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Technical Memo

ARGONNE NATIONAL LABORATORY
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MASTER

ASSESSMENT OF POTENTIAL
AND EXISTING PROBLEMS CONCERNING INTERFACE
BETWEEN ELECTRIC UTILITIES AND COGENERATORS

Prepared by

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for

Energy and Environmental Systems Division
Argonne National Laboratory
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ABSTRACT

In assessing the potential and existing problems, concerning the interface between U.S. electric utilities and cogenerators, this report considers the issues by region and draws conclusions therefrom. Also considered are regulatory barriers, rates and contracts, economic feasibility, and impact on system planning. Finally, the impact of the National Energy Act on the marketability potential of cogeneration is reviewed. The three appendixes summarize the utility meetings on cogeneration held in Washington, D.C., Los Angeles, and Chicago.

1 INTRODUCTION

The purpose of this analysis is to evaluate the U.S. market for cogeneration. As defined by IEEE, cogeneration is the coincident generation of electric power or mechanical shaft power in combination with useful thermal energy supply. These types of systems are also called "topping" cycles and are typified by systems where heat is recovered following expansion through steam or combustion turbines. Cogeneration also applies to "bottoming" cycles where electric power or mechanical shaft power is generated by energy recovered from any process having a byproduct of combustible waste, or exothermal processes such as from smelters, blast furnaces, black-liquor recovery, bark, refuse, hydrogen, refinery gas, pulp digesters, thermomechanical pulping, or from fluids and/or condensate having temperatures of 200°C (392°F) or less. Contrary to common misconception, cogeneration does not require electrical connections to other generating systems or any restrictions as to types of ownership. During the past five years, interest has increased in this mode of jointly producing heat as needed by industry (and other large-scale users) and electric power. Two basic problems have spurred this interest. First, the Nation has come to realize that there are limits to the energy that can be brought to market economically. Second, largely for environmental reasons, so many obstacles have blocked the construction of utility generating stations that a real likelihood of shortages exists in generating capacity by the late 1980s and early 1990s.

Cogeneration offers a partial solution to both of these problems. Where appropriate, cogeneration is a more efficient form of producing a combination of heat and electricity than are separate installations using steam boilers. Furthermore, electric generating capacity can be enhanced by a number of on-site generating facilities where byproduct electricity is made available to the central generating systems.

In the final analysis, economics must delineate the instances where these two general principles are applicable. Shortage is always shortage at any price, and the idea of selling "surplus" power by a cogenerator to a utility depends on whether it is economically sound for the utility to cooperate. Otherwise, its customers would be subsidizing private cogenerators' operations. Similarly, it must be economical for the cogenerator to operate in this mode. Finally, the economics of these operations are governed by the site-specific interface between a utility and a potential cogenerator. All that can be attempted here is a discussion of the principles that should govern the making of these arrangements and an illustration of how these principles can actually be applied.

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2 POTENTIAL FOR ECONOMIC INTERFACE BETWEEN U.S. ELECTRIC UTILITIES AND COGENERATORS

The conceptual bases for utility evaluation of cogeneration projects and establishment of policy guidelines concerning such projects should be the same as those used to evaluate any other alternative energy project, e.g., additions to utility-owned plant. To minimize costs, the process used to evaluate projects requires that the utility look at costs at the margin (i.e., long-run incremental costs). Although it is appropriate to account for differences in reliability among alternative projects, there is no reason for utilities to put cogeneration on a different basis from other alternative energy projects.

As will be discussed later, the concept of utilizing a utility's marginal cost in evaluating the feasibility of purchasing from a cogenerator is recognized in the requirements of Section 210 of Title II of the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 210 requires, among other things, that...the rate charged by a cogenerator shall not exceed the incremental cost to the electric utility of alternative electric energy.

Thus, both economic efficiency and the mandate of Congress require that utilities evaluate cogeneration projects by looking at their costs at the margin. The potential market penetration level which cogenerators can achieve will be based largely on their ability to produce electricity for sale to electric utilities at a cost that does not exceed the utilities' costs so measured.

Because of the many factors involved, e.g., a utility's "need" for capacity and energy, lead-time problems, capacity availability, etc., a first step toward evaluating potential cogeneration projects is the quantification of the marginal cost of electricity to the utilities. Completion of this step will give potential cogenerators some guidelines as to the likely price of cogenerated electricity they can expect to receive from the utilities.

Tables 2.1 through 2.6 estimate the likely marginal costs of selected electric utilities in the various regions of the country.* The basis for these estimates is a series of analyses that quantifies the marginal costs facing various utilities throughout the country. A detailed discussion of the quantification approach can be found in Refs. 1 and 2 as incorporated into the Electric Power Research Institute's Rate Design Study. All costs are time differentiated and reflect the long-run marginal cost of an additional kW or kWh. These costs are presented on a disaggregated basis, i.e., per kW of capacity and per kWh of energy for each pricing period. Also presented in Tables 2.1 through 2.6 is the resulting "rolled-in" cost per kWh that would occur during specific periods. In particular, the cost per kWh is presented for each utility for three potential types of purchase/sell agreements.

*The marginal costs discussed here consist of costs at the generation and transmission level of service, because it is expected that potential cogenerators will offer electricity to utilities at that level of service. All costs are in 1978 dollars.

Table 2.1. Electricity Costs^a By Region--
New York, New England

Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
			A	B	C
			100% Load Factor	Peak Hours Only	Off-Peak Hours Only
			----- (¢/kWh) -----		
1) <u>Central Maine</u>					
Winter (Nov.-Feb.)			4.28	6.06	2.84
On Peak					
(Weekdays 7 a.m.-10 p.m.)	3.21	36.62			
Off Peak	2.84				
Base (March-Oct.)			3.35	3.98	2.84
On Peak					
(Weekdays 7 a.m.-10 p.m.)	3.21	20.25			
Off Peak	2.84				
2) <u>Rochester Gas & Electric</u>					
Summer/Winter					
(Dec.-Feb., June-Sept.)			3.68	5.66	1.87
On Peak					
(Weekdays 6 a.m.-10 p.m.)	2.34	80.40			
Off Peak	1.87				
Base (March-May, Oct.-Nov.)			2.34	2.85	1.87
On Peak					
(Weekdays 7 a.m.-10 p.m.)	2.85				
Off Peak	1.87				
3) <u>Con Edison</u>					
Summer (May-Sept.)			8.01	15.32	2.77
On Peak					
(Weekdays 8 a.m.-10 p.m.)	4.13	171.29			
Off Peak	2.77				
Base (Oct.-April)			3.16	3.70	2.77
On Peak					
(Weekdays 8 a.m.-10 p.m.)	3.56	2.81			
Off Peak	2.77				

^aIn 1978 \$.

Table 2.2. Electricity Costs^a By Region--
Middle Atlantic Southeast

Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
			A 100% Load Factor	B Peak Hours Only	C Off-Peak Hours Only
			----- (¢/kWh) -----		
1) <u>VEPCO</u>					
Summer/Winter (Dec.-Feb., July-Sept.)			4.28	6.63	3.13
On Peak (Weekdays 10 a.m.-10 p.m.)	4.70	30.18			
Off Peak	2.80	5.16			
Base (March-June, Oct.-Nov.)			3.86	5.49	3.09
On Peak (Weekdays 10 a.m.-10 p.m.)	4.30	18.72			
Off Peak	2.80	4.50			
2) <u>Duke Power & Light</u>					
Summer (July-Sept.)			2.86	5.85	1.43
On Peak (Weekdays 10 a.m.-9 p.m.)	2.95	27.83			
Off Peak	1.43				
Base			2.20	3.83	1.43
On Peak (Weekdays 10 a.m.-9 p.m.)	2.38				
Off Peak	1.43				
3) <u>TVA</u>					
Winter (Dec.-Feb.)			2.07	2.62	1.67
On Peak (Weekdays 7 a.m.-10 p.m.)	1.78				
Off Peak	1.67				
Summer (June-Sept.)			2.16	3.04	1.57
On Peak (Weekdays 9 a.m.-10 p.m.)	2.20				
Off Peak	1.57				
Base (March-May, Oct.-Nov.)					

^aIn 1978 \$.

Table 2.3. Electricity Costs^a By Region--
Midwest

Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
			A	B	C
			100% Load Factor	Peak Hours Only	Off-Peak Hours Only
			----- (¢/kWh) -----		
1) <u>WEPCO</u>					
Summer (July, August)			3.65	7.86	1.00
On Peak					
(Weekdays 9 a.m.-10 p.m.)	2.10	33.18			
Off Peak	1.00				
Winter (Nov.-Jan.)			3.41	6.17	1.20
On Peak					
(Weekdays 7 a.m.-10 p.m.)	2.70	34.22			
Off Peak	1.20				
Base (Feb.-June, Sept.-Oct.)			2.36	3.91	1.10
On Peak					
(Weekdays 7 a.m.-10 p.m.)	2.30	36.29			
Off Peak	1.10				
2) <u>Dayton Power & Light</u>					
Summer (June-August)			2.38	5.05	1.25
On Peak					
(Weekdays 11 a.m.-9 p.m.)	2.21	18.63			
Off Peak	1.25				
Winter (Dec.-Feb.)			3.32	6.07	1.36
On Peak					
(Weekdays 7 a.m.-9 p.m.)	2.84	29.04			
Off Peak	1.36				
Base (March-May, Sept.-Oct.)			2.44	4.09	1.25
On Peak					
(Weekdays 7 a.m.-9 p.m.)	1.89	40.26			
Off Peak	1.25				
3) <u>Minnesota Power & Light</u>					
On Peak			3.22	5.46	1.20
(Weekdays 6 a.m.-11 p.m.)	2.60	126.88			
	1.20				

^aIn 1978 \$.

Table 2.4. Electricity Costs^a By Region--
Southwest

Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
			A	B	C
			100% Load Factor	Peak Hours Only	Off-Peak Hours Only
			----- (¢/kWh) -----		
1) <u>Public Service New Mexico</u>					
Summer (June-August)			3.45	8.59	1.83
On Peak					
(Weekdays 11 a.m.-7 p.m.)	2.53	31.91			
Off Peak	1.83				
Winter (Dec.-Feb.)			2.67	4.00	1.72
On Peak					
(Weekdays 8 a.m.-10 p.m.)	2.36	14.77			
Off Peak	1.72				
Base (March-May, Sept.-Nov.)			2.84	3.96	2.04
On Peak					
(Weekdays 8 a.m.-10 p.m.)	2.82	20.87			
Off Peak	2.04				
2) <u>Tucson Gas & Electric</u>					
Summer (June-Sept.)					
On Peak					
(Weekdays 10 a.m.-10 p.m.)					
Off Peak					
Base (Oct.-May)					
On Peak					
(Weekdays 10 a.m.-10 p.m.)					
Off Peak					
Annual	2.39	58.83	3.05	4.26	2.51
3) <u>Public Service Company of Colorado</u>					
Summer (July-August)			3.51	6.18	1.59
On Peak					
(Weekdays 9 a.m.-11 p.m.)	2.04	25.83			
Off Peak	1.15	3.78			
Winter (Nov.-Feb.)			1.96	2.87	1.57
On Peak					
(Mon.-Sun. 4 p.m.-11 p.m.)	1.61	10.59			
Shoulder					
(Mon.-Sun. 6 a.m.-4 p.m.)	1.36	5.30			
Off Peak					
(Mon.-Sun. 11 p.m.-6 a.m.)	1.07	1.51			
Base			1.98	2.53	1.60
On Peak					
(Weekdays 9 a.m.-11 p.m.)	1.57	17.41			
	1.15	11.36			
Off Peak					

^aIn 1978 \$/

Table 2.5. Electricity Costs^a By Region--
Northwest

Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
			A	B	C
			100% Load Factor	Peak Hours Only	Off-Peak Hours Only
			-----	(¢/kWh)	-----
<hr/>					
1) <u>Pacific Power & Light</u>					
Winter (Nov.-March)			4.07	5.12	
On Peak					
(Weekdays 6 a.m.-7 p.m.)		38.95			
Off Peak					
Summer (April-Oct.)			3.04	3.08	
On Peak					
(Weekdays 8 a.m.-10 p.m.)		2.05			
Off Peak					
Annual	3.00				3.00
<hr/>					
2) <u>Puget Sound Power & Light</u>					
Winter (Nov.-March)			4.13	7.50	
On Peak					
(Weekdays 7 a.m.-10 a.m., 5 p.m.-9 p.m.)		44.65			
Off Peak					
Summer (April-Oct.)			2.95	3.07	
On Peak					
(Weekdays 7 a.m.-10 a.m., 5 p.m.-9 p.m.)		2.35			
Off Peak					
Annual	2.90				2.90

Table 2.6. Electricity Costs^a By Region--
West and South

West	Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
				A	B	C
				100% Load Factor	Peak Hours Only	Off-Peak Hours Only
				----- (¢/kWh) -----		
1) <u>Southern California Edison</u>						
Summer (May-Oct)				3.58	6.17	3.02
On Peak						
(Weekdays 12 a.m.-6 p.m.) 2.88 25.94						
Off Peak 2.84 6.50						
Base (Nov.-April)				3.49	5.95	3.06
On Peak						
(Weekdays 5 p.m.-10 p.m.) 2.94 19.44						
Off Peak 2.87 7.06						

^aIn 1978 \$.

South	Utility	Energy Cost (¢/kWh)	Capacity Cost (\$/kWh)	Total Cost/kWh		
				A	B	C
				100% Load Factor	Peak Hours Only	Off-Peak Hours Only
				----- (¢/kWh) -----		
1) <u>Arkansas Power & Light</u>						
	Summer (June-Sept.)			3.22	6.26	1.92
	On Peak					
	(Weekdays 11 a.m.-9 p.m.)	2.34	34.20			
	Off Peak	1.92				
	Winter (Dec.-Feb.)			2.24	2.96	1.89
	On Peak					
	(Weekdays 6 a.m.-12 p.m.,		5.70			
	4 p.m.-9 p.m.)	2.15				
	Off Peak	1.89				
	Base (March-May, Oct.-Nov.)			2.04	2.57	1.70
	On Peak					
	(Weekdays 7 a.m.-8 p.m.)	2.04	7.60			
	Off Peak	1.70				

^aIn 1978 \$.

The first arrangement is the 100% load factor agreement whereby the cogenerator provides firm power to the utility at all times (subject to scheduled maintenance and forced outage conditions). In the second type of arrangement, the cogenerator provides electricity during the utility's peak period. In the third type of arrangement, the cogenerator provides electricity to the utility during the utility's off-peak period. Many other arrangements are possible, and those mentioned may not turn out to be the most typical.

As shown in Table 2.7, the marginal costs facing utilities vary widely among and within regions. Perhaps more significant for the potential cogeneration market is the wide variation of costs depending on the season and time of day when the electricity is offered. Moreover, it is likely that, for some utilities, the price they would be willing to pay for electricity may be well below the long-run marginal costs set forth in Tables 2.1 - 2.6. Several utility systems, particularly in the Northeast, presently have excess capacity (with reserve margins exceeding 40% in some cases). This condition is expected to continue for several years.

The economic feasibility of cogenerator/utility interface would likely be seriously hampered if a capacity credit to the cogenerator were not economic. In the following example, using Duke Power Company's estimated marginal costs under various types of interface arrangements with and without marginal capacity costs, the significant effect of excluding capacity costs is illustrated.

Thus, the utility's need for capacity will materially affect the price received by a cogenerator for its electricity. Moreover, the cogenerator's ability to provide the electricity when the utility needs it will also affect the price received by the cogenerator. With respect to energy, however, the utility should always desire to displace any energy costing more than the cogenerator's energy.

Quantification of the marginal cost of electricity is a useful step toward evaluating the potential market for cogeneration. The next step in such an evaluation would involve estimating the cost characteristics of various cogeneration arrangements. In particular, it will be necessary to examine the cogenerator's cost over its load cycle. Cost estimates based on the cogenerator's average costs could mask opportunities for economic interface with a utility.

2.1 REGIONAL ANALYSIS

An overview of the potential for cogeneration/utility interface for the various regions (and utilities) has been set forth in the following sections.

Table 2.7. Duke Power Co's Long-Run Marginal Costs
with and without Capacity Costs

(1) Capacity Costs Included

<u>Period</u>	<u>100% Load Factor</u>	<u>Peaking Service Arrangement c/kWh</u>	<u>Off-Peak Service Arrangement</u>
Summer Period	2.86	5.85	1.43
Base Period	2.20	3.83	1.43

(2) Capacity Costs Not Included

	<u>100% Load Factor</u>	<u>Peaking Service Arrangement c/kWh</u>	<u>Off-Peak Service Arrangement</u>
Summer Period	2.02	2.95	1.43
Base Period	1.80	2.38	1.43

2.1.1 New York/New England

As indicated in Table 2.1, marginal energy costs in this region are high and reflect the large percentage of oil-fired generation in this area. However, the long-run marginal capacity costs shown for utilities in this region are substantially above the price that the utilities actually would be willing to pay a potential cogenerator because of the excess capacity situation. Current costs for renting capacity in this region approximate \$20/kW/yr. Although, it might be possible through energy efficiency for a potential cogenerator, using oil-fired capacity, to have energy costs below the utility's peak period marginal energy costs, it is unlikely that a utility in this region could offer a material capacity credit to the cogenerator. Moreover, utilities in this region are trying to reduce their reliance on oil-fired generation.

2.1.2 Middle Atlantic/Southeast

Widespread variation in marginal costs exists in this region and reflects the different mix of generation of each utility examined. Virginia Electric Power Co. (VEPCO), with approximately equal coal, oil, and nuclear generation, has relatively high marginal oil, nuclear, and hydro-generating sources, has fairly high peak period marginal energy costs but very low off-peak energy costs. TVA, which is heavily dependent on coal and hydro, has the lowest marginal costs of any utility studied.

As a result of meetings with utility representatives, it has become clear that VEPCO, for instance, was interested in exploring the potential for utility/cogenerator interface because of a potential shortage of capacity as a result of delays in getting planned units on line. Similarly, other utilities in this region may require future alternative peaking capacity as the expansibility of hydro becomes limited.

2.1.3 Midwest

In terms of generation mix, the Midwest utilities studied, are considered to be the closest to optimal of the utilities examined. These utilities have indicated that their present expansion plans to not include additional oil-fired peaking units even though, in theory, adding peaking units would be the best alternative. Rapid increases in oil prices and fear of supply shortages were cited as reasons for their position. Therefore, the needs of those utilities are for non-oil-fired peaking capacity; but will coal be able to meet the challenge?

2.1.4 Southwest

The utilities in this region are faced with rapidly expanding demands for electricity, which are being met primarily through additional baseload

coal and nuclear capacity as seen in their off-peak marginal energy costs. The potential for cogeneration in this region would seem to be in those instances where delays in planned-for coal or nuclear units could lead to capacity shortages. However, it is unlikely that oil-fired cogeneration would be economical in this area.

2.1.5 Northwest

The utilities in this region are in a transitional stage as they move from hydraulically dominated systems to thermal-based systems. The transitional process is expected to continue for several more years. As a result of this transition, which is caused primarily by the lack of additional sources of hydroelectric power, the marginal costs facing these utilities are considerably higher than their present rates. The opportunity for cogeneration/utility interface is probably greatest in this region, particularly where the cogenerator's fuel source is wood. The full potential for cogeneration has not yet been realized because cogenerators were competing against very inexpensive hydropower. Soon this will no longer be the case.

2.1.6 South

Utilities in this region also are in a transitional stage as they switch from gas- and oil-fired generating capacity to coal- and nuclear-based capacity. Cogeneration (non-oil-fired) may have a limited role here, similar to that in the Southwest, i.e., helping to bridge any capacity gap caused by delays in planned-for units coming on line.

2.1.7 West

Utilities on the West Coast face potential capacity shortages in the 1980s caused by in-state siting problems. They are also heavily dependent on oil-fired generation. The potential for cogenerator/utility interface should be relatively high, particularly because of the California Public Utility Commission's leading role in encouraging cogeneration.

2.2 CONCLUSIONS

Although there are several regions where the potential for economic cogeneration/utility interface may be significant, any definitive analysis would require an examination of the cost characteristics of cogeneration under various load configurations and assumptions as to the fuel used in cogeneration. Nevertheless, it is evident that the potential for cogeneration would be greatly expanded were feasible means developed to utilize coal in the potential cogeneration market.

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3 UTILITIES AND COGENERATION: AN OVERVIEW

As part of a review of the economic and practical ramifications of an interface between electric utilities and cogenerators, several meetings with utility representatives were held in various parts of the country, such as Washington, D.C., Los Angeles, and Chicago. The minutes of each of these meetings are included as Appendixes A, B and C, respectively.

Although the level of cogeneration activity in different parts of the country varies widely, the issues concerning the utilities do not. Areas of primary concern are regulatory barriers, rates and contracts, economic feasibility, and impact on system planning.

3.1 REGULATORY BARRIERS

Some areas of extensive discussion included:

- (1) how the Public Utility Regulatory Policies Act of 1978 (PURPA) would finally be implemented;
- (2) what the guidelines would be; and
- (3) how the guidelines would affect the provisions of other state and federal statutes.

The lack of specific guidelines was seen as a pervasive problem, as was the uncertainty of who was going to regulate what and how much. Because it is anticipated that cogenerators and small power producers will be members of the private sector, it was generally agreed that these entities would not be willing to subject themselves to further regulation.

3.2 RATES AND CONTRACTS

The development of practical rates and the negotiation of reasonable contracts were perceived as areas of difficulty. Three questions were raised:

- (1) What rate structure would be most equitable to both the utility and the cogenerator and truly reflect the costs and benefits to each?
- (2) How would the reliability of the power be taken into consideration?
- (3) Could the entities negotiate a contract, or would the existing rate schedules and provisions of the utility apply?

As yet, there are no clear-cut answers to these questions. The restrictions on and regulation of contracts and rates vary from jurisdiction to jurisdiction. Until the final PURPA guidelines are formulated and put into effect and state regulatory bodies promulgate their own guidelines, this area will remain murky.

3.3 ECONOMIC FEASIBILITY

Whether cogeneration technologies would prove to be cost effective and efficient was felt to be another problematic area. Considering the economies of scale present in the generation of electricity, the small size of most cogeneration projects may preclude them from producing electricity at a competitive price. The most prevalent suggested fuel source was oil which is now in disfavor; modest-sized, environmentally satisfactory coal installations are not yet approaching market readiness. The exotic nature of some forms of fuel (e.g., biomass) and the newness of the technology may prevent some suggested forms of cogeneration from becoming effective methods of energy production.

3.4 IMPACT ON SYSTEM PLANNING

Inclusion of cogeneration in the system planning process may be difficult. The potential for cogeneration and small power production projects becoming significant elements in the utilities' plans appears to be limited. Given the anticipated small size of these projects, and the fact that many utilities plan additions in relatively large blocks of capacity, inclusion of some cogeneration projects into the system planning process may present problems. Moreover, differences in planning horizons and length of plant life are factors to be taken into consideration. Conversely, if several projects were to be feasible and come on line, they should become part of the system planning process.

3.5 SUMMARY

In general, the utilities indicated a willingness to consider cogeneration and small power production projects within their service territories. Many of the utilities represented at the meetings either have cogenerators operating within their territories or are engaged in dialogues with potential cogenerators. However, they also feel that murky areas and issues must be clarified before economic interface between utilities and cogenerators can occur on a consistent and efficient basis. Thus, the degree to which a utility can actually count on the cogeneration capacity raised another problem.

4 POTENTIAL OF COGENERATION IMPACT OF NATIONAL ENERGY ACT ON MARKETABILITY

A review of those portions of the National Energy Act (the Act) that relate to cogeneration has been made to determine to what extent this new direction in energy policy could affect institutional and economic barriers to the development of cogeneration.

Although the Act improves the position of potential cogenerators, definitive departmental rules have not yet been established. Four sections of the Act relate to cogeneration:

- (1) PURPA,
- (2) the Fuel Use Act,
- (3) the Energy Tax Act, and
- (4) the National Energy Policy and Conservation Act (NEPCA).

Section 210 of PURPA describes the method of fixing payments by and to cogenerators for services of a public utility nature. The stated purpose of the Act is to foster such projects. Utilities are obligated to purchase surplus power from cogenerators and are obligated further to sell backup and supplemental power to such facilities at nondiscriminatory prices. Moreover, the facilities are exempted from certain provisions of the Federal state laws and regulations (but not from NEPCA). This section delineates the methodology by which prices for cogenerators' surplus electricity may be sold to the utilities, essentially on an incremental cost basis (called "avoided costs" in the most recent rulemaking proposal by FERC). This rule also describes the principles that should govern utility charges to the cogenerators for supplemental or backup service.

In this respect, the rules of FERC have not been formally adopted, but they are taking shape. In general, the rules rely on the Section 133 filings (November, 1979) by utilities for the data on which costs (and prices) may be computed. Concerning the actual computations, FERC proposes to rely on the state commissions having jurisdiction to provide the detailed rules for the price schedules that will govern the flow of service to and from cogenerators. These schedules will be utility-specific.

Until any state has taken action on proposed schedules, it is useless to speculate on the extent to which utility payments will actually "encourage" the development of cogeneration. For example, it is likely that the incidence of peak demands often may be the same on both the utility's system and the cogenerator's system. This would mean that their off-peak periods (nights and weekends) would likely be generally the same. If such is the case, the cost basis of the energy component of the credit for service (on the basis of "avoided" costs) may not encourage the provision of much surplus power to the utilities (or much net revenue to the cogenerator who, in most cases, will be paying the equivalent of diesel fuel costs). Moreover, the potential of capacity credit allowances for the sale of electricity to utilities presents additional uncertainties. Factors, such as the degree of

utility control over the purchase (its assurance that the capacity will be available), the durability of the contract, and, in some areas, the surplus capacity situation among utilities all will tend to shrink the capacity credit component of the rate. Nevertheless, until federal and state rules actually are promulgated and there are illustrations as to how these perplexing problems are going to be treated, nothing definitive can be offered. Proposed FERC Rules in Dockets 79-54 and 79-55 only lay the groundwork.

The exemption from certain provisions of the Federal Power Act--particularly the ratemaking provisions--are important, but they pertain principally to mitigating the institutional obstacles to making these arrangements rather than to improving their economics.

Perhaps the greatest single encouragement in these days of oil scarcity is the provision in the Power Plant and Industrial Fuel Use Act that permits the Secretary to exempt cogenerators from the prohibitions against using gas and oil to generate electricity.

Section 212(c) of the Act, as administered by the Secretary, is expected to favor cogeneration development--particularly with the legislative concern that has been expressed in this area. Thus, it is extremely important to the small- and medium-size potential cogenerators that they be permitted to use diesel fuel or natural gas. Without these exemptions, and unless coal-burning in smaller installations becomes feasible, cogeneration would likely be precluded as an energy-saving technique.

Section 301 of The Energy Tax Act appears to allow the full 20% investment tax credit for cogeneration facilities; but the regulations adopted by the Department of Treasury will have to be developed fully to define the extent to which this apparent intention for the full 20% tax credit will be uniform and readily applicable.

Utilities have expressed concern that the Act and FERC's rules seem to discourage utility-owned cogeneration projects. For example, utility-owned cogeneration projects apparently would not be exempt from the rate provisions of the Federal Power Act. Moreover, utility-owned cogeneration projects may not be eligible for the full 20% tax credit.*

Contrarily, it can be argued that utilities always have had sufficient incentive to undertake cogeneration projects, where economic, and that the purpose of the Act was to encourage new entries into the electricity supply field.

In either case, it seems unlikely that any further incentives will be provided to utilities to undertake cogeneration projects. Rather, it would seem that if the economics were right, i.e., if the utilities' costs would be minimized, no artificial incentives should be required.

Finally, if necessary, the NEPCA may facilitate the financing of cogeneration facilities. However, of all the provisions of the Act, financing seems to be the least significant, in terms of promoting cogeneration.

*The rules permit utility minority holdings, but without control.

Because of the uncertainties surrounding cogeneration development -- including the future availability and price of oil and gas -- they will likely be undertaken in most cases on a relatively short pay-back basis. In this case, financing would not present a serious problem. These developments will have to be watched to learn how the various mortgage facilities are applied to "energy conservation improvements." The above analysis suggests various developments that will bear watching, in terms of whether the encouragement offered by Congress is actually borne out in the implementation stage.

REFERENCES

1. National Economic Research Associates, Inc. (NERA), *A Framework for Marginal Cost-Based, Time-Differentiated Pricing in the United States: Topic 1.3* (Feb. 21, 1977).
2. National Economic Research Associates, Inc. (NERA), *How to Quantify Marginal Costs: Topic 4* (March 10, 1977).

APPENDIX A

Summary of Utility Meeting on Cogeneration
Washington, D.C.
March 8, 1979

A.1 INTRODUCTION

A meeting, sponsored by Argonne National Laboratory (Argonne) and National Economic Research Associates, Inc. (NERA), was held on March 8, 1979 at NERA's Washington, D.C. office. In attendance were representatives of Argonne, NERA, and six electric utilities (listed at the end of this appendix). The purpose of the meeting was to explore the economic and practical ramifications of the interface between electric utilities and cogenerators and potential problem areas associated with this interface.

L. T. Mahoney, Jr. (NERA) opened the discussion and outlined the primary areas for initial discussion. Personnel from Argonne then presented a summary of recent activities in the field of cogeneration and related areas.

A. S. Kennedy (Argonne) first described the studies undertaken with respect to the Integrated Community Energy System (ICES) Program and its commercial potential, both as a grid-connected component and as an autonomous entity. He indicated that Argonne's interest in this area was twofold: first, to analyze the potential of emerging energy technologies from the viewpoints of economic efficiency and energy conservation, and second, to develop marketing strategies to further the commercialization and expanded use of those technologies that are likely to be economically feasible and energy efficient.

Next, a representative of Consolidated Edison Company of New York (Con Edison) commented that, with respect to oil-fired cogeneration, net lifetime use of oil, rather than energy efficiency, would be more appropriate as a qualification for the development of cogeneration projects.

I. von Zuckerstein (Argonne) then described several projects in which Argonne has been active: specifically, ICES installations at Clark University in Massachusetts; Trenton, New Jersey; New Orleans, Louisiana; and in Northern Minnesota.** Mr. von Zuckerstein outlined the primary economic and institutional obstacles to the interface of ICES cogenerators and electric utilities, i.e., reliability, problems of integration with utility generation dispatch, pool requirements, and financial incentives from the utilities' point of view.

*National Economic Research Associates, Inc.

**It was noted that the above-cited projects were not a complete list of Argonne activities in the cogeneration area; other potential projects were dropped when it became clear that the economics were not favorable. In addition, not all of the projects cited above are in operation as yet.

At this point, Mr. Mahoney interjected that if the basic economics of cogeneration made sense, many of these presently perceived obstacles would tend to disappear.

P. Donnelly (Argonne) next described some of the present regulatory impediments to an economic interface between electric utilities and potential cogenerators. He indicated that, in his opinion, there are many instances where government agencies are operating at cross-purposes -- sometime at the same level of government.

I. Sewell (Department of Energy) observed that his office was not committed to any particular technology. Instead, DOE was seeking input as to if, how, and where a variety of emerging energy technologies could be integrated into existing energy delivery systems. He indicated that his office was taking a multifaceted approach to the problem and would move forward without preconceptions on whatever was workable.

A brief overview of the work performed by NERA for Argonne during the past year was presented by Mr. Mahoney, who suggested that an important consideration for both utilities and potential cogenerators is the necessity of undertaking a rational economic evaluation of potential interface opportunities. Such an evaluation must be based on (utility and cogenerator) costs at the margin. He concluded by saying that while, in his opinion, cogeneration was not likely to be the panacea that some are hoping for, it may be appropriate in certain circumstances. The key is to find the appropriate utility-cogenerator match.

After these introductory remarks, the meeting was opened to the floor, and discussion turned to the wide-ranging issues concerning potential utility-cogenerator interface.

B. Netschert (NERA) suggested that a definition of the term cogeneration could be formulated, and the following working definition was adopted:

Cogeneration is the capability of producing both thermal and electrical energy with the potential to produce additional electricity to sell to electric utilities.*

Virginia Electric and Power Company (VEPCO) representatives indicated that their company was now exploring the possibility of purchasing up to 200 MW of capacity and energy from a group of paper mills, all of which are also customers of VEPCO. As the range of issues that emerged from such discussions was presented, the group was able to focus with greater clarity on the emerging questions raised by utility-cogenerator interface. The major issues discussed are summarized below.

*After the meeting, it was suggested that the above definition of cogeneration was perhaps too general. One participant offered the IEEE definition as an alternative. It is included in the Introduction to this report.

A.2 RELIABILITY

The group agreed that, to a certain extent, the use of the term, reliability, was a serious misapplication. The real concern is whether the cogenerator would give as much priority to the dispatch of power to the utility as it does to its primary business of producing the goods that are its main source of revenue.

From the utility's point of view, the ideal situation would be for it to have its "finger on the button" that controls the integration of the cogenerator's output with the utility's system. Cogenerators would not allow this because, in effect, they would be surrendering control of their plants. Contrarily, it became clear that the cogenerator must understand that to receive credit for firm capacity, that capacity must be available when the utility requires it. The cogenerator must recognize that an agreement to provide capacity and associated energy to a utility is no less binding than commitments to its customers to provide the goods it manufactures.

Similarly, utilities should see that it is to their advantage to contract for capacity with several cogenerators so that diversity can be achieved, and the potential shortage cost can be reduced. This, in turn, would provide an incentive to the utility to contract for capacity as well as for energy.

Another way to solve this problem would be for the cogenerator to have its own backup power to provide capacity whenever the utility requires it.

A.3 UTILITY STANDBY RATES

It was agreed that, in some cases, the present standby rates included in a utility's rate structure may not reflect the true economic cost of providing standby power or backup power. It was NERA's contention that, ideally, the basis for the utility backup rate should reflect the marginal shortage cost to the utility. In theory, this cost would reflect the probability (at the generation level) that power will be required at any given time. Moreover, this cost should reflect the carrying costs associated with having an electric system in place.

A.4 BASIS FOR ECONOMIC INTERFACE

It was generally agreed that the price a utility should be willing to pay to cogenerators should be based on a comparison of the probable cost of cogeneration purchases with alternative energy projects and its potential purchases from other sources. For areas such as the Northeast, where utilities generally have an excess of generation capacity, it was recognized that utilities would be unwilling to pay for incremental capacity. In this case, the upper bound might be the incremental cost of fuel and related operations and maintenance (O&M) expenses of the utility. It was also pointed out that some believe that any arrangements between a utility and a cogenerator should be undertaken only if the utility's customers would receive both short-term and long-term benefits.

Con Edison representatives raised the point that cogeneration projects having oil-based generation would seem to be inconsistent with the intent of the National Energy Act. They also pointed out that, in New York City at least, a comparison of alternative energy projects with cogeneration proposals is distorted by the material differences in taxes faced by the utility and the potential cogenerators.

As the discussion shifted from national to regional considerations, all agreed that the potential for economic interface between utilities and cogenerators will vary from region to region depending, in part, on each utility's present mix of generating equipment, its potential alternative sources of energy, and the particular cogenerator's operating characteristics and chosen design criteria.

Mr. Mahoney (NERA) pointed out that, in undertaking an economic evaluation of a particular cogeneration project, potential cogenerators should consider the cost and benefit of building additional capacity beyond that required by their thermal loads. The larger the plant, the more likely it would be economic for a utility to interface with it because of technological and scale economies. Directly related to this is the fact that utilities normally do not include (as a specific item) small (25 MW) generation units in their expansion plans. For cogenerated power to "make a difference," it would have to either displace a planned-for unit or delay the period when a unit would be required. Thus, returning to VEPCO's example, the potential capacity from the paper mill cogenerators (some 200 MW) would allow VEPCO some leeway in installing an additional 200 MW in the future.

Mr. Sewell (DOE) then raised the question of whether it would be in the interest of a utility to own and operate cogeneration facilities themselves. The ensuing discussion brought out the following issues.

A.4.1. Disposal of Thermal Energy

The utilities indicated that, if they owned the cogeneration unit, it would have to be located at or near the market for the thermal load to avoid the cost of an extensive delivery system. Various examples of this situation were given, including the Northern States Power plant which, in addition to generating electricity, provides thermal energy to a greenhouse. The utilities agreed that it would be useful if Argonne could offer some guidance as to likely market locations for cogenerated power.

A.4.2 Regulation of Thermal Operation

It was generally recognized that, if the utilities became involved in thermal service, that service would come under the jurisdiction of state regulatory authorities.* Two potential problems were envisioned. First, the economics of cogeneration generally require a faster payback period than would be allowed to electric utilities. Related to this problem is the uncertainty of how these essentially joint costs, i.e., thermal versus power generation, would be allocated.

Second, in some jurisdictions there is an explicit "public service obligation." After an entity has undertaken to serve a specific thermal load, it might be forced to take on additional thermal loads even if it were not economic to do so.

A.4.3 Cogeneration as Part of the Planning Process

Mr. Sewell (DOE) posed the following question to the utility representatives:

Would the utilities consider, as part of their system planning process, the alternative of several small cogeneration units (from 1 to 300 MW) close to the utility's market areas instead of a large generating unit located at a remote site?

Con Edison reiterated that, with respect to oil-fired cogeneration facilities, this proposal would run counter to that defined by Energy Secretary Schlesinger in his letter to Chairman Dingel, calling for "net lifetime savings of oil taking into account all parties whose oil consumption would be affected."

Utility representatives indicated that they believed there would be severe siting problems associated with the installation of such units. They also indicated that they would consider such alternatives if they had some knowledge of their costs which could be compared with remote-sited generating units.

Mr. Mahoney (NERA) then suggested that one of the barriers to a potential interface between electric utilities and cogenerators was an ignorance of each other's costs at the margin. He suggested that both the utilities and the potential cogenerators shed "some of their veils" and provide each other with reasonable estimates of the costs they respectively face. He also indicated that both Argonne and DOE could be primary catalysts in a "dropping-of-the-veil" process.

The meeting concluded with the general feeling that the interchange of ideas had been useful and should be continued. As one participant aptly noted: "We have met the enemy, and it is us."

*After the meeting, the Boston Edison Company (Boston Edison) representative indicated that Boston Edison's steam business may be about the only unregulated steam business in the country today.

ATTACHMENT A

List of Attendees
at
Utility Meeting on Cogeneration

1.	Arnold Rosenthal	-	Con Edison
2.	William Wagers	-	Con Edison
3.	Arthur Sharp	-	Boston Edison
4.	Joseph Miller	-	LILCO
5.	Alfred Calsetta	-	TVA
6.	Gene Lewis	-	TP&L
7.	George Flowers	-	VEPCO
8.	John Barr	-	VEPCO
9.	R. W. Garney	-	VEPCO
10.	Kenneth Miller	-	VEPCO
11.	Peter Donnelly	-	Argonne
12.	Allen Kennedy	-	Argonne
13.	Ivan von Zuckerstein	-	Argonne
14.	Isiah "Ike" Sewell	-	DOE
15.	Leo T. Mahoney, Jr.	-	NERA
16.	Bruce C. Netscxert	-	NERA

APPENDIX B

Summary of Utility Meeting on Cogeneration
Los Angeles, California
May 25, 1979

B.1 INTRODUCTION

A meeting sponsored by Argonne National Laboratory (Argonne) and National Economic Research Associates, Inc. (NERA) was held on May 22, 1979 at NERA's Los Angeles office. In attendance were representatives of Argonne, NERA, and ten Pacific Coast utilities* (listed at the end of this appendix). This was the second such meeting to take place; the first was held in Washington, D.C., on March 8, 1979 and was attended by representatives of East Coast utilities. The purpose of the L.A. meeting was to explore further the economics and practical ramifications of the interface between cogenerators and utilities and the potential problem areas associated with this interface.

After a brief introduction of the purpose of the meeting by a NERA representative, Argonne personnel expanded on the focus of the meeting, Argonne's philosophy concerning cogeneration, and summarized the exposure to the practical application of cogeneration experienced to date. Argonne as DOE's development arm, has been contacting utilities to learn more about the problems encountered in making cogeneration projects economic, feasible, and cost effective. These contacts are being made because cogeneration can be a viable energy delivery system that may become increasingly attractive as the availability of fossil fuels lessens and cost increases.

During the last three years, Argonne, under DOE sponsorship, has developed the Integrated Community Energy Systems (ICES) Program. The goals of this program include planning the use of the energy sources of a community or district in the most efficient, economic, and environmentally acceptable manner possible to ensure a firm future supply of all forms of energy and to help meet the goals of national energy conservation policy. Cogeneration is one potential component of an ICES program. The focus of ICES has concentrated on using conventional technologies; however, as new technologies emerge, these too will be phased in as they become more economic and efficient. Presently, Argonne is involved in approximately 70 projects ranging from large-scale heating and cooling projects to small-scale urban-waste utilization programs. The emphasis of these programs is not solely on technology, but includes developing the economic, planning, and management tools needed to promote efficient, conservative, and cost-effective integral energy systems. An ICES/utility interface is thought to be one of the more economical ways to achieve an integrated system.

The discussion then was opened to the floor to explore the utilities' point of view regarding the problems of developing an interface with cogenerators in both the industrial and nonindustrial (e.g., an apartment building) sectors. Because the California Public Utilities Commission,

*Also represented was the Electric Power Research Institute (EPRI).

in particular, has urged the utilities under its jurisdiction to seek out potential cogenerators, much of the ensuing discussions focused on the problems already encountered in trying to develop the necessary interface. Although wide-ranging subjects were covered, comments centered on the following areas:

The discussion then was opened to the floor to explore the utilities' point of view regarding the problems of developing an interface with cogenerators in both the industrial and nonindustrial (e.g., an apartment building) sectors. Because the California Public Utilities Commission, in particular, has urged the utilities under its jurisdiction to seek out potential cogenerators, much of the ensuing discussions focused on the problems already encountered in trying to develop the necessary interface. Although wide-ranging subjects were covered, comments centered on the following areas:

- (1) the need to develop general criteria for the analysis of feasibility of a given cogeneration project;
- (2) current regulatory barriers and the problems caused by a lack of specific guidelines;
- (3) recognition of the differences in risk perception and economic realities of interface on the part of utilities and potential cogenerators;
- (4) difficulties involved in negotiating long-term contracts and the reliability factor; and
- (5) lack of a unified approach among agencies to energy problems.

A discussion of each of these areas is summarized below.

B.2 GENERAL CRITERIA

Each of the utilities in attendance has had some contact with a potential cogenerator, and all have found that, in general, each cogeneration project must be considered on its own merits. Because cogeneration projects are highly site specific, an analysis of the economics and feasibility of each project must be tailored to the characteristics of the specific situation being examined. The potential cogenerator must determine probable thermal and electric needs in the near- and long-term future; whereas the utility must have available its present and projected generation mix and determine its capacity and load characteristics. However, there is no simple method whereby the potential cogenerator and the utility can determine the feasibility of the interface and its costs and benefits to both parties.

Concern was expressed that some policy-makers at DOE and in Congress fail to realize that the interface is not simply a matter of "trading" kWh and that capacity and energy have different values at different times. It was generally agreed that the basis for an appropriate economic interface should rest on the utility's costs at the margin, and the nature of the

service being offered to the utility by the cogenerator. The arrangement made between the utility and the cogenerator also includes a reasonable sharing of any benefits.

Of specific concern to utilities dealing with potential cogenerators was the issue of capacity credits to the cogenerator. One utility participant described the issue in the following way:

"One of the things that I found about the capacity issue is that most non-utility people are unable to accept the lead times that we work with (it's normally seven years) and we are working with five years with our cogenerators and we want the five years advance notice that you need to honestly defer something. Let's face it, we have got our rate-payer to take care of and we can't be making capacity payments on a project when we don't need the capacity. See, what you have to do, is have the appropriate lead time to integrate that capacity in your system or, as we are doing, discount the capacity payout contingent with the reduction of the lead time so that you are not making any subsidy of cogeneration projects for the first three or four years through the other ratepayers.

And that's where you get into a capacity payment issue with utilities and, generally speaking, I think that's true of each of us. If there is an entity that has capacity available on a firm basis today, we really can't offer a capacity payment today simply because our capacity needs are met by our program. But we can make the capacity payment beginning, its now mid-1979, let's say, on a very short-range basis, mid-1982. Then the capacity becomes valuable because we have taken the position we can defer other resources that are planned to accommodate cogeneration and slip it in rather than a component of another project that we are working on. I guess the utility has learned by now that you can always delay and hold up and if there is something that comes along for which you can do that, like cogeneration, we'll find a place for

The potential regulatory barriers facing utility/cogenerator interface caused significant concern to the attendees. The root of the problem seemed to be a lack of reasonably certain guidelines for utility/cogenerator interface situations. Although PURPA (Section 210) exempts cogenerators from federal regulation (and perhaps from some state rules), FERC has not yet established its guidelines for cogeneration. Furthermore, how relevant portions of the Holding Company Act, Fuel Use Act, and other federal statutes may affect interface has not yet been delineated. Serious environmental questions also must be answered. Although the cogenerator may be exempt from utility commission regulation regarding the price it can negotiate for its power, there are still environmental standards to be met; some of these standards fall under the jurisdiction of state and federal regulatory agencies. Industry is not going to place itself voluntarily in a position where it could be subject to further regulation at any level, especially if large

if large amounts of capital are required. Another issue to be settled concerns what, if any, anticompetitive or antitrust problems may emerge as a result of negotiations between a regulated utility and a non-regulated potential cogenerator.

Another specific concern of the utilities in the Pacific Northwest is the issue of take-or-pay requirements with potential cogenerators of nonfirm power. As one participant noted:

"You have to reserve the right not to take the cogenerated power, which is another big issue. For instance, we are spilling water right now and that's kind of a no-no. If we are doing this kind of an arrangement, we are buying cogenerated power and spilling more water, right away you want to say 'forget the cogenerated power, we're spilling water.' So one of the issues that we have run up against is when you try to tie power to the utility operating system, then you have got to tie provision in the contract whereby you can refuse power when you have better or more attractive source."

The utilities also expressed regret that current regulatory and legislative policy provides no incentive for utility-owned cogeneration. In the words of one utility executive:

"The utilities in federal policy are given no incentive for cogeneration. They are not given any tax breaks. In fact, the rules have been written to preclude us from benefits and all legislation coming out of Congress is anti-utility cogeneration. There is not one piece of legislation that encourages us to own and operate cogeneration sources. So if DOE or anyone else wants utilities to own cogeneration plants, they can give us the capacity credits or the tax breaks. However, as soon as you give us a tax break our local regulatory agency will take it away because they will take a look at total revenue vs. total cost and all you will have done is given us a tax break that will be taken away in our next rate case because we can only earn nine percent overall."

B.4 LACK OF UNDERSTANDING OF INTERFACE SCENARIOS AND DIFFERENCES IN RISK PERCEPTION

A more basic problem, however, was the apparently differing perceptions of the utilities and the potential cogenerators as to the ingredients that were required to make an economic interface. Not only are the risk factors involved perceived differently by both participants, but also, as potential cogenerators learn more about utility and energy economics, their willingness to explore interface seems to be lessening, at least for the moment.

Part of the difficulty arises because utilities must work with longer planning horizons, longer payback periods, and lower rates of return on

investment than would potential cogenerators. The rates of return allowed a utility and expected by the potential cogeneration investor are quite different; the utility is allowed 9-12% rate of return; whereas, the investor feels that the money can be used in other places that yield a higher rate of return at less risk. The priorities of utility and an industry/cogenerator also are different. Industry is interested in maximizing its returns, but it is not interested in getting into actual power production beyond its immediate needs; it is definitely not interested in having a second party involved in the operation of a facility it owns. Thus, the issues, of ownership and O&M will continue to concern both the utility and the potential cogenerator and may affect the potential for utility/cogenerator interface.

B.5 LONG-TERM CONTRACTS AND RELIABILITY

The difficulties of negotiating a long-term contract for cogenerated energy and being able to factor this energy into the utilities' planning process were areas of extensive discussion. The reliability of this power was a major concern -- not as to whether the energy will be available, but for how long. If potential cogenerators want their energy to be treated as a firm resource, they, in turn, must be prepared to commit that energy to the long term, i.e., 10 to 20 years. The potential cogenerator normally is not required to plan that far ahead, and does not seem to understand why the utility must.

As one participant noted:

"Our main concern is that, if we include cogeneration as part of our system resources, like a coal plant or combined cycle or gas turbines or geothermal, we want to make sure that behind that cogeneration project there is enough life supported by fuel. With regard to a wood burning plant, we have had the experience that the supplier or the entity that we want to join up with in building a wood waste burning power plant that provides steam for the lumber mill and power into our system was ready to provide a guarantee of fuel for "x" number of years and when it came down to brass tacks the fuel supply was considerably reduced because we discovered that it had higher market value for other purposes."

B.6 LACK OF A UNIFIED APPROACH

One point that arose repeatedly was that the various energy and regulatory agencies seem to be approaching the exploration of alternative energy sources (cogeneration being only one alternative) on a fragmented and duplicative basis. Several agencies are looking into the feasibility of cogeneration; for example, extensive examination of the feasibility of cogeneration

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ATTACHMENT A

Attendees

Bruce Ambrose	- NERA
Donald E. Barclay	- Idaho Power Company
Milton Bracy	- LADWP
Stephen Braithwait	- EPRI
J. Wesley Coryell	- Idaho Power Company
John Daer	- Salt River Project
C. P. Davenport	- Pacific Power & Light
Edward J. Doyle, Jr.	- Argonne
John Edwards	- San Diego Gas & Electric
Kenneth Hub	- Argonne
Allen S. Kennedy	- Argonne
Philip Kier	- Argonne
Leo T. Mahoney, Jr.	- NERA
Daniel McCormick	- Portland General Electric
Joseph Meyer	- Pacific Gas & Electric
Lloyd H. Meyers	- Washington Water Power
Norman E. Nichols	- LADWP
John Shue	- Pacific Power & Light
Michael C. Slota	- Public Service of New Mexico
John F. Sullivan	- Salt River Project
Michael J. Vogeler	- Southern California Edison
Ivan von Zuckerstein	- Argonne
Dennis Whitney	- LADWP
Jewel L. Whysong	- Argonne
Ruth E. Zientek	- NERA

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APPENDIX C

Summary of Utility Meeting on Cogeneration
Chicago, Illinois
September 20, 1979

C.1 INTRODUCTION

A meeting sponsored by Argonne National Laboratory (Argonne) and National Economic Research Associates, Inc. (NERA) on the subject of cogeneration was held on September 20, 1979 at the O'Hare Motor Inn. In attendance were representatives of Argonne, NERA, the Department of Energy (DOE) and Midwest utilities (listed at the end of this Appendix). This was the third, and last, such meeting to take place. Previously, meetings with representatives of East Coast and West Coast utilities had been held in Washington, D.C. and Los Angeles, respectively. The purpose of the Chicago meeting was to discuss specific potential economic, technical, and institutional barriers to an economic interface between utilities and cogenerators and to explore the potential for utility-owned cogeneration.

A NERA representative opened the meeting with a brief outline of the purpose of the meeting, which was then expanded on by Argonne personnel before opening the discussion to the floor. It was generally agreed that the discussion would include not only cogeneration, but also small power production because the interface problems are similar. Those utilities in attendance have had experience with both. The ensuing discussion centered on perceived regulatory problems, impacts on system planning, the economics of retrofitting, and projects already operating or under active consideration.

C.2 PERCEIVED REGULATORY PROBLEMS

The perceived potential regulatory problems with cogeneration and other forms of alternative technologies centered particularly on what the final rulemakings would be regarding both utilities and other entities, in the wake of the Public Utilities Regulatory Policy Act of 1978 (PURPA). The proposed rules (Section 201) preclude utilities from truly active* participation in projects that involve cogenerators and small power producers. As one participant phrased his perception of setting up a cogeneration project they are actively participating in:

"In viewing the cogeneration rule, although we would have undertaken this project anyway because the economics were right, there is really nothing for a utility in this par-

*The proposed Section 201 rules limit utilities to a 50 percent ownership participation in QFs (qualifying facilities, which encompasses both cogenerator and small power producers). The proposed rules do not limit operating participation.

ticular instance because we are the owner of the unit and FERC is saying that the utility can't be the owner. I find this rather incredible because, given the structure of the utility business, the person best able to be in the utility business is a person in the utility business. By law, that person is excluded."

The tone of the discussion seemed to be that the participating utilities did not think anyone was out to "get them;" rather, they did not understand why they should be excluded from any "extra" benefits* which may accrue to a non-utility entity initiating such a project. It was not understood why a non-utility, which, for the most part, is not experienced in producing energy in the required form, should be encouraged to develop peripheral expertise that utilities already possess or have been in the process of developing. The Midwest utilities have been involved with both cogeneration technologies and alternative systems** for several years.

C.3 IMPACT ON SYSTEM PLANNING

In general, the attendees agreed that the size of a particular system will determine whether a particular cogeneration project is given overt consideration in the system planning process. The larger the system and the smaller the cogeneration project, the smaller the impact on the system planning process. The attendees agreed that a number of facilities coming on line within approximately the same time frame would have an impact, but they did not foresee that happening. They felt that cogeneration and other alternative technologies each had their specific applications, and the opportunities to develop such facilities within each service area would be relatively few. Where the opportunities exist, and the economics are right, the utilities are pursuing cogeneration and other projects and integrating them where feasible into the system planning process.

As an example, one utility representative spoke of a potential garbage burning plant within its service territory:

"The concept there is to build a plant to burn garbage that essentially would be owned by the city or a third part, and we would take the steam or electricity or both. The proposed location of this plant would be on the northern end of our system where we could use a little help and I think it would work very well. However, it is a special application and it fits the circumstances. We do have a concern about counting on the plant for firm steam service. What if the truck drivers go on strike and there is no garbage pickup? They would have to put in some kind of alternative fuel-fired boiler. But it still appears to be a feasible situation."

*For example, a tax credit.

**Please refer to the discussion in Section 4 of this summary, Projects Operating or Under Active Consideration.

C.4 RETROFIT

Retrofitting an existing plant to provide steam and electricity was not perceived to be economic for an industrial or commercial entity. The reason for this is that most industrial processes utilize low-pressure steam; whereas, to produce electricity as a by-product of steam generation, high pressure is required. Retrofit might be a possibility for a district heat project, but it was felt that such a project would not be commercially attractive to anyone other than a utility because of the capital outlay required and the long payback period.

C.5 PROJECTS OPERATING OR UNDER ACTIVE CONSIDERATION

Each of the utilities attending had either cogeneration or cogeneration-type projects operating and/or under consideration. One utility is operating an electricity-producing steam plant for two major corporations, with supplemental electricity being drawn from the grid.

As mentioned earlier, another utility is having discussions concerning a waste-burning plant. Several utilities have greenhouses that are utilizing waste heat. In each instance the application is specific. It was generally felt that district heating would be feasible in some areas, but the present lack of data on the economics of this and other alternative technologies is a hindrance to implementation. As the data are developed and such projects are determined to be economically feasible, marketplace pressures will be the deciding factor as to which type of technology will be used in which location.

ATTACHMENT A

Attendees

Conrad J. Aas	Northern States Power
David Cory	Otter Tail Power
Charles Gartside	Argonne
M. W. Heidman	Detroit Edison
Arlene A. Juracek	Commonwealth Edison
Allen S. Kennedy	Argonne
Philip Kier	Argonne
L. L. Loomans	Detroit Edison
John MacFarlane	Otter Tail Power
Leo T. Mahoney, Jr.	NERA
S. H. Nelson	S. H. Nelson Ent.
R. J. Peterman	Gulf States Utilities
Wayne Pferdehirt	Argonne
Isiah O. Sewell	DOE
Ivan von Zuckerstein	Argonne
Jewel Whyson	Argonne
Ruth E. Zientek	NERA