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Summary of the Research and Development Effort on Open-Cycle Coal-Fired Gas Turbines

M. E. Lackey

MASTER

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M. E. Lackey

ABSTRACT

The extensive experience gained with gas turbines operating not only with coal as fuel but also with dusty inlet air and with dirty fuels (such as heavy oils and blast furnace gas) as well as petroleum catalytic cracking units has been reviewed. All this experience indicates that the particulate content of the hot gases fed to the turbine must be kept to less than $\sim$1 ppm to keep turbine bucket erosion to an acceptable level for turbine inlet temperatures of 1500°F (815°C) or more. Dropping the turbine inlet temperature below 1110°F (600°C) makes it possible to obtain turbine bucket lives of around three years with $\sim$100 ppm of particulates if a number of compromises are made in the turbine design.

A buildup of deposits in the turbine is a serious problem if sulfates or chlorides are present in the gas stream and the turbine inlet temperature is above $\sim$1110°F (600°C). At this temperature level, these materials become soft and sticky and form films on the blades that act like "flypaper" and accumulate deposits of the silicates and oxides present in the ash of a coal-fired combustor. Problems with deposits become particularly severe at temperatures above 2000°F (1093°C); difficulties have been experienced with inlet air dust concentrations less than 0.1 ppm.

Extensive experience with many types of cyclone separators shows that they can be used to reduce the particulate content to as low as $\sim$100 ppm under the best conditions. Granular bed filters have yielded similar performance. Electrostatic precipitators are not effective above $\sim$1110°F (600°C) because the dust deposits on insulators become conducting and short out the grids. The only effective way found to reduce the particulate content of blast furnace gas and gas from coal gasification units to the $\sim$1 ppm required for a high-temperature gas turbine is to cool the gas and pass it through a two-stage water scrubber or equivalent before burning it.

In brief, it appears doubtful that any of the hot-gas clean-up concepts being investigated will yield the low particulate contents required for the satisfactory, economical operation of 1500 to 1600°F (816 to 870°C) long-lived gas tubines. However, the technology is available for satisfactory service if the turbine inlet temperature is kept below 1110°F (600°C).

INTRODUCTION

This is one of a series of topical reports summarizing the research and development (R&D) effort on various phases of advanced power conversion systems.[1] This report is especially concerned with the possibility of employing an open-cycle coal-fired gas turbine with a pressurized fluidized-bed combustor.

The first portion of this report presents a background history of the research and development effort on coal-fired gas turbines up to 1976. The next section discusses recommended development programs and priorities. This is followed by a presentation of the principal problem areas, performance parameters, and figures of merit characteristic of the system to provide perspective on the various problems. The principal parameters and figures of merit include such quantities as the operating life of experimental units, turbine inlet temperature, particulate content of the turbine inlet gas, etc. Subsequent sections summarize the current status of development and experience in system research and development work.

This work was carried out at the request of the Office of Program Planning and Analysis, Fossil Energy Program, Department of Energy with funds provided for a general appraisal of advanced fossil energy systems.

BACKGROUND

Work on coal-burning gas turbines began in 1944 but was largely phased out by 1960 because of serious difficulties with turbine bucket erosion and deposits. Interest in the open-cycle coal-burning gas turbine has been renewed in recent years, primarily because it offers the possibility of pressurizing a fluidized-bed coal combustor for a combined cycle system.[2-4]

System Decription

The system commonly envisioned currently is a combined gas turbine—steam cycle in which the bulk of the heat of combustion released in a fluidized-bed coal combustor is transferred to a steam generator tube matrix in the fluidized bed while the balance of the heat in the hot combustion products flows to a gas turbine. The gas turbine drives the compressor (with a pressure ratio of $\sim$10:1) and the generator. A flowsheet for a typical system is shown in Fig. 1. Note the particle removal equipment between the fluidized bed and the gas turbine.

Advantages and Disadvantages

The system shown in Fig. 1 has the advantage that it would give a somewhat higher thermal efficiency than a steam cycle alone because of the extra power obtained from the gas turbine topping cycle[4] and because absorbing the sulfur from the coal in the fluidized bed should eliminate the losses associated with stack gas scrubbers.[2] A further advantage is that pressurization of the furnace greatly reduces its size and capital cost and the number of coal feed points, which means a reduction in the complexity and cost of the coal feed system. Pressurizing the bed also permits an increase in the bed depth; this increases the transit time through the bed for small particles of coal and sorbent, thus increasing the efficiency of combustion and sorbent utilization. These points are presented in more detail in a companion report.[2]

The principal disadvantages of the system are the problems of particulate removal from the hot gases flowing to the gas turbine and the gas turbine bucket erosion and deposits caused by the small amounts of fine dust that eludes the particle separation equipment and reaches the turbine. This set of problems is the principal subject of this report.

Operating Experience

A brief survey of gas turbine operating experience pertinent to the development of coal-fired gas turbines is presented in this section to give perspective on the problems involved. Much more detailed information on salient points from this experience is presented in later sections.

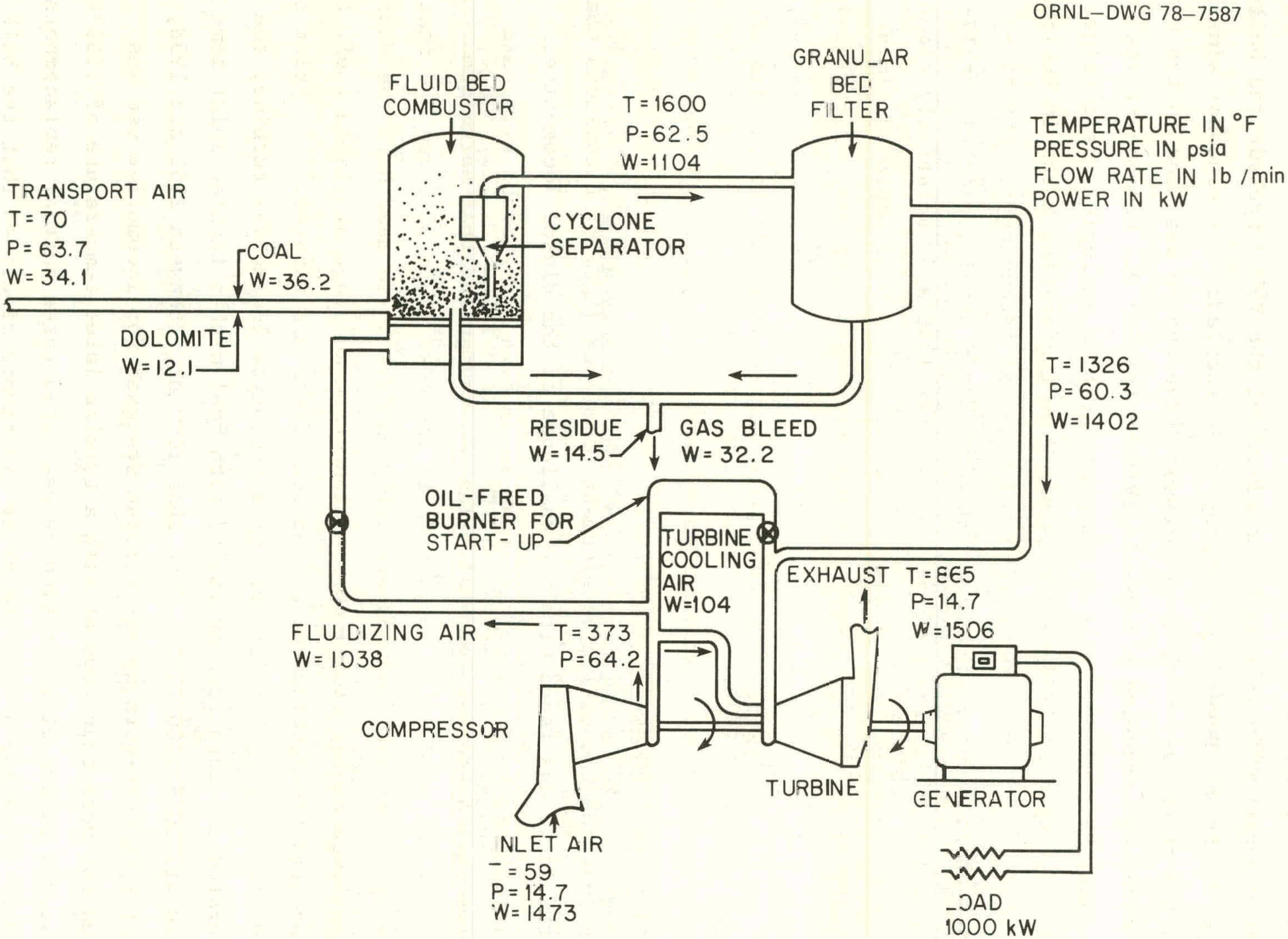

Fig. 1. Flowsheet for a coal-fired open-cycle gas turbine.

Early work on gas turbines

The first practical application of a gas turbine drive for an axial compressor occurred in 1932 with the advent of the Velox pressurized boiler developed by Brown, Boveri and Company of Switzerland.[5] A somewhat similar application of the gas turbine compressor drive system was used in the Houdry catalytic cracking process in 1936 by the Sun Oil Company at its Marcus Hook, Pa., plant.[6] The first power station employing gas turbines only was developed in 1939 by the Escher Wyss Engineering Works in Zurich, Switzerland.[7] Utilizing the design and material technology of the aircraft jet engine developed during and after World War II, electric utilities began installing gas turbines in the late 1940's.[3] Relatively clean fuels, such as natural gas or distillate oils, have been employed almost exclusively as the energy supply for industrial gas turbines. Dirty fuels containing mineral constituents in sufficient quantities to have harmful effects on the turbine blading have proved to be difficult to utilize effectively.

Locomotive Development Committee

In 1944 the Locomotive Development Committee (LDC) of Bituminous Coal Research, Inc., was faced with the challenge of the diesel locomotive, which threatened to displace the steam locomotive and thereby eliminate the large railway market for coal. The LDC recognized that petroleum and natural gas production would peak in the next 20 to 30 years and that the energy market would depend primarily on coal.[8] To meet both the short-term challenge of the diesel and the long-term shortage of liquid fuel, the LDC pioneered the development of the coal-fired gas turbine.[8-28] Prior to 1951, while awaiting the delivery of a prototype locomotive turbine, the LDC operated a Houdry turbine fueled with coal with a turbine inlet temperature of 750°F (400°C) for more than 1000 hr. Between 1951 and 1958, the prototype coal-burning gas turbine designed for locomotive use was operated for more than 4000 hr with a turbine inlet temperature of 1250°F (675°C), and severe blade erosion necessitated three partial replacements of blades. A review of the operating experience discloses that the bulk of the erosion and deposits occurred in the upper stages where the gas temperature was above 1050°F (565°C). The importance of gas temperature is indicated by the fact that the LDC operated the turbine with an inlet temperature of 1050°F (565°C) for approximately 500 hr with negligible erosion and deposits. Blade erosion with a turbine inlet temperature of 1250°F (675°C) remained a major obstacle to the coal-burning turbine development when the LDC withdrew financial support of the program in 1959, at which time the cumulative cost of the program in then-year dollars was about $5,500,000.[9]

Concurrently, a similar effort in England and another modest effort in Canada were carried out with no greater success.[29]

Union Pacific Railroad

The Union Pacific Railroad, wishing to utilize its large coal reserves, commissioned Alco and General Electric to modify an oil-fired gas turbine engine so that it could be fired with coal and operated in a locomotive to carry the LDC program to its logical conclusion.[30] Experience with this unit in rail service was disappointing; in the initial operation, the power fell off badly in 200 hr. Improvements were made in the cyclone separation system used to remove the dust, and a second test was run in which operation up to 400 hr was obtained before the loss in power output became so severe that the test was terminated.

Bureau of Mines

After the termination of the LDC effort, the United States Bureau of Mines continued the investigation under a cooperative agreement with Bituminous Coal Research, Inc.[31] The turbine and auxiliary equipment was transferred to the Bureau's Coal Research Center at Morgantown, W. Va. The Bureau arranged with General Electric for the design and construction of new blades for the turbine[32] and by 1964 had completed testing of the turbine at an inlet temperature of 1250°F (675°C) with a total of approximately 2000 hr of running. The new blade design gave improved resistance to erosion as compared to those tested in the LDC program. The estimated life of the rotor blades was 20,000 to 30,000 hr; the stator blades had an estimated life of only 5000 to 7500 hr.[31]

Australian program

Concurrently with the coal-fired gas turbine programs in the United States, an investigation in Australia of the problems of firing a gas turbine with coal was initiated in 1948 by the Aeronautical Research Laboratories (ARL) at a total cost in then-year dollars of about $1,500,000.[33-36] In the earlier stages of the ARL effort, the major thrust of the program was directed toward the problems of coal pulverizing and handling, high-intensity combustion and combustor development, and ash fouling and erosion. Considerable progress had been made on the problems of handling and burning coal for use as fuel in gas turbines when 4 tons of Victorian brown coal were burned satisfactorily in the LDC experimental Houdry gas turbine system in 1951.[34] Rig experiments on a coal-fired aircraft supercharger gave little evidence of erosion but did indicate an ash deposition problem. Inasmuch as the supercharger blading was aerodynamically crude and it was believed that the rate of ash deposition would depend upon the blade design, a nonrecuperative gas turbine unit consisting of a 13-stage compressor, a 2-stage compressor turbine, and a 2-stage power turbine was obtained and commissioned in 1958. The system was operated for approximately 400 hr at an inlet temperature of 1200°F (650°C) on various grades of Australian coal between 1959 and 1963. Ash deposition and erosion remained a problem throughout this phase of the test program.

In 1963, the 2-stage compressor drive turbine was replaced with a 3-stage turbine designed to operate with a gas velocity of 800 fps (244 m/sec) compared to the 1200 fps (366 m/sec) in the 2-stage machine. The redesigned machine was commissioned in 1969, and testing with coal was completed in 1970 with a total running time of approximately 125 hr with a turbine inlet temperature of about 1200°F (650°C). The blades remained clean throughout the test except for a film of ash on the first-row stators. The estimated life made on the basis of only 125 hr of testing was 30,000 to 50,000 hr for the rotor blades and 25,000 to 50,000 hr for the stator blades.[33]

Catalytic-cracking units

The use of gas turbines to provide combustion air to burn out the coke that accumulates on the Al_2O_3-based pellets used as the catalyst in petroleum refinery catalytic-cracking units[6] was confined to operation with turbine inlet temperatures largely below 800°F (425°C) until the 1950's and hence little or no net useful power was obtained.

In 1950, the Elliott Company made the first sophisticated effort to recover power from a petroleum catalytic-cracking unit by introducing a higher inlet temperature turboexpander into the flue gas stream directly downstream of the regenerator.[37] Because there was nothing ahead of the expander to reduce the particulate level, the performance deteriorated rapidly and by the end of 750 hr the turbine was virtually useless.

A review of the Elliott Co. experience and the LDC work indicated that not only should the particulate content of the gas be reduced but every effort should be made to keep it uniformly dispersed in the gas stream to avoid severe local erosion, particularly at the roots and tips of the blades. This led to the decision to use a single-stage turbine with a long straight inlet passage. This, together with extensive development work on particle separators, led to a test with three stages of cyclone separators conducted in 1957 by the Shell Development Company.[37,38] After 4000 hr of continuous operation, inspection of the blading revealed no serious erosion. Commercial installation of these units began in 1963 and was extended to eight refineries by 1973. The total power recovery capacity of the eight installations is approximately 62 MW with an estimated turbine life of 25,000 to 40,000 hr.[37-39] These units operate with a turbine inlet temperature of about 1100°F (594°C). Turbine inlet temperatures as high as 1150°F (620°C) have been used with Inconel X blades coated with tungsten carbide to give a turbine life of two to three years.[39] Extensive experience with these units indicates that erosion can be kept to a tolerable level with two stages of cyclone separators followed by a third-stage multicyclone (which gives a particulate loading of ∿100 ppm*) for operation at turbine inlet temperatures up

*1 ppm = 1.22 mg/m^3 = 0.0345 mg/ft^3 = 0.00054 grain/ft^3.

to $\sim$1150°F (620°C) if a single-stage turbine is used with excellent inlet conditions.[37-44]

Gas turbines operated on low-Btu gas from blast furnaces and gasifiers

A substantial amount of experience has been obtained in the United States and in Europe with gas turbines operating on low-Btu gas from blast furnaces with turbine inlet temperatures around 1350°F (730°C). After extensive testing of hot-gas cleanup equipment, it has been found best to cool this gas and clean it with a two-stage wet scrubber and/or an electrostatic filter prior to burning it in a combustion chamber ahead of the turbine.[45-50] The particulate content in the gas fed to the turbine is commonly kept below 1 ppm by weight. The same approach and requirement have been imposed on the low-Btu gas supplied from Lurgi gasifiers to the gas turbine of the combined-cycle plant at Lünen, Germany.[51]

A typical example of turbine performance with blast furnace gas is a Sulzer gas turbine employed for supercharging a blast furnace at the Hainaut-Sambre works in Belgium. The turbine has produced 7500 kW(e) with a gas inlet temperature of 1310°F (710°C) since 1955. Erosion of the first-stage turbine buckets progressed to the point where some loss in efficiency occurred after 81,000 hr of operation, at which point these blades were replaced. However, the second- and third-stage blades were still in satisfactory condition after 136,000 hr of operating time.[52]

Oil-burning gas turbines

In the United States, commercial specifications for conventional gas turbines limit the particulate content to no more than 1 ppm by weight and the maximum particle size to 10 μm for gas turbine applications, whether for operation on fuel oil or in dusty environments.[53,54] Severe erosion has occurred in both industrial and utility gas turbines as a consequence of dust in the air entering the compressor; hence air filters are normally required.

Cascade tests with fluidized beds at BCURA

The British Coal Utilization Research Association, Ltd. (BCURA), has devoted practically all its effort since 1971 to research and development work on fluidized-bed combustion and gasification. Design studies indicate that there are major advantages to pressurizing the fluidized-bed combustor with a gas turbine.[2,55] There are indications that the ash from a fluidized bed will be less erosive than that from a pulverized coal burner. Experiments at BCURA with a pressurized fluidized-bed coal combustion system have included a number of runs in which the hot gases leaving the bed at about 6 atm have been directed through a cascade of blades representing a turbine nozzle.[55,56] Tests run with inlet gas temperatures of around 1550°F (843°C) showed relatively little in the way of deposits or erosion for a period of 500 hr of operation. For comparison, a similar experiment conducted by the LDC as a part of the 1421-hr turbine test also gave negligible deposits and erosion at 1250°F (677°C). The most recent BCURA test of record was carried out with an inlet gas temperature of 1600 to 1700°F (870–925°C). This yielded appreciable deposits and little erosion, but photomicrographs indicate appreciable corrosion. In general, the corrosion was comparable to that found with oil-fired gas turbines operating at the same temperature, with comparable amounts of sulfur in the fuel, but the deposits were substantially greater.

The results of the BCURA tests with blade cascades are encouraging but not definitive. The particulate content of the gas entering the test section ran about 250 ppm by weight with 90% of the particles smaller than 10 μm.

Combustion Power Company

The Combustion Power Company began work on coupling a gas turbine to a fluidized-bed burning solid wastes in 1969 and subsequently shifted in 1974 to operation with coal.[57-60] By 1976, the unit had accumulated approximately 600 hr of turbine operation at an inlet temperature of approximately 1400°F (760°C). The hot-gas cleanup system for these tests was operated at temperatures of 1500 to 1600°F (815–870°C) with cooling downstream of the last stage of particle separation so as to not exceed the design turbine inlet temperature of 1450°F (788°C). The hot-gas cleanup devices used in this series of tests consisted of tangential entry cyclones and 6- and 3-in. (15.2- and 7.6-cm) multicyclones. In each test the multicyclones became ineffective after a few hours of operation owing to ash plugging which resulted in heavy fouling and erosion in the turbine. Subsequent work has been directed toward the use of granular bed filters.[60]

Turbosupercharged fluidized-bed furnaces for steam generators

The extensive experience outlined above clearly indicates that coal-burning gas turbines have always given serious trouble with erosion and deposits when operated with turbine inlet temperatures above ~1200°F (650°C) but have been relatively free of these difficulties if the inlet temperature is below ~1050°F (565°C). This experience is consistent with basic considerations of metal erosion rates as a function of temperature and the softening point of the lower-melting-point constituents of coal ash.[61,62] In view of this, it has been proposed at ORNL that a low-temperature gas turbine be employed to supercharge a fluidized-bed furnace in the same manner as Bucchi turbochargers are employed to supercharge diesel engines.[62] In fact, production units for large diesels might be used. There would be no attempt to obtain any net electrical power; the objective would be simply to raise the furnace pressure and thus improve combustion conditions and reduce capital costs.

Accumulated Costs and Running Time

The expenditures in the U.S. and Australia for the development of the open-cycle coal-fired gas turbine for the 1945–75 period are summarized in Table 1, and the operating hours accumulated at various turbine inlet temperatures are given in Table 2. The operating experience with coal-fired gas turbines under the Locomotive Development Committee is summarized in Table A.5 (see appendix) to show the effects of turbine inlet temperature and hot-gas particulate content on turbine bucket erosion and deposits. The cumulative costs and turbine operating time are shown in Fig. 2 for the period 1945–75. Inspection of Fig. 2 shows a

Table 1. Expenditures in the U.S. and Australia for open-cycle coal-fired gas turbine development during the period 1945–1975 ($\$ \times 10^3$)[a]

	1945–50	1951–55	1956–60	1961–65	1966–70	1971–75	1945–75
Locomotive Development Committee	500	3000	2000				5,500
U.S. Bureau of Mines				4500	500		5,000
Union Pacific Railroad			500[b]				500
Aeronautical Research Laboratories	50[b]	75[b]	236	445	780	39	1,625
Petroleum Refineries			1000[b]				1,000
Combustion Power Company[c]					500	3000	3,500
Total	550	3075	3736	4945	1780	3039	17,125

[a] Expenditures are given in then-year dollars.

[b] Estimated.

[c] The Combustion Power Company turbine expenditures were taken as 25% of their yearly costs.

Table 2. Open-cycle coal-fired gas turbine operating hours during the period 1945–1975

	Turbine inlet temperature [°F (°C)]				
	<1000 (538)	1000–1100 (538–593)	1101–1250 (593–677)	1251–1450 (677–788)	>1450 (788)
Locomotive Development Committe	1250	478	3281		
U.S. Bureau of Mines			2963		
Union Pacific Railroad			∿500		
Aeronautical Research Laboratories			428		
Petroleum Refineries					
Combustion Power Company				591	
Total	1250	478	7172	591	0

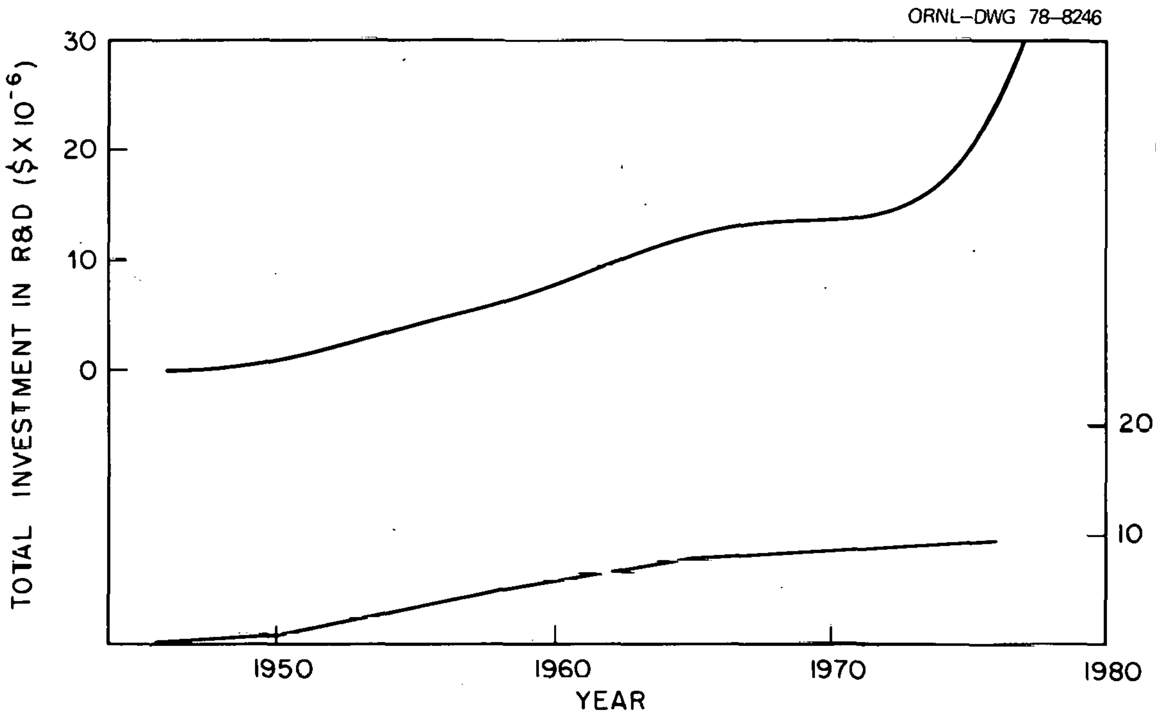

Fig. 2. Research costs and operating time for open-cycle coal-fired gas turbines during the period 1945–1975.

total expenditure in then-year dollars of approximately $17,000,000 and a total operating time of approximately 9500 hr during the 30-year period.

RECOMMENDED DEVELOPMENT PROGRAM

The two key developmental problems of the open-cycle coal-fired gas turbine are turbine bucket erosion and deposits, both of which are heavily dependent on the temperature of the combustion gases entering the turbine. The hardness of turbine bucket alloys decreases rapidly with an increase in turbine inlet temperature above about 1110°F (600°C), thus making turbine bucket erosion a serious problem for particulate contents of over 100 ppm at 1110°F (600°C) or over 1 ppm at a turbine inlet temperature of ~1560°F (850°C). Further, a small percentage of the ash consists of low-melting glasses (e.g., sulfates) that are sticky at temperatures down to about 1110°F (600°C) and tend to adhere to surfaces on which they impact. The resulting film acts like "flypaper" and accumulates hard ceramic deposits of higher-melting-point ash particles. Extensive experience with hot-gas cleanup equipment indicates that it is difficult indeed to reduce the particulate content to 10 ppm and that excessive deposits are formed even at this level if the turbine inlet temperature exceeds about 1100°F (594°C). In fact, commercial gas turbine specifications normally limit the ash content of the fuel oil and the particulate content of the inlet air to the equivalent of no more than ∿2 ppm in order to limit deposits to an acceptable level.

Efforts to develop suitable hot-gas particle removal equipment are under way and should be continued. However, since past experience is not encouraging, commitments to build gas turbine systems (other than small experimental units) should be deferred pending the demonstration on a small scale of an economical, promising, long-lived, hot-gas cleanup system operated with a fluidized bed that burns a coal having a representative ash composition.

Extensive experience with coal-fired gas turbines, gas turbines operating on blast furnace gas, conventional gas turbines operating with dusty inlet air, and gas turbines used in conjunction with catalytic-cracking units in petroleum refineries indicates that it is doubtful that the particulate content of the products of combustion from the fluidized-bed coal combustion system can be reduced at a reasonable cost to a level that will permit gas turbine operation with inlet temperatures much above 1110°F (600°C). However, the same body of experimental experience indicates that satisfactory turbine life could be obtained with the products of combustion from a fluidized-bed coal combustion system for turbine inlet temperatures below 1050°F (565°C); this can be done with the state-of-the-art particulate removal systems used in catalytic-cracking units, that is, two stages of cyclone separators followed by a single-stage multicyclone separator to supply a single-stage turbine with gas having a particulate content in the range of less than 100 ppm. Although the low turbine inlet temperature would give only enough power to drive the compressor and hence provide only a small improvement in thermal efficiency, pressurizing the furnace would reduce its capital cost and the cost and complexity of the coal feed system relative to atmospheric-pressure fluidized beds. It would also increase the efficiency of both combustion and sorbent utilization and give improved system control characteristics.

To demonstrate the use of a turbine-compressor unit supercharging a pressurized coal-fired fluidized-bed combustor, attention should be directed toward such a system with the furnace operating at approximately 4 atm with flue gas cooling in the steam generator sufficient to give a turbine inlet temperature in the 1000 to 1050°F (546–565°C) range. Operating under these conditions, the turbine erosion, corrosion, and deposit problems should become secondary considerations. This would give a test bed for the solution of the other problems associated with pressurized fluidized-bed combustion. Provision for incorporating advanced particulate separation systems in the overall design of the experiment should be made to allow higher turbine inlet temperatures to be employed if they become available after other components of the overall design have been adequately developed.

PRINCIPAL PROBLEMS AND PARAMETERS

The principal problems associated with the open-cycle coal-fired gas turbine are erosion and corrosion of the turbine blades, the deposition of solids on the blades in sufficient quantity to obstruct the gas flow passages, the capital costs of the turbine and associated equipment, the operating life, and the reliability and maintenance problems. These in turn depend heavily on the detailed design of the turbine, the particulate removal equipment, the coal combustion system, and the overall equipment layout. Note that full-scale experience in both experimental and commercial installations is available for an assessment of the coal-fired gas turbine for use in advanced power generation systems.[6–60] Thus, there is no question that an advanced power generation system employing an open-cycle coal-fired gas turbine can be built and operated for short periods. The key questions are concerned with the detailed costs for a full-scale commercial system including the effects of reliability and maintainability, particularly the effectiveness of hot-gas cleanup equipment and the consequent limitations on the useful life of the turbine blading imposed by erosion and deposits.

Erosion

Some excellent analytical and experimental studies of the basic mechanism of erosion of turbine buckets by small particles have been carried out in recent years.[63-75] These studies indicate that the erosion rate depends on the type of particle, size of particle, the angle of incidence relative to the surface on which it impinges, the velocity of impingement, the particulate content of the gas stream, and the physical properties of the surface subject to erosion. The effects of these are discussed in the following sections.

Effects of particle character and angle of incidence

Extensive tests have been carried out with extremely different particle types, ranging from angular grains of silica sand to water droplets. Both analyses and experiments indicate that the damage mechanism is fundamentally different for these particle types. The maximum damage caused by a particle of sand occurs at an incident angle of approximately 20 to 35 deg relative to the surface, and the resulting damage appears to be primarily a scoring of the surface.[63-71] With liquid droplets, on the other hand, the maximum damage occurs when the angle of incidence of the particle is 90 deg, and the form of the damage appears to be mainly plastic indentation of the blade material and subsequent failure by low-cycle fatigue if the material is soft and ductile. In hard materials, the damage appears to be similar to that in the races of ball bearings; that is, high shear stresses are induced below the surface by the impact, and fatigue causes material to spall off producing pits.[72-74]

Further, liquid droplet erosion in wet vapor turbines also differs in a fundamental way from that in gas turbines in that the micron-size droplets of moisture that form in the wet vapor do not cause erosion directly. Rather, they impinge on stator vanes, the resulting liquid film is carried to the trailing edge, and large droplets are then shed from the trailing edges of stator blades.[73,75] It is these large droplets that are responsible for erosion in the rotor. This is partly because a liquid film tends to form on the surface of the rotor blade and act as a cushion to protect the blade from very small droplets whose diameter is not many times greater than the thickness of the liquid film. As a consequence, the measures taken by both the designer and the operator to cope with turbine bucket erosion in wet vapor turbines are quite different from those in gas turbines that ingest solid particles.

Hoy[55] suggested that the erosion of blades in a gas turbine coupled to a fluidized-bed coal combustion chamber might be much less serious than if a pulverized coal burner were employed. The ash formed in a fluidized bed tends to be soft and friable because it is formed well below the fusion point, whereas the ash particles in a pulverized coal burner are vitreous cinders that are formed well above the fusion point of the ash and subsequently chilled by the secondary air. Evidence supporting this contention can be seen by examining the results of the first two tests of the Ruston and Hornsby "TA" turbine by ARL.[33] In these tests (described in the appendix), the direct coal-fired machine was operated with and without a cyclone upstream of the turbine. Without the cyclone a heavy deposit of a dense, sintered material was formed on the leading edges of the stator blades. With the cyclone in place the hard sintered deposit was no longer in evidence and had been replaced by a lightly bonded, soft, friable ash. The inclusion of the ash separator resulted in a reduction in the erosion rate in the turbine by a factor of approximately 50. Perhaps a third of this reduction might be accounted for by the reduction in the particulate loading. The additional reduction probably resulted from the change in the physical characteristics of the particulates that were not removed by the cyclone separator. On the other hand, microscopic examination of particles in the hot-gas stream from a fluidized bed has shown a high incidence of angular grains that one would expect to be abrasive, and about 20% of the total weight of the particles escaping from the cyclones has been found to be SiO_2.[59]

Effects of blade hardness

The choice of blade material influences the erosion rate. Figure 3 shows the effect of metal target hardness erosion rate and supports one's intuitive feeling that increasing the hardness of the blades should reduce the erosion rate. It also supports Hoy's thesis that the softer particles from a fluidized bed should be less erosive than ash from conventional

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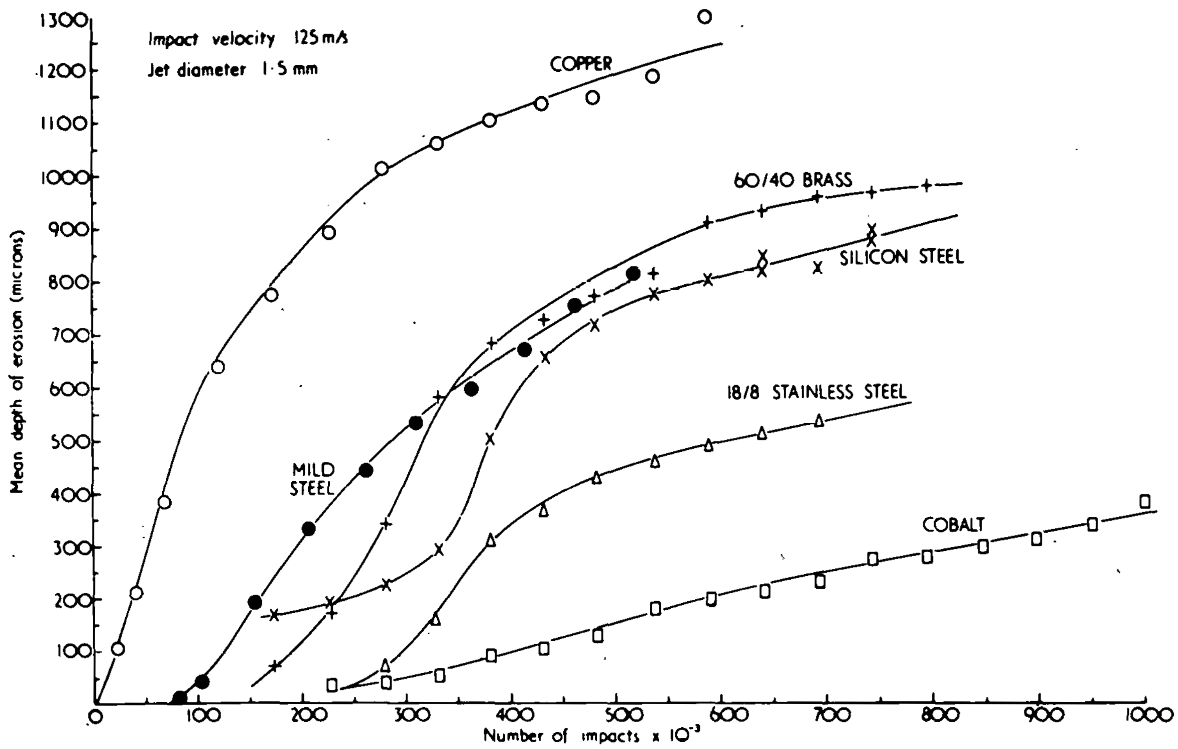

Fig. 3. Erosion as a function of the number of liquid droplet impacts on typical metals and alloys (Ref. 74).

burners. Another good indication of the effects of temperature on turbine blade erosion is given by Fig. 4, taken from Ref. 69. That study, as summarized in Fig. 4, shows good correlation between the erosion rate and the ratio of the melting point of the blade alloy to its modulus of elasticity. A review of data on the latter parameter for Fe-Cr-Ni-Co alloys indicates that dropping the temperature from 1600 to 1000°F (871–538°C) increases the modulus of elasticity by 30 to 60%. Figure 4 indicates that such an increase in the modulus should reduce the erosion rate by a factor of about 10.

Experience with steam turbines has indicated that a very hard alloy such as Stellite is exceptionally resistant to erosion by wet vapor, and experience with hard nickel-chromium alloys in gas turbines is consistent with the steam turbine experience.[31,74] Inasmuch as the high nickel-chromium alloys are also exceptionally good from the high-temperature

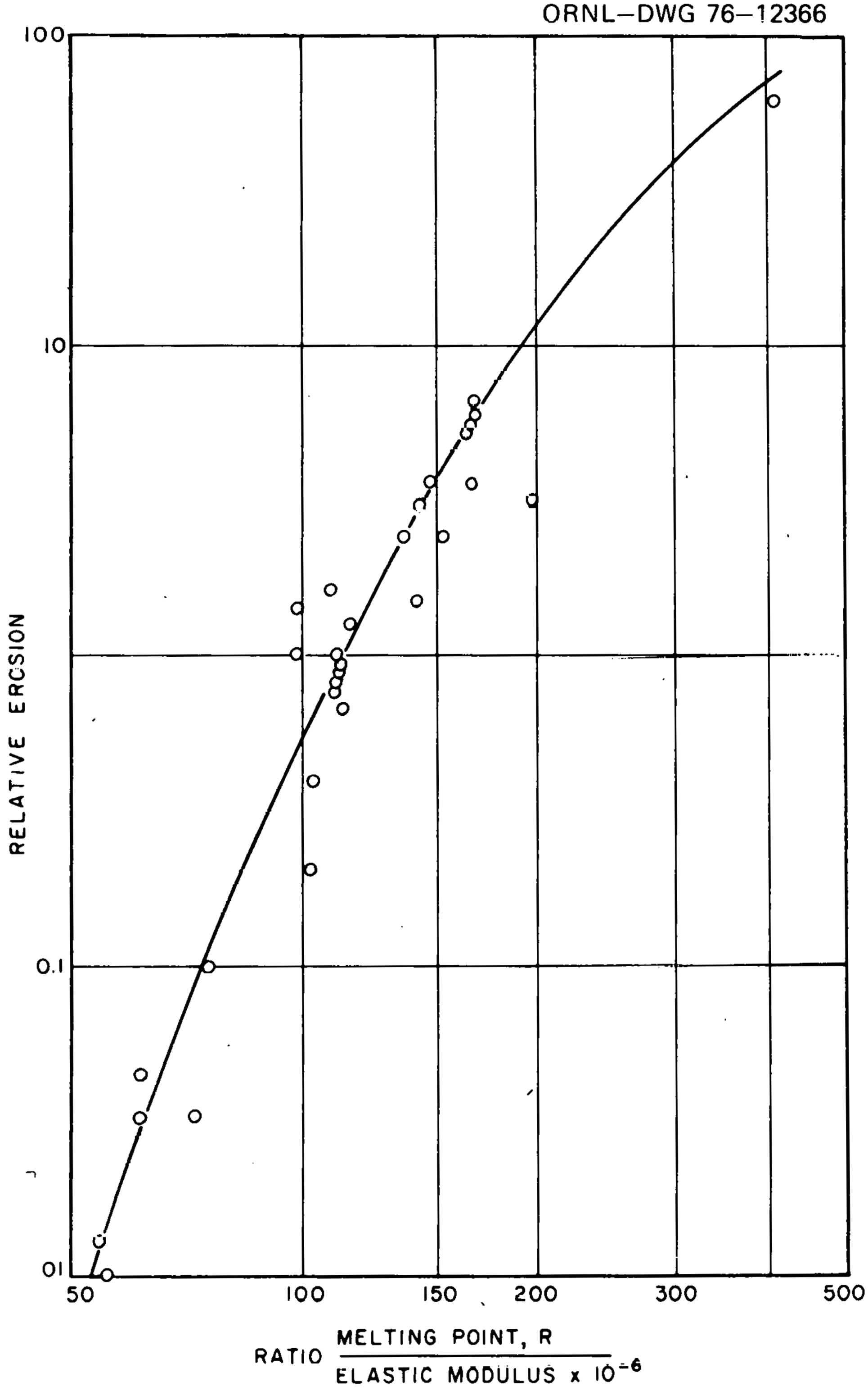

Fig. 4. Correlation of erosion with ratio of melting point to elastic modulus (Ref. 69).

strength standpoint, and hence commonly used in gas turbine blades, the usual materials of construction are about as erosion resistant as one might find.

It should be noted that in the work carried out by the Bureau of Mines with the turbines from the Locomotive Development Committee program, the use of titanium carbide inserts near the blade roots essentially eliminated erosion with no changes in the particulate content of the gas or in the turbine wheel tip speed, and that flame spraying blade surfaces with tungsten carbide has increased the life of turbines in cat cracker service.[31,39] This supports the intuition that increasing the turbine blade hardness will reduce the erosion rate.

Effects of particle size

The effects of particle size on the erosion rate are indicated by Fig. 5. These data were obtained with silica particles.[64] Somewhat similar data for helicopter and ground-based engines[63] (Fig. 6) indicate that

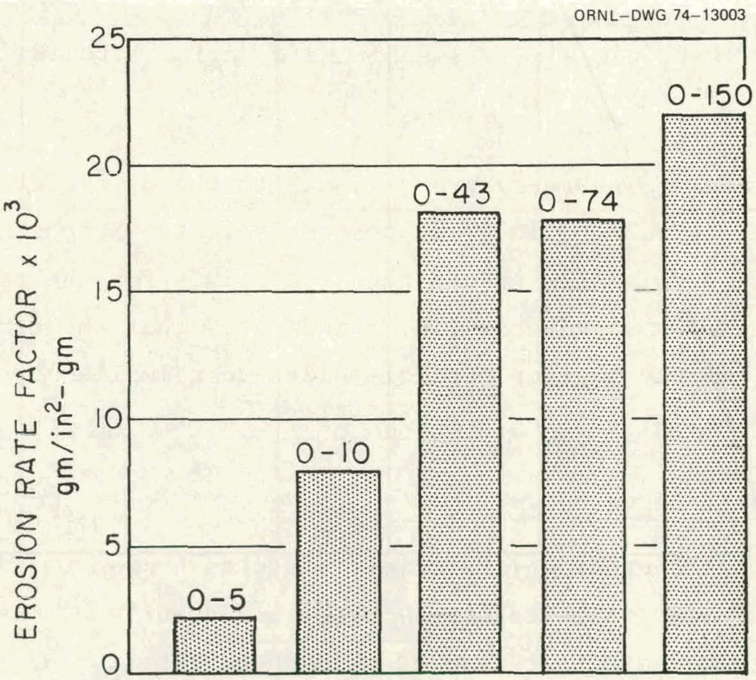

Fig. 5. Erosion loss vs dust particle size range for pearlitic C-1050 steel with 375-ppm (0.013-g/ft^3) dust concentration, 850-fps air-stream velocity, 40-deg apparent impact angle (Ref. 64).

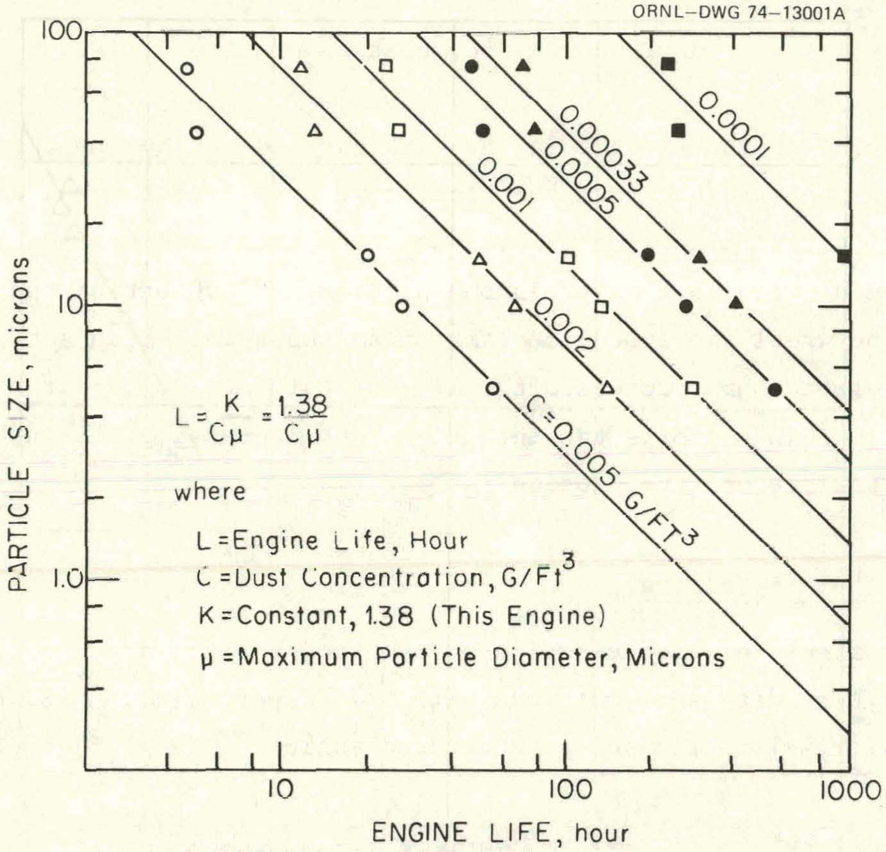

Fig. 6. Particle size vs usable safe engine life (Ref. 63).

the erosion rate is inversely proportional to the particle size for a given particulate content in grams per cubic foot. Note that these curves were extrapolated linearly beyond the data points for the smallest particle size (about 5 μm) and that Fig. 5 indicates that the damage would be less serious for the smaller particle sizes than implied by the curve extrapolations of Fig. 6.

Effects of particle velocity

Turbine blade erosion is strongly affected by the particle velocity and the impingement angle relative to the blade surface. Experiments indicate that the erosion rate varies as a power function of the relative velocity (Fig. 7), which suggests that the erosion problem can be drastically eased by reducing the design tip speed of the turbine.[63,64] This thesis has been validated by the Australian work, where a reduction in

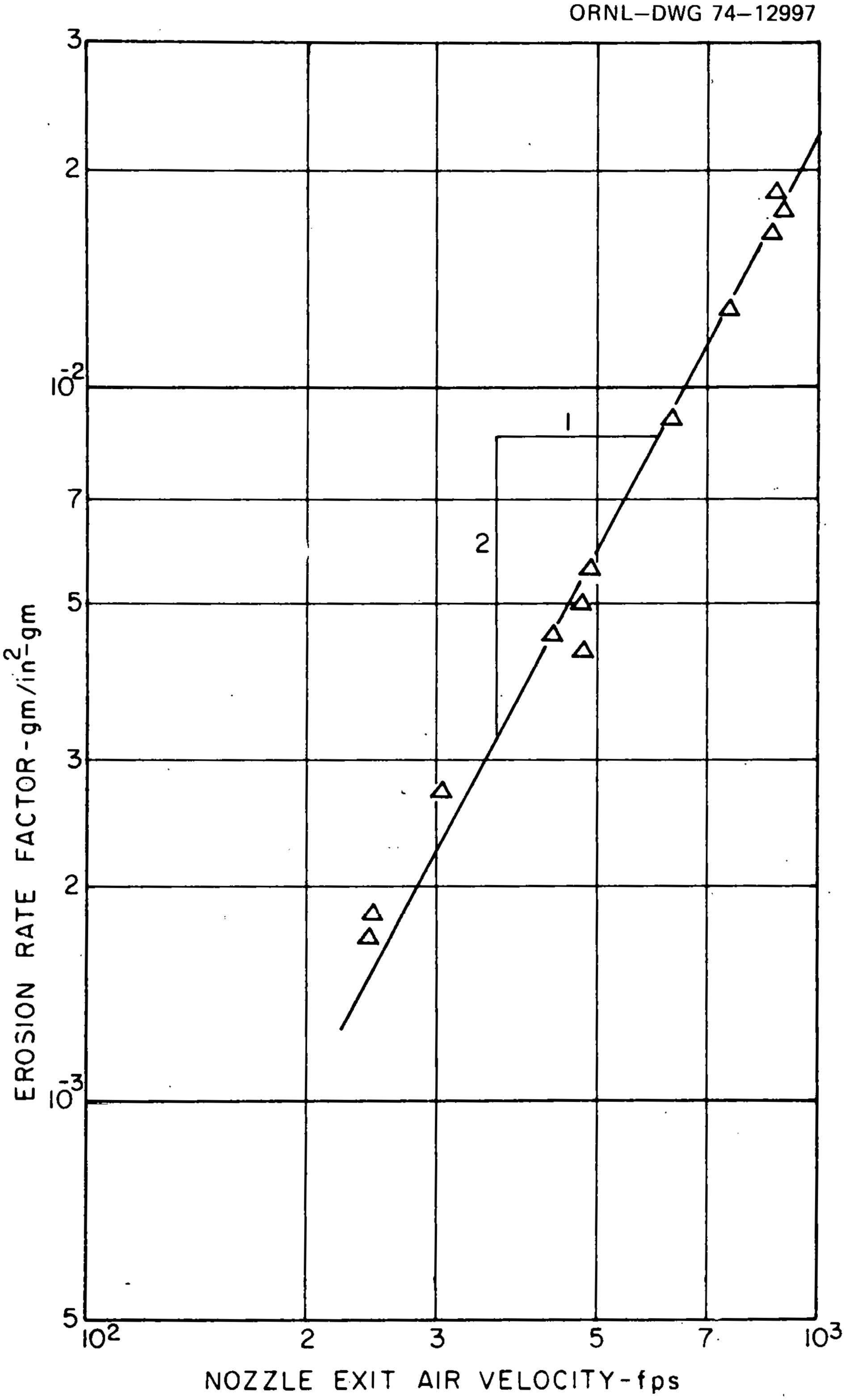

Fig. 7. Erosion loss vs airstream velocity with tempered C-1050 steel for 375-ppm (0.013-g/ft^3) dust concentration; 0–74 μm silica flour; 40-deg apparent impact angle (Ref. 64).

the relative velocity from 1100 to 800 fps essentially eliminated erosion.[33] A reduced tip speed has also been found helpful in expander turbines for catalytic-cracking unit service.[39] However, this approach has the disadvantage that the work output per stage varies as the square of the velocity; hence, cutting the velocity from 1100 to 800 fps would, in effect, require increasing the number of stages by a factor of about 2, thus increasing the cost of the turbine by nearly as great a factor.

Effects of particulate content of the gas stream

The rate of erosion appears to be directly proportional to the quantity of particulate matter passing through a turbine for a given particle size and character. This is, of course, as one would expect.

Deposits

Every effort to operate a gas turbine on the products of combustion of coal and/or solid wastes has met with difficulties with the buildup of deposits, particularly in the stator blades.[24-27,31,33,58] In cases where no effort has been made to remove the ash particles between the combustor and the turbine, the deposit buildup has forced the turbine out of service (in one case in as little as 2 hr) as a consequence of a severe loss of power or a reduction in airflow to the point where compressor surge was imminent.[33] Thus, the first step ordinarily taken has been to remove as much of the dust as possible with cyclone separators or some type of filter. A second method of reducing deposits is to reduce the turbine inlet temperature, which results in a reduction in the turbine work and thereby limits the degree to which this technique can be utilized.

Buildup of engine deposits

The character of the deposits formed in an engine depends on the type of dust. In military gas turbines, where the dust consists primarily of particles of silica and feldspars, the melting or softening point is sufficiently above the operating temperature that the dust does not tend to stick, and deposits build up only in regions where local aerodynamic conditions favor deposition. The hot ash in coal-burning gas turbines presents a quite different set of problems. In the direct coal-fired operation of turbines in the LDC, ARL, and the United States Bureau of Mines programs, the pulverized coal was burned in near-stoichiometric proportions to give flame temperatures approaching 2500°F (1370°C); the products of combustion were then cooled by mixing with secondary air to give the desired turbine operating temperature. The volatile alkali metal sulfates formed during the combustion tended to condense and stick to the blades where they formed a coating to which other ash particles tended to stick and agglomerate, with the alkali metal sulfates acting as bonding agents.[31]

An excellent insight into the effects of both low-melting constituents in the ash and turbine inlet temperature on ash deposits in the turbine was obtained in Australia in a test rig designed to simulate turbine conditions.[33] Tests were carried out with both ash from a typical Australian coal and with MgO containing low-melting salts that would serve as bonding agents (i.e., give a "flypaper" effect of the sort noted in the Bureau of Mines tests).[31] Figure 8 shows the results of this set of controlled experiments. Perhaps the most significant point to note with respect to the question of immediate interest is that the amount of material deposited from the Yalbourn coal ash dropped rapidly with a reduction in temperature becoming practically zero at 500°C. Note also that pure MgO with no bonding agent also gave almost no deposits at 932°F (500°C). However, the addition of a low-melting salt in the form of sodium, potassium, or magnesium chloride or eutectic mixtures of these materials led to both heavier deposits and a shifting of the temperature for a low deposition rate to a lower value.

Experience at BCURA with a fluidized-bed coal combustor operating at temperatures in the 1450 to 1750°F (787 to 954°C) range (which is well below the ash fusion temperature) has shown a high retention of the alkali metals in the ash. Therefore, one might at first expect that a higher turbine inlet temperature could be utilized with a fluidized-bed coal combustor than with a pulverized coal burner. However, a mixture of calcium and magnesium sulfates (compounds formed as a result of the sulfur removal

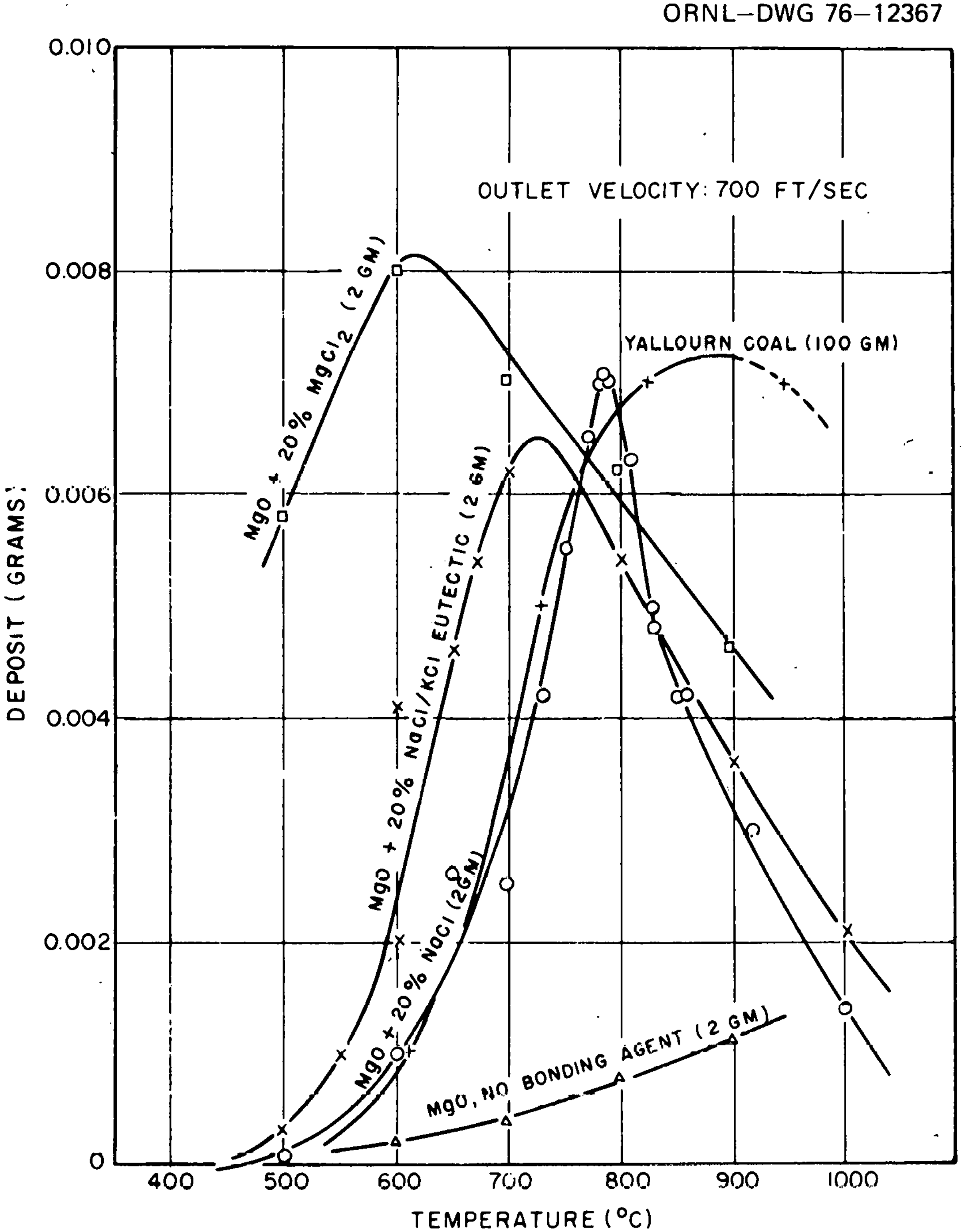

Fig. 8. Effects of temperature on the deposition rate of both coal ash and various mixtures of MgO and chloride salts fed into the hot-gas stream of a turbine simulation test rig in Australia. The particle size used was nominally 5 μm (Ref. 33).

operation) will form a glass that is soft and plastic at about 1300°F (700°C) and may be expected to give the same mechanism for the buildup of deposits as the alkali metal sulfates from the pulverized coal burner. Deposits formed in the first-stage cyclone separators of the Combustion Power and BCURA units may have been caused by this calcium-magnesium sulfate glass.[57]

The hardness and adherence properties of the ash deposits in coal-burning gas turbines vary with the type of coal and limestone or dolomite used, the particle size, the efficiency of combustion, and the particle temperature at the instant it impinges on the metal surface. These variables greatly complicate any test program.

Effects of particle size

The buildup of ash deposits in a turbine tends to be relatively more serious than erosion as the particle size of the ingested dust is reduced.[31,33] In fact, some experimenters claim to have obtained a relatively good balance between large and small particles so that the incidence of larger particles is sufficient to scrub away the deposits built up by the smaller particles.[10,33] Such a favorable balance, of course, is obtained at the expense of some erosion and will be peculiar to a particular set of operating conditions, coal composition, etc.

Effects of particle temperature

The particle temperature at impact is related to the transport gas temperature and the efficiency of the coal combustor. Inefficient combustion results in a high-carbon-content flyash which in turn results in afterburning. Experiments with an open-cycle coal-fired gas turbine resulted in deposits on the turbine blading at a gas inlet temperature of 1200°F (650°C).[31] At a turbine inlet temperature of 1050°F (565°C), no deposits were formed.[31] In a similar experiment using synthetic ash to simulate the ash from a coal-fired fluidized-bed combustor, deposits did not occur below a temperature of 1500°F (816°C).[58] Evidently, the composition of the synthetic ash differed in some way from that of the ash in the coal of the earlier test.

Corrosion

The corrosion problem in coal-burning gas turbines is closely related to the problems posed by erosion and deposits. For example, erosion may abrade protective oxide films and thus accelerate corrosion. Deposits of alkali metal sulfates and vanadates may react with the metal in the blades to produce sulfidation and corrosion. All these mechanisms are very dependent not only on the engine design and operating conditions, but also on the type of coal employed.

Effects of temperature

The corrosion rate of metal superheater surfaces by the products of coal combustion has been found to be very dependent on the metal operating temperature in conventional steam power plants. The flame temperature in the burners runs about 2500°F (1370°C) and hence the alkali metal sulfates and vanadates formed are vaporized. They subsequently tend to condense on colder metal surfaces, where they are present in liquid form in the temperature range around 1300°F (700°C).[76] If this occurs, the liquid dissolves the protective oxide film and rapid attack by the liquid occurs. Interestingly enough, the sulfates and vanadates are in vapor form at higher temperatures, so this corrosion mechanism is not present. However, solid-state diffusion processes take place at a higher rate as the temperatures increase; hence, sulfur tends to be absorbed at the surface to form metal sulfides and migrates inward along the grain boundaries to give a condition known as sulfidation. This effect is often dependent on local imperfections in protective oxide films and hence is widely scattered and not obvious in a cursory inspection, but it weakens the material.

In a fluidized-bed coal combustion system it would be expected that the alkali metal sulfates would not be vaporized as in pulverized coal burner flames. However, they will be present in the ash particles deposited in the turbine and some difficulty with sulfidation of the turbine blades may occur. Limited data available from tests at BCURA on cascades of blades and at Combustion Power on coupons located in the free board indicate that sulfidation is not a problem at metal temperatures of 1500°F (816°C); however, at a metal temperature of 1700 to 1750°F (925—955°C), there was heavy sulfidation of the turbine blade materials in both sets of experiments.[56,58] Recent work indicates that, if there is not a substantial excess of oxygen, sulfidation and corrosion under an ash deposit can be quite serious in as little as 500 hr in the 1200 to 1500°F (650—815°C) range, particularly with high-nickel alloys.[77–79]

Effects of type of coal

Experience with open-cycle coal-fired turbines operating at 1050 to 1250°F (565—675°C) by the LDC, ARL, and the U.S. Bureau of Mines, utilizing a wide variety of coals from both the United States and Australia, has shown only minimal corrosion of the turbine blades after a total operating time of 7000 hr.[8,31,33] These coals were burned in pulverized coal burners at flame temperatures approaching 2500°F (1370°C), and the products of combustion were cooled with secondary air to the turbine operating temperatures. For a fluidized-bed coal combustor with a high retention of the alkali metals in the ash, as indicated by BCURA tests, one would expect that higher turbine inlet temperatures could be utilized for a wide variety of coals without appreciable blade corrosion.[56] Recent tests indicate that, if there is more than ∿10% excess air, corrosion of chromium-nickel alloys should not be serious at temperatures up to the 1500 to 1600°F (815—870°C) range.[77–79]

Particle Separators

The open-cycle coal-fired gas turbines that have been operated have employed both conventional high-temperature cyclone separators and multicyclones to remove ash particles from the hot gases (∿675°C) flowing out of the combustion chamber. Conventional cyclones are effective in removing most of the dust down to about 20 μm. Two stages are commonly employed, with the first serving as a roughing stage to remove most of the larger particles and to reduce the variation in the particulate loading induced by variations in the combustor loading. The cyclone separators are often followed by a third stage in the form of a multicyclone, which is a large number of small-diameter cyclone separators operating in parallel. The individual cyclones are often as small as 1.5 in. (3.8 cm) in diameter and are effective in removing most of the dust down to about 10 μm. Figure 9 shows the particle removal efficiency of a unit of this type and the pressure drop as a function of the airflow rate per unit of inlet face area of the separator bank.[67] These data were for dust in which 25% by weight of the particles had equivalent diameters of less than 10 μm.

Removal of particles below about 5 μm is best accomplished with some form of fabric filter if the gas temperature is below 500°F (260°C).

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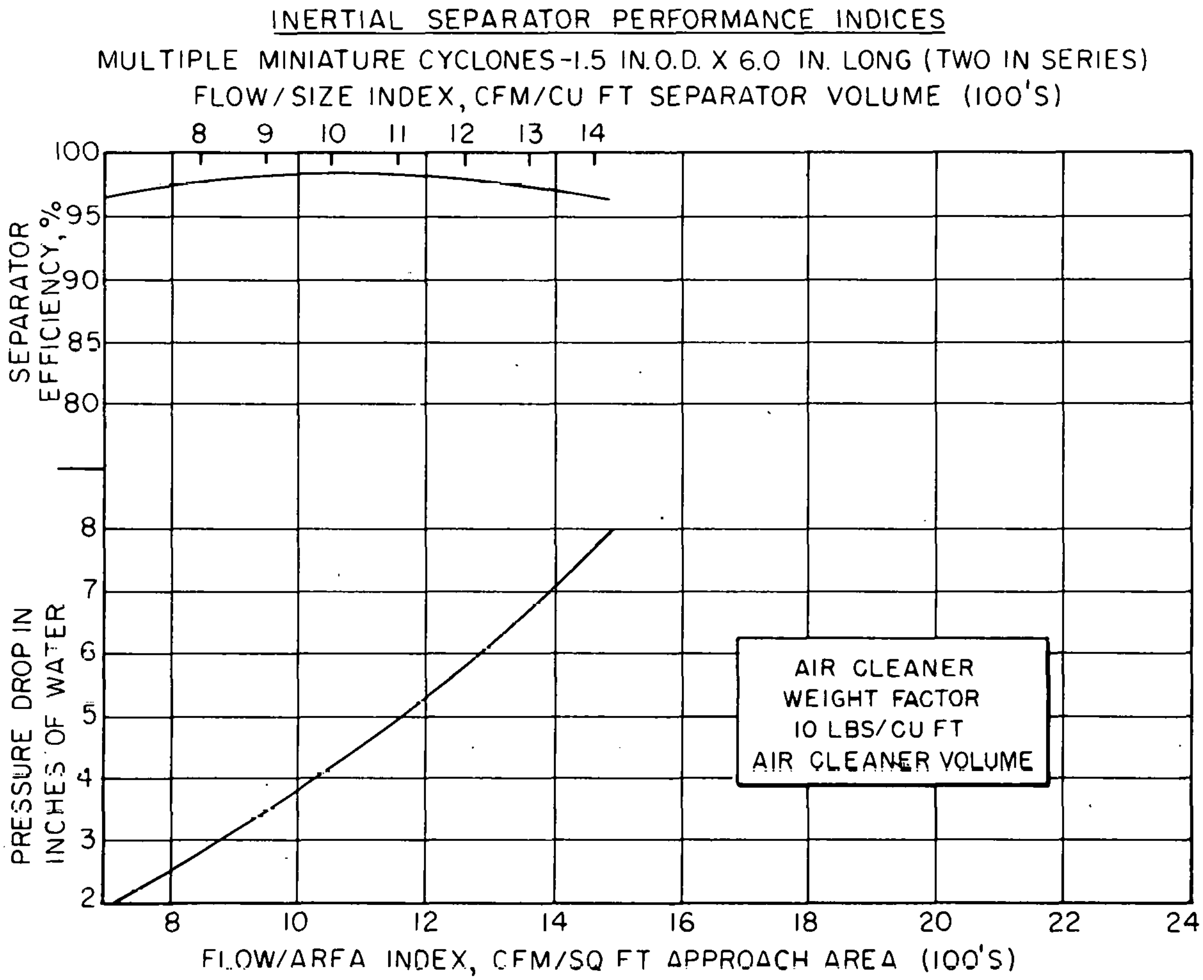

Fig. 9. Separator performance characteristics for 1.5- by 6-in. tubes in series. Performance is based on a scavenging airflow requirement of 15% of the airflow rate (Ref. 67).

Electrostatic precipitators can be used at temperatures to about 1000°F (537°C). At higher temperatures the electrical conductivity of the coal ash becomes sufficient that deposits formed on the electrical insulators produce high tension shorts that prevent the buildup of an adequate voltage to give effective electrostatic precipitation. Further, because of the relatively low velocities involved, the size and cost of the pressure vessel required to house the large volume of precipitator plates present serious problems if such a unit is installed between the combustor and a gas turbine where the pressure will run ∿10 atm.

CURRENT STATUS OF DEVELOPMENT

The current status of the development of the open-cycle coal-fired gas turbine as determined from a review of available pertinent literature indicates that, with careful design of the turbine and ash removal system, acceptable operation can be attained for turbine inlet temperatures up to about 1200°F (650°C) and particulate loadings of approximately 100 ppm. However, the present interest in the use of a pressurized fluidized-bed coal combustor for a combined-cycle power plant requires that the turbine inlet temperature be increased to the 1500 to 1600°F (815–870°C) range,[80-82] and this apparently requires that the particulate content of the hot gas be less than ∿1 ppm. Thus present development thrusts are directed toward more effective hot-gas cleanup methods. Among the methods being evaluated are high-efficiency cyclones; granular bed filters; metallic and/or ceramic cloth filters; and high-pressure, high-temperature electrostatic precipitators. Dilution of the combustion gas stream with air heated in the fluidized bed is another method of reducing the particulate loading in the gas turbine inlet stream,[82] and the Curtiss-Wright Corporation is in the midst of an experimental program to investigate this possibility. As can be deduced from the flowsheet in Fig. 10, this entails the use of about one-third of the air discharged from the compressor as combustion air for the fluidized bed, while the other two-thirds passes through tubes in the fluidized bed to remove about two-thirds of the heat of combustion. The combustion gases are cleaned up and recombined with the clean air heated by the bed and fed to the turbine. This approach

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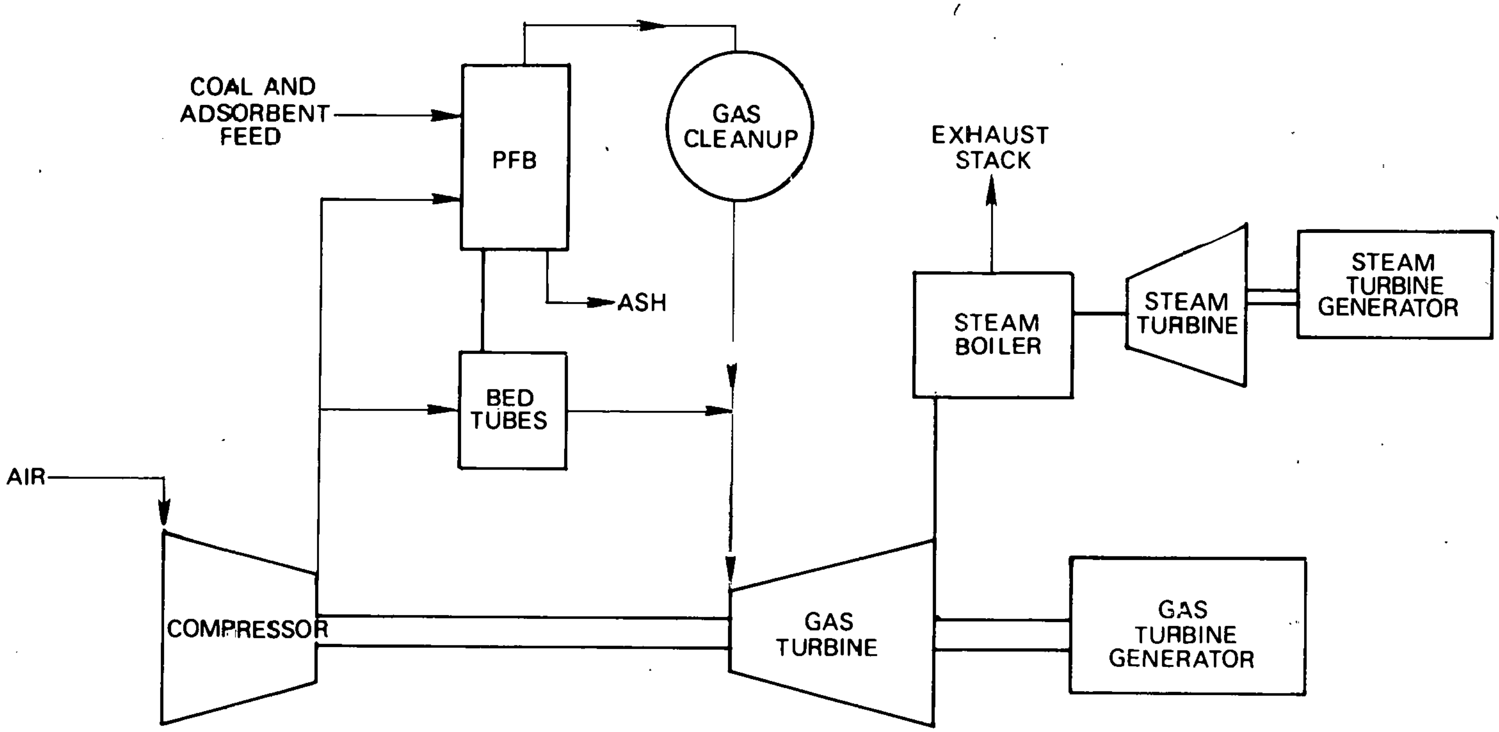

Fig. 10. Simplified flowsheet for the Curtiss-Wright pressurized fluidized bed–gas turbine–steam turbine combined cycle power system.[82]

greatly reduces both the size and the required efficiency of the particle separation equipment.

The crux of the problem is to obtain a particulate removal system that will operate at a temperature of approximately 1600°F (870°C) for long periods of time without either clogging to give an excessive pressure drop or losing its effectiveness in removing particulate matter. The status of the principal experimental efforts is outlined below.

Exxon Research and Engineering Company

The Exxon Miniplant flue gas exits from a 30-cm-diam fluidized-bed combustor and discharges through two stages of cyclone separators. The solids from the first-stage cyclone are returned to the combustor, and those from the second-stage cyclone are discarded by means of a lock hopper system. The discharge gases from the second-stage cyclone are further cleaned by a granular bed filter before entering the test section for the simulated turbine. The hot gases enter the filter at approximately 9 atm and 1200 to 1550°F (650–843°C).

A series of tests has been run with granular bed filters.[83,84] The first set of these was run with hot-gas downflow through a 50-mesh inlet screen and a bed of 250- to 600-mesh particles of crushed quartz. The inlet screens clogged quickly, so that it was necessary to clear them at intervals of 5 to 10 min by blowing back first one and then another of several units operating in parallel. However, the backflow operation was only partially effective in clearing the units and reducing the pressure drop to the design range; the pressure drop became excessive within 24 hr of running. The filters were then modified by removing the inlet screens; this helped but led to excessive losses of the fine silica particles in the filter bed. This problem was corrected by changing to coarser particles of crushed alumina (840–1400 μm). Tests with these at the time of writing indicate that when starting with a clean bed the particulate content in the exit gas stream can be held to the EPA specification for stack emissions of 0.05 grain/ft^3 (gas volume at standard conditions). However, the fine dust tends to intermix with the granular bed when it is fluidized during the blowback operation, and after a few hours of running the particulate content of the gas leaving the bed rises to the point where it exceeds the target limit of 0.05 grain/ft^3. Efforts are under way at the time of writing to improve the arrangements for clearing out the fines in the blowback operation.

It should be noted that the EPA limit of 0.05 grain/ft^3 is for the stack gas emissions to the atmosphere. This value corresponds to approximately 100 ppm and is about 100 times as high as can be tolerated in a gas turbine designed to operate with an inlet temperature of about 1550°F (843°C).

Combustion Power Company

Combustion Power Company is using a moving granular-bed filtration system for removal of particulate material from the hot-gas stream supplied to a gas turbine.[85] The bed is in the form of a cylindrical annulus about 11.8 in. (30 cm) thick contained between two sets of louvered plates with the louvers sloped inward toward the bed so that the granular material is contained (see Fig. 11). The concept entails gradual movement

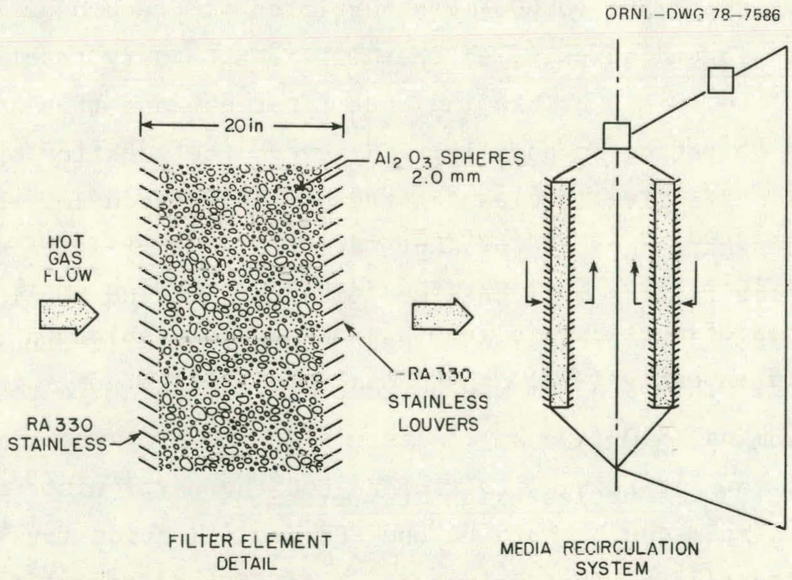

Fig. 11. Description of the Combustion Power Co. design for an granular-bed filter.

of the granular material downward through the bed so that the filter cake on the inlet face is broken up and fine particles that get into the bed can be removed in the course of recycling the granular material from the bottom to the top of the bed. A test with a full-scale hot-flow unit was terminated in the initial shakedown by a creep buckling type of failure. This led to the decision to run a reduced-scale cold-flow test as the next step. A cold-flow model has been built and tested to determine the effects of bed thickness, filter media size, and flow rates on filtration performance. Data from these experiments show that particulate loadings of as low as 20 ppm can be obtained in the exit gas stream.[86] These data are being used to design a system for operation with a fluidized-bed coal combustor.

NASA-Lewis Research Center

The NASA-Lewis fluidized bed is a combination of a cylindrical and a conical bed.[87] The fuel is burned in the lower cylindrical bed, while the upper conical bed serves as a fixed bed filter for the flue gases supplied to a turbine test section. The system became operable in 1977, and a test program involving a turbine section, high-temperature cyclones, and a high-temperature ceramic filter is scheduled to begin in early 1978.

Westinghouse Research and Development Center

A high-temperature, high-pressure test facility is being constructed by the Westinghouse R&D Center to test particulate control equipment. The facility is designed to investigate the effects of temperature, pressure, flow rate, particle type, loading, and size distribution on the performance of various types of particulate removal devices.[88] Shakedown runs are expected to begin in early 1978.

Curtiss-Wright Corporation

The Curtiss-Wright program to develop a pressurized fluidized-bed combustion system coupled to a gas turbine has entailed, as a first major step, the design and construction of a facility called the Small Gas Turbine—Pressurized Fluidized Bed (SGT/PFB) rig.[82] This unit employs a 3-ft (0.8-m-diam) fluidized-bed furnace designed to operate at 6.5 atm. A portion of the combustion products passes through a series of cyclone separators and a granular-bed filter en route to a small gas turbine. The effectiveness of various designs for the particle removal equipment will be determined as a function of the principal variables. Concurrently, the effects of the particulate content of the combustion gas entering the gas turbine on turbine bucket erosion and deposits will be investigated. The test rig was undergoing shakedown tests as of January 1978. Test results should begin to be available by mid-1978.

Deposits of Particulates Entering with the Inlet Air

Commercial gas turbines have been troubled by deposits stemming from dust in the inlet air stream. As a consequence, the engine manufacturers recommend that air filters be incorporated in the installation to keep the dust content to less than ~2 ppm,[89] and this is commonly found necessary in many urban environments. However, recent experience indicates that even tighter restrictions are required as the turbine inlet temperature is increased. One of the first strong indications of this was encountered in a 1974 gas turbine acceptance test at the Philadelphia Navy Yard. Substantial deposits were noted after only a few hundred hours of operation under cycling conditions in which the average turbine inlet temperature was in the 2100°F (1150°C) range about half the time.[90] The cooling air discharge ports in the first stage stator blades were affected and some blades were damaged by overheating (Fig. 12). Investigation disclosed that the bulk of the deposit consisted of submicron-size Fe_2O_3 particles that entered the engine with the inlet air that had a particulate content of only 0.06 ppm. Further investigation disclosed that Philadelphia air was not dirtier in this respect than the air in most localities and that the deposits did not form when the nominal turbine inlet temperature was limited to ~1800°F (982°C). Note that the melting point of the Fe_2O_3 is 2860°F (1570°C) which implies a sintering temperature of ~2030°F (1110°C).

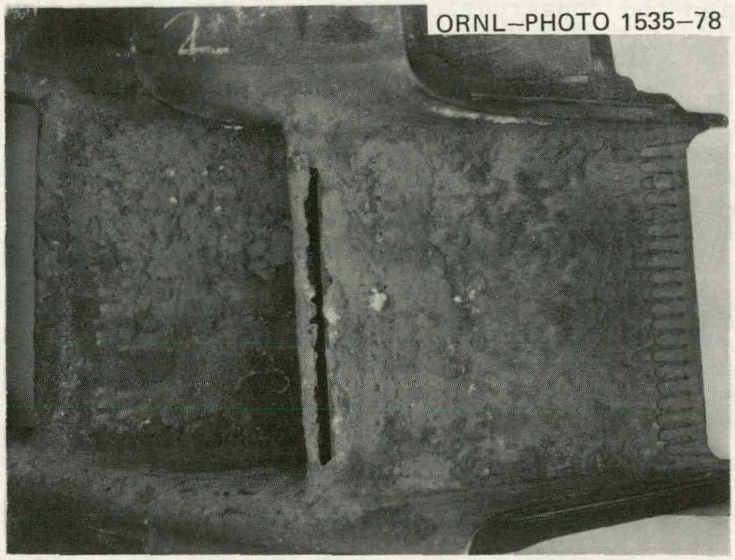

Fig. 12. Photograph of two first-stage stator vanes from an LM2500 engine after cycled operation at the Philadelphia Navy Yard. Note that deposits on the blades have partially blocked the cooling air discharge ports near the leading edge of the vane at the left and the blockage of ports near the leading edge of the blade at the right led to severe overheating and burning of a slot through what was the cooling air discharge port region (courtesy of the Philadelphia Navy Yard).

This appears to be the reason that this type of deposit did not prove a problem until operations at a turbine inlet temperature of 2100°F (1150°C) were initiated. Note, too, that coal ash commonly contains ∿5% Fe_2O_3.

Recent work by NASA,[91] Westinghouse,[92–94] and UTC (United Technologies Corp.) seems to be consistent with the Navy experience. One of the interesting analyses of the problem was evolved by G. Vermes at Westinghouse to explain the markedly heavier deposits found on both the pressure and suction surfaces in engines with cooled blades. He has shown that the temperature differential between hot particles in the gas stream and the cooler metal blade surfaces induces a force that drives the particles toward the blade surface and causes them to adhere, a phenomenon he calls "thermophoresis."[93] His analytically derived relations correlate a substantial amount of experimental data surprisingly well and support his analytical relations indicating that the greater the temperature difference and the smaller the particle, the greater the deposition rate.

Another analytical study carried out at Westinghouse by Chamberlin[94] indicates that Brownian movement effects in the boundary layer also tend to cause the deposition of submicron-size particles on both the pressure and suction surfaces. Burner rig tests both at NASA[91] and at UTC have demonstrated that these deposits form at high temperatures and tend to clog the small cooling air discharge ports in the blades. Note that the UTC tests were carried out with Al_2O_3 dust with a melting point far above the gas temperature, yet the deposits formed were hard and adherent. Apparently, trace amounts of lower-melting-point materials act as binders to fuse high-melting-point materials such as Fe_2O_3 and Al_2O_3 into hard ceramic deposits. These are not only adherent, but there seems to be no simple method to remove them from suction surfaces; a water wash with crushed nut shells is effective only for removing deposits on pressure surfaces.

This test experience, together with the related studies, has serious implications for both water-cooled blades and transpiration air-cooled blades intended for turbine inlet temperatures in the 2500 to 3000°F (1370 to 1650°C) range. From this standpoint, perhaps the most significant test projected for the near future is a 1000-hr test planned by Curtiss-Wright Corp. In this test one of their engines will be run with a turbine inlet temperature of ∿3000°F (1650°C) using transpiration-cooled blades designed to operate with a metal temperature of 1350°F (732°C). Flyash from a Commonwealth Edison coal-fired steam plant will be added to the combustion air with operation on clean distillate fuel.[95] Three levels of particulate flow rate will be investigated: ∿2 ppm with 80% smaller than 1 μm, ∿10 ppm with 80% under 2 μm, and ∿20 ppm with 80% smaller than 2.5 μm. The alkali metal content of the distillate fuel oil will be held to 0.65, 3.4, and 6.5 ppm, respectively.

Summary

The various particulate removal systems presently being evaluated by DOE contractors are designed to offer a workable method of removing particles below 5 μm at temperatures in the 1600 to 1900°F (870–1040°C) range and thus clean up the fluidized-bed coal combustor flue gas stream sufficiently to permit good gas turbine operation. These values represent experimental objectives and have not as yet been demonstrated. A thorough examination of the many experiments that have been and are being conducted indicates that it is doubtful that any of the concepts being investigated will give the low particulate contents required for the economical operation of 1500 to 1600°F (816 to 870°C) long-lived gas turbines.

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Appendix A

SUMMARY OF LITERATURE CONCERNING THE RESEARCH AND DEVELOPMENT EFFORT ON OPEN-CYCLE COAL-FIRED GAS TURBINES

The industrial application of gas turbine drives for process compressors and electric generators began in the early thirties and had gained general acceptance by the late forties.[5-7] These turbines usually operated with relatively clean fuels, such as natural gas or distillate oils. In the mid-forties and early fifties, investigations directed toward the industrial applications of gas turbines supplied with a gas containing a high solids loading were undertaken.[30-38] The solids were introduced into the gas stream by one of two methods. The first involved a gas turbine located in a process stream, such as a turbine receiving gas from a catalytic cracker.[37,38] The second method involved the direct firing of a high-ash fuel such as coal.[30-36]

The problems associated with the direct firing of coal in an open-cycle gas turbine were investigated over a 26-year period (1944—1970) by the Locomotive Development Committee of Bituminous Coal Research, Inc., in the United States and by the Aeronautical Research Laboratories in Australia.[8,33]

Locomotive Development Committee

Houdry 5-stage reaction turbine

A Houdry process turbine built by Allis-Chalmers Company during World War II for use in Russian refineries and transferred as war surplus to the U.S. Bureau of Mines was lent to the LDC to serve as the first full-scale coal-fired gas turbine plant. The unit was installed and began coal-fired operation on November 7, 1949.

The Houdry plant consisted of an Allis-Chalmers type VA 820, 20-stage axial compressor rated at 39 psig (0.37 MPa) at 5180 rpm when handling 46,600 cfm (22 m^3/sec) of inlet air at 60°F (15.6°C) and 14.7 psia (0.1 MPa).[11,12] The compressor was driven by a 5-stage reaction turbine that produced 6200 hp (4625 kW) at 5180 rpm with an inlet temperature of 950°F (510°C).

The following description of the operation of the Houdry plant was taken from Ref. 12:*

> The compressor raises the pressure of the air to about 53.5 psi (0.37 MPa) absolute, heating it in the process to 370°F (188°C). About 5600 hp (4175 kW) is required to compress the 206,000 lb (93,400 kg) of air taken into the system each hour.
>
> As the air leaves the compressor, the stream is divided into the tempering air line, which takes 113,000 lb/hr (51,000 kg/hr) and the combustion air supply line. The mixture of combustion air and coal is heated to 1300°F (705°C) by burning approximately 2000 lb (907 kg) of pulverized coal per hour in the coal combustor. This stream then passes through the louver separator, where the larger ash particles are concentrated into a smaller air stream [5000 lb/hr (2300 kg)] and blown out of the system. The louver also equalizes the temperature across the stream.
>
> Separation of the fine ash is accomplished by a battery of 18 American Blower Corporation type ST-361 tubes. The air and dust are rotated by a spinner at the entrance to each tube which is used to carry the dust away, while the main stream, now free of the large dust particles, passes on to the turbine.
>
> The secondary air stream must also be cleaned and returned to the turbine. This is accomplished by taking the secondary flow from the 18 primary collector tubes through 3 secondary collectors, where the dust in the original 10% secondary flow is further concentrated to a 1% stream which carries the ash out through a blowdown nozzle. The remaining 9% will be returned to the main air flow on its way to the turbine.
>
> The remaining 77,000 lb (35,000 kg) of air at 1300°F (705°C) is now diluted by the addition of the 113,000 lb (51,000 kg) of 370°F (188°C) air coming through the tempering line. The resulting mixture, 190,000 lb/hr (86,000 kg/hr), enters the turbine at 740°F (394°C), where it does just enough work to drive the compressor at full speed.

Four 250-hr tests of the Houdry unit were conducted during the 1950–51 period. The description and analysis of the results of these tests given below are summaries of data given in Refs. 13 through 16.

Inspection of the turbine after the first 250 hr of coal-fired operation revealed erosion in several sections of the first row of stator blading. The erosion was most pronounced in the upper half of the casing, between 12 and 2 o'clock. The rotor blades suffered no damage of any importance except for a number of nicks on the leading edges of the first

*The metric equivalent of all units have been added to direct quotes for clarity for the reader.

blade row, indicating that many large ash fragments had passed through the ash separator.

The first-row stator blading was also eroded badly near the lashing wire, about 1 in. from the blade tip. Bends in the inlet gooseneck and the sharp changes of direction at the first-stage entrance apparently concentrated the ash and caused the localized erosion.

A shield was installed at the turbine inlet to deflect the ash stream and distribute it more uniformly around the turbine inlet for the second 250-hr test. The change was ineffective. The erosion continued on the first-row stator blading and extended to the first-row rotor blading.

The first-row stator (with the lashing wires omitted) and rotor blading were replaced after the second 250-hr test. Also the ash separator design was changed in an effort to improve the quality of the turbine inlet gas stream. The third 250-hr test resulted in much more severe erosion than had been found previously. The first-row stator blading was again severely eroded between 10 and 2 o'clock, and the second and third rows of stator blading suffered severe erosion damage. The rotor blading showed no evidence of damage other than polishing.

For the fourth 250-hr test, the first three rows of stator blades were replaced. The lashing wire was restored to the first row of stator blades to avoid the vibration which had been noted in the third 250-hr run. A new design ash separator was installed. Careful inspection of the blades at the end of the test showed that only very slight traces of erosion existed in the stator blading. The rotor blading (the first row had 500 hr of service and rows two through four had 1000 hr) was in excellent shape, with the only noticeable change being a slight thinning and sharpening of the blade tips.

Representative subsieve analyses of the turbine and separator inlet dust samples taken during the four 250-hr runs are given in Table A.1.[13]

Deposits were encountered for the first time during the fourth 250-hr test, when a deposit built up on the trailing edge of the last row of rotor blades. The deposit extended from about 1 in. (2.5 cm) beyond the roots of the blades out to about 1.5 in. (3.8 cm) from the tips. The deposit was first noticed after about 50 hr of the fourth test period. The deposited material was relatively soft and easily removed and contained 72% carbon.

Table A.1. Subsieve analyses of turbine inlet dust from four 250-hr coal-burning tests at 740°F (393°C)

Particle size (μ)	Separator inlets 1 thru 4[a]	Separator outlet 1	Separator outlet 2	Separator outlet 3	Separator outlet 4[a]
−10	47.0	57.7	69.1	40.7	84
+10 −20	29.4	34.5	26.3	37.7	29.4
+20 −40	19.2	6.5	2.0	16.9	2.1
+40	4.4	1.3	2.6	4.7	
Total +10	53.0	42.3	30.9	59.3	16.0
Total +20	23.6	7.8	4.6	21.6	2.1

[a] The dust loading at the separator and turbine inlets during the fourth 250-hr test was approximately 900 and 88 ppm, respectively.

Allis-Chalmers 6-stage reaction turbine

A coal-burning gas turbine designed by Allis-Chalmers for railroad service was installed in the LDC test facility at Dunkirk, New York, in late 1951. The following description of the installation was taken from Ref. 17.

> The turbine designed and built by Allis-Chalmers is a six-stage reaction machine operating at 5700 rpm with a maximum inlet temperature of 1300°F (705°C). The rotor was machined from a forging of Timken alloy (16-25-6); the cylinder blading was precision cast from S-590, while the rotor blades were forged and final machined from the same alloy. The turbine casing was fabricated from 19-9-DL. At maximum load, 60°F (16°C) inlet air, turbine develops 16260 hp (12120 kW), compressor takes 11750 hp (8760 kW), plant delivers 4350 hp (3240 kW) at shaft. Turbine efficiency averaged 87.5% from idling to full load.
>
> The compressor is a 21 stage axial flow machine, designed and built by Allis-Chalmers. Tests show full speed capacity of 65,000 cfm (30.7 m^3/sec), with test efficiency ranging from 82 to 86%.

Figure A.1 shows the turbine inlet and outlet temperatures as a function of the turbine shaft horsepower.[16] The compositions of the alloys used in the turbine are given in Table A.2,[15] and gas velocities relative to the turbine blades are given in Table A.3.[31]

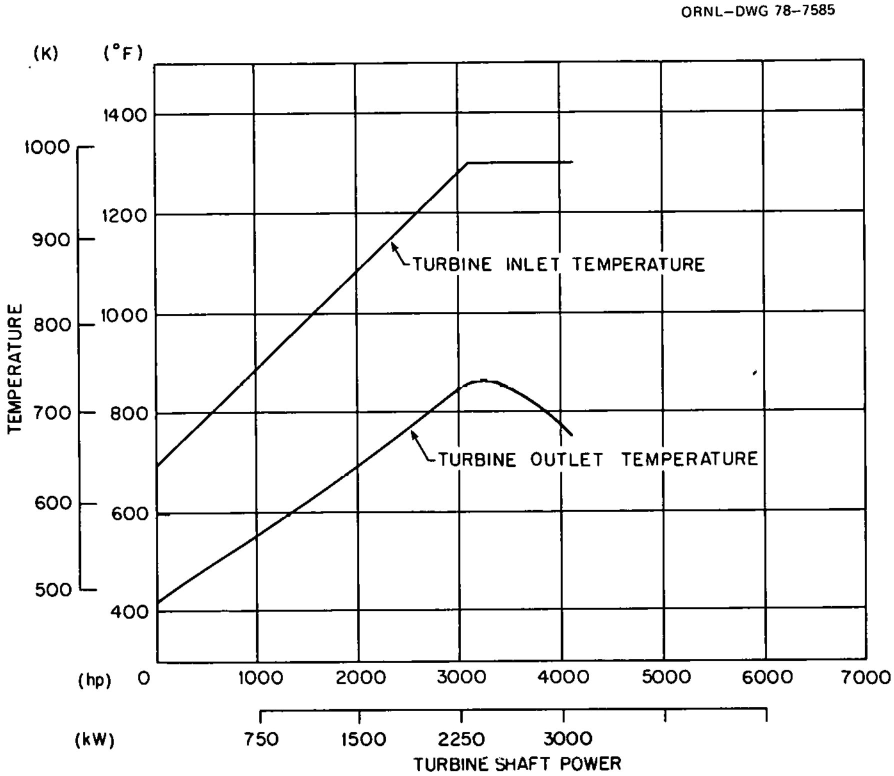

Fig. A.1. Locomotive Development Committee six-stage turbine inlet and outlet temperatures. Compressor inlet 80°F (300°K) at 14.7 psia (0.1 MPa) (Ref. 16).

Table A.2. Composition of alloy steels used in the coal-fired gas turbine (Ref. 15)

Element	Percent element in alloy —				
	S-590	19-9-DL	Timken 16-25-6	HS-31	GMR-235
Iron	24.6	67.2	49.0	2.00 max	8.0–12.0
Chromium	20.0	19.0	16.0	23.0–28.0	14.0–17.0
Nickel	20.0	9.0	25.0	9.0–12.0	Balance
Cobalt	20.0			Balance	
Molybdenum	4.0	1.25	6.5		4.5–6.0
Tungsten	4.0	1.25		6.0–9.0	
Manganese	0.75	0.75	1.5		0.25 max
Silicon	0.65	0.5	0.75		0.60 max
Columbium	4.0	0.4			
Titanium		0.35			1.5–2.5
Carbon	0.4	0.3	0.09	0.45–0.60	0.10–0.20
Aluminum	1.64				2.5–3.5
Nitrogen			0.15		
Boron					0.025–0.100

Table A.3. Gas velocities relative to blading for LDC design (Ref. 31)

[Six-stage turbine, 5700 rpm, 1300°F (705°C) inlet temperature, 71.0 psia (0.47 MPa) inlet pressure, 15.06 psia (0.1 MPa) exhaust pressure, 233,220 lb/hr (28 kg/sec) flow]

Stage	Blade root		Blade midsection		Blade tip	
	Velocity (fps)	Distance from center of rotor (in.)	Velocity (fps)	Distance from center of rotor (in.)	Velocity (fps)	Distance from center of rotor (in.)
1. Stator inlet	430	10.0	428	11.79	426	13.58
Stator exit	1000		893		804	
Rotor inlet	585		465		405	
Rotor exit	764		826		892	
2. Stator inlet	430	10.0	427	12.14	425	14.28
Stator exit	1000		872		780	
Rotor inlet	585		441		402	
Rotor exit	764		839		913	
3. Stator inlet	430	10.0	427	12.51	422	15.01
Stator exit	1000		853		758	
Rotor inlet	585		432		405	
Rotor exit	764		853		937	
4. Stator inlet	430	10.0	427	12.93	419	15.85
Stator exit	1000		834		733	
Rotor inlet	585		417		419	
Rotor exit	764		869		963	
5. Stator inlet	430	10.0	426	13.42	415	16.83
Stator exit	1000		812		710	
Rotor inlet	585		407		443	
Rotor exit	764		887		983	
6. Stator inlet	430	10.0	425	14.00	410	18.0
Stator exit	1000		790		680	
Rotor inlet	585		400		490	
Rotor exit	764		905		1030	

The turbine was first run on coal in September 1951. A description of the test is taken from Ref. 17:

> As soon as the acceptance test had been successfully completed, the fuel controls were turned from "Oil" to "Coal" and the plant was operated for a total of 178 hours on Pittsburgh seam high volatile bituminous coal. The machine operated as well with coal as with oil, and, in general, it was impossible for a casual observer to tell whether the plant was burning oil or coal. The stack was relatively clear and the ash disposal system worked satisfactorily. Combustion efficiency, as determined by ash analysis, was consistently above 95 percent. Trouble was encountered with damp coal and a number of alterations had to be made in the coal system. The width of the coal feed-pump rotor had to be increased to 5.0 in. (12.7 cm), and the method of venting the pump was altered. The duration of the coal-fired tests ranged from a few hours to a maximum of 43 hours.

This preliminary 178 hr of operation was carried out with a pilot oil burner in each combustor, and the maximum load carried for any significant period of time was 2000 hp (1492 kW) at a turbine inlet temperature of 1060°F (571°C).[19]

Figures A.2 and A.3 are photographs of the turbine rotor which were taken as soon as the cover had been lifted. The blades are entirely free from deposits and erosion. A slight discoloration of the last row of blades, extending inward about 0.5 in. from the tips, was the only indication that the turbine had been running on heated air.[20]

Experience with the Houdry unit had led to the expectation that erosion might be encountered in the stator blading, but a careful examination of the entire turbine showed only one very small spot of erosion. Figure A.4 shows the appearance of the upper half of the first row stator blading as seen from the inlet end. There is some brightening of the leading edges, but the only erosion was that on the two blades located at 12 o'clock, as shown in Fig. A.5. There were no deposits of ash anywhere in the turbine, and the labyrinth seals were all perfectly clean.[17]

The combustor was modified to eliminate the oil pilot flame, and the turbine was operated for an additional 757 hr at an average turbine inlet temperature of 1225°F (663°C).[21] During the first 71 hr of operation, a leak developed within the flyash separator and resulted in a large amount of coarse ash passing through the turbine, seriously eroding the first-row stator blading.[19] The leak was repaired and the test continued, but the turbine gradually lost power and there was a major reduction in power output from 625 to 757 hr. The test was terminated and the equipment dismantled for inspection. Erosion was noted on the trailing edges of the first five rows of rotor and stator blading, being progressively less toward the low-pressure end of the turbine. The sixth row of blading was only slightly eroded. No significant ash deposition was found on the turbine blading.[22,23]

Ash in the combustion gases driving the turbine was sampled at the turbine inlet and at the exhaust. About 40 lb/hr (18.2 kg/hr) of ash entered the turbine when the separation system was functioning at maximum effectiveness. The size distribution of the ash was approximately 2% plus

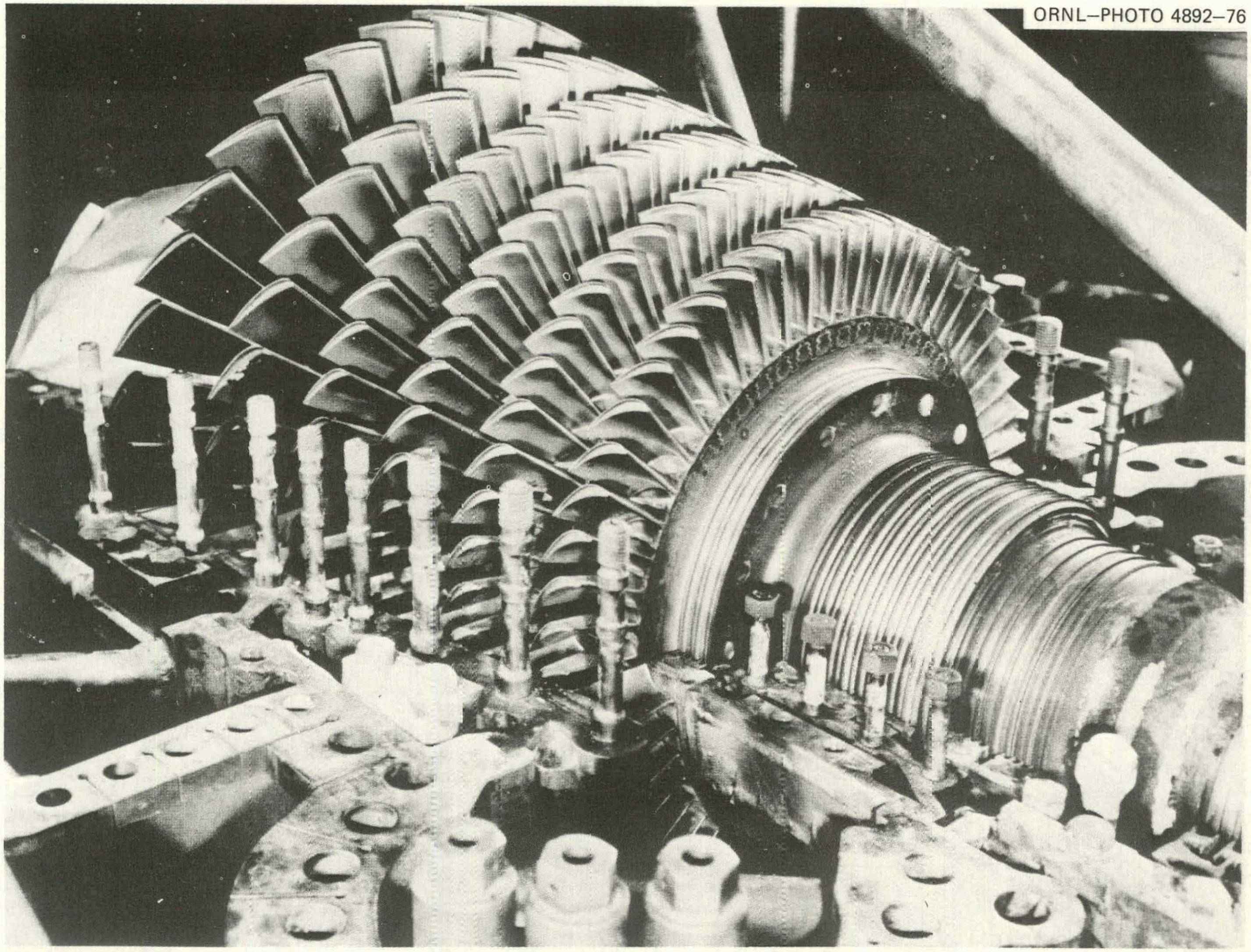

Fig. A.2. General view of locomotive turbine rotor, left side (Ref. 18).

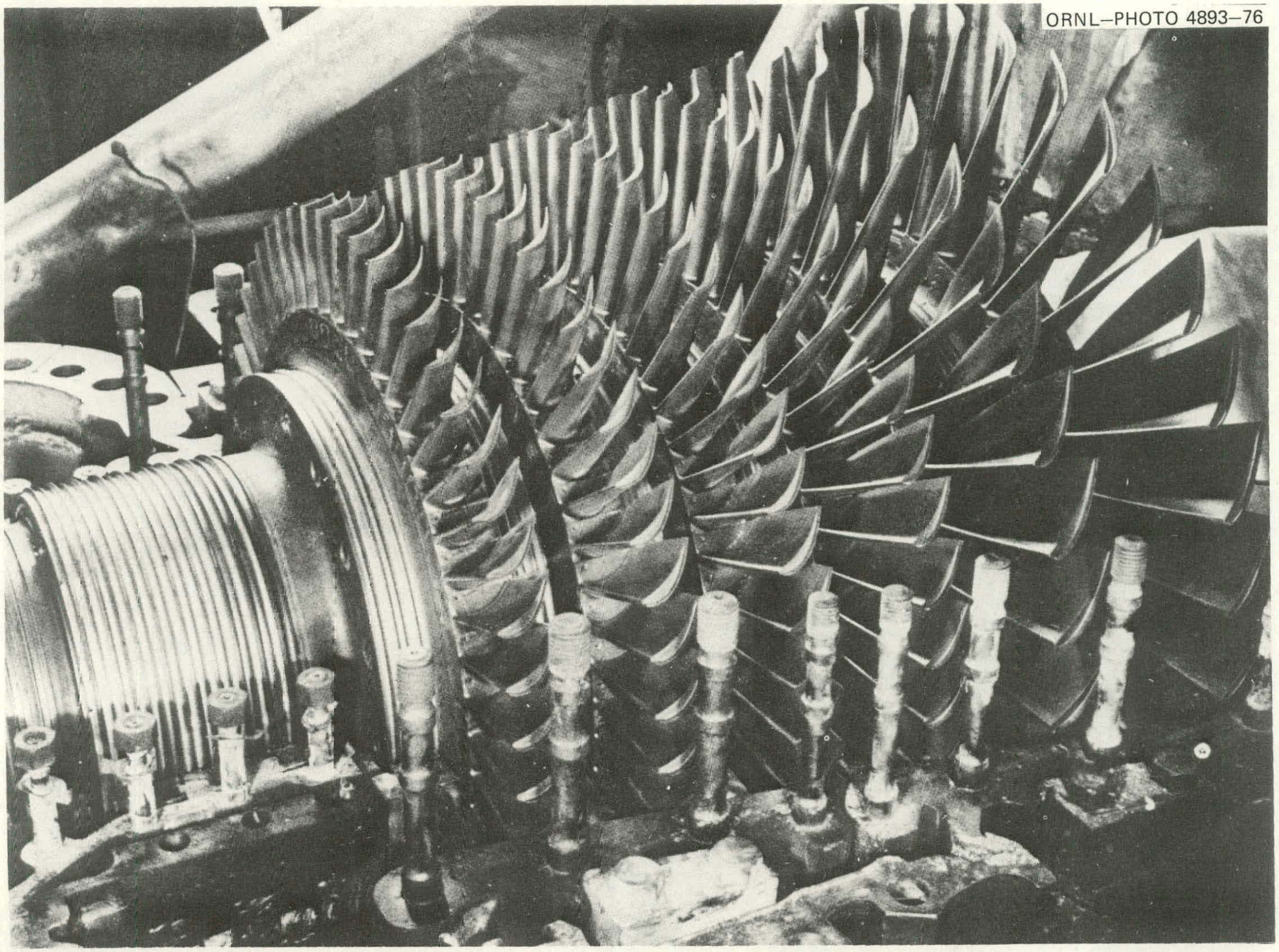

Fig. A.3. General view of locomotive turbine rotor, right side (Ref. 18).

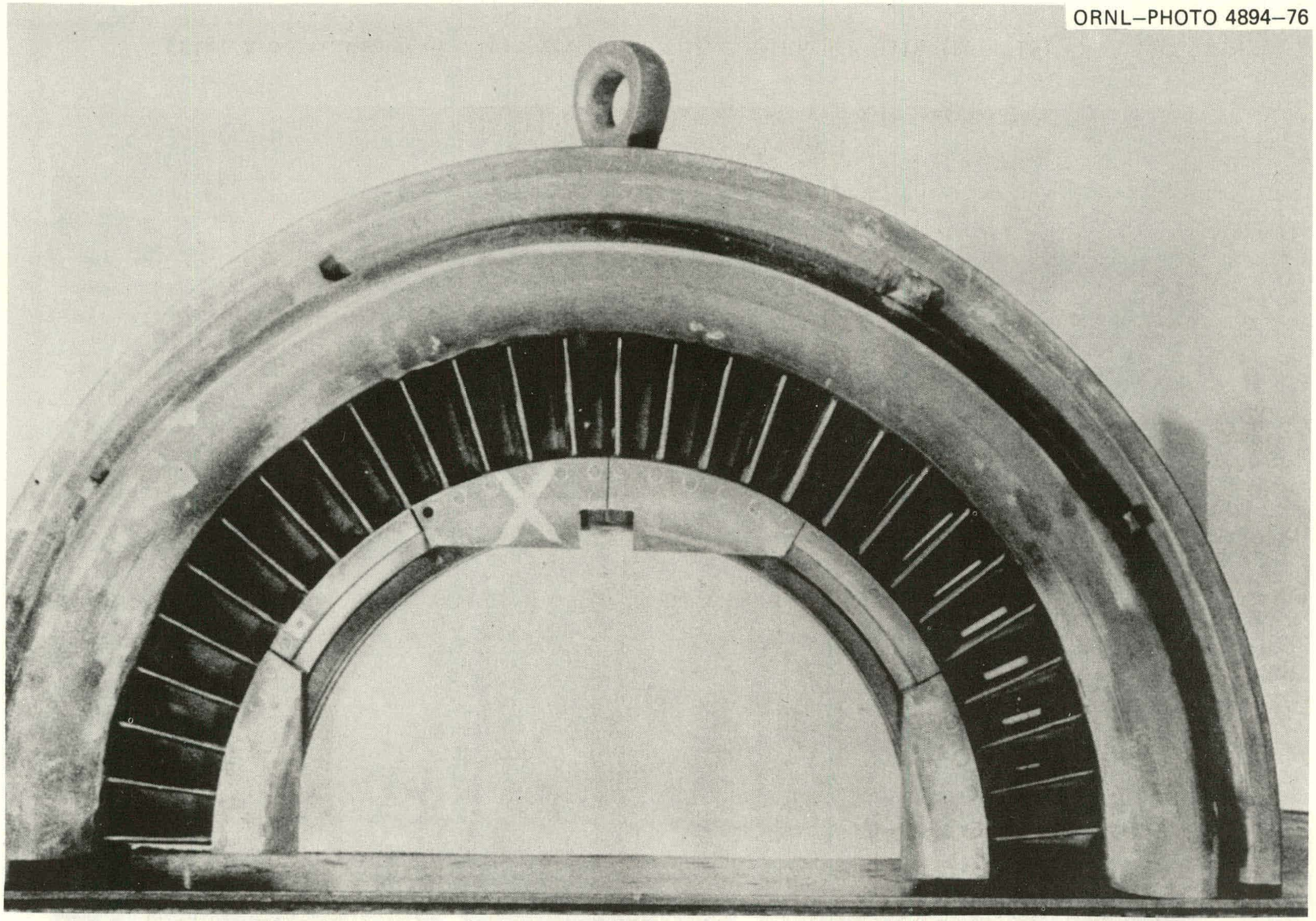

Fig. A.4. Front view of turbine stator blading, upper half (Ref. 18).

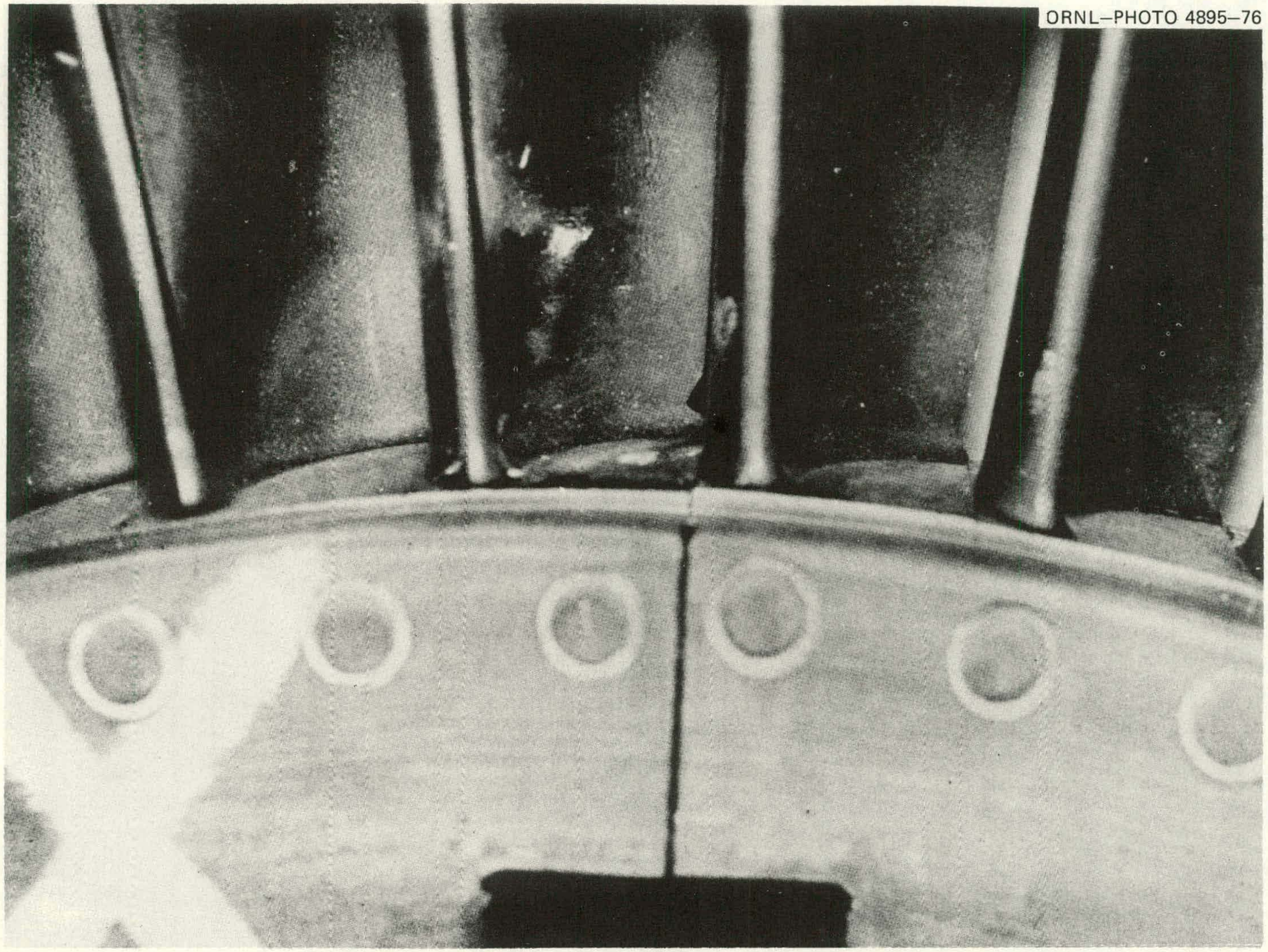

Fig. A.5. Closeup of first-row stator blading, upper half (Ref. 18).

20 μm and 15% plus 10 μm. Performance of the separator frequently deteriorated during the 757-hr test, increasing both the amount and size of the ash entering the turbine. Gas from the exhaust contained virtually no plus 10-μm ash particles, indicating that the turbine had pulverized the particles as they struck the blades.[22,31]

After the 757-hr test, the first four rows of rotor blades were replaced with blades of 19-9DL steel (Table A.2). The first four rows of stator blades were replaced with S-590 alloy, but the last two rows of rotor and stator blades were not changed. The regenerator was removed, and the combustor-to-separator path was lengthened by about 8 ft (2.44 m). The turbine was operated at 1060°F (571°C) inlet temperature and 4500 rpm for runs totaling 301 hr, and the ash separator functioned effectively throughout. Ash particles were rarely present in amounts greater than 1% plus 20 μm and 10% plus 10 μm. The first four stages of rotor blades did not erode, and erosion of the last two rows of rotor blades did not advance beyond that noted at the end of the 757-hr test. The stator blades were also free of erosion.[25]

Figures A.6 and A.7 are photographs of the turbine rotor taken as soon as the cover had been lifted. No ash deposits can be seen, although there is a thin layer of scale on the convex surfaces of the first row of blades.[25] Figure A.8 is a front view of the first-row stator blades. The insert is a closeup of the blades at 12 o'clock, which shows two small nicks that represent the only measurable erosion in the entire turbine.[25] Comparison of Fig. A.5, taken at the same location after the 178-hr tests, with Fig. A.8 indicates an almost identical nick that also represented the only measurable erosion in the entire turbine.

For comparison of the erosion in the first 316 hr of the 757-hr test with the 300-hr test, photographs of the first row stator blading taken at various times are shown in Fig. A.9.[25] Parts *a* to *c* apply to the 757-hr test, and parts *d* to *f* apply to the 300-hr test. Figure A.9*a* was taken after 71 hr of operation at an average turbine inlet temperature of 1050°F (546°C).[24] As mentioned earlier, during this period of operation a leak developed within the flyash separator and large quantities of coarse ash entered the turbine, resulting in serious erosion.[25] Figure A.9*b* was taken 124 hr later. During this period the turbine was operated with an average

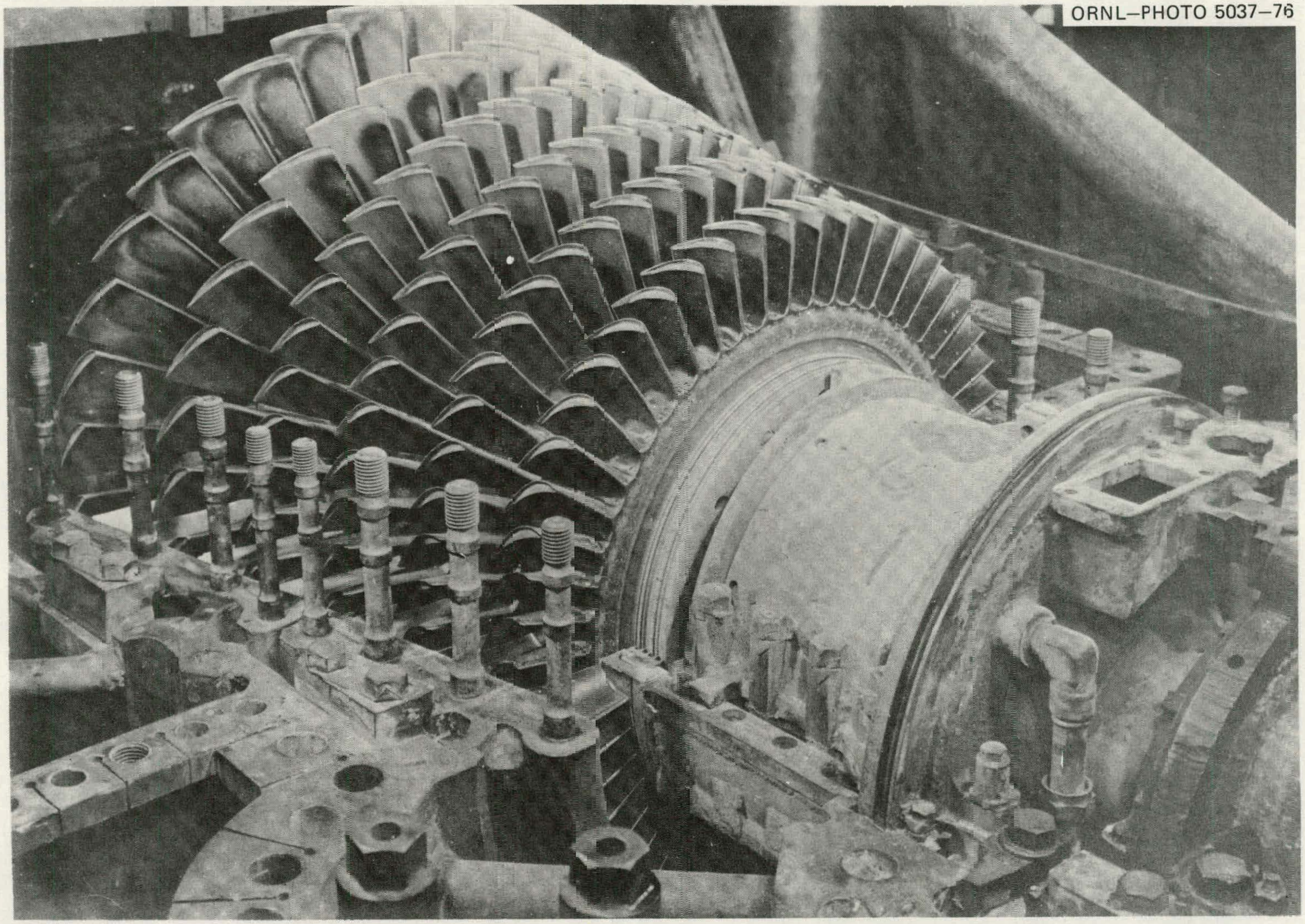

Fig. A.6. Turbine rotor after 300-hr test, view from left side (Ref. 23).

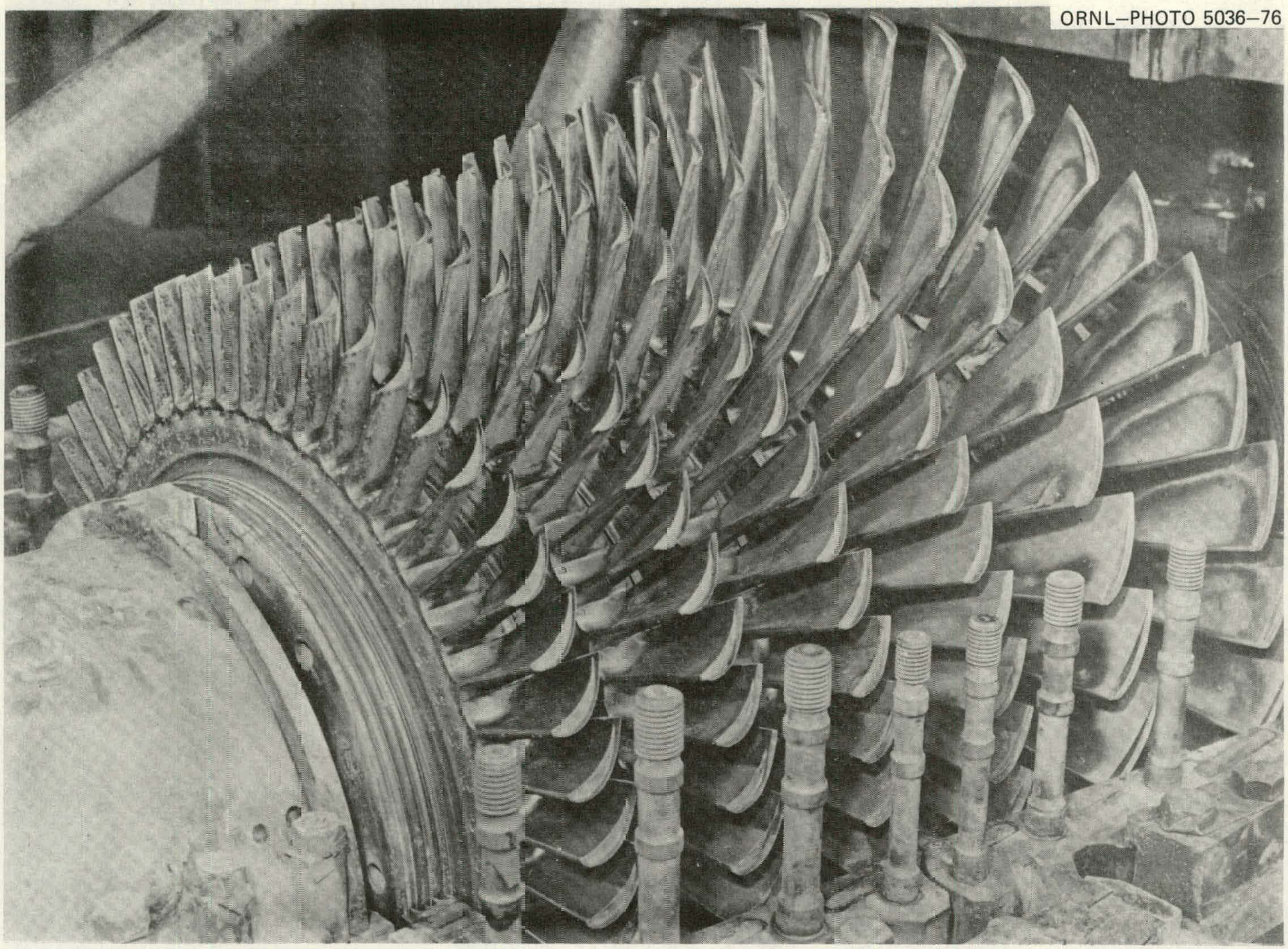

Fig. A.7. Turbine rotor after 300-hr test, view from right side (Ref. 23).

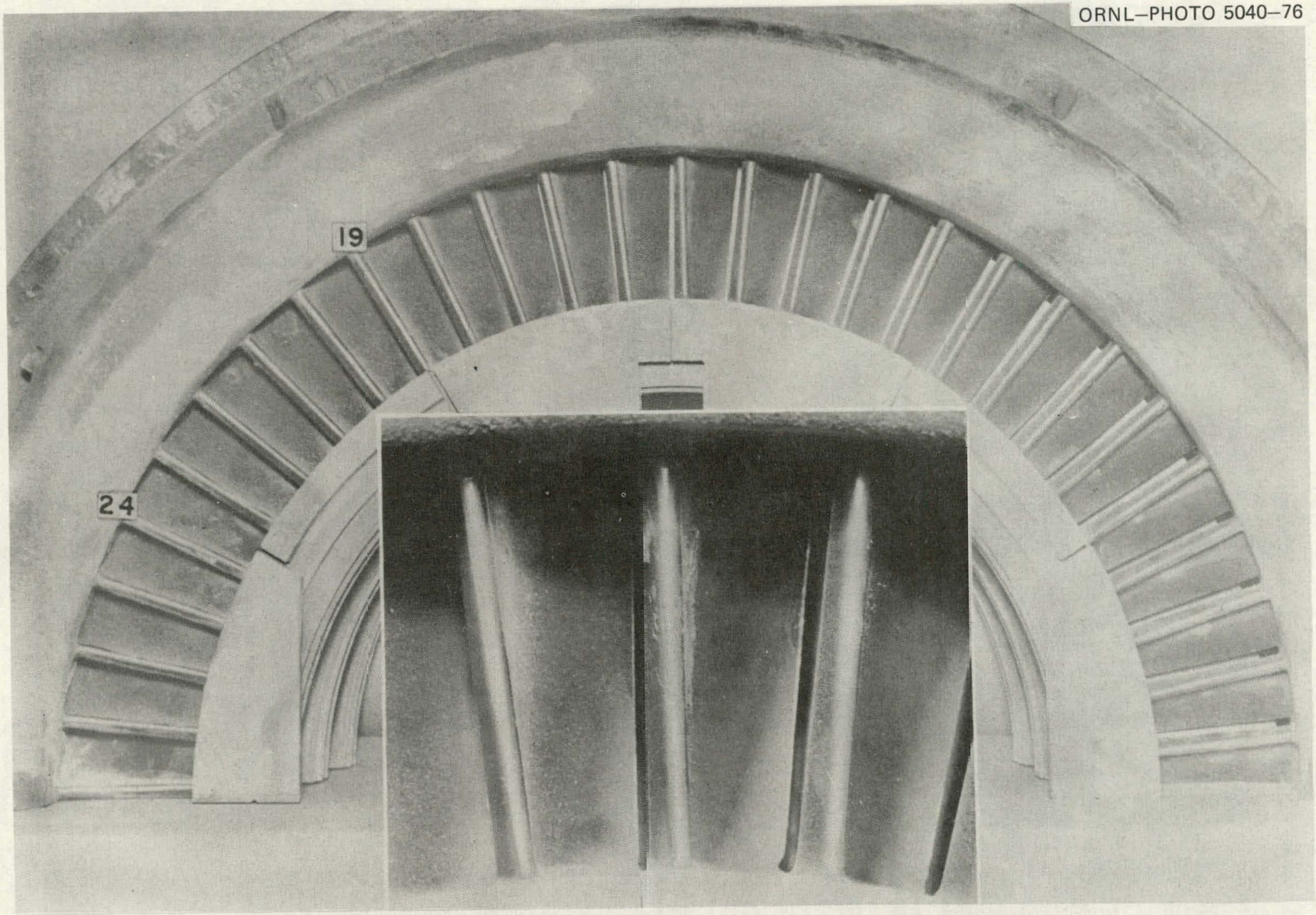

Fig. A.8. Front view of first-row stator blades. Insert shows closeup of blades at 12 o'clock (Ref. 23).

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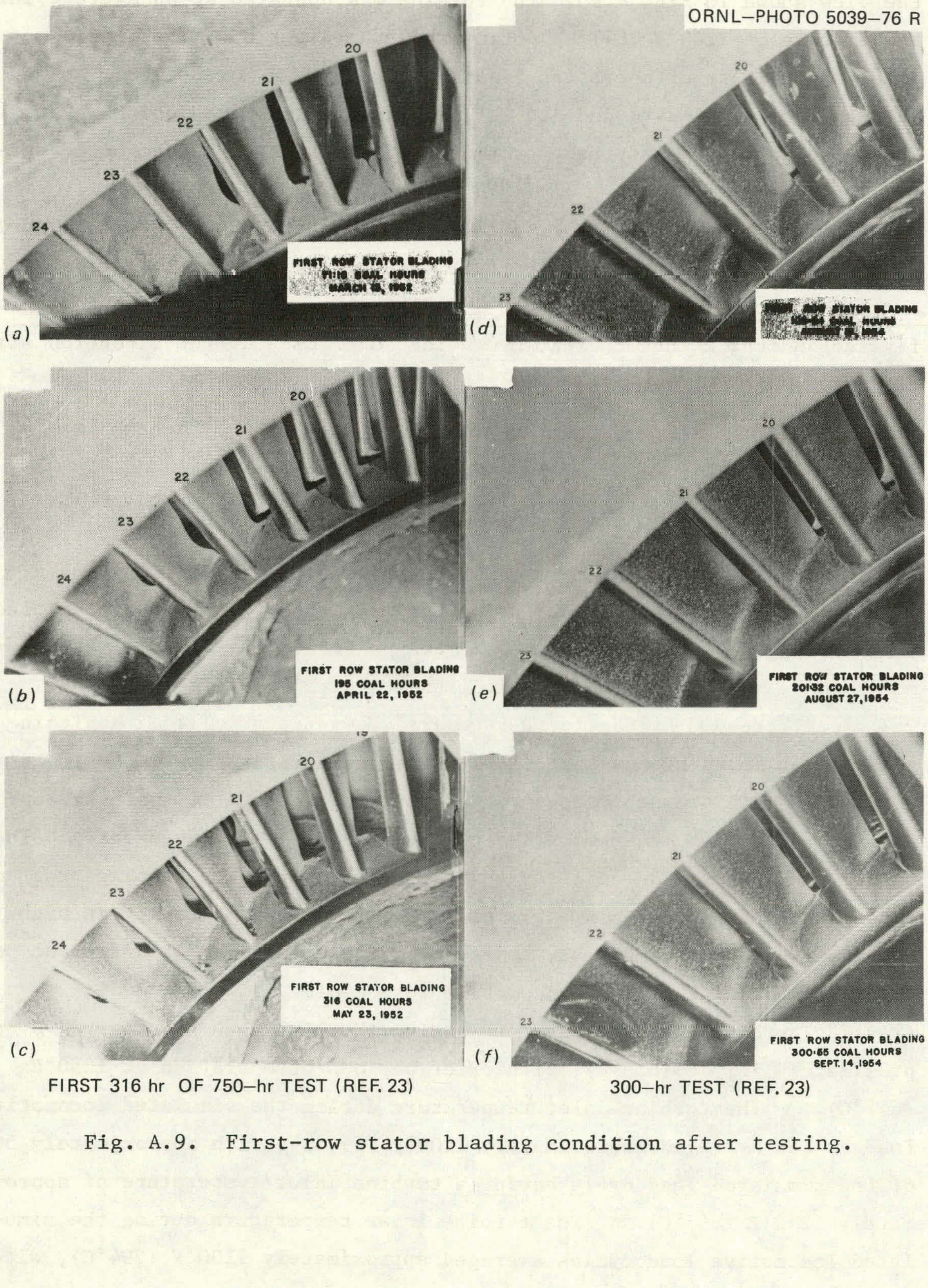

Fig. A.9. First-row stator blading condition after testing.

inlet temperature of 1160°F (627°C). Figure A.9*c* was taken 121 hr after the view shown in Fig. A.9*b*. The turbine was operated at an average inlet temperature of 1240°F (671°C) during this third period. The erosion noted after 71 hr of operation became progressively more severe, as can be seen from Figs. A.9*b* and A.9*c*. The extent of the erosion shown in Fig. A.9*c* was such that the performance of the turbine had begun to suffer.[25]

Figures A.9*d* to A.9*f* are photographs taken at 100-hr intervals during the 300-hr test.[25] During this test, the turbine was operated with an average inlet temperature of 1060°F (571°C).[24] Inspection of these three figures indicates that there was no visible erosion of the first-row stator blading.

Figure A.10*a* is a photograph of the discharge side of the third-row stator blading taken at the end of the 757-hr test, and Fig. A.10*b* is a photograph of the same location taken at the end of the 300-hr test.[25] Figure A.10*a* shows the extent to which the third-row stator was eroded. Apparently, the large particles that entered the turbine had not been reduced in size at this point in the turbine. The third-row stator blading shown in Fig. A.10*b* after the 300-hr test was found by micrometer measurements to be virtually unchanged from the original installation.[25]

After the 300-hr test, the regenerator was reinstalled. Replacing the regenerator moved the combustors back to their original position immediately ahead of the flyash separator and shortened the combustion path by approximately 12 ft (3.66 m) as compared to the 300-hr test arrangement.[26] The system was operated on coal for a total of 1421 hr. The testing program consisted of two parts. First, the system was run continually at high power for a period of 852 hr, and then it was run 569 hr at different power levels to simulate various locomotive load cycles.[27]

The turbine inlet temperature during the high-load test averaged approximately 1210°F (655°C), with brief periods of operation at 1250°F (677°C).[26] The turbine inlet temperature during the simulated locomotive load cycles averaged approximately 1100°F (594°C), with approximately 50% of the simulated load cycle having a turbine inlet temperature of approximately 1230°F (666°C).[26] The turbine inlet temperature during the simulated locomotive load cycles averaged approximately 1100°F (594°C), with

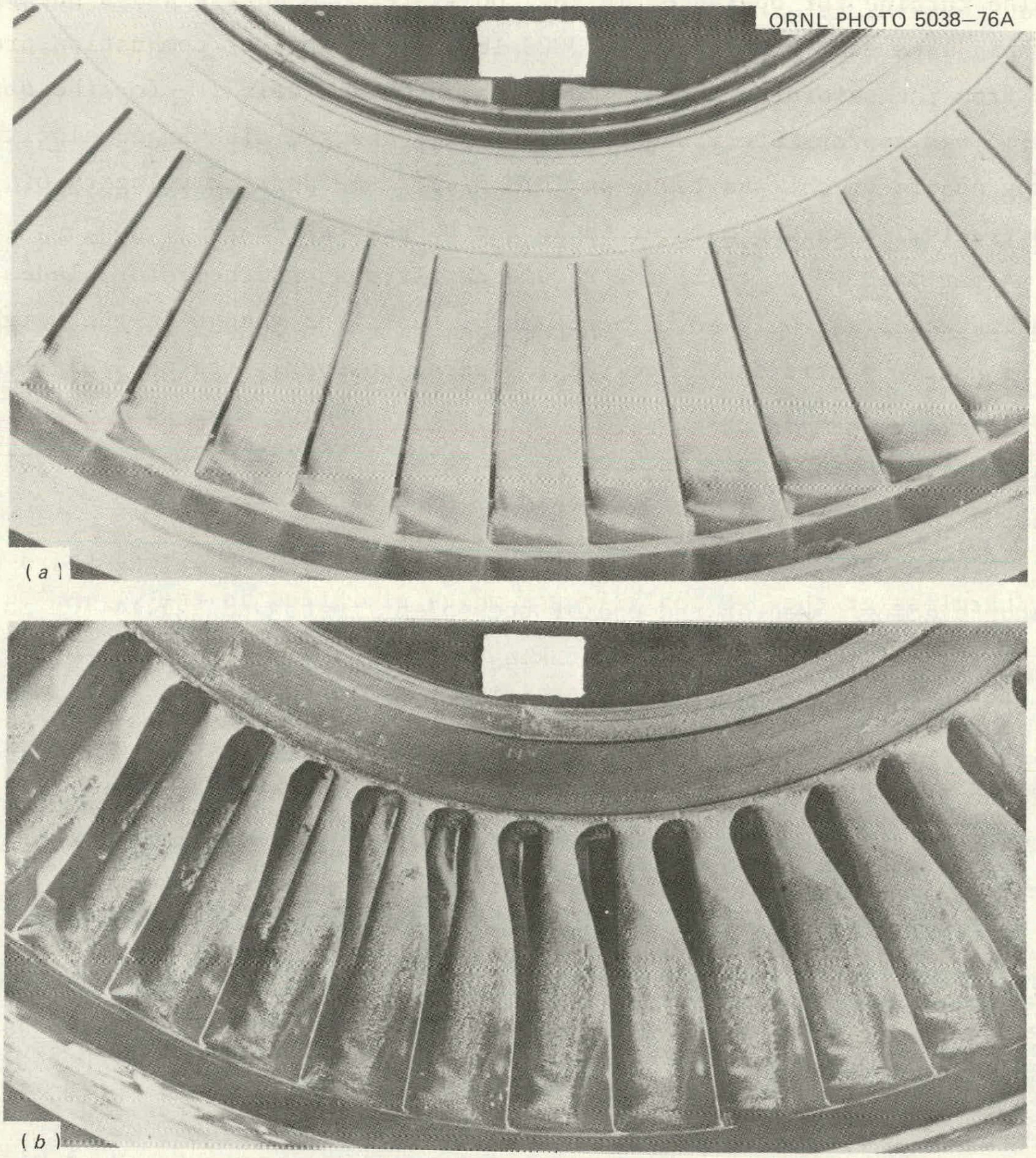

Fig. A.10. Discharge side, third-row stator blading. (a) At end of 750 hr; (b) at end of 300 hr test (Ref. 23).

approximately 50% of the simulated load cycle having a turbine inlet temperature of approximately 1230°F (666°C).[26] The size of the ash entering the turbine ran as high as 12% plus 20 μm and 32% plus 10 μm.

During the first 907 hr of the 1421-hr test of the turbine, erosion tests were conducted to obtain information as to the suitability of an impulse turbine for operation in the LDC system. A nozzle and a bucket test rig were each supplied with 3000 lb/hr (380 g/s) of combustion products from the separator outlet flow. The approach velocity for the nozzle rig was approximately 340 fps (104 m/s), and the discharge velocity at the nozzle throat was 1900 fps (579 m/s). An approach velocity of 1400 fps (427 m/s) was maintained in the bucket test rig.

After the 907-hr test, the nozzle partitions and the rotor blades were inspected and weighed. There was virtually no change in the weight of the nozzle partitions. The rotor blades, however, were severely eroded, especially the concave side.

The conclusion drawn from these tests by the LDC and which is valid only for the particular test conditions is taken from Ref. 26.

> The quality of air entering the LDC turbine is relatively harmless at the 340 fps velocity which prevailed in the nozzle test rig. Extremely rapid acceleration to a velocity as high as 1900 fps (579 m/s) also caused very little wear on the concave surface of the partition. In the blade test rig, air of the same quality proved to be very erosive at an approach velocity of 1400 fps (427 m/s). These facts lead to the conclusion that a multi-stage reaction turbine has a far better chance of operating successfully with coal as its fuel than does an impulse turbine with very high velocities.

After the 1421-hr test, the turbine was opened for inspection. The first-row rotor blades were not seriously eroded, but the second row suffered wear in a narrow band near the rotor. In addition, small notches were cut in the trailing edges of some blades, and stresses at these notches formed cracks. Semicircular notches were cut in the third row of rotor blades, near the blade roots, and there were cracks near the notches in many of the blades. Wear of the fourth-row blades was similar to that of the third row. Rotor blades in the fifth and sixth rows suffered somewhat more wear than they had during the first test run, but there was no marked change in their condition.

Wear on the stator blades followed approximately the same pattern as that on the rotor blades — a narrow band near the turbine rotor. A second zone of localized wear occurred in a narrow band extending radially inward for approximately 1/8 in. (0.32 cm) at the outer diameter of the stator blades in the last four stages.

Light ash deposits were found on the backs of some of the stator blades, but only the third stage had ash coatings thicker than 0.005 in. (0.13 mm).[27] Normal blade wear was confined to approximately 0.0053 in./1000 hr (0.135 mm/1000 hr) on the concave surfaces of both the stator and rotor blading.[26]

After the 1421-hr test, the turbine was reconditioned and operated on coal for 1103 hr. The reconditioning of the turbine included the installation of a deflector ring in front of the base of the first-row stator blades to block the flow of the concentrated stream of dust at this point. Skimmers were installed in the turbine inlet to remove dust concentrated at the concave surface of the turbine inlet.

The first four stages of rotor blades were replaced with new blades made of HS-31 and GMR-235 (Table A.2). The last two stages of blades were unchanged, and the stator blading was the same as used in the preceding run, except that the inner stage shroud and seal rings for rows two, three, and four were removed.[28]

During the 1103-hr test, the turbine operated with an average load of 2960 hp (2200 kW), which probably corresponds to an average turbine inlet temperature of approximately 1200 to 1230°F (649 to 666°C). The size of the ash entering the turbine inlet and passing through the turbine was similar to that of the 1421-hr test.[31]

After completion of the test the turbine was opened for inspection. The first-stage rotor blades were free from erosion. The second, third, and fourth stages were seriously undercut at the base of the leading edge of the blade, but no other serious erosion was noted on the turbine rotor blades. The pressure surfaces of the stator blading were in good condition. The trailing edge of the blades in rows 3 to 6 suffered some erosion, and the ash also cut notches at the outer sidewall base of the leading edges of these blades.[31]

United States Bureau of Mines

With the completion of the 1103-hr test, the Locomotive Development Committee (LDC) ended its experimental program in 1959. The U.S. Bureau of Mines under a cooperative agreement with Bituminous Coal Research, Inc., obtained the LDC turbine and associated equipment for further development. The equipment was moved from Dunkirk, New York, to Morgantown, West Virginia.

The Bureau of Mines contracted with the Gas Turbine Division of the General Electric Company to review the LDC tests and develop a new blade design specifically tailored for a coal-fired turbine plant. A description from the turbine modification recommended by General Electric is excerpted from Ref. 31.

> While no single theory uniquely explained the erosion pattern observed in the LDC tests, significant features of the erosion problem were uncovered and described. Two changes were recommended to reduce the rate of erosion. One change was to encourage ash to concentrate at the outer sidewall, rather than at the roots of the rotor blades. Wear at the rotor blade tips and outer sidewall base of the nonrotating stator blades is less damaging than wear at the base of the highly stressed rotor blades. The second recommendation was the use of titanium carbide wear strips (titanium carbide wears at 1/9 the rate of the Hastelloy-31 blade metal) at the outer sidewall base of certain stator blades to minimize erosion. Wear strips also were specified for the base of certain rotor blades, in case ash still concentrated at the inner sidewall.
>
> Detailed changes recommended for the new design contemplated the use of the existing turbine rotor, casing, and inlet hood to minimize the need for extensive modifications to the turbine. Skimmers and deflectors installed in the inlet hood prior to the 1103 hr test were retained since they appeared to have a beneficial effect of the existing inlet as a condition of the new design.
>
> The first major change was the provision of an axial space between the first-stage stator and rotor blades to centrifuge ash particles toward the outer casing by main stream gas flow. This space was provided by removing rotor row 1 and stator row 2 from the six-stage turbine, converting the unit to a five-stage turbine. Calculations indicated that this would clear the inner 1.8 inches of the annulus at the entrance to the first-stage rotor blade of all particles larger than 12 μ. The second change involved the design of stator blades to minimize flow separation and end whirls (passage vortex buildup) by the use of new profile shapes and a higher solidity. Blade chords were not changed, but the trailing edges of the blades were reduced to the minimum practicable thickness [.035 in. (0.89 mm)]. These changes were designed to minimize the radial inflow of ash to the inner diameter. None of the stators, except for the first and fifth stages, were to have inner sidewalls (as in the 1103 hr test). Stator blade tips were specified as

solid, without rub strips, with tip clearance the same as in the 1103 hr test. This duplicated the conditions of the 1103 hr test, in that there would be the same leakage under the stator tips. The solid tip design, however, was expected to reduce the rate at which the tip clearance increased due to erosion.

The third change called for the inner and outer sidewalls to be stepped, and for titanium carbide wear strips to be installed to take the impact of ash flowing through the clearance at the tips of the stator and rotor blades.

The fourth design feature was that the rotor blades have approximately the same cross sections as used before, except the thickness of the trailing edge was increased to the maximum value [0.120 in. (3.0 mm)] consistent with turbine efficiency to encourage ash flow radially outward from the inner diameter.

Table A.4 from Ref. 31 shows the gas velocities relative to the blading for the new design.

Table A.4. Gas velocities relative to blading for new design (Ref. 31)

[Five-stage turbine, 5700 rpm, 1300°F (705°C) inlet temperature, 79.2 psia (0.5 MPa) inlet pressure, 15.64 psia (0.1 MPa) exhaust pressure, 288,000 lb/hr (36 kg/sec) flow]

Stage	Blade root		Blade midsection		Blade tip	
	Velocity (fps)	Distance from center of rotor (in.)	Velocity (fps)	Distance from center of rotor (in.)	Velocity (fps)	Distance from center of rotor (in.)
1. Stator inlet						
Stator exit	1314	10.3	1125	12.25	990	14.25
Rotor inlet	840	10.3	599	12.25	450	14.25
Rotor exit	833	10.3	889	12.25	952	14.25
2. Stator inlet	456	10.3	440	12.25	430	14.25
Stator exit	1296	10.3	1085	12.60	941	14.95
Rotor inlet	825	10.3	558	12.60	424	14.95
Rotor exit	854	10.3	919	12.60	995	14.95
3. Stator inlet	473	10.3	453	12.60	441	14.95
Stator exit	1265	10.3	1030	13.05	884	15.80
Rotor inlet	798	10.3	512	13.05	421	15.80
Rotor exit	896	10.3	996	13.05	1057	15.80
4. Stator inlet	510	10.3	486	13.05	466	15.80
Stator exit	1265	10.3	1005	13.55	849	16.80
Rotor inlet	802	10.3	499	13.55	457	16.80
Rotor exit	918	10.3	998	13.55	1106	16.80
5. Stator inlet	538	10.3	505	13.55	489	16.80
Stator exit	1245	10.3	948	14.30	789	18.25
Rotor inlet	783	10.3	457	14.30	504	18.25
Rotor exit	940	10.3	1040	14.30	1176	18.25

The turbine was operated 1963 hr cumulative in two tests with an inlet temperature of approximately 1230°F (666°C). The first test ran for 878 hr and was ended by buildup of deposits on the first-stage stator blading. The buildup caused surging in the compressor which prevented restart after a shutdown. The turbine was disassembled, inspected, cleaned, and returned to service. The second test of the turbine continued for 1085 hr and shutdown was voluntary for evaluation of the erosion damage to the blading.

A description of the condition of the turbine blading after the two tests is excerpted from Ref. 31.

> The first-stage stator blades showed little visible evidence of erosion. Blades in stages 2 to 5 were significantly eroded at the outer sidewall bases. Except for the first stage, ash deposition on the blades was minimal. Pressure faces of the first-stage stators were relatively clean, but their backs were coated with ash. Also, large curlicues of hard, bonded ash gradually built up between the bases of the first-stage stator blades, eventually blocking the gas flow and forcing an end to the test. Light deposits of ash formed on the second-stage stators, and they were slightly eroded as indicated by a polished area at the base of the leading edge.
>
> Only very light deposits of ash formed on the last three stages of stator blades. Ash eroded notches in the polished areas at the base of the leading edges of these blades, just above the titanium carbide inserts, and thinned the edges of these blades near the bases.
>
> The rotor blades were in excellent condition following the first test. Although not seriously eroded, polished spots on the leading edges and sides of the base of rotor blades in rows 3, 4, and 5 indicated minor erosion caused by concentration of ash near the rotor. The rotor blades were lightly coated with ash, primarily on the backs; the coating was heaviest on the first stage and progressively lighter on successive stages.
>
> Inspection after the second test indicated that the ash deposition and erosion followed the same pattern as in the first test, although the ash buildup on the first-stage blades was not as heavy as before. The stator blades were eroded in the same areas as in the first test, but erosion was more severe. Much larger notches were cut into the bases of the leading edges, primarily in rows 2, 3, and 4. Also, ash eroded the trailing edges of the blades in these rows much more than in the first test.
>
> The rotor blades after the second test showed little damage, with the extent and pattern of ash deposition approximately

the same as after the first test. The rotor blades were visibly free of wear after the second test, although slight wear was visible along 1/3 the length of the leading edge of each blade, measured from the tip. All rotor blades were weighed before and after the second test. The weight loss for each blade was almost constant at 9 grams. All in all, the rotor blades were in good condition following the second test, and without notches at the roots of the blades — the most seriously eroded area in the last LDC test.

The significant increase in stator blade erosion in the second test was unexpected because both operating conditions and running time were virtually the same as in the first test. This marked increase in erosion is attributed to false information from improperly connected thermocouple leads. Thermocouple readings served to indicate ash plugging of the discharge lines of the centrifugal-type ash separators — 26 in two banks of 13 tubes each. Thermocouple leads from each bank were connected to separate recorders. For the first 185 hours of the second test, these leads were connected to opposite banks, plugging of separators in the right bank being indicated on the left bank recorder. The thermocouples were believed faulty when plugging was not verified by examination; therefore, operations were carried on with several plugged separators in one bank. Thus, the concentration and size of ash entering the turbine probably was markedly higher during the first 185 hours of the second test.

Rotor blade profiles, measured with a probograph before and after each test to determine the loss of metal from erosion, indicated the rotor suffered comparible wear. Similar measurements could not be made on the stator blades, because they were welded together into segments. These measurements showed that 70 percent of the wear on the pressure faces of the rotor blades occurred during the 1085-hour second test. Thus, the average erosion rate during the second test was almost twice that of the first test.

Blade erosion was effectively reduced by the blade design. Aerodynamic features of the new blades reduced the concentration of ash at the rotor — the rotor blade roots and stator blade tips were not seriously eroded. Small quantities of ash, however, still concentrated near the rotor, as evidenced by shiny areas at the bases of the rotor blades in the last three rows. Also, as expected, ash concentrated heavily at the turbine casing, eroding the rotor blade tips and stator blade bases.

Effectiveness of another design feature, the stepped-side-walls and titanium carbide wear strips, is questionable. Erosion of stator blade roots was not prevented, and it is not clear if the reduced erosion of the rotor blade roots was due to the wear strips or the aerodynamic design features intended to concentrate ash at the casing. None of the wear strips were significantly eroded. Significant quantities of ash may have struck the rotor

> blade wear strips, but with insufficient velocity to erode the titanium carbide.
>
> Manufacturers of industrial gas turbines (who inspected the blades) and Bureau of Mines engineers estimate the effective life of the rotor blades as 20,000 hr and the stator blades at 5,000 hr. These estimates assume a uniform erosion rate, and are based on the condition of the blades after 1963 hr. If these figures are adjusted to compensate for the plugged ash separator discharge lines in the second test, the estimated life for the rotor blades would be 30,000 hr and for the stator blades 7500 hr.

A summary of the operating experience by both the Locomotive Development Committee and the U.S. Bureau of Mines on the five-stage Houdry turbine and six-stage Locomotive turbine is given in Table A.5. It should be noted that the 757-hr test in 1952 and the 1085-hr test in 1964 were conducted under conditions of unknown ash separator efficiency at the start of the experiments. For the remaining data given in Table A.5, the flyash separation system was functioning as designed throughout the test. Examination of these data indicate that satisfactory operation (minimal deposits and erosion) for a direct coal-fired gas turbine could be obtained for a particulate loading of approximately 100 ppm with a size range of 10 to 15% plus 10 μm and 1 to 2% plus 20 μm at a turbine inlet temperature of 740 to 1060°F (394–571°C).

Aeronautical Research Laboratories

Ruston and Hornsby "TA" turbine

During the period between 1948 and 1970, the Aeronautical Research Laboratories (ARL), Department of Supply, Melbourne, Australia, investigated the technical feasibility of the direct-fired operation of a coal-burning gas turbine. The following description of their work is excerpted from Ref. 33.

> In the earlier stages of the investigation (1948–1958), rig scale experiments were conducted on three aspects of the general problem:
>
> a. coal pulverizing and handling,
> b. high intensity combustion and combustor development,
> c. ash fouling and erosion.

Table A.5. Locomotive Development Committee operating experience with open-cycle coal-burning gas turbines

Engine[a]	Year of test	Power [kW(e)]	Turbine inlet temperature (°F)	Air flow (lb/sec)	Tip speed (fps)	Maximum length of run[b] (hr)	Total running time (hr)	Particulate content (ppm)	Particle size (% + 10 μ/ % + 20 μ)	Erosion and deposits[c]
					Negligible erosion and deposits					
A	1951	0	740	57		250	1250	88	16/2.1	E-N, D-S
B	1951	1500	1060	57	713	178	178		15/1.5	E-N, D-N
B	1954	1500	1060	57	713	300	300	∿130	10/1	E-N, D-N
					Serious erosion and deposits					
A	1950	0	740	57		250	1250		42/8	E-H, D-N
A	1950	0	740	57		250	1250		31/5	E-H, D-N
A	1951	0	740	57		250	1250		59/22	E-M, D-N
B	1952	2060	1225	66	832	757[d]	757	170[e]	15/2[e]	E-H, D-N
B	1955	2160	1250	66	832	1271	1421		32/12	E-M, D-S
B	1957	2210	1250	66	832	1102	1103		32/12	E-M, D-S
C	1963	1235	1229	66	832	878[f]	878	210	10/2	E-M, D-M
C	1964	1235	1229	66	832	1085	1085	210[g]	10/2[g]	E-M, D-M

[a] A, Allis-Chalmers 5-stage Houdry turbine; B, Allis-Chalmers 6-stage locomotive turbine; C, Allis-Chalmers 5-stage turbine (turbine B modified and operated by the U.S. Bureau of Mines).

[b] Runs not terminated because of turbine difficulty.

[c] Deposits: D-N, negligible; D-S, slight; D-M, moderate; D-H, heavy. Erosion: E-N, negligible; E-S, slight; E-M, moderate; E-H, heavy.

[d] Run terminated because of major reduction in output power.

[e] Separator inoperative first 71 hr and deterioration throughout test.

[f] Run terminated because of blade deposits preventing restart.

[g] Half of separators inoperative first 185 hr of test.

By mid-1953 the research program had reached the stage where it was believed that most of the difficulties to be encountered with fuel preparation and combustion had been revealed.

The results of tests on a coal-fired rig turbine based on an aircraft supercharger produced little evidence of erosion but revealed a serious ash deposition problem. The real magnitude of the ash deposition problem was not known, because the rig turbine blading was aerodynamically crude as compared to the current gas turbine technology; and it was believed that the rate of ash deposition would be a strong function of the blade configuration.

A Ruston and Hornsby "TA" gas turbine system was obtained and commissioned in 1958. The system consisted of a 13-stage axial compressor driven by a 2-stage turbine. The gas exhaust from the compressor drive turbine was used to drive a 2-stage power turbine. The engine was designed for operation on distillate fuel with a maximum turbine inlet temperature of 1340°F (727°C). For operation with direct coal firing, the maximum turbine inlet temperature was reduced to 1202°F (650°C).

Comparative operating data on oil and coal are listed in Table A.6.

For the initial testing machine, the fuel oil combustor was replaced with a close-coupled coal-burning combustion chamber using Yalbourn brown

Table A.6. Operating data for Ruston and Hornsby turbine fueled with oil and coal

	Oil operation	Coal operation
Compressor turbine inlet temperature, max °F (°C)	1,340 (727)	1,202 (650)
Power output, bhp (kW)	1,300 (970)	900 (671)
Air flow, lb/sec (kg/sec)	23 (10.46)	20 (9.09)
Compressor pressure ratio	4.15	3.33
Compressor speed, rpm	11,500	10,200
Power turbine inlet temperature, °F (°C)	1,024 (551)	946 (507)
Power turbine exhaust temperature, °F (°C)	844 (451)	800 (427)
Power turbine speed, rpm	6,000	5,000
First-stage stator mean exit velocity		
Compressor turbine, fps (m/sec)	1,265 (386)	1,100 (335)
Power turbine, fps (m/sec)	902 (275)	784 (239)

coal as the fuel. Typically this coal contains 15% moisture, 1.5% ash, and 44% volatile matter and has a higher heating value of 9290 Btu/lb (2.16×10^7 J/kg).

The ash from the combustion of the coal fuel was fed directly to the compressor turbine with the combustion air without any attempts to reduce the ash content by means of an ash separator.

During the preliminary tests with solid fuel, low combustion efficiency and large coal particle sizes (30 to 40% greater than 53 μm) resulted in high blade erosion rates and heavy sintered deposits on the convex surface of all blade rows in the compressor turbine.

Modifications to the coal pulverizer produced a coal feed 80% smaller than 53 μm. The system was operated at a compressor turbine inlet temperature of 1202°F (650°C) for a period of 20 hr.

The turbine was operated with distillate fuel for short periods during the test to obtain a measure of the engine performance. These tests showed a decrease in the power output of 2.5% over the 20-hr period. Inspection after the 20-hr test showed a severe buildup of ash on the stator leading edge which probably resulted in a reduction in the "swallowing" capacity of the engine.

Erosion of the stator and rotor blades occurred in both stages of the compressor and the power turbine. The metal loss rates for the stator blading are given in Table A.7. The erosion rates are based upon the blade wetted area.

Table A.7. Stator blade weight loss — 20-hr test without ash separation (Ref. 33)

	Erosion rate (mg/cm/hr)		
	Maximum	Minimum	Average
Compressor turbine			
First row	1.2	0.34	0.62
Second	2.73	1.34	2.15
Power turbine			
First row	0.16	0.09	0.13
Second row	0.21	0.16	0.20

The following description of the ash deposition is taken from Ref. 33:

> The magnitude of the ash deposition problem was indicated in the tests. The blades most seriously affected were in the first stator row of the compressor turbine which received gases from the combustor at the highest temperature, and at the relatively low velocity of 540 fps (165 m/s). Two types of ash deposit were evident:
>
> (a) A dense, sintered material in the region of the leading edge of the blade, and, depending on the position of the blade in the stator ring, extending over a portion of the concave or convex face. It appeared to build up in the areas of attached flow, was very brittle and often spalled away from the blade on cooling; polishing of the blade surface increased the tendency for the deposit to break away.
>
> (b) A light brown, powdery deposit, which built up to a depth of about 1/16 in. (1.6 mm) downstream of a region of flow separation, mainly on the convex surface. Particles from this deposit were in the submicron range and could be easily removed from the blade surface by water washing.
>
> The dense, sintered deposit was confined to the first row of stator blades; the remaining rows of stators, and the rotor blades in the compressor and power turbines, exhibited a light powdery deposit only in regions of separated flow.
>
> Examination of the hard deposit under a microscope revealed a porous matrix, but it was not possible to identify individual particles. An X-ray diffraction analysis showed that the principal constituent was magnesium oxide, together with iron oxide and calcium sulphate. A chemical analysis confirmed these findings and indicated also the presence of small smounts of sodium, presumably in the form of sodium sulphate. The relative concentrations of the constituents of the deposit were similar to those existing in the original coal ash.
>
> These tests showed that blade erosion would be a serious problem. With the existing engine arrangement the high rate of metal removal, particularly in the second stage of the compressor turbine, would not be industrially acceptable; it was estimated that the life of the more heavily eroded blades would be of the order of 100 hr.
>
> The operation of the engine was satisfactory, although the power output at the turbine inlet temperature of 650°C (1,202°F) decreased by the order of 2.5 percent over the 20-hour period. The progressive deposition of the hard ash on the concave face of the first row of stator blades would constitute an obstacle to extended running even if blade erosion could be prevented.

Early bench-scale ash deposition experiments conducted by ARL indicated the importance of the effects of incomplete combustion of the fuel upon the formation of deposits.[33] One of these experiments involved the impingement of ash-char and ash-coal mixtures on a flat specimen placed 5/8 in. (1.59 cm) from and at 90 deg to the supply nozzle. A description of the results of this experiment is taken from Ref. 33:

> Impingement tests were made with compositions containing 25, 50, 75 and 100 percent of coal or char, the remainder being ash, prepared by burning a representative sample of coal and then grinding it to less than 10 μ in size.
>
> The ratio of coal or char to ash in the mixture at the instant of impingement differs from that of the original mixture introduced into the airline; some of the coal or char particles burn in passing through the heating coil thus reducing the effective ratio of carbon to ash.
>
> No trace of unburnt carbon was detected in the deposit. It would seem that any carbon particles which reached and adhered to the specimen were burned in the presence of excess oxygen. However, the addition of coal or char to the ash could increase the weight of the deposit by as much as ten times.
>
> The maximum weight of deposit occurred with concentrations of coal or char in the mixture of between 25 and 50 percent. In general, the weight of deposit was greater with coal than with char, particularly for the larger particle sizes.
>
> Figure A.11 shows the weight of deposit expressed as a percentage of the total ash fed into the system. The total ash fed is the sum of the ash constituent plus the ash content of the coal or char. Therefore as the proportion of coal or char in the mixture increases, the total weight of ash fed in a given time decreases.
>
> It was significant that the percentage build-up was generally greater for the coarse particle sizes of both coal and char, and increased as the percentage of carbon in the mixture increased. This may be explained by the burning of the coal or char particles within the furnace. This action would release ash at temperatures closer to the combustion temperature of coal or char than the ambient temperature of the carrying air. Certain constituents would probably be quite sticky and able to form a coherent structure in which the more refractory particles could be retained upon impingement.

The results of this experiment clearly indicate the importance of complete combustion of the carbon ahead of the turbine upon the formation of deposits in a coal-fired gas turbine.

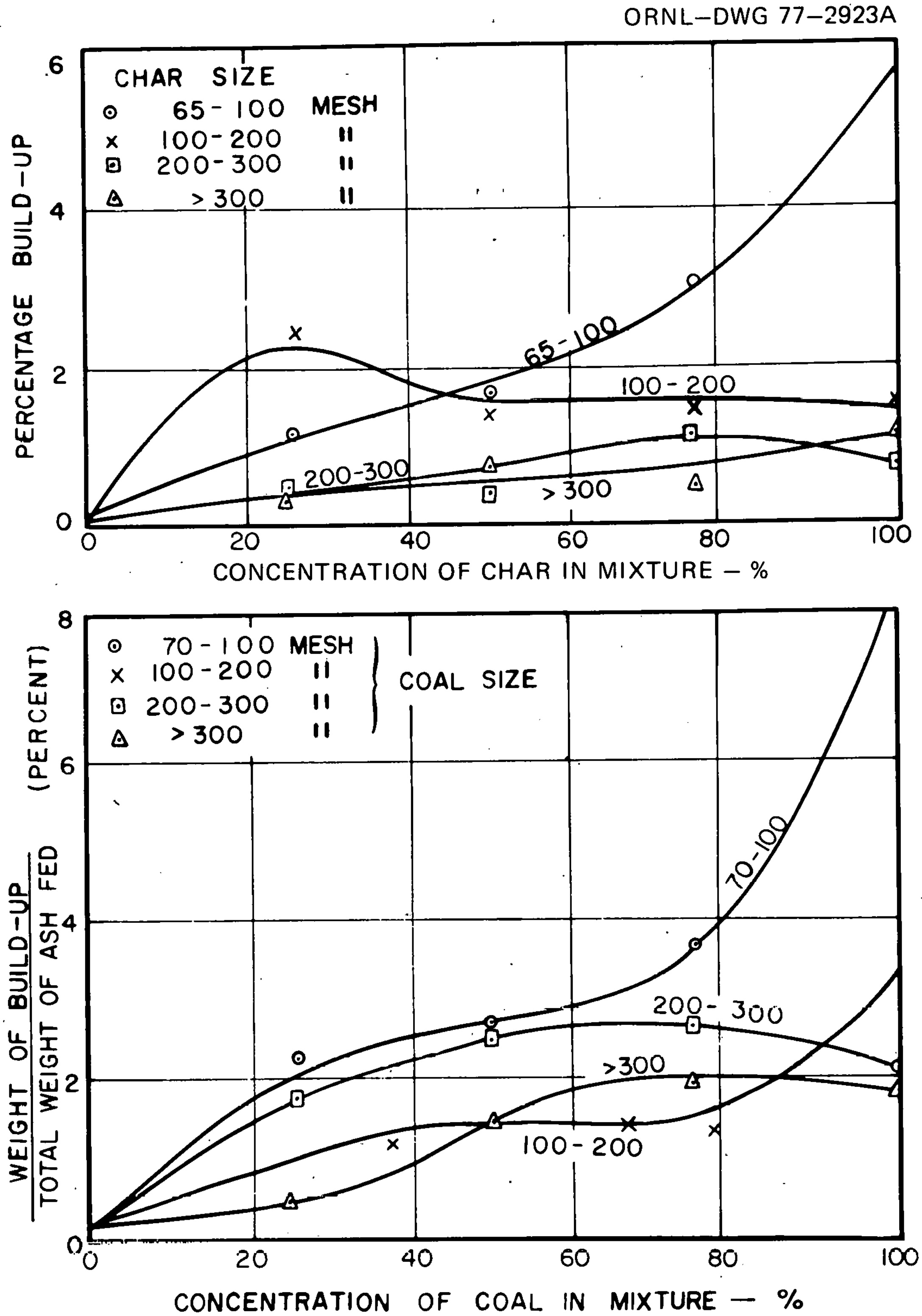

Fig. A.11. Deposition of ash-coal and ash-char mixtures (Ref. 33).

The effects of gas velocity and temperature upon the deposition rate of flyash produced by coal combustion without ash separation were investigated by ARL.[33] Two experiments were conducted: one measured the effects of temperature at a constant velocity of 350 fps (107 m/s), and the second measured the effects of velocity at a constant temperature of 1290°F (700°C). Two distinct types of deposit were observed: a dense sintered deposit formed in the region of direct impingement and a light soft deposit in the region of separated flow. Both of these experiments were conducted with a close-coupled combustor that allowed incandescent particles (determined by visual observation) to strike the target.

An erosion experiment conducted by Fisher and Davis[10] with raw flyash obtained from several power plants operating on pulverized coal resulted in both dense and light soft deposits similar to those described in the ARL work.

A carpet plot employing these data is shown in Fig. A.12. The extrapolation of the data in the figure indicates the interrelationship of the gas temperature and velocity on the ash deposition. The deposition varies directly with the fifth to seventh power of the absolute gas temperature and inversely as the first power of the gas velocity.

Another experiment was conducted by ARL[33] to determine the effect of combustion residence time upon the ash deposition. A target was placed 20 ft (6.1 m) from the exit of the combustor. At an operating temperature of 1292°F (700°C), a threefold reduction in dense deposit was measured as compared to a target placed at the combustor exit.

These experiments indicate the importance of complete combustion in avoiding deposits of ash in the turbine system. It was considered that deposition could be reduced by one of three methods. A description of the methods is taken from Ref. 33:

> (a) removal of the larger particles prior to entering the combustor;
> (b) increasing the residence time in the combustor to ensure complete burnout;
> (c) removal of the larger particles after combustion but prior to entering the turbine.
>
> Based on the experience gained in combustor development, it was considered that unless fine grinding combined with classification ensured 100 percent rejection of coal particles greater

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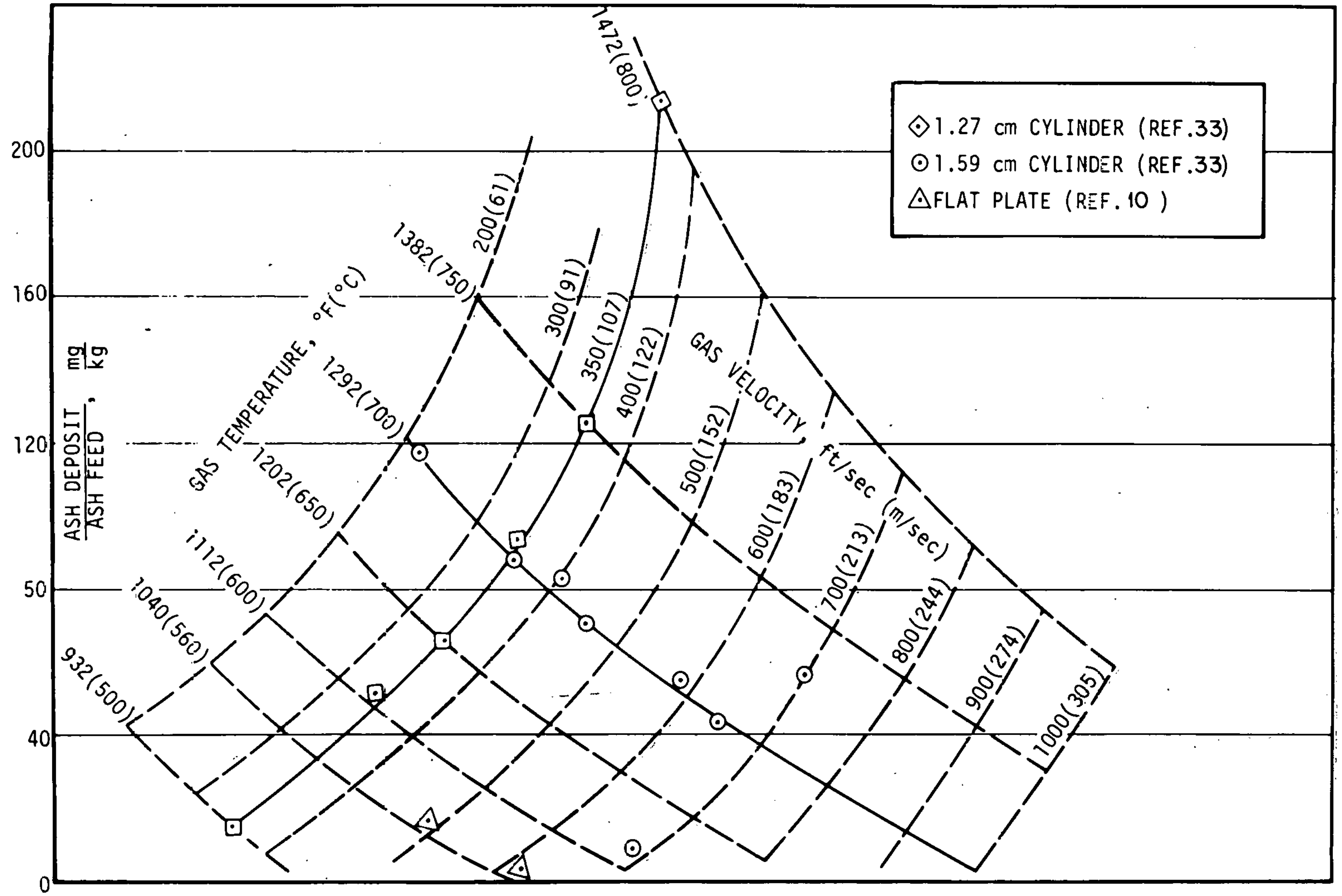

Fig. A.12. Effects of temperature and velocity on ash deposition.

> than 300 B.S.S. sieve size (53 μ), the benefits from this source alone would be marginal. Apart from this, the cost of grinding and classifying to this standard would be prohibitive.
>
> A substantial increase in the residence time in the combustor and the turbine inlet appeared to be the most reliable arrangement. The elimination of the larger particles from the gas stream would be expected to reduce both the rate of deposition and the rate of erosion.

The experimental arrangement was modified to include a multicyclone ash separator consisting of 48 cyclone separators of 6 in. (15.2 cm) diameter. The coal combustor was close-coupled to the ash separator and the clean gas fed to the compressor turbine through approximately 40 ft (12.2 m) of 18-in. (45.7-cm) pipe. The increased separation of the coal combustor from the turbine inlet should provide additional time for after-burning and result in lower unburned fuel fed to the turbine.

Table A.8 gives the compositions of the blade material used in the tests of the Ruston and Hornsby "TA" gas turbine. All the blading used in the 20-hr test without an ash separator was Nimonic 89A except for the compressor turbine first-stage rotor where Nimonic 90 was used.

Prior to a 20-hr test of the system with an ash separator, samples of stator blades fabricated from C.242 and H.R. Crown Max. alloys (see Table A.8) were fitted to the two stator rows of the compressor turbine. Several of the C.242 blades were given a sprayed alumina surface coating.

During the 20-hr test with the ash separator, the compressor turbine inlet temperature was maintained at 1202°F (650°C). Material (ash plus carbon) entered the separator from the combustor at a rate of 71.25 lb/hr (32.4 kg/hr). This material contained approximately 50.9% carbon. Material (virtually pure ash) left the separator and entered the compressor turbine at a rate of 21.75 lb/hr (9.9 kg/hr) at a particulate concentration of 340 ppm and particle size range of 3.8% plus 20 μm and 26% plus 10 μm.

The following description of the ash deposition and blade erosion during the 20-hr test with ash separation is taken from Ref. 33:

> Examination of the turbine blades after the 20-hour test showed that removal of certain ash constituents by the ash separator had markedly changed the balance between ash erosion and deposition.

Table A.8. Blade composition (Ref. 33)

Blade material	Composition (%)											
	C	Si	Fe	Mn	Cr	Ti	Al	Co	Mo	Ni	W	Cb
Nimonic 90	0.13	1.5	5.0	1.0	18–21	1.8–3.0	0.8–2.0	15–21		Bal.		
Nimonic 80A	0.10	1.0	5.0	1.0	18–21	1.8–2.7	0.5–1.8	2.0		Bal.		
Haynes stellite H.S. 31	0.45–0.6		2.0		23–28			Bal.		9–12	6–9	
N.155	0.2–0.4	0.5	30.0	1.5	21			20	3	20	2.5	1.0
C.242	0.27–0.35	0.2–0.5	0.75	0.2–0.5	20–23	0.3	0.3	9.5–11	10–11	Bal.		
H. R. Crown Max.	0.15–0.25	0.75–2.0	Bal.	0.01 Max.	20–25					10–15	2.5–3.5	

The hard sintered deposit found on the first row stator blades in the test without the separator was no longer in evidence, and had been replaced by a lightly bonded material; although the total weight of deposit on the blade had been reduced, the area of blade covered by ash had increased. The material on the leading edge was generally friable, but showed no tendency to spall away from the blade, even under conditions of rapid heating and quenching.

The distribution of ash between the compressor turbine stator rows varied from that in the earlier test; the deposit on the second row stators was now much greater than on the first row, but the material was of similar density. The first and second stage rotor blades now carried a deposit on their leading edges whereas formerly the metal had been eroded in this position; on all blades there was a light fluffy deposit in regions of separated flow. Table A.9 gives a comparison of the ash deposition rates on the blade rows in the two tests.

With the increase in the area of the blades covered by the ash deposit, the areas of erosion were correspondingly reduced. Impact-type erosion on the leading edge of the second row stators and the first stage rotors of the compressor turbine, and undercutting of the leading edge of both rotor stages at the blade root, were eliminated and replaced by ash deposition. Similarly,

Table A.9. Variation in deposit rate in 20 hr running — turbine inlet gas temperature 650°C (1202°F) (Ref. 33)

Blade row	Average deposit rate per blade (g/hr)	
	Without separator	With separator
Compressor turbine		
1st stator	0.161	0.071
2nd stator	0.064	0.146
1st rotor		0.092
2nd rotor		0.079
Power turbine		
1st stator	0.013	0.015
2nd stator	0.021	0.029
1st rotor		0.037
2nd rotor		0.031

the leading edges of the power turbine stators were no longer polished but had acquired a thin film of ash.

Removal of metal from all stator and rotor blade stages was now confined to a scouring process over the trailing half of the pressure (concave) face of the blade.

Table A.10 gives the measured weight loss for the original Nimonic-80A blades over the 20-hour test period with and without gas cleaning. Weight losses are expressed on the basis of unit blade wetted area.

With the inclusion of the ash separator, the rate of metal loss in the compressor turbine had been reduced by factors of 30 and 70 respectively in the successive stator stages; these factors are based on the average value over the blade row. The wear rate between individual blades in a row varied by a factor of 4 and 3 in the first two stator rows respectively, and 1.5 in the later stages due to the asymmetric ash concentration caused by the inlet duct. Owing to the relative difficulty of removing rotor blades for cleaning and weighing, only one blade in each rotor row was processed and the weight loss was much the same as that of the adjacent stators. (Table A.10).

In view of the elimination of impact erosion on the blade in the tests with ash separation, it is of interest, when correlating changes in metal loss rates with variation in ash quality, to modify the stator stage metal loss factors quoted above to indicate specifically the variation in the rate of trailing edge erosion caused by removal of ash from the working gas. It was

Table A.10. Turbine blade weight loss with Nimonic-80A blades — 20-hr tests (Ref. 33)

	Erosion rate, av (mg/cm^2-hr)	
	Without separator	With separator
High-pressure turbine		
1st stator	0.62	0.020
2nd stator	2.15	0.030
1st rotor		0.047
2nd rotor		0.035
Low-pressure turbine		
1st stator	0.13	0.006
2nd stator	0.20	0.007
1st rotor		
2nd rotor		

computed from blade profile measurements in the test without the ash separator that the ratio of impact erosion metal loss on the leading edge to scouring loss at the trailing edge was 2:5 for the second stage stators. It may therefore be assessed that the trailing edge metal loss alone for this stage was reduced by a factor of 50 by gas cleaning. This process was not applicable to the first stage stators where impact erosion did not take place in the first test, so that in the second test erosion on the concave face was reduced by the full factor of 30 quoted above.

The absolute rate of metal loss from the power turbine was about half that in the compressor turbine, but, because of the larger size of the low pressure blading the metal loss rate based on the unit area of blade surface was about one quarter.

The wear performance of blades of alternative materials fitted in the first two stator rows of the compressor turbine is given in Table A.11.

There was a considerable difference in the metal loss rate between the Nimonic 80A blades which had also been used in the previous test without gas cleaning, and some new Nimonic blades fitted prior to the twenty-hour test with gas cleaning. The weight loss of the new blades was about 0.4 to 0.5 times that of the original blades in both stages. Visual examination of the new blades showed that the original machining marks were still well defined; there was no obvious corrosion or evidence of the oxide layer having failed. Microscopic examination confirmed these findings and showed no sign of corrosion along grain boundaries or sub-surface alloy depletion.

In the instance of the original blades, however, there was polishing of those areas that had been heavily eroded in the

Table A.11. Variation in metal loss rate for various blade materials having material compositions shown in Table A.8 (Ref. 33)

Material	Erosion rate (mg/cm^2-hr)	
	First-row stator blades	Second-row stator blades
Nimonic 80A, new	0.008	0.015
Nimonic 80A, old	0.020	0.030
C.242	0.121	0.037
H.R. Crown Max.	0.037	0.026
Alumina-sprayed surface on C.242		0.027

test without ash separation, and pitting of the oxide layer and of the blade surface in regions of transition from deposition to erosion.

The continued resistance of the new blades to corrosive action could not be guaranteed, and the actual difference in overall life of a new blade as compared to an old blade may not be as great as the weight loss measured in this short term test would suggest.

The higher rate of weight loss of the C.242 blades in the first row stators was attributed mainly to the failure of the bond between the oxide layer and the parent metal in a particular area of the blade during cleaning after removal from the engine. This area invariably coincided with a region of a thick deposit of soft ash. One of a number of factors influencing the corrosion or oxidation resistance of high nickel, relatively low chromium alloys is the molybdenum content of the alloy. This element is described as an oxidation accelerant for the parent metal, and maximum quantities of the order of 1.0 percent are recommended; C.242 alloy contains 10 percent. As the C.242 stator blades in the second stage did not show a similar high rate of loss, but were in fact comparable to the Nimonic and H.R. Crown Max. blades, the effect of temperature and thickness of ash coverage might also have an influence on the behaviour of the oxide layer.

The H.R. Crown Max. alloy performed well in the second stage stator row; this material lends itself to relatively cheap precision casting, and could be a possible alternative to the more expensive alloys when gas temperatures are suitable.

The alumina-sprayed blades showed a tendency to surface failure, and the metal loss rates quoted in Table A.11 refer only to blades which retained their surface coating.

After the completion of the 20-hr test with the ash separator, a 203-hr test was conducted to establish firm figures for the blade metal loss rates. To avoid difficulties due to blockage of turbine passages by ash deposits, a cleaning procedure was adopted consisting of the injection of 15 gal (68.2 liters) of water in 10-sec bursts through 36 nozzles situated immediately before the stators while concurrently feeding 6 lb (2.7 kg) of milled apricot stones into the turbine entry duct. The procedure was carried out over a 2-min period once every 10 hr during the 203-hr test.

The following description of the ash deposition and erosion during the 203-hr test is taken from Ref. 33:

With the one exception noted below, the wear patterns of all blades were similar to those described in the 20-hour test with ash separation.

Some modification of the overall blade metal loss rates might be expected since the cleaning process itself was reputed to result in some surface erosion caused by impingement of water droplets and cleaning solids. On the other hand long term operation might result in formation of an ash layer on blade surfaces which could protect the blade against abrasion.

Table A.12 shows the total blade metal loss rates for the original Nimonic-80A material obtained during the 200-hour test. The overall metal loss has also been divided into the loss attributable to cleaning and that due to abrasion by ash particles. The cleaning weight loss has been estimated from blade weight losses measured after a typical cleaning cycle.

The overall hourly weight loss from the stator stages of the compressor turbine is less than that encountered in the short term test despite the water spray and abrasive solids. In the power turbine, the reduction in specific weight loss is particularly marked.

The only blade row to show an increased rate of metal loss is the first stage rotor of the compressor turbine. The weight loss quoted is based on measurements on one blade only; removal of rotor blades is not a simple matter and it is not desirable to do this for the complete row. The increased rate of metal loss for this blade over the longer test can be ascribed in part to the loss of blade shape. The rotor blades were not replaced prior to this test and having been subjected to abrasion equivalent to more than 2,000 hours of engine service with ash separation, had commenced to lose sections of the very thin trailing edge.

Examination of the blading after the 200-hour test showed a new area of localized erosion on both rotor stages of the compressor turbine. It consisted of a short groove on the convex face near the blade root at about one third of the chord from the leading edge, and was probably due to the change in tip profile of the adjacent stator blade, which had also been eroded by leakage under the stator tip.

Ash deposits had accumulated in the stator blade passages near the inner diameter owing to the incomplete penetration of the cleaning water spray. Examination of the cleaned blades revealed that surface corrosion had taken place under these ash deposits; the extent of corrosion varied considerably between the various blade alloys. Table A.13 shows the metal loss rates from the three metal surfaces used in the first and second stator stages of the compressor turbine.

The Nimonic-80A alloy blades exhibited clear signs of corrosion, particularly beneath the ash deposit near the blade tips which built up in the 200-hour test. Scaling of the oxide layer under ash deposits was marked in the case of H.S. 31 alloy blades in the first stage stators, and was similar to the behaviour of the alloy C.242 used in the 20-hour test.

Table A.12. Turbine blade metal losses during 200-hr test (Nimonic 80A blades only) (Ref. 33)

	Weight loss (g)			Erosion rate (mg/cm^2-hr)			Erosion rate, 20-hr test, abrasion only (mg/cm^2-hr)
	Overall average	Cleaning (computed)	Abrasion (by difference)	Cleaning	Abrasion	Overall	
Compressor turbine							
1st stator	0.074	0.040	0.034	0.0079	0.0067	0.0146	0.0203
2nd stator	0.195	0.040	0.155	0.0051	0.0197	0.0248	0.0307
1st rotor[a]	0.313	0.040	0.273	0.0074	0.050	0.057	0.047
2nd rotor[a]	0.243	0.040	0.203	0.0057	0.028	0.034	0.035
Power turbine							
1st stator	0.008		0.008		0.0006	0.0006	0.0056
2nd stator	0.019		0.019		0.0012	0.0012	0.0071
1st rotor[a]	0.007		0.007		0.0007	0.0007	
2nd rotor[a]	0.010		0.010		0.0009	0.0009	

[a]Single blades.

Table A.13. Comparison of average metal loss rates for different blade materials (Ref. 33)

Material	First-stage stators		Second-stage stators	
	Number of blades	Erosion rate (mg/cm^2-hr)	Number of blades	Erosion rate (mg/cm^2-hr)
Nimonic 80A	22	0.0146	23	0.0248
Stellite (H.S. 31)	19	0.0307	23	0.0250
Chrome-plated surface	7	0.0129	14	0.0033

The good wear properties of the chrome-plated blade surfaces in the second stage stator were probably due both to the corrosion resistance of this material and to its surface hardness. The high metal weight loss of these blades in the first stage stator was due to their location in the portion of the stator ring where the offset inlet to the turbine produced a high ash concentration and hence high wear rates. Microscopic inspection of a section of chromium-plated blade showed the ash deposit attached to a thin, well defined oxide film formed on the plated surface. There was no zone of alloy depletion and the surface of the parent metal, C.242, appeared to be completely protected by the plating. Failure of the surface coating due to thermal cracking occurred on a number of blades in the vicinity of the leading and trailing edges.

The blade metal loss rates are not in themselves of any significance, except for the purpose of comparison, unless they are related to the ultimate life of a blade. A knowledge of blade life is of prime importance in determining the commercial feasibility of the coal-fired gas turbine system.

The most heavily eroded blades in the Ruston and Hornsby turbine were the rotor blades in the compressor turbine. These were the original blades supplied with the engine and had been used for a total of 35 hours without ash separation and 250 hours with the separator fitted to the engine. With gas cleaning, erosion occurs primarily on the concave face near the trailing edge; it was estimated from profile measurements on the original blade and at the end of the two test periods that the wear rate in this region without gas cleaning is some 60 to 70 times greater than with the ash separator in the system. On this basis, the wear resulting from 35 hours without ash separation is equivalent to some 2,300 hours with ash separation; alternatively, the erosion of the concave face near the trailing edge produced during the test periods is equivalent to that resulting from about 2,500 hours of operation with ash separator fitted.

A stress analysis showed that the maximum stress (at the leading edge blade root) had increased by 14 percent through erosion.

This increase resulted from undercutting of the leading edge root in the tests without ash separation; as the separator had practically eliminated this type of erosion the rate of stress increase with ash separation would be very low. Consequently the rotor blades in the compressor turbine, though worn, were considered to have a remaining useful life considerably in excess of the 2,500 hours equivalent operation estimated above.

The rates of metal loss in the power turbine were some 50 times lower than in the high pressure turbine during the 200-hour test. Visual inspection of these blades showed little sign of wear after the full complement of testing, and it was concluded that their useful life might be counted in tens of thousands of hours.

For the next series of turbine tests, a low-ash bituminous coal (Aberdare No. 7) from the Greta seam in New South Wales was used as the fuel. Typically, this coal contains 1 to 2% moisture, 5% ash, and 42% volatile matter. The experiments were designated as Greta tests 1, 2, 3, and 4.

The following description of the tests is taken from Ref. 33:

(a) Rotor blades

The eroded blades removed from the compressor turbine at the conclusion of the Yalbourn brown coal tests were re-installed in the engine prior to Greta Test 1. A matched pair of new first and second row rotor blades were fitted at the start of Greta Test 1 for comparison with the blades which had been heavily eroded. Further erosion during Greta Tests 1 and 2 resulted in an excessive reduction in aerodynamic efficiency which necessitated replacement of all first and second stage rotor blades before the commencement of Greta Test 3; these blades were also used in Greta Test 4.

The blades of the power turbine which had been used throughout the Yalbourn brown coal tests were retained for the four tests with Greta coal.

(b) Stator blades

In addition to standard Nimonic-80A stator blades, samples of blades of various alloys and surface treatments were installed in the compressor turbine to evaluate their erosion resistance; the blades installed in each test are listed in Table A.14, and the material composition is given in Table A.8. The evaluation blades were distributed around the stator ring to offset the effect of uneven ash distribution caused by the elbow entry to the turbine. Blades of Nimonic 80A and of other materials to be evaluated which were considered serviceable after operation in the earlier coal tests, were retained. The policy adopted for stator blade replacement was to discard any blades which showed excessive profile

Table A.14. Compressor turbine stator blades (Ref. 33)

Blade material	Number of blades per stage evaluated			
	Test 1	Test 2	Test 3	Test 4
	First stage			
Nimonic 80A	23	13	17	16
Haynes Stellite H.S. 31	14	15	16	15
C.242	5	5	8	8
N.155	5	7	5	5
Chromium plate[a]	14	15	15	15
Diffused chromium[b]	3	8	8	8
Total[c]	64	63	69	67
	Second stage			
Nimonic 80A	25	16	16	16
Haynes Stellite H.S. 31	13	10	13	13
C.242		5	16	16
N.155	4	3	3	3
Chromium plate[a]	23	24	15	15
Diffused chromium[b]		3		
Total[c]	65	61	63	63

[a]Blades designated "chromium plate" were investment cast in the alloy C.242 or H.R. Crown Max. and plated with a 0.010-in. layer of hard chromium plate.

[b]Some H.S. 31, C.242, and N.155 blades were given a diffused chromium coating approximately 0.002 in. deep by a proprietary process known as the Diocrom Diffusion Coating Process.

[c]The total number of blades per stage is 76. Balance of blades were "pegged" and were not removed for evaluation.

wear; this was mainly determined by the degree to which the trailing edge thickness had been reduced.

The original Nimonic 80A stator blades in the power turbine were retained for all Greta tests.

During the Greta tests, the turbine inlet temperature was maintained at 650°C (1202°F) to facilitate comparisons with the results from the Yalbourn brown coal tests; the turbine was calibrated with liquid fuel at the end of each test, and its performance related to that of an engine with new blading.

During each test the weight of coal fed to the combustor and the weight of ash collected in the separator were measured. The major factors affecting the operation during the Greta tests are given below:

(a) Greta Test 1 (17 hours)

An inspection of the ash separator at the conclusion of this test revealed damage to eight of the cyclones caused by after-burning within the separator.

(b) Greta Test 2 (13 hours)

The discharge tubes of the eight damaged cyclone units were blanked off prior to the start of the test; analysis of the results at the conclusion of this test showed a reduction in separator efficiency compared with the first test, and that large solid particles were passing to the turbine. Atmospheric tests with the separator using sized silica showed that blanking off the discharge tube degraded the separator performance, and that this could only be restored by completely blanking off the damaged units.

(c) Greta Test 3 (10 hours)

Prior to the test:

(i) the eight damaged cyclone units were completely blanked off, reducing the number of effective units from 48 to 40;

(ii) both rotor stages of the compressor turbine were rebladed with new blades; some difficulty had been experienced in restarting the engine due to the low aerodynamic efficiency of the eroded blades at the end of Greta Test 2;

(iii) a modified classifier was installed in the coal pulverising system to reduce the coal particle size delivered to the combustor.

During the test the pulverizing system could not produce the required throughput of coal and liquid fuel was required to maintain a turbine inlet temperature of 650°C (1,202°F).

(d) Greta Test 4 (20 hours)

Modification to the classifier prior to the test resulted in satisfactory fineness of grinding and rate of throughput.

The separator efficiency was based on the percentage of ash in the coal fed to the combustor and the amount collected in both the primary and secondary hoppers of the ash separator at the conclusion of the test. The percentage of carbon in ash samples taken from the separator hopper was less than 1 percent, indicating almost complete burn-out of the solids caught by the separator.

The overall combustion efficiency for the combustion chamber, separator and turbine inlet ducting was determined from the carbon-to-solids ratio in samples collected at entry to the compressor turbine inlet.

The results for each of the tests is given in Table A.15.

the mean particle size of solids passing through the engine is given in Table A.16; the values for the intermediate turbine stages have been eliminated.

Inspection of both the compressor and power turbines at the conclusion of each test showed a light ash deposit on the surface of some of the first row stator blades of the compressor turbine. The deposit was limited to one quadrant of the stator assembly and is probably due to the non-uniformity of flow from the elbow to the turbine. There were no signs of ash deposit in the subsequent stages of the compressor or power turbines.

Turbine blade erosion was severe in all stages of the compressor turbine. In spite of a reduction of the mean particle size in Tests 3 and 4 to that achieved in Yalbourn brown coal experiments, the metal loss rate was about four times greater in the Greta-seam coal tests.

The matched pair of new first and second row rotor blades installed in the compressor turbine at the start of Greta 1 were examined at the end of Greta 2. They exhibit a smooth eroded surface on the concave face and evidence of trailing edge pitting and root erosion on the convex side. Deep etching of the convex surface of the blades retained from the previous Yalbourn brown coal test (285 hr) was evident. Microscopic examination of a blade section indicated evidence of impact damage probably caused during the earlier testing; again stator tip (inner diameter) leakage had resulted in a furrow on the convex surface of the rotor blade roots in both compressor turbine stages.

The compressor turbine rotors were rebladed at the conclusion of Test 2. Examination of the blades after completion of

Table A.15. Efficiency of combustion and ash separation — Greta Tests 1 to 4 (Ref. 33)

	1	2	3	4
Combustion efficiency overall, %	94	91	98	98
Separator efficiency, %	49	7	66	62
Solids rate to turbine, kg/hr	48	71.8	8.35[a]	13.2
Mean particle size at turbine inlet, μ	20.4	30.2	5.5–6.4	6.0–8.0
Particulate content at turbine inlet,[b] ppm	1600	2400	285	442
Particulate carbon content at turbine inlet,[b] %	58.8	64.3		26.3

[a]Additional liquid fuel used during this test.

[b]These values were derived from data taken from Ref. 35.

Table A.16. Mean particle size through engine — Greta Tests 1 to 4 (Ref. 33)

Test	Entry 1st stage stator (μ)	Entry 2nd stage stator[a] (μ)	Entry 3rd stage stator (μ)	Entry 4th stage stator[a] (μ)
1	22	20.5	19.3	18
2	30	28.3	26.5	24.8
3	5.5–6.4	5.2–6.0	4.8–5.6	4.4–5.2
4	6.0–8.0	5.6–7.5	5.3–7.0	4.8–6.5

[a]Estimated.

Test 4 showed that the erosion rate had been considerably reduced compared with Tests 1 and 2, although erosion near the root of the leading edge is still apparent. Pitting at the trailing edge was practically eliminated and the erosion pattern was similar to that with Yalbourn brown coal operation.

Severe erosion of the stator blades in both rows of the compressor turbine was evident at the conclusion of Tests 1 and 2. This was most marked on the concave (pressure) face of the blade in a region extending from mid-span to the outer diameter. Some surface pitting had occurred on the suction face close to the blade trailing edge. There were similar erosion patterns at the conclusion of Tests 3 and 4 but the rate of metal loss was very much reduced.

The erosion damage to the blading in the power turbine was much less than that measured in the corresponding stages of the compressor turbine. The areas affected were substantially the same, but the rate of erosion in the worst case (Greta Test 2) was about equal to the lowest erosion rate measured for the compressor turbine rotor blades during operation with Yalbourn brown coal.

The original blade material, Nimonic 80A, exhibited the highest erosion rate of the blade alloys and surface treatments evaluated, while the erosion resistance of hard chromium plate was superior to all other blades tested; however, some surface failures occurred due to thermal cracking and crazing of the chromium layer.

The stator blades treated by the chromium diffusion process exhibited low erosion rates and were not subject to surface failure. Spalling of the oxide layer on the C.242 and H.S. 31 blades which had occurred during Yalbourn brown coal testing, and which was thought to be influenced by corrosion, was not evident.

After the completion of the Greta seam coal tests, a 10-hr test was carried out with Callide coal from Central Queensland. Typically, this coal contains 8 to 15% moisture, 15% ash, and 26 to 28% volatile matter.

The following description of the test is taken from Ref. 33:

> Stator blades of various alloys and surface treatments were installed in the compressor turbine to evaluate their resistance to erosion. Tables A.17 and A.18 give the blade materials and surface treatments used, and the blade history at the start of the test, while Table A.8 lists the blade material compositions.

In addition to the alloys used in the test, a number of stator blades were treated by proprietary surface coatings; these are listed in Table A.19.

The various surface treatment methods (taken from Ref. 35) were:

(a) Metal spraying

The Plasma Jet method was used to spray surface coatings of alumina (L.A.2) and tungsten carbide (L.W.1) to the base metal H.S.31. The coating thickness varied from 0.005 in. to 0.010 in. (0.13 to 0.26 mm) and covered the whole of the blade surface apart from the root which was masked during the process.

Table A.17. Compressor turbine first-stage stator blades (Ref. 35)

Blade material	Blade history		
	New blades	Used in Greta coal test	Total
Nimonic 80A		10	10
L.A.2 Alumina coating on H.S. 31	3		3
L.W.1 Tungsten carbide on H.S. 31	3		3
H.S. 31	12		12
Chromium plate on H.S. 31	12		12
N.155	3	3	6
C.242	6		6
H.R. Crown Max	6		6
L.W.5 Tungsten and chromium carbides on H.S. 31	6		6
Diffused chromium on H.S. 31	8		8

Table A.18. Compressor turbine second-stage stator blades (Ref. 35)

Blade material	Blade history: New blades	Blade history: Used in Greta coal test	Total
Nimonic 80A		7	7
L.A.2 Alumina coating on H.S. 31	3		3
L.W.1 Tungsten carbide on H.W. 31	3		3
H.S. 31	9		9
Chromium plate on H.S. 31	11	3	14
N.155	3	4	7
C.242	7	6	13
H.R. Crown Max.		8	8
L.W.5; Tungsten and chromium carbides on H.S. 31	5		5
Diffused chromium on H.S. 31	7		7

The blades identified as L.W.5 in Table A.19 were also metal-sprayed using the "Detonation Flame Plating" process developed by Union Carbide Corporation. In this case only the concave surface and blade leading edge were treated, the coating thickness being about 0.003 in. (0.08 mm).

A description of the blade coatings is given in Table A.19.

(b) Diffused chromium

Investment cast blades in H.S. 31 were pack chromised at approximately 1,100°C (2,012°F) using a process patented by Metal Diffusions Limited of Britain.

(c) Chromium plate

A number of H.S. 31 blades were plated with hard chromium. To minimize the thermal cracking which had occurred in earlier tests the coating thickness was reduced to 0.007 in. (0.18 mm) and the blade tips radiused to improve adhesion.

The rotor blades in both stages of the compressor turbine installed at the start of Greta Test 3 were retained, as were the original Nimonic-80A blades used in all stages of the power turbine.

Table A.19. Metal-sprayed stator blades (Ref. 33)

Blade material	Coating	Composition	Hardness (V.P.N.)	Maximum working temperature [°C (°F)]
H.S. 31	Alumina (L.A.2)	99% Al_2O_3	1100	982 (1800)
H.S. 31	Tungsten carbide (L.W.1)	Tungsten carbide + 9% Co	1300	538 (1000)
H.S. 31	Tungsten/chromium (L.W.5)	25% WC + 5% Ni + mixed W-Cr carbides	1075	760 (1400)

The separator efficiency was based on the weight of ash collected in the separator, together with the ash content of the coal and total coal fed to the combustor. Burn-off tests of samples recovered from the hopper showed insignificant carbon content, indicating complete burn-out of the larger carbon particles in the separator. The quantity of solids entering the turbine includes the ash not collected in the separator together with an unburnt carbon content, as determined by standard burn-off tests. The greatest possible error in the solids loading has been estimated as ±13 percent.

Table A.20 summarizes the performance of the combustion chamber and ash separator.

Inspection of both the compressor and power turbines at the conclusion of the test showed no apparent ash deposits, although a close inspection revealed small areas of deposit on the concave surface of a few stator blades in the first row of the compressor turbine.

The erosion patterns on the various blades were very similar to those produced in Greta Tests 3 and 4; the highest erosion rate occurred in the first stage rotor blades of the compressor turbine which show light erosion on the root section near the blade leading edges and on the pressure face towards the trailing edge. The power turbine blades have been used in all tests and showed little wear.

The stator blades in the compressor turbine showed erosion in the region of the trailing edge tip and on the pressure face towards the trailing edge, with some surface pitting on the suction face close to the trailing edge.

As in the Greta coal tests, the material most susceptible to particle erosion was Nimonic 80A, the original blade material. The ratio of wear rates between these blades and those treated by chromium plating was approximately 6:1 and 8:1 in the first and second stator rows respectively.

The first row stator blades treated by the chromium diffusion process initially showed a slight weight gain after 1 hour

Table A.20. Combustor and separator efficiency (Ref. 33)

Combustion efficiency, % (including separator and ducts)	98
Separator efficiency, %	65
Solids rate to turbine, kg/hr	52.2
Mean particle size, μ	
Entry to compressor turbine	4.6–6.4
Entry to power turbine	4.0–6.0
Exhaust duct	4.0–4.2
Particulate content at turbine inlet,[a] ppm	1740
Particulate carbon content at turbine inlet,[a] %	30

[a]The values were derived from data taken from Ref. 35.

of operation and at the end of the test had not achieved a stabilized rate of erosion. With the higher level of erosion occurring in the second stage of stator blades, a reasonable weight loss did result; the ratio of the metal removed from the chromium diffused blades to that removed from the Nimonic blades was about 1:10.

Of the other materials tested, H.S. Crown Max. and H.S. 31 exhibited the greatest resistance to erosion, whilst those blades treated by the "Plasma Jet" or the "Detonation Flame Plating" process proved unsatisfactory in a number of cases, due possibly to faulty processing causing coating failures.

Sections taken from four different blades were subjected to metallographic examination to determine if corrosion of the blade material had occurred; no indication of any deterioration could be found, and in each case a well defined oxide layer was evident.

Modified Ruston and Hornsby "TA" Turbine

After the Callide coal test, examination of all the erosion data indicated that operation using a low-ash coal as fuel and ash separation that the life of the blades in the compressor turbine was between 2500 and 5000 hr. The estimated life of the blades in the power turbine was at least an order of magnitude greater.[33] The major difference in the operating conditions in the two turbines was the gas velocity. The gas velocity was approximately 1100 fps (335 m/sec) in the compressor turbine and 800 fps (244 m/sec) in the power turbine. The lower gas velocity and consequently lower particle velocity results in a decrease in metal loss per impact.

In addition to the reduction in metal loss resulting from the lower impact velocity, the larger annular area required for the same mass flow at lower velocity results in an increased blade area and a corresponding reduction in the unit particulate concentration.

The compressor turbine was redesigned to have velocities of approximately 800 fps (244 m/sec) and at the same time incorporate other features believed to be important in extending blade life. A description of the redesigned compressor turbine is taken from Ref. 33:

> Calibration of the original engine on coal following the installation of the ash separator showed that the running line on the compressor characteristic differed slightly from that in the general performance data provided by Ruston and Hornsby as being typical of a "TA" turbine operating on oil. A point on the former characteristic was chosen as the design point; this corresponded to a turbine inlet temperature of 650°C (1,202°F) which is somewhat lower than the maximum cycle temperature of the original engine. This value had been selected in the initial tests and was retained to facilitate direct comparisons between the results of the various tests. The turbine speed at the design point was 10,200 r.p.m.
>
> The relative gas exit velocity at the mean radius of the rotor blades was about 1,100 ft/sec (335 m/s) at the derated condition of the original compressor turbine. Preliminary estimates showed that with velocities of 800 ft/sec (244 m/s) insufficient power would be available from a two-stage turbine built within the original engine scantlings, even with close to the maximum practical gas deflection. Consequently a three-stage rotor was necessary. Fortunately it was possible, by adaptation of the shaft, bearing, and casing in the region of the compressor turbine, to accommodate the three turbine stages without major structural alteration. A design was then prepared for this arrangement based on a gas velocity of about 800 ft/sec (244 m/s), although this meant that other important design conditions such as blade efficiency, reaction, etc. could not be given primary considerations. The basic dimensions of the turbine were so chosen that it was possible to use the first, second, and fourth stage rotor discs of the Ruston and Hornsby "TF" gas turbine which is another model produced by this maker. These discs were obtained in the fully machined condition from the manufacturer and were adapted for use with the redesigned engine; this determined the number of rotor blades per stage (57), and also fixed the maximum axial blade chord.
>
> The required temperature drop through the turbine was calculated from the compressor temperature rise based on an inlet temperature of 15°C (59°F) and a compressor isentropic efficiency of 0.80; the latter is lower than the value of 0.825 quoted for the

original engine, and was used to allow for possible deterioration in performance caused by compressor blade fouling by contaminated intake air. The work output was shared equally between the three stages, as this results in approximately equal velocities in each stage.

Velocity triangles for the stator and rotor rows were constructed to give the required work output, using trial values of pressure loss and gas velocity; the nozzle velocity was made about 100 ft/sec (30 m/s) greater than the rotor relative velocity, as it was considered likely that more erosion could be tolerated on the stator blades before the occurrence of an unacceptable reduction in performance.

Additional features were incorporated into the design to limit the high erosion rate found in localized areas of the original blades.

Apart from the gross maldistribution of ash produced by the angle entry to the turbine, local concentrations result from a number of features of the gas flow within the turbine stages; these have been described by Junge (Ref. 32) during the work of the U.S. Locomotive Development Committee. The main features are:

(a) A concentration of particles of the pressure face of the blade toward the trailing edge, produced by deflection of the gas stream through the blades.
(b) The transport of ash towards the outer boundary by
    (i) centrifugal forces produced by the tangential velocity components in the blade passages;
    (ii) centrifugal forces on particles in regions of separated flow on convex face and in the wake of the rotor blade.
(c) The transport of ash towards the inner boundary resulting from a static pressure gradient which produces an inward flow of gas and particles in regions of separated flow on the convex face and in the wake of the stator blade.
(d) The transport of ash towards both the inner and outer walls is assisted by vortices formed at the blade tips and roots; gas and ash from the blade boundary layer (particularly on the pressure face) tend to feed into these vortices, thus reaching the side walls. This is termed cross channel flow. In the case of a nozzle with a moving inner side wall, the gas and ash may move down the blade and under the tip rather than cross the passage.

These considerations led to the inclusion of the following design features. The trailing edge thickness of both the stator and rotor was increased to 0.060 in. (1.5 mm) to provide more metal which must be removed from the pressure face before the blade chord would be affected. This could increase the aerodynamic losses, but the economic consequence of the latter should be outweighed by the increase in time between blade replacements. Aerodynamic performance is unlikely to deteriorate with erosion until the blade chord is affected; in fact the engine power could increase slightly as erosion thins the trailing edge and the trailing edge losses are reduced.

This modification increases the size of the stator blade trailing edge wake, and hence the amount of ash fed to the inner diameter, and from there into the stator tip leakage flow. Thus the amount of ash eventually impinging on to the rotor blade leading edge could be increased. To limit this action and yet retain thick trailing edges, mid-span stator wake fences were built into the stator blades to redistribute portion of the ash into the main gas stream.

To limit the effect of ash reaching the inner boundary and striking the rotor leading edge, the stator blade tips were recessed into the inner boundary below the level of the rotor blade root, so that most erosion would occur on the blade platform rather than on the working surfaces of the blade itself.

The rotor blade platform section was extended to form the recessed stator blade tip boundary and to provide a gap to control turbine disc and root cooling air flows.

No special measures were taken to limit local erosion of the roots (O.D.) of the stator blades produced by ash concentrations on the outer wall. These blades are lightly stressed and it was considered unlikely that any serious problem would arise.

Because of the highly twisted blade profile, the complicated blade platform section and the relative costs of production, both rotor and stator blades in the compressor turbine were investment cast in the cobalt based alloy H.S. 31. In each of the three stator stages, four blades surface-treated by the Interchrome process of chromium; both produce diffusion-type surface alloying which is dependent on the substrate composition.

The carbon content of the base alloys tends to stabilize the depth to which the coating can diffuse. In the Interchrome process it was considered that a depth of 0.0005 in. (0.013 mm) of hard coating with good oxidation resistance had been obtained. The U.C. process of aluminizing produced a depth of diffusion of 0.0015 in. (0.038 mm), consisting of inner and outer layers of approximately equal thickness.

The Nimonic-80A blades originally fitted to both rotor and stator rows of the power turbine and used in all earlier engine tests were retained.

Before commencing solid fuel tests on the Ruston and Hornsby engine with the redesigned compressor turbine, the unit was calibrated on liquid fuel to determine if the thermodynamic and mechanical design requirements had been fulfilled.

After two hours running at idling conditions the compressor turbine was dismantled, inspected and dimensionally checked for signs of distortion of new parts. No mechanical anomalies were detected in this or in subsequent inspections at various stages throughout the test programme with solid fuel.

The unit was then operated at progressively increasing load to the maximum turbine inlet temperature of 650°C (1,202°F), and performance data recorded over the full range of operating conditions.

The design velocity triangles for the redesigned compressor turbine, assuming equal work output per stage, were compared with those estimated from the results of the calibration. In both cases the turbine inlet temperature is 650°C (1,202°F), but the compressor speed at the design point was 10,200 r.p.m. compared with 10,500 r.p.m. during the calibration. The relevant data is listed for all three stages in Table A.21; it will be seen that the velocities at exit from the stators (V_0) and rotors (V_1), and the corresponding gas angles α_0 and α_2, are similar to the design values.

Table A.21. Comparison of design and measured velocity triangles (Ref. 33)

Turbine entry temperature = 650°C (1202°F)
Compressor speed = 10,200 rpm

	Design data for stage —			Experimental data for stage —		
	1	2	3	1	2	3
U, blade speed, fps	740	763	786	762	785	809
V_0, nozzle outlet velocity, fps	877	864	827	865	836	800
V_1, rotor outlet velocity, fps	776	780	821	770	789	865
α_0, nozzle gas angle	66°8'	66°59'	65°59'	65°48'	66°26'	65°36'
α_2, rotor gas angle	63°31'	64°9'	64°55'	63°30'	65°8'	66°29'

After calibration of the engine with liquid fuel, the engine was operated with solid fuel. The fuel used was a low ash, high volatile Greta-seam coal from the Aberdare No. 7 mine. Typically this coal contains 1 to 2% moisture, 5 to 7% ash, and 39 to 42% volatile matter.

The following description of the test is taken from Ref. 33:

> Following a preliminary run of 18.4 hours to check that the particle size in the coal feed and the combustion efficiency were unaltered from those in Greta Test 4, further runs of 33.0, 29.1, 19.1 and 15.2 hours were undertaken, making a total of 124.8 hours operation with coal. Table A.22 summarizes the performance of the combustion chamber and ash separator.

Table A.22. Combustor and separator efficiency (Ref. 36)

Combustion efficiency overall, %	98
Separator efficiency, %	60
Solids rate to turbine, kg/hr	22.3
Mean particle size, μm	
Entry to compressor turbine	4.3–7.8
Exhaust duct	3.0–7.5
Particulate carbon content at turbine inlet, %	46.4
Particulate content at turbine inlet, ppm	650

At the conclusion of each test period the following blades were cleaned and weighed:

(a) Compressor turbine
  (i) all stator blades including those with surface treatment, but excepting the eight per row located by dowels;
  (ii) three blades spaced 120 degrees apart in each rotor stage.

(b) Power turbine
  (i) ten stator blades in each row (a further ten were weighed at the beginning and end of the test series);
  (ii) one rotor blade per stage.

Calibration of the engine on oil at the end of the test series showed that there was no detectable change in performance from that measured in the earlier calibrations.

As in the previous tests with Callide coal there was little ash deposition on the turbine blades. Deposition was restricted to the first row stators of the compressor turbine, where a light film of ash extended from the leading edge to a maximum of about one third of the blade chord, with its location and extend depending on its position in the blade row. Moving around the stator from the inlet duct the film on the convex fact contracted to the leading edge over 180 degrees around the row, and then gradually extended over the concave face over the remaining 180 degrees. This indicates a progressive change in gas incidence angle around the stator row, probably produced by the elbow entry to the inlet volute.

A very thin, hard deposit had formed along the stagnation line on the leading edge of all blades in all rotor and stator rows.

The progressive metal loss from the rotor blades was plotted against hours of engine operation on coal; the curves show that the rate of metal loss was initially high, but decreased during the first 50 hours of the test to a stable value for the remainder of the test. This constant value of erosion rate for the final

73.4 hour period was accepted as the stable erosion rate and was used as the basis for blade life estimation.

The rotor blades in the power turbine had been used in previous tests with pulverized fuel, and their erosion rates were constant over the whole test period.

Table A.23 gives the blade metal losses and erosion rates for the final 73.4-hour period for all weighed rotor blades of the compressor turbine, and for a 106-hour period for the power turbine.

The trend for a higher erosion rate in the first stage than the second stage of the compressor turbine, and for comparable erosion rates in both stages of the power turbine, was also obtained in earlier tests on the original turbine with pulverized coals.

As with the rotor blades the wear rate of each stator blade in the redesigned compressor turbine stabilized over the first 50 hours of the test, and remained at a constant value for the remaining 73.4 hours.

The elbow entry of the inlet volute carrying the hot gas stream from the ash separator causes a non-uniformity in ash loading at inlet to the first row of stator blades. This results in a variation in the blade metal loss around the stator ring, with a peak opposite the entry to the volute; this pattern of blade wear persists throughout the remaining high pressure stator stages, but in the second and third stages the peaks of maximum erosion are progressively displaced in the direction of rotor rotation due to swirl through the stages. The blade metal loss, and erosion rates for all stator rows, are summarized in Table A.24.

The wear rates on the diffusion coated blades were much lower than those measured on adjacent H.S. 31 cobalt based blades. In Table A.25 four groups of blades from each stator stage of the high pressure turbine are compared. The blades in each group were adjacent and the groups equispaced around the stator casing. The negative sign indicates a weight loss, the positive sign a weight gain.

Unlike the H.S. 31 blades, few of the surface treated blades attained a stabilized erosion rate over the last 73.4 hours of the test. The four chromized blades in the first stator row showed the most consistent wear rates, the average metal loss being approximately one fifth that of the untreated H.S. 31 blades; this relative value had also been obtained in previous tests. In the second and third stator row the chromized blades exhibited a change in weight varying from a loss of 31.6 milligrams to a gain of 4 milligrams without any consistent trend. Similarly, the aluminized blades in all rows showed a weight change varying from a loss of 8.3 milligrams to a gain of 6.0 milligrams without any consistent trend.

Three blades from the first stage stator, one chromized, one aluminized and one untreated, were subjected to metallographic

Table A.23. Rotor blade erosion data — solids loading 22.3 kg/hr

Stage	Blade area (cm^2)	No. of blades	Blade No.	Metal loss (mg)	Blade erosion rate		Stage erosion rate (mg/kg ash)
					$mg/cm^2 \times hr$	$(mg/cm^2 \times kg\ ash) \times 10^3$	
Three-stage compressor turbine (73.4-hr period): Ruston & Hornsby "TA" gas turbine (Ref. 33)							
1 (H.S. 31)	53.6	57	1	82.5	0.021	0.945	
			19	73.6	0.019	0.843	
			38	76.5	0.020	0.876	
			Av	77.5	0.020	0.89	2.71
2 (H.S. 31)	52.6	57	1	56.0	0.012	0.55	
			19	53.7	0.012	0.53	
			38	54.3	0.012	0.53	
			Av	54.7	0.012	0.54	1.91
3 (H.S. 31)	57.4	57	1	65.8	0.013	0.60	
			19	64.2	0.013	0.59	
			38	69.2	0.014	0.63	
			Av	66.4	0.013	0.61	2.32
Two-stage power turbine (106-hr period)							
1 (Nimonic 80A)	52	97	24	112.5	0.020	0.908	4.58
2 (Nimonic 80A)	59	97	24	122.8	0.019	0.873	5.00

Table A.24. Stator blade erosion data — solids loading 22.3 kg/hr

Stage	Blade area (cm^2)	No. of blades	Metal loss per blade (mg)	Blade erosion rates: $mg/cm^2 \times hr$	Blade erosion rates: $(mg/cm^2 \times kg\ ash) \times 10^3$	Stage erosion rate (mg/kg ash)
Three-stage compressor turbine (73.4-hr period): Ruston & Hornsby "TA" gas turbine (Ref. 33)						
1 (H.S. 31)	47.6	64	80.8 max			
			4.6 min			
			32.5 mean	0.0094	0.42	1.28
2 (H.S. 31)	66.6	48	202.9 max			
			37.3 min			
			95.1 mean	0.020	0.88	2.80
3 (H.S. 31)	81.6	48	170.2 max			
			55.6 min			
			106.5 mean	0.018	0.80	3.14
Two-stage power turbine (106-hr period)						
1 (Nimonic 80A)	60	92	133.7 max			
			102.7 min			
			117.0 mean	0.0183	0.82	4.52
2 (Nimonic 80A)	67	92	235.8 max			
			155.0 min			
			186.3 mean	0.026	1.16	7.19

Table A.25. Comparison of untreated and surface treated H.S. 31 stator blades (Ref. 33)

Treatment	Weight change per blade in 73.4 hr (mg)		
	Stage 1	Stage 2	Stage 3
Chromized	−4.0	−23.0	−5.2
Aluminized	+5.7	+0.3	−8.3
Untreated	−36.0	−110.1	−125.4
Chromized	−7.5	+4.6	+3.4
Aluminized	+5.3	+6.0	+0.7
Untreated	−24.7	−40.8	−61.7
Chromized	−7.3	−31.6	−20.5
Aluminized	−5.1	−5.6	−6.5
Untreated	−22.7	−78.2	−172.9
Chromized	−8.8	+1.4	−1.7
Aluminized	+3.0	+1.1	−4.4
Untreated	−35.0	−67.4	−77.5

examination and the following conclusions reached:

(1) The metallurgical structure of the blades appeared satisfactory.

(2) The untreated H.S. 31 blade had suffered some surface pitting and possibly limited penetration [to about 0.0004 in. (0.01 mm)] of the turbine gases at the operating temperatures.

(3) The chromized blade had withstood the operating conditions better than the untreated blade and the blade surface remained smooth. The protective chromized layer was reduced to about half its original thickness [i.e., to 0.00025 in. (0.006 mm)] during the operating life of the blade.

(4) The aluminized blade had also withstood the operating conditions without visible change to its metallurgical structure; however, the upper layer suffered some surface pitting and erosion. The coating was apparently reduced from an original thickness of approximately 0.0015 in. to 0.0009 in. (0.038 to 0.023 mm) due mainly to the removal of the upper layer.

If it is assumed that this thickness of material was removed from the entire blade surface then the weight loss after 73.4 hours of operation would be many times greater than that actually measured. These reductions in layer thickness should, therefore, be interpreted only as indicating some change in the nature of the diffusion coating.

Hence, neither the long term behaviour of the surface treated blades, nor the estimated time of operation before resurfacing becomes necessary, can be predicted from these tests.

Examination of the blades on the completion of the 124.8 hours of operation showed various degrees of polishing in local areas of the blade surface, but insufficient metal had been removed to permit a realistic measurement of the depth of erosion. However from the degree of polishing, surface texture and colour it was possible to grade the erosion rate in specific areas of a blade into one of four relative categories:

"High" erosion
"Medium" erosion
"Low" erosion
"No" erosion

On the concave face of the first row stator blades the rate of erosion was "low" to "medium" over the rear half of the blade. The location of an area of "high" erosion varied with the position of the blade around the stator ring; starting at the gas entry center line this area moved down the trailing edge from the blade tip (I.D.) to root (O.D.), across the root towards the leading edge for about two thirds of the chord, then up the blade span and finally back to the trailing edge tip (I.D.).

On the convex face there was "medium" erosion over the leading half of the blade surface and an area of "high" erosion near the leading edge root (O.D.).

The erosion pattern on the two subsequent stator rows was basically similar to the first stage, except that the area of "high" erosion on the concave face was always located near the trailing edge root (O.D.) and increased in size in successive rows.

The erosion rate on the blade platforms varied from "low" to "medium."

On the concave face of the first stage rotor blade the rate of erosion increased progressively from the leading to trailing edge, while on the convex face there was an area of "high" erosion near the leading edge on the outer three quarters of the span, which gave way to "medium" erosion in the mid-chord area with "no" erosion near the trailing edge. There was also a small area of "high" erosion near the leading edge root on the convex face.

The pattern of erosion on the second and third stage blade surfaces was basically similar to that in the first stage with the exception that the "high" erosion rate near the leading edge on the convex face was limited to the outer half of the blade span.

In all rotor stages, erosion was "high" on the verical step below the leading edge and "medium" or "high" on the corresponding blade platform. Erosion was "low" on the trailing blade platform.

The various flow conditions described by Junge (Ref. 32) which contribute to local variations in the concentration of ash particles and hence affect erosion rates are relevant to the erosion patterns determined during this test series.

Due to gas deflection within the blade passages the solid particles, particularly in the larger sizes, are centrifuged towards the concave face; their impact with the blade produces the "high" to "medium" erosion rates evident near the trailing edge of both stator and rotor blades.

Superimposed on this, the high swirl velocity of the mean gas stream centrifuges the particles towards the outer wall. This action is reinforced by the rotor transport action whereby particles entering the low relative velocity areas of the boundary layer, separated flow regions and rotor blade wake will also be centrifuged towards the outer wall. Some evidence of this concentration of particles in the outer annulus is presented by the fact that all areas of "high" erosion on the second and third row stator blades occur in this region.

Erosion on the convex face of a blade near the leading edge is typical of that produced by particles, and particularly the larger sizes, which do not reach the full gas velocity and hence enter the blade passage with a negative angle of incidence and strike the blade on the convex surface. This form of erosion is evident on all stator and rotor blades, and is more severe between the mid-span and outer diameter, probably due to the concentration of the larger particles in this region.

Some of the smaller ash particles which follow the gas stream more readily are probably caught up in the end whirl and the stator trailing edge wake secondary flows, which are fed from low momentum gas in the boundary layer on the outer wall and from the blade pressure surface where these particles are then transported towards the inner diameter in the direction of the pressure gradient produced by the vortex flow. In the redesigned turbine the fence incorporated into the trailing edge of the stator at about mid-span stops the particles from migrating onto the outer half of the blades. These particles then probably enter the stator wake and strike the convex face near the leading edge of the rotor blade, to be centrifuged outwards and add to the erosion in this region. It is perhaps significant that the outer surface of the fence showed some polishing, and that the "high" erosion on the outer part of the rotor blades in the second and third stage commences opposite the fence.

Some of the particles being transported over the inner half of the stator blades are entrained in the stator tip leakage flow. This high velocity flow is produced by the pressure difference across the stator blade (between the pressure and suction surfaces) and impinges on the rotor drum as it passes under the stator tip, and then on the vertical step in front of the rotor blade root, producing "medium" and "high" erosion in these areas. The particles then probably come under the influence of the main gas stream flow and strike the convex face of the rotor blades near the leading edge root producing a localized area of "high" erosion. The highly polished nature of these areas near the rotor blade root suggests that the finer ash particles are responsible.

In the original two-stage turbine the undercutting of the leading edge root of the rotor blade by ash entrained in the tip leakage flow was a serious problem. The fence on the stator blade trailing edges appears to be effective in reducing the amount of ash migrating to the inner wall, and in distributing the intercepted ash over a reasonable area of the lighter stressed outer rotor blade section. Recessing the stator blades below the root of the rotor blades also appears effective since the brunt of the erosion is taken on the vertical step in front of the rotor, and the ash impinging on the rotor root is spread over a larger area than in the original two-stage machine.

The reasons for the variation in erosion rate from row to row (Tables A.23 and A.24) are not so obvious, but the trends shown in the redesigned turbine are consistent with these observed in the original two-stage machine. A possible explanation of the low erosion rate in the first stage stator blades is that, although the mean relative gas velocities do not vary greatly from stage to stage, the solid particles entering the inlet volute with zero axial velocity may not have been accelerated to velocities approaching that of the gas before they enter the first row stators. If, on reaching the first stage rotor the velocity of the particles is still appreciably lower than the gas velocity they will enter the blade passage with a negative angle of incidence, which may explain the somewhat higher erosion rate in this rotor row. This view is supported by the relatively large area of "high" erosion on the convex face near the leading edge of the first row rotors.

The rotor and stator blade erosion rates obtained from the operation of the original and redesigned turbine are summarized in Tables A.26 and A.27. An assessment of the effects of the turbine redesign upon blade life, made by ARL (Ref. 33), is given below.

The effect of the change of gas velocity in the two turbines on the erosion rate can be assessed from the stage metal loss per kilogram of ash under the various operating conditions; this erosion rate, together with an estimate of the corresponding stage exit gas velocity, is listed in Table A.28 for Greta Test 4 with the original turbine and for the redesigned machine.

The blade materials in the original and redesigned compressor turbine are Nimonic and H.S. 31 alloys respectively; previous

Table A.26. Rotor blade erosion rates (Ref. 33)

Test	Solids rate (kg/hr)	Mean particle size (μ)	Erosion rate ($mg/cm^2 \times hr$)	Specific erosion rate [($mg/cm^2 \times$ kg solids) $\times 10^3$]	Total erosion rate per stage (mg/kg solids)
High-pressure turbine — first stage rotor blade					
Greta coal					
1	48.0	22	2.65	55.2	123.7
2	71.8	30	5.2	72.5	162.4
3	8.4	5.5–6.4	0.18	20.6	46.1
4	13.2	6.0–8.0	0.21	15.9	35.5
Callide coal	52.2	4.6–6.4	0.96	18.5	41.4
3-stage turbine	22.3	4.3–7.8	0.02	0.89	2.7
High-pressure turbine — second stage rotor blade					
Greta coal					
1	48.0	20.6	1.61	33.5	97.3
2	71.8	28.0	3.22	44.8	130.4
3	8.4	5.2–6.0	0.11	13.6	39.4
4	13.2	5.6–7.5	0.14	10.9	31.3
Callide coal	52.2	4.3–6.0	0.70	13.3	38.6
3-stage turbine	22.3	4.0–7.7	0.012	0.54	1.9
High-pressure turbine — third stage rotor blade					
3-stage turbine	22.3	3.7–7.6	0.013	0.61	2.3
Low-pressure turbine — first stage rotor blade					
Greta coal					
1	48.0	19.3	0.18	3.81	19.2
2	71.8	26.5	0.43	5.96	30.0
3	8.4	4.8–5.6	0.012	1.47	7.4
4	13.2	5.3–7.0	0.009	0.73	3.7
Callide coal	52.2	4.0–5.6	0.06	1.17	6.0
3-stage turbine	22.3	3.4–7.6	0.02	0.91	4.6
Low-pressure turbine — second stage rotor blade					
Greta coal					
1	48.0	17.9	0.14	2.92	16.1
2	71.8	24.7	0.344	4.78	27.4
3	8.4	4.4–5.2	0.013	1.57	8.9
4	13.2	4.8–6.5	0.008	0.61	3.5
Callide coal	52.2	3.5–5.2	0.06	1.17	6.5
3-stage turbine	22.3	3.1–7.5	0.019	0.87	5.0

tests in the original turbine (Tables A.26 and A.27) showed that the erosion rate of H.S. 31 is about half that of the Nimonic alloys. To give a more meaningful comparison of the erosion rates in the redesigned and the original compressor turbines and in the power turbine, the corresponding erosion rates that would apply if the redesigned turbine had been fitted with blades made of Nimonic alloy are shown in brackets in Table A.28.

In comparison with that in the original turbine, metal loss per kilogram of ash in the redesigned compressor turbine (assuming the use of Nimonic blading) was reduced by factors of 6.6 and 8.2 for the first and second row rotor blades respectively, and by a factor of 4.7 for the first and second stage stator blades.

Table A.27. Stator blade erosion rates (Ref. 33)

Test	Solids rate (kg/hr)	Mean particle size (μ)	Total erosion per stage[a] (mg/kg solids)	Average specific erosion rate [(mg/cm^2-kg solids) × 10^3]								
				Nimonic 80A	H.S.31	N.155	Chrome plate	Chromized	Aluminized	C.242	L.W.5	H.R.Cr.max
High-pressure turbine — first stage stator blades												
Greta coal												
1	48.0	22	85.7	45.1	18.9	24.2	3.8	21.0				
2	71.8	30	127.3	67	30.0	41.5	7.0	43.17				
3	8.4	5.5–6.4	23.8	12.5	5.9	4.2	2.8	5.9				
4	13.2	6.0–8.0	12.2	6.4	2.0	0.7	1.2	0.7				
Callide coal	52.2	4.6–6.4	23.4	12.3	3.3	5.1	2.0	Very low		5.3	10.1	2.2
3-stage turbine	22.3	4.3–7.8	1.28[b]		0.42			Very low	Very low			
High-pressure turbine — second stage stator blades												
Greta coal												
1	48.0	20.6	96.5	32.6	28.2		3.4					
2	71.8	28.0	143.8	48.6	41.3		4.8			42.5		
3	8.4	5.2–6.0	36.4	12.3	8.6		0.7			11.7		
4	13.2	5.6–7.5	26.0	8.8	4.2		0.3			5.3		
Callide coal	52.2	4.3–6.0	42.6	14.4	7.4	10.0	1.7	1.3		9.0	7.9	6.3
3-stage turbine	22.3	4.0–7.7	2.80[b]		0.88			Very low	Very low			
High-pressure turbine — third stage stator blades												
3-stage turbine	22.3	3.7–7.6	3.14[b]		0.80			Very low	Very low			
Low-pressure turbine — first stage stator blades												
Greta coal							All blades in this stage are Nimonic 80A					
1	48.0	19.3	23.1	4.17								
2	71.8	26.5	51.5	9.34								
3	8.4	4.8–5.5	5.3	0.96								
4	13.2	5.3–7.0	3.3	0.60								
Callide coal	52.2	4.0–5.6	10.4	1.89								
3-stage turbine	22.3	3.4–7.6	4.52	0.82								
Low-pressure turbine — second stage stator blades												
Greta Coal							All blades in this stage are Nimonic 80A					
1	48.0	17.9	25.9	4.20								
2	71.8	24.7	54.2	8.80								
3	8.4	4.4–5.2	11.9	1.94								
4	13.2	4.8–6.5	6.2	1.0								
Callide Coal	52.2	3.5–5.2	13.9	2.26								
3-stage turbine	22.3	3.1–7.5	7.19	1.16								

[a] Column 4 gives the total erosion per stage assuming the row was composed entirely of Nimonic 80A blades.

[b] H.S.31.

Table A.28. Corresponding erosion rates for standard and redesigned turbine (Ref. 33)

	Compressor (H.P.) turbine					Power (L.P.) turbine			
	Standard turbine (Greta test 4)		Redesigned turbine			Standard turbine (Greta test 4)		Redesigned turbine	
	Exit velocity (fps)	Stage erosion (mg/kg ash)	Exit velocity (fps)	Stage erosion (mg/kg ash) H.S.31	Stage erosion (mg/kg ash) Nimonic	Exit velocity (fps)	Stage erosion (mg/kg ash)	Exit velocity (fps)	Stage erosion, Nimonic (mg/kg ash)
Rotors									
First stage	930	35.5	770	2.71	5.4	670	3.7	750	4.58
Second stage	930	31.3	770	1.91	3.8	670	3.5	750	5.00
Third stage			770	2.32	4.6				
Stators									
First stage	1000	12.1	810	1.28	2.6	720	3.3	784	4.52
Second stage	1000	26.0	810	2.82	5.6	720	6.1	784	7.19
Third stage			810	3.14	6.3				

In general, a turbine blade operating in an erosive environment must be replaced if either:

(a) the increase in blade stress produced by undercutting of the root section, or

(b) the loss in aerodynamic performance due to changes in blade profile, reaches an unacceptable limit.

Previous analyses on the original Ruston and Hornsby turbine showed that in this conventional machine, designed for a blade life of 100,000 hours with liquid fuel, the loss in aerodynamic performance was the limiting factor. This is also likely to be the case in the redesigned compressor turbine, particularly since the stator blade trailing edge fence and the recessing of the stator blade tip below the rotor blade root appear to have reduced the undercutting of the rotor blade root.

In the assessment of blade life it was assumed that the blades reach the end of their useful life when the trailing edge thickness [originally 0.060 in. (1.5 mm)] has been reduced to zero. It will be noted in the blade erosion patterns that the trailing edge is worn on the concave surface only, and that on this face the erosion rate is zero near the leading edge, and in general increases along the blade chord through "medium" to "high" rates at the trailing edge. Hence it was assumed that the wear on the concave face would increase uniformly from zero at the leading edge to 0.060 in. (1.5 mm) at the trailing edge.

It was further assumed that during this period the other areas of the blades classified as "high," "medium," "low" and "zero" erosion would be worn to depths of 0.060, 0.040, 0.020 and 0.000 in. (1.5, 1.0, 0.5, 0 mm) respectively.

From the measured areas on the blade corresponding to each of the four erosion rates, the total metal loss per blade was computed; this together with the experimentally determined total metal loss per blade per hour gave the estimated life of the blade. The lives, based on the mean erosion rate per stage, are listed in Table A.29.

Because of the non-uniform ash distribution at the entrance to the turbine, the erosion rate and hence the blade life vary

Table A.29. Estimated mean H.S.31 blade lives — compressor turbine (hr) (Ref. 33)

	Rotors	Stators
First stage	31,000	51,000
Second stage	52,000	25,000
Third stage	51,000	27,000

around the stator row. The number of stator blades in the redesigned turbine having a life in a specific range is shown in Table A.30. This illustrates the importance of the inlet volute design in a gas turbine operating on dirty gases and emphasizes that care should be taken to produce an ash distribution as close to uniform as practicable at the inlet to the turbine.

Table A.30. Number of stator blades with stated life range (Ref. 33)

Blade life (hr × 10^3)	Number of stator blades		
	First stage	Second stage	Third stage
10–15		5	
15–20	2	7	10
20–25	3	8	12
25–30		5	4
30–40	10	9	10
40–50	15	6	8
50–80	21	9	4
80+	13		

Shell Development Company

In 1950 the Elliott Company drove a gas compressor with a single-stage turbine installed in the exhaust gas stream from a catalytic regenerator in a small refinery in Ohio.[37] No separation equipment was installed ahead of the turbine and by the end of 750 hr of operation, the turbine was considered to be virtually useless.[37,40]

The Elliott experiment and the development of the coal-fired gas turbine focused attention upon the need for gas cleanup ahead of the turbine. The Shell Oil Development Company installed a gas-turbine-driven air compressor in the East Montreal refinery in 1957.[41] The installation was similar to the Elliott experiment except that a separator was installed ahead of the turbine inlet to remove enough of the particulate material from the flue gas stream to prevent serious erosion of the turbine blading. The turbine was operated with an inlet temperature of approximately 1100°F

(594°C) for 4000 hr. After the 4000-hr test, examination of turbine indicated only minor polishing of the blades.[40] To demonstrate the contribution of the separator, it was removed from the system and the turbine was operated as in the Elliott experiment. After 650 hr, the turbine efficiency decreased from 79 to 49%. Erosion was severe in both stator and rotor blades.[37] During this phase of the experiment, the particulate concentration in the turbine inlet stream was approximately 1300 ppm and a particle size range of 50% plus 20 μm and 80% greater than 10 μm.[40]

Based upon the Montreal experiment, the Shell Oil Company in 1962 began the installation of turbines in the flue gas stream of the catalytic regenerators in both new and existing refineries. Table A.30 (Ref. 37) lists typical refinery installations made between 1963 and 1973.

Actual field results of separation taken in 1968 from the Deer Park, Texas, installation (see Table A.31) are given in Table A.32.[41]

Table A.31. Refinery power recovery worldwide by U.S. manufacturers (Ref. 37)

Refinery	Location	Driven equipment	Expander hp	Expander mfr.	Startup
Shell Oil	Norco, La.	Clark cent. comp.	9,000	Ingersoll-Rand	Aug. 1963
Shell Oil	Oakville, Ont.	Elliott, cent. comp.	4,000	Elliott	Nov. 1963
Shell Oil	Deer Park, Tex.	I-R cent. comp.	7,000	Ingersoll-Rand	Sept. 1964
Shell Oil	Martinez, Cal.	I-R Axial comp. G.E. motor/generator	15,700	Ingersoll-Rand	Aug. 1966
Humble	Bayway, N.J.	Elliott cent. comp. Westinghouse motor/gen.	20,000	Elliott	Dec. 1967
Shell Oil	Berre, France	I-R cent. comp. French motor/generator	6,000	Ingersoll-Rand	Sept. 1970
Gulf Oil	Edmonton, Alta.	I-R cent. comp.	6,000/9,000	Ingersoll-Rand	July 1971
Sun Oil	Toledo	I-R axial comp. Westinghouse motor/gen	22,000	Ingersoll-Rand	Spring 1973

Table A.33 shows the extremes of the particle-size distribution which have been encountered in actual operation. The data are not related directly to the data in Table A.32.[41]

Turbine blades fabricated from tungsten-carbide-flame-coated A-286 [for 1150°F (620°C) service] and Inconel X [for 1200°F (650°C)] have a life expectancy of 25 to 35,000 hr without significant power reduction caused by erosion.[39,43,44] No difficulties with deposits in these installations have been reported after nearly 13 years of commercial operation.

Table A.32. Flue-gas loadings in cyclones[a] and separator (Ref. 41)

	Flue-gas loading (tons/day)	Catalyst concentration [ppm (wt)]	Catalyst loading (tons/day)
Entering 1st-stage cyclone	5000	3,000,000	15,000
Entering 2nd-stage cyclone	5000	20,000	100
Entering 3rd-stage separator	5000	800	4
Entering turboexpander	4900	120–160	0.6–0.8

[a]Based on 85,000 cfm air; 33,500 lb/hr coke.

Table A.33. Catalyst size distribution (%) in cyclones and separator (Ref. 41)

	Entering cyclones	Entering separator	Leaving separator
>80 μm	17–36		
40–80 μm	75–83	3–16	
20–40 μm	18–1	23–54	
10–20 μm		34–22	3
4–10 μm		14–8	5–17
2–4 μm		14–3	15–40
0–2 μm		17–3	80–40

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