RESIDUAL OIL BURNING EXPERIENCE AT THE
PUTNAM PLANT OF FLORIDA POWER & LIGHT COMPANY
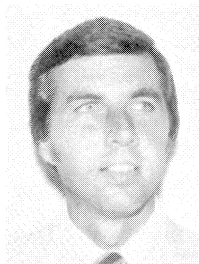
by

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William J. Hensler received his B.S.M.E. at the University of Illinois in January, 1971, after which he became an Assistant Engineer at the Meramec Plant of Union Electric, for the next two and a half years.

In June 1973, Mr. Hensler joined Florida Power and Light, where he was Maintenance Supervisor and Engineering Design Coordinator for Power Resources Staff at the Turkey Point Nuclear Plant from June 1973 to November 1978.

From the Manatee Plant, where he was Operations Superintendent for two years, Mr. Hensler went to the Putnam Plant in 1980, where he presently serves as Operations Superintendent.

ABSTRACT

Florida Power & Light Company has four Westinghouse 501B gas turbines in operation at the Putnam Plant. The gas turbines are components of the two PACE 260 combined cycle units at that site.

The units are designed to operate on either distillate fuel or a low sulfur residual fuel. An electrostatic fuel treatment facility is in service to prepare the residual fuel for use in the gas turbines.

The units were placed in service in 1976 and operated on distillate fuel until 1978. At that time, two of the gas turbines started burning residual fuel and the other two began using residual in 1979. Through May, 1982, the turbines have accumulated approximately 24,500 fired hours on residual oil.

Several problems have been encountered while burning this fuel and the following major problem areas are discussed in the paper. Each discussion includes a description of the symptoms, corrective action taken and current status.

    I. Fuel Preparation

    II. Fuel Filter Plugging

    III. Fuel Transfer

    IV. Starting Reliability

    V. Compressor Surges

    VI. Heat Rate

    VII. Gas Turbine Component Life

        A. Combustors

        B. Transition Ducts

        C. Blades/Vanes

    VIII. Availability

The experience at the Putnam Plant demonstrates that
treated residual fuel can be successfully burned in large industrial gas turbines.

INTRODUCTION

The Florida Power & Light Company Putnam Plant located in East Palatka, Florida consists of two Westinghouse PACE 260 units. Each unit has two 501B gas turbines, two heat recovery steam generators (HRSG) and one steam turbine. Afterburners are installed in the duct work between the gas turbine exhaust and the HRSG. These afterburners can be fired while the gas turbine is operating to raise the heat input to the HRSG and increase the steam turbine output. A barge unloading and storage facility, fuel treatment facility, six cell mechanical draft cooling tower, water treatment plant and waste water treatment facility are the major auxiliary components.

The plant was constructed to supply electricity on an intermediate load basis of between 2,000 and 7,000 hours per year. As shown in Figure 1, the units were put in service during 1976. Since that time, they have operated about 2,000 hours per year and averaged about ten hours per start. Figure 2 summarizes the annual operating history of a typical unit during 1981.

The units were designed to operate on either distillate or treated low-sulfur residual oil. The plant was selected to participate in an Electric Power Research Institute study (EPRI AP-1882, Project 1079) to characterize the costs and operating factors of a combined cycle power plant when firing No. 2 distillate fuel compared to firing a low sulfur blended residual oil. The formal program lasted from August, 1978 through May, 1979.

It has been determined that firing treated low-sulfur residual oil in a combined cycle plant creates problems in a

GAS TURBINE FIRED HOUR SUMMARY
THRU MAY 31, 1982

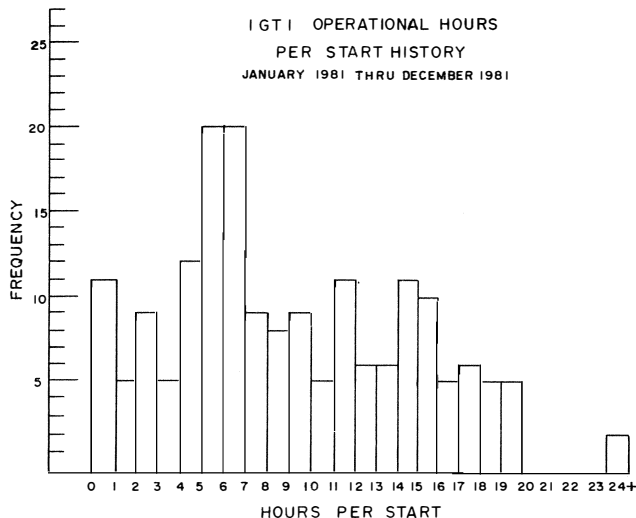|	1 GT 1	1 GT 2	2 GT 1	2 GT 2
DATE FIRST PUT ON LINE	5-25-76	5-5-76	9-22-76	8-26-76
FIRED HOURS ON NO. 2 OIL	3933.7	3797.5	6192.6	6637.2
DATE FIRST FIRED NO. 6 OIL	5-16-78	4-24-78	6-15-79	8-7-79
FIRED HOURS ON NO. 6 OIL	6980.3	6785.8	5411.6	5343.8
TOTAL FIRED HOURS	10914.0	10583.3	11604.2	11981.0

Figure 1. Plant Data Summary.

Figure 2. Annual Operating History.

large number of different areas. Fouling of the tubes in the heat recovery steam generators has been and continues to be a significant problem.

This paper, however, will be limited to the following problems associated with treating the residual oil and burning it in the gas turbines:

  I. Fuel Preparation

  II. Fuel Filter Plugging

  III. Fuel Transfer

  IV. Starting Reliability

  V. Compressor Surges

  VI. Heat Rate

  VII. Gas Turbine Compressor Life

  A. Combustors

  B. Transition Ducts

  C. Blades/Vanes

  VIII. Availability

Each of these problems was most severe during the initial operation of the turbines and their conversion to residual oil burning. In order to overcome the problems, effort was concentrated on identifying the cause of each problem, evaluating solutions and implementing modifications. The discussion includes a description of the modifications which have been effective in eliminating or minimizing the effects of an identified problem. The modifications which are currently being evaluated or implemented are also presented, although the effectiveness of these modifications cannot be reported at this time.

I. FUEL PREPARATION

The No. 6 residual oil that is received at the Putnam Plant must be processed before it is used in the gas turbines. Water soluble salts, normally sodium (Na) and potassium (K), must be removed to prevent corrosion of the turbine. A four stage electrostatic desalter manufactured by the Petrolite Corporation was provided for this purpose.

Based on the experience accumulated at Putnam Plant, the following three major areas deserve special attention in order to successfully prepare the residual oil for combustion:

A. Fuel Specifications

The following is the fuel specification for No. 6 residual oil received, processed and burned in the gas turbines at the Putnam Plant:

● Untreated Fuel

  Properties

Gravity	18.0° API minimum
Viscosity	1000 SSU @ 100°F maximum
Pour Point	60°F maximum

  Contaminants

Vanadium	200 ppm maximum
Sodium plus Potassium	200 ppm maximum
Lead	2.0 ppm maximum
Calcium	10 ppm maximum
Sulfur	0.7% by weight
Sediment & Water	2.0 maximum

● Treated Fuel

  Properties

Gravity	N/A
Viscosity	100 SSU at firing temperature
Pour Point	N/A

  Contaminants

Vanadium	200 ppm maximum
Magnesium	3:1 ratio Mg to V minimum
Sodium plus Potassium	less than 0.5 ppm total
Lead	less than 2.0 ppm
Calcium	less than 10.0 ppm

Discussion of Fuel Specifications

Gravity

The maximum API gravity of 18° is placed on the fuel for treatment considerations. The fuel treatment plant was designed to treat residual oil with a 21.4° API average and 18.0° API minimum gravity.

Viscosity

The viscosity limit on the oil is an FP&L Company standard for 0.7% sulfur oil. Westinghouse places a viscosity limit of 100 SSU for combustion. Oil with a viscosity of 1000 SSU @ 100°F has to be heated to approximately 200°F for combustion. This is well within the capability of the fuel heating equipment available.

Pour Point

The pour point limit of the fuel is an FP&L Company standard. A maximum pour point of 60°F insures the oil can be transported and handled without undue problems.

Vanadium

The limit on Vanadium is a Westinghouse specification. Corrosion of turbine parts because of Vanadium can be inhibited with Magnesium additives. The more Vanadium there is in the oil, the more Magnesium is required to inhibit corrosion. This increases the cost of treating the fuel and also means increased deposits in the turbine and heat recovery boilers.

Sodium and Potassium

The maximum value of 200 ppm of Sodium plus Potassium is a specification the manufacturer used in designing the fuel treatment plant. Theoretically, this value could be higher and experience has shown this to be true.

Fuel to be burned in the gas turbines must not have more than 0.5 ppm Sodium plus Potassium. This is a Westinghouse specification and is required to minimize hot corrosion in the turbines. Residual fuel processed through the treatment plant must meet this specification before it can be stored for use in the turbines.

Lead

Lead base compounds formed during combustion can also cause corrosion of turbine parts. Since lead cannot be washed out of the fuel, a limit is placed on the oil received at the site. The 2.0 ppm limit is a Westinghouse specification.

Calcium

Calcium in fuel oil is not considered harmful to gas turbines from a corrosion standpoint. However, calcium can form tenacious deposits that are not self-spalling and are difficult to remove. For this reason, Westinghouse has placed a limit of 10 ppm on the oil.

Magnesium

Magnesium is not normally found in crude oil. It is added to the processed fuel in the form of a magnesium-containing compound. The compound is added in sufficient quantity to maintain a weight ratio of magnesium to vanadium in the fuel of about 3:1 for corrosion control.

Sulfur

The maximum sulfur content of the fuel burned at the Putnam Plant is 0.7% by weight. This is an air quality limit imposed on the plant by the State of Florida.

Sediment and Water

It is obviously desirable to receive oil with the least amount of sediment and water possible and this value is an FP&L Company standard.

B. Fuel Oil Sampling and Analysis

If a residual grade oil is to be used in gas turbines, it is important that the oil delivered to or processed at the site, meet all applicable specifications (see Fuel Oil Specifications). This is accomplished by periodic sampling and analysis using the appropriate methods and equipment.

Sampling

It is essential that the oil delivered to the plant be tested before it is offloaded. Some of the contaminants, such as Pb and Ca, cannot be removed or inhibited. They must be controlled through delivery specification.

Periodic sampling is also required to insure that the oil which is being processed, meets the specified limits. While the fuel treatment plant is in service, it is tested every four hours. The "clean" oil is checked for Mg and V to insure the proper ratio of Mg to V is maintained. Tests are also run for Na and K to insure that the level of Na plus K does not exceed 0.5 ppm. Even though Pb and Ca are checked at the same time, these contaminants should remain in limits because of the "as received" specifications.

Samples are taken in two ounce plastic bottles that have been rinsed with Trichloroethane solvent. When testing treated oil, care must be taken to avoid sample contamination. Sample bottles are not reused and the technician should avoid touching the inner rim of the bottle of the inside of the cap. Salts from the hand can contaminate a sample giving erroneous Na and K values.

Sample lines should be carbon steel, stainless steel or plastic where appropriate. Teflon joint compound or a comparable substitute should be used where it is required. Experience has shown that galvanized piping or metallic-based joint compounds used on sample lines can contaminate samples. This type of contamination may show up as high or very erratic Pb values.

Analysis

Analysis of the oil for the elements mentioned earlier is performed using a Baird Atomic fluid analysis spectrometer. This allows simultaneous analysis to be performed for Mg, Ca, V, Pb, Na and K in just a few minutes.

When making the decision on the type of machine to be used for fuel oil analysis, several key factors should be taken into consideration.

1. The machine needs to provide fairly rapid analysis. Normally each test is the average of five analyses for each of the six elements mentioned earlier. This alone could be quite a task every four hours. Add to this the need from time to time to run many extra tests for troubleshooting and the requirement for rapid analysis becomes even more important. As many as 25 analyses have been run on each of the six elements every two hours in the past when troubleshooting problems occurred with the system. Over 50,000 analyses have been run since the first turbine burned residual oil in April, 1974.

2. The equipment should be relatively easy to operate. At the Putnam Plant, when the fuel treatment is in service, technicians are scheduled around the clock to test the treated oil. This means they must all be proficient at operating and calibrating the equipment.

3. When making the decision on the type of instrument to be purchased, the user must make certain it is accurate to the degree required. At the Putnam Plant, the maximum allowable Na plus K is 0.5 ppm. This means if the instrument cannot analyze both of these elements to within something less than 0.1 ppm, the cumulative error could be over 0.2 ppm. This is almost half the given tolerance in error alone. This has been the biggest problem with oil analysis at the site. Analyses of all elements in ranges greater than 1.0 ppm have caused no significant problems.

   To minimize the possible error when analyzing Na and K in the less than 0.5 ppm range, several procedures were developed.

a. The Baird speedometer is fully calibrated once a week. The limits of acceptable calibration were reduced from those originally provided by the manufacturer.

b. All samples are analyzed fives times and then averaged.

c. A special standard in the range of the analysis was made up. It is a base oil with a 0.5 ppm Na and 0.5 ppm K added. This standard is analyzed daily and provides the "blank" to be applied to the regular analysis.

d. An atomic absorption unit is also available for backup analysis. This is much slower, but will provide much more accurate anlysis when there are any questions with the Baird's results. The analysis is run by the wet method using flame emission.

In summary, the quality of the fuel oil analysis program is dependent upon the care in sampling and analyzing the oil.

Also, the accuracy of the analysis cannot exceed the limits of the equipment used.

c. Fuel Treatment Plant Waste Water Problems

Disposal of the effluent water from the fuel treatment plant posed one of the most difficult operating problems that had to be overcome in residual oil treatment. Environmental limits are imposed on the oil and grease content in the waste water discharged from the site. These restrictions state that there will be no visible sheen in the effluent and the dissolved oil and grease is limited to 15 mg/L average with a maximum of 20 mg/L.

Effluent water from the first stage treater is routed to the waste water treatment skid that was included with the treatment system. This skid includes a gravity plate separator followed by an air flotation separator. The effluent water from this skid usually has 20 to 40 mg/L dissolved oil and grease in it. Because of unidentified characteristics in the untreated oil, the dissolved oil and grease have been in excess of 200 mg/L and there has been, on occasion, more free oil coming from the first stage than the skid was designed to handle. Obviously, this water could not be discharged so a system had to be developed to handle it. [2]

An existing fuel oil tank was converted to a waste water holding tank. The tank has a capacity of approximately two million gallons. The effluent from the waste water skid is routed to this holding tank. The residence time allows any free oil carried over with the waste water to separate and rise to the top where it can be removed as required. When the fuel treatment plant is not in operation, water from the bottom is reprocessed through the waste treatment skid and then to holding ponds.

There are three ponds in a series configuration and the water enters the first and then overflows to the second and then to the third. By the time the water has reached the third pond, the oil and grease content is less than 5 mg/L. This reduction occurs due to the biological degradation of the oil by naturally existing microorganisms in the water. The water in the last pond meets all the environmental criteria for discharge as a low volume waste source. Even though the water can be discharged from the site, it is mainly used as the water source for the site sprinkler system. The only time that discharges are made are during periods of heavy rainfall when storm water is routed to the ponds.

II. FUEL FILTER PLUGGING

Westinghouse specified five micron filters for use at the suction and discharge of the main fuel oil pump, as shown in Figure 3. Although these filters were acceptable when using distillate oil, they required changing about once per hour when used with treated residual oil.

Obviously, this was unacceptable and a series of filters were tried including 20 micron pleated paper, 40 micron pleated paper, 75 micron excelsior filled cartridges and 100 micron pleated monel. Experience has shown that the 75 micron excelsior filled cartridges last longer in service than any of the others and this filter is now used in both the suction and discharge side of the fuel pump. The suction filters are changed when the differential pressures exceeds 10 psi and the discharge filters are changed at 5 psi differential pressure. These filters now last approximately five months between changes.

The main concern about using the larger particle size filters is the possible detrimental effect that the particles might have on the main fuel oil pump, flow divider and nozzles. Through May, 1982, approximately 25,000 hours of experience
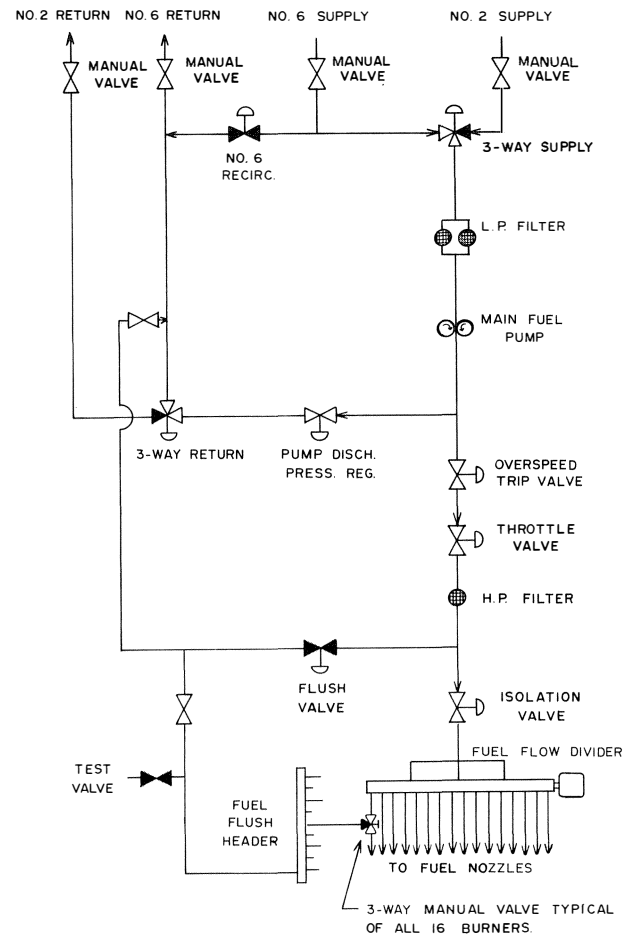

Figure 3. Gas Turbine Fuel Delivery System.

burning residual oil, with the 75 micron excelsior filters, has indicated no abnormal wear on any of these components.

Samples of the material which plugged the filters have been extensively analyzed and the results reported in Appendix C of EPRI Report AP-1882 [1]. Specifically, the following explanations have been suggested:

a. Asphaltenes and Asphaltic Solids — These were either caused by concentration of the asphaltenes due to long term storage instability of the blended residual oil or mixing the residual oil with small amounts of the distillate oil causing precipitation of the asphaltenes and their subsequent concentration and agglomeration.

b. Magnesium Additive Dropout — An oil soluble magnesium compound is added to the treated residual oil as a vanadium deposit inhibitor. This has been very stable during storage, but some magnesium particles have been removed from the filters.

c. Contamination — Debris, tank bottoms and other foreign material which have become suspended in the oil during shipment, processing and storage.

While the exact cause of the filter pluggage is an interesting topic, from a practical standpoint, it has been demonstrated that treated residual oil can be adequately filtered using 75 micron excelsior filled cartridges and the filter replacement interval is very reasonable.

III. FUEL TRANSFER

The Westinghouse 501B gas turbines operating at Putnam Plant have the capability of operating on either distillate or low sulfur residual fuel. However, due to the design of the gas turbines, they must be started and shut down on distillate fuel. During a start up, the gas turbine is brought up to speed and synchronized to the transmission system using distillate fuel. Normally, a fuel transfer is started at a generator load of four megawatts with a load increase of one-half megawatt per minute. The load rate of change may be increased as the fuel oil temperature through the flow divider is increased.

The distillate fuel oil does not require heating and is burned at ambient temperature. However, the viscous residual fuel oil must be maintained at a minimum firing temperature of 155°F to assure proper atomization.

During the fuel transfer the temperature difference between the two fuels can thermally shock the fuel flow divider causing the internal gears to bind due to uneven expansion. When this happens, the fuel flow to the nozzles is interrupted causing the gas turbine to flame out. This occurred on a frequent basis during the initial operation of the units on residual oil, so a program was initiated to improve the fuel transfer system.

In order to more closely monitor the performance of the flow divider, a strip chart recorder was utilized in the control room to monitor the unfiltered signal from the flow divider speed pickup. This signal was recorded during each start-up to determine if the flow divider was beginning to bind. This information was of tremendous benefit when analyzing the effectiveness of the following modifications which were made to the flow divider.

A modification was made to execute the fuel transfer over a period of about thirty minutes to reduce the effects of the differential expansion. This was accomplished by installing a small needle valve to throttle the control air regulating the rate of travel of the three-way fuel transfer valve. This proved to be unacceptable because of the long delay in loading the gas turbine.

Further improvements were made to reduce the transfer time by replacing the rigid piping between the fuel header and the three inlet ports to the fuel flow divider with a flexible stainless steel hose. Also, the flow divider was freed from restraint on its base mount by removing the floor anchor bolts, thus allowing it to "float" and further reduce the effects of differential expansion.

Experiments determined that a temperature rate of change of 20°F per minute through the flow divider could not be exceeded without jeopardizing the success of the transfer from distillate to residual fuel. The transfer time was then reduced to approximately five minutes.

While making significant improvement in reducing the time delay in loading the gas turbine, problems still remained in the smoothness in which the transfer took place. The higher pressure on the residual supply created by the residual recirculation valve closing immediately upon initiation of a transfer affected the smoothness of the transfer. Corrections were made by installing a pressure controller to govern the position of the residual recirculation valve in order to maintain the residual supply pressure equal to the distillate supply pressure. This allowed a more uniform fuel transfer and reduced the temperature gradient during the transfer.

To increase the distillate savings a check valve was installed around the needle valve on the control air line to the three-way fuel transfer valve. This did not affect the three-way valve opening rate, but rather allowed the valve to transfer back to the distillate position immediately when transferring from residual to distillate.

Flow divider problems were also experienced when the heat tracing on the fuel oil piping between the gas turbine fuel skid and the flow divider malfunctioned. When the heat tracing failed to cut off, the distillate fuel remaining in the line after shutdown was continuously heated until the next start. When started, the flow divider would experience a large temperature shock which resulted in binding. An immediate remedy was to turn off the heat tracing on the line. Since the units were located in a warm climate, it was possible to start up without heating the distillate oil and the heat tracing had been removed. It has proven to be beneficial to keep the heat tracing in operation on the flow divider.

The failure rate of the flow divider has also been reduced by lowering the oil temperature from 180°F to 155°F. The lower oil temperature minimizes the thermal gradient during fuel transfer, but still allows adequate atomization of the fuel.

Many of these modifications were implemented over a period of several years. Historical accounts of flow divider outages have shown a significant reduction in failures as a result of implementing these modifications.

While many improvements have been made, it is felt that further improvements are possible. One area involves enlarging the total axial clearance of each element within the flow divider by 0.0003 inches. It is believed that this will reduce binding, as it has already proven successful in reducing assembly problems.

In addition, a procedure for flow testing the flow divider prior to operating the engine has been implemented. This procedure includes transferring fuel from distillate to residual several times.

As a result of these modifications and the test procedure, it is anticipated that forced outages due to flow divider failures will be eliminated.

IV. STARTING RELIABILITY

Starting reliability at Putnam Plant has been a major concern since the initial startup of the units. The reliability varied between 60 and 80 percent while the turbines were operating on distillate fuel and declined further when they were converted to residual oil burning.

Early attempts to determine the cause of the starting problems were frustrated by the lack of information available to diagnose the start attempts. A multipen recorder was installed to monitor the following variables on each start:

1. Unfiltered output from the flow divider speed pickup

2. Average blade path temperature

3. Speed

4. Filtered fuel flow

5. Fuel control signal output

6. Fuel demand signal to fuel control valve

7. Flame scanner No. 1 burner position

8. Flame scanner No. 16 burner position

9. Signal to start main fuel pump (20 IDX)

In addition, the 16 blade path thermocouples were recorded at 12-second intervals during each start attempt.

Based on an analysis of the available information and discussions with representatives of Westinghouse, the following changes have been made to improve the starting reliability:

1. The initial fuel flow was increased from 9 gallons per

minute to 11.5 gallons per minute by adjusting the throttle valve prelift setting.

2. The starting curve which controls fuel flow as a function of time and speed was altered to minimize fuel cutbacks and prevent flame-outs after ignition.

3. Three-way valves were added immediately adjacent to each burner to allow the fuel lines to be flushed to a drain header. This was done to remove any residual oil trapped in the fuel lines following a gas turbine trip while operating on residual fuel. Before this modification, the gas turbine would experience approximately two starting failures before the trapped residual oil was replaced with distillate oil.

4. The water-wash procedure has been modified to include an operator-initiated purge of the system with 200 psi air. This was done to eliminate starting failures, following a water wash, caused by water which accumulated in the water-wash/atomizing air system.

5. All of the piping in the water-wash system was sloped toward the drain to prevent the accumulation of water.

6. The manual isolation valve upstream of the water wash system is kept closed except during a water wash to prevent the entry of water into the atomizing air system if the automatic water-wash isolation valves leak.

7. The ignitors are removed from the engine before a water wash and they are "sparked" prior to installation following a water wash.

8. A cross flame tube was installed between burner 1 and burner 16.

9. The automatic 90-second low pressure (27 psi) air purge of the atomizing air system and burners, initiated by tripping the gas turbine, was extended to three minutes.

10. An automatic 30-second high pressure (200 psi) air purge of the atomizing air system and burners, initiated by tripping the gas turbine, was added.

11. An operator-initiated air purge of the atomizing air system and burners is performed several times before each start attempt.

12. Atomizing air pressure was increased from 17 psi to 27 psi.

13. The atomizing air system is periodically checked for air leaks and all fittings have been welded or sealed with a silicone caulking.

14. The one-inch diameter atomizing air ring header was replaced with a two-inch diameter ring header of all welded construction.

15. A burner maintenance quality control program was instituted. This included pressure testing each rebuilt burner assembly before reinstallation in the unit.

16. The trip hammer was removed from the overspeed trip mechanism. On several occasions, vibration caused unnecessary actuation of the overspeed trip protection and the need for trip hammer was eliminated by Westinghouse memo PM 05340.

17. All of the successful starts are now analyzed for indications of pending problems. By plotting the blade path temperatures at ignition, it has been possible to iden-

tify partially-plugged burners and have them replaced before they cause a starting failure.

18. During each 500 hour inspection, all of the fuel nozzles are replaced.

Obviously, a large number of changes have been made in a relatively short time to improve starting reliability. This has made it very difficult to evaluate the effectiveness of any specific modification, but the following conclusions have been reached:

1. As shown in Figure 4, installation of the cross flame tube between burner 1 and burner 16 caused a noticeable increase in starting reliability.

2. The purge air system uses combustor shell air to purge the burners. Since flow through this system is caused only by the pressure drop across the combustor basket, any air leakage in the piping, flexible hoses or fittings will cause the air flow through the nozzle to stop or reverse. This reverse flow allows oil mist and products of combustion to enter the burner air passages and the atomizing air system. All of the changes which involve purging the atomizer air system address the symptoms of the inadequate purge system. The installation of the welded two-inch diameter atomizing air ring header reduces the pressure drop through this header and improves the quality of the purge system. This header has only been installed on 2GT2 and it has had a noticeable impact on starting reliability. Sixty-four of the last 65 attempts were successful and the one failure was not ignition related.

The starting reliability of all the four gas turbines at Putnam Plant has averaged 86% for the last four months and it is anticipated that the goal of 95% will be achieved in the near future.
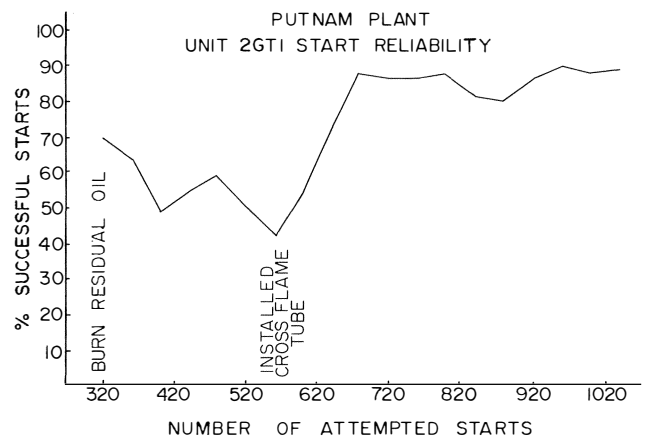

Figure 4. Gas Turbine Starting Reliability.

V. COMPRESSOR SURGE

The burning of No. 6 oil causes deposits on the turbine blades that lower the power output and restrict the air flow through the turbine. This restriction in air flow causes a higher back pressure on the compressor. If the deposits become severe, the reduced air flow and high shell pressure can cause a stall or surge of the compressor.

There were a total of seven compressor surges at Putnam, with the first occurring on 1GT1 (8/1/78) and the last occurring on 1GT1 (7/5/79). 1GT1 had a total of three surges and 1GT2 had a total of four surges. These surges have occurred at

various loads. No surges occurred on 2GT1 or 2GT2, which were burning No. 2 distillate oil during this period.

Typical symptoms of the compressor surges at Putnam are as follows:

a. A series of low pitch muffled booms occurring approximately every 1 to 2 seconds, increasing in amplitude to a loud final boom, audible at long distances (200 to 400 yards).

b. The actual gas turbine trip is normally caused by high blade path temperature.

c. Reverse current conditions also occur causing the generator breaker to open.

When a surge occurs, all accessible components of the engine are visually inspected for damage. The compressor and turbine sections are also water washed before returning the unit to service.

A definite relationship exists between air flow and combustor shell pressure which, if known accurately, could indicate a surge condition; however, attempts to monitor the condition of the gas turbine relative to surge have not been successful. Westinghouse provided Putnam Plant with surge curves which indicated safe and unsafe conditions based on the compressor air flow and compressor discharge pressure, but surges have occurred even when tests indicated the compressor to be in the safe operating area. The inability to predict surges was probably due to the lack of accuracy in determining performance parameters. The following factors limited the accuracy of the data:

1. Compressor discharge temperature is measured in the air cooler line which is heated above its real value due to the proximity of this line to the combustor.

2. The compressor pressure ratio is a ratio of static pressures only and does not include total pressure components.

3. The engine instrumentation allows reading combustor shell pressure to only a five percent accuracy.

In addition to compressor stall, these other possible causes of the surges were considered:

1. Compressor damage

2. Fuel system fluctuation (instrumentation)

3. Fuel oil flashing (heat trace malfunctions)

It is conceivable that the last surge on 1GT2 (5/12/79) and probably the trip on 5/10/79 were caused by compressor damage or a combination of compressor damage and turbine deposits.

It is felt that the other incidents which are summarized in Figure 5 and Figure 6 were surges [3]. For example, on December 7, 1978, Unit 1GT2 was shut down at 0800 due to an unusual noise in the inlet duct. The unit was restarted at 1700 and it surged at 1727. Fortunately, a multipen strip chart recorder was being used to monitor critical performance parameters during this surge. A reproduction of this strip chart is attached. (Figure 7). This chart clearly shows a dramatic change in combustor shell pressure and blade path temperatures with no change in fuel flow.

As a result of the numerous surges which occurred during 1978 and 1979, several alternatives were evaluated to either prevent the surge from occurring or determine when a surge condition was being approached. A summary of the alternatives which were considered and the action which has been taken to date is listed below.

1 GT 1

DATE	TOTAL HOURS	# 6 HOURS	HOURS SINCE LAST SHELLING		HOURS SINCE LAST WASH	
			TOTAL	# 6	TOTAL	# 6
08/01/78	2270	232	565	UNK.	1096	232
12/07/78	3396	827	28	0	337	103
07/05/79*	4533	1295	155	127	104	85

* DEEP MUFFLED NOISE HEARD APPROXIMATELY 1-2 SECOND INTERVAL PRECEEDING SURGE.

Figure 5. Surge Occurrences 1GT1.

1 GT 2

DATE	TOTAL HOURS	# 6 HOURS	HOURS SINCE LAST SHELLING		HOURS SINCE LAST WASH	
			TOTAL	# 6	TOTAL	# 6
12/07/78*	2865	578	3	0	249	51
04/14/79	3918	805	35	34	1051	327
05/10/79	4190	1054	7	6	272	149
05/12/79	4210	1070	27	22	20	16

* SURGE CAPTURED ON BRUSH RECORDER.

Figure 6. Surge Occurrences 1GT2.

1. Install compressor high density Row 1 and Row 2 diaphragms to increase the surge margin.

These were installed in all of the gas turbines during overhauls in 1980 and 1981.

2. Water wash the compressor and turbine each 100 hours.

This procedure was adopted in July, 1979 and closely adhered to until the high solidity diaphragms were installed. This frequent washing could be performed during the normal cycling of the units. Since the diaphragms were installed, the gas turbines have been operated on several occasions as long as 500 hours between washes without surging.

3. Coat compressor blade path parts to retard deposit buildup.

The compressor blades and diaphragms were coated with Sermetel 725 during overhauls in 1980 and 1981.

4. Instrument each engine sufficiently to monitor the operating variables that govern surge.

A microcomputer was installed to monitor fuel oil flow, compressor shell pressure, scroll pressure drop, flame scanner signals and percentage of water in the fuel oil. The unit was in service for
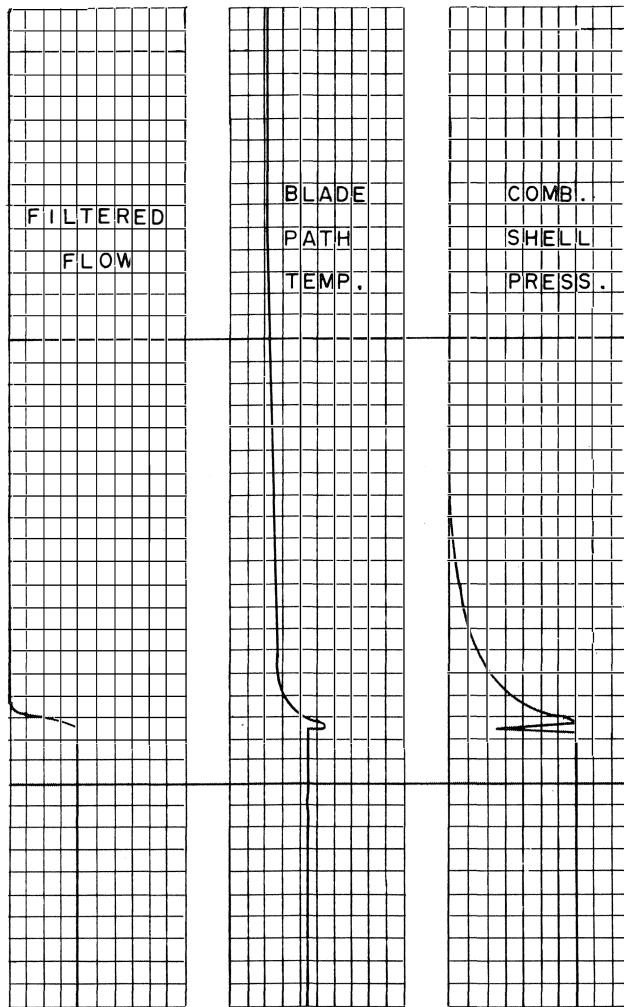
Figure 7. Brush Recording of Compressor Surge.

approximately six months and no surges occurred during that time.

5. Develop a design concept to alarm or trip the gas turbine when a surge limit is approached.

This was not completed because surges were eliminated after the water-wash schedule was revised.

6. Develop a design concept to take automatic preventive action when approaching a surge condition.

Consideration was given to automatic load reduction, modulation of the air bleed valves and/or automatic I.G.V. actuation, but the project was not completed because the surges had been eliminated.

7. Reduce turbine fouling by injecting water during operation.

This was attempted at various water to fuel ratios of between 20 and 50 percent. The program was terminated because the water injection was not effective in preventing or removing the deposits.

Westinghouse has serious doubt that these events are typical compressor surges caused by the compressor reaching its surge limit, but rather the so-called "surges" are triggered from other causes for the following reasons:

1. At 8:00 AM on 12/07/78, events resembling "surges" were experienced by two units within a few minutes. The units shared a common fuel supply system. It seems highly unlikely that two of the very few "surges" would occur at the same time when they had a common trigger.

2. The 1GT2 unit "surge" event that was recorded on the strip chart occurred at approximately ¼ load. The measured pressure ratio at the "surge" was 8.75 to 1. The same engine had operated at pressure ratio of 11.1 to 1 on 12/05/78 at full load and at 10.65 to 1 near full load on 12/08/78, all at essentially the same referenced speed.

3. Westinghouse intentionally surged the compressor of every engine tested in the shop at near full speed to check surge margin. In all their experience, they had never heard a "surge" that gave a prior warning.

4. Two events at other sites described as compressor "surge" had been found to be caused by intermittent fuel flow. One was due to flow divider chatter, the other by running out of fuel.

VI. HEAT RATE

The combustion of treated residual oil in the gas turbines adversely affects the operating heat rate for several reasons.

a. Fouling — The heat rate increases 0.024% per operating hour due to the fouling of the compressor and turbine blading. While data taken at Putnam indicates that this rate is similar to the fouling rate experienced while operating on distillate fuel, it is still unacceptable. A washing schedule has been implemented and the compressor and turbine sections are washed every 100 hours if conditions permit. Occasionally, it has been necessary to operate the turbines for several hundred hours prior to a wash, but plant management has not permitted more than 500 hours of operation without a turbine wash. Thus, the operating heat rate of the units is represented by a saw-tooth curve which approaches the design heat rate each time the turbine is washed.

b. Fuel Transfer — The gas turbines cannot be started on residual oil, so they are started on distillate fuel. Westinghouse recommends changing fuels after the unit has reached synchronous speed (3600 rpm). In order to reduce the amount of distillate fuel used, this transfer is initiated at the minimum load of 4 megawatts. To minimize the thermal gradient at the flow divider, the transfer is completed at essentially steady load. The heat rate at this low load is about 70,000 BTU/KW-hr and the transfer takes about five minutes to complete.

c. Auxiliary Energy — The net heat rate also increases when burning residual oil due to the energy needed to process and heat the oil. Steam for these two functions is produced by burning residual oil in a package boiler.

1. About 60 barrels of oil are burned per day to provide the process steam needed to wash 550 gallons of oil per minute.

2. About eight barrels of oil are burned per day to supply the steam to heat the oil consumed by one

gas turbine from ambient temperature to 160°F for combustion.

d. Firing Temperature — Westinghouse limits the firing temperature of the gas turbines operating on residual oil. Following installation of cooled Row 2 blades, the firing temperature of the Putnam gas turbines could be raised about 50°F if the units were burning distillate oil or natural gas. The lower firing temperature limits the capability of the turbine by about two megawatts and increases the heat rate by 140 BTU/KW-hr.

e. Mechanical Degradation — A gradual increase in heat rate occurs as a result of blade erosion, seal wear, etc. This heat rate is only recoverable by rebuilding the turbine during an overhaul. Experience at Putnam Plant indicates that an increase in heat rate of about 60 BTU/KWH-hr occurred on one of the gas turbines following about 5,000 hours of operation on distillate oil and 2,800 hours of operation on residual oil.

VII. GAS TURBINE COMPONENT LIFE

The combustor baskets, transition ducts, turbine blades and turbine vanes are the major gas turbine components which are directly affected by the type of fuel which is being burned. The service life of each of these components is important, because of the high replacement parts cost and the impact on unit availability.

A. Combustors

The service life of the combustor baskets has only been averaging about 2200 hours on the residual oil fired gas turbines at Putnam Plant. The failure mode of almost all of the baskets has been the formation of a hole in the second and/or third ring at the six o'clock position.

This rapid basket failure has necessitated an internal crawl through inspection of each engine at 500 hour intervals. These frequent inspections significantly affect the availability of the units.

Westinghouse and Florida Power & Light Company recognized the rapid failure of the combustor basket and agreed to cooperate in a combustor basket test program.

The first phase of the program was intended to characterize the current 501B combustor basket and determine the mode of failure. During phase one, the data indicated that the surface metal temperatures were well below the operating limits for Hastelloy; however, some large thermal gradients (greater than 200°F) were measured in the six and seven o'clock positions on the second ring.

Although Westinghouse has not completed their evaluation of the basket which failed during phase one, their preliminary analysis indicates that the hole was not a "burnout" due to excessive temperatures. It appears that the hole was caused by a combination of corrosion caused by the fuel deposit, mechanical deformation and temperature. They are performing metallurgical analysis of the metal surrounding the hole, but this analysis has not been completed.

B. Transition Duct

The cost of transition ducts and the reduced availability that can result in changing them out make this an area of high concern to the user. Premature failure of these parts has been a topic on which much time has been spent at the Putnam Plant.

The average service hours on a transition duct before replacement is required has been 5,000 to 6,000 fired hours.

The failure mode has been almost exclusively due to cracking. There is no evidence that the type of fuel used, distillate or residual, relates to the actual failure or the failure rate.

Cracks in the transiton ducts pose a serious potential problem in gas turbines. If the problem is left unchecked, it can progress to the point that part of the transition breaks away and passes through the power turbine. This has resulted in catastrophic damage to turbines at other sites. In an effort to minimize the chance of this happening, the combustion section is inspected every 500 hours. This results in reduced availability of the units, but is necessary until the problem of cracked transitions is resolved.

The root cause of the transition cracking is being addressed in the following ways:

1. The alloy the transition ducts are made of is being changed from Nimonic to Hastelloy. The new Hastelloy transitions are more resistant to cracking than the Nimonic. They are also more easily repaired if cracks do develop.

2. Procedures for installing and aligning transitions have been changed. The new procedures improve the alignment of the transitions and reduce the mechanical forces acting on it.

If the premature failure of the transitions due to cracking is corrected, then the average service life is sure to increase. With an increased service life, the type of fuel used in the turbine may have some significant effects on them; however, at the present time, no conclusions can be drawn relating transition service life to fuel.

C. Blades/Vanes

The service life of the blades and vanes varies widely according to their location within the turbine. Figure 8 shows the average life of the blades and vanes installed at Putnam Plant.

As noted at the bottom of Figure 8, several failures of row 2 blades have occurred. These blades have now been modified to provide air cooling and they have been coated with RT-22. Following these modifications, the life expectancy of row 2 blades is anticipated to drastically increase.

Historical data shows very little difference between the degree of hot corrosion observed while operating on residual fuel as compared to distillate fuel. [4]

In a test performed by Electric Power Research Institute (EPRI) the degree of hot corrosion observed at Putnam Plant was somewhat greater than expected for oil-fired combustion turbines of similar designs and alloy selections. This abnormality was attributed to the ingestion of high levels of sodium contaminated mist from the adjacent cooling tower through the turbine compressor inlet. [5]

Modifications are being considered to improve the efficiency of the cooling tower mist eliminators. Sodium analyzers are also presently being installed to monitor the sodium intake at the turbine compressor inlet.

Other conditions which may contribute to the failure of these components at Putnam Plant are:

1. Ingestion of the mist from the boiler blowdown which is located on top of the HRSG near the gas turbine air inlet.

2. The higher particulate content in the air resulting from soot blowing of the HRSG.

3. Location of the plant within 20 miles of the ocean.

4. Cyclic operation of the Putnam units.

COMPONENT	APPROX.** LIFETIME	MODIFICATION
ROW 1 VANES	1650 HR.	
	2500 HR.	MOD 1 - TWIN INSERTS
	5800 HR.	MOD 2 - TWIN INSERTS
	IN SERVICE	TWIN INSERTS WITH RT-44 COATING
ROW 1 BLADES	9500 HR.	
	IN SERVICE	RT-22 COATING
ROW 2 VANES	6500 HR.	
	IN SERVICE	RT-44 COATING
ROW 2 BLADES	9500 HR.	
	IN SERVICE	RT-22 COATING MODIFIED TO BE AIR COOLED,
ROW 3 VANES	>11000 HR* IN SERVICE	
ROW 3 BLADES	>11000 HR IN SERVICE	
ROW 4 VANES	>11000 HR. IN SERVICE	
ROW 4 BLADES	>11000 HR IN SERVICE	REPROFILED

* ONE SET REPLACED IN 2GT1 AFTER 8500 HRS. OF OPERATION. ALL OTHERS STILL IN SERVICE.

** DOES NOT INCLUDE BLADE/VANE REPLACEMENT CAUSED BY ROW 2 BLADE FAILURES ON 1 GT 2 - 480 HRS. OPER., 2 GT 1 - 1845 HRS. OPER., AND 2 GT 2 - 2159 HRS. OPER..

Figure 8. Blade/Vane Service Life.

Installation of a filter on the turbine air inlet and rerouting the boiler blowdown to the condensor are being considered.

VIII. AVAILABILITY

The gas turbines are components of the combined cycle units at Putnam Plant and the availability results are normally calculated for the unit instead of each gas turbine.

In order to determine the availibility of a gas turbine operating on residual oil, the historical data for 2GT2 was analyzed for 1979 through 1981. During this three-year period, the forced outage rate was 4.06%. Failure of fuel related components including flow dividers, fuel oil filters, and fuel nozzles contributed to this forced outage rate.

During this same period, the maintenance outage factors was 22.47%. Thus, the gas turbine was only available 73.47% of the time. This is much lower than expected because of the high maintenance outage factor. A non-routing outage during the base period to modify the turbine rotor and install air cooled Row 2 blades caused a significant increase in the maintenance outage factor.

In order to project a more reasonable maintenance outage factor, it was assumed that in the future, outages would be

	GAS (HOURS)	DISTILLATE (HOURS)	RESIDUAL (HOURS)	APPROX. DURATION (HOURS)
GT WASHING	N/A	N/A	100	12
COMBUSTION SECTION INSPECTION	500	500	500	18
TURBINE SECTION INSPECTION	15,000 x(CDF)	12,000 x(CDF)	6,800 x(CDF)	1,000
MAJOR INSPECTION	30,000 x(CDF)	24,000 x(CDF)	20,400 x(CDF)	2,000

*BASED ON AVERAGE OF 10 HOURS OPERATION/START CYCLICAL DUTY FACTOR (CDF) = 0.80

Figure 9. Inspection Interval.

performed at the recommended intervals shown in Figure 9. This would result in an average maintenance outage factor of 8.0%. If the forced outage rate remains at 4.06%, the future availability of the gas turbines will be about 88%.

It is important to note that if the same units are operated on another fuel, the inspection intervals will be lengthened as shown in Figure 8. For example, if the Putnam units operated on natural gas, the maintenance outage factor would decrease to about 5% and the availability would increase to over 90%. It is also anticipated that the forced outage rate would decrease, resulting in further corresponding improvement in availability.

CONCLUSION

The preparation and firing of treated low sulfur residual oil in an industrial gas turbine is difficult. However, over 25,000 fired hours of experience has demonstrated that it can be burned successfully in a combined cycle plant with a starting reliability above 85% and an availability of about 90%.

In order to utilize a lower cost fuel, the plant is being converted to permit the use of natural gas fuel. The ability to burn distillate and residual oil will be retained and residual oil will be used whenever it is economically attractive.

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