Steam Generator, Cooling Tower,
and Low Load Modeling
at Catawba Nuclear Station

by

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In response to a number of plant events and/or planning for evolutions that involve placing the secondary plant in an unusual condition, Catawba has utilized PEPSE to accurately predict plant performance and behavior.

Steam Generator Modeling

Catawba is equipped with BWI recirculating steam generators on Unit 1 and Westinghouse Model D-5 steam generators on Unit 2. During 2005, a project was underway to uprate both units to take advantage of more accurate feedwater flow measurement instruments. Thus, it was necessary to determine exactly how much uprate capacity was available. Part of this evaluation was modeling of the steam generators to model the uprated conditions, and determine the steam generators response to changes in reactor coolant temperature and tube plugging. A screen shot of the steam generator model is shown below.

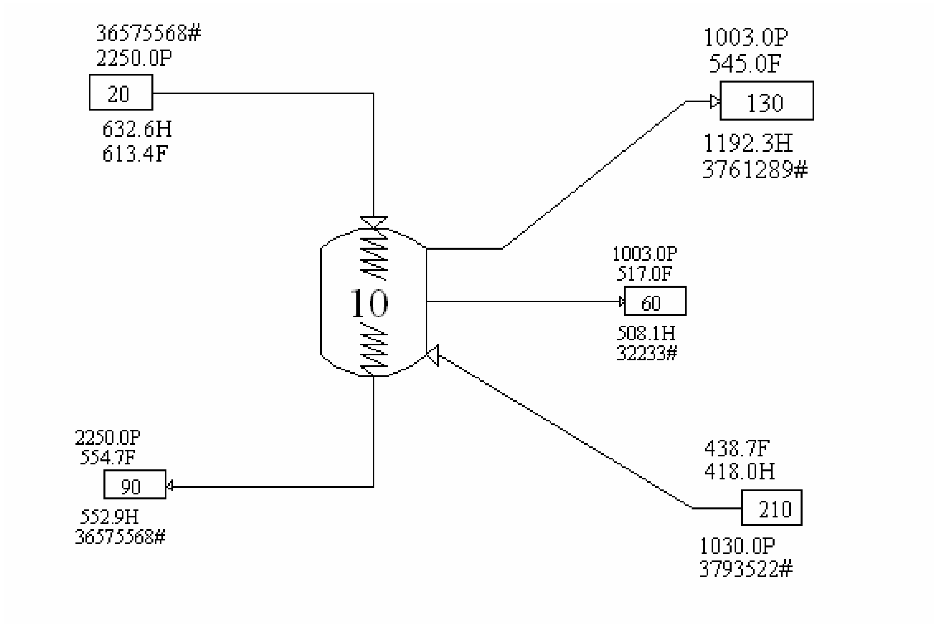

Figure 1 - PEPSE Representation of Steam Generator

Steam generator geometrical data was input to a design mode steam generator. Plant data was then used to “tune” the model to actual performance.

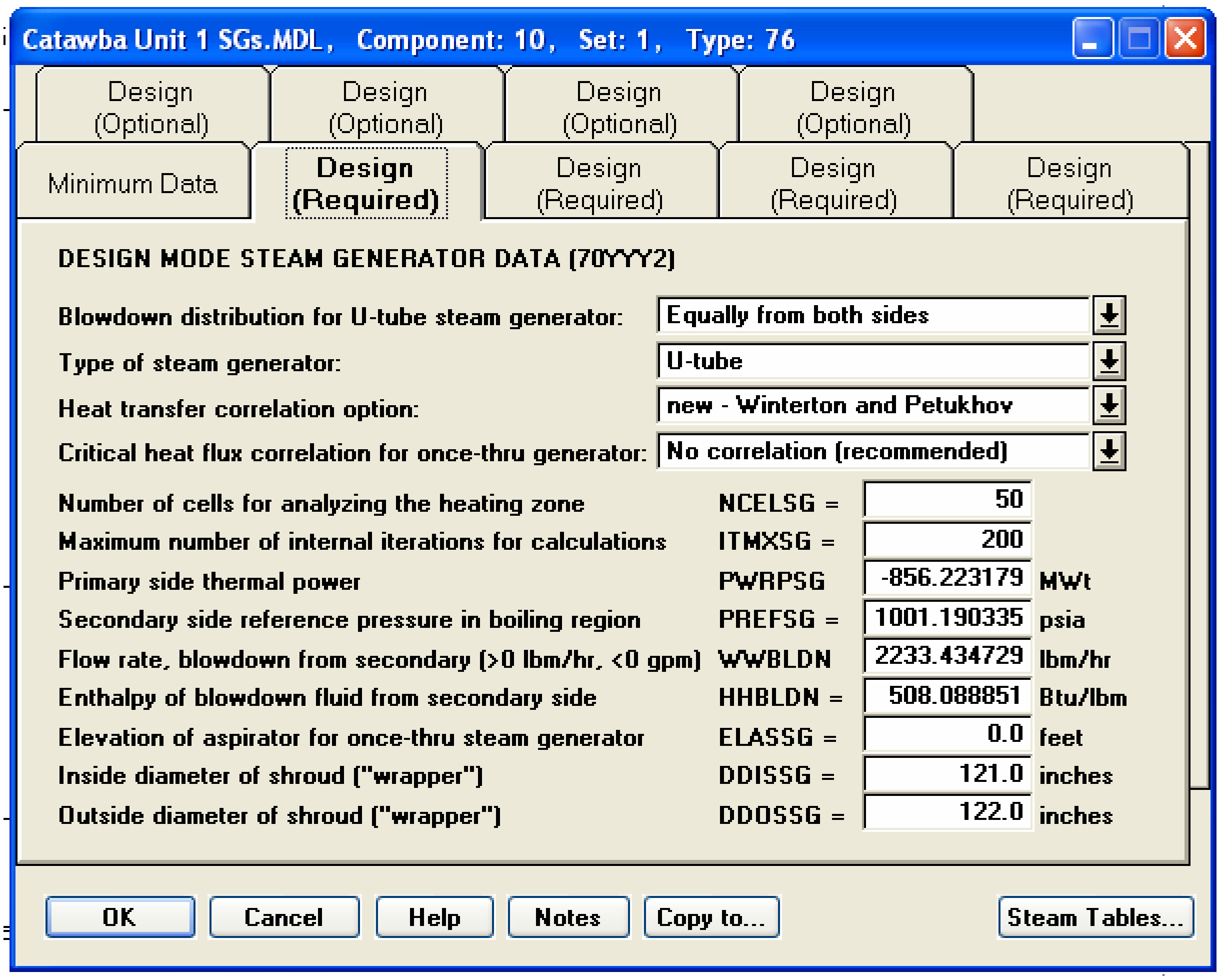

Figure 2 - Steam Generator Design Mode Required Data, Panel 1

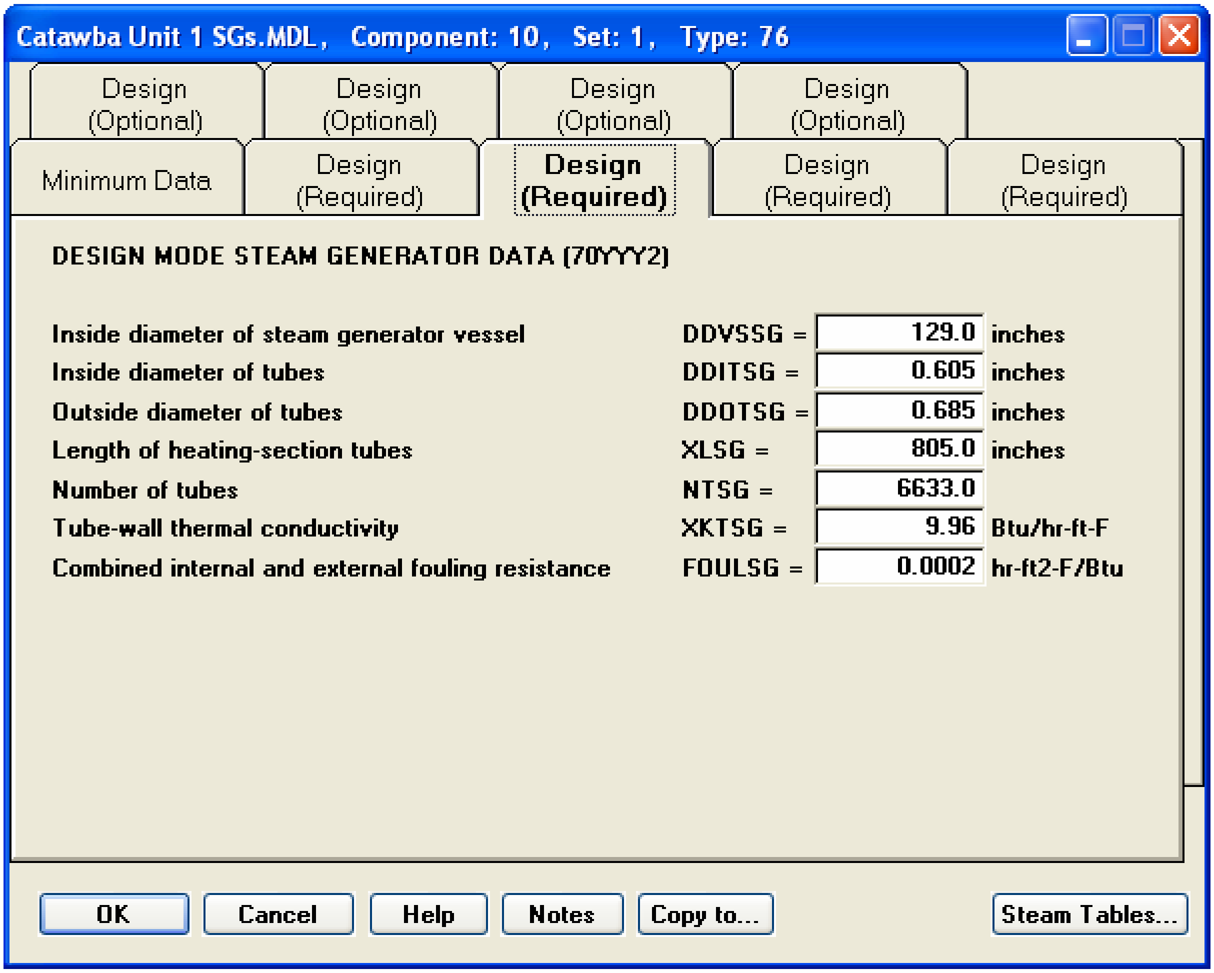

Figure 3 - Steam Generator Design Mode Required Data, Panel 2

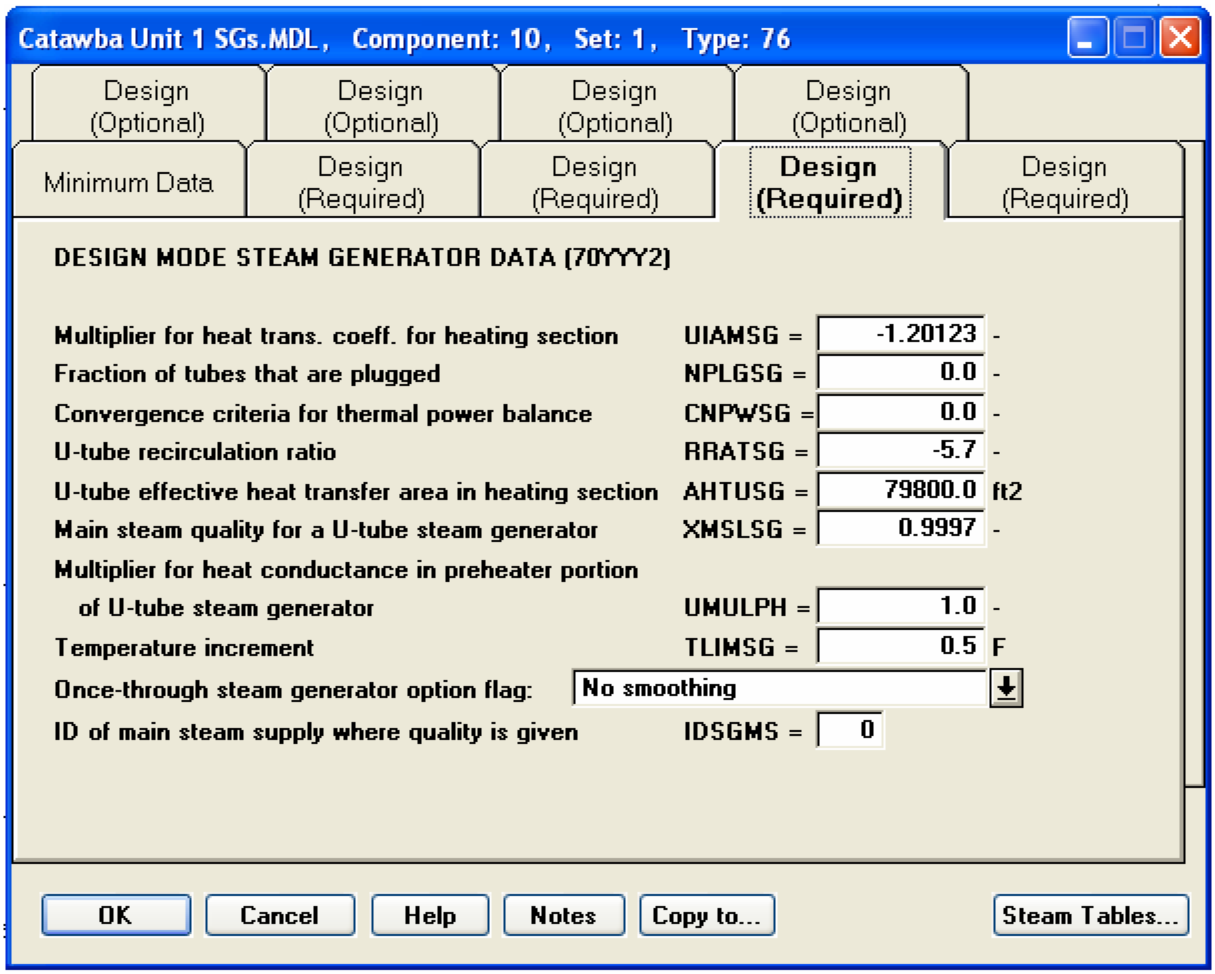

Figure 4 - Steam Generator Design Mode Required Data, Panel 3

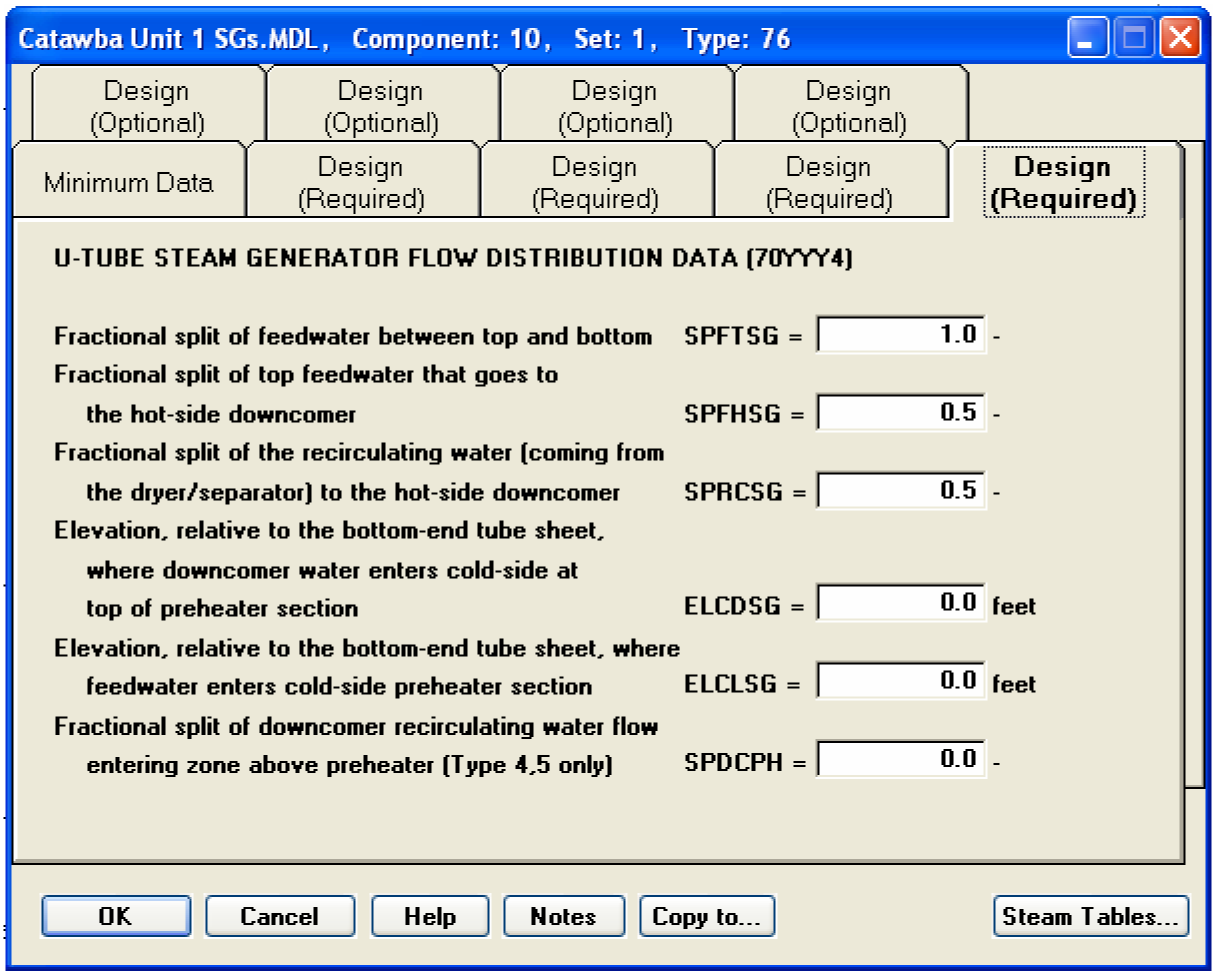

Figure 5 - Steam Generator Design Mode Required Data, Panel 4

Once the tuning factor (UIAMSG) is determined, the model is ready for use in predicting plant performance. Figure 6 shows predicted main steam pressure vs actual steam pressure during a Unit startup in June 2006. The predicted values match closely with the actual values throughout the startup.

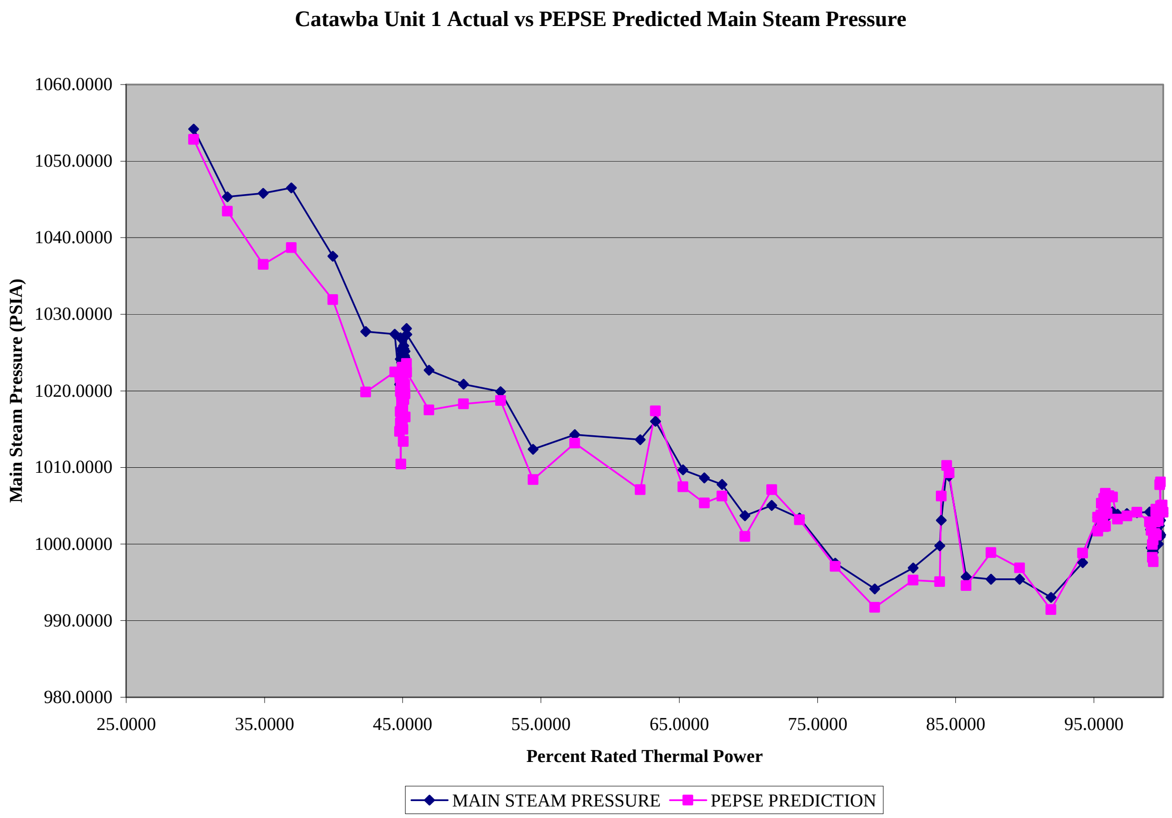

Figure 6 - Actual Main Steam Pressure vs PEPSE Prediction During Unit 1 Startup

The model can also be used to determine the effect of tube plugging and reactor coolant temperature on main steam pressure. Figure 7 demonstrates the effect on main steam pressure as more steam generator tubes are plugged.

Many PWRs have lowered the reactor coolant temperature to extend the service life of their steam generators. This also reduces steam pressure and might limit the unit to operation at less than 100% of rated thermal power. Figure 8 demonstrates the effect of lowering reactor coolant hot leg temperatures on main steam pressure.

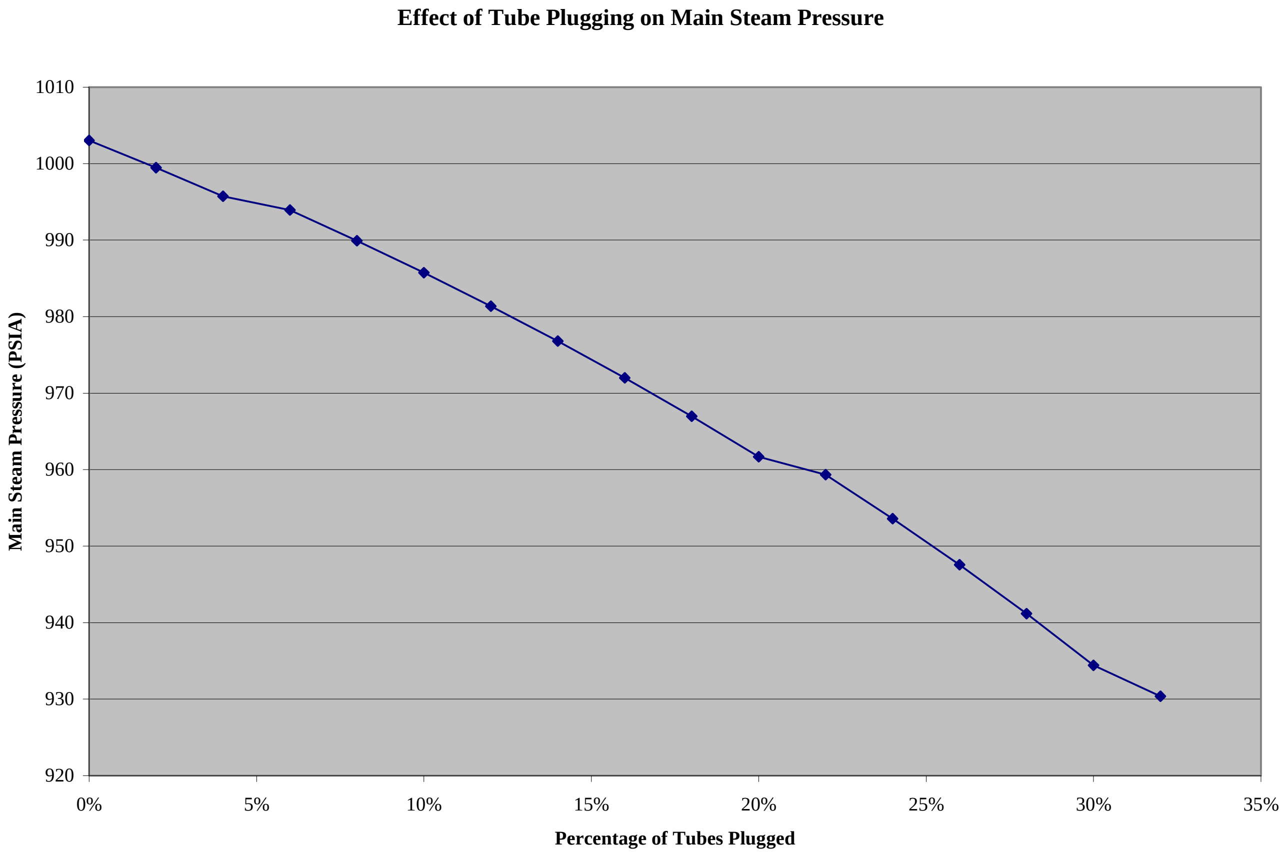

Figure 7 - Main Steam Pressure vs Tube Plugging

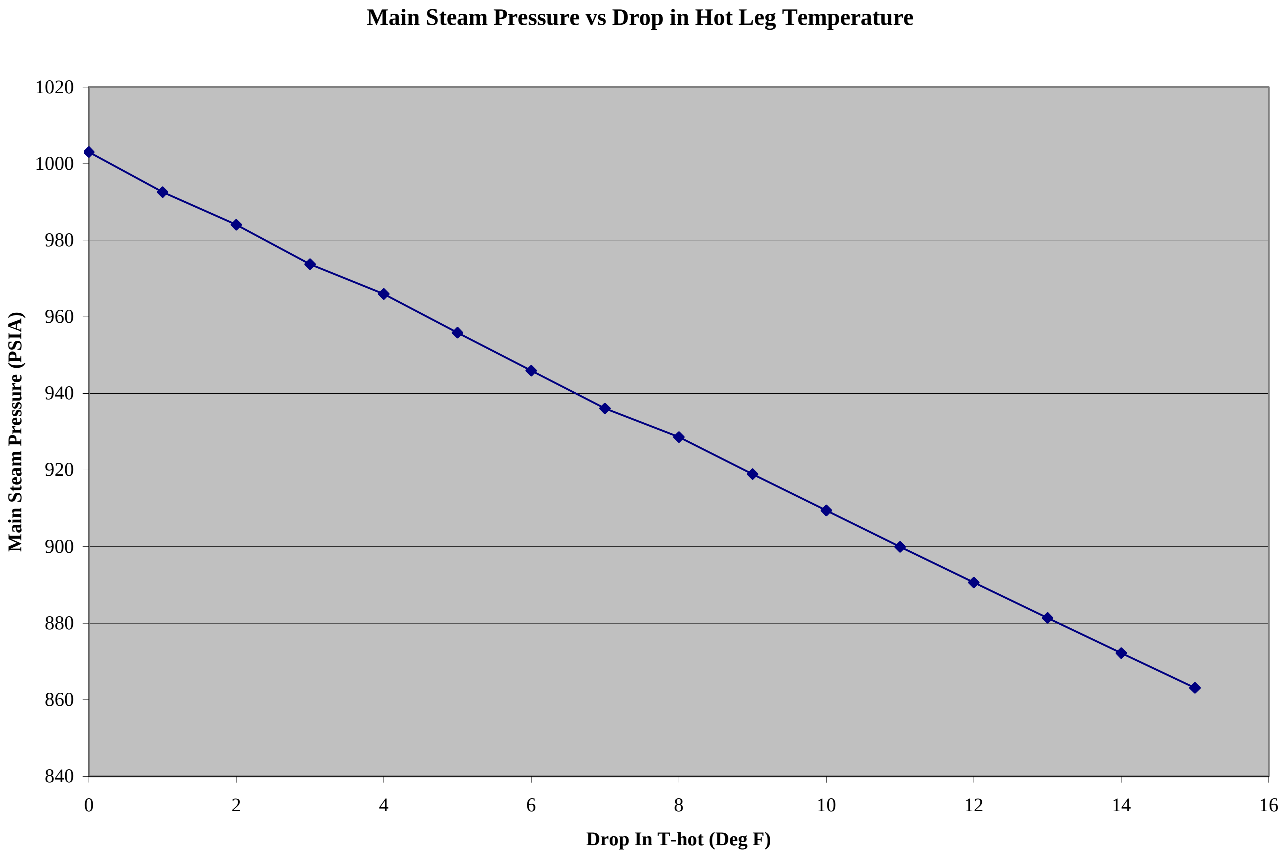

Figure 8 - Effect of Lowering Hot Leg Temperature on Main Steam Pressure

Cooling Tower Modeling

Three mechanical draft cooling towers have been incorporated into the Catawba PEPSE model. A typical representation of one is shown in Figure 9.

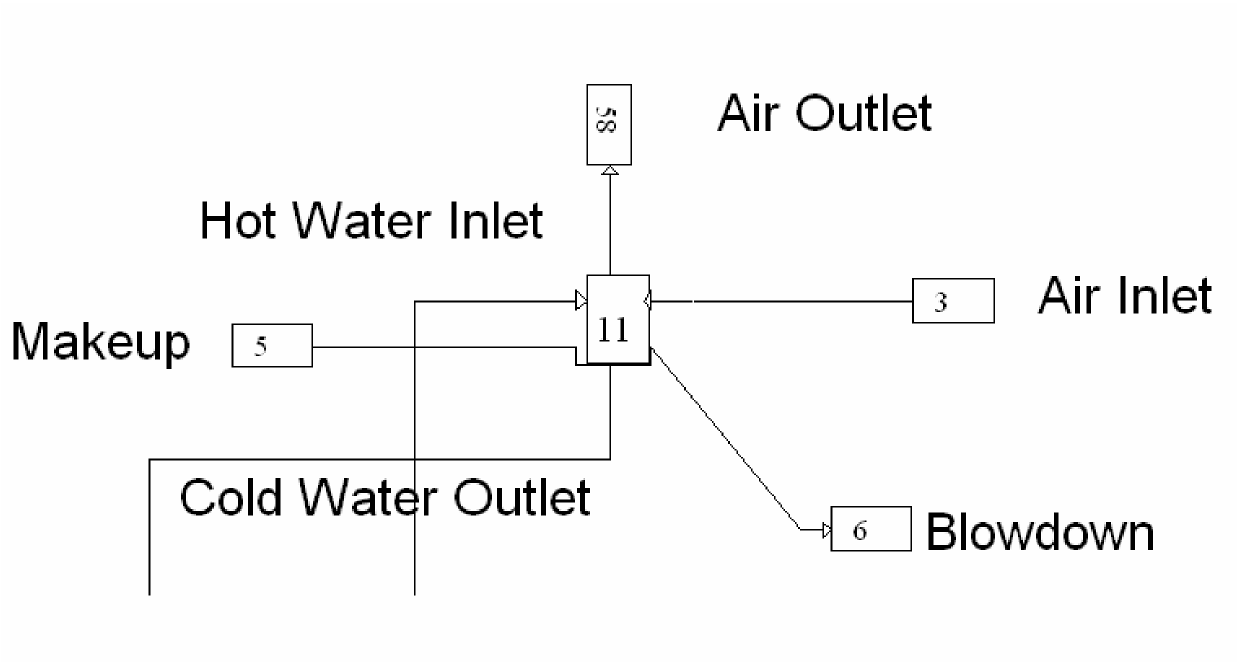

Figure 9 - Cooling Tower Component

To accurately model the tower in design mode, the following information is needed:

1. Performance curves showing cold water temperature as a function of wet bulb temperature and cooling range.
2. Circulating water flow rate.
3. Wet bulb temperature.
4. Dry bulb temperature.
5. Relative humidity.
6. Blowdown flow.
7. Temperature of makeup source.

With these parameters, a prediction of cold water temperature can be made. However, this is frequently not the only information that needs to be determined. If design and actual fan power is known, a prediction of tower performance can be made with fans out of service. Also, if actual flow, range, fan power, wet bulb temperature, and outlet temperature are known, the tower's percent capability can be determined. Capability is expressed as the ratio of the actual amount of water cooled to the specified outlet temperature to the amount water the tower should be able to cool to the same temperature. For example, if the tower is cooling 400,000 gpm of water to 75 °F when it should be able to cool 500,000 gpm to 75 °F, the capability would be 80%.

An excerpt from the PEPSE output file is shown below for the determination of cooling tower capability:

DETAILED COOLING TOWER PERFORMANCE OUTPUT

CAPA-BILITY (%)	RANGE (F)	APPROACH (F)	WET BULB TEMP (F)	COLD WATER TEMP (F)	COLD WATER FLOW (LBM/HR)	EVAPO-RATION RATE (LBM/HR)	FAN POWER (KW)
83.3	22.51	13.98	76.00	89.98	1.018E+08	1.982E+06	1839.1

This tower is operating at 83.3% capability (not too good).

Another parameter of interest is the evaporation rate. To accurately determine this, the air flow must be known. Since this is not measured at Catawba, an assumed volumetric flow rate per fan from the manufacturer is used. Then, a control is used within PEPSE to control the cooling tower's outlet air temperature such that the air exiting the tower has a relative humidity of 100%.

The circulating water flow rate at Catawba is not measured, but cooling tower inlet and outlet temperature are measured and recorded on the plant computer. With this information, a PEPSE control can be used to adjust the circulating water flow to match the actual cooling tower range. Use of such a control at Catawba actually detected a circulating water pump discharge valve that had a broken shaft and was indicating open when it was actually almost fully closed. Normal daily monitoring calculated an unusually low circulating water flow. Investigation of local instrumentation showed one pump operating at near shutoff head. The pump was stopped prior to being damaged.

Low Load Operation

While nuclear units are typically base load units that run at full power for extended periods, the ability to model plant behavior at low loads is desirable to monitor during plant startup. The PEPSE model for Catawba was generally limited to ~85% load before numerical instabilities would cause the model to fail prior to convergence. The problem was in the last extraction of the low pressure turbine. At some point during the calculation the demanded extraction flow would be greater than the flow into the turbine and the calculation would stop.

This problem can be solved by the use of flow update relaxation factor (RELAXF) and fractional flow updating limiter (FUPMXF) to limit the change in extraction flow in successive iterations. This can be programmed into PEPSE using operations that lowers the value of RELAXF and FUPMXF when the load drops below a threshold level.

When using special option 4, the initial guess for main steam flow must be close to the actual flow. If full load steam flow is used, the model will not converge. To automatically generate a reasonable guess for main steam flow, a schedule was input that varied main steam flow from 0 to 15 MPPH as reactor power varied from 0 to 100%. The schedule was set to initiate at iterate 0 and given an iteration interval of 1500. This ensures that the main steam flow is not adjusted any further. Otherwise, it will interfere with special option 4, by having steam flow adjusted by both the schedule and special option 4. Table 1 shows a comparison of actual generation vs PEPSE prediction during unit power escalation.

Percent of Full Power	Actual Generation	PEPSE Prediction
40.78	434.7	436.9
50.05	544.2	555.5
60.34	683.9	677.8
75.34	855.2	864.1
85.03	1028.8	1030.9
99.90	1210.2	1210.1

Table 1- PEPSE Prediction of Partial Load Operation

This ability to model low load operation detected a malfunction in the generator power measurement in April, 2006. While operating at ~ 40% power following a refueling outage, the power meter was discovered to be indicating significantly higher than the PEPSE prediction. Subsequent investigation discovered a calibration error in the power meter.

<u>Use of Special Option 1</u>

Many PWR plants have been power limited due to low steam pressure caused by steam generator tube plugging. Special Option 1 can be used to determine the power level at which the unit will reach valves wide open. This can be done by inputting the valves wide open test data into special option 1. PEPSE will vary main steam flow to reach the valves wide open conditions. Figure 10 shows the relationship between maximum reactor power vs main steam pressure.

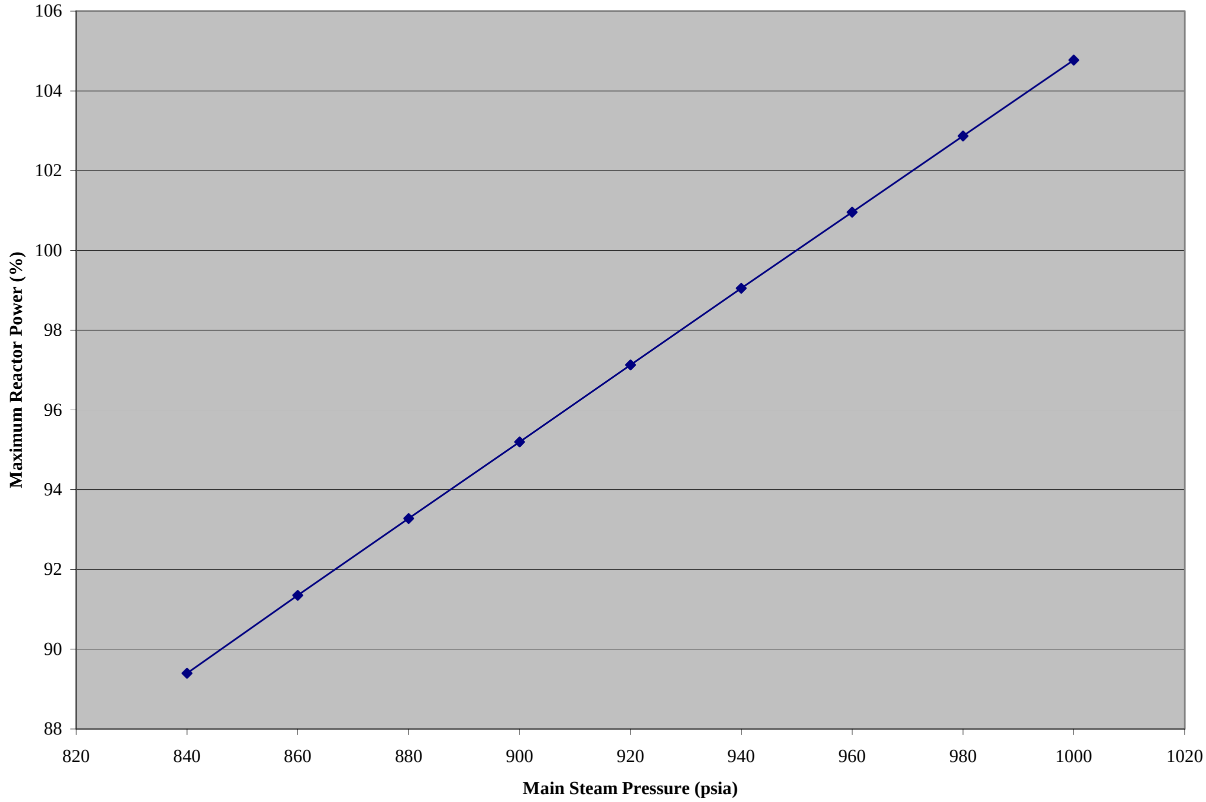

Figure 10 - Maximum Reactor Power vs Main Steam Pressure