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Alternative cogeneration plant configurations and operating strategies are examined with the use of DOE-2 computer simulations and net present value economic analyses to determine optimal cogeneration systems for high-rise office buildings. The examination takes the form of a case study for a hypothetical office building located in San Francisco, California, where a new regulatory attitude toward grid interconnection for cogenerators has begun to emerge. The conclusion of the study is that, under current economic conditions, the optimal cogeneration system is an internal combustion engine sized well-below the electrical requirements of the building and operated so that most of the by-product heat recovered is utilized. Notably, most of the systems fail to meet the efficiency requirement upon which receipt of the regulatory and economic benefits is predicated.

Energy use in office buildings is a growing concern, and efforts to improve the efficiency by which energy services are delivered continue to be an important challenge (1). Well-designed and operated cogeneration systems can play an important role in meeting this challenge.

The economic attractiveness of cogeneration systems has been increased by recent changes in regulatory policies. Stimulated by the passage of the Public Utilities Regulatory Policies Act (PURPA), utilities have been directed to eliminate discriminatory pricing policies previously aimed at discouraging cogenerators from interconnecting with the utility grid (2). The ability to buy and sell electricity freely from or to a utility increases the flexibility a potential cogenerator has in sizing and operating a cogeneration system. This report examines how this flexibility affects the choice of systems by determining the conditions for optimal cogeneration systems for high-rise office buildings.

Previously, a decision to cogenerate often meant leaving the grid entirely. Under these conditions, the choice of a cogeneration system was dictated by the requirement that the system always be able to meet the electrical load. This requirement translated into higher costs since redundant capacity would be required and recovered heat might not be utilized. These factors, in turn, often made cogeneration systems prohibitively expensive. It comes as no surprise that Manhattan, with the highest priced electricity in the nation, is one of the few instances where cogeneration systems have been installed in office buildings (3,4).

This report takes the form of a case study of a hypothetical office building located in San Francisco, California, where policies to encourage cogeneration are at an advanced stage of implementation. The study begins by reviewing the technical, environmental, legal, and regulatory considerations that affect the choice of a cogeneration system. Next, a variety of system sizes and operating strategies are proposed and simulated using DOE-2, a computer model for building energy analysis. The results of the simulation, along with current economic data and projections, are then used to estimate net present values for the purpose of ranking the proposals. Finally, a sensitivity analysis is performed to test the strength of the results.

COGENERATION TECHNOLOGIES

Cogeneration technologies are no more than traditional prime movers that have been equipped to recover heat as either an input to or an output of the conversion process to electricity. The fuel efficiency of cogeneration technologies lies with the ability to recover or use heat that otherwise would be wasted. Large central station power plants, for example, could be considered cogeneration systems, if the heat rejected from the conversion of fuel to electricity were utilized.

The relationship of the heat recovery operation to the generation of electricity defines the cogeneration cycle. In a bottoming-cycle plant, fuel first provides heat for some process and recovered heat is used to produce electricity. In a topping-cycle, fuel is used first to produce electricity and the rejected heat is recovered for use in some productive process. Topping-cycle plants typically operate at far higher temperatures than bottoming-cycle plants and so more of the energy embodied in the fuel is available for conversion to electricity.

The large requirements for electricity, compared to thermal needs, and the low temperature of those needs mean that topping-cycle systems are the preferred technologies for office buildings because the outputs of such systems more closely match the end-uses in offices. There are three topping-cycle technologies currently available for cogeneration applications: steam turbines, gas turbines, and internal combustion engines. In what follows, the suitability of each for cogeneration applications in office buildings is reviewed. The parameters emphasized in this preliminary review are the efficiency of fuel conversion to electricity, heat recovery, fuel flexibility, and operating characteristics. Following this review additional considerations arising from the requirements of existing laws and regulations are considered.

Steam turbines are the most popular means by which electricity is produced from large central station power plants. In the relevant range of capacities for office building applications (less than ten megawatts), however, efficiencies are very low ranging from six to nineteen percent and can be even further reduced by the extraction of heat at an intermediate stage in the turbine (5,6,7). This low conversion efficiency makes the steam turbine an unattractive candidate for office building applications.

Gas turbines are better known as jet engines. Operating on the Brayton-cycle, compressed air is heated to high temperatures in a combustor and then forced through a turbine, which drives a generator. Gas turbines must be run on high quality fuels, such as natural gas or number two oil, since the products of combustion are the working fluid for the cycle (5,7,8). As a direct result of development for use as prime movers in aircrafts, gas turbines have a high ratio of power to weight and space (7,9,10,11). The electrical conversion efficiency of gas turbines can exceed that of steam turbines and ranges from fourteen to twenty eight percent in the relevant range of outputs (less than five megawatts) (5,7,9). Gas turbines operate best at full-load and are notorious for having poor part-load performance. The significance of this characteristic is, of course, a function of the extent to which the machines are run full-out and not to follow a load. The quantity of exhaust heat recoverable is high with the recovery of up to eighty percent of the energy in the exhaust being typical (5,7,12). The thermodynamic quality of this heat (roughly, the temperature of the exhaust) is also high. Further, since there is a substantial amount of oxygen in the exhaust, the quantity of recovered heat can be supplemented by the combustion of additional fuel directly in the exhaust stream for use in raising steam in a boiler. These features make gas turbines very attractive from the standpoint of cogeneration applications since high quality heat recovered in the form of high pressure steam can be used in high efficiency absorption cooling machines. The ability to use heat to produce cooling may offset the lower electrical conversion efficiency of gas turbines (compared to internal combustion engines) since what cooling is produced reduces the need for electricity to provide the same end.

Internal combustion engines are best known for applications as prime-movers in automobiles and trucks. There are two primary operating cycles. In the Diesel cycle, a mixture of fuel and air is ignited by the high pressures created by the compression stroke of a piston in cylinder. In the Otto cycle, the combustion process is initiated by a spark. The resulting expansion of gasses reverses the direction of the piston and drives a rotating crankshaft that turns a generator. The precise requirements for the combustion process typically restrict the fuels for Diesels to be of high quality, such as Number Two distillate oil, but natural gas has been cited as a suitable fuel. Otto-cycle or gas engines are more tolerant of lower quality fuels and can also run on natural gas (5). High ratios of power to weight and space are often cited for these engines, which helps to explain their popularity in mobile applications (7,9,10). Well known for high fuel efficiencies, Diesel engines are capable of converting thirty to thirty seven percent of the energy embodied in the fuel to electricity (7,9,10,13,14). Conversion efficiencies for spark-ignition engines lag behind, ranging from twenty seven to thirty one percent. The part load performance of Diesels very good and superior to that of spark-ignition engines, although both are better performing than gas turbines at part loads. Often, there is only a small increase in specific fuel consumption (Btu/kWh) down to about twenty five percent of the rated load (5,7,10,12,13,14). Heat can be recovered from the exhaust, jacket, and lubricating oil of internal combustion engines. Taken together, approximately forty percent of the energy in the fuel can be recovered as heat (13,14). As a result of the high performance of the engines in converting fuel to electricity, the quality of heat recovered is low. Heat can be recovered from the jacket and oil in the form of hot water at 150 to 180 degrees Fahrenheit. The quantity of heat recoverable from the exhaust is limited by need to avoid the formation of corrosive compounds in the exhaust stack. Corrosion occurs when the the temperature of the exhaust stream falls below three hundred degrees F. With respect to the use of this heat in absorption cooling machines, only single-stage machines of lower efficiencies can utilized heat in this temperature regime.

ENVIRONMENTAL CONSIDERATIONS

The primary environmental insults associated with cogeneration technologies are the generation of noise and the emission of pollutants into the air. Noise is not, however, a major concern because techniques to mitigate the anticipated noise levels of all the technologies are well known and, to a certain extent, are already provided by the location of the systems in the enclosed machine rooms of the office buildings. Air emissions, consisting of oxides of nitrogen (NOx), oxides of sulfur (SOx), carbon monoxide (CO), un-burned hydrocarbons (HC), and particulates, are of special concern due the location of office buildings in downtown areas. Of these emissions, NOx are the most noisome for the San Francisco area and are, therefore, analyzed as the constraining pollutant for the systems.

The Bay Area Air Quality Management District (BAAQMD) is the the authority that would issue the permits for the air quality impacts of cogeneration systems. The principal reference for determining allowable emissions are the New Source Review Rules and the Gaseous and Particulate Emissions Rules. These rules require that a project, which proposes to result in a net increase in emissions of more than one hundred and fifty pounds of NOx per day, be constructed with Best Available Control Technology (BACT), where BACT is defined to be the more stringent of the most effective control technique used by similar sources or any other technique found, after public hearing by the Air Pollution Control Officer, to be technologically feasible and cost-effective. With BACT, emissions of up to five hundred and fifty pounds are permitted without requiring offsets.

BACT for diesel engines is the selective catalytic conversion of the oxides of nitrogen through the injection of ammonia. This complicated process is expensive and difficult to control (15). Uncertainty surrounding the availability of BACT for diesel engines has lead to the abandonment of further consideration of the engine for a cogeneration application in the San Francisco Bay Area (16). For this reason, diesel engines are eliminated as candidates for application in San Francisco office buildings.

BACT for the gas turbine is water injection and for the Otto-cycle engine BACT is non-selective catalytic conversion (16). With these devices in place, up to ninety percent of the oxides of nitrogen can be removed. Both of these BACT's are available in the San Francisco area and can be serviced through maintenance contracts. Assuming no offsets are available, twenty four hour operation, and ninety percent removal, the total capacity for a spark-ignition engine cogeneration system would be 5.3 MW. The calculation is performed for a Otto-cycle engine burning natural gas because, on a unit basis, more NOx is emitted by these engines on a unit basis than the gas turbine burning natural gas. Without pollution abatement, spark-ignition engine will emit approximately five micrograms of NOx per joule of fuel. In lieu of a BACT (emissions of one hundred fifty pounds per day, no removal), the largest engine(s) permitted would be .3 MWe.

OTHER REGULATORY CONCERNS

Cogeneration systems also are affected by laws and regulations regarding the regulatory status and fuel-use impacts of the projects. and land-use impacts. There are two federal regulations germane to the operation of cogeneration projects: The Public Utilities Regulatory Act (PURPA) and The Powerplant and Industrial Fuel Use Act (PIFUA).

PURPA was designed to stimulate cogeneration by removing certain economic and regulatory barriers that had impeded the development of alternative electricity producing facilities. In particular, the law provides for two accounting treatments of electricity production. One option, called simultaneous buy/sell, has the utility purchase the entire output of the machines at a price, which has been determined to be the cost avoided by the utility not having to generate that power, while the electricity used by the facility is billed at the standard tariff. The second option, called net sale, has the utility purchase only the excess of generation over demand at the avoided cost, and the facility (having received no power from the grid) pays no bill. Receipt of the benefits, however, is predicated upon a determination that the facility is a Qualifying Facility (QF). For cogeneration systems in San Francisco office buildings, this determination is made by the California Public Utilities Commission (CPUC), based on rules promulgated by the Federal Energy Regulatory Commission (17,18). One criterion is an efficiency measure. For topping-cycle systems, it states that the energy content of the net electrical output and that of one half the thermal output (averaged for the year) must be at least 42.5 percent of the energy content of the fuel. The second criterion is an ownership requirement. No QF is permitted to have more than fifty percent ownership by a utility.

PIFUA was designed to stimulate the use of coal by placing strict restrictions on the use of natural gas and petroleum derived fuels. Exemptions exist for cogeneration systems, however, since these systems represent efficient processes for the utilization of these fuels. The exemptions permit facilities that will be cogenerating electricity to consume up to two hundred and fifty million Btu's per hour of the restricted fuels (19). For the least efficient gas turbine engine, this level of use corresponds to an installed capacity of over ten megawatts.

ENERGY SIMULATION OF PROPOSED COGENERATION PLANTS

The next step in the assessment of cogeneration systems for office buildings is the calculation of quantitative measures for the performance of the systems. The calculations are performed with the aid of a computer code, which is capable of simulating a variety of hypothetical cogeneration systems under several different operating assumptions. After an overview of the simulation tool, which includes comparisons of the computer generated results to other measures of the energy performance of San Francisco office buildings, a description of the proposed systems and operating strategies is presented, and some preliminary observations about the results of the simulation are made.

The DOE-2 program models the performance of buildings on an hourly basis in three sequential steps (20). Initially, weather data and user-input information regarding the envelope and schedules of internal thermal gains are used to calculate the heating and cooling gains as seen by the secondary or air-side heating, ventilating, and air-conditioning equipment (HVAC). The second step treats the response of the secondary HVAC equipment to these loads as the systems attempt to maintain temperatures and humidity set-points. At this stage, a demand for hot water or steam, cold water, and electricity is calculated and passed to final stage of the simulation. The final step of the simulation is to model the performance of the primary HVAC equipment in meeting these demands. At this stage, the operation of a cogeneration system is simulated. The outputs of the program used by the economic analysis include the time-differentiated electrical demands of the building and electricity production of the cogeneration system, the quantity of heat recovered and utilized, and the quantity of fuel used.

The building simulated is a hypothetical thirty- one-story office building taken from the library of DOE-2 sample buildings, which is then run with weather data from San Francisco. Additional data regarding the operating schedules of the building were obtained from information compiled by GE in a sampling of the energy use and operating practices of large San Francisco office buildings (21). This study also presented data on the composition of the office buildings in the sample, which indicate that the hypothetical building is representative of San Francisco office buildings with respect to both height and floor area.

For each technology (gas turbine or spark-ignition internal combustion engine), six capacities were chosen, ranging from 0.5 to 5.0 megawatts. The smallest size reflects an attempt to match the thermal output of the plant to the thermal demands of the building. The largest represents an attempt to install the largest possible system, given the air pollution sizing constraint calculated previously. This latter system could always produce electricity in excess of building demands yet, at the same time, generate heat that would be recoverable but not utilized. Implicit in this set-up is an attempt to gain the benefits of the avoided cost payments guaranteed by PURPA while using the thermal demands of the building as, essentially, an undersized cooling grid for the purpose of meeting the efficiency requirement in order to receive Qualifying Facility status. The intermediate sizes are attempts to size a system that could either meet the entire electrical needs of the building, meet most of the anticipated peak demand, meet most of the anticipated daytime baseload demand, or meet half of the daytime peak demand.

The operating strategies consist of either running at the full rated capacity of the machines or tracking the electrical demands of the facility and, for these modes of operation, schedules that include operating all day long, just during business hours, or a combination of the two (using two modes of operation). Running the machines full-out follows the reasoning that, if machines are to be run, running them full-out results in the best performance of the machines with respect to fuel consumption per unit of electricity production. Operation during business hours is an attempt to utilize the machines when the value of such operation is highest. That is, business hours are both the hours of highest electricity use and when the cost of that use from a utility is also highest due to the temporal location of those demands during the peak and shoulder-peak demand periods of the utility.

All of the configurations and operating schedules follow several general rules during the simulation. First, for each capacity, three identically sized machines are specified to allow for the efficient loading and unloading of the machines when attempting to follow loads; it is more efficient, for example, to run two machines at seventy five percent of nominal rating than a single large machine at forty percent of its rating. In the event that the machines are running full-out, the simulation assumes that the efficiency of three machines, combined, is equal to that of one having the same total capacity of the three. This assumption is, of course, subject to the actual performance of available machines. Second, for each system, absorption chillers were specified that could handle the entire heat output of the generators and were scheduled so that any cooling load would be first given to the absorption machines and the remainder to the electricity-driven ones. In this manner, all the recovered heat that could be used would be used, if such a demand existed.

The results of the energy simulations display one striking feature: No system, under any operating strategy, utilizes all of the recoverable heat available from the prime-movers. Even the smallest system wastes some of the recoverable heat, although the requirement of additional fuel for a supplementary boiler indicates that there is a mismatch in time between the amount of heat available and the magnitude of the demands for thermal energy. Another significant result of these simulations is that most of the plants fail to meet the efficiency criterion outlined by FERC's interpretation of PURPA. The ultimate consequence of these results will be seen in the following section where dollar values are attached to determine the economic worth of the projects.

ECONOMIC ANALYSIS

The optimal cogeneration system for an office building is one that maximizes the wealth of the developer. Thus, the technical, legal, and regulatory attractiveness of such projects via the results of the computer simulation and currently available data on present and future costs are translated into economic quantities for use in evaluating the projects on a commensurable basis. Through this analysis, the related question, whether optimality means practicality, is also addressed. This question asks whether a project, beyond being the best in its class, is also better than the competing uses for the monies required in order to implement such a project.

The method employed in this analysis is to calculate and compare the Net Present Value (NPV) of the projects over a ten year period under three discount rates (22). In operation, the after-tax returns to a project are discounted and summed to yield a present value for the future benefits. These benefits are traded-off against the first cost of the project to generate a net present worth or value. The decision rule for an investor is to choose that project with the highest net present value. In this manner, the expectations of the investor are accounted for by appropriate choice of a discount rate and the absolute worth of the projects is calculated by not restricting the calculation to, say, a payback period. Three discount rates (15, 25, and 35 percent) are used to reflect the investment criteria of three distinct classes of investors. Uncertainty regarding the future is bounded by taking only a ten year period as the basis for the calculations. Hence, the method differs from a Life Cycle Cost in that ten years is only a fraction of the useful life of the projects.

The NPV method is dependent upon a variety of assumptions regarding the tax treatment of the project. In the present analyses, the following assumptions are used. The tax rate is taken to be fifty percent, which is the incremental tax rate for corporations. The tax life of the equipment is assumed to be five years and the depreciation method follows the schedule outlined in the Economic Recovery Tax Act of 1981. An investment tax credit of ten percent is taken during the first year. The effect of these last two assumptions is examined more closely in the sensitivity analysis.

The capital and installation cost of the systems is extrapolated from a variety of sources (7,8,16). The estimates surveyed ranged from four hundred to one thousand dollars per installed kilowatt (1982 dollars), with a majority of the estimates falling in the lower range of this scale. For the present analyses, a figure of eight hundred dollars per kilowatt is used. In this regard, it is interesting to note that there has been very little fluctuation in the level of the estimates over the past ten years despite the existence of substantial rates of inflation. The effect of variations in this cost will be examined in the sensitivity analysis. The costs for interconnection equipment, for example, are extremely variable as each utility is permitted some flexibility in the specification of the required equipment (23).

The future benefits of a cogeneration system are the revenues generated by the systems in the form of electricity sales or credits, and thermal credits from the recovery of heat less the costs, including fuel, resulting from the operation of the systems. Before discussing the components of these revenues and costs, another comment about the treatment of the future is in order. Projections of what the future might look like emanate from a variety of sources. For the present analyses, those published by the local utility are used (24). The arbitrariness of this choice is lessened somewhat by reference to the fact that the utility is the agency from which the benefits derive, subject to regulatory approval.

The revenues to the projects consist of the value of the electricity produced and of the heat recovered. The valuation of the electricity produced depends upon the accounting treatment taken. If the price paid by the utility for electricity is greater than the cost of purchasing electricity from the utility, the simultaneous buy/sell option is preferred method for valuation. Presently, the price paid is less than the cost of purchasing the electricity from the utility, therefore, the net sale option is employed (25,26). Accordingly, all electricity produced in a given time-of-use period in excess of the demands of the building is valued at the avoided cost offered by the utility for that period and the remainder is valued at the rate that would be paid the facility, if that quantity were purchased from the utility. A credit for the heat recovered and subsequently utilized is calculated by determining the amount of fuel that would be required to produce that heat in a conventional boiler burning natural gas.

The costs incurred by the operation of the systems consist of expenditures for fuel, operation and maintenance, and stand-by charges for electricity in the event of a forced outage. The CPUC has authorized a special rate for natural gas for use by cogeneration systems. Currently, this rate is .52126 dollars per therm (27). The operation and maintenance of cogeneration systema is extrapolated from many of the same sources used to determine the cost of the investment. The estimates range from less than one mill per kilowatt-hour to 7 mills per kilowatt-hour (a mill is equal to .001 dollars). For the present analyses, a figure of 5 mills per kilowatt-hour is used. The effect of a higher cost is examined in the sensitivity analysis. The stand-by charge for back-up electricity is similar in structure to a demand charge and currently hovers about one dollar per kilowatt of expected demand per month (28).

The results of the economic analyses indicate that no project under any discount rate has a positive net present value after ten years of operation. Under these conditions, it is unlikely that any of the projects will be undertaken. Of interest for the present study, however, is the relative ranking of the projects and the implications contained in these ranking for cogeneration systems, generally. Several general observations emerge from the rankings.

One is that the value of an efficient conversion of fuel to thermal and electrical energy is function of the degree to which these products can be utilized for some productive purpose; the value of the efficient production of electricity by the cogeneration systems does not overwhelm the economic need to effectively utilize the by-product waste heat. That is, the results the economic analysis along with those of the energy simulation indicate that a strong correlation between the degree of thermal energy utilization and NPV exists. Hence, in an almost uniform manner, the ranking corresponds inversely with plant size; increasing plant sizes yield larger and larger negative NPV's.

Another observation addresses the cash flows generated by the projects. Lower discount rates correspond to higher negative NPV's for identical projects. The implication is that, since the effect of higher discount rates is to reduce the magnitude of future returns (be they positive or negative), not only are the projects losers in the short term, but they probably will never break even.

SENSITIVITY ANALYSIS OF THE ECONOMIC ASSUMPTIONS

The variations employed by the sensitivity analysis fall into three separate categories: costs, tax treatment, and level of avoided cost payments for electricity sales to the utility. No attempt was made to vary the rates of escalation applied to the stream of future benefits/disbenefits The cost variations reduce the first cost of the systems by fifty percent to reflect the lower end of the scale of investment costs found in literature review, or, in a separate set of runs, increase the cost of operation and maintenance by one hundred percent to capture some of the uncertainties that appeared to underlie some of the estimates for these costs. A plausible source for this increase might arise from the operation of air pollution equipment. The tax benefits to the projects stem from the depreciation schedule used and the investment tax credit. Four separate variations are examined. The shorten tax life form of a five year accelerated depreciation allowance is eliminated and a twenty year straight-line one substituted in an attempt to replicate revisions in the tax laws. Another move to modify the economics of the projects through the political process is an increase in the first-year investment tax credit to twenty five percent. The combination of both of these changes is the third permutation. The final tax measure removes the first year tax credit. The final set of alternative economic assumptions address the avoided cost payments for purchases of electricity by the utility. One case takes the baseline case, in which the net sale option is chosen, and examines the effect of the simultaneous buy/sell option. The second and third cases increase the level of the payments by fifty percent and employ the simultaneous buy/sell and net sale options, respectively. It should be noted that the avoided cost payments offered by PG&E were, in fact, approximately fifty percent higher in the summer of 1981 than those of today (28). A final variation increases the level of payments by seventy five percent and uses the simultaneous buy/sell option.

The results of these alterations in economic assumptions bear-out the conclusion that optimality for cogeneration plants lies with the ability to effectively utilize the thermsl outputs of the systems. With the exception of the economic regimes in which the avoided cost is increased and the simultaneous buy/sell option employed, the rankings are almost identical. These results also emphasize that the prospects for cogeneration in San Francisco office buildings are negative.

The cases involving high avoided costs highlight an interesting irony. On the one hand, these conditions so alter the rankings that the plants producing the greatest amount of electricity generate NPV's that are positive, in some cases, to a substantial degree. On the other hand, the production of this quantity of electricity results in a tremendous quantity of recoverable heat going unused. So great is this amount of wasted heat that the plants then fail to meet the efficiency criterion promulgated by FERC, which is requisite for the receipt of the payments that yield the large returns. Thus, the fact that level of these payments have retreated from the high ones of 1981 means that, from the standpoint of the efficient utilization of resources, inefficient utilization is discouraged but at the price of no cogeneration, at least, not in San Francisco office buildings.

CONCLUSION

Recent changes in regulatory policies toward cogenerators have increased the flexibility of engineers in sizing and operating these systems. For high rise office buildings, this flexibility, coupled with current economic conditions and regulations, favors cogeneration systems that have high ratios of electrical to thermal output, and that are sized and operated in a manner that results in a high degree of utilization of the thermal output. Under conditions where the avoided cost for electricity is high, systems that maximize the production of electricity, even to extent that a great deal of thermal energy is wasted, are favored. The benefits that result in this favorability, however, are predicated on an efficiency criteria that would no longer be met.

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