A Three Model System for Identifying and Quantifying Turbine Cycle Losses

September 1983

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ABSTRACT

The objective of this report is to provide a discussion of the application of PEPSE as a tool for turbine cycle performance calculations on older, small-to-medium-sized fossil fuel generating units. At the Ohio Edison Company (OEC), PEPSE has been incorporated with an established performance testing program and is now used to alleviate time-consuming manual calculations, to ensure standardized analyses, and to provide sensitivity study capabilities for off-design operating conditions.

At OEC, the approach with PEPSE has been to provide each generating unit with three separate models. The first provides performance parameter calculations for turbine cycle components based on actual test data input. The second duplicates the calculations for the unit operating under design conditions. The third allows direct substitution of design for actual performance parameters and boundary conditions to quantify the effects of off-design conditions on gross machine output and turbine heat rate.

The PEPSE program has thus far been used primarily by OEC's Central Performance and Projects Engineering Group. Its use in the plants is currently being expanded through telecommunications links with a central computer. To date 7 of 19 OEC small fossil fuel generating units have been modeled with PEPSE, ranging in size from 48 to 156 MW. Efforts continue on the remaining units; completion of all unit modeling is expected by mid-1984. The accuracy of the PEPSE design models, determined by comparing PEPSE calculations to the manufacturer's design information, ranges from ± 0.2% to ± 0.5%. Extensive use of controls and schedules has been necessary to achieve this degree of accuracy.

This report describes in greater detail the development of the three types of PEPSE models used by OEC. It also describes the use of PEPSE as part of a routine performance testing program. Finally, hardware applications and data input format are also discussed.

Section 1

INTRODUCTION

The Ohio Edison Company (OEC) is the 17th largest investor owned electric utility in the United States. Headquartered in Akron, Ohio, OEC services approximately 840,000 customers. A wholly owned subsidiary, Penn Power, headquartered in New Castle PA., serves about 125,000 customers. Including Penn Power, OEC currently operates 38 fossil fuel generating units totaling 6373 MW. OEC also owns 425 MW of nuclear generating capacity currently operating and 1199 MW of nuclear generating capacity now under construction. The nuclear generating units are not operated by OEC. Fossil fuel units include combustion turbine and diesel peaking units, ranging from 6 to 30 MW, and pulverized coal steam units ranging from 35 to 800 MW.

At OEC, PEPSE has been incorporated with an established generating unit performance testing program and is now used to alleviate time consuming manual calculations, insure standardized analysis and to provide sensitivity study capabilities for off-design operating conditions. The objectives of this report are to provide an overview of our performance testing program and a discussion of the application of PEPSE to this program.

The generating units that are of primary concern in this report may be classified as older, small-to-medium-sized fossil fuel generating units. They typically range in size from 48 to 160 MW and have had between 25 and 40 years of operating service at the time of this writing. Detailed design information, required for the PEPSE program, is not readily available for some units of this description. To circumvent this problem, OEC has resorted to several expediencies that may be of interest to other PEPSE users. This report describes in some detail the development of three basic types of turbine cycle models. Hardware applications and data input formats are also discussed.

Section 2

OEC Performance Testing Program, An Overview

The majority of OEC's pulverized coal steam units are routinely tested for performance by a centralized performance engineering group that is assigned to the General Office. The goals of the performance testing program may be summarized as:

1. Conduct periodic performance investigations on system equipment to quantify operating conditions for each generating unit.
2. Provide definitive recommendations to maintenance and operations personnel for correction of operating or equipment conditions that would prevent continuous, efficient unit operation.
3. Assist in formulation of plans for corrective actions.
4. Trend performance parameters and provide estimated operation costs associated with correctable unit inefficiencies.
5. Publish performance investigation results in a timely manner.
6. Provide a formal discussion of results between operating, maintenance and performance personnel.

The current, centralized performance testing program was initiated in 1980. Prior to that time, performance testing was conducted entirely by Plant Site personnel and was done in addition to normal plant duties. Often, more urgent day to day operating and maintenance tasks took precedence over performance monitoring so that minimal testing and evaluation was completed. Equipment performance evaluations were not standardized; technique, emphasis and experience varied among the plants. To avoid those problems, the current program was started. Designed around a central testing group, dedicated only to performance evaluation, and assigned to the General Office, the current program places the responsibility for scheduling, general direction of testing, calculations, analysis and publication of results on the central group. Plant personnel are responsible for instrument calibration, unit operation within test guidelines and the majority of data gathering.

Performance tests are conducted on each generating unit on a regularly scheduled basis. For all plants except Sammis and Mansfield, tests are done twice each year by the General Office Performance & Projects Group and once by the Plant Engineering Staff. Tests done by the G.O. Group bracket the annual maintenance outage, while the plant performance test is scheduled to balance the remaining interval between G.O. tests. The pre-maintenance outage test is normally scheduled for 10-12 weeks ahead of the outage and the post-outage test for 2-6 weeks following the outage. Sammis and Mansfield Plants conduct unit performance tests twice a year, bracketing unit maintenance outages, and are conducted entirely by Plant Engineering personnel.

Each unit performance test is comprised of an evaluation of the operating conditions of the unit boilers, turbine, condenser, pumps, feedwater heaters, pulverizers and air heaters. Testing on additional unit equipment is conducted as warranted. Performance tests are conducted over a two-to-four hour period during which operating conditions are held constant. Parameters such as throttle flow and steam conditions are maintained at, or near, the manufacturers capacity rating and are duplicated, within tolerances, between tests. Further, to insure valid comparisons between tests, corrections are made for deviant boundary conditions such as ambient temperatures and pressures. Testing generally follows the guidelines established for the various components within the A.S.M.E. Power Test Codes.

Results of unit performance tests are published in reports issued to the Plants, General Office Production Maintenance, and Production Operations Sections. The reports summarize performance parameters, make recommendations concerning specific maintenance and/or operating characteristics, trend performance parameters and contain copies of all pertinent calculations and test data. The reports are on file in the General Office Production Performance Section and at the Plants.

Section 3

Application of PEPSE within Performance Testing Program

At OEC, the approach with PEPSE has been to provide each generating unit with three separate models. The first provides performance parameter calculations for turbine cycle components based on actual test data input. The second duplicates this set of calculations for the unit operating at design conditions, while the third allows direct substitution of design for actual performance parameters and boundary conditions to quantify the effects of off-design conditions on gross machine output and turbine heat rate.

The unit models are accessible through ROSCOE, OEC's data storage facility. Test data is inputted by calling the appropriate model and entering the information at pre-formatted locations. Simplicity and user ease have been primary objectives in the development of OEC unit models. Liberal use of comment lines for identifying information inputs by labels and underlining obviates the necessity for continual reference to the users manual. Duplicate inputs, sometimes required by PEPSE, are minimized by the use of special input/output and operations features. Each model contains initial job control language (JCL) that calls the PEPSE program as a subroutine. Input formats of all models are generally similar. This facilitates the use of PEPSE by persons other than those that participated in the model development.

Following the entry of all indicated data, the completed model is submitted and run batch. Upon completion, program output is either viewed on the CRT screen or a hard copy print requested. PEPSE output formats exceed the 80 character line limit of the CRT's, but this can be circumvented by terminal manipulations. Generally, we have limited the output to display only component fluid properties, turbine enthalpy/entropy conditions and efficiency calculations, feedwater heater performances and over-all turbine cycle efficiency results.

Following are generic descriptions of each the three basic model types currently used by OEC performance engineering:

1. <u>Turbine Cycle Performance Based on Actual Test Data</u>

   These models require the input of all turbine cycle performance data normally acquired during a routine performance test. Typical test data input description is contained on Table No. 1, attached. The output provides a detailed mass-energy balance, calculates turbine stage group efficiencies, heat exchanger performance parameters and the over-all turbine heat rate.

   For this case the gross machine output is input and the turbine cycle balanced around this and the test throttle flow through the use of Special Option No. 2. Typically, we allow the turbine expansion line to swing from the point corresponding to the I.P.-L.P. cross-over. All turbine stage groups are modeled as component type 8, or general turbine stage groups. Solution method is by IPCASE 5 in which shell pressure and enthalpy are input. Where shell pressure is not measured directly, extraction pressures are used, these must be corrected for line pressure drop. Corrections may be made by an operation, in this manner duplicate inputs (i.e., BFW heater extraction pressure, PPSI; CTYPE 14, 16 or 18) are avoided.

Feedwater heaters are solved in the special performance mode (NMODFW=3). Design TTD's and DCA's are installed in the base model but are updated by the inputs of actual feedwater and drain temperatures and extraction steam conditions for each test case. These inputs exceed the minimum data requirements for performance calculations, but seem to us to be more straightforward than having to input calculated TTD's and DCA's.

Measurable minor flows such as attemperation, make-up and auxiliary services are input directly as bleed rates from fixed flow splitters. Gland leakages and other flows that are not normally measured during a routine unit performance test are scheduled. The scheduled flow rates are typically derived from initial field efficiency tests in which these flows were measured at various loads, or from the manufacturer's design heat balances. Fixed flow splitters, (CTYPE 61) are also used for gland leakages and dummys, shaft leakage splitters (CTYPE 64) are avoided as packing leakage constants (PACLEK) are generally unobtainable for our older units.

The "Bottom Line" unit performance parameter that we use PEPSE to calculate is gross turbine heat rate (THR). It is difficult for us to separate boiler station power from turbine station power. For this reason, we have found it preferable to calculate the overall unit heat rate (UHR) by modifying the PEPSE derived turbine heat rate by the following equation:

$$UHR = \left(\frac{THR}{\text{boiler eff.}} + \text{make-up losses}\right)\left(\frac{GKW}{GKW - \text{total sta. pwr.}}\right)$$

To obtain results that are comparable with the manufacturers predicted heat rates we have found it necessary to mix superheat attemperation back into the main BFW stream ahead of the turbine cycle output component. Reheat attemperation is inherently self-contained within the cycle since the reheaters are identified as turbine cycle components.

2. Turbine Cycle Performance Based on Design Information

These models require only the input of turbine throttle flow and an indication of whether auxiliary devices such as combustion air heaters are in, or out of service. We find it preferable to compare design, expected and actual performance parameters on the basis of mass flow rather than machine output, therefore Special Option No. 1 is not used. The output for these models provide a detailed mass-energy balance, turbine stage group efficiencies, heat exchanger performance that through the use of controls modifying expansion line factors (EFMULT and SHAPER) can be obtained that will correct PEPSE to match the manufacturer's values. This is typically the situation for Westinghouse machines. We generally find it necessary to use efficiency multipliers (EFMULT) for both the H.P. and I.P. sections and shape factors (SHAPER) for all groups within the I.P. and L.P. sections. EFMULTS and SHAPERS are derived from the VWO condition and remain constant throughout the load range. Through the use of these expansion line modifiers, we have matched enthalpies to within ± 0.5 Btu/Lbm and pressures to within 1 psia. We have also used controls to calculate governing stage pitch diameters where that information is otherwise unavailable. To do this, we set a control to calculate that variable based on known first stage enthalpies.

All minor flows, including attemperation, make-up and leakages are scheduled as functions of throttle flow. As with the actual test case, packing leakage constants (PACLEK) are typically unavailable so fixed flow splitters are used throughout. For the design case other quantities are also scheduled. These include throttle and reheat steam temperatures and pressures as functions of throttle flow, pump discharge pressures and efficiencies as functions of condensate flow and combustion air heater heat transfer as a function of extraction pressure.

Component description inputs typically do not exceed the minimum data requirements for performance calculations by PEPSE. We limit the maximum number of iterations allowed (ITERMAX) to 20 and extended the maximum allowable flow imbalances to 10 Lbm/Hr per extraction (EXTERR) and 100 Lbm/Hr for the entire unit (CIERR). Most PEPSE runs are executed within 12 iterations with this criterion. Turbine calculation procedure are based on performance data (NGEPRO=0).

3. Loss Analysis Calculation Models

These models have been developed to quantify the effects of off-design conditions. They allow the direct substitution of design for actual performance results and boundary conditions and thereupon calculate gross machine output and heat rate. The differences between results of the initial conditons (Actual Test Case) and the updated conditions (Design Case) are evaluated for each deviant condition. In this manner, the effect of each condition may be quantified in terms of lost generation and/or increased heat rate.

These models are in effect similar to our design case models in that they predict the gross machine output for a given throttle flow. The primary differences are the use of general turbine components (CTYPE 8) instead of generic GOV., H.P., I.P. and L.P. types and the requirement that most minor flows and boundary conditions be input rather than automatically scheduled.

Turbine stage groups are solved by inputting efficiencies and either pressure ratios or shell flow coefficients (IPCASE 1 or 3). The last stage of the L.P. turbine requires IPCASE 5, in which shell enthalpy is input. In this case, the E.L.E.P. at the base pressure for the design or test case is input. For the last stage in the H.P. and I.P. groups, IPTYPE must be specified as 5. This insures that the pressure ratio for that stage is held constant at the inputted value. By proceeding in this manner, the physical conditions of each stage, independent of inlet and exhaust conditions may be evaluated.

Physical conditions of feedwater heaters are best defined by TTD and DCA. The loss analysis model therefore requires input of these values. The design case TTD's and DCA's are installed in the basic model and are labeled and underlined for easy updating. Actual TTD's and DCA's, calculated by the PEPSE actual test case model, may be substituted on an individual or combined basis.

Boundary conditions and minor flow rates are also required input for these models. A list of deviant conditions that are typically evaluated for each performance test is presented in Table No. 2, attached.

Our procedure for using the loss analysis model requires that all design case performance parameters and boundary conditons be input and run. Bottomline results, in terms of gross generation and heat rate, are compared. Typically, loss analysis case gross generation agrees with the design case within ± 0.2% and heat rate within ± 0.1%. Following this, the exercise is repeated for actual case conditions. The differences between the loss analysis case results and actual case results are typically also within the same range of accuracy. At this point, performance conditions are altered sequentially and accumulatively. Each alteration requires an individual run. Typically, 10 to 20 individual conditions are evaluated.

The accuracy of our models, determined by comparing PEPSE design case results to manufacturer's design information, ranges from ± 0.2% to ± 0.5% for machine output and ± 0.1% to ± 0.2% for gross turbine heat rate. Our efforts to improve accuracy seem to become asymptotic beyond this limit. We have also noticed that accuracy tends to diminish at reduced load cases. Generally, we find that PEPSE more closely matches MFG's design information for G.E. than Westinghouse units despite the use of shape factors and efficiency multipliers.

Section 4

PEPSE Proliferation, Extending its Use to the Plants

The use of PEPSE and the unit models that have been developed to date are not limited to the G.O. Performance and Projects Section. The program and models may be accessed by Plant Engineering personnel through telecommunications links with a central computer. Each user may store and modify any model in his (or her) ROSCOE library. Information packages for each unit modeled with PEPSE, containing copies of each of the three types of model input format, model identification, component and geometry identification, accuracy statements and special instructions are currently being prepared by Performance and Projects Section; these will be issued to the Plants upon completion.

A description of the equipment currently in use at OEC on which PEPSE is utilized follows:

Main Frame Computer	:	IBM 3081 - OS/MVS 16 MEG's M.I.P.S. Capacity - 11.5
Local (G.O.) Terminals	:	Harris 817 D Application - ROSCOE/Batch Input
Local (G.O.) Printer	:	IBM 3268 Model 2
Remote (Plants) Cluster Control	:	IBM 8130
Remote (Plants) Terminals	:	IBM 8775 Application - ROSCOE/Batch Input
Remote (Plants) Printer	:	IBM 3268 Model 1

Table No. 1; Listing of Actual Test Case PEPSE Model Input

1.	Unit No.	________	
2.	Test Date	________	
3.	Power Factor	________	
4.	Hydrogen Pressure	________	PSIA
5.	Gross Generation	________	GKW
6.	S.H. Steam Temp.	________	°F
7.	S.H. Steam Pres.	________	PSIA
8.	Throttle Flow	________	Lbm/Hr
9.	1st Stage Pres.	________	PSIA
10.	S.H. Inlet Pres. (same as Item 7)	________	PSIA
11.	H.R.H. Pres. After INTCPT. Valve	________	PSIA
12.	X-over Pres.	________	PSIA
13.	HP-3 Ext. Pres. (Item 61 x 1.05)	________	PSIA
14.	HP-3 Ext. Enthalpy	________	Btu/Lbm
15.	C.R.H. Pres. (Item 57 x 1.05)	________	PSIA
16.	C.R.H. Enthalpy	________	Btu/Lbm
17.	H.R.H. Temp.	________	°F
18.	Reheat % Pres. Drop (0. Item 18 1.00)	________	%
19.	Combustion Air Heater in Service	________	Y or N
20.	HP-1 Ext. Pres. (Item 53 x 1.05)	________	PSIA
21.	HP-1 Ext. Enthalpy	________	Btu/Lbm
22.	LP-3 Ext. Pres. (Item 49 x 1.05)	________	PSIA
23.	LP-3 Ext. Enthalpy	________	Btu/Lbm
24.	LP-2 Ext. Pres. (Item 45 x 1.05)	________	PSIA
25.	LP-2 Ext. Enthalpy	________	Btu/Lbm
26.	LP-1 Ext. Pres. (Item 41 x 1.05)	________	PSIA
27.	LP-1 Ext. Enthalpy (Best Estimate)	________	Btu/Lbm
28.	Turbine Exhaust Back Pressure	________	PSIA
29.	Estimated Exhaust Enthalpy	________	Btu/Lbm
30.	Total Attemperation	________	Lbm/Hr
31.	Reheat Attemperation	________	Lbm/Hr
32.	Attemperation Water Temp.	________	°F
33.	Attmp. Water Pres.	________	PSIA
34.	R.H. Attmp. Flow (same as Item 31)	________	Lbm/Hr
35.	Aux. Heater Shell Temp.	________	°F

Listing of Actual Test Case PEPSE Model Input (Cont'd)

36.	Aux. Heater Shell Pres.	______	PSIA
37.	Aux. Heater Shell Flow	______	Lbm/Hr
38.	Aux. Heater Drain Temp.	______	°F
39.	Monkey Flow	______	Lbm/Hr
40.	Drain Cooler DCA (T_{D-O} - T_{BFW-IN})	______	°F
41.	LP-1 Ext. Pres.	______	PSIA
42.	LP-1 BFW-Out Temp.	______	°F
43.	LP-2 Drain Temp.	______	°F
44.	LP-2 Ext. Temp.	______	°F
45.	LP-2 Ext. Pres.	______	PSIA
46.	LP-2 BFW-Out Temp.	______	°F
47.	LP-3 Drain Temp.	______	°F
48.	LP-3 Ext. Temp.	______	°F
49.	LP-3 Ext. Pres.	______	PSIA
50.	LP-3 BFW-Out Temp.	______	°F
51.	HP-1 Drain Temp.	______	°F
52.	HP-1 Ext. Temp.	______	°F
53.	HP-1 Ext. Pres.	______	PSIA
54.	HP-1 BFW-Out Temp.	______	°F
55.	HP-2 Drain Temp.	______	°F
56.	HP-2 Ext. Temp.	______	°F
57.	HP-2 Ext. Pres.	______	PSIA
58.	HP-2 BFW-Out Temp.	______	°F
59.	HP-3 Drain Temp.	______	°F
60.	HP-3 Ext. Temp.	______	°F
61.	HP-3 Ext. Pres.	______	PSIA
62.	HP-3 BFW-Out Temp.	______	°F
63.	Make-up Water Temp. (Inc. Monkey Heat)	______	°F
64.	Make-up Flow (Include Monkey)	______	Lbm/Hr
65.	Circ. Water Inlet Temp.	______	°F
66.	Circ. Water Inlet Pres.	______	PSIA
67.	Circ. Water Flow (Best Estimate)	______	Lbm/Hr
68.	BFP Discharge Pressure	______	PSIA
69.	Cond. Pump Disc. Pres.	______	PSIA
70.	Condenser Back Pressure	______	PSIA
71.	Hotwell Temperature (Optional)	______	°F

Table No. 2; Listing of Loss Analysis Case PEPSE Model Input

1.	LP-1 TTD (Design at 3.5)	____________	°F
2.	LP-2 TTD (Design at 4.0)	____________	°F
3.	LP-2 DCA (Design at 10.0)	____________	°F
4.	LP-3 TTD (Design at 2.0)	____________	°F
5.	LP-3 DCA (Design at 10.0)	____________	°F
6.	HP-1 TTD (Design at 0.0)	____________	°F
7.	HP-1 DCA (Design at 10.0)	____________	°F
8.	HP-2 TTD (Design at 0.)	____________	°F
9.	HP-2 DCA (Design at 10.0)	____________	°F
10.	HP-3 TTD (Design at 0.)	____________	°F
11.	HP-3 DCA (Design at 10.0)	____________	°F
12.	Condenser B.P. (Design at -2.00)	____________	in.HgA (-)
13.	Hotwell Temp. (Design at 101°F)	____________	°F
14.	H.R.H. Steam Temp. (Design at 1000°F)	____________	°F
15.	% Reheat Pres. Drop (Design at 0.11651)	____________	%
16.	Comb. A.H. HT X-fer (Design at -11.0 E6)	____________	Btu/Hr
17.	Comb. A.H. In Service	____________	Y or N
18.	S.H. Steam Temp. (Design at 1000°F)	____________	°F
19.	S.H. Steam Pres. (Design at 1465.)	____________	PSIA
20.	Throttle Flow	____________	Lbm/Hr
21.	Gov. Stage Efficiency (0. Eff 1.00)	____________	
22.	Gov. Stage Shell Flow Coefficient	____________	
23.	HP-101 Stage Efficiency	____________	
24.	HP-101 Stage SFC	____________	
25.	HP-102 Stage Eff.	____________	
26.	HP-102 Shell Pressure	____________	PSIA
27.	IP-110 Stage Eff.	____________	
28.	IP-110 Stage SFC	____________	
29.	IP 111 Stage Eff.	____________	
30.	IP 111 Stage SFC	____________	
31.	LP-120 Stage Eff.	____________	
32.	LP-120 Stage SFC	____________	
33.	LP-121 Stage Eff.	____________	
34.	LP-121 Stage SFC	____________	
35.	LP-122 Stage Eff.	____________	

36. LP-122 Base ELEP	____________	°F
37. HP Inlet Pressure	____________	PSIA
38. HP Inlet Enthalpy	____________	Btu/Lbm
39. HP Inlet Mass Flow	____________	Lbm/Hr
40. IP Inlet Pressure	____________	PSIA
41. IP Inlet Enthalpy	____________	Btu/Lbm
42. IP Inlet Mass Flow	____________	Lbm/Hr
43. LP Inlet Pressure	____________	PSIA
44. LP Inlet Enthalpy	____________	Btu/Lbm
45. LP Inlet Mass Flow	____________	Lbm/Hr