.81	0.433	1584
				4360 #/HR

(2) BASIC STEAM RATE (FIG IX)

	2 STG	3 STG
	6.2	4.4
DISCH PRESS MULTIPLIER (FIG IX)	1.01	1.01
STEAM PRESSURE CORRECTION (FIG IX)	0.36	0.86
NONCONDENSIBLE CORRECTION (FIG X)	1.14	1.2
MOTIVE LOAD, #/HR	26767	13663
FOR 2 PSIG DISCH (102)	27302	19036

(3) FOR 15.7 psig (812 mm Hg Abs)

TWO STAGE $\sqrt[2]{852/30} = 5.33$ APPROXIMATE ΔP INTER 8 mm Hg
AFTER 40 mm Hg

BY TRIAL AND ERROR:

30 mm — 164 mm Ø — 156 mm — 852 mm Ø 812 mm

$CR_1 = 5.47$ $CR_2 = 5.46$

(3) CONT.

THREE STAGE $\sqrt[3]{662/30} = 2.85$

APPROXIMATE CONDENSER PRESSURE DROPS

1 - 5mm 2 - 13mm 3 - 40mm

BY TRIAL AND ERROR:

30mm 45mm ⌀ 90mm 264mm ⌀ 271mm 652 ⌀ 812mm

$CR_1 = 3.17$ $CR_2 = 3.16$ $CR_3 = 3.14$

(4) 100% STEAM AT A PRESSURE LEVEL OF 30 MM HgA WOULD HAVE A CONDENSING TEMPERATURE OF APPROXIMATELY 84°F. THEREFORE THE FIRST STAGE EJECTOR SHOULD BE A BOOSTER STAGE DIRECTLY COUPLED TO THE SECOND STAGE EJECTOR. [redacted]

(5) $\frac{X}{46.2} = \frac{24}{(64-46.2)}$

$X = 62.3$

(62.3 mLs)(18) = 1121 #/HR

1121 − 1008 = 113 #/HR INCREASE FOR 1 F° INCREASE!

[redacted]

FIRED HEATERS

OR

FURNACES

D.B. Gelfand

UOP DESIGN ENGINEERING SEMINAR

Autumn 1991

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I. REASON FOR DISCUSSION

A. Why do we want to discuss or talk about this equipment?

1. It is one of the most neglected pieces of equipment in a unit.
2. It is usually a piece of equipment purchased as the least cost item which probably means the most tightly designed piece of equipment.
3. It is the only place in the unit where there are exposed fires used to process flammable fluids.
4. It usually is pushed over design during operation without operator knowledge.
5. Operator judgements are frequently made with a lack of understanding.
6. Improper operation can lead to disastrous consequences.

B. Figure Ia, Ib, Ic

This heater is a two service heater, i.e. Charge service and a Fractionator Reboiler service, with an air preheat system. The fire started when tube no. 14 (hip section) of H-H2 (Reboiler) ruptured, Fig. Ia, during a start-up. The liquid drained to the floor and into the common air ducting which caused the fire to spread underneath and over the whole heater, stacks and forced-air system. The heater was essentially damaged from an explosion after the tube failure. The fire damages were minimal.

Soon after the unit was commissioned, the operating group may have assumed that the H-H2 was too large. This may have been due to an over-sight of the duty of the convection tubes. Consequently, in future start-up's, the reboiler radiant section may not have been operated while the reactor charge section was operating. Thus, the possible contaminated condensate in the

cooler H-H2 parallel radiant coil tubes vaporized, in the zones shown on sketch no. Ia, from the hot flue gases of the reactor charge coils section.

Tube wall thinning was definitely on the inside. Note sketch no. Ia "Section BB". Externally, the tubes indicated that they had never been exposed to excessive temperatures.

It was obvious that the corroded/eroded surface was caused by vapors contaminated with traces of chlorides. This was being influenced by the flue gas temperatures from the reactor charge section of the heater. The external U-bends were not attacked.

Tube material was inferior in quality making it most susceptible to even weak corrosive environments of this nature.

The unit was about 7 years old. At each shut-down it is completely steamed-out. By means of a flow sheet of the unit it was shown how small traces of chloride could reach the H-H2 coils from the stripper column, if the unit was not properly water flushed and drained before each start-up. Figures Ib and Ic are the results of this occurrence. Delay in returning the unit to operation was about one year.

C. Figure 2

A typical aftermath of a heater firebox explosion. Leaking fuel gas valves allowed an explosive build-up of gas during the purging period. The operator's torch caused ignition while three feet away from the firebox.

D. Figure 3

A typical common breeching situation. A fire which originated in the center heater damaged both of the others and severely damaged the common stack.

E. Figure 4

One result of congestion - Note the final resting place of the toppled heater stack impaled on the small tower.

F. Figure 5

The result of a tube failure in the convection section. This tube was inaccessible for inspection.

G. Figure 6a, 6b, 6c, 6d, 6e, 6f, 6g are the results of a tube rupture at high pressure. Back flow resulted in erosion of the exterior elbow. This caused most of the external damage. The fire was contained in the heater.

H. Figure 7a, 7b, 7c, 7d, 7e

Results of a tube rupture. The consequences were spectacular. The major fire was contained in the firebox and only the tube bank needed replacement.

These are just a few of the occurances that happen with this equipment. It demonstrates that more attention to the equipment and superior equipment should be considered in your units.

II. HEATER NOMENCLATURE

Figures 8 through 13 describe roughly the nomenclature used by furnace or heater designers. These are just a couple of samples but will give you an idea as to what the terms mean and location of the items so named.

III. HEATER CLASSIFICATION

A. By Service

1. No decomposition
    a. Atmospheric distillation
    b. Vacuum distillation
    c. Catalytic processes
        (1) Hydrodesulfurization
        (2) Catalytic cracking
        (3) Catalytic reforming
        (4) Other (Hydrocracking, Steam-methane, Styrene, etc.)
    d. Reboilers
    e. Miscellaneous
2. Partial conversion
    a. Thermal cracking
        (1) Single coil
        (2) Selective
    b. Continuous coking
3. Total conversion
    a. Thermal reforming
    b. Viscosity breaking
    c. Pyrolytic cracking
        (1) Light hydrocarbons

4. Combined duties in a single heater

B. Classification as to Type

1. By predominate heat transfer means

a. Convection

b. Radiant

c. Radiant - Convection

2. By general arrangement

a. Box

b. Cellular

c. Circular

IV. FUNCTION OF HEATER

A. General

Most refining processes require a source of heat to raise the temperature of the streams to be processed. More attention has developed in design of the equipment as processing has become more sophisticated.

Petroleum heaters can be divided into three main groups, according to the amount of decomposition obtained:

1. Heaters used for heating only with little or no decomposition of the processing fluid.
2. Heaters where in addition to the heating, substantially all of the processing fluid decomposition desired for the refining process is obtained in the heater.
3. Heaters where only partial decomposition is obtained in the heater, with the remainder of the reaction being carried out in the reaction chambers or soaking drums, usually not heated externally.

Heaters of the first group are designed to give maximum time-temperature effect at the highest operating temperature employed. They are used for non-destructive distillation where no chemical change of the overhead and residual products is desired, such as topping, atmospheric or vacuum distillation, rerunning, etc, or pre-reaction heating .

Heaters of the second group are designed to give maximum time temperature effect at the highest operating temperature employed. They are used with cracking units for the lighter overhead stocks where no reaction chamber is employed. These heaters are usually designed so the heating surface nearest the heater outlet is subjected to lower rates of heat input than the rest of the tube bank. This provides a reaction or "soaking" section in the heater where very little or no increase in temperature is obtained.

Heaters of the third group are the most difficult to design. They are particularly difficult for residual cracking stocks that are highly sensitive to thermal treatment. These heaters must be designed for a time-temperature effect that will permit highest coil outlet temperatures, and consequently highest reaction chamber temperatures. This is to assure effective operation of the chamber, without excessive decomposition and resultant coke deposition in the coil.

B. Historical Development

The earliest heaters for petroleum refining consisted of cylindrical shells set over a firebox, with the lower portion of the cylinder absorbing heat from the flame, the refractories and the products of combustion that swept the lower rear portion of the shell on their way to the stack.

Shell heaters were limited to low rates of heat input. This was due to a large volume of oil per unit of heat-absorbing surface and low oil velocities wwashing the surfaces. The permissible maximum was determined by the rate of free convection or convection. This rate was induced by steam jets within the body of the oil. It was still too low to permit rates much in excess of 3,000 B.t.u. per square foot per hour without over-heating the oil in contact with the heated portion of the shell.

Coke deposition and burning out of still bottoms almost invariably followed attempts to operate above these rates. The addition of internal flues to shell heaters (to simulate a fire tube boiler) materially improved their operation and increased capacity. However, shell heaters were primarily batch heaters, and continuous operation, which gradually displaced batch operation in the larger refineries, could be accomplished only by operating a battery of shell heaters in series; each shell operated at a slightly higher temperature than its predecessor. Batteries of shell heaters became too cumbersome with large scale operation in some areas.

Comparatively successful application of tubular heaters on a small scale for dehydration and refining of emulsified oils led to the gradual adoption of tubular heaters for general refining purposes. Eventually tubular heaters were substituted for shell heaters in large-scale refining operations.

The introduction of cracking contributed greatly to the development of tubular heaters. It definitively demonstrated their superiority over the shell type. Cracking called for heaters that could withstand higher pressures and higher metal temperatures than could be withstood by an externally heated shell,

The earlier tubular heaters varied little in their setting from shell heaters. The shell was displaced by a bank of tubes placed over the firebox. Average rates of 5,000 - 6,000 B.t.u. per hour per square foot were obtained. This was due to the a velocity was imparted to the oil by pumping in continuously through the tube bank. It was also due to the increase in the ratio of heating surface to volume. These earlier tubular heaters presented zones of local over-heating, or "hot spots". Actual rates of 15,000 to 20,000 B.t.u. per square foot were present in some sections of the tubes directly over the fires .

As the average rates of heat input and oil temperatures were increased, the hot spots became more pronounced and tubes failed particularly in heaters where counter-current flow of oil and gases was intended. The troubles were first attributed to radiation from the flames in the firebox. A number of tubular heaters were built with the tube bank separated from the firebox by solid or perforated walls to protect the tubes from this radiation. Greater average rates of heat input were obtained in these heaters because of more uniform heat distribution. It was soon found that even with the bank shielded from the visible flames, the tubes first coming in contact with the invisible products of combustion became easily over-heated. It was necessary to reduce the gas temperature below a certain minimum for successful operation.

Reduction of the temperature of the gases entering the tube bank was the next step in the development of tubular heaters. This was done in two different ways. In the so-called "convection" heaters, where only "fluid" heat from gases flowing over the tubes was used, the products of combustion were diluted first with excess air and later with recirculated flue gases. In this manner, the desired temperature of the gases entering the tube bank or the "heating chamber" was obtained .

In other heaters, "radiant" tubes were installed in the combustion chamber to cool the products of combustion. They absorbed radiant heat from the flame, the gases and the refractories of the combustion chamber before the gases entered the "main" or "convection" bank of the heater. The convection section was intended to supply the major portion of the total heat. It was usually separated from the combustion chamber by a refractory wall . Particular care was taken in these heaters to place the "radiant" tubes out of the path of the products of combustion. The flames or the small number of radiant tubes were shielded. This reduced the heat input rates since the tubes had been subjected to the full radiation of the combustion chamber. refractory shields cut radiant rates approximately in two.

Flue gas recirculation and the shielded "radiant tube" heaters were gradually abandoned. High maintenance and operating costs of flue gas recirculating equipment had been required. There were frequent failures of the enclosures around the tubes or the flame. These heaters were replaced with the open flame heaters whom had had comparatively satisfactory operation.

The open flame heaters did not employ flue gas recirculation. Neither the tubes nor the flames were shielded by refractory.

Improvement in heat generation and distribution and better understanding of the laws of radiant and convection heat transfer, greatly contributed to the development of open-flame heaters and their almost universal adoption for oil refining. The proportion of radiant heat input has been gradually increased from 25 per cent of the total in the early heaters to as high as 80 per cent of the total in the latest designs.

Fig. 14a A & B shows a flue gas recirculating heater of an early type widely used in petroleum refining. In this heater the fresh products of combustion generated in the combustion chamber are mixed with flue gases withdrawn from the flue to the stack by means of a flue gas recirculating fan, and distributed along the length of the heater through openings in a distributing duct.

Mechanical problems with this style of heater were numerous. There are other styles of flue gas recirculation systems that were used but time does not permit discussion.

Fig. 14a B shows an early shielded radiant heat oil heater in which a roof bank was installed to absorb sufficient radiant heat from the products of combustion before they enter the "main" or the convection bank of the heater, to permit their safe use in this bank without flue gas recirculation or high amounts of excess air. To protect the relatively small number of the tubes in the roof bank from the full radiation in the combustion chamber, the portion of the tubes over the combustion chamber where radiation was the most intense was covered with ceramic enclosures. Cast-iron enclosures were used on the portion over the main bank where radiation was

comparatively low. Comparatively high amounts of excess air (100 - 150 percent) had to be used in this heater to reduce the temperature of the gases entering the main bank, when the heater was operated at high enough capacities effectively to utilize all of the surfaces in the main bank.

Fig. 14a, C shows another type of an early shielded radiant heat oil heater where shielding enclosures or "muffles" were placed aound the flames and the products of combustion to protect from direct radiation the comparatively small amount of radiant heat-absorbing surface used. Because of the high temperature to which the enclosures were subjected and to obtain comparatively high rates of heat transfer through these enclosures to the radiant tubes, carborundum was used for the enclosures. The heater was intended for operation with low excess air to obtain high flame-burst temperatures and the highest radiation through the carborundum.

Fig. 14b, D shows an early open flame radiant heat oil heater with a much larger combustion chamber than that of the heater shown in Fig. 14a, A, and with approximately one-half of the total tube bank located along the roof of the combustion chamber to permit the use of bare radiant heating tubes and open flames.

Fig. 14b, E shows an open flame heater with radiant heat-absorbing tubes along the roof and at least two walls of the combustion chamber.

Fig. 14b, F shows a partially shielded flame heater where the muffles shield only a small portion of the flames and act more for promoting and completing combustion than as shields between the flames and the tubes. Approximately 75 percent of the total surface is exposed to radiation and the floor and the back walls of the

heater, in addition to the roof, are covered with tubes.

Fig. 14b, G shows an early down-draft heater consisting of a vertical cylindrical section with the tubes placed along the whole circumference of this section, a secondary horizontal cylindrical section with tubes located along the lower half of this section, and a convection section. No air preheater was generally used. The later design down-draft heaters consist only of a vertical cylindrical section and an air preheater.

Fig. 14c, H shows an updraft heater of the same general type as Fig. 14b, G. The convection section when used is very small, and an alloy air preheater is usually employed to reduce the temperature of the gases going to the stack.

The heaters shown on Figs. 14a, B to 14c, H inclusive represent the complete range of proportions of radiant heat-absorbing surface to total surface used. The heaters shown on Fig. 14a, B & C have too little radiant heat-absorbing surface, so that shielding of the surface was required to protect these tubes from excessive rates, overheating of the tubes, coke deposition in the tubes and their eventual burning out. The heater shown on 14c, H has too much radiant heat-absorbing surface in proportion to the furnace envelope, with the result that the effectiveness of the surface is comparatively low, unless the gases are made to wash the upper portion of the tubes to supply an appreciable amount of purely convection heat to these tubes.

Fig. 14c, I shows a heater with approximately 50 per cent of the total heat-absorbing surface located along the roof and the floor of the combustion chamber. The tube banks in the combustion chamber form approximately two-fifths of the area of the furnace envelope.

With single rows of tubes used in the combustion chamber, the optimum effectiveness of the circumferential area of tubes irradiated from one side is obtained. As a general rule, the floor tubes of the heater are the tubes of the highest rates of heat input.

Heaters shown previous to Fig. 14c, I, had fixed heat distributions and were rather inflexible as to a change in the type of service it was to perform i.e. design strictly for a certain process operation.

The heater on Fig. 14c, I can be operated to obtain a limited control changing the character of the flame and therefore the relative rates of heat input into the convection section, the roof tubes and the floor tubes of the heater. The burners fire through three compartment firing tunnels, of which the center tunnel F is the firing tunnel proper and the upper and lower tunnels A and B are for admission of secondary air to the fuel after its ignition in tunnel F. With all the air passing through compartment F as primary air, and short non-luminous flames, the rates of heat input into the floor tubes and the roof tubes near the firing wall are proportionally lower, and the rates of heat input into the convection section and the roof tubes over the bridge wall and near the back wall of the heater are proportionally higher than if only a portion of the air is sent through compartment F and the rest of the air used as secondary air through compartments A and B to produce luminous flames.

Restricting the flow of air through compartment F and admitting a large portion of the air as secondary through compartment A, produces semi-luminous flames with a hotter face toward the floor

tubes. Admitting the secondary air through compartment B gives a semi-luminous flame with a hotter face toward the roof tubes.

Fig. 14c, J shows an updraft rectangular heater in which the radiant heat absorbing surface is located along the roof and the side wall of the heater, with the tubes in the roof subject to both radiant heat and fluid heat from the gases passing to the convection section. Special tile is placed over the top row of the roof tubes to act as distributing baffles and to direct the gases at high velocities along the shielded faces of these tubes, so as to impart a high convection component to the shielded faces and partially equalize the heat pickup along the circumference of the top row of the roof tubes. The parallel flow arrangement is used for large capacities. Series flow arrangement is shown by the dashed lines.

By changing the type and rate of firing of the two sets of burners in the combustion chamber a wider variations can be obtained in this heater than in the heater shown on Fig. 14c, I. If a separating wall is installed in this heater, as shown in dotted lines, to divide the combustion chamber into practically two separate compartments a wide range of heating curves may be obtained in this heater. Because of the relative flexibility of firing, this type of heater once installed may be used without changes for a wider range of charging stocks that the heaters shown on Figs. 14a, B - 14c, I inclusive, since the heating curve in this heater may be changed to obtain the desired time-temperature effect for the stock processed.

Fig. 14c, K shows a 2-compartment heater often referred to as the double end-fired heater. In this heater the two combustion chambers

are completely separated and the floor and roof tubes of one chamber function wholly independent of those in the other chamber, providing more definite control of the heating curve than that which could be obtained in the heater shown on Fig. 14a, B - 14c, J. This heater is used with either parallel flow, as shown in solid lines, for processing two streams of oil, or with a single flow in series through both compartments, as shown in dotted lines.

In the early 1930's, UOP developed the Equiflux Heater. This development basically was due to overcome all the deficiencies of the earlier box type heaters. It was and still is the best heater for the services of that day, namely, thermal cracking and was developed for that service. Controlability of the heating curve was the main reason for its use; the one drawback was the cost of the heater as it did indeed cost more than the box type. This heater is shown as Fig. 15. The first designs were the down-fired as shown in 15A & B. Later in the 1930's, the updraft type, Fig. 15C was designed.

The cellular structure of the heaters permits the use of any number of streams with each stream subjected to the optimum thermal treatment. The cellular structure also permits maintaining the optimum dimensional relationship of the heater structure for the best gas hydraulics within the structure irrespective of the total heat requirements of the process.

The radiant tubes were spaced farther apart than in other types of heaters. The radiant tube spacing for other types of heaters was usually twice the tube outside diameter. The Equiflux Heater spaced radiant tubes on 2.6 diameters. The radiant tubes were also placed

in the middle of the firebox. This combination of wider tube spacing and a location in the center of the firing zone allowed the tubes to receive almost equal radiation around the whole circumference of the tube and hence the name, "Equiflux". There is only about 5% variation in heat input rates between the radiant tubes at the top of the furnace and those at the bottom the box type heater had about 20% variation in radiant rates.

When thermal cracking black oil, the Equiflux radiant tubes were usually designed for 15,000 Btu/Hour/external exposed sq. ft. of surface.

The Equiflux type of heater cost more than other types of heaters of similar size. The refractory (brick work) was not protected by tubes like the walls in the box type heater. Since the radiant tubes were on wider than normal spacing, less radiant surface could be installed in a given combustion space in spite of the fact that the allowable radiant heat input rates were higher. The tube supports had to be high nickel alloy and the walls had to be super-refractory firebrick.

In about 1936, Figure 16, UOP built the center wall updraft heater and shortly thereafter, the first updraft without a center wall was installed. This has many features which have been changed from the original centerwall.

The average radiant rates in the center wall updraft heater were usually 11,000 - 11,500 Btu/Hour/external exposed sq. ft. and 10,000 - 10,500 in the heater without the center wall. These floor fired types were good heaters when gas was fired but not so good for oil firing. This is one of the reasons why the updraft heater without the center wall was designed, Fig. 17. It could be fired from the

ends horizontally or vertically from floor. UOP then built a side fired center wall updraft heater and made it wider than previously. The two heaters shown above were about 10'-6" wide. The side fired heater was about 19 ft. wide and was built in about 1955.

In about 1945, Petrochem built a circular heater with vertical tubes. There was a previous heater designed by Sinclair Ref. Co. called the "De Florez Heater" but Sinclair was about the only refiner who used a circular heater in thermal cracking service. The Petrochem heater was rarely used for thermal cracking service. It was primarily used for Crude, Vacuum and Reboiler heaters. It was cheaper than most heaters, took up less space, but was less efficient thermally. The early models had fins on the upper section of the tubes and used a cone to increase the flue gas velocity.

The average heat rates in crude service were about 10,000 Btu/Hour/Sq.Ft. The center wall updraft in crude service used 11,500 - 12,000 Btu/Hour/Sq.Ft.

In about 1960, Phillips Pet. Co. built the "Selas Heater". It looks similar in shape and tube bank arrangement to the UOP updraft Equiflux. It had gas burners arranged on each side wall to control the shape of the heating curve.

The above and the better heaters are shown as Figure 18. They may be called the following although the names are not standardized:

A. End fired down-convection

B. Large double cell box-type

C. Separate-convection (Lummus)

D. A-frame (Kellogg)

E. Double upfired centerwall (UOP)

F. Floor fired horizontal (BORN)

G. Equiflux downfired (UOP)

H. Circular (De Florez)

J. Isoflow (Petrochem)

K. Isoflow (Integral tube) (Petrochem)

L. Radiant wall (Selas)

M. Inverted wicket (UOP)

There are other shapes but this is only to give a rough idea of availability.

Although all of the stills of Fig. 18 are useful for many services, there are certain features in which each excels or may be deficient.

1. Flame Impingement. Too large a flame can cause impingement or overheating of certain tubes in nearly all of the stills, but tubes that are vulnerable are those just above the bridgewall in (A) down-convection, and the lowest tubes of (E) double-upfired centerwall or (F) straight-up. The difficulty disappears in stills (F) and (E) when the capacity is large, i.e., the stills can be wider. Note the black tubes in Fig. 18.
2. Hot Tubes. The rate of heat absorption tends to be high at the entrance to the convection section because heat is delivered by both radiation and convection (black tubes in type (A), (B), (D), (E), and (F). The feed, because it is cooler, is sometimes introduced through the tubes (a screen bank), and in some instances steam is superheated or water is heated in the screen bank. Likewise, the tubes situated closest to the flame receive the largest amount of heat (Black tubes in (E), (F), (H), (K), and (M).

3. Oil Firing. Oil fuel tends to produce larger flames especially because larger burners are used. Stills (A), (B), (C), and (D) are best suited for oil firing although the larger sizes of the other stills encounter little difficulty.
4. Heat Distribution. One phase of poor heat distribution has been mentioned in item (2) above, but in addition the rate of heating varies widely in different parts of the boxes or cavities of such stills as (A) and (B), although most of the other vertical stills can attain a fairly uniform distribution of heat.
5. Two-coil Heating. Still (A) is not suited for two-coil flow although by experiment it is possible to use it for two streams. Symmetrical two-coil arrangements can be devised for most of the other stills, but if a different rate of heat input is needed in each coil, the stills with a center bridgewall are most effective.
6. Control of Rates. Stills (G) and (L) are eminently suitable for process control of the rate of heat input and for operation at exceedingly high (1000 to 1500°F) temperatures. Very low rates of heat absorption can be attained in the circular types (H), (J), and (K); and in other types if enough radiant surface is provided.
7. Capacity. Stills (A), (F), (G), (K), and (L) can be built for the lowest capacities, and types (B), (C), (D), and (E) are best suited for large capacities.
8. Stacks. Stills (A), (B), (C), and (G) require tall stacks, but scarcely any stack (except to release the gas at a high level) is needed with the other stills because the hot furnace itself produces a draft.
9. Type M is well suited for extremely low pressure drops.

Air preheat is indicated in Fig. 18-H (DeFlorez), and it can be employed in any still that is mechanically tight from gas leakage. The recirculation of flue gas through the combustion chamber by means of a fan is not indicated in any of the stills. The flue gas is reheated by the flame, causing a lower flame temperature and thus a milder radiation rate. At the same time the convection-section duty is increased, and a larger convection section must be provided. Thus, flue-gas recirculation is particularly suited to the older convection-type stills. When it is necessary to alter or regulate the rate of radiant absorption, no method other than flue gas recirculation is available except such expensive methods as the use of large amounts of excess air, a reduction in capacity, or possibly to obtain a fuel which radiates less. Flue-gas-recirculation stills were widely used during the development of thermal cracking processes; but, now the engineers know how to design stills for specific radiant-absorption rates recirculation stills are no longer installed.

V. CONSIDERATIONS IN HEATER DESIGN

A. General

The fired heaters are basically large heat exchangers. The heat input is provided by burning fuel, usually gas or oil, in the combustion chambers. Heat is transferred from the hot gas to the fluid contained in tubes. As with any heat exchanger, the rating involves a heat balance between the heat releasing and heat absorbing streams and a rate relationship. But in contrast to the usual heat exchanger, much of the heat is transferred by radiation instead of convection.

The radiant section provides space for the fuel to be completely mixed with air and burned. It contains the radiant heat absorbing tubes which remove a large percentage of the heat from the flue gas before it passes out to the convection section. The convection section recovers additional heat from the flue gas, at a lower temperature level than can be economically obtained in the radiant section. We will use the problem developed in the process design of the Crude Unit for sample calculations.

B. Modes of Heat Transfer

1. Conduction. Conduction is the transmission of heat through a material by contact between adjacent objects or molecules at different temperatures. The metallic handle of a metal pan will be too hot to touch though only the pan itself is cooking over a fire.

2. Convection. Convection is the transmission of heat between moving masses of matter or between a moving particles (flue gas for example) and a stationary mass (heater tube). Heat will flow from a high temperature body to one of lower temperature. The motion of the fluid may be due to the natural buoyancy of the heated molecules (hot air rises). This is termed free or natural convection. The motion of the fluid may be mechanically produced (as by a fan) in which case it is termed forced convection. The radiator fan on an automobie cools the radiator by convection; cooler air is forced against the hot radiator to remove heat.

3. Radiation: Radiation may be considered to be the energy transmitted in straight lines without obstruction between two or more bodies. Radiant heat travels in straight lines and may pass through a vacuum, air, some gases, some liquids, and a few solids such as glass and

quartz. Radiation is considered to be a wave phenomenon but in many instances is considered to exemplify particulate qualities as well.

Radiation is entirely different from the conduction and convection. Light is a form of radiation, but all heatradiation is not necessarily visible (light). A person can feel the heat radiation from a furnace wall or a hot piece of metal even though neither may be red hot (that is, neither is radiating light). As we sit on a beach on a sunny day, we can feel the radiant energy of the sun warming our body.

C. Radiant Section - Lobo-Evans Method

Extensive investigations have been made of the radiant heat transfer between solid surfaces in various arrangements, and between hot gases and solids. Lobo and Evans applied the basic radiation concepts to furnace design, and developed a rating method that was generally applicable without excessive complication. The method described here follows their basic pattern. It has been further simplified, however, by elimination of some minor variables and inclusion of additional general correlations.

The basis for radiant heat transfer is the Stefan-Boltzman equation. A black body at absolute temperature T radiates energy at a rate W_B, given by the relation:

$$W_B = \sigma T^4 \quad (1)$$

Where:

W_B = Radiant Energy Rate

σ = Stefan-Boltzman Constant

T = Absolute Temperature, °R

The Stefan-Boltzman constant, σ, has a value of 0.1713×10^{-8} $Btu/ft^2hr°R^4$.

For radiant heat transfer between two real surfaces at temperatures T_a and T_b, the relation becomes equation (2):

$$q_r = \sigma \alpha A F (T_a^4 - T_b^4) \qquad (2)$$

where:

q_r = Radiant Heat Transfer, Btu/Hr

A = Area, ft^2 (one of the surfaces)

F = Radiant Exchange Factor

T_a = Temp., °R of One Surface

T_b = Temp., °R of Other Surface

A is the area of either of the surfaces. F is an exchange factor which depends on the relative area and arrangement of the surfaces, and on the emissivity and absorptivity of each. Either the heat-losing or heat-absorbing surface may be used as a basis for determining q_r. However, the value of the exchange factor depends on which surface is used.

1. Equivalent Cold Plane Surface

   The heat-absorbing surface is usually well defined in a furnace. Furthermore, the rate of heat transfer per unit of absorbing area is important to the design. Therefore, it has become accepted practice to use the heat-absorbing, or "cold", surface as a basis for computing the radiant heat transfer.

   The usual heat-absorbing surface consists of a number of parallel cylindrical tubes in front of a refractory wall. Part of the radiation from the hot gas strikes the tubes directly and is absorbed. The remainder passes through to the refractory, and is reradiated back into the furnace. Again, part of the reradiated energy is absorbed by the tubes, and the remainder passes through.

This complicated situation is handled in the calculations by replacing the tube bank with an equivalent plane surface, A_{cp}. It equals the number of tubes, multiplied by their exposed length and the center-to-center spacing, Equation (3).

$$A_{cp} = N \times L \times S \qquad (3)$$

where:

A_{cp} = Cold Plane Surface (Area)

N = Number of tubes

L = Length of tubes, effective, ft

S = Center-to-center spacing, ft

The tube bank, however, will not absorb all the energy radiated to the cold plane area. The total cold plane area must be corrected by an absorption effectiveness factor, α. Hottel has published values for the factor as a function of tube arrangement and spacing. His curves for one or two rows of tubes in front of a refractory wall are reproduced in Figure 19.

The product of the actual cold-plane area and the absorption effectiveness factor, αA_{cp}, is called the equivalent cold-plane area. It is the area of an ideal black plane having the same absorbing capacity as the actual tube bank.

Equivalent Cold Plane Area = αAcp

where:

Acp = Cold Plane Surface (Area)

α = Effectiveness Factor

The shield tubes require special handling. These tubes are not backed by a reradiating refractory wall. Instead, any energy that is not directly absorbed by the shield tubes passes on to the tubes in the convection section, and is absorbed there. Therefore, from the standpoint of the radiating gas, α for the shield tubes is unity. So in calculating the total equivalent cold-plane area in a furnace, the applicable value of α is applied only to the refractory-backed tubes. The coldplane area of the shield tubes is taken at full value. It might be argued that the shieldtubes do not pick up all this heat, so the computed heat absorption in the radiant section will be too high. However, actual experience shows that because of the high gas velocities past the shield tubes, convective transfer to them is higher than to the normal radiant tubes, and more than compensates for the loss in radiant transfer. The assumption that α equals unity for these tubes is a reasonable allowance for the added convective effects, and simplifies the calculations.

2. Exchange-Factor.

The remaining term to be evaluated in Equation 2 is the exchange factor, F. First, we must account for the fact that the gas in the firebox is far from an ideal black body. The only constituents in normal flue gas that contribute significantly to the radiant emission are carbon dioxide and water. Figure 20 shows the amount of water vapor and carbon dioxide in a typical fuel oil on a wet basis. Figure 21 shows the products on a dry basis. The emissivity of a body of gas depends on concentration of each of these two components, the furnace dimensions, and the temperatures of the gas and of the absorbing

surface. Lobo and Evans have shown that the composition and dimensional effects can be accounted for by a single term, the partial pressure of carbon dioxide plus water multiplied by the mean beam length. Figure 22 shows the partial pressure, P, of the radiating components as a function of excess air for the usual hydrocarbon fuels, Table 1 gives the mean beam length, L, for various furnace shapes. It has been found that the tube wall temperature has only a minor effect. Therefore, the emissivity can be correlated as a function of the PL product and gas temperature, as shown in Figure 23. Variations in tube wall temperature between 400 and IOOO~F can be seen-by the deviation from these curves as 23a thru d.

The exchange-factor is also dependent on the amount of reradiation from exposed refractory. Energy striking such refractory is, in effect, reflected back toward the tubes. Thus a furnace with a large amount of exposed refractory will transfer more heat per unit of tube surface than one with most of the walls covered by tubes. This effect can be correlated on the basis of the ratio of exposed refractory area to equivalent cold-plane area, as shown in Figure 24. The exposed refractory area is defined as the area which would be exposed if the tube bank were replaced by the equivalent cold plane. That is, it is the total envelope area of the firebox, less the equivalent cold-plane area of all the tubes.

Figure 24 also allows for the fact that the tubes do not completely absorb all the radiant energy that strikes them. The curves are based on a tube-surface absorptivity of 0.9, which is a commonly accepted value for oxidized metal surfaces.

The working equation for calculating radiant heat transfer in the firebox thus becomes Equation (5):

$$q_{Rr} = \sigma \propto A_{cp} F (T_g^4 - T_t^4) \qquad (5)$$

q_{Rr} = Radiant heat transfer by radiation in Radiant Section.

F = Exchange Factor.

$\propto$ = Efficiency Factor (Hottel)

T_g = Flue Gas Temp., °R

T_t = Tube Wall Temp., °R

3. Convective Transfer

Although radiation accounts for most of the heat transfer in the radiant section, convection cannot be neglected. The relative amount of heat transferred by convection may be from five to twenty percent of the total radiant duty, or more, depending on the temperature level. The relation for convective heat transfer is shown as Equation (6).

$$q_{Rc} = h_{Rc} A_{Rt} (T_g - T_t) \qquad (6)$$

q_{Rc} = Heat transfer by convection in Radiant Section, Btu/Hr.

h_{Rc} = Coefficient of heat transfer by convection in Radiant Section

A_{Rt} = Tube Area in Radiant Section

Since convective heat transfer is not the major contributor, we make some simplifying approximations. For the usual furnace, h_{Rc} is about 2.0 Btu/Hr., sq. ft., °F, and A_{Rt} is about two times $\propto A_{cp}$. Making these substitutions into Equation 6, we can put it into a form similar to Equation 5 and have Equation 7.

$$q_{Rc} = h_{Rc} A_{Rt} (T_g - T_t)$$

since $h_{Rc} = \sim 2.0$ BTU/hr ft^2 °F

$$A_{Rt} = \sim 2 \propto A_{cp}$$

$$q_{Rc} = 2(2 \propto A_{cp})(T_g - T_t) = 4 \propto A_{cp}(T_g - T_t) \qquad (7)$$

4. Total Heat Transfer Rate

The total heat absorbed in the radiant section is the sum of the radiant and convective transfer.

$$q_R = q_{Rr} + q_{Rc} = \sigma \propto A_{cp} F (T_g^4 - T_t^4) + 4 \propto A_{cp} (T_g - T_t) \qquad (8)$$

dividing both side by $\propto A_{cp} F$

$$\frac{q_R}{\propto A_{cp} F} = \sigma (T_g^4 - T_t^4) + \frac{4(T_g - T_t)}{F}$$

For the usual furnace, the exchange factor, F, is approximately 0.57. Substituting into the right hand side of the above equation:

$$\frac{q_R}{\propto A_{cp} F} = \sigma (T_g^4 - T_t^4) + \frac{4}{0.57} (T_g - T_t)$$

or

$$\frac{q_R}{\propto A_{cp} F} = \sigma (T_g^4 - T_t^4) + 7.02 (T_g - T_t) \qquad (8a)$$

This relation is shown in Figures 25 a-c or Figure 28.

The distance between the tubes and the wall in a single fired heater can affect heat transfer rates. A tube placed one diameter from a reradiating wall will absorb considerably more heat than a tube contacting the wall (see Figure 25d).

The movement of gases to the walls of a furnace contact the tubes and walls. The both will be heated by convection as they are contacted by the furnace gases. The wall temperature will be increased as convective heat transfer augments radiative. The heated walls will radiate heat back to the wall side of the tubes.

Convective heat transfer to the tubes will be reduced as the distance between tube and wall is decreased; it will be more difficult for the gases to go past the tube and heat the back end. Radiant heat transfer will be reduced. Radiation reflecting and emitting from the walls will transfer heat over a full hemispherical angle. The radiant waves emanating in these directions will contact fewer tube surfaces as the tubes are placed closer to the walls. Lower heat transfer rates in the back end of the tube will result. The overall radiant heat absorption rate will decline. It will be necessary to increase the firing rate to transfer more heat to the process.

Points of maximum tube wall temperatures (TWTs) are located on the front end (side facing the burners) of the tubes. Decreased tube to wall clearances may raise TWTs to levels higher than recommended as a portion of the heat load is transferred from the back end to the front end of the radiant section tubes.

A refiner may wish to add insulation in an existing single fired heater to reduce heat losses and increase heater efficiency. The distance between tube and wall will decrease as more insulation as added to the shielded walls. This can reduce the heat absorbing capacity of the radiant section. The furnace may be forced to fire harder to increase the heat transfer rate up to previous levels. The efficiency will decrease as the fuel fired increases. Instead of increasing efficiency by limiting heat losses, the efficiency may decrease.

.....But how can we determine the Tube Wall Temperature (T_t)

ΔT Across the Tube Metal (ΔTm)

The basic relation of heat flow by conduction is Fourier's Law:

$$\frac{dq}{dA} = - K \frac{\partial T}{\partial t}$$

where A = Area of isothermal surface

t = Distance measured normally to surface

q = Rate of heat flow across surface in direction normal to surfaces

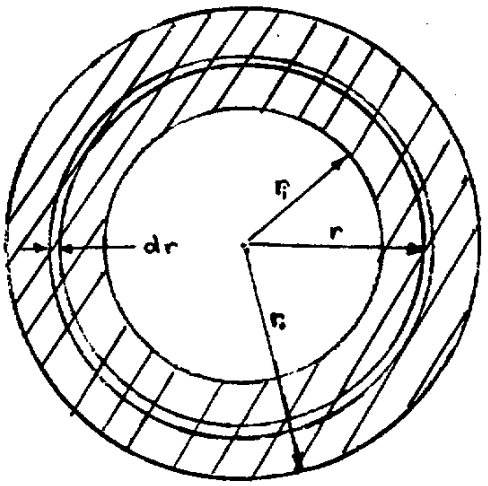
T = Temperature

K = Proportionality constant

In steady state operation, assuming K is independent of T and heat losses are negligible, we have:

$$\frac{q}{A} = - K \frac{dT}{dt} \qquad \text{or} \qquad dT = - \frac{q}{KA} \, dt$$

Let us look at heat flow through a tube:



Where r_i = inside radius

r_o = outside radius

r = radius of very thin cylinder between r_o and r_i

dr = thickness of very thin cylinder of radius r

T_i = temperature of inside surface

T_o = temperature of outside surface

L = length of tube

We will assume dr is so small when compared to the thickness of the cylinder (r) that the lines of heat flow may be considered to be parallel.

Our equation for steady conduction can be rearranged as follows:

$$\frac{q}{A} = -K\frac{dT}{dt} \qquad q = -KA\frac{dT}{dt}$$

applying this relation to our cylinder:

$$q = K(2\pi rL)\frac{dT}{dr}$$

where $A_{cyl} = 2\pi rL$

$dt = dr$

rearranging and integrating

$$\int_{r_i}^{r_o}\frac{dr}{r} = \frac{2\pi LK}{q}\int_{T_o}^{T_i} dT$$

$$\ln r_o - \ln r_i = \frac{2\pi LK}{q}(T_i - T_o)$$

$$q = \frac{K(2\pi L)(T_i - T_o)}{\ln(r_o/r_i)}$$

for convenience let's place this equation in another form for simplification

$$q = \frac{K\bar{A}_L(T_i - T_o)}{r_o - r_i}$$

in order for the equation to be correct

$$\frac{K\bar{A}_L(T_i - T_o)}{r_o - r_i} = \frac{K(2\pi L)(T_i - T_o)}{\ln(r_o/r_i)}$$

solving for $\bar{A}_L$

$$\bar{A}_L = \frac{2\pi L(r_o - r_i)}{\ln(r_o/r_i)}$$

note that the logarithmic mean radius, $\bar{r}_L = \frac{r_o - r_i}{\ln(r_o/r_i)}$

therefore $\bar{A}_L = \frac{A_o - A_i}{\ln(A_o/A_i)}$ = logarthmic mean area

rearranging our basic equation

$$\Delta T_m = Ti - To = \frac{q}{\bar{A}_L}\left(\frac{t}{K}\right)$$

where $t = r_o - r_i$

To put the heat flux, q/A in terms of the outside circumferential area, we note

$$\bar{A}_L = \frac{A_o - A_i}{\ln(A_o/A_i)} = 2\pi\bar{r}_L L = \pi \bar{D}_L L$$

where A_i = inside circumferential area
A_o = outside circumferential area
$\bar{D}_L$ = logarithmic mean diameter

since

$\bar{A}_L = \pi\bar{D}_L L$ then $\frac{\bar{A}_L}{A_o} = \frac{\bar{D}_L}{D_o}$

$A_o = \pi D_o L$

therefore $\bar{A}_L = A_o\left(\frac{\bar{D}_L}{D_o}\right)$

returning to our basic equation:

$$\Delta T_M = \frac{q}{\overline{A}_L}\left(\frac{t}{k}\right)$$

$$= \frac{q}{A_O}\left(\frac{D_O}{\overline{D}_L}\right)\left(\frac{t}{K}\right)$$

$$= \frac{q}{A_O}\left[\frac{D_O}{\frac{D_O-D_i}{\ln(D_O/D_i)}}\right]\left[\frac{(D_O-D_i)/2}{K}\right]$$

$$= \frac{q}{A_O}(D_O)\left[\ln\left(\frac{D_O}{D_i}\right)\right]\left(\frac{1}{2K}\right)$$

$$= \frac{q}{A_O}\left(\frac{D_O}{2K}\right)\left(\ln\ \frac{D_O}{D_i}\right)$$

$$\Delta T_M = \frac{q}{A_O}\left(\frac{D_O}{2K}\right)\left(\ln\ \frac{D_O}{D_i}\right)$$

ΔT Across the Inside Film (ΔT_f)

The heat transfer coefficient, h, is defined generally by the following equation:

$$h = \frac{dq/dA}{T_f - T_w}$$

Where q = rate of heat flow across surface in direction normal to surface

A = area of isothermal surface

T_f = bulk temperature of fluid

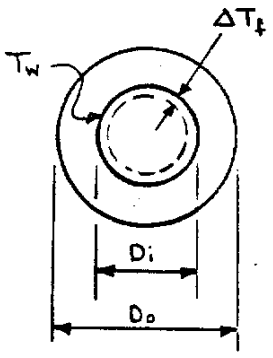
T_w = temperature at wall

Rearranging gives

$$(T-T_w) = \Delta T_f = \frac{dq}{dA}\left(\frac{1}{h}\right)$$

or

$$\Delta T_f = \frac{q}{A}\left(\frac{1}{h}\right)$$



Expressing the flux rate on an outside tube area basis and correcting the flux rate to its location on the inside tube area:

Since $\frac{Do}{Di} = \frac{Ao}{Ai}$

$$\Delta T_f = \frac{q}{Ao}\left(\frac{1}{h}\right)\left(\frac{Do}{Di}\right)$$

Tube Metal Temperature (T_t or TWT)

$$TWT = T_f + \Delta T_f + \Delta T_m$$

$$= T_f + \frac{q}{Ao}\left(\frac{1}{h}\right)\left(\frac{Do}{Di}\right) + \frac{q}{Ao}\left(\frac{Do}{2K}\right) \ln\left(\frac{Do}{Di}\right)$$

Please Note:

If there are coke deposits and scale deposits on the interior of the tube, the equation becomes:

$$TWT = T_f + \Delta T_f + \Delta T_{coke} + \Delta Tscale + \Delta T_m$$

Individual Heat Transfer Coefficients

Earlier, we touched upon the subject of heat transfer coefficients in calculating the temperature drop across the inside tube film. We should note the heat transfer coefficient is an artificial property used to determine convective heat transfer.

If a fluid in turbulent flow flows through a tube, there are three separate regions. There is a thin layer of fluid at low velocity at the wall and a turbulent region at the center of the tube. Between the two regions is a third, a transition region. The velocity gradient is largest at the wall and smallest at the tube center. The temperature gradient is affected similarly: it is large at the wall and through the viscous sublayer, in rapid change through the transition zone and small in the turbulent core.

The viscous sublayer is of primary concern with respect to heat transfer. Heat transfer through this layer may be described as approximating conduction due to its low velocities. Other fluid regions may be considered to be fairly equal in temperature as a result of rapidly moving eddy currents within them.

The overall resistance to the flow of heat is a result of the two viscous layers on either side of the tube wall and the wall itself in convective heat transfer. The overall heat transfer coefficient would best approximated by analyzing it in terms of the three aforementioned resistances. This approach requires the use of individual heat transfer coefficients for the fluid streams on either side of the wall.

Radiant heat transfer predominates in the radiant section. The outside (flue gas side) coefficient can be ignored since radiant heat transfer is predominantly a surface phenomenon. We can concentrate on the inside (in tube) film coefficient.

The individual heat transfer coefficient (individual film coefficient), h, is defined generally by the equation:

$$h = \frac{dq/dA}{T_f - T_w}$$

where:

q = Quantity of heat transferred per unit time in direction normal to surface

A = The isothermal surface area through which heat is transferred

Tf = Average fluid temperature of the stream

Tw = Temperature at the wall

The heat transfer coefficient is not a measurable quantity as is length and mass but a theoretical quantity produced empirically through experimentation. Throughout the literature, individual heat transfer coefficient correlations differ with one another considerably. One can open several engineering books only to discover each has its own correlation for a specific substance. Most employ Reynolds, Prandtl and Nusselt numbers.

We recommend the Sieder-Tate method for determining the individual inside heat transfer coefficient for all systems except hydrocarbon vapor (single phase). The Sieder-Tate equation is as follows:

$$h = \frac{K}{D}\left[\frac{CZ}{K}\right]^{1/3}\left(\frac{Z}{Zw}\right)\Phi\left(\frac{DG}{Z}\right)$$ See figure 45 for the nomenclature.

When determining the individual heat transfer coefficient in hydrocarbon vapor phase systems we use the following correlation by McAdams:

$$h = \frac{16.6\ Cp\ G^{0.8}}{D_i^{0.2}}$$

Where:

Cp = heat capacity, Btu/lb°F

G = mass velocity, lb/ft^2sec

Di = inside diameter of tube, in

Heat Distribution in the Radiant Section

Heater tubes in the radiant section of refinery furnaces do not utilize their available surface to the fullest. Picture a heater tube intersected by a plane perpendicular to the centerline of the tube. Let us center our attention on the intersection of the plane and the outside circumferential area.

Ideally at all points on this circumference, the heat flux will be equal. However, due to the geometry of the heater and the burner and wall orientation we find the circumferential flux distribution to vary considerably. Figure 25e demonstrates the radiant circumferential heat flux distribution for a heater tube receiving heat from a radiant source on one side of the tube (refractory wall on the other) and a heater tube receiving heat from radiant sources on both sides.

Diagram A of Figure 25e displays the circumferential flux distribution of a heater tube shielding a refractory wall. The area of maximum heat transfer is immediately opposite the radiating plane while the point of minimum heat transfer is 180° away, immediately opposite the refractory wall. The minimum point does not "see" the radiating plane directly and only receives radiant heat indirectly from radiant rays rebounding off the refractory walls.

Similarly, we observe the circumferential flux distribution for a tube accepting direct radiant heat on either side in diagram B of Figure 25e . The surface area is better utilized but still is not perfect. We note the direct radiation profile on either side of the tube mirrors that of the direct radiation profile of the hot side of the shielded (single fired) wall tube. The overall heat transferred would be greater in the double fired (radiating planes on both sides) tubes if we fire equivalently on both sides, each side firing at a rate equivalent to that of the single fired tube

Let us compare shielded tubes vs. double fired tubes. Let us assume the tubes are spaced on two nominal diameters, center to center. The ratio of radiant maximum flux to average will be approximately 1.90 for the former and 1.22 for the latter. This means that if we are, for some reason, limited by a certain maximum circumferential flux, a double fired tube will have an average flux rate more than 55% (1.9/1.22) greater than the single fired tube; the total surface area of the single fired tube will be capable of absorbing 55% more heat.

Increasing the distance between the tubes will decrease the maximum to average heat flux ratio. As the centerline to centerline distance increases, the ratio of the maximum to average flux will decrease. This is more pronounced in single fired tubes. With single firing, more heat is transferred to the tube by reradiation of the refractory wall as the tube spacing is increased. Although the peak will remainunchanged, the back of the tube will absorb more radiant heat. API RP 530, Recommended Practice for Calculation of Heater Tube Thickness in Petroleum Refineries, provides a graph of the ratio of the circumferential maximum to average heat flux on a tube

The discussion, so far, made no mention of the convective constituent of the overall heat transfer in the convection section. The heat distribution with the convective component further rounds out each curve, in particular, the single fired system. As we have seen before, the distance of the tube from the wall will affect the overall heat absorption of the tube.

In most furnaces, there is a longitudinal flux distribution as well as a circumferential flux distribution. Unfortunately, this variation is not as easily placed upon paper. This longitudinal variation usually rests between 1.2 and 1.5 and may vary considerably between different sections of the furnace.

API RP 530, Recommended Practice for Calculation of Heater Tube Thickness in Petroleum Refineries, provides a method for the determination of tube metal temperatures. More importantly, it also provides a method to determine required heater tube thicknesses. The equations for heater tube thickness determination are as follows:

For tube metal temperatures in the elastic (low temperature) zone -

$$t_{min} = \frac{P_E D_o}{2S_E + P_E}$$

where:

t_{min} = minimum tube wall thickness required, in

P_E = design pressure, psig

D_o = tube outside diameter, inches

S_E = elastic allowable stress at maximum tube wall temperature, psi

For tube metal temperatures in the plastic (high temperature) zone -

$$t_{min} = \frac{P_R D_o}{2S_R + P_R}$$

where:

P_R = maximum operating pressure at any normal operation condition, psig

S_R = rupture allowable stress at maximum tube wall temperature, psi

Both elastic and rupture allowable stresses at their respective temperatures are provided in API RP 530.

During the determination of the required tube wall thickness, both equations should be used. The maximum thickness calculated governs and is added to any required corrosion allowance to give the overall thickness required.

Tube thickness is described as either average wall (see ASTM Specification No. A 530) or minimum wall (see ASTM Specification No. A 450). If average wall thickness is specified, the smallest permissible thickness at any point cannot be less than 87.5% of the average (12.5% lower). If minimum wall thickness is specified, the tube wall thickness cannot be less than that specified at any point.

5. Radiant Heat Balance

To determine the temperature of the flue gas in the firebox, we must now consider the heat balance around the furnace. Heat is put into the radiant section from three sources - the net heat of combustion, q_n, the sensible heat of the combustion air, q_a, and the sensible heat of the fuel, q_f. Heat is removed in three ways: that absorbed by the tubes, q_r, the losses, q_L, and the sensible heat of the exit flue gas q_g . Expressed as Equation 9:

$$q_n + q_a + q_f = q_R + q_L + q_g \qquad (9)$$

$$q_R = q_n + q_a + q_f - q_L - q_g \qquad (10)$$

q_n = Net heat of combustion

q_a = Sensible heat of combustion air

q_f = Sensible heat of fuel

q_R = Absorbed by tubes

q_L = Losses

q_g = Sensible heat of exit flue gas

Equation 10 can be modified to a form similar to Equation 8a:

$$\frac{q_R}{\alpha AcpF} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_L}{q_n} - \frac{q_a}{q_n} \right] \frac{q_n}{\alpha AcpF} \qquad (11)$$

The net heat release q_n is established as soon as the total heater duty and efficiency are established. The values of q_a and q_f are fixed by the temperature of the fuel and combustion air. The loss q_L is usually from one to three percent of the net heat release, and can generally be estimated from past experience. This leaves q_g as the only variable on the righthand side of Equation 11. It turns out that the fraction of net heat-release retained in the flue gas is primarily a function of temperature and excess air, for all common liquid and gaseous fuels. This relation is shown in Figure 26a - d for

a typical oil. Data for sixteen fuel gases and seventeen fuel oils agree with the curves, Fig. 37, within two percent.

6. Temperatures

Figure 28 shows the rate of heat transfer between a mass of gas at one uniform temperature, and a tube surface at another uniform temperature. In most actual furnaces, however, neither of these temperatures is constant. Average effective temperatures must be selected in order to use Figure 28.

Tube wall temperature depends on the temperature of the fluid inside, the intube transfer coefficient, the thermal resistance of the tube wall, and the total heat flux. Fluid temperature can almost always be taken as the arithmetic mean of the radiant section inlet and outlet. The difference between fluid and tube wall temperatures can, if necessary, be determined from the usual intube film-coefficient correlations. Since radiant absorption rate is fairly insensitive to tube wall temperature, however, it is usually accurate enough to add IOO°F to the average fluid temperature.

The average effective gas temperature depends on the general shape of the furnace and the firing conditions. Experience has shown that for heaters of the type with an approximately square cross-section and no large areas of refractory with direct flame impingement, the average effective gas temperature is very close to that of the exit gas. For some other types, however, such as a cylindrical furnace with a high length/diameter ratio, the average effective firebox gas is appreciably hotter than the exit gas. The magnitude of this difference must be determined empirically from experience with similar designs.

7. Radiant Section Absorption

Equation 8a gives the heat transferred to the tubes in the radiant section as a function of average gas temperature. Equation 11 gives the heat removed from the flue gas as a function of exit temperature. Simultaneous solution of the two equations gives the firebox temperature and the amount of heat transferred.

The solution is most easily obtained graphically by superimposing a plot of Equation 11 on Figure 28. The value of t_g is read where the plot of Equation 11 crosses the applicable tube wall temperature. Then, from a heat balance, q_r is readily determined. Note that it is not necessary to plot Equation 11 over the full temperature range. Only that part which crosses the curves in Figure 28 is required. Furthermore, since Equation 11 is nearly linear with respect to gas temperature, two calculated points close to the intersection, joined by a straight line, are usually sufficient.

D. Convection Section

1. General

As in the radiant section, heat is transferred in the convection section by both radiation and convection. A firm basis for calculating convection-section heat transfer was first outlined by Monrad. He accounted for convection heat radiation from the gas, and radiation from the refractory walls. The method outlined here follows Monrad's theory, but with revised correlations to include later experimental results.

2. Convective Heat Transfer

The correlation offered by Monrad has been revised to include later and more extensive data for film transfer coefficients.

$$h_{Cc} = \frac{2.14\ T_f^{0.28}\ G_{max}^{0.6}}{d^{0.4}} \qquad (12)$$

where:

h_{Cc} = Convection Coefficient of Heat Transfer in the Convection Section

T_f = Temperature of film, °R

G = Mass Velocity flue gas, lbs/ft^{2}sec

d = Tube Outside Diameter, in

Figure 29 shows the convection coefficient for several common tube sizes. The average gas film temperature is defined as the average intube temperature plus one-half the log mean temperature difference from flue gas to fluid. The flue gas rate is at the minimum cross-section in the convection section. It has been found that flue gas rates for all ordinary gaseous and liquid fuels can be correlated on the basis of net heat release and percent excess air. The relation is shown in Figure 27.

3. Radiation from Flue Gas

A method for calculating the heat transfer by radiation from flue gas to a bank of tubes has been presented by Hottel. His basic relation was solved using typical tube spacing of about two tube diameters, a tube surface absorptivity of 0,9, and a typical partial pressure of carbon dioxide plus water. The results are shown on Figure 30. The average gas temperature is defined as the average intube fluid temperature plus the log mean temperature difference from the flue gas to fluid. The average tube wall temperature may be taken as average fluid temperature plus IOO°F. Radiation from Refractory Walls

Following Monrad's pattern, we express the effective coefficient for wall-to-wall transfer as a function of tube wall temperature, as shown in Figure 31. This coefficient, together with the relative wall and tube areas in the convection section, determines a correction factor, f, Equation 13:

$$f = \frac{h_{Cw}}{h_{Cc} + h_{Cr} + h_{C\,w}} \left(\frac{A_{Cw}}{A_{Ct}}\right) \qquad (13)$$

where:

h_{Cw} = Heat transfer coefficient in convection section from refractory walls

h_{Cr} = Heat transfer coefficient in convection section due to radiation

A_{Cw} = Refractory wall area per row in convection section

A_{Ct} = Bare tube area in convection section.

4. Overall Heat Transfer Coefficient

The total apparent gas film coefficient is determined from the individual coefficients by the following Equation 14:

$$hc = (1 + f)(h_{Cc} + h_{Cr}) \qquad (14)$$

The intube coefficient is calculated by standard methods, based on the flow-rate and physical properties of the fluid. The resistance of the tube wall is small, and is usually neglected. The over-all transfer coefficient in the convection section then becomes Equation 15.

$$U_C = \frac{h_C(h_{Ci})}{h_C + h_{Ci}} \qquad (15)$$

In many rating problems, particularly during preliminary work, the detailed calculations outlined above are not justified. For these cases, the curves in Figure 32 can be used. These represent overall convection section coefficients, assuming usual tube arrangements, fluid temperatures, and intube film coefficients.

If we refer to the literature on heat transfer by convection the overall heat transfer coefficient is given by the following:

$$U_o = \frac{1}{\frac{D_o}{D_i h_{di}} + \frac{D_o}{D_i h_i} + \frac{t_w}{k_m}\frac{D_i}{D_L} + \frac{1}{h_o} + \frac{1}{h_{do}}} \quad \text{or}$$

$$U_i = \frac{1}{\frac{D_i}{D_o h_{do}} + \frac{D_i}{D_o h_o} + \frac{t_w}{k_m}\frac{D_i}{D_L} + \frac{1}{h_i} + \frac{1}{h_{di}}}$$

where:

U_i = overall heat transfer coefficient based upon inside tube area

U_o = overall heat transfer coefficient based upon outside tube area

D_i = inside tube diameter

D_L = logarithmic mean tube diameter

D_o = outside tube area hdi = fouling factor for deposits on inside of tubes

h_{do} = fouling factor for deposits on outside of tubes

h_i = inside heat transfer coefficient ho = outside heat transfer coefficient

K_m = thermal conductivity of tube

t_w = tube wall thickness

If we look at this overall coefficient more closely and make the following assumptions and observations:

I) The ratio of the diameters is small and approaches unity, the overall coefficient becomes—

$$U_o = \frac{1}{\frac{1}{h_{di}} + \frac{1}{h_i} + \frac{t_w}{k_m} + \frac{1}{h_o} + \frac{1}{h_{do}}}$$

2) The resistance due to the tube wall is negligible in comparison with the other resistances -

$$U_o = \frac{1}{\frac{1}{h_{di}} + \frac{1}{h_i} + \frac{1}{h_o} + \frac{1}{h_{do}}}$$

3) Fouling is negligible —

$$U_o = \frac{1}{\frac{1}{h_i} + \frac{1}{h_o}}$$

If we multiply both the numerator and the denominator of the right hand side by ho hi, we have

$U_C = \frac{h_o(h_i)}{h_o + h_i}$ or equation (15), $U_C = \frac{h_C(h_{Ci})}{h_C + h_{Ci}}$

Ideally, this equation should be satisfactory but in cases where fouling may be substantial, we must include fouling resistances.

5. Extended Surface

Extended surface on the tubes in the convection section is often used as a means of obtaining additional heat transfer per unit of prime tube surface. Convective transfer coefficients for such tubes depend upon the exact size and arrangement, and must be determined for the particular type being considered. It should be noted that the extended surface increases only the convective transfer. Radiant transfer must be computed on the basis of prime tube surface. With most types of extended surface now being used, radiant transfer to the convection section tubes is so small that it could be neglected.

EXTENDED SURFACE

A. Finned Surface

1. History

In order to lay a foundation for our discussion, some background on the history of high temperature fin tubes will be discussed. An early method of applying extended surface to a tubular product involved cast iron rings which were shrunk to the tube in such a fashion as to transfer heat from the tube. This type of extended surface, known as "gill rings", was very expensive, extremely heavy, and has been replaced by more modern methods of attaching extended surface. Early contributions to the industry included the brazing of both longitudinal and square plate-type extended surface to tubular products. This also remained a costly and less attractive method of attachment.

At this point, two methods of attaching a spiral wound fin to a tubular product were introduced to the industry and received immediate acceptance and widespread use, One involved grooving a tubular product and rolling a smooth, continuous fin into the groove, resulting in a tight mechanical bond. The other method used cut-type fins with a rolled underfoot that was spirally wound around the tube and spot welded by resistance-welding equipment to the tubular product. At about this same time, longitudinal type fins were being attached to tubular products in the same manner as the spiral wound product. In addition to the spiral-wound type fin tubes, a "stud" type fin is also available which is resistance welded to the tube. This product has found application in vertical-type furnaces and in some

high temperature services. However, owing to its low external surface ratio, it does not compete in general applications with the spiral-wound type fins. Another spiral-wound fin tube employs a heli-arc weld at the base of the fin stock providing a continuous fillet weld.

A more recent development in spiral-wound fin tubes involves a smooth continuous fin which is tension wrapped around the tube and high-frequency welded as it is wrapped onto the tube.

The latest of the spirally wrapped fin tubes is an advancement or improvement in two previously mentioned type of tubes.

The first is a continuously welded cut type fin in lieu of the old spaced type weld. The second is a serrated high frequency welded fin tube.

B. Serrated Fins (Fig, 48)

1. Rating Instructions

All fin tube manufacturers have rating instructions. We feel that there are no short cut methods that are sound as they contain flaws and limit their scope and seriously affect their accuracy.

2. Type of weld

The most widely accepted type of weld in recent years is the continuous weld. The flange of the fin is continuously welded to the tube by a resistance weld which leaves the tube unchanged metallurgically; hence, normalizing after welding is unnecessary, regardless of alloy. The width of this weld is always greater than the thickness of the fin. This provides a broad heat transfer path from the

fin tip to the inside of the tube. If space welding is to be used, the tip of each weld should not be greater than $^1/_8$" apart.

3. Cleanability

Sootblower manufacturers have demonstrated that the serrated fin is easier to clean than the continuous fin. The space between the segments permits lateral flow of the gas during operation (as well as the steam during cleaning). This permits more effective steam cleaning. However, it appears the serrated fin will foul more rapidly than a continuous fin.

C. Solid Fin (Fig. 48)

1. Strength

A few operating companies feel that the solid fin is easier to handle and replace in the field. The continuous fin apparently slides through the tube sheets and supports easier.

2. Thicker Fins

There is a great advantage of a solid fin welded to the tube by the high frequency welding process. The fins can be made much thicker than by the standard frequency process. Fin thicknesses can reach 0.1875". By increasing the fin thickness, one raises the fin efficiency. This allows the individual to use fins at higher flue gas temperatures; at temperatures where the maximum fin tip temperature is exceeded for thinner tubes.

Recommended fin tip temperatures for a given material should not be exceeded; the fins can corrode and decay. They can lose their effectiveness.

The most commonly used materials and the maximum fin tip temperatures are as follows:

Carbon Steel	875°F
11% Chrome	1100°F
18-8	1500°F

3. Type of Weld

The base of the fin is continuously welded to the tube by a special, high frequency resistance welding process.

The width of this continuous weld will be no less than 90% of the thickness of the fin, This provide a broad heat transfer path from the fin tip to the inside of the tube. This is actually a forge type weld of the I type (no flange). There is a thickening at the base of the fin which is the fin metal.

D. Figures 49 & 50 - Tube Failures

E. Studs (Fig. 51, 52 & 53)

The studding followed essentially the same development as the finning, however, it was developed for boilers and then adapted to process heaters.

F. Calculations

1. General

In the foregoing example we will replace the bare tube convection bank with a solid fin bank that is suitable for firing fuel oil.

As the cost of fuel increases, it is increasingly important to improve the operating efficiency of refinery heating equipment. One way to improve the efficiency of fired heaters is to increase the heat recovery in the convection section by using finned tubes. In actual practice, the sample we are using would be totally redone but for now we will just substitute tube banks.

2. Rating Method

This method is basically for finned-tube convection sections. The rating problem is divided into three parts:

a. The heat transfer for flow of gases across banks of finned tubes.

b. The radiation leakage from the combustion chamber to the convection section

c. The gas pressure drop across the bank of finned tubes

The total heat transferred to the finned tubes is the radiation leakage through the shield coil (if any plus the heat transferred by convection and radiation with in the tube bank.

$$q_C = q_{SL} + U_C A_t (LMTD) \qquad (20)$$

where:

q_c = Convective heat rate, Btu/Hr

q_{SL} = Heat Rate Shield leakage, Btu/hr

U_C = Convective overall heat transfer coefficient, $Btu/Hr/ft^2/°F$

A_t = tube area, ft^2

Heat Transfer for Cross Flow of Gases

The classic reference on rating fired-heater convection sections is a paper Monrad published in 1932. In this paper, Monrad developed the relations covering heat transfer to the convection section by convection from the gases, radiation from the gases, and radiation from the refractory walls. He used convection heat transfer data for smooth tubes only. He did not consider the additional heat input due to radiation leakage from the combustion chamber when the convection section can "see" the radiant section through the shield coil.

After Monrad's paper was published, Colburn developed a more satisfactory relation for the convection coefficient.

$$\frac{h_c D_o}{k} = 0.36 \left(\frac{C_p \mu}{k}\right)^{1/3} \left(\frac{D_o G_{max}}{\mu}\right)^{0.6} \qquad (21)$$

where:

h_c = Convective Film heat transfer coefficient and BTU/hr/sq. ft. °F

D_o = Outside diameter, ft.

k = Thermal Conductivity, BTU/hr sq. ft., °F/ft.

c_p = Specific Heat, BTU/#

μ = Viscosity, Lb/ft.hr.

G = Mass Velocity, Lb/sq. ft./sec.

The constants used here are not those originally proposed by Colburn, but are revised values in accord with extensive data published later by Huge, Pierson and Tucker.

Colburn's equation and the data of Huge, Pierson and Tucker are for plain tubes. Gardner developed a general relationship for the effectiveness of a fin which can be used to compute the film coefficient for a finned tube from the coefficient for a plain tube of equal root diameter. Gardner's general relationship for rectangular cross-section, helical fins is:

$$E = \frac{\tanh (u_b)}{u_b} \qquad (22)$$

where:

E = fin efficiency

u_b = parameter determined at base of fin

$$= x\sqrt{\frac{2h_c}{kY}}$$

where:

x = fin height, ft.

Y = cross-sectional width of fin, ft.

The film coefficient for the finned tube is related to the coefficient for a plain tube by the following equation.

$$h_f = h_c\left(\frac{EA_f + A_t}{A_t}\right) \qquad (23)$$

where:

h_f = fin convective heat transfer coefficient, Btu/Hrft^2°F

A_f = Fin Area, ft^2/ Row

A_t = Total Surface Area of bare tube, ft^2/Row

The fin efficiency, E, depends on the fin dimensions, the thermal conductivity of the fins and the convective heat transfer film coefficient. In developing Equation (22), Gardner made the following assumptions:

a. The heat flow and temperature distribution throughout the fin is independent of time; i.e., heat flow is steady.
b. The fin material is homogeneous and isotropic.
c. There is no heat source in the fin itself.
d. The heat flow to or from the fin surface at any point is directly proportional to the temperature difference between the surface at that point and the surrounding fluid.
e. The thermal conductivity of the fin is constant.
f. The heat transfer coefficient is the same over the entire fin surface.
g. The temperature of the fluid surrounding the fin is uniform.
h. The temperature of the fin base is uniform.

i. The fin to tube offers no bond resistance.

j. The fin thickness is so small compared with its height that the fin width temperature gradients may be neglected.

k. The heat transferred through the outermost edge of the fin is negligible compared with that passing into the fin through the sides.

Figures 54 and 55 graphically present Equation (22) for annular fins and spines, respectively. The use of a fin efficiency factor makes Equation (23) useful for both annular fins and spines.

Monrad's basic reference for radiant heat transfer from non-luminous gases is a paper by Hottel published in 1927. Hottel has since published the material, with later data, as a chapter in McAdams' book, Heat Transmission. The apparent heat transfer coefficient for radiation from the hot gases to the convection section is

$$h_{Cr} = \frac{\sigma \left(\frac{1 + \varepsilon_t}{2}\right) (\varepsilon_g T_g^4 - \alpha_g T_t^4)}{T_g - T_t} \qquad (24)$$

where:

T_g = absolute gas temperature

T_t = absolute average tube wall temperature

α_g = gas absorptivity

ε_t = tube emissivity

ε_g = gas emissivity

σ = Stefan-Boltzman constant

To account for radiation from refractory walls to the tubes, Monrad expressed the radiant heat transmission as a fraction of the heat transferred directly to the tubes.

$$f = \frac{h_{Cw}}{h_{Cr} + h_{Cc} + h_{Cw}} \left(\frac{A_{Cw}}{A_{Ct}} \right) \qquad (25)$$

where:

A_{Ct} = Bare tube area per row

A_{Cw} = Refractory wall area per row

f = Wall radiation correction factor

Four factors must be considered in order to evaluate the heat transfer for cross flow of gases: (1) the convective heat transfer coefficient; (2) the fin efficiency; (3) the radiation from the gas; and (4) the radiation from refractory walls.

There are a number of tube arrangements possible, but for the purpose of this presentation equilateral triangular pitches of 1.5 and 2.0 times the nominal diameter of the tube are chosen as standard. Therefore, when a tube size is selected, the tube spacing is fixed by the chosen standard of tube arrangement. The tube size, the number of tubes per row, the area per row and the minimum cross-sectional area for the flue gas flow are considered in this rating presentation.

Usually, in fired-heaters, the tube size in the radiant section is the same as in the convection section, and the number of tubes per row is such that the flue gas rate is about or below 15 ft/sec. The surface area per row is the exposed area per tube times the number of tubes. The minimum cross-section area for flue gas flow is the total cross

sectional area of the convection section less the projected area of one row of tubes.

The design conditions for the convection section are set by the overall design conditions and by the radiant section rating. The flue gas rate, the stack heat content, the stack temperature and the intube fluid inlet temperature must satisfy the overall design conditions. The flue gas inlet temperature and the intube fluid outlet temperature must satisfy the over-all design conditions; and they must fit in with the radiant section rating. The design temperature data are used to calculate the log mean temperature difference, the average gas film temperature and the average gas temperature.

For simplicity, the convection coefficient correlation proposed by Colburn is used with revised coefficients based on the data of Huge, Pierson and Tucker. Equation (21) is simplified as follows, for use in computing flue gas film heat transfer coefficients:

$$h_{Cc} = \frac{2.14\, T_f^{0.28}\, G_{max}^{0.6}}{d^{0.4}} \qquad (26)$$

where:

T_f = Outside film temperature, °R

G = Flue gas mass velocity, $lb/ft^2 sec$

d = Outside diameter of tube, in

The effective heat transfer coefficient for a finned tube is given by Equation (23).

The method for calculating the amount of heat transferred by radiation from the flue gas within the convection section was presented by Hottel. For finned tubes, the gas radiation coefficient is based on the root diameter of the tube. The area used to compute the radiant heat transfer is the area of the bare tube. The basic relation for standard tube-to-tube clearances (1.5 and 2.0 diameters apart) was solved by assuming a tube surface emissivity of 0.90, and a constant partial pressure of carbon dioxide and water. The apparent heat transfer coefficient for radiation from the flue gas within the convection section is given by Equation (24). Figure 56 is a graphical solution of Equation (24). The average gas temperature is defined as the average intube temperature plus the log mean temperature difference from gas to intube fluid. The average tube wall temperature is approximately the average intube temperature plus 100°F.

Radiation from the refractory walls is still another method of transferring heat to the convection section tubes. It is assumed that the convective and radiative coefficients for heat transfer to the refractory are the same as the coefficients for heat transfer to the tubes, and any heat loss from the convection section is neglected. Monrad expressed the indirect radiant transfer as a fraction of heat transferred directly to the tubes in Equation (25). He assumed that T_w is equal to 1.25 T_t, that the tubes and walls form infinite parallel planes, and the wall emissivity is 1.0. On this basis, Equation (25) is plotted in Figure 57.

$$h_w = 9.46 \left(\frac{T_t}{1000}\right)^3 \qquad (27)$$

The overall heat transfer coefficient is calculated from the apparent gas film coefficient and the intube film coefficient. This apparent gas film coefficient is

$$h_C = (1 + f)(h_f + h_r) \qquad (28)$$

Radiation Leakage from Combustion Chamber

The Wimpress method expressed here is based upon the Lobo and Evans method for calculating the heat absorption in furnace radiant sections. It is used here to calculate the radiant heat which leaks through the shield coil into the convection section. The difference between the incident radiant energy and the direct absorption is the radiation leakage absorbed by the convection section:

$$q_{sL} = \sigma(1 - \alpha) A_{cp} F (T_g^4 - T_t^4) \qquad (29)$$

where A_{cp} is the cold plane area of the shield coil, F is the radiant exchange factor of the radiant section, T_g is the radiating temperature in the combustion chamber, T_t Is the shield coil tubewall temperature, and is a factor of comparison for direct radiation. Figure 58 is a plot of Equation (29) rearranged as:

$$\frac{q_{SL}}{(1 - \alpha) A_{cp} F} = \sigma(T_g^4 - T_t^4) \qquad (30)$$

In evaluating the shield coil leakage, the tubewall temperature at the cross-over between the convection section and the radiant section is used. Radiation leakage through the shield coil to the convection section does not occur if the convection section does not "see" the radiant section through the shield coil.

Pressure Drop Across the Bank of Finned Tubes.

Gunter and Shaw presented the normal form of the friction factor for a specific tube bank as:

$$f = \Delta P\left(\frac{2g_c\rho_g}{(G_{max})^2}\right)\left(\frac{\mu}{\mu_w}\right)^{0.14}\left(\frac{D_v}{S_T}\right)^{-0.4}\left(\frac{S_L}{S_T}\right)^{-0.6} \qquad (31)$$

ΔP = Pressure Drop, inches H_20

g_c = Gravitational constant, 32.17 lb_m ft/lb_f sec^2

ρ_g = Density of gas, lbs/ft^3

D_v = Volumetric hydraulic diameter, ft

$$= \frac{4(\text{Net Free Volume})}{\text{Friction Surface}}$$

L = Mean length of radiant beam, ft

μ = Flue Gas Viscosity, lb/ft hr

μ_w = Flue gas viscosity at tube wall, lb/ft hr

S_T = Transverse pitch, center-to-center distance from one tube to another in the same row, ft.

S_L = Longitudinal pitch, center-to-center distance from tube in one row to the tube in the next row, ft.

Equation (31) is based on the intensive data of Seider and Scott, Huge and Pierson. The viscosity ratio to the 0.14 power is approximately 1.0. Therefore, for equilateral spacing, S_L equals S_T. Then:

$$\Delta P = \left(\frac{f(G_{max})^2 L}{2g_c\rho_g D_v}\right)\left(\frac{D_v}{S_T}\right)^{0.4} \qquad (32)$$

Now, combining the constants together and converting the pressure drop into inches of water:

$$\Delta P = 0.003\left(\frac{f(G_{max})^2 L}{\rho_g D_v}\right)\left(\frac{D_v}{S_T}\right)^{0.4} \qquad (33)$$

The friction factor, f, is plotted as a function of the Reynold's number in Figure 59.

Determine the size of a convection bank required to transfer 23.4×10^6 BTU/Hr from flue gases to a process coil.

1) Use 2 bare rows of shield tubes at the bottom of the convection section.
2) Remaining tubes are finned with 1" high, 2 fins per inch of 0.05" thick carbon steel fins.

PROCESS CONDITIONS:

98,640 Lb/Hr flue gases in at 1610°F, out at 483°F

Process fluid in at 380°F, out at 483°F

$hi = 100 \frac{BTU}{Hr\ Ft^2\ °F}$

use 6, 4.5" O.D. tubes per row, 8" center to center spacing, triangular pitch, effective length = 38.5 ft.

Convection bank width = 52"

Firing occurs at 25% excess air at the rate of 97.5×10^6 BTU/hr. Assume there are 6,4" (4.5" O.D.) tubes in the shield row atop the radiant section. Center to center tube spacing is 8" and each tube has an effective length of 38.5'. The radiant section has an exchange factor equal to 0.635.

Recommended Method

Let the 2 bottom convection rows be bare and the remaining rows shall be finned as in 2).

A) Calculate the radiation leakage through the shield tubes:

Shield row in radiation section -

$$Acp = \frac{6 \text{ tubes } (8 \text{ in. C to C}) (38.5\text{ft})}{12 \text{ in/ft}} = 154 \text{ ft}^2$$

$$\frac{C \text{ to } C}{D_o} = \frac{8}{4.5} = 1.78; \alpha = 0.74$$

$$(1 - \alpha)AcpF = (1 - 0.74)(154)(0.635) \quad \text{exchange}$$

$$= 25.4 \text{ ft}^2$$

Assuming TWT = 483 + 100 = 583°F (from Figure 6, Schweppe and Torrijos) Figure 58:

$$\frac{q_{SL}}{(1 - \alpha)AcpF} = 29600 \frac{\text{BTU}}{\text{ft}^2\text{hr}} \quad \text{Fig. 58}$$

$$q_{SL} = 29600(25.4) = 0.75 \times 10^6 \text{ BTU/hr}$$

B) Determine the flue gas temperature to the first row of bare tubes (correcting the flue gas enthalpy for the loss of radiant heat through the shield tubes).

$$\frac{\text{Heat content of flue gas}}{\text{Net heat release}} \text{ @ } 1610°F + 25\% \text{ excess air}$$

$$= 0.45 - \frac{0.75 \times 10^6}{97.5 \times 10^6} = 0.45 - \frac{q_{SL}}{q_n}$$

$$= 0.44$$

From Figure 37 (Wimpress, Figure 7):

$$T = 1585°F$$

C) Determine convective heat transfer to the 2 bare rows:

Gross width = = 52
Projected width = 6 (4.5) = 27
Free width = 25" = 2.08'

$$\text{Mass velocity} = \frac{98640}{3600(38.5)(2.08)} = 0.342 \ \frac{\text{lb}}{\text{ft}^2\text{sec}}$$

$$\text{Surface} = A_t = \frac{\pi(4.5)(38.5)(6)}{12} = 272 \ \text{ft}^2/\text{row}$$

1) Assume convective heat transfer = 6×10^6 BTU/hr Gas

a) Calculate flue gas T leaving 2nd bare row:

$$\frac{\text{Heat content of flue gas}}{\text{Net heat release}} = 0.45 - \frac{(0.75 + 6.00) \times 10^6}{97.5 \times 10^6} = 0.38$$

flue gas T out = 1398°F, Figure 37

b) Calculate fluid temperature in:

$$T_{fl.in} = 483 - \frac{(6 + 0.75)}{23.4}(483 - 380) = 453°F$$

c) Temperature Difference:

hot = 1585 − 483 = 1102 cold = 1398 − 453 = 945

$$\text{LMTD} = \frac{1102 - 945}{\text{Ln } \frac{1102}{945}} = 1021.5$$

d) Average Temperatures

Oil = (483 + 453)/2 = 468
Tube Wall = 468 + 100 = 568
Gas = 468 + 1022 = 1490
Gas Film = 468 + 1022/2 = 979

e) Calculate surface required

$$h_{cc} = \frac{2.14 \ (979 + 460)^{0.28}(0.342)^{0.6}}{4.5^{0.4}} = 4.72$$ CONVECTIVE COEF

$h_{cr} = 2.93$ From Figure 56 (Figure 10, Wimpress and Fig. 2, S & T)

$$h_{cw} = 9.46\left[\frac{(568 + 460)}{1000}\right]^3 = 10.28$$ WALL COEFFICIENT

$$\text{Wall Area} = 2\left(\frac{8}{12}\right)(0.866)(38.5) = 44.45 \ \text{ft}^2$$

CORR FOR BARE CLO

$$f = \frac{10.28}{4.72 + 10.28 + 2.93}\left(\frac{44.45}{272}\right) = 0.0984$$

$$h_c = (1 + 0.0984)(4.72 + 2.93) = 8.40$$

$$U_c = \frac{8.40(100)}{8.40 + 100} = 7.75$$

$\frac{h_o h_u'}{h_o + h_u'}$

$$\text{Surface Area Required} = \frac{6 \times 10^6}{7.75(1021.5)} = 758$$

$$\text{No. of rows} = \frac{758}{272} = 2.79 \quad - \quad \underline{\text{Too High}}$$

Lower estimate of heat absorption

2) Assume convective heat transfer = 4.45×10^6 BTU/HR

a) Calculate Flue Gas T leaving 2nd bare row:

$$\frac{\text{Heat Content of Flue Gas}}{\text{Net Heat Release}} = 0.45 - \frac{(4.45 + 0.75) \times 10^6}{97.5 \times 10^6} = 0.40$$

flue gas T out = 1445°, Figure 37

b) Calculate Fluid Temperature in

$$T_{fl.in} = 483 - \frac{(4.45 + .75)}{23.4}(483 - 380) = 460$$

c) Temperature Differences

hot = 1585 − 483 = 1102 cold = 1445 − 460 = 985 $\quad LMTD = \frac{1102 - 985}{\ln \frac{1102}{985}} = 1042$

d) Average Temperatures

Oil	= (460 + 483)/2	= 472
Tube Wall	= 472 + 100	= 572
Gas	= 472 + 1042	= 1514
Gas Film	= 472 + 1042/2	= 993

e) Calculate Surface Required

$$h_{cc} = \frac{2.14\,(993 + 460)^{0.28}(.342)^{0.6}}{4.5^{0.4}} = 4.73$$

h_{cr} = 3.05 (Fig. 10, Wimpress or Fig. 4, S&T), Figure 56

$$h_{cw} = 9.46 \left[\frac{(572 + 460)}{1000}\right]^3 = \underline{10.40}$$

$$f = \frac{10.40}{4.73 + 10.40 + 3.05} \left(\frac{44.45}{272}\right) = 0.0935$$

$$h_c = (1 + 0.0935)(4.73 + 3.05) = 8.51$$

$$U_c = \frac{8.51\ (100)}{8.51 + 100} = 7.84$$

$$\text{Surface Area Required} = \frac{4.45 \times 10^6}{7.84(1042)} = \underline{544.7}$$

$$\text{No. of Rows Required} = \frac{544.7}{272} = \underline{2.003} - \text{O.K.}$$

D) Determine the remaining number of finned rows required using 1" high, 0.05" thick carbon steel fins, 2 fins per inch.

Gross Width = = 52"
Projected Width = $6[4.5 + 2(.05)(1)(2)]$ = 28.2"
D_6 2. 23.8" = 1.98'

$$\text{Mass Velocity} = \frac{98640}{3600(38.5)(1.98)} = 0.359\ \frac{lb}{ft^2 sec}$$

$$\text{Surface of Fins} = \frac{\pi}{4}\left[\frac{6.5^2 - 4.5^2}{144}\right](2)(2)(12)(38.5)(6)$$

$$= 1390\ ft^2/row$$

Temperature Differences:

$$\text{hot} = \begin{array}{r} 1445 \\ -460 \\ \hline 985 \end{array} \quad \text{cold} = \begin{array}{r} 820 \\ -380 \\ \hline 440 \end{array} \quad \text{LMTD} = \frac{985 - 440}{\ln \frac{985}{440}} = 675$$

Average Temperatures:

Oil	= (460 + 380)/2	= 420
Tube Wall	= 420 + 100	= 520
Gas	= 420 + 675	= 1095
Gas Film	= 420 + 675/2	= 757

$$h_{cc} = \frac{2.14(757 + 460)^{0.28}(0.359)^{0.6}}{4.5^{0.4}} = 4.64$$

fin efficiency:

$$X\sqrt{\frac{2h}{kY}} = \frac{1}{12}\sqrt{\frac{2(4.64)}{31(0.05/12)}} = 0.705$$

$$\frac{d_f}{d_o} = \frac{6.5}{4.5} = 1.445$$

From Figure 54 (Figure 2, Schweppe & Torrijos):

Efficiency = 0.84

$$h_f = 4.64\left[\frac{0.84(1390) + 272}{272}\right] = 24.56$$

h_{cr} = 2.07 Figure 56 (Fig. 10, Wimpress or Fig. 4, S & T)

$$h_{cw} = 9.46\left[\frac{(520 + 460)}{1000}\right]^3 = 8.90$$

$$f = \frac{8.90}{24.56 + 8.90 + 2.07}\left(\frac{44.45}{272}\right) = 0.0409$$

$$h_c = (1 + 0.0409)(24.56 + 2.07) = 27.72$$

$$U_c = \frac{27.72(100)}{27.72 + 100} = 21.70$$

Surface Area Required:

$$A = \frac{[23.4 - (4.45 + 0.75)] \times 10^6}{21.70(677)} = 1239$$

No. of finned rows = $\frac{1239}{272} = 4.55$ Use 5 finned rows

E. Stack Design

1. General

In a natural-draft heater, the stack must create sufficient draft to overcome frictional drop through the burners, the convection section, the damper, and the stack.

2. Burners

Pressure drop across the burners is often required to draw in secondary air. Its magnitude is usually set by the burner manufacturer, and depends on the type of burner and the fuel. A normal value is about 0.25 inch of water.

3. Convection Section

The pressure drop across bare horizontal tubes in the convection section, is about one-half velocity-head per row. The velocity-head in inches of water is given by the following.

$$P_v = \left(\frac{V^2}{2g}\right)\left(\frac{\rho_g}{\rho_w}\right)(12) = 0.0030\ V^2\ (\rho_g) = .003\ \frac{G^2}{\rho_g} \qquad (16)$$

V^2 = Velocity, ft/sec.

g = Gravitational constant, 32.17 ft/sec^2

ρ_g = Density of flue gas, lbs/cu.ft.

ρ_w = Density of water, lbs/cu.ft.

Flue gas densities are shown in Figure 33. In the convection section, the gas density is evaluated at the same average gas temperature that was used to calculate the convection section transfer coefficient.

4. Stack and Damper

The various remaining losses are expressed in terms of velocity-head in the stack.

Stack entrance	0.5 velocity-heads	H, Height, Ft.
Damper	1.5	D, Diameter, Ft.
Stack friction	H/50D	
Stack exit	1.0	
TOTAL	3.0 plus H/50D	

Equation 16 and Figure 33 are used to calculate the velocity-head, just as for the convection section.

5. Draft

The draft effect depends on the difference in density between the hot flue gas and the surrounding air.

$$\Delta P = H\left(\frac{\rho_a - \rho_g}{\rho_w}\right) \quad (12) = 0.187H(\rho_a - \rho_g) \qquad (17)$$

Available draft per 100 feet of height is shown in Figure 34. To allow for heat loss from the stack, its draft should be computed on the basis of a temperature 100°F lower than that of the flue gas leaving the convection section.

6. Furnace Pressure

It is usually desirable for all sections of the heater to be below atmospheric pressure. Then any leaks through peep-holes, tube-openings, or cracks in the setting will be outside air moving in, rather than hot flue gas moving out. In heaters with tall radiant sections, such as vertical cylindrical types, the firebox alone may develop more draft than is required by the burners. In such cases, the stack height must be increased as necessary to maintain sub-atmospheric pressure at the convection section inlet.

7. Stack Size

In many installations, minimum stack heights are set by fume dispersal requirements, particularly if there are tall structures nearby. If such is the case, the stack is sized so that the

total friction drop is no greater than the available draft. If there are no such outside limitations, the most economical combination of diameter and height can be selected. Usual designs have flue gas velocities in the stack of about 25 - 30 feet per second.

F. Furnace Rating Procedure

1. General

We now come to the problem of applying the principles outlined above to a specific furnace design. The following paragraphs describe general concepts that are normally used, and present the outline of a procedure that has been found to require a minimum of trial and error computation.

2. Basic Design Considerations

The function of a process furnace is to heat a prescribed amount of some material from one temperature to another, using a particular fuel. In addition to this requirement, other limitations are generally imposed. Some are needed to fit additional process requirements, and others are set on the basis of past experience. The usual restrictions are discussed in the following paragraphs.

Over-all furnace efficiency determines the basic operating cost of the heater. The optimum efficiency for a particular application depends on a number of factors, such as the cost of fuel, the temperature of the fluid being heated, the type of tube material required, and the user's policy on investment payout. For process heaters without air preheat, over-all efficiencies are usually in the 70 to 80 percent range, based on net heating value.

Table II shows furnace efficiencies based on fuel oil and exit flue gas temperatures. Each fuel will have its

own efficiency chart, however, variations are not extreme and this chart is sufficient for fuel oil firing. Another general curve for estimating efficiency for design or analysis is shown as Figure 35. Each fuel has its own characteristics and to be truly correct a curve should be developed for your fuel.

Excess combustion air has a significant effect on efficiency. In general, the lower the excess air, the smaller the heater for a specific job. However, too little excess air can cause operating difficulties from incomplete combustion, poor flame characteristics, and erratic control. Usual excess air rates are 15 to 25 percent for gas-firing and 25 to 40 percent for oil.

The maximum absorption rate in the radiant section is usually specified by the user on the basis of past experience. High radiant rates generally result in smaller, less expensive heaters. Lower rates give lower tube wall and refractory temperature, thus tending toward lower maintenance. Normal design figures for clean service with with good intube transfer coefficients are in the range of 10,000 to 15,000 Btu per hour per square foot of tube surface.

Maximum heat release per unit firebox volume may be specified. Unit heat release is a rough measure of the probability of flame impingement on the tubes. However, current practice is to judge the possibility of flame

impingement from the furnace shape and the type of burner, rather than to set an arbitrary heat release limit.

Maximum pressure drop of the process fluid is usually dictated by the user. This places some restrictions on the tube size and number of parallel passes.

3. Preliminary Design Steps

Before starting the detailed rating, certain aspects of the design can be established from the process requirements and the other limitations described above. First, calculate the net heat release, using the specified absorption duty and efficiency.

Then select an excess air percentage and determine the flue gas rate from Figure 27 or 26c & d.

Normal heaters will handle about 70 percent of the total duty in the radiant section. On this basis, estimate the radiant heat absorption q_R. From enthalpy or specific heat data for the process fluid, estimate the temperature at the crossover between the convection and radiant sections, and the average fluid temperature in the radiant section. Add 100°F to the average fluid temperature to get the average tube wall temperature. Using the specified allowable radiant transfer rate, calculate the total radiant tube surface.

The convection bare tube surface is usually about equal to that in the radiant section. On this basis, select a tube size and pass arrangement that will give the required total surface and meet the specified pressure drop limitation.

4. Radiant Section Rating

Choose a center-to-center spacing for the radiant tubes which is compatible with the selected tube size. Wide tube spacing permits high radiant absorption rates with relatively low firebox temperatures, and gives good circumferential heat distribution. Closer spacing permits more tubes to be installed in a given size firebox. The usual spacing is about twice the nominal pipe size, for example, 8 inch spacing for 4 inch (4.5 inch O.D.) tubes.

Using the approximate radiant tube surface determined above, choose firebox dimensions that will accommodate the required total tube length. The exact proportions depend on judgment and past experience. Long furnaces minimize the number of return bends required, thus decreasing total cost. Shorter and wider fireboxes, on the other hand, usually give more uniform heat distribution and lessen the probability of flame impingement on the tube surface.

For the selected firebox dimensions, calculate the equivalent cold-plane surface, the effective refractory surface, and the mean beam length. Read the partial pressure of carbon dioxide plus water from Figure 22 and calculate the PL product.

If preheated air or fuel is used, calculate the heat content of each stream above 60°F, and its ratio to the total net heat release. The heat content of any of these streams below 100°F can usually be neglected. Estimate the heat loss through the setting.

Assume a value for the average temperature of the flue gas in the radiant section, t_{g_2}. At this temperature, read the gas

emissivity from Figure 23c & d, and then the exchanger from Figure 24. Calculate the ratio $q_n/\alpha A_{cp}F$.

If the furnace design is one for which experience has shown a significant difference between average effective gas temperature and exit temperature, apply the appropriate factor to correct the exit temperature t_{g2}. Read the corresponding value of q_{g2}/q_n from Figure 37. Then, using Equation 10, calculate $q_R/\alpha A_{cp}F$ and plot it against average furnace temperature on Figure 28.

If the assumed value of t_g was correct, the computed point will be on the absorption curve for the average tube wall temperature. Usually, of course, there will be a discrepancy. Then select another value of t_g on the other side of the absorption curve, and repeat the above procedure. When two points on opposite sides of the curve are obtained, join them by a straight line. The point of intersection of this line with the absorption curve is the correct firebox temperature. For this temperature, calculate t_{g2}, read q_{g2}/q_n from Figure 37, and calculate q_R from Equation 9. This is the heat actually absorbed in the radiant section.

It is now necessary to check the computed radiant absorption to be sure it meets the design limitations. First, divide the heat absorption by the total exposed tube area to get the average heat flux. If it is higher than the allowable maximum, a new furnace with more tube surface must be selected, and the rating repeated. If the actual heat flux is considerably below the allowable value, a smaller furnace should be considered. Then, from enthalpy data on the process fluid, calculate the crossover

temperature from convection to radiant section. If the computed temperature is significantly different from that assumed in starting the rating, it may be necessary to go back and repeat with a new value of average tube wall temperature. Tube wall temperature, however, has such a small effect on the radiant absorption rate that such refinement is usually unnecessary.

There is one point to watch in regard to the cross-over temperature. The fluid temperature determined as described above corresponds to the transition from true convection tubes to shield tubes. Many heaters include the shield tubes as part of the convection section, and the crossover piping is actually between the shield and radiant tubes. For such cases, the temperature in the crossover piping will be higher than that calculated in the rating, by an amount corresponding to heat absorption in the shield tubes.

5. Convection Section Rating

The convection section must pick up the difference between the heat absorbed in the radiant section and the total heater duty. The temperatures of the flue gas entering the convection section and the process fluid leaving it have already been calculated as part of the radiant section rating. The incoming fluid temperature is set by the original design conditions. The flue gas temperature going to the stack is determined by an over-all heat balance and Figure 37.

$$q_n + q_a + q_f = q_L + (q_R + q_c) + q_s \qquad (18)$$

$$\frac{q_s}{q_n} = 1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_L}{q_n} - \frac{(q_R + q_c)}{q_n}$$

Using these temperatures, calculate the average fluid temperature, the log mean temperature difference, the average gas temperature, and the average gas-film temperature.

Select a convection tube arrangement that will give a maximum flue gas mass-velocity of about 0.3 to 0.4 pounds per square foot per second. Calculate the mass-velocity G. For precise ratings, calculate the gas-film coefficient using Figures 29, 30 and 31, and Equations 13 and 14. Calculate the intube coefficient using any applicable method. Then calculate the over-all transfer coefficient from Equation 15. For less critical ratings, read the over-all design coefficient from Figure 32. In either case, finally determine the convection area from the usual heat-transfer equation

$$A_c = \frac{q_c}{U_c (LMTD)} \qquad (19)$$

The calculated convection surface will usually not correspond to an integral number of tube rows. In many cases, the computed surface is simply rounded up to an even number of tube rows, and the excess considered as a margin of safety. If a more exact rating is desired, however, it is necessary to assume a new over-all efficiency and repeat the entire rating. The results can then be interpolated to the desired number of tubes.

Finally, calculate the flue gas pressure drop through the convection section, using Equation 16. Evaluate the flue gas density at the same average temperature that was used in calculating the transfer coefficients.

6. Stack Design

The stack must provide enough draft to hold the firebox at a negative pressure, and to overcome frictional losses through the convection section and stack. First, calculate the draft caused by the firebox itself. Determine whether the limiting factor is pressure drop across the burners or the necessity of maintaining negative pressure throughout the firebox.

Assume a stack temperature 100°F lower than the flue gas leaving the convection section. Select a stack diameter to give a stack velocity of about 25 to 30 feet per second, and calculate the velocity head. Estimate the stack height, and calculate the friction loss through it, allowing 1.5 velocity heads for the inlet and exit losses, 1.5 velocity heads for the damper, and 1 velocity head for each 50 diameters of stack height.

Read the stack draft per 100 feet from Figure 34. Calculate the draft that the stack must produce, and the required height. If additional height is required for fume dispersal, the stack diameter may be reduced.

TABLE 3 - Altitude Correction Factors for Gas-Density and Draft

Altitude Above Sea Level	Multiple Density And Draft By
0	1.000
1000	0.964
2000	0.930
3000	0.896
4000	0.863
5000	0.832
6000	0.801
7000	0.772
8000	0.743

VI. SAMPLE CALCULATIONS

To better understand the foregoing discussion, we will do a sample problem. I have chosen that which was developed in your Crude Unit process heat and weight balance. The data from the heat and weight balance is as shown on Figure 38a and the flash curve as Figure 38b. There really isn't much information in the attached data so that we will generate data to try to match or come close to that given. A UOP 9.6 profile was used and we obtained the following curves, Figure 40a and Figure 40b.

Check Ht. Content

Assume 180 psig pressure drop

at outlet

T_o = 685°F P_o = 15 psig H_o = 438 Btu/Lb.

at inlet

T_i = 490°F P_i = 195 psig H_i = 245 Btu/Lb.

H Btu/Lb 193 Btu/Lb.

Duty = 1.240.000 x 193 = 239.32 x 10^6 Btu/Hr.

$\approx$ 237.92 (Figure 38a)

Vaporization at outlet = 68%

Process Specs $\approx$ 55

We will use the higher vapor point as it will be safer from pressure drop considerations.

We have decided that we would use the heater structure similar to that shown on Figure 42. It also is necessary to decide on a radiant heat transfer rate and as a guide we will use the number from Table 4 Figure 43 for Crude service of 12,000 Btu/Hr/Sq.Ft.

We will burn fuel oil so that we must establish an efficiency on the basis of the inlet fluid temperature. From Figure 39 or Figures 35 or 36 with a bare tube convection bank we obtain the following assuming a 300°F approach temperature between the exit flue gas and the inlet fluid temperature with 30% excess air.

Gross Heater Efficiency = 71.25%

Net Heater Efficiency = 76.25%

$$\text{Net Heat Release} = \frac{239.32 \times 10^6}{.7625} = 313.86 \times 10^6 \text{ Btu/Hr}$$

From Figure 27 there are 1,080 Lbs. flue gas/MM Btu Net Release

Actually, rather than using a general chart, a chart similar to that shown as Figure 41 should be used for your specific fuel. It is developed quite easily and it should be done. We will use the general correlation of Figure 27.

Total Flue Gas =

1080 x 313.86 = 338,971 Lbs/Hr

= 94.2 Lbs/Sec.

Radiant Section

Assume that the radiant section will absorb 70% of the total absorption required.

Radiant Duty = .7 x 239.32 x 10^6 = 167.52 x 10^6 Btu/Hr.

With 12,000 Btu/Hr/Sq.Ft., the radiant surface required = $\frac{167.52 \times 10^6}{12{,}000 \text{ (Table 4)}}$

= 13,960 Sq. Ft. From Table 5, Figure 44 we will select 6" I.P.S. Schedule 40 thickness, then the number of passes required at approximately 3 ft/sec. cold velocity would be $\frac{99{,}900 \text{ B/D}}{1{,}000 \times 8 \text{ passes}}$ x .31 = 3.8 ft/sec.

It would be too complicated to use more passes in this style of box we have chosen. A recommended velocity for this service is about 3.5 ft/sec.

Surface per foot of tube (Table 5) = 1.734 Sq.Ft./Ft.

Length of tubing required = $\frac{13,960}{1.734}$ = 8051 ft.

Assume tube length of 60 ft.,

then No. tubes required = $\frac{8051}{60}$ = 134.2 tubes

tubes/pass = $\frac{134.2}{8}$ = 16.8 say 17 tubes/pass

We normally use 50 equivalent diameters for a return bend (Table 5).

Equivalent length per tube = 60 + 25.3 = 85.3 ft.

Equivalent length per pass = 1450.1 ft.

G = Mass velocity = $\frac{1,240,000 \text{ Lbs/Hr}}{3,600 \times 8 \times 0.2008}$ = 214.4 lbs/sec. sq.ft.

satisfactory - not less than 150

Cross Over Temperature

Now let us estimate the crossover temperature accordingly with the following procedure:

Outlet conditions: 685°F & 15 psig ⟶ H = 438 Btu/Lb

Crossover conditions:

$$\Delta H_{co} = \frac{\text{Radiation section heat absorbed, Btu/Hr}}{\text{Fluid heated, lb/hr}}$$

$$\Delta H_{co} = \frac{167.52 \text{ MM Btu/Hr}}{1.24 \text{ MM Lb/Hr}} = 135 \text{ Btu/Lb}$$

$$\Delta H_{co} = H_o - H_{co} \qquad H_{co} = H_o - \Delta H_{co}$$

$$H_{co} = 438 - 135 = 303 \text{ Btu/Lb}$$

Pressure assumed = 140 psig, so T_{co} = 554°F (Fig. 40a)

Estimated Pressure Drop

$$\frac{\Delta P}{100'} = \frac{.517\ f\ G^2}{ID \times \rho}$$

f = 0.004 for this service

ID = 6.065 in. (pipe size ID)

G = 214.42 lb/sec. sq.ft.

ρ = @ Process Conditions

$$\rho = \frac{1}{S.V} = \frac{1}{1.8}\ ft^3/lb$$

then:

$$\frac{\Delta P}{100'} \text{ @ outlet cond.} = \frac{(.517)(.004)(214.42)^2}{(6.065)\left(\frac{1}{1.8}\right)}$$

$$= (15.6765)(1.8) = 28.22\#/100'$$

$$\frac{\Delta P}{100'} \text{ @ crossover cond.} = (15.6765)(S.V \text{ @ Cross over cond.})$$

specific volume = .125 @ P_{co} = 140 PSIG & T_{co} = 554°F

$$\frac{\Delta P}{100'} \text{ @ crossover cond.} = (15.6765)(.125) = 1.96\#/100'$$

$$LM\Delta P = \frac{28.22 - 1.96}{\ln \frac{28.22}{1.96}} = \frac{26.26}{\ln 14.4} = \frac{26.26}{2.6672} = 9.846\#/100'$$

Pressure calculated = $\frac{9.846\#}{100'} \times 1450.1' = 142.8\#$ vs. 140.0#

Accepted deviation: 10 - 20%

T_{co} = cross over temperature = 554°F

Average fluid temp. = $\frac{T_{co} + T_o}{2} = \frac{554 + 685}{2} = \frac{1239}{2} \approx 620°F$

Tube Wall Temperature Check

Now let us estimate the tube wall temperature by means of Sieder & Tate equation as follows:

$$h = \frac{K}{D}\left(\frac{CZ}{K}\right)^{1/3}\left(\frac{Z}{Z_w}\right)^{0.14} \cdot \phi\left(\frac{DG}{Z}\right)$$

h = Film Coeff. Btu/Hr/Sq.Ft./°F

K = Film thermal conduct. Btu/Hr/Sq.Ft./(°F/Ft)

L = Heated tube length, ft.

D = Inside tube diameter, inches

Z_w = Absolute viscosity, centipoises at average tube wall temperature

G = Mass velocity, lb/sec/sq.ft.

C = Specific heat of fluid at average fluid temp., Btu/Lb/°F

Z = Absolute viscosity, centipoises at average temperature of fluid

Crude oil properties will be determined at an average temperature of 620°F.

Crude properties: API 34.8 Charact. factor 11.9

K = 0.0654

L = 1450.1 ft.

D = 6 in. (6.065 I.D.)

$(Z/Z_w)^{.14} \approx 1.0$

Z = .3 Centistokes @ 620°F

G = 214.42

C = 0.76 x 1.005 = .7638

Corrected by UOP K factor accordingly to UOP Chart F-1

($Z = Z_{cp}/S.G.$ ∴ $Z_{cp} = (Z)(S.G) = (.3)(.625)$

S.G. @ 620°F = .625 from UOP PD-194

$$\text{Modified Reynolds Number} = \frac{DG}{Z} = \frac{(6)(214.42)}{(.1875)} = 6861$$

$$\text{From Fig. 45: } \phi\left(\frac{DG}{Z}\right) = 22{,}000$$

From Equation 1:

$$h = \frac{(.0654)}{(6)}\left[\frac{(.7638)(.1875)}{(.0654)}\right]^{1/3}(1)^{.14}(22{,}000) = 239.8\,[2.1898]^{1/3}$$

$$H = (239.8)(1.3) = \underline{311.74}$$

The temperature difference through the oil film for a clean tube, is:

$$\Delta T_{film} = 12000\left(\frac{6.625}{6.065}\right)\frac{1}{311.74} = 42.0$$

The temperature difference through the tube wall, is:

$$\Delta T_{metal} = 12000\left[\frac{6.625}{2(190)}\right]\ln\left(\frac{6.625}{6.065}\right) = 18.5$$

$$\text{Total } \Delta T = \Delta T_{film} + \Delta T_{metal} = 42 + 18.5 = 60.5$$

$$\text{Average Tube Wall Temperature} = \frac{554 + 685}{2} + 60.5 = 680^{\circ}F$$

Radiation Section Lay-Out

The lay-out of the heater is shown on Fig. 42 and 46. The heater dimensions are: 32.5 feet wide by 33 feet high.

Total number of tubes: 136

Tube Long Overall: 60 ft.

Exposed Length: 58.5 ft. (1.5 ft available for support and bank)

Center-Center distance: 1 ft.

Shield Tubes: 8

Number of Passes: 8

Space between the Wall and the Tube: One Tube Diameter

Burners to tube clearance: 5' Minimum

Permissible temperature difference between leaving streams: 30-40°F

Firebox Temperature Calculation

Surface per tube = 58.5 ft/tube x 1.734 sq. ft/ft = 101.44 sq. ft./tube

Total Surface = 136 tubes x 101.44 sq. ft./tube = 13796 sq. ft.

Spacing ratio - center-center distance/O.D. = 12/6.625 = 1.8

Effectiveness factor, α = .92 (Fig. 19)

Shield tubes, A_{cps} = exposed length/tube x No. of tubes x center-center distance.

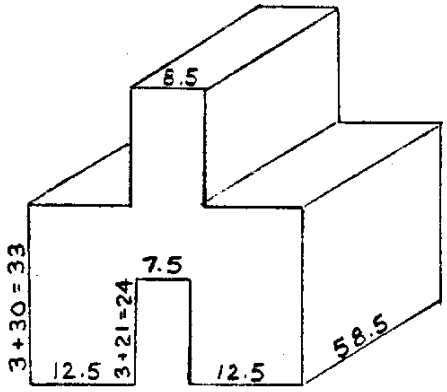
= 58.5 ft/tube x 8 tubes x 1 ft = 468 sq. ft.

Wall tubes, A_{cpw} = 58.5 ft/tube x 128 tubes x 1 ft = 7488 sq. ft.

Total Wall Tubes = $\alpha A_{cps} + \alpha A_{cpw}$ = Total equivalent cold plane surface

= (1) (468) + (.92)(7488) = 468 + 6889 = 7357 (α for shield tubes is consider unity.)

Envelope area = 2 (32.5) (33) + 2 (58.5) (33) + 2 (58.5) (32.5)



+ 2 (58.5) (24) - 8.5 (58.5) - 2 (7.5) (24)

= 11759 sq. ft.

A_R = Refractory area = Envelope area - Total equivalent cold plane surface

= 11759 - 7357 = 4402 sq. ft.

$\frac{A_R}{A_{cp}} = \frac{4402}{7357} = 0.598$

Dimensions each side = 12.5:33:58.5 = 1:2.64:4.68

L = Mean Beam Length = $\frac{1.3 + 1.8}{2}$ (Smallest dimension)

= 1.55 (12.5) = 19.38

P = Partial Pressure CO_2 + H_2O = 0.225 Figure 22 @ 30% E.A.

PL = 0.225 (19.38) = 4.36 atm. ft.

Let us assume for the heater operation there is no preheated air or fuel,

so $q_a = q_f = 0$.

Total average loss = q_L/q_n = 0.02

Estimated average firebox temperature = 1500°F

Flame emissivity: For T_G = 1500°F & PL = 4.36 atm. ft.

Tube Metal Temp., °F	P_F
600	.545
680	.543
800	.542

By interpolation from Fig. 23a - d

Exchange factor, $F = 0.607$ at $P_F = .543$ & $A_R/\alpha A_{cpt} = 0.598$ (Fig. 24)

$$\alpha A_{cpt} F = (7357)(0.607) = 4466 \text{ sq. ft.}$$

$$q_n/\alpha A_{cpt} F = \frac{313.86 \text{ MM BTU/hr}}{4466 \text{ sq. ft.}} = 70282 \text{ BTU/hr sq. ft.}$$

For this type of furnace, assume that the exit gas temperature is the same as for the average firebox temperature, i.e. like a well-stirred fire box.

Then $t_{g2} = t_g = 1500°F$

$q_{g2}/q_n = .43$ Fig. 37 @ 30% E.A.

$$\frac{q_R}{\alpha A_{cpt} F} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_{g2}}{q_n} - \frac{q_L}{q_n}\right]\left[\frac{q_n}{\alpha A_{cpt} F}\right]$$

$$= [1 + 0 + 0 - .43 - 0.02]\ 70282$$

$$= (.55)(70282) = 38655 \text{ BTU/hr sq. ft.}$$

If we plot the calculated $q_R/\alpha A_{cpt} F$ of 38655 at the assumed firebox temperature of 1500°F, the point lies to the left of the absorption curve (Fig. 25b).

So, let us try another calculation at 1750°F emissivity, by interpolation @ 30% E.A.

$T = 1750°F$ & $PL = 4.36$ atm. ft.

Tube Metal Temp., °F	P_F
600	.525
680	.521
800	.520

Exchange factor, $F = 0.588$ at $P_F = .521$ & $A_R/A_{cpt} = 0.598$

$$\alpha A_{cpt} F = (0.588)(7357) = 4326 \text{ sq. ft.}$$

$$q_n/\alpha A_{cpt} F = \frac{313.86 \text{ MM BTU/hr}}{4326 \text{ sq. ft.}} = 72553 \text{ BTU/hr sq. ft.}$$

$$q_{g2}/q_n = .52$$

$$q_R/(\alpha A_{cpt} F) = (1 - 0.02 - .52)\ 72553 = 33375 \text{ BTU/hr sq. ft.}$$

Plotting this point on Fig. 25b and joining the two calculated points by a straight line, it crosses the absorption curve at 1621°F. This is the firebox box temperature.

Now, again from Fig. 37:

$q_g/q_n = 0.47$

$q_R = (1 - 0.02 - 0.47)\ (313.86) = 160.07 \times 10^6$ Btu/hr

$$q_r/A_{Rt} = \frac{160.07 \times 10^6 \text{Btu/hr}}{13796\ \text{ft}^2} = 11603\ \text{BTU/hr ft}^2$$

The obtained heat flux is just below the allowable value of 12,000 -- now check the crossover temperature of the oil.

$$\text{Enthalpy change} = \frac{160.07 \times 10^6 \text{Btu/hr}}{1240000\ \text{lb/hr}} = 129\ \text{BTU/lb}$$

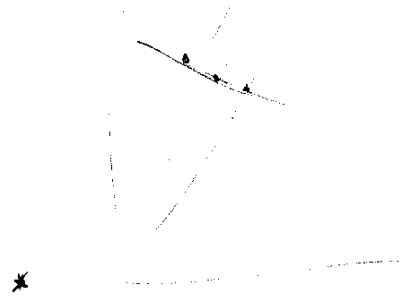
$H_{co} = H_o - H_{co} = 438 - 129 = 309$ BTU/lb

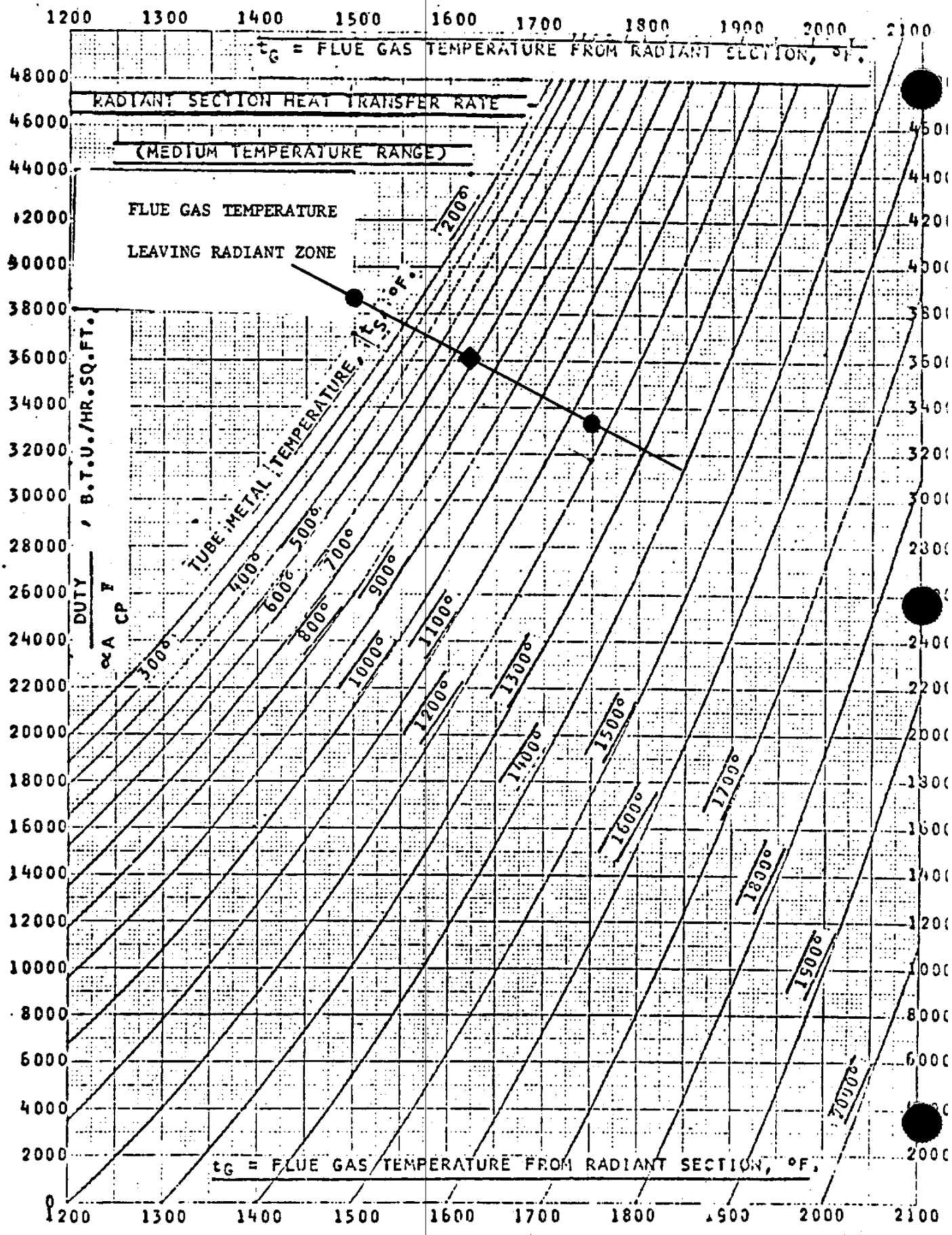
Crossover temperature = 558°F vs ~554°F (Assumed) - Fig. 40a

Average radiant fluid temperature = 558 + 685 = 621°F vs. 620°F (O.K.)

Average Tube Wall = 621 + 60.5 = 681°F vs. 680°F

Calculated values are so close to assumptions no further correction is necessary.




RADIANT SECTION HEAT TRANSFER RATE
(MEDIUM TEMPERATURE RANGE)
FLUE GAS TEMPERATURE LEAVING RADIANT ZONE
t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
t_S = TUBE METAL TEMPERATURE, °F.
DUTY / α A CP, B.T.U./HR.SQ.FT.
200° 300° 400° 500° 600° 700° 800° 900° 1000° 1100° 1200° 1300° 1400° 1500° 1600° 1700° 1800° 1900° 2000°
48000 46000 44000 42000 40000 38000 36000 34000 32000 30000 28000 26000 24000 22000 20000 18000 16000 14000 12000 10000 8000 6000 4000 2000 0
1200 1300 1400 1500 1600 1700 1800 1900 2000 2100

Convection Section Design

Heat Absorbed

Convection section duty = heater duty - radiant section duty

Convection section duty = 239.32 - 160.07 = 79.25 x 10^6 Btu/hr

$$\frac{\text{Stack Heat Content}}{\text{Heat Release}} = \frac{q_s}{q_n} = 1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \left(\frac{q_R + q_C}{q_n}\right) - \frac{q_L}{q_n}$$

$$= 1 + 0 + 0 - 0.763 - 0.02 = 0.217$$

@ $\frac{q_s}{q_n}$ = 0.217 and 30% excess air:

Stack Temperature = 830°F (Figure 37)

Radiation Losses Through the Shield Tubes

$(1 - \alpha)\ A_{cp}F = (1 - 0.76)\ (468)\ (0.598) = 67.2\ ft^2$

where F = 0.598 is determined by interpolation at our firebox temperature at 1621°F.

From Fig. 58 and TWT_{est} = 558 + 60 = 618

$$\frac{q_{SL}}{(1 - \alpha)A_{cp}F} = 30500\ \text{Btu/ft}^2\text{hr}$$

q_{SL} = 30500 (67.2) = 2.05 x 10^6 Btu/Hr

Determing flue gas temperature to the convection section

$$\frac{\text{Heat Content of Firebox Gases}}{\text{Net Heat Release}} \text{ @ } 1621°F = 0.47 \quad \text{(Figure 37)}$$

$$\frac{\text{Heat Content of Flue Gas to Conv. Section}}{\text{Net Heat Release}} = 0.47 - \frac{2.05 \times 10^6}{313.86 \times 10^6} = 0.46$$

From Fig. 37:

Flue gas temperature to the convection section tubes = 1597°F

Temperatures

Temperature Differences:

ΔT Hot Side= $T_g - T_{co}$ = 1597 - 558 = 1039°F

ΔT Cold Side = $T_s - T_i$ = 830 - 490 = 340°F

$$\text{Log Mean Temp} = \frac{\Delta T_{\text{hot side}} - \Delta T_{\text{cold side}}}{\ln \frac{\Delta T_{\text{hot side}}}{\Delta T_{\text{cold side}}}} = \frac{1039-340}{\ln \frac{1039}{340}} = 626$$

Average Temperatures:

$$\text{Oil Average Intube Fluid} = \frac{T_{hi} + T_{co}}{2} = \frac{490 + 558}{2} = 524$$

Tube Wall = Oil Average Intube Fluid + 100 = 524 + 100 = 624°F

Gas = Oil Average Intube Fluid+ Log Mean Temp. = 524 + 626 = 1150°F

Gas Film = Oil Average Intube Fluid + 1/2 Log Mean Temp. = 524 + 1/2 (626) = 837°F

Convection Section Lay-out

Let us select a convection section with eight 6.625 in. O.D. tubes per row,12 inches spacing, staggered on an equilateral triangular pitch:

Gross width = (No. tubes/row + 1/2 tube/row) x tube spacing, in.

= (8 + 1/2) x 12 = 102 inches

Free Width = Gross width - tube wall plane

= 102 - (8 x 6) = 54 inches = 4.5 ft.

Free width area = Free width x exposed tube length = 4.5 x 58.5 = 263.25 ft^2

$$\text{Flue Gas Mass Velocity} = G = \frac{\text{Total Flue Gas Mass}}{\text{Free Width Area}}$$

$$= \frac{94.2 \text{ lb/sec}}{263.25 \text{ ft}^2} = 0.356 \text{ lb/ft}^2\text{sec}$$

(Typical permissible maximum flue gas mass velocity for natural draft operation ~ 0.5 lb/ft^2sec. Velocity is governed by convection bank pressure differential and stack temperature among other factors)

Film Transfer Correlation

For G = .356; 6-5/8" O.D. & Gas Film Temp. = 837°F From Fig. 29

or $h_{cc} = \frac{2.14\ (T_f)^{0.28}\ (G_{max})^{0.6}}{D_i^{0.4}} = \frac{2.14(837+460)^{0.28}\ (.356)^{0.6}}{6.625^{0.4}}$

$= 4.02$ Btu/Hr $Ft^2°F$

For Av. Gas Temp. = 1150°F & Tube Wall Temp. = 626°F From Fig. 30

$h_{cr} = 2.37$ Btu/Hr. sq.ft. °F

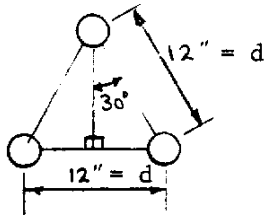
For Ave. Tube Wall Temp. = 626°F From Fig. 31

or $h_{cw} = 9.46 \left[\frac{T_t}{1000}\right]^3 = 9.46 \left[\frac{626 + 460}{1000}\right]^3 = 12.12$

then $h_{cc} + h_{cr} + h_{cw} = 4.02 + 2.37 + 12.12 = 18.51$ Btu/Hr sq.ft. °F

Row-to-Row Tube Spacing

For an equilateral convection section lay out we have:



a = Row-to-Row tube spacing = d cos 30°

$= \frac{12}{12} \times .866$

$= .866$ ft.

A_{cw} = tube area per row = two walls x a x L_e (exposed length)

$= 2 \times 8.66 \times 58.5 = 101.322$ sq. ft.

A_{ct} = tube area per row = No. tubes/row x area/tube

$= 8 \times 58.5 \times 1.734 = 811.512$ sq.ft.

Convection Section Convection Factor $= f = \frac{h_{cw}}{h_{cc} + h_{cr} + h_{cw}} \left(\frac{A_{cw}}{A_{ct}}\right)$

$f = \frac{12.12}{18.51}\left(\frac{101.322}{811.512}\right) = 0.0818$

Overall-All Transfer Coefficient

Total Apparent Gas Film Coefficient $= h_c = (1 + f)(h_{cc} + h_{cr})$

$h_c = (1 + 0.0818)(4.02 + 2.37)$

$h_c = 6.91$ Btu/Hr. sq.ft. °F

Intube Film Coefficient $= h_c = \frac{K}{D}\left(\frac{CZ}{K}\right)^{1/3}\left(\frac{Z}{Z_w}\right)^{.14}\phi\left(\frac{DG}{Z}\right)$

Crude oil properties will be taken at an average temperature of 474°F

Crude Oil Properties:

API = 34.8
K = .0695
D = 6 in.
(Z/Z_w) .14≈1.0
SG. @ 474°F = 0.70 from UOP PD-194
Z = .46 Centistokes @ 474°F

Charact. factor = 11.9
G = 214.42
C = .68 x 1.005 = 6834
Corrected by UOP K factor according to UOP Chart F-1

$Z = Z_{cp}/S.G.$ $\therefore Z_{cp} = Z \times S.G. = (.46)(.7) = .322$ Centipoise

Modified Reynolds Number $= DG/Z_{cp} = \frac{(6)(214.42)}{(.322)} \approx 4000$

$\phi\left(\frac{DG}{Z}\right) = 14800$

From Equation (1)

$$h_{ci} = \frac{(.0695)}{(6)}\left[\frac{(.6834)(.322)}{(.0695)}\right]^{1/3}(1)^{.14}(14800) = 171.42\,[3.1662]^{1/3}$$

$h_{ci} = (171.43)(1.4678) = 251.62$ Btu/Hr.sq.ft. °F

Convection Section Over-All Transfer Coefficient $= U_c = \frac{h_c\,(h_{ci})}{h_c + h_{ci}}$

$U_c = \frac{(6.91)(251.62)}{6.91 + 251.62}$

$U_c = 6.73$ Btu/Hr. Sq.Ft. °F

For comparison, the approximate over-all coefficient from Fig. 32 is 6.66
For 6-5/8" O.D. & av. Gas Temp. = 1150°F

Convection Section Area

Convection section area is estimated from the usual heat-transfer equation:

$$A_C = \frac{q_c}{U_C\ (LMTD)}$$

$$A_C = \frac{(79.25-2.07) \times 10^6\ \text{Btu/Hr.}}{\left(6.73\ \frac{\text{Btu}}{\text{Ht.Sq.Ft.}\ ^\circ\text{F}}\right)(626^\circ\text{F})} = 18320\ \text{Sq. Ft.}$$

$$\text{Number of tubes} = \frac{\text{Convection area, ft2}}{\text{area/tube}} = \frac{18320}{58.5 \times 1.734} \qquad 181.\ \text{tubes}$$

$$\text{Number of rows} = \frac{181\ \text{tubes}}{8\ \text{tubes/row}} = 22.6\ \text{rows use 23 rows}$$

23 rows are required or a total number of 176 tubes.

As we can see, 23 convection section rows are required to meet our remaining duty requirement. However, if we note the flow through our furnace we can see the heater inlet (convection section inlet) and the convection section outlet are on opposite sides of the furnace. The convection section outlet immediately feeds the radiant section inlet on the same side. Since the radiant section has 17 tubes per pass, the heater outlet (radiant section outlet) will exit the opposite side of the furnace; therefore, the furnace inlets and outlets are on the same side of the furnace.

When the furnace inlet and outlet are on opposing sides, there is wasted piping more than one furnace length. To remedy this, we can either add another row of tubes or remove a row of tubes to have the terminals on the same side. An additional row will increase the efficiency minutely since the LMTD of the individual row will be relatively small. Similarly, the removal of one row will decrease the efficiency for the same reason. This increase in efficiency will cause the furnace to fire slightly higher, increasing our average radiant flux minutely.

FIGURE 8A
VERTICAL HEATER
BOTTOM SUPPORTED TUBES

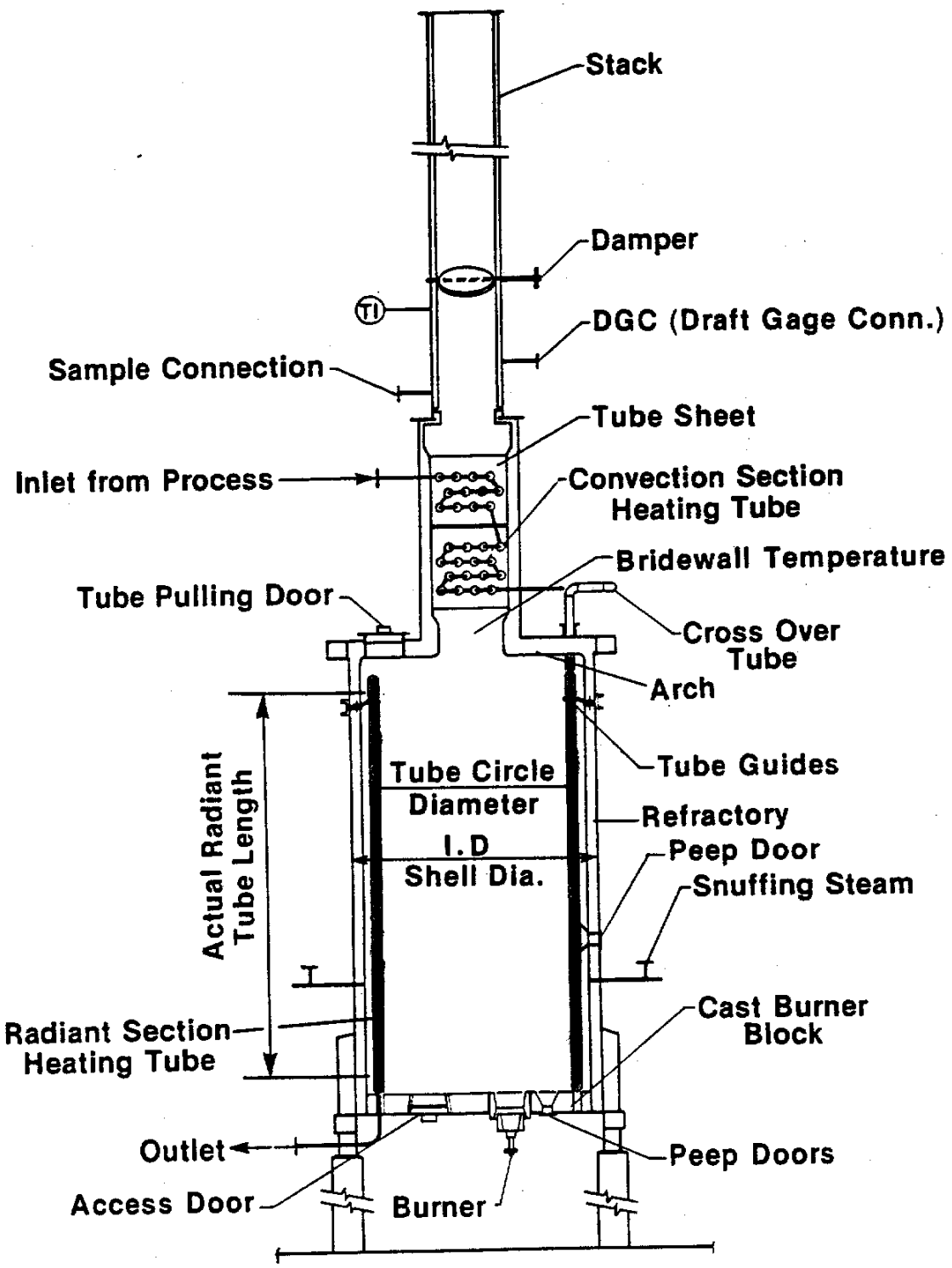
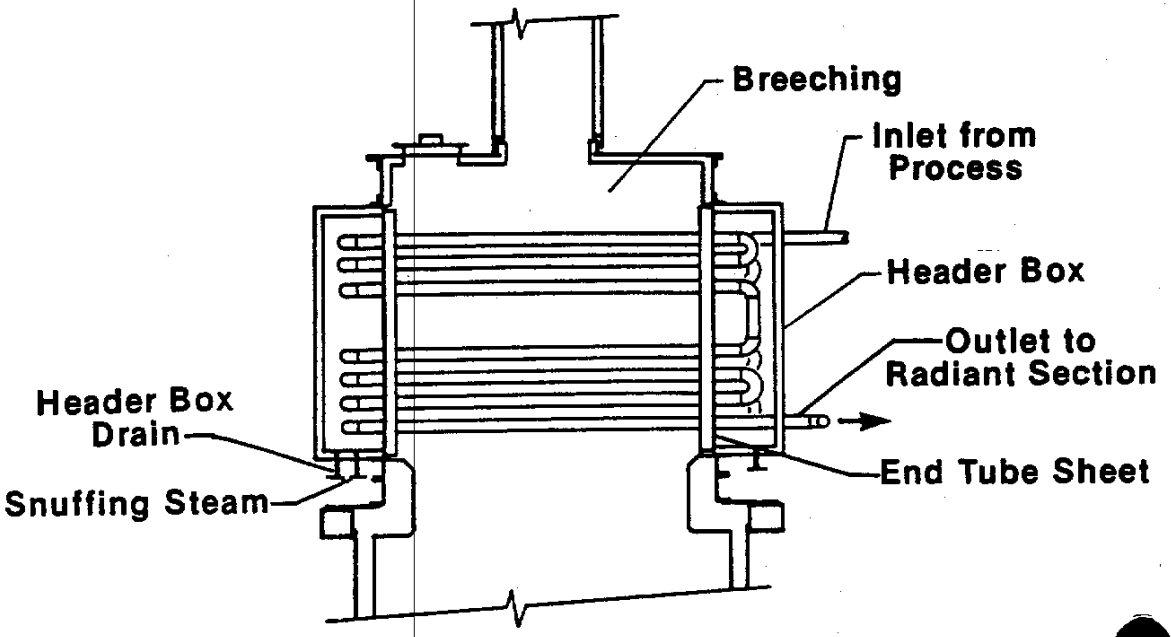
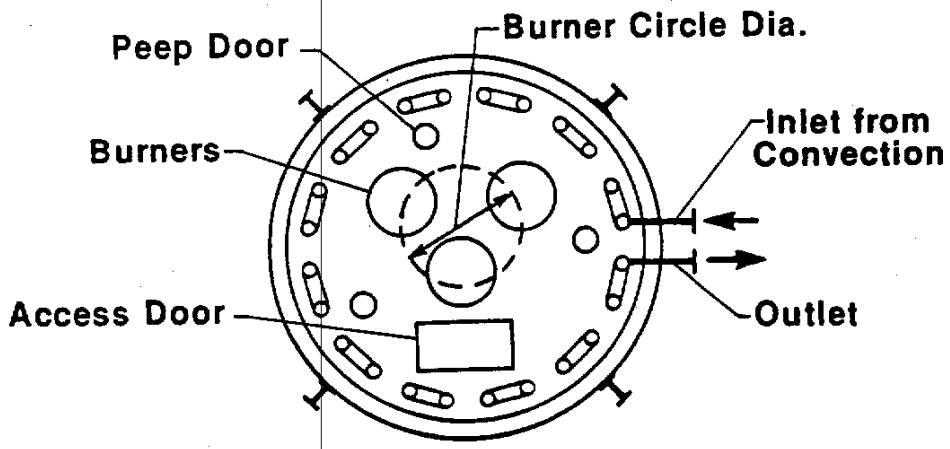


FIGURE 8B



CONVECTION SECTION
FOR VERTICAL HEATER



RADIANT SECTION

FIGURE 9A
SIDE FIRED CENTERWALL HEATER

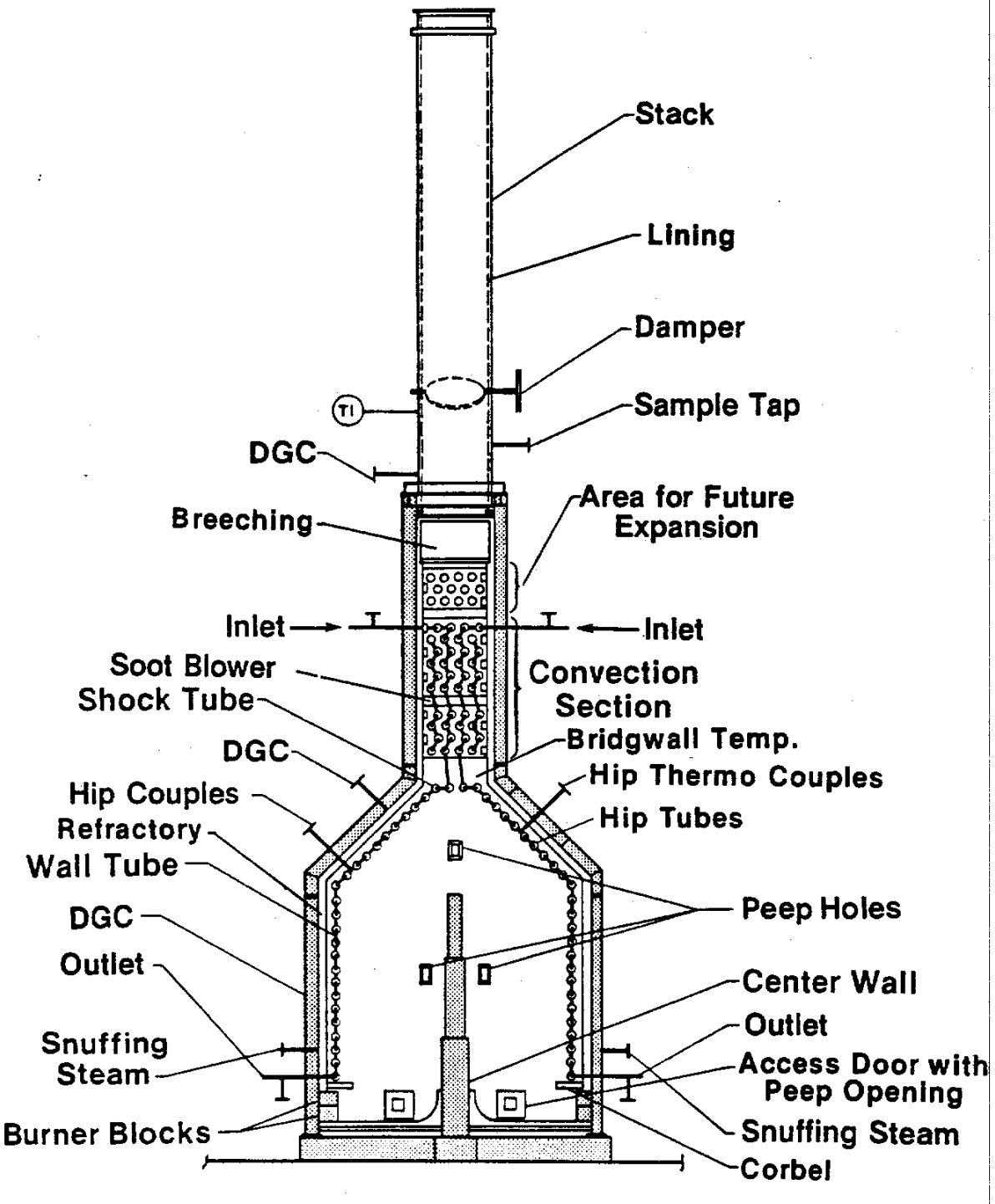


FIGURE 9B
SIDE VIEW CENTERWALL

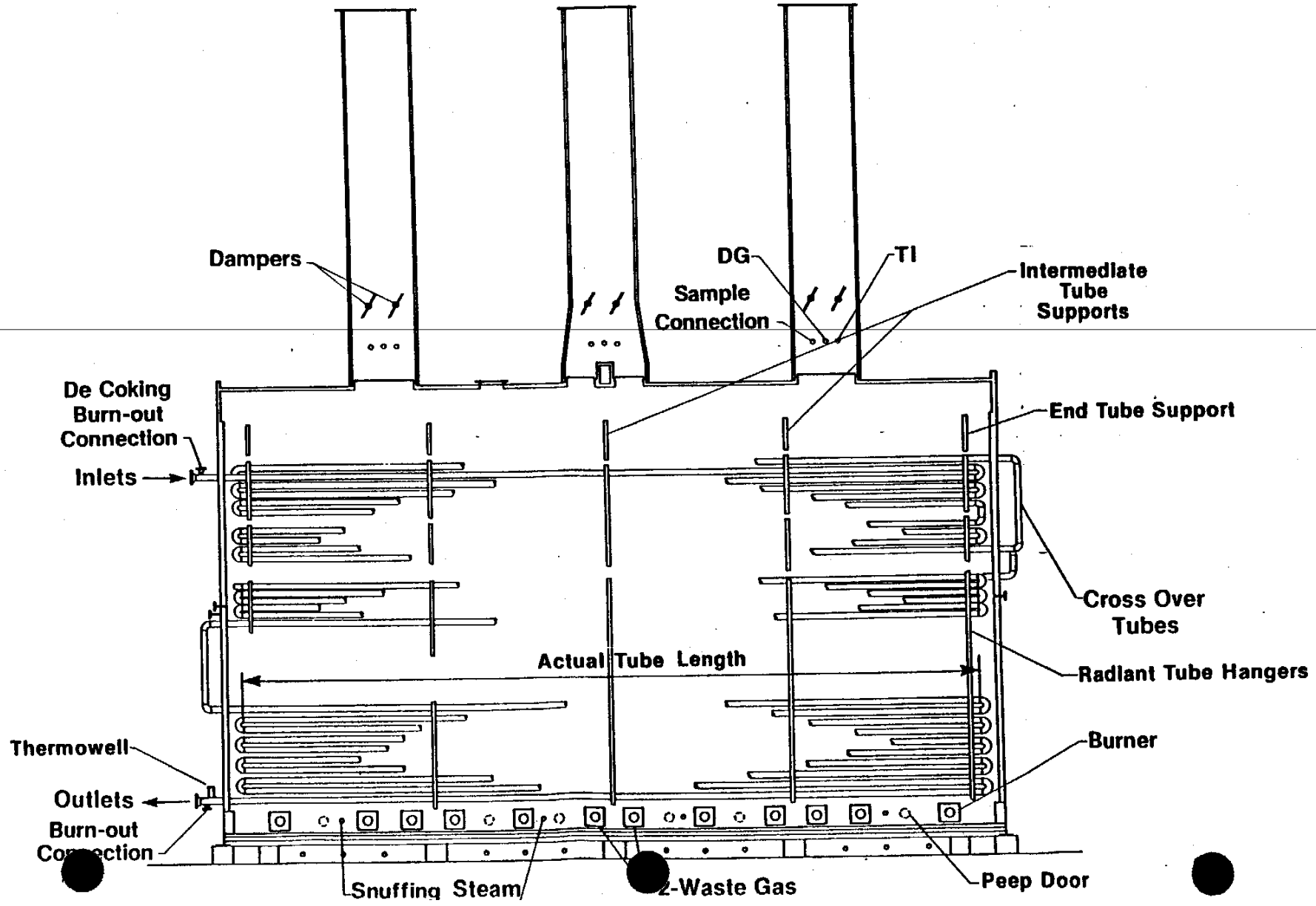


FIGURE 10A

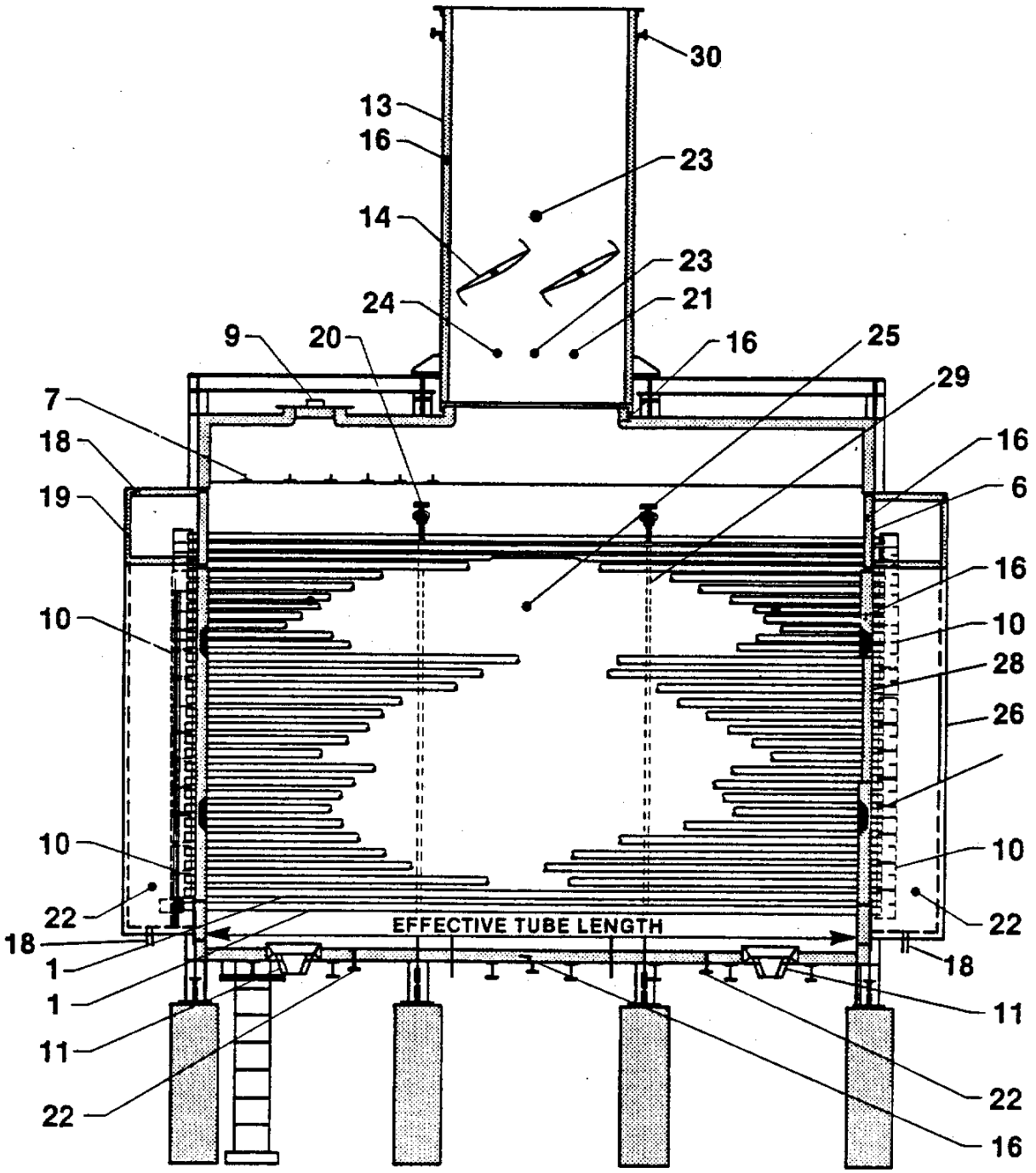
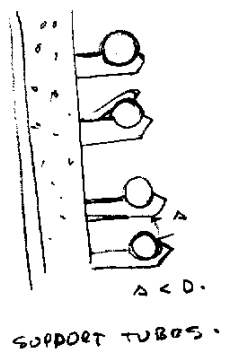

30
13
16
23
14
23
24
21
9
20
16
25
29
7
18
16
19
6
16
10
10
28
26
10
22
EFFECTIVE TUBE LENGTH
22
18
1
18
1
11
11
22
22
16

FIGURE 10B
ALL RADIANT BOTTOM FIRED CENTERWALL

No.	Nomenclature
1.	Radiant Tube
2.	Shock Tube
3.	Shock Tube Support
4.	Hip Tube Support
5.	Wall Tube Support
6.	End Tube Sheet
7.	Baffle
8.	Access Door
9.	Roof Access Door
10.	Peep Door
11.	Burner
12.	Casing Plate
13.	Stack
14.	Damper
15.	Fire Brick Centerwall

No.	Nomenclature
16.	Insulation Concrete
17.	Buckstay
18.	Drain
19.	Mineral Wool Blanket
20.	Tube Support Beam
21.	Thermocouple Conn. fo Flue Gas Temperature
22.	Snuffing Steam Conn.
23.	Draft Gage Conn.
24.	Flue Gas Sampling Con
25.	Hip Thermocouple Conn
26.	Header Box
27.	Plug Type Fittings
28.	End Tube Sheet
29.	Intermediate Tube Supports
30.	Painters Trolley



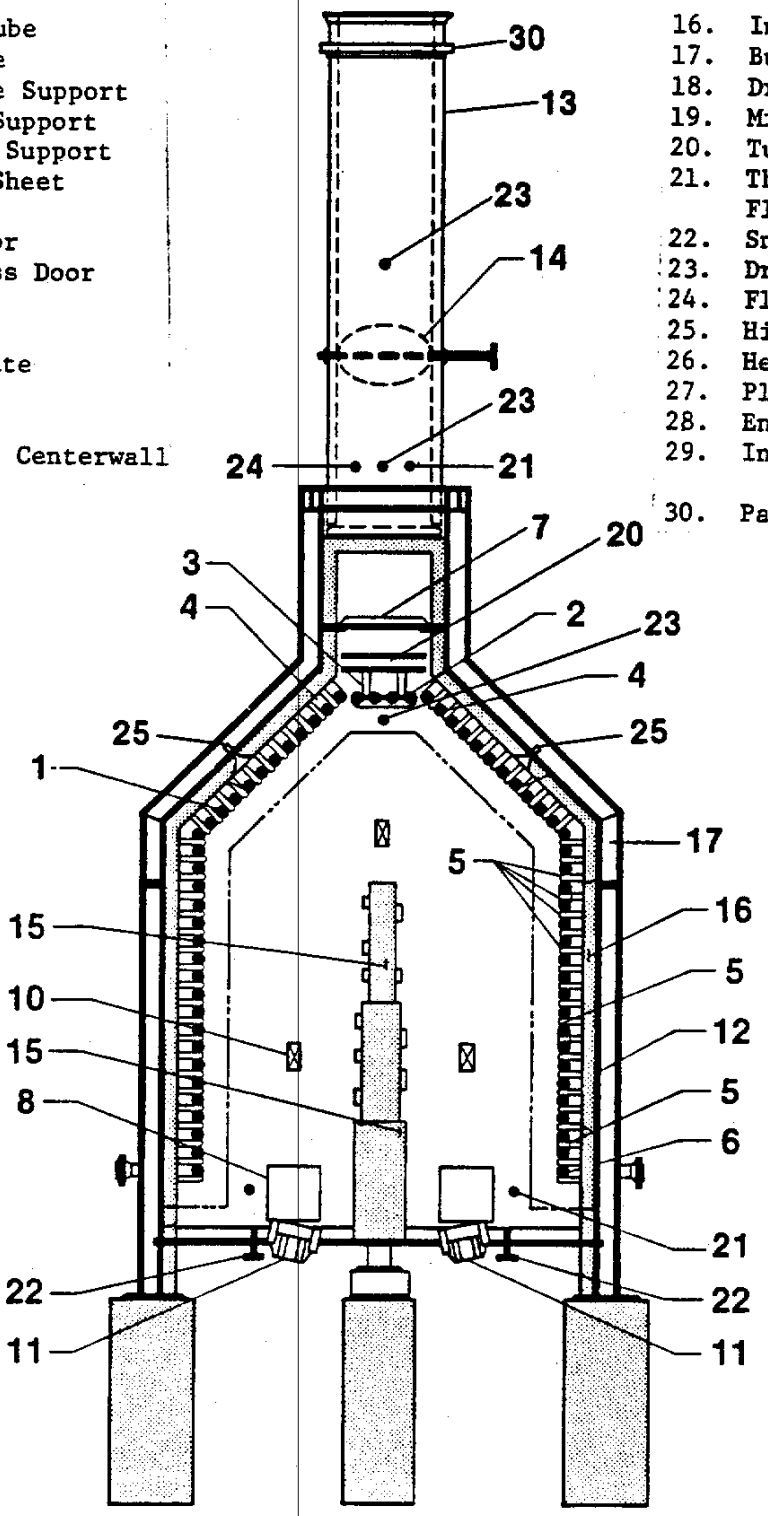


FIGURE 11A
DOUBLE FIRED HEATER

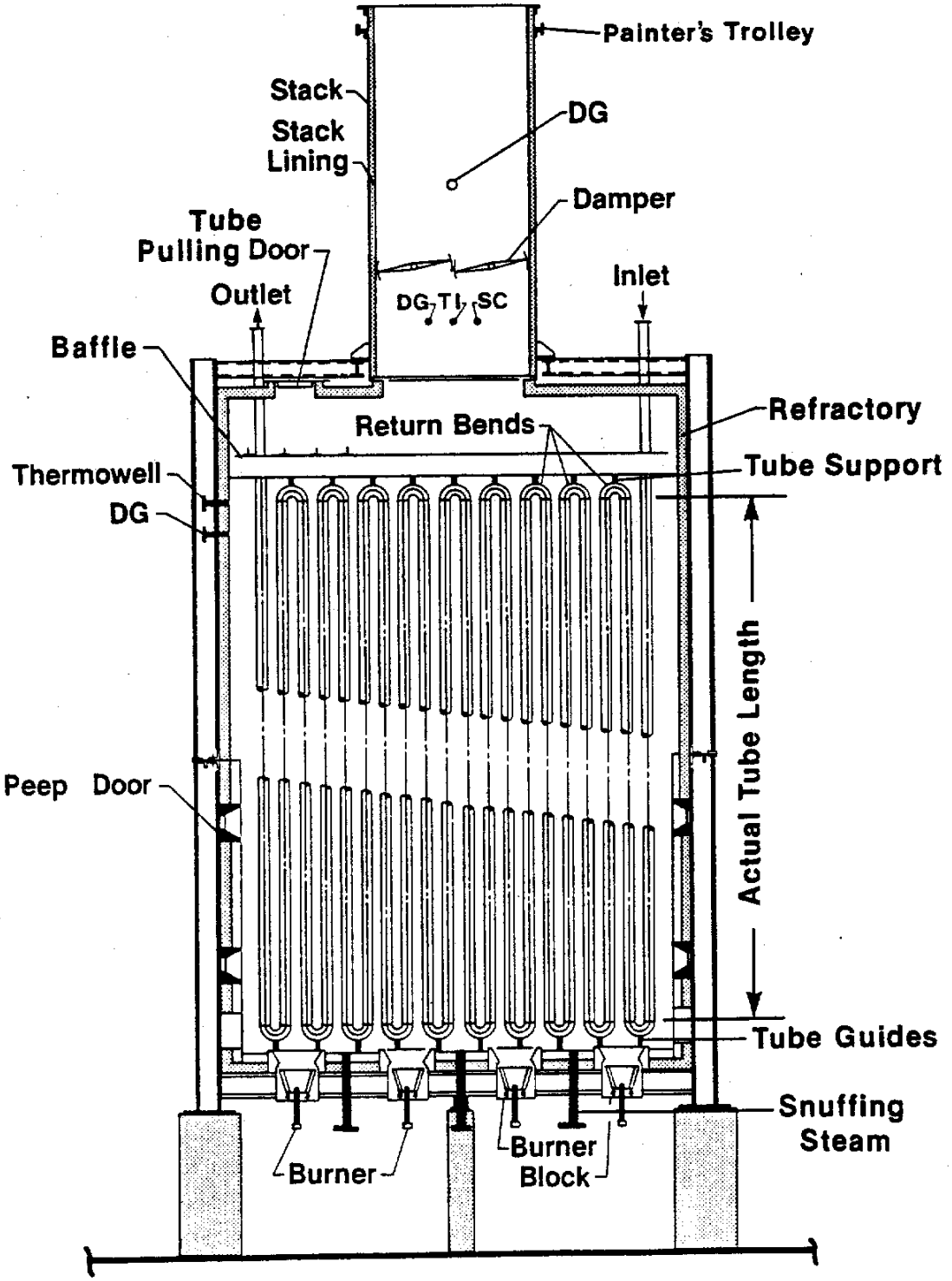


FIGURE 11B

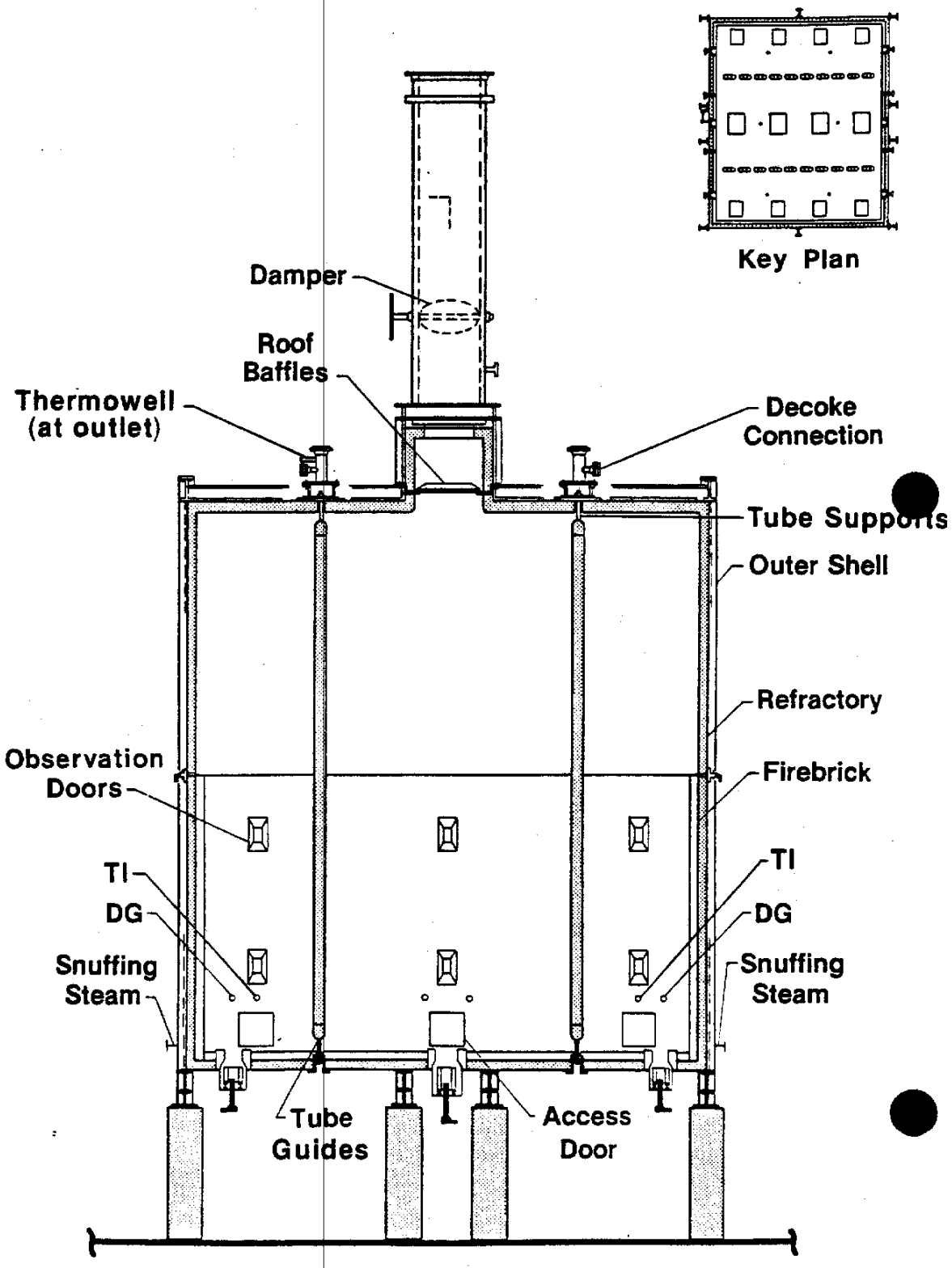

Key Plan
Damper
Roof Baffles
Thermowell (at outlet)
Decoke Connection
Tube Supports
Outer Shell
Refractory
Firebrick
Observation Doors
TI
DG
Snuffing Steam
TI
DG
Snuffing Steam
Tube Guides
Access Door

FIGURE 12
HELICAL COIL HEATER

No.	Nomenclature
1.	Heating Tube
2.	Tube Support
3.	Top Support Guide
4.	Shell
5.	Stack
6.	Painters Trolley
7.	Damper
8.	Platform (1st)
9.	Platform (2nd)
10.	Ladder with Cage
11.	Ladder
12.	Access Door

No.	Nomenclature
13.	Peep Door
14.	Burner
15.	Insulation
16.	Refractory
17.	Floor Peep Door
18.	Draft Gage
19.	Sample Point
20.	Stack Ti Thermowell
21.	Fire Box Ti Thermowe
22.	Snuffing Steam
23.	Damper Position Indicator

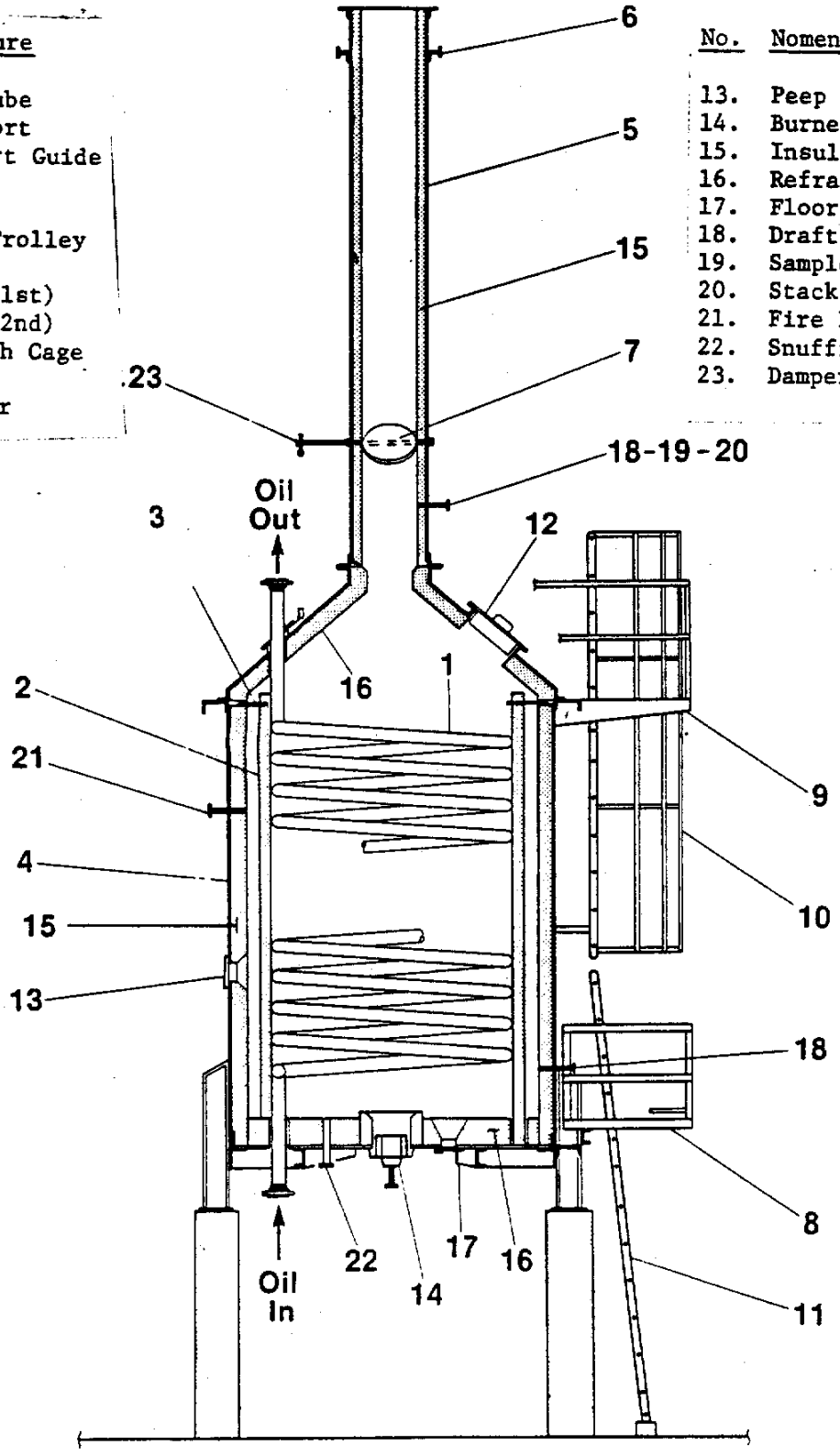


FIGURE 13

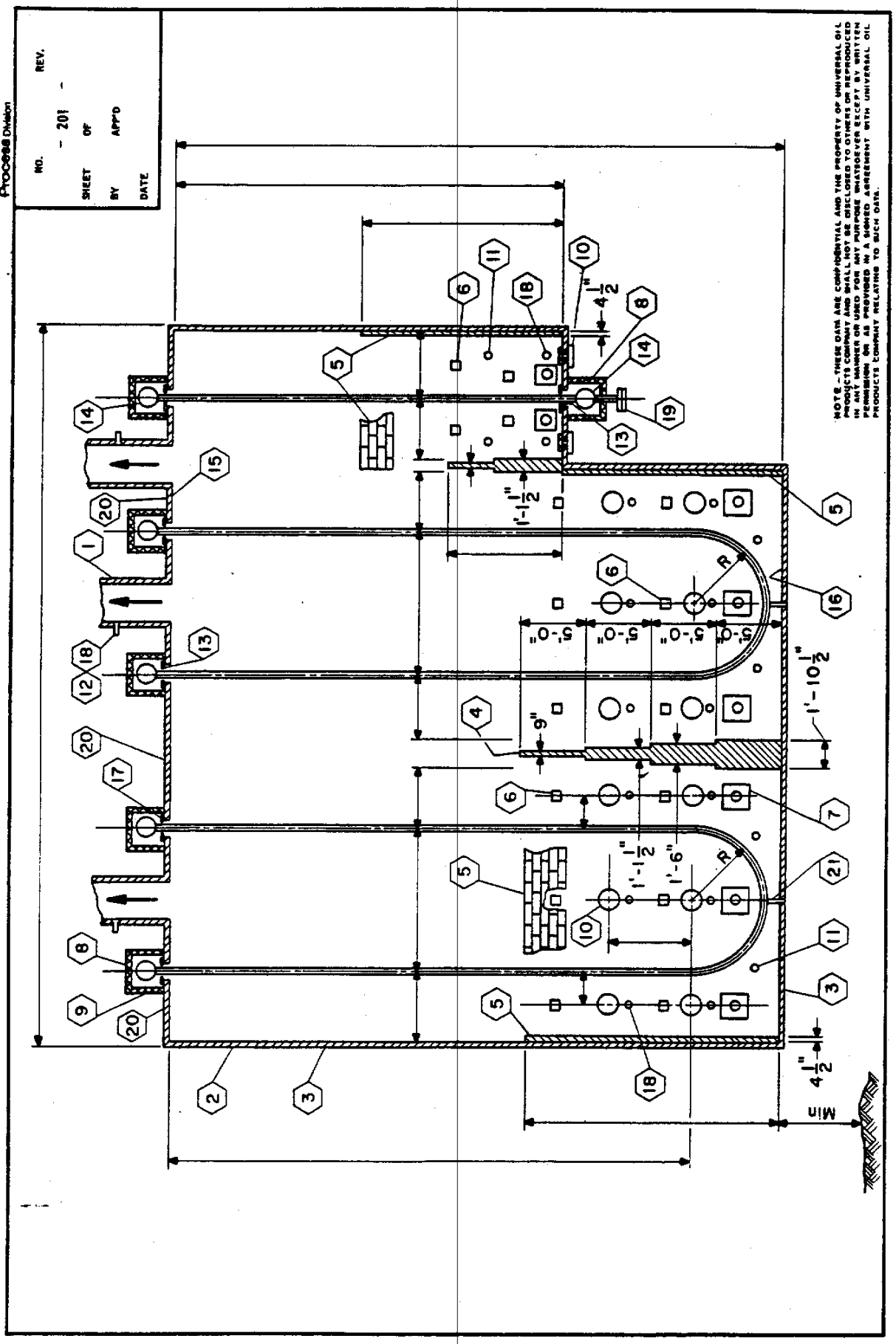
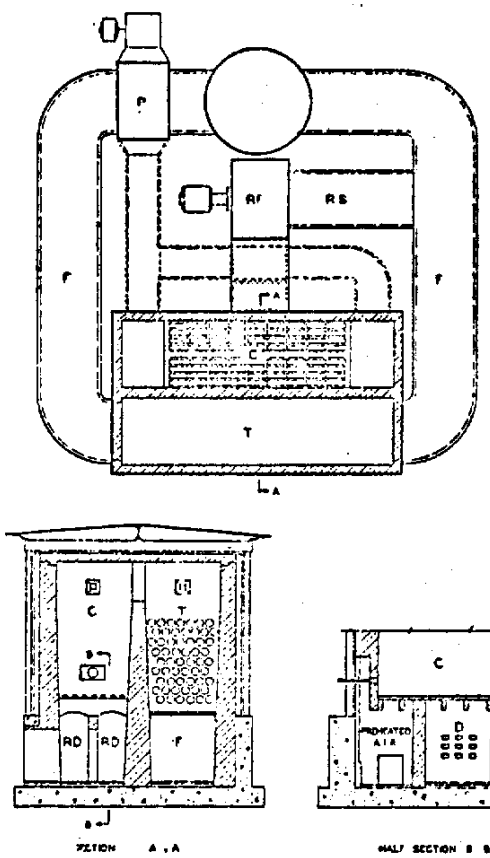
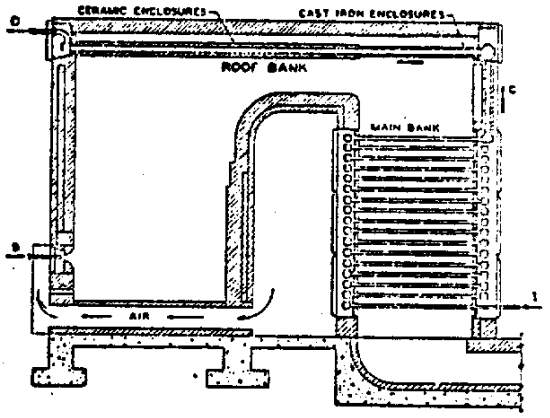

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5'-0"
5'-0"
5'-0"
5'-0"
1'-10 1/2"
1'-1 1/2"
1'-6"
9"
4 1/2"
Min

FIGURE 14a



Flue Gas Recirculating Furnace with Air preheater
C—Combustion chamber; T—Tube or heating chamber; P—Flue to stack; RF—Recirculating fan; RD—Recirculating gas distributing duct; RS—Recirculating fan suction duct; P—Air, preheater

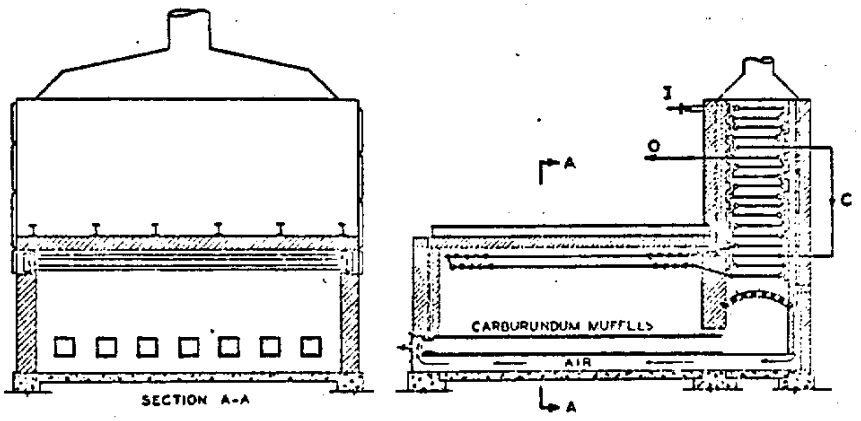
A



Early shielded tube radiant heat oil heater
I—Oil inlet; O—Oil outlet; C—Outside cross-over; B—Burners

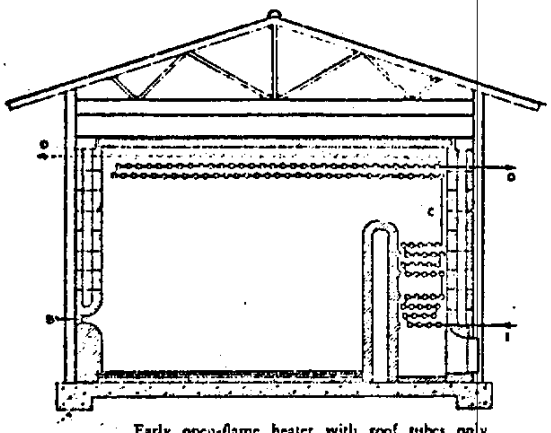
B

Early shielded flame radiant heat oil heater
I—Oil inlet; O—Oil outlet; C—Outside cross-over



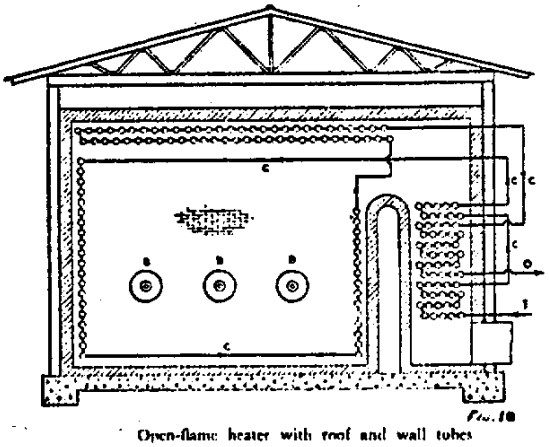
C

FIGURE 14b



Early open-flame heater with roof tubes only
I—Oil inlet; O—Oil outlet; B—Burners

D



Open-flame heater with roof and wall tubes
I—Oil inlet; O—Oil outlet; C—Outside cross-overs; B—Burners

E

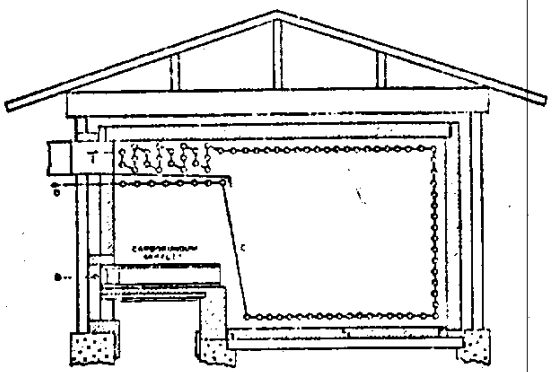
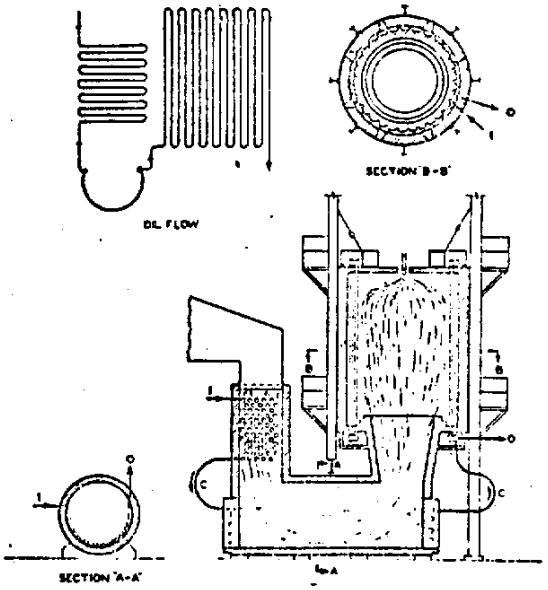


Fig. 19. Partially shielded flame heater
I—Oil inlet; O—Oil outlet; C—Outside cross-over; B—Burners

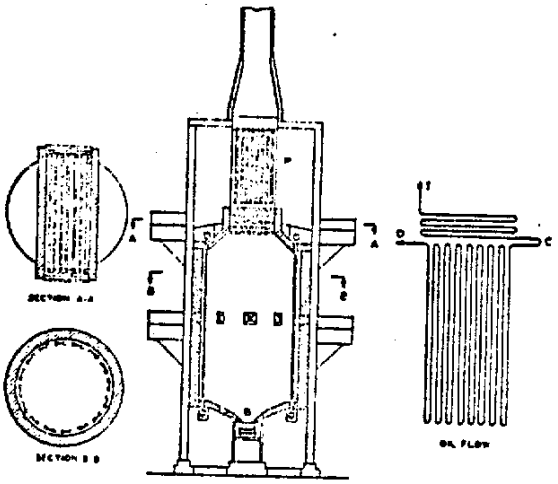
F



Early down-draft cylindrical heater
I—Oil inlet; O—Oil outlet; C—Outside cross-overs

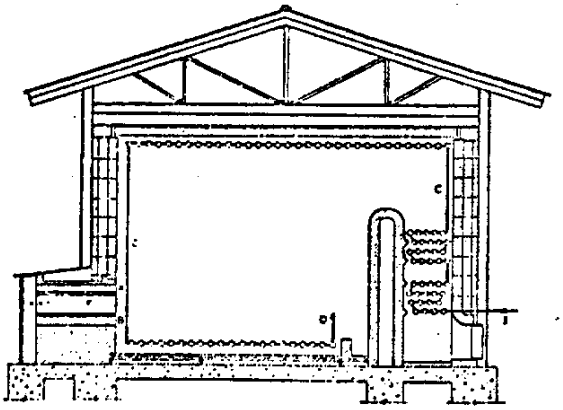
G

FIGURE 14c



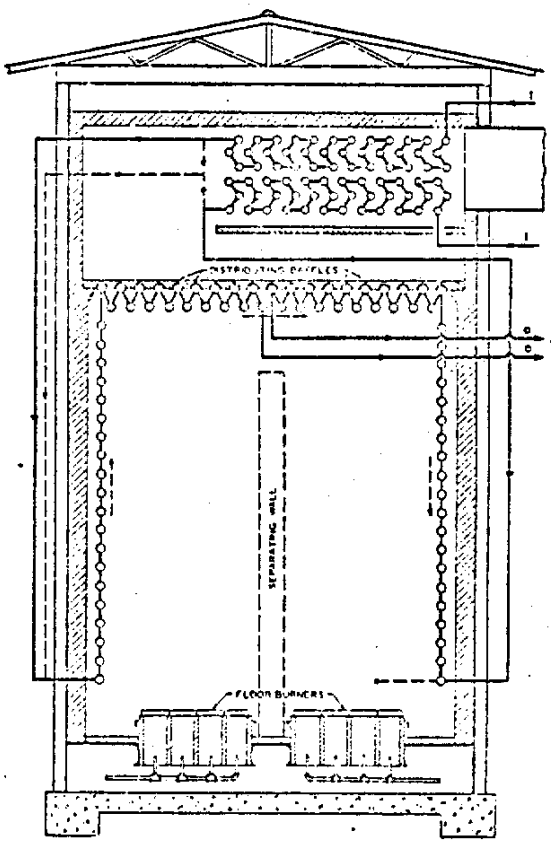
Updraft cylindrical heater
I—Oil inlet; O—Oil outlet; B—Burner; P—Air preheater

H



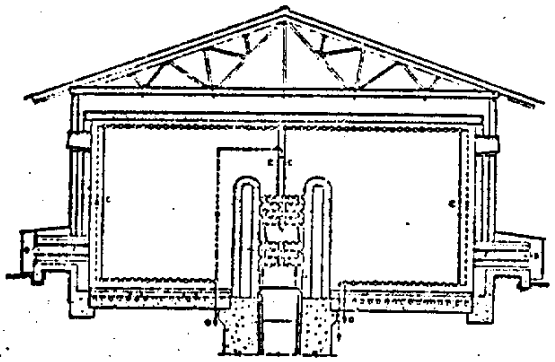
Roof and floor tube heater
I—Oil inlet; O—Oil outlet; C—Outside cross-over

I



Updraft rectangular heater

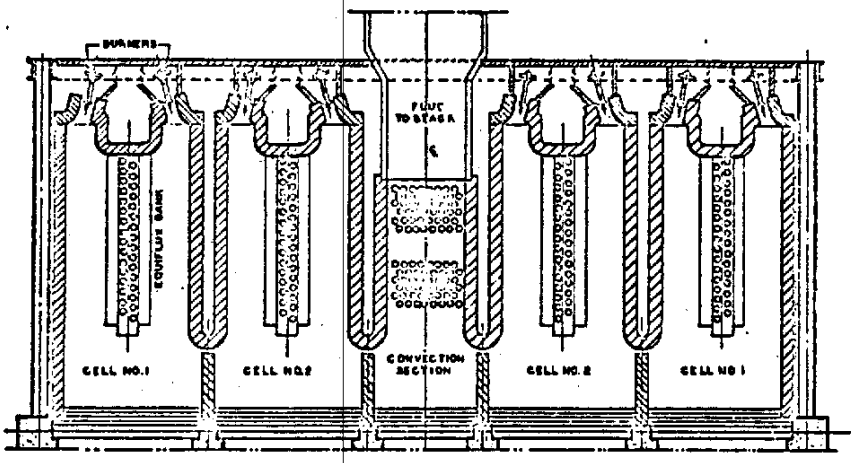
J



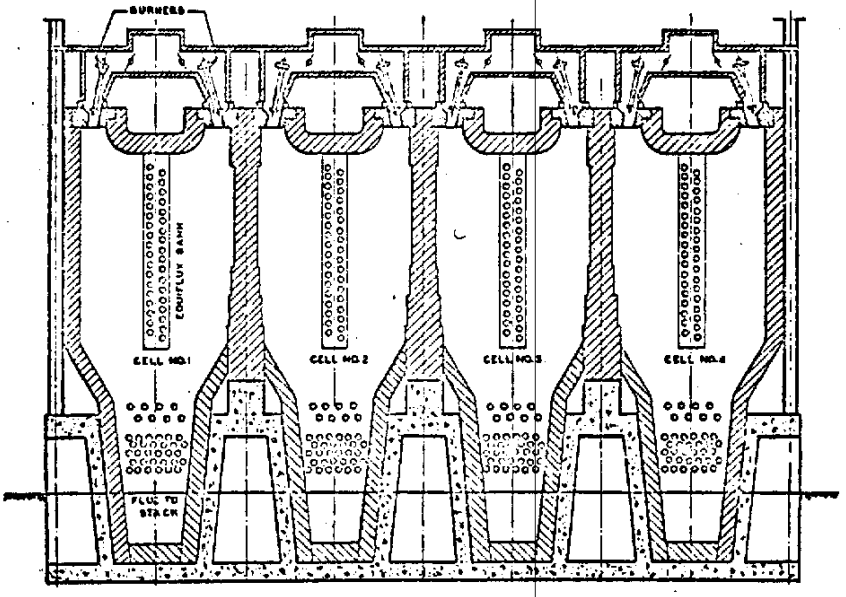
Two compartment heater

K

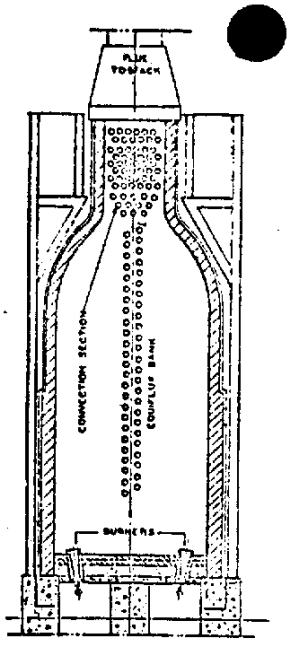
FIGURE 15



A



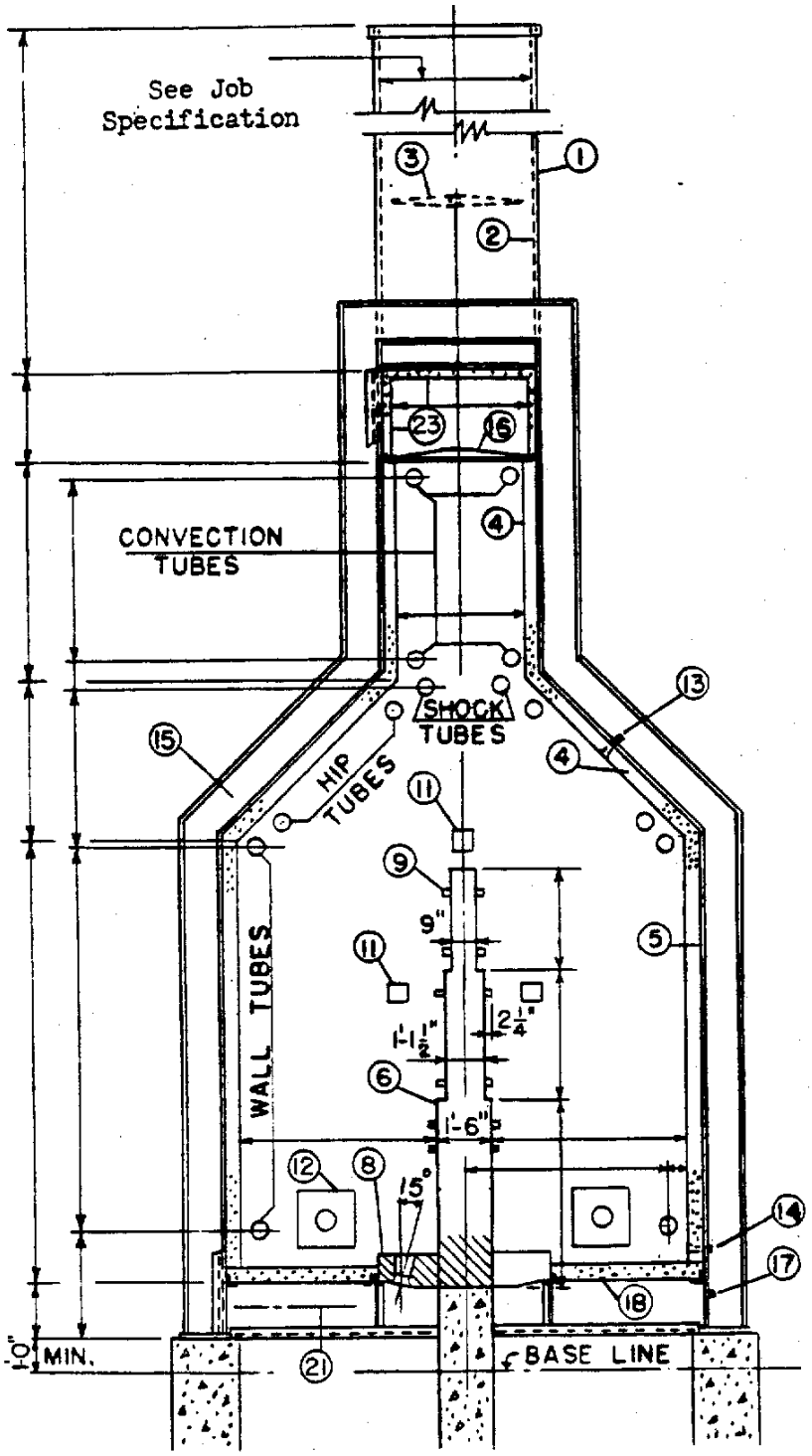
B



C

FIGURE 16

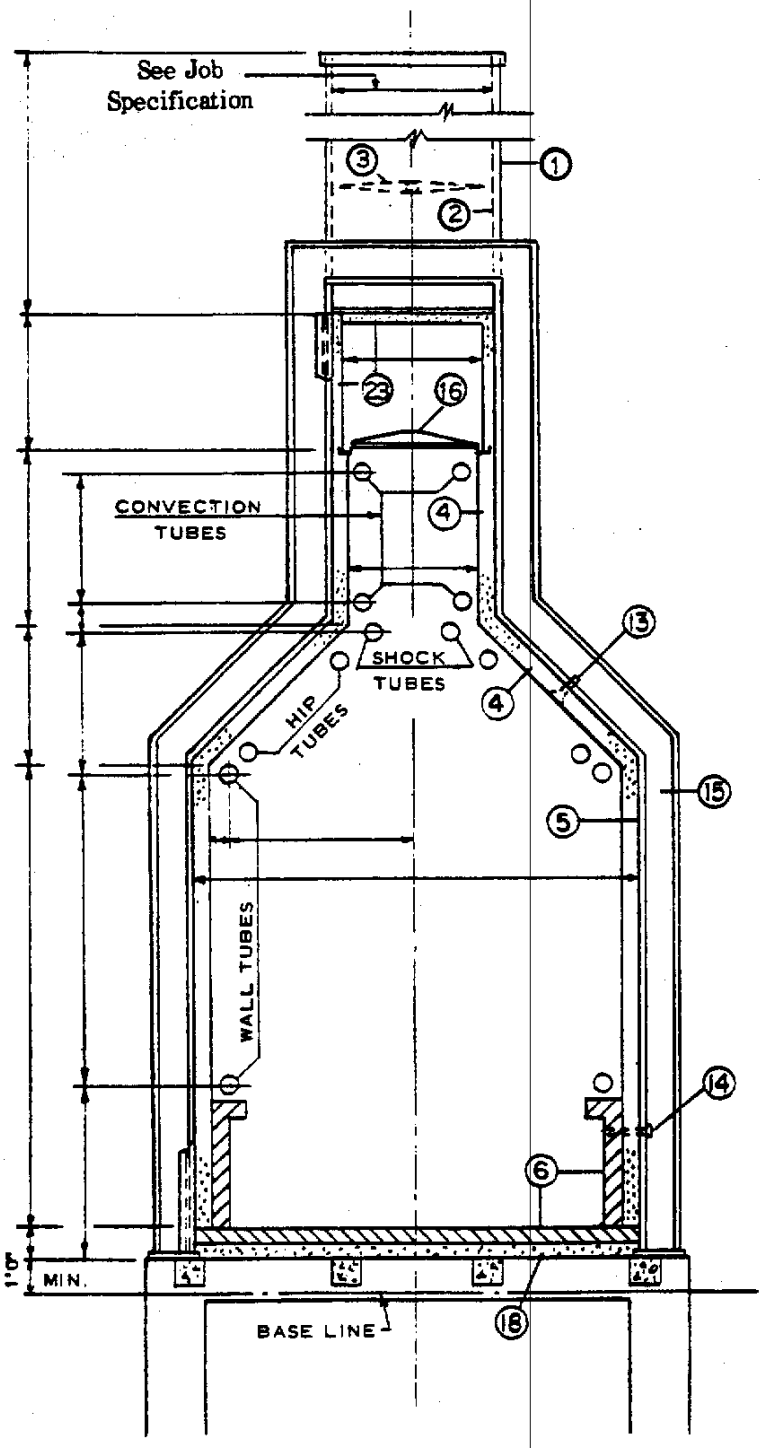
CENTER-WALL UPDRAFT
CROSS SECTION



1. Stack ¼" steel plate minimum thickness.
2. 1½" insulation UOP Specification No. 292.
3. 18-8 stainless steel damper and damper parts with positive manual 2-way control from grade.
4. 5" insulating concrete UOP Specification No. 294 or No. 296.
5. 3/16" steel casing plate
6. High duty regular type firebrick ASTM C-27.
8. High duty regular type fireclay precast burner blocks ASTM C-27.
9. Brick projections.
11. Peep openings (both ends) See Job Specification
12. Access openings (both ends) See Job Specifications.
13. 1½" thermocouple connections (plugged) See Job Specifications
14. 1" steam smothering connections. See Job Specification.
15. Heater frame (buckstay).
16. Meehanite process HR-1 or alloy plate baffles.
17. 3/4" steam smothering connections. See Job Specification
18. 5" reinforced heat resisting concrete UOP Specification No. 293.
21. Gas burners-See Job Specification
23. 3" insulation UOP Specification No. 294 or No. 296.

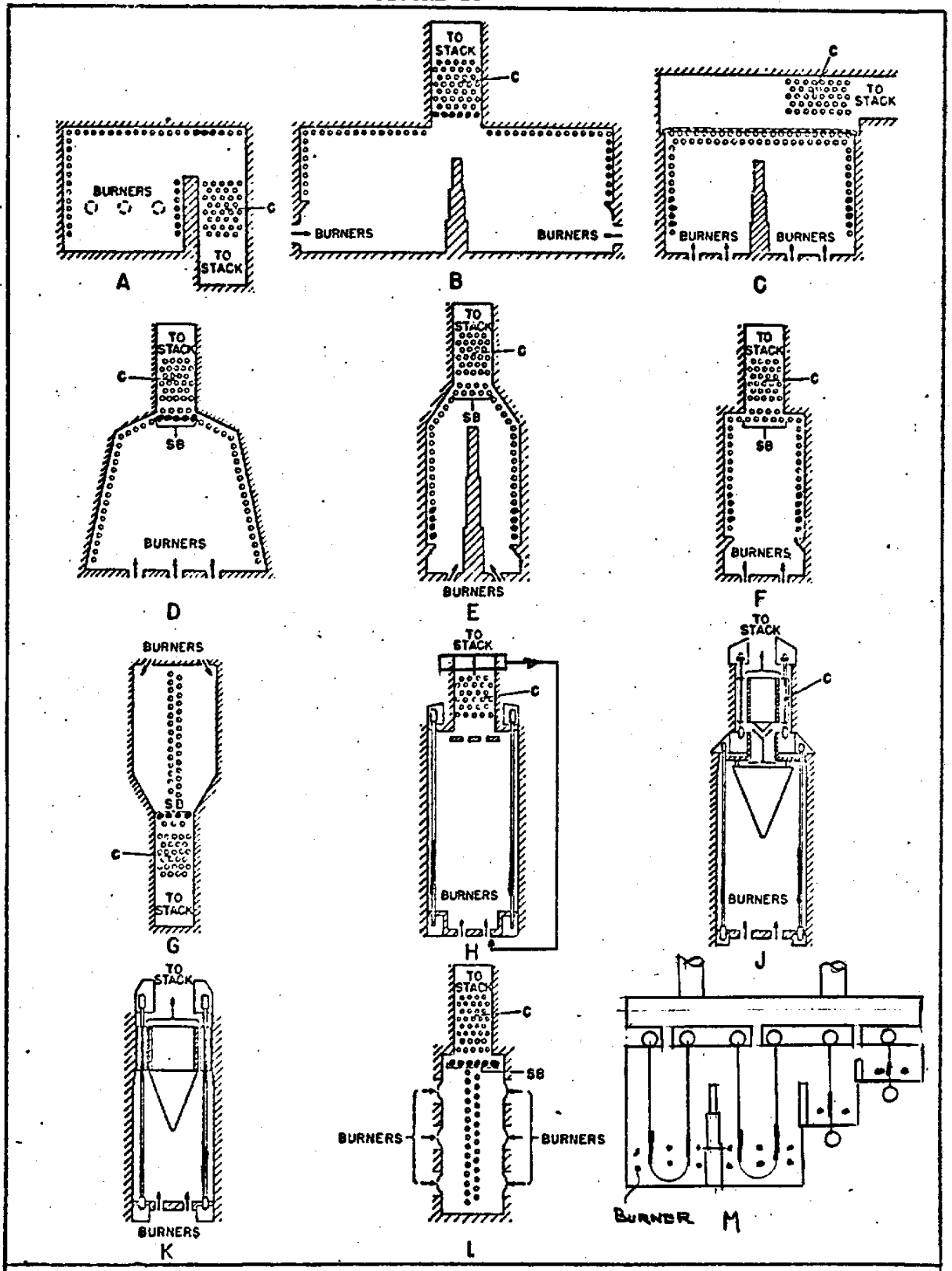
FIGURE 17

END OR BOTTOM FIRED UPDRAFT
CROSS SECTION



1. Stack ¼" steel plate minimum thickness.
2. 1½" insulation UOP Specification No. 292.
3. 18–8 stainless steel damper parts with positive manual 2-way control from grade.
4. 5" insulating concrete UOP Specification No. 294, or No. 296.
5. 3/16" steel casing plate.
6. High duty regular type firebrick ASTM C-27.
11. Peep openings (both ends) See Job Specification.
12. Access openings (both ends) See Job Specification.
13. 1½" thermocouple connection (plugged) See Job Specification.
14. 1" steam smothering connections. See Job Specification.
15. Heater frame (buckstay)
16. Meehanite process HR-1 or alloy plate baffles.
18. 5" reinforced heat resisting concrete UOP Specification No. 293.
23. 3" insulation UOP Specification No. 294 or No. 296.
24. Burners – See Job Specification

FIGURE 18



BASIC TYPES OF PROCESS HEATERS -

FIGURE 21

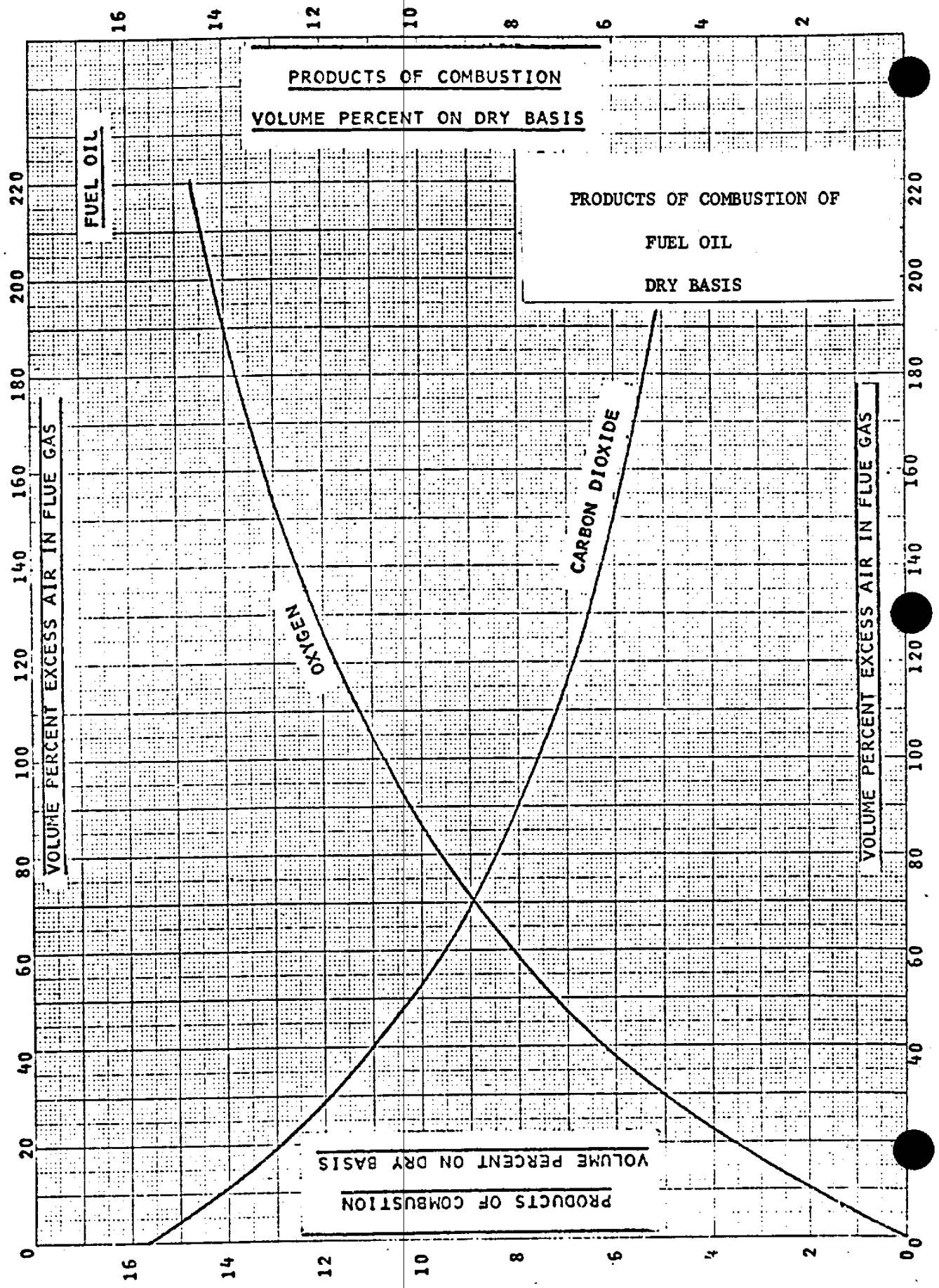

PRODUCTS OF COMBUSTION
VOLUME PERCENT ON DRY BASIS
PRODUCTS OF COMBUSTION OF
FUEL OIL
DRY BASIS
FUEL OIL
VOLUME PERCENT EXCESS AIR IN FLUE GAS
OXYGEN
CARBON DIOXIDE
VOLUME PERCENT ON DRY BASIS
PRODUCTS OF COMBUSTION
0
20
40
60
80
100
120
140
160
180
200
220
16
14
12
10
8
6
4
2
0

FIGURE 19

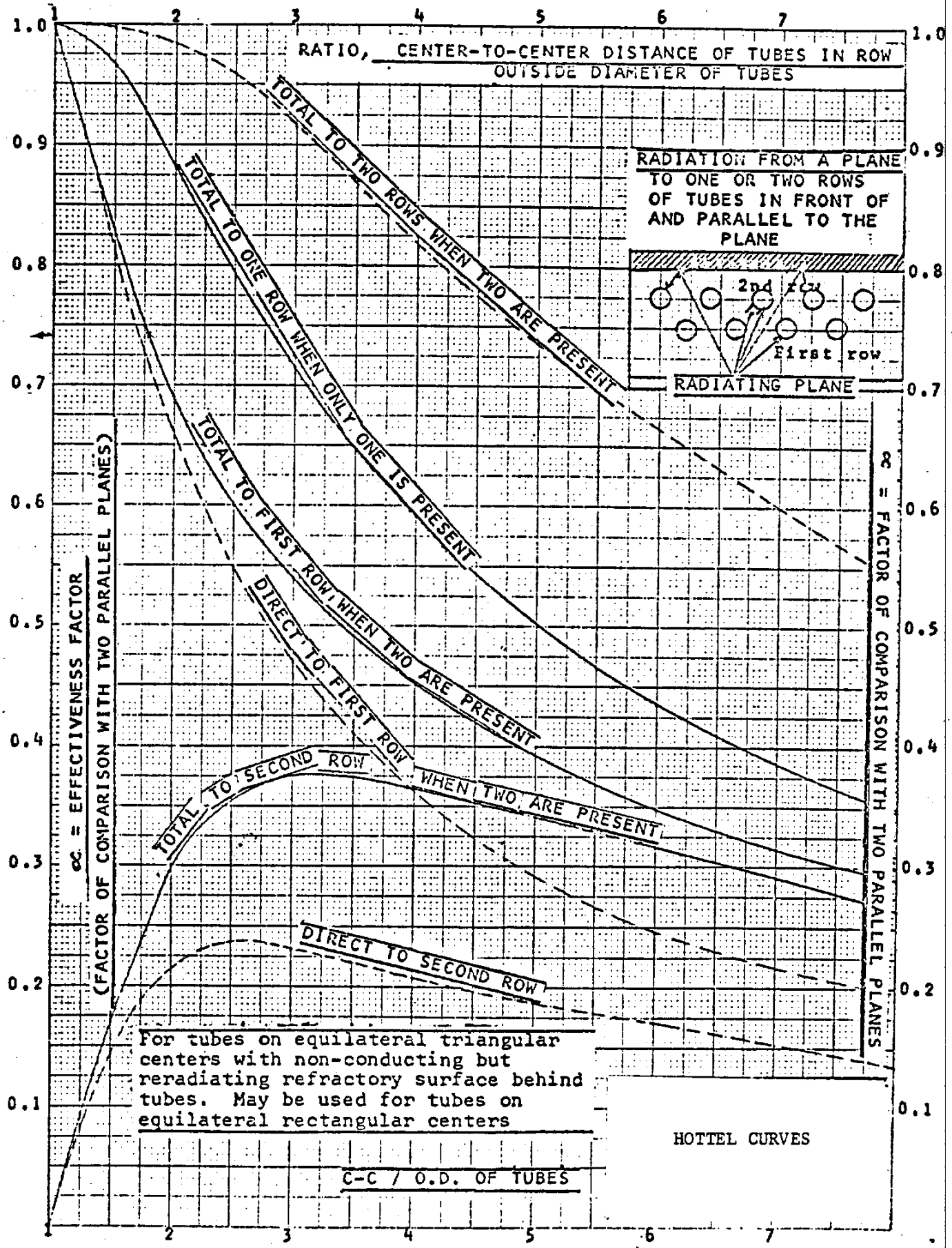
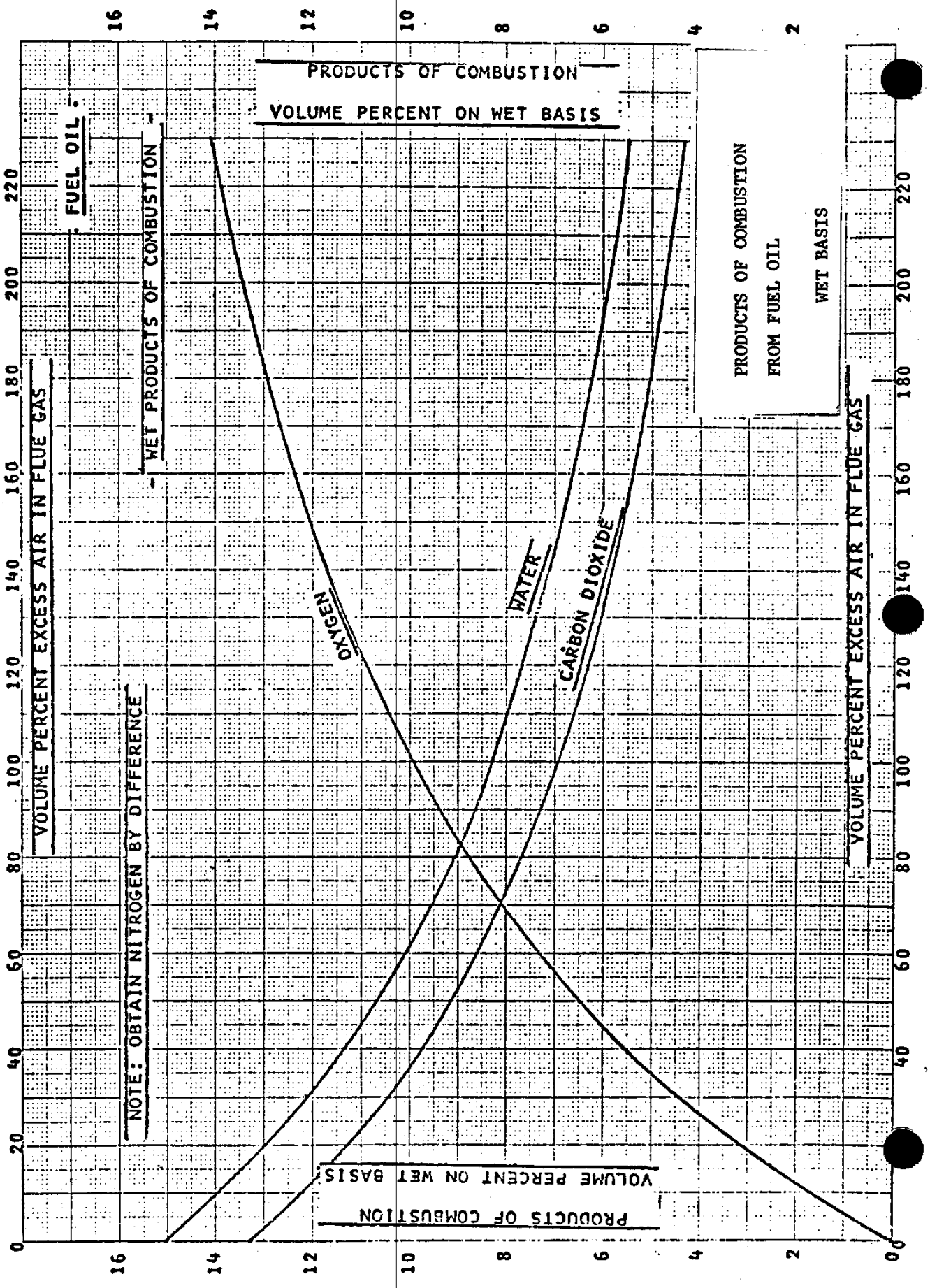

RATIO, CENTER-TO-CENTER DISTANCE OF TUBES IN ROW / OUTSIDE DIAMETER OF TUBES
TOTAL TO TWO ROWS WHEN TWO ARE PRESENT
TOTAL TO ONE ROW WHEN ONLY ONE IS PRESENT
TOTAL TO FIRST ROW, WHEN TWO ARE PRESENT
DIRECT TO FIRST ROW
TOTAL TO SECOND ROW, WHEN TWO ARE PRESENT
DIRECT TO SECOND ROW
RADIATION FROM A PLANE TO ONE OR TWO ROWS OF TUBES IN FRONT OF AND PARALLEL TO THE PLANE
2nd row
First row
RADIATING PLANE
α = EFFECTIVENESS FACTOR (FACTOR OF COMPARISON WITH TWO PARALLEL PLANES)
α = FACTOR OF COMPARISON WITH TWO PARALLEL PLANES
For tubes on equilateral triangular centers with non-conducting but reradiating refractory surface behind tubes. May be used for tubes on equilateral rectangular centers
C-C / O.D. OF TUBES
HOTTEL CURVES

FIGURE 20


PRODUCTS OF COMBUSTION
VOLUME PERCENT ON WET BASIS
FUEL OIL
WET PRODUCTS OF COMBUSTION
VOLUME PERCENT EXCESS AIR IN FLUE GAS
NOTE: OBTAIN NITROGEN BY DIFFERENCE
OXYGEN
WATER
CARBON DIOXIDE
PRODUCTS OF COMBUSTION
FROM FUEL OIL
WET BASIS
VOLUME PERCENT ON WET BASIS
PRODUCTS OF COMBUSTION
VOLUME PERCENT EXCESS AIR IN FLUE GAS
0
20
40
60
80
100
120
140
160
180
200
220
16
14
12
10
8
6
4
2
0

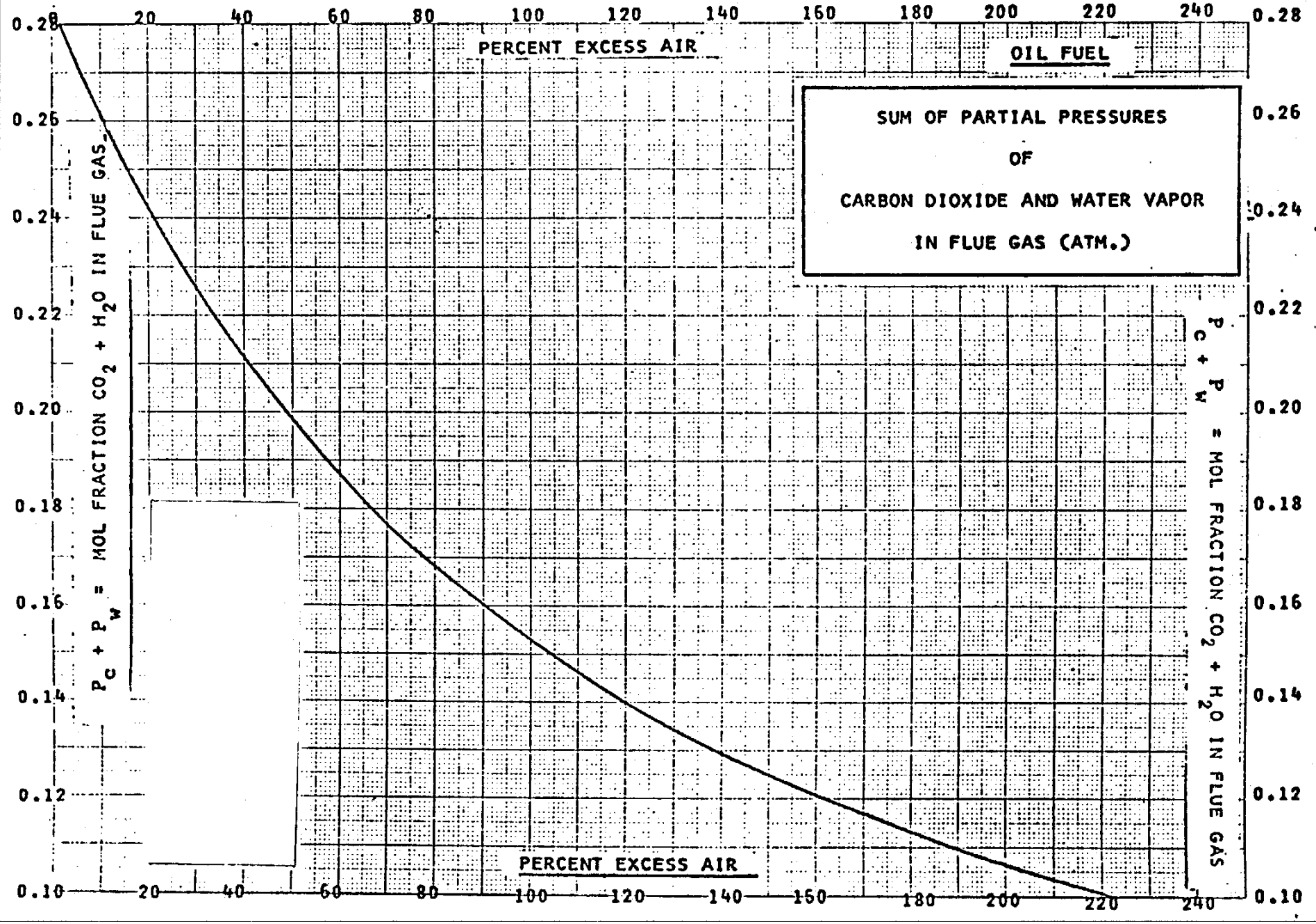

SUM OF PARTIAL PRESSURES
OF
CARBON DIOXIDE AND WATER VAPOR
IN FLUE GAS (ATM.)
OIL FUEL
PERCENT EXCESS AIR
PERCENT EXCESS AIR
$P_C + P_W$ = MOL FRACTION $CO_2 + H_2O$ IN FLUE GAS
$P_C + P_W$ = MOL FRACTION $CO_2 + H_2O$ IN FLUE GAS
0.28
0.26
0.24
0.22
0.20
0.18
0.16
0.14
0.12
0.10
20
40
60
80
100
120
140
150
180
200
220
240

FIGURE 22

The following table gives the mean beam length for gas radiation for various standard furnace shapes.

TABLE 1

Shape	Characterizing Dimension	Factor by which X is multiplied to obtain mean beam length When $P_GL = 0$	For average values of P_GL		
Cylinders					
Infinite					
Radiation to convex surface	diameter			0.95	
Radiation to center of base	diameter	1.00		0.90	
Infinite of half-circular cross section, radiating to center of base	radius			1.26	
Semi-infinite, radiating to center of base	diameter			0.90	
Height = diameter radiating					
to center of base	diameter			0.77	
radiating to whole surface	diameter	0.67		0.60	
			P_GL		
Parallelepipeds			0.01	0.10	1.00
1:1:1 (cube)	edge	0.67	0.61	0.58	0.54
1:1:4					
radiating to 1 x 4 face	shortest edge	0.90	0.82	0.77	0.73
radiating to 1 x 1 face	" "	0.86	0.78	0.74	0.70
radiating to all faces	" "	0.89	0.81	0.77	0.72
1:2:6					
radiating to 2 x 6 face	shortest edge	1.18	1.07	1.02	0.95
radiating to 1 x 6 face	" "	1.24	1.13	1.07	1.00
radiating to 1 x 2 face	" "	1.18	1.07	1.02	0.95
radiating to all faces	" "	1.20	1.09	1.03	0.97
1:∞:∞ (infinite parallel planes)	distance between planes	2.00	1.82	1.72	1.62

For rectangular parallelepipeds, radiating to the base, values of L for low values of P_GL may be obtained from Curve No. B-333. For average values multiply by 0.85. For right circular cylinders of varying height to diameter ratio, radiating to the cylindrical walls L may be obtained from Curve No. B-339.

TABLE I

FIGURE 22a

MEAN LENGTH OF RADIANT BEAMS IN VARIOUS GAS (FURNACE) SHAPES

Dimensional Ratios (length, width, height in any order or diameter (d), feet)	Length of Beam, Feet
Rectangular Furnaces:	
1:1:1 to 1:1:3	2/3 $\sqrt[3]{\text{furnace volume}}$
1:2:1 to 1:2:4	2/3 $\sqrt[3]{\text{furnace volume}}$
1:1:4 to 1:1:∞	1.0 x (smallest dimension)
1:2:5 to 1:2:8	1.3 x (smallest dimension)
1:3:3 to 1:∞:∞	1.8 x (smallest dimension)
Cylindrical Furnaces:	
d x d	2/3 x (diameter)
d x 2d to d x ∞d	1.0 x (diameter)

FIGURE 23a

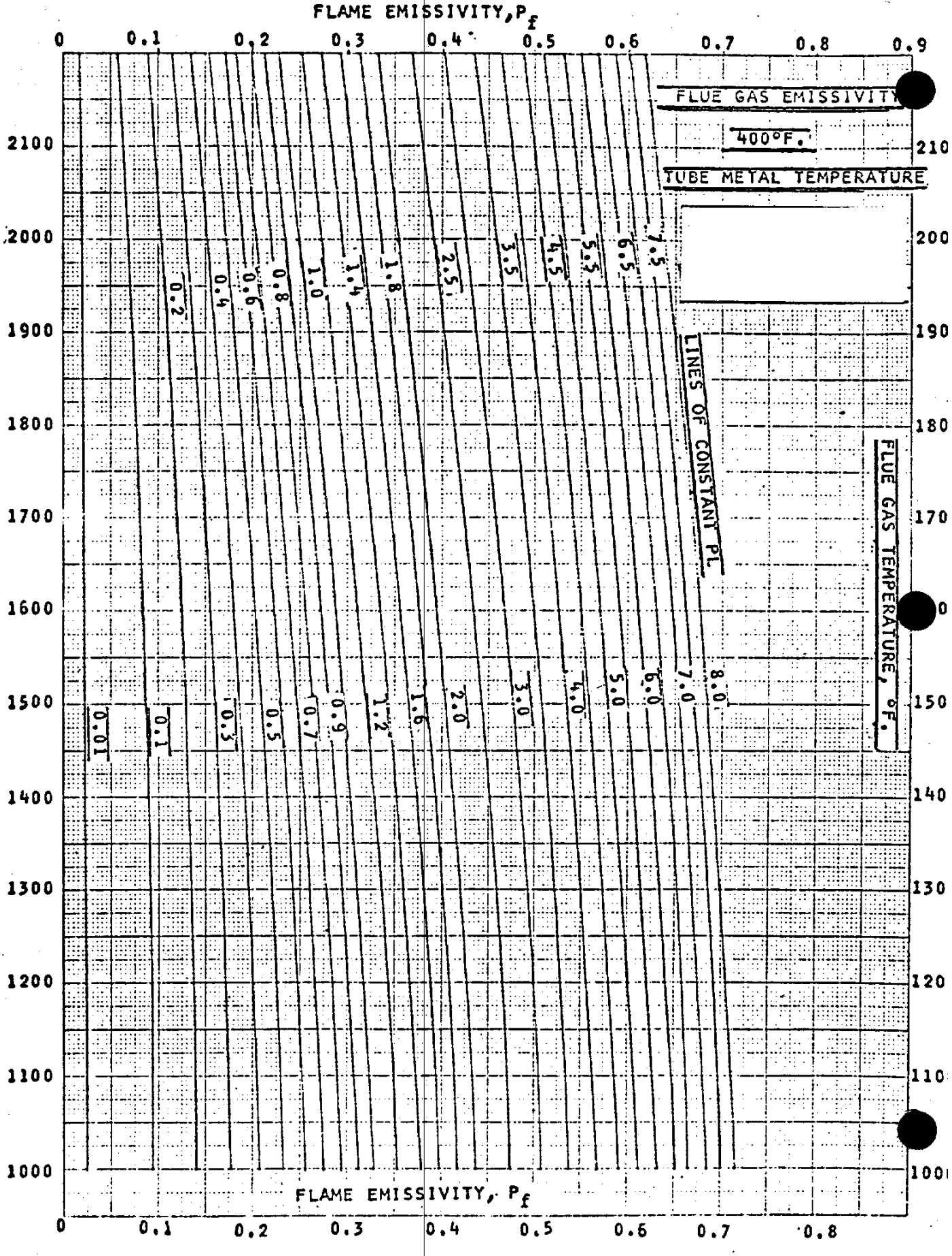
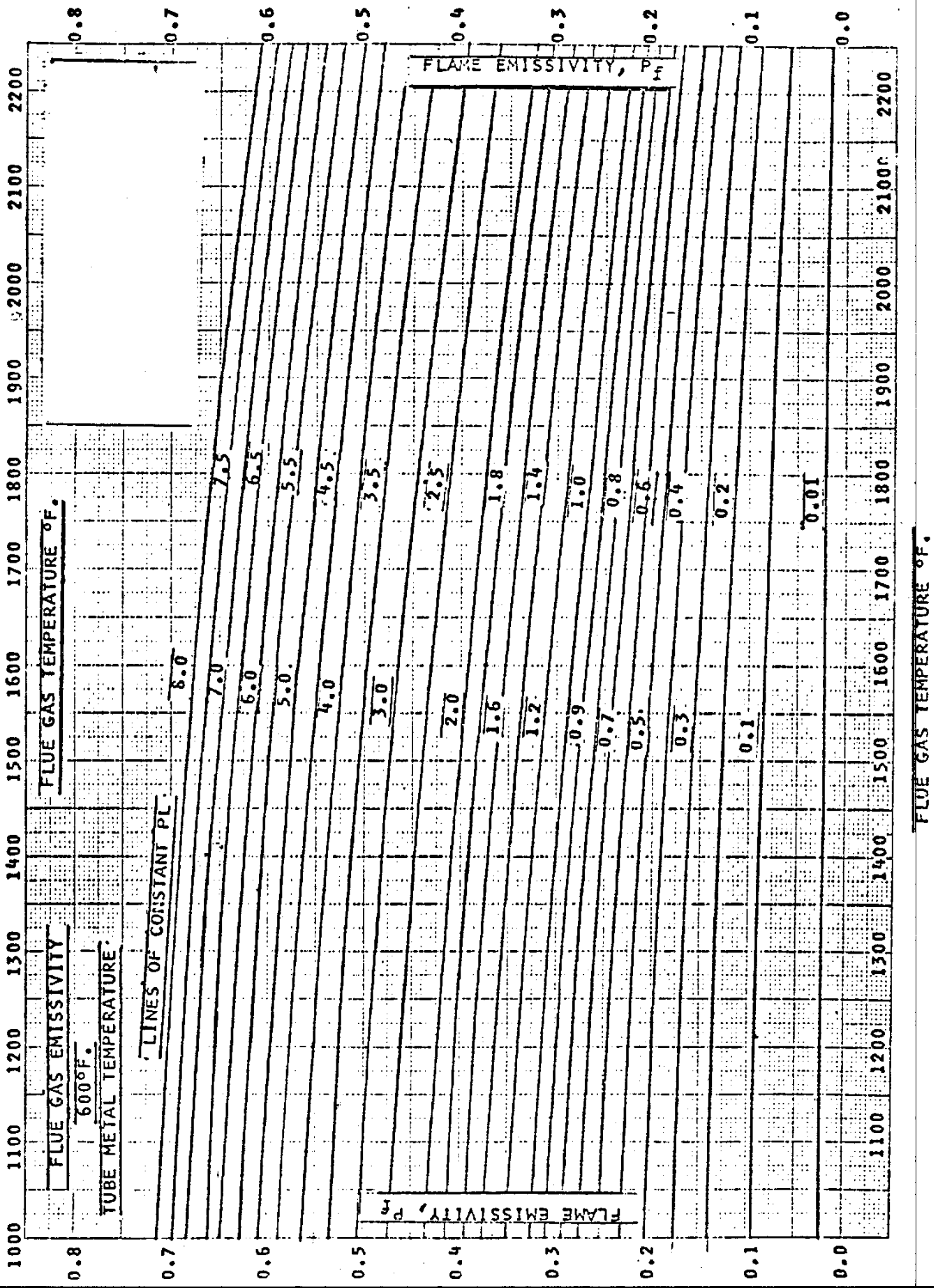

FLAME EMISSIVITY, P_f
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
FLUE GAS EMISSIVITY
400°F.
TUBE METAL TEMPERATURE
LINES OF CONSTANT PL
0.01
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
1.2
1.4
1.6
1.8
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
6.5
7.0
7.5
8.0
FLUE GAS TEMPERATURE, °F.
2100
2000
1900
1800
1700
1600
1500
1400
1300
1200
1100
1000
210
200
190
180
170
160
150
140
130
120
110
100
FLAME EMISSIVITY, P_f

FIGURE 23b


FLAME EMISSIVITY, P_f
FLUE GAS TEMPERATURE °F.
FLUE GAS EMISSIVITY
600°F.
TUBE METAL TEMPERATURE
LINES OF CONSTANT PL
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.8
1.6
1.4
1.2
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.01
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0

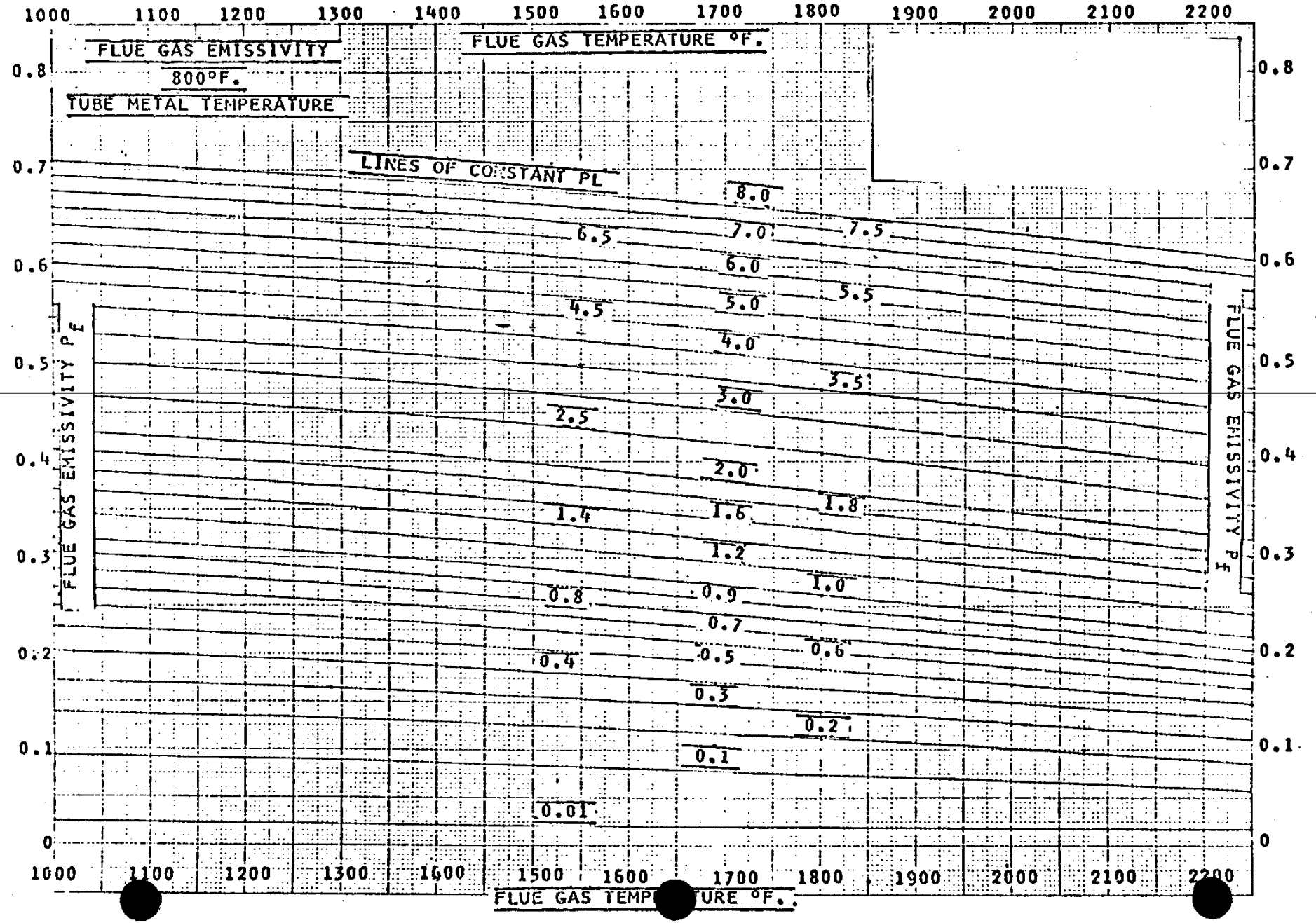

FLUE GAS EMISSIVITY
800°F.
TUBE METAL TEMPERATURE
FLUE GAS TEMPERATURE °F.
LINES OF CONSTANT PL
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.8
1.6
1.4
1.2
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.01
FLUE GAS EMISSIVITY P_f
1000 1100 1200 1300 1400 1500 1600 1700 1800 1900 2000 2100 2200
0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8

FIGURE 23c

FIGURE 23d

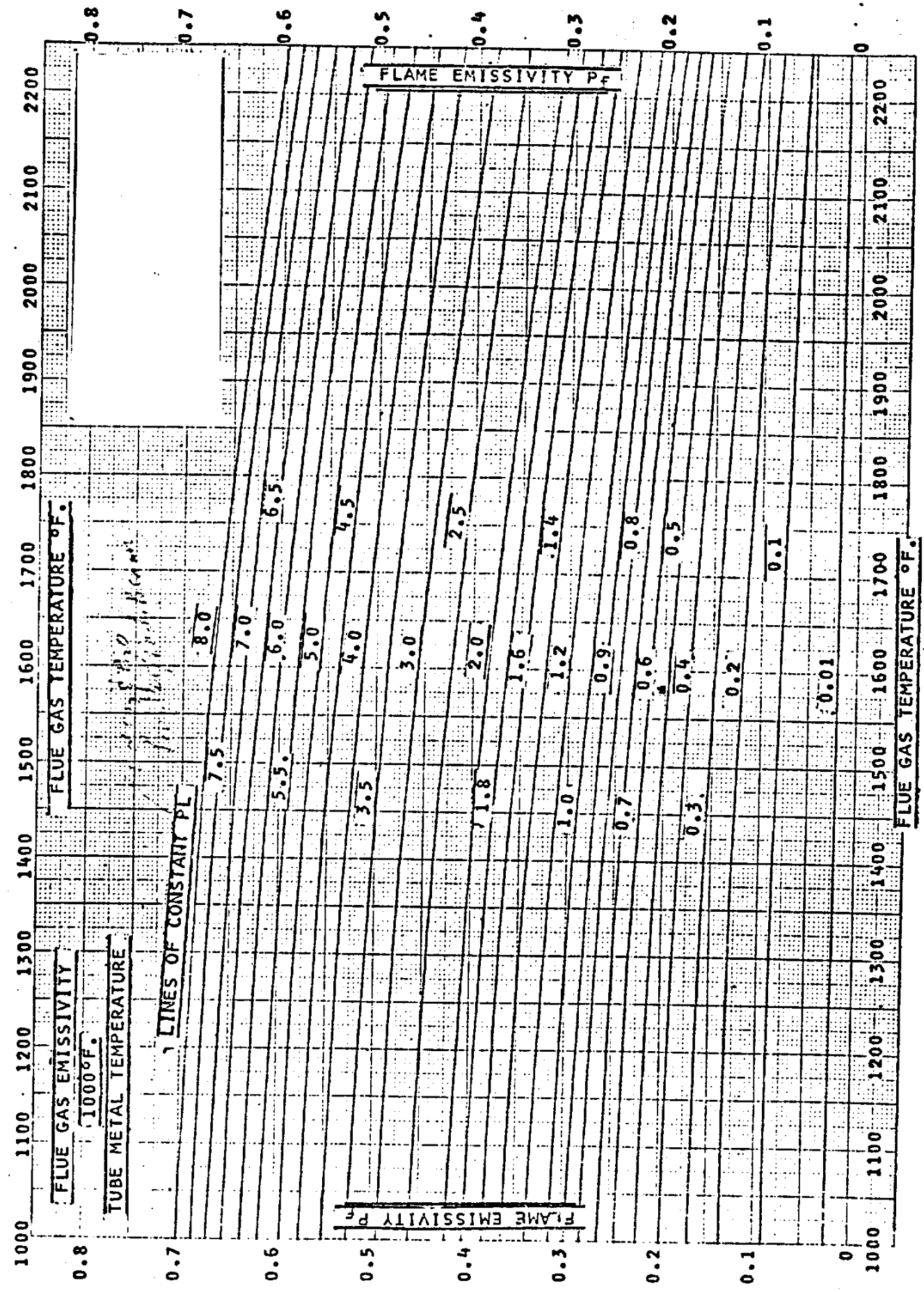
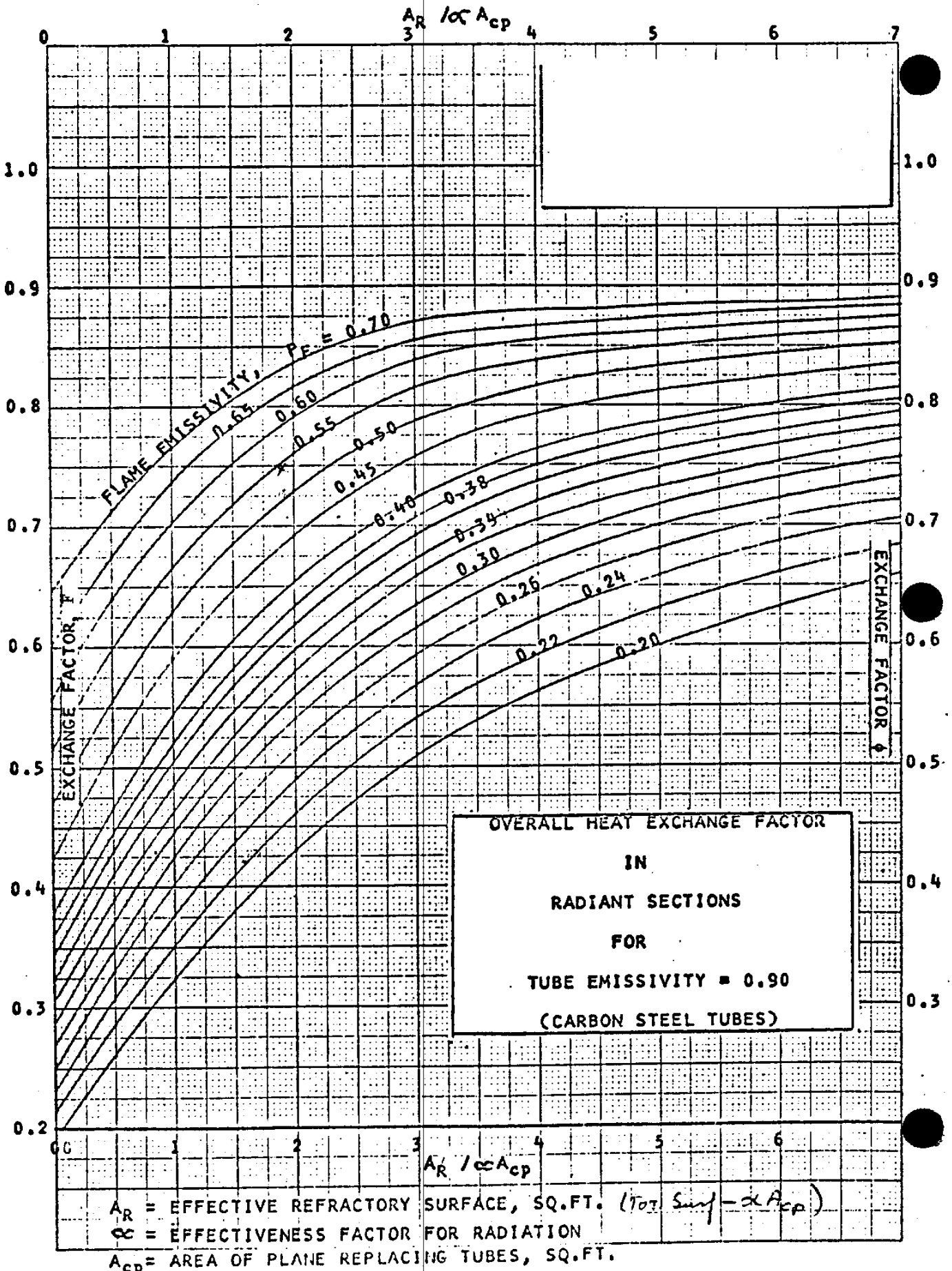

FLAME EMISSIVITY P_f
FLUE GAS TEMPERATURE °F.
FLUE GAS EMISSIVITY
1000°F.
TUBE METAL TEMPERATURE
LINES OF CONSTANT PL
FLAME EMISSIVITY P_f
FLUE GAS TEMPERATURE °F.

FIGURE 24



A_R = EFFECTIVE REFRACTORY SURFACE, SQ.FT. (Tot Surf $- \alpha A_{cp}$)

α = EFFECTIVENESS FACTOR FOR RADIATION

A_{cp} = AREA OF PLANE REPLACING TUBES, SQ.FT.

FIGURE 25a

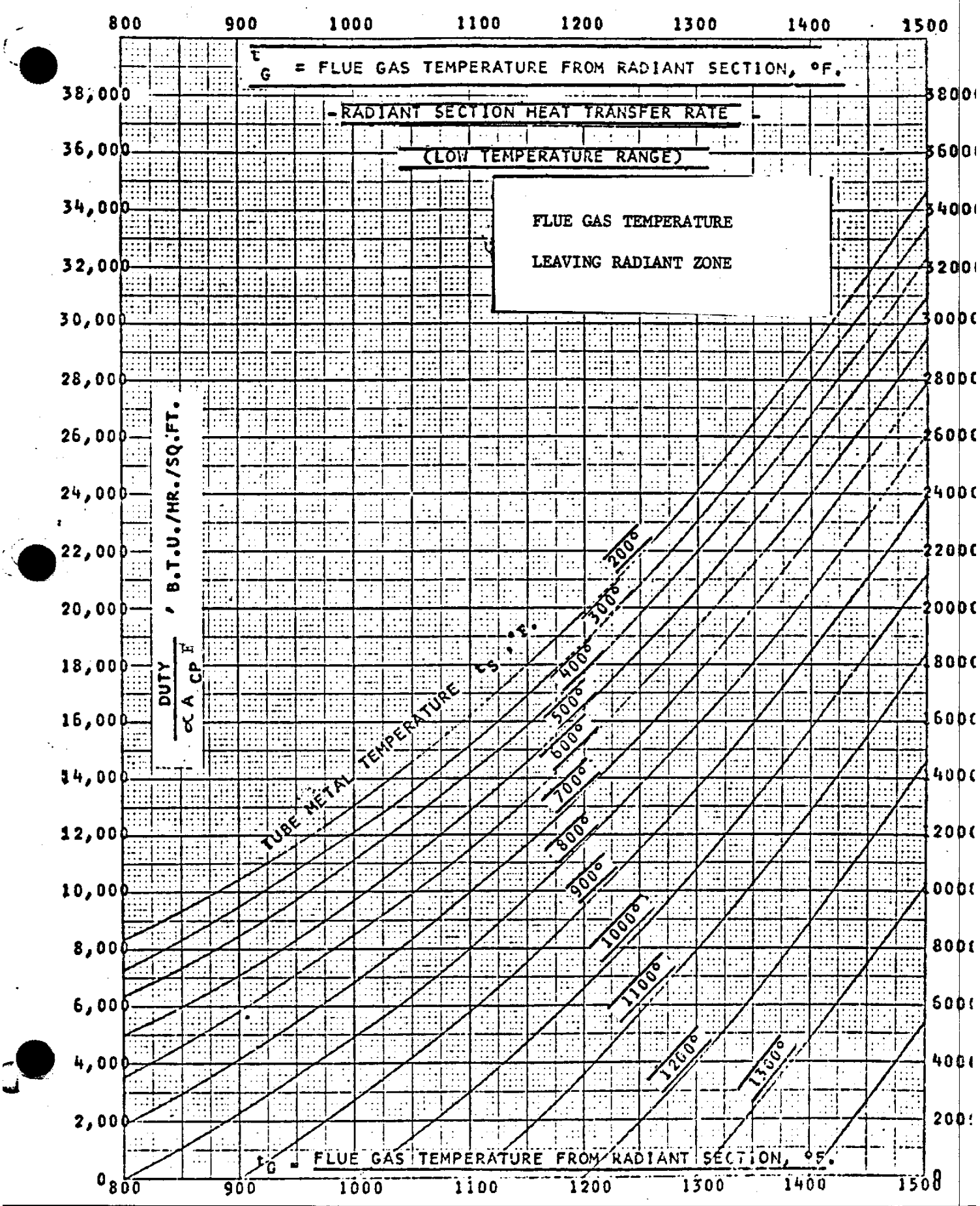

t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
RADIANT SECTION HEAT TRANSFER RATE
(LOW TEMPERATURE RANGE)
FLUE GAS TEMPERATURE
LEAVING RADIANT ZONE
DUTY / ∝ A CP F, B.T.U./HR./SQ.FT.
TUBE METAL TEMPERATURE t_S, °F.
200°
300°
400°
500°
600°
700°
800°
900°
1000°
1100°
1200°
1300°
t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
800
900
1000
1100
1200
1300
1400
1500
38,000
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0

FIGURE 25b

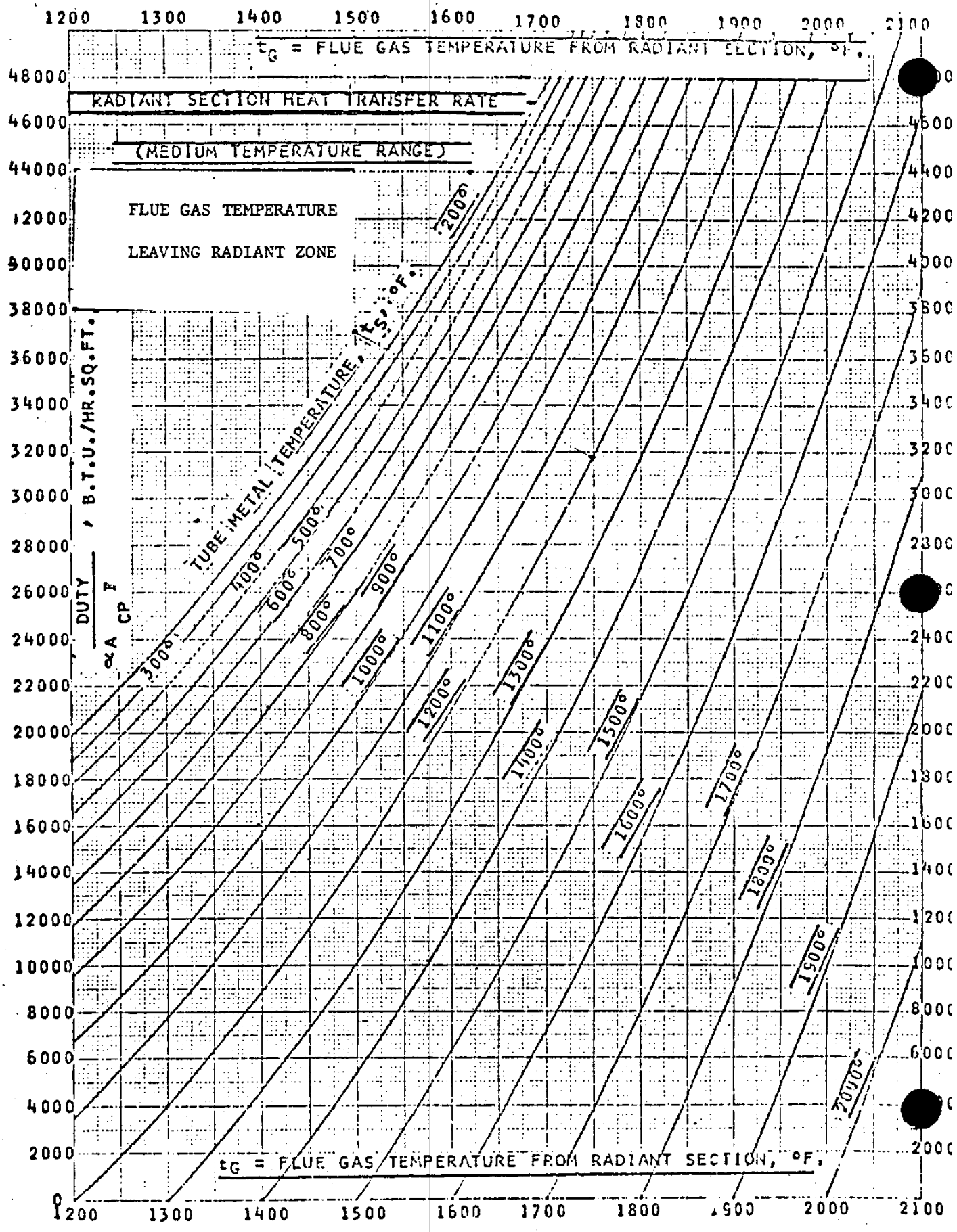

RADIANT SECTION HEAT TRANSFER RATE
(MEDIUM TEMPERATURE RANGE)
FLUE GAS TEMPERATURE
LEAVING RADIANT ZONE
t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
TUBE METAL TEMPERATURE, t_S, °F.
DUTY / αA_{CP} F, B.T.U./HR.SQ.FT.
200°
300°
400°
500°
600°
700°
800°
900°
1000°
1100°
1200°
1300°
1400°
1500°
1600°
1700°
1800°
1900°
2000°
48000
46000
44000
42000
40000
38000
36000
34000
32000
30000
28000
26000
24000
22000
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100

FIGURE 25c

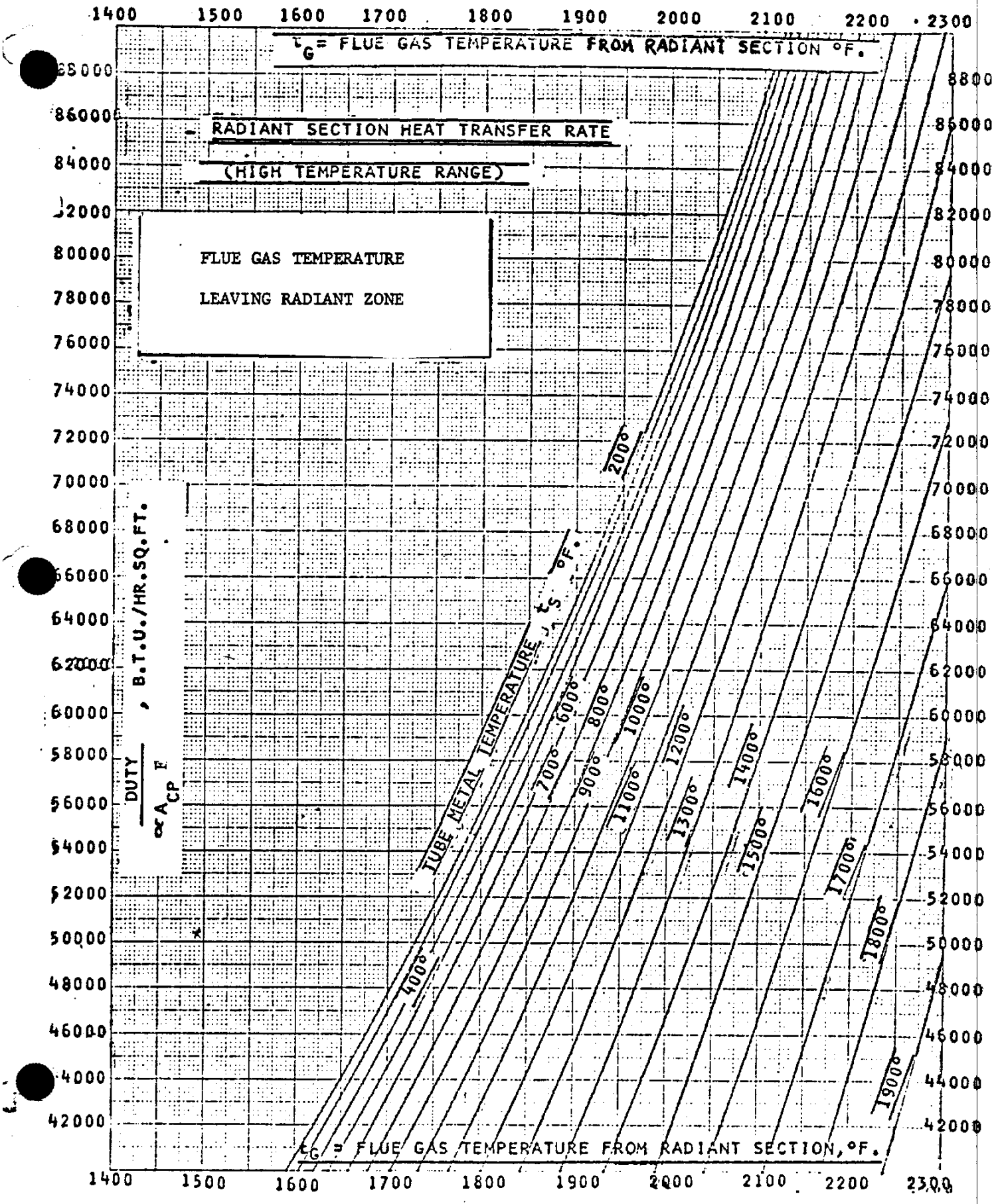

t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION °F.
RADIANT SECTION HEAT TRANSFER RATE
(HIGH TEMPERATURE RANGE)
FLUE GAS TEMPERATURE
LEAVING RADIANT ZONE
DUTY / $\propto A_{CP} F$, B.T.U./HR.SQ.FT.
TUBE METAL TEMPERATURE, t_S °F.
200°
400°
600°
700°
800°
900°
1000°
1100°
1200°
1300°
1400°
1500°
1600°
1700°
1800°
1900°
t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
1400 1500 1600 1700 1800 1900 2000 2100 2200 2300
88000 86000 84000 82000 80000 78000 76000 74000 72000 70000 68000 66000 64000 62000 60000 58000 56000 54000 52000 50000 48000 46000 44000 42000

FIGURE 25d

EFFECT TUBE DISTANCE FROM WALL HAS ON RADIANT TRANSFER RATE

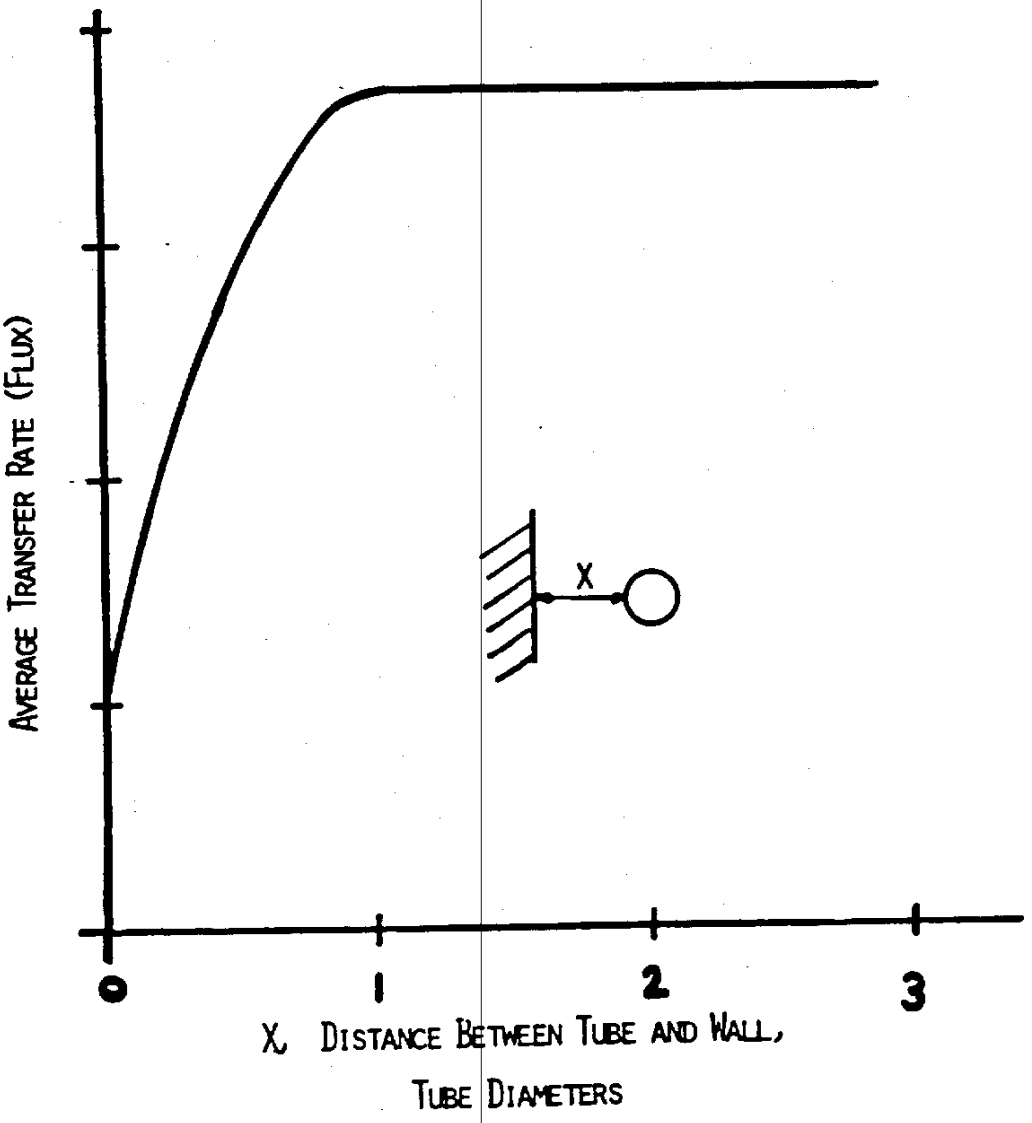
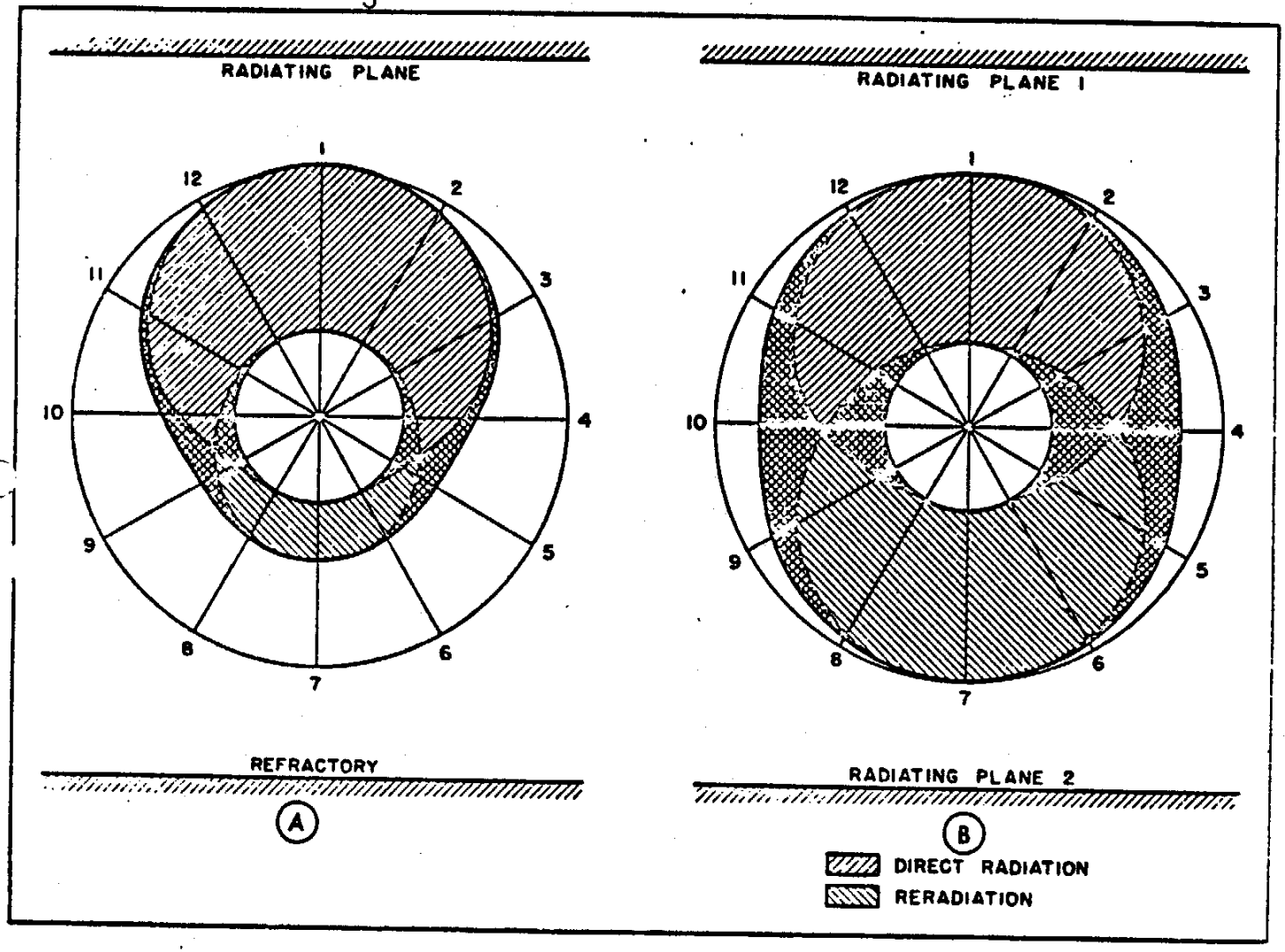
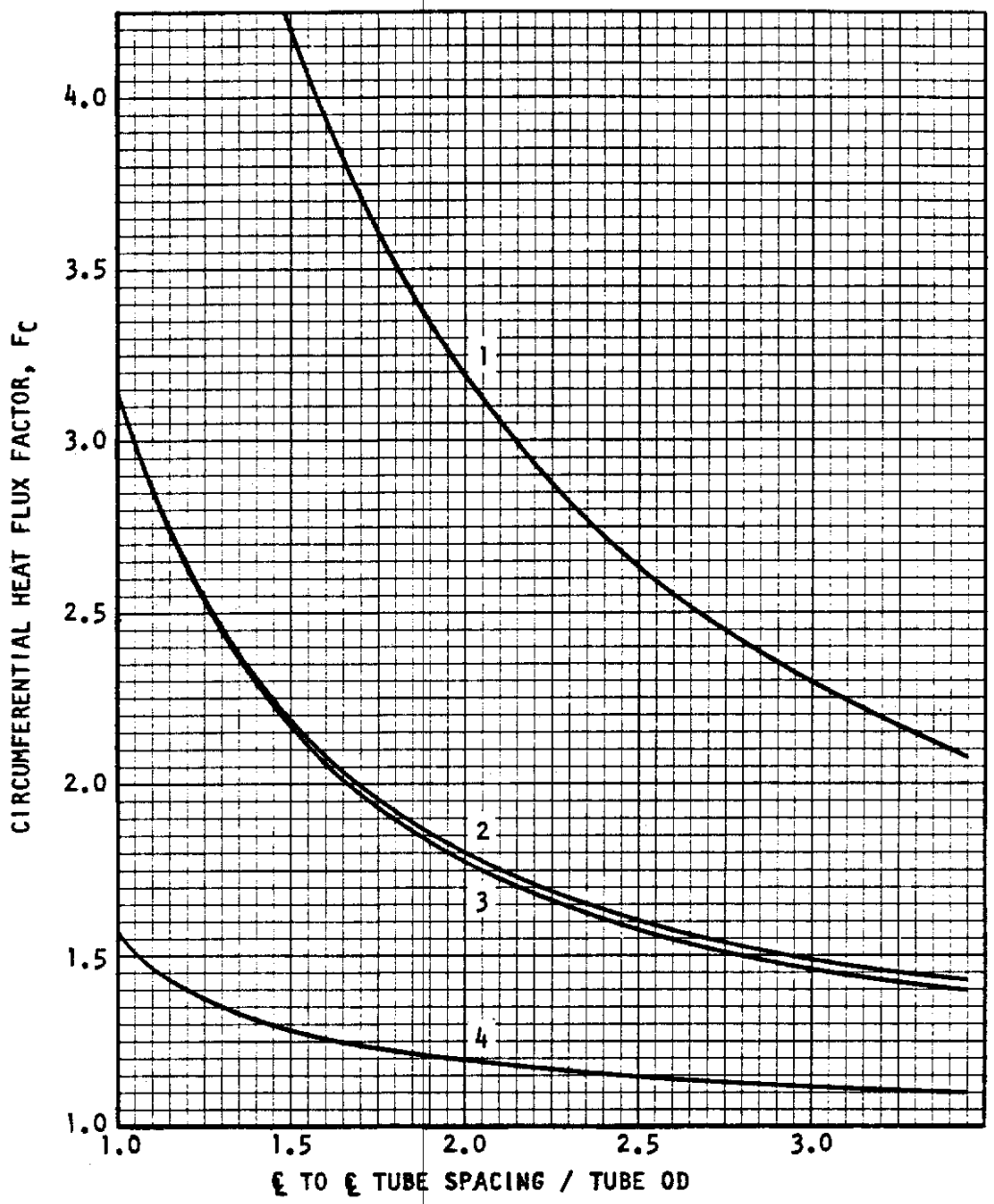


Figure 25e



Flux Distribution around Circumference of Tubes in Single Row Banks. A—Primary Radiating Plane from One Side,—Refractory from the Other. B—Primary Radiation Both Sides



Curves

1. Double row against wall triangular spacing.
2. Double row with equal radiation from both sides. Two diameters between rows (tubes are spaced equilaterally).
3. Single row against wall.
4. Single row with equal radiation from both sides.

Explanatory Notes

1. These curves are valid when used with a tube center to refractory wall spacing of one and one-half times the nominal tube diameter involved. Any appreciable variation from this spacing must be given special consideration.

2. These curves do not consider convection heat transfer to the tubes, circumferential heat transfer by conduction in the tube wall, or variations in heat flux in different zones of the radiant section.

3. These curves are based on the work of H. C. Hottel.

—Ratio of Maximum Local to Average Heat Flux

Figure 25f

FIGURE 26a

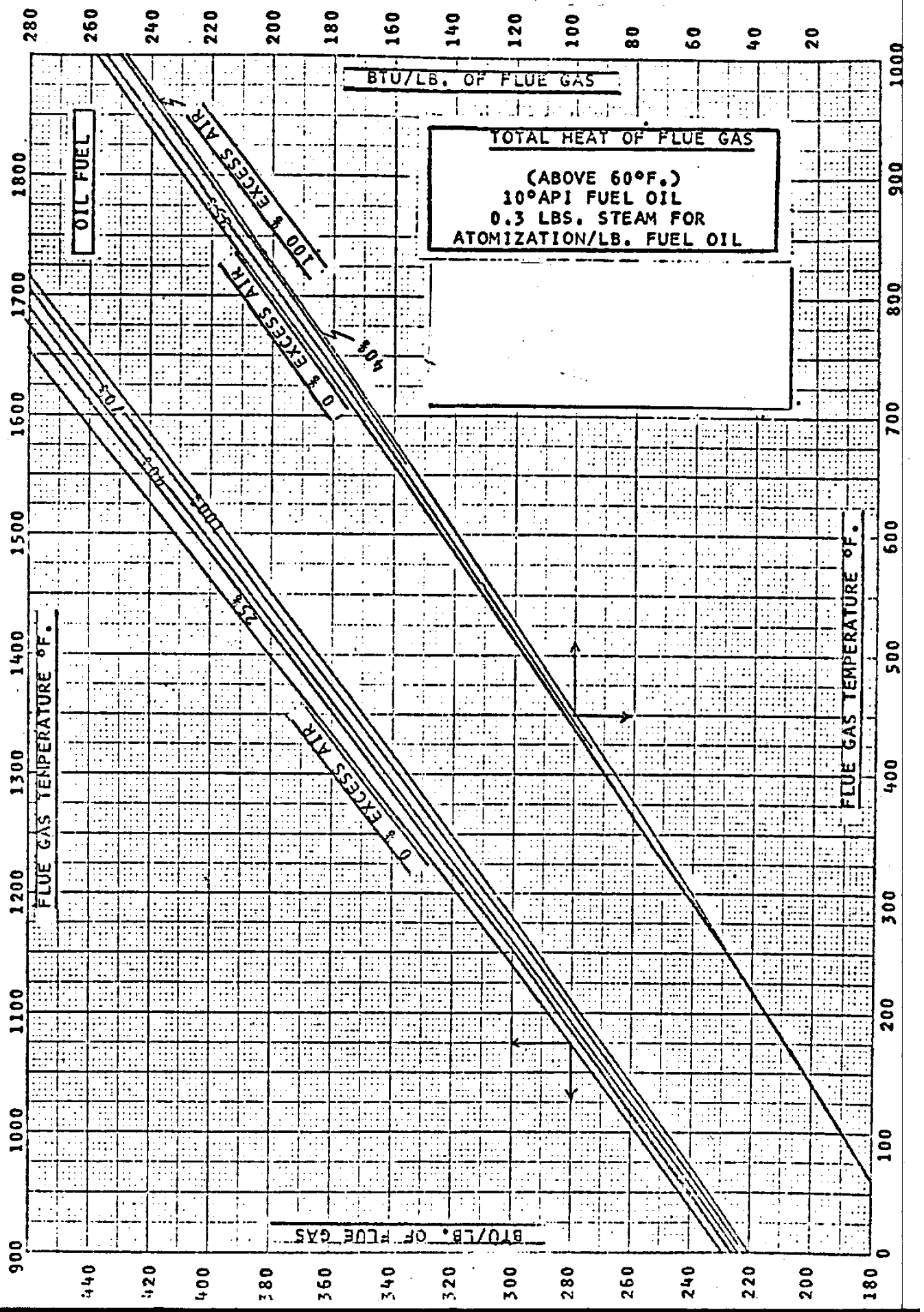

TOTAL HEAT OF FLUE GAS
(ABOVE 60°F.)
10°API FUEL OIL
0.3 LBS. STEAM FOR
ATOMIZATION/LB. FUEL OIL
OIL FUEL
BTU/LB. OF FLUE GAS
FLUE GAS TEMPERATURE °F.
0 % EXCESS AIR
100 % EXCESS AIR
25% EXCESS AIR
BTU/LB. OF FLUE GAS
FLUE GAS TEMPERATURE °F.

FIGURE 26b

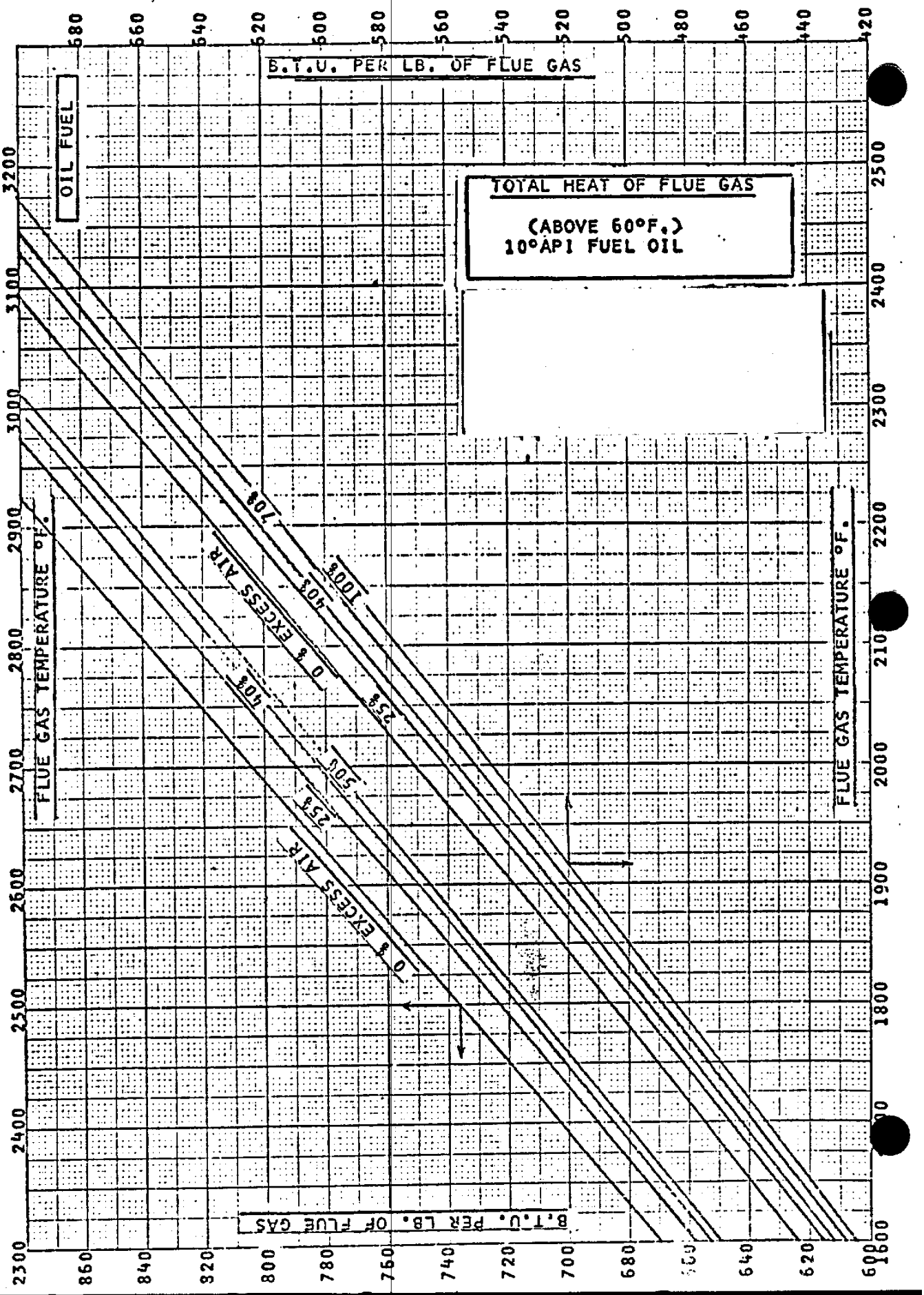

B.T.U. PER LB. OF FLUE GAS
OIL FUEL
TOTAL HEAT OF FLUE GAS
(ABOVE 60°F.)
10°API FUEL OIL
FLUE GAS TEMPERATURE °F.
0 % EXCESS AIR
25% EXCESS AIR
50% EXCESS AIR
75% EXCESS AIR
100% EXCESS AIR
B.T.U. PER LB. OF FLUE GAS
FLUE GAS TEMPERATURE °F.

FIGURE 26c

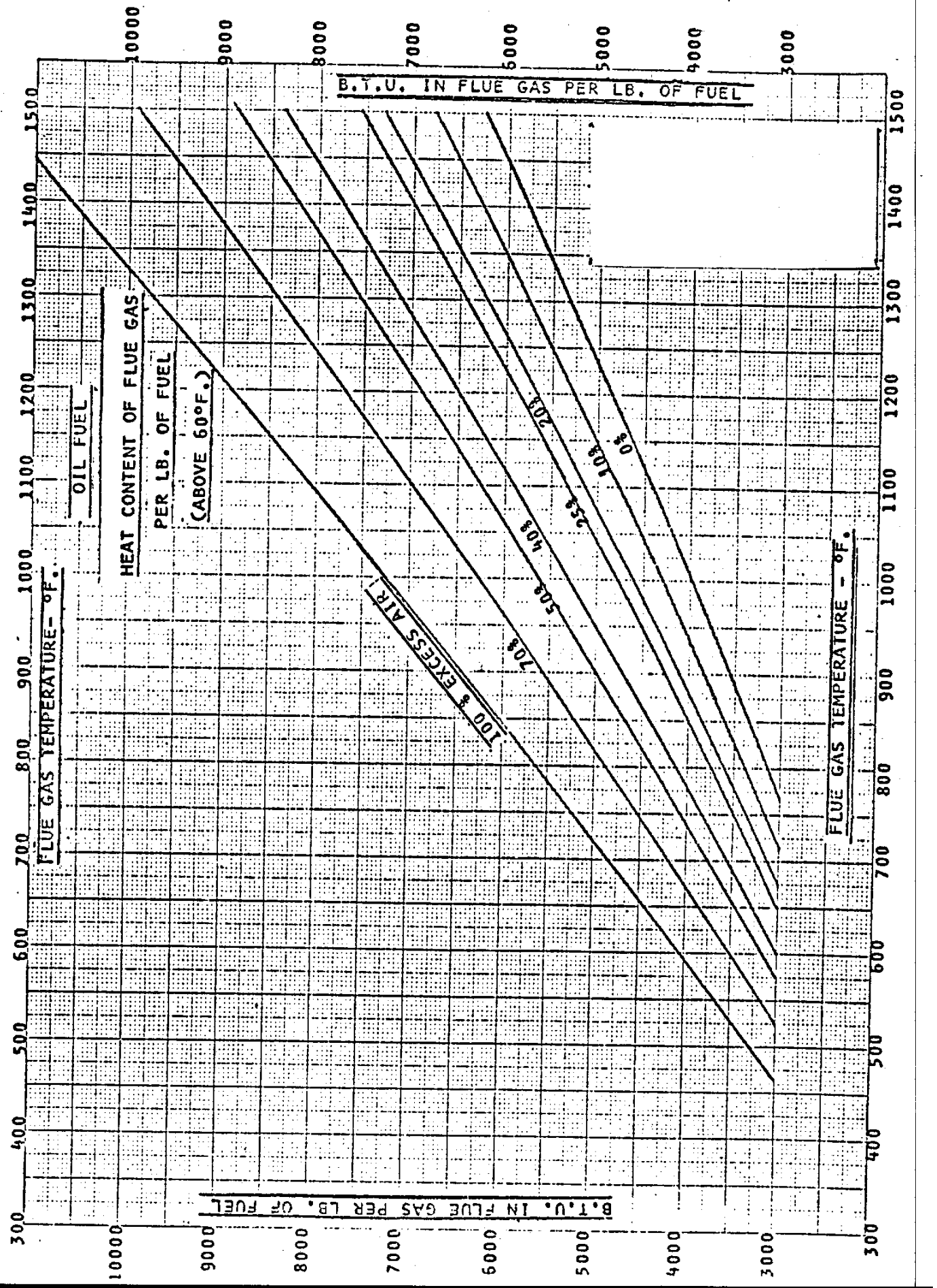

B.T.U. IN FLUE GAS PER LB. OF FUEL
HEAT CONTENT OF FLUE GAS
PER LB. OF FUEL
(ABOVE 60°F.)
OIL FUEL
FLUE GAS TEMPERATURE - °F.
100 % EXCESS AIR
70%
50%
40%
25%
10%
0%
20%
B.T.U. IN FLUE GAS PER LB. OF FUEL
FLUE GAS TEMPERATURE - °F.

FIGURE 26d

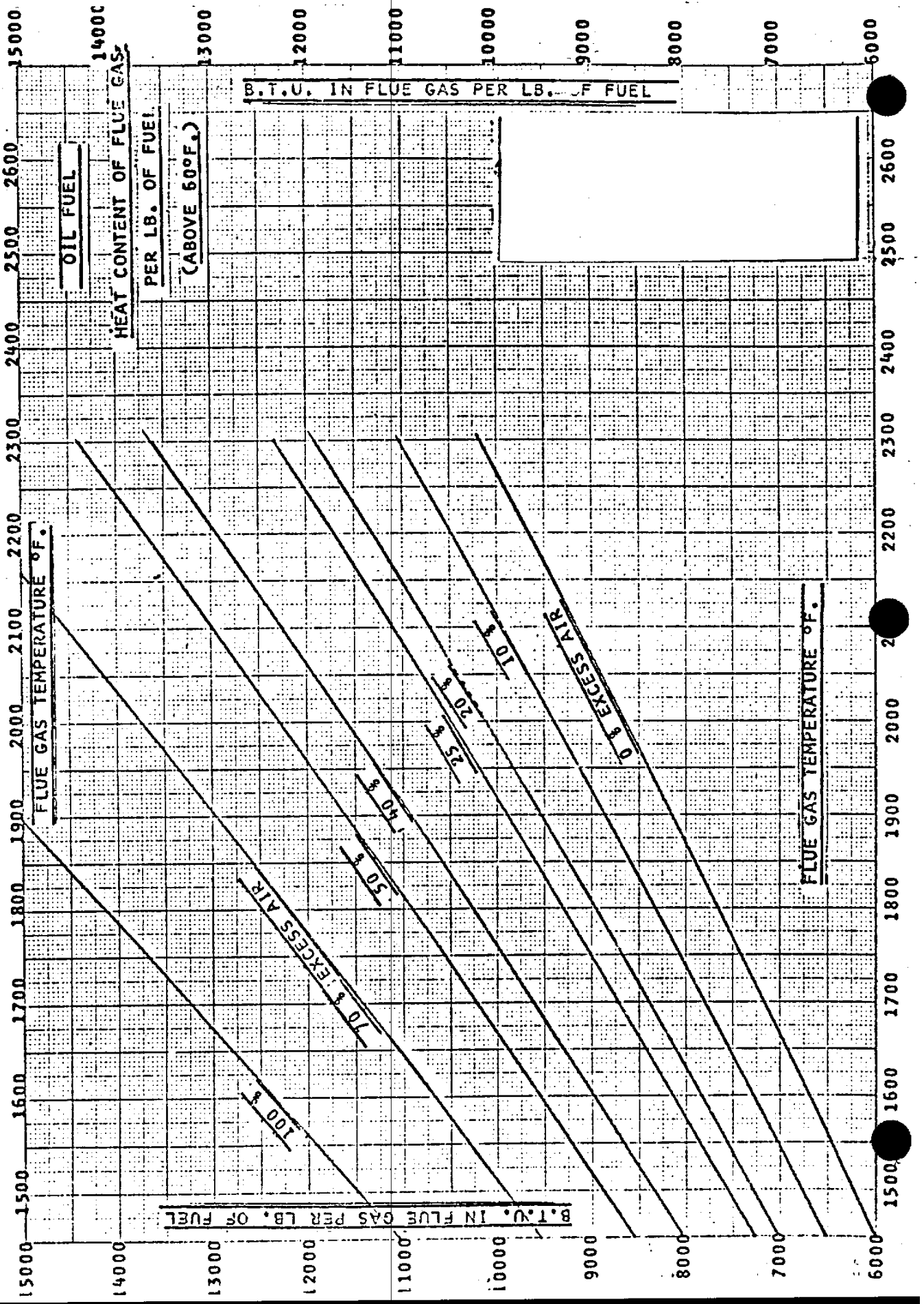

OIL FUEL
HEAT CONTENT OF FLUE GAS
PER LB. OF FUEL
(ABOVE 60°F.)
B.T.U. IN FLUE GAS PER LB. OF FUEL
FLUE GAS TEMPERATURE °F.
0 % EXCESS AIR
10 %
20 %
25 %
40 %
50 %
70 % EXCESS AIR
100 %
B.T.U. IN FLUE GAS PER LB. OF FUEL
FLUE GAS TEMPERATURE °F.
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
2600
2500
2400
2300
2200
2100
2000
1900
1800
1700
1600
1500

FIGURE 27

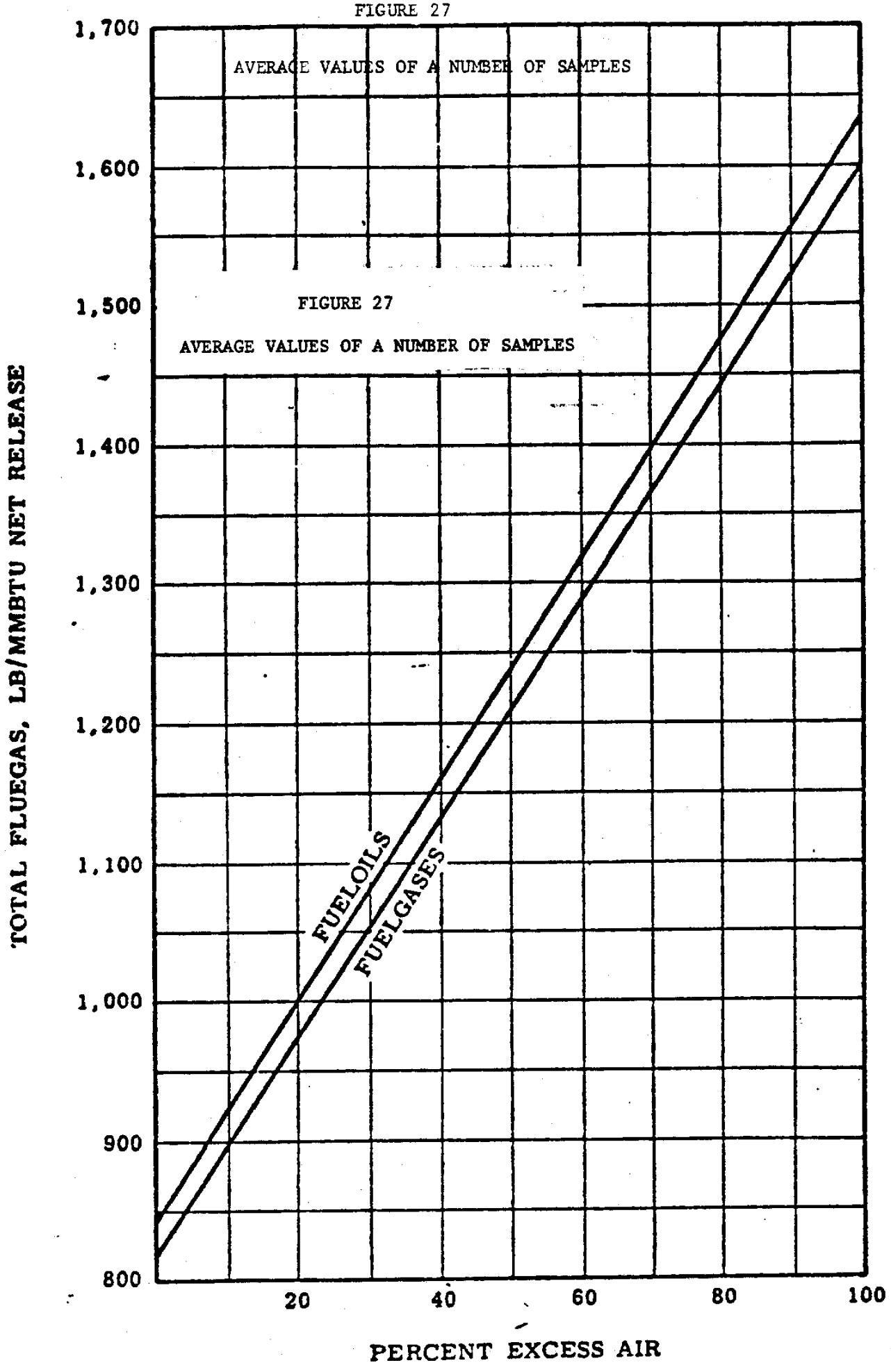
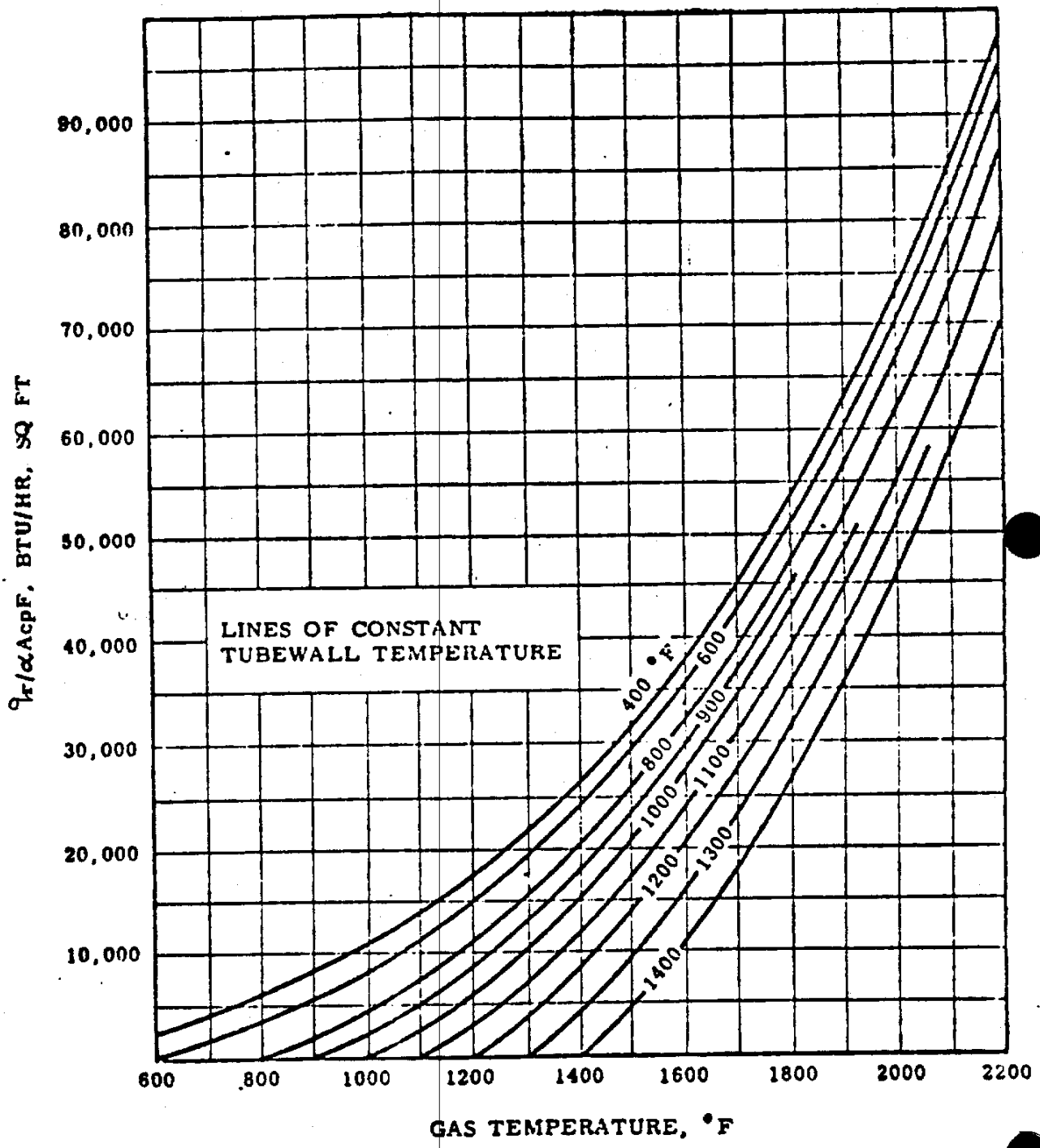

AVERAGE VALUES OF A NUMBER OF SAMPLES
FIGURE 27
AVERAGE VALUES OF A NUMBER OF SAMPLES
TOTAL FLUEGAS, LB/MMBTU NET RELEASE
1,700
1,600
1,500
1,400
1,300
1,200
1,100
1,000
900
800
FUELOILS
FUELGASES
20
40
60
80
100
PERCENT EXCESS AIR

FIGURE 28



—Total heat-absorption in the radiant section.

FIGURE 29

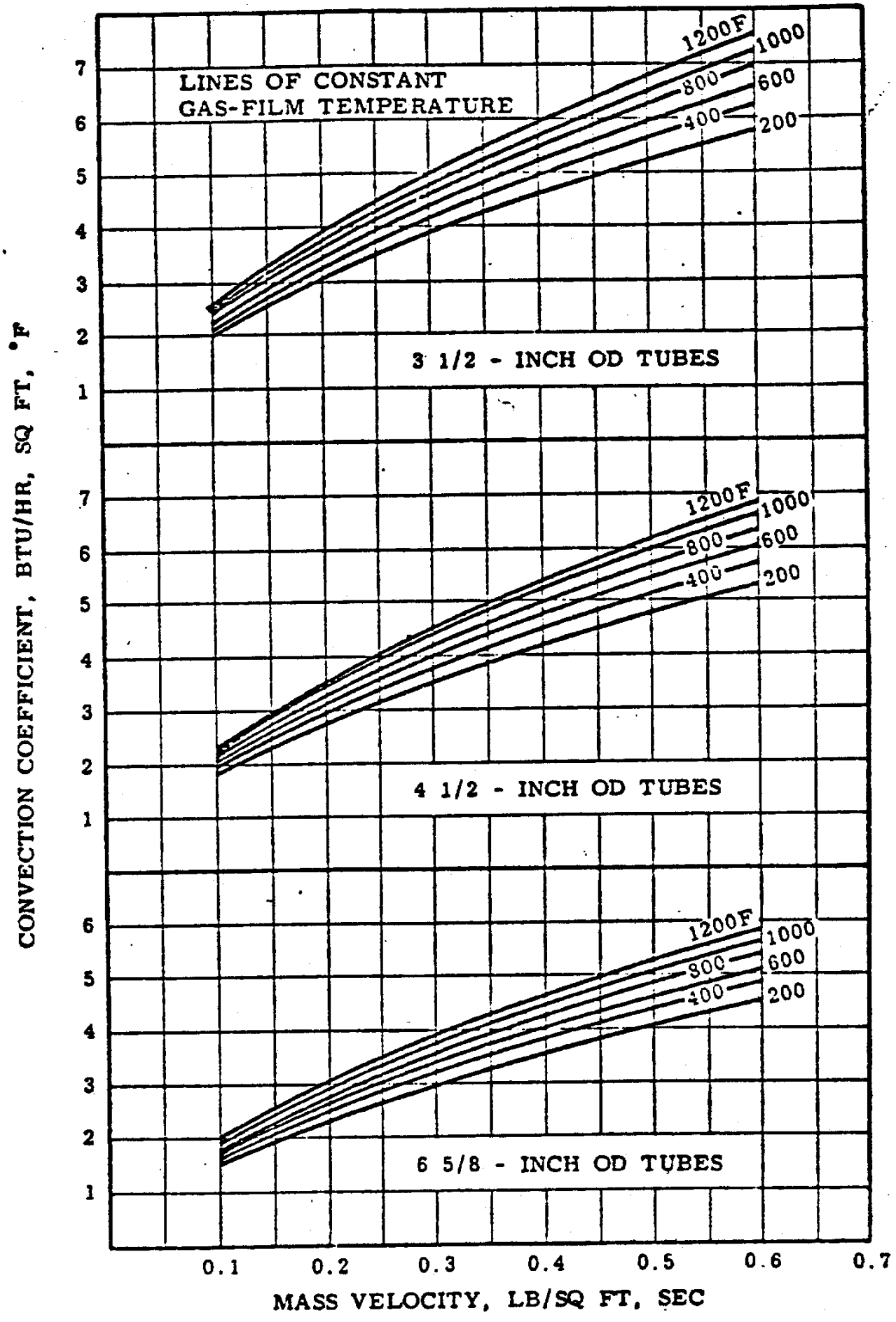

LINES OF CONSTANT
GAS-FILM TEMPERATURE
1200F
1000
800
600
400
200
3 1/2 - INCH OD TUBES
4 1/2 - INCH OD TUBES
6 5/8 - INCH OD TUBES
CONVECTION COEFFICIENT, BTU/HR, SQ FT, °F
1
2
3
4
5
6
7
0.1
0.2
0.3
0.4
0.5
0.6
0.7
MASS VELOCITY, LB/SQ FT, SEC

FIGURE 30

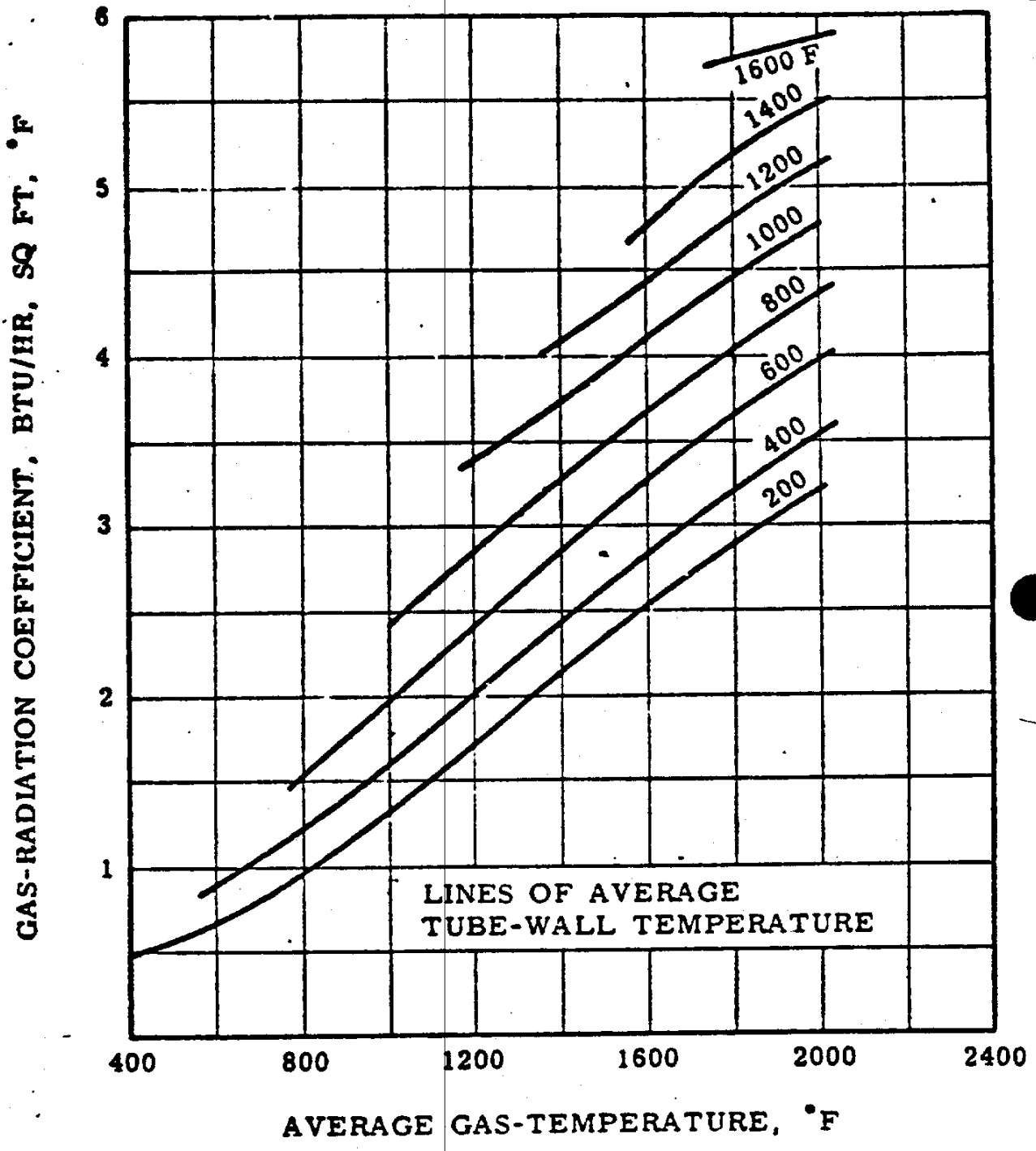

GAS-RADIATION COEFFICIENT, BTU/HR, SQ FT, °F
6
5
4
3
2
1
1600 F
1400
1200
1000
800
600
400
200
LINES OF AVERAGE
TUBE-WALL TEMPERATURE
400
800
1200
1600
2000
2400
AVERAGE GAS-TEMPERATURE, °F

FIGURE 31

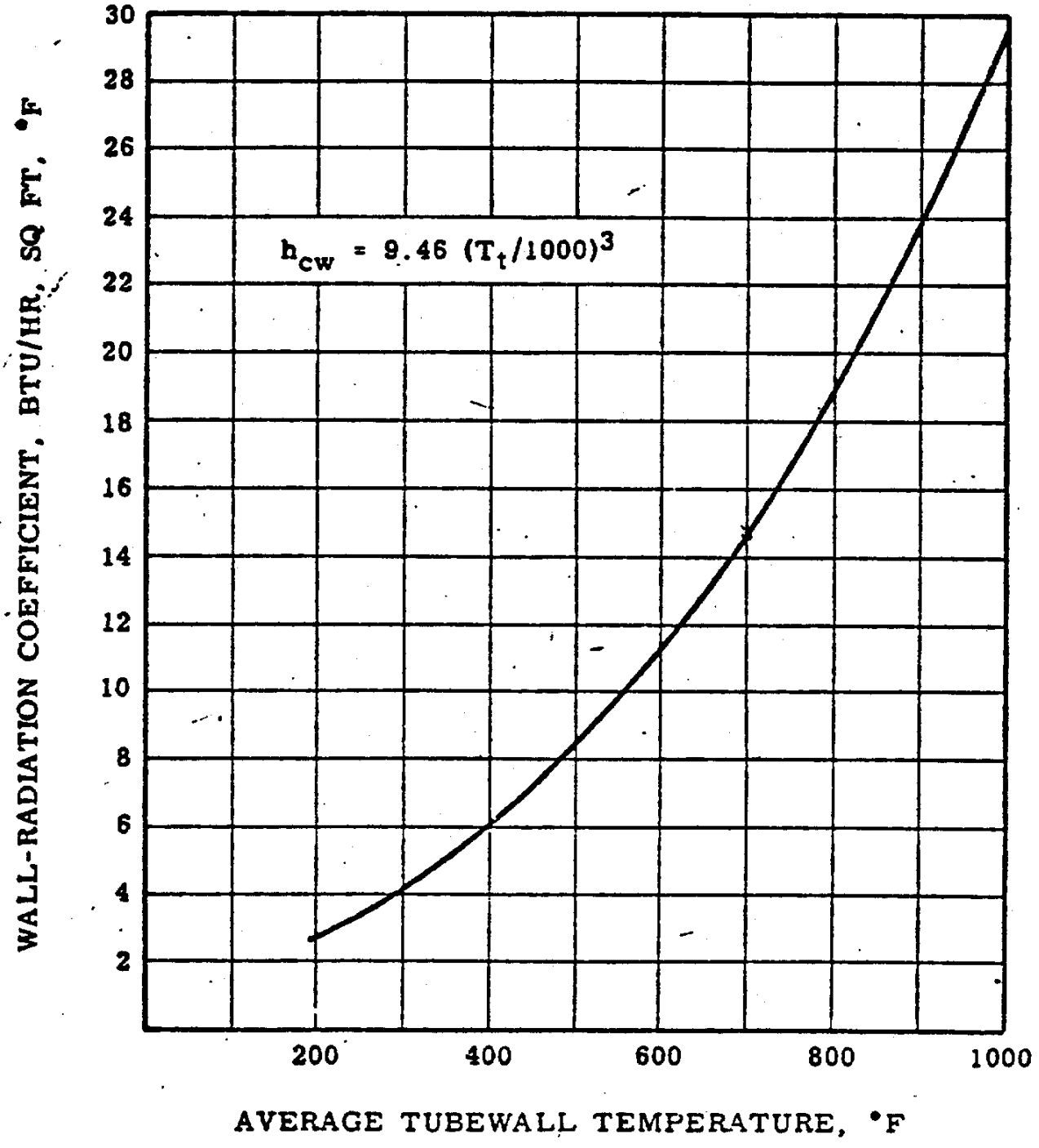

$h_{cw} = 9.46\ (T_t/1000)^3$
WALL-RADIATION COEFFICIENT, BTU/HR, SQ FT, °F
30
28
26
24
22
20
18
16
14
12
10
8
6
4
2
200
400
600
800
1000
AVERAGE TUBEWALL TEMPERATURE, °F

FIGURE 32

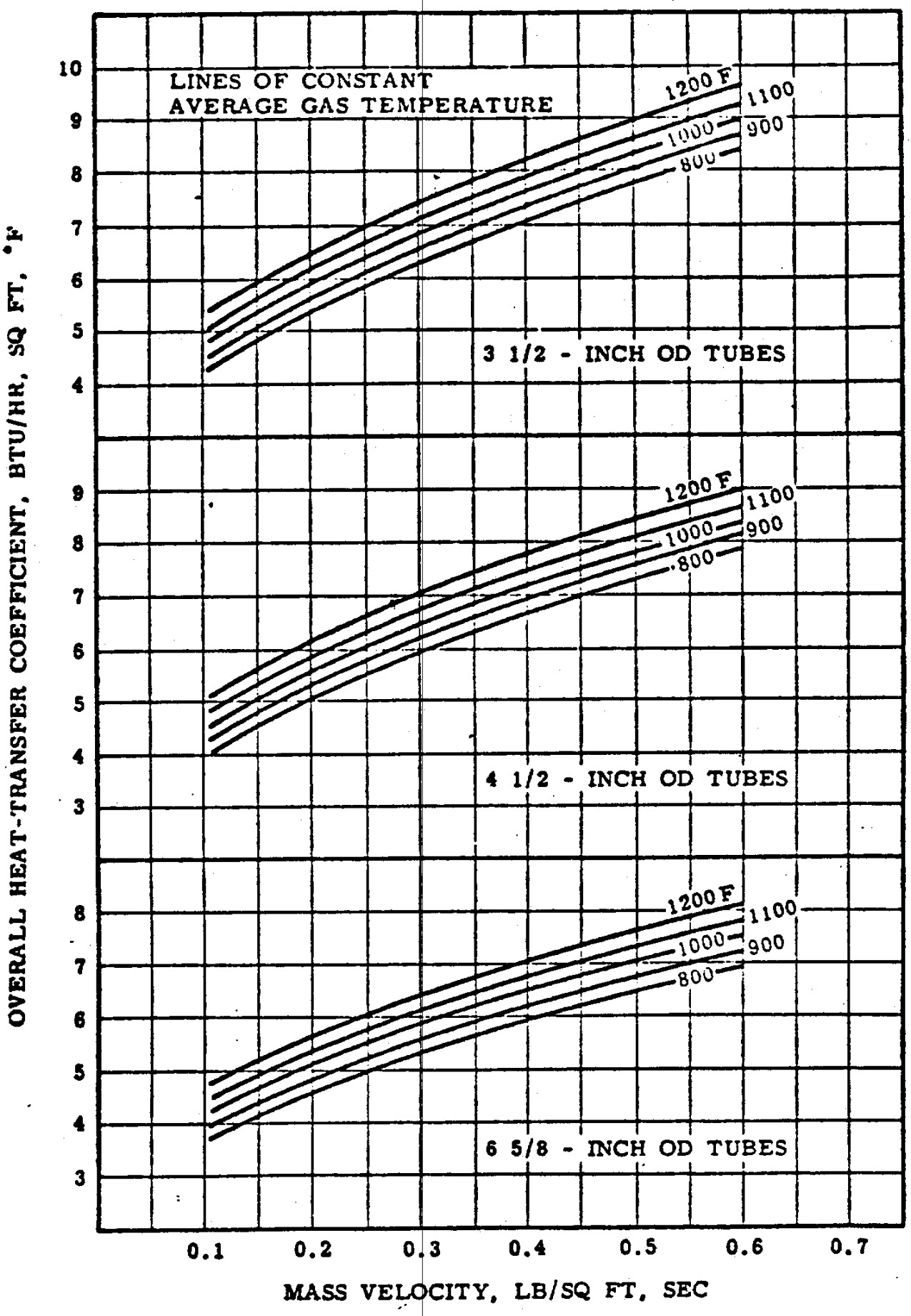

LINES OF CONSTANT
AVERAGE GAS TEMPERATURE
1200 F
1100
1000
900
800
3 1/2 - INCH OD TUBES
4 1/2 - INCH OD TUBES
6 5/8 - INCH OD TUBES
OVERALL HEAT-TRANSFER COEFFICIENT, BTU/HR, SQ FT, °F
MASS VELOCITY, LB/SQ FT, SEC
0.1
0.2
0.3
0.4
0.5
0.6
0.7

FIGURE 33

DENSITY OF FLUE GAS

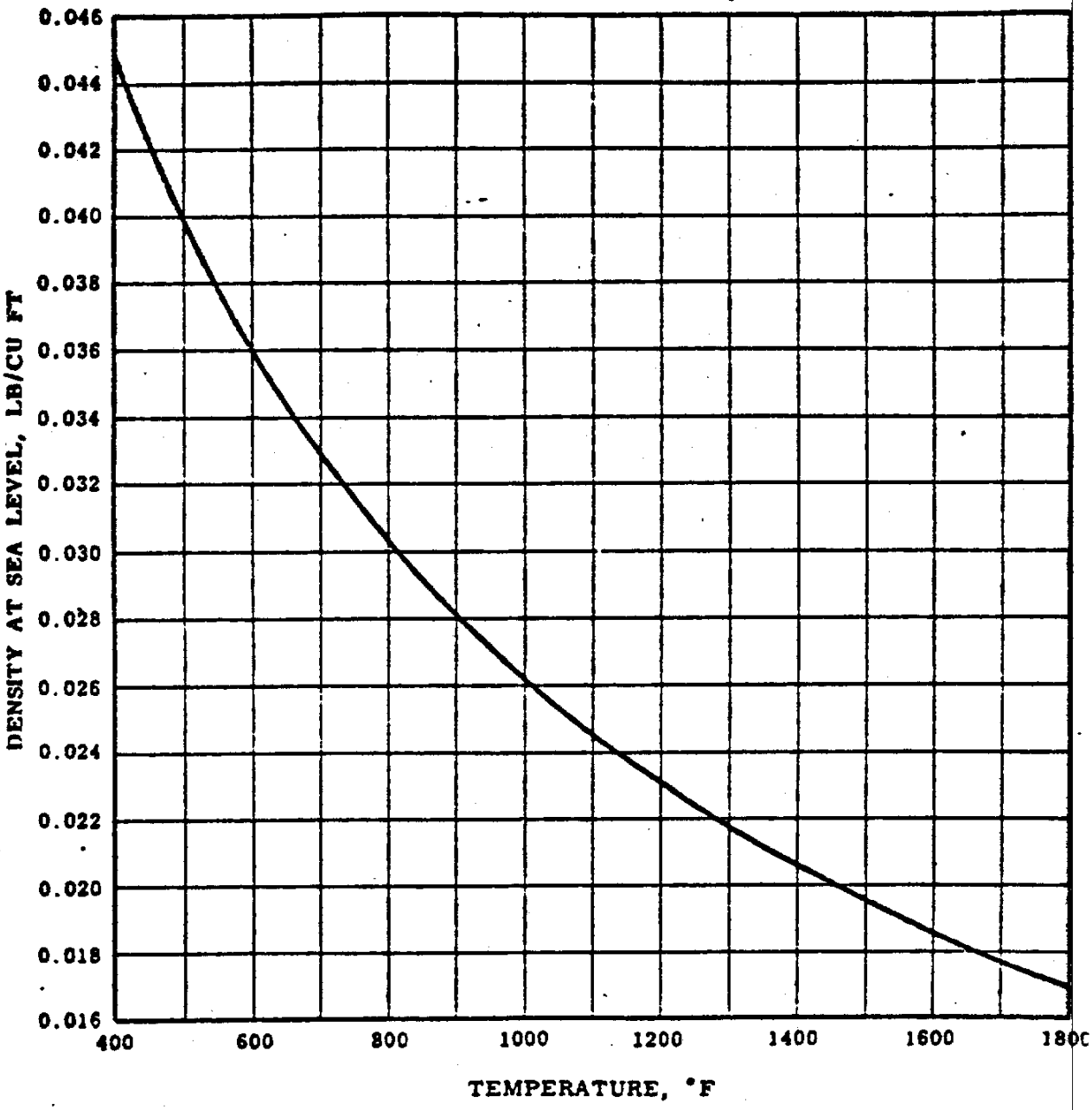


FIGURE 34

STACK DRAFT AT SEA LEVEL

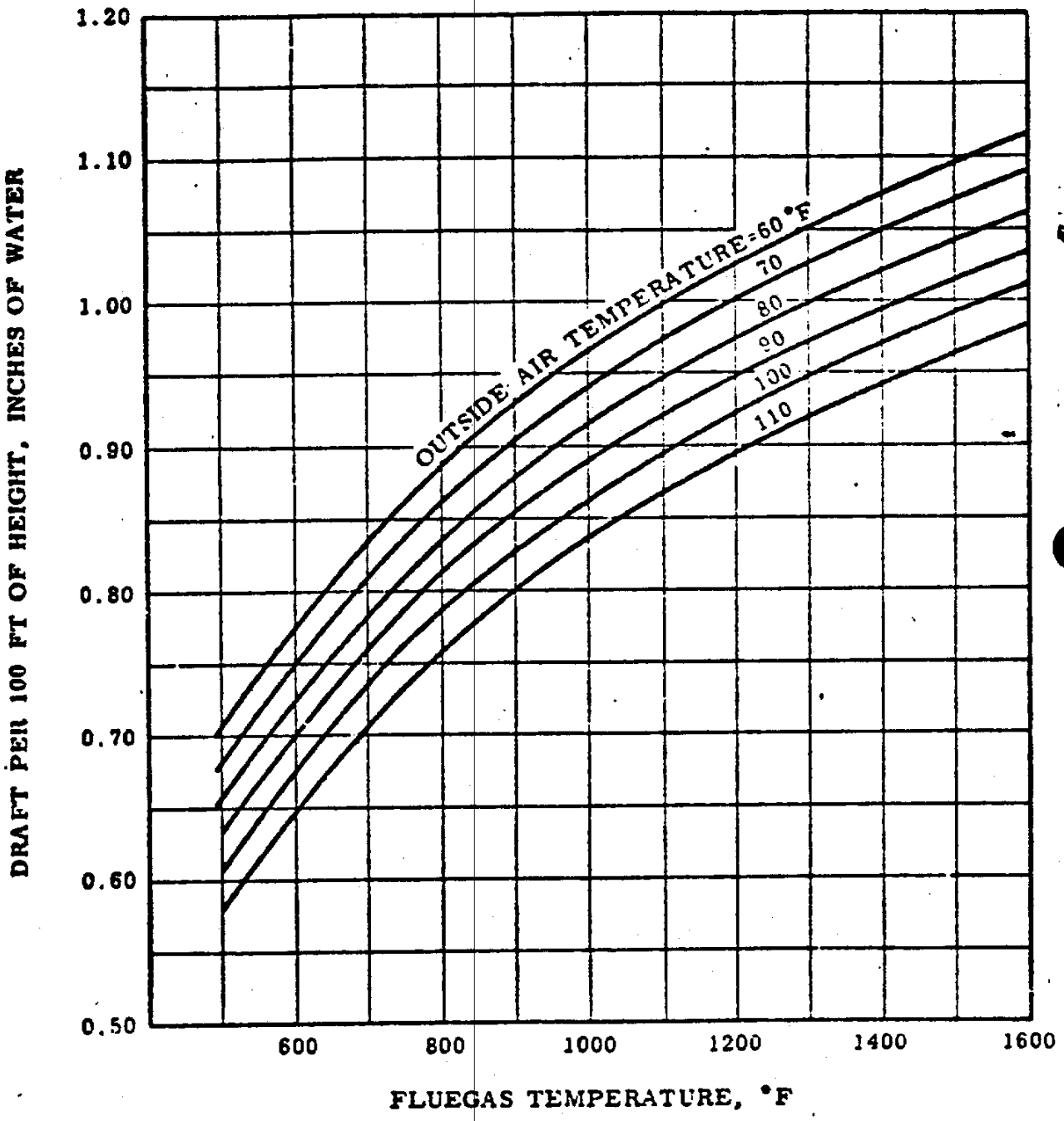


TABLE 2

FUEL OIL

FURNACE EFFICIENCY

WITHOUT AIR PREHEATER

FLUE GAS TEMP. °F	B.T.U. PER LB. FLUE GAS	B.T.U. PER LB FUEL	FURNACE EFFICIENCY PER CENT
40% EXCESS AIR - 20.83 LB. FLUE GAS PER LB. FUEL			
500	114.1	2377	83.12
550	127.7	2660	81.47
600	141.4	2945	79.81
650	155.1	3231	78.14
700	168.8	3516	76.47
750	182.6	3804	74.79
800	196.4	4091	73.12
850	210.5	4385	71.40
900	224.5	4676	69.70
950	238.7	4972	67.97
1000	253.0	5270	66.23
1050	267.3	5568	64.50
1100	281.7	5868	62.74
1150	296.3	6172	60.97
1200	311.0	6478	59.18
1250	325.9	6788	57.37
1300	340.9	7101	55.55
1350	355.9	7413	53.72
1400	370.9	7726	51.90
1450	386.0	8040	50.06
1500	401.3	8359	48.20

BASIS

FUEL: 10° A.P.I. FUEL OIL. 17,130 B.T.U. PER LB. LOWER HEATING VALUE.
NO AIR PREHEATER: AIR AT 50% RELATIVE HUMIDITY AND 60° FAHR.
RADIATION LOSS: 3.00% OF TOTAL HEAT LIBERATED BY FUEL.
STEAM FOR ATOMIZATION OF FUEL: 0.30 LB. PER LB. OF FUEL.

FUEL OIL ANALYSIS

CARBON	85.0%	BY WEIGHT	OXYGEN	0.7%	BY WEIGHT
HYDROGEN	12.0%	" "	NITROGEN	0.8%	" "
SULPHUR	1.5%	" "			

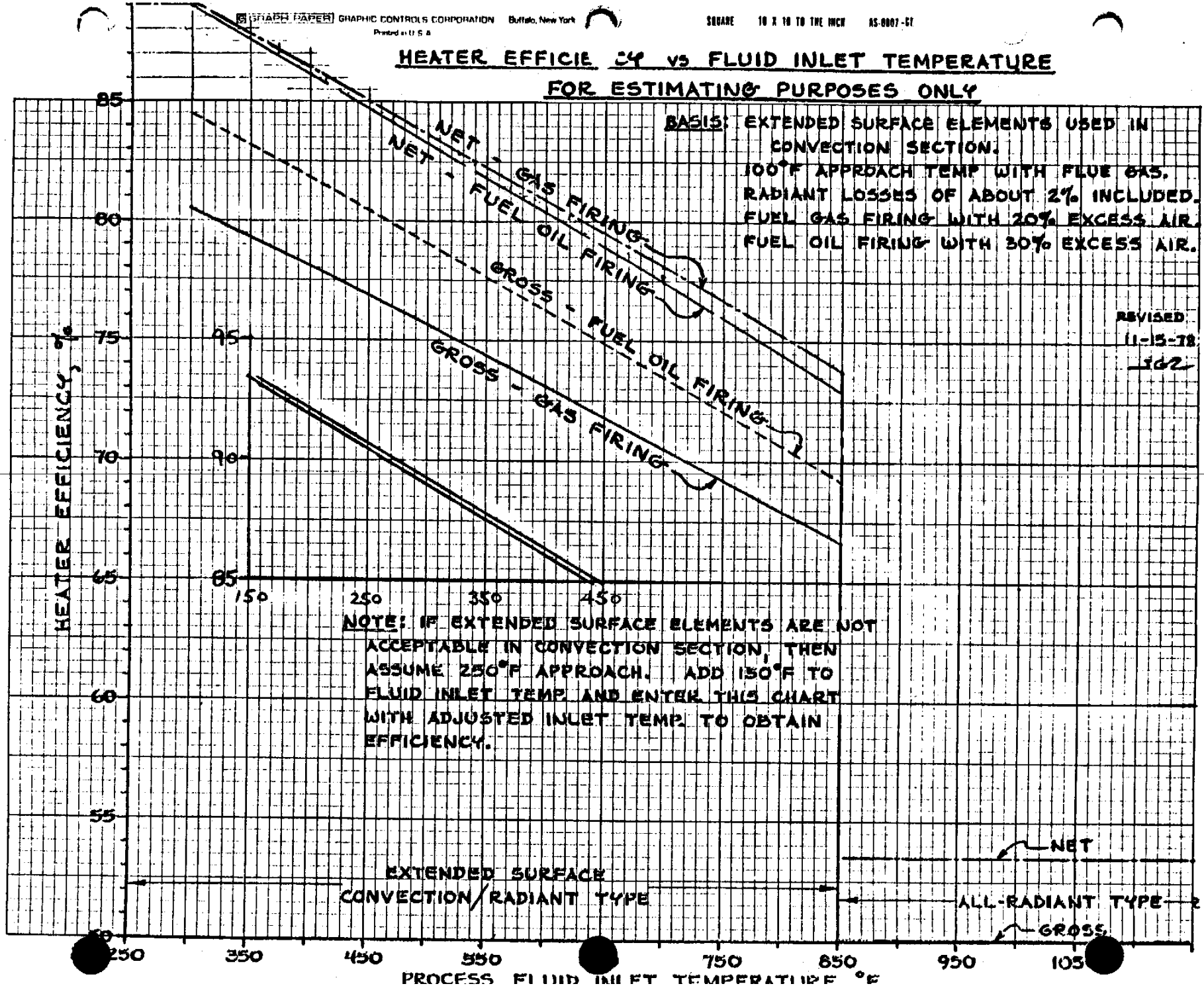

GRAPH PAPER GRAPHIC CONTROLS CORPORATION Buffalo, New York
SQUARE 10 X 10 TO THE INCH
HEATER EFFICIENCY vs FLUID INLET TEMPERATURE
FOR ESTIMATING PURPOSES ONLY
BASIS: EXTENDED SURFACE ELEMENTS USED IN CONVECTION SECTION.
100°F APPROACH TEMP WITH FLUE GAS.
RADIANT LOSSES OF ABOUT 2% INCLUDED.
FUEL GAS FIRING WITH 20% EXCESS AIR.
FUEL OIL FIRING WITH 30% EXCESS AIR.
REVISED
1-15-78
162
NET - GAS FIRING
NET - FUEL OIL FIRING
GROSS - FUEL OIL FIRING
GROSS - GAS FIRING
HEATER EFFICIENCY, %
85
80
75
70
65
60
55
95
90
85
150
250
350
450
NOTE: IF EXTENDED SURFACE ELEMENTS ARE NOT ACCEPTABLE IN CONVECTION SECTION, THEN ASSUME 250°F APPROACH. ADD 150°F TO FLUID INLET TEMP. AND ENTER THIS CHART WITH ADJUSTED INLET TEMP. TO OBTAIN EFFICIENCY.
NET
EXTENDED SURFACE CONVECTION/RADIANT TYPE
ALL-RADIANT TYPE
GROSS
250
350
450
550
750
850
950
105
PROCESS FLUID INLET TEMPERATURE °F

FIGURE 35

FIGURE 36

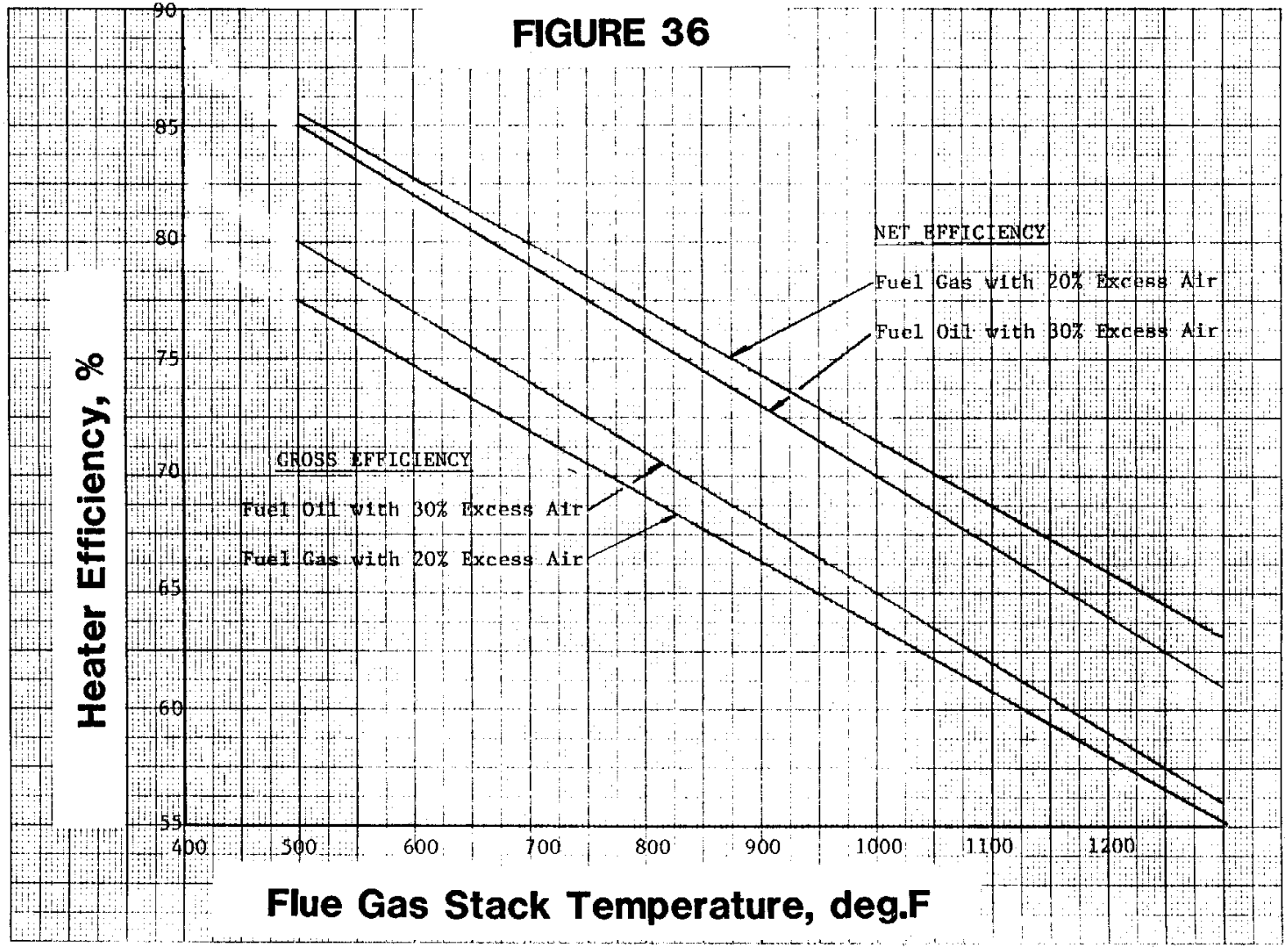

Heater Efficiency, %
90
85
80
75
70
65
60
55
400
500
600
700
800
900
1000
1100
1200
Flue Gas Stack Temperature, deg.F
NET EFFICIENCY
Fuel Gas with 20% Excess Air
Fuel Oil with 30% Excess Air
GROSS EFFICIENCY
Fuel Oil with 30% Excess Air
Fuel Gas with 20% Excess Air

FIGURE 37

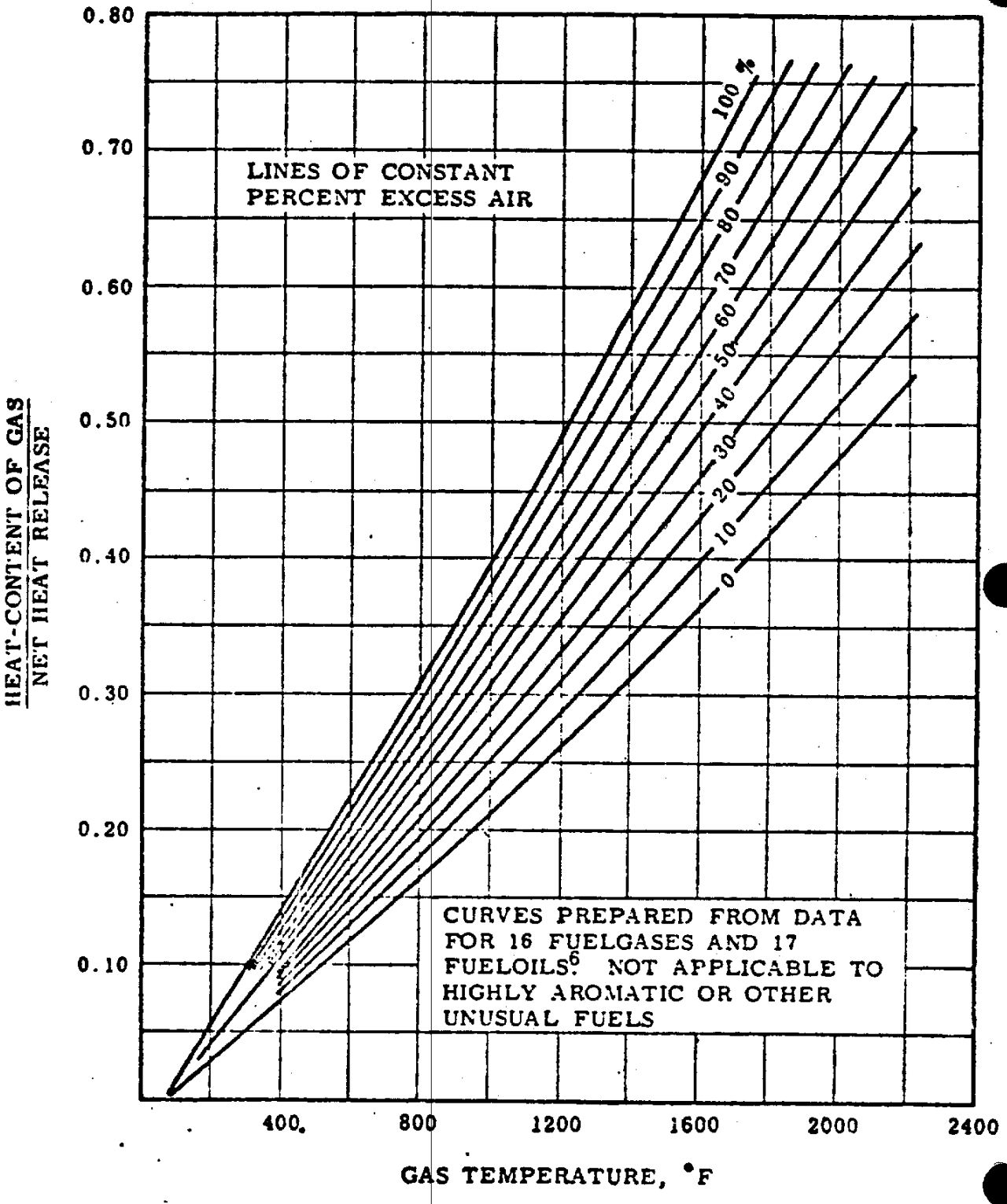

0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
LINES OF CONSTANT
PERCENT EXCESS AIR
100 %
90
80
70
60
50
40
30
20
10
0
CURVES PREPARED FROM DATA
FOR 16 FUELGASES AND 17
FUELOILS[6]. NOT APPLICABLE TO
HIGHLY AROMATIC OR OTHER
UNUSUAL FUELS
400
800
1200
1600
2000
2400
GAS TEMPERATURE, °F
HEAT-CONTENT OF GAS
NET HEAT RELEASE

FIGURE 38a

LICENSEES' TRAINING COURSE

HEATER DUTIES

	Crude Heater	Stabilizer Reboiler Heater	
		Summer Operation	Winter Operation
Charge to Heater:	Crude	Gasoline	Gasoline
BPSD	99,900	69,425	88,200
Lb/Hr	1,240,000	744,600	946,100
°API	34.8	60.5	61.5
Wt. % S	0.56	0.13	0.13
Temperatures, °F			
Inlet	490	350	390
Outlet	685	365	410
Outlet Pressure, PSIG	15	150	250
Vaporization at Outlet, Wt. %	55.0	35	35
Vapor, M.W.	131.4	98.8	99.7
Heater Duty, 10^6 Btu/Hr	237.92	37.23	43.52

Assumptions

Fuel Oil Firing @ 30% Excess Air
Stack Flue Gas Approach 300°F
Bare Tube Convection Section

FIGURE 38b

PROCESS DIVISION

DISTILLATION CHART

CUSTOMER Licensee's Training Course

SUBJECT Redwater Crude - Flash Curves

PAGE NO.

DATE

PROJECT 6626

BY JNW

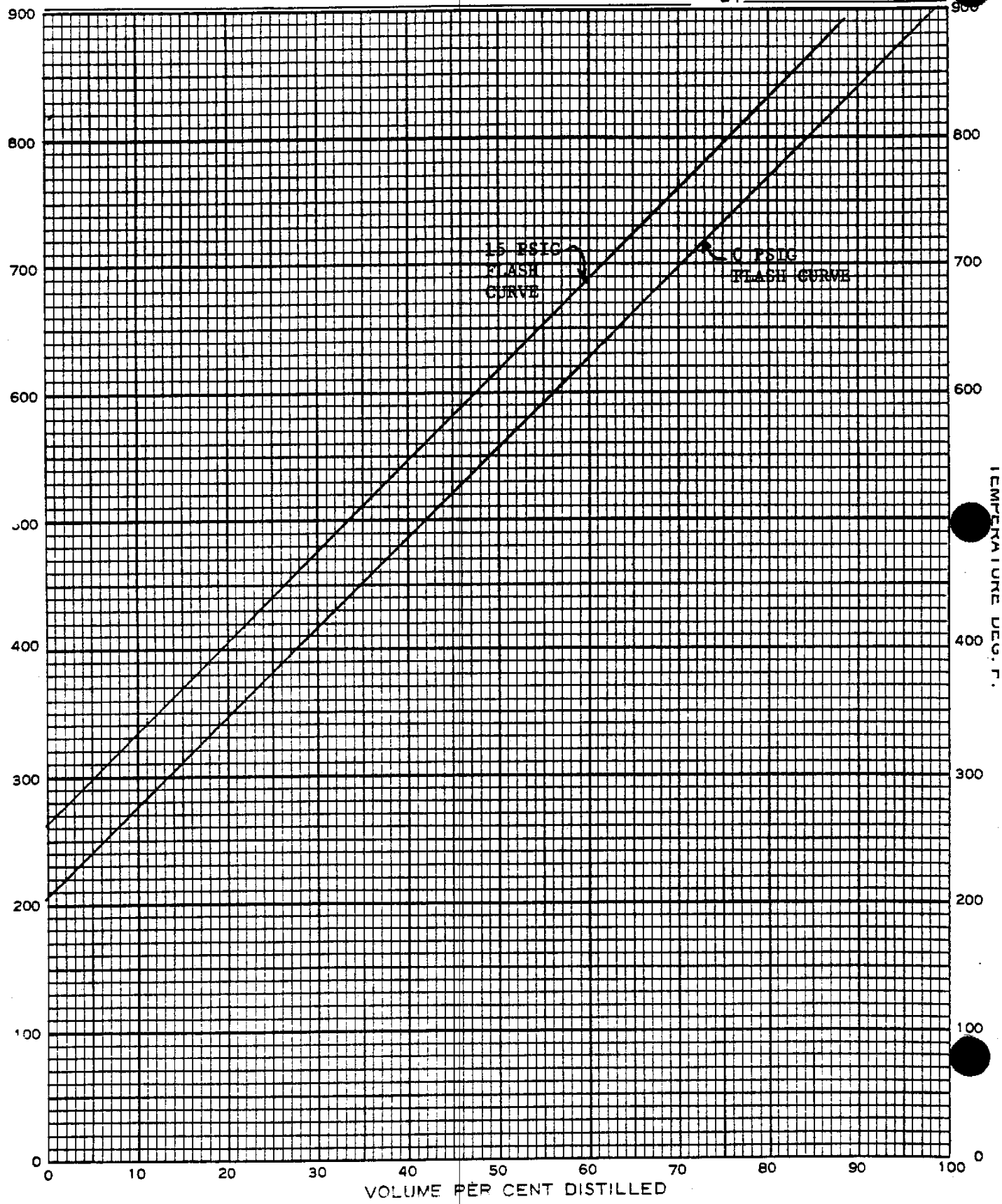


FIGURE 39

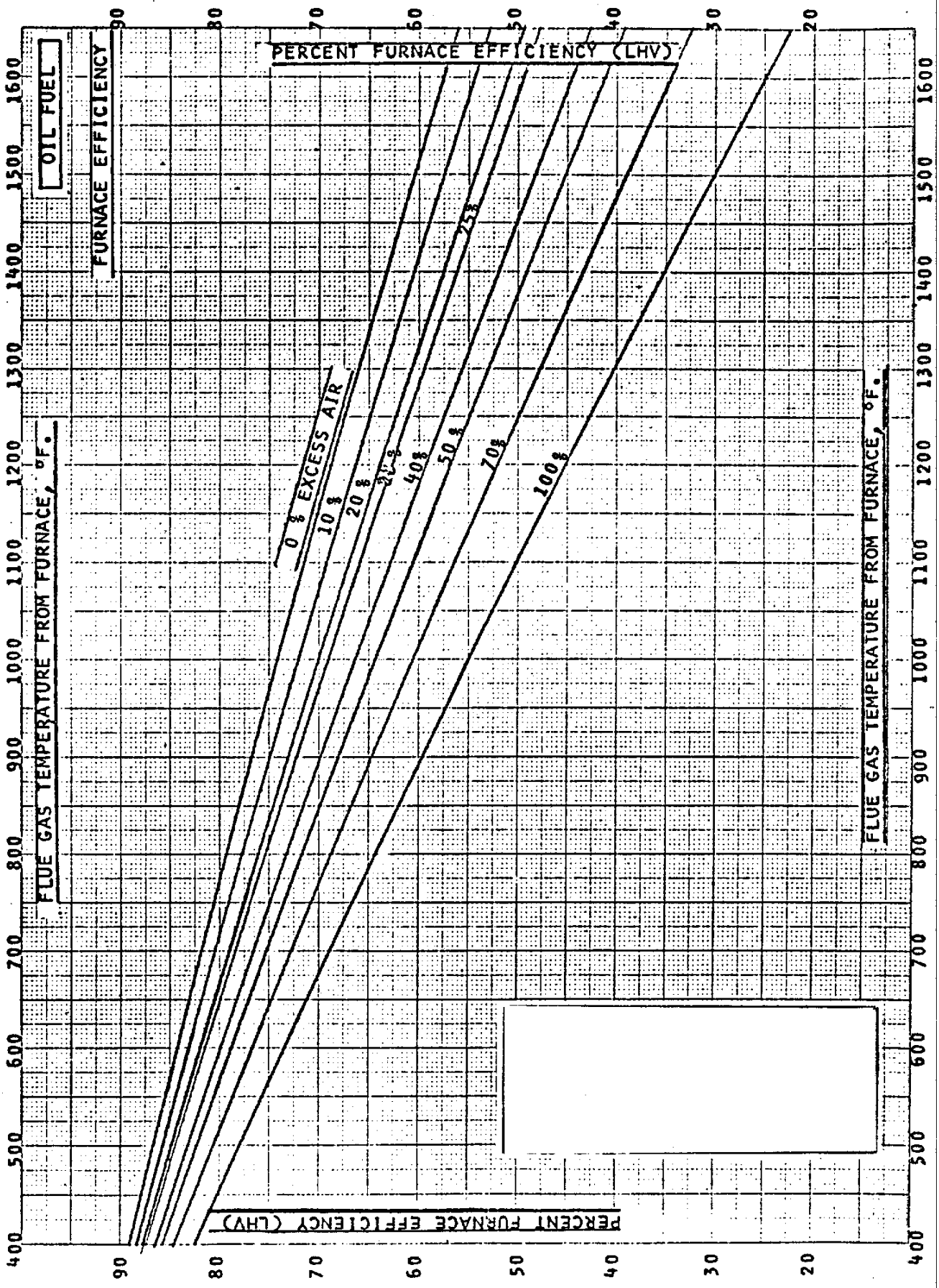

OIL FUEL
FURNACE EFFICIENCY
PERCENT FURNACE EFFICIENCY (LHV)
FLUE GAS TEMPERATURE FROM FURNACE, °F.
0 % EXCESS AIR
10 %
20 %
25 %
40 %
50 %
70 %
100 %
90
80
70
60
50
40
30
20
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600

FIGURE 40a

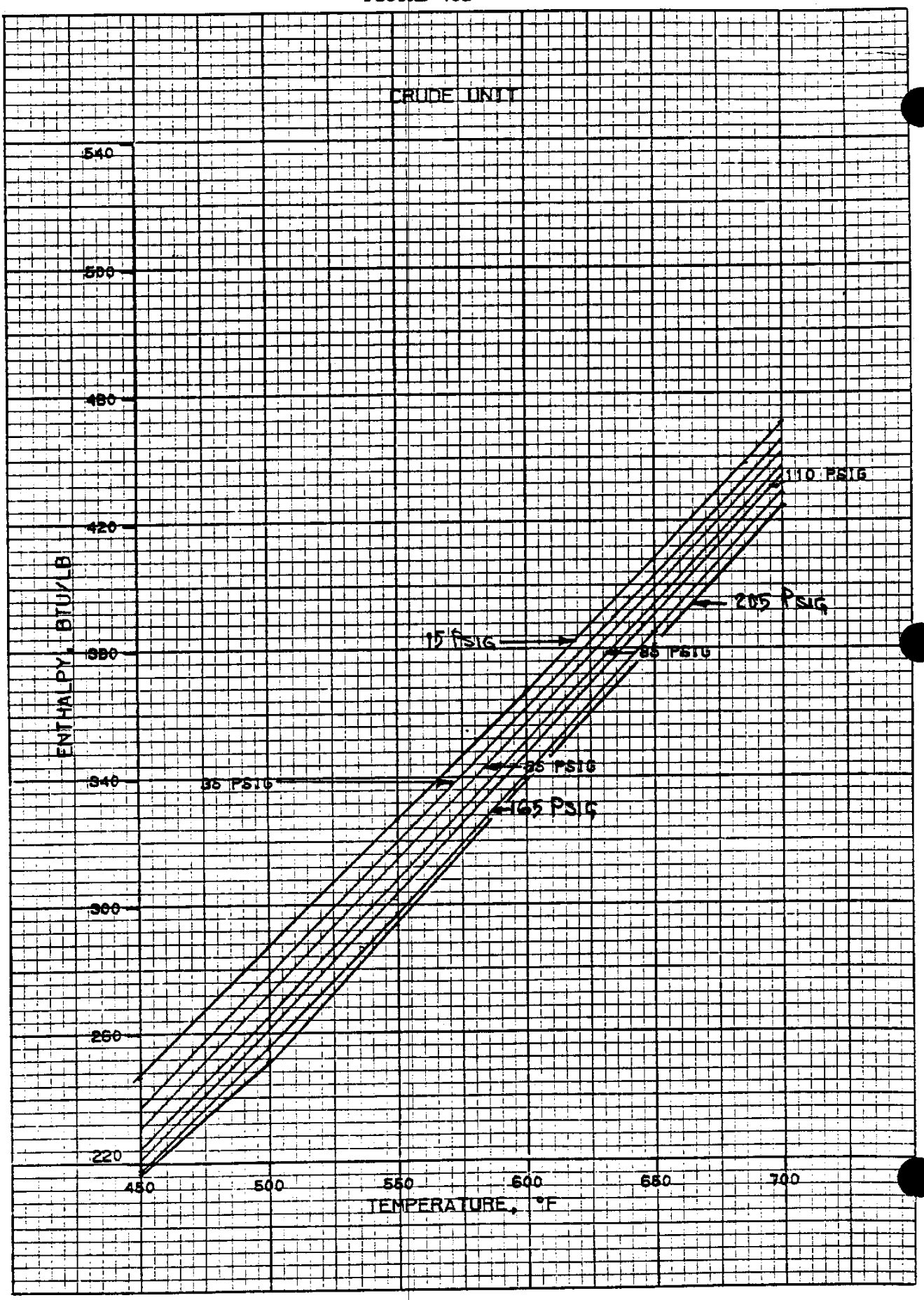

CRUDE UNIT
540
500
460
420
380
340
300
260
220
ENTHALPY, BTU/LB
450
500
550
600
650
700
TEMPERATURE, °F
110 PSIG
205 PSIG
15 PSIG
85 PSIG
35 PSIG
85 PSIG
165 PSIG

FIGURE 40b

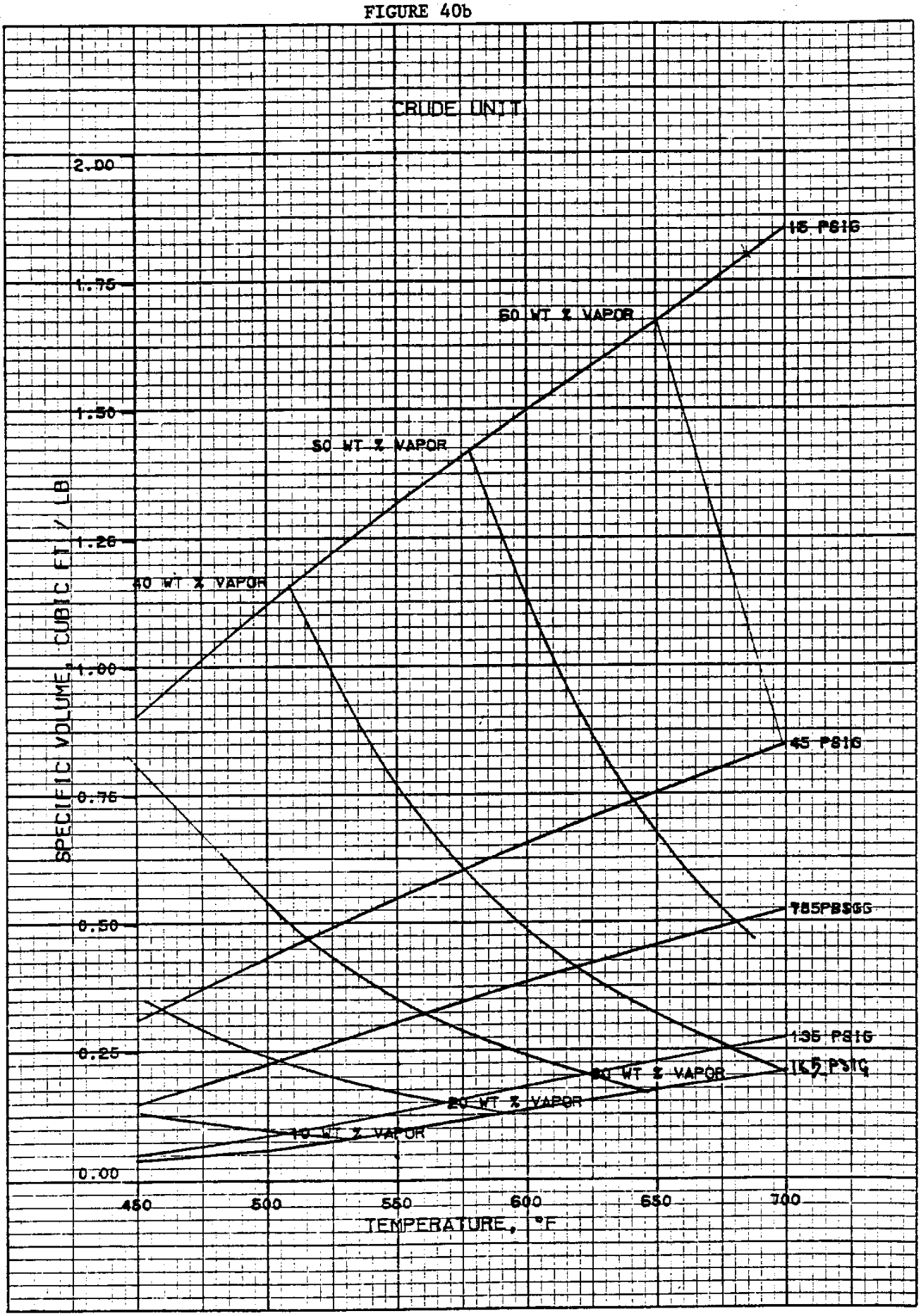

CRUDE UNIT
SPECIFIC VOLUME, CUBIC FT / LB
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
0.00
450
500
550
600
650
700
TEMPERATURE, °F
185 PSIG
60 WT % VAPOR
50 WT % VAPOR
40 WT % VAPOR
45 PSIG
135 PSIG
30 WT % VAPOR
20 WT % VAPOR
10 WT % VAPOR

FIGURE 41

AIR-FUEL AND FLUE GAS-FUEL RATIOS

FUEL OIL

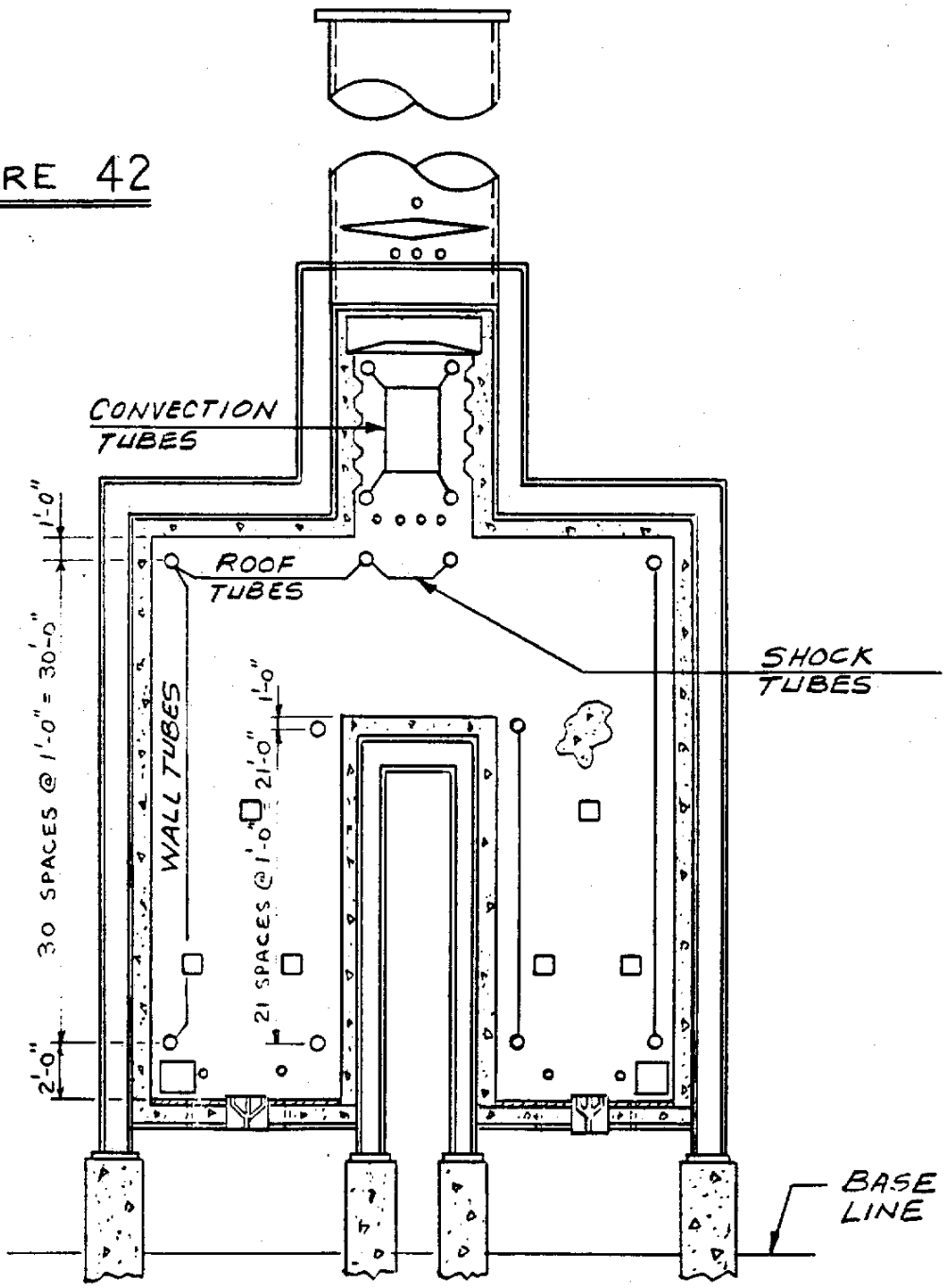
PERCENT EXCESS AIR	AIR LB. PER LB. FUEL	FLUE GAS LB. PER LB. FUEL
0	13.95	15.25
5	14.65	15.95
10	15.34	16.64
15	16.04	17.34
20	16.74	18.04
25	17.44	18.74
30	18.13	19.43
35	18.83	20.13
40	19.53	20.83
45	20.23	21.53
50	20.92	22.22
55	21.62	22.92
60	22.32	23.62
65	23.02	24.32
70	23.72	25.02
75	24.41	25.71
80	25.11	26.41
85	25.81	27.11
90	26.50	27.80
95	27.20	28.50
100	27.90	29.20
105	28.59	29.89
110	29.29	30.59
115	29.99	31.29
120	30.69	31.99
125	30.38	32.68
130	32.08	33.38
135	32.78	34.08
140	33.48	34.78
145	34.18	35.48
150	34.87	36.17

FUEL OIL ANALYSIS

CARBON	85.0%	BY WEIGHT
HYDROGEN	12.0%	" "
SULPHUR	1.5%	" "
OXYGEN	0.7%	" "
NITROGEN	0.8%	" "

PERFECT COMBUSTION ASSUMED.
STEAM FOR ATOMIZATION OF FUEL: 0.30 LB. PER LB. FUEL
AIR AT 50% RELATIVE HUMIDITY AND 60° FAHR.
LOWER HEATING VALUE = 17,130 Btu/Lb

FIGURE 42


CONVECTION TUBES
ROOF TUBES
SHOCK TUBES
WALL TUBES
1'-0"
30 SPACES @ 1'-0" = 30'-0"
2'-0"
21 SPACES @ 1'-0"
21'-0"
1'-0"
BASE LINE

43

Figure 43

TABLE 4

Typical Design Heat Absorption Rates
Average for Radiant Section
For 20 x 10^6 and Greater

Service	Average Heat Abs. BTU/Hour/Sq. Ft.
Crude Oil Distillation	12,000
Vacuum Distillation	8,000 - 10,000
Reboiling	10,000 - 12,000
Lube Oil Solvent	8,000
Propane Deasphalting	9,000
Catalytic Reforming	11,000 - 13,000
Hot Oil Belt	12,000
Black Oil Cracking	10,000 - 12,000
Fluid Catalytic Feed	12,000
Hydro-Treating	10,000 - 12,500
Pipe Line Heating	10,000

Figure 44

TABLE 5

PIPE SIZE FACTORS

Size I.P.S.	O.D. Inches	I.D. Inches	Cold Oil Vel.Ft/Sec 1000 O/D @ 60°F	O.D. Sq. Ft. per ft.	t in.	Vol.,Ft^3/Ft. I.D. Cross Sectional Area Sq. Ft.	$(I.D.)^5$ Inches	$(I.D.)^{0.2}$ Inches	Eq. Lg. - 180° bend 50 d	75 d	100 d
2"											
Sch. 40	2.375	2.067	2.79	.622	.154	.0233	37.73	1.156	8.6	13.0	17.3
Sch. 80	2.375	1.939	3.17	.622	.218	.0205	27.41	1.142	8.1	12.1	16.2
Sch. 160	2.375	1.689	4.19	.622	.343	.0155	13.74	1.110	7.0	10.6	14.1
2-1/2"											
Sch. 40	2.875	2.469	1.96	.753	.203	.0332	91.8	1.198	10.3	15.4	20.6
Sch. 80	2.875	2.323	2.21	.753	.276	.0294	67.6	1.184	9.7	14.6	19.4
Sch. 160	2.875	2.125	2.64	.753	.375	.0247	43.3	1.163	8.9	13.3	17.7
3"											
Sch. 40	3.500	3.068	1.27	.916	.216	.0512	271.8	1.251	12.8	19.2	25.6
Sch. 80	3.500	2.900	1.42	.916	.300	.0458	205.0	1.238	12.1	18.0	24.2
Sch. 160	3.500	2.626	1.73	.916	.438	.0376	125.0	1.213	11.0	16.4	21.9
3-1/2"											
Sch. 40	4.000	3.548	0.95	1.047	.226	.0685	562	1.288	14.8	22.2	29.6
Sch. 80	4.000	3.364	1.05	1.047	.318	.0617	431	1.275	14.1	21.1	28.1
4"											
Sch. 40	4.500	4.026	0.74	1.178	.237	.0884	1,058	1.322	16.8	25.2	33.6
Sch. 80	4.500	3.826	0.82	1.178	.337	.0798	820	1.308	16.0	23.9	31.9
Sch. 120	4.500	3.626	0.91	1.178	.438	.0717	627	1.294	15.1	22.7	30.2
Sch. 160	4.500	3.438	1.01	1.178	.531	.0644	480	1.280	14.3	21.5	28.6
5"											
Sch. 40	5.563	5.047	0.47	1.456	.258	.1390	3,275	1.381	21.0	31.5	42.0
Sch. 80	5.563	4.813	0.52	1.456	.375	.1260	2,583	1.369	20.1	30.1	40.1
Sch. 120	5.563	4.563	0.57	1.456	.500	.1135	1,978	1.354	19.1	28.5	38.0
Sch. 160	5.563	4.313	0.64	1.456	.625	.1015	1,492	1.340	18.0	27.0	36.0
6"											
Sch. 40	6.625	6.065	0.31	1.734	.280	.2008	8,206	1.434	25.3	38.0	50.5
Sch. 80	6.625	5.761	0.36	1.734	.432	.1810	6,350	1.420	24.0	36.1	48.0
Sch. 120	6.625	5.501	0.39	1.734	.562	.1650	5,037	1.407	23.0	34.4	46.0
Sch. 160	6.625	5.189	0.44	1.734	.718	.1465	3,760	1.389	21.6	32.4	43.2
8"											
Sch. 40	8.625	7.981	0.19	2.258	.322	.3470	32,400	1.515	33.3	49.9	66.5
Sch. 80	8.625	7.625	0.20	2.258	.500	.3180	25,800	1.501	31.8	47.6	63.5
Sch. 100	8.625	7.439	0.215	2.258	.593	.3020	22,800	1.494	31.0	46.5	62.0
Sch. 120	8.625	7.189	0.23	2.258	.718	.2820	19,200	1.482	30.0	44.9	59.8
Sch. 160	8.625	6.813	0.257	2.258	.906	.2530	14,700	1.468	28.4	42.6	56.8
10"											
Sch. 40	10.750	10.020	0.119	2.81	.365	.5470	101,000	1.585	41.7	62.5	83.3
Sch. 80	10.750	9.564	0.131	2.81	.593	.4980	80,000	1.570	39.9	59.8	79.6
Sch. 100	10.750	9.314	0.138	2.81	.718	.4730	70,100	1.563	38.8	58.2	77.6
Sch. 120	10.750	9.064	0.145	2.81	.843	.4480	61,200	1.553	37.8	56.6	75.5
Sch. 160	10.750	8.500	0.165	2.81	1.125	.3935	44,400	1.534	35.4	53.1	70.8

FIGURE 45

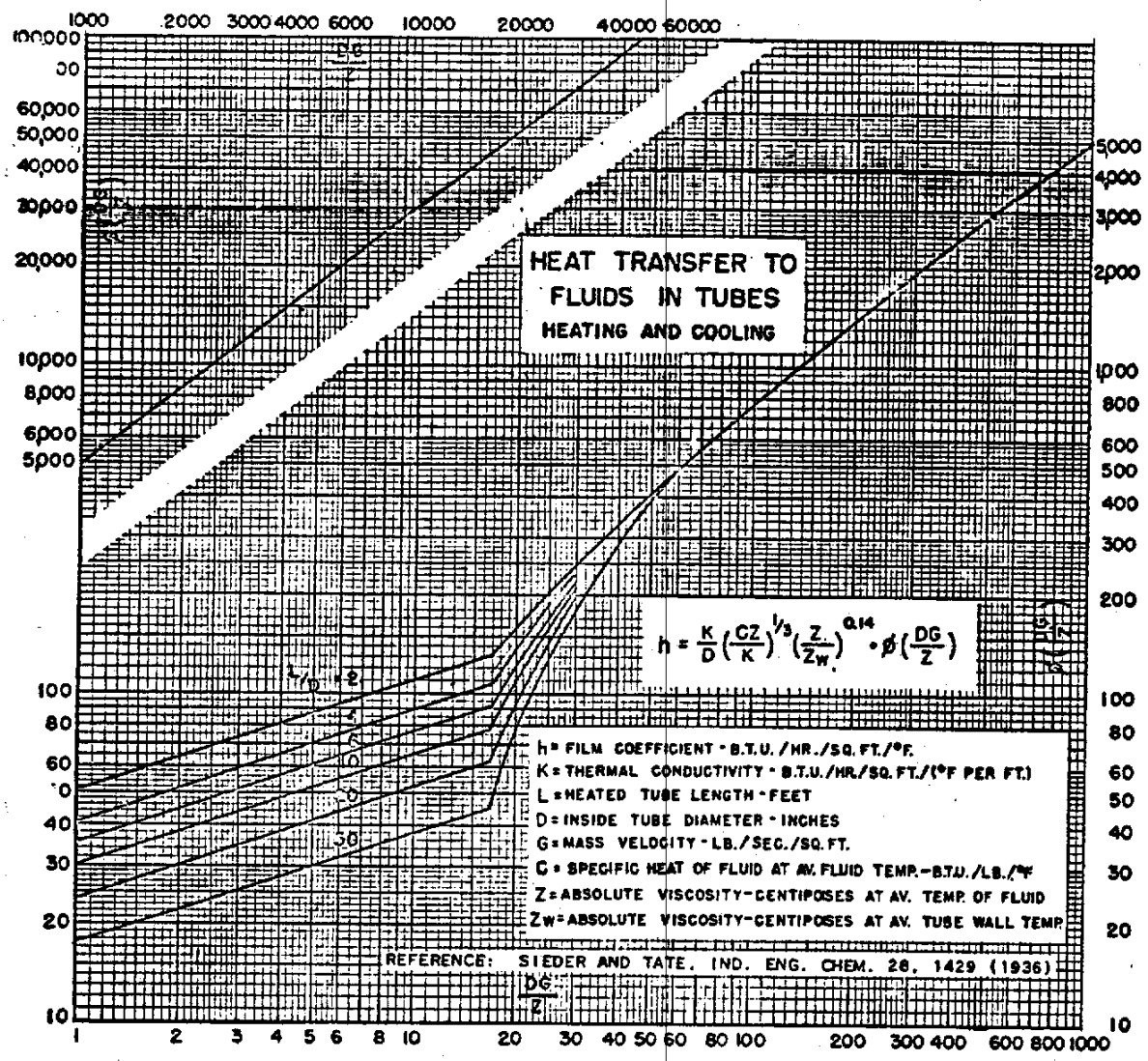
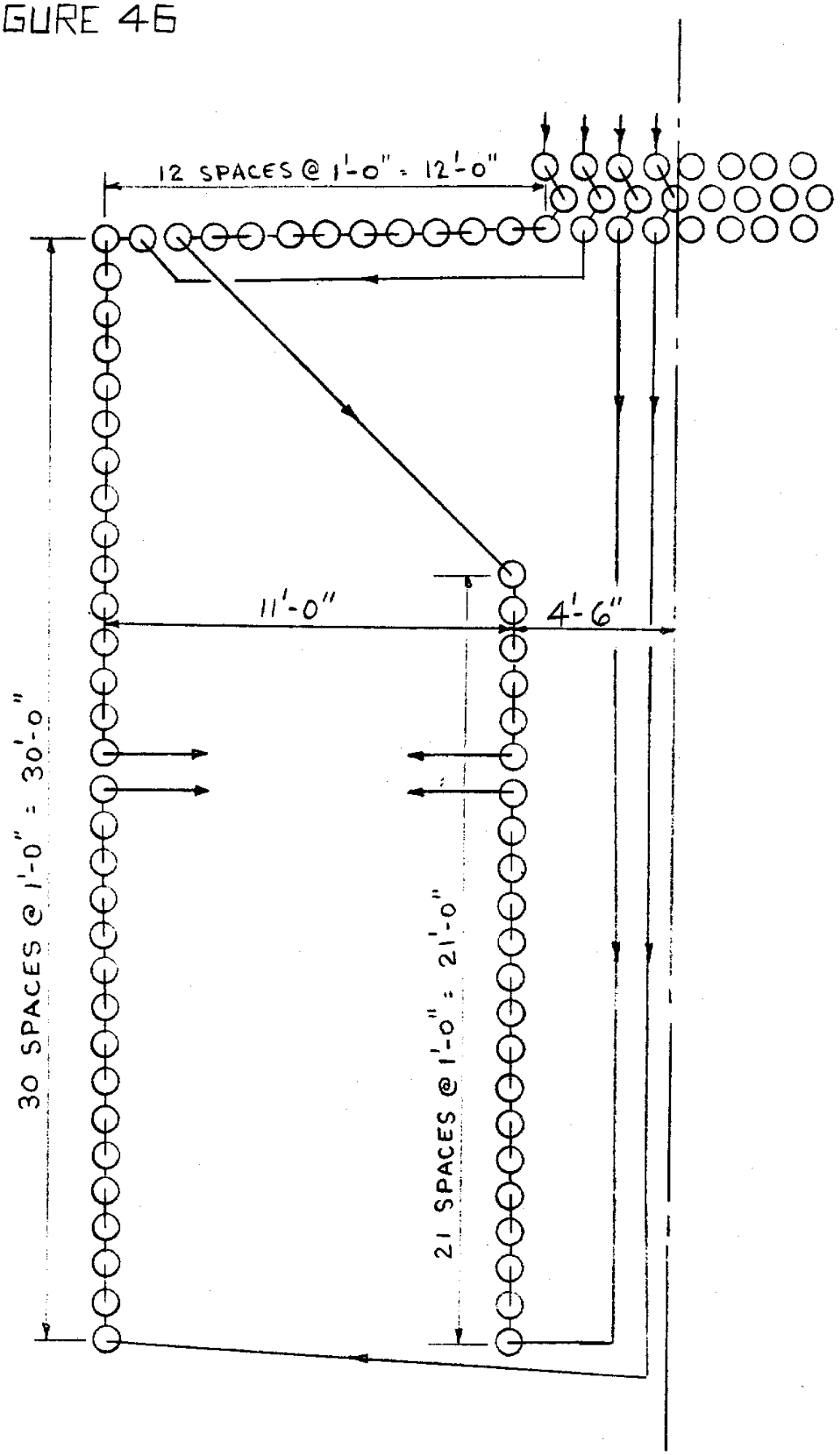

HEAT TRANSFER TO FLUIDS IN TUBES
HEATING AND COOLING
$h = \frac{K}{D}\left(\frac{CZ}{K}\right)^{1/3}\left(\frac{Z}{Z_w}\right)^{0.14} \cdot \phi\left(\frac{DG}{Z}\right)$
h = FILM COEFFICIENT - B.T.U. /HR./SQ. FT./°F.
K = THERMAL CONDUCTIVITY - B.T.U./HR./SQ. FT./(°F PER FT.)
L = HEATED TUBE LENGTH - FEET
D = INSIDE TUBE DIAMETER - INCHES
G = MASS VELOCITY - LB./SEC./SQ. FT.
C = SPECIFIC HEAT OF FLUID AT AV. FLUID TEMP. - B.T.U./LB./°F
Z = ABSOLUTE VISCOSITY - CENTIPOISES AT AV. TEMP. OF FLUID
Zw = ABSOLUTE VISCOSITY - CENTIPOISES AT AV. TUBE WALL TEMP
REFERENCE: SIEDER AND TATE, IND. ENG. CHEM. 28, 1429 (1936)
L/D = 2
4
10
20
30
50
DG/Z
1000 2000 3000 4000 6000 10000 20000 40000 60000
100000
80000
60,000
50,000
40,000
30000
20,000
10000
8,000
6000
5000
100
80
60
50
40
30
20
10
5000
4000
3000
2000
1000
800
600
500
400
300
200
100
80
60
50
40
30
20
10
1 2 3 4 5 6 8 10 20 30 40 50 60 80 100 200 300 400 600 800 1000

FIGURE 46



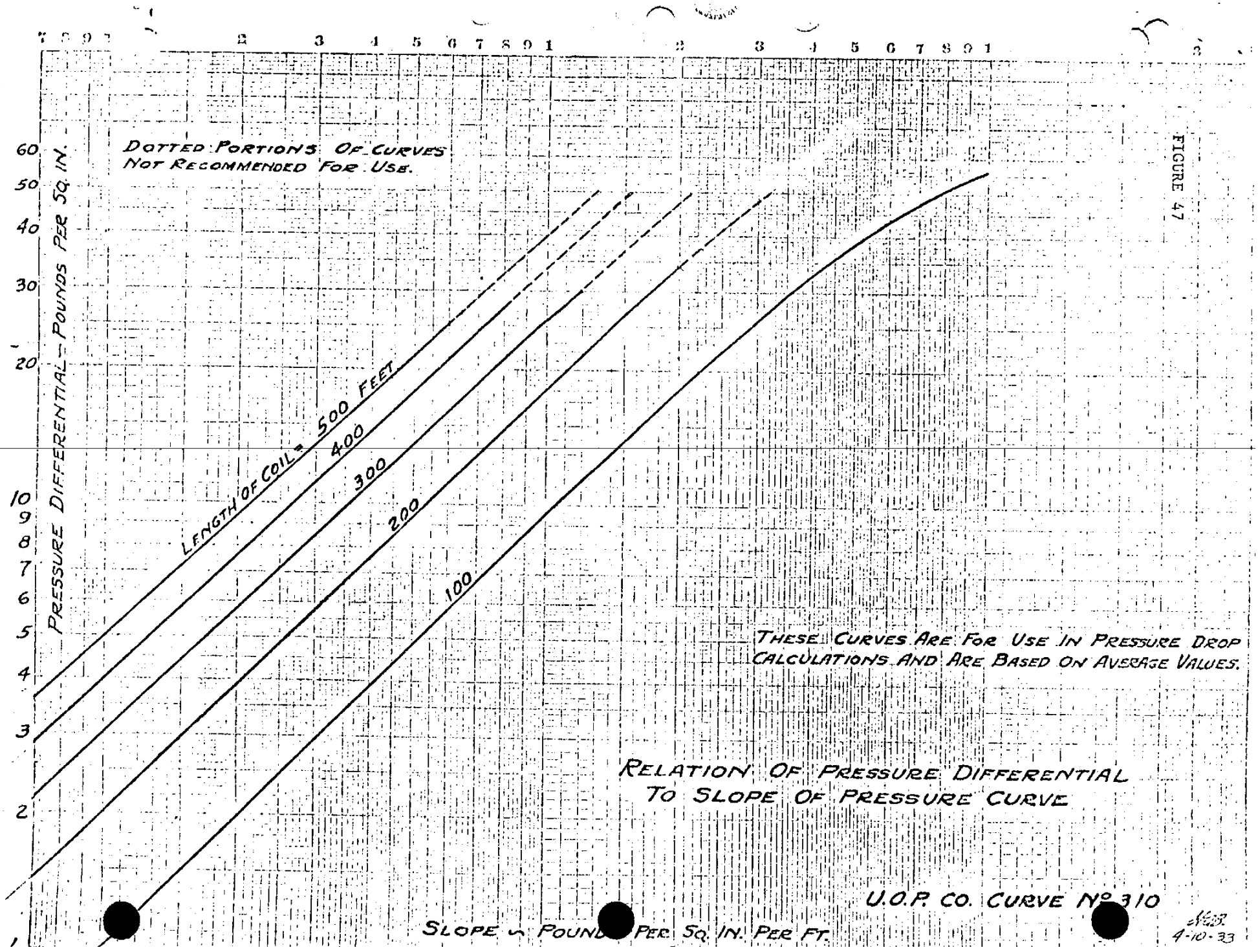
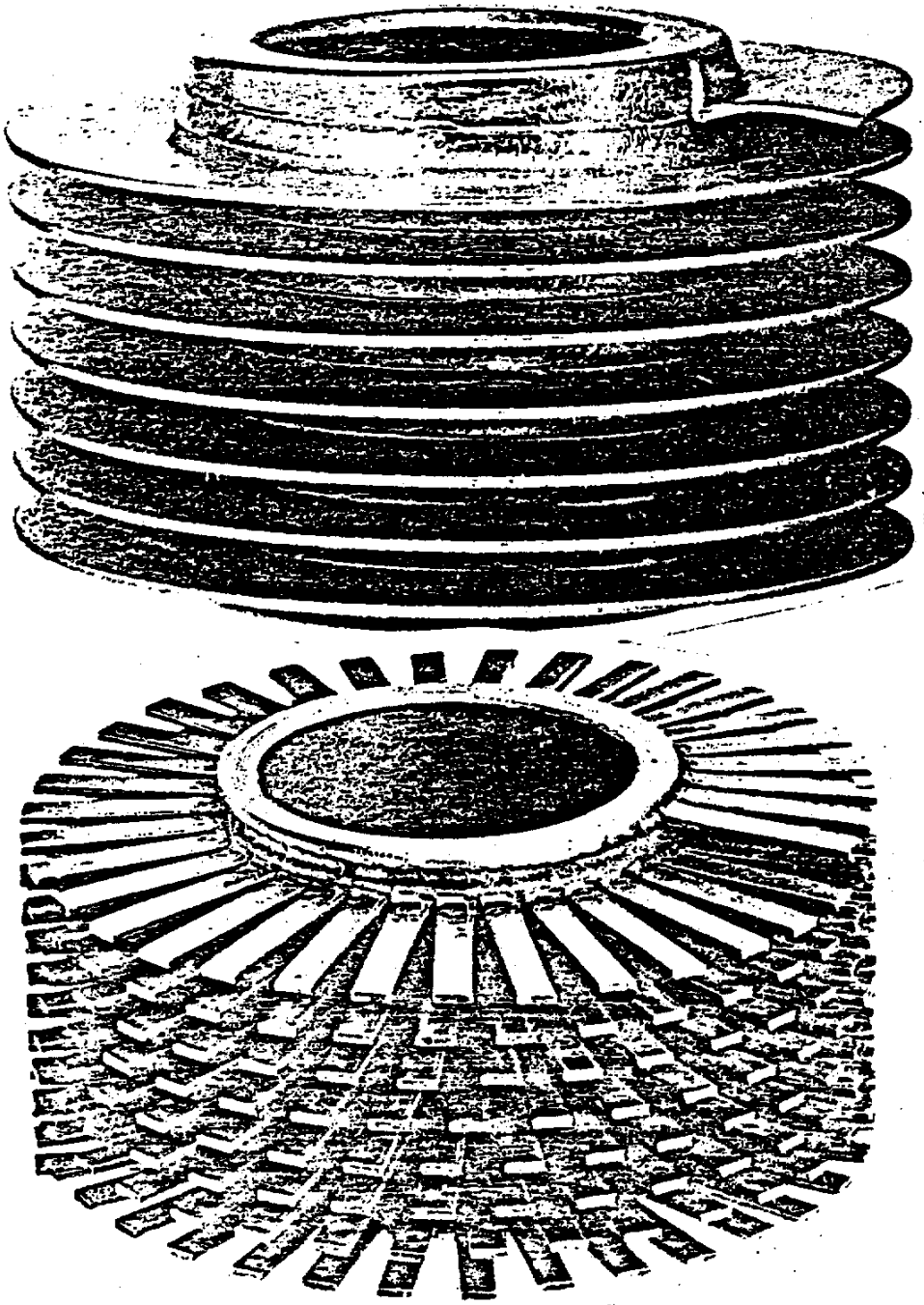

DOTTED PORTIONS OF CURVES NOT RECOMMENDED FOR USE.
PRESSURE DIFFERENTIAL – POUNDS PER SQ. IN.
LENGTH OF COIL = 500 FEET
400
300
200
100
THESE CURVES ARE FOR USE IN PRESSURE DROP CALCULATIONS AND ARE BASED ON AVERAGE VALUES.
RELATION OF PRESSURE DIFFERENTIAL TO SLOPE OF PRESSURE CURVE
U.O.P. CO. CURVE Nº 310
SLOPE = POUNDS PER SQ. IN. PER FT.
4-10-33

FIGURE 47

Fig.
48



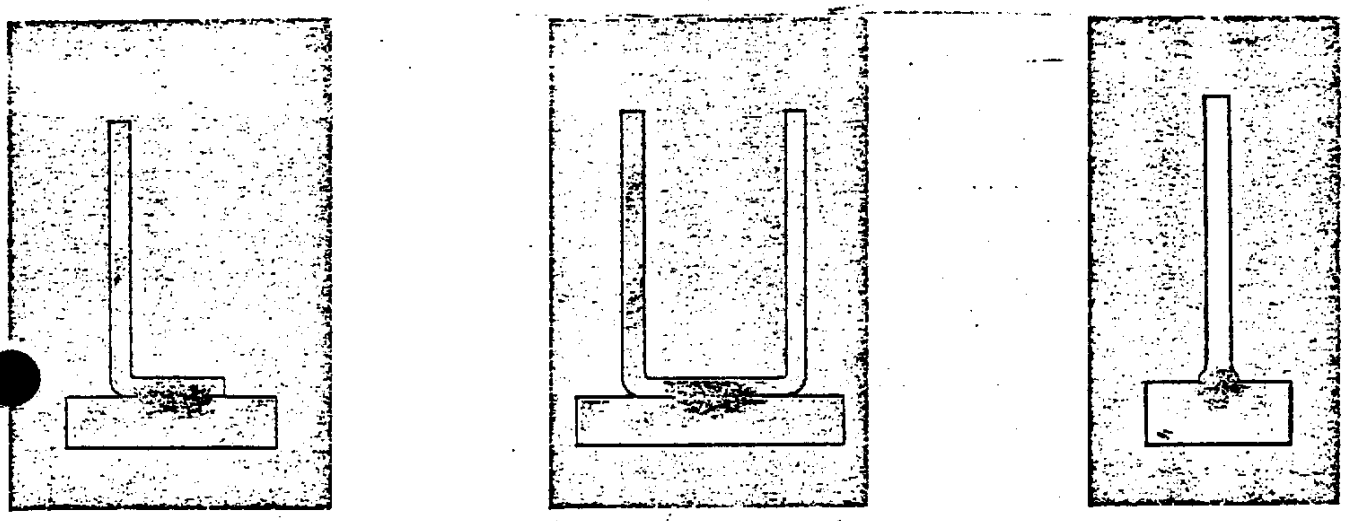
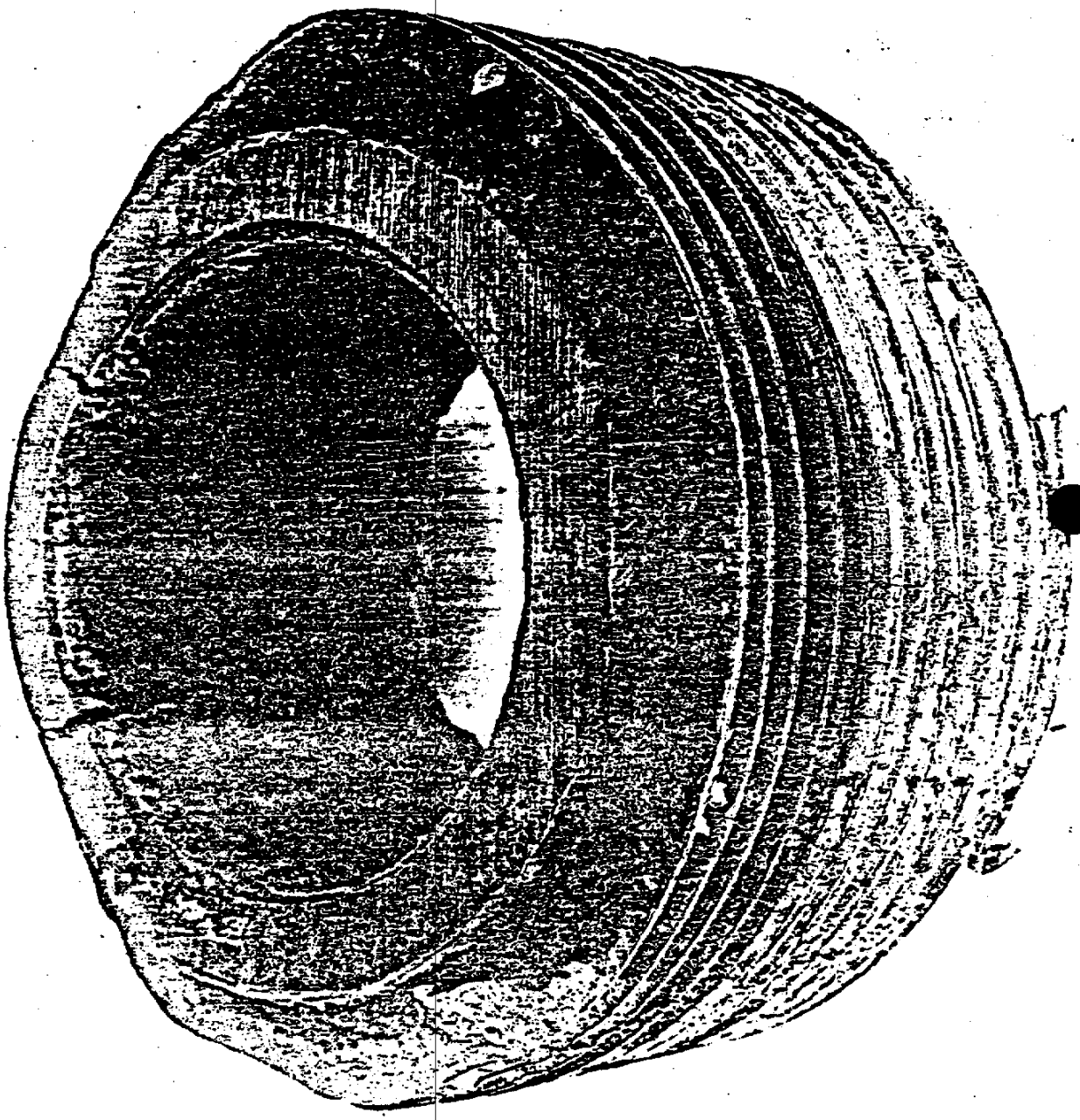


FIGURE 49



50

FIGURE 50

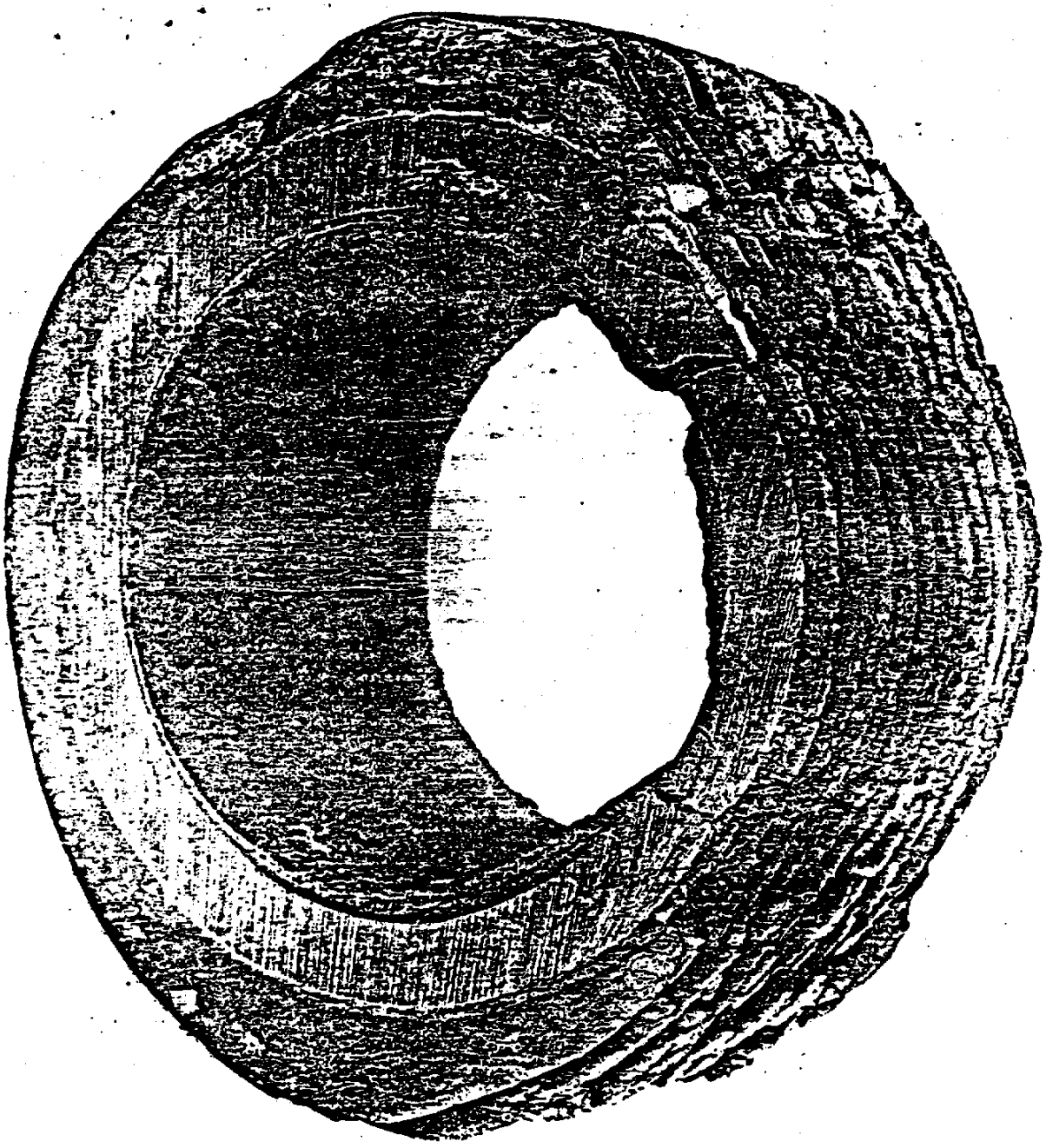
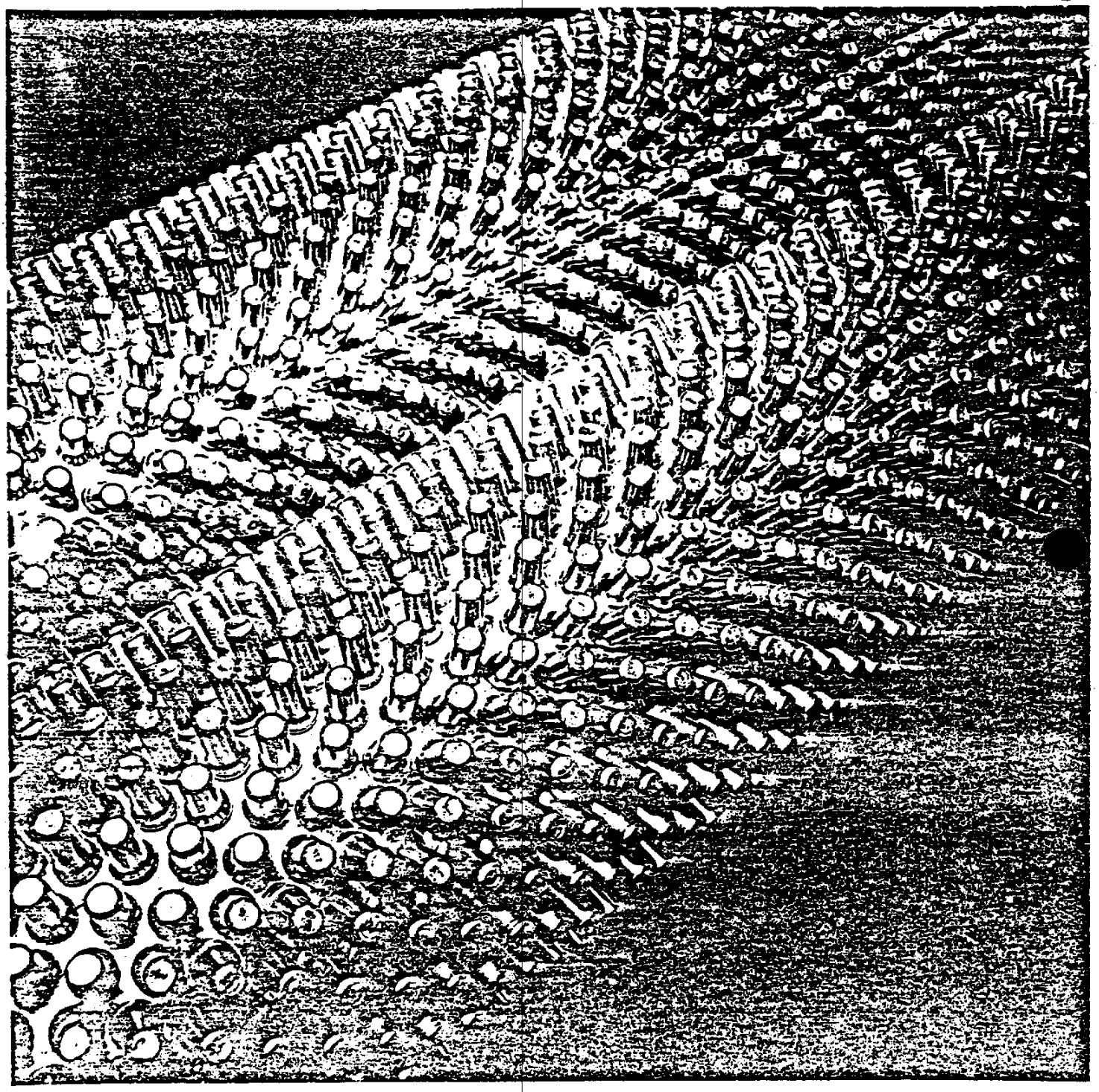
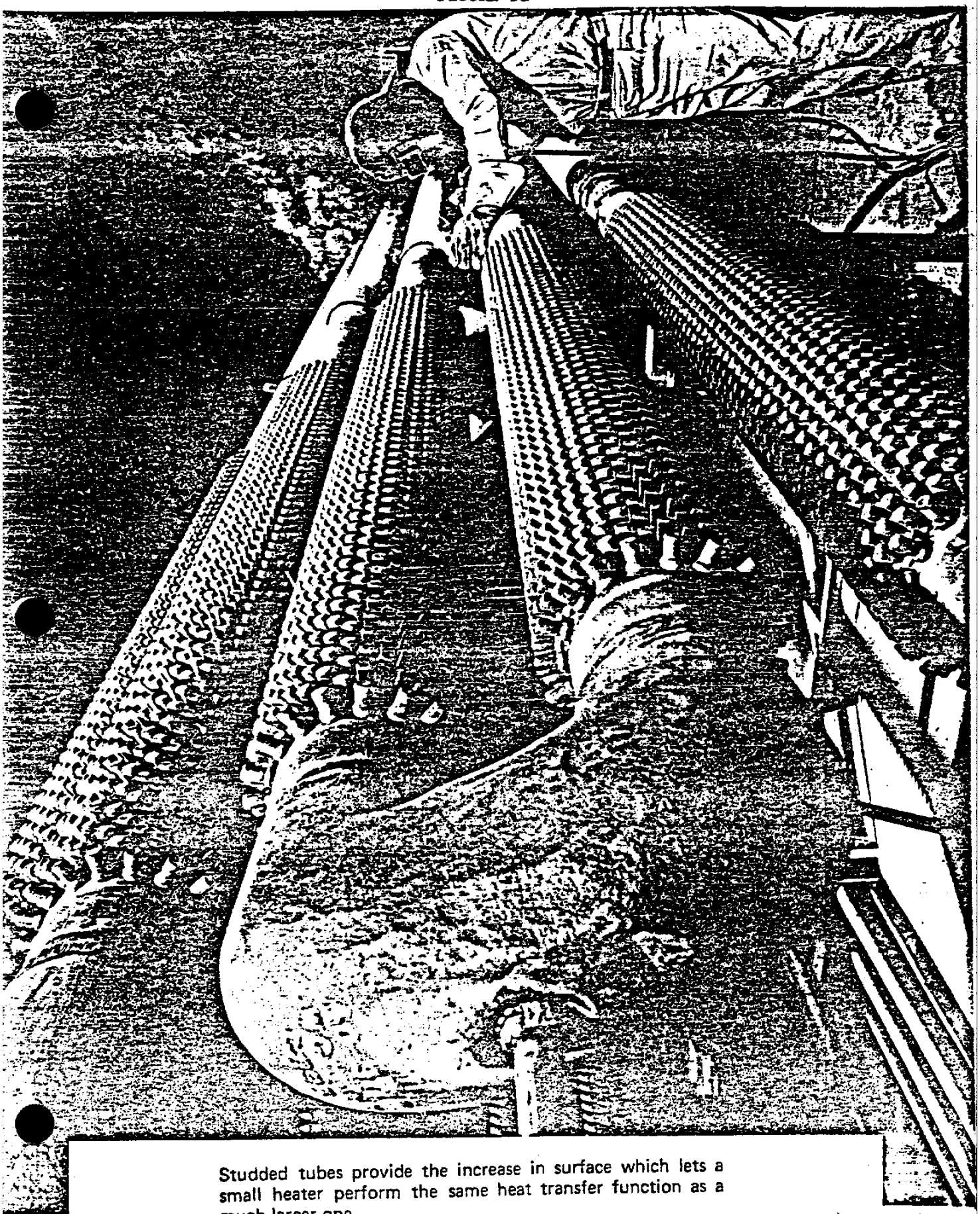


FIGURE 51



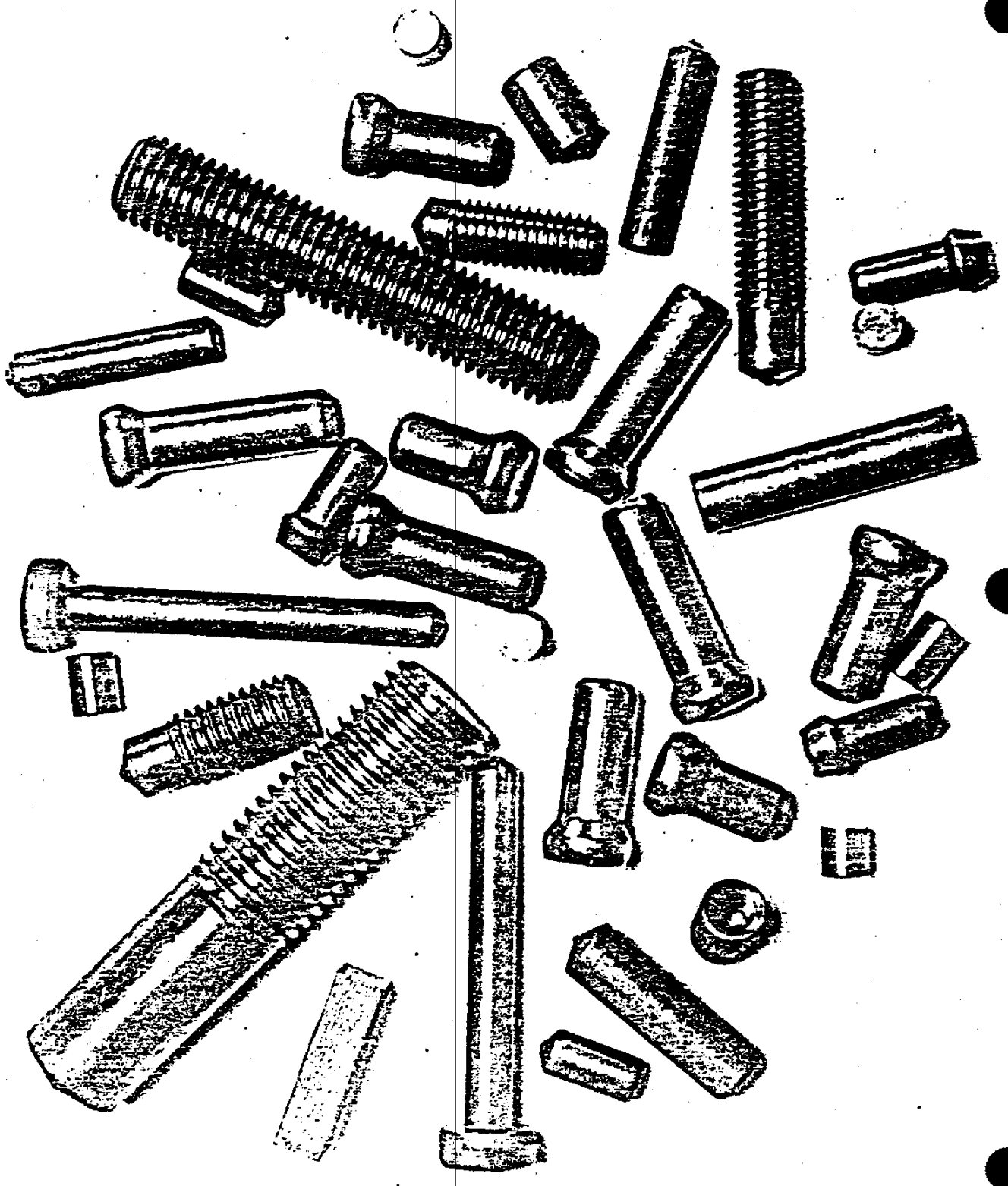
Extended surface of sturdy studs well-bonded to the tube improves heat transfer performance and gives long life under corrosive conditions.

FIGURE 52



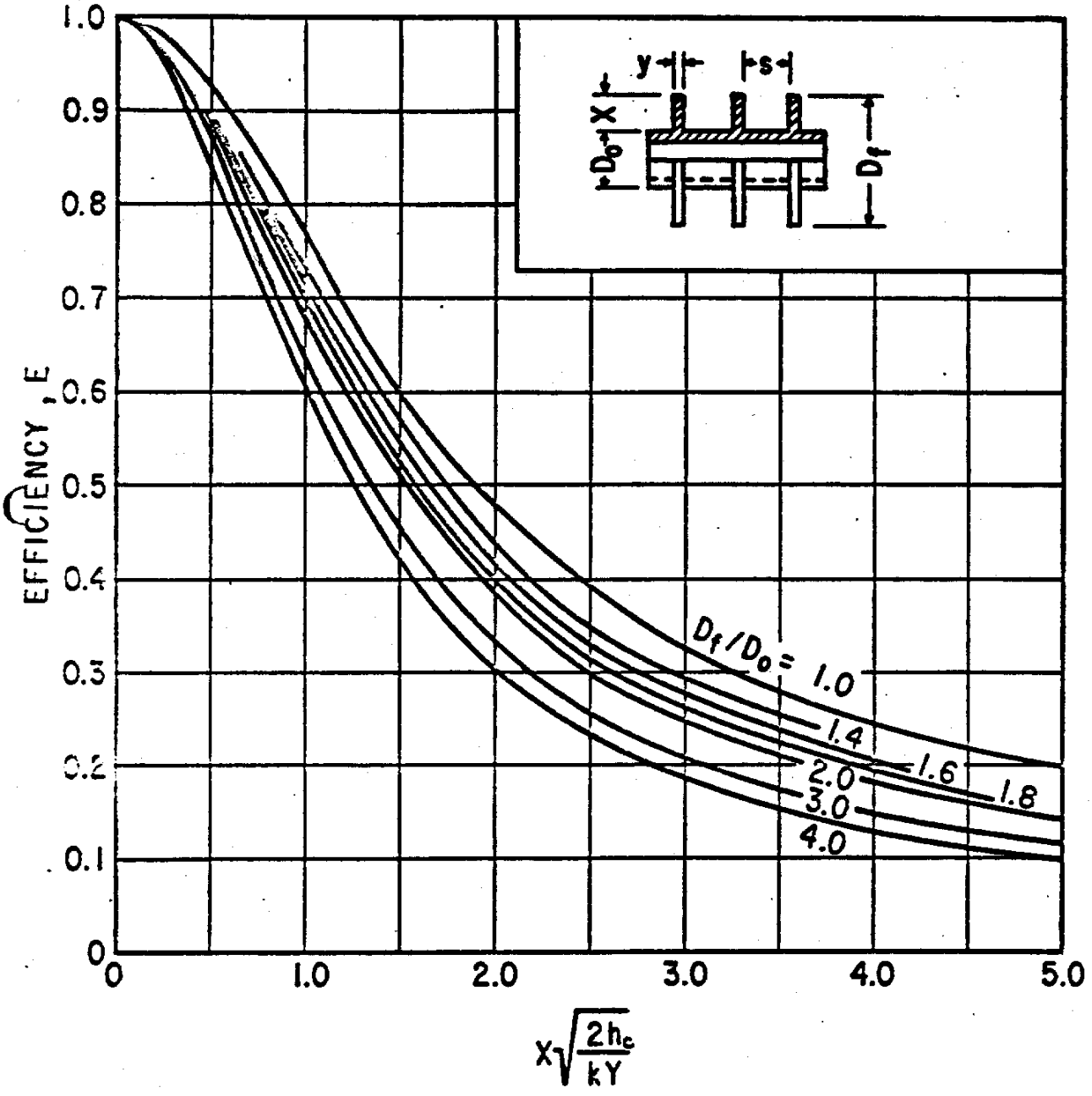
Studded tubes provide the increase in surface which lets a small heater perform the same heat transfer function as a much larger one.

FIGURE 53



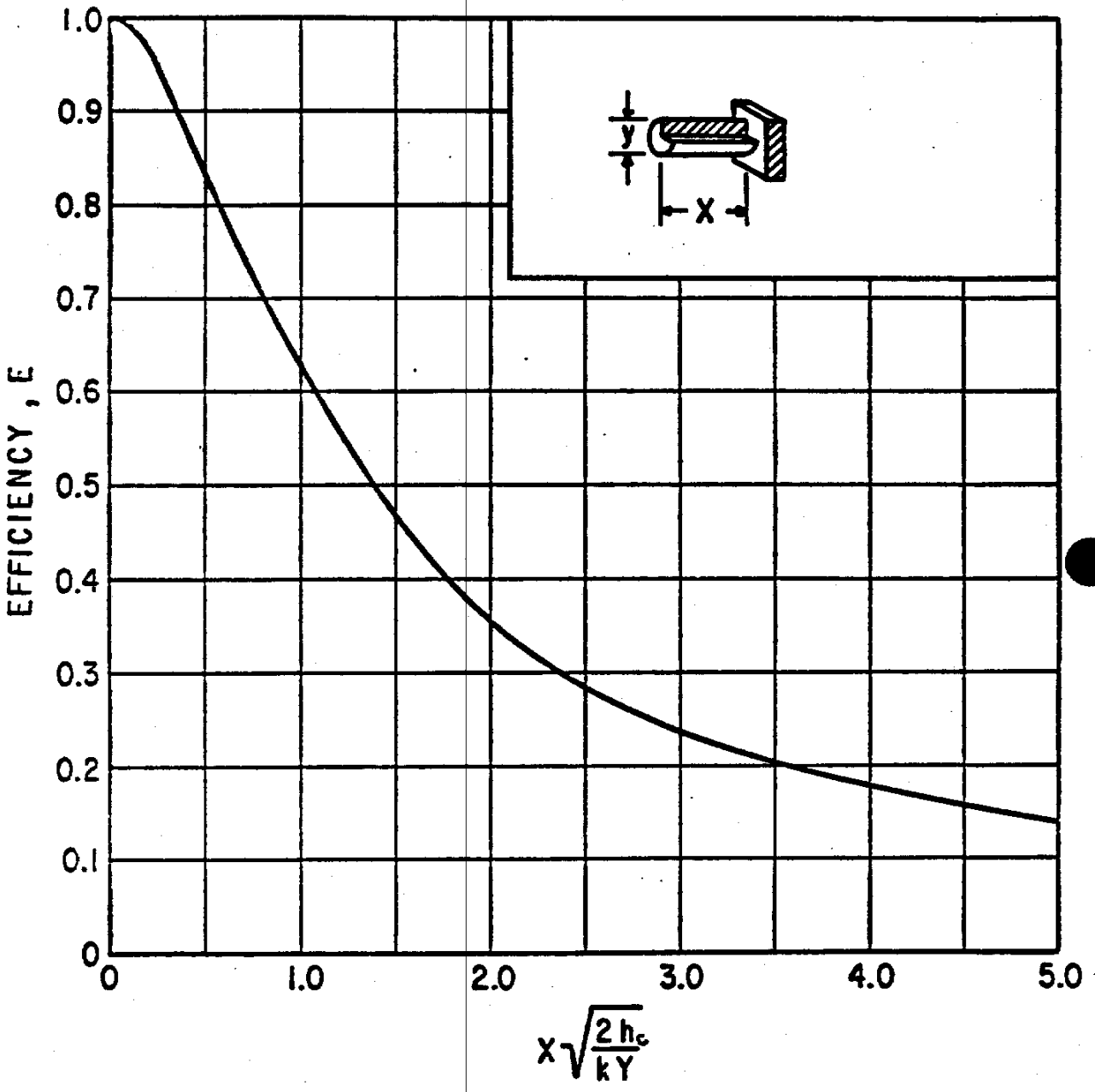
Studs can serve many functions. Here are many standard and special studs which have been installed either automatically or manually.

FIGURE 54



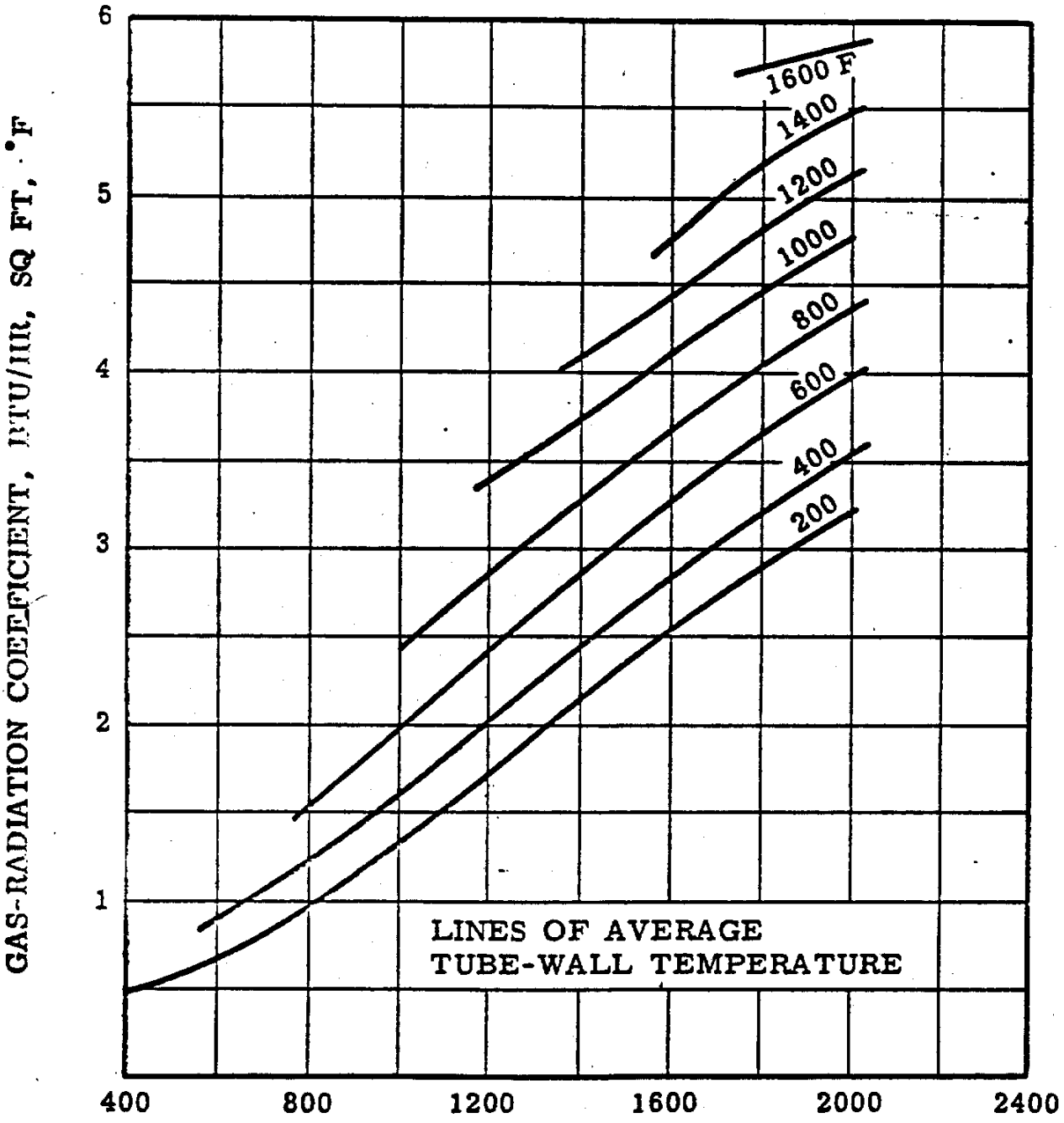
-Efficiency of annular fins of constant thickness.[6]

FIGURE 55



-Efficiency of spines of constant diameter.[6]

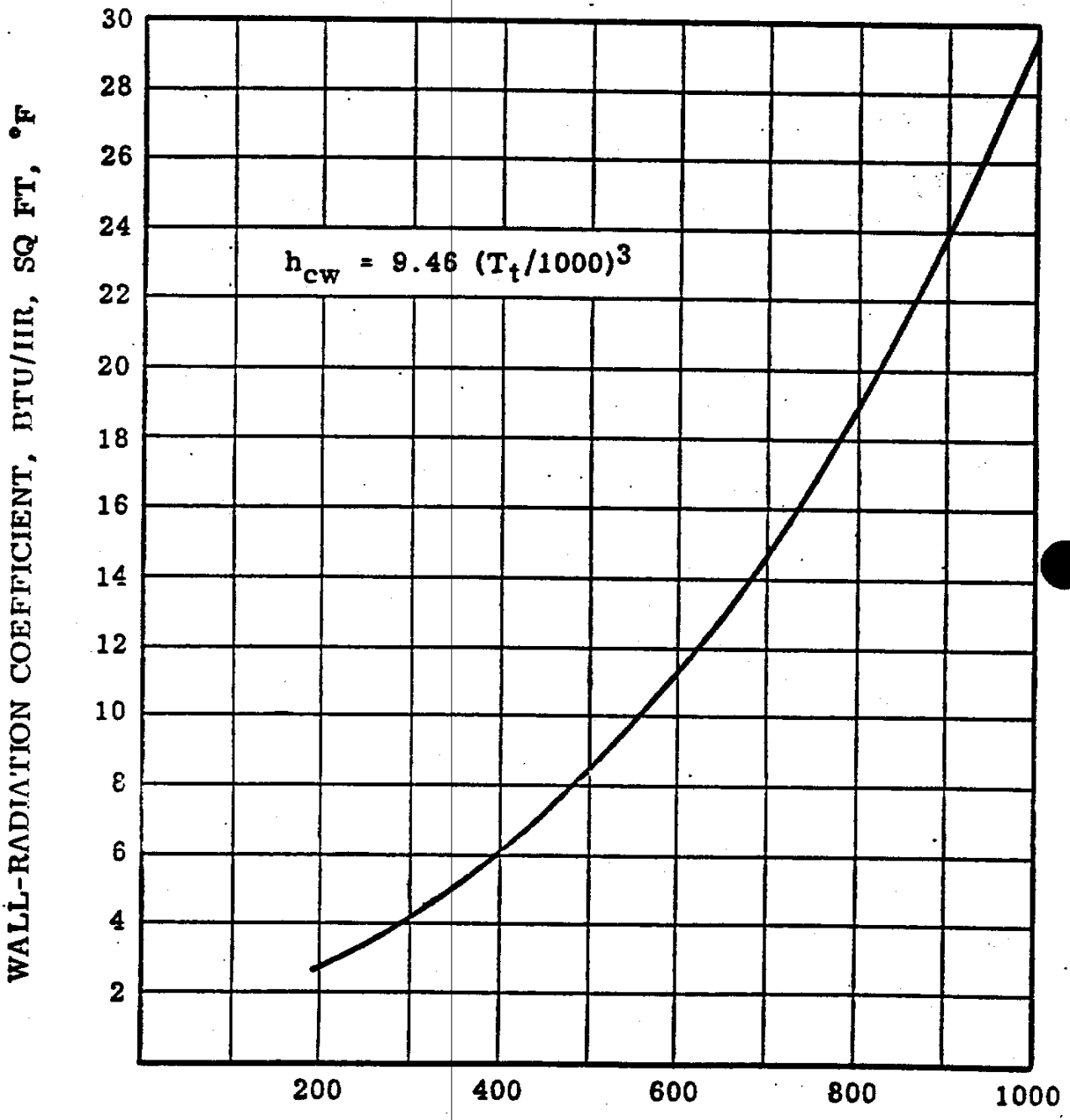
FIGURE 56



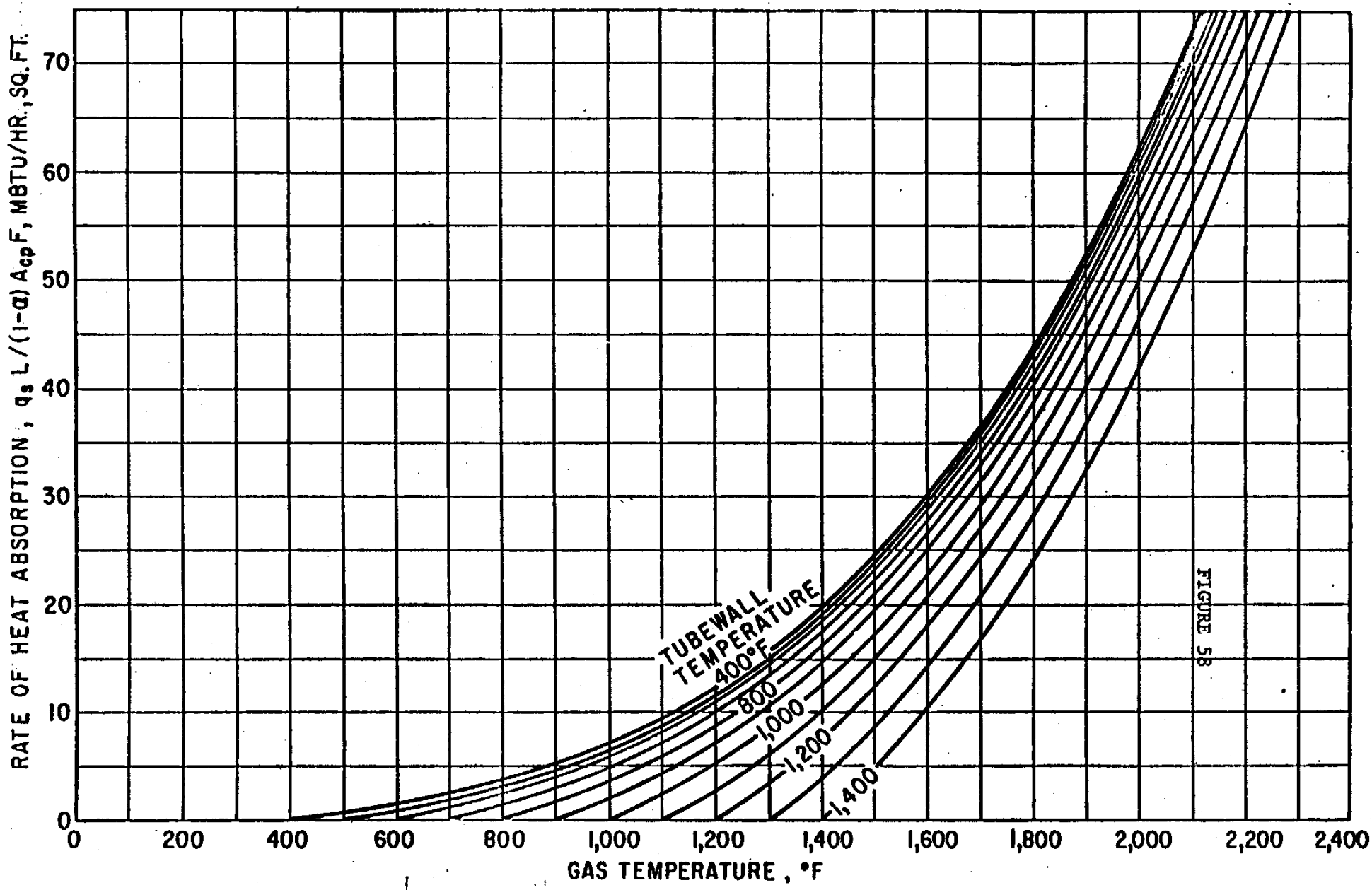
Gas radiation coefficients.[1]

57

FIGURE 57

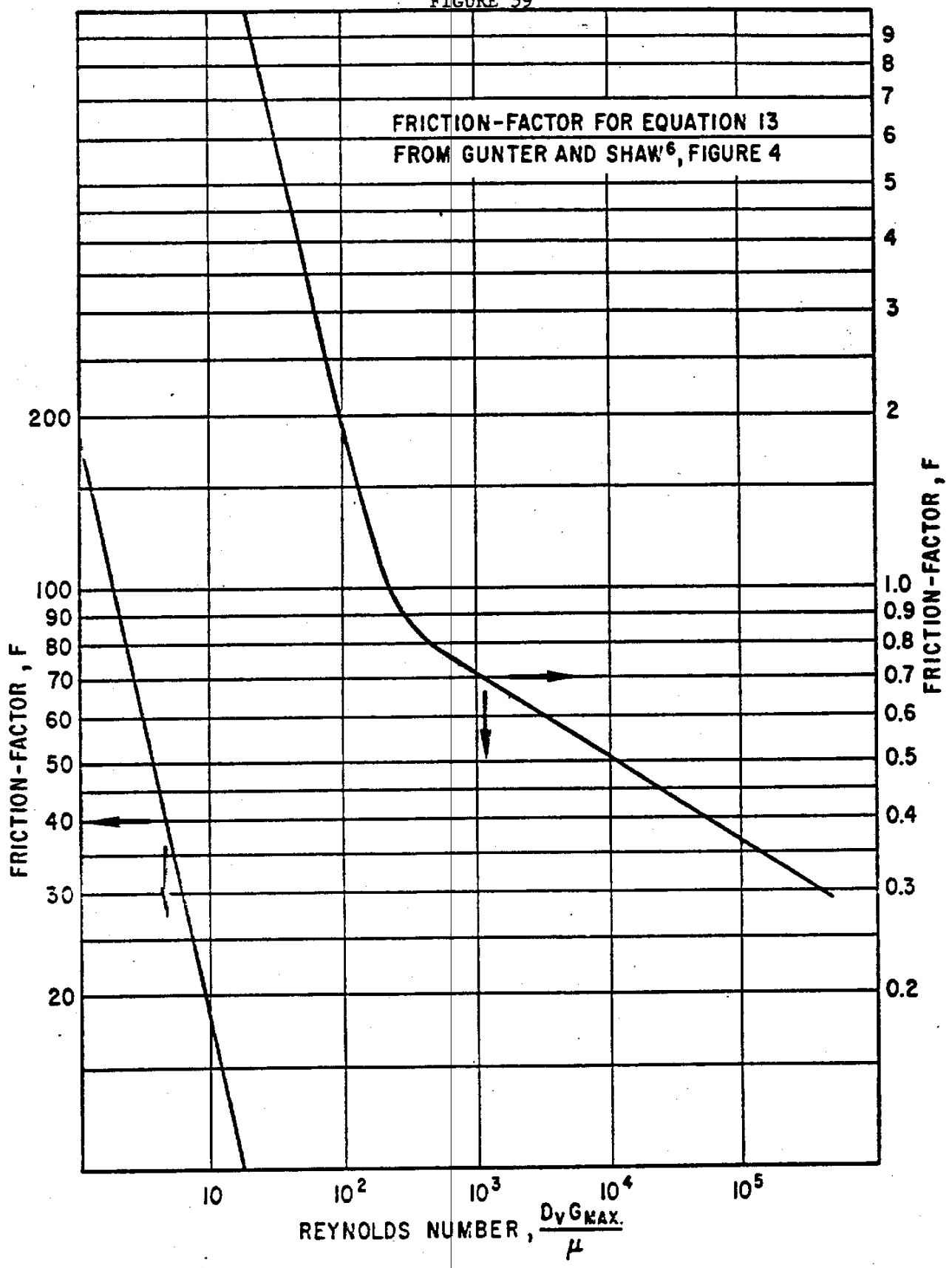


-Coefficient for radiation from convection section walls.[1]



—Radiation leakage through shield coil.

FIGURE 59



Cross flow friction factor.



A SPECIAL REPORT

Rating Fired Heaters

The method of rating or predicting the performance of direct fired heaters presented in this special report simply involves a heat balance calculation between the heat releasing streams or hot furnace gases and the heat absorbing process streams plus a rate relationship.

There are several limitations on furnace design. One is efficiency which depends on fuel costs, process fluid temperature, tube material and the user's policy on investment payout. Excess air rates also have a significant effect on furnace efficiency, and, in general, the lower the rates the smaller the heater.

Another limitation on design is the maximum allowable absorption rate in the radiant section. The higher rates result in smaller, less expensive heaters but also generally require more maintenance. The user must determine the optimum rate according to his particular philosophy, at the time, on investment versus maintenance costs.

Finally, the user usually sets the maximum allowable pressure drop of the process fluid in the heater. A process designer who specifies a low pressure drop can increase heater costs considerably by requiring the heater designer to use higher tube sizes and reduce the number of parallel passes.

Here at last is a method of predicting fired heater performance that will provide the user with an optimum sized heater and can serve as a common basis for calculation between the user and manufacturer.

Frank P. Evans Jr.

MECHANICAL ENGINEERING EDITOR

Here is a method used to predict the performance of direct-fired heaters in typical refinery and petrochemical process applications

R. N. Wimpress, C F Braun & Co, Alhambra, Calif.

DIRECT-FIRED HEATERS have been used to supply process heat ever since the beginning of the refining and petrochemical industries. Relatively little information, however, has been published covering methods for predicting the performance of these heaters. The heat transfer situation existing in a refinery heater is so complicated that direct application of the basic radiation and convection relationships is extremely involved and laborious. Therefore, the industry has depended to a large degree on strictly empirical correlations.

This article describes a method for computing the performance of both the radiant and convection sections of fired heaters. The method is based on fundamental correlations for heat transfer by radiation and convection. It is applicable to the usual types of refinery heater, where combustion takes place in a firebox without flame impingement on tubes or refractory walls. However, it cannot be used directly for applications involving radiant-type burners or specially-fired refractory walls.

The rating procedures were developed from methods presented by Lobo and Evans[3] for the radiant section, and Monrad[5] for the convection section. No attempt will be made here to repeat the detailed basis and development of their correlations. Reference should be made to the original papers if more extensive background information is required.

Rating a fired heater simply involves a heat balance betwee

General. Fired heaters are essentially large heat exchangers. The heat-input is provided by burning fuel, usually oil or gas, in a combustion chamber. Heat is transferred from the hot gas to fluid contained in tubes. As with any heat exchanger, the rating involves a heat balance between the heat-releasing and heat-absorbing streams, and a rate relationship. But in contrast to the usual process heat exchanger, much of the heat is transferred by radiation instead of by convection.

Figure 1 shows a cross-section of a typical fired heater as used in refineries today. It consists of a firebox or radiant section, a convection section, a hood for collecting the cooled flue gas, and a stack to dispose of the gas and provide draft.

The radiant section provides space for the fuel to be completely mixed with air and burned. It also contains heat-absorbing tubes, which remove a large portion of the heat from the flue gas before it passes out to the convection section. The tubes are generally arranged around the outside of the firebox just in front of refractory walls, as shown in the sketch. For some applications, however, tubes may be located in the center of the furnace, with burners arranged to fire on both sides. At the temperature levels existing in the firebox, most of the heat is transferred by radiation. Therefore, the tubes must be arranged for uniform and efficient radiant absorption.

Many heaters in the past have been designed so that the convection section was completely shielded from the firebox by a refractory bridge wall. This was to protect the front rows of convection tubes from excessive radiant heat. It has been found, however, that with proper design of the convection section, a bridge wall is not required. The tubes in the convection section that can see the fire are called shield-tubes. Although they may be included mechanically as part of the convection section, for process design the shield tubes must be considered as part of the radiant section.

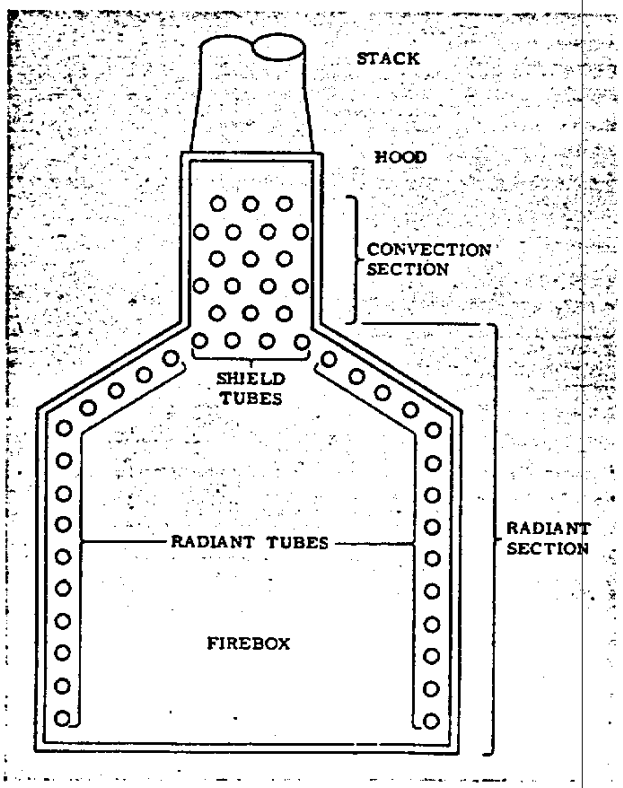


FIGURE 1—Cross-section of a typical fired heater.

The convection section recovers additional heat from the flue gas, at a lower temperature level than can be economically obtained in the radiant section. Here the tubes are arranged to give high mass velocities and turbulence in the gas, so as to obtain good convective transfer.

The hood and stack must simply collect and dispose of the flue gas without excessive frictional loss, and provide enough draft to draw the gases through the firebox and convection section.

Since the physical arrangement and governing heat transfer mechanism are different in the radiant and convection sections, different methods are used to rate the two sections.

HEAT TRANSFER: RADIANT SECTION

Extensive investigations have been made of the radiant heat transfer between solid surfaces in various arrangements, and between hot gases and solids.[1,4,7] Lobo and Evans[3] applied the basic radiation concepts to furnace design, and developed a rating method that was generally applicable without excessive complication. The method described here follows their basic pattern. It has been further simplified, however, by elimination of some minor variables and inclusion of additional general correlations.

The basis for radiant heat transfer is the Stefan-Boltzman equation. A black body at absolute temperature T radiates energy at a rate W_B, given by the following relation.

$$W_B = \sigma T^4 \qquad (1)$$

The Stefan-Boltzman constant σ has a value of 0.173×10^{-8} Btu/sq ft., hr, $^\circ R^4$.

For radiant heat transfer between two real surfaces at temperatures T_a and T_b, the relation becomes

$$q_r = \sigma AF (T_a^4 - T_b^4) \qquad (2)$$

Here A is the area of one of the surfaces, and F is an exchange factor which depends on the relative area and arrangement of the various surfaces, and on the emissivity and absorptivity of each. Either the heat-losing or heat-absorbing surface may be used as a basis for determining q_r. However, the value of the exchange factor depends on which surface is used.

Equivalent Cold-Plane Surface. In a furnace, the heat-absorbing surface is usually well defined. Furthermore, the rate of heat transfer per unit of absorbing area is important to the design. Therefore, it has become accepted practice to use the heat-absorbing, or "cold," surface as a basis for computing the radiant heat transfer.

The usual heat-absorbing surface consists of a number of parallel cylindrical tubes in front of a refractory wall.

ams and a rate relationship

Part the radiation from the hot gas strikes the tubes dire and is absorbed. The remainder passes through to the refractory, and is reradiated back into the furnace. Again, part of the reradiated energy is absorbed by the tubes, and the remainder passes through.

This complicated situation is handled in the calculations by replacing the tube bank with an equivalent plane surface, A_{cp}. It equals the number of tubes, times their exposed length, times the center-to-center spacing. The tube bank, however, will not absorb all the energy radiated to the cold plane area. So the total cold plane area must be corrected by an absorption efficiency factor α. Hottel[1,7] has published values for the factor α as a function of tube arrangement and spacing. His curves for one or two rows of tubes in front of a refractory wall are reproduced in Figure 2.

The product of the actual cold-plane area and the absorption efficiency factor, αA_{cp}, is called the equivalent cold-plane area. It is the area of an ideal black plane having the same absorbing capacity as the actual tube bank.

In the type of heater shown in Figure 1, the shield tubes require special handling. These tubes are not backed by a reradiating refractory wall. Instead, any energy that is not directly absorbed by the shield tubes passes on to the tubes in the convection section, and is absorbed there. Therefore, from the standpoint of the ra ing gas, the factor α for the shield tubes is unity. Sc , calculating the total equivalent cold-plane area in a furnace, the applicable value of α is applied only to the refractory-backed tubes. The cold-plane area of the shield tubes is taken at full value. It might be argued that the shield tubes do not pick up all this heat, so the computed heat-absorption in the radiant section will be too high. However, actual experience shows that because of the high gas velocities past the shield tubes, convective transfer to them is higher than to the normal radiant tubes, and more than compensates for the loss in radiant transfer. The assumption that α equals unity for these tubes is a reasonable allowance for the added convective effects, and simplifies the calculations.

Exchange-Factor. The remaining term to be evaluated in Equation 2 is the exchange-factor, F. First, we must account for the fact that the gas in the firebox is far from an ideal black body. The only constituents in normal flue gas that contribute significantly to the radiant emission are carbon dioxide and water. The emissivity of a body of gas depends on concentration of each of these two components, the furnace dimensions, and the temperatures of the gas and of the absorbing surface. Lobo and Evans have shown that the composition and dimensional effects can be accounted for by a single m, the partial pressure of carbon dioxide plus water ltiplied by the mean beam length. Figure 3 shows the partial pressure P of the radiating components as a function of excess air for the usual hydrocarbon fuels. Table 1 gives the mean beam length L for various furnace shapes. It has been found that the tube wall temperature has only a minor effect. Therefore, the emissivity can be correlated as a function of the PL product and gas temperature, as shown in Figure 4. Variations in tube wall temperature between 600 and 1200° F cause less than one percent deviation from these curves.

The exchange-factor is also dependent on the amount

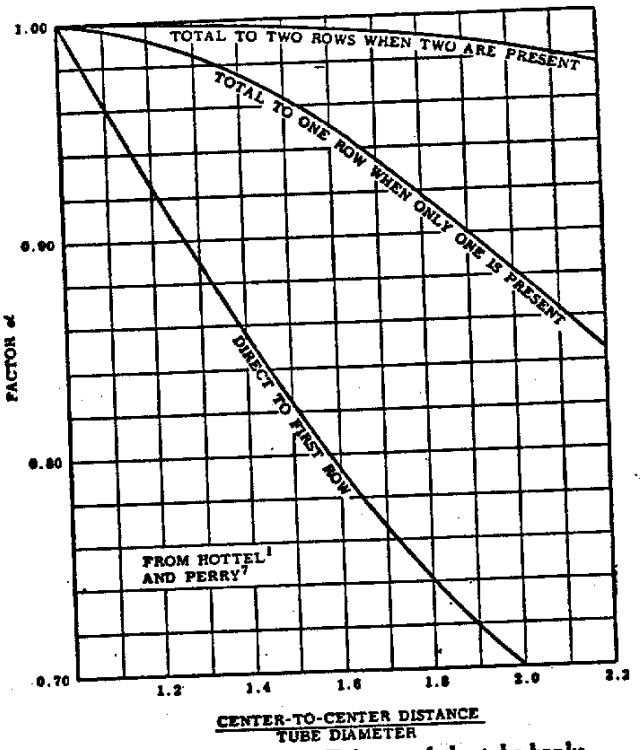


FIGURE 2—Absorption efficiency of the tube-banks.

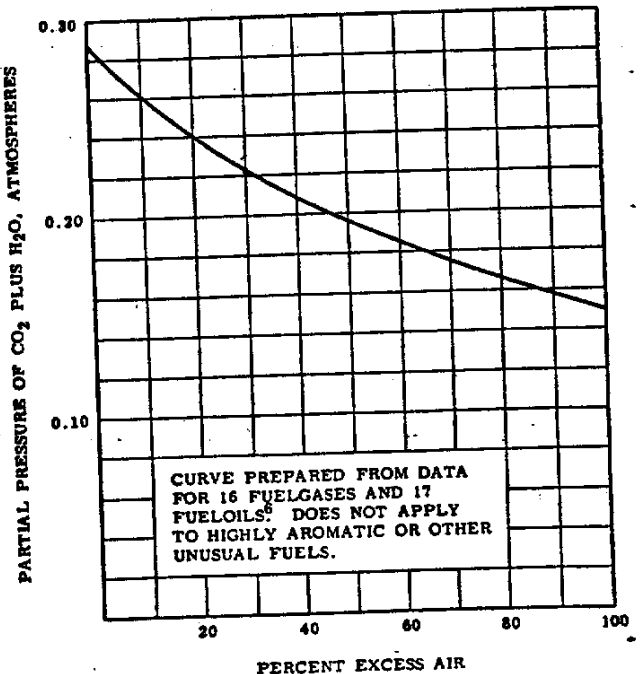


FIGURE 3—Partial pressure of CO_2 plus H_2O in flue gas.

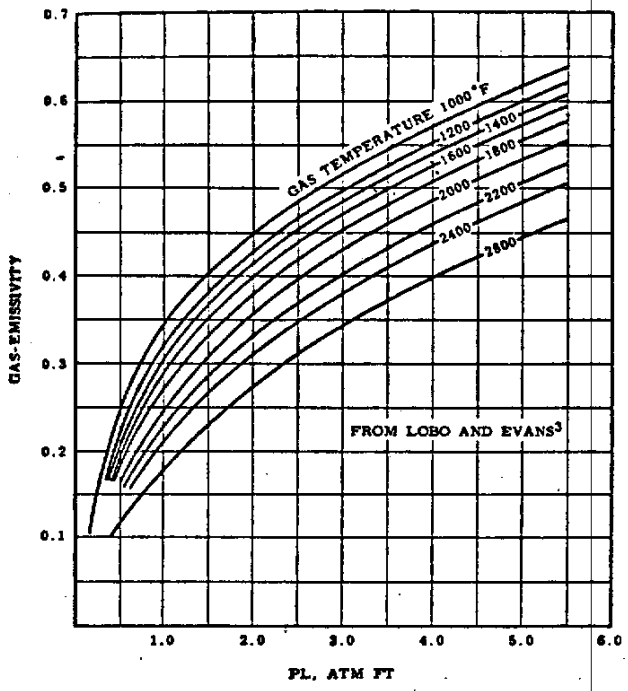


FIGURE 4—Gas-emissivity.

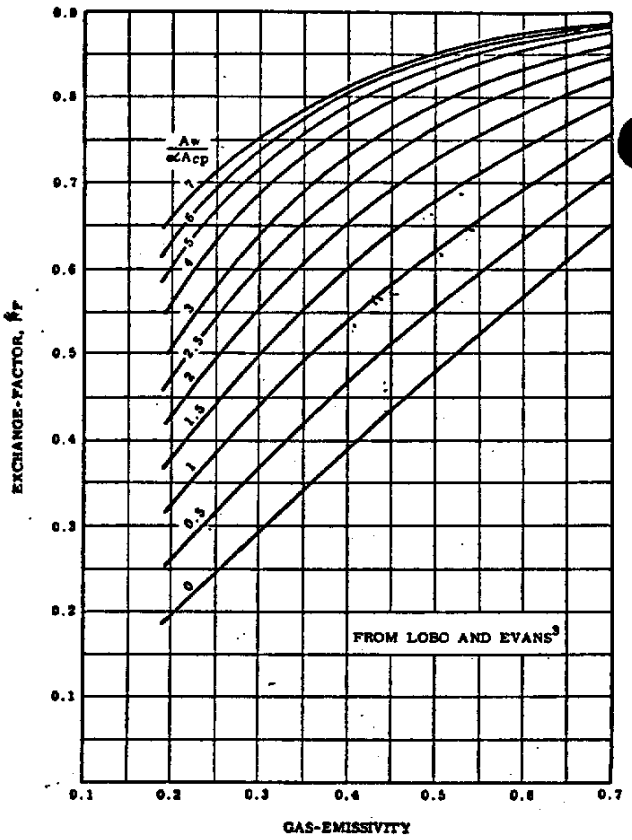


FIGURE 5—Over-all radiant exchange-factor.

of reradiation from exposed refractory. Energy striking such refractory is, in effect, reflected back toward the tubes. Thus a furnace with a large amount of exposed refractory will transfer more heat per unit of tube surface than one with most of the walls covered by tubes. This effect can be correlated on the basis of the ratio of exposed refractory area to equivalent cold-plane area, as shown in Figure 5. The exposed refractory area is defined as the area which would be exposed if the tube bank were replaced by the equivalent cold plane. That is, it is the total envelope area of the firebox, less the equivalent cold-plane area of all the tubes.

Figure 5 also allows for the fact that the tubes do not completely absorb all the radiant energy that strikes them. The curves are based on a tube-surface absorptivity of 0.9, which is a commonly accepted value for oxidized metal surfaces.

TABLE 1—Beam Lengths for Gas Radiation

DIMENSION RATIO	MEAN BEAM LENGTH, L
Rectangular Furnaces, Length-Width-Height, In Any Order	
1-1-1 to 1-1-3 1-2-1 to 1-2-4	⅔ (Furnace Volume)$^{1/3}$
1-1-4 to 1-1-∞	1 x Smallest Dimension
1-2-5 to 1-2-∞	1.3 x Smallest Dimension
1-3-3 to 1-∞-∞	1.8 x Smallest Dimension
Cylindrical Furnaces, Diameter-Height	
1-1	⅔ x Diameter
1-2 to 1-∞	1 x Diameter

The working equation for calculating radiant heat transfer in the firebox thus becomes

$$q_{Rr} = \sigma \alpha A_{cp} F (T_g^4 - T_t^4) \quad (3)$$

Convective Transfer. Although radiation accounts for most of the heat transfer in the radiant section, convection cannot be neglected. The relative amount of heat transferred by convection may be from five to twenty percent of the total radiant duty, depending on the temperature level. The relation for convective heat transfer is

$$q_{Rc} = h_{Rc} A_{Rt} (T_g - T_t) \quad (4)$$

Since convective heat transfer is not the major contributor, we may make some simplifying approximations. For the usual furnace, h_{Rc} is about 2.0 Btu/hr sq ft F, A_{Rt} is about two times αA_{cp}, and the exchange factor F is about 0.57. Making these substitutions into Equation 4, we can put it into a form similar to Equation 3.

$$q_{Rc} = (2.0)\ (2\,\alpha\,A_{cp})\ (F/0.57)\ (T_g - T_t) = 7.0\,\alpha\,A_{cp}\,F\,(T_g - T_t) \quad (5)$$

Total Heat-Transfer Rate. The total heat absorbed in the radiant section is the sum of the radiant and convective transfer

$$q_R = q_{Rr} + q_{Rc} = \sigma\,\alpha\,A_{cp}\,F\,(T_g^4 - T_t^4) + 7.0\,\alpha\,A_{cp}\,F\,(T_g - T_t) \quad (6)$$

or, dividing through by αA_{cp} F,

$$\frac{q_R}{\alpha\,A_{cp}\,F} = \sigma(T_g^4 - T_t^4) + 7.0\,(T_g - T_t) \quad (7)$$

Thus the ratio $q_R/\alpha A_{cp} F$, is a function of gas and tube wall temperatures only. The relation is shown in Figure 6.

Radiant Section Heat Balance. To determine the temperature of the flue gas in the firebox, we must now consider the heat balance around the furnace. Heat is put into the radiant section from three sources—the net heat of combustion q_n, the sensible heat of the combustion air q_a, and the sensible heat of the fuel q_f. Heat is removed in three ways—that absorbed by the tubes q_R, the losses q_L, and the sensible heat of the exit flue gas q_{g2}. Expressed as an equation,

$$q_n + q_a + q_f = q_R + q_L + q_{g2} \qquad (8a)$$

Solving this equation for the heat absorbed.

$$q_R = q_n + q_a + q_f - q_L - q_{g2} \qquad (8b)$$

Finally, Equation 8b can be modified to a form similar to Equation 7.

$$\frac{q_R}{\alpha A_{cp} F} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_{g2}}{q_n}\right] \frac{q_n}{\alpha A_{cp} F} \qquad (9)$$

The net heat release q_n is established as soon as the total heater duty and efficiency are established. The values of q_a and q_f are fixed by the temperature of the fuel and combustion air. The loss q_L is usually from one to three percent of the net heat release, and can generally be estimated from past experience. This leaves q_{g2} as the only variable on the right-hand side of Equation 9. It turns out that the fraction of net heat-release retained in the flue gas is primarily a function of temperature and excess air, for all common liquid and gaseous fuels. This relation is shown in Figure 7. Data for sixteen fuel gases and seventeen fuel oils agree with these curves within two percent.

Temperatures. Figure 6 shows the rate of heat transfer between a mass of gas at one uniform temperature, and a tube surface at another uniform temperature. In most actual furnaces, however, neither of these temperatures is constant. Average effective temperatures must be selected in order to use Figure 6.

Tube wall temperature depends on the temperature of the fluid inside, the intube transfer coefficient, the thermal resistance of the tube wall, and the total heat flux. Fluid temperature can almost always be taken as the arithmetic mean of the radiant section inlet and outlet. The difference between fluid and tube wall temperatures can, if necessary, be determined from the usual intube film-coefficient correlations. Since radiant absorption rate is fairly insensitive to tube wall temperature, however, it is usually accurate enough to add 100° F to the average fluid temperature.

The average effective gas temperature depends on the general shape of the furnace and the firing conditions. Experience has shown that for heaters of the type shown in Figure 1, with an approximately square cross-section and no large areas of refractory with direct flame impingment, the average gas temperature is very close to that of the exit gas. For some other types, however, such as a cylindrical furnace with a high length/diameter ratio, the average firebox gas is appreciably hotter than the exit gas. The magnitude of this difference must be determined empirically from experience with similar designs.

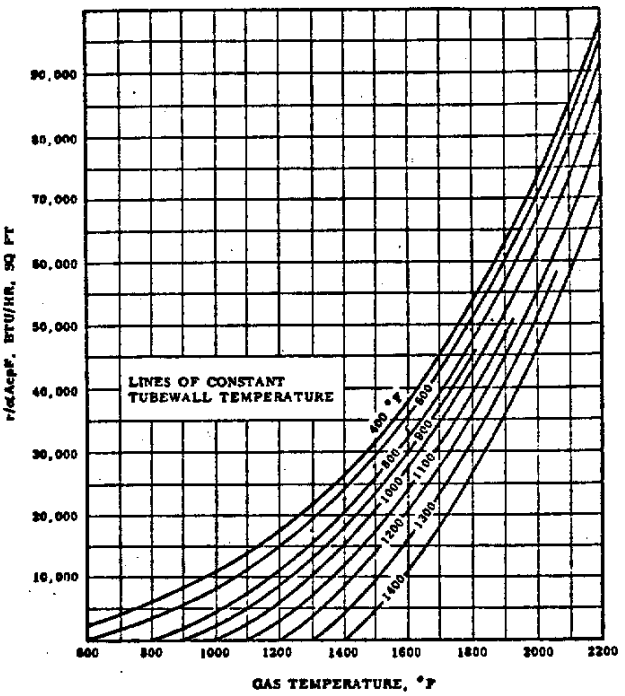


FIGURE 6—Total heat-absorption in the radiant section.

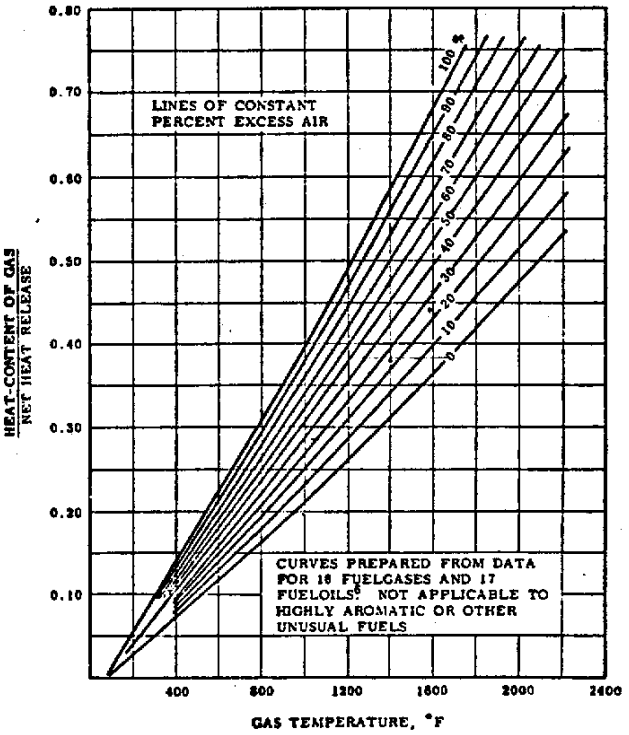


FIGURE 7—Heat-content of flue gas.

Radiant Section Heat Absorption. Equation 7 gives

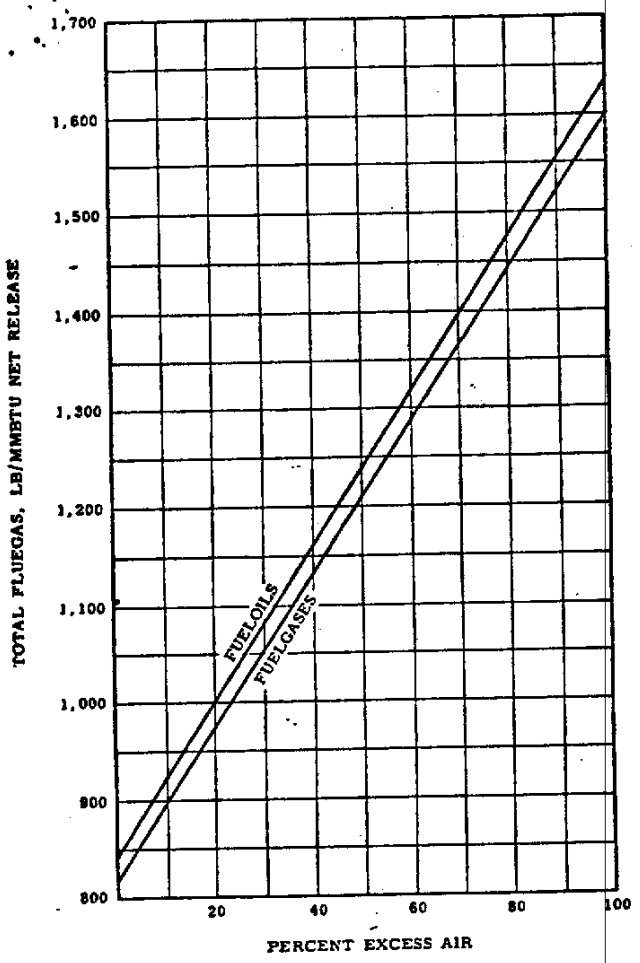


FIGURE 8—Fluegas rates.

the heat transferred to the tubes in the radiant section as a function of average gas temperature. Equation 9 gives the heat removed from the flue gas as a function of exit temperature. Simultaneous solution of the two equations gives the firebox temperature and the amount of heat transferred.

The solution is most easily obtained graphically by superimposing a plot of Equation 9 on Figure 6. The value of t_g is read where the plot of Equation 9 crosses the applicable tube wall temperature. Then, from a heat balance, q_R is readily determined. Note that it is not necessary to plot Equation 9 over the full temperature range. Only that part which crosses the curves in Figure 6 is required. Furthermore, since Equation 9 is nearly linear with respect to gas temperature, two calculated points close to the intersection, joined by a straight line, are usually sufficient.

HEAT TRANSFER: CONVECTION SECTION

As in the radiant section, heat is transferred in the convection section by both radiation and convection. A firm basis for calculating convection-section heat transfer was first outlined by Monrad.[5] He accounted for ;t convection, radiation from the gas, and radiation from the refractory walls. The method outlined here follows Monrad's theory, but with revised correlations to include later experimental results.[2,8,9]

Convective Heat Transfer. The correlation offered by Monrad has been revised to include later and more extensive data for film transfer coefficients

$$h_{Ce} = \frac{2.14\,(T_f)^{0.28}\,(G_{max})^{0.6}}{d^{0.4}} \qquad (10)$$

Figure 9 shows the convection coefficient for several common tube sizes. The average gas film temperature is defined as the average intube fluid temperature plus one-half the log mean temperature difference from flue gas to fluid. The flue gas rate is at the minimum cross-section in the convection section. It has been found that flue gas rates for all ordinary gaseous and liquid fuels can be correlated on the basis of net heat release and percent excess air. The relation is shown in Figure 8.

Radiation From Flue Gas. A method for calculating the heat transfer by radiation from flue gas to a bank of tubes has been presented by Hottel.[1] His basic relation was solved using typical tube spacing of about two tube diameters, a tube surface absorptivity of 0.9, and a typical partial pressure of carbon dioxide plus water. The results are shown in Figure 10. The average

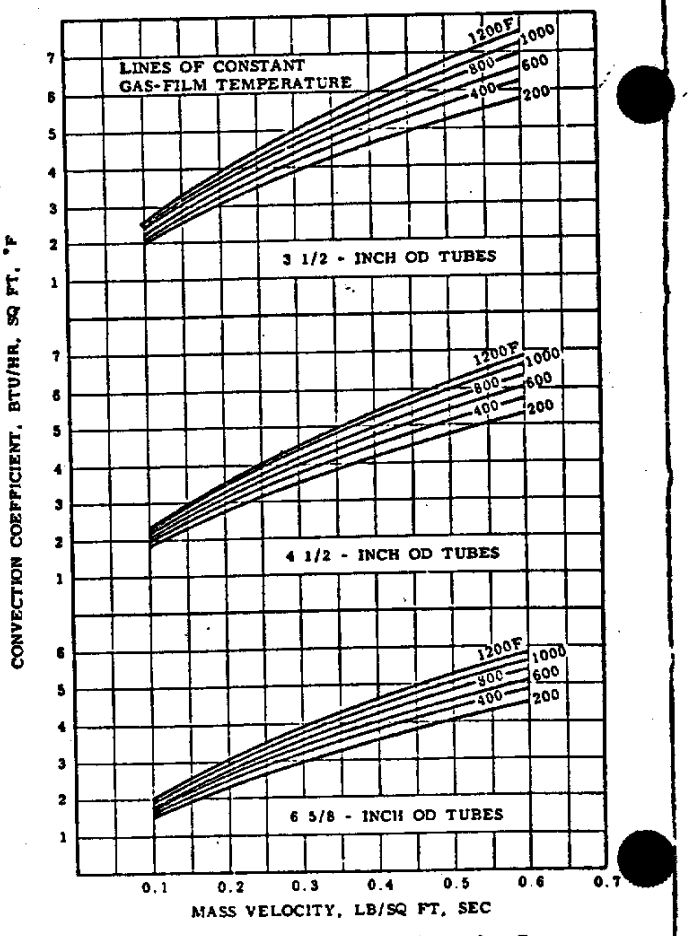


FIGURE 9—Flue gas convection-coefficients for flow across staggered banks of bare tubes.

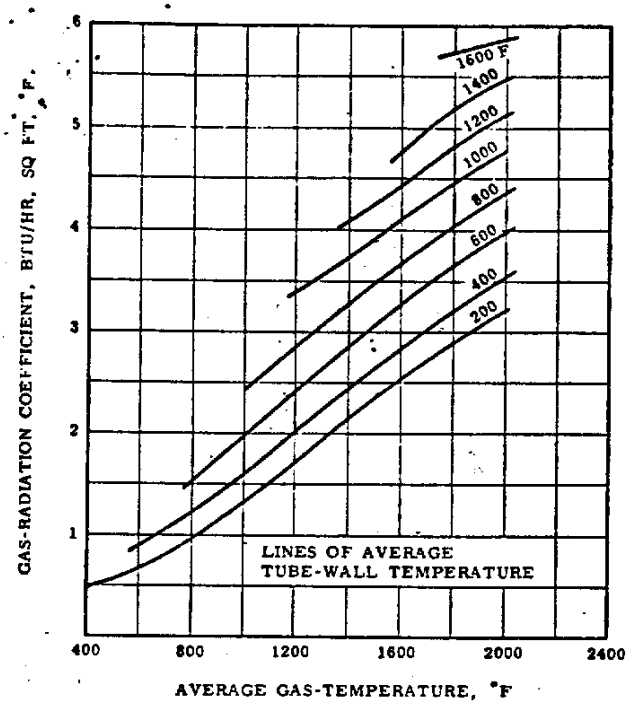


FIGURE 10—Gas-radiation coefficients.

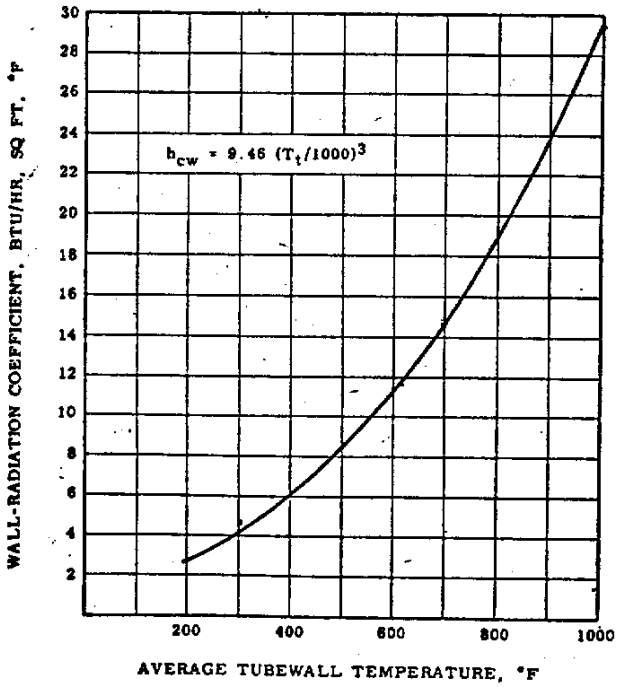


FIGURE 11—Coefficient for radiation from convection-section walls.

gas temperature is defined as the average intube fluid temperature plus the log mean temperature difference from the flue gas to fluid. The average tube wall temperature may be taken as average fluid temperature plus 100° F.

Radiation From Refractory Walls. Following Monrad's pattern, we express the effective coefficient for

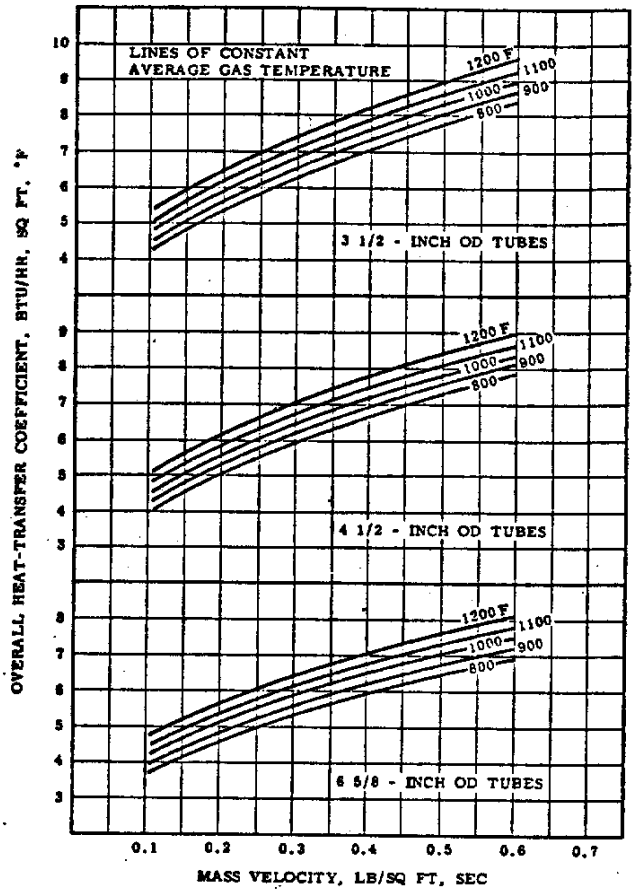


FIGURE 12—Over-all heat-transfer coefficients in the convection section.

wall-to-tube transfer as a function of tube wall temperature, as shown in Figure 11. This coefficient, together with the relative wall and tube areas in the convection section, determines a correction factor f.

$$f = \frac{h_{cw}}{h_{cc} + h_{cr} + h_{cw}} \left(\frac{A_{cw}}{A_{ct}} \right) \qquad (11)$$

Over-all Transfer Coefficient. The total apparent gas film coefficient is determined from the individual coefficients by the following equation

$$h_o = (1 + f)\ (h_{cc} + h_{cr}) \qquad (12)$$

The intube coefficient is calculated by standard methods, based on the flow-rate and physical properties of the fluid. The resistance of the tube wall is small, and is usually neglected. The over-all transfer cofficient in the convection section then becomes

$$V_o = \frac{h_o\ (h_{ci})}{h_o + h_{ci}} \qquad (13)$$

In many rating problems, particularly during preliminary work, the detailed calculations outlined above are not justified. For these cases, the curves in Figure 12 can be used. These represent overall convection section coefficients, assuming usual tube arrangements, fluid temperatures, and intube film coefficients.

Finned Tubes. Extended surface on the tubes in the convection section is often used as a means of obtaining

additional heat transfer per unit of prime tube surface. Convective transfer coefficients for such tubes depend upon the exact size and arrangement, and must be determined for the particular type being considered. It should be noted that the extended surface increases only the convective transfer. Radiant transfer must be computed on the basis of prime tube surface. With most types of extended surface now being used, radiant transfer to the convection section tubes is so small that it can be neglected

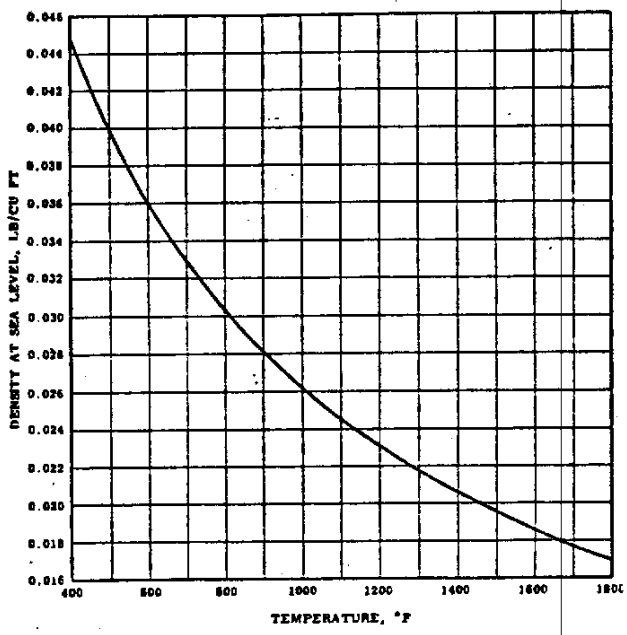


FIGURE 13—Density of flue gas.

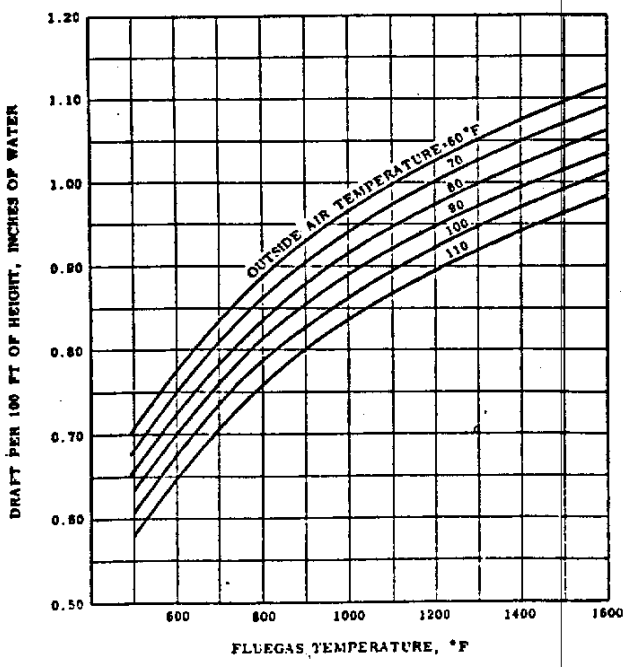


FIGURE 14—Stack draft.

STACK DESIGN

In a natural-draft heater, the stack must create sufficient draft to overcome frictional drop through the burners, the convection section, the damper, and the stack.

Burners. Pressure drop across the burners is often required to draw in secondary air. Its magnitude is usually set by the burner manufacturer, and depends on the type of burner and the fuel. A normal value is about 0.25 inch of water.

Convection Section. The pressure drop across horizontal tubes in the convection section is about one-half velocity-head per row. The velocity-head in inches of water is given by the following equation

$$p_v = \left(\frac{V^2}{2g}\right)\left(\frac{\rho_g}{\rho_w}\right)(12) = 0.0030\, V^2 \rho_g = 0.0030\, \frac{G^2}{\rho_g} \qquad (14)$$

Flue gas densities are shown in Figure 13. In the convection section, the gas density is evaluated at the same average gas temperature that was used to calculate the convection section transfer coefficient.

Stack and Damper. The various remaining losses are expressed in terms of velocity-head in the stack.

Stack entrance	0.5 velocity-heads
Damper	1.5
Stack friction	H/50D
Stack exit	1.0
Total	3.0 plus H/50D

Equation 14 and Figure 13 are used to calculate velocity-head, just as for the convection section.

Draft. The draft effect depends on the difference in density between the hot flue gas and the surrounding air.

$$\Delta p = \frac{H\,(\rho_a - \rho_g)}{\rho_w}(12) = 0.187\, H\,(\rho_a - \rho_g) \qquad (15)$$

Available draft per 100 feet of height is shown in Figure 14. To allow for heat loss from the stack, its draft should be computed on the basis of a temperature 100° F lower than that of the flue gas leaving the convection section.

Furnace Pressure. It is usually desirable for all sections of the heater to be below atmospheric pressure. Then any leaks through peepholes, tube-openings, or cracks in the setting will be outside air moving in, rather than hot flue gas moving out. In heaters with tall radiant sections, such as vertical cylindrical types, the firebox alone may develop more draft than is required by the burners. In such cases, the stack height must be increased as necessary to maintain sub-atmospheric pressure at the convection section inlet.

Stack Size. In many installations, minimum stack heights are set by fume dispersal requirements, particularly if there are tall structures nearby. If such is the case, the stack is sized so that the total friction drop is no greater than the available draft. If there are no such outside limitations, the most economical combination of diameter and height can be selected. Usual designs have flue gas velocities in the stack of about 30 feet per second.

FURNACE RATING PROCEDURE

We now come to the problem of applying the principles outlined above to a specific furnace design. The following paragraphs describe general concepts that are normally used, and present the outline of a procedure that has been found to require a minimum of trial and error computation.

Basic Design Considerations. The function of a process furnace is to heat a prescribed amount of some material from one temperature to another, using a particular fuel. In addition to this requirement, other limitations are generally imposed. Some are needed to fit additional process requirements, and others are set on the basis of past experience. The usual restrictions are discussed in the following paragraphs.

Over-all furnace efficiency determines the basic operating cost of the heater. The optimum efficiency for a particular application depends on a number of factors, such as the cost of fuel, the temperature of the fluid being heated, the type of tube material required, and the user's policy on investment payout. For process heaters without air preheat, over-all efficiencies are usually in the 70 to 80 percent range, based on net heating value.

Excess combustion air has a significant effect on efficiency. In general, the lower the excess air, the smaller the heater for a specific job. However, too little excess air can cause operating difficulties from incomplete combustion, poor flame characteristics, and erratic control. Usual excess air rates are 15 to 25 percent for gas-firing and 25 to 40 percent for oil.

The maximum absorption rate in the radiant section is usually specified by the user on the basis of past experience. High radiant rates generally result in smaller, less expensive heaters. Lower rates give lower tube wall and refractory temperatures, thus tending toward lower maintenance. Normal design figures for clean service with good intube transfer coefficients are in the range of 10,000 to 15,000 Btu per hour per square foot of tube surface.

Maximum heat release per unit firebox volume may be specified. Unit heat release is a rough measure of the probability of flame impingement on the tubes. However, current practice is to judge the possibility of flame impingement from the furnace shape and the type of burner, rather than to set an arbitrary heat release limit.

Maximum pressure drop of the process fluid is usually dictated by the user. This places some restrictions on the tube size and number of parallel passes.

Preliminary Design Steps. Before starting the detailed rating, certain aspects of the design can be established from the process requirements and the other limitations described above. First, calculate the net heat release, using the specified absorption duty and efficiency. Then select an excess air percentage and determine the flue gas rate from Figure 8.

Normal heaters will handle about 70 percent of the total duty in the radiant section. On this basis, estimate the radiant heat absorption q_R. From enthalpy or specific heat data for the process fluid, estimate the temperature at the crossover between the convection and radiant sections, and the average fluid temperature in the radiant section. Add 100° F to the average fluid temperature to get the average tube wall temperature. Using the specified allowable radiant transfer rate, calculate the total radiant tube surface.

The convection tube surface is usually about equal to that in the radiant section. On this basis, select a tube size and pass arrangement that will give the required total surface and meet the specified pressure drop limitation.

Radiant Section Rating. Choose a center-to-center spacing for the radiant tubes which is compatible with the selected tube size. Wide tube spacing permits high radiant absorption rates with relatively low firebox temperatures, and gives good circumferential heat distribution. Closer spacing permits more tubes to be installed in a given size firebox. The usual spacing is about twice the nominal pipe size corresponding to the outside tube diameter, for example, 8-inch spacing for 4.5-inch OD tubes.

Using the approximate radiant tube surface determined above, choose firebox dimensions that will accommodate the required total tube length. The exact proportions depend on judgment and past experience. Long furnaces minimize the number of return bends required, thus decreasing total cost. Shorter and wider fireboxes, on the other hand, usually give more uniform heat distribution and lessen the probability of flame impingement on the tube surface.

For the selected firebox dimensions, calculate the equivalent cold-plane surface, the effective refractory surface, and the mean beam length. Read the partial pressure of carbon dioxide plus water from Figure 3 and calculate the PL product.

If preheated air or fuel is used, calculate the heat content of each stream above 60° F, and its ratio to the total net heat release. The heat content of any of these streams below 100° F can usually be neglected. Estimate the heat loss through the setting.

Assume a value for the average temperature of the flue gas in the radiant section, t_g. At this temperature, read the gas emissivity from Figure 4, and then the exchange factor from Figure 5. Calculate the ratio $q_n/\alpha A_{cp} F$.

If the furnace design is one for which experience has shown a significant difference between average effective gas temperature and exit temperature, apply the appropriate correction to determine the exit temperature t_{g2}. Read the corresponding value of q_{g2}/q_n from Figure 7. Then, using Evuation 9, calculate $q_R/\alpha A_{cp} F$ and plot it against average furnace temperature on Figure 6.

If the assumed value of t_g was correct, the computed point will be on the absorption curve for the average tube wall temperature. Usually, of course, there will be a discrepancy. Then select another value of t_g on the other side of the absorption curve, and repeat the above procedure. When two points on opposite sides of the curve are obtained, join them by a straight line. The point of intersection of this line with the absorption curve is the correct firebox temperature. For this temperature, calculate t_{g2}, read q_{g2}/q_n from Figure 7, and calculate q_R from Equation 8b. This is the heat actually absorbed in the radiant section.

It is now necessary to check the computed radiant absorption to be sure it meets the design limitations. First, divide the heat absorption by the total exposed tube area to get the average heat flux. If it is higher

than the allowable maximum, a new furnace with more tube surface must be selected, and the rating repeated. If the actual heat flux is considerably below the allowable value, a smaller furnace should be considered. Then, from enthalpy data on the process fluid, calculate the crossover temperature from convection to radiant section. If the computed temperature is significantly different from that assumed in starting the rating, it may be necessary to go back and repeat with a new value of average tube wall temperature. Tube wall temperature, however, has such a small effect on the radiant absorption rate that such refinement is usually unnecessary.

There is one point to watch in regard to the crossover temperature. The fluid temperature determined as described above corresponds to the transition from true convection tubes to shield tubes. Many heaters include the shield tubes as part of the convection section, and the crossover piping is actually between the shield and radiant tubes. For such cases, the temperature in the crossover piping will be higher than that calculated in the rating, by an amount corresponding to heat absorption in the shield tubes.

Convection Section Rating. The convection section must pick up the difference between the heat absorbed in the radiant section and the total heater duty. The temperatures of the flue gas entering the convection section and the process fluid leaving it have already been calculated as part of the radiant section rating. The incoming fluid temperature is set by the original design conditions. The flue gas temperature going to the stack is determined by an over-all heat balance and Figure 7.

$$\frac{q_s}{q_n} = 1 + \left(\frac{q_a}{q_n}\right) + \left(\frac{q_f}{q_n}\right) - \left(\frac{q_R + q_C}{q_n}\right) \qquad (16)$$

Using these temperatures, calculate the average fluid temperature, the log mean temperaure difference, the average gas temperature, and the average gas-film temperature.

Select a convection tube arrangement that will give a maximum flue gas mass-velocity of about 0.3 to 0.4 pounds per square foot per second. Calculate the mass-velocity G. For precise ratings, calculate the gas-film coefficient using Figures 9, 10 and 11, and Equations 11 and 12. Calculate the intube coefficient using any applicable method. Then calculate the over-all transfer coefficient from Equation 13. For less critical ratings, read the over-all design coefficient from Figure 12. In either case, finally determine the convection area from the usual heat-transfer equation

$$A_C = \frac{q_C}{U_C\,(LMTD)} \qquad (17)$$

The calculated convection surface will usually not correspond to an integral number of tube rows. In many cases, the computed surface is simply rounded up to an even number of tube rows, and the excess considered as a margin of safety. If a more exact rating is desired, however, it is necessary to assume a new over-all efficiency and repeat the entire rating. The results can then be interpolated to the desired number of tubes.

Finally, calculate the flue gas pressure drop through the convection section, using Equation 14. Evaluate the flue gas density at the same average temperature that was used in calculating the transfer coefficients.

Stack Design. The stack must provide enough draft to hold the firebox at a slight negative pressure, and to overcome frictional losses through the convection section and stack. First, calculate the draft caused by the firebox itself. Determine whether the limiting factor is pressure drop across the burners or the necessity of maintaining negative pressure throughout the firebox.

Assume a stack temperature 100° F lower than the flue gas leaving the convection section. Select a stack diameter to give a stack velocity of about 30 feet per second, and calculate the velocity head. Estimate the stack height, and calculate the friction loss through it, allowing 1.5 velocity heads for the inlet and exit losses, 1.5 velocity heads for the damper, and 1 velocity head for each 50 diameters of stack height.

TABLE 2—Altitude Correction Factors for Gas-Density and Draft

Altitude Above Sea Level	Multiply Density And Draft By
0	1.000
1000	0.964
2000	0.930
3000	0.896
4000	0.863
5000	0.832
6000	0.801
7000	0.772
8000	0.743

Read the stack draft per 100 feet from Figure 14. Calculate the draft that the stack must produce, and the required height. If additional height is required for fume dispersal, the stack diameter may be reduced.

SAMPLE CALCULATION

The following example illustrates the use of the rating method in designing a typical refinery heater. Assume we are to design a box-type heater as shown in Figure 1 to heat 27,270 barrels per day of 26 API oil from 380° F to 675° F. The fuel is refinery fuelgas at 60° F, with a lower heating value of 1350 Btu/scf. Further assume that the user has specified an efficiency of 77 percent, no air preheat, 25 percent excess air, 12,000 Btu/hr, sq ft maximum radiant heat-flux, and 40 psi maximum pressure drop.

Density = 7.48 lb/gal at 60° F, 5.93 lb/gal at 530° F
Flow = 27,270 x 42 x 7.48/24 = 357,000 lb/hr
Enthalpy = 273 Btu/lb at 380° F, 483 Btu/lb at 675° F
Duty = 357,000 (483-273) = 75.0 MM Btu/hr
Net Heat release = 75.0/0.77 = 97.5 MM Btu/hr
Flue gas at 25 percent excess air
= 97.5 x 1010 = 98,500 lb/hr
= 27.4 lb/sec (Figure 8)
Approximate radiant duty = 0.7 x 75.0 = 52.5 MM Btu/hr
Crossover temperature = about 675 — 0.7 (675-380) = 468° F
Average fluid = (468 + 675)/2 = 572° F
Average tube wall = 572 + 100 = 672° F
Radiant surface = 52.5 x 10⁶/12,000 = 4370 sq. ft.
Total surface = about 8700 sq. ft.
Select 4.5-inch OD tubes, 4 parallel passes
Velocity = 6.4 ft/sec
Pressure drop = 29 psi
Surface = 1.178 sq ft/ft
Total exposed radiant length = 4370/1.178 = 3710 ft.

...y a heater 20 feet wide by 25 feet high, with 96 tubes 40 feet long overall, 38.5 feet exposed, 8-inch centers. Estimate 6 shield tubes.

Surface per tube = 38.5 x 1.178 = 45.4 sq ft
Total surface = 96 x 45.5 = 4360 sq ft
Spacing ratio = 8.0/4.5 = 1.78, $\alpha = 0.92$ (Figure 2)
Shield tubes $A_{cp} = 38.5 \times 6 \times 8/12 = 154$ sq ft
Wall tubes $A_{cp} = 38.5 \times 90 \times 8/12 = 2310$ sq ft
$\alpha A_{cp} = 154 + 0.92 \times 2310 = 2280$ sq ft
Envelope area = $2(20 \times 25) + 2 \times 38.5\ (20 + 25)$
= 4470 sq ft
$A_R = 4470 - 2280 = 2190$ sq ft, $A_R/\alpha A_{cp} = 0.96$
Furnace volume = 20 x 25 x 38.5 = 19,250 CF
Mean beam length = $(2/3)(19{,}250)^{1/3} = 17.9$ ft
Partial pressure, $CO_2 + H_2O$, = 0.23 atm (Figure 3)
PL = 0.23 x 17.9 = 4.1 atm-ft

Since there is no preheated air or fuel, $q_a = q_f = 0$. Assume $q_L/q_n = 0.02$. Estimate that the average firebox temperature equals 1500° F.

Emissivity = 0.54 (Figure 4)
Exchange factor = 0.645 (Figure 5)
$\alpha A_{cp} F = 2280 \times 0.645 = 1470$ sq ft
$q_n/\alpha A_{cp} F = 97.5 \times 10^6/1470 = 66{,}400$ Btu/hr, sq ft
For this type of furnace, assume that the exit gas temperature is the same as the average firebox temperature
$t_{g2} = t_g = 1500°$ F
$q_{g2}/q_n = 0.415$ (Figure 7)
$q_R/\alpha A_{cp} F = (1 + 0 + 0 - 0.02 - 0.415)\ 66{,}400$
$= (0.565)\ 66{,}400 = 37{,}500$ Btu/hr, sq ft (Equation 9)

Figure 15 shows a small portion of Figure 6 with the absorption curve for 672° F tubewall. Plot the calculated $q_R/\alpha A_{cp}$ F of 37,500 at the assumed firebox temperature of 1500° F. This lies to the left of the absorption curve. So try another calculation at 1700° F.

Emissivity = 0.525
F = 0.635
$\alpha A_{cp} F = 1450$
$q_n/\alpha A_{cp} F = 67{,}300$
$q_{g2}/q_n = 0.48$
$q_R/\alpha A_{cp} F = (0.98 - 0.48)\ 67{,}300 = 33{,}600$
Plot this point on Figure 15, and join the two calculated points by a straight line. It crosses the absorption curve at 1610° F. This is the firebox temperature.
$q_{g2}/q_n = 0.45$
$q_R = (0.98 - 0.45)\ 97.5 = 51.7$ MM Btu/hr
$q_R/A_{Rt} = 51.7 \times 10^6/4360 = 11{,}850$ Btu/hr, sq ft

The heat-flux is just below the allowable value of 12,000. Now check the crossover temperature of the oil.

Enthalpy change = $51.7 \times 10^6/357{,}000 = 145$ Btu/lb
Crossover enthalpy = 483 — 145 = 338 Btu/lb
Temperature = 483° F
Average radiant fluid = (483 + 675)/2 = 579° F
Average tube wall = 579 + 100 = 679° F

The calculated tube wall is so close to the assumed value of 672° F that no further correction is necessary.

For the convection-section design, calculate the various temperatures.

Convection section duty = 75.0 — 51.6 = 23.4 MM Btu/hr
Stack heat content/release = 1 — 0.02 — 0.77 = 0.21 (Equation 16)
Stack Temperature = 820° F (Figure 7)

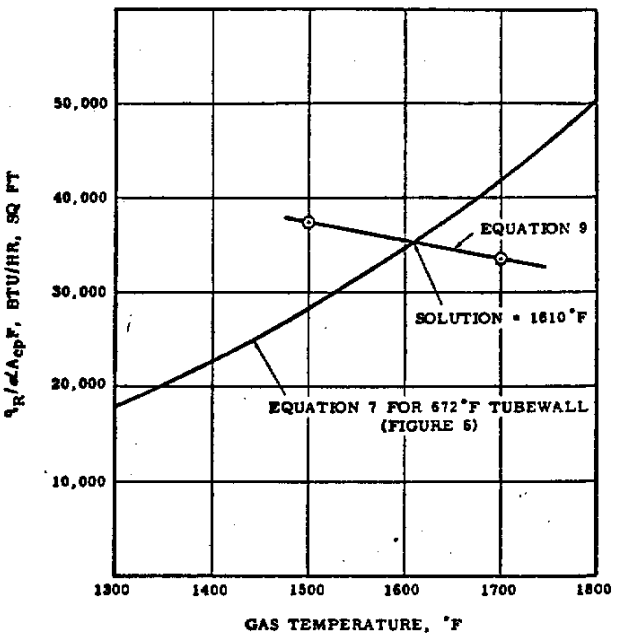


FIGURE 15—Example of graphical solution for flue gas temperature in the radiant section.

Temperature differences, hot = 1610 — 483 = 1127° F
cold = 820 — 380 = 440° F
log mean = 731° F

Average temperatures
Oil (380 + 483)/2 = 432° F
Tube wall 432 + 100 = 532° F
Gas 432 + 731 = 1163° F
Gas film 432 + 731/2 = 798° F

Select a convection section with six 4.5-inch OD tubes per row, 8-inch spacing, staggered.

Gross width = 6.5 x 8 = 52 inches
Free width = 52 — 6 x 4.5 = 25 inches = 2.08 ft
Area = 2.08 x 38.5 = 80 sq ft
G = 27.4/80 = 0.342 lb/sq ft, sec

Using the detailed film transfer correlations

$h_{Cc} = 4.5$ (Figure 9)
$H_{Cr} = 2.2$ (Figure 10)
$h_{Cw} = 9.3$ (Figure 11)
Total 16.0

Row-to-row tube spacing = 0.866 x 8/12 = 0.58 ft
Wall area per row = 2 x 0.58 x 38.5 = 44.6 sq ft
Tube area per row = 6 x 45.4 = 272 sq ft

$$f_f = \frac{9.3}{16.0} \times \frac{44.6}{272} = 0.095 \qquad \text{(Equation 11)}$$

$$h_e = 1.095\ (4.5 + 2.2) = 7.3 \qquad \text{(Equation 12)}$$

For this example, assume the calculated intube film coefficient is 100

$$U_C = \frac{100 \times 7.3}{100 + 7.3} = 6.8 \qquad \text{(Equation 13)}$$

$$A_C = \frac{q_C}{U_C\ (LMTD)} = \frac{23.4 \times 10^6}{6.8 \times 731} = 4{,}700 \text{ sq ft} \qquad \text{(Equation 17)}$$

Tubes = 4,700/45.3 = 104 tubes
Use 18 rows = 108 tubes = 4,900 sq ft

For comparison, the approximate over-all coefficient

from Figure 12 is 7.2. It is also worth noting that the most laborious part of computing the total gas-film coefficient is determining the relatively small wall-effect correction. For many problems, an estimated value of about 10 percent is accurate enough.

In order to get an integral number of tube rows, and yet divide the four streams equally, it was necessaary to include 4 percent additional convection surface. This means that the heater should be slightly more efficient than the 77 percent specified. Repeating the rating procedure, assuming 78 percent efficiency, gives a convection section requirement of 111 tubes. By interpolation, the efficiency with 108 tubes is 77.6 percent, and the stack temperature is 800° F.

The total number of tubes is 96 radiant and shield, plus 108 convection, or 51 tubes per pass. With this number of tubes, the pressure drop is 32 psi, still within the specified limit of 40 psi.

Finally the stack size must be determined. First, determine the draft effect of the firebox. Assume sea level elevation, 100° F outside air

Flue gas temperature = 1610° F
Draft = 1.01 inches/100 ft (Figure 14)
Estimate shield tubes are 18 ft above burners
Draft = 1.01 x 18/100 = 0.18 inch

Assuming the burners require 0.25 inch, they are limiting. At the shield tubes, the draft must be 0.07 inch

Convection section G = 0.342
Density = 0.0236 lb/CF (Figure 13)
Velocity head = $0.0030 \times (0.342)^2/0.0236 = 0.0149$ inch (Equation 14)
Friction = 18 x 0.0149/2 = 0.13 inch
Stack temperature = 800 — 100 = 700° F
Density = 0.0330 lb/CF (Figure 13)
Gas volume = 27.4/0.0330 = 830 CF/sec

Try a 6-foot ID stack, which gives a velocity of 29.4 ft/sec.

Velocity head = $0.0030 \times (29.4)^2 \times 0.0330 = 0.086$ inch (Equation 14)
Say height = 100 ft

L/50 D = 100/(50 x 6) = 0.3
Loss = (3.0 + 0.3) x .086 = 0.28 inch
Total draft required = 0.07 + 0.13 + 0.28 = 0.48 inch
Draft from stack = 0.74 inch/100 ft (Figure 14)
Height = (0.48/0.74) x 100 = 65 ft above shield tubes

In practice, the stack height would probably be increased above the calculated value to allow for unforeseen variations in operating conditions.

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Wimpress

NOMENCLATURE

A	Area, sq ft
A_{cp}	Cold plane area, sq ft
A_w	Effective refractory area, sq ft
D	Diameter, ft
d	Diameter, inches
F	Radiant exchange factor
f	Factor for wall-radiation in convection section
G	Mass velocity at minimum cross section, lb/sq ft, sec
g	Gravitational constant, 32.17 ft/sec²
H	Stack height, ft
h	Film heat transfer coefficient, Btu/hr, sq ft, °F
L	Mean length of radiant beam, ft
LMTD	Log-mean temperature difference, °F
P	Partial pressure of carbon dioxide plus water in the flue gas, atmospheres
P_V	Velocity-head, inches of water
$\Delta\rho$	Pressure drop, inches of water
q	Heat rate, Btu/hr
T	Temperature, °R
t	Temperature, °F
U	Over-all heat transfer coefficient, Btu/hr, sq ft, °F
V	Velocity, ft/sec
W_B	Radiant emission from a black body, Btu/hr, sq ft
α	Factor of comparison between a tube-bank and a plane
ρ	Density, lb/cu ft
ρ_a	Density of outside air, lb/cu ft
ρ_g	Density of flue gas, lb/cu ft
ρ_w	Density of water, lb/cu ft
σ	Stefan-Boltzman constant, 0.173 x 10^{-8} Btu/hr, sq ft, °R⁴

SUBSCRIPTS

a	Combustion air
C	Convection section
c	Convective heat-transfer
f	Fuel or film
g	Flue gas
i	Intube fluid
n	Net heat of combustion
R	Radiant section
r	Radiant heat-transfer
t	Tube or tube wall
w	Refractory wall
1	Inlet conditions
2	Outlet conditions

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How to Rate Finned-Tube Convection Section in Fired Heaters

Six rows of finned tubes in the convection section of a fired heater can do the work of 18 rows of bare tubes. This rating method shows why

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As the cost of fuel increases, it is increasingly important to improve the operating efficiency of refinery heating equipment. One way to improve the efficiency of fired heaters is to increase the heat recovery in the convection section by using finned tubes.

This article describes a method for computing the performance of a convection section which includes tubes fitted with annular fins or spines. The method is fully compatible with the fired heater rating method presented by Wimpress.[1] The accuracy of the convection section rating method is about 5 percent for heat transfer and 10 percent for pressure drop.

The rating procedures were presented in a master's thesis by Torrijos[2] and are based on methods presented by Lobo and Evans[3] for combustion section radiation; Monrad[4] and Briggs and Young[5] for heat transfer within the convection section; Gardner[6] for efficiency of extended surfaces; and Gunter and Shaw[7] for pressure drop in cross flow.

Some graphical solutions and simplified correlations are offered to facilitate the evaluations. A sample calculation for the rating of an annular finned-tube bank is included.

The convection section is an integral part of a typical fired heater, Figure 1. Its purpose is to recover additional heat from the flue gas. It operates at a lower temperature level than the radiant section, but through the use of finned tubes, may attain a heat flux rate which approaches that in the radiant section.

The shield tubes separate the convection section from the radiant section. For heat transfer they are included in the radiant section, but they differ from the other radiant tubes in that no refractory wall reflects heat to the side away from the firebox. The radiant heat which is not absorbed directly can be assumed to be absorbed by the convection section. Also, the convection heat transfer rate to the shield tubes is higher than to the other radiant-section tubes.

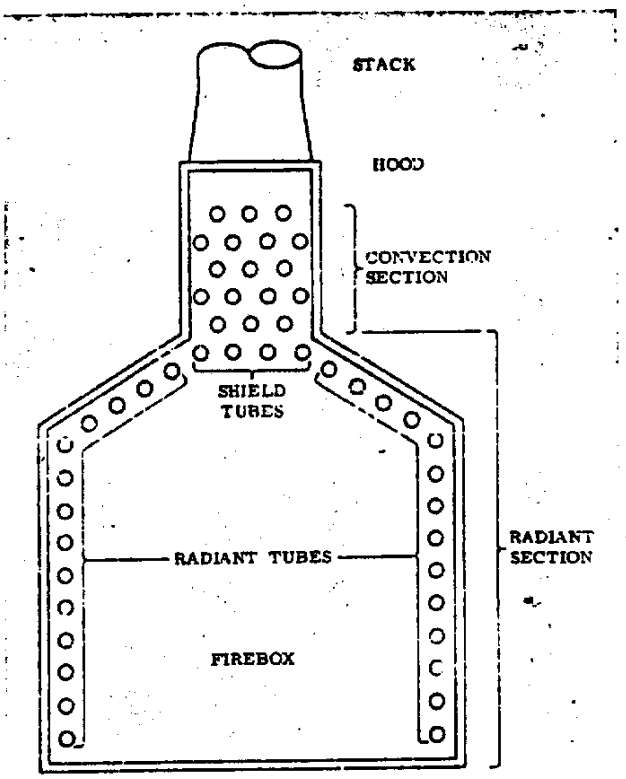


FIGURE 1—Cross-section of typical fired heater.[1]

The rating method will determine if a particular convection section will satisfy the specified performance requirements. If the first selection is inadequate, adjustments must be made in the design and the rating must be repeated. The method presented here is restricted to heat exchange equipment in which gases flow across banks of tubes fitted with annular fins or spines.

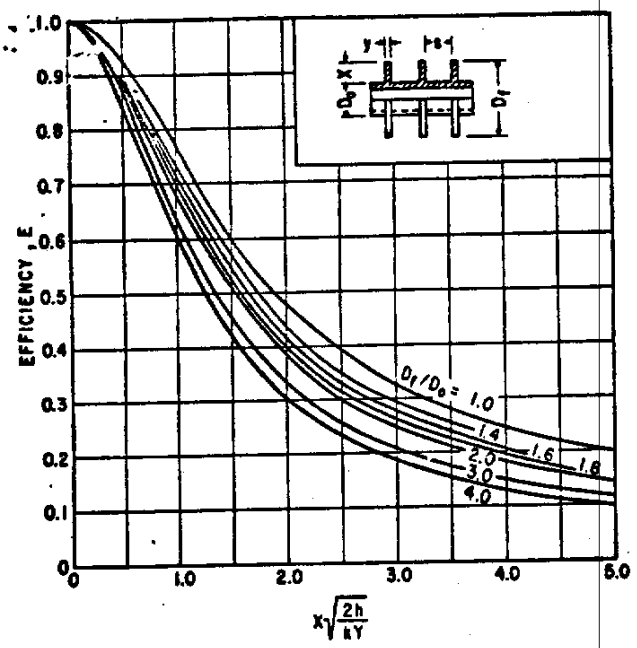


FIGURE 2—Efficiency of annular fins of constant thickness.[6]

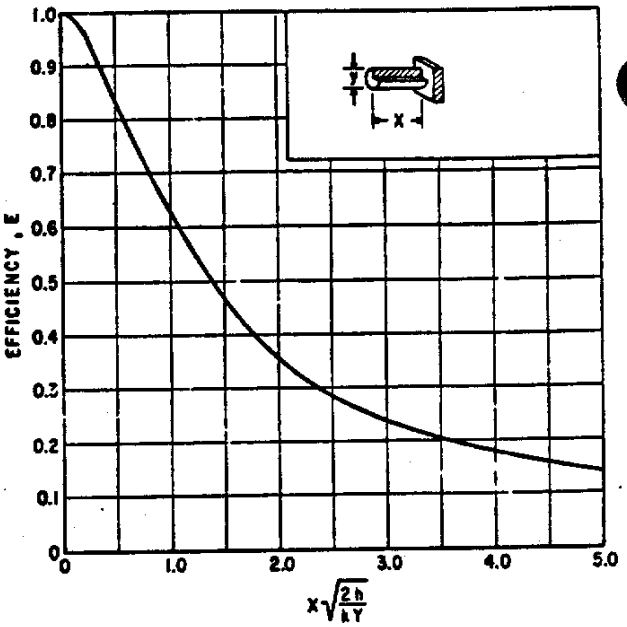


FIGURE 3—Efficiency of spines of constant diameter.[6]

Rating Method. The basic rating method presented here is applicable to extended surface equipment in general, but it is designed especially for the finned-tube convection section of fired heaters. The rating problem is divided into three parts:

- The heat transfer for flow of gases across banks of finned tubes
- The radiation leakage from the combustion chamber to the convection section
- The gas pressure drop across the bank of finned tubes

The total heat transferred to the finned tubes is the radiation leakage through the shield coil (if any) plus the heat transferred by convection and radiation within the tube bank.

$$q_o = q_{sL} + U_o A_t \text{ (LMTD)} \qquad (1)$$

Heat Transfer For Cross Flow of Gases. The classic reference on rating fired-heater convection sections is a paper Monrad[4] published in 1932. In this paper, Monrad developed the relations covering heat transfer to the convection section by convection from the gases, radiation from the gases, and radiation from the refractory walls. He used convection heat transfer data for smooth tubes only. He did not consider the additional heat input due to radiation leakage from the combustion chamber when the convection section can "see" the radiant section through the shield coil.

After Monrad's paper was published, Colburn[8] developed a more satisfactory relation for the convection coefficient.

$$\frac{h_o D_o}{k} = 0.36 \left(\frac{c_p \mu}{k}\right)^{1/3} \left(\frac{D_o G_{max}}{\mu}\right)^{0.6} \qquad (2)$$

The constants used here are not those originally proposed by Colburn, but are revised values in accord with extensive data published later by Huge,[9] Pierson,[10] and Tucker.[11]

Colburn's equation and the data of Huge, Pierson and Tucker are for plain tubes. Gardner[6] developed a general relationship for the effectiveness of a fin which can be used to compute the film coefficient for a finned tube from the coefficient for a plain tube of equal root diameter. Gardner's general relationship is

$$E = \frac{\tanh\ (u_b - u_o)}{u_b - u_o} \qquad (3)$$

where

$$u = x\sqrt{\frac{h_o\, dA}{ka\ (dx)}} \qquad (4)$$

The film coefficient for the finned tube is related to the coefficient for a plain tube by the following equation.

$$h_f = h_o \frac{(EA_f + A'_t)}{A'_t} \qquad (5)$$

The fin efficiency, E, depends on the fin dimensions, the thermal conductivity of the fins and the convective heat transfer film coefficient. In developing Equation (3), Gardner[6] made the following assumptions:

1) The heat flow and temperature distribution throughout the fin is independent of time; i e, heat flow is steady.

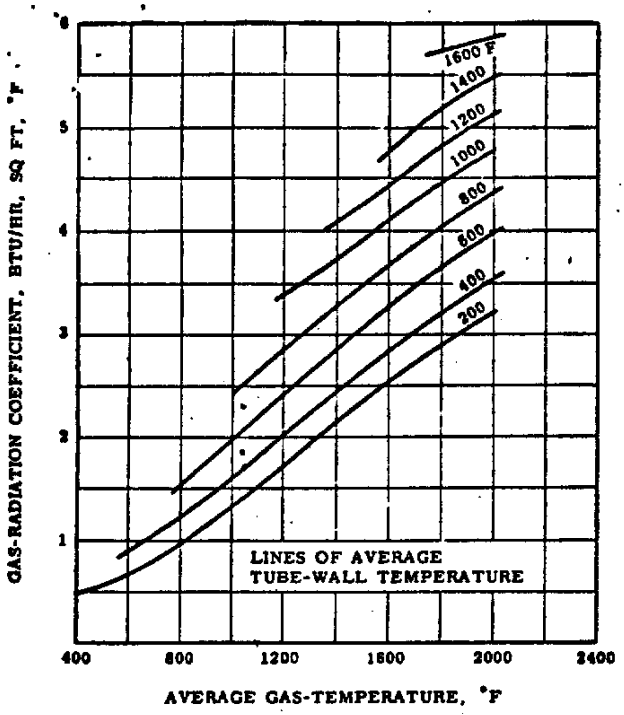


FIGURE 4—Gas radiation coefficients.[1]

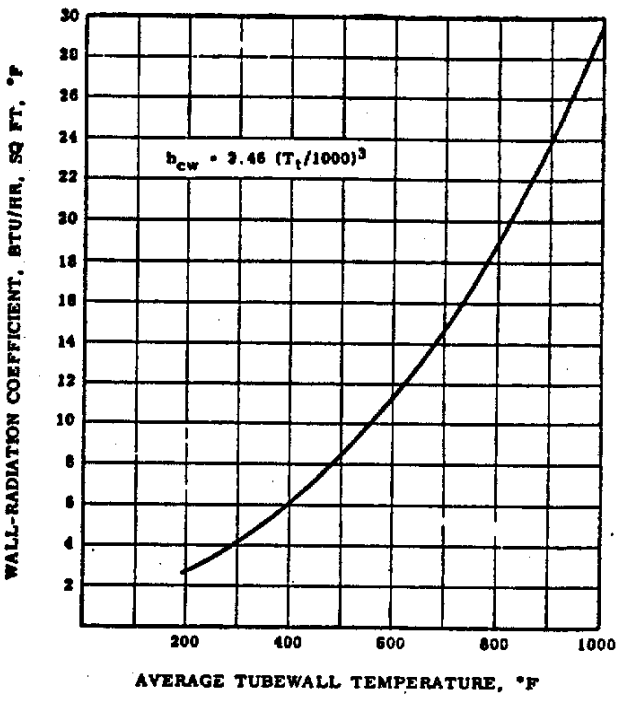


FIGURE 5—Coefficient for radiation from convection section walls.[1]

2) The fin material is homogeneous and isotropic.

3) There is no heat source in the fin itself.

4) The heat flow to or from the fin surface at any point is directly proportional to the temperature difference between the surface at that point and the surrounding fluid.

5) The thermal conductivity of the fin is constant.

6) The heat transfer coefficient is the same over the entire fin surface.

7) The temperature of the fluid surrounding the fin is uniform.

8) The temperature of the fin base is uniform.

9) The joint between the fin and tube is assumed to offer no bond resistance.

10) The fin thickness is so small compared with its height that temperature gradients across the width of the fin may be neglected.

11) The heat transferred through the outermost edge of the fin is negligible compared with that passing into the fin through the sides.

Figures 2 and 3 give the graphical solution of Equation (3) for annular fins and spines respectively. Note that the use of a fin efficiency factor makes Equation (5) useful for both annular fins and spines.

Monrad's basic reference for radiant heat transfer from non-luminous gases is a paper by Hottel[12] published in 1927. Hottel has since published the material, with later data, as a chapter in McAdams' book on heat transmission.[13] The apparent heat transfer coefficient for radiation from the hot gases to the convection section is

$$h_r = \frac{(\sigma)\,\frac{(1+e_t)}{2}\,(e_g T_g^4 - e_t T_t^4)}{(T_g - T_t)} \qquad (6)$$

To account for radiation from refractory walls to the tubes, Monrad[4] expressed the radiant heat transmission as a fraction of the heat transferred directly to the tubes.

$$\beta = \frac{h_w}{(h_c + h_r + h_w)}\,\frac{A_w}{A'_t} \qquad (7)$$

Four factors must be considered in order to evaluate the heat transfer for cross flow of gases. (1) The convective heat transfer coefficient. (2) The fin efficiency. (3) The radiation from the gas. And (4) the radiation from refractory walls.

There are a number of tube arrangements possible, but for the purpose of this presentation equilateral triangular pitches of 1.5 and 2.0 times the nominal diameter of the tube are chosen as standard. Therefore when a tube size is selected, the tube spacing is fixed by the chosen standard of tube arrangement. The tube size, the number of tubes per row, the area per row and the minimum cross-sectional area for flue gas flow are considered in this rating presentation. Usually, in fired-heaters, the tube size in the radiant section is the same as in the convection section, and the number of tubes per row is such that the flue gas rate is about or below 15 ft/sec. The area per row is the

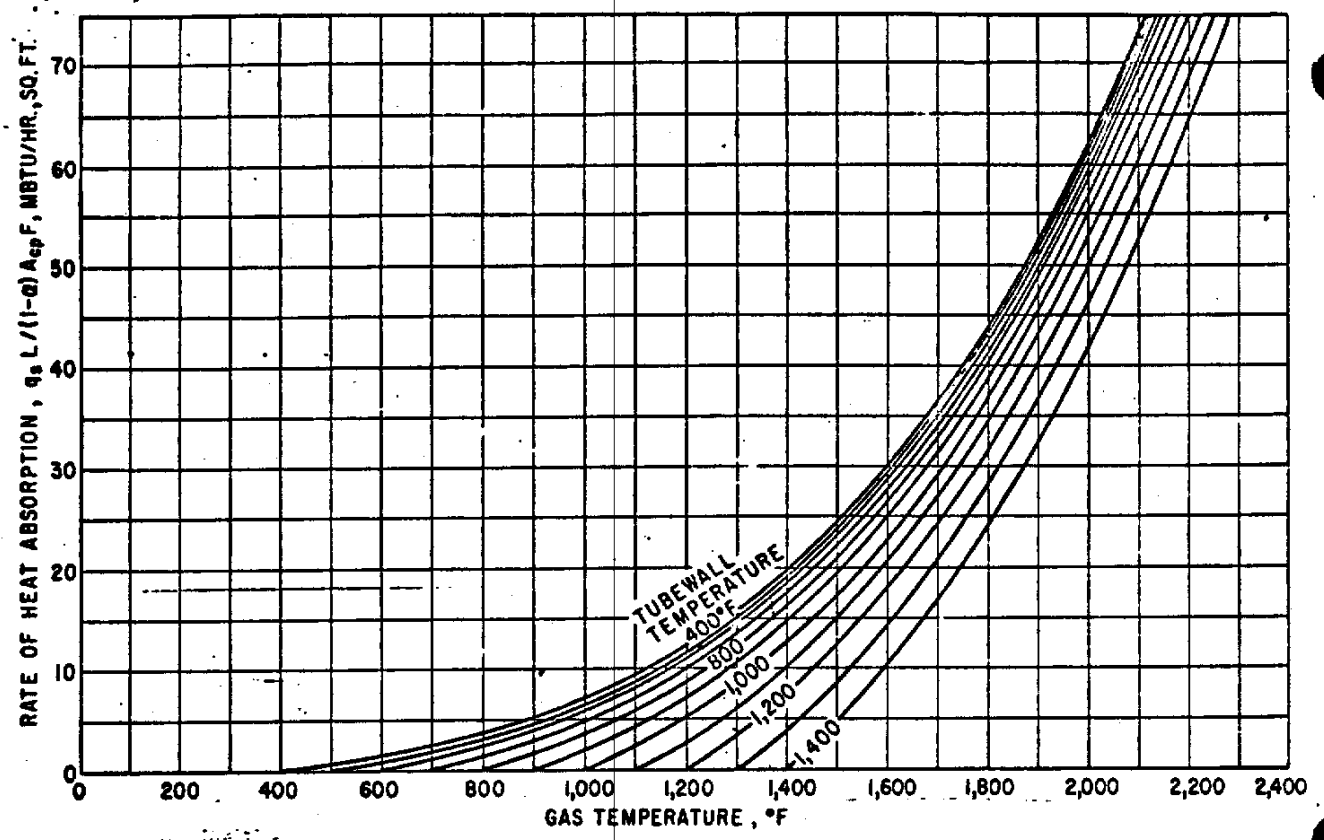


FIGURE 6—Radiation leakage through shield coil.

exposed area per tube times the number of tubes. The minimum cross-section area for flue gas flow is the total cross-sectional area of the convection section less the projected area of one row of tubes.

The design conditions for the convection section are set by the overall design conditions and by the radiant section rating. The flue gas rate, the stack heat content, the stack temperature and the intube fluid inlet temperature must satisfy the overall design conditions. The flue gas inlet temperature and the intube fluid outlet temperature must satisfy the over-all design conditions; and they must fit in with the radiant section rating, if the exchanger is a fired-heater. The design temperature data are used to calculate the log mean temperature difference, the average gas film temperature and the average gas temperature.

For simplicity, the convection coefficient correlation proposed by Colburn[8] is used with revised coefficients based on the data of Huge,[9] Pierson[10] and Tucker.[11] Equation (2) is simplified as follows, for use in computing flue gas film heat transfer coefficients.

$$h_o = \frac{2.14\, T_f^{0.28}\, (G_{max})^{0.6}}{d_o^{0.4}} \qquad (8)$$

The effective heat transfer coefficient for a finned tube is given by Equation (5).

The method for calculating the amount of heat transferred by radiation from the flue gas within the convection section was presented by Hottel.[12] For finned tubes, the gas radiation coefficient is based on the root diameter of the tube. The area used to compute the radiant heat transfer is the area of the bare tube. The basic relation for standard tube-to-tube clearances (1.5 and 2.0 diameters apart) was solved by assuming a tube surface emissivity of 0.90, and a constant partial pressure of carbon dioxide and water. The apparent heat transfer coefficient for radiation from the flue gas within the convection section is given by Equation (6). Figure 4 is a graphical solution of Equation (6). The average gas temperature is defined as the average intube temperature plus the log mean temperature difference from gas to intube fluid. The average tubewall temperature is approximately the average intube temperature plus 100° F.

Radiation from the refractory walls is still another method of transferring heat to the convection section tubes. It is assumed that the convective and radiative coefficients for heat transfer to the refractory are the same as the coefficients for heat transfer to the tubes, and any heat loss from the convection section is neglected. Monrad expressed the indirect radiant transfer as a fraction of heat transferred directly to the tubes in Equation (7). He assumed that T_w is equal to 1.25 T_t, that the tubes and walls form infinite parallel planes, and the wall emissivity is 1.0. On this basis

$$h_w = 9.46 \left(\frac{T_t}{1000}\right)^2 \quad (9)$$

Equation (9) is plotted in Figure 5.

The overall heat transfer coefficient for the convection section is calculated from the apparent gas film coefficient and the intube film coefficient. This apparent gas film coefficient is

$$h_o = (1+\beta)(h_f + h_r) \quad (10)$$

Radiation Leakage From the Combustion Chamber. The Lobo and Evans[3] method for calculating the heat absorption in furnace radiant sections is the basis for Wimpress' method[1] which is used here to calculate the radiant heat which leaks through the shield coil into the convection section. The difference between the incident radiant energy and the direct absorption is the radiation leakage absorbed by the convection section.

$$q_{aL} = \sigma (1-\alpha) A_{cp} F (T_g^4 - T_t^4) \quad (11)$$

where A_{cp} is the cold plane area of the shield coil, F is the radiant exchange factor of the radiant section, T_g is the radiating temperature in the combustion chamber, T_t is the shield coil tubewall temperature, and α is a factor of comparison for direct radiation. Figure 6 is a plot of Equation (11) rearranged as

$$\frac{q_{aL}}{(1-\alpha) A_{cp} F} = \sigma (T_g^4 - T_t^4) \quad (12)$$

In evaluating the shield coil leakage, the tubewall temperature at the cross-over between the convection section and the radiant section is used. Radiation leakage through the shield coil to the convection section does not occur if the convection section does not "see" the radiant section through the shield coil.

Pressure Drop Across the Bank of Finned Tubes. Gunter and Shaw[7] presented the normal form of the friction factor for a specific tube bank as

$$f = \Delta P \frac{2 g_c \rho_g}{(G_{max})^2} \left(\frac{D_v}{L}\right) \left(\frac{\mu}{\mu_w}\right)^{0.14} \left(\frac{D_v}{S_T}\right)^{-0.4} \left(\frac{S_L}{S_T}\right)^{-0.6} \quad (13)$$

Equation (13) is based on the intensive data of Sieder and Scott,* Huge[8] and Pierson.[10] The ratio of viscosities to the 0.14 power is approximately 1.0, and for equilateral spacing, S_L equals S_T. Then

$$\Delta P = \frac{f (G_{max})^2 L}{2 g_c \rho_g D_v} \left(\frac{D_v}{S_T}\right)^{0.4} \quad (14)$$

Now, combining the constants together and converting the pressure drop into inches of water

$$\Delta P = 0.003 \frac{f (G_{max})^2 L}{\rho_g D_v} \left(\frac{D_v}{S_T}\right)^{0.4} \quad (15)$$

The friction factor, f, is plotted as a function of the Reynold's number in Figure 7.

Sample Calculation. The following example serves two purposes: (1) It illustrates the use of the rating method for finned tube convection sections. And (2) by utilizing the process specifications given in the sample calculation in Wimpress' paper,[1] it gives a comparison between plain and finned tube sections. Wimpress' process conditions were as follows:

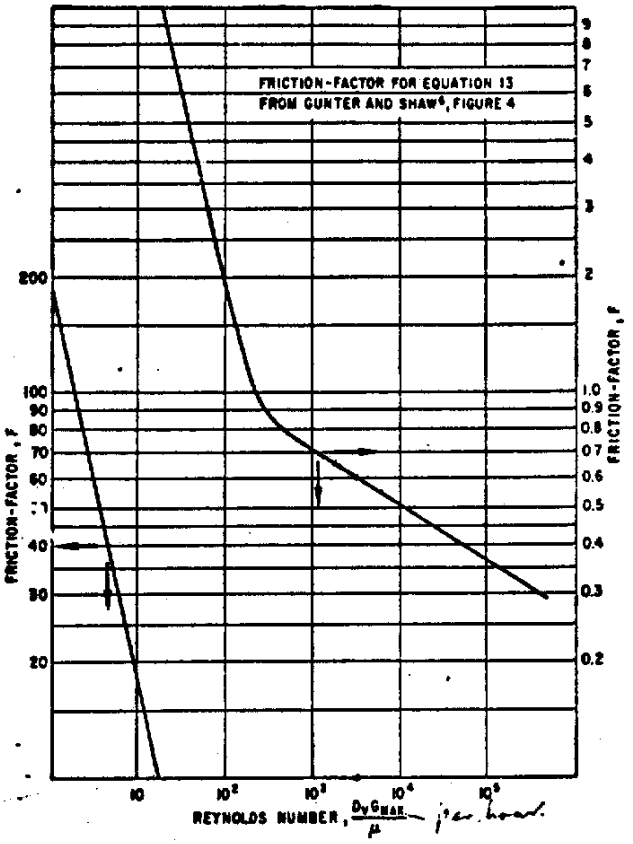


FIGURE 7—Cross flow friction factor.

- Heat 27,270 barrels per day (357,000 lb/hr) 26 API oil from 380°F to 675°F
- Burn refinery fuel gas at 60°F, Lower Heating Value = 1,350 Btu/scf
- Efficiency 77 percent with no air preheat, 25 percent excess air
- Maximum radiant flux 12,000 Btu/hr ft²
- Maximum pressure drop 40 psi
- Fuel density 7.48 lb/gal at 60°F, 5.93 lb/gal at 530°F
- Fuel enthalpy 273 Btu/lb at 380°F, 483 Btu/lb at 675°F
- Duty = 357,000 (483-273) = 75.0 MM Btu/hr.
- Net heat release = 75.0/0.77 = 97.5 MM Btu/hr
- Fuel gas rate = 97.5 (1010 from Figure 9) = 98,500 lb/hr or 27.4 lb/sec
- Radiant section duty = 51.7 MM Btu/hr
- Crossover temperature = 483°F
- Gas temperature at firebox exit = 1610°F

* Cited from Gunter and Shaw.[7]

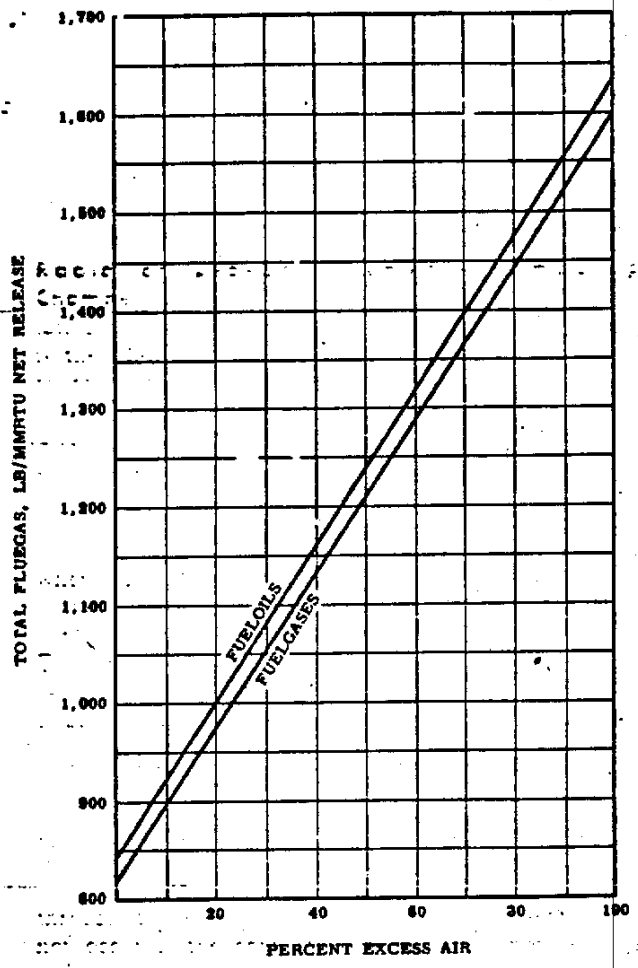


FIGURE 8—Flue gas rates.[1]

• Convection section duty = 75-51.7 = 23.3 MM Btu/hr

Temperature data for the convection section are as follows:

Differences:	Flue gas.....in	1610°F	.....out	820°F
	Oil.....out	483°F	.....in	380°F
		1127°F		440°F

$$\text{LMTD} = \frac{1127 - 440}{\ln(1127/440)} = \frac{687}{0.940} = 731°F$$

Average fluid temperature (380 + 483)/2 = 432°F

Approximate tubewall temperature 432 + 100 = 532°F

Average flue gas film temperature 432 + (731/2) = 798°F

Average flue gas temperature = 432 + 731 = 1163°F

Heat Transfer. Select a convection section with the same size tube as the radiant section, 4.5 inches OD 40 ft long overall, 38.5 ft exposed. Use six tubes per row and 8-inch equilateral spacing. Use annular steel fins, 1-inch high, two 0.05-inch thick fins per inch. The width of the convection section is

$$\text{Gross width} = (6.5 \text{ tube rows})\left(\frac{8}{12}\right) = 4.33 \text{ ft}$$

The bare tube and refractory areas are

Tube surface = 1.178 sq ft/ft

$$A'_t = 6\ (38.5)\ 1.178 = 272 \text{ sq ft/row}$$

$$A_w = 0.866\ (38.5)\ (2)\ 8/12 = 44.6 \text{ sq ft/row}$$

$$A_w/A'_t = 44.6/272 = 0.1635$$

The fin surface area per row is

$$A_f = \left[\frac{\pi}{4}\left(\frac{6.5^2 - 4.5^2}{144}\right) 2\right] (2)\ (12)\ (38.5)\ 6 = 1390 \text{ sq ft/row}$$

The gas flow area is restricted by both the tube and the fins. The projected area of the finned tube is

$$\frac{4.5 + 2(0.05)\ 2}{12} = 0.392 \text{ sq ft/ft}$$

Gas flow area = 38.5 (4.33 — (6) 0.392) = 38.5 (1.98) = 76.2 sq ft

Gas velocity = 27.4/76.2 = 0.359 lb/sec sq ft

The heat transfer rate can now be computed. First consider the radiation leakage through the shield coil. From Wimpress' paper[1]

$$\alpha = 0.74$$

$$A_{cp} = 154 \text{ sq ft}$$

$$F = 0.635$$

Now $(1 - \alpha)\ A_{cp}\ F = 0.26\ (154)\ 0.635 = 25.4$ sq ft

The tubewall temperature at the entrance to the convection section is approximately 483 + 100 = 583°F. From Figure 6, using a tubewall temperature of 583°F and a radiating gas temperature of 1,610°F, the heat absorption is 29.6 (10^3) Btu/hr sq ft. From Equation (12)

$$q_{sL} = 29.6\ (10^3)\ 25.4 = 0.75\ (10^6) \text{ Btu/hr sq ft}$$

The convective heat transfer coefficient for a bare tube is computed from Equation (8), (or Wimpress', Figure 9).

$$h_c = \frac{2.14\ (798 + 460)^{0.28}\ (0.359)^{0.8}}{(4.5)^{0.4}} =$$

$$\frac{2.14\ (7.36)\ 0.542}{1.825} = 4.68 \text{ Btu/hr sq ft°F}$$

The fin efficiency is obtained from Figure 2.

$$X\sqrt{\frac{2h}{kY}} = \frac{1}{12}\sqrt{\frac{2(4.68)}{31(0.05/12)}} = 0.853\sqrt{72.3} = 0.705$$

$$d_f/d_o = 6.5/4.5 = 1.445$$

The fin efficiency, E = 0.84. The effective heat transfer coefficient for the finned tube is, from Equation (5)

$$h_f = 4.68\,\frac{0.84\ (1390) + 272}{272} = 24.8 \text{ Btu/hr sq ft °F}$$

To account for the radiation from the gas within the convection section, use the average flue gas

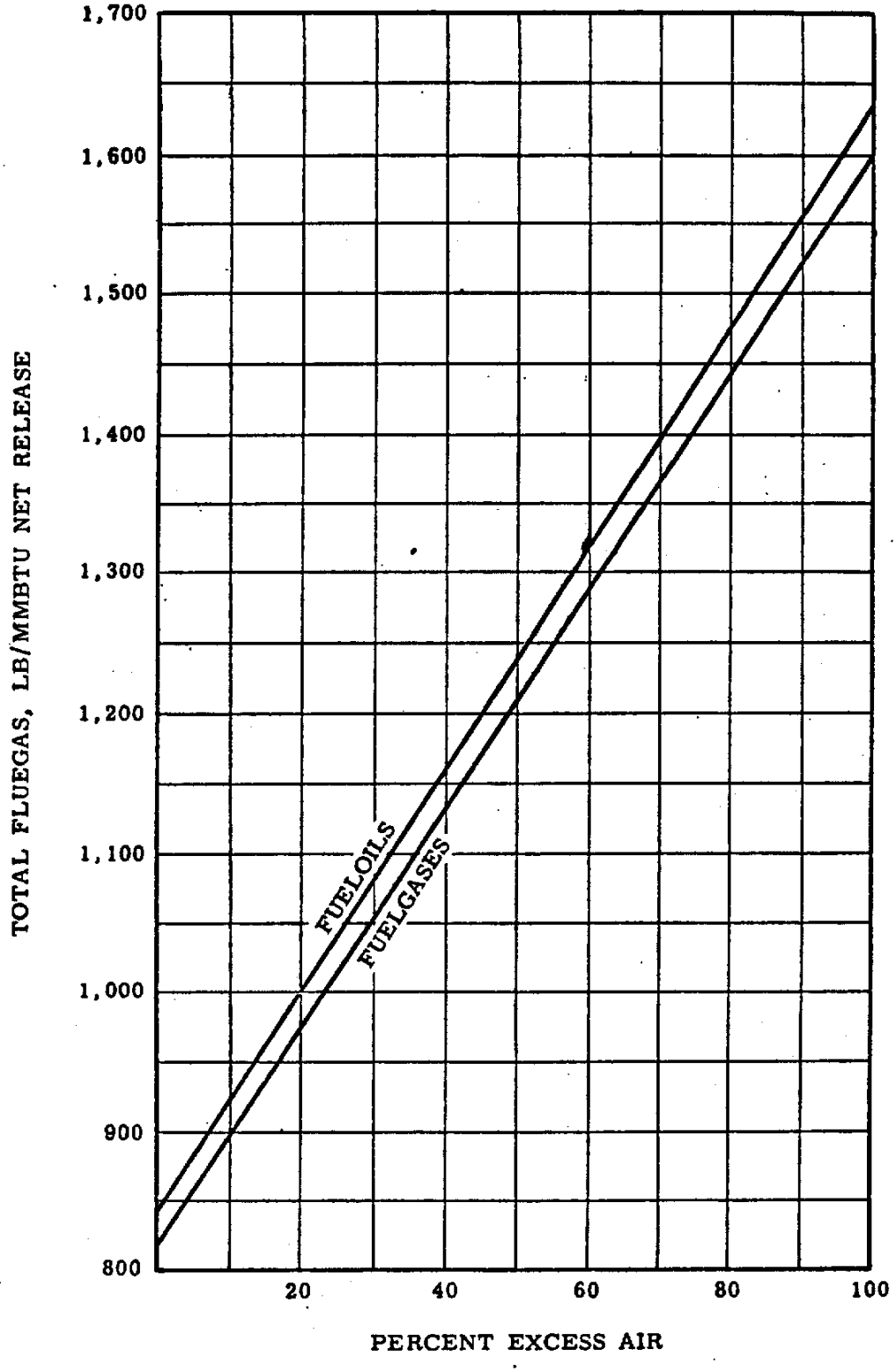


FIGURE 8—Flue gas rates.[1]

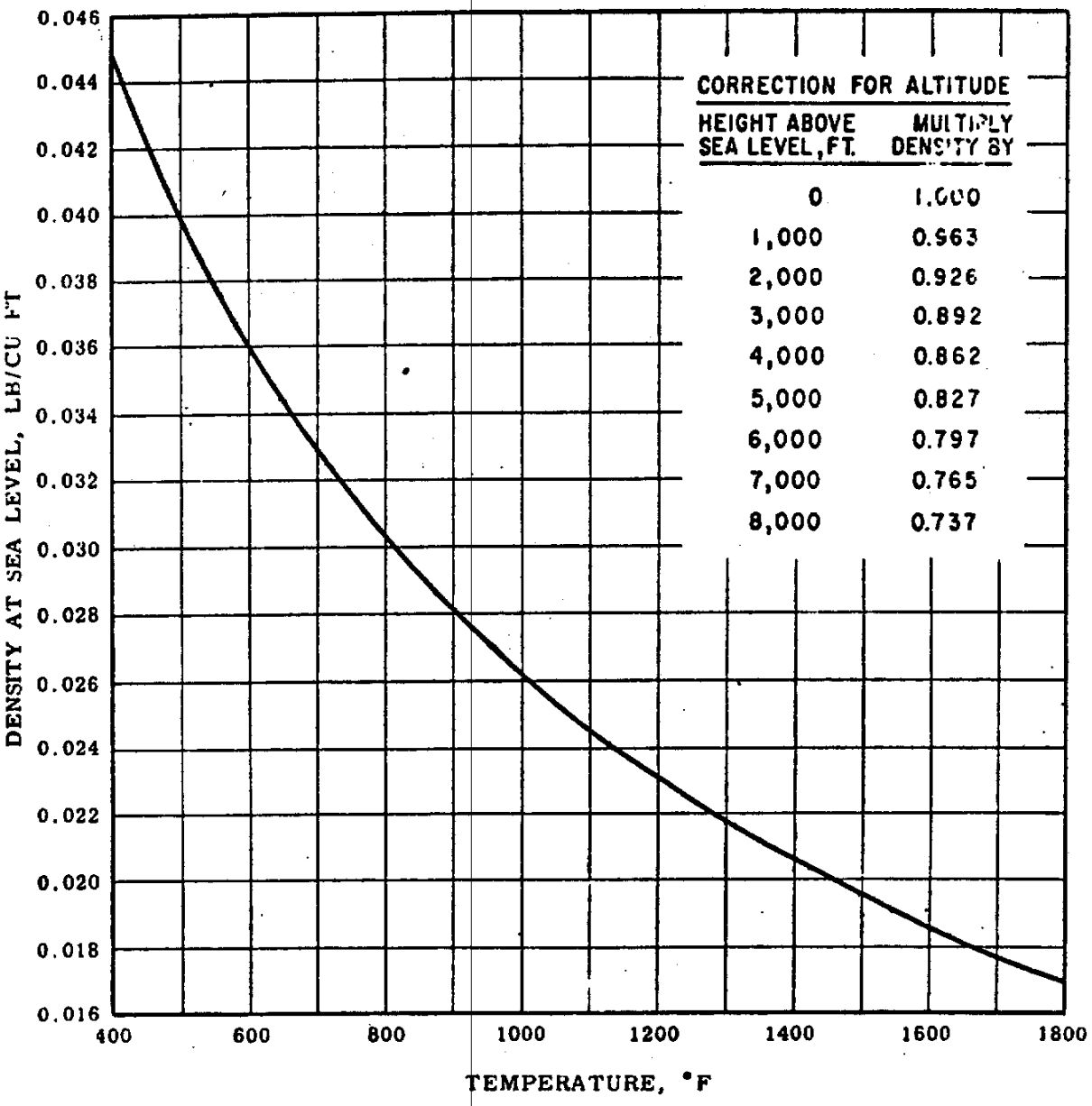


FIGURE 9—Density of flue gas.[1]

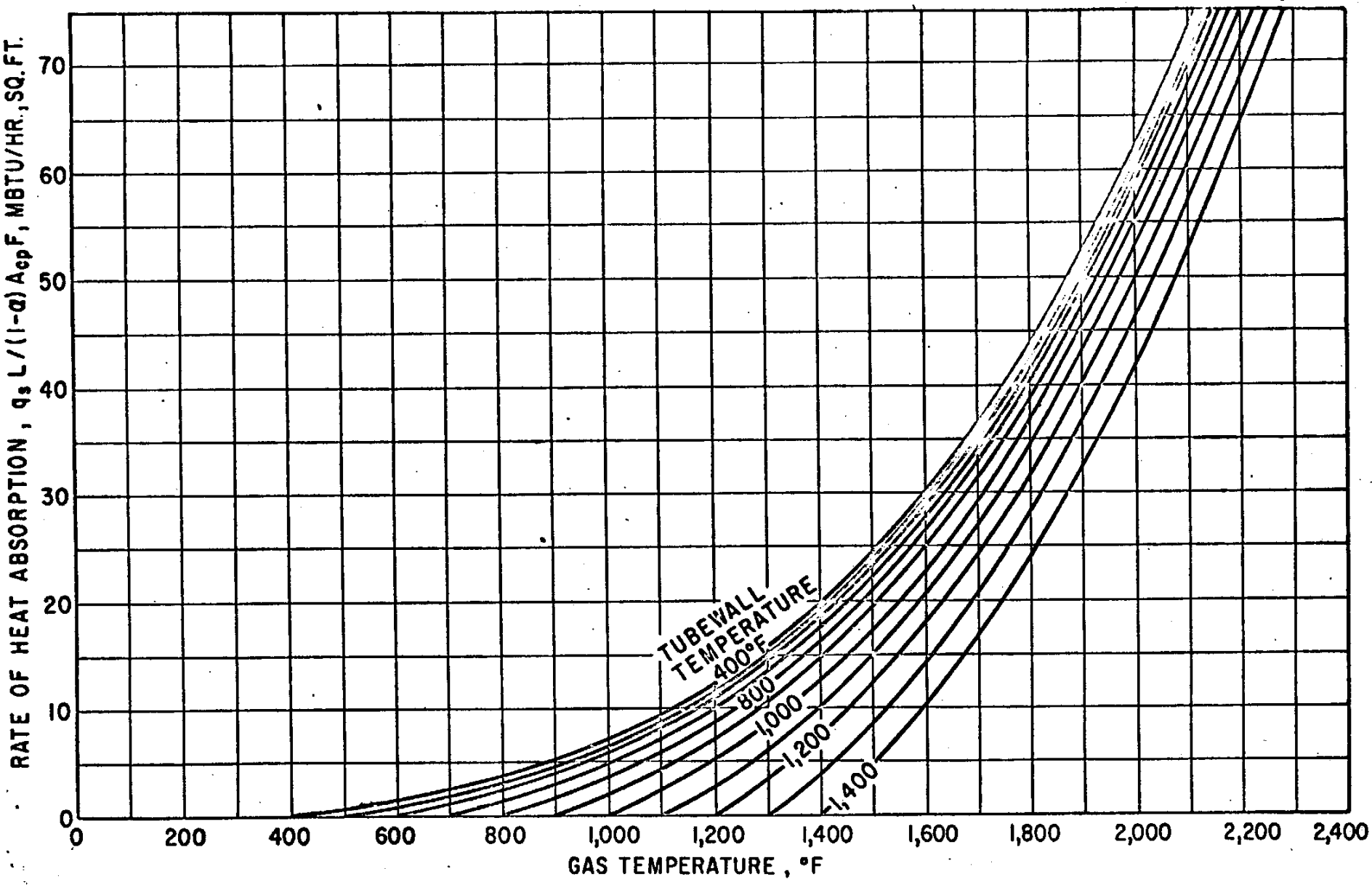


FIGURE 6—Radiation leakage through shield coil.

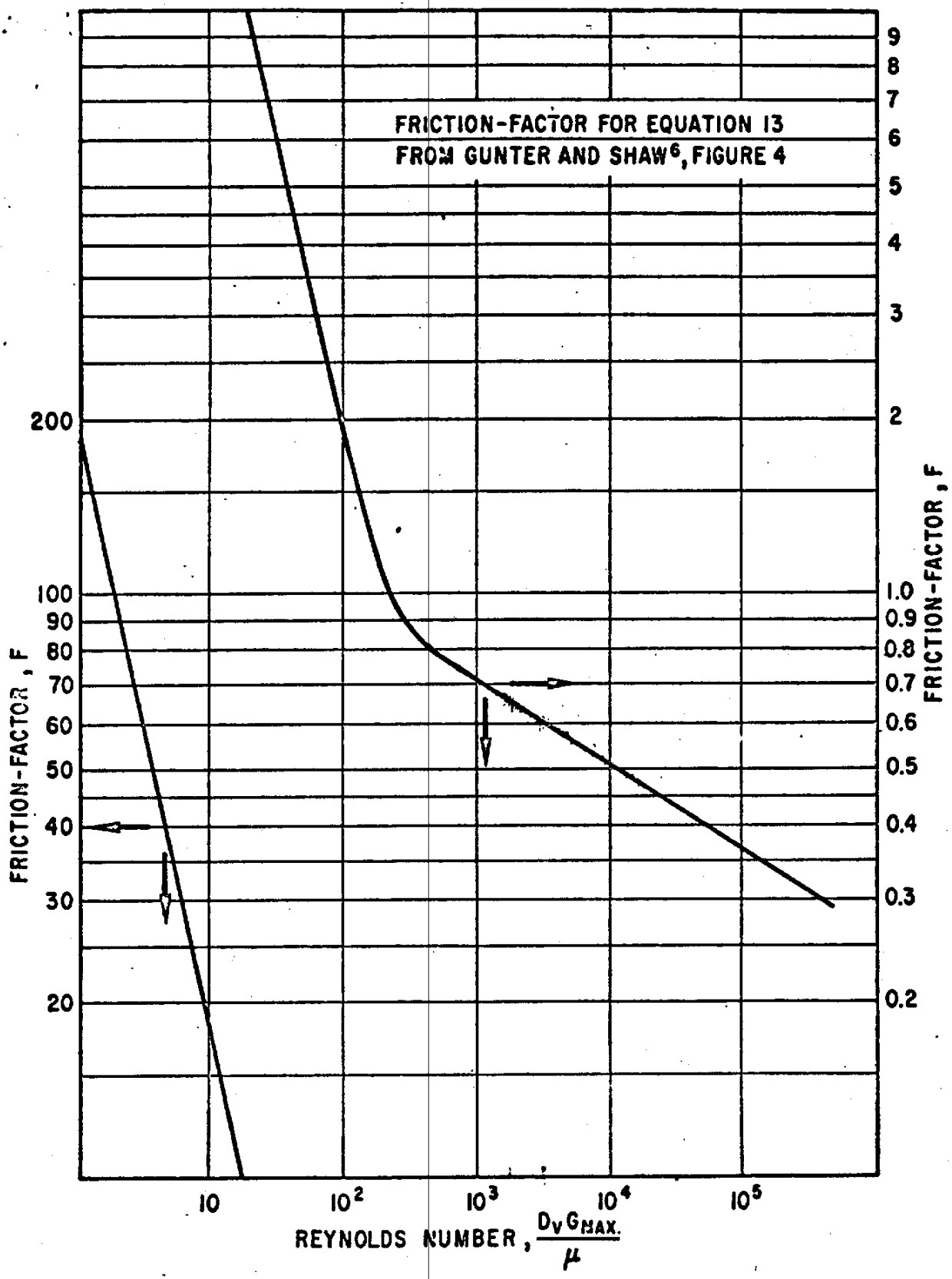


FIGURE 7—Cross flow friction factor.

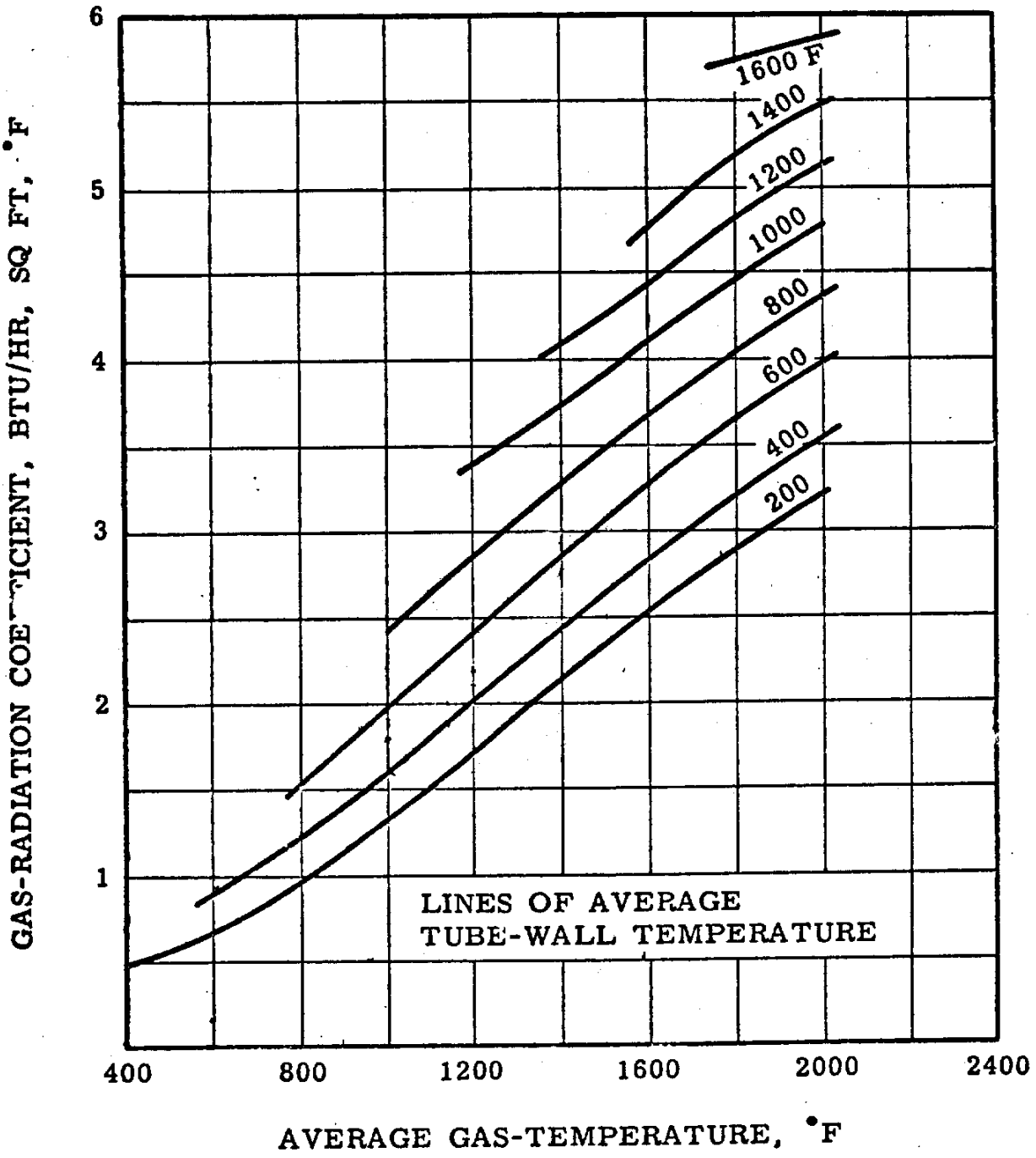


FIGURE 4—Gas radiation coefficients.[1]

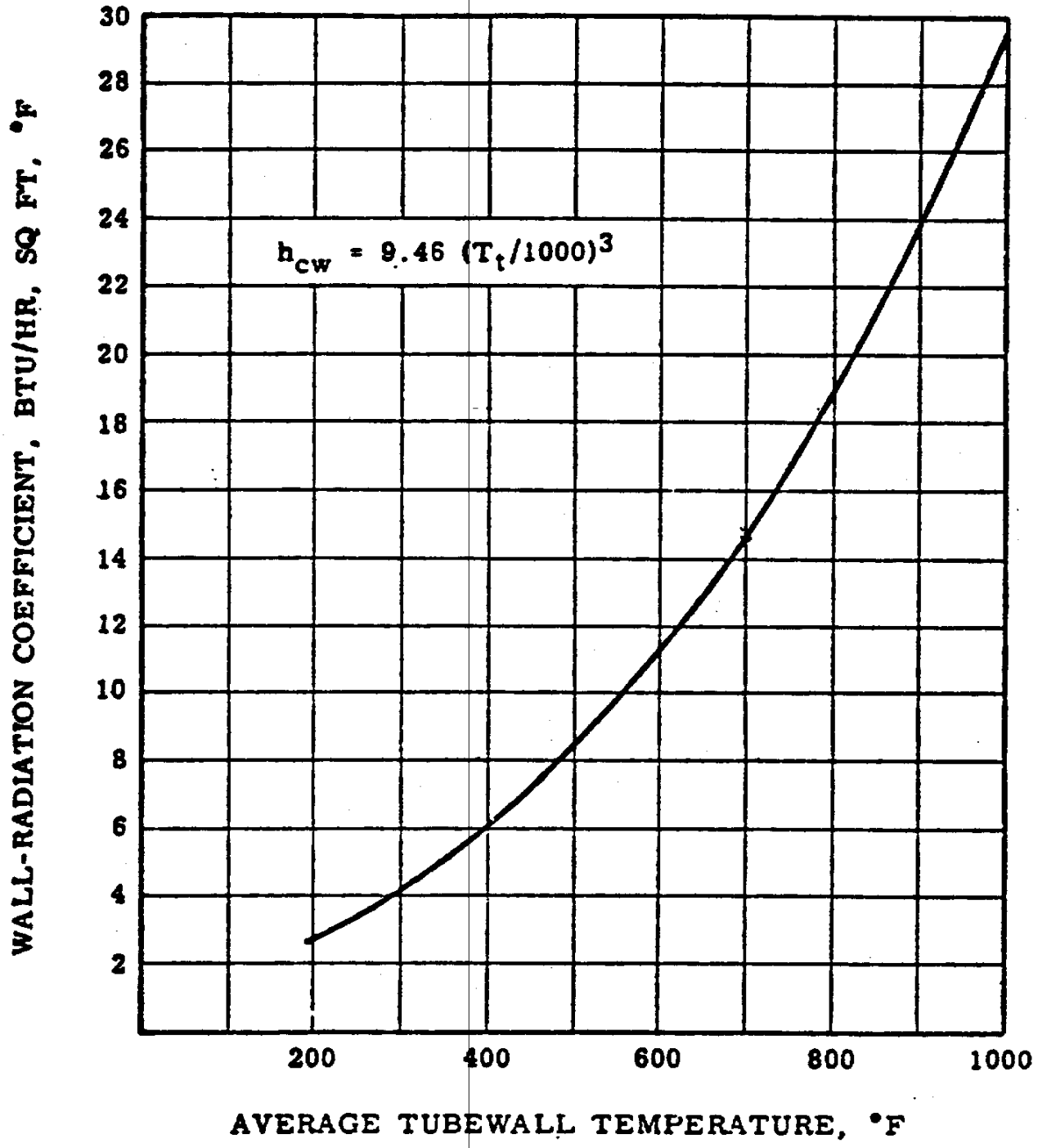


FIGURE 5 - WALL RADIATION COEFICIENTS

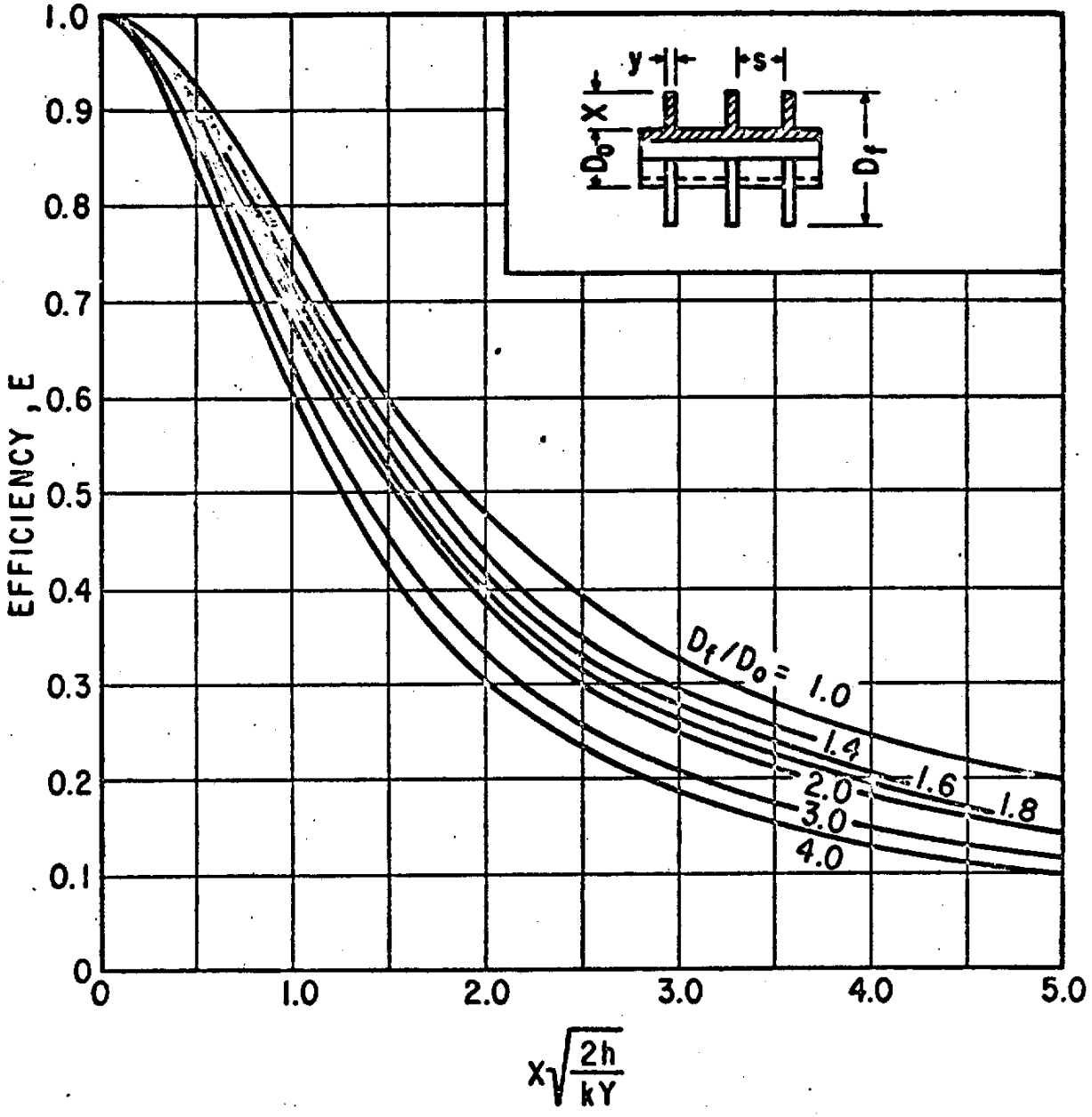


FIGURE 2—Efficiency of annular fins of constant thickness.[6]

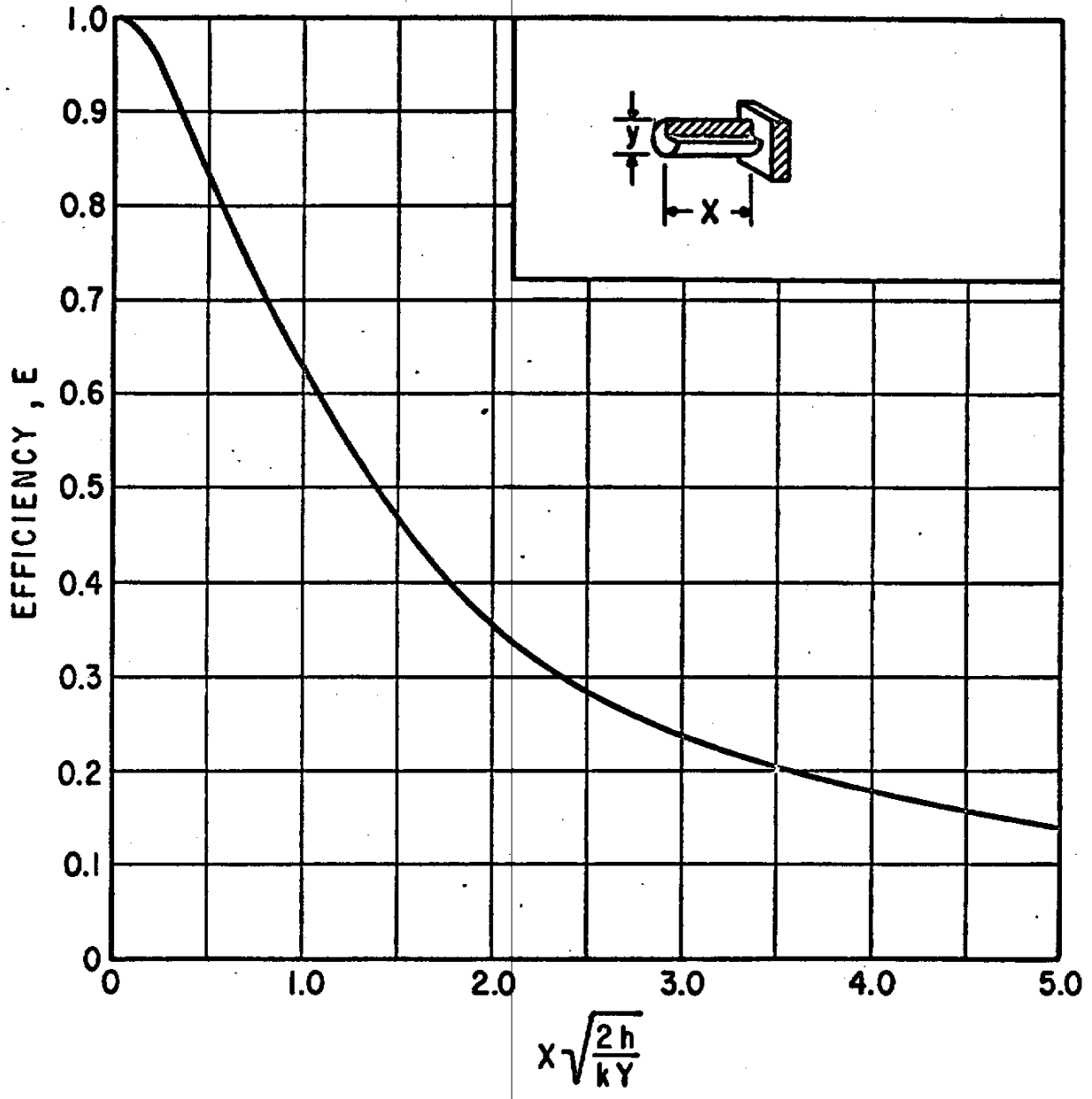


FIGURE 3—Efficiency of spines of constant diameter.[6]

temperature (1,163°F) and average tubewall temperature (532°F) in Figure 4 to obtain the heat transfer coefficient due to gas radiation.

$$h_r = 2.25 \text{ Btu/hr sq ft °F}$$

The refractory wall also accounts for some heat transfer by indirect radiation to the convection section. From Figure 5, using an average tubewall temperature of 532°F, the heat transfer coefficient for the wall radiation, $h_w = 9.5$ Btu/hr sq ft °F. Following Monrad's method, express the radiant heat from the wall as a fraction of the heat directly transferred to the tubes as in Equation (7)

$$\beta = \frac{9.5}{(24.8 + 2.25 + 9.5)} (0.1635) = 0.0424$$

The apparent gas film coefficient is expressed by Equation (10).

$$h_o = (1 + 0.0424)\ (24.8 + 2.25) = 28.2 \text{ Btu/hr sq ft °F}$$

For this example, assume the calculated intube coefficient is 100.
Then

$$U_c = \frac{28.2\ (100)}{28.2 + 100} = 22.0 \text{ Btu/hr sq ft °F}$$

The value of $U_c = 22.0$ Btu/hr sq ft °F, does not take into consideration the metal resistance. The metal resistance is assumed to be small enough that it may be neglected without introducing any appreciable error. Also, for this example, fouling factors are not considered. It is assumed that the tubes are clean. However, if the particular type of service for the heater is such that fouling factors are critical, then they should be included. Now, use Equation (1) to compute the heat transfer area

$$A_t = \frac{q_c - q_{cL}}{U_c(\text{LMTD})} = \frac{23.3 - 0.75}{22.0\ (731)} = 1400 \text{ sq ft}$$

$$\text{The number of rows} = \frac{A_t}{A'_t}$$

$$= \frac{1400}{272} = 5.15$$

Therefore 6 rows or 36 tubes should be used. The heater efficiency will be improved by the additional tubes to approximately 78 percent and the stack temperature will drop to about 780°F. The total convection section area will be 1,630 sq ft, resulting in an average heat flux of 23.4/1630 = 14,400 Btu/hr sq ft.

Pressure Drop. The next problem is the calculation of the pressure drop of the flue gas as it crosses the selected finned-tube convection section. Using the design information for tubes per row, number of rows, tube spacing, fin and tube geometry and fin pitch, compute the net free volume and friction surface of the convection section.

$$\text{Net Free Volume} = 0.866\ S_T^2 - \frac{\pi}{4} D_o^2 - \frac{\pi}{4} (D_f^2 - D_o^2)\ Y\ (12\ p) = 0.259 \text{ cu ft/ft}$$

$$\text{Friction Surface} = A_t + A_f = \frac{\pi d_o}{12} + \frac{\pi}{4} (d_f^2 - d_o^2)\ 2\ (12p)/144 = 6.99 \text{ sq ft/ft}$$

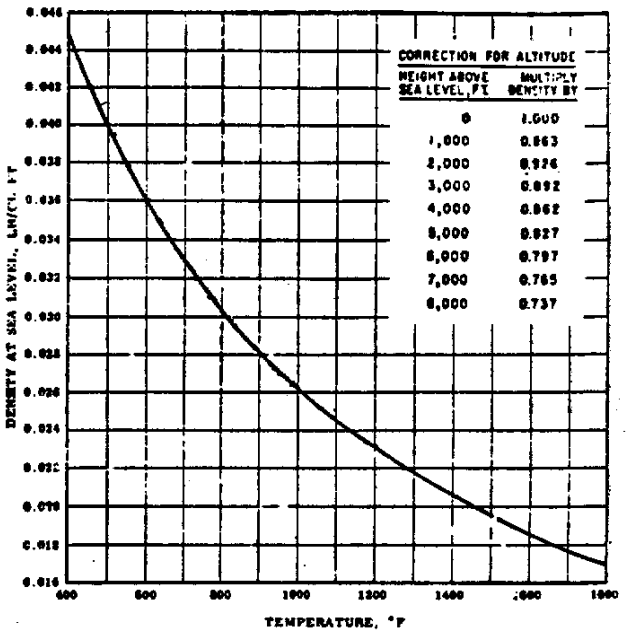


FIGURE 9—Density of flue gas.[3]

The volumetric hydraulic diameter, D_v, is defined as

$$D_v = \frac{4\ (\text{Net Free Volume})}{\text{Friction Surface}} = \frac{4\ (0.259)}{6.99} = 0.148 \text{ ft}$$

To obtain a friction factor for the flue gas flow, the Reynold's number is calculated as

$$\text{Re} = \frac{D_v G_{c,ax}}{\mu} = \frac{0.148\ (0.359)\ (3{,}600)}{2.42\ (0.042)} = 1800$$

Now enter Figure 7 with Re = 1,800 to obtain a friction factor, f = 0.645.

The pressure drop, ΔP (inches of water), is given by Equation (15). First determine the gas flow length, L, and the flue gas density, ρ_g, at the bulk temperature.

L = number of rows (tube spacing 0.866) = 3.46 ft

The flue gas density may be obtained from Figure 9 using an average flue gas temperature of 1,163 °F.

$\rho_g = 0.0231$ lb/cu ft

$$\Delta P \text{ (inches of water)} = 0.003 \frac{0.645\ (0.344)^2\ (3.46)}{0.0231\ (0.148)} \left(\frac{0.148}{8/12}\right)^{2.4} = 0.127 \text{ inches of water}$$

Method Differences. The method presented here differs from the convection section rating method presented by Wimpress[1] in two respects. (1) It provides for rating finned-tube sections. And (2) it includes credit for radiation leakage through the shield coil. The radiation leakage is admittedly small. But it does heat the convection section and, therefore, should be credited.

The results show that six rows of finned tubes can do the work of 18 rows of bare tubes. Finned tubes are more expensive than bare tubes, but other costs must also be considered. These include the costs of additional steel structure, refractories, and return headers.

Finally, the results show an average heat flux of 14,400 Btu/hr sq ft for the convection section. Although

this value exceeds the specified maximum for the radiant section, it should not cause overheating of the oil for two reasons. (1) The heat input around the tubes is relatively uniform compared with radiant section tubes. And (2) the oil temperature is lower than in the radiant section. Whenever a lower heat flux is required to lower either oil or fin temperature, it can be obtained by increasing the spacing between fins or by reducing the fin height.

NOMENCLATURE

A	Area, sq ft
A_{cp}	Cold plane area, sq ft
A_f	Total fin surface area, sq ft/row
A_t	Total surface area of plain tube, sq ft
A'_t	Total surface area of plain tube, sq ft/row
A_w	Effective refractory area, sq ft/row
a	Cross sectional area of fin normal to x-axis at point x
c_p	Constant pressure specific heat, Btu/lb °F
D	Diameter, ft
d	Diameter, inches
D_v	Volumetric hydraulic diameter = $\frac{4\ (\text{Net Free Volume})}{\text{Friction Surface}}$, ft
E	Fin efficiency
e_g	Emissivity of gas at radiating temperature in combustion chamber
e_t	Emissivity of tube at tubewall temperature
F	Radiant exchange factor
f	Friction factor for pressure drop relation
G_{max}	Mass velocity at minimum cross section, lb/sq ft, sec
g_c	Gravitational constant, 32.17 lbm ft/lbf sec²
h	Film heat transfer coefficient, Btu/hr, sq ft, °F
k	Thermal conductivity, Btu/hr, sq ft, °F/ft
L	Mean length of radiant beam, ft Length of flow path across tube bank, ft
LMTD	Log-mean temperature difference, °F
ΔP	Pressure drop, inches of water
q	Heat rate, Btu/hr
R_e	Reynolds number
S_L	Longitudinal pitch, center-to-center distance from tube in one row to the tube in the next row, ft
S_T	Transverse pitch, center-to-center distance from one tube to another in the same row, ft
T	Temperature, °R
t	Temperature, °F
U	Over-all heat transfer coefficient, Btu/hr, sq ft, °F
u_b	Equation (4) evaluated at base of fin
u_e	Equation (4) evaluated at edge of fin
X	Fin height, ft
x	Fin height, in
Y	Fin thickness or spine diameter, ft
y	Fin thickness or spine diameter, in
α	Factor of comparison between a tube-bank and a plane
β	Factor for wall-radiation in convection section
ρ	Density, lb/cu ft
ρ_g	Density of flue gas, lb/cu ft
σ	Stefan-Boltzman constant, 0.173 x 10^{-8} Btu/hr, sq ft, °R⁴
μ	Viscosity, lb/ft hr

SUBSCRIPTS

C	Convection section
c	Convective heat-transfer, convection section
f	Film or fin
g	Flue gas
o	Outside
r	Radiant heat-transfer
sL	Shield leakage
sR	Shield radiant absorption
t	tube or tube wall
w	refractory wall

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About the Authors



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An existing, double-fired Platforming heater was designed for 30.47×10^6 Btu/hr.

Calculate the following:

a) The inside film coefficient using both McAdams' and Sieder and Tate's methods. Evaluate the former using the average heat capacity. Evaluate the latter using the outlet conditions.

b) The maximum tube wall temperature using both McAdam's and Sieder and Tate's inside film coefficient.

Operating Conditions	Inlet	Outlet
Flow Rate, lb/hr	169063	169063
Temperature, °F	820	1010
Pressure, psig	171	161
Molecular Weight	27.1	27.1
Viscosity, cp	0.021	0.023
Thermal Conductivity, Btu/hrft°F/in	0.076	0.087
Heat Capacity, Btu/lb°F	0.914	0.981
Design Pressure, psig	205	205

Tube Information:

Orientation	Single row
Number of Tubes	23
Number of Passes	23
Effective Length/ tube, ft	77
Outside Diameter of Tube, inches	3.5
Inside Diameter of Tubes, inches	3.068
Center to Center Tube Spacing, inches	6
Tube Thermal Conductivity, Btu/ft^{2}hr°F	208

Tube Cross-sectional Area

$$= \frac{\pi}{4} \frac{(3.068 \text{ inches})^2}{(144 \text{ in}^2/\text{ft}^2)} = 0.0512 \text{ ft}^2$$

Mass Velocity, G, lb/ft^2sec

$$= \frac{169063 \text{ lb/hr}}{23 \text{ passes } (3600 \text{ sec/hr}) (0.0512 \text{ft}^2/\text{pass})}$$

$$= 39.88 \text{ lb/ft}^2\text{sec}$$

McAdams:

$$C_p = \frac{30.47 \times 10^6 \text{ Btu/hr}}{(1010°F - 820°F)\ (169063 \text{ lb/hr})}$$

$$= 0.949$$

$$h = \frac{16.6\ (0.949)\ (39.88)^{0.8}}{3.068^{0.2}}$$

$$= 240.3 \text{ Btu/hrft}^2{}^\circ\text{F}$$

Sieder and Tate:

at outlet:

$$\frac{DG}{Z} = \frac{3.068 \quad (39.88)}{0.023} = \quad 5320$$

$$\Phi\left(\frac{DG}{Z}\right) = \quad 18300$$

$$h = \frac{K}{D}\left[\frac{C_p Z}{K}\right]^{1/3}\left(\frac{Z}{Z_w}\right)^{0.14}\Phi\left(\frac{DG}{Z}\right)$$

$$= \frac{0.087}{3.068}\left[\frac{0.981 \quad (0.023)}{0.087}\right]^{1/3}\left(\frac{0.023}{0.024}\right)^{0.14} \quad (18300)$$

$$= 329.0 \quad \text{Btu/hrft}^2\,^\circ\text{F}$$

McADAMS

$$G = \frac{169063\ \text{LB/HR}}{23\ \text{PASSES}\left(\frac{3600\ \text{SEC}}{\text{HR}}\right)\left(\frac{0.0512\ \text{FT}^2}{\text{PASS}}\right)}$$

$$= 39.88\ \frac{\text{LB}}{\text{FT}^2\ \text{SEC}}$$

$$C_P = \frac{30.47 \times 10^6\ \text{BTU/HR}}{(1010^\circ\text{F} - 820^\circ\text{F})(169063\ \text{LB/HR})}$$

$$= 0.949\ \frac{\text{BTU}}{\text{LB}\ ^\circ\text{F}}$$

$$h = \frac{16.6\,(0.949)(39.88)^{0.8}}{3.068^{0.2}} = 240.3\ \frac{\text{BTU}}{\text{HR FT}^2\ ^\circ\text{F}}$$

S + T

AT OUTLET :

$$\frac{DG}{Z} = \frac{3.068\,(39.88)}{0.023} = 5320$$

$$\phi\left(\frac{DG}{Z}\right) = 18300$$

$$h = \frac{0.087}{3.068}\left[\frac{0\,981\,(0.023)}{0.087}\right]^{1/3}\left(\frac{0.023}{0.024}\right)^{0.14}(18300)$$

$$= 329.0\ \frac{BTU}{HR\ FT^2\,^\circ F}$$

SURFACE =

$$\left[\frac{\pi(3.5)}{12}\right](23\ \text{PASSES})\left(\frac{77\ \text{FT}}{\text{PASS}}\right)$$

$$= 1622\ \text{FT}^2$$

AVERAGE FLUX =

$$\frac{30.47 \times 10^6\ \text{BTU/HR}}{1622\ \text{FT}^2}$$

$$= 18783\ \frac{\text{BTU}}{\text{FT}^2\ \text{HR}}$$

$$TWT_{MAX} = T_F + \Delta T_F + \Delta T_M$$

McADAMS

$$= 1010 + 1.24(18783)\left(\frac{3.5}{3.068}\right)\left(\frac{1}{240.3}\right)$$

$$+ 1.24(18783)\left[\frac{3.5}{2(208)}\,LN\left(\frac{3.5}{3.068}\right)\right]$$

$$= 1010 + 110.6 + 25.8 = 1146°F$$

S & T

$$= 1010 + 1.24(18783)\left(\frac{3.5}{3.068}\right)\left(\frac{1}{329.0}\right)$$

$$+ 1.24(18783)\left[\frac{3.5}{2(208)}\,LN\left(\frac{3.5}{3.068}\right)\right]$$

$$= 1010 + 80.8 + 25.8 = 1117°F$$

Determine the heat absorption in the radiant section of the heater shown below. The heater is firing 36×10^6 Btu/hr of fuel oil.

The tubes are 6" IPS (outside diameter = 6.625"), schedule 40 average wall, carbon steel.

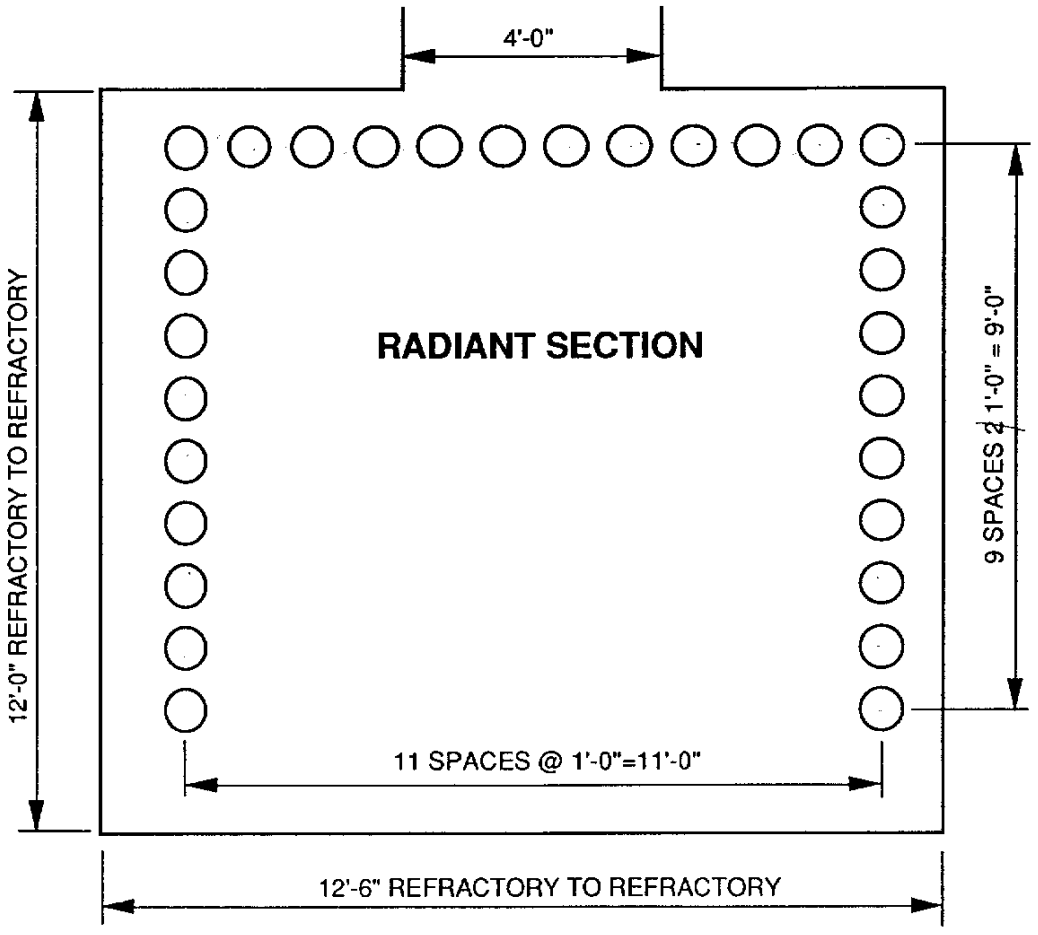
The return bends are outside the firebox in header boxes.

The tube effective length is 40 feet.

Fuel oil is being fired with 30% excess air. There is no preheated air or fuel.

Radiant section heat losses are 2%

The average tube wall temperature is 800°F.



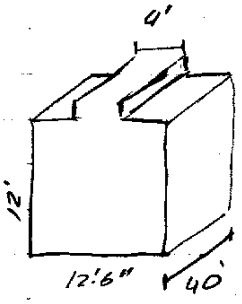
CRITERIO DE UDP

- 25% EXCESO DE AIRE DISEÑO DE HORNOS

PUDIENDO ESTE VALOR SER MENOR, DEPENDIENDO DE LAS RESTRICCIONES DE CONSERVACION DEL MEDIO AMBIENTE.

1) CALCULETE THE EFFECTIVE COLD PLANE AREA.

αA_{cp}.



$SUP/TUBO = 40' \times \frac{1.734 Ft^2}{Ft} = 69.36 Ft^2/TUBE$.

$N_T = 30$ WALL.

$TOTAL\ SUP = \frac{69.36 Ft^2}{TUBE} \times 30\ TUBES$

$TOT\ SUP = 2081.30 Ft^2$.

SPACING RATIO = $12/6.625 = 1.81$

WALL TUBES $\frac{40 FT}{TUBE} \times 30\ TUBES \times 1 - 40 \times 4 \times 1 = 1040$

$\alpha = 0.92$.

$\alpha A_{cp\,w} = 0.92 \times 1040 = 956.8$.

ENVELOPE AREA = $2 \times 12 \times 40 + 2 \times 12.5 \times 40 - 4 \times 40 + 2 \times 12 \times 12.5$

$= 2100\ Ft^2$.

$\Delta R = 2100 - 956.8 = 1143.2$.

$\frac{\Delta R}{\alpha A_{cp}} = \frac{1143.2}{956.8} = 1.19$.

12.5 : 12 : 40

1 : 1 : 3.33

P = PRESION PARCIAL $CO_2 + H_2O = 0.225$ @ 30% EA

$q_c/q_n = 0.02$

1470 °F

$P_L = 0.225 \times$

SP. BOARD : 1.8

SMALLEST DIMENSION = 12FT.

L = 1.55 x 12 = 18.6

P_L = 4.185 FT

TG = 1500

600	0515
800	0.540
1000	0560

680 → 0.525 → 0.73

$\alpha \Delta CPT\ F$ = 956.18 x 0.73 = 698.

$q_n/\alpha \Delta CPT\ F$ = $\frac{36.\times 10^6}{698.}$ = 515 75.9 BTU/H SQ FT.

q_r/q_n = 0.43 ≠ 30% ca.

$\frac{q_r}{\alpha \Delta CPT\ F}$ = (1 + 0 + 0 - 0.43 + 0.02) 51575

= 28366.3.

FIRST POINT | 1470°

32

0.540 FIG N°24 27660

EXCH FACTOR = 0.748

$\alpha \Delta CPT\ F$ = 956.8 x 0.748 = 715

$q_n/\alpha \Delta CPT\ F$ = $\frac{36.\times 10^6}{715}$ = 50301.

50301 · 0.55

SPACING RATIO = CENTER TO CENTER TUBE SPACING

$$= \frac{12\text{ in.}}{6.625\text{ in.}} = 1.81$$

EFFECTIVENESS FACTOR, F = 0.92 for wall tubes
(figure 19)

EFFECTIVENESS FACTOR, F = 1.00 for shield tubes

COLD PLANE AREA, A_{cp} (wall tubes)

$$= \frac{40\text{ ft}}{\text{tube}} \text{ (26 tubes)} \left(\frac{12\text{ in c to c}}{\text{tube}}\right)\left(\frac{\text{ft}}{12\text{in}}\right)$$

$$= 1040\text{ ft}^2$$

COLD PLANE AREA, A_{cp} (shield tubes)

$$= \frac{40\text{ ft}}{\text{tube}} \text{ (4 tubes)} \left(\frac{12\text{in c to c}}{\text{tube}}\right)\left(\frac{\text{ft}}{12\text{in}}\right)$$

$$= 160\text{ ft}^2$$

TOTAL EQUIVALENT COLD PLANE AREA

$= \alpha A_{cp}(\text{shield}) + \alpha A_{cp}(\text{wall})$

$= 1.00\ (160) + 0.92\ (1040)$

$= 1117\ ft^2$

ENVELOPE AREA

$= 40\ ft\ (12.5\ ft)\ (2) + 40\ ft\ (12\ ft)\ (2)$

$+ 12.5\ ft\ (12\ ft)\ (2) - 4\ ft\ (40\ ft)$

$= 2100\ ft^2$

A_R = ENVELOPE AREA

-TOTAL EQUIVALENT COLD PLANE AREA

$= 2100\ ft^2 - 1117\ ft^2$

$= 983\ ft^2$

$$\frac{\text{REFRACTORY AREA}}{\text{TOTAL EQUIVALENT COLD PLANE AREA}}$$

$$= \frac{983\ ft^2}{1117\ ft^2} = 0.880$$

FURNACE VOLUME

$$= 40\ ft\ (12.5\ ft)\ (12\ ft) = 6000\ ft^3$$

MEAN BEAM LENGTH, L

$$= 2/3\ (6000\ ft^3)^{1/3} = 12.11\ ft\ (table\ 1)$$

PARTIAL PRESSURE CO_2 AND H_20 @ 30% EXCESS AIR, P

$$= 0.225\ atmospheres\ (\ figure\ 22\ )$$

$$PL = 0.225\ atm.\ (12.11\ ft) = 2.73\ atm.\ ft$$

Since there is no preheated air or fuel, $q_a = q_f = 0.$

With 2% radiant heat losses, $q_L/q_n = 0.02$

ASSUMPTION 1: Average firebox temperature
$= 1350^{\circ}F$

FLAME EMISSIVITY @ $T_g = 1350^{\circ}F$, PL = 2.73 atm ft
and $T_t = 800^{\circ}F$,
$P_f = 0.465$ (figure 23c)

EXCHANGE FACTOR, F, @ $P_f = 0.465$ & $\frac{A_R}{\alpha A_{cp}} = 0.880$

$= 0.585$ (figure 24)

$$\frac{q_n}{\alpha A_{cp} F} = \frac{36.00 \times 10^6 \text{ BTU/hr}}{1117 \text{ ft}^2 \ (0.585)} = \frac{36.00 \times 10^6}{653.4}$$

$= 55093 \text{ BTU/ft}^2 \text{ hr}$

We will assume that for this type of furnace, the exit gas temperature is the same as the average firebox temperature, i.e. as a well- stirred firebox.

Therefore: $T_{g2} = T_g = 1350\ F$

$q_{g2}/q_n = 0.38$ (figure 37)

$$\frac{q_r}{\propto A_{cp} F} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_{g2}}{q_n} - \frac{q_L}{q_n}\right] \frac{q_n}{\propto A_{cp} F}$$

$$= (1 + 0 + 0 - 0.38 - 0.02)(55093)$$

$$= 33055$$

Plot the above on figure 25b at (1350, 33055).
Since the above point does not fall on $T_t = 800\ F$, *try another point that will hopefully fall on the opposite side 0f the* T_t *isotherm.*

ASSUMPTION 2 : Average firebox temperature
$= 1750^{\circ}F$

FLAME EMISSIVITY @ $T_g = 1750^{\circ}F$, $PL = 2.73$ atm ft
and $T_t = 800^{\circ}F$,

$$P_f = 0.428 \text{ (figure 23c)}$$

EXCHANGE FACTOR, F, @ $P_f = 0.428$, $\dfrac{A_R}{\alpha A_{cp} F} = 0.880$

$$= 0.555 \text{ (figure 24)}$$

$$\frac{q_n}{\alpha A_{cp} F} = \frac{36.00 \times 10^6 \text{ BTU/hr}}{1117 \text{ ft}^2 \text{ (} 0.555 \text{)}} = 58071 \text{ BTU/ft}^2 \text{ hr}$$

Since we are assuming $T_{g2} = T_g = 1750^{\circ}F$,

$q_{g2}/q_n = 0.51$ (figure 37)

$$\frac{q_r}{\propto A_{cp} F} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_{g2}}{q_n} - \frac{q_L}{q_n} \right] \left(\frac{q_n}{\propto A_{cp} F} \right)$$

$$= (1 + 0 + 0 - 0.51 - 0.02) (58071)$$

$$= 27293$$

Plot the above on figure 25b at (1750, 27293).
We now have two points plotted.
Draw a straight line between both of the points.

Since we are assuming $T_{g2} = T_g = 1750^{\circ}F$,

$q_{g2}/q_n = 0.51$ (figure 37)

$$\frac{q_r}{\propto A_{cp} F} = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_{g2}}{q_n} - \frac{q_L}{q_n} \right] \left(\frac{q_n}{\propto A_{cp} F} \right)$$

$$= (1 + 0 + 0 - 0.51 - 0.02) (58071)$$

$$= 27293$$

Plot the above on figure 25b at (1750, 27293).
We now have two points plotted.
Draw a straight line between both of the points.

Note where the straight line intersects the average tube wall temperature, 800 F. This is the point at which the radiant section is balanced. Move down to the abscissa, and read the firebox temperature.

FIREBOX TEMPERATURE = 1562°F

@ 1562°F, q_{g2}/q_n = 0.45 (figure 37)

Noting:

$$q_r + q_L + q_{g2} = q_n + q_a + q_f$$

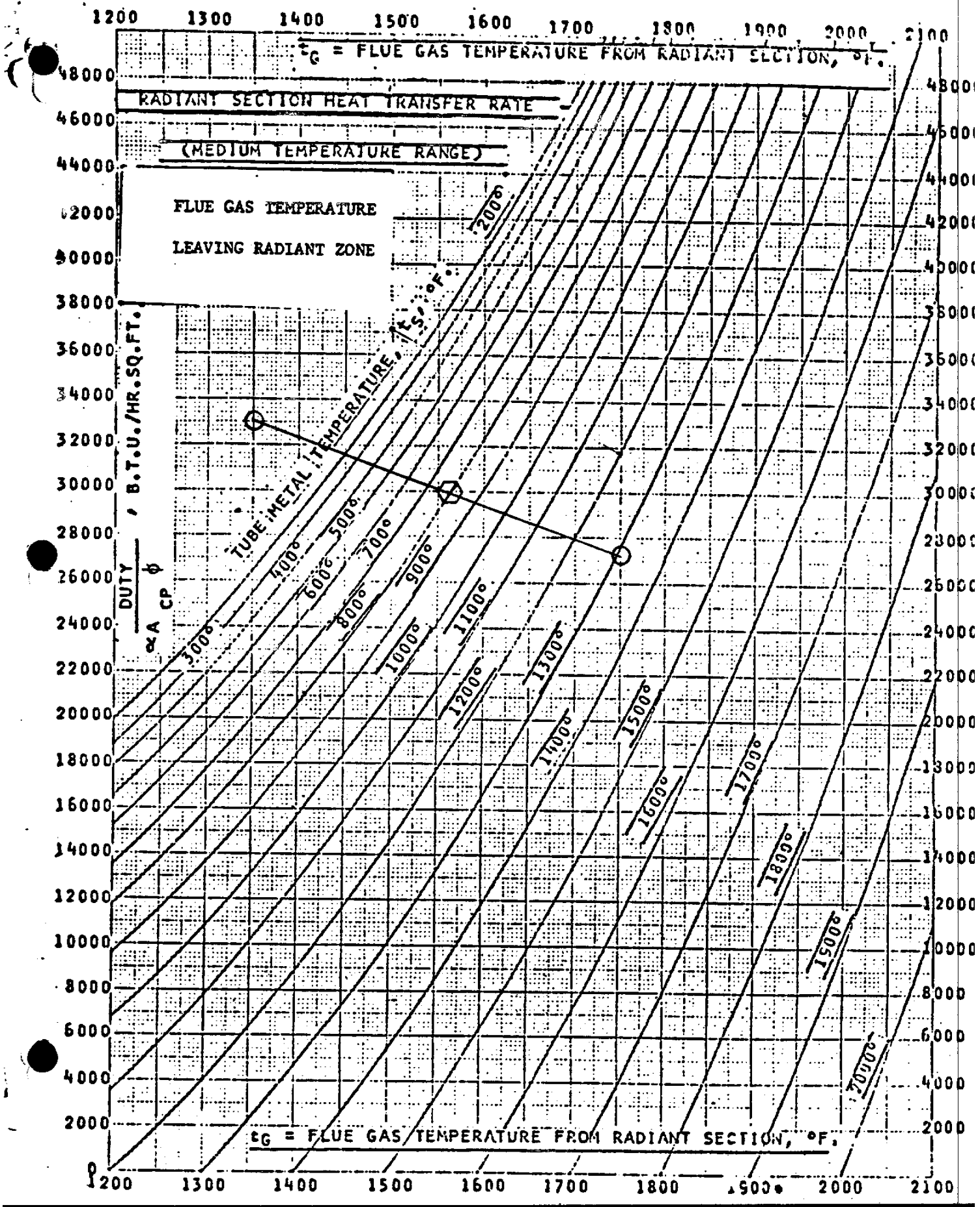
$$q_r = q_n + q_a + q_f - q_L - q_{g2}$$

$$q_r = \left[1 + \frac{q_a}{q_n} + \frac{q_f}{q_n} - \frac{q_L}{q_n} - \frac{q_{g2}}{q_n} \right] \quad q_n$$

$$q_r = (1 + 0 + 0 - 0.45 - 0.02) (36.00 \times 10^6 \text{ BTU/hr})$$

$$= 19.08 \times 10^6 \text{ BTU/hr}$$

FIGURE 25b


t_G = FLUE GAS TEMPERATURE FROM RADIANT SECTION, °F.
RADIANT SECTION HEAT TRANSFER RATE
(MEDIUM TEMPERATURE RANGE)
FLUE GAS TEMPERATURE LEAVING RADIANT ZONE
t_s, °F.
TUBE METAL TEMPERATURE,
$\frac{DUTY}{\alpha A \phi CP}$, B.T.U./HR.SQ.FT.
1200 1300 1400 1500 1600 1700 1800 1900 2000 2100
2000° 300° 400° 500° 600° 700° 800° 900° 1000° 1100° 1200° 1300° 1400° 1500° 1600° 1700° 1800° 1900° 2000°
48000 46000 44000 42000 40000 38000 36000 34000 32000 30000 28000 26000 24000 22000 20000 18000 16000 14000 12000 10000 8000 6000 4000 2000 0

Determine the number of finned rows required in a convection section.

Process Side: Duty = 1.35×10^6 Btu/hr

Inlet Temperature = 640°F

Outlet Temperature = 656°F

h_i = 200 Btu/hrft^2°F

Flue Gas side: Duty = 1.35×10^6 Btu/hr

Inlet Temperature = 1244°F

Outlet Temperature = 735°F

Throughput = 9218 lb/hr.

There are 2, 6" (6.625 inch O.D.) tubes per row.

Effective Length = 9.0 ft.

Width of convection bank = 36 inches.

Corbel height = 6 inches.

All tubes are finned with 0.105 inches thick, carbon steel fins, 0.75 inches high, 3 fins per inch.

Fin thermal conductivity = 24.4 Btu/hrft°F

Neglect fouling and wall resistances.

Flow is counter-current.

Assume shield losses have already been considered.

REMAINING CONVECTION SECTION ROWS

DUTY, Q = 1.35×10^6 BTU/hr
Fin thickness, Y = 0.105 in.
Fin height, X = 0.75 in.
Fin pitch, P = 3 fins/in.

LOG MEAN TEMPERATURE DIFFERENCE (LMTD):

	Hot Side	Cold Side
Flue gas Temperature, °F	1244	735
Process fluid temperature, °F	656	640
Temperature difference, °F	588	95

$$LMTD = \frac{588 - 95}{\ln\left(\frac{588}{95}\right)} = 270^\circ F$$

Average fluid temperature

$$= \frac{656 + 640}{2} = 648^\circ F$$

Average tube wall temperature

$$= 648 + 100 = 748^\circ F$$

Average flue gas temperature

$$= 648 + 270 = 918^\circ F$$

Average flue gas film temperature

$$= 648 + 270/2 = 783^\circ F$$

FLUE GAS MASS VELOCITY:

wall to wall = 36 in.
gross width = 36 - 6 = 30 in.
projected area of fin and tube = $D_o + 2PXY$

where Do = tube outside diameter, in.
P = fin pitch, fins/in.
X = fin height, in.
Y = fin thickness, in.

$= 6.625 + 2(3)(0.75)(0.105)$

$= 7.0975$ in/ft

$$\text{free width} = \left[30 \text{ in.} - 2 \text{ tubes } (7.0975 \text{in})\right] \frac{\text{ft}}{12 \text{in}}$$

$= 1.317$ ft

mass velocity, G

$$= \frac{9218 \text{ lb/hr}}{3600 \text{ sec/hr } (1.317 \text{ ft})(9 \text{ ft})}$$

$$= 0.216 \frac{\text{lb}}{\text{ft}^2 \text{ sec}}$$

SURFACE AREAS PER ROW:

Bare Tubes:

$$A_t = \frac{\pi(6.625\ \text{in})}{12\ \text{in/ft}} (9\ \text{ft/tube})(2\ \text{tubes/row})$$

$$= 31.2\ \text{ft}^2/\text{row}$$

Fins:

$$A_f = \frac{\pi}{4}\left[\frac{D_f^2 - D_o^2}{144\text{in}^2/\text{ft}^2}\right](2)(P)(12\text{in/ft})\ LN$$

where D_f = finned tube diameter, in

D_o = bare tube outside diameter, in

L = effective length of tubes, ft

N = number of tubes per row

$$= \frac{\pi}{4}\left(\frac{8.125^2 - 6.625^2}{144}\right)(2)(3)(12)(9)(2)$$

$$= 156.4\ \text{ft}^2/\text{row}$$

HEAT TRANSFER COEFFICIENT CONSTITUENTS:

$$h_{cc} = \frac{2.14\,(\,783 + 460\,)^{0.28}(\,0.216\,)}{6.625^{0.4}}$$

$$= 2.94$$

h_{cr} = 2.15 (figure 30)

$$h_{cw} = 9.46 \left[\frac{748 + 460}{1000}\right]^{3} = 16.68$$

DETERMINE FINNED TUBE CONVECTIVE COEFFICIENT:

Determine fin efficiency (see figure 54)

$$\frac{D_f}{D_o} = \frac{8.125}{6.625} = 1.226$$

$$X\sqrt{\frac{2h_c}{KY}} = \frac{0.75}{12}\sqrt{\frac{2\ (2.94\ )}{(\ 24.4\ )\ (0.105/12)}}$$

$$= 0.328$$

Efficiency, E = 0.97

Calculate the convective constituent of the heat transfer coefficient for the finned tube.

$$h_f = h_{cc}\left[\frac{EA_f + A_t}{A_t}\right]$$

$$= 2.94\left[\frac{0.97\ (\ 156.4\ ) + 31.2}{31.2}\right]$$

$$= 17.24$$

CALCULATE THE OVERALL CONVECTION SECTION OUTSIDE HEAT TRANSFER COEFFICIENT:

Calculate the wall area per row:

$$A_w = (2)(12\text{in c to c})\left(\frac{\text{ft}}{12\text{in}}\right)(9\text{ft})(0.866)$$

$$= 15.59$$

Determine the correction factor, f, for expressing h_{cw} in terms of h_f and h_{cr}.

$$f = \frac{h_{cw}}{h_{cw} + h_f + h_{cr}}\left(\frac{A_w}{A_t}\right)$$

$$= \frac{16.68}{16.68 + 17.24 + 2.15}\left(\frac{15.59}{31.2}\right)$$

$$= 0.231$$

Calculate the overall convection section outside heat transfer coefficient:

$$h_c = (1 + f)(h_f + h_{cr})$$

$$= (1 + 0.231)(17.24 + 2.15)$$

$$= 23.86$$

Calculate the overall convection section heat transfer outside coefficient

$$U_o = \frac{h_i h_o}{h_i + h_o}$$

$$= \frac{300\,(23.86)}{300 + 23.86} = 22.10\ \text{BTU/ft}^2\text{°F hr}$$

Calculate the surface area required, A_{to}

$$= \frac{Q}{Uo\,(LMTD)} = \frac{1.35 \times 10^6\ \text{BTU/hr}}{(22.10\ \text{BTU/ft}^2\text{°F hr})(270\text{°F})}$$

$$= 226.2\ \text{ft}^2$$

Calculate the number of finned rows required

$$= \frac{A_{to}}{A_t} = \frac{226.3\ \text{ft}^2}{31.2\ \text{ft}^2}$$

$$= 7.25\ \text{rows} \qquad \text{use 8 rows}$$

EXPANDING RELATIONSHIP FOR Uo (assuming no fouling):

$$U_o = \frac{1}{\frac{D_o}{D_i h_{fi}} + \frac{D_o}{D_i h_i} + \left(\frac{t_w}{k_m}\right)\left(\frac{D_i}{D_L}\right) + \frac{1}{h_o} + \frac{1}{h_{fo}}}$$

$$= \frac{1}{\frac{6.625}{6.065\,(300)} + \left(\frac{0.280/12}{24.5}\right)\left(\frac{6.625}{6.341}\right) + \frac{1}{23.86}}$$

$$= 21.48$$

$$A_{to} = \frac{1.35 \times 10^6}{21.48\,(\,270\,)} = 232.8\ ft^2$$

$$\text{Number of finned rows} = \frac{232.8}{31.2} = 7.46 \text{ rows}$$

EXPANDING RELATIONSHIP FOR Uo (including fouling):

fouling factors- inside = 1000

outside = 67

$$U_o = \frac{1}{\frac{D_o}{D_i h_{fi}} + \frac{D_o}{D_i h_i} + \left(\frac{t_w}{k_m}\right)\left(\frac{D_i}{D_L}\right) + \frac{1}{h_o} + \frac{1}{h_{fo}}}$$

$$= \frac{1}{\frac{6.625}{6.065(1000)} + \frac{6.625}{6.065(300)} + \left(\frac{0.280/12}{24.5}\right)\left(\frac{6.625}{6.341}\right) + \frac{1}{23.86} + \frac{1}{67}}$$

$$= 15.99$$

$$A_{to} = \frac{1.35 \times 10^6}{15.99\,(\,270\,)} = 312.7$$

$$\text{Number of finned rows} = \frac{312.7}{31.2} = 10.02 \text{ rows}$$

UOP Engineering Design Seminar

FALL 1991

LINE SIZING

I. OBJECTIVES

A. DETERMINE LINE SIZES AND PRESSURE DROP (PSI/100 FT)

B. DETERMINE EQUIPMENT PRESSURE DROP (PSI)

C. DETERMINE VARIABLE PRESSURE DROP/INCREASES

i) PRESSURE DROP FOR CONTROL VALVES

ii) DIFFERENTIAL HEAD FOR PUMPS AND COMPRESSORS

PIPING CONSTRUCTION

INTRODUCTION

Pipe is used extensively in the petroleum and chemical refinery. It is used to transfer process fluids and gases, steam, water and air from one location to another.

Pipe is defined as a pressure-tight hollow cylinder used to convey a fluid or to transmit a fluid pressure, ordinarily designated "pipe" in applicable material specification. Material designated "tube" or "tubing" in specification is treated as pipe when intended for pressure service.

A term you will hear often in the refinery is "piping." Piping is defined as assemblies of pipe, fitting, flanges, bolting, gaskets, valves and other components, or their pressure containing parts, used to convey, distribute, mix, separate, discharge, meter, control, or snub fluid flows. Piping also includes pipe-supporting elements.

The "fluid service" of a piping system is a general term concerning the application of a particular piping system. It considers the combination of fluid properties, operating conditions, and other factors which establish the basis for design of a piping system.

PIPING DESIGN CODES

Piping codes set forth the engineering requirements for safe design and construction of piping systems. The following codes, specifications, and references (latest editions and addenda) are used in process piping design.

1. ASME Code for Pressure Piping B31, an American National Standard, Chemical Plant and Petroleum Refinery Piping (ANSI/ASME B31.3).

2. American National Standard Pipe Flanges and Flanged Fittings (ANSI B16.5).

3. ASME Boiler and Pressure Vessel Code Section 1, Section VIII, Division 1 and Section IX (ANSI/ASME BPV-1, BPV-VIII, and BPV-IX).

4. National Association of Corrosion Engineers (NACE) Standard RP-01-69, Recommended Practice, Control of External Corrosion of Underground or Submerged Metallic Piping Systems.

5. API RP520, Part 1 Design and Part 2 Installation of Pressure Relieving Systems in Refineries.

6. API RP521, Guide for Pressure Relief and Depressuring Systems.

7. AGA, Gas Measurement Committee Report No. 3, Orifice Metering of Natural Gas.

8. Fluid Meters, Their Theory and Application; an ASME Publication.

9. API TP550, Installation of Refinery Instruments and Control Systems.

10. American National Standard Surface Texture (ANSI B46.1).

SCOPE OF B31.3

This code prescribes minimum requirements for the material, design, fabrication, assembly, erection, examination, inspection, and testing of piping systems subjected to pressure or vacuum in chemical and petroleum refineries.

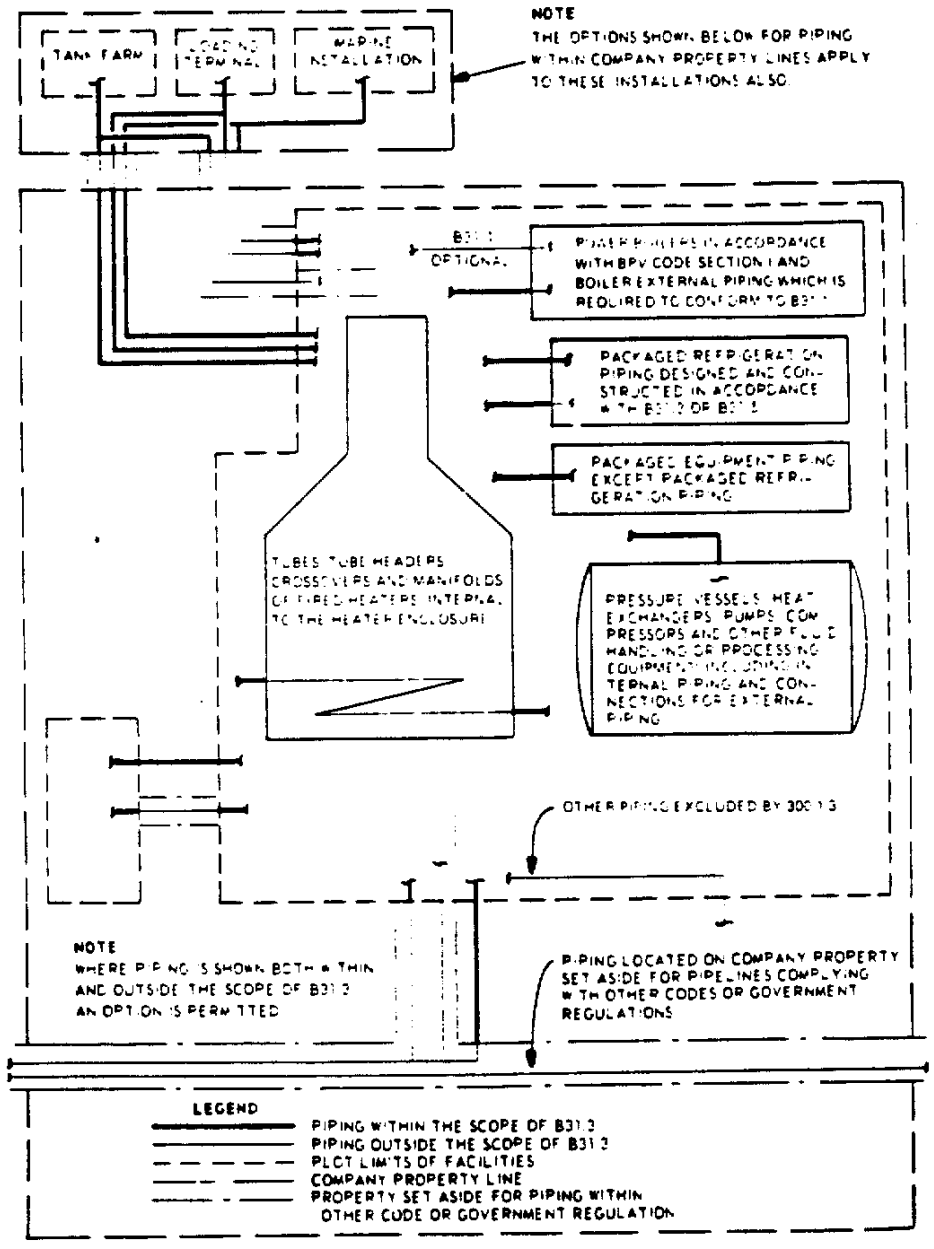
B31.3 applies to piping systems handling all fluids, including fluidized solids, and to all types of service including raw, intermediate, and finished chemicals, oil, and other petroleum products, gas, steam air, water, and refrigerants except for piping which interconnects individual pieces or stages of equipment with a package equipment assembly shall be in accordance with B31.1 - Power Piping, except that:

Packaged refrigeration piping may conform to either B31.3 or B31.6 - Refrigeration Piping.

Except as excluded below, this Code covers all piping within the property limits of facilities engaged in the processing or handling of chemical, petroleum, or related products. Examples are chemical, plants, petroleum refinery, loading terminal, natural gas processing plant (including liquified natural gas facilities) bulk plant, compounding plant, and tank farm. Figure 5-1 illustrates the scope of B31.3.

FIGURE 5-1

DIAGRAM ILLUSTRATING SCOPE OF B31.3 PIPING



Piping for gases (including air) not now included with the scope of any existing Section of the Code may be designated, fabricated, inspected, and tested in accordance with the requirements of this code when piping is in plants, buildings, and similar facilities not otherwise within the scope of this Code.

EXCLUSIONS

Piping systems designed for internal gauge pressures at or above zero but less than 15 psi (103 kPa), provided the fluid handled is nonflammable, nontoxic, and not damaging to human tissue and its design temperature is from -20°F (-29°C) through 366°F (186°C); or Power boilers in accordance with ASME BPV Code Section 1 and boiler external piping which is required to conform to B31.1 - Power Piping; or

Tubes, tube headers, crossovers, and manifolds of fired heaters, which are internal to the heater enclosure; or

Pressure vessels, heat exchangers, pumps, compressors, and other fluid handling or processing equipment, including internal piping and connections for external piping; or

Piping located on company property which has been set aside for pipelines conforming to B31.4 - Liquid Petroleum Transportation Piping Systems, or B31.8 - Gas Transmission and Distribution Piping Systems or applicable governmental regulations; or

Plumbing and sewers; or

Fire protection systems constructed in compliance with insurance underwriters' or other recognized fire protection engineering standards.

PIPING DRAWINGS

Piping and instrument (P&I) drawings of a process unit provide information on process flow, line sizes, flange ratings, design and operating pressures and temperatures, type of valves, and instrumentation for a particular unit. The P & I drawings are very useful, not only during the construction phase but also when setting up an inservice inspection program.

Another good source of information, if available, are the original fabrication drawings used during the construction of the process unit. These piping drawings are called "spool drawings or sheets." They contain pipe sizes, pipe schedules, line dimensions, offsets, material, flange ratings, design and operating pressures and temperatures, location of valves and type, corrosion allowance, etc.

PIPE MATERIAL

The following materials may be used in the fabrication of the pipe depending upon code and service requirements.

Cast Iron
Malleable Iron
High Silicon Iron (14.5%)
Carbon Steel
Low and Intermediate Alloy Steels
High Alloy (Stainless) Steels
Nickel and Nickel Base Alloys
Copper and Copper Alloys
Titanium and Titanium Alloys
Zirconium and Zirconium Alloys
Tantalum and Plastic

Cast iron, malleable iron, and high silicon iron (14.5%) - their lack of ductility and sensitivity to thermal and mechanical shock must be considered and evaluated when using these materials in piping. These materials are not permitted to be used under severe cyclic conditions and are subjected to the following B31.3 Code limitations:

Cast iron pipe or fittings are not permitted to be used above ground within process unit limits in hydrocarbon or other flammable fluid service at temperatures above 300°F (150°C) nor at gauge pressures above 150 psi (1030 kPa). It finds some use in utility systems (air, water, steam, low pressure steam, etc.) and is used for equipment internals such as pump impellers. It is brittle upon impact.

Malleable iron pipe or fittings are not permitted to be used in any fluid service at temperatures below -20°F (-29°C) or above 650°F (350°C) and is not permitted to be used in flammable fluids service at temperatures above 300°F (150°C) nor at gauge pressures above 400 psi (2760 kPa).

High Silicon Iron (14.5%) is not permitted to be used in flammable fluid service.

The following are specific considerations to be evaluated when applying certain metals in piping:

Carbon Steel, and Low and Intermediate Alloy Steels - the possibility of embrittlement when handling alkaline or strong caustic acids; the possible conversion of carbides to graphite during long time exposure to temperatures above 800°F (427°C) of carbon steels, plain nickel steel, carbon-manganese steel, manganese-vanadium steel, and carbon-silicon steel; the possible conversion of carbides to graphite during long time exposure to temperatures above 875°F (468°C) of carbon-molybdenum steel, manganeses-molybdenum-vanadium steel, and chromium-vanadium steel; the advantage of silicon-killed steel (0.1% silicon min) for temperatures above 900°F (428°C); the possibility of hydrogen damage when piping is exposed to hydrogen or to aqueous acid solutions at certain temperature-pressure conditions; the possibility of deteriorations when piping material is exposed to hydrogen sulfide at elevated temperatures.

High Alloy (Stainless) Steels - the possibility of stress corrosion cracking of austenitic stainless steels exposed to media such as chlorides or other halides either internally or externally; the latter can result from improper selection or application of thermal insulation; the susceptibility of intergranular corrosion of austenitic stainless steels after sufficient exposure to temperatures between 800 and 1600°F (427 and 871°C) unless stabilized or low carbon grades are used; the susceptibility to intercrystalline attack of austenitic stainless steels on contact with zinc or lead above their melting points or with many lead and zinc compounds at similarly elevated temperatures; the brittleness of ferritic stainless steels at room temperature after service at temperatures above 700°F (370°C).

Nickel and Nickel Base Alloys - the susceptibility to grain boundary attack of nickel and nickel base alloys not containing chromium when exposed to small quantities of sulfur at temperatures above 600°F (315°C); the susceptibility to grain boundary attack of nickel base alloys containing chromium at temperatures above 1100°F (595°C) under reducing conditions and above 1400°F (760°C) under oxidizing conditions; the possibility of stress corrosion cracking of nickel-copper alloy (70 Ni-30 Cu) in hydrofluoric acid vapor if the alloy is highly stress or contains residual stresses from forming or welding.

Aluminum or Aluminum Alloys - the compatibility with aluminum of thread compounds used in aluminum threaded joints to prevent seizing and galling; the possibility of corrosion from concrete, mortar, lime, plaster, or other

alkaline materials used in buildings or structures; the susceptibility of Alloys Nos. 5154, 5086, 5083, and 5446 to exfoliation or intergranular attack; and the upper temperature limit of 150°F (65°C) to avoid such deterioration.

Copper and Copper Alloys - the possibility of dezincification of brass alloys; the susceptibility to stress-corrosion cracking of copper-based alloy; and the possibility of unstable acetylide formation when exposed to acetylene.

Titanium and Titanium Alloys - the possibility of deterioration of zirconium and zirconium alloys above 600°F (315°C).

Zirconium and Zirconium Alloys - the possibility of deterioration of zirconium and zirconium alloys above 600°F (315°C).

Tantalum - above 570°F (300°C), the possibility of reactivity of tantalum with all gases except the inert gases. Below 570 F the possibility of embrittlement of tantalum by nascebt (monatomic) hydrogen (but not molecular hydrogen). Nascent hydrogen is produced by galvanic action, or as a product of corrosion by certain chemicals.

TYPES OF METALLIC PIPE

Types of pipe, according to the method of manufacture, are defined below:

Electric Resistance-Welded Pipe - pipe produced in individual lengths or in continuous lengths from coiled skelp and subsequently cut into individual lengths, having a longitudinal butt joint wherein coalescence is produced by heat obtained from resistance of the pipe to the flow of electrical current in a circuit of which the pipe is a part, and by the application of pressure.

Furnace Butt Welded Pipe, Bell Welded - pipe produced in individual lengths from cut-length skelp, having it longitudinal butt joint forged welded by the mechanical pressure developed in drawing the furnace-heated skelp through a cone shaped die (commonly known as "welding bell") which serves as a combined forming and welding die.

Furnace Butt Welded Pipe, Continuous Welded - pipe produced in continuous lengths from coiled skelp and subsequently cut into individual lengths, having it longitudinal butt joint forged welded by mechanical pressure developed in passing the hot-formed and edge-heated skelp through a set of round pass welding rolls.

Electric-Fusion Welded Pipe - pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc-welding. The weld may be single (welded from one side) or double (welded from inside and outside) and may be made with or without the addition of filler metal.

Double Submerged-Arc Welded Pipe - pipe having a longitudinal butt joint produced by at least two passes, one of which is on the inside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding is shielded by a blanket of granular fusible metal on the work. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode or electrodes.

Seamless Pipe - pipe produced by piercing a billet followed by rolling or drawing, or both. Of the various types of pipe, seamless pipe is the most common in petroleum and chemical refineries.

Spiral Welded Pipe - pipe having a helical seam with either a butt, lap, or lock-seam joint which is welded using either electrical resistance, electric fusion or double-submerged arc welding process. Not recommended for process piping or severe cyclic conditions.

PIPE SIZES AND SCHEDULES

Table 5-1A and B shows commercial wrought steel pipe sizes. Steel and alloy pipe are manufactured to standard dimensions in sizes up to 24" (610 mm) and in standard thicknesses called Schedules. For pipe 12" (305 mm) and smaller, the size refers to the nominal inside diameter. For pipes 14" (356 mm) and larger the size denotes the actual outside diameter. The thickness of the drawn or cast pipe may vary from nominal thickness by as much as ± 12 1/2%. This is a standard manufacture tolerance for pipe. For design purposes the minimum thickness is used.

Example: 6" Schedule 40 pipe.
Nominal Wall Thickness = 0.280"
Tolerance = ± .035"
Minimum Thickness = (Min. THK.)
Maximum Thickness = (Max. THK.,)

Min. THK. = 0.280" - 0.035" = 0.245"
Max. THK. = 0.280" + 0.035" = 0.315"

PIPE JOINTS

Piping joints for metallic pipe are required to be suitable for the pressure temperature conditions and are selected according to the joint tightness and mechanical strength under design conditions (including external loadings) to piping material of construction, and to the nature of the fluid handled.

THREADED JOINTS

Screwed fittings (see Figure 5-2) are used primarily on service lines such as water, plant air, instrument air, and on all connections made directly to an instrument, such as orifice taps, pressure gauges, thermowells and thermometers. Electric conduit is also threaded; however, the fittings should never be interchanged with threaded or screwed fittings used to contain process fluids. The use of threaded fittings is limited by the ability to make a good leak-free seal at the threads. It can be done, but a welded fitting is much more reliable, particularly if a joint will be heated up and cooled down many times. A good thread lubricant will aid in sealing the threaded joint. However, it must be compatible with the process, since some thread lubricants can contain compounds that will poison catalyst. A thread lubricant recommended by UOP is Fel Pro C-100.

TABLE 5-1A

COMMERCIAL WROUGHT STEEL PIPE DATA

SCHEDULE WALL THICKNESS

	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter		Inside Diameter Functions In Inches				Transverse Internal Area	
	Inches	Inches	Inches	Inches	Feet						
Schedule 10	14	14	0.250	13.5	1.125	182.25	2460.4	33215	448400	143.14	0.994
	16	16	0.250	15.5	1.291	240.25	3723.9	57720	894660	188.69	1.310
	18	18	0.250	17.5	1.458	306.25	5359.4	93789	1641309	240.53	1.670
	20	20	0.250	19.5	1.625	380.25	7414.9	144590	2819500	298.65	2.074
	24	24	0.250	23.5	1.958	552.25	12977	304980	7167030	433.74	3.012
	30	30	0.312	29.376	2.448	862.95	25350	744288	21864318	677.76	4.707
Schedule 20	8	8.625	0.250	8.125	0.6771	66.02	536.38	4359.3	35409	51.85	0.3601
	10	10.75	0.250	10.25	0.8542	105.06	1076.4	11038	113141	82.52	0.5731
	12	12.75	0.250	12.25	1.021	150.06	1838.1	22518	275855	117.86	0.8185
	14	14	0.312	13.376	1.111	178.92	2393.2	32012	428185	140.52	0.9758
	16	16	0.312	15.376	1.281	236.42	3635.2	55894	859642	185.69	1.290
	18	18	0.312	17.376	1.448	301.92	5246.3	91156	1583978	237.13	1.647
	20	20	0.375	19.250	1.604	370.56	7133.3	137317	2643352	291.04	2.021
	24	24	0.375	23.25	1.937	540.56	12568	292205	6793832	424.56	2.948
	30	30	0.500	29.00	2.417	841.0	24389	707281	20511149	660.52	4.587
Schedule 30	8	8.625	0.277	8.071	0.6726	65.14	525.75	4243.2	34248	51.16	0.3553
	10	10.75	0.307	10.136	0.8447	102.74	1041.4	10555	106967	80.69	0.5603
	12	12.75	0.330	12.09	1.0075	146.17	1767.2	21366	258304	114.80	0.7972
	14	14	0.375	13.25	1.1042	175.56	2326.2	30821	408344	137.88	0.9575
	16	16	0.375	15.25	1.2708	232.56	3546.6	54064	824801	182.65	1.268
	18	18	0.438	17.124	1.4270	293.23	5021.3	85984	1472397	230.30	1.599
	20	20	0.500	19.00	1.5833	361.00	6859.0	130321	2476099	283.53	1.969
	24	24	0.562	22.876	1.9063	523.31	11971	273853	6264703	411.00	2.854
	30	30	0.625	28.75	2.3958	826.56	23764	683201	19642160	649.18	4.508
Schedule 40	1/8	0.405	0.068	0.269	0.0224	0.0724	0.0195	0.005242	0.00141	0.057	0.00040
	1/4	0.540	0.088	0.364	0.0303	0.1325	0.0482	0.01756	0.00639	0.104	0.00072
	3/8	0.675	0.091	0.493	0.0411	0.2430	0.1198	0.05905	0.02912	0.191	0.00133
	1/2	0.840	0.109	0.622	0.0518	0.3869	0.2406	0.1497	0.09310	0.304	0.00211
	3/4	1.050	0.113	0.824	0.0687	0.6789	0.5595	0.4610	0.3799	0.533	0.00371
	1	1.315	0.133	1.049	0.0874	1.100	1.154	1.210	1.270	0.864	0.00600
	1 1/4	1.660	0.140	1.380	0.1150	1.904	2.628	3.625	5.005	1.495	0.01040
	1 1/2	1.900	0.145	1.610	0.1342	2.592	4.173	6.718	10.82	2.036	0.01414
	2	2.375	0.154	2.067	0.1722	4.272	8.831	18.250	37.72	3.355	0.02330
	2 1/2	2.875	0.203	2.469	0.2057	6.096	15.051	37.161	91.75	4.788	0.03322
	3	3.500	0.216	3.068	0.2557	9.413	28.878	88.605	271.8	7.393	0.05130
	3 1/2	4.000	0.226	3.548	0.2957	12.59	44.663	158.51	562.2	9.886	0.06870
	4	4.500	0.237	4.026	0.3355	16.21	65.256	262.76	1058	12.730	0.08840
	5	5.563	0.258	5.047	0.4206	25.47	128.56	648.72	3275	20.006	0.1390
	6	6.625	0.280	6.065	0.5054	36.78	223.10	1357.8	8230	28.891	0.2006
Schedule 60	8	8.625	0.322	7.981	0.6651	63.70	508.36	4057.7	32380	50.027	0.3474
	10	10.75	0.365	10.02	0.8350	100.4	1006.0	10080	101000	78.855	0.5475
	12	12.75	0.406	11.938	0.9945	142.5	1701.3	20306	242470	111.93	0.7773
	14	14.0	0.438	13.124	1.0937	172.24	2260.5	29666	389340	135.28	0.9394
	16	16.0	0.500	15.000	1.250	225.0	3375.0	50625	759375	176.72	1.2272
	18	18.0	0.562	16.876	1.4063	284.8	4806.3	81111	1368820	223.68	1.5533
	20	20.0	0.593	18.814	1.5678	354.0	6659.5	125320	2357764	278.00	1.9305
	24	24.0	0.687	22.626	1.8855	511.9	11583	262040	5929784	402.07	2.7921
Schedule 80	8	8.625	0.406	7.813	0.6511	61.04	476.93	3725.9	29113	47.96	0.3329
	10	10.75	0.500	9.750	0.8125	95.06	926.86	9036.4	88110	74.66	0.5185
	12	12.75	0.562	11.626	0.9688	135.16	1571.4	18268	212399	106.16	0.7372
	14	14.0	0.593	12.814	1.0678	164.20	2104.0	26962	345480	128.96	0.8956
	16	16.0	0.656	14.688	1.2240	215.74	3168.8	46544	683618	169.44	1.1766
	18	18.0	0.750	16.500	1.3750	272.25	4492.1	74120	1222982	213.83	1.4849
	20	20.0	0.812	18.376	1.5313	337.68	6205.2	114028	2095342	265.21	1.8417
	24	24.0	0.968	22.064	1.8387	486.82	10741	236944	5229036	382.35	2.6552
Schedule 80	1/8	0.405	0.095	0.215	0.0179	0.0462	0.00994	0.002134	0.000459	0.036	0.00025
	1/4	0.540	0.119	0.302	0.0252	0.0912	0.0275	0.00831?	0.002513	0.072	0.00050
	3/8	0.675	0.126	0.423	0.0353	0.1789	0.0757	0.03200	0.01354	0.141	0.00098
	1/2	0.840	0.147	0.546	0.0455	0.2981	0.1628	0.08896	0.04857	0.234	0.00163
	3/4	1.050	0.154	0.742	0.0618	0.5506	0.4085	0.3032	0.2249	0.433	0.00300
	1	1.315	0.179	0.957	0.0797	0.9158	0.8765	0.8387	0.8027	0.719	0.00499
	1 1/4	1.660	0.191	1.278	0.1065	1.633	2.087	2.666?	3.409	1.283	0.00891

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TABLE 5-1B

COMMERCIAL WROUGHT STEEL PIPE DATA

SCHEDULE WALL THICKNESS

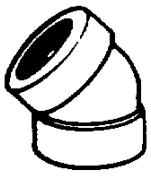
	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter		Inside Diameter Functions (In Inches)				Transverse Internal Area	
						d^2	d^3	d^4	d^5	a	A
	Inches	Inches	Inches	Inches	Feet					Sq In	Sq Ft
Schedule 80 cont	1½	1.900	0.200	1.500	0.1250	2.250	3.375	5.062	7.594	1.767	0.01225
	2	2.375	0.218	1.939	0.1616	3.760	7.290	14.136	27.41	2.953	0.02050
	2½	2.875	0.276	2.323	0.1936	5.396	12.536	29.117	67.64	4.238	0.02942
	3	3.5	0.300	2.900	0.2417	8.410	24.389	70.728	205.1	6.605	0.04587
	3½	4.0	0.318	3.364	0.2803	11.32	38.069	128.14	430.8	8.888	0.06170
	4	4.5	0.337	3.826	0.3188	14.64	56.006	214.33	819.5	11.497	0.07986
	5	5.563	0.375	4.813	0.4011	23.16	111.49	536.38	2583.	18.194	0.1263
	6	6.625	0.432	5.761	0.4801	33.19	191.20	1101.6	6346.	26.067	0.1810
	8	8.625	0.500	7.625	0.6354	58.14	443.32	3380.3	25775.	45.663	0.3171
	10	10.75	0.593	9.564	0.7970	91.47	874.82	8366.8	80020.	71.84	0.4989
	12	12.75	0.687	11.376	0.9480	129.41	1471.7	16747.	190523.	101.64	0.7058
	14	14.0	0.750	12.500	1.0417	156.25	1953.1	24414.	305176.	122.72	0.8522
	16	16.0	0.843	14.314	1.1928	204.89	2932.8	41980.	600904.	160.92	1.1175
	18	18.0	0.937	16.126	1.3438	260.05	4193.5	67626.	1090518.	204.24	1.4183
	20	20.0	1.031	17.938	1.4948	321.77	5771.9	103536.	1857248.	252.72	1.7560
	24	24.0	1.218	21.564	1.7970	465.01	10027.	216234.	4662798.	365.22	2.5362
Schedule 100	8	8.625	0.593	7.439	0.6199	55.34	411.66	3062.	22781.	43.46	0.3018
	10	10.75	0.718	9.314	0.7762	86.75	807.99	7526.	69357.	68.13	0.4732
	12	12.75	0.843	11.064	0.9220	122.41	1354.4	14985.	165791.	96.14	0.6677
	14	14.0	0.937	12.126	1.0105	147.04	1783.0	21621.	262173.	115.49	0.8020
	16	16.0	1.031	13.938	1.1615	194.27	2707.7	37740.	526020.	152.58	1.0596
	18	18.0	1.156	15.688	1.3057	246.11	3861.0	60572.	950250.	193.30	1.3423
	20	20.0	1.281	17.438	1.4532	304.08	5302.6	92467.	1612438.	238.83	1.6585
	24	24.0	1.531	20.938	1.7448	438.40	9179.2	192195.	4024179.	344.32	2.3911
Schedule 120	4	4.50	0.438	3.624	0.302	13.133	47.595	172.49	625.1	10.315	0.07163
	5	5.563	0.500	4.563	0.3802	20.82	95.006	433.5	1978.	16.35	0.1136
	6	6.625	0.562	5.501	0.4584	30.26	166.47	915.7	5037.	23.77	0.1650
	8	8.625	0.718	7.189	0.5991	51.68	371.54	2671.	19202.	40.59	0.2819
	10	10.75	0.843	9.064	0.7553	82.16	744.66	6750.	61179.	64.53	0.4481
	12	12.75	1.000	10.750	0.8959	115.56	1242.3	13355.	143563.	90.76	0.6303
	14	14.0	1.093	11.814	0.9845	139.57	1648.9	19480.	230137.	109.62	0.7612
	16	16.0	1.218	13.564	1.1303	183.98	2495.5	33849.	459133.	144.50	1.0035
	18	18.0	1.375	15.250	1.2708	232.56	3546.6	54086.	824804.	182.66	1.2684
	20	20.0	1.500	17.000	1.4166	289.00	4913.0	83521.	1419857.	226.98	1.5762
	24	24.0	1.812	20.376	1.6980	415.18	8459.7	172375.	3512313.	326.08	2.2645
Schedule 140	8	8.625	0.812	7.001	0.5834	49.01	343.15	2402.	16819.	38.50	0.2673
	10	10.75	1.000	8.750	0.7292	76.56	669.92	5862.	51291.	60.13	0.4176
	12	12.75	1.125	10.500	0.8750	110.25	1157.6	12155.	127628.	86.59	0.6013
	14	14.0	1.250	11.500	0.9583	132.25	1520.9	17490.	201136.	103.87	0.7213
	16	16.0	1.438	13.124	1.0937	172.24	2260.5	29666.	389340.	135.28	0.9394
	18	18.0	1.562	14.876	1.2396	221.30	3292.0	48972.	728502.	173.80	1.2070
	20	20.0	1.750	16.5	1.3750	272.25	4492.1	74120.	1222981.	213.82	1.4849
	24	24.0	2.062	19.876	1.6563	395.06	7857.1	156169.	3103022.	310.28	2.1547
Schedule 160	½	0.840	0.187	0.466	0.0388	0.2172	0.1012	0.04716	0.0021197	0.1706	0.00118
	¾	1.050	0.218	0.614	0.0512	0.3770	0.2315	0.1421	0.087236	0.2961	0.00206
	1	1.315	0.250	0.815	0.0679	0.6642	0.5413	0.4412	0.3596	0.5217	0.00362
	1¼	1.660	0.250	1.160	0.0966	1.346	1.561	1.811	2.100	1.057	0.00734
	1½	1.900	0.281	1.338	0.1115	1.790	2.396	3.206	4.288	1.406	0.00976
	2	2.375	0.343	1.689	0.1407	2.853	4.818	8.136	13.74	2.241	0.01556
	2½	2.875	0.375	2.125	0.1771	4.516	9.596	20.39	43.33	3.546	0.02463
	3	3.50	0.437	2.626	0.2188	6.896	18.109	47.55	124.9	5.416	0.03761
	4	4.50	0.531	3.438	0.2865	11.82	40.637	139.7	480.3	9.283	0.06447
	5	5.563	0.625	4.313	0.3594	18.60	80.230	346.0	1492.	14.61	0.1015
	6	6.625	0.718	5.189	0.4324	26.93	139.72	725.0	3761.	21.15	0.1469
	8	8.625	0.906	6.813	0.5677	46.42	316.24	2155.	14679.	36.46	0.2532
	10	10.75	1.125	8.500	0.7083	72.25	614.12	5220.	44371.	56.75	0.3941
	12	12.75	1.312	10.126	0.8438	102.54	1038.3	10514.	106461.	80.53	0.5592
	14	14.0	1.406	11.188	0.9323	125.17	1400.4	15668.	175292.	98.31	0.6827
	16	16.0	1.593	12.814	1.0678	164.20	2104.0	26961.	345482.	128.96	0.8956
	18	18.0	1.781	14.438	1.2032	208.45	3009.7	43454.	627387.	163.72	1.1369
	20	20.0	1.968	16.064	1.3387	258.06	4145.3	66590.	1069715.	202.67	1.4074
	24	24.0	2.343	19.314	1.6095	373.03	7204.7	139152.	2687562.	292.98	2.0346

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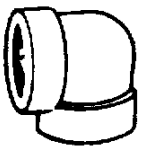
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FIGURE 5-2

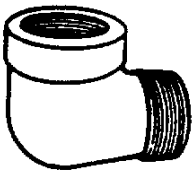
SCREWED FITTINGS
(FITTINGS, FLANGES, UNIONS)



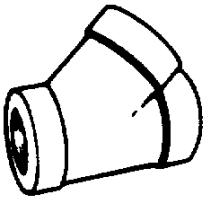
45° ELL



90° ELL



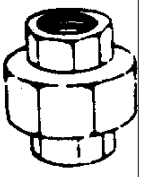
STREET ELL



45° LATERAL



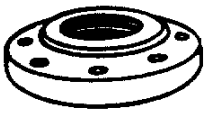
PIPE CAP



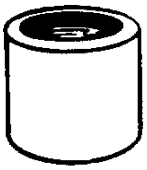
UNION



PLUG



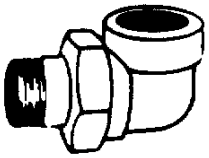
ANSI FLANGE



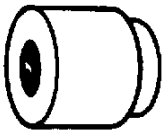
COUPLING



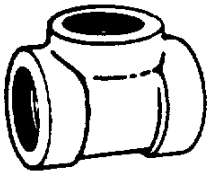
WELD COUPLET



UNION ELL



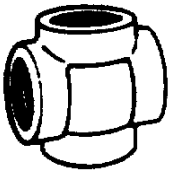
REDUCER INSERT



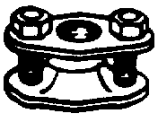
TEE



HEXAGON BUSHING



CROSS

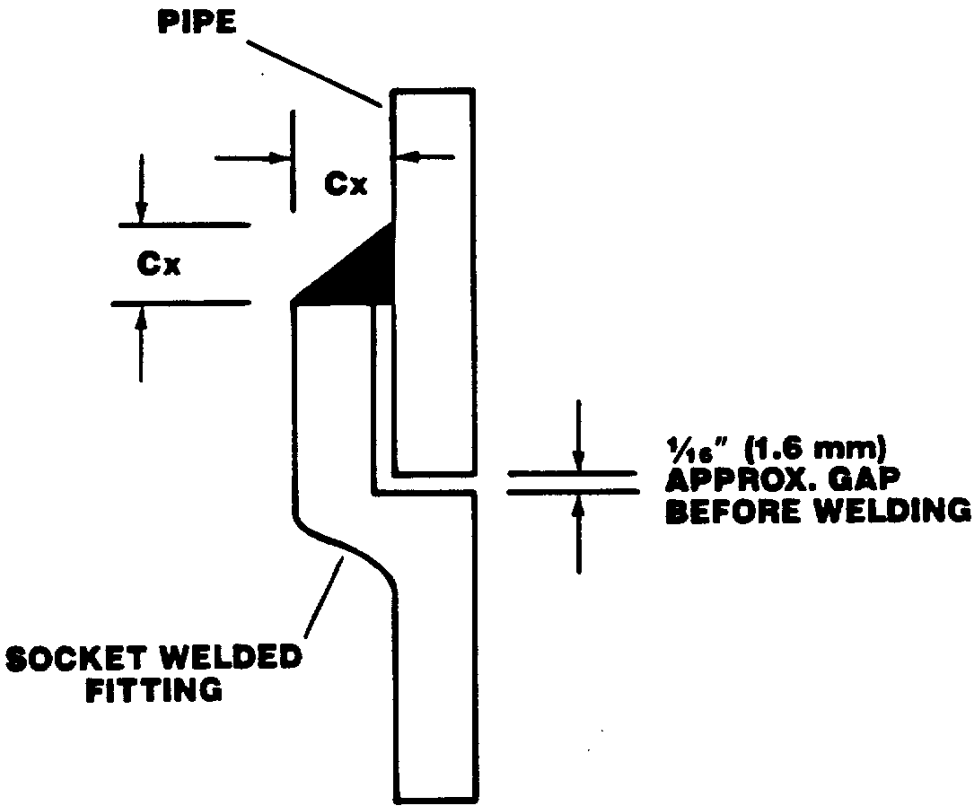


HYDRAULIC FLANGE UNION

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FIGURE 5-3
SOCKET WELDED JOINT



Cx (MIN.) 1¼ t BUT NOT LESS THAN ⅛" (3.2 mm)

MINIMUM WELDING DIMENSIONS FOR SOCKET WELDED COMPONENTS OTHER FLANGES

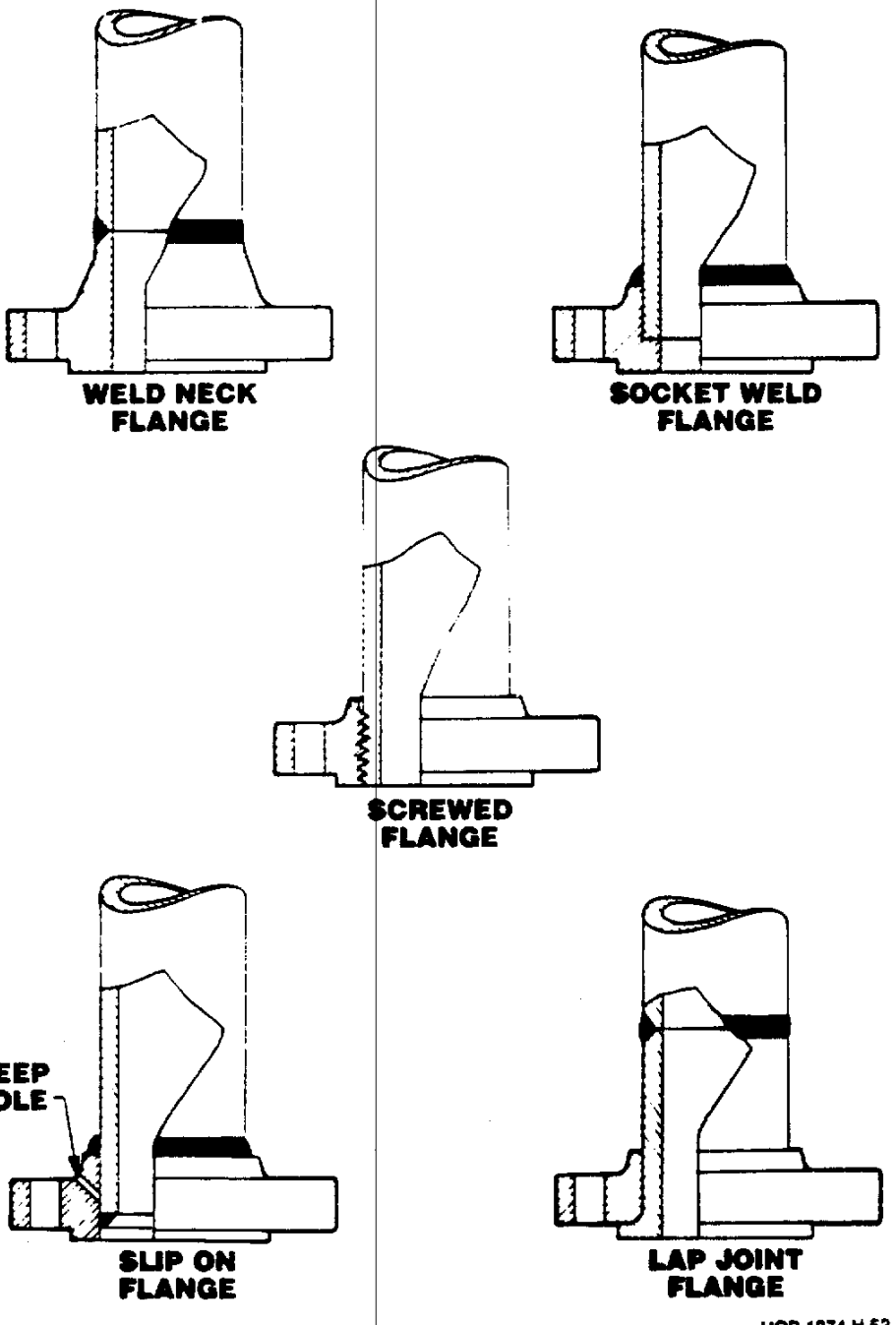
t = *THICKNESS*

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FIGURE 5-4

TYPES OF FLANGES



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Threaded pipe and fittings should be avoided in any service where crevice corrosion, severe erosion, or cyclic loading may occur. When threaded joints are designed to be seal welded, seal compound shall not be used. All exposed threads of seal welded joints are required to be seal welded and welding performed by qualified welders. Seal welds are used only to prevent leakage of the threaded joint. They are not considered as contributing any strength to the joint. Threaded joints containing sealing compound which leak during a pressure test may be seal welded provided all compound is cleaned from exposed threads. Stresses must be minimized on threaded joints with special attention to thermal expansion and operation of valves, particularly a valve at a free end.

SOCKET WELDED JOINTS

Socket dimensions must conform to ANSI B16.5 for flanges and ANSI B16.11 for other socket welded components. Socket welded joints should be avoided in any service where crevice corrosion, or severe erosion may occur. Socket welds larger than NPS 2 are not permitted to be used under severe cyclic conditions. When welding a socket joint a 1/16" (1.6 mm) gap is required between the male and female components of the socket joint. (See Figure 5-3.) This gap is required to permit thermal expansion when the line is in service. Failure to provide such a gap could result in excessive stress on the socket weld resulting in its failure (cracking).

BOLTED JOINTS

Flanges provide a means of joining or ending sections of pipe. They are so constructed that pieces of equipment may be installed or removed without a change in the piping. There are seven basic types of flanges; namely: welding neck, slip-on, lap joint, screwed, socket welded, orifice, and blind flanges. (See Figure 5-4, 5-11 and 5-12)

Welding neck flanges are distinguished from other types by their long tapered hub and gentle transition of thickness in the region of the butt weld joining them to the pipe. Flanges of this type are preferred for severe service conditions. Welding neck flanges are particularly recommended for handling explosive, flammable or costly liquids.

Slip-on flanges continue to be preferred to welding neck flanges by many users because of their lower initial cost and because of the reduced accuracy required in cutting the pipe to length. However, the final cost will be approximately the same as the welding neck type. Their calculated strength under internal pressure is about two-thirds that of the welding neck and their life under fatigue is about one-third that of the welding neck. Slipon flanges are limited to moderate services where major shocks or extreme pressure or temperature fluctuations are not present.

Screwed flanges, made of steel, are confined to special applications. Their chief merit lies in the fact that they can be assembled without welding. Screwed flanges are unsuited for conditions involving temperature or bending stresses of any magnitude, particularly under cyclic conditions where leakage through the threads may occur in relatively few cycles of heating or stress.

Socket weld flanges were initially developed for use on small size high pressure piping. Smooth, pocketless bore conditions can readily be attained. The internally welded socket type flange is becoming increasingly popular in chemical process piping where the internal weld is ground smooth.

The various methods of mating flanges are illustrated in Figure 5-6.

The raised face is the most common facing employed with steel flanges. It is 1/16" high for 150 lb. and 300 lb. flanges and 1/4" high for all other pressure classes. The facing is machine-tool finished with spiral or concentric grooves (approximately 1/64" deep on approximately 1/32" centers) to bite into and hold the gasket. Because both flanges of a pair are identical, no stocking or assembly problems are involved in its use. Raised face flanges generally are installed with flat ring composition gaskets which are equal in width to the raised face, but when flat metal gaskets are used, the gasket width should extend out to the bolt holes.

Lap joint flanges are primarily used with lap joint stub ends, the combined cost of the two items being approximately one-third higher than that of comparable welding neck flanges. One prime use of lap joint flanges in carbon or low alloy steel piping systems is in services necessitating frequent dismantling for inspection and cleaning. The chief use of lap joint flanges, however, is in corrosion resistant piping where a corrosion resistant material may be used for the stub end and a carbon steel flange used for the joint. This considerably reduces the cost of the joint since corrosion resistant materials are usually rather expensive.

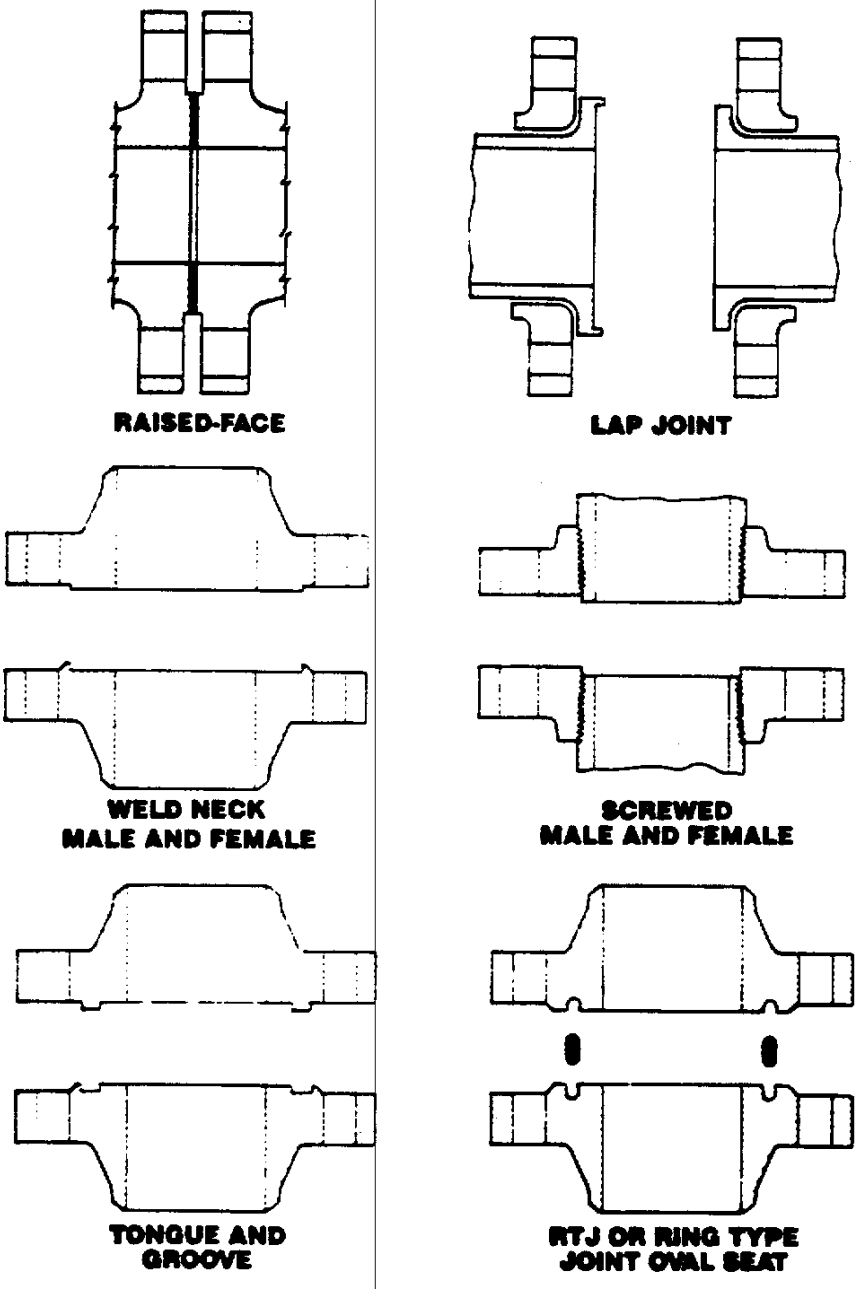
Male-and-female facings are standardized in both large and small types. The female face is 3/16" deep and the male face 1/4" high and both are usually smooth finished since the outer diameter of the female face acts to locate and retain the gasket. As can be seen, the width of the weld neck male and female gasket contact surface, like the raised face, is much greater than the screwed male and female gasket surface especially for screwed flanges assembled with standard weight pipe.

Tongue-and-Groove facings are also standardized in both large and small types. They differ from male-and-female in that the inside diameters of tongue-and-groove do not extend to the flange bore, thus retaining the gasket on both its inner and outer diameter. This removes the gasket from corrosive or erosive contact with the line fluid. The small tongue-and-groove construction provides a minimum area for the gasket, thus resulting in the minimum bolting load for compressing the gasket and the highest joint efficiency possible with flat gaskets.

Ring joint facing is the most expensive standard facing but also the most efficient, partly because the internal pressure acts on the ring to increase the sealing force. Both flanges of a pair are alike, thus reducing the stocking and assembling problem found with both male-and-female and tongue-and- groove joints. Because the surfaces the gasket contacts are below the flange face, the ring joint facing is least likely of all facings to be damaged in handling or erecting. The flat bottom groove is standard. Both the oval ring and the octagonal ring gasket may be used in this type of groove. Only the oval ring gasket may be used in the round bottom groove. Never use thread compound or other types of sealant with a ring joint gasket and flange. The ring joint and gasket must be perfectly clean, then wiped with a light oil. The seating surface must be metal to metal. Sealing compounds will flow out at high temperatures and whatever sealing effect they created could be lost and the joint leak. Strict attention must be paid to the code on each ring since this will describe the alloy metal of the ring. See the UOP Piping Specifications for the unit you are working on for the proper alloy to be used.

FIGURE 5-5A

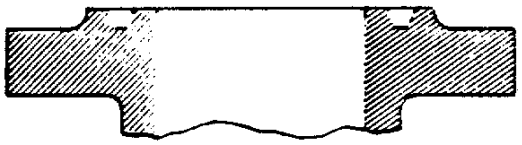
METHODS OF MATING FLANGES



uop

FIGURE 5-5B

OCTAGONAL RING JOINT FLANGE WITH OVAL AND OCTAGONAL RING JOINT GASKET



RING JOINT FLANGE



OCTAGONAL FLANGE SEAT



OVAL RING GASKET



OCTAGONAL RING GASKET

UOP 1374 H-54

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Flat Faces are a variant of raised faces, and are sometimes formed by machining off the 1/16" raised face of 150 lb. and 300 lb. flanges. Their chief use is for mating with 125 lb. and 250 lb. cast iron valves and fittings. A flat-face steel flange permits employing a gasket whose outer diameter equals that of the flange or is tangent to the bolt holes. In this manner, the danger of cracking the cast iron flange when the bolts are tightened is minimized.

Flange faces are required by Code to be aligned for bolting to the design plane to within 1/16 in./ft (0.5% maximum) measured across the diameter, and flange bolt holes are required to be aligned to within 1/8" (3.2 mm) maximum offset. Any damage to the gasket seating surface which would prevent sweating of the gasket must be repaired for the flange replaced. When bolting gasketed flanged joints the gasket is required to be uniformly compressed to the proper design loading. Bolts for bolted flange joints should extend completely through their nuts. Bolts that fail to do so are acceptable by Code provided the lack of complete thread engagement is not more than one thread.

GASKETS

With the exception of pipe joined to fittings by welds, threads or screwed unions, most joints will be flanged and the mating of the two flanges will be sealed by a gasket to prevent leakage. Gaskets are made from many materials such as asbestos, rubber, plastics, and almost all of the metals and the alloys of metals. On cast iron flanges, 125 and 250 pound rated, the flange bolt will go through the gasket. This is to prevent cracking the brittle cast iron flange. This type of flange is used in water and some steam services. The remaining flanges from 150 pounds and up will use a gasket centered inside the flange bolts, but never protruding over the inside pipe diameter. The material used to form the gasket will determine in what service the gasket may be used. Composition gaskets made of asbestos, bound with various materials such as paper, rubber, plastics, etc., are not used with temperatures exceed 260 C, or for hydrocarbon service or where process fluids may dissolve blinders.

Metal gaskets consisting of two layers of metal with a layer of asbestos between them are commonly used. The face of the metal sections of the gasket can be smooth or corrugated. Another type of gasket that can be used in almost all services is the spiral wound gasket. This is a spiral of metal held together by an inner and outer retainer ring.

Asbestos or teflon is contained between each spiral to further aid in forming the seal between gaskets. The ring joint gasket will prevent leakage of process fluid under the most severe conditions and is used extensively in high pressure hydrogen service where high temperature is also present. This type of gasket can only be used with flanges designed for it.

All gaskets must be properly installed and all flanges must be diametrically tightened so that the gasket which is softer than the flanges will compress evenly.

TYPES OF WELDED FITTINGS

While pipe is used to contain and direct the flow of fluids from one vessel to another in somewhat of a straight line, varied fittings are used to change the direction of the flow of fluids. Some of the more common fittings are listed below and illustrated in Figure 5-9. For process piping, carbon steel or alloy forgings are used.

Long Radius Elbow is used to change the direction of flow gradually, 90 degrees.

Short radius elbow is used to change the direction of flow rapidly, 90 .

45 elbow is used to change the direction of flow only 45 .

Tee is used to offer a branch flow off the main flow. Dependent on valve arrangements.

Cross is used to offer more than one branch flow from the main flow depending on valve arrangements.

45 lateral is used to offer a branch flow off the main flow, depending on valve arrangement. This fitting is generally fabricated in the field.

Return bends are used to change the direction of flow 180 degrees. Generally, these will be used in heater and boiler fire boxes.

FIGURE 5-6
GASKETS

METAL CLAD AND SINGLE CORRUGATED METAL SHEET GASKETS FOR RAISED FACE FLANGES

PIPE SIZE	FLANGE RATING	150#	300#	400#	600#	900#	1500#	2500#	PIPE SIZE
	I.D.	O.D.	O.D.	O.D.	O.D.	O.D.	O.D.	O.D.	
1/2	1	1-7/8	2-1/8	2-1/8	2-1/8	2-1/2	2-1/2	2-3/4	1/2
3/4	1-5/16	2-1/4	2-5/8	2-5/8	2-5/8	2-3/4	2-3/4	3	3/4
1	1-1/2	2-5/8	2-7/8	2-7/8	2-7/8	3-1/8	3-1/8	3-3/8	1
1-1/4	1-7/8	3	3-1/4	3-1/4	3-1/4	3-1/2	3-1/2	4-1/8	1-1/4
1-1/2	2-1/8	3-3/8	3-3/4	3-3/4	3-3/4	3-7/8	3-7/8	4-5/8	1-1/2
2	2-7/8	4-1/8	4-3/8	4-3/8	4-3/8	5-5/8	5-5/8	5-3/4	2
2-1/2	3-3/8	4-7/8	5-1/8	5-1/8	5-1/8	6-1/2	6-1/2	6-5/8	2-1/2
3	4-1/4	5-3/8	5-7/8	5-7/8	5-7/8	6-5/8	6-7/8	7-3/4	3
3 1/2	4-3/4	6-3/8	6-1/2	6-3/8	6-3/8				3-1/2
4	5-3/16	6-7/8	7-1/8	7	7-5/8	8-1/8	8-1/4	9-1/4	4
5	6-5/16	7-3/4	8-1/2	8-3/8	9-1/2	9-3/4	10	11	5
6	7-1/2	8-3/4	9-7/8	9-3/4	10-1/2	11-3/8	11-1/8	12-1/2	6
8	9-3/8	11	12-1/8	12	12-5/8	14-1/8	13-7/8	15-1/4	8
10	11-1/4	13-3/8	14-1/4	14-1/8	15-3/4	17-1/8	17-1/8	18-3/4	10
12	13-1/2	16-1/8	16-5/8	16-1/2	18	19-5/8	20-1/2	21-5/8	12
14	14-3/4	17-3/4	19-1/8	19	19-3/8	20-1/2	22-3/4		14
16	16-3/4	20-1/4	21-1/4	21-1/8	22-1/4	22-5/8	25-1/4		16
18	19-1/4	21-5/8	23-1/2	23-3/8	24-1/8	25-1/8	27-3/4		18
20	21	23-7/8	25-3/4	25-1/2	26-7/8	27-1/2	29-3/4		20
24	25-1/4	28-1/4	30-1/2	30-1/4	31-1/8	33	35-1/2		24

RING NUMBERS FOR RING JOINT FLANGES

PIPE SIZE	1/2	3/4	1	1-1/4	1-1/2	2	2-1/2	3	3-1/2	4	5	6	8	10	12	14	16	18	20	24
150#	-	-	R15	R17	R19	R22	R25	R29	R33	R36	R40	R43	R48	R52	R56	R59	R64	R68	R72	R76
300# 400# 600#	R11	R13	R16	R18	R20	R23	R26	R31*	R34	R37	R41	R45	R49	R53	R57	R61	R65	R69	R73	R77
900#	R12	R14	R16	R18	R20	R24	R27	R31	-	R37	R41	R45	R49	R53	R57	R62	R66	R70	R74	R78
1500#	R12	R14	R16	R18	R20	R24	R27	R35	-	R39	R44	R46	R50	R54	R58	R63	R67	R71	R75	R79
2500#	R13	R16	R18	R21	R23	R26	R28	R32	-	R38	R42	R47	R51	R55	R60	-	-	-	-	-

NOTES

1. ALL DIMENSIONS ARE IN INCHES.
2. METAL CLAD AND SHEET GASKET DIMENSIONS ARE IN ACCORDANCE WITH A.S.A. B16.5 APPENDIX E FIGURE 7
* THE RING NUMBER FOR 3" SIZE LAPPED FLANGE IS R30.

FIGURE 5-7
GASKETS

NONMETAL GASKETS FOR PIPE FLANGES

PIPE SIZE	125#C.I./150#F.S. FULL FACE		150#F.S. R.F.		250#C.I. R.F.		300#F.S. R.F.	
	I.D.	O.D.	I.D.	O.D.	I.D.	O.D.	I.D.	O.D.
1/2			27/32	1-7/8			27/32	2-1/8
3/4			1-1/16	2-1/4			1-1/16	2-5/8
1	1-5/16	4-1/4	1-5/16	2-5/8	1-5/16	2-7/8	1-5/16	2-7/8
1-1/4	1-21/32	4-5/8	1-21/32	3	1-21/32	3-1/4	1-21/32	3-1/4
1-1/2	1-29/32	5	1-29/32	3-3/8	1-29/32	3-3/4	1-29/32	3-3/4
2	2-3/8	6	2-3/8	4-1/8	2-3/8	4-3/8	2-3/8	4-3/8
2-1/2	2-7/8	7	2-7/8	4-7/8	2-7/8	5-1/8	2-7/8	5-1/8
3	3-1/2	7-1/2	3-1/2	5-3/8	3-1/2	5-7/8	3-1/2	5-7/8
3-1/2	4	8-1/2	4	6-3/8	4	6-1/2	4	6-1/2
4	4-1/2	9	4-1/2	6-7/8	4-1/2	7-1/8	4-1/2	7-1/8
5	5-9/16	10	5-9/16	7-3/4	5-9/16	8-1/2	5-9/16	8-1/2
6	6-5/8	11	6-5/8	8-3/4	6-5/8	9-7/8	6-5/8	9-7/8
8	8-5/8	13-1/2	8-5/8	11	8-5/8	12-1/8	8-5/8	12-1/8
10	10-3/4	16	10-3/4	13-3/8	10-3/4	14-1/4	10-3/4	14-1/4
12	12-3/4	19	12-3/4	16-1/8	12-3/4	16-5/8	12-3/4	16-5/8
14	14	21	14	17-3/4	14	19-1/8	14	19-1/8
16	16	23-1/2	16	20-1/4	16	21-1/4	16	21-1/4
18	18	25	18	21-5/8	18	23-1/2	18	23-1/2
20	20	27-1/2	20	23-7/8	20	25-3/4	20	25-3/4
24	24	32	24	28-1/4	24	30-1/2	24	30-1/2
30	30	38-3/4			30	37-1/2		
36	36	46			36	44		
42	42	53			42	50-3/4		
48	48	59-1/2			48	58-3/4		

NOTES
1. ALL DIMENSIONS ARE IN INCHES.
2. GASKET SIZES ARE IN ACCORDANCE WITH A.S.A B16.21.

FIGURE 5-8
BOLTS

STUD BOLTS FOR RING JOINT FLANGES

PIPE SIZE	150#		300#		400#		600#	
	No.	SIZE	No.	SIZE	No.	SIZE	No.	SIZE
1/2			4	1/2 x 3	4	1/2 x 3	4	1/2 x 3
3/4			4	5/8 x 3-1/2	4	5/8 x 3-1/2	4	5/8 x 3-1/2
1	4	1/2 x 3	4	5/8 x 3-1/2	4	5/8 x 3-1/2	4	5/8 x 3-1/2
1-1/4	4	1/2 x 3-1/2	4	5/8 x 4	4	5/8 x 4	4	5/8 x 4
1-1/2	4	1/2 x 3-1/2	4	3/4 x 4	4	3/4 x 4-1/2	4	3/4 x 4-1/2
2	4	5/8 x 4	8	5/8 x 4-1/2	8	5/8 x 4-1/2	8	5/8 x 4-1/2
2-1/2	4	5/8 x 4	8	3/4 x 5	8	3/4 x 5	8	3/4 x 5
3	4	5/8 x 4	8	3/4 x 5	8	3/4 x 5	8	3/4 x 5
3-1/2	8	5/8 x 4	8	3/4 x 5	8	7/8 x 5-1/2	8	7/8 x 5-1/2
4	8	5/8 x 4	8	3/4 x 5-1/2	8	7/8 x 6	8	7/8 x 6
5	8	3/4 x 4-1/2	8	3/4 x 5-1/2	8	7/8 x 6	8	1 x 6-1/2
6	8	3/4 x 4-1/2	12	3/4 x 5-1/2	12	7/8 x 6-1/2	12	1 x 7
8	8	3/4 x 5	12	7/8 x 6-1/2	12	1 x 7	12	1-1/8 x 8
10	12	7/8 x 5	16	1 x 7	16	1-1/8 x 8	16	1-1/4 x 8-1/2
12	12	7/8 x 5	16	1-1/8 x 7-1/2	16	1-1/4 x 8	20	1-1/4 x 9
14	12	1 x 6	20	1-1/8 x 8	20	1-1/4 x 8-1/2	20	1-3/8 x 9-1/2
16	16	1 x 6	20	1-1/4 x 8	20	1-3/8 x 9	20	1-1/2 x 10
18	16	1-1/8 x 6-1/2	24	1-1/4 x 8-1/2	24	1-3/8 x 9	20	1-5/8 x 11
20	20	1-1/8 x 6-1/2	24	1-1/4 x 9	24	1-1/2 x 10	20	1-5/8 x 11-1/2
24	20	1-1/4 x 7	24	1-1/2 x 10	24	1-3/4 x 11	24	1-7/8 x 13

PIPE SIZE	900#		1500#		2500#	
	No	SIZE	No	SIZE	No	SIZE
1/2	4	3/4 x 4-1/2	4	3/4 x 4-1/2	4	3/4 x 5
3/4	4	3/4 x 4-1/2	4	3/4 x 4-1/2	4	3/4 x 5
1	4	7/8 x 5	4	7/8 x 5	4	7/8 x 5-1/2
1-1/4	4	7/8 x 5	4	7/8 x 5	4	1 x 6
1-1/2	4	1 x 5-1/2	4	1 x 5-1/2	4	1-1/8 x 7
2	8	7/8 x 6	8	7/8 x 6	8	1 x 7
2-1/2	8	1 x 6-1/2	8	1 x 6-1/2	8	1-1/8 x 8
3	8	7/8 x 6	8	1-1/8 x 7	8	1-1/4 x 9
3-1/2						
4	8	1-1/8 x 7	8	1-1/4 x 8	8	1-1/2 x 10-1/2
5	8	1-1/4 x 7-1/2	8	1-1/2 x 10	8	1-3/4 x 12-1/2
6	12	1-1/8 x 8	12	1-3/8 x 10-1/2	8	2 x 14
8	12	1-3/8 x 9	12	1-5/8 x 12	12	2 x 15-1/2
10	16	1-3/8 x 9-1/2	12	1-7/8 x 13-1/2	12	2-1/2 x 20
12	20	1-3/8 x 10	16	2 x 15-1/2	12	2-3/4 x 22
14	20	1-1/2 x 11	16	2-1/4 x 17		
16	20	1-5/8 x 11-1/2	16	2-1/2 x 18-1/2		
18	20	1-7/8 x 13-1/2	16	2-3/4 x 20-1/2		
20	20	2 x 14	16	3 x 22		
24	20	2-1/2 x 18	16	3-1/2 x 25-1/2		

NOTES

1. ALL DIMENSIONS ARE IN INCHES

BOLT LENGTH GIVEN ABOVE

uop

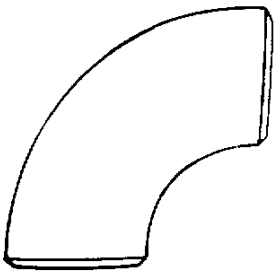
Reducing fittings are illustrated in Figures 5-10 and 5-11. A reduced fitting is one that has a larger sized opening at one end than it has at the opposite end. When specifying reducing fittings, the largest run opening is given first, followed by the smallest run opening. The sizes of the branch opening are then given with the largest first. For example, a 4" x 3" x 2" cross indicates that the run reduces from 4" to 3" and the branch opening is 2". Likewise, a 4" x 4" x 3" tee indicates a straight run of 4" and a branch outlet of 3".

Blind flanges (see Figure 5-11) are used to blank off ends of piping, valves and pressure vessel openings. From the standpoint of internal pressure and bolt loading, blind flanges, particularly in the large sizes, are the most highly stressed of all ASA flange types. However, in comparison with other companion flanges, they are favored by the fact that they are not required to withstand line strains caused by the piping system. Where severe water hammer may be involved, consideration should be given to closures made of weld caps (see Figure 5-11).

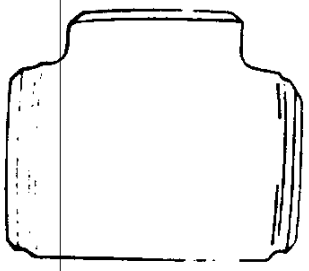
Orifice flanges (see Figure 5-12) are widely used in conjunction with orifice meters for measuring the rate of flow of liquids and gases. They are basically the same as the standard welding neck except for the provision of radial, tapped holes in the flange ring for meter connections and additional bolts to act as jack screws to facilitate the separation of flanges for inspection or replacement of the orifice plate.

FIGURE 5-9

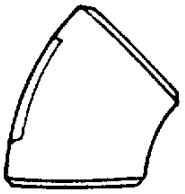
ELLS, TEES, CROSSES, AND 45° LATERALS



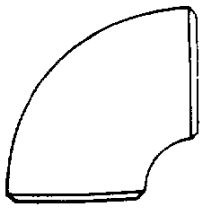
LONG RADIUS ELL



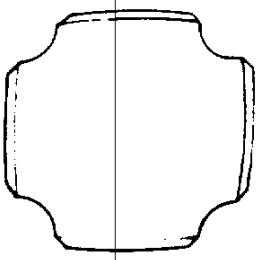
WELD TEE



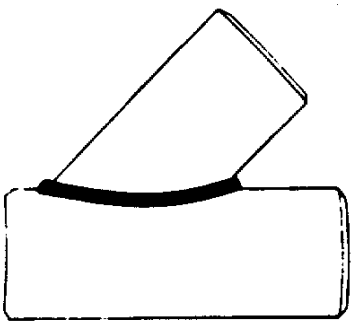
45° ELL



SHORT RADIUS ELL

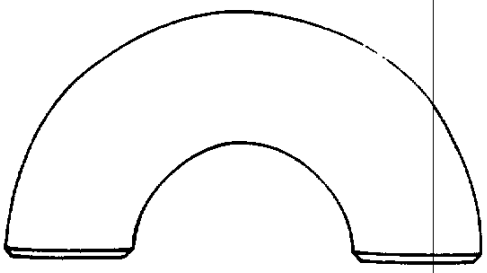


WELD CROSS

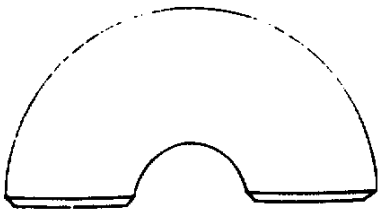


45° LATERAL

RETURN BENDS



LONG RADIUS RETURN BEND



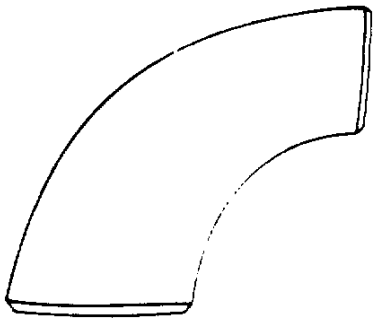
SHORT RADIUS RETURN BEND

UOP 1374 H-55

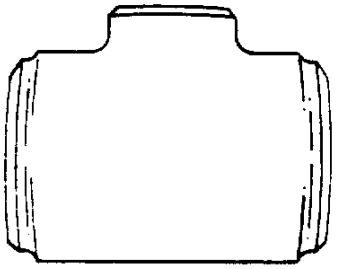
uop

FIGURE 5-10

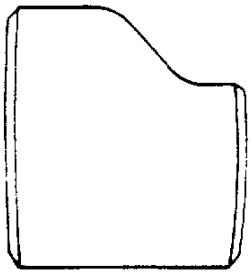
REDUCING FITTINGS



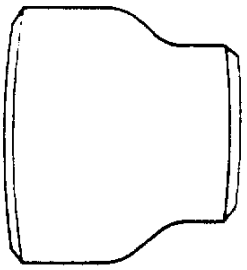
LONG RADIUS
REDUCING ELL



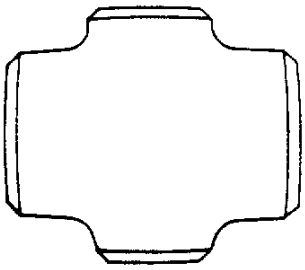
WELD REDUCING TEE



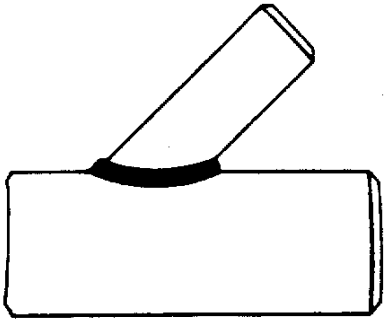
ECCENTRIC REDUCING
FITTING



CONCENTRIC REDUCING
FITTING



WELD CROSS WITH
REDUCING BRANCHES



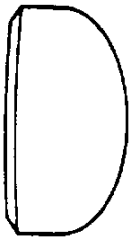
REDUCING 45° LATERAL

UOP 1374 H-56

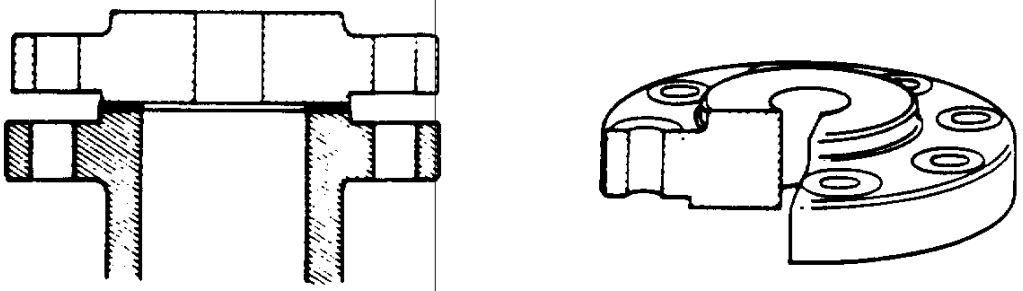
uop

FIGURE 5-11

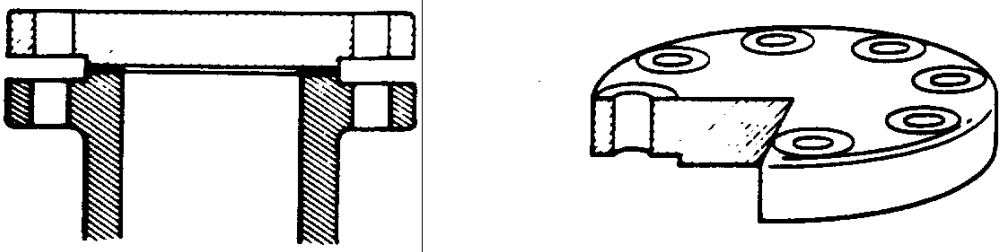
SPECIAL FITTINGS



WELD CAP



REDUCING FLANGE



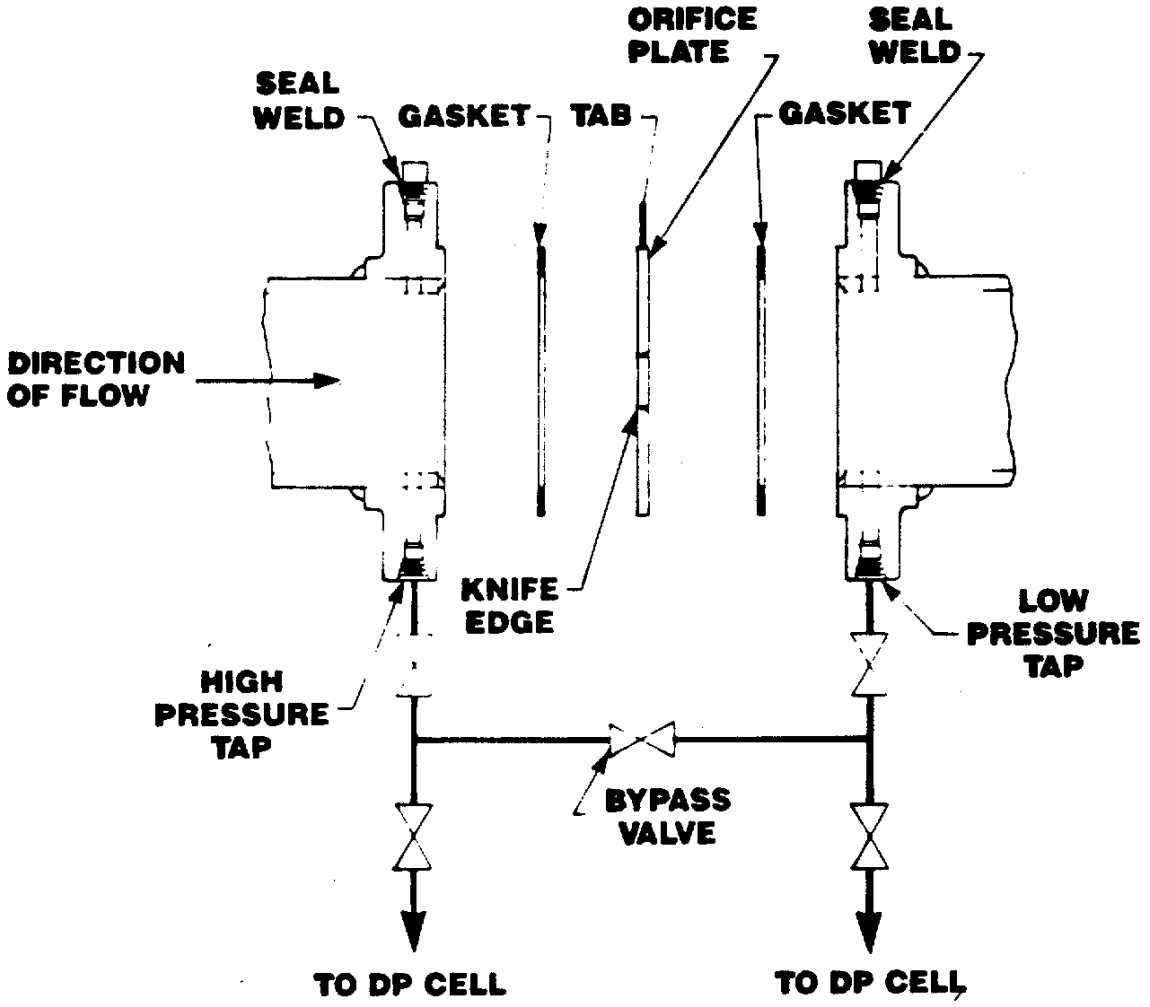
BLIND FLANGE

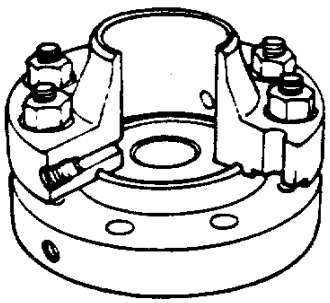
UOP 1374 H-57

uop

FIGURE 5-12

ORIFICE FLANGE MANIFOLD





UOP 132F-15
UOP 1374 H-58

uop

WELDED JOINTS

Prior to welding ends of pipe together or welding fittings to pipe, the butt welded ends must be prepared for welding. For piping within the scope of B31.3 butt welding end preparation contained in ANSI B16.25 or any other end preparation which meets the procedure qualification is acceptable. Figure 5-13 illustrates typical but weld end preparations.

WELDING PIPE JOINTS

B31.3 welded joints are required to be welded by qualified welders with all welding done in accordance with a qualified welding procedure specification (WPS). Filler metal must conform to the requirements of the ASME Code, Section IX. Filler metal not yet contained in Section IX may be used with the owner's approval if a procedure qualification test is first successfully made. Pipes are joined together by welding the ends together. Welded joints are required to be welded by qualified welders and all welding done in accordance with a qualified welding procedure specification (WPS), including any repair welds.

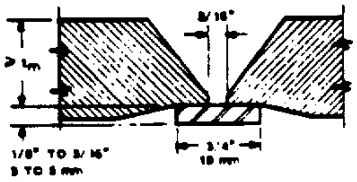
Consumable inserts or backing rings, if specified in the WPS, may be used in assisting the welder making a pipe weld. Consumable inserts are preplaced filler metal in the root opening of the weld joint which are completely fused during welding and becomes a part of the weld. Various types of consumable inserts are illustrated in Figure 5-13.

A backing ring is a material in the form of a ring used to support the molten weld metal during welding. Commonly used types are shown in Figure 5-13. If backing rings are used to weld pipe joints where inservice crevice corrosion, vibration or severe cyclic conditions exist they must be removed after welding and the internal joint ground smooth. In cases where the ring can not be removed, welds can be made without a backing ring or with a consumable insert. Backing rings may be of the continuous machined or split band type.

Preheating and post weld heat treatment (PWHT) of pipe welds may be required by Code and should be specified in the WPS. In some cases PWHT may be required by service and not by Code. Preheating and heat treatment of welds are a means used to avert or relieve the detrimental effects of the high temperatures and severe thermal gradients inherent during welding. Heat treatment is also used to relieve residual stresses created during bending or forming of pipe. B31.3 gives requirements for both preheating and heat treatment of weldments as do other codes.

FIGURE 5-13

TYPICAL PIPE BUTTWELDED JOINTS



(A)
* BUTT JOINT WITH BORED PIPE ENDS AND SOLID OR SPLIT BACKING RING

(B)
* BUTT JOINT WITH TAPER-BORED ENDS AND SOLID BACKING RING

*REFER TO ANSI B16.25 FOR DETAILED DIMENSIONAL INFORMATION ON PIPE BORE

(C)
NONMETALLIC REMOVABLE BACKING RING (REFRACTORY)

(D) SQUARE RING OR ROUND WIRE TYPE

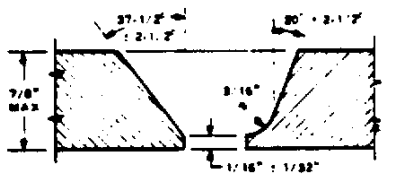
(E) FLAT RECTANGULAR RING

(F) FORMED RING TYPE

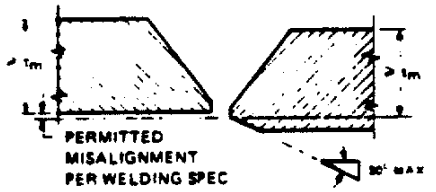
(G) Y - TYPE

TYPICAL CONSUMABLE INSERTS

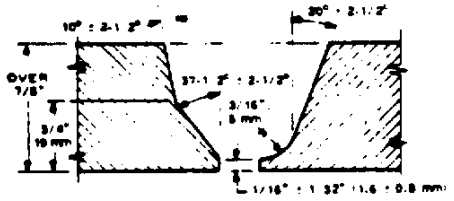
TYPICAL BACKING RINGS AND CONSUMABLE INSERTS



(A) WALL THICKNESS 3/16" - 7/8" INCL (5-22 mm)

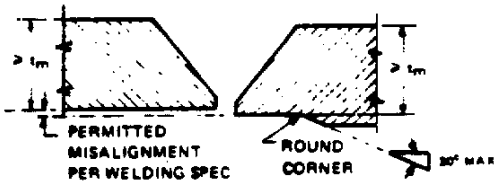


(A) THICKER PIPE TAPER-BORED TO ALIGN



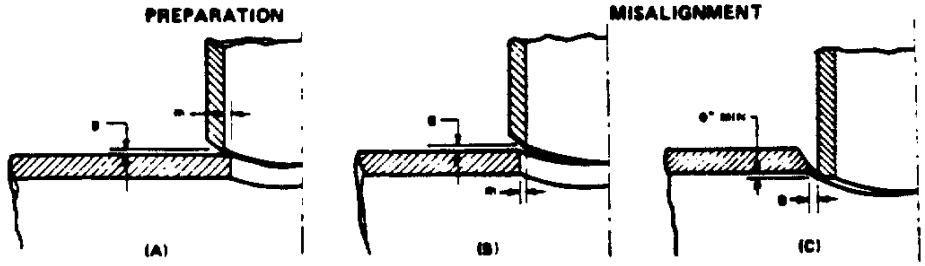
(B) WALL THICKNESS OVER 7/8"

TYPICAL BUTTWELD END PREPARATION



(B) THICKER PIPE BORED FOR ALIGNMENT

TRIMMING AND PERMITTED MISALIGNMENT



g = ROOT GAP, PER WELDING SPECIFICATION

m = THE LESSER OF 1/8 in. (3.2 mm) OR 0.5 T_b

PREPARATION FOR BRANCH CONNECTIONS

PIPE SUPPORTS

In general, pipe is never supported rigidly. An exception to this would be pipe that is subject to vibration and is never subjected to changes in temperature other than outside air temperature. The following are some of the methods used to support pipe and still permit the pipe to move (see Figure 5-14).

THE PIPE SHOE

This is used in conjunction with the pipe rack. It is T-shaped, and the "T" is inverted. The horizontal part of the "T" rests on the pipe rack. The vertical end of the "T" is tack welded to the pipe. As the pipe expands, the horizontal section of the "T" slides on the pipe rack but still supports the pipe. In some cases, due to excessive expansion or improper design, the pipe shoe will slide off the pipe rack. Notify your supervisor at once so that the pipe shoe can be repositioned or lengthened. In any case, the pipe can be temporarily supported.

GROUND SUPPORT

Pipe manifolds to control valves or pumps are often run to within a few feet of the ground. A pipe is welded to the elbows of the manifold. A shoe is welded to the opposite end of the pipe and rests on the ground. The shoe is able to slide on the ground allowing the manifold to move with expansion but still support the weight of the manifold.

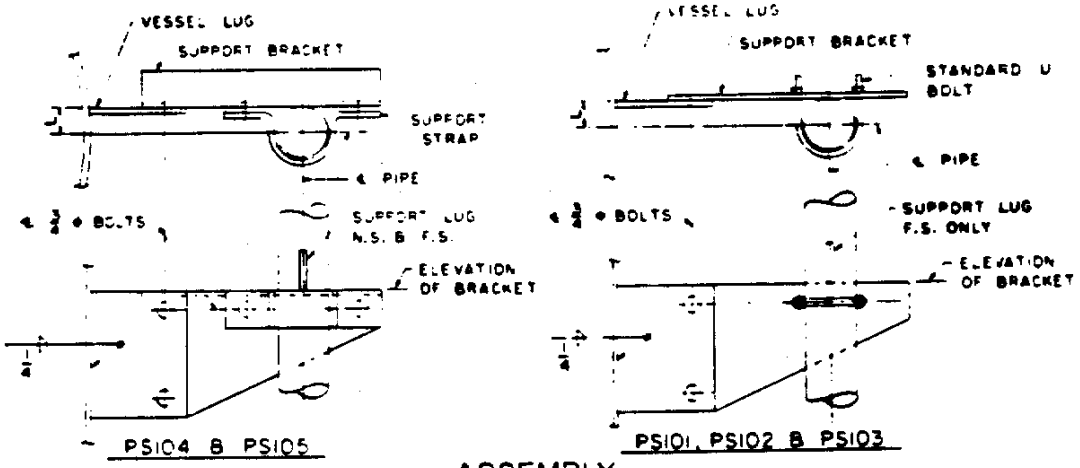
"U" BOLTS

The "U" bolt pipe support is used in a loosened condition to guide pipe but still permit it to slide. however, when the "U" bolt is tightened, it will hold a pipe rigid and in some cases, this is desirable. Generally, common sense will dictate whether a pipe is subject to some form of growth, caused by the temperature rise in the pipe or the vessel it connects with, and enable you to decide what is right or wrong. When in doubt, report the situation to your supervisor.

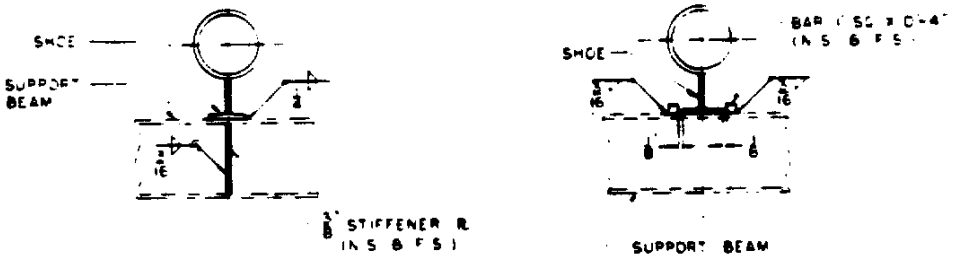
FIGURE 5-14

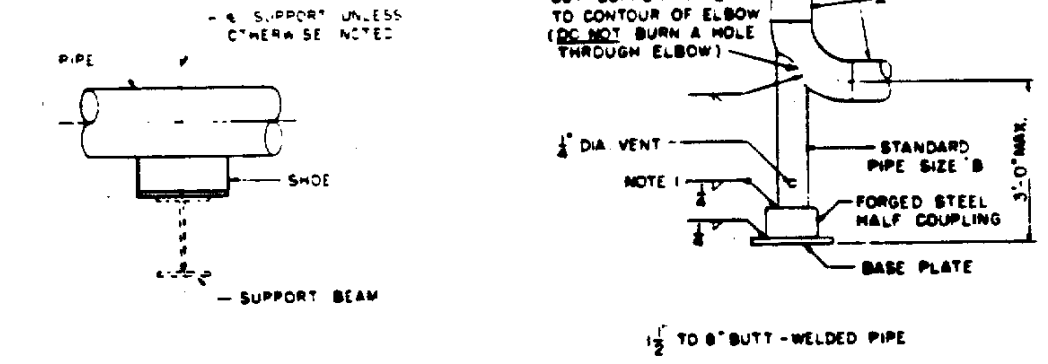
PIPE SUPPORTS

NOTE 1 ALL BOLTS SHALL CONFORM TO ASTM SPEC A307 OR ASTM SPEC A325



ASSEMBLY





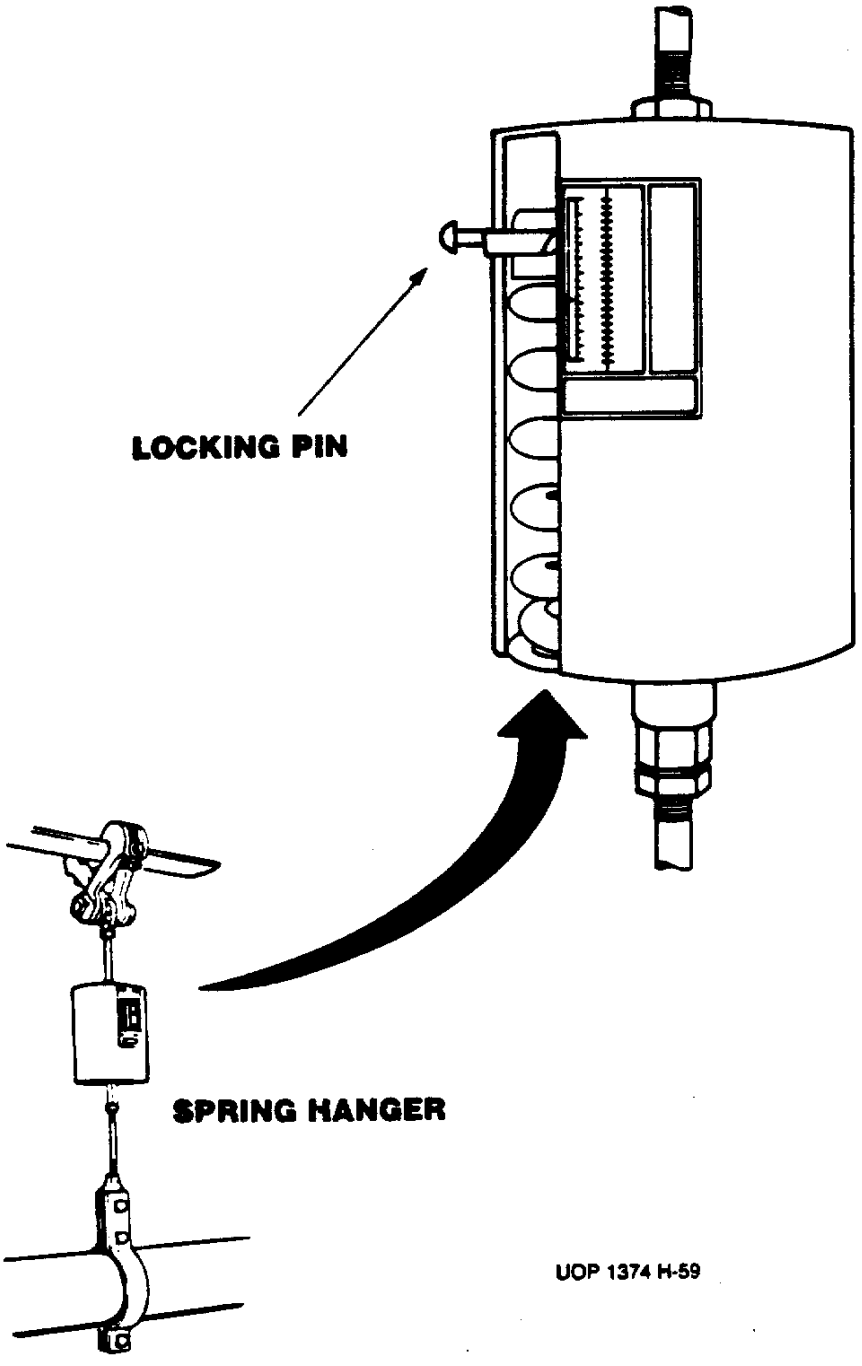
THE SPRING HANGER

The spring hanger (see Figure 5-15) is used to support pipe that may change position due to expansion or contraction of the pipe or vessels that the pipe is fastened to when the temperature of the process fluids are changed. If the pipe were rigidly supported, the great force created by the expansion of the pipes and vessels would tear away the rigid support or cause the pipe to bend or separate pipe and vessel flange joints allowing the process fluids to escape to the atmosphere. This condition would necessitate a shutdown of the process unit involved. The spring in the spring hanger will support the pipe in a way that will allow the pipe to move up and down, while the rod connecting the spring to the pipe will allow the pipe to move backwards and forwards because the rod is on a pivot.

A spring hanger is shipped from the factory and is installed with a locking pin. The pin is removed after installation and hydrotesting of the pipe has been completed. A spring hanger that is designed to support a pipe containing process vapor should never be filled with a liquid without the locking pin being replaced. The additional weight of liquid may damage or change the adjustment of the spring hanger. For a view of a spring hanger showing the locking pin, see Figure 5-15.

FIGURE 5-15

PIPE SPRING HANGER

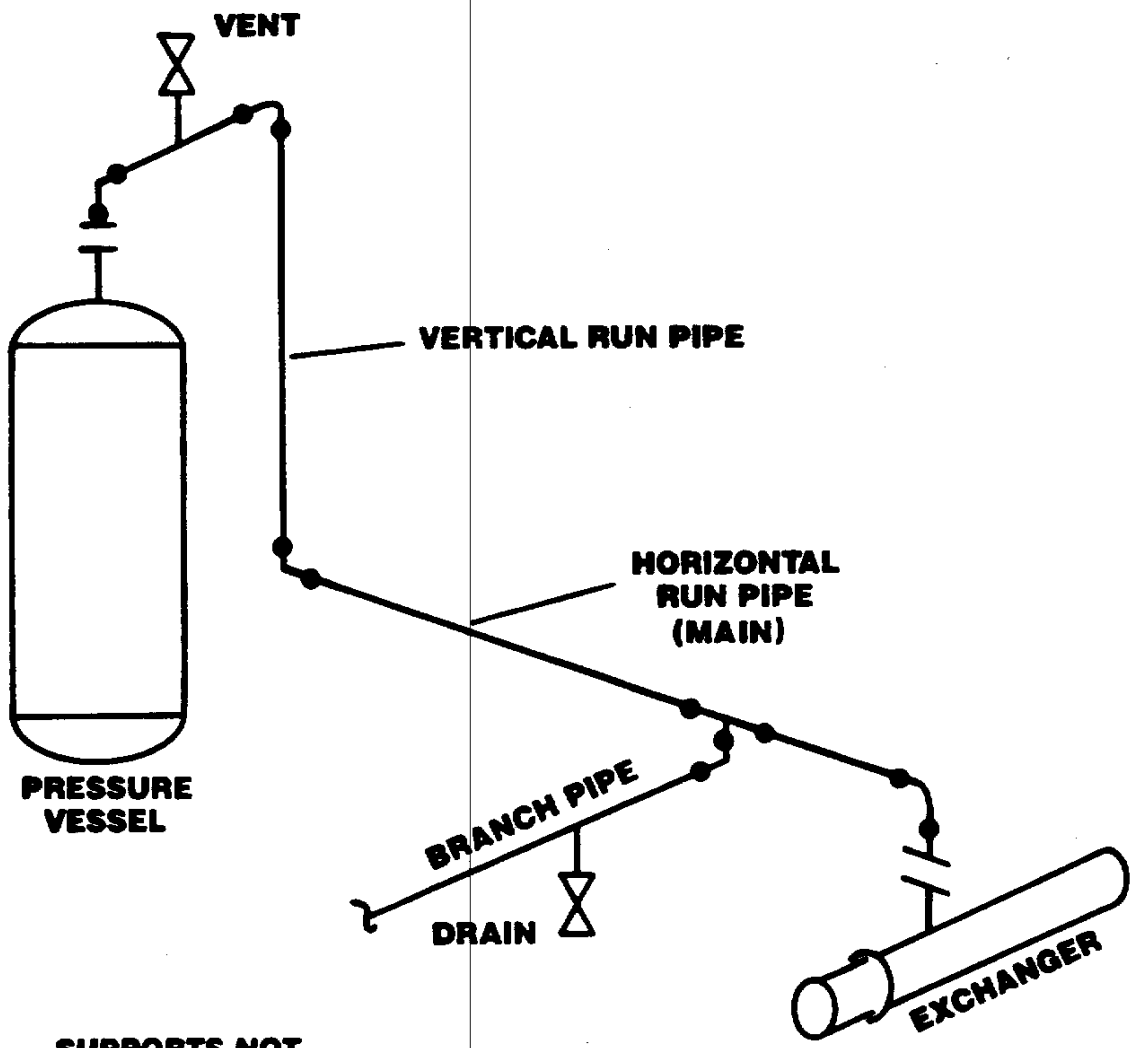


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uop

FIGURE 5-16

PROCESS LINE

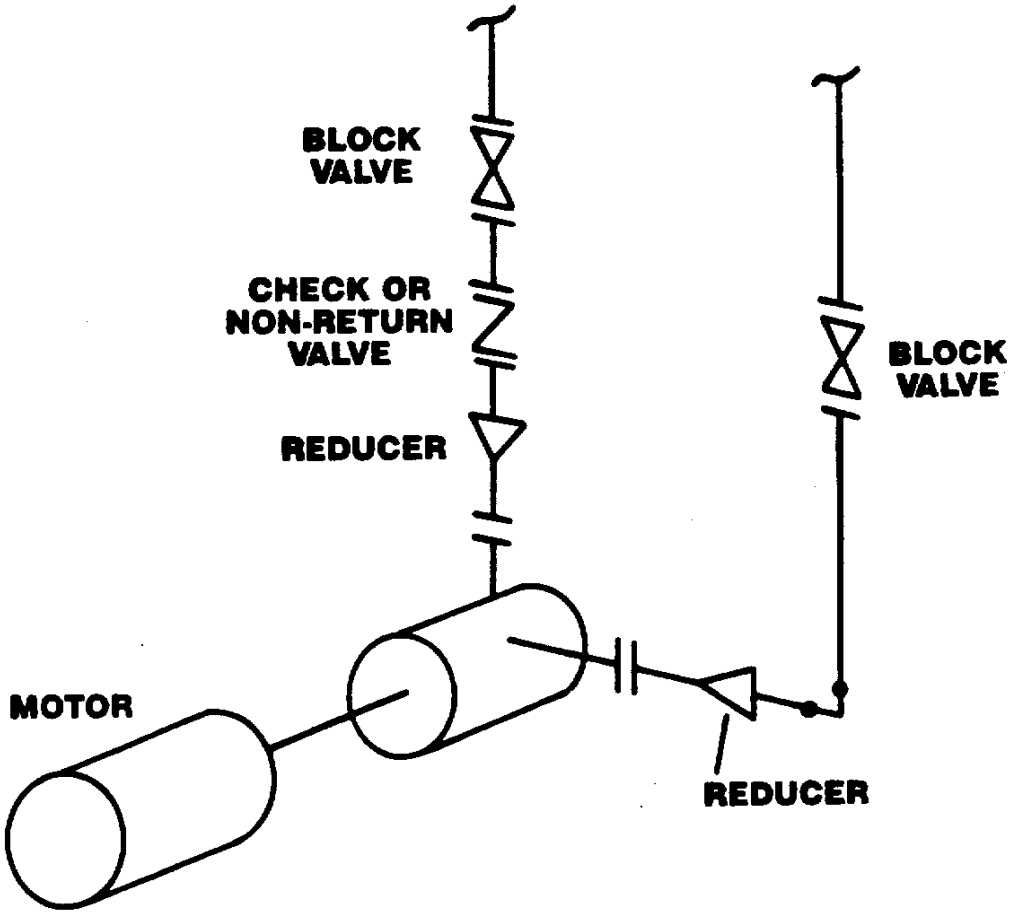


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uop

FIGURE 5-17

TYPICAL PUMP ARRANGEMENT

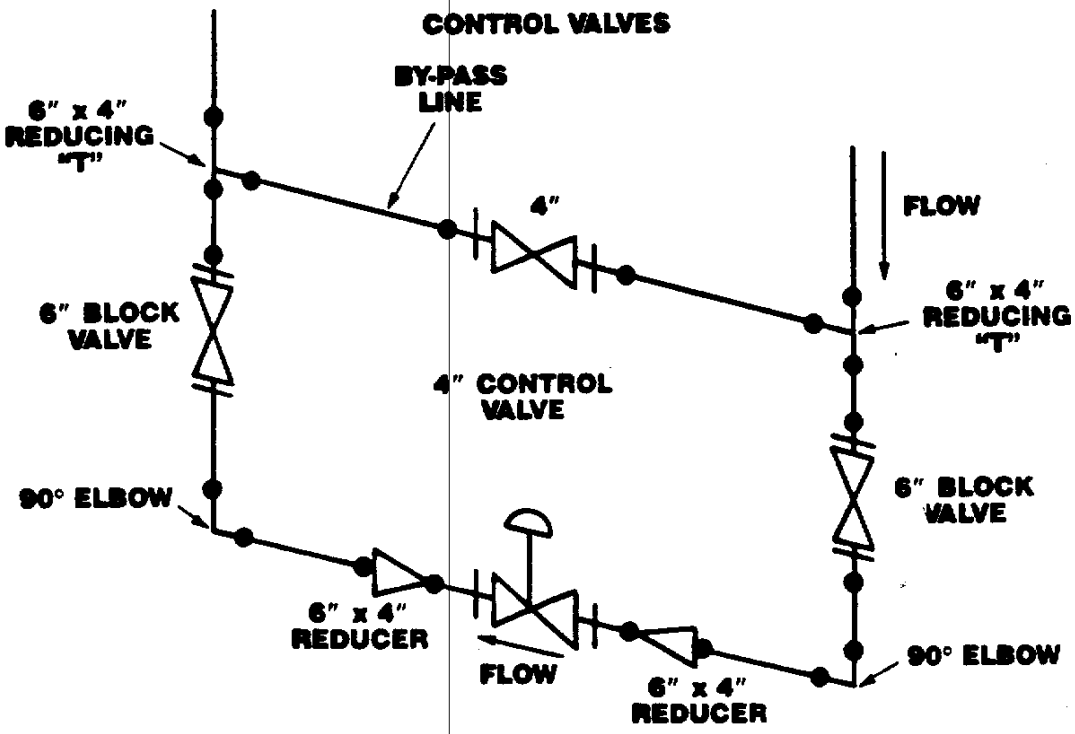


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uop

FIGURE 5-19

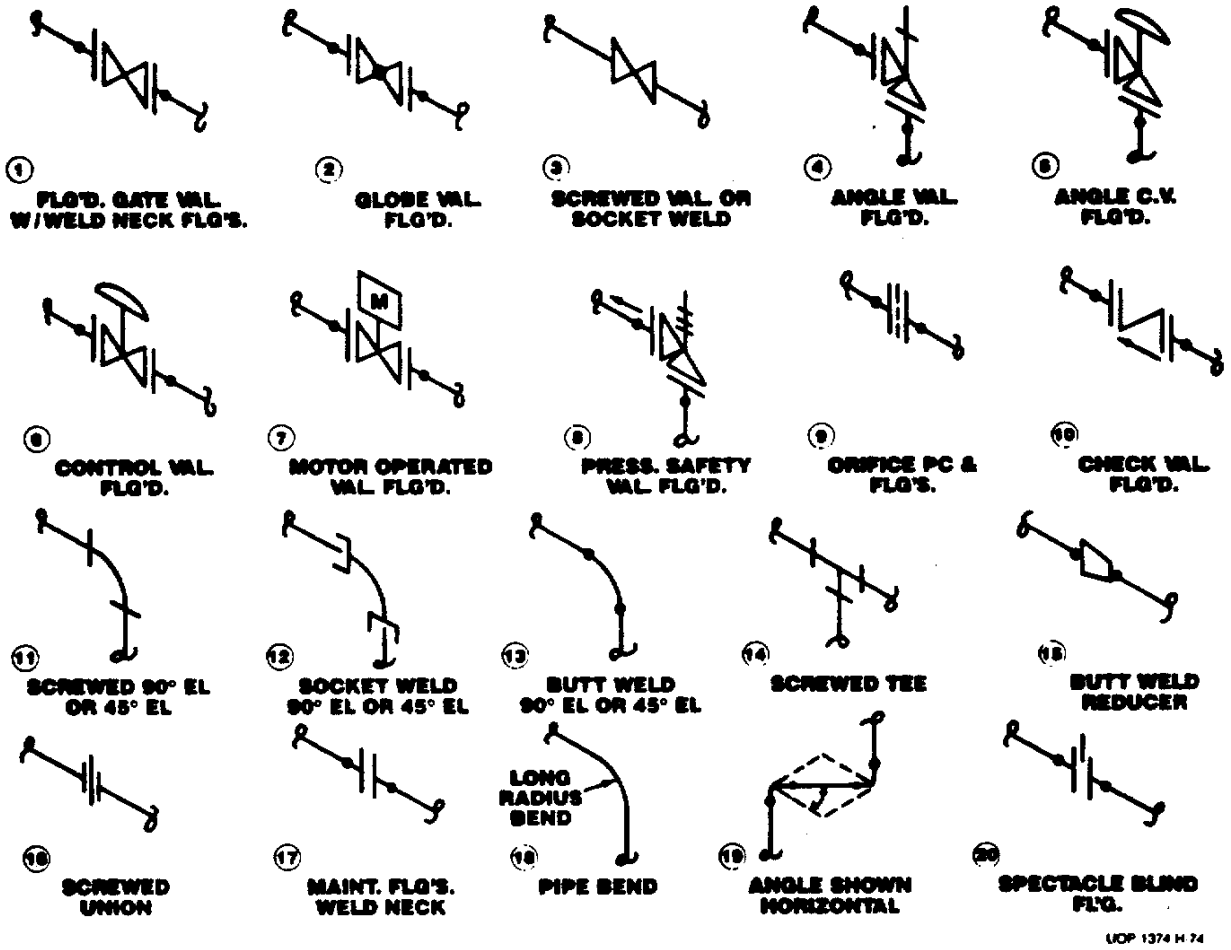
TYPICAL CONTROL VALVE STATION



uop

FIGURE 5-20A

ISOMETRIC PIPING SYMBOLS

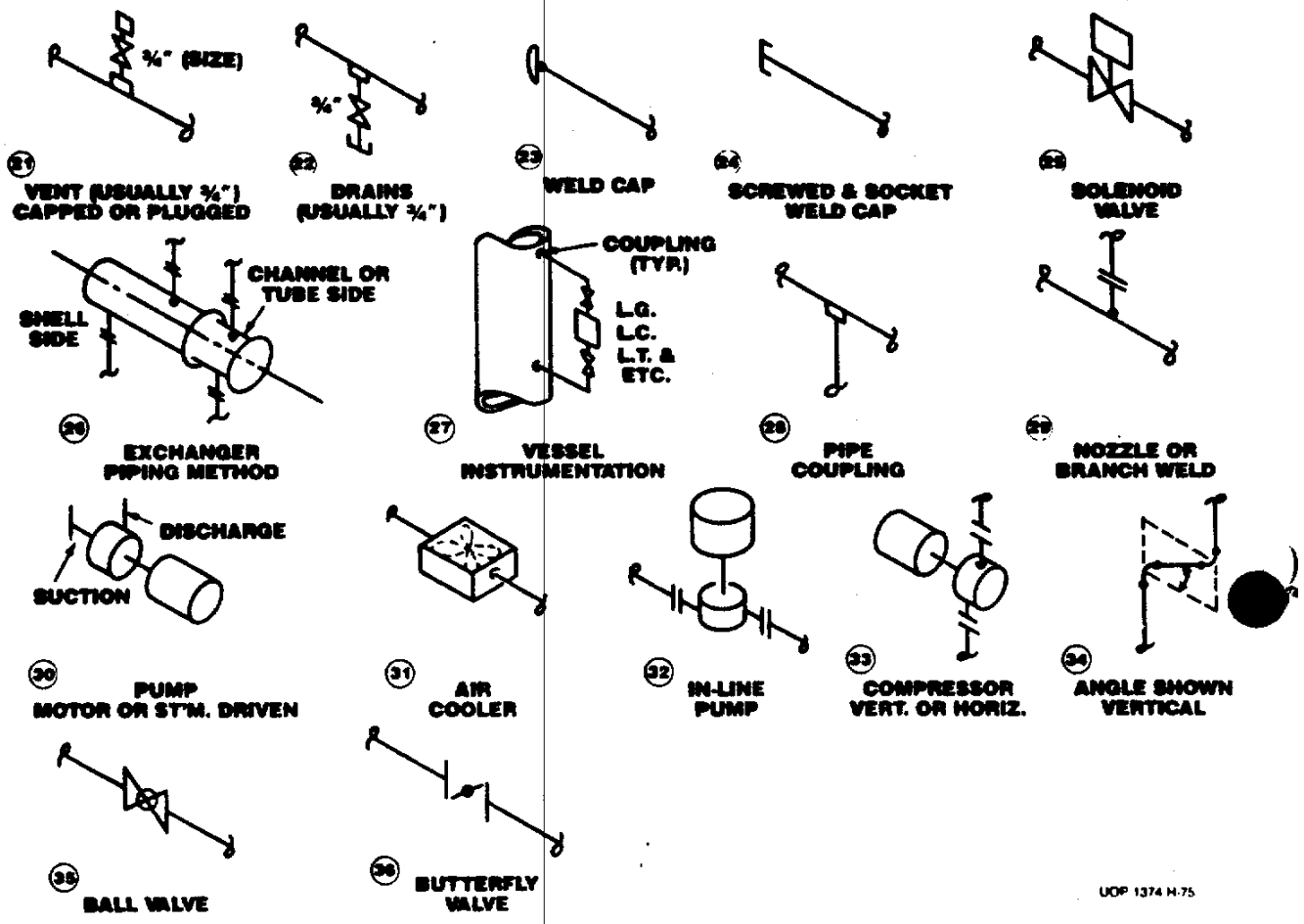


UOP 1374 H 74

uop

FIGURE 5-20B (CONTINUED)

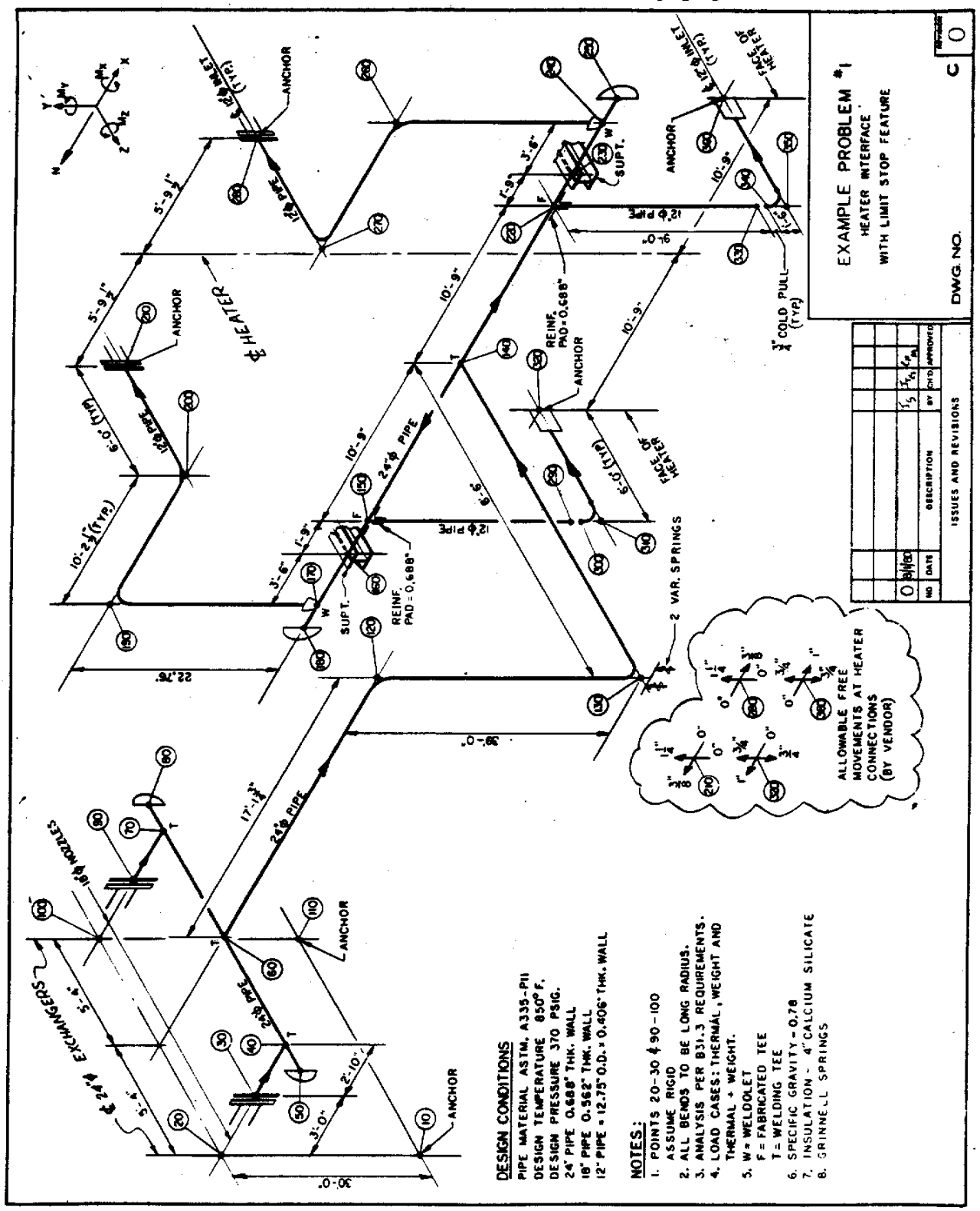
ISOMETRIC PIPING SYMBOLS



uop

5. SAMPLE PROBLEM

A sample problem is presented on the following pages.



```
EXAMPLE #1
HEATER INTERFACE
WITH LIMIT STOPS
 JTG
OPT
T,N,TPW,NGRA,P72,B313,EQU
PIPE
12,12,0.406
18,18,0.562
24,24,0.688
LAYOUT
L10,KA,M4,P24,CT=850,P=370,SG=.78
F10,T20,Y30
T30,P18,JR,X3
T40,KT,X2-10,CINS=4
T50,P24,Z1,CWGT=130
F40,T60,KT,Z-5-4
T70,KT,Z-5-4
T80,Z-1,CWGT=130
F70,T90,P18,X-2-10
T100,JR,X-3
T110,KA,P24,Y-30
F60,T120,KI,X17-1-3/4
T130,KI,Y-39,C2VS12A1
T140,KT,Z-6-6
T150,KF,X-10-9,CPAD=.688
T160,X-0-21,CLY
T170,KW,X-3-6
T180,X-1,CWGT=130
F170,T190,KI,P12,Y22.76
T200,KI,X10-2-1/2
T210,KA,Z-6,CLX(-.375,0),LY(0,1.25)
F140,T220,KF,P24,X10-9,CPAD=.688
T230,X0-21,CLY
T240,KW,X3-6
T250,X1,CWGT=130
F240,T260,KI,P12,Y22.76
T270,KI,X-10-2.5
T280,KA,Z-6,CLX(0,.375),LY(0,1.25)
F150,T290,Y-9
T300,JS,Y-0-0-3/4
T310,KI,Y-1-6
T320,KA,Z-6,CLX(-1,0),LY(-.75,.75)
F220,T330,Y-9
T340,JS,Y-0-0-3/4
T350,KI,Y-1-6
T360,KA,Z-6,CLX(0,1),LY(-.75,.75)
COB
B31.3,4,0,0,0,26000,14500,14500
```

*** * P I P E L I N E * ***

INPUT CARD IMAGE

```
         1         2         3         4         5         6         7         8
12345678901234567890123456789012345678901234567890123456789012345678901234567890

1EXAMPLE #1
1HEATER INTERFACE
1WITH LIMIT STOPS
1 JTG
2X X  X  A     XX   X
41212      0.406
41818      0.562
42424      0.688
510       A4 24                                                  T=850,P=370,SG=.78
5    10 20                    30
5       30     18R3
5       40 T      2-10                                          INS=4
5       50     24                          1                   WGT=130
5    40 60 T                               -5-4
5       70 T                               -5-4
5       80                                 -1                  WGT=130
5    70 90     18 -2-10
5       100      R-3
5       110A   24             -30
5    60 120I      17-1-3/4
5       130I                   -39                             2VS12A1
5       140T                               -6-6
5       150F      -10-9                                        PAD=.688
5       160       -0-21                                        LY
5       170W      -3-6
5       180       -1                                           WGT=130
5    170190I    12             22.76
5       200I      10-2-1/2
5       210A                               -6                  LX(-.375,0),LY(0,1.2
5                                                              5)
5    140220F    24 10-9                                       PAD=.688
5       230       0-21                                         LY
5       240W      3-6
5       250       1                                            WGT=130
5    240260I    12             22.76
5       270I      -10-2.5
5       280A                               -6                  LX(0,.375),LY(0,1.25
5                                                              )
5    150290                    -9
5       300       S            -0-0-3/4
5       310I                   -1-6
5       320A                               -6                  LX(-1,0),LY(-.75,.75
5                                                              )
5    220330                    -9
5       340       S            -0-0-3/4
```

EXAMPLE #1
HEATER INTERFACE
WITH LIMIT STOPS
JTG

* * P I P E L I N E * *

INPUT CARD IMAGE

```
         1         2         3         4         5         6         7         8
12345678901234567890123456789012345678901234567890123456789012345678901234567890

5       350I                    -1-6
5       360A                                -6                  LX(0,1),LY(-.75,.75)
7B31.34 0 0   0  20000    14500    14500
```

HANGER REPORT
GRINNELL TYPE SPRINGS

DATA PNT.	SPRING MARK NO.	UNITS	FIG.	SIZE	VERT. MVT.	PER UNIT - OPER LOAD	PER UNIT - INSTAL LOAD	SPRING RATE	HORIZONTAL MOVEMENT (X)	HORIZONTAL MOVEMENT (Z)
130	12A1	2	82	17	0.009	9463	9497	4000	0.368	0.908

---------- INPUT DATA LISTING ----------

LOAD OPTIONS SPECIFIED:

STATIC:	THERMAL ONLY	( )
	PRESSURE ONLY	( )
	WEIGHT ONLY	( )
	THERMAL + PRESSURE	( )
	THERMAL + WEIGHT	( )
	THERMAL+PRESSURE+WEIGHT	(X)
	PRESSURE + WEIGHT	( )
DYNAMIC:	MODAL EXTRACTION	( )
	RESPONSE SPECTRUM	( )
	STATIC EQUIVALENT	( )
HANGER DESIGN REQUEST		( )
EQUIPMENT.		(X)

OUTPUT OPTIONS:

SI INPUT/OUTPUT	( )
SI+ENGLISH OUTPUT	( )
FR INPUT/OUTPUT	( )
FR+ENGLISH OUTPUT	( )
72 COLUMN PRINT	(X)
B31.3 CODE	( )
B31.3 REPORT	( )
B31.1 CODE	( )
B31.1 REPORT	( )
B31.4 CODE	( )
B31.4 REPORT	( )
B31.8 CODE	( )
B31.8 REPORT	( )
NAVY CODE	
NAVY REPORT	

PROPERTIES OF MATERIALS USED:

MAT. CODE	TEMP.	MODULUS	POISSONS RATIO	THERMAL COEFFICIENT	WEIGHT DENSITY	MASS DENSITY
4	70.0	29900000.0	0.289	0.00000607	0.2830	0.000732
	300.0			0.00000660		
	500.0			0.00000702		
	700.0			0.00000744		
	900.0			0.00000784		

SECTION PROPERTIES OF ELEMENTS USED:

	PIPE			
PROP CODE	OD	WALL THICK	COR. ALL.	SECTION MODULUS
12	12.750	0.4060	0.0	47.092
18	18.000	0.5620	0.0	130.17
24	24.000	0.6880	0.0	285.49

INPUT DATA LISTING

DATA PNT.		TYPE	MAT	PROP	TEMP	PRES	BEND RAD	BEND ANG	LENGTH	COORDINATES X	Y	Z
10	*		4	24						0.0	0.0	0.0
	*								ANCHOR			
	**	RUN	4	24	850	370			30.000			
	*								PIPE RUN			
	*								ADDED WPL		135.8	
	*								AMBIENT	70.0		
20	*		4	24						0.0	30.00	0.0
	*											
20	*		4	18						0.0	30.00	0.0
	*								3.000			
	**	JOINT	4	18	850	370			RIGID			
	*									3.00	30.00	0.0
30	*		4	18								
	*											
30	*								2.833			
	**	RUN	4	18	850	370			PIPE RUN			
	*								ADDED WPL		96.6	
	*									5.83	30.00	0.0
40	*		4	18					WELDING T			
	*								STRESS INT.	1.90	2.21	
	*											
40	*								WELDING T			
	*								STRESS INT.	1.90	2.21	
	**	RUN	4	24	850	370			1.000			
	*								PIPE RUN			
	*								ADDED WPL		162.6	
50	*		4	24						5.83	30.00	1.00
	*											
	*								FORCES	0.0	-130.0	0.0
40	*								WELDING T			
	*								STRESS INT.	1.90	2.21	
	**	RUN	4	24	850	370			5.333			
	*								PIPE RUN			
	*								ADDED WPL		162.6	
60	*		4	24						5.83	30.00	-5.33
	*								WELDING T			
	*								STRESS INT.	1.90	2.21	
60	*								WELDING T			
	*								STRESS INT.	1.90	2.21	
	**	RUN	4	24	850	370			5.333			
	*								PIPE RUN			
	*								ADDED WPL		162.6	

---------- INPUT DATA LISTING ----------

DATA PNT.		TYPE	MAT	PROP	TEMP	PRES	BEND RAD	BEND ANG	LENGTH	COORDINATES X	Y	Z
70	*		4	24						5.83	30.00	-10.67
	*							WELDING T				
	*							STRESS INT.		1.90	2.21	
70	*							WELDING T				
	*							STRESS INT.		1.90	2.21	
	**	RUN	4	24	850	370			1.000			
	*							PIPE RUN				
	*							ADDED WPL			162.6	
80	*		4	24						5.83	30.00	-11.67
	*							FORCES		0.0	-130.0	0.0
70	*							WELDING T				
	*							STRESS INT.		1.90	2.21	
	**	RUN	4	18	850	370			2.833			
	*							PIPE RUN				
	*							ADDED WPL			96.6	
90	*		4	18						3.00	30.00	-10.67
90	*		4	18						3.00	30.00	-10.67
	**	JOINT	4	18	850	370			3.000			
	*							RIGID				
100	*		4	18						0.0	30.00	-10.67
100	*											
	**	RUN	4	24	850	370			30.000			
	*							PIPE RUN				
	*							ADDED WPL			162.6	
110	*		4	24						0.0	0.0	-10.67
	*							ANCHOR				
60	*							WELDING T				
	*							STRESS INT.		1.90	2.21	
	**	RUN	4	24	850	370			14.146			
	*							PIPE RUN				
	*							ADDED WPL			162.6	
120	*		4	24						19.98	30.00	-5.33
120	*							BEND START				
	*							STRESS INT.		2.54	2.11	
120	*		4	24						22.98	30.00	-5.33
	*											
	**	BEND	4	24	850	370	36.0	90.	4.712			

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)		RESULTANT (PSI)	S(E) (PSI)
10	* RU * N	3628	-13421	85032	1.00	106344	1.00	5723	5751
20	* N	3628	-13421	27814	1.00	-53586	1.00	2537	2599
20	* JN * T	-1907	-53586	-13421		27814			
30	* RU * N	-1907	-53586	2571		16929			
30	* RU * N	-1907	-53586	2571	1.00	16929	1.00	1578	5186
40	* RU * N	-1907	-53586	-17676	1.91	6650	2.21	2687	5623
40	* RU * N	0	0	0	1.91	0	2.21	0	0
50	* N	0	0	0	1.00	0	1.00	0	0
40	* RU * N	-5331	-6650	-17676	1.91	-53586	2.21	5178	5185
60	* N	-5331	-6650	7503	1.91	72936	2.21	6805	6811
60	* RU * N	-3800	18524	17566	1.91	45449	2.21	4452	4520
70	* N	-3800	18524	-24647	1.91	-33960	2.21	3724	3804
70	* RU * N	0	0	0	1.91	0	2.21	0	0
80	* N	0	0	0	1.00	0	1.00	0	0
70	* RU * N	-1327	33960	24647	1.91	-18524	2.21	4554	5527
90	* N	-1327	33960	13880	1.00	24627	1.00	2606	4073
90	* JN * T	-1327	33960	13880		24627			
100	* RU * N	2154	-2479	-31089	1.00	33960	1.00	1935	1938
110	* N	2154	-2479	-70917	1.00	-80043	1.00	4495	4496
60	* RU * N	-3234	-27487	10062	1.91	25174	2.21	2406	2669
120	* N	-3234	-27487	11592	1.00	-56620	1.00	2429	2690
120	* BE * N	-3234	-27487	56620	2.54	-11592	2.12	6139	6247
120	* N	-6376	-28978	66044	2.54	7991	2.12	7095	7199

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)		RESULTANT (PSI)	S(E) (PSI)
	* D								
120	*	-5782	-16185	64262	2.54	22894	2.12	7165	7197
120	* R	-5782	-16185	-64262	1.00	22894	1.00	2867	2947
	* U								
130	* N	-5782	-16185	42487	1.00	-27624	1.00	2130	2236
130	* B	-5726	-16185	27624	2.54	-42487	2.12	4800	4848
	* E								
130	* N	-5131	-44330	25839	2.54	-25460	2.12	3573	4030
	* D								
130	*	-1530	-52192	15036	2.54	6480	2.12	1707	2780
130	* R	-1530	-52192	6480	1.00	15036	1.00	688	2299
	* U								
140	* N	-1530	-52192	-4841	1.91	5007	2.21	589	2271
140	* R	510	452	-4099	1.91	-7435	2.21	765	765
	* U								
150	* N	510	452	11780	2.52	381	3.02	1246	1246
150	* R	510	-663	11853	2.52	-36	3.02	1253	1253
	* U								
160	* N	510	-663	-229	1.00	-10069	1.00	423	424
160	* R	510	-663	-229	1.00	-10069	1.00	423	424
	* U								
170	* N	510	-663	-2592	2.68	-761	2.68	304	305
170	* R	0	0	0	2.68	0	2.68	0	0
	* U								
180	* N	0	0	0	1.00	0	1.00	0	0
170	* R	-2136	-761	-2592	2.68	663	2.68	1044	1062
	* U								
190	* N	-2136	-761	-8264	1.00	-2569	1.00	2205	2213
190	* B	-2136	-761	8264	2.52	-2569	2.10	5480	5484
	* E								
190	* N	-1871	-2422	7867	2.52	-1439	2.10	5109	5146
	* D								
190	*	-510	-2797	5825	2.52	533	2.10	3751	3818
190	* R	-510	-2797	-533	1.00	-5825	1.00	1490	1652
	* U								
200	* N	-510	-2797	562	1.00	9572	1.00	2443	2545

DATA PNT.		SYSTEM FORCES F(X) (LBS)	F(Y) (LBS)	F(Z) (LBS)	SYSTEM MOMENTS M(X) (FT-LBS)	M(Y) (FT-LBS)	M(Z) (FT-LBS)
10	* RUN	-1907	3628	5331	106344	-13421	85032
20	* RUN	-1907	3628	5331	-53586	-13421	27814
20	* JUMP	-1907	3628	5331	-53586	-13421	27814
30	* RUN	-1907	3628	5331	-53586	2571	16929
30	* RUN	-1907	3628	5331	-53586	2571	16929
40	* RUN	-1907	3628	5331	-53586	17676	6650
40	* RUN	0	0	0	0	0	0
50	* RUN	0	0	0	0	0	0
40	* RUN	-1907	3628	5331	-53586	17676	6650
60	* RUN	-1907	3628	5331	-72936	7503	6650
60	* RUN	1327	-2154	3800	-45449	17566	-18524
70	* RUN	1327	-2154	3800	-33960	24647	-18524
70	* RUN	0	0	0	0	0	0
80	* RUN	0	0	0	0	0	0
70	* RUN	1327	-2154	3800	-33960	24647	-18524
90	* RUN	1327	-2154	3800	-33960	13880	-24627
90	* JUMP	1327	-2154	3800	-33960	13880	-24627
100	* RUN	1327	-2154	3800	-33960	2479	-31089
100	* RUN	1327	-2154	3800	-33960	2479	-31089
110	* RUN	1327	-2154	3800	80043	2479	-70917
60	* RUN	-3234	5782	1530	-27487	-10062	25174
120	* RUN	-3234	5782	1530	-27487	11592	-56620
120	* BEND	-3234	5782	1530	-27487	11592	-56620
120	* RUN	-3234	5782	1530	-22894	16185	-64262
120	* R	-3234	5782	1530	-22894	16185	-64262

DATA PNT.		SYSTEM FORCES F(X) (LBS)	F(Y) (LBS)	F(Z) (LBS)	SYSTEM MOMENTS M(X) (FT-LBS)	M(Y) (FT-LBS)	M(Z) (FT-LBS)
130	* U N	-3234	5782	1530	27624	16185	42487
130	* B N D	-3234	5726	1530	27624	16185	42487
130	* R U N	-3234	5726	1530	15036	6480	52192
140	* R U N	-3234	5726	1530	-5007	-4841	52192
140	* R U N	-510	404	416	-452	4099	7435
150	* R U N	-510	404	416	-452	-381	11780
150	* R U N	-510	-1019	152	663	36	11853
160	* R U N	-510	-1019	152	663	-229	10069
160	* R U N	-510	-2136	152	663	-229	10069
170	* R U N	-510	-2136	152	663	-761	2592
170	* R U N	0	0	0	0	0	0
180	* R U N	0	0	0	0	0	0
170	* R U N	-510	-2136	152	663	-761	2592
190	* R U N	-510	-2136	152	-2569	-761	-8264
190	* B N D	-510	-2136	152	-2569	-761	-8264
190	* R U N	-510	-2136	152	-2797	-533	-5825
200	* R U N	-510	-2136	152	-2797	-533	-5825
200	* B N D	-510	-2136	152	-2797	562	9572
200	* R U N	-510	-2136	152	406	24	12777
210	* R U N	-510	-2136	152	406	24	12777
140	* R U	-2724	5322	1114	-4554	-8940	44756

SYSTEM LOADS ACTING ON ANCHORS AND RESTRAINTS

DATA PNT.	FORCES (LBS) F(X)	F(Y)	F(Z)	F	MOMENTS (FT-LBS) M(X)	M(Y)	M(Z)	M
10	-1907	3628	5331	6724	106344	-13421	85032	136819
110	-1327	2154	-3800	4565	-80043	-2479	70917	106968
160	0	-1116	0	1116	0	0	0	0
230	0	-4688	0	4688	0	0	0	0
130	0	-55	0	55	0	0	0	0
320	0	-1423	-264	1447	6863	418	72	6876
360	2543	-2271	-935	3535	9747	12158	-6341	16823
210	510	2136	-152	2201	-10019	2273	-12777	16395
280	181	1637	-178	1656	-7207	2035	12383	14471

* MAX STRESS AT POINT 220 IS 8012 *

STATIC: THERMAL

SYSTEM DISPLACEMENTS AND ROTATIONS

DATA PNT	--- DISPLACEMENTS (INCHES) --- X	Y	Z	---- ROTATIONS (DEGREES) ----- (X)	(Y)	(Z)
10	-0.000	0.000	0.000	0.000	-0.000	0.000
20	-0.503	2.174	0.410	0.064	-0.042	0.136
30	-0.286	2.260	0.436	0.064	-0.042	0.136
40	-0.081	2.344	0.460	0.018	-0.035	0.144
50	-0.088	2.340	0.533	0.018	-0.035	0.144
60	-0.046	2.350	0.074	-0.009	-0.030	0.148
70	-0.017	2.329	-0.312	-0.027	-0.021	0.138
80	-0.013	2.323	-0.384	-0.027	-0.021	0.138
90	-0.222	2.251	-0.319	-0.056	-0.008	0.123
100	-0.440	2.173	-0.324	-0.056	-0.008	0.123
110	-0.000	0.000	-0.000	-0.000	-0.000	0.000
120	0.979	2.788	0.168	-0.050	-0.029	0.130
120	1.197	2.608	0.224	-0.083	-0.026	-0.074
130	0.418	0.219	0.857	-0.077	0.030	-0.103
130	0.368	-0.012	0.669	0.000	0.008	-0.028
140	0.362	-0.010	0.415	0.002	0.009	-0.009
150	-0.417	0.000	0.437	0.001	0.010	-0.000
160	-0.544	-0.000	0.441	0.001	0.010	0.001
170	-0.797	-0.002	0.448	0.002	0.010	0.003
180	-0.870	-0.003	0.450	0.002	0.010	0.003
190	-0.768	1.537	0.437	-0.017	-0.009	-0.052
190	-0.626	1.601	0.429	-0.041	-0.003	-0.186
200	-0.104	1.315	0.435	-0.065	-0.003	-0.173
200	0.003	1.265	0.326	-0.022	0.005	-0.068

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)	SIF	RESULTANT (PSI)	S(L) (PSI)
10	* R * U	-12731	958	-6217	1.00	-621	1.00	262	-515
20	* N	-3524	958	-8224	1.00	-287	1.00	345	-415
20	* J * N	-66	-287	958		-8224			
30	* T	-66	-287	925		2008			
30	* R * U	-66	-287	925	1.00	2008	1.00	203	-206
40	* N	-66	-287	-893	1.91	10544	2.21	1707	-1709
40	* R * U	0	0	0	1.91	296	2.21	27	-27
50	* N	0	0	0	1.00	0	1.00	0	0
40	* R * U	11	-10544	-893	1.91	-584	2.21	89	90
60	* N	11	-10544	536	1.91	-6742	2.21	628	628
60	* R * U	-108	10051	-1509	1.91	-6488	2.21	615	-617
70	* N	-108	10051	375	1.91	-1992	2.21	187	-189
70	* R * U	0	0	0	1.91	-296	2.21	27	27
80	* N	0	0	0	1.00	0	1.00	0	0
70	* R * U	-212	1695	-375	1.91	-10051	2.21	1623	-1630
90	* N	-212	1695	-683	1.00	901	1.00	104	-111
90	* J * N	-212	1695	-683		901			
100	* T	-212	1695	-1008		-10076			
100	* R * U	-3804	1008	10076	1.00	1695	1.00	429	-504
110	* N	-13818	1008	3699	1.00	-1559	1.00	168	-442
60	* R * U	-279	254	-2046	1.91	20595	2.21	1867	-1873
120	* N	-279	254	353	1.00	3941	1.00	166	-171
120	* B * E	-279	254	-3941	2.54	-353	2.12	422	-428
120	* N	-3255	34	4106	2.54	-176	2.12	439	-503

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)		RESULTANT (PSI)	S(L) (PSI)
280	* UNDER *	-47	-77	-219	1.00	-4406	1.00	1124	-1127
150	* RUN *	1705	-214	1258	2.52	-1369	3.02	759	867
290	* UNDER *	739	-214	454	1.00	241	1.00	131	178
290	* JNT *	737	-214	454		241			
300	* UNDER *	737	-214	466		252			
310	* BEND *	736	-214	-252	2.52	-466	2.10	297	344
310	* BEND *	557	-565	-155	2.52	-379	2.10	226	261
310	*	179	-751	341	2.52	-70	2.10	222	233
310	* RUN *	179	-751	-70	1.00	341	1.00	88	100
320	* UNDER *	179	-751	-926	1.00	1428	1.00	433	445
220	* RUN *	1705	148	-307	2.52	62	3.02	116	224
330	* UNDER *	739	148	-307	1.00	136	1.00	85	132
330	* JNT *	737	148	-307		136			
340	* UNDER *	737	148	-307		137			
350	* BEND *	736	148	-137	2.52	307	2.10	186	233
350	* BEND *	446	322	125	2.52	112	2.10	100	129
350	*	22	307	692	2.52	-148	2.10	451	452
350	* RUN *	22	307	-148	1.00	692	1.00	180	181
360	* UNDER *	22	307	-148	1.00	1779	1.00	454	456

* MAX STRESS AT POINT 60 IS -1873 *

STATIC: WEIGHT

DATA PNT.		SYSTEM FORCES F(X) (LBS)	F(Y) (LBS)	F(Z) (LBS)	SYSTEM MOMENTS M(X) (FT-LBS)	M(Y) (FT-LBS)	M(Z) (FT-LBS)
10	* R U N	-66	-12731	-11	-621	958	-6217
20	* N	-66	-3524	-11	-287	958	-8224
20	* J N	-66	-3411	-11	-287	958	-8224
30	* T	-66	-3411	-11	-287	925	2008
30	* R U N	-66	-3297	-11	-287	925	2008
40	* N	-66	-2727	-11	-287	893	10544
40	* R U N	0	-463	0	296	0	0
50	* N	0	-129	0	0	0	0
40	* R U N	-66	-2263	-11	-584	893	10544
60	* N	-66	-483	-11	6742	536	10544
60	* R U N	212	700	108	6488	-1509	-10051
70	* N	212	2480	108	-1992	-375	-10051
70	* R U N	0	-463	0	-296	0	0
80	* N	0	-129	0	0	0	0
70	* R U N	212	2944	108	-1695	-375	-10051
90	* N	212	3514	108	-1695	-683	-901
90	* J N	212	3659	108	-1695	-683	-901
100	* T	212	3659	108	-1695	-1008	10076
100	* R U N	212	3804	108	-1695	-1008	10076
110	* N	212	13818	108	1559	-1008	3699
60	* R U N	-279	-1183	-119	254	2046	20595
120	* N	-279	3538	-119	254	353	3941
120	* B N D	-279	5111	-119	-104	-4	-7549
120	* R	-279	5111	-119	-104	-4	-7549

SYSTEM LOADS ACTING ON ANCHORS AND RESTRAINTS

DATA PNT.	FORCES (LBS) F(X)	F(Y)	F(Z)	F	MOMENTS (FT-LBS) M(X)	M(Y)	M(Z)	M
10	-66	-12731	-11	12731	-621	958	-6217	6320
110	-212	-13818	-108	13820	-1559	1008	-3699	4138
160	0	-10371	0	10371	0	0	0	0
230	0	-10503	0	10503	0	0	0	0
130	0	-18990	0	18990	0	0	0	0
320	190	0	179	261	-1428	926	-751	1860
360	0	0	22	22	-1779	148	307	1811
210	111	-1025	-33	1031	4012	436	37	4035
280	-22	-1088	-47	1089	4406	219	-77	4412

* MAX STRESS AT POINT 60 IS -1873 *

STATIC: WEIGHT

SYSTEM DISPLACEMENTS AND ROTATIONS

DATA PNT	--- DISPLACEMENTS (INCHES) --- X	Y	Z	---- ROTATIONS (DEGREES) ----- (X)	(Y)	(Z)
10	-0.000	-0.000	-0.000	-0.000	0.000	-0.000
20	0.052	-0.002	-0.004	-0.001	0.003	-0.017
30	0.052	-0.013	-0.006	-0.001	0.003	-0.017
40	0.052	-0.023	-0.008	-0.001	0.004	-0.013
50	0.053	-0.023	-0.008	-0.001	0.004	-0.013
60	0.048	-0.024	-0.008	0.000	0.004	-0.007
70	0.044	-0.022	-0.008	0.002	0.003	-0.013
80	0.043	-0.022	-0.008	0.002	0.003	-0.013
90	0.044	-0.013	-0.006	0.000	0.003	-0.017
100	0.044	-0.002	-0.004	0.000	0.003	-0.017
110	-0.000	-0.000	-0.000	-0.000	0.000	-0.000
120	0.048	-0.010	-0.022	0.001	0.005	0.013
120	0.054	-0.002	-0.026	0.001	0.006	0.002
130	0.029	0.001	-0.019	-0.005	0.006	-0.005
130	0.024	-0.006	-0.014	-0.011	0.003	-0.001
140	0.022	-0.014	-0.014	-0.010	0.003	-0.000
150	0.022	-0.002	-0.009	-0.008	0.002	-0.006
160	0.022	-0.000	-0.008	-0.007	0.002	-0.005
170	0.022	0.002	-0.006	-0.007	0.002	-0.002
180	0.022	0.002	-0.006	-0.007	0.002	-0.002
190	0.000	0.001	-0.006	0.005	-0.001	0.004
190	0.001	-0.001	-0.004	0.007	-0.002	-0.007
200	0.001	-0.009	-0.000	0.009	-0.002	-0.003
200	0.001	-0.006	-0.000	0.009	0.001	0.000

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)		RESULTANT (PSI)	S(E) (PSI)
10	* RUN	-9070	-13242	82269	1.00	107564	1.00	5692	5719
20	* RUN	137	-13242	19042	1.00	-54890	1.00	2442	2504
20	* JNT	-2107	-54890	-13242		19042			
30	* RUN	-2107	-54890	3003		18291			
30	* RUN	-2107	-54890	3003	1.00	18291	1.00	1708	5341
40	* RUN	-2107	-54890	-18345	1.91	16452	2.21	3687	6261
40	* RUN	0	0	0	1.91	296	2.21	27	27
50	* RUN	0	0	0	1.00	0	1.00	0	0
40	* RUN	-5415	-16452	-18345	1.91	-55187	2.21	5335	5380
60	* RUN	-5415	-16452	7105	1.91	67389	2.21	6288	6326
60	* RUN	-3877	28252	16466	1.91	39496	2.21	3901	4077
70	* RUN	-3877	28252	-24828	1.91	-35491	2.21	3853	4032
70	* RUN	0	0	0	1.91	-296	2.21	27	27
80	* RUN	0	0	0	1.00	0	1.00	0	0
70	* RUN	-1567	35194	24828	1.91	-28252	2.21	5725	6581
90	* RUN	-1567	35194	13843	1.00	25736	1.00	2694	4217
90	* JNT	-1567	35194	13843		25736			
100	* RUN	-1567	35194	2211		21781			
100	* RUN	-1463	-2211	-21781	1.00	35194	1.00	1739	1742
110	* RUN	-11477	-2211	-68814	1.00	-81117	1.00	4471	4472
60	* RUN	-3675	-27892	9361	1.91	44705	2.21	4104	4268
120	* RUN	-3675	-27892	12396	1.00	-56861	1.00	2446	2712
120	* BEN	-3675	-27892	56861	2.54	-12396	2.12	6177	6287
120	* RUN	-9901	-29840	74659	2.54	7694	2.12	8009	8107

DATA PNT.		SYSTEM FORCES F(X) (LBS)	F(Y) (LBS)	F(Z) (LBS)	SYSTEM MOMENTS M(X) (FT-LBS)	M(Y) (FT-LBS)	M(Z) (FT-LBS)
10	* RU * N	-2107	-9070	5415	107564	-13242	82269
20	* N	-2107	137	5415	-54890	-13242	19042
20	* JN * T	-2107	250	5415	-54890	-13242	19042
30	* RU * N	-2107	250	5415	-54890	3003	18291
30	* RU * N	-2107	363	5415	-54890	3003	18291
40	* RU * N	-2107	933	5415	-54890	18345	16452
40	* RU * N	0	-463	0	296	0	0
50	* N	0	-130	0	0	0	0
40	* RU * N	-2107	1397	5415	-55187	18345	16452
60	* N	-2107	3178	5415	-67389	7105	16452
60	* RU * N	1567	-1641	3877	-39496	16466	-28252
70	* N	1567	139	3877	-35491	24828	-28252
70	* RU * N	0	-463	0	-296	0	0
80	* N	0	-129	0	0	0	0
70	* RU * N	1567	602	3877	-35194	24828	-28252
90	* N	1567	1173	3877	-35194	13843	-25736
90	* JN * T	1567	1318	3877	-35194	13843	-25736
100	* RU * N	1567	1318	3877	-35194	2211	-21781
100	* RU * N	1567	1463	3877	-35194	2211	-21781
110	* N	1567	11477	3877	81117	2211	-68814
60	* RU * N	-3675	4819	1538	-27892	-9361	44705
120	* N	-3675	9540	1538	-27892	12396	-56861
120	* BN * D	-3675	9540	1538	-27892	12396	-56861
120	* R	-3675	11113	1538	-23278	17010	-76172
120	* R	-3675	11113	1538	-23278	17010	-76172

SYSTEM LOADS ACTING ON ANCHORS AND RESTRAINTS

DATA PNT.	FORCES (LBS) F(X)	F(Y)	F(Z)	F	MOMENTS (FT-LBS) M(X)	M(Y)	M(Z)	M
10	-2107	-9070	5415	10771	107564	-13242	82269	136064
110	-1567	-11477	-3877	12215	-81117	-2211	68814	106396
160	0	-10578	0	10578	0	0	0	0
230	0	-14459	0	14459	0	0	0	0
130	0	-18927	0	18927	0	0	0	0
320	0	-2424	-121	2427	10031	488	-72	10043
360	2936	-3457	-987	4641	13442	14119	-7185	20776
210	626	1198	-192	1365	-6450	2459	-13032	14747
280	111	668	-236	717	-3401	2293	12630	13279

* MAX STRESS AT POINT 220 IS 9063 *

STATIC: T+P+W

SYSTEM DISPLACEMENTS AND ROTATIONS

DATA PNT	--- DISPLACEMENTS (INCHES) --- X	Y	Z	---- ROTATIONS (DEGREES) ---- (X)	(Y)	(Z)
10	-0.000	-0.000	0.000	0.000	-0.000	0.000
20	-0.467	2.188	0.413	0.064	-0.041	0.122
30	-0.250	2.265	0.439	0.064	-0.041	0.122
40	-0.044	2.341	0.462	0.016	-0.034	0.134
50	-0.051	2.338	0.535	0.017	-0.034	0.134
60	-0.009	2.346	0.074	-0.009	-0.029	0.143
70	0.018	2.326	-0.315	-0.025	-0.020	0.128
80	0.022	2.321	-0.388	-0.025	-0.020	0.128
90	-0.188	2.256	-0.322	-0.056	-0.007	0.110
100	-0.406	2.187	-0.327	-0.056	-0.007	0.110
110	-0.000	-0.000	-0.000	-0.000	-0.000	0.000
120	1.022	2.802	0.163	-0.050	-0.027	0.143
120	1.249	2.630	0.218	-0.084	-0.023	-0.069
130	0.437	0.226	0.859	-0.078	0.036	-0.111
130	0.382	-0.014	0.673	-0.012	0.011	-0.029
140	0.373	-0.020	0.417	-0.009	0.011	-0.009
150	-0.411	-0.001	0.445	-0.006	0.013	-0.004
160	-0.539	-0.000	0.449	-0.006	0.013	-0.001
170	-0.794	-0.002	0.459	-0.005	0.012	0.003
180	-0.867	-0.003	0.461	-0.005	0.012	0.003
190	-0.774	1.546	0.451	-0.012	-0.004	-0.057
190	-0.630	1.607	0.444	-0.035	0.003	-0.195
200	-0.104	1.308	0.439	-0.058	0.005	-0.179
200	0.003	1.260	0.328	-0.014	0.004	-0.069

ANSI B31.3-1980 COMPLIANCE REPORT

	FROM	TO	MAT	PROP	O.D.	WALL	C.A.	MILL	F 302.3.5	Y 304.1.1
RUN	10	20	4	24	24.000	0.688	0.0	0.875	1.000	0.400
JNT	20	30	4	18	18.000	0.562	0.0	0.0	1.000	0.400
RUN	30	40	4	18	18.000	0.562	0.0	0.875	1.000	0.400
RUN	40	50	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	40	60	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	60	70	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	70	80	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	70	90	4	18	18.000	0.562	0.0	0.875	1.000	0.400
JNT	90	100	4	18	18.000	0.562	0.0	0.0	1.000	0.400
RUN	100	110	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	60	120	4	24	24.000	0.688	0.0	0.875	1.000	0.400
BEND	120	120	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	120	130	4	24	24.000	0.688	0.0	0.875	1.000	0.400
BEND	130	130	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	130	140	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	140	150	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	150	160	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	160	170	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	170	180	4	24	24.000	0.688	0.0	0.875	1.000	0.400
RUN	170	190	4	12	12.750	0.406	0.0	0.875	1.000	0.400
BEND	190	190	4	12	12.750	0.406	0.0	0.875	1.000	0.400
RUN	190	200	4	12	12.750	0.406	0.0	0.875	1.000	0.400
BEND	200	200	4	12	12.750	0.406	0.0	0.875	1.000	0.400
RUN	200	210	4	12	12.750	0.406	0.0	0.875	1.000	0.400

ANSI B31.3-1980 COMPLIANCE REPORT

DATA PNT.			--PRESSURE-- DES.	ALLOW	--- 302.3.5 (C) STRESS --- SLP	SLW	SLT	SH	--- 302.3.5 (D) --- S(E)	SA	SAL
10	*	R	370	742	3074	-515	2858	14500	5751	28625	40266
	*	U									
20	*	N	370	742	2988	-415	3250	14500	2599	28625	39874
20	*	J									
	*	N									
30	*	T									
30	*	R	370	809	2735	-206	2831	14500	5186	28625	40293
	*	U									
40	*	N	370	809	2767	-1709	4300	14500	5623	28625	38824
40	*	R	370	742	2951	-27	2979	14500	0	28625	40145
	*	U									
50	*	N	370	742	2951	0	2951	14500	0	28625	40173
40	*	R	370	742	3022	90	3094	14500	5185	28625	40030
	*	U									
60	*	N	370	742	3046	628	3492	14500	6811	28625	39632
60	*	R	370	742	3020	-617	3500	14500	4520	28625	39624
	*	U									
70	*	N	370	742	2991	-189	3111	14500	3804	28625	40013
70	*	R	370	742	2951	27	2979	14500	0	28625	40145
	*	U									
80	*	N	370	742	2951	0	2951	14500	0	28625	40173
70	*	R	370	809	2765	-1630	4252	14500	5527	28625	38872
	*	U									
90	*	N	370	809	2732	-111	2779	14500	4073	28625	40345
90	*	J									
	*	N									
100	*	T									
100	*	R	370	742	2983	-504	3280	14500	1938	28625	39844
	*	U									
110	*	N	370	742	3004	-442	2804	14500	4496	28625	40320
60	*	R	370	742	3054	-1873	4728	14500	2669	28625	38396
	*	U									
120	*	N	370	742	3095	-171	2977	14500	2690	28625	40147
120	*	B	370	742	3319	-428	3020	14500	6247	28625	40104
	*	N									
120	*	D	370	742	3341	-908	4046	14500	7197	28625	39078

---------- INPUT DATA LISTING ----------

LOAD OPTIONS SPECIFIED:

STATIC:	THERMAL ONLY	( )
	PRESSURE ONLY	( )
	WEIGHT ONLY	( )
	THERMAL + PRESSURE	( )
	THERMAL + WEIGHT	( )
	THERMAL+PRESSURE+WEIGHT	(X)
	PRESSURE + WEIGHT	( )
DYNAMIC:	MODAL EXTRACTION	( )
	RESPONSE SPECTRUM	( )
	STATIC EQUIVALENT	( )
HANGER DESIGN REQUEST		( )
EQUIPMENT.		(X)

OUTPUT OPTIONS:

SI INPUT/OUTPUT	( )
SI+ENGLISH OUTPUT	( )
FR INPUT/OUTPUT	( )
FR+ENGLISH OUTPUT	( )
72 COLUMN PRINT	(X)
B31.3 CODE	( )
B31.3 REPORT	( )
B31.1 CODE	( )
B31.1 REPORT	( )
B31.4 CODE	( )
B31.4 REPORT	( )
B31.8 CODE	( )
B31.8 REPORT	( )
NAVY CODE	
NAVY REPORT	

PROPERTIES OF MATERIALS USED:

MAT. CODE	TEMP.	MODULUS	POISSONS RATIO	THERMAL COEFFICIENT	WEIGHT DENSITY	MASS DENSITY
4	70.0	29899984.0	0.289	0.00000607	0.2830	0.000732
	300.0	29000000.0		0.00000660		
	500.0	28000000.0		0.00000702		
	700.0	26600000.0		0.00000744		
	900.0	24500000.0		0.00000784		

SECTION PROPERTIES OF ELEMENTS USED:

---------- P I P E ----------

PROP CODE	OD	WALL THICK	COR. ALL.	SECTION MODULUS
12	12.750	0.4060	0.0	47.092
18	18.000	0.5620	0.0	130.17
24	24.000	0.6880	0.0	285.49

DATA PNT.		AXIAL FORCE (LBS)	TORSIONAL MOMENT (FT-LBS)	CALCULATED STRESS ---IN PLANE--- BENDING MOMENT (FT-LBS)	SIF	---OUT PLANE--- BENDING MOMENT (FT-LBS)		RESULTANT (PSI)	S(E) (PSI)
10	* RUN	-9664	-10688	68108	1.00	89873	1.00	4739	4761
20	* RUN	-456	-10688	14482	1.00	-45857	1.00	2021	2070
20	* JNT	-1787	-45857	-10688		14482			
30	* RUN	-1787	-45857	2884	1.00	15512	1.00	1454	4470
40	* RUN	-1787	-45857	-15703	1.91	15356	2.21	3307	5367
40	* RUN	0	0	0	1.91	296	2.21	27	27
50	* RUN	0	0	0	1.00	0	1.00	0	0
40	* RUN	-4524	-15356	-15703	1.91	-46154	2.21	4470	4517
60	* RUN	-4524	-15356	6170	1.91	55189	2.21	5153	5193
60	* RUN	-3280	24807	13218	1.91	32419	2.21	3194	3360
70	* RUN	-3280	24807	-20579	1.91	-30255	2.21	3260	3423
70	* RUN	0	0	0	1.91	-296	2.21	27	27
80	* RUN	0	0	0	1.00	0	1.00	0	0
70	* RUN	-1380	29958	20579	1.91	-24807	2.21	4926	5648
90	* RUN	-1380	29958	11285	1.00	21312	1.00	2223	3545
90	* JNT	-1380	29958	11285		21312			
100	* RUN	-1380	29958	1445		16322			
100	* RUN	-1808	-1445	-16322	1.00	29958	1.00	1434	1435
110	* RUN	-11822	-1445	-57729	1.00	-68446	1.00	3763	3764
60	* RUN	-3167	-22770	7048	1.91	40163	2.21	3670	3793
120	* RUN	-3167	-22770	10552	1.00	-48120	1.00	2070	2281
120	* BEN	-3167	-22770	48120	2.54	-10552	2.12	5228	5315
120	* RUN	-8878	-24656	64372	2.54	6000	2.12	6901	6979

DATA PNT.		F(X) (LBS)	F(Y) (LBS)	F(Z) (LBS)	M(X) (FT-LBS)	M(Y) (FT-LBS)	M(Z) (FT-LBS)
	SYSTEM FORCES				SYSTEM MOMENTS		
10	* RUN	-1787	-9664	4524	89873	-10688	68108
20	* N	-1787	-456	4524	-45857	-10688	14482
20	* JN	-1787	-343	4524	-45857	-10688	14482
30	* T	-1787	-343	4524	-45857	2884	15512
30	* RUN	-1787	-230	4524	-45857	2884	15512
40	* N	-1787	340	4524	-45857	15703	15356
40	* RUN	0	-463	0	296	0	0
50	* N	0	-129	0	0	0	0
40	* RUN	-1787	803	4524	-46154	15703	15356
60	* N	-1787	2584	4524	-55189	6170	15356
60	* RUN	1380	-1295	3280	-32419	13218	-24807
70	* N	1380	484	3280	-30255	20579	-24807
70	* RUN	0	-463	0	-296	0	0
80	* N	0	-130	0	0	0	0
70	* RUN	1380	948	3280	-29958	20579	-24807
90	* N	1380	1518	3280	-29958	11285	-21312
90	* JN	1380	1663	3280	-29958	11285	-21312
100	* T	1380	1663	3280	-29958	1445	-16322
100	* RUN	1380	1808	3280	-29958	1445	-16322
110	* N	1380	11822	3280	68446	1445	-57729
60	* RUN	-3167	3880	1244	-22770	-7048	40163
120	* N	-3167	8601	1244	-22770	10552	-48120
120	* BN	-3167	8601	1244	-22770	10552	-48120
120	* D	-3167	10174	1244	-19037	14285	-66137
120	* R	-3167	10174	1244	-19037	14285	-66137

SYSTEM LOADS ACTING ON ANCHORS AND RESTRAINTS

DATA PNT.	FORCES (LBS) F(X)	F(Y)	F(Z)	F	MOMENTS (FT-LBS) M(X)	M(Y)	M(Z)	M
10	-1787	-9664	4524	10819	89873	-10688	68108	113269
110	-1380	-11822	-3280	12345	-68446	-1445	57729	89552
160	0	-12645	0	12645	0	0	0	0
230	0	-16797	0	16796	0	0	0	0
130	0	-18942	0	18942	0	0	0	0
320	0	0	-9	9	-2371	477	-198	2426
360	2557	0	-752	2665	-4041	12414	-6098	14409
210	572	889	-213	1078	-4840	2004	-11156	12324
280	38	453	-268	527	-2249	2113	10863	11292

* MAX STRESS AT POINT 220 IS 8121 *

EQUIPMENT: T+P+W

SYSTEM DISPLACEMENTS AND ROTATIONS

DATA PNT	--- DISPLACEMENTS (INCHES) --- X	Y	Z	---- ROTATIONS (DEGREES) ----- (X)	(Y)	(Z)
10	-0.000	-0.000	0.000	0.000	-0.000	0.000
20	-0.459	2.191	0.412	0.064	-0.040	0.119
30	-0.241	2.265	0.437	0.064	-0.040	0.119
40	-0.034	2.340	0.460	0.016	-0.032	0.132
50	-0.041	2.337	0.533	0.016	-0.032	0.132
60	-0.002	2.345	0.070	-0.009	-0.027	0.142
70	0.023	2.326	-0.319	-0.025	-0.018	0.125
80	0.027	2.321	-0.392	-0.025	-0.018	0.125
90	-0.183	2.257	-0.325	-0.056	-0.005	0.107
100	-0.401	2.190	-0.328	-0.056	-0.005	0.107
110	-0.000	-0.000	-0.000	-0.000	-0.000	0.000
120	1.031	2.802	0.153	-0.049	-0.024	0.144
120	1.259	2.631	0.204	-0.081	-0.019	-0.068
130	0.441	0.224	0.826	-0.076	0.039	-0.112
130	0.383	-0.017	0.640	-0.017	0.014	-0.030
140	0.372	-0.028	0.384	-0.014	0.014	-0.009
150	-0.413	-0.003	0.418	-0.011	0.015	-0.008
160	-0.541	-0.000	0.424	-0.010	0.015	-0.005
170	-0.797	0.000	0.435	-0.009	0.015	-0.000
180	-0.870	0.000	0.438	-0.009	0.015	-0.000
190	-0.777	1.550	0.442	-0.006	-0.007	-0.057
190	-0.631	1.611	0.437	-0.030	-0.001	-0.198
200	-0.105	1.307	0.439	-0.055	0.001	-0.182
200	0.003	1.259	0.328	-0.012	0.004	-0.071

T A B L E O F C O N T E N T S

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THE PRECEDING PROBLEM HAD 41 ELEMENTS AND 6 LOAD CASES
FEE IS 302 UNITS

CORE USAGE SUMMARY

DATA ITEM	NUMBER REQUIRED	NUMBER ALLOCATED
NODES	108	118
ELEMENTS	107	118
BENDS	8	8
JOINTS	17	17
MATERIAL PROPERTIES	36	36
BOUNDARIES	53	61
SPRING HANGERS	1	1
FREE ANCHORS	0	0
THERMALLY LOADED JOINTS	10	10
EXPANSION JOINTS	0	0
STRESS FACTORS	5	11
SPRINGS	1	1
SPRINGS WITH DISPLACEMENTS	1	1
APPLIED FORCES AT SPRINGS	1	1
MATERIAL-PROPERTY COMMENTS	0	0
ENTRIES IN DYNAMIC SPECTRA	0	0
ROTATING EQUIPMENT NOZZLES	0	0
ADDITIONAL MASS ENTRIES	0	0
DYNAMIC LOAD CASES	0	0
RESPONSE SPECTRA	0	0
HANGER RELEASES	1	1
LIMIT STOPS	10	10
REPORTED ELEMENTS	41	44
MODAL FREQUENCIES	0	0
STATIC LOAD CASES	5	5

TOTAL DYNAMIC CORE ALLOCATION = 13506

STRUCTURAL SOLUTION WORK SPACE= 11644

NO. OF EQUATIONS	=	330
BANDWIDTH	=	54
NO. OF BLOCKS	=	7
BLOCKSIZE	=	64

UOP ENGINEERING DESIGN SEMINAR

HYDRAULIC

General Comments
and Examples
(Overhead Slides)

OUTLINE

HYDRAULICS

A. GENERAL COMMENTS

B. TYPICAL PRESSURE DROPS FOR EQUIPMENT

C. EXAMPLES

   1. NPSH FOR PUMP

   2. PUMPED CIRCUIT

CUSTOMER _____ PAGE NO. _____

SUBJECT PUMP NPSH CALCULATION (SAMPLE) DATE _____

PROJECT _____

BY RCS

1. Estimate NPSH required.
   Pump rate 1400 GPM, 0.548 S.G., head less than 1500 feet.
   From curve (single suction 3550 RPM), minimum required NPSH = (+) 23 feet.

2. Estimate pump centerline elevation.
   From curve, pump centerline is 2 feet above base plate.
   Assume foundation projection 1 foot above base line.
   Centerline elevation above base line = (+) 3 feet

3. Estimate piping friction loss
   $\Delta P/100'$ for 12" pipe = 0.09 psi
   Assume 500 equivalent feet of suction piping
   ΔP (piping) = $\frac{500}{100} \times 0.09 \times \frac{2.31 \text{ ft. water/psi}}{0.548 \text{ S.G.}}$ = 1.9 feet

   Check for smaller suction valve
   $\Delta P/100'$ for 10" pipe = 0.22 psi
   Fully open gate valve is equivalent to 13 pipe diameters of piping
   ΔP (valve) = $\frac{13 \times 10}{100 \times 12} \times 0.22 \times \frac{2.31}{0.548}$ = 0.1 foot

   Estimate pump suction strainer pressure drop (10" strainer)
   ΔP (strainer) = $\frac{300}{100} \times 0.22 \times \frac{2.31}{0.548}$ = 2.8 feet

   Total suction piping system friction loss - say (+) 5 feet

4. Check system absolute pressure
   Liquid is from an equilibrium overhead receiver
   System absolute pressure equals liquid vapor pressure
   Additional equivalent liquid head available = (-) 0 feet

5. Consider minimum controlled liquid level
   Center of float is 5'-0" above bottom of vessel
   Float length is 48"
   Minimum controlled level is 3'-0" above bottom of vessel
   Pump is not expected to operate at full rate beyond control range.
   Liquid available for NPSH = (-) 3 feet

6. Provide for contingency
   Standard contingency = 0.15 x 23 feet = 3.5 feet
   System is clean,

   Total contingency to be provided = (+) 3.5 feet

Minimum elevation of vessel above base line (x) = 31.5 feet

HYDRAULICS

A. NET

POSITIVE

SUCTION

HEAD

THERE IS A MINIMUM POSITIVE SUCTION HEAD (PRESSURE) ABOVE THE FLUID VAPOR PRESSURE REQUIRED FOR CENTRIFUGAL PUMPS.

N P S H (R)

1. NET POSITIVE SUCTION HEAD (NPSH) IS THE PRESSURE OVER AND ABOVE THE VAPOR PRESSURE OF THE LIQUID BEING PUMPED.

2. THIS ADDITIONAL PRESSURE PREVENTS VAPORIZATION OF LIQUID AT THE PUMP INLET THUS INSURING PROPER OPERATION OF THAT PUMP.

3. NPSH IS USUALLY EXPRESSED IN FEET OF LIQUID BEING PUMPED.

NPSH (R) - REQUIRED -

IT IS CHARACTERISTIC OF PUMP. DETERMINED, USUALLY EXPERIMENTALLY, BY THE PUMP MANUFACTURER.

NPSH (A) - AVAILABLE -

THIS IS THE NPSH DESIGNED INTO SYSTEM FOR THE PUMP MENTIONED ABOVE. THIS VALUE MUST BE GREATER THAN NPSH(R) FOR PROPER OPERATION OF THE PUMP.

EXAMPLE: DESIGN A SYSTEM THAT PROVIDES SUFFICIENT NPSH TO THIS PUMP

SINGLE STAGE PUMP

CAPACITY: 500 GPM

SP. GR. = 0.65

HZ = 50

RPM. = 1450 HALF SPEED

(LIQUID VAPOR PRESSURE EQUAL SYSTEM PRESSURE) conservative

1. NPSH (R) (FROM CHART OR MANUFACTURER)....7FT.
2. PUMP CENTERLINE ABOVE BASE LINE (CHART OR MANUFACTURER)

   1.0 + 1.5 EQUALS . . . 2.5FT.

Base line to base plate

NOTE: 8" LINE, SCH-40 $P_{100} = 0.11$

3. I) FRICTION LOSS

DEDUCIDO DE LO GEOMETRIA.

$$\frac{500 \text{ FT (EQ. LENGTH)}}{100 \text{ FT}} \quad (0.11 \text{ PSI}) \quad \frac{2.31}{0.65} = 2.0$$

II) SUCTION VALVE (GATE VALVE, EQUIVALENT LENGTH EQUAL 13D) TOMAR 6" o 8"

$$(0.11 \text{ PSI}) \ (8/6)^5 \ (13) \left(\frac{6 \text{ INCH}}{12 \text{ INCH/FT}}\right) \left(\frac{1}{100 \text{ FT}}\right) \frac{2.31}{0.65} = 0.1$$

III) SUCTION STRAINER

$$(0.46 \text{ PSI}) \ \frac{(300 \text{ FT.})}{100 \text{ FT.}} \ \frac{(2.31)}{0.65} = 4.9 \text{ FT}$$

TOTAL $2.0 + 0.1 + 4.9 = 7.0$

4.	SYSTEM PRESSURE - VAPOR PRESSURE	0.0
5.	MINIMUM LEVEL IN VESSEL CONSIDERAR EL NIVEL MINIMO POR SEGURIDAD.	(0.5)
6.	CONTINGENCY	2.0
	15% OF NPSH(R) 2.0 FT MINIMUM	EL QUE RESULTE MAYOR

SUMMARY

1.	NPSH(R)	7.0
2.	PUMP CENTERLINE	2.5
3.	FRICTION LOSS	7.0
4.	SYSTEM PRESSURE	0
5.	MINIMUM LEVEL	(0.5)
6.	CONTINGENCY	2.0
	TOTAL	18.0 FT.

(FROM BASELINE TO BOTTOM OF VESSEL)

A. General Line Sizing Comments

1. Guides and Approximations
2. Reduce Time for Line Sizing
3. No Computer
4. Good Judgement and Experience

1. Use "NORMAL" Flow Rates and "NORMAL pressures from Process Design

2. Consider the Effects of:

    A. Design Case Flow Rates
    B. Maximum Flow Rates
    C. Startup Conditions
    D. Shutdown Conditions
    E. Upset Conditions

3. Use Flow Sketch To Summarize Hydraulics and Line Sizing Data

4. Flow Sketch Helps To Visualize Effects of Static Head.

Principle Criteria

1. Pressure Drop in PSI/100 feet

2. Velocity in Feet per Minute

Required Physical Properties

1. Specific Gravity - Ratio of liquid density of the Liquid at its flowing temperature to the density of water at 60°F

2. Vapor Density - lb/ft^3

3. Vapor Specific Volume - ft^3/lb

SONIC VELOCITY

1. Maximum velocity that fluid cannot exceed.

2. Occurs at end of pipe or system

3. Examples

    i. Vacuum Heater Transfer Line
    ii. Pressure relief piping
    iii. High Pressure Drop Systems

Specific Volume Change

1. If total line $\Delta P < 10\%$ of upstream absolute pressure, either upstream or downstream volume is acceptable for line ΔP calculation

2. If total line $\Delta P < 40\%$ but $> 10\%$ of upstream absolute pressure, use the average specific volume

3. If total line $\Delta P > 40\%$ of upstream absolute pressure, design the line in sections

Mechanical Considerations

1. Minimum Size Rack Piping 1"

2. Avoid 1 1/4", 2 1/2", 3 1/2" and 5" pipe.

3. For 2" and smaller pipe size, Schedule 80 minimum is recommended.

Pipe Wall Thickness

1. Constant O.D.

2. Pipe I.D. changes as wall thickness changes

3. Wall thickness tolerance is ± 12½ % for seamless pipe up to 24" O.D.

4. Wall thickness tolerance is ± 0.01" if pipe is fabricated from rolled plate

Revamp Projects

1. Economics and decision factors are different

2. Line sizes can often be smaller than for new plants

PRESSURE DROP FOR LIQUID FLOWS

The general equation for pressure drop of a liquid in a pipe can be expressed as the Darcy Equation in the form of:

$$\Delta P = \frac{f \times \rho \times L \times v^2}{144 \times D \times g}$$

WHERE:

ΔP =	**Pressure Drop , pounds per square inch (psi)**
ρ =	**Density, pounds per cubic foot, lb/ft^3**
f =	**Fanning Friction factor**
L =	**Length of pipe in feet, ft**
v =	**Velocity, feet per sec, ft/sec**
D =	**Internal diameter of pipe, ft**
d =	**Internal diameter of pipe, inches**
g =	**Gravitational constant, 32.2 ft/sec^2**
Q =	**Flow, gallons per minute, gpm**

By re-arranging we obtain:

$$\Delta P = \frac{0.000216 f \times L \times \rho \times Q^2}{d^5}$$

Assume L = 100 ft

Define $\Delta P_{(100)} = 100\ \Delta P$

and since ρ = 62.4 x S.G (Specific Gravity)

Substitution and re-arranging yields:

$$\frac{\Delta P_{100}}{S.G.} = \frac{1.348 f \times Q^2}{d^5}$$

Define:

Date a G.S.

$$\Delta P_{o(100)} = \frac{\Delta P_{100}}{S.G.}$$

By Substitution:

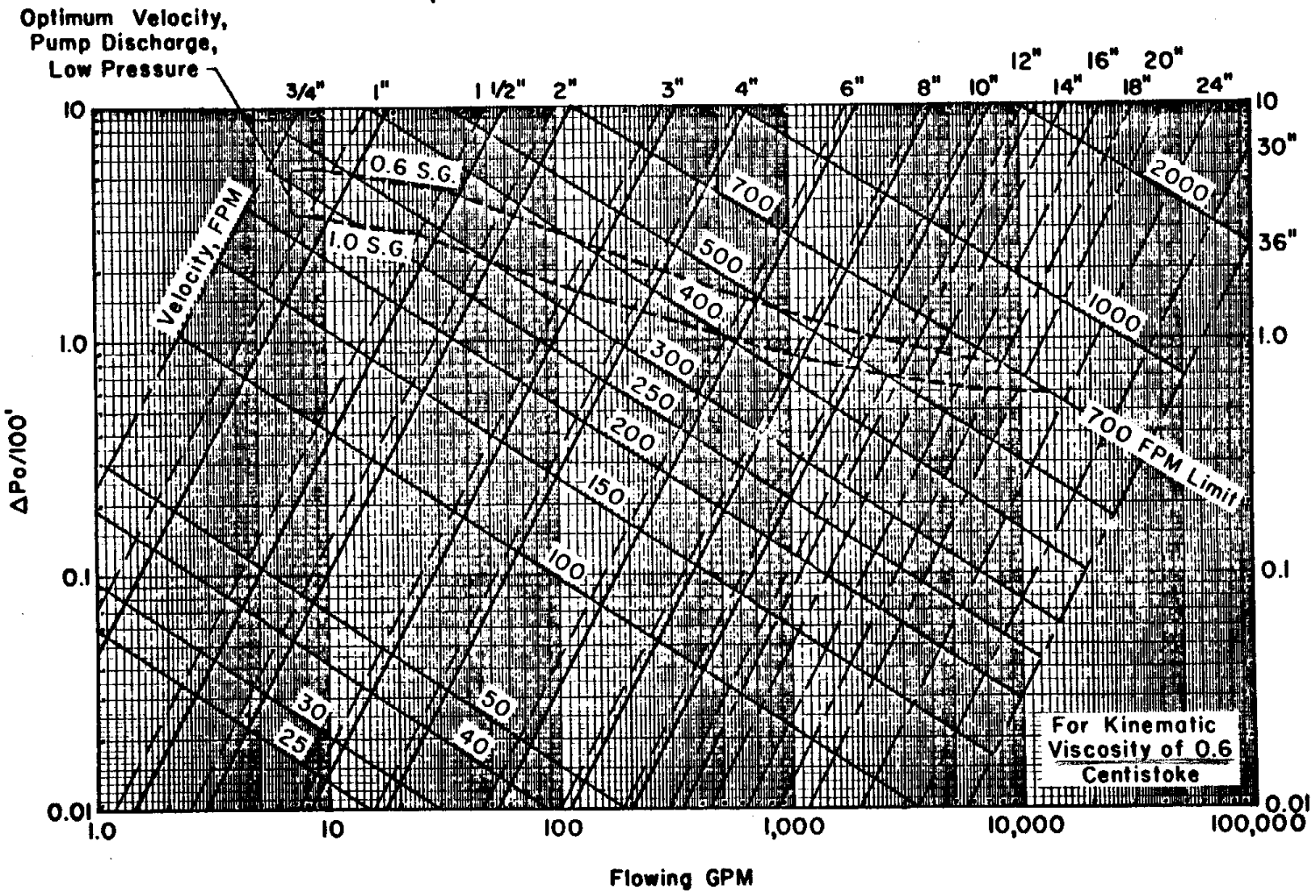
$$\Delta P_{o(100)} = \frac{1.348 f \times Q^2}{d^5}$$

For small changes in flow , Q. Assume Fanning Friction Factor, f, remains constant.

$$\frac{1.348 f}{d^5} = Constant, K$$

Equation then becomes:
$\Delta P_{o(100)} = K\ Q^2$ which is a straight line on Log-Log Graph

Liquid Flow Thru Commercial Steel Pipe



— — — — Sch. 80
——— Sch. 40
——— — ——— 3/8" Wall

Note:
To Find ΔP in PSI per 100 ft. of Pipe, Multiply ΔPo/100' by Specific Gravity.

5-9-75 RE

PD 435-C
(Supersedes PD 435-B)

VISCOSITY CORRECTION:

Chart ΔP is based on a liquid with a kinematic viscosity of 0.6 centistoke.

For more viscous materials, multiply chart ΔP by correction factor:

$$\left(\frac{\nu}{0.6}\right)^{0.2}$$

v is in centistoke

Example:

For *v* = 20 centistoke

the correction factor then evaluates to $(20/0.6)^{.2} = 2.016$

(Note: Correction is for turbulent flow Re > 2000)

v = Kinematic viscosity in centistoke
μ = Absolute viscosity in centipoise
ρ = Density, grams/cc @ 4°C
v = *μ* / *ρ*

LIQUID LINE ΔP PROBLEMS

1. FLOWING GPM = 500
   VISCOSITY (CENTISTOKES) = 0.6
   FLOWING SP. GR. = 0.75

   A. FIND ΔP/100' IN 6" SCH 80 PIPE

   $\Delta P_o/100 = 0.9$ $\Delta P/100 = \Delta P_o/100 \cdot S.G$

   $\Delta P/100 = 0.9 \times 0.75$

   $= 0.675$

   B. FIND ΔP/100' IN 8" SCH 40 PIPE

   $\Delta P_o/100 = 0.18$

   $\Delta P/100 = 0.135$

   C. FIND VELOCITY IN 8" SCH 40 PIPE

   $V = 190$ FPM.

   D. FIND CORRECTED ΔP/100' IN 6" SCH 80 PIPE IF ν = 50 CENTISTOKES

   $(50/0.6)^{0.2} = 2.42.$

   $\Delta P/100 = 2.42 \times 0.675$

   $= 1.65$

   E. WHAT SIZE PIPE WOULD RESULT IN A ΔP/100' = 0.28 IF FLOW IS 4000 GPM, SP. GR. = 0.80 AND ν = 0.6 CTSTK?

   $\Delta P/100 = 0.28$

   $\Delta P_o/100 = 0.28/0.75 = 0.35$

   16" 3/8" THK.

PRESSURE DROP FOR VAPOR FLOWS

The general equation for pressure drop of a vapor in a pipe can be expressed as the Darcy Equation in the form of:

$$\Delta P = \frac{3.36 \times 10^{-6} \times f \times L \times W^2 \times \overline{V}}{d^5}$$

WHERE:

$\Delta P =$	Pressure Drop , pounds per square inch (psi)
$\rho =$	Density, pounds per cubic foot, lb/ft^3
f =	Fanning Friction factor
L =	Length of pipe in feet, ft
V =	Specific volume of fluid, ft^3/lb
d =	Internal diameter of pipe, inches
W =	Mass Flow, lb/h

Assume L = 100 ft

Define $\Delta P_{o(100)}$ = 100 ΔP / V

Substitution and re-arranging yields:

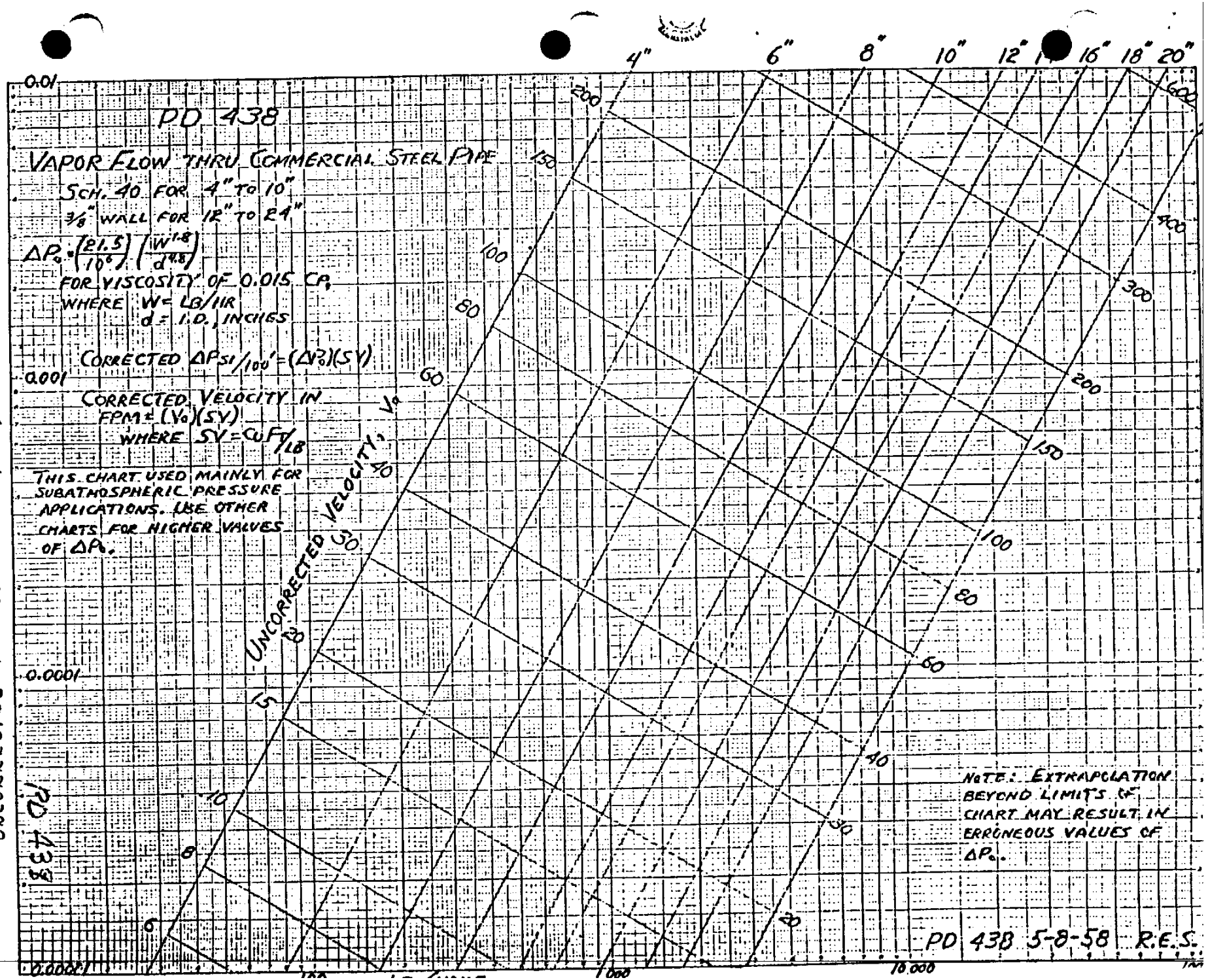
$$\Delta P_{o100} = \frac{336 f}{d^5} \left(\frac{w}{1000} \right)^2$$

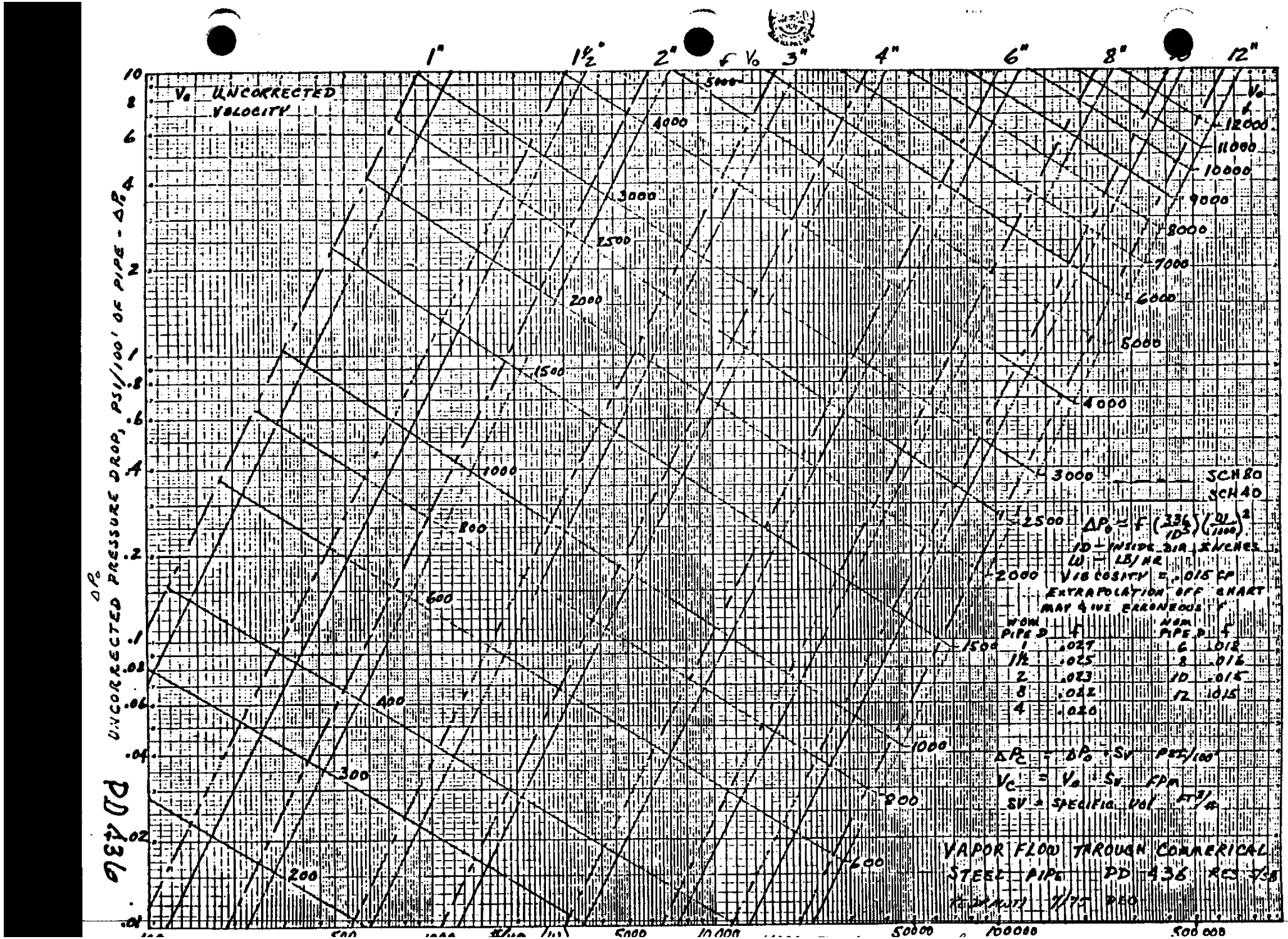
For small changes in flow W, assume the fanning friction factor , f, remains constant.

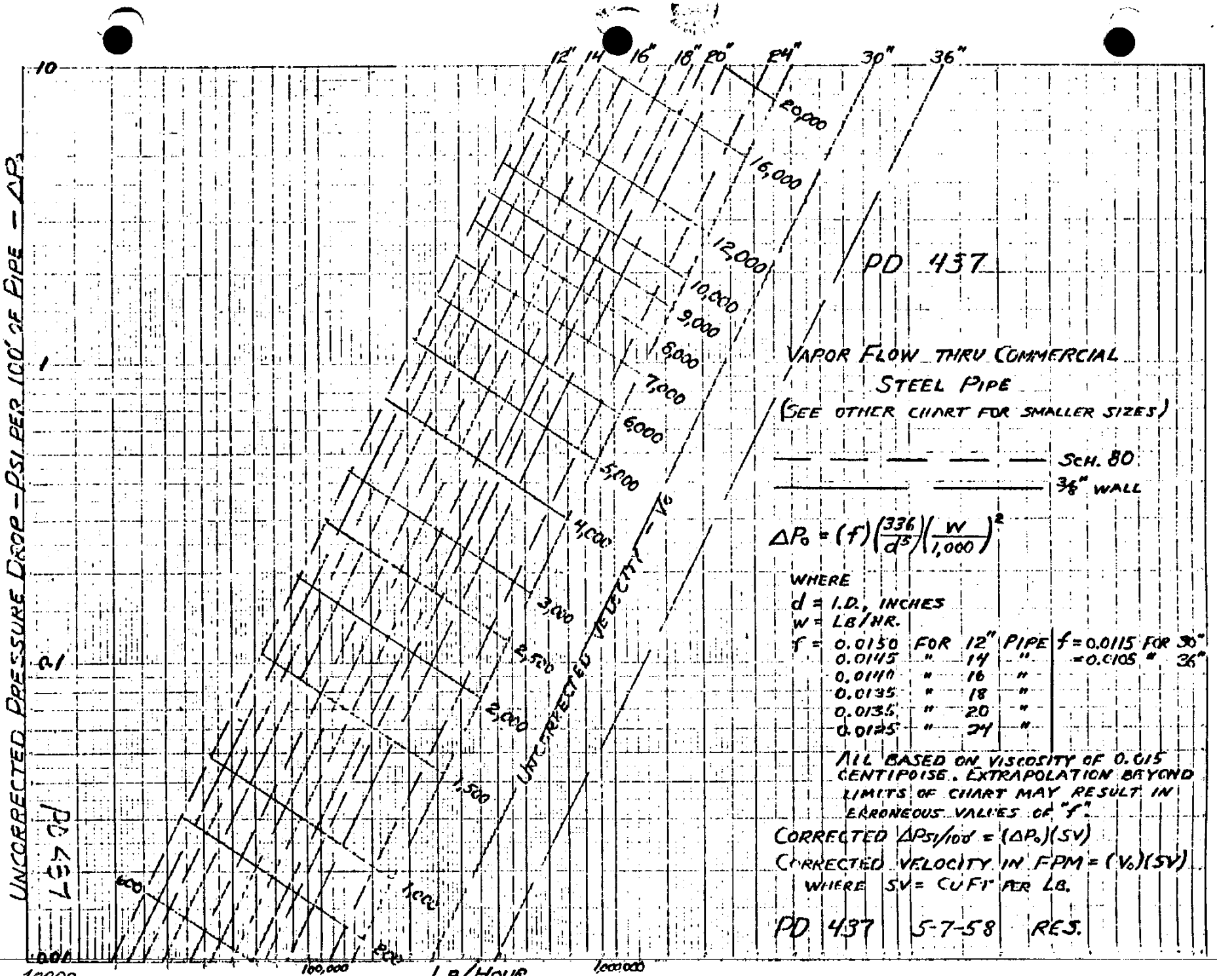
$$\frac{336 f}{d^5} = Constant, K$$

$$\Delta P_{o(100)} = K \left(\frac{W}{1000} \right)^2$$

this plots as a straight line on Log-Log graph


PD 438
VAPOR FLOW THRU COMMERCIAL STEEL PIPE
SCH. 40 FOR 4" TO 10"
3/8" WALL FOR 12" TO 24"
$\Delta P_o = \left(\frac{21.5}{10^6}\right)\left(\frac{W^{1.8}}{d^{4.8}}\right)$
FOR VISCOSITY OF 0.015 CP,
WHERE W = LB/HR
d = I.D., INCHES
CORRECTED $\Delta P_{SI}/_{100'} = (\Delta P_o)(SV)$
CORRECTED VELOCITY IN FPM = $(V_o)(SV)$
WHERE $SV = CU\,FT/_{LB}$
THIS CHART USED MAINLY FOR SUBATMOSPHERIC PRESSURE APPLICATIONS. USE OTHER CHARTS FOR HIGHER VALUES OF ΔP_o.
UNCORRECTED PRESSURE DROP, PSI/100' OF PIPE - ΔP_o
UNCORRECTED VELOCITY, V_o
4" 6" 8" 10" 12" 16" 18" 20"
0.01
0.001
0.0001
0.00001
200 150 100 80 60 40 30 20 15 10 8 6
600 400 300 200 150 100 80 60 40 30 20
1,000
10,000
NOTE: EXTRAPOLATION BEYOND LIMITS OF CHART MAY RESULT IN ERRONEOUS VALUES OF ΔP_o.
PD 438 5-8-58 R.E.S.


1"
1½"
2"
3"
4"
6"
8"
12"
V_o UNCORRECTED VELOCITY
UNCORRECTED PRESSURE DROP, PSI/100' OF PIPE - ΔP_o
ΔP_o
V_o
5000
4000
3000
2500
2000
1500
1000
800
600
400
300
200
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2500
2000
1500
1000
800
600
SCH 80
SCH 40
$\Delta P_o = f\left(\frac{336}{ID^5}\right)\left(\frac{W}{1000}\right)^2$
ID = INSIDE DIA INCHES
W = LB/HR
VISCOSITY = .015 CP
EXTRAPOLATION OFF CHART MAY GIVE ERRONEOUS f
NOM PIPE D f
1 .027
1½ .025
2 .023
3 .021
4 .020
NOM PIPE D f
6 .018
8 .016
10 .015
12 .015
$\Delta P_c = \Delta P_o \cdot Sv$ PSI/100'
$V_c = V_o \cdot Sv$ FPM
SV = SPECIFIC VOL $FT^3/\#$
VAPOR FLOW THROUGH COMMERICAL STEEL PIPE PD 436 Rev 7/58


UNCORRECTED PRESSURE DROP — PSI PER 100' OF PIPE — ΔP
UNCORRECTED VELOCITY — V
LB/HOUR
12" 14" 16" 18" 20" 24" 30" 36"
20,000
16,000
12,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,500
2,000
1,500
1,000
600
10
1
.1
.01
.001
100,000
1,000,000
PD 437
VAPOR FLOW THRU COMMERCIAL STEEL PIPE
(SEE OTHER CHART FOR SMALLER SIZES)
SCH. 80
3/8" WALL
$\Delta P_o = (f)\left(\frac{336}{d^5}\right)\left(\frac{W}{1,000}\right)^2$
WHERE
d = I.D., INCHES
W = LB/HR.
f = 0.0150 FOR 12" PIPE
0.0145 " 14 "
0.0140 " 16 "
0.0135 " 18 "
0.0130 " 20 "
0.0125 " 24 "
f = 0.0115 FOR 30"
= 0.0105 " 36"
ALL BASED ON VISCOSITY OF 0.015 CENTIPOISE. EXTRAPOLATION BEYOND LIMITS OF CHART MAY RESULT IN ERRONEOUS VALUES OF "f".
CORRECTED ΔPSI/100' = (ΔP_o)(SV)
CORRECTED VELOCITY IN FPM = (V_o)(SV)
WHERE SV = CU FT PER LB.
PD 437 5-7-58 RES.

Vapor Line ΔP problems

Flowing Quantity = 40,000 Lb/Hr

Specific Volume = 0.9 Cu.Ft./Lb

A. Find ΔP/100' in 6" Sch 80 pipe

B. Find ΔP/100' in 8" Sch 40 pipe

C. Find Velocity in 8" Sch 40 pipe

D. What size pipe would result in a ΔP/100' equal to or less than 0.4 PSI if flow is 100,000 Lb/Hr and density is 2 Lb/Cu.Ft.? What is velocity in line?

UOP
Process Division
Universal Oil Products Company
20 UOP Plaza – Algonquin & Mt Prospect Roads
Des Plaines, Illinois 60016

Sheet _____
Project _____
Cust. No. _____

HYDRAULIC TABULATION

LINE										
API or lb/gal at 60° F										
Average mol wt										
Temperature, °F										
Flowing sp gr										
Sp vol, cu ft/lb										
Flow vis, centistokes										
Vis corr factor										
	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX
Flowing USGPM										
Flow, lb/hr x 10^3										
Destination, PSIG										
Static, PSI										
Exchange, PSI										
Piping, PSI										
Valve, PSI										
Pump discharge, PSIG										
Pump suction, PSIG										
Differential, PSI										
Differential Head, Feet										
Pressure level, PSIG (BV)										
NORMAL FLOW	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH
Pipe size, IPS										
Pipe class										
Velocity, FPM										
Friction, PSI/100 Ft (Uncorr)										
Friction, PSI/100 Ft (Corr)										
PUMP DESCRIPTION										
	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE
Type										
Item No										
Driver										
Power condition										
NPSH available										
Notes										

BY | DATE | REV | BY | DATE | REV | BY | DATE | REV | BY | DATE | REV | BY | DATE | REV

UOP-17-2002A

TWO-PHASE FLOW PRESSURE DROP

1. CALCULATE FICTITIOUS ALL VAPOR PRESSURE DROP, ΔP_G^*

   USE TOTAL MASS FLOW AND FLOWING VAPOR PROPERTIES

2. CALCULATE FICTITIOUS ALL LIQUID PRESSURE DROP, ΔP_L^*

   CONVERT TOTAL MASS FLOW TO LIQUID, GPM, AND USE FLOWING LIQUID PROPERTIES.

3. CALCULATE RATIO

$$\frac{\Delta P_G^*}{\Delta P_L^*}$$

4. CALCULATE ACTUAL LIQUID VOLUME FRACTION

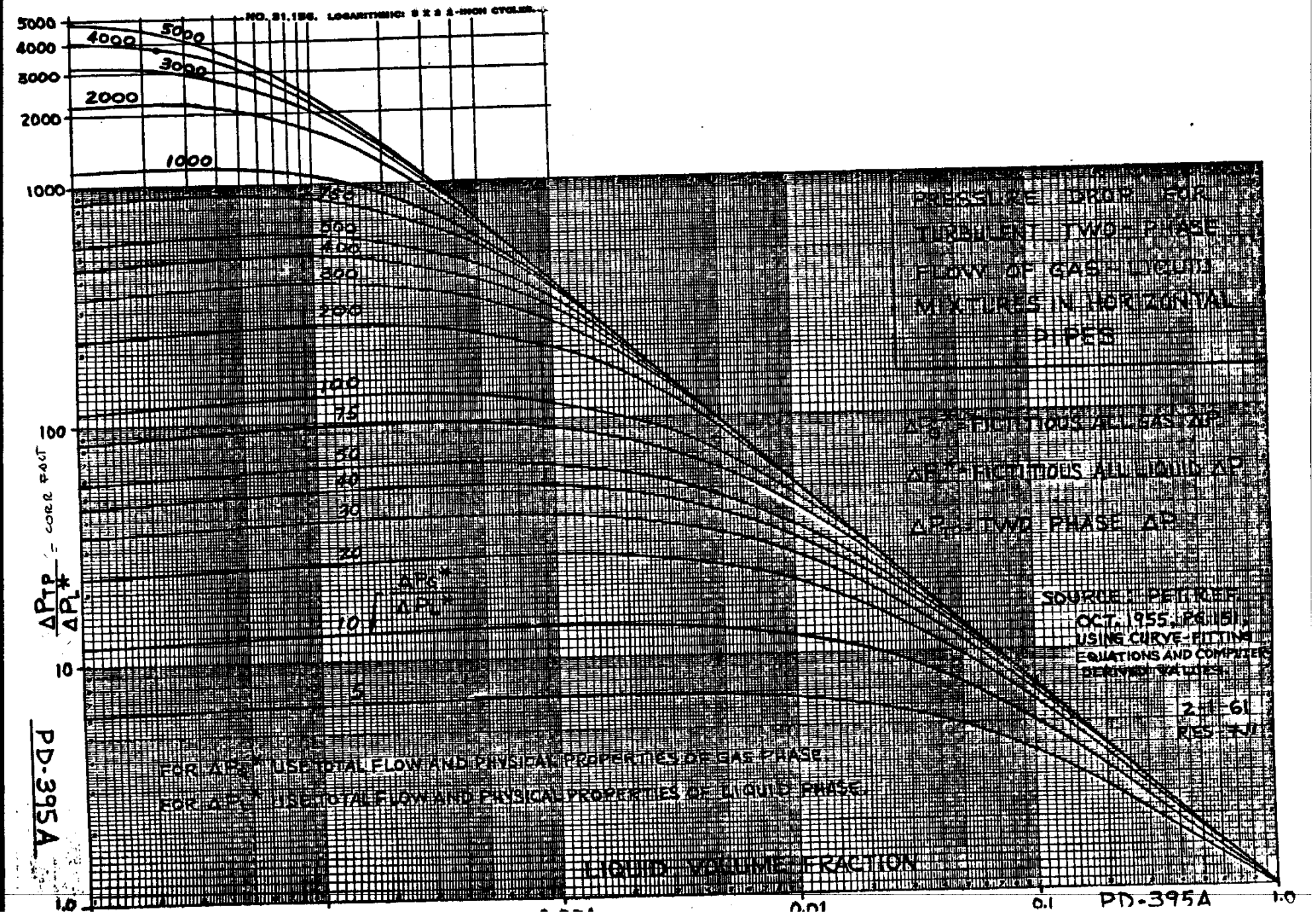
$$\frac{V_L}{V_L + V_G} = \text{LIQUID VOLUME FRACTION}$$

5. FROM CHART DETERMINE FACTOR, f

   WHERE $f = \dfrac{\Delta P_{TP}}{\Delta P_L^*}$

6. CALCULATE TWO-PHASE PRESSURE DROP, ΔP_{TP}

$$\Delta P_{TP} = f \, \Delta P_L^*$$


NO. 31.156. LOGARITHMIC: 3 X 3 1-INCH CYCLES.
PRESSURE DROP FOR TURBULENT TWO-PHASE FLOW OF GAS-LIQUID MIXTURES IN HORIZONTAL PIPES
ΔP_{TP} = FICTITIOUS ALL GAS ΔP
ΔP_L = FICTITIOUS ALL LIQUID ΔP
ΔP_{TP} = TWO PHASE ΔP
SOURCE: PETROL. OCT. 1955, PG. 181
USING CURVE-FITTING EQUATIONS AND COMPUTER DERIVED VALUES
2-1-61
REV. #1
$\frac{\Delta P_{TP}}{\Delta P_L^*}$ = CORR. FACT.
$\frac{\Delta P_G^*}{\Delta P_L^*}$
FOR ΔP_G^* USE TOTAL FLOW AND PHYSICAL PROPERTIES OF GAS PHASE.
FOR ΔP_L^* USE TOTAL FLOW AND PHYSICAL PROPERTIES OF LIQUID PHASE.
LIQUID VOLUME FRACTION
PD-395A
PD-395A

TWO-PHASE FLOW
PRESSURE DROP CALCULATION

EXAMPLE:

VAPOR FLOW:	**47,000 lb/h**
SPECIFIC VOLUME:	**0.303 lb/ft³**
LIQUID FLOW:	**443 gpm**
SPECIFIC GRAVITY:	**0.494**
LINE SIZE:	**12 INCH SCHEDULE 40 PIPE**

SUPPOSE VISCOSITY 2.5 FOR LIQUID.

STEP 1:

Calculate the liquid volume fraction:

$$\frac{Vl}{Vl+Vg}$$

$$Vl=\frac{443gpm*8.34lb/gal*0.494*60min/h}{.494*62.4lb/cf}$$

$$\therefore Vl=3550cf/h$$

calculate the vapor volume:

$$Vg=\frac{47,000lb/h}{1/.303cf/lb}$$

$$\therefore Vg=1420cf/h$$

14250

$$LiquidVolumeFraction=\frac{3550}{3550+14250}=0.2$$

Step 2:

Calculate the total weight flow:

$$Wtotal = Wliquid + Wvapor$$

$$Wliquid = 443 \frac{gal}{min} * 8.34 \frac{lb}{gal} * 0.494 * 60 \frac{min}{hr} = 109,400 \frac{lb}{h}$$

$$Wvapor = 47,000 \frac{lb}{h}$$

$$Wtotal = 109400 + 47000 = 156,400 \frac{lb}{h}$$

Step 3:

Calculate ΔP°_{G}

W total = 156,400 lb/h

Use ΔP chart to get $\Delta P_{o/100}$

$\Delta P_{o/100}$ = 0.47 (for 12 inch Sch 40)

$\Delta P_{o/100}$ = 0.47 * 0.303 = 0.143 psi/100'

Step 4:

Calculate ΔP°_{L}

W total = 156,400 lb/h

Calculate the equivalent in liquid flow assuming liquid gravity

Q gpm = 443 * (156,400 / 109,400) = 633 gpm

Use the ΔP chart for liquids to get $\Delta P_{e/100}$

$\Delta P_{e/100}$ = 0.034 psi (12 inch sch 40)

$\Delta P_{e/100}$ = 0.034 * .494 = 0.17

Step 5:

Calculate the ratio of the fictitious gas to liquid pressure drops

$\Delta P^{\circ}_{G} / \Delta P^{\circ}_{L}$ = .143/.017 = 8.4

Step 6:

From the Two-Phase Flow Chart ω ω $\Delta P^{\circ}_{G}/\Delta P^{\circ}_{L}$ = 8.4
Y LIQUID VOLUME FRACTION = 0.2 .

f = 3.0

$f = \Delta P_{TP} / \Delta P^{\circ}_{L}$

$\Delta P_{TP} = f * \Delta P^{\circ}_{L}$ = 3.0 * .017 = .05 psi/100'

Two Phase Line Sizing

Find the Schedule 80 pipe size that will result in a pressure drop of approximately 0.5 PSI/100' as a result of a two phase flow having the following components:

Liquid flow:

500 GPM

Sp. Gr. 0.75

Vapor flow:

40,000 Lb/Hr

$\bar{v}$ Sp. Vol. 0.9 Ft^3/Lb

ICNDR CSHSLO VISC, LIQUID

UOP PROCESS DIVISION
ENGINEERING DEPARTMENT

CUSTOMER _____
SUBJECT MIXED PHASE LINE SIZING _____

PAGE NO. _____
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BY _____

$$\text{LIQUID VOLUME FRACTION} = \frac{V_L}{V_L + V_G} = \frac{\dfrac{W_L}{\text{S.G.} \times 62.4}}{\dfrac{W_L}{\text{S.G.} \times 62.4} + \dfrac{W_G}{\#/FT^3}}$$

$$= \frac{\qquad\qquad}{\qquad\qquad \times 62.4 + \qquad\qquad \times 62.4} = \frac{\qquad\qquad}{\qquad\qquad + \qquad\qquad} = \qquad\qquad =$$

$$\text{TOTAL FLOW GAS} = W_L + W_G = \qquad\qquad + \qquad\qquad = \qquad\qquad \#/HR$$

$$\text{TOTAL FLOW LIQUID} = \frac{W_L + W_G}{\text{S.G.} \times 500} + \qquad\qquad = \qquad\qquad \text{GPM}$$

TRY _____ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times \text{S.G.}} = \frac{\qquad\qquad \times \dfrac{1}{\qquad\qquad}}{\qquad\qquad \times \qquad\qquad} = \qquad\qquad =$$

$$\Delta P_{Go} = f \times \frac{336}{d^5} \times \left(\frac{W}{1000}\right)^2 = \frac{\qquad\qquad \times 336 \times \qquad\qquad^2}{\qquad\qquad \times 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = \qquad\qquad \times \qquad\qquad =$$

TRY _____ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times \text{S.G.}} = \frac{\qquad\qquad \times \dfrac{1}{\qquad\qquad}}{\qquad\qquad \times \qquad\qquad} = \qquad\qquad =$$

$$\Delta P_{Go} = f \times \frac{336}{d^5} \times \left(\frac{W}{1000}\right)^2 = \frac{\qquad\qquad \times 336 \times \qquad\qquad^2}{\qquad\qquad \times 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = \qquad\qquad \times \qquad\qquad =$$

USE _____ " LINE

SP 11711A

$$\text{LIQUID VOLUME FRACTION} = \frac{V_L}{V_L + V_G} = \frac{\dfrac{W_L}{\text{S.G.} \times 62.4}}{\dfrac{W_L}{\text{S.G.} \times 62.4} + \dfrac{W_G}{\#/FT^3}}$$

$$= \frac{\qquad\qquad}{\qquad\qquad \times 62.4} = \frac{\qquad\qquad}{\qquad\qquad + \qquad\qquad}$$

$$\times 62.4$$

$$= \frac{\qquad\qquad}{+} = \qquad\qquad =$$

TOTAL FLOW GAS = $W_L + W_G$ = _____ + _____ = #/HR

TOTAL FLOW LIQUID = $\dfrac{W_L + W_G}{\text{S.G.} \times 500}$ + _____ = GPM

$$\text{x } 500$$

TRY_____ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times \text{S.G.}} = \frac{\text{x } \dfrac{1}{\qquad}}{\text{x}} = \qquad\qquad =$$

$$\Delta P_{Go} = f \times \frac{336}{d5} \times \left(\frac{W}{1000}\right)^2 = \frac{\qquad\qquad \text{x } 336 \text{ x } \qquad\qquad^2}{\text{x } 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = \_\_\_\_\_ \times \_\_\_\_\_ =$$

TRY_____ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times \text{S.G.}} = \frac{\text{x } \dfrac{1}{\qquad}}{\text{x}} = \qquad\qquad =$$

$$\Delta P_{Go} = f \times \frac{336}{d5} \times \left(\frac{W}{1000}\right)^2 = \frac{\qquad\qquad \text{x } 336 \text{ x } \qquad\qquad^2}{\text{x } 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = \_\_\_\_\_ \times \_\_\_\_\_ =$$

USE _____ " LINE

SP 11711A

SLUG FLOW
CHECK #1

CHECK FOR SLUG FLOW IN 10" SCHED. 80 PIPE

ANNULAR OR MIST FLOW IS USUALLY ASSURED IF THE VELOCITY IN FT/SEC IS APPROXIMATELY EQUAL TO (OR GREATER THAN) 60 DIVIDED BY THE SQUARE ROOT OF THE MIXED PHASE DENSITY IN LBS/FT³.

$$N_c \geq \frac{60}{\sqrt{\rho_{mp}}} \quad \text{IN FT/SEC}$$

$$\rho_{mp} = \frac{227,500}{40,000} = 5.69 \text{ LBS/FT}^3$$

$$N_c = \frac{60}{\sqrt{5.69}} = 25.2 \text{ FT/SEC}$$

$$N_{10"} = \frac{40,000}{3600 \times 0.4989} = 22.3 < 25.2 \text{ FT/SEC}$$

CHECK FURTHER BY USE OF CHART

CHART COORDINATES

$$\text{MASS VELOCITY} = \frac{227,500}{3600 \times 0.4989} = 127$$

$$\frac{1}{\left(\frac{W_L}{W_g}\right)^{0.9}\left(\frac{\rho_g}{\rho_L}\right)^{0.5}\left(\frac{\mu_L}{\mu_g}\right)^{0.1}} = \frac{1}{4.02 \times 0.15 \times 1.41} = 1.18$$

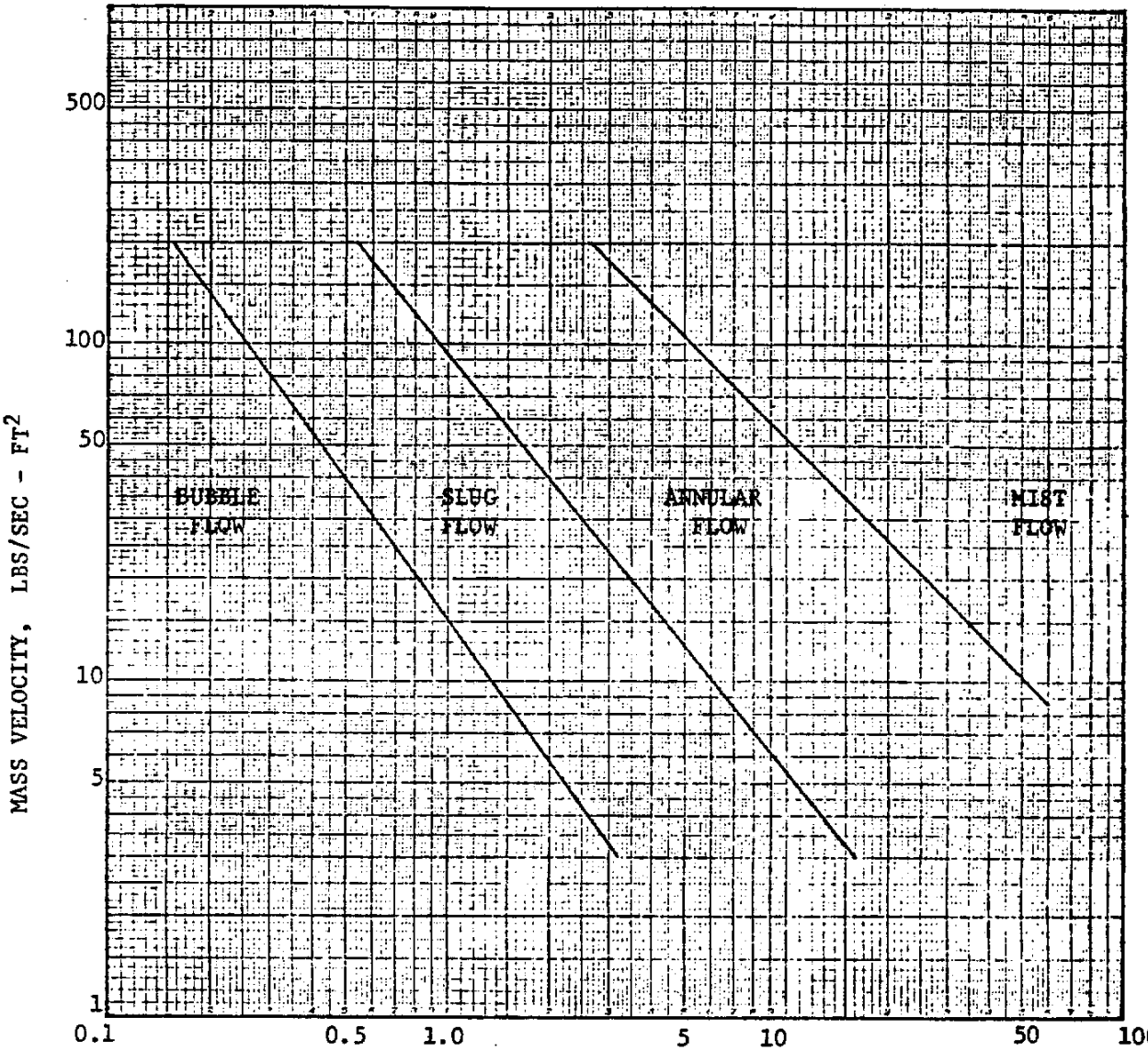
$$\left(\frac{W_L}{W_g}\right)^{0.9} = \left(\frac{187,500}{40,000}\right)^{0.9} = 4.02$$

$$\left(\frac{\rho_g}{\rho_L}\right)^{0.5} = \left(\frac{1.11}{46.9}\right)^{0.5} = 0.15$$

$$\left(\frac{\mu_L}{\mu_g}\right)^{0.1} = \left(\frac{0.6 \times 0.75}{0.015}\right)^{0.1} = 1.41$$

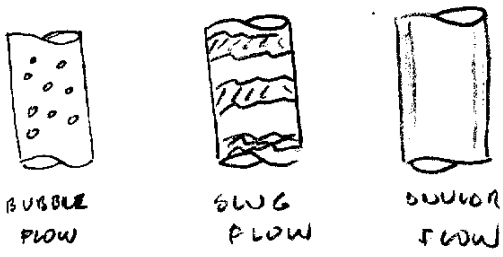
CHART INDICATES ANNULAR FLOW

APPROXIMATE TWO-PHASE FLOW PATTERNS (VERTICAL UPFLOW)



$$\frac{1}{\left(\frac{W_L}{W_g}\right)^{0.9}\left(\frac{\rho_g}{\rho_L}\right)^{0.5}\left(\frac{\mu_L}{\mu_g}\right)^{0.1}}$$

W = Lbs./Sec.
ρ = Lbs./Ft.^{3}
μ = Centipoise



Adapted from:
"What you Need to Design Thermosiphon Reboilers"

James R. Fair
Petroleum Refiner
February, 1960

HCB 5/1/75

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HYDRAULIC TABULATION

WORKSHEET

PROJECT NO._____

SHEET_____ OF_____

BY_____

DATE_____

VAPOR AND LIQUID LINE (TWO PHASE FLOW)					
(1) LIQUID FLOW USGPM					
(2) LIQUID FLOW SP. GR.					
(3) LIQUID FLOW LB./HR. x 10^3					
(4) VAPOR FLOW LB./HR. x 10^3					
(5) TOTAL LB./HR. x 10^3					
(6) VAPOR SP. VOL. CU. FT/LB.					
(7) LIQUID VOLUME CFS = $\frac{GPM}{448}$					
(8) VAPOR VOLUME CFS					
(9) TOTAL VOLUME CFS					
(10) VOL. L/TOTAL VOL. = LVF					
(11)					
(12) LINE SIZE, INCHES					
(13) PIPE SCHEDULE					
(14) IF ALL LIQUID USGPM ⋮ (1) x (5) / (3)					
(15) FRICTION PSI/100 FT. (UNCOR.)					
(16) ΔP_L* (CORR) ⋮ (15) x (2)					
(17) IF ALL GAS LB./HR. x 10^3 ⋮ (5)					
(18) FRICTION PSI/100 FT. (UNCOR.)					
(19) ΔP_G* (CORR) ⋮ (18) x (6)					
(20)					
(21) ΔP_G*/ΔP_L* ⋮ (19) / (16)					
(22)					
(23) $\Delta P_{TP}/\Delta P_L$* = (FACTOR FROM PD-395A)					
(24)					
(25) ΔP_L* x (FACTOR) = ΔP_{TP} (CORR.) ⋮ (16) x (23)					
(26)					
(27) VELOCITIES FPM (CORR.)					

ΔP_L* ∿ FICTITOUS ALL LIQUID ΔP

ΔP_G* ∿ FICTITOUS ALL GAS ΔP

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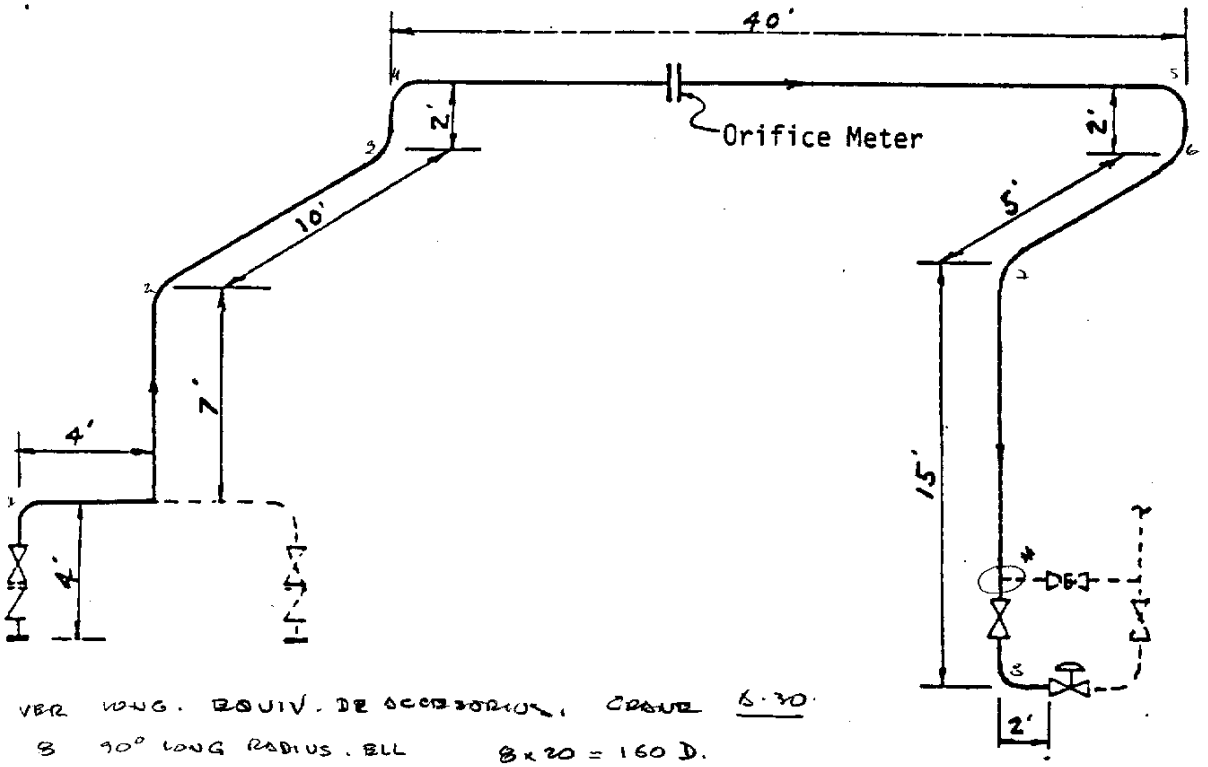
SUBJECT TYPICAL CALCULATION OF PIPING EQUIVALENT LENGTH 8" PUMP DISCHARGE LINE

PAGE NO.

DATE

PROJECT

BY HCB



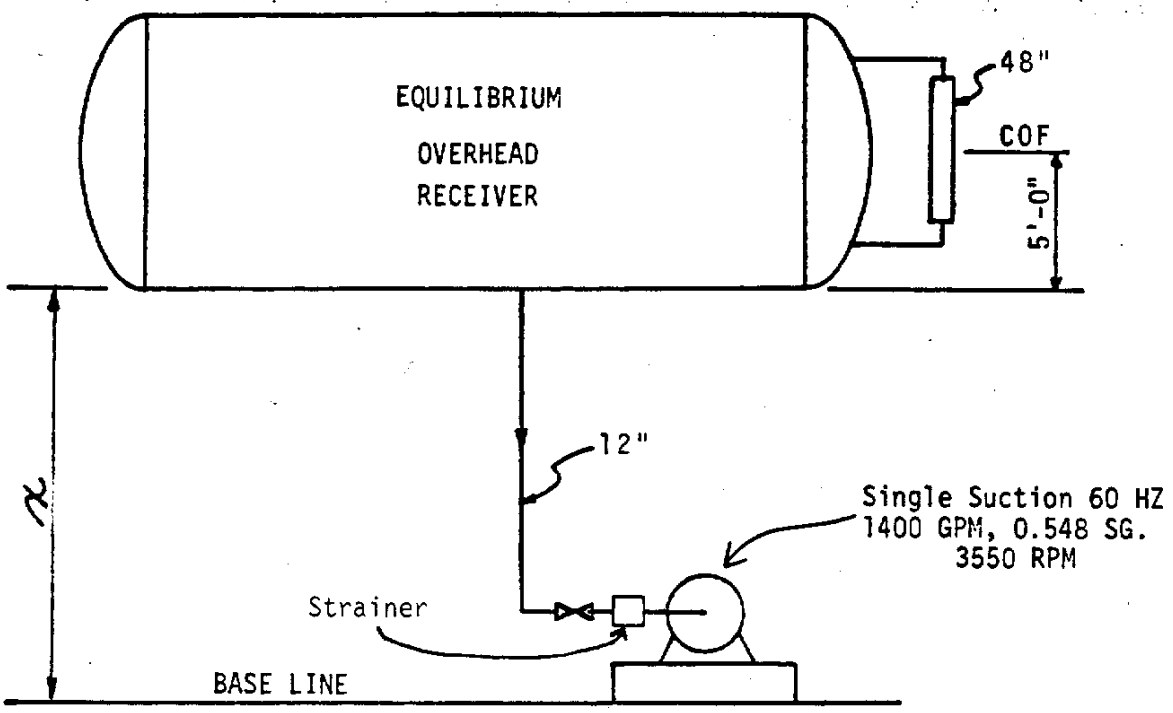
VER LONG. EQUIV. OF ACCESSORIES, CRANE 5-30

CODES	8	90° LONG RADIUS ELL	8 x 20 = 160 D.
	2	GATES.	2 x 15 = 30 D
	1	CHECK VALVE	1 x 135 = 135 D.
	1	BRANCH TEE	1 x 60 = 60 D
*	1	FLOW THRU.	1 x 20 = 20 D
		TOTAL FITINGS	401 D.
		STRAIGHT RUN PIPE	91 FT.

TOTAL EQ LENGTH $91 + 401\left(\frac{D''}{12}\right)$

IF D = 12"

$91 + 401 = 492 \Rightarrow 500$ FT 3" 1400



$$\mathcal{X} = h_{NPSH} + h_{CL} + h_{PFL} - h_P - h_{MLL} + h_{CONT}$$

SHEET_____

PROJECT_____

CUST. NO._____

HYDRAULIC TABULATION

LINE	Pump Suction									
API OR LB/GAL AT 60° F	—									
AVERAGE MOL WT	—									
TEMPERATURE, ° F										
FLOWING SP GR	0.548									
SP VOL, CU FT/LB	—									
FLOW VIS, CENTISTOKES	—									
VIS CORR FACTOR	—									
	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX
FLOWING USGPM	1400									
FLOW, LB/HR x 10^3	—									
DESTINATION, PSIG										
STATIC, PSI										
EXCHANGE, PSI										
PIPING, PSI										
VALVE, PSI										
PUMP DISCHARGE, PSIG										
PUMP SUCTION, PSIG										
DIFFERENTIAL, PSI										
DIFFERENTIAL HEAD, FT										
PRESSURE LEVEL, PSIG (BV)										
NORMAL FLOW	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH
PIPE SIZE, IPS	12									
PIPE SCHEDULE	40									
VELOCITY, FPM	-									
FRICTION, PSI/100 FT (UNCORR)	0.16									
FRICTION, PSI/100 FT (CORR)	0.09									
PUMP DESCRIPTION	Type 2a									
	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE
TYPE										
ITEM NO										
DRIVER										
POWER CONDITION										
NPSH AVAILABLE										
NOTES										

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II. PROCEDURE PDRS DRT HYDR. OF SYSTEM

A. CHOOSE A "SYSTEM" BASED ON FIXED TERMINAL PRESSURES. DETERMINE LINE SIZE AND PRESSURE DROP (PSI/100 FT) FOR THAT LINE OR LINES.

B. ESTIMATE EQUIVALENT LENGTH OF PIPE FOR EACH SEGMENT OF LINE (USE SKETCH).

C. CALCULATE FIXED PRESSURE DROP FOR SYSTEM (STATIC HEADS THAT DON'T CHANGE).

D. CALCULATE CONTROL VALVE PRESSURE DROP.

E. CALCULATE PUMP DIFFERENTIAL.

F. RE-CALCULATE CONTROL VALVE PRESSURE DROP SYSTEM PRESSURE DROP AND PUMP DIFFERENTIAL FOR ALTERNATE CASES.

CUSTOMER

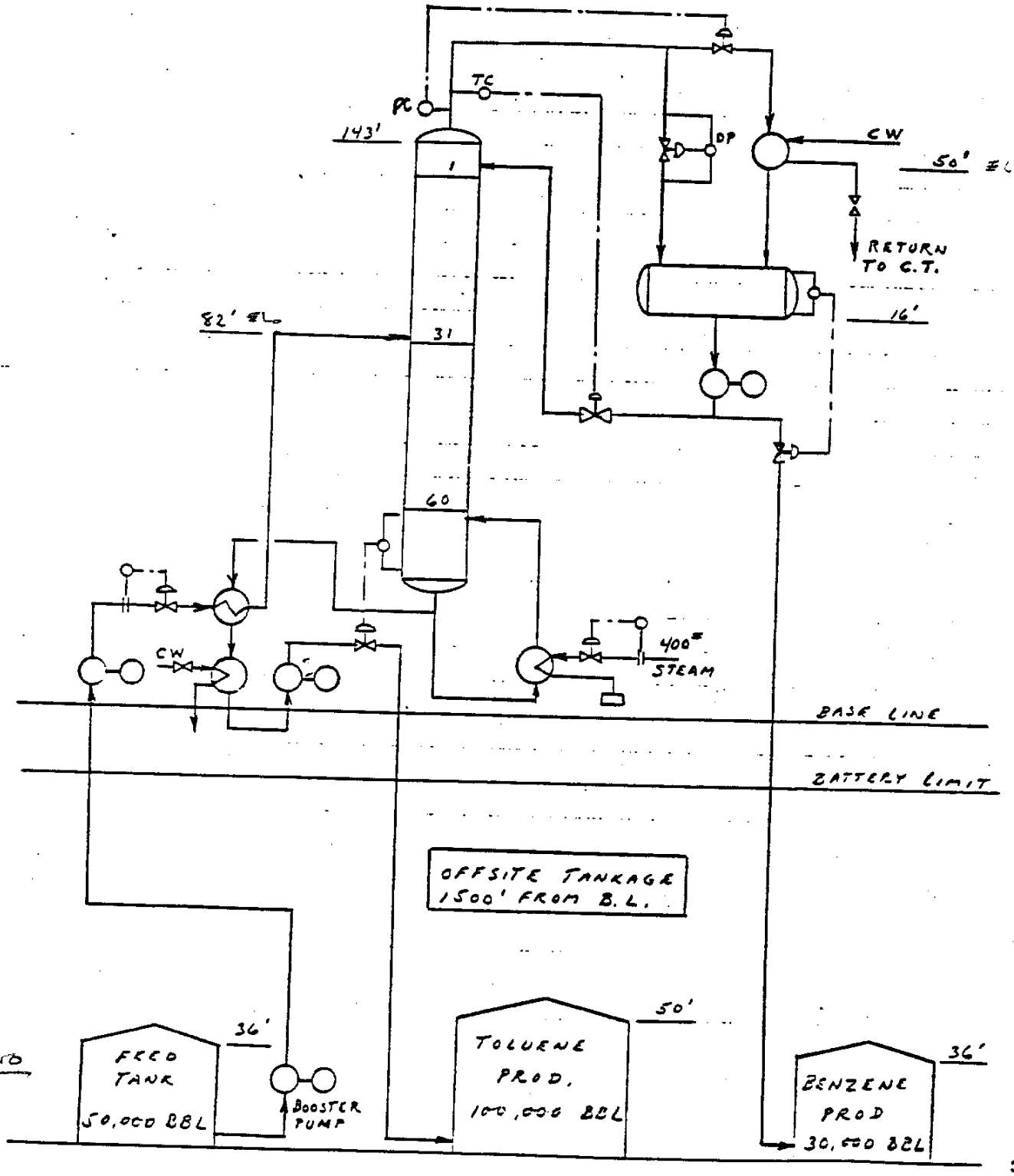
SUBJECT AROMATICS FRACTIONATION

PAGE NO.

DATE

PROJECT

BY



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Des Plaines, Illinois 60016

ENGINEERING DEPARTMENT

HEAT AND WEIGHT BALANCES

PAGE NO. 2
DATE
PROJECT
BY

AROMATICS FRACTIONATION
EXAMPLE FOR LINE SIZING ONLY

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STREAM	°API (LB/GAL)	K	MW	FLOWING SP. GR. (LB/CF)	°F	PSIG (MM HG ABS)	BPSD @60°F (10^3 SCF/D)	FLOWING GPM (CFS)	MOLS PER HR.	LB/HR	BTU/LB	10^6 BTU/HR
AROMATICS FROM STORAGE	(7.28)	10.0	89	.86	100	–	5000	148	718	63700	18	1.14
FEED - BTMS EXCH. DUTY												1.72
FEED TO COLUMN	(7.28)		89	.82	160	7	–	155	718	63700	45	2.86
OVHD VAPORS TO COND.	–		78	(0.22)	195	5	–	(87)	883	68900	225	15.5
CONDENSER DUTY												14.3
MAT'L TO RECEIVER	(7.37)		78	.86	100	0	5340	160	883	68900	17	1.2
REFLUX	"		78	.86	"	"	4340	130	718	56000	17	1.0
BENZENE PROD.	"	9.75	78	.86	"	"	1000	30	165	12900	17	0.2
LIQ. TO REBOILER	(7.26)		92	.76	265	10	26,600	890	3670	338000	97	32.80
REBOILER DUTY												16.56
MAT'L FROM REBOILER	(7.26)		92	–	265	10	–	–	3670	338000	146	49.36
VAPOR	–		92	(.30)	"	"	(11.15)	(105)	1223	113000	243	27.46
LIQUID	(7.26)		92	.76	"	"	17700	592	2447	225000	97	21.90
BTMS. TO EXCH.	(7.26)		92	.76	265	–	4000	134	553	50800	97	4.92
EXCHANGER DUTY												1.72
BTMS. TO COOLER	(7.26)		92	.79	200	–	4000	129	553	50800	63	3.20
COOLER DUTY												2.30
BTMS. TO STORAGE	(7.26)	10.1	92	.85	100	–	4000	119	553	50800	18	0.90

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Universal Oil Products Company
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ENGINEERING DEPARTMENT

HEAT AND WEIGHT BALANCES

AROMATICS FRACTIONATION

EXAMPLE FOR LINE SIZING ONLY

PAGE NO. 3
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STREAM	° API (LB/GAL)	K	MW	FLOWING SP. GR.	°F	PSIG (MM HG ABS)	BPSD @60°F (10^3 SCF/D)	FLOWING GPM (CFS)	MOLS PER HR.	LB/HR	BTU/LB	10^6 BTU/HR
				(S.V.)							ABOVE 60°F	
STEAM TO REBOILER				(1.12)	448	400				19100	1176	
REBOILER DUTY												16.56
CONDENSATE FROM REBOILER				0.88	365	150				19100	310	
NOTE ΔP FOR 50° APPROACH					315	70						
C.W. TO CONDENSER					80			1430		715000		
CONDENSER DUTY												14.3
C.W. FROM CONDENSER					100			1430		715000		
C.W. TO BTMS COOLER					80			153		76600		
COOLER DUTY												2.3
C.W. FROM BTMS COOLER					100			153		76600		

T-421

SHEET_____

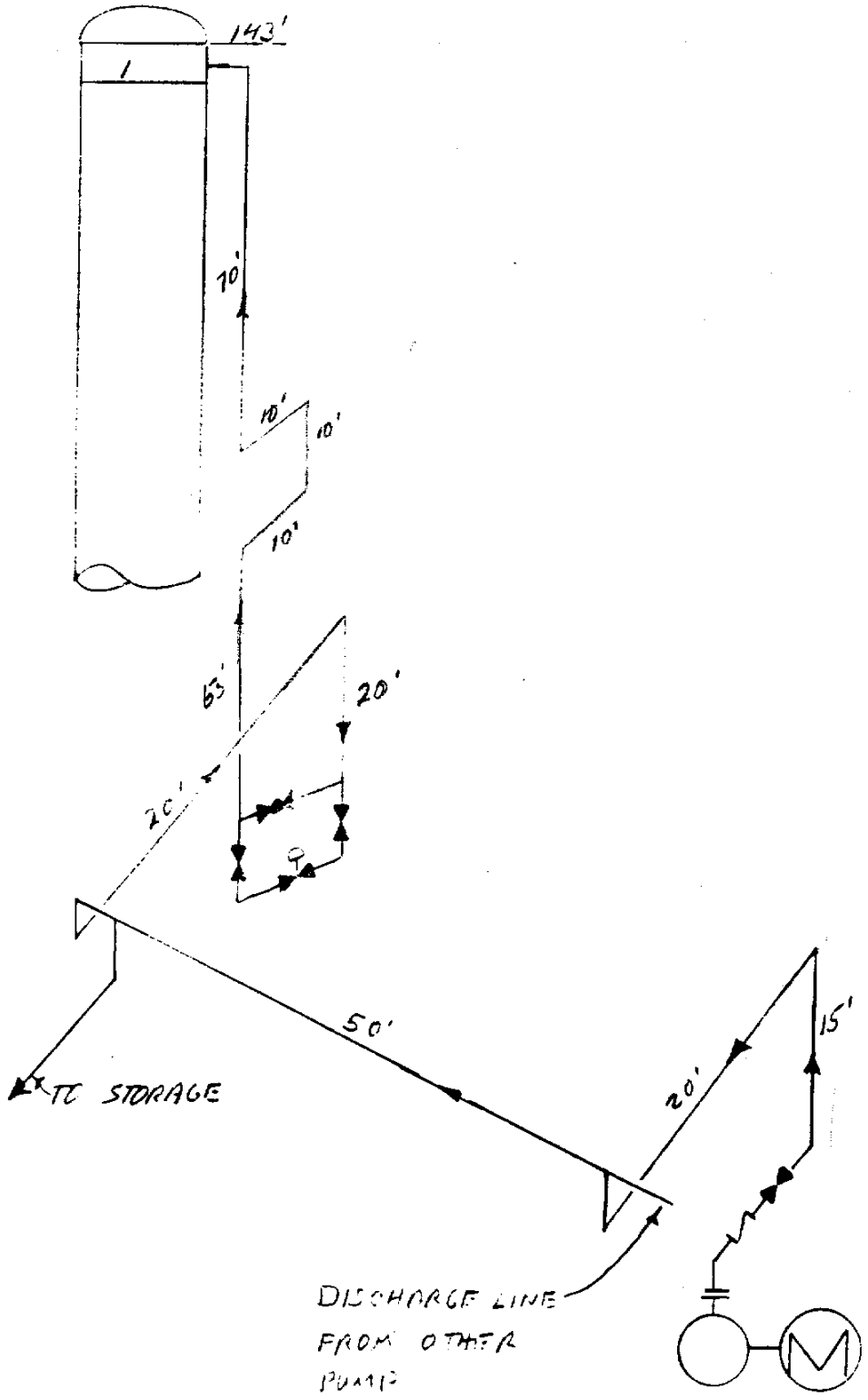
PROJECT_____

CUST. NO._____

HYDRAULIC TABULATION

LINE	Overhead pump Suction		Overhead pump Discharge		→ Reflux					
API OR LB/GAL AT 60° F										
AVERAGE MOL WT										
TEMPERATURE, ° F										
FLOWING SP GR	0.86		→		→					
SP VOL, CU FT/LB	—		—		—					
FLOW VIS, CENTISTOKES	—		—		—					
VIS CORR FACTOR	—		—		—					
	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX	NOR	MAX
FLOWING USGPM	160	176	160		130					
FLOW, LB/HR x 10^3										
DESTINATION, PSIG										
STATIC, PSI										
EXCHANGE, PSI										
PIPING, PSI										
VALVE, PSI										
PUMP DISCHARGE, PSIG										
PUMP SUCTION, PSIG										
DIFFERENTIAL, PSI										
DIFFERENTIAL HEAD, FT										
PRESSURE LEVEL, PSIG (BVI)										
NORMAL FLOW	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH	SUCT	DISCH
PIPE SIZE, IPS	6			3		3				
PIPE SCHEDULE	40			40		40				
VELOCITY, FPM	—			410		330				
FRICTION, PSI/100 FT (UNCORR)	0.08			2.5		1.70				
FRICTION, PSI/100 FT (CORR)	0.07			2.15		1.46				
PUMP DESCRIPTION	Type 2a		Type 3a		Type 3c					
	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE	OPER	SPARE
TYPE										
ITEM NO										
DRIVER										
POWER CONDITION										
NPSH AVAILABLE										
NOTES										

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143'
1
10'
10'
10'
10'
65'
20'
20'
50'
TC STORAGE
20'
15'
DISCHARGE LINE
FROM OTHER
PUMPS
M

UOP17-1177

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	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	Δp/100 FT. PSI	ESTIM. EQ. FT. x 100	DESCRIPTION
1						REFLUX TO COLUMN
2						STATIC HEAD 143' ($\frac{0.66}{\text{SG}}$)
3	—	3	40	1.46	25	LINE TO TRAY No. 1
4						6 - 90° ELL — 12D LONG RADIUS ELLBOWS
5						1 - TEE (STRAIGHT) 20D
6						1 - GATE VALVE 13D
7						SUBTOTAL 153D
8						EQUIVALENT LENGTH 38'
9						STRAIGHT PIPE 163'
10						TOTAL EQUIV. LENGTH 201'
11						USE 250 FT
12						
13						CONTROL VALVE
14	—	3	40	1.46	1.0	LINE TO CONTROL VALVE
15						4 - 90° ELL 8D
16						1 - TEE - (STRAIGHT) 20D
17						1 - GATE VALVE 13D
18						SUB TOTAL 113D
19						EQUIVALENT LENGTH 28'
20						STRAIGHT PIPE 40
21						TOTAL EQUIV. LEN 68'
22						USE 100'
23						
24						

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HYDRAULIC TABULATION

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HYDRAULIC TABULATION

PROJECT SPECIFICATION — NUMBER — — REVISION

SHEET 2 OF

BY DTJ APP'D

DATE

	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	ΔP/100 FT. PSI	ESTIM. EQ. FT. ± 10%	DESCRIPTION
1	-	3	40	2.15	2.0	PUMP DISCHARGE LINE
2						4 - 90° ELL EQD
3						1 - TEE (BRANCH) 60D
4						1 - TEE (STRAIGHT) 20D
5						1 - CHECK VALVE 135D
6						1 - GATE VALVE 13D
7						SUBTOTAL 328D
8						EQUIVALENT LENGTH 82
9						STRAIGHT PIPE 85
10						TOTAL EQUIV. LENG. 167'
11						USE 200'
12						
13						PUMP
14						STATIC 16' ($\frac{0.46}{2.31}$)
15	-	6	40	007	3.0	
16						SEE 'HYDRAULIC
17						GENERAL COMMENTS'
18						ITEM 'A-3' NPSH
19						CALCULATIONS
20						
21						
22						
23						
24						

UOP17-1177

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HYDRAULIC TABULATION

	LINE NO. (C.V. FOR ↓)	SIZE IN.	SCHEDULE	ΔP/100 FT. PSI	ESTIM. EQ. FT. x 100	DESCRIPTION	NORMAL ΔP PSI	NORMAL INLET PRESS. PSIG
1	←	3	40	2.15	2.0	PUMP DISCHARGE LINE	4.3	9865
2						4 - 90° ELL 80D		
3						1 - TEE (BRANCH) 60D		
4						1 - TEE (STRAIGHT) 20D		
5						1 - CHECK VALVE 135D		
6						1 - GATE VALVE 13D		
7						SUBTOTAL 328D		
8						EQUIVALENT LENGTH 82		
9						STRAIGHT PIPE 85		
10						TOTAL EQUIV. LENGTH 167'		
11						USE 200'		
12								
13						PUMP		5.8
14						STATIC 16' ($\frac{0.46}{2.31}$)	(6)	(0.2)
15	←	6	40	0.07	3.0		0.2	0
16						SEE 'HYDRAULIC		
17						GENERAL COMMENTS'		
18						ITEM 'A-3' NPSH		
19						CALCULATIONS		
20								
21								
22								
23								
24								

PROJECT SPECIFICATION
NUMBER – –
REVISION
SHEET 2 OF
BY DJL APP'D
DATE

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	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	ΔP/100 FT. PSI	ESTIM. EQ. FT. ± 10%	DESCRIPTION	NORMAL ΔP PSI	NORMAL INLET PRESS. PSIG
1						REFLUX TO COLUMN	—	5
2						STATIC HEAD 143' (0.6 / 5.31)	5.3	5.8
3	—	3	40	1.46	25	LINE TO TRAY No. 1	3.7	61.7
4						(6 - 90° ELL — 12OD		
5						1 - TEE (STRAIGHT) 20D		
6						1 - GATE VALVE 13D		
7						SUBTOTAL 153D		
8						EQUIVALENT LENGTH 38'		
9						STRAIGHT PIPE 173		
10						TOTAL EQUIV. LENGTH 211'		
11						USE 250 FT		
12								
13						CONTROL VALVE	25	86.7
14	—	3	40	1.46	1.0	LINE TO CONTROL VALVE	1.5	88.2
15						(4 - 90° ELL 8OD		
16						1 - TEE - (STRAIGHT) 20D		
17						1 - GATE VALVE 13D		
18						SUB TOTAL 113D		
19						EQUIVALENT LENGTH 24'		
20						STRAIGHT PIPE 40		
21						TOTAL EQUIV. LEN 68'		
22						USE 100'		
23								
24								

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HYDRAULIC TABULATION

NUMBER — REVISION —

SHEET 1 OF

BY DJN APPD

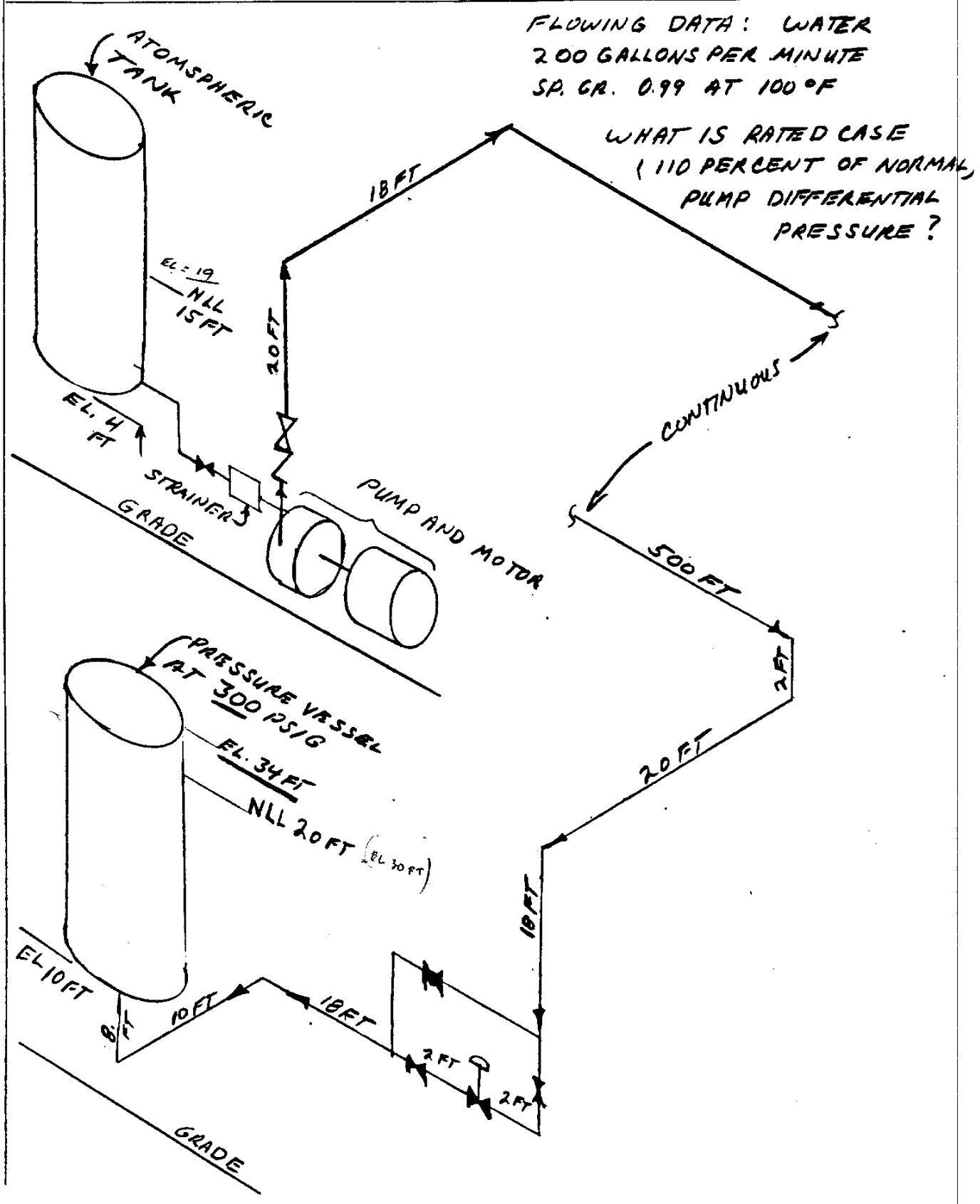
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Process Division
Universal Oil Products Company
20 UOP Plaza – Algonquin & Mt. Prospect Roads
Des Plaines, Illinois 60016 312•763-6000

PIPING SKETCH NO.

DR. _____ CK. _____

DATE _____ PROJECT _____



Nomenclature

Unless otherwise stated, all symbols used in this book are defined as follows:

A = cross sectional area of pipe or orifice, in square feet

a = cross sectional area of pipe or orifice, or flow area in valve, in square inches

B = rate of flow in barrels (42 gallons) per hour

C = flow coefficient for orifices and nozzles = discharge coefficient corrected for velocity of approach = $C_d / \sqrt{1-\beta^4}$.

C_d = discharge coefficient for orifices and nozzles

C_v = flow coefficient for valves; expresses flow rate in gallons per minute of 60 F water with 1.0 psi pressure drop across valve

D = internal diameter of pipe, in feet

d = internal diameter of pipe, in inches

e = base of natural logarithm = 2.718

f = friction factor in formula $h_L = f L v^2 / D 2g$

f_T = friction factor in zone of complete turbulence

g = acceleration of gravity = 32.2 feet per second per second

H = total head, in feet of fluid

h = static pressure head existing at a point, in feet of fluid

h_g = total heat of steam, in Btu per pound

h_L = loss of static pressure head due to fluid flow, in feet of fluid

h_w = static pressure head, in inches of water

K = resistance coefficient or velocity head loss in the formula, $h_L = Kv^2 / 2g$

k = ratio of specific heat at constant pressure to specific heat at constant volume = c_p / c_v

L = length of pipe, in feet

L/D = equivalent length of a resistance to flow, in pipe diameters

L_m = length of pipe, in miles

M = molecular weight

MR = universal gas constant = 1544

n = exponent in equation for polytropic change ($p'V_g'^n$ = constant)

P = pressure, in pounds per square inch gauge

P' = pressure, pounds per square inch absolute

(see page 1-5 for diagram showing relationship between gauge and absolute pressure)

p' = pressure, in pounds per square foot absolute

Q = rate of flow, in gallons per minute

q = rate of flow, in cubic feet per second at flowing conditions

q' = rate of flow, in cubic feet per second at standard conditions (14.7 psia and 60F)

q'_d = rate of flow, in millions of standard cubic feet per day, MMscfd

q'_h = rate of flow, in cubic feet per hour at standard conditions (14.7 psia and 60F), scfh

q_m = rate of flow, in cubic feet per minute at flowing conditions

q'_m = rate of flow, in cubic feet per minute at std. conditions (14.7 psia and 60F), scfm

R = individual gas constant = MR/M = $1544/M$

R_e = Reynolds number

R_H = hydraulic radius, in feet

r_c = critical pressure ratio for compressible flow

S = specific gravity of liquids at specified temperature relative to water at standard temperature (60 F)

S_g = specific gravity of a gas relative to air = the ratio of the molecular weight of the gas to that of air

T = absolute temperature, in degrees Rankine (460 + t)

t = temperature, in degrees Fahrenheit

$\overline{V}$ = specific volume of fluid, in cubic feet per pound

V = mean velocity of flow, in feet per minute

V_g = volume, in cubic feet

v = mean velocity of flow, in feet per second

v_s = sonic (or critical) velocity of flow of a gas, in feet per second

W = rate of flow, in pounds per hour

w = rate of flow, in pounds per second

w_g = weight, in pounds

x = percent quality of steam = 100 minus per cent of moisture

Y = net expansion factor for compressible flow through orifices, nozzles, or pipe

Z = potential head or elevation above reference level, in feet

Greek Letters

Beta

β = ratio of small to large diameter in orifices and nozzles, and contractions or enlargements in pipes

Delta

Δ = differential between two points

Epsilon

ϵ = absolute roughness or effective height of pipe wall irregularities, in feet

Mu

μ = absolute (dynamic) viscosity, in centipoise

μ_r = absolute viscosity, in pound mass per foot second or poundal seconds per sq foot

μ'_r = absolute viscosity, in slugs per foot second or pound force seconds per square foot

Nu

ν = kinematic viscosity, in centistokes

ν' = kinematic viscosity, square feet per second

Rho

ρ = weight density of fluid, pounds per cubic ft

ρ' = density of fluid, grams per cubic centimeter

Theta

θ = angle of convergence or divergence in enlargements or contractions in pipes

Subscripts for Diameter

(1)...defines smaller diameter

(2)...defines larger diameter

Subscripts for Fluid Property

(1)...defines inlet (upstream) condition

(2)...defines outlet (downstream) condition

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-30.

Schedule (Thickness) of Steel Pipe Used in Obtaining Resistance Of Valves and Fittings of Various Pressure Classes by Test*

Valve or Fitting ASA Pressure Classification			Schedule No. of Pipe Thickness
Steam Rating		Cold Rating	
250-Pound and Lower		500 psig	Schedule 40
300-Pound to 600-Pound		1440 psig	Schedule 80
900-Pound		2160 psig	Schedule 120
1500-Pound		3600 psig	Schedule 160
2500-Pound	½ to 6"	6000 psig	xx (Double Extra Strong)
	8" and larger	3600 psig	Schedule 160

*These schedule numbers have been arbitrarily selected only for the purpose of identifying the various pressure classes of valves and fittings with specific pipe dimensions for the interpretation of flow test data; they should not be construed as a recommendation for installation purposes.

Representative Equivalent Length‡ in Pipe Diameters (L/D) Of Various Valves and Fittings

Description of Product				Equivalent Length in Pipe Diameters (L/D)
Globe Valves	Stem Perpendicular to Run	With no obstruction in flat, bevel, or plug type seat	Fully open	340
		With wing or pin guided disc	Fully open	450
	Y-Pattern	(No obstruction in flat, bevel, or plug type seat)		
		– With stem 60 degrees from run of pipe line	Fully open	175
		– With stem 45 degrees from run of pipe line	Fully open	145
Angle Valves		With no obstruction in flat, bevel, or plug type seat	Fully open	145
		With wing or pin guided disc	Fully open	200
Gate Valves	Wedge, Disc, Double Disc, or Plug Disc		Fully open	13
			Three-quarters open	35
			One-half open	160
			One-quarter open	900
	Pulp Stock		Fully open	17
			Three-quarters open	50
			One-half open	260
			One-quarter open	1200
Conduit Pipe Line Gate, Ball, and Plug Valves			Fully open	3**
Check Valves	Conventional Swing		0.5†...Fully open	135
	Clearway Swing		0.5†...Fully open	50
	Globe Lift or Stop; Stem Perpendicular to Run or Y-Pattern		2.0†...Fully open	Same as Globe
	Angle Lift or Stop		2.0†...Fully open	Same as Angle
	In-Line Ball		2.5 vertical and 0.25 horizontal†...Fully open	150
Foot Valves with Strainer		With poppet lift-type disc	0.3†...Fully open	420
		With leather-hinged disc	0.4†...Fully open	75
Butterfly Valves (8-inch and larger)			Fully open	40
Cocks	Straight-Through	Rectangular plug port area equal to 100% of pipe area	Fully open	18
	Three-Way	Rectangular plug port area equal to 80% of pipe area (fully open)	Flow straight through	44
			Flow through branch	140
Fittings	90 Degree Standard Elbow			30
	45 Degree Standard Elbow			16
	90 Degree Long Radius Elbow			20
	90 Degree Street Elbow			50
	45 Degree Street Elbow			26
	Square Corner Elbow			57
	Standard Tee	With flow through run		20
		With flow through branch		60
	Close Pattern Return Bend			50
Pipe	90 Degree Pipe Bends			See Page A-27
	Miter Bends			See Page A-27
	Sudden Enlargements and Contractions			See Page A-26
	Entrance and Exit Losses			See Page A-26

**Exact equivalent length is equal to the length between flange faces or welding ends.

†Minimum calculated pressure drop (psi) across valve to provide sufficient flow to lift disc fully.

‡For limitations, see page 2-11. For effect of end connections, see page 2-10.

For resistance factor "K", equivalent length in feet of pipe *see pages A-31*

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-30.

PD-902
7-20-75
RES

Resistance of 90 Degree Bends[21]

The chart at the right shows the resistance of 90 degree bends to the flow of fluids in terms of equivalent lengths of straight pipe.

Resistance of bends greater than 90 degrees is found using the formula:

$$\frac{L}{D} = R_t + (n-1)\left(R_t + \frac{R_b}{2}\right)$$

n = total number of 90° bends in coil
R_t = total resistance due to one 90° bend, in L/D
R_t = resistance due to length of one 90° bend, in L/D
R_b = bend resistance due to one 90° bend, in L/D

Problem: Determine the equivalent lengths in pipe diameters of a 90 degree bend and a 270 degree bend having a relative radius of 12.

Solution: Referring to the "Total Resistance" curve, the equivalent length for a 90 degree bend is 34.5 pipe diameters.

The equivalent length of a 270 degree bend is:

$$L/D = 34.5 + (3-1)\,[18.7 + (15.8 + 2)]$$
$$L/D = 87.7 \text{ pipe diameters}$$

Note: This loss is less than the sum of losses through three 90 degree bends separated by tangents. For "resistance of bends theory", see page 2-12.

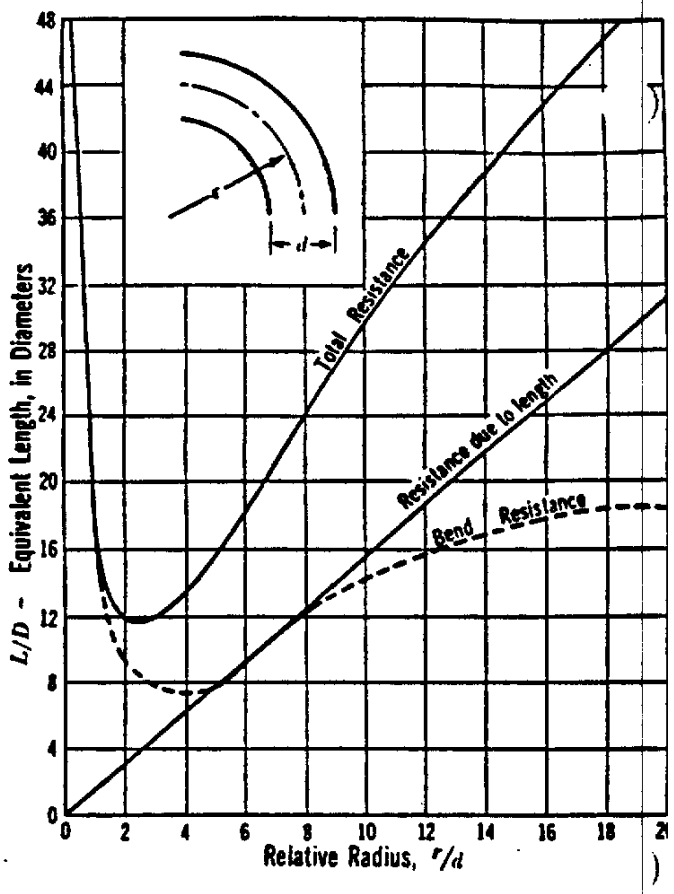


Chart for Resistance of 90 Degree Bends

From *Pressure Losses for Fluid Flow in 90 Degree Pipe Bends* by K. H. Beij. Courtesy of Journal of Research of National Bureau of Standards, Vol. 21, July, 1938.

Resistance of Miter Bends[4]

The chart at the lower right shows the resistance of miter bends to the flow of fluids. The chart is based on data published by the American Society of Mechanical Engineers (ASME).

Problem: Determine the equivalent length in pipe diameters of a 40 degree miter bend.

Solution: Referring to the "Total Resistance" curve in the chart, the equivalent length is 12 pipe diameters.

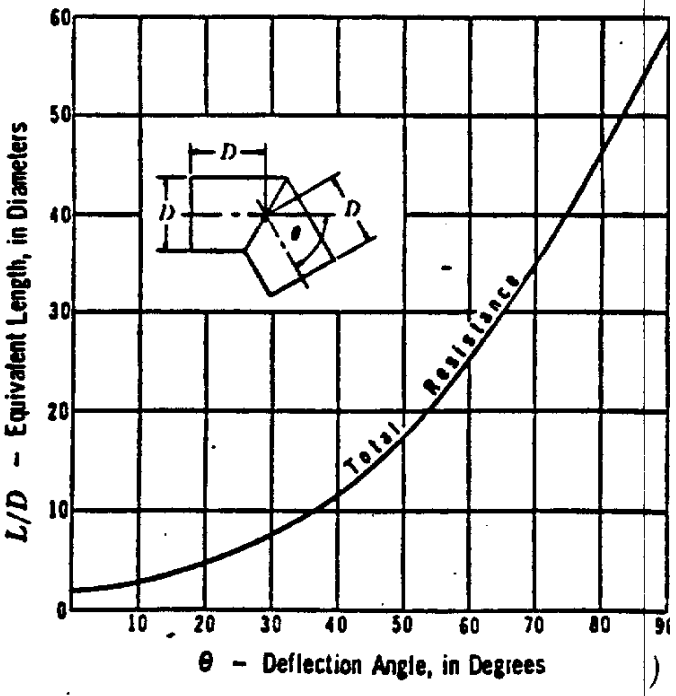


Chart for Resistance of Miter Bends

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-27.

PIPE DATA
Carbon and Alloy Steel — Stainless Steel

(also see next three pages)

Nominal Pipe Size	Outside Diam.	Identification: Steel: Iron Pipe Size	Steel: Sched. No.	Stainless Steel Sched. No.	Wall Thickness (t)	Inside Diameter (d)	Area of Metal	Transverse Internal Area: (a)	Transverse Internal Area: (A)	Moment of Inertia (I)	Weight Pipe	Weight Water	External Surface	Section Modulus
Inches	Inches				Inches	Inches	Square Inches	Square Inches	Square Feet	Inches^4	Pounds per foot	Pounds per foot of pipe	Sq. Ft. per foot of pipe	$\left(2\frac{I}{O.D.}\right)$
1/8	0.405	...	...	10S	.049	.307	.0548	.0740	.00051	.00088	.19	.032	.106	.00437
		STD	40	40S	.068	.269	.0720	.0568	.00040	.00106	.24	.025	.106	.00523
		XS	80	80S	.095	.215	.0925	.0364	.00025	.00122	.31	.016	.106	.00602
1/4	0.540	...	...	10S	.065	.410	.0970	.1320	.00091	.00279	.33	.057	.141	.01032
		STD	40	40S	.088	.364	.1250	.1041	.00072	.00331	.42	.045	.141	.01227
		XS	80	80S	.119	.302	.1574	.0716	.00050	.00377	.54	.031	.141	.01395
3/8	0.675	...	...	10S	.065	.545	.1246	.2333	.00162	.00586	.42	.101	.178	.01736
		STD	40	40S	.091	.493	.1670	.1910	.00133	.00729	.57	.083	.178	.02160
		XS	80	80S	.126	.423	.2173	.1405	.00098	.00862	.74	.061	.178	.02554
1/2	0.840	...	...	5S	.065	.710	.1583	.3959	.00275	.01197	.54	.172	.220	.02849
		...	...	10S	.083	.674	.1974	.3568	.00248	.01431	.67	.155	.220	.03407
		STD	40	40S	.109	.622	.2503	.3040	.00211	.01709	.85	.132	.220	.04069
		XS	80	80S	.147	.546	.3200	.2340	.00163	.02008	1.09	.102	.220	.04780
		...	160	...	.187	.466	.3836	.1706	.00118	.02212	1.31	.074	.220	.05267
		XXS	...	...	.294	.252	.5043	.050	.00035	.02424	1.71	.022	.220	.05772
3/4	1.050	...	...	5S	.065	.920	.2011	.6648	.00462	.02450	.69	.288	.275	.04667
		...	...	10S	.083	.884	.2521	.6138	.00426	.02969	.86	.266	.275	.05655
		STD	40	40S	.113	.824	.3326	.5330	.00371	.03704	1.13	.231	.275	.07055
		XS	80	80S	.154	.742	.4335	.4330	.00300	.04479	1.47	.188	.275	.08531
		...	160	...	.219	.612	.5698	.2961	.00206	.05269	1.94	.128	.275	.10036
		XXS	...	...	.308	.434	.7180	.148	.00103	.05792	2.44	.064	.275	.11032
1	1.315	...	...	5S	.065	1.185	.2553	1.1029	.00766	.04999	.87	.478	.344	.07603
		...	...	10S	.109	1.097	.4130	.9452	.00656	.07569	1.40	.409	.344	.11512
		STD	40	40S	.133	1.049	.4939	.8640	.00600	.08734	1.68	.375	.344	.1328
		XS	80	80S	.179	.957	.6388	.7190	.00499	.1056	2.17	.312	.344	.1606
		...	160	...	.250	.815	.8365	.5217	.00362	.1251	2.84	.230	.344	.1903
		XXS	...	...	.358	.599	1.0760	.282	.00196	.1405	3.66	.122	.344	.2136
1 1/4	1.660	...	...	5S	.065	1.530	.3257	1.839	.01277	.1038	1.11	.797	.435	.1250
		...	...	10S	.109	1.442	.4717	1.633	.01134	.1605	1.81	.708	.435	.1934
		STD	40	40S	.140	1.380	.6685	1.495	.01040	.1947	2.27	.649	.435	.2346
		XS	80	80S	.191	1.278	.8815	1.283	.00891	.2418	3.00	.555	.435	.2913
		...	160	...	.250	1.160	1.1070	1.057	.00734	.2839	3.76	.458	.435	.3121
		XXS	...	...	.382	.896	1.534	.630	.00438	.3411	5.21	.273	.435	.4110
1 1/2	1.900	...	...	5S	.065	1.770	.3747	2.461	.01709	.1579	1.28	1.066	.497	.1662
		...	...	10S	.109	1.682	.5133	2.222	.01543	.2468	2.09	.963	.497	.2598
		STD	40	40S	.145	1.610	.7995	2.036	.01414	.3099	2.72	.882	.497	.3262
		XS	80	80S	.200	1.500	1.068	1.767	.01225	.3912	3.63	.765	.497	.4118
		...	160	...	.281	1.338	1.429	1.406	.00976	.4824	4.86	.608	.497	.5078
		XXS	...	...	.400	1.100	1.885	.950	.00660	.5678	6.41	.42	.497	.5977
2	2.375	...	...	5S	.065	2.245	.4717	3.958	.02749	.3149	1.61	1.72	.622	.2652
		...	...	10S	.109	2.157	.7760	3.654	.02538	.4992	2.64	1.58	.622	.4204
		STD	40	40S	.154	2.067	1.075	3.355	.02330	.6657	3.65	1.45	.622	.5606
		XS	80	80S	.218	1.939	1.477	2.953	.02050	.8679	5.02	1.28	.622	.7309
		...	160	...	.344	1.687	2.190	2.241	.01556	1.162	7.46	.97	.622	.979
		XXS	...	...	.436	1.503	2.656	1.774	.01232	1.311	9.03	.77	.622	1.104
2 1/2	2.875	...	...	5S	.083	2.709	.7280	5.764	.04002	.7100	2.48	2.50	.753	.4939
		...	...	10S	.120	2.635	1.039	5.453	.03787	.9873	3.53	2.36	.753	.6868
		STD	40	40S	.203	2.469	1.704	4.788	.03322	1.530	5.79	2.07	.753	1.064
		XS	80	80S	.276	2.323	2.254	4.238	.02942	1.924	7.66	1.87	.753	1.339
		...	160	...	.375	2.125	2.945	3.546	.02463	2.353	10.01	1.54	.753	1.638
		XXS	...	...	.552	1.771	4.028	2.464	.01710	2.871	13.69	1.07	.753	1.997
3	3.500	...	...	5S	.083	3.334	.8910	8.730	.06063	1.301	3.03	3.78	.916	.7435
		...	...	10S	.120	3.260	1.274	8.347	.05796	1.822	4.33	3.62	.916	1.041
		STD	40	40S	.216	3.068	2.228	7.393	.05130	3.017	7.58	3.20	.916	1.724
		XS	80	80S	.300	2.900	3.016	6.605	.04587	3.894	10.25	2.86	.916	2.225
		...	160	...	.438	2.624	4.205	5.408	.03755	5.032	14.32	2.35	.916	2.876
		XXS	...	...	.600	2.300	5.466	4.155	.02885	5.993	18.58	1.80	.916	3.424

Identification, wall thickness and weights are extracted from ANSI B36.10 and B36.19. The notations STD, XS, and XXS indicate Standard, Extra Strong, and Double Extra Strong pipe respectively.

Transverse internal area values listed in "square feet" also represent volume in cubic feet per foot of pipe length.

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-30.

PIPE DATA — cont.

Nominal Pipe Size, Inches	Outside Diam., Inches	Identification: Steel, Iron Pipe Size	Identification: Steel, Sched. No.	Identification: Stainless Steel Sched. No.	Wall Thickness (t), Inches	Inside Diameter (d), Inches	Area of Metal, Square Inches	Transverse Internal Area (a), Square Inches	Transverse Internal Area (A), Square Feet	Moment of Inertia (I), Inches^4	Weight Pipe, Pounds per foot	Weight Water, Pounds per foot of pipe	External Surface, Sq. Ft. per foot of pipe	Section Modulus $\left(2\frac{I}{O.D.}\right)$
		...	...	5S	.083	3.834	1.021	11.545	.08017	1.900	3.48	5.00	1.047	.9799
		...	...	10S	.120	3.760	1.463	11.101	.07711	2.755	4.97	4.81	1.047	1.378
3½	4.000	STD	40	40S	.226	3.548	2.680	9.886	.06870	4.788	9.11	4.29	1.047	2.394
		XS	80	80S	.318	3.364	3.678	8.888	.06170	6.280	12.50	3.84	1.047	3.140
		...	...	5S	.083	4.334	1.152	14.75	.10215	2.810	3.92	6.39	1.178	1.249
		...	...	10S	.120	4.260	1.651	14.25	.09898	3.963	5.61	6.18	1.178	1.761
		STD	40	40S	.237	4.026	3.174	12.73	.08840	7.233	10.79	5.50	1.178	3.214
4	4.500	XS	80	80S	.337	3.826	4.407	11.50	.07986	9.610	14.98	4.98	1.178	4.271
		...	120	...	.438	3.624	5.595	10.31	.0716	11.65	19.00	4.47	1.178	5.178
		...	160	...	.531	3.438	6.621	9.28	.0645	13.27	22.51	4.02	1.178	5.898
		XXS	...	...	.674	3.152	8.101	7.80	.0542	15.28	27.54	3.38	1.178	6.791
		...	...	5S	.109	5.345	1.868	22.44	.1558	6.947	6.36	9.72	1.456	2.498
		...	...	10S	.134	5.295	2.285	22.02	.1529	8.425	7.77	9.54	1.456	3.029
		STD	40	40S	.258	5.047	4.300	20.01	.1390	15.16	14.62	8.67	1.456	5.451
5	5.563	XS	80	80S	.375	4.813	6.112	18.19	.1263	20.67	20.78	7.88	1.456	7.431
		...	120	...	.500	4.563	7.953	16.35	.1136	25.73	27.04	7.09	1.456	9.250
		...	160	...	.625	4.313	9.696	14.61	.1015	30.03	32.96	6.33	1.456	10.796
		XXS	...	...	.750	4.063	11.340	12.97	.0901	33.63	38.55	5.61	1.456	12.090
		...	...	5S	.109	6.407	2.231	32.24	.2239	11.85	7.60	13.97	1.734	3.576
		...	...	10S	.134	6.357	2.733	31.74	.2204	14.40	9.29	13.75	1.734	4.346
		STD	40	40S	.280	6.065	5.581	28.89	.2006	28.14	18.97	12.51	1.734	8.496
6	6.625	XS	80	80S	.432	5.761	8.405	26.07	.1810	40.49	28.57	11.29	1.734	12.22
		...	120	...	.562	5.501	10.70	23.77	.1650	49.61	36.39	10.30	1.734	14.98
		...	160	...	.719	5.187	13.32	21.15	.1469	58.97	45.35	9.16	1.734	17.81
		XXS	...	...	.864	4.897	15.64	18.84	.1308	66.33	53.16	8.16	1.734	20.02
		...	...	5S	.109	8.407	2.916	55.51	.3855	26.44	9.93	24.06	2.258	6.131
		...	...	10S	.148	8.329	3.941	54.48	.3784	35.41	13.40	23.61	2.258	8.212
		...	20	...	.250	8.125	6.57	51.85	.3601	57.72	22.36	22.47	2.258	13.39
		...	30	...	.277	8.071	7.26	51.16	.3553	63.35	24.70	22.17	2.258	14.69
		STD	40	40S	.322	7.981	8.40	50.03	.3474	72.49	28.55	21.70	2.258	16.81
		...	60	...	.406	7.813	10.48	47.94	.3329	88.73	35.64	20.77	2.258	20.58
8	8.625	XS	80	80S	.500	7.625	12.76	45.66	.3171	105.7	43.39	19.78	2.258	24.51
		...	100	...	.594	7.437	14.96	43.46	.3018	121.3	50.95	18.83	2.258	28.14
		...	120	...	.719	7.187	17.84	40.59	.2819	140.5	60.71	17.59	2.258	32.58
		...	140	...	.812	7.001	19.93	38.50	.2673	153.7	67.76	16.68	2.258	35.65
		XXS	...	...	.875	6.875	21.30	37.12	.2578	162.0	72.42	16.10	2.258	37.56
		...	160	...	.906	6.813	21.97	36.46	.2532	165.9	74.69	15.80	2.258	38.48
		...	...	5S	.134	10.482	4.36	86.29	.5992	63.0	15.19	37.39	2.814	11.71
		...	...	10S	.165	10.420	5.49	85.28	.5922	76.9	18.65	36.95	2.814	14.30
		...	20	...	.250	10.250	8.24	82.52	.5731	113.7	28.04	35.76	2.814	21.15
		...	30	...	.307	10.136	10.07	80.69	.5603	137.4	34.24	34.96	2.814	25.57
		STD	40	40S	.365	10.020	11.90	78.86	.5475	160.7	40.48	34.20	2.814	29.90
10	10.750	XS	60	80S	.500	9.750	16.10	74.66	.5185	212.0	54.74	32.35	2.814	39.43
		...	80	...	.594	9.562	18.92	71.84	.4989	244.8	64.43	31.13	2.814	45.54
		...	100	...	.719	9.312	22.63	68.13	.4732	286.1	77.03	29.53	2.814	53.22
		...	120	...	.844	9.062	26.24	64.53	.4481	324.2	89.29	27.96	2.814	60.32
		XXS	140	...	1.000	8.750	30.63	60.13	.4176	367.8	104.13	26.06	2.814	68.43
		...	160	...	1.125	8.500	34.02	56.75	.3941	399.3	115.64	24.59	2.814	74.29
		...	...	5S	.156	12.438	6.17	121.50	.8438	122.4	20.98	52.65	3.338	19.2
		...	...	10S	.180	12.390	7.11	120.57	.8373	140.4	24.17	52.25	3.338	22.0
		...	20	...	.250	12.250	9.82	117.86	.8185	191.8	33.38	51.07	3.338	30.2
		...	30	...	.330	12.090	12.87	114.80	.7972	248.4	43.77	49.74	3.338	39.0
		STD	...	40S	.375	12.000	14.58	113.10	.7854	279.3	49.56	49.00	3.338	43.8
		...	40	...	.406	11.938	15.77	111.93	.7773	300.3	53.52	48.50	3.338	47.1
		XS	...	80S	.500	11.750	19.24	108.43	.7528	361.5	65.42	46.92	3.338	56.7
12	12.75	...	60	...	.562	11.626	21.52	106.16	.7372	400.4	73.15	46.00	3.338	62.8
		...	80	...	.688	11.374	26.03	101.64	.7058	475.1	88.63	44.04	3.338	74.6
		...	100	...	.844	11.062	31.53	96.14	.6677	561.6	107.32	41.66	3.338	88.1
		XXS	120	...	1.000	10.750	36.91	90.76	.6303	641.6	125.49	39.33	3.338	100.7
		...	140	...	1.125	10.500	41.08	86.59	.6013	700.5	139.67	37.52	3.338	109.9
		...	160	...	1.312	10.126	47.14	80.53	.5592	781.1	160.27	34.89	3.338	122.6

Identification, wall thickness and weights are extracted from ANSI B36.10 and B36.19. The notations STD, XS, and XXS indicate Standard, Extra Strong, and Double Extra Strong pipe respectively.

Transverse internal area values listed in "square feet" also represent volume in cubic feet per foot of pipe length.

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-30.

PIPE DATA—cont.

Nominal Pipe Size Inches	Outside Diam. Inches	Identification Steel Iron Pipe Size	Identification Steel Sched. No.	Identification Stainless Steel Sched. No.	Wall Thickness (t) Inches	Inside Diameter (d) Inches	Area of Metal Square Inches	Transverse Internal Area (a) Square Inches	Transverse Internal Area (A) Square Feet	Moment of Inertia (I) Inches^4	Weight Pipe Pounds per foot	Weight Water Pounds per foot of pipe	External Surface Sq. Ft. per foot of pipe	Section Modulus $\left(2\frac{I}{O.D.}\right)$
		...	...	5S	.156	13.688	6.78	147.15	1.0219	162.6	23.07	63.77	3.665	23.2
		...	...	10S	.188	13.624	8.16	145.78	1.0124	194.6	27.73	63.17	3.665	27.8
		...	10	...	.250	13.500	10.80	143.14	.9940	255.3	36.71	62.03	3.665	36.6
		...	20	...	.312	13.376	13.42	140.52	.9758	314.4	45.61	60.89	3.665	45.0
		STD	30	...	.375	13.250	16.05	137.88	.9575	372.8	54.57	59.75	3.665	53.2
		...	40	...	.438	13.124	18.66	135.28	.9394	429.1	63.44	58.64	3.665	61.3
14	14.00	XS	...	...	.500	13.000	21.21	132.73	.9217	483.8	72.09	57.46	3.665	69.1
		...	60	...	.594	12.812	24.98	128.96	.8956	562.3	85.05	55.86	3.665	80.3
		...	80	...	.750	12.500	31.22	122.72	.8522	678.3	106.13	53.18	3.665	98.2
		...	100	...	.938	12.124	38.45	115.49	.8020	824.4	130.85	50.04	3.665	117.8
		...	120	...	1.094	11.812	44.32	109.62	.7612	929.6	150.79	47.45	3.665	132.8
		...	140	...	1.250	11.500	50.07	103.87	.7213	1027.0	170.28	45.01	3.665	146.8
		...	160	...	1.406	11.188	55.63	98.31	.6827	1117.0	189.11	42.60	3.665	159.6
		...	...	5S	.165	15.670	8.21	192.85	1.3393	257.3	27.90	83.57	4.189	32.2
		...	...	10S	.188	15.624	9.34	191.72	1.3314	291.9	31.75	83.08	4.189	36.5
		...	10	...	.250	15.500	12.37	188.69	1.3103	383.7	42.05	81.74	4.189	48.0
		...	20	...	.312	15.376	15.38	185.69	1.2895	473.2	52.27	80.50	4.189	59.2
		STD	30	...	.375	15.250	18.41	182.65	1.2684	562.1	62.58	79.12	4.189	70.3
16	16.00	XS	40	...	.500	15.000	24.35	176.72	1.2272	731.9	82.77	76.58	4.189	91.5
		...	60	...	.656	14.688	31.62	169.44	1.1766	932.4	107.50	73.42	4.189	116.6
		...	80	...	.844	14.312	40.14	160.92	1.1175	1155.8	136.61	69.73	4.189	144.5
		...	100	...	1.031	13.938	48.48	152.58	1.0596	1364.5	164.82	66.12	4.189	170.5
		...	120	...	1.219	13.562	56.56	144.50	1.0035	1555.8	192.43	62.62	4.189	194.5
		...	140	...	1.438	13.124	65.78	135.28	.9394	1760.3	223.64	58.64	4.189	220.0
		...	160	...	1.594	12.812	72.10	128.96	.8956	1893.5	245.25	55.83	4.189	236.7
		...	...	5S	.165	17.670	9.25	245.22	1.7029	367.6	31.43	106.26	4.712	40.8
		...	...	10S	.188	17.624	10.52	243.95	1.6941	417.3	35.76	105.71	4.712	46.4
		...	10	...	.250	17.500	13.94	240.53	1.6703	549.1	47.39	104.21	4.712	61.1
		...	20	...	.312	17.376	17.34	237.13	1.6467	678.2	58.94	102.77	4.712	75.5
		STD	...	...	.375	17.250	20.76	233.71	1.6230	806.7	70.59	101.18	4.712	89.6
		...	30	...	.438	17.124	24.17	230.30	1.5990	930.3	82.15	99.84	4.712	103.4
18	18.00	XS	...	...	.500	17.000	27.49	226.98	1.5763	1053.2	93.45	98.27	4.712	117.0
		...	40	...	.562	16.876	30.79	223.68	1.5533	1171.5	104.67	96.93	4.712	130.1
		...	60	...	.750	16.500	40.64	213.83	1.4849	1514.7	138.17	92.57	4.712	168.3
		...	80	...	.938	16.124	50.23	204.24	1.4183	1833.0	170.92	88.50	4.712	203.8
		...	100	...	1.156	15.688	61.17	193.30	1.3423	2180.0	207.96	83.76	4.712	242.3
		...	120	...	1.375	15.250	71.81	182.66	1.2684	2498.1	244.14	79.07	4.712	277.6
		...	140	...	1.562	14.876	80.66	173.80	1.2070	2749.0	274.22	75.32	4.712	305.5
		...	160	...	1.781	14.438	90.75	163.72	1.1369	3020.0	308.50	70.88	4.712	335.6
		...	...	5S	.188	19.624	11.70	302.46	2.1004	574.2	39.78	131.06	5.236	57.4
		...	...	10S	.218	19.564	13.55	300.61	2.0876	662.8	46.06	130.27	5.236	66.3
		...	10	...	.250	19.500	15.51	298.65	2.0740	765.4	52.73	129.42	5.236	75.6
		STD	20	...	.375	19.250	23.12	290.04	2.0142	1113.0	78.60	125.67	5.236	111.3
		XS	30	...	.500	19.000	30.63	283.53	1.9690	1457.0	104.13	122.87	5.236	145.7
		...	40	...	.594	18.812	36.15	278.00	1.9305	1703.0	123.11	120.46	5.236	170.4
20	20.00	...	60	...	.812	18.376	48.95	265.21	1.8417	2257.0	166.40	114.92	5.236	225.7
		...	80	...	1.031	17.938	61.44	252.72	1.7550	2772.0	208.87	109.51	5.236	277.1
		...	100	...	1.281	17.438	75.33	238.83	1.6585	3315.2	256.10	103.39	5.236	331.5
		...	120	...	1.500	17.000	87.18	226.98	1.5762	3754.0	296.37	98.35	5.236	375.5
		...	140	...	1.750	16.500	100.33	213.82	1.4849	4216.0	341.09	92.66	5.236	421.7
		...	160	...	1.969	16.062	111.49	202.67	1.4074	4585.5	379.17	87.74	5.236	458.5
		...	...	5S	.188	21.624	12.88	367.25	2.5503	766.2	43.80	159.14	5.760	69.7
		...	...	10S	.218	21.564	14.92	365.21	2.5362	884.8	50.71	158.26	5.760	80.4
		...	10	...	.250	21.500	17.08	363.05	2.5212	1010.3	58.07	157.32	5.760	91.8
		STD	20	...	.375	21.250	25.48	354.66	2.4629	1489.7	86.61	153.68	5.760	135.4
		XS	30	...	.500	21.000	33.77	346.36	2.4053	1952.5	114.81	150.09	5.760	117.5
22	22.00	...	60	...	.875	20.250	58.07	322.06	2.2365	3244.9	197.41	139.56	5.760	295.0
		...	80	...	1.125	19.75	73.78	306.35	2.1275	4030.4	250.81	132.76	5.760	366.4
		...	100	...	1.375	19.25	89.09	291.04	2.0211	4758.5	302.88	126.12	5.760	432.6
		...	120	...	1.625	18.75	104.02	276.12	1.9175	5432.0	353.61	119.65	5.760	493.8
		...	140	...	1.875	18.25	118.55	261.59	1.8166	6053.7	403.00	113.36	5.760	550.3
		...	160	...	2.125	17.75	132.68	247.45	1.7184	6626.4	451.06	107.23	5.760	602.4

Identification, wall thickness and weights are extracted from ANSI B36.10 and B36.19. The notations STD, XS and XXS indicate Standard, Extra Strong and Double Extra Strong pipe respectively.

Transverse internal area values listed in "square feet" also represent volume in cubic feet per foot of pipe length.

Crane Co. "Flow of Fluids through Valves, Fittings and Pipe", Technical Paper 410, page A-30.

PIPE DATA — cont.

Nominal Pipe Size	Outside Diam.	Identification: Steel: Iron Pipe Size	Identification: Steel: Sched. No.	Identification: Stainless Steel Sched. No.	Wall Thickness (t)	Inside Diameter (d)	Area of Metal	Transverse Internal Area: (a)	Transverse Internal Area: (A)	Moment of Inertia (I)	Weight Pipe	Weight Water	External Surface	Section Modulus
Inches	Inches				Inches	Inches	Square Inches	Square Inches	Square Feet	Inches^4	Pounds per foot	Pounds per foot of pipe	Sq. Ft. per foot of pipe	$\left(2\frac{I}{O.D.}\right)$
		...	...	5S	.218	23.564	16.29	436.10	3.0285	1151.6	55.37	188.98	6.283	96.0
		...	10	10S	.250	23.500	18.65	433.74	3.0121	1315.4	63.41	187.95	6.283	109.6
		STD	20	...	.375	23.250	27.83	424.56	2.9483	1942.0	94.62	183.95	6.283	161.9
		XS	...	...	.500	23.000	36.91	415.48	2.8853	2549.5	125.49	179.87	6.283	212.5
		...	30	...	.562	22.876	41.39	411.00	2.8542	2843.0	140.68	178.09	6.283	237.0
24	24.00	...	40	...	.688	22.624	50.31	402.07	2.7921	3421.3	171.29	174.23	6.283	285.1
		...	60	...	.969	22.062	70.04	382.35	2.6552	4652.8	238.35	165.52	6.283	387.7
		...	80	...	1.219	21.562	87.17	365.22	2.5362	5672.0	296.58	158.26	6.283	472.8
		...	100	...	1.531	20.938	108.07	344.32	2.3911	6849.9	367.39	149.06	6.283	570.8
		...	120	...	1.812	20.376	126.31	326.08	2.2645	7825.0	429.39	141.17	6.283	652.1
		...	140	...	2.062	19.876	142.11	310.28	2.1547	8625.0	483.12	134.45	6.283	718.9
		...	160	...	2.344	19.312	159.41	292.98	2.0346	9455.9	542.13	126.84	6.283	787.9
		...	10	...	.312	25.376	25.18	505.75	3.5122	2077.2	85.60	219.16	6.806	159.8
26	26.00	STD	...	...	.375	25.250	30.19	500.74	3.4774	2478.4	102.63	216.99	6.806	190.6
		XS	20	...	.500	25.000	40.06	490.87	3.4088	3257.0	136.17	212.71	6.806	250.5
		...	10	...	.312	27.376	27.14	588.61	4.0876	2601.0	92.26	255.07	7.330	185.8
		STD	...	...	.375	27.250	32.54	583.21	4.0501	3105.1	110.64	252.73	7.330	221.8
28	28.00	XS	20	...	.500	27.000	43.20	572.56	3.9761	4084.8	146.85	248.11	7.330	291.8
		...	30	...	.625	26.750	53.75	562.00	3.9028	5037.7	182.73	243.53	7.330	359.8
		...	...	5S	.250	29.500	23.37	683.49	4.7465	2585.2	79.43	296.18	7.854	172.3
		...	10	10S	.312	29.376	29.19	677.76	4.7067	3206.3	98.93	293.70	7.854	213.8
30	30.00	STD	...	...	.375	29.250	34.90	671.96	4.6664	3829.4	118.65	291.18	7.854	255.3
		XS	20	...	.500	29.000	46.34	660.52	4.5869	5042.2	157.53	286.22	7.854	336.1
		...	30	...	.625	28.750	57.68	649.18	4.5082	6224.0	196.08	281.31	7.854	414.9
		...	10	...	.312	31.376	31.06	773.19	5.3694	3898.9	105.59	335.05	8.378	243.7
		STD	...	...	.375	31.250	37.26	766.99	5.3263	4658.5	126.66	332.36	8.378	291.2
32	32.00	XS	20	...	.500	31.000	49.48	754.77	5.2414	6138.6	168.21	327.06	8.378	383.7
		...	30	...	.625	30.750	61.60	742.64	5.1572	7583.4	209.43	321.81	8.378	474.0
		...	40	...	.688	30.624	67.68	736.57	5.1151	8298.3	230.08	319.18	8.378	518.6
		...	10	...	.344	33.312	36.37	871.55	6.0524	5150.5	123.65	377.67	8.901	303.0
		STD	...	...	.375	33.250	39.61	868.31	6.0299	5599.3	134.67	376.27	8.901	329.4
34	34.00	XS	20	...	.500	33.000	52.62	855.30	5.9396	7383.5	178.89	370.63	8.901	434.3
		...	30	...	.625	32.750	65.53	842.39	5.8499	9127.6	222.78	365.03	8.901	536.9
		...	40	...	.688	32.624	72.00	835.92	5.8050	9991.6	244.77	362.23	8.901	587.7
		...	10	...	.312	35.376	34.98	982.90	6.8257	5569.5	118.92	425.92	9.425	309.4
		STD	...	...	.375	35.250	41.97	975.91	6.7771	6658.9	142.68	422.89	9.425	369.9
36	36.00	XS	20	...	.500	35.000	55.76	962.11	6.6813	8786.2	189.57	416.91	9.425	488.1
		...	30	...	.625	34.750	69.46	948.42	6.5862	10868.4	236.13	417.22	9.425	603.8
		...	40	...	.750	34.500	83.06	934.82	6.4918	12906.1	282.35	405.09	9.425	717.0

Identification, wall thickness and weights are extracted from ANSI B36.10 and B36.19. The notations STD, XS, and XXS indicate Standard, Extra Strong, and Double Extra Strong pipe respectively.

Transverse internal area values listed in "square feet" also represent volume in cubic feet per foot of pipe length.

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, Page A-30.

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HYDRAULIC TABULATION

LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	ΔP/100 FT. PSI	ESTIM. EQ. FT. x 10^3	DESCRIPTION	ΔP PSI	INLET PRESS. PSIG	ΔP PSI	INLET PRESS. PSIG	ΔP PSI	INLET PRESS. PSIG	DESIGN PRESS. PSIG
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
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24												

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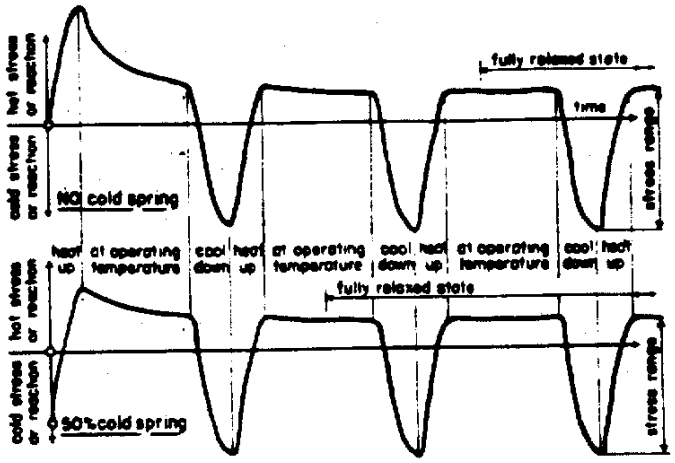


FIG. 3 EFFECT OF RELAXATION UPON REACTIONS AND STRESSES

Upon cooling down, each unit length of the line contracts again by an amount ϵ, the stress reverses, and the ultimate cold stress becomes

$$S_c'' = S_E - \frac{E_c}{E_h} S_r \qquad [10]$$

The preceding four equations fully circumscribe the extreme stress conditions encountered during the service life of a system, whether it be installed with cold spring or not, and whether it be subject to relaxation or not.

Now, as Stromeyer (6) pointed out in 1914, and Dennison (45) re-emphasized more recently, service failures are associated with cyclic, rather than static-stress application. Fatigue, with corrosion usually an important contributory factor, must be accepted as the primary cause of failure. Resistance to fatigue is measured by the so-called endurance limit (fully reversed stress supported over an indefinite number of cycles, in the millions) or by the endurance strength (stress supported over a given number of cycles), the latter being of more direct significance to the present problem, since even in the process industries the number of major temperature cycles rarely exceeds six per day, corresponding to approximately 40,000 over a 20-yr life. Actually, the stresses usually are not fully reversed in actual piping installations, but since the mean stress is indeterminate, particularly where relaxation occurs, and of subordinate importance to the stress range, the latter is taken as the sole criterion in the Proposed Rules. For simplicity, these set the value of the "calculated-stress range" equal to the stress S_E produced by 100 per cent cold spring; that this is a reasonably correct or at least conservative assumption will be shown in the text that follows.

For the initial condition (which is maintained throughout where no adjustment occurs), the stress range is given by the summation of the stresses given by Equations [7] and [8]

$$S_c' + S_h' = \frac{E_h}{E_c} S_E + \left(1 - \frac{E_h}{E_c}\right) c S_E \qquad [11]$$

For the ultimate condition in the case where relaxation does occur, it is given by the summation of Equations [9] and [10]

$$S_c'' + S_h'' = S_E + \left(1 - \frac{E_c}{E_h}\right) S_r \qquad [12]$$

As one limit, applicable to lines of small temperature change set $E_h = E_c$; then

$$S_c' + S_h' = S_E \qquad [11a]$$

$$S_c'' + S_h'' = S_E \qquad [12a]$$

As a second approximate limit, for hot lines where the relaxation limit S_r is small, set $E_h = \frac{2}{3} E_c$; then

$$S_c' + S_h' = \frac{2 + c}{3} S_E \qquad [11b]$$

$$S_c'' + S_h'' = S_E - \frac{1}{2} S_r \qquad [12b]$$

Note that at one limit the stress range equals S_E; i.e., is constant and independent of the amount of cold spring, and that at the other it is lower than S_E and affected only to a minor extent by the values of c and S_r.

In the following four equations the corresponding reactions are given as obtained by multiplying the right-hand terms of Equations [7] to [10] by R/S_E

$$R_c' = cR \qquad [13]$$

$$R_h' = (1 - c) \frac{E_h}{E_c} R \qquad [14]$$

$$R_h'' = \frac{S_r}{S_E} R \qquad [15]$$

$$R_c'' = \left(1 - \frac{E_c}{E_h} \frac{S_r}{S_E}\right) R \qquad [16]$$

Detailed discussion of the relaxation limit S_r has been deferred to this point because, under the Proposed Rules, it is considered to affect only the computation of reactions. With the establishment of the approximate stress range S_E as the primary criterion of the flexibility of the piping system proper, individual stresses at any one time during the temperature cycle have come to be ignored. In the case of the reactions, on the other hand, the extreme values in the hot and cold conditions are taken to control directly; the reason is that strain-sensitive equipment, such as pumps or turbines, can be seriously damaged by a single overload, even though this may be promptly relaxed as a result of yielding or creep somewhere in the system.

The relaxation limit S_r can be defined as the asymptotic value toward which the stress in a prestressed structure with a fixed

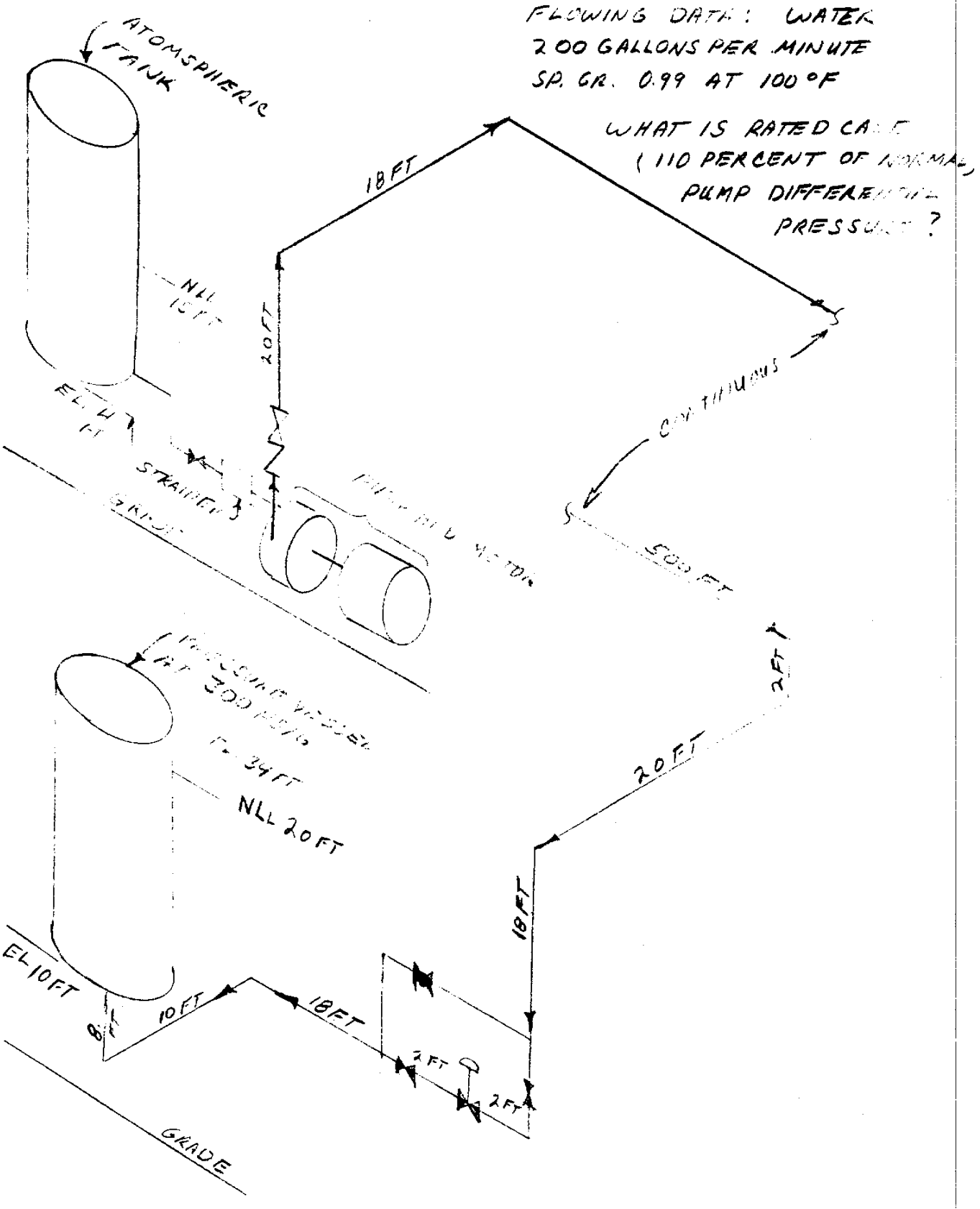
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Des Plaines, Illinois 60016 312•763-6000

SHEET 1
PIPING SKETCH NO.

DR. _____ CK. _____
DATE _____ PROJECT _____

FLOWING DATA: WATER
200 GALLONS PER MINUTE
SP. GR. 0.99 AT 100 °F

WHAT IS RATED CASE
(110 PERCENT OF NORMAL)
PUMP DIFFERENTIAL
PRESSURE ?



HYDRAULIC TABULATION

	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	Δp/100 FT. PSI	ESTIM. EQ. FT. ÷ 100	DESCRIPTION	NORMAL Δp PSI	NORMAL INLET PRESS. PSIG	110 PCT RATED (1.21) Δp PSI	110 PCT RATED (1.21) INLET PRESS. PSIG			DESIGN PRESS. PSIG
1						VESSEL (IGNORE ENTRANCE LOSS)	–	300	–	300			
2						STATIC 0.99 / 2.31	12.9	312.9	12.9	312.9			
3		4	40	0.99	1.0	LINE AFTER CONTROL VALVE	1.0	313.9	1.2	314.1			
4						LONG RADIUS ELLS 40D							
5						TEE'S (RUN) 20D							
6						GATE VALVE (1) 13D							
7						TOTAL 73D							
8						EQUIVALENT LENGTH 24'							
9						STRAIGHT PIPE 38							
10						TOTAL EQUIVALENT 62'							
11						USE 100							
12													
13						CONTROL VALVE	35	348.9					
14								~350					
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													

Sheet 3

CALCULATE THE MINIMUM REQUIRED PRESSURE DROP FOR A CONTROL VALVE

CRITERIA

i) half the friction loss in the system:

$(1.2 + 8.4)(0.5) = 4.8$ psi

ii) 10 percent of the pump head:

pump head = X. it is the sum of:

friction loss..... 9.6 psi
other:
system.....300.0
static..... 12.9
control valve press. drop. 0.1X
pump suction..... (6.7)

$X = 315.8 + 0.1X$

$X = 350.8$ psi

control valve pressure drop $\triangle P = 0.1X$
$= 35$ psi

iii) minimum control valve pressure drop is 25 psi

USE LARGEST CALCULATED PRESSURE DROP OR 35 PSI

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HYDRAULIC TABULATION

	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	Δp/100 FT. PSI	ESTIM. EQ. FT. ÷ 100	DESCRIPTION	NORMAL ΔP PSI	NORMAL INLET PRESS. PSIG	110 PCT RATE 1.21 Δp PSI	110 PCT RATE 1.21 INLET PRESS. PSIG	Δp PSI	INLET PRESS. PSIG	DESIGN PRESS. PSIG
1		4	40	0.99	7.0	LINE BEFORE CONTROL VALVE	69	357	8.4	357.5			
2						LONG RADIUS ELL'S (6) 1200							
3						TEE'S (1) RUN 200							
4						VALVES (2) 260							
5						CHECK VALVES 1350							
6						TOTAL 3010							
7						EQUIVALENT LENGTH 190'							
8						STRAIGHT PIPE 580'							
9						TOTAL EQUIVALENT 680'							
10						USE → 700							
11								357					
12						PUMP	( )	6.9	(350.8)	6.7			
13				0.13	3.0	STRAINER	0.4	7.3	0.5	7.2			
14		6	40	0.13	6.0	SUCTION LINE	0.8	8.1	0.9	8.1			
15						STATIC 19' 0.99/2.31	(8.1)	—	(8.1)	—			
16													
17													
18													
19													
20													
21													
22													
23													
24													

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Engineering Design Seminar

Hydraulics General Comments

Line sizing is only a part of the over-all subject of hydraulics. Other areas of hydraulics effect the sizing of lines, particularly in so far as the determination of available pressure drop is concerned. The following presents a discussion of some of the more important hydraulic systems and considerations with which the engineer should be familiar.

PUMP NPSH

Every centrifugal pump has a minimum positive pressure requirement at the eye of the impeller to prevent vaporization of the pumped liquid, which in turn causes cavitation. This pressure requirement is called "Net Positive Suction Head" (NPSH) and is expressed as the feet of liquid head, in excess of the fluid vapor pressure, required at the suction flange of a specific pump in order to overcome the internal pressure drop in the pump suction nozzle and passage to the eye of the impeller. The NPSH required is determined by the manufacturer as a characteristic of the pump and will set the elevations of many of the vessels in the process unit.

NPSH - Calculations

Pump NPSH calculations can be approached from two different view points. A contractor's calculation is basically a check of the system to determine if the specified suction vessel elevation is sufficient to overcome the frictional loss of the detailed piping arrangement and still provide the pump NPSH requirement as defined by the pump supplier. All details of the system and equipment are usually known at the time the contractor makes his check.

On the other hand, the goal of a design engineer's calculation is the determination of the suction vessel elevation before details of the system and equipment are known. The following considerations and estimates should be taken into account in the engineer's calculation:

1. Estimate the minimum pump NPSH requirements, in feet of liquid, by means of the attached chart. This chart is based upon approximate NPSH requirements that would permit a range of pump suppliers to be able to quote pumps that are economical in both capital cost and efficiency. The estimated NPSH requirement should be based on the pump design capacity. The chart is limited to single stage pumps with maximum differential heads of 1400 feet at 60 Hz and 1000 feet at 50 Hz. A pump vendor should be consulted for the NPSH requirements to suit unusual cases or services beyond the range of the attached chart.

2. Estimate the elevation of the pump centerline above the base line. The attached chart may be used to estimate the distance from the bottom of the base plate to the centerline of the pump. Add one additional foot for the assumed foundation projection above the base line to arrive at the estimated pump centerline elevation above the base line. NPSH - Calculations (Continued)

3. Estimate the friction loss, in feet of liquid, in the suction piping between the vessel and pump suction flange. The piping friction loss should be based on the pump design capacity and on clean pipe friction factors. The calculated friction loss per hundred feet must be multiplied by the estimated suction pipe equivalent length in hundreds of feet. For normal suction piping arrangements from process vessels, the following equivalent lengths may be assumed:

   For a single pump (with spare) service:

   $$L = 50 + 500\,D + 50\,D^{1/2}$$

For multiple pump services (with spares) with common suction piping or for a pump service with a piping split to a reboiler or other service:

From suction vessel to piping split:

$$L = 10 + 150\ D + 20\ D^{1/2}$$

From the piping split to pump suction:

$$L = 40 + 400\ D + 40\ D^{1/2}$$

Where:

L = Estimated equivalent feet of suction pipe
D = pipe I.D. in feet

Keep in mind that the pump suction valve may be one size smaller than the suction line where the suction connection on the pump is two or three sizes smaller than the line. Since the pump suction connection is not known during he engineering work, the engineer must use good judgment in determining if the smaller valve size will add a significant additional pressure drop.

Since pump suction systems are provided with permanent pump suction strainers or the temporary pump suction strainer is not removed, the additional pressure drop of the strainer must be accounted for in the liquid head. In most cases, the type of stainer to be installed is not known during the engineering work, but the engineer can compensate for the pump suction strainer pressure drop by adding the friction loss of 300 additional feet of piping.

4. Investigate the system absolute pressure on the liquid in the suction vessel to determine if the minimum pressure under all operating conditions exceeds the vapor pressure of the liquid at pump suction temperature. Any additional system pressure above the vapor pressure of the liquid at pump suction temperature can be considered as NPSH available. This situation is most likely to exist in liquid full systems or at pumps handling sub-cooled materials, such as from storage tanks or surge drums or in systems containing a cooler in the pump suction piping.

5. Next, consider the elevation of the minimum liquid level above the bottom tangent of a vertical vessel. The minimum controlled liquid level should be used to set NPSH availability. The engineer should consider if it ever likely to have an operation at the pump design capacity with the liquid level below the minimum controlled level. In such cases, the NPSH availability should be taken from the lowest liquid level at which the pump is expected to operate at the design capacity.

6. Finally, the need for and amount of contingency must be evaluated. Consider the following when determining the amount of NPSH contingency to be provided:

   Additional piping loss if the suction piping system has a tendency to become dirty or fouled in operation.

   The possibility of greater pump capacity due to a larger impeller or motor.

In any event, a standard contingency factor of 15% of the estimated pump NPSH requirement, with a minimum of two feet, should be added to the vessel elevation. Greater contingency should be added if indicated by the above considerations. The engineer's calculation should clearly record the amount and reason(s) for the contingency provided.

7. The suction vessel elevation necessary to satisfy the estimated pump NPSH requirements can now be determined by adding the feet of flowing liquid from items 1, 2, 3 and 6. From this total, deduct the feet of flowing liquid from items 4 and 5. The net result is the minimum elevation above the base line for the bottom of a horizontal suction vessel or the bottom tangent line of a vertical suction vessel to suit NPSH requirements. Mechanical and physical requirements should also be considered before setting the final vessel elevation.

THERMOSYPHON REBOILER SYSTEMS

The hydraulic design of a Thermosyphon reboiler system requires very careful consideration since the driving force is derived only from the difference in densities between the inlet liquid and the mixed phase outlet. For a maximum vaporization of 30%, the engineer can use the following approximate method to arrive at a first trail line size:

For inlet piping:

$12 < d^2/Q < 15$, or d = SQRT(Q (12 to 15))

For outlet piping:

$24 < d^2/Q < 30$, or d = SQRT(Q (24 to 30))

Where:
d = nominal pipe size in inches
Q = Reboiler duty in millions of BTU per hour

With these trial line sizes or sizes determined in the previous section, the engineer can now proceed to a more accurate analysis of the system. The following pressure drops are all additive in determining the liquid head requirements.

1. Entrance loss (psi) = $(0.5\ V^2/2g) * (S.G./2.31)$

   V = ft/sec
   S.G. = liquid specific gravity

2. Line Loss to exchanger = (psi/100ft) * (equivalent length/100)

3. Line Loss to Column = (psi/100ft) * (equivalent length/100)

4. Exchanger loss = specified loss in psi

5. Exit Loss (psi) = $(V^2/2g) * (S.G./2.31)$

   V = ft/sec
   S.G. = composite specific gravity

6. Static Loss to column (psi) = H * (S.G./2.31)

   H = estimated vertical length of return line
   S.G. = composite specific gravity

7. Contingency estimated between 1/2 and 1 psi or equal to line loss.

The sum of the above pressure drops is now converted to the liquid head required.

$$\text{Head} = \frac{\text{Total psi} * 2.31}{\text{S.G.}}$$

S.G. = liquid specific gravity

This head is now the required driving head in feet as determined from the minimum liquid level in the vessel to the centerline of the reboiler. This procedure can be used fro vertical Thermosyphon reboilers if the centerline of the exchanger is considered to be the mid-point of the tube length.

HEATER PRESSURE DROPS

Although the final heater pressure drops must be determined by the heater designer or heater vendor, the hydraulics engineer should have some approximation of heater pressure drops in order to proceed with the preliminary hydraulic survey. The following heater pressure drops may be used on a preliminary basis, to be confirmed or corrected as heater design information becomes available:

Crude Heaters	125	psi
Vacuum Heaters	75	psi
Unibon Heaters	20-60	psi
Platforming (per heater)	3-20	psi
Thermal Crackers	200	psi
Coker Heaters	300	psi
Visbreakers	250	psi
Hot Oil Heaters	20-40	psi
Fired Reboilers	50	psi
Fractionation Charge	40	psi

HEAT EXCHANGER PRESSURE DROPS

Heat exchanger pressure drops vary from mm of mercury to as much as 25 psi. Because the pressure drops vary so widely, there is no substitute for good judgement of the engineer. For normal, fluid exchangers, at least 5 psi per shell on each side should be allowed as a minimum. Some additional guidelines are as follows:

Cooling water side	10	psi
Combined Feed Exchangers	2-5	psi per side
Condensers	1-5	psi
Reboilers-Kettle & Thermosyphon	0.2-0.5	psi
Reboilers-Forced Circulation	5-10	psi
Vacuum Condensers	10-25	mm mercury

CONTROL VALVE PRESSURE DROPS

Control valve pressure drops must be considered during the hydraulic analysis of a system. However, the amount of pressure drop to be considered requires experience and judgement. In order to provide some guidance in this area, consider that control valve in the pump discharge circuits should be allowed the maximum of the following pressure drops:

25 psi	minimum
50%	of system friction pressure drop
7 - 10 %	of pump differential

Most other control valves should be allowed pressure drop in accordance with the available pressure. Provision of control valve pressure drop should be sufficient to compensate fro changes in operating conditions, fluid properties and system aging.

GRAPH-CHART by GRAPHIC CONTROLS CORPORATION Buffalo, New York
Printed in U.S.A.
SQUARE 10 X 10 TO THE CENTIMETER AS 0014 -60

RBC 10-29-68
MJ/SP 2-8-80 REV. 1

SINGLE STAGE PUMPS (CHAR. CURVE NO. 20 REV = 1800 FEET, 60 HZ = 1800 FEET)

MINIMUM REQUIRED NPSH

NPSH REQUIRED - FEET OF LIQUID

SINGLE SUCTION 3550 RPM (60 HZ)
SINGLE SUCTION 2950 RPM (50 HZ)
SINGLE SUCTION 1750 RPM (60 HZ)
SINGLE SUCTION 1450 RPM (50 HZ)
DOUBLE SUCTION 3550 RPM (60 HZ)
DOUBLE SUCTION 2950 RPM (50 HZ)
DOUBLE SUCTION 1750 RPM (60 HZ)
DOUBLE SUCTION 1450 RPM (50 HZ)

BOTTOM OF CASE TO ℄ OF PUMP (FEET)

34 32 30 28 26 24 22 20 18 16 14 12 10 8 6 4 2

3 2 1

500 1000 1500 2000 2500 3000 3500 4000 4500 5000

LINE SIZING CRITERIA

HEATER PRESSURE DROPS

C. Although the final heater pressure drops must be determined by the heater designer or heater vendor, the hydraulic engineer should have some approximation of heater pressure drops in order to proceed with his preliminary hydraulic survey. The following typical heater pressure drops may be used on a preliminary basis, to be confirmed or corrected as heater design information becomes available:

Crude Heaters	125 psi
Vacuum Heaters	75 psi
Unibon Heaters	20-60 psi
Platforming (per heater)	3-20 psi
Thermal Crackers	200 psi
Coker Heaters	300 psi
Visbreakers	250 psi
Hot Oil Heaters	20-40 psi
Fired Reboilers	50 psi
Fractionator Charge	40 psi

D. Heat Exchanger Pressure Drops

Heat exchanger pressure drops vary from mm. of mercury to as much as 25 psi. Because the pressure drops vary so widely, there is no substitute for the good judgement of the engineer. For normal, fluid exchangers, at least 5 psi per shell on each side should be allowed as minimum. Some additional guidelines are as follows:

Cooling water side	10 psi
Combined feed exchangers	2-5 psi per side
Condensers (air cond ~ 3)	1-5 psi
Reboilers-Kettle & Thermosiphon	0.2-0.5 psi
Reboilers-forced circulation	5-10 psi
Vacuum condensers	10-25 mm mercury

E. Control Valve Pressure Drops

Control valve pressure drops must be considered during the hydraulic analysis of a system. However, the amount of pressure drop to be considered requires experience and judgement. In order to provide some guidance in this area, consider that control valves in pump discharge circuits should be allowed the maximum of the following pressure drops:

- 25 psi minimum
- 50% of system friction pressure drop
- 10% of pump differential

Most other control valves should be allowed pressure drop in accordance with the available pressure. Provision of control valve pressure drop should be sufficient to compensate for changes in operating conditions, fluid properties and system aging.

INDEX OF TYPE NUMBERS

CRITERIA PAGE DIMENSIONLESS UNITS

Type	Description
1.	Gravity flow
2.	Pump suction
3.	Pump discharge
4.	Liquid to non-pumped reboiler
5.	Reboiler return to column
6.	Column overhead vapor
7.	Column hot vapor by-pass
8.	Column overhead condenser rundown
9.	Compressor suction
10.	Compressor discharge
11.	High available pressure drop (25 psi or more available for piping friction)
12.	Feed to a column
13.	Vacuum unit heater transfer
14.	Steam
15.	Condensing steam turbine exhaust
16.	Liquid at its bubble point to a control valve or steam trap
17.	Steam condensate after a control valve or steam trap
18.	Make-up gas to a hydrogen consuming process
19.	Fuel gas to heaters
20.	Fuel oil to heaters
21.	Atomizing steam to heaters

INDEX OF TYPE NUMBERS

(Continued)

Type	Description
22.	Instrument air piping
23.	Cooling water
24.	Static electricity consideration

Type 1. Gravity flow

Criteria: ΔP/100' (PSI) = 0.20 max.

Remarks: Can be tighter if line is mostly vertical.

Type 2. Pump Suction

a. Liquid at bubble point or less than 50°F below it.

Criteria: If not FCC main column bottoms or similar solids - carrying stream, ΔP/100' (PSI) = 0.20 max.

If FCC MC bottom or similar stream, velocity should be 180 FPM to avoid settling of solids. If ΔP of 0.20 PSI/100' has been exceeded, use the largest size that will still give 180 FPM.

Remarks: For lines 3" and smaller, 180 FPM will result in ΔP/100' in excess of 0.20 PSI which should be allowed for in determining NPSH availability.

b. Liquid 50°F or more below bubble point.

Criteria: ΔP/100' (PSI) = 0.35 max.

Remarks: Watch viscosity for heavy cool liquids. Consider viscosity when it is 2.0 centistokes or more, at which point the actual pressure drop could be as much as 27% higher than that calculated using viscosity of 0.6 centistokes.

Type 3. Pump Discharge

a. Single line pump discharge

Criteria: ΔP/100' (PSI) = 5.0 max.
Velocity (FPM) = 700 max.

Remarks: Carbon steel pump discharge piping is sized within the limits of the above criteria and with an economic consideration of piping material costs compared to pumping costs depending on whether the pump discharge line is considered to be "low pressure level" or "high pressure level". The dividing line is as follows:

"Low pressure level" includes pump discharge lines with design pressure of 1400 psig and design temperature of 150°F (or other combinations of pressure and temperature to give equal or lesser required pipe thickness and flange ratings). For pump discharge lines in this pressure-temperature range, optimum sizing is as indicated by curves added to the liquid line sizing chart PD 435-C for sp.gr. 0.6 to 1.0.

"High pressure level" includes design pressure and design temperature combinations resulting in pipe thicknesses and flange ratings greater than above. Due to the high cost of heavy wall pipe and heavy flanges, pump discharge lines in the "high pressure level" category are more likely to be sized close to the limit of the above criteria.

Alloy pump discharge piping is more likely to be sized at or above the limits of the above criteria due to the very high cost of alloy materials. However, at velocities in excess of 700 FPM, the increased erosion rate may require heavier pipe wall thickness at an increased material cost.

As long as the flow remains turbulent, the optimum size for a given flow rate is practically independent of viscosity. For laminar flow, the above curves on PD 435-C do not exactly represent optimum diameters, but it is suggested that they be used for sizing anyway, observing especially the limitation of 5.0 psi/100' maximum ΔP corrected for viscosity. The flow can be assumed to be laminar at Reynolds Numbers below 2000 and turbulent at 2000 and higher. The Reynolds Number can be calculated as follows:

$$\text{Reynolds Number} = \frac{(3160)(Q)}{(d)(\text{cstks})}$$

Where Q = flowing GPM
d = i.d. (inches)
cstks = flowing viscosity in centistokes

b. Downstream of a pump discharge with different conditions than at the pump.

Criteria:

1) $\Delta P/100'$ (PSI) = 5.0 max.

2) If 100% liquid, velocity (FPM) = 700 max.

3) If 100% vapor, velocity (FPM) = $6000/\sqrt{\rho_v}$ max.

where ρ_v = flowing density, lb/ft^3

4) If the line is the transfer line of a fired reboiler heater or other pumped reboiler, and it is desired to minimize heater outlet temperature:

$\Delta P/100'$ (PSI) max. = 2.5% of column bottom absolute pressure.

5) If the material in the line is in vertical upward two-phase flow, such as feed to a column or inlet to a crude heater, check to avoid slug flow. If it is impossible to satisfy this criterion (which sets a maximum permissible diameter) and also limitations 1 and 4 above, the solution will be to take (and allow for) more pressure drop, or to revise relative amounts of vapor and liquid to specify more vapor.

Remarks: Economic considerations involved in sizing carbon steel pump discharge system piping at "low pressure level" and "high pressure level" and alloy pump discharge system piping should be similar to Type 3a above.

c. Branches from a pump discharge.

Criteria: Treat as Type 3a.

Remarks: Be aware that the common pump must satisfy the pressure drop in all branches. It is possible that a low capacity branch might be sized for a high pressure drop while the high capacity branches require a low pressure drop. The common pump would be required to provide sufficient discharge pressure to satisfy the pressure drop of the low capacity branch, while control valves in the high capacity lines would handle greater than desired pressure drops.

d. Branches downstream of a pump discharge with different conditions than at the pump.

Criteria: Treat as Type 3b.

Remarks: Consider pressure drop balance as discussed for Type 3c.

Type 4. Liquid to non-pumped reboiler.

Criteria: $\Delta P/100'$ (PSI) = 0.15 to 0.20

Remarks: This type is to be sized in conjunction with the return line from the same reboiler.

Type 5. Reboiler return to column

Criteria:

1. Kettle type: $\Delta P/100'$ (PSI) = 0.20 max.

2. Thermosyphon or once-through type, non-kettle, non-pumped. For pumped types see Type 3b.

$\Delta P/100'$ (PSI) = 0.10-0.20 max.

Remarks: Maximum permissable size = 30" nominal. If calculated diameter is above this number, divide flow in half and size for this reduced flow.

For non-kettle types (two-phase flow), the line should be checked for slug flow. If slug flow is indicated, the solution will be to take (and allow for) more pressure drop, or to revise the relative amounts of vapor and liquid to specify more vapor.

Type 6. Column overhead vapor

a. All except FCC main column and crude vacuum column overhead vapor lines.

Criteria:

Limiting equations

$$\Delta P/100' \text{ (PSI)} = 0.20\sqrt{p}\left(\frac{100}{160 + 8.34d}\right) \text{ max.}$$

$$\text{Velocity (FPM)} = 6000/\sqrt{\rho_v} \text{ max.}$$

Use half of the above limiting pressure drop for columns where minimum pressure is critical.

p = receiver pressure, psia
d = i.d., inches
ρ_v = overhead vapor flowing density, lb/ft^3

Remarks: Sizing of the above column overhead vapor lines is based upon an approach to economic optimization within fixed limitations of pressure drop and velocity. The equations have been developed for carbon steel material. Alloy overhead vapor lines should be sized slightly tighter due to the higher material cost, but still within the criteria of the limiting equations.

b. FCC main column overhead vapor

Criteria: $\Delta P/100'$ (PSI) = 0.10 max.

c. Crude vacuum column overhead

The method of sizing is as follows: Determine equivalent length of the line. Size line so that ΔP over its entire length is not more than 7% of flash zone absolute pressure, limited to flash zone pressures of 35 mm and greater.

Type 7. Column hot vapor by-pass

Criteria: $\Delta P/100'$ (PSI) = 0.5 max.

Remarks: For amount of vapors thru hot vapor by-pass, use the following formula:

$$W = \left[(Mol/hr)_1 + 0.06\ (Mol/Hr)_2\right]\left[M_2\right]$$

W = by-pass vapor, lb/hr.
$(Mol/hr)_1$ = normal mols/hr of net gas
$(Mol/hr)_2$ = normal mols/hr of gross column overhead vapors
M_2 = mol weight of gross overhead vapors

Type 8. Column overhead condenser rundown.

a. Totally condensing, single phase:

Criteria:

Limiting equations

$$\Delta P/100'\ (PSI) = 0.10\sqrt{P}\left(\frac{100}{53.3 + 2.78d}\right) \text{ max.}$$

Velocity (FPM) = 200 max.

Use half of the above limiting pressure drop for columns where minimum pressure is critical.

p = receiver pressure, psia
d = i.d., inches

Remarks:

Special attention should be given to the rundown line if it is part of a pressure relief route. This situation exists when pressure relief is via a vent or relief on the receiver rather than via a relief valve on the OH vapor line or column proper. The rundown line should be at least as large as such a vent, and at least one size larger than the inlet of any RV on the receiver whose function is to protect the column. If several RV's are on the receiver serving this function the rundown line should be at least one size larger than a size whose inside cross sectional area equals the sum of the areas of the relief valve inlets.

b. Totally condensing, with traces of a second liquid present and a piping arrangement that would permit pockets of the second liquid phase to accumulate.

Criteria and remarks: Column overhead condensers are often placed below the receiver in order to provide ΔP to operate a hot vapor by-pass. In cases like this, a moderately high velocity should exist in the run-down piping (350 FPM). This becomes important in column overhead systems where traces of a heavier liquid, such as water or HF can collect in the low points of a rundown line. The higher velocities tend to keep the line clear of a pocket of heavier liquid.

However, see the remarks under Type 8a above for a discussion of rundown lines when they are part of a pressure relief route. A conflict between the need for adequate liquid velocity during normal operation and the need of low ΔP during pressure relief may influence the design of the pressure relief system.

c. Partially condensing, vapor and liquid present.

Criteria: $\Delta P/100'$ (PSI) $= 0.10\sqrt{p}\left(\frac{100}{53.3 + 2.78d}\right)$ max.

Use half of the above limiting pressure drop for columns where minimum pressure is critical.

p = receiver pressure, psia
d = i.d., inches

Remarks: Because this two-phase flow line could be vertical upflow, the line should be checked for slug flow. If slug flow is indicated, a smaller diameter should be selected, until slug flow does not exist. However, if it is impossible to satisfy both the slug flow criteria and the max $\Delta P/100'$ limitation given above, solution will be to analyze piping layout with an eye toward relaxation of the max. $\Delta P/100'$ rule.

Special attention should be given to the rundown line if it is part of a pressure relief route, as described for Type 8a. If there is a conflict between diameter required for pressure relief and diameter required for avoidance of slug flow, consideration should be given to using several smaller lines in parallel or to revising the pressure relief arrangements.

Type 9. Compressor suction

a. Reciprocating compressor

Criteria: $\Delta P/100'$ (PSI) = $0.043\sqrt{p}$ max.

$\Delta P/100'$ (PSI) = 1.0 max.

Velocity (FPM) = $2000\sqrt{\frac{28.8}{MW}}$ max.

p = line pressure, psia
MW = gas molecular weight

Remarks: Line is defined as being between a suction drum (or vessel serving as a suction drum) and the compressor. Lead-in lines to individual cylinders should also be sized according to the above criteria.

b. Centrifugal compressor

Criteria: $\Delta P/100'$ (PSI) = $0.043\sqrt{p}$ max.

$\Delta P/100'$ (PSI) = 1.0 max.

Velocity (FPM) = $3540/\rho_v^{0.25}$ max.

p = line pressure, psia
ρ_v = gas flowing density, lb/ft^3

Remarks: Line is defined as being between a suction drum (or vessel serving as a suction drum) and the compressor.

Type 10. Compressor discharge

a. Reciprocating compressor

Criteria: $\Delta P/100'$ (PSI) = $0.043\sqrt{p}$ max.

$\Delta P/100'$ (PSI) = 1.0 max.

Velocity (FPM) = $3000\sqrt{\frac{28.8}{MW}}$ max.

p = line pressure, psia
MW = gas molecular weight

Remarks: Line is defined as being between the compressor and a junction with a line carrying other fluids, or to a cooler or vessel. Lead-out lines from individual cylinders should also be sized according to the above criteria.

b. Centrifugal compressor

Criteria: $\Delta P/100'$ (PSI) = $0.043\sqrt{p}$ max.

$\Delta P/100'$ (PSI) = 1.0 max.

Velocity (FPM) = $6000/\sqrt{\rho_v}$ max.

p = line pressure, psia
ρ_v = gas flowing density, lb/ft^3

Remarks: Line is defined as being between the compressor and a junction with a line carrying other fluids, or to a cooler or vessel.

Type 11. High available pressure drop (25 psi or more available for piping friction, within the battery limits).

Criteria: Use up, but do not exceed, the available pressure drop. Also, observe the following limitations, except for pressure relief:

1. 100% liquid
   $\Delta P/100'$ (PSI) = 7.0 max.

   Velocity (FPM) = 700 max.

2. 100% vapor
   $\Delta P/100'$ (PSI) = 7.0 max.

   Velocity (FPM) = $6000/\sqrt{\rho_v}$ max.

3. Vapor plus liquid
   $\Delta P/100'$ (PSI) = 5.0 max.

Remarks: Allow high piping ΔP, but consider erosion, noise, and vaporization. For vaporizing materials, use downstream conditions for calculation of ΔP.

Type 12. Feed to a column

Criteria and remarks:

1. If line is a pump discharge or is downstream of a pump discharge, treat as Type 3, except limit the 100% liquid case to a velocity of 500 FPM.

2. If line has high available pressure drop (25 psi or more available for piping friction), treat as Type 11, except limit the 100% liquid case to a maximum velocity of 500 FPM.

3. If line is other as indicated in 1 or 2, above:

$$\Delta P/100' \text{ (PSI)} = 3.0 \left(\frac{100}{114 + 10d} \right)^{\text{max.}}$$

A) If flow is 100% liquid:

Velocity (FPM) = 500 max.

B) If flow is 100% vapor:

Velocity (FPM) = $6000/\sqrt{\rho_v}$ max.

C) If flow is two-phase: Apply the criteria for slug flow. If it is impossible to satisfy both this criterion and the pressure drop of this item 3, the solution will be to take (and allow for) more pressure drop, or to revise relative amounts of vapor and liquid to specify more vapor.

Type 13. Vacuum unit heater transfer

The method of sizing is as follows: Determine equivalent length of the line. Determine heater outlet pressure, which is often 3.0 psia. Base line sizing calculations on only the vapor portion of the flow, but in calculations of pressure drop and velocity, use diameter of only 98% of the actual diameter, to account for presence of liquid.

Observing sonic velocity limitation and allowing for changing pressure along the length of the line, size line to use up the available pressure drop between heater and flash zone. If pressure in downstream end of the line is raised because of sonic velocity limitation, the nozzle at the inlet to the column should be enlarged until sonic velocity or less can be attained in the nozzle at flash zone pressure.

Type 14. Steam

Criteria and remarks:

1. Saturated, 15 psig and less:

Velocity (FPM) = 6000 max.

$\Delta P/100'$ (PSI) = 1.1 max.

Higher rates than these are permissible where high pressure drop is available, but velocity should be less than 10,000 FPM.

2. Saturated, over 15 psig:

Velocity (FPM) = 10,000 max.

$\Delta P/100'$ (PSI) = 0.02 p max.

p = pressure, psia.

3. Superheated, over 200 psig

Velocity (FPM) = 15,000 max.

$\Delta P/100'$ (PSI) = 0.012 p max.

p = pressure, psia.

Type 15. Condensing steam turbine exhaust

The method of sizing is as follows:

Determine equivalent length of the line.

For convenience, calculations should be based on full weight flow from turbine as if it had a steam quality of 100%.

Operating pressure of turbine exhaust and condenser inlet must be known. Size line to use up the difference in pressure between turbine and condenser, except observe maximum velocity as follows:

Velocity (FPM) = $1200/\sqrt{\rho_v}$ max.

ρ_v = flowing density of steam at inlet to condenser, lb/ft^3

Type 16. Liquid at its bubble point to a control valve or steam trap

Criteria: $\Delta P/100'$ (PSI) = 0.5 to 1.5 max.

Velocity (FPM) = 700 max.

Remarks: Consider elevations of liquid surface and control valve. Consider length of line. The pressure drop due to friction should be well below the static head increase in pressure due to lower elevation of the control valve, in order to avoid vaporization before valve.

Type 17. Steam condensate after a control valve or steam trap

Criteria and remarks: There are many situations possible in the operation of condensate removal piping. Consideration should be given to the points discussed below.

1. With control valve located in steam line.

   The control valve may be placed in the steam line, if the condensate will still have sufficient pressure to flow to its destination. This would be the case when the condensate is at a temperature whose saturation pressure is sufficiently above the condensate destination pressure to permit flow. Low condensate temperatures can be tolerated when flow is to a condensate pot operating under a vacuum.

   To size the condensate line one must first obtain the destination pressure. Then an initial condensate temperature (and pressure) must be determined. This will depend on the process-side temperatures of the exchanger, on whether the flow is countercurrent or co-current, and on the condensate temperature approach to process-side temperature. Lower condensate temperatures will be governing for condensate line sizing.

   If the length of the condensate line is known, this length (equivalent feet) should be used in the pressure drop calculation. If the length is not known, as is generally the case, 300 equivalent feet may be used as being the distance to a condensate header or pot. Pipe friction pressure drop should be not more than 1/2 of the total pressure drop. It may be necessary to consider the line in sections for calculation purposes in order to account for the increased flashing as pressure falls. PD 395A may be used to find the piping two-phase pressure drop as a function of a fictitious all-liquid ΔP.

2. With control valve in condensate line.

   The control valve is often placed in the condensate line when process-side temperatures are low, resulting in low condensate temperatures. The pressure before the control valve in this case will be full steam pressure, less a small amount for exchanger pressure drop. The temperature of the condensate before the control valve can be anything from saturation temperature down to the process side temperature at the condensate outlet. For condensate line sizing, higher temperature will be governing, since more flashing will result. Condensate temperature equal to steam temperature should therefore be assumed unless there is reason to believe it to be lower.

3. General Remarks, applicable to all cases.

   Use a unit pressure drop 1-1/2 times the value for clean commercial steel pipe, to allow for roughening of the pipe walls due to the corrosive effects of condensate.

   Pressure drop per length of pipe will be greatest at the downstream end of the pipe where the pressure level is the lowest. More liquid will have flashed to vapor, and the vapor density is the lowest. There should be a limitation on instantaneous pressure drop as follows:

   $\Delta P/100'$ (PSI) = 7.5 max.

This should be calculated using 1-1/2 times the values for clean commercial steel pipe as mentioned above. Often this limitation will be governing, with the result that the steam trap or control valve will be able to operate with much more than 1/2 of the total pressure drop.

Type 18. Make-up gas to a hydrogen consuming process

Criteria: $\Delta P/100'$ (PSI) = 1.0 max.

Velocity (FPM) = $6000/\sqrt{\rho_v}$ max.

Remarks: Consider length of line. Take smaller $\Delta P/100'$ for long lines.

Type 19. Fuel gas to heaters

Criteria:

1. Before control valve:

   $\Delta P/100'$ (PSI) = 0.05 p max.

   p = gauge pressure before valve

2. After control valve:

   $\Delta P/100'$ (PSI) = 0.1 p max.

   p = gauge pressure after valve.

   If pressure is not known, the following standard values may be used:
   For gas with gross heating value of 500 BTU/SCF or more:
   10 psig

   For gas with gross heating value less than 500 BTU/SCF:
   20 psig

3. Header:

   $\Delta P/100'$ (PSI) = 0.05 p max.

   Comments of Item 2 apply, except that p refers to gauge pressure in header.

Remarks: Quantity of gas can be calculated from process specification heater duty, using an appropriate heater efficiency and fuel gas heating value.

If more than one process stream is to be heated in the same heater box, careful determination should be made for the amount of heat to be released from each set of burners.

Type 20: Fuel oil to heaters

Criteria:

GPM	Size
0 - 5.9	1" - Sch. 80
6 - 19.9	1-1/2" - Sch. 80
20 - 34.9	2" - Sch. 80
35 - 100	3" - Sch. 40
101 - 300	4" - Sch. 40

Remarks: Use 3 volumes recirculated for 1 volume burned. Use flowing temperature such as to give a viscosity of 50 centistokes. Specific gravity is about 0.9. Size lines as above.

Note that this is laminar flow.

Use same criteria for return lines to surge, storage, or refinery fuel oil system.

Type 21. Atomizing steam to heaters

Criteria: Usual steam criteria

Remarks: Use 3-4 lbs. of steam per gallon of fuel oil burned. Use pressure of 75 psig maximum after valve if there is a valve.

Type 22. Instrument air piping

Criteria: Main air supply header shall be 1-1/2" or larger.

Branch Header line size:

Number of taps	1 - 5	6 - 10	11 - 15	16 - 20
Branch header size	1/2"	3/4"	1"	1-1/2"

Type 23. Cooling water

Criteria:

0-650 GPM:	Max. $\Delta P/100'$ = 1.3 PSI
651-2800 GPM:	Max. Velocity = 500 FPM
2801-7000 GPM:	Max. Velocity = 600 FPM
Over 7001 GPM:	Max. Velocity = 700 FPM

Remarks: The 1.3 PSI/100' criterion is based on $\Delta P/100'$ obtained by using PD 435-C. Pressure drop after a long period of usage may be twice as high as this. If film type corrosion protection is used, maximum velocity should be reduced to 350-500 FPM.

Type 24. Static electricity consideration

Criteria: Velocity (FPM) = 400 max.

Remarks: When the flowing hydrocarbon is a material whose vapor pressure is such as to form an explosive mixture with air, the flowing velocity must be limited in order to minimize the buildup of static electricity. This consideration is particularly important when handling materials such as kerosene and jet fuel to storage tanks.

UOP

Engineering Design Seminar

Line Sizing General Comments

When faced with the time limitations of production engineering, the design engineer must have available to him various guidelines and rules of thumb to reduce the time consumed in line sizing. Although optimization of line sizing should not be ignored, the available increments of pipe size normally encountered make the expenditure of an extensive amount of time involved in line size optimization very questionable. UOP employs a computer program with built in optimization procedures to assist the design engineer in the performance of his line sizing job. However, for this discussion, we will approach line sizing without the aid of the computer and rely upon good judgement and experience to reduce the time required and still provide a reasonable approach to optimization.

Following are some general comments to keep in mind as we proceed through this discussion:

a. Line sizing will be based on "normal" flow rates and "normal" pressures as developed by the process design. However, the engineer should keep in mind the effect of "design" flow rates, maximum flow rates and start-up, shutdown and upset conditions that may have a significant influence on the plant pressure profile. It is generally helpful to develop a simple sketch of the plant or system piping arrangement to indicate the normal pressure profile and to record the results of investigations of alternate considerations. The sketch also provides a good means to visualize the possible effect of static head on pressure considerations used in line sizing.

b. The principle criteria for line size selection will be pressure drop, expressed as pounds per square inch (PSI) per 100 equivalent feet of pipe. Velocity, expressed in feet per minute, will also be an important factor.

c. Additional properties used in our line sizing procedures will be specific gravity, vapor density and vapor specific volume. Specific gravity will normally refer to a liquid and is a dimensionless number determined as the ratio of the density of the liquid at flowing temperature to the density of water at the temperature of its maximum density. Vapor density will be expressed in pounds per cubic foot. Vapor specific volume will be expressed as cubic feet per pound.

d. The maximum velocity that a compressible fluid can experience is the speed of sound in that fluid. This is referred to as the **sonic velocity** of the fluid. It is calculated by the equation:

$$Vs = (k\,gRT)^{1/2}$$

where sonic velocity, Vs, is in feet per second.

Sonic velocity can be easily overlooked, resulting in a calculated downstream pressure lower than that actually occurring in the system. What happens is the actual downstream pressure will be high enough such that sonic velocity of the fluid is **not** exceeded at the end of the pipe or system. The actual downstream pressure is the value that must be used for pressure drop calculations.

Examples of line sizing situations where sonic velocity is a consideration for design are:

1. vacuum heater transfer lines
2. pressure relief piping
3. high pressure drop systems

e. If the specific volume of the vapor in a line changes significantly due to line pressure drop, certain corrections should be made in the pressure drop calculation. As a general rule, if the pressure drop for a known length of line is less than 10% of the upstream absolute pressure, either the upstream or downstream specific volume can be used in the pressure drop calculation. If the total pressure drop is between 10 and 40% of the upstream pressure, use the average specific volume. If the total pressure drop is greater than 40% of the upstream pressure, divide the line into sections for calculation purposes.

f. For strength considerations, good practice limits the minimum permissable line size to 1" nominal for pipe rack runs and pipe spans between supports In order to reduce purchasing and detailing problems and to minimize inventory requirements, pipe sizes such as 1-¼, 2-½, 3-½ and 5 inch will normally be avoided. Schedule 80 minimum is recommended for 2 inch and smaller pipe size.

g. Pipe sizes have a constant outside diameter. therefore, as the wall thickness increases, the flowing area will be reduced. The engineer should keep this point in mind when working in piping systems at high pressure or when high corrosion allowances are required.

h. When considering the wall thickness for pressure requirements or corrosion allowance, remember that the wall thickness tolerance is ± 12-½% thru 24" seamless pipe size. The wall thickness tolerance is normally reduced to ± 0.01 inch for welded pipe and sizes greater than 24" when fabricated from rolled plate.

i. Although most of the information contained in this discussion is directed toward new piping, the engineer should keep in mind that the economics and decision factors involved in revamps are different. Consequently. smaller line sizes can often be used on revamps compared to new construction.

j. Chart PD 435-C is used to determine the sizing of lines for liquid flow. The engineer enters the chart with the appropriate flowing GPM at the bottom and proceeds upward, selecting the proper line size to suit the pressure drop or velocity criteria which will be discussed later. Note that for the smaller line sizes, this chart indicates separate lines for different pipe schedules or wall thicknesses. The indicated chart ΔP should be multiplied by the flowing specific gravity to determine actual. Chart PD 435-C is based on a liquid having a kinematic viscosity of 0.6 centistoke. For more viscous materials the chart ΔP should be multiplied by the correction factor $(M/0.6)^{0.2}$ where μ is in centistokes.

   For example, a flowing liquid having a viscosity of 20 centistokes will have a line pressure drop approximately twice as great as would be indicated by the chart. This factor applies for turbulant flow (Reynolds number greater than 2000) only.

k. Charts PD 436, PD 437 and PD 438 are used to determine the sizing of lines for vapor flow. These charts are used in much the same manner as PD 435-C above. The chart ΔP should be multiplied by the specific volume to determine actual ΔP and the chart velocity should be multiplied by specific volume to determine actual velocity.

l. For pressure drop calculations involving two-phase flow, chart PD 395A is used. This chart is based on a method developed for horizontal flow. However, practically all of the

two-phase flow applications encountered in process piping for refinery units are in the relatively high velocity flow regimes of annular, spray or froth flow. Therefore, it is felt that frictional pressure drops and type of flow regime are not much affected by pipe orientation at these velocities.

m. When designing two phase upflow lines, such as column feeds, reboiler returns and condenser rundowns, the flowing velocity should be kept high enough to prevent slug flow. Annular or mist flow is usually assured if the velocity in ft/sec is approximately equal to 60 divided by the square root of the mixed phase density in lbs/ft^3. The chart "Approximate Two-Phase Flow Patterns" may also be used to determine the approximate flow condition.

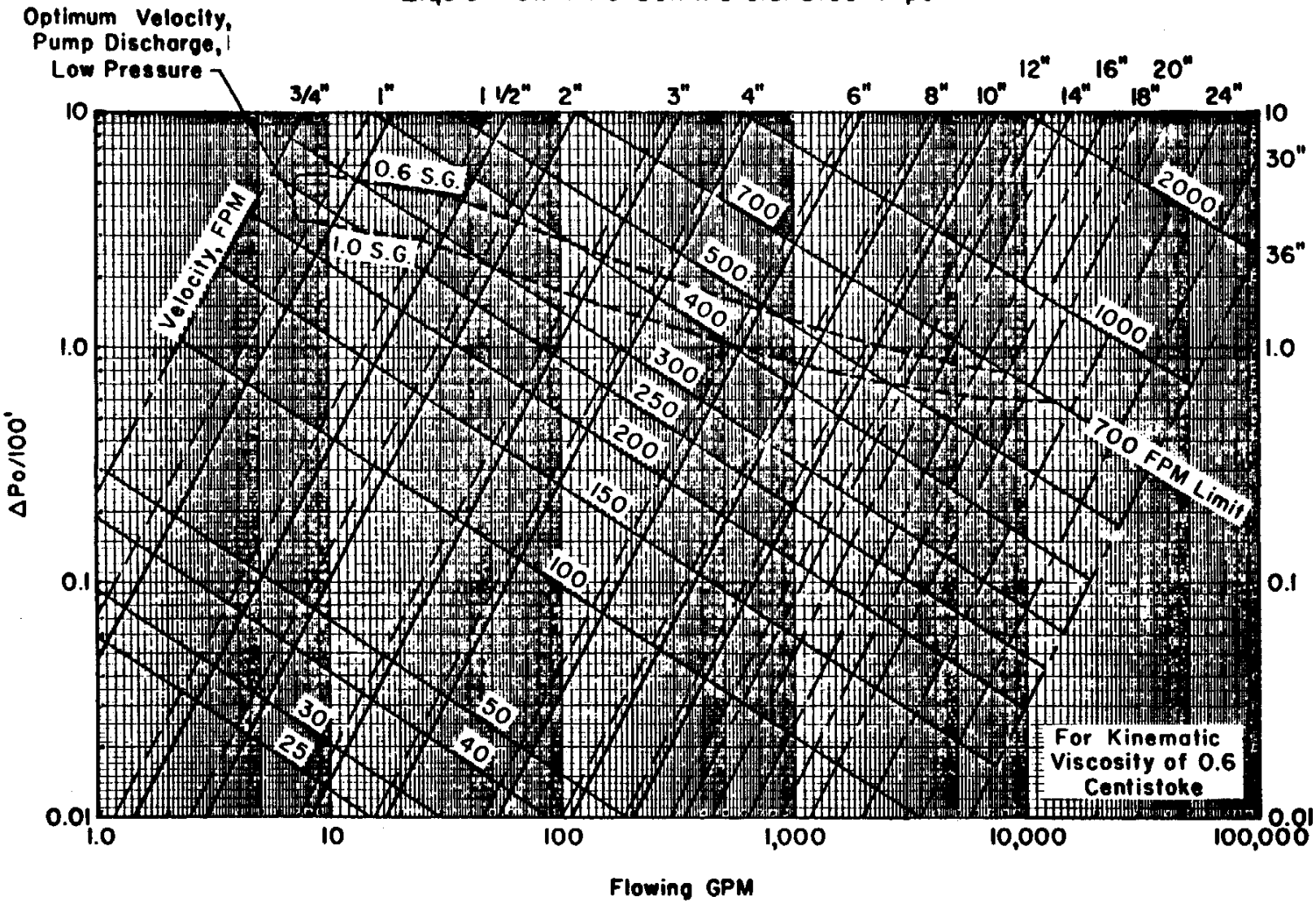
n. At UOP, the engineers use hydraulic tabulation forms to assist in their line sizing work. These forms simplify the work of the engineer and provide a convenient means to communicate the hydraulic information to specialty equipment engineers. Three examples are as follows:

Form UOP-17-2002A is used for single phase line sizing, vapor or liquid, and for pump and control valve information. The form is used in conjunction with charts PD 435-C, PD 436, PD 437 and PD 438.

Form UOP-17-1093 is used for two phase line sizing and is used in conjunction with chart PD 395-A. This form provides a convenient means for tabulating the two phase flow line sizing data.

An additional form is provided which defines the two phase sizing procedure in equation form. Some engineers may prefer to use this method to record their line sizing calculations.

Liquid Flow Thru Commercial Steel Pipe

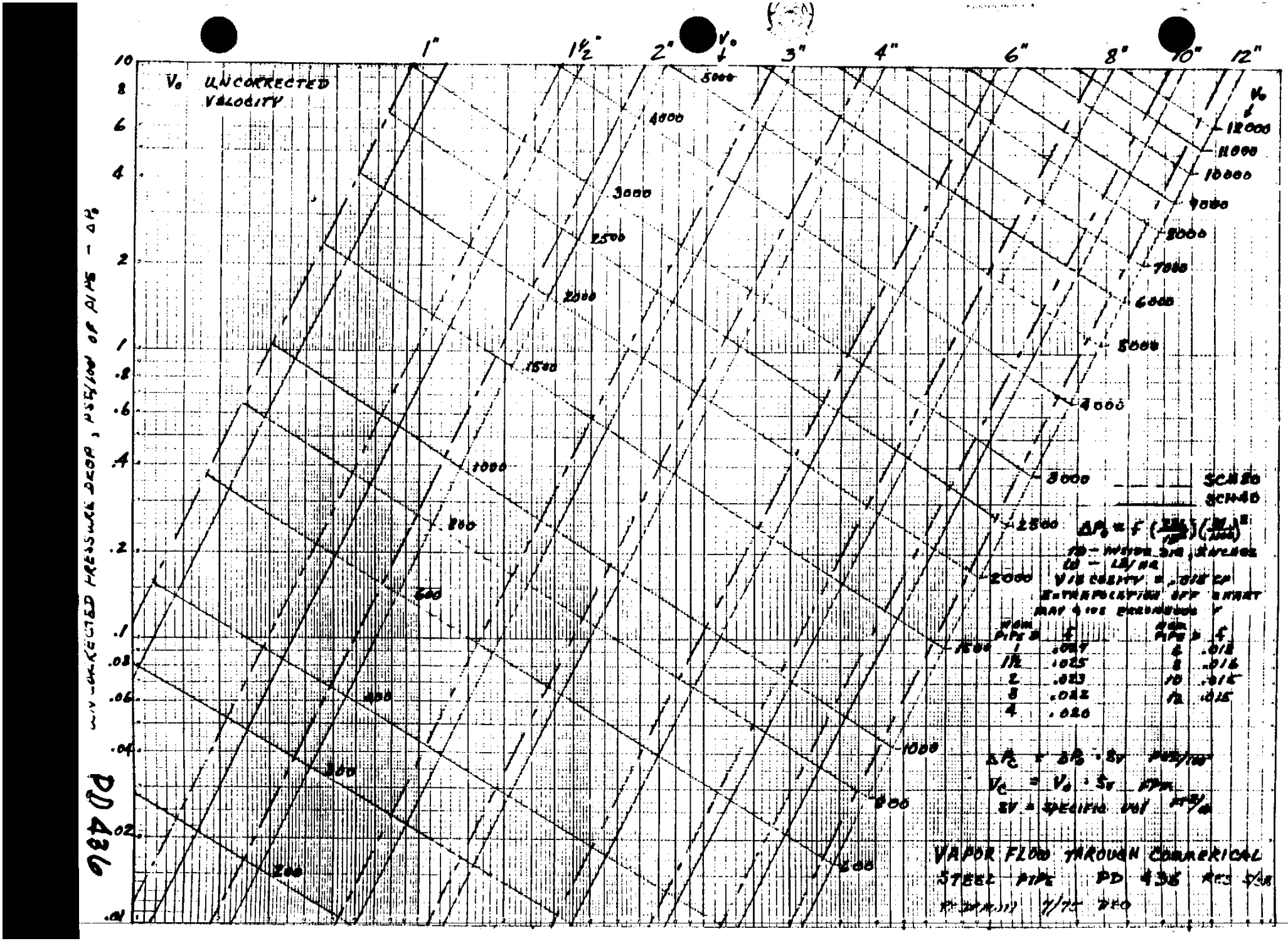


— — — — Sch. 80
——— Sch. 40
——— — ——— 3/8" Wall

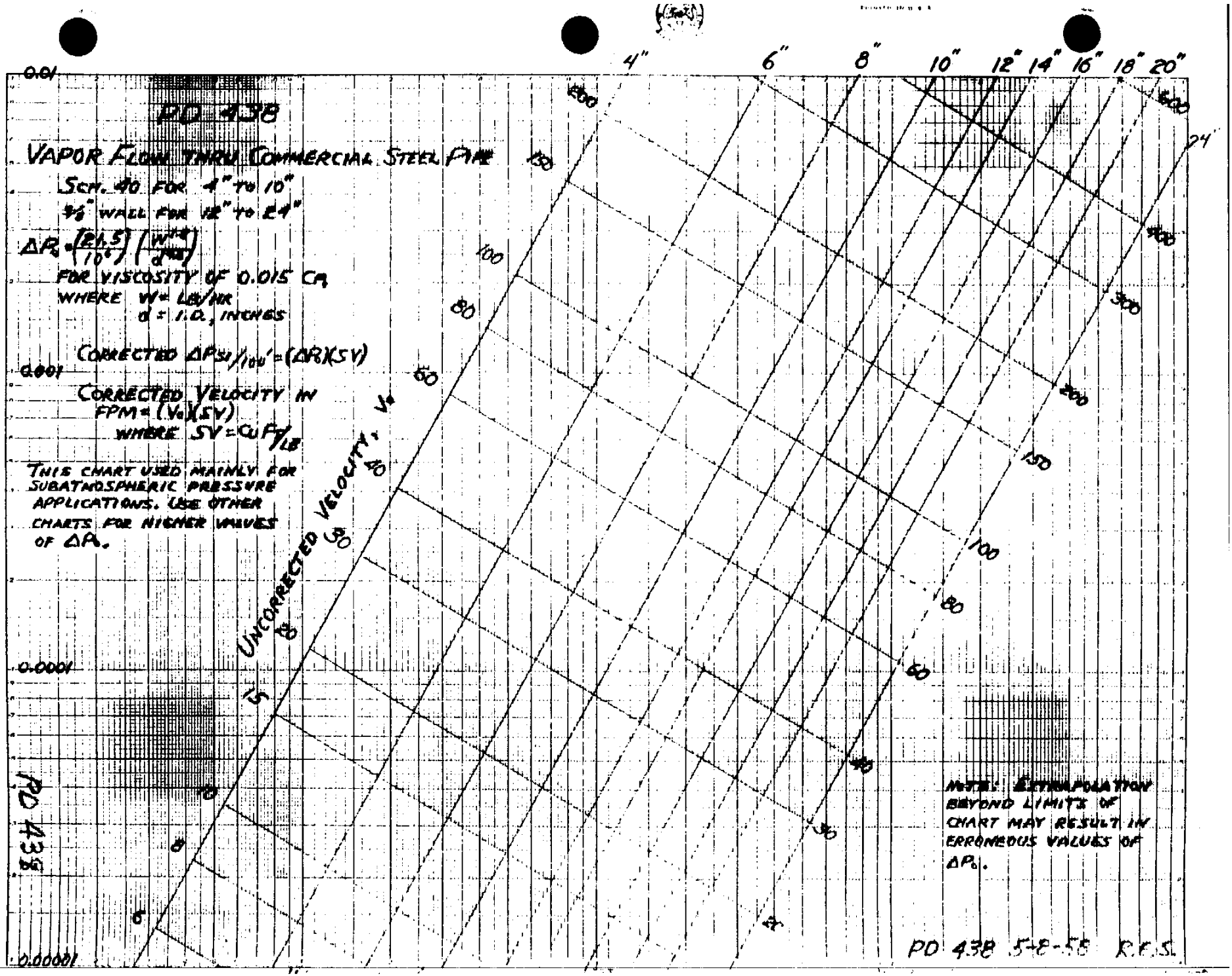
Note:
To Find ΔP in PSI per 100 ft. of Pipe, Multiply ΔPo/100' by Specific Gravity.

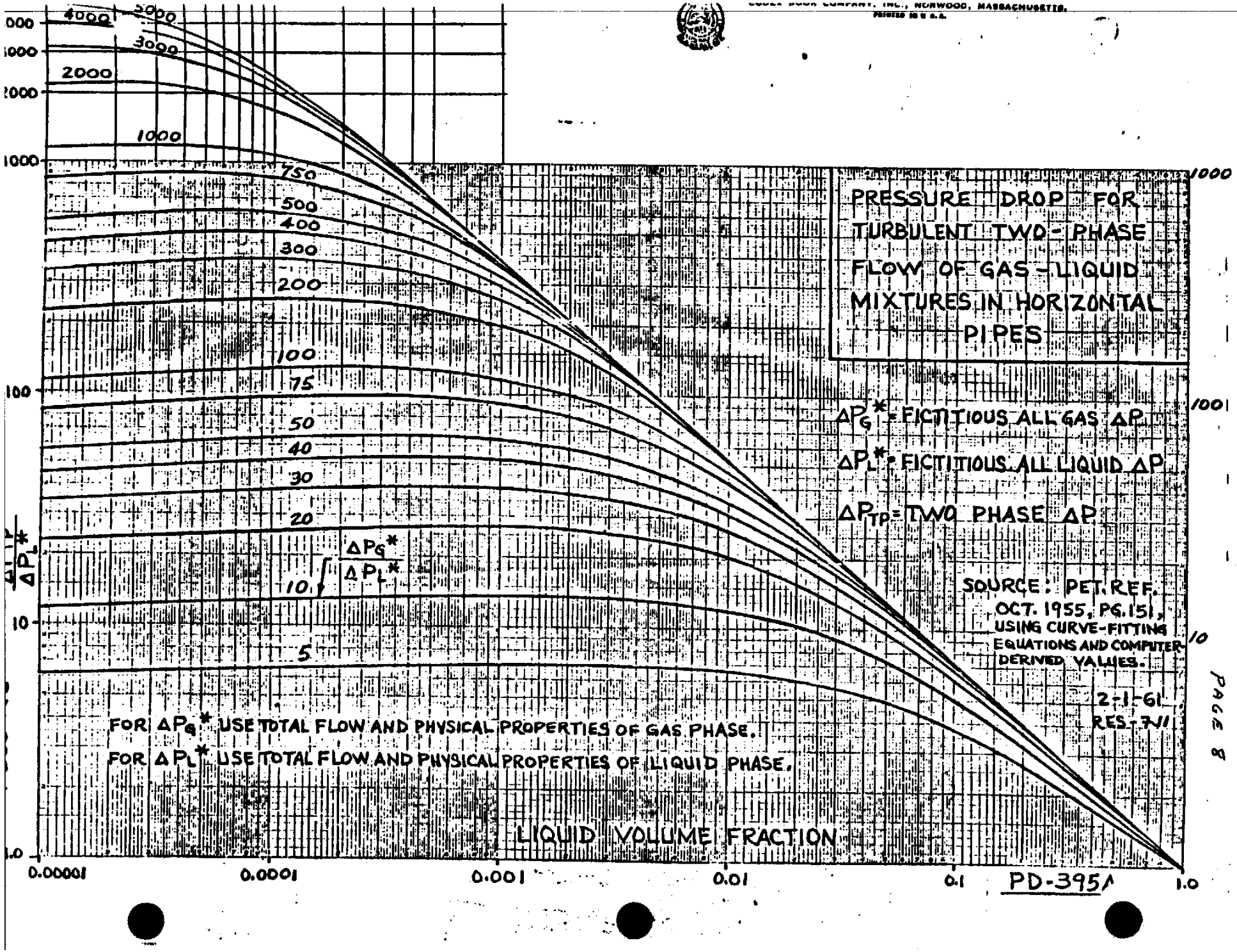
5-9-78 RES

PD 435-C
(Supersedes PD 435-B)

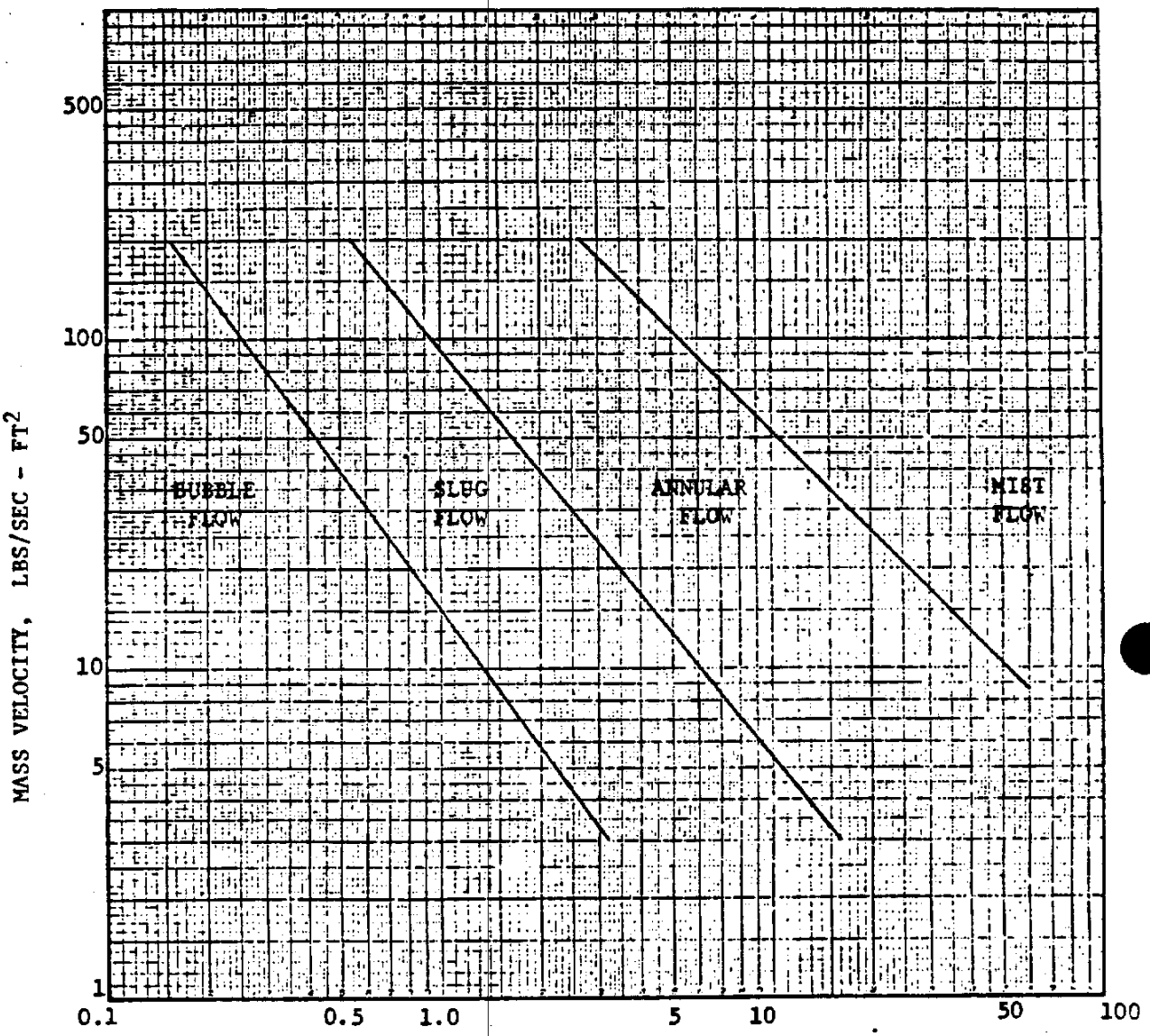

1"
1½"
2"
3"
4"
6"
8"
10"
12"
V_o UNCORRECTED VELOCITY
V_o
ΔP_f UNCORRECTED PRESSURE DROP, PSI/100 OF PIPE - ΔP_f
PD 436
SCH 80
SCH 40
VAPOR FLOW THROUGH COMMERCIAL STEEL PIPE
PD 436

PD 437
VAPOR FLOW THRU COMMERCIAL STEEL PIPE
(See other chart for smaller sizes)
SCH. 80
SCH. 40
36" wall
$\Delta P_o = (f)\left[\frac{(SG)}{(d^5)}\right]\left(\frac{W}{1,000}\right)^2$
WHERE
d = I.D. inches
W = Lbs/Hr.
f = 0.0153 FOR 12" Pipe f = 0.0145 FOR 14" = 0.0138
0.0143 " " 16" = 0.0133
0.0138 " " 18" = 0.0128
0.0135 " " 20" = 0.0125
0.0133 " " 24" = 0.0123
Connected Load Approx = (Lbs/Hr) SV
Connected velocity in Pipe = 4,000 Lbs/Hr
where SV = Cu.Ft. per Lb.
PD 437
5-7-58
M.E.S.
Uncorrected Velocity
Uncorrected Pressure Drop – Psi per 100' of Pipe – ΔP_o
10
1
.01
.001
.0001
36"
30"
24"
20"
18"
16"
14"
12"
20,000
16,000
12,000
10,000
9,000
8,000
7,000
6000
5,000
4,000
3,000
2,000
1,000
800
600
400
200
100
80
60
40
20
10
8
6
4
2
1


PD 438
VAPOR FLOW THRU COMMERCIAL STEEL PIPE
SCH. 40 FOR 4" TO 10"
⅜" WALL FOR 12" TO 24"
$\Delta P_o = \frac{(2)(1.5)}{10^6}\left(\frac{W^{1.8}}{d^{4.8}}\right)$
FOR VISCOSITY OF 0.015 CP
WHERE W = LBS/HR
d = I.D., INCHES
CORRECTED $\Delta P_{SV}/100' = (\Delta P_o)(SV)$
CORRECTED VELOCITY IN FPM = $(V_o)(SV)$
WHERE SV = CU FT/LB
THIS CHART USED MAINLY FOR SUBATMOSPHERIC PRESSURE APPLICATIONS. USE OTHER CHARTS FOR HIGHER VALUES OF ΔP_o.
UNCORRECTED VELOCITY, V_o
4" 6" 8" 10" 12" 14" 16" 18" 20" 24"
0.01
0.001
0.0001
0.00001
NOTE: EXTRAPOLATION BEYOND LIMITS OF CHART MAY RESULT IN ERRONEOUS VALUES OF ΔP_o.
PD 438 5-8-58 R.F.S.


PRESSURE DROP FOR TURBULENT TWO-PHASE FLOW OF GAS-LIQUID MIXTURES IN HORIZONTAL PIPES
ΔP_G^* = FICTITIOUS ALL GAS ΔP
ΔP_L^* = FICTITIOUS ALL LIQUID ΔP
ΔP_{TP} = TWO PHASE ΔP
SOURCE: PET. REF. OCT. 1955, PG. 151, USING CURVE-FITTING EQUATIONS AND COMPUTER DERIVED VALUES.
2-1-61
RES-711
FOR ΔP_G^* USE TOTAL FLOW AND PHYSICAL PROPERTIES OF GAS PHASE.
FOR ΔP_L^* USE TOTAL FLOW AND PHYSICAL PROPERTIES OF LIQUID PHASE.
LIQUID VOLUME FRACTION
$\frac{\Delta P_{TP}}{\Delta P_L^*}$
$\int \frac{\Delta P_G^*}{\Delta P_L^*}$
4000
3000
2000
1000
750
500
400
300
200
100
75
50
40
30
20
10
5
0.00001
0.0001
0.001
0.01
0.1
1.0
PD-395A

APPROXIMATE TWO-PHASE FLOW PATTERNS (VERTICAL UPFLOW)



$$\frac{1}{\left(\frac{W_L}{W_g}\right)^{0.9}\left(\frac{\rho_g}{\rho_L}\right)^{0.5}\left(\frac{\mu_L}{\mu_g}\right)^{0.1}}$$

W = Lbs./Sec.
ρ = Lbs./Ft.^{3}
μ = Centipoise

Adapted from:
"What you Need to Design Thermosiphon Reboilers"

James R. Fair
Petroleum Refiner
February, 1960

UOP PROCESS DIVISION
ENGINEERING DEPARTMENT

CUSTOMER ____________________ PAGE NO. 11

SUBJECT MIXED PHASE LINE SIZING DATE ____________

PROJECT ____________

BY ____________

$$\text{LIQUID VOLUME FRACTION} = \frac{V_L}{V_L + V_G} = \frac{\dfrac{W_L}{S.G. \times 62.4}}{\dfrac{W_L}{S.G. \times 62.4} + \dfrac{W_G}{\#/FT^3}}$$

$$= \frac{\dfrac{____}{____ \times 62.4}}{\dfrac{____}{____ \times 62.4} + ____} $$

$$= \frac{____}{____ + ____} = ____ =$$

$$\text{TOTAL FLOW GAS} = W_L + W_G = ____ + ____ = \quad \#/HR$$

$$\text{TOTAL FLOW LIQUID} = \frac{W_L + W_G}{S.G. \times 500} + \frac{____}{____ \times 500} = \quad GPM$$

TRY ________ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times S.G.} = \frac{____ \times \dfrac{1}{____}}{____ \times ____} = ____ =$$

$$\Delta P_{Go} = f \times \frac{336}{d^5} \times \left(\frac{W}{1000}\right)^2 = \frac{____ \times 336 \times ____^2}{____ \times 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = ____ \times ____ =$$

TRY ________ " LINE

$$\frac{\text{TOTAL FLOW } \Delta P_G}{\text{TOTAL FLOW } \Delta P_L} = \frac{\Delta P_{Go} \times \dfrac{1}{\#/FT^3}}{\Delta P_{Lo} \times S.G.} = \frac{____ \times \dfrac{1}{____}}{____ \times ____} = ____ =$$

$$\Delta P_{Go} = f \times \frac{336}{d^5} \times \left(\frac{W}{1000}\right)^2 = \frac{____ \times 336 \times ____^2}{____ \times 10^6} =$$

$$\Delta P_{TP} = \text{TOTAL FLOW } \Delta P_L \times \text{FACTOR} = ____ \times ____ =$$

USE ________ " LINE

UOP Process Division • UOP Inc.
20 UOP Plaza – Algonquin & Mt. Prospect Roads • Des Plaines, Illinois 60016 • U.S.A.

HYDRAULIC TABULATION

	LINE NO. (C.V. NO.)	SIZE IN.	SCHEDULE	ΔP/100 FT. PSI	ESTIM. EQ. FT. x 100	DESCRIPTION	ΔP PSI	INLET PRESS. PSIG	ΔP PSI	INLET PRESS. PSIG	ΔP PSI	INLET PRESS. PSIG	DESIGN PRESS. PSIG
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													

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Nomenclature

Unless otherwise stated, all symbols used in this book are defined as follows:

A = cross sectional area of pipe or orifice, in square feet

a = cross sectional area of pipe or orifice, or flow area in valve, in square inches

B = rate of flow in barrels (42 gallons) per hour

C = flow coefficient for orifices and nozzles = discharge coefficient corrected for velocity of approach = $C_d / \sqrt{1-\beta^4}$.

C_d = discharge coefficient for orifices and nozzles

C_v = flow coefficient for valves; expresses flow rate in gallons per minute of 60 F water with 1.0 psi pressure drop across valve

D = internal diameter of pipe, in feet

d = internal diameter of pipe, in inches

e = base of natural logarithm = 2.718

f = friction factor in formula $h_f = f L v^2 / D 2g$

f_T = friction factor in zone of complete turbulence

g = acceleration of gravity = 32.2 feet per second per second

H = total head, in feet of fluid

h = static pressure head existing at a point, in feet of fluid

h_g = total heat of steam, in Btu per pound

h_L = loss of static pressure head due to fluid flow, in feet of fluid

h_w = static pressure head, in inches of water

K = resistance coefficient or velocity head loss in the formula, $h_L = Kv^2 / 2g$

k = ratio of specific heat at constant pressure to specific heat at constant volume = c_p / c_v

L = length of pipe, in feet

L/D = equivalent length of a resistance to flow, in pipe diameters

L_m = length of pipe, in miles

M = molecular weight

MR = universal gas constant = 1544

n = exponent in equation for polytropic change ($p'V_g^n$ = constant)

P = pressure, in pounds per square inch gauge

P' = pressure, pounds per square inch absolute

(see page 1-5 for diagram showing relationship between gauge and absolute pressure)

p' = pressure, in pounds per square foot absolute

Q = rate of flow, in gallons per minute

q = rate of flow, in cubic feet per second at flowing conditions

q' = rate of flow, in cubic feet per second at standard conditions (14.7 psia and 60F)

q'_d = rate of flow, in millions of standard cubic feet per day, MMscfd

q'_h = rate of flow, in cubic feet per hour at standard conditions (14.7 psia and 60F), scfh

q_m = rate of flow, in cubic feet per minute at flowing conditions

q'_m = rate of flow, in cubic feet per minute at std. conditions (14.7 psia and 60F), scfm

R = individual gas constant = MR/M = $1544/M$

R_e = Reynolds number

R_H = hydraulic radius, in feet

r_c = critical pressure ratio for compressible flow

S = specific gravity of liquids at specified temperature relative to water at standard temperature (60 F)

S_g = specific gravity of a gas relative to air = the ratio of the molecular weight of the gas to that of air

T = absolute temperature, in degrees Rankine (460 + t)

t = temperature, in degrees Fahrenheit

$\overline{V}$ = specific volume of fluid, in cubic feet per pound

V = mean velocity of flow, in feet per minute

V_g = volume, in cubic feet

v = mean velocity of flow, in feet per second

v_s = sonic (or critical) velocity of flow of a gas, in feet per second

W = rate of flow, in pounds per hour

w = rate of flow, in pounds per second

w_g = weight, in pounds

x = percent quality of steam = 100 minus per cent of moisture

Y = net expansion factor for compressible flow through orifices, nozzles, or pipe

Z = potential head or elevation above reference level, in feet

Greek Letters

Beta

β = ratio of small to large diameter in orifices and nozzles, and contractions or enlargements in pipes

Delta

Δ = differential between two points

Epsilon

ϵ = absolute roughness or effective height of pipe wall irregularities, in feet

Mu

μ = absolute (dynamic) viscosity, in centipoise

μ_r = absolute viscosity, in pound mass per foot second or poundal seconds per sq foot

μ'_r = absolute viscosity, in slugs per foot second or pound force seconds per square foot

Nu

ν = kinematic viscosity, in centistokes

ν' = kinematic viscosity, square feet per second

Rho

ρ = weight density of fluid, pounds per cubic ft

ρ' = density of fluid, grams per cubic centimeter

Theta

θ = angle of convergence or divergence in enlargements or contractions in pipes

Subscripts for Diameter

(1)...defines smaller diameter

(2)...defines larger diameter

Subscripts for Fluid Property

(1)...defines inlet (upstream) condition

(2)...defines outlet (downstream) condition

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-30.

Resistance of 90 Degree Bends[21]

The chart at the right shows the resistance of 90 degree bends to the flow of fluids in terms of equivalent lengths of straight pipe.

Resistance of bends greater than 90 degrees is found using the formula:

$$\frac{L}{D} = R_t + (n-1)\left(R_t + \frac{R_b}{2}\right)$$

n = total number of "U" bends in coil
R_t = total resistance due to one "U" bend, in L/D
R_t = resistance due to length of one 90° bend, in L/D
R_b = bend resistance due to one 90° bend, in L/D

Problem: Determine the equivalent lengths in pipe diameters of a 90 degree bend and a 270 degree bend having a relative radius of 12.

Solution: Referring to the "Total Resistance" curve, the equivalent length for a 90 degree bend is 34.5 pipe diameters.

The equivalent length of a 270 degree bend is:

$$L/D = 34.5 + (3-1)[18.7 + (15.8 + 2)]$$
$$L/D = 87.7 \text{ pipe diameters}$$

Note: This loss is less than the sum of losses through three 90 degree bends separated by tangents. For "resistance of bends theory", see page 2-12.

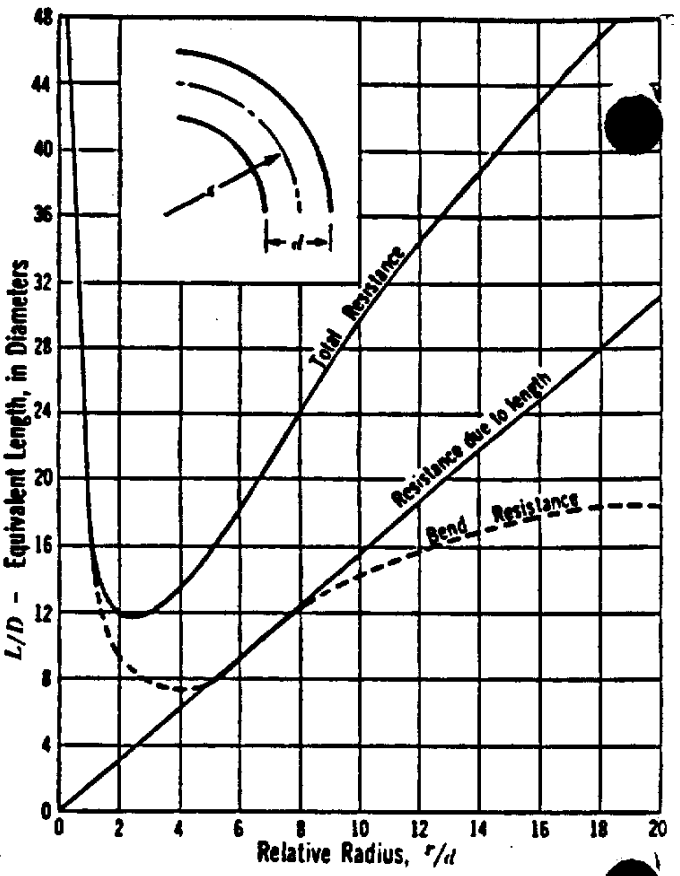


Chart for Resistance of 90 Degree Bends

From *Pressure Losses for Fluid Flow in 90 Degree Pipe Bends* by K. H. Beij. Courtesy of Journal of Research of National Bureau of Standards, Vol. 21, July, 1938.

Resistance of Miter Bends[4]

The chart at the lower right shows the resistance of miter bends to the flow of fluids. The chart is based on data published by the American Society of Mechanical Engineers (ASME).

Problem: Determine the equivalent length in pipe diameters of a 40 degree miter bend.

Solution: Referring to the "Total Resistance" curve in the chart, the equivalent length is 12 pipe diameters.

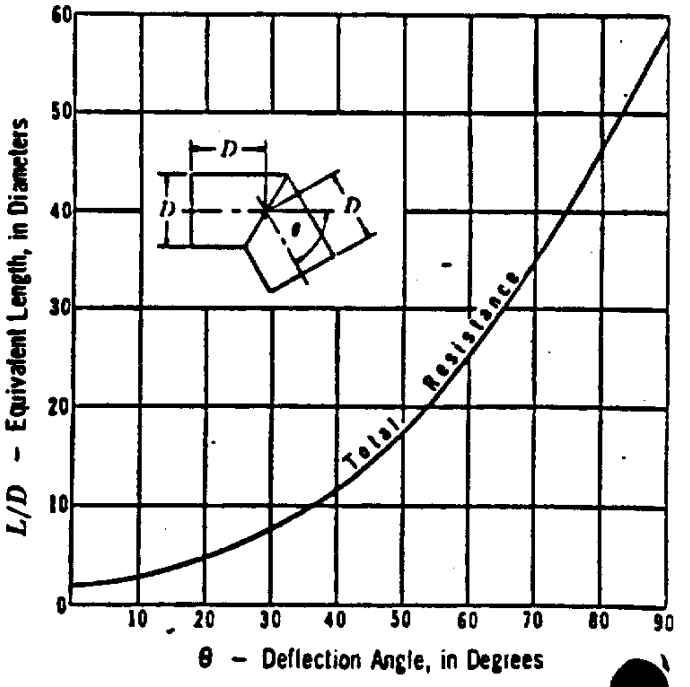


Chart for Resistance of Miter Bends

Crane Co. "Flow of Fluids through Valves, Fittings, and Pipe", Technical Paper 410, page A-27.

PD 904
7-20-75
RES

LINE SIZING AND HYDRAULICS

A. LINE SIZING

1. GENERAL COMMENTS
2. USE OF CHARTS AND FORMS
3. CRANE HANDBOOK
4. EQUIVALENT PIPING LENGTH
5. LINE SIZING CRITERIA

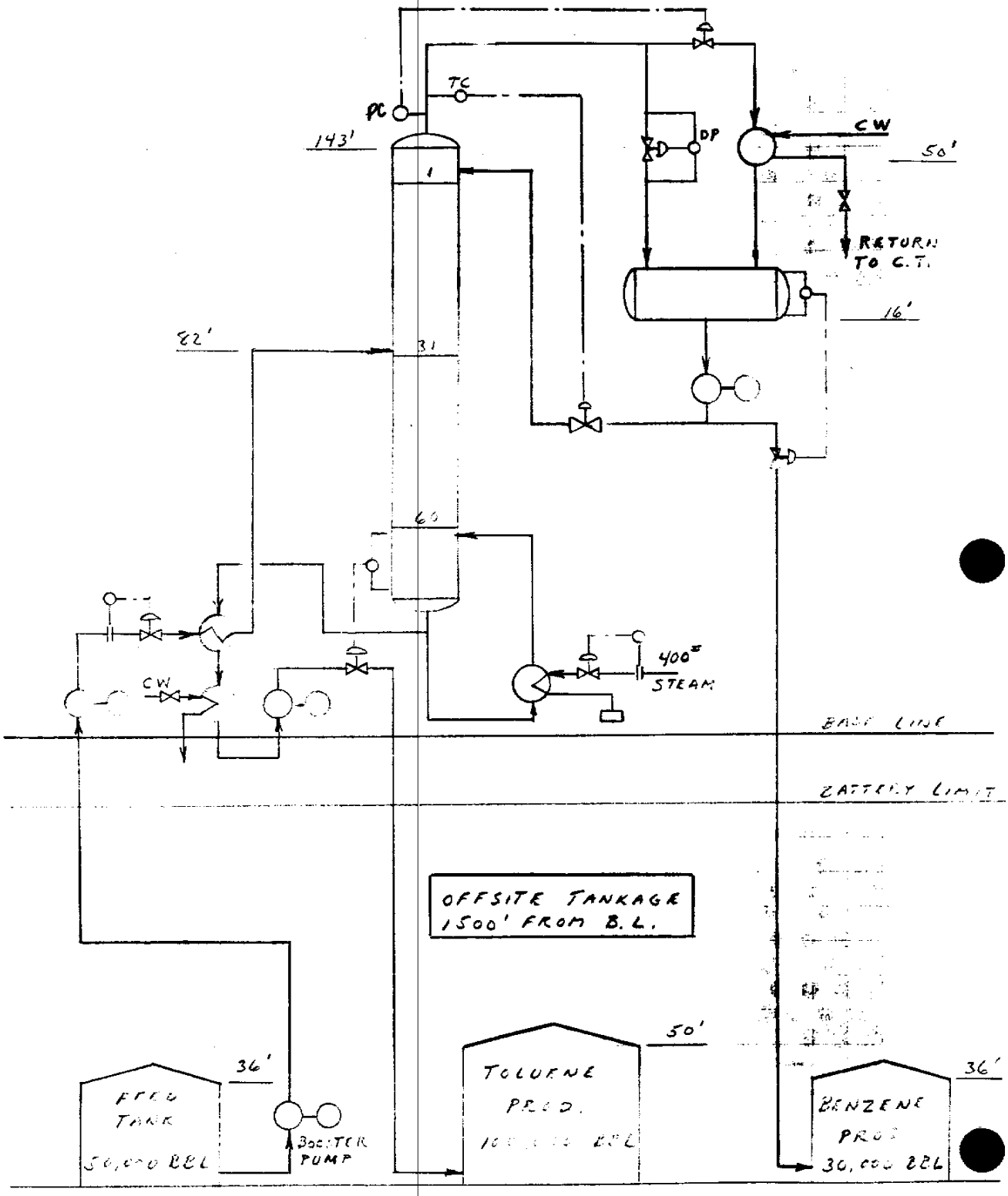
B. HYDRAULICS

1. GENERAL COMMENTS
2. TYPICAL PRESSURE DROPS FOR EQUIPMENT
3. EXAMPLES:
    - i. NPSH FOR PUMP
    - ii. PUMPED CIRCUIT

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CUSTOMER
SUBJECT AROMATICS FRACTIONATION

PAGE NO.
DATE
PROJECT
BY



SF 11713A

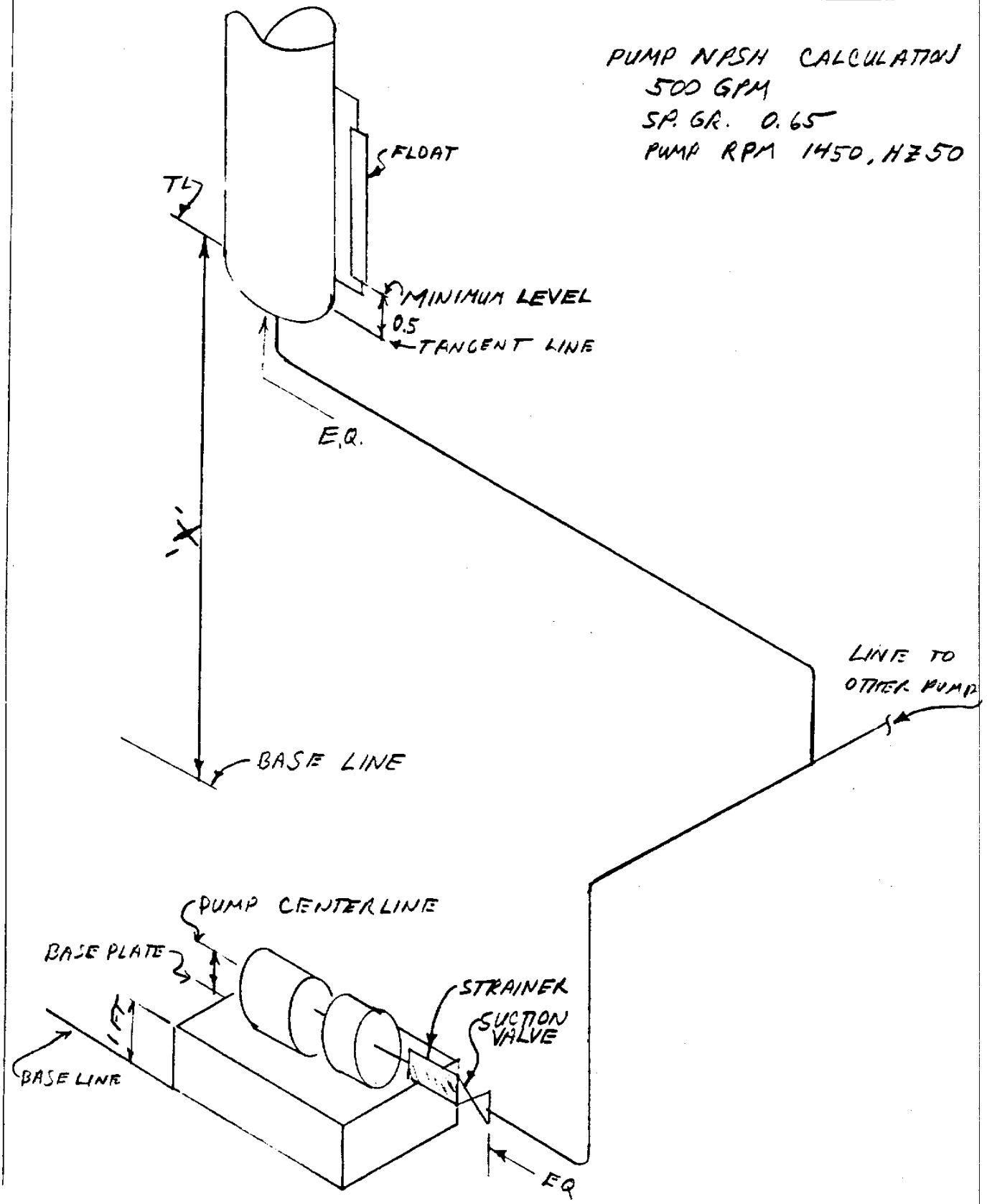
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Universal Oil Products Company
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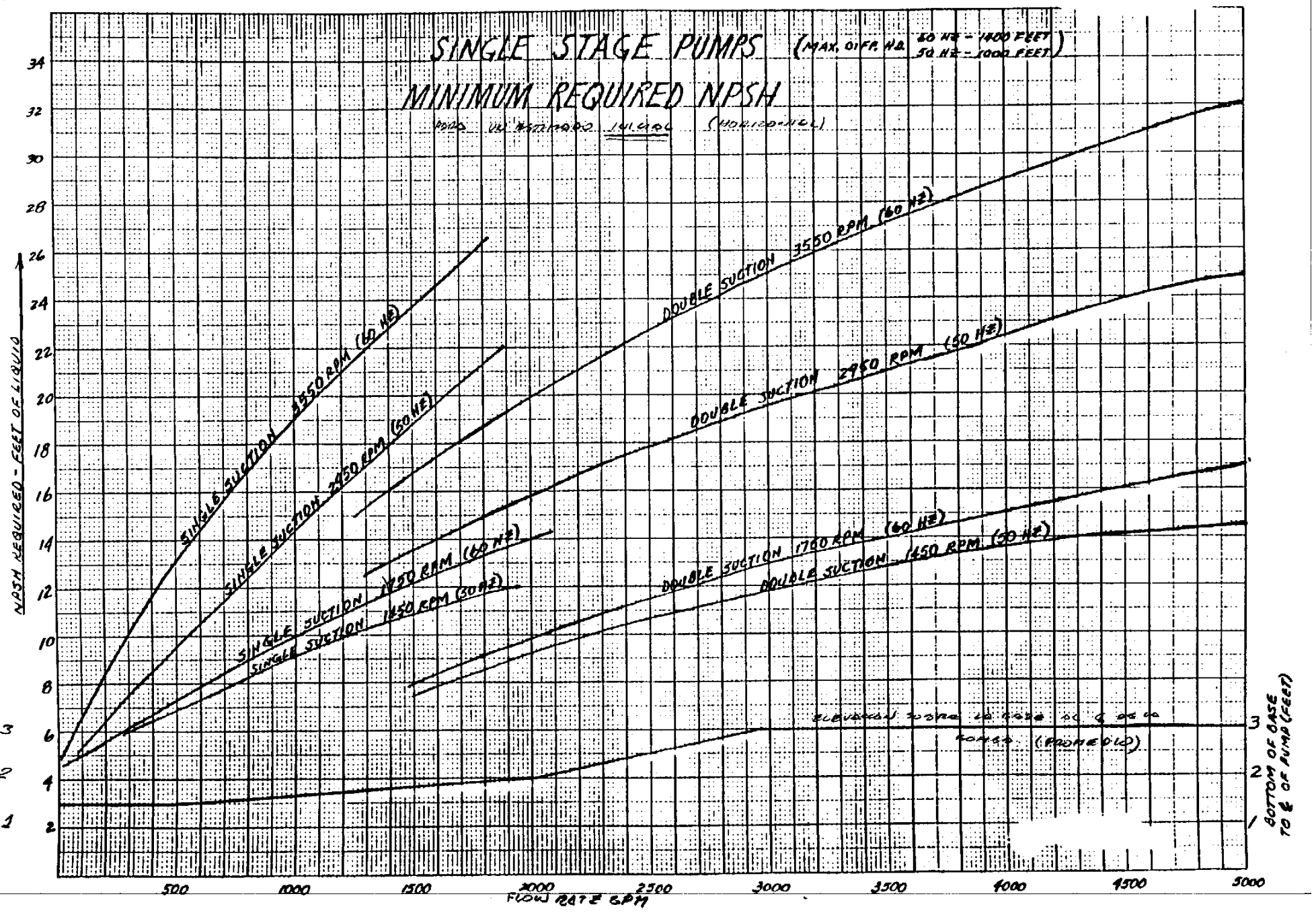
PIPING SKETCH NO.

DR. _____ CK. _____

DATE _____ PROJECT _____

PUMP NPSH CALCULATION
500 GPM
SP. GR. 0.65
PUMP RPM 1450, HZ 50




SINGLE STAGE PUMPS (MAX. DIFF. HD. 60 HZ - 1400 FEET, 50 HZ - 1000 FEET)
MINIMUM REQUIRED NPSH
SINGLE SUCTION 3550 RPM (60 HZ)
SINGLE SUCTION 2950 RPM (50 HZ)
SINGLE SUCTION 1750 RPM (60 HZ)
SINGLE SUCTION 1450 RPM (50 HZ)
DOUBLE SUCTION 3550 RPM (60 HZ)
DOUBLE SUCTION 2950 RPM (50 HZ)
DOUBLE SUCTION 1750 RPM (60 HZ)
DOUBLE SUCTION 1450 RPM (50 HZ)
NPSH REQUIRED - FEET OF LIQUID
FLOW RATE GPM
BOTTOM OF BASE TO ℄ OF PUMP (FEET)
34
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
2
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
3
2
1

1° $Q = 500$ GPM
$\nu = 0.6$ Cst
SG. $= 0.75$

a)
$\Delta P_0/100'$ 6" SCH 80

$\Delta P_0/100' = 0.9$ $\Delta P/100' = 0.675$

b) $\Delta P_0/100' = 0.18$ $= 0.135$

c) $V =$ 190 FPM

d) $\nu = 50$ $(50/0.6)^{0.2} = 2.42$.

$\Delta P/100 = 1.65$

E) $\Delta P/100 = 0.28$.
$\Delta P_0/100 = 0.55$.
$Q = 4000$ GPM.
SG $= 0.8$. $V = 0.6$ EST.

16" 3/8" TCNS

A). $W = 40.000$ LB/H.
$dv = 0.9$

$\Delta P/100$ 6" SCH 80.
$\Delta P_o/100 = 1.55$
$\Delta P/100 = 1.55 \times 0.9 = 1.395$

B) $\Delta P_o/100 = 0.27$
$\Delta P = 0.243$.

c) Val $V_o = 1950$ FPM.

$V_c = 1755$

d) $\Delta P_o/100 \leq 0.4/0.9 \leq 0.44$

$W = 100000$ LB/H.
$\rho_v = 2.7 FT^3/LB$.
$\bar{V} = \frac{1}{\rho_v} = 0.5$

$\Delta P_o = \Delta P_c \times 2$
$= 0.4 \times 2 = 0.8$.

$\Delta P_o \leq 0.8$. ϕ 8" – 10"

1 LIQ VOL FRACTION

$\frac{V_L}{V_L + V_G}$ LIQUID = 500 GPM.
SG = 0.75

VOL OF LIQUID = $\frac{500\ GPM \times 8.34\ LB/Gal \times 0.75 \times 60\ MIN/H}{0.75 \times 62.4\ LB/FT^3} = \frac{187650\ LB/H}{46.8\ LB/FT^3}$

$= 4009.6\ FT^3/H.$

VOL OF VAPOR = $40000\ LB/H \times 0.9\ FT^3/LB = 36000\ FT^3/H.$

LIQ VOL FRACT = $\frac{4000}{4000 + 36000} = 0.1$

TOTAL FLOW AS VAPOR

$W_L + W_V = 187650 + 40000 = 227650$

TOTAL FLOW AS LIQ.

$\frac{W_L + W_G}{SG \times 500} = \frac{227650}{0.75 \times 500} = 607\ GPM \Rightarrow 610\ GPM.$

8" SCH 80.

ΔP_G^M CON 227650 LB/H
$\bar{V} = 0.9\ FT^3/LB.$
$\Delta P_{G(100)} = 9$
$\Delta P_G = 9 \times 0.9 = 8.1\ PSI/100.$

ΔP_L^M: 610 GPM. 8" SCH 80
$\Delta P_0 = 0.3$
$\Delta P_L = 0.3 \times 0.75 = 0.2.\ PSI/100.$

$$\frac{\Delta P_G^2}{\Delta P_L^{\prime\prime}} = \frac{0.1}{0.2} = 40.$$

CORR FACTOR

$$\frac{\Delta P_{TP}}{\Delta P_L^{\prime\prime}} = 7$$

$$\Delta P_{TP} = 7.0 \times 0.2 = 1.4 \text{ psi}/100$$

MUY ALTO

PARA 10" SCH80

$\sim$ 0.55

PARA 12" SCH80.

CON 12" SE TIENE UNA CAIDA DE PRESION MENOR.

SE PUEDE UTILIZAR EN ESTE CASO

<u>10" SCH80</u> para satisfacer el criterio requerido.

PETROINDUSTRIAL
REFINERIA ESMERALDAS
FILIAL DE PETROECUADOR

Seminario de diseño de Procesos
UOP

Volume N° 1
Subject: General Engineering.
Handout:
* Proyect Enginnerig & Scheduling.
* Process Engineering.
* Hidrocarbon Properties.
* Vapor - Liquid Equilibria.
* Crude Break-ups.
* Heat & weight balances.
* Fractionation: Binary & Multicomponent.

Volume N° 2
Handout:
* Laboratory analisis.

Subject: Process refining design.
Handout:
* Crude Unit.
* Vacuum Unit.
* Hidrotreating.
* Asphalt oxidizier.
* Crude Unit Revamp. (HEN pinch method)

Volume N° 3
Subject: Process equipment.
Handout:
* Heat exchangers.
* Separators, drums & receivers.
* Mesh blankets.
* Pumps, Turbines, compressors & expanders.

Volume N° 4
Subject: Process equipment.
Handout:
* Column sizing.
* Flange rating.
* Vessel design.

Volume N° 5
Subject: Process equipment.
Handout:
* Metallurgy & Corrosion.
* Heaters.
* Line sizing & Hydraulics.
* Vacuum ejectors.

Volume N° 6
Subject: Process equipment.
Handout:
* Instrumentation.

Volume N° 7
Subject: Utilities & support.
Handout:
* Off sites: Tankage
Waste dispossal.
* Environmental guidelines.
* Miscellaneous.

Volume N° 8
Subject: Utilities & support.
Handout:
* Relief systems & flares.

Volume N° 9
Subject: Economics.
Handout:
* Cost estimating.
* Refinery economics: Capital investments.
Linear programing.

Subject: Miscellaneous.
Handout:
* Aditives & inhibitors: Chemical aditives. And Process aditives.

Volume N° 10
Subject: Miscellaneous.
Handout:
* Plot plans.
* Computer survey.

Volume N° 11
Subject: Anexos.
* Process charts (for hidrocarbon properties)

UOP
ENGINEERING DESIGN SEMINAR

MATERIAL SELECTION & CORROSION

D. L. Gregory

M. L. Potter

FALL 1991

Presented by: D. L. Gregory

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PREFACE

The information contained herein will give the reader a general and brief picture of the many facets involved in the areas of metallurgy and corrosion connected with materials selection and performance. These fields are very broad and encompassing, thus one small written work can only cover the surface. Many refiners have specific metallurgical and/or corrosion problems unique to their refinery. All such problems would be impossible to cover in this work, however, hopefully the contents here will provide the readers with some answers or sufficient information to develop the answers.

We would attempt to minimize the refiner's problems by using sound engineering judgment in materials specifications to provide the metallurgical and corrosion resisting properties required for the application(s) involved. This, of course, presupposes that the proper materials specifications, construction codes, operating and maintenance practices are utilized in the building and commission of the process unit(s).

One final point is that all equipment, regardless of type of manufacture, plate, forging of castings, and welds, will contain some discontinuities and flaws. Accepting this fact, the materials/design people should use the best combination of metal properties, quality control, analysis, design and operating controls (if necessary) when specifying and designing equipment commensurate with the service requirements. This will result in safe equipment with the required resistance to brittle, ductile, and corrosion type failures.

M. L. Potter

D. L. Gregory

 ING. FAUSTO ORTEGA A.
PAG 1 DE 211

I. INTRODUCTION

The intent of this part of the seminar is to illustrate the involvement the materials man has in the entire regime of metallurgy and corrosion as related to the petroleum refining and petrochemical industry needed for background and bases used for materials selection. This involvement includes the steels and alloys, their inherent mechanical and physical properties at all applicable temperature ranges, the effects of temperature on properties, corrosion resistance and other forms of deterioration or intrinsic metallurgical changes during service. The knowledge of the above along with that of the environment under consideration and previous experiences in similar applications allows the materials man to make the proper choice in material selection. It is a fact that more than one steel or alloy could be used for a particular service, with the one chosen depending on such factors as economics, product form (forgings, plate, castings, etc.), availability, customer policy with regard to design philosophy for materials selection and equipment life.

In conjunction with the above factors, close communication with the project engineers and engineering specialty groups involved in equipment design and/or specifications is very important. Cooperation with the technical service engineers, both operations and inspection, is necessary for field performance feed-back since materials specifications and/or special design requirements are based largely on field experience. Thus, there is a strong inter-relation between the materials man and the other engineering disciplines involved in a refinery process design, equipment design and fabrication, refinery operation, inspection and testing.

This text contains three major sections: Materials Selection in Process Units, Metallurgy and Corrosion. The Materials Selection section describes the factors and considerations required for proper selection with Sections on Metallurgy and Corrosion covering these areas in greater detail thus providing background information and basis for materials selection. Additional sections included are: "Corrosion Control in the Crude-Distillation Area, An Overview" and Equipment Failures.

There is some interrelation between the sections with the result that several topics will be discussed more than once although from different subject sources.

A number of Figures, Tables and Appendices, are included to augment the written work and for illustration purposes.

The materials engineer, in his quest for additional knowledge, information and data pertaining to the petroleum refining materials situation, must be constantly aware of developments by others and take

a personal and active part in the many pertinent technical society groups relating to the petroleum industry. Much of this is provided by the contributions of industry in their supplying pertinent data and the research to develop new data in relatively unknown or incompletely explored areas sponsored under the guidance of the technical and/or industry societies such as NACE, API, ASME, ASM, ASTM, ACI, MPC, AWS[1] etc. or by individual companies. Much of the data presented herein was developed by these societies and some is so acknowledged.

[1]NACE - National Association of Corrosion Engineers
API - American Petroleum Institute
ASME - American Society for Mechanical Engineers
ASM - American Society for Metals
ASTM - American Society for Testing and Materials
MPC - Metals Properties Council
ACI - American Castings Institute
AWS - American Welding Society

II. MATERIALS SELECTION IN PROCESS UNITS

1. FACTORS DETERMINING MATERIAL SELECTION

1.1 Design Life

Equipment construction materials are selected to provide a satisfactory service life for the particular environment encountered, such as:

- 20 year life - high pressure ($\geq$1000 PSIG)/heavy wall reactors, vessels and exchangers.
- 10 year life - vessels, exchanger shells, heater coils, pumps and compressor casings and alloy piping.
- 5 year life - carbon steel piping, easily replaced heat exchanger tube bundles and replaceable internals for rotating equipment.

Since there are many factors that contribute to service life of equipment, some of which we have no control over, the above target design lives are strived for based on the expected operating conditions. In most cases standard corrosion allowances will provide a service life in excess of the above.

1.2 Economic

Materials should be the most economical to keep plant costs down and should not result in high maintenance costs.

1. FACTORS DETERMINING MATERIAL SELECTION (Cont'd)

1.3 Physical Properties

Some of the physical properties in determining materials selection are as follows:

a. Strength - Materials used to contain process fluids should have adequate strength at design conditions.

b. Corrosion Resistance - Materials should possess sufficient resistance to corrosion or hydrogen attack from the process environment including start-up, shutdown and regeneration.

c. Toughness - Materials should possess toughness to resist brittle fracture.

d. Thermal Shock - Materials must be reasonably resistant to thermal shock caused by rapid process temperature changes.

e. Abrasion Resistance - In some processes, materials are selected to provide abrasion resistance from solids in the process stream.

f. Oxidation - Materials should possess oxidation resistance if high temperatures are encountered.

g. Fabrication - Materials should be compatible with all required fabrication procedures.

1.4 Design Codes, Standards, and Practices

a. Materials of construction must comply with code requirements for design, fabrication, inspection and testing. The following are utilized in the U.S.:

1. ASME Section I; Power Boilers.
2. ASME Section VIII, Division 1; Pressure Vessels.
3. ASME Section VIII, Division 2; Alternate Rules for Pressure Vessels.
4. ANSI B31.3; Refinery Piping Code.
5. ANSI B16.5; Steel Pipe Flanges and Flanged Fittings.
6. TEMA; Standards of the Tubular Exchangers Manufacturers Association.
7. API Standards & Recommended Practices.

b. For special situations other appropriate codes or practices may be used.

2. MATERIALS FOR GENERAL REFINERY USE

2.1 Designation and Description

Materials are specified by either ASTM numbers prefixed by A, ASME specification numbers prefixed by SA or by their generic names. Materials conforming to foreign standards equivalent to the ASTM specifications are acceptable. Equivalent foreign materials specifications are those that conform to method of manufacture, chemistry, mechanical properties, quality, testing and inspection.

The following three pages are a listing of materials by generic name and corresponding ASTM designations:

Attached Appendix 1 and 2 provides additional technical data and nominal properties of some of the materials, ie, Killed Steel, Cr - Mo alloys and the stainless steels.

2. MATERIALS FOR GENERAL REFINERY USE

TABLE 1

ASTM DESIGNATION OF MATERIALS

NOMBRE GENERICO MATERIAL	PLATE	PIPE	ELECTRIC FUSION WELDED PIPE	TUBES	CASTINGS	FORGINGS	WROUGHT FITTINGS	CLADDING
Carbon Steel	A-285 GR. A,B,&C	A-53 GR. A&B	A-671 GR. CA-55 A-672 GR. A45-A55	A-214 (Welded) A-179 (Seamless)	A-216 GR. WCA,WCB & WCC	A-105 A-181 CL. 60 or 70 A-266 CL. I,II,or III	A-234 GR. WPB	
Killed Steel	A-515 GR. 55-70 A-516 GR. 55-70	A-106 GR. A&B	A-672 GR. B55-B70 A-672 GR. C55-C70	A-179	A-216 GR. WCA,WCB, & WCC	A-105 A-181 CL. 60 or 70 A-266 CL. I,II,orIII	A-234 GR. WPB	
C-1/2 Mo	A-204 GR. A,B,&C	A-335 GR. P1	A-691 GR. CM 65 - CM 75	A-209 GR. T1	A-217 GR. WC1	A-182 GR. F1 A-336 CL. F1	A-234 GR. WP1	
Mn-1/2 Mo	A-302 GR. B							
1 Cr-1/2 Mo	A-387 GR. 12	A-335 GR. P12	A-691 GR. 1Cr	A-213 GR. T12		A-182 GR. F12 A-336 CL. F12	A-234 GR. WP 12	
1-1/4 Cr-1/2 Mo	A-387 GR. 11	A-335 GR. P-11	A-691 GR. 1-1/4 Cr	A-199 GR. T11 A-213 GR. T11	A-217 GR. WC6	A-182 GR. F11 A-336 CL. F11	A-234 GR. WP11	
2-1/4 Cr-1 Mo	A-387 GR. 22	A-335 GR. P-22	A-691 GR. 2-1/4 Cr	A-199 GR. T22 A-213 GR. T22	A-217 GR. WC9	A-182 GR. F22 A-336 CL. F22	A-234 GR. WP22	
3 Cr-1 Mo	A-387 GR. 21	A-335 GR. P-21		A-199 GR. T21 A-213 GR. T21		A-182 GR. WP21 A-336 CL. F21		
5 Cr-1/2 Mo	A-387 GR. 5(Formerly A-357)	A-335 GR. P5	A-691 GR. 5 Cr	A-199 GR. T5 A-213 GR. T5	A-217 C5	A-182 GR. F5 A-336 CL. F5	A-234 GR. WP5	
9 Cr- 1Mo		A-335 GR. P9		A-199 GR. T9 A-213 GR. T9	A-217 GR. C12	A-182 GR. F9 A-336 CL. F9	A-234 GR. WP9	
12 Cr-AL-TP405	A-240 TP405	A-268 GR. TP405		A-268 GR. TP405				A-263
13 Cr-TP410	A-240 TP410	A-268 GR. TP410		A-268 GR. TP410	A-217 GR. CA15	A-182 GR. F6 A-336 CL. F6		A-263
13 Cr-TP410S	A-240 TP-410S							A-263
17 Cr-TP430	A-240 TP430	A-268 GR. TP430		A-268 GR. TP430				A-263

GR = Gradacion, constituyen diferentes niveles de resistencia

2. MATERIALS FOR GENERAL REFINERY USE

TABLE 1 (Cont'd)

ASTM DESIGNATION OF MATERIALS

MATERIAL	PLATE	PIPE	ELECTRIC FUSION WELDED PIPE	TUBES	CASTINGS	FORGINGS	WROUGHT FITTINGS	CLADDING
18 Cr-8 Ni-TP304	A-240 TP304	A-312 GR. TP304 A-376 GR. TP304	A-358 GR. 304	A-213 GR. TP304 A-249 GR. TP304	A-351 GR. CF8 A-744 GR. CF8	A-182 GR. F304 A-336 CL. F304	A-403 GR. WP304	A-264
18 Cr-8 Ni TP304L	A-240 TP304L	A-312 GR. TP304L	A-358 GR. 304L	A-213 GR. TP304L A-249 GR. TP 304L	A-351 GR. CF3 A-744 GR. CF3	A-182 GR. F304L A-336 CL. F304L	A-403 GR. WP304L	A-264
18 Cr-8 Ni TP304H	A-240 TP304H	A-312 GR. TP304H A-376 GR. TP304H	A-358 GR. 304H	A-213 GR. TP304H A-249 GR. TP304H		A-182 GR. F304H A-336 CL. F304H	A-403 GR. WP304H	A-264
16 Cr-12 Ni-2 Mo TP316	A-240 TP316	A-312 GR. TP316 A-376 GR. TP316	A-358 GR. 316	A-213 GR. TP316 A-249 GR. TP316	A-351 GR. CF8M A-744 GR. CF8M	A-182 GR. F316 A-336 CL. F316	A-403 GR. WP316	A-264
16 Cr-12 Ni-2 Mo TP316L	A-240 TP316L	A-312 GR. TP316L	A-358 GR. 316L	A-213 GR. TP316L A-249 GR. TP316L	A-351 GR. CF3M A-744 GR. CF3M	A-182 GR. F316L A-336 CL. F316L	A-403 GR. WP316L	A-264
16 Cr-12 Ni-2 Mo TP316H	A-240 TP316H	A-312 GR. TP316H A-376 GR. TP316H	A-358 GR. 316H	A-213 GR. TP316H A-249 GR. TP316H		A-182 GR. F316H A-336 CL. F316H	A-403 GR. WP316H	A-264
18 Cr-13 Ni-3 Mo TP317	A-240 TP317	A-312 GR. TP317		A249 GR. TP317	A-351 GR. CG-8M A-744 GR. CG-8M	A-276 TP317 (Bar Stock)		A-264
18 Cr-13 Ni-3 Mo TP317L	A-240 TP317L	A-312 GR. TP317L					A-403 GR. WP317L	A-264
18 Cr-10 Ni-Ti TP321	A-240 TP321	A-312 GR. TP321 A-376 GR. TP321	A-358 GR. 321	A-213 GR. TP321 A-249 GR TP321		A-182 GR. F321 A-336 CL. F321	A-403 GR. WP321	A-264
18 Cr-10 Ni-Ti TP321H	A240 TP321H	A-312 GR. TP321H A-376 GR. TP321H		A-213 GR. TP321H A-249 GR. TP321H		A-182 GR. F321H A-336 CL. F321H	A-403 GR. WP321H	A-264
18 Cr-10 Ni-Cb TP347	A-240 TP347	A-312 GR. TP347 A-376 GR. TP347	A-358 GR. 347	A-213 GR. TP347 A-249 GR. TP347	A-351 GR. CF8C A-744 GR. CF8C	A-182 GR. F347 A-336 CL. F347	A-403 GR. WP347	A-264
18 Cr-10 Ni-Cb TP347H	A-240 TP347H	A-312 GR. TP347H A-376 GR. TP347H		A-213 GR. TP347H A-249 GR. TP347H		A-182 GR. F347H A-336 CL. F347H	A-403 GR. WP347H	A-264
23 Cr-12 Ni TP309	A-240 TP309S	A-312 GR. TP309	A-358 GR. 309	A-213 GR. TP309	A-351 GR. CH-20		A-403 GR. WP309	A-264
25 Cr-20 Ni TP310	A-240 TP310S	A-312 GR. TP310	A-358 GR. 310	A-213 GR. TP310 A-249 GR. TP310	A-351 GR. CK-20	A-182 GR. F310 A-336 CL. F310	A-403 GR. WP310	A-264

2. MATERIALS FOR GENERAL REFINERY USE

TABLE 1 (Cont'd)

ASTM DESIGNATION OF MATERIALS

MATERIAL	PLATE	PIPE	ELECTRIC FUSION WELDED PIPE	TUBES	CASTINGS	FORGINGS	WROUGHT FITTINGS	CLADDING
Inconel 600 (Ni-Cr-Fe)	B-168	B-167 B-517		B-163 Alloy Ni-Cr-Fe B-516	A-744 GR. Cy-40	B-564 Alloy Ni-Cr-Fe B-166(Bar Stock)	B-366 GR. WPNCI	A-265
Incoloy 800 (Ni-Fe-Cr)	B-409	B-407 B-514		B-163 Alloy Ni-Fe-Cr B-515		B-564 Alloy Ni-Fe-Cr B-408 (Bar Stock)	B-366 GR. WPNIC	A-265
Alloy 20 (Cr-Ni-Fe-Mo-Cu-Cb)	B-463	B-464	B-474	B-468	A-351 GR. CN-7M A-744 GR. CN-7M	B-462	B-366 GR. WP20CB	A-265
Admiralty	B-171 No. C44300 C44400 C44400			B-111 No. C44300 C44400 C44500				
Naval Brass	B-171 No. C46400							
Al. Brass				B-111 No. C68700				
Al. Bronze	B-171 No. C61400							B-432
90-10 Cu-Ni	B-171 No. C70600	B-466 No. C70600		B-111 No. C70600				B-432
80-20 Cu-Ni		B-466 No. C71000		B-111 No. C71000				
70-30 Cu-Ni	B-171 No. C71500	B-466 No. C71500		B-111 No. C71500				B-432
Monel (Ni-Cu)	B-127	B-165		B-163 Alloy Ni-Cu	A-744 GR. M-35-1	B-564 Alloy Ni-Cu B-164 (Bar Stock)	B-366 GR. WPNC	A-265
Hastelloy B (Ni-Mo)	B-333	B-619 Alloy Ni-Mo B-622 Alloy Ni-Mo		B-622 Alloy Ni-Mo B-626 Alloy Ni-Mo	A-494 N-12M-1	B-335 (Alloy Rod)	B-366 GR. WPHB	A265
Hastelloy C (Ni-Mo-Cr)	B-575	B-619 Alloy Low C Ni-Mo-Cr B-622 Alloy Low C Ni-Mo-Cr		B-622 Alloy Low C Ni-Mo-Cr B-626 Alloy Low C Ni-Mo-Cr	A-494 GR. CW-12M-1	B-574 (Alloy Rod)	B-366 GR. WPHC	A-265
Aluminum 3003	B-209 Alloy 3003	B-241 Alloy 3003 B-210 Alloy 3003		B-234 Alloy 3003		B-247 Alloy 3003	B-361 Alloy WP3003	
Titanium	B-265	B-337		B-338	B-367	B-381	B-363	

2. MATERIALS FOR GENERAL REFINERY USE DESCRIPCION

2.2 Carbon Steel

This is the most common material used in process plants. Carbon steels are used in most general refinery applications where killed steel quality is not required.

2.3 Killed Carbon Steel

Killed steels are defined as those which are thoroughly deoxidized during melting practices. Deoxidation is accomplished by use of silicon, manganese, and aluminum additions to combine with dissolved gasses, usually oxygen during solidification. This results in cleaner, better quality steel which has fewer gas pockets and inclusions. Killed carbon steel is specified for equipment in the following services to minimize the possibility or extent of hydrogen blistering (AMPOLLAMIENTO) and hydrogen embrittlement (FRAGILIZACION):

a. Hydrogen - Where hydrogen is a major component in the process stream resulting in an operating hydrogen partial pressure of greater than 50 psia.

b. Hydrogen Sulfide

   1. Where H_2S present in a concentration greater than 0.3 mole percent with an aqueous phase.

   2. Where liquid water is present that contains greater than 10 ppm of H_2S.

c. Hydrofluoric Acid and Boron Trifluoride - Process streams containing any amount of HF acid, BF_3, or BF_3 compounds.

d. Alkanolamines (Amines) - Monothanolamine (MEA) and Diethanolamine (DEA) in solutions greater than 5 weight percent.

Killed steel is also used for equipment designed at temperatures greater than 900°F since the ASME boiler and pressure vessel code does not list design allowable stresses for carbon steel over 900°F. 480 °C

HIDROGEN BLISTERING: CORROSION REACCION
- DIFUSSION OF ATOMIC HYDROGEN
  HIDROGEN
- VOID
- LAMINATION
  SLAG INCLUSION
- SULFIDE INCLUSION

HIDROGEN EMBRITTLEMENT

2. MATERIALS FOR GENERAL REFINERY USE

2.4 Low Alloy Steels

a. Carbon - 1/2% moly and manganese - 1/2% Moly. These low alloy steels are used for higher temperature service than carbon steel and most frequently for intermediate temperatures for its resistance to hydrogen attack. They have the same maximum temperature limitation as killed steel (ASME Code - 1000°F) but the strength above 700°F is substantially greater.
370°C 535°C
USES: MATERIAL BASE DE RX COMPONENTS OF INTERCONNECTIONS,

b. 1% Chrome - 1/2% Moly and 1 1/4% Chrome - 1/2% Moly. These alloys are used for higher temperature resistance to hydrogen attack and a modest resistance to sulfur corrosion. They are also used for services where temperatures are above the rated temperatures for the lower alloys. VESSEL BASE HTC, UNIBON RX REFORMING RX. FCC RX, FCC PIPING

c. 2 1/4% Chrome - 1% Moly and 3% Chrome - 1% Moly. These alloys have the same uses as 1 1/4% Cr, but have greater resistance to hydrogen attack and higher strength at elevated temperature. HYDROCRACKER RX HOT SEP

d. 5% Chrome - 1/2% Moly. This alloy is used most frequently for protection against combined sulfur attack at temperatures
285°C above 550°F. Its resistance to hydrogen attack is better than 2 1/4% CR- 1% Moly but improved resistance to H_2S is minimal. PIPING, VACUUM FCC, UNIBON, EXCH WHP GRVDR HEATER TUBES.

e. 7% Chrome - 1/2% Moly. This alloy is sometimes used for heater tubes in crude and vacuum services where slightly better resistance to sulfur over 5 Cr is needed.

f. 9% Chrome - 1% Moly. This alloy is primarily used for resistance to high sulfur stocks at elevated temperatures. Use is generally limited to heater tubes.

2.5 Ferritic and Martensitic Stainless Steels

a. 12% Chrome (Types 405 and 410S) - This Ferritic or Martensitic stainless steel is used primarily as a clad lining. It has an excellent resistance to combined sulfur and good resistance to hydrogen sulfide at low concentrations and intermediate temperatures.

b. 13% Chrome (Type 410) - This stainless steel is used extensively for standard trim on all process valves and pumps, and for vessel trays and tray components. It is also used for heat exchanger tubes for the same processing conditions as Type 405. TYPE 430 - 17% CHROMIUM

TIPES OR LINING.
- CLAD
  HOT ROLL - BONDED
  EXPLOSION BONDED
- WELD OVERLAY
- STRIP LINING.
  FOR FIELD LINING

2. MATERIALS FOR GENERAL REFINERY USE

2.6 Austenitic Stainless Steels (18-8 SS)

a. Type 304 - This is the lowest cost type of 18-8 stainless and is used for exchanger tubes and other equipment which are not welded, for protection against hydrogen and hydrogen sulfide attack at elevated temperatures. It is susceptible to polythionic stress corrosion and chloride stress corrosion.

b. Types 309 and 310 - These are special heat resistant austenitic stainless steels which have oxidation resistance up to about 2000°F. Their composition is 25% Cr-12% Ni and 25% Cr-20% Ni, respectively, and are used in high temperature services and tube supports in heaters.

25 CR -12 NI
25 CR - 20 NI
1090°C

c. Types 321 and 347 - These are stabilized grades of about 18 Cr-10 Ni composition which are used where welding is required. The addition of Titanium or Columbium stabilizers prevent carbide precipitation when welded and thus minimize intergranular corrosion. As with Type 304, all equipment in sulfiding service should be neutralized with soda ash prior to allowing air to contact sulfided surfaces. TP 321 - TI. CbNb

d. Type 316 - This grade is not stabilized and finds most of its use in corrosive environments such as phosphoric acid, naphthenic acid and low concentration sulfuric acid services. It is also used in high temperature, low sulfur containing services for its very good high temperature strength.

e. Carpenter 20 - This is an austenitic alloy of 20% Cr, 29% Ni, 2% Mo and 3% Cu and the balance iron and trace ingredients. It was developed to furnish superior sulfuric acid resistance to the other stainless steels as well as better chloride resistance.

TODOS SE PUEDEN ENCONTRAR CON
L : LOW CARBON
H = 0.04 - 0.10% CARBON & SOLUTION HEAT TREATMENT

INTERGRANULAR SCC
NEED : - SENSITIZED MATERIAL
- CARBIDE PRECIPITATION
- CORROSIVE
POLITHONIC ACID.
- STRESS
APPLIED
RESIDUAL
TO MINIMIZE
- STABILIZED
· Cb COLUMBIO (o NIOBIO)
· Ti
- LOW C
- NEUTRALIZATION

EL LIQUIDO CON CORROSIVO
ES PARA NEUTRALIZAR EL CONTENIDO DE ACIDOS POLITHONICOS
Y CREAR UN FILM EN LA
SUPERFICIE DEL MATERIAL

2. MATERIALS FOR GENERAL REFINERY USE

2.7 Copper and Copper Alloys

a. Copper - Pure copper finds very limited use in process equipment because of its low strength and its tendency to work harden. It and most of its alloys have better resistance to chlorides, hydrochloric and hydrofluoric acids, marine and atmospheric corrosion than steel. It is susceptible to attack by hot sulfides and moist ammonia. It is used occasionally for heat exchange service, usually as gaskets.

b. Brasses - The brasses are the most widely used of the copper alloys and are alloys of copper and usually zinc with minor amounts of other elements. Admiralty is used for condenser tubes by many refiners, particularly if no treatment of the water is used. Aluminum brass is used for sea water condenser tube service and Naval brass is used for the tube sheets. Dezincification may occur to alloys above 15% zinc unless inhibited with antimony, arsenic or phosphorous. Other copper alloys are used in process equipment for bearings and other elements in pumps and rotating equipment.

c. Cupro-Nickels - These are alloys of copper and nickel (90-10, 80-20 and 70-30) with minor amounts of iron and manganese. They are the most corrosion resistant of the copper alloys and are used in services exposed to sea water and mineral acids, and at higher temperatures than the brasses.

2. MATERIALS FOR GENERAL REFINERY USE

2.8 Nickel and Nickel Alloys

a. **Nickel - Pure nickel finds very limited use in equipment. It has good strength and excellent resistance to many corrosive environments at low temperature. It has good resistance to chloride attack at low temperatures. It has poor resistance to sulfur compounds at moderate and high temperatures.**

b. Monel - Monel is a 70% nickel, 30% copper alloy with a small amount of iron and manganese. This alloy is widely used for resistance to chloride and fluoride attack and in sea water services. It is very susceptible to sulfidation at temperatures above 400°F.

c. **Inconel - This high (about 80%) nickel-chromium-iron alloy is used in services requiring high resistance to oxidation or reducing atmospheres at temperatures**
1090°C **up to 2000°F. It is inferior to Monel in handling sulfuric, hydrochloric and hydrofluoric acids. It is not recommended in sulfur or sulfide environments above**
535°C **1000°F.**

d. Incoloy - This alloy is very similar in its properties to austenitic stainless steels, but because of its higher nickel content (32%) is more expensive. It has greater resistance to chloride stress corrosion cracking than the 18-8 stainless steels.

e. **Hastelloys - These expensive alloys are composed of nickel, molybdenum, iron and chromium. They are normally used in very corrosive services. They may not resist attack if oxidizing agents are present.**

- INCONEL 600
  76 Ni - 8 Fe - 16 Cr.
- INCOLOY 800
  32% Ni - 46 Fe - 21 Cr
- ALLOY 20
  20 Cr - 29 Ni - 2 Mo - 3 Cu | RESIST SL SC. SULFURIC CONCENTRATED
- MONEL 70 Ni - 30 Cu
- HASTELLOY
  HAST B 61 Ni - 28 Mo.
  C 54 Ni - 16 Cr - 16 Mo. | PUMPS USED IN INSTRON.

2. MATERIALS FOR GENERAL REFINERY USE

2.9 Aluminum and Titanium

a. Aluminum and Aluminum Alloys - Aluminum alloys are not used too frequently in refinery applications because of their inherent low strength and low melting points. However, in shell and tube type exchangers, coolers and condensers, aluminum has performed quite admirably in hydrocarbon environments containing aqueous phases of hydrogen sulfide and ammonia. One of the biggest uses of aluminum in plants is as external insulation covering and weather shielding.

b. Titanium - Titanium has excellent corrosion resistance to many environments found in petroleum and petrochemical plants. With its cost now being competitive, mainly with the nickel base alloys, it is finding an increasing number of applications as tubes in exchangers, coolers and condensers where serious chloride cracking problems are anticipated. It also is essentially immune to corrosion by sea water and most sour or waste water treating environments.

3. COMMON ENVIROMENTAL CONSIDERATIONS

3.1 Elevated Temperature Hydrogen

Resistance to hydrogen attack must be provided for materials in contact with liquids and vapors containing hydrogen at elevated temperatures and pressures. The guide used for selecting hydrogen resistant materials is the API Publication 941 entitled "Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants." A brief study of the curve reveals that the principle alloying elements which impart resistance to elevated temperature hydrogen attack are chromium and molybdenum.

The method in which we utilize this API curve is as follows:

a. **Determine the hydrogen partial pressure (psia) by multiplying the mole per cent hydrogen in the vapor phase by the design pressure (psia).**

b. **The hydrogen partial pressure in a liquid is the same as in the vapor in equilibrium with it. Do not use the mol percent hydrogen in the liquid for determination of the hydrogen partial pressure. An example where this controls materials selection is a Unibon hot separator recycle pump and its associated piping.**

c. **Using the design temperature for the particular equipment involved find the point defined by it and the design hydrogen partial pressure (determined in Paragraph 3.1a above).**

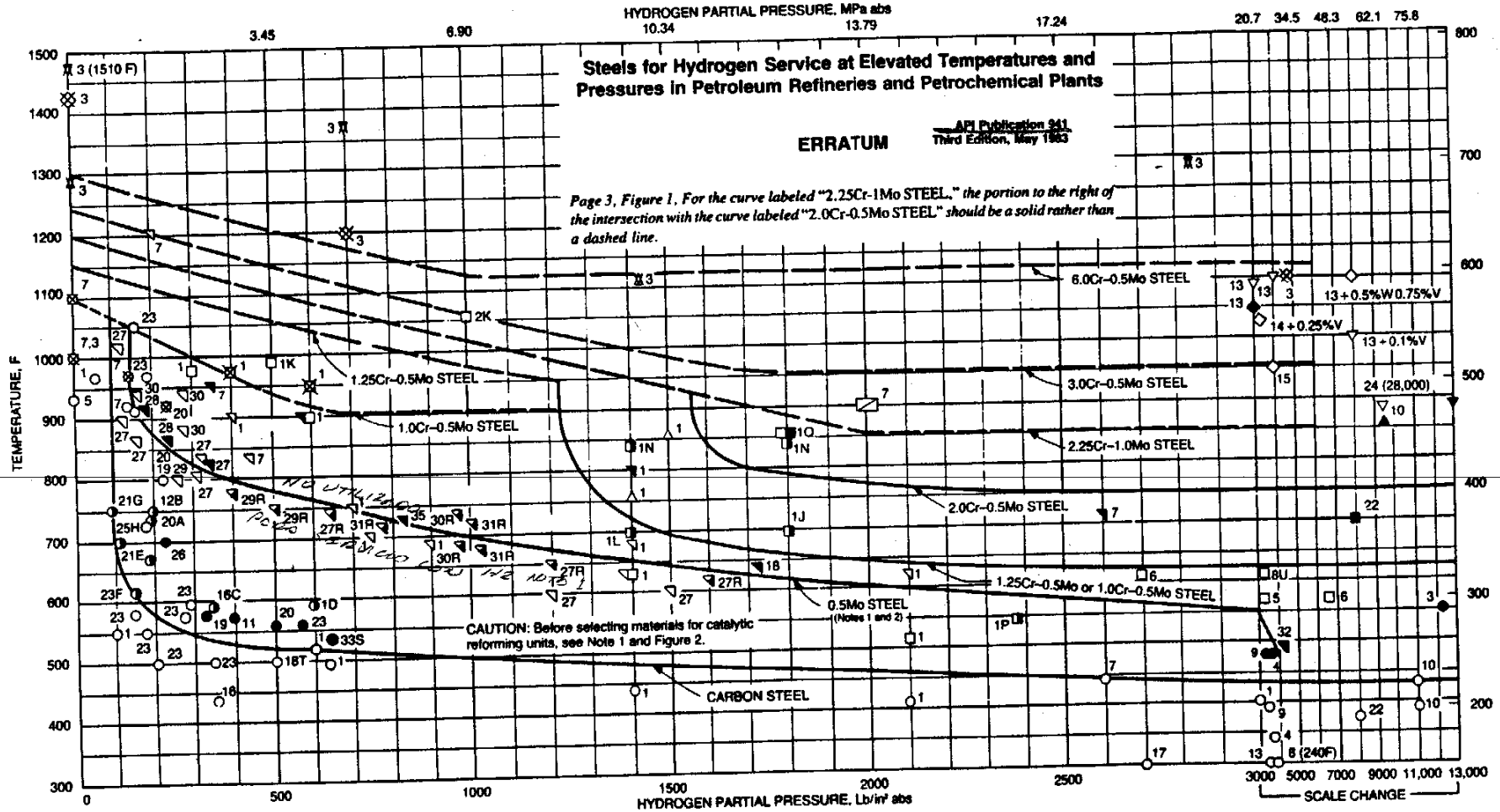
d. **The point defined by Paragraph 3.1c above identifies the appropriate minimum alloy material to resist hydrogen attack. If the point defined is on a material line, specify the next higher material.**

For example, for the conditions of 800°F and 500 psia hydrogen partial pressure the point defined is above the carbon steel line and the 0.5 Mo Steel line but below the 1Cr-½Mo line, therefore the appropriate minimum alloy material to resist hydrogen attack would be 1Cr-½Mo.

Alloy steels commonly used to resist high temperature hydrogen attack are as follows:

1. **C-1/2 Mo & Mn - 1/2 Mo**
2. **1 Cr - 1/2 Mo**
3. **1-1/4 Cr - 1/2 Mo**
4. **2 1/4 Cr - 1 Mo**
5. **3 Cr - 1 Mo**
6. **5 Cr - 1/2 Mo**
7. **9 Cr - 1 Mo**

The Nelson Curve (as depicted in API 941) is shown on the following page.



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NOTES:

1. After approximately 9–18 years' service, eight occurrences of hydrogen attack have been reported in C-0.5Mo steels operating below the 1977 0.5Mo curve in catalytic reforming units. These steels experienced hydrogen attack under conditions in which extensive decarburization or carbon migration to grain boundaries was not documented or reported prior to 1980. Further use of 0.5Mo steel in catalytic reforming units to resist internal fissuring should be evaluated rigorously until information is available to explain this phenomenon. Refer to 2.3 in the text, Table 1, and Figure 2.
2. The curve for 0.5Mo steel can apply to either C-0.5Mo or Mn-0.5Mo steels.
3. Austenitic stainless steels are generally not decarburized in hydrogen at any temperature or hydrogen pressure.
4. Effect of trace alloying elements (up to 1000 pounds per square inch absolute [6.90 megapascals] hydrogen partial pressure and below 1000 F [538 C]):
   a. Mo has four times the resistance of Cr to hydrogen attack.
   b. Mo is equivalent to V, Ti, or Nb up to 0.1 percent.
   c. Si, Ni, Cu, P, and S do not increase resistance.
5. The limits described by these curves are based on experience with cast steel as well as annealed and normalized steels at stress levels defined by the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1. Refer to 2.5 and 2.6 in the text for additional information.

Figure 1—Operating Limits for Steels in Hydrogen Service to Avoid Decarburization and Fissuring

FIGURE 1

3. COMMON ENVIROMENTAL CONSIDERATIONS

3.2 Sulfur

For determining materials of construction for an oil stream containing sulfur we utilize the curve entitled "Average Rate Curves for High Temperature Sulfur Corrosion" (See following page). This curve aids us in determining corrosion rates for materials in contact with sulfur bearing hydrocarbon streams and is used primarily for Crude, Vacuum, Visbreaker, Asphalt Oxidizing units and raw oil charge lines to hydrodesulfurizing and hydrocracking units. In using this curve we use the maximum operating temperature of the equipment involved and pick the corresponding corrosion rate for one of the materials listed, then adjust the corrosion rate with a correction factor which takes into account the weight per cent sulfur. It should be noted that the reference sulfur level for this curve is 1.0 weight per cent. As one can see from this curve, an increase in chromium content impart increasing resistance to high temperature sulfur corrosion.

An example utilizing this curve is as follows:

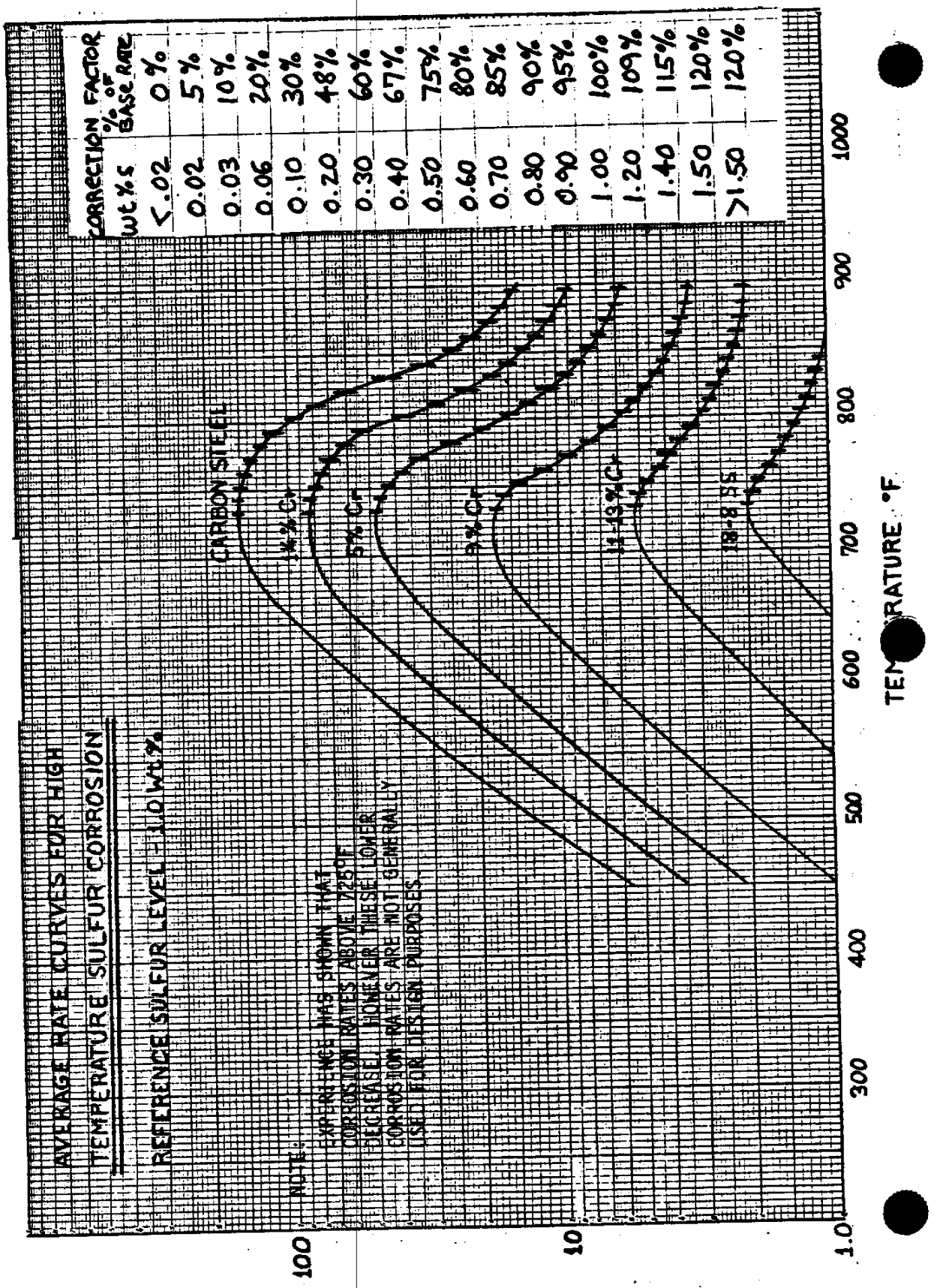
A refiner is changing his charge stock to his crude unit from crude containing 0.3 Wt. % sulfur to crude containing 1.00 Wt. % S. His crude transfer piping is 5 Cr-1/2 Mo and operates at 700°F. He wants to know what increase in corrosion rate would be experienced. Using the curve we find that the corrosion rate on 5 Cr-1/2 Mo at 700°F, and 0.3 Wt. % sulfur is 27 MPY (mils per year) which is .027 inches per year. For the new conditions of 700°F and 1.0 Wt. % S we can expect a rate of 45 MPY which is about 67 per cent higher than the present conditions.

For new designs we utilize this curve to predict corrosion rates and adjust the corrosion allowance to satisfy the design life requirement of the particular equipment in question. We use the maximum anticipated process fluid temperature for corrosion rate determination. The effects of metal wall temperatures on heater and heat exchanger tubes must be considered since this can result in either higher or lower anticipated corrosion rates. We generally specify carbon steel for most equipment to the 500-550°F temperature range and adjust the corrosion allowance to satisfy design life. The maximum corrosion allowance used is 0.250 inches. Vessels in this service are carbon steel; where improved corrosion resistance is necessary we specify TP 405 or TP 410S stainless cladding. Depending on the anticipated corrosion rates, heater tubes are usually 5 Cr-1/2 Mo, 7 Cr-1/2 Mo, or 9 Cr-1 Mo. Piping systems are usually carbon steel and 5 Cr-1/2 Mo with varying corrosion allowances. For larger diameter piping ($\geq$16" dia., usually heater transfer lines), an alternate of carbon steel clad with TP 405 or TP 410 S stainless steel is specified. Heat exchanger tubes are usually of a higher alloy than other equipment since very little corrosion allowance can be incorporated in them. Common exchanger tube alloy materials are 1 1/4 Cr-1/2 Mo, 5 Cr-1/2 Mo and TP 410 stainless steel.

FIGURE 2.

C. COMMON ENVIRONMENTAL CONSIDERATIONS

2. Sulfur



3. COMMON ENVIROMENTAL CONSIDERATIONS

3.3 Hydrogen Sulfide

For determining materials of construction for process streams handling hydrogen sulfide (H_2S) at elevated temperatures, the curves entitled "Trend Curves for Predicting Corrosion Rates" for steels in H_2S Environments at Elevated Temperatures are used. This includes a family of curves grouped according to alloy content as follows:

A-Figure 3	B-Figure 4	C-Figure 5	D - Figure 6
0-5% Chromium	9% Chromium	11-13% Chromium	18-8 Stainless Steel
Carbon Steel	9 CR-1 Mo	TP 405	TP 304
C -1/2 Mo		TP 410	TP 304L
1 CR-1/2 Mo		TP 410S	TP 304H
1 1/4 CR-1/2 Mo			TP 316
2 1/4 CR-1 Mo			TP 316L
3 CR-1 Mo			TP 316H
5 CR-1/2 Mo			TP 321
			TP 321H
			TP 347
			TP 347H

We use the maximum expected operating temperature encountered in the particular equipment and the mole per cent H_2S in the stream. Since the majority of these streams also contain hydrogen and in some cases sulfur the selection of a material of construction is more difficult. First a material must be selected to resist any hydrogen present. If the stream contains any sulfur, a corrosion rate must be determined for the hydrogen resistant material. Finally a corrosion rate is then determined based on H_2S. Only after these three steps can the final material of construction be determined.

For equipment where very little corrosion allowance can be incorporated, such as exchanger tubing we generally limit the maximum anticipated corrosion rate to about 5 mils per year.

Heavy wall vessels and reactors wherethe design service life is 20 years are lined with either a stainless steel overlay (TP 347) or clad with stainless steel (either TP 321, TP 405, TP 410S) on a base material that is resistant to the hydrogen environment, such as the 1 1/4 Cr-1/2 Mo, 2 1/4 Cr-1 Mo, 3 Cr-1 Mo alloys.

FIGURE 3

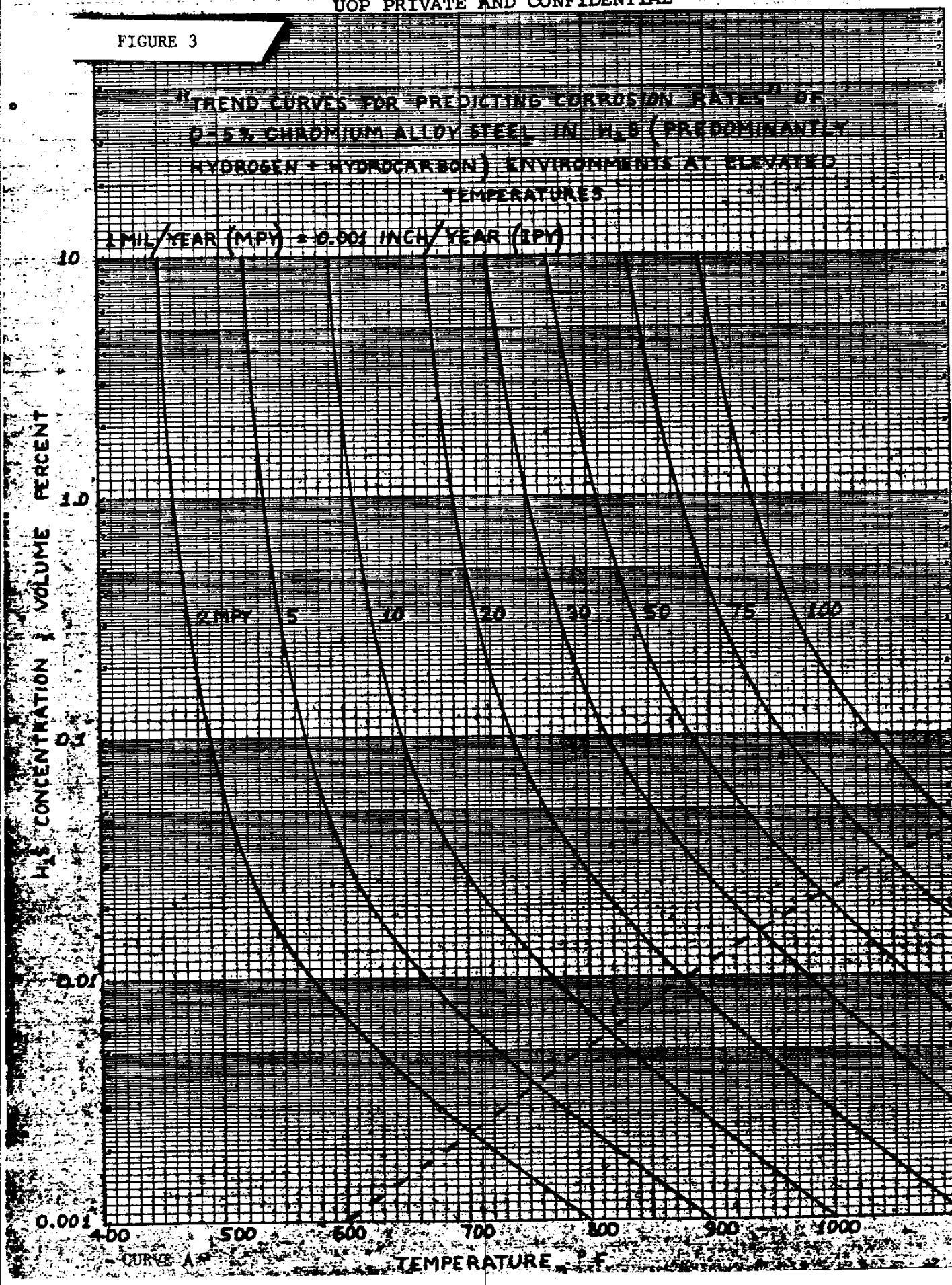

"TREND CURVES FOR PREDICTING CORROSION RATES" OF 0-5% CHROMIUM ALLOY STEEL IN H_2S (PREDOMINANTLY HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
H_2S CONCENTRATION, VOLUME PERCENT
10
1.0
0.1
0.01
0.001
2 MPY
5
10
20
30
50
75
100
400
500
600
700
800
900
1000
CURVE A
TEMPERATURE, °F

FIGURE 4

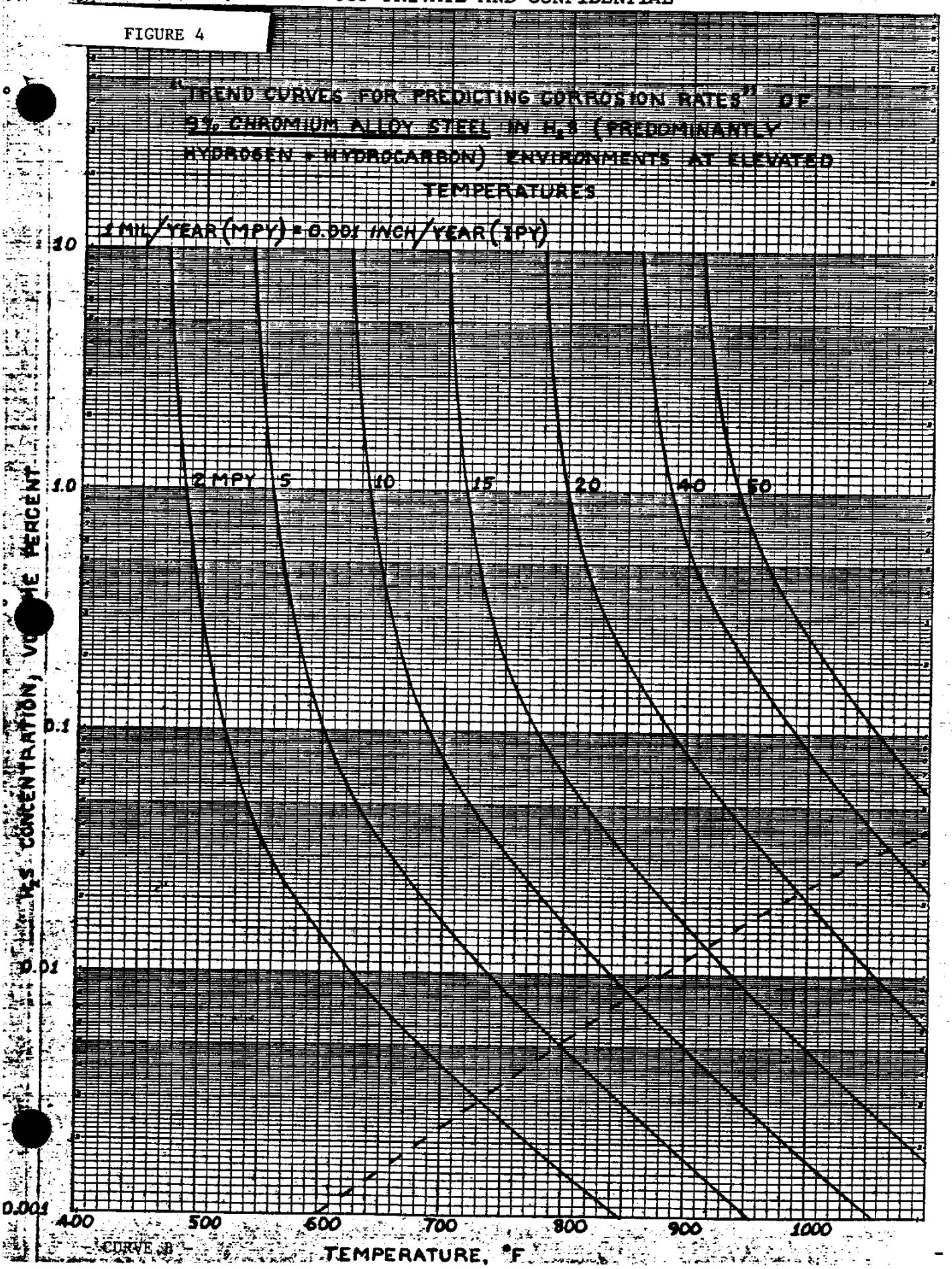

"TREND CURVES FOR PREDICTING CORROSION RATES" OF 9% CHROMIUM ALLOY STEEL IN H_2S (PREDOMINANTLY HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
2 MPY
5
10
15
20
40
50
10
1.0
0.1
0.01
0.001
H_2S CONCENTRATION, VOLUME PERCENT
400
500
600
700
800
900
1000
TEMPERATURE, °F
CURVE B

FIGURE 5

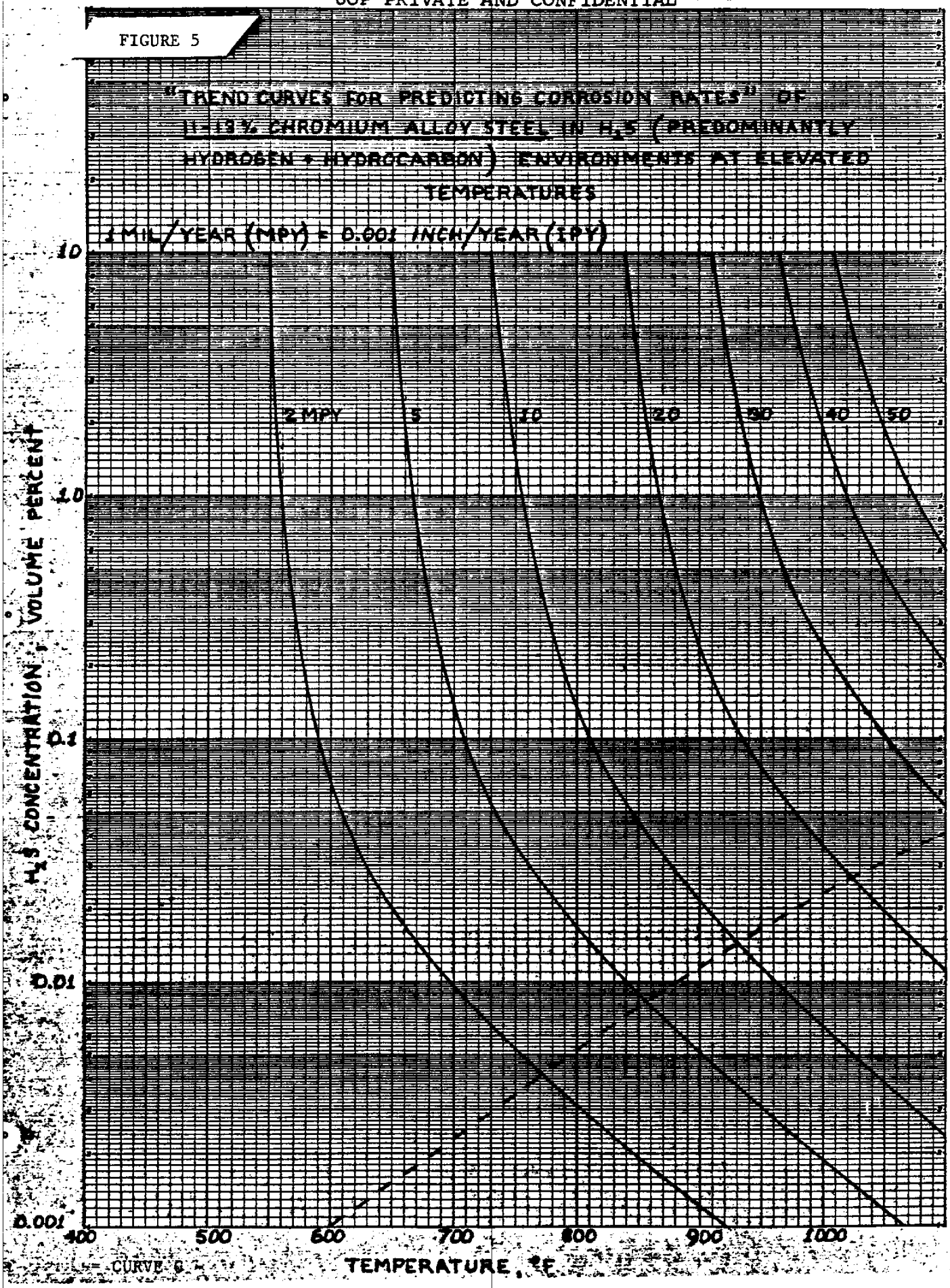
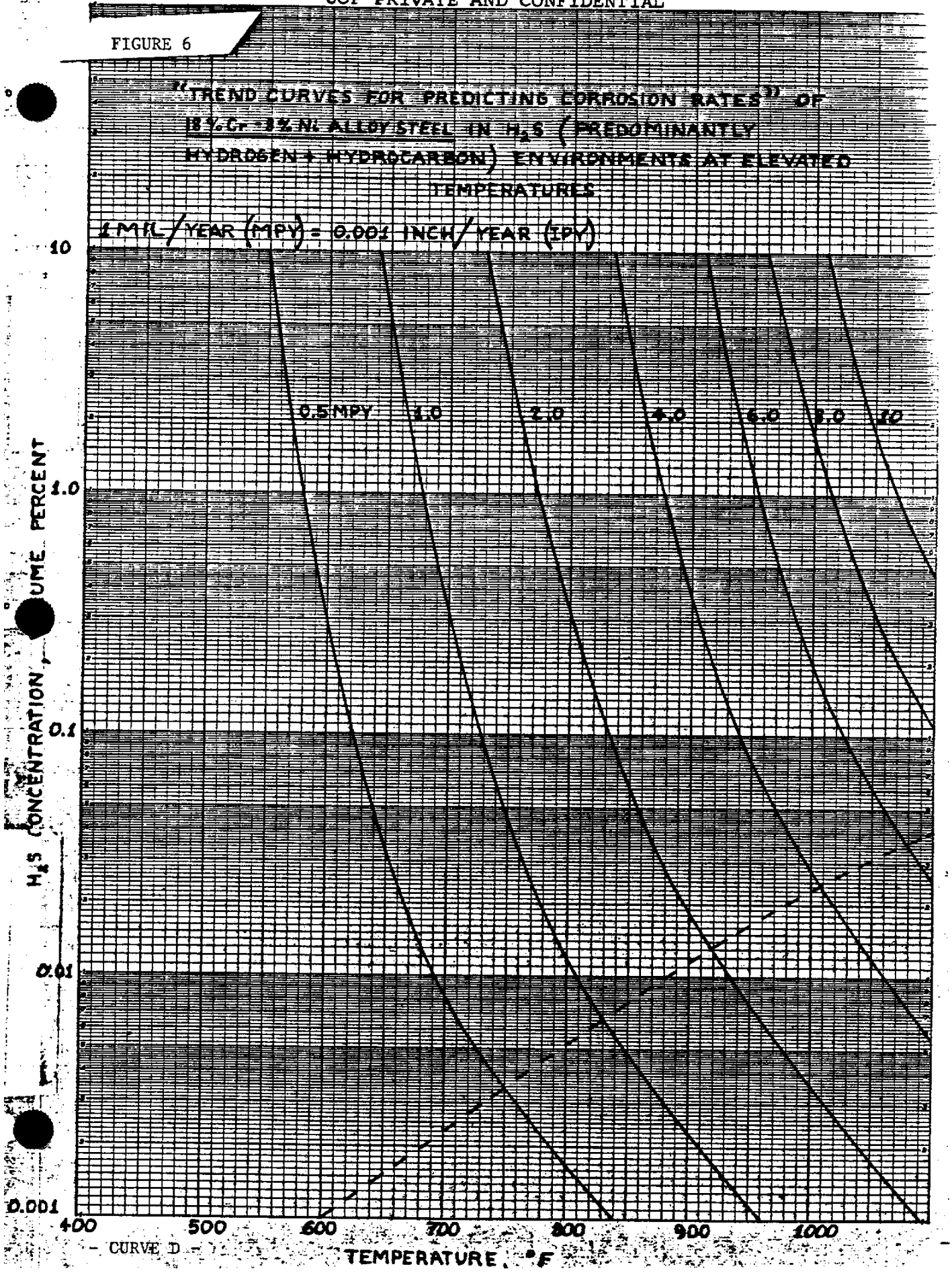

"TREND CURVES FOR PREDICTING CORROSION RATES" OF 11-13% CHROMIUM ALLOY STEEL IN H2S (PREDOMINANTLY HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
H2S CONCENTRATION, VOLUME PERCENT
10
1.0
0.1
0.01
0.001
2 MPY
5
10
20
30
40
50
400
500
600
700
800
900
1000
TEMPERATURE, °F
CURVE 6

FIGURE 6


"TREND CURVES FOR PREDICTING CORROSION RATES" OF
18% Cr - 8% Ni ALLOY STEEL IN H_2S (PREDOMINANTLY HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
0.5 MPY
1.0
2.0
4.0
6.0
8.0
10
10
1.0
0.1
0.01
0.001
H_2S CONCENTRATION, VOLUME PERCENT
400
500
600
700
800
900
1000
TEMPERATURE, °F
CURVE D

3. COMMON ENVIRONMENTAL CONSIDERATIONS

3.4 Low Temperature

For operating temperatures or low ambient temperatures, below -20°F (-29°C), special materials or requirements are necessary because at low temperatures steels may suffer from an appreciable loss in impact strength (toughness) and be susceptable to brittle failure.

a. Process

1. For temperatures down to -50°F (-46°C), the fully killed steels are generally adequate by modifying the melting practice during manufacturing and utilizing a normalizing heat treatment to provide a finer grain structure; giving improved toughness.

2. Below -50°F (-46°C), nickel alloy steels containing 3-1/2% Ni are utilized. nickel - 150°F

3. Below -150°F (-101°C) the 9% Ni alloy is utilized.

4. The austenitic (300 series - Cr - Ni) stainless steels are good at all low temperatures. 18-8 SS

b. Ambient

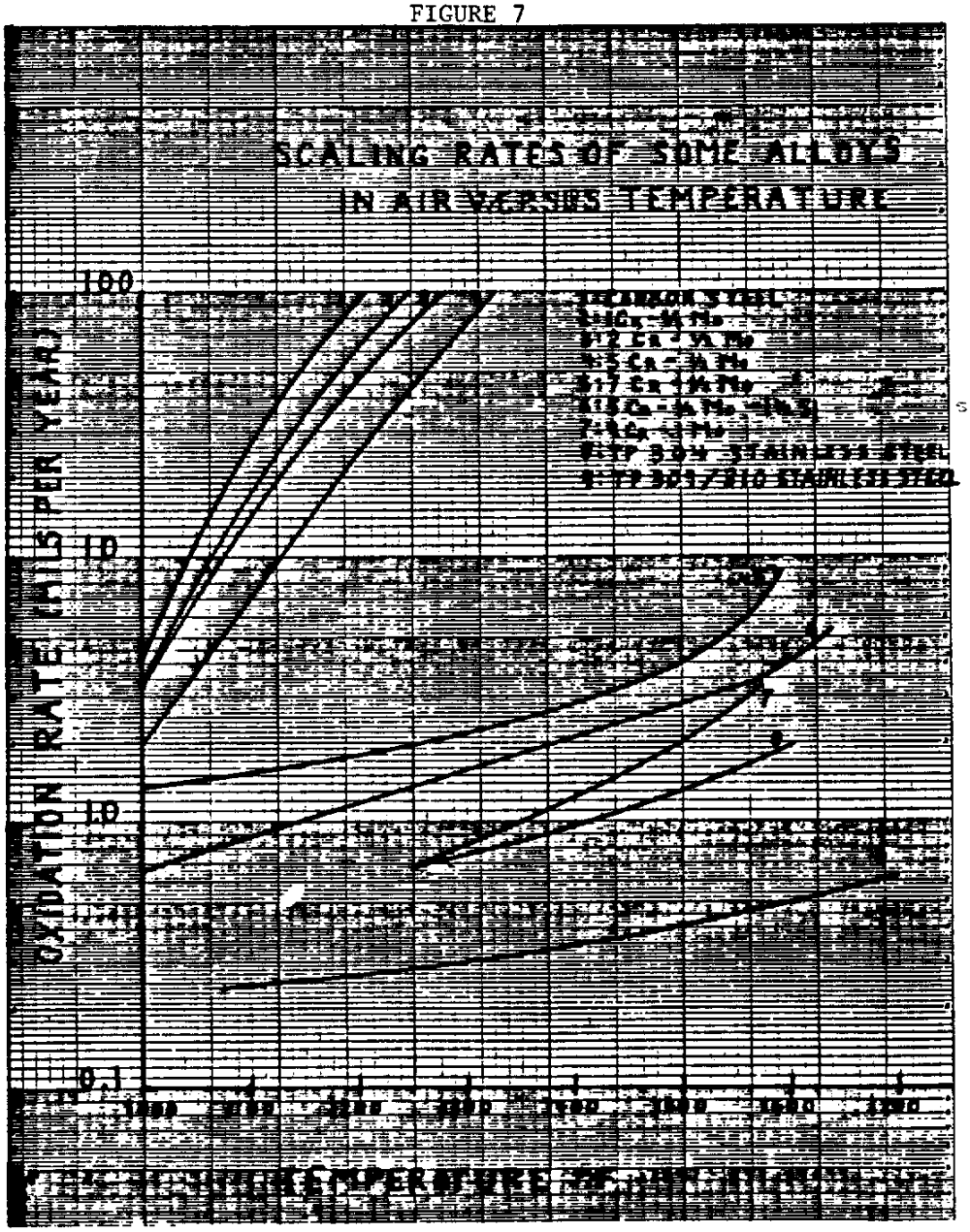
1. Where winterizing temperatures between -21°F (-29.5°C) -50°F (-46°C) are encountered the schedule 'A' requires a project specification for 'special materials requirements - winterizing'. This specification gives low temperature metallurgical requirements for structural steel, pressure vessel steel, supports, etc.

3. COMMON ENVIROMENTAL CONSIDERATIONS

3.5 Oxygen

The following curve shows comparative scaling behavior of various steels in air. Oxidation resistance must be considered in design of equipment where elevated temperatures are encountered. Examples are furnace tubes, tube supports, and equipment handling hot FCC flue gases.

FIGURE 7



3. COMMON ENVIROMENTAL CONSIDERATIONS

3.6 Acids

a. Hydrochloric (HCL) - Where resistance to HCL (formed during processing) must be provided, Monel is generally specified. Some examples of this are monel lining in the top of a crude column, monel mesh blankets in Platformer equipment, and monel trim valves in streams handling wet Platformer gas.

b. Naphthenic - Where resistance to naphthenic acids is required, Type 316 is used.

Generally Type 316 is employed in Crude and Vacuum Units processing crude oils that possess acid neutralization number (Mg KOH/g Crude) over 0.6. The Type 316 is used in areas of high velocity where temperatures range from about 450°F to 750°F. The most common areas where Type 316 is employed for Naphthenic Acid protection is the vacuum column cladding (lining) from about the 500°F zone and hotter, the vacuum gas oil side cut circuit and possibly the vacuum unit heater tubes and transfer piping.

c. Phosphoric (H_2PO_4) - Where resistance to phosphoric acid is required, Type 316 is used. Some examples of this are certain areas of catalytic condensation units (Cumene and Tetramer) where phoshporic acid "syrup" is formed.

d. Hydrofluoric (HF) - For resistance to hot HF acid environments and HF acid concentractions below about 60 percent at ambient temperature, monel is employed. Some examples of this (all in the HF Alkylation Process) are the Acid Regenerator, Polymer Surge Drum and the scrubbing section of the Relief Gas Scrubber.

4. POSTWELD HEAT TREATING (PWHT)

4.1 Residual Stresses

Residual stresses and changes in metallurgical structure produced by welding and forming particularly in thick walled vessesl render the vessel prone to cracking failure. Therefore, the ASME Code requires PWHT above the following thicknesses for carbon steel and alloys:

Carbon Steel	above 1 1/2 inches
Carbon Steel - 1/2 Mo	above 5/8 inches
Chrome, Moly Alloys	varies with alloy content
Austenitic St. Steel	not required

4.2 Enviromental Requirements

Post Weld heat treatment is specified for killed carbon steel and carbon steel regardless of Code requirements under the following enviromental conditions to minimize susceptibility to H_2 embrittlement and stress corrosion cracking:

a. Hydrogen Sulfide (H_2S) -

1. Where H_2S is present in a concentraction greater than 0.3 mole percent with an aqueous phase.
2. Where liquid water is present containing greater than 10 ppm of H_2S.

b. Hydrofluoric Acid and Boron Trifluoride - For equipment where the process steam contains any amount of HF acid or BF_3. (This is not a requirement where seal or strength welding of heat exchanger tubes is performed).

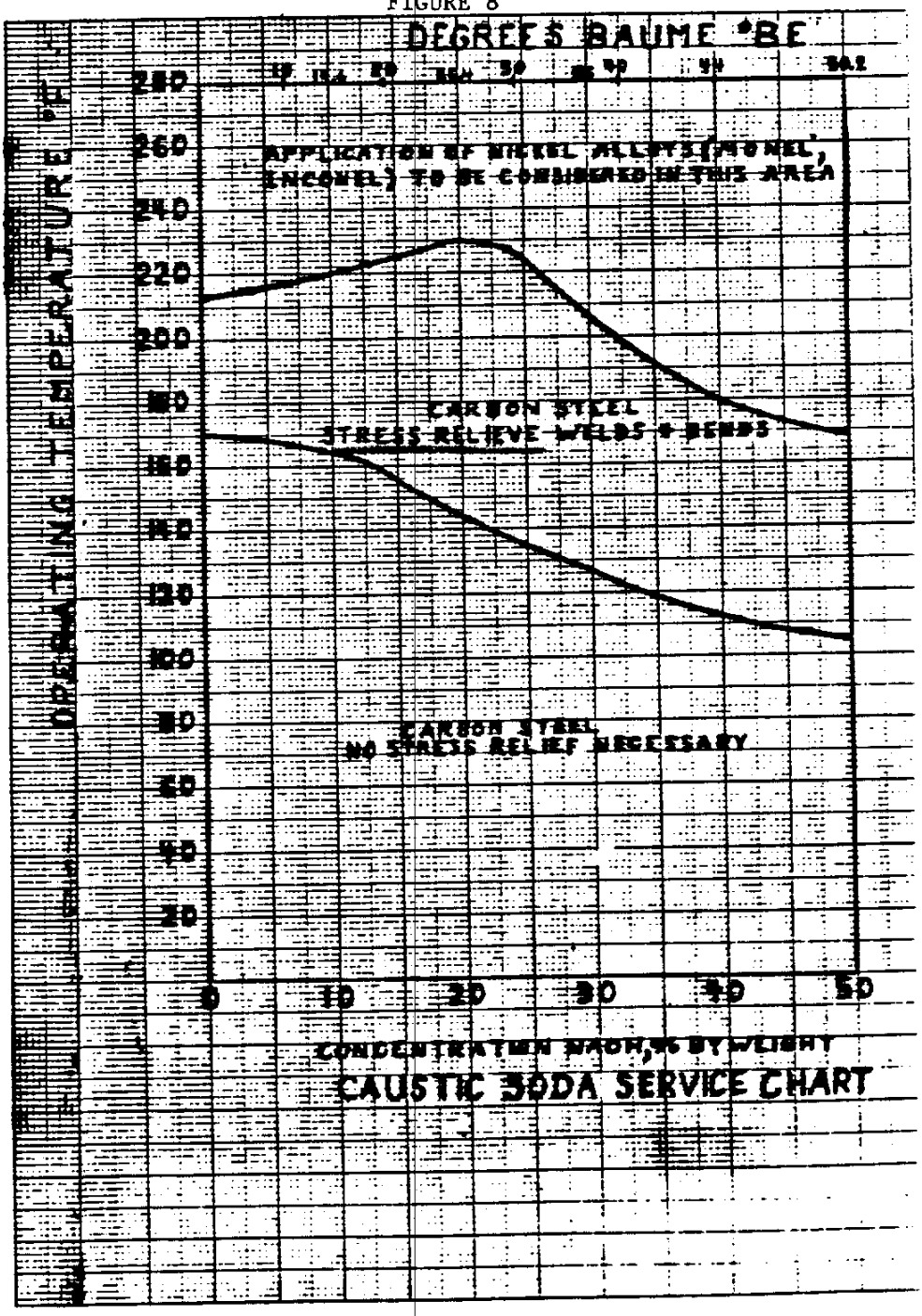
c. Caustic (NaOH) - Refer to "Caustic Soda Service Chart" Fig. 8 to determine if PWHT is required. Use operating temperature and concentraction of NaOH (weight per cent or degrees Baume). The same criteria are followed for KOH.

d. Amine - All equipment and piping in MEA or DEA Service.

4.2 **Enviromental Requirements** (Cont'd)

Caustic Soda Service Chart

FIGURE 8



5. RADIOGRAPHIC EXAMINATION (RT)

Radiographic examination is required for process reasons in addition to construction code requirements for the following environments:

5.1 Hydrofluoric Acid (HF Alkylation Unit)

a. 100 per cent radiographic examination is required for the following equipment, due to the high concentraction of HF acid.

1. Alkylation Reactor
2. Acid Mixer
3. Acid Settler
4. Acid Storage Drum
5. Acid Regenerator
6. Polymer Surge Drum

b. Spot radiographic examination is required for all vessels (excluding those listed in paragraph 5 1a containing any amount of HF acid.

5.2 Boron Trifluoride (Alkar Unit)

Spot radiographic examination is required for equipment containing any amount of BF_3.

6. MATERIALS FOR SPECIAL EQUIPMENT

6.1 Mesh Blankets

The standard construction material for vessel mesh blankets is an 18-8 type stainless steel, usually Type 304. The grid and wire are constructed of the same material as the blanket. Exceptions to the standard material are as follows:

a. Monel mesh blankets are to be used in the following environments:

1. Chloride and HCL - Examples are the top mesh blanket in a vacuum column, product separator mesh blanket in Butamer, Isomar, Penex and Platforming Units; and mesh blankets in compressor suction drums handling chloride containing gases.

2. Hydrofluoric Acid - Mesh blankets in contact with hydrocarbons or gas streams containing HF.

3. Boron Trifluoride - Mesh blankets in contact with hydrocarbon or gas streams containing BF_3.

b. Type 316 mesh blankets are to be used in the following environments:

1. Hydrogen sulfide and ammonium hydrosulfide - an example is the product separator in hydrotreating service.

2. Phosphoric Acid - Examples are in Catalytic Condensation Units where the presence of phosphoric acid syrup is anticipated.

TIPO 312
SO_2 + H_2O

6. MATERIAL FOR SPECIAL EQUIPMENT

6.2 Valve Trim

The standard material for valve trim in a carbon steel valve is a hardened straight chromium stainless steel, usually 11-13% chromium. Exceptions to the standard valve trim are as follows:

a. Monel trim valves are used in the following environments:

1. For all process streams containing any amount of hydrofluoric acid.

2. For all process streams containing any amount of boron trifluoride.

3. For cold (less than 400°F) gas streams, saturated with water, containing greater than 0.3 mole per cent hydrogen sulfide.

4. For cold (less than 400°F) gas streams, saturated with water, containing chlorides. An example of this is Platforming gas used as make-up gas in a hydrotreating unit.

5. For valves in sour water streams where liquid water is present containing greater than 10 ppm of H_2S. (Exception to this is covered in 6.2b2 (below).

b. Type 316 trim valves are used in the following environemnts:

1. Where the presence of phosphoric acid syrup is anticipated in a Catalytic Condensation Unit.

2. In a sour water stripper unit, including the block valves on the individual feed lines to the unit.

c. 300 series stainless steels (TP 304, 316, 321, or 347) are used for valve trim for all carbon steel valves handling hot carbonate solutions in the CO_2 removal section of a hydrogen production unit.

d. Valve trim substitutes. The following materials can be substituted for special trim valves as follows:

1. Hastelloy B is an acceptable substitute for monel trim in services described above in Paragraphs 6.2a1 and 2.

2. Stellite (Cobalt/Chromium/Tungsten Alloy) is an acceptable substitute for monel trim for valves in the services described above in Paragraphs 6.2a3, 4 and 5 and 6.2b.

7. MATERIALS OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.1 Crude Unit

a. Monel lining is employed in the upper section (usually the top head and shell through tray four) of the crude column for protection against HCl corrosion.

b. Type 405 or Type 410S (11-13%Cr) lining is used for resistance to high temperature sulfur corrosion. The entire bottom section of the crude column, up to a zone where the temperatures are in the range of 500-550°F, is lined.

c. Trays in the lined areas are the same material as the shell lining, i.e. Monel and Type 410.

d. Crude heater tubes are either 5 Cr - 1/2 Mo, 7 Cr - 1/2 Mo or 9 Cr - 1 Mo depending on anticipated corrosion rate.

e. Heat exchanger tubes are either Type 410, 5 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo, depending on anticipated corrosion rate; taking into consideration that very little corrosion allowance can be added to tubing.

f. Piping is usually 5 Cr - 1/2 Mo or carbon steel with corrosion allowances adjusted based on anticipated corrosion rate. Large diameter pipe (≥16" Diameter) may be specified as carbon steel clad with Type 405 or Type 410S as an alternate to 5 Cr - 1/2 Mo.

7.2 Vacuum Unit

a. The same approach is used for materials selection as in crude units, however, Monel is not used in the upper section of the vacuum tower.

b. When naphthenic acids are a consideration, Type 316 (Type 316L for welded components) stainless steel may be used for the heater tubes, heater transfer piping, vacuum column lining (the bottom section up to the including the zone where the temperature is approx, 500°F) and the vacuum gas oil circuit.

7.3 Thermal Cracking and Visbreaker Units

a. The same approach is used for materials selection as crude units.

b. The residium stripper and the lower section of the flash fractionator are lined with Type 405 or Type 410S stainless steel.

c. Piping in the hot areas (usually above 550°F) is 5 Cr - 1/2 Mo with various corrosion allowances.

7. MATERIAL OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.4 Fluid Catalytic Cracking

a. The major considerations for materials selection are corrosion resistance, elevated temperature strength, oxidation and abrasion resistance. The majority of areas where abrasion resistance is required are lined with hexsteel and an abrasion resistant concrete (Resco AA-22).

b. The reactor is 1 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo lined with Type 405 or Type 410S.

c. The regenerator is an internally insulated carbon steel vessel.

d. Regenerator cyclones and internals are Type 304H materials.

e. The main column is carbon steel in the upper section and 1 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo lined with Type 405 or Type 410S in the lower section.

f. Hot piping around the Reactor and Regenerator is either Type 304H or 1 1/4 Cr - 1/2 Mo, lined with hextsteel and concrete.

g. Slurry piping is 5 Cr - 1/2 Mo.

7.5 Catalytic Reforming (Platforming)

a. The primary concern with selection of construction materials in this unit is resistance to elevated temperature hydrogen.

b. Heater tubes are either 2 1/4 Cr - 1 Mo or 9 Cr - 1 Mo; the latter being used where the tube design temperatures are approx. 1175°F. At this temperature the 9 Cr - 1 Mo is selected due to its superior oxidation resistance.

c. Reactors are either 1 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo, with internals or either Type 316, Type 316L , Type 321 or Type 347.

d. The combined feed exchanger is , 1 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo depending on resistance to hydrogen.

e. Mesh blankets, relief valve trim, orifice plates and thermowells are monel.

7. MATERIALS OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.6 Hydrodesulfurization and Hydrocracking Units

a. Criteria for materials selection in these units is primarily resistance to elevated temperature hydrogen, sulfur and hydrogen sulfide.

b. Reactors, hot separator and flash drums are usually 1Cr - 1/2 Mo, 1-1/4 Cr - 1/2 Mo, 2-1/4 Cr - 1 Mo or 3 Cr - 1 Mo lined with either Type 405, Type 410S, Type 321 or Type 347.

c. Reactor charge heater tubes are usually 1-1/4 Cr - 1/2 Mo, 5 Cr - 1/2 Mo, 9 Cr - 1 Mo or Type 347H.

d. Combined feed vs. effluent exchanger tubes are usually Type 304, (TP321 or TP347 when welded to tube sheet), Type 410, Type 430, 5 Cr - 1/2 Mo, 1-1/4 Cr - 1/2 Mo or C-1/2 Mo, depending on anticipated corrosion rate at operating temperature. Type 316L has been specified for tubing in the colder shells of some exchanger trains where an aqueous phase and H_2S are present. An example of this is the coldest bundle in a hot separator versus recycle gas exchanger.

e. Reactor circuit piping is 1-1/4 Cr - 1/2 Mo, 2-1/4 Cr - 1 Mo, 5 Cr - 1/2 Mo, Type 321 or Type 347. (Aluminized pipe of a material that resists the elevated temperature hydrogen may be considered).

f. Mesh blankets in vessels downstream of the reactor circuit are either Monel or Type 316. With heavier charge stocks that contain nitrogen, Type 316 is specified because experience has shown severe deterioration of Monel where ammonium hydrosulfide is present.

g. Some higher pressure recycle gas scrubbers are specified to be lined with Type 304L; with a lined scrubber, piping to the amine flash drum is also specified as Type 304L.

h. Product fractionators may be specified to be lined with Type 405 or Type 410S if the anticipated corrosion rate warrants.

i. Monel valve trim is specified in may areas where an aqueous phase and H_2s are present.

j. Material selection is often dependent upon minimizing corrosion products which could plug the reactor bed.

7. MATERIALS OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.7 Hydrodealkylation Units (Hydeal and THDA)

a. Materials selection is based primarily on elevated temperature strength and resistance to elevated temperature hydrogen.

b. Reactors are of the cold shell design. They are either 1Cr-½ Mo or 1¼ Cr-½ Mo with an internal lining of 5" thick insulating refractory, and may have an internal metal liner of Type 347.

c. Charge heater tubes are Type 347H.

d. Hot reactor circuit piping is Type 316H or Type 304H.

e. The hot combined feed exchanger is constructed primarily of Type 316 H. or TP 304H.

f. Incoloy 800 H may be used for heater tubes, piping and exchanger components.

g. The materials of construction for the cold combined feed exchangers are based solely on resistance to elevated temperature hydrogen. They are usually 1 Cr-1/2 Mo or 1 1/4 Cr - 1/2 Mo.

7.8 HF Alkylation

a. Monel is used for its resistance to hot hydrofluroic acid in the following equipment:

1. Acid Regenerator

2. Polymer Surge Drum

3. The scrubber section of the Relief Gas Scrubber.

4. Acid Regenerator Overhead Condenser.

b. All carbon steel valves in HF service are specified with Monel trim and other special UOP requirements.

7. MATERIAL OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.9 Catalytic Condensation (Cumene & Tetramer)

a. Type 316L (Type 316L for welded components) is used in this process for resistance to phosphoric acid "syrup".

b. Type 316 is specified for the following equipment:

1. The Effluent Rectifier is lined in the bottom area up to the feed point.

2. The acid knockout drum.

3. All internals in the lined portion of vessels.

4. The piping from the reactor effluent pressure control valve to the rectifier, and from the effluent rectifier to the acid knockout drum.

7.10 Amine Treating

a. Type 304L is used for lining at the feed area of the amine regenerator.

b. The piping from the control valve just upstream of the regenerator is Type 304L.

c. Type 304 exchanger tubing is used in the regenerator reboiler and the amine reclaimer.

7.11 Waste (Sour) Water Stripper

a. Contact Condenser Design

1. The stripper column is lined in the contact condenser area with Type 316L; trays in the lined area are Alloy 20.

2. The side-cut pump around circuit pump is specified to have an Alloy 20 case and impeller.

3. The side-cut pump around cooler is either 3003 Alclad tubes and headers with a maximum tube inlet velocity of 35 feet per second, or Titanium with no velocity restrictions.

b. Overhead Receiver Design

1. The stripper column has Type 316 trays, usually three at the feed point.

2. The overhead receiver reflux pump is specified to have an Alloy 20 case and impeller.

3. The stripper overhead condenser is the same as in 7.11a3.

7. MATERIAL OF CONSTRUCTION FOR COMMON PROCESS UNITS

7.12 Hydrogen Plant

a. Reformer furnace tubes are centrifugally cast HK-40 stainless steel.

b. The inlet header and pig-tails are either 1 1/4 Cr - 1/2 Mo or 2 1/4 Cr - 1 Mo depending on temperature.

c. The outlet header and pig-tails are Incoloy 800H.

d. Materials for the remaining equipment are based on resistance to elevated temperature hydrogen. This equipment is usually 1 Cr - 1/2 Mo or 1 1/4 Cr - 1/2 Mo.

7.13 Hot Carbonate CO_2 Removal Unit

a. Type 304 is used for the majority of equipment where both water and CO_2 are present.

b. The rich carbonate solution line is Type 304 from the pressure reducing valve to the solution stripper.

c. The top head area of the solution stripper is lined with Type 304.

d. All piping containing lean or semi-lean carbonate solution are carbon steel, except all components smaller than full line size (reducers, valves and line segments) are Type 304.

e. Type 316 case and impeller are used for pumps handling streams containing carbonate solution or CO_2 and water.

(3) HCl y H_2S forman ácidos corrosivos con pH 1-2
oxigeno acelera la corrosión
fuentes de oxigeno.
- lugos
- crudo
- agua de lavado

DESALADO
CAUSTIC INJECTION
NEUTRALIZACION
WATER - WASHING
ADICION DE INHIBIDOR.

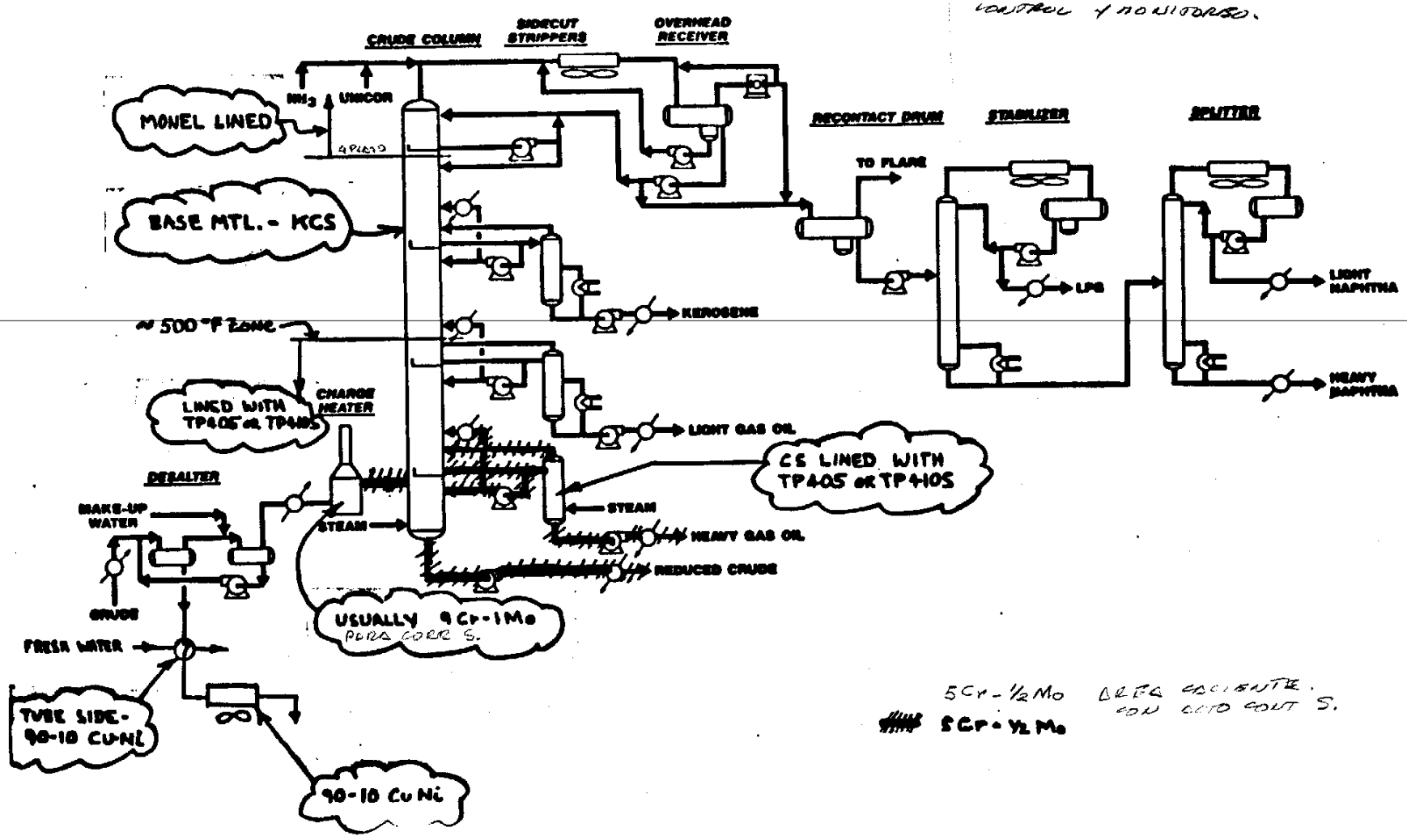
DIM FOR PH 6.5-7.5
IN OVERHEAD RECEIVER
WATER.

(1) CRUDES CONTIENEN
- SALES.
Ca & Mg Cloruros
forman HCl

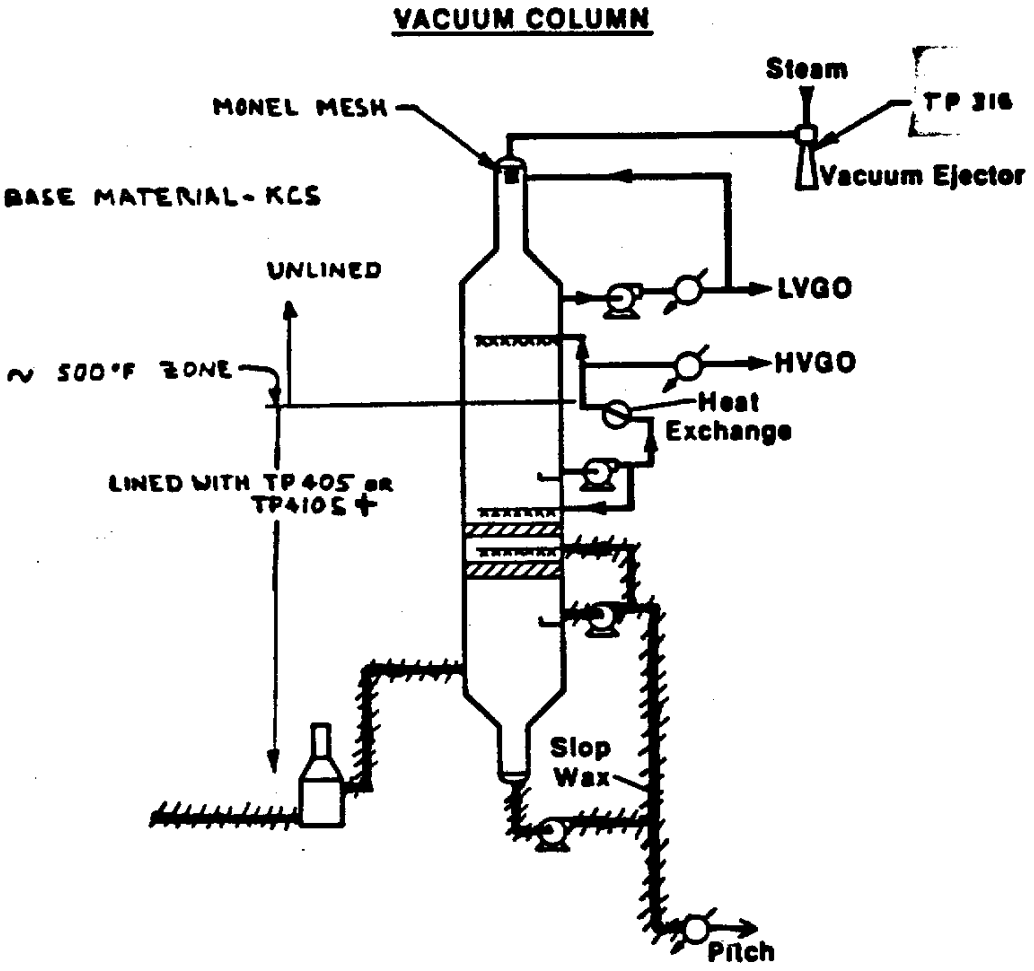
CONTROL
- PRETRATADO CRUDO
- NEUTRALIZACION
- LAVADO CON AGUA

REQUIERE JUICIOSO
CONTROL Y MONITOREO.

CRUDE DISTILLATION UNIT



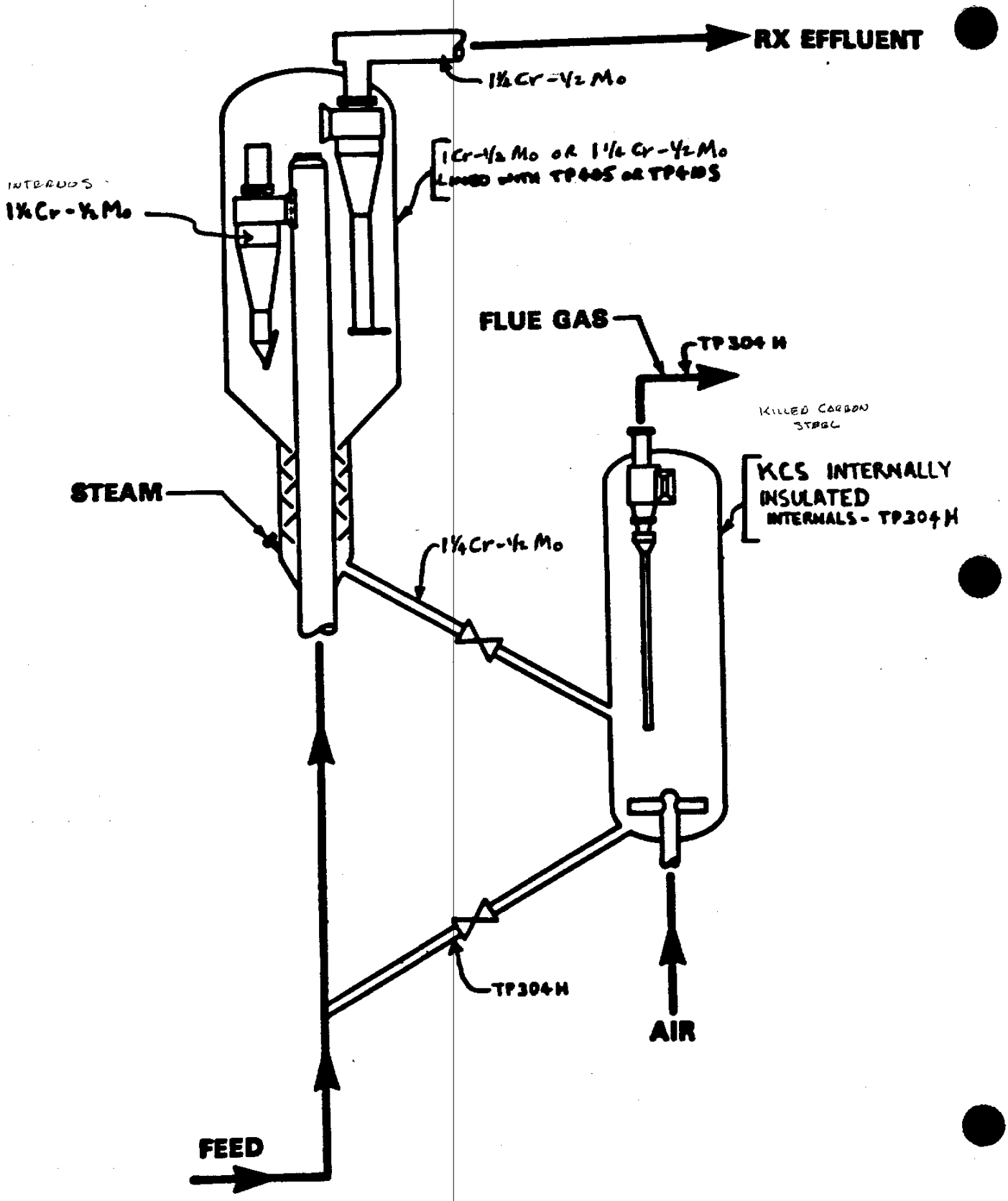
VACUUM DISTILLATION UNIT

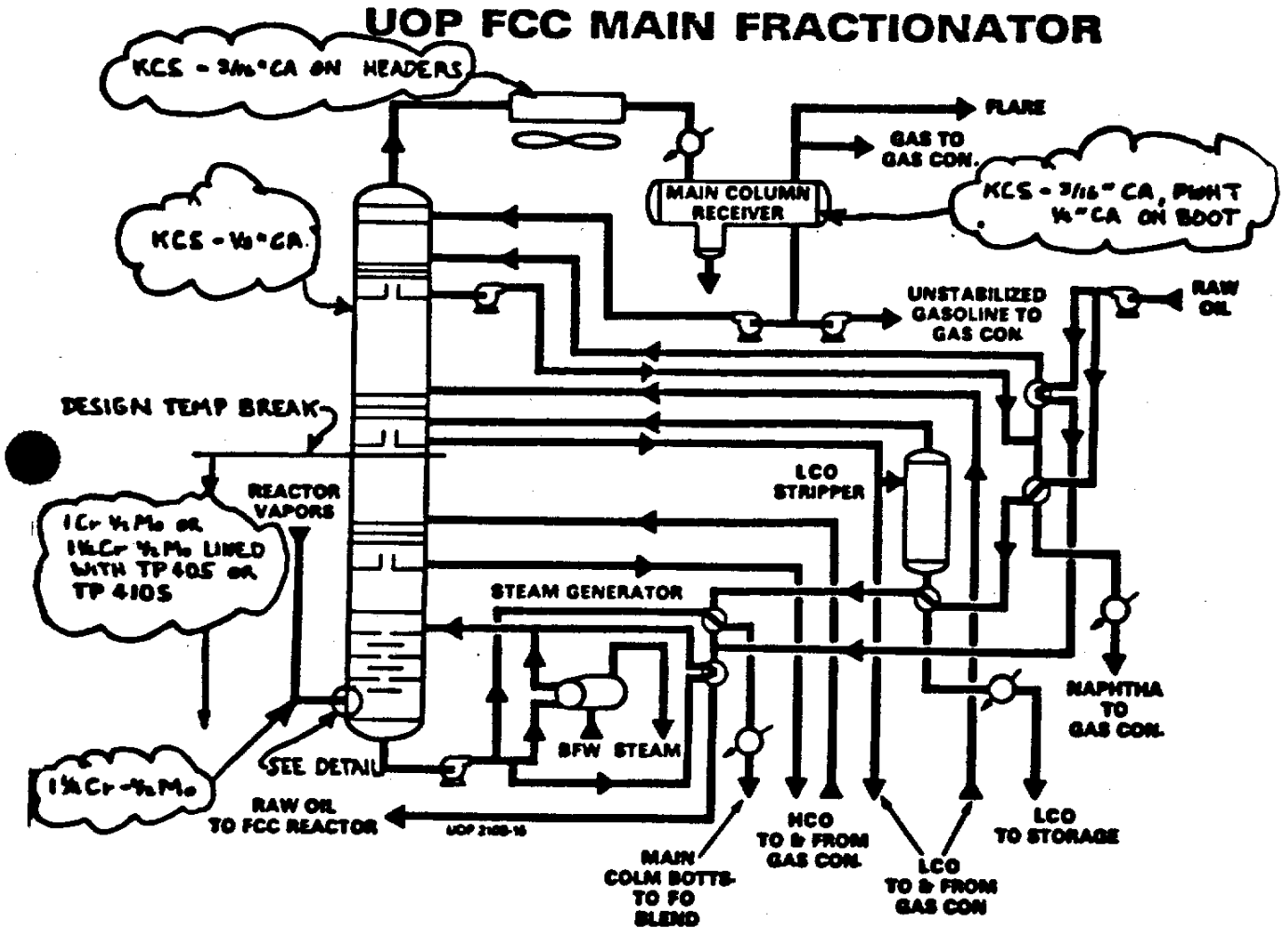


+ FOR NAPHTHENIC ACID DESIGNS
LINING IS TP316L

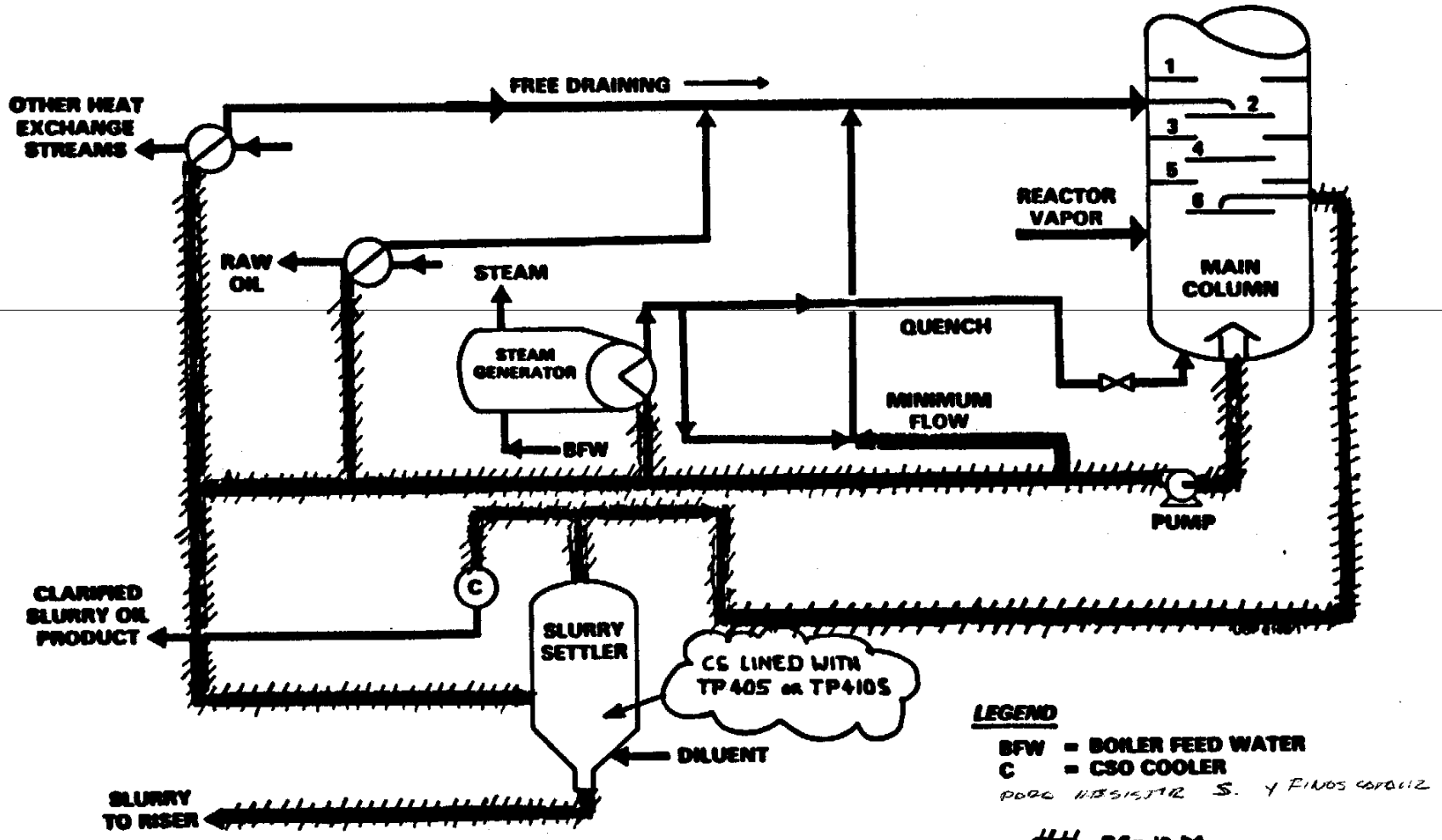
//// 5Cr - ½ Mo

FCC UNIT

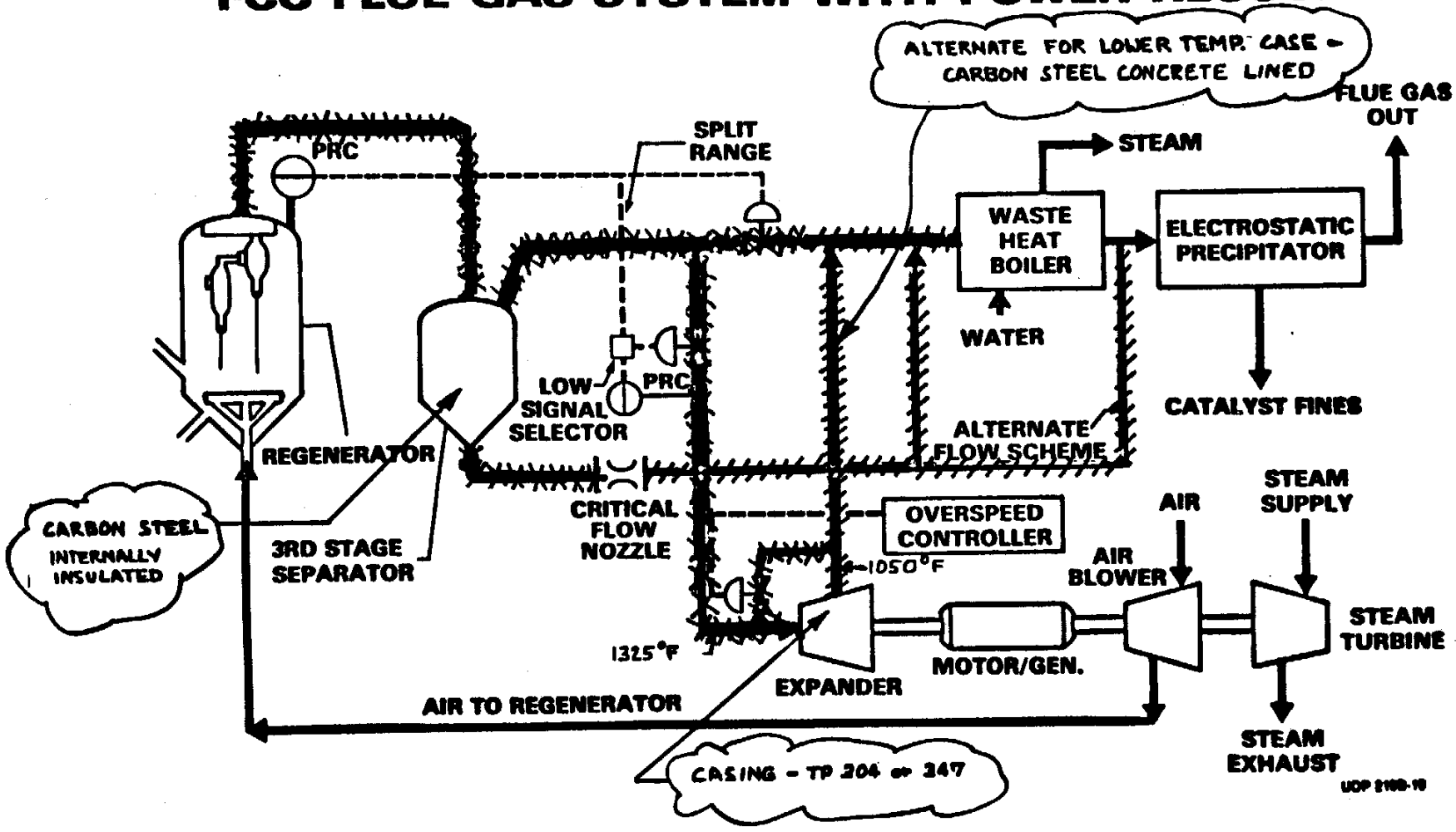

RX EFFLUENT
1¼Cr-½Mo
1Cr-½Mo OR 1¼Cr-½Mo
LINED WITH TP405 OR TP410S
INTERNALS
1¼Cr-½Mo
FLUE GAS
TP304H
KILLED CARBON
STEEL
KCS INTERNALLY
INSULATED
INTERNALS - TP304H
STEAM
1¼Cr-½Mo
TP304H
AIR
FEED


UOP FCC MAIN FRACTIONATOR
KCS - 3/16" CA ON HEADERS
KCS - 1/8" CA
DESIGN TEMP BREAK
1Cr ½Mo OR 1¼Cr ½Mo LINED WITH TP 405 OR TP 410S
REACTOR VAPORS
1¼Cr-½Mo
SEE DETAIL
RAW OIL TO FCC REACTOR
FLARE
GAS TO GAS CON.
MAIN COLUMN RECEIVER
KCS - 3/16" CA, PLUS 1/4" CA ON BOOT
UNSTABILIZED GASOLINE TO GAS CON.
RAW OIL
LCO STRIPPER
STEAM GENERATOR
BFW STEAM
NAPHTHA TO GAS CON.
MAIN COLM BOTTS TO FO BLEND
HCO TO & FROM GAS CON.
LCO TO & FROM GAS CON
LCO TO STORAGE

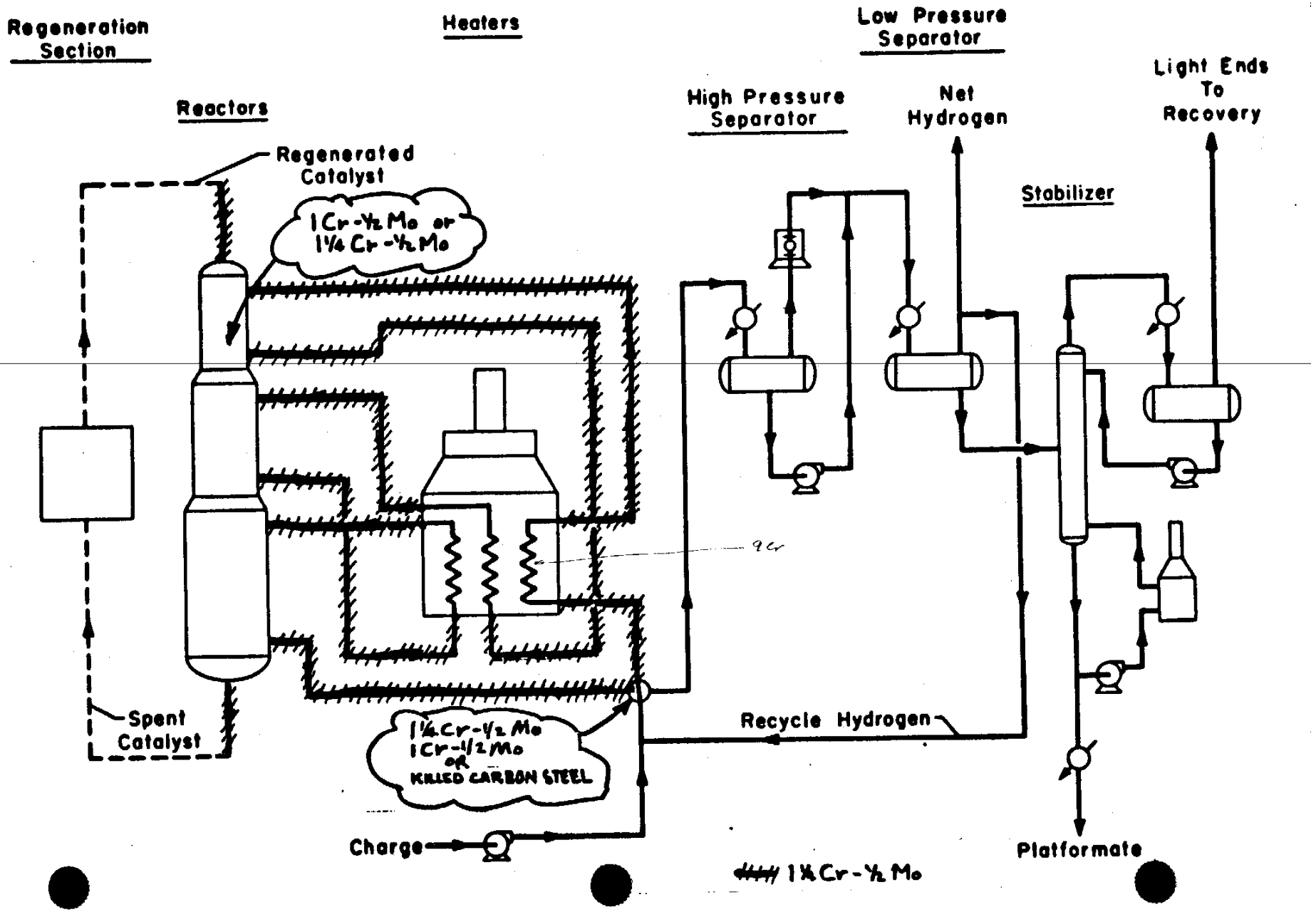
MAIN COLUMN BOTTOMS PROCESS FLOW



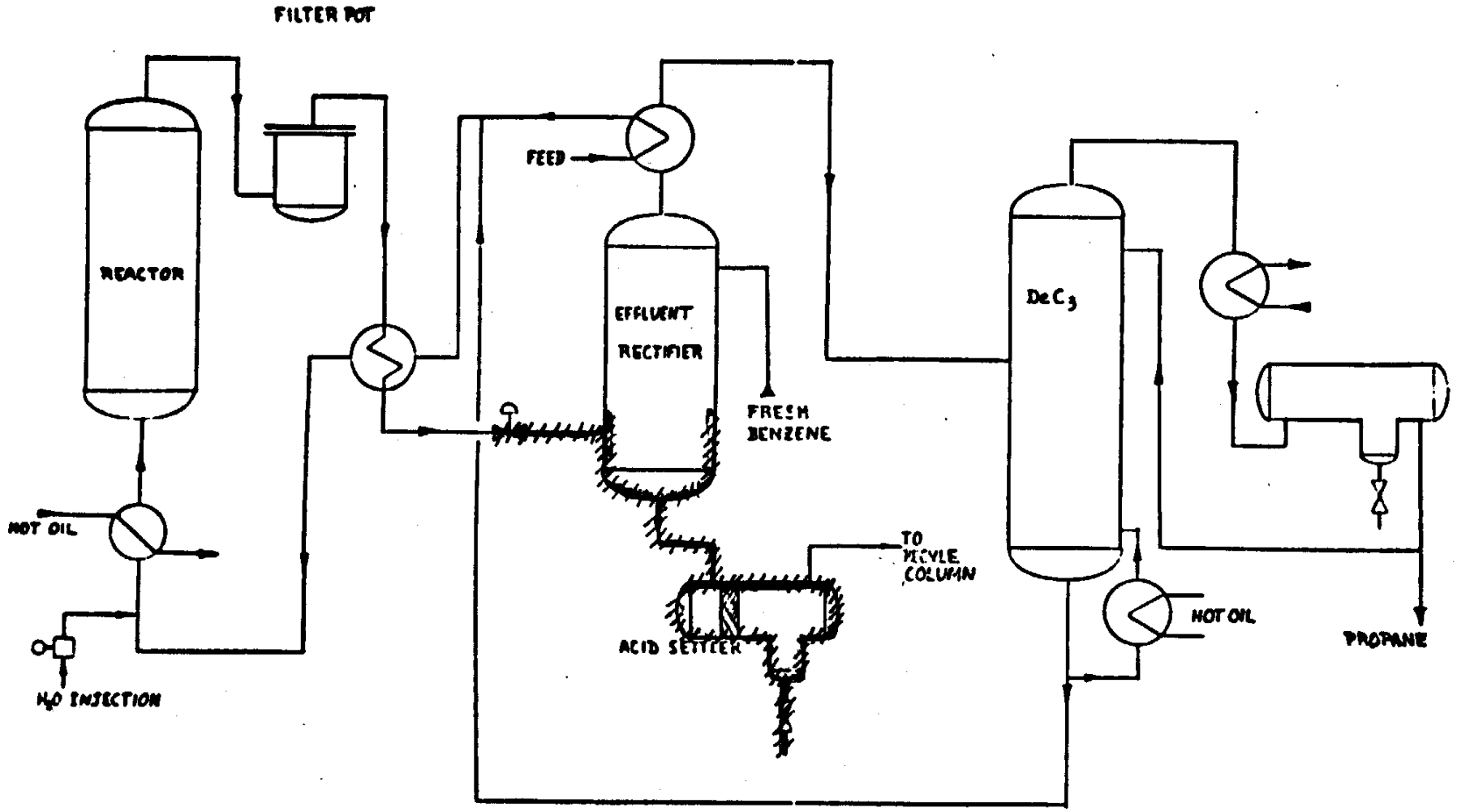
FCC FLUE GAS SYSTEM WITH POWER RECOVERY



UOP Continuous Platforming Process

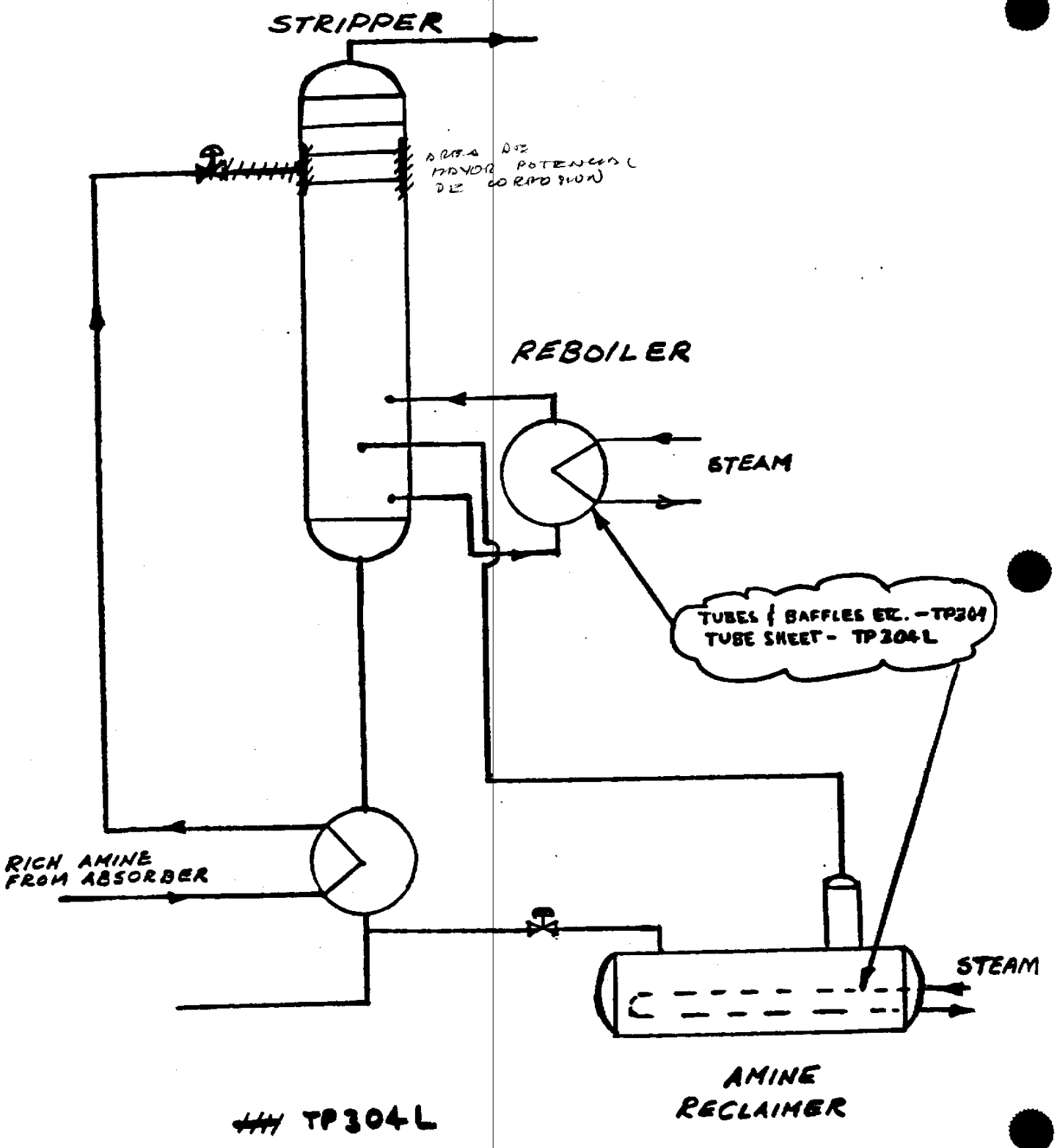


CUMENE UNIT



~~TP~~ TP 316 L

AMINE TREATING



~~###~~ TP304L

8. EXAMPLES

Piping Material Selection Logistics

1. Select hydrogen resistant material - use Design Temperature and Design Hydrogen Partial Pressure to consult Nelson Chart (API Publication 941). In the majority of cases this will result in either carbon steel of 1-1/4 Cr - 1/2 Mo piping.

2. Using Operating Temperature and wt. % sulfur, determine corrosion rate on material selected in step 1), from the "Sulfur Corrosion Data."

   a. If rate for carbon steel is $\geq$ 35 MPY, determine the corrosion rate for 5 Cr - 1/2 Mo.

   b. If rate for 1-1/4 Cr - 1/2 Mo, 2-1/4 Cr - 1 Mo, and 3 Cr - 1 Mo is $\geq$30 MPY, determine the corrosion rate for 5 Cr - 1/2 Mo.

3. Using Operating temperature and mole % H_2S determine corrosion rate from "Trend curves for predicting corrosion rates" of 0-5% chromium alloy steel in H_2S environments at elevated temperatures.

4. Compare corrosion rates anticipated from both wt. % sulfur and mole % H_2S. Use the greater of the two rates for determination as follows:

   a. If pipe is in a hydrogen containing process unit (or where scale carry over is a design consideration such as a feed system to a catalyst bed) use critical service logic - H.5.

   b. For other piping (where scale carry over is not a design consideration) use non-critical service logic - H.6.

8. (Cont'd)

EXAMPLES (continued)

5. Critical Service Logic

   a. Materials of Construction

      1) carbon steel
      2) 1-1/4 Cr - 1/2 Mo
      3) 2-1/4 Cr - 1 Mo
      4) 3 Cr - 1 Mo
      5) 5 Cr - 1/2 Mo
      6) TP 321 or TP 347

   b. Corrosion Allowances - based on anticipated corrosion rates from elevated temperature Sulfur and/or Hydrogen Sulfide corrosion.

      1) 1/16" - where anticipated rate is ≤5 MPY
      2) 1/8" - where anticipated rate is >5 MPY and ≤15 MPY
      3) 3/16" - where anticipated rate is >15 MPY and ≤21 MPY
      4) 1/4" - where anticipated rate is >21 MPY and ≤30 MPY

   c. If anticipated corrosion rate is >30 MPY use TP 321 or TP 347 pipe with 1/16" corrosion allowance.

6. Non-Critical Service Logic

   a. Materials of Construction

      1) carbon steel
      2) 5 Cr - 1/2 Mo

   b. Corrosion Allowances - based on anticipated corrosion rates from elevated temperature. Sulfur and/or Hydrogen Sulfide corrosion.

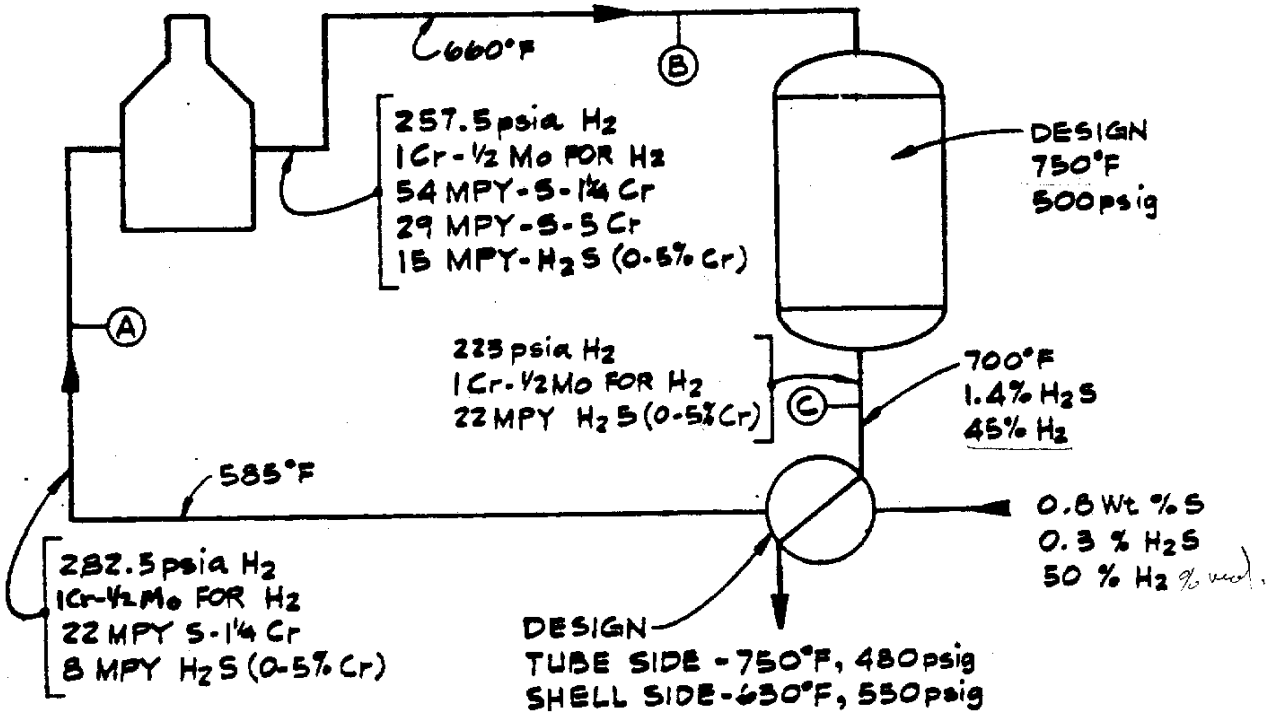
      1) 1/16" - where anticipated rate is ≤9 MPY
      2) 1/8 " - where anticipated rate is >9 MP and ≤19 MP. Also for carbon steel piping operating at a temperature 450°F even if anticipated rate is ≤9 MPY.
      3) 3/16" - where anticipated rate is >19 MPY and ≤30 MPY.
      4) 1/4" - where anticipated rate is >30 MPY.

NOTE: 1 Mil/Year (MPY) = 0.001 inch/year

8. (Cont'd)

EXAMPLE 1

KEROSINE UNIBON COMBINED FEED EXCHANGER



Ⓐ & Ⓒ - 1¼ Cr - ½ Mo - ¼" C.A.
Ⓑ - 5 Cr - ½ Mo - ¼" C.A.
[CRITICAL SERVICE PIPING]

REACTOR - 1Cr - ½Mo OR 1¼Cr - ½Mo LINED WITH ⅛" TP405 OR TP410S.
INLET ELBOW - SAME AS Ⓑ (5 Cr - ½Mo - ¼" C.A.)

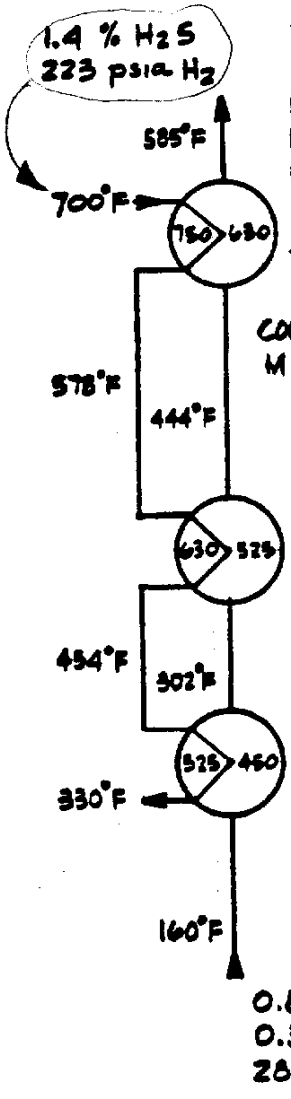
NOTE - WHEN REACTOR CIRCUIT PIPING IS TP321 OR TP347 THE REACTOR IS CONSTRUCTED FROM A BASE MATERIAL TO RESIST HYDROGEN LINED WITH ⅛" TP321 OR TP347. INLET ELBOW IS THE SAME AS THE REACTOR.

$P_{PH_2} = 0.5 \times (550 + 15)$ PSIA
$= 282.5$ PSIA @ T = 630°C

8. (Cont'd)

EXAMPLE 1 (CONTINUED)

KEROSINE UNIBON COMBINED FEED EXCHANGER



	TUBES	TUBE SHEET	CHANNEL	SHELL	BAFFLES
H_2 RESISTANT MATERIAL	1 Cr-½ Mo TP410-9MPY (NOTE 1)		22 MPY 1 Cr-½ Mo	8MPY-H_2S 22MPY-S 1¼Cr-½ Mo 12MPY-S 5 Cr	
CONSTRUCTION MATERIAL	(NOTE 5) TP 304	(NOTE 2) TP 321	(NOTE 3) 1 Cr-½ Mo OR 1¼ Cr-½ Mo LINED WITH TP321/347	5Cr-½ Mo	(NOTE 4) TP 304
H_2 MTL.	1Cr-½Mo 2MPY-TP410		8 MPY 1Cr-½Mo	KC. S. 5MPY-S 2MPY-H_2S	
CONST. MTL.	TP 410 or TP 430	1 Cr-½ Mo or 1¼ Cr-½ Mo		KC. S.	C.S.
H_2 MTL.	KC. S.		2 MPY ON KCS	NIL CORR. ON KCS	C.S.
CONST. MTL.	KC. S.				C.S.

8. (Cont'd)

NOTES TO COMBINED FEED EXCHANGER EXAMPLE

1. Limit total corrosion of tubes to 5 mpy.

2. When tubes are TP304, tube sheet is either H_2 resistant base material lined with 1/8" TP321 or TP347 or solid TP321. Solid TP321 tube sheets are specified when the shell is lined to avoid a double lined tube sheet or when shell is 5 Cr - 1/2 Mo since 5 Cr - 1/2 Mo clad plate is not commonly available.

3. When tubes are TP304, channel is specified as H_2 resistant base material lined with 1/8" TP321 or TP347.

4. When tubes are TP304; baffles, tube supports, tie rods and spacers are specified as TP304 for expansion compatibility.

5. When 300 series stainless steel tubes are required specify TP304; if the tubes are seal welded or strength welded, specify TP321.

The following is a general listing of alloys used for combined feed heat exchanger construction in ascending order:

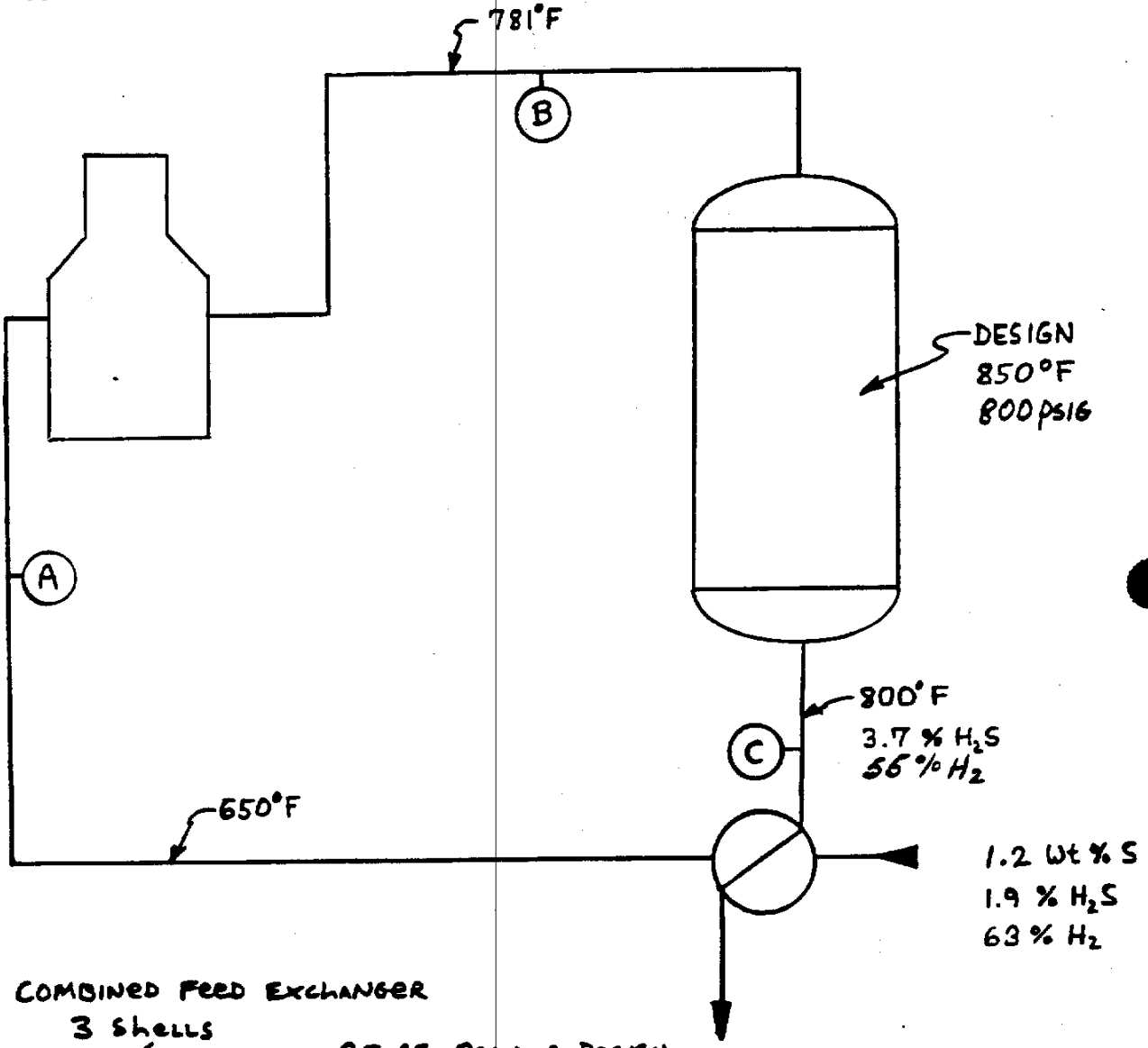
TUBE ALLOYS	SHELL & CHANNEL MATERIALS
	1/8" - 3/16" corr. allw.
Killed Carbon Steel	Killed Carbon Steel
1Cr-1/2 Mo+/1 1/4 Cr - 1/2 Mo	1Cr-1/2 Mo+/1 1/4 Cr -1/2 Mo
2 1/4 Cr - 1 Mo++	2 1/4 Cr - 1 Mo++
3 Cr - 1 Mo++	3 Cr - 1 Mo++
5 Cr - 1/2 Mo	5 Cr - 1/2 Mo
Type 410/430	Hydrogen resistance base material clad with Type 405/410S
Type 304	Hydrogen resistant gase material lined with Type 321/347

\+ 1 Cr - 1/2 Mo is specified as an alternate material for 1 1/4 Cr - 1/2 Mo, if resistant to hydrogen.

++ 2 1/4 Cr - 1 Mo & 3 Cr - 1 Mo are specified only if required for hydrogen resistance, and anticipated corrosion rates are within acceptable limits.

9. PROBLEM

Make material selection for reactor circuit based on information given below.



COMBINED FEED EXCHANGER

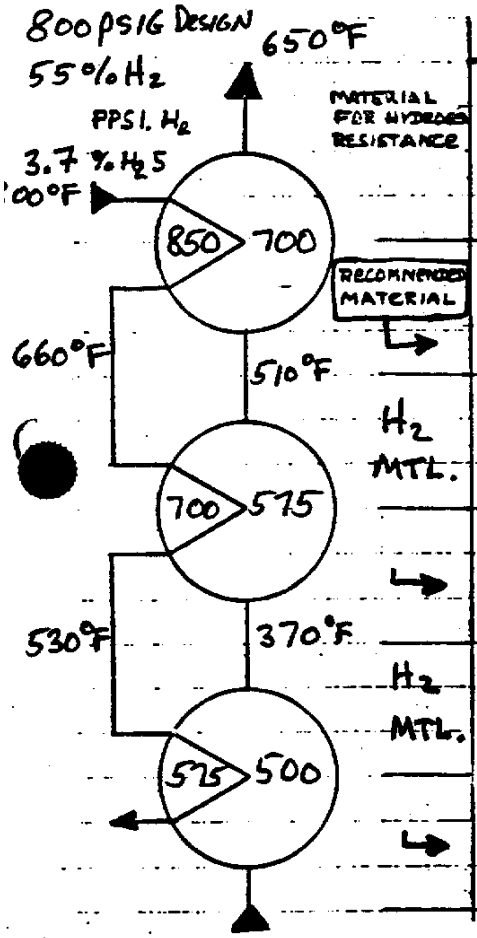
3 Shells

HOT
- Tube side - 850°F, 800 psig Design
- Shell side - 700°F, 850 psig Design

MID
- Tube side - 700°F Design ; 660°F inlet, 530°F outlet
- Shell side - 575°F Design ; 370°F inlet, 510°F outlet

COLD
- Tube side - 575°F Design
- Shell side - 500°F Design

COMBINED FEED EXCH WORKSHEET



	TUBES	TUBE SHEET	CHANNEL	SHELL	BAFFLES ETC
MATERIAL FOR HYDROGEN RESISTANCE					
RECOMMENDED MATERIAL					
H_2 MTL.					
H_2 MTL.					

III. METALLURGY

1. General Comments

Although there are literally hundreds of alloys available, we will discuss the ones commonly used in the refinery and their forms. They are identified by generic type and ASTM Specification number as related to product form and are shown in Section II, Table 1, page 6

The ASTM specifications, developed by cooperative effort from manufacturers, producers and consumers, are those used in this country by industry to provide a consistent quality level of product forms. Different specification numbers are used for the particular type of material to cover the different product forms such as plate, tubing, forgings, castings, etc. These specifications cover the various grades, purchase requirements, manufacturing methods, chemical and mechanical properties, type of testing required, and minimum quality requirements. These specifications are continually being revised as deemed necessary and are issued on an annual basis. The ASME Code has sections (Section II) covering material specifications also and with a few exceptions is identical to ASTM. The quality levels of the various product forms are generally minimum determined to be commensurate with the general applications intended for that particular product. It is up to the materials engineer and/or designer to specify further quality control requirements based on service requirements if deemed necessary. This is usually not the case as the specifications are generally quite acceptable.

Engineering companies, such as UOP, have their own standard specifications, practices, etc., that define applicable codes, materials, fabrication and special design requirements. Job project specifications will show materials required and any special requirements needed not covered in the general standard specifications for the particular process units. Such requirements are altered or changed when found necessary by field experience or new developments.

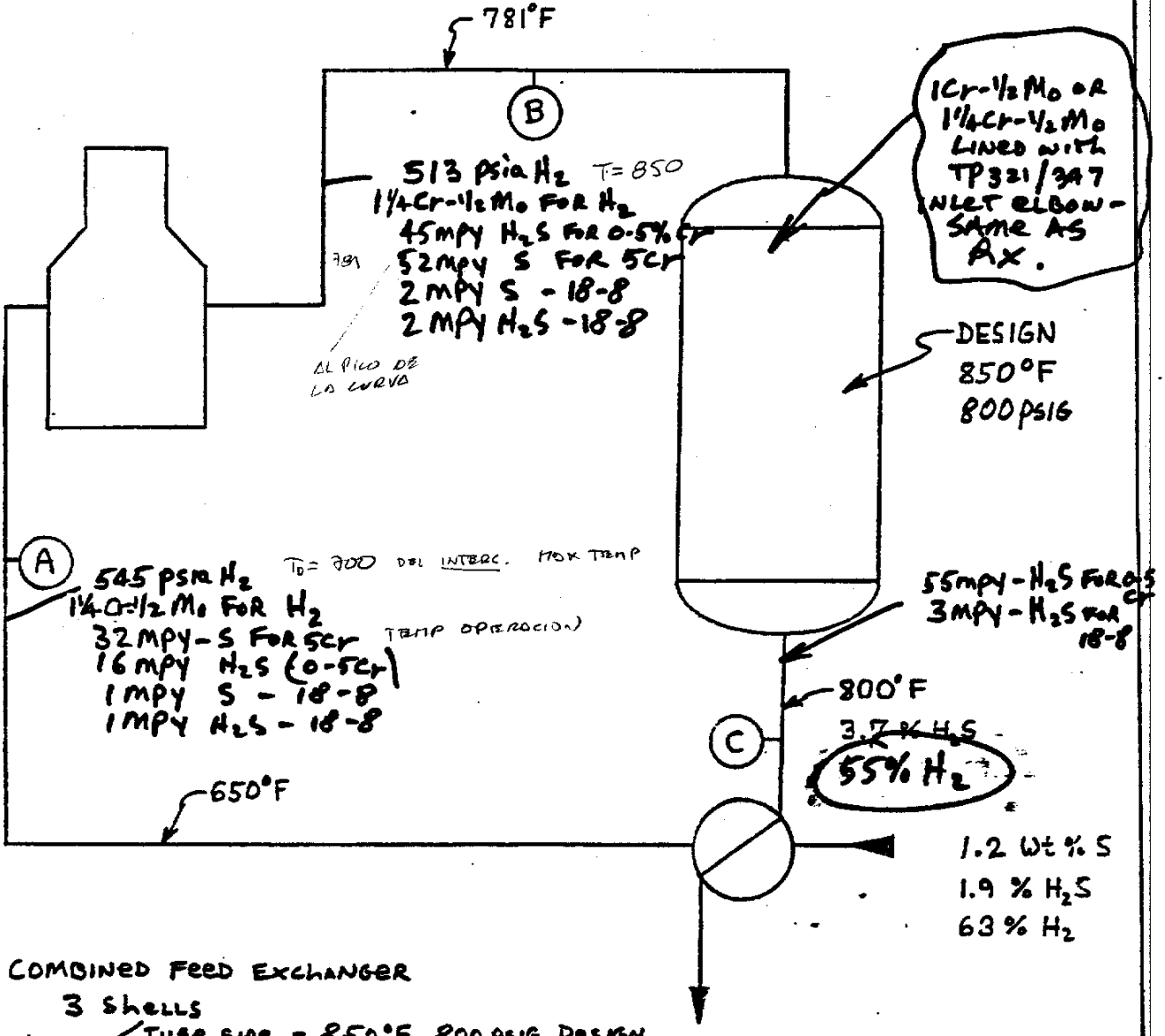
2. Temperature Considerations

2.1 Low Temperature:

In general, carbon steels and alloys have reasonably good ductility and toughness properties in the temperature range commonly used in most applications. However, at low temperatures, steels may suffer from an appreciable loss in impact strength (toughness) and be susceptible to brittle failures. (Refer to Section III-5.5 for discussion on Ductile vs. Brittle Behavior.) For temperatures down to about -50°F the better quality fully killed steels are generally adequate by merely modifying the melting practice during manufacturing plus a normalizing heat treatment to

9½-PROBLEM

Make material selection for reactor circuit based on information given below.



COMBINED FEED EXCHANGER

3 Shells

HOT
- Tube side - 850°F, 800 psig Design
- Shell side - 700°F, 850 psig Design

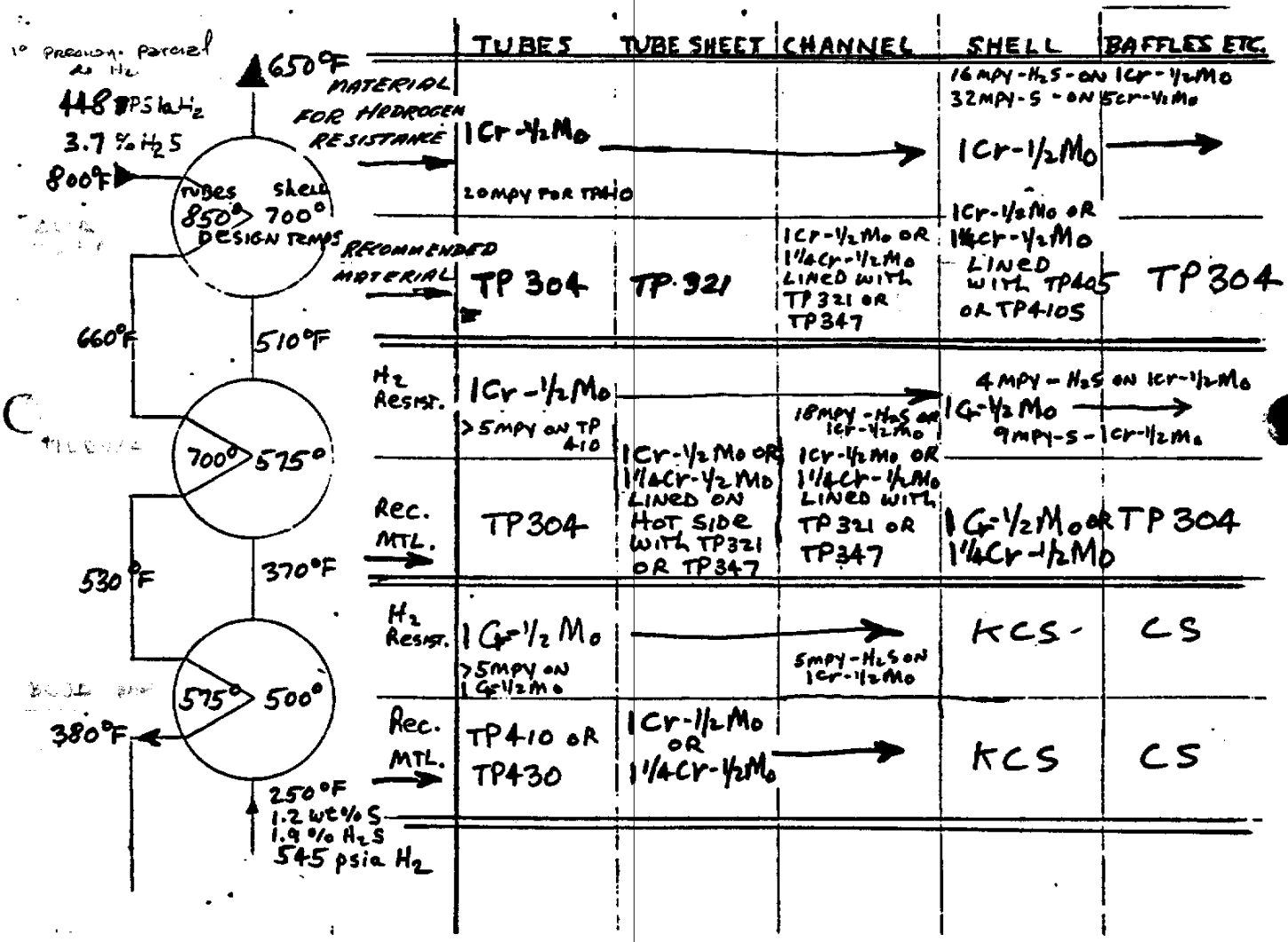
MID
- Tube side - 700°F Design; 660°F inlet, 530°F outlet
- Shell side - 575°F Design; 370°F inlet, 510°F outlet

COLD
- Tube side - 575°F Design
- Shell side - 500°F Design

(A) (B) & (C) - TP321 or TP 347 - 1/16" CA ✓

PROBLEM SOLUTION -

CF/EFF EXCHANGER



2.1 (Cont'd)

provide the toughest grain structure condition. At temperatures below -50°F to -150°F nickel alloy steels containing 3-1/2% Ni provide good properties and below -150°F, the 9% Ni alloy is good although only available in plate form. The austenitic (Cr-Ni) stainless steels, aluminium alloys, some copper base alloys and the high nickel base alloys are good at all the low temperatures with the austenitic Cr-Ni stainless finding the widest application.

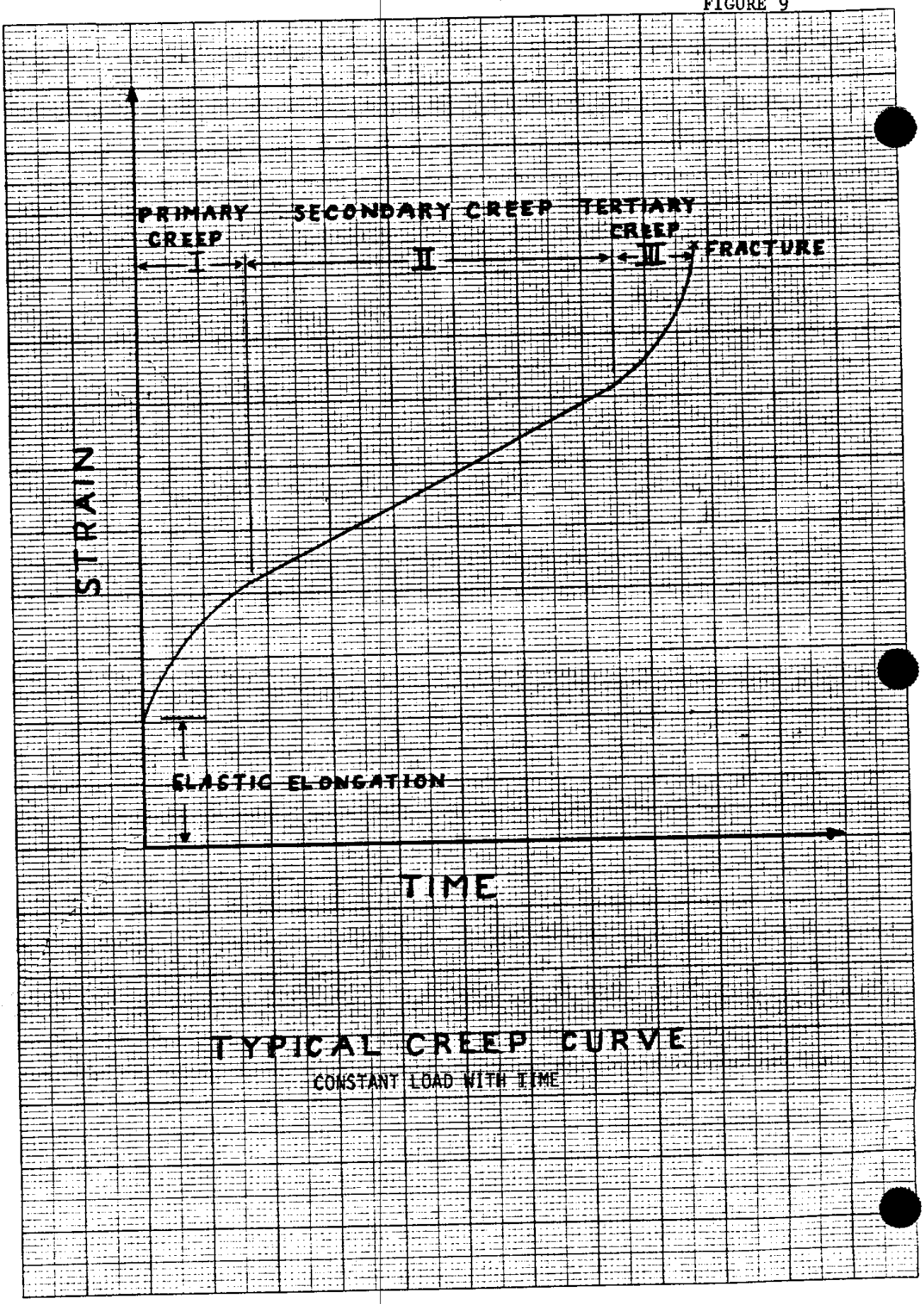
Along with the appropriate material for low temperature use, design and fabrication practices are extremely important to minimize notches. Section II, 3-4, shows the materials-temperature ranges used by UOP.

2.2 Elevated Temperature:

At temperatures above about 650°F tensile and yield strengths are starting to drop and the creep and rupture strengths start to play an important role in material performance. Creep is that phenomenom associated with a material in which the material elongates with time under a constant applied stress. The term "creep" was derived because, at the time it was first recognized, the deformation which occurred at the design conditions occurred at a relatively slow rate. For steels, creep becomes evident at temperatures above about 650°F. Creep becomes an important factor with different metals and alloys at different temperatures. For example, lead behaves similarly to carbon steel at 1000°F, for some of the Cr-Mo alloy steels at 1200°F, and the austenitic stainless steels at 1500°F, and super alloys at even higher temperatures.

Fundamentally, there are three stages of creep, which is measured as strain, (plastic) vs. time; primary (first stage), secondary (second stage) and tertiary (third stage). The first stage of creep generally occurs rapidly and is the original elastic strain plus some short term yielding. The second stage of creep is the steady, uniform plastic strain with time. This creep rate is reported as a percent strain per unit time, such as .01% in 1000 hrs. and is used in design. Third stage of creep is the final stage, when the rate of strain increases rapidly with time to failure. See attached Figure 9 for a schematic creep curve pattern.

FIGURE 9



TYPICAL CREEP CURVE

CONSTANT LOAD WITH TIME

SQUARE 10 X 10 TO THE HALF INCH AS 0813-DT
[GRAPH-PAPER] GRAPHIC CONTROLS CORPORATION Buffalo, New York
Printed in U.S.A.

2.2 (cont'd)

Therefore, depending upon the stress load, time and temperature, the extention of a metal associated with creep finally ends in a rupture failure. Creep-rupture (or stress-rupture) is the term used to indicate the stress level to produce failure in a material at a given temperature for a particular period of time. For example, the stress to produce rupture for carbon steel in 10,000 hours (1.14 years) at a temperature of 900°F is substaintially less than the ultimate tensile strength of the steel at the corresponding temperature. The tensile strength of carbon steel at 900°F in one case is 54,000 psi, whereas the stress to cause rupture in 10,000 hours is only 11,500 psi.

Although strain rate and time will govern the fracture characteristics of metals in the creep temperature range, in almost all cases, creep-rupture fracture will occur around the grains (intercrystalline). Tensile failures below the creep temperature range occur through the grains (transcrystalline) of the metal and is accompanied by considerable grain distortion. See attached Figure 10 which shows a typical intergranular creep-rupture failure in the top photograph and a hot tensile failure in the bottom photograph, showing transgranular failure with reduction in thickness and grain distortion. Such fracture characteristics indicate that at temperatures below the creep range, there is greater strength in the grain boundaries than in the grain itself. As temperature is increased a point is reached at which the grain and grain boundaries are equal in strength. This temperature is called the "equicohesive temperature" Below this temperature, initial deformation is elastic, whereas above this temperature deformation becomes more of a plastic rather than an elastic property.

With this in mind one can generalize that for lower temperatures, a fine grain material metal with greater grain boundary area is best whereas at high temperature a coarse grain material with less grain boundary area is best. This is the main reason that for improved elevated temperature creep strength, metals and alloys are given a heat treatment to produce a coarse(er) grain size. Contrariwise, for lower temperature services, heat treatments to produce fine grain size are used.

Because failure will ultimately occur if creep is allowed to continue, the designer must not only consider stress values used in design such that the creep deformation will not exceed a limiting amount for the contemplated service life, but also that fracture does not occur. In refinery practice, the design stress is usually based on the average stress to produce rupture in 100,000 hours (11.4 years) or the average stress needed to produce a creep rate of 0.01% per 1000 hours (considered to be the same as 1% in 100,000 hours) with appropriate safety factors.

FIGURE 10



Intergranular Creep-Rupture Failure



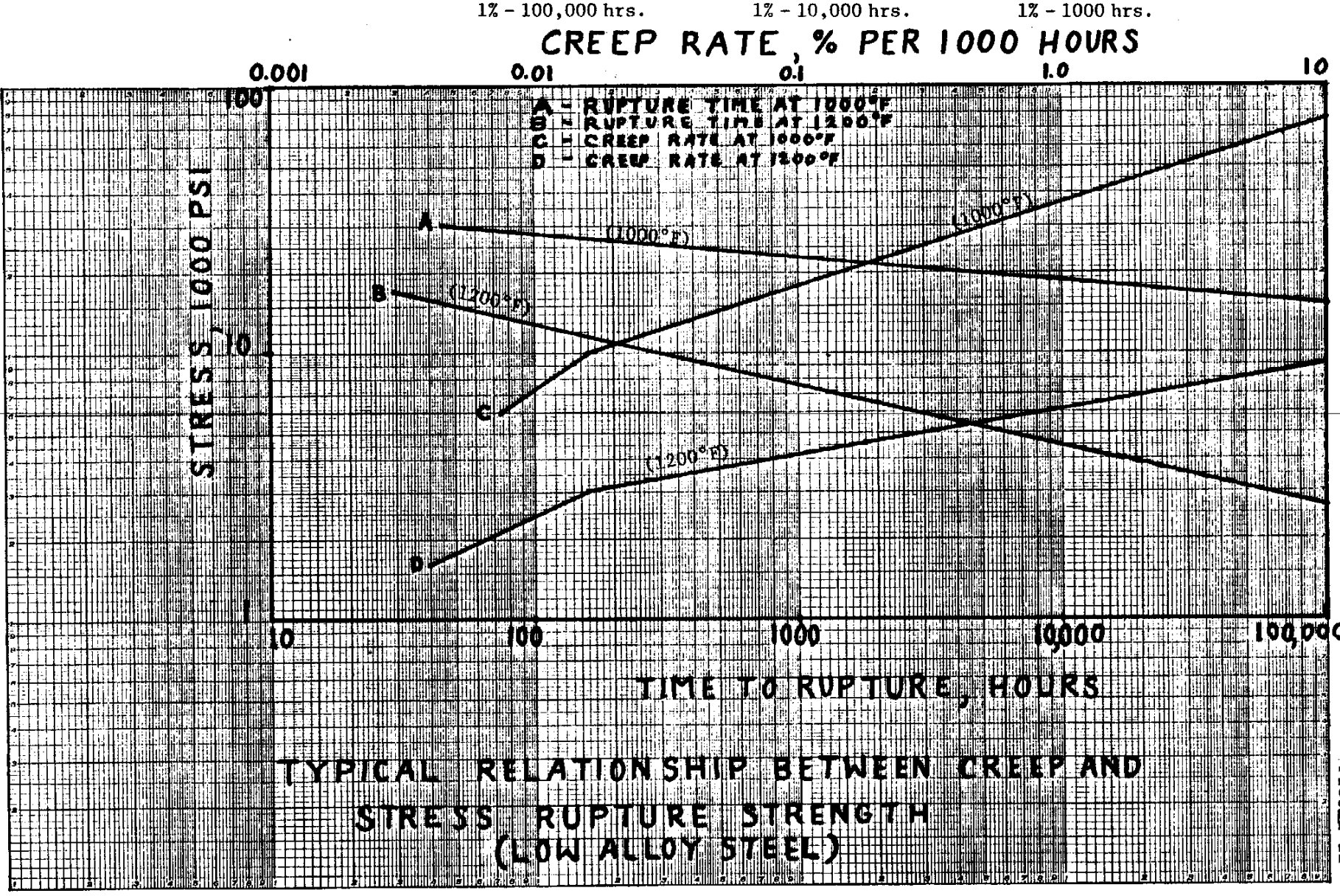
Transgranular Hot Tensile Failure

2.2 (cont'd)

A criterion based on rupture life is easier to determine than low creep rates.

Attached Figure 11 shows typical creep and rupture curves as they are plotted and used for design purposes.

NO. 31,156-R. LOGARITHMIC: 5 BY 3 2-INCH CYCLES (BASE LONG WAY). codex GRAPH PAPER® IN STOCK DIRECT FROM CODEX BOOK CO., NORWOOD, MASS. 02062 PRINTED IN U.S.A.



TYPICAL RELATIONSHIP BETWEEN CREEP AND STRESS RUPTURE STRENGTH (LOW ALLOY STEEL)

FIGURE 11

3. Welding Metallurgy

The mere exercise of striking an arc on or holding a wire in a gas flame to the piece (s) to be welded is by no means the sum and substance of making a satisfactory weld. The requirements and necessity of making joints between metals with the full range of alloys and strength properties along with relatively new and complex welding processes has developed into a separate engineering discipline. The welding engineer therefore needs to have an intimate knowledge of welding methods, procedures, and alloys but most of all welding metallurgy.

The knowledge of welding metallurgy is necessary from the very start of welding where the first problems of oxidation and nitrogen pickup arise to the final operation where the microstructure and resulting mechanical properties may depend on the rate of cooling from a high temperature. Where certain requirements, for mechanical properties or for corrosion resistance must be met by the weldment, a knowledge of metallurgy is necessary in planning the welding procedure and any necessary pre or post weld treatments.

Much of the progress made in welding has come from the practical and scientific application of metallurgical principles. The use of these principles has resulted in greater control over microstructural changes in the weld metal and base metal heat-affected zones. A greater understanding of metallurgy reveals why detrimental microstructures are formed in some metals through rapid cooling from welding and in others, thru slow cooling. The application of sound metallurgical rules has been largely responsible for the elimination of many defects previously common to welding. Answers to many welding problems can be discovered through a study of the fundamentals of welding metallurgy. The results of increased knowledge in welding metallurgy will be reflected not only in the efficiency of the weld joints but in every phase of weldment fabrication.

One of the most, and possibly the most, important factors in the broad and complex field of welding metallurgy is the temperature effect during welding. This is because temperature range and distribution is the primary factor determining the metallurgical response and its effect on changes in mechanical properties and microstructures. Therefore, since mechanical properties and microstructures of welds and HAZ's govern the suitability of the welded component we can see the importance of temperature effects.

Temperature range is generally controlled by the welding parameters used; current, voltage and speed plus the type of welding process used. These parameters are determined for the particular material being welded, the thickness range involved and the required weld joint geometry by developing specific welding procedures. The type of weld metal required plus the need for preheat and PWHT is also determined in the welding procedures. Regardless of the material to be welded, the ASME Code

3 (cont'd)

Section IX (used in this country) sets forth minimum but rather strict requirements for qualifying weld procedures for the entire range of materials. This section of the Code lists the required weld metal chemistry range to be used, tensile requirements, various bend tests and where and how tests are to be taken. Along with qualifying weld procedures, Section IX of the Code also requires qualifying the welders. The best weld procedure in the world can be rendered useless if poor quality unqualified welders are permitted to do the welding.

Essentially all steels and alloys used in the refinery are readily welded, assuming of course, the proper procedures are followed. For the hardenable alloys, such as the straight Cr stainless steels (11-13% Cr) and the Cr-Mo alloys, 1%Cr-½%Mo through 9%Cr-1%Mo, preheat is almost always required as well as PWHT to prevent weld and HAZ metal cracking.

Since alloy usage is for corrosion and/or hydrogen resistance rather than for strength in the majority of cases, the type weld metal deposited should conform alloywise to the base metal being welded. With very few exceptions (Type 321 stainless steel being one), electrode materials are available for all alloys with ranges of matching chemistries.

Aside from imparting comparable corrosion resistance to the weld, similar alloy weld deposits will provide essentially the same mechanical and physical properties after PWHT which is important. Physical properties of main importance are the thermal expansion and conductivity. Great differences between the weld and base metal expansion and conductivity properties leads to both mechanical and thermal stress gradients that, depending on weld joint geometry and weld quality, could lead to eventual cracking failures at the points of greatest stress concentration, i.e., weld root and juncture between weld and base metal.

In some cases, however, dissimilar metal weld joints are required. In the case where carbon steel is welded to the low and intermediate alloys (½Mo and Cr-Mo) or if these alloys are welded to each other, the general approach is to use the weld metal chemistry of the lowest alloy of the joint. However, for all practical purposes, any weld metal falling between the chemistry of the two metals to be joined could be used. The preheat and PWHT requirements of the higher alloy of the weld joint must be followed.

When welds between carbon steel or the Cr-Mo alloys and one of the austenitic Cr-Ni stainless steels needs to be made, higher alloy weld metal is required. Considerable dilution may take place at the weld interface between the weld metal and alloy, resulting in a gradation of Cr-Ni content which could be low enough to lose the good ductile properties of the stainless steel.

Thus, such welds are generally made with the higher austenitic Cr-Ni alloy

3 (cont'd)

weld metals such as Type 309 (25 Cr-12 Ni) or Type 310 (25 Cr-20 Ni). However, these stainless alloys have different physical properties, such as thermal conductivity, resistivity and expansion coefficients than carbon steel or the low alloys. That these differences are appreciable is illustrated schematically in Figure 12 which shows the stainless Cr-Ni alloys to have 50% greater expansion coefficient, about one-third the thermal conductivity and five times the resistivity compared to steel. Therefore, such welds should be limited as much as possible to smooth joint geometry types, such as straight butt welds, and quality of the weld joint is of the utmost importance especially regarding alignment, full penetration and smooth root (initial) weld bead(s). Also, they should not be used in cyclic temperature service or where large fluctuations in temperature are expected.

To eliminate or greatly minimize the problems described above with the Types 309 or 310 welds, the high nickel Inconel Type weld metals are oftentimes utilized since they have expansion coefficients in much closer proximity to the steel or low alloy than the Cr-Ni stainless side of the weld joint. This being the case, the maximum stress is pushed to the more ductile stainless steel side of the joint.

Probably the most outstanding and surprising success story concerning welding of refinery equipment is that of welding the Cr-Mo alloys to each other with the Type 310 (25 Cr-20Ni) weld metal. There are literally thousands of such welds in service for many years at elevated temperatures (the majority being in 5 Cr-½Mo piping and heater tubes) with very few reported failures of the welds. The reason the success is surprising is twofold: the large difference between the physical properties (mainly expansion coefficients) of the two alloys results in the stainless weld acting as a wedge trying to drive the two sides of the joint apart when hot but under appreciable compressive stress due to expansion constraint with reversal to tensile stress during cooling; and the hard, brittle condition of the 5Cr-½Mo alloy HAZ (or other Cr-Mo alloy) with its relatively high propensity to crack formation and propagation. That numerous failures have not occurred is probably due to the good ductility of the 25 Cr-20 Ni weld and its ability to absorb high stress loads without cracking. The few failures that the authors have examined showed that cracking initiated at a gross lack of penetration at the root area with crack propagation through brittle 5 Cr-½Mo (HAZ) juncture between the pipe and weld metal.

Although many such dissimilar weld joints are in service and some refiners still use this type welding to preclude PWHT, we always recommend that similar alloy weld metals be used. Many PWHT methods (and equipment) are readily available today whereas when the majority of the Type 310 welds were made, PWHT was difficult and very time consuming in the field.

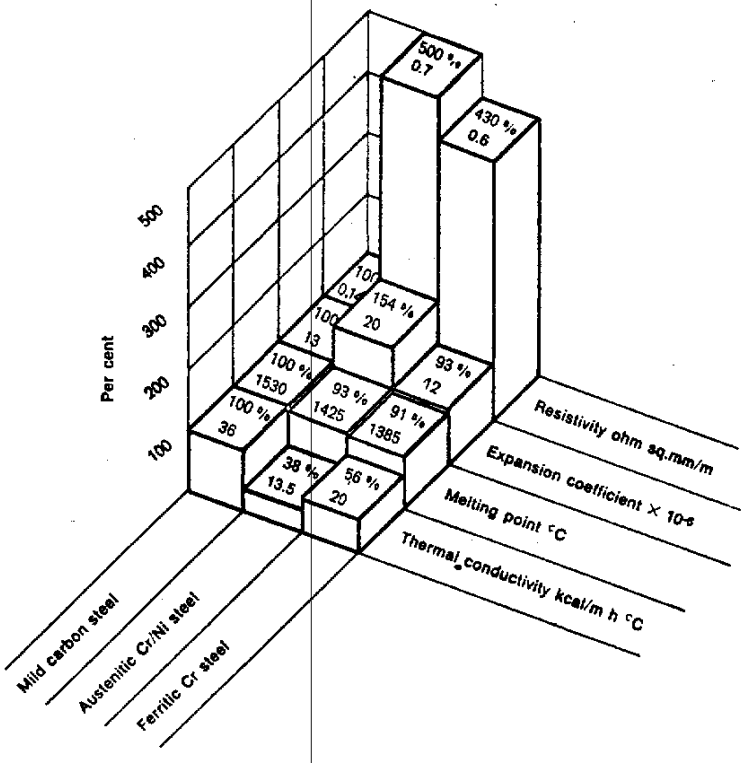
FIGURE 12

PHYSICAL PROPERTIES
OF
AUSTENITIC STAINLESS STEELS VS. CARBON STEEL

The physical properties of the austenitic stainless steels, compared with those of mild steels are shown in the sketch below. The straight Cr stainless steels are also included for comparison purposes. As will be observed, the electrical resistivity of the stainless steels is much greater.

The expansion coefficient of the stainless steels is about 50% higher, while the heat conductivity is about 40% lower. The difference in thermal expansion is shown very clearly. These differences result in greater shrinkage when welding stainless steel compared with unalloyed steel.

When welding these steels, the temperature gradients become steeper adjacent to the welds as a result of the poor thermal heat conductivity, which, combined with the strong thermal expansion, easily leads to high stresses.



3 (cont'd)

Regarding welding electrodes, alloys are available to match materials to be welded with very few exceptions, Type 321 stainless steel being one. Electrodes, either coated or bare, are covered by the ASME and/or AWS specifications. ASME Section II, Part C lists all the electrode specifications.

The welding processes used in the vast majority of cases for refinery equipment are the shielded metal arc (MA), tungsten inert gas (TIG), metal inert gas (MIG) and the submerged metal arc process (SMA). The MA process utilizes coated metal electrodes for manual (hand) welding, the coating providing protection to the molten weld puddle by keeping air away and acting as a fluxing agent to remove impurities. There are several different types of coatings, mainly to control weld deposit flow characteristics, tailored to the current used, AC or DC for arc stability and the position of welding, such as horizontal, vertical, overhead, etc. Coatings are various mixtures and combinations of materials such as titania, various silicious materials, cellulose, ferromanganeses, sodium silicate, calcium and/or potassium components and iron powders. Many of the coatings are very low in H_2 content which is desirable when welding alloys, heavy sections and where maximum weld quality is required. Needless to say, for refinery applications, the low H_2 type electrodes are preferred.

The TIG process (previously call Heliarc) uses bare weld wire and a shielding inert gas, either helium, argon or CO_2 or combinations thereof. The arc producing electrode is a tungsten alloy which is not consumed to become a part of the weld. The filler wire is fed by hand into the weld puddle. This process is more expensive to use although it gives greater penetrating power and allows better control of the molten puddle by the welder. This control results in much smoother weld bead contour which is an advantage when making the first or root pass in weld joints. In the past, this process was used almost exclusively for welding high alloys such as the austenitic Cr-Ni stainless steels since better control and quality was required and deemed necessary. However, in recent years TIG welding has been adapted for carbon steels and the low alloys where improved quality and good smooth inside diameter root bead contour is desirable. It can be used in the field as well as the shop. Most TIG welding is done manually, however, automatic equipment is used in shops for pipe welding and some corrosion resistant weld overlay applications.

The MIG process is also in the generic Heliarc classification although it is a semi-automatic process whereby the bare wire electrode is continuously fed and consumed as part of the weld deposit. Since the process is semi-automatic it is generally limited to shop welding applications and also joints that require greater control or a minimum of weld deposti and dilution penetration. One of the variations, called the MIG Short-Arc process, uses a rapid short circuiting of the arc to provide welding temperature. This process is adaptable to applying high alloy weld overlay to steel base metals, to welding strip linings

3 (cont'd)

to steel equipment, since it has rather shallow penetration and minimizes heat input to the base metal. It is used in some pipe fabrication shops for making the root pass or the entire weld. However, since weld penetration is limited and sometimes difficult to control, its use for making quality strength welds is sometimes questionable. With the probability that zones of lack of penetration at edges of the weld joint and between weld layers, called "cold-laps", may be produced, X-Ray quality welds may be difficult. Although many completely satisfactory welds have been and are being made with the MIG short-arc process, the possibility still exists of developing cold-laps thus strength welds in piping for critical type services should be made preferrably by the TIG and MA process.

The SMA process is used in fabrication shops for making the butt welds in vessels, exchangers, etc. It utilizes either a single or multiple bare wire feed into the weld joint and is completely submerged under a granular flux for protection. The process is automatic although a welding operator is required and can manually adjust current, voltage, wire feed and speed parameters as necessary. The process is adaptable to a broad range of thicknesses which require multiple passes. Such welds are characterized by good penetration and smooth surfaces. The wire(s) is continuously fed automatically from a reel. The flux, which may be neutral or contain some alloying elements, is also continuosly fed thru a funnel slightly ahead of the wire feed. The excess and some of the fused flux is removed shortly after the weld pass automatically solidifies and dropped into a container. It is common to reuse neutral fluxes after careful screening to remove fused particles however reuse of alloy containing flux is not recommended unless very careful screening is done to make assurance that all fused flux is removed and chemical analysis are taken of representative samples of the screened flux to confirm required alloy content.

Another welding process worthy of mention is the electroslag process. This process is used predominantly for making longitudinal (vertical) welds in heavy wall pressure vessel cylinders. After the cylinders are rolled to the required diameter, a rather wide gap is left between the edges to be joined. The cylinder is placed on one end positioned close to the vertical boom supporting the weld head which rides up (and down) on the boom. With appropriate backing plates on both faces of the weld and at the bottom molten weld metal is fed into the weld groove from multiple bare electrode wires moving progressively upward until the entire weld joint is finished. The main advantage of this process is speed and the elimination of multiplicity of weld layers required by the SMA process. Since the weld metal is essentially a casting it has a very coarse grain structure which lacks ductility and toughness. Thus, such electroslag welds require a normalizing heat treatment to refine grain structure prior to any further fabrication steps.

3 (cont'd)

Two applications of welding not connected with making strength joints between two components, are that of weld deposit overlays for corrosion and/or abrasion resistance. All the welding processes mentioned above (except electroslag) are adaptable to weld overlay application. For required corrosion resistance some heavy wall reactors are overlayed with Cr - Ni stainless alloys, usually TP 308L, 309, and 347 either in combination or singularly depending on thickness required and specific weld procedure used. Most of the heavy wall desulfurization type reactors are lined in this manner for resistance to S/H_2S corrosion. Many field applications of manual weld overlay are done, one example being in HF alkylation units where carbon steel is overlayed with Monel for protection against HF acid.

Regarding weld overlay for abrasion resistance, commonly referred to as hard facing or surfacing, for abrasion resistance, high carbon, high Cr, iron base weld deposits are used on FCC components to resist catalyst abrasion. At temperatures above 1000°F, the high carbon, Cr, cobalt cobalt base alloys are generally used. Catalyst carrying lines, cyclones and slide valves are the components utilizing the various hard surfacing alloys.

Weld joint design details are also very important in the satisfactory performance of weld joints. Incomplete weld penetration, sharp corners, excessive undercutting, etc., can increase local stress concentrations to the point where cracking can be initiated and propagated under many stress situations. Under cyclic stress conditions, either from thermal or mechanical means, fatigue failures can occur at weld geometries conducive to stress concentration.

Appendix 3 shows recommended weld metals for various alloys and combinations.

4. Heat Treatment

The primary purposes of heat treatments are to reduce residual stresses or to effect changes in the metallurgical structure.

Where the reduction of residual stresses in welds or mechanically strained components is the primary consideration, an improvement in the resistance to service environments involving the following is desired:

1. Fatigue loading (mechanical or thermal)
2. Brittle fracture conditions (usually at low temperatures)
3. Stress corrosion cracking/hydrogen embrittlement
4. Localized corrosion
5. Geometrical and dimensional stability

Heat treatments to produce desired metallurgical changes may be made to provide:

1. Homogenization of the structure
2. Solution of specific phases
3. Stabilization of specific phases
4. Age hardening
5. Formation of specific structures

The results may be hardening, strengthening, softening, improved formability, better weldability or other properties.

The various heat treatments to facilitate the above purposes are identified generically as:

A - Annealing
B - Normalizing
C - Quenching
D - Tempering
E - Preheat
F - Post Weld Heat Treatment - PWHT

There are many modifications of the above and the terminology may be slightly different dependent on the specific objective of the heat treatment. We will discuss these and the connection with the above defined purposes of heat treatments.

A. Annealing is carried out temperatures generally between about 1500°F and 2000°F (or over) depending on the material being heat treated. Cooling from the annealing temperature is generally done slow in the furnace and results in a material with relatively coarse grain size, the softest and the lowest strength condition with maximum ductility, and in the ferritic steels reduced toughness properties at ambient and lower temperatures. The slow cooling used results in a very stable homogenous structure, which is desirable for most aspects of fabrication requiring changes in shape and/or dimensions. When treatment is used for solution of specific phases, a rapid cool is generally required to keep these phases in solution. This is called a solution anneal and is often used for the austenitic Cr-Ni stainless steels for carbon solution and retention.

Along this same line, the problem with carbide instability and precipitation at grain boundaries is greatly reduced by using the stabilized grades of stainless steel, Type 321 with Ti and Type 347 with Cb.

4. (cont'd)

However, for these elements to be effective, a stabilizing heat treatment is generally required which allows formation of and precipitation of Ti and/or Cb carbides in preference to Cr_4C.

Temperatures generally used for stabilization heat treatments range between 1600°-1800°F for Type 321. It generally takes two to four hours at 1600°F and one-half hour at 1800°F therefore economics would generally dictate the higher temperature. For Type 347, stabilization is generally done about 100°F higher due to the more rapid rate of formation and precipitation of CbC at this higher temperature level.

Other types of annealing treatments or modifications are used for purposes such as to minimize stress corrosion cracking in severe environments when maximum softness and reduction in residual stresses are needed and to provide improved creep-rupture strength. Annealing at the lower temperature range is used for some alloys of aluminum, nickel, etc. for purposes of precipitating specific phases and/or compounds for strengthening purposes. This is termed age hardening.

B - Normalizing is carried out more in the middle range of temperatures shown for annealing. This treatment utilizes an air cooling which results in a finer grain size. The carbon and low alloy steels are given this treatment to enhance toughness properties when improved impact strength is required for low(er) temperature service, for improved fabricability of heavy sections and for construction code requirements.

C - Quenching is similar to Normalizing although a much more rapid cooling is used, water or oil is generally used as the quenching medium. This treatment results in the highest hardness, tensile and yield strengths, much lower ductility and toughness. Because of this, quenched materials must and are always tempered. The low alloy steels are used quite often in this heat treated condition because of their tremendous ability to attain high strengths and maximum toughness.

D - Tempering is a lower temperature treatment done in the range from about 800°F to 1300°F, the temperature based on the desired properties. As the tempering temperature is increased, the tensile and yield strengths decrease and the ductility and toughness increase. As mentioned above, tempering treatments are necessarily given to quenched materials and often times to normalized materials. For the low alloys, these treatments give the best possible combination of strength and toughness.

E - Preheat is the treatment given to materials being welded, either because ambient temperatures are low, are of heavy thicknesses or the material is very hardenable such as the Cr-Mo alloys. The objective of preheat is to retard cooling rates and temperature gradients in the weld area and adjacent metal thus reduces stresses and increases ductility in the weld HAZ. Preheat temperatures may range anywhere from 100°-600°F depending on alloy content, thickness and weld joint geometry. Generally, unless thickness is great and joint geometry would cause severe stress concentrations at corners, etc., the low and intermediate carbon steels, the austenitic Cr-Ni stainless steels such as Types 304, 316, 321, 347, etc., the nickel alloys, etc., do not require preheat. The hardenable alloys such as the Mo and Cr-Mo alloys require preheat in almost all thicknesses.

4. (cont'd)

If weldments are not preheated when required, the problem of cracking in both the weld and/or HAZ's is likely and probable.

F - Post Weld Heat Treatment (PWHT) is done to relieve residual tensile stresses, restore ductility, reduce hardness and improve toughness properties. This heat treatment is probably the most widely used and most important in petroleum industry equipment. Even though construction codes may not require heat treatment, many environments in the refinery may lead to localized corrosion, stress corrosion cracking and/or hydrogen embrittlement. PWHT of steels and alloys is one relatively simple method to prevent such problems. Also, since fatigue failures and brittle fracture of metals at low temperatures can be aggravated by both metallurgical and mechanical notches that provide locations for stress concentration, the PWHT will effectively reduce or relieve the residual stress condition and alter the structure to reduce the probability of a metallurgical notch contributing to failure.

Regardless of heat treatment used or the purpose for same, it is extremely important that adequate controls are utilized to provide uniform heating and cooling rates and that the right temperature range is attained and held for the required length of time. Proper heat treatment is as essential to a soundly fabricated refinery process equipment system as are good design, forming, and welding procedures. Many service failures can be ascribed to careless or improper heat treatments, or to the elimination of heat treatment where it is, or should have been called for.

The attached Table 2 lists recommended temperatures for some of the various heat treatments of the commonly used alloys. This data is basically that used for piping materials and the P Numbers shown are those used for identifying alloys or groups of alloy ranges by the Codes. For vessels manufactured of the Cr-Mo alloys, lower PWHT temperatures in the range of 1225°F-1325°F are permitted and acceptable for the higher tensile and yield strength condition (Normalized and/or Quenched and Tempered) providing the toughness and hardness requirements are met.

The methods of heat treatment, whether in the shop or in the field, are numerous however fall into three major categories: gas, electric and exothermic.

Gas is by far used the greatest extent because of cost and ease of adaptability. Natural gas is recommended since in most instances is low in sulfur compounds and has good thermal input. For field heat treating, low sulfur propane is sometimes used where availability of natural gas is limited. Large (or small) shop heat treating furnaces use gas almost exclusively. Field heat treating of small weldments such as pipe welds, can be done by gas burners. Complete vessels or parts of vessels can be field heat treated using both low and high velocity gas burners placed inside the vessel with location of burners and baffling placed strategically to facilitate distribution of flame pattern and provide uniform heating and temperature distribution.

4. (cont'd)

Both resistance wire and induction coils are used in electric heat treating. Special designed elements made with high resistivity wire are adaptable to almost any weldment regardless of size or geometry. One great advantage of the resistance type heat treating elements is that most of them can be used for both preheating and PWHT of welds and temperatures can be controlled quite accurately since the heat source is in direct contact with the work piece. Resistance elements can generally be used many times.

The electric induction type heat treating is generally limited to simple butt joints in piping since the induction coil has to surround the weld. This method is readily adaptable to field heat treating applications and may have the advantage of being simpler to set up and require less power than the resistance methods. For field treating, a welding machine or a series of machines are generally used to provide the electric power requirements.

Exothermic materials are used quite successfully for PWHT of field welds. Specially designed kits containing the exothermic material and insulation are made to fit particular weld joint configurations and are tailored to provide the required temperature for the alloy being heat treated. Generally, such heat treating methods are used only for piping component welds although some small vessels have been done successfully. One of the biggest advantages of this method is that many kits can be put in place by a minimum of personnel and lit off together with no continuous monitoring required. This allows numerous welds to be PWHT simultaneously. When ordering the exothermic kits, it is of extreme importance that the manufacturer of the kits be provided with information identifying type of alloy, size, thickness, geometry, required PWHT temperature, hold times and cooling rates required.

Regardless of heat treating method, sufficient thermocouples need to be used for controlling and monitoring temperatures.

TABLE 2

RECOMMENDED TEMPERATURES FOR PREHEAT, POST WELD HEAT TREATMENT, HOT FORMING, AND HEAT TREATMENT AFTER HOT FORMING.

P Number	Material Group	Preheat Temperature, °F [1]	Post Weld Heat Treatment [6]			Hot Forming Temperature °F	Heat Treatment After Hot Forming	
			Metal Temperature, °F	Holding Time, Hr/in. Wall Thickness	Holding Time, Minimum, hr		Temperature, °F	Holding Time, Hr/in. Wall Thickness
P1	Carbon steel	not req'd [2]	1150-1250 [3]	1	½	1400-2000	May be necessary on heavy wall thickness or if heat for hot forming was uneven.	
P2	Wrought iron	not req'd [2]	—	—	—	1400-2000	—	—
P3	Maximum alloy: ¾% Cr; 2% total	300-600	1275-1350 [4,5]	1	1	1500-2000	1275-1350	1
P4	Maximum alloy: ¾-2% Cr; 2¾% total	400-600	1300-1400 [5]	1	1	1600-2000	1300-1400	1
P5	Maximum alloy: 2-3% Cr	400-600	1300-1450 [5]	1	1	1600-2000	1300-1400	1
	Maximum alloy: 10% total	500-600	1300-1425	2	2	1600-2000	A:1550-1600 [7] N:1650-1700 [7] T:1300-1425 [7]	1 [10] 1
P6	Martensitic stainless	500-700	1400-1500	1	2	Varies with alloy and application.	1400-1500	1
P7	Ferritic stainless	not req'd	not req'd [8]	—	—	1500-1900	not req'd [8]	—
P8	Austenitic stainless	not req'd	not req'd [8]	—	—	1500-2100	not req'd [8]	—
P9	Nickel alloy	300-500	1200-1300	1	1	1600-2000	1200-1300	1

[1] Use lower temperature for sections up to ½-in. thick and higher temperature for sections over 2-in. thick, with intermediate temperatures for intermediate thicknesses.

[2] If the ambient temperature is less than 32°F, local preheating so that material is warm to the touch is required. Preheat may be desirable where the carbon content exceeds 0.30%, particularly in heavier wall thicknesses.

[3] Post weld heat treatment is not required for carbon steel if its thickness is less than ¾ in.

[4] Post weld heat treatment is required for ½ per cent molybdenum steel if its thickness is less than ½ in.

[5] Post weld heat treatment is not mandatory for socket welds and butt welds of joints 4 in. OD and less and wall thicknesses of less than ½ in. for all P3 and P4 groups and the 2¼ and 3 per cent Cr materials of the P5 group.

[6] The heating rate up to 600°F is optional; above 600°F, it is optional for light wall thicknesses. However, for pipe wall thicknesses over 1 in. for the P1-P3 groups, over ¾ in. for the P4-P5 groups (to 3 per cent Cr), and over ½ in. for the P5-P6 groups, the following heating and cooling rates above 600°F apply: For induction heating up to 1½-in. wall thickness, the maximum rate is 500°F per hr for both 60 and 400 cycles; for wall thicknesses of 1½ in. and above, the maximum rate is 500°F per hr for 60 cycles and 400°F per hr for 400 cycles. For furnace, gas, electric resistance, and other surface heating methods, the maximum rate is 400°F per hr, or 400°F per hr divided by one-half the wall thickness, whichever is smaller.

[7] Heat treatment after hot forming involves either annealing (A) or normalizing (N) and tempering (T) at the temperatures shown.

[8] Post weld heat treatment may be desirable for some grades to improve ductility.

[9] Annealing heat treatments may be necessary for some grades to improve corrosion resistance in specific environments.

[10] With furnace cooling at 50°F per hr to 1100°F.

[11] With air cooling.

Postheat Temperatures for Various Base-Metal Combinations.

	C-steel	C-Mo	½ Cr – ½ Mo	1 Cr – ½ Mo	1¼ Cr – ½ Mo	2 Cr – ½ Mo	2¼ Cr – 1 Mo	5 Cr – ½ Mo	7 Cr – ½ Mo	9 Cr – 1 Mo	18-8 Stainless
C-steel	—	B	C	C	D	D	D	E	E	E	A
C-Mo	B	B	C	C	D	D	D	E	E	E	A
½ Cr – ½ Mo	C	C	C	C	D	D	D	E	E	E	A
1 Cr – ½ Mo	C	C	C	C	D	D	D	E	E	E	A
1¼ Cr – ½ Mo	D	D	D	D	D	D	D	E	E	E	A
2 Cr – ½ Mo	D	D	D	D	D	D	D	E	E	E	A
2¼ Cr – 1 Mo	D	D	D	D	D	D	D	E	E	E	A
5 Cr – ½ Mo	E	E	E	E	E	E	E	E	E	E	F
7 Cr – ½ Mo	E	E	E	E	E	E	E	E	E	E	F
9 Cr – 1 Mo	E	E	E	E	E	E	E	E	E	E	F
18-8 Stainless	A	A	A	A	A	A	A	F	F	F	—

A. Postheating not usually required.

B. Postheating required where carbon content exceeds 0.20 percent or with sections over ½ in. wall thickness. Heat to 1150° to 1250° F for one hour per inch of wall thickness. No postheating required for socket-type joints.

C. 1200° to 1300° F for one hour per inch of thickness, except not required on: (1) Valves 2 in. and smaller, (2) piping or tubing with a diameter of less than 4 in. and wall thickness under ⅜ in. and (3) socket-type joints.

D. 1275° to 1350° F for one hour per inch of thickness, except not required on: (1) Valves 2 in. and smaller, (2) piping or tubing with a diameter of less than 4 in. and wall thickness under ⅜ in. and (3) socket-type joints.

E. 1300° to 1375° F for one hour per inch of thickness. Cool to preheat temperature or below before applying postheating.

F. Not required for sections up to ½ in. wall thickness. Sections over ½ in. wall thickness heated to 1300° to 1375° F for one hour per inch of thickness.

5. Metallurgical Factors in Service

The question of what material to use for a particular service is usually answered by considering the following factors:

a) Temperature and Pressure
b) Environment - Corrosion resistance required
c) Strength properties required
d) Economics

These above factors can be fairly well defined for a specific application with the known properties, corrosion resistance and cost of the materials being considered. However, along with the strength and chemical resistance properties, there areintrinsic metallurgical qualities peculiar to some steels and alloys that need consideration when considering their application. Some worthy of mention are as follows:

5.1 Carbide Precipitation, Sensitization: This phenomenon occurs in the unstabilized or non-low carbon grades of the austenitic Cr-Ni stainless steels such as Types 304 and 316. When these alloys are held in the temperature range of 800°-1600°F, because of the insolubility of Cr_4C, they will precipitate out at the grain boundaries with the resulting depletion of chromium adjacent to the boundaries. In severe cases, a continuous carbide envelope forms around each grain, drastically reducing corrosion and/or cracking resistance in some environments. The effect on room and elevated mechanical properties is nominal although impact strength is lowerd at very low temperatures (under -320°F) . When such intergranular precipitation may cause a reduction in service performance or life, susceptable materials should not be used, or operating and/or maintenance practices should be adopted to negate problems. This is discussed more thoroughly in sections III-4-Heat Treatment, and IV-2.5 - Intergranular Corrosion.

5.2 885°F Embrittlement: This phenomenon is peculiar with the straight Cr ferritic stainless steels with Cr content over 15% (and possible 13% when aluminum is present such as Type 405) when heated in and held in the temperature range of about 700°-1050°F. The 885°F name was given because embrittlement seems to be the most severe between 875° and 900°F. Although the exact cause is still unknown, it is postulated that complex chromium compounds precipitate out which results in room temperature brittleness after exposure at temperature. Therefore, when room temperature ductility is required, the use of the ferritic stainless steels over about 13% should not be used over 700°F.

5.3 Sigma Phase Embrittlement: This type of embrittlement is peculiar to some of the austenitic stainless steels and the higher Cr ferritic stainless steels. Alloys so sigmatized suffer from a loss of ductility at ambient temperatures (<500°F). Sigma-phase formation, which is an intermetallic compound of iron -chromium, may occur in the susceptable alloys during long time service exposure between about 1050°F and 1600°F. The presence of considerable amounts of sigma phase can result in serious embrittlement at atmospheric temperatures. The temperature range and rate of sigma formation

5.3 (cont'd)

is affected to varying degrees by composition, metallurgical structure and deformation. For example, sigma forms much more slowly in the 18 Cr-8 Ni Type 304 fully austenitic alloys than in the higher Cr-Ni alloys such as the 25 Cr-20Ni Type 310 and 25 Cr-12Ni Type 309. Generally, regardless of exposure time or temperature, sigma will not appear in Type 304 in detrimental proportions. Sigma will form more readily in the grades containing Mo, such as Type 316, and Cb, such as Type 347.

Sigma phase can also form in the higher Cr ferritic stainless steels such as the 17 Cr Type 430 and the 27 Cr Type 446, however these grades are rarely used in refinery applications in the temperature range where sigma forms.

For the austenitic grades, despite the fact that sigma can form, very little, if any, effect on their elevated temperature properties occur plus the fact that very few failures have been reported that were found to be caused by sigma. Thus, these alloys continue to be used without too much concern with the sigma phase phenomena.

5.4 Graphitization: This has occurred in some carbon steels and ½ Mo alloys when exposed for long periods of time in the temperature range of about 850°-1100°F. The problem is manifested by the breakdown of iron carbide into iron and carbon with the carbon precipitating as graphite. The most harmful form of graphite is in the elongated form that could form into a "chain" along side welds and areas of high strain (bends, etc). In this form, the material becomes quite brittle. Fine grained and fully killed steels (killed with aluminum) are those most susceptable. The use of the silicon killed steels or those alloys containing chromium will eliminate the problem(or limit service temperature to 850°F).

5.5 Ductile vs. Brittle Behavior: Steel is generally considered to be a ductile material and when overloaded gives a warning by flowing plastically before rupturing. However, steels sometimes fail in a brittle manner without prior warning with little plastic flow and the energy required to propagate the fracture appears to be quite low. Three conditions control this tendency for steel to behave in a brittle fashion. These are: 1) high stress concentration caused by notches, internal flaws or sharp changes in geometry, 2) a high rate of straining; and 3) low environmental temperatures. These three factors are so interrelated that the determination of the effect of any one of them provides an indication of how the steel will react to the intensification of either or both of the others. The effect of lowering the testing temperature is the condition most convenient to measure quantitatively. Therefore, the transition from ductile to brittle behavior of a steel is generally expressed in terms of temperature. "The transition temperature for any steel is the temperature above which the steel behaves in a predominantly ductile manner and below which it behaves in a predominantly brittle manner." Steel with a high transition temperature is more likely to behave in a brittle manner

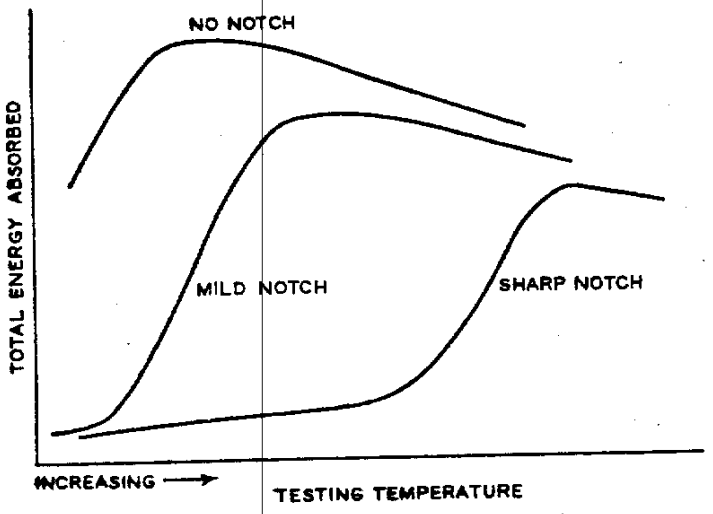
5.5 (cont'd)

during fabrication or in service. The transition temperature is commonly referred to as the NDT, Nil Ductility Temperature.

It should be recognized that there exists no one "transition temperature" for a given steel except for a particular set of conditions and one criterion of brittleness. Each particular forging, pipe or plate from a given steel will exhibit a range of temperatures in which the fracture shifts from ductile to brittle. This range may be varied considerably by changing the metallurgical and mechanical properties of the steel. Metallurgical factors, such as deoxidation practice, chemical composition, rolling, forging or extruding practices and subsequent heat treatment, influence transition temperatures of steel. Steels under the worst condition, may have a transition temperature above 200°F, and under the best condition below -100°F. Steels which have been fully annealed are in the poorest condition to resist brittle failure. Normalizing provides improvement, with further improvement by tempering and/or stress relieving after welding. Optimum properties are obtained by fully quenching and tempering to moderate strength levels.

Although there is no single test that will measure a materials resistance to brittle failure, especially with regards to its behavior in an actual fabricated structure, the influence of such factors as design, workmanship, surface notches, welding quality, restraints, and stress distribution, the charpy V-notch test is generally used. These tests require notched specimens and permit comparison of the various types and grades of steel and provide knowledge of the approximate relation of such factors as thickness, chemical composition, deoxidation practice, sharpness of notches, heat treatment, etc. to fracture characteristics and impact energy/temperature relationships.

The presence of notches (or notch sensitivity) will effect transition temperature. The greater the severity (sharpness) of the notch, the higher the transition temperature regardless of criterion used. A steel which contains extremely severe notches will fail in a brittle manner at higher temperatures than if less severe notches were present. This is illustrated below:



Effects of notch severity on the transition temperature.

5.5 (cont'd)

It should also be noted that where service conditions impose a triaxial state of stress as in internally loaded vessels, brittle behavior may be encountered even in the absence of notches. This is accentuated as thickness increases.

5.6 Temper Embrittlement: Along similar lines of the phenomenon of ductile vs. brittle behavior discussed in the prior section (III 5.5), some alloy steels suffer from a temper embrittlement phenomenon which manifests itself in a similar manner, a change in the transition temperature.

The following is a brief description of the phenomena and suggested means to avoid problems from same.

Temper embrittlement can be defined as an upward shift in the Charpy V-notch impact energy absorption and fracture appearance curves to higher temperatures when a heat treated alloy steel is either slow cooled through the temperature range of 1100°F to 700°F or held for long periods of time in this range. This phenomenon is also identified as an upward shift in ductile to brittle transition (NDT) temperature. The Charpy transition temperature (NDT) is also defined as the temperature below which gross defects or cracks may propagate in a fast, brittle nature and above which the same defects will be arrested due to the inherent toughness of the material. Loading and stress levels also control. The embrittlement is reversible with short time heating above 1100°F followed by rapid cooling through the embrittling temperature range.

Theories as to the cause of temper embrittlement center mainly on the role of impurities such as As, Sb, P and Sn. Large amounts of Mn and Si, increased austenitic grain size, and microstructure (heat treated condition) also effect tendency toward embrittlement and extent of upward temperature shift of NDT. This phenomenon may be seen in all product forms of a given alloy including weld metal. Automatic submerged arc welds seem to have the greatest susceptablility toward embrittlement.

Alloys may develop some degree of temper brittleness during exposure to service temperature and result in greater susceptability to brittle fracture. Of chief concern is heavy wall equipment, such as vessels during startups, and shutdowns. Some vessel designs utilized enhanced properties developed by heat treatments such as normalizing and tempering and quenching (accelerated cooling) and tempering, whereas other designed vessels used annealed properties. Although these different heat treated conditions result in different degrees and rates of embrittlement, the final NDT transition temperature is about the same for all conditions. What this all means is that where an acceptable impact strength, say 30-40 ft.-lbs., was required at a +50°F temperature in original design, after long time exposure in the temperature range of 700°F-1100°F a temperature from 50°F to 300°F may be required to produce the same impact strength. See attached Figure 13 for schematic illustration of this temperature shift. The inherent toughness of the material

5.6 (cont'd)

is not lost, but the normal, expected loss in toughness at relatively low temperatures occurs at higher temperatures. Temper embrittlement seems only to manifest itself during relatively high strain rates, such as would occur during an impact test, and not during slow strain rates, such as in tensile testing. The unknown precise (and unresearched) effect of joint geometry such as at a nozzle to head or shell welds(s) and effect of weld defects (if present) on strain rate due to stress concentration during pressurization would suggest the importance of the minimization of vessel stresses until a safe temperature is reached.

Therefore it is recommended that pressure be kept to a reasonably low level until a safe temperature is reached. One approach is to raise the vessel temperature to about 300°F prior to exceeding 20% of the original shop hydrostatic test or 25% of the Design Pressure whichever is less. Problems in this area can be avoided by the simple expedient of making sure the vessel is at a safe temperature level prior to full pressurization, and although even though some embrittlement (loss in NDT) may have occurred does not indicate a brittle fracture is imminent.

Notwithstanding the potential problem of temper embrittlement, there is no concern about the integrity of the vessel(s) during service with regard to reduction in any required metal properties used in the design of the vessels, i.e. tensile, yield, creep and rupture strengths.

The alloys of chief concern to us are the 2¼ Cr-1 Mo and 3 Cr-1 Mo which are used predominantly in high pressure hydrogen service heavy wall equipment. The lower alloys such as ½ Mo, 1 Cr-½Mo and 1¼ Cr-½ Mo apparently suffer very little from the temper embrittling phenomenon thus special precautions with equipment from these alloys have not been deemed necessary to date. Much research is going on now in the form of characterization studies to better define causes, alloy susceptability, chemistry effects, manufacturing procedures, etc. with the ultimate goal to eliminate or greatly minimize the problem.

UOP imposes special requirements at the present time in chemistry restrictions, additional testing and impact energy/temperature relationships to provide material with greatly improved resistance to temper embrittlement susceptibility. We also impose operating start-up temperature/pressure restrictions as mentioned above.

SCHEMATIC - EFFECT OF TEMPER EMBRITTLEMENT ON IMPACT CHARACTERISTICS

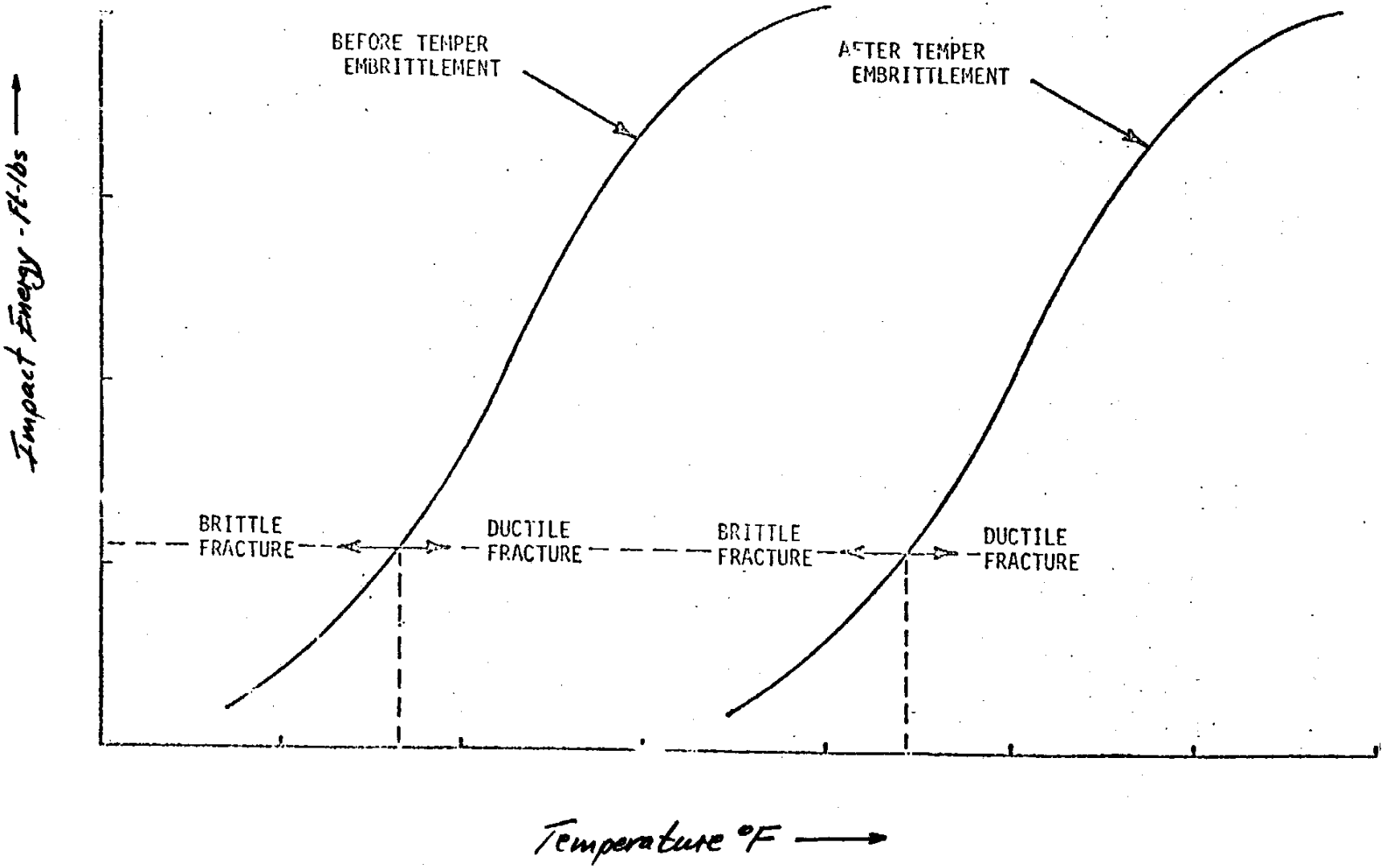


FIGURE 13

IV. CORROSION

1. General Description

Corrosion can be defined as the gradual destruction or alteration of a metal or alloy and their mechanical properties caused by direct chemical attack at low or high temperatures or by electrochemical reaction. These basic types of corrosion are manifest, either singly or in combination, and with or without other influences, in the common types to be discussed later.

The significance of corrosion as an industrial expense resulting from deterioration of equipment, increased maintenance, product contamination and loss of productivity is recognized. It has been estimated that the annual cost of corrosion to industry in the U.S. is more than $10,000,000,000 (10 billion). Compared to the total picture, corrosion in the petroleum refining and petrochemical industries may be more varied and more severe as a result of the complexities of the processes that are involved. Not only are the processes complex, and are becoming increasingly so, but the problems that are encountered vary from plant to plant depending on the nature of the crude that is being processed, the specific process in use, types of catalyst if used, and the types of products that are made. The increased emphasis on on-stream efficiency and run life, reliability and dependability of equipment and the trend toward larger, integrated refineries places an added responsibility on the materials/ corrosion engineer.

Of materials, the most serious offender is the metal most widely used, iron and steel. Under favorable, or perhaps more aptly put, unfavorable conditions, all metals corrode, thus none are completely immune. Corrosion can best be prevented by eliminating the corrosive conditions. In the processing industries this is generally not possible, therefore it is more feasible to change materials and use various corrosion control measures. For the engineer to control or eliminate corrosive conditions, he must have a workable knowledge of the fundamentals of corrosion.

The forces that cause corrosion are constantly in action. Different metals are affected to different degrees and corrosive attack takes many different forms. Attack may be by general tarnishing or rusting with occasional perforations in especially affected areas. Corrosion may develop preferentially near the junction of two different metals. The metal may suffer highly localized attack by pitting. The strength of a metal may be destroyed by cracking induced by corrosion. Corrosion may also be confined to crevices, under gaskets or washers, or in sockets. It may have the effect of removing one of the constituents of an alloy so as to leave a weak residue.

The study of corrosion considers reactions between a metal and its environment. It also concerns the suppression of corrosion by changing the characteristics of metals and their environments. The battle against corrosion has been based on a better understanding of the forces concerned and on the development of the scientific principles upon which effective control of corrosion must be based.

1. (cont'd)

It is possible to explain how this action occurs and what can be done to reduce it by illustrating some of these principles. The essential details of galvanic corrosion and cathodic protection was worked out back in 1824 by Sir Humphrey Davy when he initiated the use of zinc to control corrosion of ships hulls. In 1847 Rich Adie demonstrated the generation of current and corrosion caused by differences in oxygen at the surface of iron in different locations in a flowing stream. Dr. Willis Rodney Whitney worked out and expressed in its most useful form one of the principles which constitute the basic structure for modern methods of corrosion control. He investigated the corrosion of steel pipes in water under conditions simulating those encountered in service and he sought to discover under what conditons iron will corrode and what factors influence the rate of attack.

From these experiments it was concluded: "Practically the only factor which limits the life of iron is oxidation, under which name are included all the chemical processes whereby the iron is corroded, eaten away, or rusted. In undergoing this change, the iron always passes through or into a state of solution, and as we have no evidence of iron going into aqueous solution except in the form of ions, we have really to consider the effects of conditions upon the potential difference between iron and its surroundings. The whole subject of corrosion of iron, is therefore, an electrochemical one, and the rate of corrosion is simply a function of electromotive force and resistance of circuit." Dr. Whitney thus concluded that corrosion is electrochemical in nature like the action taking place in a dry cell.

The application of the electrochemical principles developed by these investigators provides the means for modern methods of corrosion control. The basic cause of corrosion is the instability of metals in their refined forms. Because of this free energy relationship, the metals tend to revert to their natural states through the processes of corrosion. In the case of iron the action of rain forms rust. When you analyze rust, you find it is iron oxide. When you analyze natural iron ore,you find it too is iron oxide. In rusting, iron has reverted to its original native state. To begin with, the basic nature of corrosion is almost always the same, a flow of electricity between certain areas of a metal surface thru a solution capable of conducting an electric current. This electrochemical action causes destructive alteration or eating away of a metal at areas which are called anodes where the electric current leaves the metal and enters the solution. It is the critical step in the series of events we associate with corrosion.

The presence of an electrolyte is one of the first requirements of corrosion. An electrolyte, is any liquid that contains ions. Ions are electrically charged atoms, or groups of atoms, in solution. Pure water, for example, contains positively charged hydrogen ions and negatively charged hydroxyl ions, in equal concentrations. For example, a single drop of water may contain about 3 million-million hydrogen ions and an equal number of hydroxyl ions. So our corrosive environment may be any form of moisture ranging from plain water to the strongest acid, or the strongest alkali. It may be just moisture condensed from the air or it may be salt water. But, in any environment regardless of its nature, the basic mechanism of corrosion is in principle the same as the

1. (cont'd)

electrochemical action in an electric dry cell. There is always an electrolyte that contains many ions, and we must have two electrodes, an anode and a cathode, where current enters the metal from the electrolyte. The electrodes may consist of two different kinds of metal or they may be different areas on the same piece of metal. In either case, there must be a potential difference between the two electrodes, or areas, so that electricity will flow between them. A wire or metallic path is necessary to complete the circuit for the flow of electrons which are negatively charged particles moving in the wire from the negative to the positive. The popular concept of current flow visualizes imaginary positive charges moving in the opposite direction. This electron path may be provided by any kind of metallic bridge, or merely by the fact that the two metals are in contact with each other.

At the anode when corrosion occurs, positively charged atoms of metal meet detach themselves from the solid surface and enter into solution as ions while the corresponding negative charges, in the form of electrons, are left behind in the metal. The detached positive ions bear one or more positive charges. In the corrosion of iron, each iron atom releases two electrons and becomes an iron ion carrying two positive charges. The released electrons travel through the metal to the cathode area.

The electrons reaching the surface of the cathode through the metal meet and neutralize some positively charged hydrogen ions which have arrived at the same surface through the electrolyte. In losing their charge, the positive ions become neutral atoms again, and may combine to form hydrogen gas. The release of hydrogen ions results in the accumulation of a relatively high concentration of OH- ions which are left behind to increase the alkalinity at the cathode or to make the solution less acid.

Briefly then, for corrosion to occur, there must be a release of electrons at the anode, and a formation of metal ions through oxidation and disintegration of the metal. At the cathode, there must be a simultaneous acceptance of the electrons such as by neutralization of positive ions or formation of negative ions. Action at the anode cannot go on alone, nor can action at the cathode. The two reactions go on at the same time at equivalent rates, but corrosion, occurs almost always at the areas that act as anodes.

If we place a piece of ordinary iron in a solution of hydrochloric acid, we obtain a vigorous formation of hydrogen bubbles. Under such conditions, the metal corrodes very quickly. The usual dissolution of the metal is occurring only at the anodes, with hydrogen bubbles forming only at the cathodes even though it may appear that they are being released all over the surface rather than at well-defined cathodic areas. The anodic and cathodic areas may shift from time to time. This permits substanitally uniform corrosion to occur, because there are many tiny anode and cathode areas on the surface of the metal. These areas are often so small as to be invisible, and so numerous as to be almost inseparable. There are many causes for this: such as

1. (cont'd)

inclusions in the metal, lack of homogeneity, surface imperfections, orientation of grains, localized stresses and variations in environment. If we could see just one anode and one cathode we would see electrons released by the formation of ferrous ions flowing through the metal from the anode to the cathode, where they meet the hydrogen ions in solution which acts as electron acceptors at the cathode surface, one electron being accepted in the discharge of one hydrogen ion. The hydrogen then appears as hydrogen gas coating the metal surface. As this process continues, oxidation and corrosion of iron occurs at the anodes, and plating out of hydrogen occurs at the cathodes. This formation of hydrogen molecules and the evolution of hydrogen gas are the principal reactions in corrosion by acids. In neutral electrolytes, such as a sodium chloride solution, the evolution of hydrogen gas is very slow, and the accumulation of a layer of hydrogen on the metal slows down the reaction by a process we call cathodic polarization.

However, reactions involving oxygen dissolved in the electrolyte can occur to complete the cathodic reaction. Oxygen can react with the accumulated hydrogen to form water, and by removing it this way, permit corrosion to proceed. In doing this oxygen acts as a cathodic depolarizer. Therefore, the cathodic reactions can involve either hydrogen evolution or some reaction with oxygen. Other reactions are the reduction of oxygen in water to form hydrogen peroxide and hydroxyl ions or completely to hydroxyl ions.

The products of the anode and cathode processes frequently meet and enter into further reactions that yield many of our common visible corrosion products. For example, with iron in water the hydroxyl ions from the cathodic reaction in their migration through the electrolyte towards the anode encounter ferrous ions moving in the opposite direction. These ions combine to form ferrous hydroxide. This soon becomes oxidized by oxygen in solution to form ferric hydroxide which precipitates as a form of iron rust which we are all familiar with. Depending on the alkalinity, oxygen content and agitation of the solution, this rust may form either away from the iron surface or right next to it where it can exert more of an influence on the further progress of corrosion.

The action of oxygen ranks high on the list of factors influencing corrosion. For this reason, oxygen is removed from boiler waters to reduce corrosion of the boiler. Deaeration of industrial waters is one example of corrosion control.

2. Common Types

2.1 Uniform Attack - This is the most common form of corrosion which proceeds uniformly over the metal surface exposed to the corrosive. A prime example of this is the rusting of metals exposed to the atmosphere. Other examples of this would be the attack by acids such as HCl, H_2SO_4, HF, sulfur compounds and others.

2.2 Galvanic Corrosion - This type of attack occurs when dissimilar metals are in contact or otherwise coupled together electrically in the presence of a corrosive medium (electrolyte). The tendency of the metals to corrode depends on differences in potential and is measured in volts, which is the driving force of the corrosion reaction. Arranging the metals according to their tendency to corrode galvanically results in the approximate order as shown in the Galvanic Series of Metals and Alloys in Table 3. When such a couple is exposed to a conducting solution, the less noble (more anodic) of the two metals at the top of the series is attacked at a faster rate than would be encountered under non-galvanic conditions. The more noble (cathodic) member of the cell is attacked at a much lower rate than if it were exposed to the corrodent by itself.

Factors that have a great effect in galvanic corrosion in addition to the coupling of metals with large potential differences shown in Table 3 are; conductivity of the corrosive medium, proximity, and anode to cathode area relationships. The greater the conductivity the greater the corrosion will be. For example, distilled water is such a poor conductor that galvanic corrosion even with metals coupled together with large potential differences will see very little corrosion, however water containing impurities and salts such as sea water, alkalies, and acid solutions are generally good conductors and galvanic corrosion will proceed quite rapidly. When metals are close together or touching, corrosion may be severe. Where small anodic areas are exposed to large cathodic areas, rapid corrosion will occur at the anode area. Conversely, the opposite is true. An example of this would be a steel rivet in copper or nickel alloy sheet in which the steel rivet would be rapidly corroded whereas a copper or nickel rivet in a steel sheet would produce little corrosion except some at the immediate contact area on the steel sheet.

Another example of this would be in a cooler or condenser where aluminum tubes were rolled into a copper alloy tubesheet in which case severe corrosion of the aluminum tube ends would occur. This phenomenon is often used to the designer's advantage when sacrificial anodes made of an inexpensive material are utilized to increase the life of more expensive (cathodic) parts. For example, in exchangers where stainless steel tubes may be used, the tube sheets can be made of thick carbon steel thus the stainless tubes would be protected at the expense of the steel tube sheet. In sea water, coolers and condensers where copper alloy tubes are needed, Mg or Zn would corrode to protect the steel which is galvanically coupled to the tubes. In some instances where galvanic coupling is unavoidable such as in some fastener (bolting) applications, corrosion can be greatly reduced by the use of electrically insulating

2.2 (cont'd)

washers and sleeves such as neoprene, nylon, etc.

TABLE 3

GALVANIC SERIES OF METALS AND ALLOYS IN SEA WATER

Magnesium
Zinc
Aluminum, Alclad 3003
Aluminum 3003
Aluminum 6061
Aluminum 6063
Aluminum 5052
Low Steel
Alloy Steel
Cast Iron
Stainless Steel, Type 410 (Active)
Stainless Steel, Type 430 (Active)
Stainless Steel, Type 304 (Active)
Stainless Steel, Type 316 (Active)
Ni-Resist
Muntz Metal
Yellow Brass
Admiralty
Aluminum Brass
Red Brass
Copper
Aluminum Bronze
Composition G Bronze
Cupro-nickel, 10%
Cupro-nickel, 30%—Low Iron
Cupro-nickel—High Iron
Nickel
Inconel
Silver
Stainless Steel, Type 410 (Passive)
Stainless Steel, Type 430 (Passive)
Stainless Steel, Type 304 (Passive)
Stainless Steel, Type 316 (Passive)
Monel
Hastelloy C
Titanium

2.3 Crevice corrosion - This is similar to galvanic corrosion with the exception that differences occur in the concentration of the corrodent. Crevices or other surface irregularities such as protruding or recessed rivets, bolts, washers, gaskets, deposits, etc., which interfere with the circulation and contact of the corrosive medium may cause severe localized corrosion. This type of corrosion is sometimes referred to as concentration-cell or contact corrosion.

2.4 Pitting - This is a form of extremely localized attack. It differs from uniform attack in that anodic areas remain fixed and a rapid localized attack occurs. This type attack is particularly destructive in that it can result in failure and leakage of equipment in a short time with a negligible overall weight loss if conditions are severe. Alloys that depend on a protective oxide film for corrosion resistance, such as the stainless steels and aluminum, are particularly susceptible to pitting if this film is broken. Pitting can occur at localized areas of mechanical damage, where scale has been incompletely removed, deposits are allowed to accumulate, at crevices, etc. Pitting is often associated with specific anions such as Cl-in the case of stainless steels.

2.5 Intergranular corrosion - Virtually all metals are susceptable to localized grain boundary attack, in certain environments. The classic example, however, involves the austenitic (Cr-Ni) stainless steels such as types 304 and 316. For example, in these alloys, the carbon content up to .08% percent is in a supersaturated solution in austenite after a full solution annealing heat treatment, about 1800°-2000°F with a rapid cool. When the alloy is heated in the temperature range of 800°-1600°F, such as during welding or in service, chromium carbides (Cr_4C) precipitate out at or adjacent to the grain boundaries. See Figure 14a for microstructure illustration of carbide precipitation. When this occurs, chromium is removed from solid solution leaving a chromium depleted zone adjacent to the grain boundaries. This zone is less resistant to corrosion and susceptable to preferential attack as shown in Figure 14b.The phenomenon of carbide precipitation is termed sensitization. The common remedies for sensitization and thus intergranular corrosion are: use of a solution heat treatment after welding, use of extra low carbon grades, and use of grades containing strong carbide formers (stronger than chromium) such as titanium, columbium and/or tantalum to stabilize carbides. Regarding the use of the solution heat treatment after welding, this would take the carbides back into solution however due to the high temperatures required, 1800°-2000°F, it is often impractical to submit welded equipment to these temperatures with the necessary rapid cool because of handling problems, distortion, etc. For simple items and if service temperatures are below 800°F, this treatment may be used, however if service over 800°F is anticipated, Cr_4C will re-precipitate and result in intergranular corrosion in an environment condusive to same.

2.5 (cont'd)

Since the carbon solubility in austenite at room temperature is approximately 0.02%, it would stand to reason that if the carbon content is kept at or below that figure, carbide precipitation would not occur. However, since these steels are difficult to make commercially with this low a carbon, compromises were made between the practical and economic aspects, and the low carbon grades, such as Types 304L and 316L, evolved with carbon .035-.04% maximum. These grades are used predominantly for welded applications and in temperature applications in the lower part of the sensitizing range.

With the addition of the carbide stabilizing elements, the chromium then remains in solution retaining full corrosion resistance. The Types 321 and 347 are used almost exclusively in welded equipment and in temperature applications in the carbide sensitizing range. Although the Types 321 and 347 are theoretically stabilized with Ti and Cb respectively for resistance against intergranular corrosion when in the stabilized heat treated condition (Section III-4 A-Annealing) they are susceptable at times to a highly localized attack adjacent to the welds. This attack called knifeline corrosion is due to a very narrow band of carbide precipitation that occurs during the heating and cooling cycles under welding heat. The various times at temperature and cooling rates may be such that the TiC or CbC will not form and subsequent reheating in the 800°-1600°F range will precipitate Cr_4C.

Environments that will cause intergranular corrosion, where susceptability exists, are many. Some of the most aggressive are HNO_3 HCl, H_2SO_3, H_2SO_4, HF, H_3PO_4 naphthenic and polythionic acids. In the refinery, the sulfidic type acids that may form in some environments are the most common. In this category, the most notorious are the so called polythionic acids H_2S_xO6 which are formed when H_2S (or iron sulfides) combine with air and moisture. Intergranular corrosion depending on severity, results in weakening of the alloy and loss of load carrying ability (or strength)of the affected areas. Appendix 4 shows some corrosive environments that can cause intergranular corrosion of metals.

2.6 Stress Corrosion Cracking - This phenomenon may be defined as the cracking of a material under the combined effects of stress (static) and corrosion. The stress involved may be either residual or applied and the corrosion is generally highly localized. The localized corrosion on the surface acts as a stress raiser (or concentrator), and the combination of corrosive attack plus stress results in propagation of the crack. This type of corrosion is most insiduous as it generally occurs without prior warning, any physical change in size or appearance of the material and is not repairable. Cracking can be transgranular or intergranular or both depending on the type of alloy, its metallurgical condition and the environment as can be seen in Figure 14.

2.6 (cont'd)

The austenitic stainless steels (Cr-Ni 300 series) are particularly susceptable to stress corrosion cracking especially in hot chloride environments. Any chlorides that are present in process streams may cause problems especially during downtimes when free moisture is present. The chloride type stress corrosion cracking almost always manifests itself as transgranular cracking. It occurs in an aqueous phase, and is more severe at the maximum temperature where water exists. The Nickel alloys, mainly Monel, Inconel, and Incoloy are much more resistant. An example of non-aqueous phase cracking of these alloys is in strong, hot caustic solutions.

An example of stress corrosion cracking of the unstabilized austenitic stainless steels such as Types 304 and 316 is the intergranular type caused by the Polythionic ($H_2S_xO_6$) acids. This is of great concern in the desulfurizing and similar type units in the refinery where sulfide environments are common and a large amount of the austenitic stainless steels are used for their good corrosion resistance in the high temperature parts of the units such as exchanger tubing, transfer piping, heater tubing, and reactor vessel internals. Generally the stabilized grades of stainless Types 321 and 347 are used where polythionic acid problems may occur although many years of satisfactory service has been realized with the unstabilized grades such as Types 304 and 316 especially in exchanger tubes. The low carbon grades 304L and 316L have also performed where temperature of application is 800°F or less and the lower strengths are acceptable such as in non-load bearing parts of vessel internals.

Regardless of the type of austenitic stainless steel used, although the Types 304 and 316 are much more susceptable and the Types 321 and 347 have performed satisfactorily without any special protective measures, we recommend downtime protection procedures when equipment may be opened and exposed to the atmosphere. As mentioned above, the polythionic acids may form when sulfides react with air and moisture, therefore to protect susceptible alloys from the potential intergranular stress corrosion cracking, either air and/or moisture must be eliminated, temperatures of equipment must be kept above water dew points, or equipment must be washed with an alkaline solution to neutralize any polythionic acids that could form. A thorough inert gas blanket and purge, generally accomplished with nitrogen plus some ammonia, will keep air out of the system or to such low levels that polythionic acids cannot form. For heater tubes, keeping a low fire, generally pilots are adequate, in the box will keep tube wall temperatures above water dew points. This must be carefully monitored with thermocouples in the heater box and also tube skin couples to prevent excessive tube wall temperatures since at downtime there will be no flow through the tubes. Oftentimes, heater tubes will be protected by both an inert gas purge in the tubes plus the low fires in the box if no entry into the box is required for inspection or repair.

An alkaline wash of a 5% soda ash solution or 1 to 2% caustic (NaOH or KOH) solution has proven to be an effective neutralizing

FIGURE 14

A



Sensitized Structure of Type 304 Showing Carbide Precipitation at Grain Boundaries

B



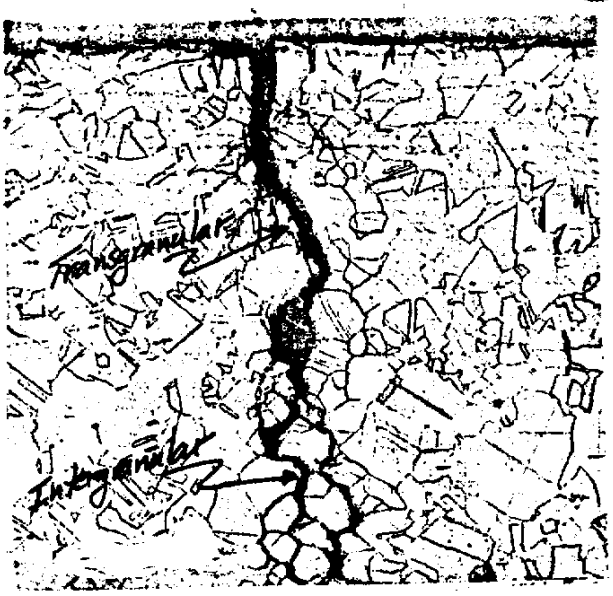
Intergranular Corrosion of Sensitized Type 304

C



Transgranular Stress Corrosion Cracking

D



Transgranular and Intergranular Stress Corrosion Cracking of Type 304

2.6 (cont'd)

agent for protection against polythionic acid attack. For this to be effective, the solution must contact the metal surface and be present when the equipment is opened to the atmosphere. We recommend a thorough circulation of the solution to enhance wetting of all surfaces. If the unit is going to be down for any period of time, the equipment should be left full of the solution unti which time it must be drained. After draining, the soda ash residue should be allowed to remain on the metal surfaces. If rinsing or flushing of the equipment is required for process reasons, only fresh ammoniated water should be used. Since the austenitic stainless alloys are susceptable to chloride stress corrosion cracking, it is recommended that sodium nitrate be added to the alkaline solution to give a .5% concentration as an inhibitor. Appendix 5 gives the UOP recommended shutdown procedures for protections.

Although the frequency of the polythionic intergranular stress corrosion cracking phenomenon in refinery equipment is diminishing, mainly because of awareness on the part of the refiner and using protective measures, it only takes one occurrence to enlighten a refiner to its dramatic effects and convince him that the downtime protection procedures are worthwhile. We would much prefer the refiner take the recommended protection procedures seriously than learn the hard way. Figure 15 shows the severe intergranular cracking in Type 304 stainless pipe tnat occurred during a one month shutdown for inspection.

Other types of stress corrosion cracking encountered in refinery applications are the well known caustic embrittlement of steels over about 160°F, cracking of stressed Monel and high strength steels in HF acid and of high strength steels in wet sulfide (H_2S) environments.

The cracking of steels in caustic environments can occur in straight caustic service or in environments that may precipitate caustic in small amounts and build up in concentration to the point where cracking is possible. Two environments fitting the latter would be in environments where caustic is used for neutralizing acids such as in Crude units and in steam service where caustic is injected as a treating agent. In such environments where the caustic is above a certain concentration or it is suspected that it can build up to such levels, steels are recommended to be PWHT to relieve the residual tensile stresses to a safe level. Figure 16 shows the temperature-concentration parameters where PWHT or stress relieving heat treatments are recommended to preclude cracking problems.

Regarding the HF acid causing stress corrosion cracking, this has occurred in HF alkylation processes, both in the liquid and vapor phases of highly stressed and welded Monel equipment. A simple PWHT or stress relief heat treatment at 1000°-1200°F will relieve tensile residual stresses to the point where cracking will be eliminated.

FIGURE 15

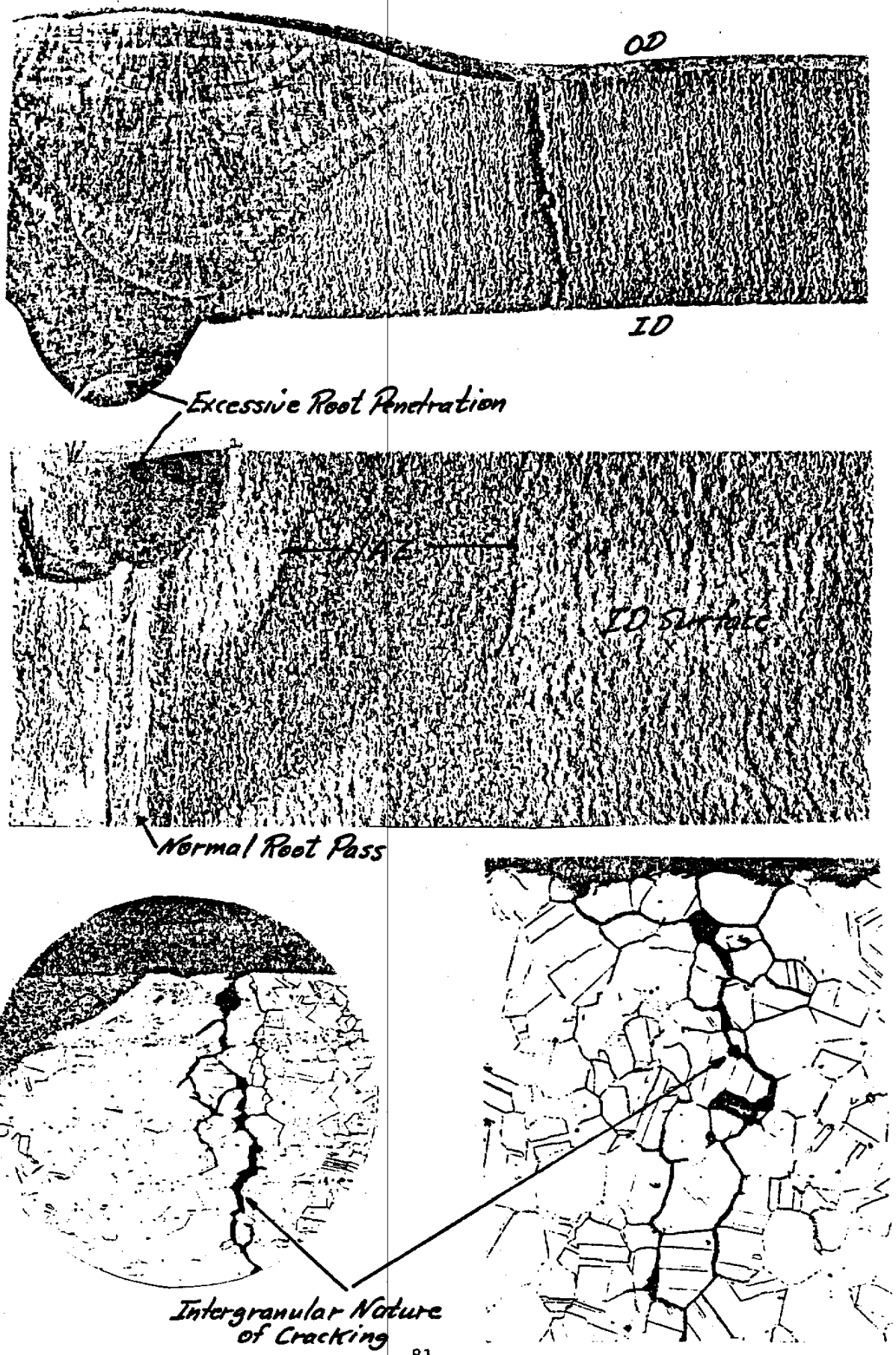
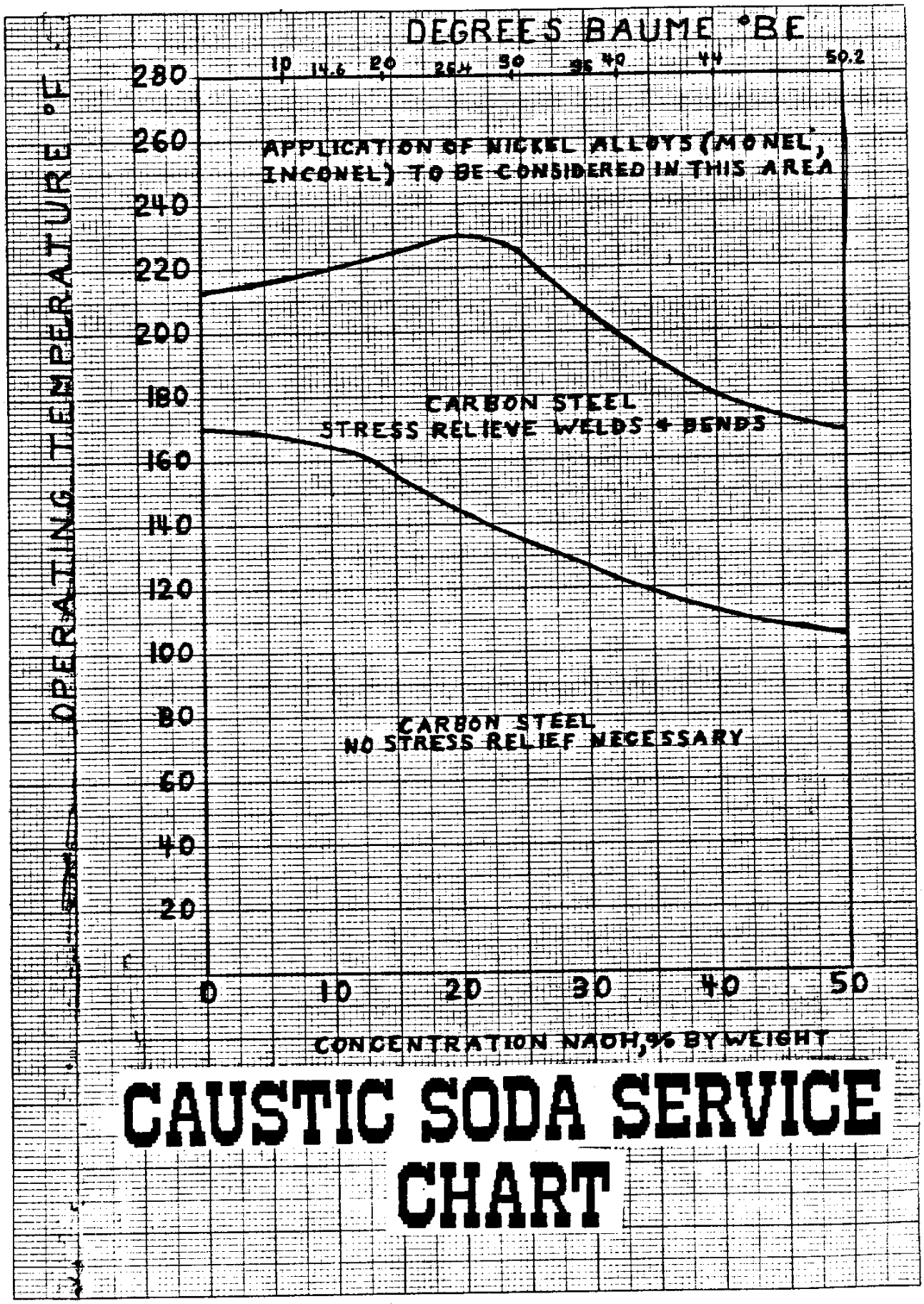

OD
ID
Excessive Root Penetration
Normal Root Pass
Intergranular Nature of Cracking

FIGURE 16



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SQUARE 10 X 10 TO THE HALF INCH AS 0813 OT

2.6 (cont'd)

Highly stressed steel and the high strength alloy steels over 100,000 psi TS. are also susceptable to HF stress corrosion cracking. The solution to this again is to require PWHT of welded steel equipment and to limit strength and hardness levels in the alloy steels. This cracking problem as related to the higher strength alloy steels is also termed Hydrogen Embrittlement and will be discussed further in the following section 4, Part 4.5.1. The cracking of steels in a wet sulfide environment is also included in the area termed Hydrogen Embrittlement and will be covered in that section. Brass alloys such as Admiralty, Aluminum Brass and others, used throughout refineries for cooling water service are susceptable to severe transgranular stress corrosion cracking in high pH's such as moist ammonia. In process streams, where ammonia is present, either from injection or conversion from nitrogen compounds, where an aqueous environment exists and the pH gets much above 9, cracking may occur. Resistant materials would be the cupro-nickel alloys and carbon steel if water (cooling) permits its use. For an expanded list of media that cause stress corrosion cracking of various metals and alloys see Appendix 6.

Where stress corrosion cracking environments are known to exist, the best way to prevent problems is to use materials resistant to that particular environment. Where susceptable materials need to be used for other reasons, they should be put into the most resistant condition by such means as heat treatment, protective measures during downtimes, keeping exposure times to a minimum and by design if possible.

2.7 Corrosion Fatigue

This is similar to stress corrosion cracking, the difference being that corrosion fatigue is cracking of material under the combined effects of corrosion and cyclic stress where stress corrosion cracking results from corrosion and static stress. Cracks develop at the root of corrosion pits under the influence of repeated stress. Under such stress, pits become deep and sharp and provide continuous path for propagation,usually transgranular. Any unit, structure or component that is subject to vibration, or any other fluctuating stress in presence of a corrosive environment may fail from corrosion fatigue. Prevention of corrosion fatigue can be accomplished by eliminating or minimizing the corrosive environment and utilizing design features to keep vibrations to a safe level.

2.8 Dezincification

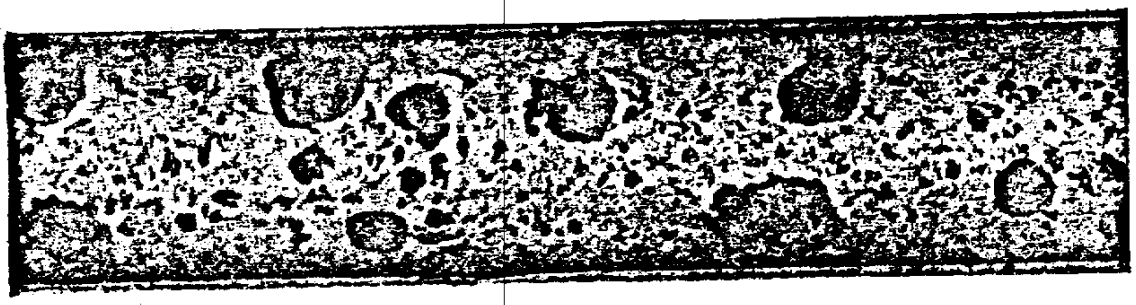
This is a type of corrosion that sometimes occurs in copper-zinc brass alloys that contain greater than 15% zinc. It is a highly selective type attack that results in the dissolving of both copper and zinc and the redeposition of copper back on the area corroded leaving a porous copper deposit. There are two types of this phenomena, the layer-type and plug type. The layer type covers generally a larger area in a narrow elongated pattern whereas plug is more of a round, resembling a large pit type geometry. This type corrosion occurs only in an acidic aqueous environment and almost always in a stagnant location where sludge type deposits are likely.

Dezincification has been seen in coolers and condenser with the admiralty or aluminum brass type tubes and tubesheets. Changes in flow pattern to eliminate stagnant locations, pH adjustment to approximately neutral (7) or reducing corrosivity, and changing tube material to 90-10 Cu Ni, 70-30 Cu-Ni and monel will minimize or eliminate dezincification.

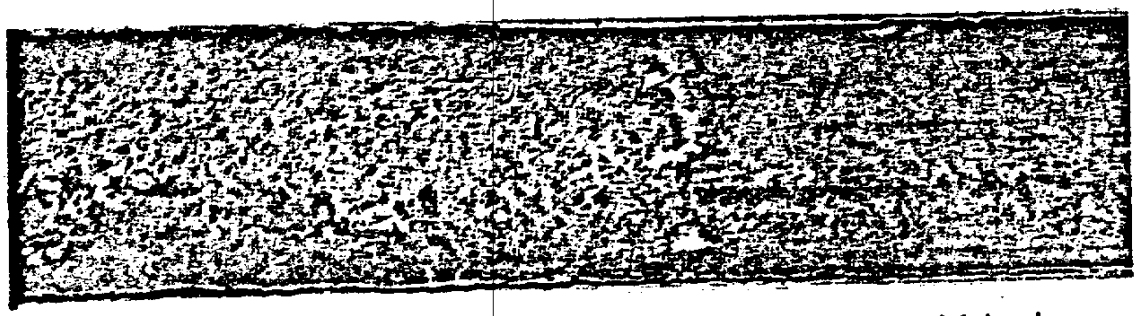
FIGURE 17



A corrosion fatigue crack in an aluminum brass tube progressing from the base of a pit. A corrosive condensate and excessive vibration of the tube produced the cracking. 150X.



Plug-type dezincification of the inside surface of an uninhibited aluminum brass tube.



Layer-type dezincification of the inside surface of a Muntz metal tube, left hand portion cleaned.

3. Passivity and Protective Films

The effect of oxygen on corrosion is variable and complex. It increases corrosion by acting as an electron acceptor and removing the film of hydrogen at a cathode. In higher concentration, oxygen can also retard corrosion. Oxygen, or oxidizing agents such as nitric acid, can form invisible protective films of their own and in this manner reduce corrosive action.

When some active metals become passive, they take on many features of the noble metals, as illustrated in the Galvanic Series. For instance, iron made passive by an oxygen layer or oxide film approaches the noble potential of platinum and resists corrosion.

However, the film responsible for the passivity of the iron in this case is rather frail and easily damaged. If we made a piece of iron passive by immersing it in nitric acid, a protective film formed by the nitric acid prevents corrosive action. If we dip this passivated iron into copper sulfate, no plating out of copper occurs but a "light tap" is sufficient to rupture the passive film. The iron becomes active again and copper plates out radially from the point where the film is broken since an active area at the point of impact becomes anodic to the surrounding passive area acting as a cathode. The reducing action at the cathode destroys passivity and corrosive action spreads. This type of unstable passive film is obviously not a dependable means for protecting iron against corrosion.

Fortunately, by alloying iron with chromium or a combination of chromium and nickel, it can be given a much more stable passivity, such as we have in the stainless steels. Whether these alloys are active or passive depends upon their composition and their environments. For example, iron with 3 percent chromium is active in copper sulfate solution and plates out copper. With 6 percent chromium, the plating out is proceeding more slowly but it is still active. When the alloy contains about 12 percent or more of chromium it achieves substantial passivity, and will resist corrosion in many environments, and of course, the 18 percent chromium-8 percent nickel stainless steel is also passive in copper sulfate as it is in nitric acid and many other corrosive media. This passivity is substantial and cannot be destroyed by striking the specimen rod such as occurred with the ordinary steel specimen treated in this way.

Difference in potential will occur when active and passive areas develop on the same piece of stainless steel. For example, the passivity of stainless steel depends upon a protective film of oxide or oxygen, which while not visible, is nevertheless very real. Should the metal surface lose its passivity, at any point, for some reason, a small local active area would develop, creating a large potential difference between it and the surrounding passive area. The result would be a galvanic action between the small active area as the anode, and the large surrounding passive areas as cathode, with intense corrosive action (pitting) at the small active area, the anode.

Severe corrosion can occur under many kinds of deposits thus it is

3. (cont'd)

important to keep stainless steels free from deposits to take the full advantage of their most useful corrosion resisting properties.

Unlike the invisible films just discussed, thick films, such as rust, can be seen with the naked eye. Rust is a product of destructive action, but it may also have a protective value although the mechanism of that protection is different from that of the passive films on stainless steel. With thick films, such as rust formed on iron or low alloy steels exposed to the atmosphere, penetration of oxygen and water to the metal surface is retarded. Hence, the rate of corrosion diminishes as the rust becomes more impervious. But, there is a big difference in the nature of the rusts that develop on steels of different composition. Steels that show poor resistance to corrosion, form heavy voluminous rusts that offer little resistance to the penetration of moisture. Differences in the rate of corrosion can be illustrated by the behavior of three steels, a steel of exceptionally low copper content, an ordinary steel, and a nickel-copper-chromium steel. The differences are due primarily to differences in the protective qualities of their rusts as a result of the addition of "alloying elements". They all corrode at about the same rate at the start; but as the more protective rust develops on the nickel steel, its rate of weight loss diminishes considerably, while the rate remains practically constant on the ordinary steel and actually increases a little on the steel of very low copper content.

One of the most striking examples of protective films found in refinery applications is that in the HF alkylation unit where carbon steel forms a very tight, adherent thin layer of iron fluoride when exposed to "anhydrous" HF. If this were not the case very rapid corrosion would occur and carbon steel would not be a useful material in this process.

4. Environmental Induced Attack

This section describes some of the more common environments found in the refinery that need to be considered in materials selection.

4.1 Oxidation

A corrosive attack termed oxidation of the metal surface can occur during service at elevated temperatures. It usually occurs as uniform metal loss although in some cases, attack can occur preferentially at grain boundaries. Oxidation resistance is always a very important consideration in choosing materials for use at elevated temperatures.

The scaling of a metal at a constant temperature may be considered to be the result of two processes, one a chemical combination of oxygen with the metal to form an oxide, or oxides, and the other a process whereby the scale formed retards further metal-oxygen reaction.

When alloying elements are added to steel, its scaling behavior may become quite complex. The effects of time and temperature and even the amount of alloying additions on rates of scaling are not simple, and behavior is not readily predictable. Surface oxidation is similar in effect to general corrosion, resulting in a gradual decrease in thickness of the sound material. Although air is the common agent causing oxidation, superheated steam as well as combustion atmospheres, have similar effects. Oxidation is also influenced by CO/CO_2 ratios, velocity or gases, and the pressure of contaminants such as sulfur, sodium, V_2O_5 and other acid type constituents generally in the direction of reducing resistance.

The resistance of steel to oxidation by air is greatly increased by the addition of elements such as chromium, silicon, and aluminum, which form stable oxide films. These elements are oxidized preferentially and form a scale which retards further oxidation. Small additions of chromium to iron increase the oxidation resistance. The addition of 5% chromium results in a notable increase in air oxidation resistance of steel at about 1000°F. Increased operating temperatures require materials of increasing chromium contents to insure adequate resistance to oxidation. Figure 18 presents a graph which illustrates the required chromium contents of steel for adequate resistance to oxidation at increasing temperatures. These results are based on safe operating temperatures of steels in normal combustion atmospheres.

4.1 (cont'd)

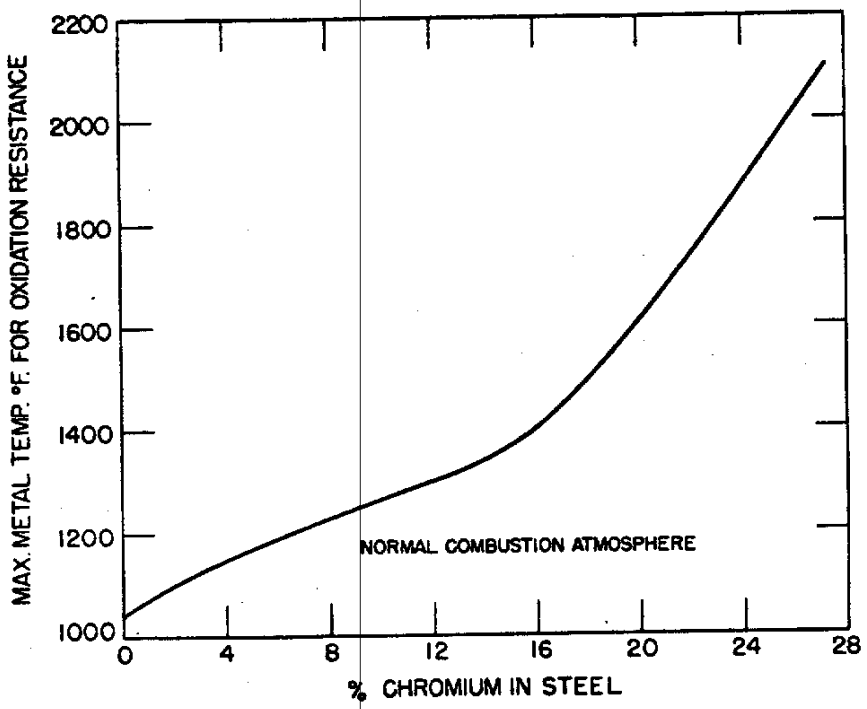


FIGURE 18 - EFFECT OF CHROMIUM ON OXIDATION RESISTANCE OF STEEL

General oxidation is ordinarily uniform over all exposed surfaces of a material. The resistance to surface oxidation may be estimated from experience or suitable laboratory tests. Material need not be completely resistant to oxidation for satisfactory service, provided that an allowance is made in the design for expected thickness losses.

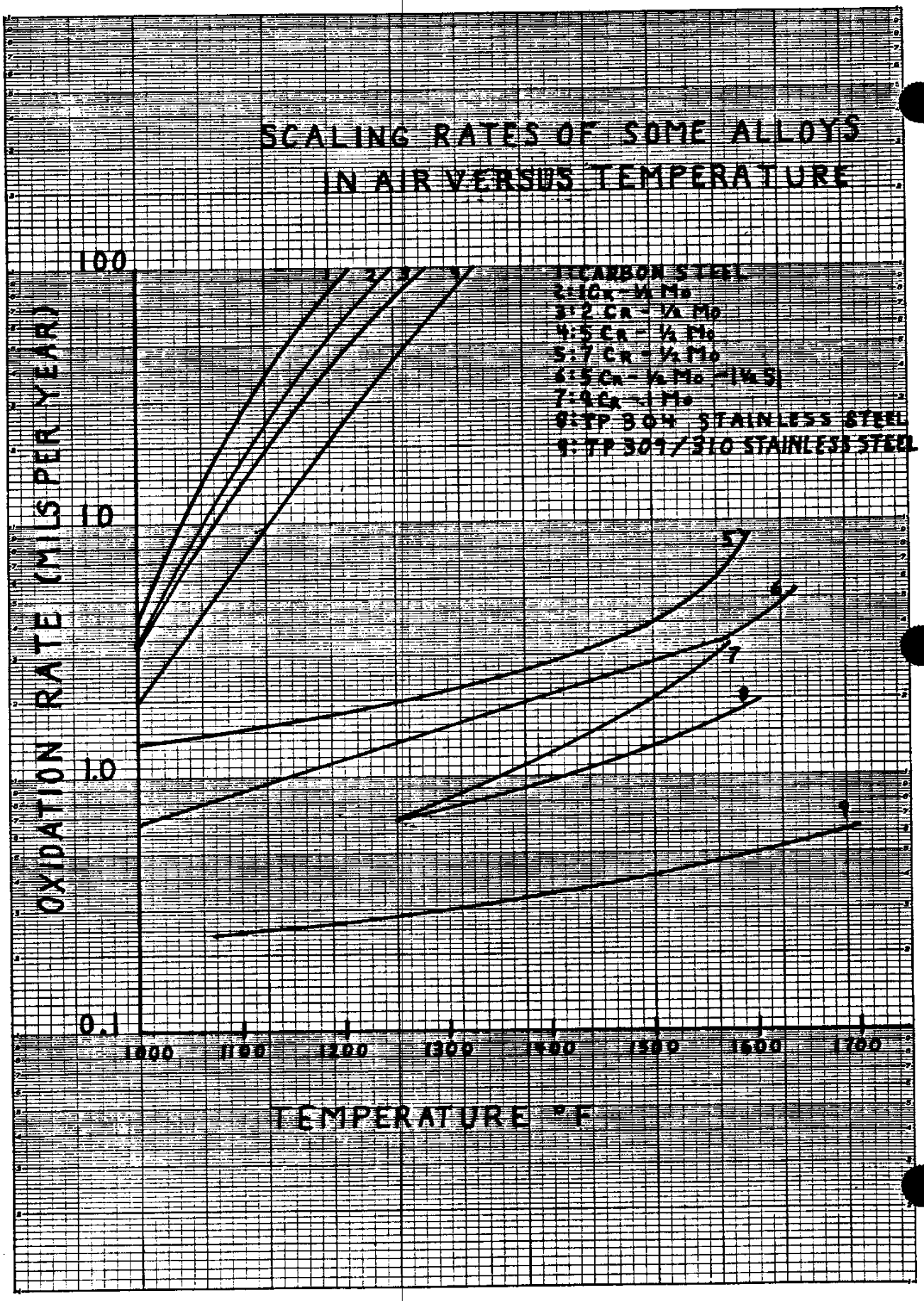
Since metals have a strong tendency to react with oxygen at elevated temperatures and since the rates of chemical reactions increase with increasing temperatures, the problem of oxidation becomes particularly important at high temperatures. Appropriate testing methods are therefore necessary to determine the limits of practical use of a metal because of oxidation considerations. Two general methods have been employed in laboratory testing to determine the scaling resistance of materials. In one of these, the scale is removed from a specimen after a period of exposure at elevated temperatures, and the loss in weight of metal is determined. Since scaling is generally not linear with time, a study of the effect of time requires the testing of a number of samples. The weight loss of such samples can be converted to a common basis for comparison such as inches per year penetration. In the other commonly employed technique, the gain in weight resulting from

4.1 (cont'd)

oxidation of a specimen is determined. The same specimen may be employed for a continuous series of measurements, thus allowing a considerable saving in experimental effort.

Another important consideration in the oxidation of metals and alloys is the effect of repeated cycles of heating and cooling. Since the scales formed on materials do not have the same characteristics of thermal expansion as the base metal, repeated heating and cooling can cause spalling of the scale because of the stresses at the metal-scale interface. Spalling exposes a fresh surface to the service environment. Such a surface would not be protected by any scale formation and would be repeatedly subjected to the initial high rates of scale formation. Suitable testing is necessary to determine the effects of thermal cycling for alloys intended for such service. The effect of the composition of the atmosphere is of considerable practical importance, since metals can be subjected to different environments. The usual oxidation service requirements at high temperatures are combustion atmospheres and steam. It is difficult to predict the resistance of materials to specific atmospheres as various contaminants can change their scaling characteristics. Specific requirements must be considered separately as they are normally limited to some particular application, therefore it may be necessary to evaluate materials under actual operating conditions to obtain scaling rates usable as design criteria. Figure 19 shows comparative scaling behavior of various steels in air. Some equipment in refineries where oxidation is a problem and need to be considered in design includes furnace tubes and supports, gas generators and fluid catalytic cracking regenerators.

FIGURE 19



NO. 31,289. 10 DIVISIONS PER INCH (70 DIVISIONS) BY FIVE 2-INCH CYCLES RATIO RULING. codex® GRAPH PAPER IN STOCK DIRECT FROM CODEX BOOK CO. INC. NORWOOD, MASS. U.S.A. PRINTED IN U.S.A.

4.2 Sulfur Corrosion

Corrosion from sulfur in crude oils is an extremely complex problem. The principal variables seem to be material composition, sulfur content of the crude, vapor content of heated crude, velocity and metal temperature. The sulfur present in the crude is in a variety of forms, including elemental sulfur, hydrogen sulfide, aliphatic sulfides, aromatic sulfides, polysulfides, mercaptans, and disulfides. Vapor content and velocity are related to the nature of the crude, high or low boiling point components. Although it is apparent that chemical analyses alone, regardless of sophistication, cannot be used to quantitatively predict corrosivity without relating it to corrosion rates obtained in the refinery or laboratory, it can give a qualitative or relative indication of anticipated corrosion performance. Aside from the fact that laboratory tests, pilot plant tests and in plant tests certainly have their place in determining corrosivity of various crudes, there are so many variables in effect that actual simulation is very difficult if not impossible. Regardless of the worth of such tests, the fact remains that there is always the question as to whether the many compounds involved and factors such as velocities, time effects, heating and condensing conditions, location, etc., are as important in the corrosion regime as the fact that damage is caused by the amount of H_2S evolved from dissociation. Although the above factors obviously have an effect on the corrosivity of crude containing sulfur compounds, the problem is how one measures them and utilizes the information in developing design criteria. The fact that consensus of opinions relates corrosivity of crudes to the extent of H_2S evolution at various temperatures does not simplify the job for designers and specifiers of materials since they do not have this information for all crudes and mixtures that a refiner may use. Therefore to solve an acute problem for new construction he makes it not so acute by specifying sufficient alloy to withstand the most corrosive crude. Data developed some years ago by an API committee which relates corrosion to total sulfur content of the crude is used. These, slightly modified, data shown in Figure 20 are considered to be conservative. Unless a refiner has specific corrosion experience with an anticiapted crude which differs from the curve used, materials are chosen based on these curves. The curves are slightly modified to reflect field experience. The curve shows anticipated corrosion rates at a given sulfur level for different alloys with correction factors for lower and higher sulfur levels.

The curve data is based on total combined organic sulfur regardless of source and type and is probably conservative. However this is the approach and methodology used by most designers. The API has sponsored a study to develop more realistic and accurate methods of determining crude oil corrosivity. The first publication covering this study is

4.2 (Cont'd)

available to the industry as API Publication 943, September 1974. In this work an attempt is made to define all the variables involved in crude oil corrosion and to define a specific corrosivity test which allow developing more accurate parameters in determining corrosivity. This publication does a good job of defining the problems associated with crude oil corrosivity but does not provide the designer with definite parameters for materials usage. Further work in this area is planned to provide these parameters. Until these are available, we must use good engineering judgement with the tools presently available. We feel that our approach to material selection in this area accomplishes this by using the best information available to designers so far and is conservative.

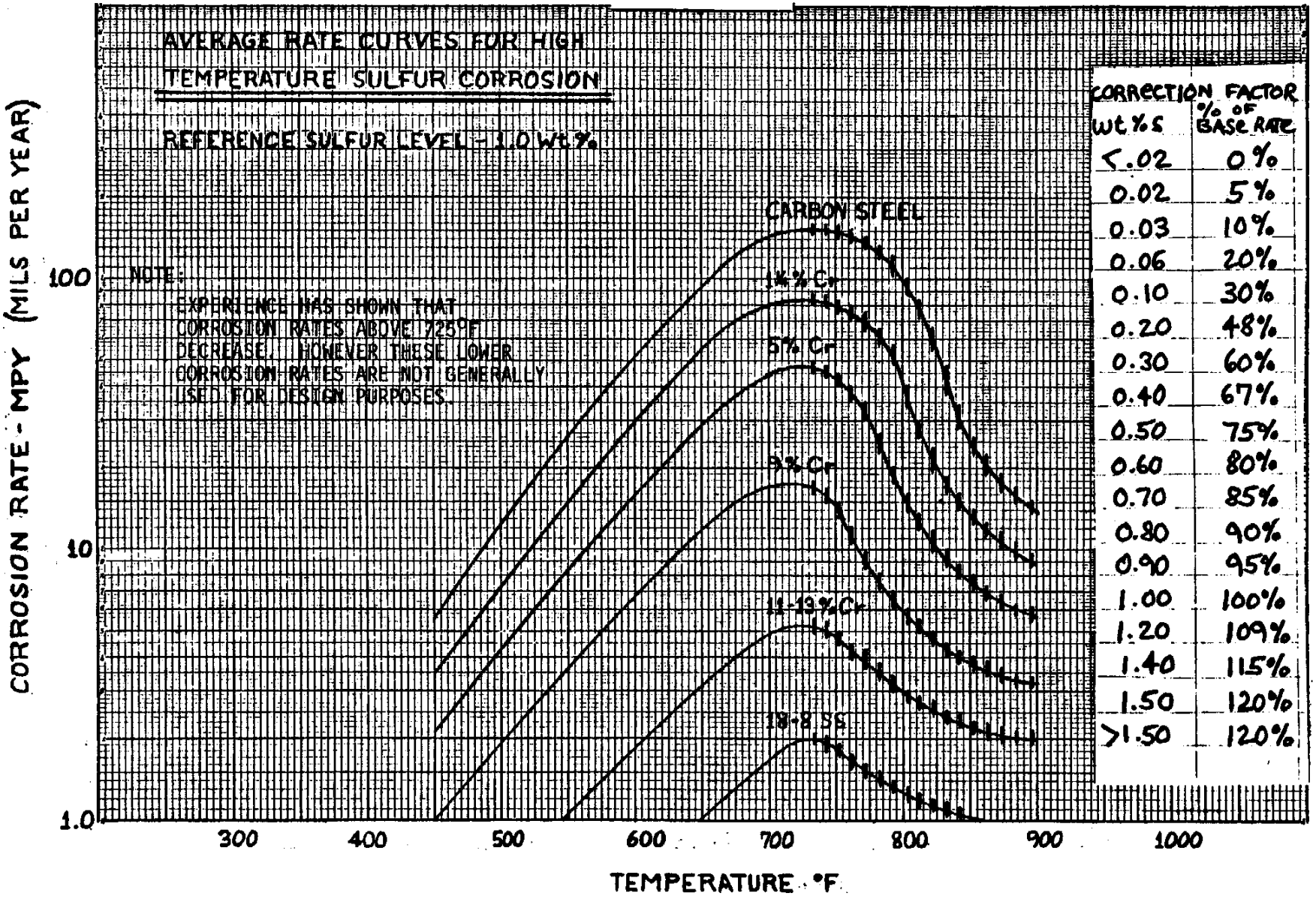

AVERAGE RATE CURVES FOR HIGH TEMPERATURE SULFUR CORROSION
REFERENCE SULFUR LEVEL - 1.0 Wt.%
NOTE:
EXPERIENCE HAS SHOWN THAT CORROSION RATES ABOVE 725°F DECREASE. HOWEVER THESE LOWER CORROSION RATES ARE NOT GENERALLY USED FOR DESIGN PURPOSES.
CARBON STEEL
1¼% Cr
5% Cr
9% Cr
11-13% Cr
18-8 SS
CORROSION RATE - MPY (MILS PER YEAR)
100
10
1.0
300
400
500
600
700
800
900
1000
TEMPERATURE °F
CORRECTION FACTOR
Wt.% S | % OF BASE RATE
<.02 | 0%
0.02 | 5%
0.03 | 10%
0.06 | 20%
0.10 | 30%
0.20 | 48%
0.30 | 60%
0.40 | 67%
0.50 | 75%
0.60 | 80%
0.70 | 85%
0.80 | 90%
0.90 | 95%
1.00 | 100%
1.20 | 109%
1.40 | 115%
1.50 | 120%
>1.50 | 120%

FIGURE 20

4.3 Hydrogen Sulfide - Hydrogen Corrosion:

Corrosion by H_2S in the presence of hydrogen becomes appreciable at temperatures over 600°F for carbon steels and low alloys. This attack results in an iron sulfide type scale (usually FeS) which can be voluminous, somewhat porous and not very adherent. As a result, the scale so formed can be carried into equipment and cause plugging problems, especially in catalyst beds. In contrast to the experience gained in non-hydrogen type processes where "sulfur" corrosion seems to reach a peak at 725°F, this type of corrosion has no apparent peak temperature. Where incremental increases in Cr improve resistance to "Sulfur" corrosion, little or no such advantage occurs in the H_2S-H_2 system. Resistance is only improved when Cr reaches about 9% and greater. In severe environments, only the higher Cr-Ni austenitic stainless steels and aluminized materials have sufficient resistance and are used to protect against excessive corrosion rates and sulfide scaling problems.

There have been many published reports and papers showing corrosion rates vs temperature at different volume percents and H_2S partial pressures. We have studied all these reports and have put together a family of trend curves adjusted in the direction dictated by service performance in UOP licensed process units. A short discussion on how these Trend Curves (Figures 21 thru 24) evolved and their usage follows.

TREND CURVES FOR PREDICTING CORROSION RATES IN H_2S ENVIRONMENTS AT ELEVATED TEMPERATURES

The attached curves represent what we feel are a sound basis for predicting corrosion rates of the commonly used steels in an H_2S environment. Data used for plotting the curves is that accumulated for the last 15-20 years to the present time. The result is a correlation of many published and private curves, data points adjusted in the direction dictated by service performance in UOP processes, i.e. Unifining and Isomax. This adjustment was in the general direction of showing lower corrosion rates that one would predict from the available published curves. Although we adjusted the rates downward, mainly because of our experience factor, a natural discrepancy exists in the early curves since most data was derived from short term laboratory and pilot plant tests which reflects initial high rates. Recent curves published by the NACE, T-8 Committee on Refinery Corrosion show about a 50% reduction in rates of various alloys. From earlier curves, these curves were a result of a computer study by A.S. Couper, American Oil Company of many data submitted by industry and are not too far removed from our curves. This computer study determined that pressure, in the range studied, was an insignificant factor, therefore, volume or mol percent of H_2S was used rather than partial pressure. Although our preliminary curves were based on H_2S partial pressure versus temperature, most of our applications are at higher pressures where we also feel partial pressure of H_2S is less significant than volume percent. We, therefore, decided to use the vol.% as our criteria.

The attached curves are grouped according to alloy content: 0-5% Chromium, Figure 21; 9% Chromium, Figure 22; 11-13% Chromium Stainless Steel, Figure 23; and 18% Chromium -8% Nickel Stainless Steel, Figure 24. These curves apply to hydrogen sulfide environments (hydrogen-hydrocarbon diluent) at temperatures from 400 to 1100°F and hydrogen sulfide concentrations from 0.001 to 10.0 volume percent. The curves are titled "Trend Curves For Predicting Corrosion Rates." Exact corrosion rates are impossible to predict because of the big scatter of the data. Many variables contribute to corrosion and effect its behavior, (i.e., type of hydrocarbon diluent, fluctuations in operating conditions, number and severity of regenerations, etc.). However, these curves do predict rates that can be utilized for material selection in new units with an acceptable level of confidence. To further clarify these curves one will note a dotted line at 600°F and 0.001 vol % H_2S to 1100° F and 0.04 vol.%H_2S. This line represents the "Thermodynamic Cut-Off" line under which no corrosion would occur if a pure thermodynamic reaction is obtained. The reaction $Fe+H_2S \rightarrow FeS+H_2$

in the areas under this dotted line reverses and corrosion would not occur. Since this thermodynamic reaction is an ideal situation it is shown only for academic purposes (dotted), since any variation in operating conditions and possible corrodents other than H_2S make the use of this "Thermodynamic Cut-Off" impractical for actual operations. Corrosion rates are in mils per year (MPY) and 1 mil per year = 0.001" per year (IPY). For hydrocarbon diluent of naphtha these curves should be conservative since the predicted corrosion rate is probably higher than what will be encountered. It has been shown in some published data that H_2S in a gas oil diluent is somewhat more corrosive than in a naphtha diluent for the 0-9% Cr materials.

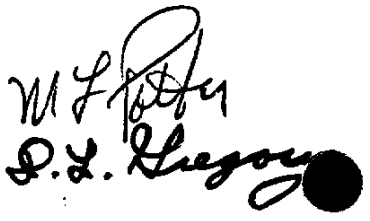
We have not shown any difference in corrosion rates in our 0-5% Cr and 9% Cr curves that would reflect the type of hydrocarbon present even though some data, as mentioned above, show higher rates in the heavier oils, such as gas oils vs. naphtha when H_2S content is the same.

As pointed out and identified, the curves are trend lines to be used for predicting corrosion rates and as a basis for alloy selection regardless of hydrocarbon medium. We feel the confidence of these predicted rates is better than anything we have had in the past. Also, they will be a helpful tool for project engineers and others for guidance on preliminary material selection.

The design philosophy for the particular unit and the specific piece of equipment has a major bearing on the tolerable or acceptable corrosion rate used for material selection. For example, heat exchanger tubes in Feed vs. Effluent Exchangers will be relatively thin and not able or practical to be designed with much corrosion allowance. In this case, a high alloy material with a predicted corrosion rate about 5 MPY max. would be selected. In the same unit, the shell can be designed with a larger corrosion allowance and thus possibly lower alloy. Piping can also be designed with greater corrosion allowance, thus where FeS scale carryover is not a problem, it can tolerate more corrosion and thus lower alloy. Heater tubes generally require higher alloy because of the higher ID tube wall temperature and its effect on increasing corrosion rates and scaling.

When estimating corrosion rates to choose material for corrosion only, use the maximum operating temperature rather than design. This does, often, result in some economy of material choice.

M.L. Potter
D.L. Gregory



MLP/DLG/mc
Attch.

FIGURE 21

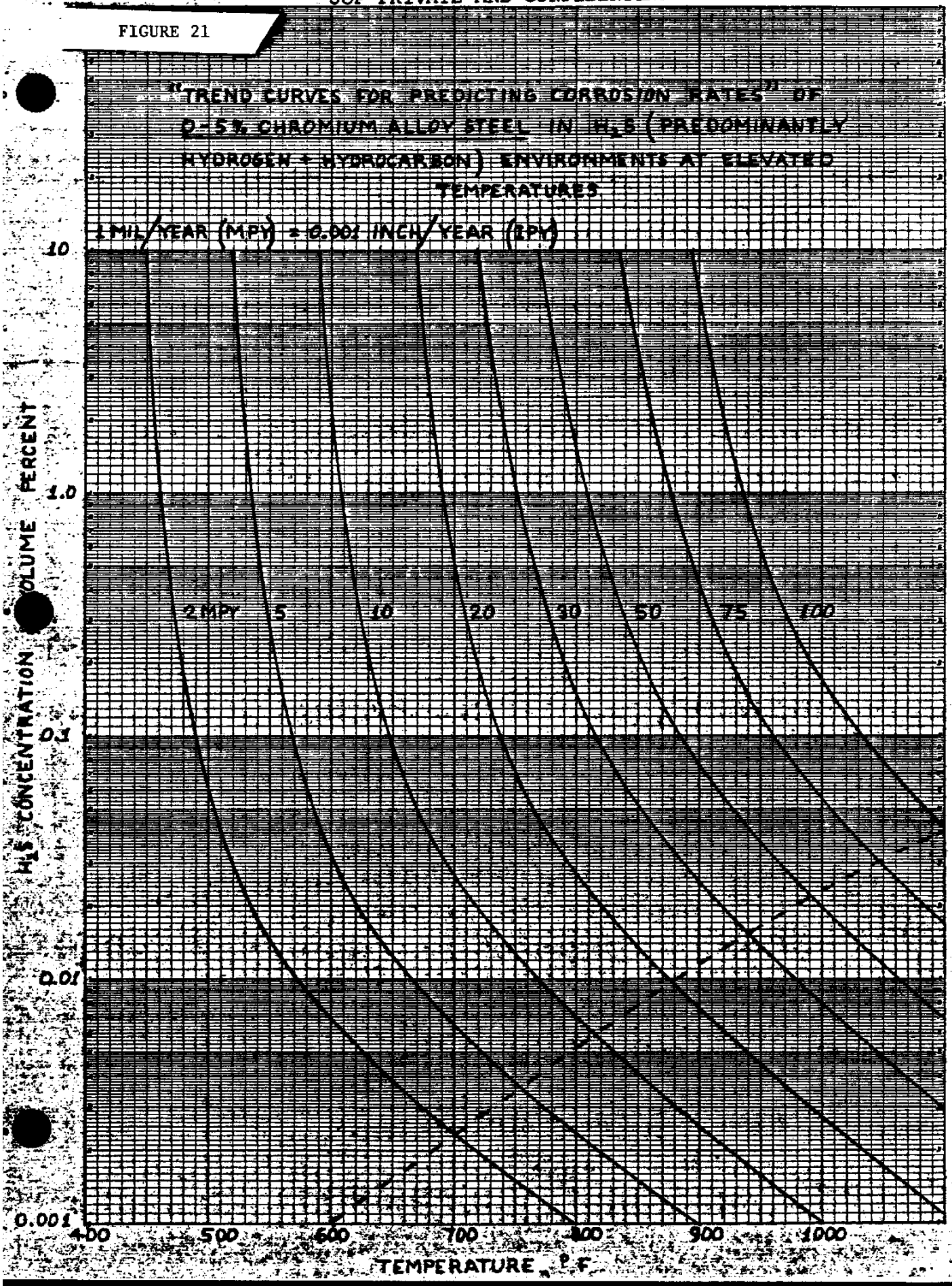

"TREND CURVES FOR PREDICTING CORROSION RATES" OF
0-5% CHROMIUM ALLOY STEEL IN H_2S (PREDOMINANTLY
HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED
TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
H_2S CONCENTRATION VOLUME PERCENT
10
1.0
0.1
0.01
0.001
2 MPY
5
10
20
30
50
75
100
400
500
600
700
800
900
1000
TEMPERATURE °F

FIGURE 22

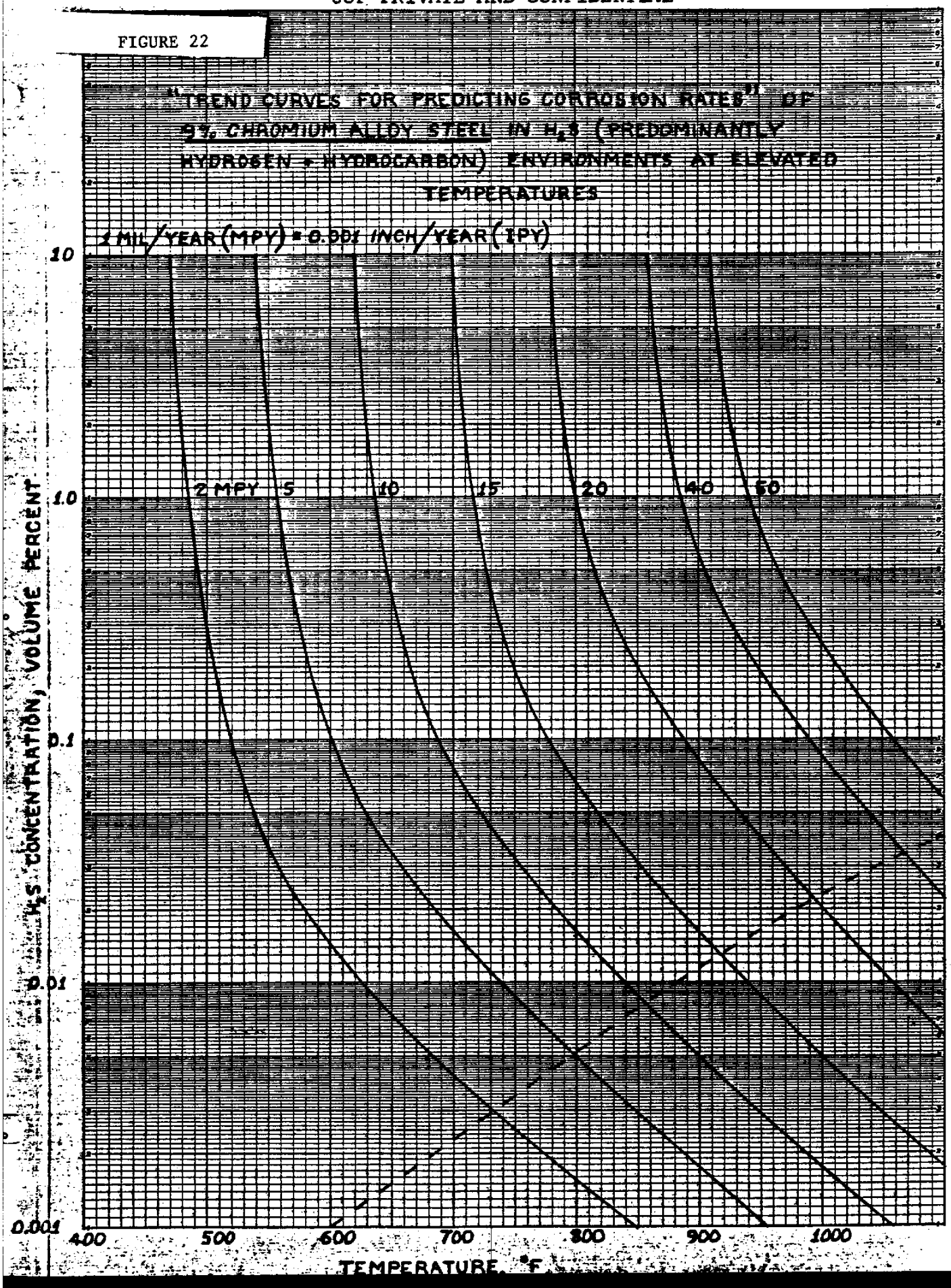

"TREND CURVES FOR PREDICTING CORROSION RATES" OF
9% CHROMIUM ALLOY STEEL IN H_2S (PREDOMINANTLY
HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED
TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
2 MPY
5
10
15
20
40
60
10
1.0
0.1
0.01
0.001
H_2S CONCENTRATION, VOLUME PERCENT
400
500
600
700
800
900
1000
TEMPERATURE, °F

FIGURE 23

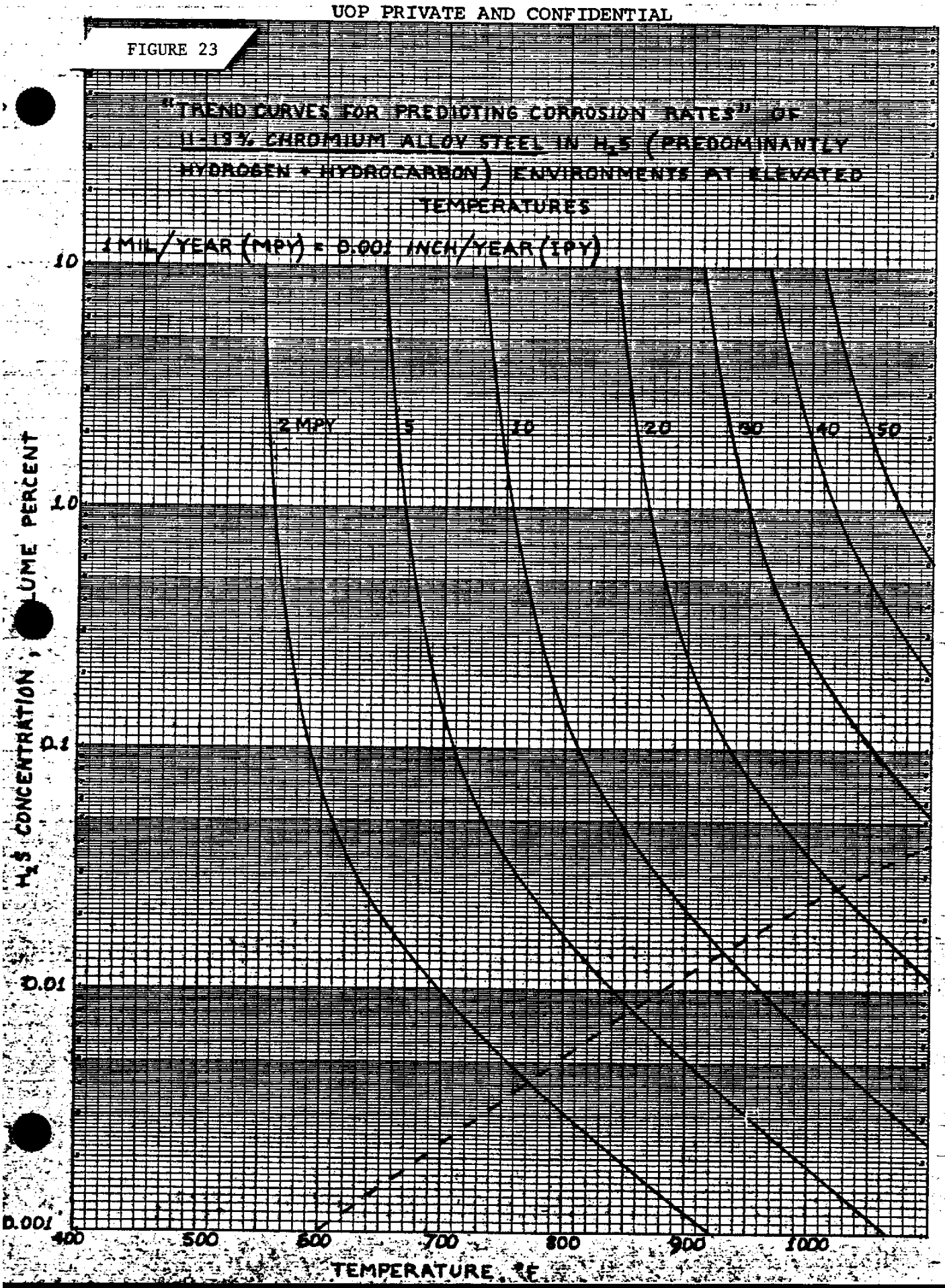
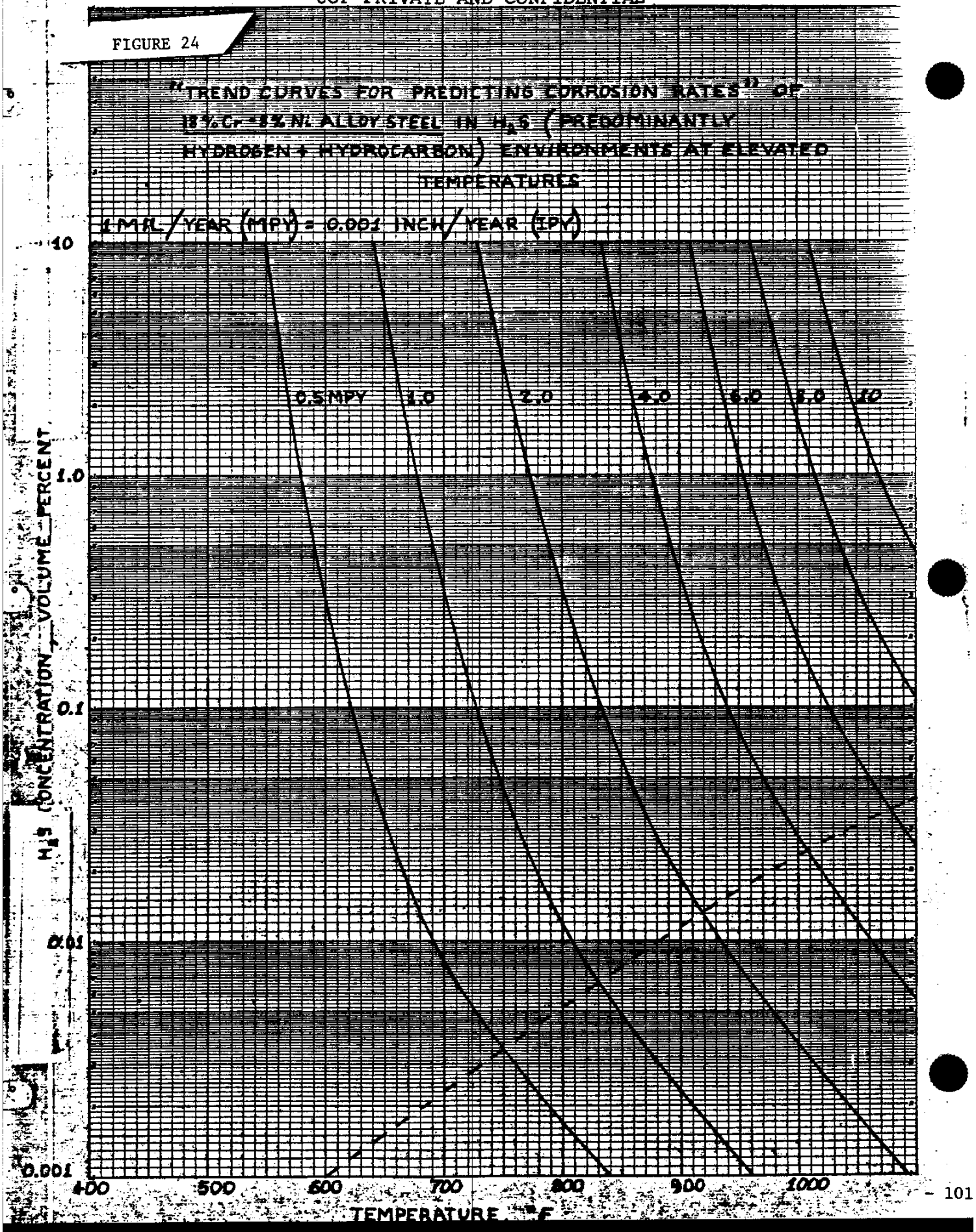

"TREND CURVES FOR PREDICTING CORROSION RATES" OF 11-13% CHROMIUM ALLOY STEEL IN H_2S (PREDOMINANTLY HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
2 MPY
5
10
20
30
40
50
10
1.0
0.1
0.01
0.001
H_2S CONCENTRATION, VOLUME PERCENT
400
500
600
700
800
900
1000
TEMPERATURE, °F

FIGURE 24


"TREND CURVES FOR PREDICTING CORROSION RATES" OF
18% Cr - 8% Ni ALLOY STEEL IN H_2S (PREDOMINANTLY
HYDROGEN + HYDROCARBON) ENVIRONMENTS AT ELEVATED
TEMPERATURES
1 MIL/YEAR (MPY) = 0.001 INCH/YEAR (IPY)
0.5 MPY
1.0
2.0
4.0
6.0
8.0
10
H_2S CONCENTRATION — VOLUME PERCENT
10
1.0
0.1
0.01
0.001
400
500
600
700
800
900
1000
TEMPERATURE, °F

4.4 Acid Corrosion

The following section lists some of the more common acids that are found in the refineries, the alloys used for resistance and means to minimize corrosion.

4.4.1 Naphthenic Acid

Naphthenic acid is a collective name for organic acids present in some but not all crude oils. In addition to true naphthenic acids (naphthenic carboxylic acids represented by the formula X-COOH in which X is a cycloparaffin radical), the total acidity of a crude may include various amounts of other organic and sometimes mineral acids. Thus the total neutralization number of a stock, which is a measure of its total acidity, includes (but does not necessarily represent) the level of naphthenic acids present. The neutralization number is the number of milligrams of potassium hydroxide required to neutralize one gram of stock as determined by titration, and may range as high as 10 mg. KOH/gr. for some crudes. The neutralization number does not usually become important as a corrosion factor however, unless it is at least 0.5 mg. KOH/gm; however it is generally agreed that neutralization numbers in excess of 1 are considered to be corrosive to steels. Most crude oils do not have neutralization numbers greater than 1.5 and if they do, they are usually blended with a nonacidic crude to lower the overall value.

Naphthenic acid attack occurs under condensing conditions in the towers. The various distillate fractions may exhibit neutralization numbers as high as 6 to 8 even though the total neutralization number of the crude is less than one. This occurs since most of the naphthenic acids originally in the crude condense out in a small fraction and become concentrated.

Theoretically, corrosion rates from naphthenic acids are proportional to the level of the neutralization number of feed stocks; but investigators have been unable to find a precise correlation between these factors. Predicting corrosion rates based on neutralization number remains uncertain. Published data, however, indicate a scattered trend toward increasing corrosion with increasing neutralization number. Temperatures required for corrosion by naphthenic acids range from 450 to 750°F with maximum rates often occcuring between 520 and 535°F. Whenever rates again show an increase with a rise in temperature above 650°F, such increase is believed to be caused by the influence of sulfur compounds which become corrosive to carbon and low-alloy steels at that temperature.

4.4.1 (Cont'd)

Naphthenic acid corrosion occurs primarily in crude and vacuum distillation units, and less frequently in thermal and catalytic cracking operations. It usually occurs in the furnace coils at the exit, heater transfer line, vacuum column, sidestream coolers and pumps. This corrosion is most pronounced in locations of high velocity, turbulence and impingement, such as at elbows, weld reinforcements, pump impellers, steam injection nozzles and at locations where freshly condensed fractions drip upon or run down metal surfaces.

Metal surfaces corroded by naphthenic acids are characterized by sharp edged, streamlined grooves or ripples resembling erosion effects in which all corrosion products have been swept away leaving very clean, surfaces.

Unalloyed mild steel parts have been known to corrode at rates as high as 800 mils per year. The low-chrome steels, through 9 Cr-, are sometimes more resistant than mild steel. In some cases good service has been realized, with both 2½Cr and 5Cr furnace tubes, where carbon steel tubes in the same service suffered severe corrosion. The 12 Cr stainless steels are scarcely, if any, better than the low-chromes or carbon steel. But the 18-8 Cr-Ni steels, without molybdenum, are often quite resistant under conditions of low velocity, although they are sometimes subject to severe pitting.

Type 316 (18-12-2 Cr-Ni-Mo) has much better resistance to naphthenic acids than any of the non molybdenum containing grades and provides adequate protection under most circumstances. Where corrosion of Type 316 has been experienced at the more severe conditions, Type 317 (slightly higher in Cr-Ni and Mo) has proven to be better.

4.4.1 (Cont'd)

Aside from using the appropriate corrosion resistant alloy(s), neutralization of the acids with caustic soda has been tried with some success, however some reported adverse effects on the quality of some products has rendered this approach almost non-existent. Additional info. is included in the papers in Appendix 7 and 8.

4.4.2 Hydrochloric Acid

Corrosion from HCl in the refinery is generally limited to the Crude Unit overhead system, Catalystic Reforming units and sometimes in desulfurization units. In the case of the crude unit system, HCl may be formed from hydrolysis of chloride salts, catalytic reforming from chloride release from the catalyst and in desulfurization from hydrogenation of organic chlorides in the feed. These HCl environments, when encountered, are only corrosive when aqueous phase dew point temperatures are reached. The high nickel alloys, predominantly Monel are used for components for required resistance.

In most cases, the use of Monel is kept to a minimum by the use of various mitigating measures such as efficient desalting, inhibition, neutralization, water washing and operating procedures.

The one exception to the aqueous, dew point requirement is in the catalyst regeneration section of the CCR Platformer. Inconel is used to resist the high temperature HCl/Cl_2 vapor encountered.

4.4.3 Sulfuric and Sulfurous Acids

Corrosion by sulfuric acid in the refinery is not a big problem since very little exposure to H_2SO_4 is found. In the alkylation process corrosion from H_2SO_4, especially if wet can be quite severe to carbon steel. Organic acid esters are formed and during fractionation, may break down and form polymers and sulfur oxides. These sulfur oxides form acid when wet and become quite corrosive. Experience in these units has led to the following generalities regarding materials usage.

4.4.3 (Cont'd)

Carbon steel is used for the majority of equipment since H_2SO_4 concentrations are high and the environment is dry. Where in contact with H_2SO_4 regardless of conentrations, all steel welds are PWHT'd to minimize highly localized corrosion of the welds and HAZ's. Alloys are generally used in valves, pumps and piping where the hydrocarbons and H_2SO_4 mix. Alloys used are Alloy 20, Hastelloy B, 8% Al Bronze and Type 316 (in low acid concentrations).

Corrosion problems are minimized by the following:

a) Keep the feed dry -

b) Control caustic wash by using a 2-8% solution while maintaining good circulation and sufficient contact time.

c) Minimize acid organic ester formation and breakdown by keeping temperatures below 350°F and utilizing a water wash.

d) Use of inhibitors in fractionation section plus NH_4 for pH control when necessary.

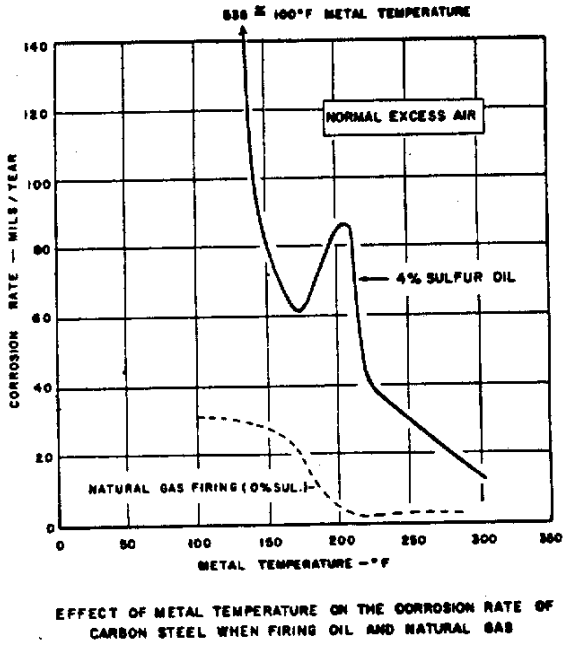
Probably a more common area than the above cited alkylation process in which sulfuric acid can be a problem is in boilers and process heaters firing high sulfur fuel oils. This is identified as "dew-point corrosion" which is caused by a mixture of sulfurous (H_2SO_3) and sulfuric (H_2SO_4) acids. The basic ingredients are SO_2, SO_3, and H_2O all of which are present in the flue gases. These oxides are products of combustion of the high sulfur low grade fuel oils.

When fireside metal surface temperatures drop below the dew point of the flue gas a highly acidic solution will form. The vapor phase with even small amount of sulfuric acid will cause the dew point to increase. The liquid phase formed on the metal surface will contain a high concentration of sulfuric acid. The fact that the sulfur compounds in the vapor phase (flue gases) increase the dew point so markedly also increases the likelihood that the acid condensate will form.

All boilers are designed to operate such that, when properly fired, the fire side metal surfaces operate at temperatures well above the dew point of the flue gases. To insure that metal surfaces stay above the dew point, suggested operating procedures and settings should be strictly followed. The effect of metal temperature on the corrosion rate of carbon steel

4.4.3 (cont'd)

exposed to the flue gases of a low grade (4% sulfur) fuel oil is shown in Figure 22. This emphasizes the need for proper operation.



EFFECT OF METAL TEMPERATURE ON THE CORROSION RATE OF CARBON STEEL WHEN FIRING OIL AND NATURAL GAS

FIGURE 22

Accompanying the combustion of any low grade fuel oil is the formation of ash deposits which collect on the fire side of all metal surfaces. These deposits contain among other things, sulfur compounds such as sulfates and sulfites. In the absence of moisture, the deposits are of little concern. But when water vapor in the air condenses on the surfaces covered by ash, the sulfur compound will readily hydrolyze to form the strongly acidic solutions mentioned previously.

The problem of dew point corrosion by condensation from the atmosphere will be a greater problem in areas of frequently high humidity.

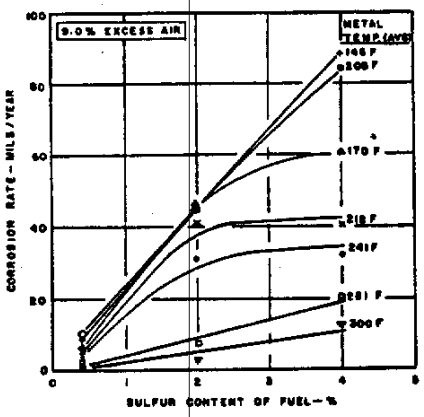
The following steps are recommended for shutdown maintenance to protect against dew point corrosion.

1. Clean fireside tube and tube sheet surfaces thoroughly of their accumulation of ash, soot, and other products of combustion immediately after shutdown.

4.4.3 (cont'd)

2. These surfaces should then be flushed completely with water or alkaline solution and fully dried by blowing air through the boiler. This will dissolve, dilute and remove any sulfur compounds remaining after the deposits are cleaned off.

3. Finally, the present fuel should be evaluated for sulfur content: if it is high, switch to one containing less sulfur if possible. Figure 23 illustrates the effectiveness of lowering the sulfur content of the fuel on corrosion rates. Also, the lower the content in the fuel, the less the amount of sulfur that is deposited in the ash.



EFFECT OF SULFUR CONTENT OF FUEL OIL AND METAL TEMPERATURE ON THE CORROSION RATE OF CARBON STEEL

FIGURE 23

4.4.4 Polythionic Acids

These acids with the chemical formula of H_2SxO_6, where x is usually 3, 4 or 5 can form readily in petroleum refinery units during shutdown. Only the interaction of sulfide, moisture and oxygen is required. Sulfide as a corrosion product and H_2S is present in numerous refinery units. Moisture usually is available from general humidity, from washing or from steaming out units for safety reasons during downtimes. Oxygen is available from the air which can enter equipment as soon as it is opened.

Unless suitable precautions are taken, the Cr-Ni austenitic stainless steels which have been exposed to a sulfur-bearing environment may become susceptible to failure by intergranular stress corrosion cracking during a subsequent shutdown. For more discussion on the polythionic acid intergranular stress corrosion cracking, refer to section IV, part 2.6.

4.4.5 Hydrofluoric Acid

HF can be an extremely corrosive acid to most steels and alloys and is also very lethal to humans. However, the HF acid used in the alkylation process is rather non-corrosive comparatively speaking when proper operation, neutralization and maintenance practices are followed and resistant materials are used where the HF acid contains water and temperatures are high.

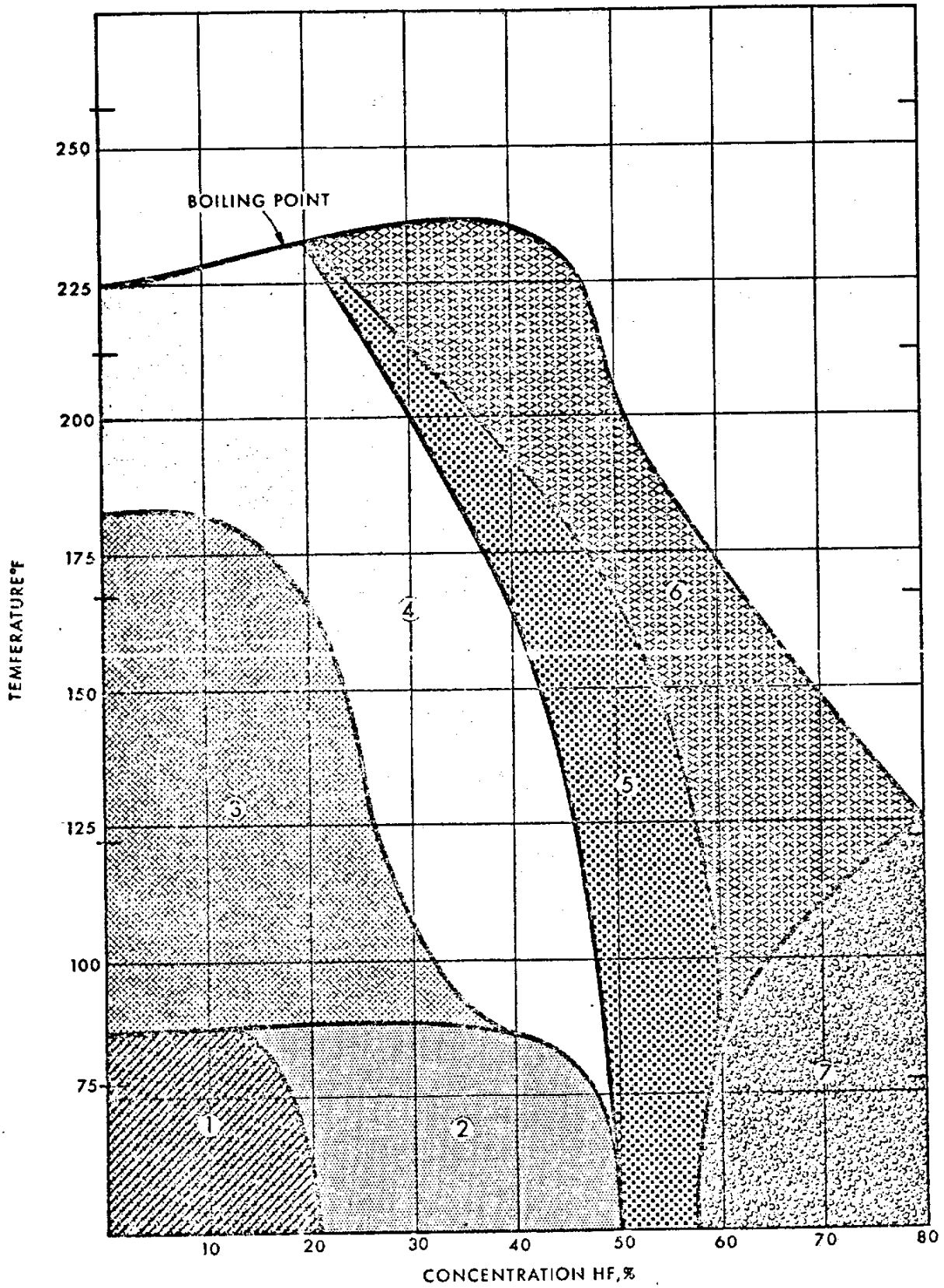
The majority of equipment in the HF Alkylation unit is constructed of killed carbon steels with weld radiographed and Post Weld Heat Treated. This provides quality welds and a reduction in residual tensile stresses that could result in stress corrosion and cracking.

It was discovered early in the process development that the Monel alloy had very good resistance to the high temperatures involved in the Acid Regeneration section, and in exchange and condensing equipment where water might be present. Therefore, Monel is the basic non-carbon steel used in the unit although Hastelloy B and C have been an acceptable alternate to Monel in some locations. The 70-30 Cupro Nickel alloy has been used with success in condensing equipment where sea water cooling is used.

4.4.5 (Cont'd)

Figure 24 shows the different materials that can be used in various HF concentrations vs. temperature zones. The zones are based on the materials having a corrosion rate less than 0.02 ipy. One can see why Monel is used in the HF alkylation process since it exhibits resistance in all zones. Most of the HF Alkylation environments would fit in Zone 7 which shows carbon steel to be useful. Actually, corrosion rates of steel are generally less than 0.02 ipy. This is due to the production of a very dense and tenacious iron fluoride corrosion product on the exposed steel surfaces. This effectively stifles further corrosion. The use of this curve has to be done with some caution since performance of some of the alloys in hydrocarbon-HF streams may not be the same as in the HF-water system. for example, silver is shown to be an acceptable material in all zones, however early experience proved rather dramatically that the presence of sulfur compounds in the hydrocarbon caused very rapid corrosion and solution of silver. Also, although copper and some brass alloys have acceptable resistance in many HF acid environments, it was found that under velocity and impinging conditions, these materials deteriorated rapidly.

FIGURE 24



CORROSION RESISTANCE OF MATERIALS TO HYDROFLUORIC ACID

CORROSION RATE LESS THAN 0.020" PER YEAR

CODE FOR HYDROFLUORIC ACID CHART - FIGURE 24 (Cont'd)

Materials in shaded zones having reported corrosion rate less than 0.020" per year

Zone 1

Monel (Air Free)
Copper (Air Free)
70 Cu-30 Ni (Air Free)
Lead (Air Free)
Nickel (Air Free)
Alloy 20
Ni Resist
Hastelloy C
Platinum
Silver
Gold
Impervious Graphite
Haveg 43
Rubber
25 Cr-20 Ni Steel

Zone 2

Monel (Air Free)
70 Cu-30 Ni (Air Free)
Copper (Air Free)
Lead (Air Free)
Nickel (Air Free)
Alloy 20
Hastelloy C
Platinum
Silver
Gold
Impervious Graphite
Rubber
Haveg 43

Zone 3

Monel (Air Free)
70 Cu-30 Ni (Air Free)
Copper (Air Free)
Lead (Air Free)
Alloy 20
Hastelloy C
Platinum
Silver
Gold
Impervious Graphite
Haveg 43
Rubber

Zone 4

Monel (Air Free)
70 Cu-30 Ni (Air Free)
Copper (Air Free)
Lead (Air Free)
Hastelloy C
Platinum
Silver
Gold
Impervious Graphite
Haveg 43

Zone 5

Monel (Air Free)
70 Cu-30 Ni (Air Free)
Lead (Air Free)
Hastelloy C
Platinum
Silver
Gold
Impervious Graphite
Haveg 43

Zone 6

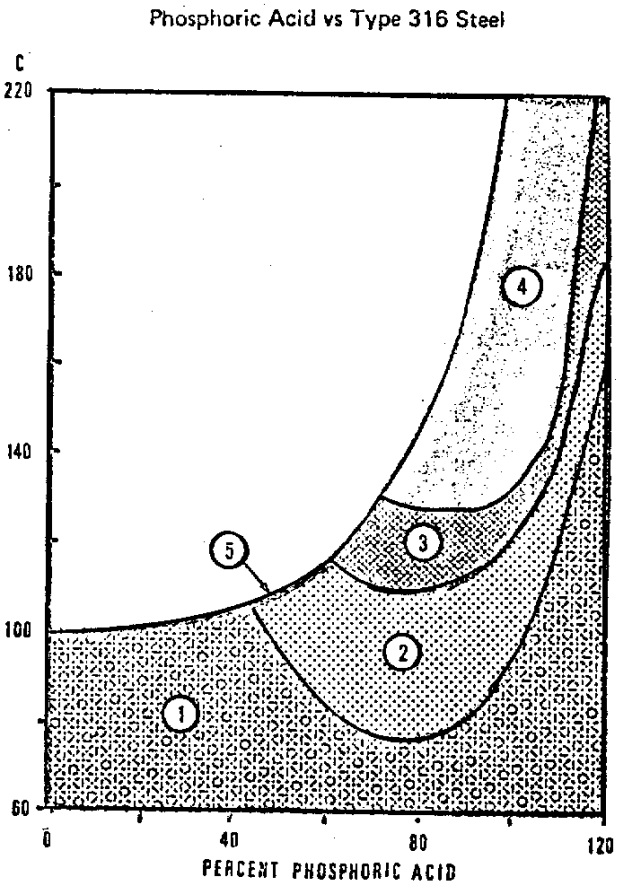
Monel (Air Free)
Hastelloy C *or B*
Platinum
Silver
Gold
Haveg 43

Zone 7

Carbon Steel
Monel (Air Free)
Hastelloy C *or B*
Platinum
Silver
Gold
Haveg 43

4.4.6 Phosphoric Acid

In the catalytic condensation (polymerization) process units such as Cumene and Tetramer catalyst containing phosphorous pentoxide (P_2O_5) is utilized. The reactor effluent stream will contain some phosphoric acid components which at the lower temperatures, condense out as a heavy "syrup" material. This syrup is quite corrosive to carbon steel. Type 316 stainless steel is used for equipment where resistance is necessary. Figure 25 shows isocorrosion curves for Type 316 Stainless Steel in phosphoric Acid.



Isocorrosion of Type 316 steel in furnace grade phosphoric acid under mildly agitated conditions. Mils per year averages: (1) = 0 to 1. (2) = 1 to 10 (3) = 10 to 50 (4) = >50 (5) = Boiling point curve.

FIGURE 25

4.5 Hydrogen Attack

Gaseous molecular hydrogen does not readily permeate steel at atmospheric temperatures even at quite high pressure. However, atomic hydrogen will diffuse into and pass through the crystal lattices of metals causing damage, called hydrogen attack. Metals most subject to hydrogen attack are the carbon, low-alloy, ferritic and martensitic stainless steels. Sources of hydrogen in the processing of hydrocarbons include the following:

a- Nacent (atomic) hydrogen released at metal surfaces from a corrosion reaction

b- Nacent (atomic) hydrogen, released by a process reaction such as catalytic reforming

c- Dissociation of molecular hydrogen gas under pressure at metal surfaces

Hydrogen attack is characterized by three types of damage which we will put in the following two categories.

4.5.1 Low Temperature Blistering and Embrittlement

These two types of damage generally occur under aqueous phase conditions in the pressure of a corrosive environment. In the refinery, these environments may be acids such as HCl, HF, and H_2S in water. For blistering to occur, the atomic hydrogen released from the corrosion reaction diffuses into the steel and combines to form molecular hydrogen gas in any voids until local yielding or cracking occurs. Such voids include laminations, slag pockets, shrinkage cavities in castings and unvented spaces.

Embrittlement is caused by the presence of atomic hydrogen within the metal crystal lattices. Such embrittlement becomes permanent when hydrogen atoms combine in submicroscopic and larger voids to form trapped molecules which may build up sufficient stresses to cause subsurface fissuring.

When the source of hydrogen is corrosion of the containing equipment, high strength, highly stressed parts, such as carbon steel or low-alloy gas compressor rotor blades, exchanger floating-head bolts, valve internals and safety valve springs are particularly susceptible to embrittlement.

4.5.1 (cont'd)

Experience has confirmed, however, that if yield strengths are limited to 90,000 psi, maximum and working stresses are limited to 80 percent of yield, cracking failures are minimized in compressors. Welds and their heat affected zones should be stress relieved,hardnesses should be limited to Rockwell C22 or less, and they should be free from hard spots, slag pockets, sub-surface as well as surface cracks and other voids.

The use of fine-grained, fully-killed carbon steels are not always justifiable as a first choice for aqueous-phase hydrogen services since these premium grades may be equally subject to embrittlement and subsurface fissuring as the lower grades. In the absence of blistering such embrittlement is not easily discernible. Although the lower grades may blister, this blistering serves as its own warning that steps should be taken to protect the equipment from hydrogen damage. However, in applications where experience has shown hydrogen attack may be severe, fully killed steel is specified along with PWHT requirements and hardness limits.

When corrosion is the source of diffusing hydrogen, the elimination of this reactive hydrogen is necessary to stop its diffusion into the metal. This can be done either by (1) eliminating the corrosion, or by (2) eliminating chemicals in the process stream that "poison" the corroding metal surface: that is, by eliminating chemical agents which retard or inhibit the combining of nacent hydrogen atoms at the corroding surface into molecular hydrogen which cannot enter the metal.

Corrosion can be eliminated by the use of corrosion resistant barriers and/or alloys. This becomes necessary in situations in which measures to eliminate "poisoning agents" are not permissible or effective. Concrete linings over expanded metal mesh, and to a limited extent, plastic coatings have been used successfully where the normal operating pH is maintained above 7.0. Corrosion resistant alloy cladding may be used for severe operating conditions.

Compounds such as hydrogen sulfide and cyanides are the most common metal surface "poisons" occurring in process units subject to aqueous phase hydrogen attack. In some process units, these compounds can be effectively eliminated and hydrogen diffusion stopped by adding ammonium polysulfides and thiocyanates provided the pH is kept on the alkaline side. This practice has been followed by some

4.5.1 (Cont'd)

refiners, however requires judicious control of injection and monitoring. It has been UOP's practice and recommendations in the area of FCC Gas Concentration Units for years to utilize a water washing system whereby the components causing hydrogen attack are essentially removed from the system. This along with pH control and inhibitor injection in most cases eliminates hydrogen attack in the form of blistering and embrittlement; in cases where cyanide contents are appreciable, alloying may be necessary if the normal water washing scheme doesn't work completely.

Hydrogen blistering and embrittlement have been found in the FCC Gas Con Units where an aqueous phase with H_2S is present, in the catalytic reformer where moist environments with HCl are present and in various parts of the HF alkylation unit. Blisters come in all sizes, from about 1/8" diameter to several feet in diameter. Unless the depth, number and orientation is such that the strength of the vessel is reduced below the required level, the normal procedure of carefully drilling the blisters to release the trapped hydrogen renders them harmless. Since no loss in effective cross section thickness results, little or no loss in hoop strength occurs. In cases of severe blistering, the entire vessel or blisters section have been replaced. When hydrogen blistering occurs on a piece of equipment, a very thorough ultrasonic inspection to map the extent, depth and geometry of the blisters should be done. This allows one to make a judgement as to the necessity and extent of repairs required to put the equipment back in service.

It is not unusual when blistering is found, to also find evidence of embrittlement in highly stressed areas such as unheat treated welds and in high strength steels such as bolting, valve trim and some compressor parts. Therefore, in environments where blistering and/or cracking due to H_2 embrittlement is highly probable, welded equipment should be post weld heat treated, and hardness and strength maximums should be imposed on the high strength steels. If these limits cannot be imposed, the more resistant materials need to be used.

4.5.1 (cont'd)

Being cognizant of the potential hazards of hydrogen embrittlement failures (also called sulfide stress corrosion cracking when H_2S is involved) of welds and equipment, the refinery corrosion committees of both NACE and API have published Recommended Practices providing guidelines to the industry for choice of materials, welding parameters and properties to maximize resistance to cracking. Appendix 9 shows the NACE Standard RP-04-72 (1976 revision). The API Recommended Practice, Publ. 942, is very similar.

4.5.2 High Temperature Decarburization and Cracking

The action on steel at elevated temperatures under hydrogen pressures is illustrated in Figure 26. This chart, developed over the past 25 years, depicts operating limits for carbon, carbon-molybdenum, and chromium-molybdenum steels in contact with plant process hydrogen. Satisfactory performance points were plotted only if the samples or equipment had been exposed for a minimum one-year period. Unsatisfactory performance points from either laboratory or plant data were plotted regardless of the length of time exposed. Data to support the curves were obtained from a variety of commercial processes and laboratory experiments that used hydrogen at high temperatures and pressures.

The original version of Fig. 26 was prepared for the American Petroleum Institute in 1949 and has generally been identified as the "Nelson Chart". Much experience has since been gained, enabling certain curves to be more firmly located or adjusted and others to be added.

Revisions have been made to all of the original curves, while curves defining operating limits for 0.25 Mo., 1.25 Cr - 0.5 Mo, and 2.2 5 Cr - 1 Mo steels have been added. Composition of these steels as well as all steels, (except for 0.25 Mo) should conform to the minimum limits of ASTM Specifications for the various grades. As 0.25 Mo steel is not an ASTM Grade, it should have a minimum limit of 0.25 Mo.

The slashed lines at the top of Fig. 26 represent tendencies for steels to decarburize through the surface while in contact with hydrogen.

4.5.2 (cont'd)

Surface decarburization does not produce fissures and in this respect is similar to decarburization created by exposure of steel to certain other gases, e.g., air, oxygen, or carbon dioxide. Usual effects are a slight loss in strength and hardness, accompanied by an increase in ductility. A number of theories have been proposed to explain this phenomenon, but the currently accepted view is based on migration of carbon to the surface where gaseous compounds of carbon, CH_4, or CO,when oxygen-containing gases are present, are formed, thus rendering the steel less rich in carbon. Moisture hastens the reaction. Carbon in solution diffuses to the surface so that the rate-controlling mechanism appears to be carbon diffusion.

Inasmuch as the carbon in solution is supplied continuously from the carbides, carbide stability can contribute to a lower rate of surface decarburization. Alloy steels containing more than 2 percent chromium plus 0.5 to 1.0 percent molybdenum may never exhibit internal attack, as such, for a given temperature and hydrogen pressure, (below 6,000 psi) but may eventually decarburize. Since internal reaction sites are significantly reduced by these alloy additions, the surface reaction is favored. At very high pressures (above 6,000 psi) internal attack is also noted. For plain carbon steel, the combination of high temperatures and low hydrogen pressures favors surface decarburization without internal decarburization. The combination of low temperature (but above 430°F) and high hydrogen pressure favors internal decarburization and cracking.

Limits for decarburization of steels containing more than 2.0 percent Cr-0.5 percent Mo have been extended only to 6,000 psia. At the high temperatures shown and at pressures above 6,000 psia, these steels must be further fortified with other carbide stabilizers, such as tungsten or vanadium, to render them resistant to both internal and surface decarburization.

The solid lines on Fig.26 define the areas above where failures by internal decarburization and internal cracking have been reported. Below and to the left of the curves for each alloy, satisfactory performance has been experienced with periods of exposure up to 35 years. At temperatures above and to the right of the solid curves, internal decarburization occurs. Internal decarburization is preceded by an incubation period which is dependent on temperature and pressure.

4.5.2 (cont'd)

Internal decarburization and cracking is caused by hydrogen permeating the steel and reacting to form other gases; e.g., hydrogen may react with carbon to form methane. The methane which is formed cannot diffuse out of the steel. Accumulation of methane in voids, many of which form at grain boundaries, results in the development of high stresses which ultimately fissure, crack, or blister the metal.

Fissures in hydrogen-damaged steel are initially microscopic. However, in advanced stages of attack, their sheer quantity produces a substantial deterioration of mechanical properties. For example, a steel with strength originally of 60,000 psi had it reduced to 25,000 psi and its elongation of reduced from 30 percent to nil.

Addition of carbide stabilizers to steel results in a situation where internal cracking is less likely. Elements such as chromium, molybdenum, tungsten, vanadium, titanium, and niobium reduce the number of nucleation sites and tie up the carbon, thereby lowering the amount of this element available for methane formation.

The solid line curves on Fig. 26 reflect the added resistance to internal attack when chromium or molybdenum are present in concentrations of less than 2.0 percent and 0.5 percent, respectively. Austenitic stainless steels are resistant to high-temperature damage because of their high chromium content.

The presence of slag or inclusions tends to increase the degree of damage. When steel is contaminated with segregated impurities or stringy laminations, methane accumulations in these areas may cause severe blistering. Also, in the welding of steels to be used in hydrogen service, it is important that sound, "inclusion-free" welds be obtained.

Damage to steels by high-pressure-high-temperature hydrogen is preceded by a period of time when no noticeable change in properties can be detected by usual commercial testing methods. After this period of time has elapsed, cracking occurs with resultant decreases in strength and ductility. The length of time before hydrogen attack can be detected is termed the "incubation period". Duration of this period varies with the type of steel and severity of exposure, lasting only a few hours under extreme conditions and becoming progressively longer at lower temperatures and pressures. With some steels under mild conditions, no damage can be detected by commercial testing methods, even after many years of exposure.

4.5.2 (cont'd)

Various theories have been proposed to explain the incubation period, but the most plausible theory maintains that during the incubation period methane pressure builds up in submicroscopic voids. At first the pressure is balanced by surface tension and a void can only grow slowly. The action at this stage is reversible with hydrogen pressure and no change occurs in mechanical properties. When a void reaches a critical size, it grows much more rapidly and at a still larger size, growth rate increases further as the controlling mechanism becomes creep. With expansion of cavities to microscopically visible fissures, effects on mechanical properties becomes significant. The incubation time is dependent on many variables, including the type of steel, degree of cold working, pressure, and temperature. It is very important to realize that equipment operating under a blanket of high-pressure hydrogen retains its initial strength only during the incubation period.

The length of the incubation period is important. A guide to determine approximate safe operating times for steels operating above their prescribed levels is shown in the incubation curves for carbon steel (see Figure 27) and 0.5 Mo steel (see Figure 28) as times for incipient attack to occur. Data of this type are important in that they permit estimates of damage that could occur during periods of temperature and/or hydrogen pressure increases. Data such as this is also useful when temporary repairs of existing equipment is necessary or replacement for short periods of time of existing equipment with that of lower alloy. This approach has been followed many times successfully.

References to satisfactory performance of steels as shown on Fig.26 were obtained from pressure-retaining equipment constructed of annealed or normalized and tempered steels that were designed at stress levels defined by the 1969 or earlier editions of the commonly accepted codes; i.e., ASME Section VIII, Div. 1, etc. Therefore, operating stresses for steels operating in zones below the solid curves would represent those no greater than permitted by these codes. The data in Fig.26 do not reflect service experience with equipment designed using the higher allowable stresses now permitted in Section VIII, Division 2, of the ASME Code, where enhanced property (quenched and tempered or normalized and tempered) steels may be utilized. As temperatures approach the surface decarburization levels (see Fig.26 for 2.25 Cr-1.0 Mo, 3.0 Cr-0.5 Mo, and 6.0 Cr-0.5 Mo steels), meager unpublished data indicate that the creep-rupture strength of 2.25 Cr-1.0 Mo steel in a 5,000 hr. test for example, may be somewhat lower when tested in hydrogen

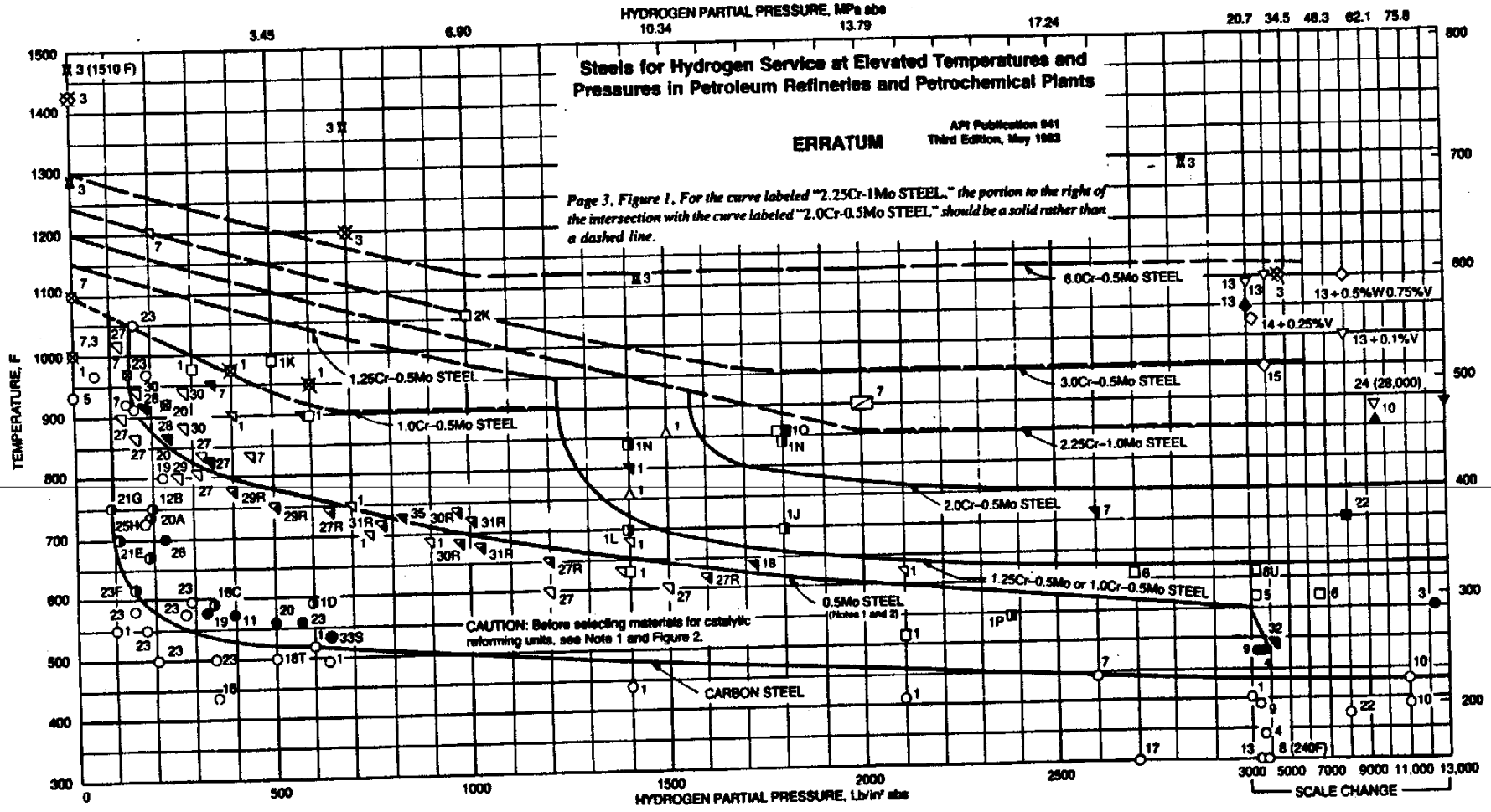
4.5.2 (cont'd)

than when tested in argon. Creep-testing programs are in operation and will provide very useful information on strength at temperatures approaching surface decarburization levels for all low-alloy steels shown in the curves.

Even though the alloy may have adequate resistance to the high temperature hydrogen attack, the retention of dissolved hydrogen (atomic) in the metal could possibly result in stress cracking, especially in equipment with greater thickness,or embrittlement at lower temperatures. This would be of chief concern in steels that are heat treated to high yield strengths and containing hard structures more susceptable to hydrogen cracking/embrittlement. Therefore, the same limits are generally placed tensile, yield, and hardness properties as for the aqueous environments causing hydrogen embrittlement discussed earlier.

Hydrogen attack is accelerated by cold work and resulting strain since these are locations of greater stress. Therefore, in design and fabrication, it is important to remove highly stressed areas due to strain and to remove notches that could concentrate stress.

Although the data shown in the curves indicate safe operating limits in hydrogen service, it must be remembered that it is used solely as a guide and must be used in conjunction with sound engineering judgement.



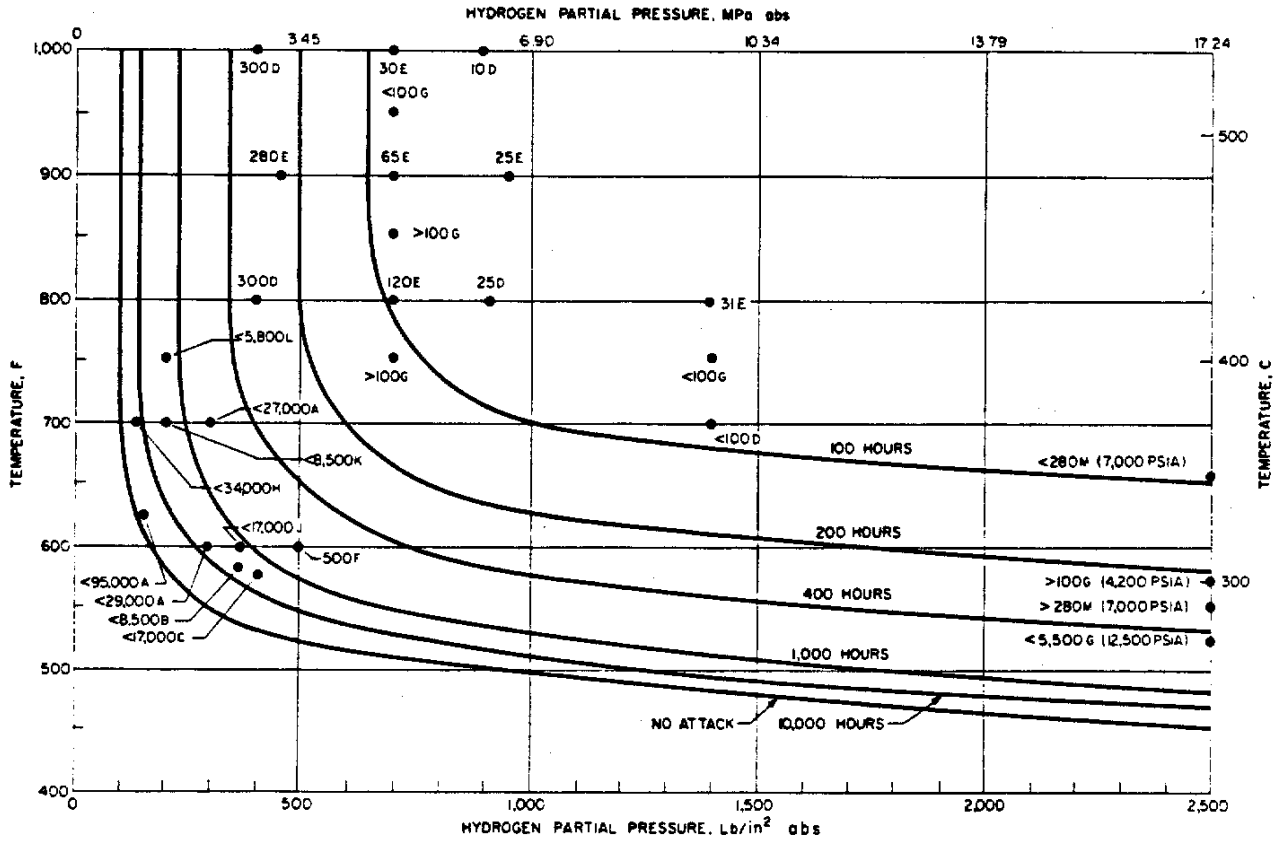
Copyright © 1967 by G. A. Nelson. Reproduction rights granted by author to API. This figure has been revised by API in 1969, 1977, and 1982.

NOTES:

1. After approximately 9–18 years' service, eight occurrences of hydrogen attack have been reported in C-0.5Mo steels operating below the 1977 0.5Mo curve in catalytic reforming units. These steels experienced hydrogen attack under conditions in which extensive decarburization or carbon migration to grain boundaries was not documented or reported prior to 1960. Further use of 0.5Mo steel in catalytic reforming units to resist internal fissuring should be evaluated rigorously until information is available to explain this phenomenon. Refer to 2.3 in the text, Table 1, and Figure 2.
2. The curve for 0.5Mo steel can apply to either C-0.5Mo or Mn-0.5Mo steels.
3. Austenitic stainless steels are generally not decarburized in hydrogen at any temperature or hydrogen pressure.
4. Effect of trace alloying elements (up to 1000 pounds per square inch absolute [6.90 megapascals] hydrogen partial pressure and below 1000 F [538 C]):
   a. Mo has four times the resistance of Cr to hydrogen attack.
   b. Mo is equivalent to V, Ti, or Nb up to 0.1 percent.
   c. Si, Ni, Cu, P, and S do not increase resistance.
5. The limits described by these curves are based on experience with cast steel as well as annealed and normalized steels at stress levels defined by the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1. Refer to 2.5 and 2.6 in the text for additional information.

Figure 1—Operating Limits for Steels in Hydrogen Service to Avoid Decarburization and Fissuring

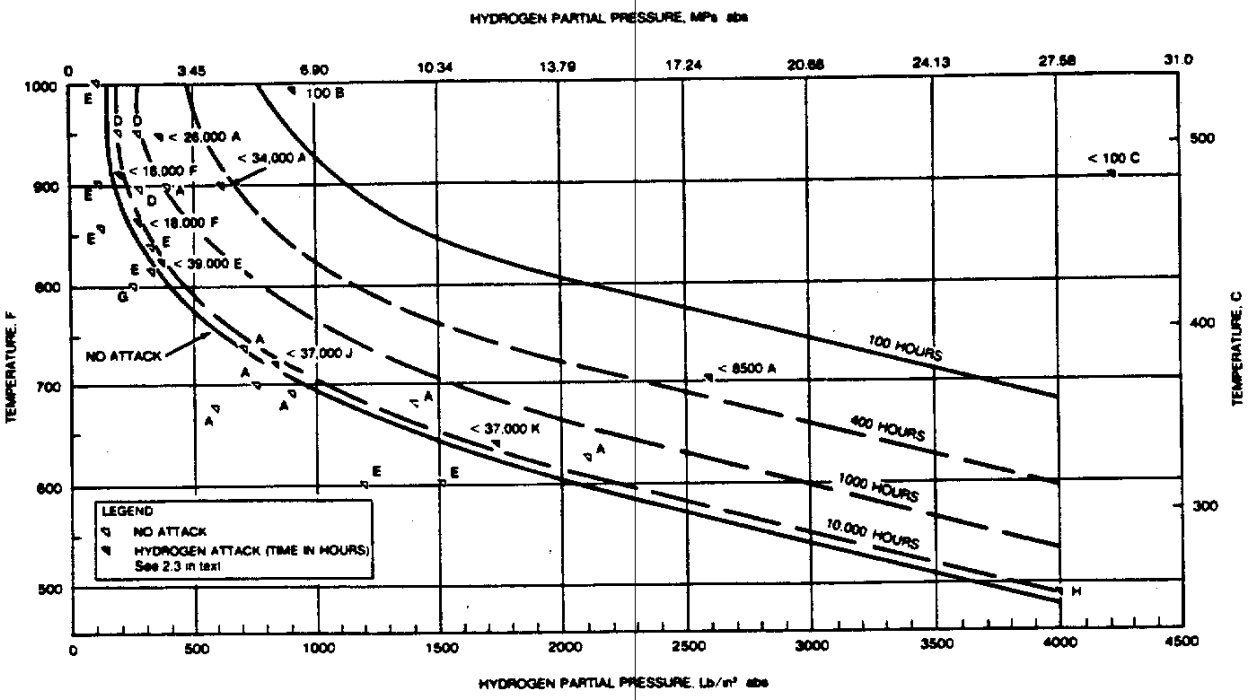
FIGURE 26



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Figure 4—Time for Incipient Attack of Carbon Steel in Hydrogen Service

API 941 THIRD EDITION



REFERENCES:

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Figure 5—Time for Incipient Attack of 0.5Mo Steel in Hydrogen Service

API 941 THIRD EDITION

4.6 Fuel Ash Corrosion

Fuel ash corrosion of components in process furnaces, utility boilers and other equipment is due to the effect of vanadium and sodium contained in the fuel fired. Crudes from Venezuela, other Caribbean sources, the western United States and Canada have high concentrations of vanadium and other metals. These metals are found in the form of organometallic complexes called porphyrins which are concentrated during the refining cycle in heavy residual fuels. In addition to these organometallic complexes, caustic and entrained salt in the crude are also concentrated in the heavy fuels. These salts acts synergistically with the vanadium compounds present and can cause accelrated corrosion of metals and refractories in utility boiler and process furnaces when firing these types of fuels.

Sodium plus vanadium in the fuel in excess of 50-100 ppm can be expected to form fuel ashes corrosive to metals.

Combustion of fuels containing significant amount of porphyrins and other metallic salts results in formation of low melting point vanadium pentoxide (V_2O_5), vanadates such as Na_2O-$6V_2O_5$, or alkali sulfates which are corrosive to metals at combustic temperatures. At high combustion temperatures, approximately 2,800°F, and especially when low amounts of excess O_2 are present, the sub-oxides of vanadium, V_2O_3 or VO_2, are formed. These sub-oxides are refractory and do not cause corrosion. At lower temperatures, less than 2,400°F, and with higher excess air levels, the low melting point V_2O_5 is formed. The latter condition is most prevalent during combustion and corrosion of furnace components results.

Physical property data for vanadates, phase diagrams, laboratory experiments and numerous field investigations have shown that the sodium vanadates are the lowest melting compounds and are the most corrosive to metals and refractories. These compounds are thought to form by either the vapor phase reaction of NaCl and V_2O_5 or by the combination of fine droplets of these materials upon the cooler parts of combustion equipment.

Excess sodium hydroxide present can also be troublesome as the alkali reacts with the SO_3 present in the gas stream to form a range of alkali sulfates which in themselves are highly corrosive to metallic components. In addition, the combination of alkali sulfate + V_2O_5 can result in compounds having melting points as low as 600°F. This situation is only encountered when alkali is present in amounts in excess of that which can react stoichiometrically with V_2O_5.

Maximum corrosion rates have been found to occur with alkali vanadates approximating the Na_2O-$6V_2O_6$ compound (6-10 weight percent Na_2O). This corrosion rate maximum can be influenced

4.6 (cont'd)

by the presence of other oxides and sulfur. The sodium vanadates are most corrosive over the temperature range of 1,100-1,500°F. At temperatures below 1,100°F little or no liquid phase would be found, thus corrosion of metals is low. At temperatures above 1,550°F, the maximum corrosion rate shifts toward melts having high proportions of V_2O_5.

Corrosion of metals by V_2O_5 or alkali vanadates is influenced by several variables the most important being: a) Partial pressure of oxygen, b) characteristics of the metal vanadates formed, c) dissolution rate of the oxide films present and d) composition of the fuel ash.

Corrosion of metals by fuel ashes only occurs where the fuel ash contains a liquid phase. Temperatures at which the first liquid will form are inversely proportional to the oxygen partial pressure. Thus, when firing fuels at high excess air ratios, fuel ash corrosion occurs at lower temperatures than when firing fuels with low excess air ratios.

Metals forming oxide films high in Cr_2O_3, NiO and CoO are found to corrode at much lower rates than those forming films predominantly of Fe_2O_3. Films of Cr_2O_3, NiO, and CoO are tightly adherent and thus, may act as barriers to O_2 diffusion. Dissolution rates for these oxides are also low and thus retard the over-all corrosion rate. Furthermore, the vanadates which do form are refractory and tend to form skins which act as barriers to further transport of O_2 and molten ash to the metal surface. Iron vanadates show unique behavior. Fe_2O_3 is readily dissolved in vanadates over the range $Na_2O \cdot 6V_2O_5$ to $5Na_2O \cdot V_2O_5$, and can be dissolved in these melts in amounts equal to the weight of the melt before the melting point is raised above 1,300°F. Since these sodium vanadates cover the range of the compositions found in most fuel ashes, the corrosion of iron bearing alloys is extensive when in contact with these molten ashes.

Methods which have been used to control fuel ash corrosion are: Fuel oil additives, excess air control, refractory coatings, and choice of alloys.

Oil additives are normally introduced as suspension of metallic oxides or other salts such as MgO, $Mg(OH)_2$, $Ca(OH)_2$, Al_2O_3, etc., in fuel oil or water. Use of these compounds, although being effective in reducing corrosion, has been generally shown to be uneconomic, and to cause more problems, such as tube fouling, increased soot blower usage, solids disposal, etc., than they cure.

Improved desalting will reduce the sodium content however desulfurization down to the level to prevent sulfur compounds is impractical.

Use of excess air levels of 5 percent or less has been shown to reduce fuel ash corrosion in furnaces, most likely by

4.6 (cont'd)

stabilizing the vanadium as a refractory suboxide, VO_2 or V_2O_3. Utility plants have had some success using this method to control vanadium ash corrosion, however, practical application of excess air control in refinery and chemical plant operations is difficult, and has not been particularly successful. Problems with particulates, smoke, pollution and flame control are encountered unless the necessary expensive control systems and operator attention are constantly available.

Monolythic refractory coatings have been applied to metal components in furnaces in an attempt to control fuel ash corrosion. Results have been less than satisfactory because of bonding difficulties and the large thermal expansion mismatch between the metal and refractory. Failure usually occurs upon thermal cycling which causes cracking, eventual spalling of the refractory and direct exposure of the metal to the effects of the fuel ash.

Field experience and laboratory data indicate that alloys high in chromium offer the best solution to fuel ash corrosion. Alloys having relatively high chromium contents such as 26/28 Cr Type 446 stainless steel and 50 Cr/50 Ni show improved fuel ash corrosion resistance. Type 310(26 Cr-20 Ni) stainless steel offers little or no more corrosion resistance than Type 304 (18 Cr-8 Ni) stainless steel.

Extensive field experience has shown the 50 Cr-50 Ni and 60 Cr-40 Ni alloys offer the best resistance to fuel oil ash corrosion. Type 446 stainless steel also shows acceptable corrosion rates but since it has low strength at elevated temperatures and weldability is poor, its use is limited. Since components of 50 Cr-50 Ni in contact with vanadium-sodium fuel ash melts still suffer some corrosion, they should be designed to minimize the amount of surface area available on which ash may accumulate.

UOP's practice at the present time is; when the fuel burned in the heater(s) contains more than 50 wt. ppm Vanadium, the 50 Cr-50 Ni alloy castings shall be used for tube supports, guides, retainers, baffles and baffle supports, regardless of the temperature of the gases to which they are exposed.

V. CORROSION CONTROL IN THE CRUDE DISTILLATION AREA - "AN OVERVIEW"

Corrosion by acidic water and inorganic salts in crude-distillation condensers is a major problem in petroleum refineries. As refineries become larger and must be kept on stream continuously to be economically profitable, control of corrosion becomes an essential part of refinery operation.

Crudes received at a refinery vary widely in potential corrosivity both because of differences in chemical composition, and because of differences in pretreatment at the well and during transportation recovery operations using oxygen-containing water or gas, acidizing, solvent de-waxing, stripping, with gases containing oxygen, adding corrosion inhibitors which increase the amount of water carried in the crude, and aeration during storage and handling can all increase corrosivity - particularly in refinery condensers. Hydrogen chloride and hydrogen sulfide produced by thermal decomposition of impurities in the crude are the principal offenders, and their corrosivity is increased in the presence of oxygen and water.

Hydrogen Chloride:

Because crudes generally are found in the presence of salt water, the water entrained in crude contains about 3 to 10% salts, mostly chlorides. Hydrogen chloride is formed when chloride salts, mainly of Mg and Ca, are heated to about 250°F in the presence of water. Although most water is separated from the crude at the wellhead, some water and dissolved salt reach the refinery. In the preheaters, temperatures are high enough to convert these salts to hydrochloric acid which is the major corrodent in overhead condenser systems.

Most hydrogen sulfide, as such, is removed from crude before it reaches the refinery. However, crudes will frequently contain up to 6% (by weight) sulfur in organic sulfur compounds. In the preheaters at temperatures above 450°F., these compounds decompose to form hydrogen sulfide.

Both HCL and H_2S are formed in other refinery units by thermal or catalytic decomposition in catalytic crackers and cokers, by hydro-dechlorination and hydrodesulfurization with hot hydrogen in reformers, hydrodesulfurizers, hydrotreaters, and hydrocrackers, and by decomposition of processing catalysts such as aluminum chloride used in some isomerization and alkylation processes. In all units, the HCl, H_2S and possibly some volatile organic acids go overhead with the vapor from distillation towers and combine with condensed water to form a strongly acid solution (pH 1-2) particularly corrosive to carbon steel.

Oxygen:

Oxygen accelerates corrosion by HCl and H_2S and also minimizes the benefits of some corrosion inhibitors. Air can enter units by leaks in vacuum equipment or dissolved in the crude, in desalter or other wash water and in distillation and gas stripping steam.

V. (cont'd)

Techniques for controlling corrosion:

The following discussion and Figure 30 are related to controlling corrosion in primary or atmospheric stills. However, the principles involved are applicable to all refinery distillation corrosion problems. Desalting, neutralization, and inhibitor addition can be used alone or in combination to essentially stop corrosion in crude or other unit condensers, provided the limitations are recognized and adequate control is exercised.

The following summarizes the advantages and disadvantages of the common methods of corrosion control:

Treatment	Advantages	Disadvantages
Desalting	Minimizes HCl evolution Removes solids	Removes a sulfidic-corrosion inhibito May add oxygen May add volatile salts Adds water for salt hydrolysis
Neutralizing	Minimizes corrosivity Minimizes inhibitor usage	Forms chloride salts Deposits chloride salts May add oxygen May stress-corrosion crack copper alloys
Water washing	Minimizes fouling	May form highly corrosive salt Forms emulsions Adds water to product and to reflux May add oxygen
Adding corrosion inhibitors	Essentially eliminates corrosion	May accelerate corrosion at low concentrations Emulsifies at high concentrations Corrosive above 250°F at high concentrations

V.(cont'd)

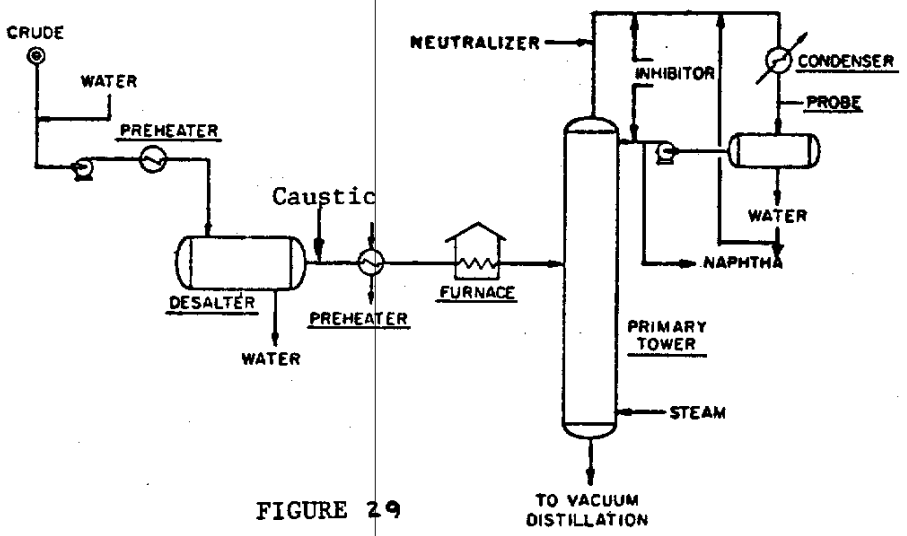


FIGURE 29

Typical Crude Distillation Unit

A typical crude desalter is shown schematically above. Crude from tankage is mixed thoroughly with 3 to 5% water in the feed pump, the mixture is heated to about 250°F, and the resulting emulsion is broken chemically or electrostatically in the desalter. This treatment generally removes more than 95% of the salt and 50 to 75% of entrained solids. The amount of HCl liberated when the crude is heated in the furnace is reduced markedly by desalting, so that the potential for corrosion in the condenser system is reduced. Some refineries now use two desalters in series to reduce salt content to only a trace. Solids removal minimizes fouling in subsequent equipment.

Without adequate control, desalting can cause additional corrosion problems. Desalting water should be as pure as possible for maximum efficiency. In particular, the water should be air-free to prevent additional oxygen pick-up by the crude. Generally crudes are slightly acidic, so it is often advantageous to add some caustic to the desalter water. This extracts acids and leaves the crude slightly alkaline, thus minimizing subsequent hydrolysis of residual salts to HCl. Also, the alkaline (pH 8.0 to 8.5) desalter effluent water, which contains about 8% salt, is less corrosive todisposal equipment than is an acidic effluent.

Air-free steam condensate, boiler blowdown or full stripped sour water is preferred for desalting. Ammonia-rich refinery "sour" water from distillation tower condensers, if used for desalting, can cause plugging of distillation towers and condensers with ammonium salts and under-deposit corrosion.

Although complete chloride removal is desirable to minimize corrosion in the overhead system of the distillation tower, it appears that chlorides may tend to inhibit high-temperature corrosion by sulfidic compounds.

V. (cont'd)

Neutralizers:

To minimize the corrosivity of the overhead condensate, neutralizers are added to control pH. Ammonia has been preferred because it is cheap; it is easy to handle as a liquid, as a gas, or as an aqueous solution; its salts are very soluble in water and can be readily removed by water washing. In most units the pH is controlled by manual adjustment of neutralizer feed rate on the basis of spot samples.

Dilute ammonium hydroxide (about 10% by weight) is normally recommended for injection to maximize pH control and to minimize the possibility of stress-corrosion cracking of copper alloys. More concentrated NH_4OH (28%) has been used, particulary in cold climates where dilute NH_4OH freezes. Anhydrous ammonia in gas cylinders is used where pumps are not available. In some units, steam is used to carry the ammonia to the tower overhead. This prevents freezing and disperses the ammonia in the vapor for better utilization and more sensitive control.

The two primary dangers in the use of ammonia are the possibilities of salt deposition - mainly NH_4OH and $(NH_4)_2S$ - and stress-corrosion cracking of copper alloys commonly used in exchanger tubes.

In refineries, cracking of copper alloys has occurred where ammonia was added above about pH9, and in units using anhydrous ammonia, where there was a dead space for ammonia to collect. Ammonium chloride deposits also can induce cracking because they produce ammonia in the presence of copper:

$$2NH_4Cl + Cu \longrightarrow CuCl_2 + 2\ NH_3 + H_2$$

Deposits of salt can be controlled by using the minimum necessary amount of neutralizer or by injecting air-free water to wash out salt. However, insufficient water could result in more severe corrosion of carbon steel by moderately concentrated NH_4Cl solutions above 200°F.

Operating the overhead system at pH 4 to 6 is another method used to minimize salt deposition and corrosion. This method can increase the potential corrosivity of the system for carbon steel. Therefore, to operate at a lower pH, the corrosion inhibitor must be reliable. If the inhibitor is not adequately dispersed to all parts of the system, severe localized corrosion could occur. Also, most inhibitors are active only in a specific pH range close to neutral. Thus the low pH approach requires very close control.

Ammonium sulfide, which can be formed in the system from NH_4OH and H_2S reduces NH_4Cl corrosivity to carbon steel. Corrosion decreases with increased $(NH_4)_2S$ concentration above a minimum, but is highly dependent on the absence of free sulfur. $(NH_4)_2S$ solutions can oxidize to elemental sulfur or polysulfides which accelerate corrosion of carbon steel.

V. (cont'd)

Thus, while ammonium hydroxide can effectively neutralize acid corrosion, care must be used in the rate of addition of NH_4OH. Too little will not effectively prevent acid corrosion; too much can result in salt deposition and alkaline corrosion. Mono-, di-, and tri-ethanoloamines (MEA, DEA, and TEA) morpholine, and diethylamine have also been used as neutralizers. These amines are more expensive than ammonia and can still cause salt deposition and allow some corrosion of carbon steel.

Dilute NaOH solutions can be injected alone or emulsified with an inhibitor, but precautions against caustic embrittlement of carbon steel must be taken. Separate injections of neutralizer and inhibitor are preferred for independent control, but single injections may be used if an existing unit cannot conveniently provide two separate systems. The use of judiciously controlled caustic injection has proven to be an excellent method of corrosion control in the Crude Unit. Appendix 10 describes UOP Guidelines.

Corrosion Inhibitors:

Injection of the proper amount of corrosion inhibitors into the Crude Column overhead along with a neutralizer for pH control and water injection can essentially eliminate corrosion of carbon steel. Too little inhibitor may result in accelerated local corrosion and too much may cause emulsification problems. Injection, typical dosage of about 3 pounds per 1000 barrels of gross liquid throughput, into a horizontal or down-ward flowing section of the vapor line ahead of the first exchanger. At the above dosage, pH should be controlled to 6.5 to 7.5.

Evaluation of Corrosion Control:

The long range effectiveness of a corrosion control program can be determined by use of several testing methods. Periodic analyses of crudes, before and after desalting, and of effluent waters from both the desalters and the condensing systems, are essential to determine the methods and the efficiency of corrosion control. Additional information on salt deposition and fouling must be obtained by regular evaluations of process conditions such as heat transfer coefficients and distillation efficiency. The degree and rate of corrosion can be determined by careful unit inspection during shutdowns, by on-stream non-destructive testing techniques, by analyses of process streams for metals, and by corrosion probe and corrosion coupon exposures at carefully selected locations.

Determination of dissolved iron and copper should be made on the process water. With good inhibition about 0 to 10 ppm of each metal will be found, whereas corrosive conditions are indicated by 50 to 500 ppm of these metals. Occasional upsets that remove scale may give misleading results. However, similar consecutive analyses can indicate how fast metal is being lost because of corrosion.

V. (cont'd)

On stream inspection of selected equipment by radiographic and ultrasonic techniques give more definite indications of corrosion damage without shutting the unit down. However, these methods are not sensitive enough for day-to-day evaluations. Like visual inspection during shutdowns, non-destructive testing determines the long term efficiency of the corrosion control program.

Corrosion probes in the outlet of overhead condensers appear to correlate best with actual corrosion rates. Probes are also valuable in the vapor space of towers and exchanger inlets where temperatures may fall below the dew point. Retractable corrosion probes are preferred because with suitable safety precautions they can be replaced without shutting down the unit.

Corrosion probes operate on the principle that electrical resistivity is dependent on the cross-section of the conductor. As corrosion removes metal from a probe, its resistance increases. Measurement of the current passing through the probe (a wire of the same material as the reactor) can be easily converted to mils (0.001 inch) metal lost to corrosion. By plotting these measurements along a time scale, corrosion rates can be determined and correlated with desalter, neutralizer and inhibitor control as well as other operating variables that affect corrosion.

Corrosion rates of 500-1000 mils per year can exist on carbon steel with no corrosion control program. If either neutralization or an inhibitor is used, this rate will drop to 10-200 mpy. With use of both inhibition and neutralization corrosion rates of 0.5 mpy can be expected on carbon steel.

Summary:

Control of crude pretreatment, neutralization, wash water injection and both selection and injection of inhibitor are essential to prevent or minimize corrosion of carbon steel and alloys in the highly corrosive environments of refinery operation. Alloying with Admiralty metal, Monel, and even Hastelloys B and C can reduce the rate of corrosion of the process equipment but cannot stop the attack as completely as the process treatment approach. The cost of alloying all equipment exposed to process waters is prohibitive; so usually only some critical equipment is alloyed and a process treatment system is devised.

Complete desalting will minimize chloride corrosion of crude condensers and fouling by suspended solids, but may accelearte sulfidic corrosion of furnace tubes. The use of ammonia-rich water in the desalter can cause additional corrosion in distillation towers by ammonium salt deposition. The same type of salt corrosion can occur when the crude tower overhead is neutralized with ammonia solutions to minimize stream corrosivity and inhibitor dosage. Ammonia solutions can cause stress-corrosion cracking of copper alloys often used in condensers equipment. Water washing can remove salts and sufficiently dilute corrodents but may increase corrosion by forming a moderately concentrated NH_4Cl solution and by adding oxygen to the system. The corrosion of carbon steel by NH_4Cl solution is inhibited

V. (cont'd)

by the presence of oxygen-free sulfide, but is accelerated if the sulfide has oxidized. Monoethonolamine and diethanolamine form less corrosive neutralization products than does ammonia.

Corrosion inhibitors can give essentially complete protection under specific conditions; however, low concentrations can accelerate corrosion and high concentrations can cause emulsification with resulting loss of product or product quality. The activity of some inhibitors is reduced markedly at both high and low pH. Adequate dilution and dispersion of the high-boiling inhibitors in the process stream are essential, not only to insure complete protection, but also to avoid corrosion by concentrated inhibitor solutions at the hot injection point.

Rapid and, on occasion, major changes in these corrosion-control techniques may be required and since the variables are highly interdependent, consultation with competent corrosion engineers is advisable. Since each crude unit is unique, the methods used to control corrosion must be combined in the most economical manner with a clear understanding of the corresponding advantages and potential disadvantages.

Additional information on Corrosion Control in Crude Units is provided in the paper in Appendix 11.

VI. EQUIPMENT FAILURES: CAUSES, ANALYSES, AND REMEDIES

Despite the care used, or philosophy employed, in material selection, design, analyses, fabrication, inspection and testing for and of equipment for refinery units, failures do occur occasionally. Failures may be manifested by excessive deformation, brittle fracture, corrosion and/or cracking or deterioration of properties. Although numerous conditions may cause or lead to service failures, the responsibility for a failure can generally be assigned to one of five classifications.

A) Design - includes structural inadequacies, notches, improper joint locations, alignment, or configuration.

B) Materials - includes selection, original manufacturing and handling of base and welding materials, improper identification or use of wrong materials.

C) Defects - includes base and weld metal defects introduced during manufacture.

D) Fabrication - includes welding, wrong weld filler metal, improper heat treatment, improper controlled repairs in shop and/or field.

E) Service - includes excessively severe conditions mainly due to improper control of or changes in operating parameters.

In many or most instances, the responsibility can be related to a combination of several of the above factors. For example, a pipe weld containing root defects such as lack of penetration may not fail during service until thermal or mechanical cycling of sufficient severity cause cracking and crack propagation by fatigue of the existing defect across the wall thickness.

Along with the above five failure responsibility classifications, the failure mode, in the case of cracking type failures, is either the brittle or ductile type or combination of both. These are intimately related to the loading mode (static, repeated, impact), stress type (tension, compression, shear), operating temperature (low, ambient, high), material type (brittle, ductile), and environment. Information as to the operating history of the unit containing the failed component is very important. Changes in operating conditions such as feeds, temperature, pressure and environment can be directly related in many instances to failures. The introduction of contaminants may accelerate corrosion and/or cracking of materials which are suitable without such contaminants.

In conjunction with the importance of information on the above listed classifications, modes, and operating conditions, various analyses, tests and examinations (both visual and microscopic) are needed to ascertain which are involved in the failure cause(s).

Chemical analyses of the failed material are needed to see if it met

VI. (cont'd)

specification, of the process fluid for off spec material or evidence of contaminants, and of corrosion products to identify corrosive medium. Tests including tensile, bend and impact may be necessary if the failure indicates mechanical properties are a contributing factor.

Examinations may include non-destructive types such as a liquid penetrant and magnetic particle for surfaces, cracks or defects and ultrasonic or radiography for internal defects. Hardness tests are very informative in many cases as they will provide information as to tensile strength and microstructural condition which often times bears a direct relationship to failures, such as stress corrosion cracking and/or H_2 embrittlement. Metallography (study of microstructures) by both optical and electron microscopy and fractography (study of fracture surfaces) provide invaluable information in failure analysis. These studies will identify fracture mode, intergranular or transgranular cracking pattern and in most cases fracture origin.

Most refinery equipment failures would not require all the investigative factors described above since they are generally not that involved. An experienced investigator may need only to look into several aspects of failure analysis to find a cause and in some cases less. Oftentimes just a visual examination along with knowledge of the service will provide the answer to the failure cause because of previous experiences with similar failures.

The knowledge of failure mechanisms, environments that may cause failures in certain alloys, steels and alloys susceptibility to various types of failures, and experience with the multitude of processes are invaluable to the materials man involved with failure analyses. As mentioned at the beginning of this section, this knowledge and experience is best first put to use in the original material selection along with the best metallurgical condition for the service design criteria and quality requirements to preclude failures as much as possible for the original design and normal operating conditions.

Once the failure mechanism and cause is established, the remedies available to preclude future similar failures are rather easily developed. UOP has the expertise and facilities to perform failure analyses for their licensees.

CONDENSED TECHNICAL DATA ON INTERMEDIATE CROLOY STEELS IN COMMON USE

	Carbon steel (killed)	*Carbon molybdenum* ½ Mo	*Croloy ½* ½ Cr – ½ Mo	*Croloy 1¼* 1¼ Cr – ½ Mo	*Croloy 2* 2 Cr – ½ Mo	*Croloy 2¼* 2¼ Cr – 1 Mo	*Croloy 3M* 3 Cr – 1 Mo	*Croloy 5* 5 Cr – ½ Mo	*Croloy 5 SI* 5 Cr – ½ Mo–Si	*Croloy 7* 7 Cr – ½ Mo	*Croloy 9M* 9 Cr – 1 Mo
Applications	Mild corrosion resistance. Fair strength up to 1000°F.	Higher creep strength than carbon steel with no increase in corrosion or oxidation resistance.	Better graphitization resistance and creep strength than carbon moly. for higher-temperature steam piping.	Economy grade. Good creep strength. Better corrosion resistance than non-chromium steels. Available in either open hearth or electric furnace qualities.	Economy grade. Good oxidation and corrosion resistance. Excellent high temperature strength.	Very high creep strength for polymerization and high-pressure cracking. Otherwise similar in character to Croloy 2.	Better creep strength and resistance to corrosion and oxidation than Croloy 2.	Where corrosion resistance is a prime consideration. Creep strength and oxidation resistance superior to Croloy 2.	Where oxidation resistance is a prime consideration. Excellent resistance to scaling under straight oxidizing conditions.	Intermediate between Croloys 5 and 9 for use where corrosion resistance is of prime concern. Better oxidation resistance than Croloy 5.	For severe conditions where high corrosion and oxidation resistance are essential. Suitable for hydrogenation processes.
Minimum mechanical properties											
Tensile strength, psi	47,000	55,000	55,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Yield point, psi	26,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Elongation, %/2 in.	35	30	30	30	30	30	30	30	30	30	30
Rockwell B hardness	77 max.	81 max.	85 max.	85 max.	85 max.	85 max.	85 max.	85 max.	89 max.	89 max.	89 max.
Physical properties											
Thermal conductivity (Btu/hr/sq.ft./in. thickness/°F at 212°F)	350	310	285	215	203	195	195	189	—	—	182
Thermal expansion, in./in./°F (x 10⁶)	70 to 400 = 6.90 70 to 1200 = 8.30	70 to 400 = 6.83 70 to 1200 = 8.28	70 to 800 = 7.51 70 to 1100 = 7.79	70 to 600 = 7.40 70 to 1200 = 8.50		13 to 402 = 6.90 73 to 1207 = 8.90	70 to 410 = 7.51 70 to 1209 = 8.08	70 to 400 = 6.40 70 to 1200 = 7.30	70 to 800 = 7.08 70 to 1300 = 7.44	70 to 400 = 6.28 70 to 1200 = 7.20	70 to 300 = 6.25 70 to 1200 = 7.30
Short-time tensile strength, psi											
Temp., °F											
800	50,000	70,500	65,000	69,000	64,500	87,000	59,000	54,000	65,000	59,500	60,000
900	38,000	63,500	60,000	67,500	61,500	64,000	53,500	53,500	60,500	52,500	53,000
1000	25,500	57,500	54,500	58,000	55,500	50,000	45,000	45,500	47,500	43,500	45,000
1100	15,500	45,000	45,500	47,500	44,000	39,000	38,000	32,000	37,000	33,000	36,000
1200	11,500	27,000	34,500	33,500	31,000	31,000	24,500	24,500	24,500	22,000	23,000
1300	—	16,000	20,000	23,000	19,500	24,000	19,000	18,000	13,500	18,000	16,000
Creep strength, °F	(a)* (b)‡	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)	(a) (b)
800	19,500 13,500	33,500 23,500	— 32,000	— —	— —	40,500 22,000	— —	— —	— —	— —	— —
900	11,000 8,400	24,500 17,200	35,000 21,000	35,000 20,000	28,000 18,000	16,350 7,600	19,500 12,000	17,900 15,000	— —	— —	— —
1000	7,200 2,150	12,400 6,200	12,000 5,600	14,700 8,200	11,000 8,300	9,200 4,910	12,500 7,000	9,200 7,200	8,200 5,700	14,500 9,200	33,250 24,750
1100	— —	— —	3,800 1,300	5,500 2,125	5,875 3,325	4,175 2,510	8,000 4,000	4,800 2,400	4,400 2,700	8,000 5,000	12,000 8,500
1200	— —	— —	— —	3,375 910	3,400 1,075		4,000 1,550	1,800 900	1,600 850	4,400 2,500	6,950 3,775
										2,000 1,300	2,300 1,600
Oxidation resistance											
Max. temp. (°F) limit under oxidizing conditions	850	875	1025	1050	1080	1125	1125	1150	1200	1175	1200

*Stress psi for 10,000 hr (0.10% – 1,000 hr) with 1% elongation.
‡Stress psi for 100,000 hr (0.01% – 1,000 hr) with 1% elongation.

UOP 130-10

PROPERTIES OF 200 AND 300 SERIES ENDURO STAINLESS STEELS

REPUBLIC DESIGNATION	17-4-6	18-5-6	17-7	18-8	18-8-S	18-8-FM	18-8-S	18-8-SL	18-8-FS	20-10-S	HCN	NC-3	18-8-SMo (1)	18-8-SMoL	18-8-STi	18-8-SCb
A. I. S. I. TYPE NUMBER	201	202	301	302	302B	303	304	304L	305	308	309	310	316 (317) (1)	316L	321	347
PRINCIPAL ALLOYING ELEMENTS, %	C 0.15 Max. Mn 5.50- 7.50 Si 1.00 Max. Cr 16.50-18.00 Ni 3.50- 5.50 N 0.25 Max.	C 0.15 Max. Mn 7.50-10.00 Si 1.00 Max. Cr 17.00-19.00 Ni 4.00- 6.00 N 0.25 Max.	C 0.15 Max. Mn 2.00 Max. Si 1.00 Max. Cr 16.00-18.00 Ni 6.00- 8.00	C 0.15 Max. Mn 2.00 Max. Si 1.00 Max. Cr 17.00-19.00 Ni 8.00-10.00	C 0.15 Max. Mn 2.00 Max. Si 2.00- 3.00 Cr 17.00-19.00 Ni 8.00-10.00	C 0.15 Max. Mn 2.00 Max. Si 1.00 Max. Cr 17.00-19.00 Ni 8.00-10.00 S or Se 0.15 Min. Mo * 0.60 Max.	C 0.08 Max. Mn 2.00 Max. Si 1.00 Max. Cr 18.00-20.00 Ni 8.00-10.50	C 0.03 Max. Mn 2.00 Max. Si 1.00 Max. Cr 18.00-20.00 Ni 8.00-12.00	C 0.12 Max. Mn 2.00 Max. Si 1.00 Max. Cr 17.00-19.00 Ni 10.50-13.00	C 0.08 Max. Mn 2.00 Max. Si 1.00 Max. Cr 19.00-21.00 Ni 10.00-12.00	C 0.20 Max. Mn 2.00 Max. Si 1.00 Max. Cr 22.00-24.00 Ni 12.00-15.00	C 0.25 Max. Mn 2.00 Max. Si 1.50 Max. Cr 24.00-26.00 Ni 19.00-22.00	C 0.08 Max. Mn 2.00 Max. Si 1.00 Max. Cr 16.00-18.00 Ni 10.00-14.00 Mo 2.00- 3.00	C 0.03 Max. Mn 2.00 Max. Si 1.00 Max. Cr 16.00-18.00 Ni 10.00-14.00 Mo 2.00- 3.00	C 0.08 Max. Mn 2.00 Max. Si 1.00 Max. Cr 17.00-19.00 Ni 9.00-12.00 Ti 5 x C. Min.	C 0.08 Max. Mn 2.00 Max. Si 1.00 Max. Cr 17.00-19.00 Ni 9.00-13.00 Cb-Ta 10 x C. Min.
PHYSICAL PROPERTIES																
Density, lb./cu. in.	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Mod. of Elasticity in Tension x 10^6 lb./sq.in.	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Structure	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic	Austenitic
Specific Heat, B.t.u./°F./lb./32-212° F.	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Thermal Conductivity, B.t.u./sq. ft./hr./°F./ft. (212° F.)	9.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.0	9.0	8.2	8.4	8.4	8.3	8.3
Thermal Conductivity, B.t.u./sq. ft./hr./°F./ft. (832° F.)	—	12.5	12.4	12.6	12.5	12.4	12.6	12.6	12.4	12.5	10.0	10.0	12.4	12.4	12.0	12.0
Mean Coefficient of Thermal Expansion per °F. x 10^{-6} 32-212° F.	6.2	9.7	9.4	9.6	9.6	9.6	9.6	9.6	9.6	9.6	8.3	8.3	8.9	8.9	9.3	9.3
Mean Coefficient of Thermal Expansion per °F. x 10^{-6} 32-600° F.	6.7	10.2	9.5	8.8	8.8	9.0	9.0	9.0	9.0	9.0	8.3	8.8	8.8	8.8	9.5	9.5
Mean Coefficient of Thermal Expansion per °F. x 10^{-6} 32-1000° F.	10.2	10.7	10.1	10.2	10.2	10.2	10.2	10.2	10.2	10.2	9.6	9.6	9.7	9.7	10.3	10.3
Mean Coefficient of Thermal Expansion per °F. x 10^{-6} 32-1200° F.	—	11.8	10.4	10.4	10.6	11.2	10.4	10.4	10.4	10.4	10.0	9.7	10.3	10.7	10.7	10.6
Melting Range	2500-2650° F.	2550-2650° F.	2550-2590° F.	2550-2590° F.	2500-2550° F.	2550-2590° F.	2550-2650° F.	2500-2650° F.	2500-2650° F.	2550-2590° F.	2500-2650° F.	2550-2650° F.	2500-2550° F.	2500-2600° F.	2550-2600° F.	
ELECTRICAL PROPERTIES																
Magnetic Permeability, Annealed	Non-magnetic $\mu = 1.02$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.02$	Non-magnetic $\mu = 1.008$	Non-magnetic —	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$	Non-magnetic $\mu = 1.008$
Elec. Resistivity, microhm-cm, 70° F.	80.0	80.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	78.0	78.0	74.0	74.0	71.0	72.0
MECHANICAL PROPERTIES																
Brinell Hardness (Bars) Annealed	—	—	135-185	135-185	150-190	135-185	135-185	125-165	—	135-185	140-195	140-210	135-185	130-185	130-185	130-185
Brinell Hardness (Bars) Heat Treated	210 Max.	210 Max.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Brinell Hardness (Bars) Cold Drawn	—	—	210-330	130-330	—	180-330	180-330	—	—	—	—	—	180-300	—	180-300	—
Rockwell Hardness (Sheet or Strip) Annealed	95 Rb	85-90 Rb	75-85 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-90 Rb	75-85 Rb	75-85 Rb	75-85 Rb	75-90 Rb	75-90 Rb
Rockwell Hardness (Sheet or Strip) Heat Treated	25-41 Rc	—	25-43 Rc	—	—	—	—	—	—	—	—	—	—	—	—	—
Rockwell Hardness (Sheet or Strip) Cold Rolled	½ to full hard	—	¼ to full hard	10-35 Rc	—	—	10-35 Rc	—	—	10-35 Rc	—	—	10-35 Rc	—	10-35 Rc	10-35 Rc
Ultimate Tensile Strength, lbs./sq. in. Annealed	95,000-125,000	95,000-115,000	90,000-110,000	75,000-100,000	80,000-100,000	75,000-100,000	70,000- 95,000	70,000-80,000	70,000-90,000	80,000-90,000	75,000-95,000	75,000-95,000	75,000-90,000	70,000-85,000	75,000-95,000	75,000-100,000
Ultimate Tensile Strength, lbs./sq. in. Heat Treated	125,000-185,000	—	175,000-185,000	—	—	—	—	—	—	100,000-130,000	—	—	100,000-150,000	—	100,000-150,000	100,000-150,000
Ultimate Tensile Strength, lbs./sq. in. Cold Worked (?)	½ to full hard	—	¼ to full hard	100,000-150,000	—	100,000-150,000	100,000-150,000	—	—	—	—	—	—	—	—	—
Yield Strength, lbs./sq. in. Annealed	45,000-65,000	40,000-60,000	35,000-50,000	30,000-50,000	35,000-50,000	30,000-50,000	25,000-50,000	25,000-45,000	25,000-45,000	35,000-48,000	35,000-55,000	35,000-55,000	30,000-60,000	25,000-55,000	30,000-55,000	30,000-55,000
Yield Strength, lbs./sq. in. Heat Treated	(73,000-148,000	—	(75,000-140,000	50,000-150,000	—	80,000-100,000	80,000-150,000	—	—	50,000-150,000	—	—	80,000-125,000	—	80,000-125,000	80,000-125,000
Yield Strength, lbs./sq. in. Cold Worked (?)	½ to full hard	—	¼ to full hard	—	—	—	—	—	—	—	—	—	—	—	—	—
Elongation in 2 inches Annealed	60-50%	60-50%	85-55%	90-50%	60-50%	60-50%	65-50%	65-50%	55-45%	60-50%	55-40%	55-40%	60-45%	65-45%	60-45%	60-45%
Elongation in 2 inches Heat Treated	(25-8%)	—	(25-8%)	50-10%	—	40-30%	50-10%	—	—	50-10%	—	—	50-10%	—	50-10%	50-10%
Elongation in 2 inches Cold Worked (?)	½ to full hard	—	¼ to full hard	—	—	—	—	—	—	—	—	—	—	—	—	—
Reduction of Area Annealed	—	—	70-60% (Bar)	75-50% (Bar)	70-50% (Bar)	65-50% (Bar)	75-60% (Bar)	75-65% (Bar)	70-55% (Bar)	70-50% (Bar)	70-50% (Bar)	70-50% (Bar)	75-60% (Bar)	75-65% (Bar)	65-55% (Bar)	65-55% (Bar)
Reduction of Area Heat Treated	—	—	—	—	—	60-45%	—	—	—	—	—	—	—	—	—	—
Reduction of Area Cold Worked (?)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Impact Strength, Izod Value, ft. lbs. Annealed	120-100	120-100	120-100	120-100	100-80	100-70	120-100	120-100	120-100	115-100	120-100	115-100	120-95	120-95	120-95	120-90
Impact Strength, Izod Value, ft. lbs. Heat Treated	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Ductility, Annealed – Ohsm, inches	0.425-0.500	0.400-0.450	0.425-0.500	0.400-0.450	—	—	0.400-0.450	—	0.400-0.450	—	—	—	0.400-0.500	0.400-0.500	0.400-0.500	0.400-0.500
Creep Strength, Life of 10,000 hrs. with 1% Elongation, lb./sq. in. At 1000° F.	—	—	—	17,000	—	16,500	17,000	17,000	—	—	17,000	17,000	22,000	22,000	18,000	18,500
Creep Strength, Life of 10,000 hrs. with 1% Elongation, lb./sq. in. At 1100° F.	—	—	—	12,000	—	11,500	12,000	12,000	—	—	13,000	13,000	16,000	16,000	13,000	14,000
Creep Strength, Life of 10,000 hrs. with 1% Elongation, lb./sq. in. At 1200° F.	—	—	—	7,000	—	8,500	7,000	7,000	—	—	9,000	9,000	11,000	12,000	8,000	8,500
Creep Strength, Life of 10,000 hrs. with 1% Elongation, lb./sq. in. At 1300° F.	—	—	—	4,000	7,000 4,500	3,500	4,000	4,000	—	—	4,500	4,500	6,000	6,500	4,500	5,200
Strength at Elevated Temps., Short Time Tests, lb./sq. in. 1300° F.	—	—	—	30,000	45,000	34,000	30,000	—	—	—	48,000	50,000	48,000	—	38,000	40,000
Strength at Elevated Temps., Short Time Tests, lb./sq. in. 1500° F.	—	—	—	22,000	30,000	20,000	22,000	—	—	—	29,000	32,000	28,000	—	22,500	23,500
Strength at Elevated Temps., Short Time Tests, lb./sq. in. 1700° F.	—	—	—	13,500	17,000	12,500	13,500	—	—	—	16,000	18,000	18,000	—	17,000	17,500
HEAT TREATMENT Full Anneal	Cool rapidly from 1850-2050° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1800-2000° F.	Cool rapidly from 1800-2000° F.	Cool rapidly from 1800-2000° F.	Cool rapidly from 1850-2050° F.	Cool rapidly from 1900-2050° F.	Cool rapidly from 1900-2100° F.	Cool rapidly from 1800-2000° F.	Cool rapidly from 1800-2000° F.	Cool rapidly from 1750-1950° F.	Cool rapidly from 1850-1950° F.
Process Anneal	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full	Same as full
Hardening – Quench from	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening
Tempering	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening	Non-hardening
Initial Forging Start	2200° F.	2200° F.	2200° F.	2200° F.	2200° F.	2200° F.	2200° F.	2200° F.	2200° F.	2150° F.	2150° F.	2150° F.	2200° F.	2200° F.	2150° F.	2200° F.
Initial Forging Finish	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1800° F.	Over 1800° F.	Over 1700° F.	Over 1700° F.	Over 1700° F.	Over 1800° F.
HEAT-RESISTANCE Scaling Temperature Continuous Service	1550° F.	1550° F.	1650° F.	1650° F.	1950° F.	1550° F.	1700° F.	1700° F.	1650° F.	1700° F.	2000° F.	2050° F.	1700° F.	1700° F.	1650° F.	1700° F.
Scaling Temperature Intermittent Service	1400° F.	1500° F.	1500° F.	1600° F.	1800° F.	1450° F.	1550° F.	1550° F.	1500° F.	1550° F.	1850° F.	1900° F.	1550° F.	1550° F.	1500° F.	1550° F.
WELDING PROPERTIES	Very good Tough welds	Very good Tough welds	Very good Tough welds	Very good Tough welds	Good Tough welds	Fusion welding not recommended	Very good Tough welds	Very good Tough welds	Very good Tough welds	Good Tough welds	Good Tough welds	Good Tough welds	Very good Tough welds	Very good Tough welds	Very good Tough welds	Good Tough welds
MACHINING PROPERTIES, Compared to Bessemer Screw Stock No. B1112	About 45%	About 45%	About 45%	About 45%	About 45%	About 80%	About 45%	About 45%	About 45%	About 45%	About 45%	About 45%	About 45%	About 45%	About 36%	About 36%
DRAWING OR STAMPING	Good	Good	Good	Good	Good	Fairly good	Very good	Very good	Very good	Good	Good	Good	Good	Good	Good	Good

*optional

NOTES

(1) Properties of Type 317 (19-9-SMo) are similar to Type 316 except chemistry and cost.

(2) Values apply to cold rolled sheet and strip in the 300 series except Type 303 where values apply to annealed and cold drawn 1" dia. bar.

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UOP 132G-11

PROPERTIES OF 400 SERIES ENDURO STAINLESS STEELS

REPUBLIC DESIGNATION	S-1 Aluminum	409	S-1 [1]	S-1 Nickel	FC	S High Carbon	AA	AA-FM	AA Nickel	AA+Mo	AA+Mo+Cb	442	HC	CARBON STEEL
A. I. S. I. TYPE NUMBER	405	409	410 (403)[1]	414	416	420	430	430-F	431	434	436	442	446	C1020
PRINCIPAL ALLOYING ELEMENTS, %	C 0.08 Max. Cr 11.50-14.50 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max. Al 0.10- 0.30	C 0.08 Max. Cr 10.00-13.00 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max. Ti Optional +8 x C Min.[1]	C 0.15 Max. Cr 11.50-13.50 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.15 Max. Cr 11.50-13.50 Ni 1.75- 2.50 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.15 Max. Cr 12.00-14.00 Mn 1.25 Max. Si 1.00 Max. P 0.06 Max. S 0.15 Min. Mo 0.06 Max.*	C 0.15 Max. Cr 12.00-14.00 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.12 Max. Cr 16.00-18.00 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.12 Max. Cr 16.00-18.00 Mn 1.25 Max. Si 1.00 Max. P 0.06 Max. S 0.15 Min. Mo 0.60 Max.*	C 0.20 Max. Cr 15.00-17.00 Ni 1.25- 2.50 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.12 Max. Cr 16.00-18.00 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max. Mo 0.75- 1.25	C 0.12 Max. Cr 16.00-18.00 Cb 8 x C Min. 0.70 Max. Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.20 Max. Cr 18.00-23.00 Mn 1.00 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max.	C 0.20 Max. Cr 23.00-27.00 Mn 1.50 Max. Si 1.00 Max. P 0.040 Max. S 0.030 Max. N 0.25 Max.	C 0.18-0.23 Mn 0.30-0.80 P 0.040 Max. S 0.050 Max.
PHYSICAL PROPERTIES														
Density, lb./cu. in.	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.28
Mod. of Elasticity in Tension x 10⁶ lb./sq. in.	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	30.0
Structure	Ferritic	—	Martensitic	Martensitic	Martensitic	Martensitic	Ferritic	Ferritic	Martensitic	Ferritic	Ferritic	Ferritic	Ferritic	Ferritic
Specific Heat, B.t.u./° F./lb./32-212° F.	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.11
Thermal Conductivity, B.t.u./sq. ft./hr./° F./ft. 212° F.	15.6	14.4	14.4	14.4	14.4	14.4	15.1	15.1	11.7	—	13.8	12.5	12.1	29.9
Thermal Conductivity, B.t.u./sq. ft./hr./° F./ft. 932° F.	—	16.6	16.6	16.6	16.6	—	15.2	15.2	—	15.2	15.0	14.2	14.1	—
Mean Coefficient of Thermal Expansion per ° F. x 10⁻⁶ 32- 212 F.	6.0	6.0	5.5	5.5	5.5	5.7	5.8	5.8	6.5	6.6	5.2	5.8	5.0	8.3
32- 600 F.	6.4	6.4	5.6	6.1	5.8	6.0	6.1	6.1	6.7	—	—	5.9	6.0	8.9
32-1000 F.	6.7	6.7	6.4	6.7	6.4	6.3	6.3	6.3	—	—	—	6.3	6.2	9.8
32-1200 F.	7.5	7.5	6.9	6.9	6.5	6.8	6.6	6.6	—	—	—	6.5	6.4	—
Melting Range	2700-2790° F.	2700° F.-2790° F.	2700-2790 F.	—	2700-2790° F.	2650-2750° F.	2600-2750 F.	2600-2750 F.	—	2600-2750° F.	2600-2750° F.	2600-2750° F.	2600-2750° F.	—
ELECTRICAL PROPERTIES														
Magnetic Permeability, Annealed	Magnetic	Magnetic	Magnetic μ = 700-1000	Magnetic	Magnetic μ = 700-1000	Magnetic	Magnetic μ = 500-1100	Magnetic μ = 500-1100	Magnetic	Magnetic μ = 600-1100	Magnetic μ = 600-1100	Magnetic	Magnetic μ = 400-700	Magnetic
Elec. Resistivity, microhm-cm. 70° F.	91.0	81.0	57.0	72.0	57.0	55.0	60.0	60.0	72.0	60.0	60.0	64.0	67.0	8.8
MECHANICAL PROPERTIES														
Brinell Hardness, *Bars — Annealed	150-180	70-85Rb	135-215	230-260	135-215	190-225	140-185	140-185	240-270	140-185	140-185	140-185	140-185	120-140
Heat Treated	—	—	200-425	250-415	200-425	250-550	—	—	270-440	—	—	—	—	150-383
Cold Drawn	—	—	170-235	250-315	170-235	—	185-230	190-230	270-325	185-230	185-230	185-230	185-230	—
Rockwell Hardness, †Sheet or Strip — Annealed	70-85Rb	70-85Rb	75-85Rb	98Rb-20Rc	—	92Rb	75-90Rb	—	30-35Rc	75-90Rb	75-90Rb	75-90Rb	75-90Rb	70-78Rb
Heat Treated	—	—	85Rb-45Rc	25-45Rc	—	—	—	—	25-45Rc	—	—	—	—	80Rb-38Rc
Cold Rolled	—	—	—	—	—	—	90-105Rb	—	—	90-105Rb	90-105Rb	—	—	—
Ultimate Tensile Strength, lb./sq. in. — Annealed	60,000- 75,000	65,000-105,000	65,000-105,000	115,000-125,000	65,000-105,000	95,000-110,000	65,000- 85,000	70,000- 90,000	120,000-130,000	65,000- 85,000	65,000- 85,000	75,000- 85,000	75,000- 85,000	55,000- 65,000
Heat Treated	—	—	95,000-200,000	120,000-210,000	95,000-200,000	110,000-235,000	—	—	140,000-220,000	—	—	—	—	75,000-170,000
Cold Worked[1]	90,000-130,000	75,000-115,000	75,000-115,000	125,000-140,000	75,000-115,000	100,000-120,000	90,000-130,000	85,000-115,000	130,000-150,000	90,000-130,000	90,000-130,000	90,000-110,000	90,000-110,000	85,000- 95,000
Yield Strength, lb./sq. in. — Annealed	40,000- 55,000	35,000- 65,000	35,000- 85,000	90,000-110,000	35,000- 85,000	50,000- 70,000	40,000- 65,000	40,000- 55,000	95,000-115,000	40,000- 65,000	40,000- 65,000	45,000- 60,000	45,000- 60,000	35,000- 45,000
Heat Treated	—	—	70,000-150,000	90,000-110,000	70,000-150,000	70,000-215,000	—	—	100,000-180,000	—	—	—	—	55,000-133,000
Cold Worked[1]	65,000-125,000	60,000-100,000	60,000-100,000	110,000-130,000	60,000-100,000	80,000-100,000	65,000-125,000	70,000-100,000	110,000-140,000	65,000-125,000	65,000-125,000	70,000-100,000	70,000-100,000	80,000- 90,000
Elongation In 2 Inches, % — Annealed	25%-30%	35-20%	35-20%	20-15%	30-20%	25-20%	30-20%	30-20%	25-15%	30-20%	30-20%	30-30%	30-20%	40-30%
Heat Treated	—	—	30-10%	20-15%	25-10%	25-7%	—	—	20-10%	—	—	—	—	70-25%
Cold Worked[1]	20-10%	25-15%	25-15%	15-10%	20-10%	20-15%	20-2%	10-10%	15-10%	20-2%	20-2%	20-15%	20-15%	42-20%
Reduction of Area, % — Annealed	—	—	80-65%	60-55%	75-60%	65-55%	70-60%	60-55%	60-55%	70-60%	70-60%	60-45%	60-45%	70-60%
Heat Treated	—	—	75-55%	55-30%	60-40%	60-25%	—	—	55-30%	—	—	—	—	60-20%
Cold Worked[1]	—	—	75-60%	50-35%	65-50%	60-50%	60-45%	55-40%	50-35%	60-45%	60-45%	45-30%	45-30%	—
Impact Strength, Izod Value, ft. lb. — Annealed	35-20	—	170-65	80-50	85-60	80-60	50-5	50-5	80-50	—	50-5	15-5	10-2	70-40
Heat Treated	—	—	110-20	80-40	60-20	60-5	—	—	70-25	—	—	—	—	—
Ductility, Annealed — Olsen, inches	—	0.275"-0.350"	.275-.350	—	—	—	.300-.400	—	—	.300-.400	.300-.400	—	.250-.300	.350-.425
Creep Strength, Life of 10,000 hrs. with 1% Elongation, lb./sq. in. — At 1000° F.	8,000	—	12,000	—	17,500	—	9,400	8,400	—	8,400	8,400	—	8,400	5,000
At 1100° F.	—	—	5,500	—	5,000	—	3,900	4,900	—	4,900	4,900	—	3,000	2,000
At 1200° F.	—	—	2,600	—	2,100	—	2,200	2,200	—	2,200	2,200	—	1,500	750
At 1300° F.	—	—	1,400	—	1,400	—	1,400	1,400	—	1,400	1,400	—	600	—
Strength at Elevated Temps., Short Time Tests, lb./sq. in. — 1300° F.	13,500	—	15,000	32,000	15,000	26,500	15,000	15,000	26,000	13,000	15,000	—	18,000	11,000
1500° F.	8,000	—	9,000	22,000	8,500	13,500	8,000	8,000	10,500	8,000	8,000	—	9,000	8,000
1700° F.	3,000	—	8,500	11,000	7,500	5,000	5,000	5,000	8,000	5,000	5,000	—	5,000	4,000
HEAT TREATMENT — Full Anneal	Air Cool from 1350-1500° F.	Air Cool from 1350° F.-1500° F.	Slow Cool from 1550-1650° F. to 1100° F.	Not Practical	Slow Cool from 1550-1650° F. to 1100° F.	Slow Cool from 1550-1650° F. to 1100° F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	Not Practical.	Air Cool from 1350-1500° F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	Slow Cool from 1600° F.
Process Anneal	Air Cool from 1350-1500° F.	Air Cool from 1350° F.-1500° F.	Air Cool from 1200-1400° F.	Air Cool from 1150-1250° F.	Air Cool from 1200-1300° F.	Air Cool from 1300-1400° F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	Air Cool from 1150-1200 F.	Air Cool from 1350-1500° F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	Air Cool from 1350-1500 F.	—
Hardening—Quench from	Non-hardening	Non-hardening	1700-1850° F.	1700-1900° F.	1700-1850° F.	1700-1900° F.	Non-hardening	Non-hardening	1700-1950 F.	Non-hardening	Non-hardening	Non-hardening	Non-hardening	1575-1650° F.
Tempering[1]	Non-hardening	Non-hardening	400-1300° F.	400-1200° F.	400-1300° F.	300-700° F.	Non-hardening	Non-hardening	400-1200 F.	Non-hardening	Non-hardening	Non-hardening	Non-hardening	300-1300° F.
Initial Forging Temp., °F. — Start	2100° F.	Start 2100° F.	2200° F.	2100° F.	2200° F.	2100° F.	1950° F.	2050° F.	2100° F.	1950° F.	1950° F.	1950° F.	1950° F.	—
Finish	Over 1400° F.	Finish Over 1400° F.	Over 1400° F.	Over 1500° F.	Over 1500 F.	Over 1600° F.	Over 1200 F	Over 1400 F.	Over 1500° F.	Over 1200° F.	Over 1200° F.	Over 1200 F.	Over 1200° F.	—
HEAT-RESISTANCE — Scaling Temperature, °F. — Continuous Service	1300 F.	1300 F.	1300 F.	1250° F.	1250 F.	1200° F.	1350° F.	1500 F.	1500 F.	1550° F.	1550° F.	1800° F.	1900° F.	800° F.
Intermittent Service	1450 F.	1450 F.	1450 F.	1400° F.	1400 F.	1400 F.	1650 F.	1600 F.	1600 F.	1650 F.	1650 F.	1950° F.	2050 F.	1000° F.
WELDING PROPERTIES	Good. Fairly tough welds.	Good	Fair. Preheat 400-500° F. Anneal 1250 F. after welding.	Fair. Preheat 400-500 F. Anneal 1250° F. after welding.	Poor. Preheat 300-500 F. Anneal 1250 F. after welding.	Fair. Preheat 400-500° F. Anneal 1250° F. after welding.	Fair. Non-ductile welds. Some response to annealing.	Poor. Non-ductile welds. Some response to annealing.	Fair. Preheat 400-500 F. Anneal 1200° F. after welding.	Fair. Non-ductile welds. Some response to annealing.	Fair. Non-ductile welds. Some response to annealing.	Fair. Non-ductile welds. Slight response to annealing.	Fair. Non-ductile welds. Slight response to annealing.	Good.
MACHINING PROPERTIES. Compared to Resistance Screw Stock No. B1112	About 50%	—	About 50%	About 40%	About 80%	About 45%	About 50%	About 80%	About 40%	About 50%	About 50%	About 50%	About 40%	Good.
DRAWING OR STAMPING	Fairly good.	Fairly good.	Fairly good.	Not recommended.	Fair.	Fair.	Fairly good.	Fairly good.	Not recommended.	Fairly good.	Fairly good.	Fair.	Fair.	Good.

**optional

NOTES

(1) Properties of Type 403 are similar to Type 410 except chemistry.

(2) Values apply to annealed and cold drawn 1" diameter bar stock in the 400 series except Types 430, 405, 442 and 446 where cold rolled sheet and strip values apply.

(3) Tempering temperatures of 800 to 1100° F. should be avoided where impact properties are important.

UOP 132G-12

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Filler Metals for Various Base-Metal Combinations

	C-steel	C-Mo	½ Cr – ½ Mo	1 Cr – ½ Mo	1¼ Cr – ½ Mo	2 Cr – ½ Mo	2¼ Cr – 1 Mo	5 Cr – ½ Mo	7 Cr – ½ Mo	9 Cr – 1 Mo	18-8 Stainless
C-steel	—	A	A	A	A, B	B, C	B, C	C, D	C, D	C, D	G
C-Mo	A	B	B	B	B	B, C	B, C	C, D	C, D	C, D	G
½ Cr – ½ Mo	A	B	C	C	C	C	C	C, D	C, D	C, D	G
1 Cr – ½ Mo	A	B	C	C	C	C	C	C, D	C, D	C, D	G
1¼ Cr – ½ Mo	A, B	B	C	C	C	C	C	C, D	C, D	C, D	G
2 Cr – ½ Mo	B, C	B, C	C	C	C	D	D	D	D	D	G
2¼ Cr – 1 Mo	B, C	B, C	C	C	C	D	D	D	D	D	G
5 Cr – ½ Mo	C, D	C, D	C, D	C, D	C, D	D	D	E	E	E	G
7 Cr – ½ Mo	C, D	C, D	C, D	C, D	C, D	D	D	E	F	F	G
9 Cr – 1 Mo	C, D	C, D	C, D	C, D	C, D	D	D	E	F	F	G
18-8 Stainless	G	G	G	G	G	G	G	G	G	G	—

Filler Metals

A. Carbon Steel (such as E7016 or E7018)

B. Carbon – ½ Mo (such as E7016-A1 or E7018-A1)

C. 1¼ Cr – ½ Mo (such as E8016-B2 or E8018-B2)

D. 2¼ Cr – 1 Mo (such as E9016-B3 or E9018-B3)

E. 5 Cr – ½ Mo (such as E502-15)

F. 9 Cr – 1 Mo

G. *For Cyclic Service and wherever postheating is to be used:*
75 Nickel – 16 Chromium – 7 Iron

For Non-Cyclic Service above 800° F:
75 Nickel – 16 Chromium – 7 Iron (Preferred)
25 Chromium – 20 Nickel (Type 310) (Alternate)
25 Chromium – 12 Nickel (Type 309) (Alternate)

For Non-Cyclic Service below 800° F:
25 Chromium – 12 Nickel (Type 309), 25 Chromium – 20 Nickel (Type 310), 29 Chromium – 9 Nickel (Type 312) or 75 Nickel – 16 Chromium – 7 Iron

*GENERAL GUIDE FOR SELECTING ELECTRODES AND WELDING RODS FOR DISSIMILAR METAL JOINTS IN AUSTENITIC STAINLESS STEEL PIPE AND TUBE**

AISI Type	*304L*	*308*	*309*	*309S*	*310*	*310S*	*316 316H*	*316L*	*317*	*321 321H*	*347, 347H 348, 348H*
304H, 305, 304	308	308	308 309	308 309	308 309 310	308 309 310	308 316	308 316	308 316 317	308	308
304L		308	308 309	308 309	308 309 310	308 309 310	308 316	308L 316L	308 316 317	308L 347	308L 347
308			308 309	308 309	308 309 310	308 309 310	308 316	308 316	308 316 317	308	308 347
309				309	309 310	309 310	309 316	309 316	309 316	309 347	309 347
309S					309 310	309S 310S	309 316	309S 316L	309 316	309 347	309 347
310							316 310 310Mo	316 310Mo 310	317 310Mo 310	308 310	308 310
310S							316 310Mo	316 310Mo	317 310Mo	308 310	308 310
316H, 316								316	317 316	308 316	308 316 347
316L									317	316L	316L 347
317										308 317	308 317 347
321H, 321											308L 347

*Electrodes and welding rods listed are not in any preferred order.

Table 64.7—Covered electrodes recommended for welds between stainless, heat resisting and carbon steels and other alloys

Source: Wayne L. Wilcox, Arcos Corp.

Base Metals →	Carbon Steel	1¼Cr-½Mo	2¼Cr-1Mo	Nickel	Inconel	Monel	Copper-Nickel Alloys
201	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
202	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
301	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
302	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
302B	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
303(a)	(g); E309	(g); E309	(g); E310	(p)	(p)	(p)	(q)
304	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
304L	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
305	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
308	(d); E309	(d); E309	(d); E309	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
309	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
309S	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
310	E310; (e)	E310; (e)	E310; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
310S	E310; (e)	E310; (e)	E310; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
314	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
316	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
316L	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
317	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
317L(b)	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
321	(d); E309; (e)	(d); E309; (e)	(d); E309; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
330(b)	(g); E312; (e)	(g); E312; (e)	(g); E312; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
347	(g); E312; (e)	(g); E312; (e)	(g); E312; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
348	(g); E312; (e)	(g); E312; (e)	(g); E312; (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
403	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
405	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
410	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
414	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o); ENiCrFe-3
416(a)	E309	E309	E309	(p)	(p)	(p)	(q)
420	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
430	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
430F(a)	E309	E309	E309	(p)	(p)	(p)	(q)
431	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
440A	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
440B	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
440C	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
446	(r); (l); (e)	(s); (l); (e)	(t); (l); (e)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
501	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
502	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
505	(r); (l)	(s); (l)	(t); (l)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
Carbon Steel	(r)	(u)	(u)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
1¼Cr-½Mo	(s)	(s)	(s)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
2¼Cr-1Mo			(t)	ENiCrFe-3	ENiCrFe-3	ENiCrFe-3; ENiCu-2	(o)
Nickel				ENi-1	ENiCrFe-3	ENiCu-2	ECuNi; ENiCu-2
Inconel					ENiCrFe-3	ENiCu-2; ENiCrFe-3	ECuNi; ENiCu-2
Monel						ENiCu-2	ECuNi; ENiCu-2
Copper-Nickel Alloys							ECuNi

When two or more electrodes are listed for a given combination of base metals, the first is suitable for most applications. Others have been listed as alternates, or as recommendations for more demanding applications, or for use where cracking might occur with particular lots or heats of material welded with the first electrode. The service requirements at the joint will dictate the most suitable electrode. Recommended electrodes were selected because they are adequate for most applications, and because they are commonly available. The recommendations do not imply that other electrodes would be unsuitable for many applications. In those instances the electrodes shown were selected on the basis of material costs.

Suppliers may be contacted regarding preheat and postheat treatments for best serviceability.

Electrode designations are in accordance with the following AWS-ASTM Filler Metal Specifications: Stainless steels, AWS A5.4, ASTM A298, nickel-base alloys, AWS A5.11, ASTM B295, mild steels, AWS A5.1, ASTM A233; low alloy steels, AWS A5.5, ASTM A316; copper alloys, AWS A5.6, ASTM B225.

(a) Includes selenium-bearing grade, although welding usually is not recommended for any of the free-machining steels when high quality joints are required.
(b) Not a standard AISI grade designation.
(d) Butter chromium steel with E309; complete joint with E308.
(e) ENiCrFe-3 preferred, especially for joints for high temperature service in low sulfur atmospheres, or when one member is a copper-bearing alloy.
(g) Butter chromium steel with E309, and chromium-nickel steel with E312; complete joint with E308.
(l) E309 or E310 may be used when matching composition weld metal is not required.
(o) Butter copper-nickel member with two or more layers of ENi-CrFe-3; complete joint with ENiCrFe-3.
(p) Butter free-machining steel); complete joint with ENiCrFe-3.
(q) Butter free-matching steel with two layers of E309 (312 for chromium-nickel free-machining steel); and butter nickel-copper member with one or two layers of ENiCrFe-3, complete joint with ENiCrFe-3.
(r) Any E60XX or E70XX mild steel electrode.
(s) E8015-B2L, E8016-B2, or E8018-B2 (low alloy steel electrodes).
(t) E9015-B3L, E9015-B3, E9016-B3, or E9018-B3 (low alloy steel electrodes).
(u) E7015, E7016, E7018 or E7028 (mild steel electrodes).

Table 64.8—Covered electrodes recommended for welds between stainless and heat-resisting steels

Base Metals→ ↓	201	202	301	302	302B	303(a)	304	304L	305	308	309	309S	310	310S	314	316	316L	317	317L(b)	321	330(b)	347
201	E308(c)	E308(c)	E308(c)	E308	E308	E308; E312	E308	E308	E308	E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
202		E308(c)	E308(c)	E308	E308	E308; E312	E308	E308	E308	E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
301			E308(c)	E308	E308	E308; E312	E308	E308	E308	E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
302				E308	E308	E308; E312	E308	E308	E308	E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
302B					E308	E308; E312	E308	E308	E308	E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
303(a)						E308; E312	E308; E312 E308(h)	E308; E312 E308	E308; E312 E308	E308; E312 E308	E308; E312 E308	E308; E312 E308	E312 E308	E312 E308	E312 E308; E312	E308; E312 E308	E308; E312 E308	E308; E312 E308	E308; E312 E308	E308; E312 E308	E312; E309 E312; E309	E308; E312 E308
304								E308L	E308; E310	E308	E308	E308	E308	E308	E308; E312	E308	E308L	E308	E308L	E308L	E312; E309	E308L
304L									E308; E310	E308	E308	E308	E310; E308	E310; E308	E312	E308	E308	E308	E308	E308	E312; E309	E308
305										E308	E308	E308	E308	E308	E308; E312	E308	E308	E308	E308	E308	E312; E309	E308
308											E309	E309	E309	E309	E309; E312	E309	E309; E316	E309	E309	E308 E347	E312; E309	E308; E347
309												E309S(i); E309	E309 E310	E309S(i); E309 E310	E309 E312 E310; E312 E310; E312	E309S(i); E316L E316 E316	E316 E316 E316	E316 E317 E317	E316 E317L(j) E317L(j) E317	E308; E347 E308 E308	E312; E309 E312; E310 E312; E310	E308; E347 E308; E347 E308; E347 E308
309S																						
310																						
310S																						
314																						
316																E316;(k)	E316	E316	E316	E308	E312; E309	E308;(k)
316L																	E316L	E316	E316L	E308L	E312; E309	E316L
317																		E317	E317	E308	E312; E309	E308L;(k)
317L(b)																			E317L(j)	E308L; E347	E312; E309	E308L
321																				E347	E312; E309	E347
330(b)																					E330	E312; E309 E347
347																						
348																						
403																						
405																						
410																						
414																						
416(a)																						
420																						
430																						
430F(a)																						
431																						
440A																						
440B																						
440C																						
446																						
501																						
502																						
505(b)																						

When two or more electrodes are listed for a given combination of base metals, the first is suitable for most applications. Others have been listed as alternates, or as recommendations for more demanding applications, or for use where cracking might occur with particular lots or heats of material welded with the first electrode. The service requirements of the joint will dictate the most suitable electrode. Recommended electrodes were selected because they are adequate for most applications, and because they are commonly available. The recommendations do not imply that other electrodes would be unsuitable for many applications. In those instances the electrodes shown were selected on the basis of material costs.

Suppliers may be contacted regarding preheat and postheat treatments for best serviceability.

Electrode designations are in accordance with the following AWS-ASTM Filler Metal Specifications: Stainless steels, AWS A5.4, ASTM A298; nickel-base alloys, AWS A5.11, ASTM B295; mild steels, AWS A5.1, ASTM A233; low alloy steels, AWS A5.5, ASTM A316; copper alloys, AWS A5.6, ASTM B225.

(a) Includes selenium-bearing grade, although welding usually is not recommended for any of the free-machining steels when high quality joints are required.

(b) Not a standard AISI grade designation.

(c) Weld metal will be somewhat lower in strength than base metal.

(d) Butter chromium steel with E309, complete joint with E308.

(e) ENiCrFe-3 preferred, especially for joints for high temperature service in low sulfur atmospheres, or when one member is a copper-bearing alloy.

(f) Butter chromium-nickel steel with E312 complete joint with E310.

(g) Butter chromium steel with E309 and chromium-nickel steel with E312; complete joint with E308.

(h) E308L recommended for cryogenic applications.

(i) E309S is not a standard electrode designation. The "S" implies 0.08% C max, compared with a 0.15% C max for E309.

(j) E317L is not a standard electrode designation. The "L" implies 0.04% C max, compared with 0.08% C max for E317.

(k) E16-8-2 recommended for less embrittlement during long-time high temperature service.

(l) E309 or E310 may be used when matching composition weld metal is not required.

(m) Special electrode with matching composition (including carbon content) required when hardness of quenched and tempered weld metal must equal that of base metal.

(n) 28Cr is not a standard electrode designation. It signifies an electrode which has a typical as-deposited analysis of 0.10 C, 1.0 Mn, 0.50 Si, 29 Cr and 0.15 N.

(o) Butter copper-nickel member with two or more layers of ENiCrFe-3; complete joint with ENiCrFe-3.

(p) Butter free-machining steel with two layers of E309 (E312 for chromium-nickel free-machining steel), complete joint with ENiCrFe-3.

(q) Butter free-machining steel with two layers of E309 (312 for chromium-nickel free-machining steel); and butter nickel-copper member with one or two layers of ENiCrFe-3, complete joint with ENiCrFe-3.

(r) Any E60XX or E70XX mild steel electrode.

(s) E8015-B2L, or E8018-B2, or E8018-B2 (low alloy steel electrodes).

(t) E9015-B3L, E9015-B3, E9016-B3, or E9018-B3 (low alloy steel electrodes).

(u) E7015, E7016, E7018 or E7028 (mild steel electrodes).

Table 64.8—Covered electrodes recommended for welds between stainless and heat-resisting steels (continued)

348	403	405	410	414	416(a)	420	430	430F(a)	431	440A	440B	440C	446	501	502	505(b)	←Base Metals ↓
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	201
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	202
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	301
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	302
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	302B
E308; E312	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(f)	(g); E309	(g); E309;	(g); E309	303(a)
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	304
E308L	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	304L
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	305
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309	(d); E309	(d); E309	308
E308; E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	309
E308; E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	309S
E308; E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E309; E310;(e)	E310;(e)	E310;(e)	E310;(e)	310
E308; E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E309; E310;(e)	E310;(e)	E310;(e)	E310;(e)	310S
E308	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E309; E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	314
E308; E316	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	316
E316L	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	316L
E308L;(k)	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	317
E308L	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	317L(b)
E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	E310;(e)	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	321
E312; E309	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312	(g); E312;(e)	(g); E312;(e)	(g); E312;(e)	330(b)
E347	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309	(d); E309;(e)	(d); E309;(e)	(d); E309;(e)	347
E348	(d); E309 E410;(l)	(d); E309 E410;(l) E410;(l)	(d); E309 E410;(l) E410;(l)	(d); E309 E410;(l) E410;(l) (m); E309	(d); E309 E410;(d) E410;(d) E410;(d) E410; E309	(d); E309 E410;(l) E410;(l) E410;(l) E309 E420; E410;(l)	(d); E309 E410;(l) E430;(l) E430;(l) E430;(l) E410; E309 E410;(l) E430;(l)	(d); E309 E309 E309 E309 E309 E309 E309	(d); E309 E410;(l) E410;(l) E410;(l) E410;(l) E410; E309 E410;(l) E430;(l)	E410;(l) E410;(l) E410;(l) E410;(l) E410;(l) E309 E420;(l) E430;(l)	E410;(l) E410;(l) E410;(l) E410;(l) E410;(l) E309 E420;(l) E430;(l)	E410;(l) E410;(l) E410;(l) E410;(l) E410;(l) E309 E420;(l) E430;(l)	E410;(l) E410;(l) E410;(l) E410;(l) E410;(l) E309 E430;(l) E309; E310	E502;(l) E502;(l) E502;(l) E502;(l) E502;(l) E309 E502;(l) E502;(l)	E502;(l) E502;(l) E502;(l) E502;(l) E502;(l) E309 E502;(l) E502;(l)	E505;(l) E505;(l) E505;(l) E505;(l) E505;(l) E309 E505;(l) E505;(l)	348 403 405 410 414 416(a) 420 430
								E309	E309 (m); E309	E309 (m); E309 (m); E309 (m); E309	E309 (m); E309 (m); E309 (m); E309 (m); E309	E309 (m); E309 (m); E309 (m); E309 (m); E309	E309; E310 E309; E310 E309; E310 E309; E310 E309; E310 28 Cr(n); E310	E309 E502;(l) E502;(l) E502;(l) E502;(l) E502;(l);(e) (m);E502;(l)	E309 E502;(l) E502;(l) E502;(l) E502;(l) E502;(l);(e) E502;(l) E502;(l)	E309 E505;(l) E505;(l) E505;(l) E505;(l) E505;(l);(e) E502;(l) E502;(l) E505;(l)	430F(a) 431 440A 440B 440C 446 501 502 505(b)

NICKEL ALLOYS

Table 67.22—Typical dissimilar-metal combinations

Joint Materials	Welding Products	
	Shielded Metal-Arc	Gas Shielded-Arc
MONEL alloy 400 to:		
Steel	ENiCu-2, ENi-1	ERNi-3
Stainless Steel	ENiCrFe-2, ENiCrFe-3	ERNiCrFe-6, ERNiCr-3
70/30 Copper-Nickel	ENiCu-2, ECuNi	ERNiCu-7, RCuNi
HASTELLOY alloy B	ENi-1	ERNi-3
Nickel 200 to:		
Steel	ENi-1	ERNi-3, ERNiCr-3
Stainless Steel	ENi-1, ENiCrFe-3, ENiCrFe-2	ERNi-3, ERNiCr-3, ERNiCrFe-6
MONEL alloy 400	ENi-1, ENiCu-2	ERNiCu-7, ERNi-3
70/30 Copper-Nickel	ENi-1, ENiCu-2, ECuNi	ERNi-3, RCuNi
HASTELLOY alloy B	ENi-1, ENiCrFe-3, ENiCrFe-2	ERNiCr-3, ERNiCrFe-6
INCONEL alloy 600 or INCOLOY alloy 800 to:		
Steel	ENiCrFe-3, ENiCrFe-2	ERNiCr-3, ERNiCrFe-6
Stainless Steel	ENiCrFe-3, ENiCrFe-2	ERNiCr-3, ERNiCrFe-6
MONEL alloy 400	ENiCrFe-3, ENiCrFe-2	ERNiCr-3, ERNiCrFe-6
Nickel 200	ENi-1, ENiCrFe-3, ENiCrFe-2	ERNi-3, ERNiCr-3
70/30 Copper-Nickel	ENi-1, ENiCrFe-2	ERNi-3
HASTELLOY alloy B	ENiCrFe-3, ENiCrFe-2	ERNiCr-3, ERNiCrFe-6
MULTIMET alloy to:		
Types 310, 316, and 347 SS	ENiMo-3	ERNiMo-6
HASTELLOY alloy B to:		
HASTELLOY alloy C	ENiMo-3	ERNiMo-6
HASTELLOY alloy N to:		
Type 347 SS	ENiCrFe-3	ERNiCr-3
INCONEL alloy 600	ENiCrFe-3	ERNiCr-3
Nickel 200	ENiCrFe-3	ERNiCr-3

COPPER & COPPER ALLOYS

Table 68.16—Weldability and filler metals for copper-tin alloys

Copper Alloy No.	Weldability	Filler Metal
502	X	—
505	X	—
507	X	—
508	A	CuSn-A
509	A	CuSn-A
510	A	CuSn-A
518	A	CuSn-A
519	A	CuSn-A
521	A	CuSn-C
524	X	—
526	X	—
529	A	CuSn-C

A — Weldable, X — Not weldable, or usually not welded.
Copper-tin-lead alloys, copper alloys 532, 534, 544, 546 are not weldable.

Table 68.19—Filler metal alloys for copper-aluminum alloys

Copper Alloy No.	Shielded Metal-Arc	Inert-Gas Processes
612	CuAl-A2	CuAl-A2
613	CuAl-A2	CuAl-A2
614	CuAl-A2	CuAl-A2
618	CuAl-A2	CuAl-A2
619	CuAl-B	CuAl-A2
620	CuAl-B	CuAl-A2
622	CuAl-C	CuAl-B
623	CuAl-A2	CuAl-A2
624	CuAl-B	CuAl-A2
625	CuAl-C	CuAl-B
626	NiAl Bronze	NiAl Bronze
628	NiAl Bronze	NiAl Bronze
630	NiAl Bronze	NiAl Bronze

Note: Copper Alloys 606, 607, 608, 610, 616, 617, 633, 634, 636, 637, 638, 639, and 642 are not usually welded.

Table 68.31—Filler metals for repair of copper alloy castings

Alloy Family	Process			
	Gas Welding	SMAW	GTAW	GMAW
Red Brasses	RCuSnC	ECuSnA ECuSnC ECuAl-A2	RCuSnA RCuSnC	ECuSi ECuSnC
Yellow Brasses	RCuZnB RCuZnC	ECuSnA ECuSnC ECuAl-A2	RCuAl-A2 RCuSi	ECuAl-A2
Manganese Bronze			RCuAl-A2 RCuSi	
Silicon Bronze	RCuZnC or composition matching casting	ECuSi ECuAl-A2	RCuSiA	ECuSi
Phosphor Bronze	not recommended best is RCuSnC or bronze weld with RCuZnC	ECuSnA ECuSnC	RCuSnA (for low tin) RCuSnC (for high tin)	
Aluminum Bronze		ECuAl-A2 ECuAl-B ECuAl-C ECuAl-D ECuAl-E	RCuAl-A2 (ac or dc)	ECuAl-A2
Copper-nickels	RCuNi	ECuNi	RCuNi	ECuNi

Table 68.33—Filler wires for surfacing applications

Wire Designation	Brinell Hardness	Yield Strength, ksi	Tensile Strength, ksi	Deposition Methods	Applications
E/RCu	50-60	8	28	OAW, GTAW, SMAW	Corrosion resistant
RCuSn	70-85		35	GTAW	Bearings, corrosion resistant
E/RCuSn-A	70-85		35	SMAW, GMAW	Porous bearings
ECuSn-C	85-100	30	40-50	SMAW, GMAW	Corrosion resistant
E/RCuSn-D	90-110			GMAW	Corrosion resistant
E/RCuSn-E	40-60			SMAW	Corrosion resistant
ECuSi	80-100		50	GMAW	Bearings, corrosion resistant
RCuSi-A	80-100	25	50-55	OAW, GTAW	Erosion corrosion
E/RCuNi	60-80	10-20	50	OAW, SMAW, GTAW	Resistant, bearing
E/RCuAl-A1	100-150	25-30	55-65	GMAW, GTAW	Bearing overlay,
E/RCuAl-A2	130-190	30-35	60-75	GMAW, GTAW, SMAW	Cavitation resistant
E/RCuAl-B	140-220	40-45	90-110	GMAW, GTAW, SMAW	Bearing overlay
E/RCuAl-C	180-280	40-45	90-100	GMAW, GTAW, SMAW	Cavitation resistant
E/RCuAl-D	250-350	50-55	75-85	GTAW, SMAW	Wear resistant
E/RCuAl-E	290-390	55-70	70-80	GTAW, SMAW	Bearings, dies
NiAl Bronze	180-200	55-60	100	GMAW, GTAW, SMAW	Erosion, corrosion resistant
MnNiAl Bronze	180-220	55-65	95-110	GMAW, GTAW, SMAW	Erosion, corrosion resistant
RBCuZnA	70-90		50	OAW	Corrosion resistant
E/RCuZnB	80-110		50-60	OAW	Bearings, corrosion resistant
RCuZnC	80-110		50-60	OAW	Bearings
RBCuZnD	90-110		50-60	OAW	Wear and corrosion
E/RCuZnE	120-140			OAW, SMAW	

Table 68.36—Alloys for joining clad steel[1]

Cladding Alloy	Alloy for Overlay on Steel	Overlay Process	Alloy for Welding Cladding	Process for Welding Cladding
Copper	RCu RCuAl-A2 RCuSi-A RNi-3	GTAW	RCu	GTAW
Copper-zinc	RCuZn-C RCuAl-A2	OAW GTAW	RCuZn-C RCuAl-A2	OAW GTAW
Copper-tin-zinc	RCuSn-A ECuSn-A	GTAW SMAW	RCuSn-A ECuSn-A	GTAW SMAW
Copper-aluminum	RCuAl-A2 ECuAl-A2	GTAW SMAW	RCuAl-A2 ECuAl-A2	GTAW SMAW
Copper-silicon	RCuSi-A	GTAW	RCuSi-A	GTAW
Copper-nickel	RCuNi ERNiCu-7	GTAW SMAW	RCuNi ERNiCu-7	GTAW SMAW

[1] For joint preparation see Figure 68.13. Alloy designations correspond to compositions in latest issue of AWS Specifications A5.6, A5.7 or A5.14.

Table 69.15—Guide to the choice of filler metal for general purpose welding

Base Metal	319.0, 333.0, 354.0, 355.0, C355.0, 380.0	413.0, 443.0 A444.0, 356.0 A356.0, A357.0, 359.0	514.0, A514.0, B514.0, F514.0	7005*k*, 7939, A712.0, C712.0, D712.0	6070	6061, 6063 6101, 6151 6201, 6951	5456	5454	5154 5254*a*	5086	5083	5052 5652*a*	5005 5050	3004 Alc. 3004	2219	2014 2024	1100 3003 Alc. 3003	1060 EC
060, EC	ER4145*c,i*	ER4043*i,f*	ER4043*e,i*	ER4043*i*	ER4043*i*	ER4043*i*	ER5356*c*	ER4043*e,i*	ER4043*e,i*	ER5356*c*	ER5356*c*	ER4043*i*	ER1100*c*	ER4043	ER4145	ER4145	ER1100*c*	ER1260*c,j*
100, 3003 Alclad 3003	ER4145*c,i*	ER4043*i,f*	ER4043*e,i*	ER4043*i*	ER4043*i*	ER4043*i*	ER5356*c*	ER4043*e,i*	ER4043*e,i*	ER5356*c*	ER5356*c*	ER4043*e,i*	ER4043*e*	ER4043*e*	ER4145	ER4145	ER1100*c*	
2014, 2024	ER4145*g*	ER4145	...	...	ER4145	ER4145	...	...	...	...	...	...	...	...	ER4145*g*	ER4145*g*		
2219	ER4145*g,c,i*	ER4145*c,i*	ER4043*i*	ER4043*i*	ER4043*f,i*	ER4043*f,i*	ER4043	ER4043*i*	ER4043*i*	ER4043	ER4043	ER4043*i*	ER4043	ER4043	ER2319*c,f,i*			
3004	ER4043*i*	ER4043*i*	ER5654*b*	ER5356*e*	ER4043*e*	ER4043*b*	ER5356*e*	ER5654*b*	ER5654*b*	ER5356*e*	ER5356*e*	ER4043*e,i*	ER4043*e*	ER4043*e*				
Alclad 3004 5005, 5050	ER4043*i*	ER4043*i*	ER5654*b*	ER5356*e*	ER4043*e*	ER4043*b*	ER5356*e*	ER5654*b*	ER5654*b*	ER5356*e*	ER5356*e*	ER4043*e,i*	ER4043*d,e*					
5052, 5652*a*	ER4043*i*	ER4043*b,i*	ER5654*b*	ER5356*e,h*	ER5356*b,c*	ER5366*b,c*	ER5356*b*	ER5654*b*	ER5654*b*	ER5356*e*	ER5356*e*	ER5654*a,b,c*						
5083	...	ER5356*c,e,i*	ER5356*e*	ER5183*e,h*	ER5356*e*	ER5356*e*	ER5183*e*	ER5356*e*	ER5356*e*	ER5356*e*	ER5183*e*							
5086	...	ER5356*c,e,i*	ER5356*e*	ER5356*e,h*	ER5356*e*	ER5356*e*	ER5356*e*	ER5356*b*	ER5356*b*	ER5356*e*								
5154, 5254*a*	...	ER4043*b,i*	ER5654*b*	ER5356*b,h*	ER5356*b,c*	ER5356*b,c*	ER5356*b*	ER5654*b*	ER5654*a,b*									
5454	ER4043*i*	ER4043*b,i*	ER5654*b*	ER5356*b,h*	ER5356*b,c*	ER5356*b,c*	ER5356*b*	ER5554*e,i*										
5456	...	ER4043*b,i*	ER5356*e*	ER5556*e,h*	ER5356*e*	ER5356*e*	ER5556*e*											
6061, 6063, 6101 6201, 6151, 6951	ER4145*c,i*	ER5356*c,e,i*	ER5356*b,c*	ER5356*b,c,h,i*	ER4043*b,i*	ER4043*b,i*												
6070	ER4145*c,i*	ER4043*e,i*	ER5356*c,e*	ER5356*c,e,h,i*	ER4043*e,i*													
7005*k*, 7039, A712.0, C712.0, D712.0	ER4043*i*	ER4043*b,h,i*	ER5356*b,h*	ER5039*e*														
514.0, A514.0, B514.0, F514.0	...	ER4043*b,i*	ER5654*b,d*															
413.0, 443.0, A444.0, 356.0,	ER4145*c,i*	ER4043*d,i*																
A356.0, A357.0, 359.0	ER4145*d,c,i*																	

NOTE: 1 — Service conditions such as immersion in fresh or salt water, exposure to specific chemicals or a sustained high temperature (over 150°F) may limit the choice of filler metals. Filler alloys 5356, 5183, 5556, and 5654 are not recommended for sustained elevated temperature service.

NOTE: 2 — Recommendations in this table apply to gas shielded-arc welding processes. For gas welding, only R1100, R1260 and R4043 filler metals are ordinarily used.

NOTE: 3 — Filler metals designated with ER prefix are listed in AWS specification A5.10

a Base metal alloys 5652 and 5254 are used for hydrogen peroxide service. ER5654 filler metal is used for welding both alloys for low-temperature service (150°F and below).

b ER5183, ER5356, ER5554, ER5556 and ER5654 may be used. In some cases they provide: (1) improved color match after anodizing treatment, (2) highest weld ductility, and (3) higher weld strength. ER5554 is suitable for elevated temperature service.

c ER4043 may be used for some applications.

d Filler metal with the same analysis as the base metal is sometimes used.

e ER5183, ER5356 or ER5556 may be used.

f ER4145 may be used for some applications.

g ER2319 may be used for some applications.

h ER5039 may be used for some applications.

i ER4047 may be used for some applications.

j ER1100 may be used for some applications.

k This refers to 7005 extrusions only. (X-prefix still applies to sheet and plate.)

NOTE: 4 — Where no filler metal is listed, the base metal combination is not recommended for welding.

Table 69.16--Composition of aluminum welding rods and electrode material for GMAW and GTAW

AWS Classification	Silicon, per cent	Iron, per cent	Copper, per cent	Manganese, per cent	Magnesium, per cent	Chromium, per cent	Nickel, per cent	Zinc, per cent	Titanium, per cent	Other Elements,[g] per cent, Each	Other Elements,[g] per cent, Total	Aluminum, per cent
ER1100	[b]	[b]	0.05-0.20	0.05	...	...	...	0.10	...	0.05	0.15	99.00 min.[h]
ER1260	[c]	[c]	0.04	0.01	...	...	...	...	...	0.03	...	99.60 min.[h]
ER2319[i]	0.20	0.30	5.8-6.8	0.20-0.40	0.02	...	...	0.10	0.10-0.20	0.05	0.15	remainder
ER4145	9.3-10.7	0.8	3.3-4.7	0.15	0.15	0.15	...	0.20	...	0.05	0.15	remainder
ER4043	4.5-6.0	0.8	0.30	0.05	0.05	...	...	0.10	0.20	0.05	0.15	remainder
ER4047	11.0-13.0	0.8	0.30	0.15	0.10	...	...	0.20	...	0.05	0.15	remainder
ER5039	0.10	0.40	0.03	0.30-0.50	3.3-4.3	0.10-0.20	...	2.4-3.2	0.10	0.05	0.10	remainder
ER5554	[c]	[c]	0.10	0.50-1.0	2.4-3.0	0.05-0.20	...	0.25	0.05-0.20	0.05	0.15	remainder
ER5654[j]	[d]	[d]	0.05	0.01	3.1-3.9	0.15-0.35	...	0.20	0.05-0.15	0.05	0.15	remainder
ER5356	[e]	[e]	0.10	0.05-0.20	4.5-5.5	0.05-0.20	...	0.10	0.06-0.20	0.05	0.15	remainder
ER5556	[c]	[c]	0.10	0.50-1.0	4.7-5.5	0.05-0.20	...	0.25	0.05-0.20	0.05	0.15	remainder
ER5183	0.40	0.40	0.10	0.50-1.0	4.3-5.2	0.05-0.25	...	0.25	0.15	0.05	0.15	remainder
R-C4A[a]	1.5	1.0	4.0-5.0	0.35	0.03	...	...	0.35	0.25	0.05	0.15	remainder
R-CN42A[a]	0.7	1.0	3.5-4.5	0.35	1.2-1.8	0.25	1.7-2.3	0.35	0.25	0.05	0.15	remainder
R-SC51A[a]	4.5-5.5	0.8[f]	1.0-1.5	0.50[f]	0.40-0.60	0.25	...	0.35	0.25	0.05	0.15	remainder
R-SG70A[a]	6.5-7.5	0.6	0.25	0.35	0.20-0.40	...	...	0.35	0.25	0.05	0.15	remainder

NOTE 1—Single values shown are maximum percentages, except where a minimum is specified.
NOTE 2—For purposes of determining conformance to these limits, an observed value or a calculated value obtained from analysis shall be rounded off to the nearest unit in the last righthand place of figures used in expressing the specified limit, in accordance with Recommended Practices for Designing Significant Places in Specified Limiting Values (ASTM Designation: E29), 1968 Book of ASTM Standards, Part 32.
NOTE 3—Analysis shall be made for the elements for which specific limits are shown. If, however, the presence of other elements is suspected, or indicated in the course of routine analysis, further analysis shall be made to determine that these other elements are not in excess of the limits specified for "other elements."

[a] For repair of castings.
[b] Silicon plus iron shall not exceed 1.0 per cent.
[c] Silicon plus iron shall not exceed 0.40 per cent.
[d] Silicon plus iron shall not exceed 0.45 per cent.
[e] Silicon plus iron shall not exceed 0.50 per cent.
[f] If iron exceeds 0.45 per cent, manganese should be present in an amount equal to one half the iron.
[g] Beryllium shall not exceed 0.0008 per cent.
[h] The aluminum content is the difference between 100.00 per cent and the sum of all other metallic elements present in amounts of 0.010 per cent or more each, expressed to the second decimal.
[i] Vanadium content shall be 0.05-0.15 per cent. Zirconium content shall be 0.10-0.25 per cent.
[j] Effective with the 1969 revision of AWS A5.10, ER5654 has replaced filler metal composition ER5154, ER5254 and ER5652.

CORROSIVES WHICH INDUCE INTERGRANULAR CORROSION IN AUSTENITIC STAINLESS STEEL

Acetic Acid

Acetic Acid + Salicylic Acid

Ammonium Nitrate

Ammonium Sulfate

Ammonium Sulfate + H_2SO_4

Beet Juice

Calcium Nitrate

Chromic Acid

Chromium Chloride

Copper Sulfate

Crude Oil

Fatty Acids

Ferric Chloride

Ferric Sulfate

Formic Acid

Hydrocyanic Acid

Hydrocyanic Acid + Sulfur Dioxide

Hydrofluoric Acid + Ferric Sulfate

Lactic Acid

Lactic Acid + Nitric Acid

Maleic Acid

Nitric Acid

Nitric Acid + Hydrochloric Acid

Nitric Acid + Hydrofluoric Acid

Oxalic Acid

Phenol + Naphthenic Acid

Phosphoric Acid

Phthalic Acid

Salt Spray Polythionic Acid

Sea Water

Silver Nitrate + Acetic Acid

Sodium Bisulfate

Sodium Hydroxide + Sodium Sulfide

Sodium Hypochlorite

Sulfite Cooking Liquor

Sulfite Solution

Sulfite Digester Acid
(Calcium Bisulfite + Sulfur Dioxide)

Sulfamic Acid

Sulfur Dioxide (Wet)

Sulfuric Acid

Sulfuric Acid + Acetic Acid

Sulfuric Acid + Copper Sulfate

Sulfuric Acid + Ferrous Sulfate

Sulfuric Acid + Methanol

Sulfuric Acid + Nitric Acid

Sulfurous Acid

Water + Starch + Sulfur Dioxide

Water + Aluminum Sulfate

UOP HYDROCRACKING, HYDRODESULFURIZATION AND HYDRODEALKYLATION UNITS

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VI. REFERENCES

uop

A.E.Lipka/M.L.Potter
Des Plaines, Illinois
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Revised

PROTECTION OF AUSTENITIC STAINLESS STEEL

I. INTRODUCTION

Since corrosion cracking of austenitic stainless steel can lead to failure of the equipment involved, it is of the utmost importance that this equipment be properly protected to prevent corrosive environments from occurring. Therefore, all operating personnel, and especially the supervisory personnel, must be familiar with the locations of piping and equipment fabricated from austenitic stainless steel. They should also recognize the need for special handling of these sections of the unit during startup, shutdown, flushing, cleaning, maintenance and inspection, and should be thoroughly familiar with the procedures to be used for the proper protection of the equipment.

It is recognized that corrosion cracking of austenitic stainless steel is much less likely to occur in hydrodealkylation units than in hydrocracking and hydrodesulfurization units, because of the relatively low sulfur concentrations involved combined with the wide use of the stabilized grades of austenitic stainless steel. Nevertheless sufficient danger of corrosion cracking exists in hydrodealkylation units to warrant due consideration for adequate protection procedures.

A number of both general and detailed instructions are contained in this discussion, however, all possibilities cannot be covered. Therefore, if situations arise which are not covered in this discussion, the refiner is advised to discuss the matter with UOP before proceeding.

II. GENERAL

A. Austenitic Stainless Steels

Austenitic stainless steels are those of the "300 series," the compositions of which are nominally 18% chromium and 8% nickel. The most common types used in the petroleum refining industry are Types 304, 316, 321 and 347. Because of their inherent high temperature strength properties and high corrosion resistance, they are particularly suitable for use in hydrocracking, hydrodesulfurization, and hydrodealkylation units in areas of moderate and high temperature, and where substantial resistance to hydrogen sulfide corrosion is required, such as in heater tubes, reactors, reactor effluent exchangers and piping. Types 321 and 347 are stabilized to minimize intergranular carbide precipitation and are preferred because they are more resistant to the intergranular corrosion cracking caused by polythionic acid attack, which can occur particularly during downtime periods when exposed to air and moisture. Since these stabilized grades are not completely immune to intergranular corrosion

cracking, special handling procedures are recommended for the protection of these materials as well as the unstabilized grades.

B. Chloride Attack

The presence of halides (chlorides are usually the most serious offenders) along with an aqueous phase and tensile stresses can result in stress corrosion cracking of austenitic stainless steels. This type of cracking is predominantly transgranular and is somewhat dependent on time, temperature and chloride concentration. Therefore, precautions should be taken to minimize the amount of chloride in the process material which will come in contact with austenitic stainless steel equipment. Under normal shutdown period conditions, chloride cracking is not likely to be a problem as long as chlorides are not allowed to accumulate and concentrate in hot equipment, and as long as precautions are taken to limit the chloride content to low levels in any flushing, purging or neutralizing agents used in the system.

C. Polythionic Acid Attack

Once a unit has been placed on stream, even if the sulfur content of the feedstock is low, every item made of austenitic stainless steel should be considered to contain a layer of iron sulfide scale. Even though these layers of scale in many cases may be very thin, they represent a potential hazard to the underlying steel. The action of water and oxygen on this sulfide scale forms weak sulfurous type acids, commonly referred to as polythionic acids, which can attack austenitic stainless steels and cause intergranular corrosion and cracking. These stainless steels are vulnerable to this type of corrosion, particularly in areas of residual tensile stresses and in areas where intergranular carbides may exist, such as the heat-affected zones adjacent to welds. Therefore, special precautions should be taken to protect austenitic stainless steel from this corrosive environment.

D. Protection Against Polythionic Acid Attack

Protection against polythionic acid attack can be accomplished by preventing the corrosive environment from forming or by providing an agent which will neutralize any corrosive acids as they are formed:

1. Preventing the Formation of Polythionic Acids

Since these acids are formed by the action of water and oxygen with hydrogen sulfide or sulfide scale, elimination

of either liquid phase water or oxygen will prevent these acids from being formed. Since there will usually be an equilibrium amount of water vapor present during the normal operation of a unit, then during shutdown periods this water vapor can be prevented from condensing by maintaining the temperature of the austenitic stainless steel equipment above the dew point of water.

Under normal operations, other than a startup immediately following a catalyst regeneration where there may be significant amounts of oxygen present before purging, there should be essentially no oxygen present in the system. The only other time any significant amount of oxygen might enter the system would be during a shutdown period when the system is depressured and the equipment is opened and exposed to air. Under these conditions a suitable purge of nitrogen should be established through the equipment involved to prevent any air from entering the system, and maintained until the system is again closed. If possible, the equipment should be blinded or blanked-off during this period and kept under a slight positive pressure of nitrogen.

2. Neutralization

Whenever austenitic stainless steel cannot be adequately protected by maintaining temperatures above the dew point of water or by an adequate nitrogen purge, a protective neutralizing environment should be established in this equipment prior to exposure to air. An effective neutralizing environment can be provided by purging with and maintaining an ammoniated nitrogen blanket, or by washing with a dilute soda ash solution.

III. PURGING AND NEUTRALIZING

A. Purging Nitrogen

Nitrogen used for the purging and protection of austenitic stainless steels should be dry and of good commercial quality. The oxygen content of the nitrogen used should be specified by the supplier. If the only nitrogen available has an oxygen content in excess of 1000 ppm, or if the oxygen content is unknown, then as a safeguard, ammoniated nitorgen should be used where possible. However, for this case, catalyst safety considerations might be necessary.

PROTECTION OF AUSTENITIC STAINLESS STEEL

B. Ammoniated Nitrogen

To prepare ammoniated nitrogen for use in purging or blanketing an austenitic stainless steel system, sufficient ammonia is added to the nitrogen to provide a minimum concentration of 5000 ppm ammonia. Whenever ammonia is added to the reactor system, the ammonia content of the recycle gas should be checked frequently. It is expected that the catalyst will absorb a considerable amount of ammonia, and therefore additional ammonia makeup will be required to maintain the 5000 ppm ammonia concentration until the system reaches equilibrium.

One convenient method of adding ammonia to the system, especially when the system is at high pressure, is to use a high pressure "blow case." With this type of arrangement liquid ammonia is pressured into the blow case at low pressure from the ammonia cylinder, and then the blow case is isolated. High pressure gas from the discharge of the recycle gas compressor is then used to pressure up the blow case and to force the ammonia into the system at a location of lower pressure.

CAUTION

1. All personnel working in the unit should be familiar with the toxic nature of ammonia, and must follow proper safety precautions in working with this system when it contains ammonia. For example, workers opening flanges or manways in a system containing ammonia should be equipped with fresh air masks or other oxygen breathing equipment.

2. In order to preserve the activity of the catalyst in the reactors, ammonia is not to be passed over the catalyst when it is in its oxidized form, that is, whenever the catalyst is either fresh or freshly regenerated. When dealing with platinum type catalysts or HC-2 catalyst, ammonia should be excluded regardless of the state of the catalyst.

3. Brass and most other copper alloys are subject to corrosion attack from ammonia. Therefore, arrangements should be made to isolate this equipment from the system before admitting any ammonia.

PROTECTION OF AUSTENITIC STAINLESS STEEL

C. Soda Ash Solutions

1. Composition

Aqueous neutralizing solutions of soda ash (Na_2CO_3) should be prepared in the range of 2% to 5% by weight. Preheating the water to about 100°F will facilitate dissolving all the soda ash. In this range a sufficiently high level of alkalinity will be provided to affect neutralization of any reasonable amount of polythionic acids which may be formed. To avoid exposing the austenitic stainless steel equipment to a concentration of chlorides, the chloride content of the soda ash used to prepare the solution should be limited to a maximum of 500 ppm, while the chloride content of the water should not exceed 50 ppm. As added protection against chloride attack from the small amount of chloride present in the neutralizing solution, 0.5% by weight of sodium nitrate should be added to the soda ash solution. Sodium nitrate concentrations much above 0.5% should not be used, however, in order to avoid the possibility of stress corrosion cracking of carbon steel piping and equipment in the system.

2. Neutralization Techniques

Whenever a soda ash solution is used for neutralizing and protecting austenitic stainless steel, the piping or piece of equipment involved should be filled completely full with the solution. The equipment should then be allowed to soak for a minimum of two hours before the soda ash solution is drained and the equipment is exposed to the air. If there are any pockets or unvented high areas in the equipment which cannot be reached by filling with the soda ash solution, then the solution should be vigorously circulated through the equipment to assure thorough contact of all austenitic stainless steel surfaces. This circulation should be continued for a minimum period of two hours before draining and exposing the equipment to air. For extremely large surfaces, such as reactor or large vessel walls and internals, where filling with soda ash solution is not only impractical but in some cases impossible because of foundation load limitations, it is recommended to wash the areas very thoroughly by means of a high pressure hose equipped with a spray nozzle. This type of washing will have to be done after the vessel has been opened to allow entry. Until the soda ash washing has been completed, the vessel should be maintained under a nitrogen blanket to prevent the entry of air.

PROTECTION OF AUSTENITIC STAINLESS STEEL

3. Protective Film

In all cases of flushing or washing with soda ash solution, after the solution is drained from the equipment the surfaces should be allowed to dry so that a film or fine deposit of soda ash remains on all surfaces for added protection against polythionic acid formation. Therefore, after draining the soda ash solution, do not rinse the system with steam or water. For large accessible surfaces, such as vessels or reactor walls and internals, the excess dried soda ash can be removed just prior to startup with a brush or dry cloths; but do not use wet cloths and do not flush with steam or water. The small amount of soda ash remaining on the surfaces, even if it were all deposited on the catalyst, would not have any significant effect on the activity of all but the platinum-type catalysts under consideration in this paper.

4. Precautions with Platinum Catalysts

When platinum-type catalyst is used in the system, any soda ash film which may have been applied and is present should be removed just prior to reloading catalyst or just prior to connecting the austenitic stainless steel equipment back into the reactor circuit, as applicable, to prevent sodium contamination of the catalyst and loss of activity. To remove the soda ash film, first check to assure that the equipment involved is properly isolated from the reactor to prevent any contact of the catalyst by soda ash. Then thoroughly purge the system with nitrogen to remove all oxygen. While maintaining a nitrogen blanket on the system to prevent the entry of air, flush the system thoroughly with clean deaerated condensate to remove the soda ash deposits. Continue to maintain a nitrogen blanket on the system and drain the condensate. Then purge with nitrogen at maximum rate to remove any remaining pockets of water. Where austenitic stainless steel heater tubes are involved, small fires should be lit as soon as the nitrogen purging is started and adjusted for the nominal 400°F firebox temperatures, to thoroughly dry the tubes. Make all necessary connections to prepare the unit for startup and normal operation while maintaining sufficient nitrogen purges from both sides of flanges, etc., to be closed so as to prevent any air from entering the system.

PROTECTION OF AUSTENITIC STAINLESS STEEL

IV. HYDROTESTING

A. New Austenitic Stainless Steel

When conducting hydrostatic tests on new austenitic stainless steel equipment, the water used should have a chloride content not exceeding 50 ppm by weight, in order to reduce the possibility of concentrating chlorides in pockets or dead areas of the system. If chlorides were allowed to accumulate and concentrate (such as during subsequent heating operations) in such areas, stress corrosion cracking could result. If the only water available has a chloride content in excess of 50 ppm, then 0.5% of sodium nitrate should be added.

B. Used Austenitic Stainless Steel

Whenever a piece of equipment has been used for the processing of hydrocarbons in hydrocracking, hydrodesulfurization or hydrodealkylation service, it must be assumed that some degree of sulfide scale can be present. Therefore, even if this sulfide scale is so slight that it is difficult to detect, the possibility of polythionic acid formation with resulting intergranular corrosion cracking exists. Even if the equipment has been cleaned by mechanical means, burning or acidizing, it is difficult to assure that no traces of sulfide scale remain. Therefore, any hydrostatic testing (and any cleaning by hydroblasting) operations on used equipment should be conducted using the dilute soda ash solution specified for neutralizing this equipment. Here again, a protective film of dried soda ash should be allowed to remain on the surfaces of the equipment while it is exposed to the air.

V. SPECIAL PROCEDURES

A. Reactor Charge Heater Tubes

1. Maintaining Small Fires

The austenitic stainless steel tubes in a reactor charge heater can best be protected by maintaining a balanced set of small fires (or pilots, as applicable) in the heater box at all times, even when there is no circulation of process material through the tubes. These small fires should be adjusted to keep the tubes warm and dry, to maintain the environment inside the tubes above the dewpoint of water. As a general rule, about 400°F, as measured by thermocouples placed in the hip sections of the heater, and directly below any convection coils that

may exist, will usually be sufficient for this purpose. The dew point, however, should be determined for each specific condition involved and the temperature should be adjusted as necessary. Only fuel gas firing should be used for this operation because of the difficulty in controlling and maintaining sufficiently small flames when burning fuel oil.

It is important during these periods of heater operation, that the heater firing be under strict control and that the firing pattern be properly established to provide good heat distribution. Sufficient thermocouples should be installed throughout the hip sections of the heater to provide a good measurement of the firebox temperatures and to monitor the distribution of heat in the firebox. These thermocouples should be located below any convection bank in the heater, and should be connected to a continuous recorder provided with high and low alarm points. The low alarm point should be set at about 300°F and the high alarm point at about 450°F. CAUTION: Stack temperatures should never be used to control firebox temperatures.

2. To Shut Down Fires

If it should be necessary for any reason to shut down the fires in a charge heater containing austenitic stainless steel tubes, then this should be done only when it is absolutely certain that the environment within the tubes does not contain both oxygen and water (or water vapor). As a result of the operation of the reactor effluent water wash facilities in units so equipped, there will normally be an equilibrium amount of water present in the entire reactor circuit both during normal operation, and during or after a period of in situ catalyst regeneration. If the heater fires must be shut down during a period of normal operation, it is required only that no oxygen is present, which is usually the case during normal processing periods. As the heater tubes cool there will be small amounts of water condensing inside the tubes, however, this water should not be harmful in the absence of oxygen.

If the heater must be cooled down and it is suspected that trace quantities of oxygen might be present, then before cooling the heater the system should be depressured completely, but do not evacuate. Evacuation at

this point is perhaps possible, but not recommended because it introduces the possibility of allowing air to enter the system. Continue to maintain the 400°F heater box temperatures while depressuring and purging. After the system has been depressured, pressure with nitrogen to any convenient pressure level. Repeat this depressuring/pressuring procedure as many times as required to reduce the oxygen concentration, by dilution, to as much below 100 ppm as is possible and reasonable. Then the fires can be shut down and the heater allowed to cool.

3. Neutralization

If neutralization is necessary, such as when a tube or tubes are cut out of the coil or any time when exposure to air at temperatures below the dew point of water cannot be avoided, the tubes should be filled with soda ash solution and allowed to soak for a minimum of two hours. With vertical coils, where it is not possible to completely fill the unvented upper return bends, it is necessary instead to vigorously circulate the soda ash solution through the tubes for a minimum of two hours to assure contact of all surfaces. After draining the soda ash solution, do not flush with steam or water but instead allow a film of protective soda ash to remain in the tubes.

4. Exterior Surfaces

Whenever heater fires must be shut down and the tubes are allowed to cool, it is recommended that the exterior tube surfaces be protected, especially in heaters where fuel oil or high sulfur content fuel gas is employed. As a result of the sulfur in the fuel, a sulfide or sulfate scale can build up on the exterior tube surfaces as well as on the inside tube surfaces. If moisture is allowed to condense on the tubes as the heater box is cooled, the action of oxygen and moisture on the scale can form polythionic acids which can attack the austenitic stainless steel tube surfaces and lead to intergranular stress corrosion cracking. There are two recommended procedures that can be followed to prevent this from occurring:

First, it is possible to prevent any moisture from condensing on the tubes, and thus prevent the formation of polythionic acids, by purging the firebox with copious amounts of dry air. Normal instrument air is prepared by processing

PROTECTION OF AUSTENITIC STAINLESS STEELS

through a set of driers where the dew point is reduced to a sufficiently low level to prevent condensation from occurring at ambient conditions. This air can be effectively used to maintain a dry air blanket in the heater box both during cooling and throughout the entire period the fires are out. In order to minimize the consumption of instrument air, and to prevent moist air from entering the heater box, the stack damper, all burner air registers, and all doors and ports in the heater box should be kept closed.

Second, an alternate method of protecting the tubes from polythionic acid attack is to cover the exterior tube surfaces with a protective film of soda ash, which will act to neutralize any polythionic acids as they are formed. The neutralizing soda ash should be the same dilute solution recommended for general neutralization, and should be applied to the tube surfaces as soon as the heater box has cooled sufficiently to prevent vaporizing the soda ash solution, and preferably before any moisture has begun to condense out on the tube surfaces. A fairly efficient and effective method of applying the soda ash solution is to utilize a vat or tank with a small portable pump which can pump the solution through a hose fitted with a spray nozzle which will produce a fairly fine mist. Small diameter pipe extensions can be fitted to the hose to allow reaching up to the tube areas at the top of the heater box. This type of spray equipment will minimize the soda ash consumption and provide a reasonable means to reach all tube surfaces which are exposed to the heater flames. Once the soda ash solution has been applied, it should be allowed to dry to form a protective film on the surfaces of the tubes; do not wash off this protective film.

If the exterior tube surfaces are heavily coated with an oxide or carbonaceous material, it should be removed by wire brushing or sandblasting. This cleaning, however, will also remove any protective soda ash film that may have been applied. In this case, the tube surfaces should be further protected by applying another film of soda ash without delay.

On the occasions when the heater fires are shut down, it is convenient to also schedule inspection of the tubes. Inspection should include measuring the tube outside diameters for comparison to the original new tube O.D's, dye penetrant checking of welds and heat affected zones for cracks, and random ultrasonic flaw detection of the heat affected zones around welds. Periodic radiographic inspection should be conducted to check for scale or deposits inside the tubes.

PROTECTION OF AUSTENITIC STAINLESS STEEL

B. Fractionator Heater Tubes

Where the fractionator heater tubes are made of austenitic stainless steel and it is necessary to work on the fractionator section, and in particular to prepare for opening the fractionator column, the following steps should be taken:

1. Pump or pressure all the oil from the flash drum or fractionator feed drum into the fractionator and out to storage or slop. Fire the heater as necessary to maintain a firebox temperature, as measured by thermocouples placed in the hip section of the heater, of about 400-600°F to keep the tubes warm and dry, above the dew point of water, and to assure that the steam that will be used to purge the system will not condense in the tubes. Some judgement by operators and supervisors is necessary at this time.

2. Drain all condensate from the steam lines, then open the steam valves at the inlet of the fractionator heater wide open on all heater passes. Superheated steam is preferred for this purging operation. At the same time increase the heater firing as necessary to heat the steam above its saturation temperature to assure it will not condense in the tubes. A heater transfer temperature of about 600°F is generally preferred, as long as the temperature limitations of the heater or the fractionator system are not exceeded.

3. After the system has been thoroughly purged with steam, stop the steam and immediately cut in a nitrogen purge through the coils and into the column to sweep out any remaining steam. The nitrogen flow will usually be less than the steam flow, and as a result a corresponding reduction in heater firing will be necessary.

4. If the heater is not to be entered, then the fires should be reduced only to the point where a 400°F firebox temperature, as measured by the previously discussed hip section thermocouples, can be maintained. If the heater must be entered, cut the fires and maintain a continuous nitrogen purge through the tubes. The exterior tube surfaces should be protected from polythionic acid attack whenever the heater fires are shut down, in accordance with the recommendations in the "Exterior Surfaces" section V.A.4 (page 9).

PROTECTION OF AUSTENITIC STAINLESS STEEL

5. If the fractionator column is to be opened, install blinds at the column to isolate the heater coils, and maintain a positive pressure of nitrogen in the coils. If heater tubes are to be cut, or for some reason the insides of the tubes will be exposed to air, then the tubes should first be thoroughly soaked or flushed with soda ash solution, as discussed in the section on "Reactor Charge Heater Tubes."

C. Heat Exchangers

If lines leading to or from heat exchangers containing austenitic stainless steel are to be opened, blinds can be rapidly inserted to isolate the exchanger, while maintaining a nitrogen purge through the exchanger involved to prevent air from entering. A nitrogen blanket or continuous nitrogen purge should then be maintained in the exchanger during this maintenance period.

If shell and tube exchangers containing austenitic stainless steel are to be opened and inspected, or if the tube bundles are to be pulled, then before exposing this equipment to air both shell and tube sides should be flooded with soda ash solution and allowed to soak for a minimum of two hours. If there are any pockets or high areas which cannot be reached with the soda ash solution, then the soda ash solution should be vigorously circulated through the exchanger for a minimum of two hours. Do not rinse with water, but instead allow a film of soda to remain on the surfaces.

If tube bundles of austenitic stainless steel are to be cleaned by hydroblasting, then soda ash solution should be used for this purpose instead of just water.

D. Reactor Internals

Any time a reactor is to be opened, maintain sufficient nitrogen purges to prevent the entry of air into any part of the system and isolate the charge heater coils and the reactor effluent system with blinds. A blanket of nitrogen should also be maintained in the reactor, especially if it contains unregenerated catalyst. A slight amount of air coming in contact with the reactor internals for relatively short periods of time is normally not considered to be harmful to the metal, however, precautions should be taken to prevent contact with water or moisture, especially in the presence of air. If any exposure to air has occurred, the air should be purged out with nitrogen as soon as possible.

PROTECTION OF AUSTENITIC STAINLESS STEEL

When the reactor internals are to be exposed to air for a prolonged period of time, such as during a catalyst change, the reactor walls and internals should be washed very thoroughly as soon as possible with a high pressure hose, using copious amounts of soda ash solution. A portable pump and a vat of soda ash solution on skids is advisable for this operation. In order to do this washing properly, a workman equipped with a fresh air mask and following all other proper safety precautions, might have to enter the vessel to make sure all surfaces, including the underside of the top head, are thoroughly wetted. Be especially careful to thoroughly soak welded areas with particular emphasis on welds normally required to support heavy loads, such as those on support beams, grids and trays.

When the reactor contains trays, which would make wetting all surfaces with soda ash solution difficult, a sufficient amount of soda ash solution should be sprayed around the top of the reactor, and allowed to rain down through the reactor to wet as much of the surfaces as possible in the areas below the top tray. Be sure to thoroughly soak and keep wetted any used catalyst remaining in the reactor. Then air can be drawn through the reactor so that personnel can enter. During this time, a small flow of soda ash solution to the reactor should be maintained, and as each tray manway is removed, the vessel area beneath that tray and the underside of the tray should be thoroughly washed with soda ash solution.

Whenever spent, unregenerated catalyst is unloaded from a reactor, some amounts of catalyst will inadvertently remain on the trays and in the bottom of the reactor. This catalyst must be kept wet to prevent ignition of sulfide scale when air is admitted, which is another reason for conducting a thorough washing operation with the soda ash solution.

After washing with soda ash solution, allow the surfaces to dry with a fine deposit of soda ash. Do not rinse this residue off with water. Later, just prior to reloading catalyst, wipe as much excess soda ash residue from the surfaces as possible with brushes or dry cloths; do not use water or wet cloths.

E. Cooling Catalyst After Regeneration

When it is necessary to reduce the temperature in an austenitic stainless steel charge heater coil below the dew point of water when oxygen is present, such as during the procedure of cooling the catalyst bed to a temperature which would allow entering the reactor following a catalyst regeneration, the

oxygen must first be reduced to an acceptable level. Maintain the final reactor temperature used in the regeneration and continue gas circulation; and depressure to the minimum allowable for recycle compressor operation. Then pressure with nitrogen. Conduct this procedure at least three times, or as necessary to reduce the oxygen concentration in the circulating gas by dilution to as much below 1000 ppm as is possible and reasonable. Maintain reactor temperatures and gas circulation, after shutting down and draining the caustic and water systems, until the reactor system is dry and no more water collects in the separator. Then the system can be cooled to about 150°F at the reactor outlet. At this point shut down the recycle gas compressor but maintain heater fires sufficient to maintain about 400°F firebox temperatures throughout the shutdown period.

VI. REFERENCES

Additional information on the subject of the protection of austenitic stainless steel can be found in the NACE Standard RP-01-70, entitled "Recommended Practice, Protection of Austenitic Stainless Steel in REfineries Against Stress Corrosion Cracking by Use of Neutralizing Solutions During Shut Down" and approved October 1970. Copies may be obtained from NACE Headquarters, 2400 West Loop South, Houston, Texas 77027.

A. E. Lipka/M.L.Potter
Des Plaines, Illinois
May 1974

AEL/MLP:mac

STRESS CORROSION CRACK-INDUCING ENVIRONMENTS

Process equipment may fail either from the inside or from the outside. Process streams may contain unexpected contaminants, or known contaminants may concentrate unexpectedly in crevices or at heat-transfer surfaces. The equipment may be contaminated on the inside by accident during fabrication, erection, startup, operation, shutdown, downtime, or during cleaning. The equipment may crack from the outside because of contamination by the natural environment, by accidental spillage, by leachings from thermal insulation, by windborne contaminants, or by other and unusual causes.

Several lists of corrodents that may cause stress-corrosion cracking have been published. These lists are based on typical experience within the process industries where the true cracking agent may be an unkown and minor contaminant in the main stream. Thus the actual aggressive agents are probably fewer in number than those given. There has been no attempt made to trace each report to its original source to determine the actual corrodent. Except for a few well documented corrodents for each alloy, the corrosive agents listed in these tables should be used as indications of product streams in which something has been known to cause stress corrosion cracking or hydrogen embrittlement.

COPPER-BASE ALLOYS

Corrosive Agent	*Alloy Type*
Steam	Al bronze, Si bronze
NH_3	Brasses, bronzes
Amines	Brasses, bronzes
Air	P bronze, Cu-As
Water	Mn bronze
NH_4NO_3	Brass
$BaCl_2$	Brass
Butane + SO_2	Brass
HCl*	Brass
HF*	Brass
$Hg_2(NO_3)_2$	Brass
Mercury	Brass
HNO_3 vapor	Brass
Organic chlorides	Brass
KOH	Brass
NaOH	Brass

* *Nitrogen compounds also present.*

NICKEL-BASE ALLOYS

Corrosive Agent	*Alloy,*
H_2SiF_6	Monel
	Nickel
$Hg_2(NO_3)_2$	Monel
Mercury	Monel
NaOH, KOH	Nickel
	Inconel
HF	Monel
	Nickel
HT* Steam	Monel
Organic chlorides	Monel
HT* water	Inconel
Steam + SO_2	Inconel
Concd. Na_2S	Inconel
HT* Sulfur	Nickel
HCN (Impure)	Nickel

* *HT, high temperature.*

TITANIUM ALLOYS

Corrosive Agent
Red-fuming HNO_3
High temperature Cl^-
HCl
Methanol + Cl^-
Chlorinated hydrocarbons
NaCl

AUSTENITIC STAINLESS STEEL

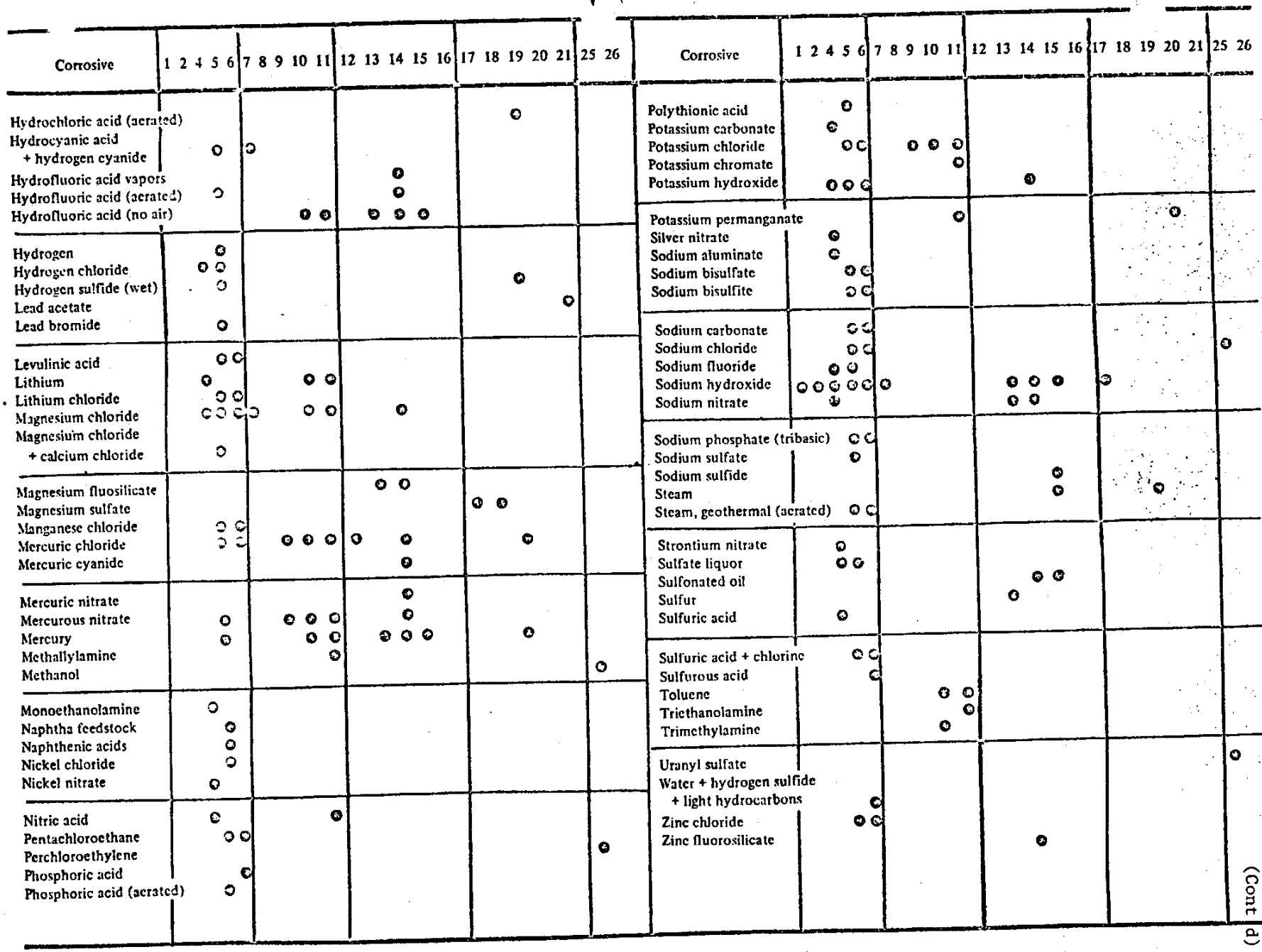
Corrosive Agent
$Al_2(SO_4)_3$
NH_4CO_3 (cold-worked steel)
Inorganic chlorides (hot)
Organic chlorides (hot)
Ethyl benzene
H_2SiF_6
HCl
HNO_3
HCl, HNO_3, HF pickling solutions
Organic acids and chlorides
KOH, NaOH
$NaAlO_2$
Na_2SO_4
Steam condensate + 5 p.p.m. NH_3
Sulfate liquor
Sulfite liquor
H_2SO_3 + metal chlorides
Brackish and sea water (cold-worked steel)
H_2S (cold-worked steel)
H_2SO_4 and $CuSO_4$
Methamine methylation stream
High temperature steam
Na_2CO_3 + NaCl
Polythionic acids
H_3PO_4

STRUCTURAL CARBON AND ALLOY STEELS

Corrosive Agent
$AlCl_3$
NH_4NO_3
$Ca(NO_3)_2$
HCl
HCN
$MgCl_2$
Monoethanol amine
$NiNO_3$
HNO_3 + $MnCl_2$
$KMnO_4$
$NaAlO_2$
NaOH, KOH
HCN
HCN + $SnCl_2$ + $AsCl_3$ + $CHCl_3$
Acrylonitrile + HCN, H_3PO_4, HAc
$CaCl_2$
H_2S
NH_4CNS
Concd. HNO_3
H_2SO_4 + HNO_3
NH_3 (anhyd.)
NaF

MARTENSITIC STAINLESS STEELS

Corrosive Agent
Marine atmosphere
H_2S
NaOH
NH_3 solution
HNO_3
H_2SO_4
NaF
Phosphate solutions
NH_4Cl
$MgCl_2$
$Ca(NO_3)_2$



Appendix 6
(Cont'd)

FERROUS ALLOYS				AUSTENITIC STAINLESS STEELS			Martensitic Stainless 405-410	COPPER BASE ALLOYS			
CAST IRON			Mild Steel	302, 304, 321, 347	316, 317	ACI CN-20 20Cr-30Ni		Copper 85-99.9	Brass 70-80Cu +Zn, Sn or Pb	Brass 59-93Cu +Al, Zn or As	Cupro-Nickel 66-88 : 11-33
Gray	Nickel	Silicon									
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)

NICKEL BASE ALLOYS						MISCELLANEOUS METALS AND ALLOYS							
Nickel 99	Ni-Cu 66-32	Ni-Cr-Fe 76-16-7	Ni-Fe-Cr 32-47-20	Ni-Mo 62-28 +Fe, V	Ni-Cr-Mo 54-15-16 +Fe, W	Aluminum	Gold	Lead	Platinum	Silver	Tantalum	Titanium	Zirconium
(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)

MEDIA CAUSING STRESS CORROSION CRACKING

Use the schedule above to identify materials by the numbers

Corrosive	1	2	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	25	26
Acetic acid + mercury salts							●	●	●									●				
Alkyl aryl sulfonates				○																		
Aluminum chloride				○	○																	
Aluminum sulfate				●																		
Ammonia			●						●	●												
Ammonium biphosphate				◎	○																	
Ammonium chloride				○	○																	
Ammonium fluosilicate													●									
Ammonium hydroxide								○	○	○												
Ammonium nitrate			●																			
Aniline										○												
Barium chloride				◎	○																	
Barium nitrate			●																			
Bismuth								○										●				
Calcium bromide				◎	○																	
Calcium chloride				○																		
Calcium nitrate			●																			
Carbon tetrachloride				◎	○																	
Chlorine				◎	◎																	
Chloranilines										●												

Corrosive	1	2	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	25	26
Chlorobenzene													●									
Chloroform				◎	○																	
Chlorotoluidines										●												
Chromic acid			●							●			●									
Copper tetramine										●												
Cresol			●																			
Cresylic acid vapors			○																			
Cyanogen			●																			
Dichlorophenol				◎	○																	
Epichlorhydrin				◎	○																	
Ethanol																					○	
Ethylamine			●																			
Ethyl chloride				◎	○																	
Ferric chloride			●							●												●
Ferrous chloride				◎	◎																	
Fluosilicic acid												◎	◎			◎	◎					
Gasoline vapor				●																		
Glutamic acid				◎	○																	
Glycerol				◎																		
Hexachloroethane				◎	◎																	

Appendix 6 (Cont'd)

Naphthenic Acid Corrosion – An Old Enemy Of the Petroleum Industry*

By W. A. DERUNGS



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Abstract

The term "naphthenic acids" is a collective name for organic acids present in various crudes. It has been proved that while minor quantities of other organic acids are included, the main acids from naphthenic base crudes are saturated ring structures containing acid groups.

The circumstances under which naphthenic acid corrosion occurs are analogous to those of sulfur corrosion. A practical differentiation between naphthenic acid and sulfur corrosion is possible on the basis of different corrosion phenomena. It would appear that the rate of naphthenic acid corrosion is dependent on the concentration of the naphthenic acids in the oil, operating temperature, fluid velocity and activity of the naphthenic acids. Of these factors fluid velocity seems to be the most important. Unfortunately the critical velocity values below which the corrosion rates become negligible are not yet known.

Data are given to show the relationship between temperature and corrosion rates at selected locations in a high vacuum column of a distilling plant. Corrosion of mild steel by naphthenic acids becomes apparent at operating temperatures in excess of 220 C (430 F) with a maximum at approximately 280 C (540 F). Above 400 C no evidence of this type of corrosion has ever been found.

Naphthenic acid corrosion can be counteracted by removal or neutralization of the naphthenic acids, by modifying fluid velocity conditions where possible and by proper selection of the constructional materials. Some hints on the suitability of various materials of construction are given. 4.4.2

Introduction

NAPHTHENIC ACID corrosion was observed for the first time in the 1920's when certain crudes from Roumania, Russia (Baku Region), South America and California were distilled. As early as 1930, during the 11th annual meeting of the API, Blount[1] stated that the crude oils contained three distinct sources of corrosion in distilling equipment:

1. Magnesium chloride
2. Sulfur
3. Naphthenic acids

In the presence of water, magnesium chloride is hydrolyzed during the distilling process. It then develops aqueous hydrochloric acid which, below its dew point, is very corrosive to nearly all common metals and alloys.

In contrast to hydrochloric acid, hydrogen sulfide, which may be developed from sulfur-containing crudes, becomes most active at higher temperatures without the necessity of water being present. This behavior holds true also for the naphthenic acids which are present in several crude oils.

Because nearly all crudes containing naphthenic acids also contain material quantities of sulfur compounds which under similar conditions can give rise to severe corrosion of refinery equipment, it is obvious that a differentiation between sulfur corrosion and naphthenic acid corrosion is difficult. It is reasonable to assume that at least part of the corrosion generally attributed to naphthenic acids is due to the action of sulfur, and vice versa. However, by observing the corrosion phenomena on steel, it is possible to make a practical differentiation between naphthenic acid and sulfur corrosion. Streams high in naphthenic acid content generally produce very characteristic, sharp-edged holes or—in cases where the stream is of high velocity—sharp-edged streamlined grooves. Such typical forms of attack have never been observed when processing crudes free from naphthenic acids. Also, in the presence of naphthenic acids, the critical temperature at which severe corrosion may occur is considerably lower than in the case where only sulfur is present.

In the early 1930's corrosion by sulfur and naphthenic acids at high temperature was an extremely serious problem. When mild steel furnace tubes were used, tube bursts once a week were common. Cast steel return bends had a service life of as short as 80 days and transfer lines of mild steel had to be replaced within 100 days to one year. Serious corrosion of mild steel heat exchangers was another source of trouble.

In the course of time it was found that steel could be made resistant to sulfur by alloying it with chromium. Addition of 5 percent Cr makes steel fairly resistant, and with 12 percent Cr-steel very satisfactory results are obtained under practically all circumstances.

Where naphthenic acid corrosion is involved the remedy is not so simple as that. Not enough facts

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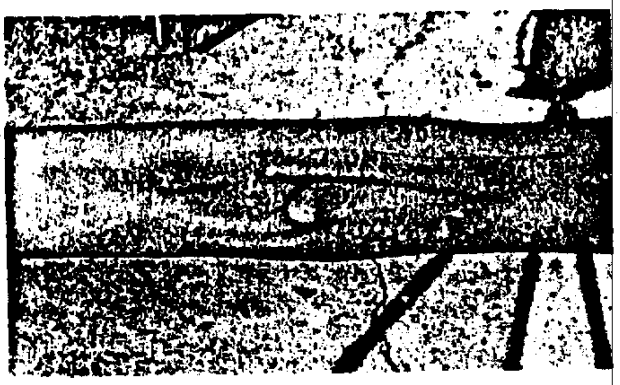


Figure 1—Failure of mild steel furnace tube. Tube was from a high vacuum plant which had operated for 163 days on sweet crude and 259 days on naphthenic crude. Operating temperature was 300 C.

TABLE 1—Type Distribution of Oils Obtained from Naphthenic Acids from a Luboil Range

TYPE	Mol Weights of Oil Fractions		
	281	384	470
Saturates	68	58	46
Monoaromatics[1]	18	18	18
Diaromatics[1]	6	12	23
Benzothiophenes[1]	5	8	
Resins	6	4	16

[1] Monoaromatics are to a large extent condensed with five or six-membered naphthene rings while only a small proportion of diaromatics and benzothiophenes is condensed in this way.

are known to predict the occurrence of naphthenic acid corrosion, whereas satisfactory protection against it is in general expensive and often complicated. Therefore, certain risks are taken, often resulting in unanticipated, sudden failures.

Figure 1 represents a mild steel furnace tube which not so long ago had failed in a furnace of a high vacuum plant after 422 days of operation. It had operated on sweet crude for 163 days and on crudes containing naphthenic acid for 259 days at an oil temperature of approximately 300 C (570 F). On the other hand expensive materials sometimes have been used to safeguard operation when it was found later that less valuable materials would have performed just as well.

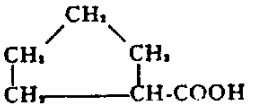
Considering all these circumstances, a more extensive investigation into naphthenic acid corrosion appears justified.

Data on Commercially Available Naphthenic Acids

A number of grades of naphthenic acids are marketed for various purposes. The grades are distinguished by their acid values, as, for example, the "230 Grade" and "170 Grade" acids, having a minimum acid value of 230 and 170 mg KOH/g respectively. The higher acid value material is obtained from kerosene and light gas oil, the lower acid value material from heavy gas oil. The average molecular weight is in the range of 200-300. The flash points may vary from 138-150 C (280-300 F). Specific gravity is near unity. Naphthenic acids are barely soluble in water, but readily soluble in most organic solvents, particularly hydrocarbons.

Chemical Constitution of Naphthenic Acids

"Naphthenic acids" is a collective name for organic acids present in various crude oils. The name is derived from the fact that acidity was first observed in naphthenic base crudes (Russian crude oils of the Baku region). Although there are minor amounts of other organic acids included, it was confirmed later that the main acids from naphthenic base crudes are actually naphthenic in their character (i.e., acids with a saturated ring structure such as given below):



Boiling point = 55-64 C (131-147 F) at 20 mm Hg
Mol. weight = 114

The molecular weights of the naphthenic acids extend over the extremes from high to low but the bulk of the naphthenic acids in crude oils generally is found in the gas oil and light lubricating oil fractions.

The Royal Dutch/Shell Laboratory at Amsterdam recently investigated the naphthenic acids from a luboil range making use of improved methods for the isolation and fractionation of the acids, followed by complete conversion of these acids into neutral compounds ($COOH \rightarrow CH_3$). Analysis of these neutral compounds by means of the methods currently applied in oil constitution work revealed that these compounds closely resembled the neutral distillate fraction with a similar molecular weight and from the same crude oil. The only difference observed was the absence of polyaromatics (except diaromatics). Naphthenic acids therefore are based upon saturates, monoaromatics, diaromatics and sulphur compounds. Table 1 shows the type distribution of the oils obtained from the corresponding acids.

Characteristics of Naphthenic Acid Corrosion

Locations

Naphthenic acid corrosion is encountered mainly in crude distilling plants and in high vacuum distilling plants processing certain sour crudes or derivatives thereof. Type of equipment chiefly subject to this corrosion includes hot oil centrifugal pumps, furnaces (especially return bends and tube inlet ends), transfer lines, feed and reflux sections of columns, heat exchangers, condensers and objects which hinder a smooth stream (e.g., thermowells, bolts and rough welding seams).

Naphthenic acid corrosion has not been found to be of much importance in cracking plants, nor in the re-processing of cracked products. However, certain acids (i.e., carbon dioxide, light fatty and unsaturated acids) are split off from naphthenic acids in cracking plants in addition to hydrocarbons. These light acids may be corrosive primarily at low temperatures, especially so if water is present. This is in direct contrast to the high temperature corrosion attributable to naphthenic acids.

Acidity of Feedstock

In addition to sulfur compounds it is probable that all sour crudes also contain a certain amount of naphthenic acids. These acids become important as a corrosion factor only if the acid value of the feed-



Figure 2—Naphthenic acid corrosion on mild steel furnace tube inlet end.

stock is at least 0.5 mg KOH/g. It might be pointed out that acid values up to 10 mg KOH/g may occur.

Appearances of Naphthenic Acid Corrosion

The appearances of naphthenic acid corrosion are generally highly characteristic, varying with increase in stream velocity from sharp-edged, crater-like holes to sharp-edged streamlined grooves (see Figures 2, 3 and 4). The corrosion products—at least those from iron and copper and their common alloys—are easily dissolved in moving hot oil and washed off, leaving no scale behind. These facts explain the characteristic appearance of the attacked metal. One is inclined to think of erosion, whereas actually velocity corrosion has taken place. Evidence for this velocity corrosion is found in the fact that acid-free, cracked or neutralized oil does not give any such wear, and also that a soft material like aluminum, which does not react with naphthenic acids, remains practically unaffected.

State of Aggregation of the Active Naphthenic Acids

Whether the naphthenic acids are more corrosive in the liquid than in the vapor phase, or whether they are corrosive only in the one or the other state respectively, is difficult to say. A definite pronouncement is all the more difficult inasmuch as the naphthenic acids present in distilling plants are only a minor part of the total product. They are dissolved in fractions of oil showing the same boiling range as the naphthenic acids. As a further circumstance the true boiling range of the naphthenic acids may be shifted by other components. Moreover, corrosion inhibitors and promoters may play a role.

Describing his experience in the refining of California crudes, Tandy[2] states that the naphthenic acids are most active at their boiling points but that most severe corrosion generally occurs on condensation, whereas in the vapor state practically no corrosion takes place. Laboratory tests conducted by the author's company have confirmed Tandy's findings. These findings, however, are in striking conflict with plant experience which indicates that where a vapor phase exists, corrosion is invariably more severe than in a pure liquid phase. This contradiction possibly

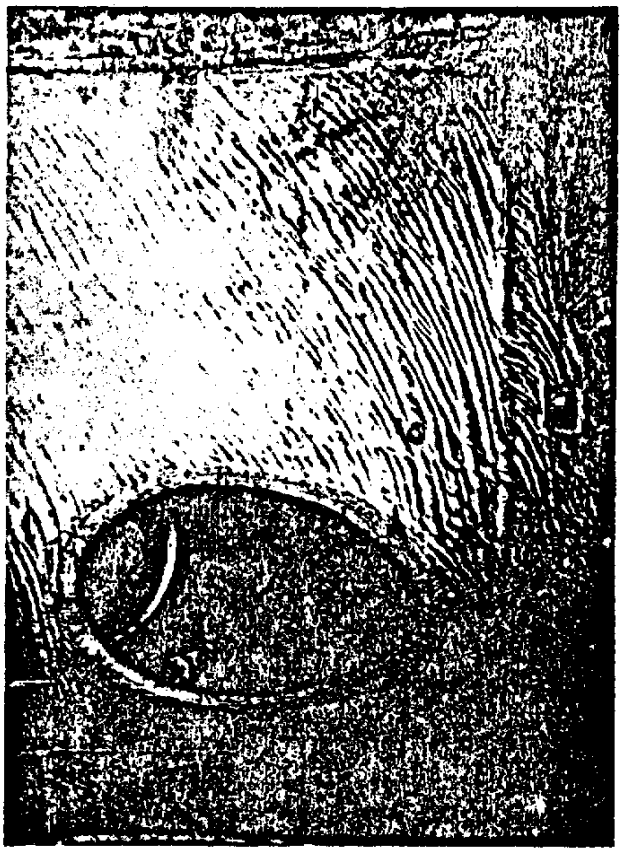


Figure 3—Naphthenic acid corrosion in feed section of a high vacuum column.

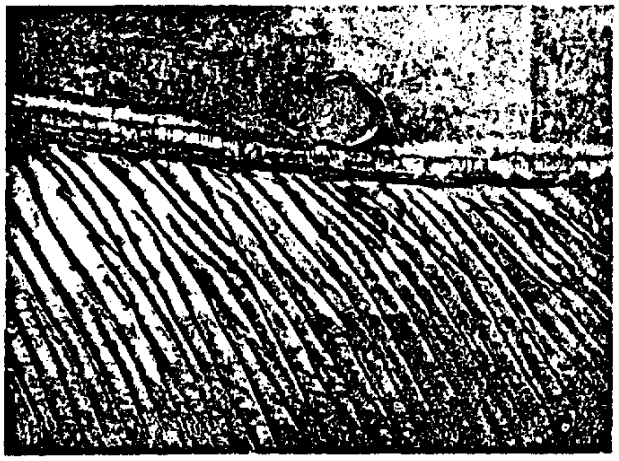


Figure 4—Additional view of naphthenic acid corrosion in feed section of a high vacuum column.

can be explained by the fact that the liquid velocity is considerably increased if vaporization occurs.

Influence of Temperature

In considering the influence of temperature on corrosion a distinction must be made between actual metal wall temperature and product temperature. As the metal wall temperature generally is not known reference will be made instead to the oil temperature. It is realized that the actual wall temperature may

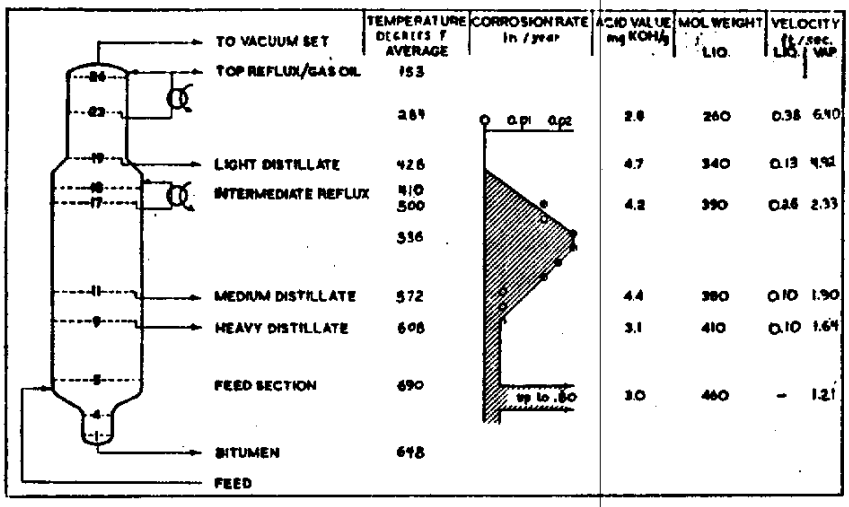


Figure 5—Corrosion and operating data of a high vacuum column processing a reduced crude.

be either higher (e.g., furnace tube) or lower (e.g., transfer line) than oil temperature. Apart from practical considerations the use of the product temperature seems justified, inasmuch as the activity of the naphthenic acids themselves depends greatly on the temperature.

Considering for the time being the corrosion behavior of unalloyed steel only, the minimum temperature below which oil in the absence of water is not at all corrosive is 220 C (430 F). At higher temperatures naphthenic acid corrosion becomes evident, the rate of corrosion gradually increasing with the temperature. Maximum corrosion often occurs at a temperature around 270-280 C (520-535 F). At a temperature of 350 C (660 F) upwards the corrosion rate again increases rapidly, being due for the most part to the action of sulfur. Above 400 C (750 F) no evidence of naphthenic acid corrosion has ever been found. This relationship between corrosion rate and temperature may be seen in the discussion that follows.

In some distilling plants processing reduced crude, corrosion in the hottest furnace tubes and transfer lines was about 6 mm per year (.24 in/year). Product temperature in such cases was about 375 C (710 F). When the transfer temperature was lowered to 350 C (660 F) practically no further corrosion occurred.

Later it became necessary to modify the same plants to work up total crude oil. Owing to this modification the transfer temperature was further reduced to about 270 C (520 F). This drop in temperature caused corrosion rates again to become of the order of 10 mm/year (.4 in/year). In consequence of this, further restrictions on temperature (and load) had to be stipulated.

In fractionating columns of high vacuum distilling plants processing a reduced crude oil a maximum corrosion rate of approximately 0.6 mm/year (.024 in/year) at around 280 C (535 F) has been measured (see Figure 5). Another maximum of corrosion, being up to 20 mm/year (.8 in/year), could be found in the inlets of the columns where evaporation took place at around 380 C (715 F). Similar high corrosion rates have been found in furnaces (especially in return bends and tube inlet ends) and transfer lines (especially in bends), although without distinctly showing a separate maximum corrosion rate dependent on temperature. Apart from the action by sulfur these extremely high corrosion rates undoubtedly are due in part to the presence of napthenic acids at places where high fluid velocity exists: Fluid velocity (vapor-liquid mixture consisting chiefly of vapor) has been calculated to reach an average of up to 185 m/sec (600 ft/sec) at the furnace outlet.

What is the reason for the decrease in naphthenic acid corrosion after a temperature of 280 C (535 F) is exceeded? Could this be due to the fact that above this temperature naphthenic acids decompose?

As already stated above, naphthenic acid corrosion in cracking plants is of little importance. This is due primarily to the fact that the liquid velocity in the furnace is relatively low and that in the vapor phase the naphthenic acids decompose. The exact temperature at which decomposition sets in is not known; it must, however, be below 485 C (905 F), the furnace outlet temperature.

In the distilling plants for straight-run distillation, i.e., at temperatures up to 320 C (610 F), the naphthenic acids are definitely not decomposed. A naphthenic acid balance made at a high vacuum distilling plant proved that no marked decomposition of the naphthenic acids had taken place. The furnace outlet temperature had been 400 C (750 F) in this case. It also has been found that the acid value of asphalt obtained from a vacuum plant increases sharply when the transfer temperature is reduced from, say, 420 C (790 F) to 380 C (715 F) while still producing the same grade of asphalt.

The above facts lead to the conclusion that naphthenic acids present in refining equipment are decomposed in a temperature range somewhere between 400-485 C (750-905 F), and more probably at the lower limit. Therefore the occurrence of a maximum corrosion rate at 280 C (535 F) in vacuum columns cannot be ascribed to decomposition of the naphthenic acids above this temperature.

It is known that corrosion by naphthenic acids is much dependent on fluid velocity. In order to find out whether different velocities play an important role in fractionating columns of high vacuum distilling plants, the internal load of a column processing reduced crude was calculated. The relative liquid and vapor velocities obtained are shown in Figure 5. As relative velocities the liquid velocity through the downcomers and the vapor velocity through the whole column cross section were calculated. From this calculation it appears that in the case under consideration the velocity effect is rather small and

by no means gives an explanation for the extraordinary corrosion phenomenon in the column.

The acid values and molecular weights of the various streams were determined as shown in Figure 5. It can be seen that the acid value (a.v.) in the column increases from the feed (a.v. = 3.0) upwards to the light distillate stream (a.v. = 4.7). Up to a certain degree the increase of the acid value is in correlation with the increase of corrosion. However, corrosion is most severe immediately below the intermediate reflux section, where the acid value (a.v. = 4.2) is even somewhat lower than at the draw-off of the medium distillate (a.v. = 4.4) and at the draw-off of the light distillate (a.v. = 4.7). An explanation of this phenomenon can be found when taking the molecular weights or more exactly the activities of the various naphthenic acids into account. It is quite clear that the molecular weights will decrease in the upwards direction of the column. With a decrease of the molecular weights the activity of the naphthenic acids will increase, since the smaller the molecules the greater becomes their activity. Furthermore, if it is taken for granted that these smaller molecules are more active in liquid than in vapor phase and in liquid phase more active near the boiling point, corrosion will necessarily be at a maximum where these most active molecules are condensing or boiling respectively. Such conditions obviously occur below the intermediate reflux section.

It is true that at the draw-off of the light distillate even more active naphthenic acids may exist. For that reason at least the same high corrosion rate as below the intermediate reflux section might be expected. This is not the case, because the operating temperature is considerably lower.

Condensing or boiling point of the most active naphthenic acids will depend also on the constitution of these naphthenic acids, which constitution will vary somewhat with various crudes.

There is little chance of accumulation of naphthenic acids at condensing or boiling conditions in furnaces and transfer lines. This may explain why here generally no maximum corrosion rate dependent on an intermediate temperature between 220-400 C (430-750 F) is found.

The above explanation is a hypothesis which will have to be confirmed by experiments. For this purpose it is recommended that corrosion tests be made with various fractions at various temperatures.

Influence of Velocity

Fluid velocity is of preponderant influence on the rate of corrosion. Often very severe corrosion is found at places where a high turbulent stream—possibly combined with impact—exists, whereas at neighboring places free from intensive turbulence only little corrosion occurs. This fact is most clearly demonstrated in return bends and tube inlet ends of furnaces, and in bends of transfer lines. Another example is the difference in corrosion experienced in the hottest furnace tubes of a distilling plant processing a certain crude, where it was found that at a temperature of 270 C (520 F) the corrosion rate remained low with a load of 40 tons/day sq inch cross section but became high with a load of 70 t or more. Unfortunately, the critical absolute velocity values (varying with temperature) below which the corrosion rates remain low are not yet known.

Volatility of a product, operating pressure, and injection of steam will have a considerable influence on the fluid velocity.

Volatility: The lighter the intake material, the greater the amount of vaporization. Since an increase in vapor volume means a greater velocity, a higher rate of corrosion must be expected.

Pressure: When distilling in vacuum the velocities will increase directly owing to the increased volume and indirectly owing to the increased vaporization.

Steam: Injection of steam (or presence of water in the feed) again will increase the vapor volume and consequently the fluid velocity and rate of corrosion.

Protection Against Naphthenic Acid Corrosion

Reduction of Free Naphthenic Acid Content

There are two principal ways to reduce the free naphthenic acid content of crude oils or derivatives thereof:

1. **Removal:** Active naphthenic acids may be removed by pretopping at relatively low temperature so that little corrosion will occur.
2. **Neutralization:** Naphthenic acids present in kerosene and gas oil fractions can be removed by extraction with aqueous caustic soda. Acids of higher molecular weight present in lubricating oil stocks cannot be removed by this method, owing to severe emulsification. In order, therefore, to obtain neutral distillates, the crude lubricating oil feedstock is neutralized with either lime or caustic soda during high vacuum distillation. The calcium or sodium naphthenates are drawn off as a side stream in the column above the feed inlet in order to prevent increase of the ash content of the bottom product.

Proper Selection of Materials of Construction

Unalloyed steel: Mild steel is not attacked by naphthenic acid-containing oils below a temperature of 220 C (430 F). In the temperature range of, say, 220-400 C (430-750 F) mild steel may be attacked up to 20 mm/year (.8 in/year), depending on operating conditions. Extra low carbon steel (e.g., Armco iron) has proved to be somewhat more resistant than normal mild steel.

Cast iron: Cast iron has been found to be up to about 15 times more resistant than mild steel. It may be useful for internal parts of column.

Alloyed cast irons: Ni-Resist (15 percent Ni, 6 percent Cu, 2 percent Cr, rest Fe) and other alloyed cast irons have no improved corrosion resistance over unalloyed cast iron.

Low alloy steel: Under conditions of increased fluid velocity 5 Cr-½ Mo steel may be up to 15 times as resistant as mild steel. Except perhaps for furnace and heat exchanger parts the usefulness of this material is doubtful, inasmuch as it is often very irregularly attacked, chiefly in the form of pitting.

Stainless steel: 12 percent Cr-steel (AISI 405, 410) often appears to be even less resistant than mild steel and, therefore, should not be used in the presence of naphthenic acids. Stainless steel of the type 18 Cr-8 Ni (AISI 304, 321, 347) is often quite resistant under conditions of low fluid velocity such as exist in certain parts of columns. It sometimes is subject, however, to severe pitting and therefore is not very reliable. On the other hand, stainless steel of the type 18 Cr-8 Ni-3 Mo (AISI 316) has proved to be very resistant under all circumstances. Mo-contents of 1½ percent, however, are quite sufficient for naphthenic acids. The same applies to the 25 Cr-20 Ni (AISI 310) and 25 Cr-12 Ni (AISI 309) types of stainless steel.

High nickel alloys; With the exception of copper-containing nickel alloys (e.g., Monel = 66 percent Ni, 30 percent Cu + other elements) these are all highly resistant. However, these materials (e.g., Inconel = 76 percent Ni, 15 percent Cr, rest Fe and Hastelloy B = 65 percent Ni, 30 percent Mo, 5 percent Fe) are much more expensive than AISI 316, and have little more advantage over the latter.

Copper and copper alloys: These materials are not suitable, being attacked at 150 C (300 F).

Aluminum and Aluminum Alloys: Aluminum has proved to be very resistant under all conditions. Unfortunately, its use thus far has been restricted by its mechanical and welding properties. Copper-containing aluminum alloys (e.g., Duralumin with 5 percent Cu) are not suitable.

Summary

Naphthenic acid corrosion has been and still is a problem in the petroleum industry.

The term "naphthenic acids" is a collective name for organic acids present in various crudes. It has been proved that, although there are minor quantities of other organic acids included, the main acids from naphthenic base crudes are saturated ring structures containing acid groups.

The circumstances under which naphthenic acid corrosion occurs are analogous to those of sulfur corrosion. A practical differentiation between naphthenic acid and sulfur corrosion is possible on the basis of different corrosion phenomena.

It appears that the rate of naphthenic acid corrosion is dependent on the concentration of the naphthenic acids in the oil, operating temperature, fluid velocity and activity of the naphthenic acids.

Naphthenic acid corrosion is counteracted by removal or neutralization of the naphthenic acids, by modifying fluid velocity conditions, where possible, and by proper selection of the constructional materials. Some hints on the suitability of various materials of construction are given.

References

1. *API Proceedings*, 11, No. 75 (1930), Sect. 3, p. 102.
2. E. H. Tandy, Inspection of Petroleum Refinery Equipment. *Corrosion*, 10, No. 5, 161 (1954) May.

DISCUSSION

Comment by E. H. Tandy, Standard Oil Company of California, El Segundo, Calif.:

Mr. Derungs is to be congratulated for his fine paper on naphthenic acid corrosion. We agree that naphthenic acid corrosion is severe at points of high velocity and turbulence in furnace tubes and headers, transfer lines, etc. Corrosion in the flash zone or feed section of the fractionating column is the result of hydrogen sulfide, naphthenic acid and high velocity. This combination is particularly severe because no scale is formed to protect the metal surface. The appearance of the shell in Figures 3 and 4 suggests that one of the major factors is the condensation on the shell of heavy naphthenic acids which then run down in rivulets corroding the grooves. The rivulets in Figure 3 around the transfer inlet are displaced because of the circular sweep of the vapors in that area. Once the naphthenic acids have reached the top stripping tray they become diluted by the oil on the tray thus causing the abrupt drop in corrosion below the flash zone.

It seems to be characteristic of naphthenic acids that they have rather sharp dew points. As Mr. Derungs suggests, they probably form azeotropic mixtures with the hydrocarbons which are high in acid content thus causing severe corrosion to any surface on which they condense. This theory can also be applied to the area of the column under the intermediate reflux section. Here, as the vapors are cooling down, the naphthenic acid-oil mixtures condense on the shell causing the corrosion. Once this mixture runs down onto the tray it becomes diluted by the oil on the tray and is much less corrosive. Usually the shell does not have the striated appearance found in the flash zone because the shell is wetted with a continuous sheet of condensate. However, if there are any projections or unused nozzles in this area the shell will be grooved under them from the rivulet of acid-oil that collects there and then runs down the shell.

This phenomena of high corrosion at the dew point also is found in fractionating column condensing equipment where the top tray temperature is high enough for the naphthenic acid vapors to go out overhead. The condensing system often will have small zones of high corrosion when compared with the areas immediately above and below. The corroded area is usually in the zone where condensation first begins. The first condensate is the acid-oil mixture which quickly becomes diluted as it falls further in the system.

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CORROSION/76

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NAPHTHENIC ACID CORROSION

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INTRODUCTION

Naphthenic acid corrosion is not a new problem for refiners. Over 45 years ago, it was identified as potentially troublesome in U.S. refineries that processed unusually acidic crudes (1). By 1956, Derungs had outlined the crude characteristics and processing conditions that favor naphthenic acid corrosion and had suggested ways to minimize such damage in distillation towers, which he identified as the most susceptible units (2). But even as late at 1963, a nationwide survey by the National Association of Corrosion Engineers indicated that such corrosion was not a major concern in the U.S. petroleum industry, except for a few refineries on the West Coast (3). Nonetheless, the survey concluded that further research was warranted to determine how to predict potential naphthenic acid corrosion from a particular crude and to determine cause and effect relationships with respect to corrosion rates.

Recently, the need for such research has intensified (4). Refiners must now process a wide range of domestic and foreign crudes, many of which have relatively high concentrations of naphthenic acids. Without reliable corrosion data, unit designers may be tempted to choose needlessly expensive alloys to withstand corrosion that could possibly be controlled by other means, or even be avoided altogether.

The available field surveys (2,3), have indicated that the likelihood of naphthenic acid corrosion increases when the crudes to be processed have a neutralization number above 0.5, when distillation temperatures are between 430 and 750°F, and when fluid velocities are high--especially in transfer lines, return bends, and other restricted areas of the equipment.* Absence of scale on corroded metal often is the sole evidence for naphthenic acid corrosion. Attack apparently is greatest at the condensation point where the vapor stream draws liquid over the metal, producing a characteristic grooving of the metal

* The neutralization number is expressed as the milligrams of KOH required to neutralize the acids in a one-gram sample.

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that seems to distinguish it from high-temperature sulfur attack(5). However, few, if any, laboratory data have been available to correlate process variables with the corrosion rates of various alloys.

To supply such data, we have carried out controlled studies to determine corrosion rates as affected by crude neutralization numbers from 0 to over 45, temperatures from 70 to 750°F, pressures up to 600 psi, and fluid velocities up to 13 ft/sec. Corrosion coupons were exposed to both liquid and vapors phases. We found primarily that: (1) corrosion of most steels approximately triples with each 100°F increase in temperature , (2) at a given temperature, corrosion is directly related to naphthenic acid content of a hydrocarbon stream, (3) corrosion requires a liquid phase, and (4) solution-annealed, austenitic (18/8) stainless steels protect against naphthenic acids unless impingement-type attack occurs.

EXPERIMENTAL

Materials

Test liquids were a crude oil and a refined, colorless white oil with the following properties:

	Crude Oil	White Oil
Distillation Range		
Initial B.P.	197	540
5%	270	600
10%	313	620
20%	419	648
50%	560	720
80%	704	775
90%	709	804
95%	711	880
Gravity (°API)	31.5	30
Pour Point (°F)	55	--
Sulfur (% wt)	0.3	0.0
Neutralization Number	0.9-1.0	0.0

The neutralization number of the white oil was adjusted with ARCO 145*, a mixture of naphthenic acids having a neutralization number of 191. The neutralization number of the crude oil ranged from 0.9 to 1.0 and was not adjusted further.

Table I shows the composition of the eight alloys evaluated. The corrosion coupons, which generally measured 1 x 1 x 1/16 in., were pretreated in various ways. For example, the three austenitic (18/8) stainless steels were usually solution annealed. However, for some tests, the coupons were: (1) sensitized by holding at 1200°F for four hours, followed by slow cooling in air, or (2) stabilized at 1650°F for four hours, followed by quenching in water. Some coupons were preactivated by abrasion with 240 grit emery paper while submerged in white oil to prevent contact with air; others were passivated in dilute nitric acid.

Equipment and Procedures

To permit evaluation of a wide range of conditions, tests were carried out in a continuous flow unit, a Parr rocking autoclave, and a variety of distillation equipment. In all tests, the oils were blanketed with nitrogen

* ARCO Chemical Company, Philadelphia Pa.

to exclude air and prevent oxidation. Neutralization numbers were determined at the beginning and end of each test by potentiometric titration with potassium hydroxide (ASTM D-664).

Continuous Flow Unit

The continuous flow unit (CFU) consisted of a heated autoclave equipped with a stirrer, a feed tank, and a recovery tank for spent feed. All high-temperature sections were of Hastelloy Alloy C, and all ambient-temperature sections of Type 316 austenitic stainless steel. A calibrated positive-displacement pump metered the feed stream, which had been preheated in a 4-ft transfer line. A second heating system initially heats the autoclave and provided exact temperature control during a test. To maintain a constant liquid level, a DP cell, connected across the autoclave level sight-glass, and a level controller activated a valve that discharged excess liquid from the autoclave into the recovery tank. Pressure was monitored and maintained by a DP cell and a pressure controller, which activated a valve that vented excess nitrogen. Operating variables, including temperature, pressure, flow rate, and liquid level, were controlled and recorded automatically. If any variable exceeded a predetermined Low/High range during unattended operation, a warning light and horn signaled the problem and the equipment shut down, except for the recording instruments.

In a typical test, eight corrosion coupons were suspended in the autoclave--four in the liquid, and four in the vapor above the liquid. The test liquid was charged continuously at about 7 ml/min. The stirrer rotated at 1000 rpm to provide flow velocities of 2 to 3.5 ft./sec, past the coupons (depending on location). A constant, selected temperature between 330° and 725°F was maintained during a test, and a pressure of 600 psig prevented vaporization of naphthenic acids and light hydrocarbons.

Parr Rocking Autoclave

Tests at 560°F were done in a rocking autoclave to prevent loss of naphthenic acids and light hydrocarbons. In a typical test, a 500-ml electrically heated autoclave mounted in a Parr rocking cradle was filled with test liquid to within one inch of the top. The corrosion coupons were suspended from a suitable rack and immersed in the liquid. The autoclave was then purged with nitrogen and closed. The pressure was allowed to build to the steady state vapor pressure of the test liquid at the test temperature--typically, this pressure ranged from 80 to 290 psig. Agitation was provided by the rocking cradle, which tilted the autoclave through a 30-degree arc from vertical 36 times per minute.

Distillation Equipment

Corrosion tests were carried out in distillation equipment of various sizes. For one set of tests, the equipment consisted of a 200-ml, three-necked, round-bottomed distillation flask fitted with a water-cooled condenser to prevent loss of volatiles,and an electric heating mantle. In a typical test, 125 ml of the test liquid was added to the flask, and four coupons were suspended from a glass holder--two coupons in the liquid, and two in the vapor (about one inch above the liquid).

To allow a greater number of coupons to be evaluated simultaneously, a 2000-ml resin kettle was equipped with a stirrer, a reflux condenser, and a heating mantle. In a typical test, 700 ml of test liquid was added to the kettle, and the coupons were suspended from a glass holder or from a vertical insulated motor shaft. In some tests, a single-speed synchronous motor provided low flow rates past the coupons. In other tests, the coupons were mounted on the shaft of a variable-speed stirring motor that permitted velocities up to

1100 rpm (about 13 ft/sec). Up to six different alloys were evaluated in a single test, with one set of coupons in the liquid and another set about one inch above the liquid.

Batch distillations were done in a 3000-ml, four-necked distillation flask fitted with an electric mantle, a side arm, a water-cooled condenser, and a distillate receiver. In a typical test, 1400 ml of test liquid was added to the flask, and the stirrer was rotated at a constant rate to help maintain the contents at a constant temperature. Throughout the test, 15-ml batches of distillate were continuously removed from the receiver, and the neutralization number of every fifth batch was determined. Along with every fifth batch of distillate, a 15-ml batch of bottoms was also removed for determination of its neutralization number. Distillation was stopped when the bottoms temperature reached 800°F.

RESULTS AND DISCUSSION

The naphthenic acid corrosion data for the different metals are analyzed primarily in terms of temperature, neutralization number, pressure, and flow velocity of the test liquids. Special emphasis is placed on the roles that vaporization and condensation play in naphthenic acid corrosion.

Effect of Temperature

Tables II and III summarize corrosion data for carbon steel and Type 410 stainless steel exposed to liquids with a neutralization number of about 1.0. Tests at atmospheric pressure (about 15 psig) were done well below the initial boiling point of the crude (197°F) or the white oil (about 540°F), whereas tests at higher temperatures were done at 600 psig. Regardless of conditions, corrosion rates in the liquid and vapor phases were almost always identical. The neutralization number of the liquids did not change during the tests, indicating that vaporization of naphthenic acids was prevented. The blank runs at 200°, 500°, and 580°F (Table III) show that white oil without naphthenic acid is essentially noncorrosive to the metals.

As shown in Figure 1, parabolic kinetics apparently apply to the corrosion rates measured at 450°F and atmospheric pressure in the white oil/naphthenic acid blends.

Figure 2, which shows corrosion rates plotted against the reciprocal of absolute temperature, indicates that there is no significant difference between the effects of crude oil and white oil. Consequently, naphthenic acid content must be an important corrosion variable. The straight-line temperature dependence above 550°F indicates that the kinetics of naphthenic acid corrosion obey the Arrhenius equation and thus permit calculation of an activation energy of about 16,400 cal/mole for both metals. This value suggests that chemisorption controls the rate of corrosion. At these higher temperatures, Type 410 stainless steel corroded at approximately half the rate of carbon steel. However, corrosion below 450°F was quite low (less than 3 mpy) with essentially no significant difference between carbon steel and Type 410 stainless steel. Lack of precision in the data at low temperatures probably obscured the straight-line dependence observed at temperatures above 550°F.

In the absence of data to the contrary, it can be tentatively concluded that naphthenic acid corrosion continues to increase up to at least 725°F provided, of course, that naphthenic acids are not lost through vaporization.

Effect of Neutralization Number and Alloying

Table IV summarizes corrosion data for various alloys in white oil/

naphthenic acid blends with initial neutralization numbers ranging from 9.6 to 47.0. These tests were done at atmospheric pressure and at temperatures ranging from 370° to 455°F. The alloys were exposed in the liquid phase only, and there was no intentional agitation. However, some stripping of the naphthenic acids occurred as reflected by a significant decrease in neutralization number above 430°F. The test data show that both Type 304 and Type 316 stainless steel in the solution-annealed condition essentially were unaffected up to 455°F. Calculated corrosion rates for these two alloys did not exceed 0.8 mpy and such small weight losses probably were due largely to handling and weighing errors.

Figures 3 through 6 show isotherms of corrosion rates as a function of average neutralization number for carbon steel, 7 Cr-½ Mo steel, 9 Cr-1 Mo steel and Type 410 stainless steel. Figure 3, which includes additional data points at 480°, 530°, and 580°F (from results in Table V), reveals that the corrosion of carbon steel slows above 430°F. Because no such phenomenon was observed in the tests at elevated pressure, it must be concluded that significant non-linear stripping of naphthenic acids occurred above 430°F at atmospheric pressure. As a result, actual neutralization numbers probably were considerably lower than the "averaged" values through much of the exposure period, causing the isotherms to crowd close together above 430°F.

Nevertheless, the straight-line shape of the isotherms indicates that naphthenic acid corrosion obeys a first-order rate law over the temperature interval investigated. More specifically, the corrosion rate of carbon steel, 7 Cr-½ Mo steel, and 9 Cr-1 Mo steel increased about 2.5 times when the neutralization number was doubled (Figures 3, 4 and 5). In contrast, the corrosion rate of Type 410 stainless steel increased nearly 4.6 times with a doubling of the neutralization number (Figure 6).

This much steeper increase probably occurred because the Type 410 stainless steel corroded predominantly in the form of localized attack at low temperatures and neutralization numbers. While there are not enough data to allow a definite conclusion, Type 410 stainless steel appears to offer few advantages over carbon and low-chrome steels at high temperatures and neutralization numbers once its passive surface film has been destroyed. There was no real indication, however, that naphthenic acid can corrode Type 410 stainless steel at rates higher than those of carbon and low-chrome steels as has been suggested by Derungs (2). This is also demonstrated in Figure 7, which compares the data obtained at 455°F for carbon steel, 7 Cr-½ Mo steel, 9 Cr-1 Mo steel, Type 410 stainless steel, and Monel. A curved isotherm indicates the active/passive behavior of Type 410.

At 455°F, Monel reduces naphthenic acid corrosion by a factor of seven, compared with the various ferrous alloys. No further tests were done with Monel, however, because it has poor resistance toward high-temperature sulfidation, which normally accompanies naphthenic acid corrosion in refinery applications.

Effect of Vaporization and Condensation

Corrosion data for carbon steel exposed to both liquid and vapor white oil/naphthenic acid blends are presented in Table V. These tests were done at atmospheric pressure, and there was no intentional agitation. All three series of tests show a drop in neutralization number, especially at 580°F. This was accompanied in some cases by exceptionally high vapor-phase corrosion rates.

Figure 8 shows the vapor-phase corrosion data from Table V compared with the three high-temperature liquid-phase isotherms previously plotted in Figure 3. The large discrepancy between these liquid-phase (dashed lines) and vapor-phase (solid lines) isotherms at 480° and 580°F provides the first experimental evidence

for the role that condensate formation plays in naphthenic acid corrosion.

At 480°F, the vapor-phase isotherm falls well below the liquid phase isotherm, and the corrosion rates average only 30 to 60 percent of those of the liquid-phase. As only relatively little flashing of naphthenic acids could have occurred at this temperature, corrosion of the vapor-space specimens evidently was caused by condensate that had a neutralization number lower than that of the bulk liquid. For example, liquid with a neutralization number of 20 (Point A) should form condensate with a neutralization number of 11.5 (Point B) under the test conditions.

At 530°F, the vapor-phase isotherm happened to coincide with the liquid-phase isotherm, indicating that the neutralization numbers of condensate and bulk liquid must have been identical, or nearly so.

At 580°F, flashing of the lower-boiling naphthenic acid fractions occurred so rapidly that additional tests at higher temperatures became out of the question, at least at atmospheric pressure. Under these conditions, vapor-phase corrosion rates averaged from 150 to 350 percent of the liquid-phase corrosion rates (these figures actually were as high as 480 percent in individual tests). For example, liquid with a neutralization number of 20 (Point C) should form condensate with a neutralization number of 36 (Point D) under the test conditions.

Further tests confirmed that vapor-phase corrosion is caused by a condensate film on the metals rather than by naphthenic-acid-containing vapors. These tests were carried out at atmospheric pressure and 530°F, using white oil/naphthenic acid blends with a neutralization number of 2.0. Carbon steel coupons mounted on a vertical stirrer shaft, were located both in the liquid and about 1 inch above the liquid and rotated at velocities up to 1100 rpm (about 13 ft/sec). As shown in Table VI and Figure 9, corrosion in the liquid phase decreased slightly from an average of about 9 mpy to 4.5 mpy, despite an increase in velocity from 0 to 13.3 ft/sec. This decrease can be attributed to some loss of naphthenic acid vapors from the system, as reflected by a 25 to 50 percent drop in neutralization number at the end of most tests. But even after allowing for this loss, it can only be concluded that the effect of flow velocity was quite small. In contrast, a drastic increase in vapor-phase corrosion, from 5.9 to 145 mpy, occurred as velocity was increased from 0 to 0.4 ft/sec. Undoubtedly, the increased agitation increased vaporization of lower-boiling naphthenic acids from the liquid phase and, hence, increased the condensation of vapors on the coupons. As velocity increased even further, from 0.4 ft/sec to 13.3 ft/sec, vapor-phase corrosion rates decreased in direct proportion, probably because centrifugal forces prevented the naphthenic acid-rich condensate film from forming at high velocities. The appearance of the vapor-phase coupons confirmed this conclusion because any corrosion attack was concentrated along the lower trailing edge.

Simple batch distillation tests at atmospheric pressure confirmed quantitatively that preferential vaporization and condensation of naphthenic acids significantly increased the neutralization number of the condensate as compared to that of the original stock.

Figures 10 through 12 show the neutralization number of both condensed distillate and remaining bottoms liquid plotted against temperature. Crude oil with a neutralization number of 0.9 formed a distillate at 450° to 500°F which had neutralization numbers as high as 1.3 (Figure 10). With the higher-boiling white oil/naphthenic acid blend, a distillate with a neutralization number of 1.8 was formed as the temperature reached 700°F (Figure 11). A white oil/naphthenic acid blend with neutralization number of 19 formed distillate with a neutralization number of nearly 36 at 680°F (Figure 12). These data help explain the high vapor-phase corrosion rates noted in earlier tests.

Vaporization and condensation of naphthenic acids can be prevented by elevating the pressure, as was done in the tests in the CFU. Yet, the data in Tables II and III reveal nearly identical liquid-phase and vapor-phase corrosion rates. Therefore, it must be concluded that splashed liquid, due to rapid stirring, covered and corroded the vapor-phase coupons in the CFU tests.

Effect of Pressure

It is difficult to draw any definite conclusions from the test data with regard to the effect of pressure on naphthenic acid corrosion. In comparing the results at 450°F and 15 and 600 psig, respectively (Table III), one finds, for example, that a 20-fold increase in pressure only slightly more than doubled the corrosion rate of steel in white oil/naphthenic acid blends but had no effect on the corrosion rate of Type 410 stainless steel. As shown in Table VII, additional tests carried out in the Parr rocking autoclave at 560°F and up to 290 psig, tended to confirm those results. Both Type 304 and Type 316 stainless steel in the solution-annealed condition again were unaffected--corrosion rates were below 1.2 mpy.

Figure 13 shows corrosion rates for carbon steel, 9 Cr-1 Mo steel, Type 410 stainless steel, and Monel plotted against average neutralization number. Also shown is the isotherm for carbon steel corrosion at atmospheric pressure (derived from Figure 3). Both the location and slope are in excellent agreement with those of the isotherm obtained at elevated pressure.

On the other hand, corrosion rates predicted by extrapolation for carbon steel and Type 410 stainless steel (and presumably, also for the low-alloy steels) at a neutralization number of 1.0 and atmospheric pressure (isotherms in Figures 3 through 6) were only one half to one third as high as those measured directly in the CFU at 600 psig (Figure 2). Despite the differences in experimental procedures, however, it can be tentatively concluded that pressure has only a small effect on the kinetics of naphthenic acid corrosion. Differences in pressure do, of course, affect vaporization of naphthenic acids and, hence indirectly, corrosion.

Effect of Heat Treatment of Austenitic (18/8) Stainless Steels

Table VIII summarizes corrosion data for differently heat-treated Type 304, Type 316, and Type 317 stainless steels. For the solution-annealed steels, corrosion was always low (less than 1.4 mpy).

However, corrosion of sensitized Type 304 stainless steel significantly increased with increases in neutralization number and temperature. For example, at 560°F, this steel corroded at 89.8 mpy in a liquid with an initial neutralization number of 36.6; in contrast, sensitized Type 316 and Type 317 stainless steels corroded at rates below 2.6 mpy. Under similar conditions, carbon steel corroded at 160 mpy and Type 410 stainless steel at 257 mpy (Table VII).

Depending on neutralization number and temperature, stabilized Type 304 stainless steel corroded at rates ranging from 8.1 to 181.0 mpy. Type 316 stainless steel also exhibited higher corrosion rates in the stabilized condition, as compared to the solution-annealed or sensitized condition, with corrosion rates reaching 9.3 mpy at 560°F and a neutralization number of 29. The corrosion rate of stabilized Type 317 stainless steel did not exceed 2.3 mpy in the tests.

Effect of Preactivation of Stainless Steels

Table IX summarizes data on the effect of preactivation on the corrosion of several stainless steels. Preactivation of the Type 410 stainless steel

resulted in a significant increase in corrosion rate--from 0.2 mpy to 10.6 mpy--at 400°F; but at 480°F, the corresponding change was only from 110 mpy to 126 mpy mpy. These few data tentatively confirm the conclusion that loss of passivity at high neutralization numbers and temperatures accounts for the relatively steep slope of the corrosion isotherm of Type 410 stainless steel (Figure 7). Type 304 and Type 304L were the only other preactivated steels which exhibited a definite, but much smaller, increase in corrosion at 480°F.

Effect of Flow Velocity

Although increasing the flow velocity from 0 to about 13 ft/sec did not increase the corrosion of carbon steel (Table VI), velocity could have been a possible factor in producing the generally higher corrosion rates obtained in the CFU tests as compared to the static tests at atmospheric pressure.

As shown by the data in Figure 1, naphthenic acid corrosion initially obeys a parabolic rate law. It is doubtful, however, that a protective scale is formed (as in the case of sulfidic corrosion), because the principal corrosion products are hydrocarbon-soluble metal naphthenates. This fact, the active-passive behavior exhibited by Type 410 stainless steel in the tests, and the pronounced effect of heat treatment on the susceptibility of austenitic (18/8) stainless steels to naphthenic acid corrosion, all suggest that velocity-associated mechanical surface damage can be expected to play an important role in naphthenic acid corrosion, as it occurs in the field. Specifically, a flow regime resulting in high-velocity droplet impingement can be expected to destroy the passivity of stainless steels and lead to severe localized attack.

Field Experience

Since the beginning of 1972, we have followed the corrosion history of some crude distillation units that process feed stocks with neutralization numbers averaging about 0.6 and, occasionally, reaching 1.0 and higher. The following information obtained at one unit is typical of most other units.

The nickel and iron concentrations in the heavy vacuum gas oil varied consistently with the neutralization number of the feed stock:

Neutralization No. of Feed Stock	Heavy Vacuum Gas Oil		
	Neutralization No.	Nickel (ppm)	Iron (ppm)
0.0	0-0.4	<0.04	0.4-1.2
0.3-0.4	0.4-0.8	0.1-0.2	1.5-2.5
0.5-0.8	0.6-1.3	0.2-0.3	2 -3.5

As the feed stocks have an inherently low metals content, the high metals content of the gas oil was attributed to increased corrosion.

On-stream monitoring with corrosion coupons confirmed that naphthenic acid corrosion was occurring in heavy vacuum gas oil at 540°F where carbon steel, 5 Cr-½ Mo steel and Type 410 stainless steel corroded at nearly identical rates ranging from 9 to 18 mpy (Table X). Coupons exposed in vacuum tower feed at 800°F exhibited eratic corrosion behavior. While the carbon steel coupons corroded at consistently high rates ranging from 70 to 117 mpy, the 5 Cr-½ Mo and Type 410 stainless steel coupons corroded at very high rates (32 to 166 mpy) during one exposure period but at very low rates (1 to 5 mpy) during another. Because vacuum tower feed at 800°F is mostly vaporized, naphthenic acid corrosion was ruled out. The appearance of the corroded coupons confirmed that impingement-

type corrosion, probably by sulfur compounds in residual liquid droplets, was the cause. Calculations indicated that vapor velocities reach 400 ft/sec at certain locations of the vacuum tower transfer line.

Subsequent inspection revealed evidence of severe naphthenic acid corrosion on certain trays of the vacuum distillation tower (Table XI). Most of the damge, in the form of severe pitting and hole-throughs, occurred on trays 6 and 7 which operate in the range of 580° to 640°F. The top and bottom of the Type 317 (tray 6 at 580°F) and Type 316 (tray 7 at 640°F) bubble caps and the underside of the tray floors were severely pitted by condensing naphthenic-acid enriched vapors (Figures 14-16). Impingement-type attack evidently contributed to the damage. As the tops of these trays are covered by liquid hydrocarbons including heavy gas oil reflux, relatively little damage occurred (the neutralization number of heavy gas oil typically ranged from 0.3 to 1.3).

Evidence of naphthenic acid corrosion was found in three other areas in the vacuum tower system. At about 560°F, the Type 316 woven wire mesh demister pad was severely corroded, with 40 percent of the pad completely missing (Figure 17). At about 425°F, Type 410 tray valves were badly corroded. The Type 410 tray floor showed general thinning, with knife-edge attack occurring at the valve openings. Downcomers of this tray also were corroded. Impingement-type attack probably contributed to the damage at these two locations. Naphthenic acids evidently caused pitting of the Type 410 weld overlay on the valve discs of several gate valves in the heavy vacuum gas oil line.

The vacuum distillation tower shell below tray 4 (425°F and higher) is lined with Type 405 stainless steel and showed no evidence of deterioration. There were signs of some wash-out in the unlined carbon steel shell above tray 4.

As far as is known, naphthenic acid corrosion has not been a problem in atmospheric distillation towers, none of which have required opening for repairs or inspection. Based on the results of the laboratory investigation, however, naphthenic acid corrosion can also be expected to occur on atmospheric tower trays operating in the range of 550° to 650°F.

CONCLUSIONS

Our studies have led to the following general conclusions regarding naphthenic acid corrosion:

(1) Corrosion of carbon steel and Type 410 stainless steel (and probably low-alloy steels)initially obeys a parabolic rate law. It is doubtful, however, that a protective scale is formed.

(2) The corrosion kinetics can be represented by an Arrhenius-type equation at temperatures above 550°F (and probably at low temperatures). Corrosion of carbon steel and Type 410 stainless steel approximately triples with each 100°F increase in temperatures. This relationship probably applies also to low-alloy steels.

(3) If loss of naphthenic acid (due to vaporization) is prevented, corrosion continues to increase with temperature, at least up to our maximum test temperature of 725°F.

(4) At a given temperature, corrosion is directly related to naphthenic acid content (or neutralization number) of a hydrocarbon stream. Corrosion of

carbon steel, low-alloy steels, and Monel approximately doubled when the neutralization number was doubled. Corrosion of Type 410 stainless steel increased, however, by a factor of almost five (probably due to gradual loss of passivity) with increased neutralization number. Minimum alloying, equivalent to Type 304 stainless steel, is required to markedly reduce such corrosion.

(5) Corrosion takes place only in the presence of a liquid phase. Vapor-phase corrosion is insignificant if condensate formation is prevented.

(6) Corrosion by condensate is directly related to naphthenic acid content (or neutralization number).

(7) Pressure appears to have little effect on the kinetics of corrosion.

(8) Sensitization and stabilization significantly decrease the resistance of austenitic (18/8) stainless steels to naphthenic acid corrosion.

(9) Alloying with molybdenum increases the resistance of sensitized and stabilized austenitic (18/8) stainless steels toward such corrosion. Any differences in corrosion resistance of solution-annealed Type 304, Type 316, and Type 317 stainless steels are small.

(10) Preactivation decreases the resistance of Type 410 and Type 304 stainless steels to corrosion.

For refinery distillation units, where the neutralization number of feed stocks normally does not exceed 1.0, the following specific conclusions can be drawn:

(1) Below approximately 450°F, naphthenic acid corrosion of carbon steel, low-alloy steels, Type 410 stainless steel, and austenitic (18/8) stainless steels is of no concern.

(2) Above approximately 500°F, naphthenic acids become partially vaporized, depending on temperature, pressure, and type of crude. Vaporization normally decreases the naphthenic acid content of most liquid feed stocks and should counteract any increase in corrosion tendency due to increased temperatures. Vaporized naphthenic acids, as such, are not aggressive to common materials of construction.

(3) The presence of naphthenic acids can be expected to compound any existing impingement-type corrosion problems and lead to new ones. It is doubtful that alloying (even with Type 317 stainless steel) will prevent impingement-type corrosion in all cases; process changes are required to lower heat fluxes and vapor velocities and to avoid abrupt changes in flow direction.

(4) Normally, corrosion will be confined to those areas where the neutralization number of the hydrocarbon liquids is increasing because the naphthenic acid vapors are condensing out. This should occur on a limited number of trays in atmospheric and vacuum towers of crude distillation units, usually from 550° to 650°F. Corrosion will be particularly severe if the right conditions for impingement-type corrosion exist at these locations.

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TABLE I COMPOSITION OF ALLOYS USED IN NAPHTHENIC ACID CORROSION TESTS

Alloy	ANALYSIS (WT%) C	Cr	Ni	Mo	Mn	P	S	Si	Cu	Fe
Carbon Steel	0.03	0.03	0.02	0.01	0.33	0.004	0.011	0.01	0.03	Bal.
7Cr-½Mo Steel	0.13	7.09	--	0.58	0.47	0.011	0.015	--	--	Bal.
9Cr-1Mo Steel	0.15	9.03	--	1.08	0.43	0.009	0.016	--	--	Bal.
Type 410 Stainless Steel	0.12	12.43	0.21	--	0.45	0.011	0.012	0.38	0.09	Bal.
Type 304 Stainless Steel	0.05	18.59	9.01	0.18	0.96	0.018	0.011	0.52	0.18	Bal.
Type 316 Stainless Steel	0.07	17.46	12.98	2.02	1.40	0.023	0.015	0.39	0.20	Bal.
Type 317 Stainless Steel	0.05	18.83	13.15	3.46	1.59	0.029	0.014	0.41	--	Bal.
Monel	0.09	--	64.7	--	0.69	--	0.004	0.12	30.9	1.27

TABLE II EFFECT OF TEMPERATURE AND PRESSURE ON CORROSION OF CARBON STEEL AND TYPE 410 STAINLESS STEEL IN CRUDE OIL (NEUTRALIZATION NUMBER=1.0)

Temp.(°F)	Press. (psig)	Neutralization Number Initial	Final	Exposure Time (hrs.)	Corrosion Rate of Carbon Steel (mpy) Liquid	Vapor	Corrosion Rate of Type 410 (mpy) Liquid	Vapor
70	15	1.0	1.0	210	0.7	--	0.6	--
330	600	1.0	1.0	152	2.6	2.7	1.4	1.2
400	600	1.0	1.0	118	1.2	1.1	1.3	0.7
500	600	1.0	1.1	116	1.3	1.9	0.7	0.9
600	600	1.0	1.1	115	10.2	7.7	6.8	6.7
650	600	1.0	1.0	93	26.3	19.6	9.9	11.8
675	600	1.0	0.9	118	29.0	25.3	16.4	7.6
725	600	1.0	0.1	8 *	47.0	56.0	24.0	23.0

* Test was terminated because excessive flashing of volatiles made pressure control impossible. Therefore, indicated corrosion rates are estimates only.

TABLE III

EFFECT OF TEMPERATURE AND PRESSURE ON CORROSION OF CARBON STEEL AND TYPE 410 STAINLESS STEEL IN WHITE OIL/NAPHTHENIC ACID BLENDS (NEUTRALIZATION NUMBER=1.0)

Temp. (°F)	Press. (psig)	Neutralization Number Initial	Neutralization Number Final	Exposure Time (hrs.)	Corrosion Rate of Carbon Steel (mpy) Liquid	Corrosion Rate of Carbon Steel (mpy) Vapor	Corrosion Rate of Type 410 (mpy) Liquid	Corrosion Rate of Type 410 (mpy) Vapor
200	15	0.0 *	0.0	96	0.9	0.7	1.0	0.5
212	15	1.0	1.1	162	0.9	0.8	0.7	0.8
400	600	1.0	0.9	48	8.4	6.6	2.0	2.7
450	15	1.2	1.2	18	6.1	5.1	4.2	3.6
450	15	1.2	1.2	42	4.6	4.6	2.5	3.3
450	15	1.2	1.2	66	3.1	3.8	2.2	0.9
450	15	1.0	--	91	2.6	2.7	1.9	1.9
450	15	1.2	1.2	138	2.0	2.3	1.5	1.7
450	600	1.2	1.2	117	5.8	5.2	1.6	1.6
500	15	0.0*	0.0	88	1.0	1.0	0.8	0.6
500	600	1.0	1.0	51	9.5	10.5	9.4	10.8
500	600	1.0	1.0	120	6.2	3.2	1.1	1.6
550	600	1.1	1.4	115	1.4	1.6	1.4	1.0
580	15	0.0*	0.0	96	1.1	1.2	0.8	0.7
600	600	1.0	0.9	66	9.5	9.3	6.5	5.6
650	600	1.0	0.8	64	26.4	20.6	16.2	15.0
675	600	1.0	1.1	45	9.5	12.9	2.0	1.5

*Blank Run

TABLE IV

EFFECT OF TEMPERATURE AND NEUTRALIZATION NUMBER ON CORROSION OF VARIOUS ALLOYS IN WHITE OIL/NAPHTHENIC ACID BLENDS

Temp. (°F)	Neutralization Number Initial	Neutralization Number Final	Exposure Time (hrs.)	Corrosion Rate (mpy) Carbon Steel	7Cr-½Mo	9Cr-1Mo	Type 410	Type 304	Type 316	Monel
370	9.6	9.2	164	5.3	1.1	1.4	0	0	0	--
	18.5	17.4	164	25.5	8.3	12.5	0	0	0	--
	29.0	29.0	164	29.6	10.2	15.0	0.3	0	0	--
	36.6	36.9	164	6.1	4.5	5.8	0.2	0	0.1	--
	47.0	45.3	164	12.8	7.0	9.2	1.0	0.2	0	--
400	9.6	8.1	120	15.0	10.7	19.4	1.4	0	0	--
	18.5	17.7	120	17.6	15.4	17.1	3.0	0.1	0	--
	29.0	27.5	120	33.7	23.6	28.4	17.5	0.1	0.1	--
	36.6	34.0	120	21.9	15.3	21.4	21.5	0.2	0	--
	47.0	42.4	120	32.8	24.8	26.1	47.0	0.3	0.2	--
430	9.6	1.5	69	20.8	1.8	1.5	0.5	0.5	0.7	--
	18.5	10.3	69	90.6	33.3	39.9	3.1	0.4	0.5	--
	29.0	22.9	66	58.9	37.6	40.1	35.9	0.4	0.1	--
	36.6	30.0	66	84.9	46.6	58.0	48.1	0.3	0.3	--
	47.0	39.0	66	115.4	59.2	83.2	72.5	0	0.3	--
455	9.6	8.4	82	19.7	24.4	15.1	1.9	0.5	0.5	3.7
	18.5	17.0	82	74.5	42.2	55.0	47.9	0.5	0.7	9.9
	29.0	24.7	83	77.3	99.1	66.3	73.4	0.6	0.3	7.6
	36.6	27.8	83	131.9	108.8	120.9	161.6	0.4	0.3	13.1
	47.0	35.5	93	121.0	119.5	126.0	161.5	0.8	0	--

TABLE V EFFECT OF TEMPERATURE AND NEUTRALIZATION NUMBER ON CORROSION OF CARBON STEEL IN WHITE/OIL NAPHTHENIC ACID BLENDS AND IN VAPOR CONDENSATE

Temp. (°F)	Neutralization Number Initial	Final	Exposure Time (hrs.)	Corrosion Rate (mpy) Liquid	Vapor
480	9.6	8.3	46	34.9	18.6
	18.5	16.3	46	64.4	47.0
	29.0	23.8	46	128.5	57.0
	36.6	32.2	46	219.0	63.9
	47.0	40.3	46	274.0	81.3
530	2.0	0.8	96	9.2	8.0
	5.0	2.0	96	7.0	5.9
	9.6	4.7	46	28.8	35.0
	18.5	7.3	46	70.8	88.7
	29.0	11.7	46	78.1	95.9
	36.6	15.1	46	182.7	157.4
	47.0	19.9	46	293.0	74.6
580	9.6	1.0	46	25.1	43.1
	18.5	1.3	46	59.6	287.0
	29.0	1.7	46	104.3	247.0
	36.6	1.0	46	129.0	366.0
	47.0	1.5	46	202.7	307.5

TABLE VI EFFECT OF VELOCITY ON CORROSION OF ROTATING CARBON STEEL COUPONS IN WHITE OIL/NAPHTHENIC ACID BLENDS AND IN VAPOR CONDENSATE AT 530°F TEMPERATURE (NEUTRALIZATION NUMBER=2.0)

Velocity (Ft/sec)	Neutralization Number Initial	Final	Exposure Time (hrs.)	Corrosion Rate (mpy) Liquid	Vapor
0	2.0	2.3	95	7.0	5.9
0.2	2.0	1.2	93	12.8	44.5
0.4	2.0	1.4	92	8.2	145.0
2.2	2.0	1.3	140	8.9	118.0
6.6	2.0	1.2	142	3.4	74.0
9.7	2.0	1.0	103	2.0	42.0
13.3	2.0	1.5	92	5.5	10.0

TABLE VII EFFECT OF NEUTRALIZATION NUMBER ON CORROSION OF VARIOUS ALLOYS IN WHITE OIL/NAPHTHENIC ACID AT 560°F TEMPERATURE AND ELEVATED PRESSURE (ROCKING AUTOCLAVE)

eutralization Number Initial	Final	Exposure Time (hrs.)	Final Pressure(psig)	Corrosion Rate (mpy) Carbon Steel	9Cr-1Mo	Type 410	Type 304	Type 316	Monel
9.6	6.7	93	80	52.1	29.5	8.5	0.4	0.3	16.7
18.5	8.0	82	100	60.7	35.0	106.7	1.2	0.6	--
	17.3	65	290	131.0	159.0	169.0	1.0	0.9	--
36.6	21.0	71	150	160.0	107.8	257.0	0.9	1.0	36.4

TABLE VIII EFFECT OF HEAT TREATMENT OF VARIOUS AUSTENITIC (18/8) STAINLESS STEELS ON CORROSION IN WHITE OIL/NAPHTHENIC ACID BLENDS AT DIFFERENT NEUTRALIZATION NUMBERS

Temp. (°F)	Neutralization Number Initial	Final	Final Pressure (psig)	Exposure Time (hrs.)	Corrosion Rate (mpy) Type 304 SA	SS	ST	Type 316 SA	SS	ST	Type 317 SA	SS	ST
450	9.6	9.8	15	73	1.0	2.7	13.7	1.1	2.0	3.4	--	--	--
	18.5	17.3	15	73	1.1	3.1	10.1	1.4	2.7	6.3	--	--	--
	29.0	29.4	15	74	1.2	3.3	25.9	0.6	2.8	4.2	--	--	--
	36.6	29.0	15	74	0.3	5.8	80.2	0.6	2.2	3.4	--	--	--
560	9.6	7.3	80	70	1.3	2.9	8.1	--	2.6	4.8	--	--	--
	18.5	14.7	96	77	0.6	19.7	62.5	0.5	1.1	7.8	0.2	--	2.0
	29.0	17.3	290	65	1.0	18.2	--	0.9	--	9.3	--	--	--
	36.6	31.5	130	79	0.7	89.8	181.0	0.5	2.2	--	0.3	1.2	2.3

SA = Solution annealed
SS = Sensitized at 1200°F for 4 hours, air-cooled
ST = Stabilized at 1650°F for 4 hours, water-quenched

TABLE IX EFFECT OF SURFACE PRETREATMENT OF VARIOUS STAINLESS STEELS ON CORROSION IN WHITE OIL/NAPHTHENIC ACID BLENDS (NEUTRALIZATION NUMBER=29.0)

Alloy	Corrosion Rate at 400°F Temperature (mpy) Preactivated	Passivated	Corrosion Rate at 480°F Temperature (mpy) Preactivated	Passivated
Type 410	10.6	0.2	126.0	111.0
Type 304	0.1	0.1	1.9	0.1
Type 304L	0.1	0.2	2.6	0.2
Type 316	0.1	0.1	0.1	0.1
Type 316L	0.0	0.1	0.1	0.1
Type 317	0.3	0.1	0.1	0.1
Type 317L	0.0	0.2	0.0	0.1

Test Duration: 134 hours
Final Neutralization Numbers: 25.3 (400°F)
22.0 (480°F)

TABLE X RESULTS OF FIELD CORROSION TESTS DURING CRUDE RUNS WITH NAPHTHENIC-ACID-CONTAINING CRUDE OIL

Location	Process Stream	Temperature	Neutralization Number	Corrosion Rate (mpy) Carbon Steel	5Cr-½Mo	Type 410	Type 304	Type 316
Heater Transfer Line	Atmospheric Tower Feed	660	0.3-0.8	6-60	1-3	<1	<1	<1
Pump Suction Line	Diesel Cut	525	0.3-0.6	2- 5	< 2	< 1	< 1	< 1
Heater Inlet Line	Reduced Crude	610	0.9-1.1	1- 5	1-4	1-2	<1	<1
Heater Transfer Line	Vacuum Tower Feed	800	0.9-1.1	70-117	1-32	5-166	< 1	1-2
Pump Suction Line	Light Vacuum Gas Oil	350	0.7-1.0	3- 4	2-3	< 1	< 1	< 1
Pump Discharge Line	Heavy Vacuum Gas Oil	540	0.6-1.3	14-18	14-16	9-17	1-4	< 1
Pump Discharge Line	Vacuum Tower Wash Oil	740	0.5-0.7	29-49	2-6	1-3	2-3	2-3
Transfer Line	Vacuum Resid	700	0.5-0.7	26-27	6-11	1-4	1-2	1-2

TABLE XI MATERIALS OF CONSTRUCTION AND CORROSION DAMAGE OF VACUUM DISTILLATION TOWER INTERNALS

Tray No.	Type	Material	Temperature (°F)	Overall Condition	Appearance of Corrosion Damage: Valves or Caps	Tray Floor	Tray Supports	Downcomers
1	Rect. Cap	Type 410	230	Excellent	ok	ok	ok	ok
2	Valve	Type 410	290	Excellent	ok	ok	ok	ok
3	Valve	Type 410	350	Excellent	ok	ok	ok	ok
4	Valve	Type 410	425	Poor	45% missing	general thinning & knife-edged attack at valve openings	slight, general attack	general thinning
5	Rect. Cap	Type 317	545	Excellent	ok	ok	ok	ok
Demister Pad	Woven Wire Mesh	Type 316	560	Poor	40% of pad missing	ok	severe pitting	ok
6	Rd. Cap	Type 317	580	Poor	35% severely pitted	overall pitting of underside	ok	ok
7	Rd. Cap	Type 316	640	Poor	45% severely pitted	overall pitting of underside	ok	ok
8	Rd. Cap	Type 316	680	Excellent	ok	ok	ok	ok
9	Rd. Cap	Type 316	740	Excellent	ok	ok	ok	ok

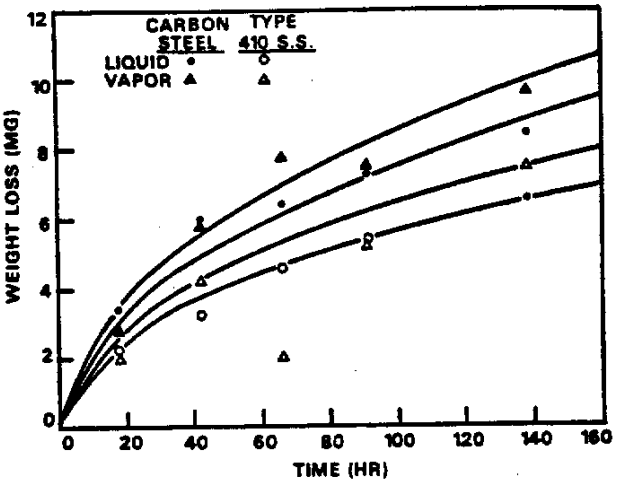


FIGURE 1 SHORT-TERM PARABOLIC WEIGHT LOSS CURVES FOR CORROSION IN WHITE OIL/NAPHTHENIC ACID BLENDS AT 450°F TEMPERATURE (NEUTRALIZATION NUMBER=1.0)

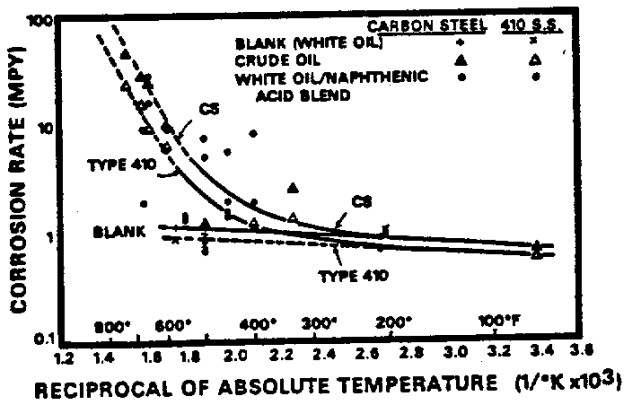


FIGURE 2 ARRHENIUS PLOT FOR CORROSION IN CRUDE OIL AND IN WHITE OIL/NAPHTHENIC ACID BLENDS WITH NEUTRALIZATION NUMBERS=1.0

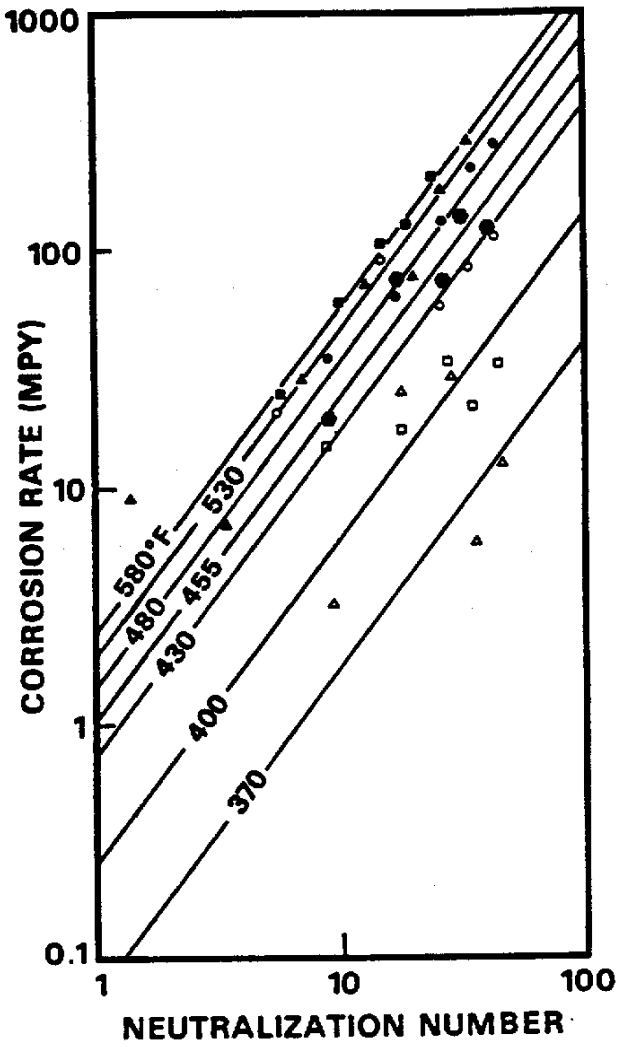


FIGURE 3 CORROSION ISOTHERMS FOR CARBON STEEL IN WHITE OIL/NAPHTHENIC ACID BLENDS

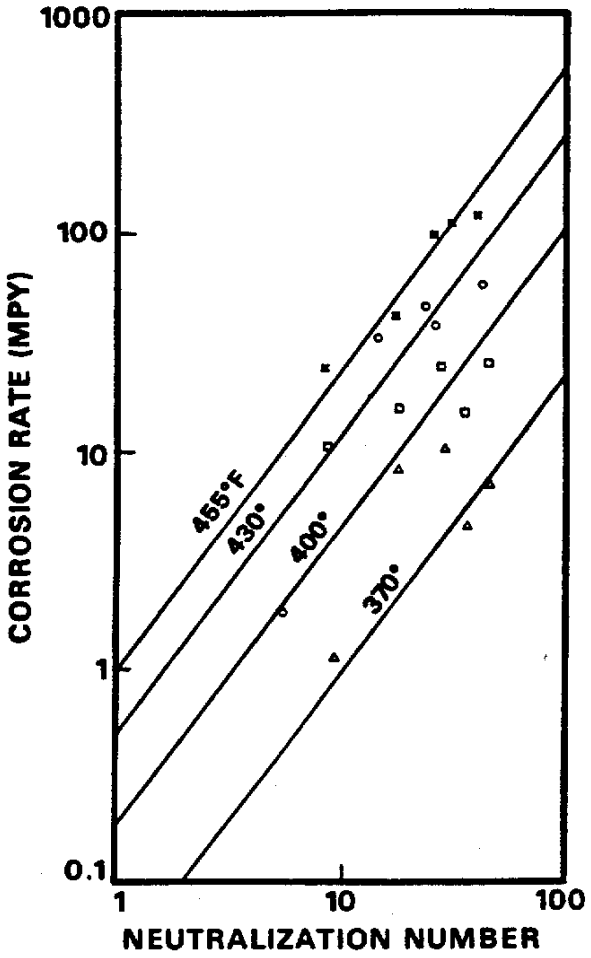


FIGURE 4 CORROSION ISOTHERMS FOR 7 Cr-½ Mo STEEL IN WHITE OIL/ NAPHTHENIC ACID BLENDS

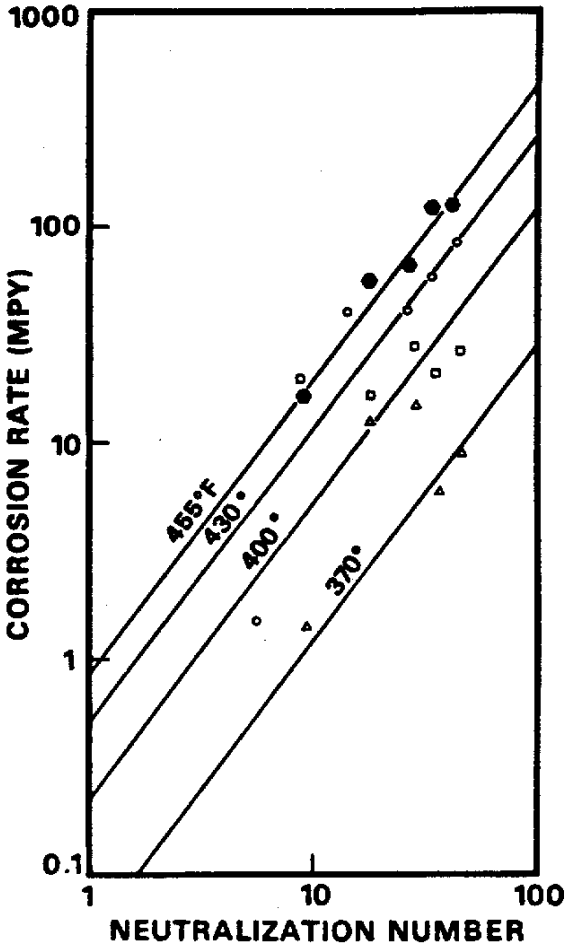


FIGURE 5 CORROSION ISOTHERMS FOR 9 Cr-1 Mo STEEL IN WHITE OIL/ NAPHTHENIC ACID BLENDS

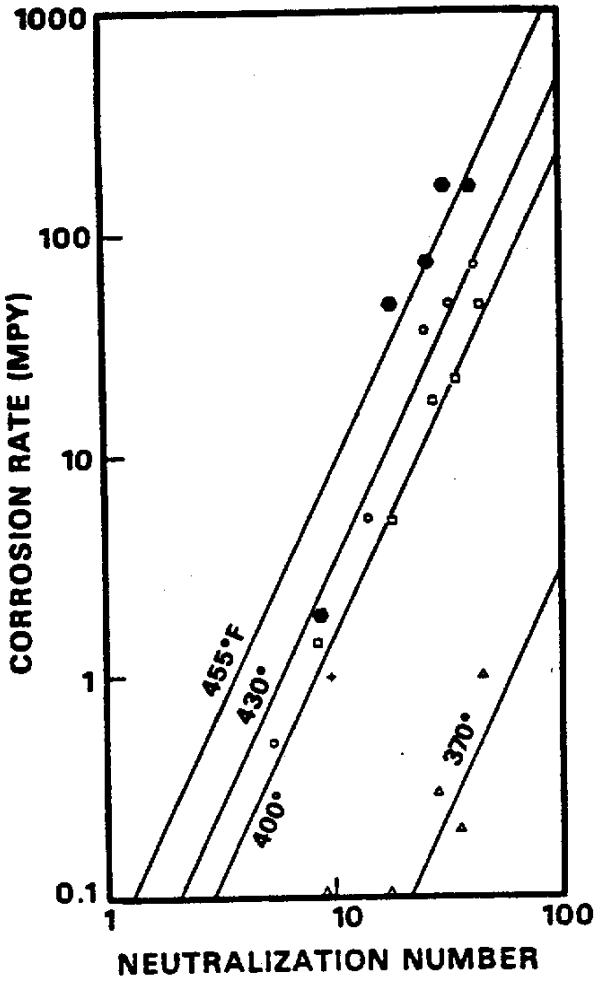


FIGURE 6 CORROSION ISOTHERMS FOR TYPE 410 (12 Cr) STAINLESS STEEL IN WHITE OIL/NAPHTHENIC ACID BLENDS

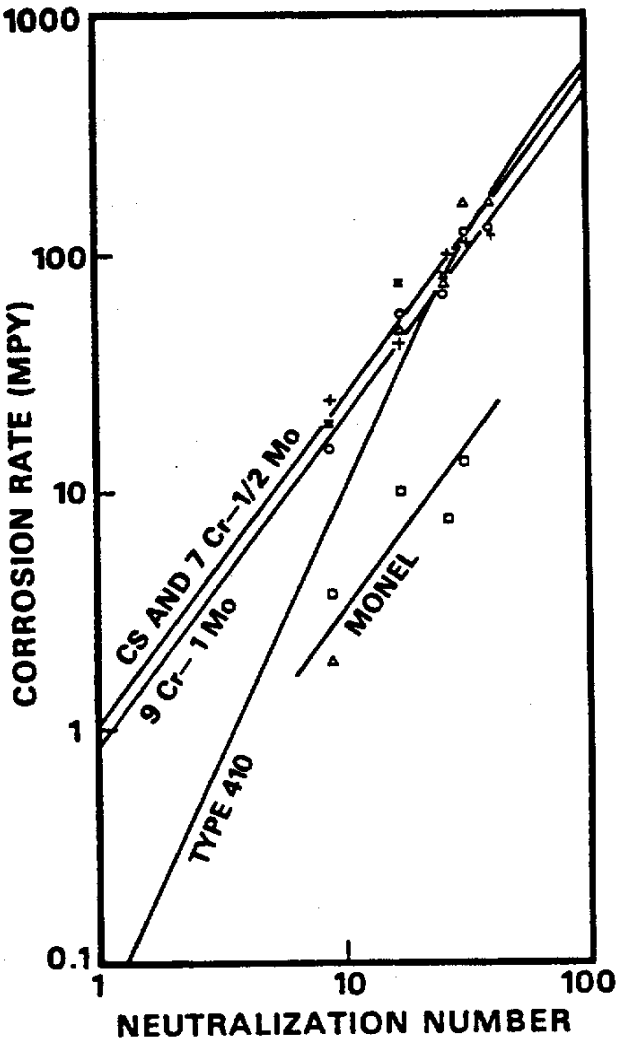


FIGURE 7 CORROSION ISOTHERMS FOR VARIOUS STEELS AND MONEL IN WHITE OIL/NAPHTHENIC ACID BLENDS AT 455°F TEMPERATURE

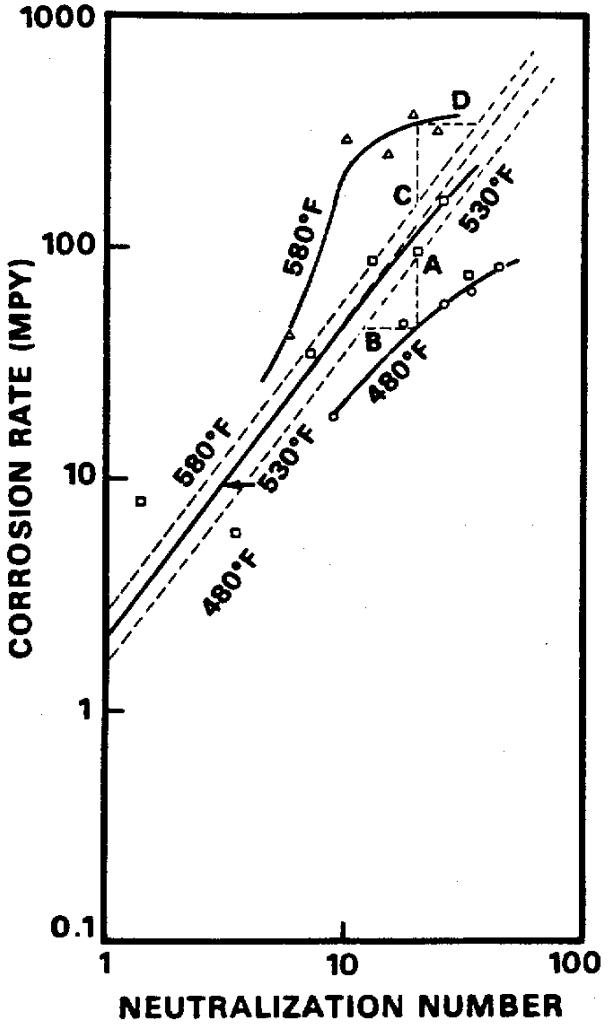


FIGURE 8 GRAPHIC ANALYSIS OF THE NEUTRALIZATION NUMBER OF CONDENSATE FROM CORROSION ISOTHERMS FOR CARBON STEEL IN WHITE OIL/ NAPHTHENIC ACID BLENDS (SOLID LINES REPRESENT VAPOR-PHASE CORROSION, DASHED LINES REPRESENT LIQUID-PHASE CORROSION)

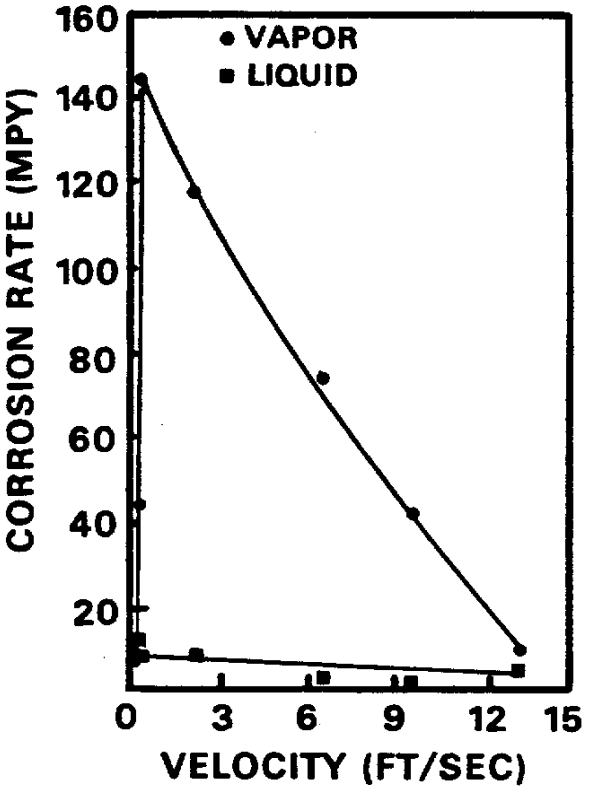


FIGURE 9 EFFECT OF VELOCITY ON LIQUID AND VAPOR-PHASE CORROSION OF CARBON STEEL IN WHITE OIL/NAPHTHENIC ACID BLENDS AT 530°F TEMPERATURE (NEUTRALIZATION NUMBER=2.0)

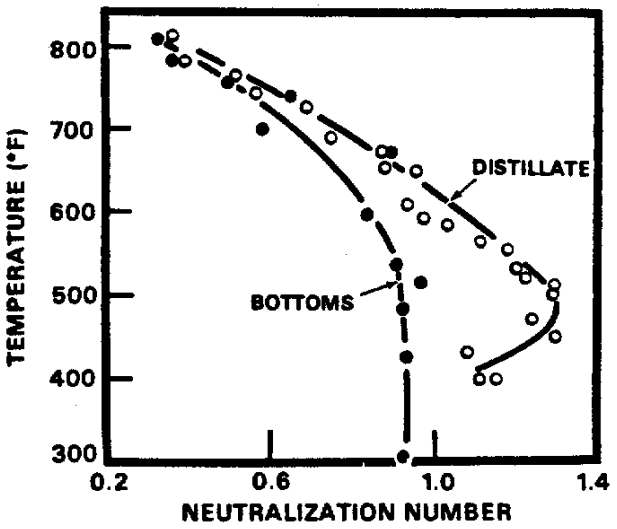


FIGURE 10 INCREASE IN THE NEUTRALIZATION NUMBER OF DISTILLATE DURING BATCH DISTILLATION OF CRUDE OIL WITH NEUTRALIZATION NUMBER=0.9

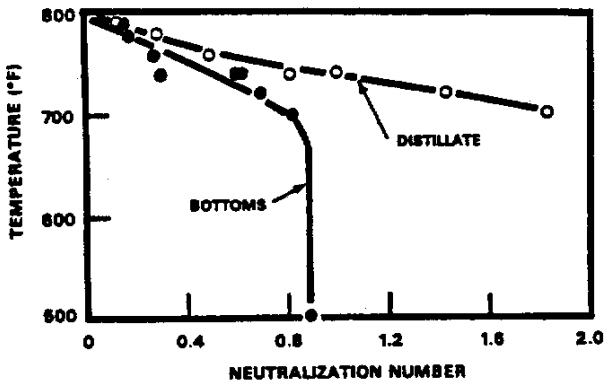


FIGURE 11 INCREASE IN THE NEUTRALIZATION NUMBER OF DISTILLATE DURING BATCH DISTILLATION OF WHITE OIL/NAPHTHENIC ACID BLEND WITH NEUTRALIZATION NUMBER=0.9

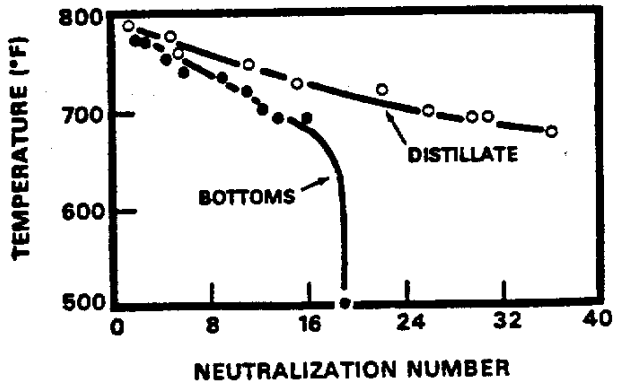


FIGURE 12 INCREASE IN THE NEUTRALIZATION NUMBER OF DISTILLATE DURING BATCH DISTILLATION OF WHITE OIL/NAPHTHENIC ACID BLEND WITH NEUTRALIZATION NUMBER=19

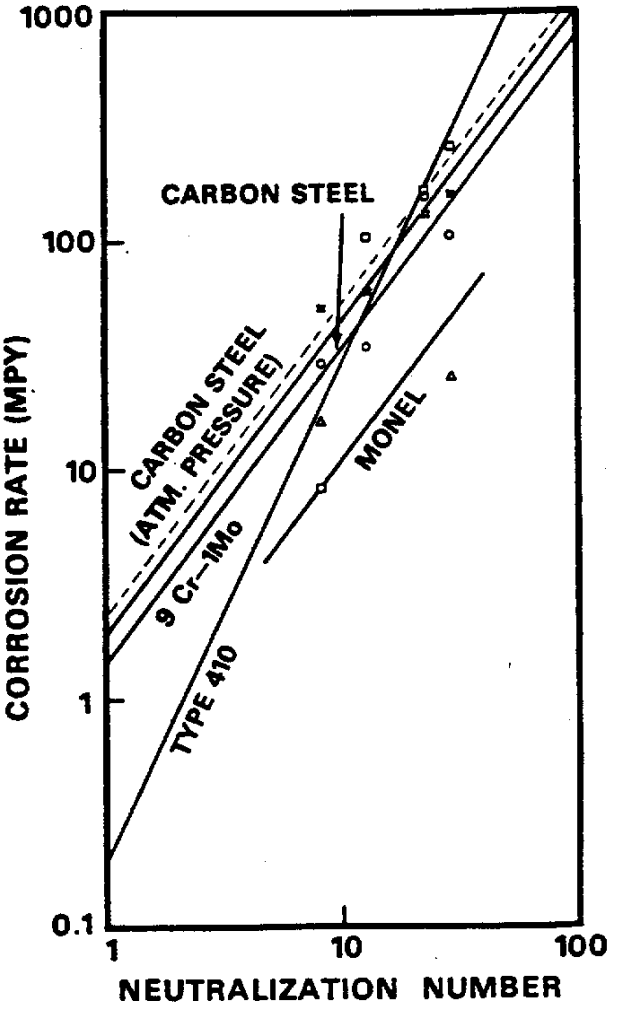


FIGURE 13 CORROSION ISOTHERMS FOR VARIOUS STEELS AND MONEL IN WHITE OIL/NAPHTHENIC ACID BLENDS AT 560°F TEMPERATURE AND ELEVATED PRESSURE (DASHED LINE REPRESENTS CORROSION ISOTHERM FOR CARBON STEEL AT ATMOSPHERIC PRESSURE)



FIGURE 14 NAPHTHENIC ACID CORROSION DAMAGE OF TYPE 317 BUBBLE CAPS AND TOP SIDE OF TRAY 6 IN VACUUM DISTILLATION TOWER. OPERATING TEMPERATURE: 580°F

NACE Standard RP0472-87
Item No. 53011

technical practices committee

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

Standard

Recommended Practice

Methods and Controls to Prevent In-Service Cracking of Carbon Steel Welds in P-1 Materials in Corrosive Petroleum Refining Environments

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Standard Recommended Practice

Methods and Controls to Prevent In-Service Cracking of Carbon Steel Welds in P-1 Materials in Corrosive Petroleum Refining Environments

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The National Association of Corrosion Engineers (NACE) issues this standard in conformity with the best current technology regarding the specific subject. This standard represents minimum requirements and should in no way be interpreted as a restriction on the use of better procedures or materials. Neither is this standard intended to apply in any and all cases relating to the subject. Unpredictable circumstances may negate the usefulness of this standard in specific instances. NACE assumes no responsibility for the interpretation or use of this standard by other parties and accepts responsibility for only those official NACE interpretations issued by NACE in accordance with its governing procedures and policies which preclude the issuance of interpretations by individual volunteers.

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Foreword

Carbon steel is a common construction material for many equipment items in oil refineries, gas plants, storage tanks, etc. Numerous weld failures in pressure vessels, heat exchangers, tanks, and piping have been documented in NACE publications.[1] Many of these weld failures were caused by sulfide stress cracking in "sour" service and were a form of hydrogen stress cracking (HSC). It should be noted, however, that sulfides are not the only cause of such failures, since corrosion reactions resulting from other corrosive media can introduce hydrogen into metal with similar results.[2]

Since such weld failures can result in safety problems for personnel, expensive mechanical repairs, and substantial process losses in production and products, this NACE recommended practice was developed to provide the industry with a method of minimizing risk of failure in all equipment constructed of P-1 classification steels having a minimum specified tensile strength of 70,000 psi (480 MPa) or less. Alloyed steels and/or steels having minimum specified tensile strengths higher than 70,000 psi (480 MPa) are also subject to hydrogen induced cracking, but they are outside the scope of this recommended practice, which simply imposes a hardness limitation.

This recommended practice, issued by NACE under the auspices of Group Committee T-8 on Refinery Industry Corrosion, was prepared by NACE Task Group T-8-7 composed of corrosion consultants, corrosion engineers, and other specialists associated with the petroleum refining industry. API[2] Recommended Practice 942, Controlling Weld Hardness of Carbon Steel Refinery Equipment to Prevent Environmental Cracking, addresses the same problem and closely parallels this document.

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(1) See Paragraph 1.2.

(2) American Petroleum Institute (API), Washington, DC.

Section 1: General

1.1 This recommended practice establishes guidelines to prevent in-service cracking of welds on P-1 steel equipment. Information is also given on the three primary factors believed to be related to in-service cracking of carbon steel welds: (1) corrosive environment, (2) hardness, and (3) total stress.

1.2 Unless otherwise indicated, guidelines given in this recommended practice are to be applied to refinery and gas plant pressure vessels, heat exchangers, tanks, and piping constructed of steels specifically classified as P-1 in the ASME[3] Code, Section IX in the ASME/ANSI[4] Piping Code B31.3, and in API Standards 620 and 650, but excluding those steels over 70,000 psi (480 MPa) minimum specified tensile strength.

1.3 Historical data have shown that a 200 Brinell hardness (HBN) limit is generally successful in preventing cracking. However, user discretion is an inherent part of this recommended practice since susceptibility to cracking depends on environmental severity, among other things. In less severe wet hydrogen sulfide environments, successful experience has been reported for macrohardness levels as high as 235 HBN. On the other hand, strong crack-promoting agents such as solutions containing both cyanides and sulfides have been shown to cause cracking in nonstress-relieved welds with macrohardness levels under 200 HBN.

1.4 The user of this recommended practice is cautioned that cracking of carbon steel welds can occur in alkaline environments as a result of mechanisms other than HSC. Such environments include NaOH solutions, amine solutions, etc. In such environments, cracking can occur in welds having a hardness less than the maximum permitted by this recommended practice, and other preventive measures such as reduction of peak residual stresses by postweld heat treatment (PWHT) must be undertaken.

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(3) American Society of Mechanical Engineers (ASME), New York, NY.

(4) American National Standards Institute (ANSI), New York, NY.

Section 2: Hardness Guidelines

2.1 This standard establishes guidelines for weld deposit hardnesses and not hardnesses for base metal or weld heat affected zones (HAZ).

2.2 Hardness of completed weld deposits in P-1 steel equipment shall not exceed 200 HBN, unless the purchaser has agreed to a higher allowable hardness.

2.2.1 Hardness readings shall be taken with a portable hardness tester in accordance with ASTM[5] Standard E10, Test for Brinell Hardness of Metallic Materials. Experience reported to date indicates no high hardness readings in welds made in P-1 steel by the shielded metal arc process (SMAW) using E-60XX or E-70XX carbon steel coated electrodes, and SMAW welds made using these electrodes need not be hardness tested (see Paragraph 3.4.1).

2.2.2 Hardness readings shall be taken on the outside and, where accessible, on the inside of pressure retaining weld seams and on sweep-type nozzle butt welds at the rate of one reading on each 20 ft (6 m) of weld in each seam, with a minimum of one reading per seam.

2.3 Welds found to exceed 200 HBN (or purchaser specified hardness) shall be either removed and rewelded or heat treated to reduce the hardness to the proper specification.

2.3.1 Hard welds shall be reported to the purchaser. The specific approach to be used shall be subject to the purchaser's approval before corrective action is taken by the fabricator.

2.3.2 Regardless of the welding process or heat treatment used for corrective action, the repaired welds shall be retested to ensure hardness of no more than the specified hardness.

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(5) ASTM, Philadelphia, Pennsylvania.

Section 3: Hardness Related Factors

3.1 Weld hardness is directly related to weld strength, and adequate strength for P-1 steels can be attained at hardness levels below 200 HBN. It is not generally desirable for refinery equipment to have welds that are considerably stronger than the base metal, but current national construction codes do not provide mandatory weld hardness limitations and thus allow such a mismatch.

3.2 A thorough review of welding procedures used where in-service cracking of carbon steel welds has occurred, or where high hardness welds were produced, shows a direct correlation between high hardness welds and submerged arc welding with the use of a low or medium manganese wire in combination with an active flux.[4-6] High hardness welds have also been produced with the use of the gas metal arc welding process (GMAW) or the flux cored arc welding process (FCAW) and high manganese and/or 0.5% molybdenum wire.

3.3 Submerged Arc Welding

3.3.1 Although active fluxes (i.e., flux containing ferrosilicon and/or ferromanganese whereby silicon and/or manganese is transferred from the flux to the weld deposit) may have value for single pass welds, most manufacturers do not recommend the general use of active fluxes for multipass welds.

3.3.2 Although ASME SFA 5.17 Specification for Carbon Steel Electrodes and Fluxes for Submerged Arc Welding places limits on the chemical composition of wires and on mechanical property requirements of deposited welds made under controlled, standardized welding conditions, it does not establish limits on chemical composition or mechanical properties of deposited welds made under other weld conditions or those having significant base metal dilution.

3.3.3 Changes in welding process variables such as voltage, travel speed, etc., can make substantial differences in weld bead hardness even when the same wire and flux are used in successive passes.

3.3.4 The fabricator shall therefore be responsible for producing welds that comply with all of the requirements of this recommended practice and all other requirements of the purchase order or contract. The final acceptance of any welding procedure and the resulting welds shall reside with the purchaser. Mechanical properties and chemical composition of the completed weld deposit shall essentially match the properties and composition of the base metal. Exceptions to this basic requirement shall be the option of the purchaser only.

3.3.5 Unless otherwise agreed upon, production weld deposits shall meet the A-No. 1 chemical composition shown in Table QW-442 of the ASME Boiler and Pressure Vessel Code, Section IX.[7] This table allows a maximum carbon content of 0.15%, a maximum manganese content of 1.6%, and a maximum silicon content of 1.0%. In addition, the combined amount of chromium, nickel, and molybdenum in production weld deposits shall not exceed 0.25%. Welds required to be postweld heat treated may not achieve their required tensile strength without exceeding the A-No. 1 chemistry limits.[8]

3.3.6 PWHT may be of value in tempering or softening the martensite or hard microstructures in submerged arc weld deposits, but it may not in all cases bring the hardness to 200 HBN or less, especially in those welds with high manganese and silicon content which often contain highly localized hard zones.[9] The ASME Pressure Vessel Code, Section VIII, Division 1 does not require hardness testing of heat treated carbon steel welds.

3.4 Other Welding Processes

3.4.1 Coated electrodes for SMAW shall conform to ASME SFA 5.1 Carbon Steel Covered Arc Welding Electrodes. Electrodes having ASME SFA 5.5 compositions shall not be used unless tests on the weld deposits show that the hardness is under 200 HBN.

3.4.2 Filler metals for gas shielded arc welding processes (gas tungsten arc welding or GMAW) shall conform to ASME SFA 5.18 Carbon Steel Filler Metals for Gas Shielded Arc Welding. Those not listed or not conforming to AWS A 5.18 shall not be used unless tests on the weld deposits show that the hardness is under 200 HBN.

3.4.3 Filler metals for FCAW shall conform to AWS A 5.20.

Section 4: Corrosive Environments

4.1 Carbon steel weld cracking is believed to be caused by the absorption of atomic hydrogen. The atomic hydrogen may be generated by the corrosion of steel in wet environments such as hydrogen sulfide, cyanides, hydrochloric acid, sulfuric acid, hydrofluoric acid, and acid salts.

4.2 Threshold limits for corrosive service have not been established that will guarantee the absence of weld cracking. Normal service, startup, shutdown, and upset conditions should be considered in evaluating the corrosivity aspects.

Section 5: Stress

5.1 All welded joints contain residual stresses and variations in hardness resulting from the weld cooling process. In some weld zones, the residual weld stress level can be near yield strength of the base metal.

5.2 Residual welding stresses, fabrication stresses, and in-service stresses resulting from pressure, temperature, etc., are additive.

5.3 Because of combined total stresses, PWHT should be considered to minimize residual welding and fabrication stresses along with tempering the martensite present in the steel. PWHT will not correct a serious strength mismatch of base metal and weld metal nor will it soften all localized hard spots, but it usually reduces HAZ hardness.

References

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2. Welding Research Council Bulletin No. 145, "Interpretive Report on Effect of Hydrogen in Pressure Vessel Steels," October, 1969, Welding Research Council, New York, New York.

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8. H. W. Ebert and J. F. Winsor, "Carbon Steel Submerged Arc Welds—Tensile Strength vs. Corrosion Resistance," Welding Research Supplement to the Welding Journal, July, 1980.

9. D. J. Kotecki and D. G. Howden, Welding Research Council Bulletin No. 184, "Submerged Arc Weld Hardness and Cracking in Wet Sulfide Service," June, 1973, Welding Research Council, New York, NY.

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UOP GUIDELINES FOR CAUSTIC INJECTION

Caustic injection facilities should be provided, in addition to ammonia injection facilities, in those units where only single stage desalting is used. Where two stage desalting is used, no caustic injection should be provided but the ammonia injection should be retained.

Where caustic injection is provided the following guidelines are recommended:

1. Use a solution of 10 Wt.% sodium hydroxide.

2. Inject the caustic solution at a point in the Crude stream between the desalter and the heater but where good mixing will take place ahead of the heater.

3. Set the normal injection rate at 1 pound of sodium hydroxide per pound of salt per thousand barrels of desalted Crude oil with an absolute maximum of 4 pounds of caustic per 1000 bbls of desalted crude. Normal control would be a rate such that chlorides in the Crude tower overhead would be in the range of 10 - 20 ppm. Final pH control of the overhead water should be done with ammonia injection.

Corrosion Control in Crude Oil Distillation Units*

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Control of operating and process conditions to reduce corrosion of atmospheric crude oil pipe stills is discussed. Case histories of control measures applied to stills in the 80,000-120,000 bbl/day range are presented. Additives and process operating controls helpful in reducing attacks by hydrochloric acid at 2 pH, naphthenic acids and sulfides, the latter mainly hydrogen sulfide are reviewed. Control of sulfide attack is acknowledged to be mainly through materials selection, while chloride attack can be reduced by careful injection of sodium hydroxide into overhead streams causing Ca and Mg chlorides to form NaCl, which is eliminated via the bottom stream. Desalting, while beneficial, may be hard to justify economically and overhead corrosion is principally controlled by reducing water concentration factors. Ammonia injection into overhead may cause fouling by ammonium chloride which itself is corrosive to equipment downstream. Inhibitors, though costly, when injected into overhead stream, reduce fouling and solids deposition.

*Presented during Corrosion/75, April 14-18, 1975, Toronto, Ontario, Canada.

February, 1976

THIS PAPER REVIEWS the important corrosion problems and preventive measures in atmospheric crude oil distillation units, commonly known as atmospheric pipestills. The approach will be to emphasize corrosion control methods relying on manipulation of process/operating conditions, rather than on traditional use of resistant alloy materials. Successful application of these techniques necessarily demands close co-operation between the chemical engineer and the materials engineer. Their overlapping contribution to a well functioning corrosion control program is highlighted by several case histories. These illustrate the close influence of process and operating variables on corrosion, and the kind of problems that can arise from incorrect or careless execution.

The atmospheric pipestill unit (APS) receives crude oil feed and separates it into fractions of different boiling ranges. A typical pipestill in operation today might have a capacity of 80,000 to 120,000 barrels per stream day (bpsd (16-23 Mlsd)] while larger units under construction have capacities up to 300,000 bpsd (58 Mlsd). The new larger units are highly integrated from the point of view of heat usage and may consequently have less flexibility to operate with heat exchangers out of use than do older units.

Figure 1 shows a schematic flow plan of an atmospheric pipestill. Both single and "dry" double drum overhead systems are

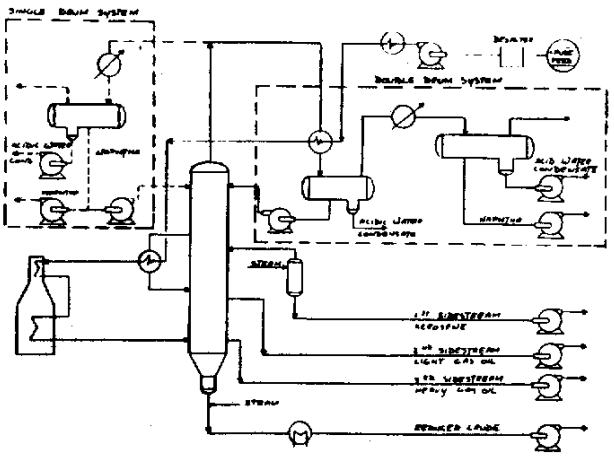


FIGURE 1 – Schematic flow plan for an atmospheric pipestill (APS) unit showing both single and double drum overheat systems.

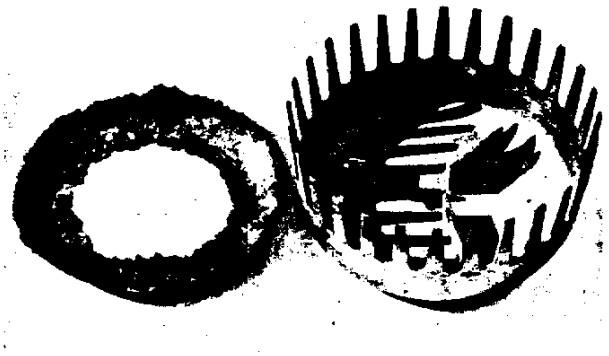


FIGURE 2 – Corroded carbon steel bubble cap from top section of APS tower–new cap is shown for camparison.

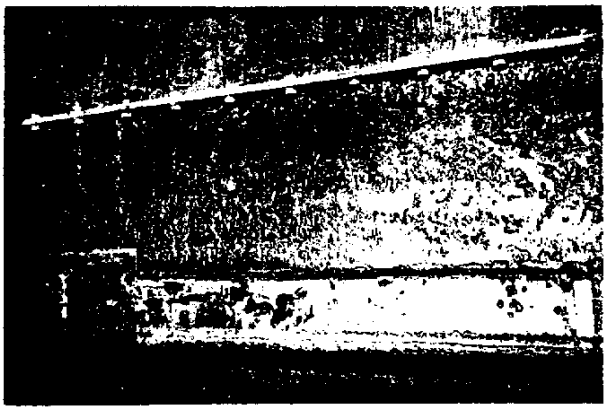


FIGURE 3 – Corroded carbon steel shell of APS tower processing high naphthenic acid crude.

shown. The areas of particular interest are:

- **Preheat train** – preheating of cold crude by heat exchange with pipestill bottoms, side, and overhead streams, or hot streams from downstream processes. Such trains may consist of 20 or more shell-and-tube exchangers.
- **Furnace** – supplying the remaining heat requirement for the crude feed by direct firing. Heat duties in these large multipass furnaces can approach 1,000,000,000 BTU/hr (290 MW/hr).
- **Pipestill tower** – fractionates crude charge into up to 7 cuts–overhead, 5 sidestreams, and bottoms–in conventional distillation columns. Live steam is injected for stripping.
- **Overhead system** – condenses a naphtha stream, part of which goes to product and part of which is used for reflux. A typical overhead system has upward of 8 shell and tube exchangers or airfin condensers.

There are three main impurities in the crude which contribute to corrosion in pipestills. They are acid-forming inorganic salts, organic acids, and sulfur compounds. Each of these will be examined in greater detail to review how and where they strike, before delving into the available corrosion control methods.

Crudes always contain varying amounts of sodium chloride and other inorganic salts, among them $MgCl_2$ and $CaCl_2$. Generally, the ratio of these salts to one another is similar to that in sea water, itself a common contaminant (originating from ballast operations in tankers). Salt corrosion results from the partial hydrolysis of $MgCl_2$ and $CaCl_2$ to HCl in the crude preheat train and furnace, and the stripping section in the bottom of the pipestill tower. NaCl is more stable and does not hydrolyze appreciably.

The hydrogen chloride so generated is not corrosive as a vapor, but becomes virulent in the pipestill overhead system where temperatures fall below the dew point. Under these conditions, the highly soluble HCl vapor dissolves in the water phase to form hydrochloric acid. The amount of HCl generated is dependent upon the total salt content of the feed; however, even quite low salt contents can produce appreciable quantities of acid because hydrolysis appears to be more complete with low salt crudes. Generally, crude salt contents have been creeping up over recent years, partly due to current recovery methods using high salt natural brines. This problem will be magnified when more marginal wells are exploited in the present energy shortage.

The actual amounts of acid generated can be surprisingly large. For example, crude containing 20 pounds of total salt per 1000 barrels [ptb (46 mg/l)] fed into a 100,000 bpsd (19 Mlsd) unit introduces one ton (900 kg) of total salt per day. Assuming 10% $MgCl_2$ and $CaCl_2$, 170 lbs (77 kg) of HCl is formed. If this were absorbed as a 0.01N hydrochloric acid solution (pH 2.0) it would form 50,000 US gpd (190 kl/d). Such low pH can occur without neutralizing additives and can cause rapid wastage of carbon steel equipment.

Corrosion by acidic chlorides is illustrated in Figure 2, showing the remnants of a 6 inch (15 cm) diameter bubble cap from the top section of an APS tower. Although corrosion progressed faster opposite the chimneys and in the slot area (due to greater turbulence) the rate of metal loss in the remaining portion is quite uniform. Another form of attack by wet chlorides is stress corrosion cracking of austenitic stainless steels, discussed later on.

The second broad category of corrodents in crude is organic acids, notably naphthenic acids. The corrosivity of a crude containing an organic acid is related to the "neutralization number" which represents milligrams of KOH required to neutralize the acid in one gram of crude. Neutralization numbers above 2.0 generally necessitate some special form of protection. Corrosion from organic acids is usually confined to a temperature range of 450 to 550 F (232 to 288 C), notably under turbulent conditions. Corrosion of this type can occur in atmospheric pipestills but is more prevalent in vacuum units.

Naphthenic acid attack is characterized by sharp edged pits which are notably free of corrosion products. This form of attack is illustrated in Figure 3 showing typical metal wastage in a pipestill processing Tia Juana crude, one of the most notorious offenders. In nozzles and piping components, metal wastage is often in the form of erosion-corrosion, characterized by grooves and rivulets along the direction of flow.

It is fortunate that only few crudes have high naphthenic acid content because Cr-Mo alloy steels and even Cr-Ni stainless steels are attacked. Since it is necessary to use materials such as the molybdenum-containing stainless steels (Type 316 and 317) or



FIGURE 4 — Sulfide corrosion of carbon steel trays and beams in APS tower handling sour crudes.

aluminized steels to achieve adequate resistance, refineries endeavor to segragate naphthenic crude processing in pipestills designed for this severe service. Most refineries cannot afford this approach, and reduce corrosion by blending with less aggressive crudes, and by reducing velocities and turbulence where practical. Some limited success has been achieved with neutralizing additives to the crude but this can create operational problems due to emulsion formation.

Sulfide corrosion, the most prevalent form of high temperature attack in APS units, results from direct chemical reaction of iron with elemental sulfur and/or its compounds, (primarily hydrogen sulfide and various organic molecules). At the high temperatures reached in the preheat furnace, many organic sulfide compounds found in so-called "sour" crudes break down to form lower molecular weight sulfur compounds or H_2S. As a rule of thumb, the lighter molecules tend to be more aggressive than the heavier stable sulfur compounds, such as thiophenes which are essentially non-corrosive.

Sulfide corrosion normally takes the form of uniform metal loss, with corroded surfaces typically covered by a bulky, semi-protective iron sulfide scale. High velocities and turbulence tend to disrupt or destroy the scale, causing accelerated metal wastage of exposed areas. For this reason, the rate of tray corrosion in pipestill towers is usually several times higher than attack of adjacent shell plates. This is well illustrated in Figure 4 which shows the lower middle section of an all carbon steel pipestill tower after a few years' operation with sour crudes. Several trays have completely corroded away and even the heavy support beams are nearly destroyed. By contrast, the shell section in the photograph showed relatively little thinning, probably less than 0.1 inch (2.5 mm) total loss.

The rate of sulfide corrosion is strongly temperature dependent. In broad terms, carbon steel is relatively unaffected below 500 to 550 F (260 to 288 C), marginal in the 550 to 650 F (288 to 343 C) range, and unsuitable above 650 F (343 C) for equipment processing sour crudes and respective fractions. Figure 5 shows data for a

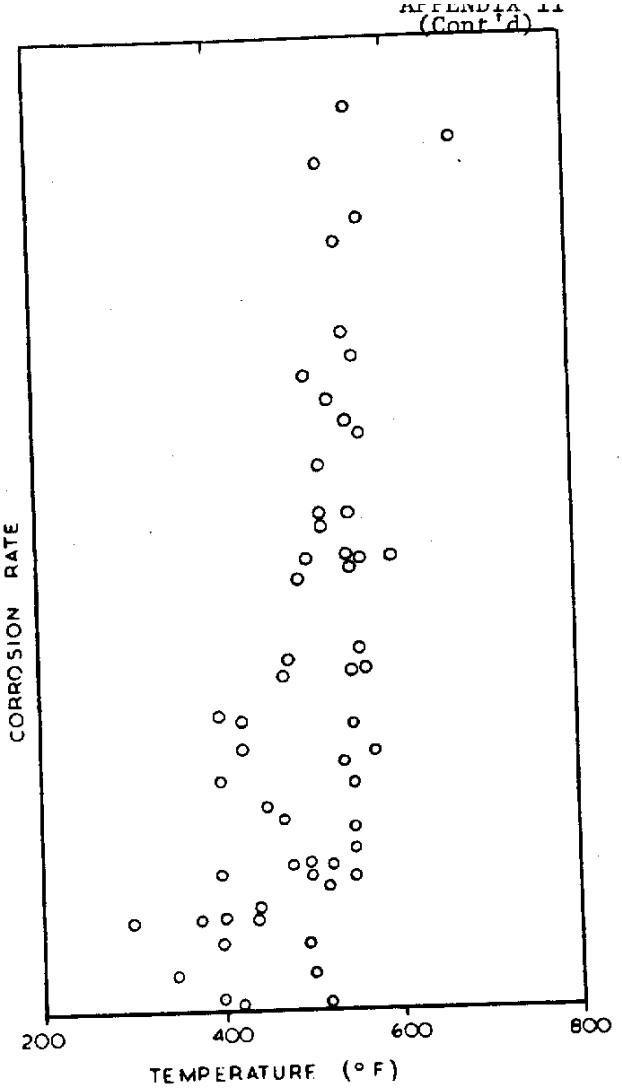


FIGURE 5 — Effect of temperature on corrosion of carbon steel by high temperature sour gas oils.

specific crude with a slightly different temperature break point. The data points plotted are actual metal loss measurement from several refineries processing a specific class of high sulfur crudes. Correlations such as this for different crudes and derived stocks form the basis of design curves used for selection of materials and corrosion allowances in many refineries.

Sulfide corrosion is not amenable to process-oriented control schemes; rather, its solution lies in straightforward materials upgrading. The traditional countermeasure is via use of relatively inexpensive 5Cr-0.5Mo steel, the alloy workhorse of the refining industry. The markedly improved resistance of steels by quite modest additions of chromium is illustrated in Figure 6, a cross plot of an API-sponsored corrosion correlation. The shape of corrosion vs Cr content curves varies from crude to crude, but the general trend applies to most forms of sulfide corrosion. The notable exception is hydrogen sulfide attack which does not respond to alloy content below about 12 to 15% however, serious H_2S corrosion is rarely the predominant corrosion factor in APS units.

Exxon Research and Engineering Company has recently developed a novel technique for predicting corrosivity of sour hydrocarbon streams by means of type and quantity of sulfur compound present. Based on extensive laboratory studies, supplemented by field data, the following type of functional relationships have been established for direct calculation of corrosion rate.

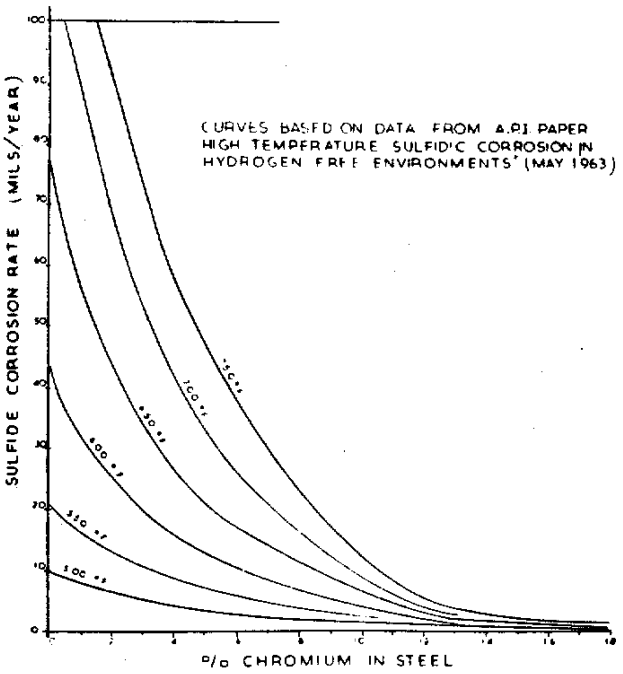


FIGURE 6 – Effect of chromium content in steel on high temperature sulfide corrosion.

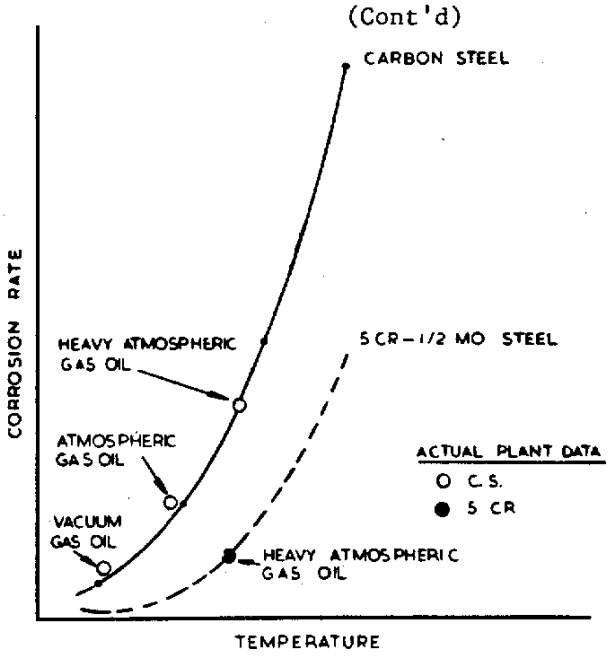


FIGURE 7 – Comparison of measured corrosion rates and calculated corrosion curves for high sulfur gas oil streams.

$$C.R. = f(K_1, K_2, aA, bB, cC, dD, eE)$$

where K_1 and K_2 depend on material, nature of refinery stream (*e.g.*, phase) and flow velocity. Lower case letters, a, b, c, d, and e depend on type of sulfur compound class, temperature and type of steel. The letters A, B, C, D, and E represent the Wt% sulfur compound in the refinery stream, grouped into five classes: H_2S, aliphatic sulfides, elemental sulfur and polysulfides, disulfides and mercaptans. Methods of analysis for the various type of compounds are simple and available.

This technique for estimating elevated temperature corrosivity is proving itself a useful tool not only for design purposes, but also for operation planning and troubleshooting.(1) It is particularly suited for predicting analytically the effect of process and/or feedstock changes on corrosion, which heretofore was left to educated guesswork. Further refinement and verification is proceeding to improve the accuracy of this predictive technique. The results from one such study are presented in Figure 7, showing the exceptionally good agreement between calculated and measured corrosion rates for a particular gas oil from a U.S. crude.

After this brief review of the important forms of corrosion encountered in APS units, we will now examine the principal ways in which corrosion can be controlled by manipulation of process and operating factors, and by additives. Emphasis is placed on the drawbacks and pitfalls of these corrosion control schemes, to serve as a caution and help plant personnel in putting them into effective practice.

Let us briefly characterize the important process oriented corrosion control schemes listed below, recognizing that they are not mutually exclusive. Most refineries employ a combination of these or other measures. Such a multiple tactic approach is common, even in heavily alloyed APS units which rely principally on built-in corrosion resistance.

- Injection of inorganic crude additives, and transformation and neutralization of corrosive chlorides.
- Removal of high percentage of crude salt content by means of chemical or electrical desalters.
- Temperature control in overhead heat exchanger banks to control condensation and corrosion.
- Injection of ammonia into pipestill tower overhead system to neutralize acidic aqueous condensates.
- Injection of organic corrosion inhibitors into pipestill tower overhead system to reduce corrosion and fouling.

Reasonable control of chloride corrosion in the pipestill overhead and in the preheat train can be achieved by injecting sodium hydroxide into the crude feed. Caustic reacts with Ca and Mg chlorides to form NaCl which does not hydrolyze in the pipestill, and which is eliminated via the APS bottom stream. A variant of this crude additive system is used successfully at over 25 Exxon units throughout the world. The chief advantage of this economically attractive system is the elimination of almost all chlorides from the overhead system. This not only suppresses corrosion such that carbon steel equipment gives reasonable life, but also significantly reduces fouling and carryover of chlorides into downstream units.

By this method the level of chloride in the pipestill overhead can be reduced to about 10 to 20 ppm. Worldwide experience indicates that the crude additive system can be successfully employed with crude salt contents of up to about 40 ptb (90 mg/l). The actual amount of caustic required varies for each crude and pipestill, but runs in the range of 2 to 4 times the stoichiometric quantity for conversion of $CaCl_2$ and $MgCl_2$ to NaCl.

The dramatic reduction of overhead chlorides after commencement of caustic injection is illustrated in Figure 8, representing data collected from a pipestill processing undesalted Middle East crude containing about 15 ptb (34 mg/l) salt. Similarly impressive is the favorable effect on overhead condensate pH, with little, if any, need for supplemental injection of ammonia (typical rates range from 0.3 to 0.1 ppm NH_3 on total APS feed). Corrosion rates in carbon steel APS overhead systems employing the crude additive scheme seldom exceed 40 to 50 mpy (1.0 to 1.3 mm/yr). Although quite high, it is considered a tolerable upper limit for carbon steel equipment in this application because of the costliness of resistant alloys.

Desalting of crude feed to APS units is obviously beneficial, but installation of desalters may be difficult to justify on economic grounds solely for corrosion control, especially when a workable additives system can be used. Other benefits of desalting to be credited are reduction of fouling, and removal of water from the

(1) This technology is available for licensing—inquiries should be directed to Exxon Research and Engineering Company, P. O. Box 55, Linden, New Jersey 07036.

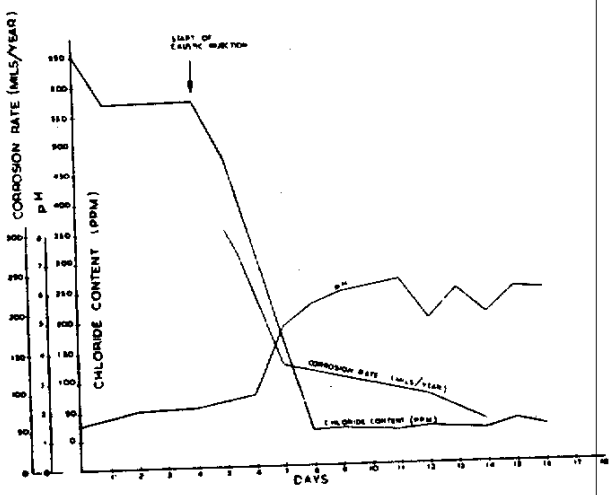


FIGURE 8 — Effect of caustic injection on carbon steel corrosion in APS overhead system.

crude feed. Desalting may be necessary when there is a tight specification on sodium in fuel oil. This factor can also pose a practical constraint on caustic injection since it increases total sodium content.

Corrosion mitigation in the overhead system can be attained to a considerable extent by control of the conditions under which water condensation occurs. Typically, large quantities of water are condensed in the overhead system. In the single drum system, shown in the lefthand box of Figure 1, a stream of naphtha/water is condensed and part of the naphtha returned from the drum to the tower as reflux. This reflux stream is usually cold enough to cause shock condensation of water in the tower top.

With a double drum system, shown in the righthand box of Figure 1, only partial condensation occurs prior to the first drum. Consequently, the condensing temperature can be kept high enough to avoid a free water phase in this drum. In units designed on this "dry" basis, carbon steel can be successfully employed for the primary exchanger bank normally used for partial crude preheat. Our company operates single drum APS units as well as "dry" and "wet" double drum systems. However, all recently built double drum systems are designed to operate with no water accumulation in the first drum.

Shock condensation on the top trays of pipestill towers can be minimized by maintaining the reflux temperature at least 20 F (11 C) above the water dew point of the overhead vapor. This permits the use of ordinary carbon steel rather than costly alloy construction. In practice, such temperature control tends to impose process and operating constraints. Consequently, some refineries prefer instead to control corrosion by means of Monel liners and trays in the very top section of pipestill towers.

Although the bulk temperature of the condensate in the first (reflux) drum in a double drum system may be above the water dewpoint, serious corrosion of exchanger bundles may occur. The explanation is that low tube metal temperatures in the first overheat exchanger cause a water film to condense on the tubes. Initial condensate films are appreciably more acidic than the water phase in the second drum because hydrogen chloride gas dissolves much more readily in hot water than ammonia vapor.

The relatively small amount of local condensate formed by shock condensation is easily revaporized by the warm overhead vapor stream sweeping water droplets off the tubes. Consequently, there is little, if any, water accumulation in the reflux drum. This simple mechanism undoubtedly explains most instances of so-called "dry ammonium chloride" corrosion. Note further that shock condensation can be a similar problem with air coolers, notably during wet and cold weather.

To reduce such attack, tube metal temperatures must be controlled above the water dewpoint. This is accomplished by avoiding the use of cold crude or other low temperature cooling media. Since the first bank overhead condensers usually use crude feed, this in turn necessitates proper location of such exchangers in the crude preheat train. By contrast, corrosion of second bank condensers is insensitive to coolant temperature (usually air or water) since they necessarily operate below the water dewpoint.

Ammonia injection directly into the overhead of the pipestill suffers from the drawback that fouling by NH_4Cl may occur in the tower and overhead exchanger equipment unless sufficient water is present to retain this salt in solution in all parts of the system. In some pipestills, they may require considerable quantities of water and, therefore, can become a significant operating debit. Ammonium chloride is itself corrosive and, moreover, can carry over to downstream units such as naphtha catalytic reformers, causing serious corrosion and possible catalyst degradation. Suppression of chloride evolution by the addition of caustic to the feed reduces these problems by minimizing or eliminating the need for injection of ammonia into the overhead.

Another widely practiced form of overhead corrosion control utilizes organic corrosion inhibitors injected directly into the overhead system. Either filming or neutralizing amines, or a mixture of the two are commonly used. Operating experience indicates that inhibitors are capable of effective corrosion mitigation. Our own studies indicate that their chief drawback is cost, particularly when weighed against the inexpensive chemicals employed with crude additive systems. Also, there have been reports of NH_4Cl fouling of compressors in catalytic reformers downstream of pipestills using neutralizing amines to control overhead corrosion.

On the other hand, inhibitors offer a bonus owing to their detergent effect which decreases solids deposition. This fact is stressed by inhibitor suppliers, claiming that the cost of operating the injection facility should be adjusted for savings through improved heat transfer and greater service factors. While such savings may be realized, their extent will vary from one pipestill to another, and with operational factors such as type of stock, fuel value, cleaning provisions, etc.

An alternative to various process-oriented corrosion preventive measures is by use of special materials for the upper part of the pipestill tower and overhead equipment. The disadvantage of this approach is the very high cost of sophisticated materials required to resist hydrochloric acid. Monel has been used quite extensively over the years, both for internals and linings in the top of APS towers, as well as for overhead exchanger construction. In recent years, use of thin walled titanium tubes is becoming fairly popular for overhead bundles, particularly with salt or brackish water cooling.

Application of costly materials occupies an important place in APS overhead corrosion control but, as will be discussed later, their use is not necessarily a panacea. All of the corrosion preventive schemes highlighted can backfire if carelessly or improperly applied. The remainder of this paper will illustrate some of the problems that have occurred, and show instances of how maloperation can lead to corrosion and materials failures. It is in this area that the role of the operator is vital in complementing that of the materials or corrosion engineer.

For example, although it is relatively simple and effective, injection of caustic for control of chloride corrosion in the overhead system can bring its own problems if the system is improperly designed or operated. Caustic solutions normally used range in concentration from 3 to 12% by weight. Lower concentration causes inconvenience in handling and storing the large amounts involved; higher concentrations may give rise to deposition and plugging of the injection nozzle. Adequate mixing of the caustic is extremely important; without it, hot concentrated caustic may accumulate as a sludge in downstream equipment and cause caustic corrosion and cracking. An illustration of the latter is shown in Figure 9 which depicts caustic embrittlement of a carbon steel crude preheat exchanger shell directly downstream of the injection point.

The caustic solution should always be injected at the cold end of the preheat train to avoid massive concentration due to flashing of water at the injection point. To ensure mixing, caustic is normally injected on the suction side of crude feed or booster pumps. The feed is then preferably put through the tubeside of



FIGURE 9 — Craze cracking of carbon steel shell of crude preheat exchanger downstream of caustic injection point.

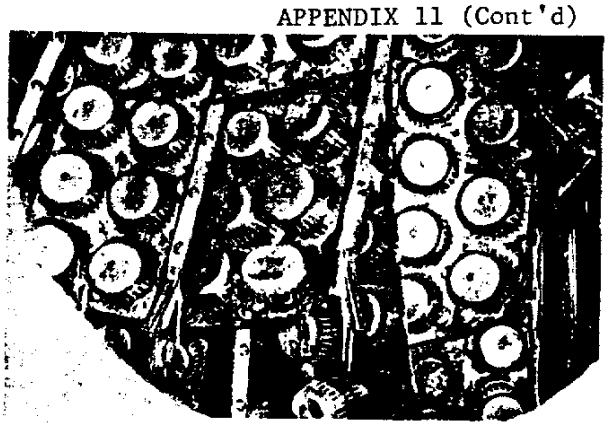


FIGURE 11 — Displacement of trays caused by flashing of water in small pipestill tower.

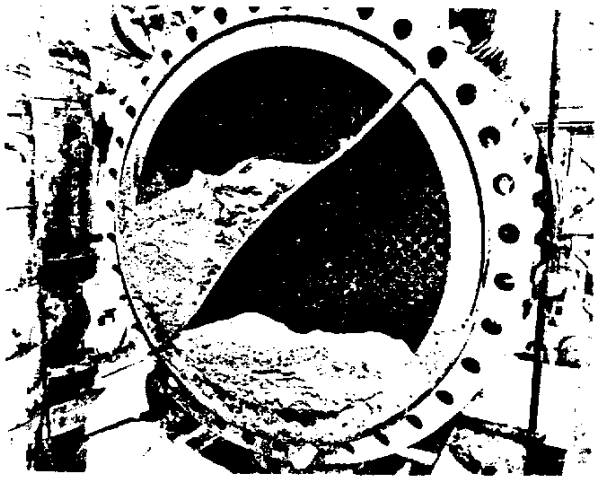


FIGURE 10 — Accumulation of solids on crude side of APS preheat exchanger.

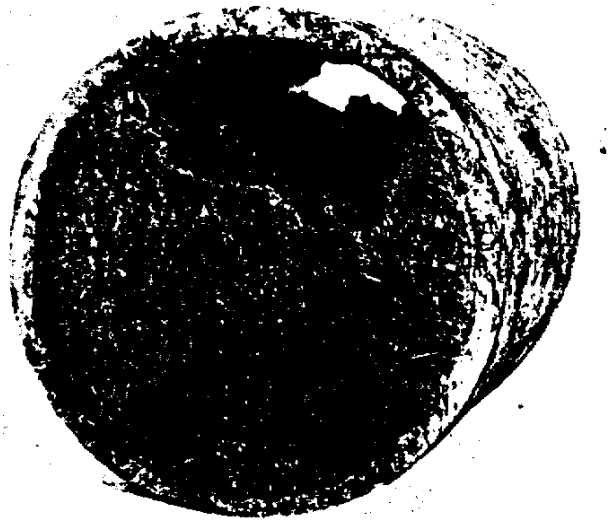


FIGURE 12 — Plugging salt deposits inside tube of APS furnace preheating high salt crude.

preheat exchangers; failure to take these precautions can result in serious corrosion and cracking of the lower tubes by caustic sludge trapped by the tube supports at the bottom of the shell. One refinery lost three bundles in such an exchanger within less than a year, two of them stainless steel.

Over-injection of caustic in an attempt to completely suppress overhead chloride carryover can aggravate fouling. This problem is obviously most severe when high salt content crudes are run in units without desalters. In this connection it should be noted that pipestill preheat train fouling is one of the most troublesome operating problems in refineries, causing decreased heat transfer, increased pressure drop and sometimes complete blockages. Fouling deposits arise not only from inorganic sources (*e.g.*, salts in crude, neutralizing additives, desalter water injection) but also from organic compounds (*e.g.*, polymers, waxes). Enormous quantities of solids can find their way into pipestill feed trains, as shown in Figure 10.

This picture is of double interest, because the mechanical damage to the exchanger illustrates yet another problem which may arise from poor design or maloperation, in this case the introduction of excessive amounts of water with the crude feed. The deformed channel partition plate resulted from flashing of water slugs in a tubular exchanger preheating cold crude with a hot oil stream. Sudden release of large quantities of water vapor also does serious damage in distillation columns, as illustrated in Figure 11 depicting a small atmospheric pipestill tower. Excessive water ingress into APS feed streams may occur through inadequate settling in crude tankage or from overflow of desalter brine.

Another consequence of over-injection of caustic or of processing high salt crudes may be coking and consequent overheating of APS furnace tubes. Deposits of sodium salts are doubly harmful because in addition to their direct role in hot spot formation, they appear to catalyze coking. At one location, processing of a crude containing about 100 ptb (230 mg/l) of salt resulted in massive solids deposition in furnace tubes leading to consequent overheating and eventual tube ruptures. As illustrated in Figure 12, nearly the entire flow cross section was blocked with material which analysis confirmed to be largely NaCl. This represents an instance where an otherwise effective corrosion control system was extended well beyond its limits due to the exceptionally high salt content of the crude.

Returning now to APS overhead corrosion prevention, let us examine the proper control parameters, and illustrate what can happen if these get out of hand due to careless operation, or equipment malfunction.

For each unit there is an optimum pH for minimizing overhead corrosion. At low pH values, the predominant mode of attack is chloride corrosion. Above the neutral point, there is progressive danger of sulfide corrosion by dissolved H_2S. Over-injection of ammonia can moreover give rise to NH_4Cl fouling unless chloride levels are low. The optimum pH depends not only on the nature and amounts of corrosive agents but also upon what constructional

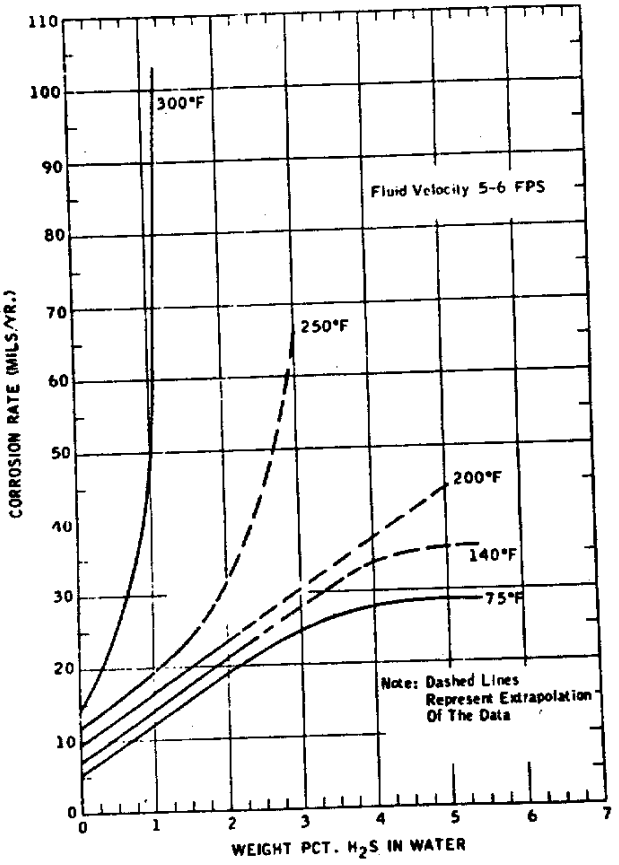


FIGURE 13 — Laboratory corrosion test data for carbon steel in sour water containing dissolved H_2S and NH_3.

materials are employed in the overhead circuit. Copper base alloys will generally withstand acidic pH conditions better than carbon steel, but are especially prone to rapid attack above pH 9.0 due to complexing with excess ammonia. On the other hand, carbon steel performs better at neutral or alkaline conditions than in the acidic range. General experience in systems shown the optimum pH to be in the area of 6.0 to 6.5.

Contrary to common belief, high pH levels can also be quite damaging to carbon steel when large quantities of sulfides are present, as explained by the following considerations. Under neutral or slightly alkaline conditions, the solubility of H_2S is quite low, usually well below 100 ppm. However, with increasing ammonia above the neutral point, solubility of H_2S increases dramatically due to the solubilizing effect of ammonia. There is rapid mass transfer of dissolved sulfides from the voluminous hydrocarbon phase into the much smaller amount of aqueous phase. This extraction mechanism plus the increasing ionization of dissolved sulfides can result in appreciable concentrations of aggressive NH_4HS and $(NH_4)_2S$ in pipestill overhead condensates, appropriately called sour water.

As shown by the lab corrosion test results reproduced in Figure 13, sour water corrosion is sharply dependent on the amount of dissolved sulfide, notably at higher temperatures. Rates of attack are far higher than experienced in pure H_2S/H_2O system. Refinery experience indicates that aggressiveness of sour waters high in NH_3/H_2S is very sensitive to velocity. In Pipestill units, such attack is likely to be encountered at areas of turbulence in overhead condensate, particularly in sour water draw-off systems. Pump impellers are a prime site for such erosion-corrosion, as illustrated in Figure 14. This particular pump was handling virgin naphtha containing entrained sour water due to inadequate settling in the APS overhead drum. The attack mechanism appears to be associated with the formation of a semi-protective sulfide scale which is



FIGURE 14 — Corrosion-erosion of carbon steel pump impeller by sour water contaminated naphtha in APS overhead system.



FIGURE 15 — Small hydrogen blisters in heat of APS overhead drum—note pressure gauge screwed into manhole reinforcing pad.

damaged or completely destroyed by swiftly flowing liquid, similar to high temperature sulfide corrosion.

Below pH 7.0, there is growing tendency for increased hydrogen activity which, in isolated instances, has given rise to hydrogen blistering. Indications are that this will happen only in equipment where badly laminated plate or piping has been employed. One such instance is illustrated in Figure 15, showing an APS overhead drum with more than 100 blisters in one of its heads. Fortunately, they are quite small and as such are not considered a significant safety hazard. In this instance, blister formation and growth was adequately suppressed by means of pH adjustment. The inverse relationship between hydrogen activity and pH is illustrated in Figure 16. Pressure buildup was monitored by a Bourdon gauge

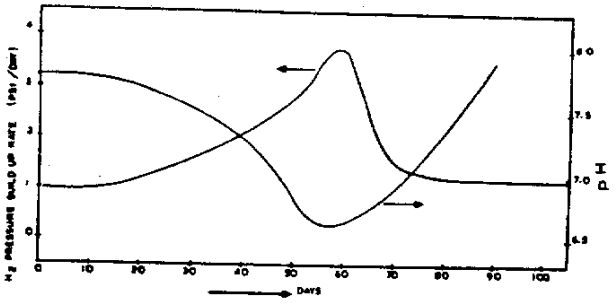


FIGURE 16 – Effect of pipestill overhead condensate pH on hydrogen blistering activity.



FIGURE 18 – Process side pitting of ferritic-austenitic alloy steel (A-699) tube in APS overhead condenser.



FIGURE 17 – Chloride stress corrosion cracking of austenitic stainless steel thermowell in crude preheat circuit.

screwed into and extending through the manhole reinforcing pad. This technique or direct drilling into shell blisters is not advocated in high pressure service. In such equipment one employs standard hollow-tube hydrogen probes to avoid unnecessary risks. The pH range recommended earlier (6.0 to 6.5) is that observed to give the best control of corrosion in the overhead system, rather than control of blistering which is a problem only is a few cases. One cannot normally operate a pipestill to control hydrogen blistering.

A prevalent attitude encountered in corrosion problem solving is to "alloy up", on the misconception that expensive metals such as stainless steels must necessarily be better. This is not always true, and can in fact create greater problems than the one intended to be solved. A fairly obvious example is the use, or rather misuse, of 18Cr-8Ni stainless steels in wet chloride environments encountered in APS units. As mentioned earlier, stainless steel crude preheat exchanger bundles are subject to rapid failure. Against these failures one must weigh the generally good experience with 18/8 valve trim and thermowells in this service. However, under exceptionally severe conditions even these components can fail rapidly. This is illustrated in Figure 17, which is a micrograph of a classic transgranular chloride stress corrosion cracking failure that occurred within a week or two of startup. Significantly, the failed part is a thermowell, which demonstrates that even lightly stressed components are susceptible.

The specification of costly alloy materials for APS overhead bundles does not necessarily guarantee satisfactory corrosion behavior and service life. Monel has been successfully used for many years, notwithstanding occasional corrosion problems. Its chief drawback is high cost, which has risen disproportionately relative to other candidate materials. Some refineries have installed experimental bundles of semi-austenitic stainless alloy compositions specially developed for resistance to chloride attack. Success with such proprietary alloys has been mixed. Figure 18 shows pitting attack experienced on duplex phase alloy (ASTM A-669) tubes. In another refinery similar tubes failed in 50 days by chloride stress corrosion cracking initiating at surface flaws. There are, of course, many installations where specialty alloys are serving well. Our intent is not to discredit them, but to emphasize that they all have limitations.

Titanium tubes are excellent in APS overhead service, but problems can develop due to the low wall thickness normally specified in the interest of cost saving. Although 20 BWG [0.035 inch (0.89 mm)] or even 22 BWG [0.028 inch (0.71 mm)] tubes are satisfactory from the corrosion point of view, extreme care is required in handling and assembling to avoid mechanical damage. Also, bundles utilizing thin gauge tube thicknesses require careful design since the low stiffness of the tubes makes them prone to vibration and consequent fatigue failure. This can be overcome by close spacing of baffles, an important factor to be considered when retubing steel or brass exchangers with titanium. Galvanic corrosion does not appear to be a problem when titanium tubes are rolled into existing copper alloy tube sheets; nevertheless, titanium-faced tube sheets are recommended for new construction.

As a final example, we have selected an unexpected corrosion problem recently encountered in an APS overhead airfin condenser. Figure 19 shows severe metal wastage [over 1 inch/year (25 mm/hr)] from a carbon steel plug in the outlet header box, which had been relatively unaffected over several years' operation. Corrosion of this and neighboring plugs occurred suddenly when several corroded carbon steel tubes were replaced with corrosion resistant alloys. Only the plugs opposite the new tubes were similarly affected. The direct cause was impingement attack

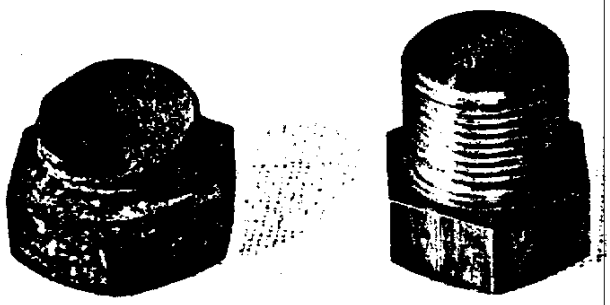


FIGURE 19 — Impingement corrosion of carbon steel plug from outlet header box of APS overhead airfin condenser.

resulting from greatly increased flow velocity through the larger bore, smoother surface alloy tubes. This trivial incident stands as yet another reminder of the complexities encountered in corrosion engineering.

Summary

In summary, this paper has briefly reviewed corrosion manifestations in APS units and highlighted the many different approaches to corrosion mitigation. Effective corrosion control requires selective and judicious application of all available methods. Our intension was to concentrate more on the process/operating oriented methods rather than on mechanical design and materials selection. Cited in illustration is the application of a simple and inexpensive crude additive system in refineries which permits extensive use of ordinary carbon steel equipment. Its success is largely credited to conscientious implementation and monitoring by trained refinery operating staff.

MATERIAL SELECTION PROBLEM

A) FEED: T: P:
- 1.2% WT S. 650°F 850 Psi.
- 1.9 % H_2S
- 63% H_2

$P_{H_2} = 0.63 \times (850 + 15)$
$= 545$ psiA. 700°F

1° NELSON CHART 545 psiA ≠ ~~650~~ °F 0.5 Mo.
1-¼Cr - ½ Mo STEEL.

2° 1.2 % W S. → 1¼ Cr. = 60 MPY NO
5 Cr = 31.61 MPY OK
0-5 Cr 9 Cr.

3° 1.9 % H_2S 16. MPY. 12 MPY

CRITICAL SERVICE
⇒ TP 321 or TP 347 1/16" C.A. 9Cr 1/8"

B) 1.2 % W S T = 731 P = 300
1.9 % H_2S
63% H_2.

1° $P_{H_2} = 0.63 \times (800 + 15) = 513.5$ psiA.
1.Cr - 0.5 Mo.

2° 1.2 % W S. EN PARTE DESCENDENTE SUMA AL MASIMO

3° 1.9 H_2S ≈ 40 MPY (0-5) / 19 MPY (9 Cr.) 9Cr 3/16"
CRITICAL SERVICE
→ TP 321 OR TP 347 3/16.

C) T 800 °C P = 800 PSIG.

% S
% 3.7 H_2S
% 55 H_2.
$P_{H_2} = 0.55 \times 815 = 448$r

1 Cr ½ Mo. 9 Cr.
3.7 % H_2S. ≈ 55 MPY a 800 ≈ 24 MPY
9Cr 1/16"

Reactor

HYDROG RESISTANCE

513 psi @ Hr 850°F

1 Cr - 1/2 Mo.

Dr LINING. TP 321.