RECENT PEPSE AND PMAX EXPERIENCES AT TVA NUCLEAR UNITS

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Abstract

Like many of our competitors, TVA Nuclear (TVAN) has sustained a fair amount of turnover in our Thermal Performance staff, due to retirements and reorganizations. As one of the many steps taken to manage this change, in 1997 TVAN adopted the PEPSE heat balance software as a standard and developed design heat balance models for each of our five operating units. Over the past seven years, these models have been used extensively to support design change improvements and to quantify megawatt losses in support of search and recovery efforts. TVAN is currently nearing completion of the implementation phase of our PMAX project which was undertaken to standardize our Thermal Performance Monitoring tools and techniques for the three sites (Browns Ferry, Sequoyah, and Watts Bar). This paper summarizes some of the successful and not so successful TVAN applications of PEPSE, as well as the lessons learned during PMAX implementation. Specifically, this paper describes the following experiences:

- Resolution of 13 MWe difference between Browns Ferry Units 2 & 3
- Prediction of extraction bellows megawatt loss for Browns Ferry Unit 2
- Prediction of Moisture Separator effectiveness for Browns Ferry units
- Prediction of Sequoyah Unit 1 power change due to MSR steam supply isolation
- Multi-site PMAX implementation

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Introduction

The Tennessee Valley Authority (TVA) is a government agency founded by the TVA Act in 1933 as one of the New Deal agencies. TVA is America's largest public power company, with 31,658 megawatts of dependable generating capacity. TVA's power facilities include 11 fossil plants, 29 hydroelectric dams, three nuclear plants, six combustion turbine plants, a pumped-storage facility, and 17,000 miles of transmission lines. Through 158 locally owned distributors, TVA provides power to nearly 8.5 million residents in the Tennessee Valley.

The three nuclear plant sites are Browns Ferry, Sequoyah, and Watts Bar, all of which are all located along the Tennessee River. TVA Nuclear (TVAN) currently operates five units on these sites consisting of Browns Ferry 2 & 3 (BWRs), Sequoyah 1 & 2 and Watts Bar 1 (PWRs). Browns Ferry Unit 1 is scheduled to be restarted in May of 2007. TVAN also has Watts Bar Unit 2 and Bellefonte Units 1 & 2 in partial stages of completion.

Historically, TVA did the design, construction, and startup of all of its generating facilities including the nuclear units. The Balance of Plant (BOP) design was supported largely by the Mechanical Engineering Branch, Heat Cycle Group. During the nuclear recovery period between 1988 and 1994, TVAN reorganized and downsized to focus more on nuclear plant operation. The Mechanical and Nuclear Branches were merged and the Heat Cycle Group was eliminated, leaving only one or two engineers with the knowledge and ability to perform cycle heat balance work. Concurrent with these design organization changes were similar changes in the operating organizations which ultimately placed the responsibility for unit thermal performance with the BOP System Engineering Staff at each site and primarily in the hands of a single Thermal Performance Engineer (TPE) for each site.

As interest in deregulation began to emerge, focus on plant efficiency increased and TVAN performed a series of plant performance enhancement studies which identified the benefit of and need for standardization of the tools and techniques used to predict and monitor plant thermal performance. In 1996, the PEPSE heat balance software was selected as the standard for the TVA nuclear units and design PEPSE heat balance models were developed for each nuclear unit shortly thereafter. These models were thoroughly documented and tuned to the turbine vendor's thermal kit as well as the plant specific design configuration.

Unfortunately, the design PEPSE models have almost always predicted more unit output than is actually generated and the site Thermal Performance Engineers have not had the opportunity to train and become proficient PEPSE users with the skills required to tune their models to the actual plant process computer data. To address this gap, TVAN has purchased the PMAX online thermal performance software and associated SCIENTECH services for model development, setup, tuning, and training. At the time of this writing, the Browns Ferry and Sequoyah models are complete and the Watts Bar model is scheduled for completion by the end of September, 2004.

As the TVAN Corporate BOP/Heat Cycle Specialist (Thermal Performance Program Manager), I am frequently called upon to perform PEPSE and other thermal-hydraulic studies to predict off-normal operation and/or identify the likely cause for unaccounted megawatt losses. This paper presents several recent PEPSE case studies as well as the lessons learned in implementation of the PMAX software for TVAN. The following sections describe the analyses, results, and conclusions for:

- Resolution of 13 MWe difference between Browns Ferry Units 2 & 3
- Prediction of extraction bellows megawatt loss for Browns Ferry Unit 2
- Prediction of Moisture Separator effectiveness for Browns Ferry units
- Prediction of Sequoyah Unit 1 power change due to MSR steam supply isolation
- Multi-site PMAX implementation

Browns Ferry Unit Difference

Browns Ferry Nuclear (BFN) Units 2 and 3 were uprated to 105% of original licensed thermal power (OLTP) in 1998 and 1999, respectively. Both units are now licensed at 3458 MWt and the design PEPSE full power gross generation is predicted to be 1163 MWe at design backpressure of 2 "Hga. Testing subsequent to the stretch uprates was limited to "before and after" megawatt difference tests which did not yield any useful turbine performance data. The units never matched predicted design output. Initially Unit 3 performed better than Unit 2, and later Unit 2 performed better than Unit 3. At various times the difference ranged from 4 MWe to 13 MWe as indicated in Figure 1.

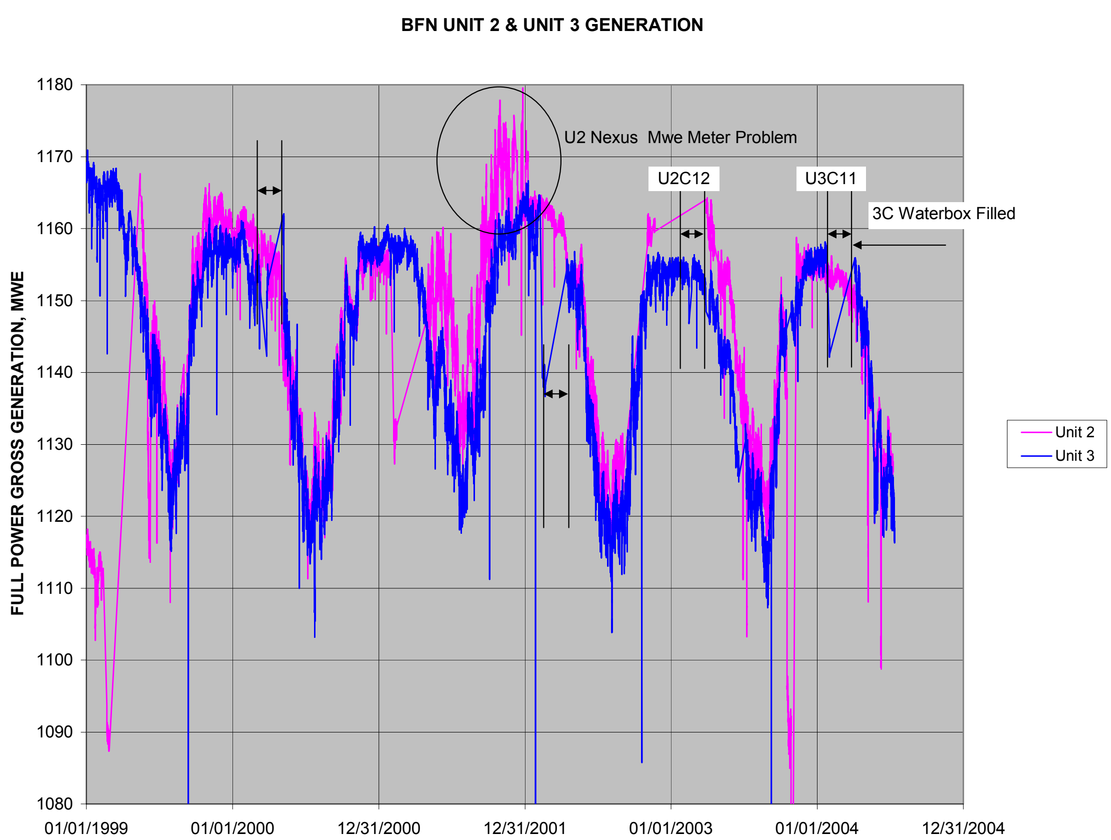

FIGURE 1 – BFN UNIT 2 & UNIT 3 GENERATION
(Data filtered for greater than 99.9% MWt)

In May 2002, the site staff requested some PEPSE analyses to prove or disprove their theories for the cause of the unit difference. The postulated cause and PEPSE analyses are summarized in the following paragraphs and then the most recent investigation and resulting resolution of the difference is described.

Problem Statement (May 2002):

Unit 3 is producing approximately 4 MWe less than Unit 2 and the difference is increasing with increasing river temperature. In addition, this trend has existed since both units were restarted (1990's).

Postulated Cause (May 2002):

Condenser pressure instrumentation is not accurate. The A condenser zone on each unit receives miscellaneous drains which represent an increased heat load relative to the other zones. However, the Unit 3 "A" zone Condenser Circulating Water (CCW) supply incorporates the debris screen which may reduce its cooling water supply relative to the other zones. The combined effect of reduced cooling and increased heat load are postulated to increase the A zone backpressure enough to cause the observed MWe loss.

Test for Cause (May 2002):

1. Determine how much increase in back-pressure on A condenser is required to account for the loss by doing a series of PEPSE runs with increasing A zone back-pressures.

   <u>Result:</u> An increase of 0.8" Hga in Zone A = - 4 MWe
   <u>Conclusion:</u> Postulated cause is feasible, if sufficient heat load or reduction in CCW flow is existent.

2. If the answer to 1. is reasonable, modify the PEPSE model to dump the miscellaneous drains in the Zone A and do a run with current CCW supply to determine the maximum increase in Zone A pressure due solely to non-symmetric miscellaneous drain heat load.

   <u>Result:</u> Even if all drains are non-mechanistically dumped in Zone A with current CCW flow and temperature, the increase in Zone "A" pressure is only 0.33" Hga (3.04" vs. 2.71"). A review of system flow diagrams also did not reveal any significant additional heat loads on the A condenser.
   <u>Conclusion:</u> Non-symmetric miscellaneous drains heat load is probably not a significant contributor to the cause for this deviation in performance.

3. Review the CCW debris screen design to determine the maximum pressure drop contributed by the screen and the associated CCW flow reduction.

   <u>Result:</u> Vendor data indicates that the maximum screen DP = 14.5 psi (75" WC) but the SE said that the screen operates at 40" WC with automatic back-washing. The system design calculations indicate that CCW flow to the A condenser will be reduced by no more than

2450 gpm out of 700000 gpm (.35%).

4. Run a PEPSE balance with all drains into "A" zone and with "A" zone CCW flow reduced by 2450 gpm relative to "B" & "C" to determine if the combined effect could account for the MWe difference.

   Result: the reduced CCW flow only raised the "A" zone pressure an additional 0.01" Hga
   Conclusion: CCW debris screen flow reduction is not contributing cause.

5. If none of the above results, support the postulated cause, consider the possibility that U3 condenser overall performance is less effective than U2 condenser and investigate the effect of increasing river temperature on degraded versus non-degraded condensers. Do two series of PEPSE runs for CCW inlet temperatures from 65F to 85F with condenser cleanliness values of 85% and 75%.

   Result: The PEPSE results are tabulated and graphed in Figure 2 on the following page. The megawatt difference increases with increasing CCW inlet temperature similar to the observed trend in the U2 minus U3 megawatt data over the past 10 years. The absolute values of the difference are also approximately the same as the unit differences at equivalent CCW inlet temperatures.
   Conclusion: Based on the similarity of these results to the current unit generation difference and the historical trend in that data, it appears that the Unit 3 condenser may be less efficient overall than the Unit 2 condenser and consequently more sensitive to increased CCW inlet temperature.

Conclusion (May 2002):

The postulated cause for the current performance difference is not supported by the results of this study. However, the results of the condenser performance study (step 5) point to a deficiency in the performance characteristic of the Unit 3 condenser relative to the Unit 2 condenser. Unfortunately, there are no reliable, accurate instruments on the condensers or the CCW system to accurately determine the condenser heat rejection rate. An instrument upgrade project has been proposed for the CCW/condenser system, but is not currently funded for implementation. It is recommended that the priority of this project be raised and the project implemented so that the true cause of the current performance difference may be determined.

BFN CONDENSER PERFORMANCE STUDY
31-May-02

	85% Cleanliness		75% Cleanliness		
CCW IN	MWE	BP	MWE	BP	MWe Difference
65	1162.6	2.06	1160.4	2.25	2.2
70	1159.2	2.34	1156.1	2.55	3.1
75	1153.8	2.67	1149.1	2.9	4.7
80	1145.4	3.06	1138.9	3.31	6.5
85	1133.8	3.5	1125.9	3.79	7.9

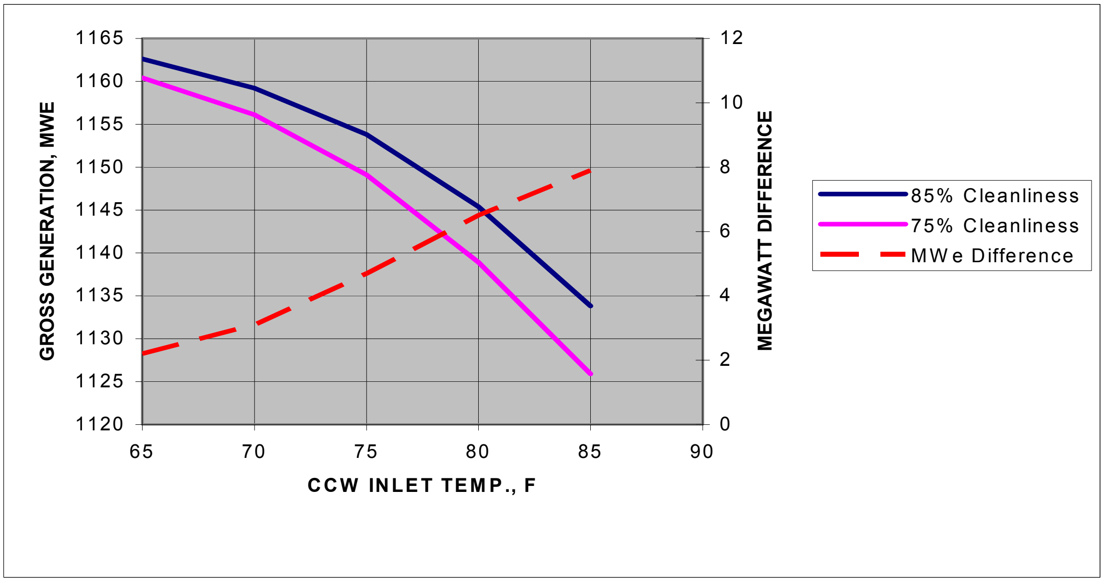

FIGURE 2 – BFN CONDENSER PERFORMANCE STUDY

In the summer of 2002 the difference between Units 2 and 3 was as high as 10 MWe and later that fall, the difference reduced to 5 MWe at a river temperature of 55 degrees. During this time it was determined that there was a leak in the Unit 3 number three extraction steam line. This loss, estimated at 5 MWe, along with the degraded performance of the unit 3 condenser caused the 10 MWe losses in the summer.

By July of 2003 the difference had increased to 13 MWe with increasing extraction steam leakage. However, after the extraction steam leak was repaired during the U3 Midcycle Outage from 6/19/03 to 7/6/03, the difference reduced to 5 MWe indicating that approximately 8 MWe were recovered from this repair.

After these repairs the unit difference was 5 to 6 MWe during the summer. This delta decreased with decreasing river temperatures indicating a difference in condenser performance between the units. To determine the root cause of the difference between the unit 2 and 3 condensers a Condenser Performance Test was performed by the TVA Norris Engineering Labs to determine the distribution of flow through the water boxes and measure the individual water box inlet and outlet temperatures. Preliminary conclusions from the test were that the Unit 3 backpressure was higher than Unit 2 with the same CCW inlet temperatures due to the actual cleanliness being worse for Unit 3 than the indicated cleanliness.

Problem Revisited (January 2004):

While visiting the site in January 2004 and discussing the upcoming U3 refueling outage, the CCW/Condenser System Engineer mentioned a long standing problem with one of the vacuum priming valves. A leaky valve could limit the performance of the system and prevent complete filling of the U3 water boxes. To quantify the percentage of ineffective condenser tube surface required to account for the elevated U3 backpressure, two series of PEPSE cases were run varying the number of plugged tubes from 0% to 50% plugged at two different cleanliness values, 100% clean and 85% clean. All runs were done at the then current CCW inlet temperature of 42.6F. The results of the study are summarized in Figure 3.

CASE	CONDITIONS	TUBE AREA, %	100% CLEAN BACKPRESSURE	MWE	BP POLY
1	DESIGN, 75% MS EFFECTIVENESS	100		1157.7	
2	3 CCW, 42.6F, 66.9% CLEAN	100		1159.3	
3	2 CCW, 42.6F, 100% CLEAN	100		1161.3	
4	3 CCW, 42.6F, 100% CLEAN, 90% AREA	90	1.13	1160.8	1.133051
5	3 CCW, 42.6F, 100% CLEAN, 80% AREA	80	1.2	1161	1.202957
6	3 CCW, 42.6F, 100% CLEAN, 70% AREA	70	1.29	1160.8	1.292743
7	3 CCW, 42.6F, 100% CLEAN, 60% AREA	60	1.41	1160.9	1.412437
8	3 CCW, 42.6F, 100% CLEAN, 50% AREA	50	1.71	1161.5	1.712063
		52.68371			1.600068

CASE	CONDITIONS	TUBE AREA, %	85% CLEAN BACKPRESSURE	MWE	BP POLY
1	DESIGN, 75% MS EFFECTIVENESS	100		1157.7	
2	3 CCW, 42.6F, 66.9% CLEAN	100		1159.3	
3	2 CCW, 42.6F, 100% CLEAN	100		1161.3	
4	3 CCW, 42.6F, 85% CLEAN, 90% AREA	90	1.31	1160.7	1.30943
5	3 CCW, 42.6F, 85% CLEAN, 80% AREA	80	1.4	1160.9	1.39904
6	3 CCW, 42.6F, 85% CLEAN, 70% AREA	70	1.52	1161.3	1.51881
7	3 CCW, 42.6F, 85% CLEAN, 60% AREA	60	1.69	1161.6	1.68872
8	3 CCW, 42.6F, 85% CLEAN, 50% AREA	50	2.11	1158.7	2.10875
		64.33316			**1.600253**

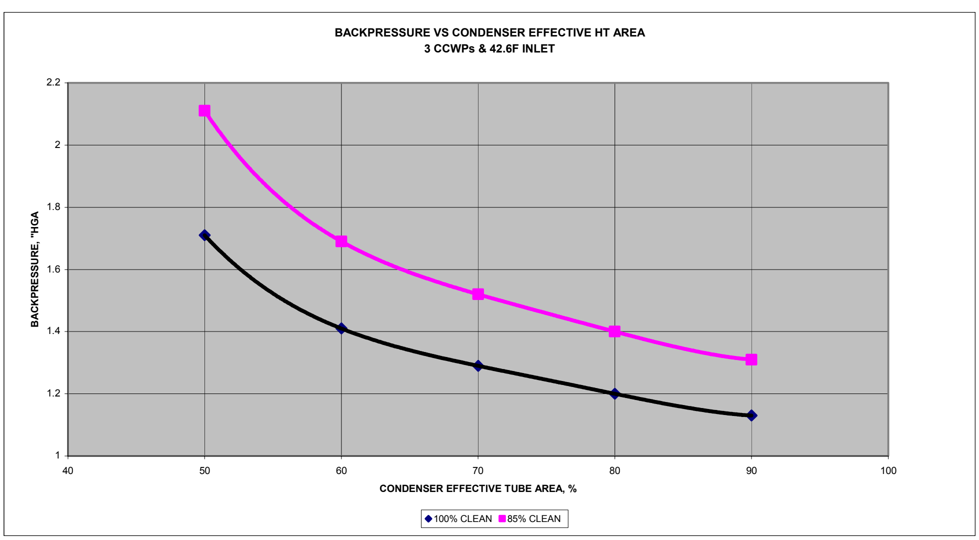

FIGURE 3 – BFN CONDENSER EFFECTIVE TUBE AREA STUDY

This study indicated that, at design cleanliness of 85%, the U3 water boxes would have to be only 64% full to produce the measured backpressure of 1.60 "Hga. Although it did not seem feasible that this could be the case, maintenance on the vacuum priming valves was prioritized and performed in the March 2004 outage. When the unit was returned to full power following the outage, the generation difference between U2 and U3 no longer existed.

Browns Ferry Unit 2 Extraction Bellows Prediction

On October 11, 2003, BFN Unit 2 experienced a leak in the number 2 extraction steam bellows inside the "C" condenser zone. TVA numbers heaters from highest pressure to lowest pressure so #2 is next to the highest pressure extraction. The 12" diameter #2 extraction lines from the three LP turbines join in a 24" diameter header outside the condenser before splitting into separate 12" diameter lines to each of three #2 heaters. Over a six hour period, #2 extraction pressure was observed to drop about 1 psi and unit generation declined about 6 MWe. The BFN thermal performance engineer (TPE) identified the problem and requested some PEPSE analysis support to strengthen his root cause analysis conclusions for management. On October 15th, we developed a spreadsheet calculation estimating the maximum steam leakage flow rate as a function of equivalent leak diameter and we modified the BFN 2 PEPSE model as shown in Figure 4 to include a leak flow path direct to the "C" condenser from the #2 extraction.

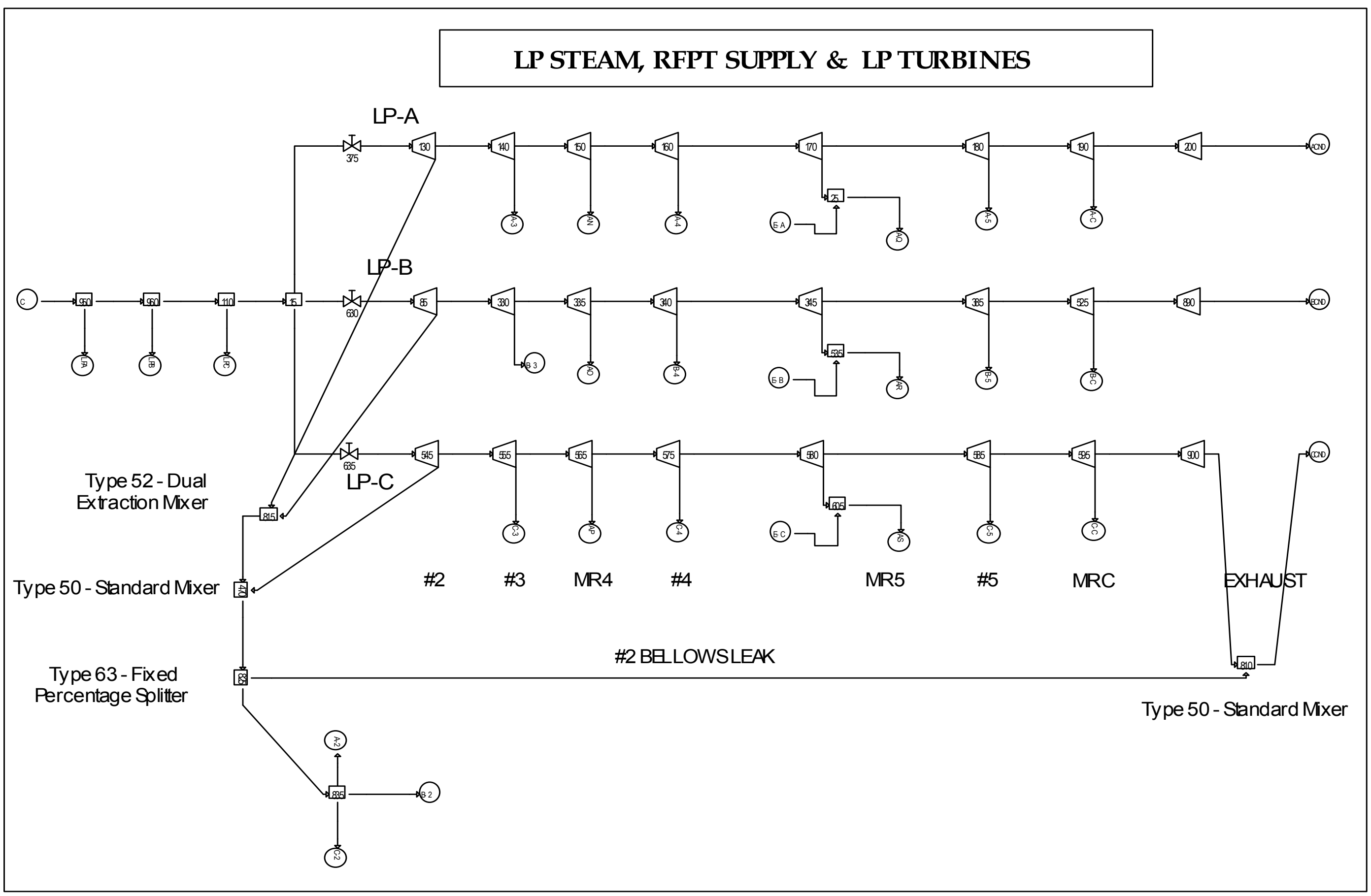

FIGURE 4 – BFN #2 EXTRACTION LEAK MODEL

Using this modified PEPSE model, we ran four cases of specified leak flow varying the percentage of the extraction flow to the B Port of the leak splitter from 0% to 66%. The condensers were modeled in the HEI Simplified Design Mode with the measured inlet water supply temperature of 72.2F and design cleanliness of 85%. The results of this parametric study are shown in Table 1.

CASE	% MWT	MWT	CCW INLET TEMP	#2 EXTRACTION LEAK TO C-CONDENSER	MWE	MWE DEVIATION	#2 EXT PRESSURE	#2 EXTR PRESSURE DEVIATION	FINAL FW TEMP	FW TEMP DEVIATION	#2 EXTRACTION FLOW	LEAK FLOW
			F				PSIA					
1	100.00%	3458	73	0%	1155.815	0.0	126.6	0	380.7	0	369602	0
2	99.94%	3456	72.2	20%	1150.374	-5.4	125.3	-1.3	380.5	-0.2	367219	91805
3	99.94%	3456	72.2	22%	1149.785	-6.0	125.2	-1.4	380.5	-0.2	366993	101509
4	99.94%	3456	72.2	66%	1112.964	-42.9	117.5	-9.1	379.5	-1.2	352946	690000

TABLE 1 – BFN #2 EXTRACTION LEAK PEPSE RESULTS

These results indicated that the observed 6 MWe deviation equated to a 22% leak. The predicted extraction pressure and leak flow rate were then used to predict the equivalent leak diameter for a single-ended pipe cross section. The results of this spreadsheet calculation are shown in Table 2.

LEAK FLOW RATE ESTIMATE

Crane TP-410 Compressible Flow Equation

Y	C	DP	v	P	h	d	W
0.718	0.6	125.3	3.396072	125.3	1146.5	4.307309	91805
0.718	0.6	125.2	3.398716	125.2	1146.5	4.531023	101509
0.718	0.6	117.5	3.598262	117.5	1142.5	**6**	167587.8
0.718	0.6	117.5	3.598262	117.5	1142.5	**7**	228105.6
0.718	0.6	117.5	3.598262	117.5	1142.5	**8**	297933.8
0.718	0.6	117.5	3.598262	117.5	1142.5	**9**	377072.5
0.718	0.6	117.5	3.598262	117.5	1142.5	**10**	465521.5
0.718	0.6	117.5	3.598262	117.5	1142.5	**11**	563281.1
0.718	0.6	117.7	3.598262	117.5	1142.5	**12**	670921.3

TABLE 2 – BFN #2 EXTRACTION LEAK SIZE ESTIMATE

Figure 5 shows the estimated leak flow rate and associated megawatt loss prediction as a function of leak equivalent diameter. Figures 6 and 7 show the #2 extraction pressure and final feedwater temperature deviations as functions of the leak size respectively.

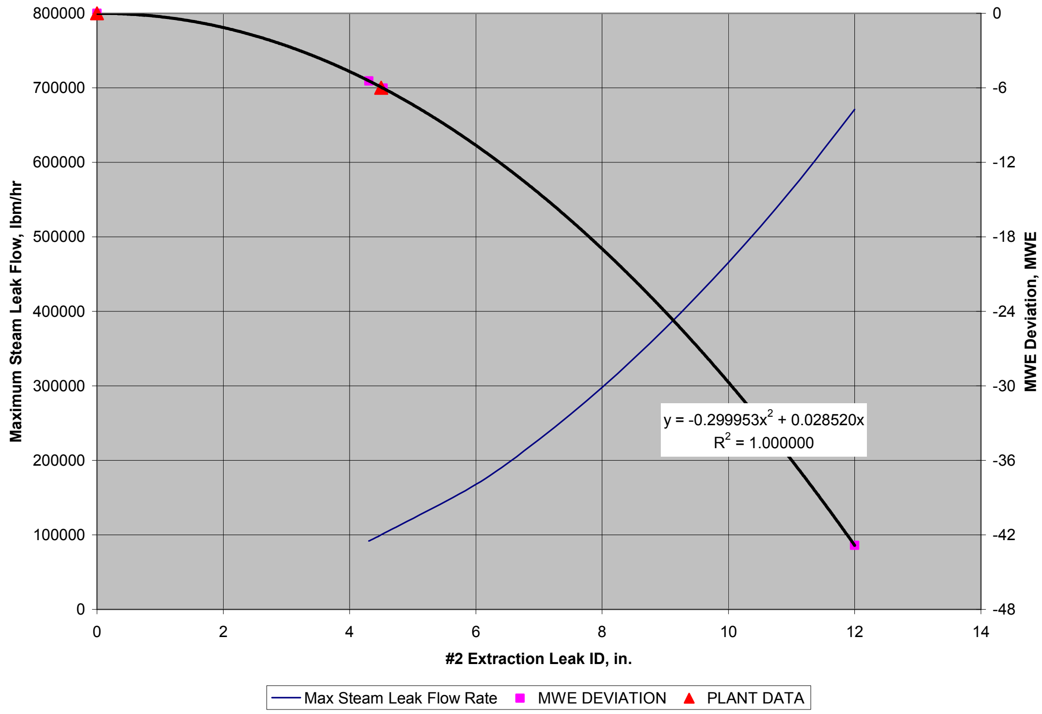

FIGURE 5 – BFN #2 EXTRACTION LEAK FLOW & MEGAWATT LOSS

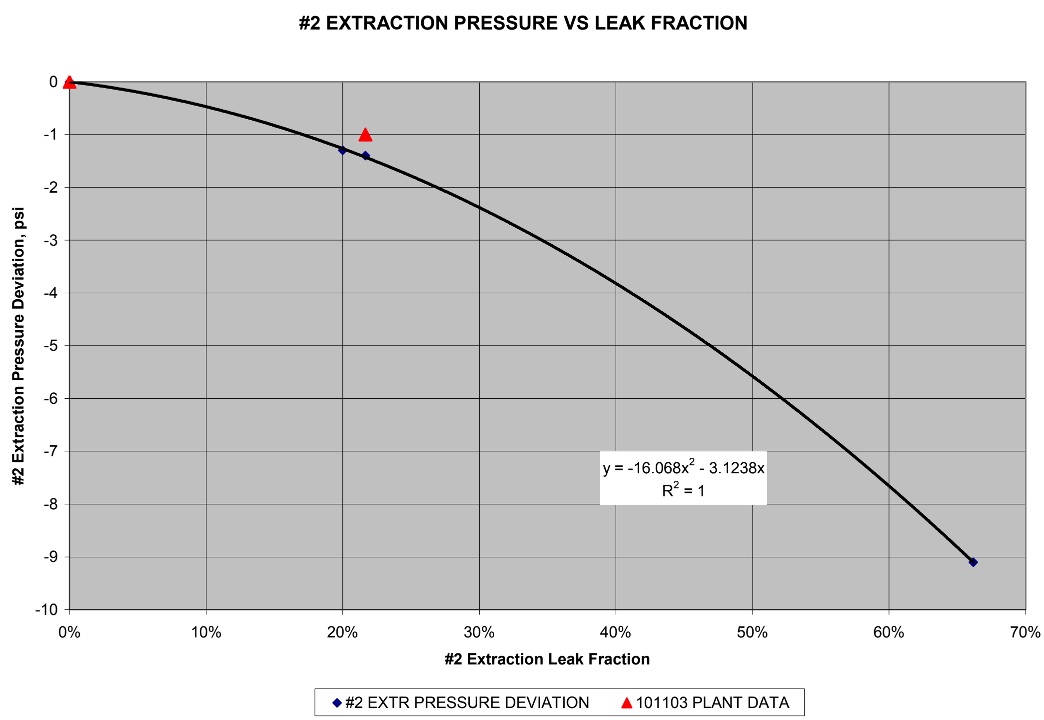

FIGURE 6 – BFN #2 EXTRACTION PRESSURE DEVIATION

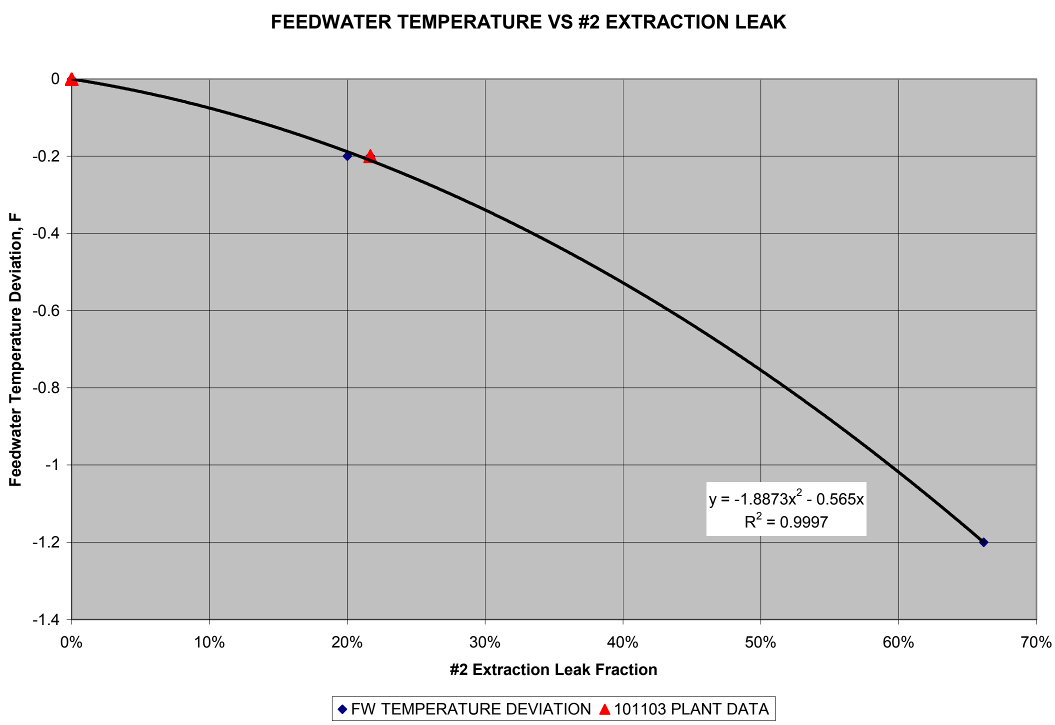

FIGURE 7 – BFN #2 EXTRACTION LEAK FEEDWATER TEMPERATURE DEVIATION

This analysis produced a fairly accurate prediction of the deviations expected with increasing #2 extraction leak size. I would like to think that it helped influence the plant management decision to shutdown the unit the following week when the megawatt loss had increased to 56 MWe. The PEPSE estimate under-predicted the actual loss because flow to the failed #2 bellows location was supplied from both ends of the pipe and ultimately four additional nearby bellows failed or were severely damaged. Figures 8 shows the extent of the damage.

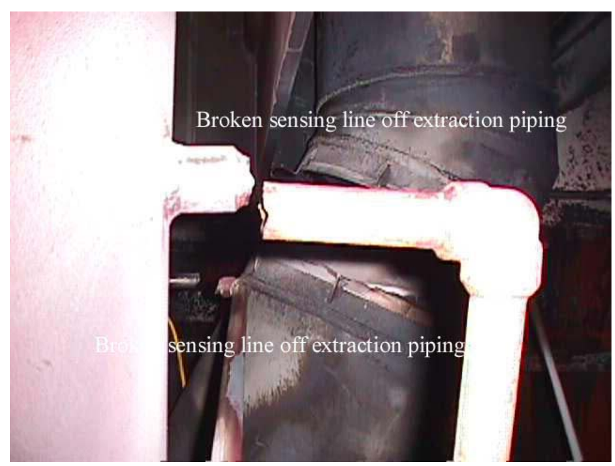

FIGURE 8 – BFN #2 EXTRACTION BELLOWS FAILURE

Browns Ferry Prediction of Moisture Separator Effectiveness

The Browns Ferry design incorporates six moisture separators per unit without reheat. These separators are GE original equipment with Peerless single-pocket chevrons. The GE design specification sheet for these separators indicates that they were designed to remove 85% of the moisture in the entering HP turbine exhaust. The BFN Unit 1 pre-operational tests (early 1970's) included tracer testing of the turbine cycle including the moisture separators. This testing indicated that the separators were approximately 99% effective. However, the GE thermal kit and all subsequent design heat balance calculations assumed only 85% effectiveness for the separators. Following the 105% power uprates for Units 2 & 3 the measured output exceeded the design heat balance predictions by about 6 MWe and my theory was that the actual MS effectiveness had degraded somewhat from 99% to approximately 95%. Two PEPSE runs at 95% and 85% MS effectiveness confirmed that generation would increase by 6 MWe with the increased MS effectiveness. Figure 9 shows the unit gross generation versus cooling water temperature characteristic predicted with PEPSE for 85% and 75% MS effectiveness.

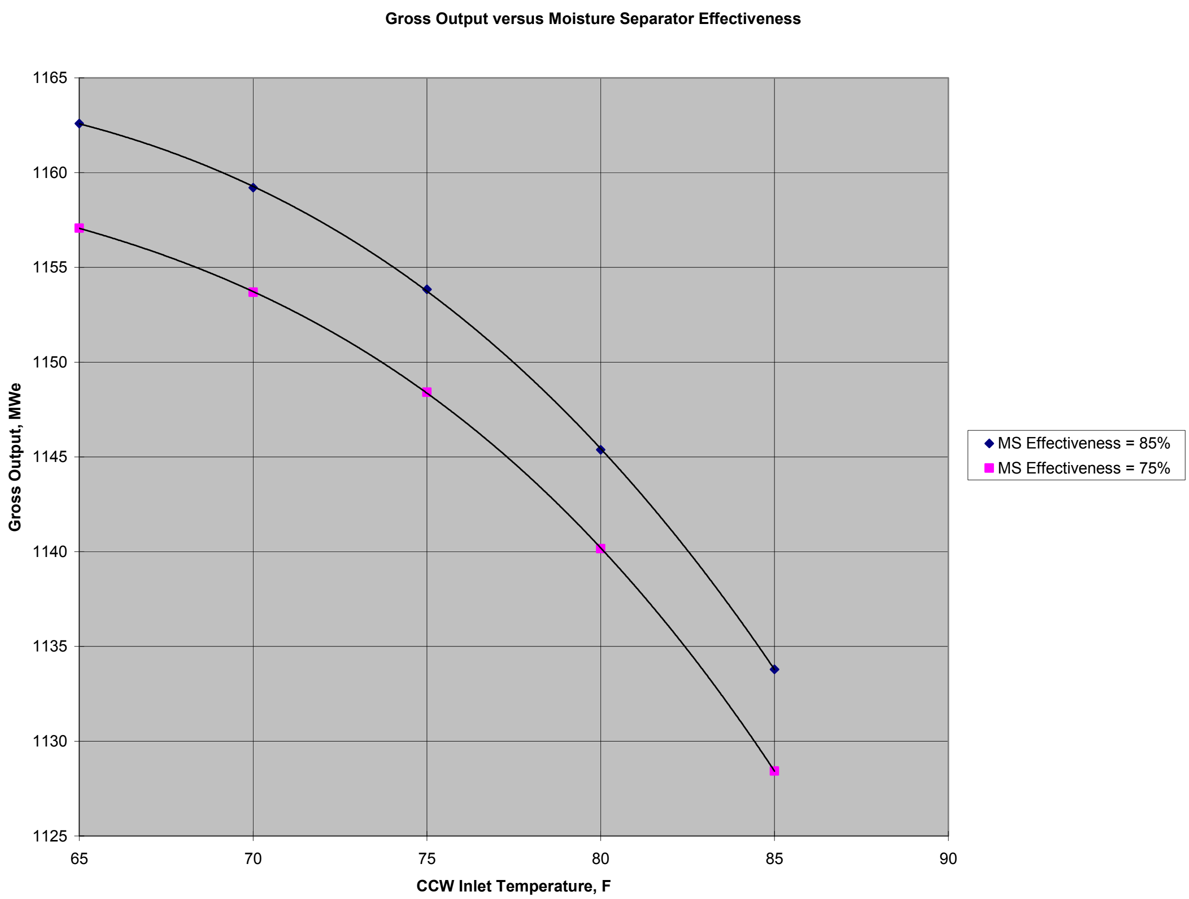

FIGURE 9 – BFN GENERATION VERSUS MOISTURE SEPARATOR EFFECTIVENESS

Subsequent studies were performed to support the 120% OLTP Extended Power Uprate Project which will increase the throttle flow and consequently the steam flow to the moisture separators.

It is well known from testing that this type of vane separator has a characteristic water carryover threshold velocity at which performance begins to drop off sharply. Since the BFN pre-operational tests did not exceed that threshold, test data for similar chevrons in another BWR plant was obtained. The composite set of data was used and PEPSE runs were made to predict the effect of the increased MS inlet flow (and velocity). Figure 10 presents the results, which indicated that EPU conditions would require upgraded moisture separators. This was confirmed by the Thermal Engineering Inc. estimate for the effectiveness at EPU conditions.

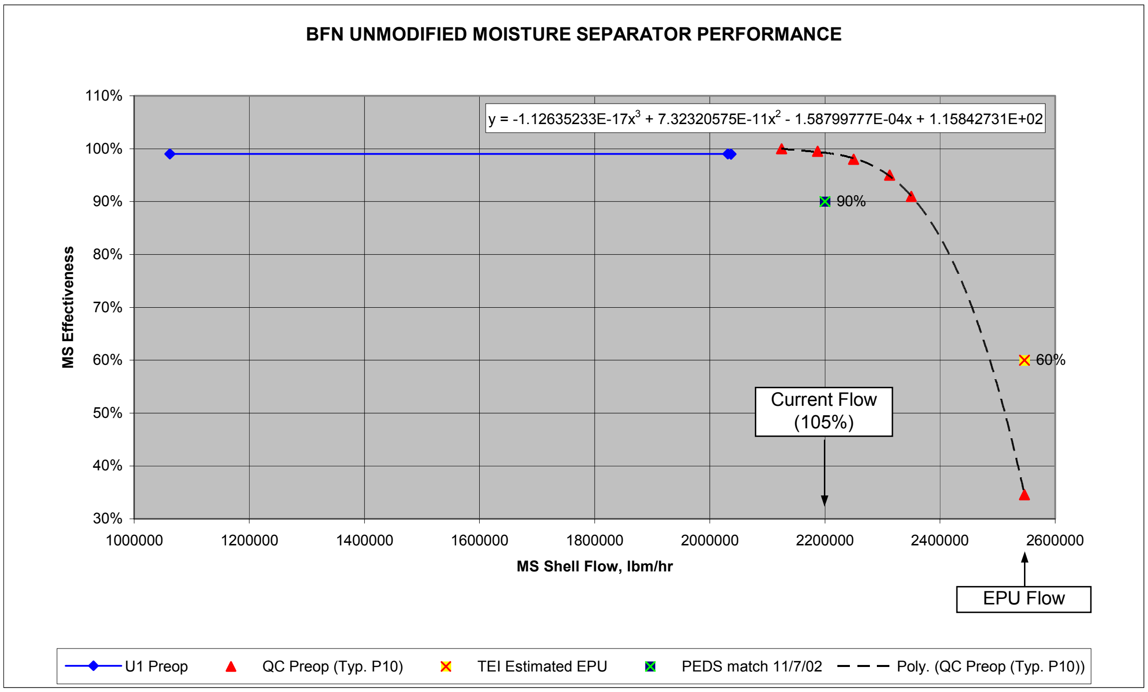

FIGURE 10 – BFN UNMODIFIED MOISTURE SEPARATOR PERFORMANCE AT EPU CONDITIONS

Prediction of Sequoyah Unit 1 Power Change Due to MSR Steam Supply Isolation

In January 2004, maintenance was being done on a Sequoyah Unit 1 Instrument Power Distribution Panel which, when de-energized would close the 8" main steam supply valves to the MSR HP bundles, leaving only the 2" bypass valves open. To support this maintenance, plant management requested an engineering evaluation of the impact on unit operation. The TPE understood that this evolution involved competing effects on reactor power. Closing the MSR HP steam supply valves increases system resistance and reduces steam generator steam flow. Since the MSR HP drains and excess steam discharge to the HP heater extraction, reducing this flow was expected to reduce final feedwater temperature. Decreasing steam flow reduces reactor power while decreasing feedwater temperature causes an increase in reactor power.

The SQN PEPSE model was used to help quantify the expected changes, subject to the limitations of the model, the users, and the time allotted for the evaluation. Features and limitations of the SQN Unit 1 PEPSE model include the following:

- No Steam Generators are modeled
- Special Option 4 is invoked to determine throttle flow from input thermal power
- Steam Generator pressure, MS throttle pressure, and HP turbine inlet pressure are scheduled as functions of throttle flow
- Controls are used to obtain the desired TTD's for the MSR HP and LP bundles
- Multiple HP turbines are included to model the non-symmetric extractions

The Incorrect Estimate

An estimate was made of the decrease in the number 1 (HP) feedwater heater pressure and the number 1 extraction line pressure drop was increased in the PEPSE model to reflect this. The results of this analysis indicated a drop in final feedwater temperature of approximately 0.7 ºF. The effect of this decrease in final feedwater temperature on reactor thermal power was determined to be an increase of 3.25 MWt using the calorimetric spreadsheet.

Because of the time constraints and the limitations of the PEPSE model, the decrease in reactor power expected from the decrease in steam flow could not be evaluated. Consequently, the TPE advised the Operations staff that reactor power should be reduced conservatively by 10 MWt prior to isolating the instrument power distribution panel.

During performance of this activity in the plant, feedwater temperature actually dropped by 0.8 ºF. This very closely matched the predicted value. However, when the MSR HP steam supply valves went closed, the reactor thermal power actually dropped by 17 MWt. A review of the data indicates that this was due to decreased main steam flow. Closing the MSR HP steam supply valves restricted steam flow to the secondary side of the unit. The lower steam flow caused the feedwater flow to decrease in order to maintain steam generator levels on program. During the activity, feedwater flow decreased by approximately 120,000 lbm/hr and RCS Tavg increased by 0.3 ºF.

Subsequent Analyses and Conclusions

In this case, the Sequoyah design PEPSE model was too sophisticated to serve the immediate need and the users were not skillful enough to modify the model quickly to address the proposed configuration. Later, the Sequoyah model was modified to vary the MSR HP TTD and a better estimate was calculated. However, a correct model of this off-normal configuration was never successfully developed. This experience emphasized the value of PEPSE training and experience. It also emphasized the risk of providing less than complete analysis results which can be misinterpreted.

Multi-site PMAX Implementation

The TVAN project to standardize the thermal performance monitoring tools and techniques by implementing PMAX was initiated in 2002. The scope of the project includes development of PMAX models for five units (Browns Ferry 2 & 3, Sequoyah 1 & 2, and Watts Bar 1). Funding was finally approved for implementation of the project starting January 5, 2004 in three phases corresponding to the three sites; Browns Ferry, Sequoyah and finally, Watts Bar. Each site purchased one server license and ten concurrent user licenses. The purpose of this discussion is to outline the configuration adopted for the PMAX server/client architecture and to relate some of the lessons learned to date in the implementation phases. As of this writing, the Browns Ferry and Sequoyah models are complete and available to client computers at all three sites and in the Chattanooga corporate offices.

Achieving this stage of progress was not easy. We were faced with many choices relative to how to implement this software. Typically, PMAX(R*TIME) is loaded on a PC designated as the server computer, which communicates with the plant process computer for on-line data. The client computers then use the PMAX Data Viewer application to view the PMAX displays. The entire application is typically installed on site. The obvious advantages of this option are that the hardware and software are controlled locally and usually by the TPE himself/herself. The disadvantages included limited off-site access, variations in software/hardware technical support, and limited corporate support.

To allow better peer communication between the three site TPE's, TVA wanted all three sites and corporate to have access to all the models. To achieve this goal, the communication links to the various plant process computers had to be addressed. TVA uses in-house developed software called DatAWare to access the plant process computer data at both the Nuclear and Fossil TVA stations. Consequently, TVA already had a standardized link through the plant firewalls to the process data. These links are dedicated and hardwired to ensure secure communications. DatAWare standardizes the data retrieval/storage process relative to the various models of process computers, so it was logical to link PMAX to DatAWare to obtain the process computer data. To facilitate Scientech's development of the interface between PMAX and DatAWare, TVA provided the DatAWare application along with complete sample sets of plant data which Scientech used in their offices during the model development phases. When the Sequoyah models were implemented in the second phase of the project, Scientech developed a "Top Plant Menu" (Figure 11) which allows each user to choose any of the units from a single PMAX Data Viewer desktop shortcut.

Three high-end PC's were purchased as part of the project to be used as the PMAX servers for each site. These servers are located in the TVAN Computer Engineering Group computer room in the Chattanooga offices. This location was selected because it is also the location of the DatAWare servers and is continuously monitored and maintained by the CEG staff. A four port KVM switch was procured to allow local switching at the server location between the three servers and the single keyboard/monitor setup. Each of the servers was purchased with a pair of RAID zero, mirrored hard drives which provide continuous backup capability. Also, the servers are powered from a UPS source. In this configuration, both the Thermal Performance Program Manager who is the "owner" of the PMAX application and the CEG staff can maintain the hardware and software without burden to the site TPE's. This configuration is also good for development and testing of the Information Services (IS) desktop installation scripts which allow remote software installation and upgrade "pushes."

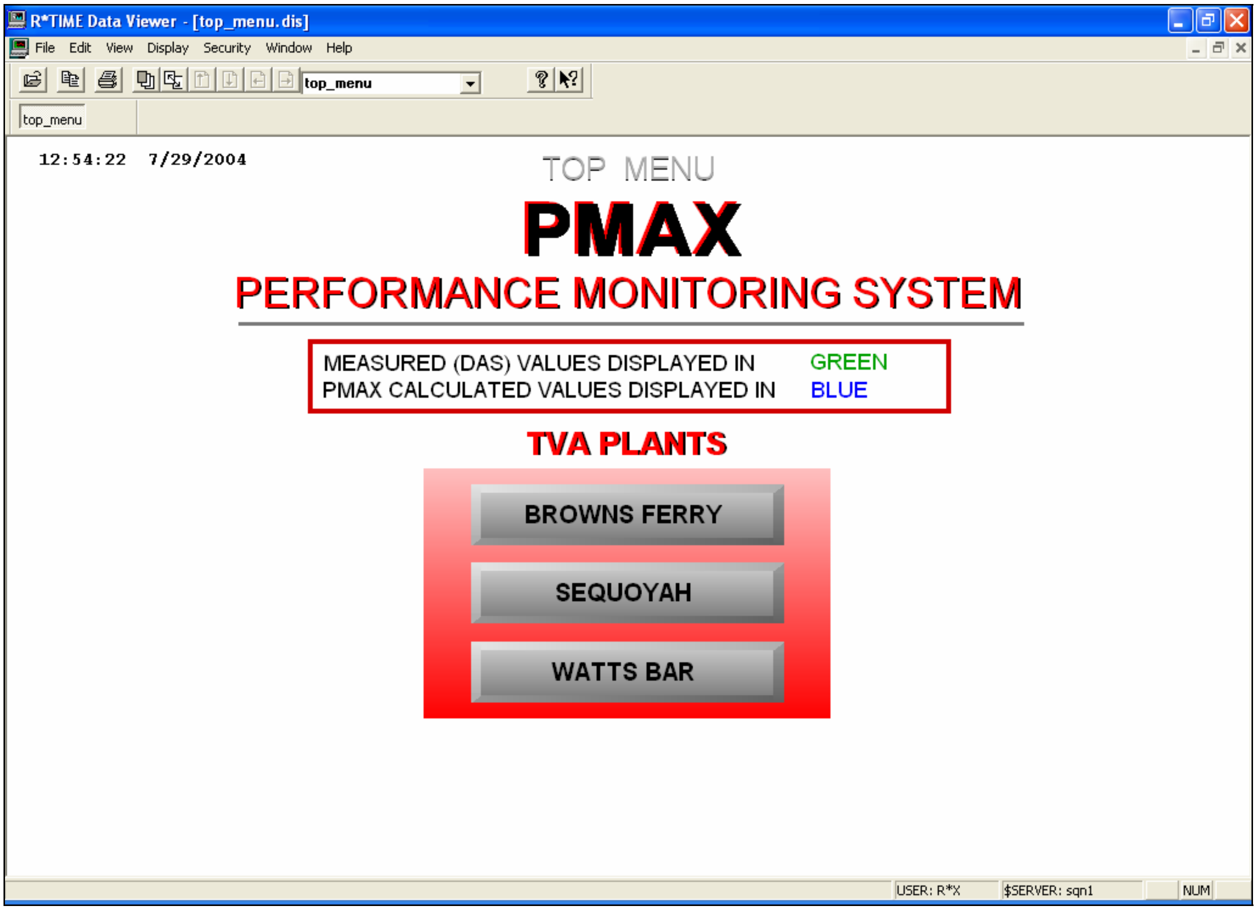

FIGURE 11 – PMAX PLANT TOP MENU

To control and limit changes to the unit models, two PMAX user levels were defined; the Basic User and the Power User. The Power User installation script performs the standard PMAX setup which provides PMAX Modeler, Display Builder, and Data Viewer applications. The Basic User script performs a limited setup which only installs the PMAX Data Viewer. These scripts are updated after each phase of the project to provide the latest displays and model features to all users.

The TVA interface for development of the plant models was primarily managed by the corporate TP Program Manager who provided day-to-day responses to the developer's questions and input needs. However, the three site TPE's actively participated in the project Kickoff Meeting at the Browns Ferry site. This meeting was very productive and allowed agreements to be reached between the TPE's on standardizing the basic display features and reports generated by PMAX. Active TPE participation in the final week of model tuning, where the preliminary PMAX models are checked and compared against the previous thermal performance monitoring system results and methods is imperative.

During the PMAX implementation phases we made several technical observations of interest. Sequoyah Unit 1 recently replaced the HP turbine with a Siemens-Westinghouse turbine. The thermal kit was developed with Siemens heat balance software that allowed the non-symmetric extraction configuration to be modeled. Previous Westinghouse heat balances and TVA PEPSE models assumed symmetric extractions for the number 1 and number 2 extractions. The non-symmetric extractions result in a 6 MWe penalty over the symmetric assumption. Consequently, the non-symmetric model yields a better match with the actual plant data.

In review of the Sequoyah MSR TTD's calculated by PMAX, it became clear that the PMAX TTD definition is not consistent with the industry standard definition. Both PMAX and PEPSE define the reheater bundle TTD as the difference between the saturation temperature of the tube-side drains and the shell-side steam outlet temperature. The industry standard definition is the difference between the incoming heating steam temperature and the outgoing shell-side steam temperatures. In our case, the PMAX/PEPSE TTD is about 2 ºF lower than that obtained from the standard definition. To correct this, we adjusted the PMAX TTD's to display values, corrected to the standard definition.

Finally, it is observed that it is very beneficial for the PMAX users to use the PMAX applications and explore the features for a period of time prior to their training experience. This helps debug the models and peak the interest of the users in preparation for their training. At this time, TVAN has not had any of the formal training purchased as part of the project and we are anxious to learn more!