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by

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ABSTRACT

In the Cogeneration Technology Alternatives Study (CTAS) a number of advanced coal-fired systems were examined. Systems using an integrated coal gasifier or a fluid bed combustor were found to yield attractive cogeneration results in industrial cogeneration applications. In this paper an integrated gasifier combined cycle (IGCC) and an atmospheric fluid bed (AFB) steam turbine system are compared for a range of site requirements and cogeneration sizing strategies using ground rules based on CTAS. The effect of time variations in site requirements and the sensitivity to fuel and electricity price assumptions are examined. The economic alternatives of industrial or utility ownership are also considered. The results indicate that the IGCC system has potentially higher fuel and emission savings and could be an attractive option for utility ownership. The AFB-steam turbine system has a potentially higher return on investment and could be attractive assuming industrial ownership.

SUMMARY

A performance and economic analysis was made of an integrated gasifier combined cycle (IGCC) and an atmospheric fluid bed (AFB) steam turbine system in industrial cogeneration applications. These systems were studied at two reference cogeneration sites, one with a high required power-to-heat ratio and the other with a low required power-to-heat ratio. Both sites are representative of the industrial site requirements encountered in the Cogeneration Technology Alternatives Study (CTAS) and are also sites where the IGCC and AFB-steam turbine systems would be expected to be most attractive. Different sizing options were considered when matching these cogeneration systems to the reference sites. The cogeneration results were compared to results for the noncogeneration cases where electrical power is purchased from a utility and steam produced in an on-site boiler. The sensitivity of the economic results to changes in the electricity and fuel prices was examined. Likewise, the effect of time varying site requirements on the cogeneration results was determined. The economic alternatives of industrial or utility ownership were also considered.

Both the IGCC and AFB-steam turbine system achieved attractive cogeneration results. The IGCC system had superior fuel energy and emission savings at both reference sites. The fuel energy and emission savings achieved by the AFB-steam turbine system were higher at the low power-to-heat ratio site than at the site with the high power-to-heat ratio. At the low power-to-heat ratio site the AFB-steam turbine system had higher levelized annual energy cost savings (LAECS) compared to the IGCC, whereas at the high power-to-heat ratio site the IGCC had a more favorable LAECS. Because of its smaller size and lower capital cost, the AFB-steam turbine generally achieved a higher return on investment (ROI) than the IGCC system, thereby indicating its economic attractiveness for industrial ownership. The IGCC system, with its higher electrical efficiency, was also found to be potentially an attractive candidate for utility ownership when the sale of both electrical power and process steam are considered. The economic comparison of the two cogeneration systems was found to be sensitive to fuel and electricity prices, with the combination of high electricity and low coal prices favoring the IGCC system and low electricity with high coal prices favoring the AFB-steam turbine system. The economic attractiveness of both cogeneration systems increases substantially when oil rather than coal is the noncogeneration on-site boiler fuel. The cogeneration results were also found to be relatively insensitive to moderate time variations in the reference site requirements.

INTRODUCTION

The Cogeneration Technology Alternatives Study (CTAS) was a broad screening study undertaken by the National Aeronautics and Space Administration (NASA) for the Department of Energy (DOE) that compared and evaluated selected advanced energy conversion systems appropriate for use in industrial cogeneration systems for the 1985-2000 time period. The study was primarily concerned with those advanced-technology systems that could use coal or coal-derived fuels in industrial cogeneration applications. Among the advanced coal-fired systems examined in CTAS, those using an integrated coal gasifier or a fluid bed combustor yielded attractive cogeneration results. In this report, results from a performance and economic analysis for an integrated gasifier combined cycle (IGCC) and an atmospheric fluid bed (AFB)-steam turbine system in industrial cogeneration applications are discussed and compared. The purpose of this investigation was to make a more detailed technical and economic comparison of these cogeneration systems than was done in CTAS.

The IGCC and AFB-steam turbine systems were chosen for this analysis as being representative of systems using integrated gasifier and fluid bed coal conversion technologies. The performance and economics of these cogeneration systems are compared at two reference cogeneration sites whose electrical and heat requirements fall within the range of industrial site requirements encountered in CTAS. The technical and economic ground rules used in this analysis are based on those used in CTAS. Fuel and electricity prices were updated from CTAS to reflect more recent price projections. All prices are expressed in terms of 1980 dollars.

A number of different cogeneration sizing strategies were considered for both cogeneration systems. One set of strategies consisted of sizing the power system to match the site electrical power requirement. Depending upon the site heat requirement, the power system could either simultaneously match the heat requirement or, not being able to meet it entirely, would require the use of an on-site supplementary boiler. Another set of sizing options was to size the power system to match the site heat requirements. Again, depending upon the specific site electrical power requirement, the power system could simultaneously match the site electrical requirement, produce excess electrical power which is sold to a utility, or not produce enough power resulting in the necessity of purchasing power to meet the requirement. Results for these cogeneration sizing options are compared with results for the noncogeneration case, where the entire site electrical requirements are purchased from a utility and the site heat requirements are met by an on-site boiler. The comparison is made using either coal or oil as the noncogeneration on-site boiler fuel.

Because the cogeneration economic results depend on the assumed prices for electrical power and fuel, the effect of changes in these prices is also examined. Those cogeneration options having the most attractive economic results, and the range of electricity or fuel prices for which they are most attractive, are determined. Also the criterion for determining economic attractiveness depends on whether the cogeneration system is owned by the industry whose site is being cogenerated, or by the utility, who may site the cogeneration system at or near the industrial plant and sell the power and steam. In the former case, the after-tax return-on-investment (ROI) may be the appropriate economic criterion. In the latter case, the cost of producing electricity, appropriately modified to take into account a credit for the sale of steam, may be economically more meaningful. In this analysis, the utility ownership option is investigated for a selected cogeneration case.

In CTAS, the cogeneration analyses were performed assuming that the industrial site electrical and steam requirements remained constant throughout the year. In the present analysis, the effect of time variations in the site requirements on the cogeneration results is studied for selected cogeneration options.

Two important considerations in the selection of cogeneration systems at industrial sites are the environmental intrusions from the power systems and the amounts of coal used and waste produced. In many instances, these factors could greatly affect the decision as to which cogeneration system to install at a specific site. In some cases, they could even preclude the use of a cogeneration system, even though it might yield attractive cogeneration performance and economic results. In this report, atmospheric emissions, coal use, and waste production at the utility and industrial sites are compared among the various cogeneration options and with the noncogeneration cases.

APPROACH

Power System Selection

Figure 1 shows the minimum power-to-heat ratio (corresponding to the maximum possible process heat extraction) that can be attained for the coal-fired power systems studied in CTAS. Some of the power systems are represented by a range of minimum power-to-heat ratio because of a multitude of design options and/or differences in CTAS contractor results. The first five power systems in the figure are fluid bed systems and the final three are gasifier systems. All of the power systems are capable of operating from the minimum value of power-to-heat ratio shown in the figure up to a power-to-heat ratio of infinity simply by reducing the amount of process heat provided by the power system.

The results in figure 1 show that the fluid bed systems generally have a lower minimum power-to-heat ratio capability than the gasifier systems. At the higher power-to-heat ratios where the gasifier systems operate, the fluid bed systems probably cannot compete with the higher electrical efficiency of the gasifier systems. For the two power systems selected for analysis, the AFB-steam turbine system was taken as representative of the relatively low minimum power-to-heat ratio capability of fluid bed systems and the IGCC power system for the relatively high minimum power-to-heat ratio capability of the gasifier systems. Which one of the two power systems would look best for any given site application would be expected to depend on the specific power-to-heat ratio requirements of the site.

Site Selection

The selection of site requirements was also based on CTAS results. Figure 2 shows the site power-to-heat ratio requirement and the site power requirement for all of the various sites investigated in CTAS. The two reference sites selected for this analysis are shown by the solid symbols. Both sites have an electrical power requirement of 30 MWe. Power-to-heat ratios of 0.33 and 1.0 (process heat requirements of 90 MW_t and 30 MW_t) were considered. These sites were selected to not only fall within the range of sites investigated in CTAS but also within a more specific range where cogeneration looked to be most attractive (re. 1). In addition, the selected site power-to-heat ratios of 0.33 and 1.0 were chosen to correspond to sites that would be expected to be most favorable to AFB-steam turbine and IGCC power systems, respectively. At the power-to-heat ratio of 0.33 the AFB-steam turbine system would be operating near maximum extraction and at the power-to-heat ratio of 1.0 the IGCC would be operating near maximum extraction.

Ground Rules and Assumptions

The ground rules and assumptions used in the analysis are summarized in table 1. The fuel and electricity prices are 1985 prices in 1980 dollars that have been updated from values used in CTAS based on recent DOE/EIA information (ref. 2). As in CTAS, the price for power sold to the utility was assumed to be 60% of the utility selling price. Results are also presented assuming a 100% sell back price. The utility electrical efficiency is the same as that used in CTAS and includes transmission losses. In the noncogeneration case, the industrial site buys power from a utility and makes its own process steam using a boiler fired with oil or with coal using flue gas desulfurization (FGD) scrubbers. The utility is assumed to be using coal-fired steam power plants with FGD scrubbers. The emission guidelines are given in the table and are the same as those used in CTAS. The economic ground rules for calculating levelized annual energy cost and return on investment (i.e., cost of money, depreciation, taxes, etc.) are also the same as those used in CTAS.

Evaluation Parameters

The evaluation parameters that are used throughout the paper are summarized in table 2. The first two parameters represent the levelized annual costs (levelized annual operating cost (LAOC) and levelized annual energy cost (LAEC)) for the noncogeneration and cogeneration cases. The final four parameters represent a comparison of the cogenerating power system (AFB-steam turbine or IGCC) to the noncogeneration case. The fuel energy savings ratio (FESR) and the emissions savings ratio (EMSR) include fuel use and emissions produced at the utility site as well as at the cogenerating industrial site. The levelized annual costs (LAOC and LAEC), the levelized annual energy cost savings ratio (LAECSR), and the return on investment (ROI) take into account the costs associated with either buying or selling electrical power. Also, these economic parameters consider only the capital costs associated with the industrial site. A more detailed description of the evaluation parameters is given in reference 1.

POWER SYSTEM DESCRIPTION

Schematic diagrams of the cogeneration power systems are shown in figure 3. The schematic for the IGCC system is shown in part (a). Air for the gasifier is supplied from the gas turbine subsystem compressor. After further compression in a motor-driven boost compressor, the air is injected, along with steam and coal, into the gasifier. The gasifier produces a low-Btu gas which is cooled in the raw gas cooler before entering the gas cleanup system. In the cleanup system, particulates and H_2S are removed. The H_2S is converted to elemental sulfur for disposal. After leaving the cleanup system, the clean low-Btu gas is heated in the raw gas cooler and then injected into the gas turbine combustor. Electrical power is produced by the gas turbine/generator and heat from the gas turbine exhaust is recovered in a heat recovery steam generator (HRSG), which produces throttle steam for the steam turbine and heats feedwater for the raw gas cooler. Gasifier steam and throttle steam for the steam turbine are raised in the raw gas cooler. The throttle steam from the raw gas cooler is combined with that produced in the HRSG, and the total is sent to the steam turbine/generator, where additional electrical power is produced. Steam for process use is extracted from the steam turbine at the appropriate pressure. The electrical power produced by the steam turbine/generator varies with the amount of steam extracted from the steam turbine as the process steam requirements change.

In part (b) of figure 3, the schematic diagram for the AFB-steam turbine cogeneration system is shown. Coal, air and a limestone sorbent are injected into the AFB furnace. Most of the sulfur in the coal is captured by the limestone sorbent. Particulates in the AFB exhaust gas are removed by cyclone separators and recycled back to the AFB. The exhaust gas is then cooled by preheating combustion air. Final particulate removal is done by either electrostatic precipitators (ESP's) or bag-house filters to meet emission guidelines. Throttle steam for the steam turbine is raised within the AFB furnace. The steam turbine/generator produces electrical power and process steam is extracted from the steam turbine at the appropriate pressure. The steam turbine/generator electrical output will vary as the amount of steam extraction changes.

An energy diagram showing the interfaces between the various subsystems of the IGCC system is displayed in figure 4. The energy values shown are based on 100 units of coal energy input and correspond to the sum of chemical, sensible and latent energies associated with the flow streams between subsystems, and the sensible heat transferred by heat exchangers from one subsystem to another. Also shown are the various losses from the subsystems, along with the electrical energy and process steam produced. The relative widths of the various energy flow arrows roughly indicate the relative amount of energy transfer between subsystems.

Part (a) of the energy diagram is for the zero extraction case when no process steam is extracted from the steam turbine. The energy delivered to the gas turbine in the form of clean, heated, low-Btu gas is equal to 79.5% of the coal input energy to the gasifier. As was shown in the schematic for the IGCC system, steam for the steam plant subsystem is obtained from both the gas turbine and gasifier/cleanup subsystems. Electrical power is produced by both the gas turbine and steam plant. At zero extraction, the net electrical efficiency of the total IGCC system is 37.5%.

In part (b), the energy diagram for only the steam plant subsystem is shown for the case when the maximum amount of process steam is extracted. In this study the gasifier/cleanup and gas turbine subsystems are assumed to operate at a constant output. Therefore, the top part of the diagram, as shown in part (a), remains unchanged and is not shown in part (b) for simplicity. At maximum extraction, the steam plant electrical efficiency is reduced with a corresponding increase in the production of process steam. The net IGCC electrical efficiency for this case is 29.6%, whereas process steam production accounts for 34.9% of the input coal energy, resulting in a total system power-to-heat ratio at maximum extraction of 0.848.

An energy diagram for the AFB-steam turbine system is shown in figure 5. For this system, 85% of the input coal energy is transferred in the form of steam to the steam plant from the AFB furnace system. At zero steam extraction (part (a)), the net electrical efficiency is 24.5%. At maximum steam extraction (part (b)), the net electrical efficiency decreases to 15.2%, while process steam production is 66.2% of the input coal energy. This results in a power-to-heat ratio at maximum extraction of 0.230 which is considerably smaller than the power-to-heat ratio produced by the IGCC system at maximum extraction. These results correspond well with the power-to-heat ratios shown in figure 1 for the AFB-steam turbine and IGCC systems studied in CTAS.

The major operating parameters for the cogeneration power systems are shown in table 3. Part (a) gives the major parameters for the IGCC system. The gas turbine operating conditions represent state-of-the-art equipment. The relatively low steam turbine throttle conditions reflect the small steam turbine size and the relatively low temperature of the gas turbine exhaust gas. The gasifier and clean-up subsystem data is based on that presented in ref. 3. The operating pressure shown for the Westinghouse air-blown fluid bed gasifier is higher than the gas turbine pressure level to overcome gasifier/cleanup pressure losses and to enable the fuel gas to be injected into the combustor. The higher heating value of the clean, low-Btu fuel gas entering the combustor is shown. The Holmes-Stretford desulfurization system converts the H_2S removed from the fuel gas into an elemental solid sulfur cake, which can be easily transported and disposed. The specific emissions of the IGCC system are seen to be very low. SO_x emissions are reduced to low levels by the efficient removal of H_2S from the fuel gas in the Holmes-Stretford desulfurization system prior to combustion in the gas turbine. The low flame temperature produced by the low-Btu fuel gas results in low thermal NO_x emissions. Particulate emissions are low because of the use of cyclone separators and venturi scrubbers prior to desulfurization.

The major operating parameters for the AFB-steam turbine system are shown in table 3 (b). The steam turbine throttle conditions and fluid bed temperature are the same as used in CTAS. Sulfur removal is done within the fluid bed using a limestone sorbent. A calcium-to-sulfur atom ratio of 3 to 1 was assumed in this analysis. Particulates are removed from the combustion products leaving the AFB furnace by cyclone separators and either electrostatic precipitators or bag-house filters. These system emission control parameters were chosen to just meet the SO_x and particulate emission guidelines. Further reductions in atmospheric emissions would be possible with the AFB-steam turbine system by increasing the ratio of limestone sorbent to coal to increase sulfur capture and the use of additional cyclones, bag-house filters, and electrostatic precipitators to increase particulate removal. The former, however, would increase the plant operating cost whereas the latter would increase the capital cost. The NO_x emissions from the AFB system are well below the NO_x emission guidelines because of the relatively low fluid bed temperature. It should be noted that there are substantial differences in the specific emissions shown in table 3 for the IGCC and AFB-steam turbine systems. The effect of these specific emissions on total plant emissions when the power systems are configured in cogeneration applications will be shown later.

In figure 6, the capital cost estimates for the IGCC and AFB-steam turbine systems are shown as a function of power system zero extraction electrical output. These cost estimates were made assuming that the power systems were "mature" (i.e. they were not the "first of a kind"). The solid lines represent the capital cost models used in this analysis and are based on CTAS capital cost estimates. For reference, CTAS capital cost estimates for selected systems are also shown. All capital cost estimates include materials, direct and indirect installation labor, contingency, and architectural and engineering services for the power system and any heat recovery equipment. Capital costs for supplementary boilers are not included.

The CTAS contractors' cost estimates for the AFB-steam turbine systems differ substantially at the 10 MWe size primarily because of different assumptions concerning the decrease in system performance with decreasing power system size. Except for this difference, the CTAS reference systems shown have the same ranking in terms of capital cost at power system sizes of 10 MWe and 30 MWe, with the AFB-gas turbine being the most expensive and the AFB-steam turbine the least expensive.

COGENERATION PERFORMANCE AND ECONOMICS

In a cogeneration analysis many power system sizing and operating options are possible at each reference site. Two options for both the IGCC and AFB-steam turbine systems are shown in figure 7 for each site. The cogeneration system electrical power and process heat outputs for steam turbine extraction rates from zero to maximum extraction are shown for both options. The power output at zero steam extraction corresponds to the full power design point rating of the power system. Along the solid lines shown, the fuel input is held constant and, as the process steam extraction rate is increased, the steam turbine power output is reduced. For the IGCC systems, the gasifier and gas turbine are allowed to operate at full design power levels along these lines. Likewise, for the AFB-steam turbine systems the fluid bed maintains full design steam turbine throttle conditions and steam flow rates as the steam turbine extraction rate is varied.

For both reference sites, option A represents the AFB-steam turbine system sized such that the process steam produced at the maximum steam extraction rate matches the site steam requirement. As shown in the figure, this sizing option for the AFB-steam turbine system results in a cogeneration system producing only part of the site power requirement, with the remainder being purchased from a utility. In option B, the AFB-steam system is sized larger than option A so that at some extraction rate less than the maximum, the cogeneration system can simultaneously match the site power and process heat requirements.

Part (a) of the figure shows that the required site power-to-heat ratio for the reference site requiring 30 MWe power and 90 MWth of process steam is outside the range of power-to-heat ratios that can be produced by the IGCC system. Therefore, the IGCC system cannot simultaneously match the power and heat requirements of this site. Option C represents an IGCC system that is sized such that at maximum extraction the required site power is produced. This option is shown to produce less than half the required process heat, with the remainder being produced in a supplementary boiler. In option D, the IGCC system is sized so that at the maximum extraction rate it produces the required amount of site process steam. In this option, an excess amount of power is produced. This excess power would then be available for sale to a utility.

At the high power-to-heat ratio site (part (b) of the figure), the IGCC option C is analogous to AFB-steam turbine option A. The IGCC is sized so that the process steam produced at the maximum extraction rate matches the site requirement, while additional power is purchased. Likewise, IGCC option D is analogous to AFB-steam turbine option B in that the cogeneration system simultaneously matches the site power and process heat requirements.

A summary comparison of cogeneration performance and economics for the cogeneration options defined in figure 7 is shown in table 4 for the two reference sites. The noncogeneration on-site boiler is coal fired using FGD scrubbers. The power system capacity displayed in the table refers to the zero-extraction power output shown in figure 7. In part (a), results are shown for the low power-to-heat ratio site. All the cogeneration cases show savings in operating costs over the noncogeneraton case. As figure 7 shows, option A requires the purchase of 9.2 MWe of power, while option D requires the sale of 46.2 MWe of excess power. Option D displays the lowest operating cost, but this cost is also shown to be very sensitive to the sellback price of electricity. All the cogeneration cases exhibit significant fuel savings compared to the noncogeneration case. The fuel savings for the IGCC system are generally higher than those achieved by the AFB-steam turbine systems. Emission savings for all the cogeneration cases are also significant, and are particularly high for the IGCC systems primarily because of their much lower specific emissions as shown in table 3.

The levelized annual energy cost savings ratios are generally higher for the AFB-steam turbine systems (with the exception of IGCC option D with 100% sellback price) because of their smaller size and capital cost. It should be noted that the ROI's displayed in the table do not include inflation effects, and are therefore somewhat lower than if inflation had been included. The ROI's relative to the noncogeneration case are higher for the AFB-steam turbine system. Likewise, the incremenal ROI's for options B, C, and D relative to option A are low. Thus, if ROI is the economic criterion, option A appears to be the most attractive cogeneration option for this site.

In part (b), results are summarized for the high power-to-heat ratio site. As figure 7(b) shows, options A and C involve purchase of a portion of the site power requirement, and no excess power for sale to a utility is generated by any of the cogeneration options considered for this site. Again, all the cogeneration options show operating cost savings over the noncogeneration case. The IGCC system has lower operating costs than the AFB-steam turbine systems. All cogeneration options, with the exception of option B, show fuel and emission savings. Figure 7(b) shows that option B operates at a relatively low steam extraction rate. The small amount of heat recovery, along with the relatively low electrical efficiency of the system, results in option B using more fuel than the noncogeneration case. The IGCC systems have higher fuel and emissions savings ratios, as well as higher levelized annual cost savings ratios, than the AFB-steam turbine systems. The highest ROI relative to the noncogeneration case is achieved by the AFB-steam turbine system in option A, which is a much smaller power system with lower fuel energy savings compared to the IGCC options. Again, if ROI is the economic criterion, option A appears to be the most attractive option.

The results shown in table 5 differ from those in table 4 only in that the noncogeneration on-site boiler has been changed from coal-fired with FGD scrubbers to oil-fired. Thus, the noncogeneration boiler capital cost is lower in table 5, and its operating cost is higher because of the higher price of oil. The fuel energy savings of the cogeneration cases are the same as shown in the previous table. The emission savings in table 5 are lower because of the lower site emissions with the oil-fired noncogeneration boiler. Economically, the cogeneration cases appear more attractive in table 5 because of the higher operating costs for the oil-fired noncogeneration boiler. The comparisons among the cogeneration options are similar to those made in table 4. Thus, the results in tables 4 and 5 display the effect of the noncogeneration fuel on the evaluation of coal-fired cogeneration systems, and indicate that both the IGCC and AFB-steam turbine systems look economically more attractive when compared to noncogeneration cases using more expensive oil as the on-site boiler fuel. The effects of changing the noncogeneration and cogeneration fuel prices and electricity prices are further displayed in the sensitivity analysis which follows.

SENSITIVITY TO FUEL AND ELECTRICITY PRICES

Fuel and electricity prices can have a major effect on cogeneration economic results. An example of this effect is shown in figure 8, where the variation in economic results with changes in electricity prices are displayed. Capital costs versus levelized annual operating costs (LAOC) are shown for the noncogeneration cases and cogeneration options defined previously for the low power-to-heat ratio site (fig. 7(b)). Also shown are lines of constant levelized annual energy cost (LAEC). The slope of a line between any two cases on this figure is proportional to the incremental ROI of the higher capital cost case relative to the lower capital cost case. This relationship between the slope and the ROI is displayed in the upper right hand corner of the figure. The change in operating costs as a function of the percentage change in the electrical power purchase price is also indicated for each cogeneration option and noncogeneration case.

As seen in the figure, some cogeneration options are more sensitive to electricity price variations than others. For example, the noncogeneration cases are sensitive to changes in the electricity price because electrical power is bought in these cases. Likewise, cogeneration option D displays a sensitivity to electricity price because a large amount of excess electrical power is sold. However, cogeneration options A, B and C either match or nearly match the site power requirements so that no (or very little) electrical power is bought, resulting in these options being relatively insensitive to electricity price variations.

To illustrate the effect of electricity price variations on the economic results, the following example is discussed. For a 30% increase in the electricity price, the levelized annual operating cost for the oil-fired noncogeneration case increases from $29 million to $32.5 million per year. For the same increase in electricity price, the levelized annual operating cost for cogeneration option D (assuming a 60% sellback electricity price) decreases (due to the revenue from the sale of power) from $12 million to $9 million per year. This results in an increase in the levelized annual energy cost savings ratio (LAECSR) for this cogeneration option from 31% to 48% relative to the oil-fired noncogeneration case and an increase in ROI from 12% to 18%. Likewise, as the price for oil in this noncogeneration case increases relative to coal and electricity prices, all the coal-fired cogeneration options will look more attractive. In figure 8, as the oil price is increased relative to the coal and electricity prices, the point representing the oil-fired noncogeneration case will move to the right, resulting in higher LAECSR and ROI for the cogenereration options. There will be no change in the relative economic attractiveness among the cogeneration systems themselves, since only the oil-fired noncogeneration case changes position with changes in the assumed oil price.

In table 4(a), option A is shown to have the highest LAECSR for the low power-to-heat ratio reference site. However, if the sellback price of excess electricity in option D equals the purchase price of electricity, this option has the highest LAECSR. For the high power-to-heat ratio site shown in table 4(b), option D has the highest LAECSR. The results in table 4 assume an electricity price of $0.0388/kW-h. Since these various cogeneration options involve the purchase and sale of different amounts of electricity, the comparisons among the various cogeneration options would be expected to change with variations in the electricity price. Those cogeneration options with the lowest levelized annual energy cost (LAEC) for both reference sites are identified in table 6 as a function of electricity price. For both reference sites, option A, which has the smallest power plant size and involves the purchase of a portion of the site electrical requirement, has the lowest LAEC for low electricity prices. Likewise, option D, which has the largest power plant size resulting in the largest amount of on-site electrical generation, has the most attractive LAEC at higher electricity prices. As would be expected, the comparison of options A and D for the low power-to-heat ratio site is very dependent on the sellback price of the excess power generated in option D. Note that the changes in results between options A and D occur within 25% of the base electricity price assumed for the results shown in table 4.

Since the various cogeneration options involve different power system sizes and operating conditions resulting in different amounts of coal usage, it would also be expected that the comparisons between these options would depend on the coal price. The cogeneration options with the lowest LAEC for both reference sites are shown in table 7 as a function of coal price. Note that the variation in coal price applies only to that coal used in the cogeneration options and in the on-site noncogeneration boiler, and for the purposes of this analysis does not affect the price of electricity bought from the utility, even though the utility is coal-fired and the electricity price would actually also be a function of coal price. In part (a), the results for the low power-to-heat ratio site indicate that option D, which has the largest power system size and coal usage, has the lowest LAEC at low coal prices. At the higher coal prices, option A, with the smallest power system size and coal usage, has the lowest LAEC. The comparison of the options depends on the sellback price for the excess power generated in option D. In part (b), option B has the lowest LAEC at very low coal prices for the high power-to-heat ratio reference site. At somewhat higher coal prices, the lowest LAEC is achieved with option D. At high coal prices, option A, which has a considerably smaller power system and coal usage than options B and D, has the lowest LAEC. Thus, those options which have large power systems (and hence use more coal on-site) look relatively more attractive at lower coal prices, while those options with smaller power systems look more attractive at higher coal prices.

EFFECT OF TIME VARIATIONS IN SITE REQUIREMENTS

The results presented up to this point have been for the two power systems operating full-time, year-round at a specific site condition. In an actual application, one would expect that the electrical power and the process heat requirements of the site would vary with time - either hour by hour, with the day of the week or seasonally. Both of the power systems being examined here have the flexibility to change the amount of extraction steam and thus follow time variations in the site process heat requirement. To examine the effect of moderate time variations of the site requirements on cogeneration power system performance and economic results, both of the cogeneration power systems were considered at each of the two reference sites with separate ±10 MW variations in electrical power or process heat requirements. This results in sites having relatively high ratios of average to peak load, which would be expected to be a necessary condition to achieve attractive cogeneration results. The site variations are illustrated in figure 9(a) for the low power-to-heat ratio reference site and in figure 9(b) for the high power-to-heat ratio reference site.

The ±10 MW variations in electrical power or process heat were accomplished in 2 MW increments as shown in the figure by the triangular symbols for the electrical power variation with constant process heat and by the circular symbols for process heat variation with constant electrical power. In both cases, whether electrical power variation or process heat variation, it was assumed that an equal portion of the year's time was spent at each of the particular combinations of required electrical power and process heat.

The power system sizing options selected for analysis with these time varying site conditions are also shown in figure 9. At the low power-to-heat ratio reference site conditions, figure 9(a), option A for the AFB-steam turbine power system and option C for the IGCC power system were selected for analysis since for steady state operation at this site condition, these particular sizing options had the best overall combination of performance and economics as discussed earlier. At the high power-to-heat ratio reference site, figure 9(b), option A for the AFB-steam turbine power system and option D for the IGCC power system were selected for analysis for the same reason.

When possible, both power systems are operated so as to match the process heat requirement and the electrical power output of the power system at that operating point is then compared to the site electrical power requirement and electrical power is bought or sold accordingly. If the power system cannot provide enough process heat, then it operates at the maximum extraction point and a supplementary boiler is added to provide the remainder of the process heat required.

Performance and economic results for the power systems with the time varying site conditions illustrated in figure 9 are presented in table 8. In table 8(a) results are shown for both power systems with time variations at the low power-to-heat ratio reference site and in table 8(b) for time variations at the high power-to-heat ratio reference site. For comparison, each table also repeats the results for the steady state site conditions that were presented in table 4.

The overall conclusion that can be drawn from the results shown in table 8 is that the time variations considered result in either no change at all or a relatively small reduction in each of the evaluation parameters. As an example, for the IGCC power system at low power-to-heat ratio, table 8(a), the variation in process heat requirement necessitates a larger supplementary boiler to provide the higher peak process heat requirement and hence the cost savings are somewhat reduced because of the higher capital cost of the larger boiler. However, there is no change at all in the fuel and emission parameters since the time variation in process heat requirement averages out to be the same as operating full time at the reference site condition. The IGCC power system itself is unaffected by the variable site conditions and always operates at the maximum extraction point with the time variation in process heat provided by the supplementary boiler. At this same reference site, the time variation in electrical power for the IGCC power system has the effect of reducing all the evaluation parameters somewhat. This results from the need to buy power for half the time coupled with the need to sell power for the remaining half the time but at only 60% of the buying price. Again the actual operation of the power system in this particular case is unaffected - it operates always at the maximum extraction point and the time varying electrical power requirements are met by buying or selling power as required.

For the AFB-steam turbine power system at the low power-to-heat ratio reference site, table 8(a), the time variation in process heat requirement also reduces all of the evaluation parameters somewhat. This reduction is a result of the need for a supplementary boiler to provide the higher peak process heat requirement, and the operation of the power system at less than maximum extraction (and hence reduced cogeneration effectiveness) for half the time. The time varation in electrical power for the AFB-steam system has the effect of slightly lowering the cost evaluation parameters. This is a result of the condition at the lowest electrical power requirement (see fig. 9(a)) where electric power is being sold but at only 60% of the purchase price. At all the other site requirements for this case, electric power is being purchased. The overall effect is just a slight decrease in cost savings as compared to full time operation at the reference site condition.

Similar results are apparent in table 8(b) for time variations at the high power-to-heat ratio reference site with the reasoning used in the discussion of table 8(a) providing explanations for the lack of change or slight decrease in each of the evaluation parameters.

UTILITY OWNERSHIP ALTERNATIVE

The cogeneration economic parameters that have been discussed and presented in tables 4 through 8 are parameters which take the perspective of a potential industrial owner. Another perspective worth examining is that of utility ownership, which may be of particular interest for systems such as the IGCC power system which has relatively high electrical efficiency even while providing maximum process heat. For example, option D for the IGCC power system (nominally 100 MWe at zero extraction) at the low power-to-heat ratio site was sized to operate at maximum steam extraction to provide the site heat requirement and as a result produced much more electrical power than that required by the site (76 MWe produced versus 30 MWe required). If such a powerplant were owned and dispatched by a utility, the levelized annual energy cost savings ratio of 38.8% for the 100% sellback rate shown in table 4(a) is indicative of the potentially significant savings to a utility which would result from the sale of the process steam. In addition, the fuel savings and emission savings parameters are also significantly attractive for this power system.

Another way to illustrate this potential cost savings is to calculate the cost of electricity (COE) credit that a utility could realize from the revenue produced by the sale of the process steam from such a power system. Such a credit is shown in figure 10 for sizing option D for the IGCC power system at the low power-to-heat ratio reference site. In calculating the credit, the selling price of the process steam has been assumed to be equal to the industrial owner's levelized cost of owning and operating a properly sized boiler divided by the product of the amount of steam produced and the ratio of power to heat produced by the power system. As figure 10 indicates, this COE credit is dependent upon the price of fuel for the boiler that an industrial customer would have to pay if he were producing his own process steam - the higher the fuel price, the higher the cost of making steam with a boiler and hence the higher the utility credit for selling the steam. The COE credit is also dependent upon the type of boiler fuel, as indicated in the figure, since both the capital and O&M cost of a coal fired boiler differ from that of an oil fired boiler. The figure indicates the potentially significant leverage the sale of steam from such a cogeneration power system could have in reducing the effective bus-bar cost of electricity.

In order to take advantage of the potential cogeneration fuel and cost savings, such a utility owned powerplant would have to be located relatively close to potential steam customers and would likely be a smaller plant than those usually considered for utility central station application. It would be expected that the capital cost per kilowatt capacity of the nominal 100 MWe cogenerating IGCC would be somewhat higher than a central station power system of larger size. However, because of the COE credit for the steam sales shown in figure 11, the higher capital cost per kilowatt of the small cogenerating IGCC may not necessarily result in a higher effective busbar COE. To illustrate this point, figure 12 shows the amount in dollars per kilowatt by which the capital cost of the relatively small IGCC cogenerating powerplant could exceed that of a large central station powerplant and still yield the same effective busbar COE because of the COE credit from the steam sales. As expected, the results are dependent upon the type of fuel that would have been used by the steam customer had he made his own steam and also on the efficiency of the central station powerplant. (It is assumed that the cogenerating IGCC power plant operates at maximum extraction resulting in an electrical efficiency of about 30%.) Also indicated in the figure is the sensitivity of the results to a $\pm$25% change in the price of fuel.

The capital cost difference shown in figure 11 is nearly always greater than that which would be expected for the capital cost difference between a 600 MWe central station unit and a 100 MWe cogenerating unit. Therefore, there is the potential for a significant cost savings for a utility owning and operating such a power system.

ENVIRONMENTAL AND SITING CONSIDERATIONS

An important consideration in evaluating and comparing alternative coal-fired cogeneration systems is their ability to be sited in appropriate industrial areas. Important factors in siting include the amount of input materials required for operation, the form and amount of waste materials which must be removed from the site, and the atmospheric emissions produced at the site. The use of coal and limestone, and the production of solid waste for the noncogeneration case and cogeneration options are shown in figure 12. Also shown are the input materials and solid waste outputs attributable to the utility site when power is purchased for use at the industrial site. It is assumed that the utility power plant is a coal-fired steam turbine plant with FGD scrubbers. The noncogeneration industrial site boiler is assumed to be coal-fired with FGD scrubbers. Results for the low power-to-heat ratio reference site are shown in part (a), while those for the high power-to-heat site are shown in part (b).

In the cogeneration options, the use of coal and limestone, and the production of solid waste is seen to shift from the utility site to the industrial site. The AFB steam turbine systems generally require the use of more coal and limestone, and produce more solid waste than the IGCC systems because of their generally lower cogeneration performance and their need for a relatively large amount of limestone for sulfur capture. The IGCC systems, whose solid waste consists of ash and sulfur cake, produces much less solid waste than the AFB-steam turbine systems, whose waste consists of ash and spent sorbent. At the low power-to-heat ratio site IGCC option C requires a small amount of limestone because its required supplementary boiler is assumed to be coal-fired using FGD scrubbers. An alternative method of firing this boiler would be to assume a larger gasifier/cleanup system which would produce excess clean fuel gas to be used in the supplementary boiler. At this same site in part (a), option D requires the largest amount of coal, but produces over twice as much electrical power as required by the site. Thus, the amount of coal displaced at the utility site is actually more than twice that shown for the utility in the noncogeneration case.

Atmospheric emissions at the utility and industrial site are shown in figure 13 for the noncogeneration cases and cogeneration options. The utility site emissions are those attributable to the power purchased for use at the industrial site. The utility power system is assumed to just meet the emission guidelines for a coal-fired power plant. Results are shown for the low power-to-heat ratio site in part (a), and for the high power-to-heat ratio site in part (b). Both coal and oil-fired on-site boilers were considered in the noncogeneration cases.

The utility site emissions attributable to power produced at the utility are shown to be decreased or completely eliminated with the production of power on-site in the cogeneration options. The industrial site emissions for the AFB-steam turbine cogeneration options A and B are shown to be the same or higher than the noncogeneration on-site emissions. The idustrial site emissions of IGCC cogeneration options C and D are lower than those of the coal-fired noncogeneration cases. The low emissions for the IGCC option shown in figure 13 are a result of the low IGCC specific emissions displayed in table 3. With the exception of option C in part (a) of the figure, the industrial site atmospheric emissions for the IGCC cogeneration options are even lower than the oil-fired noncogeneration industrial on-site boiler emissions. For the low power-to-heat ratio reference site, option C requires the use of a supplementary boiler which is assumed to be coal-fired. The emissions for this option could be further reduced by firing the boiler with low-Btu fuel from a somewhat larger gasifier. Note also that at the lower power-to-heat ratio site option D has approximately the same atmospheric industrial site emissions as the oil-fired noncogeneration on-site boiler, but uses coal as the fuel and produces much more power than required by the industrial site.

CONCLUDING REMARKS

The IGCC and AFB-steam turbine systems achieved attractive cogeneration results at two reference industrial sites. Both systems displayed operating cost savings compared to the noncogeneration cases, where electrical power is bought from a utility and steam is raised in on-site boilers. The IGCC system had significant fuel energy and emission savings compared to the noncogeneration cases,and these savings were generally higher than those achieved with the AFB-steam turbine system because of the IGCC's much higher electrical efficiency over the total range of steam extraction rates. The AFB-steam turbine system displayed higher fuel and emission savings at the low power-to-heat ratio site compared to that achieved at the high power-to-heat ratio site because of the inherently lower power-to-heat ratio produced by this cogeneration system.

The IGCC system has the potential to achieve much lower atmospheric emissions than the AFB-steam turbine system. Particulates and sulfur bearing compounds in the raw fuel gas leaving the gasifier can be efficiently and economically removed before combustion in the gas turbine, thereby making it possible to achieve significantly lower emissions than the maximum allowed. In this analysis, the AFB-steam turbine system was assumed to just meet these maximum allowable emission guidelines for SO_x and particulates. Further decreases in these emissions could be possible at the expense of increasing the operating and capital costs of the AFB system. The NO_x emissions for both the IGCC and AFB-steam turbine are much lower than the maximum allowable.

At the low power-to-heat ratio site, the levelized annual energy cost savings ratio (LAECSR) for the AFB-steam turbine system are generally higher than those for the IGCC system. The exception to this is the IGCC system sizing option where a large amount of excess electrical power is produced and sold to the utility at 100% of the utility electrical selling price. At the high power-to-heat ratio site the IGCC achieved the larger LAECSR. The AFB-steam turbine system achieves a higher value of ROI at both reference sites because of its generally smaller size and capital cost, thereby making it an attractive candidate for industrial ownership. Likewise, both cogeneration systems are economically more attractive if oil is the noncogeneration on-site boiler fuel because of the higher price for oil compared to coal.

The above conclusions are based on the assumed base prices for electricity and fuel. The economic attractiveness of these cogeneration systems were found to be sensitive to the electricity and fuel prices. At low electricity prices, the AFB steam turbine is economically more attractive, whereas at high electricity prices the IGCC system was more economic. Likewise, at low coal prices, the IGCC system is more economic and at high coal prices the AFB-steam turbine is economically favorable.

The consideration of moderate time variations in the reference site electrical power and heat requirements resulted in either no change in the cogeneration results or small reductions in the cogeneration performance and economic attractiveness compared to cases where the site requirements are assumed constant.

The concept of utility ownership was considered for the IGCC cogeneration system because of its relatively high electrical efficiency even while providing maximum process heat. This was examined at the low power-to-heat ratio site for the IGCC sizing option where a large amount of electrical power is exported from the reference site. In this case, a credit to the cost of electricity for the sale of the process steam produced by the cogeneration system was calculated and found to be significant in reducing the busbar COE. This COE credit for the sale of process steam was used to calculate the amount by which the capital cost, in dollars per kilowatt, of the relatively small IGCC cogeneration system could exceed that of a large utility central station power plant and still yield the same COE as the utility power system. The allowable capital cost increase for the IGCC cogeneration system was found to be greater than would be expected for the power system size differences, thus indicating the economic viability of utility ownership of this cogeneration system in these circumstances.

The siting considerations of coal use, solid waste production, and atmospheric emissions were also examined. The use of cogeneration at industrial sites was shown to shift the burdens of these factors from the utility site to the industrial site. Generally, coal use and solid waste production will increase at the industrial site with cogeneration compared to the noncogeneration case. The solid waste produced by the IGCC system was found to be significantly less than that produced by the AFB-steam turbine system. The industrial site atmospheric emissions from the AFB-steam turbine cogeneration system were greater than the noncogeneration industrial site emissions. However, the site emissions from the IGCC cogeneration systems were generally lower than those from the noncogeneration industrial site using a coal-fired boiler and, in some cases, even lower than the emissions from the noncogeneration oil-fired on-site boiler.

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1. Barna, G. J., Burns, R. K., and Sagerman, G. D., "Cogeneration Technology Alternatives Study (CTAS), Volume I - Summary," NASA TM-81400, 1980.
2. Borg, S. and Moden, R., "Historic and Forcasted Energy Prices by DOE Region and Fuel Type for Three Macroeconomic Scenarios and One Imported Oil Price Escalation Scenario," DOE/EIA-0102/27, Department of Energy, Washington, D.C., Dec. 1978.
3. Bloomfield, H. S., et al., "Conceptual Design Study of a Coal Gasification Combined Cycle Powerplant for Industrial Cogeneration," NASA TM-81687, 1981.

TABLE 1. - GROUND RULES AND ASSUMPTIONS

Fuel prices, \$/MJ (\$/MBtu)	
Oil	0.00472 (5.00)
Coal	0.00193 (2.04)
Electricity price, \$/kW-h	0.0388
Exported electricity price, \$/kW-h	0.0233, 0.0388
Electric utility efficiency, %	32
Noncogeneration fuel use:	
Utility	Coal - FGD
Industrial site	Oil, coal - FGD
Emission guide lines, kg/MJ (lb/MBtu)	
Solid fuel	
SO_x	5.16×10^{-4} (1.2)
NO_x	3.01×10^{-4} (0.7)
Particulates	4.30×10^{-5} (0.1)
Liquid fuel	
SO_x	3.44×10^{-4} (0.8)
NO_x	1.72×10^{-4} (0.4)
Particulates	4.30×10^{-5} (0.1)
Economic ground rules for calculation of levelized annual energy cost savings and return on investment	Same as CTAS

TABLE 2. - DEFINITION OF EVALUATION PARAMETERS

Evaluation parameter		Definition
LAOC:	Levelized annual operating cost	The constant cost required each year of the economic life to meet operating expenses of the noncogeneration or cogeneration industrial plant including fuel costs, operating and maintenenace costs, and electricity costs.
LAEC:	Levelized annual energy cost	LAOC + levelized annual capital charge for recovery of initial investment at industrial site for noncogeneration or cogeneration case.
FESR:	Fuel energy savings ratio	$\mathrm{FESR} = \frac{(\text{Fuel energy})_{\text{noncogen}} - (\text{Fuel energy})_{\text{cogen}}}{(\text{Fuel energy})_{\text{noncogen}}}$
EMSR:	Emissions savings ratio	$\mathrm{EMSR} = \frac{(\text{Emissions})_{\text{noncogen}} - (\text{Emissions})_{\text{cogen}}}{(\text{Emissions})_{\text{noncogen}}}$
LAECSR:	Levelized annual energy cost savings ratio	$\mathrm{LAECSR} = \frac{(\mathrm{LAEC})_{\text{noncogen}} - (\mathrm{LAEC})_{\text{cogen}}}{(\mathrm{LAEC})_{\text{noncogen}}}$
ROI:	Return on investment	The interest rate that equates the present value of future incremental cash flows (increment between cogeneration and noncogeneration systems) with the initial incremental capital investment.

TABLE 3. - MAJOR PARAMETERS

(a) Integrated gasifier combined cycle

Gas turbine (nominal)	
Turbine inlet temperature, °C (°F)	1094 (2000)
Compressor pressure ratio	16 to 1
Steam cycle	
Throttle conditions, MPa/°C (psia/°F)	4.29/399 (615/750)
Condenser pressure, MPa (in. Hga)	0.013 (4.0)
Gasifier	
Type	Westinghouse fluid bed (air blown)
Operating pressure, MPa (psia)	1.98 (284)
Clean low-Btu gas higher heating value, MJ/kg (Btu/lb)	5.151 (2216)
Clean-up system	
Particulate removal	Cyclones, Venturi Scrubber
Desulfurization	Holmes-Stretford
Specific emissions, kg/MJ (lb/MBtu)	
SO_x	4.30×10^{-5} (0.1)
NO_x	4.30×10^{-5} (0.1)
Particulates	7.31×10^{-7} (0.0017)

(b) AFB-steam system

Steam cycle	
Throttle conditions, MPa/°C (psia/°F)	8.375/510 (1200/950)
Condenser pressure, MPa (in. Hga)	0.0205 (6.1)
Fluid bed temperature, °C (°F)	844 (1550)
Clean-up system	
Particulate removal	Cyclones, electrostatic precipitation or bag house filters
Desulfurization	In bed using limestone sorbent
Calcium/sulfur ratio	3:1
Specific emissions, kg/MJ (lb/MBtu)	
SO_x	5.16×10^{-4} (1.2)
NO_x	8.60×10^{-5} (0.2)
Particulates	4.30×10^{-5} (0.1)

TABLE 4. - SUMMARY COMPARISON

(a) Site: P = 30 MWe; Q = 90 MWth; noncogen fuel = coal

	w/o Cogen	AFB-steam		IGCC	
		Option A	Option B	Option C	Option D
On-site equipment					
Boiler capacity, MWt	90	0	0	53.4	0
Boiler cost, $\$10^6$	16.6			9.8	
Power system capacity, MWt	0	33.3	42.6	38.0	96.6
Power system cost, $\$10^6$		32.6	39.7	42.5	81.7
Electric power purchased, MWe	30	9.2	0	0	0
Electric power sold, MWe	0	0	0	0	46.2
Operating cost, $\$10^6$/yr	18.27	13.2	12.84	13.08	11.37[a] (5.1)[b]
Fuel energy savings ratio (FESR), %	Base	17.3	12.9	17.0	25.1
Emission savings ratio (EMSR), %	Base	34.4	34.7	62.7	92.5
Levelized annual energy cost savings ratio (LAECSR), %	Base	18.5	17.3	10.6	6.8[a] (38.8)[b]
ROI	Base	19.8	14.8	9.0	6.4[a] (12.9)[b]
		Base	2.6	~0	1.7[a] (10.5)[b]

(b) Site: P = 30 MWe; Q = 30 MWth; noncogen fuel = coal

On-site equipment					
Boiler capacity, MWt	30	0	0	0	0
Boiler cost, $\$10^6$	7.7				
Power system capacity, MWe	0	11.1	34.2	32.2	36.8
Power system cost, $\$10^6$		13.6	33.3	37.8	41.5
Electric power purchased, MWe	30	23.1	0	4.6	0
Electric power sold, MWe	0	0	0	0	0
Operating cost, $\$10^6$/yr	12.89	11.19	10.3	8.49	7.92
Fuel energy savings ratio (FESR), %	Base	8.9	Neg	22.3	23.9
Emission savings ratio (EMSR), %	Base	17.7	18.9	82.2	92.3
Levelized annual energy cost savings ratio (LAECSR), %	Base	8.6	2.7	13.1	15.0
ROI	Base	18.1	6.0	9.0	9.1
		Base	2.2	6.7	7.1

[a]Sellback price of exported power = 60% of utility selling price.
[b]Sellback price of exported power = 100% of utility selling price.

TABLE 5. - SUMMARY COMPARISON

(a) Site: P = 30 MWe; Q = 90 MWth; noncogen fuel - oil

	w/o Cogen	AFB-steam		IGCC	
		Option A	Option B	Option C	Option D
On-site equipment					
Boiler capacity, MWt	90	0	0	53.4	0
Boiler cost, $\$10^6$	3.7			9.7	
Power system capacity, MWt	0	33.3	42.6	38.0	96.6
Power system cost, $\$10^6$		32.6	39.7	42.5	81.6
Electric power purchased, MWe	30	9.3	0	0	0
Electric power sold, MWe	0	0	0	0	46.2
Operating cost, $\$10^6$/yr	26.3	13.2	12.9	13.1	11.4[a] (5.1)[b]
Fuel energy savings ratio (FESR), %	Base	17.3	12.9	17.0	25.1
Emission savings ratio (EMSR), %	Base	Neg	Neg	40.0	90.5
Levelized annual energy cost savings ratio (LAECSR), %	Base	39.9	39.0	34.1	31.3[a] (54.9)[b]
ROI	Base	28.1	23.5	17.3	12.2[a] (17.4)[b]
		Base	2.6	~0	1.7[a] (10.5)[b]

(b) Site: P = 30 MWe; Q = 30 MWth; noncogen fuel = oil

On-site equipment					
Boiler capacity, MWt	30	0	0	0	0
Boiler cost, $\$10^6$	1.6				
Power system capacity, MWt	0	11.1	34.2	32.2	36.8
Power system cost, $\$10^6$		13.6	33.3	37.8	41.5
Electric power purchased, MWe	30	23.1	0	4.6	0
Electric power sold, MWe	0	0	0	0	0
Operating cost, $\$10^6$/yr	15.6	11.2	10.3	8.5	7.9
Fuel energy savings ratio (FESR), %	Base	8.9	Neg	22.3	24.0
Emission savings, Ratio (EMSR), %	Base	Neg	Neg	77.5	90.5
Levelized annual energy cost savings ratio (LAECSR)	Base	21.2	16.2	25.1	26.7
ROI	Base	23.0	10.4	12.3	12.1
		Base	2.2	6.7	7.1

[a]Sellback price of exported power = 60% of utility selling price.
[b]Sellback price of exported power = 100% of utility selling price.

TABLE 6. - SENSITIVITY ANALYSIS SUMMARY:

COGENERATION OPTIONS WITH LOWEST

LEVELIZED ANNUAL ENERGY COST

FOR RANGE OF ELECTRICITY

PRICES

(a) Site = 30 MWe, 90 MWth

Price for exported power	Option with lowest LAEC	Electricity price ($/kW-hr)
100% of electricity price	A D	<0.0305 >0.0305
60% of electricity price	A B D	<0.0413 0.0413 to 0.0473 >0.0473

(b) Site = 30 MWe, 30 MWth

Option with lowest LAEC	Electricity price ($/kw-hr)
A	<0.0348
D	>0.0348

TABLE 7. - SENSITIVITY ANALYSIS SUMMARY:

COGENERATION OPTIONS WITH LOWEST

LEVELIZED ANNUAL ENERGY COST

FOR RANGE OF COAL PRICES

(a) Site = 30 MWe, 90 MWth

Price for exported power	Option with lowest LAEC	Coal price ($/MBtu)
100% of electricity price	D A	<3.10 >3.10
60% of electricity price	D B A	<1.06 1.06 to 1.82 >1.82

(b) Site = 30 MWe, 30 MWth

Option with lowest LAEC	Coal price ($/MBtu)
B	<0.51
D	0.51 to 2.60
A	>2.60

TABLE 8. - EFFECT OF TIME VARIATION IN-SITE CONDITIONS

[Noncogeneration fuel is coal.]

(a) Low power-to-heat ratio

	IGCC P_{ECS} = 38.03 (option C)			AFB-Steam P_{ECS} = 33.32 (option A)		
	P = 30 Q = 90	P = 30 Q = 80 to 100	P = 20 to 40 Q = 90	P = 30 Q = 90	P = 30 Q = 80 to 100	P = 20 to 40 Q = 90
Fuel energy savings, %	17.03	17.03	16.33	17.34	16.34	17.33
Emission savings, %	62.71	62.71	60.14	34.38	33.37	3[illegible].34
Levelized annual cost savings, %	10.61	10.58	8.72	18.48	17.01	18.44
ROI, %	8.97	8.99	8.27	19.77	17.44	19.74

(b) High power-to-heat ratio

	IGCC P_{ECS} = 36.80 MWe (option D)			AFB-Steam P_{ECS} = 11.11 MWe (option A)		
	P = 30 Q = 30	P = 30 Q = 20 to 40	P = 20 to 40 Q = 30	P = 30 Q = 30	P = 30 Q = 20 to 40	P = 20 to 40 Q = 30
Fuel energy savings, %	23.95	23.23	22.46	8.94	7.38	8.94
Emission savings, %	92.33	90.60	86.60	17.73	16.17	17.73
Levelized annual cost savings, %	15.01	13.91	12.27	8.59	6.82	8.59
ROI, %	9.08	8.79	8.34	18.07	13.72	18.07

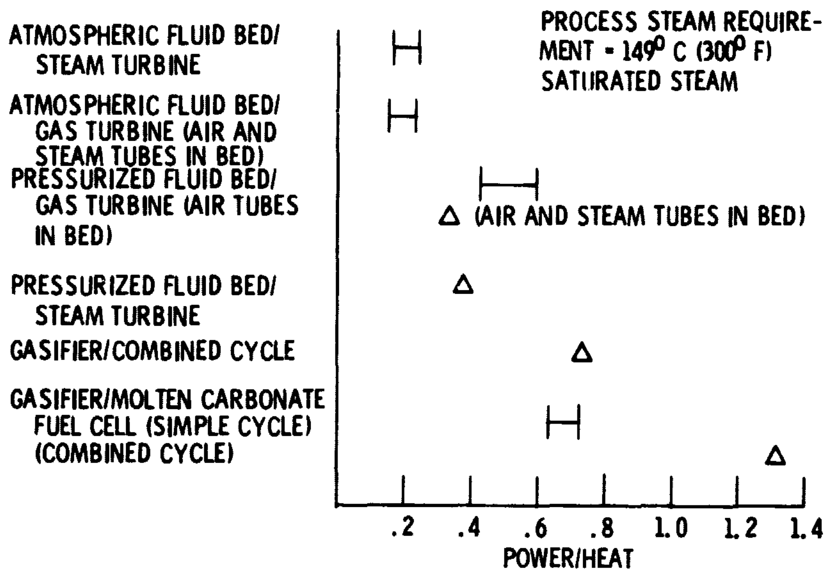


Figure 1. - Minimum power/heat produced by advanced coal fired power systems in CTAS.

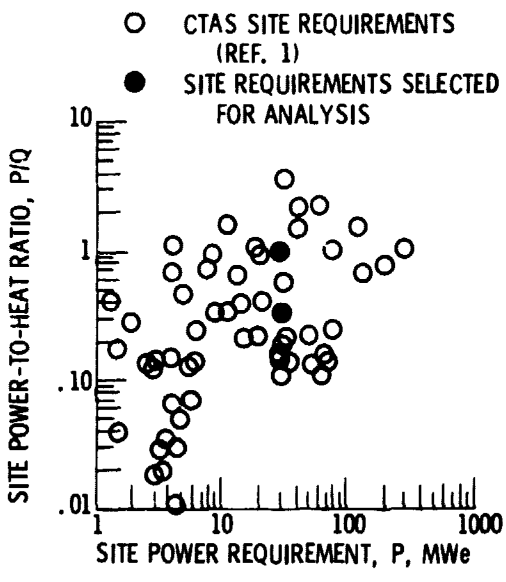
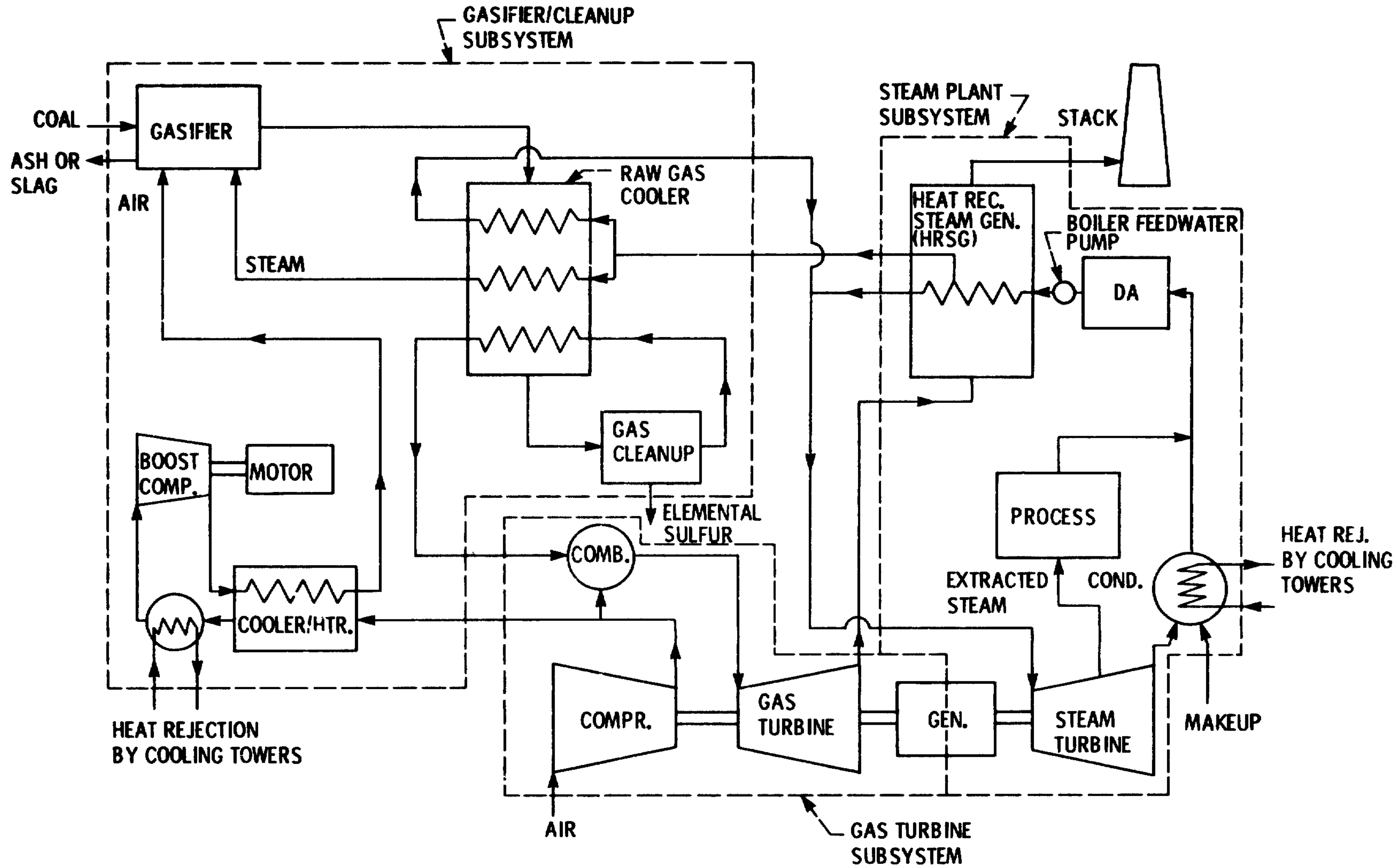
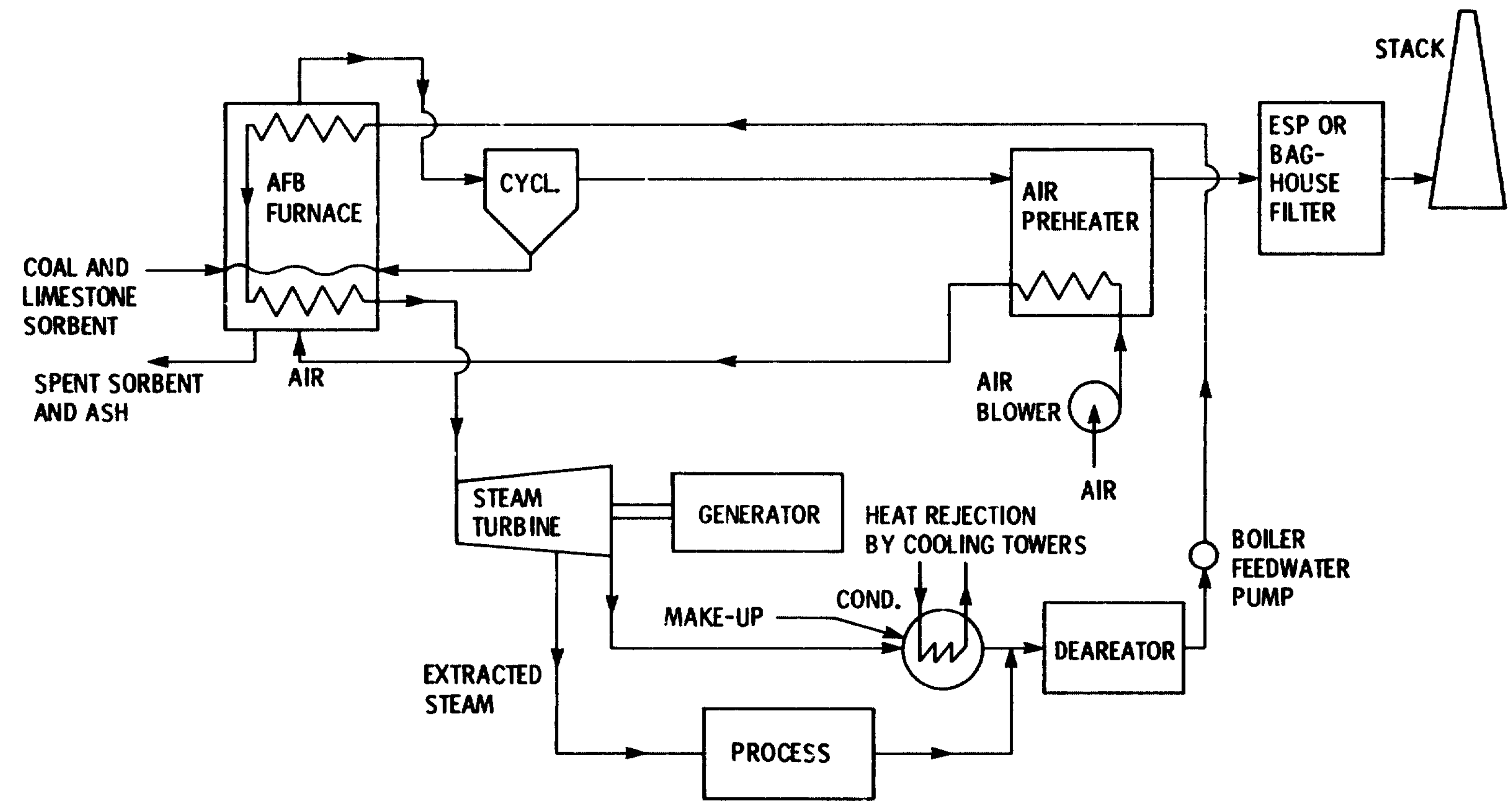


Figure 2. - Site requirements selected for analysis and their relationship to CTAS site requirements.



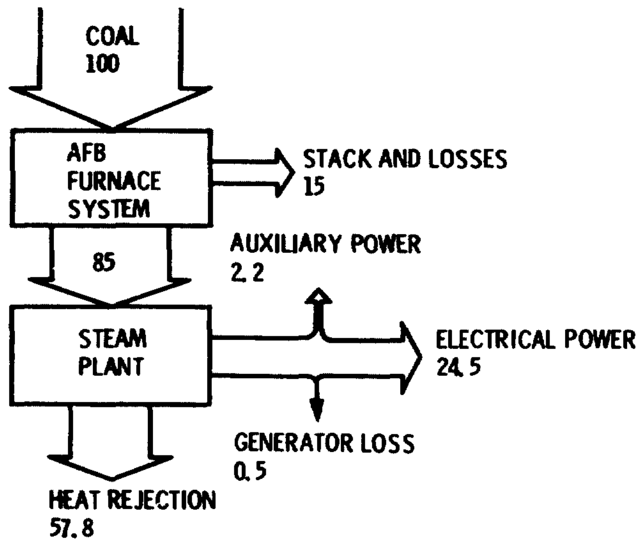
(a) IGCC POWER SYSTEM.

Figure 3. - Schematic diagrams of power systems.

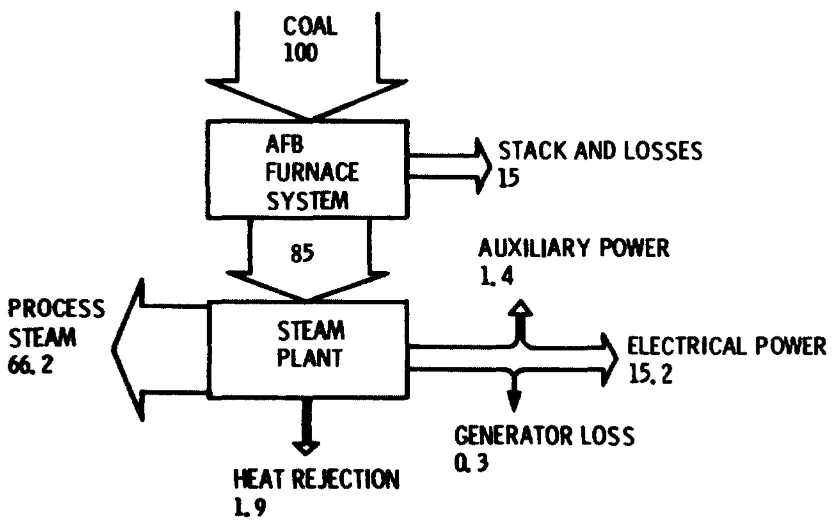


(b) AFB - STEAM POWER SYSTEM.

Figure 3. - Concluded.



(a) ZERO EXTRACTION.



(b) MAXIMUM EXTRACTION.

Figure 5. - Energy flow diagrams for AFB - steam power system.

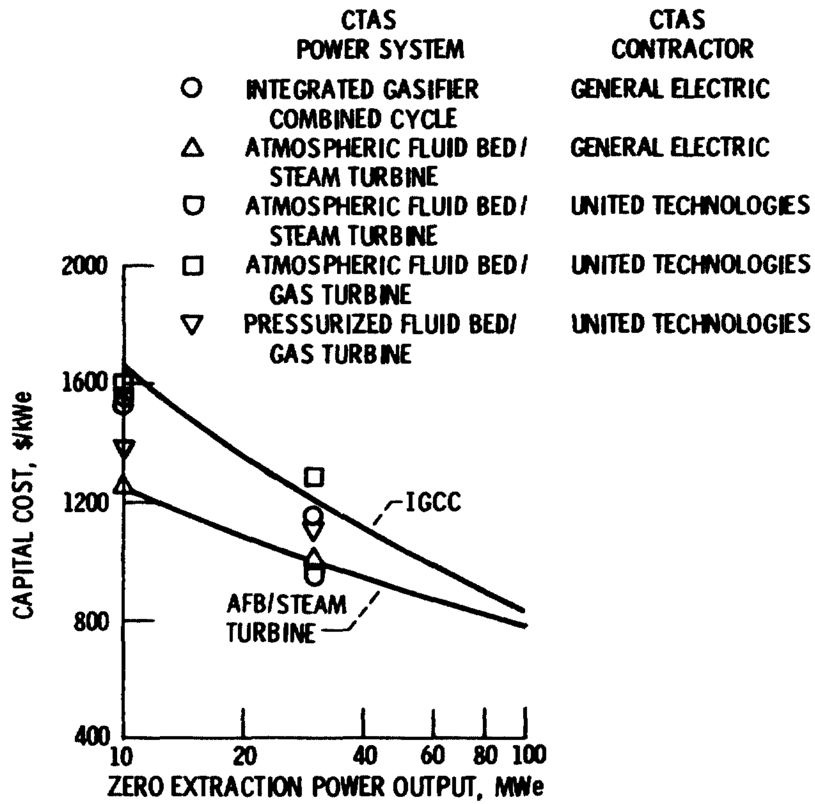
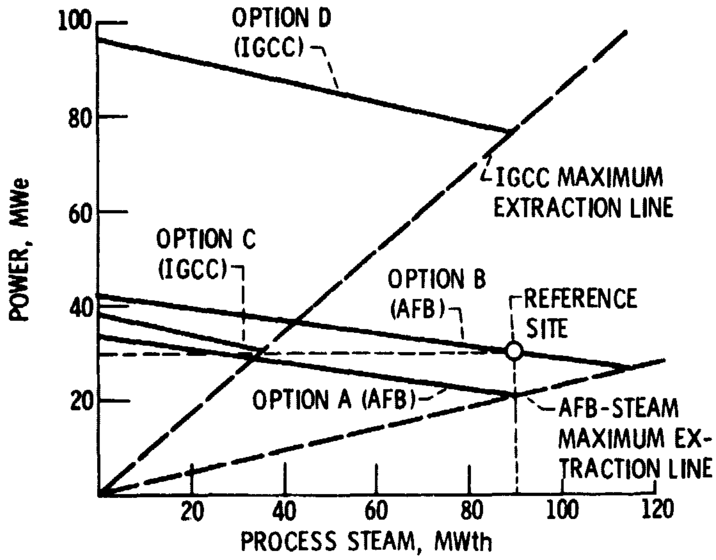
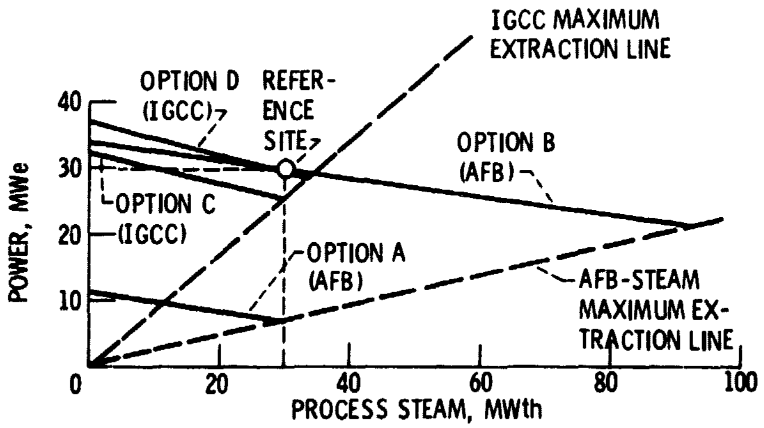


Figure 6. - Capital cost estimates for IGCC and AFB/steam turbine plus relationship to CTAS.



(a) SITE = 30 MWe, 90 MWth

Figure 7. - Power system sizing options.



(b) SITE = 30 MWe, 30 MWth.

Figure 7. - Concluded.

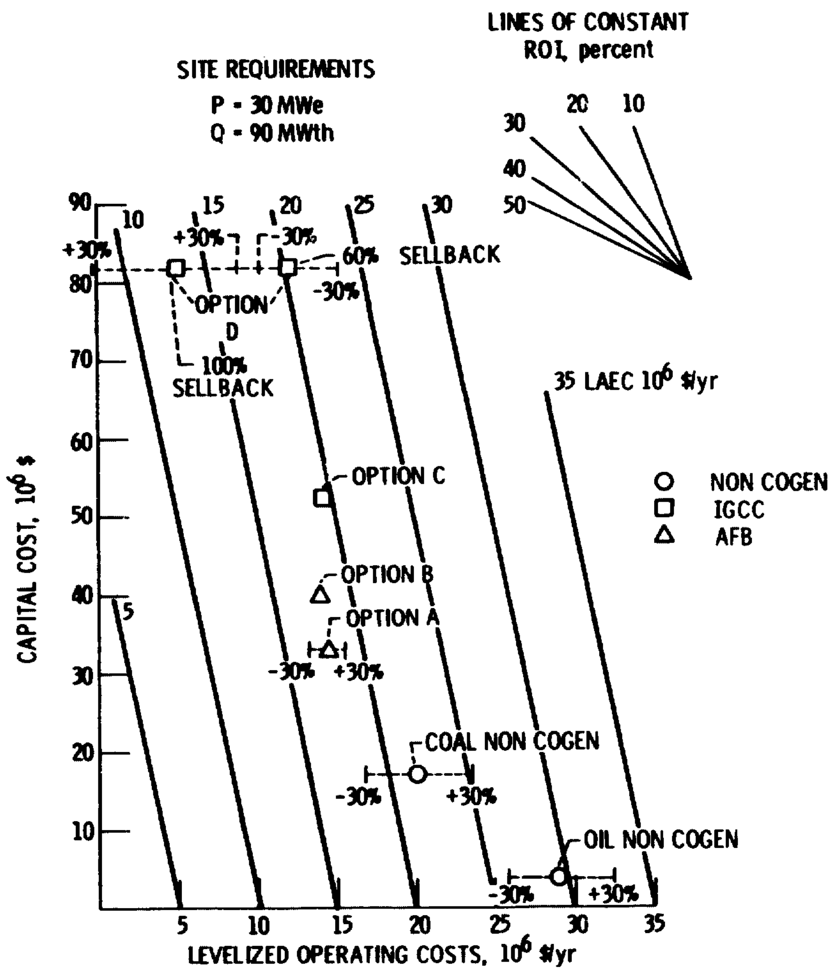


Figure 8. - Sensitivity of electricity price on economic results.

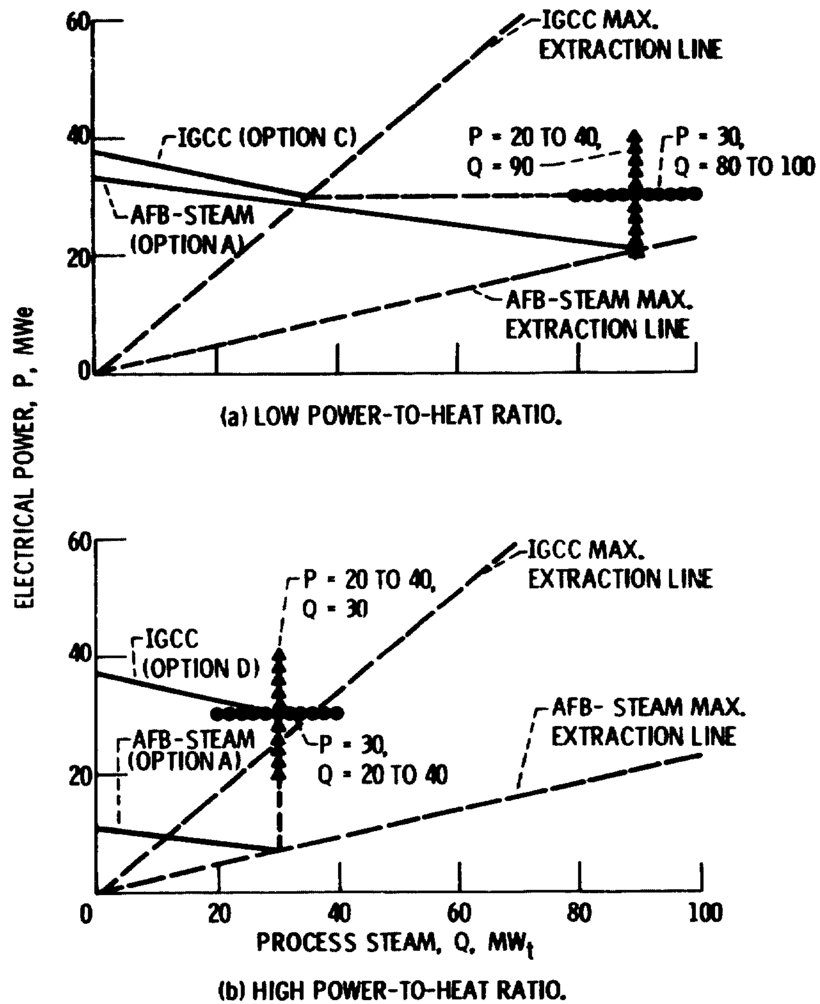


Figure 9. - Time variation in site conditions and power systems selected for evaluation.

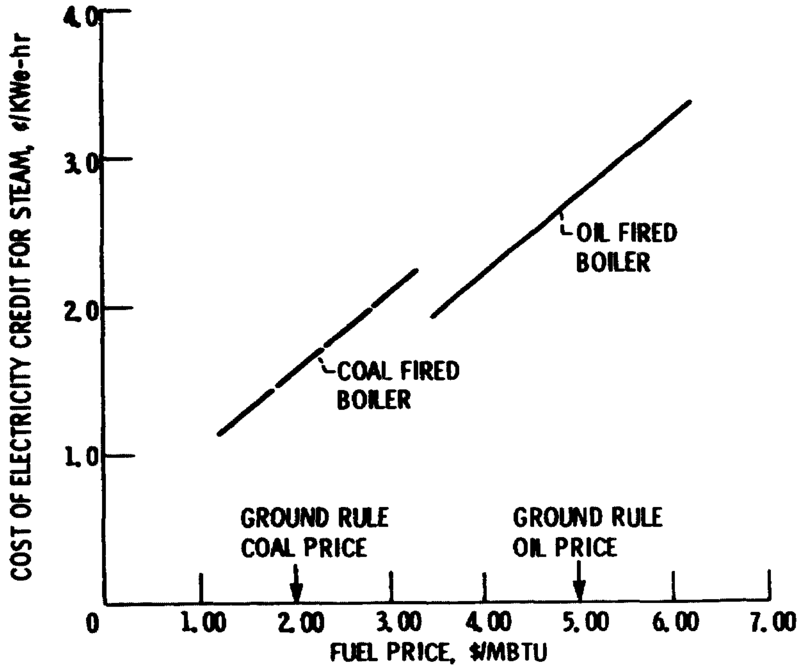


Figure 10. - Cost of electricity credit for steam extracted from IGCC system - 90 MWt site thermal requirement.

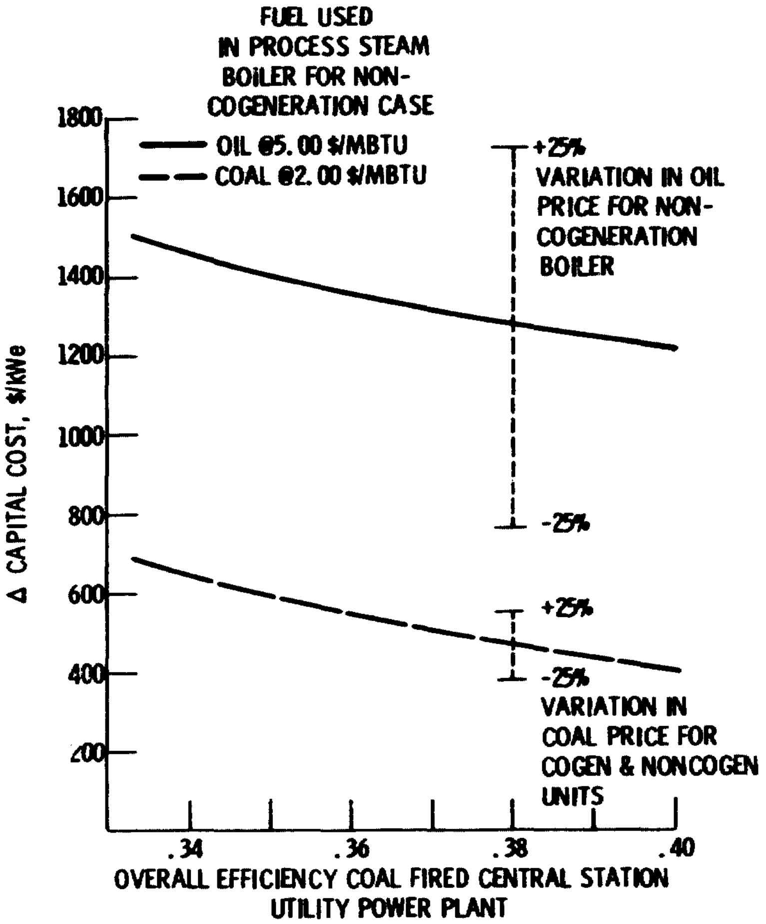
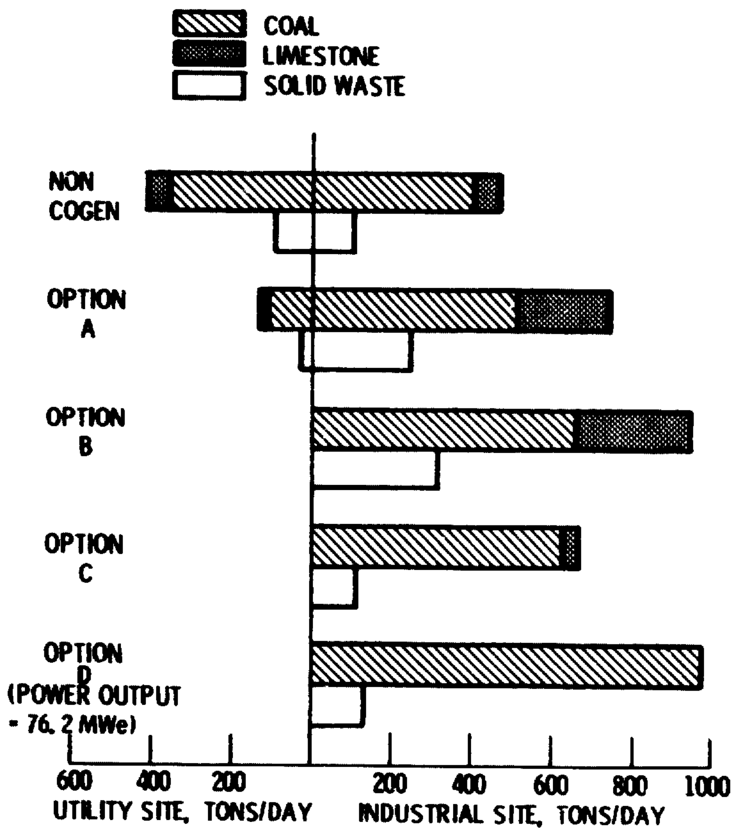
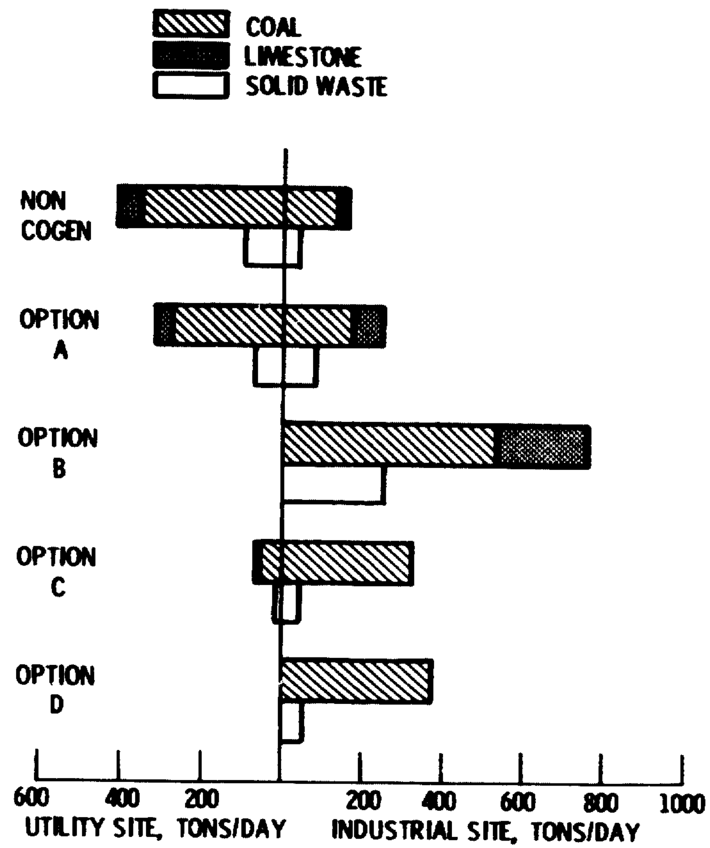


Figure 11. - Affordable capital cost difference between small-cogenerating IGCC plant and large central station utility plant.



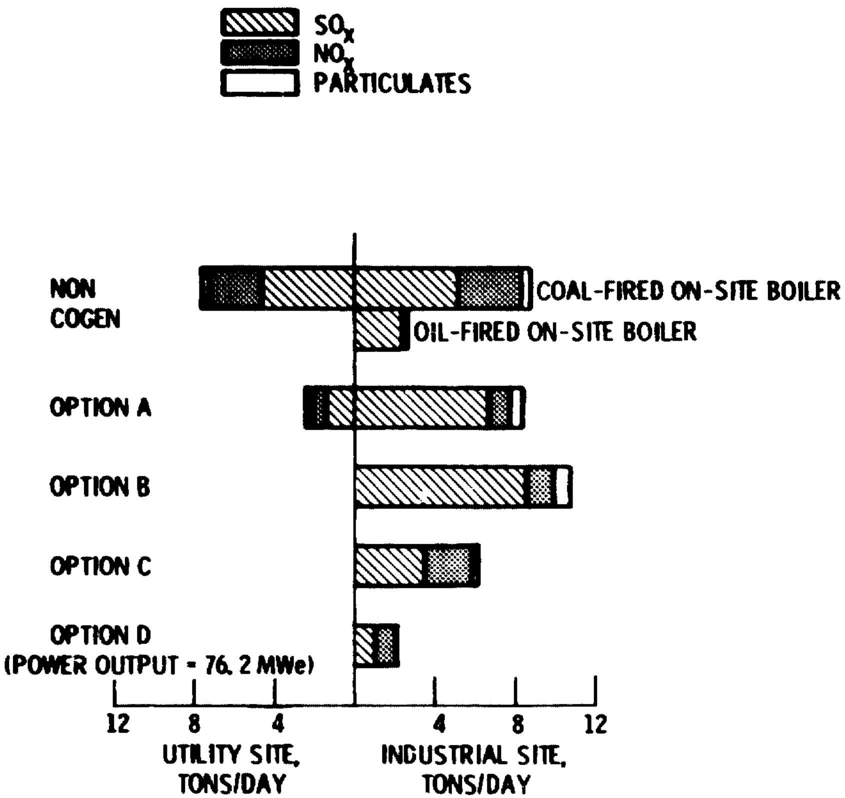
(a) SITE = 30 MWe, 90 MWth

Figure 12. - Coal, limestone, and solid waste for noncogeneration case and cogeneration options.



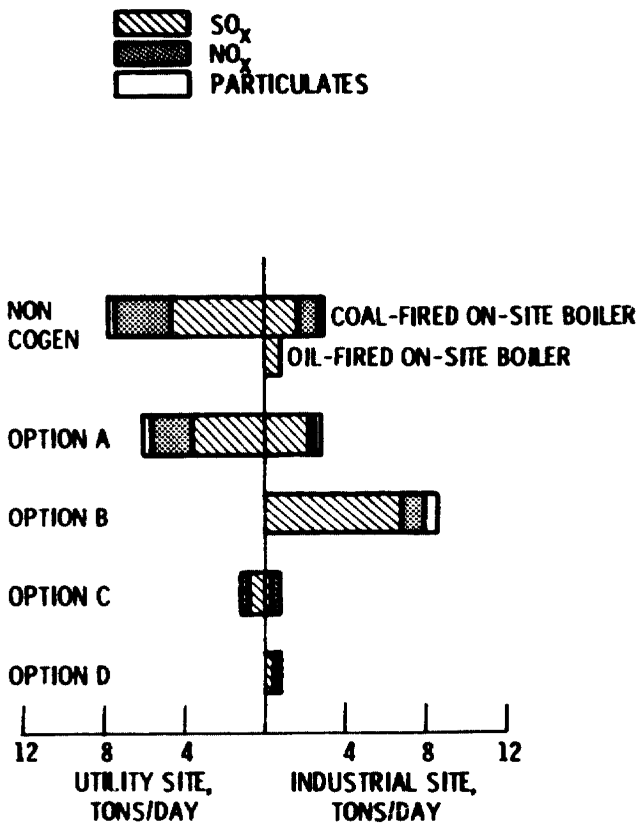
(b) SITE = 30 MWe, 30 MWth.

Figure 12. - Concluded.



(a) SITE - 30 MWe, 90 MWth.

Figure 13. - Utility and industrial site emissions for non-cogeneration case and cogeneration options.



(b) SITE - 30 MWe, 30 MWth.

Figure 13. - Concluded.