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STATE AND LOCAL REGULATION OF DISTRICT HEATING-AND-COOLING SYSTEMS: ISSUES AND OPTIONS

by

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EXECUTIVE SUMMARY

This report addresses the issues raised by state and local regulation of district heating and cooling (DHC) systems. It examines traditional regulatory policies of state legislatures and their public utility commissions (PUCs). It also examines newer variations of those policies, which some states apply to DHC systems for the purpose of encouraging their development or revitalization. Certain aspects of municipal supervision, such as zoning restraints, are mentioned. The report clarifies how these various regulatory approaches affect the growth prospects of DHC technology in the U.S. -- and how they affect the technology's potential for conserving and efficiently using energy.

Most states regulate DHC systems. In contrast to electric utilities, which offer a commodity that can supply a unique range of services, DHC services are not uniquely supplied by DHC systems. Those services are space heating and cooling and domestic water heating, and they can also be supplied by gas or electric utilities or distributors of fuel oil. DHC systems can therefore be expected to operate in competition with these other energy suppliers and not to attain a monopoly status. Also, DHC systems that currently serve the general public are rare, and it is therefore unlikely that such systems will ever become so numerous that competitive disputes over service areas will arise between them. This situation makes the need for full regulation of DHC systems less acute than for electric utilities.

Moreover, potential proprietors of DHC systems may be dissuaded from proceeding with the development of a viable system by the specter of burdensome, pervasive regulations. New DHC systems will have high capital costs. They may therefore require a higher rate of return than do electric utilities. The high DHC capital-cost structure indicates that market conditions may exercise a greater restraint on DHC operations and service rates than regulation by a state PUC.

On the other hand, some degree of supervision by a state PUC can assist a DHC system in several ways -- and in the process advance public policy by reducing consumption of scarce fuels and by promoting economic stability. Regulation can provide the authority to obtain property rights required for DHC distribution pipes, can build investor and customer confidence, and can require compact DHC systems that do not inefficiently duplicate the equipment of established utilities. Regulation of entry into a thermal-energy market, of abandonment of service, and of provision of reasonable standards of safety, service, and reliability can also ensure that a DHC system operates in the public interest.

A variety of organizations could own or operate a DHC system or its major components. Two are of special interest: municipalities and electric utilities. With municipal ownership, the profit motive can be subordinated to the public welfare -- although, of course, a profitable municipal operation would benefit the taxpayers. A waste-to-energy facility tied in with a DHC system can alleviate trash-disposal problems. Alternatively, a DHC system can be part of a program to rehabilitate older multifamily residences and to stimulate local economic development. Municipal financing is generally less expensive than other kinds of financing. Also, municipally owned utilities have comparatively few regulatory problems because they are not subject to the supervision of a state PUC in most (35) states; in a few states, however, uncertainty exists as to whether a municipality can own or operate a DHC system. Analysis of the European experience indicates that district heating prospers in those countries in which it is strongly backed by municipalities.

Electric utilities can play a key role in the development of new DHC systems and in the revitalization of older ones under their control. Investor-owned utilities are accustomed to being regulated. Retrofit of existing power plants to cogeneration -- or construction of new cogenerating power plants -- would make the utility capable of producing thermal as well as electrical energy. Cogenerating the two forms of energy is a more efficient process than generating both of them separately. A major problem in the development of new DHC systems is obtaining enough revenue to cover the lean, early years of operation. This problem can be solved if a DHC system is the subsidiary of an electric utility, and provided due account is taken of the effect of the DHC system on the net-present-value revenue requirements of the parent company; DHC equipment, merged into the combined rate base of the two systems, can help pay DHC operating expenses in the early years -- without amounting to cross subsidization. Finally, electric utilities, because of their experience in the energy business, would probably inspire greater confidence among potential system investors and subscribers than would most other types of DHC proprietors.

Three of the basic components of a DHC system -- an energy-production system, a distribution system, and the in-building equipment customers use -- need not be under the same ownership. A municipally owned incinerator may supply thermal energy to a utility-owned distribution system; or a utility-owned cogeneration plant could supply a municipally owned distribution system. Sections 201 and 210 of the Public Utility Regulatory Policies Act (PURPA) encourage development of nonutility-controlled cogeneration by requiring electric utilities to purchase electricity from such qualifying facilities -- and by requiring them to base their payments for the electricity so purchased on their own avoided operating costs. The thermal-energy output could be sold wholesale to a DHC system. So long as there is some review of the contract between the energy producer and the DHC system to ensure that the latter is not overpaying, there is no strong reason why an energy producer should be regulated solely because of such sales.

Line extensions to individual buildings and in-building conversion equipment constitute important components of DHC systems. Regulatory policy on how the costs of this equipment are to be allocated and, if allocated to system customers, how payments are to be made, can affect a DHC system's ability to attract customers. In general, a system has two options: to make DHC service economically attractive to customers by spreading all extension and possibly in-building equipment costs to all customers, or else to set lower general service rates and require each customer to pay the full cost of his own hookup.

Many DHC systems will use energy from cogeneration facilities. Because joint production of electricity and heat is more efficient than separate production, benefits as well as joint costs must be allocated to purchasers of the two energy outputs. An allocation procedure favorable to a DHC system would be to consider the thermal energy output as an addition to a baseload electrical power plant. Then the incremental costs and benefits could be allocated to the purchasers of thermal rather than electrical energy. That is, the condition of the utility's electricity customers would be the same whether or not a DHC system existed.

A DHC system that serves customers with different consumption patterns or heat-quality needs should group its customers into different classes. A rate structure based on the traditional criterion of cost of service may not be advantageous for DHC systems -- especially during their early years of operation, when capacity may be less than fully utilized. In such a situation, the marginal cost of DHC service could be less than its average cost; and this would probably cause a DHC system to lose or be unable to attract customers whose alternative energy sources are priced below the DHC average cost but above the marginal cost. Classifying customers on the basis of their respective opportunity costs and elasticities of demand, and using a value-of-service procedure to set rates, could circumvent these disadvantages.

The development of new DHC systems and the revitalization of old systems can provide direct benefits to society from greater energy efficiency and reduced consumption of scarce and imported fuels -- as well as indirect benefits from enhanced employment and the maintenance and rehabilitation of urban areas. Therefore, it would be valid for legislators and regulators to take actions that would encourage the development of district heating. This report focuses on regulatory issues and possible actions to remove -- or to avoid imposing -- unwarranted regulatory barriers to such development. Of equal if not greater importance are actions to provide financial assistance or incentives to DHC systems. However, there was a strong feeling among those interviewed during the course of preparing this report (see Acknowledgments section) that such assistance should not come in the form of cross subsidies from the customers of electric or gas utilities. The assistance would have to come in the form of tax credits, loan guarantees, or other financial incentives, all of which are beyond the scope of this report.

STATE AND LOCAL REGULATION OF DISTRICT HEATING AND COOLING SYSTEMS: ISSUES AND OPTIONS

ABSTRACT

This report investigates basic questions pertaining to public regulation of district heating and cooling (DHC) systems. Any such system not completely contained within a single tract of privately owned land, or which makes retail sales of thermal energy, may be subject to the same sort of state regulation that electric and gas utilities receive. Many states apply traditional utility regulation to DHC systems, especially those that are investor-owned. State regulation of an energy utility usually establishes pervasive control over the utility's basic activities: its entry into a market, construction (though usually not siting) of its facilities, its service rates and revenue requirements, the quantity and quality of service it provides, and the conditions under which service may be abandoned. Some states, however, take less traditional approaches to DHC regulation -- including nonregulation, less regulation for DHC than for electric and gas companies, and DHC regulaton on a case-by-case basis. These approaches are examined to determine how each affects the startup of new DHC systems, the revitalization of old systems, and development of both. The report also addresses a variety of possible ownership arrangements for a DHC system and its main subsystems, as well as a variety of cost-allocation procedures that can be employed by a company cogenerating electrical and thermal energy. Material appended to the report backgrounds DHC operations in several European countries and presents U.S. case law and recent state legislation pertaining to DHC regulation. The authors view district heating as a socially useful technology that can reduce U.S. consumption of scarce and imported fuels, and they argue in general that appropriate DHC regulation is one means of helping the technology become established and expand. They recommend no specific regulatory approach, however; instead, they seek to clarify issues and present options on which decisions about DHC regulation can be based.

1 INTRODUCTION

District heating and cooling (DHC) systems are thermal-energy systems that produce hot water or steam and carry it from one or more central production stations to service the energy needs of commercial, residential, institutional, and industrial users. The DHC thermal loop allows heat (measured in Btu), as distinguished from fuels, to be bought and sold within the community. A system may be small-scale and serve hospital complexes, educational facilities, shopping centers, and dense residential developments; or it may serve large sections of a city. The specific characteristics of a community determine how a successful DHC system can be developed. Whatever those characteristics, a DHC system should have two guiding purposes: to fully utilize local energy resources, especially renewable fuels, and to strike a desired balance among the community's economic, social, environmental, and energy goals. Financial and regulatory mechanisms can be used to advance a system's ability to satisfy these purposes.

1.1 DHC SYSTEM COMPONENTS

Four fundamental components, or subsystems, are typically required in a DHC system: a resource system, a central plant system, a distribution and storage system, and an end-use system.

Resource System

The resource component of a DHC system concerns the supply of the primary fuel. Use of multiple fuels is possible and may be desirable. The primary fuel or energy resource may change over time, as the system grows and matures; or it may vary by season and time of day, as loads change and the energy streams fluctuate. A spectrum of fuels -- ranging from scarce oil or natural gas to abundant or renewable sources of energy such as coal, solid waste, or geothermal energy -- can be used. Integration of technologies in a DHC system offers considerable potential for substituting abundant or renewable sources of energy for scarce fuels.

Central Plant System

This component converts primary resources into usable forms of energy -- electricity, steam, or hot water -- that are transported to end users. Although electricity is not transported by the DHC system's distribution component, it may be produced in the central plant through cogeneration. This is a method of significantly raising the total useful energy output of the process of generating electricity. Depending on community needs, the central plant system can be one centrally located plant or several interconnected, strategically placed facilities.

Distribution and Storage System

This component distributes, through a network of pipes, the thermal energy produced in the central plant to end users in the community. The pipes can be contained in pipe tunnels or concrete culverts; they can be directly buried; or they can have an above-ground configuration. Systems that serve heavy space-cooling requirements and high-density commercial or office buildings can distribute either hot or chilled water, according to seasonal need. Storage capacity may be incorporated into the distribution system if the thermal-demand profile does not coincide with the supply profile. The economics of the distribution system are important in determining service areas of new or expanding systems because the specific distribution cost decreases appreciably with increasing load density.

End-Use System

The final component of a DHC system is the end-use system. This system includes line extensions, from the distribution component, and in-building conversion equipment. Both of these equipment types place the actual thermal load on the DHC system. The owner of the DHC system must provide thermal-energy services at rates that can attract and hold subscribers. Those rates should be "price-stable;" i.e., subscribers should be able to expect that their energy expenditures will represent a relatively constant share of their budgets. When thermal energy is priced competitively, subscription may be attractive to individual building owners because it can save building space -- fewer boilers and less associated equipment are needed -- as well as reduce maintenance costs.

1.2 OVERVIEW OF THE REGULATORY ISSUE

The preceding discussion indicates that a DHC system requires large expenditures for capital equipment and special use of land for the distribution system. The general concern in such a situation is that unrestrained competition might result in woefully inefficient use of capital equipment, with this inefficiency precluding the advantages of economies of scale. A duplication of services may lead to ruinous competition. At the opposite pole is the situation in which a single supplier can dominate the market and force customers to pay an unreasonably high price for energy service. Both conditions deprive customers of fair and adequate service at a reasonable price. In response to these potential inefficiencies and inequities, state legislatures decided to regulate sales of certain forms of energy and certain fuels to the public, along with telephone and transportation services.

Regulation of public utilities, especially energy utilities, involves complex questions of economics and engineering. Legislatures have therefore established public utility commissions (PUCs) and have delegated to these agencies the authority to supervise public utilities. PUCs have broad powers to implement public utility statutes, and courts usually defer to their expertise on factual issues. However, because PUCs are bound by the provisions of their enabling statutes, courts will more readily overrule them on matters of interpretation, or construction, of those statutes.

PUCs have authority to determine the need for new energy-production facilities, but they usually do not have jurisdiction over the siting of those facilities. Some states -- e.g., Washington -- do have comprehensive statutes governing the siting of energy facilities and have established siting agencies. In the absence of a comprehensive state statute, local governments, municipalities, and counties may restrict siting through their traditional zoning powers. A DHC system serving the public would usually need to lay its distribution piping under public ways. Therefore, in most states, the system would need to obtain franchises from municipalities and possibly counties. Finally, some states -- e.g., Minnesota -- give municipalities the option of regulating DHC systems. Thus, although a state regulatory agency and its enabling statute are the key regulatory determinants, other requirements may be present.

The arguments for full utility-type regulation of DHC systems are weaker than for other energy utilities, especially in regard to rate regulation. DHC systems are sparsely located, meaning there is little possibility of competition among DHC systems. Also, because of the high capital costs of starting up a new DHC system, it can be expected to have difficulty competing with established utilities, at least during its early years of operation. Thus, the market restraints on the price a DHC system can charge for its product may be more severe than the rate restraints imposed by a PUC.

While rate regulation is the primary instrument of traditional utility regulation, other instruments include limiting entry, limiting the construction of new facilities to those needed to provide adequate service, and specifying performance standards. A PUC can limit entry to those systems capable of providing safe, good-quality service. It can also help ensure that the system will remain in service and, if it does not, that customers will not be injured. It can provide a partly protected market for infant systems or rehabilitated systems. It can build customer and investor confidence. Thus, regulation can have positive effects on the development of DHC systems and should not necessarily be considered as an impediment to the systems. Additionally, of course, regulation is a tool for implementing public policy.

The questions, therefore, become whether and how DHC systems should be regulated. If regulation is decided upon, its exact nature must take into account the possibly conflicting needs of the three parties involved; namely, the proprietor of a DHC system, the system customer or prospective customer, and society in general. The DHC proprietor is faced with extensive initial capital outlays for startup, rehabilitation, or early-year expansion. Unless the proprietor is able to raise the required capital, DHC service will not be in place at the time when its competitive position could be the strongest -- i.e., when the costs of established energy services have increased greatly, owing to inefficient use of scarce fuels. The prospective customer, on the other hand, has no assurance that a DHC system will ever become viable, and he cannot be coerced into accepting DHC service. A customer does not want to pay increased rates or higher taxes to support a system that may become obsolete within a few years. Nor should society support a "white elephant," as one interviewee commented. However, there may be benefits to society from increased fuel efficiency (if the system produces heat through cogeneration) or from utilization of waste or renewable and indigenous resources to displace scarce fuels. Indirect but important benefits from the development of DHC systems include contributions to the maintenance of the economic and employment bases of urban areas. Appropriate regulation is one vehicle that can help achieve these societal benefits.

The cost effectiveness of a DHC system is extremely site-specific. A system can take advantage of cogeneration, waste incineration, industrial waste heat, or geothermal opportunities that otherwise would be lost.

Bearing these characteristics in mind, it is instructive to briefly set forth the four basic regulatory approaches that have been taken historically in various states.

1. <u>DHC systems are no different from other energy utilities and are therefore regulated in the same traditional manner as the others.</u> This view tends to reflect a legislative

choice made decades ago, before the era of inexpensive oil and gas -- and when DHC systems were relatively widespread in th U.S.

2. A case-by-case approach is used to determine how each DHC system can be regulated in order to meet the specific needs of that system and its customers with the least amount of administrative cost. This tends to be the approach of states with low urban densities and a consequently limited number of DHC applications.

3. DHC systems are not state-regulated. This approach is used where DHC systems distribute heat only within institutions for private use.

4. DHC systems are subjected to a minimum of regulatory restraints in the normal sense of utility regulation. This approach is taken in recognition of DHC as an alternative energy technology, as a prime means of using heat from the cogeneration process, and therefore as a means of promoting energy conservation and efficient use.

2 ISSUES AND OPTIONS

2.1 ASPECTS OF REGULATION

2.1.1 Introduction

This subsection addresses issues pertinent to the question of whether companies operating district heating and cooling (DHC) systems should be subject to traditional public-utility regulation -- perhaps including market entry and exit, rates, and service standards. These aspects of regulation may be comprehensive and plenary or may be limited to discrete components of a DHC system.

Before entering into a detailed discussion of regulatory options, it is important to examine the general perspective of state regulators. This perspective influences regulatory decisions that could critically affect development of a DHC system. The perspective is intimately related to the technical realities of DHC service.

Many regulators view DHC service as inherently restricted to industrial or institutional settings -- and DHC systems, therefore, as discrete, compact, and generally self-contained. Because statutes define public utilities as entities that offer services to the "public," DHC systems dedicated to industrial and institutional applications are therefore normally not regulated. Systems that do not fit the industrial/institutional mold are often viewed as having been absorbed by general-purpose utilities. The latter receive no special regulatory treatment; at the same time, they are often examined on a case-by-case basis, the assumption being that each DHC system is unique and unlikely to be replicated.

An existing regulatory framework may needlessly inhibit a revival of interest in developing DHC systems. That framework is established by statutes, agency regulations, and case law; it subjects businesses "affected with the public interest" to regulation traditionally keyed to the ownership of the system and the nature of the subscribers. One of the assumptions inherent in the regulation of energy utilities, in particular, is that such utilities are natural monopolies and that, consequently, the prospect of destructive competition must be foreclosed. However, rapid inflation in the costs of fossil fuels and utility property during the 1970s has led to a reappraisal of the reasons for regulation, particularly when there is room in the market for alternative energy resources that may benefit energy consumers and society. The startup needs of a system using alternative energy sources, as well as the benefits possibly derived from such sources, may require redefining the character of regulation. Factors to be considered in such a redefinition include type and size of fuel sources; their effect on competition within a particular market; and the possible benefits of using those sources to strengthen a local economy, add to the number of local jobs, or maintain and enhance a community's building stock. The components of a DHC enterprise should also be examined separately. For example, in some situations it may be appropriate to regulate the distribution component of a system, while allowing the generation component to compete freely in the marketplace.

For regulators, proprietors of DHC systems, and DHC customers alike, the question of what degree of regulation to impose -- if any -- is complex. It is facile to conclude that regulation is always disadvantageous to the industry or that DHC systems will have their best chance to thrive in an unregulated market. A business starting up may have an easier time meeting its critical needs of attracting capital and subscribers if it has the relative security that may be attained through regulation. On the other hand, the cost of transactions and the limitation on rates of return associated with regulation could have the effect of dampening development. These factors must be analyzed in conjunction with the more traditional regulatory considerations in order to make three judgments affecting the balanced best interests of all parties: whether any utility-type regulation is needed, and, if so, what kind and to what degree.

2.1.2 Market Entry*

The initial device for regulating DHC systems is the exercise of franchising or similar authority to determine which entities, if any, may produce and sell steam or hot-water heating services.

The public power to control market entry can be exercised in four ways.

1. The most common approach is to require a DHC supplier to obtain a certificate of public convenience and necessity. This approach exemplifies the traditional method of regulating public utilities. The certificate of convenience and necessity generally confers an exclusive right and obligation to provide a particular type of service to the public. Generally, an applicant for a certificate has to make two showings: (1) that the proposed system would be in the best interests of the public; and (2) that the applicant is capable of meeting the obligations imposed by the certificate. Certification is common and perhaps desirable when a natural monopoly is present; but where competing forms of thermal energy are available, such a requirement may be inappropriate, especially for systems that propose to replace scarce fuels with those that are more available or more efficient. The certification process may also be unwarranted with respect to a DHC system that in no way threatens existing energy suppliers. In fact, increased competition could benefit consumers by applying competitive pressure on existing utilities to upgrade their performance. On the other hand, it may not be in the economic interest of a community for a DHC system to lay pipes parallel to existing gas pipes when the gas utility can provide thermal services with its existing system at very low marginal cost.

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*The related issue of market exit will be discussed as a consumer-protection issue in Sec. 2.4 of this report.

2. A less strict entry-limiting alternative uses service standards as the certification criterion. Under this approach any system that can demonstrate an ability to meet customer needs, within reasonable standards of safety and reliability, would be allowed to operate. This method alleviates the burden generally associated with certification and franchising but retains control over the quality of service by establishing a threshold test that must be met. The establishment of minimum service standards, by discouraging marginal systems, should provide a net benefit in the area of consumer protection and environmental quality. Many standards already exist. For example, even in the absence of specific public-utility regulation, DHC systems must comply with applicable federal boiler-safety and pipe-laying standards.

3. Even less restrictive than the use of service standards is the establishment of reporting requirements. This is not a regulatory device in the sense that entry may be barred or granted, but as a monitoring scheme it does provide some public supervision of a DHC system's operations.

4. For those jurisdictions where the primary DHC issue is whether such a system will have an adverse impact on the environment, the use of siting laws for energy facilities is an appropriate alternative to normal utility regulation. To gain market entry, a DHC system must demonstrate negligible adverse environmental impact. This can prove to be an awesome obstacle in some cases, but it is often seen as a reasonable and productive path to follow.

The absence of enabling legislation can preclude market entry to systems owned by local units of government and similar public entities. For example, in the absence of a plenary home-rule grant of power by statute or state constitution, municipalities are limited to those activities enumerated in their enabling statutes. Thus, if its enabling statute does not explicitly allow a municipality to own or operate a DHC system, it is likely to be precluded from doing so. Even where such authority exists, there may be uncertainty as to whether extra-territorial customers can be served and whether several municipalities may jointly own and operate a system. A recently introduced bill to remove uncertainties of this kind in the State of Washington is discussed in Appendix C.

Many unregulated DHC systems operate completely within the boundaries of university campuses or hospital complexes. Some of these systems may be able to sell heat profitably for use in nearby loads. However, if the university or hospital is state-owned, its enabling statute may not allow such an activity, which is not normally considered ancillary to its primary mission. Thus, state legislatures may wish to consider broadening the enabling statutes of state departments and instrumentalities to remove impediments to sales of excess heat from DHC systems under their control. For example, the State of Illinois has recently broadened the enabling statute for state universities to permit sales of excess heat from university-owned heating plants. (Appendix C also contains a brief description of this Illinois action.)

2.1.3 Rates

Regulating DHC rates has great impact on two basic problems facing a DHC system, namely, how to attract capital (or investors) and how to attract subscribers. Even when the market-entry problem is resolved, the inability of a system proprietor to charge customers reasonable rates and to allow investors a fair return on capital will render all other questions moot.

There are two primary methods of regulating utility rates. The first is to regulate the revenue that the utility will receive for providing its service. This is generally done by regulating profit, or the rate of return on capital invested in the entity by its owners. The second method is to allocate the total costs of the utility service among the several classes of customers or types of service. For DHC systems utilizing cogeneration facilities there is an additional task of splitting the capital and operating costs of those facilities between thermal-energy and electricity customers. Allocation issues are discussed in Sec. 2.2 of this report.

The issues confronting the regulator are complex. A DHC system should be allowed sufficient revenue to attract investment without discouraging subscription. A new DHC system will have capital equipment bought with devalued dollars (owing to inflation) compared with the cost of old capital equipment of established energy utilities. For a system to be competitive, therefore, it must burn fuel more efficiently or burn fuels whose cost is not expected to escalate as rapidly as fuels burned by the established utility. A proposed DHC system that would not be cost-effective over its life cycle should probably not be built. Even a proposed DHC system that may be cost-effective over its life cycle might need assistance, or subsidies, during its early years of operation, before the cost of fuels burned by competing facilities has fully escalated. The assistance may take the form of regulatory incentives or, at the state or federal level, financial subsidies such as tax credits and loan guarantees. (Without reflection on the importance of non-regulatory actions that promote the development of DHC systems, such actions will not be analyzed here because they are outside the scope of this report.)

Regulatory incentives designed to assist marginal DHC systems, or systems facing difficulties because of high startup costs, are limited. One possibility is to include cost of construction work in progress (CWIP) in the rate base, even though property under construction is not generally considered "used and useful" in the regulatory context. However, to include this cost might raise rates to the point of making DHC service unattractive to customers.

When a DHC system is part, or a subsidiary, of a combined energy utility, the DHC property can possibly be merged into the total property or rate base of the combined utility. As demonstrated in Sec. 2.4, this merger need not involve cross sudsidization of DHC customers by customers of the other services. A DHC system, by supplying a portion of a community's total demand for thermal-energy services, should displace to some extent the need for future additional thermal capacity by other suppliers -- thus benefiting the customers of the other suppliers. It should be possible for regulators to develop a mechanism enabling a DHC system to take credit for such displaced or deferred capacity additions. One such mechanism could be based on Sec. 210 of the Public Utility Regulatory Policies Act (PURPA), in which a qualifying facility receives a capacity credit if the electricity it sells an electric utility allows that utility to defer or eliminate the construction of a new power plant.

A standard rate for DHC service simplifies the regulatory process and offers potential investors a firm pricing signal upon which to base their decisions. The glaring inadequacy in this approach, however, is its inflexibility and its potential for inequities. The line between feasible and infeasible projects may become too harsh and arbitrary, especially when considering the public benefits that may accrue from the exploitation of new energy sources. A rate scheme that would be advantageous to the proprietors of a DHC system would be to base the price they can charge for service on the marginal costs they pay for alternative energy supplies. (For DHC service rates to be competitive, the fuel prices a system pays to its suppliers would also have to be based on marginal rather than average costs of producing the fuel.) The adoption of such a pricing scheme might be appropriate during the early years of DHC operation, but it might have to be reviewed for the possibility of windfall profits when the system becomes mature.

A more flexible method of regulating DHC service rates is to establish a sliding rate scale with maximum and minimum prices that can be charged. This approach can better represent costs paid to the supplier and rates charged to the customer, but it still may not be accurate because of the rigidity of simply having an upper and a lower level. Again, rate regulation will depend on the regulator's view of DHC systems; i.e., whether they should be encouraged and therefore given some incentive, or whether they should be regulated in the same manner as producers of conventional energy.

DHC service prices can also be established by free market forces, with a supplier and a consumer negotiating a mutually satisfactory price. This approach appeals to large customers such as major manufacturers, which may have strong bargaining positions and may also desire the certainty of a long-term contract rather than a rate subject to periodic change by a public utilities commission (PUC). When the customers of a DHC system, on the other hand, are predominately residential, it may be more appropriate to have PUC regulation of rates -- such customers are usually not in a position to bargain effectively especially after their buildings have been hooked into a DHC system. The issues here are closely related to those used in determining whether a DHC system is a public utility subject to regulation; however, depending on the nature of the system, there may be reasons to retain PUC supervision yet still allow the parties to negotiate rates.

2.1.4 Customer Protection and Service Standards

Another major area of regulation concerns the standard of service that a customer can expect from the DHC system or that the system can be held to by the customer. There are, of course, general safety and technical standards that the state will enforce as market-entry criteria -- these do not directly affect the customer-system relationship. The pertinent customer-protection issues are hookup policy, reliability of service, and continuity of service (abandonment policy).

Hookup Policy

Hookup involves line extension, in-building equipment, and the issues of conversion equipment. It is a prime area for flexible and creative regulation. The regulating body can choose to leave the problems to the negotiating skills of the parties involved, or it can take a more active role to foster the growth of a DHC system.

Line extension is usually approached in either of two ways: the customer pays a flat cost for the extension, or the utility recovers the cost of all extensions as an operating expense factored into its rate. The cost of extension is usually computed in one of two ways: (1) on a per-foot basis for the actual extension, or (2) on a foot-frontage basis regardless of the extension's actual length. The problem with DHC main-line extensions is that the large costs involved in laying pipe can discourage potential users if they are liable for the full costs. Regulators therefore are faced with a dilemma: they can make the service more initially attractive to a customer by spreading all line-extension costs to all customers, or they can impose lower general rates while requiring each customer to pay his own full cost of hookup.

The most attractive and equitable solution may have to come in a financing rather than a regulatory context. This would involve subsidizing the cost of distribution equipment in some form such as low-interest loans, possibly with a concurrent user's fee or surcharge to be levied against the customer over a long period. The problems with in-building conversion equipment are parallel to those of line extension and can be addressed similarly.

Reliability of Service

Reliability standards are particularly important in two situations. The first involves the consumer's expectation of service at a continuous level. This can be regulated by establishing capacity standards to ensure that the system can meet its peak demand, with appropriate arrangements for backup and supplemental power. The second involves the reliability of thermal-energy sales from small producers to the larger distributor. Standards in both cases will affect the economic feasibility of DHC service.

The current problem with DHC service is limited demand, forcing the sytems that do operate to be self-contained. This means a system must meet its peak demands strictly with its own capacity, because there are no pools or exchanges available. Such a situation creates the possibility of extreme wastefulness through unused reserves. There are several ways to alleviate this problem. The DHC system could be allowed to offer interruptable rates. This would shift some of the requirement for reserve capacity from the system to the individual subscriber. The system could be encouraged to have supplemental energy-production facilities available for its needs, perhaps by contract with local industries. A planned, phased development of the system could also reduce unused reserves.

Continuity of Service

The establishment of an abandonment policy is crucial to the success of an infant DHC system; without the element of certainty about continued service, which such a policy provides, many potential users will not buy the service because of its inherent risk. Hard questions of who must bear the costs of supporting a system suffering financial losses must be answered. Some specific questions are: should the state subsidize the system? should system customers be forced to pay higher rates? should owners be forced to keep the system operating at negligible profit levels, or even losses, and be offered tax and credit deductions as compensation? should the state step in to operate a less-than-profitable system?

Regulators who have dealt with aging DHC systems are familiar with abandonment issues. Their response has often consisted of an attempt to balance all factors in a particular situation; e.g., the remaining financial resources of the DHC system, the cost to customers of converting to alternative heating systems, the size of the territory, the size of the system, the availability of a buyer for the system, and the composition of a system's customer group. Often, regulators have had no choice but to allow the inevitable liquidation of a bankrupt system. On other occasions, however, regulators have been able to assist in the recovery of hard-pressed DHC systems by approving unusual financing schemes. Another option has been utilized in a limited number of situations: regulators have required a failing DHC system to subsidize, out of its liquidation proceeds, the costs to its customers of converting to alternative heating sources. This is not always an attractive alternative because its prospect increases risk for investors and therefore discourages them from providing capital to keep the system alive.

2.1.5 Miscellaneous Issues and Options

As in other industries in the energy area, many issues of utility operation lie beyond the jurisdiction of utility commissions because of the segmented nature of government-agency jurisdictions. The most notable issues of this sort involve ownership, environmental, and zoning matters. Many other regulatory options do not fit within traditional utility-control concepts. These include the market-control devices used in PURPA and the concept of generation and distribution systems being jointly owned by public and private entities.

The matter of ownership is pertinent to the basic generic issue of whether DHC systems should be regulated at all. Three different ownership situations suggest somewhat different approaches to the necessity and appropriateness of DHC regulation: (1) investor-owned systems, (2) cooperatively owned systems, and (3) municipally owned systems. The focus of the ownership issue is the balance of bargaining power between the DHC system as a seller of services and the customer group as a collective buyer of services.

The rationale for subjecting a system to regulation is strongest for an investor-owned system (IOS). The IOS serves two interests that may not always be consistent: the interest of investors in maximizing rate of return and the interest of customers in reasonably priced, safe, and reliable service. The regulator may be viewed as the party that balances and, to the extent possible, reconciles these competing interests. Other factors also bear on whether an IOS should be subject to regulation. These include whether other activities of the company are already regulated and whether the IOS needs to maintain or add to its number of customers and to the classes of customers it serves. It can readily be ascertained that these factors affect the relative bargaining power of buyer and seller. To the extent that market forces create a situation where there is relative equality of bargaining power, regulation would appear to be neither necessary nor appropriate. Where the market lends itself to monopolistic abuses, however, regulation is a recognized method of achieving some balance between price and service.

The rationale for regulation is weaker for cooperatively and municipally owned systems. In those ownership situations a closer proximity of interest between buyer and seller exists, making the two interests consistent with each other. A cooperative is controlled by its customers and a municipally owned system is owned by the municipality's taxpayers, who may closely approximate the system's subscribership. To the extent that these interests actually overlap -- i.e, the price and quality of service approximate what they would be in a competitive market -- regulation is neither necessary nor appropriate. Thus, the focus of inquiry is to ascertain the anticipated effects of price and service factors in a DHC market -- and whether those effects will tend to serve the balanced best interests of a system and its customers or, instead, create an inequitable, monopolistic situation.

Whether a DHC system will have a beneficial or a harmful effect on air quality depends on a variety of factors -- e.g., the location of fuel-burning facilities, types of fuel burned, and effectiveness of pollution control at DHC facilities and at facilities that the DHC system displaces. When there is a favorable environmental impact, it would be appropriate to expedite the process by which a DHC system gets environmental permits -- or even to exempt the system from environmental regulation.

DHC systems are generally subject to local regulation in the form of zoning ordinances, building and housing codes, and franchising requirements. The energy-production facility will have to be located in an appropriately zoned area, and franchises will have to be obtained enabling the distribution system to use public ways. The zoning requirement should present no obstacle to DHC systems that serve industrial plants, and the franchise requirement should present no difficulty unless another utility has an exclusive franchise or unless the granting of a franchise depends upon public-utility status. Building and housing codes should introduce no problems so long as there are standards for the in-building conversion equipment.

If local regulation inhibits the development of DHC systems, the potential for energy efficiency and scarce-fuels displacement by such systems may prompt a state legislature to preempt local ordinances in favor of a comprehensive plan.

2.1.6 Conclusion

Applying traditional utility regulation to a DHC system may be inappropriate. The inflexibilities and uncertainties of such regulation may inhibit development of the system. On the other hand, because DHC systems do offer important potential benefits -- by substituting for scarce and imported fuels those that are renewable and more readily available, by centralizing and thus facilitating better environmental control of the fuel-burning in an area, and by creating jobs and revitalizing a local economy -- it would be valid public policy for a state to encourage them.

This encouragement could take nonregulatory forms such as subsidies or tax credits. It could also take the form of a regulatory scheme that would either remove or refrain from imposing unnecessary impediments. The scheme most beneficial to DHC system development would include making market entry as painless as possible, by limiting restrictive standards to health and safety considerations and thereby reducing the transactional and administrative costs associated with the regulatory process. Once entry is assured, there must be a reasonable expectation of a market for the service, and the expectation must be based on selling thermal energy at competitive prices. Competitive prices are essential for two reasons. First, mandatory hookup is probably not feasible. Second, it is unlikely that a DHC system would be able to achieve a monopoly position. This pressure for competitive prices should preclude the need for regulating DHC rates beyond the possibility of setting minimum and maximum service charges keyed to the prices of other thermal-energy sources. Consistent with this general approach, service standards could be negotiated by the system and its customers. This would allow system flexibility while maintaining customer protection by means of a regulatory commission's power to inspect DHC facilities -- and a customer's right to petition the commission regarding any grievances.

The preceding is a general outline based on typical DHC systems. Each system will have site-specific functions and other special characteristics that will affect the regulatory response. Regulatory commission flexibility and foresight are needed if the development of DHC systems is not to be unduly inhibited.

2.2 ASPECTS OF COST ALLOCATION AND RATES

2.2.1 Introduction

This analysis of certain aspects of cost allocation and rates is intended as a summary rather than an exhaustive review of the issues.

The issue of allocating DHC capital costs and operating expenses applies only to a system relying on a dual-purpose, or cogenerating, power plant. "Basically, the question involved is to determine the portions of jointly used facilities that are devoted to steam heating and electric-utility functions and properly assignable to each, and the allocation of (operating) expenses associated therewith."*

The method of allocation chosen determines the costs and expenses assigned to thermal service. Those costs and expenses are in turn reflected directly in the rates charged to customers of the thermal service. And it is the level of these rates that ultimately determines whether or not DHC thermal service is competitive in the market with other alternatives available to actual or potential customers. Thus, cost and expense allocation is one of the most important determinants of the commercial viability of a DHC system that relies on a cogeneration plant.

The procedure of cost allocation concludes with a determination of the total amount of revenues that must be recovered from DHC customers through service rates. Another important set of issues involves the structure of these rates as differentiated from their level. The structure of rates should reflect the technology of the physical plant and such market conditions as the prices of alternative fuels, customer and system load factors, customer diversity, and system reliability. The rate structure should also reflect the conditions of the market in which the cogenerated electricity (if any) is sold. A well designed rate structure is important because it helps to ensure that each customer pays an equitable portion of DHC system costs -- and that each customer decides whether or not to initiate or continue to take service on the basis of rates that accurately reflect the actual pattern of demand and the burden of costs imposed on a DHC system by that demand.

The analysis below is organized as follows. First the issues of capital cost and operating expanse will be discussed and analyzed, and the advantages and disadvantages of each of several approaches will be examined. Second, the issues of rate structure will be discussed. Primary emphasis is placed on the identification of the nature of costs and market factors and their proper reflection in rates.

2.2.2 Capital Cost and Expense Allocation

The allocation of the capital costs and operating expenses between the thermal and electrical energy streams produced by a cogenerating power plant is the primary step in the formulation of a DHC system's revenue requirement, determination of the cost of its service, and thus it ultimate rates. To some extent, cost-allocation procedures are an accounting function. The uniform system of accounts used in any particular jurisdiction probably prescribes methods of allocating the common administrative and overhead costs of, for example, integrated gas and electric utilities. It is expected that the system of accounts could similarly handle an allocation of these types of general expenses for a DHC system integrated with an electric utility.

At the same time, each individual cogenerating power plant and DHC system will almost certainly exist under a unique set of technical, economic,

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*Public Service Commission of Wisconsin, Docket 2-U-7131, cross-examination of William Torkelson, Transcript 186, August 1971.

and regulatory circumstances. This means that economists and engineers should be responsible for allocating capital costs and operating expenses of the plant itself.

It should be recognized at the outset that the existence of a cogenerating power plant or a DHC system does not necessarily mean that an allocation problem exists. Allocation will not be an issue, for example, at a DHC system that generates steam in a thermal-only plant or at one that purchases steam from an industrial firm. A DHC system that sells wholesale cogenerated electricity to an electric utility may also avoid an allocation problem because the revenues derived from the electricity sales will leave a pool of expenses that must be recovered from thermal sales. Thus, the allocation problem will have been implicitly solved. In broad terms, it can be said that capital cost and operating expense allocation is an issue requiring regulatory action when a regulated entity is retailing two energy streams produced in the same plant with common equipment.

Nature of the Issue

In general terms, there are two types of costs incurred in the construction and operation of a cogeneration plant: separable costs and joint costs. Separable costs are those that are easily attributable to one or the other output. The easiest way to distinguish these separable costs is that they are unmistakably matched with one of the outputs and would not have been incurred if that output were not a product of the plant. Separable costs directly assignable to electric service include the turbine-generator equipment. Separable costs of the thermal service include such things as steam-extraction piping, associated equipment to regulate the pressure of steam, and piping that connects the plant to the thermal-distribution system.

Joint costs cannot be easily attributed to either of the plant's outputs, and these costs would still be incurred if either were to be eliminated. Joint costs arise from technologically integrated production processes of the plant's two outputs. Joint capital costs include such things as land, boilers, fuel-handling equipment, feedwater-treatment facilities, and environmental control. Fuel represents the major portion of the joint operating cost, but this cost also includes ash handling and disposal and other common operating and maintenance expenses.

Economic theory does not require that costs be allocated in order to set prices for joint products. Rather, it says that the price for each product should be set so that it equals that product's marginal cost. Determining the marginal cost of each output, however, is not a simple matter. In addition, it is highly unlikely that a rate set at marginal cost will produce a pool of revenues equal to the regulated utility's revenue requirement.

The need for a cost allocation stems from the precondition that a regulatory body bases utility rate levels on the utility's revenue requirement. Thus, a cost-allocation process is necessary for determining the fair and equitable share of the total revenue requirement that each class of customer should pay.

The economics of technically integrating a cogenerating power plant suggest another perspective from which to view the cost-allocation problem. The reason that a cogenerating plant is built is that such a plant reduces costs below those that would be incurred to produce the same outputs at separate plants. Any cost-allocation process, while directly assigning costs to each cogenerated output, also implicitly allocates these cost savings to each of the two outputs. Therefore, it is important to realize that any cost allocation is also a benefit allocation, the benefits being the economies of joint production.

Three groups potentially reap the benefits of a cogenerating power plant: purchasers of electricity, purchasers of thermal energy, and owners of the plant. One method of using these benefits to enhance the viability of a DHC system would be to allocate them only to the plant owners and the purchasers of thermal energy -- and not to allocate them to the purchasers of electrical energy. That is, the condition of the utility's electricity customers would be the same whether or not a DHC system existed.

Economic and Technical Considerations

Any allocation process must start with a thorough analysis of the technical relationship between the thermal and electrical capabilities of the plant and of the market economics affecting its two outputs. The purpose of this analysis is to determine what the production of one product costs in terms of forgone output of the other product -- in short, how the cost of producing one product affects the cost of producing the other.

The main technical question here is to what degree the electrical and thermal loads overlap. A related aspect of the question is whether the seasonal and diurnal capabilities of the two systems can meet their respective loads. Answers to these load questions require an analysis of present and projected capacity needs of the electric utility, especially to determine if there will be too much or to little capacity. A specific factor in such a determination is how the reliability of the electrical system would be affected by a reduction in electrical generating capacity caused by the nature and timing of thermal-load requirements. Reducing electrical generating capability during the winter because of the thermal load may not impose any cost on a summer-peaking utility -- the capacity displaced by the thermal load may not need to be replaced.

A cogeneration power plant supplying a thermal load will usually become a "must-run" plant. That is, it may be removed from the normal order of economic dispatch and be fired before other plants with possibly cheaper generation. In this case, the system's thermal-load requirement may cause fuel costs for the electrical system to be higher than they would have been without that requirement. The cost differential needs to be allocated to the system's thermal customers.

The existence of a must-run plant will also probably affect maintenance scheduling at the electrical system plants. A thermal load that consists of space heating may mean that the plant would not be able to shut down during the low-loading times in fall and spring. Thus, the utility may need to cover this maintenance period with short-term purchases or high-cost generation.

It should be stressed that the cost to an electrical system of a thermal load is the cost of building or purchasing enough additional capacity to give the electrical system a level of reliability equivalent to what it would have without the thermal load.

Some Allocation Methods

A cost-allocation procedure incorporating this logic was proposed by the Wisconsin Electric Power Co. for a new cogenerating plant built in downtown Milwaukee in the late 1960s.* The company contended that the main purpose of the plant was to provide capacity for electrical generation and that the plant's location was chosen to provide for greater reliability of service in the downtown area. It was therefore argued that only those additional capital costs required for the plant to provide steam to the existing heating network should be allocated to the heating utility. That is, Wisconsin Electric Power costed the plant both with and without the additional thermal equipment and proposed allocating only the incremental cost to the heating system. What makes the method logical in this case is that the electric utility has a strong summer peak and has excess generating capacity during the winter heating months. Therefore, the boiler capacity used by the heating system added no opportunity cost to the electrical system. This incremental approach led to all capital cost savings being allocated to customers of the heating system and none of those savings being allocated to customers of the electrical system.

Such an incremental cost-allocation procedure, when used in appropriate circumstances, is the best method of enhancing the economic viability of a DHC system. It is also logically consistent to argue that all of the capital cost savings should be allocated to the DHC system because the savings themselves would not exist if the DHS system did not exist -- and the DHC system may not be viable unless it gets the savings.

Another method of allocating capital costs and operating expenses is known as the "use-of-facilities" method. This procedure is an engineering approach to cost allocation, and it has many variations. Basically, it involves calculating the percentages of thermal energy used for electrical and DHC purposes. These percentages are then multiplied by the total capital costs and operating expenses to produce a final cost allocation in dollars. For example, if the analyst calculates that 30% of a plant's thermal energy is used for producing electricity, then 30% of the total costs would be allocated to electricity generation and 70% to district heating.

This method is simple and relies on readily available data. However, it is based on engineering considerations that may have no basis in economic concepts of cost. In addition, equally logical variations of the method lead to widely varying results. For example, the cost allocated to producing electricity will depend not only on the quantity of thermal energy used for this purpose but also on the quality (temperature, pressure) of that thermal energy. Therefore the effect of this methodology on the economic viability of a DHC system is difficult to predict.

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*Public Service Commission of Wisconsin, Docket 2-U-7131.

The alternative-justifiable-expenditure (AJE) method of cost allocation was originally devised for public works projects and has been investigated as a utility cost-allocation procedure by Ernst & Whinney. Basically this method involves an examination of alternative methods that could be used independently to provide equivalent electrical and thermal energy. The cost of the least costly alternative for each would be the upper bound of cost allocated to the respective outputs. From the standpoint of enhancing the economic viability of a DHC system, this procedure is especially attractive when the alternative sources of supply are purchased in the market place. That is, the value of the electricity produced (and thus the upper bound of its share of costs) would be the price of bulk power in that locality. The method may also diminish the viability of a DHC system, however, if electricity is priced at average cost rather than marginal cost. In addition, the AJE method predicts only the bounds for cost allocation rather than providing a definitive solution. This could be turned to the advantage of a DHC system, however, because any excess cost savings could be allocated to it. The AJE is of interest because, unlike the other methods, it examines opportunity costs.*

Numerous other methods can and have been used to allocate joint costs. However, most of these methods are not suited to the cogeneration application because they fail to take into account the factors of demand for the outputs and the opportunity costs of the output forgone when one or the other output is produced.

The Issue of Subsidization

The cost-allocation process, because it tends to be somewhat arbitrary, will lead customers of one service to plead that they are subsidizing other customers. These arguments can often be effectively refuted if the allocation process is performed carefully and with consideration for all factors affecting costs.

The question also frequently arises as to whether regulators should actively promote certain utility services such as DHC systems by allowing their costs to be subsidized by revenues from other utility services. In the present context, this would involve shifting some of the cost burden of the cogeneration plant attributable to the DHC system onto the electric system. This cross subsidization might be considered in order to assist the DHC system overcome high startup costs encountered during its initial period of operation. In addition, such a subsidy would reduce the riskiness of the project to the utility and enable it to acquire funds more easily.

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*For a detailed discussion of the use-of-facilities and AJE methods and other cost-allocation issues, see "Development of a Joint Cost Allocation Manual for Integrated Community Energy Systems" [ANL/ICES-TM-20 (Sept. 1978)] and "Development of a Joint Cost Allocation Manual for Integrated Community Energy Systems, Phase II" [ANL/CNSV-TM-33 (1980)] -- both reports were prepared for Argonne National Laboratory, Energy and Environmental Systems Division, by Ernst & Whinney.

However, there was a feeling among the interviewees that any cross subsidization (i.e., lowering the cost to DHC customers below that consistent with the specific allocating method used) would either be unwise or unlawful. An attempt by a PUC to allow it without a clear statutory mandate would undoubtedly engender litigation and intervention in rate proceedings by adversely affected parties. The specter of contested rate proceedings could act as a powerful disincentive to potential DHC system proprietors. Minnesota, which is encouraging district heating in a recently enacted statute that provides for state-financed bonds for municipal systems, has expressly rejected cross subsidization. (See Appendix C.) In fact, in the section of the statute concerned with cost allocations for cogeneration facilities, DHC subscribers are held responsible for increases in the cost of electrical generation arising from operation of the facility. For example, if the cogeneration plant is oil-fired -- and if, in the absence of the DHC system, electricity generated in the cogeneration facility would have been generated in a coal-fired plant -- DHC subscribers would be charged for any incremant in the cost of electricity caused by burning oil in the cogeneration facility rather than burning coal.

2.2.3 Rate Structure

Rates for DHC systems have received little attention in the public utility literature. However, focusing attention on improved rate-design principles and procedures is important for several reasons. First, a well designed rate structure can improve the ability of a DHC system to attract potential customers and retain existing customers. Second, an efficient rate structure can improve the profit potential for the owners of the system.

It is useful to consider DHC rates as a hybrid version of electricity and natural gas rates. Electricity rates provide a useful framework because electricity and thermal energy for DHC are both produced in central plants and must respond instantaneously to changes in customer loads. The only major technological differences are that electrical systems carry energy to system customers over wires and can tie together a network of geographically dispersed plants embodying multiple technologies. Natural gas rates provide a useful analogy in that the demand for thermal service, like that for gas, is probably elastic because of keen competition in the marketplace from alternative fuels -- with the elasticity of demand varying greatly between customers. Ratemaking principles and ideas developed in the context of electricity and natural gas thus can serve as a convenient starting point for the process of examining DHC rates. Among the useful concepts to examine are customer classes, cost of service, time-differentiated rates, interruptible rates, and fuel-adjustment mechanisms.

Customer Classes and Cost of Service

The generally accepted purpose of grouping electric and gas utility customers into various classes is to combine customers with like usage and consumption patterns in order that the costs associated with different consumptions patterns can be reflected more accurately in the utility service rates. A system of defining DHC customer classes, each with a homogeneous usage pattern, would probably be readily accepted by customers of a DHC system because classes are a familiar tool in rate design for other utility services.

The total cost of utility service (as determined by the utility's overall revenue requirement) is usually allocated between the various customer classes by means of a cost-of-service study. Rates for each class are established based on the results of the study. This type of rate-design procedure has many advantages for DHC use, the major ones being that it is familiar to utilities and regulators and that it provides well defined criteria for relating costs and rates. The disadvantage of the procedure is that it produces rates based on average historical costs rather than marginal costs.

This disadvantage becomes a definite problem for DHC systems because in the early years of a system's existence, or even after it has reached maturity, the system is likely to suffer from underutilized capacity (either seasonally or during higher load periods). This means that the marginal cost of providing additional service is probably less than the average cost. The system is therefore likely to either lose or be unable to attract customers whose alternative energy source is priced below the DHC average cost but above its marginal cost. The result is that the remaining customers must shoulder a larger burden, forcing even more customers to leave the system.

When the marginal cost is less than the average cost, classifying customers based upon their respective opportunity costs and elasticities of demand in order to effect some sort of price discrimination may be appropriate. This is usually known as value-of-service pricing.

Rates based on value of service do not necessarily mean that customers who pay the higher rates are being harmed. If the additional sales revenue caused by the lower rates to some customers more than covers the marginal costs of providing that service, then the low-rate customers are making a contribution to the fixed costs that would otherwise have been borne entirely by the high-rate customers.* High-rate customers can thus benefit from these sales.

Value-of-service pricing requires that customers be grouped according to elasticity of demand. This could easily be accommodated by grouping customers with a readily available alternative fuel capability together. In a sense, this is analogous to interruptible rates for natural gas, where customers with an alternate-fuel capability receive a lower rate because they take service only when the system has excess capacity -- when marginal cost is below average cost. Interruptible rates should be considered as a possibility for DHC systems to improve load factor and as a method of gaining customers who would not pay a firm service rate.

Value-of-service pricing would allow DHC systems to compete more vigorously in the market and result in more efficient pricing, when DHC capacity is underutilized, than fully distributed rates based on cost of

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*Alfred E. Kahn, The Economics of Regulation, John Wiley and Sons, Inc., Vol. I, pp. 130-158 (1971).

service. It could allow a previously "noneconomic" system to regain viability and offer regulators a tool to promote new systems. In some jurisdiction, however, rates based on value of service may violate discrimination statutes. Such rates are often misunderstood; some customers feel that the pricing method gives large customers an unjustified price break.

Time-Differentiated Rates

Time-differentiated rates have been advocated for utility services where the cost of providing them varies over time. In electrical systems, this has meant that costs, and thus prices, should be higher when generating capacity is scarce or when running costs are high. In DHC systems, this will also be the case, although fuel costs tend to remain relatively constant. In a system with a cogeneration plant, times when the opportunity cost of the boiler capacity is high, due to the need for electrical generation, are also times of relatively higher DHC cost.

Thus the basis for differentiating DHC rates according to time will depend on two relationships: that between the thermal load and DHC capacity and that between the opportunity cost of the boiler capacity and the electrical load on the plant.

DHC systems that rely on space-heating loads will face the greatest possibility of reaching system capacity in the winter months. In this case, some type of seasonally differentiated rate might be appropriate. The same type of rate may be in order for a system that is connected to an electric utility with a strong winter peak. The key point is that boiler capacity for either service is usually the limiting factor.

Time-of-day rates may be appropriate in certain circumstances. This would be true where thermal or electrical loads vary greatly over the course of the day and the plant has little load-following ability or must be kept in a "hot-shutdown" mode. Thus, a DHC system cogenerating with a cycling plant that generates little electricity at night may be able to provide thermal capacity at little cost during these hours. Time-of-day rates will depend on available metering technology and cost. For large industrial customers especially, such rates should be considered as a method of gaining marginal customers who could take advantage of off-peak service.

Technical Considerations

Rates for thermal service are usually based on some measure of delivered heat such as a Btu or pound of steam. These units are simple to measure, familiar, and readily comparable to those of other energy-producing systems.

DHC systems usually produce only at one temperature and pressure. However, multiple extraction systems that produce steam at different temperatures and pressures, and thus at different costs, should be considered in conjunction with determining a rate structure.

Other Considerations

Large customers of DHC systems often desire to enter into a medium- or long-term contract to purchase service. These are instruments enabling the customer and the utility to reduce their exposure to risk. Such contracts, however, may pose certain regulatory issues. If the DHC system is regulated, regulators must decide on the appropriateness of certain contract clauses, duration of a contract, and whether regulatory approval is required for contract validation. In some respects these contracts are desirable even from a regulatory standpoint; on the other hand, the point of industrial-utility negotiations is to arrive at mutually satisfactory private agreements about price and service by the process of wholly free, and therefore unregulated, negotiation.

Fuel-adjustment provisions have been receiving much attention in electric and gas utility regulation. The same arguments concerning the tradeoff of reduced risk and reduced incentives for efficiency apply here as well. Some type of fuel-adjustment mechanism will probably be required for a system that uses a variable mix of fuels (coal and refuse) or that relies on purchases of thermal energy from several suppliers.

2.3 DEVELOPMENT, STARTUP, AND EXPANSION

2.3.1 Markets

The four major markets a DHC system can serve are commercial, industrial, residential, and institutional. Each of the four markets carries somewhat different implications for a DHC system regarding its service requirements, sophistication, desired payback rates, general location in the community, innovativeness, financial capability, and the age of its energy-producing equipment. These varied implications importantly affect the securing of customer hookups in the different markets.

Commercial Market

The commercial market for thermal energy generally consists of large buildings in a high-density central business district, other large individual structures, office buildings, and entire shopping centers. Many newer buildings in this market may in fact already have in-building systems producing hot and/or chilled water. Commercial users generally require the shortest paybacks for energy-related investments. Beyond the issue of first cost, potential disruption resulting from construction is one of the most frequent issues raised.

Industrial Market

The industrial market requires emphasis on reliability and straightforward Btu-equivalent comparisons. Since manufacturers and other industrial customers can often afford energy-system investments with reasonable paybacks, these users buy on fuel price to a greater degree than do other potential DHC users. Reliability of energy supply is also a prime consideration. Often during district-heating discussions, managers of industrial firms discover they really do not need steam to meet many of their service requirements. Convention and the absence of a DHC system often leads to the installation of steam boilers.

Many companies -- in such industries as textiles, rubber, plastics, and food products -- have low-temperature heat requirements and are therefore the most likely DHC system customers. Some industries require high-quality energy and therefore reject large quantities of waste heat, which can be captured and sold to other customers through a thermal loop. Paper and allied products, chemicals, primary metals, and stone, glass, and concrete are examples of industries that can become part of the resource component of a DHC system.

Residential Market

The residential market consists of multifamily high rises, apartments, attached housing/condominiums, and single-family houses. Substantial debate surrounds district heating and cooling service for this market. Most of the debate focuses on the specific distribution cost involved. The distribution cost required to serve single-family homes is greater than that required to serve a paper mill, or similar concentrated demand. However, medium- and high-density residential areas represent desirable loads. Like so many other DHC energy-system issues, service to lower-density housing will require site-specific analysis.

Proximity of lower-density residential areas to other large customers, level of system maturity, the price of competing fuels, and the system's concurrent thermal and electrical load curves are among the specific considerations that must be examined to determine the feasibility of residential hookups.

Institutional Market

The institutional market is similar to the commercial market in that the service requirement consists mainly of space conditioning, without many applications for process heat. As in the industrial market, reliability and the Btu cost-equivalent comparison are important. An institutional market often consists of several buildings or other facilities under common ownership or control. Most importantly, many institutional structures will have their own central energy system or building-scale hot or chilled water systems. The institutional market includes hospitals, colleges and other schools, military bases, and nonmilitary government buildings.

2.3.2 System Ownership

Three basic ownership arrangements are possible for DHC systems: all private, all public, and combination of private and public ownership. Within these basic arrangements, numerous local variations can exist. Final ownership arrangements will depend on the needs of each city or utility, the financial requirements of a DHC system, and legal and regulatory limitations.

Although single-owner situations will occur, many ownership arrangements will probably involve some sort of partnership between a local government and a utility, with each of them owning or financing parts of a system. Joint ownership will often be considered because of the capital intensity of DHC systems, the anticipated high rates associated with private borrowing, and the complexities inherent in community retrofit. Ownership configuration of a particular DHC system may change over time as the system grows and heat islands are connected. The following lists present components and the more common system-ownership arrangements.

- Main components of a DHC system: production facilities, the distribution system, end-user equipment
- Potential owners of a component: utility, municipality, entrepreneur(s), special local-government district, corporation, the owner of a building (containing end-user equipment)

Because a local government and a utility have different purposes and motivations, each will enter an ownership arrangement with different goals and priorities.

Investor-owned utilities exist to provide a public service and to earn a reasonable profit on their investments. The profit-seeking part of this rationale requires not only that a profit be earned from the direct sale of thermal energy but that this profit equal the return on invested capital of other potential investments, such as increased electricity production and distribution. In the event an investor-owned utility determines that the risk associated with a DHC system surpasses other typical investments, then it is reasonable for the utility to seek the safer, higher returns. A utility cannot subsidize energy production and distribution systems that do not make money, nor can a utility be reasonably expected to follow unprofitable courses in order to advance government energy policies. On the contrary, a utility will attempt to divest itself of a losing operation.

A city, on the other hand, is not required to make a profit on its invested capital in the conventional sense. This is not to say that municipal investments should be divorced from profit or from the need to bring in some return. But a city can justify certain investments that have marginal profitability if they contribute to the "public good" -- e.g., by rehabilitating older buildings or maintaining an employment base. A DHC system, if determined to be in the public interest, can be such an investment.

Entrepreneurs include industries and other parties. While it is not likely that an entrepreneur would own an entire energy system (except for smaller single heat-island projects), such an entity or person may wish to own certain parts or components of thermal systems. This type of interest will be motivated by an expected return on investment -- either directly from revenues, or indirectly, for example, from an enhanced ability to hold down the total cost of manufacturing a product.

Special districts exist in many communities to carry some of the costs of new development as well as to produce operating revenues. Particularly in suburban developments, the "sanitary-improvement district" or "metropolitan utilities district" can be a powerful governmental instrument. Often these units of government have authority in more than one political jurisdiction. Through their statutory authority to levy taxes in order to oversee the adequate and efficient provision of utility services, these special districts play useful roles in modern urban and suburban development. With regard to special districts located within municipal corporate limits, the boards that oversee them are often influential and can provide important links to business and city government.

Community corporations are usually groups of local citizens incorporated to promote the "public good." They do this by investing in projects that a city may find outside its scope of services or institutionally difficult to control because of legal or financial barriers. These corporations are generally nonprofit and have the ability to raise capital through debt issues or other typical financial mechanisms. Often the community corporation will take direction from and contract with a city government. District heating and cooling can be an appropriate activity for such a group.

Commercial and office building owners have become increasingly aware of space-conditioning costs and the potential inconveniences associated with fuel-use limits. Large buildings are frequently clustered in central business districts, mall developments, or office parks. Commercial, hotel, and office buildings have space-conditioning requirements 365 days a year and usually fire in-building boilers, which burn an expensive fuel such as light oil or natural gas. Conversion to a system using an abundant energy resource is difficult without joint action by several owners.

While all of the foregoing entities and persons have access to financial markets, their respective abilities to secure financing vary. Debt capacity will vary depending on size, capability, assets and numerous other considerations -- as judged by rating agencies, underwriters, and investors. Financial capacity will dictate the level of ownership that any group can accept. As a result, partnerships of two or more owners are likely, with each partner owning different components and each pursuing its own priorities. This will allow the partners to enter the ownersip matrix in the most appropriate manner.

How the partnerships are structured will be determined on a case-by-case basis. An appropriate partnership in Atlanta, Ga., may not be appropriate in Augusta, Maine. Each district energy system will be designed to meet the thermal needs and characteristics of a service area. Because DHC systems are site-specific, each ownership structure will be based on the needs and characteristics of a system and the community it is to serve.

If a system is jointly owned, the regulatory issue can become especially complex. The definition of a public utility in the statutes of most states includes entities that own facilities for the <u>production</u> of heat when the heat is for public use. Such a definition might be interpreted as making a producer of heat a public utility even when the heat is sold to a separately owned distribution system that enventually resells it to the public -- and even though the distributor may be a nonregulated municipality. Subjecting a producer of heat who sells to a distributor to supervision by a PUC might disincline a potential producer from entering the field -- in addition to serving no valid public purpose. If the distributor is not regulated, it would be incongruous and provide no protection to the public to regulate only the producer. If the distributor is regulated, then the public could be adequately protected by having a PUC merely review the contract for sales to the distributor. Such a review would be intended to ensure that the cost of heat from the producer does not exceed that from alternative sources. For example, a recent Nevada law exempts producers of geothermal energy from regulation when they sell to an intermediary distributor. (This example is presented in Appendix C.)

A final question about ownership is this: which person, group, or organization will own the system ultimately? A local arrangement should accommodate the possibility that system ownership may change over time. The arrangements necessary for development may not necessarily be appropriate for long-term growth and operation. A community corporation may be an appropriate group to develop a thermal-distribution system, but, lacking necessary operational skills, it may subsequently wish to sell or lease the system to a utility. This is one example of the changes that may take place over time due to the "appropriateness" of the partners' roles. System planners and regulators should be sensitive to the priorities of the partners so that the right ownership arrangement can be accommodated at the right time.

2.3.3 Prototypical Development Cases

Notwithstanding the many advantages of DHC systems, their large-scale development presents a particular set of historical technical, financial, institutional, and regulatory issues. Until recently, there was little interest in or serious consideration of DHC systems by investor-owned utilities because of their own past experience with downtown district steam systems, some of which were abandoned decades ago for economic reasons. Prior to the 1970s, the capital cost of energy production constituted the major share of total cost -- fuels remained relatively cheap. This situation favored fuel-intensive systems and economies of scale based on apparently unlimited supplies of oil and gas. New electrical generating stations grew in megawatt capacity and were located farther and farther away from urban centers. All of these facts have created an inertial barrier for district systems. Furthermore, DHC systems do not constitute short-term solutions to energy shortages; the process of planning and building a system is long and expensive.

Despite all this, several different kinds of DHC systems are actively being considered throughout the nation. Given the diversity of systems under development or on the drawing boards, it is impossible to discuss each and every specific configuration, its related arrangements and obstacles, and its regulatory implications. It is possible, however, to construct four typical DHC cases, or scenarios, and to summarize their inherent issues and problems. The following paragraphs describe four typical development cases. The differentiating characteristics of each situation are identified.

Small Central Utility System

The first typical scenario of DHC development and operation consists of a small central utility serving three to six relatively large, nearby office buildings and institutional structures. A cogenerating system burning natural gas or oil is connected to the electrical grid. The central plant and distribution system will probably be owned by an entrepreneur.

This scenario requires capital expenditures for construction of a central plant, installation of a distribution system, and in-building retrofits. In addition, the early costs associated with planning, design, customer contracts, local electric utility arrangements, and system finance must be carried. The system's major problems in this scenario concern retrofit of, and technical interface with, existing building systems; the one-time cost of building retrofit; and installing a thermal-distribution system in a developed area.

New Urban Development Project

In this case, a small district heating and cooling system is incorporated in the development of a new mixed-use construction project. Such a scenario presents the fewest problems technically and institutionally, because a new system can be designed to interface with a larger district heating system and because no end-user retrofit costs are incurred. The DHC system may be owned by a local development corporation or the land developer.

Central Business District

The third DHC case involves the construction of a municipal solid-waste, cogeneration, central energy plant (resource recovery); the installation of a thermal-distribution system; and the retrofit of large buildings in a high-density central business district (CBD). The resource-recovery plant component will be owned by the city. Thermal energy will be sold to the distribution company and electrical energy sold to the local electric utility. (The electric utility may also be the thermal-distribution company.)

Although the high-load density inherent in the CBD case is attractive, a DHC faces the high initial cost of building a distribution system. The cost of retrofitting large individual buildings will also be high. Disruption of trade and transportation associated with distribution-system construction must be mitigated. Depending upon the extent of thermal service provided and the percentage of all potential customers purchasing the service during the startup period, provisions must also be made for future expansion and service to new customers.

Large, Phased DHC

The final typical DHC case is the most ambitious and has received much recent attention. A community-scale DHC system will be developed over many years, beginning geographically with the most profitable service areas and ultimately expanding to cover significant portions of the community. Such a system will need several thermal sources to serve many industrial, commercial, institutional, and residential customers.

The problems anticipated for developing large DHC systems in phases are in some ways similar to those faced by other utilities concerned with meeting future growth requirements. However, the DHC obstacles are compounded by the high costs of installing pipe larger than is initially needed and of retrofit ting power plants -- and the technical difficulty of circumventing physical barriers when extending distribution pipe.

There are two major differences between fledgling DHC systems and other new or established utilities. First, water and sewer utilities make extensive use of government grant programs to plan and install facilities sized for future expansion. Thus, governments realize the necessity of underwriting expenditures made for future service requirements. Second, mature electric utilities need to maintain annual growth rates of only 3-4% to be financially healthy. A new DHC system has to grow many times faster than that rate to succeed financially. This necessitates substantial capital investment in distribution and plant capacity, and investment of such magnitude cannot be covered immediately by operating revenue.

Numerous federal and state laws and regulations will have differing degrees of impact on developing district energy systems. Legal and regulatory issues will obviously vary according to the state in which a specific project is located. Other relevent issues will depend on such project characteristics as: number and type of users, fuels and central-plant configurations, specific plant locations, system ownership, air-quality conditions, and local codes and ordinances.

2.3.4 Main Obstacles to System Growth

As mentioned earlier, establishing a district heating system raises important initial questions about regulation -- rate setting, market entry, cost allocation and customer protection; these deserve separate and thorough attention. Whether or not a system is regulated becomes a moot point, however, if the system proprietors cannot overcome the three main obstacles to system growth, which are:

1. Initial marketing,
2. Sound financing, and
3. Long-term expansion.

Initial Marketing

The most difficult of the three obstacles will be overcoming the inherent inertia of building owners or industrial managers who see little point in changing from their existing heating, cooling, or process systems to district heating and cooling service. This inertia is especially unfavorable for a new or expanding DHC system in a developed area. The current problem is compounded because a convincing "proof of market" will be required to secure project financing for construction of the central plant and distribution components of a DHC system.

The problem of predicting consumer behavior in a private marketplace is not new. Every private company that markets goods or services has to solve this problem. Simply installing a thermal-distribution network and observing whether or not consumers actually hook up to it is obviously an unacceptable approach for owners, underwriters, and investors. Quantifying thermal markets for new projects requires a combination of empirical market analysis and marketing customer contracts. The strongest proof of market strength is the customer contract. The contract has many variations, some of which have popular names such as charter flight, hell or high water, take or pay, fixed rate, floating rate, firm, and contingency. The type of contract is determined by the ownership arrangements and financial constraints of the project. State legislative and PUC policy can influence the DHC system's ability to secure a market by establishing what types of contracts will be allowed; how certain types of regulation will affect the rate structure; and, conversely, whether a PUC rate policy would supersede terms in a contract.

Regulatory policy toward the ownership and financing of in-building equipment can affect the securing of markets. Many potential subscribers can hook into a DHC system more readily when the equipment in their buildings is owned and provided by a utility. Even then, however, the question would remain that was discussed in Sec. 2.1: whether the cost of hooking each building into a system would be included in the rate base and distributed to all users of the system, or whether it would be charged to a particular subscriber. Utility ownership might raise problems in property law by affecting a subscriber's ability to easily convey his property. However, if the subscriber is required to own the in-building equipment and pay for it "up front," he may be deterred from subscribing. This problem can be alleviated if the subscriber is allowed to pay for the equipment over a period of years, with the DHC system being a lender or lessor. Such a scheme has been advanced by the Maine PUC regarding equipment for interconnecting a qualifying facility with an electric utility.

A potential subscriber who has a boiler or heat plant with appreciable remaining useful life may be deterred from subscribing if hooking into a DHC system would render that equipment useless. If the DHC utility were allowed to buy or give credit for such equipment, this kind of resistance could be overcome. However, it would violate regulatory principles to allow such equipment that is not "used or useful" to be included in the general rate base -- nor would utility owners want to simply absorb the costs. In appropriate situations, the problem could be solved by using such equipment as supplementary energy sources or by allowing a utility to credit it as backup equipment.

Sound Financing

Typically, the central-plant component will constitute 25% of the total cost of a DHC system. Distribution and storage components will constitute another 50% of the total cost. The remaining 25% will be needed for the end-user equipment discussed above. Regardless of who owns the various parts of a DHC system, the basic system must be profitable. Its operations must be secured by sufficient thermal demand, adequate rates, and competent management. Consequently, the financial structure of a system must be able to meet the requirements of planning, design, construction and startup, and subsequent system expansion. Setting up such a structure at the outset will go far towards overcoming the financing obstacle to DHC system growth.

Strict control of early costs will definitely contribute to the solution. Technical aspects will be discussed below in terms of phasing system development. Both large and small developers of DHC systems cite the cost of regulation as an entry-limiting factor. Entrepreneurs engaged in developing small central utility systems feel that the regulatory process is inappropriately cumbersome for them; that costs related to market entry, rate setting, and other matters assume a large investor-owned utility to be the sponsor. These entrepreneurs charge that the regulatory process and inherent costs should be more sensitive to their small size, limited predevelopment financial resources, and limited size of professional staff. In their turn, investor-owned utilities also seek DHC regulatory relief, arguing that the rate-setting process for their district steam systems is as costly and time-consuming as that for electricity rate increases.

DHC system owners can use any of several possible financing mechanisms. The mechanism selected will depend upon system ownership arrangements, state regulation, and market conditions. Joint ownership in which different system components have different owners offers the opportunity to draw upon the strengths of both public and private financing. For example, an investor-owned utility might supply heat from a retrofitted intermediate-load generating station to a municipally owned distribution system financed with tax-exempt bonds. Progressive debt service could help DHC systems deal with shortfalls of revenue during the early years of operation; within limits, this approach can shift cost to later years. This would allow unit energy cost to more accurately reflect the true value of thermal energy over time.

The seven financing mechanisms that might be applicable are as follows.

Private Corporate Bonds. These generally carry the highest interest rate. These bonds are placed on the market by firms, and the firm's assets are pledged to retirement of the debt.

General Obligation Bonds. These are bonds backed by the tax base of a city; the "full faith and credit" of the city and its tax revenues are pledged for debt repayment. These tax-free bonds offer the lowest-cost financing short of receiving subsidies.

Municipal Revenue Bonds. These are bonds pledging the revenues of a DHC system for bond repayment. Revenue bonds are riskier to an investor than general obligation bonds in that the bonds are defaulted if the revenues of the system are insufficient to cover the debt. However, they offer higher interest than general obligation bonds.

Industrial Revenue Bonds. These are bonds that pledge project revenues to the debt retirement and are sponsored by cities or development corporations to insure certain public goals such as jobs or redevelopment. The bonds are generally placed at interest rates lower than those of corporate bonds. They also are limited, by certain tax regulations, as to what they can be used to finance. The various components of a district heating and cooling system may or may not be eligible for this kind of financing.

Leasing. This is a method of acquiring system components without buying them. For example, if a utility and a city determine that a thermal system is desirable, but neither party has sufficient financial capability for owning and building the entire system, the utility could either build or retrofit a thermal source -- and the city, using its tax-free financing capability, could build and own a distribution system. The city could then lease the distribution system to the utility for a fee amounting to the cost of retiring the bonds.

Leveraged Leasing. This is a method of passing on the tax advantages of the system to the leasee. The mechanism improves the financial position of the leasee in that he now has some of the tax advantages of ownership without the costs of ownership.

Lease-Increment Bonds. This is a method of issuing revenue bonds, in effect, to cover lease charges to the system operator. The bond interest rate will depend on the system's ability to produce the necessary revenue to retire its debt.

Long-Term Expansion

The preceding discussion leads to the conclusion that phasing the development of a DHC system can overcome the third main obstacle to its success, the need for continuous growth and expansion. System phasing is based on engineering, economic, financial, and institutional considerations.

DHC developers should phase system construction in order to match central-plant capacity with prevailing thermal and electrical loads. This may require the use of temporary heat-only boilers during the startup period. As the system matures, more efficient cogenerating plants burning solid fuels can be justified. The phased engineering approach requires regulatory recognition of planned energy source changes as they relate to scarce fuel consumption, air quality, and service area expansion.

System phasing may also allow the developer/owner to postpone installation of the largest thermal-transmission lines until later years, when several service areas or heat islands are connected and the system moves to a large central generating plant.

Phased development raises market-entry issues, which may or may not be resolved in advance. It is certainly possible for several small systems, owned by different entities, to be concurrently developed within different neighborhoods in one city. This presents no technical or financial problems unless the long-term profitability of one system depends on expansion to neighborhoods served by another system. For example, a system's long-term profitability way depend on producing heat in a facility that burns coal. However, coal-burning facilities have to be very large to be cost-effective -- which in turn may mean that, sooner or later, such a system will either have to grow at the expense of another system or else go out of business itself.

2.4 RELATIONSHIPS WITH OTHER UTILITIES

A DHC system will enter a field populated with several other suppliers of thermal energy services. The other suppliers may be regulated electric or gas utilities or nonregulated distributors of fuel oil or bottled gas. The establishment of a DHC system will affect these other suppliers when it begins serving some part of a total thermal-energy market. The framework of relationships that might develop among a community's energy suppliers, following the market entry of a DHC system, is discussed below.

2.4.1 Electric Utilities

A DHC system could be a separately owned entity, or it could be a division or subsidiary of an electric or gas utility. One advantage for the DHC system of being owned by either type of utility is that the prospect of regulation by a state PUC should not be a great disincentive -- utilities are used to operating under the supervision of a PUC.

Ownership of the DHC system by an electric rather than a gas utility would constitute another advantage, both for the DHC system and its parent company: thermal energy can be produced efficiently in a joint production process with electricity in a cogeneration facility. Although a cogeneration facility need not be owned by an electric utility, such an ownership arrangement is logical.

A further advantage of electric utility ownership is that the firm's electricity customers could help finance the DHC system during its difficult early period. If such assistance would amount to cross subsidization, however, it might be contrary to state statute or judicial precedent and therefore would not be allowed. Still, it is possible for short-run financial assistance to result in long-run benefits to the utility's electricity customers -- and not amount to cross subsidization -- as the following analysis and a table on page 35 illustrate.

For purposes of this analysis, the measure of long-run benefit is the net present value of the revenue requirement of the utility. If the net present value of the revenue requirement decreases, then the wealth of customers increases -- and vice versa. Using this criterion allows for comparisons of payments made in multiple time periods. The ability to make this comparison is essential because project lives in the utility industry are generally estimated to be 30 years.

Further, use of the net-present-value criterion clarifies cross subsidization. This occurs, given a utility with two or more subsidiaries, if a flow of funds between these subsidiaries leads to the net present value of the revenue requirement from the customers of one subsidiary being higher than it would have been had the subsidiary been an independent entity.

The full implication of the above definition can be demonstrated with an example. Let us say a utility has two subsidiaries, one providing electric service and the other providing DHC service. The utility faces an allowed rate of return of 10%. The rate base of the electric business is $10,000 and annual expenses are $5,000. The DHC subsidiary has a rate base of $2,000 and annual expenses of $1,000.

The total life of the project is collapsed for the sake of the example into two periods, this year and next year. "This year" represents the period of time in which the DHC subsidiary loses money. "Next year" represents the period of time in which the DHC system breaks even or becomes profitable.

Revenues of the DHC subsidiary are only $1000 this year. To meet the company's revenue requirement, it is therefore necessary to charge the electric customers an additional $200 this year. This additional charge is not a subsidy if -- and only if -- the DHC customers repay the electric customers an amount that will insure that the net present value of the revenue requirement of the electric subsidiary is no higher than it would have been had the electric customers not been charged the additional $200. The calculation of net present value shows that if the electric customers pay $6200 this year, then their next-year payment must be reduced by at least $220, to $5780. This calculation assumes that if both the company and its customers face the same 10% discount rate, then (1 + r) [this year's additional charge] = next year's payback or (1 + 0.10) 200 = 220. If next year's payback is less than $220, the electric customer is subsidizing the DHC customer; if the next year's payback is greater than $220, the DHC customer is subsidizing the electric customer.

However, the above example does not demonstrate a rationale mandating that electric customers provide the venture capital to the DHC system. If the DHC system is capable of making the necessary payback in the latter year, then it should be able to raise capital in the open market. If the DHC system is not capable of making the payback, then why should electric customers bear this burden or accept the risk that the payback might not be made?

To show how it can pay an electric customer to finance a DHC customer, it is necessary to alter the previous example to include the cost savings inherent in the joint production of heat and electricity. That is, if the utility builds one combined heat and power plant instead of two separate facilities, then its combined account would have a rate base of $11,500 and annual expenses of $5900. Therefore, its new revenue requirement is $7050 each year.

A table on the next page shows the advantages to a utility of cogeneration.

While the numbers in the altered example are somewhat arbitrary, they meet two requirements. First, the combined-account revenue requirement has been reduced. Second, if revenue from DHC customers remains at $1000, then the electric customers must still pay more this year ($6050) than if the DHC service did not exist ($6000).

However, the net present value of the combined-account revenue requirement has been reduced by $286 (from $13,745 to $13,459). This amount is the net benefit to the customers of the company. This value allows the electric customer to receive a payback next year greater than (1 + r) times the utility's additional charge this year. Further, the district heating system's revenue requirement next year is smaller than it would have been if the DHC system had been independently financed. Thus, both customer groups can benefit from the project.

This conclusion is not predicated on the method used to allocate the joint cost of the project to the two classes of utility customers. An allocation scheme simply weighs the net flow of benefits towards one of the groups

Hypothetical Example of the Point of a Utility's Established Electric System Furnishing Short-Run Financial Help to the Utility's New DHC System

Economic Assumptions	Energy Production Costs ($): Electricity, Separately Generated	Energy Production Costs ($): Heat (DHC), Separately Generated	Energy Production Costs ($): BUT: Heat and Electricity, Cogenerated
For "This" Year[a]			
Expenses	5000	1000	5900
Cost of capital	1000	200	1150
Revenue requirement	6000	1200	7050
If DHC revenues = $1000, electric system contributes (for total cost of producing electricity and heat)	6200 (200 more than if DHC system did not exist)		6050 (50 more than if DHC system did not exist)
For "Next" Year[b]			
Expenses	5000	1000	5900
Cost of capital	1000	200	1150
Revenue requirement	6000	1200	7050
If DHC revenues = $1200, electric system contributes (for total cost of producing electricity and heat)	6000 (same as if DHC system did not exist)		5850 (150 less than if DHC system did not exist)

[a]Period in which DHC system loses money.

[b]Period in which DHC system breaks even or becomes profitable.

and away from the other. Further, the net benefits can be shared with stockholders in an investor-owned utility. By sharing the net benefits with stockholders, the customer of an investor-owned utility would provide the company with an incentive that would prompt it to undertake the project.

For a realistic assessment of the prospect of electric utility ownership of DHC systems, a discussion of the history of such relationships is in order. Most DHC systems in the U.S. are subsidiaries of electric utilities. However, as electric utilities matured and pursued their mandate to provide cheap, reliable electricity, they tended to neglect the steam subsidiary and in some cases allowed them to deteriorate. Not only were possibilities of enlarging the steam systems ignored; some electric utilities did not seek rate increases needed to maintain the profitability of the steam subsidiary.

Historically, electric utilities established steam utilities for two reasons. First, the electric utility sold the steam as a loss leader to attract customers to its electric business. The customer class this policy was instituted to attract included large office buildings and department stores in the business cores of large cities. Each building usually had its own boiler plant. These plants provided the building owner with the capability of supplying the building's heat and electricity needs through cogeneration. When the electric utility agreed to provide steam to the buildings, the owners dismantled the boiler plant and purchased both steam and electricity from the utility.

Second, the generation of electricity always produces heat as a by-product. When diesel engines are used to generate electricity, the by-product heat is high-quality steam. Diesel engines were used to generate a significant portion of the electricity load at the beginning of the 20th century. The managers of electric utilities established steam subsidiaries as a mechanism to sell the exhaust steam.

With the passage of time, the incentives mentioned above disappeared for two reasons. First, cogeneration within district heating areas in individual buildings was eliminated. Second, the electric utilities switched to steam turbines to generate most of their electricity load. The exhaust of a steam turbine is low-quality heat when the turbine is operating to provide a maximum amount of electricity per unit of fuel burned. Deprived of a product to sell because of changing technology, the managers of electric utilities are no longer interested in enlarging the steam market.

Two policy recommendations can be drawn from this historical review. One is that a new set of incentives must be provided to the electric utility industry for it to become involved once again in the development of new DHC systems. Another is that methods of fostering the development of DHC systems not under the control of electric utilities should be pursued.

To a limited extent, Title II of the Public Utility Regulatory Policies Act (PURPA) encourages the development of DHC systems that use cogeneration and are not owned by electric utilities. The viability of such systems is dependent upon their ability to generate and sell electricity. Although PURPA is silent as to retail sales of thermal energy, by requiring electric utilities to purchase electricity from qualifying cogeneration facilities and to pay their avoided costs, the Act encourages nonutility-owned DHC cogeneration facilities by ensuring a market for the electrical output of such facilities.

Implementation of PURPA by PUCs and nonregulated utilities is now underway, but it is too early to assess the Act's effectiveness. Inherent in the PURPA scheme are transactional costs (costs of hearings, PUC staff effort, legal and economic consulting fees, etc.) and informational costs (the cost of determining avoided costs, especially the capacity component, and the cost of surveillance to ensure that calculations are accurate). How these costs are allocated among the PUC, the electric utility, and the cogenerator will depend upon the rules adopted by individual PUCs. However, to the extent that these transactional and informational costs would be avoided by utility ownership of DHC systems, society would benefit.

Electric utilities are faced with a variety of load-management problems. Prominent among these are diurnal and seasonal variations in demand. Seasonal peaks are caused by heavy air-conditioning loads in summer and resistance-heating loads in the winter. Diurnal peaks are caused by the daily rhythm of human activities. Techniques such as peak-load pricing and hydroelectric pumped storage have been used as methods to solve these problems. Here, the ability of DHC systems to affect and to potentially alleviate load problems is examined.

DHC systems provide an energy source that can substitute for electrically heating space and water, and for air conditioning. The provision of heat from the system is straightforward. The provision of air conditioning, or cooling, is more complex.

To affect the diurnal load-management problem, a DHC system must be connected to a combined heat and power facility. In addition, the effect will be greater if hot- or chilled-water accumulators are connected to the distribution systems. The operations of a combined heat and power facility will be tied to power system's need for peak electricity. If the combined station produces more heat than is necessary to meet the heat load, then the heat can be stored in heat accumulators. Later, when power system needs decline, the cogenerating plant and/or auxiliary heat-only boilers can be shut down. Then the heat from the heat accumulators can be used to maintain the temperature of the water in the distribution network.

Determining whether DHC is a viable load-management alternative requires a detailed analysis of the compatability of thermal and electric loads. This analysis should include an examination of the technology of the thermal plant, of the patterns of thermal and electric loads, and of the opportunity costs of the boiler capacity used to provide thermal and/or electric service at any particular time.

2.4.2 Gas Utilities

Natural gas utilities and DHC systems can interact in several ways. First, the two are natural competitors in the provision of thermal-energy services. Space and water heating, the prime uses of natural gas, are expected to constitute the largest market for DHC systems. Second, because DHC systems can be fueled by natural gas, they could become wholesale purchasers from gas utilities. The conditions and price of this sale can mean the difference between a viable and a defunct DHC system. Gas utilities are aware of this relationship, and there is the potential for exploitation when the DHC system is not one of its own subsidiaries.

The following analysis will indicate how a value-of-service pricing strategy can adversely affect the competitive positon of DHC systems. In using this standard, the gas utility would charge customer classes on the basis of the best alternative available to each customer class. For homeowners, this standard would mean that the price of natural gas would track the price of No. 2 fuel oil. With the present price of No. 2 fuel being approximatly twice that of natural gas, the gas utility could increase the price to homeowners substantially before it would lose subscribers in that class. As a larger fraction of its revenue requirements would be met from sales to the homeowner class, it could lower its rates to commercial and industrial classes, which would be expected to be the prime markets for the DHC system. Thus, the gas utility by adopting a value-of-service pricing methodology could put the DHC system at a severe competitive disadvantage.

Although most PUCs adhere formally to cost-of-service pricing, value-of-service pricing may nevertheless appear in a rate schedule. For example, there have been recent attempts to use marginal-cost pricing to set rates. The rates are set to equal marginal costs. However, only under very fortuitous circumstances will marginal-cost rates generate the prescribed revenue requirement. Thus, the rate setter must develop a reconciliation method to adjust the marginal-cost rates. The most popular reconciliation method is the Barmal-Bradford inverse elasticity model. This model dictates that rates in customer classes with the lowest elasticity should bear the greatest burden of the reconciliation; it therefore yields results similar to value-of-service pricing.

DHC systems could become a major new market for gas utilities. Already, air-pollution standards have forced many DHC systems to switch to natural gas. This buyer-seller relationship gives the gas utility leverage over its DHC competitor, however, because natural gas must be purchased in large quantities.

One way this leverage could be exercised is associated with the question of curtailments. A typical DHC system will have a customer mix that includes hospitals, industrial, and commercial establishments. Curtailment standards are different for these groups. A decision must be made to classify the DHC utility in one of the groups. If, because it serves hospitals, a DHC receives the same priority ranking as a hospital, then its industrial and commercial customers receive a windfall gain. This high ranking would attract industrial and commercial customers to a DHC system and away from natural gas utilities. On the other hand, if a DHC system receives a lower priority ranking, then hospitals will be reluctant to connect to a DHC system. The loss of hospital sales would be a severe blow to a DHC system.

For pricing purposes, a DHC system would prefer to be classified as an interruptible customer. However, as a utility, it has an obligation to serve its customers at all times. To qualify as an interruptible customer and to meet its own obligations, the DHC system must have the ability to switch fuel sources. The type of alternative fuel that a DHC system can use will effect its relationship with the natural gas utility. If the alternative is a distillate fuel oil, then the gas utility will develop a special category for the DHC utility and charge a relatively high price for interruptible gas. If the alternative is coal or residual fuel oil, then the DHC system will probably pay a lower price for interruptible gas service.

The establishment of a DHC system could be expected to affect the owners and customers of a gas utility. Affected would be the total sales of the gas utility, its distribution costs, and the prices of its primary fuels.

Although the mix of gas company customers would definitely change, total sales of the gas utility would not be expected to change significantly. Natural gas is such a clean, desirable fuel that the gas utility should be able to readily attract new customers to replace lost space-heating customers. The new customers would probably switch from oil, and such a change could help reduce the nation's dependence on imported oil.

Distribution costs for the remaining gas company customers would probably increase because economies of scales inherent in pipeline-distribution networks would decrease. However, the impact on distribution costs can be mitigated by proper planning. A DHC system whose service area is compact should have a less deleterious effect on a gas company than one that sprawls across the company's service area.

The growth of DHC systems should reduce the price of primary energy, all other things being equal. To the extent that DHC systems use cogeneration facilities -- or burn municipal waste or coal, or use industrial waste heat -- they should tend to reduce the demand for scarce and imported fuels. Thus, there should be a lower demand for oil than there would otherwise be. A lower demand for oil should result in a lower price for oil and for natural gas at the wellhead. The net impact on gas utilities will depend on the specific balance between the conflicting effects of lower primary fuel prices and higher distribution costs.

2.4.3 Electric-Utility Regulation as a Means of Promoting DHC

Regulatory incentives can be developed to encourage electric utilities to provide DHC service. One type of incentive could be tied to the rate of return on equity. This incentive scheme has been used in Kansas, where utilities are encouraged to invest in projects that use renewable resources as fuel -- Kansas allows a higher-than-normal return on these investments -- and in Michigan, where the incentive is triggered by high system availability.

In order to foster district heating and cooling, a regulatory incentive could link rate of return to the overall heat rate of the electric utility. Lower heat rates could be rewarded with higher rates of return, and higher heat rates could be penalized with lower rates of return. In order to achieve low heat rates and therefore obtain higher rates of return, the electric utility would have to establish a district heating and cooling system. This necessity is based upon the existing technological constraints. The best condensing turbines under ideal conditions have fuel-cycle efficiencies of 40%. An extracting, or back-pressure, turbine can have fuel-cycle efficiencies as high as 85%. If the utility were to build cogenerating heat and power facilities, then its average efficiency for all its plants would increase.

A PUC can also use its rate-regulating power to encourage electric utilities to investigate the viability of DHC systems. For an investment to be included in the rate base it must be used and useful, and to be useful it must be a prudent investment. A PUC can question whether an electric utility building a condensing turbine with large cooling towers is making a prudent investment -- if the utility has not also examined the viability of a back-pressure turbine, without a cooling tower, connected to a DHC system.

Care would have to be exercised in the use of these regulatory incentives to encourage the development of DHC systems. For example, increasing the rate of return on all the utility's investment could induce it to start an uneconomical DHC system. Perhaps the most efficient, least distorting, and easiest incentive to implement would be to allow the utility to form a DHC subsidiary and allow it an unregulated return.

A state legislature and a PUC can modify state regulations, as appropriate, to encourage electric utilities to broaden their planning perspectives. The point of such modification would be to bring the proprietors of these utilities to a new understanding of their reason for being in business: to provide useful energy, not just electricity. This reorientation, in itself, could lead to the development of more DHC systems.

2.5 REVITALIZATION OF OLD SYSTEMS

DHC systems presently in operation tend to be investor-owned steam systems or unregulated institutional systems. Many of the investor-owned systems are in deteriorating condition. Most are more than 40 years old and in their original state of technology. It is instructive to consider an example of such an older system.

The Wisconsin Electric district heating system, more viable than most systems of its kind, covers a service area of approximately two square miles in downtown Milwaukee. It serves roughly 600 customers, most of them owners of offices and public buildings. Its customers are supplied through a network of high-pressure and low-pressure steam mains. No condensate return is provided for. The primary steam-supply point for the system is Wisconsin Electric's Valley Plant. This plant contains two extraction turbines. Two boilers feed each turbine. The plant can continuously produce steam in excess of 10^6 lb/h and can produce up to $1.7 \cdot 10^6$ lb/h for limited periods. The plant is rated at 280 MWe with no steam extraction. Its capacity falls to 130 MWe at maximum extraction. Additional steam is available to the sytem from two other plants. The system provides heat for space and water heating. Because of this, its summer and winter sales vary greatly, resulting in a 30% load factor. The system's number of customers has remained relatively constant for several years. Although discussions have been held with several potential industrial customers, any major addition of load would require the installation of additional capacity and steam distribution facilities.

Revitalizing such older systems as that of Wisconsin Electric requires a number of concurrent actions. Relaxation of traditional utility-type regulations, new organizational and economic approaches affecting system operation, and modifications of system equipment all are important to revitalization.

Numerous technical changes are possible and may be necessary. There may be a need to retrofit. In older systems, retrofit must be approached with caution. Older turbines, with 20 or fewer years of remaining useful life, may have to supply new distribution systems having a useful life of 50 years. This means the turbines will eventually have to be replaced. Generally, then, plans for retrofit of older systems must take several factors into account. Five leading factors are as follows.

- An older system may need capacity in addition to that provided by its retrofitted original equipment.
- An old turbine may not be adaptable to a modern system because it may have too short a remaining working life when operated under baseload conditions.
- Replacing an old unit may not be economical if it is physically small and in a special location.

- Proper load matching is necessary.
- Costs and benefits of retrofit should be carefully analyzed to ensure that the costs are not excessive.

In addition to retrofit, renovation of current distribution systems and extension of existing systems to new customers may be called for. Distribution systems currently in operation have losses ranging up to 42%. Many DHC economies of scale, which constitute advantages over onsite systems, disappear when such losses are taken into account. Indeed, because many systems are old and rely upon piping buried beneath crowded central city streets, the process of tracking down and sealing off leaks can be disruptive and expensive. Extension of distribution systems to new customers presents another dilemma. For many utilities, providing service to new customers is not worthwhile because the cost of extending distribution pipe is often excessive due to understreet congestion and high labor costs.

Fuel substitution constitutes another possible means of revitalizing an old DHC system. Often, the unfavorable competitive position that thermal systems have vis a vis natural gas is caused by natural gas being the fuel burned to produce their energy. This usually results in an economic impossibility unless alternate and cheaper fuels can be substituted. Burning coal or solid waste instead of natural gas could alleviate this situation; however, those fuels engender problems of their own. Environmental constraints, the installation of costly scrubbers, and the escalating cost of coal (and even waste) may be mentioned in this regard. There is also the cost of a new coal-fired unit or the cost of retrofitting. Recent experience indicates, however, that while coal costs do increase they do not increase as rapidly as the costs of oil and natural gas. Similarly, environmental constraints can be met and accommodated.

Revitalization may also be achieved by expanding a steam-only system into a hybrid that delivers both steam and hot water. Because steam systems operate with less heat capacity than do hot water systems, expansion of existing systems may involve the laying of new hot water distribution systems in conjunction with, and gradually replacing, existing steam lines. Such a hybrid could be designed to deliver hot water to high- and medium-density commercial, institutional, and industrial load areas. A hot water system can deliver heat over longer distances than a steam-only system. Larger steam pipes could be replaced with smaller and simpler hot water lines. The key to this sort of technical upgrading is gradual, rather than abrupt, change.

The problems associated with public regulation often constitute a major obstacle limiting revitalization of older DHC systems. Public-utility regulation is the most pervasive and complex form of governmental regulation of business that exists in the United States. PUCs have broad powers that may affect service to customers. This authority includes the power to approve or disapprove many activities of public utilities, including changes in the rates for providing service to customers. Criteria may be established by PUCs concerning the quality of utility services and the manner in which they are provided. A variety of periodic reporting requirements may be demanded by these agencies. In some instances, regulatory scrutiny may extend to or affect nonutility operations. The costs associated with formal ratemaking proceedings required to obtain rate increases can far outweigh the benefits accrued and therefore act to discourage interest in older DHC systems.*

To ameliorate the effects that such regulations have on older DHC systems, changes are necessary. In particular, the following options could be examined.

1. State and local agencies and cognizant utilities could develop joint plans for revitalizing an old DHC system. This could commit all of the parties to making the revitalization program succeed.

2. Direct governmental grants or subsidies could be provided to assist revitalization efforts. Revitalization of older systems is an expensive activity. Governmental assistance can prove crucial in this regard.

3. The connection of new buildings to a revitalized DHC system might be mandated. This could provide a more favorable basis from which to obtain the capital necessary for revitalization. However, it is extremely unlikely that a state or local agency would mandate connection.

4. A municipality could acquire ownership of the DHC system to be revitalized. Under this arrangement, the system would not be subject to taxes, and it would be funded with low-cost money. In addition, municipal ownership can provide a means of avoiding costly ratemaking proceedings.

5. Regulatory procedures could be streamlined, the purpose being to make DHC rate cases less expensive and time consuming. Often, DHC ratemaking proceedings are as elaborate as those required for electrical ratemaking. The amounts of money involved, however, do not warrant such detail. The time consumed and the expense involved act as significant obstacles to efficient operation of older systems.

An alternative to revitalizing an old system is abandonment of services. For small, noneconomic and inefficent older systems, abandonment may be the wisest course. Prior to abandonment of service, certain statutory requirements would have to be met. About 80% of the states in the U.S. specifically require PUC approval of abandonment of service. In the remaining states, PUCs exercise some control. Most states have no specific procedures or standards for approving abandonments. Usually, however, an application for approval must be filed; the abandonment is allowed only if alternative service is available to the petitioning utility's customers.

These, then, represent options for revitalizing older DHC systems, technically and otherwise. The appropriateness of any one option depends upon the circumstances of a situation. Those technical, financial, and organizational circumstances must be assessed before the right options and changes can be determined. Older DHC systems are important energy resources and should be

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*For an example of a recent rate case concerning the Detroit Edison system, see 39PUR 4th 107 (1981).

preserved where possible. These systems have the virtue that they are in place and operative. They have well defined clienteles, ownership, and relationships with regulatory agencies. As such, they enable their owners to avoid certain problems associated with initial startup of new systems. While many older systems are inefficient and uneconomical as presently constituted, they need not remain so. Revitalization can overcome such shortcomings.

APPENDIX A
THE EUROPEAN EXPERIENCE

A.1 INTRODUCTION

District heating is a viable and growing industry in Europe, primarily for three reasons. First, the reconstruction that followed the destruction of World War II provided utilities with an opportunity to install pipe-distribution networks cheaply. Second, high fuel costs have provided an incentive for the purchase of heat from a fuel-saving energy supply system. Third, the use of hot water as a distribution fluid instead of steam has significantly lowered the cost of constructing new systems. (The technology of hot-water distribution was developed in the late 1920s and early 1930s in the U.S., but European countries led in its use.) While all have contributed to DHC growth, it is of interest to note that strict application of these causal factors does not necessarily lead to consistent predictions about the development of DHC systems. As an example, if rebuilding is important, why has England lagged behind other countries, and why, on a per capita basis, are the Scandinavian countries leaders in Europe?

The common characteristic that typifies countries with dynamic district heating industries is the involvement of local government in heat supply. This factor is important even in eastern European countries, where cities commonly have authority over and responsibility for heat supply. The Moscow Power System is run by city officials. It is the world's largest system, with 13 cogeneration stations whose total heating capacity is 23,260 MW.

A.2 SWEDEN

A.2.1 Development

District heating began in Sweden in 1948, in the city of Karlstad. The original connected load was 2000 kW, and energy supplied in the first year was 2100 MWh. The next two cities to establish systems were Malmo and Norrkoping. Both started operation in 1951. Vasteras, the most publicized system, was started in 1954.

The total connected load in Sweden for the fiscal year ending June 30, 1977, was 11.5 GW; the total quantity of heat delivered was 21.8 TWh. Heat supplied by a district heating system represented approximately 20% of the space heat and hot water used by commercial and residential buildings. The electricity generated by district heating utilities was 5% of national electricity consumption. The growth rate of district heating systems was lower during the mid 1970s than in earlier periods. However, the growth rates are still significant in absolute terms. Indeed, when compared to the growth rate of the Swedish economy as a whole, district heating systems have grown substantially faster.

Approximtely three out of four Swedish systems operate between 1700 and 2300 h/yr. This means the systems are utilized at between 19.4% and 23.9% of load factor. American systems appear to have a slightly higher load factor, but the spread in load factors is also larger in the U.S. than it is in Sweden. Higher load factors in this country are consistent with U.S. systems serving proportionally more industrial customers than do Swedish systems, and possibly serving seasonal air-conditioning loads.

American systems also distribute heat over shorter distances than do their Swedish counterparts. The 10 largest U.S. systems have an annual range of 18.1-69.1 m/GWh, with a median of 47 m/GWh. The ten smallest U.S. systems have an annual range of 29.1-270 m/GWh. However, this range is distorted by the extreme case of Ricelake, Minn., a system with the specific length of 270 m. Approximately 70% of the Swedish systems operate within an annual range of 76-150 m/GWh.

The typical Swedish utility runs at energy efficiency levels of 75-85%. Direct comparisons to U.S. systems are difficult because data about electricity produced at cogeneration plants are not available. At those U.S. systems that produce only heat (including six of the ten largest and seven of the ten smallest U.S. systems), efficiency levels ranged between 45% and 55% in 1978. One of the newest systems built in the U.S. -- in Hartford, Conn. -- has an efficiency of 64%; this is significantly higher than the U.S. average but far below the 95% level of the most efficient Swedish utilities.

The success of the Swedish systems in achieving high energy efficiencies stems from three factors.

1. Use of hot water instead of steam as a heat-transmission fluid. This method requires less energy put into the system than does the steam method, and it also reduces distribution losses below those of a steam system.
2. A relatively high proportion of cogeneration plants -- 12 of 50 Swedish district heating systems also generate power.
3. Lack of an air-conditioning load, which requires high heat values in the transmission fluid during summer operations.

A.2.2 Organizational Framework

In Sweden, the organizational framework of district heating utilities evolved in response to two questions. First, who owns heat-supply facilities? Second, what is the division of responsibility for electricity supply between the municipalities and the national electric grid? Each municipality distributes both heat and electricity.

In fulfilling its distribution and possible generation responsibilities, the municipality can create a variety of organizational structures. Usually a separate corporation, whose stock is wholly owned by the municipality, is established to fulfill each responsibility. A district heating corporation might own and operate the distribution network and the hot-water generation facilities. Alternatively, a heating system can be a subsidiary of a previously established electric corporation; the district heating company might own and operate the distribution system, while the heat-production facilities could be jointly owned with either the city electric corporation or the State Power Board. Or a district heating company could own and operate the distribution system and purchase heat from other sources. The choice between these alternatives seems to have been made by historical accident and local preference; in each, the decision was made by the municipality.

The division of responsibility for electricity supply has also had important consequences for the development of district heating. In particular, the size, number, and profitability of cogeneration plants are directly related to the rules and rates established by the State Power Board, the body that owns and controls the national grid. To understand why this particular division of responsibility exists today, it is necessary to provide some details of the historical development of the electrical supply industry.

This development can be broken into four stages. First, local governments set up distribution networks and built coal-fired generation facilities. Second, hydroelectric power was developed in northern Sweden after the national government passed two water acts allowing developers to construct transmission lines across land owned by others and to allow for private expropriation of land along rivers. Hydroelectric power undersold the coal plants, eventually causing the coal plants to shut down. The municipalities maintained the distribution networks and purchased electricity from the national grid. These purchases led to a dispute over control of the national grid; the dispute ended when the government granted the State Power Board sole ownership and control of the national grid in 1946.

The year 1946 also marked the beginning of the third stage. In this stage, the State Power Board expanded its control over the entire system. Ownership of producing facilities remained divided between the State Power Board and private producers. During this stage, it became clear that expansion of electricity demand would exceed the supply potential of hydroelectric sites. Two alternatives to hydroelectric power developed. First, nuclear power was initiated by the large producers in combined projects with the State Power Board. Second, the cities, led by Vasteras, started building cogeneration stations. The cities formed a distributors' cartel whose objectives were to use the national grid as means to obtain stand-by power, reduce peaking problems, or to wheel power between the cities. Under this scheme, the private producers would become providers of stand-by and peak power.

The choice between these alternatives was made by the State Power Board. In 1963, it initiated a series of tariff reforms that destroyed the distributors' cartel. The policy brought the Swedish electric system into its fourth stage. This stage has three characteristics: (1) baseload electricity is generated at hydroelectric and nuclear facilities, with the facilities either separately or jointly owned by private producers and the State Power Board; (2) municipalities provide a significant amount of peaking power in relatively small cogeneration facilities; and (3) the State Power Board has hegemony over the entire system by virtue of its control of the national grid.

A.2.3 Rates

While the cost of district heating varies from city to city, a maximum price is agreed upon by all Swedish heating utilities. This maximum price is set by the country's District Heating Association, using the price of oil heat as a reference point. The maximum price of district heating is always kept slightly below the price of oil heat. The general procedure used in pricing district heating is to divide the costs into three parts: a connection charge, an annual fixed charge, and an energy charge.

The connection charge covers the cost of hookup. In practice, this charge is set on the basis of the size of the dwelling or of the heat demanded when the outdoor temperature reaches a certain point. Implicitly, therefore, the connection charge includes a charge for the sizing of the entire distribution network and not just the marginal cost of connecting the additonal customer.

Some utilities have used a system of rebates of the connection charge as an incentive to hook into the system. For instance, the connection charge is forgiven if the owner agrees to hook into the system while the main is being installed. Alternatively, when a house is sold, the new owner is given a 75% rebate if he joins the system immediately after purchasing the property.

An annual charge is based on the peak load of the customer. Block rates and customer classifications are used in devising this annual charge.

The charge for energy actually used is determined by the type of meter installed. If the meter records both water flow and temperature drop, then the energy charge is based on therms used. If the meter records only water flow, then the energy is based on the water flow. In the latter case, the customer can reduce variations in home heating costs by installing a more efficient heat exchanger.

A.2.4 Finances

A typical district heating corporation might have the following financial structure.

Loans from subscribers	35%
Self-financing	15%
External loans	50%
	100%

Loans from subscribers are obtained in the following manner. When a residential customer connects to a system, he obtains a loan from the State via the National Housing Board. The residential customer then reloans 75% of the housing loan to the utility. These loans have a 30-yr term. In 1977, the interest rate on these loans was 8.75%.

Self-financing refers to the use of retained earnings. This method is primarily used when the heating company is a subsidiary of the electric utility. Profits of the electric utility are used to build the district heating company, which generally does not generate profits in the first 5-10 yr of operation.

Outside funding can be provided by loans from town councils, or bonds sold on national or international markets. Cogeneration facilities built jointly with the State Power Board are usually financed by the State Power Board, which has better access to bond markets than does an electric utility.

A.2.5 Energy Planning

The Swedish government has instituted two complementary energy plans since the first oil crisis in 1973/74. The goal of these plans is to separate the growth of the economy from the growth in energy demand. Specifically, the government intends to hold the energy-growth demand to 2% annually in the 1980s and to move to a zero-growth rate in the 1990s.

As applied to district heating, this program has four provisions.

1. Community-owned enterprises can mandate hookup within specified areas. The enterprise must pay the customer a fair market price for heating equipment made obsolete by this action.
2. All communities must consider energy consequences in their planning activities.
3. The government will increase its funding for loan associations that finance district heating schemes.
4. The National Board of Industry is authorized to use its funds for grants to support connection of new customers to district heating systems. An individual grant may cover up to 35% of the internal costs of connection.

A.3 DENMARK

A.3.1 Development

The district heating systems in Denmark can be divided into two groups: small systems supplied by boilers and large systems supplied by cogeneration plants. As of 1978, there were 400 small systems in operation, a growth of approximately 150 systems since 1962. The primary fuel used to fire hot-water boilers was oil. Approximately 2% of the fuel input into these systems was refuse.

Two significant points can be made regarding DHC in Denmark. First, there has been a steady expansion of the service since World War II. Second, by world standards Danish systems are small. Almost two-thirds of the systems have a capacity of 11.6 MW or less. Six cities have been served by the same power plants for many years. Three additional cities have recently connected district heating systems to power plants. A tenth city, Hernig, is in the process of connecting to a power plant.

Following the completion of the Hernig project, 11 of 18 major electrical facilities in Denmark will be operated as cogeneration plants. As of 1978, the thermal efficiencies of the 18 plants averaged 45.5%. Heat sales have increased the thermal efficiency of the electric supply industry by 10 percentage points. The Danish electric industry is in the process of transforming oil-fired to coal-fired units. As of 1978, 52% of the fuel used to generate electricity was coal. This percentage is expected to rise to 80% by the middle 1980s. At present, cogeneration plants supply 10% of the Danish heat load. Another 20% of the heat load is supplied by the small systems. Denmark has the highest per capita DHC capacity in Western Europe.

A.3.2 Organizational Framework

District heating utilities are a branch of local government, similar in organization to a typical water and sewage department in U.S. communities. Relationships between the heating utilities and the electric utilities follow a formal pattern. Electric utilities, usually cooperatives owned by several cities, charge the heat utilities on the basis of kWh of electricity not generated owing to the plant being operated to produce useful heat.

A.3.3 Rates

Rates are set by town councils, whose activities are supervised by the national Gas and Heat Price Committee. Each town council must submit its prices to the Committee, which has the power to order town councils to change their rates. The Committee has a chairman and 13 other members. The chair and 7 members of the Committee are to be independent of the supply industry and the municipal governments. They represent consumer interests and provide expert opinion. The remaining 6 members of the committee represent organizations with a vested interest in heat supply.

In general, the district heating utilities are to operate on a nonprofit basis yet at the same time be self-sustaining. Rates should cover legitimate costs, including payments to reserves for new investment, which would be considered profits. Payments to town councils over and above interest on debt are not allowed; consequently, utilities cannot be used as a covert tax-gathering institution. Rates have not been set in terms of oil-equivalent prices. To do so would generate large profits for most sytems.

For example, in 1979, in Odense, the owner of an average single-family dwelling paid an annual heat charge of $341 U.S. Equivalent heat provided by an individual oil-fired boiler would have cost $1188 U.S. Each customer must pay a connection charge at the time he joins the system. The connection charge is based on the volume of the dwelling and the length of pipe needed to connect the house to the system. This charge can be financed over a 15-yr period with a loan obtained from the utility. The annual charge is based on a three-part rate scheme: meter charge, fixed charge, and water charge. For dwellings, the fixed charge is based on the volume of space heated. The water charge is based on the amount of water that passes through the customer's heat-exchanger. For most dwellings, temperature drop is not recorded; consequently, there is no exact measure of energy use per dwelling. To obtain an energy measure would entail a large increase in metering costs, and this has not been deemed worthwhile.

A.3.4 Finances

District heating systems are financed through the Danish town councils. As of 1978, 11 billion kron (kr) had been invested in district heating schemes. Investments in distribution networks are increasing by approximately 500 million kr per year. Cogeneration plants are built by the electric cooperatives. These cooperatives rely on towns for financial aid and on grants from the national government.

A.3.5 Energy Planning

In the Act on Measures and Energy Policy, April 1976, the Minister of Commerce was directed to prepare reports on energy policy. To comply with the act, the Minister of Commerce produced a report called the "Danish Energy Policy 1976." The report set forth three broad objectives:

1. To reduce dependence on vulnerable energy supplies, particularly oil, as quickly as possible;
2. To establish a versatile energy supply, under which efforts can be made to utilize indigenous sources of energy; and
3. To cut the growth rate of energy consumption.

The plan also set forth two, more specific goals: first, to reduce annual oil consumption by 1985 22% below its 1975 level; second, to reduce oil's share of total energy consumption from 87% in 1975 to 48% by 1995. To further the energy plan, the Minister of Commerce set up a Heat Plan Committee in April 1977. The objective of this committee was to devise a plan to reduce Denmark's dependence on oil for home heating.

The first report of the committee appeared in October 1977. The report stressed the need to develop pipeline heat as a substitute for oil. Pipeline heat would appear in the form of hot water from cogeneration plants and natural gas from North Sea wells. It was envisioned that powerplant heat would supply between 35 and 40% of the heat requirement, and that natural gas would supply 20 to 25% of the heat required by 1995. This plan would require a huge investment in distribution networks. To implement this development strategy, the Heat Plan Committee made a series of subsidiary recommendations. Many of these recommendations were incorporated in the 1979 Act on Heat Supply.

The 1979 Act on Heat Supply mandates a comprehensive heat plan for the entire nation. The plan will be developed by the local and county governments and supervised by the Minister of Commerce. Under this plan, each local authority is directed to develop a heat map. The map should include existing heat requirements, the present method of meeting those requirements, and the amounts of waste or surplus heat available in the area. Each local authority must then establish a heat plan. The plan should specify the preferred heat-supply method in each area of the locality. Plants needed to supply heat must be sited within the area, and tentative pipeline networks must be outlined. A timetable for building the distribution network must also be part of a local plan. Local authorities are authorized to force compliance with the plan by mandating connection to the distribution network. If the municipality demands immediate connection, it can subsidize the building owner's heat-system transformation and connection costs. Finally, the municipality has the right to expropriate property for the purpose of building distribution networks.

A.4 UNITED KINGDOM

A.4.1 Development

In the United Kingdom, less than 1% of the space-heating load is supplied by district heating. Most DHC systems are small. The typical project serves 100-200 dwellings with a heat load of less than 0.3 MW.

A.4.2 Organizational Framework

At present, electricity boards have the responsibility to promote district heating from cogeneration plants. The Electricity Act of 1947 authorized the boards to sell heat that is produced jointly with electricity. This Act gave the industry its present structure. There exists a Central Electricity Generating Board (CEGB), 12 area boards, and the Electricity Council. The CEGB generates the electricity, maintains the transmission grid, and determines bulk power rates. Area boards purchase electricity from the CEGB, resell electricity to customers, and build and maintain the distribution system. The Electricity Council is an advisory and a research group. Institutionally, the UK's Secretary of State has responsibility for supervising the electric industry. The Electricity Act of 1957 also allows area boards to generate electricity. First to cogenerate pursuant to the Act was the Midlands Board; its plant will supply process steam to food processors. No residential space heating is planned.

Local authorities that have attempted to build cogeneration plants often encounter financial difficulties due to the policies of the electric industry and the national Gas Corp. First, the electric industry, by exerting its monopsony (buying) power, purchases electricity at prices below its alternative costs. Second, if the cogeneration station uses a gas turbine, then the Gas Corp. will charge that station a higher-than-normal interruptible rate. This Corporation is able to charge the higher rate because the only substitute fuel is gas oil, a relatively high-priced fuel. The Gas Corp. follows this policy for two reasons. First, price discrimination will increase its profits. Second, it if destroys existing projects or discourages new projects with the high rate, then it maintains control of the residential heat market.

A.4.3 Rates

The Midlands Electric Board in 1978 built a cogeneration power project in Hereford. It chose to price heat at a level 10% below the industrial customer's own costs. This pricing policy was based on the belief that the customers must receive some compensation for the loss of freedom -- they no longer operate their own heating plants once they switch to a cogeneration system.

A.4.4 Finances

It is generally presumed that all future district heating systems will be financed through a government agency. At present, nationalized industries are required, among other things, to show an estimated real rate of return of 5% on future investment projects in order to obtain Treasury financing. This rate is a change from the recent past, when a 10% nominal rate had been used. One would expect that future district heating projects that meet this criterion will be able to obtain Treasury financing.

A.4.5 Energy Planning

At the end of 1974, UK's Secretary of State established a Combined Heat and Power Group. Its task was "to consider the economic sale of combined heat and power in the United Kingdom and to identify technological, institutional, planning, legal, or other obstacles to the fulfillment of the role and to make recommendations." In 1979, the study group published its final report: Energy Paper No. 35, "Combined Heat and Electrical Power Generation in the United Kingdom." The following methodology was used to analyze the feasibility of district heating in the UK.

1. The future was divided into three time periods.

   a. The short term. This period is characterized by relatively cheap and abundant natural gas and oil.

   b. The medium term. This period is characterized by the growing scarcity of gas and oil. Specific dates for this period are approximately from the mid 1980s through the year 2000.

   c. The long term. In this period, the only two dependable fuel sources will be coal and uranium.

2. Heat demand was estimated for a typical small city and a typical large city. Demand characteristics such as density and peak were included in the estimates.

3. Cost comparisons were made for the two typical cities, during the three time periods, using a variety of heat-supply systems.

4. Cost comparisons were subjected to sensitivity analysis. The three variables that were allowed to change in the analysis were the fuel price, the interest rate, and the heat-load density.

A summary of the study group's conclusion include the following recommendations. First: in the short term, natural gas is the preferred fuel to be used for space heating. Second: in the medium term, cogeneration stations would be the preferred method of supplying heat to the dense areas of large cities. Third: in the long term, cogeneration stations should carry a significant portion (approximately 30%) of the UK space-heating load. Fourth: if district heating through cogeneration systems is to be an integral part of the future energy-supply system, then it is necessary to start building these systems today. This process should take place in designated lead cities, even if it is necessary to subsidize them in the short term. Fifth: a National Heat Board should be established. Its task would be to identify lead cities, establish local boards, carry out detailed studies of other cities and work with the government to coordinate a national energy policy. The task of the local heat boards will be to build, own, and operate the district heating schemes.

A.5 WEST GERMANY

District heating systems have existed in Germany since the turn of the century. Prior to World War II, there were at least 35 systems in operation. By 1975, 112 utility companies were operating 104 cogeneration plants and 363 heat-only boilers. The total connected load was 24,000 MW. By 1978, total heat sales were greater than 60 TWh.

A survey of district heating systems in Germany results in the following capacity statistics.

- 3 systems with a capacity greater than 1160 MW
- 5 systems between 580 and 1160 MW
- 15 systems between 290 and 580 MW
- 21 systems between 116 and 290 MW
- 14 systems between 58 and 116 MW
- 22 systems between 29 and 58 MW
- 29 systems between 6 and 29 MW

Hamburg has the largest system, with a connected load of more than 3000 MW. It is interesting that Hamburg is one of the few cities in the world with competing district heating companies. By way of comparison, the largest three U.S. systems -- New York, Philadelphia, and Detroit -- have capacities of 4390, 1130, and 858 MW, respectively. The largest system in the UK, Nottingham, has a capacity of 85 MW; and the largest system in France, Paris, has a capacity of 1821 MW.

District heating systems in West Germany receive financial aid from federal and local governments. For the years 1977 through 1980, these governments have allocated 680 million marks as investment incentives for the systems.

A.6 FRANCE

The total capacity of French district heating systems is 10,000 MW. For 1978, total sales were approximately 12 TWH. The Paris system is supplied by three refuse incinerators and a back-pressure turbine. The refuse units supply approximately one-third of the steam sold. One other system produces heat using a cogeneration plant. It is located in Metz and was built in 1957. This system is operated by a regies, or local electric board, one of a small number of local electric boards still in existence. Most of the other boards have been either dissolved or are nonfunctioning. It is interesting to note that the only cogeneration plant built since the nationalization of the electricity system (the Paris plants predate nationalization) is connected to an institution controlled by a local government.

APPENDIX B

EXAMPLES OF DHC-RELATED CASE LAW

Generally, the definition of what is wise or sound as public policy in statutory regulation of DHC companies is determined, within constitutional limitations, primarily by the legislative branch of government. It is the court's role to interpret and illuminate legislative intent and statutory dictates. The right to regulate is measured by the public interest; it will not be inferred by the courts in the absence of express legislation. The test as to whether the regulatory powers of boards and commissions may be invoked does not depend upon the use which the customer makes of the energy supplied, but upon the duty undertaken by the company and owed to the public. Several areas of regulation seem to be particularly susceptible to litigation. It is the purpose of this section to briefly explore these areas and to provide illustrative examples of relevant case law.

B.1 PUBLIC USE

As its name suggests, the term "public utility" implies a public use and service; indeed, a principal characteristic of a public utility is that of service to, or readiness to serve, an "indefinite public." (The term must be defined by either precise statutory language or judicial decision.) There must in this sense be a dedication or holding out -- either express or implied -- of services to the public. The term thus precludes the idea of service that is private in nature and not to be obtained by members of the public. Some courts, in fact, reject the notion that in order to be a public utility subject to governmental regulation the nature of the service must be such that all members of the public have a normally enforceable right to demand it, and have declared any business to be a public utility which in fact serves such a substantial part of the public as to make its operations a matter of public concern. A recent Oklahoma Supreme Court decision broadly interprets a governmental right to regulate supplying process heat to a few companies.

In State of Oklahoma ex rel Jan Eric Cartwright v. Oklahoma Ordance Works Authority, 613 P.2d 476 (1980), the attorney general of the State of Oklahoma appealed an Oklahoma Corporation Commission decision that concluded that the Oklahoma Ordnance Works Authority (OOWA) did not serve the general public and thus could not be considered a public utility. OOWA produced steam, which it sold to a limited number of industrial customers. This steam was used exclusively for manufacturing processing. All but one customer of OOWA were located in the Mid-America Industrial District, which was owned and operated by OOWA. It was OOWA's contention that, because it served only a small number of customers, it should not be considered a public utility subject to the Oklahoma Corporation Commission. The attorney general contended that a determination of the legislative intent indicated that the legislature desired the Commission to regulate all supply systems of heat. In its decision, the Court agreed with the attorney general. The Court noted that the small number of OOWA patrons could not remove OOWA from the jurisdiction of the Commission. "The number of customers served does not establish service to the general public." Instead, the Court found that the legislature intended that the Commission have ratemaking authority and general jurisdiction over all steam-supply systems, regardless of how the customers utilize the steam or how many customers are served.

B.2 COMPETITION BETWEEN REGULATED UTILITIES

Since part of the rationale for controlling market entry is to avoid duplication of services, the question arises whether existing gas or electric utilities might successfully challenge attempts by DHC companies to obtain certification to operate within the existing utility's territory. The argument would be that district heating is unnecessary because an existing utility provides equivalent service. The most important determinant in such cases is likely to be the scope of the existing utility's own certification and of its actual operations. Such challenges have traditionally been successful only when the competing utility offers an identical service or commodity, or the same commodity in a different physical state. In such cases, the new entrant has typically been required to show that the certified utility has failed to render adequate service at reasonable rates. Direct use of DHC might compete with existing gas or electric utilities, but it does not offer an identical commodity. In general, courts and commissions have allowed firms that offer substitute fuels to enter a market; they have not construed the monopoly franchise so broadly as to preclude all forms of competition. Indeed, there has always been some interest in promoting competition even among specialized providers. An example of such promotion can be found in an Arkansas Supreme Court decision.

In Department of Public Utilities et al. v. Arkansas Louisiana Gas Company, 142 S.W.2d 213 (1940), the Louisiana Nevada Transit Co. filed an application with the Arkansas Department of Public Utilities for a certificate of convenience to serve an area being partially served by the Arkansas Louisiana Gas Co. After lengthy testimony, the Department granted Louisiana Nevada a certificate. A series of rehearings and appeals ensued. In its decision, the Arkansas Supreme Court found that the transport and distribution of natural gas is a business that should not be immune from competition. Since the gas to be offered by Louisiana Nevada would be considerably cheaper than that available from Arkansas Louisiana, the Court found that the Department of Public Utilities had acted properly in the interests of the affected gas customers. In so ruling, it held that that the Department's decision to allow competition to exist between the two gas companies was not an arbitrary decision. Instead, the Court found that the Department had based its decision on substantial grounds.

B.3 ABANDONMENT

About 40 states require commission approval of abandonment of service. In the remaining states, commissions exercise some control over abandonment pursuant to general supervisory authority. Most states have not established specific procedures or standards to be considered in approving abandonments. Usually, an application for approval must be filed with the state commission; the abandonment is allowed only if alternative service is available to the petitioning utility's customers. An example of an attempted steam-service abandonment may be found in an early Colorado Supreme Court case.

In Seaton Mountain Electric Light, Heat & Power Company et al. v. Idaho Springs Investment Company, 111 p. 834 (1910), the Seaton Co. had secured a franchise from the city of Idaho Springs authorizing it to supply, among other things, steam heat to various businesses and residences in the city. Later, Seaton assigned its interests to a leasing company, which notified Seaton's steam customers that their service was to be terminated unless the customers purchased all their electrical needs from the leasing company. It was argued by the company that not to do so would increase its operating expenses since it would have to generate live steam to supply its nonelectric steam customers. The Court was not convinced by this argument. In noting that quasi-public corporations are required to serve the inhabitants of the territory in which they operate, the Court found that Seaton "... cannot excuse its proposed action on the ground that furnishing steam alone will entail a loss which can be avoided if electric current is also taken by the consumer..." Instead, the Court found that the customer had the right to choose for himself the type of service he wished to use. The company's actions were regarded as simple coercion and disallowed.

B.4 ADVERTISING EXPENSES

A new district heating system may need to advertise substantially to attract subscribers. State commissions have taken a variety of positions with regard to expenditures for advertising. A few jurisdictions exclude all advertising expenditures from a utility's cost of service. A number of jurisdictions allow as an operating expense only that advertising which directly relates to energy conservation or which encourages customers to direct their usage to off-peak periods. Other jurisdictions have adopted a more flexible rule, which allows advertising as an operating expense where the utility can show it is of some material benefit to the utility customer. The introduction of competition has resulted in some commissions allowing expenditures for advertising costs incurred in meeting such competition. This has been tempered, however, by a concern that it is not in the public interest to encourage consumption of nonrenewable resources. An example of current thinking along this line may be found in a recent Ohio Supreme Court case.

In <u>City of Cleveland et al. v. Public Utilities Commission of Ohio et al</u>, 406 N.E. 2d 1370 (1980), the basis for granting a rate increase to the Cleveland Electric Illuminating Co. by the Public Utilities Commission of Ohio was questioned. In particular, the commission's allowance of certain advertising expenses was questioned. In considering this issue, the Ohio Supreme Court observed that utilities engage in basically four types of advertising: (1) institutional, which is designed to enhance or preserve the corporate image of the utility, and to present it in a favorable light; (2) promotional, which is designed to obtain new utility customers, to increase usage by present customers, or to encourage one form of energy in preference to another; (3) consumer or informational, which is designed to inform the customer of rates, charges and conditions of service, of benefits and savings to the customer, and of proper safety precautions and emergency procedures and similar matters; and (4) conservation, which is designed to inform the customer of the means whereby he can conserve energy and reduce his usage. Of these four types the Court found that only the last two provide direct, primary benefits to the customer. It held that unless the institutional and promotional advertising expenses could be clearly demonstrated to be a direct, primary benefit to the customers, they must not be allowed. Inasmuch as the utility could not so demonstrate, the expenses were disallowed by the Court.

B.5 INTERFERENCE WITH EXISTING CONTRACTS

The change from an unregulated to a regulated utility is accompanied by complications in existing contracts. For utilities that do not serve the public at large but that serve a few large industrial customers, individual contracts between utility and customer may be entered into. These contracts are not generally subjected to public utility commission review because a utility providing limited, specialized service is not regarded as a public utility. Instead, since the contracts are negotiated at "arm's length," no customer protection via the regulatory process is necessary. Expansion of such a utility, however, could result in its being considered a public utility. Under such circumstances, its privately negotiated existing contracts would be subject to scrutiny by the commission. An example apropos of such change may be found in an early California Supreme Court decision.

In Law v. Railroad Commission of California, 195 P. 423 (1921), the ability of the Commission to interfere with an existing long-term contract to supply steam was challenged. It was the plaintiff's contention that the Commission's action was an interference with a private contract and thus amounted to a violation of his constitutional rights. The Court disagreed with the plaintiff. Instead, it noted that, if the service contracted for was devoted to public use, the contract in question would properly be subject to the Commission's authority. In finding that such service was indeed so devoted, the Court upheld the Commission's ruling.

APPENDIX C

EXAMPLES OF PRO-DHC STATE LEGISLATION

This appendix briefly describes five state legislative bills that are intended to encourage the development of DHC systems. They are Minnesota House Bill 493 (introduced March 24, 1981); Washington Substitute Senate Bill 3033 (introduced Feb. 6, 1981); Nevada Senate Bill 164 (introduced Feb. 2, 1980; Colorado Senate Bill 481; and Illinois Senate Bill 361 (introduced March 21, 1979). Each has been signed into law except for the Washington bill, which is being reintroduced 1981-1982 session. Taken together, they illustrate a variety of ways that state legislative action can remove impediments to, or provide incentives for, the development of DHC systems.

C.1 MINNESOTA (HOUSE BILL 493)

The primary objective of this legislation is establishing a program of district heating loans to municipalities. The loans can be used for specified percentages of system design and construction costs, with the percentages depending upon the municipality.

The loan fund is administered by the Commissioner of Finance. Priority is to be given to a loan applicant who demonstrates, in one or more of the following ways, that his project:

- Employs cogeneration techniques;
- Uses renewable or nonpetroleum sources of energy;
- Reduces use of petroleum or natural gas without adversely affecting the environment;
- May be readily expanded to serve additional customers or supply additional amounts of energy; or
- Has obtained additional financing from the federal government, private sources, or other sources of capital.

The Minnesota Energy Agency has responsibility for promulgating rules governing this loan program.

The legislation expressly authorizes the various classes of municipalities to run or operate district heating systems, and it defines their powers in such an undertaking. Certain classes of municipalities are authorized to sell energy to customers located outside of their boundaries.

The legislation authorizes the district heating utility to purchase steam or hot water from other entities. When thermal energy is produced in a cogeneration power plant owned by a public utility, the legislation specifies four principles, with which the methods used to allocate costs between electrical and thermal energy produced must be consistent. These principles are as follows.

- The method used shall result in a cost per unit of electricity no greater than the cost per unit from an electricity-only power plant, owned by the public utility.
- Costs incurred by a public utility for the exclusive benefit of the district heating system, including but not limited to backup and peaking facilities, shall be assigned to thermal energy produced by cogeneration.
- The methods and procedures used for retrofitted cogeneration plants may differ from those used for new cogeneration plants.
- The methods should encourage cogeneration but should also prevent subsidization of thermal customers by electricity customers; both heat and electricity customers should be treated fairly and equitably with respect to the costs and benefits of cogeneration.

The legislation appropriated $49,970,000 to develop DHC systems -- with $43,170,000 of that appropriation for loans to municipalities. The remainder is earmarked for specific district heating projects, such as systems for the State Capitol complex and Moorhead State University.

C.2 WASHINGTON (SUBSTITUTE SENATE BILL 3033)

In contrast to the Minnesota legislation, which provides financial support for municipal district heating systems, the primary objective of this bill is to remove legal impediments to municipal ownership and operation of such systems. Municipalities are corporate entities that exist by virtue of state law. They posses no inherent powers, but rather only those powers granted to them by the constitution or by statute. The traditional view, termed Dillon's Rule, is that a legislative grant of power is to be construed strictly against a municipality.

The Washington bill expressly and in detail grants a municipality, which is defined to include counties and park districts but to exclude public utility districts, the power to own and operate a DHC system. A municipally owned system is permitted to serve persons outside the corporate limits of the municipality and can condemn property for the distribution system, although to the extent feasible public lands should be used. The municipality cannot acquire heat sources by condemnation, however.

C.3 NEVADA (SENATE BILL 164)

This bill amends several statutes. It is intended to encourage the use of geothermal energy for district heating by reducing statutory uncertainty. It amends the water resources statutes such that the use of geothermal resources for domestic heating is now defined as a "beneficial" use. Under Nevada law, a use of water must be "beneficial" to be allowed. The bill defines corporations or persons selling geothermal energy to the public as public utilities subject to the jurisdiction of the utility regulatory commission.

But it exempts from this jurisdiction publicly owned geothermal utilities and entities engaged in the production and sale of geothermal energy to public utilities and to others for resale to the public. It also requires an applicant for a permit to construct a new energy production facility using fossil fuels to examine, among other things, conservation measures and alternative sources of energy, including goethermal sources.

C.4 COLORADO (SENATE BILL 481)

This bill enables municipalities and "county improvement districts" to own and operate district heating and cooling systems that use geothermal resources, solar or wind energy, hydroelectric power, renewable biomass resources, waste heat, or cogenerated heat. Improvement districts are taxing units that may be created within counties to make specified kinds of improvements. Powers are given for the condemnation and appropriation of private property, including heating and cooling works. The bill specifies, however, that the rendering of local gas and electric service by public utilities under the jurisdiction of the state's Public Service Commission should not be adversely affected.

C.5 ILLINOIS (SENATE BILL 361)

Many DHC systems currently operating serve a university or hospital complex. The heat is solely for internal use, and the facilities are entirely contained within the complex -- so that there is little if any regulation. If the complex is located in an urban area, it may be technically and economically feasible to sell excess heat to neighbors. When the university or hospital is a state institution, however, there is a question of whether its enabling statute enpowers it to go into the business of selling hot or chilled water.

This legislation enables state universities to operate energy facilities that make retail sales of excess energy. It also exempts from regulation by the Illinois Commerce Commission a state university when it does so. The bill was introduced to allow the University of Illinois to purchase a district heating system that serves its medical school and hospital, and other hospitals as well, in a medical center approximately two miles west of downtown Chicago.

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