UNIT OPERATION WITH
FEEDWATER HEATERS OUT OF SERVICE

Energy Incorporated
PEPSE User's Group Meeting
November 1-2, 1984
New Orleans, Louisiana

J. P. Campbell
J. V. Locher
Pennsylvania Electric Company
November 1, 1984

ABSTRACT

The advent of the PEPSE Computer Code has resulted in the ability to analyze specific plant operating conditions. As a result, operating procedures have been developed to assure equipment protection, maximize generation, and increase unit efficiency while operating with feedwater heaters out of service.

It has become necessary, at many of Pennsylvania Electric's Generating Stations, to operate for extended periods of time with feedwater heaters out of service due to tube leaks. To insure turbine protection, turbine manufacturers have developed generic operating procedures which recommend maximum operating limits with various combinations of feedwater heaters out of service. These procedures, although effective in equipment protection, are extremely conservative and often result in unnecessary load reductions.

As an alternative to vendor recommendations and/or improper unit operation, Penelec has developed a procedure where each operating situation is reviewed on an individual basis to determine maximum safe operating limits. This procedure, which utilizes turbine, boiler, and feedwater heater loading as limiting parameters, has minimized both generation and efficiency losses at Penelec.

INTRODUCTION

Pennsylvania Electric Company owns or operates eight (8) coal-fired generating stations consisting of twenty-one (21) individual units with a total installed capacity of 6,314 MW. Many of these units are periodically required to operate with feedwater heaters out of service due to tube failures. Traditionally, these units were operated in this mode according to the turbine manufacturer's procedures for operating with feedwater heaters out of service. The vendor procedures generally required a load reduction to the unit's nameplate rating.

As Penelec became more familiar with the PEPSE code, it became apparent that the vendor procedures were very conservative and were resulting in unnecessary forced losses. It was decided that the PEPSE code could be utilized to develop operating procedures which would be tailored to individual units, with specific combinations of feedwater heaters out of service. A basic set of criteria was developed to be used in the analysis of any particular mode of operation. Loading on any turbine section would not exceed the loading present during normal operation at the unit's nominal rating. Boiler heat input would not exceed the heat input at nominal rated load. Individual feedwater heater loading would not exceed the maximum design loading (Many feedwater heaters are manufactured with substantial design margins and are capable of loadings in excess of those present at nominal rated load). The above criteria, and any other miscellaneous limitations inherent to an individual unit, would then be utilized to determine the throttle flow required to satisfy all imposed limitations.

This paper details the methodology required to analyze a specific unit to determine safe operating limits with various combinations of feedwater heaters out of service.

TEXT

Shawville Unit 1 will be used to illustrate the procedure for determining the safe operating point with feedwater heaters out of service. Shawville Unit 1 is rated at 145 MW and consists of a General Electric tandem compound, triple flow reheat turbine, and a Babcock & Wilcox 1900 psig, induced draft boiler. The feedwater system consists of dual high pressure heater strings, and a single low pressure string which extracts steam from seven stages of the turbine.

Two specific modes of operation will be analyzed in this paper. The first mode will consist of one high pressure string out of service with 50% of the feedwater flow being bypassed around the string which remains in service. Often, feedwater heaters are designed to operate in an overload condition, and can help minimize the effect of heater removals, but in this case, no design margin exists and heater loadings must not exceed the base loadings. Therefore, only 50% of the total feedwater flow can be passed through the remaining string. The second mode of operation will consist of one low pressure heater out of service with a 100% feedwater bypass.

The removal of high pressure feedwater heater strings does not present the problems or require the considerations that are necessary when low pressure heaters are removed from service. When an H.P. string is removed from service, its heat load is normally provided by the boiler. The only other component that is significantly affected, other than the turbine, is the deaerator where a slight increase in extraction steam flow occurs. Removal of L.P. heaters usually results in an extremely large increase in deaerator loading, and depending upon the deaerator capacity, an increase in H.P. heater loading could occur. Since the deaerator is a contact heater and is at saturated conditions, its outlet conditions are determined solely by the pressure of the extraction steam. Therefore, to accurately depict actual deaerator operation, the deaerator extraction line pressure drop must be modified to vary with the square of the flow.

Extraction line pressure drops are normally expressed as a percentage of turbine shell pressure, and although a percentage relationship may be acceptable under normal conditions, it does not provide an accurate representation during abnormal operation. Failure to modify the deaerator extraction line pressure drop will result in feedwater outlet conditions higher than would be expected in actual operation. This in turn will result in lower than actual H.P. heater loadings. If the deaerator capacity is such that its outlet conditions do in fact result in H.P. heater overloads, and the heaters are capable of handling the overload conditions, their extraction line pressure drops must also be modified.

PEPSE stream types 1 and 2 both provide pressure drops which vary as the square of the flow, and will accurately determine actual extraction line pressure differentials. Care must be taken, however, when applying these stream types in situations where large heater overloads occur. The maximum extraction flow for any heater at a given feedwater flow and temperature is ultimately determined by turbine shell pressure and extraction line piping configuration. The possibility exists that a choked flow (sonic velocity) condition could arise during extreme overloads. PEPSE stream types 1 and 2 do not address this possibility. Therefore, it may be necessary to manually calculate the choke point of a given extraction line to assure that the PEPSE calculated flow does not exceed the flow under a choked condition. The following analyses have been performed with only the deaerator extraction line pressure drop modified. The H.P. heaters, as mentioned previously, have no design margin, and extraction flows cannot exceed the flows which would occur during normal operation at rated load. Therefore, it is not necessary to modify their extraction line pressure drops.

The feedwater system consists of dual high pressure heater strings which extract steam from the 9th and 12th stages of the turbine. The initial step in analyzing the removal of one H.P. heater string from service is to determine if any process or equipment limitations exist other than the basic turbine, boiler, and feedwater heater limits. In the case of Shawville Unit 1, no additional limitations exist. The next step is to establish a base run at the units nominal rating with all heaters in service and no abnormal operating conditions. This base run will establish all of the parameters which will be imposed as limitations when heaters are removed from service. Figure I shows a schematic of the cycle with the base run data included. Upon establishing the base line data, run #2 is made. Run #2 consists of a string of H.P. heaters out of service with a 50% feedwater bypass, and no turbine, boiler, or feedwater heater limitations (Figure II). An analysis of run #2 indicates that boiler, turbine, and L.P. feedwater heater loadings exceeded the limits established in the base run. Boiler heat input increased by 5.5%, H.P. turbine loading increased by approximately 5.0%, I.P. by 7.5%, and L.P. heater loadings increased by an average of 10.0%.

A determination must now be made on where to place the initial cycle limits. Although the highest overload is occurring on the L.P. heaters, it is much easier from a modeling standpoint to limit either the boiler or the turbine. Therefore, on run #3, the flow through the 13th, 14th, and 15th stages of the I.P. turbine will be limited to that flow determined in the base run. This can be most easily accomplished by writing a control with the base run I.P. flow as a goal variable, and throttle flow as the control variable. The results of run #3 are shown in Figure III, and indicate that the limit imposed on the I.P. turbine results in a calculated throttle flow of 829,200 lb/hr, a reduction of 64,800 lb/hr. In addition, the reduction in flow eliminates the overload conditions on both the boiler and the L.P. heaters. All of the imposed limitations have been satisfied by limiting the I.P. turbine flow. Therefore, the unit will be limited to a throttle flow of 829,200 lb/hr when a string of H.P. heaters is removed from service.

Although the analysis is complete, another consideration remains which is critical to the effectiveness of the above procedure. A basic parameter in the analysis is the percentage of feedwater flow which bypasses the heater string which remains in service. The amount of feedwater bypass has a significant effect on the final results of the analysis. Therefore, it is important to be able to accurately determine bypass flow in the field. The ideal method would be to have some type of flow measuring device permanently installed in the bypass line. If a measuring device is not available, an alternate method must be developed which will provide a reliable indication of flow. There are several methods available which can be used in lieu of flow measurement. They include pressure drop across a valve or through feedwater heaters, and final feedwater temperature indication. The Penelec procedure utilizes the pressure drop through feedwater heaters as an indication of flow. During normal operation, tube side pressure drop is monitored through specific combinations of heaters. When it becomes necessary to remove a string of heaters from service, the feedwater bypass is opened until the pressure differential through the remaining string equals the differential measured during normal operation.

The second part of the analysis deals with removing a single L.P. heater from service. The condensate system consists of a single string of low pressure heaters which extract steam from the 17th, 19th, 20th, and 21st stages of the turbine. In this analysis the 17th stage heater will be removed. The same basic procedure that was used to analyze the removal of the H.P. heater string will be used to analyze the removal of the 17th stage heater. The first step is a PEPSE run with the 17th stage heater out of service and no boiler, turbine, or feedwater heater limitations (Figure IV). The results of the run indicate that boiler heat input remained the same, I.P. turbine loading increased by 5.0%, and extraction steam flows to the deaerator and 12th stage heaters increased by 71% and 27% respectively.

The limits for the second run will be placed on the I.P. turbine, and the 9th and 12th stage heaters. The 9th and 12th stage heater limits are required because their feedwater inlet temperature will be reduced as a result of the decreased deaerator pressure, and an overload condition would develop if limits were not imposed.

The deaerator will not require any limitations since, in an overload condition, it is not as susceptible to internal damage as is a tube and shell heat exchanger. In addition, the importance of modifying the deaerator extraction line pressure drop to reflect a square root flow relationship is illustrated in this run. The 71% increase in deaerator steam flow as a result of removing the 17th stage heater, increased the deaerator extraction line pressure drop from 4.8 psi to 20.8 psi and resulted in an 18.5^{o}F decrease in feedwater outlet temperature. Had the pressure drop remained as a percentage of the turbine shell pressure, the outlet temperature would have remained virtually the same, and no increase in 9th and 12th stage heater loading would have been seen. The 17th, 18th, and 19th stages of the I.P. turbine will be limited, as before, by a control. Again, the goal variable is the flow through the indicated stages, and the control variable is throttle flow. The 9th and 12th stage heaters steam flows will be limited by specifying the feedwater temperature difference across each of the heaters. The results of the second run are shown in Figure V, and indicate that the imposed limitations are satisfied when the throttle flow is reduced by 24,000 lb/hr. The maximum throttle flow when operating with the 17th stage heater out of service will be 870,000 lb/hr.

SUMMARY

The procedure outlined in this paper shows how PEPSE can be used to make operating decisions with feedwater heaters out of service. Use of this procedure has allowed Penelec to optimize efficiency and cut load reductions.

The following tabulation summarizes the results of the previous examples, and illustrates the differences between vendor and PEPSE developed procedures for operating with feedwater heaters out of service.

	BASE CASE	CASE I		CASE II	
	Nominal Rating	H.P. String Removed		17th Stage Removed	
	PEPSE	PEPSE	VENDOR	PEPSE	VENDOR
Throttle Flow (KLB/HR)	894.0	829.2	578.4	870.0	603.7
Generation (MW)	141.8	138.5	100.0	139.5	100.0
Heat Rate (BTU/KWH)	7721	7820	7865	7793	7793

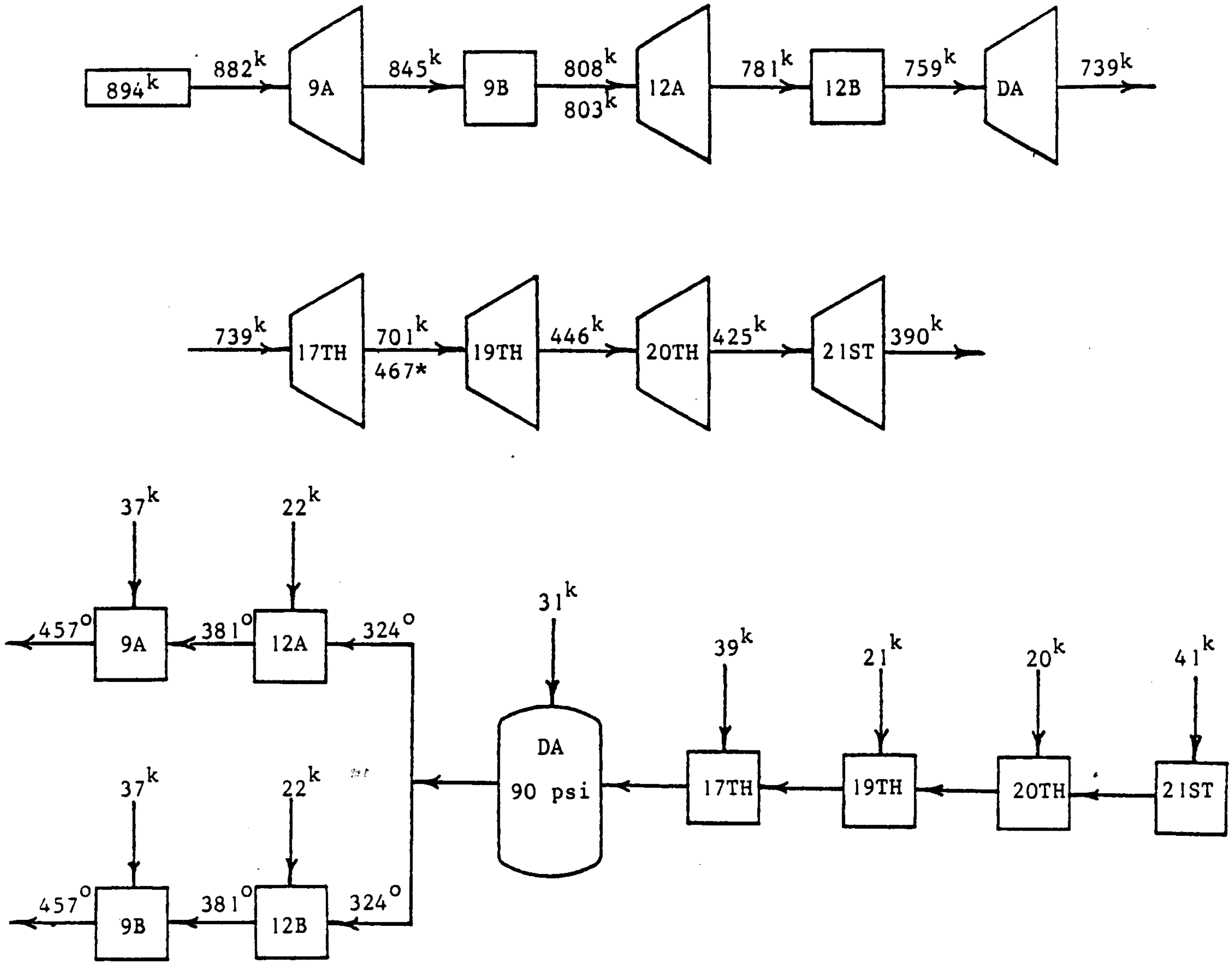
In both cases, the vendor procedures recommended load reductions of approximately 42 MW to the units nameplate rating of 100 MW. In comparison, the PEPSE developed procedures required load reductions of only 3.3 MW and 2.3 MW for Cases I and II respectively. In addition, the vendor procedure for Case I resulted in a heat rate penalty of 45 BTU/KWH. These losses equate to approximately $30,000/day in replacement energy costs.

As illustrated by the previous examples, PEPSE has enabled the utility engineer to analyze plant specific problems without solely relying on manufacturer's procedures. The turbine manufacturer's procedures for

operating with feedwater heaters out of service have to be conservative to protect their equipment under every possible operating condition. But the utility industry now has the ability to analyze each operating problem and determine the most effective, safe operating point for each plant. This has enabled Penelec to increase unit equivalent availability and realize significant cost savings.

SHAWVILLE UNIT #1

BASE CASE



* Flow Discontinuity Due To Triple Flow LP Turbine

Generation 141.8 MW

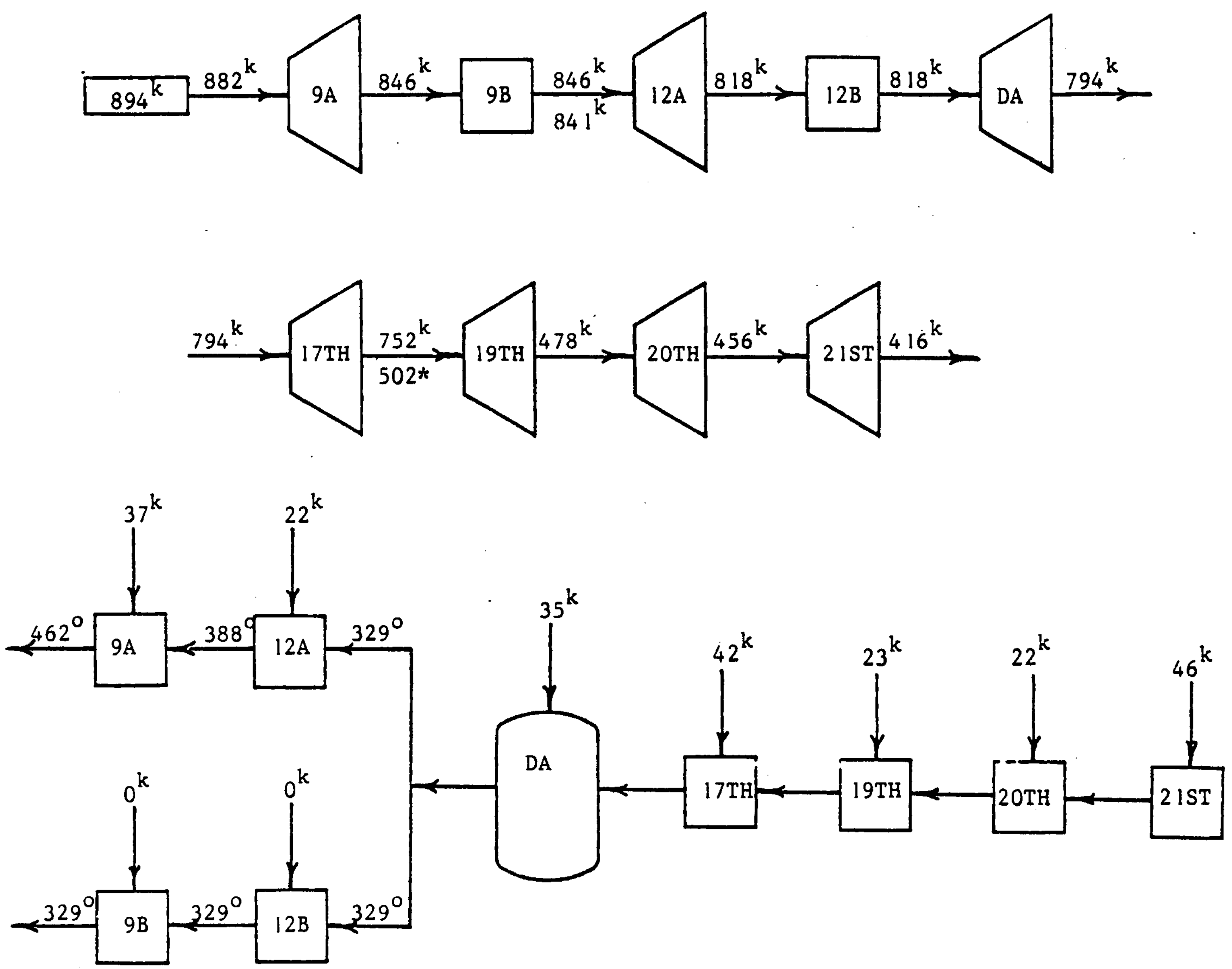
Heat Rate 7721 BTU/KWH

Heat Input 1.09×10^9 BTU/HR

Figure I

SHAWVILLE UNIT #1

HP STG OOS / NO LIMITS



* Flow Discontinuity Due To Triple Flow LP Turbine

Generation 147.4 MW

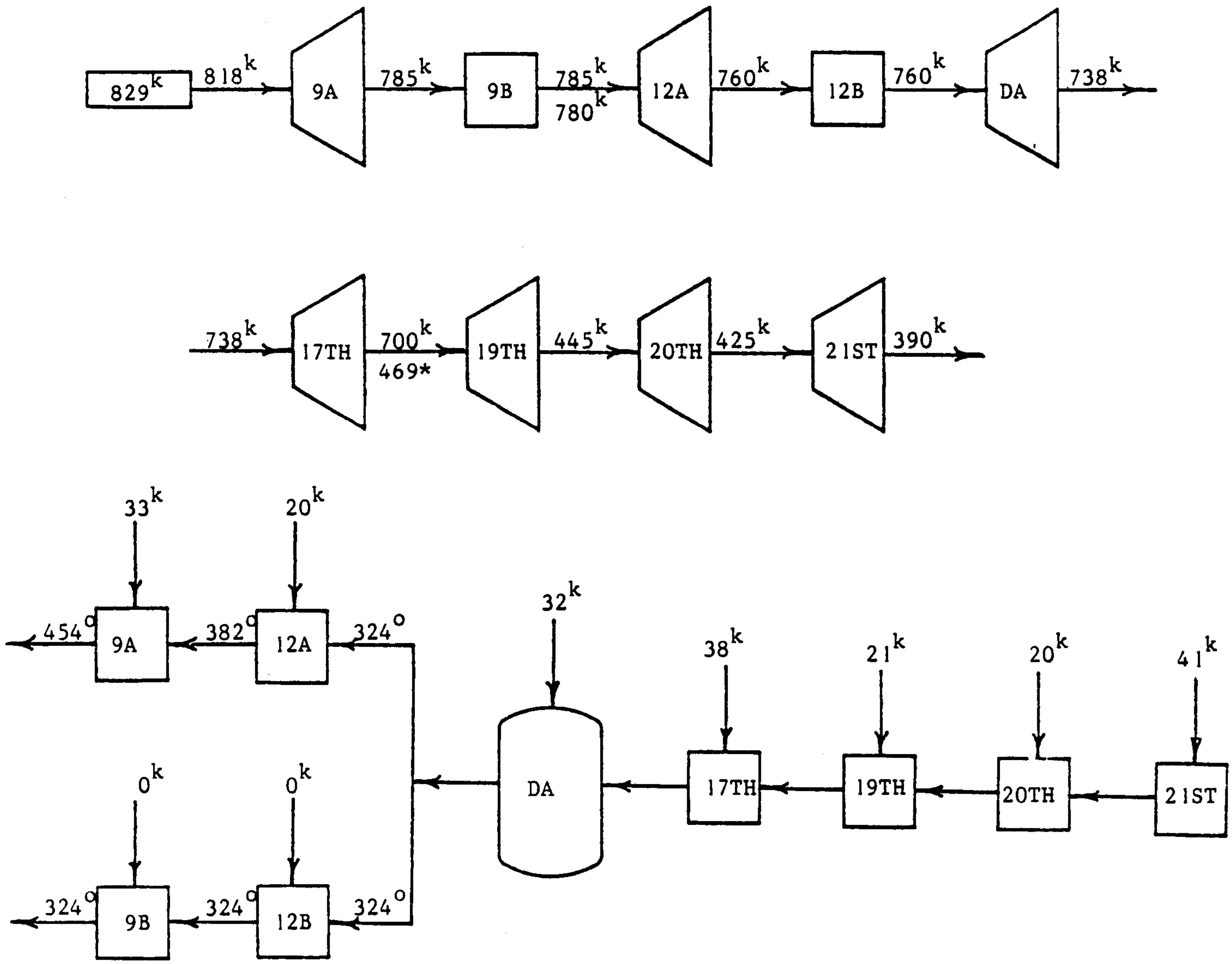
Heat Rate 7835 BTU/KWH

Heat Input 1.16×10^9 BTU/HR

Figure II

SHAWVILLE UNIT #1

HP STG OOS / IP LIMITED



* Flow Discontinuity Due To Triple Flow LP Turbine

Generation 138.5 MW

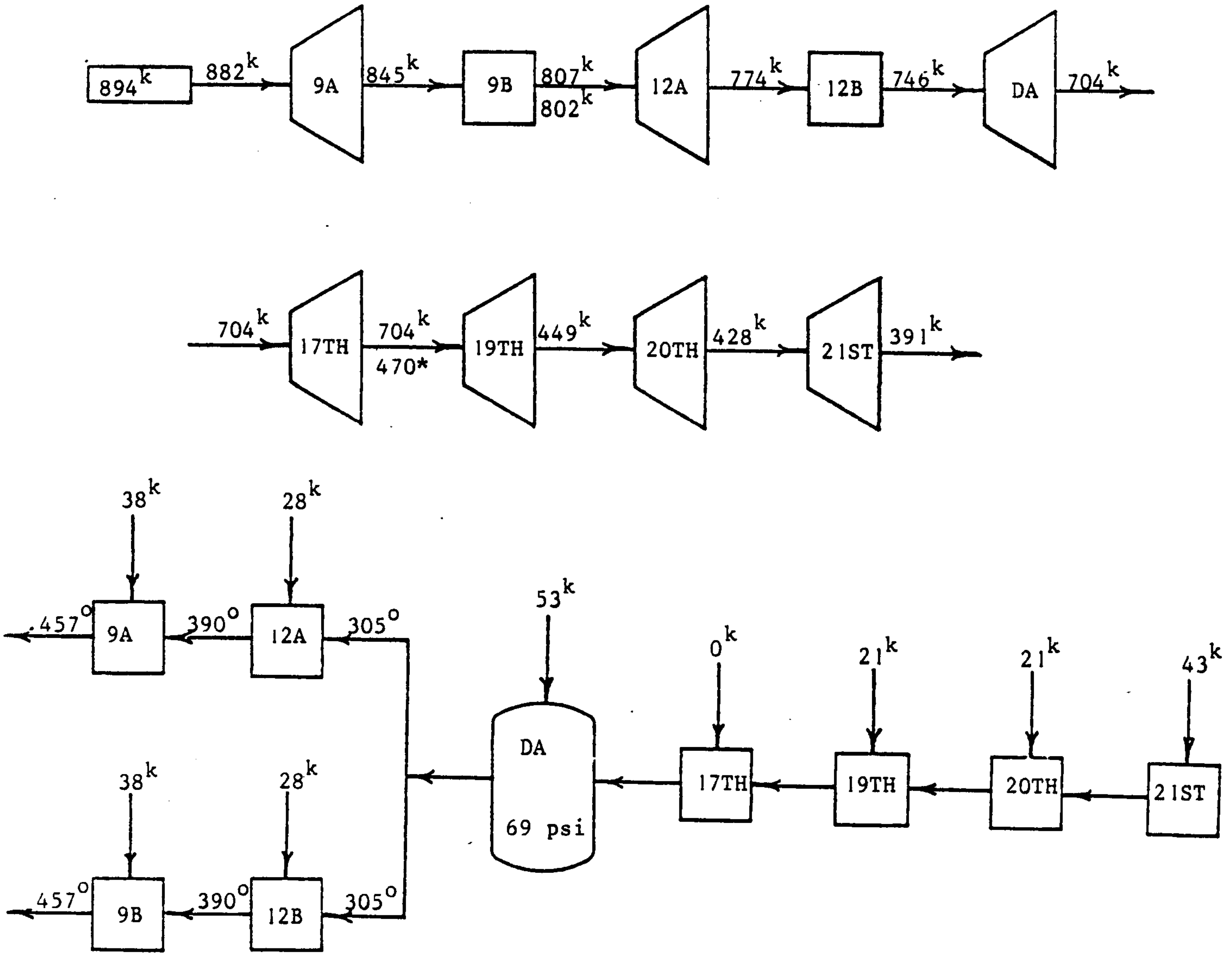
Heat Rate 7820 BTU/KWH

Heat Input 1.08×10^9 BTU/HR

Figure III

SHAWVILLE UNIT #1

17TH STG OOS / NO LIMITS



* Flow Discontinuity Due To Triple Flow LP Turbine

Generation	141.1 MW
Heat Rate	7760 BTU/KWH
Heat Input	1.09×10^9 BTU/HR

Figure IV