ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

CALCULATION SHEET

Revised September, 1965

OWNER OF PLANT . . . TEST NO. . . . BOILER NO. . . . DATE

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\dfrac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = $\dfrac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\dfrac{\text{ITEM 43}}{100} - \left[\dfrac{\text{ITEM 22} \times \text{ITEM 23}}{14{,}500}\right]$ = ...

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\dfrac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S)

$$= \frac{11 \times \text{ITEM 32} + 8 \times \text{ITEM 33} + 7\left(\text{ITEM 35} + \text{ITEM 34}\right)}{3 \times \left(\text{ITEM 32} + \text{ITEM 34}\right)} \times \left[\text{ITEM 24} + \frac{\text{ITEM 47}}{267}\right] = \ldots\ldots$$

36 EXCESS AIR† $= 100 \times \dfrac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \dfrac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})} = \ldots\ldots\ldots$

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = ITEM 25 ...... × 0.24 Unit ...... (ITEM 13) – (ITEM 11) .... =	......	$\frac{65}{41}$ × 100 =	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41}$ × 100 =	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41}$ × 100 =	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 ...... × ITEM 23 ...... = ...	......	$\frac{68}{41}$ × 100 =	......
69	HEAT LOSS DUE TO RADIATION* = $\dfrac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL — ITEM 28}}$	......	$\frac{69}{41}$ × 100 =	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ × 100 =	......
71	TOTAL	......	......	......
72	EFFICIENCY = (100 – ITEM 71)	......	......	......

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

Printed in U.S.A. (10/74)

This Test Form (C-37) may be obtained from ASME, 345 E. 47 St., New York, N.Y. 10017

SUMMARY SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

	TEST NO.	BOILER NO.	DATE
OWNER OF PLANT	LOCATION		
TEST CONDUCTED BY	OBJECTIVE OF TEST		DURATION
BOILER MAKE & TYPE		RATED CAPACITY	
STOKER TYPE & SIZE			
PULVERIZER, TYPE & SIZE		BURNER, TYPE & SIZE	
FUEL USED	MINE	COUNTY	STATE	SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R H INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON) (BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP AIR FOR COMBUSTION (This is Reference Temperature) †	F	
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS./LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS./LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item } 28 \times \text{Item } 41)}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item } 26 \times \text{Item } 20) + (\text{Item } 27 \times \text{Item } 21) + \text{Item } 30}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	
33	O_2	% VOL	
34	CO	% VOL	
35	N_2 (BY DIFFERENCE)	% VOL	
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE		51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL
	COAL OR OIL AS FIRED ULTIMATE ANALYSIS		54	CO	
43	CARBON		55	CH_4 METHANE	
44	HYDROGEN		56	C_2H_2 ACETYLENE	
45	OXYGEN		57	C_2H_4 ETHYLENE	
46	NITROGEN		58	C_2H_6 ETHANE	
47	SULPHUR		59	H_2S	
40	ASH		60	CO_2	
37	MOISTURE		61	H_2 HYDROGEN	
	TOTAL			TOTAL	
	COAL PULVERIZATION			TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64 INPUT-OUTPUT EFFICIENCY OF UNIT % $= \frac{\text{ITEM } 31 \times 100}{\text{ITEM } 29}$

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		
66	HEAT LOSS DUE TO MOISTURE IN FUEL		
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		
69	HEAT LOSS DUE TO RADIATION		
70	UNMEASURED LOSSES		
71	TOTAL		
72	EFFICIENCY = (100 – Item 71)		

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

Printed in U.S.A. (10/74)

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PTC 4.1 - 1964

R-29-91
R-31-85

REAPPROVED '79

Steam Generating Units

POWER TEST CODES

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
United Engineering Center
345 East 47th Street New York, N.Y. 10017

Steam Generating Units

POWER
TEST
CODES

Printed in the United States of America

FOREWORD

THE Test Code for Stationary Steam-Generating Units was one of the group of ten forming the 1915 Edition of the ASME Power Test Codes. A revision of these codes was begun in 1918 and the Test Code for Stationary Steam-Generating Units was reissued in revised form in October, 1926. Further revisions were issued in February, 1930 and January, 1936.

In October, 1936 the standing Power Test Codes Committee requested PTC Committee No. 4 to consider a revision of the Code to provide for heat balance tests on large steam generating units. In re-writing the Code advantage was taken of the experience of the several companies in the utility field which had developed test methods for the large modern units including the necessary auxiliary equipment directly involved in the operation of the units. At the same time the needs of the small installations were not overlooked. At the November 30, 1945 meeting of the standing Power Test Codes Committee, this revision was approved and on May 23, 1946 the Code was approved and adopted by the Council.

In view of the continuously increasing size and complexity of steam generating units, it was obvious that changes were required in the 1946 Edition of the Test Code. In May, 1958 the technical committee was reorganized to prepare this revision. The completely revised Code, the Test Code for Steam Generating Units, was approved by the Power Test Codes Committee on March 20, 1964. It was further approved and adopted by the Council as a standard practice of the Society by action of the Board on Codes and Standards on June 24, 1964.

December, 1964

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ASME POWER TEST CODES
Test Code for Steam Generating Units

CONTENTS

SECTION 0, INTRODUCTION

0.1 This Code contains instructions for testing steam generating units. These units are defined as combinations of apparatus for liberating and recovering heat, together with apparatus for transferring to a working fluid the heat thus made available. For the purpose of this Code, such a unit may include the boiler, furnace, superheater, reheater, economizer, air heater, and fuel-burning equipment. The economizer and air heater are not considered a part of the unit when the heat absorbed by them is not returned to the unit. It is not the intent of these testing procedures to obtain data for establishing design criteria of individual parts of the over-all steam generator. Code Supplements PTC 4.2 and PTC 4.3 cover testing of pulverizers and air heaters, respectively.

0.2 It is intended that in using this Code a detailed examination will be made of the Code on General Instructions PTC 1 and all other Codes herein referred to before starting preparations for the tests. Such study is for the purpose of assuring an orderly and thorough testing procedure since it provides the user with an over-all understanding of the ASME Power Test Codes requirements and enables him to understand readily the interrelationship of the various Codes. Care should be exercised to obtain and use the latest revisions of the Codes.

0.3 While Section 2 of this Code is concerned with symbols and their descriptions applying specifically to testing of steam generating units, the user is referred to the Code on Definitions and Values PTC 2 for a more complete discussion of the items which will be encountered.

0.4 The Supplements on Instruments and Apparatus PTC 19 referred to herein should be studied thoroughly because the value of the test results depends on the selection and application of the instruments, their calibration and the accuracy of the readings.

0.4.1 Other items of vital importance to the value of the test are the proper determination of the high-heat value and other properties of the fuel used. The appropriate Code for the type of fuel burned and ASTM Standard Method pertaining to Heat of Combustion should be followed carefully.

0.5 This Code is intended as a guide for the conduct of all steam generator tests, but it could not possibly detail a test applicable to every variation in the design of steam generators. In every case a competent engineer must study the particular unit and its relation with the rest of the cycle and develop test procedures which are in agreement with the general accuracy and intention of this Code. Examples of the design variations in operation at the time of preparation of this Code are subcritical and supercritical once-through units and dual-cycle steam generators. Such units were considered as the Code was being prepared and it is believed that the provisions herein can be applied to the testing of such steam generators.

0.6 The general instructions contained in this Code shall also apply to the testing of high temperature water heaters, except that efficiency determination shall be by heat loss method only, as described in Section 5. The input-output method is not acceptable because of potentially large inaccuracies introduced by the presence of indeterminant quantities of steam in the output and by the small temperature measurement errors in a large volume flow output.

Test capacity or output shall be determined from measured heat input and efficiency, or by direct measurement of heat output if a high degree of accuracy is not required.

0.7 The testing of nuclear and combined-cycle steam generators were not included because their development at the time of revising this Code was such that specific recommendations could not be made.

0.8 Advanced instrument systems, such as those using electronic devices or mass flow techniques, may, by mutual agreement, be used as alternates to the mandatory Code instrument requirements, provided that the application of such instruments has demonstrated accuracy equivalent to that required by this Code.

SECTION 1, OBJECT AND SCOPE

1.01 The purpose of this Code is to establish procedures for conducting performance tests to determine:

1.01.1 Efficiency

1.01.2 Capacity

1.01.3 Other related operating characteristics such as steam temperature and control range, exit gas temperature, draft loss, steam – water – and air – pressure drops, solids in steam and air leakage.

1.02 A determination of any or all of the performance items specified above may be necessary for other purposes such as:

1.02.1 Checking the actual performance against guarantee.

1.02.2 Comparing these items with a standard of operation.

1.02.3 Comparing different conditions or methods of operation.

1.02.4 Determining the performance of different parts of the steam generating unit.

1.02.5 Comparing performance when firing different fuels.

1.02.6 Determining the effects of changes to equipment.

1.03 The rules and instructions given in this Code apply to the equipment defined in the introduction. Testing of auxiliary apparatus shall be governed by the Power Test Code applying specifically to the auxiliary in question.

1.04 Instructions are given for two acceptable methods of testing steam generators to determine efficiency. One method is the direct measurement of input and output, hereinafter referred to as the input-output method. The other method is the direct measurement of heat losses and is hereinafter referred to as the heat loss method. The method followed in conducting the tests shall be clearly defined in the report.

1.04.1 The input-output method requires the accurate measurement of the quantity and high-heat value of the fuel, heat credits and the heat absorbed by the working fluid or fluids.

1.04.2 The heat loss method requires the determination of losses, heat credits and ultimate analysis and high-heat value of the fuel. To establish the capacity at which the losses occur it is necessary to measure either the input or output.

1.04.3 Throughout this Code, input is defined as the chemical heat in the fuel(high-heat value of the fuel as determined from laboratory analysis) plus heat credits added to the working fluid or fluids, air, gas and other fluid circuits which cross the envelope boundary as shown in Fig. 1.* The envelope boundary encompasses the equipment to be included in the designation "steam generating unit." Heat input and output that cross the envelope boundary are involved in the efficiency calculations. Apparatus is outside the envelope boundary when it requires an outside source of heat or where the heat exchanged is not returned to the steam generating unit.

1.04.4 The output is defined as the heat absorbed by the working fluid or fluids.

1.04.5 Heat credits are defined as those amounts of heat added to the envelope of the steam generator unit other than the chemical heat in the fuel "as fired". These credits include quantities such as sensible heat (function of specific heat and the measured temperature) in the fuel, in the entering air and in the atomizing steam, and heat from power conversion in pulverizer, circulating pump, primary air fan and recirculating fan.

1.04.6 For a better understanding of the relationships between input, output, credits and losses, refer to Fig. 2.*

1.05 Capacity of steam generators is defined as actual evaporation in pounds of steam per hour delivered or Btu per hour absorbed by the working fluid or fluids. Capacity of hot water heaters is defined as the heat absorbed by water and the heat of any steam that may be generated (Btu per hour).

1.06 The efficiency of steam generating equipment determined within the scope of this Code is the gross efficiency and is defined as the ratio of heat absorbed by the working fluid or fluids to the heat input as defined in Par. 1.04.3. This definition disregards the equivalent heat in the power

*Note: Figs. 1 and 2 are available in pad form through the ASME Order Department.

required by the auxiliary apparatus external to the envelope (See Fig. 1).

1.06.1 Efficiency for the two methods is expressed by the following equations:

Input-Output Method –

$$\text{Efficiency (per cent)} = \frac{\text{Output}}{\text{Input}}$$

$$= \frac{\text{Heat absorbed by working fluid or fluids}}{\text{Heat in fuel + heat credits}} \times 100$$

For derivation see Par. 7.2

Heat Loss Method –

Efficiency (per cent)

$$= 100 - \left(\frac{\text{Heat Losses}}{\text{Heat in fuel + Heat Credits}} \times 100\right)$$

For derivation see Par 7.3.

1.07 For conducting an abbreviated efficiency test that considers only the major losses, and only the chemical heat in the fuel as input, the data and calculation procedures in the ASME Test Report for Simplified Efficiency Test may be used. (Note: These forms are available in pad form through the ASME Order Department.)

The use of abbreviated test procedures are not encouraged, but it is recognized that on routine testing of all sizes of steam generators and on acceptance testing of small heating and industrial steam generators that a simplified test is the only practical approach. Although the abbreviated test procedure ignores the minor losses and heat credits, the test procedures for obtaining the major items will be the same as specified in PTC 4.1, Test Code for Steam Generating Units and therefore the contents of this Code should be read and understood prior to running a simplified efficiency test. Where heat losses are to be adjusted to compensate for variations in fuel, or changes in inlet air temperature, as would be done in verifying an efficiency guarantee, the procedure given in Section 7, Corrections to Standard or Guarantee Conditions of the Code should be followed.

1.08 The adjustment of test results to include the effect of equivalent heat in auxiliary power to determine "net efficiency" is not a requirement of the Code. If net efficiency is to be determined, it shall be by the method given in Par. 6.2.

1.09 Both the heat loss and the input-output methods of this Code apply to steam generating units operating with either solid, liquid or gaseous fuels.

1.09.1 This Code will apply only when tests are run using a single fuel.

1.09.2 Where test have to be made using a combination of fuels, it will be necessary to establish test procedures and calculations based on the guiding principles and general intent of this Code. For assistance in approaching this problem reference is suggested to Volume 78, Transactions ASME, August, 1956 "Combustion Calculations for Multiple Fuels."

1.10 The determination of data of a research nature or other special data is not covered by this Code.

1.11 It is recommended that a report be prepared for each test, either the abbreviated or complete test, giving complete details of the conditions under which the test has been made including a record of test procedures and all data in form suitable for demonstrating that the objectives of the test have been attained.

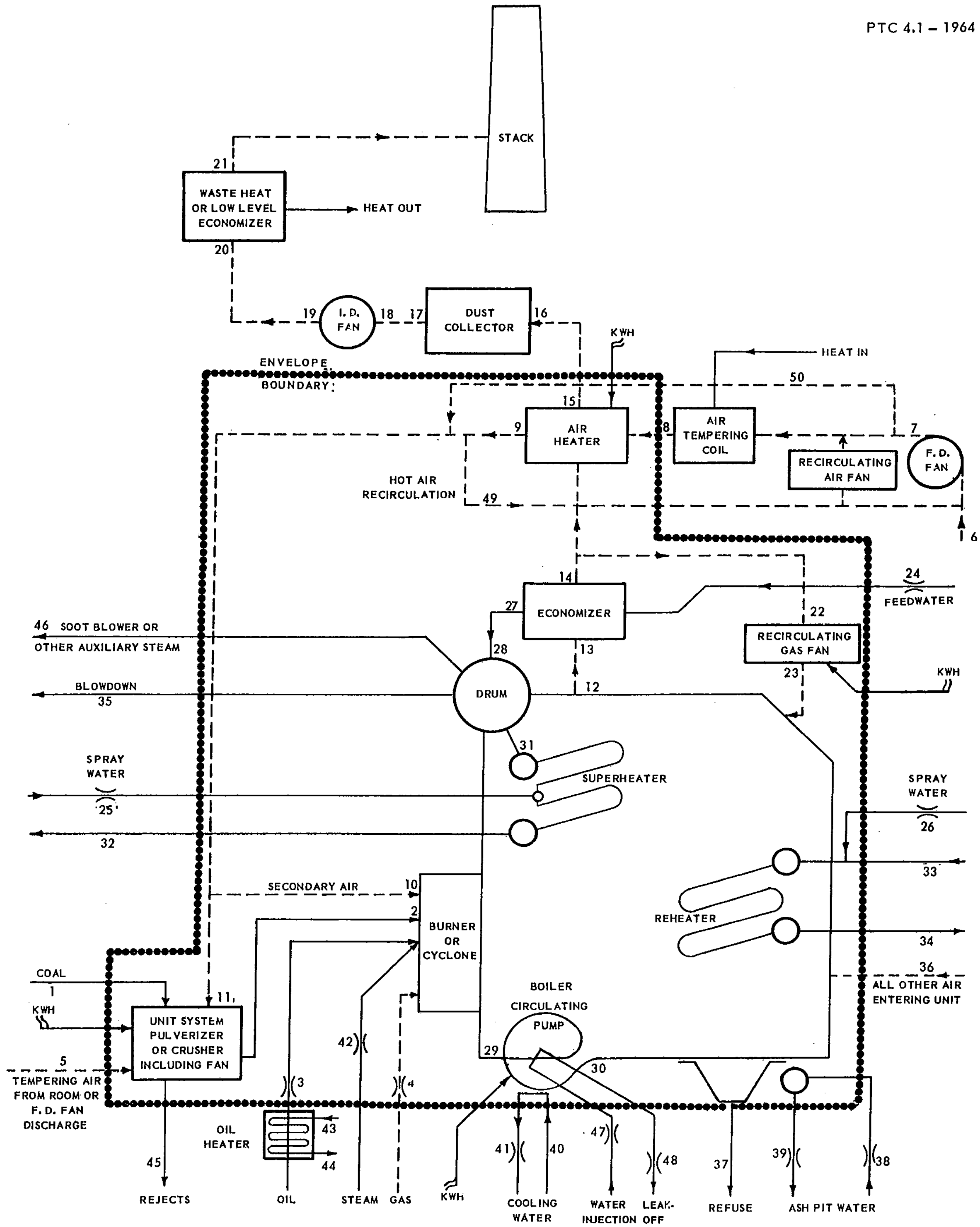
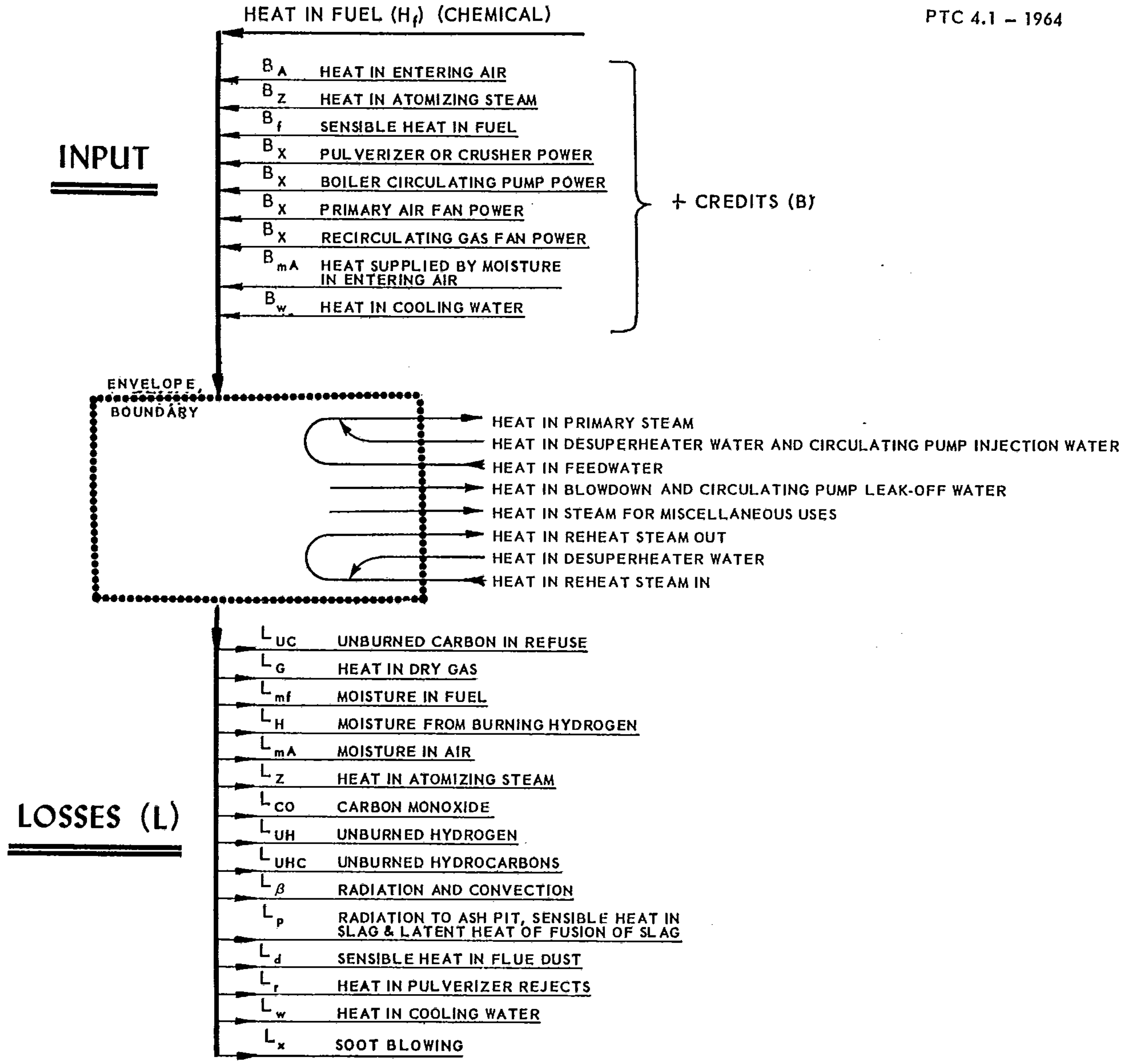


FIG 1 STEAM GENERATING UNIT DIAGRAM



OUTPUT = INPUT − LOSSES

DEFINITION: EFFICIENCY (PERCENT) $= \eta_g (\%) = \dfrac{\text{OUTPUT}}{\text{INPUT}} \times 100 = \dfrac{\text{INPUT} - L}{H_f + B} \times 100$

HEAT BALANCE: $H_f + B = \text{OUTPUT} + L$ OR $\eta_g (\%) = \left[1 - \dfrac{L}{H_f + B}\right] \times 100$

FIG. 2 HEAT BALANCE OF STEAM GENERATOR

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

SUMMARY SHEET

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14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

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22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	

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27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{\text{(Item 28} \times \text{Item 41)}}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{\text{(Item 26} \times \text{Item 20)} + \text{(Item 27} \times \text{Item 21)} + \text{Item 30}}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	
33	O_2	% VOL	
34	CO	% VOL	
35	N_2 (BY DIFFERENCE)	% VOL	
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
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38	VOL MATTER		52	Sp. Gravity Deg. API*	
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40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL
	COAL OR OIL AS FIRED ULTIMATE ANALYSIS		54	CO	
43	CARBON		55	CH_4 METHANE	
44	HYDROGEN		56	C_2H_2 ACETYLENE	
45	OXYGEN		57	C_2H_4 ETHYLENE	
46	NITROGEN		58	C_2H_6 ETHANE	
47	SULPHUR		59	H_2S	
40	ASH		60	CO_2	
37	MOISTURE		61	H_2 HYDROGEN	
	TOTAL			TOTAL	
	COAL PULVERIZATION			TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	
64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$			

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		
66	HEAT LOSS DUE TO MOISTURE IN FUEL		
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		
69	HEAT LOSS DUE TO RADIATION		
70	UNMEASURED LOSSES		
71	TOTAL		
72	EFFICIENCY = (100 – Item 71)		

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

CALCULATION SHEET

PTC 4.1-b (1964)

OWNER OF PLANT	TEST NO.	BOILER NO.	DATE

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} \; \ldots \; - \; \text{ITEM 17} \; \ldots}{1000}\right]$ = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43} \; \ldots\ldots}{100} - \left[\frac{\text{ITEM 22} \; \ldots\ldots \times \text{ITEM 23} \; \ldots\ldots}{14.500}\right]$ = ...

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S)

$$= \frac{11 \times \text{ITEM 32} \; \ldots + 8 \times \text{ITEM 33} \; \ldots + 7\left(\text{ITEM 35} \; \ldots + \text{ITEM 34} \; \ldots\right)}{3 \times \left(\text{ITEM 32} \; \ldots + \text{ITEM 34} \; \ldots\right)} \times \left[\text{ITEM 24} \; \ldots + \frac{\text{ITEM 47} \; \ldots}{2.67}\right] = \ldots\ldots$$

36 EXCESS AIR† = $100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = ITEM 25 ...... × 0.24 ...... (ITEM 13) ...... − (ITEM 11) ...... =	......	$\frac{65}{41} \times 100 =$	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41} \times 100 =$	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41} \times 100 =$	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 ...... × ITEM 23 ...... = ...	......	$\frac{68}{41} \times 100 =$	......
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	......	$\frac{69}{41} \times 100 =$	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41} \times 100 =$	......
71	TOTAL	......	......	......
72	EFFICIENCY = (100 − ITEM 71)	......	......	......

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

SECTION 2, SYMBOLS AND THEIR DESCRIPTIONS

2.1 Numerical Subscripts. The diagram of a steam generating unit, shown in Fig. 1, is intended to serve as a key to numerical subscripts employed throughout this Code to indicate the location to which reference is made. Many large installations will have all of the apparatus shown. Small industrial and commercial installations will be less elaborate. Even though the apparatus may not be in exactly the same relative position, it is believed that the numerical identification shown on this line diagram will prove applicable and helpful.

2.1.1 In the case of chemical symbols, the numerical subscripts refer to the number of atoms and not to the key diagram. The standard chemical symbols are used throughout this Code and are so well known that it is considered unnecessary to enumerate all of them.

2.1.2 When net efficiency is to be computed as outlined in Par. 6.2, it is necessary to determine certain values at points not indicated on Fig. 1. These items will carry subscripts higher than those shown on Fig. 1.

2.2 Symbols. A list of symbols for use in the computation is included at the end of this section. The chemical symbols are also used in some cases as subscripts.

2.2.1 With so many quantities and points of reference involved, it has been found impractical to restrict the Code to the use of single subscripts. Where both letter and numerical subscripts are used, the numerical one is given second; for example W_{se32}. This symbol means "W" for pounds, "s" for steam, "e" for elapsed time and "W_{se32}" then should be read "pounds of steam per hour at location 32 on Fig. 1" (Superheater outlet).

Symbols and Description

Symbol	Description	Unit
A	Air	....
A'	Dry Air	....
A.F.	As fired	....
API_{gr}	Gravity of the fuel based on the API scale	deg API
A_θ	Theoretical quantity of air required for complete combustion of the fuel	lb per lb of A.F. fuel
A_X	Excess air is the actual quantity of air used minus the theoretical air required divided by the theoretical air, and expressed as a percentage	per cent
a	Ash content of the fuel	per cent by weight
B	Heat credits added to the steam generator in the form of sensible heat	Btu
B_{Ae}	Sensible heat supplied by the entering air (rate)	Btu per hr
$B_{A'e}$	Sensible heat supplied by the *dry* entering air (rate)	Btu per hr
B_e	Heat credits added to the steam generator in the form of sensible heat (rate)	Btu per hr
B_{fe}	Sensible heat supplied with the fuel (rate)	Btu per hr
B_{mAe}	Heat supplied from the moisture entering with the inlet air (rate)	Btu per hr
B_{xe}	Heat supplied by auxiliary drives (rate)	Btu per hr
B_{ze}	Heat supplied by the atomizing steam (rate)	Btu per hr
b	Burned	....
C	Pounds of carbon per pound of "as fired" fuel – (laboratory analysis)	lb per lb of A.F. fuel
C_b	Pounds of carbon burned per pound of "as fired" fuel	lb per lb of A.F. fuel
CO	Per cent carbon monoxide per volume of dry flue gas. Determined by flue gas analysis	per cent
CO_2	Per cent carbon dioxide per volume of dry flue gas. Determined by flue gas analysis	per cent
CO_{2HC}	The pounds of carbon dioxide formed from burning the hydrocarbon in the dry flue gas	lb per lb of dry gas
c	Specific heat	Btu per lb F
c_p	Specific heat at constant pressure	Btu per lb F
$c_{pA'}$	Mean specific heat of dry air at constant pressure	Btu per lb F
c_{pd}	Mean specific heat at constant pressure for the flue dust over the temperature from the reference to the flue gas temperature	Btu per lb F

Symbols and Description (Cont'd)

Symbol	Description	Unit
c_{pf}	Mean constant pressure specific heat of the inlet fuel determined for temperature difference between fuel inlet temperature and reference temperature	Btu per lb F
c_{pG}	Mean specific heat of the flue gas	Btu per lb F
c_{ps}	Specific heat of steam	Btu per lb F
D	Standard or guarantee	....
d	Flue gas refuse (dust)	....
d'	Dry flue gas refuse (dust)	....
E	Energy	Btu
E_x	Energy consumed by auxiliaries	Btu
e	Elapsed time	hr
f	Fuel	....
G	Flue gas	....
G'	Dry flue gas	....
g	Gross	....
H	Pounds of hydrogen exclusive of that in moisture per pound of "as fired" fuel (laboratory analysis)	lb per lb of A.F. fuel
H_2	Hydrogen content of the flue gas (laboratory analysis)	cu ft per cu ft dry gas
HC	Per cent hydrocarbons per volume of dry flue gas (laboratory analysis)	per cent
$H_{d'p'}$	High-heat value of total dry refuse (laboratory analysis)	Btu per lb of refuse
H_{fp}	High-heat value of the fuel at constant pressure	Btu per lb
H_{fv}	High-heat value of the fuel at constant volume	Btu per lb
H_f	High-heat value (chemical heat) of the fuel on the "as fired" basis (laboratory analysis)	Btu per lb
$H_{f'}$	High-heat value (chemical heat) of the fuel on a dry basis (laboratory analysis)	Btu per lb
H_r	High-heat value (chemical heat) of the pulverizer rejects (laboratory analysis)	Btu per lb
h	Enthalpy	Btu per lb
h_{Rw}	Reference enthalpy of entering moisture. It is the enthalpy of the liquid at the reference temperature	Btu per lb
h_{Rv}	Reference enthalpy of entering vapor. It is the enthalpy of the saturated vapor at the reference temperature	Btu per lb
h_s	Enthalpy of steam	Btu per lb
h_{sx}	Enthalpy of steam supplied to any auxiliary steam drive	Btu per lb

Symbols and Description (Cont'd)

Symbol	Description	Unit
h_v	Enthalpy of the vapor	Btu per lb
h_w	Enthalpy of the liquid	Btu per lb
i	Isentropic process	....
K	Btu per cubic foot of dry flue gas (laboratory analysis)	Btu per cu ft of dry gas
(kwh)	Electrical energy	Kilowatt-hour
L	Heat loss from the steam generator which could have been added to the working fluid	Btu per lb of A.F. fuel
L_{CO}	Heat loss due to the formation of carbon monoxide	Btu per lb of A.F. fuel
L_d	Heat loss due to sensible heat in flue dust	Btu per lb of A.F. fuel
$L_{G'}$	Heat loss due to heat in dry flue gas	Btu per lb of A.F. fuel
L_H	Heat loss due to moisture from burning hydrogen	Btu per lb of A.F. fuel
L_{mA}	Heat loss due to moisture in the combustion air	Btu per lb of A.F. fuel
L_{mf}	Heat loss due to moisture in the "as fired" fuel	Btu per lb of A.F. fuel
L_p	Heat loss due to radiation to ashpit, sensible heat in slag and, if applicable, latent heat of fusion of slag	Btu per lb of A.F. fuel
L_r	Heat loss due to heat in pulverizer rejects	Btu per lb of A.F. fuel
L_{UC}	Heat loss due to unburned carbon	Btu per lb of A.F. fuel
L_{UH}	Heat loss due to unburned hydrogen	Btu per lb of A.F. fuel
L_{UHC}	Heat loss due to unburned hydrocarbons	Btu per lb of A.F. fuel
L_w	Heat loss due to heat rejected to cooling water used within the envelope Fig. 1	Btu per lb of A.F. fuel
L_z	Heat loss due to heat in the atomizing steam	Btu per lb of A.F. fuel
L_β	Heat loss due to radiation and convection	Btu per lb of A.F. fuel
M	Molecular weight of any substance	lb per mole
M_{HC}	Molecular weight of hydrocarbons	lb per mole

Symbols and Description (Cont'd)

Symbol	Description	Unit
m	Moisture content	per cent by weight
m_f	Moisture in fuel	lb of water per lb of A.F. fuel
m_p	Moisture in pit refuse	lb of water per lb of pit refuse
N	Pounds of nitrogen per pound of "as fired" fuel (laboratory analysis)	lb per lb of A.F. fuel
N_2	Per cent nitrogen per volume of dry flue gas. Determined by subtracting the sum of the measured quantities CO_2, O_2 and CO from 100	per cent
n	Net	....
O	Pounds of oxygen per pound of "as fired" fuel (laboratory analysis)	lb per lb of A.F. fuel
O_2	Per cent oxygen per volume of dry flue gas. Determined by flue gas analysis	per cent
P	Pressure	....
P_A	Atmospheric pressure	psia
P_f	Pressure of gaseous fuel at the primary measuring element	psia
P_{mA}	The partial pressure or vapor pressure of the moisture in the air	psia
P_{mG}	The partial pressure or vapor pressure of the moisture in the flue gas	psia
P_s	Pressure of the steam measured at the point indicated by the appropriate numerical subscript (Fig. 1)	psia
P_w	Pressure of the water measured at the point indicated by the subscript number (Fig. 1)	psia
p	Ashpit refuse	lb
$\boxed{p}$	Ashpit	....
p'	Dry pit refuse	lb
Q_{fe}	Quantity of gaseous fuel fired (rate) – based on 14.7 psia and 68 F. Note that the standard cu ft in the gas industry is based on 60 F and 14.73 psia	cu ft per hr
R	Reference	....
R_u	Universal gas constant (1545)	ft-lb/lb mole, deg R
r	Pulverizer rejects	lb
S	Pounds of sulfur per pound of "as fired" fuel (laboratory analysis)	lb per lb of A.F. fuel

Symbols and Description (Cont'd)

Symbol	Description	Unit
SO_2	Per cent sulfur dioxide per volume of dry flue gas (laboratory analysis)	per cent
s	Steam	....
T	Temperature Rankine	R
t	Temperature Fahrenheit	F
t_{RA}	Reference air temperature is the base temperature to which sensible heat losses and credits are compared for efficiency computations	F
t_A	Temperature of air	F
t_f	Temperature of fuel	F
t_G	Temperature of flue gas	F
t_s	Temperature of steam	F
t_w	Temperature of the water	F
U	Unburned	....
V	Volume of any substance – substance indicated by subscript	cu ft
v	Vapor	....
W	Weight	lb
W_A	Pounds of moist air supplied per pound of "as fired" fuel	lb per lb of A.F. fuel
$W_{A'}$	Pounds of dry air supplied per pound of "as fired" fuel	lb per lb of A.F. fuel
W_{Ae}	Pounds of air supplied (rate)	lb per hr
$W_{A'e}$	Pounds of dry air supplied (rate)	lb per hr
$W_{G'}$	The pounds of dry gas leaving unit per pound of "as fired" fuel	lb per lb of A.F. fuel
$W_{d'p'}$	Pounds of dry refuse per pound of "as fired" fuel	lb per lb of A.F. fuel
$W_{d'p'e}$	Pounds of dry refuse collected (rate)	lb per hr
W_{fe}	Pounds of fuel fired (rate) either solid or liquid	lb per hr
$W_{G'N_2}$	Pounds of nitrogen in dry gas per pound of "as fired" fuel	lb per lb
$W_{mA'}$	Pounds of moisture per pound of dry air	lb per lb of dry air
W_{se}	Pounds of steam per hour flowing at any location identified by appropriate numerical subscript	lb per hr
W_{sxe}	Pounds of steam supplied (rate) to all the steam driven auxiliaries	lb per hr
W_{we}	Pounds of water (rate)	lb per hr
W_z	Pounds of atomizing steam per pound of "as fired" fuel	lb per lb of A.F. fuel

Symbols and Description (Cont'd)

Symbol	Description	Unit
w	Water	....
X	Excess	....
x	Auxiliary	....
z	Atomizing steam	....
β	Radiation and convection	....
γ	Gas specific weight at 68 F and 14.7 psia	lb per cu ft of gas
δ	Corrected	....
η	Efficiency	per cent
η_g	Gross efficiency	per cent
η_n	Net efficiency	per cent
η_x	Efficiency of auxiliary drives	per cent
θ	Theoretical	....
ψ	The number of pound moles of any substance – substance indicated by subscript	....
$'$ (prime)	Dry	....
Δ	Change	....

2.3 Test and Run. Throughout this Code the word "test" is applied only to the entire investigation, and the word "run" to a subdivision. A run consists of a complete set of observations made for a period of time with one or more of the independent variables maintained virtually constant.

SECTION 3, GUIDING PRINCIPLES

3.01 Items on Which Agreement Shall be Reached. In order to achieve the objectives of the test the interested parties must reach agreement on the following pertinent items:

3.01.01 Gross efficiency determination – Defined in Par. 1.06.

3.01.01.1 General method – Heat loss or input-output.

3.01.01.2 Heat credits to be measured.

3.01.01.3 Heat credits to be assigned where not measured.

3.01.01.4 Heat losses to be measured.

3.01.01.5 Heat losses to be assigned where not measured.

3.01.01.6 Permissible deviation in efficiency between duplicate runs.

3.01.02 Capacity or Output – Defined in Par. 1.05.

3.01.03 Other related operating characteristics – See Section 8.

3.01.04 Allocation of responsibility for all performance and operating conditions which affect the test.

3.01.05 Selection of test personnel to conduct the test.

3.01.06 Establishment of acceptable operational conditions, number of load points, duration of runs, basis of rejection of runs and procedures to be followed during the test.

3.01.07 Cleanliness of unit initially and how this is to be maintained during the test. See Par. 3.04.2.

3.01.08 Actual air leakage to be allowed, if any, initially or during the test.

3.01.09 The source of thermodynamic properties to be used. Sources such as "Thermodynamic Properties of Steam" by Keenan and Keyes, and ASME Supplement thereto, and "Vapor Charts" by Ellenwood and Mackey are acceptable.

3.01.10 The fuel to be fired, the method of obtaining fuel samples and the laboratory to make the analysis.

3.01.11 Observations and readings to be taken to comply with the object or objectives of the test.

3.01.12 Instruments to be used, calibration of instruments, methods of measurement and equipment to be used in testing the unit. The Power Test Code Supplements on Instruments and Apparatus should be used, when applicable.

3.01.13 Tolerances and limits of error in measurement and sampling.

3.01.14 Distribution of fuel refuse quantities between various collection points and methods of sampling.

3.01.15 Corrections to be made for deviations from specified operating conditions.

3.02 Selection of Personnel. To insure obtaining reliable results, all personnel participating in the test shall be fully qualified to perform their particular function.

3.03 Tolerances and Limits of Error. This Code does not include consideration of over-all tolerances or margins on performance guarantees. The test results shall be reported as computed from test observations, with proper corrections for calibrations.

3.03.1 Allowances for errors of measurement and sampling are permissible provided they are agreed upon in advance by the parties to the test and clearly stated in the test report. The limits of probable error on calculated steam generator efficiency, shall be taken as the square root of the sum of the squares of the individual effects on efficiency.

3.03.2 Whenever allowances for probable errors of measurement and sampling are to be taken into consideration, the reported test results shall be qualified by the statement that the error in the results may be considered not to exceed a given plus or minus percentage, this value having been determined in accordance with the foregoing method for computing limits of probable error.

3.03.3 The following table is included as a guide to show the effect on efficiency of measurement errors exclusive of sampling errors. The measurement error range in the table is not intended to be authoritative but conforms approximately with experience. The values in the table are not intended to be used in any calculation of test results.

PROBABLE MEASUREMENT ERRORS
AND RESULTING ERRORS IN EFFICIENCY CALCULATIONS

3.03.4 I – Input-Output Method

Measurement	Measurement error, per cent	Error in calculated Steam Generator Efficiency, per cent
(1) Weigh tanks (calibrated scales)	±0.10	±0.10
(2) Volumetric tanks (calibrated)	±0.25	±0.25
(3) Calibrated flow nozzle or orifice including manometer	±0.35	±0.35
(4) Calibrated flow nozzle or orifice including recorder	±0.55	±0.55
(5) Coal scales – Batch or dump (calibrated)	±0.25	±0.25
(6) Uncalibrated flow nozzle or orifice including manometer	±1.25	±1.25
(7) Uncalibrated flow nozzle or orifice including recorder	±1.60	±1.60
(8) Fuel heating value (coal)	±0.50	±0.50
(gas and oil)	±0.35	±0.35
(9) Reheat flow (based on heat balance calculations)	±0.60	±0.10
(10) Superheater outlet temperature (calibrated measuring device)	±0.25	±0.15
(11) Superheater outlet pressure (calibrated measuring device)	±1.00	±0.00
(12) Reheater inlet and outlet temperature (calibrated measuring device)	±0.25	±0.10
(13) Reheater inlet and outlet pressure (calibrated measuring device)	±0.50	±0.00
(14) Feedwater temperature (calibrated measuring device)	±0.25	±0.10

3.03.5 II – Heat Loss Method

Measurement	Measurement error, per cent	Error in calculated Steam Generator Efficiency, per cent
(1) Heating value (coal)	± 0.50	± 0.03
(gas and oil)	± 0.35	± 0.02
(2) Orsat analysis	± 3.00	± 0.30
(3) Exit gas temperature (calibrated measuring device)	± 0.50	± 0.02
(4) Inlet air temperature (calibrated measuring device)	± 0.50	± 0.00
(5) Ultimate analysis of coal (carbon)	± 1.00	± 0.10
(hydrogen)	± 1.00	± 0.10
(6) Fuel moisture	± 1.00	± 0.00

3.04 Acceptance Test. An acceptance test shall be undertaken only when the parties to the test certify that the unit is operating to their satisfaction and is, therefore, ready for test. Especially in the case of fuel burning equipment, adjustments and changes are sometimes necessary to obtain optimum performance. The acceptance test should be started as soon as the unit is in satisfactory condition for test, provided the load and other governing factors are suitable.

3.04.1 Parties to the test may designate a person to direct the test and to serve as arbiter in the event of disputes as to the accuracy of observations, conditions or methods of operation, see Par. 8.04.1.

3.04.2 All heat transfer surfaces, both internal and external, should be commercially clean (normal operating cleanliness) before starting the test, refer to Par. 3.01.7. During the test, only the amount of cleaning shall be permitted as is necessary to maintain normal operating cleanliness.

3.04.3 After a preliminary run has been made, it may be declared an acceptance run if agreed to and provided that all the requirements of a regular run have been met.

3.04.4 At least two runs shall be made approximating the load required for acceptance. If the results exceed the previously agreed upon deviation in efficiency between runs, a third run will be required. The test efficiency at the required load will be the average of the two runs which fall within the permissible deviation in efficiency.

3.05 Preparation for All Tests.

3.05.1 The entire steam generating unit shall be checked for leakage. Air heater internal leakage shall also be checked. Excessive leakage shall be corrected.

3.05.2 Before the test is started, it shall be determined whether the fuel to be fired is substantially as intended.

3.05.3 Any departures from standard or previously specified conditions in physical state of equipment, cleanliness of heating surfaces, fuel characteristics, or constancy of load, shall be described clearly in the report of the test.

3.06 A Preliminary Run shall be made for the purpose of:

3.06.1 Checking the operation of all instruments.

3.06.2 Training the observers and other test personnel.

3.06.3 Making minor adjustments, the needs for which were not evident during the preparation for the test, and establishing proper combustion conditions for the particular fuel and rate of burning to be employed.

3.07 Starting and Stopping. Combustion conditions, rate of feeding fuel (also quantity of fuel on grate if stoker fired), rate of feeding water, water level in drum (if of drum type), excess air and all controllable temperatures and pressures shall be, as nearly as possible, the same at the end of the run as at the beginning. These, and any other conditions in which variations might affect the results of the test, shall be essentially reached and held as constant as possible. There must be reasonable assurance that the temperature of the refractories of the setting and all other parts of the equipment have reached equilibrium before the run is started. The time required to attain stabilization or equilibrium with respect to temperatures will vary widely with the design of the unit and character of materials in the setting. This period of stabilization can vary from a minimum of one hour to more than three hours.

3.07.1 In some instances it may be necessary to terminate a run prematurely because of inability to maintain one or more of the operating conditions at the desired value.

3.07.2 In order to attain the desired operating conditions when solid fuel is fired by stokers, it is essential that major cleaning and conditioning of the fuel bed shall be accomplished some length of time before the run starts and again the same length of time before the run is completed. Minor occasional normal cleaning of the fuel bed may be permitted during the run. Rate of burning or feeding fuel after the initial cleaning of fires shall be kept at that rate which is to prevail during the run. The fuel bed depth shall be the same at the beginning and end of the run. The ashpit shall be emptied either just after the initial and final cleaning and conditioning of the fuel bed or just before the start and end of the run so that the weight of refuse corresponds to the weight of coal burned.

3.07.3 In the case of runs to determine the maximum output at which the unit can be operated for a short period, the run should be started as soon as the maximum output is reached and continued until conditions necessitate terminating the run.

3.08 Duration of Runs.

3.08.1 When determining the efficiency of coal fired units, using pulverized coal or crushed coal as in the case of cyclone firing, the runs should be preferably of not less than four hours duration. This duration is satisfactory even for tests conducted by the input-output method provided a unit system of pulverizers or crushers is used, and the fuel weighed as it is fed to the pulverizers or crushers. For those stations having a centralized fuel preparation plant, it may be impractical to weigh the fuel fed to any one unit, in which case the loss method should be used.

3.08.2 When determining the efficiency of a stoker fired steam-generating unit by input-output, the runs should be preferably of twenty-four hours duration. However, in the case of continuous ash discharge stokers, if conditions make it advisable, the length of a run may be reduced, but not to less than ten hours. The longer the duration of the runs the less will be the possibility of significant error due to estimating the difference in amount of unburned fuel on the grate at the beginning and end of the run. In many cases it is difficult to estimate the change in thickness of a large fuel bed closer than three inches. When the ratio of ash to unburned fuel is also indeterminate, the final estimate of effective change in bed thickness will frequently be in error by as much as four inches. The possible error due to estimating the effective change in the amount of unburned fuel on the grate at the beginning and end of each run should be considered in determining the duration of each run. Runs by heat loss method shall be of at least four hours duration.

3.08.3 When determining the efficiency of steam generating units fired with liquid or gaseous fuels, the runs should preferably be of not less than four hours duration.

3.08.4 For waste heat boilers, efficiency runs shall be for not less than four hours duration.

3.08.5 The duration of runs to determine the maximum short period output, when the efficiency is not to be determined, shall be by agreement of the parties to the test.

3.08.6 The actual duration of all runs from which the final test data are derived shall be clearly stated in the test report.

3.09 Performance Curves. It is desirable, but not mandatory, that runs be made at not less than four different outputs, so that curves may be drawn to relate the test points. Such curves, showing pertinent test data, plotted against output, are very useful in appraising the performance of the unit, because the desired outputs are seldom exactly obtained during the test. Where there are enough test points to establish characteristic curves, the performance at any output may be read from the curves.

3.10 Frequency and Consistency of Readings. Except for quantity measurements, the readings shall be taken at 15 minute intervals. If, however, there are fluctuations, the readings shall be taken at such frequency as may be necessary to determine the average.

3.10.1 Where the amount of fuel or feedwater is determined from integrating instruments, a reading shall be taken every hour. If the quantities to be determined are weighed, the frequency of weighing is usually determined by the capacity of the scales, but the intervals shall be such that a total can be obtained for each hour of the test. The time shall be recorded when each hopper of coal or each tank of feedwater is dumped. When indicating flowmeters or manometers are used with venturi tubes, flow nozzles or orifice plates for subsequently determining quantity measurements, the flow indicating element shall be read at five minute intervals or more frequently when deemed necessary.

3.10.2 It is suggested that, in so far as feasible, pertinent data of the run be plotted continuously, as the run progresses, on coordinate paper of suitable scale arrangements to permit a complete review of the conduct of the run at least hourly.

3.11 Rejection of Runs. Should serious inconsistencies in the observed data be detected during a run or during the computation of the results, the run shall be rejected completely, or in part if the affected part is at the beginning or at the end of the run. A run that has been rejected shall be repeated, if necessary to attain the objectives of the test.

3.12 Records and Test Reports. All observations, measurements and instrument readings necessary for the objective of the test shall be recorded as observed. Corrections and corrected values shall be entered separately in the test record.

3.13 Instruments and Methods of Measurement. The necessary instruments and procedures for making measurements are prescribed herein and should be used in conjunction with the following ASME Power Test Codes Supplements on Instruments and Apparatus, and other publications for detailed specifications on apparatus and procedures involved in the testing of steam-generating units. In all cases, care shall be exercised to refer to the latest revision of the document concerned.

3.13.1 ASME Power Test Codes:

- General Instructions PTC 1
- Definitions and Values PTC 2
- Diesel and Burner Fuels PTC 3.1
- Solid Fuels PTC 3.2
- Gaseous Fuels PTC 3.3
- Coal Pulverizers PTC 4.2
- Air Heater PTC 4.3
- Centrifugal, Mixed Flow and Axial Flow Compressors and Exhausters PTC 10
- Fans PTC 11
- Dust Separating Apparatus PTC 21
- Determining Dust Concentration in a Gas Stream PTC 27

3.13.2 Supplements on Instruments and Apparatus PTC 19:

- Part 1, General Considerations PTC 19.1
- Part 2, Pressure Measurement PTC 19.2
- Part 3, Temperature Measurement PTC 19.3
- Part 5, Measurement of Quantity of Materials PTC 19.5
- Part 6, Electrical Measurements in Power Circuits PTC 19.6
- Part 10, Flue and Exhaust Gas Analyses PTC 19.10
- Part 11, Determination of Quality of Steam PTC 19.11
- Part 12, Measurement of Time PTC 19.12
- Part 13, Measurement of Rotary Speed PTC 19.13
- Part 16, Density Determinations PTC 19.16
- Part 17, Determination of Viscosity of Liquids PTC 19.17
- Part 18, Humidity Determinations PTC 19.18
- Part 21, Leakage Measurement PTC 19.21

3.13.3 ASME Research Publication:

- Fluid Meters — Their Theory and Application

3.13.4 American Gas Association:
Orifice Metering of Natural Gas – Gas Measurement Committee Report No. 3, April, 1955

3.13.5 ASTM Standard Methods:
Methods of Sampling Coals, D 492
Laboratory Sampling and Analysis of Coal and Coke, D 271
Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, D 240
Test for Calorific Value of Gaseous Fuel by the Water-Flow Calorimeter, D 900

3.13.6 National Bureau of Standards:
Methods of Measuring Humidity and Testing Hygrometers, Circular 512

SECTION 4, EFFICIENCY BY INPUT-OUTPUT METHOD

4.01 Determination of Steam Generator Efficiency by Input-Output Method. This method is based on the ratio of the output, to the sum of the fuel input plus heat credits. It requires accurate measurement of the quantity and high-heat value of the fuel and the heat absorbed by the steam generator.

Input Measurement

4.02 The following paragraphs describe the methods of determining the steam generator input. These methods shall be used when evaluating the steam generator by the input-output method.

4.03 Solid Fuel-Quantity Measurement. Fuel shall be weighed near the point where it is to be used. All loss of fuel between the point of weighing and the point of introduction to the steam generating unit shall be measured and accounted for. The weighing scales shall be calibrated prior to and after the test. Experience indicates a possible measurement error within 0.25 per cent in the range of loads weighed. Checks and calibrations shall be made in accordance with I & A, Measurement of Quantity of Materials PTC 19.5, Chapter 1.

4.03.1 Arrangement and operation of fuel weighing equipment shall preferably be such that checks can be made on consumption during each hour of the run as a matter of convenience and guide. Only the totals, however, are to be used in the final calculations.

4.04 Solid Fuel Sampling. A representative sample of fuel shall be obtained in accordance with the Test Code for Solid Fuels PTC 3.2.

4.04.1 "Because of the many variations in the conditions under which coal must be sampled, and the nature of the material being sampled, it is essential that the samples be collected by a trained and experienced sampler. Variations in the manner in which the coal is handled are such that it is impossible to specify rigid rules describing the exact manner of sample collection. Correct sampling principles must be applied to conditions as they are encountered.

4.04.2 "The first principle of coal sampling for a boiler test is to obtain the sample from a moving stream. The second principle is to obtain as many increments as is practical. The ASTM increments listed under Section 5, Special Purpose Sampling Procedure, should be considered the minimum accepted for fairly uniform coal from one source."*

4.04.3 The special sample for moisture determination shall be separated from the general sample, quickly placed in a non-corrosive air tight container and sealed immediately. This sample for moisture shall not be quartered or crushed prior to moisture determination in the laboratory. Every effort shall be made to avoid loss of moisture due to strong drafts at the point of sampling (such as may occur at a pulverizer feeder for example).

4.05 Solid Fuel Analysis and High-Heat Value. Fuel analysis and high-heat value determination shall be made in accordance with the Test Code for Solid Fuels PTC 3.2 and ASTM Standard Methods of Laboratory Sampling and Analysis of Coal and Coke, ASTM D 271. This is a constant volume determination. However, the fuel is burned at constant pressure in the steam generator, and therefore, the high-heat value at constant volume as determined in the bomb calorimeter must be converted to a constant pressure high-heat value. See Par. 7.2.6.2. This high-heat value for constant pressure combustion is referred to as the high-heat value throughout this Code. When testing in accordance with the input-output method, only the high-heat value and the moisture content of the fuel are required.

4.06 Liquid Fuel – Quantity Measurement. The preference for this measurement is by means of calibrated weigh tanks. If such facilities are not available then calibrated volumetric tanks should be used. Experience indicates the former to have a possible measurement error within ±0.10 per cent and the latter within ±0.25 per cent. Calibrations and handling of the tanks during tests should be such as to obtain these accuracies. Positive displacement meters may be used if carefully calibrated under conditions simulating those existing during the test in regard to grade of fuel,

*Material under quotation marks is from ASTM D 492-48 Method of Sampling Coals.

temperature, pressure, rate of flow and meter location. Calibrated meter accuracy must be within ±0.50 per cent.

4.06.1 Leakage of fuel between point of measurement and point of firing shall be measured and accounted for in the flow calibration. Branch connections on the fuel piping shall be either blanked off or provided with double valves and suitable telltale drains for detecting leakage. Leakage from valve stuffing boxes shall be prevented. Any unavoidable leakage from pump stuffing boxes, or elsewhere, shall be collected and accounted for. Where an oil return system from the burners is used, both supply and return flows shall be measured by calibrated meters.

4.06.2 Practice and precautions relative to the use of weigh tanks and volumetric tanks for liquid fuel measurement shall be those stated in Pars. 4.14 and 4.15.

4.07 Liquid Fuel-Sampling. A representative sample of fuel shall be obtained in accordance with the Test Code for Diesel and Burner Fuels PTC 3.1.

4.08 Liquid Fuel Analysis and High-Heat Value. Fuel analysis, high-heat value, density and viscosity determination shall be made in accordance with the Test Code for Diesel and Burner Fuels PTC 3.1, ASTM Standard Methods for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter D 240, Density Determinations PTC 19.16 and Determination of the Viscosity of Liquids PTC 19.17. This is a constant volume determination. However, the fuel is burned at constant pressure in the steam generator and, therefore, the high-heat value at constant volume as determined in the bomb calorimeter must be converted to a constant pressure high-heat value. See Par. 7.2.6.2. This high-heat value for constant pressure combustion is referred to as the high-heat value throughout this Code.

4.09 Gaseous Fuel – Quantity Measurement. Measurement of the relatively large volumes of gaseous fuel normally encountered in testing steam generators requires the use of the orifice, flow nozzle or venturi. The measuring device shall be calibrated prior to and after the test. For probable measurement errors see Par. 3.03.4.

4.09.1 The recommendations of I & A, PTC 19.5, Chapter 4, shall be followed with reference not only to the design, construction, calibration and use of flow measuring elements, but also to their location and installation in the pipe line and the installation of the connecting piping system between the primary element and manometer. All computations of flow rate from the observed differentials, pressures and temperatures shall be made in accordance with the provisions of PTC 19.5, Chapter 4. Where natural gas is used, it may be advantageous to use the method and procedure of "Orifice Metering of Natural Gas." See Par. 3.13.4.

4.09.2 If fluctuations in flow are present, due to reciprocating devices or other source of pulsation, the difference between the indicated maximum and minimum flow rates shall be minimized and must be made to be less than ±5 per cent of the average flow, by the introduction of a cushion chamber, surge chamber, or other means of absorbing the pulsations between the source of pulsation and the primary device, before measurement is considered acceptable. For further discussion of pulsating flow measurement see ASME Research Publication: Fluid Meters – Their Theory and Application – Pars. 106 to 109, inclusive.

4.09.3 Pressure of the gaseous fuel at point of volume determination and at other required points shall be measured by a suitable manometer or pressure gage as described in Instruments and Apparatus, Pressure Measurement PTC 19.2. Temperature shall be measured with thermometers in accordance with I & A Temperature Measurement PTC 19.3, Chapter 5 on Liquid-in-Glass Thermometers.

4.10 Gaseous Fuel-Sampling. The gas shall be properly sampled in accordance with the Test Code for Gaseous Fuels PTC 3.3.

4.11 Gaseous Fuel Analysis and High-Heat Value. Fuel analysis and high-heat value determination shall be made in accordance with the Test Code for Gaseous Fuels PTC 3.3 and ASTM Standard Methods of Test for Calorific Value of Gaseous Fuels by the Water-Flow Calorimeter D 900 or Tentative Method of Test for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, ASTM D 1826.

4.12 Heat Credits. Heat credits are sensible heats added to the steam generator envelope Fig. 1 and are listed in Fig. 2. Heats of each are determined by a quantity measurement multiplied by an enthalpy difference, or by the conversion to thermal units if an electrical energy measurement.

Output Measurement

4.13 The method of measuring output flow in connection with the input-output method is to measure the water flow into the unit as outlined in Pars. 4.14, 4.15 and 4.16 and also as given in PTC 6, Test Code for Steam Turbines. These are the only accepted test measurements of output flow.

4.14 Weigh Tanks. Suitable tanks and scale shall be calibrated prior to and after the test and caused to weigh to a possible measurement error within ±0.10 per cent in the range of loads weighed. The weight of water used must be corrected for any steam or condensate entering or leaving the cycle, after the weigh point. A heat balance diagram shall be prepared to reveal additional sources of supply, if any, to the feedwater circuit.

4.14.1 Design, construction, calibration and operation of weighing tanks shall be in accordance with I & A Measurement of Quantity of Materials PTC 19.5.

4.15 Volumetric Tanks. Volumetric tanks shall be calibrated prior to and after the test and caused to measure a possible measurement error within ±0.25 per cent in the range of loads measured.

4.15.1 Volumetric tanks shall be calibrated with weighed increments of water at a constant temperature and measurement accuracy of ±2 F. In the use of volumetric tanks, density corrections shall be made for water temperature differences during testing and calibration. Corrections shall also be made for the change in thermal expansion of the tank metal.

4.15.2 The precautions given in Par. 4.14 shall be observed wherever they apply to volumetric tanks.

4.15.3 Design, construction, calibration and operation of volumetric tanks shall be in accordance with I & A Measurement of Quantity of Materials PTC 19.5.

4.16 Venturi Tube, Flow Nozzle or Thin Plate Orifice. Water quantity may be measured by venturi tube, flow nozzle or thin plate orifice. Measuring devices including manometers shall be calibrated prior to and after the test and caused to measure to an accuracy within ±0.35 per cent in the range of loads measured.

4.16.1 The recommendations of I & A Measurement of Quantity of Materials PTC 19.5, Chapter 4, shall be followed with reference not only to the design, construction, calibration and use of flow measuring elements, but also to their location and installation in the pipe lines and the installation of the connecting piping system between the primary element and the manometer. All computations of flow rate from the observed differentials, pressures and temperatures shall be made in accordance with the provisions of PTC 19.5, Chapter 4.

4.16.2 Venturi tube, nozzle or orifice selected shall be such that the differential pressure at any test output as shown by the manometer is at least five inches of manometric liquid. See PTC 19.5, Chapter 4.

4.16.3 If fluctuations in flow are present, due to reciprocating devices or other source of pulsation, the difference between the indicated maximum and minimum flow rates shall be reduced to not more than ±5 per cent of the average flow by the introduction of a cushion chamber, surge chamber or other means of absorbing the pulsations between the source of pulsation and the primary device, before measurement is considered acceptable. For further discussion of the pulsating flow measurement see ASME Research Publication: Fluid Meters — Their Theory and Application, Pars. 106 to 109, inclusive.

4.16.4 Differential pressure at the primary metering element shall be measured by two complete manometer systems which shall agree within ±0.2 per cent of each other. Both manometers of a two-manometer system shall be in accordance with I & A, Pressure Measurement PTC 19.2, Chapter 3.

4.17 Flow Measurement of Steam. Output steam flow to be used in the input-output method must be obtained from feedwater measurement as described in Pars. 4.14, 4.15 and 4.16 and Test Code for Steam Turbines PTC 6 corrected for any addition or withdrawal of fluid beyond the measuring element, such as continuous blowdown, desuperheating spray water, boiler circulating pump injection water, etc.

4.17.1 For determining capacity or other related operating characteristics, the output quantity of the main and reheat steam may be determined by means of nozzles or thin plate orifices. Steam line pressure drops may be used for this purpose if they have been previously calibrated.

4.17.2 Reheat steam flow can be computed by subtracting appropriate extraction steam, high pressure turbine leakage and auxiliary steam from the main steam flow and adding desuperheater flow when latter is used. See PTC 6 for example.

4.17.3 The recommendations of I & A Measurement of Quantity of Materials PTC 19.5, Chapter 4, shall be followed with reference not only to the design, construction, calibration and use of flow nozzles and orifices, but also to their location and installation in the pipe line and the installation of the connecting piping system between the primary element and the manometer. All computations of flow rate from the observed differential pressures and temperatures shall be made in accordance with the provisions of Measurement of Quantity of Materials PTC 19.5, Chapter 4.

4.17.4 Differential pressures at the primary metering element shall be measured by a direct reading manometer system.

4.18 Precautions and Corrections Relating to Output Quantity Measurements. All leakage which may affect test results shall be eliminated. If not eliminated, it must be measured and accounted for. Errors due to steam or water entering or leaving the equipment under test, through connecting piping, shall be prevented by blanking off such connections or by providing open telltale drains between double valves to give visible assurance that no flow exists. Leakage tests shall be made in accordance with I & A, Leakage Measurement PTC 19.21.

4.18.1 Water content of all locations where water can accumulate between point of measurement and the boiler, such as surge tanks, feedwater heaters and receiving tanks to which measuring tanks discharge, shall be recorded at the start and conclusion of the run and proper allowances made.

4.18.2 Blowing down during a run shall preferably be avoided. If this is not possible, the amount of heat can be determined by heat balance around the blowdown heat recovery system. Corrections shall be made for any steam and water which are sampled for the determination of solids or for chemical analysis.

4.18.3 Soot blower operation during a run should either be avoided or allowance made.

4.19 Steam and Feedwater Temperatures. Saturated steam temperature may be measured at any point in the steam line where convenient but as close to the saturated steam outlet as possible. The temperature of superheated steam shall be measured as close to the superheater and/or reheater outlets as possible to minimize error from heat loss. Feedwater temperatures shall be measured as close to the economizer inlet and boiler inlet as possible. Steam and feedwater temperatures which are of primary importance shall each be taken at two different points as close together as practical and the mean of the two readings after corrections to each shall be the temperature of the fluid. Discrepancies between the two corrected readings exceeding 0.25 per cent for steam and 0.50 per cent for water shall be investigated.

4.19.1 Mercury-in-glass thermometers, resistance thermometers or thermocouples are acceptable for temperatures up to 700 F. At or above 700 F either resistance thermometers or thermocouples shall be used.

4.19.2 All temperature measuring devices shall be calibrated before and after tests. When employing mercury-in-glass thermometers, proper allowance shall be made for differences between thermometer stem temperature during calibration and test. See I & A, Temperature Measurement PTC 19.3.

4.19.3 The following precautions shall be observed in the use of temperature measuring devices.

4.19.3.1 All temperature measuring instruments and wells shall be constructed, installed, and the instruments calibrated and operated in accordance with I & A Temperature Measurement PTC 19.3.

4.19.3.2 Temperature measuring devices shall be installed so that they will not be affected by radiation or conduction.

4.19.3.3 The heat receiving part of the instrument shall not be located in a dead pocket of the fluid, the temperature of which is a subject of measurement.

4.20 Moisture in Steam. Moisture in steam at saturation temperature in connection with output determination shall be measured with a suitable calorimeter constructed, installed and operated in the manner described in I & A, Methods for Determination of Quality and Purity of Steam PTC 19.11.

4.21 Steam and Feedwater Pressures. Pressure gages shall be located where they will not be affected by any disturbing influences such as extremes of heat and cold and vibration and shall be located in convenient positions for reading. While calibrated Bourdon test gages or deadweight gages may be used, the use of the latter is preferred.

4.21.1 Gage connections shall be as short and direct as possible.

4.21.2 Gages shall be protected with syphons or their equivalent. Convolutions of syphons shall be as few in number as possible, consistent with the gage remaining cool, because of their tendency to introduce errors due to unbalanced water columns in the convolutions.

4.21.3 All gage connections shall be tight.

4.21.4 Pressure connections shall be located and installed with extreme care in order to avoid errors due to impact and eddies. Pressure gage pulsations shall not be dampened by throttling the connection to the gage or by the use of commercial gage dampers, but a volume chamber may be employed. The arrangement may be considered satisfactory if the maximum and minimum values of the instantaneous pressure do not differ by more than 2.0 per cent from the mean value. Bourdon test gages shall be calibrated, installed and used in accordance with I & A, Pressure Measurement PTC 19.2. These gages shall be calibrated before and after the test and at intervals of not more than one week if the test is extended beyond that period.

SECTION 5, EFFICIENCY BY HEAT LOSS METHOD

Definition and Data

5.01 Steam Generator Efficiency by Heat Loss Method. This method is based upon accurate and complete information which will make possible the calculations to determine all accountable losses and heat credits. The efficiency then is equal to 100 per cent minus a quotient expressed in per cent. The quotient is made up of the sum of all accountable losses as the numerator, and heat in the fuel plus heat credits, as the denominator. The capacity at which the unit is to be tested may be based upon either water flow measurement in accordance with Pars. 4.14, 4.15 and 4.16 or steam flow measurement in accordance with Par. 4.17.

5.02 Data Required. Accurate data on the following items are required:

5.02.1.01 Fuel analysis.

5.02.1.02 Flue gas composition or analysis for CO_2, O_2, CO and other gaseous combustibles.

5.02.1.03 Flue gas temperature determined as result of a velocity and temperature traverse of the cross sectional area.

5.02.1.04 Temperature of air supplied to unit for combustion.

5.02.1.05 Combustible content and quantity of dust carried by exit gases.

5.02.1.06 Combustible content and respective quantities in dust collector hoppers and all miscellaneous hoppers.

5.02.1.07 Combustible content and quantity of ashpit refuse.

5.02.1.08 Temperature of fuel supplied at point entering unit.

5.02.1.09 Temperature pressure and quantity of any medium used for operation of the boiler, such as water for cooling doors, atomizing steam, circulating water for pump glands, etc.

5.02.1.10 Humidity of air supplied for combustion.

5.02.1.11 Radiation.

5.02.1.12 Sensible heat in flue dust.

5.02.1.13 Ashpit heat loss.

5.02.1.14 Pyrites (pulverizer rejects).

5.02.1.15 Electric power for gas recirculation fans, boiler circulating water pumps, primary air fans, pulverizers and crushers. See Par. 6.1.1.2.

5.02.2 With the above information accurately obtained, all losses on the unit can be calculated in terms of per cent of the sum of the high-heat value of the "as fired" fuel plus heat credits. Equations for calculating all losses and credits are given in Section 7.

Fuel Sampling and Analysis

5.03 The accuracy of the heat loss method depends upon an accurate sample and ultimate analysis of the fuel being fired. The analysis should break the fuel constituents into the various chemical elements which are combustible or take part in the chemical reaction. These elements are determined in per cent by weight or per cent by volume of the "as fired" fuel. Refer to Fuel Sampling and Analysis, Section 4 of this Code, and Power Test Codes; Diesel and Burner Fuels PTC 3.1, Solid Fuels PTC 3.2, and Gaseous Fuels PTC 3.3.

Flue Gas Sampling and Analysis

5.04 Sampling Locations. Orsat analysis of the flue gases at the exit of the steam generator is required. This will be at locations 15, 14 or 12, Fig. 1 depending upon the equipment which comprises the steam generator. Frequently analyses are required at other points. There may be considerable variation in flue gas analysis over the cross section of the gas passage due to stratification and air infiltration. The best practical method of obtaining representative results is to divide the cross section of the gas passage into equal areas and to take velocity measurements and simultaneous gas samples from the centers of these component areas. A weighted average can then be calculated, taking into consideration the gas temperature, Par. 5.08, as well as the velocity. The number and arrangement of the equal areas will depend on the size and configuration of the gas passage. The areas shall be approximately square and the sampling points shall be not more than 3 feet apart, and a total of not less than four points shall be used. In round ducts, test points shall be located on two traverses along axes normal to each other. It is recognized that there may be cases in which the gas velocity is so low that velocity measurements would be impractical. In such cases an arithmetic average rather than a weighted average should be employed. Where accuracy is not impaired, an aspirator and suitable apparatus for obtaining a composite sample from several sampling points may be employed. With the exception of the area sampling instruction above, all of the procedures are to be in accordance with recommendations of I & A, Flue and Exhaust Gas Analyses PTC 19.10.

5.05 Sampling Lines. Sampling tubes shall be made of material which shall not contaminate the sample by the temperatures encountered. For sampling high temperature flue gas, such as in a furnace or at the gas entrance to a waste heat boiler, suitable water cooled samplers must be employed. Sampling lines shall be as short and straight as possible, shall be accessible for cleaning and blowing out, shall slope in the direction of the flow, shall be suitably drained and shall be maintained tight. All sampling apparatus shall be in accord with the recommendations of I & A, Flue and Exhaust Gas Analyses PTC 19.10.

5.06 Method of Analysis. Apparatus and method of analysis to be employed are dependent upon the type of fuel burned and upon the purpose of the test. Design, construction and operation of the apparatus and preparation of the reagents shall be in accordance with I & A, Flue and Exhaust Gas Analyses PTC 19.10.

5.06.1 An analysis should be made to verify presence or absence of gaseous combustibles. If combustibles are found and cannot be eliminated by adjustment to the fuel burning equipment, the hydrogen and hydrocarbons shall be measured and the loss therefrom calculated as covered in Section 7.

5.06.2 For hydrogen and hydrocarbon analyses, it is necessary to obtain representative field samples of the gases for submission to a qualified laboratory. Refer to I & A, Flue and Exhaust Gas Analyses PTC 19.10.

5.07 Precautions. Proper steps shall be taken to prevent leakage to or from gas analyzing apparatus and sampling lines, to avoid contamination and exhaustion of reagents, to provide fresh reagents when needed, to keep manifolds clear of reagents, to avoid errors due to physical solubility of gases in reagents and confining liquids, to avoid personal injury by contact with reagents, to allow for burette error and drainage time, to avoid change of sample temperature during analysis, to keep apparatus clean, to minimize personal errors by employing careful operators who are given adequate information on common sources of error, to provide operators with adequate light and reasonable comfort, to verify results by checking against theoretical, and in all other ways, to assure that recorded data are correct and their degree of precision known. Sampling should be continuous when possible. Because all gases, especially SO_2 and CO_2, are soluble to some extent in water, the water in the levelling bottle shall be saturated with sample gas before taking any readings.

5.07.1 Detailed precautions given in I & A, Flue and Exhaust Gas Analyses PTC 19.10 shall be followed.

Flue Gas and Air Temperature Measurement

5.08 Outlet Flue Gas Temperature. Flue gas temperature measurement at the exit of the steam generator is required. This will be at locations 15, 14 or 12, Fig. 1 depending upon the equipment which comprises the steam generator. This may in certain instances be measured at other points such as the inlet to a waste heat boiler or at the inlet and discharge of air or gas recirculating fans.

5.08.1 Gas temperatures must be taken at the same sampling points as used for flue gas sampling, Par. 5.04, to minimize the effect of gas temperature stratification.

5.08.2 If a preliminary survey of flue gas flow, Par. 5.04, indicates severe stratification, it is recommended that the temperature measurements at individual locations in the duct cross section be weighted in proportion to the gas flow at the corresponding locations and an average of the weighted temperatures be used as representing the gas temperature at that cross section.

5.08.3 Choice of temperature measuring instruments depends upon the conditions of the individual case. The selection, design, construction, calibration, installation and operation of temperature measuring instruments shall be in accordance with I & A, Temperature Measurement PTC 19.3.

5.09 Air and Recirculated Flue Gas Temperature. The same general methods and the same precautions noted in Par. 5.08 shall apply to the determination of temperatures of primary air, secondary air, recirculated air or flue gas and temperature of air entering and leaving the air heater.

Flue Gas and Air Weight

5.10 Weight Determination. Flue gas quantity shall be determined by calculation from fuel analysis and flue gas composition. Calculation procedure for gas weight per heat unit of fuel is given in Par. 7.3.2.02. Similarly, air quantities shall be calculated as per Par. 7.2.8.1.

5.10.1 In some instances it is desirable to know flue gas or air quantities other than total for the unit, such as recirculated flue gas, primary air, secondary air, etc. These may be calculated by heat balances, by differences or may be measured if they cannot be calculated.

5.10.2 Methods of measurement available for flue gas and air quantity for testing purposes are covered in ASME publication Fluid Meters — Their Theory and Application. Where continual knowledge of such flows is required, flow nozzles, venturi or thin plate orifices can be installed following procedures outlined in I & A, Measurement of Quantity of Materials PTC 19.5, Chapter 4.

Refuse

5.11 Quantity Measurement. The heat loss method of this Code requires the determination of heat loss due to unburned combustible in the refuse. It is also necessary in the input-output method if the test is to be checked by a heat balance. From the viewpoint of testing, the most difficult part of this determination is the accurate measurement of all the refuse discharged or removed from the unit. In some installations it may be impractical or even impossible to collect and weigh all the refuse. When this is the case, it becomes necessary to estimate any undetermined amounts of refuse by volumetric measurement or a refuse balance difference. Care should be exercised to include all the refuse discharged or removed from the unit and to exclude any refuse which is returned to the unit for further combustion. In order to be sure that the refuse collected is in proper relation to the weight of ash in the coal burned, the collection must take into account the time required for the refuse to pass from the furnace to the point of discharge, as discussed in Par. 3.07. This may be especially important in stoker fired units.

5.11.1 The refuse collected at various points in the unit shall be weighed separately and preferably in the dry state, although any burning refuse must be quenched with water immediately upon its withdrawal from the unit. The moisture content of the refuse shall be determined by laboratory analysis. Flue dust collected at all points in the steam generating unit ahead of the samples taken from the gas stream, shall be collected, weighed, sampled and analyzed separately. The amount and combustible content of the fly ash carried in suspension by the flue gas shall be determined in accordance with Pars. 5.13 to 5.19, inclusive.

5.12 Sampling. Refuse sampling is subject to large errors and every precaution shall be taken to insure as representative a sample as possible.

5.12.1 Soot, siftings, cinders and dust separator refuse collected in hoppers shall each be reduced by successive quartering to obtain two 15 pound samples in each location. Where the total collection is less than 30 pounds for the duration of the test, the quantity shall be equally divided to constitute the two required samples. One sample shall be sent to the laboratory for analysis and the other sample shall be retained as a duplicate until final results of the tests have been reviewed and declared acceptable.

5.12.2 In the case of furnace bottom refuse either from a stoker fired or dry bottom pulverized fuel fired unit a gross sample of approximately 1000 pounds shall be taken in equal increments of approximately 50 pounds from each ton of refuse. Care shall be exercised to obtain proper proportions of coarse and fine refuse in each increment. If the total amount of furnace bottom refuse is less than 1000 pounds, then the entire amount of refuse shall constitute the gross sample. The gross sample shall be crushed and reduced to two 15 pound samples in accordance with instructions and Table I of ASTM Specification D 492 for coal sampling. One sample shall be sent to the laboratory for analysis and the other shall be retained as a duplicate until final results have been reviewed and declared acceptable.

5.12.3 The reduction of the gross samples to laboratory size shall proceed as rapidly as possible to prevent undue loss of moisture by evaporation and the two laboratory size samples shall be placed and sealed in airtight containers.

5.13 Analysis. Refuse samples shall be analyzed for moisture, combustible content and heat value.

5.13.1 For moisture determination, the refuse shall be crushed, if necessary, in a jaw crusher to pass through a 4-mesh sieve, spread over suitable galvanized iron pans, and dried at a temperature in the range of 220 F to 230 F in an air drying oven until the weight loss per hour is not more than 0.1 per cent of the weight of the sample. Suitable pans and drying ovens are described in ASTM Specification D 271. Care shall be used, when drying samples of fine material such as refuse from soot hoppers and precipitators, to regulate the flow of air through the drying oven to a velocity which will not pick up and carry away any of the sample.

5.13.2 The heat value of the refuse shall be determined by bomb calorimeter, ignition loss method and/or by assuming that the combustible is carbon. In the calorimetric determination of the heat value of refuse, if the combustible is too low for ignition, it is necessary to add a measured quantity of combustible of known heat value to the refuse sample.

5.13.3 For high ash material the direct determination of heating value of refuse by the bomb calorimeter is difficult and subject to errors. A more accurate method is to determine the total hydrogen and carbon in the refuse and calculate the heating value. Provisions must be made to exclude hydrogen from water in the sample and carbon from inorganic carbonates.

5.13.4 The method used to determine the carbon and hydrogen is the combustion train as described in ASTM Standards on Coal and Coke D 271 with appropriate modifications in amount of sample and handling technique. Apparatus, reagents and preparations are described in ASTM D 278.

5.13.5 Procedure modifications are to weigh a sampling boat contained in a weighing bottle, then adding approximately 1.0 grams of sample and drying in a moisture oven at 105 C to a constant weight. Seal the sample and boat in the weighing bottle, weigh when cool and keep intact until introduced into the combustion train.

5.13.6 When the sample is treated as above the carbon and hydrogen calculated as described in ASTM D 278 will be on a dry basis, eliminating corrections for water hydrogen in the sample. Since the total carbon so determined includes carbon from inorganic carbonates in addition to combustible carbon, it is necessary to determine a correction. One of the methods described in ASTM D 1760 Carbon Dioxide in Coal can be used.

5.13.7 The calculated refuse heating value is equal to the sum of the products of weight fraction and high-heat value for combustible carbon and hydrogen contents in the refuse.

5.14 Dust Sampling and Analysis. The general principles of sampling apply to tests made to determine the dust analysis and concentration in flue gas as well as to occasional tests for fineness of coal and for properties of suspended materials in gaseous fuel to burners. Dust samples are obtained by inserting one or more sampling tubes into and facing the gas stream in question, drawing off a measured quantity of the gas at such a rate that the velocity of the gas entering the mouth of the sampling tube is the same as the velocity of the main body of gas at that point in the cross section of the duct and collecting all the dust carried by this quantity of gas.

5.14.1 All apparatus and test procedures shall be in accordance with the Test Codes for Dust Separating Apparatus PTC 21 and Determining Dust Concentration in a Gas Stream PTC 27.

5.15 Design of Dust Sampling Apparatus. The design of sampling apparatus shall be in accordance with the instructions of the Test Code for Dust Separating Apparatus PTC 21.

5.15.1 The volume of gas drawn through the sampling tube shall be measured by a displacement gas meter of known accuracy, by an orifice or flow nozzle, or by some other acceptable means such as a pitot tube suitably incorporated in the sampling tube.

5.15.2 Separation of dust from the gas sample shall be by suitable filters of ceramic or paper thimble or cloth bag type, by one of these in conjunction with a cyclone separator or by other acceptable sample collecting apparatus.

5.15.3 It is usually necessary to draw the gas sample through the sampling tube, separator and metering apparatus. For this purpose, air, water and steam operated aspirators and motor driven pumps and blowers, such as employed in vacuum cleaners, are suitable. In general, use of the blower is limited to types of collecting sample apparatus having relatively low resistance.

5.15.4 In cases where normal temperature of the apparatus is below the dew point of the gas samples, precipitation of moisture shall be prevented by suitable insulation or by heating the apparatus.

5.16 Dust Sampling Points. A careful preliminary survey shall be made to show the variation in dust concentration over the cross section of the duct as a guide in determining the number and location of sampling points necessary to obtain the required accuracy. Points of sampling should be located in a long straight run of duct, preferably vertical rather than horizontal, shall be not more than three feet apart and a total of not less than four points shall be used. In round ducts, test points shall be located on two traverses along axes normal to each other, as described in the Test Code for Determining Dust Concentration in a Gas Stream PTC 27.

5.17 Dust Sampling Tubes. Since the number of sampling points necessary to attain the required accuracy will probably exceed the number of samplers it is practical to employ, the sampling tubes should be so designed that they can be moved to sample each required point.

5.18 Method of Determining Proper Rate of Gas Flow Through Dust Sampler. Proper sampling rates at each sampling point shall be determined by a pitot tube or its equivalent. Where duct velocities are determined by pitot tube and the gas at the sample metering device is at a temperature or pressure appreciably different from that in the duct, proper allowances shall be made. In some instances a traverse of the duct with a thermocouple is necessary.

5.19 Dust Sampling Precaution. Sampling should be continued throughout the duration of the run. Filters shall be changed when necessary, with the least possible loss of time. Correction shall be made for time lost while changing filters.

5.19.1 Sampling shall begin immediately after inserting the sampling tube in the duct. The stopping of sampling and the removal of the sampling tube shall likewise be as nearly simultaneous as possible.

5.19.2 When a sampling tube is moved from point to point to obtain an average, the duration of exposure shall be the same at all points and the sampling rate shall be regulated to correspond with the duct velocities at the individual points. The mouth of the sampling tube shall always point in the upstream direction.

5.19.3 Great care must be exercised to collect all the dust drawn into the sampling tube. This often requires that the piping between the sampling mouth and the dust separating device be cleaned with a weighed swab and the dust so collected accounted for. The sample and its container must be thoroughly dried before weighing.

5.19.4 Before use, filter bags, thimbles and other parts in which dust for the sample may collect shall be thoroughly dried and accurately weighed. This weight and that of any swabs or other cleaning media constitute a tare weight in the calculation.

5.20 Moisture in Combustion Air. The moisture carried by combustion air must be taken into consideration when calculating the efficiency by the heat loss method. This moisture may be determined with the aid of a sling-type psychrometer or similar device. From the dry- and wet-bulb thermometer readings taken from the psychrometer at the observed barometric pressure, the absolute or specific humidity (pounds of moisture per pound of dry air) can be determined either from the chart published in I & A, Part 18, Humidity Determinations, or from psychrometic tables published in the U. S. Weather Bureau Bulletin No. 235.

5.20.1 The dry and wet bulb temperatures may be determined at the atmospheric air inlet to the system. This is possible since the desired quantity is pounds of moisture per pound of dry air for combustion. Since the specific humidity does not change with heat addition unless there is moisture addition, the air moisture crossing the envelope, Fig. 1, is the same as that measured at the air inlet.

Radiation and Ashpit Losses

5.21 Surface Radiation and Convection. The radiation heat loss will be approximated by the use of the chart included in Section 7, Fig. 8. The measurement of the radiation heat loss on any installation, particularly a large one, requires an extensive installation of thermocouples over selected areas. See Appendix, Par. 9.5. Recent radiation tests on large installations showed that the value of radiation loss given by the reference curve is conservatively high.

5.22 Radiation Loss to the Ashpit. Part of the heat released in the furnace is transmitted to the ashpit by radiation and is lost as sensible heat in the ash discharged to the ashpit and in the ashpit water. In small boilers with dry ashpits which are not equipped with means for quenching the ash, a portion of this heat is lost through the walls of the ashpit. Since it is difficult and impractical to measure this loss for this type of boiler, it is not calculated as an individual loss but is included as a part of surface radiation and convection. Par. 5.21.

5.23 Wet Ashpit Losses-Evaporation and Heat to the Liquid. In boilers with dry ashpits provided with quenching pool ash hoppers and in continuous slag tap boilers provided with slag quenching tanks, the heat loss to the ashpit is manifested by a rise in quenching water temperature and by evaporation of a portion of the quenching water. Under these conditions, it is possible to determine this loss to the ashpit with a reasonable degree of accuracy by measuring very accurately the quantity and temperature of the water flowing to the ash hopper or quenching tank and the quantity and temperature of the overflow water. The quantity of water evaporated is equal to the difference between these quantities, corrected for the water displaced by the ash falling into the hopper or tank. It is important that the displaced quantity of water be carefully estimated.

5.23.1 The water level in the ash hopper or slag quenching tank shall be maintained as nearly constant as practicable. The level at the beginning and end of each test run shall be recorded and allowance shall be made in the calculations for the difference in volumes.

5.23.2 Stabilize water flows and temperatures between the time ashes are sluiced and the time the test run begins.

5.23.3 It is important to eliminate leakage of quenching water from the ash hopper or slag quenching tank in order to insure accurate test results. If leakage cannot be eliminated, then it must be measured and allowance made for it in the calculations.

5.23.4 Water flow to the ash hopper or quenching tank shall be measured by means of an orifice plate, flow nozzle or water meter. The gravity overflow shall be measured by means of weigh tanks, volumetric tanks or weir plate mounted in a weir tank provided with stilling baffles and a hook gage.

5.23.5 Although the quantity of quenching water evaporated is relatively small compared with the quantity of water flowing to the ash hopper or quenching tank, the heat loss due to evaporation of the quenching water is a relatively large part of the ashpit heat loss. For this reason, it is recommended that the device used to measure the flow of water to the ash hopper or quenching tank be calibrated with the same equipment used to measure the overflow to insure that the error in measurement of the difference between these two quantities will be a minimum.

5.23.6 The method of calculating the heat loss for those types of ashpits is detailed in Par. 7.3.2.11.

SECTION 6, MISCELLANEOUS INFORMATION

6.1 Power for Auxiliaries. For determining the energy consumption of the auxiliaries *inside the envelope*, Fig. 1, the information listed below is required.

6.1.1.1 Determination of energy consumption of steam auxiliary drives necessary for the operation of the steam generator requires measurement of steam flow quantities, and the initial and exhaust steam pressures, temperatures, and quality. Methods of measuring these are in general the same as those described in Output Measurement, Pars. 4.13 to 4.21.4, inclusive. Steam quantities may be determined by heat balance calculations on feedwater heaters, etc., the necessary corrections and precautions in regard to leakage, heat loss, etc., being observed.

6.1.1.2 Determination of energy consumption of electrically driven auxiliaries shall be made in accordance with the methods described in I & A, Part 6 on Electrical Measurements in Power Circuits PTC 19.6. Watthour meters are generally preferable to other types of instruments for this purpose.

6.1.2 In evaluating the heat equivalent of auxiliaries the equipment should be operated as near design conditions as possible.

6.2 Net Efficiency. As stated in Pars. 1.06 and 1.08, performance of steam generating units shall be based on the gross efficiency only. Net efficiency, while beyond the scope of this Code, is sometimes a matter of interest and therefore the following is included as an aid to those considering this facet of performance. Net efficiency is the output of the steam generator, which is the heat absorbed by the working fluid, divided by the total of all the heat in the fuel, plus credits, plus the heat equivalent of the auxiliaries *outside the envelope*, plus the heat equivalent of the driver losses of the auxiliaries *inside the envelope*. The following constitutes the usual auxiliaries outside the envelope, see Fig. 1, and therefore should be included in computing net efficiency:

- Forced draft fans
- Induced draft fans
- Recirculating air fans
- Soot blowers
- Ash or flue dust handling systems (clinker grinders, conveyors, etc.)
- Electric precipitators
- Control drives
- Fuel handling systems (prorate to steam generator being tested)
- Fuel pumps (if central system, prorate to steam generator being tested)
- Coal preparation systems (pulverized coal or cyclone fired storage or bin systems – prorate to steam generator being tested)
- Stoker drives
- Auxiliary boilers (prorate to steam generator being tested)
- Cooling water (prorate to steam generator being tested)
- Light and heat (prorate for area of plant occupied by steam generator being tested)

To the heat equivalent of the above listed auxiliaries *outside* the envelope, must be added the heat equivalent of the driver losses of the auxiliaries *inside* the envelope including motors, turbines, electric and hydraulic couplings and gears that may be associated with the following auxiliaries:

- Pulverizers
- Exhausters
- Crushers
- Boiler circulating pumps
- Recirculating gas fans
- Air heaters

6.2.1 Heat equivalent of all steam driven auxiliaries is:

Hourly steam flow × (Enthalpy in inlet steam – isentropic enthalpy of exhaust steam) = Btu per hr.

Where

Steam flow = metered flow in lb per hr.

Enthalpy of inlet steam is the enthalpy at inlet pressure and temperature or quality.

Isentropic enthalpy of exhaust steam is the enthalpy at exhaust pressure and initial entropy.

6.2.1.1 This computation will require metering of steam and determining inlet pressure, inlet steam temperature or moisture, and exhaust pressure. Steam quantities may be determined by heat balance calculations on the plant heat cycle if the arrangement of the cycle permits this.

6.2.1.2 Measurement of steam flow, temperature, pressure and moisture should follow procedures given in Pars. 4.17 to 4.21, inclusive.

6.2.2 Heat equivalent of all electrically driven auxiliaries will be:

$$\text{kilowatt input} \times 3413 = \text{Btu per hr}$$

6.2.2.1 The power input is preferably determined by watt or watthour meters, but where this is not possible, reliable ammeter, voltmeter and power factor readings may be used and heat equivalent for the usual 3 phase power is then:

$$\frac{\sqrt{3} \times \text{Volts} \times \text{Amperes} \times \text{Per cent Power factor}}{1000 \times 100} \times 3413$$

$$= \text{Btu per hr}$$

6.2.2.2 Electrical measurements should be made as specified in I & A Electrical Measurements in Power Circuits PTC 19.6.

6.2.3 When auxiliaries are a combination of steam and electrically driven equipment, the heat equivalent will be the sum of the heats calculated by Pars. 6.2.1 and 6.2.2, respectively.

6.3 Special Instructions for Testing a Waste Heat Boiler. Waste heat boiler testing technique differs from that employed with a steam generator to which the major energy is supplied in the form of fuel.

6.3.01 Input is the total of the sensible and latent heat contents of the entering gas stream, any radiation into the boiler and the chemical heat of combustion resulting from burning of supplementary fuel or residual combustible products in the entering gas. To this equivalent fuel energy input must be added any of the conventional heat credits listed on Fig. 2, which may include sensible heat of supplementary fuel and combustion air entering the boiler, etc.

6.3.02 Output takes the same form found in conventional steam generators, i.e., heat absorbed by the working fluid.

6.3.03 Determination of input and output quantities shall follow methods outlined in Section 4 wherever applicable.

6.3.04 Methods to be employed in determining or otherwise allowing for radiation heat input to the unit will depend upon individual conditions. The heat added from outside radiation may be estimated from the temperatures of heat source and absorbing surface and flat projected areas of radiating source and absorbing surfaces.

6.3.05 Determination of the heat content of the gas entering the boiler requires measurement of temperature and weight flow of gas, and analysis of the gas.

6.3.06 Gas temperature measurement at the boiler inlet requires special equipment and procedures. Because of the high temperatures usually encountered, probes must be water cooled. If inlet temperature measurements are taken at a location which permits the thermocouple to radiate to a surface at a lower temperature than the gas being measured, all measurements must be made with properly designed high temperature thermometry, see I & A, Temperature Measurement PTC 19.3.

6.3.07 Gas quantity entering may be determined by the following methods: (1) calculation from the amount of fuel burned in the process, analysis of this fuel and waste gas composition; (2) actual measurement of the gas quantity; (3) measurement of the gas quantity leaving the boiler, analysis of the gases entering and leaving the boiler and calculation of any supplementary combustion products. For method (1) fuel quantity and analysis shall be determined in accordance with Pars. 4.02 to 4.11, inclusive. Method (2) requires use of calibrated flow nozzles, orifices or water cooled pitot tube and temperature probes in accordance with I & A, PTC 19.3 and PTC 19.5. Method (3) minimizes problems arising from measurements in high temperature gas streams but still requires water cooled sampling probes at the boiler inlet to prevent reaction between probe metal and gas sample. Sampling shall be in accordance with Pars. 5.04 to 5.10, inclusive.

6.3.08 Heat content of entrained matter entering and leaving must be determined for calculation of total heat content of waste gas. Sampling of particulates shall be in accordance with Pars. 5.14 to 5.19, inclusive.

6.3.09 Losses will vary with types of input.

6.3.09.1 For boilers which do not involve combustion within the waste heat unit, heat losses consist of: (1) the difference between sensible heat content of the gas at the exit gas temperature and reference air temperature – usually ambient – (dry gas loss), see Par. 7.3.2.03;

(2) the difference between the latent heat content of the gas at the exit gas temperature and reference air temperature. (Loss due to moisture in the stack gas), see Par. 7.3.2.05; (3) radiation and convection loss may be obtained from ABMA radiation loss chart, see Fig. 8, by taking the radiation loss per cent and multiplying it by 100 times the gross heat input.

6.3.09.2 For boilers which include combustion within the unit, conventional steam generator losses, as defined in Section 5, should be accounted for and on a proportional basis added to the losses computed in the preceding paragraphs to constitute the units total losses. Basis for proportioning shall be a ratio of weight of all constituents entering into combustion to total gas weight, as discussed in Par. 5.10.

6.3.10 When determining the efficiency the duration of runs shall be not less than four hours.

SECTION 7, COMPUTATIONS

7.1 The following computation procedures are for determining the gross efficiency of a steam generating unit by both the input-output and the heat loss methods for the actual operating conditions of the tests. Where a comparison is to be made between test efficiency and a standard or guaranteed efficiency, adjustments should be made in computations for deviation of test conditions from the standard or guaranteed conditions for certain heat credits and heat losses. Each computation subject to adjustment is so noted in the following section, and the procedure for adjusting is as described under "Corrections to Standard or Guarantee Conditions." Pars. 7.4 to 7.6, inclusive.

Efficiency by Input-Output Method

7.2 $\eta_g = \dfrac{\text{Output}}{\text{Input}}$

Where

Output is defined as the heat absorbed by the working fluid

Input is defined as chemical heat in the fuel plus heat credits added to the working fluid, air, gas and other fluid circuits which cross the envelope boundary, see Fig. 1.

$$\eta_g = \left[\frac{W_{se31}\ (h_{s32} - h_{w24}) + W_{we25}\ (h_{s32} - h_{w25})}{H_f \times W_{fe} + B_e} + \frac{W_{se33}\ (h_{s34} - h_{s33}) + W_{we26}\ (h_{s34} - h_{w26}) + W_{we35}\ (h_{w35} - h_{w24})}{H_f \times W_{fe} + B_e}\right] \times 100$$

Note 1: The preceding equation applies to the more common single reheat usage. For multiple reheats, the heat absorbed in successive stages of reheat is additive in the numerator.

Note 2: Auxiliary steam usages are not indicated in the above equation, but wherever they occur, their heats are additive in the numerator.

Note 3: When testing steam generators which incorporate a circulating pump the following must be added to the outputs in the numerator of the equation:

$$W_{we48}\ (h_{w48} - h_{w47}) + (W_{we47} - W_{we48}) \times (h_{w24} - h_{w47})$$

The first group of terms correct for the heat removed by the "leak-off" water and the second group accounts for the heat required to bring the injected water to economizer inlet water temperature.

Where

η_g = Per cent = Gross efficiency.

7.2.1 $W_{se31} = \dfrac{\text{lb steam}}{\text{hr}}$ = Steam flow entering superheater.

7.2.2 $W_{se33} = \dfrac{\text{lb steam}}{\text{hr}}$ = Reheat steam flow.

7.2.3 h_{s32}, h_{s33}, h_{s34} $= \dfrac{\text{Btu}}{\text{lb steam}}$ = Enthalpy of steam at superheater outlet, reheater inlet and reheater outlet.

7.2.4 h_{w24}, h_{w25}, h_{w26}, h_{w35}, h_{w47}, h_{w48} $= \dfrac{\text{Btu}}{\text{lb water}}$ = Enthalpy of feedwater entering unit, enthalpy of superheater spray water, enthalpy of spray water, enthalpy of blowdown, enthalpy of injection water, and enthalpy of leak-off.

7.2.5 W_{we25}, W_{we26}, W_{we35}, W_{we47}, W_{we48} $= \dfrac{\text{lb water}}{\text{hr}}$ = Superheater spray water flow, reheat spray water flow, blowdown flow, injection flow, and leak-off flow.

7.2.6 $H_f = \dfrac{\text{Btu}}{\text{lb A.F. fuel}}$ = Heating value of fuel to be obtained by laboratory analysis and adjusted to an "as fired" basis from laboratory determination of moisture in fuel. For gaseous fuels, the use of continuous recording calorimeter is permitted, see ASTM D 1826.

7.2.6.1 Adjustment for moisture will be as follows:

$$H_f = H_{f'} \times \frac{100 - m_f}{100}$$

Where

$H_{f'} = \dfrac{\text{Btu}}{\text{lb fuel (dry basis)}}$ = Laboratory determination by fuel analysis on a dry basis.

m_f = Per cent moisture in fuel as determined by analysis of moisture sample.

7.2.6.2 When the heating value is determined at constant volume (see Pars. 4.05 and 4.08) it must be converted to a constant pressure value as follows:

$$H_f = H_{fp} = H_{fv} + \frac{\Delta\Psi R_u T}{778.2} = H_{fv} + \Delta\Psi\,\frac{1545 \times 537}{778.2}$$

$$H_f = H_{fv} + \Delta\Psi 1066 = H_{fv} + \frac{1066}{4.032}\,\text{H} = H_{fv} + 264.4\,\text{H}$$

$H_{fp} = \dfrac{\text{Btu}}{\text{lb A.F. fuel}}$ = High-heat value of fuel at constant pressure.

$H_{fv} = \dfrac{\text{Btu}}{\text{lb A.F. fuel}}$ = High-heat value of fuel at constant volume.

$\Delta\Psi = \dfrac{\text{lb moles}}{\text{lb A.F. fuel}}$ = lb moles of oxygen removed in the reaction by the condensing water vapor formed.

$$\Delta\Psi = \frac{\text{H}}{2 \times 2.016} = \frac{\text{H}}{4.032}$$

$\text{H} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of hydrogen exclusive of that in moisture per pound of "as fired" fuel from laboratory analysis.

$R_u = 1545\,\dfrac{\text{ft-lb}}{\text{lb mole R}}$ = Universal Gas Constant.

T = 537 R = Standard Calorimeter Temperature.

778.2 ft-lb = 1 Btu = mechanical equivalent of heat.

See Appendix for complete derivation of above formula for conversion of high-heat value at constant volume as obtained with the bomb calorimeter to the high-heat value at constant pressure.

7.2.7 $W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = measured fuel rate.

If solid or liquid fuels are used the weight is determined by direct measurement. If gaseous fuel is used, the measured volume must be converted to a weight basis as follows:

7.2.7.1 $W_{fe} = Q_{fe} \times \gamma_f$

Where

$W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = measured fuel rate.

$Q_{fe} = \dfrac{\text{cu ft}}{\text{hr}}$ = Quantity of gaseous fuel fired.

$\gamma_f = \dfrac{\text{lb}}{\text{cu ft}}$ = Fuel gas specific weight at the primary measuring element. This value may be obtained from standard American Gas Association tables, and corrected to 68 F.

7.2.8 $B_e = \dfrac{\text{Btu}}{\text{hr}}$ = Total heat credit and is defined as those amounts of heat added to the envelope of the steam generator other than the chemical heat in the fuel "as fired."

$$B_e = B_{Ae} + B_{ze} + B_{fe} + B_{xe} + B_{mAe}$$

7.2.8.1 $B_{Ae} = \dfrac{\text{Btu}}{\text{hr}}$ = Heat supplied by entering air from such sources as steam air heaters.

$$B_{Ae} = (W_{A'} - W_{A'_5}) \times W_{fe} \times c_{pA'}[t_{A7,A8} - t_{RA}] + W_{A'_5} \times W_{fe} \times c_{pA'}[t_{A'_5} - t_{RA}]$$

Where

$W_{A'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of dry air per pound of "as fired" fuel

$$W_{A'} = \frac{(W_{G'N_2} - N)}{0.7685}$$

Where

$$W_{G'N_2} = \frac{\text{lb nitrogen in dry gas}}{\text{lb A.F. fuel}} = \frac{\text{lb dry gas}}{\text{lb A.F. fuel}} \times \frac{\text{lb nitrogen in dry gas}}{\text{lb dry gas}}$$

$$W_{G'N_2} = \frac{W_{G'} \times 28.02\ N_2}{44.01\ CO_2 + 32.00\ O_2 + 28.02\ N_2 + 28.01\ CO}$$

$W_{G'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of dry gas per pound of "as fired" fuel

$$W_{G'} = \frac{44.01\ CO_2 + 32.00\ O_2 + 28.02\ N_2 + 28.01\ CO \times \left(C_b + \dfrac{12.01\ S}{32.07}\right)}{12.01\ (CO_2 + CO)}$$

$$W_{G'N_2} = \frac{28.02\ N_2}{12.01\ (CO_2 + CO)} \left(C_b + \frac{12.01\ S}{32.07}\right)$$

$$W_{A'} = \frac{W_{G'N_2} - N}{0.7685}$$

For complete fundamental derivation, see Appendix.

The preceding formula is based on molecular weights accurate to four significant figures, but it is not to be implied that the weight of dry air has this degree of accuracy. The four digit molecular weights are used to hold errors from calculation procedures to a minimum. The values used are from the National Bureau of Standards Circular 564, dated 11/1/55.

CO_2, O_2 and CO = per cent by volume of dry flue gas. (Location 12, 14 or 15, Fig. 1.)

N_2 being determined by subtracting the total of CO_2, O_2 and CO from 100 per cent.

$$C_b = C - \frac{W_{d'p'} \times H_{d'p'}}{14500}$$

Where

$C_b = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of carbon burned per pound of "as fired" fuel.

$C = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds carbon in "as fired" fuel by laboratory analysis

$W_{d'p'} = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of total dry refuse per pound of "as fired" fuel, See Par. 7.3.2.01.

$H_{d'p'} = \frac{\text{Btu}}{\text{lb dry refuse}}$ = Heat value for total dry refuse from laboratory determination.

$14500 = \frac{\text{Btu}}{\text{lb}}$ = Heat value of 1 lb of carbon as it occurs in refuse.

$S = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds sulfur per pound of "as fired" fuel as determined for laboratory analysis.

$N = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of nitrogen per pound of "as fired" fuel.

For those who wish to know the theoretical air and excess air, the equations are given in the appendix.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Fuel rate as determined by weighing procedures outlined in Section 4.

$c_{pA'}$ = Mean specific heat of dry air at inlet temperature, as obtained from curve sheet. See Fig. 3. It is determined from the instantaneous values over the range between inlet air temperature andthe reference temperatures.

t_{A7} or t_{A8} = F = Inlet air temperature. If the unit is equipped with a steam or water coil air heater before the main air heater and it is supplied with heat from a source external to the unit being tested (as defined by Fig. 1), the inlet air temperature t_{A8} shall be measured in the air stream after this heater and in this case the heat added to the inlet air is a heat credit. If the coil above or recirculated hot air is being supplied by heat direct from the unit being tested, inlet air temperature t_{A7} shall be measured in the air stream ahead of the heater and there is no heat credit.

t_{RA} = F = Reference air temperature. This is the base temperature to which sensible heat losses and credits are compared for efficiency computations. When heat is added to the combustion air before the forced draft fan, corrections must be made to the measured temperature at location 7 on Fig. 1. Where adjustment is to be made for deviation from standard or guarantee conditions, see Par. 7.4.1.

7.2.8.2 $B_{ze} = \frac{\text{Btu}}{\text{hr}}$ = *Heat supplied by atomizing steam when the source is external to the unit being tested.*

$$B_{ze} = W_{ze} \times (h_{z42} - h_{Rv})$$

Where

$W_{ze} = \frac{\text{lb}}{\text{hr}}$ = Metered atomizing steam flow.

h_{z42} = Enthalpy of atomizing steam at pressure and temperature at metering point.

h_{Rv} = Enthalpy of saturated vapor at reference temperature.

7.2.8.3 $B_{fe} = \frac{\text{Btu}}{\text{hr}}$ = *Heat supplied by sensible heat in fuel.*

$$B_{fe} = W_{fe} \times c_{pf} (t_{f1,3,4} - t_{RA})$$

Where

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate

$c_{pf} = \frac{\text{Btu}}{\text{lb F}}$ = Mean specific heat of fuel. Use 0.3 Btu/lb/F for coal. See Fig. 4 for fuel oil. See Fig. 5 for gas. It is determined from the instantaneous values over the range between inlet fuel temperature and the reference temperature.

If liquid fuel is heated by a source external to the unit being tested, the inlet temperature shall be measured after this heater, but if heated directly from the unit being tested temperature shall be measured before the heater.

t_{f1}, t_{f3}, t_{f4} = F = Fuel inlet temperature.

t_{RA} = Reference air temperature.

7.2.8.4 $B_{xe} = \frac{\text{Btu}}{\text{hr}}$ = *Heat supplied by auxiliary drives within the envelope.*

$$B_{xe} = W_{sxe} (h_{sx} - h_{ix}) \eta_x$$

Where

$W_{sxe} = \frac{\text{lb}}{\text{hr}}$ = Steam flowrate.

$h_{sx} = \frac{\text{Btu}}{\text{lb}}$ = Enthalpy of the steam supplied to drive the auxiliaries.

$h_{ix} = \frac{\text{Btu}}{\text{lb}}$ = Enthalpy at the exhaust pressure and the initial entropy of steam supplied to drive the auxiliaries.

η_x = Over-all drive efficiency – includes turbine and gear efficiency.

For electric auxiliaries the heat supplied is:

$$B_{xe} = 3413 \text{ (kwh) } \eta_x$$

η_x = Over-all drive efficiency – includes such items as motor efficiency, electric and hydraulic coupling efficiency and gear efficiency.

7.2.8.5 $B_{mAe} = \frac{\text{Btu}}{\text{hr}}$ = *Heat supplied from the moisture entering with the inlet air.*

$$B_{mAe} = W_{mA'} \times W_{A'e} \times c_{ps} \times (t_{A7}, t_{A8} - t_{RA})$$

Where

$W_{mA'} = \dfrac{\text{lb}}{\text{lb dry air}}$ = Pounds of water vapor per pound of dry air. Refer to Par. 5.20.

$W_{A'e} = W_{A'} \times W_{fe}$

Where

$W_{A'e} = \dfrac{\text{lb}}{\text{hr}}$ = Pounds of dry air supplied per hour.

$W_{A'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of dry air supplied per pound of "as fired" fuel. Refer to Par. 7.2.8.1.

$W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate.

$c_{ps} = \dfrac{\text{Btu}}{\text{lb F}}$ = Mean specific heat of steam from curve on Fig. 6. It is determined from the instantaneous values over the range between inlet steam temperature and reference temperature.

t_{A7} or t_{A8} = F = Inlet air temperature.

t_{RA} = F = Reference air temperature.

7.2.9 The foregoing heat credits are to be summarized into total heat credits and used as the value of B_e in the equation in Par. 7.2 for solving for gross efficiency by the input-output method.

Efficiency by Heat Loss Method

7.3

$$\eta_g = 100 - \frac{L}{H_f + B} \times 100$$

Derivation of this formula is as follows:

$$\eta_g = \frac{\text{Output}}{\text{Input}} \times 100$$

Where

η_g = Per cent = Gross efficiency

Output = Input − L as defined in Par. 1.04.4.

Input = $H_f + B$ as defined in Par. 1.04.3.

Then

$$\eta_g = \frac{\text{Input} - L}{H_f + B} = \frac{(H_f + B) - L}{H_f + B} = 1 - \frac{L}{H_f + B}$$

Converting to per cent:

$$\eta_g = 100 - \frac{L}{H_f + B} \times 100$$

Where

7.3.1

η_g = Per cent = Gross efficiency

7.3.2 $L = \dfrac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Total heat loss from the steam generator.

$$L = L^*_{UC} + L_{G'} + L_{mf} + L_A + L_{mA} + L^*_z + L_{CO} + L_{UH} + L_{UHC} + L_\beta + L^*_{\boxed{P}} + L^*_d + L^*_r + L^*_w$$

*A fuel rate is used in the calculation of these losses.

7.3.2.01

$L_{UC} = \dfrac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to unburned carbon in total dry refuse.*

$$L_{UC} = W_{d'p'} \times H_{d'p'}$$

Where

$$W_{d'p'} = \frac{W_{d'p'e}}{W_{fe}}$$

Where

$W_{d'p'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of total dry refuse per pound of "as fired" fuel.

Where refuse rate at various collection points, such as ashpit, dust collector and boiler hoppers is not actually determined it may be estimated. See Par. 3.01.14.

$W_{d'p'e} = \dfrac{\text{lb}}{\text{hr}}$ = Pounds of total dry refuse rate.

$W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate.

If fuel rate is not measured, the expected rate for the test may be used, and considered sufficiently accurate for this calculation. Iteration will be required for more accurate results.

$H_{d'p'} = \dfrac{\text{Btu}}{\text{lb dry refuse}}$ = Laboratory determination of per cent combustible × 14,500 Btu/lb

or

$H_{d'p'} = \dfrac{\text{Btu}}{\text{lb dry refuse}}$ = Laboratory determination of heating value.

If it is possible and desirable to measure the refuse collection rate at all collection points, then the following calculation procedure will be used to determine unburned carbon loss.

$$L_{UC} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}} = a + b + c + d + e$$

(a) Btu/lb in ashpit $= \dfrac{\text{lb dry refuse in ashpit}}{\text{lb A.F. fuel}} \times \dfrac{\text{Btu}}{\text{lb ashpit refuse}}$

(b) Btu/lb in boiler hopper $= \dfrac{\text{lb dry refuse in boiler hopper}}{\text{lb A.F. fuel}} \times \dfrac{\text{Btu}}{\text{lb boiler hopper refuse}}$

(c) Btu/lb in econ. hopper $= \dfrac{\text{lb dry refuse in economizer hopper}}{\text{lb A.F. fuel}} \times \dfrac{\text{Btu}}{\text{lb econ. hopper refuse}}$

(d) Btu/lb in air heater hopper $= \dfrac{\text{lb dry refuse in air heater hopper}}{\text{lb A.F. fuel}} \times \dfrac{\text{Btu}}{\text{lb air heater hopper refuse}}$

(e) Btu/lb in dust collector hopper $= \dfrac{\text{lb dry refuse in dust collector hopper}}{\text{lb A.F. fuel}} \times \dfrac{\text{Btu}}{\text{lb dust collector refuse}}$

If the flue dust is sampled prior to all collection points, with the exception of the ashpit, and all parties agree ashpit combustible is negligible, flue dust rate may be estimated or determined by dust concentration measurements. Then the loss due to unburned combustible will become:

$$L_{UCd} = \frac{\text{Btu}}{\text{lb A.F. fuel}} = \textit{Heat loss due to unburned carbon in flue dust.}$$

$$L_{UCd} = W_{d'} \times H_{d'}$$

Where

$$W_{d'} = \frac{\text{lb}}{\text{lb A.F. fuel}} = \text{Pounds of dry flue dust per pound of “as fired” fuel.}$$

$$H_{d'} = \frac{\text{Btu}}{\text{lb of dust}} = \text{Heat value of flue dust.}$$

7.3.2.02

$$L_{G'} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}} = \textit{Heat loss due to heat in dry flue gas.}$$

$$L_{G'} = W_{G'} \times c_{pG'} \, (t_G - t_{RA})$$

Where

$$W_{G'} = \frac{\text{lb}}{\text{lb A.F. fuel}} = \text{Pounds of dry gas per pound of “as fired” fuel.}$$

$$W_{G'} = \frac{44.01\, CO_2 + 32.00\, O_2 + 28.02\, N_2 + 28.01\, CO}{12.01\,(CO_2 + CO)} \times C_b + \left[\frac{12.01\, S}{32.07}\right]$$

The preceding formula is based on molecular weights accurate to four significant figures, but it is not to be implied that the dry gas loss has this degree of accuracy. The four digit molecular weights are used to hold errors from calculation procedures to a minimum. The values used are from the National Bureau of Standards Circular 564, dated 11/1/55.

CO_2, O_2, and CO = per cent by volume of dry flue gas (location 12, 14 or 15, Fig. 1)

N_2 being determined by subtracting the total of CO_2, O_2 and CO from 100 per cent.

$$C_b = C - \frac{W_{d'p'} \times H_{d'p'}}{14500}$$

Where

$$C_b = \frac{\text{lb}}{\text{lb A.F. fuel}} = \text{Pounds of carbon burned per pound of “as fired” fuel.}$$

$$C = \frac{\text{lb}}{\text{lb A.F. fuel}} = \text{Pounds of carbon in “as fired” fuel by laboratory analysis.}$$

$W_{d'p'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}} =$ Pounds of total dry refuse per pound of “as fired” fuel. See Par. 7.3.2.01

$$H_{d'p'} = \frac{\text{Btu}}{\text{lb dry refuse}} = \text{Heat value for total dry refuse from laboratory determination.}$$

$$14500 = \frac{\text{Btu}}{\text{lb}} = \text{Heat value of 1 lb of carbon as it occurs in refuse.}$$

$S = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds sulfur per pound of "as fired" fuel as determined by laboratory analysis.

$c_{pG'} = \dfrac{\text{Btu}}{\text{lb F}}$ = Mean specific heat of the dry flue gas as obtained from curves on Fig. 7. It is determined from the instantaneous values over the range between gas temperature leaving the unit and the reference temperature.

t_G = Gas temperature leaving the unit, such as t_{G12}, t_{G14} or t_{G15}. If this temperature is to be corrected because of deviation from standard or guarantee air heater inlet air temperature see Par. 7.5.2.

t_{RA} = F = Reference air temperature. If this temperature is to be corrected because of deviation from standard or guarantee inlet air temperature see Par. 7.4.1.

7.3.2.03

$L_{mf} = \dfrac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to moisture in the "as fired" fuel.

$$L_{mf} = m_f (h_{12,14,15} - h_{Rw})$$

Where

$m_f = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds moisture per lb of "as fired" fuel by laboratory analysis.

$h_{12,14,15}$ = Enthalpy of vapor at partial pressure, and exit gas temperature $t_{G12,14,15}$ to be determined from steam tables.

$$P_{mG} = \frac{P_A}{1 + \dfrac{100 \times 1.5\ C_b}{m_G\ (CO_2 + CO)}}$$

Where

$P_{mG} = \dfrac{\text{lb}}{\text{sq in. abs}}$ = Partial pressure of the moisture in the flue gas.

The above formula is a rigorous treatment. For practical use, P_{mG} approximates one psia for the partial pressure existing at the steam generator exit.

$P_A = \dfrac{\text{lb}}{\text{sq in. abs}}$ = Atmospheric pressure

$C_b = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds carbon burned per lb A.F. fuel

$$m_G = 8.936\ H + (W_{mA'})(W_{A'}) + m_f + W_z + m_p$$

Where

$m_G = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of moisture in the flue gas per pound of "as fired" fuel.

8.936 = 8.936 pounds of water produced from burning one pound of hydrogen.

$H = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of hydrogen exclusive of that in moisture from an "as fired" fuel by laboratory analysis.

$W_{mA'} = \dfrac{\text{lb}}{\text{lb dry air}}$ = Pounds of moisture per pound of dry air at boiler inlet.

$W_{A'} = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of dry air per pound of "as fired" fuel.

$m_f = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of moisture per pound of "as fired" fuel.

$W_z = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of atomizing steam per pound of "as fired" fuel.

$m_p = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of moisture evaporated in ashpit per pound of "as fired" fuel.

CO_2, CO = per cent by volume of dry flue gas.

h_{Rw} = Enthalpy of saturated liquid at t_{RA} is used for solid and liquid fuels. Where moisture loss is to be adjusted for deviation from standard or guarantee conditions see Par. 7.5.4.

7.3.2.04

$L_H = \dfrac{Btu\ loss}{lb\ A.F.\ fuel}$ = *Heat loss due to moisture from burning of hydrogen.*

$L_H = 8.936 \times H\,(h_{12,14,15} - h_{Rw})$

Where

8.936 = 8.936 pounds of water produced from burning one pound of hydrogen.

$H = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of hydrogen exclusive of that in moisture in "as fired" fuel by laboratory analysis.

Remaining items will be identical with Par. 7.3.2.03. Where hydrogen loss is to be adjusted for deviation from standard or guaranteed conditions see Par. 7.5.4.

7.3.2.05

$L_{mA} = \dfrac{Btu\ loss}{lb\ A.F.\ fuel}$ = *Heat loss due to moisture in the air.*

$L_{mA} = W_{mA'} \times W_{A'}\,[h_{12,14,15} - h_{Rv}]$

Where

$W_{mA'} = \dfrac{lb}{lb\ dry\ air}$ = Pounds of water vapor per pound of dry air obtained from Par. 5.20.

$W_{A'} = \dfrac{lb}{lb\ A.F.\ fuel}$ = Pounds of dry air supplied per lb of "as fired" fuel. Refer to Par. 7.2.8.1.

$h_{12,14,15}$ will be identical with Par. 7.3.2.03.

$h_{Rv} = \dfrac{Btu}{lb\ H_2O}$ = Enthalpy of the saturated vapor at t_{RA}. Refer to Par. 7.2.8.1

7.3.2.06

$L_z = \dfrac{Btu\ loss}{lb\ A.F.\ fuel}$ = *Heat loss due to heat in atomizing steam.*

$$L_z = \frac{W_{ze}}{W_{fe}}\,(h_{12,14,15} - h_{Rv})$$

Where

$W_{ze} = \frac{\text{lb}}{\text{hr}}$ = Pounds of metered or estimated atomizing steam as agreed to by all parties.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as in Par. 7.3.2.01.

$h_{12,14,15} = \frac{\text{Btu}}{\text{lb steam}}$ will be identical with Par. 7.3.2.03.

$h_{Rv} = \frac{\text{Btu}}{\text{lb } H_2O}$ = Enthalpy of saturated vapor at reference temperature at t_{RA}. Refer to Par. 7.2.8.1.

7.3.2.07

$L_{CO} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to formation of carbon monoxide.*

Where it is established that CO is present and cannot be eliminated by operating adjustments:

$$L_{CO} = \frac{CO}{CO_2 + CO} \times 10160 \times C_b$$

Where

CO and CO_2 per cent by volumc of flue gas.

10160 = Btu generated burning 1 lb of carbon in CO to CO_2 and represents the difference between the burning carbon as it occurs in fuel to CO_2 (14540 Btu), and burning carbon as it occurs in fuel to CO (4380 Btu); that is 14540 – 4380 = 10160 Btu (Fuels & Combustion Hand-Book – Johnson & Auth, published by McGraw-Hill Book Company)

$C_b = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of carbon burned per lb of "as fired" fuel.

7.3.2.08

$L_{UH} = \frac{\text{Btu Loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to unburned hydrogen.*

Where it is established that unburned hydrogen is present and cannot be eliminated by operating adjustments:

$$L_{UH} = \frac{\frac{H_2\ (\text{cu ft})}{\text{cu ft dry gas}} \times W_{G'} \times 318.9}{\text{flue gas specific weight}}$$

Where

$\frac{H_2\ (\text{cu ft})}{\text{cu ft dry gas}}$ = Laboratory determination of H_2 content of flue gas in Par. 5.06.

$W_{G'} = \frac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of dry gas per lb of "as fired" fuel as determined in Par. 7.3.2.02.

318.9 = Btu/cu ft of hydrogen at 14.7 psia and 68 F.

Flue gas specific weight at 68 F and 14.7 psia

$$= 0.0401 \left[\frac{CO_2}{35.11} + \frac{O_2}{48.28} + \frac{CO}{55.16} + \frac{N_2}{55.14} + \frac{SO_2}{24.12} + \frac{H_2}{766.36} + \frac{\frac{HC}{1545}}{M_{HC}} \right]$$

Where

CO_2, O_2, CO, etc. = Per cent = Per cent by volume constituents as determined by laboratory analysis of flue gas.

M_{HC} = Molecular weight of hydrocarbon in flue gas.

For derivation of flue gas specific weight, see Appendix.

7.3.2.09

$$L_{UHC} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}} = \textit{Heat loss due to unburned hydrocarbons.}$$

Where it is established that unburned hydrocarbons are present and cannot be eliminated by operating adjustments:

$$L_{UHC} = \frac{\dfrac{\text{UHC (cu ft)}}{\text{cu ft dry gas}} \times W_{G'} \times K_{UHC}}{100 \times \text{flue gas specific weight}}$$

Where

$\dfrac{\text{UHC (cu ft)}}{\text{cu ft dry gas}}$ = Laboratory determination of flue gas constituents as in Par. 5.06.

$W_{G'} = \dfrac{\text{lb}}{\text{lb A.F. fuel}}$ = Pounds of dry gas per lb of "as fired" fuel, as determined in Par. 7.3.2.02.

K_{UHC} = Btu/cu ft of unburned hydrocarbons as determined by laboratory analysis

Flue gas specific weight at 68 F and 14.7 psia determination in Par. 7.3.2.08.

7.3.2.10

L_β = *Loss due to surface radiation and convection.*

This loss may be obtained from ABMA radiation loss chart, see Fig. 8 and correction for air velocities, see Fig. 9 by taking the radiation loss per cent and multiplying it by the chemical heat in one pound of "as fired" fuel (H_f).

7.3.2.11

$L_{\boxed{P}} = \dfrac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to radiation to ashpit, sensible heat in slag, and if applicable the latent heat of fusion of slag.*

Where measured by procedures outlined in Pars. 5.22 and 5.23 will be:

$L_{\boxed{P}}$ = Heat loss to increasing temperature of pit water + heat loss to evaporation of pit water + sensible heat loss in the refuse as it leaves the pit.

$$\text{Heat loss to increasing temperature of pit water} = \frac{W_{we38} \times (t_{w39} - t_{w38})}{W_{fe}}$$

Where

$W_{we38} = \dfrac{\text{lb}}{\text{hr}}$ = Pounds of water per hour metered to pit.

t_{w39} = F = Water temperature leaving pit.

t_{w38} = F = Water temperature entering pit.

$W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as in Par. 7.3.2.01.

Heat loss to evaporation of pit water

$$= \left[W_{we38} + \left(W_{fe} \times \frac{p}{100} \times \frac{\text{specific weight of water}}{\text{specific weight of refuse}} \right)^{*} - W_{we39} \right] \times \left[\frac{h_{v12,14,15} - h_{w39}}{W_{fe}} \right]$$

Where

$W_{we38} = \frac{\text{lb}}{\text{hr}}$ = Pounds of water per hour metered to pit.

$W_{we39} = \frac{\text{lb}}{\text{hr}}$ = Pounds of water per hour metered from pit.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as in Par. 7.3.2.01.

p = pit refuse = in this case expressed as per cent of "as fired" fuel to pit.

Specific weight of water = lb/cu ft at t_{w39}.

Specific weight of refuse = lb/cu ft pit refuse by actual dry weight or as agreed to by participating parties.

$h_{v12,14,15}$ = Enthalpy of vapor as in Par. 7.3.2.03.

h_{w39} = Enthalpy of outlet water.

Heat loss due to the sensible heat in the refuse as it leaves

the pit $= C_{pp} \frac{W_{pe}}{W_{fe}} (t_{w39} - t_{RA})$

Where

$C_{pp} = \frac{\text{Btu}}{\text{lb F}}$ = Specific heat of wet refuse.

$W_{pe} = \frac{\text{lb}}{\text{hr}}$ = Pounds of wet refuse per hour.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as in Par. 7.3.2.01

t_{w39} = F = Water temperature leaving the pit

t_{RA} = F = Reference temperature as in Par. 7.2.8.1

Where refuse is removed in the dry state from the pit this loss may be measured as follows:

$L_{p'} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to sensible heat in the dry ashpit refuse.

$$L_{p'} = \frac{c_{pp'} \, (t_{p'37} - t_{RA}) \times W_{p'e}}{W_{fe}}$$

Where

$c_{pp'} = \frac{\text{Btu}}{\text{lb F}}$ = Specific heat of dry ashpit refuse at average refuse temperature. Use 0.25.

$t_{p'37}$ = F = Temperature of ashpit refuse as indicated in Fig. 1.

*The value within the parentheses may be determined from comparison of clean-pit and ash laden-pit water fill volumes, or an estimate of total ash volume in the pit and displacement measurements on sample batches of pit refuse.

t_{RA} = Reference air temperature as in Par. 7.2.8.1.

$W_{p'e} = \frac{\text{lb}}{\text{hr}}$ = Weighed or estimated dry ashpit refuse leaving pit.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as given in Par. 7.3.2.01.

7.3.2.12

$L_{d'} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to sensible heat in flue dust.*

$$L_{d'} = \frac{c_{d'}\,(t_{G12,14,15} - t_{RA}) \times W_{d'e}}{W_{fe}}$$

Where

$c_{d'} = \frac{\text{Btu}}{\text{lb F}}$ = Specific heat of flue dust at average flue dust temperature. Use 0.20.

$t_{G12,14,15}$ = F = Temperature of flue gas at each collection point as indicated in Fig. 1.

t_{RA} = F = Reference air temperature as in Par. 7.2.8.1.

$W_{d'e} = \frac{\text{lb}}{\text{hr}}$ = Weighed or estimated dust at each collection point.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as given in Par. 7.3.2.01

7.3.2.13

$L_r = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to heat in pulverizer rejects.*

$$L_r = \frac{W_{re} \times H_r}{W_{fe}}$$

Where

$W_{re} = \frac{\text{lb}}{\text{hr}}$ = Pounds of pulverizer rejects, preferably weighed.

$H_r = \frac{\text{Btu}}{\text{lb}}$ = Heating value of rejects from laboratory analysis of representative sample.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as given in Par. 7.3.2.01.

7.3.2.14

$L_w = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = *Heat loss due to heat pick-up by cooling water entering envelope* (Fig. 1).

$$L_w = \frac{W_{we}\,(t_{w\,\text{outlet}} - t_{w\,\text{inlet}})}{W_{fe}}$$

Where

$W_{we} = \frac{\text{lb}}{\text{hr}}$ = Pounds of cooling water flow.

$W_{fe} = \frac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as given in Par. 7.3.2.01.

7.3.2.15 *Summarizing Losses.*

$$L = L_{UC} + L_{G'} + L_{mf} + L_H + L_{mA} + L_z + L_{CO} + L_{UH} + L_{UHC} + L_\beta + L_{\boxed{p}} + L_d + L_r + L_w$$

Where

$L = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Total heat losses. Par. 7.3.2.

$L_{UC} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to unburned carbon in refuse. Par. 7.3.2.01

$L_{G'} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to heat in dry flue gas. Par. 7.3.2.02.

$L_{mf} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to moisture in the "as fired" fuel. Par. 7.3.2.03.

$L_H = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to moisture from burning of hydrogen. Par. 7.3.2.04.

$L_{mA} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to moisture in the air. Par. 7.3.2.05.

$L_z = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to heat in atomizing steam. Par. 7.3.2.06.

$L_{CO} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to formation of carbon monoxide. Par. 7.3.2.07

$L_{UH} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to unburned hydrogen. Par. 7.3.2.08.

$L_{UHC} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to unburned hydrocarbons. Par. 7.3.2.09.

$L_\beta = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to surface radiation and convection. Par. 7.3.2.10.

$L_{\boxed{p}} = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to rediation to ashpit, sensible heat in slag and, if applicable, latent heat of fusion of slag. Par. 7.3.2.11.

$L_d = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to sensible heat in flue dust. Par. 7.3.2.12.

$L_r = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to heat in pulverizer rejects. Par. 7.3.2.13.

$L_w = \frac{\text{Btu loss}}{\text{lb A.F. fuel}}$ = Heat loss due to heat pickup by cooling water entering envelope, Fig. 1, Par. 7.3.2.14.

7.3.3

$H_f = \frac{\text{Btu}}{\text{lb A.F. fuel}}$ = Chemical heat in fuel to be obtained as in Par. 7.2.6.

7.3.4

$B = \dfrac{\text{Btu credit}}{\text{lb A.F. fuel}}$ = Total heat credits per pound of "as fired" fuel added to the steam generator in the form of sensible heat.

$$B = \frac{B_{Ae} + B_{ze} + B_{fe} + B_{xe} + B_{mAe}}{W_{fe}}$$

Where

$B_{Ae} = \dfrac{\text{Btu credit}}{\text{hr}}$ = Heat credit supplied by entering air. Par. 7.2.8.1

$B_{ze} = \dfrac{\text{Btu credit}}{\text{hr}}$ = Heat credit supplied by atomizing steam. Par. 7.2.8.2

$B_{fe} = \dfrac{\text{Btu credit}}{\text{hr}}$ = Heat credit supplied by sensible heat in fuel. Par. 7.2.8.3

$B_{xe} = \dfrac{\text{Btu credit}}{\text{hr}}$ = Heat credit supplied by auxiliary drives. Par. 7.2.8.4.

$B_{mAe} = \dfrac{\text{Btu credit}}{\text{hr}}$ = Heat credit supplied from the moisture entering with the inlet air. Par. 7.2.8.5.

$W_{fe} = \dfrac{\text{lb A.F. fuel}}{\text{hr}}$ = Measured fuel rate as given in Par. 7.3.2.01.

For a more accurate calculation of gross steam generator efficiency, the gross efficiency obtained from the initial calculation can be used as the basis for determining a refined fuel rate. When this value is substituted in formulas for determining heat losses and credits, a more accurate calculated gross efficiency is obtained.

Corrections to Standard or Guarantee Conditions

7.4 Corrections to Heat Credits.

7.4.1 Corrections to the heat credits, "heat supplied by entering air," and "heat supplied by sensible heat in fuel" for changes from test reference air temperature (see Par. 7.2.8.1) to a standard or guaranteed air inlet temperature are made by substituting the standard or guaranteed temperature for the test reference temperature in the heat credit formulas.

7.4.2 Corrections to the heat credits, "heat supplied by atomizing steam" and "heat supplied by moisture in entering air" for changes from test reference air temperature to a standard or guaranteed temperature air inlet temperature are made by substituting the enthalpy corresponding to the standard or guaranteed temperature for the enthalpy corresponding to the test reference temperature in the heat credit formulas.

7.5 Corrections to Heat Losses.

7.5.1 Corrections to heat losses, besides including a correction for changes from the test reference air temperature to standard or guaranteed air inlet temperature as in the treatment of heat credit corrections, must also include, when an air heater is used, a correction for the change in gas exit temperature resulting from the above change in air inlet temperature. The corrected gas outlet temperature is given in the Test Code for Air Heaters PTC 4.3 and uses the following formula:

$$t_{G_{15}}\delta = \frac{t_{A8D}\ (t_{G14} - t_{G15}) + t_{G14}\ (t_{G15} - t_{A8})}{(t_{G14} - t_{A8})}$$

Where

$t_{G_{15}}\delta$ = F = corrected air heater exit gas temperature.

t_{A8D} = F = Standard or guaranteed air heater inlet air temperature.

t_{G14} = F = air heater inlet gas test temperature.

t_{G15} = F = air heater exit gas test temperature.

t_{A8} = F = air heater inlet air test temperature.

A further minor correction caused by leakage differences between test and standard or guaranteed temperatures is being developed for the Test Code for Air Heaters PFC 4.3. When this later code is issued, this further correction is to be considered a part of PFC 4.1.

7.5.2 Corrections to the heat losses, "Dry gas loss" and "Heat loss due to sensible heat in the flue dust" for changes from test reference air temperature to a standard or guaranteed air inlet temperature are made by substituting the standard or guaranteed temperature for the test reference air temperature and also by substituting the corrected gas exit temperature for the test gas exit temperature in the heat loss formulas.

7.5.3 Corrections to the heat losses, "Heat loss due to moisture in fuel," "Heat loss due to moisture in air" and "Heat loss due to atomizing steam," for changes from the test reference air temperature to a standard or guaranteed air inlet temperature are made by substituting the appropriate enthalpy corresponding to the standard or guaranteed air inlet temperature for the enthalpy corresponding to the test reference air temperature and also by substituting the enthalpy corresponding to the corrected gas exit temperature for the enthalpy corresponding to the test gas exit temperature, in the heat loss formulas. The "appropriate" inlet enthalpy referred to above relates to the state of the entering moisture (liquid or vapor).

7.5.4 Corrections to the heat losses, "Heat loss due to moisture in fuel" and "Heat loss due to hydrogen in fuel" for changes of moisture and hydrogen content from the test fuel to the fuel used for the standard or guaranteed computations, are made by substituting the weight of moisture or hydrogen per pound of fuel in the standard or guaranteed fuel for the weight of moisture or hydrogen per pound of fuel, of the test fuel, in the heat loss formulas.

7.5.5 Corrections to the heat loss "Loss due to moisture in air" for changes of moisture content from the test air to the air used for standard or guaranteed computations, are made by substituting the weight of moisture in the standard or guaranteed air for the weight of the moisture in the test air, in the heat loss formula. The magnitude of this correction in most cases will be negligible.

7.5.6 Other heat losses listed in the computations are not considered in these correction paragraphs either because they do not apply or the magnitude of the correction is usually insignificant.

7.6 The corrected steam generator efficiency resulting from the preceding adjustments of credits and losses to standard or guarantee conditions can then be compared with the standard or guarantee conditions, respectively.

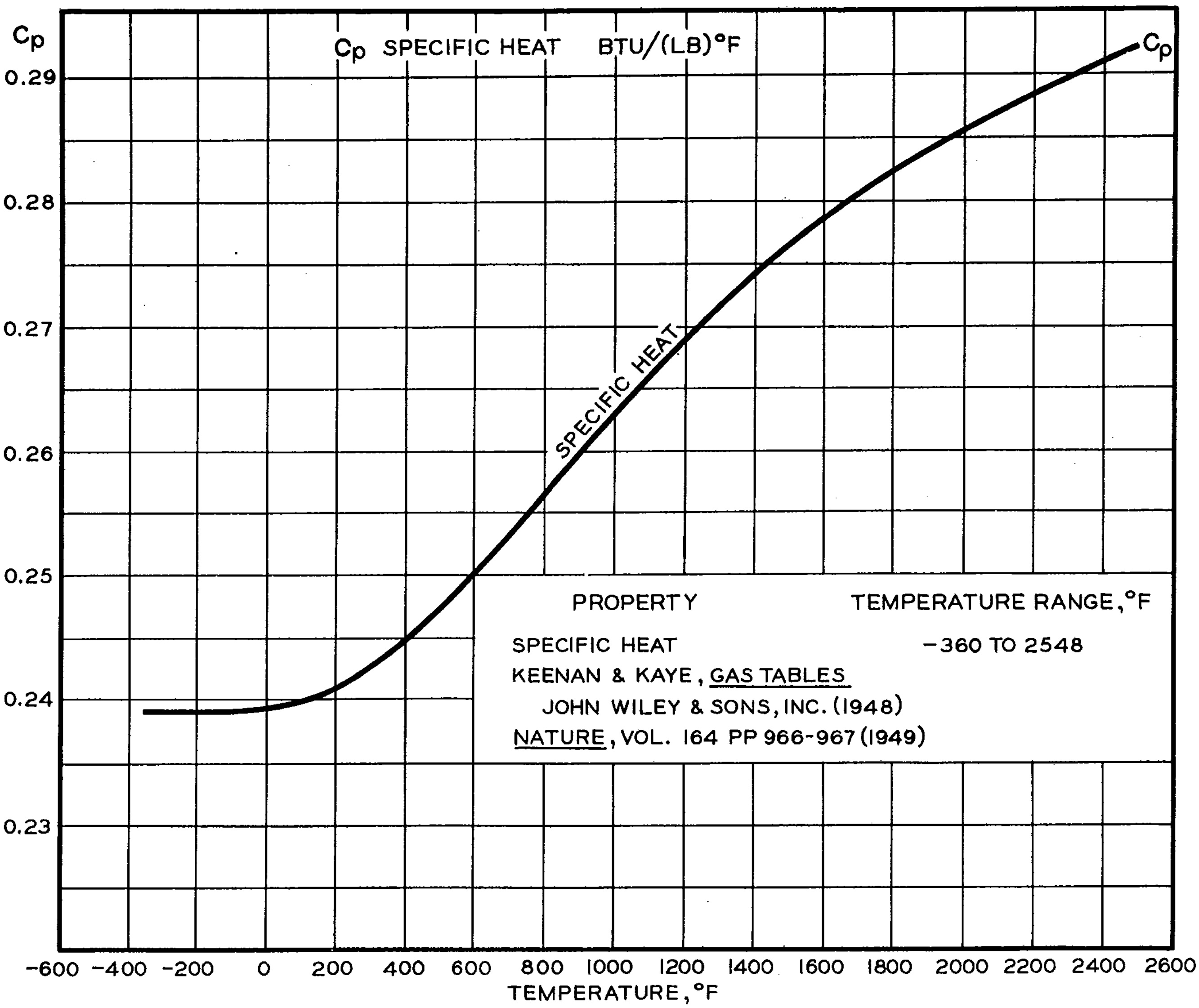

FIG. 3 INSTANTANEOUS SPECIFIC HEAT OF AIR

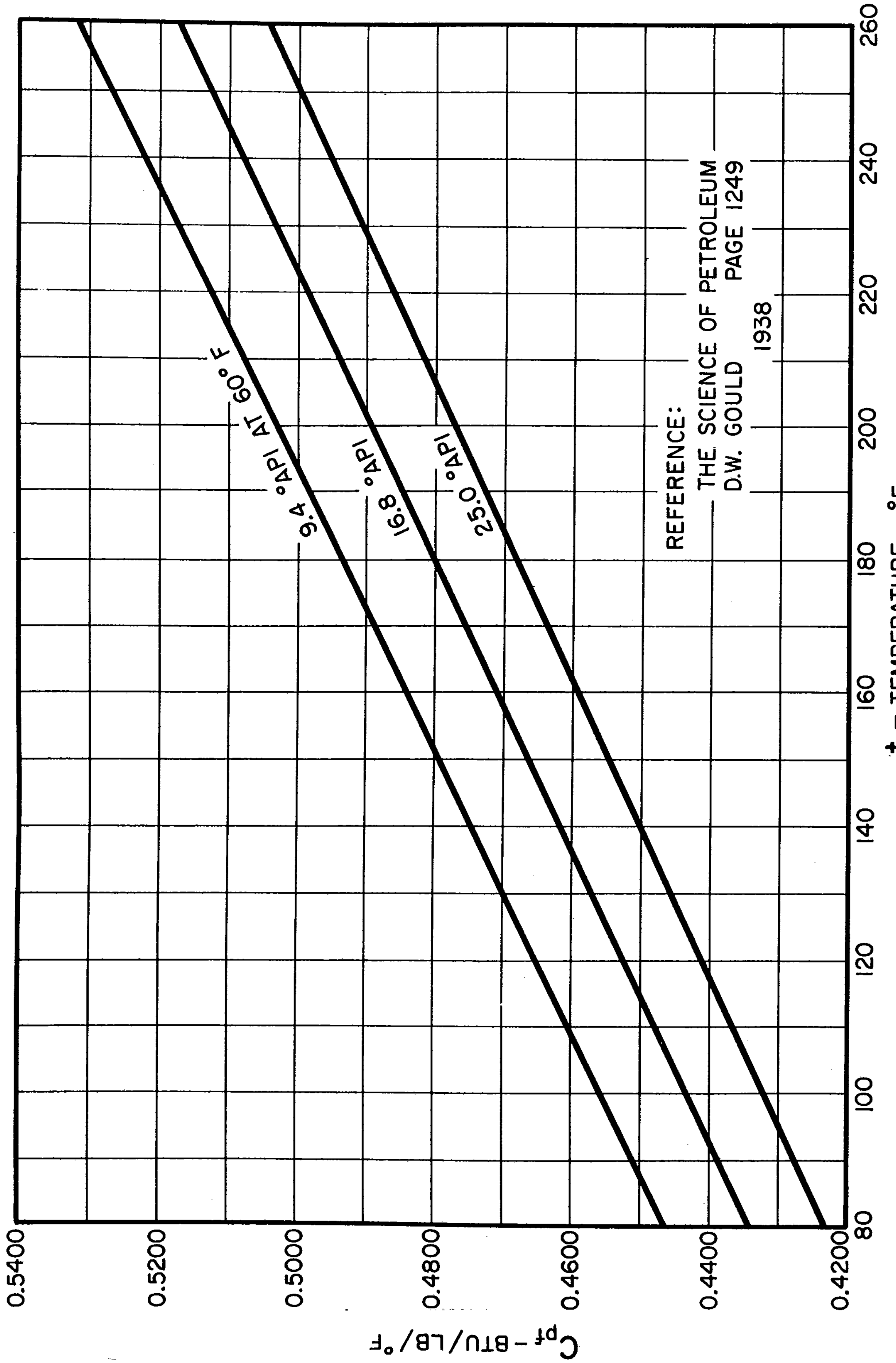

FIG. 4 INSTANTANEOUS SPECIFIC HEAT OF FUEL OIL – 1 ATMOSPHERE

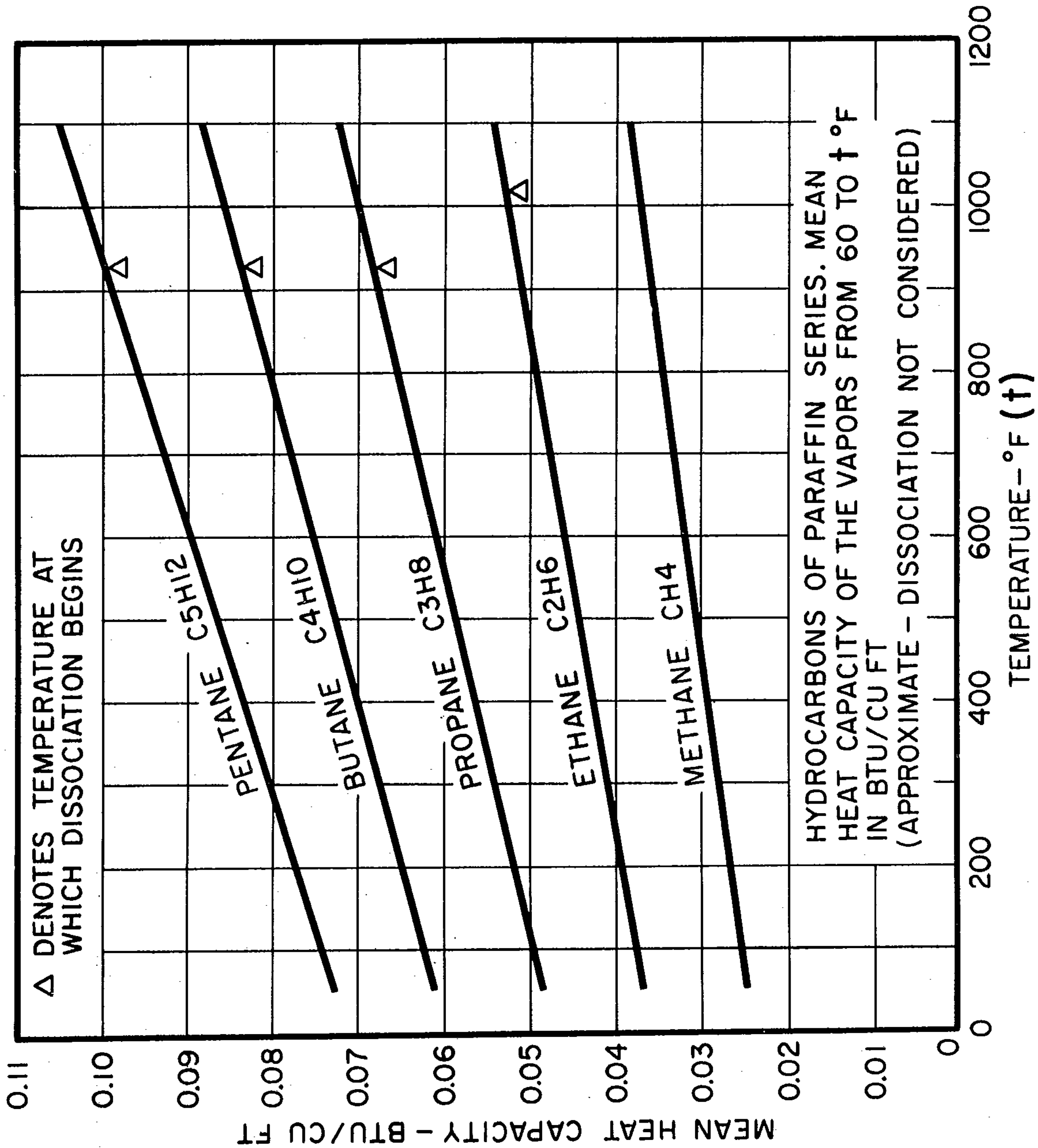

FIG. 5 INSTANTANEOUS SPECIFIC HEAT OF FUEL GAS

(Reference: American Gas Association Publication of 1954, P 124, Edited by Louis Shnidman)

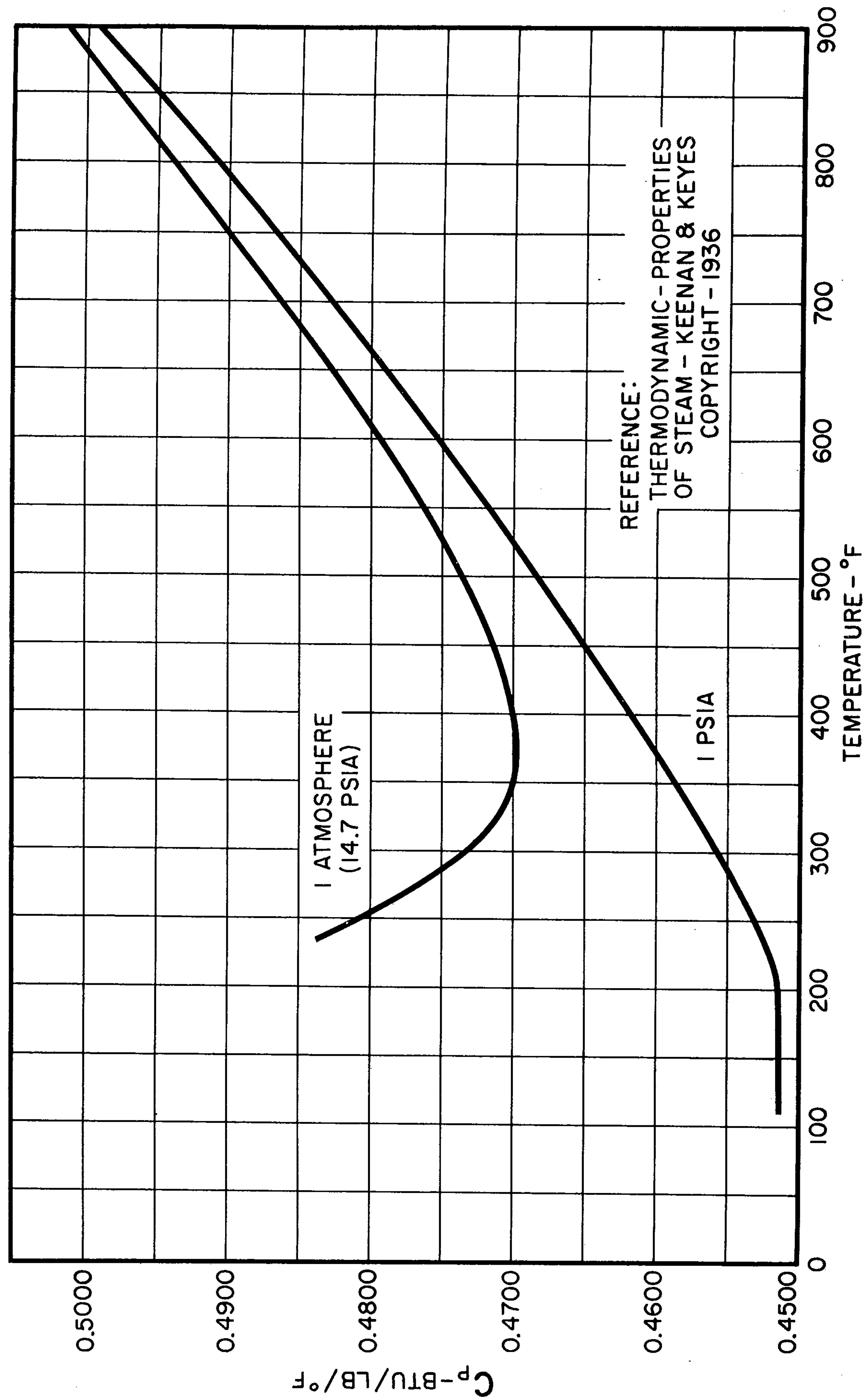

FIG. 6 INSTANTANEOUS SPECIFIC HEAT OF STEAM

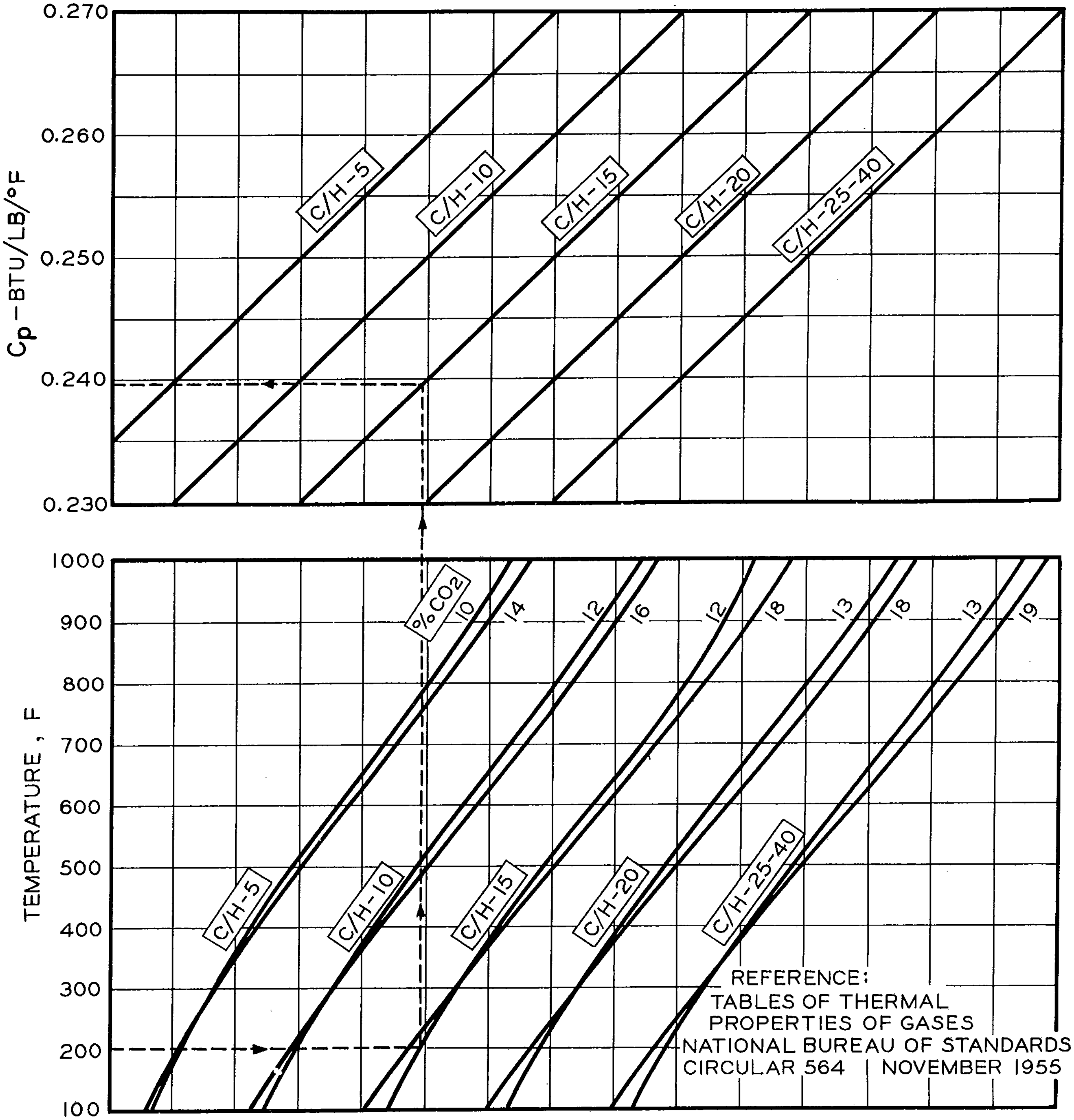

FIG. 7 INSTANTANEOUS SPECIFIC HEAT OF DRY FLUE GAS FOR CARBON HYDROGEN RATIOS (FUEL) = 5 – 40

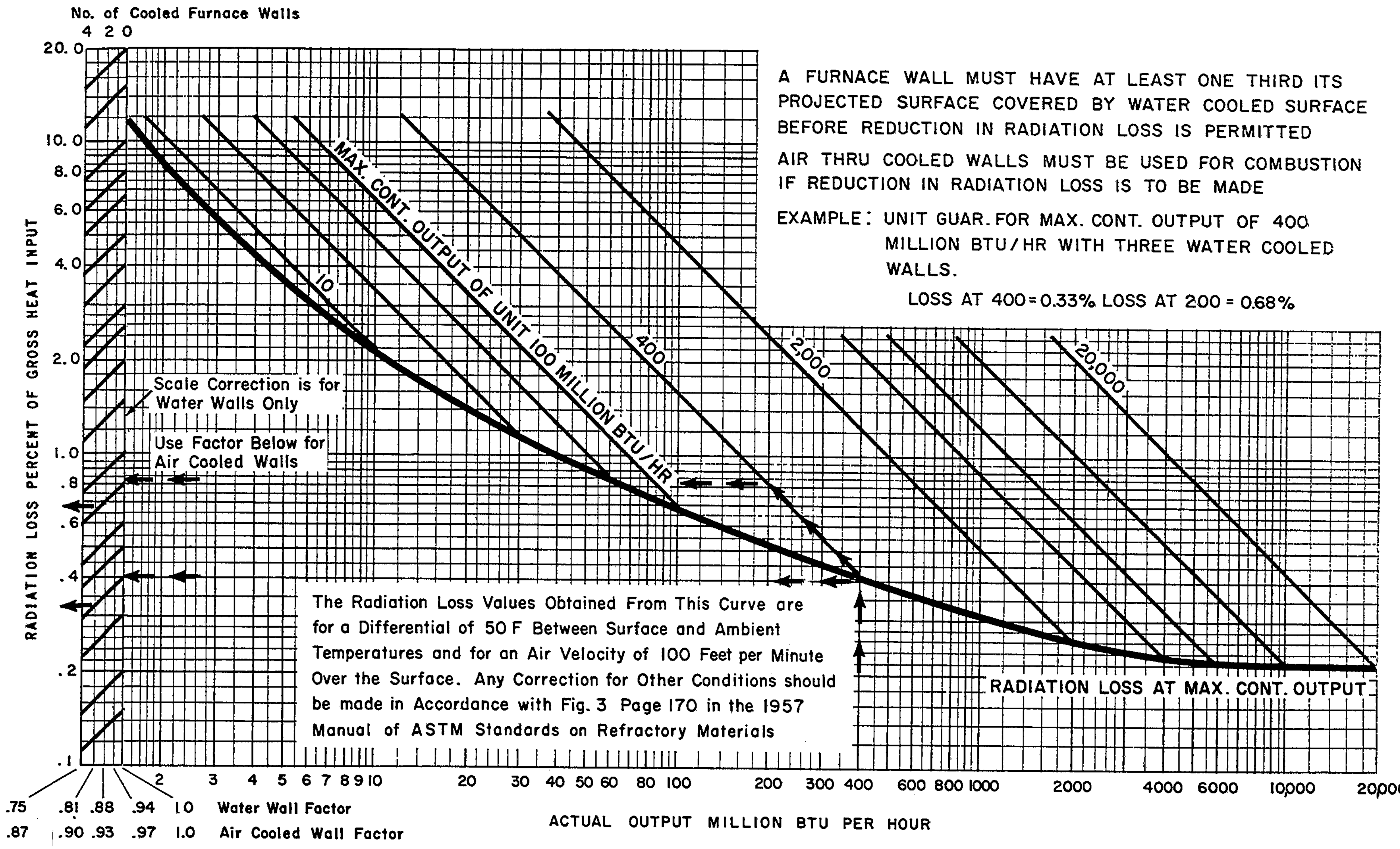

FIG. 8 ABMA STANDARD RADIATION LOSS CHART

To facilitate the use of the major correction which is for air velocity, this correction is included in the Code on Fig. 9, the lower curve of which is the basis of the ABMA curve.

(Published through the courtesy of the American Boiler Manufacturers Association.)

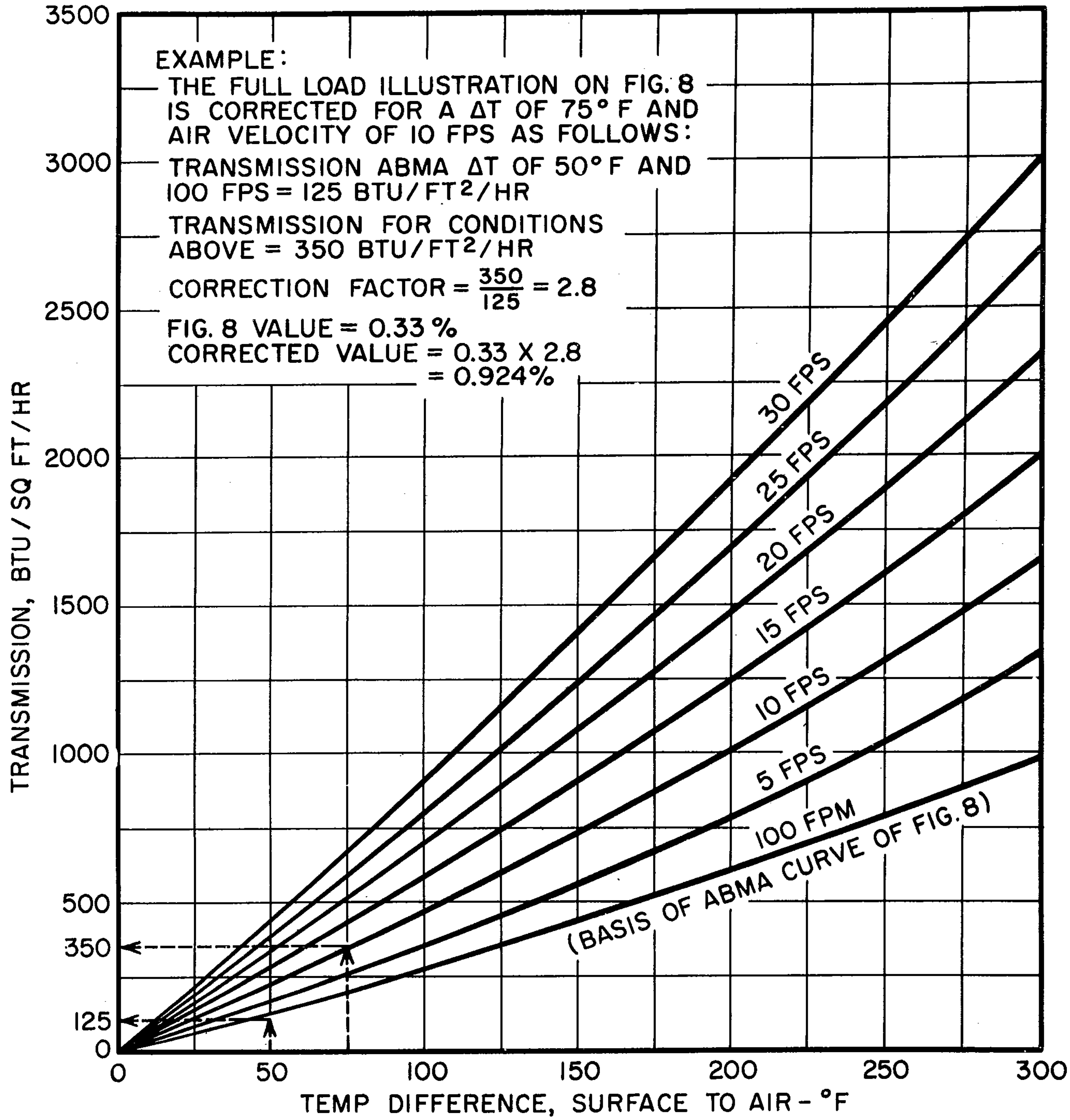

FIG. 9 SURFACE TRANSMISSION FOR VARIOUS AIR VELOCITIES BASED ON EMISSIVITY OF 0.95 AND AIR TEMPERATURE OF 70 F

(Basic data above were obtained from ASTM Standard on Refractory Materials)

SECTION 8, OTHER OPERATING CHARACTERISTICS

8.01 The continuing satisfactory performance of a steam generator requires the determination of many operating characteristics other than its ability to meet its design capacity and efficiency guarantee. This section describes factors affecting performance and how these should be determined by test.

8.02 Measurement of Air Leakage or Infiltration. When it is desired to determine the amount of air infiltration or leakage through any portion of the enclosure of a steam generating unit, beyond the furnace exit, it should be done by comparing excess air, as determined from flue gas analyses. The sampling locations preferably should lie in planes normal to the flue gas flow, located as close as practical to the zones of comparison. Frequency of sampling points should be as recommended in Par. 5.04, "Flue Gas Sampling and Analysis – Sampling Locations." The gas temperatures at the sampling location will determine whether or not a water cooled sampler is required. It is advisable to use a water cooled sampler at temperatures in excess of 950 F.

8.02.1 The amount of air infiltration or leakage is normally expressed in terms of increase in excess air, reduction in CO_2 or per cent leakage. The latter is as follows:

$$W_L \text{ (per cent)} = \frac{(\text{per cent total weight of air at } S_2) - (\text{per cent total weight of air at } S_1)}{(\text{per cent total weight of air at } S_1)} \times 100$$

8.02.2

Where

W_L = Per cent air leakage.

S_1 = Upstream sampling location.

S_2 = Downstream sampling location.

8.02.3 Measurement of air leakage of a regenerative air heater is covered in the Test Code for Air Heaters PTC 4.3.

8.03 Peak Load Capacity. When it is desired to establish the ability of a steam generating unit to maintain anticipated peak load capacity, commercial feedwater or steam flow recording meters may be used. Flows must be corrected to compensate for deviation of test pressures and temperatures at the flow nozzle or orifice, from design pressure and temperature conditions, and the instrument must be calibrated immediately prior to the test.

8.03.1 When desuperheating spray water is to be measured or accounted for as part of capacity determination, and this water flow is not metered, the spray flow rate may be determined by heat balance, using steam flow at either the entrance or exit to the desuperheater, steam pressures and temperatures at the entrance and exit of the desuperheater, and spray water temperature. Temperatures and pressures will be measured as outlined in Par. 4.19, "Steam and Feedwater Temperatures," and Par. 4.21, "Steam and Feedwater Pressures."

8.03.2 Reheat steam flow can be measured or computed as described in Par. 4.17.

8.04 Steam Temperature. When superheater and/or reheater steam temperature characteristic and control ranges thereof are to be verified by test, steam temperature measurement should be in accordance with procedures outlined in Par. 4.19, "Steam and Feedwater Temperatures."

8.04.1 Operating conditions which can affect a temperature test such as steam flow, steam pressure, feedwater temperature, excess air, cold reheat pressure and temperature and characteristics of the fuel fired should be as specified by design. Control apparatus for maintaining and regulating temperature such as burner tilt, recirculating gas fans, spray valves, bypass dampers, etc., shall have been adjusted prior to the test. Selection and setting of burners shall also be agreed upon. The period of operation prior to running such a test should be of sufficient duration to insure stabilization of furnace cleanliness. All heat transfer surfaces, both internal and external, should be commercially clean (normal operating cleanliness) before starting the test. During the test, only the amount of cleaning shall be permitted as is necessary to maintain normal operating cleanliness.

8.04.2 Measurement of steam flows, temperatures, pressures, and excess air, which provide essential supplementary data, should be as specified in Pars. 4.17, 4.19, 4.21 and 8.02.

8.05 Exit Gas Temperature. When a gas temperature at the exit of a steam generating unit is to be verified by test, the procedures outlined in Par. 5.08, "Flue Gas Temperature," should be followed. Operating conditions, unit cleanliness and necessary test measurements should be given the same consideration as in Par. 8.04.

8.06 Static Pressure of Gas and Air. Static pressure connections shall be installed in a manner as to avoid errors due to gas velocity. Piping or tubing shall preferably be specifically installed for the test, and shall be proved tight with provisions made for cleaning and drainage. The recommendations of I & A Pressure Measurement PTC 19.2, Chapter 6, shall be followed.

8.06.1 Flue gas and air pressures shall be measured by suitable manometers designed, built, installed, calibrated, and used as specified in I & A Pressure Measurement PTC 19.2, Chapter 3, on Liquid -Level Gages.

8.07 Draft Loss, or Resistance to Air or Gas Flow. When a draft loss or resistance across a steam generating unit, or a section of a unit, is to be measured, a differential manometer should be used in preference to absolute draft or pressure gages.

8.07.1 Operating conditions, unit cleanliness and necessary test measurements should be given the same consideration as in Pars. 8.04 and 8.05.

8.08 Pressure Loss. When the steam, water or other fluid pressure loss is to be determined across a steam generating unit, or a portion of a unit, the general pressure measurement procedures specified in Par. 4.21 "Steam and Feedwater Pressures," apply.

8.08.1 In addition to the above measurement technique, either the pressure from all points shall be taken with individual deadweight gages without a manifold or by means of a common manifold with one calibrated Bourdon gage. In the latter case the connections to the manifold shall be double valved. Manometers of suitable range and construction may also be used. Calibrated differential type gages or transducers may be used by agreement.

8.08.2 The steam, water or other fluid flows, pressures and temperatures should be the same as the design conditions for which the pressure loss prediction was made.

8.09 Measurements for Determining Solids. Samples of condensed steam for determination of solids are given in I & A, Methods for the Determination of the Quality and Purity of Steam PTC 19.11. There are three accepted methods for the determination of solids in steam. These are:

(1) Gravimetric method for total solids.
(2) Electrical conductivity method for dissolved solids.
(3) Flame photometry.

8.09.1 The gravimetric determination of total solids in the condensed steam may be made in accordance with Section 3, I & A, Methods for the Determination of the Quality and Purity of Steam PTC 19.11. For measuring performance by the gravimetric method, the results shall be expressed as the average of three determinations made upon a composite sample which shall be taken throughout the entire test period.

8.09.2 The electrical conductivity determination of dissolved solids in the condensed steam shall be made in accordance with Section 4, I & A, Methods for the Determination of the Quality and Purity of Steam PTC 19.11. Remove dissolved gases from the sample as completely as possible by mechanical means without contaminating the sample with any added material which will increase its conductivity. The conductivity shall be corrected to compensate for residual ammonia, carbon dioxide or other gases remaining in the sample and the dissolved solids shall be calculated from this corrected conductivity. For measuring performance by the electrical conductivity method, the average of ten determinations made at regular intervals throughout the test period shall be used.

8.09.3 Where extreme purities are encountered use the trace element method, Method B, in accordance with ASTM D 1428 "Sodium and Potassium in Industrial Water and Water Formed Deposits by Flame Photometry."

SECTION 9, APPENDIX

9.1 Derivation of the Weight of Dry Air. The following is the derivation of the equation for computing the weight of dry air per pound of "as fired" fuel. See Par. 7.2.8.1. In this derivation the assumption is made that whatever sulfur is present in the fuel is burned to sulfur dioxide. This is not entirely true, a fraction may be burned to sulfur trioxide and another fraction could form oxides with the ash. In addition some of the sulfur may be in the form of sulfides or sulfates and unavailable for combustion. However, the treatment presented here appears to be the best for general usage. An additional minor assumption made is that all the sulfur dioxide sampled is removed in the orsat by the carbon dioxide reagent.

$$\text{Pounds of dry gas per mole of dry gas} = 44.01\frac{(CO_2)}{100} + 28.01\frac{(CO)}{100} + 32.00\frac{(O_2)}{100} + 28.02\frac{(N_2)}{100}$$

$$\text{Pounds of equivalent carbon burned per mole of dry gas} = 12.01\frac{(CO_2 + CO)}{100}$$

In order to use this equation the pounds of carbon burned per pound of "as fired" fuel must be adjusted for the sulfur dioxide absorbed in the orsat as carbon dioxide.
To reduce the sulfur in the fuel to its carbon equivalent, multiply the sulfur in the fuel by $\left[\frac{12.01}{32.07}\right]$

Molecular weight: C = 12.01
S = 32.07

Then the equivalent carbon burned is $C_b + \frac{12.01}{32.07}S$

The pounds of dry gas per pound of "as fired" fuel is obtained as follows:

$$W_{G'} = \frac{\text{lb dry gas}}{\text{mole dry gas}} \times \frac{1}{\dfrac{\text{lb carbon}}{\text{mole dry gas}}} \times \frac{\text{lb carbon}}{\text{lb A.F. fuel}} = \frac{\text{lb dry gas}}{\text{lb A.F. fuel}}$$

$$W_{G'} = \frac{44.01\,(CO_2) + 28.01\,(CO) + 32.00\,(O_2) + 28.02\,(N_2)}{12.01(CO_2 + CO)}\left(C_b + \frac{12.01}{32.07}S\right)$$

$$\text{Pounds of nitrogen per mole of dry gas} = 28.02\frac{(N_2)}{100}$$

$$W_{NG'} = \frac{1}{\dfrac{\text{lb dry gas}}{\text{mole dry gas}}} \times \frac{\text{lb nitrogen}}{\text{mole dry gas}} = \text{pounds of nitrogen in the dry gas per pound of dry gas}$$

$$W_{NG'} = \frac{28.02\,(N_2)}{44.01\,(CO_2) + 28.01\,(CO) + 32.00\,(O_2) + 28.02\,(N_2)}$$

Pounds of nitrogen in the dry gas per pound of dry gas multiplied by pounds of dry gas per pound of "as fired" fuel = $W_{NG'} \times W_{G'}$ = Pounds of nitrogen in the dry gas per pound of "as fired" fuel = $W_{G'N_2}$.

Therefore:

$$W_{G'N_2} = \frac{28.02\,(N_2)}{44.01\,(CO_2) + 28.01\,(CO) + 32.00\,(O_2) + 28.02\,(N_2)} \times \frac{44.01\,(CO_2) + 28.01\,(CO) + 32.00\,(O_2) + 28.02\,(N_2)}{12.01\,(CO_2 + CO)}\left(C_b + \frac{12.01}{32.07}S\right)$$

$$W_{G'N_2} = \frac{28.02\,(N_2)}{12.01\,(CO_2 + CO)}\left(C_b + \frac{12.01}{32.07}S\right)$$

$W_{A'}$ = lb of dry air per lb of "as fired" fuel

N = lb of nitrogen per lb of "as fired" fuel – (From laboratory analysis of the fuel)

$$W_{A'} = \frac{W_{G'N_2} - N}{0.7685} = \text{weight of dry air per pound of "as fired" fuel.}$$

0.7685 = the pounds of nitrogen per pound of standard air (see International Critical Tables – Vol. 1)

The complete equation for the weight of dry air per pound of "as fired" fuel is equal to:

$$W_{A'} = \frac{\dfrac{28.02\,(N_2) \times \left(C_b + \dfrac{12.01}{32.07} S\right)}{12.01\,(CO_2 + CO)}}{0.7685} - N$$

9.2 Computation of Theoretical and Excess Air. For those interested in calculating theoretical and excess air the following formulas are useful:

Theoretical Air:

$$A'_\theta = 11.51\,C + 34.30\left(H - \frac{O}{7.937}\right) + 4.335\,S$$

$A'_\theta = \dfrac{\text{lb of dry air}}{\text{lb A.F. fuel}}$ = Theoretical dry air in pounds required to completely burn a pound of "as fired" fuel

$C = \dfrac{\text{lb carbon}}{\text{lb A.F. fuel}}$ From laboratory analysis of the fuel

$H = \dfrac{\text{lb hydrogen}}{\text{lb A.F. fuel}}$ From laboratory analysis of the fuel

$O = \dfrac{\text{lb oxygen}}{\text{lb A.F. fuel}}$ From laboratory analysis of the fuel

$S = \dfrac{\text{lb sulfur}}{\text{lb A.F. fuel}}$ From laboratory analysis of the fuel

All constants are based on molecular weights from National Bureau of Standards Circular 564 dated 11/1/55.

Excess air:

$$A'_X = \frac{W_{A'} - A'_\theta}{A'_\theta} \times 100$$

A'_X = per cent excess air

$W_{A'} = \dfrac{\text{lb of dry air}}{\text{lb A.F. fuel}}$ = Weight of dry air per pound of "as fired" fuel

$A'_\theta = \dfrac{\text{lb of dry air}}{\text{lb A.F. fuel}}$ = Pounds of dry air theoretically required to completely burn a pound of "as fired" fuel

9.3 Derivation of Flue Gas Specific Weight. The following derivation of flue gas specific weight at 68 F and 14.7 psia (see Par. 7.3.2.08) is based on the assumption that the flue gas conforms to the ideal gas law:

$$PV = \Psi R_u T$$

Where

$P = \frac{lb}{sq\ ft}$ = Absolute pressure

V = cu ft = volume

Ψ = number of pound moles

$R_u = \frac{1545\ ft\text{-}lb}{lb\ mole,\ deg\ R}$ = Universal gas constant (see International Critical Tables, Vol. 1, page 18)

T = deg R = Temperature Rankine

Multiplying both sides by the molecular weight M

$$\therefore MPV = M\Psi M R_u T$$

But $M\Psi = W$ = Pounds of gas

$$MPV = WR_u T$$

$$MP = \frac{W}{V} R_u T$$

Specific weight of gas $= \gamma = \frac{W}{V}$

$$\therefore MP = \gamma R_u T$$

$$\gamma = \frac{P}{T} \times \frac{M}{R_u}$$

At standard conditions:

$$P = 14.7 \text{ lb per sq in.} \times 144 \frac{sq\ in.}{sq\ ft} = 2115 \frac{lb}{sq\ ft}$$

$$T = 68\ F + 460 = 528\ R$$

$$\frac{P}{T} = \frac{2115}{528} = 4.01$$

Therefore:

$$\gamma = 4.01 \frac{M}{R_u}$$

$$\gamma = \frac{4.01}{100} \left[\frac{(CO_2 \times M_{CO_2}) + (O_2 \times M_{O_2}) + (N_2 \times M_{N_2}) + (CO \times M_{CO}) + (SO_2 \times M_{SO_2}) + (H_2 \times M_{H_2}) + (HC \times M_{HC})}{1545} \right]$$

$$\gamma = 0.0401 \left[\frac{CO_2}{\frac{1545}{44.01}} + \frac{O_2}{\frac{1545}{32.00}} + \frac{N_2}{\frac{1545}{28.02}} + \frac{CO}{\frac{1545}{28.01}} + \frac{SO_2}{\frac{1545}{64.07}} + \frac{H_2}{\frac{1545}{2.016}} + \frac{HC}{\frac{1545}{M_{HC}}} \right]$$

This simplifies to the equation for the flue gas specific weight given in Par. 7.3.2.08 and below.

$$\gamma = 0.0401 \left[\frac{CO_2}{35.11} + \frac{O_2}{48.28} + \frac{N_2}{55.14} + \frac{CO}{55.16} + \frac{SO_2}{24.12} + \frac{H_2}{766.36} + \frac{HC}{\frac{1545}{M_{HC}}} \right]$$

9.4 Heating Value of Carbon As It Occurs In Refuse. A review of the published information on the heat value of carbon to be used in estimating the heat loss due to combustible in the refuse in boiler heat balance reveals a variation ranging approximately from 14,400 to 14,600 Btu per pound mainly due to the form in which the carbon is present. See supplementary volume to Chemistry of Coal Utilization.

The Code Committee has used the value of 14,500 on the basis that its accuracy is consistent within other aspects of the Code and with the endorsement of the Chairman of PTC 3.2 after his referral of the matter to the U.S. Bureau of Mines.

9.5 Radiation and Convection Loss. This is the only significant loss in the Code, the computation of which is not based on test measurements. The Committee in its early considerations of this subject were desirous to treat the loss like all others, i.e. to take test readings and compute the loss. However, the test installation required was so extensive that in the opinion of the Committee, it was an unwarranted requisite. It was, therefore, decided to estimate this loss using the ABMA curve as was done in the 1946 Edition of the Code. The Manufacturers revised this curve based on their joint availability of data, and extended it well beyond present day capacities, see Fig. 8. The curve's values were checked against the actual measured losses on several large boilers and the curve values found to be conservatively high.

9.5.1 In order that this curve may be improved in accuracy in future years, users of this Code are encouraged to take radiation and convection loss readings on acceptance tests and from these compute the loss and report the results to the ASME Power Test Code Committee No. 4 on Steam Generating Units, giving a detailed description of the unit in regard to exposure, wind velocities, type of wall construction, method of testing, etc. In conducting such tests the following method is suggested for obtaining test data and computing the loss.

9.5.2 Determine this loss through the steam generator walls, roof, bottom, air heater, ducts, piping and any other exposed surfaces by installing at the center of every one hundred square feet of area a pair of thermocouples in a block of insulation of known conductivity. With the temperature gradient measured by the thermocouples, the known distance between thermocouples and the conductivity of the insulation compute the radiation and conductivity loss for each 100 square feet. The sum of these losses for each 100 square feet divided by the steam generator heat input rate will be the radiation and convection loss for the unit.

9.6 Conversion of Heating Value from Constant Volume to Constant Pressure. The formula for the conversion of the high-heat value at constant volume as obtained with the bomb calorimeter to the high-heat value at constant pressure is based on the first law of thermodynamics and the general energy equations. In a heating value determination there is no thermodynamic work performed nor kinetic energy change, therefore, the heating value at constant volume is the change in internal energy between the reactants and products. Similarly and for the same reasons, the heating value at constant pressure is the change in enthalpy between the reactants and products. This being the situation the general energy equation relating the constant volume heating value with the constant pressure heating value is as follows:

$$H_{fp} = H_{fv} + \frac{\Delta P V}{778.2}$$

Assuming the perfect gas law can be applied to the gaseous constituents of the reactions:

$$\frac{\Delta P V}{778.2} = \frac{\Delta \Psi R_u T}{778.2}$$

and

$$H_{fp} = H_{fv} + \frac{\Delta \Psi R_u T}{778.2}$$

where

$H_{fp} = \frac{\text{Btu}}{\text{lb A.F. fuel}}$ = High-heat value of fuel at constant pressure

$H_{fv} = \frac{\text{Btu}}{\text{lb A.F. fuel}}$ = High-heat value of fuel at constant volume

$\Delta\Psi$ = Change in the number of pound moles of gaseous products when compared to the pound moles of gaseous reactants. Only the number of gaseous moles are of importance because the volume occupied by a mole of liquid or solid material is so small that it is insignificant and the perfect gas law does not apply to these fractions.

$R_u = \dfrac{1545 \text{ ft-lb}}{\text{lb mole R}}$ = Universal Gas Constant

T = 537 R This is the absolute value of the standard calorimeter temperature

778.2 ft-lb = 1 Btu = mechanical equivalent of heat.

Determination of the change in the number of moles caused by the combustion reactions of solid or liquid fuels.

REACTANTS		PRODUCTS
C (solid) or (liquid)	+ O_2 (gas)	CO_2 (gas)
N (solid) or (liquid)		N_2 (gas)
H (solid) or (liquid)	+ ½ O_2 (gas)	H_2O (liquid)
S (solid) or (liquid)	+ O (Gas)	SO_2 (gas)

O, *A*, *M* } in combined state as reactants, therefore, they cannot enter reaction except for occasional rare constituents.

The carbon (C) reaction has no change in the number of gaseous moles from reactants to products, therefore, no correction required.

The Nitrogen (N) reaction, assuming it is released as a gas in the products and reacted as a solid or liquid, increases by one (1) mole per mole of nitrogen reactant. This causes a PV change and requires an adjustment between the high-heat value at constant pressure and volume.

Hydrogen as a liquid or solid portion of a compound is released and unites with oxygen to form water which is condensed to a liquid. Therefore, the net effect of the reaction is a decrease of half a mole of product for each mole of hydrogen exclusive of that in the fuel moisture.

Solid sulfur reacts with a mole of oxygen to form a mole of sulfur dioxide in the products. There is no net change in gaseous constituents, therefore, no correction required.

All oxygen in the fuel is assumed to be in the combined state. The compounds envisioned are water and metallic oxides in the ash. In the foregoing forms the oxygen in the fuel will not react and appears unchanged in the products and no correction is required. Similar reasoning applied to the ash and moisture in the fuel proves no need for a correction on their behalf.

$$\Delta\Psi = \frac{-N}{28.016} + \frac{1}{2}\,\frac{H}{2.016}$$

Note the sign convention – Where there is an increase in the mole volume, work is done on the surroundings and results in a negative sign.

$N = \dfrac{\text{lb}}{\text{lb A. F. fuel}}$ = Pounds of nitrogen per pound of "as fired" fuel

$28.016 = \dfrac{\text{lb}}{\text{lb mole}}$ = Pounds of nitrogen per pound mole of nitrogen

$H = \dfrac{\text{lb}}{\text{lb A. F. fuel}}$ = Pounds of hydrogen exclusive of that in the moisture per pound of "as fired" fuel

$2.016 = \dfrac{\text{lb}}{\text{lb mole}}$ = Pounds of hydrogen per pound mole of hydrogen.

Substituting into the general equation:

$$H_{fp} = H_{fv} + \left(\frac{-\text{N}}{28.016} + \frac{\text{H}}{4.032}\right) \frac{R_u T}{778.2}$$

Substituting for R_u and assuming a standard calorimeter temperature of 77 F this reduces to:

$$H_{fp} = H_{fv} + \left(\frac{-\text{N}}{28.016} + \frac{\text{H}}{4.032}\right) 1066$$

The nitrogen in liquid and solid fuel is less than 2 per cent by weight, therefore, the nitrogen correction is less than 0.76 Btu per pound of fuel. This correction is only required if the nitrogen is in the solid or liquid form in the fuel and is released as a gas during combustion. If it is an entrapped gas initially or forms an ash compound during combustion, no correction is required. In considering these various contingencies it was decided to neglect the nitrogen correction and the formula as found in Par. 7.2.6.2 and given here reduces to the following results:

$$H_{fp} = H_{fv} + 264.4\,\text{H}$$

9.7 References. The following material may be helpful to the Code user who may wish to investigate in more details various facets of the Code.

(1) Combustion Calculations for Multiple Fuels, by Tibor Buna, Trans. ASME, Vol. 78, August, 1956.
(2) Code Testing of Large Boilers – Input-Output or Heat-Loss Method by J. A. Bostic and W. F. Long, Paper No. 60 – Power – 5, not published in Trans. ASME or Mechanical Engineering, on file in Engineering Societies Library.
(3) Efficiency Determination of Marine Boilers: Input-Output Versus Heat-Loss Method, by L. Cohen and W. A. Fritz, Jr., ASME Journal of Engineering for Power, Vol. 84, January, 1962.
(4) Performance Testing of Large Steam Generators, by R. E. Vuia, Paper No. 62-WA-267, not published in Trans. ASME or Mechanical Engineering, on file in Engineering Societies Library.

1968 ADDENDUM

STATIONARY STEAM GENERATING UNITS, PTC 4.1–1964

Date of Issue, September, 1968

PTC 4.1 Stationary Steam-Generating Units has revised Paragraphs 0.6 and 1.05.

The orginal wording and revised wording of these two paragraphs follow.

Original wording:

0.6 The general instructions contained in this Code shall also apply to the testing of high temperature water heaters, except that efficiency determination shall be by heat loss method only, as described in Section 5. The input-output method is not acceptable because of potentially large inaccuracies introduced by the presence of indeterminant quantities of steam in the output and by the small temperature measurement errors in a large volume flow output.

Test capacity or output shall be determined from measured heat input and efficiency, or by direct measurement of heat output if a high degree of accuracy is not required.

1.05 Capacity of steam generators is defined as actual evaporation in pounds of steam per hour delivered or Btu per hour absorbed by the working fluid or fluids. Capacity of hot water heaters is defined as the heat absorbed by water and the heat of any steam that may be generated (Btu per hour).

Revised wording:

0.6 The general instructions contained in this Code shall also apply to the testing of high temperature water heaters. When either the heat loss or input-output method of testing (see Par. 1.04) is used, the unit must be pressurized above saturation temperature to assure against the presence of steam at the point of measurement. The amount of pressurization shall be an item of agreement. When the input-output method (see Par. 1.04) is used to test such equipment, the water temperature rise through the unit shall be determined by differential temperature measurements rather than by separate measurements of inlet and outlet water temperatures (see Pars. 31, 32, and 44, Chapter 4, PTC-19.3, Part 3, 1961).

When using the heat loss method to determine efficiency, the capacity or output point at which the run is being made shall be determined from measured heat input and efficiency (see Par. 4.02) or by direct measurement of heat output (see Pars. 4.14, 4.15, and 4.16).

1.05 Capacity of steam generators is defined as actual evaporation in pounds of steam per hour delivered or Btu per hour absorbed by the working fluid or fluids. Capacity of hot water heaters is defined as the heat absorbed by the water (Btu per hour).

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1969 ADDENDUM

STATIONARY STEAM GENERATING UNITS, PTC 4.1–1964

Date of Issue, March, 1969

PTC Committee 4.1 Stationary Steam-Generating Units has revised Paragraphs 3.05.2, 3.05.3 and 7.5.4.

The original wording and revised wording of these three paragraphs follow.

Original wording:

3.05.2 Before the test is started, it shall be determined whether the fuel to be fired is substantially as intended.

3.05.3 Any departures from standard or previously specified conditions in physical state of equipment, cleanliness of heating surfaces, fuel characteristics, or constancy of load, shall be described clearly in the report of the test.

Revised wording:

3.05.2 Before the test is started, it shall be determined whether the fuel to be fired is substantially as intended. The obtaining of a reliable, accurate efficiency test for the purpose of equipment acceptance is dependent upon the fuel being in close agreement with the fuel for which the steam generating unit was designed. Significant deviations of fuel constituents and high heating value can result in appreciable inaccuracies in heat loss calculations and resulting efficiencies. The magnitude of deviation that is tolerable is difficult to establish, but it should be recognized that fuel analysis variation producing changes in high heating value in the order of 10% can alter final calculated efficiency in the order of 1%.

3.05.3 Any departures from standard or previously specified conditions in physical state of equipment, cleanliness of heating surfaces, fuel characteristics, or constancy of load, shall be described clearly in the report of the test. If deviations of operating conditions or fuel characteristics do occur, appropriate adjustments to calculated results shall be applied in accordance with provisions in Section 7 for Corrections to Standard or Guarantee Conditions, recognizing that this will not produce the precise results to be obtained by testing with a fuel that would not require such calculation adjustments.

Original wording:

7.5.4 Corrections to the heat losses, "Heat loss due to moisture in fuel" and "Heat loss due to hydrogen in fuel" for changes of moisture and hydrogen content from the test fuel to the fuel used for the standard or guaranteed computations, are made by substituting the weight of moisture or hydrogen per pound of fuel in the standard or guaranteed fuel for the weight of moisture or hydrogen per pound of fuel, of the test fuel, in the heat loss formulas.

Revised wording:

7.5.4 Corrections to heat losses; dry gas loss, loss due to moisture in the fuel, loss due to hydrogen in the fuel, are made by substituting in all formulae (Items 24, 25, 65, 66, 67 of Abbreviated Efficiency Test Form) affecting the calculation of these losses, the design values of fuel constituents and design high heating value of the fuel, but using test gas temperatures, test reference temperature and test unburned combustible in refuse, where applicable and when appropriately adjusted as specified in paragraphs 7.5.2 and 7.5.3.

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