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User's Manual for PRESTO

A Computer Code for the Performance of Regenerative Superheated Steam-Turbine Cycles

L. C. Fuller
T. K. Stovall

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A COMPUTER CODE FOR THE PERFORMANCE OF REGENERATIVE SUPERHEATED STEAM-TURBINE CYCLES

L. C. Fuller   T. K. Stovall

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16 Abstract

The PRESTO computer code is designed to analyze the performance of regenerative and reheat superheated steam turbine cycles. The user may model not only standard turbine cycles for base-load power plants but also cycles with such additional features as process steam extraction and induction and feedwater heating by external heat sources. Peaking, and high back pressure cycles are also included. The code's general methodology is to use the expansion line efficiencies, exhaust loss, leakages, mechanical losses, and generator losses to calculate the heat rate and generator output.

This user's manual includes a general description of the code as well as the instructions for input data preparation. Two complete example cases are appended.

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CONTENTS

CONTENTS (continued)

1. INTRODUCTION

PRESTO is a computer code developed at the Oak Ridge National Laboratory (ORNL) to analyze the performance of regenerative steam-turbine cycles using superheated steam such as that normally available from large fossil-fueled steam generators. Throttle pressures may be either sub- or supercritical. The turbine arrangement may be tandem- or cross-compound and have zero, one, or two reheaters. Cycles modeled for study may thus range from a simple one-section nonextraction cycle to a three-section cycle with multiple reheat. The computer code is also designed to analyze the performance of steam-turbine cycles containing such additional features as steam induction, extraction, and feedwater heating by an external heat source. These features allow the user to combine the steam-turbine cycle with a high-temperature topping cycle or to integrate it with an advanced-concept heat source.

The General Electric heat balance shown in Fig. 21 of the Environmental Protection Agency report No. EPA-600/7-77-126 was modeled using the PRESTO code. The net heat rates matched within 9 Btu/kWhr or approximately 0.1%.

For the user's convenience, this manual has been divided into three major sections. Section 2 is a general description of the code's methodology. Section 2 will give the user a basic understanding of the code and is a starting point for any programmer who wishes to alter the computer program.

Section 3, entitled Options, describes the options built into the code to handle cogeneration cycles, peaking units, etc. If the user's model is relatively straightforward, that is, similar to a modern, conventional power plant cycle, the user may wish to skip or lightly skim this portion of the manual.

Section 4, entitled Data Input Instructions, gives the user instructions for the data input preparation. A namelist feature is used for specifying the data, and a synopsis is given with each variable's name and description.

The minimum-input data required to run PRESTO are listed in Sect. 4. The code output provides all the information normally shown on a heat balance diagram.

Section 5, entitled Example Cases, contains three example cases. The first example shows a conventional power plant cycle, and the second demonstrates the use of those special features described in Sect. 3. The third example is a practical case that explains how to delete a feedwater heater in response to an error message.

Appended, the user will find the example cases' computer output, a list of subroutines, and a common map. An index of terms and variable names is also included.

PRESTO is the third computer code released by the Oak Ridge National Laboratory to analyze the performance of large steam turbine-generator units. The original ORCENT code[1] was designed to perform heat-rate calculations at maximum guaranteed turbine loading for steam conditions commonly associated with light-water reactors. It could accommodate one- to three-section machines with one external reheater and a one- or two-stage steam reheater. ORCENT used the Keenan and Keyes[2] steam properties and could handle from 0 to 200°F superheat. The efficiency calculations assumed the low-pressure turbines were designed for wet steam conditions. ORCENT was based on a General Electric (G.E.) report (GER-2454A).[3]

ORCENT II[4] altered the original code to perform calculations at valves-wide-open and part load as well as at maximum guaranteed conditions. This code was still designed for typical light-water reactor steam conditions but used the 1967 ASME steam properties[5,6] instead of the Keenan and Keys[2] steam properties. ORCENT II was based on report GET-6020[7] and eliminated the intermediate-pressure turbine from the cycle models.

The PRESTO computer code is written in standard FORTRAN IV for the IBM 360/370 series of digital computers. Turbine performance calculations are based on a G.E. report (GER-2007C),[8] with the flow logic similar to that of the original ORCENT code.[1] The PRESTO code uses the 1967 ASME formulations and iterative procedures for the calculation of the properties of steam adapted for use at the Oak Ridge National Laboratory by D. W. Altom.[5,6] Any single computer run will execute in less than 3 sec on the 360/91 and use approximately 222K (bytes) of core. The PRESTO code will be available from COSMIC, 112 Barrow Hall, the University of Georgia, Athens, Georgia 30602, telephone (404) 542-3265.

2. DESCRIPTION OF THE PRESTO CODE

2.1 Code Background

The PRESTO code uses a General Electric (G.E.) report (GER-2007C)[8] as the basis for its logic and functional relationships. This G.E. report is referenced throughout this manual and will prove an invaluable aid to the user.

In summary, G.E. report GER-2007C[8] methodology is to (1) calculate the expansion line efficiency as a function of volume flow, pressure ratio, initial pressure and temperature, and the governing stage design; and (2) use this expansion line efficiency and the exhaust loss, packing and valve stem leakages, mechanical losses, and generator losses to calculate the heat rate and generator output.

General Electric report GER-2007C[8] contains many figures and functions that were used during the iterative calculations, and they have all been provided, in a mathematical format, within the code.

2.2 Flow Diagram

Figures 2.1—2.9 are general flow diagrams that describe the PRESTO program logic. The user may find them to be a helpful reference during the following description of the code. Turbine expansion efficiencies calculated by PRESTO follow the procedure outlined in Table I of G.E. report GER-2007C.[8] The program's logic path varies according to the number of turbine sections and reheaters in order to follow these General Electric expansion line definitions.

2.3 Code Initiation

The PRESTO code begins (Fig. 2.1) with the default data set and accepts user-specified input data. Before iterations begin, the throttle steam thermodynamic properties are calculated, and preliminary conditions are defined for the governing stage bowl. These preliminary conditions include the steam flow, pressure, and enthalpy.

ORNL–DWG 79–5758 ETD

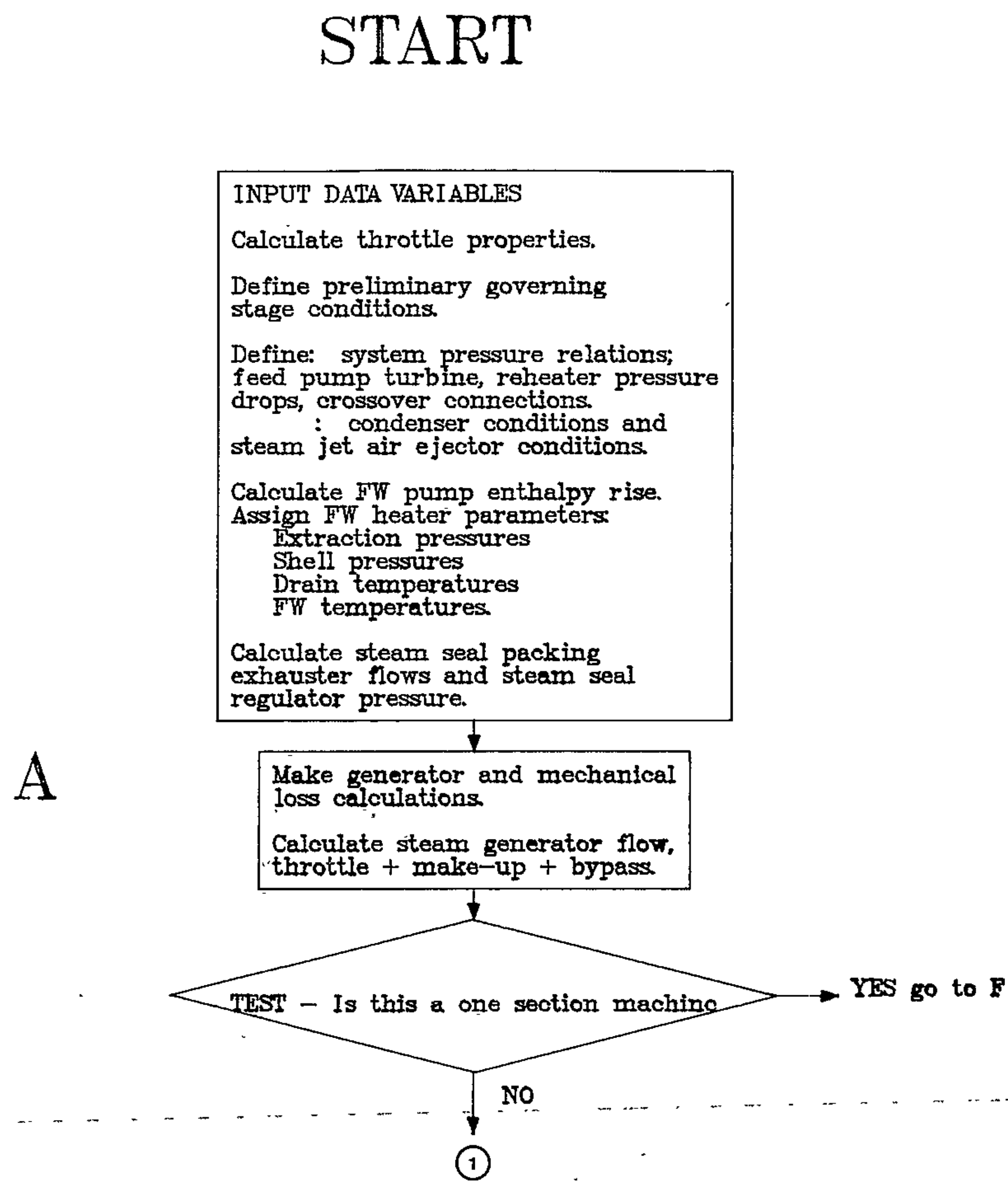
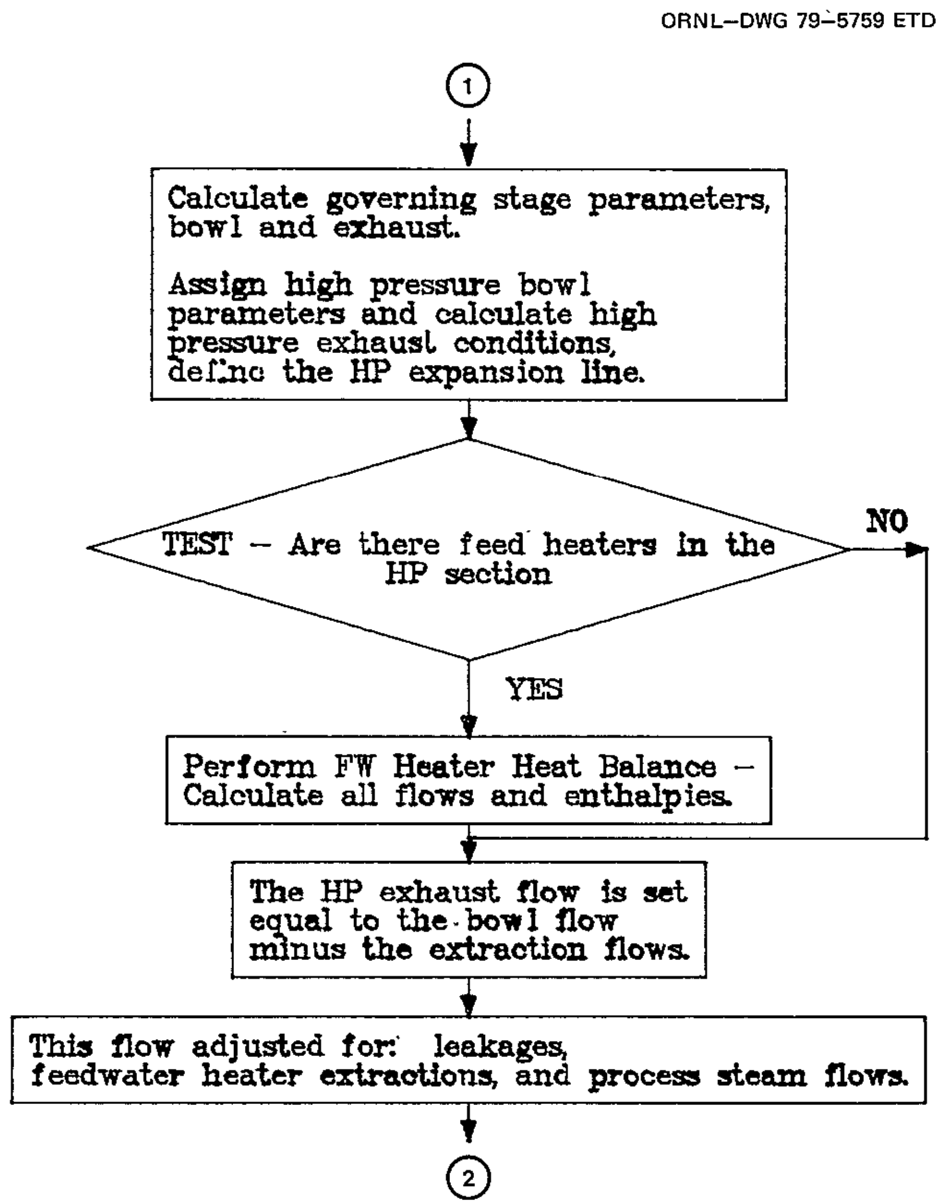


Fig. 2.1. Program initiation.



B

Fig. 2.2. High-pressure turbine balance.

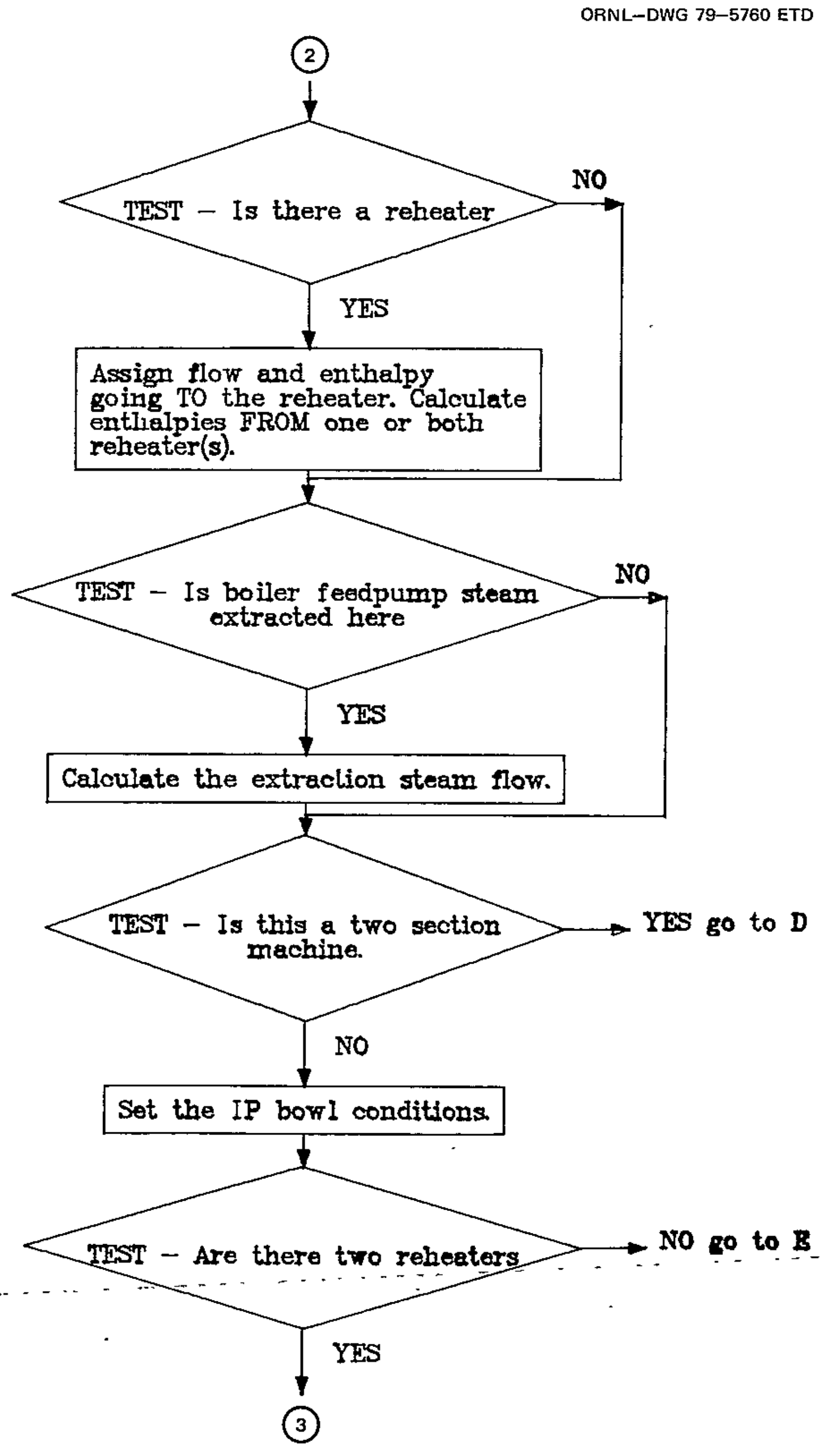


Fig. 2.3. Reheaters and steam routing.

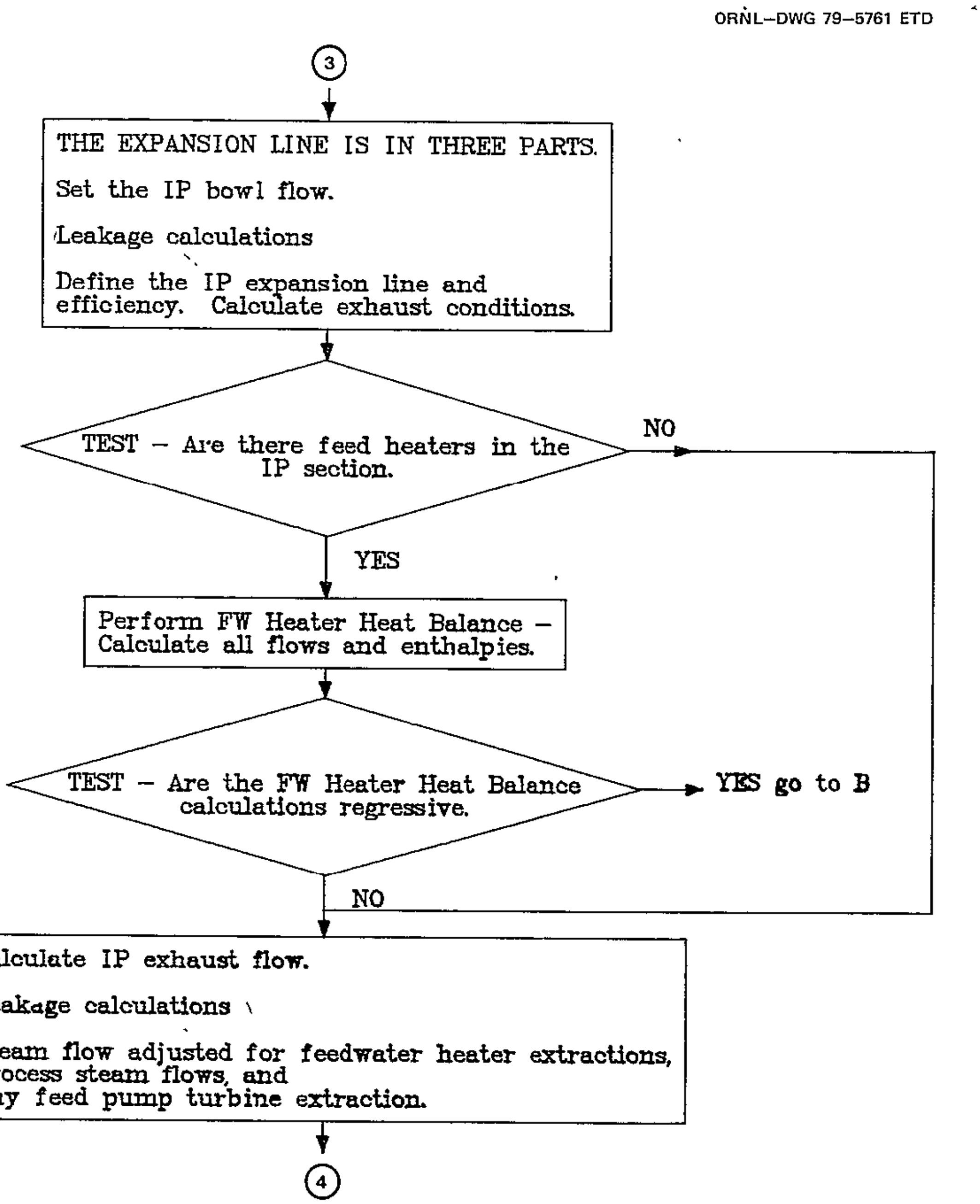


Fig. 2.4. Intermediate-pressure turbine balance.

C

ORNL–DWG 79–5762 ETD

D

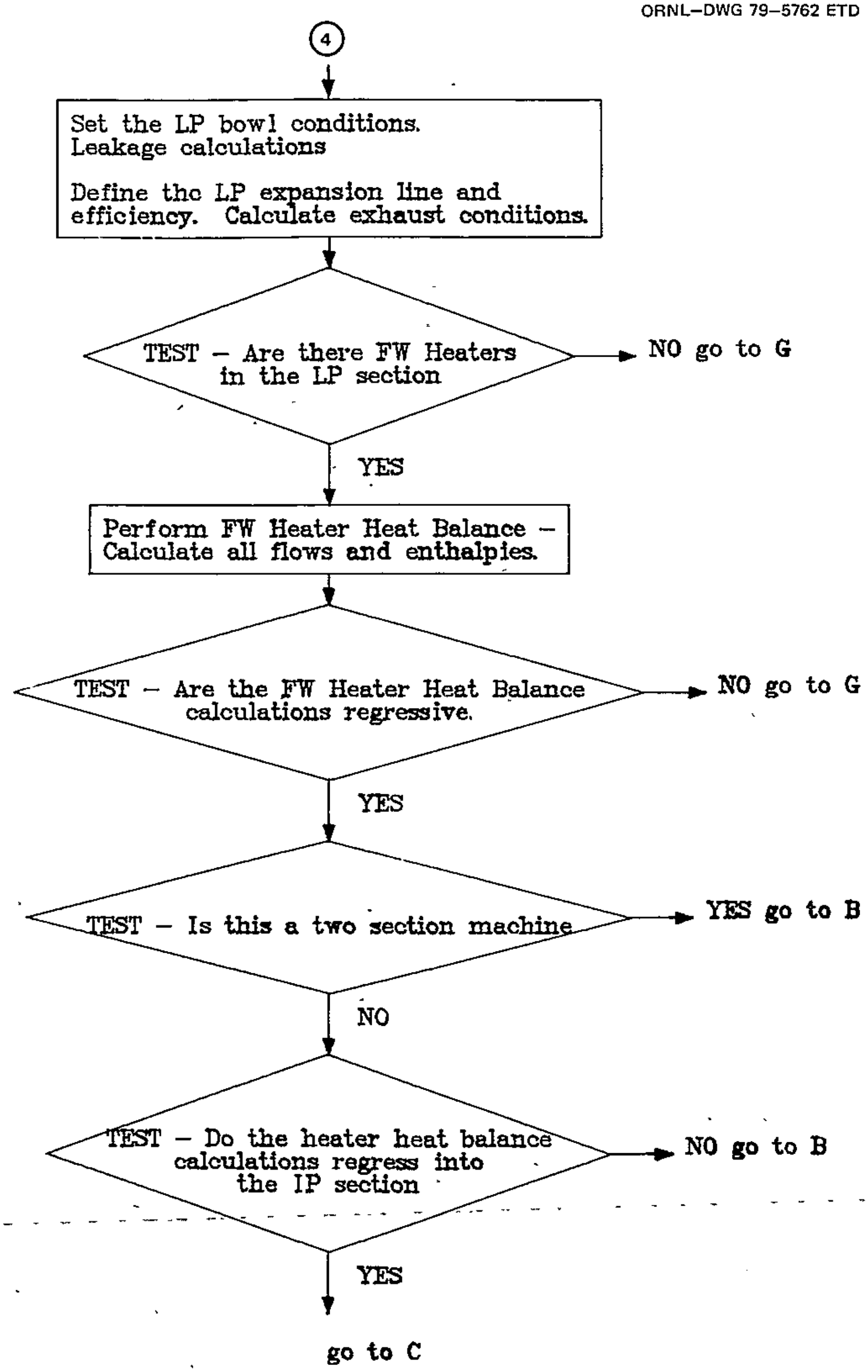


Fig. 2.5. Low-pressure turbine balance.

ORNL-DWG 79-5763 ETD

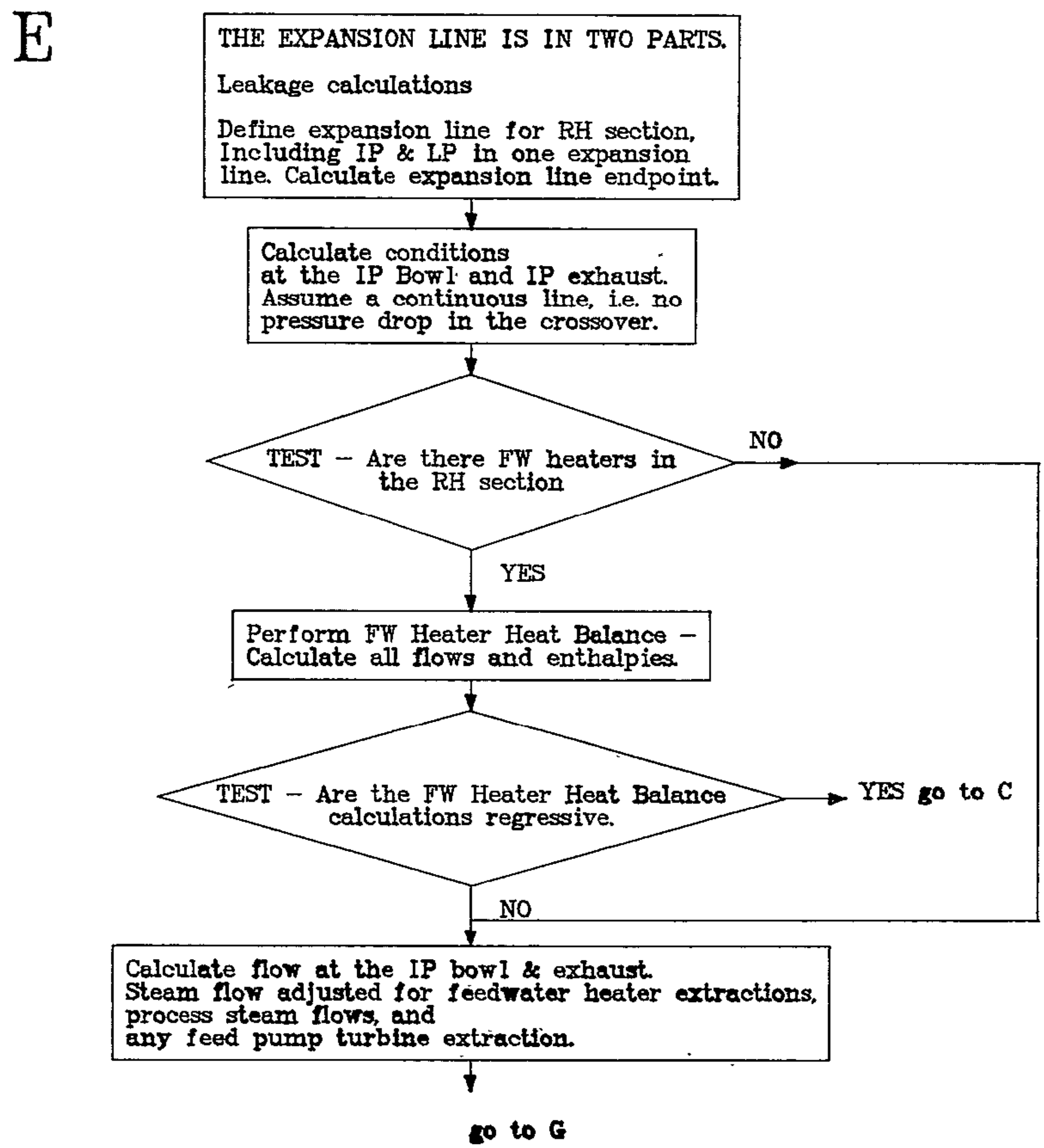


Fig. 2.6. Reheat turbine balance.

F

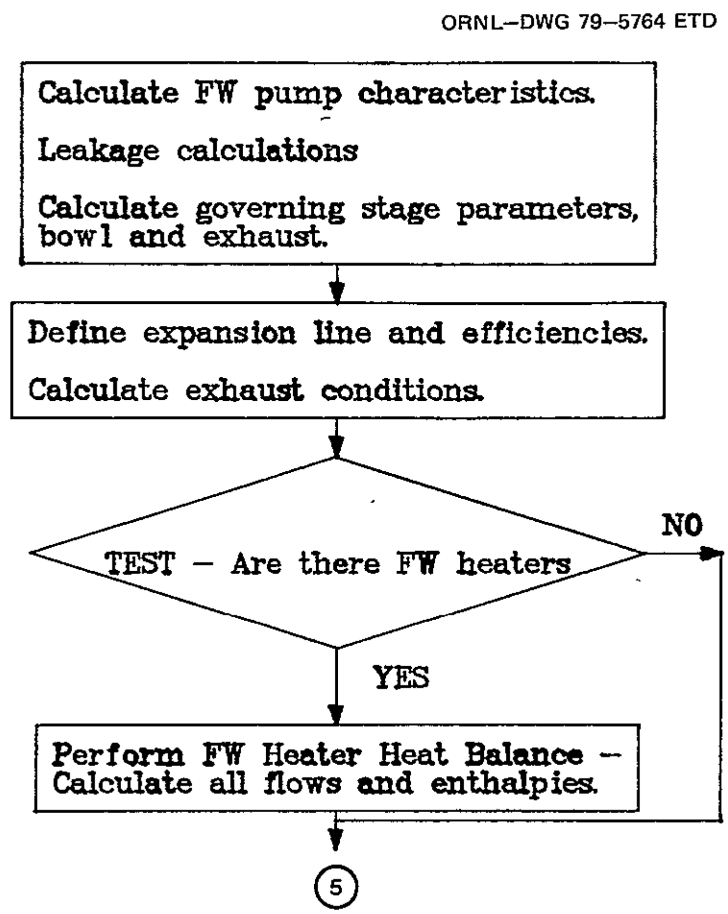


Fig. 2.7. Nonreheat turbine balance.

ORNL–DWG 79–5765 ETD

G

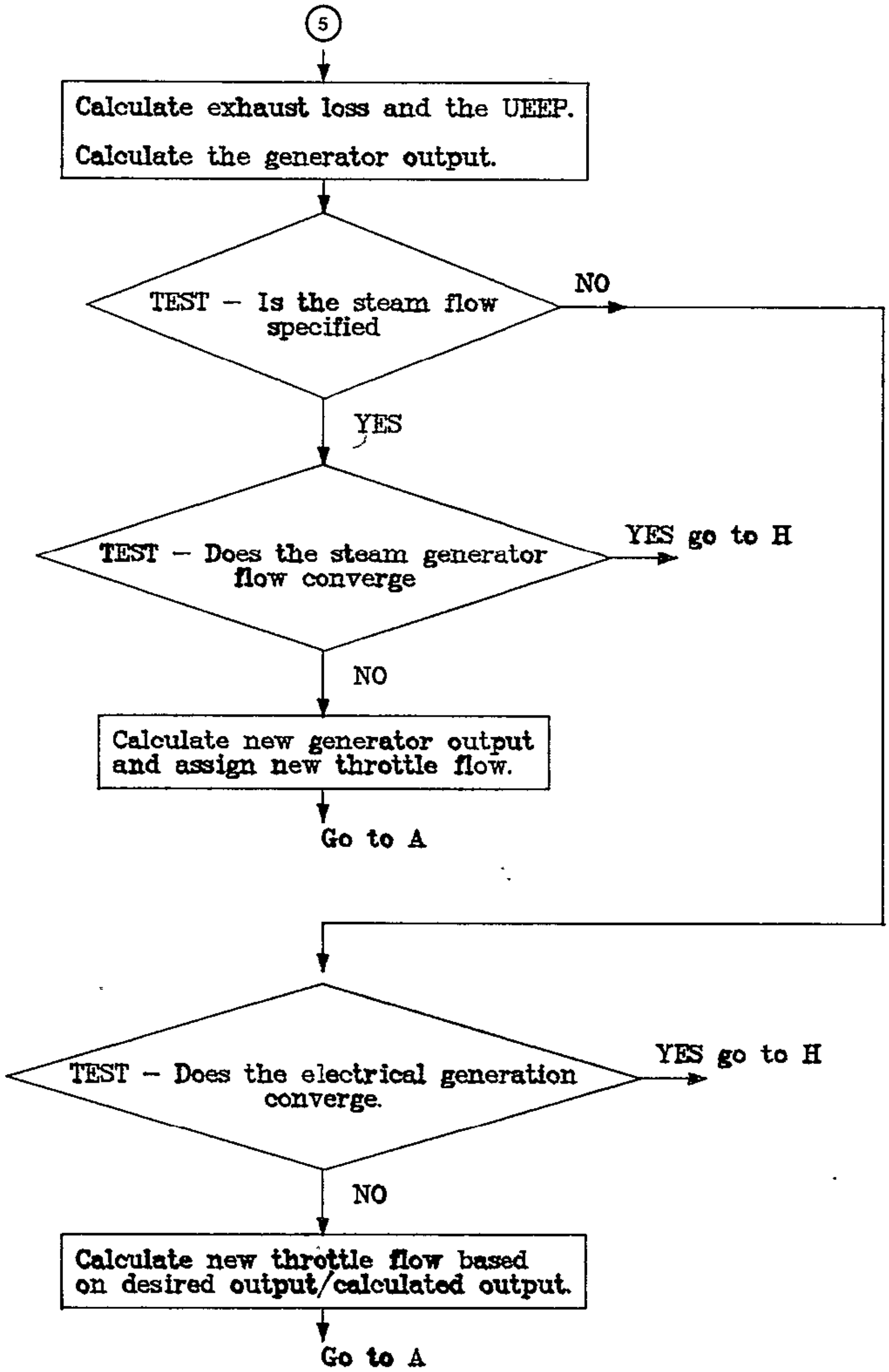


Fig. 2.8. Convergence calculations.

ORNL–DWG 79–5766 ETD

H

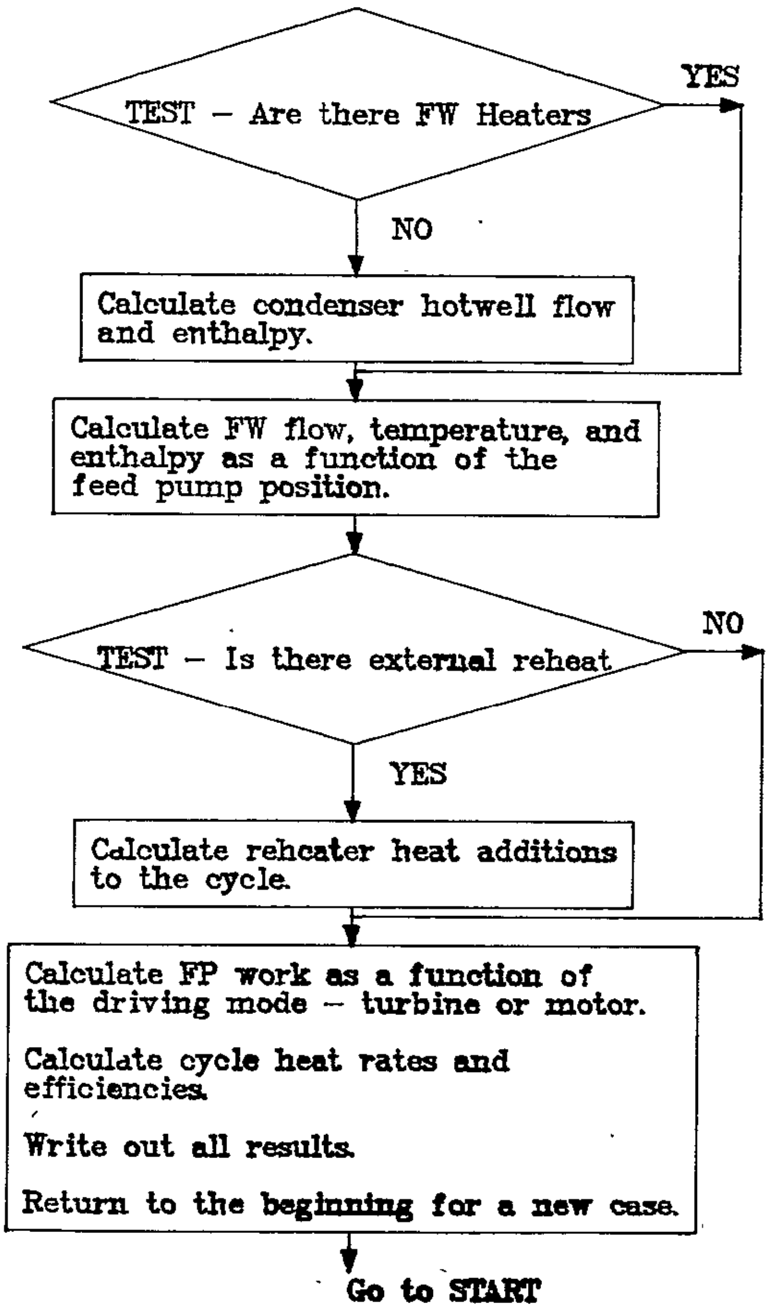


Fig. 2.9. Final calculations.

The system pressure relationships are defined including the feedwater pump turbine inlet and outlet pressures and the reheater pressure drop(s). The condenser and steam-jet air-ejector conditions are determined by the input data.

The feedwater pump enthalpy rise is calculated as a function of the throttle pressure, pump inlet pressure, and pump efficiency. Subroutine FWHPAR is called to assign the feedwater heater parameters using the input data for extraction pressures, terminal temperature differences, and drain cooler approach temperature differences. Subroutine FWHPAR then calls the appropriate steam property subroutines to assign the feedwater temperatures and enthalpies and the heater shell temperatures and enthalpies.

The steam seal packing exhauster flows and the steam seal regulator pressure are assigned values dependent upon the unit rating and the turbine rotational speed.

2.4 Main Loop Iteration Point

This description is now at point A in Fig. 2.1. This is the starting point for the main program iteration loop. All iterations begin at the high-pressure end of the cycle and progress toward the condenser. A common cycle will usually converge in less than ten major iterations.

The generator and mechanical losses depend on the generator loading as well as the generator capability and are calculated for later use.

The steam generator flow is set equal to the sum of the throttle flow, makeup flow, and any condensate bypassed from the condenser to the steam generator.

If the cycle under study is a one-section machine, the logic line goes to Fig. 2.7. For a multisection cycle, proceed to Fig. 2.2.

2.5 High-Pressure Turbine Balance

Governing stage parameters are calculated using the governing stage pitch diameter, number of blade rows, and the steam volume flow. J. Kenneth Salisbury's discussions on turbine stage design and efficiency are followed during these calculations in the following manner:

wheel speed = constant × pitch diameter × rpm;

theoretical steam velocity = wheel speed ÷ 0.5;

available energy = (theoretical steam velocity)^2 ÷ (2 × g × J);

ideal shell enthalpy = bowl enthalpy — available energy

actual shell enthalpy = bowl enthalpy — efficiency × available energy;

using bowl entropy and ideal (isentropic) shell enthalpy, calculate shell pressure.

The HP bowl conditions are determined by the governing stage exit.

The HP section efficiency is calculated as a function of volume flow, governing stage design, and the pressure ratio (exhaust to throttle). This expansion line efficiency and exhaust pressure determine the HP exhaust conditions.

If there are any feedwater heaters fed from the HP section, they are balanced and all flows and enthalpies are calculated.

2.6 Regressive Feedwater Heater Calculations

Point B in Fig. 2.2 is a reentry point if downline feedwater calculations are found to be regressive. Feedwater heater heat balances are made in a cascading order from highest shell pressure to lowest. Certain conditions (pumped drains or external heat additions) will cause the calculations to regress to the next highest pressure feedwater heater. If this heater receives extraction steam from a turbine section other than the one being balanced, the program returns to rebalance the previous turbine section.

2.7 HP Exhaust

The HP exhaust flow is set equal to the bowl flow minus the internal extraction flows from the HP section.

The continuing steam flow is then adjusted for any leakage flows, any feedwater heater extraction taken from the exhaust line, and for any process steam added to or removed from the line. The calculation continues in Fig. 2.3.

2.8 Reheaters and Steam Routing

This steam flow illustrated in Fig. 2.3 is checked for several options before being passed to the next turbine section.

If the cycle includes a reheater, the flow and enthalpy of the cold reheat flow are assigned, and the enthalpy of the discharge flow from the reheater(s) is calculated. If the boiler feedwater pump is turbine driven, and if the extraction point follows this reheater, the extraction steam flow is calculated and subtracted from the hot reheat steam flow.

If the cycle has only two turbine sections, the low-pressure bowl conditions are set, and the logic transfers to point D in Fig. 2.5. Otherwise the intermediate-pressure bowl conditions are defined, and the number of reheaters is checked. Because of G.E.'s definition of a "reheat section," which includes all turbine sections downstream of a solitary reheater, a three-section machine with only one reheater is treated thermodynamically as a two-section machine (only two expansion lines). For this case, follow point E in Fig. 2.6. For a double reheat cycle, refer to Fig. 2.4.

2.9 Intermediate-Pressure (IP) Turbine Balance

The IP turbine balance begins by setting the bowl flow and by adjusting this flow to account for the various leakage flows. The expansion line efficiency is calculated as a function of bowl initial volume flow and the pressure ratio (bowl to exhaust). Given this efficiency, the expansion line end point (ELEP) is fixed and the expansion line defined.

If there are feedwater heaters fed from the IP turbine, they are balanced and the calculations checked for regression as previously discussed. If the calculations are regressive, the HP turbine and feedwater heaters are rebalanced, and the steam flows are adjusted accordingly (follow the diagram to point B in Fig. 2.2).

Otherwise, the IP exhaust flow is set equal to the bowl flow minus the extraction flows. The steam flow to the second reheater is adjusted for leakage flows and for any feedwater heater extraction steam taken from the exhaust steam line. Process steam may be added or removed, and boiler feed pump turbine steam may be extracted before the second reheater.

The bowl conditions of the low-pressure turbine are set equal to the exit conditions of the second reheater.

2.10 Low-Pressure (LP) Turbine Balance

Point D in Fig. 2.5, is the next step in our logic diagram. Low-pressure leakage flows, if any, are calculated and subtracted from the bowl flow. The expansion line efficiency is calculated as a function of volume flow and initial pressure and temperature. Further corrections are included for a cross-compound 1800-rpm LP turbine. With this efficiency, the expansion line and its end point (ELEP) are defined.

If there are feedwater heaters receiving extraction steam from the LP section, they are balanced and checked for regression. Regressive calculations return to either point B (Fig. 2.2) in the HP section or point C (Fig. 2.4) in the IP section. Otherwise, the logic passes to point G in Fig. 2.8.

2.11 Reheat Turbine Balance

Fig. 2.6, reheat turbine balance, is arranged much like the turbine balances already discussed. The IP and LP turbine sections are treated as one turbine for expansion line and feedwater heater calculations and are then separated for steam flow calculations.

Between the IP exhaust and the LP bowl, corrections are made for possible leakages and extractions, including an exhaust line feedwater heater and the feedwater pump turbine. Notice that process steam may be removed at this point in the logic diagram but not added. If process steam is added in the crossover of a reheat section, the code treats it as a case with three expansion lines to allow the induction of steam at a condition different from that of the crossover steam (follow Fig. 2.4).

After these corrections, control logic passes to point G in Fig. 2.8.

2.12 Nonreheat Turbine Balance

Fig. 2.7, nonreheat turbine balance, is used for a one-section turbine cycle. The feedwater pump characteristics are defined and the leakages calculated. The governing stage parameters are computed as they were for the high-pressure section in Figure 2.2. The code follows the procedures listed for a nonreheat, two-row governing stage turbine in Table I of G.E. report GER-2007C.[8] The expansion line efficiency is a function of volume flow, governing stage design, and initial pressure and temperature.

Any feedwater heaters present are balanced. Note that regressive calculations are impossible in a one-section cycle.

2.13 Convergence Tests

Point G of Fig. 2.8 is the next step. The exhaust loss and the used energy end point (UEEP) are determined by the exhaust volume flow, turbine rotational speed, and exhaust annulus area. Given the UEEP, it is possible to calculate the generator output.

The user has a choice, through his input data, of two convergence tests — electrical generation or steam-generator outlet flow. If a user has specified the electrical generation, the calculated generator output for an estimated steam flow will be checked against the required power output. If these two are approximately equal, the code passes to its final calculations in Fig. 2.9. If they are not, a new throttle flow is estimated and control passes to point A on Fig. 2.1.

If steam-generator outlet flow was the chosen critieria, it is checked in a like manner. If the steam-generator outlet flow has not converged, a new throttle flow and a new estimated electrical output are assigned, and control again passes to point A in Fig. 2.1.

These convergence criteria choices are further discussed in Sects. 4.4.6, 4.4.43, and 4.4.44.

If the code has converged (or the iteration limit is reached), the final cleanup calculations are made.

2.14 Final Calculations

If there are no regenerative feedwater heaters in the turbine cycle, the condenser hot-well flow and enthalpy are set. The feedwater flow, temperature, and enthalpy are calculated as a function of the feedwater pump position. Correction factors are computed for any external heat effects such as reheaters, process steam, or external feedwater heating.

After the feedwater pumping power has been calculated, the net and gross heat rates and efficiencies are computed. The heat rate definition employed by PRESTO is

$$\left(\sum \text{heat added} - \sum \text{heat removed}\right)/\text{electrical generation},$$

where "heat added" terms include steam generator, reheater, and induction heat additions. "Heat removed" terms represent steam extractions or heat removed from the feedwater string. When working with cycles containing external steam or heat flows, this may give an exaggerated cycle efficiency, and other heat-rate definitions may have more value. The user should check for this situation and if necessary recalculate the heat rate treating external flows as desired to accurately portray a specific cycle efficiency. One definition commonly used for this purpose sets the heat rate equal to $\sum$ heat added/electrical generation.

The results are then written out, and the code returns to "start" in Fig. 2.1 to read data for a new case.

The PRESTO code uses many subroutines during these calculations. Appendix B lists these subroutines with a brief description of each one.

3. OPTIONS

Options have been included in the PRESTO code to allow the user to extend turbine cycle models to the limits of and beyond those cycles found in commercial use.

3.1 Peaking or Two-Shift Turbines

Peaking, or two-shift, units are designed for quick starts and minimal use. Their stage group efficiencies are therefore lower, and they have a higher exhaust loss than a baseload unit. The flag variable IPEAK will cause the stage group efficiencies to be corrected as described in G.E. report GER-2007C.[8] The user must adjust the last stage blade length (BLS) and the pitch diameter of the last stage (PDLS) to conform to a high exhaust loss. Figures 16, 17, and 18 in G.E. report GER-2007C[8] give exhaust loss as a function of blade length, pitch diameter, and volume flow rate. Page 5 of the G.E. report GET-2050C[10] gives last stage loading limits. The variables IPEAK, BLS, and PDLS are described in Sects. 4.4.12, 4.4.1, and 4.4.35 respectively.

3.2 High Back-Pressure Turbines

The user may model a high back-pressure (5 to 15 in. Hga) unit for use with dry cooling towers by setting the exhaust pressure, PXLP (psia) or PXLPI (in. Hga), equal to the desired pressure. The last stage blade length and pitch diameter should be chosen from Fig. 18 in G.E. report GER-2007C.[8] The code will make the necessary expansion efficiency and exhaust loss corrections.

3.3 External Heat

Several features have been added to the PRESTO code to allow the user to model external steam or heat flows. These features include the extraction of process steam, the induction of steam at a turbine exhaust or feedwater heater extraction line, and feedwater heating by low-quality external heat. These options allow design flexibility and are often desired to improve the overall efficiency of an energy conversion system. Such systems may combine the steam-turbine cycle with a high-temperature topping cycle or integrate it with an advanced heat source. Cogeneration cycles may be modeled using the steam extractions available.

As discussed in Sects. 3.3.1 and 3.3.4, steam may be inducted to or extracted from the feedwater heater extraction lines and at the HP and IP turbine exhausts. The condensate of any extracted steam may be returned to any feedwater heater shell (Sect. 3.3.3) or to the condenser (Sect. 3.3.6). An induction steam flow may be balanced by removing condensate from any feedwater heater shell or the condenser. External feedwater flow paths are discussed in Sect. 3.3.5, which allow the addition of external heat in parallel with one or more regenerative feedwater heaters.

The second example case in Sect. 5 demonstrates most of these PRESTO options.

3.3.1 Extraction lines

Steam may be added to or removed from any feedwater heater extraction line. If steam is added, its enthalpy must be specified. If the steam is removed, the code will set the enthalpy equal to that of the extraction steam. Variables QEXT and HEXT represent the flow in pounds per hour and the enthalpy in British thermal units per pound.

3.3.2 Parallel or series heat input

External heat may be directly added to or removed from the feedwater heating string. Heat may be added between any two feedwater heaters and after the highest pressure heater or in parallel with any feedwater heater. Variables EXTSER (series) and EXTPAR (parallel) are specified in British thermal units per hour.

3.3.3 Feedwater heater shells

Condensate or steam may be returned to any feedwater heater shell, and the enthalpy must be given for each of these flows. If two or more flows are input to the same shell, the user must calculate the total flow and mixed enthalpy. Condensate may also be removed from any feedwater heater shell, in which case the enthalpy is set equal to the feedwater heater shell drain enthalpy by the code. QECOND is in pounds per hour and HECOND is defined as British thermal units per pound.

3.3.4 Turbine exhaust

Process steam may be drawn from the HP or IP exhaust, and it is not necessary to define the enthalpy for these steam extractions. If, however, you wish to induct steam at these points, both the flow and the corresponding enthalpy must be specified. Inducting steam between the IP and LP sections when there is not a second reheater will introduce a 2 to 3% error in the overall heat rate. This is due to the use of two expansion lines rather than the single IP-LP reheat line required in G.E. report GER-2007C[8] and the resulting use of improper turbine efficiency calculations. Variables QPROSS (pounds per hour) and HPROSS (British thermal units per pound) define both process and induction steam flows and enthalpies.

3.3.5 External feedwater flows

Feedwater may be drawn from or added to the feedwater heating string between any two feedwater heaters and after the highest pressure feedwater heater. If feedwater is taken from the line, its enthalpy is set equal to the feedwater enthalpy leaving the previous heater. If feedwater is added, the user must specify its enthalpy. The condensate return from an extracted steam flow may be added to the feedwater in this manner. The variables QFWEXT (pounds per hour) and HFWEXT (British thermal units per pound) specify these flows.

3.3.6 Unbalanced flows

Any flows left unbalanced by the user will be automatically balanced in the condenser. Excess flow (from a steam or water induction source) is removed at the condensate enthalpy. Makeup flow will be added to the condenser and also at the condensate enthalpy.

3.3.7 Results and error checks

When the results are printed out, the user is given each external flow and its enthalpy as well as the total external heat applied to the system.

It is possible that an external heat input would be inappropriate for the turbine cycle model being studied. Since the feedwater enthalpy leaving each feedwater heater is fixed by the extraction pressure and terminal temperature difference, any external heat applied must be of a reasonable magnitude. Problems will occur any time an external source attempts to add an amount of heat equal to the original feedwater heater duty. An external source, improperly sized or misapplied, could cause a negative steam flow through an extraction line (actually inducting steam directly into the turbine), or it could force feedwater to flow backwards through the feedwater heater string.

The code will check for these conditions and either make proportional corrections or disallow the external source. In such a case, the user will receive a warning message to let him know the results printed do not reflect the input data he specified. The user should then review the model and make the necessary alterations. In cases where a negative extraction flow was flagged, the user may wish to replace the feedwater heater involved with an external heater in series, using the variable EXTSER. See Sect. 5 for an example of this situation.

4. DATA INPUT INSTRUCTIONS

4.1 Input Data Format

Data is read into the program through two namelists, NAME and NAME2. The first namelist contains all the basic cycle configuration information as well as thermodynamic parameters. The second namelist contains external feedwater heating options discussed in Sect. 3. All variable names follow the standard convention for integers and real numbers. I, J, K, L, M, and N are integer indicators if they are the first letter in a variable name. Real variables should be entered with a double-precision format.

Each data input set representing a turbine cycle model must consist of at least two data cards. The first card image is read as a comment card. The contents of this comment card will be printed as the case title on each page of the computer output. The second, and more as required, card image(s) will be read as the data namelist, NAME, following standard Fortran Namelist conventions. If the optional namelist, NAME2, is included, its card image(s) must immediately follow those of the first namelist.

Multiple-case runs are possible if the title comment card is inserted between each set of namelists. Any variable not reset by the user will retain its last value from the previous case. This is a useful feature for parametric studies where the user may wish to change only a few variables each time.

4.2 Minimum Required Data

Several major cycle parameters have no default value. If these variables (listed in Table 4.1) are not defined by the user, the case will most likely fail. For a cross-compound case, the user must add NLP2, GC2, and WRATE2.

Table 4.1. Variable definitions for minimum required data

GC	Generator capability, MVA
GC2[a]	Second shaft generator capability, MVA
ND	Feedwater heater drain types
NDC	Drain cooler flags
NF	Total number of feedwater heaters
NFH	Number of extractions from HP turbine
NFI	Number of extractions from IP turbine
NFL	Number of extractions from LP turbine
NLP2[a]	Number of turbine sections on second shaft
PE	Extraction stage pressures, psia
PT	Throttle steam pressure, psia
PXLP[b]	Condenser pressure, psia
PXLPI[b]	Condenser pressure, in. Hga
QGEN	Specified steam generator outlet steam flow, lb/hr
QT	Estimated throttle steam flow, lb/hr
QTD	Design throttle steam flow, lb/hr
TT	Throttle steam temperature, °F
WRATE	Electrical output (MWe) required or estimated
WRATE2[a]	Electrical output (MWe) from second shaft

[a]Cross-compound cases only.
[b]PXLP or PXLPI, but not both, must be input.

4.3 Custom-Made Default Cycle

If a user plans to make extensive parametric studies with a single turbine cycle, it may prove desirable to develop a new BLOCK DATA subroutine containing default values for every input variable. None of the variables presently in BLOCK DATA may be eliminated, but their values may be changed to represent another cycle. The variables listed in Table 4.1 as having no default values may easily be added since they are already represented in the appropriate commons.

4.4 Variable Definitions

The following is a list of the variable names in namelist NAME with a short description of each variable's function. Table 4.2 is a concise summary of all the variable names, default values, and short definitions.

Table 4.2. Variable definitions and default values for all input parameters

Variable name	Default value	Definition
BLS	30.1	Length of last stage blades LP section, in.
CP1	171.7	Pressure at the feedwater pump inlet, psia
CP2	1.30	Ratio of feedwater pump discharge pressure to HP turbine throttle pressure
EFM	0.90	Feedwater pump motor-drive efficiency
EFP	0.84	Feedwater pump isentropic efficiency
EFT	0.81	Feedwater pump turbine efficiency
EXTPAR	12*0.0	External heat supplied parallel to a feedwater heater, Btu/hr
EXTSER	12*0.0	External heat supplied downstream of heater No. N, Btu/hr
GC	None	Generator capability, MVA
GC2	None	Second shaft generator capability, MVA
HECOND	13*0.0	Enthalpy of external flow to a feedwater heater shell, Btu/lb
HEXT	12*0.0	Enthalpy of steam added to a feedwater heater extraction steam line, Btu/lb
HFWEXT	12*0.0	Enthalpy of external feedwater flow, Btu/lb
HPROSS	2*0.0	Enthalpy of steam inducted at a turbine exhaust, Btu/lb
ICC	0	Generator cooling method = 0, conductor cooled = 1, conventionally cooled
IFPT	1	Feedwater pump drive = 0, motor driven = 1, turbine driven

Table 4.2 (continued)

Variable name	Default value	Definition
IMETER	0	Output format choice = 0, English units = 1, metric units
INAME2	0	Flag to read second namelist = 0, NAME2 is not read = 1, NAME2 is read
IP	2	Feedwater pump location indicator = 0, after feedwater heater No.1 = N, before feedwater heater No. N
IPEAK	0	Flag for peaking unit = 0, normal operation = 1, peaking unit
IPLACE	2	Feedwater pump turbine extraction position = 1, before IP turbine bowl = 2, before LP turbine bowl
IRHP	3600	Rotational speed of HP turbine, rpm
IRIP	3600	Rotational speed of IP turbine, rpm
IRLP	3600	Rotational speed of LP turbine, rpm
LK	1	= 0, leakages will not be calculated = 1, leakages will be calculated
NCASE	0	Turbine casing flag = 0, no shared casings = 1, HP-IP casings shared = 2, HP-LP casings shared = 3, IP-LP casings shared
ND	None	Feedwater heater drain types = 0, flashed drain = 1, pumped drain
NDC	None	= 0, no drain cooler section on feedwater heater = 1, drain cooler section

Table 4.2 (continued)

Variable name	Default value	Definition
NF	None	Total number of feedwater heaters
NFH	None	Number of feedwater heaters receiving extraction steam from the HP section
NFI	None	Number of feedwater heaters receiving extraction steam from the IP section
NFL	None	Number of feedwater heaters receiving extraction steam from the LP section
NHP	1	Number of parallel HP sections
NIP	1	Number of parallel IP sections
NLP	4	Number of parallel LP sections
NLP2	0	Number of parallel LP turbine sections on a second, cross-compound, shaft
NOSPE	1	= 0, no steam packing exhauster = 1, steam packing exhauster included
NRGS	1	Number of governing stage blade rows
NRH	1	Number of external reheat stages
NSHAFT	3	Number of turbine sections in series, 1, 2, or 3
PBIP	633.	Bowl pressure at the IP section, psia
PBLP	177.	Bowl pressure at the LP section, psia
PCMU	0.0	Feedwater makeup rate, %
PDGS	40.	Pitch diameter of governing stage, in.
PDLS	85	Pitch diameter of last stage LP section, in.
PE	None	Extraction stage pressures, psia
PF	0.90	Generator power factor
PT	None	Throttle steam pressure, psia

Table 4.2 (continued)

Variable name	Default value	Definition
PXDROP	3., 6.	Extraction line pressure drop, %
PXLP	Dummy	Main condenser pressure, psia
PXLPI	Dummy	Main condenser pressure, in. Hga
QAE	0.0	Steam flow to steam-jet air ejector
QCR	0.0	Condensate flow bypassed to the steam generator
QECOND	13*0.0	Steam or condensate returned to a feedwater heater shell, lb/hr
QEXT	12*0.0	Steam added to a feedwater heater extraction line, lb/hr
QFWEXT	12*0.0	External feedwater flow added after feedwater heater No. N, lb/hr
QGEN	None	Specified steam generator outlet flow, lb/hr
QPROSS	2*0.0	Process or induction steam at a turbine exhaust, lb/hr (1) HP turbine exhaust (2) IP turbine exhaust
QT	None	Estimated throttle steam flow, lb/hr
QTD	None	Design throttle steam flow, lb/hr
TDCA	2*10., 0., 3*10., 6*0.	Drain cooler approach temperature difference, °F
TRH1	1000.	Exit temperature of first stage reheater, °F
TRH2	0.0	Exit temperature of second stage reheater, °F
TT	None	Throttle steam temperature, °F
TTD	3*0., 4*5, 5*0.	Feedwater heater terminal temperature difference, °F
WRATE	None	Electrical output (MWe) required or estimated
WRATE2	None	Electrical output (MWe) from second shaft

4.4.1 BLS

BLS is the last stage blade (or bucket) length in inches with a default value of 30.D0. Turbines of 3600 rpm will have blade lengths ranging from 20 to 33.5 in., while 1800-rpm units vary from 38 to 52 in. Table 4.3 shows the corresponding last stage pitch diameter (PDLS) for each last stage blade length. The longer blade lengths give a lower exhaust loss and heat rate at full load but have a higher capital cost. The shorter blade lengths require less capital investment but cause a relatively higher exhaust loss at full load. These shorter blades are better suited for low load conditions. The exhaust loss curves of Fig. 16, 17, and 18 in G.E. report GER-2007C[8] show that the exhaust loss reaches a minimum at an annulus velocity that is a function of the last stage design. Below this velocity, the exhaust losses increase rapidly so that the blade length must be properly matched to the anticipated loading conditions. Page 5 of G.E. report GET-2050C[10] shows the maximum allowable exhaust flow (lb/hr per row of last stage blades) at valves-wide-open (VWO) design flow, 5% over pressure, and an exhaust pressure of 3.5 in. Hga.

Table 4.3. BLS and PDLS

	3600 rpm					
Last stage bucket length, in.	20	23	26	30	33.5	20[a]
Pitch diameter, in.	60	65.5	72.125	85	90.5	75
	1800 rpm					
Last stage bucket length, in.	38	38	43	52		
Pitch diameter, in.	115	127.5	132	152		

[a]High back-pressure units only.

Typical exhaust losses [the difference between the expansion line end point (ELEP) and the used energy end point (UEEP)] will be 20 to 30 Btu/lb at normal exhaust pressures and will be lower for elevated back pressures.

4.4.2 CP1, CP2

CP1 and CP2 define the feedwater pump operating conditions. CP1 is the pressure at the feedwater pump inlet with a default value of 171.7 psia. This value should be set equal to the shell pressure of the deaerating heater in most cases. Pumping power is calculated only for this main feedwater pump; therefore, the user should adjust the net output for other auxiliaries which may include condensate pumps, circulating water pumps, booster pumps, and drain pumps.

CP2 is the ratio of feedwater pump discharge pressure to HP turbine throttle pressure. The default value for CP2 is 1.30 (dimensionless). A change in CP2 from 1.30 to 1.25 decreased the net heat rate of the first example case by 8 Btu/kWhr.

Other input parameters which influence the feedwater pump model are EFM, EFP, and EFT, the drive motor efficiency, pump efficiency, and turbine efficiency respectively. Other variables involved are IFPT, the drive mode selection; IP, the pump position; and IPLACE, which chooses the steam extraction point for a turbine-driven feedwater pump.

4.4.3 EFM

EFM is the motor-drive efficiency for motor-driven feedwater pumps. The default value is 0.90D0. Other feedwater pump parameters are listed in Sect. 4.4.2.

4.4.4 EFP

EFP is the feedwater pump isentropic efficiency with a default value of 0.84. A decrease in pump efficiency of 10% raises the heat rate of the first example case by 21 Btu/kWhr (approximately 0.3%) as an indication of the code's sensitivity to this variable. Other feedwater pump parameters are listed in Sect. 4.4.2.

4.4.5 EFT

EFT is the turbine efficiency for a turbine-driven feedwater pump. If the default value of 0.81 is increased by 10%, the net heat rate of the first example case will only decrease by approximately 0.3%. Other feedwater pump parameters are listed in Sect. 4.4.2.

4.4.6 GC, GC2

GC is the generator capability in megavolt-amperes and has no default value. For a cross-compound configuration, GC is the sum capability of both generators, and GC2 is the generator capability in megavolt-amperes of the second, or LP generator. A lower-limit estimate of the generator capability is the electrical output, at valves-wide-open (VWO) design flow (i.e., QT = QTD), divided by the generator power factor.

In cases where the steam generator outlet flow, QGEN, is provided as input data, there is no direct method of selecting generator capability without making two runs. Until the electrical output is known, it cannot be divided by the power factor to obtain the generator capability. Until the generator capability is known, the electrical output cannot be precisely determined. One should make a VWO run (by setting QT = QTD and QGEN = QT + QAE in the input data), determine electrical output with the assumed generator capability, and then rerun the case with a corrected capability.

For cross-compound turbines, the problem becomes more severe because it is difficult to estimate the power split between the two generators. It is desirable to have nearly equal electrical output for each generator; this can only be achieved by a second run adjusting GC and GC2 and also by increasing or decreasing the LP turbine bowl pressure and/or the IP turbine bowl pressure.

4.4.7 ICC

ICC is used to flag the generator cooling method. ICC = 0 (default) calls for a conductor-cooled generator, while ICC = 1 defines a conventionally cooled one.

Figures 20 and 23 in G.E. report GER 2007-C [8] show conventionally cooled generators used for generator ratings up to 300 MVA for 3600 rpm and 400 MVA for 1800 rpm. Conductor cooling is shown for generators with ratings above 200 MVA. If the user chooses a generator combination outside these limits, the code will extrapolate the curve and print a warning message before continuing to completion.

4.4.8 IFPT

The user has the option of specifying motor-driven (IFPT = 0) or turbine-driven (IFPT = 1) feedwater pumps. The default value is 1, a turbine-driven feedwater pump. In the absence of other information, it is suggested that motor-driven feedwater pumps be used for cycles with an electrical output below 150 to 200 MWe (at throttle pressures of 1800 to 2400 psia), turbine-driven feedwater pumps be used above 400 or 500 MWe (at throttle pressures of 2400 or 3500 psia), and either drive may be selected in the intermediate range. It should be noted that turbine drive shows a significant improvement in heat rate over motor drive. When the example case was changed to motor drive, the heat rate increased by 37 Btu/kWhr or 0.5%. Provisions for shaft-driven pumps are not included.

Other parameters describing the feedwater pump are listed in Sect. 4.4.2.

4.4.9 IMETER

IMETER is a flag which will, if set equal to one, cause the case results to be printed out in metric units. The default value of IMETER is zero.

4.4.10 INAME2

INAME2 is a flag which, if set equal to one, will cause the namelist NAME2 to be read. The default value of INAME2 is zero, that is, NAME2 will not be read unless the flag is set equal to one. Read Sect. 3.3 as well as the data input descriptions in Sects. 4.5–4.6 for instructions on using this optional feature.

4.4.11 IP

IP indicates the feedwater pump location. IP = 0 places the pump after feedwater heater No. 1 (the highest pressure feedwater heater). IP = N places the pump before feedwater heater No. N. Reference to typical heat-balance diagrams or flow schematics for similar cycles may provide the best guide for normal practice in locating the feedwater pump. If a deaerating heater is used as a means of boiling condensate to eliminate entrained gases, the feedwater pump suction might best be taken from this heater. The default value of IP is 2. Other variables related to the feedwater pump are listed in Sect. 4.4.2.

4.4.12 IPEAK

IPEAK is a flag set equal to one to signal a peaking unit. The default value of IPEAK is zero. For a further discussion of peaking units, refer to Sect. 3.1.

4.4.13 IPLACE

IPLACE enables the user to position the feedwater pump turbine steam extraction point. If IPLACE = 1, the extraction is just before the IP turbine bowl; if IPLACE = 2 (the default value), the steam is taken from the crossover just before the LP turbine bowl. For a motor-driven feed pump (IFPT = 0), IPLACE need not be set. Other variables related to the feedwater pump are listed in Sect. 4.4.2.

4.4.14 IRHP, IRIP, IRLP

IRHP, IRIP, and IRLP are the rotational speeds (3600 or 1800 rpm) of the HP, IP, and LP turbine sections with default values of 3600. IRHP and IRIP should be 3600 rpm for the range of cycles covered by this code. In the case of split LP sections (in a cross-compound configuration), give the speed of the second shaft for IRLP.

4.4.15 LK

LK is a flag. The default value of 1 will cause leakage calculations to be performed. If the user wishes to suppress this option, a value of zero should be entered; this will cause the heat rate to improve by approximately 0.5%.

The leakage flows are modeled after Table II in G.E. report GER-2007C [8] and are arranged in an array of 21 possible combinations. Their pressures and destinations vary with the turbine configurations. Table 4.4 identifies the leakage numbers with their locations. The lowest number in each group corresponds to the first leakage flow, this is the one closest to the turbine and having the highest pressure.

Table 4.4. Steam leakage locations

Leakage number	Location
1–4	HP Bowl (governing stage shell)
5–7	HP Shell
8–11	IP Bowl
12–14	IP Shell
15–17	LP Bowl
18	LP Shell
19–21	Throttle valve stem

4.4.16 NCASE

NCASE is a flag used by the leakage subroutines to describe the physical arrangement of the turbine sections. If each section stands alone (as in the default case), there are separate casings and NCASE = 0. NCASE equals one if the HP-IP turbines are housed together in a single casing, two for an HP-LP single casing, and three if the IP-LP turbines share a single casing. If leakage calculations are not made (LK is set equal to zero), NCASE need not be set.

4.4.17 ND

ND is an array of twelve flags used to define the feedwater heater arrangements and has no default value. If ND(L) is set equal to zero, the feedwater heater No. L will have a flashed drain configuration. If

ND(L) equals one, the feedwater heater drain will be pumped forward. Generally, flashed drains should be selected for all but the deaerating feedwater heater and perhaps the lowest pressure feedwater heater. Flashing these last drains to the condenser rather than pumping them forward makes a difference of only 2 Btu/kWhr to the net heat rate in the first example case. The increased operating problems with pumped drains are likely to more than offset this slight improvement in heat rate. A deaerating heater is specified by setting ND equal to one and TTD equal to zero. A list of related feedwater heater parameters is included in Sect. 4.4.19.

4.4.18 NDC

NDC is an array of 12 flags indicating a drain cooler section (NDC = 1) or no drain cooler section (NDC = 0) for each possible feedwater heater. There are no default values for this array; the user is required to define NDC for each feedwater heater.

A feedwater heater with a pumped drain should not have a drain cooler section. Drain coolers are recommended for all desuperheating-type feedwater heaters. The drain cooler approach temperature difference, TDCA, should be specified for each drain cooler. Other related feedwater heater parameters are listed in Sect. 4.4.19.

4.4.19 NF

NF (no default value) is the total number of feedwater heaters and must be specified. To define the arangement of the feedwater heater train, the following variables must be given: ND (drain type); NDC (drain cooler flag); NF; NFH (the number of feedwater heaters fed from the HP turbine section); NFI (the number of feedwater heaters from the IP section); NFL (the number of feedwater heaters from the LP section); PE (extraction stage pressures); TDCA (drain cooler approach temperature difference); and TTD (terminal temperature difference). The feedwater heaters are numbered from the highest pressure (1) to the lowest pressure (NF).

4.4.20 NFH

NFH identifies the number of feedwater heaters receiving extraction steam from the HP turbine section. NFH has no default value and must be specified by the user. The sum of NFH, NFI, and NFL should equal NF. See Sect. 4.4.19 for a list of related feedwater heater parameters.

4.4.21 NFI

NFI is the number of feedwater heaters receiving extraction steam from the IP turbine section. NFI has no default value and must be specified by the user. The sum of NFH, NFI, and NFL should equal NF. Refer to Sect. 4.4.19 for a list of related feedwater heater parameters.

4.4.22 NFL

NFL represents the number of feedwater heaters receiving extraction steam from the LP turbine section. NFL has no default value and must be specified by the user. The sum of NFH, NFI, and NFL should equal NF. Refer to Sect. 4.4.19 for a list of related feedwater heater parameters.

4.4.23 NHP

NHP is the number of parallel HP turbine sections with a default value of one.

4.4.24 NIP

NIP represents the number of parallel IP turbine sections and has a default value of one. Double-flow (NIP = 2) turbines are not common but are used occasionally.

4.4.25 NLP

NLP is the number of parallel LP turbine sections and will normally be an even number. The default value of NLP is 4. TC4F is a standard manner of denoting a four-flow LP turbine section on a tandem-compound machine. For such a case, NLP should be set equal to four. If a cross-compound turbine cycle is being modeled, NLP is the total of the parallel flow LP turbines on both shafts, while NLP2 represents only those on the second shaft.

4.4.26 NLP2

NLP2 is the major flag for a cross-compound configuration and equals the number of LP turbine sections on the second shaft. If NLP2 is equal to zero (default value), all cross-compound calculations are skipped, and a tandem configuration is assumed. Generator capability is the major factor in selection of cross-compound turbines. Above approximately 950 MWe, single 3600-rpm generators are not commercially available in the United States, and consideration must be given to cross-compound turbines. Cross-compound turbine generators may be 3600/1800 rpm or 3600/3600 rpm. The weight of an 1800-rpm generator may be 2.5 times that of a 3600-rpm generator. A cross-compound unit does have the advantage of a simpler control system than the duplicate controls required for two tandem-compound turbine generators. A tandem-compound turbine generator is much more economical, easier to operate, and cheaper to install than a cross-compound unit of equivalent rating. A cross-compound unit should place approximately 50% of the electrical load on each generator when operated at design conditions.

4.4.27 NOSPE

NOSPE is a flag which, if set equal to one, places a steam packing exhauster between the condenser and the last feedwater heater. If this is not desired, NOSPE should be set equal to zero.

The default value of NOSPE is one. Dropping the steam packing exhauster from the first example case caused the gross heat rate to increase by only 0.01%.

4.4.28 NRGS

NRGS represents the number of blade rows in the governing stage. One-row governing stages (as in the default case) are most often used. Although two-row machines (NRGS = 2) are not common, their efficiency does not drop off as fast with load as a turbine with a one-row governing stage. For this reason, a baseload unit is sometimes equipped with a two-row wheel to ensure high efficiency over a broad range of operating conditions.

4.4.29 NRH

NRH represents the number of reheaters in the turbine cycle. NRH has a default value of one and can be set equal to a zero or two. A double reheat (NRH = 2) is normally applied only to a supercritical cycle with an output greater than 600 MWe.

4.4.30 NSHAFT

NSHAFT indicates the number of turbine sections in series. A turbine cycle with HP, IP, and LP turbines is a three-section machine (NSHAFT = 3). Except at low throttle pressures below 1000 psia, an NSHAFT value of three (default value) is normal. An HP-LP turbine cycle would have NSHAFT = 2, and a turbine cycle with only an LP section would have NSHAFT = 1. The user must be careful to follow these conventions when naming the corresponding feedwater heaters, that is, a one-section turbine cycle must have NFH and NFI equal to zero.

4.4.31 PBIP

PBIP is the pressure (psia) at the bowl of the IP turbine section. Generally, the ratio of HP exhaust pressure to throttle pressure for single reheat turbine cycles ranges from 22 to 27% at throttle pressures between 1800 and 2500 psig. That, coupled with the assumed 10% reheater and 2% intercept value pressure drops, gives a PBIP:PT ratio of approximately 22%.

The default value of PBIP is 633.D0 psia, which corresponds to the first example case in Appendix A.

4.4.32 PBLP

PBLP is the pressure (psia) at the bowl of the LP turbine section. Single reheater, three-section, turbine cycles will have a PBLP:PT ratio of roughly 5%. For a double reheater, 3500-psig throttle pressure turbine cycle, the ratio will be approximately 10%. For a one-section machine, PBLP should be identified as PT by the user.

The default value of PBLP is 177.D0 psia, which corresponds to the first example case in Appendix A.

4.4.33 PCMU

PCMU is the feedwater makeup rate as a percentage of throttle flow. PCMU has a default value of zero.

4.4.34 PDGS

PDGS is the pitch diameter (in inches) of the governing stage. Figure 7 of G.E. report GER-2007C[8] shows these diameters ranging from 30 to 46 in. Increasing the diameter of the governing stage decreases the full-load efficiency but is of some benefit at light loads. Since the code is relatively insensitive to changes in PDGS, the default value (40.D0) will be satisfactory for most work. Unless the cycle being evaluated has a turbine of known governing stage pitch diameter, no change is necessary.

4.4.35 PDLS

PDLS is the pitch diamter of the LP turbine's last stage with a default value of 85.D0. A 3600-rpm turbine will have a PDLS ranging from 60 to 90.5 in., while an 1800-rpm turbine will go from 115 to 152 in. These values are related to the last stage blade length (BLS) in Table 4.3. See the discussion of last stage design in Sect. 4.4.1.

4.4.36 PE

PE is an array of 12 extraction pressures (psia), one for each possible feedwater heater, and has no default value. If an extraction point is located at a turbine exhaust, an extraction pressure of zero should be given. It is desirable to select extraction pressures that will result in approximately equal rises in condensate enthalpy across each feedwater heater. The temperature rise across a feedwater heater is typically in the range of 45 to 85°F although exceptions are common. In multisection turbines, it is desirable (because of a lower pressure drop) to make use of the turbine section exhaust for feedwater heating (by setting PE = 0.D0) as opposed to an additional turbine shell penetration. The highest pressure feedwater heater will usually receive its extraction steam from the cold reheat line, or HP turbine exhaust. There is a list of related feedwater heater variables in Sect. 4.4.19.

4.4.37 PF

PF is the generator(s) power factor. The default value of 0.90D0 is a commonly used value.

4.4.38 PT

PT is the throttle steam pressure (psia) and has no default value. PT will normally be in the range of 850 to 2400 psia for nonreheat cycles and 1450 to 2400 psia or 3200 to 3500 psia for reheat cycles. Pressures closer to the critical pressure tend to produce vapor/liquid separation problems in the steam generator. The PRESTO code will run over a continuous spectrum from very low to very high pressures.

Other related throttle variables are TT (temperature), QT (flow), and QTD (design flow).

4.4.39 PXDROP

PXDROP is an array of two extraction line pressure drops in percent. The first corresponds to the pressure drop from a turbine exhaust to a feedwater heater and has a default value of 3.D0%; the second represents the pressure drop from a turbine shell opening to a feedwater heater and has a default value of 6.D0%. An increase of 2% in each of these variables will cause a rise of 9 Btu/kWhr (0.1%) in the example case heat rate.

4.4.40 PXLP, PXLPI

PXLP represents the low-pressure turbine exhaust, or condenser, pressure in psia. PXLPI is the same pressure expressed in inches of mercury. The user must specify either or both of these values. If both are specified, PXLPI should equal PXLP multiplied by 2.03602234D0.

The default values for PXLP and PXLPI are dummy values used in comparison logic. If the user elects to replace the BLOCK DATA subroutine as mentioned before, PXLP and PXLPI must bear the correct relationship, and PXLPIO should be set equal to PXLPI. PXLPIO is an internal variable and is never input through namelist.

If PXLPI is greater than 5.DO, the cycle is considered a high back-pressure cycle. In this case, the user should refer to Sect. 3.2 for a brief discussion of high back-pressure units.

Recommended values of PXLPI range from 1.5 to 2.5 in. Hga for once-through cooling, 2.5 to 4.5 in. Hga for cooling ponds or wet cooling towers, and 8.0 to 15.0 in. Hga for dry cooling tower cycles.

4.4.41 QAE

QAE is a steam flow (lb/hr) extracted between the steam generator outlet and the turbine throttle for the steam-jet air ejector. QAE has a default value of 0 lb/hr.

4.4.42 QCR

QCR is a condensate flow (lb/hr) which bypasses the feedwater heating train and enters the steam generator. QCR has a default value of zero.

4.4.43 QGEN

QGEN is the required steam-generator outlet flow in pounds per hour. As pointed out in Sect. 2.13, the user may specify either a desired electrical output or the steam-generator outlet flow, QGEN. If QGEN is specified, the code will treat the electrical output, WRATE, as an estimate and use the appropriate convergence test in Fig. 2.8. QGEN has no default value and, if not specified, must be set equal to zero. QGEN differs from the throttle flow by only one term. The steam flow to the air ejectors, QAE, is extracted before the throttle. If this flow is zero, QGEN will equal QT.

For best control of the throttle flow ratio [QT/QTD = 1 for valves wide open (VWO), QT/QTD = 1/1.05 for maximum guaranteed], the user should set QGEN equal to QT plus QAE. The code will then calculate the electrical output, WRATE. The user should check this calculated electrical output against the estimated generator capability, GC. If they are not properly related (as discussed in Sect. 4.4.6), GC should be corrected and the case rerun. Note that an estimated value of WRATE must still be supplied by the user. For a good first estimate of WRATE, the user may divide QT by 7000, ±50%.

In the first example case in Sect. 5, at a constant low-pressure turbine exhaust pressure, the increase in electrical output from maximum guaranteed to VWO is about 3.2%.

4.4.44 QT, QTD

QT is the user-supplied estimated throttle flow (lb/hr), and there is no default value. If QT is set equal to the design throttle flow, QTD (lb/hr), the heat balance will be a VWO heat balance. For a maximum guaranteed case, QT should equal QTD/1.05. If a run has converged to the required electrical output, WRATE (i.e., QGEN is equal to zero), there is no assurance that the calculated QT will still bear the correct relationship to QTD for the correct percentage of valves-wide-open generation. It may then be necessary to reset QT and QTD and rerun the case. The user may, however, elect to fix QT by setting the variable QGEN, as discussed in Sect. 4.4.43.

It is possible to estimate QT for a first run by multiplying the required electrical output in megawatts, WRATE, by 7000. Given this estimate ±50%, the code will converge toward the proper figure.

Other related throttle variables are PT, throttle pressure, and TT, the throttle temperature.

4.4.45 TDCA

TDCA is an array of 12 drain cooler approach temperature (°F) differences corresponding to the 12 possible feedwater heaters. The default value set is 2*10.D0, 0.D0 3*10.D0, and 6*0.D0. TDCA is the difference between the feedwater heater drain and the feedwater inlet temperatures and must be specified for each feedwater heater having a drain cooler section.

Changing all drain cooler approach temperature differences in the first example case from 10 to 15°F made a difference of only 2 Btu/kWhr in the net heat rate.

Other related feedwater heater parameters are listed in Sect. 4.4.19.

4.4.46 TRH1, TRH2

TRH1 and TRH2 are the exit temperatures (°F) of reheaters following the HP and IP turbine sections respectively. TRH1 has a default value of 1000.D0, and TRH2 is preset to zero. When TT and TRH1, in the example case, were each raised 50°F, the net heat rate decreased by 2%.

NRH is a related variable.

4.4.47 TT

TT is the throttle steam temperature (°F) and has no default value. TT will normally be in the range of 900 to 1050°F for large steam-turbine-generator units classed as fossil types. While the code will run to completion well outside this range, lower temperatures may indicate that ORCENT II[4] (the heat balance code for nuclear-type cycles) might be a more appropriate code to use. A 50°F reduction in throttle and reheat temperatures caused a 2% increase in the example case heat rate.

Related throttle variables are PT (pressure), QT (flow), and QTD (design flow).

4.4.48 TTD

TTD is an array of 12 feedwater heater terminal temperature differences in degrees Fahrenheit and has a default value set of 3*0.D0, 4*5.D0, and 5*0.D0. The code will accept feedwater heater terminal temperature differences which are positive, zero, or negative. With a negative terminal temperature difference, that is, a feedwater outlet temperature greater than saturation temperature at the feedwater heater shell pressure, the user must be sure there is no pinch between the steam and feedwater temperature profiles.

A direct contact or deaerating feedwater heater is specified by letting TTD equal zero and ND equal one. For a list of related feedwater heater parameters, see Sect. 4.4.19.

4.4.49 WRATE, WRATE2

WRATE is the net electrical output (MWe) required from the turbine cycle under study. The net electrical output for a cycle with a turbine-driven boiler feed pump is equal to the total shaft work minus the electrical and mechanical losses. If the boiler feed pump has a motor drive, this pumping power is also subtracted from the shaft work. For a cross-compound configuration, WRATE is the total output, and WRATE2 is the generation (MWe) of the second (or LP) generator. These variables have no default values. WRATE must always be specified by the user. WRATE2 must be specified any time NLP2 is greater than zero.

If the steam-generator outlet flow, QGEN, is specified, WRATE becomes an estimate rather than a fixed value but must still be input by the user.

4.5 Introduction to the NAME2 Variables

The namelist NAME2 is used only for cycles with external steam, feedwater, or heat flows. These features are discussed in Sect. 3.3. To access this second namelist, the flag variable, INAME2, must be set equal to one in the namelist, NAME. Refer to Sect. 3.3 and its subsections before attempting to use namelist, NAME2.

4.6 NAME2 Variable Definitions

Following is a list of the variable names in namelist NAME2 with a short description of each variable's function.

4.6.1 EXTPAR

EXTPAR is used to add or remove heat (Btu/hr) in parallel with any feedwater heater. If EXTPAR has a negative value, heat will be removed from the feedwater heater. For example, if there were 15,000 Btu/hr available for feedwater heating at a proper temperature for the third feedwater heater, the input data would be EXTPAR(3) = 15.D3. In a similar manner, if it is desirable to remove heat for an external process or storage, the data input could be EXTPAR(3) = −15.D3. The array EXTPAR has a default value set of 12 zeros.

4.6.2 EXTSER

EXTSER is like EXTPAR but is applied in series, or between two feedwater heaters, rather than in parallel. EXTSER(1) acts between the highest pressure feedwater heater and the steam generator. EXTSER(4) acts between feedwater heaters 3 and 4. EXTSER is also specified in British thermal units per hour and has the default value set of 12*0.D0.

4.6.3 HECOND

HECOND is the enthalpy (Btu/lb) of steam or condensate added to or removed from a feedwater heater shell or the condenser. HECOND(L) must be specified for each positive QECOND(L). The user is not required to define HECOND(L) if flow is being removed from the shell, that is, if QECOND(L) is negative. In these cases, the code will automatically set the enthalpy equal to the shell drain enthalpy. HECOND has the default value set of 13*0.D0.

4.6.4 HEXT

HEXT is the enthalpy (Btu/lb) of steam added to or removed from a feedwater heater extraction steam line. If steam is removed [QEXT(L) is less than zero], HEXT(L) will automatically be set equal to the extraction steam enthalpy. If steam is added [a positive QEXT(L)], the enthalpy HEXT(L) must be given by the user. The default values of HEXT are 12*0.D0.

4.6.5 HFWEXT

HFWEXT is the enthalpy (Btu/lb) of water added to or removed from the feedwater stream using variable QFWEXT. If water is removed from the system, the code will set its enthalpy equal to the feedwater enthalpy leaving the previous feedwater heater. If water is added, QFWEXT(L), the user must specify the corresponding enthalpy, HFWEXT(L). The array, HFWEXT, has a default value set of 12*0.D0.

4.6.6 HPROSS

HPROSS is the enthalpy (Btu/lb) of steam added to or removed from a turbine exhaust line using variable QPROSS for the flow rate. The code will set HPROSS equal to the in-line enthalpy if steam is removed. The user must specify HPROSS(L) for any positive QPROSS(L). The default values for the array HPROSS are 0.D0.

4.6.7 QECOND

QECOND is the flow (lb/hr) of condensate or steam added to or removed from a feedwater heater shell. If QECOND is negative, flow is removed from the shell, and if it is positive, flow is added. The enthalpy of each positive flow, QECOND(L), must be specified by HECOND(L). QECOND can be used to return steam extractions to the feedwater cycle and is often used to dump steam or condensate into the deaerating feedwater heater shell. The default value set of this array of 13 (12 feedwater heaters and the condenser) is 13 zeros.

4.6.8 QEXT

QEXT is the steam flow (lb/hr) added to (a positive value) or removed from (a negative value) a feedwater heater extraction steam line. The 12 values of the array, QEXT, will default to zero unless given as input data. The enthalpy, HEXT(L), must be given for each positive flow, QEXT(L). The enthalpy of a negative flow will be set equal to the extraction steam enthalpy by the code. If the user attempts to add more steam to the line than the feedwater heater can handle, the code will give an error message and adjust the input data.

4.6.9 QFWEXT

QFWEXT is used to add to (positive) or remove from (negative) feedwater (lb/hr) between two feedwater heaters or after the first feedwater heater. For example, QFWEXT(3) = –500.D0 would remove 500 lb/hr from the feedwater stream between feedwater heaters 2 and 3. QFWEXT(1) = 500.DO would add 500 lb/hr to the feedwater entering the steam generator. When water is added, its enthalpy must be specified using the variable HFWEXT. The default value set of the array QFWEXT is 12*0.DO.

4.6.10 QPROSS

QPROSS is a steam flow (lb/hr) removed from or inducted at a turbine exhaust. QPROSS(1) is located at the HP exhaust, and QPROSS(2) is at the IP exhaust. If QPROSS is greater than zero, steam is inducted, and its enthalpy must be specified with the corresponding HPROSS. A negative QPROSS represents an extraction flow, and its enthalpy is set by the code equal to the steam line mixed enthalpy (usually identical to the turbine exhaust enthalpy). The default values of QPROSS are both zero.

5. EXAMPLE CASES

5.1 Example Case No. 1 Description

The example case depicted in Fig. 5.1 is a supercritical, single-reheat power cycle typical of a modern baseload power plant. The turbine arrangement is tandem compound, that is, a single turbine-generator shaft, and the feedwater pump is turbine driven. Leakage flows are not shown in Fig. 5.1 but are calculated and described in Table VII of the example output in Appendix A. The case was run at valves-wide-open (VWO) design conditions.

The input data required to run the example case is illustrated by Fig. 5.2. Note the use of free form in the namelist, the variables may appear in any random order. The variables listed in this example are those identified as the "minimum required" in Sect. 4.2.

The first example is shown in two ways. The first entry calls for a given electrical output and lets the code calculate the steam-generator outlet flow. Note that the calculated throttle flow was very close to the specified design flow. If it had been significantly different, the user would have had to reset QTD and rerun the case. The next entry specifies the steam flow by setting QGEN, and the generator electrical output is calculated.

5.2 Example Case No. 2 Description

This second example case uses the first as its basis and demonstrates the external heating options described in Sect. 3.3. Figure 5.3 shows the cycle with the external flows symbolized by the capital letters A through G. Figure 5.4 contains the input data necessary to run this example. Note that the flag variable INAME2 was set equal to one, and the namelist, NAME2, followed immediately behind the first.

The symbols of Fig. 5.3 have the following corresponding entries in Fig. 5.4.

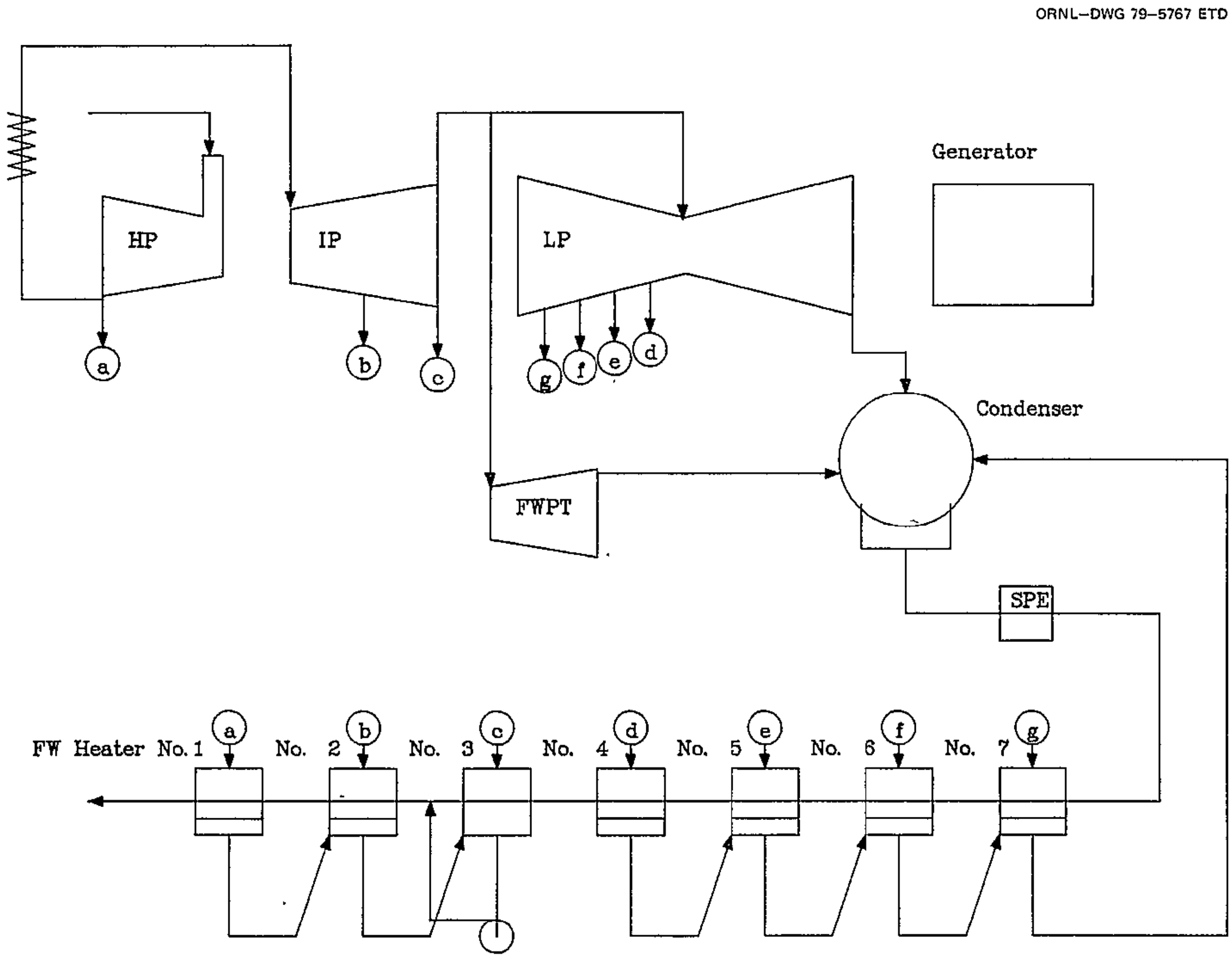


Fig. 5.1. Example problem No. 1.

ORNL–DWG 79–5768 ETD

TWELVE DIGIT LONG FORM

KEYPUNCHING INSTRUCTIONS
Punch only those cards containing data

BY

REMARKS

DATE

PAGE OF

CHARGE

REFERENCE

```
---EXAMPLE CASE NØ 1 WITH GENERATØR ØUTPUT SPECIFIED---
 $NAME  GC=717.DO, ND=0,0,1,9*0, NF=7,
 PE=0.DO,387.DO,0.DO,66.7DO,42.6DO,12.4DO,5.5DO,
 PT=3515.DO, QT=4357000.DO, TT=1000.DO,
 NDC=1,1,0,4*1, NFH=1, NFI=2, NFL=4,
 QTD=4357000.DO, QGEN= 0.DO, PXLPI=2.5DO, WRATE=645.DO $END
---SAME EXAMPLE CASE NØ 1 WITH STEAM FLØW SPECIFIED---
 $NAME QT=4357000.DO, QGEN=4357000.DO $END
```

Fig. 5.2. Input data for example problem No. 1.

ORNL-DWG 79-5769 ETD

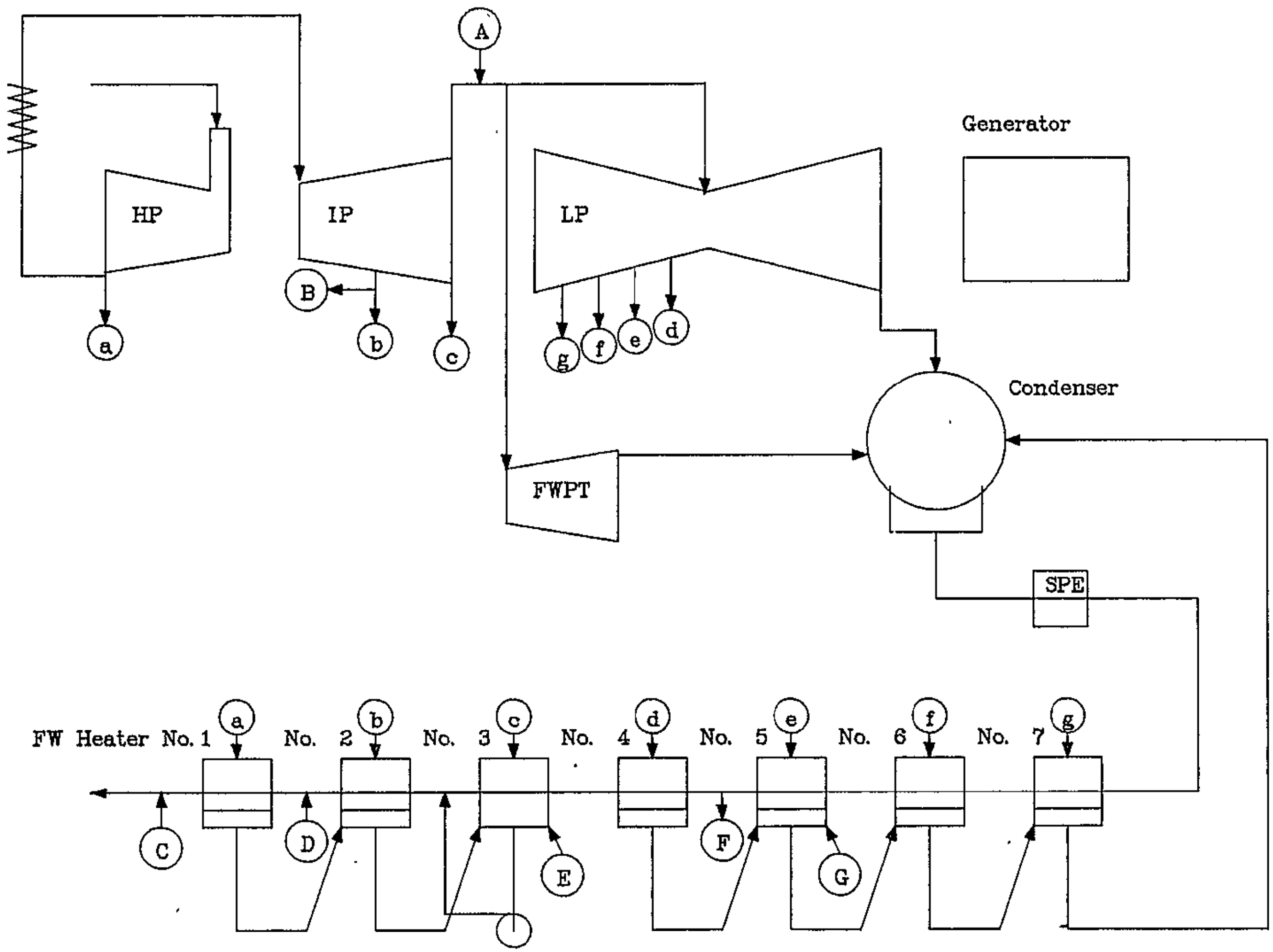


Fig. 5.3. Example problem No. 2.

ORNL–DWG 79–5770 ETD

TWELVE DIGIT LONG FORM

KEYPUNCHING INSTRUCTIONS
Punch only those cards containing data

BY

REMARKS

DATE

PAGE OF

CHANGE

REFERENCE

```
---EXAMPLE CASE NØ 2.---
$NAME GC=717.DO, ND=0,0,11,8*0, NF=7,
INAME2=1,
PE=0.DO,387.DO,0.DO,66.7DO,42.6DO,12.4DO,5.5DO,
PT=3515.DO, QT=4357000.DO, TT=1000.DO,
NDC=1,1,0,4*1, NFH=1, NFI=2, NFL=4,
QTD=4357000.DO, QGEN= 4357000.DO, PXLPI=2.5DO, WRATE=645.DO, $END
$NAME2 EXTPAR(5)=-10.D3, EXTSER(1)=15.D3,
QPRØSS(2)=6000.DO, HPRØSS(2)=1400.DO,
QECØND(3)=5000.DO, HECØND(3)=1000.DO,
QEXT(2)=-5000.DO,
QFWEXT(2)=7000.DO,0.,0.,-7000.DO,
HFWEXT(2)=430.DO, $END
```

Fig. 5.4. Input data for example problem No. 2.

```
A  QPROSS(2) =   6000.D0
   HPROSS(2) =   1400.D0

B  QEXT(2)   =  -5000.D0

C  EXTSER(1) =  15000.D0

D  QFWEXT(2) =   7000.D0
   HFWEXT(2) =    430.D0

E  QECOND(3) =   5000.D0
   HECOND(3) =   1000.D0

F  QFWEXT(5) =  -7000.D0

G  EXTPAR(5) = -10000.D0
```

Entry A represents 6000 lb/hr of steam with an enthalpy of 1400 Btu/lb inducted at the crossover before the LP bowl. The flow was left unbalanced by the user, and the code automatically removed 6000 lb/hr of condensate from the condenser hotwell.

Entries B and E show 5000 lb/hr steam removed from the second extraction line and returned at an enthalpy of 1000 Btu/lb to the shell of the third heater, which was also the deaerating heater in this example.

Entry C is an external heat input of 15,000 Btu/hr between the first feedwater heater and the steam generator.

Entries D and F represent 7000 lb/hr of condensate removed between heaters 4 and 5, heated externally, and returned between heaters 1 and 2 at an enthalpy of 430. Btu/lb.

Entry G shows the removal of 10,000 Btu/hr from the fifth feedwater heater. This amount is not included in the heater duty listed in Table IV of the example output in Appendix A.

5.3 Deleting a Feedwater Heater

If an error message, such as discussed in Sect. 3.3.7, is received when external heat is added, the user may wish to delete a feedwater heater.

This would involve renumbering the feedwater heaters and altering the following variables: ND, NDC, NF, NFH, NFI, NFL, PE, TDCA, and TTD to eliminate the data describing the replaced feedwater heater. The new series external heat input should bear the same subscript as the feedwater heater being deleted.

Figure 5.5 is an example case where external heat is added in parallel with the No. 4 regenerative feedwater heater. Given the following original input data:

```
ND = 0,0,1,0,0,0,0
NDC = 1,1,0,1,1,1,1
NF = 7
NFH = 1
NFI = 2
NFL = 4
PE = 0.,387.,0.,66.7,42.6,12.4,5.5
TDCA = 10.,10.,0.,4*10.
TTD = 3*0.,4*5.
EXTPAR(4) = 150.D6
```

Assume the user receives a warning message indicating that EXTPAR(4) was too large and was reduced to 53.D6. The heater duty listed for the fourth feedwater heater was 48.D6 Btu/hr. The user should then recognize that all of the available external heat cannot be applied to this position in the feedwater heating cycle. If the fourth feedwater heater is replaced by a series external heat input, the user may be able to add the total of 101.D6 Btu/hr between the two regenerative feedwater heaters. The altered input data would be:

```
ND = 0,0,1,0,0,0
NDC = 1,1,0,1,1,1
NF = 6
NFL = 3
PE(4) = 42.6, 12.4, 5.5
TDCA = 10., 10., 0., 3 * 10.
TTD =  3 * 0., 3 * 5.
EXTSER(4) = 101.D6 (=53.D6 + 48.D6)
```

There are still 49.D6 Btu/hr of external heat available. Depending upon the temperature profile, the user may try to apply this heat to any of the remaining feedwater heaters. Refer to Fig. 5.5 for a pictorial representation of the before and after cases. Tables 5.1–5.4 are Tables IV and IV-A from the computer output for this example case.

ORNL–DWG 79–5771 ETD

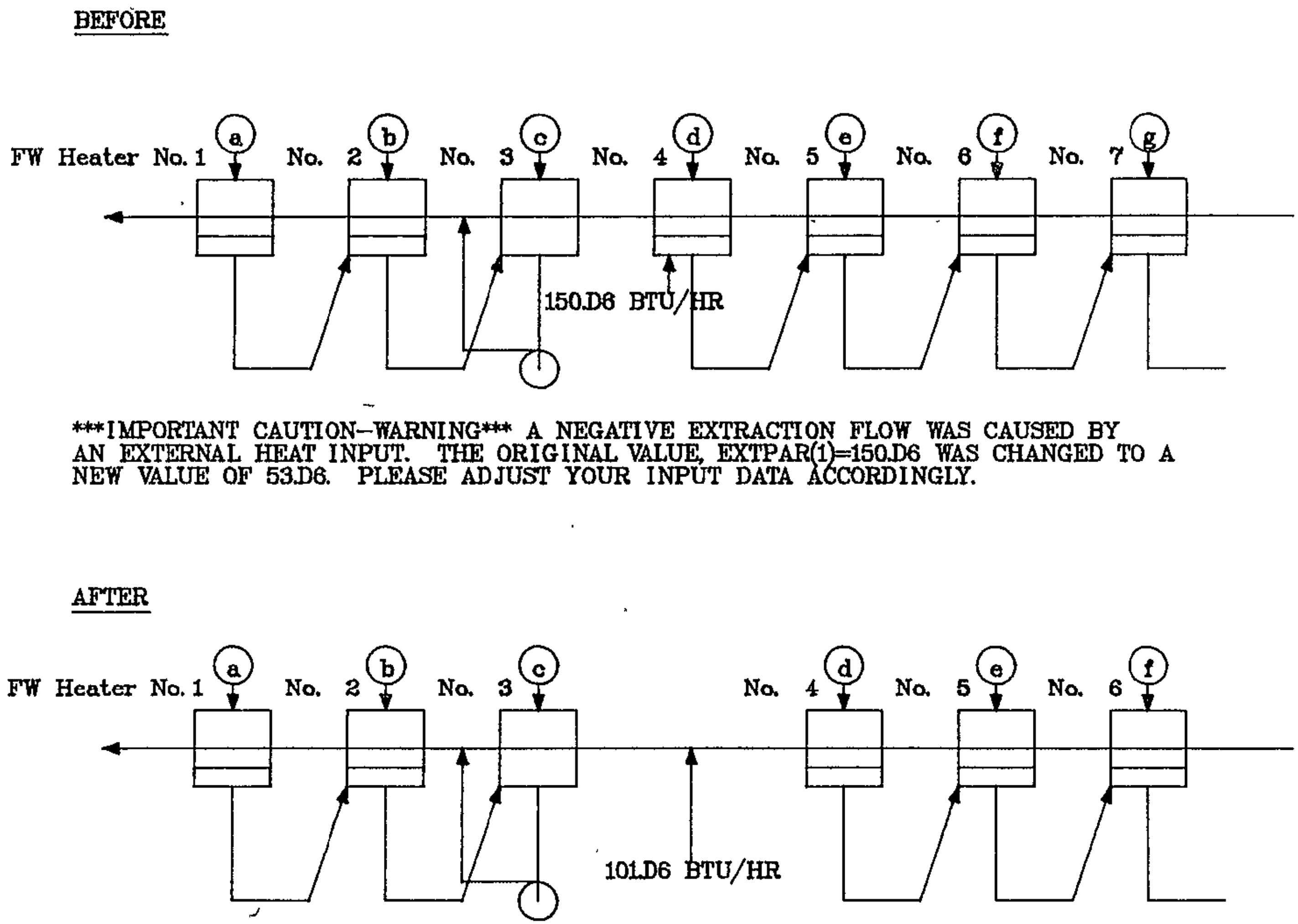


Fig. 5.5. Excess external heat example.

Table 5.1

EXAMPLE OF BAD EXTERNAL
STEAM TURBINE CYCLE HEAT BALANCE
PRESTC, VERSION 02/10/79

CALCULATED RESULTS, PAGE 3

TABLE IV FW HEATERS

FW HEATER NO.	1	2	3	4	5	6
FW FLOW, LB/HR	4357000.	4357000.	3502668.	3502668.	3502668.	3502668.
FW TEMPERATURE OUT, F	502.5	435.4	369.2	290.6	262.3	195.5
FW ENTHALPY OUT, BTU/LB	490.7	417.9	342.1	260.0	231.1	163.6
FW TEMPERATURE IN, F	435.4	379.9	290.6	262.3	195.5	158.7
FW ENTHALPY IN, BTU/LB	417.9	359.7	260.0	231.1	163.6	126.6
EXTRACTION STAGE PRESSURE, PSIA	717.7	397.0	177.0	66.7	42.6	12.4
EXCTION STEAM FLOW @ HTR, LB/HR	367361.	210286.	268390.	0.	220980.	119258.
EXTTION STEAM FLOW @ TURB, LB/HR	367361.	210286.	268390.	0.	220980.	119258.
EXCTION STM ENTHALPY @ HTR, B/LB	1269.6	1453.7	1364.5	1269.2	1230.9	1141.5
EXTTION STM ENTHALPY @ TURB, B/LB	1269.6	1453.7	1364.5	1269.2	1230.9	1141.5
SHELL PRESSURE, PSIA	696.2	363.8	171.7	62.7	40.0	11.7
SHELL TEMPERATURE, F	502.5	435.4	369.2	295.6	267.3	200.5
SHELL DRAIN FLOW, LB/HR	374388.	585943.	854332.	41947.	262928.	382186.
SHELL DRAIN TEMPERATURE, F	445.4	389.9	369.2	272.3	205.5	168.7
SHELL DRAIN ENTHALPY, BTU/LB	425.1	364.2	342.1	241.3	173.7	136.6
HEATER DUTY, BTU/HR	317248763.7	253240688.3	287358812.0	48344039.8	236470996.1	129583080.5

FW HEATER NO.	7
FW FLOW, LB/HR	3502668.
FW TEMPERATURE OUT, F	158.7
FW ENTHALPY OUT, BTU/LB	126.6
FW TEMPERATURE IN, F	109.7
FW ENTHALPY IN, BTU/LB	77.6
EXTRACTION STAGE PRESSURE, PSIA	5.5
EXCTION STEAM FLOW @ HTR, LB/HR	143954.
EXTTION STEAM FLOW @ TURB, LB/HR	143954.
EXCTION STM ENTHALPY @ HTR, B/LB	1091.6
EXTTION STM ENTHALPY @ TURB, B/LB	1091.6
SHELL PRESSURE, PSIA	5.2
SHELL TEMPERATURE, F	163.7
SHELL DRAIN FLOW, LB/HR	532562.
SHELL DRAIN TEMPERATURE, F	119.7
SHELL DRAIN ENTHALPY, BTU/LB	87.6
HEATER DUTY, BTU/HR	171521868.0

Table 5.2

EXAMPLE OF BAD EXTERNAL
STEAM TURBINE CYCLE HEAT BALANCE
PRESTC, VERSION 02/10/79

CALCULATED RESULTS, PAGE 4

TABLE IV-A EXTERNAL HEAT ADDITION (REMOVAL)

TOTAL EXTERNAL HEAT ADDED TO THE TURBINE CYCLE IS	52962482.	BTU/HR
EXTERNAL HEAT ADDITION PARALLEL TO FW HEATER NO 4 EXTPAR=	52962482.	BTU/HR

Table 5.3

```
===SAME CASE ADJUSTED TO REPLACE 4TH HEATER W/ SERIES EXTERNAL INPUT==
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE  3
```

TABLE IV   FW HEATERS

FW HEATER NO.	1	2	3	4	5	6
FW FLOW, LB/HR	4357000.	4357000.	3502335.	3502335.	3502335.	3502335.
FW TEMPERATURE OUT, F	502.5	435.4	369.2	262.3	195.5	158.7
FW ENTHALPY OUT, BTU/LB	490.7	417.9	342.1	231.1	163.6	126.6
FW TEMPERATURE IN, F	435.4	379.9	290.5	195.5	158.7	109.7
FW ENTHALPY IN, BTU/LB	417.9	359.7	259.9	163.6	126.6	77.7
EXTRACTION STAGE PRESSURE, PSIA	717.7	387.0	177.0	42.6	12.4	5.5
EXCTION STEAM FLOW @ HTR, LB/HR	367360.	210286.	268723.	173346.	120938.	149041.
EXTTION STEAM FLOW @ TURB, LB/HR	367360.	210286.	268723.	173346.	120938.	149041.
EXCTION STM ENTHALPY @ HTR, B/LB	1269.6	1453.7	1364.5	1230.9	1141.5	1091.6
EXTTION STM ENTHALPY @ TURB, B/LB	1269.6	1453.7	1364.5	1230.9	1141.5	1091.6
SHELL PRESSURE, PSIA	696.2	363.8	171.7	40.0	11.7	5.2
SHELL TEMPERATURE, F	502.5	435.4	369.2	267.3	200.5	163.7
SHELL DRAIN FLOW, LB/HR	374388.	585943.	854665.	217031.	337969.	491031.
SHELL DRAIN TEMPERATURE, F	445.4	389.9	369.2	205.5	168.7	119.7
SHELL DRAIN ENTHALPY, BTU/LB	425.1	364.2	342.1	173.7	136.6	87.7
HEATER DUTY, BTU/HR	317243763.7	253240688.3	287699064.9	236448534.2	129570771.6	171348788.5

Table 5.4

```
===SAME CASE ADJUSTED TO REPLACE 4TH HEATER W/ SERIES EXTERNAL INPUT==
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE  4
```

TABLE IV-A EXTERNAL HEAT ADDITION (REMOVAL)

TOTAL EXTERNAL HEAT ADDED TO THE TURBINE CYCLE IS	101000000.	BTU/HR
EXTERNAL HEAT ADDITION AFTER FW HEATER NO 4 EXTR=	101000000.	BTU/HR

REFERENCES

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3. F. G. Baily, K. C. Cotton, and R. C. Spencer, *Predicting the Performance of Large Steam Turbine-Generators Operating with Saturated and Low Superheat Steam Conditions*, GER-2454A, General Electric Company, April 1967.
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10. General Electric Company, *Heat Rates for Fossil Reheat Cycles Using General Electric Steam Turbine-Generators 150,000 KW and Larger*, GET-2050C, General Electric Company, February 1974.

Appendix A
EXAMPLE CASE OUTPUT

```
&NAME
GC=  717.0000000000000     ,IP=          2,LK=          1,ND=          0,          0,          1,          0,          0,          0,
          0,          0,          0,          0,          0,          0,NF=          7,PE= 0.0                 ,
  387.0000000000000     , 0.0                   ,  66.70000000000000     ,  42.60000000000000     ,  12.40000000000000     ,
  5.500000000000000     , 0.0                   , 0.0                   , 0.0                   , 0.0                   ,
 0.0                    ,PF= 0.9000000000000000    ,PT=  3515.000000000000     ,QT=  4357000.000000000     ,TT=  1000.000000000000     ,
BLS=  30.00000000000000     ,CP1=  171.7000000000000     ,CP2=  1.300000000000000     ,EPM= 0.9000000000000000    ,EPP=
 0.8400000000000000    ,EPT= 0.8100000000000000    ,GC2=  921344.5020517110     ,ICC=          0,NDC=          1,          1,
          0,          1,          1,          1,          1,          0,          0,          0,          0,          0,NFH=
          1,NFI=          2,NPL=          4,NHP=          1,NIP=          1,NLP=          4,NRH=          1,QAE=
 0.0                    ,QCR= 0.0                   ,QTD=  4357000.000000000     ,TTD= 0.0                   , 0.0                   ,
 0.0                    ,  5.000000000000000     ,  5.000000000000000     ,  5.000000000000000     ,  5.000000000000000     ,
 0.0                    , 0.0                   , 0.0                   , 0.0                   , 0.0                   ,IFPT=
          1,IRHP=       3600,IRIP=       3600,IRLP=       3600,NLP2=          0,NRGS=          1,PBIP=  633.0000000000000     ,PBLP=
  177.0000000000000     ,PCMU= 0.0                  ,PDGS=  40.00000000000000     ,PDLS=  85.00000000000000     ,PXLP=
 -5.000000000000000     ,QGEN= 0.0                  ,TDCA=  10.00000000000000     ,  10.00000000000000     , 0.0                   ,
  10.00000000000000     ,  10.00000000000000     ,  10.00000000000000     ,  10.00000000000000     , 0.0                   ,
 0.0                    , 0.0                   , 0.0                   , 0.0                   ,TRH1=  1000.000000000000     ,TRH2=
 0.0                    ,IPEAK=          0,NCASE=          0,NOSPE=          1,PXLPI=  2.500000000000000     ,WRATE=
  645.0000000000000     ,IMETER=          0,INAME2=          0,IPLACE=          2,NSHAFT=          3,PXDROP=  3.000000000000000     ,
  6.000000000000000     ,WRATE2=  7.000007872702586
&END
```

```
==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

INPUT DATA

     THROTTLE STEAM TEMPERATURE                                    1000.0      F
     THROTTLE STEAM PRESSURE                                       3515.0      PSIA
     ESTIMATED THROTTLE STEAM FLOW                               4357000.      LB/HR
     DESIGN THROTTLE FLOW                                        4357000.      LB/HR

     FW MAKE-UP RATE (TO CONDENSER HOTWELL)                           0.0      PER CENT
     CONDENSATE BY-PASSED TO STEAM GENERATOR                          0.       LB/HR

     GENERATOR RATED CAPABILITY                                     717.000    MVA
     GENERATOR POWER FACTOR                                           0.90

     TOTAL REQUIRED ELECTRICAL OUTPUT                               645.000    MWE

     CONDUCTOR-COOLED GENERATOR, ICC= 0
     ROTATIONAL SPEED OF TURBINE-GENERATOR                         3600        RPM

     1-ROW GOVERNING STAGE
     PITCH DIAMETER OF GOVERNING STAGE                               40.00     IN.

     NO. OF TURBINE SECTIONS IN SERIES                                3
     NUMBER OF PARALLEL HP SECTIONS                                   1
     NUMBER OF PARALLEL IP SECTIONS                                   1
     NUMBER OF PARALLEL LP SECTIONS                                   4

     BOWL PRESSURE IP SECTION                                       633.0      PSIA

     BOWL PRESSURE LP SECTION                                       177.0      PSIA
     EXHAUST PRESSURE LP SECTION                                      1.22788  PSIA    =     2.50   IN. HGA
     PITCH DIAMETER OF LAST STAGE LP SECTION                         85.00     IN.
     LENGTH OF LAST STAGE BUCKETS LP SECTION                         30.00     IN.

     FEEDWATER PUMP ISENTROPIC EFFICIENCY                             0.8400
     FEEDWATER PUMP TURBINE EFFICIENCY                                0.8100
     PRESSURE AT FWP INLET                                          171.70     PSIA
     RATIO OF FWP DISCHARGE PRESSURE TO HP THROTTLE PRESSURE          1.30
     FWP TURBINE EXTRACTION BEFORE LP BOWL
     FW PUMP IS LOCATED BEFORE FW HEATER NO.  2, IP=  2
     FW PUMP IS TURBINE DRIVEN, IFPT=  1

     NUMBER OF STAGES OF REHEAT                                       1
     FIRST REHEAT TEMPERATURE                                      1000.0      F

     TOTAL NO. OF FW HEATERS                                          7
     NO. OF FW HEATERS HP SECTION                                     1
     NO. OF FW HEATERS IP SECTION                                     2
     NO. OF FW HEATERS LP SECTION                                     4

     EXTRACTION LINE PRESSURE DROP AT TURBINE EXHAUST                 3.0      PER CENT
     EXTRACTION LINE PRESSURE DROP ALL OTHERS                         6.0      PER CENT

     FW HEATER NO.  1

       EXTRACTION STEAM FROM TURBINE EXHAUST
       TERMINAL TEMPERATURE DIFFERENCE                                0.0      F
       DRAIN IS FLASHED, ND( 1)= 0
       THERE IS A DRAIN COOLER SECTION, NDC( 1)= 1
       DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                  10.0      F

     FW HEATER NO.  2

       EXTRACTION STAGE PRESSURE                                    387.0      PSIA
       TERMINAL TEMPERATURE DIFFERENCE                                0.0      F
       DRAIN IS FLASHED, ND( 2)= 0
       THERE IS A DRAIN COOLER SECTION, NDC( 2)= 1
       DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                  10.0      F
```

FW HEATER NO. 3

EXTRACTION STEAM FROM TURBINE EXHAUST		
TERMINAL TEMPERATURE DIFFERENCE	0.0	F
DRAIN IS PUMPED, ND(3)= 1		
THERE IS NO DRAIN COOLER SECTION, NDC(3)= 0		

FW HEATER NO. 4

EXTRACTION STAGE PRESSURE	66.7	PSIA
TERMINAL TEMPERATURE DIFFERENCE	5.0	F
DRAIN IS FLASHED, ND(4)= 0		
THERE IS A DRAIN COOLER SECTION, NDC(4)= 1		
DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE	10.0	F

FW HEATER NO. 5

EXTRACTION STAGE PRESSURE	42.6	PSIA
TERMINAL TEMPERATURE DIFFERENCE	5.0	F
DRAIN IS FLASHED, ND(5)= 0		
THERE IS A DRAIN COOLER SECTION, NDC(5)= 1		
DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE	10.0	F

FW HEATER NO. 6

EXTRACTION STAGE PRESSURE	12.4	PSIA
TERMINAL TEMPERATURE DIFFERENCE	5.0	F
DRAIN IS FLASHED, ND(6)= 0		
THERE IS A DRAIN COOLER SECTION, NDC(6)= 1		
DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE	10.0	F

FW HEATER NO. 7

EXTRACTION STAGE PRESSURE	5.5	PSIA
TERMINAL TEMPERATURE DIFFERENCE	5.0	F
DRAIN IS FLASHED, ND(7)= 0		
THERE IS A DRAIN COOLER SECTION, NDC(7)= 1		
DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE	10.0	F

THERE IS NO STEAM JET AIR EJECTOR, QAE = 0.

VALVE STEM AND PACKING LEAKAGES WILL BE CALCULATED, LK= 1

THERE IS A STEAM PACKING EXHAUSTER, NOSPE= 1

==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 1

TABLE I OVERALL PERFORMANCE

NET TURBINE CYCLE HEAT RATE, BTU/KW-HR	7791.
NET TURBINE CYCLE EFFICIENCY, PER CENT	43.80
GROSS TURBINE CYCLE HEAT RATE, BTU/KW-HR	7528.
GROSS TURBINE CYCLE EFFICIENCY, PER CENT	45.33
GENERATOR OUTPUT, MWE	645.000
SHAFT WORK, MW	656.712
POWER REQUIRED BY TURBINE-DRIVEN FW PUMP, MW	22.545
GENERATOR OUTPUT PLUS FW PUMP POWER, MW	667.546
MECHANICAL LOSSES, KW	2980.
GENERATOR LOSSES, KW	8732.

==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 2

TABLE II TURBINE EXPANSION LINE

	STEAM FLOW LB/HR	PRESSURE PSIA	TEMPERATURE F	MOISTURE FRACTION	ENTHALPY BTU/LB	ENTROPY BTU/LB-F
TURBINE THROTTLE	4357052.	3515.0	1000.0	0.0	1421.7	
GOVERNING STAGE BOWL	4347898.	3409.6	995.0	0.0	1421.7	1.4729
GOVERNING STAGE ELEP AND UEEP	4347898.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION BOWL	4294850.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION ELEP	4294850.	717.7	586.6	0.0	1269.6	1.4957
1ST STAGE REHEATER INLET	3949031.	717.7			1270.7	
1ST STAGE REHEATER OUTLET	3949031.	645.9	1000.0		1516.0	
IP SECTION BOWL	3931944.	633.0	999.3	0.0	1516.0	1.7088
IP SECTION ELEP	3721655.	177.0	678.5	0.0	1364.5	1.7286
LP SECTION BOWL	3196406.	177.0	678.5	0.0	1364.5	1.7286
LP SECTION ELEP	2668022.	1.22788	108.7	0.0953	1010.4	1.7877
LP SECTION UEEP		1.22788			1023.4	

TABLE III THERE IS NO STEAM JET AIR EJECTOR

==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 3

TABLE IV FW HEATERS

FW HEATER NO.	1	2	3	4	5	5
FW FLOW, LB/HR	4357052.	4357052.	3502709.	3502709.	3502709.	3502709.
FW TEMPERATURE OUT, F	502.5	435.4	369.2	290.6	262.3	195.5
FW ENTHALPY OUT, BTU/LB	490.7	417.9	342.1	260.0	231.1	163.6
FW TEMPERATURE IN, F	435.4	379.9	290.6	262.3	195.5	158.7
FW ENTHALPY IN, BTU/LB	417.9	359.7	260.0	231.1	163.6	125.6
EXTRACTION STAGE PRESSURE, PSIA	717.7	387.0	177.0	66.7	42.6	12.4
EXTRACTION STEAM FLOW, LB/HR	367365.	210289.	268393.	51527.	217686.	117482.
EXTRACTION STEAM ENTHALPY, BTU/LB	1269.6	1453.7	1364.5	1269.2	1230.9	1141.5
SHELL PRESSURE, PSIA	696.2	363.8	171.7	62.7	40.0	11.7
SHELL TEMPERATURE, F	502.5	435.4	369.2	295.6	267.3	203.5
SHELL DRAIN FLOW, LB/HR	374393.	585950.	854343.	93474.	311161.	428643.
SHELL DRAIN TEMPERATURE, F	445.4	389.9	369.2	272.3	205.5	168.7
SHELL DRAIN ENTHALPY, BTU/LB	425.1	364.2	342.1	241.3	173.7	135.6
HEATER DUTY, BTU/HR	317252548.5	253243709.4	287362236.9	101307729.6	236473814.5	129584624.9

FW HEATER NO.	7
FW FLOW, LB/HR	3502709.
FW TEMPERATURE OUT, F	158.7
FW ENTHALPY OUT, BTU/LB	126.6
FW TEMPERATURE IN, F	109.7
FW ENTHALPY IN, BTU/LB	77.6
EXTRACTION STAGE PRESSURE, PSIA	5.5
EXTRACTION STEAM FLOW, LB/HR	141689.
EXTRACTION STEAM ENTHALPY, BTU/LB	1091.6
SHELL PRESSURE, PSIA	5.2
SHELL TEMPERATURE, F	163.7
SHELL DRAIN FLOW, LB/HR	576753.
SHELL DRAIN TEMPERATURE, F	119.7
SHELL DRAIN ENTHALPY, BTU/LB	87.6
HEATER DUTY, BTU/HR	171524678.4

==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 4

TABLE V CONDENSER

CONDENSER PRESSURE, PSIA	1.22788	2.50	IN. HGA
CONDENSATE FLOW, LB/HR	3502709.		
CONDENSATE TEMPERATURE, F	108.7		
CONDENSATE ENTHALPY, BTU/LB	76.7		
CONDENSER DUTY, BTU/HR	2749444398.		

TABLE VI CONDENSATE AND FEEDWATER

FW FLOW TO FW PUMP, LB/HR	4357052.		
FW TEMPERATURE TO FW PUMP, F	369.2		
FW ENTHALPY TO FW PUMP, BTU/LB	342.1		
FW ENTHALPY RISE ACROSS FW PUMP, BTU/LB	17.7		
FW PRESSURE INCREASE ACROSS FW PUMP, PSI	4398.		
FW FLOW TO STEAM GENERATOR, LB/HR	4357052.		
FW TEMPERATURE TO STEAM GENERATOR, F	502.5		
FW ENTHALPY TO STEAM GENERATOR, BTU/LB	490.7		
MAKE-UP TO CONDENSER HOTWELL, LB/HR	0.		
STEAM FLOW FROM STEAM GENERATOR, LB/HR	4357052.		
STEAM ENTHALPY FROM STEAM GENERATOR, BTU/LB	1421.7		
THROTTLE STEAM FLOW FW PUMP TURBINE, LB/HR	252734.		
THROTTLE PRESSURE FW PUMP TURBINE, PSIA	171.7		
THROTTLE ENTHALPY FW PUMP TURBINE, BTU/LB	1364.5		
EXHAUST PRESSURE FW PUMP TURBINE, PSIA	1.47346	3.00	IN. HGA
EXHAUST ENTHALPY FW PUMP TURBINE, BTU/LB	1060.1		

==EXAMPLE CASE NO 1. WITH GENERATOR OUTPUT SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 5

TABLE VII VALVE STEM AND SHAFT LEAKAGES

STEAM SEAL REGULATOR	
FLOW TO SSR, LB/HR	11622.
ENTHALPY AT SSR, BTU/LB	1375.1
FLOW FROM SSR TO MAIN CONDENSER, LB/HR	2400.
FLOW FROM SSR TO STEAM PACKING EXHAUSTER, LB/HR	2800.
FLOW FROM SSR TO FW HEATER NO. 7, LB/HR	6422.
MAKE-UP FROM THROTTLE STEAM, LB/HR	0.
ENTHALPY OF MAKE-UP STEAM, BTU/LB	0.0
THROTTLE VALVE STEM	
LEAK NO. 19 (DRAINS TO FW HEATER NO. 1), LB/ HR	7028.
ENTHALPY LEAK NO. 19, BTU/LB	1421.7
LEAK NO. 20 (DRAINS TO FW HEATER NO. 2), LB/ HR	1268.
ENTHALPY LEAK NO. 20, BTU/LB	1421.7
LEAK NO. 21 (DRAINS TO SSR), LB/HR	858.
ENTHALPY LEAK NO. 21, BTU/LB	1421.7
HP TURBINE SECTION, BOWL	
LEAK NO. 1 (DRAINS TO SHELL OF THIS TURBINE SECTION.)	39447.
ENTHALPY LEAK NO. 1, BTU/LB	1394.9
LEAK NO. 3 (DRAINS TO FW HEATER NO. 4), LB/ HR	11589.
ENTHALPY LEAK NO. 3, BTU/LB	1394.9
LEAK NO. 4 (DRAINS TO SSR), LB/HR	2013.
ENTHALPY LEAK NO. 4, BTU/LB	1394.9
HP TURBINE SECTION, SHELL	
LEAK NO. 6 (DRAINS TO FW HEATER NO. 4), LB/ HR	15105.
ENTHALPY LEAK NO. 6, BTU/LB	1269.6
LEAK NO. 7 (DRAINS TO SSR), LB/HR	2795.
ENTHALPY LEAK NO. 7, BTU/LB	1269.6
IP TURBINE SECTION, BOWL	
LEAK NO. 8 (DRAINS TO FW HEATER NO. 4), LB/ HR	15254.
ENTHALPY LEAK NO. 8, BTU/LB	1516.0
LEAK NO. 9 (DRAINS TO SSR), LB/HR	1833.
ENTHALPY LEAK NO. 9, BTU/LB	1516.0
IP TURBINE SECTION, SHELL	
LEAK NO. 12 (DRAINS TO SSR), LB/HR	4122.
ENTHALPY LEAK NO. 12, BTU/LB	1364.5

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  6.000000000000000    ,WRATE2=  7.000007872702586
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```

```
 ===SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

INPUT DATA

     THROTTLE STEAM TEMPERATURE                                        1000.0      F
     THROTTLE STEAM PRESSURE                                           3515.0      PSIA
     ESTIMATED THROTTLE STEAM FLOW                                  4357000.       LB/HR
     DESIGN THROTTLE FLOW                                           4357000.       LB/HR

     FW MAKE-UP RATE (TO CONDENSER HOTWELL)                               0.0      PER CENT
     CONDENSATE BY-PASSED TO STEAM GENERATOR                              0.       LB/HR

     GENERATOR RATED CAPABILITY                                         717.000    MVA
     GENERATOR POWER FACTOR                                               0.90

     TOTAL ESTIMATED ELECTRICAL OUTPUT                                  645.000    MWE
     REQUIRED STEAM GENERATOR FLOW                                  4357000.       LB/HR

     CONDUCTOR-COOLED GENERATOR, ICC= 0
     ROTATIONAL SPEED OF TURBINE-GENERATOR                             3600        RPM

     1-ROW GOVERNING STAGE
     PITCH DIAMETER OF GOVERNING STAGE                                   40.00     IN.

     NO. OF TURBINE SECTIONS IN SERIES                                    3
     NUMBER OF PARALLEL HP SECTIONS                                       1
     NUMBER OF PARALLEL IP SECTIONS                                       1
     NUMBER OF PARALLEL LP SECTIONS                                       4

     BOWL PRESSURE IP SECTION                                           633.0      PSIA

     BOWL PRESSURE LP SECTION                                           177.0      PSIA
     EXHAUST PRESSURE LP SECTION                                          1.22788  PSIA    =     2.50  IN. HGA
     PITCH DIAMETER OF LAST STAGE LP SECTION                             85.00     IN.
     LENGTH OF LAST STAGE BUCKETS LP SECTION                             30.00     IN.

     FEEDWATER PUMP ISENTROPIC EFFICIENCY                                 0.8400
     FEEDWATER PUMP TURBINE EFFICIENCY                                    0.8100
     PRESSURE AT FWP INLET                                              171.70     PSIA
     RATIO OF FWP DISCHARGE PRESSURE TO HP THROTTLE PRESSURE              1.30
     FWP TURBINE EXTRACTION BEFORE LP BOWL
     FW PUMP IS LOCATED BEFORE FW HEATER NO.  2, IP=  2
     FW PUMP IS TURBINE DRIVEN, IPPT=  1

     NUMBER OF STAGES OF REHEAT                                           1
     FIRST REHEAT TEMPERATURE                                          1000.0      F

     TOTAL NO. OF FW HEATERS                                              7
     NO. OF FW HEATERS HP SECTION                                         1
     NO. OF FW HEATERS IP SECTION                                         2
     NO. OF FW HEATERS LP SECTION                                         4

     EXTRACTION LINE PRESSURE DROP AT TURBINE EXHAUST                     3.0      PER CENT
     EXTRACTION LINE PRESSURE DROP ALL OTHERS                             6.0      PER CENT

     FW HEATER NO.  1

       EXTRACTION STAGE PRESSURE                                        717.7      PSIA
       TERMINAL TEMPERATURE DIFFERENCE                                    0.0      F
       DRAIN IS FLASHED, ND( 1)= 0
       THERE IS A DRAIN COOLER SECTION, NDC( 1)= 1
       DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                      10.0      F
```

```
FW HEATER NO.  2

  EXTRACTION STAGE PRESSURE                              387.0      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          0.0      F
  DRAIN IS FLASHED, ND( 2)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 2)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE            10.0      F

FW HEATER NO.  3

  EXTRACTION STAGE PRESSURE                              177.0      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          0.0      F
  DRAIN IS PUMPED, ND( 3)= 1
  THERE IS NO DRAIN COOLER SECTION, NDC( 3)= 0

FW HEATER NO.  4

  EXTRACTION STAGE PRESSURE                               66.7      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          5.0      F
  DRAIN IS FLASHED, ND( 4)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 4)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE            10.0      F

FW HEATER NO.  5

  EXTRACTION STAGE PRESSURE                               42.6      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          5.0      F
  DRAIN IS FLASHED, ND( 5)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 5)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE            10.0      F

FW HEATER NO.  6

  EXTRACTION STAGE PRESSURE                               12.4      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          5.0      F
  DRAIN IS FLASHED, ND( 6)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 6)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE            10.0      F

FW HEATER NO.  7

  EXTRACTION STAGE PRESSURE                                5.5      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                          5.0      F
  DRAIN IS FLASHED, ND( 7)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 7)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE            10.0      F

THERE IS NO STEAM JET AIR EJECTOR, QAE =        0.

VALVE STEM AND PACKING LEAKAGES WILL BE CALCULATED, LK= 1

THERE IS A STEAM PACKING EXHAUSTER, NOSPE= 1
```

```
 ===SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE  1



TABLE I  OVERALL PERFORMANCE

NET TURBINE CYCLE HEAT RATE, BTU/KW-HR               7791.
NET TURBINE CYCLE EFFICIENCY, PER CENT                 43.80

GROSS TURBINE CYCLE HEAT RATE, BTU/KW-HR             7528.
GROSS TURBINE CYCLE EFFICIENCY, PER CENT               45.33

GENERATOR OUTPUT, MWE                                 644.994
SHAFT WORK, MW                                        656.706

POWER REQUIRED BY TURBINE-DRIVEN FW PUMP, MW           22.545
GENERATOR OUTPUT PLUS FW PUMP POWER, MW               667.539

MECHANICAL LOSSES, KW                                2980.
GENERATOR LOSSES, KW                                 8732.
```

===SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 2

TABLE II TURBINE EXPANSION LINE

	STEAM FLOW LB/HR	PRESSURE PSIA	TEMPERATURE F	MOISTURE FRACTION	ENTHALPY BTU/LB	ENTROPY BTU/LB-F
TURBINE THROTTLE	4357000.	3515.0	1000.0	0.0	1421.7	
GOVERNING STAGE BOWL	4347846.	3409.6	995.0	0.0	1421.7	1.4729
GOVERNING STAGE ELEP AND UEEP	4347846.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION BOWL	4294798.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION ELEP	4294798.	717.7	586.6	0.0	1269.6	1.4957
1ST STAGE REHEATER INLET	3948983.	717.7			1270.7	
1ST STAGE REHEATER OUTLET	3948983.	645.9	1000.0		1516.0	
IP SECTION BOWL	3931896.	633.0	999.3	0.0	1516.0	1.7088
IP SECTION ELEP	3721610.	177.0	678.5	0.0	1364.5	1.7286
LP SECTION BOWL	3196367.	177.0	678.5	0.0	1364.5	1.7286
LP SECTION ELEP	2668121.	1.22788	108.7	0.0953	1010.4	1.7877
LP SECTION UEEP		1.22788			1023.4	

TABLE III THERE IS NO STEAM JET AIR EJECTOR

===SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 3

TABLE IV FW HEATERS

FW HEATER NO.	1	2	3	4	5	5
FW FLOW, LB/HR	4357000.	4357000.	3502668.	3502668.	3502668.	3502668.
FW TEMPERATURE OUT, F	502.5	435.4	369.2	290.6	262.3	195.5
FW ENTHALPY OUT, BTU/LB	490.7	417.9	342.1	260.0	231.1	163.6
FW TEMPERATURE IN, F	435.4	379.9	290.6	262.3	195.5	158.7
FW ENTHALPY IN, BTU/LB	417.9	359.7	260.0	231.1	163.6	125.6
EXTRACTION STAGE PRESSURE, PSIA	717.7	387.0	177.0	66.7	42.6	12.4
EXTRACTION STEAM FLOW, LB/HR	367361.	210286.	268390.	51526.	217684.	117491.
EXTRACTION STEAM ENTHALPY, BTU/LB	1269.6	1453.7	1364.5	1269.2	1230.9	1141.5
SHELL PRESSURE, PSIA	696.2	363.8	171.7	62.7	40.0	[illegible]
SHELL TEMPERATURE, F	502.5	435.4	369.2	295.6	267.3	[illegible]
SHELL DRAIN FLOW, LB/HR	374388.	585943.	854332.	93473.	311157.	[illegible]
SHELL DRAIN TEMPERATURE, F	445.4	389.9	369.2	272.3	205.9	[illegible]
SHELL DRAIN ENTHALPY, BTU/LB	425.1	364.2	342.1	241.3	173.[illegible]	[illegible]
HEATER DUTY, BTU/HR	317248763.7	253240688.3	287358812.0	101306522.2	[illegible]	[illegible]

FW HEATER NO.	7
FW FLOW, LB/HR	3502668.
FW TEMPERATURE OUT, F	158.7
FW ENTHALPY OUT, BTU/LB	126.6
FW TEMPERATURE IN, F	109.7
FW ENTHALPY IN, BTU/LB	77.7
EXTRACTION STAGE PRESSURE, PSIA	5.5
EXTRACTION STEAM FLOW, LB/HR	141556.
EXTRACTION STEAM ENTHALPY, BTU/LB	1091.6
SHELL PRESSURE, PSIA	5.2
SHELL TEMPERATURE, F	163.7
SHELL DRAIN FLOW, LB/HR	576615.
SHELL DRAIN TEMPERATURE, F	119.7
SHELL DRAIN ENTHALPY, BTU/LB	87.7
HEATER DUTY, BTU/HR	171365066.1

===SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 4

TABLE V CONDENSER

CONDENSER PRESSURE, PSIA	1.22788	=	2.50	IN. HGA
CONDENSATE FLOW, LB/HR	3502668.			
CONDENSATE TEMPERATURE, F	108.7			
CONDENSATE ENTHALPY, BTU/LB	76.7			
CONDENSER DUTY, BTU/HR	2749400935.			

TABLE VI CONDENSATE AND FEEDWATER

FW FLOW TO FW PUMP, LB/HR	4357000.			
FW TEMPERATURE TO FW PUMP, F	369.2			
FW ENTHALPY TO FW PUMP, BTU/LB	342.1			
FW ENTHALPY RISE ACROSS FW PUMP, BTU/LB	17.7			
FW PRESSURE INCREASE ACROSS FW PUMP, PSI	4398.			
FW FLOW TO STEAM GENERATOR, LB/HR	4357000.			
FW TEMPERATURE TO STEAM GENERATOR, F	502.5			
FW ENTHALPY TO STEAM GENERATOR, BTU/LB	490.7			
MAKE-UP TO CONDENSER HOTWELL, LB/HR	0.			
STEAM FLOW FROM STEAM GENERATOR, LB/HR	4357000.			
STEAM ENTHALPY FROM STEAM GENERATOR, BTU/LB	1421.7			
THROTTLE STEAM FLOW FW PUMP TURBINE, LB/HR	252731.			
THROTTLE PRESSURE FW PUMP TURBINE, PSIA	171.7			
THROTTLE ENTHALPY FW PUMP TURBINE, BTU/LB	1364.5			
EXHAUST PRESSURE FW PUMP TURBINE, PSIA	1.47346	=	3.00	IN. HGA
EXHAUST ENTHALPY FW PUMP TURBINE, BTU/LB	1060.1			

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***SAME EXAMPLE CASE NO 1. WITH STEAM FLOW SPECIFIED***
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE  5


TABLE VII VALVE STEM AND SHAFT LEAKAGES

STEAM SEAL REGULATOR
  FLOW TO SSR, LB/HR                                          11622.
  ENTHALPY AT SSR, BTU/LB                                      1375.1
  FLOW FROM SSR TO MAIN CONDENSER, LB/HR                       2400.
  FLOW FROM SSR TO STEAM PACKING EXHAUSTER, LB/HR              2800.
  FLOW FROM SSR TO FW HEATER NO.  7, LB/HR                     6422.
  MAKE-UP FROM THROTTLE STEAM, LB/HR                              0.
  ENTHALPY OF MAKE-UP STEAM, BTU/LB                               0.0

THROTTLE VALVE STEM

  LEAK NO. 19(DRAINS TO FW HEATER NO.  1), LB/ HR              7028.
  ENTHALPY LEAK NO. 19, BTU/LB                                 1421.7

  LEAK NO. 20(DRAINS TO FW HEATER NO.  2), LB/ HR              1268.
  ENTHALPY LEAK NO. 20, BTU/LB                                 1421.7

  LEAK NO. 21(DRAINS TO SSR), LB/HR                             858.
  ENTHALPY LEAK NO. 21, BTU/LB                                 1421.7

HP TURBINE SECTION, BOWL

  LEAK NO.  1(DRAINS TO SHELL OF THIS TURBINE SECTION.)       39446.
  ENTHALPY LEAK NO.  1, BTU/LB                                 1394.9

  LEAK NO.  3(DRAINS TO FW HEATER NO.  4), LB/ HR             11589.
  ENTHALPY LEAK NO.  3, BTU/LB                                 1394.9

  LEAK NO.  4(DRAINS TO SSR), LB/HR                            2013.
  ENTHALPY LEAK NO.  4, BTU/LB                                 1394.9

HP TURBINE SECTION, SHELL

  LEAK NO.  6(DRAINS TO FW HEATER NO.  4), LB/ HR             15105.
  ENTHALPY LEAK NO.  6, BTU/LB                                 1269.6

  LEAK NO.  7(DRAINS TO SSR), LB/HR                            2795.
  ENTHALPY LEAK NO.  7, BTU/LB                                 1269.6

IP TURBINE SECTION, BOWL

  LEAK NO.  8(DRAINS TO FW HEATER NO.  4), LB/ HR             15254.
  ENTHALPY LEAK NO.  8, BTU/LB                                 1516.0

  LEAK NO.  9(DRAINS TO SSR), LB/HR                            1833.
  ENTHALPY LEAK NO.  9, BTU/LB                                 1516.0

IP TURBINE SECTION, SHELL

  LEAK NO. 12(DRAINS TO SSR), LB/HR                            4122.
  ENTHALPY LEAK NO. 12, BTU/LB                                 1364.5
```

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 0.0                   , 0.0                   , 0.0
&END
```

```
==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

INPUT DATA

     THROTTLE STEAM TEMPERATURE                             1000.0     F
     THROTTLE STEAM PRESSURE                                3515.0     PSIA
     ESTIMATED THROTTLE STEAM FLOW                       4357000.      LB/HR
     DESIGN THROTTLE FLOW                                4357000.      LB/HR

     FW MAKE-UP RATE (TO CONDENSER HOTWELL)                    0.0     PER CENT
     CONDENSATE BY-PASSED TO STEAM GENERATOR                   0.      LB/HR

     GENERATOR RATED CAPABILITY                              717.000   MVA
     GENERATOR POWER FACTOR                                    0.90

     TOTAL ESTIMATED ELECTRICAL OUTPUT                       645.000   MWE
     REQUIRED STEAM GENERATOR FLOW                       4357000.      LB/HR

     CONDUCTOR-COOLED GENERATOR, ICC= 0
     ROTATIONAL SPEED OF TURBINE-GENERATOR                  3600       RPM

     1-ROW GOVERNING STAGE
     PITCH DIAMETER OF GOVERNING STAGE                        40.00    IN.

     NO. OF TURBINE SECTIONS IN SERIES                         3
     NUMBER OF PARALLEL HP SECTIONS                            1
     NUMBER OF PARALLEL IP SECTIONS                            1
     NUMBER OF PARALLEL LP SECTIONS                            4

     BOWL PRESSURE IP SECTION                                633.0     PSIA

     BOWL PRESSURE LP SECTION                                177.0     PSIA
     EXHAUST PRESSURE LP SECTION                               1.22788 PSIA     =     2.50  IN. HGA
     PITCH DIAMETER OF LAST STAGE LP SECTION                  85.00    IN.
     LENGTH OF LAST STAGE BUCKETS LP SECTION                  30.00    IN.

     FEEDWATER PUMP ISENTROPIC EFFICIENCY                      0.8400
     FEEDWATER PUMP TURBINE EFFICIENCY                         0.8100
     PRESSURE AT FWP INLET                                   171.70    PSIA
     RATIO OF FWP DISCHARGE PRESSURE TO HP THROTTLE PRESSURE   1.30
     FWP TURBINE EXTRACTION BEFORE LP BOWL
     FW PUMP IS LOCATED BEFORE FW HEATER NO.  2, IP=  2
     FW PUMP IS TURBINE DRIVEN, IFPT=  1
```

```
NUMBER OF STAGES OF REHEAT                                       1
FIRST REHEAT TEMPERATURE                                      1000.0      F

EXTERNAL HEAT ADDITION AFTER FW HEATER NO  1                  15000.      BTU/HR

EXTERNAL FEEDWATER FLOW ADDED AFTER FW HEATER NO.  2           7000.      LB/HR
AT AN ENTHALPY OF                                               430.      BTU/LB

STEAM REMOVED FROM THE NO  2 FW HEATER EXTRACTION LINE         -5000.      LB/HR

EXTERNAL COND RETURNED TO THE NO  3 FW HEATER SHELL            5000.      LB/HR
AT AN ENTHALPY OF                                              1000.      BTU/LB

EXTERNAL HEAT ADDITION PARALLEL TO FW HEATER NO  5           -10000.      BTU/HR

EXTERNAL FEEDWATER FLOW REMOVED AFTER FW HEATER NO.  5        -7000.      LB/HR

PROCESS STEAM AT THE IP TURBINE EXHAUST                        6000.      LB/HR
AT AN ENTHALPY OF                                             1400.0      BTU/LB

TOTAL NO. OF FW HEATERS                                          7
NO. OF FW HEATERS HP SECTION                                     1
NO. OF FW HEATERS IP SECTION                                     2
NO. OF FW HEATERS LP SECTION                                     4

EXTRACTION LINE PRESSURE DROP AT TURBINE EXHAUST               3.0      PER CENT
EXTRACTION LINE PRESSURE DROP ALL OTHERS                       6.0      PER CENT

FW HEATER NO.  1

  EXTRACTION STEAM FROM TURBINE EXHAUST
  TERMINAL TEMPERATURE DIFFERENCE                              0.0      F
  DRAIN IS FLASHED, ND( 1)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 1)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

FW HEATER NO.  2

  EXTRACTION STAGE PRESSURE                                  387.0      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                              0.0      F
  DRAIN IS FLASHED, ND( 2)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 2)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

FW HEATER NO.  3

  EXTRACTION STEAM FROM TURBINE EXHAUST
  TERMINAL TEMPERATURE DIFFERENCE                              0.0      F
  DRAIN IS PUMPED, ND( 3)= 1
  THERE IS NO DRAIN COOLER SECTION, NDC( 3)= 0

FW HEATER NO.  4

  EXTRACTION STAGE PRESSURE                                   66.7      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                              5.0      F
  DRAIN IS FLASHED, ND( 4)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 4)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

FW HEATER NO.  5

  EXTRACTION STAGE PRESSURE                                   42.6      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                              5.0      F
  DRAIN IS FLASHED, ND( 5)= 0
  THERE IS A DRAIN-COOLER SECTION, NDC( 5)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

FW HEATER NO.  6

  EXTRACTION STAGE PRESSURE                                   12.4      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                              5.0      F
  DRAIN IS FLASHED, ND( 6)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 6)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

FW HEATER NO.  7

  EXTRACTION STAGE PRESSURE                                    5.5      PSIA
  TERMINAL TEMPERATURE DIFFERENCE                              5.0      F
  DRAIN IS FLASHED, ND( 7)= 0
  THERE IS A DRAIN COOLER SECTION, NDC( 7)= 1
  DRAIN COOLER APPROACH TEMPERATURE DIFFERENCE                10.0      F

THERE IS NO STEAM JET AIR EJECTOR, QAE =         0.

VALVE STEM AND PACKING LEAKAGES WILL BE CALCULATED, LK= 1

THERE IS A STEAM PACKING EXHAUSTER, NCSPE= 1
```

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 1

TABLE I OVERALL PERFORMANCE

NET TURBINE CYCLE HEAT RATE, BTU/KW-HR	7780.
NET TURBINE CYCLE EFFICIENCY, PER CENT	43.86
GROSS TURBINE CYCLE HEAT RATE, BTU/KW-HR	7518.
GROSS TURBINE CYCLE EFFICIENCY, PER CENT	45.39
GENERATOR OUTPUT, MWE	646.827
SHAFT WORK, MW	658.574
POWER REQUIRED BY TURBINE-DRIVEN FW PUMP, MW	22.545
GENERATOR OUTPUT PLUS FW PUMP POWER, MW	669.372
MECHANICAL LOSSES, KW	2980.
GENERATOR LOSSES, KW	8766.

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 2

TABLE II TURBINE EXPANSION LINE

	STEAM FLOW LB/HR	PRESSURE PSIA	TEMPERATURE F	MOISTURE FRACTION	ENTHALPY BTU/LB	ENTROPY BTU/LB-F
TURBINE THROTTLE	4357000.	3515.0	1000.0	0.0	1421.7	
GOVERNING STAGE BOWL	4347846.	3409.6	995.0	0.0	1421.7	1.4729
GOVERNING STAGE ELEP AND UEEP	4347846.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION BOWL	4294798.	2675.0	921.1	0.0	1394.9	1.4763
HP SECTION ELEP	4294798.	717.7	586.6	0.0	1269.6	1.4957
1ST STAGE REHEATER INLET	3948983.	717.7			1270.7	
1ST STAGE REHEATER OUTLET	3948983.	645.9	1000.0		1516.0	
IP SECTION BOWL	3942789.	633.0	999.3	0.0	1516.0	1.7088
IP SECTION ELEP	3726931.	177.0	664.0	0.0	1357.1	1.7221
LP SECTION BOWL	3210922.	177.0	664.5	0.0	1357.3	1.7223
LP SECTION ELEP	2664601.	1.22788	108.7	0.0944	1011.3	1.7894
LP SECTION UEEP		1.22788			1024.3	

TABLE III THERE IS NO STEAM JET AIR EJECTOR

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 3

TABLE IV FW HEATERS

FW HEATER NO.	1	2	3	4	5	6
FW FLOW, LB/HR	4357000.	4350000.	3492240.	3492240.	3499240.	3499240.
FW TEMPERATURE OUT, F	502.5	435.4	369.2	290.6	262.3	195.5
FW ENTHALPY OUT, BTU/LB	490.7	417.9	342.1	260.0	231.1	163.6
FW TEMPERATURE IN, F	435.4	379.9	290.6	262.3	195.5	158.7
FW ENTHALPY IN, BTU/LB	417.9	359.7	260.0	231.1	163.6	126.6
EXTRACTION STAGE PRESSURE, PSIA	717.7	387.0	177.0	66.7	42.6	12.4
EXCTION STEAM FLOW @ HTR, LB/HR	367361.	210858.	266246.	66065.	217881.	117344.
EXTTION STEAM FLOW @ TURB, LB/HR	367361.	215858.	266246.	66065.	217881.	117344.
EXCTION STM ENTHALPY @ HTR, B/LB	1269.6	1448.8	1357.1	1265.2	1228.0	1140.6
EXTTION STM ENTHALPY @ TURB, B/LB	1269.6	1448.8	1357.1	1265.2	1228.0	1140.6
SHELL PRESSURE, PSIA	696.2	363.8	171.7	62.7	40.0	11.7
SHELL TEMPERATURE, F	502.5	435.4	369.2	295.6	267.3	200.5
SHELL DRAIN FLOW, LB/HR	374388.	586515.	857760.	96532.	314413.	431757.
SHELL DRAIN TEMPERATURE, F	445.4	389.9	369.2	272.3	205.5	168.7
SHELL DRAIN ENTHALPY, BTU/LB	425.1	364.2	342.1	241.3	173.7	136.6
HEATER DUTY, BTU/HR	317248763.7	252833829.2	286503330.0	101004927.5	236249591.5	129456273.7

FW HEATER NO.	7
FW FLOW, LB/HR	3499240.
FW TEMPERATURE OUT, F	158.7
FW ENTHALPY OUT, BTU/LB	126.6
FW TEMPERATURE IN, F	109.7
FW ENTHALPY IN, BTU/LB	77.7
EXTRACTION STAGE PRESSURE, PSIA	5.5
EXCTION STEAM FLOW @ HTR, LB/HR	145031.
EXTTION STEAM FLOW @ TURB, LB/HR	145031.
EXCTION STM ENTHALPY @ HTR, B/LB	1091.4
EXTTION STM ENTHALPY @ TURB, B/LB	1091.4
SHELL PRESSURE, PSIA	5.2
SHELL TEMPERATURE, F	163.7
SHELL DRAIN FLOW, LB/HR	580292.
SHELL DRAIN TEMPERATURE, F	119.7
SHELL DRAIN ENTHALPY, BTU/LB	87.7
HEATER DUTY, BTU/HR	171197372.6

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 4

TABLE IV-A EXTERNAL HEAT ADDITION (REMOVAL)

TOTAL EXTERNAL HEAT ADDED TO THE TURBINE CYCLE IS	7092967.	BTU/HR
EXTERNAL HEAT ADDITION AFTER FW HEATER NO 1 EXTSER=	15000.	BTU/HR
EXTERNAL FEEDWATER ADDED AFTER FW HEATER NO 2 QFWEXT =	7000.	LB/HR
AT AN ENTHALPY OF HFWEXT =	430.0	BTU/LB
STEAM REMOVED FROM THE NO 2 FEEDHEATER EXTRACTION LINE, QEXT =	-5000.	LB/HR
CONDENSATE RETURNED TO THE NO 3 FW HEATER,QECOND=	5000.	LB/HR
AT AN ENTHALPY OF HECOND =	1000.0	BTU/LB
EXTERNAL FEEDWATER TAKEN AFTER FW HEATER NO 5 QFWEXT =	-7000.	LB/HR
AT AN ENTHALPY OF HFWEXT =	231.1	BTU/LB
EXTERNAL HEAT ADDITION PARALLEL TO FW HEATER NO 5 EXTPAR=	-10000.	BTU/HR
CONDENSATE RETURNED TO THE CONDENSER, QECOND =	-6000.	LB/HR
AT AN ENTHALPY OF HECOND =	76.7	BTU/LB
STEAM INDUCTED AFTER IP EXHAUST, QPROSS =	6000.	LB/HR
AT AN ENTHALPY OF HPROSS =	1400.0	BTU/LB

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 5

TABLE V CONDENSER

CONDENSER PRESSURE, PSIA	1.22788	=	2.50	IN. HGA
CONDENSATE FLOW, LB/HR	3499240.			
CONDENSATE TEMPERATURE, F	108.7			
CONDENSATE ENTHALPY, BTU/LB	76.7			
CONDENSER DUTY, BTU/HR	2750333992.			

TABLE VI CONDENSATE AND FEEDWATER

FW FLOW TO FW PUMP, LB/HR	4350000.			
FW TEMPERATURE TO FW PUMP, F	369.2			
FW ENTHALPY TO FW PUMP, BTU/LB	342.1			
FW ENTHALPY RISE ACROSS FW PUMP, BTU/LB	17.7			
FW PRESSURE INCREASE ACROSS FW PUMP, PSI	4398.			
FW FLOW TO STEAM GENERATOR, LB/HR	4357000.			
FW TEMPERATURE TO STEAM GENERATOR, F	502.5			
FW ENTHALPY TO STEAM GENERATOR, BTU/LB	490.7			
MAKE-UP TO CONDENSER HOTWELL, LB/HR	0.			
STEAM FLOW FROM STEAM GENERATOR, LB/HR	4357000.			
STEAM ENTHALPY FROM STEAM GENERATOR, BTU/LB	1421.7			
THROTTLE STEAM FLOW FW PUMP TURBINE, LB/HR	255147.			
THROTTLE PRESSURE FW PUMP TURBINE, PSIA	171.7			
THROTTLE ENTHALPY FW PUMP TURBINE, BTU/LB	1357.3			
EXHAUST PRESSURE FW PUMP TURBINE, PSIA	1.47346	=	3.00	IN. HGA
EXHAUST ENTHALPY FW PUMP TURBINE, BTU/LB	1055.8			

==EXAMPLE CASE NO 2. ===
STEAM TURBINE CYCLE HEAT BALANCE
PRESTO, VERSION 02/10/79

CALCULATED RESULTS, PAGE 6

TABLE VII VALVE STEM AND SHAFT LEAKAGES

STEAM SEAL REGULATOR	
FLOW TO SSR, LB/HR	8704.
ENTHALPY AT SSR, BTU/LB	1366.3
FLOW FROM SSR TO MAIN CONDENSER, LB/HR	2400.
FLOW FROM SSR TO STEAM PACKING EXHAUSTER, LB/HR	2800.
FLOW FROM SSR TO FW HEATER NO. 7, LB/HR	3504.
MAKE-UP FROM THROTTLE STEAM, LB/HR	0.
ENTHALPY OF MAKE-UP STEAM, BTU/LB	0.0
THROTTLE VALVE STEM	
LEAK NO. 19(DRAINS TO FW HEATER NO. 1), LB/ HR	7028.
ENTHALPY LEAK NO. 19, BTU/LB	1421.7
LEAK NO. 20(DRAINS TO FW HEATER NO. 2), LB/ HR	1268.
ENTHALPY LEAK NO. 20, BTU/LB	1421.7
LEAK NO. 21(DRAINS TO SSR), LB/HR	858.
ENTHALPY LEAK NO. 21, BTU/LB	1421.7
HP TURBINE SECTION, BOWL	
LEAK NO. 1(DRAINS TO SHELL OF THIS TURBINE SECTION.)	39446.
ENTHALPY LEAK NO. 1, BTU/LB	1394.9
LEAK NO. 3(DRAINS TO FW HEATER NO. 4), LB/ HR	11589.
ENTHALPY LEAK NO. 3, BTU/LB	1394.9
LEAK NO. 4(DRAINS TO SSR), LB/HR	2013.
ENTHALPY LEAK NO. 4, BTU/LB	1394.9
HP TURBINE SECTION, SHELL	
LEAK NO. 6(DRAINS TO FW HEATER NO. 4), LB/ HR	15105.
ENTHALPY LEAK NO. 6, BTU/LB	1269.6
LEAK NO. 7(DRAINS TO SSR), LB/HR	2795.
ENTHALPY LEAK NO. 7, BTU/LB	1269.6
IP TURBINE SECTION, BOWL	
LEAK NO. 8(DRAINS TO SHELL OF THIS TURBINE SECTION.)	3396.
ENTHALPY LEAK NO. 8, BTU/LB	1516.0
LEAK NO. 10(DRAINS TO FW HEATER NO. 4), LB/ HR	1584.
ENTHALPY LEAK NO. 10, BTU/LB	1516.0
LEAK NO. 11(DRAINS TO SSR), LB/HR	1215.
ENTHALPY LEAK NO. 11, BTU/LB	1516.0
IP TURBINE SECTION, SHELL	
LEAK NO. 13(DRAINS TO FW HEATER NO. 4), LB/ HR	2189.
ENTHALPY LEAK NO. 13, BTU/LB	1357.1
LEAK NO. 14(DRAINS TO SSR), LB/HR	1823.
ENTHALPY LEAK NO. 14, BTU/LB	1357.1

Appendix B

PRESTO SUBROUTINES

BIVPOL is a mathematical routine used to solve bivariate polynomials as defined in Appendix I of GER-2007C. BIVPOL is called by subroutines F2 through F25.

BLOCK DATA initializes a collection of variables to their default values.

CONVRT converts case output to metric units. It is called from METRIC.

DATAIN reads the input data and prints out the cycle parameters. DATAIN is called from MAIN.

FWHEAT performs cascading feedwater heater heat balances. It is called from MAIN for each turbine section.

FWHPAR uses the input data to assign feedwater heater heat parameters for use by FWHEAT. FWHPAR is called once from MAIN.

FWPT calculates feedwater pump turbine flows, enthalpies, and work. It is called from MAIN.

F2—F25 are mathematical subroutines corresponding to GE Figs. 2—26 in GER-2007C. F25 contains both GE Figs. 25 and 26. The following is a description of each figure:

Fig. 2. Nonreheat condensing, 2-row governing stage, design flow, efficiency correction for governing stage pressure ratio (design governing stage exit to throttle) as a function of volume flow.

Fig. 3. Nonreheat condensing, 2-row governing stage, part-load efficiency correction for throttle flow ratio.

Fig. 4. Nonreheat condensing, 2-row governing stage, part-load efficiency correction for governing stage pressure ratio (throttle to governing stage exit) as a function of throttle flow ratio.

Fig. 5. Nonreheat condensing, 2-row governing stage, efficiency correction for mean-of-valve loops as a function of throttle flow ratio (optional).

Fig. 6. 3600-rpm high-pressure turbine section, 1-row governing stage, design flow efficiency correction for pressure ratio (exhaust to rated throttle).

Fig. 7. 3600-rpm high-pressure turbine section, 1-row governing stage, design flow efficiency correction for governing stage pitch diameter.

Fig. 8. 3600-rpm high-pressure turbine section, 1-row governing stage, part-load efficiency correction for governing stage pitch diameter as a function of throttle flow ratio.

Fig. 9. 3600-rpm high-pressure turbine section, 1-row governing stage, part-load efficiency correction for throttle flow ratio as a function of pressure ratio (rated throttle to design exhaust).

Fig. 10. 3600-rpm high-pressure turbine section, 2-row governing stage, design flow efficiency correction for pressure ratio (design exhaust to rated throttle).

Fig. 11. 3600-rpm high-pressure turbine section, 2-row governing stage, part-load efficiency correction for throttle flow ratio as a function of pressure ratio (rated throttle to design exhaust).

Fig. 12. 3600-rpm high-pressure turbine section, 1- or 2-row governing stage, efficiency correction for mean-of-valve loops (optional).

Fig. 13. 3600-rpm intermediate-pressure turbine section, without governing stage, section efficiency as a function of pressure ratio (initial bowl to exhaust) and volume flow.

Fig. 14. 3600 and 1800-rpm reheat and nonreheat condensing section, efficiency correction for initial steam conditions (temperature and pressure).

Fig. 15. 3600- and 1800-rpm, reheat and nonreheat condensing section, correction to expansion line end point for exhaust pressure as a function of percent moisture.

Fig. 16. 3600-rpm condensing section exhaust loss as a function of last stage annulus area and volume flow.

Fig. 17. 1800-rpm condensing section exhaust loss as a function of last stage annulus area and volume flow.

Fig. 18. 3600-rpm condensing section exhaust loss for high-back-pressure units as a function of annulus area and volume flow.

Fig. 19. Mechanical losses as a function of generator rating and configuration.

Fig. 20. Generator loss factor K1 as a function of generator rating and cooling method.

Fig. 21. Generator loss factor K2 as a function of generator loading and cooling method.

Fig. 23. Change in generator loss with hydrogen pressure, at constant kVA.

Figs. 24–26. Expansion line construction guidelines.

GSTAGE calculates the governing stage exit conditions as a function of volume flow and stage design. It is called from MAIN.

HXTRAC looks up the extraction enthalpies using the turbine expansion line and the extraction pressures. It is called from MAIN.

LAGRAN is a mathematical interpolation routine.

LEAKS performs steam seal regulator calculations and contains leakage logic from Table II in GER-2007C.[8] It is called from MAIN.

LKAV is a multiple-entry subroutine containing leakage calculations detailed in Table II of GER-2007C.[8] ENTRY LKA corresponds to block A of Table II and so on. ENTRY LKV contains the valve-stem-leakage calculations. LKAV is called from MAIN and LEAKS.

METRIC prints the case results in metric units. METRIC is called from MAIN.

PROPHS is a steam table subroutine. Given enthalpy and entropy, this subroutine returns moisture, specific volume, temperature, pressure and state (superheated, dry and saturated, or wet).

PROPPH is similar to PROPHS, but the input properties are pressure and enthalpy.

PROPPS is similar to PROPHS, but the input properties are pressure and entropy.

RATFUN is a mathematical subroutine. It performs the rational function calculations defined in Appendix I of GER-2007C.[8] It is called by subroutines F2–F25.

RESULT is called from MAIN to print out the tables of results calculated during the last run. See Appendix A for a sample output.

SGROUP performs stage group efficiency calculations. Using the logic from Table I of GER-2007C,[8] this subroutine returns an expansion line endpoint to MAIN for each turbine expansion line.

SSRE calculates the steam seal regulator enthalpy and flows.

STER is an error subroutine called from the steam properties subroutines. It returns a traceback to aid in error location.

UNIPOL is a mathematical subroutine. It performs the univariate polynomial calculations defined in Appendix I of GER-2007C.[8]

XLOSS calculates the exhaust loss as a function of the last stage blade length and volume flow.

Appendix C

LIST AND LOCATION OF COMMONS

PRECEDING PAGE BLANK NOT FILMED 82

SUBROUTINES

BLOCK	CONVRT	DATAIN	FWHEAT	FWHPAR	FWPT	GSTAGE	HXTRAC	LEAKS	LKAV	MAIN	METRIC	RESULT	SGROUP	SSRE	XLOSS	COMMONS
BLOCK																BLOCK
COMPND		COMPND								COMPND	COMPND	COMPND				COMPND
CONST	CONST	CONST	CONST			CONST				CONST	CONST	CONST	CONST		CONST	CONST
CONV			CONV							CONV			CONV			CONV
DATA		DATA						DATA		DATA			DATA			DATA
DATBLK		DATBLK								DATBLK						DATBLK
	DUTY		DUTY									DUTY				DUTY
	ENTHM										ENTHM					ENTHM
	ENTRM										ENTRM					ENTRM
EXTHT	EXTHT	EXTHT	EXTHT							EXTHT	EXTHT	EXTHT				EXTHT
	EXTM										EXTM					EXTM
FEED		FEED			FEED					FEED						FEED
FPT	FPT	FPT			FPT					FPT	FPT	FPT				FPT
FWH	FWH	FWH	FWH							FWH	FWH	FWH				FWH
	GS							GS	GS	GS	GS	GS				GS
GSNEW										GSNEW			GSNEW			GSNEW
HEAT	HEAT	HEAT	HEAT	HEAT			HEAT			HEAT		HEAT				HEAT
	HP							HP		HP	HP	HP				HP
	IP							IP		IP	IP	IP				IP
IP2	IP2	IP2						IP2		IP2		IP2				IP2
LEAK	LEAK	LEAK	LEAK					LEAK	LEAK	LEAK	LEAK	LEAK		LEAK		LEAK
LP	LP	LP						LP	LP	LP	LP	LP	LP			LP
	MASSM										MASSM					MASSM
	MIS							MIS	MIS	MIS	MIS	MIS				MIS
PAR1	PAR1	PAR1	PAR1	PAR1				PAR1	PAR1	PAR1	PAR1	PAR1				PAR1
	PAR2								PAR2	PAR2		PAR2				PAR2
	PRESSM										PRESSM					PRESSM
	RH1								RH1	RH1	RH1	RH1				RH1
	RH2									RH2	RH2	RH2				RH2
	T								T	T	T	T	T			T
	TEMPM										TEMPM					TEMPM

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