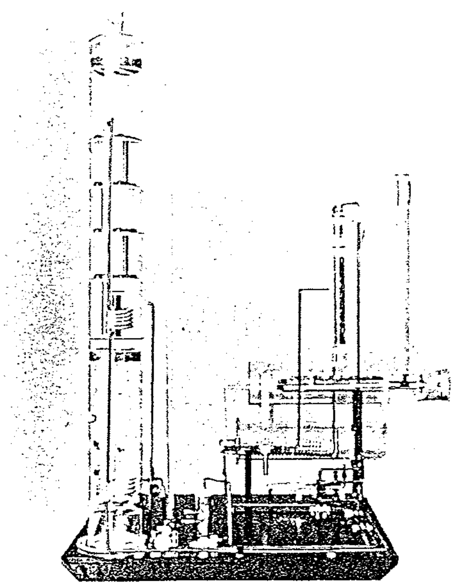
CESSCO
ENGINEERING DATA SECTION

The data in this section is recommended for general sizing and application of CESSCO equipment. For critical applications and conditions not covered herein, please consult CESSCO.



PROCESS EQUIPMENT DIVISION:

CONTENTS

SEPARATOR SIZING

SIZING FOR GAS CAPACITY

Separator gas capacity depends on the operating pressure, gas gravity, temperature, and density of the liquid particles. The following charts predict separator gas capacities based on (a) liquid particles in the gas stream being 10 micron or larger; (b) temperature above the oil cloud point and the hydrate temperature; (c) non-heading flow; (d) non-foaming oil.

Method:

1. determine gas density, from Fig. 1, 2 or 3.
2. determine Area Factor "A", from Fig. 4, 5, or 6.
3. divide the flow rate (in MM/day) by "A", to determine required Size Coefficient "S".
4. choose a separator from Table 1 with Size Factor at least equal to that required. (Be sure the separator meets the required liquid capacity.)

Example:

Choose a 1200 psi w.p. separator to handle 10 MMSCFD of 0.70 sp. gas at 80° F and 900 psig . The oil gravity is 50° API.

Solution:

Fig 2 shows the gas density is 3.9#/Ft³. Fig. 5 shows an Area Factor of 7.8. Dividing 10 MM/day by 7.8 gives 1.28 as the required Size Coefficient "S" Table 1 shows that, for 1200 psi w.p., a 20" x 7½' horizontal, or a 30" x 5' vertical, are the smallest applicable.

(The maximum capacity of a 20"x7½' horizontal 1200 #w.p. separator under the above conditions is found by multiplying "S" from Table 1 by "A" = 1.51 x 7.8 = 11.8 MMSCFD.)

Sizing for Oil Capacity

Oil capacities in Table 2 are for two-phase separators, and are based on approximately 1 minute retention time with the liquid height one-third of the diameter, and (a) valve and line of sufficient size to discharge the oil properly; (b) non-foaming oil; (c) temperature above the oil cloud point; (d) non-heading oil flow.

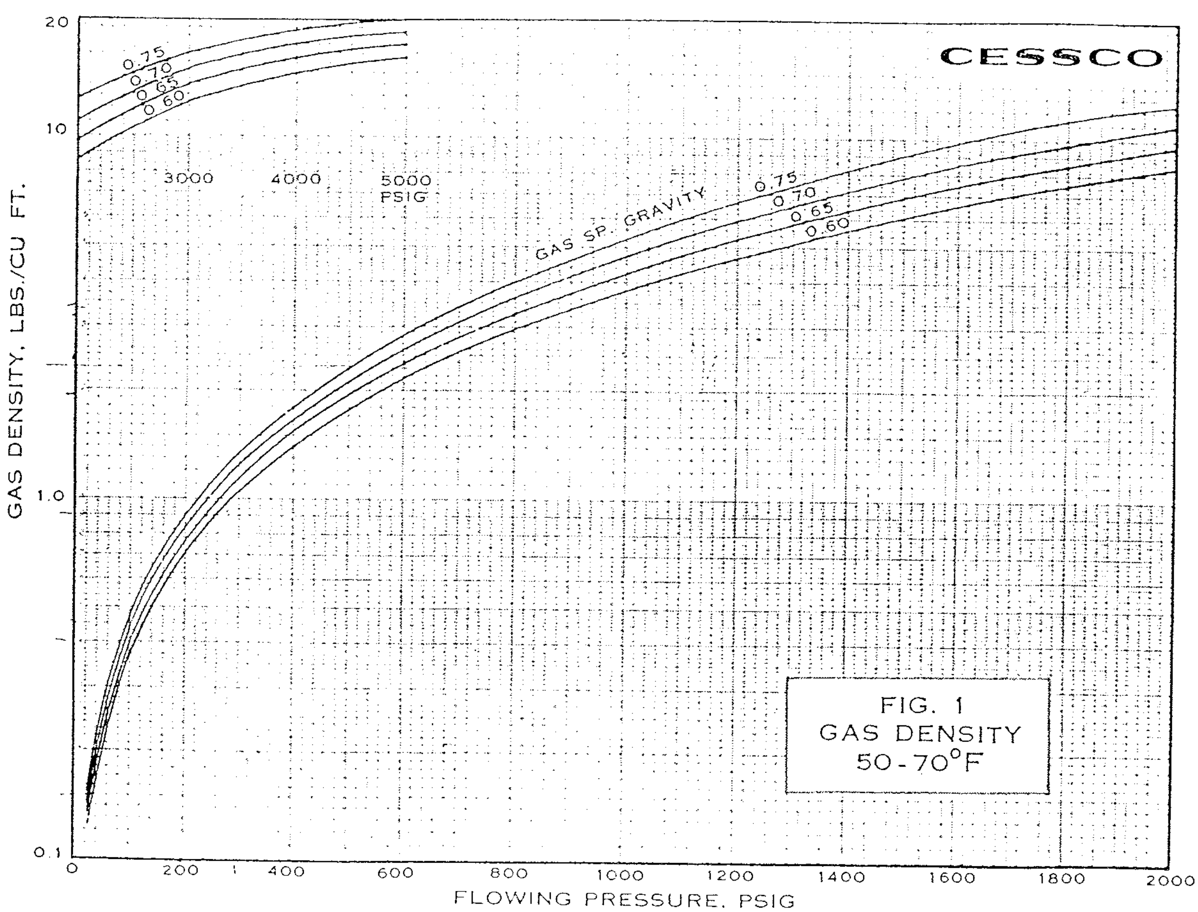


FIG. 1
GAS DENSITY
50-70°F

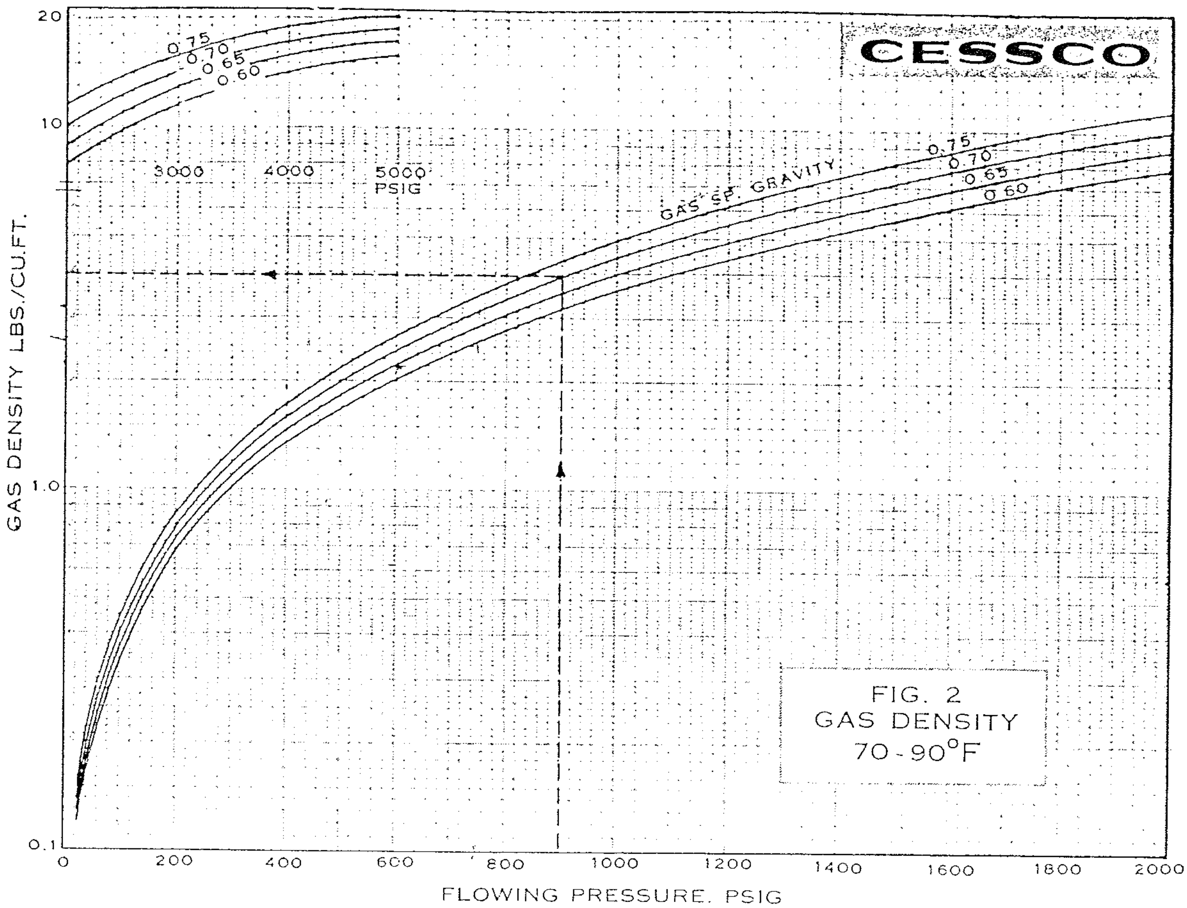


FIG. 2
GAS DENSITY
70-90°F

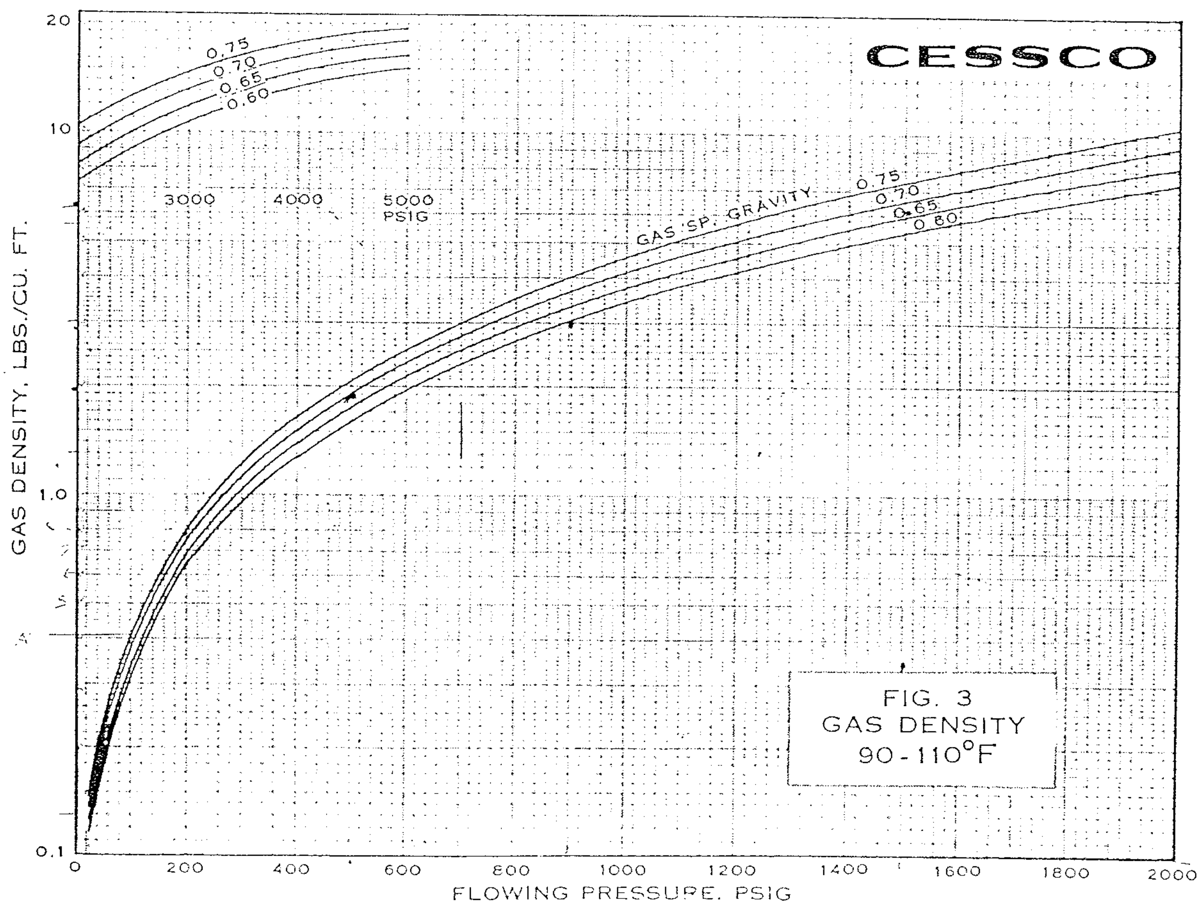


FIG. 3
GAS DENSITY
90-110°F

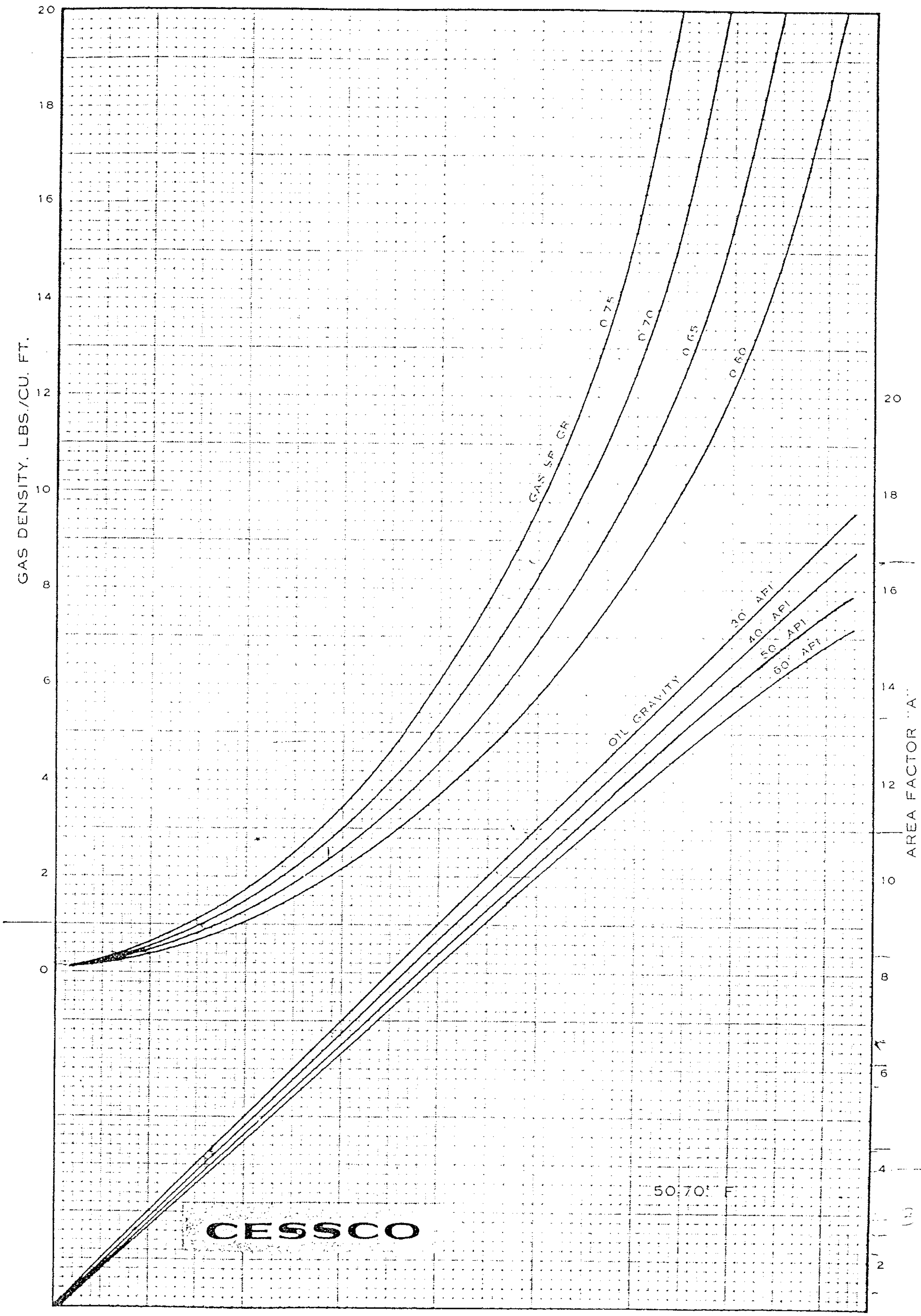


FIG. 4 SEPARATOR AREA FACTOR "A", 50-70° F GAS TEMPERATURE

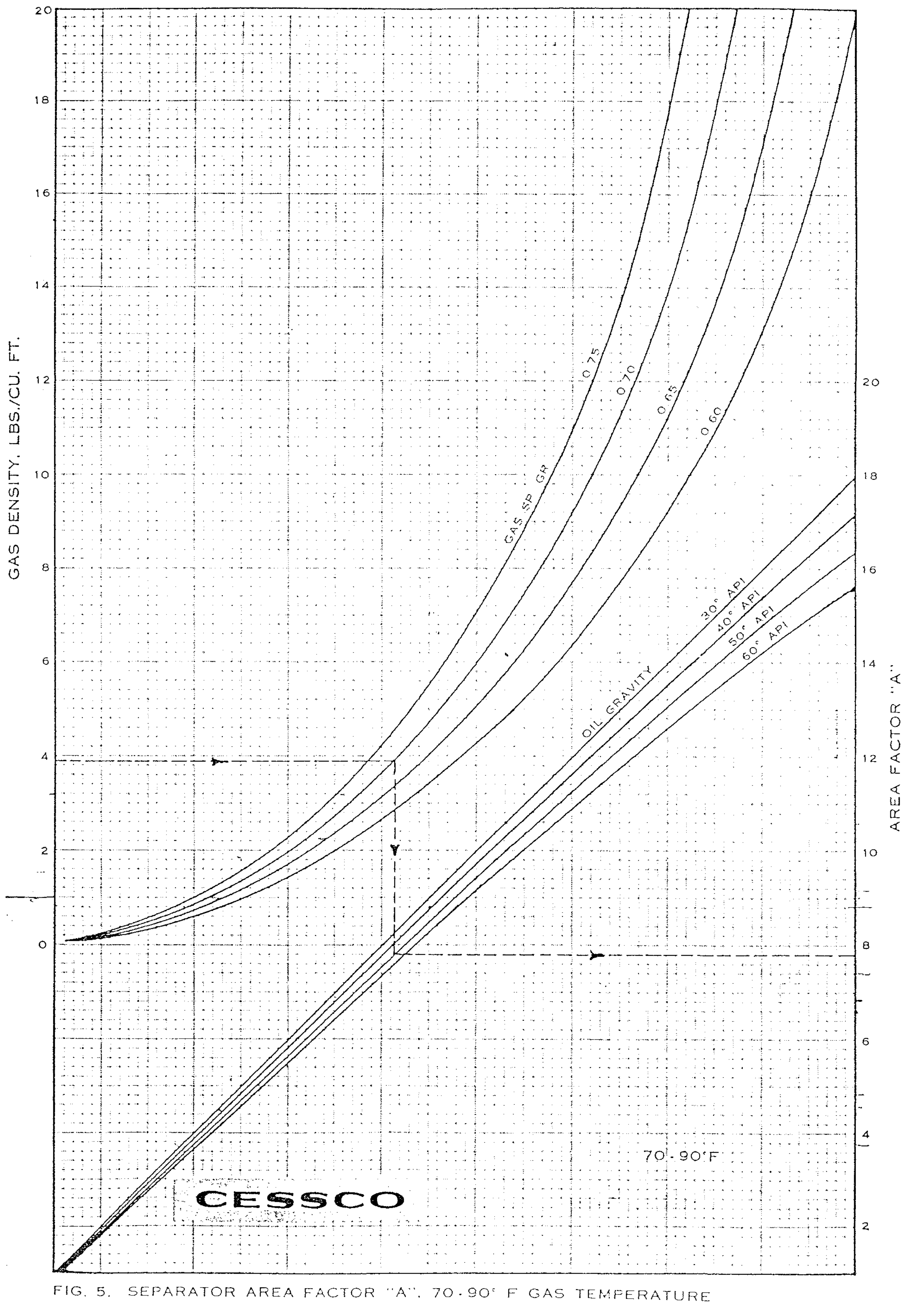


FIG. 5. SEPARATOR AREA FACTOR "A", 70-90° F GAS TEMPERATURE

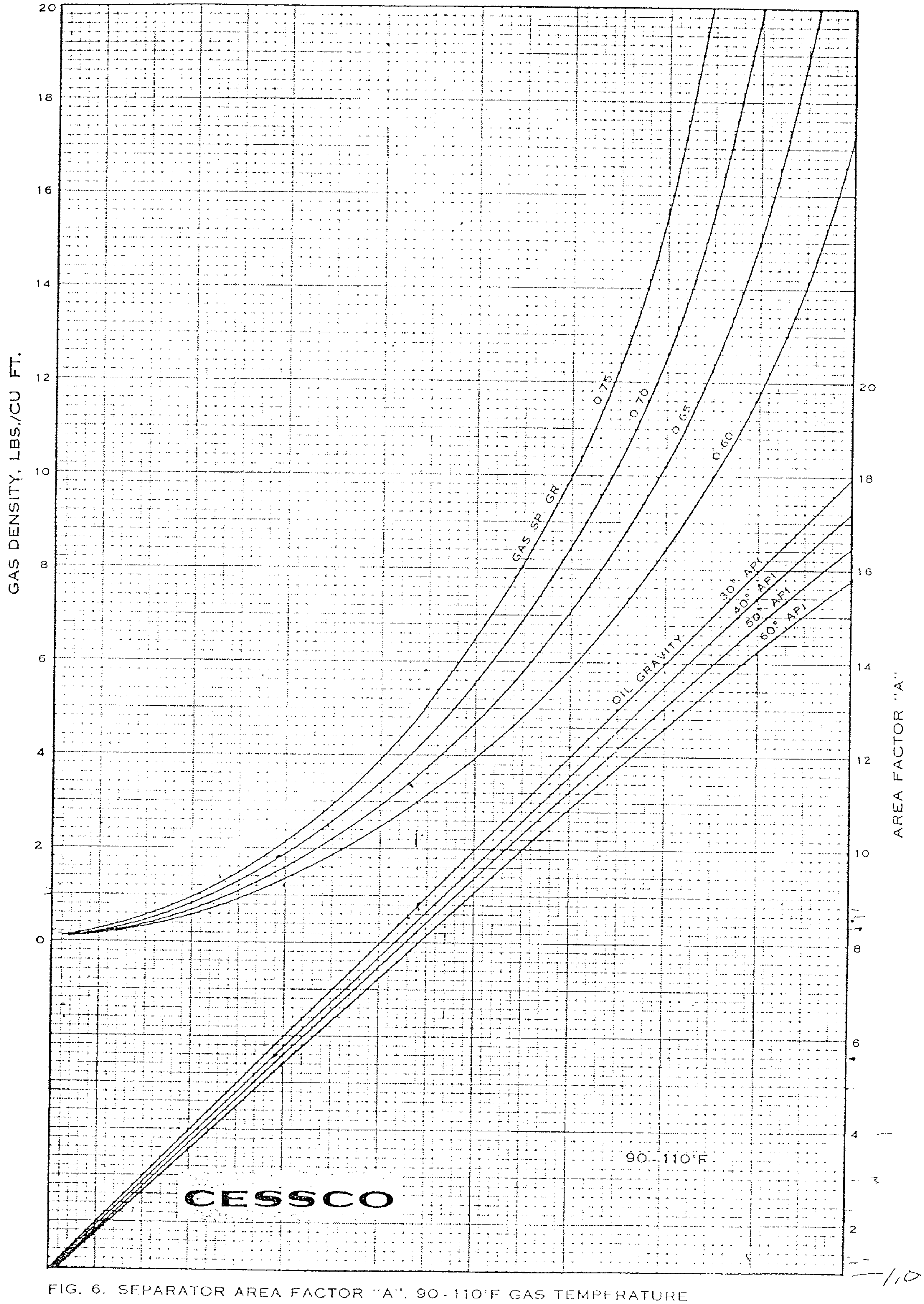


FIG. 6. SEPARATOR AREA FACTOR "A". 90-110°F GAS TEMPERATURE

TABLE 1. SIZE COEFFICIENT "S" FOR SEPARATORS

HORIZONTAL SEPARATORS O.D. x Length	VESSEL WORKING PRESSURE 125 PSI	230 PSI	500 PSI	600 PSI	1000 PSI	1200 PSI	1440 PSI	1500 PSI	2000 PSI	3000 PSI	3500 PSI
12¾" x 5'	......	0.43	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.38	0.37
x 7½'	......	0.52	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.46	0.45
x 10'	......	0.60	0.57	0.57	0.56	0.56	0.56	0.56	0.56	0.53	0.52
5'	0.47	0.65	0.58	0.57	0.76	0.79	0.91	0.91	0.70	0.62	0.60
x 7½'	0.57	0.80	0.71	0.70	0.93	0.97	1.11	1.11	0.85	0.76	0.73
x 10'	0.66	0.92	0.82	0.81	1.07	1.12	1.28	1.28	0.98	0.88	0.84
20" x 5'	0.73	1.13	1.30	1.20	1.23	1.23	1.18	1.18	.93	1.07	1.04
x 7½'	0.89	1.39	1.58	1.47	1.51	1.51	1.44	1.45	1.13	1.32	1.27
x 10'	1.03	1.60	1.83	1.70	1.74	1.74	1.66	1.67	1.31	1.52	1.47
x 15'	1.26	1.96	2.18	2.01	1.91	2.12	2.03	2.05	1.61	1.86	1.80
24" x 5'	1.06	1.92	1.78	1.64	1.56	1.73	1.70	1.73	1.70	1.59	1.58
x 7½'	1.30	2.35	2.18	2.00	1.91	2.11	2.08	2.12	2.08	1.95	1.94
x 10'	1.50	2.71	2.52	2.31	2.21	2.44	2.40	2.45	2.40	2.25	2.24
x 15'	1.84	3.32	3.09	2.83	2.71	2.99	2.94	3.00	2.94	2.76	2.75
x 20'	2.12	3.83	3.56	3.27	3.13	3.45	3.39	3.47	3.39	3.18	3.17
30" x 5'	1.93	2.99	2.97	2.83	2.63	2.63	2.58	2.67	2.38	2.16	2.14
x 7½'	2.36	3.66	3.64	3.46	3.22	3.21	3.16	3.26	2.91	2.64	2.62
x 10'	2.73	4.23	4.20	4.00	3.72	3.71	3.65	3.77	3.36	3.05	3.02
x 15'	3.35	5.18	5.15	4.90	4.56	4.55	4.47	4.62	4.12	3.74	3.70
x 20'	3.86	5.98	5.94	5.66	5.26	5.25	5.16	5.33	4.75	4.31	4.27
36" x 7½'	4.43	5.60	5.67	5.33	4.63	4.69	4.66	4.74	4.62	3.27	3.22
x 10'	5.12	6.47	6.55	6.15	5.35	5.41	5.38	5.47	5.33	3.77	3.72
x 15'	6.27	7.93	8.02	7.54	6.56	6.63	6.59	6.70	6.53	4.62	4.56
x 20'	7.24	9.15	9.26	8.70	7.56	7.65	7.61	7.74	7.54	5.33	5.26
42" x 10'	7.65	9.20	9.08	8.62	7.79	7.96	7.88	8.02	7.87	4.93	4.91
x 15'	9.37	11.3	11.1	10.6	9.54	9.75	9.65	9.82	9.64	6.04	6.02
x 20'	10.8	13.0	12.8	12.2	11.0	11.3	11.1	11.3	11.1	6.97	6.94
48" x 10'	8.50	11.7	11.9	11.4	10.6	10.7	10.5	10.7	10.5	6.17	6.11
x 15'	10.4	14.3	14.6	14.0	13.0	13.1	12.9	13.1	12.9	7.56	7.49
x 20'	12.0	16.5	16.8	16.1	15.0	15.1	14.9	15.1	14.9	8.72	8.64
54" x 10'	10.7	14.0	13.8	13.6	11.3	11.2	11.0	11.1	.....	.....	.....
x 15'	13.1	17.2	16.9	16.7	13.8	13.7	13.5	13.6	.....	.....	.....
x 20'	15.1	19.8	19.5	19.2	16.0	15.8	15.6	15.7	.....	.....	.....
60" x 10'	11.6*	14.7	16.7	16.0	13.8	14.1	13.8	14.0	.....	.....	.....
x 15'	14.2*	18.0	20.5	19.6	16.9	17.3	16.9	17.2	.....	.....	.....
x 20'	16.4*	20.8	23.6	22.6	19.5	19.9	19.5	19.8	.....	.....	.....
66" x 10'	16.2	17.9	18.8	18.1	17.0	16.9	17.5	17.8	.....	.....	.....
x 15'	19.8	21.9	23.1	22.2	20.8	20.7	21.4	21.8	.....	.....	.....
x 20'	22.9	25.3	26.6	25.6	24.0	23.9	24.8	25.2	.....	.....	.....
72" x 10'	19.1	21.4	22.5	21.7	20.1	20.6	20.1	20.5	.....	.....	.....
x 15'	23.4	26.2	27.6	26.6	24.6	25.2	24.6	25.1	.....	.....	.....
x 20'	27.0	30.3	31.8	30.7	28.4	29.1	28.4	29.0	.....	.....	.....
15'	34.0	45.0	32.3	31.2	29.1	29.8	29.0	29.7	.....	.....	.....
20'	39.2	51.9	37.3	36.0	33.6	34.4	33.5	34.3	.....	.....	.....

* @ 100 psig.

VERTICAL

VERTICAL SEPARATORS O.D. x Height	VESSEL WORKING PRESSURE 125 PSI	230 PSI	500 PSI	600 PSI	1000 PSI	1200 PSI	1440 PSI	1500 PSI	2000 PSI	3000 PSI	3500 PSI
12¾" x 5'	......	.348	.353	.369	.349	.340	.327	.327	.310	.295	.290
x 7½'	......	.348	.353	.369	.349	.340	.327	.327	.310	.295	.290
x 10'	......	.348	.353	.369	.349	.340	.327	.327	.310	.295	.290
16" x 5'	......	.572	.588	.585	.535	.541	.510	.519	.508	.493	.490
x 7½'	......	.572	.588	.585	.535	.541	.510	.519	.508	.493	.490
x 10'	......	.572	.588	.585	.535	.541	.510	.519	.508	.493	.490
20" x 5'	0.89	.945	.920	.923	.837	.839	.808	.830	.795	.798	.810
x 7½'	0.89	.970	.971	.923	.837	.839	.808	.830	.795	.798	.810
x 10'	0.89	1.02	1.06	.923	.837	.839	.808	.830	.795	.798	.810
24" x 5'	1.19	.995	.960	.965	.872	.870	.923	.943	.820	.803	.812
x 7½'	1.19	1.22	1.16	1.14	1.10	1.08	1.13	1.13	.984	.943	.982
x 10'	1.19	1.44	1.40	1.31	1.28	1.24	1.35	1.35	1.15	1.09	1.12
30" x 5'	1.43	1.52	1.45	1.54	1.40	1.38	1.25	1.32	1.23	1.09	1.12
x 7½'	2.01	1.89	1.75	1.69	1.74	1.70	1.54	1.60	1.48	1.38	1.33
x 10'	2.29	2.21	2.15	1.99	1.98	1.91	1.83	1.89	1.72	1.60	1.54
36" x 7½'	2.73	2.66	2.69	2.62	2.25	2.23	2.40	2.45	2.38	1.74	1.74
x 10'	3.21	3.23	3.15	2.92	2.67	2.65	2.69	2.83	2.71	2.03	2.03
x 15'	3.75	3.81	3.25	3.10	2.90	3.04	2.98	3.10	2.95	2.54	2.54
42" x 7½'	3.30	3.73	3.55	3.38	3.30	3.29	3.27	3.30	.....	.....	.....
x 10'	4.51	4.75	4.30	4.00	3.90	3.82	3.75	3.77	.....	.....	.....
x 15'	5.29	5.70	5.00	4.30	4.20	4.35	4.13	4.15	.....	.....	.....
48" x 7½'	4.63	4.73	4.80	4.62	4.42	4.35	4.33	4.43	.....	.....	.....
x 10'	5.46	5.52	5.60	5.38	5.12	5.10	5.00	5.00	.....	.....	.....
x 15'	6.42	6.02	6.00	5.85	5.58	5.60	5.50	5.50	.....	.....	.....
x 20'	7.06	6.62	6.60	6.43	6.14	6.16	6.05	6.05	.....	.....	.....
54" x 10'	6.14	5.72	5.80	5.54	5.33	5.31	5.29	5.38	.....	.....	.....
x 15'	7.51	6.97	6.90	6.77	6.59	6.58	6.54	6.70	.....	.....	.....
x 20'	8.63	7.67	7.60	7.45	7.25	7.24	7.19	7.37	.....	.....	.....
60" x 10'	7.17*	7.21	7.20	6.92	6.59	6.58	6.44	6.60	.....	.....	.....
x 15'	8.87*	8.80	8.81	8.31	8.15	8.15	7.98	8.02	.....	.....	.....
x 20'	10.2*	9.15	9.40	9.14	9.41	9.34	8.85	9.15	.....	.....	.....
66" x 10'	8.5	8.46	8.55	8.31	8.15	8.15	8.08	8.21	.....	.....	.....
x 15'	10.7	10.5	10.6	10.2	9.98	9.98	9.90	10.1	.....	.....	.....
x 20'	11.7	11.6	11.6	11.2	11.0	11.0	10.9	11.1	.....	.....	.....
10'	10.6	10.2	10.4	10.0	9.65	9.55	9.62	9.81			
15'	13.0	12.7	12.9	12.3	11.9	11.7	11.7	12.0			
20'	14.9	14.0	14.2	13.5	13.1	12.9	12.9	13.2			
x 15'	16.5*	14.7	15.3	14.3	14.1	14.1	14.1	14.4			
x 20'	18.0*	16.9	17.5	16.5	16.4	16.4	16.3	16.7			

* @ 100 psig.

TABLE 2. SEPARATOR LIQUID CAPACITIES, BPD
(TWO PHASE OPERATION)
(BASED ON 1 MIN. RETENTION TIME)

O.D. x LENGTH	VERTICAL (All W.P.)	HORIZONTAL* 125 PSI W.P.	HORIZONTAL* 230 PSI W.P.	HORIZONTAL* 500, 600 PSI W.P.	HORIZONTAL* 1000 Thru 2000 PSI W.P.	HORIZONTAL* 3000, 3500 PSI W.P.
12¾″ x 5′	100	......	350	360	360	240
x 7½′	115	......	520	540	540	360
x 10′	115	......	700	720	720	480
16″ x 5′	250	500	400	450	450	320
x 7½′	275	750	650	675	675	480
x 10′	275	1000	850	900	900	640
20″ x 5′	500	750	650	690	600	460
x 7½′	575	1130	970	1000	900	690
x 10′	575	1500	1300	1400	1200	920
x 15′	......	2250	1950	2100	1800	1380
24″ x 5′	600	1090	750	750	700	550
x 7½′	850	1630	1100	1100	1050	825
x 10′	1200	2180	1500	1500	1450	1100
x 15′	......	3270	2250	2250	2100	1650
x 20′	......	4350	3000	3000	2800	2200
30″ x 5′	750	1690	1150	1000	1100	700
x 7½′	1250	2540	1600	1600	1600	1050
x 10′	1800	3380	2100	2100	2200	1400
x 15′	......	5070	3200	3200	3200	2100
x 20′	......	6740	4500	4500	4400	2800
36″ x 7½′	1900	3670	3280	3100	2000	1350
x 10′	2700	4920	4360	4200	2600	1800
x 15′	3100	7380	6560	6200	4000	2700
x 20′	......	9800	8700	8400	5200	3600
42″ x 7½′	3200	......	......	......	......	......
x 10′	4500	6660	5520	5400	4200	2400
x 15′	5200	9990	8140	8100	6300	3600
x 20′	......	13,300	10,800	10,800	8400	4800
48″ x 7½′	4800	......	......	......	......	......
x 10′	6900	8720	7200	7200	5300	3000
x 15′	7900	13,500	10,800	10,800	8000	4500
x 20′	9100	18,000	14,500	14,400	10,600	6000
54″ x 10′	7500	11,000	9800	9800	6900	......
x 15′	10,000	16,500	14,700	14,700	10,300	......
x 20′	11,500	22,000	19,600	19,600	13,800	......
60″ x 10′	8400	13,600	11,900	11,400	8700	......
x 15′	14,000	20,400	17,900	17,000	13,000	......
x 20′	16,000	27,200	23,800	22,800	17,300	......
66″ x 10′	11,400	16,000	14,400	13,700	10,900	......
x 15′	19,000	24,000	21,600	20,600	16,400	......
x 20′	21,800	32,200	28,800	27,400	21,900	......
72″ x 10′	15,000	19,800	17,100	16,300	12,800	......
x 15′	25,000	29,700	25,700	24,400	20,000	......
x 20′	28,800	39,600	34,200	32,600	25,700	......
84″ x 15′	28,000	40,000	35,000	33,200	27,000	......
x 20′	40,000	53,000	47,000	44,500	36,000	......

Capacities based on 1 min. retention time. *For other retention times,* decrease or increase capacities proportionately. (Example: for 2 min. retention time, *divide* above capacity by 2.0).

* Capacities for horizontal separators are for approximately ⅓ (of I.D.) liquid height. *For other liquid heights* (available on special application), multiply above liquid capacity by Factor "L" and regular gas capacity by Factor "G":

Liquid Height	Factor "L"	Factor "G"
¼ I.D.	0.70	1.14
½ I.D.	1.70	0.70

HEATER SIZING FOR GAS

The amount of heat input required to produce given temperature rise in a gas stream is calculated by the formula

$Q = W \times \Delta t \times Cp$

where Q = heat inpot to gas, Btu/Hr.
W = gas flow, Lbs/Hr.
Δt = temperature rise, °F
Cp = gas specific heat, Btu/Lb/°F

This formula is solved graphically by Fig. 8.

NOTE: Where a two-phase stream consisting of both gas and liquid is to be heated, size for the gas by Figs. 8 and 9 and the oil by Figs. 14 and 15, adding the heat and coil area requirements to arrive at the total heater requirement.

The flow coil area required to transmit the necessary heat to the gas is calculated by the formula

$$A = \frac{Q}{U \times LMTD}$$

where A = required coil area, sq ft.
Q = heat input to gas, Btu/Hr.
U = overall coefficient of heat transfer, Btu/Hr ft^2 °F
$LMTD$ = logarithmic mean temperature difference, °F

This formula is solved graphically by Fig. 9.

TABLE 3. FLOW RATE CORRECTION FACTOR "F"
Corrected flow rate = actual flow rate x corr. factor

SP GRAV	F	SP. GRAV	F	SP. GRAV.	F	SP. GRAV	F	SP. GRAV.	F
55	0.786	60	0.857	.65	0.929	.70	1.00	.75	1.07
56	0.800	.61	0.871	66	0.943	.71	1.01	.76	1.09
57	0.814	62	0.886	67	0.957	.72	1.03	.77	1.10
58	0.829	63	0.900	68	0.971	.73	1.04	.78	1.11
59	0.843	64	0.914	.69	0.986	.74	1.06	.79	1.13

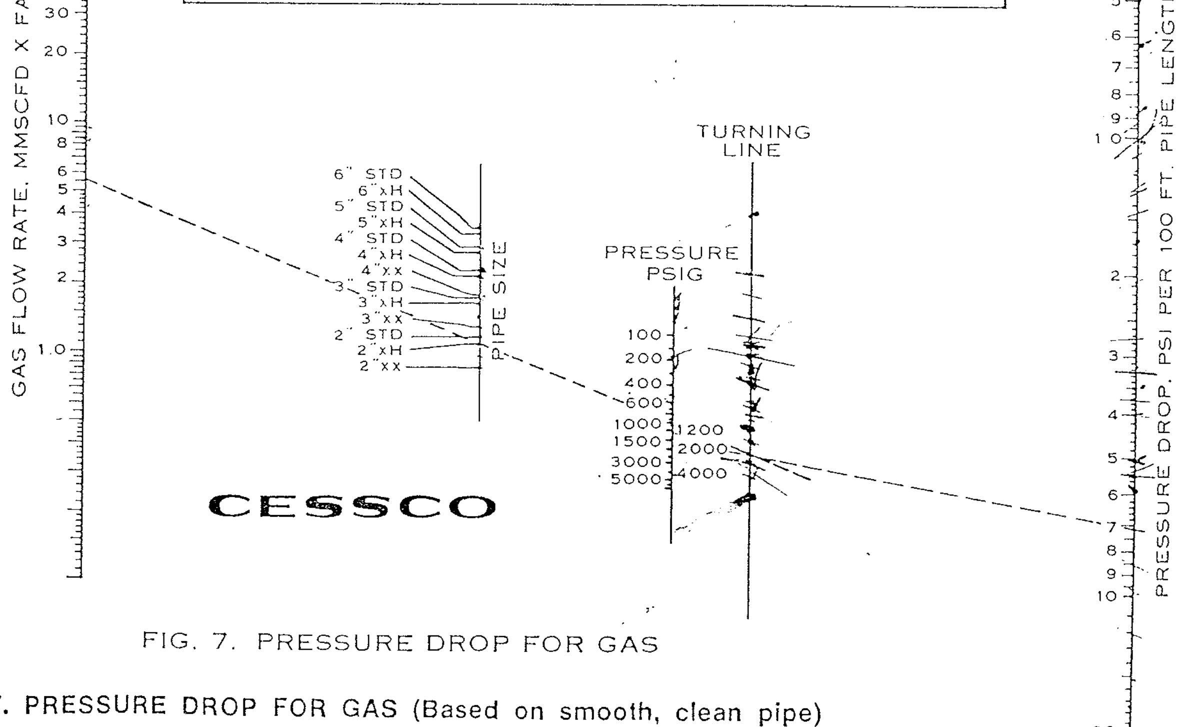


FIG. 7. PRESSURE DROP FOR GAS

FIG. 7. PRESSURE DROP FOR GAS (Based on smooth, clean pipe)

To estimate gas pressure drop through a coil.

Method:

(1) Multiply flow rate by factor F from Table 3. (2) Locate corrected flow rate on left scale and lign with pipe size. (3) Mark intersection on rning line, align with flowing pressure, then (4) ead pressure drop on right scale.

EXAMPLE:

Estimate the pressure drop for 6 MMSCFD of 0.65 specific gravity gas, flowing through a 2" XH coil with an equivalent length of 95 ft., at 1500 psig.

SOLUTION:

The corrected flow rate is 6 x .929 = 5.6 MM/day. Align 5.6 MM with 2" XH pipe, then align the turning line intersection with 1500 psig and read 7.25 psi/100 ft. on the right scale. Pressure drop is 7.25 x .95 = 7 Psi.

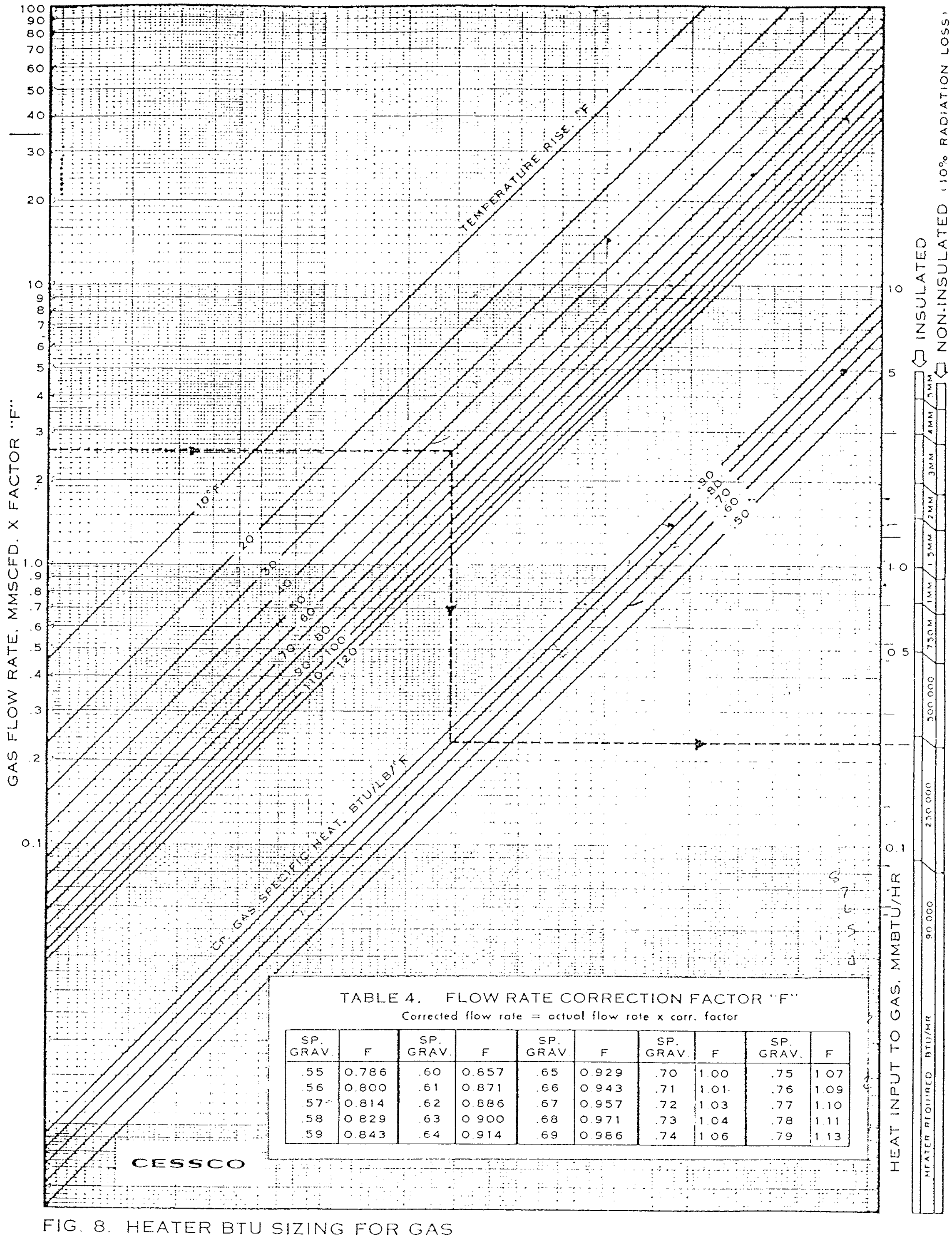


TABLE 4. FLOW RATE CORRECTION FACTOR "F"

Corrected flow rate = actual flow rate x corr. factor

SP. GRAV.	F	SP. GRAV.	F	SP. GRAV.	F	SP. GRAV.	F	SP. GRAV.	F
.55	0.786	.60	0.857	.65	0.929	.70	1.00	.75	1.07
.56	0.800	.61	0.871	.66	0.943	.71	1.01	.76	1.09
.57	0.814	.62	0.886	.67	0.957	.72	1.03	.77	1.10
.58	0.829	.63	0.900	.68	0.971	.73	1.04	.78	1.11
.59	0.843	.64	0.914	.69	0.986	.74	1.06	.79	1.13

FIG. 8. HEATER BTU SIZING FOR GAS

PURPOSE:

To determine the Btu/Hr required for gas heating.

METHOD:

(1) Multiply flow rate by factor "F", Table 4. (2) Enter chart with corrected rate, (3) intersect temp. rise curve, (4) follow down to sp. heat curve, then (5) across to Btu/Hr required. (6) Continue to the right for heater size.

EXAMPLE:

3MM D of .60 sp. gr. gas @ 70°F is to be reduced from 2500 to 1150 psi after heating. Temperature at 1150 psi is to be 5°F above hydrate temperature. (Fig. 19 shows a temperature drop of 53°F. Fig. 20 shows a hydrate temperature of 62°F for 0.06 sp. gr. gas @ 1150 psi. So, temperature prior to pressure reduction must be 62° + 5° + 53° = 120°F)

Select a heater to raise the temperature from 70° to the required 120°F.

SOLUTION:

Multiply 3 MM D by .857 from Table 4, giving 2.57 MM, D corr. rate. Enter chart at 2.57 MM, intersect 50° Δt curve, then down to .81 Cp (see Fig. 12). Read 232,000 Btu Hr *heat input. Note that a 250,000* Btu/Hr insulated heater, *or a* 500,000 Btu Hr non-insulated heat*er is required.*

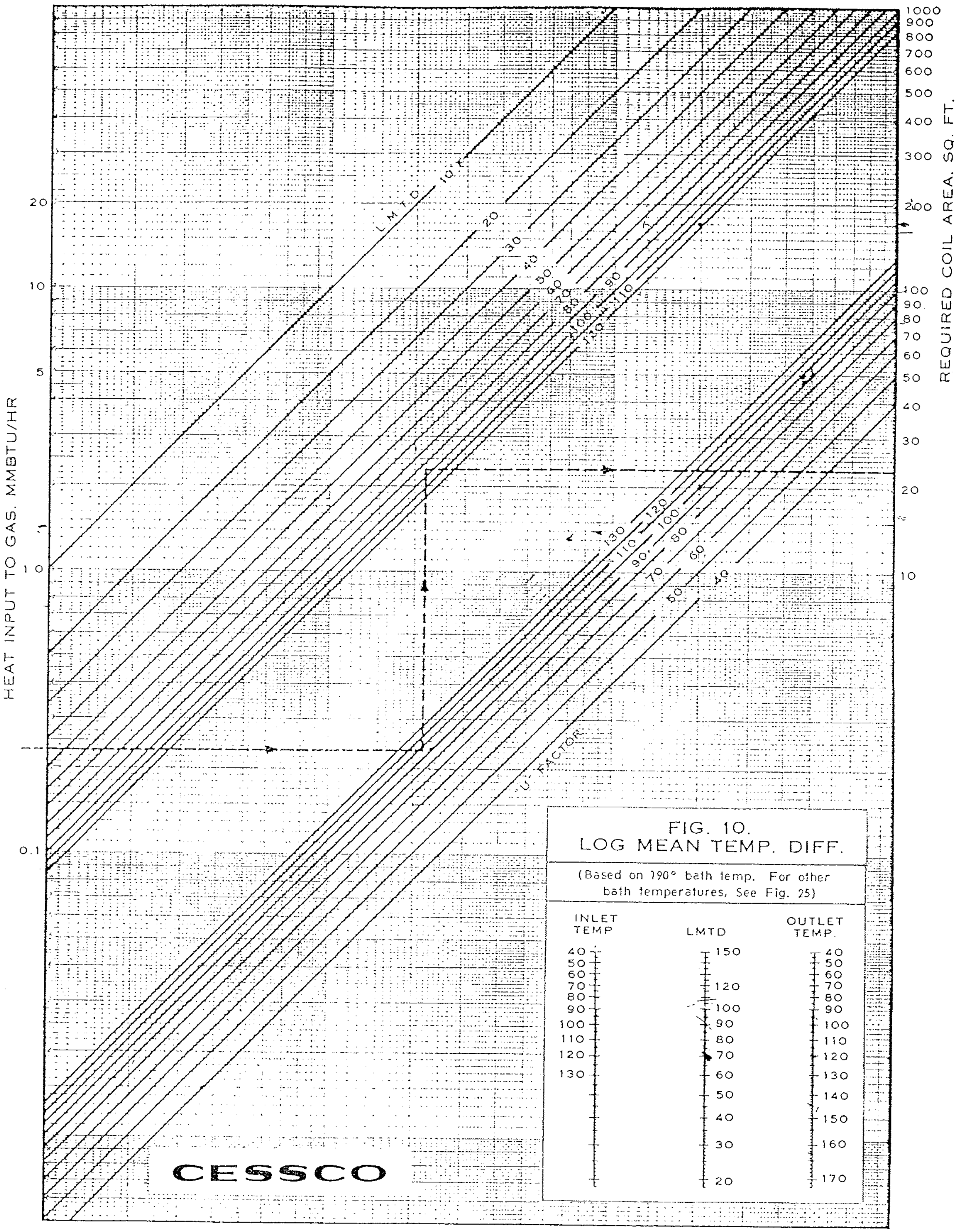


FIG. 9. HEATER FLOW COIL SIZING FOR GAS

PURPOSE:

To determine the coil area required for gas heating.

THOD:

(1) Continue from Fig. 8, entering with the required heat input. (2) Follow to the "U" factor curve, then (3) to the LMTD curve. (4) Read required area.

EXAMPLE:

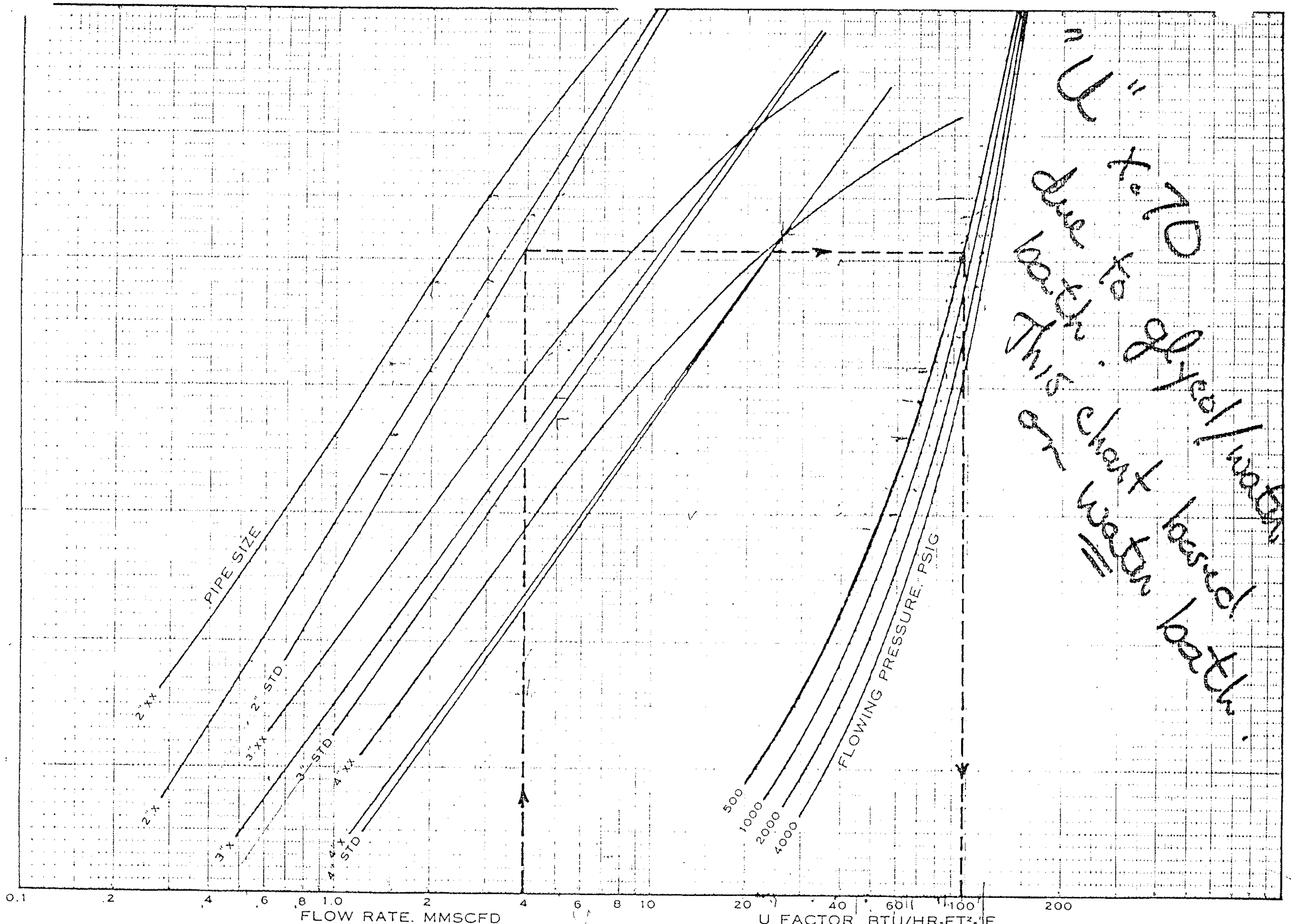
Determine the coil area, using 2" XH pipe to handle the example given with Fig. 8.

SOLUTION:

Fig. 11 shows "U" for 3.0 MM through 2" XH pipe to be 109. From Fig. 10, the LMTD, based on 70°F inlet, 120°F outlet, 190°F (standard) heater bath temperature, is 93°F. Continuing from Fig. 8, enter at 232,000 Btu Hr heat input. Follow to the 109 "U" curve, then to the 93° F LMTD curve. Read 23 ft² required coil area.

In summary, select either an insulated 250,000 Btu Hr. or a non-insulated 500,000 Btu Hr. heater, with a 2" XH coil of at least 23 ft coil area.

FIG. 11 OVERALL HEAT TRANSFER RATES ("U" FACTORS) FOR GAS



"U" x .70 due to glycol/water bath. This chart based on water bath.

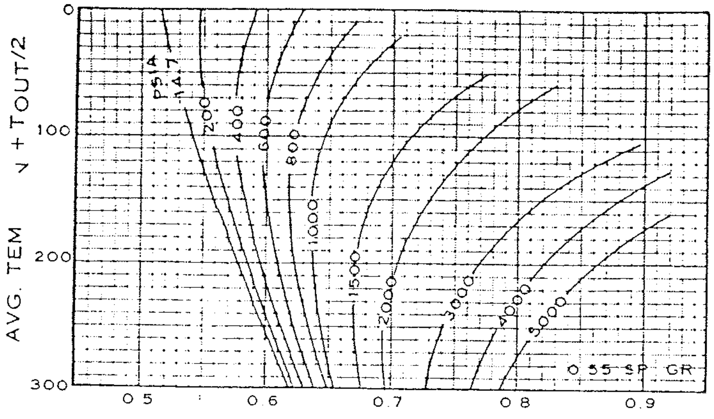
With a given temperature difference, the amount of heat that can be transmitted to the gas through a pipe coil of given area depends primarily on the flow rate, flowing pressure, size and thickness of the pipe, and the condition of the pipe.

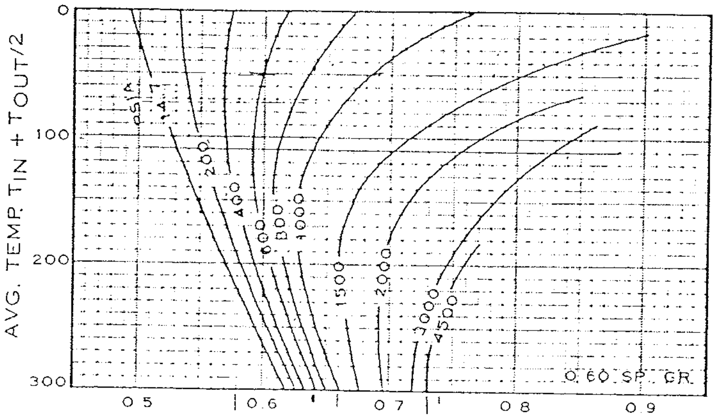
These factors are taken into consideration in the "U" Factor, the overall coefficient of heat transfer (Btu/Hr ft² °F). This coefficient is used in determining the required area of heat transfer surface (nominal coil area).

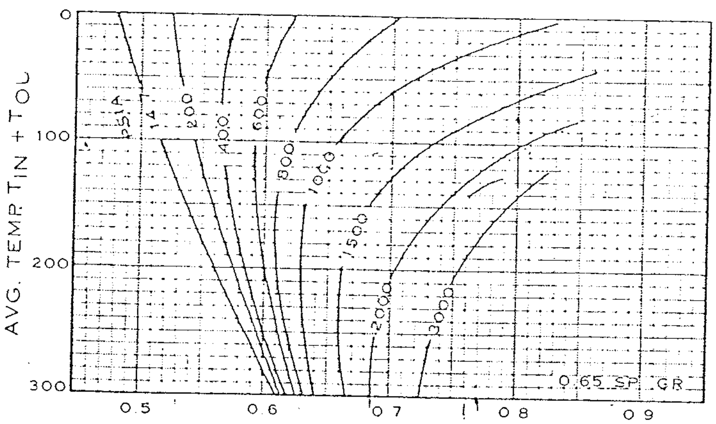
EXAMPLE:
Determine the "U" factor for 4.0 MMSCFD flowing through 2" std. pipe at a pressure of 500 psig.

SOLUTION:
Locate 4.0 MMSCFD on the chart, intersect the 2" std. pipe curve, and read across to 500 psig. Read down to 97 Btu/Hr ft² °F.

Normal U for salt bath = 50-60







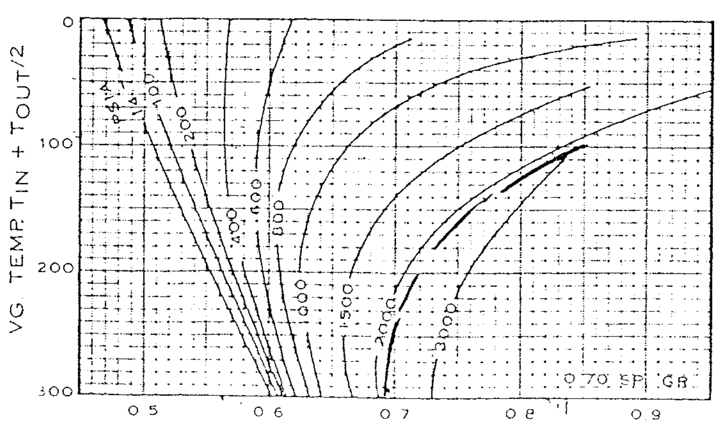
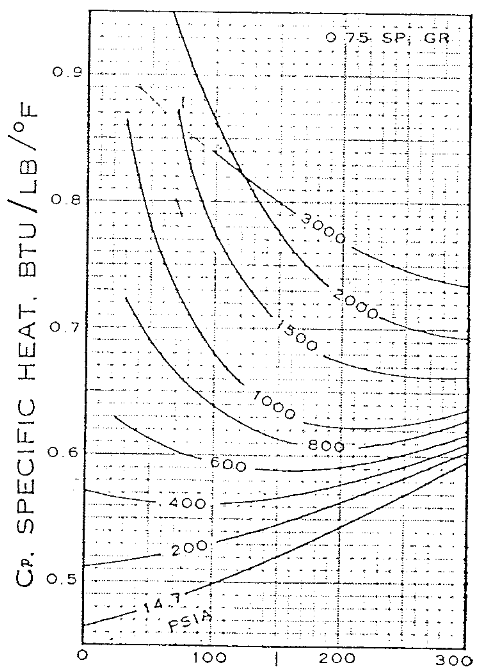


FIG. 12. SPECIFIC HEAT OF GASES, Cp

Purpose: To determine the specific heat of a gas.

Method: (1) Enter curve with the *average* gas temperature in the heat coil (½ of the sum of inlet plus outlet temperatures), then (2) read Cp. opposite the flowing pressure.



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HEATER SIZING FOR OIL

PURPOSE:
To determine the Btu Hr requirement for oil heating.

METHOD:
(1) Enter with flow rate, (2) follow to % water curve. (3) Follow to temperature rise curve, then (4) to the oil gravity curve. Then (5) to the oil Cp curve, then (6) read the heat input requirement. (7) Continue to the right to determine the heater size.

EXAMPLE:
Select a heater to rise the temperature of 2400 BPD From 50 to 100°F; the liquid is 80% oil (30°API gravity) 20% water.

SOLUTION:
Fig 13 shows Cp to be 0.45 Btu Lb/°F. Enter with 2400BPD, follow to the 20% water curve, then to the 50°F t curve. Continue to the 30° API curve, then to the 0.45 Btu/Lb/°F Cp curve. Read 900,000 Btu/Hr input required. Note that a 1,000,000 Btu/Hr heater is adequate, insulated or non-insulated.

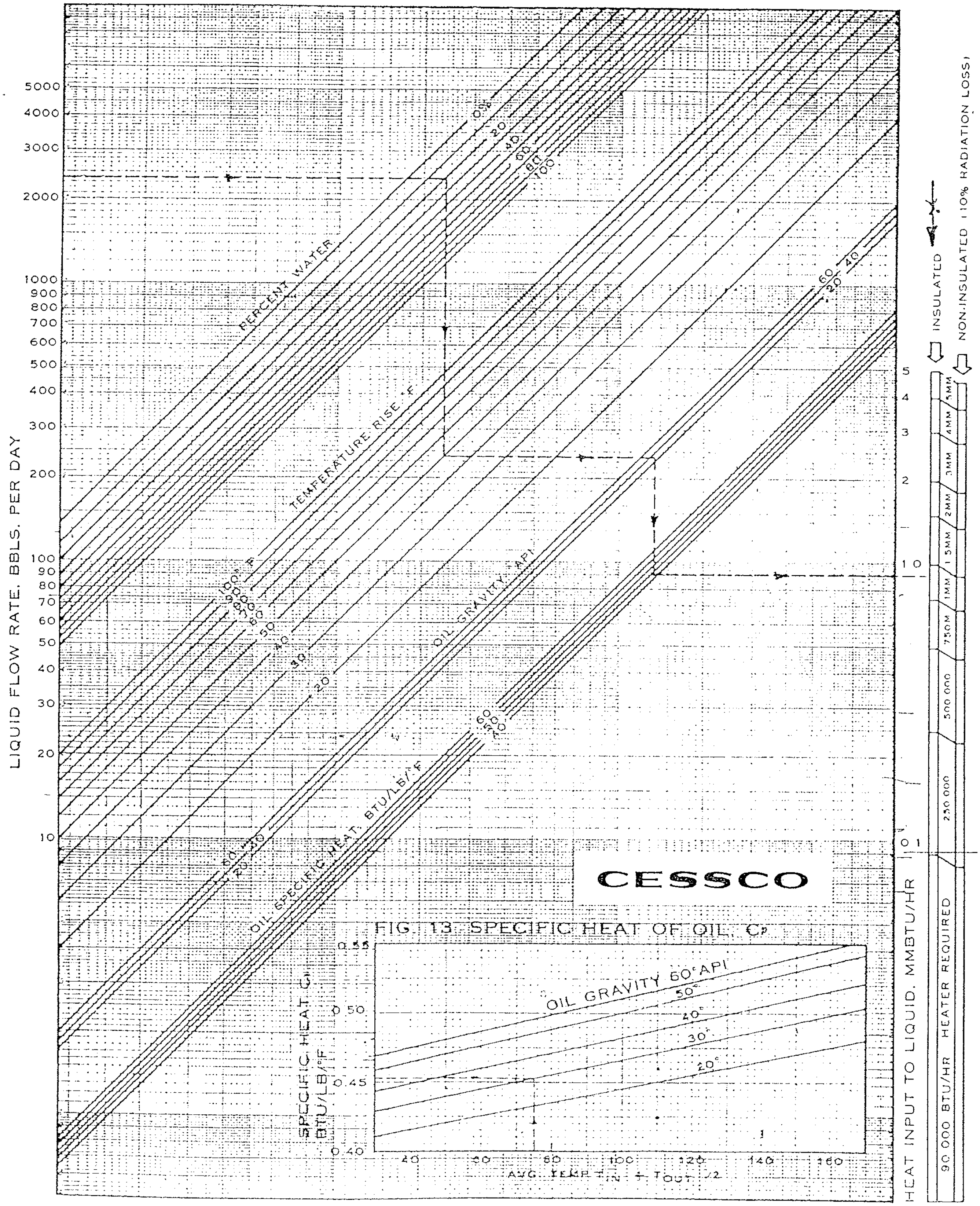

FIG. 14 HEATER BTU SIZING FOR LIQUID (Assumes Water Gravity of 1.02).

PURPOSE:

To determine the heater coil area for oil heating.

METHOD:

(1) Continue from Fig 14 with the required heat input. (2) Follow to "U" Factor (Fig. 17), then (3) to LMTD (Fig. 16) and (4) read required coil area.

EXAMPLE:

Determine the coil area, using 3" std. pipe, to handle the example given with Fig. 14. The oil viscosity is 4.0 ntipoises at 100°F.

LUTION:

Convert viscosity from centipoises to centistokes by dividing by the oil sp. gravity, 0.8760: 4.0/.876=4.6 centistokes. Fig. 17 shows "U" for 2400 BPD and 4.6 centistokes to be 58. Fig. 16 shows the LMTD, based on 50° inlet and 100° outlet, to be 112°F. Continuing from Fig 14 with 900,000 Btu/Hr heat input, follow to 58 "U" Factor, then to 112°F LMTD. Read 140 ft² required coil area.

In summary, select a 1,000,000 Btu/Hr. heater with a 3" std. coil of at least 140 ft² area.

$$*\text{Sp. gr.} = \frac{141.5}{°\text{API}+131.5}$$

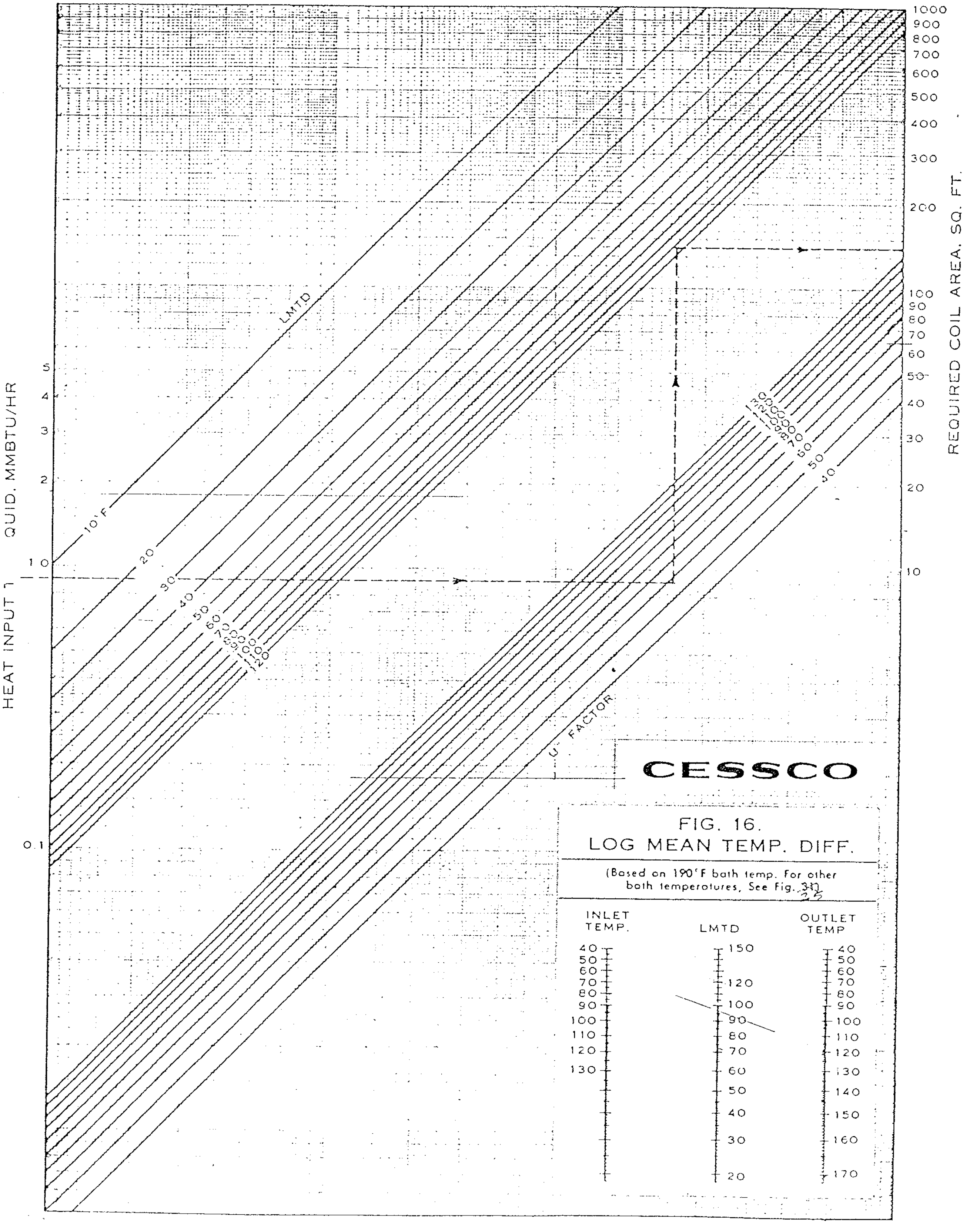

FIG. 15. HEATER FLOW COIL AREA SIZING FOR LIQUID

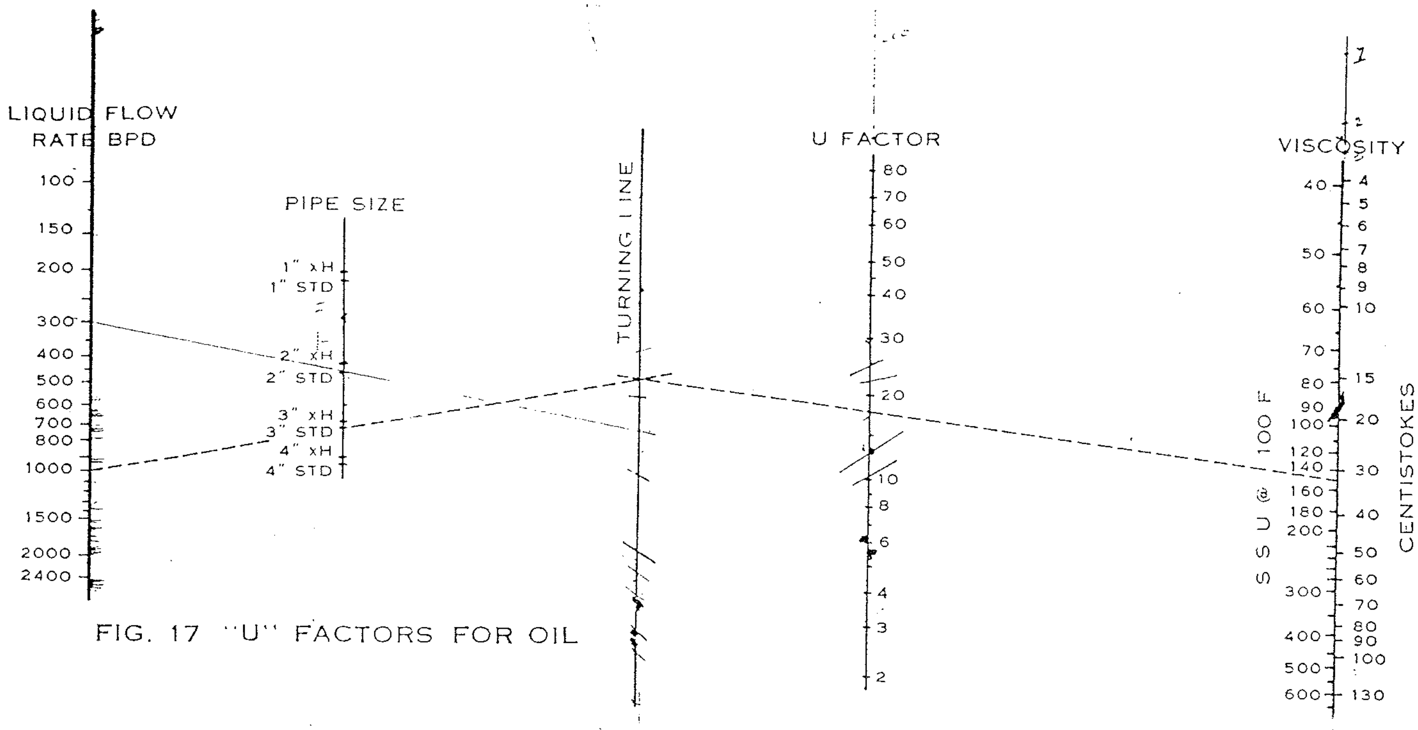

FIG. 17 "U" FACTORS FOR OIL

PURPOSE:
To determine the "U" Factor (overall heat transfer coefficient, Btu/Hr. °F ft²) for heat transfer to a liquid.

METHOD:
(1) Align the liquid flow rate with the pipe size, marking the intersection on the turning line. (2) Align this intersection with the viscosity, and (3) read the "U" Factor.

EXAMPLE:
Determine the "U" Factor for 1000 BPD of 150 SSU viscosity oil, flowing through 3" standard pipe.

SOLUTION:
Draw a line between 1000 BPD and 3" standard pipe, and align the intersection at the turning line with 150 SSU on the right-hand scale. Read the "U" Factor of 81 SSU on the right-hand scale. Read the "U" Factor of 18 Btu/Hd. °F ft². (Notes If viscosity is given in centipoises convert to centistokes by dividing by the oil specific gravity.)

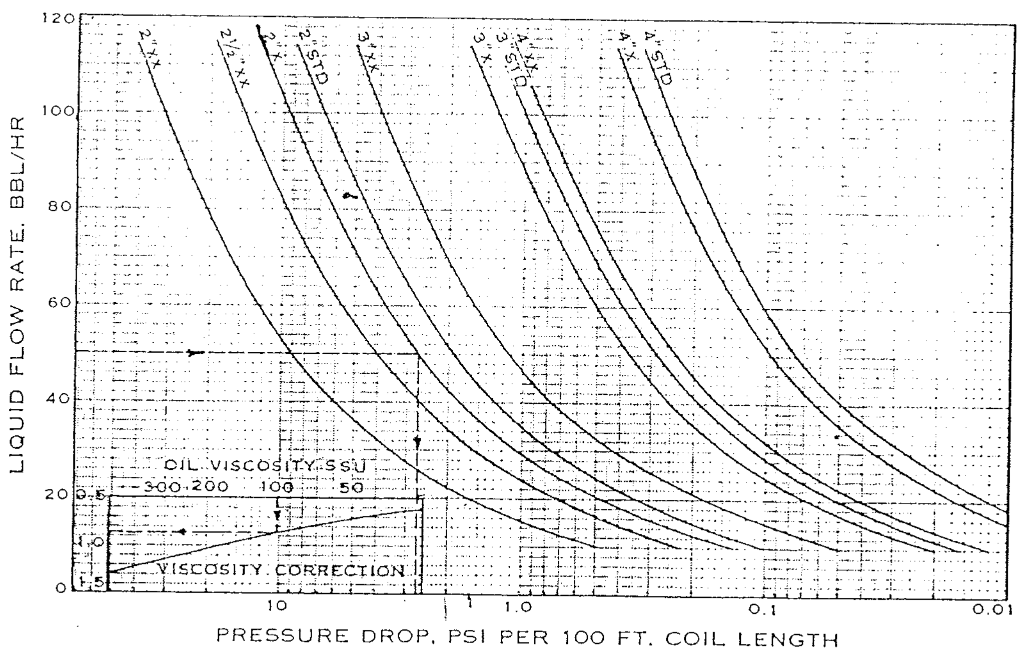

FIG. 18. PRESSURE DROP FOR LIQUIDS

EXAMPLE:
Estimate the pressure drop in a 2" XH heater coil of 95 ft. equivalent length, with a flow rate of 50 barrels per hour and a viscosity of 100 SSU @ 100°F.

SOLUTION:
Enter the chart at 50 BPH, read across to the 2" XH curve, then down to 2.7 psi per 100'. Correct for viscosity by multiplying by 0.88 (see inset correction curve), giving a pressure drop of 2.7 x 0.88 = 2.4 psi/100 ft. The total pressure drop would be 2.4 x 95/100 = 2.3 psi.

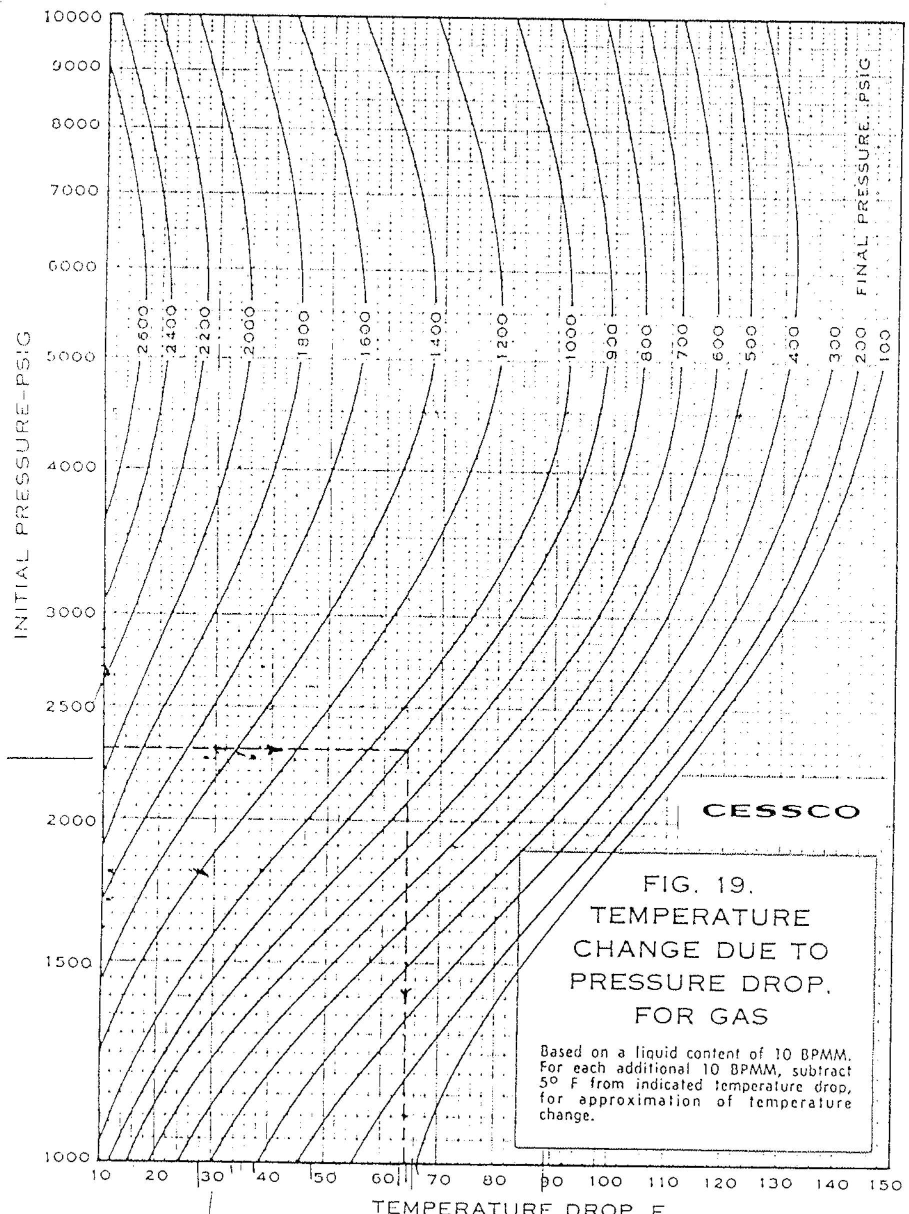

FIG. 19.
TEMPERATURE CHANGE DUE TO PRESSURE DROP. FOR GAS

Based on a liquid content of 10 BPMM. For each additional 10 BPMM, subtract 5° F from indicated temperature drop, for approximation of temperature change.

The above chart based on 0.7 sp. gravity gas.

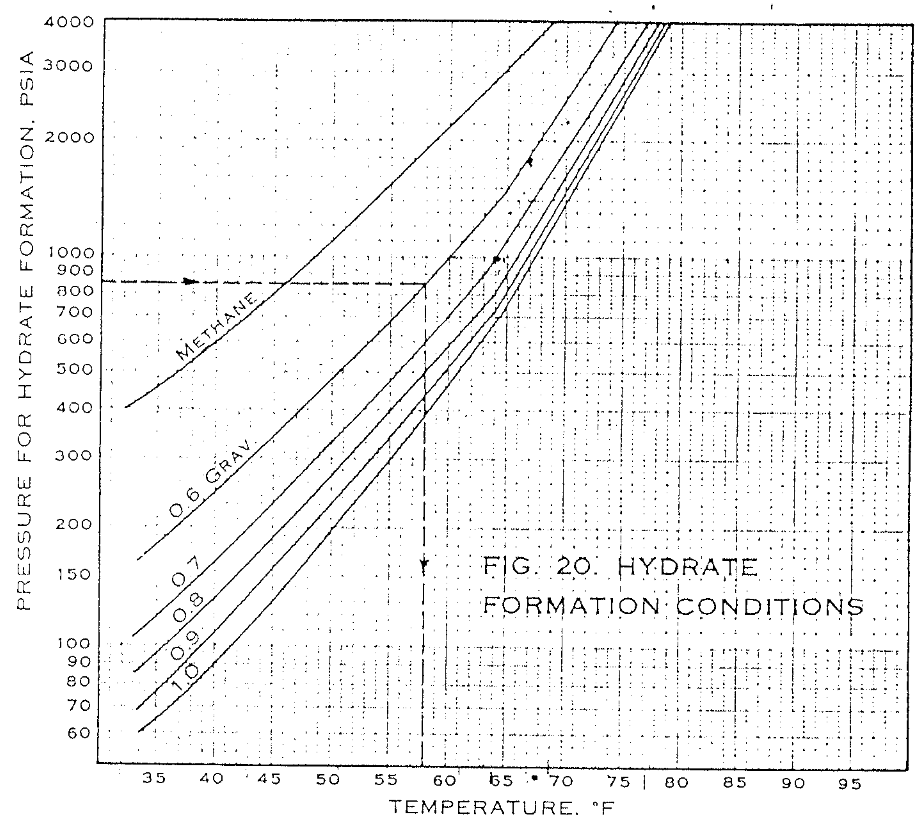

FIG. 20. HYDRATE FORMATION CONDITIONS

Fig. 20. Hydrate Formation Conditions. *Purpose*: To predict the temperature below which hydrates will form, where sufficient liquid water is present.

EXAMPLE

Below what temperature will hydrates form in 0.60 sp. gravity gas at 850 psia?

SOLUTION:

Enter chart at 850 psia, read across to 0.6 gravity, then down to 58°F.

Fig. 19. Temperature Change Due to Pressure Reduction. *Purpose:* To estimate the temperature change due to pressure reduction of natural gas.

EXAMPLE:

A lean 0.7 sp. gr. gas stream is to be choked from 2300 and 110°F to 900 psig. What will be the resulting temperature?

SOLUTION:

Enter at 2300 psig, read across to the 900 psig final pressure curve, then down to 64°F temperature drop. The temperature will be 110 — 64 = 46°F.

GLYCOL DEHYDRATOR SIZING

ABSORBER SIZING:

Step 1. From Fig. 21 choose Correction Factor "F".

Step 2. (a) *If no integral scrubber is required* divide the flow rate (in MMSCF-D) by "F". Refer to Table 5, page 55 and choose an absorber whose capacity at least equals (flow rate/F).

(b) *If an integral scrubber is required,* refer to Table 7 for an "M" Factor. Divide the flow rate, in MMS-CFD, by (F x M). Refer to Table 5, page 55, and choose an absorber whose capacity at least equals (flow rate/F x M).

REGENERATOR SIZING:

Step 1. From Fig 23, Water Content Chart, figure the water to be removed per day.

Step 2. Refer to Fig. 22 Knowing the required dewpoint depression, determine the choices of glycol circulation rates vs. number of absorber trays. (If an outlet dewpoint of — 15°F or below is required, add the additional trays indicated by Table 8.) 41

Step 3. Refer to Catalog Page ~~24~~ which lists the water removal capacities of regenerators at various glycol circulation rates. Knowing the water to be removed per day from Step 1, choose for *each* circulation rate of Step 2 the smallest regenerator with adequete water capacity.

Step 4. You now have one or more combinations of regenerator and absorber trays, any of which would handle the condition. The final choice will be the least expensive regenerator-absorber tray combination.

EXAMPLE 2.

A flow rate of 16 MMSCFD is to be dehydrated to a water content of 5 lbs. per MM. The gas temperature is 110°F, pressure is 1100 psig, sp. gravity 0.65. Size both with and without integral scrubber (distillate is 62° API). Desired W.P. vessel: 1200 psig.

SOLUTION:

Fig. 21 shows F = 1.06. 16 MMSCFD/1.06= 15.1 MMSCFD. Table 5 shows a Model GA-3012-0-15 Absorber will be adequate where no integral scrubber is required.

With an integral scrubber, Table 7 shows M = 0.97. 16 MMSCFD/1.06×0.97=15.6 MMSCFD. Table 5 shows a Model GA-3012-0-15 is adequate Therefore, the same absorber will apply whether or not an integral scubber is required.

REGENERATOR SIZING:

Fig. 23 shows a water removal requirement of 78 — 5 = 73 #/MM, or 1168 #/day at a 16 MM per day rate. Also, Fig. 23 shows that the outlet gas dewpoint is 25°F; therefore, the dewpoint depression is 110°F — 25° = 85°F Fig. 26 shows, for a 85°F D.P.D., that the following choices are applicable:

(1) 2.0 gal/#H_2O circulation rate, 6 absorber trays;

(2) 3.5 gal/#H_2O circulation rate, 5 absorber trays.

Reffering to Catalog Pg. 24, it is seen that for a 2.0 circulation rate, a 250,000 Btu/Hr regenerator is required, to remove 1168 #/day of water. At 3.5 circulation rate, a 375,000 Btu/Hr regenerator is required. Therefore, the lowest priced of these combinations should be chosen:

* *(1) 250,000 Btu/Hr regenerator, 6 tray absorber;*

(2) 375,000 Btu/Hr regenerator, 5 tray absorber.

FIG. 21. TRAY ABSORBER CORRECTION FACTORS

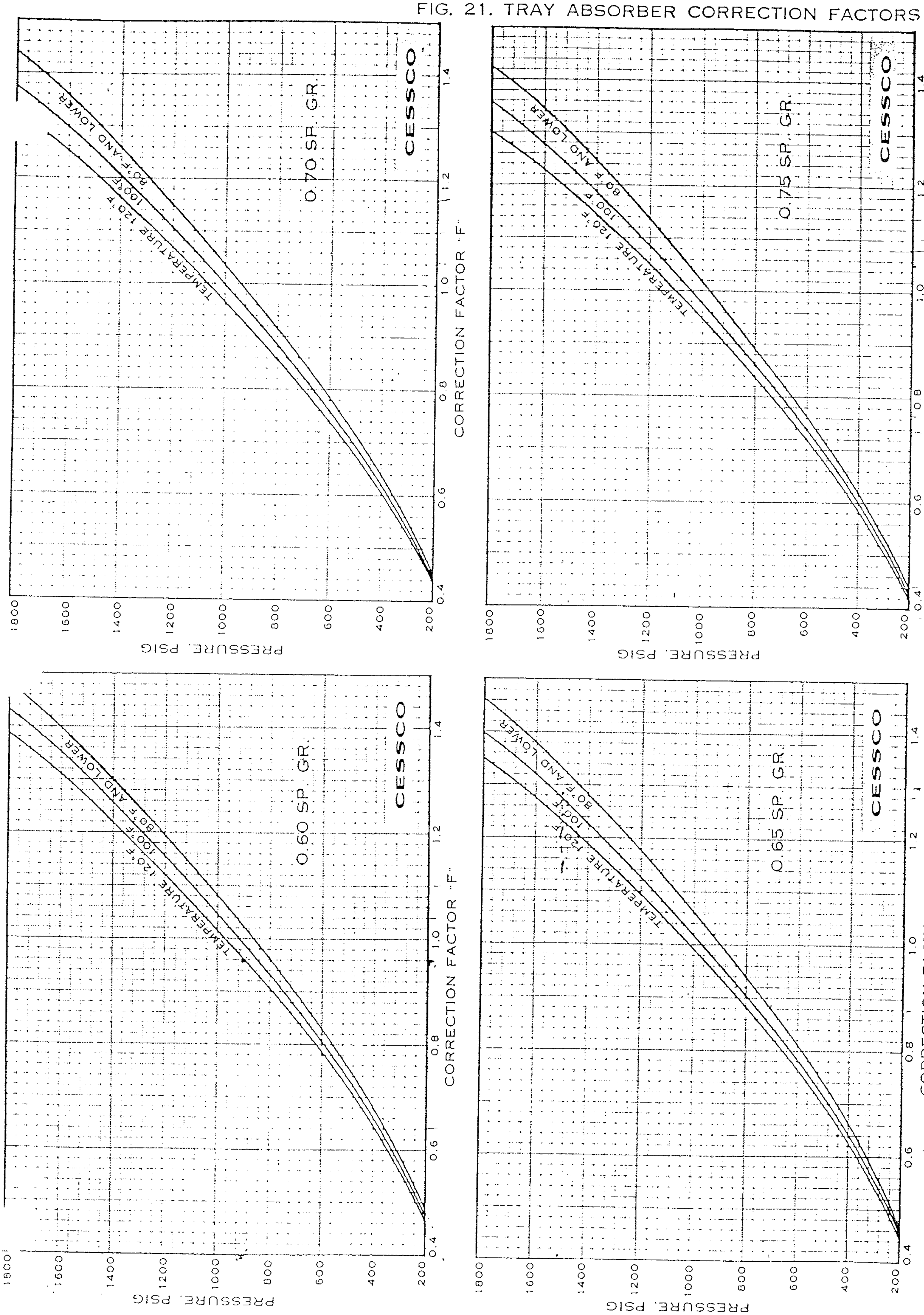

TABLE 5. ABSORBER CAPACITIES

Model**	Dia.	Corrected Absorber Capacities MMSCFD (All W.P.)*	Model	Dia.	Corrected Absorber Capacities MMSCFD (All W.P.)*	Model	Dia.	Corrected Absorber Capacities MMSCFD (All W.P.)*
GA-20 ( )-0-10	20" OD	5.9	GA-36 ( )-I	36" ID	28.6	GA-60 ( )-I	60" ID	79.3
GA-20 ( )-0-15	20" OD	7.6	GA-42 ( )-0	42" OD	33.6	GA-66 ( )-0	66" OD	85.0
GA-24 ( )-0-10	24" OD	8.3	GA-42 ( )-I	42" ID	39.0	GA-66 ( )-I	66" ID	96.0
GA-24 ( )-0-15	24" OD	10.9	GA-48 ( )-0	48" OD	45.2	GA-72 ( )-0	72" OD	100.0
GA-30 ( )-0-12.5	30" OD	13.2	GA-48 ( )-I	48" ID	50.7	GA-72 ( )-I	72" ID	114.5
GA-30 ( )-0-15	30" OD	17.4	GA-54 ( )-0	54" OD	56.5	GA-78 ( )-I	78" ID	134.7
GA-36 ( )-0-12.5	36" OD	20.0	GA-54 ( )-I	54" ID	64.4	GA-84 ( )-I	84" ID	156.0
GA-36 ( )-0-15	36" OD	24.0	GA-60 ( )-0	60" OD	69.4	GA-90 ( )-I	90" ID	178.0

* Capacities are corrected to 1000 psig, 100° F, and 0.7 sp. gr. See sizing procedure
** Parentheses are for W.P.: GA-2012-0-10 is 1200 psi W.P., etc.

TABLE 6. ABSORBER HEIGHTS
(nominal, seam-to-seam, subject to variation)

Tray Spacing	Dia.	NUMBER OF TRAYS									Add for Integral Scrubber:		
		4	5	6	7	8	9	10	11	12	Diameter	2-Phase	3-Phase
18"	20", 24"	10'	11'	12'	13'	14'	15'	16'	17'	18'	20"—36"	5'	7½'
	30", 36"	12.5'	13.5'	14.5'	15.5'	16.5'	17.5'	18.5'	19.5'	20.5'	42"—54"	6'	8½'
30"	All	15'	17.5'	20'	22.5'	25'	27.5'	30'	32.5'	35'	60"—78"	7'	10'
											84"—90"	9'	11'

WEIGHTS: To estimate weight, multiply weight of 4-tray absorber by (actual height ÷ height of 4 tray absorber).

TABLE 7. INTEGRAL SCRUBBER CORRECTION FACTOR "M"

LIQUID GRAVITY 30—40° API				
Below 76° F	76—80° F	81—90° F	91—100° F	101° F Plus
1.0	1.0	1.0	1.0	1.0

LIQUID GRAVITY 41—50° API				
Below 71° F	71—80° F	81—90° F	91—100° F	101° F Plus
1.0	1.0	1.0	1.0	1.0

LIQUID GRAVITY 51—60° API					
Below 64° F	64—70° F	71—80° F	81—90° F	91—100° F	101° F Plus
1.0	1.0	.99	.99	.99	.99

LIQUID GRAVITY 61—70° API					
Below 60° F	60—70° F	71—80° F	81—90° F	91—100° F	101° F Plus
1.0	.99	.97	.97	.97	.97

Use this Table only where an integral scrubber is to be furnished.
Multiply M x F from Fig. 24 or 25, to obtain the corrected "F" Factor.

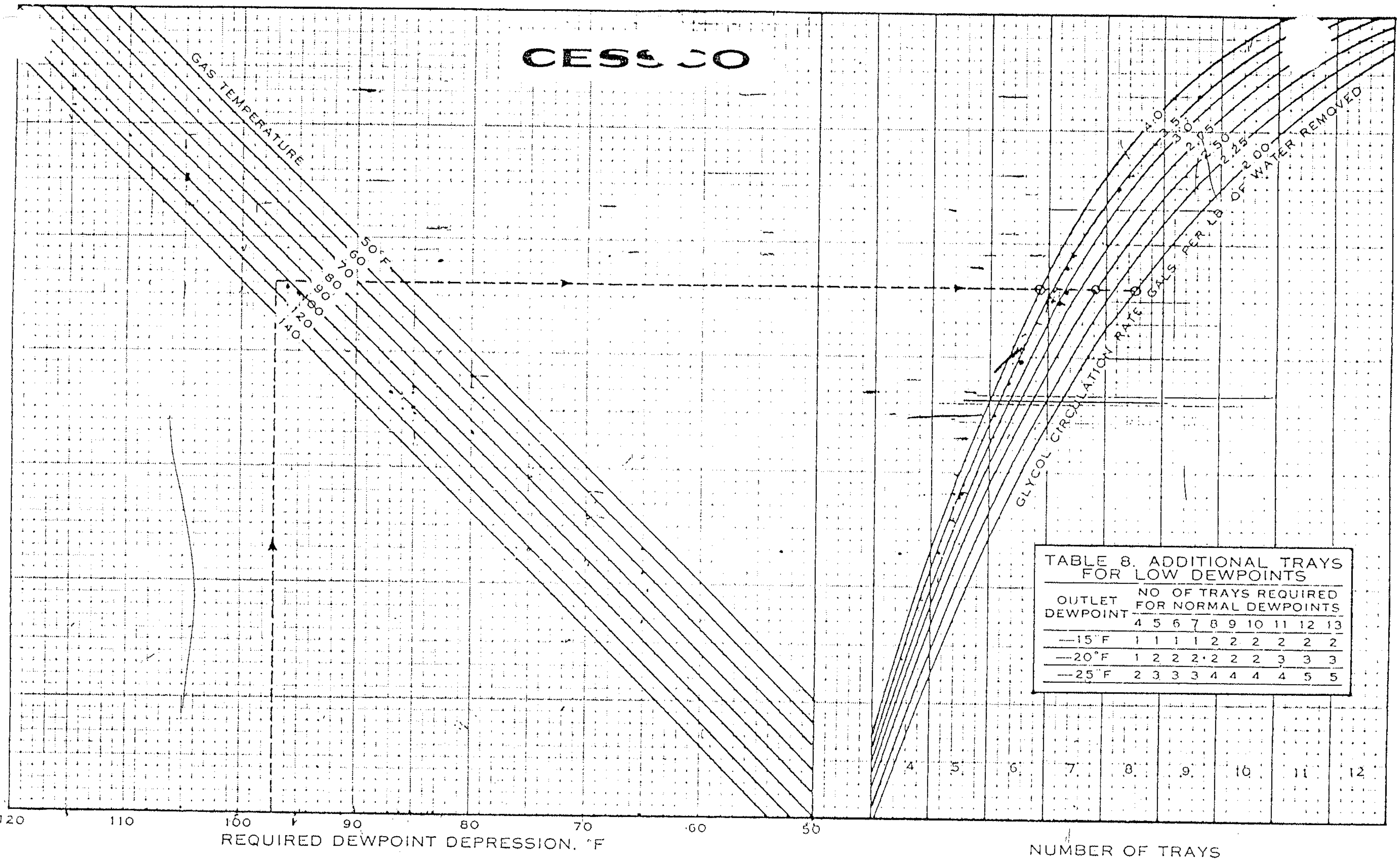

TABLE 8. ADDITIONAL TRAYS FOR LOW DEWPOINTS

OUTLET DEWPOINT	NO OF TRAYS REQUIRED FOR NORMAL DEWPOINTS									
	4	5	6	7	8	9	10	11	12	13
—15°F	1	1	1	1	2	2	2	2	2	2
—20°F	1	2	2	2	2	2	2	3	3	3
—25°F	2	3	3	3	4	4	4	4	5	5

FIG. 22. GLYCOL CIRCULATION RATE VS. NO. OF TRAYS For Dehydrators (based on 99.8% triethylene glycol at top tray inlet).

PURPOSE:

To determine the choices of absorber trays vs. glycol circulation rates for glycol dehydrators.

METHOD:

(1) Enter with required dewpoint depression, (2) read to gas temperature, then (3) to circulation rate curves. (4) Choose the circulation rate curves *farthest to the right* in each of the vertical trays divisions. This gives the choices of circulation rates vs. number of trays. (5) Calculate water to be removed per day (Fig. 27), then determine the regenerator required for each of the circulation rate choices. (6) Choose the more economical combination of regenerator and absorber trays. (Where dewpoints of —15°F and below are required, consult Table 8 for additional trays required).

EXAMPLE:

Determine the number of trays and regenerator size for dehydrating 25 MMSCFD at 600 psig and 110°F, to a water content of 5#/MM.

SOLUTION:

Fig. 27 shows the inlet water content to be 120 #/MM. Water to be removed is 120 —5 = 115#/MM or 2875#/day. Also, from Fig. 27 5#/MM corresponds to an outlet dewpoint of 13°F. The dewpoint depression is therefore 110 — 13 = 97°F. Enter at 97°F D.P.D., read to the 110°F curve, then to the circulation rate curves. The intersections farthest to the right in each division indicate these choices: (a) 6 trays, 4.0 gal/# circ. rate; (b) 7 trays, 2.5 gal/# circ. rate; (c) 8 trays, 2.0 gal/# circ. rate. Referring to Pg. 000, to remove 2875 lbs. of water per day, these regenerators are required: (a) 4.0 gal/# rate: 1,000,000 Btu/Hr; (b) 2.5 gal,# rate: 625,000 Btu/Hr.; (c) 2.0 gal/# rates 500,000 Btu /Hr.

Therefore, the final choice will be the lowest-priced of the following alternates: (a) 6 tray absorber with 1,000,000 Btu/#Hr. regenerator; (b) 7 tray absorber with 625,000 Btu/Hr. regenerator; (c) 8 tray absorber with 500,000 Btu/Hr. regenerator.

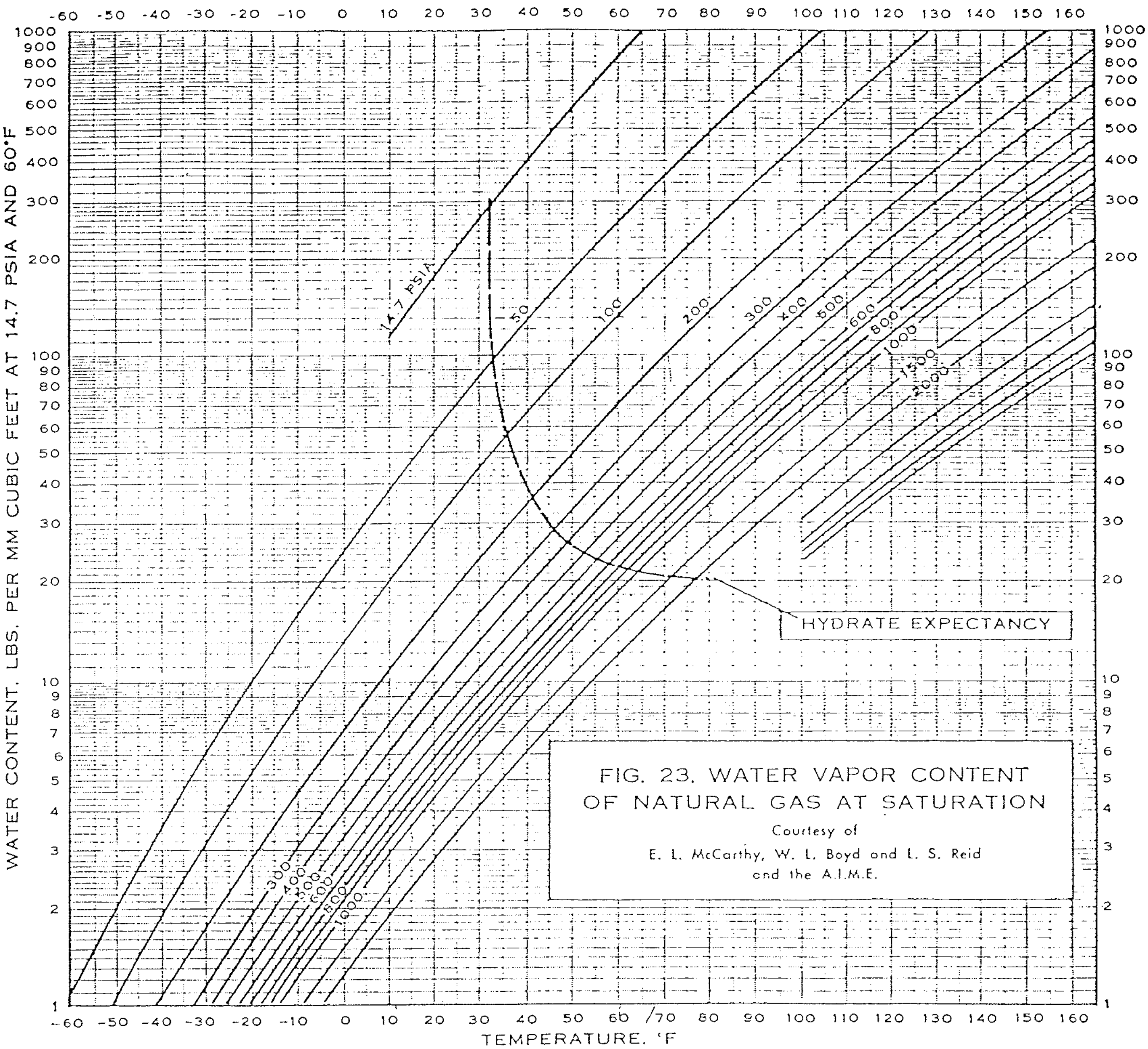

FIG. 23. WATER VAPOR CONTENT OF NATURAL GAS AT SATURATION

Courtesy of

E. L. McCarthy, W. L. Boyd and L. S. Reid and the A.I.M.E.

Example:

1. Determine the water vapor content of gas saturated at 100°F and 800 psi: enter chart at 100°F, read 76#/MM opposite 800 psia.

2. Determine the amount of water vapor to be removed in dehydrating the above gas to a final dewpoint of 20°F dewpoint at 800 psia is 5.2 #/MM. Therefore, the water vapor to be removed is 76#/MM — 5.2 #/MM = 70.8#/MM.

3. Determine the dewpoint of a gas that has been dehydrated to a water content of 6#/MM at 1000 psia: enter the chart at 6#/MM read across to 1000 psia, then down to 28°F.

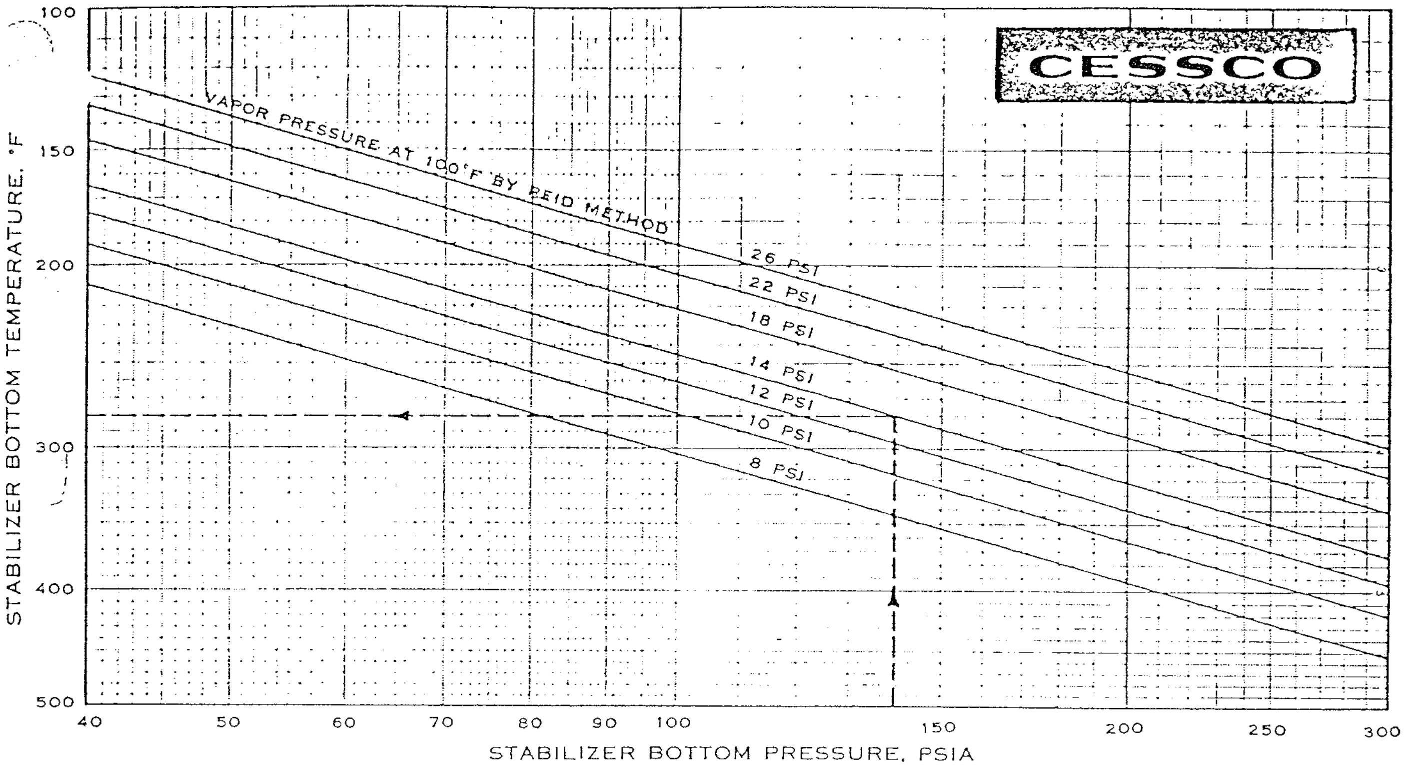

FIG. 24. STABILIZER VAPOR PRESSURES

PURPOSE:
To determine stabilizer bottom conditions to produce ven RVP product.

THOD:
(1) Enter chart at operating pressure, (2) intersect curve of desired RVP product, (3) read temperature at left.

EXAMPLE:
At what temperature should stabilizer bottom be maintained to produce a 14# RVP product at an operating pressure of 125 psig?

SOLUTION:
Enter chart at 139.7 psia (125 psig + atmospheric pressure), read 280°F opposite curve for 14# RVP.

TABLE 9. PHYSICAL CONSTANTS OF HYDROCARBONS AND OTHER COMPOUNDS

Compound	Formula	Molecular Weight	Vapor Pressure @ 100° F (psia)	BBL/mm Factor **	GPM Factor ***	Boiling Point @ 14.7 psia (° F)	Calorific Value (Btu/Cu.Ft. Vapor)	
							Net	Gross*
Methane	CH_4	16.043	....	4.036	0.169	−259	911	1012
Ethane	C_2H_6	30.070	780	6.051	0.255	−127	1631	1783
Propane	C_3H_8	44.097	190	6.532	0.279	− 44	2353	2557
i-Butane	iC_4H_{10}	58.124	72.2	7.768	0.336	+ 11	3094	3354
n-Butane	C_4H_{10}	58.124	51.6	7.490	0.325	31	3101	3369
i-Pentane	iC_5H_{12}	72.151	20.44	8.687	0.365	82	3698	4001
n-Pentane	C_5H_{12}	72.151	15.57	8.605	0.361	97	3709	4009
Hexane	C_6H_{14}	86.178	4.956	9.766	0.410	156	4404	4756
Heptane	C_7H_{16}	100.205	1.620	10.962	0.460	209	5101	5503
Octane	C_8H_{18}	114.232	0.537	12.160	0.511	258	5797	6250
Nonane	C_9H_{20}	128.259	0.179	13.369	0.561	303	6493	6996
Decane	$C_{10}H_{22}$	142.206	0.073	14.590	0.613	345	7190	7743
Carbon Dioxide	CO_2	44.010	....	4.084	0.173	− 109	....	....
Hydrogen Sulfide	H_2S	34.076	....	....	....	− 77	621	672
Air	N_2O_2	28.964	....	....	....	−318	....	....
Hydrogen	H_2	2.016	....	....	....	−423	273	324
Oxygen	O_2	31.999	....	....	....	−297	....	....
Nitrogen	N_2	28.016	....	....	....	−320	....	....
Water	H_2O	18.015	0.9492	....	....	+212	....	....

* Gross heat on dry basis at 14.7 psia and 60° F. To convert to water saturated basis, multiply by 0.9825.
** Barrels of liquid equivalent to 1.0 mmcf gas.
*** Gallons of liquid equivalent to 1.0 mcf gas.

LOG MEAN TEMP. DIFF. CHART

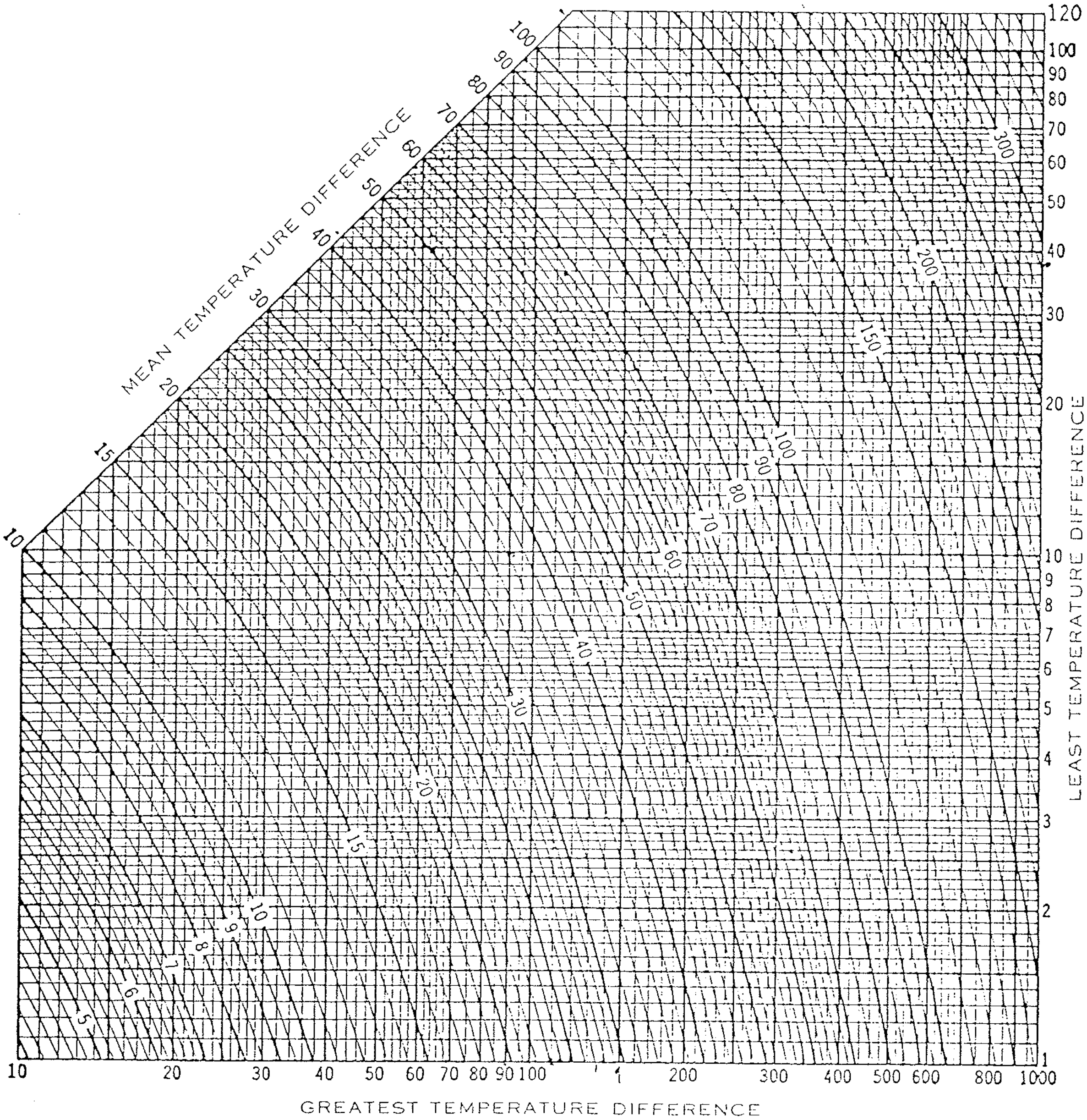

FIG. 25. CHART FOR SOLVING MEAN TEMPERATURE DIFFERENCE FORMULA

Example: GTD = 100°F, LTD = 10°F.
From intersection of these lines, read 39.1°F on MTD scale.

CONVERSION TABLES

LENGTH

Feet	Inches	Millimeters	Meters
1	12	304.80	0.3048
0.08333	1	25.40	0.0254
3.2808	39.370	1000	1

AREA

Sq. Inches	Sq. Ft.	Acres	Sq. Centimeters
1	0.00694	....	6.45163
144	1	....	929.03412
....	43,560	1	....

VOLUME

Cu. Inches	Cu. Ft.	Cu. Meters	Gallons (U.S.)	Gallons (Imp.)	Barrels (42 U.S. Gal.)
1	0.0005787	0.000016387	0.004329	0.0036047	0.00010307
1728	1	0.028317	7.48052	6.228878	0.1781076
9702	5.61458	0.158988	42	34.972555	1
231	0.1336806	0.0037854 34	1	0.8326799	0.02380952

WEIGHT

Pounds	Ounces	Kilograms
1	16	0.45359

PRESSURE

PSI	Kg. Per Sq. Cm.	MM Mercury	In. Mercury	In. Water
1	0.070307	51.71308	2.035944	27.68049

POWER

Horsepower	Ft. Lbs. Per Min.	Watts	Kilowatts	BTU/Min.
1	33,000	746	.746	42.4
1.341	44,250	1000	1	56.8
.0236	778.4	17.6	.0176	1

$API = \left\{\frac{141.5}{SG}\right\} - 131.5$

TEMPERATURE

°F........................	(9/5 x °C) +32°
°C........................	5/9 (°F —32°)

OIL GRAVITY

SP. GR. .... $\frac{141.5}{°API + 131.5}$

ELECTRICAL DATA

To Find	DIRECT CURRENT	ALTERNATING CURRENT Single-Phase	ALTERNATING CURRENT Three-Phase*
Amps.....................	$\frac{\text{H.P. x 746}}{\text{Volts x Efficiency}}$	$\frac{\text{H.P. x 746}}{\text{Volts x Eff. x P.F.}}$	$\frac{\text{H.P. x 746}}{\text{Volts x 1.73 x Eff. x P.F.}}$
Kilowatts..................	$\frac{\text{Amps x Volts}}{1000}$	$\frac{\text{Amps x Volts x P.F.}}{1000}$	$\frac{\text{Amps x Volts x 1.73 x P.F.}}{1000}$
Power Factor...............		$\frac{\text{Kilowatts x 1000}}{\text{Amps x Volts}}$	$\frac{\text{Kilowatts x 1000}}{\text{Amps x Volts x 1.73}}$
(Output)..............	$\frac{\text{Amps x Volts x Eff.}}{746}$	$\frac{\text{Amps x Volts x Eff. x P.F.}}{746}$	$\frac{\text{Amps x Volts x 1.73 x Eff. x P.F.}}{746}$

P.F. and Eff. should be expressed as decimals.
* For 2-phase 4-wire, substitute 2.0 for 1.73. For 2-phase 3-wire, substitute 1.41 for 1.73.