Categorizing Units Based on Controllable Loss Parameters using PEPSE$^{\theta}$

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Abstract

Certain controllable losses appear to detrimentally affect heat rate during periods of load regulation. It is believed that the performance of different generating units, of similar size and design, is impacted similarly by these controllable losses. This paper explores using PEPSE to categorize different units based on the detrimental heat rate effects of varying main steam temperature and increased reheat attemperation flow.

Introduction

Allegheny Energy is currently testing generating units in an effort to determine costs associated with operating in load regulation. Allegheny frequently operates its units in load regulation; therefore it makes good business sense to quantify if there is an associated heat rate penalty that occurs during these periods. Hence, we implemented this project to research, and quantify, how much of an impact load regulation actually has on unit heat rate.

Prior testing on one of Allegheny Energy's generating units, Hatfield Unit 1, had indicated that fluctuations in main steam temperature, and increased reheat spray flow, were the two controllable losses that had the greatest detrimental impact on heat rate during periods of load regulation. Based on this testing, we decided to use these two controllable losses as the basis for the series of tests presently being implemented.

This testing was brought about, in part, by Allegheny's involvement with a Regional System Operator. We needed to quantify preliminary heat rate impact costs associated with operating in load regulation, on a per unit basis, based on actual test results. In addition, we needed to provide Initial cost predictions on fairly short notice.

Since it appeared impractical to test each and every one of Allegheny Energy's 22 coal fired units in the short term, we felt that they could be grouped representatively based on the heat rate effects of decreased main steam temperature and increased reheat spray flow. Once the groupings were established, representative units from each group would be selected, and tested during periods of load regulation, and then equal periods of non-regulation. PMAX models that were already operational on these units would be used to calculate the heat rate of the units selected for testing on a real time basis. Results of the tests would then be compared.
We decided that PEPSE was the best tool available for quantifying the heat rate effects of the controllable losses in question and placing our units into appropriate groups.

Discussion

PEPSE models have been built that represent all of the 22 units owned by Allegheny Energy. We have steam turbine / generators of different sizes and ages built by various turbine and boiler manufacturers. All of our newer units have reheat sections, but a few older units do not. Since some of Allegheny's units are identical in design, there have been a total of 15 steam turbine cycle PEPSE models built over the years that represent all of our units. All PEPSE models are based on the manufacturer design heat balances.

For the actual unit controllable loss impact grouping, 20 of Allegheny's 22 units were considered. Since the remaining 2 units were older, and incapable of load regulation, they were not included in the study.

The first part of the PEPSE study focused on determining what impact decreased main steam temperature has on heat rate. Of the units considered, the design main steam temperature varies from 1000 Deg. F. on our newer units to 900 Deg. F on two of our older units. Design gross turbine heat rate, as calculated by PEPSE, was used as the benchmark case. The main steam temperature was reduced from design in 5-degree increments up to a maximum decrease of 15 degrees. The resulting gross turbine heat rate at each main steam temperature was then compared to the benchmark. The average heat rate penalty over the sensitivity temperature range in Btu/Kwh/Deg. F was then calculated for each unit. The results are shown in Table 1.

Next, PEPSE was used to ascertain what impact increased reheat spray flow has on heat rate. Obviously, only units with reheat sections were considered for this part of the study. Design gross turbine heat rate, as calculated by PEPSE, with zero reheat attemperation spray flow was used as the benchmark case. In order to keep the results of units of varying sizes relevant to each other for this study, we decided to determine the increase in reheat spray flow for each unit as a percentage of full load heat balance throttle flow, rather than at a series of constant reheat spray flow increases in pounds per hour. The reheat spray flow was then increased as a percentage of throttle flow in 1 percent increments up to a maximum of 5 percent of throttle flow. The resulting gross turbine heat rate at each reheat spray flow was then compared to the benchmark heat rate. The average heat rate penalty in Btu/Kwh/ 10,000 Lb/Hr of reheat spray flow was then calculated for each unit. The results are shown in Table 2.

As a sanity check, the results of this PEPSE study were compared to industry average heat rate effects caused by main steam temperature deviations and increased reheat spray flow as published in the EPRI Heat rate Improvement Reference Manual. The PEPSE predicted average effect of main steam temperature deviation for our units operating at 1000 Deg. F. is 1.5 Btu/kWh/Deg. F. This average closely agrees with EPRI's utility average of 1.4 Btu/kWh/Deg F. The PEPSE predicted average heat rate deviation for reheat attemperation was 11.2 Btu/kWh/ 10,000 Lb/Hr of reheat spray flow. This average value fell well within the sampled utility range as published by EPRI.

Table 1: Impact of Main Steam Temperature Variations on Heat Rate

As calculated using Pepse models based on design heat balance conditions

Unit	Design Full Load Throttle Flow (Klb / Hr.)	Calculated Gross Generation (Mw)	Design Main Steam Temp. (Deg. F.)	Design Gross Turbine Heat Rate (Btu / Kwh)		Heat Rate Resulting from Decreased Main Steam Temp (Btu / Kwh)			Heat Rate Penalty (Btu/Kwh / Deg F)
Units operating at 1000 Deg. F main steam temperature									
					Temp:	**995**	**990**	**985**	
Albright 3	1000.000	145.22	1000	8161		8166	8171	8177	1.1
Armstrong 1	1221.000	178.50	1000	8015		8019	8024	8029	0.9
Armstrong 2	1217.028	182.82	1000	7859		7865	7871	7876	1.1
Fort Martin 1 & 2	3519.620	523.43	1000	7615		7624	7634	7643	1.9
Harrison 1 & 2	4382.237	641.95	1000	7890		7897	7905	7913	1.5
Harrison 3	4901.284	729.21	1000	7788		7793	7803	7813	1.7
Hatfield 1, 2, & 3	3968.078	594.83	1000	7660		7669	7679	7689	1.9
Mitchell 3	2014.440	281.46	1000	7944		7955	7967	7979	2.3
Pleasants 1 & 2	4930.414	713.15	1000	7724		7733	7741	7750	1.7
R. Paul Smith 4	568.940	82.77	1000	8208		8213	8218	8223	1.0
Willow Island 2	1220.000	179.69	1000	7947		7952	7957	7962	1.0
Units operating at 950 Deg. F main steam temperature									
					Temp:	**945**	**940**	**935**	
Rivesville 6	856.166	100.49	950	8934		8946	8957	8969	2.3
Willow Island 1	497.783	59.10	950	8992		9005	9019	9032	2.7
Units operating at 900 Deg. F main steam temperature									
					Temp:	**895**	**890**	**885**	
Albright 1 & 2	682.000	81.42	900	9181		9195	9210	9224	2.9

Table #2: Impact of Reheat Spray Flow on Heat Rate

As calculated using Pepse models based on design heat balance conditions

Unit	Design Full Load Throttle Flow (Klb / Hr.)	Calculated Gross Generation (Mw)	Design Reheat Spray Flow (Lb / Hr.)	Design Gross Turbine Heat Rate (Btu / Kwh)		Heat Rate Resulting from Increased Reheat Spray Flow (spray flow determined as percent of throttle flow)					Heat Rate Penalty (Btu/Kwh / 10000 lb/Hr RH spray)
Reheat Units:											
					Percent:	1%	2%	3%	4%	5%	
					Klb/hr spray flow:	10	20	30	40	50	
Albright 3	1000.000	145.22	0	8161	Heat Rate:	8178	8194	8210	8226	8242	16.5
					Klb/hr spray flow:	12	24	37	49	61	
Armstrong 1	1221.000	178.52	0	8015	Heat Rate:	8035	8054	8073	8091	8109	15.8
					Klb/hr spray flow:	12	24	37	49	61	
Armstrong 2	1217.028	182.82	0	7859	Heat Rate:	7877	7895	7912	7930	7948	14.7
					Klb/hr spray flow:	35	70	106	141	176	
Fort Martin 1 & 2	3519.620	523.43	0	7615	Heat Rate:	7634	7653	7671	7689	7706	5.3
					Klb/hr spray flow:	44	88	131	175	219	
Harrison 1 & 2	4382.237	641.95	0	7890	Heat Rate:	7907	7924	7941	7958	7974	3.9
					Klb/hr spray flow:	49	98	147	196	245	
Harrison 3	4901.284	729.21	0	7788	Heat Rate:	7801	7815	7828	7841	7853	2.7
					Klb/hr spray flow:	40	79	119	159	198	
Hatfield 1, 2, & 3	3968.078	594.83	0	7660	Heat Rate:	7672	7685	7697	7709	7720	3.1
					Klb/hr spray flow:	20	40	60	81	101	
Mitchell 3	2014.440	281.46	0	7944	Heat Rate:	7962	7979	7996	8013	8029	8.6
					Klb/hr spray flow:	49	99	148	197	247	
Pleasants 1 & 2	4930.414	713.15	0	7724	Heat Rate:	7742	7760	7778	7795	7812	3.6
					Klb/hr spray flow:	6	11	17	23	28	
R. Paul Smith 4	568.940	82.77	0	8208	Heat Rate:	8228	8247	8265	8284	8302	33.9
					Klb/hr spray flow:	12	24	37	49	61	
Willow Island 2	1220.000	179.69	0	7947	Heat Rate:	7966	7984	8003	8021	8039	15.3
										Average:	11.2

Results

This PEPSE study enabled us to successfully place our units into representative groups for testing based on certain controllable losses. The actual testing will focus on how load regulation impacts our ability to maintain controllable losses at or near design conditions on units in a given group, and how it impacts our operating costs.

Since it was impractical to test all of our units initially, we plan on selecting representative units from each group for testing. Once these representative units are selected, our installed PMAX real time performance monitoring systems will be used to quantify the results of the testing. Since PMAX is presently installed on 12 of our 22 units, it is necessary to pick units presently equipped with PMAX from each group to expedite the testing.

After analysis of the modeling results, we were able to categorize our units into three groups based on the following similarities in heat rate effects:

Group 1:

- Average main steam temperature deviation effect from 1.5 to 2.3 Btu/kWh/Deg. F
- Average reheat attemperation flow effect from 2.7 to 8.6 Btu/kWh/10,000 Lb/hr spray flow
- Units that fall under this grouping include all ten of our supercritical units plus our largest drum unit, Mitchell 3.

Group 2:

- Average main steam temperature deviation effect from 0.9 to 1.1 Btu/kWh/Deg. F
- Average reheat attemperation flow effect from 14.7 to 33.9 Btu/kWh/10,000 Lb/hr spray flow
- Units that fall under this grouping include all of our drum type units except Mitchell 3.

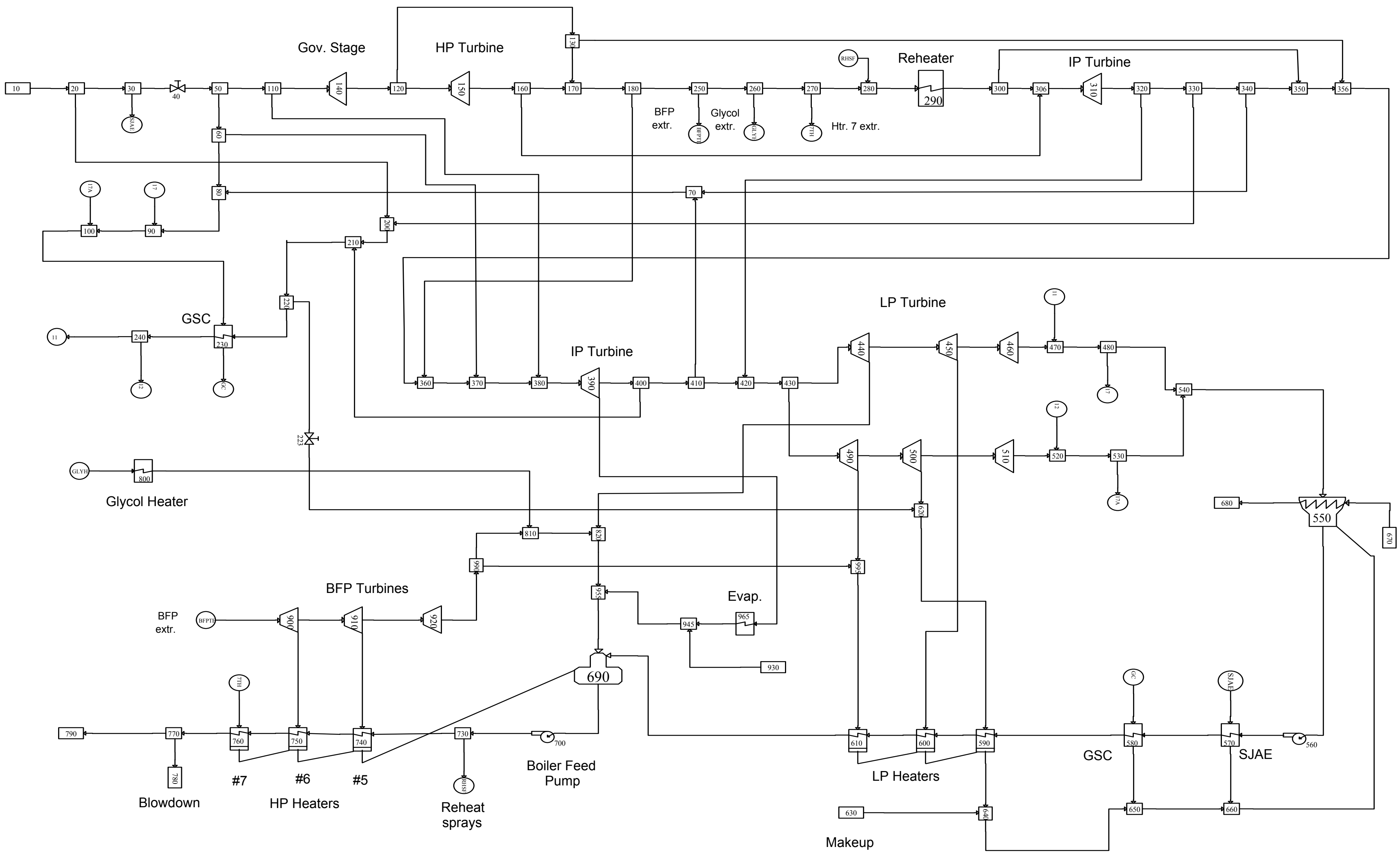
Group 3:

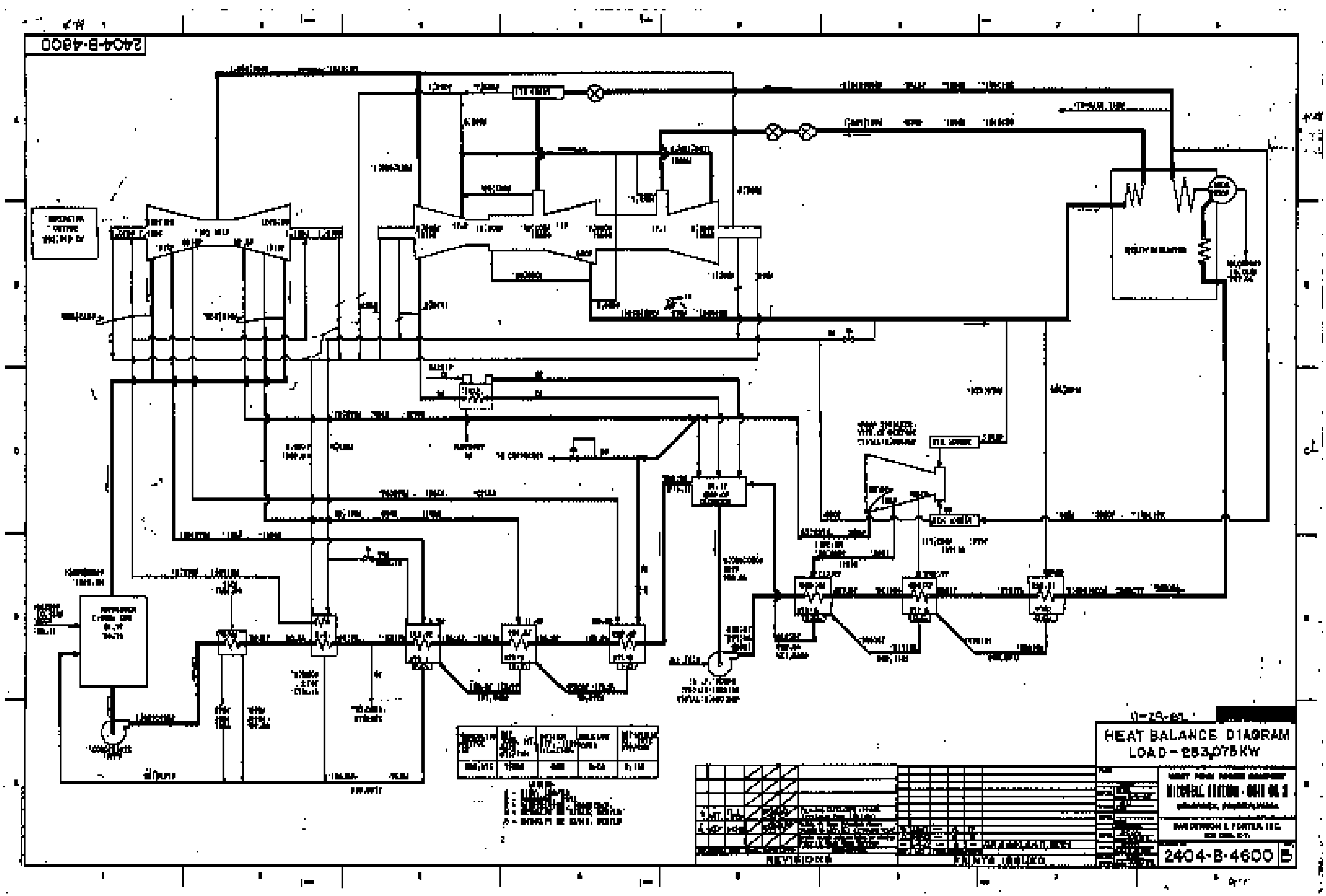
- Average main steam temperature deviation effect from 2.3 to 2.9 Btu/kWh/Deg. F
- Average reheat attemperation flow effect not applicable
- Units that fall under this group include all non-reheat units.

All of our units fell into groups much as we expected that they would, with the exception of Mitchell 3. This is our largest drum unit. It is a Westinghouse turbine / generator with steam supplied from a Combustion Engineering tangential fired boiler. Mitchell 3 has an NSOC rating of 285 MWe. Design main steam conditions are 1000 Deg. F at 2400 PSIG, and 1000 degree F hot reheat temperature.

The most probable reason for Mitchell falling into a group with the larger supercritical units rather than with other drum units closer to its size is the unique design of its turbine cycle. What makes it different from the typical turbine cycle is that the steam supply for the steam driven boiler feed pump turbines, under normal operation, comes from cold reheat steam. Extraction steam is then taken from various stages of the boiler feed pumps to supply the #6 and #5 high-pressure feedwater heaters. The exhaust of the boiler feed pumps is sent to the deaerator. The PEPSE model for Mitchell 3 is shown in Figure 1 and the vendor heat balance is shown in Figure 2.

FIGURE 1: MITCHELL UNIT 3 PEPSE TUBINE CYCLE MODEL





2404-B-4600
HEAT BALANCE DIAGRAM
2404-B-4600

Conclusion

At the time of this writing, Allegheny Energy had just commenced with the initial phase of regulation testing after using PEPSE to group our units. Preliminary results are inconclusive.

Hatfield 1 was the first unit selected for testing out of Group 1, which contains all of our larger supercritical units. We targeted Hatfield 1 for the initial phase of the testing because it was the same unit for which the initial studies were performed to determine the effects of decreased main steam temperature and increased reheat spray flow. We felt that this would offer the best initial results comparison. Also, Hatfield 1 has a well-tuned PMAX system, which enabled us to monitor and archive heat rate changes that occurred during testing.

Hatfield 1 was run through a predetermined regulation pattern at its standard rate of change. The PMAX system was used to monitor the heat rate of the unit during this period. Figure 3 shows a trend plot of net unit heat rate and generation during the time frame of the test. The unit was then held at a steady load at about the middle of the test band of regulation. The time frame of the test at steady load was equal to the time frame of the load regulation test. Again, PMAX was used to monitor unit heat rate. During this time, the heat rate settled into more of a steady state condition, as expected. The results of the two tests were then compared.

Additional units have also been selected and tested from Group 1, as well as from Group 2. Based on initial results of the testing, it appears that heat rate does increase when a unit is operated in load regulation. Test results indicate that the unit’s regulation band, the rate of change, and the frequency of change, all have the ability to impact unit heat rate. In addition, the responsiveness of the unit control system plays a large part in the ability to maintain controllable losses at or near design conditions. Proper control system operation and tuning will minimize controllable loss excursions from design and thus their detrimental impact on unit heat rate during load changes.

Initial indications, as figure 3 shows, are that load changes don't always impact heat rate detrimentally. Instantaneous heat rate sometimes improves during a load change. During a load increase, extra heat must be put in to the cycle with a net effect of a heat rate increase. But during a load decrease, heat already in the cycle is used; with a net effect of a heat rate decrease, at least until the unit hits a stable non-decreasing load.

At this point the results are still inconclusive. We need to collect, and analyze, more data in order to obtain better repeatability. More testing and data quantification are planned, in a continuing effort to determine exactly how much of an average heat rate penalty is incurred while operating in load regulation. Once we determine what the average heat rate penalty is for a representative unit in a group, this penalty can then be applied to other units in that same group, until such a time that we can test each unit individually.

We hope to prove, with this and subsequent testing, what effect load regulation has on operating costs, if any. We anticipate that that both PEPSE and PMAX will play a roll in determining how we proceed with future load regulation testing, and the quantification of the results of the tests.

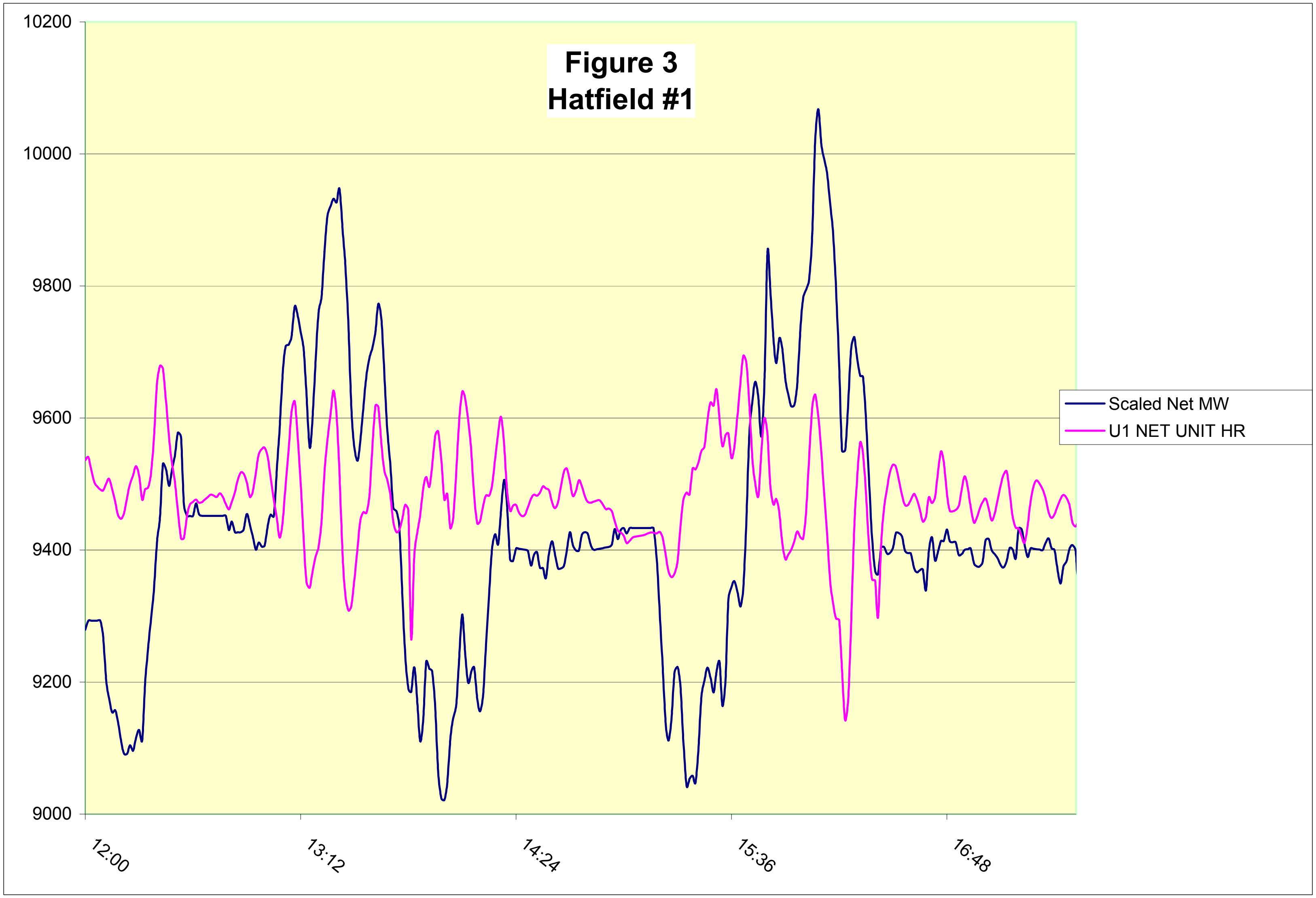


Figure 3
Hatfield #1
10200
10000
9800
9600
9400
9200
9000
12:00
13:12
14:24
15:36
16:48
Scaled Net MW
U1 NET UNIT HR

Summary

This paper demonstrates that PEPSE can be a very useful tool for predicting the effects that certain controllable losses have on unit heat rate. PEPSE enabled Allegheny Energy to easily compare and categorize our various units based on pre-defined controllable losses. From the results of this PEPSE study, we initiated a representative testing program in an effort to monitor controllable losses and determine heat rate costs incurred by operating a unit in load regulation.

References

1. PEPSE Manual Volume I, Version GT 4.0, Scientech Inc., 440 West Broadway, Idaho Falls, Idaho.

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