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Heavy-Duty Gas Turbine
Operating and Maintenance Considerations

Introduction

Maintenance costs and machine availability are two of the most important concerns to a heavy-duty gas turbine equipment owner. Therefore, a well thought out maintenance program that reduces the owner’s costs while increasing equipment availability should be instituted. For this maintenance program to be effective, owners should develop a general understanding of the relationship between the operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and all equipment manufacturer’s recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting component life and proper operation of the equipment.

In this document, operating and maintenance practices for heavy-duty gas turbines will be reviewed, with emphasis placed on types of inspections plus operating factors that influence maintenance schedules.

Note:

- The operation and maintenance practices outlined in this document are based on full utilization of GE-approved parts, repairs, and services.
- The operating and maintenance discussions presented are generally applicable to all GE heavy-duty gas turbines; i.e., Frames 3, 5, 6, 7, and 9. Appendix G provides a list of common B/E- and F-class heavy-duty gas turbines with current and former naming conventions. For purposes of illustration, the GE GT-7E.03 was chosen for most components except exhaust systems, which are illustrated using different gas turbine models as indicated. Also, the operating and maintenance discussions presented for all B/E-class units are generally applicable to Frame 3 and Frame 5 units unless otherwise indicated.
- Consult the GE Operation and Maintenance (O&M) Manual for specific questions on a given machine, or contact the local GE service representative.

Maintenance Planning

Advanced planning for maintenance is necessary for utility, industrial, independent power, and cogeneration plant operators in order to maintain reliability and availability. The correct implementation of planned maintenance and inspection provides direct benefits in the avoidance of forced outages, unscheduled repairs, and downtime. The primary factors that affect the maintenance planning process are shown in Figure 1. The owners’ operating mode and practices will determine how each factor is weighted. Gas turbine parts requiring the most careful attention are those associated with the combustion process, together with those exposed to the hot gases discharged from the combustion system. These are called the combustion section and hot gas path parts, and they include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds, and turbine buckets.

Additional, longer-term areas for consideration and planning are the lives of the compressor rotor, turbine rotor, casings, and exhaust diffuser. The basic design and recommended maintenance of GE heavy-duty gas turbines are oriented toward:

- Maximum periods of operation between inspections and overhauls
- In-place, on-site inspection and maintenance
- Use of local trade skills to disassemble, inspect, and re-assemble gas turbine components

In addition to maintenance of the basic gas turbine, other station auxiliaries require periodic servicing including the control devices, fuel-metering equipment, gas turbine auxiliaries, and load package. The primary maintenance effort involves five basic systems: controls and accessories, combustion, turbine, generator, and balance-of-plant. Controls and accessories are typically serviced in outages of short duration, whereas the other four systems are maintained through less frequent outages of longer duration. This document is focused on maintenance planning for the basic gas turbine, which includes the combustion and turbine systems. The other systems, while outside the scope of this document, also need to be considered for successful plant maintenance.

The inspection and repair requirements, outlined in the O&M Manual provided to each owner, lend themselves to establishing a pattern of inspections. These inspection patterns will vary from site to site, because factors such as air and fuel quality are used to develop an inspection and maintenance program. In addition, supplementary information is provided through a system of Technical Information Letters (TILs) associated with specific gas turbines after shipment. This updated information, in addition to the O&M Manual, assures optimum installation, operation,
and maintenance of the turbine. (See Figure 2.) Many of the TILs contain advisory technical recommendations to help resolve issues and improve the operation, maintenance, safety, reliability, or availability of the turbine. The recommendations contained in TILs should be reviewed and factored into the overall maintenance planning program.

• O&M Manual
  - Turbine-specific manual provided to customer
  - Includes outline of recommended Inspection and Repair requirements
  - Helps customers to establish a pattern of systematic inspections for their site

• Technical Information Letters (TILs)*
  - Issued after shipment of turbine
  - Provides O&M updates related to turbine installation, maintenance, and operation
  - Provides advisory technical recommendations to help resolve potential issues

* Specific smaller frame turbines are issued service letters known as Customer Information Notices (NICs) instead of TILs

Figure 2. Key technical reference documents to include in maintenance planning

Gas Turbine Design Maintenance Features

The GE heavy-duty gas turbine is designed to withstand severe duty and to be maintained on-site, with off-site repair required only on certain combustion components, hot gas path parts, and rotor assemblies needing specialized shop service. The following features are designed into GE heavy-duty gas turbines to facilitate on-site maintenance:

• All casings, shells and frames are split on machine horizontal centerline. Upper halves may be lifted individually for access to internal parts.

• With upper-half compressor casings removed, all stationary vanes can be slid circumferentially out of the casings for inspection or replacement without rotor removal.

• With the upper-half of the turbine shell lifted, each half of the first stage nozzle assembly can be removed for inspection, repair, or replacement without rotor removal. On some units, upper-half, later-stage nozzle assemblies are lifted with the turbine shell, also allowing inspection and/or removal of the turbine buckets.
• All turbine buckets are moment-weighed and computer charted in sets for rotor spool assembly so that they may be replaced without the need to remove or rebalance the rotor assembly.

• All bearing housings and liners are split on the horizontal centerline so that they may be inspected and replaced when necessary. The lower half of the bearing liner can be removed without removing the rotor.

• All seals and shaft packings are separate from the main bearing housings and casing structures and may be readily removed and replaced.

• On most designs, fuel nozzles, combustion liners and flow sleeves can be removed for inspection, maintenance, or replacement without lifting any casings. All major accessories, including filters and coolers, are separate assemblies that are readily accessible for inspection or maintenance. They may also be individually replaced as necessary.

• Casings can be inspected during any outage or any shutdown when the unit enclosure is cool enough for safe entry. The exterior of the inlet, compressor case, compressor discharge case, turbine case, and exhaust frame can be inspected during any outage or period when the enclosure is accessible. The interior surfaces of these cases can be inspected to various degrees depending on the type of outage performed. All interior surfaces can be inspected during a major outage when the rotor has been removed.

• Exhaust diffusers can be inspected during any outage by entering the diffuser through the stack or Heat Recovery Steam Generator (HRSG) access doors. The flow path surfaces, flex seals, and other flow path hardware can be visually inspected with or without the use of a borescope. Diffusers can be weld-repaired without the need to remove the exhaust frame upper half.

• Inlets can be inspected during any outage or shutdown.

As an alternative to on-site maintenance, in some cases plant availability can be improved by applying gas turbine modular replacements. This is accomplished by exchanging engine modules or even the complete gas turbine with new or refurbished units. The removed modules/engines can then be sent to an alternate location for maintenance.

Provisions have been built into GE heavy-duty gas turbines to facilitate several special inspection procedures. These special procedures provide for the visual inspection and clearance measurement of some of the critical internal components without removal of the casings. These procedures include gas path borescope inspection (BII), radial clearance measurements, and turbine nozzle axial clearance measurements.

A GE gas turbine is a fully integrated design consisting of stationary and rotating mechanical, fluid, thermal, and electrical systems. The turbine’s performance, as well as the performance of each component within the turbine, is dependent upon the operating interrelationship between internal components and the total operating systems. GE’s engineering process evaluates how new designs, design changes, and repairs affect components and systems. This design, evaluation, testing, and approval assures the proper balance and interaction between all components and systems for safe, reliable, and economical operation.

The introduction of new, repaired, or modified parts must be evaluated in order to avoid negative effects on the operation and reliability of the entire system. The use of non-GE approved parts, repairs, and maintenance practices may represent a significant risk. Pursuant to the governing terms and conditions, warranties and performance guarantees are predicated upon proper storage, installation, operation, and maintenance, conforming to GE approved operating instruction manuals and repair/modification procedures.

**Borescope Inspections**

An effective borescope inspection program monitors the condition of internal components without casing removal. Borescope inspections should be scheduled with consideration given to the operation and environment of the gas turbine and information from the O&M Manual and TILs.

GE heavy-duty gas turbine designs incorporate provisions in both compressor and turbine casings for borescope inspection of intermediate compressor rotor stages, first, second and third-stage turbine buckets, and turbine nozzle partitions. These provisions are radially aligned holes through the compressor casings, turbine shell, and internal stationary turbine shrouds that allow the penetration of an optical borescope into the compressor or turbine flow path area, as shown in Figure 3.
Borescope inspection access locations for F-class gas turbines can be found in Appendix E.

Figure 4 provides a recommended interval for a planned borescope inspection program following initial baseline inspections. It should be recognized that these borescope inspection intervals are based on average unit operating modes. Adjustment of these borescope intervals may be made based on operating experience, mode of operation, fuels used, and the results of previous borescope inspections.

In general, an annual or semiannual borescope inspection uses all the available access points to verify the condition of the internal hardware. This should include, but is not limited to, signs of excessive gas path fouling, symptoms of surface degradation (such as erosion, corrosion, or spalling), displaced components, deformation or object damage, material loss, nicks, dents, cracking, indications of contact or rubbing, or other anomalous conditions.

<table>
<thead>
<tr>
<th>Borescope</th>
<th>Gas and Distillate Fuel Oil</th>
<th>At combustion inspection or annually, whichever occurs first</th>
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<tr>
<td></td>
<td>Heavy Fuel Oil</td>
<td>At combustion inspection or semianually, whichever occurs first</td>
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Figure 4. Borescope inspection planning

During BIs and similar inspections, the condition of the upstream components should be verified, including all systems from the filter house to the compressor inlet.

The application of a borescope monitoring program will assist with the scheduling of outages and preplanning of parts requirements, resulting in outage preparedness, lower maintenance costs, and higher availability and reliability of the gas turbine.
Major Factors Influencing Maintenance and Equipment Life

There are many factors that can influence equipment life, and these must be understood and accounted for in the owner’s maintenance planning. Starting cycle (hours per start), power setting, fuel, level of steam or water injection, and site environmental conditions are some of the key factors in determining maintenance interval requirements, as these factors directly influence the life of replaceable gas turbine parts.

Non-consumable components and systems, such as the compressor airfoils, may be affected by site environmental conditions as well as plant and accessory system effects. Other factors affecting maintenance planning are shown in Figure 1. Operators should consider these external factors to prevent the degradation and shortened life of non-consumable components.

GE provides supplementary documentation to assist in this regard.

In the GE approach to maintenance planning, a natural gas fuel unit that operates at base load with no water or steam injection is established as the baseline condition, which sets the maximum recommended maintenance intervals. For operation that differs from the baseline, maintenance factors (MF) are established to quantify the effect on component lives and provide the increased frequency of maintenance required. For example, a maintenance factor of two would indicate a maintenance interval that is half of the baseline interval.

Starts and Hours Criteria

Gas turbines wear differently in continuous duty application and cyclic duty application, as shown in Figure 5. Thermal mechanical fatigue is the dominant life limiter for peaking machines, while creep, oxidation, and corrosion are the dominant life limiters for continuous duty machines. Interactions of these mechanisms are considered in the GE design criteria but to a great extent are second-order effects. For that reason, GE bases gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval. A graphical display of the GE approach is shown in Figure 6. In this figure, the inspection interval recommendation is defined by the rectangle established by the starts and hours criteria. These recommendations for inspection fall within the design life expectations and are selected such that components acceptable for continued use at the inspection point will have low risk of failure during the subsequent operating interval.

<table>
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<tr>
<th>Continuous Duty Application</th>
<th>Cyclic Duty Application</th>
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<tbody>
<tr>
<td>Rupture</td>
<td>Thermal Mechanical Fatigue</td>
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<tr>
<td>Creep Deflection</td>
<td>High-Cycle Fatigue</td>
</tr>
<tr>
<td>Corrosion</td>
<td>Rubs/Wear</td>
</tr>
<tr>
<td>Oxidation</td>
<td>Foreign Object Damage</td>
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Figure 5. Causes of wear – hot gas path components

An alternative to the GE approach, which is sometimes employed by other manufacturers, converts each start cycle to an equivalent number of operating hours (EOH) with inspection intervals based on the equivalent hours count. For the reasons previously stated, GE does not use this approach. While this logic can create the impression of longer intervals, it actually may result in more frequent maintenance inspections, since separate effects are considered additive. Referring again to Figure 6, the starts and hours inspection “rectangle” is reduced by half as defined by the diagonal line from the starts limit at the upper left hand corner to the hours limit at the lower right hand corner. Midrange duty applications, with hours-per-start ratios of 30-50, are particularly penalized by this approach.

This is further illustrated in Figure 7 for the example of a 7E.03 gas turbine operating on natural gas fuel, at base load conditions with no steam or water injection or trips from load. The unit operates 4000 hours and 300 starts per year. Following GE’s recommendations, the operator would perform the hot gas path inspection after four years of operation, with starts being the limiting condition. Performing maintenance on this same unit based on an equivalent hours criteria would require a hot gas path inspection after 2.4 years. Similarly, for a continuous duty application operating 8000 hours and 160 starts per year, the GE recommendation would be to perform the hot gas path inspection after three years of operation with the operating hours being the limiting condition for this case. The equivalent hours criteria would set the hot gas path inspection after 2.1 years of operation for this application.
Figure 6. GE bases gas turbine maintenance requirements on independent counts of starts and hours.

Figure 7. Hot gas path maintenance interval comparisons. GE method vs. EOH method.
Service Factors

While GE does not subscribe to the equivalency of starts to hours, there are equivalencies within a wear mechanism that must be considered. As shown in Figure 8, influences such as fuel type and quality, firing temperature setting, and the amount of steam or water injection are considered with regard to the hours-based criteria. Startup rate and the number of trips are considered with regard to the starts-based criteria. In both cases, these influences may reduce the maintenance intervals.

Typical baseline inspection intervals (6B.03/7E.03):
- Hot gas path inspection 24,000 hrs or 1200 starts
- Major inspection 48,000 hrs or 2400 starts
Criterion is hours or starts (whichever occurs first)

Factors affecting maintenance:

Hours-Based Factors
- Fuel type
- Peak load
- Diluent (water or steam injection)

Starts-Based Factors
- Start type (conventional or peaking-fast)
- Start load (max. load achieved during start cycle, e.g. part, base, or peak load)
- Trips

When these service or maintenance factors are involved in a unit’s operating profile, the hot gas path maintenance “rectangle” that describes the specific maintenance criteria for this operation is reduced from the ideal case, as illustrated in Figure 9. The following discussion will take a closer look at the key operating factors and how they can affect maintenance intervals as well as parts refurbishment/replacement intervals.

Maintenance Factors Reduce Maintenance Interval

Fuel

Fuels burned in gas turbines range from clean natural gas to residual oils and affect maintenance, as illustrated in Figure 10. Although Figure 10 provides the basic relationship between fuel severity factor and hydrogen content of the fuel, there are other fuel constituents that should be considered. Selection of fuel

Figure 8. Maintenance factors

Figure 9. GE maintenance intervals

Figure 10. Estimated effect of fuel type on maintenance
severity factor typically requires a comprehensive understanding of fuel constituents and how they affect system maintenance. The selected fuel severity factor should also be adjusted based on inspection results and operating experience.

Heavier hydrocarbon fuels have a maintenance factor ranging from three to four for residual fuels and two to three for crude oil fuels. This maintenance factor is adjusted based on the water-to-fuel ratio in cases when water injection for NOx abatement is used. These fuels generally release a higher amount of radiant thermal energy, which results in a subsequent reduction in combustion hardware life, and frequently contain corrosive elements such as sodium, potassium, vanadium, and lead that can cause accelerated hot corrosion of turbine nozzles and buckets. In addition, some elements in these fuels can cause deposits either directly or through compounds formed with inhibitors that are used to prevent corrosion. These deposits affect performance and can require more frequent maintenance.

Distillates, as refined, do not generally contain high levels of these corrosive elements, but harmful contaminants can be present in these fuels when delivered to the site. Two common ways of contaminating number two distillate fuel oil are: salt-water ballast mixing with the cargo during sea transport, and contamination of the distillate fuel when transported to site in tankers, tank trucks, or pipelines that were previously used to transport contaminated fuel, chemicals, or leaded gasoline. GE’s experience with distillate fuels indicates that the hot gas path maintenance factor can range from as low as one (equivalent to natural gas) to as high as three. Unless operating experience suggests otherwise, it is recommended that a hot gas path maintenance factor of 1.5 be used for operation on distillate oil. Note also that contaminants in liquid fuels can affect the life of gas turbine auxiliary components such as fuel pumps and flow dividers.

Not shown in Figure 10 are alternative fuels such as industrial process gas, syngas, and bio-fuel. A wide variety of alternative fuels exist, each with their own considerations for combustion in a gas turbine. Although some alternative fuels can have a neutral effect on gas turbine maintenance, many alternative fuels require unit-specific intervals and fuel severity factors to account for their fuel constituents or water/steam injection requirements.

As shown in Figure 10, natural gas fuel that meets GE specification is considered the baseline, optimum fuel with regard to turbine maintenance. Proper adherence to GE fuel specifications in GEI-41040 and GEI-41047 is required to allow proper combustion system operation and to maintain applicable warranties. Liquid hydrocarbon carryover can expose the hot gas path hardware to severe overtemperature conditions that can result in significant reductions in hot gas path parts lives or repair intervals. Liquid hydrocarbon carryover is also responsible for upstream displacement of flame in combustion chambers, which can lead to severe combustion hardware damage. Owners can control this potential issue by using effective gas scrubber systems and by superheating the gaseous fuel prior to use to approximately 50°F (28°C) above the hydrocarbon dew point temperature at the turbine gas control valve connection. For exact superheat requirement calculations, please review GEI 41040. Integral to the system, coalescing filters installed upstream of the performance gas heaters is a best practice and ensures the most efficient removal of liquids and vapor phase constituents.

Undetected and untreated, a single shipment of contaminated fuel can cause substantial damage to the gas turbine hot gas path components. Potentially high maintenance costs and loss of availability can be minimized or eliminated by:

- Placing a proper fuel specification on the fuel supplier. For liquid fuels, each shipment should include a report that identifies specific gravity, flash point, viscosity, sulfur content, pour point and ash content of the fuel.
- Providing a regular fuel quality sampling and analysis program. As part of this program, continuous monitoring of water content in fuel oil is recommended, as is fuel analysis that, at a minimum, monitors vanadium, lead, sodium, potassium, calcium, and magnesium.
- Providing proper maintenance of the fuel treatment system when burning heavier fuel oils.
- Providing cleanup equipment for distillate fuels when there is a potential for contamination.

In addition to their presence in the fuel, contaminants can also enter the turbine via inlet air, steam/water injection, and carryover from evaporative coolers. In some cases, these sources of contaminants have been found to cause hot gas path
degradation equal to that seen with fuel-related contaminants. GE specifications define limits for maximum concentrations of contaminants for fuel, air, and steam/water.

In addition to fuel quality, fuel system operation is also a factor in equipment maintenance. Liquid fuel should not remain unpurged or in contact with hot combustion components after shutdown and should not be allowed to stagnate in the fuel system when strictly gas fuel is run for an extended time. To minimize varnish and coke accumulation, dual fuel units (gas and liquid capable) should be shutdown running gas fuel whenever possible. Likewise, during extended operation on gas, regular transfers from gas to liquid are recommended to exercise the system components and minimize coking.

Contamination and build-up may prevent the system from removing fuel oil and other liquids from the combustion, compressor discharge, turbine, and exhaust sections when the unit is shut down or during startup. Liquid fuel oil trapped in the system piping also creates a safety risk. Correct functioning of the false start drain system (FSDS) should be ensured through proper maintenance and inspection per GE procedures.

Firing Temperatures
Peak load is defined as operation above base load and is achieved by increasing turbine operating temperatures. Significant operation at peak load will require more frequent maintenance and replacement of hot gas path and combustion components. Figure 11 defines the parts life effect corresponding to increases in firing temperature. It should be noted that this is not a linear relationship, and this equation should not be used for decreases in firing temperature.

It is important to recognize that a reduction in load does not always mean a reduction in firing temperature. For example, in heat recovery applications, where steam generation drives overall plant efficiency, load is first reduced by closing variable inlet guide vanes to reduce inlet airflow while maintaining maximum exhaust temperature. For these combined cycle applications, firing temperature does not decrease until load is reduced below approximately 80% of rated output. Conversely, a non-DLN turbine running in simple cycle mode maintains fully open inlet guide vanes during a load reduction to 80% and will experience over a 200°F/111°C reduction in firing temperature at this output level. The hot gas path parts life changes for different modes of operation. This turbine control effect is illustrated in Figure 12. Turbines with DLN combustion systems use inlet guide vane turndown as well as inlet bleed heat to extend operation of low NOx premix operation to part load conditions.

\[
\begin{align*}
B/E\text{-class: } A_p &= e^{(0.018\times\Delta T_f)} \\
F\text{-class: } A_p &= e^{(0.023\times\Delta T_f)}
\end{align*}
\]

\[A_p = \text{Peak fire severity factor}\]
\[\Delta T_f = \text{Peak firing temperature adder (in °F)}\]

Figure 11. Peak fire severity factors - natural gas and light distillates

Firing temperature effects on hot gas path maintenance, as described above, relate to clean burning fuels, such as natural gas and light distillates, where creep rupture of hot gas path components is the primary life limiter and is the mechanism that determines the hot gas path maintenance interval impact. With ash-bearing heavy fuels, corrosion and deposits are the primary influence and a different relationship with firing temperature exists.

Steam/Water Injection
Water or steam injection for emissions control or power augmentation can affect part life and maintenance intervals even when the water or steam meets GE specifications. This relates to the effect of the added water on the hot gas transport properties. Higher gas conductivity, in particular, increases the
heat transfer to the buckets and nozzles and can lead to higher metal temperature and reduced part life.

Part life reduction from steam or water injection is directly affected by the way the turbine is controlled. The control system on most base load applications reduces firing temperature as water or steam is injected. This is known as dry control curve operation, which counters the effect of the higher heat transfer on the gas side and results in no net effect on bucket life. This is the standard configuration for all gas turbines, both with and without water or steam injection. On some installations, however, the control system is designed to keep firing temperature constant with water or steam injection. This is known as wet control curve operation, which results in additional unit output but decreases parts life as previously described. Units controlled in this way are generally in peaking applications where annual operating hours are low or where operators have determined that reduced parts lives are justified by the power advantage. Figure 13 illustrates the wet and dry control curve and the performance differences that result from these two different modes of control.

An additional factor associated with water or steam injection relates to the higher aerodynamic loading on the turbine components that results from the injected flow increasing the cycle pressure ratio. This additional loading can increase the downstream deflection rate of the second- and third-stage nozzles, which would reduce the repair interval for these components. However, the introduction of high creep strength stage two and three nozzle (S2N/S3N) alloys, such as GTD-222™ and GTD-241™, has reduced this factor in comparison to previously applied materials such as FSX-414 and N-155.

Water injection for NOx abatement should be performed according to the control schedule implemented in the controls system. Forcing operation of the water injection system at high loads can lead to combustion and HGP hardware damage due to thermal shock.

Cyclic Effects and Fast Starts
In the previous discussion, operating factors that affect the hours-based maintenance criteria were described. For the starts-based maintenance criteria, operating factors associated with the cyclic effects induced during startup, operation, and shutdown of the turbine must be considered. Operating conditions other than the standard startup and shutdown sequence can potentially reduce the cyclic life of the gas turbine components and may require more frequent maintenance including part refurbishment and/or replacement.

Fast starts are common deviations from the standard startup sequence. GE has introduced a number of different fast start systems, each applicable to particular gas turbine models. Fast starts may include any combination of Anticipated Start Purge, fast acceleration (light-off to FSNL), and fast loading. Some fast start methods do not affect maintenance factors. Fast starts that do affect maintenance factors are referred to as peaking-fast starts or simply peaking starts.

The effect of peaking-fast starts on the maintenance interval depends on the gas turbine model, the unit configuration, and the particular start characteristics. For example, simple cycle 7F.03 units with fast start capability can perform a peaking start in which the unit is brought from light-off to full load in less than 15 minutes. Conversely, simple cycle 6B and other smaller frame units can perform conventional starts that are less than 15 minutes without affecting any maintenance factors. For units that have peaking-fast start capability, Figure 14 shows conservative peaking-start factors that may apply.

Because the peaking-fast start factors can vary by unit and by system, the baseline factors may not apply to all units. For example, the latest 7F.03 peaking-fast start system has the start factors shown in Figure 15. For comparison, the 7F.03 nominal fast start that does not affect maintenance is also listed. Consult applicable unit-specific documentation or your GE service representative to verify the start factors that apply.
**Starts-Based Combustion Inspection**

\( A_s = 4.0 \) for B/E-class

\( A_s = 2.0 \) for F-class

**Starts-Based Hot Gas Path Inspection**

\( P_s = 3.5 \) for B/E-class

\( P_s = 1.2 \) for F-class

**Starts-Based Rotor Inspection**

\( F_s = 2.0 \) for F-class*

* See Figure 22 for details

---

**7F.03 Starts-Based Combustion Inspection**

\( A_s = 1.0 \) for 7F nominal fast start

\( A_s = 1.0 \) for 7F peaking-fast start

**7F.03 Starts-Based Hot Gas Path Inspection**

\( P_s = \) Not applicable for 7F nominal fast start (counted as normal starts)

\( P_s = 0.5 \) for 7F peaking-fast start

**7F.03 Starts-Based Rotor Inspection**

\( F_s = 1.0 \) for 7F nominal fast start

\( F_s = 2.0 \) for 7F peaking-fast start*

* See Figure 23 for details

---

**Hot Gas Path Parts**

Figure 16 illustrates the firing temperature changes occurring over a normal startup and shutdown cycle. Light-off, acceleration, loading, unloading, and shutdown all produce gas and metal temperature changes. For rapid changes in gas temperature, the edges of the bucket or nozzle respond more quickly than the thicker bulk section, as pictured in Figure 17. These gradients, in turn, produce thermal stresses that, when cycled, can eventually lead to cracking.

Figure 18 describes the temperature/strain history of a 7E.03 stage 1 bucket during a normal startup and shutdown cycle. Light-off and acceleration produce transient compressive strains in the bucket as the fast responding leading edge heats up more quickly than the thicker bulk section of the airfoil. At full load conditions, the bucket reaches its maximum metal temperature and a compressive strain is produced from the normal steady state temperature gradients that exist in the cooled part. At shutdown, the conditions reverse and the faster responding edges cool more quickly than the bulk section, which results in a tensile strain at the leading edge.

Thermal mechanical fatigue testing has found that the number of cycles that a part can withstand before cracking occurs is strongly influenced by the total strain range and the maximum metal temperature. Any operating condition that significantly increases the strain range and/or the maximum metal temperature over the normal cycle conditions will reduce the fatigue life and increase the starts-based maintenance factor. For example,
Figure 19 compares a normal operating cycle with one that includes a trip from full load. The significant increase in the strain range for a trip cycle results in a life effect that equates to eight normal start/stop cycles, as shown. Trips from part load will have a reduced effect because of the lower metal temperatures at the initiation of the trip event. Figure 20 illustrates that while a trip from between 80% and 100% load has an 8:1 trip severity factor, a trip from full speed no load (FSNL) has a trip severity factor of 2:1. Similarly, overfiring of the unit during peak load operation leads to increased component

**Key Parameters**
- Max Strain Range
- Max Metal Temperature

**Figure 18.** Bucket low cycle fatigue (LCF)

**Figure 19.** Low cycle fatigue life sensitivities – first stage bucket
metal temperatures. As a result, a trip from peak load has a trip severity factor of 10:1.

Trips are to be assessed in addition to the regular startup/shutdown cycles as starts adders. As such, in the factored starts equation of Figure 43, one is subtracted from the severity factor so that the net result of the formula (Figure 43) is the same as that dictated by the increased strain range. For example, a startup and trip from base load would count as eight total cycles (one cycle for startup to base load plus 8-1=7 cycles for trip from base load), just as indicated by the 8:1 maintenance factor.

Similarly to trips from load, peaking-fast starts will affect the starts-based maintenance interval. Like trips, the effects of a peaking-fast start on the machine are considered separate from a normal cycle and their effects must be tabulated in addition to the normal start/stop cycle. However, there is no -1 applied to these factors, so a 7F.03 peaking-fast start during a base load cycle would have a total effect of 1.5 cycles. Refer to Appendix A for factored starts examples, and consult unit-specific documentation to determine if an alternative hot gas path peaking-fast start factor applies.

While the factors described above will decrease the starts-based maintenance interval, part load operating cycles allow for an extension of the maintenance interval. Figure 21 can be used in considering this type of operation. For example, two operating cycles to maximum load levels of less than 60% would equate to one start to a load greater than 60% or, stated another way, would have a maintenance factor of 0.5.

Factored starts calculations are based upon the maximum load achieved during operation. Therefore, if a unit is operated at part load for three weeks, and then ramped up to base load for the last ten minutes, then the unit’s total operation would be described as a base load start/stop cycle.

**Rotor Parts**

The maintenance and refurbishment requirements of the rotor structure, like the hot gas path components, are affected by the cyclic effects of startup, operation, and shutdown, as well as loading and off-load characteristics. Maintenance factors specific to the operating profile and rotor design must be incorporated into the operator’s maintenance planning. Disassembly and inspection of all rotor components is required when the accumulated rotor starts or hours reach the inspection limit. (See Figure 44 and Figure 45 in the Inspection Intervals section.)

The thermal condition when the startup sequence is initiated is a major factor in determining the rotor maintenance interval and individual rotor component life. Rotors that are cold when the startup commences experience transient thermal stresses as the turbine is brought on line. Large rotors with their longer thermal time constants develop higher thermal stresses than smaller rotors undergoing the same startup time sequence. High thermal stresses reduce thermal mechanical fatigue life and the inspection interval.

Though the concept of rotor maintenance factors is applicable to all gas turbine rotors, only F-class rotors will be discussed in detail. For all other rotors, reference unit-specific documentation to determine additional maintenance factors that may apply.
The rotor maintenance factor for a startup is a function of the
downtime following a previous period of operation. As downtime
increases, the rotor metal temperature approaches ambient
conditions, and thermal fatigue during a subsequent startup
increases. As such, cold starts are assigned a rotor maintenance
factor of two and hot starts a rotor maintenance factor of less
than one due to the lower thermal stress under hot conditions.
This effect varies from one location in the rotor structure to
another. The most limiting location determines the overall rotor
maintenance factor.

Initial rotor thermal condition is not the only operating factor
that influences rotor maintenance intervals and component
life. Peaking-fast starts, where the turbine is ramped quickly
to load, increase thermal gradients on the rotor. Trips from
load, particularly trips followed by immediate restarts, and hot
restarts reduce the rotor maintenance interval. Figure 22 lists
recommended operating factors that should be used to determine
the rotor’s overall maintenance factor for certain F-class rotors.

### F-class* Rotors

<table>
<thead>
<tr>
<th></th>
<th>Rotor Maintenance Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Peaking-Fast Start**</td>
</tr>
<tr>
<td>Hot 1 Start Factor</td>
<td>4.0</td>
</tr>
<tr>
<td>(0–1 Hr. Down)</td>
<td></td>
</tr>
<tr>
<td>Hot 2 Start Factor</td>
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<tr>
<td>(1–4 Hrs. Down)</td>
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<tr>
<td>Warm 1 Start Factor</td>
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<tr>
<td>(4–20 Hrs. Down)</td>
<td></td>
</tr>
<tr>
<td>Warm 2 Start Factor</td>
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<tr>
<td>(20–40 Hrs. Down)</td>
<td></td>
</tr>
<tr>
<td>Cold Start Factor</td>
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<tr>
<td>(&gt;40 Hrs. Down)</td>
<td></td>
</tr>
<tr>
<td>Trip from Load Factor</td>
<td>4.0</td>
</tr>
</tbody>
</table>

*Other factors may apply to early 9F.03 units
**An F-class peaking-fast start is typically a start in which the unit is brought from light-off to full load in less than 15 minutes.

The significance of each of these factors is dependent on the unit
operation. There are three categories of operation that are typical
of most gas turbine applications. These are peaking, cyclic, and
continuous duty as described below:

- **Peaking units** have a relatively high starting frequency and a low
  number of hours per start. Operation follows a seasonal demand.
  Peaking units will generally see a high percentage of warm and
cold starts.

- **Cyclic units** start daily with weekend shutdowns. Twelve to
  sixteen hours per start is typical, which results in a warm rotor
  condition for a large percentage of the starts. Cold starts are
generally seen only after a maintenance outage or following a
two-day weekend outage.

- **Continuous duty applications** see a high number of hours
  per start. Most starts are cold because outages are generally
  maintenance driven. While the percentage of cold starts is high,
the total number of starts is low. The rotor maintenance interval
on continuous duty units will be determined by operating hours
rather than starts.

Figure 23 lists operating profiles on the high end of each of
these three general categories of gas turbine applications. These
duty cycles have different combinations of hot, warm, and cold
starts with each starting condition having a different effect on
rotor maintenance interval as previously discussed. As a result,
the starts-based rotor maintenance interval will depend on an
application’s specific duty cycle. In the Rotor Inspection Interval
section, a method will be described to determine a maintenance
factor that is specific to the operation’s duty cycle. The application’s
integrated maintenance factor uses the rotor maintenance factors
described above in combination with the actual duty cycle of a
specific application and can be used to determine rotor inspection
intervals. In this calculation, the reference duty cycle that yields
a starts-based maintenance factor equal to one is defined in
Figure 24. Duty cycles different from the Figure 24 definition,
in particular duty cycles with more cold starts or a high number
of trips, will have a maintenance factor greater than one.

Turning gear or ratchet operation after shutdown and before
starting/restarting is a crucial part of normal operating procedure.
After a shutdown, turning of the warm rotor is essential to avoid
bow, or bend, in the rotor. Initiating a start with the rotor in a
bowed condition could lead to high vibrations and excessive rubs.
Figure F-1 describes turning gear/ratchet scenarios and operation guidelines (See Appendix). Relevant operating instructions and TILs should be adhered to where applicable. As a best practice, units should remain on turning gear or ratchet following a planned shutdown until wheelspace temperatures have stabilized at or near ambient temperature. If the unit is to see no further activity for 48 hours after cool-down is completed, then it may be taken off of turning gear.

Figure F-1 also provides guidelines for hot restarts. When an immediate restart is required, it is recommended that the rotor be placed on turning gear for one hour following a trip from load, trip from full speed no load, or normal shutdown. This will allow transient thermal stresses to subside before superimposing a startup transient. If the machine must be restarted in less than one hour, a start factor of 2 will apply.

Longer periods of turning gear operation may be necessary prior to a cold start or hot restart if bow is detected. Vibration data taken while at crank speed can be used to confirm that rotor bow is at acceptable levels and the start sequence can be initiated. Users should reference the O&M Manual and appropriate TILs for specific instructions and information for their units.

Combustion Parts

A typical combustion system contains transition pieces, combustion liners, flow sleeves, head-end assemblies containing fuel nozzles and cartridges, end caps and end covers, and assorted other hardware including cross-fire tubes, spark plugs and flame detectors. In addition, there can be various fuel and air delivery components such as purge or check valves and flex hoses. GE provides several types of combustion systems including standard combustors, Multi-Nozzle Quiet Combustors (MNQC), Integrated Gasification Combined Cycle (IGCC) combustors, and Dry Low NOx (DLN) combustors. Each of these combustion systems has unique operating characteristics and modes of operation with differing responses to operational variables affecting maintenance and refurbishment requirements.

DLN combustion systems use various combustion modes to reach base load operation. The system transfers from one combustion mode to the next when the combustion reference temperature increases to the required value, or transfer temperature, for the next mode.
• Continuous mode operation is defined as operation in a combustion mode for longer than what is required during normal startup/shutdown.

• Extended mode operation is defined as operation in a combustion mode at a firing temperature greater than the transfer temperature to the next combustion mode.

The DLN combustion mode recommended for continuous mode operation is the premixed combustion mode (PM), as it achieves lowest possible emissions and maximum possible part life. Continuous and extended mode operation in non-PM combustion modes is not recommended due to its effect on combustion hardware life as shown in Figure 25. The use of non-PM combustion modes has the following effects on maintenance:

• DLN-1/DLN-1+ extended lean-lean operation results in a maintenance factor of 10 (excluding Frame 5 units where MF=2).

• DLN 2.0/DLN 2+ extended piloted premixed operation results in a maintenance factor of 10.

• Continuous mode operation in lean-lean (L-L), sub-piloted premixed (sPPM), or piloted premixed (PPM) modes is not recommended as it will accelerate combustion hardware degradation.

• In addition, cyclic operation between piloted premixed and premixed modes leads to thermal loads on the combustion liner and transition piece similar to the loads encountered during the startup/shutdown cycle.

Continuous mode operation of DLN 2.6/DLN 2.6+ combustors will not accelerate combustion hardware degradation.

Another factor that can affect combustion system maintenance is acoustic dynamics. Acoustic dynamics are pressure oscillations generated by the combustion system, which, if high enough in magnitude, can lead to significant wear and cracking of combustion or hot gas path components. GE practice is to tune the combustion system to levels of acoustic dynamics low enough to ensure that the maintenance practices described here are not compromised. In addition, GE encourages monitoring of combustion dynamics during turbine operation throughout the full range of ambient temperatures and loads.

Combustion disassembly is performed, during scheduled combustion inspections (CII). Inspection interval guidelines are included in Figure 39. It is expected, and recommended, that intervals be modified based on specific experience. Replacement intervals are usually defined by a recommended number of combustion (or repair) intervals and are usually combustion component specific. In general, the replacement interval as a function of the number of combustion inspection intervals is reduced if the combustion inspection interval is extended. For example, a component having an 8,000-hour CI interval, and a six CI replacement interval, would have a replacement interval of four CI intervals if the inspection interval were increased to 12,000 hours (to maintain a 48,000-hour replacement interval).

For combustion parts, the baseline operating conditions that result in a maintenance factor of one are fired startup and shutdown to base load on natural gas fuel without steam or water injection. Factors that increase the hours-based maintenance factor include peak load operation, distillate or heavy fuels, and steam or water injection. Factors that increase starts-based maintenance factor include peak load start/stop cycles, distillate or heavy fuels, steam or water injection, trips, and peaking-fast starts.

Casing Parts

Most GE gas turbines have inlet, compressor, compressor discharge, and turbine cases in addition to exhaust frames. Inner barrels are typically attached to the compressor discharge case. These cases provide the primary support for the bearings, rotor, and gas path hardware.

The exterior of all casings should be visually inspected for cracking, loose hardware, and casing slippage at each combustion, hot gas path, and major outage. The interior of all casings should be inspected whenever possible. The level of the outage determines which casing interiors are accessible for visual inspection. Borescope inspections are recommended for the inlet cases, compressor cases, and compressor discharge cases.
during gas path borescope inspections. All interior case surfaces should be visually inspected during a major outage.

Key inspection areas for casings are listed below.

- Bolt holes
- Shroud pin and borescope holes in the turbine shell (case)
- Compressor stator hooks
- Turbine shell shroud hooks
- Compressor discharge case struts
- Inner barrel and inner barrel bolts
- Inlet case bearing surfaces and hooks
- Inlet case and exhaust frame gibs and trunions
- Extraction manifolds (for foreign objects)

Exhaust Diffuser Parts

GE exhaust diffusers come in either axial or radial configurations as shown in Figures 26 and 27 below. Both types of diffusers are composed of a forward and aft section. Forward diffusers are normally axial diffusers, while aft diffusers can be either axial or radial. Axial diffusers are used in the F-class gas turbines, while radial diffusers are used in B/E-class gas turbines.

Exhaust diffusers are subject to high gas path temperatures and vibration due to normal gas turbine operation. Because of the extreme operating environment and cyclic operating nature of gas turbines, exhaust diffusers may develop cracks in the sheet metal surfaces and weld joints used for diffuser construction. Additionally, erosion may occur due to extended operation at high temperatures. Exhaust diffusers should be inspected for cracking and erosion at every combustion, hot gas path, and major outage.

In addition, flex seals, L-seals, and horizontal joint gaskets should be visually/borescope inspected for signs of wear or damage at every combustion, hot gas path, and major outage. GE recommends that seals with signs of wear or damage be replaced.

To summarize, key areas that should be inspected are listed below. Any damage should be reported to GE for recommended repairs.

- Forward diffuser carrier flange (6F)
- Diffuser strut airfoil leading and trailing edges
- Turning vanes in radial diffusers (B/E-class)
- Insulation packs on interior or exterior surfaces
- Clamp ring attachment points to exhaust frame (major outage only)
- Flex seals and L-seals
- Horizontal joint gaskets

Off-Frequency Operation

GE heavy-duty single shaft gas turbines are engineered to operate at 100% speed with the capability to operate over a 95% to 105% speed range. Operation at other than rated speed has the potential to affect maintenance requirements. Depending on the industry code requirements, the specifics of the turbine design, and the turbine control philosophy employed, operating conditions can result that will accelerate life consumption of gas turbine components, particularly rotating flowpath hardware. Where this is true, the maintenance factor associated with this operation must be understood. These off-frequency events must be analyzed and recorded in order to include them in the maintenance plan for the gas turbine.
Some turbines are required to meet operational requirements that are aimed at maintaining grid stability under sudden load or capacity changes. Most codes require turbines to remain on line in the event of a frequency disturbance. For under-frequency operation, the turbine output may decrease with a speed decrease, and the net effect on the turbine is minimal.

In some cases of under-frequency operation, turbine output must be increased in order to meet the specification-defined output requirement. If the normal output fall-off with speed results in loads less than the defined minimum, the turbine must compensate. Turbine overfiring is the most obvious compensation option, but other means, such as water-wash, inlet fogging, or evaporative cooling also provide potential means for compensation. A maintenance factor may need to be applied for some of these methods. In addition, off-frequency operation, including rapid grid transients, may expose the blading to excitations that could result in blade resonant response and reduced fatigue life.

It is important to understand that operation at over-frequency conditions will not trade one-for-one for periods at under-frequency conditions. As was discussed in the firing temperature section above, operation at peak firing conditions has a nonlinear, logarithmic relationship with maintenance factor.

Over-frequency or high speed operation can also introduce conditions that affect turbine maintenance and part replacement intervals. If speed is increased above the nominal rated speed, the rotating components see an increase in mechanical stress proportional to the square of the speed increase. If firing temperature is held constant at the overspeed condition, the life consumption rate of hot gas path rotating components will increase as illustrated in Figure 28 where one hour of operation at 105% speed is equivalent to two hours at rated speed.

If overspeed operation represents a small fraction of a turbine's operating profile, this effect on parts life can sometimes be ignored. However, if significant operation at overspeed is expected and rated firing temperature is maintained, the accumulated hours must be recorded and included in the calculation of the turbine's overall maintenance factor and the maintenance schedule adjusted to reflect the overspeed operation.

Compressor Condition and Performance

Maintenance and operating costs are also influenced by the quality of the air that the turbine consumes. In addition to the negative effects of airborne contaminants on hot gas path components, contaminants such as dust, salt, and oil can cause compressor blade erosion, corrosion, and fouling.

Fouling can be caused by submicron dirt particles entering the compressor as well as from ingestion of oil vapor, smoke, sea salt, and industrial vapors. Corrosion of compressor blading causes pitting of the blade surface, which, in addition to increasing the surface roughness, also serves as potential sites for fatigue crack initiation. These surface roughness and blade contour changes will decrease compressor airflow and efficiency, which in turn reduces the gas turbine output and overall thermal efficiency. Generally, axial flow compressor deterioration is the major cause of loss in gas turbine output and efficiency. Recoverable losses, attributable to compressor blade fouling, typically account for 70-85% percent of the performance losses seen. As Figure 29 illustrates, compressor fouling to the extent that airflow is reduced by 5%, will reduce output by up to 8% and increase heat rate by up to 3%. Fortunately, much can be done through proper operation and maintenance procedures both to minimize fouling type losses and to limit the deposit of corrosive elements. On-line compressor wash systems are available to maintain compressor efficiency by washing the compressor while at load, before significant fouling has occurred. Off-line compressor wash systems are used to clean heavily fouled compressors. Other procedures include maintaining the inlet filtration system, inlet
evaporative coolers, and other inlet systems as well as periodic inspection and prompt repair of compressor blading. Refer to system-specific maintenance manuals.

There are also non-recoverable losses. In the compressor, these are typically caused by nondeposit-related blade surface roughness, erosion, and blade tip rubs. In the turbine, nozzle throat area changes, bucket tip clearance increases and leakages are potential causes. Some degree of unrecoverable performance degradation should be expected, even on a well-maintained gas turbine. The owner, by regularly monitoring and recording unit performance parameters, has a very valuable tool for diagnosing possible compressor deterioration.

**Lube Oil Cleanliness**

Contaminated or deteriorated lube oil can cause wear and damage to bearing liners. This can lead to extended outages and costly repairs. Routine sampling of the turbine lube oil for proper viscosity, chemical composition, and contamination is an essential part of a complete maintenance plan.

Lube oil should be sampled and tested per GEK-32568, “Lubricating Oil Recommendations for Gas Turbines with Bearing Ambients Above 500°F (260°C).” Additionally, lube oil should be checked periodically for particulate and water contamination as outlined in GEK-110483, “Cleanliness Requirements for Power Plant Installation, Commissioning and Maintenance.” At a minimum, the lube oil should be sampled on a quarterly basis; however, monthly sampling is recommended.

**Moisture Intake**

One of the ways some users increase turbine output is through the use of inlet foggers. Foggers inject a large amount of moisture in the inlet ducting, exposing the forward stages of the compressor to potential water carry-over. Operation of a compressor in such an environment may lead to long-term degradation of the compressor due to corrosion, erosion, fouling, and material property degradation. Experience has shown that depending on the quality of water used, the inlet silencer and ducting material, and the condition of the inlet silencer, fouling of the compressor can be severe with inlet foggers. Similarly, carryover from evaporative coolers and water washing more than recommended can degrade the compressor. Figure 30 shows the long-term material property degradation resulting from operating the compressor in a wet environment. The water quality standard that should be adhered to is found in GEK-101944, “Requirements for Water/Steam Purity in Gas Turbines.”

For turbines with AISI 403 stainless steel compressor blades, the presence of water carry-over will reduce blade fatigue strength by as much as 30% and increase the crack propagation rate in a blade if a flaw is present. The carry-over also subjects the blades to corrosion. Such corrosion may be accelerated by a saline environment (see GER-3419). Further reductions in fatigue strength will result if the environment is acidic and if pitting is present on the blade. Pitting is corrosion-induced, and blades with pitting can see material strength reduced to 40% of its original value. This condition is exacerbated by downtime in humid environments, which promotes wet corrosion.

**Effect of Corrosive Environment**

- Reduces Vane Material Endurance Strength
- Pitting Provides Localized Stress Risers

![Figure 30. Long-term material property degradation in a wet environment](image)
Uncoated GTD-450™ material is relatively resistant to corrosion while uncoated AISI 403 is more susceptible. Relative susceptibility of various compressor blade materials and coatings is shown in Figure 31. As noted in GER-3569, aluminum-based (Al) coatings are susceptible to erosion damage leading to unprotected sections of the blade. Because of this, the GECC-1™ coating was created to combine the effects of an Al coating to prevent corrosion and a ceramic topcoat to prevent erosion. Water droplets will cause leading edge erosion on the first few stages of the compressor. This erosion, if sufficiently developed, may lead to an increased risk of blade failure.

The disassembly inspection requires opening the turbine for inspection of internal components. Disassembly inspections progress from the combustion inspection to the hot gas path inspection to the major inspection as shown in Figure 32. Details of each of these inspections are described below.

**Standby Inspections**

Standby inspections are performed on all gas turbines but pertain particularly to gas turbines used in peaking and intermittent-duty service where starting reliability is of primary concern. This inspection includes routinely servicing the battery system, changing filters, checking oil and water levels, cleaning relays, and checking device calibrations. Servicing can be performed in off-peak periods without interrupting the availability of the turbine. A periodic startup test run is an essential part of the standby inspection.

The O&M Manual, as well as the Service Manual Instruction Books, contains information and drawings necessary to perform these periodic checks. Among the most useful drawings in the Service Manual Instruction Books for standby maintenance are the control specifications, piping schematics, and electrical elementaries. These drawings provide the calibrations, operating limits, operating characteristics, and sequencing of all control devices. This information should be used regularly by operating and maintenance personnel. Careful adherence to minor standby inspection maintenance can have a significant effect on reducing overall maintenance costs and maintaining high turbine reliability. It is essential that a good record be kept of all inspections and maintenance work in order to ensure a sound maintenance program.

**Running Inspections**

Running inspections consist of the general and continued observations made while a unit is operating. This starts by establishing baseline operating data during startup of a new unit and after any major disassembly work. This baseline then serves as a reference from which subsequent unit deterioration can be measured.

Data should be taken to establish normal equipment startup parameters as well as key steady state operating parameters. Steady state is defined as conditions at which no more than a 5°F/3°C change in wheelspace temperature occurs over a
15-minute time period. Data must be taken at regular intervals and should be recorded to permit an evaluation of the turbine performance and maintenance requirements as a function of operating time. This operating inspection data, summarized in Figure 33, includes: load versus exhaust temperature, vibration level, fuel flow and pressure, bearing metal temperature, lube oil pressure, exhaust gas temperatures, exhaust temperature spread variation, startup time, and coast-down time. This list is only a minimum and other parameters should be used as necessary. A graph of these parameters will help provide a basis for judging the conditions of the system. Deviations from the norm help pinpoint impending issues, changes in calibration, or damaged components.

A sudden abnormal change in running conditions or a severe trip event could indicate damage to internal components. Conditions that may indicate turbine damage include high vibration, high exhaust temperature spreads, compressor surge, abnormal changes in health monitoring systems, and abnormal changes in other monitoring systems. It is recommended to conduct a borescope inspection after such events whenever component damage is suspected.

Figure 32. 7E.03 heavy-duty gas turbine – disassembly inspections

**Disassembly Inspections**
- Combustion
- Hot Gas Path
- Major Inspection

Figure 33. Operating inspection data parameters
Load vs. Exhaust Temperature
The general relationship between load and exhaust temperature should be observed and compared to previous data. Ambient temperature and barometric pressure will have some effect upon the exhaust temperature. High exhaust temperature can be an indicator of deterioration of internal parts, excessive leaks or a fouled air compressor. For mechanical drive applications, it may also be an indication of increased power required by the driven equipment.

Vibration Level
The vibration signature of the unit should be observed and recorded. Minor changes will occur with changes in operating conditions. However, large changes or a continuously increasing trend give indications of the need to apply corrective action.

Fuel Flow and Pressure
The fuel system should be observed for the general fuel flow versus load relationship. Fuel pressures through the system should be observed. Changes in fuel pressure can indicate that the fuel nozzle passages are plugged or that fuel-metering elements are damaged or out of calibration.

Exhaust Temperature and Spread Variation
The most important control function to be monitored is the exhaust temperature fuel override system and the back-up over temperature trip system. Routine verification of the operation and calibration of these functions will minimize wear on the hot gas path parts.

Startup Time
Startup time is a reference against which subsequent operating parameters can be compared and evaluated. A curve of the starting parameters of speed, fuel signal, exhaust temperature, and critical sequence bench marks versus time will provide a good indication of the condition of the control system. Deviations from normal conditions may indicate impending issues, changes in calibration, or damaged components.

Coast-Down Time
Coast-down time is an indicator of bearing alignment and bearing condition. The time period from when the fuel is shut off during a normal shutdown until the rotor comes to turning gear speed can be compared and evaluated.

Close observation and monitoring of these operating parameters will serve as the basis for effectively planning maintenance work and material requirements needed for subsequent shutdown periods.

Rapid Cool-Down
Prior to an inspection, a common practice is to force cool the unit to speed the cool-down process and shorten outage time. Force cooling involves turning the unit at crank speed for an extended period of time to continue flowing ambient air through the machine. This is permitted, although a natural cool-down cycle on turning gear or ratchet is preferred for normal shutdowns when no outage is pending.

Forced cooling should be limited since it imposes additional thermal stresses on the unit that may result in a reduction of parts life.

Opening the compartment doors during any cool-down operation is prohibited unless an emergency situation requires immediate compartment inspection. Cool-down times should not be accelerated by opening the compartment doors or lagging panels, since uneven cooling of the outer casings may result in excessive case distortion and heavy blade rubs.

Combustion Inspection
The combustion inspection is a relatively short disassembly inspection of fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors, and combustor flow sleeves. This inspection concentrates on the combustion liners, transition pieces, fuel nozzles, and end caps, which are recognized as being the first to require replacement and repair in a good maintenance program. Proper inspection, maintenance, and repair (Figure 34) of these items will contribute to a longer life of the downstream parts, such as turbine nozzles and buckets.

Figure 32 illustrates the section of a 7E.03 unit that is disassembled for a combustion inspection. The combustion liners, transition pieces, and fuel nozzle assemblies should be removed and replaced with new or repaired components to minimize downtime. The removed liners, transition pieces, and fuel nozzles can then be cleaned and repaired after the unit is returned to operation and be available for the next combustion inspection interval. Typical combustion inspection requirements are:
• Inspect combustion chamber components.
• Inspect each crossfire tube, retainer and combustion liner.
• Inspect combustion liner for TBC spalling, wear, and cracks.
• Inspect combustion system and discharge casing for debris and foreign objects.
• Inspect flow sleeve welds for cracking.
• Inspect transition piece for wear and cracks.
• Inspect fuel nozzles for plugging at tips, erosion of tip holes, and safety lock of tips.
• Inspect impingement sleeves for cracks (where applicable).
• Inspect all fluid, air, and gas passages in nozzle assembly for plugging, erosion, burning, etc.
• Inspect spark plug assembly for freedom from binding, check condition of electrodes and insulators.
• Replace all consumables and normal wear-and-tear items such as seals, lockplates, nuts, bolts, gaskets, etc.
• Perform visual inspection of first-stage turbine nozzle partitions and borescope inspect (Figure 3) turbine buckets to mark the progress of wear and deterioration of these parts. This inspection will help establish the schedule for the hot gas path inspection.
• Perform borescope inspection of compressor.

### Combustion Inspection

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<tr>
<th>Key Hardware</th>
<th>Inspect For</th>
<th>Potential Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion liners</td>
<td>Foreign object damage (FOD)</td>
<td>Repair/refurbish/replace</td>
</tr>
<tr>
<td>Combustion end covers</td>
<td>Abnormal wear</td>
<td>• Transition Pieces</td>
</tr>
<tr>
<td>Fuel nozzles</td>
<td>Cracking</td>
<td>• Liners</td>
</tr>
<tr>
<td>End caps</td>
<td>Liner cooling hole plugging</td>
<td>• Strip and recoat</td>
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<td>Transition pieces</td>
<td>TBC coating condition</td>
<td>• Weld repair</td>
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<tr>
<td>Cross fire tubes</td>
<td>Oxidation/corrosion/erosion</td>
<td>• Creep repair</td>
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<tr>
<td>Flow sleeves</td>
<td>Hot spots/burning</td>
<td>• Fuel nozzles</td>
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<tr>
<td>Purge valves</td>
<td>Missing hardware</td>
<td>• Weld repair</td>
</tr>
<tr>
<td>Check valves</td>
<td>Clearance limits</td>
<td>• Flow test</td>
</tr>
<tr>
<td>Spark plugs</td>
<td></td>
<td>• Leak test</td>
</tr>
<tr>
<td>Flame detectors</td>
<td></td>
<td>• Repair out-of-roundness</td>
</tr>
<tr>
<td>Flex hoses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGVs and bushings</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compressor and turbine (borescope)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exhaust diffuser</td>
<td>Cracks</td>
<td>Weld repair</td>
</tr>
<tr>
<td>Exhaust diffuser Insulation</td>
<td>Loose/missing parts</td>
<td>Replace/tighten parts</td>
</tr>
<tr>
<td>Forward diffuser flex seal</td>
<td>Wear/cracked parts</td>
<td>Replace seals</td>
</tr>
<tr>
<td>Compressor discharge case</td>
<td>Cracks</td>
<td>Repair or monitor</td>
</tr>
<tr>
<td>Cases – exterior</td>
<td>Cracks</td>
<td>Repair or monitor</td>
</tr>
</tbody>
</table>

### Criteria
- O&M Manual
- TILs
- GE Field Engineer

### Inspection Methods
- Visual
- Liquid Penetrant
- Borescope

### Availability of On-Site Spares is Key to Minimizing Downtime

---

*Figure 34. Combustion inspection – key elements*
• Visually inspect the compressor inlet, checking the condition of the inlet guide vanes (IGVs), IGV bushings, and first stage rotating blades.
• Check the condition of IGV actuators and rack-and-pinion gearing.
• Verify the calibration of the IGVs.
• Visually inspect compressor discharge case struts for signs of cracking.
• Visually inspect compressor discharge case inner barrel if accessible.
• Visually inspect the last-stage buckets and shrouds.
• Visually inspect the exhaust diffuser for any cracks in flow path surfaces. Inspect insulated surfaces for loose or missing insulation and/or attachment hardware in internal and external locations. In B/E-class machines, inspect the insulation on the radial diffuser and inside the exhaust plenum as well.
• Inspect exhaust frame flex seals, L-seals, and horizontal joint gaskets for any signs of wear or damage.

• Verify proper operation of purge and check valves. Confirm proper setting and calibration of the combustion controls.
• Inspect turbine inlet systems including filters, evaporative coolers, silencers, etc. for corrosion, cracks, and loose parts.

After the combustion inspection is complete and the unit is returned to service, the removed combustion hardware can be inspected by a qualified GE field service representative and, if necessary, sent to a qualified GE Service Center for repairs. It is recommended that repairs and fuel nozzle flow testing be performed at qualified GE service centers.

See the O&M Manual for additional recommendations and unit specific guidance.

**Hot Gas Path Inspection**

The purpose of a hot gas path inspection is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The hot gas path inspection outlined in *Figure 35* includes the full scope of the combustion inspection and, in addition, a detailed inspection of the turbine nozzles.

### Hot Gas Path Inspection

**Combustion Inspection Scope—Plus:**

<table>
<thead>
<tr>
<th>Key Hardware</th>
<th>Inspect For</th>
<th>Potential Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nozzles (1, 2, 3)</td>
<td>Foreign object damage</td>
<td>Repair/refurbish/replace</td>
</tr>
<tr>
<td>Buckets (1, 2, 3)</td>
<td>Oxidation/corrosion/erosion Cracking</td>
<td>• Nozzles</td>
</tr>
<tr>
<td>Stator shrouds</td>
<td>Cooling hole plugging</td>
<td>• Buckets</td>
</tr>
<tr>
<td>Compressor blading (borescope)</td>
<td>Remaining coating life</td>
<td>– Weld repair</td>
</tr>
<tr>
<td></td>
<td>Nozzle deflection/distortion</td>
<td>– Reposition</td>
</tr>
<tr>
<td></td>
<td>Abnormal deflection/distortion</td>
<td>– Recoat</td>
</tr>
<tr>
<td></td>
<td>Abnormal wear</td>
<td>• Stator shrouds</td>
</tr>
<tr>
<td></td>
<td>Missing hardware</td>
<td>– Weld repair</td>
</tr>
<tr>
<td></td>
<td>Clearance limits</td>
<td>– Blend</td>
</tr>
<tr>
<td></td>
<td>Evidence of creep</td>
<td>– Recoat</td>
</tr>
</tbody>
</table>

| Turbine shell                | Cracks                                   | Repair or monitor                 |

### Criteria

- O&M Manual
- TILs
- GE Field Engineer

### Inspection Methods

- Visual
- Borescope
- Liquid Penetrant

### Availability of On-Site Spares

Is Key to Minimizing Downtime

*Figure 35. Hot gas path inspection – key elements*
stator shrouds, and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed. Prior to shell removal, proper machine centerline support using mechanical jacks is necessary to assure proper alignment of rotor to stator, obtain accurate half-shell clearances, and prevent twisting of the stator casings. Reference the O&M Manual for unit-specific jacking procedures.

Special inspection procedures apply to specific components in order to ensure that parts meet their intended life. These inspections may include, but are not limited to, dimensional inspections, Fluorescent Penetrant Inspection (FPI), Eddy Current Inspection (ECI), and other forms of non-destructive testing (NDT). The type of inspection required for specific hardware is determined on a part number and operational history basis, and can be obtained from a GE service representative.

Similarly, repair action is taken on the basis of part number, unit operational history, and part condition. Repairs including (but not limited to) strip, chemical clean, HIP (Hot Isostatic Processing), heat treat, and recoat may also be necessary to ensure full parts life. Weld repair will be recommended when necessary, typically as determined by visual inspection and NDT. Failure to perform the required repairs may lead to retirement of the part before its life potential is fulfilled. In contrast, unnecessary repairs are an unneeded expenditure of time and resources. To verify the types of inspection and repair required, contact your GE service representative prior to an outage.

For inspection of the hot gas path (Figure 32), all combustion transition pieces and the first-stage turbine nozzle assemblies must be removed. Removal of the second- and third-stage turbine nozzle segment assemblies is optional, depending upon the results of visual observations, clearance measurements, and other required inspections. The buckets can usually be inspected in place. FPI of the bucket vane sections may be required to detect any cracks. In addition, a complete set of internal turbine radial and axial clearances (opening and closing) must be taken during any hot gas path inspection. Re-assembly must meet clearance diagram requirements to prevent rubs and to maintain unit performance. In addition to combustion inspection requirements, typical hot gas path inspection requirements are:

- Inspect and record condition of first-, second-, and third-stage buckets. If it is determined that the turbine buckets should be removed, follow bucket removal and condition recording instructions. Buckets with protective coating should be evaluated for remaining coating life.
- Inspect and record condition of first-, second-, and third-stage nozzles.
- Inspect seals and hook fits of turbine nozzles and diaphragms for rubs, erosion, fretting, or thermal deterioration.
- Inspect and record condition of later-stage nozzle diaphragm packings.
- Check discourager seals for rubs, and deterioration of clearance.
- Record the bucket tip clearances.
- Inspect bucket shank seals for clearance, rubs, and deterioration.
- Perform inspections on cutter teeth of tip-shrouded buckets. Consider refurbishment of buckets with worn cutter teeth, particularly if concurrently refurbishing the honeycomb of the corresponding stationary shrouds. Consult your GE service representative to confirm that the bucket under consideration is repairable.
- Check the turbine stationary shrouds for clearance, cracking, erosion, oxidation, rubbing, and build-up of debris.
- Inspect turbine rotor for cracks, object damage, or rubs.
- Check and replace any faulty wheelspace thermocouples.
- Perform borescope inspection of the compressor.
- Visually inspect the turbine shell shroud hooks for signs of cracking.

The first-stage turbine nozzle assembly is exposed to the direct hot gas discharge from the combustion process and is subjected to the highest gas temperatures in the turbine section. Such conditions frequently cause nozzle cracking and oxidation, and in fact, this is expected. The second- and third-stage nozzles are exposed to high gas bending loads, which in combination with the operating temperatures can lead to downstream deflection and closure of critical axial clearances. To a degree, nozzle distress can be tolerated, and criteria have been established for determining when repair is required. More common criteria are described in the O&M Manuals. However, as a general rule, first-stage nozzles will require
repair at the hot gas path inspection. The second- and third-stage nozzles may require refurbishment to re-establish the proper axial clearances. Normally, turbine nozzles can be repaired several times, and it is generally repair cost versus replacement cost that dictates the replacement decision.

Coatings play a critical role in protecting the buckets operating at high metal temperatures. They ensure that the full capability of the high strength superalloy is maintained and that the bucket rupture life meets design expectations. This is particularly true of cooled bucket designs that operate above 1985°F (1085°C) firing temperature. Significant exposure of the base metal to the environment will accelerate the creep rate and can lead to premature replacement through a combination of increased temperature and stress and a reduction in material strength, as described in Figure 36. This degradation process is driven by oxidation of the unprotected base alloy. On early generation uncooled designs, surface degradation due to corrosion or oxidation was considered to be a performance issue and not a factor in bucket life. This is no longer the case at the higher firing temperatures of current generation designs.

Given the importance of coatings, it must be recognized that even the best coatings available will have a finite life, and the condition of the coating will play a major role in determining bucket life. Refurbishment through stripping and recoating is an option for achieving bucket’s expected/design life, but if recoating is selected, it should be done before the coating is breached to expose base metal. Normally, for 7E.03 turbines, this means that recoating will be required at the hot gas path inspection. If recoating is not performed at the hot gas path inspection, the life of the buckets would generally be one additional hot gas path inspection interval, at which point the buckets would be replaced. For F-class gas turbines, recoating of the first stage buckets is recommended at each hot gas path inspection. Visual and borescope examination of the hot gas path parts during the combustion inspections as well as nozzle-deflection measurements will allow the operator to monitor distress patterns and progression. This makes part-life predictions more accurate and allows adequate time to plan for replacement or refurbishment at the time of the hot gas path inspection. It is important to recognize that to avoid extending the hot gas path inspection, the necessary spare parts should be on site prior to taking the unit out of service.

See the O&M Manual for additional recommendations and unit specific guidance.

**Major Inspection**

The purpose of the major inspection is to examine all of the internal rotating and stationary components from the inlet of the machine through the exhaust. A major inspection should be scheduled in accordance with the recommendations in the owner’s O&M Manual or as modified by the results of previous borescope and hot gas path inspections. The work scope shown in Figure 37 involves

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**Figure 36.** Stage 1 bucket oxidation and bucket life
inspection of all of the major flange-to-flange components of the gas turbine, which are subject to deterioration during normal turbine operation. This inspection includes previous elements of the combustion and hot gas path inspections, and requires laying open the complete flange-to-flange gas turbine to the horizontal joints, as shown in Figure 32.

Removal of all of the upper casings allows access to the compressor rotor and stationary compressor blading, as well as to the bearing assemblies. Prior to removing casings, shells, and frames, the unit must be properly supported. Proper centerline support using mechanical jacks and jacking sequence procedures are necessary to assure proper alignment of rotor to stator, obtain accurate half shell clearances, and to prevent twisting of the casings while on the half shell. Reference the O&M Manual for unit-specific jacking procedures. In addition to combustion and hot gas path inspection requirements, typical major inspection requirements are:

**Major Inspection**

**Hot Gas Path Inspection Scope—Plus:**

<table>
<thead>
<tr>
<th>Key Hardware</th>
<th>Inspect For</th>
<th>Potential Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compressor blading</td>
<td>Foreign object damage</td>
<td>Repair/refurbishment/replace</td>
</tr>
<tr>
<td>Unit rotor</td>
<td>Oxidation/corrosion/erosion</td>
<td>• Bearings/seals</td>
</tr>
<tr>
<td>Journals and seal surfaces</td>
<td>Cracking</td>
<td>- Clean</td>
</tr>
<tr>
<td>Bearing seals</td>
<td>Leaks</td>
<td>- Assess oil condition</td>
</tr>
<tr>
<td>Exhaust system</td>
<td>Abnormal wear</td>
<td>- Re-babbitt</td>
</tr>
<tr>
<td></td>
<td>Missing hardware</td>
<td>• Compressor blades</td>
</tr>
<tr>
<td></td>
<td>Clearance limits</td>
<td>- Clean</td>
</tr>
<tr>
<td></td>
<td>Coating wear</td>
<td>- Blend</td>
</tr>
<tr>
<td></td>
<td>Fretting</td>
<td>• Exhaust system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Weld repair</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Replace flex seals/L-seals</td>
</tr>
<tr>
<td>Compressor and compressor</td>
<td>Wear</td>
<td>Repair</td>
</tr>
<tr>
<td>discharge case hooks</td>
<td></td>
<td>• Repair or monitor</td>
</tr>
<tr>
<td>All cases – exterior and</td>
<td>Cracks</td>
<td>Casing alignment</td>
</tr>
<tr>
<td>interior</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cases – Exterior</td>
<td>Slippage</td>
<td></td>
</tr>
</tbody>
</table>

**Criteria**

- O&M Manual
- TILs
- GE Field Engineer

**Inspection Methods**

- Visual
- Borescope
- Liquid Penetrant
- Ultrasonics

*Figure 37. Gas turbine major inspection – key elements*
- Visually inspect compressor and compressor discharge case hooks for signs of wear.
- Visually inspect compressor discharge case inner barrel.
- Inspect exhaust frame flex seals, L-seals, and horizontal joint gaskets for any signs of wear or damage. Inspect steam gland seals for wear and oxidation.
- Check torque values for steam gland bolts and re-torque to full values.
- Check alignment – gas turbine to generator/gas turbine to accessory gear.
- Inspect casings for signs of casing flange slippage.

Comprehensive inspection and maintenance guidelines have been developed by GE and are provided in the O&M Manual to assist users in performing each of the inspections previously described.

**Parts Planning**

Prior to a scheduled disassembly inspection, adequate spares should be on-site. Lack of adequate on-site spares can have a major effect on plant availability. For example, a planned outage such as a combustion inspection, which should only take two to five days, could take weeks if adequate spares are not on-site. GE will provide recommendations regarding the types and quantities of spare parts needed; however, it is up to the owner to purchase these spare parts on a planned basis allowing adequate lead times.

Early identification of spare parts requirements ensures their availability at the time the planned inspections are performed. Refer to the Reference Drawing Manual provided as part of the comprehensive set of O&M Manuals to aid in identification and ordering of gas turbine parts.

Additional benefits available from the renewal parts catalog data system are the capability to prepare recommended spare parts lists for the combustion, hot gas path and major inspections as well as capital and operational spares.

Estimated repair and replacement intervals for some of the major components are shown in Appendix D. These tables assume that operation, inspections, and repairs of the unit have been done in accordance with all of the manufacturer's specifications and instructions.

The actual repair and replacement intervals for any particular gas turbine should be based on the user's operating procedures, experience, maintenance practices, and repair practices. The maintenance factors previously described can have a major effect on both the component repair interval and service life. For this reason, the intervals given in Appendix D should only be used as guidelines and not certainties for long range parts planning. Owners may want to include contingencies in their parts planning.

The estimated repair and replacement intervals are based on the recommended inspection intervals shown in Figure 39. For certain models, technology upgrades are available that extend the maintenance inspection intervals. The application of inspection (or repair) intervals other than those shown in Figure 39 can result in different replacement intervals than those shown in Appendix D. See your GE service representative for details on a specific system.

It should be recognized that, in some cases, the service life of a component is reached when it is no longer economical to repair any deterioration as opposed to replacing at a fixed interval. This is illustrated in Figure 38 for a first stage nozzle, where repairs continue until either the nozzle cannot be restored to minimum acceptance standards or the repair cost exceeds or approaches the replacement cost. In other cases, such as first-stage buckets, repair options are limited by factors such as irreversible material damage. In both cases, users should follow GE recommendations regarding replacement or repair of these components.

It should also be recognized that the life consumption of any one individual part within a parts set can have variations. This may lead to a certain percentage of “fallout,” or scrap, of parts being repaired. Those parts that fallout during the repair process will need to be replaced by new parts. Parts fallout will vary based on the unit operating environment history, the specific part design, and the current repair technology.
Figure 38. First-stage nozzle repair program: natural gas fired – continuous dry – base load

<table>
<thead>
<tr>
<th>Type of Inspection</th>
<th>Type of hours/starts</th>
<th>Hours/Starts</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>6B</td>
</tr>
<tr>
<td>Combustion (Non-DLN)</td>
<td>Factored</td>
<td>MS3002K</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MS5001PA</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MS5002C, D</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6B.03</td>
</tr>
<tr>
<td>Combustion (DLN)</td>
<td>Factored</td>
<td>8000/400</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hot Gas Path</td>
<td>Factored</td>
<td>24000/1200</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Major</td>
<td>Actual</td>
<td>48000/2400</td>
</tr>
</tbody>
</table>

Factors that can reduce maintenance intervals:
- Fuel
- Load setting
- Steam/water injection
- Peak load firing operation
- Trips
- Start cycle
- Hardware design
- Off-frequency operation

1. Units with Lean Head End liners have a 400-starts combustion inspection interval.
2. Multiple Non-DLN configurations exist (Standard, MNQC, IGCC). The typical case is shown; however, different quoting limits may exist on a machine and hardware basis. Contact a GE service representative for further information.
3. Combustion inspection without transition piece removal. Combustion inspection with transition pieces removal to be performed every 2 combustion inspection intervals.
4. Hot gas path inspection for factored hours eliminated on units that operate on natural gas fuel without steam or water injection.
5. Upgraded technology (Extendor*, PIP, DLN 2.6+, etc) may have longer inspection intervals.
6. Also applicable to 7121(EA) models.
7. Applicable to non-AGP units only.

Note:
Baseline inspection intervals reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience.
For Repair/Replace intervals see Appendix D.

Figure 39. Baseline recommended inspection intervals: base load – natural gas fuel – dry
**Inspection Intervals**

In the absence of operating experience and resulting part conditions, Figure 39 lists the recommended combustion, hot gas path and major inspection intervals for current production GE turbines operating under typical conditions of natural gas fuel, base load, and no water/steam injection. These recommended intervals represent factored hours or starts calculated using maintenance factors to account for application specific operating conditions. Initially, recommended intervals are based on the expected operation of a turbine at installation, but this should be reviewed and adjusted as operating and maintenance data are accumulated. While reductions in the recommended intervals will result from the factors described previously or unfavorable operating experience, increases in the recommended intervals may also be considered where operating experience has been favorable.

The condition of the combustion and hot gas path parts provides a basis for customizing a program for inspection and maintenance. The condition of the compressor and bearing assemblies is the key driver in planning a major inspection. Historical operation and machine conditions can be used to tailor maintenance programs such as optimized repair and inspection criteria to specific sites/machines. GE leverages these principles and accumulated site and fleet experience in a “Condition Based Maintenance” program as the basis for maintenance of units under Contractual Service Agreements. This experience was accumulated on units that operate with GE approved repairs, field services, monitoring, and full compliance to GE’s technical recommendations.

GE can assist operators in determining the appropriate maintenance intervals for their particular application. Equations have been developed that account for the factors described earlier and can be used to determine application-specific combustion, hot gas path, and major inspection intervals.

**Borescope Inspection Interval**

In addition to the planned maintenance intervals, which undertake scheduled inspections or component repairs or replacements, borescope inspections should be conducted to identify any additional actions, as discussed in the sections

"Gas Turbine Design Maintenance Features." Such inspections may identify additional areas to be addressed at a future scheduled maintenance outage, assist with parts or resource planning, or indicate the need to change the timing of a future outage. The BI should use all the available access points to verify the condition of the internal hardware. As much of the Major Inspection workscope as possible should be done using this visual inspection without disassembly. Refer to Figure 4 for standard recommended BI frequency. Specific concerns may warrant subsequent BIs in order to operate the unit to the next scheduled outage without teardown.

**Combustion Inspection Interval**

Equations have been developed that account for the earlier mentioned factors affecting combustion maintenance intervals. These equations represent a generic set of maintenance factors that provide guidance on maintenance planning. As such, these equations do not represent the specific capability of any given combustion system. For combustion parts, the baseline operating conditions that result in a maintenance factor of one are normal fired startup and shutdown (no trip) to base load on natural gas fuel without steam or water injection.

An hours-based combustion maintenance factor can be determined from the equations given in Figure 40 as the ratio of factored hours to actual operating hours. Factored hours considers the effects of fuel type, load setting, and steam/water injection. Maintenance factors greater than one reduce recommended combustion inspection intervals from those shown in Figure 39 representing baseline operating conditions. To obtain a recommended inspection interval for a specific application, the maintenance factor is divided into the recommended baseline inspection interval.

A starts-based combustion maintenance factor can be determined from the equations given in Figure 41 and considers the effect of fuel type, load setting, peaking-fast starts, trips, and steam/water injection. An application-specific recommended inspection interval can be determined from the baseline inspection interval in Figure 39 and the maintenance factor from Figure 41. Appendix B shows six example maintenance factor calculations using the above hours and starts maintenance factor equations.
Syngas units require unit-specific intervals to account for unit-specific fuel constituents and water/steam injection schedules. As such, the combustion inspection interval equations may not apply to those units.

**Hours-Based Combustion Inspection**

**Maintenance Interval**

\[
\text{Maintenance Interval} = \frac{\text{Baseline CI (Figure 39)}}{\text{Maintenance Factor}}
\]

**Maintenance Factor**

\[
\text{Maintenance Factor} = \frac{\text{Factored Hours}}{\text{Actual Hours}}
\]

**Factored Hours**

\[\sum (K_i \cdot A_f \cdot A_p \cdot t_i), i = 1 \text{ to } n \text{ in Operating Modes}\]

**Actual Hours**

\[\sum (t_i), i = 1 \text{ to } n \text{ in Operating Modes}\]

Where:

- \(i\) = Discrete Operating mode (or Operating Practice of Time Interval)
- \(t_i\) = Operating hours at Load in a Given Operating mode
- \(A_p\) = Load Severity factor
  - \(A_p = 1.0\) up to Base Load
  - \(A_p = \exp(0.009 \times \text{Peak Firing Temp Adder in °F})\) for Peak Load
- \(A_f\) = Fuel Severity Factor
  - \(A_f = 1.0\) for Natural Gas Fuel
  - \(A_f = 1.5\) for Distillate Fuel, Non-DLN (2.5 for DLN)
  - \(A_f = 2.5\) for Crude (Non-DLN)
  - \(A_f = 3.5\) for Residual (Non-DLN)
- \(K_i\) = Water/Steam Injection Severity Factor
  - \(K_i\) = Water/Steam Injection Severity Factor
  - \(K_i = \max(1.0, \exp(0.34(\% \text{Steam - 2.00\%})))\) for Steam, Dry Control Curve
  - \(K_i = \max(1.0, \exp(0.34(\% \text{Steam - 1.00\%})))\) for Steam, Wet Control Curve
  - \(K_i = \max(1.0, \exp(1.80(w/f - 0.80)))\) for Water, Dry Control Curve
  - \(K_i = \max(1.0, \exp(1.80(w/f - 0.40)))\) for Water, Wet Control Curve

Where:

- \(i\) = Discrete Start/Stop Cycle (or Operating Practice of Time Interval)
- \(N_i\) = Start/Stop Cycles in a Given Operating Mode
- \(A_s\) = Start Type Severity Factor
  - \(A_s = 1.0\) for Normal Start
  - \(A_s = \text{For Peaking-Fast Start See Figure 14}\)
- \(A_t\) = Trip Severity Factor
  - \(A_t = 0.5 + \exp(0.0125 \times \% \text{Load for Trip})\)
  - \(A_t = 1\) for No Trip
- \(A_f\) = Fuel Severity Factor
  - \(A_f = 1.0\) for Natural Gas Fuel
  - \(A_f = 1.25\) for Distillate Fuel, Non-DLN (1.5 for DLN)
  - \(A_f = 2.0\) for Crude (Non-DLN)
  - \(A_f = 3.0\) for Residual (Non-DLN)

**Starts-Based Combustion Inspection**

**Maintenance Interval**

\[
\text{Maintenance Interval} = \frac{\text{Baseline CI (Figure 39)}}{\text{Maintenance Factor}}
\]

**Maintenance Factor**

\[
\text{Maintenance Factor} = \frac{\text{Factored Starts}}{\text{Actual Starts}}
\]

**Factored Starts**

\[\sum (K_i \cdot A_f \cdot A_t \cdot A_p \cdot A_s \cdot N_i), i = 1 \text{ to } n \text{ in Start/Stop Cycles}\]

**Actual Starts**

\[\sum (N_i), i = 1 \text{ to } n \text{ in Start/Stop Cycles}\]

Where:

- \(i\) = Discrete Start/Stop Cycle (or Operating Practice of Time Interval)
- \(N_i\) = Start/Stop Cycles in a Given Operating Mode
- \(A_s\) = Start Type Severity Factor
  - \(A_s = 1.0\) for Normal Start
  - \(A_s = \text{For Peaking-Fast Start See Figure 14}\)
- \(A_t\) = Trip Severity Factor
  - \(A_t = 0.5 + \exp(0.0125 \times \% \text{Load for Trip})\)
  - \(A_t = 1\) for No Trip
- \(A_f\) = Fuel Severity Factor
  - \(A_f = 1.0\) for Natural Gas Fuel
  - \(A_f = 1.25\) for Distillate Fuel, Non-DLN (1.5 for DLN)
  - \(A_f = 2.0\) for Crude (Non-DLN)
  - \(A_f = 3.0\) for Residual (Non-DLN)

**K_i**

- \(K_i\) = Water/Steam Injection Severity Factor
  - \(K_i = \max(1.0, \exp(0.34(\% \text{Steam - 2.00\%})))\) for Steam, Dry Control Curve
  - \(K_i = \max(1.0, \exp(0.34(\% \text{Steam - 1.00\%})))\) for Steam, Wet Control Curve
  - \(K_i = \max(1.0, \exp(1.80(w/f - 0.80)))\) for Water, Dry Control Curve
  - \(K_i = \max(1.0, \exp(1.80(w/f - 0.40)))\) for Water, Wet Control Curve

\[1\) \(A_f = 10\) for DLN 1/DLN 1+ extended lean-lean, and DLN 2.0/ DLN 2+ extended piloted premixed operating modes.

**Figure 40.** Combustion inspection hours-based maintenance factors

**Figure 41.** Combustion inspection starts-based maintenance factors
Hot Gas Path Inspection Interval
The hours-based hot gas path criterion is determined from the equations given in Figure 42. With these equations, a maintenance factor is determined that is the ratio of factored operating hours and actual operating hours. The factored hours consider the specifics of the duty cycle relating to fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce the hot gas path inspection interval from the baseline (typically 24,000 hour) case. To determine the application specific maintenance interval, the maintenance factor is divided into the baseline hot gas path inspection interval, as shown in Figure 42.

Hours-Based HGP Inspection

\[
\text{Maintenance Interval} = \frac{\text{Baseline HGP Interval (Figure 39)}}{\text{Maintenance Factor}}
\]

Maintenance Factor = \[
\frac{\text{Factored Hours}}{\text{Actual Hours}}
\]

Factored Hours = \[
\sum_{i=1}^{n} (S_i \cdot A_{fi} \cdot A_{pi} \cdot t_i)
\]

Actual Hours = \[
\sum_{i=1}^{n} (t_i)
\]

\(i = 1 \) to \(n\) discrete operating modes (or operating practices of time interval)

\(t_i = \) Fired hours in a given operating mode

\(A_{pi} = \) Load severity factor for given operating mode

\(A_{pf} = \) For peak load factor see Figure 11.

\(A_{fi} = \) Fuel severity factor for given operating mode

\(A_f = 1.0\) for natural gas

\(A_f = 1.5\) for distillate

\(=1.0\) when \(A_p > 1\), at minimum \(A_{f} \cdot A_p = 1.5\)

\(A_f = 2\) to \(3\) for crude

\(A_f = 3\) to \(4\) for residual

\(S_i = \) Water/steam injection severity factor = \(K_i + (M_i \cdot I_i)\)

\(I = \) Percent water/steam injection referenced to compressor inlet air flow

\(M\&K = \) Water/steam injection constants

The starts-based hot gas path criterion is determined from the equations given in Figure 43.

As previously described, the limiting criterion (hours or starts) determines the maintenance interval. Examples of these equations are in Appendix A.

Starts-Based HGP Inspection

\[
\text{Maintenance Interval} = \frac{S}{\text{Maintenance Factor}}
\]

Where:

Maintenance Factor = \[
\frac{\text{Factored Starts}}{\text{Actual Starts}}
\]

Factored Starts = \(0.5N_A + N_B + 1.3N_P + P_s F + \sum_{i=1}^{n} (a_{Pi} \cdot T_i)

Actual Starts = \(N_A + N_B + N_P

S = \) Baseline Starts-Based Maintenance Interval (Figure 39)

\(N_A = \) Annual Number of Part Load Start/Stop Cycles (<60% Load)

\(N_B = \) Annual Number of Base Load Start/Stop Cycles

\(N_P = \) Annual Number of Peak Load Start/Stop Cycles (>100% Load)

\(P_s = \) Peaking-Fast Start Factor (See Figure 14)

\(F = \) Annual Number of Peaking-Fast Starts

\(T = \) Annual Number of Trips

\(a_T = \) Trip Severity Factor = \(f(\text{Load})\) (See Figure 20)

\(n = \) Number of Trip Categories (i.e. Full Load, Part Load, etc.)

Rotor Inspection Interval
Like hot gas path components, the unit rotor has a maintenance interval involving removal, disassembly, and inspection. This interval indicates the serviceable life of the rotor and is generally considered to be the teardown inspection and repair/replacement interval for the rotor. The disassembly inspection is usually concurrent with a hot gas path or major inspection; however, it should be noted that the maintenance factors for rotor maintenance intervals are distinct from those of combustion and hot gas path components. As such, the calculation of consumed life on the rotor may vary from that of combustion and hot gas path components. Customers should contact GE when their rotor is approaching the end of its serviceable life for technical advisement.
Figure 44 describes the procedure to determine the hours-based maintenance criterion. Peak load operation is the primary maintenance factor for the F-class rotor and will act to increase the hours-based maintenance factor and to reduce the rotor maintenance interval. For B/E-class units time on turning gear also affects rotor life.

The starts-based rotor maintenance interval is determined from the equations given in Figure 45. Adjustments to the rotor maintenance interval are determined from rotor-based operating factors as described previously. In the calculation for the starts-based rotor maintenance interval, equivalent starts are determined for cold, warm, and hot starts over a defined time period by multiplying the appropriate cold, warm, and hot start operating factors by the number of cold, warm, and hot starts respectively. Additionally, equivalent starts for trips from load are added. The total equivalent starts are divided by the actual number of starts to yield the maintenance factor. The rotor starts-based maintenance interval is determined by dividing the baseline rotor maintenance interval of 5000 starts by the calculated maintenance factor. The baseline rotor maintenance interval is also the maximum interval, since calculated maintenance factors less than one are not considered.

When the rotor reaches the earlier of the inspection intervals described in Figures 44 and 45, an unstack of the rotor is required so that a complete inspection of the rotor components in both the compressor and turbine can be performed. It should be expected that some rotor components will either have reached the end of their serviceable life or will have a minimal amount of residual life remaining and will require repair or replacement at this inspection point. Depending on the extent of refurbishment and part replacement, subsequent inspections may be required at a reduced interval.

**Hours-Based Rotor Inspection**

\[
\text{Maintenance Interval (Hours)} = \frac{R}{\text{Maintenance Factor}}
\]

\[
\text{MF} = \frac{\text{Factored Hours}}{\text{Actual Hours}} = \frac{H + 2P}{H + P}
\]

\[
\text{MF for B/E-class} = \frac{H + 2P + 2T_G}{H + P}
\]

- \( H \): Non-peak load operating hours
- \( P \): Peak load operating hours
- \( T_G \): Hours on turning gear
- \( R \): Baseline rotor inspection interval

<table>
<thead>
<tr>
<th>Machine</th>
<th>( R^{(1)} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>F-class</td>
<td>144,000</td>
</tr>
<tr>
<td>All other</td>
<td>200,000</td>
</tr>
</tbody>
</table>

(1) Maintenance factor equation to be used unless otherwise notified in unit-specific documentation.

(2) To diminish potential turning gear impact, major inspections must include a thorough visual and dimensional examination of the hot gas path turbine rotor dovetails for signs of wearing, galling, fretting, or cracking. If no distress is found during inspection or after repairs are performed to the dovetails, time on turning gear may be omitted from the hours-based maintenance factor.

(3) Baseline rotor inspection intervals to be used unless otherwise notified in unit-specific documentation.

**Starts-Based Rotor Inspection**

\[
\text{Maintenance Interval (Starts)} = \frac{5,000^{(2)}}{\text{Maintenance Factor}}
\]

\[
\text{Maintenance Factor} = \frac{\text{Factored Starts}}{\text{Actual Starts}}
\]

For units with published start factors:

\[
\text{Maintenance Factor} = \frac{F_{h1} \cdot N_{h1} + F_{w1} \cdot N_{w1} + F_{w2} \cdot N_{w2} + F_{c} \cdot N_{c} + F_{t} \cdot N_{t}}{(N_{h1} + N_{h2} + N_{w1} + N_{w2} + N_{c})}
\]

For B/E-class units:

\[
\text{Maintenance Factor} = \frac{N_{h1} + N_{w1}}{N_{t}}
\]

For all other units additional start factors may apply.

<table>
<thead>
<tr>
<th>Number of Starts</th>
<th>Start Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>( N_{h1} ) = Number of hot 1 starts</td>
<td>( F_{h1} = \text{Hot 1 start factor (down 0-1 hr)} )</td>
</tr>
<tr>
<td>( N_{h2} ) = Number of hot 2 starts</td>
<td>( F_{h2} = \text{Hot 2 start factor (down 1-4 hr)} )</td>
</tr>
<tr>
<td>( N_{w1} ) = Number of warm 1 starts</td>
<td>( F_{w1} = \text{Warm 1 start factor (down 4-20 hr)} )</td>
</tr>
<tr>
<td>( N_{w2} ) = Number of warm 2 starts</td>
<td>( F_{w2} = \text{Warm 2 start factor (down 20-40 hr)} )</td>
</tr>
<tr>
<td>( N_{c} ) = Number of cold starts</td>
<td>( F_{c} = \text{Cold start factor (down &gt;40 hr)} )</td>
</tr>
<tr>
<td>( N_{t} ) = Number of trips from load</td>
<td>( F_{t} = \text{Trip from load factor} )</td>
</tr>
<tr>
<td>( N_{s} ) = Total number of fired starts</td>
<td></td>
</tr>
</tbody>
</table>

(1) Baseline rotor inspection interval is 5,000 fired starts unless otherwise notified in unit-specific documentation.

(2) Start factors for certain F-class units are tabulated in Figure 22. For all other machines, consult unit-specific documentation to determine if start factors apply.

**Figure 44.** Rotor maintenance interval: hours-based criterion

**Figure 45.** Rotor maintenance interval: starts-based criterion
The baseline rotor life is predicated upon sound inspection results at the major inspections. For F-class rotors the baseline intervals are typically 144,000 hours and 5,000 starts. For rotors other than F-class, the baseline intervals are typically 200,000 hours and 5,000 starts. Consult unit-specific documentation to determine if alternate baseline intervals or maintenance factors may apply.

**Personnel Planning**

It is essential that personnel planning be conducted prior to an outage. It should be understood that a wide range of experience, productivity, and working conditions exist around the world. However, an estimate can be made based upon maintenance inspection labor assumptions, such as the use of a crew of workers with trade skill (but not necessarily direct gas turbine experience), with all needed tools and replacement parts (no repair time) available. These estimated craft labor hours should include controls/accessories and the generator. In addition to the craft labor, additional resources are needed for technical direction, specialized tooling, engineering reports, and site mobilization/demobilization.

Inspection frequencies and the amount of downtime varies within the gas turbine fleet due to different duty cycles and the economic need for a unit to be in a state of operational readiness. Contact your local GE service representative for the estimated labor hours and recommended crew size for your specific unit.

Depending upon the extent of work to be done during each maintenance task, a cooldown period of 4 to 24 hours may be required before service may be performed. This time can be utilized productively for job move-in, correct tagging and locking equipment out-of-service, and general work preparations. At the conclusion of the maintenance work and systems check out, a turning gear time of two to eight hours is normally allocated prior to starting the unit. This time can be used for job clean-up and preparing for start.

Local GE field service representatives are available to help plan maintenance work to reduce downtime and labor costs. This planned approach will outline the replacement parts that may be needed and the projected work scope, showing which tasks can be accomplished in parallel and which tasks must be sequential. Planning techniques can be used to reduce maintenance cost by optimizing lifting equipment schedules and labor requirements.

Precise estimates of the outage duration, resource requirements, critical-path scheduling, recommended replacement parts, and costs associated with the inspection of a specific installation may be sourced from the local GE field services office.

**Conclusion**

GE heavy-duty gas turbines are designed to have high availability. To achieve maximum gas turbine availability, an owner must understand not only the equipment but also the factors affecting it. This includes the training of operating and maintenance personnel, following the manufacturer’s recommendations, regular periodic inspections, and the stocking of spare parts for immediate replacement. The recording and analysis of operating data is also essential to preventative and planned maintenance. A key factor in achieving this goal is a commitment by the owner to provide effective outage management, to follow published maintenance instructions, and to utilize the available service support facilities.

It should be recognized that, while the manufacturer provides general maintenance recommendations, it is the equipment user who controls the maintenance and operation of equipment. Inspection intervals for optimum turbine service are not fixed for every installation but rather are developed based on operation and experience. In addition, through application of a Contractual Service Agreement to a particular turbine, GE can work with a user to establish a maintenance program that may differ from general recommendations but will be consistent with contractual responsibilities.

The level and quality of a rigorous maintenance program have a direct effect on equipment reliability and availability. Therefore, a rigorous maintenance program that reduces costs and outage time while improving reliability and earning ability is the optimum GE gas turbine user solution.
References


GEI-41040, “Fuel Gases for Combustion in Heavy-Duty Gas Turbines.”

GEI-41047, “Gas Turbine Liquid Fuel Specifications.”

GEK-101944, “Requirements for Water/Steam Purity in Gas Turbines.”

GER-3419A, “Gas Turbine Inlet Air Treatment.”

GER-3569F, “Advanced Gas Turbine Materials and Coatings.”

GEK-32568, “Lubricating Oil Recommendations for Gas Turbines with Bearing Ambients Above 500°F (260°C).”

GEK-110483, “Cleanliness Requirements for Power Plant Installation, Commissioning and Maintenance.”
Appendix

A.1) Example 1 – Hot Gas Path Maintenance Interval Calculation

A 7E.03 user has accumulated operating data since the last hot gas path inspection and would like to estimate when the next one should be scheduled. The user is aware from GE publications that the baseline HGP interval is 24,000 hours if operating on natural gas, with no water or steam injection, and at base load. It is also understood that the baseline starts interval is 1200, based on normal startups, no trips, no peaking-fast starts. The actual operation of the unit since the last hot gas path inspection is much different from the baseline case. The unit operates in four different operating modes:

1. The unit runs 3200 hrs/yr in its first operating mode, which is natural gas at base or part load with no steam/water injection.
2. The unit runs 350 hrs/yr in its second operating mode, which is distillate fuel at base or part load with no steam/water injection.
3. The unit runs 120 hrs/yr in its third operating mode, which is natural gas at peak load (+100°F) with no steam/water injection.
4. The unit runs 20 hrs/yr in its fourth operating mode, which is natural gas at base load with 2.4% steam injection on a wet control curve.

The hours-based hot gas path maintenance interval parameters for these four operating modes are summarized below:

<table>
<thead>
<tr>
<th>Operating Mode (i)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fired hours (hrs/yr)</td>
<td>t</td>
<td>3200</td>
<td>350</td>
<td>120</td>
</tr>
<tr>
<td>Fuel severity factor (Af)</td>
<td>1</td>
<td>1.5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Load severity factor (Ap)</td>
<td>1</td>
<td>1</td>
<td>[e^{100°F×100}] = 6</td>
<td>1</td>
</tr>
<tr>
<td>Steam/water injection rate (%)</td>
<td>i</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

For this particular unit, the second- and third-stage nozzles are FSX-414 material. From Figure 42, at a steam injection rate of 2.4% on a wet control curve,

\[ M_s = 0.55, \quad K_s = 1 \]

The steam severity factor for mode 4 is therefore,

\[ S_4 = K_s + (M_s \cdot i_s) = 1 + (0.55 \cdot 2.4) = 2.3 \]

At a steam injection rate of 0%,

\[ M = 0, \quad K = 1 \]

Therefore, the steam severity factor for modes 1, 2, and 3 are

\[ S_1 = S_2 = S_3 = K + (M \cdot 0) = 1 \]

From the hours-based criteria, the maintenance factor is determined from Figure 42.

\[ MF = \frac{\sum_{i=1}^{4} (S_i \cdot A_f \cdot A_p \cdot t_i)}{\sum_{i=1}^{4} t_i} \]

\[ = \frac{(1 \cdot 1 \cdot 1 \cdot 3200) + (1 \cdot 1.5 \cdot 1 \cdot 350) + (1 \cdot 1 \cdot 6 \cdot 120) + (2.3 \cdot 1 \cdot 1 \cdot 20)}{(3200 + 350 + 120 + 20)} \]

\[ MF = 1.22 \]

The hours-based adjusted inspection interval is therefore,

\[ \text{Adjusted Inspection Interval} = 24,000 / 1.22 = 19,700 \text{ hours} \]

(Note, since total annual operating hours is 3690, the estimated time to reach 19,700 hours is 19,700/3690 = 5.3 years.)

Also, since the last hot gas path inspection the unit has averaged 145 normal start-stop cycles per year, 5 peaking-fast start cycles per year, and 20 base load cycles ending in trips (aT = 8) per year.

The starts-based hot gas path maintenance interval parameters for this unit are summarized below:

| Part load cycles, NA | 40 | 0 | 0 | 40 |
| Base load cycles, NB | 100 | 5 | 20 | 125 |
| Peak load cycles, NP | 5 | 0 | 0 | 5 |

From the starts-based criteria, the maintenance factor is determined from Figure 43.

\[ MF = 0.5N_A + N_B + 1.3N_P + \frac{P_sF + \sum_{i=1}^{4} (aT_i - 1) T_i}{N_A + N_B + N_P} \]

\[ = 0.5 \cdot (40) + 125 + 1.3 \cdot (5) + 3.5 \cdot (5) + (8 - 1) \cdot 20 \]

\[ = 0.5 \cdot (40) + 125 + 5 \]

\[ MF = 1.8 \]

The adjusted inspection interval based on starts is

\[ \text{Adjusted Inspection Interval} = 1200 / 1.8 = 667 \text{ starts} \]

(Note, since the total annual number of starts is 170, the estimated time to reach 667 starts is 667/170 = 3.9 years.)

In this case the unit would reach the starts-based hot gas path interval prior to reaching the hours-based hot gas path interval. The hot gas path inspection interval for this unit is therefore 667 starts (or 3.9 years).
A.2) Example 2 – Hot Gas Path Factored Starts Calculation

A 7E.03 user has accumulated operating data for the past year of operation. This data shows number of trips from part, base, and peak load, as well as peaking-fast starts. The user would like to calculate the total number of factored starts in order to plan the next HGP outage. Figure 43 is used to calculate the total number of factored starts as shown below.

Operational history:

<table>
<thead>
<tr>
<th></th>
<th>Normal cycles</th>
<th>Peaking starts with normal shutdowns</th>
<th>Peaking starts with trips</th>
<th>Normal starts with trips</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Part load cycles, $N_A$</td>
<td>35</td>
<td>0</td>
<td>1</td>
<td>5</td>
<td>41</td>
</tr>
<tr>
<td>Base load cycles, $N_B$</td>
<td>25</td>
<td>4</td>
<td>2</td>
<td>35</td>
<td>66</td>
</tr>
<tr>
<td>Peak load cycles, $N_P$</td>
<td>40</td>
<td>0</td>
<td>0</td>
<td>10</td>
<td>50</td>
</tr>
</tbody>
</table>

Total Trips
5. 50% load ($a_{T1} = 6.5$), $T_1 = 5 + 1 = 6$
6. Base load ($a_{T2} = 8$), $T_2 = 35 + 2 = 37$
7. Peak load ($a_{T3} = 10$), $T_3 = 10$

Additional Cycles
Peaking-fast starts, F = 7

From the starts-based criteria, the total number of factored starts (FS) and actual starts (AS) is determined from Figure 43.

$$FS = 0.5N_A + N_B + 1.3N_P + P_i F + \sum_{i=1}^{n} (a_{Ti} - 1) T_i$$

$$= 0.5 \cdot 41 + 66 + 1.3 \cdot 50 + 3.5 \cdot 7 + (6.5 - 1) 6 + (8 - 1) 37 + (10 - 1) 10 = 558$$

$$AS = N_A + N_B + N_P = 41 + 66 + 50 = 157$$

Maintenance Factor $= \frac{FS}{AS} = \frac{558}{157} = 3.6$
**B) Examples – Combustion Maintenance Interval Calculations**

*reference Figures 40 and 41*

### DLN 1 Peak Load with Power Augmentation

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>+50°F Tfire Increase Natural Gas Fuel</td>
<td>5.8</td>
<td>34.5 Hours</td>
</tr>
<tr>
<td>3.5% Steam Augmentation 6 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Wet Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 34.5 Hours

**Maintenance Factor** = (34.5/6) = 5.8

Where:
- $K_i = 2.34 \max(1.0, \exp(0.34(3.50 - 1.00)))$ Wet
- $A_{fi} = 1.00$ Natural Gas Fuel
- $A_{pi} = 2.46 \exp(0.01850)$ Peak Load
- $t_i = 6.0$ Hours/Start

### Standard Combustor Base Load on Crude Oil

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Crude Oil</td>
<td>3.6</td>
<td>788.3 Hours</td>
</tr>
<tr>
<td>1.0 Water/Fuel Ratio 220 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 788.3 Hours

**Maintenance Factor** = (788.3/220) = 3.6

Where:
- $K_i = 1.43 \max(1.0, \exp(1.80(1.00 - 0.80)))$ Dry
- $A_{fi} = 2.50$ Crude Oil, Std (Non-DLN)
- $A_{pi} = 1.00$ Base Load
- $t_i = 220.0$ Hours/Start

### DLN 1 Combustor Base Load on Distillate

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Distillate</td>
<td>5.3</td>
<td>493.8 Hours</td>
</tr>
<tr>
<td>1.1 Water/Fuel Ratio 220 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 493.8 Hours

**Maintenance Factor** = (493.8/220) = 4.3

Where:
- $K_i = 1.72 \max(1.0, \exp(0.34(3.50 - 0.50)))$ Wet
- $A_{fi} = 1.00$ Natural Gas Fuel
- $A_{pi} = 1.00$ No Trip at Load
- $A_{si} = 4.0$ Peaking Start
- $N_i = 1.0$ Considering Each Start

### DLN 2.6 Base Load on Distillate

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Distillate</td>
<td>5.3</td>
<td>943.8 Hours</td>
</tr>
<tr>
<td>1.1 Water/Fuel Ratio 220 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 943.8 Hours

**Maintenance Factor** = (943.8/220) = 4.3

Where:
- $K_i = 3.53 \max(1.0, \exp(1.80(1.10 - 0.40)))$ Dry
- $A_{fi} = 1.50$ Distillate Fuel, DLN
- $A_{pi} = 1.00$ Base Load
- $A_{si} = 1.00$ Normal Start
- $N_i = 1.0$ Considering Each Start

### DLN 2.6 Base Load on Natural Gas with Trip @ Load

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Natural Gas</td>
<td>2.6</td>
<td>680 Hours</td>
</tr>
<tr>
<td>No Steam/Water Injection 168 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Trip @ 60% Load</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 680 Hours

**Maintenance Factor** = (680/168) = 4.0

Where:
- $K_i = 1.94 \max(1.0, \exp(0.34(3.50 - 0.40)))$ Wet
- $A_{fi} = 2.00$ Crude Oil, Std (Non-DLN)
- $A_{pi} = 1.00$ No Trip at Load
- $A_{si} = 1.00$ Normal Start
- $N_i = 1.0$ Considering Each Start

### DLN 2.6 Peak Load on Natural Gas with Peaking Start

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>+35°F Tfire Increase Natural Gas</td>
<td>3.1</td>
<td>12.5 Hours</td>
</tr>
<tr>
<td>3.5% Steam Augmentation 4 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 12.5 Hours

**Maintenance Factor** = (12.5/4) = 3.1

Where:
- $K_i = 1.67 \max(1.0, \exp(0.34(3.50 - 2.00)))$ Dry
- $A_{fi} = 1.00$ Natural Gas Fuel
- $A_{pi} = 1.37 \exp(0.0185)$ Peak Load
- $t_i = 4.0$ Hours/Start

### DLN 2.6 Base Load on Natural Gas with Peaking Start

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Distillate</td>
<td>5.9</td>
<td>943.8 Hours</td>
</tr>
<tr>
<td>1.1 Water/Fuel Ratio 220 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 943.8 Hours

**Maintenance Factor** = (943.8/220) = 4.3

Where:
- $K_i = 2.94 \max(1.0, \exp(1.80(1.10 - 0.40)))$ Dry
- $A_{fi} = 1.50$ Distillate Fuel, DLN
- $A_{pi} = 1.00$ Base Load
- $A_{si} = 1.00$ Normal Start
- $N_i = 1.0$ Considering Each Start

### DLN 2.6 Peak Load on Distillate

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Distillate</td>
<td>5.9</td>
<td>680 Hours</td>
</tr>
<tr>
<td>1.1 Water/Fuel Ratio 220 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 680 Hours

**Maintenance Factor** = (680/168) = 4.0

Where:
- $K_i = 2.62 0.5+\exp(0.0125*60)$ for Trip
- $A_{pi} = 1.00$ Base Load
- $A_{si} = 1.00$ Normal Start
- $N_i = 1.0$ Considering Each Start

### DLN 2.6 Peak Load on Natural Gas with Peaking Start

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fuel Type</th>
<th>Mean Maintenance Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Tfire Increase Natural Gas</td>
<td>12.8</td>
<td>12.5 Hours</td>
</tr>
<tr>
<td>+35°F Tfire Increase Natural Gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.5% Steam Augmentation 4 Hours/Start</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal Start</td>
<td>Dry Control Curve</td>
<td></td>
</tr>
<tr>
<td>Normal Shutdown (No Trip)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Factored Hours** = $K_i \times A_{fi} \times A_{pi} \times t_i$ = 12.5 Hours

**Maintenance Factor** = (12.5/4) = 3.1

Where:
- $K_i = 2.34 \max(1.0, \exp(0.34(3.50 - 0.40)))$ Wet
- $A_{pi} = 1.37 \exp(0.0185)$ Peak Load
- $A_{si} = 4.0$ Peaking Start
- $N_i = 1.0$ Considering Each Start

---

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C) Definitions

**Reliability:** Probability of not being forced out of service when the unit is needed — includes forced outage hours (FOH) while in service, while on reserve shutdown and while attempting to start normalized by period hours (PH) — units are %.

\[
\text{Reliability} = (1 - \frac{\text{FOH}}{\text{PH}}) \times 100
\]

**Availability:** Probability of being available, independent of whether the unit is needed — includes all unavailable hours (UH) — normalized by period hours (PH) — units are %:

\[
\text{Availability} = (1 - \frac{\text{UH}}{\text{PH}}) \times 100
\]

**Equivalent Reliability:** Probability of a multi-shaft combined-cycle power plant not being totally forced out of service when the unit is required includes the effect of the gas and steam cycle MW output contribution to plant output — units are %.

\[
\text{Equivalent Reliability} = (1 - \left[ \frac{\text{GT FOH}}{\text{GT PH}} + B \left( \frac{\text{HRSG FOH}}{\text{B PH}} + \frac{\text{ST FOH}}{\text{ST PH}} \right) \right] \times 100)
\]

**Equivalent Availability:** Probability of a multi-shaft combined-cycle power plant being available for power generation — independent of whether the unit is needed — includes all unavailable hours — includes the effect of the gas and steam cycle MW output contribution to plant output; units are %.

\[
\text{Equivalent Availability} = (1 - \left[ \frac{\text{GT UH}}{\text{GT PH}} + B \left( \frac{\text{HRSG UH}}{\text{GT PH}} + \frac{\text{ST UH}}{\text{ST PH}} \right) \right] \times 100)
\]

**Service Factor:** Measure of operational use, usually expressed on an annual basis — units are %.

\[
\text{SF} = \frac{\text{OH}}{\text{PH}} \times 100
\]

**Operating Duty Definition:**

<table>
<thead>
<tr>
<th>Duty</th>
<th>Service Factor</th>
<th>Fired Hours/Start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stand-by</td>
<td>&lt; 1%</td>
<td>1 to 4</td>
</tr>
<tr>
<td>Peaking</td>
<td>1% - 17%</td>
<td>3 to 10</td>
</tr>
<tr>
<td>Cycling</td>
<td>17% - 50%</td>
<td>10 to 50</td>
</tr>
<tr>
<td>Continuous</td>
<td>&gt; 90%</td>
<td>&gt;&gt; 50</td>
</tr>
</tbody>
</table>
D) Estimated Repair and Replacement Intervals
(Natural Gas Only)

Repair/replace intervals reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. Consult previous revisions of GER 3620 or other unit-specific documentation for estimated repair/replacement intervals of previous generation gas turbine models and hardware. Consult your GE service representative for further information.

**MS3002K Parts**

<table>
<thead>
<tr>
<th>Parts</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>4 (CI)</td>
<td>4 (CI)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI(1)</td>
<td>4 (CI)</td>
<td>4 (CI)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>2 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Nozzles</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Shrouds</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Shrouds</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Buckets</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Buckets</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
</tbody>
</table>

Note: Repair/replace intervals reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) Repair interval is every 2 combustion inspection intervals.
(2) Repair interval is every 2 hot gas path inspection intervals with the exception of 1st stage nozzle start-based repair interval where repair interval is one inspection interval.
(3) No repair required. GE approved repair at 24,000 factored hours may extend replace interval to 72000 factored hours.

**Figure D-1. Estimated repair and replacement intervals**

**MS5001PA / MS5002C,D Parts**

<table>
<thead>
<tr>
<th>Parts</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>4 (CI)</td>
<td>3 (CI)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI(1)</td>
<td>4 (CI)</td>
<td>4 (CI)(3)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>2 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Nozzles</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Shrouds</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Shrouds</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Buckets</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Buckets</td>
<td>HGPI(2)</td>
<td>4 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
</tbody>
</table>

Note: Repair/replace cycles reflect current production (6B.03) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) Repair interval is every 2 combustion inspection intervals.
(2) Repair interval is every 2 hot gas path inspection intervals with the exception of 1st stage nozzle start-based repair interval where repair interval is one inspection interval.
(3) No repair required.
(4) No repair required. GE approved repair at 24,000 factored hours may extend replace interval to 72000 factored hours.
(5) 6 replace intervals (starts-based) for DLN and lean head end (LHE) units.

**Figure D-2. Estimated repair and replacement intervals**

**6B.03**

<table>
<thead>
<tr>
<th>Parts</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>4 (CI)</td>
<td>4 (CI) / 5 (CI)(1)</td>
</tr>
<tr>
<td>Caps</td>
<td>CI</td>
<td>4 (CI)</td>
<td>5 (CI)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI</td>
<td>4 (CI)</td>
<td>4 (CI) / 5 (CI)(1)</td>
</tr>
<tr>
<td>Fuel Nozzles</td>
<td>CI(2)</td>
<td>2 (CI)</td>
<td>2 (CI) / 3 (CI)(4)</td>
</tr>
<tr>
<td>Crossfire Tubes</td>
<td>CI</td>
<td>1 (CI)</td>
<td>1 (CI)</td>
</tr>
<tr>
<td>Crossfire Tube Retaining Clips</td>
<td>CI</td>
<td>1 (CI)</td>
<td>1 (CI)</td>
</tr>
<tr>
<td>Flow Divider (Distillate)</td>
<td>CI</td>
<td>3 (CI)</td>
<td>3 (CI)</td>
</tr>
<tr>
<td>Fuel Pump (Distillate)</td>
<td>CI</td>
<td>3 (CI)</td>
<td>3 (CI)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI(2)</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>2 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Buckets</td>
<td>HGPI(2)</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Buckets</td>
<td>HGPI(2)</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
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<tr>
<td>Stage 3 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
</tbody>
</table>

Note: Repair/replace cycles reflect current production (6B.03) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 4(CI) for non-DLN / 5(CI) for DLN
(2) 3 (HGPI) with strip and recoat at first HGPI
(3) 3 (HGPI) for current design only. Consult your GE Energy representative for replace intervals by part number.
(4) 2 (CI) for non-DLN / 3 (CI) for DLN

**Figure D-3. Estimated repair and replacement intervals**
### 7E.03 (1)

<table>
<thead>
<tr>
<th>Component</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>3 (Cl) / 5 (Cl)(1)</td>
<td>5 (Cl)</td>
</tr>
<tr>
<td>Caps</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>5 (Cl)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI</td>
<td>4 (Cl) / 6 (Cl)(1)</td>
<td>6 (Cl)</td>
</tr>
<tr>
<td>Fuel Nozzles</td>
<td>CI</td>
<td>2 (Cl) / 3 (Cl)(1)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Crossfire Tubes</td>
<td>CI</td>
<td>1 (Cl)</td>
<td>1 (Cl)</td>
</tr>
<tr>
<td>Crossfire Tube Retaining Clips</td>
<td>CI</td>
<td>1 (Cl)</td>
<td>1 (Cl)</td>
</tr>
<tr>
<td>Flow Divider (Distillate)</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Fuel Pump (Distillate)</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Shrouds</td>
<td>HGPI</td>
<td>2 (HGPI)</td>
<td>2 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)(1,2)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)(1,2)</td>
<td>4 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
</tbody>
</table>

Note: Repair/replace intervals reflect current production (7121(EA) or 7E.03) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

Cl = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 3 (CI) for DLN / 5 (CI) for non-DLN
(2) Strip and Recoat is required at first HGPI to achieve 3 HGPI replace interval.
(3) Also applicable to 7121(EA) models.

**Figure D-4. Estimated repair and replacement intervals**

### 9E.03 (6)

<table>
<thead>
<tr>
<th>Component</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>3 (Cl) / 5 (Cl)(1)</td>
<td>5 (Cl)</td>
</tr>
<tr>
<td>Caps</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>5 (Cl)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI</td>
<td>4 (Cl) / 6 (Cl)(1)</td>
<td>6 (Cl)</td>
</tr>
<tr>
<td>Fuel Nozzles</td>
<td>CI</td>
<td>2 (Cl) / 3 (Cl)(1)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Crossfire Tubes</td>
<td>CI</td>
<td>1 (Cl)</td>
<td>1 (Cl)</td>
</tr>
<tr>
<td>Crossfire Tube Retaining Clips</td>
<td>CI</td>
<td>1 (Cl)</td>
<td>1 (Cl)</td>
</tr>
<tr>
<td>Flow Divider (Distillate)</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Fuel Pump (Distillate)</td>
<td>CI</td>
<td>3 (Cl)</td>
<td>3 (Cl)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 2 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Nozzles</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
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<tr>
<td>Stage 2 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 3 Shrouds</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>3 (HGPI)</td>
</tr>
<tr>
<td>Stage 1 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)(1,2)</td>
<td>3 (HGPI)</td>
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<td>HGPI</td>
<td>3 (HGPI)(1,2)</td>
<td>4 (HGPI)</td>
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<tr>
<td>Stage 3 Buckets</td>
<td>HGPI</td>
<td>3 (HGPI)</td>
<td>4 (HGPI)</td>
</tr>
</tbody>
</table>

Note: Repair/replace intervals reflect current production (9171(E)) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

Cl = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 3 (CI) for DLN / 5 (CI) for non-DLN
(2) Strip and Recoat is required at first HGPI to achieve 3 HGPI replace interval.
(3) Uprated 7E machines (2055 Tfire) require HIP rejuvenation at first HGPI to achieve 3 HGPI replace interval.
(4) 3 (HGPI) interval requires meeting tip shroud engagement criteria at prior HGP repair intervals.
(5) Also applicable to non-AGP units only
(6) Applicable to non-AGP units only

**Figure D-5. Estimated repair and replacement intervals**
### 6F.03

<table>
<thead>
<tr>
<th>Component</th>
<th>Repair Interval</th>
<th>Replace Interval (Hours)</th>
<th>Replace Interval (Starts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Liners</td>
<td>CI</td>
<td>2 (CI)</td>
<td>2 (CI)</td>
</tr>
<tr>
<td>Caps</td>
<td>CI</td>
<td>2 (CI)</td>
<td>2 (CI)</td>
</tr>
<tr>
<td>Transition Pieces</td>
<td>CI</td>
<td>2 (CI)</td>
<td>2 (CI)</td>
</tr>
<tr>
<td>Fuel Nozzles</td>
<td>CI</td>
<td>2 (CI)</td>
<td>2 (CI)</td>
</tr>
<tr>
<td>Crossfire Tubes</td>
<td>CI</td>
<td>1 (CI)</td>
<td>1 (CI)</td>
</tr>
<tr>
<td>Retaining Clips</td>
<td>CI</td>
<td>1 (CI)</td>
<td>1 (CI)</td>
</tr>
<tr>
<td>End Covers</td>
<td>CI</td>
<td>4 (CI)</td>
<td>2 (CI)</td>
</tr>
<tr>
<td>Stage 1 Nozzles</td>
<td>HGPI</td>
<td>2 (HGPI)</td>
<td>2 (HGPI)</td>
</tr>
<tr>
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<td>2 (HGPI)</td>
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<tr>
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<td>3 (HGPI)</td>
</tr>
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<td>Stage 1 Shrouds</td>
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<td>2 (HGPI)</td>
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<tr>
<td>Stage 2 Shrouds</td>
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<tr>
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Note: Repair/replace intervals reflect current production 6F.03 DLN 2.6i hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

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### 7F.04

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Note: Repair/replace intervals reflect current production 7F.04 DLN 2.6i hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

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### 7F.01

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Note: Repair/replace cycles reflect current production 7F.01 DLN 2.6 extended interval hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

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### 7FB.01

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Note: Repair/replace cycles reflect current production 72SB.01 DLN 2.6 extended interval hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

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### Figure D-7

Estimated repair and replacement intervals
### 9F.03

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**Note:** Repair/replace intervals reflect current production (9F.03 DLN 2.6+) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

- CI = Combustion Inspection Interval
- HGPI = Hot Gas Path Inspection Interval
- (1) Blank and liquid fuel cartridges to be replaced at each CI
- (2) 2 (HGPI) for current design with GE approved repair at first HGPI. 3 (HGPI) is possible for redesigned bucket with platform undercut and cooling modifications.
- (3) Recoating at 1st HGPI may be required to achieve 3 HGPI replacement life.
- (4) GE approved repair procedure at 1 HGPI is required to meet 2 (HGPI) replacement life.
- (5) GE approved repair procedure is required to meet 3 (HGPI) replacement life.

**Figure D-10. Estimated repair and replacement intervals**

### 9F.05

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**Note:** Repair/replace intervals reflect current production (9F.05) hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 39.

- CI = Combustion Inspection Interval
- HGPI = Hot Gas Path Inspection Interval
- (1) Blank and liquid fuel cartridges to be replaced at each CI

**Figure D-11. Estimated repair and replacement intervals**
E) Borescope Inspection Ports

**Figure E-1.** Borescope inspection access locations for 6F machines

**Figure E-2.** Borescope inspection access locations for 7F and 9F machines
## F) Turning Gear/Ratchet Running Guidelines

<table>
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<tr>
<th>Scenario</th>
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<td><strong>Following Shutdown:</strong></td>
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<tr>
<td>Case B – Immediate rotor stop necessary. (Stop &gt;20 minutes) Suspected rotating hardware damage or unit malfunction</td>
<td>None. Classified as bowed.</td>
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<tr>
<td><strong>Before Startup:</strong></td>
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<tr>
<td>Case C – Hot rotor, &lt;20 minutes after rotor stop</td>
<td>0-1 hour [3]</td>
</tr>
<tr>
<td>Case D – Warm rotor, &gt;20 minutes &amp; &lt;6 hours after rotor stop</td>
<td>4 hours</td>
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<tr>
<td>Case E.1 – Cold rotor, unbowed, off TG &lt;48 hours</td>
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</tr>
<tr>
<td>Case E.2 – Cold rotor, unbowed, off TG &gt;48 hours</td>
<td>6 hours</td>
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<tr>
<td>Case F – Cold rotor, bowed</td>
<td>8 hours [4]</td>
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<tr>
<td><strong>During Extended Outage:</strong></td>
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<tr>
<td>Case G – When idle</td>
<td>1 hour daily</td>
</tr>
<tr>
<td>Case H – Alternative</td>
<td>No TG, 1 hour/week at full speed (no load) [5]</td>
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[1] Time depends on frame size and ambient environment.
[2] Cooldown cycle may be accelerated using starting device for forced cooldown. Turning gear, however, is recommended method.
[3] 1 hour on turning gear is recommended following a trip, before restarting. For normal shutdowns, use discretion.
[4] Follow bowed rotor startup procedure, which may be found in the unit O&M Manual.

*Figure F-1. Turning gear guidelines*
### G) B/E- and F-class Gas Turbine Naming

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**Figure G-1. F-class gas turbine naming**

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Revision History

9/89 Original
8/91 Rev A
9/93 Rev B
3/95 Rev C
  • Nozzle Clearances section removed
  • Steam/Water Injection section added
  • Cyclic Effects section added
5/96 Rev D
  • Estimated Repair and Replacement Cycles added for F/FA
11/96 Rev E
11/98 Rev F
  • Rotor Parts section added
  • Estimated Repair and Replace Cycles added for FA+E
  • Starts and hours-based rotor maintenance interval equations added
9/00 Rev G
11/02 Rev H
  • Estimated Repair and Replace Cycles updated and moved to Appendix D
  • Combustion Parts section added
  • Inlet Fogging section added
1/03 Rev J
  • Off Frequency Operation section added
10/04 Rev K
  • GE design intent and predication upon proper components and use added
  • Added recommendation for coalescing filters installation upstream of gas heaters
  • Added recommendations for shutdown on gas fuel, dual fuel transfers, and FSDS maintenance
  • Trip from peak load maintenance factor added
  • Lube Oil Cleanliness section added
  • Inlet Fogging section updated to Moisture Intake
  • Best practices for turning gear operation added
  • Rapid Cool-down section added
  • Procedural clarifications for HGP inspection added
  • Added inspections for galling/fretting in turbine dovetails to major inspection scope
  • HGP factored starts calculation updated for application of trip factors
  • Turning gear maintenance factor removed for F-class hours-based rotor life
  • Removed reference to turning gear effects on cyclic customers’ rotor lives
  • HGP factored starts example added
  • F-class borescope inspection access locations added
  • Various HGP parts replacement cycles updated and additional 68 table added
  • Revision History added
11/09 Rev L
  • Updated text throughout
  • Casing section added
  • Exhaust Diffuser section added
  • Added new Fig. 26: F-class axial diffuser
  • Added new Fig. 27: E-class radial diffuser
  • Revised Fig. 3, 5, 7, 8, 11, 19, 20, 23, 35, 37, 38, 40, 41, 42, 43, 44, E-1, and E-2
  • Appendix D – updated repair and replacement cycles
  • Added PG6111 (FA) Estimated repair and replacement cycles
  • Added PG9371 (FB) Estimated repair and replacement cycles
10/10 Correction L.1
  • Corrected Fig. D-4, D-5, and D-11 combustion hardware repair and replacement cycles
2/15 Rev M
  • Updated text throughout
  • Added Fig. 14, 15, 25
  • Revised Fig. 8, 10, 12, 22, 29, 34, 35, 37, 39, 41, 42, 43, 44, 45
  • Updated Appendix A
  • Updated Appendix D
  • Added 7F.04 Estimated repair and replacement intervals
  • Added Appendix G