The Use of PEPSE™ In Evaluating Extending The Time Between Major Outages

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"The Use of PEPSE™ In Evaluating Extending The Time Between Major Outages" is a paper submitted for the 21st Annual Performance Software User's Group Meeting to be held in Chicago on August 10-12, 2004.

This paper discusses the use of PEPSE™ for studies involving the time extension between major outages for large power plant steam turbines. First the relevant PEPSE component contributions and usage are reviewed. Secondly the Bench Mark and pre-outage tests are discussed from a practical perspective. Thirdly, a simplified method is provided for utilizing the results. In addition, other concerns and influences are provided..

Introduction:
In determining the state of turbines special testing, accurate measurements and complex computations are required. It is no wonder why there is a lack of confidence when performing energy accounting. However, as instrument accuracies increase, the computational abilities also continue to improve. More than ever turbine evaluations can provide degradation rates used to evaluate the impact of extending the time in-between major outages.

The minimum cost alternative will depend on degradation rates, future load requirements, retirement dates, discount values, cost of major versus minor outages, price of fuel and other factors. These other factors could override. Abrupt changes can influence the degradation rates etc. (Example: water chemistry upsets). The cost savings occurs over the life of the unit and are dependent on many variables.

However, the many variables impacting turbine equipment performance evaluation must be normalized. This provides a means to accurately measure degradation. Observed degradation rates can be misleading as can be seen in real performance data given in figures 1-4 showing unexpected degradation rates with some reasons provided.

This paper identifies the major factors in determining the efficiency and power generation of large steam turbines using PEPSE.. Turbine tests and evaluations for these machines are described in the ASME power test codes. PEPSE provides a basis and automation for these evaluations using special option 6.

This paper first highlights the relevant PEPSE component functional contributions and usage included in special option 6 . Secondly the Bench Mark and pre-outage tests are discussed from a practical perspective by describing problems that will likely have to be overcome. Thirdly, a simplified method is provided which utilizes the PEPSE results along with some concerns.

Relevant PEPSE component contributions and usage.

The purpose of this section is to briefly describe the specific PEPSE component functions involved. In general the component's usage must account for current and historical input data availability while considering the code requirements and unit specifics. The current and historical input data is accounted for in the handling of individual components and special features. Table A shows some of the individual components.

The PEPSE components needed for evaluating steam turbines provide a framework for the complex evaluations. These perform the complex ASME PTC 6.0 code tasks including the overall conversions from the actual test turbine state to the specified equipment turbine state ("normalized" or "benchmarked" state) including compensating for:

1. Unsteady states.
2. Turbine Stage pressure ratio's.
3. Stage efficiencies.
4. Stage Bowl flow coefficients.
5. Heater Conditions.
6. Special leakage flows.
7. Specified auxiliary steam flows.
8. Generator parameters.

The rate of degradation will have increased scatter and/or bias as the test data collection accuracy deviates from the code target values. (The unit should be operated to achieve maximum steady flows, temperatures and pressures as near to the specified values as possible.) The mass flow, temperature and pressure measurement accuracies should achieve code or near code levels (See Table B). When the instruments are outside of this range more uncertainty will ensue. (Estimates of error can be made using ASME PTC 19.1-1985 Supplement on Instruments and Apparatus Part 1 – Measurement Uncertainty)

Things used for evaluating the benchmark include:

1. Collecting and verifying detailed information regarding pertinent unit design that may or may not be recorded during the commissioning/acceptance testing such as:
    - Pressure drops across valves.
    - Pressure drops across turbine bowls and extraction flanges..
    - Pressure drops across turbine shells.
    - Pressure drops across all extraction piping.
    - Vendor heat balance representations specified clearly.
    - First stage pressure and temperature and location.
    - Bowl flow coefficients and efficiency for all stages.
    - Pressure, temperature and flow for all stages inlet and outlets.
    - Specified conditions across all pumps / turbines.

- Reheater pressure drop clearly specified by location.
- Reheater Bowl pressure drop.
- Last stages extraction flange pressure drops.

2. Creating Heat Balance Diagrams for checks.
3. Evaluating the state of the unit during acceptance testing for benchmark (if possible) analogous with ASME PTC 6.0 methods. This requires complete mass and energy balances and known turbine stage characteristics. (High accuracy information.)
4. Running controls to achieve component characteristics. Data provided with measurements using high accuracy instrumentation as found during acceptance / commissioning.
5. Using Special Options to attain measured Power utilizing primary flow rates.
6. Checking all parameters from benchmark tests with PEPSE outputs using developed heat balances.
7. Eliminating "Common Modeling Mistakes". Items to check:
   - Base Endpoint PPBEND=1.5 in Hg.
   - Submit fractional stream type 2 pressure drops for extraction lines. (not specified end conditions)
   - Submit fractional stream pressure drops for major flow streams.
   - Do not set stream end conditions or unintended heat transfer occurs.
   - Re-verify turbine stage group designation NIPEN.
   - Verify turbine extraction flange pressure drop and assign this to the extraction lines instead of the turbine's DELHPX,DELIPX,DELLPX parameters.
   - Include pressure drops across valves and bowls.
   - Include pressure drops across reheater (PDHXTU). Do not set Reheater outlet pressure.
   - Do not constrain turbine outlet conditions.
   - Check carefully the reference condition.
   - Use controls for all parameter matching.
   - Make sure there is one demand supplier for each required supply.
   - Make sure there is one demand supplier for each heater.
   - Make sure heater outlet tube conditions are used.
   - Use heater inlet extractions and use extraction pressure drops as needed.
   - Remove any constraints on Bench Mark component parameters.
   - Thermodynamic quality of gland condenser drain of 0.0 (TTHXDN) Or set the shell pressure (PRESHL) at saturated liquid conditions to match required temperature.
   - Pump Steam Turbine efficiency assigned 100%. Use actual efficiencies for pump, driver and linkage otherwise use pump input enthalpy rise (HDPUM) and driver exhaust enthalpy (HHPTGX) which allows PEPSE to determine efficiencies. Demand supply steam flow determined by requirements. Replace with efficiencies to un-constrain.
   - Pass main steam pressure to mixer outlet port.
   - Use mixer type 51 to mix Minor flows into main steam flow line.

- Use mixer type 50 for mixing equal main streams.
- Never set enthalpy of splitter B-port.
- Re-estimate demand splitter flow guesses with large load changes.
- Evaluate upstream temperatures by utilizing Operations / variables when there is the introduction of other streams. Other operations might include:
    a. Heat Exchanger heat duties.
    b. Stream flow sums.
    c. Turbine Cycle Heat Rates
    d. Boiler Heat Loading
    e. BFPT Exhaust pressures definitions.
    f. Simple similar multiple calculations.
    g. Computations resolving variables needed in heat balances.
    h. Computations to determine pressures at turbine shells when presented with heater shell pressures.
    i. Computations for enthalpy of turbine shells which result from measurements downstream.

8. Verify that the model is unconstrained and commissioned acceptance test data matches as close as code requirements.
9. Utilize model results creating base deck (benchmark). This includes:
    - Inserting tuned parameters from controls such as:
        i. efficiency multiplier on the governing stage to match the HP exhaust enthalpy.
        ii. shape factor on the first HP stage following the governing stage to match the enthalpy at the shell of that stage.
        iii. Etc.
    - Scheduled flows as necessary.
    - Etc.
10. Produce the cycle test data evaluation.
    - Collect and categorize data from unit as per code recommendations.
    - Determine the reasonableness of the test data before performing heat balances.
    - Plot the turbine expansion line on a Mollier diagram using available data. insuring negative slope through all points. Considering modifications as necessary in the case a second law violation occurs. Consider pressure measurements are the most accurate. Sliding along isobars to make the curve if required.
    - Create an input deck for measured data and conversions needed. Use good labels for input template.
    - Define turbine solution method IPCASE for every turbine.
    - Be sure there is a reference card for the first stage of each group.
    - Annulus area input for the last LP stage group(s).
    - Set the turbine transformation switch to zero (i.e. for the test case force PEPSE to employ the exact value of the measured values).
    - Set the turbine solutions for available data in template.

- Insert into the input deck raw test data.
- Utilize the stream flow option to achieve the required flow rates.
- Use special option Number 2 to swing the expansion line in order to match the specified generator power.

11. Determine the Test case unit at Bench Mark conditions.
    - Throttle valve settings use values from test case so that the changing conditions produce flows representative for valve at benchmark conditions which establishes the flow passing capability at the specified valve setting.
    - Invoke special option 1 for adjusting main steam flow. This adjusts the input component so that the quantity of steam supplied to the cycle is consistent with specified throttle valve settings
    - Benchmark case boundary conditions should be activated.
        i. Main steam temperature.
        ii. Main steam pressure.
        iii. Hot reheat temperature.
        iv. Reheater pressure drop.
        v. Condenser pressure
        vi. Makeup and letdown flow conditions.
        vii. Power factor.
    - Verify following insertions occur:
        i. Turbine stage group efficiencies except the last LP stage. (The last LP stage should be the efficiency at " Base Pressure" printed out in the test case PEPSE's turbine performance table C)
        ii. Turbine stage group shell flow coefficients.
        iii. Feedwater heater terminal temperature differences (TTDs)
        iv. Feedwater heater drain cooler approach differences (DCAs)
        v. Pump efficiencies.
        vi. Boiler feed pump turbine efficiencies.
        vii. Extraction line pressure drop fractions.
        viii. Miscellaneous component and stream pressure drops.
        ix. Leakage flows.
        x. Generator hydrogen pressures or losses.

12. Determine the degradation using special option 6.
    - Overall unit degradation determined after test at Benchmark conditions are completed.
    - Evaluates individual turbine groups by replacing test parameters with benchmark parameters for the component(s) or stream(s) to upgrade.
    - Use upgrades and component boundary conditions.
    - Denote incremental changes in cycle power and heat rate.

NOTES: (special option 6)

1. Remember the benchmark is used as the starting point
2. Data required for each turbine stages must be specified.
3. Special operations, operational variables, and special input/output may need to be used to facilitate this due to stream combinations.
4. Extraction lines in Option 6 benchmarks are modeled as type 2 streams which are connected directly to the heater shells . Always check active stream outputs since if test case indicates pressure drop in those streams other cases will take on the new set of pressure drops even if benchmark case has passive streams.
5. Feedwater heaters modeled in performance mode.
6. Splitters requiring fixed flow (type 61) or fixed percentage (type 63) can use schedules or operations at the benchmark case. Unless special adjustments are made to the cases these are retained throughout the special option 6 runs.
7. Stream flow option can be applied to the test data reduction.
8. Test data values entered by input template.
9. Expansion line swing for moisture (special option 2) for wet steam region and measured generator power value and special turbine solution methods for turbines involved in the swing.
10. Special Input processor will replace any preceding benchmark case values.
11. Turbine cards are not necessary within test data case however still possible to use them.
12. Performance parameter values for turbines, heaters etc. retained from the test case are used in the benchmark data case after input readings.
13. Special Option 1 used to represent the "as tested" throttle valve flow capability (constant throttle valve setting) is automatically active for special option 6 but can be cancelled.
14. Avoid any new turbine cards for the standardization step.
15. Upgrading occurs accumulatively. In any of these steps, components, streams, or generators can be upgraded to benchmark performance.

Secondly the Bench Mark and pre-outage tests are discussed from a practical perspective.

The purpose of this section is to address a few practical problems and ways one can overcome them. The benchmark and the pre-outage test cases should provide accurate unit performance comparisons. On the other hand most plant instrumentation will not meet the CODE requirements. Therefore, certified calibrated high accuracy instruments should complement those already available. Plant flow nozzles and orifices can be used but it is impractical to perform inspections and calibrations so it is better to utilize benchmark values for throttle valve coefficients. ASME addresses the requirements for measurement overall uncertainty and random error of 0.25% for fossil fuel reheat cycles. Random error component of uncertainty can be reduced by a minimum of duplicate test runs only after reducing load at least 15% before returning for the next measurement.

The permissible number of readings required to reduce scatter impact to 0.05% is also important and is addressed as permissible fluctuations and numbers of readings from ASME PTC 6.0 Figure 3.1,3.2, and Section 7. The unaccounted for leakage < 0.1% of throttle flow is something to check for. Hydrogen purity maximized to decrease windage losses is an influencing parameter. Duration of the tests runs should be two hours in order to verify cycle isolation mainly.

The benchmark is typically the commissioned state most likely to meet most of the code requirements. Therefore, these should be used for later unit evaluations. Other tests can use the values valve characteristics for later unit evaluations. The primary flow can be determined based on: 1. a fixed control valve setting using throttle valve "reference conditions" (Usually at the VWO position) and/or 2. power generated as input for the generator depending on state measurements. The fixed valve setting using throttle valve "reference conditions" provides reliable results as long as the initial testing meets the code. If there is no high accuracy commission acceptance test data with a calibrated flow nozzle what can this tell us about the turbine? Can the turbine be evaluated without this requirement? Not without guessing. Since the design, construction, and the calibration of primary flow nozzles are expensive it is usually only measured accurately during acceptance. However as stated above special throttle valve flow characteristics can be used by PEPSE to compensate for different throttle conditions (assuming the valve flow coefficients remain constant). This is the recommended course of action since the valve flow characteristics should change only slightly with time.

After the unit is normalized an estimate for the degradation rate can be made. Factors include stage flow path clearances, rotating and stationary blade erosion, deposits, blade surface roughness and possible blade material losses. The data must be normalized by determining what the flows, pressures and temperatures would exist for the "as tested" unit condition at the "specified conditions". Of course other conditions could be specified for reference but in all cases the same conditions should be used for determining the rate of change. ASME PTC 6.0 Appendix A shows the specific computations to be performed and is provided by PEPSE using Special Options - Option 6.

A simplified method is provided for utilizing the results.

The purpose of this section is to simplify the process into a number of steps.

- Use PEPSE to determine the power and heat rate degradation rates using special option 6.
- Collect pertinent information required for the lookup tables.
- Use the lookup tables with the following information to determine the optimum time extension between major outages:
    1. Cost of Major vs. Minor Outages.
    2. Frequency of Base Extended time between Major Outages.
    3. Frequency of Extended time between Major Outages.
    4. Discount factor
    5. Cost of electricity.
    6. Major Outage time.
    7. Minor Outage time.
    8. Unit Load degradation.
    9. Unit Heat rate degradation.
    10. Life remaining.
    11. Unit Heat Rate
    12. Unit fuel cost.
    13. Nominal load.
    14. Maximum load.

A brief definition of terms is provided in the appendix.

Concerns:
Measurement uncertainty and test procedures are the primary obstacles. There are concerns regarding the utilization of instrumentation calibrated by plant and maintained by plant especially for critical flow streams (such as main steam cold and hot reheats, economizer inlets, boiler feed pump's outlets etc.). There is a concern for unaccounted for leakages across boundaries. There are concerns regarding repeat tests in order to reduce uncertainty. Also more frequent testing may be required to validate degradation rates with increasing time between major outages. The length of major outages may also depend on the amount of the extension.

References:

1. PEPSE User's Guides
2. ASME PTC 6.0-1996
3. ASME PTC 6A-1982

BRIEF DEFINITIONS OF TERMS:

Cost of Major vs. Minor Outages:
The cost of each major outage and minor outages is the dollars spent for each major and minor outage.

Frequency of base time between Major Outages:
This is the frequency that represents the time between major outages which is used to compare to in regards to savings.

Frequency of cases that extend the time between major outages:
This is frequency that represents the case where time is extended between the major outages.

Discount factor:
This is the percentage rate that represents the value of money over time and is dependent on the economic situations for the company.

Electricity Net Price:
This is the price in cents/kwhr which electricity can be sold for offset by the cost to produce it.

Major Outage Time:
This is the time in weeks it takes to complete a major outage.

Minor Outage Time:
This is the time in weeks it takes to complete a minor outage.

Load degradation:
This is the percentage unit load degradation determined just before each base major outage.

Unit heat rate degradation:
This is the percentage unit heat rate degradation determined just before each major outage for the base case.

Unit Heat Rate:
This is the heat rate in Btu/kwhr for the unit at normalized load which represents the reference for Heat rate degradation.

Life remaining:
This is the years from the next major outage for the remaining life for the unit.

Unit fuel cost:
This is the unit cost of fuel in dollars per million Btu.

Nominal Load:
This is the most frequent or weighted load.

Maximum load:
This is the normalized load at VWO.

FIGURE 1 -
UNIT X

VWO LOAD vs YEAR
(RAW DATA)

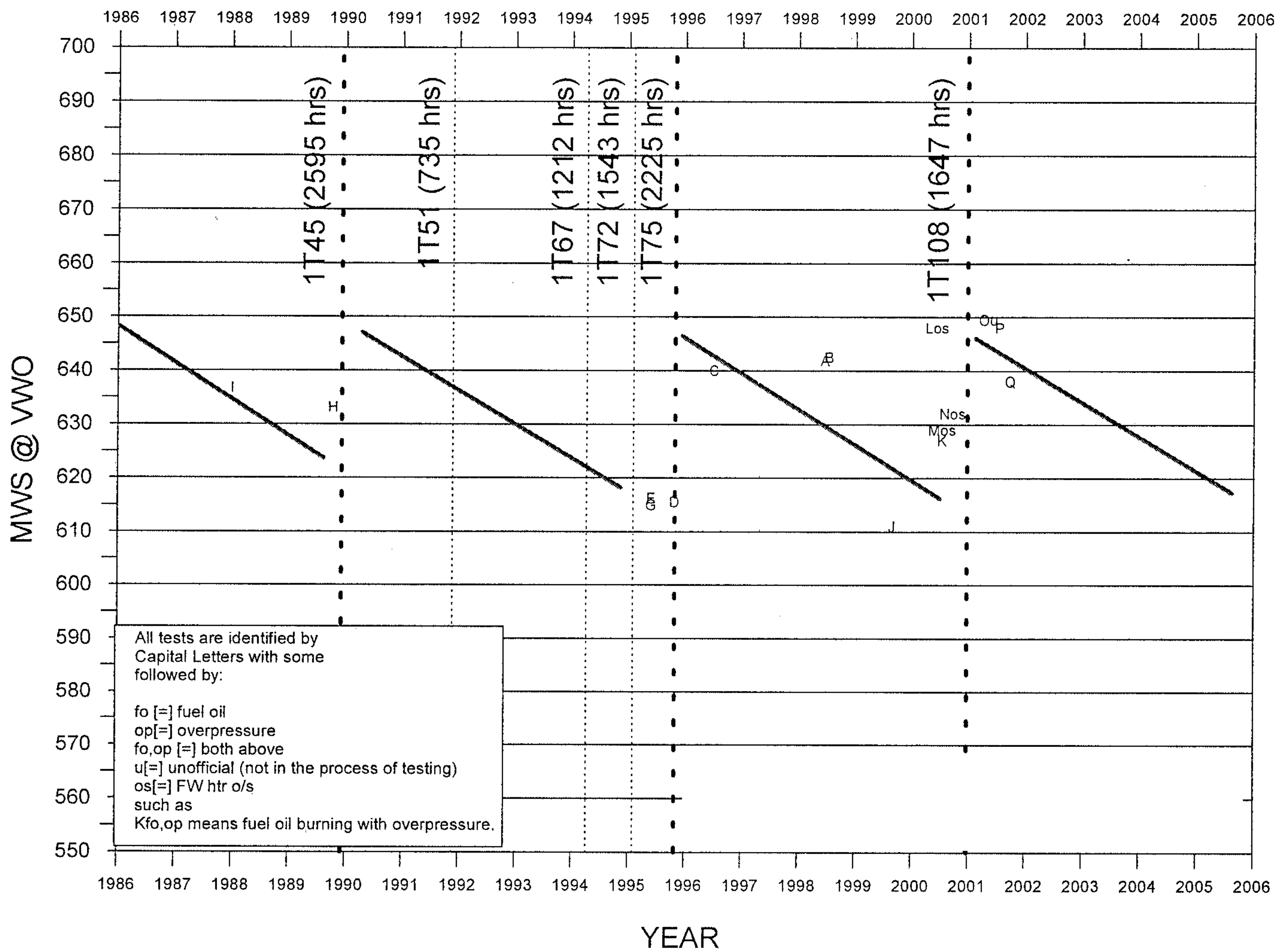

FIGURE 2 - UNIT Y

VWO LOAD vs YEAR (RAW DATA)

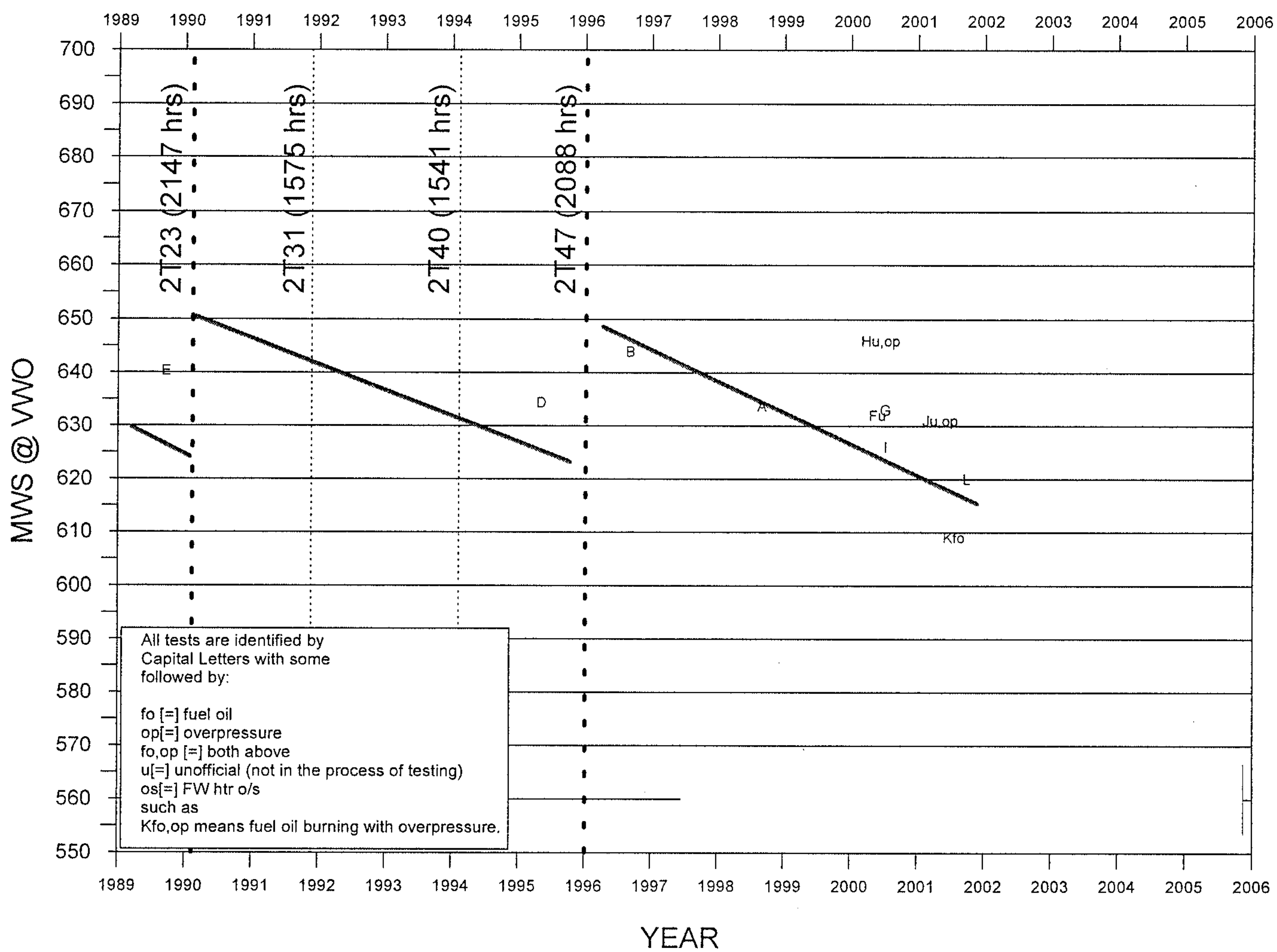

FIGURE 3 - UNIT Z

VWO LOAD vs YEAR (RAW DATA)

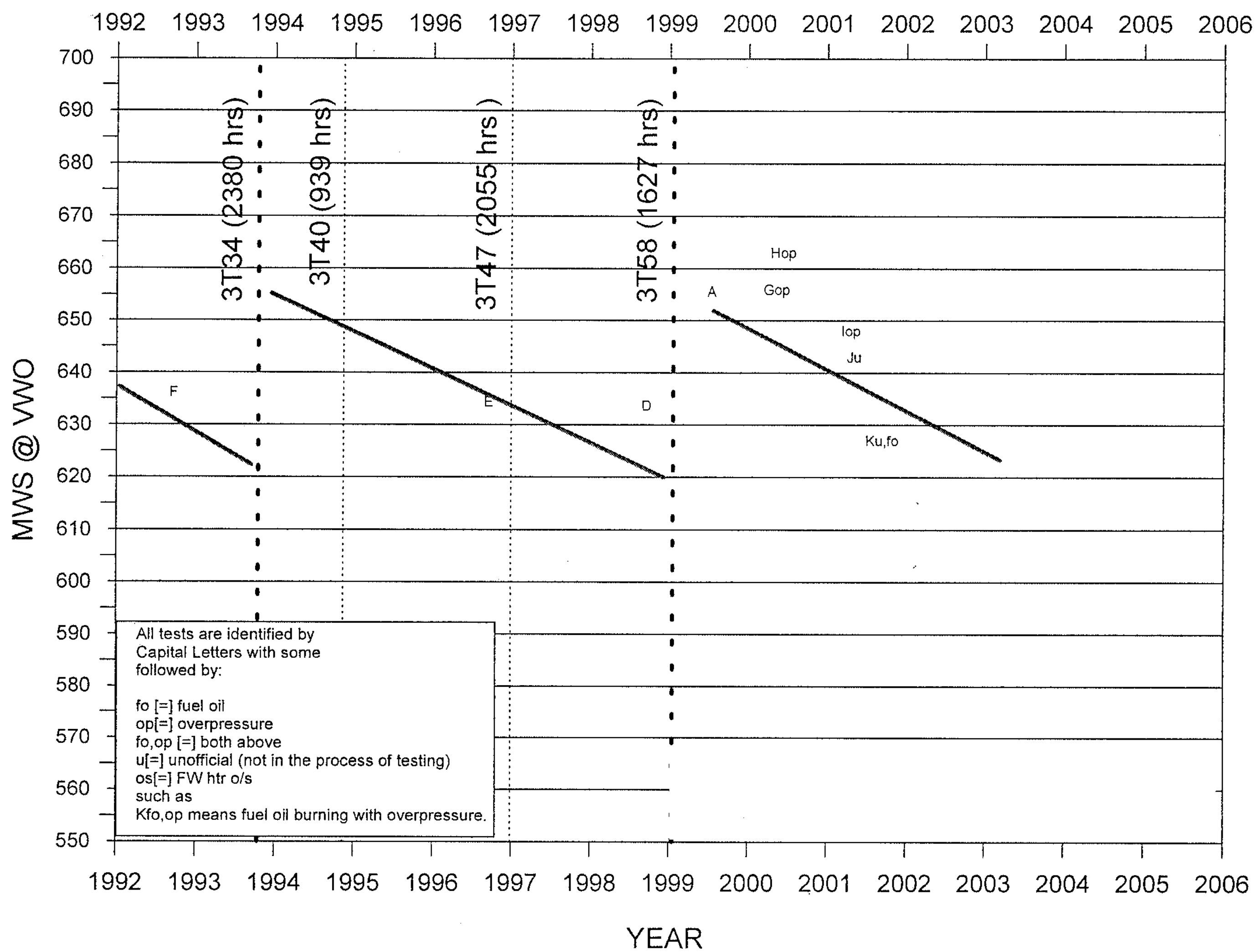

FIGURE 4 - UNIT W

VWO LOAD vs YEAR (RAW DATA)

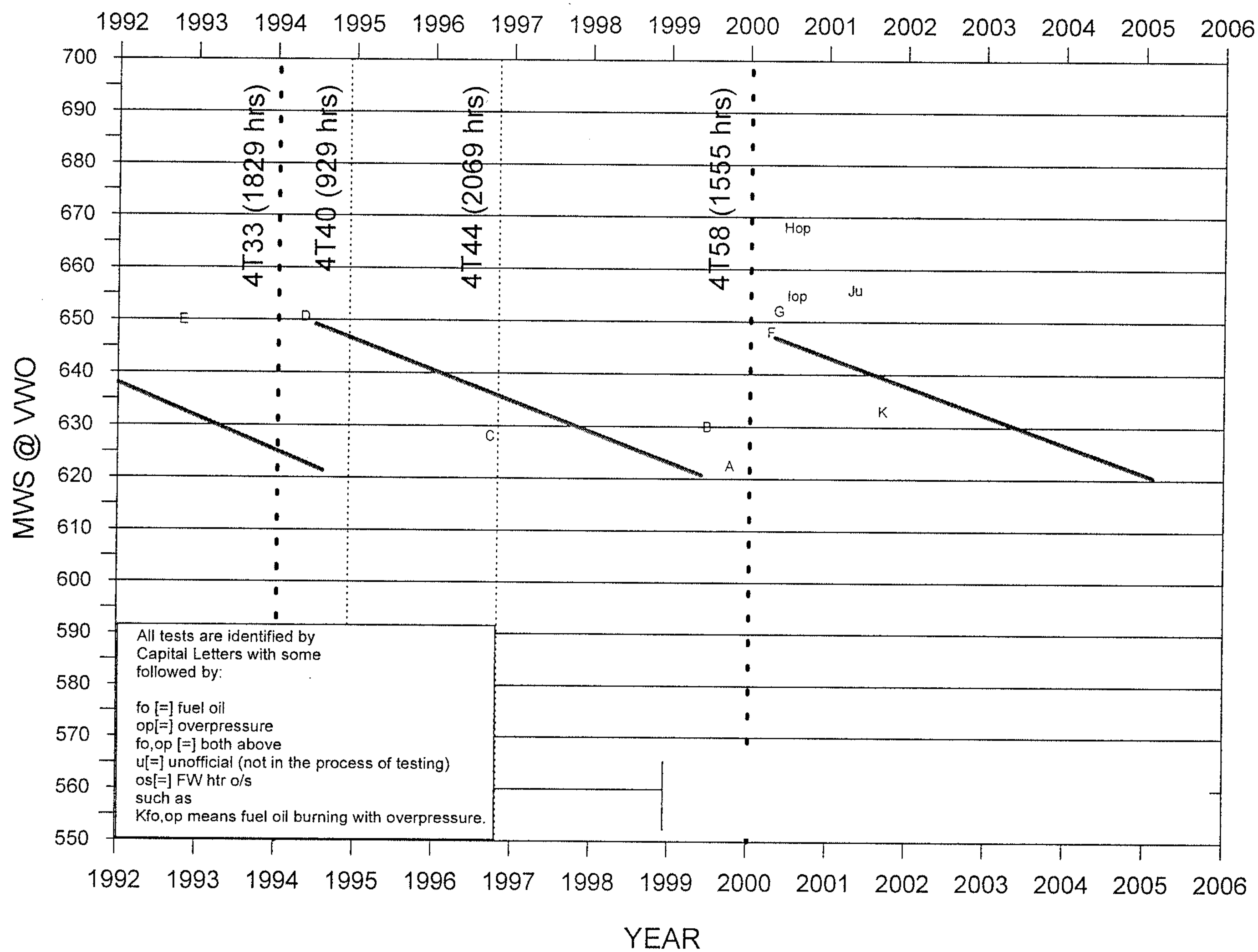

TABLE A-

Component	**Usage**
Input	Provides entering Steam flow and state inputs.
Splitters	Performs fixed, percentage, demand or scheduled flow computations.
Throttle Valves	Determines the steam properties adjusted for the valve characteristics. Valves for determining new flow values based on T,P at fixed VWO positions.
Fossil Governing Stages	Estimates the properties of the steam and power generated for the stage based on the Governing Stage Characteristics including velocity ratio and entropy incremental changes.
Fossil Governing HP, IP&LP Stage Groups	Estimates the properties of the steam and power generated for the stage based on its characteristics including pressure drops, bowl flow coefficients, efficiency and pressure ratios.
Boiler Feed Pumps / Turbines / Drives	Relates pump parameters to model.
Feedwater Heaters	Maintains heater performance under varying conditions.
Gland Steam regulators / condenser	Maintains system pressures.
Extractions	Maintains pressure drops.
Controls	Provides computations for determining component parameters.
Schedules	Provides dependent parameter values.

TABLE B-

Component	**Accuracy required by ASME PTC 6.0**
Power	<0.1% uncertainty
Pressures	<0.1%
Temperatures	<1 DEG F
Flows - Condensate	<0.05%
Flows – Throttle	<0.05%