

CRTD- Vol. 34

**CONSENSUS ON
OPERATING PRACTICES
FOR THE CONTROL OF FEEDWATER
AND BOILER WATER CHEMISTRY
IN MODERN INDUSTRIAL BOILERS**

prepared by the
FEEDWATER QUALITY TASK GROUP

for the
INDUSTRIAL SUBCOMMITTEE
OF THE
ASME RESEARCH AND
TECHNOLOGY COMMITTEE ON
WATER AND STEAM IN
THERMAL POWER SYSTEMS

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
Three Park Avenue ■ New York, New York 10016

Statement from By-Laws: The Society shall not be responsible for statements
or opinions advanced in papers...or printed in its publications (7.1.3)

Authorization to photocopy for internal or personal use is granted to libraries
and other users registered with the Copyright Clearance Center (CCC)
provided \$3/article or \$4/page is paid to CCC, 222 Rosewood Dr., Danvers,
MA 01923. Requests for special permission or bulk reproduction should be
addressed to the ASME Technical Publishing Department.

ISBN No. 0-7918-1204-9

Library of Congress Number 94-70878

(Reprinted With Editorial Corrections 1998)

Copyright © 1994 by
THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
All Rights Reserved
Printed in U.S.A.

❑ PREFACE ❑

The Industrial Subcommittee of the ASME Research and Technology Committee on Water and Steam in Thermal Power Systems, under the leadership of Mr. James O. Robinson of Betz Laboratories, Inc., has revised the *Consensus on Operating Practices for the Control of Feedwater Boiler Water Chemistry in Modern Industrial Boilers*, first published in 1979.

Revision of the original document was completed by a task group of this Subcommittee under the guidance of Mr. Robert T. Holloway of Nalco Canada Inc. The task group consisted of a cross section of manufacturers, operators, and consultants involved in the fabrication and operation of industrial boilers. Members of this group are listed in the acknowledgments.

This current document is an expansion and revision of the original, with reordered and modified texts where considered necessary. While significant revisions have been incorporated, it is recognized that there are areas of operating practice not addressed herein. Additional information is available from other sources based on experience gained in utility boiler operation in the power generation industry [20-22]. It is the plan of the ASME Research Committee to continue to review this information, and revise and reissue this document as necessary to comply with advances in boiler design and water conditioning technology.

ACKNOWLEDGEMENTS

This document was revised by the Feedwater Quality Task Group for the Industrial Subcommittee of the ASME Research and Technology Committee on Steam and Water in Thermal Power Systems. Recognition is hereby given to the following members of these groups for their contributions in preparing the document.

Feedwater Quality Task Group

Robert T. Holloway, <i>Chairman</i>	Jerome W. McQuie
Jesse S. Beecher	D. E. Noll
Wayne E. Bernahl	Charles R. Peters
Deborah M. Bloom	F. J. Pocock
Irvin J. Cotton	James O. Robinson
Robert J. Cunningham	Joseph J. Schuck
Douglas B. DeWitt-Dick	K. Anthony Selby
S. B. Dilcer, Jr.	J. W. Siegmund
Arthur W. Fynsk	David E. Simon II
C. R. Hoefs	P. M. Thomasson
R. W. Lane	T. J. Tvedt, Jr.
	J. F. Wilkes

Industrial Subcommittee

James O. Robinson, <i>Chairman</i>	R. W. Lane
Anton Banweg	P. J. Latham
T. Beardwood	Roger V. Long
Jesse S. Beecher	D. E. Noll
James C. Bellows, Ph.D.	Thomas H. Pike
Wayne E. Bernahl	F. J. Pocock
Deborah M. Bloom	L. Rosenzweig
Irvin J. Cotton	J. K. Rice
Robert J. Cunningham	J. J. Schuck
David Daniels	John W. Siegmund
Douglas B. DeWitt-Dick	David E. Simon II
S.B. Dilcer, Jr.	P. M. Thomasson
Arthur W. Fynsk	T. J. Tvedt, Jr.
F. Gabrielli	John R. Webb
S. Goodstine	W. Willsey
Karl W. Herman	J. F. Wilkes
Robert T. Holloway	David K. Woodman
K. Kelley	

**ASME Research and Technology Committee on
Steam and Water in Thermal Power Systems**

Otakar Jonas, *Chairman*
William R. Greenaway, *1st Vice
Chairman*
Torry J. Tvedt, Jr., *2nd Vice
Chairman*
Anton Banweg, *Secretary*
William E. Allmon
Jesse S. Beecher
Merl J. Bell
James C. Bellows
Robert W. Bjorge
Deborah M. Bloom
Arthur R. Brozell
Winston Chow
Richard J. Clark
R. B. Dooly
Joseph H. Duff
Arthur W. Fynsk
Frank Gabrielli
J. S. Gallagher
H. A. Grabowski
Bernard H. Herre
Robert T. Holloway
Thomas Isert

Russell W. Lane
Johanna M. H. Levelt Sengers
Joseph A. Lux
James A. Matthews
Wayne C. Micheletti
Nicholas J. Mravich
Douglas E. Noll
Bill Parry
Thomas O. Passell
Wesley L. Pearl
Thomas H. Pike
Frederick J. Pocock
Walter L. Reidel
James K. Rice
James O. Robinson
Robert M. Rosain
John W. Siegmund
Jan V. Sengers
David E. Simon II
Walter Stein
Jan Stodola
David L. Venezky
Henry J. Vyhnalek

□ CONTENTS □

1 □	Introduction	1
2 □	Scope	3
3 □	Objectives of Water Treatment	5
4 □	Organization of Water Chemistry Guidelines	7
5 □	Steam Purity	9
6 □	Water Chemistry Parameters	11
7 □	Chemical Control Analyses	19

Tables Suggested Water Chemistry Limits

1	Industrial Watertube -With Superheaters, Turbines	22
2	Industrial Watertube -Without Superheaters, Turbines	26
3	Industrial Firetube	28
4	Industrial, Coil Type, Watertube	30
5	Marine Propulsion, Watertube	32
6	Electrode, Forced Circulation, Jet	34

References	37
-------------------	-----------

□ SECTION 1 □

INTRODUCTION

This document has been prepared by the Industrial Subcommittee of the ASME Research and Technology Committee on Steam and Water in Thermal Power Systems as a consensus of proper current operating practices for the control of feedwater and boiler water chemistry in the operation of modern industrial, high duty, primary fuel fired boilers. These practices are aimed at minimizing the penalties of severe corrosion or deposition, frequent cleaning requirements, or unscheduled outages in the steam generator systems and their auxiliary steam users.

This publication is an expansion and revision of the operating practice consensus previously issued by the Committee [1]. The tabulated values herein update and replace the ones previously published. Titles have been edited and clarified. The text has been reordered and modified where necessary, and it should be considered fully when using the tabulated data. Section 5, Steam Purity, is one such section of text, as is Section 6.2, Iron, Copper, Hardness, and Suspended Solids, particularly with regard to the use of higher purity water than required for the boiler operating pressure.

Industrial boilers that use high purity, demineralized or evaporated makeup water should be operated with a minimum of 1% blowdown (100 cycles of feedwater concentration) to avoid excessive concentration of trace contaminants and the possible formation of deposits in the boilers.

The information in this document will be reviewed by the Research and Technology Committee on a regular basis and revised and reissued as necessary to comply with advances in boiler design or water treatment technology.

□ SECTION 2 □

SCOPE

The six classes of boilers covered in this document are:

- industrial watertube, high duty, primary fuel fired, drum type with superheaters and turbine drives and/or process restrictions on steam purity. This class excludes heat recovery system generators installed in gas turbine exhaust systems.
- industrial watertube, high duty, primary fuel fired, drum type without superheaters and/or process restrictions on steam purity
- industrial firetube, high duty, primary fuel fired
- industrial coil type, watertube, high duty, primary fuel fired rapid steam generators
- marine propulsion, watertube, oil fired, drum type
- electrode type, high voltage, recirculating jet type

The water chemistry values in Tables 1 through 6 apply to steam generators of the types indicated above. In every case, values are stated for current design boilers with locally high heat fluxes up to 1.5×10^5 Btu/hr/ft² (473.2 kW/m²), potentially uncertain circulation due to physical size restrictions, relatively small diameter steam drums, and relatively small furnaces. For older design units without these constraints, the suggested practices may be followed to help ensure trouble-free performance; however, it is often sufficient to use limits given for a lower pressure range, especially where experience has indicated the success of such practices. These exceptions are indicated in the notes accompanying the tables. The information also applies to steam generators in continuous or relatively steady-state operation. Special operating conditions such as startup,

shutdown, rapidly fluctuating loads, or initial operation of new boilers may impose greater water chemistry restrictions.

Operating practices are not given for the following classes of steam generators. Operation and treatment of these types of equipment is too varied to permit the inclusion of consensus values:

- mobile locomotive boilers
- boilers of copper or other unusual materials
- immersion type, electric boilers, and low voltage electrode type boilers
- heating boilers of special construction
- waste heat boilers of unusual design
- firetube boilers with superheaters
- hot water boilers
- oil field steam flood boilers

Recommendation of specific types of makeup water pretreatment, condensate treatment, and internal chemical treatment is outside the scope of this document. However, the requirement for such treatments, in many cases, is clearly implied by the suggested values for feed water quality. Specific reference is made to such pretreatments as demineralization, evaporation, softening, either where such treatments are common practice or where they describe the range of applicability of the control values in a certain table. Likewise, the use of congruent [2] phosphate-pH control, coordinated [3] phosphate-pH control, volatile treatment [4,5], chelants, polymers, and volatile amines is suggested in the tables and notes either where these treatments are commonly accepted practice, or where they are applicable.

□ SECTION 3 □

OBJECTIVES OF WATER TREATMENT

Proper treatment of makeup and feedwater is necessary to prevent scale, other deposits, and corrosion in preboiler, boiler, steam and condensate systems, and to provide required steam purity.

The absence of adequate external and internal treatment can lead to operational upsets or unscheduled outages and is ill-advised from the point of view of safety, economy, and reliability. Where a choice is available, the reduction or removal of objectionable constituents by pretreatment external to the boiler is always preferable to, and more reliable than, management of these constituents within the boiler by internal chemical treatment.

□ SECTION 4 □

ORGANIZATION OF WATER CHEMISTRY GUIDELINES

Consensus water chemistry controls for the six types of steam generator systems are presented in Tables 1 through 6. The tabulated information is categorized according to operating pressure ranges because this is the prime factor that dictates the type of internal water chemistry employed, the normal cycles of feedwater concentration, the silica volatility, and the carryover tendency. The difference between steam and water densities decreases with increasing pressure and temperature; therefore, the difficulty of separating the phases completely in the boiler drum increases accordingly. Since the tendency to carryover is greater at higher operating pressures, it is necessary to maintain lower boiler water concentrations to meet the same steam purity target.

The tables are not categorized by the type of fuel used; all the tables apply only to boilers fired with primary fuels such as oil, gas, or coal. Heat recovery or waste heat boilers not directly fired with primary fuels are too varied in design and operation to permit their inclusion in this review. As a word of caution, such waste heat boilers are sometimes designed and operated so that waterside circulation is inefficient, areas of unavoidable deposit accumulation are numerous, and localized heat fluxes are abnormally high. In such instances, the waste heat units, regardless of their operating pressure, should be operated with demineralized or evaporated makeup consistent with the values for the boilers in Table 1 above 1000 psig (6.89 MPa).

For primary fuel fired boilers, it should be recognized that oil firing causes the greatest release of radiant heat in the furnace and this creates the most stringent limitations on depositables entering the boiler with the feedwater. Coal firing releases less radiant heat while gaseous fuels release the least radiant heat. The suggested limits in the tables are for the most critical condition of oil firing. If coal or gas firing is employed, the limiting values for feedwater hardness, iron, and copper concentrations may be relaxed to numbers somewhat higher than those tabulated in the operating pressure ranges of 900 psig (6.21 MPa) and below.

□ SECTION 5 □

STEAM PURITY

Detailed discussion and definition of steam purity, steam quality, industrial requirements, and the effects on equipment and processes are beyond the scope of this document. However, valuable information on this topic is available from the referenced literature [15-19].

A specific steam purity limit is stated in the table heading or table for each category of boiler design and operation except electrode boilers (Table 6).

Steam purity required for any given boiler system is dictated by the intended use of the steam. The steam purity limits in Tables 1 through 5 are chosen to reflect the requirements for a typical industrial steam use for each category of boiler operation, i.e., "Turbine drives" for Tables 1 and 5, "Heating or process use without turbine drives" for Tables 2 and 3, and "Variable uses" for Table 4.

The relationship between boiler water chemistry and steam purity is affected by many variables. For each case of watertube boilers with relatively high steam purity requirements, the boiler water chemistry parameters must be set as low as necessary to achieve the required steam purity, as determined by empirical measurements, for protection of the superheaters and turbines and/or to avoid process contamination. See Note (9) in Table 1 for further comments.

In continuous operation, observation of the tabulated feedwater and boiler water chemistry can produce steam of the designated purity from a boiler with effective feedwater controls and mechanical steam separation drum internals that are adequate for the drum diameter, steam load rating, and drum pressure. In any case where steam of greater purity than that indicated is required, it is advisable to follow the feedwater and boiler water chemistry suggestions for at least the next higher operating pressure range. If the indicated steam purity value is

better than required, it may be possible to use the boiler water alkalinity, specific conductance, and silica values for a lower operating pressure range. Where possible, the actual permissible values for boiler water alkalinity, specific conductance, and silica should be established by careful monitoring of steam purity.

Where direct spray water is added to steam for attemperation, the purity of the spray water must be consistent with downstream uses of the steam. Specifically, the spray water should be essentially oxygen free and contain neither contaminants at concentrations greater than the saturated steam nor nonvolatile treatment chemicals.

□ SECTION 6 □

WATER CHEMISTRY

PARAMETERS

The metric units of measurement chosen for use throughout this document follow the guidelines set forth in ASTM Designation E 380 [6]. Some of these units, such as the megapascal (MPa), the microsiemens (μS), and the kilowatt per square meter (kW/m^2) may be unfamiliar to the United States reader, but their equivalence to the more familiar English units is clearly indicated by the accompanying presentation of all values in both systems of measurement. For the purposes of this document, the units mg/l and $\mu\text{g}/\text{l}$ used for measurement are considered to be equivalent to ppm and ppb, respectively.

□ 6.1 Dissolved Oxygen

Dissolved oxygen concentrations are stated for feedwater samples drawn from the indicated points in the system. Where the dissolved oxygen concentration is stated as 7 ppb ($\mu\text{g}/\text{l}$) O_2 or less measured before chemical oxygen scavenger addition, it is assumed that a well-operated deaerator is in service. In all cases, the subsequent addition of a chemical oxygen scavenger to the deaerator water storage tank, with adequate distribution and mixing, is desirable to provide essentially zero dissolved oxygen in the feedwater at the economizer inlet, or in the absence of an economizer, at the feedwater inlet to the boiler. Dissolved oxygen analyses, consistent with the desired minimum level of detectability, should be made either by the appropriate standard method [7,14] or polarographic analysis [13].

□ 6.2 Iron, Copper, Hardness, and Suspended Solids

In all cases, suspended matter in the feedwater should be as low as is practically achievable.

The suggested limits for iron, copper, and hardness in the feedwater are set at a low range because of the recognized sensitivity of the boilers and the great difficulty of effectively managing large amounts of depositables by means of internal treatment alone.

Jet type electrode boilers are subject to erosion/corrosion of internal components by metallic precipitates in the boiler water that are recirculated at a high rate. Additionally, high levels of iron and copper may increase the possibility of ground fault arcing.

Therefore, it is necessary to minimize corrosion products and hardness by external pretreatment in order to approach either the stipulated feedwater or boiler water chemistry goals. As stated in the notes to several of the tables, some internal treatments with either chelants or polymers may permit higher concentrations of feedwater iron, copper, and hardness but these higher concentrations should be allowed only after careful judgment has been exercised. The acceptability of operating with the higher concentrations must be confirmed by routine internal inspections and other deposition rate monitoring techniques [8].

Boiler inspections, for the fuel fired boilers, should preferably include removal of boiler tube samples from the high heat transfer surfaces of the boiler for determination of specific deposit weight on these surfaces. Where tube sample removal is inappropriate, certain nondestructive inspection techniques can provide useful information on boiler cleanliness.

Low pressure boilers frequently use feedwater that is suitable for use in higher pressure boilers. In these cases the boiler water chemistry limits should be based on the pressure range that is most consistent with the boiler water and feedwater chemistry. For example, if a boiler operated at 150 psig (1.03 MPa) uses feedwater of suitable quality for use in a 1001-1500 psig (6.9-10.34 MPa) boiler, then the boiler water limits and chemical treatment program should be based on the higher

pressure guidelines. This practice is necessary to ensure proper blowdown and to avoid extremely high concentrations of trace contaminants and impurities and the formation of deposits in the boiler.

The suggested limits were constructed on the basis of an annual frequency for inspection (and cleaning, if indicated). However, it is important that the operator be alert to the cumulative amount of individual species introduced with the feedwater during any period of service for the unit. If the annual equivalent of an individual component, particularly iron and copper (based on the tabulated concentration multiplied by weight of feedwater introduced per year) is actually introduced in some lesser operating period, then the interval between inspections must be reduced. If less than this annual equivalent is introduced in 1 year, or if internal treatment has been demonstrated historically to keep the boiler clean, the interval between inspection and cleanings may be extended beyond 1 year (if allowed by local regulatory authorities and insurance requirements).

□ 6.3 pH

The suggestions for feedwater pH are based on values that will protect the preboiler system from corrosion, and are consistent with the indicated pretreatment and internal boiler water treatment. In the higher operating pressure ranges given in Tables 1, 4, and 5, the indicated upward adjustment is to be accomplished through the use of volatile alkaline materials only. This limitation is consistent with the assumed use of demineralized or evaporated makeup water and the corresponding assumption that the internal boiler water treatment will utilize either congruent [2] phosphate, coordinated [3] phosphate, or all-volatile [4,5] treatment.

□ 6.4 Organic Matter

The types of organic matter that can be present in industrial boiler feedwater are numerous and extremely varied. They may exist in the

makeup water from natural sources, or be added as part of the boiler water chemistry or through inadvertent contamination of makeup water or condensate. Therefore, it is impossible to define best practice conditions for all categories in all situations. In an attempt to set some partial guidelines, the tables include suggested values for oily matter and non-volatile total organic carbon (TOC).

Oily matter [9] is not restricted to petroleum oils; it includes all non-volatile hydrocarbons, vegetable oils, animal fats, waxes, soaps, greases, and related matter, all of which are extractable in halogenated solvents at low pH. This Oily matter [9] is not restricted to petroleum oils; it includes all nonvolatile hydrocarbons, vegetable oils, animal fats, waxes, soaps, greases, and related matter, all of which are extractable in halogenated solvents at low pH. This grouping, large as it is, excludes some potentially damaging organic feed water contaminants and includes some beneficial organic compounds, which may be added intentionally as a feed water treatment.

Therefore, the tables also list values for nonvolatile TOC. This analysis is not defined by any published standard method; however, it is intended to represent a reasonable approach to the determination of organic feed-water contaminants potentially damaging to boilers. Nonvolatile TOC measurement is an unofficial modification of the TOC test [10] conducted on a sample after atmospheric boiling with the subsequent subtraction of a calculated carbon value equivalent to the carbon content of any non-volatile organic treatment chemicals.

If any organic contamination of the feedwater is detected by either the oily matter or nonvolatile TOC methods in any given boiler operation, its potential for causing internal deposition and/or carryover must be assessed. If this potential is significant, the contaminant should be removed before entering the preboiler system.

Volatile organics may cause severe damage to turbines. Since this issue is beyond the scope of this document, the reader is advised to consult other sources of information regarding such problems.

□ 6.5 Silica

Maximum boiler water silica concentrations in the operating pressure ranges above 600 psig (4.14 MPa) (Tables 1, 4, and 5) are

selected so that volatile carryover will not exceed 20 ppb ($1\mu\text{g/l}$) SiO_2 in steam, according to the well-established silica volatility data of Coulter, Pirsh, and Wagner [11].

At lower operating pressure ranges (in all tables), the boiler water silica values are selected to avoid internal deposition of complex silicates. This deposition might occur on heat transfer surfaces in fuel fired boilers and on the spray nozzles in electrode boilers. If the tabulated maximum values for feedwater iron, copper, and hardness are observed, there should be no other porous deposit on these surfaces within which the silica can concentrate and exceed the solubility of the complex silicates. There is also a recommendation in each table for fuel fired boilers operating below 900 psig (6.21 MPa): the hydroxide alkalinity concentration should be individually specified by a qualified water treatment consultant at a concentration high enough to ensure silica solubility.

□ 6.6 Alkalinity

The *maximum boiler* water alkalinity values given in Tables 1 through 4 and 6 are specified as total or methyl orange alkalinity, expressed in ppm (mg/l) CaCO_3 for all *boilers* operating below 900 psig (6.21 MPa). Total alkalinity was selected because it best correlates with pH, corrosion inhibition, and carryover tendency, and it is consistent with the historical precedent in predecessor guidelines [1,12]. In Tables 1 through 3, specific free hydroxide *alkalinity* values are not specified because consensus could not be reached.

Statements in the notes suggest individually specified minimum hydroxide alkalinity limits be set by a qualified water treatment consultant for each boiler operating in this range in order to ensure silica solubility and proper functioning of other deposit control chemical treatments.

Hydroxide alkalinity values are given for coil type boilers (Table 4) because, in this boiler category more than others, the use of hydroxide to solubilize silica is critical. No other internal deposit control agent is normally used in coil boilers. Only hydroxide alkalinity

is specified for marine propulsion boilers (Table 5) because such terminology is standard practice in the operation of these boilers.

In all cases where the makeup water is demineralized or evaporated and the operating pressure is 600 psig (4.14 MPa) or greater, the internal boiler water chemistry should follow either congruent [2] phosphate, coordinated [3] phosphate, or all-volatile [4,5] treatment. In such programs, free hydroxide alkalinity must be absent (not detectable) in the boiler water to prevent alkaline corrosion. Where feedwater contamination makes such low solids boiler water chemistry programs difficult, every effort should be made to prevent the feedwater contamination rather than resorting to a high solids, high alkalinity boiler water chemistry program.

Free hydroxide alkalinity concentrations are not specified for jet type electrode boilers. The very high recirculation in these boilers creates a high potential for foaming, especially where organic contamination of feedwater might occur.

□ 6.7 Conductivity

Suggested values for boiler water total dissolved solids as blowdown control are expressed as unadjusted specific conductance in micromhos/cm ($\mu\text{S}/\text{cm}$) at 25°C because current practice is to use a conductivity bridge to measure boiler water solids concentration. The value is often expressed as ppm (mg/l) dissolved solids, using an integral conversion factor in the measuring instrument or an external factor, mathematically applied. If such conversion is necessary to comply with past practice, it can be obtained by multiplying the specific conductance by a factor, established empirically by gravimetric analysis. For unadjusted specific conductance this factor is typically 0.5-0.7 whereas 0.75-0.8 is typical for neutralized specific conductance. The TDS values in the ABMA standards [12] are expressed as ppm (mg/l) actual solids and not as ppm (mg/l) of some arbitrarily selected salt such as sodium chloride. Therefore, in order to establish a TDS to conductivity relationship for any individual case, it was necessary to

measure actual TDS by a gravimetric determination of evaporated residue, including any water of hydration not liberated in the normal evaporation at 103°C. A typical relationship using this technique is 0.65, but the actual value must be determined empirically and it will change with variations in the composition of boiler water dissolved solids.

It should be noted that the specific conductance limits shown for Table 2 reflect the maximum ABMA limits for TDS, whereas Table 1 shows lower limits based on steam purity requirements for superheaters, turbine drives, or process restrictions.

As stated in the tables, the values are expressed as micromhos/cm ($\mu\text{S}/\text{cm}$) specific conductance without prior neutralization. The widely used practice of converting a sample to its neutral salt form before measuring conductivity in order to provide a uniform TDS to conductivity ratio is considered to be unnecessary in most cases because the alkalinity of the boiler water is normally relatively constant and the conductivity range for blowdown control is quite broad, especially in the pressure range below 900 psig (6.21 MPa). Excess neutralization of a low TDS, low conductivity water might result in a higher measured conductivity. In addition, when boilers are equipped with instrumental monitors or controllers for blowdown control, such instruments usually read directly in micromhos/cm ($\mu\text{S}/\text{cm}$) of unadjusted conductivity.

□ SECTION 7 □

CHEMICAL CONTROL

ANALYSES

The maintenance of specified feedwater and boiler water chemistry must be well regulated and documented by frequent analysis and record keeping. Either manual or instrumental water chemistry measurement is necessary to ensure continuous satisfactory equipment operation, and it is indispensable as an aid to follow up troubleshooting.

❑ TABLES ❑

SUGGESTED WATER CHEMISTRY LIMITS
INDUSTRIAL WATERTUBE, HIGH DUTY,
TABLE 1 **PRIMARY FUEL FIRED, DRUM TYPE**

Makeup water percentage: Up to 100% of feedwater
Conditions: Includes superheater, turbine drives, or process restriction on steam purity
Saturated steam purity target: See tabulated values below.

Drum Operating Pressure (1)(11)	psig 0-300 (MPa) (0-2.07)	301-450 (2.08-3.10)	451-600 (3.11-4.14)
Feedwater(7)			
Dissolved oxygen ppm (mg/l) O ₂ -measured before chemical oxygen scavenger addition (8)	<0.007	<0.007	<0.007
Total iron ppm (mg/l) Fe	≤0.1	≤0.05	≤0.03
Total copper ppm (mg/l) Cu	≤0.05	≤0.025	≤0.02
Total Hardness ppm	≤0.3	≤0.3	≤0.2
pH @ 25°C	8.3-10.0	8.3-10.0	8.3-10.0
Chemicals for preboiler system protection	NS	NS	NS
Nonvolatile TOC ppm (mg/l) C (6)	<1	<1	<0.5
Oily matter ppm (mg/l)	<1	<1	<0.5
Boiler Water			
silica ppm (mg/l) SiO ₂	≤150	≤90	≤40
Total alkalinity ppm (mg/l)*	<700(3)	<600(3)	<500(3)
Free OH alkalinity ppm (mg/l)* (2)	NS	NS	NS
Specific conductance (12) μmhos/cm (μS/cm) 25°C without neutralization	5400-1100(5)	4600-900(5)	3800-800(5)
Total Dissolved Solids in Steam (9)			
TDS (maximum) ppm (mg/l)	1.0-0.2	1.0-0.2	1.0-0.2

*as CaCO₃

NS = not specified

NO = not detectable

VAM = Use only volatile alkaline materials upstream of attemperation water source.
(10)

**SUGGESTED WATER CHEMISTRY LIMITS
INDUSTRIAL WATERTUBE, HIGH DUTY,
PRIMARY FUEL FIRED, DRUM TYPE**

TABLE 1

Makeup water percentage: Up to 100% of feedwater
Conditions: Includes superheater, turbine drives, or process restriction on steam purity
Saturated steam purity target: See tabulated values below.

601-750 (4.15-5.171)	751-900 (5.18-6.211)	901-1000 (6.22-6.89)	1001-1500 (6.90-10.34)	1501-2000 (10.35-13.79)
<0.007	<0.007	< 0.007	<0.007	<0.007
≤0.025	≤0.02	≤0.02	≤0.01	≤0.01
≤0.02	≤0.015	≤0.01	≤0.01	≤0.01
≤0.2	≤0.1	≤0.05	ND	ND
8.3-10.0	8.3-10.0	8.8-9.6	8.8-9.6	8.8-9.6
NS	NS	VAM	VAM	VAM
<0.5	<0.5	<0.2	<0.2	<0.2
<0.5	<0.5	<0.2	<0.2	<0.2
≤30	≤20	≤8	≤2	≤1
<200(3)	<150(3)	<100(3)	NS(4)	NS(4)
NS	NS	NS	ND(4)	ND(4)
1500-300(5)	1200-200(5)	1000-200(5)	≤150	≤80
0.5-0.1	0.5-0.1	0.5-0.1	0.1	0.1

NOTES TO TABLE 1

(1) With local heat fluxes $>1.5 \times 10^5$ Btu/hr/ft² (>473.2 kW/m²), use values for at least the next higher pressure range.

(2) Minimum hydroxide alkalinity concentrations in boilers below 900 psig (6.21 MPa) must be individually specified by a qualified water treatment consultant with regard to silica solubility and other components of internal treatment. See Section 6.6 of this document.

(3) Maximum total alkalinity consistent with acceptable steam purity. If necessary, should override conductance as blowdown control parameter. If makeup is demineralized quality water and boiler operates at less than 1000 psig (6.89 MPa) drum pressure, the boiler water conductance should be that in table for 1001-1500 psig (6.9-10.34 MPa) range. In this case, the necessary continuous blowdown will usually keep these parameters below the tabulated maximum values. Alkalinity values in excess of 10% of specific conductance values may cause foaming

(4) Not detectable in these cases refers to free sodium or potassium hydroxide alkalinity. Some small variable amount of total alkalinity will be present and measurable with the assumed congruent or coordinated phosphate-pH control or volatile treatment employed at these high pressure ranges

(5) Maximum values are often not achievable without exceeding maximum total alkalinity values, especially in boilers below 900 psig (6.21 MPa) with $>20\%$ makeup of water whose total alkalinity is $>20\%$ of TDS naturally or after pretreatment by lime-soda, or sodium cycle ion exchange softening. Actual permissible conductance values to achieve any desired steam purity must be established for each case by careful steam purity measurements. Relationship between conductance and steam purity is affected by too many variables to allow its reduction to a simple list of tabulated values.

(6) Nonvolatile TOC is that organic carbon not intentionally added as part of the water treatment regime. See Section 6.4 of this document.

(7) Boilers below 900 psig (6.21 MPa) with large furnaces, large steam release space, and internal chelant, polymer, and/or antifoam treatment can sometimes tolerate higher levels of feedwater impurities than those in the table and still achieve adequate deposition control and steam purity. Removal of these impurities by external pretreatment is always a more positive solution. Alternatives must be evaluated as to practicality and economics in each individual case.

(8) Values in the table assume existence of a deaerator.

(9) Achievable steam purity depends on many variables, including boiler water total alkalinity and specific conductance as well as design of boiler steam drum internals and operating conditions [Note (5)]. Since boilers in this category require a relatively high degree of steam purity for protection of the superheaters and turbines, more stringent steam purity requirements such as process steam restrictions on individual chemical species or restrictions more stringent than 0.1 ppm (mg/l) TDS turbine steam purity must be addressed specifically.

(10) As a general rule, the requirements for attemperation spray water quality are the same as those for steam purity. In some cases boiler feedwater is suitable; however, frequently additional purification is required. In all cases the spray water should be obtained from a source that is free of deposit forming and corrosive chemicals such as sodium hydroxide, sodium sulfite, sodium phosphate, iron, and copper. The suggested limits for spray water quality are <30 ppb ($\mu\text{g/l}$) TDS maximum, <10 ppb ($\mu\text{g/l}$) Na maximum, <20 ppb ($\mu\text{g/l}$) SiO_2 maximum, and it should be essentially oxygen free.

(11) Low pressure boilers frequently use feed water that is suitable for use in higher pressure boilers. In these cases the boiler water chemistry limits should be based on the pressure range that is most consistent with the boiler water and feedwater quality. See Sections 1 and 6.2 of this document regarding blowdown.

(12) Conversion from ppm (mg/l) TDS values in the ABMA standards [12] used a factor of 0.65. See Section 6.7 of this document.

SUGGESTED WATER CHEMISTRY LIMITS
INDUSTRIAL WATERTUBE, HIGH DUTY,
TABLE 2 **PRIMARY FUEL FIRED, DRUM TYPE**

Makeup water percentage: Up to 100% of feedwater
Conditions: No superheater, turbine drives, or process restriction on steam purity
Steam purity (7): 1.0 ppm (mg/l) TDS maximum.

Drum Operating Pressure	psig 0-300 301-600	(MPa) (0-2.07) (2.08-4.14)
Feedwater(3)		
Dissolved oxygen ppm (mg/l) O ₂ - measured before chemical oxygen scavenger addition (1) (2)	<0.007	<0.007
Total iron ppm (mg/l) Fe	<0.1	<0.05
Total copper ppm (mg/l) Cu	<0.05	<0.025
Total hardness ppm (mg/l) *	<0.5	<0.3
pH @ 25°C	8.3-10.5	8.3-10.5
Nonvolatile TOC ppm (mg/l) C (6)	<1	<1
Oily matter ppm (mg/l)	<1	<1
Boiler Water		
Silica ppm (mg/l) SiO ₂	<150	<90
Total alkalinity ppm (mg/l) *	<1000(5)	<850(5)
Free OH alkalinity ppm (mg/l) * (4)	NS	NS
Specific conductance /μmhos/cm (μS/cm) @ 25°C without neutralization	<7000(5)	<5500(5)

*as CaCO₃

NS = not specified

NOTES TO TABLE 2

(1) Values in the table assume existence of a deaerator.

(2) Chemical deaeration should be provided in all cases, especially if mechanical deaeration is nonexistent or inefficient.

(3) Boilers with relatively large furnaces, large steam release space and internal chelant, polymer, and/or antifoam treatment can often tolerate higher levels of feedwater impurities than those in the table and still achieve adequate deposition control and steam purity. Removal of these impurities by external pretreatment is always a more positive solution. Alternatives must be evaluated as to practicality and economics in each individual case. The use of some dispersant and antifoam internal treatment is typical in this type of boiler operation; therefore, it can tolerate higher feedwater hardness than the boilers in Table 1.

(4) Minimum and maximum hydroxide alkalinities must be individually specified by a qualified water treatment consultant with regard to silica solubility and other components of internal treatment. See Section 6.6 of this document.

(5) Alkalinity and conductance values are consistent with steam purity limits in the same table. Practical limits above or below tabulated values should be individually established by careful steam purity measurements.

(6) Nonvolatile TOC is that organic carbon not intentionally added as part of the water treatment program. See Section 6.4 of this document.

(7) This limit represents steam purity that should be achievable if other tabulated water quality values are maintained. The limit is not intended to be nor should it be construed to represent a boiler performance guarantee.

SUGGESTED WATER CHEMISTRY LIMITS
**INDUSTRIAL FIRETUBE, HIGH DUTY,
 PRIMARY FUEL FIRED**

TABLE 3

Makeup water percentage: Up to 100% of feedwater

Conditions: No superheater, turbine drives, or process restriction on steam purity

Steam purity (7): 1.0 ppm (mg/l) TDS maximum.

Drum Operating Pressure	0-300 psig 0-2.07 MPa
Feedwater(3)	
Dissolved oxygen ppm (mg/l) O ₂ - measured before chemical oxygen scavenger addition (1) (2)	<0.007
Total iron ppm (mg/l) Fe	<0.1
Total copper ppm (mg/l) Cu	<0.05
Total hardness ppm (mg/l) *	<1.0
pH @ 25°C	8.3-10.5
Nonvolatile TOC ppm (mg/l) C (6)	<10
Oily matter ppm (mg/l)	<1
Boiler Water	
Silica ppm (mg/l) SiO ₂	<150
Total alkalinity ppm (mg/l) *	<700(5)
Free OH alkalinity ppm (mg/l) * (4)	NS
Specific conductance µmhos/cm (µS/cm) @ 25°C without neutralization	< 7000(5)

*as CaCO₃

NS = not specified

NOTES TO TABLE 3

(1) Values in the table assume existence of a deaerator.

(2) Chemical deaeration should be provided in all cases, especially if mechanical deaeration is nonexistent or inefficient.

(3) Firetube boilers of conservative design, with internal chelant, polymer, and/or antifoam treatment can often tolerate higher levels of feed-water impurities than those in the table [≤ 0.5 ppm (mg/l) Fe, ≤ 0.2 ppm (mg/l) Cu, ≤ 10 ppm (mg/l) total hardness] and still achieve adequate deposition control and steam purity. Removal of these impurities by external pretreatment is always a more positive solution. Alternatives must be evaluated as to practicality and economics in each individual case.

(4) Minimum and maximum levels of hydroxide alkalinity must be individually specified by a qualified water treatment consultant with regard to silica solubility and other components of internal treatment. See Section 6.6 of this document.

(5) Alkalinity and conductance guidelines are consistent with steam purity target. Practical limits above or below tabulated values should be individually established for each case by careful steam purity measurements.

(6) Nonvolatile TOC is that organic carbon not intentionally added as part of the water treatment program. See Section 6.4 of this document.

(7) Target value represents steam purity that should be achievable if other tabulated water quality values are maintained. The target is not intended to be nor should it be construed to represent a boiler performance guarantee.

SUGGESTED WATER CHEMISTRY LIMITS
**INDUSTRIAL, COIL TYPE, WATERTUBE, HIGH DUTY,
PRIMARY FUEL, FIRED RAPID STEAM GENERATORS**

TABLE 4

Makeup water percentage: Up to 100% of water to the coil
Total evaporation: Up to 95% of the water to the coil

Steam to water ratio (volume to volume): Up to 4000: 1
Saturated steam purity target: See tabulated values below.

Drum Operating Pressure	psig 0-300 (MPa) (0-2.07)	301-450 (2.08-3.10)	451-600 (3.11-4.14)	601-900 (4.15-6.21)	>900 (>6.21)
Steam Purity Targets (1)					
Specific conductance $\mu\text{mhos/cm}$ ($\mu\text{S/cm}$) @ 25°C	$\leq 50(2)$	$\leq 24(2)$	$\leq 20(2)$	$\leq 0.5(2)$	≤ 0.2
Dissolved solids ppm (mg/l)	≤ 25	≤ 12	≤ 10	≤ 0.25	≤ 0.01
Silica ppm (mg/l) SiO_2	NS	NS	NS	≤ 0.03	≤ 0.02
Water to Coil (3)					
Dissolved oxygen ppm (mg/l) O_2 - measured after chemical oxygen scavenger addition (4)	<0.007	<0.007	<0.007	<0.007	<0.007
Total iron ppm (mg/l) Fe	<1.0	<0.3	<0.1	≤ 0.05	≤ 0.02
Total copper ppm (mg/l) Cu	<0.1	<0.05	<0.03	≤ 0.02	≤ 0.02
Total hardness ppm (mg/l)*	O-Trace	O-Trace	O-Trace	ND(6)	ND(6)
pH @ 25°C	9.0-11.0	9.0-11.0	9.0-11.0	9.0-11.0	9.0-11.0
Total alkalinity ppm (mg/l) *	<800	<600	<500	<200	<100(7)
Hydroxide alkalinity ppm (mg/l) * (5)	<300	<200	<120	<60	$\leq 50(7)$
Silica ppm (mg/l) SiO_2	≤ 150	≤ 100	≤ 60	≤ 30	$\leq 10(7)$
Specific conductance $\mu\text{mhos/cm}$ ($\mu\text{S/cm}$) @ 25°C without neutralization	<8000	<6000	<5000	<4000	<500(7)

*as CaCO_3 NS = not specified ND = not detectable

NOTES TO TABLE 4

(1) Tabulated values are based on the assumption of no superheaters or turbine drives. If the steam is used for superheat or turbine drives, use values for 901 psig (6.22 MPa) and up. If unit operation approaches superheat conditions within the coil, use values for 601-900 psig (4.15-6.21 MPa) range to avoid silica deposition on near-dry surfaces. The target is not intended to be, nor should it be construed to represent, a boiler performance guarantee.

(2) Boiler antifoams are frequently used to improve steam purity.

(3) Water to the coil can be feedwater (defined as makeup plus condensate) alone, or a combination of feedwater and concentrated water from the steam separator drain.

(4) Chemical deaeration with catalyzed oxygen scavenger is necessary in all cases because feedwater temperature limits imposed by manufacturers of coil type steam generators preclude efficient mechanical deaeration. Feed of chemical oxygen scavenger must be sufficient to maintain a detectable residual in the water to the coil. For those units that include steam separator-water storage drums and recirculate substantial amounts of boiler water, oxygen scavenger residuals should be maintained in higher ranges typical of those employed for drum type boilers.

(5) Treatment chemical should preferably be fed to the feedwater tank to minimize sludge deposits in the coils. Hydroxide alkalinity in ppm (mg/l) CaCO_3 must be maintained at a sufficient concentration to keep silica soluble and avoid complex silicate deposits. These precautions are necessary since scale control internal treatment chemicals are not usually employed to assist in the prevention of such deposits in coil type steam generators.

(6) Demineralization of makeup water is recommended practice in these pressure ranges.

(7) Suggested values vary with the operating pressure, decreasing in inverse proportion to pressure increases above 900 psig (6.21 MPa).

SUGGESTED WATER CHEMISTRY LIMITS
MARINE PROPULSION, WATERTUBE,
OIL FIRED DRUM TYPE

TABLE 5

Makeup water percentage: Up to 5% of feedwater

Pretreatment: At sea, evaporator condensate; in port, evaporator condensate or water from shore facilities meeting feedwater quality guidelines

Saturated steam purity (6): 30 ppb (µg/l) TDS max., 10 ppb (µg/l) Na max., 20 ppb (µg/l) SiO₂ max.

Drum Operating Pressure	psig 450-850 (MPa) (3.1-5.86)	851-1250 (5.87-8.62)
Feedwater(1)		
Dissolved oxygen ppm (mg/l) O ₂ - measured before chemical oxygen scavenger addition (5)	<0.007	<0.007
Total iron ppm (mg/l) Fe	<0.02	<0.01
Total copper ppm (mg/l) Cu	<0.01	<0.005
Total hardness ppm (mg/l) *	<0.1	<0.05
pH @ 25° C	8.3-9.0	8.3-9.0
Chemicals for preboiler system protection	VAM	VAM
Oily matter ppm (mg/l)	<0.05	<0.05
Boiler Water		
Silica ppm (mg/l) SiO ₂	<30	<5
Total alkalinity ppm (mg/l) * (4)	NS(4)	NS(4)
OH alkalinity ppm (mg/l) * (4)	<200(3)	ND(4)
Specific conductance µmhos/cm (µS/cm) @ 25°C without neutralization (2)	<700	<150

*as CaCO₃

NS = not specified

ND = not detectable

VAM = Use only volatile alkaline materials.

NOTES TO TABLE 5

(1) Feedwater values assume 100 cycles of concentration to boiler water and are not restricted to any specific makeup water pretreatment.

(2) Suggested maximum conductance values are intended to serve as an alarm for salt water condenser leaks and can be correlated with chloride ion content in feedwater and/or boiler water.

(3) Maximum hydroxide alkalinity that is consistent with steam purity target and sufficient to maintain silica solubility. If necessary, this value should override conductance as blowdown control parameter.

(4) Not detectable in this case refers to free sodium or potassium hydroxide alkalinity. Some small amount of total alkalinity will be present and measurable with the assumed congruent or coordinated phosphate-pH control or volatile treatment usually applied at these high pressure ranges.

(5) Values in the table assume existence of a deaerator.

(6) Maximum values represent steam purity that should be achievable if other tabulated water quality values are maintained. The limits are not intended to be, nor should they be construed to represent, boiler performance guarantees.

SUGGESTED WATER CHEMISTRY LIMITS
ELECTRODE, HIGH VOLTAGE,
TABLE 6 **FORCED CIRCULATION JET TYPE**

Makeup water percentage: Up to 100% of feedwater

Conditions: No superheater, turbine drives, or process restriction on steam purity

Operating Pressure	0-450 psig 0-3.1 MPa
Feedwater(2)	
Dissolved oxygen ppm (mg/l) O ₂ – measured before chemical oxygen scavenger addition (1)	<0.007
Total hardness ppm (mg/l) *	<0.25
pH @ 25°C	8.3-10.5
Nonvolatile TOC ppm (mg/l) C (6)	NS(8)
Boiler Water	
pH @ 25°C	8.5-10.5
Silica ppm (mg/l) SiO ₂	<150
Total alkalinity ppm (mg/l) *	<350(3)
OH alkalinity ppm (mg/l) * (8)	NS(4)
Total iron ppm (mg/l) Fe plus total copper ppm (mg/l) Cu	2.0(2)(7)
Suspended solids	NS(7)
Organic matter	NS(8)
Specific conductance µmhos/cm (µS/cm) @ 25°C without neutralization	<NS(5)

*as CaCO₃

NS = not specified

NOTES TO TABLE 6

(1) Values in the table assume existence of a mechanical deaerator. Chemical deaeration should be provided in all cases, especially if mechanical deaeration is nonexistent or inefficient.

(2) Some boilers may tolerate higher concentrations of feedwater impurities than those in the table and still achieve adequate deposition control.

(3) The use of high alumina porcelain insulators may allow the limit to be increased to 600 ppm (mg/l) CaCO_3 .

(4) Maximum hydroxide alkalinity concentration must be individually specified by a qualified water treatment consultant with regard to silica solubility, organic matter concentration, and other components of internal treatment. See Section 6.6 of this document.

(5) Boiler performance is determined by the conductivity of the boiler water. The optimum conductivity range is dependent on the specific boiler design.

(6) Nonvolatile TOC is that organic carbon not intentionally added as part of the water treatment program. See Section 6.4 of this document.

(7) Suspended solids present in the boiler water contribute to erosion/corrosion of the electrodes and counter electrodes. Additionally, the presence of suspended solids in the boiler water increases the potential for foaming and ground fault arcing.

(8) Naturally occurring organics, particularly when combined with hydroxide alkalinity, may cause foaming of the boiler water. Ground fault arcing between the electrode and upper boiler shell may result.

☐ REFERENCES ☐

1. American Society of Mechanical Engineers. 1979. Consensus on Operating Practices for the Control of Feedwater and Boiler Water Quality in Modern Industrial Boilers.
2. Marcy, V. M. and S. L. Halstead. 1964. Improved basis for coordinated phosphate pH control of boiler water. *Combustion* 35: 4547.
3. Whirl, S. F. and T. E. Purcell. 1942. Protection against caustic embrittlement by coordinated phosphate pH control. *Proc. Annual Water Conf., Eng. Soc. W. Pa.*, 3, 45-60B.
4. Daniels, G. C. 1948. Prevention of turbine-blade deposits. *ASME Paper 48-SA-25*. Abstracted in *Mech. Eng.* 70:694-95.
5. Smith, R. I. 1958. Ammonia and hydrazine for high pressure boilers. *ASME Paper 57A248*. Abstracted in *Mech. Eng.* 80:78-79.
6. American Society for Testing and Materials. 1986. Designation E 380 86, Metric practice. *Annual Book of ASTM Standards*, Vol. 14.02, Philadelphia.
7. American Society for Testing and Materials. 1988. Designation D 888 87, Standard test methods for dissolved oxygen in water. *Annual Book of ASTM Standards*, Vol. 11.01, 462-473.
8. Weick, R. H. 1975. How to determine when an industrial boiler needs cleaning. *Proc. Int'l. Water Conf., Eng. Soc. W. Pa.*, 36, 71-76.
9. American Public Health Association. 1989. Oil and grease. *Standard Methods for the Examination of Water and Wastewater*, 17th ed., 541-5-48, Washington, D.C.
10. American Society for Testing and Materials. 1985. Designation D 2579 85, Method A, Standard test methods for total and organic carbon in water (oxidation and infrared detection). *Annual Book of ASTM Standard* Vol. 11.02, 12-14, Philadelphia.

11. Coulter; E. E., E. A. Pirsh, and E. J. Wagner, Jr. 1956. Selective silica carryover in steam. Trans. ASME, 78:869-873.
12. American Boiler Manufacturers Association. 1982. Boiler Water limits and Steam Purity Recommendations for Water Tube Boilers, 3rd edition, Arlington, VA.
13. Hitchman, M. I. 1978. Measurement of dissolved oxygen. Chemical Analysis, Vol. 49, New York: John Wiley & Sons.
14. American Society of Mechanical Engineers. 1984. Deaerators Performance Test Codes, ANSI/ASME PTC 12.3-1977, New York.
15. Jonas, O. 1988. Determination of steam purity limits for industrial turbines. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 49, 137-147.
16. Dewitt-Dick, D., J. S. Beecher, and F. Seels. 1988. Steam purity problems encountered in industrial turbines. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 49, 148-159.
17. Whitehead, A. and R. T. Bievenue. 1988. Steam purity for industrial turbines, Proc. Int'l Water Conf., Eng. Soc. W. Pa., 49, 160-172.
18. Navitsky, G. and H. A. Grabowski. 1988. Steam purity for industrial steam generators. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 49, 173-180.
19. Fynsk, A. and J. O. Robinson. 1992. A practical guide to avoiding steam purity problems in the industrial plant. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 53, 415-425.
20. Sopocy, D. M., R. B. Dooley, and O. Jonas 1985. EPRI's interim consensus guidelines on fossil plant cycle chemistry. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 46, 153-186.
21. Jonas, O. and B. C. Syrett. 1987. Chemical transport and turbine corrosion in phosphate treated drum boiler units. Proc. Int'l Water Conf., Eng. Soc. W. Pa., 48, 158-166.
22. American Society of Mechanical Engineers. 1989. The ASME Handbook on Water Technology for Thermal Power Systems. New York.