MASTER

A TEST CASE FOR THE POTENTIAL APPLICATION
OF DISTRICT ENERGY SYSTEMS USING
THERMAL ENERGY COGENERATED AT
EXISTING ELECTRIC POWER PLANTS

ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS

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EXISTING ELECTRIC POWER PLANTS

by

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January 1978

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*A TEST CASE FOR THE POTENTIAL APPLICATION OF
DISTRICT ENERGY SYSTEMS USING THERMAL ENERGY
COGENERATED AT EXISTING ELECTRIC POWER PLANTS*

by

D. J. Santini and A. A. Davis

ABSTRACT

District Energy Systems (DES) for providing heating and cooling to Washington, D.C. by utilizing cogenerated electrical and thermal energy from existing power plants are examined. The results of two different but related studies are compared. The more conservative of the two studies is given greatest attention. In this study, Washington is divided into four different DES service areas. These service areas are compared to one another for relative DES economic viability. The DES economics and efficiency is also compared to (1) electricity from coal, (2) oil from liquified coal, and (3) utility gas from coal. Results of this study indicate that DESs for heating are the most efficient of the four supply options. Both studies conclude that the heating costs of DESs are less than heating with electricity when electricity is generated exclusively for heating purposes. The cost comparisons with other heating alternatives are inconclusive but they do indicate that heating by DES *may* be the most economical in some urban locations.

1 INTRODUCTION

This paper presents and discusses the results of two separate, but related studies of district energy systems (DES) for Washington, D.C. These studies were undertaken as a result of research conducted by the Energy and Environmental Systems Division of Argonne National Laboratory (Ref. 2). This research ranked all of the Standard Metropolitan Statistical Areas (SMSAs) in the U.S. with respect to the potential application of district heating utilizing cogenerated electrical and thermal energy from existing power plants (see Table 1.1). It was found that the maximum potential on a regional basis exists in the Northeast and North Central Census Regions (see Table 1.2). As a result of this research, DOE (then ERDA) decided to conduct a more thorough analysis of the potential for district heating. Argonne National Laboratory (ANL) was given the lead on this project with the understanding that Brookhaven National Laboratory (BNL) would also participate. It was decided that ANL would

TABLE 1.1 Application of District Heating Systems (DHS)
to the Residential/Commercial Sectors -- Study
Results for Most Attractive Cities (Ref. 2)

Urbanized Area	Percent of Total Potential Scarce Fuel Thermal Demand Savings from DHS	
		Cumulative %
*1. New York City - New Jersey	14	14
2. Washington, D.C. ^{a,b}	11	25
3. Chicago, Illinois ^a	9	34
*4. Boston, Massachusetts ^b	8	42
*5. Detroit, Michigan ^a	6	48
*6. San Francisco, California	6	54
*7. Philadelphia, Pennsylvania ^b	5	59
*8. Baltimore, Maryland ^b	4	63
9. Providence, R.I.	3	66
*10. Milwaukee, Wisconsin ^a	2	68
*11. Cleveland, Ohio ^a	2	70
12. Buffalo, N.Y.	2	72
*13. Minneapolis, Minnesota	2	74
14. Springfield, Massachusetts	2	76
15. Louisville, Kentucky	1	77
16. Wilmington, Delaware	1	78
*17. Pittsburgh, Pennsylvania	1	79
*18. Indianapolis, Indiana	1	80
*19. St. Louis, Missouri ^a	1	81

* Cities with existing steam systems.

^a Cities to be studied by Argonne National Laboratory.

^b Cities to be studied by Brookhaven National Laboratory.

TABLE 1.2 Application of District Heating Systems (DHS) to the Residential/Commercial Sectors -- Percentage Allocation of U.S. Total Scarce Fuel Savings Potential by Retrofit (from Ref. 2)

Region	Percentage of Savings Potential
Northeast	26.4
North Central	56.0
South	14.3
West	3.2
Total	99.9

conduct a study of the potential for district energy systems (cooling was to be considered in addition to heating) for selected cities in the North Central Census Region, while BNL would study cities in the Northeastern Region.

In order to develop a methodology by which the ANL and BNL studies could be conducted, it was determined that Washington, D.C. would be studied jointly and that differences of opinion would be resolved in Washington before completing the regional studies of other cities. Unfortunately, the complexity of the problem, the limited time available in the fiscal year, and the geographic separation of the study participants made it impossible to resolve all differences and present estimates of the attractiveness of DES by the end of the funding period. As a result, it was "agreed to disagree" on assumptions but to make those assumptions necessary to produce an estimate of DES viability in D.C. Estimates were completed by both ANL and BNL on schedule and were presented in draft form to DOE sponsors. It is the purpose of this report to present those results for public scrutiny. The methodologies used by ANL and BNL are not explained here. The approaches of the respective laboratories are presented in detail in the separate publications on findings for the Northeastern (BNL) and North Central (ANL) regions (Refs. 1 and 15, respectively). Although details of the methods are not presented here, it can be stated that these studies are more thorough and pragmatic than any so far undertaken. Previous studies have neglected many of the factors considered by the two Laboratories as they examined the D.C. test case (Refs. 9-12).

It has long been argued that cogeneration of electrical and thermal energy by electric generating plants would be a more efficient use of fuel.

The theoretical arguments are straightforward and, according to the analyses prepared for this report, are correct. However, in an era of abundant and cheap fuel supplies, there has generally not been an economic incentive to invest the extra capital necessary to extract and distribute thermal energy from power plants. In fact, the economics of thermal extraction have been so obviously unattractive that only a handful of applications exist. These applications usually involve the linkage to a steam using industry (Ref. 16). Applications to heating communities are rare and are confined to small markets (Ref. 17). As a result of the history of economic inferiority of the DES concept, most studies suggesting its use have been conducted by theoretically oriented authors who fail to conduct a comprehensive cost analysis (Refs. 10, 11, and 12). For example, no previous study has charged the DES system for electrical output lost in obtaining thermal energy from a power plant. Similarly, no other study has considered the difficulty of coordinating operating times in such a way that electrical and thermal output will coincide with demands.

One of the dominant economic characteristics of a DES is its high proportion of costs which must be devoted to the distribution system. Thermal energy in the form of hot water or steam is much more costly per unit distance to transport than competing forms of energy (i.e., electrical, gas, oil). As a result of this characteristic, the economy of a DES is extremely sensitive to the geographic distribution of demand and supply points. The greater the proximity of these points, the lesser the cost of distributing energy between them. This will always be true, but for DESs it is economically critical. Previous studies have either created artificial theoretical communities within the requisite distance (Refs. 10 and 12), or have ignored the proximity of existing power plants and centers of demand (Ref. 11). In this report on Washington, D.C. and in the BNL and ANL works on other cities, it has been found that nuclear power plants, so frequently touted for cogeneration in the past, are generally beyond an economic distance from sources of substantial demand. In general, the oldest power plants are the ones closest to downtown areas. These plants are most often intermediate load (seasonal) or peak load (seasonal and/or daily peaks) power plants whose operating cycle has at least a seasonal similarity to the demand cycle of a DES.

The consideration of District Energy Systems in both the ANL and BNL studies includes costs and efficiency from the point of extraction of the thermal resource (the power plant) to the point of final use of the thermal

energy inside the building. The working assumption of the ANL study is that oil and gas supplies will be inadequate to meet demand in the future and coal will have to be substituted for these fuels. From a public cost perspective, proper comparison of DESs to coal utilization options must include extraction of coal at the mine, delivery to conversion plants (electric generation, coal liquefaction, or coal gasification), delivery to buildings and conversion in buildings. Each of the alternatives to DES studied in the ANL work includes all of these steps. The possible steps and four alternatives considered in the ANL study are illustrated in Fig. 1.1.

Information on the cost and efficiency figures for the total energy pathways involved in converting coal to oil, gas, or electricity were obtained primarily from the *Net Energy Methodology* study by Development Sciences, Inc. (Ref. 6). The FEA *National Energy Outlook* (Ref. 13) was used as a basis for revision of the earlier Development Sciences figures. Conversion costs and efficiencies at the building were added to the Development Sciences *Net Energy* pathway. Efficiencies at the building used by ANL were based on estimates provided by Washington Gas Light Co. (Ref. 4).

The BNL study assumes that the DES will have to compete economically with current heating/cooling systems. The BNL study computes a weighted average cost per 10^6 for current systems and compares this to its estimate of the cost for the DES. It should be emphasized that all cost per Btu figures provided in this report are for final Btus delivered in the building after *all* conversion steps. It should also be pointed out that some of the differences in the two studies can be accounted for by different assumptions about energy conversion efficiencies. For example, the BNL sponsored study used a conversion efficiency of 0.60 for gas furnaces while the ANL study used 0.67. Similar figures for oil were 0.50 and 0.63. BNL conversion efficiencies were based on a study by Arthur D. Little Co. which was conducted for DOE (see Ref. 1).

The heating cost estimates obtained for Washington by ANL and the BNL sponsored study at similar interest rates are as follows:

\$3.39 per MMBtu (BNL)

\$5.22 to 11.50 per MMBtu (ANL)

Fig. 1.1 Possible Energy Pathways Analyzed in ANL Study

It can readily be seen that the ANL study provides a much less optimistic basis for evaluation of a DES. In spite of this, there are some very powerful favorable statements which can be made about DES on the basis of the ANL study. Given the range of cost estimates developed in the two studies, it would appear questionable to base viability analysis of DESs on the BNL figures. Consequently, we choose to more thoroughly discuss the ANL cost estimates with comparison to the BNL estimates as appropriate to illustrate areas of substantial inconsistency.

2 WASHINGTON, D.C.; THE TEST CASE

Several characteristics of Washington, D.C. made it attractive as a test case on which to base the further work of ANL and BNL. First, Washington is a surprisingly dense city. This fact was revealed in earlier Argonne research (Ref. 2) and was confirmed by this research. Second, it is a city with very little industry. Since industrial energy consumption patterns are much more variable than residential and commercial patterns, the D. C. energy demand estimates should be more accurate than those of other cities. Third, it is a city dependent on both gas and oil for heating. This is useful since ANL's North Central region is heavily dependent on gas and BNL's Northeastern region is heavily dependent on oil. Fourth, it is geographically central to the study participants. The design of the DES system required knowledge about economic and engineering behavior of several parameters. These include:

1. Magnitude and distribution of demand for heating and cooling;
2. Location and operating characteristics of sources of supply of thermal energy;
3. Type of piping to be used for transmission and distribution of the thermal energy;
4. Methods of retrofitting power plants and buildings for use of thermal energy; and
5. Operating behavior of the system.

2.1 DEMAND

Estimates of demand have been created for Washington based on four categories of building types. These are (1) low rise multi-family residential, (2) high rise residential, (3) commercial, and (4) industrial. These four categories were selected on the basis of differences in daily and seasonal patterns of heating/cooling demand. The approach was to develop estimates of square footage of floor space for each of these categories within each square kilometer of a checkerboard grid overlaying the city. These estimates are then translated into estimates of demand for cooling, heating, and hot water by applying a per square foot factor appropriate to each building type.

The demand estimates were actually broken down into five categories including (1) peak daily heating demand, (2) average daily heating demand, (3) daily hot water demand, (4) peak daily cooling demand, and (5) average

Fig. 2.1 Pattern of Design Day Heating Demand in Washington, D.C.

Fig. 2.2 Pattern of Design Day Heating Demand in Cleveland, Ohio

Fig. 2.3 Pattern Design Day Heating Demand in Detroit, Michigan

Fig. 2.4 Pattern of Design Day Heating Demand in Milwaukee, Wisconsin

Fig. 2.5 Pattern of Design Day Heating Demand in St. Louis, Missouri

LEGEND

(BTU $\times 10^7$)

Fig. 2.6 Pattern of Design Day Heating Demand in Chicago, Illinois

daily cooling demand. The peak daily figures were necessary for design of the piping of the DES system such that an adequate flow of energy would be maintained on the design day. Both ANL and BNL used the same building square footage factors for Washington. However, the two labs individually developed their own per square foot factors for the five categories listed previously. The two estimates of total heating demand for D.C. were within five percent of one another. However, the estimates of cooling demand were considerably different. The Brookhaven estimates were about double the Argonne estimates. For this and other reasons explained later, the use of cooling by the DES is not costed in this paper.

The capacity of the DES system was designed to meet peak heating demands. The pattern and magnitude of peak heating demand in Washington, D.C. is illustrated in Fig. 2.1. Average demand figures are also necessary to estimate the total annual demand for heat and the consequent overall annual fuel costs resulting from meeting that demand with thermal energy.

Some of the characteristics of demand discovered in the ANL study may be of interest. Demand estimates have been generated for Milwaukee, Chicago, St. Louis, Detroit, and Washington. It has been found that Washington's central business district (CBD) has levels of demand directly comparable to the CBD demands of all these cities but Chicago (see Figs. 2.2 to 2.6). In fact, Washington has a more extensive contiguous area at this demand level than any of these other cities (except Chicago). In this respect, Washington is a very good test city.

Washington is unique among cities with respect to the previously mentioned lack of industry. However, within the central areas where demand levels are highest, all cities tend to have a similar paucity of industry. In fact, the highest demands occur in the central business districts which are dominated by the commercial category of floor space. In close proximity to these CBDs are high demand residential zones which have the largest proportion of the high rise residential category in the urban area. It has been found that the CBD areas are dominated in floor space by office buildings (Ref. 3).

The boundaries of the D.C. demand area are defined by the presence of single family housing as often as by the city boundary itself. When the residential dwelling units in a zone consisted of more than 75% single family housing,

then the residential square footage for that zone was not counted. There is a precedent for this in the NASA-MIUS study (Ref. 9). In this study, it was concluded that the provision of thermal services to single family housing was not cost effective. By using this precedent in the data collection procedure, the studies cause their low density residential category to consist primarily of townhouses, garden apartments, and older three floor walk-up apartments. The high density residential category consists primarily of high rise elevator buildings of 5 floors or more.

It is worth noting that there is some cooling demand all year round in many office buildings and stores. This occurs because of high lighting loads in interior zones of buildings which are removed from the building wall itself (Ref. 14). This effect is not found in apartment buildings because apartments require external exposure (i.e., windows and natural light) to be marketable. Thus, apartment buildings do not have the depth to create an interior zone requiring cooling year round.

2.2 THERMAL SUPPLY

One of the features of the ANL study which makes it different from, and superior to, any studies preceding it (Refs. 1, 9, 10, 11, and 12) is the detailed attention to power plant retrofit. The work done on power plant retrofit details the methods and effects of retrofit of several different types of electrical generating units. The engineering properties of retrofitted power plants which are used in the ANL study are based on consideration of *each generating unit* in a power plant. Though highly detailed, the work has the deficiency that it is still theoretical in nature. As a result, it will be received with skepticism by some conservative power engineers. However, the ANL study has taken a conservative approach in its costing of the system - e.g., high maintenance and unit retrofit costs have been used - and it is still found that the DES will be more economical for heating than new power plants connected to heat pumps in buildings. These results will be discussed later. The point is that the work on power plant retrofit done for this report and the ANL study (Ref. 15) merits careful attention by the electric power industry.

Washington proper contains two major power plants and a government operated district steam system. The power plants are Benning and Buzzard Pt. Both are oil fired. Buzzard Pt. is a peaking plant which operated at 14% of full

load in 1975. More than half of the capacity of Buzzard Pt. is provided by oil fired combustion turbines, with the remainder provided by steam driven single stage turbines of an older design. Benning is an intermediate load power plant whose capacity is provided primarily by newer (since 1968) steam driven multi-stage turbines.

The three different techniques of generation mentioned above each require a different form of retrofit. Each form of retrofit is designed to provide the DES with 200°F hot water. The combustion turbine can be linked to a recuperative boiler. The older single stage turbines are to use back pressure and extraction. The newer multi-stage turbines will use intermediate cross-over and take-off. The most expensive of the three options is the back pressure and extraction of older turbines. This is estimated to cost 10% of the current cost of replacing the capacity of the retrofitted generating unit. The intermediate cross-over and take-off from newer multi-stage turbines is costed at 5% of the current cost of the retrofitted generating unit. On a capacity basis, the recuperative boiler is least costly. It is costed at \$10 kWt obtained from the retrofit. Each of these three retrofit options also has different operating characteristics and causes different electrical losses due to retrofit. The Washington results indicate that the back pressure and extraction retrofit will cause the plant capacity to be about 56% of its original electrical value. The figure for the intermediate cross over and take-off is about 70% and for the recuperative boiler it is 90%. See Table 2.1 for a description of these and other pertinent plant and retrofit characteristics.

The losses in electrical output which result when power plants are retrofitted and operated for cogeneration during peak heating demand periods must be made up by new electrical capacity. ANL estimates of retrofit costs include capital charges for making up this lost capacity with oil fired combustion turbines. (Lost capacity equals nominal power minus electric cogeneration capacity from Table 2.1)

In addition to the two oil fired power plants within D.C., there are two nearby coal fired steam power plants and one other oil fired combustion turbine power plant which we have considered using to meet Washington's thermal demands. The closest coal fired plant is at the Potomac River site. This plant is not much further from downtown D.C. than Benning and Buzzard Pt. It is an intermediate load plant, having operated at 49% of full load

TABLE 2.1 D.C. Area Power Plant Characteristics
Before and After Retrofit for Cogeneration

	Demand Stage 1*			Stage 3**		Stage 4		
	Buzzard Point		Benning	Potomac River	Dickerson		Dickerson	Morgan-town
Turbine Type	Steam	Combustion	Steam	Steam	Exist Steam	New Steam	Exist Steam	Combustion
Nominal Power (MW)	230	320	685	455	183	800	367	290
Type of Fuel	Oil No. 6	Oil No. 2	Oil No. 6	Coal	Coal	Coal	Coal	Oil No. 2
Cogeneration Capacity (MW)								
Electric	130	290	455	325	125	560	250	260
Thermal	391	640	845	600	210	875	420	580
Electrical Drawing Factor	0.565	0.906	0.664	0.714	0.682	0.700	0.682	0.897
Heat Rate (MBtu/kWh)								
Electric	9.33	12.00	8.31	8.45	8.00	7.85	8.00	12.00
Thermal	2.39	0.56	2.26	1.83	2.21	2.15	2.21	0.58
Original Nominal Efficiency	0.365	0.285	0.410	0.404	0.426	0.434	0.426	0.285
Cogenerating Efficiency	0.827	0.828	0.778	0.821	0.800	0.800	0.800	0.831
Number of Generating Units	5	2	6	5	1	1	2	6
Capability for Terminating Cogeneration & Returning to Original Electrical Capacity	No	Yes	4 No (135 MW) 2 Yes (550 MW)	Yes	Yes	Yes	Yes	Yes
1975 Load Factor	0.139		0.313	0.492	0.689	-	0.689	0.630
					For Existing Units (3)		For Existing Units (3)	For Entire 1252 MW Plant

* Stage 1 also includes 200 MW of boiler capacity.

** Stage 2 is not presented because it includes no cogeneration - only 355 MW of boiler capacity.

Fig. 2.7 Transmission Network and Stages of Construction for D.C. DES

Fig. 2.8 Demand Zones Served in Various Stages of Construction for D.C. DES

in 1975. The other coal fired plant is Dickerson, which is relatively remote. Dickerson is a base loaded plant, having operated at 69% of full load in 1975 (Ref. 16). Finally, the other oil fired plant, Morgantown, is also rather remote.

The location or direction of these power plants is indicated in Fig. 2.7. This figure also indicates the transmission network and the sequence of its construction which has been considered in this study. The first portion of the system is to link the nearby Potomac River, Benning, and Buzzard Pt. power plants to the generally high density demand zone centered on Washington's CBD. The extent of this demand zone is illustrated in Fig. 2.8. If this system alone were completed and all buildings in the zone were heated by the DES, then there would be a total of 18 different cogenerating stations and six boilers (there are multiple stations at all power plants) serving the area with more than a 20% reserve margin. The numerous independent sources of thermal energy make this an acceptable reserve margin. It is a margin that is representative for a large electric utility. Similar margins would be available if the entire system as presented in Figs. 2.7 and 2.8 were constructed. In any case, these are the margins *only* if all demand is met by the DES.

Calculations for fuel usage for the first demand zone assume that Buzzard Pt., Benning, and Potomac River power plants continue to operate primarily to meet electrical demands. Thus, since Potomac River operates most frequently, it is essentially the base load plant for the Stage 1 Washington DES. This gives the advantage of having most of the original energy for the DES come from coal. Since monthly data for D.C. indicate that Benning and Buzzard Pt. are seasonally loaded, they may be expected to often generate electrical energy at the same time thermal energy is required (Ref. 8). As for electrical service, it is assumed that Benning is an intermediate load thermal plant and Buzzard is a peaker. The hours of thermal demand from Benning and Buzzard Pt. are estimated to be considerably less than the current hours of electrical service. It is thus assumed that there is a negligible requirement to turn on one of these plants to provide thermal services at a time when electrical services from these plants are not otherwise required. In addition to the power plant retrofits, 200 MW of hot water boiler capacity is to be added at Buzzard Pt. These boilers will be used for peaking purposes and for quick response to shifts in demand not coincident with electrical demand. For this reason, they are located at the site closest to the center of demand.

Stage 2 of the DES for Washington involves retrofitting 255 MW of existing steam boilers and 100 MW of new boiler capacity. Two hundred megawatts of this capacity is part of Washington's existing district steam system. In both Stage 1 and 2, some of the existing district steam tunnels will be used to provide conduits for hot water pipes used by the DES. Stage 3 of the DES involves connecting an existing and a new unit at Dickerson to the northern and western high density residential areas of Washington. This stage will complete the first of two large transmission loops. Stage 4 involves the addition of two existing units at Dickerson, the connection of the Morgantown combustion turbines to the southeastern high density residential areas, and the completion of the second loop. Flow patterns would be adjusted after each stage of construction. The two connected loops would provide considerable flexibility in this respect.

2.3 TRANSMISSION

The transmission system sequence of construction has been described in the previous section. The locations of the transmission conduits are shown in Figs. 2.7 and 2.8. Each transmission line contains a supply and return pipe ranging from 22 inches up to 60 inches depending on the source of supply. The cost estimates were generated by the consulting firm of Burns and Roe. They are for stainless steel pipe with insulation and coating. Excavation, piping, valves, X-ray equipment, expansion loops, manholes, and labor costs have all been included. An add-on for labor costs in high density areas (called "urban" add-on) has been included (see Fig. 2.9). In the ANL study, two variants of transmission line costs were used. In the low cost option, it was assumed that aramid fiber piping would be used instead of stainless steel piping (at an overall savings of 30%) and that routing of transmission lines was done well enough to eliminate the urban add-on costs.

2.4 LOCAL DISTRIBUTION

Local distribution systems were designed by the Energy Systems Research Group, Inc. of Albany, N.Y. for Brookhaven (see Ref. 1). The design was based on a concept of uniform demand density in distribution sections, normally six square kilometers in size. Because of the vagaries of urban geography and demand density, the zones actually varied from 3 to 10 sq. km. The grid squares in distribution sections share a common pipe network for distributing the hot

Fig. 2.9 Transmission Conduit Costs (Supply and Return Piping Included)

water from main transmission pipelines to the pipes that serve individual blocks. The piping systems were designed generically for different geometrical groupings of grid squares into sections. Shifts in demand and peak demands were assumed to be adjusted for by changing pumping rates and, to some extent, input temperatures. Piping capacity was based on a 90°F temperature drop through the building and a monthly average temperature of the coldest month relative to a 65°F base. A relationship between flow rate and pipe diameter derived by Burns and Roe, Inc. was used to size the various segments of pipe in a section.

While this systematic section design approach was clearly necessary to obtain initial estimates, the accuracy of other cost figures was not considered by ANL to be great enough to warrant the repetitive use of the Energy Systems Group (ESG) technique. To save the time required to develop the inputs to the ESG technique for each city, ANL elected to derive a simple regression model of local distribution cost as a function of annual heating demand density. This model was based on the Washington results of ESG and is presented below:

$$C = 4.2540 + 0.01094D \quad R^2 = 0.91 \quad N = 9$$

$$(t = 10.45) \quad (t = 8.34)$$

where: C = cost per zone in 10⁶ dollars.

D = annual demand per sq. km in 10⁹ Btu.

This cost equation can only be expected to be valid over the range of densities occurring in Washington, D.C. For all of the cities mentioned earlier, it should give adequate estimates of local distribution costs (with the possible exception of downtown Chicago).

2.5 BUILDING RETROFIT

The building retrofit costs include costs of altering the equipment in buildings and the costs of connections to the DES system. These costs are based on estimates for generic building types as provided by Burns and Roe, Inc. The existing systems retrofitted in the Burns and Roe analysis were each steam/hot water systems. This is appropriate for Washington since 56% of the residential units use hot water or steam (Ref. 19). On the other hand, these estimates are undoubtedly not directly substitutable for the remaining residential units.

Actually, a range of retrofit costs was available from which the ANL and BNL groups should choose. Both groups selected similar cost figures. Those

figures selected were appropriate for buildings in downtown areas. This decision was made because it is clear that downtown areas will be served first and most economically by a DES. The BNL group selected a different retrofit cost per square foot value for each of the four classes of buildings, ranging from \$0.32 per sq. ft. for high rise apartments to 0.76 for commercial and institutional office buildings. The ANL group generated a high and low retrofit cost estimate based on a distinction only between residential and non-residential buildings. The high ANL estimate used \$0.32 for residential and \$0.76 for non-residential. The respective figures for the low estimate were \$0.24 and \$0.41. The cost estimates per zone were obtained by multiplying the appropriate square footage figures by these cost values.

2.6 OPERATING AND MAINTENANCE

Substantially different approaches were taken with respect to operating and maintenance expenses of equipment. The BNL study essentially ignored operating and maintenance (O&M) costs. The only cost included in the BNL study which would be comparable to O&M costs in the ANL study is for pumping. The cost figure assigned to pumping by BNL was \$0.09 per MMBtu. The low cost O&M figure used by ANL was \$0.47 per MMBtu. The technique used in the ANL study was to compute a ratio of non-fuel O&M costs to capital costs for several different fuel piping systems (gas transmission pipelines, gas distribution lines, oil pipelines, etc.). This information was obtained from the Development Sciences "Net Energy" study (Ref. 6). The low ratio of this group was then used to estimate O&M costs for the DES low estimate and the high O&M to capital ratio was used for the DES high estimate. It was also assumed in the ANL study that O&M costs of retrofitted power plants doubled during the hours when thermal and electrical output were cogenerated.

2.7 FUEL COSTS

The BNL study was weak in the area of retrofitted power plant operating characteristics. It was assumed by the BNL study team that lost electrical output could be made up by operating the plant for more hours and consequently using more fuel. The loss of capacity at peak demand periods was not treated as a problem. All retrofitted power plants were assumed to have the same operating characteristics. Fuel costs per MMBtu were uniformly assumed to be equal to \$0.25.

The overall fuel costs for Washington in the ANL study were \$1.20 per MMBtu. These costs were computed by detailed analysis of each generating unit in the retrofitted power plants of Table 2.1. Probable hours of operation of each plant were estimated while attempting to use hours in which electricity would otherwise have been generated at that plant. The thermal heat rates in Table 2.1 were used to compute costs. Note that these thermal heat rates are computed on the basis of maintaining the original electrical heat rate of the power plant. The thermal heat rates are therefore best thought of as economic heat rates arising from a logical accounting convention. The very low heat rates for combustion turbines arise because very little electrical output is sacrificed to gain a great deal of thermal output.

2.8 EQUIVALENT OVERALL COSTS

Having superficially discussed some of the methods of design and cost estimation of the ANL and BNL study, it may now be useful to present comparisons of the cost estimates of the two studies. In this manner, one can see where the major areas of difference are and what their magnitude is. The first step necessary to establish comparability of results is to put them on equal footing. The BNL study assumed an infinite lifetime for its capital equipment, while the ANL study assumed a 20 year lifetime. This assumption alone reduced BNL's cost figures by about 16% with respect to ANL figures. The two are converted to a 20 year lifetime in the comparison of costs presented below. First, however, we may compare capital, O&M, and fuel costs on a standardized basis (the market areas served by the two studies were not quite identical). These comparisons are presented in Table 2.2 below. It can readily be seen in Table 2.2 that the biggest relative differences in the cost estimates of the two

TABLE 2.2 Cost Comparisons of the Washington, D.C.
DES Study Results (\$/MMBtu)

Study	Initial Capital Costs Per Annual Demand					Annual Costs	
	Power Plant Retrofit	Electric Capacity Replacement	Transmission	Local Distribution	Building Retrofit	O&M	Fuel
BNL	1.50	0.00	10.10	14.10	9.46	0.09	0.25
ANL Low	2.47	8.62	8.66	9.64	5.48	0.47	1.20
ANL High	4.92	17.20	18.10	27.50	8.73	2.55	1.20

studies are in the areas of (1) electric replacement capacity, (2) O&M, and (3) fuel costs. Differences (1) and (3) arise from the more detailed treatment of retrofitted power plants in the ANL study.

The standardized cost figures in Table 2.2 may be used to develop estimates of the required charge per million (final) Btus by multiplying the capital costs by a selected capital recovery factor and summing across. The results of assuming a 20 year lifetime and an 8% rate of return are shown in Table 2.3.

TABLE 2.3 Annualized Cost Comparisons of Washington, D.C.
DES Study Results for 8% ROR and 20 Year Life
(\$/MMBtu)

Study	Power Plant Retrofit	Electric Capacity Replacement	Trans- mission	Local Distri- bution	Building Retrofit	O&M	Fuel	Total
BNL	0.15	0.00	1.03	1.44	0.96	0.09	0.25	3.92
ANL Low	0.25	0.88	0.88	0.98	0.56	0.47	1.20	5.22
ANL High	0.50	1.75	1.84	2.80	0.89	2.55	1.20	11.53

3 ALTERNATIVE ENERGY SUPPLY OPTIONS AND THEIR EFFICIENCIES

As mentioned earlier, the working assumption of the ANL study is that oil and gas supplies will be inadequate to meet demand in the future and coal will have to be substituted for these fuels. This assumption implies that the implementation of a DES in a U.S. city is not likely to occur until some time in the future. The DES alternative is thus considered to be a developing technology requiring research, development, and demonstration before large scale implementation. This is a considerably different perspective from the BNL study which assumed that DESs could compete with current energy supply options. To a large extent, both assumptions were appropriate, given the regional perspective of the study participants. In BNL's Northeastern study region, the predominant heating fuel is expensive foreign oil. Further, coal supplies are not readily available in this region. For ANL's North Central study region, natural gas is the predominant heating fuel. Natural gas is relatively inexpensive because of regulation. Until the price of gas rises substantially, the DES alternative is not likely to be competitive. However, when this does occur, coal is likely to be the substitute fuel of choice because of its abundance in the region.

In this section, we discuss only the results of the ANL study with respect to the overall efficiency of four different methods of using coal, including the coal fired DES. Since the DES includes extraction of thermal energy and delivery to the building, the evaluation of alternatives to DES must include all steps from extraction to delivery. Coal is considered only after its extraction from the mine. No distinction is made between deep mined and strip mined coal.

Of the four options, both coal gasification and coal liquifaction are considered to be heating alternatives only. However, for electric and thermal energy, it is possible to provide both heating and cooling with accepted technology. Electricity may be used to drive a compression chiller and thermal energy may be used to drive an absorption chiller. As mentioned earlier, the cooling options for the DES proves to be unattractive at the 200⁰F DES design temperature, when compared to the all electric option. This finding will be explained in the next section and then we will turn to the evaluation of the overall efficiencies of the four heating options.

3.1 COOLING

Let us now examine the relative efficiencies of the two cooling options. First, it must be recognized that the efficiency of both compression chillers and absorption chillers may be quite variable. A good compression chiller may have a coefficient of performance (COP), or efficiency, from 2.5 up to 4.4 depending on its sophistication (Ref. 18). (We define COP or efficiency as useful energy output divided by energy input.) Similarly, the COP of current technology single stage absorption chillers is up to 0.7 (Ref. 5).

The trade-off in comparing cooling from a DES system to that provided by conventional electrical means is that in the DES a certain amount of electrical cooling capacity must be sacrificed to gain some amount of thermally driven cooling capacity. This magnitude will vary not only because of relative efficiencies of chilling equipment, but also because of the operating characteristics of various DES retrofit systems. One method of comparing the two alternatives is to assume a constant COP of 0.7 for absorption chillers driven by the thermal energy obtained from the various retrofitted D.C. area power plants. Then calculate an equivalent minimum COP of compression chillers necessary to make it more efficient to retain the conventional electrical output than to retrofit for DES thermal output. One obtains the results presented in Table 3.1. As can be seen from this table, the only case for which the DES system is clearly superior to conventional is when combustion turbines are retrofitted.

TABLE 3.1 Compression Chiller COPs Needed to Beat
DES Chilling in Washington, D.C.

Power Plant	Generation Method	Required COP
Buzzard Pt.	Single Stage Turbines	>2.74
Benning	Single & Multi-Stage Turbines	>2.57
Potomac	Multi-Stage Turbines	>3.23
Dickerson Existing	Multi-Stage Turbines	>2.52
Dickerson New	Extraction Turbine	>2.55
Buzzard Pt.	Combustion Turbines	>14.90
Morgantown	Combustion Turbines	>16.80

Combustion turbines are operated as peak electrical generating plants only. As a result, any thermal output available from such units will be limited in extent. Consequently, there is a very small amount of thermal output that can be justified on an efficiency basis for cooling by a DES. Combined with the relatively few cooling degree days in Washington, this small thermal capacity for cooling means that the support of an expensive DES distribution system by means of revenues obtained for cooling services is improbable. On the other hand, if a DES system can be justified on the basis of heating services, then it may be possible to justify the provision of cooling services *in addition* to heating services. We have demonstrated that, from an efficiency point of view, only those units of the DES which use combustion turbines should be operated to provide thermal energy for cooling. When these units are only operated as peakers, they are unlikely to provide thermal energy throughout the entire cooling season. On the other hand, since they are *peakers* which provide energy when demand is greatest, this suggests the use of the floating air conditioning concept applied on a system wide basis. In this concept, compression and absorption chillers are used to provide total capacity. Normally, only the compression chillers are operated but during peak periods absorption chillers will also be used. This is the most efficient way to use the combination of generating units which would be connected to a Washington, D.C. DES.

3.2 HEATING

Because it is necessary to demonstrate the viability of providing heating through a DES system before the cooling option suggested above can be evaluated, we have concentrated in this report on the provision of DES heating services. The BNL study did evaluate cooling. However, there is considerable conflict between the ANL and BNL cooling demand estimates and in interpretation of engineering behavior of the DES cooling alternative.

The ANL method of evaluating heating alternatives has been to consider each energy transformation step involved in each alternative. After considering each of these steps, then the effects of indirect uses of energy have also been estimated (see Fig. 1.1, p. 6). As one would expect, the more capital involved in a pathway, the more indirect energy will be involved. As a result, the DES system suffers the most in overall efficiency through indirect energy losses. Electrical generation has the next highest level of indirect energy losses.

The efficiencies of the various steps in the four evaluated energy pathways are presented in Table 3.2. The overall efficiencies of the pathways are also listed. These efficiencies are obtained by multiplying all intermediate efficiencies together. In the case of cogeneration, the thermal and electrical pathways are computed separately and added together. Most efficiencies presented in the table are derived from ERDA report *Using Net Energy Methodology for Energy Planning: Tradeoffs of Supply vs. End-Use Technologies* (Ref. 6).

The electrical generation figures were adjusted by modifying the load factor and nominal efficiency to be consistent with the provision of heating services rather than base loading. The furnace efficiencies used for oil and gas furnaces are based on a study provided to us by Washington Gas and Light Co. (Ref. 4). The DES heating system efficiency estimates are ANL's own. There are two efficiencies presented for the alternatives involving electrical generation. One is for the final stage use of resistance heating and another is for heat pumps. The heat pump comparisons must be made with caution because heat pump efficiencies vary with outside temperatures. The figure presented in Table 3.2 is based on *seasonal* heat pump efficiencies. On peak heating days, the heat pump will actually be less efficient than resistance heating (as a rule of thumb, heat pumps become equal in efficiency to resistance heating at about 20°F). Because of this property, our equipment sizing for capital costs for electric generation presented later will be based on the assumption that all heat pumps have a resistance heating back up. For the DES option, the electric/thermal efficiencies are based on a composite average of efficiencies which would be obtained from the Washington, D.C. mix of retrofitted power plants.

Table 3.2 indicates that, if equivalent technology is used for electrical pathways (i.e., heat pumps or resistance heat), the DES will always be more efficient than the other three options. From an efficiency point of view, this table also indicates little difference between the coal gasification and liquifaction options. Depending on the end use technology applied, the electrical generation option could be the least efficient (resistance heat) or rank second of the four (heat pumps).

Of course, efficiency alone is not the only criterion that one should apply in the comparison. Economics is obviously also very critical and will be addressed in the following section. However, as we have implied earlier, the choice of fuel is also important. Any one of the four alternatives evaluated

TABLE 3.2 Comparison of Pathway Efficiencies

I. Coal to Heating Oil to Heat

<u>Process Step</u>	<u>Efficiency Estimate</u>
(a) Mine through Liquifaction	.662
(b) Refining and Storage	.935
(c) Distribution	.990
(d) Furnace Efficiency	.630
(e) Indirect Energy Use Factor	<u>.864</u>
Pathway Efficiency (= a x b x c x d x e)	.334

II. Coal to Utility Gas to Heat

<u>Process Step</u>	<u>Efficiency Estimate</u>
(a) Mine through Gasification	.533
(b) Distribution	.987
(c) Furnace Efficiency	.670
(d) Indirect Energy Use Factor	<u>.918</u>
Pathway Efficiency (= a x b x c x d)	.324

III. Coal to Electricity to Heat

<u>Process Step</u>	<u>Efficiency Estimate</u>
(a) Mine through Cleaning & Transport	.879
(b) Power Generation	.420
(c) Transmission and Distribution	.901
Heating System Efficiency	
(d) Resistance Heat	1.000
(e) Heat Pump	2.100
(f) Indirect Energy Use Factor	<u>.804</u>
Pathway Efficiency	
Resistance Heat (= a x b x c x d x f)	.267
Heat Pump (= a x b x c x e x f)	.562

TABLE 3.2 Comparison of Pathway Efficiencies (Contd.)

IV. Coal to Cogenerated Electrical and Thermal Energy to Heat (2 Pathways)Electrical Pathway

<u>Process Step</u>	<u>Efficiency Estimate</u>
(a) Mine through Cleaning & Transport	.879
(b) Electric Generation	.273
(c) Transmission & Distribution	.901
Heating System Efficiency	
(d) Resistance Heat	1.000
(e) Heat Pump	2.100
Partial Pathway Efficiency	
(f) Resistance Heat (= a x b x c x d)	.216
(g) Heat Pump (= a x b x c x e)	.454

Thermal Pathway

<u>Process Step</u>	<u>Efficiency Estimate</u>
(h) Mine through Cleaning & Transport	.879
(i) Thermal Generation	.535
(j) Transmission & Distribution	.901
(k) Heating System Efficiency	.800
(m) Partial Pathway Efficiency (= h x i x j x k)	.339
Sum of Partial Pathway Efficiencies	
(n) Resistance Heat (= f + m)	.555
(o) Heat Pump (= g + m)	.793
(p) Indirect Energy Use Factor	.752
Pathway Efficiency	
Resistance Heat (= n x p)	.417
Heat Pump (= o x p)	.596

in Table 3.2 is desirable from a fuel switching point of view since we estimate that a total of 38.7×10^{12} Btu/yr. of oil and gas can be saved by using one of these alternatives. On the other hand, according to our estimates, only the electric and cogeneration options can save *total* Btus (disregarding the fuel producing the Btu) when compared to the current heating systems. We estimate that the coal gasification option would use 30.3×10^{12} Btus more and the cogeneration option would use 4.7×10^{12} Btus less per year.

In the process of estimating the share of oil and gas used by current heating systems, we found an interesting property. According to our comparison of Hittman CBD results (Ref. 3) and U.S. Census statistics (Ref. 19), the commercial sector is considerably more likely to use oil than the residential sector. In Zone 1, we estimated that 49% of the currently used Btus are obtained by direct (non-electrical) consumption of oil. In the remaining zones, only 39% of these Btus are obtained by consumption of oil. This result indicates that likely initial construction areas (CBD's) for DESs will create a more favorable effect per dollar invested on the reduction of foreign oil imports than the surrounding residential areas.

4 ECONOMY OF THE ALTERNATIVES

In this section, we consider the relative economic position of a DES among (1) coal gasification, (2) coal liquifaction, (3) coal based electricity, (4) current heating technology, and (5) the DES itself. The ANL report estimates costs of coal based electricity and the DES which are sensitive to geographical location of the demand zone in Washington, D.C. Specifically, the relative attractiveness of the four zones described in Section 2.0 are evaluated. The ANL report also estimates locationally insensitive costs for coal liquifaction and coal gasification. The BNL report develops an estimate of the costs of current heating technology in Washington, D.C. Comparison of these estimates will allow us to make some rather substantial statements about the relative attractiveness of a DES designed to provide heating services only.

The dominant heating fuels for Washington, D.C. are currently utility gas and oil. The U.S. census shows that in 1970, 52% of the residential dwelling units in Washington were heated by utility gas, while 35% were heated by oil. Only six percent were heated by electricity (Ref. 19). While these percentages will be different for commercial and industrial uses, (see Sec. 3.2), the general pattern among fuels is similar. Comparison of residential to commercial fuel use figures for Denver and Baltimore where CBD commercial fuel use figures were developed by Hittman Associates (Ref. 3) shows this similarity between the two categories. The exception for downtown commercial space in Washington and Baltimore is the provision of heat to CBD commercial/institutional customers by existing district steam systems. The BNL study, which was sensitive to these local fuel vagaries, estimated that the weighted current D.C. cost of thermal energy for space heating and hot water is \$5.08 per MMBtu. Remember, this is the cost for final Btus delivered. Because of higher assumed firing efficiencies for heating equipment, an ANL estimate, had it been generated, would be somewhat lower.

The coal liquifaction and gasification costs estimated by ANL are based on data from the Development Sciences *Net Energy* study and the FEA *National Energy Outlook* (Refs. 6 and 13). The cost figures include all comparable costs to those in the DES pathway. Costs of cleaning coal, shipping it to a conversion facility, conversion, piping to the urban area, O&M of all components, and cost of the input coal stream are all included. Conversion costs are based on the assumption of an economically sized plant meeting demand by continuous operation and storage of product. Such a plant would have to serve a much larger

market than Washington, D.C. alone. Because of the current D.C. reliance on oil and gas, the use of either coal liquifaction or gasification will mean that initially retrofit costs for buildings will be negligible. Further, the local distribution system is already in place. As a result, the ANL cost estimates ignore building retrofit costs and local distribution costs for the coal gasification and liquifaction options. The ANL cost estimates are generated for a high (20%) and low (8%) rate of return so that the cost estimates will bracket costs actually charged by a utility. At 8%, the coal gasification option is estimated to cost \$6.19 per MMBtu and the liquifaction option to cost \$6.51 per MMBtu. At 20%, the gasification figure is \$8.62 and the liquifaction figure is \$9.26.

The electric and DES heating options have in common the need to install substantial new distribution systems and to retrofit most existing buildings. In downtown areas, the distribution system of both of these systems involve digging up streets in order to place distribution links underground. Although electrical distribution costs in urban areas must be higher than average, electrical distribution is costed on an average cost basis. Further, ANL has not included costs of retrofit of buildings in the electric supply alternative. Both of these costing decisions have the effect of causing the electric supply system cost figures to be underestimates. The DES distribution system costs, however, are not average costs but are estimates of actual cost in each service zone. The piping costs within the urban area include an urban "add on" cost which approximately doubles piping cost over its "suburban" values. Retrofit costs are also included in the DES estimates.

The assumed approach of electrical utilities is to make the best use possible of existing capital equipment. It is assumed that a summer peaking electric utility will attempt to utilize its excess winter capacity by selling electric heating services. When the electric utility has an equal summer and winter peak, it is assumed that the utility will wish to curtail further additions to load caused by heating hook-ups because the load factor will be reduced. If it can be demonstrated that any alternative provides heating at less cost than added electric system capacity, the electric utility should support measures designed to achieve such an alternative.

Thus, the question asked by ANL is: "At the point when all existing electrical capacity is used at wintertime heating peaks and customers are being denied oil and gas, what will be the least cost method of providing heat

to new and/or curtailed customers?" The problem is now framed as a cost minimization problem. For the four different service areas, as illustrated in Fig. 2.8, a ranking of costs to provide heating services to the *entire* zone by means of electric heat or cogenerated thermal heat is established. These costs are presented in Table 4.1. For purposes of comparison, the coal gasification and liquifaction costs are listed at the bottom of the table along with the cost figures estimated by BNL.

It should be stressed that initial DES cost estimates were intentionally kept on the high side. Where retrofit costs should have been expressed as a percentage of turbine costs, they were actually estimated as a percentage of complete power plant capital costs. Piping costs were for the most expensive piping system and included an urban add-on. Power plant maintenance costs were assumed to double as a result of cogeneration. Transmission system maintenance costs were based on highest ratios to capital costs found for other types of pipeline systems. The high figures for building retrofit costs were used. Fuel costs, on the other hand, were not high, but were roughly equal to current average values paid by utilities. Thus, fuel savings were not overstated as were capital and operating/maintenance costs. All in all, given these assumptions, the DES high estimate is likely to cause the DES to appear worse than it will be in reality.

As discussed earlier, the ANL study also took the opposite view and adopted a very liberal set of low capital and maintenance cost assumptions for a DES system. To do this, it eliminated the urban add-on for piping costs and multiplied the resultant piping costs by 0.70 to indicate substitution of aramid fiber pipe for steel pipe. This caused urban piping costs to be about 35% of the previous value and suburban transmission lines to cost 70% of the previous value. They also use the low side cost figures of \$0.25 per square foot for residential building retrofit (originally \$0.32) and \$0.41 for commercial and industrial building retrofit (originally \$0.76). They continue by assuming that their original estimates of power plant retrofit costs were 100% higher than necessary.

Table 4.1 illustrates the effect of these different assumptions about the DES. The most striking result illustrated by this table is that new coal electric power plants devoted exclusively to heating are invariably (within the D.C. service area) more costly than retrofitting existing power plants to

TABLE 4.1 Cost Per Million Btu Finally Delivered
for Different Demand Zones in D.C.

System	Zone	At 8% Rate of Return	At 20% Rate of Return
DES Low Estimate	1	\$ 4.67	\$ 7.62
DES High Estimate	1	9.68	16.20
Coal Electricity*	1	20.20	36.80
DES Low Estimate	2	4.68	7.13
DES High Estimate	2	10.13	16.17
Coal Electricity*	2	21.82	39.90
DES Low Estimate	3	6.07	10.60
DES High Estimate	3	14.00	23.80
Coal Electricity*	3	18.40	33.40
DES Low Estimate	4	5.85	10.50
DES High Estimate	4	14.10	24.20
Coal Electricity*	4	20.90	38.10
Coal Gasification	All Four	6.19	8.62
Coal Liquifaction	All Four	6.51	9.26
BNL DES Estimate	All Four	3.92	7.56
DES Low Estimate	All Four	5.22	8.83
DES High Estimate	All Four	11.50	19.50
Coal Electricity*	All Four	20.00	36.40
Current Costs in D.C. (BNL)		\$5.08	

* Assumes heat pumps with resistance backup but includes no inbuilding retrofit costs to provide these. Note also that these electrical costs are the marginal cost of providing capacity which will be devoted to heating only. This accounts for the substantial increase over current electrical costs which are based on much higher load factors.

provide cogenerated thermal energy for heating. Another result worthy of note is the increase in DES cost of the outer two demand zones as compared to the inner two. This was expected and is the result largely of increases in transmission and distribution costs per unit of demand served. In the inner two demand zones (1 and 2), the DES low estimate of cost is consistently lower than the coal gasification or liquifaction options. In the outer two zones, the relative positions of these options depends upon the assumed rate of return. As an energy conserving option, the DES will rank inversely with the required rate of return. In the inner two zones, the DES low estimate is actually lower than the BNL estimate of current heat costs.

The degree of superiority of the DES system over new electrical capacity for heating is striking. The implications of this research are strong for those utilities which can sell both electric and thermal energy and which expect to become winter peaking utilities in the near future. The results presented here indicate that such utilities can both conserve capital and fuel by using cogeneration to provide thermal energy for the heating of densely developed areas. However, the results here are uncertain with respect to the relative position of a DES as compared to coal gasification or liquifaction. It is worth noting that only the direct economic costs of the alternatives have been evaluated. All alternatives other than the DES imply the extraction of substantial additional amounts of coal with the subsequent environmental effects. If those effects were accounted for, then the DES would be relatively even more attractive. On the other hand, the construction and hook-up schedules for the DES are not too realistic. Phasing construction and hook-up would increase the costs listed in Table 4.1 somewhat.

It is reasonable to point out that the coal gasification and liquifaction cost and efficiency figures are only estimates. We are not aware of the quality of the figures provided in the ERDA report on *Net Energy Analysis* and the FEA *National Energy Outlook* (Refs. 6 and 13). It is also true that regulations on the price of utility gas and oil will affect the desirability of implementing coal gasification or liquifaction. If regulations prevent implementation of these energy alternatives, then cogenerated thermal energy could become the option whose economies are actually realizable. The ANL study has evaluated the four energy supply alternatives from the public sector's point of view - i.e., the lowest cost alternative ignoring current laws, regulations, and institutional structures. It has also based its analysis on estimates of

costs of providing services but not the value of the product produced. It is possible that the gaseous or liquid products which can be produced from coal may in the future have a value for use in the transportation sector which is much greater than their costs as estimated here. Since thermal energy cannot be used in the transportation sector, the DES option examined here could well become the cheapest way of providing heating to urban dwellers and workers.

It should also be observed that the low cost DES estimate by ANL and the BNL cost estimate are both low enough to beat the costs of oil at current prices. If one multiplies the costs from Table 4.1 by the efficiencies assumed in the ANL and BNL studies for oil heat, then an equivalent oil price is obtained. If one applies the ANL efficiency of 63%, then the equivalent oil price is $\$5.22 \times 0.63 = \3.29 per MMBtu. If the BNL efficiency of 50% is used, the equivalent oil price would be $\$2.61$ per MMBtu. While these prices are admittedly derived from the optimistic, low cost DES figures they do indicate that the DES concept *may* now be viable in selected high density areas of Northeastern cities. In any case, it would seem that Northeastern cities provide a logical location for development and demonstration of the DES concept.

5 SUMMARY AND CONCLUSIONS

This report summarizes and compares two studies which have developed cost estimates for a District Energy System (DES) designed to provide heating services to Washington, D.C. The DES concept has been compared to four other alternatives which are (1) current heating methods, (2) electricity from coal, (3) coal gasification, and (4) coal liquifaction. The three coal alternatives are compared to the DES by considering the total cost and efficiency of taking the fuel source (coal or hot water) from its point of extraction (mine or co-generating power plant) to its point of final use. The report presents results. It discusses but does not give details of the methods of developing these results. The methodology is to be explained in detail in other publications (Refs. 1 and 15).

The results indicate that the DES is most efficient. They also indicate the economic superiority of a cogeneration based DES over additions to the electrical system capacity when those additions are exclusively for the purpose of providing heat for urban residences and commercial buildings. The cost figures provide no basis for selecting a DES instead of coal liquifaction, coal gasification, or imported oil. Depending upon the assumptions selected, the DES may cost more or less than these options. Finally, it is noted that the results are somewhat generalizable but the relative merit of DESs depends strongly on density of urban areas, climate, and relative locations of existing power plants. The effects of these variables should be amply illustrated in the forthcoming Argonne and Brookhaven multiple city regional studies.

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