FLUIDIZED-BED COAL GASIFIER AS A LOAD-FOLLOWING CLEAN FUEL SOURCE

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INTRODUCTION

The electric power generated in the United States is growing at a rate of about 8-10%/yr. The electric load is expected to increase by a factor of 4 in the next 20 years to a total of 6.5×10^6 GWhr. It will take at least 20 years before nuclear energy, which today supplies less than 1% of our electric power, will carry the main burden of our power requirements. Therefore, for the next 15-20 years, most of the demand for electricity will have to be met by fossil fuels, i.e., coal, oil, and natural gas.

Natural gas, which is already in a short supply, will be increasingly assigned to more critical applications than combustion in large power plants. Furthermore, the available supply of natural gas may combat pollution more effectively from an overall standpoint when used for residential and small commercial needs. Coal and oil must, therefore, fill the demand for fuel for electric power generation. The use of oil for power generation must be limited to avoid heavy reliance on politically uncertain oil-producing countries. In addition, our balance of payments problems will balloon with increasing foreign oil purchases. Coal is the most logical answer to meet the growing power demand in the next 2 decades (see Figure 1).[3]

Coal is one of the largest fuel resources in the United States, but, when burned, it is a primary contributor to the sulfur and particulate pollutants in the atmosphere. One direct way of limiting sulfur emissions from coal combustion is to use low-sulfur coals; however, most are located in areas that do not coincide with the areas of need. When using high-sulfur coals, one alternative is to use scrubbing systems to remove sulfur dioxide produced during combustion. After spending $300 million on a crash program to develop a scrubbing system, no viable commercial process is yet available. Their efficiency in sulfur dioxide removal is expected to be rather low, in the range of 80-90%.

Coal gasification with gas cleaning before combustion promises the greatest reduction in sulfur emissions. According to the Environmental Protection Agency,[1] a power plant using coal gasification in conjunction with an advanced combined gas turbine-steam turbine cycle promises to have the following benefits:

- Reduction of sulfur oxide emissions up to 99%
- Nitrogen oxide reductions of 90% when compared with present-day coal-fired plants
- A 40-50% reduction in thermal pollution by power stations
- Approximately 20-30% savings in both capital and operating costs over conventional plants
- An important impact on the balance of payments when the system is successfully demonstrated in the U.S. through the foreign sale of complete systems as well as additional royalties from foreign licensees of U.S. turbine manufacturers

- Elimination of the adverse effects of pollution control measures on the coal industry, thus increasing both revenues and employment in the major coal-producing states

- Reassignment of natural gas now supplied to the power industry to higher priority use

- Retention of teams of highly trained turbine designers by the gas turbine industry. These teams are a valuable national resource which might otherwise be dispersed because of the loss of the SST program and a reduction of Department of Defense support.

After a description of the Institute of Gas Technology's coal gasification plant concept for a clean fuel gas, we will show how the fluidized-bed coal gasifier will be able to follow the electric load characteristics of an intermediate-load power plant.

COAL GASIFICATION PLANT FOR UTILITY GAS

The clean gas produced from an air-based coal gasification plant is called utility gas, producer gas, or low-Btu gas. Figure 2 is a process flow diagram for IGT's proposed utility gas coal gasification plant. Values shown are for a nominal coal feed rate of 20 tons/hr.

After the coal feed is crushed to the desired size, single-stage lock hoppers are used to transfer it from atmospheric pressure to the elevated pressure of the gasifier. Steam and air are fed to the bottom of the gasifier. Heat is recovered from the hot raw gases produced in the gasifier and the gas is then cleaned of sulfur at low temperature by a selective hydrogen sulfide removal process. The gas can be scrubbed so that it contains less than 5 ppm of hydrogen sulfide. A small part of the cleaned gas is used to pressurize the lock hoppers.

The main gas stream, after cleaning, is reheated by exchange with hot raw gas from the gasifier. The gas then expands through a gas expander to the optimum pressure level for application to a combined cycle. The gas expander generates some electricity. The gas is cooled by generating steam to about 600°F to meet the gas turbine combustor's requirements. After combustion, the gas expands through the gas turbine, generating a large percentage of the total power output. Part of the energy recovered is used to drive the compressors to supply the gasifier air and the combustor air. Exhaust gas from the gas turbine is reheated by burning gas recovered from the coal feed lock hoppers. Final heat recovery generates steam in the waste-heat boiler for additional power generation. Of the total power generated, about 35% comes from the steam turbine and 65% from the expander-gas turbine.

The hydrogen-sulfide-rich gas from the hydrogen sulfide recovery process goes to a sulfur recovery plant. Ninety five percent of the total sulfur is recovered as elemental sulfur. The Claus plant tail gases still contain about 1% hydrogen sulfide. A process such as the Beavon Process is used to reduce the sulfur content of the tail gas to less than 250 ppm.

GASIFIER

The entire utility gas concept hinges on the coal gasifier's performance. The gasifier and its design concept will not be discussed here because it has been presented elsewhere.[5] The gasifier must satisfy the following requirements:

- Operate reliably

- Gasify a high percentage of feed carbon

- Accept caking coal as feed

- Be capable of load-following

Figure 3 presents a simplified illustration of the gasifier. A single-stage lock hopper is preferred to transfer coal into the gasifier. This feed system was chosen so that the gasification plant will be simple, reliable, and cheaper. Lock hoppers tend to be attractive for utility gas production as the depressured lock hopper gas can be used without the need for recompression. The gasifier operating pressure has been set at 300 psi in this paper because the maximum operating pressure for commercially demonstrated lock hopper valves is 350 psi. We believe that higher operating pressures may be desirable; however, lock hopper valves to withstand the higher pressures have yet to be developed.

So that the utility gas process can accept the widest variety of coal feed, facilities for destroying caking properties of agglomerating coal are provided within the gasifier. We propose to pretreat at gasifier pressure and feed the hot pretreated char directly into the gasifier. The exothermic pretreatment reaction produces enough heat to generate the steam to satisfy the gasifier's requirements.

The gasifier is designed to gasify coal with air and steam in a fluidized bed. Simultaneously, the coal ash will be selectively agglomerated into larger and heavier particles for removal from the bed. The principle of ash agglomeration and separation which has been used in the gasifier design has been demonstrated both by Godel[2] and Jequier et al.[4] The gasifier, which we call an ash aggomerating reactor (AAR), resolves the main problem of coal gasification in a fluidized bed rich in carbon — that of selectively removing low-carbon-content ash from the bed. A gas residence time of 10-15 seconds is provided above the fluidized bed so that any tars and oils which may be evolved are thermally cracked to gas and carbon.

Most of the sulfur produced by coal gasification with the gasifier will appear in the form of hydrogen sulfide. Although we selected a low-temperature sulfur removal system, it would be desirable to use a yet-to-be-developed high-temperature sulfur removal system to improve plant efficiency and decrease costs. In combined-cycle plants, a 2% increase in overall power plant efficiency is realized when a high-temperature sulfur removal system is used in place of a low-temperature system as previously discussed.

The combined gas turbine-steam turbine cycle is illustrated in Figure 4. There are many alternative ways that this basic concept can be implemented. The efficiency of combined-cycle systems depends to a major degree on the allowable gas turbine inlet temperature. Gas turbines used today operate around 1800°F. The allowable inlet temperature to gas turbines is projected to increase at 100°F/yr to a maximum of about 3100°F. United Aircraft Research Laboratories[6] expects ultimate coal gasification-combined cycle thermal efficiencies of 57.7%.

POWER DEMAND REQUIREMENTS

The EPA[1], Division of Control Systems, characterized electrical generating capacity in three categories:

1. Base load. These units are 500 MW and larger and operate at a load factor of 75%. Base-load plants represent about 60% of total electrical generating capacity. Nuclear power plants are expected to fill most of this requirement in the future.

2. Swing or intermediate load. Capacity of these units is from 200 to 500 MW, and their load factor ranges from 40 to 50%. These plants represent about 30% of total capacity. The EPA believes that coal gasification, in conjunction with advanced power cycles, can be applied most favorably in this category.

3. Peak load. This load will probably be satisfied by gas turbines because quick response time is required. Units are less than 200 MW in size and operate at less than a 40% load factor.

If the coal gasification-combined cycle systems are to fill the intermediate load requirement, the coal gasifier must be able to vary its output over wide ranges with rapid response.

One of the large power companies has provided the following typical operating requirements for the upper and lower ends of the swing-load range. To fill the upper end of the range, the gasifier unit would operate 6 days/wk. On weekdays the gasifier would operate at full capacity for 8 hours, at one-third of capacity for 8 hours, and at an output varying from one-third to full capacity for the remaining 8 hours. On Saturday, the gasifier might operate at full capacity for periods up to 12 hours, or in other circumstances, it may operate at one-third capacity for the 24-hour period. The plant would be substantially shut down on Sunday. Desirably, the system would be designed to generate 10% of design output as needed on Sunday. These demands will occur for periods of less than 1 hour.

In the lower part of the range, the gasifier would operate from 6 to 12 hr/day on a random basis during about 3 days of the week. A fuel consumption of up to 5% of the full load requirement during standby periods may be acceptable, although fuel consumption should be as low as possible.

To follow the normal variations in electrical demand, the gasifier should be capable of adjusting at a typical rate of 1% of design capacity per minute. In an emergency situation, almost immediate shutdown is required.

AAR TURNDOWN

The following discussion describes attainable control methods for adjusting the output of a fluidized-bed gasifier without damaging process equipment. The following five possible methods are considered:

1. Change gas velocity in gasifier

2. Adjust gasifier temperature

3. Permit the bed to defluidize (no gas flow)

4. Change gasifier pressure

5. Operate gasifier at a fixed condition and vary the gas flow between the power generating plant and a parallel chemical fuel plant.

The gasifier output can be rapidly changed by adjusting the gas velocity through the fluid bed. The air and steam flows to the gasifier are adjusted while retaining a fixed ratio of steam to air, reactor pressure, and fluid-bed level. As an example, if the design velocity in the gasifier is 1 ft/sec and the minimum practical superficial velocity at the operating temperature is 0.3 ft/sec, a turndown of 3.3 can be obtained.

Another means of turndown is to reduce the coal reaction rates by lowering the gasifier's operating temperature. The temperature is altered by changing the ratio of steam to air entering the bed. Moderate temperature changes that are not made abruptly are satisfactory. Rapid changes over a wide range of temperatures may crack and spall the gasifier's internal insulation, causing both operating and mechanical problems. As the fluidized-bed temperature is reduced, the reaction rates drop off sharply. It is recognized that, in lowering the bed temperature, alterations in the air and steam flows to the various injection points in the bed will be necessary to minimize changes in the ability to control ash agglomeration. The coal feed rate is adjusted to maintain a constant bed height. A constant superficial gas velocity can be maintained by adjusting the steam and air flow rates. The capability of turndown by this method is shown in Figure 5 for three different superficial gas velocities. The reactor could be turned down tenfold by reducing with the superficial gas velocity to 0.33 ft/sec and the gasifier's operating temperature to 1500°F. Decreasing the superficial gas velocity to one-third of design takes only minutes and gives a turndown to 30% of design. Lowering the reactor temperature to 1500°F at a rate of 100°F/hr (a recommended rate to avoid reactor refractory damage) takes 4 hours and results in a further turndown from 30% to 10% of design. Operating at these conditions, the AAR produces a gas with a heating value of 80 Btu/SCF, as compared to about 135 Btu/SCF under full load conditions. This could be used to fire boilers to produce process plant steam. As the reactor's operating temperature is reduced, the product gas heating value decreases (Figure 6) because less steam reacts with the coal to produce hydrogen and carbon monoxide. Idling conditions could be achieved by reducing the reactor temperature to 1400°F and superficial gas velocity to 0.33 ft/sec. The coal feed rate at these conditions is about 5% of the full load rate. Just enough coal is burned to heat the feed gas (mostly steam) to 1400°F.

For complete shutdown, the gasifier could be cooled to about 1400°F, which would take about 5 hours. The gas and coal flows would then be stopped and the bed allowed to collapse. For restarting, the bed is refluidized by reinjection of air and steam and the temperature slowly raised at a rate of 100°F/hr. For emergency shutdown, the bed is permitted to defluidize at temperature. In the defluidized state, the reactor would cool down at a rate of about 100°F/day. For weekend shutdowns there is no need to supply any heat to the defluidized bed. For longer shutdowns, spurts of air to briefly refluidize and reheat the bed might be injected into the bed to replace the heat lost. With controlled cooling, a hot char bed would not solidify but would maintain a free particulate form that could be refluidized with a minimum of trouble.

The gasifier pressure level can also be changed to obtain a fairly wide range of capacity in a given unit. If the gasifier is designed for 300 psi and the lowest system pressure that can be tolerated is 50 psi, the turndown ratio is 6. Although this may be extreme, one might certaily expect that the 300-psi pressure level could be dropped to 100 psi for a relatively easy-to-obtain turndown ratio of 3. In practice, some process upsets may occur if the pressure is changed too rapidly. Given sufficient time, it should be possible to turn the gasifier down safely by this method. Each incremental change in pressure requires an equivalent incremental change in steam and air injection to maintain a fixed superficial gas velocity in the gasifier.

The fifth way to reduce electrical outputs is to fix the gasifier at constant operating conditions, and, as the electrical load changes, to direct more or less of the gas output to the power-generating equipment. The rest of the gas would flow to a Fischer-Tropsch (F-T) unit designed to accept varying amounts of gas. (The unit need not be very efficient.) A reasonable percentage of the carbon monoxide and hydrogen would be converted to liquid fuels. Unconverted gas from the F-T unit would mix with the main gas flow and be used for immediate power generation. The ash-free, sulfur-free liquid products from the F-T unit would be stored and returned to fuel the power-generating equipment during peakload periods or during periods when the gasifier is shut down for maintenance. If an excess amount of liquid fuel is produced, it can be sold as a raw material for petrochemicals or it could be used as a fuel to supplement petroleum.

Addition of a Fischer-Tropsch unit will add significantly to plant capital costs. However, if no other clean fuels are available to the electric utility for use when the gasifier is shut down for maintenance, or if other fuels are not available for the peaking gas turbines, this addition is an excellent way to supply a clean synthetic liquid from coal.

In the Fischer-Tropsch Process, carbon monoxide is hydrogenated to produce mainly straight-chain hydrocarbons and water or carbon dioxide. Catalysts which may be used are cobalt, nickel, iron, or ruthenium. The purified carbon monoxide and hydrogen-containing gas must have less than 2 ppm of sulfur compounds to minimize catalyst poisoning. Branched-chain hydrocarbons, aliphatic alcohols, aldehydes, and acids are also produced in varying amounts depending on the type of catalyst and the operating conditions. The reaction is exothermic with about 7200 Btu being liberated per pound of oil produced. Optimum temperatures are 340°-400°F for cobalt and nickel catalysts, 390°-620°F for iron catalysts, and 320°-440°F for ruthenium.

The large amount of heat evolved and the relatively narrow range of operating temperatures make the problem of removing the heat of reaction most important in the design of the plant. The presence of substantial amounts of nitrogen in the feed gas should not significantly change the yield of liquids and wax produced per volume of $2H_2 + CO$ based on pilot data. Much experience in this type of operation has been gained at Sasol over the last several years.

Interestingly, in processing part of the utility gas through a Fischer-Tropsch unit, if 15% of the reacting carbon monoxide forms methane, the exiting gas heating value is 132 Btu/SCF, assuming a feed gas heating value of 153 Btu/SCF. The difference in gas heating value that will be experienced using various methods for turndown will require sophisticated firing controls in the gas turbine and combustion systems.

Figure 7 shows how the Fischer-Tropsch plant fits in. When the gasifier operation is at design conditions for a high electrical load, only a small amount of gas flows through the F-T unit. As the electrical load decreases, more gas flows through the unit and less goes to the power plant. Finally, all of the gas flows through the F-T unit.

CONCLUSION

The concept of a fluidized-bed reactor as a gas producer for a combined-cycle power plant appears practical. It is possible, as confirmed by the experience of others, to achieve high carbon utilization in such fluidized-bed reactors by rejection of agglomerated, low-carbon ash produced in the gasifier. It is now the opinion of the people in the electric industry that a) such systems should be designed for operation in the intermediate load or swing range and b) to operate satisfactorily they must be capable of load following over a rather wide range.

Several methods which could be used to achieve this flexibility were discussed. It appears at this time that, alone and in combination, these methods will enable fluidized-bed gasifiers to perform satisfactorily under the conditions that will be required by the electric industry. The fluidized-bed reactor concept for coal gasification should find practical application in supplying a clean practical fuel produced from coal for utility use for several decades to come.

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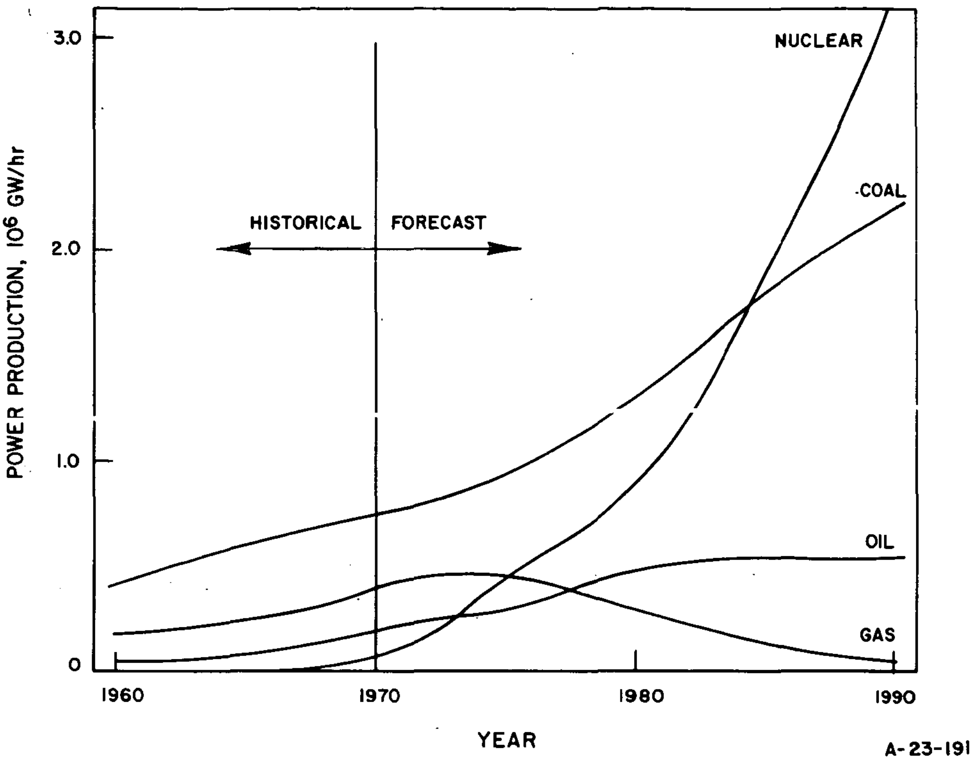

Figure 1. FORECAST OF POWER GENERATION BY FUEL IN THE U.S.

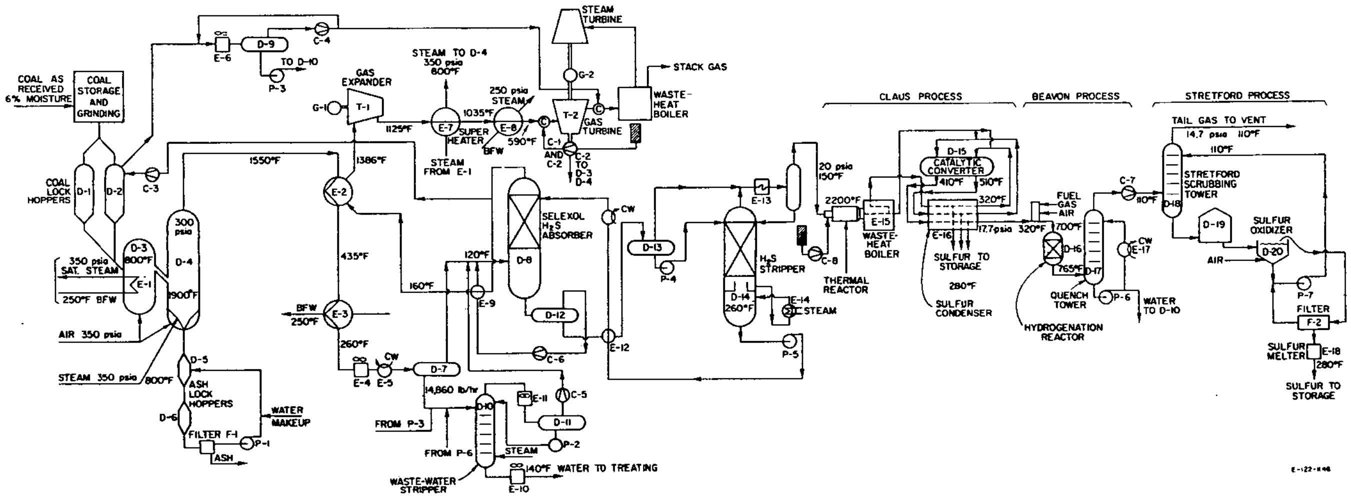

Figure 2. PROCESS FLOW DIAGRAM: UTILITY GAS FOR COMBINED-CYCLE POWER

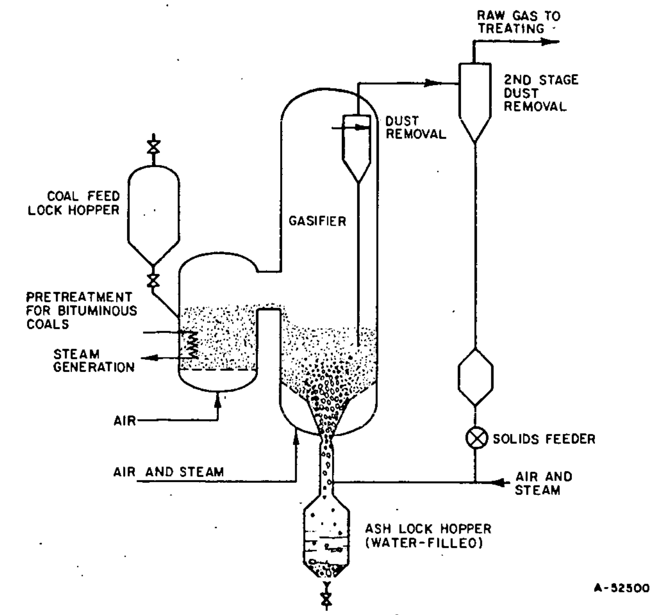

Figure 3. AGGLOMERATING BED REACTOR

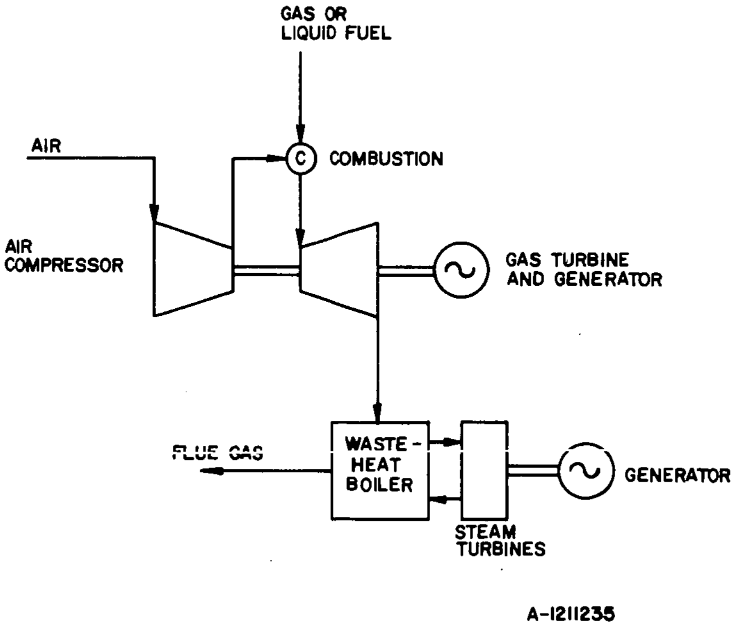

Figure 4. COMBINED-CYCLE POWER GENERATION WITH GAS AND STEAM TURBINES

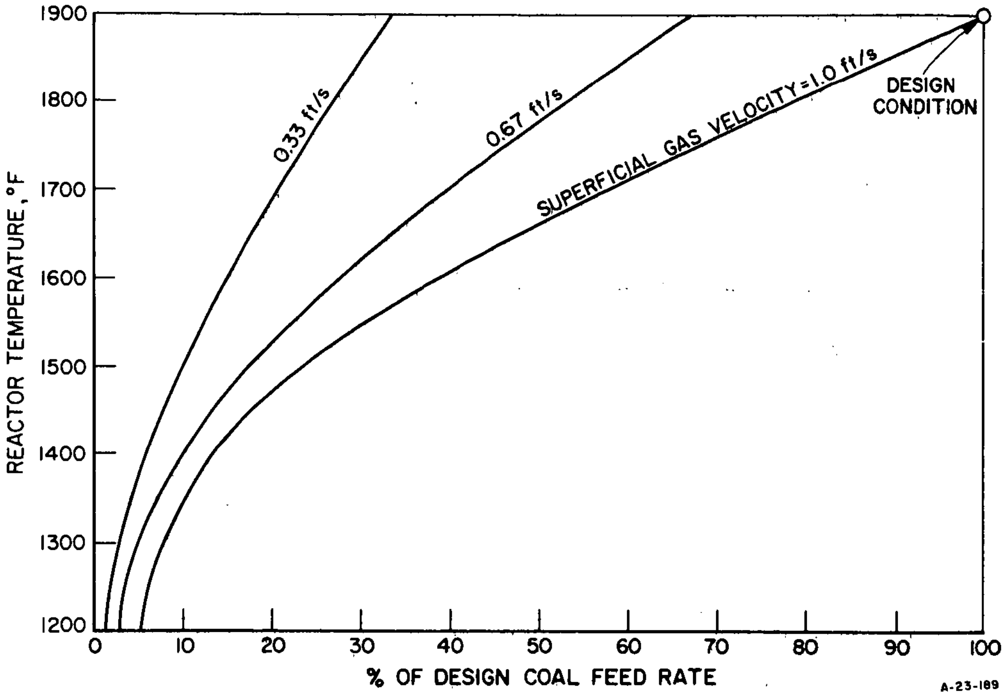

Figure 5. AAR TURNDOWN CAPABILITY

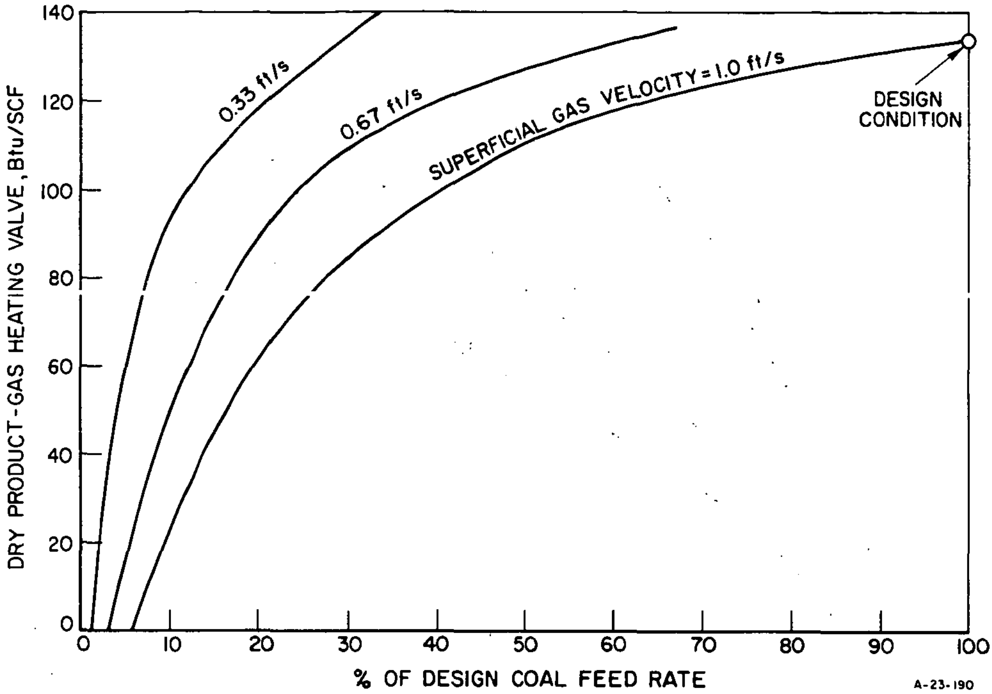

Figure 6. PRODUCT GAS HEATING VALUE AS A FUNCTION OF AAR TEMPERATURE

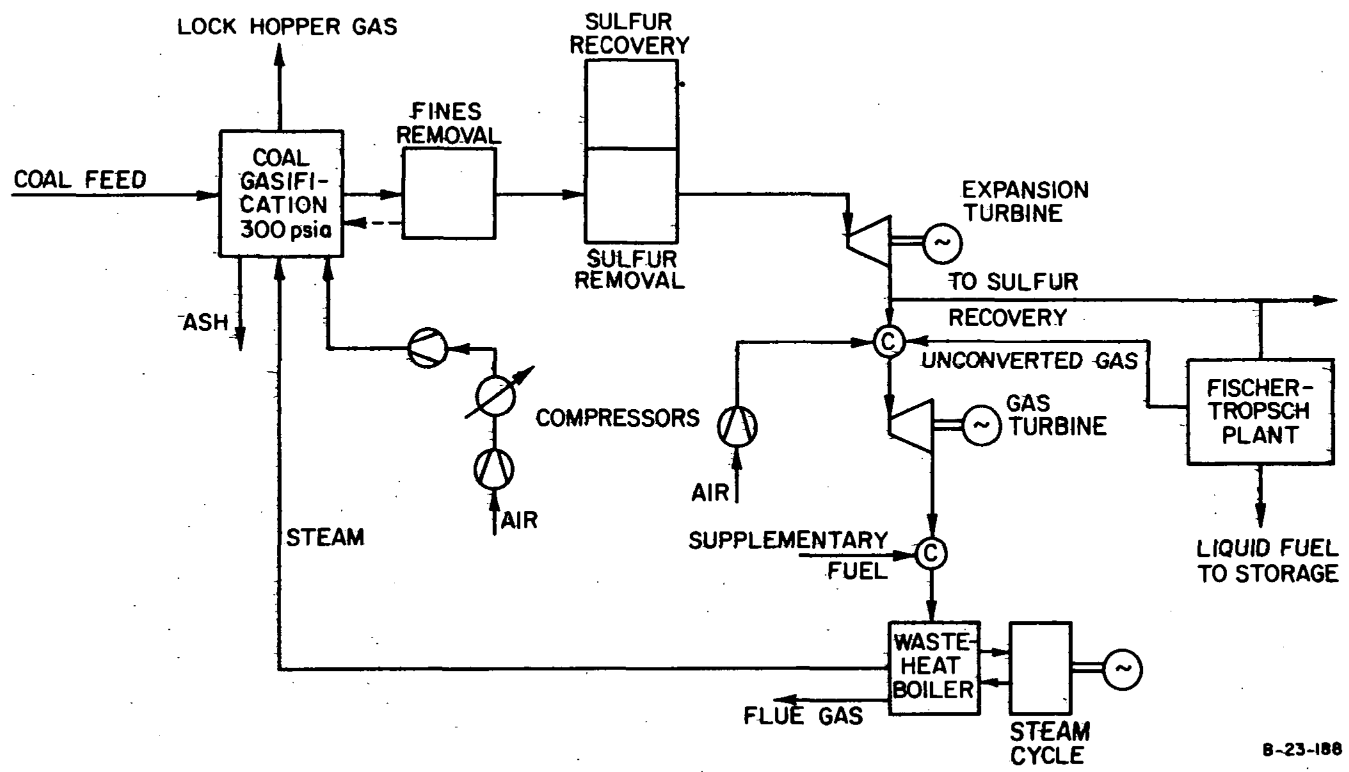

Figure 7. FISCHER-TROPSCH PLANT ADDITION TO COMBINED-CYCLE POWER GENERATION BY COAL GASIFICATION