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DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES
THROUGH POWER PLANT RETROFIT DISTRIBUTION NETWORK

Volume 4, Final Report for September 1, 1978—May 31, 1979

October 1979
Report Date

Work Performed Under Contract No. EM-78-C-02-4977

Public Service Electric and Gas Company
Newark, New Jersey

U. S. DEPARTMENT OF ENERGY

Division of Buildings and Community Systems

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DISTRICT HEATING AND COOLING SYSTEMS FOR
COMMUNITIES THROUGH POWER PLANT
RETROFIT DISTRIBUTION NETWORK

Volume IV

Final Report
Performance Period: September 1, 1978 - May 31, 1979

Prime Contractor:

Public Service Electric and Gas Company
80 Park Place
Newark, NJ 07101

Subcontractors:

Stone and Webster Engineering Corporation
Stone and Webster Management Consultants
Transflux International, Ltd.

Report Date: October 1979

Prepared for the

U.S. Department of Energy
Assistant Secretary for Conservation
and Solar Applications
Office of Buildings and Community Systems

Work Performed under Contract No. EM-78-C-02-4977

FOREWORD

This is the Final Report of Phase 1 of "District Heating for Communities Through Power Plant Retrofit Distribution Network." It is separated into four volumes:

Volume I: Executive Summary

Volume II: Task 1: Demonstration Team

Task 2: Identify Thermal Energy Sources
and Potential Service Areas

Task 3: Energy Market Analysis

Volume III: Task 4: Technical Review and Assessment

Volume IV: Task 5: Institutional Assessment

Task 6: Preliminary Economic Analysis

Task 7: Proposal for Further Work

ACKNOWLEDGEMENTS

The following key personnel contributed to the completion of this report:

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Institutional Assessment

5.1 Extent and effects of state and/or local utility commission regulation;

The New Jersey Board of Public Utilities (NJBPU) has the statutory authority to regulate utility services and terms of service and by definition would have jurisdiction over this district heating and cooling (DH/C) project. (Glen View Development Co. v. Public Service Elec. and Gas Co., 57 N.J. 304, (1970). N.J.S. 48:2-13 et seq.)

The need for new codes or statutes will have to be determined after a careful examination of the effect of district heating and cooling on energy conservation, environmental quality, fuel displacement, economics and other regional factors.

5.2 Assessment of the arrangements under which electric utilities would modify and operate power plants as part of a district heating and cooling system;

In the event that the DH/C study demonstrates the technical and economic viability of such a project, PSE&G would be willing to own and operate the retrofit district thermal supply system, including the thermal energy distribution system, provided that the commitment to such a project meets our normal criteria used in investment decision-making, including:

1. Economic advantages over other feasible alternative plans. Acceptable return on investment
2. Engineering soundness of the project and its integration with the PSE&G system. Acceptable impact of loss in PSE&G electric capacity and effects on interactions with the Pennsylvania-New Jersey-Maryland (PJM) interconnection
3. Continued ability by PSE&G to raise additional capital for financing the project
4. Acceptability from the legal and regulatory standpoint

5. Compatibility with PSE&G existing labor union agreements regarding the operation of such facilities
6. Satisfactory agreement with customers, particularly regarding the thermal energy supply rates

Specific steps that would need to be taken to resolve the provisions listed above include:

1. Identify the minimum acceptable return on investment from the DH/C project that would be satisfactory to PSE&G stockholders
2. Examine PSE&G corporate plans to ascertain capital needs for future expansion to meet electric and gas service demands and the financial impact of the DH/C project on these corporate plans including the cost of capital
3. Determine the degree of risk on electric system reliability associated with a DH/C retrofit project
4. Establish the appropriate incremental cost considered to be acceptable to the DH/C customers by classes of service
5. Analyze the DH/C energy savings potential and environmental benefits for consideration throughout the decision-making process.

Implementation factors that will need to be considered include:

- . Customer billing would initially be processed manually by the Power Billing Department, and until such time as the computerized customer billing system is implemented to include DH/C customers.
- . The PSE&G Energy Forecasting Committee would incorporate DH/C sales with the forecasting of other energy commodities sold by the Company.
- . Costs associated with the DH/C system would be assigned on an incremental basis.
- . The DH/C sales would be priced so that no penalty or benefit will be borne by other PSE&G customers.

- 5.3 Extent and effects of legal requirements to obtain easements, franchises to occupy the public right-of-way, land acquisition and to obtain certificates of convenience and necessity;

General

After a determination has been made as to the location of a proposed DH/C system, a meeting with the Mayor and other interested municipal officials to explain the project and answer questions, is recommended. DH/C distribution installations will require street opening permits, easements, some land acquisition, building permits and possibly zoning variances or Planning Board approval. If facilities are installed within a state highway or county road, approvals by the N.J. Department of Transportation and the county will also be required. Active involvement of local and regional interest groups and decision makers will be needed to develop the institutional arrangements to facilitate implementation of the Demonstration Project.

Easements

N.J.S. 48:3-17.6 et seq. provides that a utility may acquire land or other property or some interest therein which is reasonably necessary for the service, accommodation, convenience or safety of the public, as long as the acquisition thereof is not incompatible with the public interest and does not unduly injure the owners of private property. In the event the necessary interest cannot be acquired from the owner (because of disagreement over price, legal incapacity of owner, absence of owner, or any other reason), a utility can petition the NJBPU for the right to exercise the power of condemnation pursuant to N.J.S. 20:1-1 et seq.

N.J.S. 40:55D-19 gives a utility the right to petition the NJBPU if local zoning or planning ordinances interfere with or prohibit the use of the land by the utility. The NJBPU can overrule the local ordinance if it finds that the proposed use is necessary for the service, convenience or welfare of the public.

N.J.S. 48:7-2 requires that the consent of a municipality be obtained before a utility uses the public highways, streets and alleys of that municipality. The NJBPU does not have the authority to overrule a municipality's decision in this regard. In addition, N.J.S. 48:2-14 requires that the NJBPU approve any franchise granted to a utility by a municipality.

Other legal remedies are always available if adverse rulings result from the above proceedings. A NJBPU order of December 21, 1978, grants PSE&G the right to exercise the power of eminent domain for an electric right-of-way.

Franchises

The authority to occupy public streets, sometimes referred to as a franchise, can only be derived from a grant from the State of New Jersey. Such a grant may be conditional and the State may delegate its authority to the individual municipality concerned. The Company does not have a franchise from the State of New Jersey to place piping in the streets for a project of this nature.

To grant a legally effective franchise, a municipality must have been empowered to do so either expressly or by implication by the State Legislature or Constitution. For example, the New Jersey Statutes state "The [municipal] governing body may make, amend, repeal and enforce ordinances, authorizing public utility corporations to lay and construct conduits in the streets and public places to carry the wires of any such persons." N.J.S.A. 40:67-6

No general legislation that enables municipalities to grant the requisite franchise has been found. There is the possibility that the municipal charter of an individual municipality contains such authority. However, as the legislature has seen fit by means other than their charters to enable municipalities to grant other types of franchises it is unlikely that the authority for district heating franchises would be contained therein. To be certain would necessitate obtaining copies of and reviewing the charter of each municipality in which operation is contemplated.

The appropriate and necessary means for PSE&G to obtain these franchises appears to be an enactment of appropriate legislation by the State Legislature. The act could authorize the operation outright or it could mandate other required consents such as that of a state agency (e.g. the NJBPU) or the particular governing body of the municipality in which a facility is to be located. The consent of the governmental agency responsible for the maintenance of the particular road to be used is sometimes required.

The NJBPU has general jurisdiction over all public utilities. The latter are defined by statute to include among other things pipeline and heat companies. However, the statutory provisions and case law under the pipeline section are concerned only with those carrying oil or natural gas and the use of heat in the statutes is generally in the context of electric light, heat and power. It seems unlikely that the legislature had contemplated an operation like the district heating and cooling project when it defined a public utility. It would therefore be advisable to include an express directive in any proposed enabling legislation in order to clarify this point.

In summary, PSE&G does have the corporate authority to conduct a business of the type being contemplated. However, the Company does not have the requisite franchises to locate hot water district heating facilities on or beneath the public streets. Based on research of statutory and case law it seems reasonable to conclude that local government entities are not empowered at the present time to grant the necessary franchises. State legislation will be required as it was recently applied to another new technology, the cable television industry.

Permits and Zoning Ordinances

Permit requirements to comply with current street opening regulations, at two municipalities, are summarized in Table 5-1. Zoning ordinances will need to be reviewed in detail to determine any unforeseen restrictions on the construction installation of the DH/C system.

5.4 Effect of state and local tax laws;

Various aspects have been considered and further study may help identify other tax related issues.

Taxes applicable to the DH/C Project

The project itself would not be subject to any Federal tax other than that imposed on corporations in general (46%). If qualified costs of the project are expensed on the books, the economic cost of the project would be the difference between the expense and the tax @ 46%. All receipts from the taxpayer's business over, or from the whole of its lines and mains, excluding payment for

gas, electricity, or water sold and furnished to another public utility are subject to a gross receipts and franchise tax.

Tax Depreciation, Exemptions, Credits and Benefits

Tax depreciation would be taken on existing lines or mains that would no longer be used provided the property is not retired. If the property was placed in service before 1971 and is retired, there would be a decrease in the amount of tax depreciation the Company could claim.

A project organized to carry on scientific research could qualify for tax exempt status if the research is carried on in the public interest and the results are available to the general public.

The DH/C project could develop an alternate energy supply via the extraction of steam from an existing generating station after it has generated electricity and using this steam to heat water in a closed loop heating system. The cogeneration mode of plant operation improves the efficiency in fuel utilization.

However, since any expenditures the Company might make in DH/C commercialization will ultimately result in an economic benefit to the Company, it would seem that the private rather than the public interest is served and therefore DH/C commercialization would not qualify for tax exempt status. DH/C research, development and demonstration may qualify for tax exemption but a clear determination must be identified.

The Company could lease the project and receive tax benefits if it were a true lease for tax purposes. The Company could deduct the payments as they are made and could claim any Investment Tax Credit (ITC) which the lessor might elect to pass through. If it were not a true lease for tax purposes, but rather, merely a financing transaction, the costs would have to be capitalized and depreciated and would be eligible for ITC.

Assuming we follow PSE&G's normal policy, the tax benefits of accelerated depreciation and investment credit would be normalized.

Property of public utilities cannot qualify as one of the classes of energy property for purposes of energy tax credit.

5.5. Effect of a statutory mandate to serve all demands;

A utility cannot mandate that a particular customer take the service, nor can they require that new tenants take the service. N.J.S. 48:3-2 prohibits any unjust, unreasonable, unduly preferential, arbitrary, or unjustly discriminatory practices by a utility. N.J.S. 48:3-3 requires that a utility provide only safe, adequate and proper service and provide any service which can reasonably be demanded or furnished. N.J.S. 48:3-4 prohibits a utility from making or giving any undue or unreasonable preference or advantage to any person. Court interpretations of these statutes leads to the conclusion that a DH/C System would have to serve all who desire it and are located within the District.

5.6 Extent and effects of environmental regulations;

All existing steam electric generating units with the exception of Hudson No. 2 are grandfathered with respect to air permits. Because the units were built prior to a certain date, air permits to construct and operate them have not been required. It is possible, however, that any variation in the operating mode or any modification to the plants or equipment which increases the amount of any air pollutant emitted might prompt the U.S. DEP to impose certain permit requirements.

This is particularly evident in the case of Essex, one of our top priority candidates. Essex No. 1 is presently on an inactive status and has never had an air permit. However, should it be reactivated especially for an entirely new purpose, i.e., district heating, additional permits may very well be required. With respect to air permits, a favorable factor is that the additional pollution from Essex could be offset by the reduction of air emissions from individual residential and commercial locations receiving thermal services from the station.

In addition, there will also be federal and state water related permit requirements. Specifically, Essex is the only station not having a chemical waste treatment system. Should it be reactivated an NPDES permit would be required which would establish limits to discharges. A treatment system would have to be installed to meet these limits.

There will also be approval and permit requirements associated with the distribution system concerning stream crossings, flood plains, riparian lands, coastal zone, etc. These may very well entail municipal, county, state and federal involvement.

No specific listing of environmental impacts or environmental requirements can be made at this time. More data on the specific unit(s) and the system designs will be needed to provide a more comprehensive discussion of environmental issues. Additional information on environmental issues is provided at the end of this section.

- 5.7 Extent and effects of power siting laws and local zoning laws on ability to retrofit an existing power plant and build a district heating and cooling system;

The powerplant siting laws, specifically the Coastal Area Facility Review Act (N.J.S. 13:19-1 et seq.) and the Department of Energy Act (N.J.S. 52:27F-1 et seq.) do not apply to the retrofitting of existing powerplants. However, the New Jersey Department of Environmental Protection (NJDEP) and the New Jersey Department of Energy (NJDOE) may attempt to exercise siting jurisdiction where the retrofit involves a substantial change in the operation of an existing powerplant so as to be considered the construction of a new facility which might cause this issue to be brought before the courts.

A review of local zoning maps and a more detailed examination of local siting laws will need to be undertaken when the DH/C sites are more definitely established.

- 5.8 As a part of the institutional issues the institutions which will own and operate the distribution systems shall review their corporate charter(s) and applicable statutes, codes and ordinances, to confirm their legal capacity to construct, own and operate the district heating and cooling demonstration project.

The Public Service Electric and Gas Certificate of Incorporation entitles the Company to engage in any activity within the purposes for which corporations may be organized under the New Jersey Business Corporation Act (N.J.S. 14A:1-1 et seq.) Therefore, the Company is empowered to engage in the construction, ownership, and/or operation of a District Heating and Cooling project.

TABLE 5-1

DISTRIBUTION SYSTEM CONSTRUCTION PERMITS

	<u>NEWARK</u>		<u>JERSEY CITY</u>		STATE OF NEW JERSEY
	ESSEX COUNTY	MUNICIPAL	HUDSON COUNTY	MUNICIPAL	
A. Bond on file	\$5000	None	\$10000	\$10000	\$1000
B. Street Permit Fee	20	None	None	None	Yes
C. Sidewalk Permit Fee	20	None	None	None	Yes
D. Inspection Fee	50	None	None	None	None
E. Cash deposit	None Required	None Required	None Required	None Required	None Required
F. Notice before opening	Yes	Yes	Yes	Yes	Yes
G. Repaving by company	Yes	Yes	Yes	Yes	Yes

- Application made through respective State, County and Municipal Engineer.
- Hackensack Meadowlands Development Commission construction codes will be consistent with municipality requirements.

5-9

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201 430-7000

May 31, 1979

Memorandum to C. R. Guerra

DOE DISTRICT HEATING AND COOLING STUDY

Attached are various memorandums addressing the above subject as follows:

- 1) Applicable Land and Water Quality Regulations
- 2) Applicable Air Regulations
- 3) Environmental Assessment From Changes in Emissions

Air Emissions

Water Emissions

This material is submitted in reply to your memorandums of April 10, May 15 and May 29, 1979.

A handwritten signature in dark ink, appearing to read "J. A. Shissias", with a stylized flourish at the end.

James A. Shissias

RAG:cm
Attachments

5 B

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201 430-7000

May 30, 1979

MEMORANDUM

RESEARCH AND DEVELOPMENT CORPORATION
DISTRICT HEATING AND COOLING STUDY -
U.S. DEPARTMENT OF ENERGY

APPLICABLE LAND AND WATER QUALITY
REGULATIONS

The Company's generating stations which are to be utilized for this project include Essex, Kearny, Hudson, and Bergen Stations which come under the Wetlands Act and Riparian Statutes as well as the newly emerging State Coastal Management Program.

The specific land and water environmental regulations which the project will have to comply with include those listed below. We would assume, for a project of this type which is consistent with overall national energy goals, that the permits would be able to be acquired, although it is difficult to predict with any certainty the amount of delay that might be encountered.

1. Wetlands Act - New Jersey will continue to regulate activities on wetlands with authority derived from the Wetlands Act of 1970 (N.J.S.A. 13:9A-1 et seq.) and the Procedural Rules and Regulations adopted in 1972. The Act, which is administered by the Office of Wetlands Management in the Division of Marine Services, gives the state broad discretion in regulating virtually any form of development or disturbance on mapped coastal wetlands, except for mosquito control and continued commercial production of salt hay or other agricultural crops or activities.

The Act defines coastal wetlands as those wetlands subject to tidal action along specified water bodies. They are not regulated under the Act until they have been mapped and the maps promulgated, following notice to affected property owners and a public hearing.

There is a considerable amount of wetland acreage located primarily along the Delaware River, and also including approximately twenty acres of mapped wetlands located on the Raritan River, in and near Perth Amboy. The Act specifically exempts the Hackensack Meadowlands District from its coverage.

A-1

2. Riparian Statutes - In New Jersey, the use of "tide-flowed" (or riparian) lands, which are defined as those lands now, formerly or hereafter flowed by the mean high tide (including filled lands), is based on the ownership of land adjacent to the waterway. All those lands that are flowed by the tide, up to the high water mark, are owned by the State of New Jersey. The State owns the lands as trustee for the public, and they must be administered in the public interest. The State exercises control over riparian land in two ways: through its proprietary role as owner, and through its regulatory role under the Waterfront Development Law.

The State's riparian jurisdiction extends to the mean high water mark, which is determined on the basis of a theoretical 18.6 year tide. DEP's Office of Environmental Analysis (a branch of the Commissioner's Office) is presently conducting a tidelands delineation program throughout the State. Until the delineation is complete, DEP's Office of Riparian Lands Management is determining the applicability of riparian law on a case-by-case basis. Landowners proposing to build and citizens concerned about a proposed project, as well as DEP's Marine Lands Inspectors, bring individual cases to the attention of the Department.

The State's ownership role is exercised through the Natural Resource Council, which may grant, lease, or license the use of State-owned Riparian lands provided such action is in the public interest. The Council, which is composed of twelve citizens appointed by the Governor, with the advice and consent of the N.J. State Senate, has broad discretion concerning applications for riparian conveyances. The Council may make any decision it believes to be in the public interest. DEP's Commissioner and Director of Marine Services, however, have the authority to veto any Council action inconsistent with state policy by virtue of their right to approve all Council meeting minutes and instruments of conveyance. Should a veto occur, the application is returned to the Council for reconsideration. Consideration of the State's Coastal Policies in riparian decision-making is also assured by the fact that the Division of Marine Services serves as staff to the Natural Resource Council.

3. Waterfront Development Law - Persons proposing to build on the waterfront, including persons applying for a riparian grant, lease or license from the Natural Resource Council and persons already having title to, or interest in riparian lands, must obtain a Waterfront Development permit from the Office of Riparian Lands Management before any new development takes place on such lands. (N.J.S.A. 12:5-3). Development includes, but is not limited to, dredging, or the construction or alteration of a dock, wharf, pier, bulkhead, bridge, pipeline, or cable crossing.

The extent of the state's regulatory jurisdiction for Waterfront Development permits is subject to interpretation. The law states in part that "All plans for the development of any waterfront upon any navigable water or stream of this state or bounding thereon... shall be first submitted to the Department of Environmental Protection". (N.J.S.A. 12:5-3). It is the phrases "waterfront" and "or bounding thereon" which have never been formally defined and are subject to interpretation.

The language of the Waterfront Development Law suggests that the Legislature intended the State's regulatory authority to include an inland strip of land of undetermined width in addition to the land flowed by the tide. Past administrative practices by DEP, does not currently require upland land owners to obtain a Waterfront Development permit for development solely on uplands. Many upland projects are, however, brought under DEP jurisdiction because some element of the project, such as a dock or outfall pipe, extends into the area where Waterfront Development permits have traditionally been required.

4. Water Quality Programs - The Federal Clean Water Act of 1977 (33 USC 466 et seq.) sets a framework for eliminating the discharge of pollutants into navigable waters by 1985. This is to be accomplished by Federal-state partnerships under which EPA sets increasingly strict effluent standards for wastewater discharges and the states set quality standards for rivers, bays and the ocean, and develop a strategy for their attainment. The key regulatory element is the National Pollutant Discharge Elimination System (NPDES) and the key planning element is the Areawide Water Quality Management Plan (208 Plan). These elements, as well as State wastewater treatment facility requirements, are the key programs for attaining the State's water quality goals in the coastal zone and throughout the state.

NPDES Permits - Any point source of discharge into the waters of the United States, including the territorial sea, must receive a National Pollutant Discharge Elimination System Permit (NPDES) from either EPA or the State. There are 1,396 facilities currently regulated by NPDES in New Jersey. In New Jersey, permits are issued by EPA, Region II, but the State now has enabling legislation (the State Water Pollution Control Act N.J.S.A. 58:10A-1 et seq.) which allows DEP to take over the permitting function. Under the present arrangement, DEP's Division of Water Resources must certify that a proposed discharge will not prevent the attainment of the State's water quality standards before EPA may issue a NPDES permit. This certification, based on Section 401 of the Federal Clean Water Act, focuses on the chemical and biological impact of the proposed discharge on attainment of the water quality standards for the receiving body of water.

Areawide Water Quality Management (208) Plans - The Section 208 Plans become significant given the fact that the State DEP's Division of Marine Services will not issue riparian or wetlands permits to development proposals which conflict with a State Certified 208 Plan.

A Water Quality Plan developed according to Section 208 of the Clean Water Act is a comprehensive and implementable strategy for the control of water pollution in a county or multi-county area. Federal and State legislation require that the Coastal Management Program and 208 Plans be consistent. Through a Federal agreement between the Department of Commerce and the Environmental Protection Agency, and through a working relationship at the state level between the Divisions of Marine Services and of Water Resources, the policies of the two programs are being coordinated and made consistent for both point and non-point sources of pollution.

Each 208 Plan is to consist of a set of policies and a management system detailing how and by which agencies these policies will be enforced. In New Jersey, there will be five separate 208 Plans:

<u>Counties</u>	<u>Planning Agency</u>	<u>Status as of 12/78</u>
1. Middlesex	Middlesex County Planning Board	Certified by Governor
2. Mercer	Mercer County Planning Board	Awaiting Governor's certification
3. Burlington/Camden/ Gloucester	Delaware Valley Regional Planning Commission	Awaiting Governor's certification
4. Salem	DEP-Division of Water Resources	Draft Plan expected shortly
5. Bergen/Hudson/Essex/	DEP-Division of Water Resources	Draft Plan expected shortly

5. Stream Encroachment Permits - No structure or alteration within the natural and ordinary high-water mark of any stream may be made without a permit from DEP's Division of Water Resources. The Stream Encroachment Act is intended primarily for flood protection "to safeguard the public against danger from waters impounded or affected by such structures" (N.J.S.A. 58:1-26). Administration of this program tends to result in the preservation of stream channels in their natural state, which are biologically productive areas offering important recreational opportunities. Of 500 stream encroachment permit applications received in 1978, DEP granted 450. The Division of Water Resources practice is to waive Stream Encroachment Permit review for projects requiring a Waterfront Development Permit.

6. Flood Hazards - The Flood Hazards Act, N.J.S.A. 58:16A-55, authorizes DEP to adopt land use regulations for delineated floodways "designed to preserve (their) flood carrying capacity and to minimize the threat to the public safety, health and general welfare". This Act is also administered by the Division of Water Resources.

Floodways are considerably wider than the stream channels regulated under the Stream Encroachment Act. DEP has adopted, or proposed for adoption, floodway delineations in various parts of the State. Under the Act, municipalities may conduct the delineation and adopt regulations concerning their use in zoning ordinances, provided that they meet the minimum standards of the DEP regulations.

Like the Stream Encroachment Law, administration of this Act directly results in the preservation of valuable stream corridors and flood plains.

7. Wild and Scenic Rivers - The purpose of the Wild and Scenic Rivers Act of 1977 (N.J.S.A. 13:8-45 et seq.) is to preserve, protect and enhance the natural and recreational value of some of the State's most significant river segments. The Act allows the Commissioner of DEP to designate river segments as "wild", "scenic", "recreational", or "developed recreational". In any river segment so designated, all construction activities would be either prohibited or regulated within the river's flood hazard area. This would expand upon DEP's authority under the Flood Hazard Act in the areas designated, by permitting a much wider range of considerations as criteria for DEP's regulatory decisions. The types of development that are controlled will depend on which designation is applied to the segment, with "wild" rivers having the strictest prohibitions and "developed recreational" the most lenient. DEP has proposed regulations to be promulgated under this Act which would allow the creation of municipal Wild and Scenic River Commissions to decide on permits for regulated uses. These regulations are expected to be adopted in 1979. The Green Acres Administration is the DEP agency responsible for rule making and recommending rivers for designation.

The Office of Coastal Zone Management intends to work with the Green Acres Administration to nominate one or more river segments in the developed areas of New Jersey's coast for Wild and Scenic designation. The two types of river designations which appear most applicable to the developed coast area are "recreational" and "developed recreational". The characteristics of these two river types as found in the Act are as follows:

Recreational river areas are those rivers, or sections thereof, that are readily accessible, that may have some development along their shorelines, and that may have undergone some impoundment or diversion prior to their inclusion in the New Jersey Scenic River System.

Developed recreational rivers are those rivers, or sections thereof, that are readily accessible, that may have some development along their shorelines, that may have undergone substantial impoundment or diversion, but which remain suitable for a variety of recreational uses (N.J.S.A. 13:8-48).

Rivers on which PSE&G generating stations are situated could well be designated in either of these categories.

8. The Delaware and Raritan Canal State Park Law - (N.J.S.A. 13:13A-1 et seq.) This law deals with the preservation of the sixty mile Delaware and Raritan Canal and could be a consideration if district heating lines were to be run someday from Mercer Generating Station. The Delaware and Raritan Canal Commission, which is part of but largely independent of DEP, administers this law. The Commission is given project review authority over proposals within a delineated review zone which includes the Canal Park and any land on either side of it in which development will have drainage or visual impact on the park. Within this zone, the Commission has the authority to "review and approve, reject or modify any project..." (N.J.S.A. 13:13a-14c), and the Commission's decision shall be final and binding.

The projects to be reviewed by the Commission are set by the following proposed standards: Within one-half mile of the Canal Park, all projects will be reviewed for drainage, visual, noise or other ecological impacts. Outside this area, but within watersheds of streams that enter the Canal Park, projects will be reviewed only for drainage impacts.

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201 430-7000

May 31, 1979

MEMORANDUM

RESEARCH AND DEVELOPMENT CORPORATION
DISTRICT HEATING AND COOLING STUDY -
U.S. DEPARTMENT OF ENERGY

APPLICABLE LAND AND WATER QUALITY
REGULATIONS

Special NPDES Concerns

All of our plants have NPDES permits which cover water discharges from our presently under construction wastewater treatment facilities plus the ash ponds at Hudson 2 and Mercer 1 and 2. The chemical wastewater treatment facilities discharge limits do not have poundage limits, rather, only concentration limits, furthermore, our applications were submitted based upon full load conditions at these plants. Hence, an increase in capacity factor at these plants for district heating should not effect these plants' chemical wastewater treatment permits. The ash ponds would probably have to be cleared out more frequently if greater load is experienced at our coal-fired facilities, with the related concern and requirement to secure necessary permits for the ultimate disposal of this material.

Special Water Concerns - Burlington

Regarding the chemical wastewater treatment facilities at Burlington currently being installed, these facilities are sized to handle Units 5, 6 and 7, although Units 5 and 6 will not be connected to the facilities until they are returned to active service. Expenditures for this picking up of Units 5 and 6 would have to be factored into the consideration.

Special Water Concerns - Essex

Construction of the chemical wastewater treatment plants at Essex, to meet Condition 10 limits of our NPDES permits, was never started

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Special Water Concerns - Essex (Cont'd)

due to the Company's placing of Essex No. 1 on inactive status. Some preliminary engineering and design work was done for this unit, however, to reactivate the Essex unit would require the costly and complete installation of a chemical waste treatment facility. The estimated cost in 1974 for this facility was over \$1 million with probably an eighteen-month lead time needed for securing various construction permits, the actual construction, plus a shakedown operational period.

RAG:cm

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201-430-7000

May 31, 1979

MEMORANDUM

RESEARCH AND DEVELOPMENT CORPORATION
DISTRICT HEATING AND COOLING STUDY -
U.S. DEPARTMENT OF ENERGY

APPLICABLE AIR REGULATIONS

The N.J. Air Code requires the application for a permit (VEM 003-VEM 004) under NJAC 7:27-8.2(7) "Commercial fuel burning equipment having a heat input rate of 1,000,000 BTU/hr for the burning chamber." This provision we believe may apply to the modification required to install a district heating system at any unit. A change in load on a utility unit which is the projected circumstances does not require a permit but since there will be retrofit in the auxiliary equipment and an increase in emissions from the process change, it would appear to require a permit. Currently of our steam electric boiler, only the coal fired units have these permits. Therefore this would be an initial filing for the other units.

Under federal regulations, the prevention of significant deterioration (clean areas) or trade-off policy (violating areas) would seemingly be applicable if the increase in fuel oil consumption increased individual pollutants (SO_2 + part) by 100 tons/year per pollutant per emission source. The violating areas for particulates include the Hudson, Kearny, Essex and Sewaren Station areas as well as areas adjacent to Bergen Station and areas within 15 miles of Burlington Station. Hence Hudson, Kearny, Essex and Sewaren Stations will definitely fall under the trade-off policy. Depending upon the interpretation by EPA Bergen and Burlington Stations may also fall under this policy or be affected by it. Trade-off policy means that increases in emissions from these plants must be demonstrated to be more than balanced by decreased emissions from other existing sources. Under trade-off, there is a bubble concept presently being considered, which concept eliminates permits if the total emissions from a plant are not increased. However the plant definition requires that the areas be contiguous. Although the reduction of individual space heating may be equivalent to the increase in fuel use at the generating station the sites are not contiguous and hence the bubble concept would not apply. Rather the units would come under the N.J. proposed ratios for trade-offs which are:

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SO ₂ - TSP (miles)	Minimum off-set ratio
0-5.0	1.00:1
5.0-10.0	1.5:1
10.0-20.0	2.0:1

This apparently limits trade-offs to sources within twenty miles, therefore any advantage created in the PJM system would not be germane. If, as previously suggested, trade-offs would not be available beyond twenty miles the evaluations would be moot except in the circumscribed area around the plant.

In areas meeting the standards for particulates and sulfur a modeling procedure would probably be required to assess the consumption of the amount of increment allowed by regulation above the baseline in the particular area (so called prevention of significant deterioration provision). Allocation of the percentage of increment available to any one new source has not yet been determined by the regulatory authority.

The pertinent pollutant limits are governed by state regulations, a summary of these is attached.

Under the Fuel Use Act (FUA), a plant which burned oil as the primary fuel in 1977 would not be subject to the consideration of coal for any additional fuel use. Hence all of our units, with the exception of Hudson 2 and Mercer 1 & 2, may increase their oil consumption for district heating without being subject to coal use considerations required under the Fuel Use Act. Hudson 2 and Mercer 1 & 2 must depend upon coal for any increase in load.

However for emergency boilers, any unit over 100,000,000 BTU/hr or multiple units over 250,000,000 BTU/hr would be subject to the requirements of the FUA unless permitted with specific restricted operation. There are also procedures to apply for exemptions.

SPECIAL AIR CONCERNS

Burlington 5 & 6 - Essex 1 *

Burlington No. 5, No. 6 and Essex No. 1 are currently on an inactive status, (out for extended maintenance). They have no air permits under a grandfather exemption. There is some concern as to how state and federal air emission regulators would treat a return to active status of a unit currently on inactive status (new or existing source?). If these units were to be treated as new sources, they would fall under the very strict limitations of the New Source Performance Standards. We are not aware of any legal precedent regarding return to active status of inactive units, and hence it is difficult to comment on how the regulatory agency would interpret this situation.

(Note: PSE&G has no plans to reactivate any of these units. Essex 1 would be reactivated solely for the purpose of, and charged to, district heating.)

SPS:db

simultaneously in any combination, allowable SO_2 is $(y(340) + z(520)/(y + z))$, in which y and z are percent of total heat input derived from liquid and solid fuel, respectively.

Nitrogen oxides. Allowable emission is 0.2 (gaseous fossil fuel), 0.3 (liquid fossil fuel), 0.7 (solid fossil fuel except lignite or that containing 25% or more of coal refuse), 0.6 (lignite), 0.8 (lignite mined in North Dakota, South Dakota, or Montana and burned in cyclone-fired unit) lb $NO_x/10^6$ Btu heat input. Where different fossil fuels are burned simultaneously in any combination, allowable NO_x is $[w(260) + x(86) + y(130) + z(300)] / (w + x + y + z)$

in which w, x, y, z are percentages of total heat input derived from lignite, gaseous fuel, liquid fuel, and solid fuel (except lignite), respectively.

Connecticut

Dept of Environmental Protection, State Office Bldg, Hartford, CT 06115.

Particulates. Emissions for new [existing] equipment are restricted to 0.1 [0.2] lb/ 10^6 Btu/hr heat input. Proposed is a revision to 0.05 for new and 0.12 for existing installations. All compliance tests must be conducted with a heat input equal to the equipment manufacturer's or designer's guaranteed input, whichever is larger.

Sulfur oxides. Fuels are restricted to a maximum sulfur content of 0.5% by weight (dry basis). Under fuel-shortage conditions, variances can be obtained for burning higher-sulfur fuels on a temporary basis. High-sulfur fuels can also be burned if state-approved stack-gas cleaning equipment is capable of limiting total sulfur-compound emissions to the ambient air to 0.55 lb SO_2 (equivalent)/ 10^6 Btu gross heat input, and if waste discharges from the stack-gas cleaning system into state waters are approved by state authorities.

Nitrogen oxides. (1) Emissions from fuel-burning equipment rated above 250×10^6 Btu/hr heat input are limited to 0.2 (gas-fired), 0.3 (oil-fired), 0.7 (new coal-fired), or 0.9 (existing coal-fired) lb NO_x (expressed as NO_2)/ 10^6 Btu heat input.

Testing methods for determining amounts of particulate, SO_2 , SO_x , and NO_x emissions are outlined in Title 40 of Code of Federal Regulations, Part 60.

Delaware

Dept of Natural Resources & Environmental Control, Div of Environmental Control, Tatnall Bldg, Dover, DE 19901.

Particulates. Emission from fuel-burning equipment with heat input of 1×10^6 Btu/hr to 250×10^6 Btu/hr must not exceed 0.3 lb/ 10^6 Btu. For equipment of over 250×10^6 Btu/hr heat input, the construction, reconstruction, or modification of which began after 8/17/71, emissions must not exceed 0.10 lb/ 10^6 Btu heat input, and opacity must not exceed 20% (40% max allowable for no more than 2 min in any hour).

Sulfur oxides. Sulfur content of fuel used in New Castle County by fuel-burning equipment is limited to 1% by weight (0.3% for distillate oil). In Kent and Sussex Counties, sulfur content of distillate oil is limited to 0.3%, with no restriction on residual oil. High-

er sulfur content is allowed if emission controls give results equivalent to above limits on fuel. In any event, the emission of SO_2 from fuel-burning equipment shall not cause ambient-air-quality standards to be compromised. In New Castle County, emission for equipment of more than 250×10^6 Btu/hr heat input must not exceed 0.8 lb/ 10^6 Btu heat input. In Kent and Sussex Counties, the limit is 1.2 lb/ 10^6 Btu heat input.

Nitrogen oxides. For fuel-burning equipment of over 250×10^6 Btu/hr heat input, the construction, reconstruction, or modification of which began after 8/17/71, emissions are limited to 0.2 (gas-fired), 0.3 (liquid-fossil-fuel fired), and 0.7 (solid-fossil-fuel fired) lb/ 10^6 Btu heat input. When different fossil fuels are burned simultaneously in any combination, the standard is determined by proration.

Florida

Dept of Environmental Regulation, Twin Towers Office Bldg, 2600 Blair Stone Road, Tallahassee, FL 32301.

Particulates. Emissions from new sources with more than 250×10^6 Btu/hr heat input must not exceed 0.1 lb/ 10^6 Btu heat input, max 2-hr average. Visible emissions must not exceed 20% opacity (No. 1 Ringelmann), except that 40% opacity is allowed for a maximum of 2 min in any hour.

Sulfur oxides. For new sources with more than 250×10^6 Btu/hr heat input, the emission limit for SO_2 is 0.8 [1.2] lb/ 10^6 Btu heat input, max 2-hr average, when liquid [solid] fuel is burned. Existing sources with more than 250×10^6 Btu/hr heat input have various limits, depending on location and fuel, with the highest value 6.17 lb/ 10^6 Btu heat input for solid fuel in most of the state.

Nitrogen oxides. Emission limits for new sources with more than 250×10^6 Btu/hr heat input are the same as given under Delaware. Values are maximum 2-hr average.

Georgia

Air Quality Control Section, Environmental Protection Div, Dept of Natural Resources, 270 Washington St SW, Atlanta, GA 30334.

Particulates. Emission limits from fuel-burning equipment in operation or under construction on or before 1/1/72 and rated less than 10×10^6 Btu/hr heat input are $P = 0.7$. For similar units rated $10-2000 \times 10^6$ Btu/hr, $P = 0.7(10/R)^{0.875}$. For similar units rated above 2000×10^6 Btu/hr $P = 0.24$. Here P is the allowable weight of emissions in lb/ 10^6 Btu heat input and R is heat input to the equipment in 10^6 Btu/hr. Equipment on which construction began after 1/1/72 is subject to stricter limits: $P = 0.5$; $(0.5(10/R)^{0.875})$; [0.1] lb/ 10^6 Btu heat input for equipment with less than 10×10^6 ; $(10-250 \times 10^6)$; [over 250×10^6] Btu/hr heat input, respectively.

Sulfur oxides. Emission limit for new or old fuel-burning equipment is $S = 8000(h/300)^n$, with S the SO_2 emission in lb/hr, h the stack height in ft, n = 3 for stacks 30-300 ft high, and n = 2 for stacks 300 ft high or higher. For stacks less than 90 ft high, $S = 2.4h$. If several stacks are at the same site, the height used is the average stack height weighted by stack emissions.

New fuel-burning sources rated more

than 250×10^6 Btu/hr heat input that are constructed or extensively modified after 1/1/72 are limited to emissions of 0.8 [1.2] lb $SO_2/10^6$ Btu heat input (max 2-hr average) when liquid [solid] fuel is burned. Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) + (x + y + z)$$

where x, y, and z are heat input from gaseous, liquid, and solid fossil fuel, respectively, as percentages of total heat input.

No fuel-burning source (new or old) below 100×10^6 Btu/hr heat input shall burn a fuel containing more than 2.5% sulfur (by weight). All sources of 100×10^6 Btu/hr heat input or larger are limited to 3.0% sulfur (by weight).

Nitrogen oxides. New fuel-burning sources rated at above 250×10^6 Btu/hr heat input, constructed or modified extensively after 1/1/72, are subject to the same laws as Colorado.

Hawaii

State of Hawaii, Dept of Health, P.O. Box 3378, Honolulu, HI 96801.

Particulates. Visible emissions from existing stationary sources cannot be darker than 40% opacity, except for periods of not more than 3 min in any hour during startup or when equipment malfunctions. Under these variable short-term operating conditions, 60% opacity is permitted. New sources cannot have emissions darker than 20% opacity; 60% opacity is permitted them for not more than 3 min in any hour for the reasons stated above.

Sulfur oxides. Fuel oil for steam-generating facilities rated above 25 MW or 250×10^6 Btu/hr heat input is limited to max sulfur content of 0.5%. Changes in the regulations are contemplated. Parts of the state will be designated non-attainment areas for SO_2 , soon. Indication is that sulfur-content limitation will be unchanged, but regulations will allow for use of tall stacks not exceeding 2-1/2 times building height.

Nitrogen oxides. No source emission standards are listed in the regulations.

Idaho

Dept of Health & Welfare, Statehouse, Boise, ID 83707.

Particulates. For sources of 250×10^6 Btu/hr or over, constructed, modified or installed after 12/5/74, and not having a permit to construct issued before that date, particulates are limited to 0.10 lb/ 10^6 Btu heat input.

For sources constructed or with permit to construct before 12/5/74, fossil-fuel-burning equipment rated greater than $10,000 \times 10^6$ Btu heat input is limited to 0.12 lb/ 10^6 Btu heat input. Permissible emissions from equipment rated between 10 and $10,000 \times 10^6$ Btu/hr heat input is determined by:

$$\log Y = 0.2330 \log X + 0.0111$$

where X = total heat input, 10^6 Btu/hr, and Y = maximum allowable emissions, lb/ 10^6 Btu heat input.

Heat input is calculated as the aggregate higher heating value of all fuels whose combustion products pass through the stack. When two or more units are connected to a single stack, the combined heat input of all units connected to the stack is used to determine the allowable stack emission. When a single fuel-burning unit is connected to two or

reduced below 1.2. Allowable maximum hourly ground-level concentrations are the same as for new sources. The smaller values for total SO_2 emissions and for allowable ground-level concentrations hold regardless of capacity of existing equipment.

Emission sources in the rest of the state must maintain at least two weeks' supply of low-sulfur fuel.

Nitrogen oxides. For new equipment of 250×10^6 Btu/hr heat input or over, the limits on nitrogen oxides, calculated as NO_2 , are: gas firing, 0.20 lb/10⁶ Btu heat input, oil firing 0.30 lb, and coal firing 0.70 lb.

Iowa

Iowa Air Quality Commission, Dept of Environmental Quality, Henry A Wallace Bldg, 900 East Grand Ave, Des Moines, IA 50319.

Particulates. New sources rated over 250×10^6 Btu/hr heat input are subject to Federal New Source Performance Standards. Emissions of particulates are limited by Eq (15) in ASME Standard APS-1, 2nd edit, Nov 1968. In that equation, $\text{Comax}^2 = 50 \mu\text{m}^2$. Outside [inside] any standard metropolitan statistical area, max allowable emission from each stack (irrespective of stack height) serving existing equipment is 0.8 [0.6] lb/10⁶ Btu heat input. For units in operation on 1/13/76, max allowable emissions calculated under APS-1 for the configuration on 1/13/76 cannot be increased even if changes would allow a recalculation and higher max allowable emission under ASME Standard APS-1.

Sulfur oxides. New sources rated over 250×10^6 Btu/hr heat input are subject to Federal New Source Performance Standards. Solid-fuel burning units in operation before 9/23/70 in Black Hawk, Clinton, Des Moines, Dubuque, Jackson, Lee, Linn, Louisa, Muscatine, or Scott counties are limited to max emission of 6 lb SO_2 /10⁶ Btu heat input, replicated max 2-hr average. If ambient air quality standards are exceeded, then within 60 days notice the SO_2 emission limit for all solid-fuel burning units within 20 km of the air monitor will be 6 lb SO_2 /10⁶ Btu heat input.

Nitrogen oxides. No source emission standards are stated in the regulations.

Kansas

Bureau of Air Quality & Occupational Health, Dept of Health and Environment, Topeka, KS 66620.

Particulates. All fuel-burning equipment burning coal at 350,000 Btu/hr or over heat input, or No. 5 or heavier oil or No. 4 or lighter oil at 10⁶ Btu/hr heat input, or gas (or No. 4 or lighter oil on standby basis) at 100×10^6 Btu/hr heat input is subject to regulations. Emission limit for 10⁶ Btu/hr heat input or less is 0.60 lb/hr/10⁶ Btu. From 10⁶ to $10,000 \times 10^6$ Btu/hr heat input, the allowable emission limit is $A = 1.026/10^{2.33}$, where A is in lb/hr/10⁶ Btu and I is the total heat input in 10⁶ Btu/hr. For $10,000 \times 10^6$ Btu/hr and above, the allowable limit is 0.12 lb/hr/10⁶ Btu.

Sulfur oxides. For equipment with heat input of 250×10^6 Btu/hr or more, sulfur emission is limited to 1.5 lb/10⁶ Btu/hr heat input.

Nitrogen oxides. Gas- or oil-fired equipment with heat input of 250×10^6 Btu/hr or

more is limited to 0.30 lb NO_x /10⁶ Btu/hr heat input. For coal-fired equipment with heat input of 250×10^6 Btu/hr or more, the limit is 0.90 lb of NO_x (calculated as NO_2)/10⁶ Btu/hr heat input.

Kentucky

Div of Air Pollution Control, Dept for Natural Resources & Environmental Protection, Capital Plaza Tower, Frankfort, KY 40601.

Particulates. Emissions from fuel-burning sources rated 250×10^6 Btu/hr heat input or larger are limited to 0.1 lb/10⁶ Btu heat input.

Sulfur oxides. Emissions from fuel-burning sources rated 250×10^6 Btu/hr heat input or larger are limited to 0.8 [1.2] lb SO_2 /10⁶ Btu heat input for liquid and gaseous [solid] fuels. Proposed change is that in VA counties (Boyd), sources rated over 1500×10^6 Btu/hr heat input will be limited to 0.4 [0.6] lb SO_2 /10⁶ Btu heat input for liquid and gaseous [solid] fuels.

Nitrogen oxides. See Colorado.

Louisiana

Air Control Commission, P. O. Box 60630, New Orleans, LA 70160.

Particulates. Emissions from new and existing fuel-burning equipment not subject to Federal New Source Performance Standards are limited to 0.6 lb/10⁶ Btu heat input. If emissions are already below this level, control is normally not relaxed. Particulate emissions are determined by ASME PTC-27 or EPA test methods 1, 2, 3, 4, and 5. Ambient-air standards must also be met.

Sulfur oxides. For sources not subject to Federal New Source Performance Standards, SO_2 emissions are limited to 2000 ppm by volume at standard conditions. Sulfur content of liquid fuels is limited to 0.7% by weight, and variances are rare. SO_2 emissions may be determined by several methods, including EPA test methods 1, 2, 3, 4, 6, and 8. Ambient-air standards must also be met.

Nitrogen oxides. If the source is not subject to Federal New Source Performance Standards, no emission limit exists, except that ambient-air standards must be met.

Maine

Bureau of Air Quality Control, Dept of Environmental Protection, Augusta, ME 04330.

Particulates. Emissions from fuel-burning equipment rated 3×10^6 Btu/hr heat input are limited to 0.6 lb/10⁶ Btu heat input. For equipment rated 150×10^6 Btu/hr heat input, the limit is 0.3 lb/10⁶ Btu heat input. Equipment rated above 250×10^6 Btu/hr heat input is limited to 0.1 lb/10⁶ Btu heat input. Interpolation between 10×10^6 and 150×10^6 Btu/hr heat input is by straight line on log-log graph. Equipment less than 3×10^6 Btu/hr heat input is exempt. Tests include methods 1 and 5 in "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71.

Sulfur oxides. Emissions can be regulated by the use of low-sulfur fuels and/or pollution-control equipment. Fuel-burning equipment larger than 250×10^6 Btu/hr heat input is limited to 0.8 lb/10⁶ Btu heat input. Sources in the Central Maine, Down East, and Aroostook County, Northwest Maine, and

Metropolitan Portland AQRs must burn the equivalent of 2.5%-sulfur (or less) fuel. Sources in the Portland Peninsula AQR are limited to 1.5%-sulfur fuel (or less) until 11/1/85 and to 1.0%-sulfur fuel (or less) thereafter. In addition, in the Portland Peninsula AQR, no construction or expansion is permitted for any fuel-burning equipment which will burn other than No. 2 oil or its equivalent in sulfur and ash content.

Nitrogen oxides. No source emission standards are stated in the regulations.

Maryland

Dept of Health & Mental Hygiene, Environmental Health Admin, 201 West Preston St, Baltimore, MD 21201.

Particulates. Residual-oil-fired equipment constructed after 1/16/72 and rated 50 to 250×10^6 Btu/hr heat input is limited to 0.02 grains/scf (dry); these residual-oil-fired units above 250×10^6 Btu/hr heat input are limited to 0.01 grains/scf (dry); coal-fired units above 250×10^6 Btu/hr heat input, constructed after 1/16/72, are limited to 0.03 grains/scf (dry). Residual-oil-fired units constructed before 1/16/72 in Areas III and IV have the same limits as new units rated 50×10^6 Btu/hr heat input. Coal-fired units constructed before 1/17/72 in Areas III and IV rated more than 250×10^6 Btu/hr heat input have the same limits as new coal-fired units.

Sulfur oxides. In Areas I, III, and IV, all sources must burn fuel limited to 1% by weight of sulfur or use stack-gas cleanup equipment that will provide emissions equivalent to those from 1%-sulfur fuel. Residual-oil sulfur limit of 0.5% will become law 7/1/80. In Areas II, V, and VI, emissions from coal-fired units with a total maximum heat input of all units on one site of 100×10^6 Btu/hr or more are limited to 3.5 lb/10⁶ Btu heat input. Residual-oil sulfur limit is 2.0%.

Nitrogen oxides. Units constructed after 5/11/72 and rated more than 250×10^6 Btu/hr heat input are limited to 0.2 (gaseous fuel), 0.3 (liquid fuel), and 0.5 (solid fuel) lb NO_x (calculated as NO_2)/10⁶ Btu heat input (max 2-hr average). In Areas III and IV, existing sources (constructed before 5/12/72) rated 250×10^6 Btu/hr heat input or greater must meet emission levels that are attainable through the use of reasonably applied control technology. There is no requirement for existing sources in Areas I, II, V, and VI.

Massachusetts

Div of Air and Hazardous Materials, Department of Environmental Quality Engineering, 600 Washington St, Boston, MA 02111.

Particulates. New sources larger than 250×10^6 Btu/hr heat input must limit emissions to 0.05 lb/10⁶ Btu heat input, except for units with equipment designed to control or reduce SO_2 . Limit for those units is 0.1 lb/10⁶ Btu heat input. For existing sources, limit is 0.15 lb/10⁶ Btu heat input, except in critical areas, where only 0.12 lb/10⁶ Btu is allowed. Emission testing is to be done in accordance with method 5 in "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71.

Sulfur oxides. Emissions from residual-oil or coal-fired equipment are restricted to the equivalent of the uncontrolled burning of fuel

C-4

1/22/70) fuel-burning plants have the same limits as in the St. Louis Metropolitan area. In the Springfield Metropolitan area, existing (under construction before 9/25/69) fuel-burning plants rated 100, 500, 1000, 2000, 5000, 7500, and 10,000 or more $\times 10^6$ Btu/hr heat input are limited to 0.35, 0.24, 0.21, 0.17, 0.14, 0.13, and 0.12 lb/10⁶ Btu heat input, respectively.

Sulfur oxides. Source emissions in excess of 1000 lb SO₂/hr are not permitted unless they do not cause or contribute to concentrations and frequencies exceeding the following limits in ambient air at any occupied place beyond the premises on which the source is located: 0.25 ppm (1-hr avg) once in any four-day period, 0.07 ppm (24-hr avg) once in any 90-day period.

In the St. Louis Metropolitan area, emission limit for existing plants rated 2000 $\times 10^6$ Btu/hr and larger heat input will be 2.3 lb SO₂/10⁶ Btu heat input. Plants under 2000 $\times 10^6$ Btu/hr heat input are limited to 2.0% sulfur fuel during October-March, inclusive, each year, unless SO₂ emission is not over 2.3 lb SO₂/10⁶ Btu heat input. During rest of year, fuel-sulfur limit is 4.0%. Special higher limits on SO₂ are set for two plants.

Nitrogen oxides. No source emission standards for existing sources are stated in the regulations.

Montana

Dept of Health & Environmental Sciences, Air Quality Bureau, Cogswell Bldg, Helena, MT 59601.

Montana has adopted the "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71. See Nebraska.

Nebraska

Dept of Environmental Control, P.O. Box 94653, State House Station, Lincoln, NE 68509.

Nebraska adopted the U S Environmental Protection Agency's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, which are outlined here. Changes will probably occur this year, especially in regard to sulfur oxides.

Particulates. (1) Emissions are limited to 0.1 lb particulates/10⁶ Btu heat input (max 2-hr avg). (2) Opacity is limited to 20%, but 40% is permissible for not more than 2 min in any hour. (3) Where the presence of uncombined water is the only reason for failure to meet the requirements of (2), such failure is not a violation.

Sulfur oxides. (1) Emissions are limited to 0.8 [1.2] lb SO₂/10⁶ Btu heat input (max 2-hr avg) when liquid [solid] fossil fuel is burned. (2) Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) + 100$$

where y and z are heat input from liquid and solid fossil fuel, respectively, as percentages of total heat input.

Nitrogen oxides. (1) Emissions are limited to 0.2 (gaseous fossil fuel), 0.3 (liquid fossil fuel) or 0.7 (solid fossil fuel, except lignite) lb NO_x (expressed as NO₂)/10⁶ Btu heat input. (2) Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.2x + 0.3y + 0.7z) + 100$$

Equation nomenclature is as defined above.

plus x for gaseous fuel. There are no limits for existing sources.

Nevada

Div of Environmental Protection, Dept of Conservation & Natural Resources, 210 S. Fall Street, Carson City, NV 89710.

Particulates Nevada has adopted "Standards of Performance for New Stationary Sources," including New Source Performance Standards (NSPS) for Fossil-Fuel-Fired Steam Generators. For new equipment with heat input rates above 250 $\times 10^6$ Btu/hr but less than 8370 $\times 10^6$ Btu/hr, max allowable emission rate is 0.10 lb/10⁶ Btu heat input. For heat input rates of 8370 $\times 10^6$ Btu/hr or above, the max allowable emission rate is calculated from:

$$Y = 17.0X^{-0.34}$$

where Y is the allowable emission rate in lb/10⁶ Btu and X is heat input in 10⁶ Btu/hr.

For existing sources between 10 $\times 10^6$ and 4000 $\times 10^6$ Btu/hr heat input, emission is limited to

$$Y = 1.02X^{-0.211}$$

and for existing sources over 4000 $\times 10^6$ Btu/hr heat input, emission is limited to

$$Y = 17.0X^{-0.34}$$

Sulfur oxides. For new sources, subject to NSPS, with heat inputs greater than 250 $\times 10^6$ Btu/hr, max allowable emission is 0.4 (liquid fossil fuel) and 0.6 (solid fossil fuel) lb sulfur/10⁶ Btu heat input. For combination fuels, the allowable emission is calculated from:

$Y = [0.4(F_L) + 0.6(F_S)] \div (F_L + F_S)$ where Y is the allowable emission rate in lb sulfur/hr, F_L is the percent of total heat input derived from liquid fossil fuel, and F_S is the percent of total heat input derived from solid fossil fuel. Compliance is based on the total heat input from all fossil fuel burned including gaseous fuels.

For existing sources over 250 $\times 10^6$ Btu/hr heat input, emission is limited to 0.4 [0.6] lb sulfur/10⁶ Btu heat input for liquid [solid] fuel.

Nitrogen oxides. For new sources with heat input over 250 $\times 10^6$ Btu/hr, the allowable emission is 0.2 (gaseous fossil fuel), 0.3 (liquid fossil fuel), and 0.7 (solid fossil fuel except lignite or solid fossil fuel containing 25% or more by weight of coal refuse) lb NO_x (expressed as NO₂)/10⁶ Btu. For a combination of fuels, the allowable emission rate is:

$$E = [0.2(X) + 0.3(Y) + 0.7(Z)] \div (X + Y + Z)$$

where E is allowable emission rate in lb NO_x (expressed as NO₂)/hr, X is the percent of total heat input derived from gaseous fossil fuel, Y the percent derived from liquid fossil fuel, and Z the percent derived from solid fossil fuel (except lignite or solid fossil fuel containing 25% or more by weight of coal refuse).

New Hampshire

Air Pollution Control Commission, State Lab Building, Hazen Drive, Concord, NH 03301.

Particulates. Max allowable emission rate from new [existing] fuel-burning equipment rated 50 $\times 10^6$ Btu/hr heat input is 0.4 [0.46] lb/10⁶ Btu; 100 $\times 10^6$, 0.35 [0.4]; 500 $\times 10^6$, 0.10 [0.31]; 1000 $\times 10^6$, 0.10 [0.28]; 2500 $\times 10^6$, 0.10 [0.24]; 5000 $\times 10^6$, 0.10 [0.22];

7500 $\times 10^6$, 0.10 [0.20]; 10,000 $\times 10^6$ and above, 0.10 [0.19]. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. The ordinate is max emissions in lb/10⁶ Btu of heat input; the abscissa is heat input in 10⁶ Btu/hr. For all new equipment larger than 250 $\times 10^6$ Btu/hr heat input, however, the max emission rate is 0.10 lb/10⁶ Btu. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack is used in calculating the allowable emissions. When a single fuel-burning unit is connected to two or more stacks, the allowable emission from all of the stacks combined cannot exceed that for the same unit if it had been connected to a single stack.

Sulfur oxides. Gaseous fuel cannot be fired in fuel-burning installations if it contains more than 5 grains of sulfur/100 cu ft, calculated as hydrogen sulfide at standard conditions. No. 2 oil cannot contain more than 0.4% sulfur by weight, No. 4 oil cannot contain more than 1% sulfur by weight, and residual and crude cannot contain more than 2.0% sulfur by weight, except in the New Hampshire portion of the Androscoggin Valley AQCR, where 2.2% is allowed. The residual and crude rule will be reviewed by the Commission before 5/2 each year. New [existing] fuel-burning installations using solid fuel cannot burn coal with a maximum sulfur content greater than 1.5 [2.8] lb/10⁶ Btu gross heat content, provided that the weighted average of all coal received during a trimonthly period does not exceed 1 [2] lb sulfur/10⁶ Btu gross heat content. Fuels with higher sulfur content can be burned if control apparatus continuously restricts sulfur emissions to levels permitted by the regulations for uncontrolled burning of the fuel being burned.

Nitrogen oxides. No source emission standards are stated in the regulations.

New Jersey

Dept of Environmental Protection, Div of Environmental Quality, John Fitch Plaza, PO Box 2807, Trenton, NJ 08625.

Particulates. Maximum allowable emission rate from new and existing fuel-combustion equipment with a heat input rate of 200 $\times 10^6$ Btu/hr is 20 lb/hr; 1000 $\times 10^6$, 100; 5000 $\times 10^6$, 500; 10,000 $\times 10^6$, 1000. Allowable emissions for heat-input rates between those noted above are found by linear interpolation. Heat input rate is the sum of the heat-input rates of all fuel-burning equipment discharging through a single stack.

In measuring emissions, solid particles must be drawn by isokinetic procedures from the stack, and the weight of the solid particles determined gravimetrically after removing uncombined water. Specifications for the sampling train, as well as the sample procedures, are available from the above address.

Sulfur oxides. State is divided into six zones in which allowable sulfur content of fuel varies from 0.2 to 0.3% for No. 2 and lighter oils and from 0.3 to 2.0% for No. 4 and heavier oils. Liquid fuels of higher sulfur content can be burned if control apparatus continuously restricts SO₂ emissions for uncontrolled burning of the fuel. A county-by-county summary is available. For bituminous and anthracite coal, sulfur content for

C-5

ment, P.O. Box 27687, Raleigh, NC 27611.

The state has adopted Federal New Source Performance Standards (see Nebraska).

Particulates. Maximum allowable emission rate from fuel-burning sources existing before 12/24/71 or new and rated below 250×10^6 Btu/hr heat input is 0.33 lb/ 10^6 Btu for rating of 100×10^6 Btu/hr heat input; 0.18 for rating of 1000×10^6 Btu/hr heat input; 0.1 for rating of $10,000 \times 10^6$ Btu/hr heat input or greater. Allowable emissions for unit ratings between the capacities noted can be found by plotting a curve on log-log graph paper with the data given. Ordinate is maximum emissions in lb/ 10^6 Btu and abscissa is heat input in 10^6 Btu/hr. Heat input is the aggregate heat content of all fuels burned.

Sulfur oxides. Sources built before 12/24/71 are limited to emissions of 2.3 lb SO_2 / 10^6 Btu heat input.

Nitrogen oxides. Existing oil-and-gas [coal] fired boilers rated 250×10^6 Btu/hr heat input and above are limited to 0.6 [1.3] lb NO_x / 10^6 Btu heat input.

North Dakota

Dept of Health, Div of Environmental Engineering, Missouri Office Bldg, 1200 Missouri Ave, Bismarck, ND 58505.

Particulates. Maximum allowable emission rate from existing plants is 0.8 lb/ 10^6 Btu heat input. As technology develops and control equipment becomes compatible with existing plants, compliance with the standard for new plants (see below) will be required. Maximum allowable particulate emission rate, E (lb/ 10^6 Btu heat input), for new installations less than 250×10^6 Btu/hr heat input is $E = 0.811H^{-0.411}$, where H is heat input in 10^6 Btu/hr. New installations with heat input over 250×10^6 Btu/hr are limited to 0.1 lb/ 10^6 Btu.

The total heat input of all fuel-burning units at the source of emission is used in finding the maximum allowable discharge rate. Discharges are measured in accordance with EPA methods.

Sulfur oxides. Emissions from new installations less than 250×10^6 Btu/hr are limited to 3 lb SO_2 / 10^6 Btu heat input. Emissions from new installations larger than 250×10^6 Btu/hr are limited to 1.2 lb SO_2 / 10^6 Btu.

Nitrogen oxides. Emission limit for new sources rated over 250×10^6 Btu/hr heat input and fired with North Dakota lignite is 0.6 lb NO_x / 10^6 Btu heat input, except when the unit is cyclone-fired, when the limit is 0.8.

Ohio

Environmental Protection Agency, P.O. Box 1049, Columbus, OH 43216.

Particulates. Boilers in TSP non-attainment counties will be required to meet the limit of $E = 0.8H^{-0.411}$, in which H is total heat input in 10^6 Btu/hr and E is emission rate in lb/ 10^6 Btu heat input. Boilers in TSP attainment counties will be required to meet the limit of $E = 1.2H^{-0.411}$. Capacities of boilers firing only natural gas, No. 2 fuel oil, and/or refinery fuel gas will not be included in the determination of maximum capacity, and allowable emission rate for those boilers will be 0.02 lb/ 10^6 Btu heat input. US EPA Method 5 determines particulate emissions.

Sulfur oxides. US EPA regulations for Ohio were promulgated 8/27/76, specifying emission limits for specific facilities and by county. Further changes were given in the Federal Register, 5/31/77 (pp 27588-27593) and 2/15/78 (p 6646).

Nitrogen oxides. Emission limit for new sources rated 250×10^6 Btu/hr or greater is 0.2 lb NO_x (measured as NO_2)/ 10^6 Btu heat input for gas-fired boilers, 0.3 for oil-fired, and 0.9 for coal-fired. There are no Priority I regions for nitrogen.

Oklahoma

Air Quality Service, Environmental Health Services, Dept of Health, NE 10th & Stone-wall Sts, Oklahoma City, OK 73152.

Particulates. Maximum allowable emission rate from new and existing fuel-burning equipment rated up to 10×10^6 Btu/hr heat input is 0.6 lb/ 10^6 Btu; 100×10^6 , 0.35; 1000×10^6 , 0.2; $10,000 \times 10^6$ and above, 0.1. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/ 10^6 Btu of heat input and the abscissa for heat input in 10^6 Btu/hr. When one source is connected to two or more stacks, the heat input of the single source is used in determining the maximum total emission from all stacks combined.

Refuse may not be burned in fuel-burning equipment not specifically designed for it.

The opacity limit for smoke and visible emissions (except water droplets) is No. 1 on the Ringelmann chart, but No. 3 Ringelmann is permitted for sootblowing, etc, for 5 min in any hour and 20 min in a 24-hr period.

Continuous emission monitoring of equivalent opacity is required for units over 250×10^6 Btu/hr heat input with capacity factor of 30% or higher, unless (1) only gas or (2) a gas/oil combination without particulate-matter collection equipment to meet emission regulations is burned.

Sulfur oxides. Maximum allowable emission rate from new gas-burning equipment (that on which construction started after 1/23/72) is 0.2 lb SO_2 (measured as SO_2)/ 10^6 Btu heat input (max 2-hr avg). New oil-fired units are restricted to 0.8 lb SO_2 (measured as SO_2)/ 10^6 Btu heat input. New solid-fuel-burning equipment is limited to 1.2 lb SO_2 (measured as SO_2)/ 10^6 Btu heat input. Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) \div 100$$

where y and z are heat input from liquid and solid fuel, respectively, as percentages of total heat input.

Continuous monitoring of SO_2 emissions is required for units over 250×10^6 Btu/hr heat input with capacity factor of 30% or over, if the source has an air-pollution abatement operation to cut SO_2 emission significantly.

Nitrogen oxides. New installations rated 50×10^6 Btu/hr heat input and above cannot emit more than 0.2 (gaseous fuels), 0.3 (liquid fuels), and 0.7 (solid fuels) lb NO_x (calculated as NO_2)/ 10^6 Btu heat input (2-hr max).

Alternative monitoring requirements for opacity and SO_2 may be approved if it is demonstrated that continuous monitoring will be an extreme economic hardship, incompatible with plant configuration, or inaccurate. Permit regulations are under revision.

Oregon

Dept of Environmental Quality, Air Quality Div, 1234 SW Morrison St, Portland, OR 97205.

Oregon adopted the US EPA "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71, as outlined under "Nebraska."

Sulfur oxides. Sulfur content of residual fuel oils is limited to 1.75%. No. 1 distillate is restricted to 0.3% sulfur; No. 2 distillate to 0.5%; coal to 1%.

Pennsylvania

Dept of Environmental Resources, Bureau of Air Quality & Noise Control, P.O. Box 2063, Harrisburg, PA 17120.

Particulates. Maximum allowable emission rate from new and existing combustion units rated 2.5×10^6 to 50×10^6 Btu/hr heat input is 0.4 lb/ 10^6 Btu. From 50×10^6 to 600×10^6 Btu/hr heat input, the emission rate, A (lb/ 10^6 Btu heat input), is determined by the equation: $A = 3.6E^{-0.34}$, where E is the heat input in 10^6 Btu/hr. Units rated 600×10^6 Btu/hr heat input and greater are limited to 0.1 lb/ 10^6 Btu heat input. In addition to these regulations, EPA's "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71, also are enforceable by the state, since they were adopted by reference. The EPA standards are outlined above (see Nebraska).

Sulfur oxides. The sulfur-oxide regulations are divided into three categories:

(1) The following rules apply to all combustion units in all air basins except those units subject to the provisions of Sections 2 and 3. Maximum allowable emission rate from units rated 2.5×10^6 to 50×10^6 Btu/hr heat input is 3 lb SO_2 (expressed as SO_2)/ 10^6 Btu heat input. From 50×10^6 to 2000×10^6 Btu/hr heat input, the emission rate, A (lb SO_2 /10⁶ Btu heat input) is determined by the equation: $A = 5.1E^{-0.14}$, where E is heat input in 10^6 Btu/hr. Units rated 2000×10^6 Btu/hr and greater are restricted to 1.8 SO_2 (expressed as SO_2)/ 10^6 Btu heat input.

(2) For all combustion units in the Allegheny County, Beaver Valley, and Monongahela Valley air basins, the maximum allowable emission rates for units below 50×10^6 and above 2000×10^6 Btu/hr heat input are one-third those presented in Section 1. Between 50×10^6 and 2000×10^6 Btu/hr heat input, the applicable equation is $A = 1.7E^{-0.14}$.

(3) For combustion units in the Southeast Pennsylvania air basin, the maximum allowable emission rates from units 250×10^6 Btu/hr heat input and larger are 0.6 lb SO_2 /10⁶ Btu heat input for inner-zone sites and 1.2 for outer-zone sites.

(4) All combustion units not covered under Sections 1-3 must restrict emissions to 4 lb SO_2 /10⁶ Btu heat input.

In addition to the regulations, EPA's "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71 also are enforceable by the state, since they were adopted by reference. The EPA standards are outlined above (see Nebraska).

Nitrogen oxides. Although no state regulations exist, EPA's "Standards of Performance for New Stationary Sources," Federal Register, 12/23/71, are enforceable by the

Particulates. Emission limits will shortly be established for specific existing sources located in non-attainment areas. For new sources, approval will depend on Federal standards and on emission offsets.

Sulfur oxides. Limit on coal [oil] is expected to be 1.0% [1.5%] sulfur by weight unless control apparatus is operating to prevent emission of SO_2 in amounts greater than equivalent to the fuel SO_2 limit.

Nitrogen oxides. See Nebraska.

Vermont

Air & Solid Waste Programs, Agency of Environmental Conservation, PO Box 489, Montpelier, VT 05602.

Particulates. Maximum allowable emission rate from new and existing fuel-burning equipment rated 10×10^6 Btu/hr heat input and less is 0.5 lb/ 10^6 Btu heat input; 250×10^6 and above, 0.1. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emission in lb/ 10^6 Btu of heat input; the abscissa expresses heat input in 10^6 Btu/hr. Note: Units rated 1000×10^6 Btu/hr heat input and greater that were constructed after 7/1/71 are limited to 0.06 lb/ 10^6 Btu heat input. Limit for wood-burning boilers over 1300 hp is 0.10 gr/dry standard ft³ of exhaust gas corrected to 12% CO_2 .

Sulfur oxides. Emission rate for new stationary combustion units, except gas turbines, of over 250×10^6 Btu/hr is limited to 0.8 lb (liquid fossil fuels) or 1.2 lb (solid fossil fuels) SO_2 / 10^6 Btu heat input.

Nitrogen oxides. Maximum allowable emission rate from new installations, including gas turbines, over 250×10^6 Btu/hr heat input is 0.3 lb NO_x / 10^6 Btu.

Virginia

Air Pollution Control Board, Room 1106, 9th St Office Bldg, Richmond, Va 23219.

Virginia enforces Federal "Standards of Performance for New Stationary Sources," outlined under "Nebraska," but in no case are the emissions to exceed those permitted for existing sources.

Particulates. Maximum allowable emission rate E for existing (8/9/75) fuel-burning equipment is 0.6 lb/ 10^6 Btu for facilities rated under 10×10^6 Btu/hr total capacity. For facilities between 10×10^6 and $10,000 \times 10^6$ Btu/hr total capacity heat input, the rate is calculated from $E = 1.0905H^{-0.222}$, where H is the total capacity in 10^6 Btu/hr. Above $10,000 \times 10^6$ Btu/hr heat input, emission rate is 0.1 lb/ 10^6 Btu.

AQC Region-7 (Northern Virginia) facilities rated less than 100×10^6 Btu/hr total capacity are limited to 0.3 lb/ 10^6 Btu. From 100×10^6 Btu to $10,000 \times 10^6$ Btu/hr, the rate is calculated from $E = 0.9000H^{-0.222}$. Above $10,000 \times 10^6$ Btu/hr heat input, the emission rate is 0.1 lb/ 10^6 Btu.

Total capacity, expressed as heat input, is the sum of rated capacities of all existing, new, and modified fuel-burning equipment operated simultaneously at maximum load at a facility.

Maximum allowable particulate emission for a facility is the product of the total capacity and the emission rate. Emission

contribution of each unit is founded by procedures based on fuels and other conditions in the control program, or set down in the facility's registration forms.

Sulfur oxides. For existing installations, maximum allowable emission rate in lb/hr of SO_2 is calculated by multiplying 2.64 by the heat input at total capacity in 10^6 Btu/hr. For AQC Region 7, multiplier is 1.06.

Nitrogen oxides. No NO_x emission standard for existing equipment.

Washington

Office of Air Programs, Dept of Ecology, P.O. Box 829, Olympia, WA 98504.

Particulates. Maximum allowable emission rate from new and existing combustion sources is 0.1 grains/standard cu ft (dry), with the flue-gas samples corrected to 7% oxygen.

Sulfur oxides. Maximum permissible concentration from new and existing combustion sources is 1000 ppm SO_2 , with dry samples corrected to 7% oxygen.

Nitrogen oxides. No source emission standards are stated in the regulations.

West Virginia

Air Pollution Control Comm, 1558 Washington St, East Charleston, WV 25311.

West Virginia classifies fuel-burning sources in three categories: (a) any fuel-burning unit which has as its primary purpose the generation of steam or other vapor to produce electric power for sale; (b) any fuel-burning unit not classified as (a) or (c), such as industrial pulverized-fuel-fired furnaces, cyclone furnaces, gas-fired and liquid-fuel-fired units; (c) any fuel-burning unit, hand- or stoker-fired, not classified as Type (a).

Particulates. (a) Max allowable emission rate in lb/hr from all Type (a) fuel-burning units located at one plant is calculated by multiplying 0.05 by the sum of the design heat input, in units of 10^6 Btu/hr, of all sources at the plant. No more than 1200 lb/hr of particulates can be discharged to the atmosphere from all such units, however.

(b) Max allowable emission rate in lb/hr from all Type (b) fuel-burning units located at one plant is calculated by multiplying 0.09 by the sum of the design heat input, in units of 10^6 Btu/hr, of all sources at the plant. No more than 600 lb/hr of particulates can be discharged to the atmosphere from all such units, however.

(c) Max allowable emission rate in lb/hr from all Type (c) fuel-burning units located at one plant when the sum of the design heat inputs of all sources at the plants is 10^6 Btu/hr is 3.4 lb/hr; for 20×10^6 Btu/hr, 5.6 lb/hr; for 40×10^6 , 9.0; for 60×10^6 , 11.7; for 80×10^6 , 14.4; for 100×10^6 , 16.6; for 200×10^6 , 26.4; for 400×10^6 , 42.2; for 600×10^6 , 54.0; for 3333×10^6 , 300.

Sulfur oxides cannot be added to the flue-gas stream to improve efficiency of particulate-control equipment.

Sulfur oxides. Max allowable emission rate, effective 6/30/78, from all Type (a) fuel-burning units at one plant in Priority I and II regions is calculated by multiplying 2.7 [2] by the sum of design heat inputs, in 10^6 Btu/hr, of all sources at the plant. The 6/30/78 regulation also limits total SO_2 discharges from the plant to 45,000 lb/hr. In

the Kanawha Valley AQCR, the multiplier is now 1.6, with 45,000 lb/hr discharge limit. For all Priority III regions except Kanawha Valley, the multiplier is 2.0, with max discharge from a plant of 45,000 lb/hr of SO_2 .

Max allowable emission rate, effective 6/30/78, from all Type (b) and (c) fuel-burning units at one plant in Priority I and II regions is calculated by multiplying 2.3 by the sum of the design heat inputs, in 10^6 Btu/hr, at the plant. The 6/30/78 regulation also limits total SO_2 discharges from the plant to 8000 lb/hr. In the Kanawha Valley AQCR, the multiplier is 1.6 now, with a 5500-lb/hr discharge limit. For all Priority III regions except Kanawha Valley, multiplier applicable from 6/30/78 is 2.3, with a max discharge limit from a plant of 8000 lb/hr of SO_2 .

Nitrogen oxides. No source emission standards are stated in the regulations.

Wisconsin

Dept of Natural Resources, Bureau of Air Management, P.O. Box 7921, Madison, WI 53707.

Particulates. Emission rate for new or modified units must not exceed 0.15 lb/ 10^6 Btu heat input to any stack for 250×10^6 Btu/hr heat input or less, and 0.10 lb/ 10^6 Btu heat input to any stack for rates of over 250×10^6 Btu/hr. Performance tests follow EPA-required test methods.

Sulfur oxides. New or modified fossil-fuel-fired steam generators rated over 250×10^6 Btu/hr heat input are limited to 0.8 lb SO_2 / 10^6 Btu heat input with liquid fuel and 1.2 with solid fuel. Provisions which may be changed soon as result of the SIP revision process are: In the Southeast Wisconsin Intrastate AQCR, installations of 250×10^6 Btu/hr heat input or less are not allowed to burn coal with more than 1.11 lb sulfur/ 10^6 Btu. In the case of standby fuel, no fuel is permitted which will substantially contribute to exceeding of an air standard or cause pollution. Limits on sulfur in standby fuel in this AQCR are: 1.5% for coal by weight as fired, 1% for residual oil, and 0.7% for distillate oil.

Nitrogen oxides. For new or modified fossil-fuel-fired steam generators over 250×10^6 Btu/hr input, the regulations are the same as for Nebraska.

Wyoming

Air Quality Div, Dept of Environmental Quality, Hathaway Office Bldg, Cheyenne, WY 82002.

Wyoming has incorporated Federal "Standards of Performance for New Stationary Sources" into its regulations. See Nebraska for these.

Particulates. The Federal limit of 0.1 lb/ 10^6 Btu is applied to all sizes of new units.

Sulfur oxides. More restrictive than the Federal standard, limit for new units is 0.2 lb SO_2 / 10^6 Btu heat input for coal and 0.8 for oil (maximum 2-hr average) for units with heat input of 250×10^6 Btu/hr or greater.

Nitrogen oxides. Nebraska regulations apply to all sizes of units, except for new oil-fired units of less than 10^6 Btu/hr heat input and internal combustion engines with less than 200×10^6 Btu/hr heat input.

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201 430-7000

May 31, 1979

MEMORANDUM

RESEARCH AND DEVELOPMENT CORPORATION
DISTRICT HEATING AND COOLING STUDY -
U.S. DEPARTMENT OF ENERGY

ENVIRONMENTAL ASSESSMENT FROM CHANGES IN EMISSIONS

Air Emissions

A complete environmental assessment (evaluation of effects and benefits) is an extremely complex determination, would have to be undertaken over a substantial period of time, would have to take into consideration different scenarios, as well as including various technical details. Some of the considerations in such an assessment follow:

1. Geographic parameters - An analysis would have to be made as to whether the assessment should be based on the effects to only a limited area in New Jersey, or on the effects to the State of New Jersey, or on the effects over the entire PJM area. In addition, it may be necessary to compare the effects of emissions in a more rural, less developed area with emissions in an urbanized area.
2. Time period covered - Consideration must be given as to whether the evaluation should be made on an annual emission basis or on a 24-hour or three-hour worst case basis.
3. Future emission limits - Consideration must be given to whether present air code limits would be allowed or whether some less restrictive emission limits would be mandated so as to meet PSD limitations or offset limits.
4. Unique plant configurations - The details of the unique plant or source configurations such as stack height, boiler design, meteorological conditions, as well as surrounding population zones, will have to be factored into the assessment.

5. Details of individual plant loadings - More specific information on which specific PJM plants would be used to replace the generation lost when PSE&G units supply district heat would have to be considered.

A complete environmental assessment covering the factors indicated above would be costly and demanding, and should only be undertaken if the other review parameters appear favorable and if a simplistic analysis indicates that such details are necessary. A simplistic analysis indicating the changes in the emissions of SO₂ in the Hudson area only for the period 1985 and 1990 is attached. This analysis shows that there is a net change or decrease in SO₂ emissions in the Hudson area in both these time periods. This analysis is based on the assumption that present emission limits would remain in effect. In addition, it addresses only the emission of SO₂ and not of particulates or of any additional pollutants that might be a subject of future concern. (See discussions under "Environmental Regulations" for additional details on possible future constraints due to the fact that the areas under consideration are in non-attainment for particulates).

Water Emissions

Information in the table entitled "Seasonal Variation of District Heating Load" indicate the variation or reduction in thermal discharge by the month of the year. The critical months for the aquatic organisms are the nonwinter months. Information for these critical months indicate a relatively slight change in thermal discharge. Hence, this information at best could be used as a minor bargaining or discussion point with appropriate water regulatory agencies, but would not be of great significance in an overall environmental assessment. It should be noted, however, that the information to date has not considered the effect of summer cooling which, if absorbent coolers were used, would cause a greater discharge reduction. Future calculations including this information may be able to show a more positive environmental benefit.

RAG:cm
Attachment

EMISSION SO₂ IN THE HUDSON AREA

(DUE TO CHANGE IN FUEL BURNED DUE TO DISTRICT HEATING)

<u>District Heating Units</u>	<u>1985 - Hudson Only</u>		<u>1990 - Hudson Only</u>	
	<u>Change in Fuel</u>	<u>Emission SO₂ (lbs)</u>	<u>Change in Fuel</u>	<u>Emission SO₂ (lbs)</u>
PSE&G Units: No. 6 Oil (6)	+ 23,000 bbl/yr	+ 41,000	+ 255,000 bbl/yr	+ 459,900
PSE&G DH Peaking and Backup Boilers (No. 6 Oil)	+ 89,600 bbl/yr	+ 161,280	+ 89,600 bbl/yr	+ 161,280
Total	+ 112,600 bbl/yr	+ 202,280	+ 344,600 bbl/yr	+ 621,180
<u>Customers Heating Plants Replaced By DH</u>				
Natural Gas (3)	- 2,278 MMCF/yr	0	- 2,278 MMCF/yr	0
No. 2 Oil (4)	- 263,400 bbl/yr	- 316,080	- 263,400 bbl/yr	- 316,080
No. 4 and 5 Oil (5) .3	- 273,400 bbl/yr	- 492,121	- 273,400 bbl/yr	- 492,121
No. 6 Oil (6)	- 72,100 bbl/yr	- 129,780	- 72,100 bbl/yr	- 129,780
Total	-1,030,300 bbl/yr	- 935,981	-1,030,300 bbl/yr	- 935,981
<u>Net Change</u>		- 733,701		- 314,801

Footnote - Based on chart entitled "Change in Fuel Burned Due to District Heating (DH)" and excluding emissions from PJM units i.e. only including Hudson Area emissions. PJM unit emissions excluded due to distance from Hudson Area - see writeup. Emissions based on number of bbl/yr x 6 mBtu/bbl x appropriate lbs SO₂ per mBtu (.3 lbs for No. 4,5 and 6 Oil and .2 lbs for No. 2 Oil).

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 Phone 201 430-7000

July 24, 1979

Memorandum to Carlos R. Guerra

CONTRACT NO. EM-78-C-02-4977 DRAFT FINAL REPORT

Ref: Memorandum - Applicable Air Regulations
May 31, 1979

As per your request the Draft Final Report mentioned above has been reviewed for any revision and updating. In the air regulations area under federal regulations each state has been required to develop a trade-off policy to regulate growth in areas which are not now meeting the NAAQS. As previously indicated in the referenced memorandum those areas around the units at Hudson, Bergen, Essex and Kearny are designated as non-attainment for particulates. In the development of the N.J. regulation several drafts known as Chapter 18 of N.J.A.C. 7:27 have been proposed. The most recent which will be considered at a Public Hearing on August 7, 1979 and which therefore can reasonably be expected to be implemented has changed the relationship of the off-set ratios.

The recent off-set ratios which follow are more restrictive than those previously considered.

Distance of Off-Sets
From Facility (miles)

Minimum Off-Set
Ratio

SO₂, TSP

0 - 0.5
0.5 - 1.0
1.0 - 2.0

1.00 : 1
1.5 : 1
2.0 : 1

This would appear to exclude those reductions accrued beyond the two mile limit from retirement of space heating installations.

In a discussion with Mr. Ed Londres, Chief Enforcement Officer for N.J. DEP, he confirmed the two mile limit as being absolute. He seemed to concede however that a show of equivalent increases and decreases might be considered. He gave no indication of how this could be established. At the suggestion of modeling, he recommended a contact with Dr. Ray Dyba, N.J. DEP.

E-1

July 24, 1979

As previously indicated in our memorandum a change of equipment would require state air permits and therefore would make the project eligible for DEP consideration.

According to our interpretation of the Fuel Use Act, the previous information is still valid. If you would like to check with J. R. Lacey's office, it is our understanding, that the Law Department is representing the Company with DOE under whose authority the regulations are implemented.

Sara P. Siebert
Sr. Environmental Specialist
Environmental Affairs

SPS:db

District Heating and Cooling Systems for
Communities Through Power Plant Retrofit
Distribution Network

Task 6 - PRELIMINARY ECONOMIC ANALYSIS

- 2.6.1 Prepare an economic sensitivity display for the various alternatives considered. Choose any economic parameter for display.
- 2.6.2 As a minimum, the economic sensitivity display shall show the effects of:
 - a. the costs to deliver thermal energy from the power plant to the End User including installation and operating costs
 - b. the electricity foregone because of steam and/or thermal extraction at the power plant
 - c. the costs over the annual operating cycle of the cogeneration district heating and cooling system(s)
- 2.6.3 Estimate the total revenue generating potential of the alternative considered. Provide pro-forma income statement and balance sheet for the District Heating & Cooling System Demonstration Project(s). Describe the methods used in allocating capital and operating and maintenance costs to electrical and thermal energy production. Research scope of tariff conditions currently accepted in existing district heating/cooling systems. Develop rate design philosophy for district heating/cooling systems. Devise sample tariff terms and conditions and rates for 5, 10, 15, and 20 year points.

2.6.1 Economic Sensitivity Analysis of the Various Alternatives Considered

Three district heating schemes were considered in this economic analysis, namely:

Scheme #1: Retrofit of Hudson to be in full operation by 1985

Scheme #2: Retrofit of Essex to be in full operation by 1985

Scheme #3: Retrofit of Hudson to be in full operation by 1985,
Bergen in 1990, and Essex in 1995.

Exhibit 2.6.1-I shows in tabular form the cost per million Btu for each of the three district heating schemes considered for 1985, 1990, and 1995. Costs are shown for a 3% and a 10% scarce fuel differential escalation rate (oil only) for conventional financing and tax free financing. Exhibits 2.6.1-II, 2.6.1-III, and 2.6.1-IV show in graphical form the average district heat costs per million Btu for each scheme compared to the total net energy costs for gas and oil. The break even lines for the 3% and 10% escalation rates are shown thus indicating the cost level below which the district heating becomes more economical for new buildings. For existing buildings the line of the current fuel used is the decision point. These graphical comparisons are made for small and large commercial and industrial customers. Since the customer market is of such a large volume that district heating could be marketed at its full capacity if its price was competitive compared to other energy sources, or there will be no market at all for district heating if the price is not competitive. As a result, there is no variance shown in the volumes of energy sold.

From these exhibits it can be seen that Scheme #1 (retrofit of Hudson plant alone) has the lowest revenue requirements (i.e., cost). This is due to the fact that Hudson #2 is a base loaded coal fired unit and provides a large portion of the energy at the lowest fuel costs.

For each scheme the tax free financing has the lower cost as compared with conventional financing. It should be noted that these costs are based on a system which supplies mainly space heating load at an annual load factor of 27%. An improvement of this load factor by a few percent will increase

the energy sales (for the same peak loads) and reduce the cost. This may possibly be accomplished through attracting additional cooling loads and/or process loads. The economics and optimization of this market potential should be analyzed as part of the next study phase.

Average District Heating Energy Costs
For the Three Schemes
All Values in \$ per Million Btu

		<u>Scheme #1</u>					
		<u>1985</u>		<u>1990</u>		<u>1995</u>	
		<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>
C F		11.66	13.59	10.39	16.60	9.83	21.91
T F		9.21	11.12	9.02	15.19	8.99	20.97

		<u>Scheme #2</u>					
		<u>1985</u>		<u>1990</u>		<u>1995</u>	
		<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>
C F		17.78	20.66	15.06	21.58	14.33	27.28
T F		14.70	17.55	13.33	19.81	13.25	26.12

		<u>Scheme #3</u>					
		<u>1985</u>		<u>1990</u>		<u>1995</u>	
		<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>	<u>3%</u>	<u>10%</u>
C F		11.66	13.59	11.80	18.67	12.49	25.76
T F		9.21	11.12	9.99	16.80	11.02	24.20

C F = Conventional Financing

T F = Tax Free Financing

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES

LARGE INDUSTRIAL SECTOR
SCHEME I

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES

SMALL INDUSTRIAL SECTOR
SCHEME I

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
AND LOW (3%) DIFFERENTIAL ESCALATION RATES

LARGE COMMERCIAL SECTOR
SCHEME I

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
AND LOW (3%) DIFFERENTIAL ESCALATION RATES
SMALL COMMERCIAL SECTOR
SCHEME I

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES
LARGE INDUSTRIAL SECTOR
SCHEME II

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES

SMALL INDUSTRIAL SECTOR
SCHEME II

PUBLIC SERVICE ELECTRIC & GAS
 DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
 COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
 AND LOW (3%) DIFFERENTIAL ESCALATION RATES
 LARGE COMMERCIAL SECTOR
 SCHEME II_i

PUBLIC SERVICE ELECTRIC & GAS
 DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
 COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
 AND LOW (3%) DIFFERENTIAL ESCALATION RATES
 SMALL COMMERCIAL SECTOR
 SCHEME II

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES

LARGE INDUSTRIAL SECTOR
SCHEME III

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%) AND LOW (3%)
DIFFERENTIAL ESCALATION RATES

SMALL INDUSTRIAL SECTOR
SCHEME III

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY
COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
AND LOW (3%) DIFFERENTIAL ESCALATION RATES
LARGE COMMERCIAL SECTOR
SCHEME III

PUBLIC SERVICE ELECTRIC & GAS
DEPARTMENT OF ENERGY DISTRICT HEATING STUDY

COMPARATIVE NET ENERGY COSTS AT HIGH (10%)
AND LOW (3%) DIFFERENTIAL ESCALATION RATES

SMALL COMMERCIAL SECTOR
SCHEME III

2.6.2 Economic Analysis Sensitivity

The methodology used in preparing this economic analysis was to calculate the annual revenue requirements for each of the three schemes based on conventional financing, (C F) and on Tax free bond financing (i.e., pollution control bonds), (T F). Oil escalation rates of 3% and 10% above inflation (differential escalation rates) were used. The results of this analysis are presented in Exhibits 2.6.2-I (Conventional financing) and 2.6.2-II (Tax free financing). The revenue requirements shown in these exhibits exclude the Gross Receipt Tax applicable to the state of New Jersey. The total revenue requirements is estimated by multiplying by $1/(1-\text{tax rate})$ which is 14.0625%. By dividing the resulting values by the proper projected energy sales (Exhibit 2.6.2-III) for each scheme, the annual revenue requirements in \$/million Btu is obtained as presented in Exhibit 2.6.1-I in the preceding section.

Exhibit 2.6.2-IV shows graphically the 1985 cost components for scheme I at 3% fuel escalation for each financing method.

The assumptions used in calculating the revenue requirements are listed below.

1. All capital costs including station retrofit, transmission and distribution (T&D), customer metering and conversions as described in the equipment section of this report.
2. Overhead costs were calculated using 29.2% of total capital costs excluding AFUDC and working capital. The 29.2% rate was derived based on data provided by PSE&G from their statistical report.
3. Working capital was defined as 12.5% of fuel and other O&M costs, plus 1% of distribution plant.
4. AFUDC is based on 8.0% annual rate for an estimated 18 months construction period compounded semiannually.

5. Other operating and maintenance (O&M) costs were discussed under the section titled "Maintenance Required for the Customer Systems", as shown in Appendix 2.6.2-1.
6. Fuel costs were based on PSE&G's economic dispatch of electrical system generation with and without district heating. The procedure for assigning costs to the district heating and electrical systems is discussed in the letter in Appendix 2.6.2-2.
7. Capacity penalty costs were provided by PSE&G based on loss of capacity and the cost of replacing the same capacity due to the extraction of steam for district heating. Appendix 2.6.2-3 provides more detailed information.
8. Administrative & General (A&G) expenses were based on 46% of other O&M excluding fuel costs as provided by PSE&G. Customer expenses were based on \$14.21 per customer. This data provided by PSE&G was based on a study of customer expenses for gas customers.
9. The equity penalty associated with PSE&G's capital structure and costs which would be applicable to the 100% tax free financing plan is 23%. This factor can be applied to the in-service plant costs and represents the cumulative present worth of the penalty. The derivation of this factor is shown in Appendices 2.6.2-4 and 4A.
10. Fixed charge rates were based on PSE&G's estimated cost of money as outlined in Appendix 2.6.2-5.
11. Other fixed charge assumptions and the resulting annual fixed charge rates are shown in Exhibits 2.6.2-V and 2.6.2-VI for conventional and tax free bond financing respectively.

Revenue Requirements for Scheme No. 1
Conventional Financing

Exhibit 2.6.2-1
Page 1 of 3

	3% Escalation		
	\$ in 1,000		
	1985	1990	1995

STATION RETIREMENT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	0.	0.	0.
-HUDSON STATION	6337.	6251.	3223.
-KEARNY STATION	0.	0.	0.
TOTAL RETIREMENT COSTS	6337.	6251.	3223.
TOTAL TRANSMISSION COSTS	3779.	2535.	1922.
TOTAL DISTRIBUTION COSTS	4928.	3305.	2506.
TOTAL CUSTOMER COSTS	2470.	1657.	1256.
TOTAL OVERHEAD COSTS	5114.	3430.	2501.
AFUDC	502.	337.	255.
TOTAL OTHER O&M COSTS	828.	428.	828.
TOTAL FUEL COSTS	9367.	13144.	15221.
TOTAL WORKING CAPITAL	217.	348.	360.
TOTAL CAP. PENALTY COSTS	100.	100.	100.
TOTAL A&G COSTS	407.	407.	407.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	34048.	30342.	25708.

	10% Escalation		
	1985	1990	1995

STATION RETIREMENT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	0.	0.	0.
-HUDSON STATION	6337.	6251.	3223.
-KEARNY STATION	0.	0.	0.
TOTAL RETIREMENT COSTS	6337.	6251.	3223.
TOTAL TRANSMISSION COSTS	3779.	2535.	1922.
TOTAL DISTRIBUTION COSTS	4928.	3305.	2506.
TOTAL CUSTOMER COSTS	2470.	1657.	1256.
TOTAL OVERHEAD COSTS	5114.	3430.	2501.
AFUDC	502.	337.	255.
TOTAL OTHER O&M COSTS	828.	428.	828.
TOTAL FUEL COSTS	14844.	30934.	49819.
TOTAL WORKING CAPITAL	302.	690.	1072.
TOTAL CAP. PENALTY COSTS	100.	100.	100.
TOTAL A&G COSTS	407.	407.	407.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	30590.	40483.	63989.

Revenue Requirements for Scheme No. 2
Conventional Financing

	3% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	3072.	2041.	1542.
-HUDSON STATION	0.	0.	0.
-KEARNY STATION	0.	0.	0.
TOTAL RETROFIT COSTS	3072.	2041.	1542.
TOTAL TRANSMISSION COSTS	2196.	1473.	1117.
TOTAL DISTRIBUTION COSTS	2929.	1945.	1490.
TOTAL CUSTOMER COSTS	1136.	762.	578.
TOTAL OVERHEAD COSTS	2725.	1828.	1386.
AFUDC	243.	163.	124.
TOTAL OTHER O&M COSTS	3009.	3009.	3009.
TOTAL FUEL COSTS	6054.	6671.	7725.
TOTAL WORKING CAPITAL	170.	183.	203.
TOTAL CAP. PENALTY COSTS	-600.	-600.	-600.
TOTAL A&G COSTS	1364.	1364.	1364.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	22328.	18909.	17987.

	10% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	3072.	2041.	1542.
-HUDSON STATION	0.	0.	0.
-KEARNY STATION	0.	0.	0.
TOTAL RETROFIT COSTS	3072.	2041.	1542.
TOTAL TRANSMISSION COSTS	2196.	1473.	1117.
TOTAL DISTRIBUTION COSTS	2929.	1945.	1490.
TOTAL CUSTOMER COSTS	1136.	762.	578.
TOTAL OVERHEAD COSTS	2725.	1828.	1386.
AFUDC	243.	163.	124.
TOTAL OTHER O&M COSTS	3009.	3009.	3009.
TOTAL FUEL COSTS	9502.	10760.	23680.
TOTAL WORKING CAPITAL	240.	341.	518.
TOTAL CAP. PENALTY COSTS	-600.	-600.	-600.
TOTAL A&G COSTS	1364.	1364.	1364.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	25936.	27100.	30257.

3% Escalation			
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	3521.	2362.
-ESSEX STATION	0.	0.	3072.
-HUDSON STATION	6337.	4251.	3223.
TOTAL RETROFIT COSTS	6337.	7772.	8657.
TRANS & DIST COSTS			
-HUDSON AREA	8706.	5840.	4428.
-BERGEN AREA	0.	6894.	4624.
-ESSEX AREA	0.	0.	5125.
TOTAL TRANS & DIST COSTS	8706.	12734.	14178.
CUSTOMER & OVERHEAD COST			
-HUDSON AREA	7584.	5087.	3857.
-BERGEN AREA	0.	5299.	3554.
-ESSEX AREA	0.	0.	3861.
TOTAL CUSTOMER & OVERHEAD COST	7584.	10386.	11272.
AFUDC			
- HUDSON	502.	337.	255.
- BERGEN	0.	279.	187.
- ESSEX	0.	0.	243.
TOTAL AFUDC	0.	0.	0.
TOTAL OTHER O&M COSTS	828.	1270.	4409.
TOTAL FUEL COSTS	9367.	24854.	36479.
TOTAL WORKING CAPITAL	274.	646.	929.
TOTAL CAP. PENALTY COSTS	100.	200.	-400.
TOTAL A&G COSTS	407.	625.	2079.

REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	34105.	59103.	78288.

10% Escalation			
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	3521.	2362.
-ESSEX STATION	0.	0.	3072.
-HUDSON STATION	6337.	4251.	3223.
TOTAL RETROFIT COSTS	6337.	7772.	8657.
TRANS & DIST COSTS			
-HUDSON AREA	8706.	5840.	4428.
-BERGEN AREA	0.	6894.	4624.
-ESSEX AREA	0.	0.	5125.
TOTAL TRANS & DIST COSTS	8706.	12734.	14178.
CUSTOMER & OVERHEAD COST			
-HUDSON AREA	7584.	5087.	3857.
-BERGEN AREA	0.	5299.	3554.
-ESSEX AREA	0.	0.	3861.
TOTAL CUSTOMER & OVERHEAD COST	7584.	10386.	11272.
AFUDC			
- HUDSON	502.	337.	255.
- BERGEN	0.	279.	187.
- ESSEX	0.	0.	243.
TOTAL AFUDC	0.	0.	0.
TOTAL OTHER O&M COSTS	828.	1270.	4409.
TOTAL FUEL COSTS	14844.	58565.	118005.
TOTAL WORKING CAPITAL	382.	1311.	2538.
TOTAL CAP. PENALTY COSTS	100.	200.	-400.
TOTAL A&G COSTS	407.	625.	2079.

REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	39690.	93479.	161423.

Revenue Requirements for Scheme No. 1
Tax Free Financing

	3% Escalation		
	1985	1990	1995

STATION RETIREMENT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	0.	0.	0.
-HUDSON STATION	3256.	2225.	1795.
-KEAPY STATION	0.	0.	0.
TOTAL RETIREMENT COSTS	3256.	2225.	1795.
TOTAL TRANSMISSION COSTS	1902.	1327.	1071.
TOTAL DISTRIBUTION COSTS	2532.	1730.	1396.
TOTAL CUSTOMER COSTS	1269.	867.	700.
TOTAL OVERHEAD COSTS	2628.	1795.	1449.
AFUDC	258.	178.	142.
TOTAL OTHER O&M COSTS	828.	828.	828.
TOTAL FUEL COSTS	9367.	13100.	15221.
TOTAL WORKING CAPITAL	01.	100.	153.
TOTAL CAP. PENALTY COSTS	100.	100.	100.
TOTAL A&G COSTS	407.	407.	407.
TOTAL EQUITY PENALTY	4219.	3594.	2963.

REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	26896.	24343.	24235.

	10% Escalation		
	1985	1990	1995

STATION RETIREMENT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	0.	0.	0.
-HUDSON STATION	3256.	2225.	1795.
-KEAPY STATION	0.	0.	0.
TOTAL RETIREMENT COSTS	3256.	2225.	1795.
TOTAL TRANSMISSION COSTS	1902.	1327.	1071.
TOTAL DISTRIBUTION COSTS	2532.	1730.	1396.
TOTAL CUSTOMER COSTS	1269.	867.	700.
TOTAL OVERHEAD COSTS	2628.	1795.	1449.
AFUDC	258.	178.	142.
TOTAL OTHER O&M COSTS	828.	828.	828.
TOTAL FUEL COSTS	14804.	30934.	44819.
TOTAL WORKING CAPITAL	100.	202.	448.
TOTAL CAP. PENALTY COSTS	100.	100.	100.
TOTAL A&G COSTS	407.	407.	407.
TOTAL EQUITY PENALTY	4242.	3667.	3062.

REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	32465.	44308.	41217.

Revenue Requirements for Scheme No. 2
Tax Free Financing

	3% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	1578.	1078.	870.
-HUDSON STATION	0.	0.	0.
-KEARNY STATION	0.	0.	0.
TOTAL RETROFIT COSTS	1578.	1078.	870.
TOTAL TRANSMISSION COSTS	1128.	771.	622.
TOTAL DISTRIBUTION COSTS	1505.	1028.	830.
TOTAL CUSTOMER COSTS	584.	399.	322.
TOTAL OVERHEAD COSTS	1400.	957.	772.
AFUDC	125.	85.	69.
TOTAL OTHER O&M COSTS	3009.	3009.	3009.
TOTAL FUEL COSTS	6054.	6671.	7725.
TOTAL WORKING CAPITAL	71.	75.	85.
TOTAL CAP. PENALTY COSTS	-600.	-600.	-600.
TOTAL ARG COSTS	1394.	1394.	1394.
TOTAL EQUITY PENALTY	2202.	1871.	1541.
REVENUE REQUIRED EXCLUDING	18451.	16740.	16639.
GROSS RECEIPT TAX			

	10% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	0.	0.
-ESSEX STATION	1578.	1078.	870.
-HUDSON STATION	0.	0.	0.
-KEARNY STATION	0.	0.	0.
TOTAL RETROFIT COSTS	1578.	1078.	870.
TOTAL TRANSMISSION COSTS	1128.	771.	622.
TOTAL DISTRIBUTION COSTS	1505.	1028.	830.
TOTAL CUSTOMER COSTS	584.	399.	322.
TOTAL OVERHEAD COSTS	1400.	957.	772.
AFUDC	125.	85.	69.
TOTAL OTHER O&M COSTS	3009.	3009.	3009.
TOTAL FUEL COSTS	9502.	14704.	23450.
TOTAL WORKING CAPITAL	100.	143.	217.
TOTAL CAP. PENALTY COSTS	-600.	-600.	-600.
TOTAL ARG COSTS	1394.	1394.	1394.
TOTAL EQUITY PENALTY	2215.	1902.	1600.
REVENUE REQUIRED EXCLUDING	22032.	20471.	32785.
GROSS RECEIPT TAX			

Revenue Requirements for Scheme No. 3
Tax Free Financing

	3% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	1809.	1236.
-ESSEX STATION	0.	0.	1578.
-HUDSON STATION	3256.	2225.	1795.
TOTAL RETROFIT COSTS	3256.	4034.	4610.
TRANS & DIST COSTS			
-HUDSON AREA	4474.	3056.	2467.
-BERGEN AREA	0.	3542.	2420.
-ESSEX AREA	0.	0.	2634.
TOTAL TRANS & DIST COSTS	4474.	6598.	7520.
CUSTOMER & OVERHEAD COST			
-HUDSON AREA	3897.	2662.	2149.
-BERGEN AREA	0.	2723.	1860.
-ESSEX AREA	0.	0.	1984.
TOTAL CUSTOMER & OVERHEAD	3897.	5385.	5992.
AFUDC			
- HUDSON	258.	176.	142.
- BERGEN	0.	143.	98.
- ESSEX	0.	0.	125.
TOTAL AFUDC	0.	0.	0.
TOTAL OTHER O&M COSTS	828.	1270.	4409.
TOTAL FUEL COSTS	9367.	24854.	36479.
TOTAL WORKING CAPITAL	114.	270.	388.
TOTAL CAP. PENALTY COSTS	100.	200.	-400.
TOTAL A&G COSTS	407.	625.	2079.
TOTAL EQUITY PENALTY	4219.	6463.	7618.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	26919.	50019.	69061.

	10% Escalation		
	1985	1990	1995

STATION RETROFIT COSTS			
-BERGEN STATION	0.	1809.	1236.
-ESSEX STATION	0.	0.	1578.
-HUDSON STATION	3256.	2225.	1795.
TOTAL RETROFIT COSTS	3256.	4034.	4610.
TRANS & DIST COSTS			
-HUDSON AREA	4474.	3056.	2467.
-BERGEN AREA	0.	3542.	2420.
-ESSEX AREA	0.	0.	2634.
TOTAL TRANS & DIST COSTS	4474.	6598.	7520.
CUSTOMER & OVERHEAD COST			
-HUDSON AREA	3897.	2662.	2149.
-BERGEN AREA	0.	2723.	1860.
-ESSEX AREA	0.	0.	1984.
TOTAL CUSTOMER & OVERHEAD	3897.	5385.	5992.
AFUDC			
- HUDSON	258.	176.	142.
- BERGEN	0.	143.	98.
- ESSEX	0.	0.	125.
TOTAL AFUDC	0.	0.	0.
TOTAL OTHER O&M COSTS	828.	1270.	4409.
TOTAL FUEL COSTS	14844.	58565.	118005.
TOTAL WORKING CAPITAL	160.	548.	1061.
TOTAL CAP. PENALTY COSTS	100.	200.	-400.
TOTAL A&G COSTS	407.	625.	2079.
TOTAL EQUITY PENALTY	4242.	6599.	7932.
REVENUE REQUIRED EXCLUDING GROSS RECEIPT TAX	32465.	84144.	151574.

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CAPACITY & ENERGY
OF PROPOSED
DISTRICT HEATING SYSTEMS

	<u>1985</u>	<u>1990</u>	<u>1995</u>
<u>Scheme I</u>			
Capacity (10^9 Btuh)	1.6	1.6	1.6
Energy Generated (10^9 Btu)	3,777	3,777	3,777
Energy Losses	378	378	378
Energy Sales	3,399	3,399	3,399
<u>Scheme II</u>			
Capacity (10^9 Btuh)	0.772	0.772	0.772
Energy Generated (10^9 Btu)	1,623	1,623	1,623
Energy Losses	162	162	162
Energy Sales	1,461	1,461	1,461
<u>Scheme III</u>			
Capacity (10^9 Btuh)	1.6	2.8	3.572
Energy Generated (10^9 Btu)	3,777	6,476	8,099
Energy Losses	378	648	810
Energy Sales	3,399	5,828	7,289

1985 COST COMPONENTS FOR SCHEME I
3% ESCALATION ON FUEL COST

Fixed Charge Rate Assumptions
Conventional Financing

BASIC ASSUMPTIONS USED IN THIS STUDY:

COST OF CAPITAL:

	RATE-%	RATIO	WEIGHTED-%
	-----	-----	-----
DEBT	8.600	0.470	4.042
PFD	8.870	0.130	1.153
COMMON	13.000	0.400	5.200

TOTAL			10.395

BOOK LIFE = 33.0 YEARS TAX LIFE = 22.5 YEARS
 INCOME TAX RATE = 46.00 % DEFERRED TAX RATE = 46.00 %
 DEPRECIATION CLAIMED FOR TAX PURPOSES: SUM-OF-YEARS' DIGITS
 DEFERRED FIT: NORMALIZED BETWEEN S.L. BOOK AND ACC. TAX DEPRECIATION
 GENERAL TAXES = 0.00 %
 INVESTMENT TAX CREDIT = 10.0 % - NORMALIZED OVER 22.5 YEARS
 INSURANCE RATE = 0.10 %
 INTEREST CHARGED TO CONSTRUCTION : NONE

THE RESULTS BASED ON THE PRECEDING ASSUMPTIONS ARE :

SUM OF PRESENT WORTH VALUES	107.66842
CAPITAL RECOVERY FACTOR	0.10808551
LEVELIZED FIXED CHARGE	11.63740

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Annual Fixed Charge Rates
Conventional Financing

YEAR	SUPPORTING CHARGES			BOOK DEPREC.	GENERAL TAXES	INSURANCE	INCOME TAX AND REVENUE ADJUST.-NET	TOTAL CHARGES	PRESENT WORTH FACTOR	PRESENT WORTH VALLE	YR
	DEBT	PREFERRED	COMMON								
1	4.04200	1.15310	5.20000	3.03030	0.00000	0.10000	5.41190	18.93730	.90583730	17.15412	1
2	3.41349	0.97380	4.39143	3.03030	0.00000	0.10000	3.74734	15.65636	.82054123	12.84669	2
3	3.21418	0.91694	4.13502	3.03030	0.00000	0.10000	3.48047	14.87691	.74327685	11.05766	3
4	3.02190	0.86209	3.88765	3.03030	0.00000	0.10000	3.22302	14.12495	.67328790	9.51016	4
5	2.83664	0.80924	3.64932	3.03030	0.00000	0.10000	2.97498	13.40048	.60988930	8.17221	5
6	2.65842	0.75839	3.42003	3.03030	0.00000	0.10000	2.73635	12.70350	.55246048	7.01818	6
7	2.48722	0.70955	3.19979	3.03030	0.00000	0.10000	2.50714	12.03401	.50043931	6.02229	7
8	2.32306	0.66272	2.98860	3.03030	0.00000	0.10000	2.28734	11.39201	.45331660	5.16419	8
9	2.16592	0.61789	2.78644	3.03030	0.00000	0.10000	2.07694	10.77751	.41063109	4.42558	9
10	2.01582	0.57507	2.59333	3.03030	0.00000	0.10000	1.87596	10.19049	.37196496	3.79050	10
11	1.87274	0.53425	2.40926	3.03030	0.00000	0.10000	1.68440	9.63096	.33693974	3.24505	11
12	1.73669	0.49544	2.23424	3.03030	0.00000	0.10000	1.50224	9.09892	.30521259	2.77711	12
13	1.60768	0.45864	2.06826	3.03030	0.00000	0.10000	1.32950	8.59438	.27647295	2.37611	13
14	1.48569	0.42384	1.91133	3.03030	0.00000	0.10000	1.16617	8.11732	.25043951	2.03290	14
15	1.37073	0.39104	1.76343	3.03030	0.00000	0.10000	1.01225	7.66775	.22685745	1.73949	15
16	1.26260	0.36025	1.62458	3.03030	0.00000	0.10000	0.86774	7.24568	.20549594	1.48896	16
17	1.16190	0.33147	1.49478	3.03030	0.00000	0.10000	0.73264	6.85109	.18614589	1.27530	17
18	1.06803	0.30469	1.37401	3.03030	0.00000	0.10000	0.60696	6.48400	.16861789	1.09332	18
19	0.98119	0.27991	1.26230	3.03030	0.00000	0.10000	0.49069	6.14439	.15274038	0.93850	19
20	0.90138	0.25715	1.15962	3.03030	0.00000	0.10000	0.38383	5.83228	.13835793	0.80694	20
21	0.82860	0.23638	1.06599	3.03030	0.00000	0.10000	0.28638	5.54766	.12532978	0.69529	21
22	0.76285	0.21763	0.98140	3.03030	0.00000	0.10000	0.19835	5.29053	.11352839	0.60062	22
23	0.70413	0.20067	0.90586	3.03030	0.00000	0.10000	0.11972	5.06088	.10283825	0.52045	23
24	0.65244	0.18613	0.83935	3.03030	0.00000	0.10000	0.46203	5.27025	.09315472	0.44095	24
25	0.59528	0.16982	0.76582	3.03030	0.00000	0.10000	0.79703	5.45824	.08438302	0.46058	25
26	0.52913	0.15095	0.68073	3.03030	0.00000	0.10000	0.70847	5.19958	.07643729	0.39744	26
27	0.46299	0.13208	0.59564	3.03030	0.00000	0.10000	0.61991	4.94092	.06923975	0.34211	27
28	0.39685	0.11321	0.51055	3.03030	0.00000	0.10000	0.53135	4.68226	.06271995	0.29367	28
29	0.33071	0.09434	0.42545	3.03030	0.00000	0.10000	0.44279	4.42380	.05681407	0.25132	29
30	0.26457	0.07548	0.34036	3.03030	0.00000	0.10000	0.35423	4.16494	.05146430	0.21435	30
31	0.19343	0.05601	0.25527	3.03030	0.00000	0.10000	0.26568	3.90628	.04661829	0.18210	31
32	0.13228	0.03774	0.17018	3.03030	0.00000	0.10000	0.17712	3.64762	.04222858	0.15403	32
33	0.06614	0.01887	0.08509	3.03030	0.00000	0.10000	0.08856	3.38896	.03825223	0.12964	33

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Fixed Charge Rate Assumptions
Pollution Control Financing

BASIC ASSUMPTIONS USED IN THIS STUDY:

COST OF CAPITAL:

	RATE-%	RATIO	WEIGHTED-%
	-----	-----	-----
DEBT	6.600	1.000	6.600
PFD	0.000	0.000	0.000
COMMON	0.000	0.000	0.000

TOTAL			6.600

BOOK LIFE = 33.0 YEARS TAX LIFE = 22.5 YEARS
 INCOME TAX RATE = 46.00 % DEFERRED TAX RATE = 46.00 %
 DEPRECIATION CLAIMED FOR TAX PURPOSES: SUM-OF-YEARS' DIGITS
 DEFERRED FIT: NORMALIZED BETWEEN S.L. BOOK AND ACC. TAX DEPRECIATION
 GENERAL TAXES = 0.00 %
 INVESTMENT TAX CREDIT = 10.0 % - NORMALIZED OVER 22.5 YEARS
 INSURANCE RATE = 0.10 %
 INTEREST CHARGED TO CONSTRUCTION : NONE

THE RESULTS BASED ON THE PRECEDING ASSUMPTIONS ARE :

SUM OF PRESENT WORTH VALUES 77.55861
 CAPITAL RECOVERY FACTOR 0.07511458
 LEVELIZED FIXED CHARGE 5.82578

Annual Fixed Charge Rates
Pollution Control Financing

YEAR	SUPPORTING CHARGES			BOOK DEPREC.	GENERAL TAXES	INSURANCE	INCOME TAX AND REVENUE ADJUST.-NET	TOTAL CHARGES	PRESENT WORTH FACTOR	PRESENT WORTH VALUE	YR
	DEBT	PREFERRED	COMMON								
1	6,60000	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	9,73030	,93808630	9,12786	1
2	5,57374	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	7,88100	,88000592	6,93532	2
3	5,24829	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	7,55555	,82552151	6,23727	3
4	4,93432	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	7,24158	,77441042	5,60795	4
5	4,63183	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	6,93908	,72646381	5,04099	5
6	4,34081	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	6,64807	,68148575	4,53056	6
7	4,06128	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	6,36853	,63929246	4,07136	7
8	3,79322	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	6,10048	,59971149	3,65853	8
9	3,53664	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	5,84390	,56258114	3,28767	9
10	3,29154	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	5,59879	,52774967	2,95476	10
11	3,05791	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	5,36517	,49507474	2,65616	11
12	2,83577	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	5,14303	,46442283	2,38854	12
13	2,62510	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,93236	,43566870	2,14887	13
14	2,42591	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,73317	,40869484	1,93442	14
15	2,23820	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,54546	,38339104	1,74269	15
16	2,06197	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,36923	,35965388	1,57141	16
17	1,89722	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,20448	,33738638	1,41853	17
18	1,74394	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	4,05120	,31649754	1,28219	18
19	1,60214	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	3,90940	,29690201	1,16071	19
20	1,47183	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	3,77908	,27851971	1,05255	20
21	1,35299	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	3,66024	,26127553	0,95633	21
22	1,24562	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	3,55288	,24509899	0,87081	22
23	1,14974	0,00000	0,00000	3,03030	0,00000	0,10000	-0,82305	3,45700	,22992401	0,79485	23
24	1,06533	0,00000	0,00000	3,03030	0,00000	0,10000	-0,41152	3,78411	,21568857	0,81619	24
25	0,97200	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	4,10230	,20233449	0,83004	25
26	0,86400	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,99430	,18980721	0,75815	26
27	0,75600	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,88630	,17805555	0,69198	27
28	0,64800	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,77830	,16703147	0,63110	28
29	0,54000	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,67030	,15668994	0,57510	29
30	0,43200	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,56230	,14698868	0,52362	30
31	0,32400	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,45430	,13788807	0,47631	31
32	0,21600	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,34630	,12935091	0,43285	32
33	0,10800	0,00000	0,00000	3,03030	0,00000	0,10000	0,00000	3,23830	,12134232	0,39294	33

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2.6.3 Revenue Generating Potential

The revenue generating potential of the alternatives considered is defined as the cost per Btu multiplied by the potential energy sales in each scheme. From a market point of view, sales are limited to the amount of energy that can be supplied by the generating stations since this is less than 20% of the potential market within a 5 mile radius of the station considered. However, from a cost point of view, any time that the cost of the district heating energy (revenue requirements) is greater than the cost of supplying that same energy by a conventional gas or oil system the revenue producing potential of the district heating system become zero under the assumption that in a free market the customer will choose the lower cost system. The comparison of the district heating costs to the alternative fuel costs is detailed in sections 2.6.1 and 2.6.2.

PROFORMA INCOME STATEMENT

Statements of Income and Balance Sheets
for Scheme No. 1
Conventional Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 39,561	\$ 34,955	\$ 32,902
Operating Expenses -			
Fuel	9,367	13,144	15,221
Other Operation and Maintenance	1,462	1,463	1,463
Depreciation	3,845	3,859	3,867
Taxes Other Than Income.	4,828	4,266	4,015
Federal Income Taxes	6,868	3,497	2,165
Total Operating Expenses	<u>26,370</u>	<u>26,229</u>	<u>26,731</u>
Operating Income	13,191	8,726	6,171
Interest Charges	5,129	3,393	2,400
Net Income	8,062	5,333	3,771
Dividends on Preferred Stock	1,463	968	685
Available for Common Stock	<u>\$ 6,599</u>	<u>\$ 4,365</u>	<u>\$ 3,086</u>
Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$102,570	\$ 83,575
Net Current Assets	1,485	1,711	1,662
Total	<u>\$123,050</u>	<u>\$104,281</u>	<u>\$ 85,237</u>
Liabilities -			
Common Stock	\$ 42,865	\$ 31,393	\$ 22,012
Preferred Stock	13,931	10,202	7,155
Long-Term Debt	50,367	36,888	25,866
Total Capitalization	107,163	78,483	55,033
Accumulated Deferred -			
Income Taxes	3,197	15,881	23,091
Investment Tax Credits	12,690	9,917	7,113
Total	<u>\$123,050</u>	<u>\$104,281</u>	<u>\$ 85,237</u>

Statements of Income and Balance Sheets
for Scheme No. 1
Conventional Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 45,947	\$ 55,649	\$ 73,060
Operating Expenses -			
Fuel	14,844	30,934	49,819
Other Operation and Maintenance	1,463	1,465	1,467
Depreciation	3,866	3,927	3,999
Taxes Other Than Income	5,607	6,791	8,916
Federal Income Taxes	6,905	3,600	2,332
Total Operating Expenses	<u>32,685</u>	<u>46,717</u>	<u>66,533</u>
Operating Income	13,262	8,932	6,527
Interest Charges	5,157	3,473	2,537
Net Income	8,105	5,459	3,990
Dividends on Preferred Stock	1,471	991	724
Available for Common Stock	<u>\$ 6,634</u>	<u>\$ 4,468</u>	<u>\$ 3,266</u>
Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$102,570	\$ 83,575
Net Current Assets	2,150	3,766	5,414
Total	<u>\$123,715</u>	<u>\$106,336</u>	<u>\$ 88,989</u>
Liabilities -			
Common Stock	\$ 43,097	\$ 32,082	\$ 23,220
Preferred Stock	14,007	10,427	7,546
Long-Term Debt	50,639	37,697	27,283
Total Capitalization	107,743	80,206	58,049
Accumulated Deferred -			
Income Taxes	3,214	16,006	23,460
Investment Tax Credits	12,758	10,124	7,480
Total	<u>\$123,715</u>	<u>\$106,336</u>	<u>\$ 88,989</u>

Statements of Income and Balance Sheets
for Scheme No. 2
Conventional Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	<u>\$25,515</u>	<u>\$21,532</u>	<u>\$20,437</u>
Operating Expenses -			
Fuel	6,054	6,671	7,725
Other Operation and Maintenance	3,869	3,869	3,869
Depreciation	2,007	2,009	2,013
Taxes Other Than Income	3,114	2,628	2,494
Federal Income Taxes	3,585	1,817	1,125
Total Operating Expenses	<u>18,629</u>	<u>16,994</u>	<u>17,226</u>
Operating Income	6,886	4,538	3,211
Interest Charges	<u>2,677</u>	<u>1,764</u>	<u>1,248</u>
Net Income	4,209	2,774	1,963
Dividends on Preferred Stock	764	503	357
Available for Common Stock	<u>\$ 3,445</u>	<u>\$ 2,271</u>	<u>\$ 1,606</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$62,980	\$53,140	\$43,300
Net Current Assets	<u>1,251</u>	<u>1,133</u>	<u>1,056</u>
Total	<u>\$64,231</u>	<u>\$54,273</u>	<u>\$44,356</u>
 Liabilities -			
Common Stock	\$22,375	\$16,331	\$11,450
Preferred Stock	7,272	5,307	3,721
Long-Term Debt	<u>26,291</u>	<u>19,189</u>	<u>13,454</u>
Total Capitalization	<u>\$55,938</u>	<u>\$40,827</u>	<u>\$28,625</u>
Accumulated Deferred -			
Income Taxes	1,669	8,286	12,032
Investment Tax Credits	<u>6,624</u>	<u>5,160</u>	<u>3,699</u>
Total	<u>\$64,231</u>	<u>\$54,273</u>	<u>\$44,356</u>

Statements of Income and Balance Sheets
for Scheme No. 2
Conventional Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$29,639	\$30,866	\$38,952
Operating Expenses -			
Fuel	9,592	14,704	23,680
Other Operation and Maintenance	3,870	3,871	3,872
Depreciation	2,021	2,040	2,074
Taxes Other Than Income	3,617	3,767	4,754
Federal Income Taxes	3,608	1,859	1,201
Total Operating Expenses	<u>22,708</u>	<u>26,241</u>	<u>35,581</u>
Operating Income	6,931	4,625	3,371
Interest Charges	<u>2,695</u>	<u>1,799</u>	<u>1,311</u>
Net Income	4,236	2,826	2,060
Dividends on Preferred Stock	769	513	374
Available for Common Stock	<u>\$ 3,467</u>	<u>\$ 2,313</u>	<u>\$ 1,686</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$62,980	\$53,140	\$43,300
Net Current Assets	1,676	2,031	2,756
Total	<u>\$64,656</u>	<u>\$55,171</u>	<u>\$46,056</u>
 Liabilities -			
Common Stock	\$22,523	\$16,626	\$11,994
Preferred Stock	7,320	5,404	3,898
Long-Term Debt	26,465	19,536	14,092
Total Capitalization	<u>56,308</u>	<u>41,566</u>	<u>29,984</u>
Accumulated Deferred -			
Income Taxes	1,680	8,355	12,206
Investment Tax Credits	6,668	5,250	3,866
Total	<u>\$64,656</u>	<u>\$55,171</u>	<u>\$46,056</u>

Statements of Income and Balance Sheets
for Scheme No. 3
Conventional Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 39,561	\$ 67,760	\$ 89,424
Operating Expenses -			
Fuel	9,367	24,854	36,479
Other Operation and Maintenance	1,462	2,309	6,369
Depreciation	3,845	6,473	8,507
Taxes Other Than Income	4,828	8,269	10,913
Federal Income Taxes	6,868	8,164	8,142
Total Operating Expenses	<u>26,370</u>	<u>50,069</u>	<u>70,410</u>
Operating Income	13,191	17,691	19,014
Interest Charges	<u>5,129</u>	<u>6,879</u>	<u>7,394</u>
Net Income	8,062	10,812	11,620
Dividends on Preferred Stock	<u>1,463</u>	<u>1,963</u>	<u>2,109</u>
Available for Common Stock	<u>\$ 6,599</u>	<u>\$ 8,849</u>	<u>\$ 9,511</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$184,463	\$215,651
Net Current Assets	<u>1,485</u>	<u>3,446</u>	<u>4,965</u>
Total	<u>\$123,050</u>	<u>\$187,909</u>	<u>\$220,616</u>
 Liabilities -			
Common Stock	\$ 42,865	\$ 60,526	\$ 65,821
Preferred Stock	13,931	19,671	21,392
Long-Term Debt	<u>50,367</u>	<u>71,118</u>	<u>77,339</u>
Total Capitalization	107,163	151,315	164,552
Accumulated Deferred -			
Income Taxes	3,197	18,053	35,559
Investment Tax Credits	<u>12,690</u>	<u>18,541</u>	<u>20,505</u>
Total	<u>\$123,050</u>	<u>\$187,909</u>	<u>\$220,616</u>

Statements of Income and Balance Sheets
for Scheme No. 3
Conventional Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 45,947	\$107,017	\$184,156
Operating Expenses -			
Fuel	14,844	58,565	118,005
Other Operation and Maintenance	1,463	2,313	6,379
Depreciation	3,866	6,601	8,815
Taxes Other Than Income	5,607	13,060	22,474
Federal Income Taxes	6,905	8,374	8,572
Total Operating Expenses	<u>32,685</u>	<u>88,913</u>	<u>164,245</u>
Operating Income	13,262	18,104	19,911
Interest Charges	5,157	7,040	7,742
Net Income	8,105	11,064	12,169
Dividends on Preferred Stock	1,471	2,009	2,209
Available for Common Stock	<u>\$ 6,634</u>	<u>\$ 9,055</u>	<u>\$ 9,960</u>
 Balance Sheets. - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$184,463	\$215,651
Net Current Assets	2,150	7,427	14,098
Total	<u>\$123,715</u>	<u>\$191,890</u>	<u>\$229,749</u>
 Liabilities -			
Common Stock	\$ 43,097	\$ 61,886	\$ 68,824
Preferred Stock	14,007	20,113	22,367
Long-Term Debt	50,639	72,716	80,868
Total Capitalization	<u>107,743</u>	<u>154,715</u>	<u>172,059</u>
Accumulated Deferred -			
Income Taxes	3,214	18,228	36,275
Investment Tax Credits	12,758	18,947	21,415
Total	<u>\$123,715</u>	<u>\$191,890</u>	<u>\$229,749</u>

Statements of Income and Balance Sheets
for Scheme No. 1
Tax Free Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 31,059	\$ 30,252	\$ 30,050
Operating Expenses -			
Fuel	9,367	13,144	15,221
Other Operation and Maintenance	1,462	1,463	1,463
Depreciation	3,845	3,859	3,867
Taxes Other Than Income	3,790	3,692	3,667
Federal Income Taxes	1,941	611	315
Total Operating Expenses	<u>\$ 20,405</u>	<u>\$ 22,769</u>	<u>\$ 24,533</u>
Operating Income	10,654	7,483	5,517
Interest Charges	8,376	5,540	3,917
Net Income	<u>\$ 2,278</u>	<u>\$ 1,943</u>	<u>\$ 1,600</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$102,570	\$ 83,575
Net Current Assets	1,485	1,711	1,662
Total	<u>\$123,050</u>	<u>\$104,281</u>	<u>\$ 85,237</u>
 Liabilities -			
Pollution Control Debt	\$107,163	\$ 78,483	\$ 55,033
Accumulated Deferred -			
Income Taxes	3,197	15,881	23,091
Investment Tax Credits	12,690	9,917	7,113
Total	<u>\$123,050</u>	<u>\$104,281</u>	<u>\$ 85,237</u>

Statements of Income and Balance Sheets
for Scheme No. 1
Tax Free Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 37,400	\$ 50,815	\$ 69,963
Operating Expenses -			
Fuel	14,844	30,934	49,819
Other Operation and Maintenance	1,463	1,465	1,467
Depreciation	3,866	3,927	3,999
Taxes Other Than Income	4,564	6,201	8,538
Federal Income Taxes	1,951	637	342
Total Operating Expenses	\$ 26,688	\$ 43,164	\$ 64,165
Operating Income	10,712	7,651	5,798
Interest Charges	8,421	5,671	4,145
Net Income	\$ 2,291	\$ 1,980	\$ 1,653
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$102,570	\$ 83,575
Net Current Assets	2,150	3,766	5,414
Total	\$123,715	\$106,336	\$ 88,989
 Liabilities			
Pollution Control Debt	\$107,743	\$ 80,206	\$ 58,049
Accumulated Deferred -			
Income Taxes	3,214	16,006	23,460
Investment Tax Credits	12,758	10,124	7,480
Total	\$123,715	\$106,336	\$ 88,989

Statements of Income and Balance Sheets
for Scheme No. 2
Tax Free Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	<u>\$21,075</u>	<u>\$19,084</u>	<u>\$18,954</u>
Operating Expenses -			
Fuel	6,054	6,671	7,725
Other Operation and Maintenance	3,869	3,869	3,869
Depreciation	2,007	2,009	2,013
Taxes Other Than Income	2,572	2,329	2,313
Federal Income Taxes	1,013	316	164
Total Operating Expenses	<u>\$15,515</u>	<u>\$15,194</u>	<u>\$16,084</u>
Operating Income	5,560	3,890	2,870
Interest Charges	4,371	2,880	2,038
Net Income	<u>\$ 1,189</u>	<u>\$ 1,010</u>	<u>832</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$62,980	\$53,140	\$43,300
Net Current Assets	1,251	1,133	1,056
Total	<u>\$64,231</u>	<u>\$54,273</u>	<u>\$44,356</u>
 Liabilities -			
Pollution Control Debt	\$55,938	\$40,827	\$28,625
Accumulated Deferred -			
Income Taxes	1,669	8,286	12,032
Investment Tax Credits	6,624	5,160	3,699
Total	<u>\$64,231</u>	<u>\$54,273</u>	<u>\$44,356</u>

Statements of Income and Balance Sheets
for Scheme No. 2
Tax Free Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	<u>\$25,170</u>	<u>\$28,366</u>	<u>\$37,373</u>
Operating Expenses -			
Fuel	9,592	14,704	23,680
Other Operation and Maintenance	3,870	3,871	3,872
Depreciation	2,021	2,040	2,074
Taxes Other Than Income	3,072	3,462	4,561
Federal Income Taxes	1,019	326	182
Total Operating Expenses	<u>\$19,574</u>	<u>\$24,403</u>	<u>\$34,369</u>
Operating Income	5,596	3,963	3,004
Interest Charges	4,399	2,936	2,140
Net Income	<u>\$ 1,197</u>	<u>\$ 1,027</u>	<u>864</u>
Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$62,980	\$53,140	\$43,300
Net Current Assets	1,676	2,031	2,756
Total	<u>\$64,656</u>	<u>\$55,171</u>	<u>\$46,056</u>
Liabilities -			
Pollution Control Debt	\$56,308	\$41,566	\$29,984
Accumulated Deferred -			
Income Taxes	1,680	8,355	12,206
Investment Tax Credits	6,668	5,250	3,866
Total	<u>\$64,656</u>	<u>\$55,171</u>	<u>\$46,056</u>

Statements of Income and Balance Sheets
for Scheme No. 3
Tax Free Financing - 3% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	<u>\$ 31,059</u>	<u>\$ 57,276</u>	<u>\$ 78,918</u>
Operating Expenses -			
Fuel	9,367	24,854	36,479
Other Operation and Maintenance	1,462	2,309	6,369
Depreciation	3,845	6,473	8,507
Taxes Other Than Income	3,790	6,990	9,631
Federal Income Taxes	1,941	1,929	1,746
Total Operating Expenses	<u>\$ 20,405</u>	<u>\$ 42,555</u>	<u>\$ 62,732</u>
Operating Income	10,654	14,721	16,186
Interest Charges	8,376	11,231	12,072
Net Income	<u>\$ 2,278</u>	<u>\$ 3,490</u>	<u>\$ 4,114</u>
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$184,463	\$215,651
Net Current Assets	1,485	3,446	4,965
Total	<u>\$123,050</u>	<u>\$187,909</u>	<u>\$220,616</u>
 Liabilities -			
Pollution Control Debt	\$107,163	\$151,315	\$164,552
Accumulated Deferred -			
Income Taxes	3,197	18,053	35,559
Investment Tax Credits	12,690	18,541	20,505
Total	<u>\$123,050</u>	<u>\$187,909</u>	<u>\$220,616</u>

Statements of Income and Balance Sheets
for Scheme No. 3
Tax Free Financing - 10% Escalation
(000's of \$)

	<u>1985</u>	<u>1990</u>	<u>1995</u>
Statements of Income:			
Operating Revenues	\$ 37,400	\$ 96,269	\$173,106
Operating Expenses -			
Fuel	14,844	58,565	118,005
Other Operation and Maintenance	1,463	2,313	6,379
Depreciation	3,866	6,601	8,815
Taxes Other Than Income	4,564	11,748	21,125
Federal Income Taxes	1,951	1,986	1,856
Total Operating Expenses	\$ 26,688	\$ 81,213	\$156,180
Operating Income	10,712	15,056	16,926
Interest Charges	8,421	11,493	12,643
Net Income	\$ 2,291	\$ 3,563	4,283
 Balance Sheets - Year End:			
Assets -			
Net Utility Plant	\$121,565	\$184,463	\$215,651
Net Current Assets	2,150	7,427	14,098
Total	\$123,715	\$191,890	\$229,749
 Liabilities -			
Pollution Control Debt	\$107,743	\$154,715	\$172,059
Accumulated Deferred -			
Income Taxes	3,214	18,228	36,275
Investment Tax Credits	12,758	18,947	21,415
Total	\$123,715	\$191,890	\$229,749

2.6.3 Allocation of Costs

Methods for Allocation of Costs

General

To develop background industry data for the PSE&G-DOE District Heating/Cooling Study, Stone & Webster Management Consultants conducted a telephone survey of companies which are presently operating district heating and/or cooling systems. The major purpose of the survey was to investigate current cost allocation methods in use where thermal and electrical energy, or two different types of thermal energy, are generated by a common facility. The types of thermal energy to be included were steam, hot water and chilled water.

The contacted companies were selected from a list compiled by the International District Heating Association (IDHA) and included firms from throughout the United States. Of the 31 companies contacted, 13 had joint production facilities for steam and electric sales and 4 had both steam and chilled water sales. The other 14 plants have completely separate facilities for the production of steam for steam sales, or are not involved in electrical generation at all.

Most of the customers served by the companies surveyed were commercial establishments including office buildings, hospitals, apartment complexes, retail stores and the like. Industrial usage accounted for the next major customer block, while only a small number of individual residences were served.

Of the 13 companies with joint production facilities for steam and electric sales 12 are regulated by state Public Utility Commissions, while none of the 4 companies producing steam and chilled water are regulated. Of those companies selling only steam, 7 are regulated by state Public Utility Commissions.

Common Facilities for Steam and Electric Sales

Based upon our review, costs are allocated to the steam or electric sales operation depending on how the principal function of facility is viewed by the company. The two essential options are viewed as essentially an electric generating station with incidental steam sales, or as mainly a steam sales production facility with minor electric generation.

Where a plant is viewed as mainly an electric generating station often no capital costs are charged to steam sales, and consequently only fuel costs and other steam processing costs are allocated. In such cases, fuel costs are allocated by calculating the steam sales, in pounds or Btu's, as a percentage of the total steam produced in the plant. This percentage is applied to the total plant fuel cost to determine the amount of fuel costs to be charged to the steam sales operation. The steam processing costs are usually expensed on an incremental basis according to the additional costs incurred by the steam sales operation. In the cases where capital costs are included, they are generally determined on an incremental basis. When the lost electric generating capacity, due to the steam sales operation, is accounted for, it is accomplished by use of formulas that consider the diversity of steam and electric peak requirements, or by passing through to the steam sales operation the cost of the additional purchased electric power.

In plants where steam is produced mainly for steam sales, fuel costs are allocated on a ratio of steam utilization (pounds or Btu's), similar to the method previously described. Other processing and capital expenses are either allocated on an incremental manner to the electric operations or by ratios based on peak hour steam usage of each of the respective operations. One method of cost allocation determines the independent cost of producing electricity in one

of the company's separate electric generating plants and applies this cost as a credit to the expenses of the steam sales operation.

Common Facilities for Steam and Chilled Water

Perhaps due to the fact that none of the companies reviewed producing chilled water are regulated, their methods for allocating costs appear to be less clearly defined than those previously discussed. Most of the companies selling steam and chilled water allocate production costs by calculating the percentage of steam required to operate the chilling compressors and the percentage of steam produced for steam sales. These percentages are then applied to the total production costs. In a majority of cases capital costs are charged to the steam or chilled water operation depending upon the function of the item. If a joint function is indicated, the ratio method is used, however, in one company no boiler capital charges are included in the chilled water expenses. An alternative method used by some of the companies allocates fuel costs separately according to the Btu's of steam and chilled water produced for sale, while in one non-profit organization, all costs are arbitrarily divided equally between steam and chilled water.

Proposed Project Cost Allocation Methods

General

A cost allocation methodology is outlined in the following sections for use in the separation of certain costs for the proposed project. Cost separations are required to apportion principally the production facility costs between the electric generation function and the district heating function at the selected plant locations. The costs to be separated are both the plant capital costs and the plant operating expenses. In addition, certain "common" utility

costs need to be apportioned to the heating service, such as customer accounting and administrative expenses.

The following basic objectives have been established for the allocation method to be used:

1. Be easily applicable to the project sites with the available information.
2. Produce maximum potential benefits to the district heating (thermal) system operation.
3. Not impose any penalty, or to reduce the cost over the otherwise existing, to the electric function.

Outline of Method

The capital costs allocable to the thermal system will be determined basically on an incremental, as incurred, basis. This would charge basically all of the retrofit facility costs at the Electric Plant to the heating service function. If somehow the electric plant capacity were enhanced by the new facilities, the cost of this enhancement would be assigned to the electric function costs. However, if the opposite effect occurs, a penalty for electric capacity derating would be added to the heating system costs, based upon an analysis of system impacts. Other capital costs assignable to the heating function would be principally the thermal distribution system and working capital. Both of these items are to be separately determined for the heating service based upon costs actually incurred.

Operating expenses allocable to the heating service would also be allocated basically on an incremental basis. Fuel and associated running costs assigned to the thermal function would be determined from the increase in per unit cost over the previous "electric only" operations of the production plant.

To give proper accounting for the revised plant operating schedule, penalties would be added to thermal system costs for excessive unit generation at higher than necessary cost, due to thermal system output requirements. Other production plant operating expenses would be allocated to the thermal system only to the extent that these are specifically added for the thermal output function. Since one or more of the production plants under consideration may be otherwise retired by the electric function during the project life, an allowance for the addition of an operative cost penalty may be necessary to the heating function. If necessary, the cost penalty to the heating function would be the amount necessary to have the plant sufficiently economically attractive to the electric function to remain in electric operation.

Thermal distribution system operation and maintenance expenses would be entirely assigned to the thermal system. Costs for customer accounting and administrative operations would be assigned to the heating service on the basis of a company-wide allocation. The basis for such an allocation would be the Company's experience in similar (gas) utility operations.

Justification of Method

The allocation methodology proposed for the study provides a straightforward assignment of costs to the heating function based on an examination of all incremental cost effects. All incremental increases in costs, both capital and operating, which occur and are solely for the benefit of the heating service will be assigned to that function. Likewise, all capacity (and energy) cost penalties incurred by the electric system due to heating operations will be allocated to the heating service. Based upon this approach, therefore, no cost increase will be incurred by the electric operations, and the heating service will bear all necessary costs. With full cost compensation the other desirable attributes of the heating service, environmental and conservation, would seem

to promote the employment without further cost penalty. No basis has been found in review of the utility industry which would require the imposition of any costs beyond "full compensation" for heating service. Sharing-of-benefits is commonly discussed but not in a mandatory sense and is usually employed where there is a new joint participation enterprise under consideration. This is not the case in this instance as the electric system costs are already well in existence and incorporated in present service retail rates.

Cost of Service Calculations

Details of costs at each of the proposed sites are not sufficiently available to allow the calculations to be made at this time.

Allocation of Costs

The allocations of costs joint-product outputs of the plants cannot be made at this time due to insufficient available data.

2.6.3 Rates

Research Scope of Tariff Conditions currently accepted on Existing District Heating/Cooling Systems.

The scope of tariff conditions for district heating/cooling systems were researched for twenty-six member companies in the International District Heating Association. The following is a list of these companies.

1. Consolidated Edison Company of New York
2. Philadelphia Electric Company
3. Detroit Edison Company
4. Boston Edison Company
5. Indianapolis Power & Light Company
6. Baltimore Gas & Electric Company
7. Wisconsin Electric Power Company
8. Cleveland Electric Illuminating Company
9. Iowa Electric Light & Power Company
10. Union Electric Company
11. Dayton Power & Light Company
12. Allegheny County Steam Heating Company
13. Public Service Company of Colorado
14. Seattle Steam Corporation
15. Kansas City Power & Light Company
16. Pennsylvania Power & Light Company
17. Board of Water & Light
18. Georgia Power Company
19. Pacific Power & Light Company
20. Eugene Water & Electric Board
21. Pennsylvania Electric Company
22. Alabama Power Company
23. Northern States Power Company
24. Hartford Steam Service Company
25. Cambridge Steam Corporation
26. Concord Steam Corporation

Public Service Electric & Gas Company has been provided with a copy of the tariffs for each of these companies.

Although all of the companies on the above list have tariffs for steam service rather than for hot water heating service the nature of both services are such that tariff terms and conditions have provisions which are applicable to each service. This material was utilized in the development of a sample tariff terms and conditions which is presented in this subtask.

Rate Design Philosophy for District Heating/Cooling Systems

It is foreseen that the tariff form for hot water district heating service would consist of a two-part rate consisting basically of a customer, and a commodity charge. The argument for having a separate demand charge in the case of providing electric service, for example, is stronger than for providing hot water district heating service. The reason for this is because the requirements for district heating are to a large extent proportional to degree-days; thus the relationship of customers' commodity usage to their demand (load factor) is more constant between customers. A second factor in eliminating a demand charge is the question of the availability and reliability of meters which measure BTU demand.

It is estimated that Public Service Electric & Gas will have the following types of customers with annual use as given below:

<u>Customer Classification</u>	<u>Annual Use (Million BTU)</u>
Residential	40
Commercial - Small	7,206
Industrial - Small	7,122
Commercial - Large	29,358
Industrial - Large	25,723

These customer classes could be organized into three groupings, by volumes, for rate design purposes; (1) residential - consisting of apartment houses with, for example, a minimum of 25 units, (2) small commercial and small industrial, and (3) large commercial and large industrial. Each group would have a two-block declining block rate in which the distribution system fixed costs would be recovered in the first block.

There would also be a customer charge for each of the above rate groups which would be priced to recover customer conversion costs and the cost of metering equipment.

A monthly minimum charge is provided for which would either be the customer charge, or the customer charge plus those costs which are associated with customer accounting expense, and a "minimum distribution" system.

A summer/winter rate has not been proposed. If it is desired at a later time that the district heating system load factor could be improved by increasing sales during the summer months, then a "promotional" type rate could be implemented for those months.

Since the contract for hot water district heating may be for a term of up to twenty-five years, an adjustment clause is being proposed to recover increases in costs associated with power, water, and operation and maintenance expenses, including labor. Also included is a fuel adjustment clause.

Devise Sample Tariff Terms and
Conditions and Rates for 5, 10, 15
and 20 Year Points

STANDARD TERMS AND CONDITIONS

FOR

THERMAL SERVICE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLACE

NEWARK, NEW JERSEY 07101

Date of Issue:

Effective:

6-55

STANDARD TERMS AND CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as a part of the thermal service tariff of Public Service Electric and Gas Company, hereinafter referred to as "PSE&G," set forth the terms and conditions under which thermal service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of thermal service.

No representative of PSE&G has authority to modify any provision contained in this Tariff or to bind PSE&G by any promise or representation contrary thereto.

The benefits and obligations under an application or agreement for service shall begin when PSE&G makes thermal service available to the customer.

Standard agreements to supply thermal service shall be in accordance with the rate schedule and shall be based upon plant facilities which are sufficient for safe, proper and adequate service. PSE&G may require contributions toward the investment, and may establish such minimum charges and facilities charges as may be equitable under the circumstances involved where: (1) large or special investment is necessary for the supply of service; (2) capacity required to serve customer's equipment is out of proportion to the use of thermal service for occasional, intermittent, or low load factor purposes, or is for short durations.

2. OBTAINING SERVICE

- 2.1. Application: An application for service may be made at the appropriate Commercial Office of PSE&G in person or by mail. Forms for application for service, together with terms and conditions and contract forms, will be furnished upon request. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer will be required to sign an agreement or other form then in use by PSE&G covering special circumstances for the supply of thermal service.

PSE&G may reject applications for service where such service is not available or where such service might affect the supply to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13. Service Limitations, of these Standard Terms and Conditions.

- 2.2. Change of Use: Subsequent to initial application, customer shall notify PSE&G in writing of any change in his use of service which might affect the cost, size or availability of service.
- 2.3. Deposit and Guarantee: Where PSE&G deems it necessary, a deposit or other guarantee satisfactory to PSE&G may be required as security for the payment of future and final bills before PSE&G will commence or continue to render service.

A deposit may be required from a customer equal to the estimated bills which would accrue for two months' service.

OBTAINING SERVICE (Continued)

All deposits shall bear simple interest at the rate of six percent per annum, payable at the time that the deposit is refunded to the depositor, provided said deposit remains with PSE&G for a period of three months or longer. Deposits shall cease to bear interest upon discontinuance of service.

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service, PSE&G may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. PSE&G shall have a reasonable time in which to read the meters and to ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, customer will be required to restore deposit to original amount.

2.4. Main Extensions: The customer may be required to make a deposit for the extension of thermal mains as set forth in Section 3 of these Standard Terms and Conditions.

2.5. Service Conditions: The customer may be required to make a contribution toward the cost of installing a service connection as set forth in Section 5 of these Standard Terms and Conditions.

2.6. Permits: PSE&G, where necessary, will make application for any street opening permits for installing its service connections and shall not be required to furnish service until after such permits are granted. The customer may be required to pay the

OBTAINING SERVICE (Continued)

municipal charge, if any, for permission to open the street.

The customer shall obtain and present to PSE&G, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

- 2.7. Temporary Service: Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to PSE&G the cost of the facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the revenue received by PSE&G during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

3. EXTENSION OF DISTRIBUTION MAINS

- 3.1. General: PSE&G will construct, own, and maintain distribution mains located on streets, highways and on rights of way acquired by PSE&G, used or usable as part of the distribution system of PSE&G. The making of a deposit under any of the following cases

EXTENSION OF DISTRIBUTION MAINS (Continued)

shall not give the customer any interest in the facilities, the ownership being vested exclusively in PSE&G.

The following formulae shall not be binding on the parties but are suggested as a guide to customers and utilities. Parties are still free to exercise their rights under New Jersey Revised Statutes 48:2-27. When an applicant for an extension is dissatisfied with these suggested regulations he may petition the Board for a finding that the extension should be made without charge.

- 3.2 Deposits: PSE&G may require any customer to deposit an amount equal to the entire cost of the new distribution main facilities required to supply service, such amount to be subject to refund as follows: At the end of the first service year, an amount without interest equal to 10% of the total amount of the monthly bills rendered to and paid by the customer for service furnished by PSE&G for that year will be refunded, and thereafter refunds similarly determined will continue each year until such time as the accumulated annual refunds are equal to but not in excess of the sum deposited; provided, however, that any part of the deposit not returned to the customer within ten years after the beginning of the first service year shall remain the property of PSE&G. No refund will be made if service is discontinued prior to the expiration of the first service year.

EXTENSION OF DISTRIBUTION MAINS (Continued)

Where it is necessary to provide additional facilities to serve increased requirements of an existing customer, PSE&G may require the customer to deposit an amount equal to the cost of such additional facilities. This amount shall be subject to refund as outlined in the preceding paragraph, except that the refunds will be calculated at 10% of the excess revenue over a pre-determined base.

4. CHARACTERISTICS OF SERVICE

- 4.1. Standard Service Supply: PSE&G will endeavor, but does not guarantee, to furnish a continuous supply of _____
-

5. SERVICE CONNECTIONS

- 5.1. General: The customer shall consult PSE&G as to the exact point at which the service will enter the building before installing interior piping or starting any other work dependent upon the location of the service pipe. PSE&G will determine the location of the service pipe depending upon existing facilities in the street and other practical considerations.

Thermal service will be supplied to each building or premises through a single service except where, in the judgment of PSE&G, its economic considerations; conditions on its distribution system; improvement of service conditions; or volume of the customer's requirements, make it desirable to install more than one service.

SERVICE CONNECTIONS. (Continued)

The making of a payment in any of the following cases shall not give the customer any interest in the service connection, the ownership being vested exclusively in PSE&G.

- 5.2. Service Connection Charges: PSE&G will furnish and place, at no cost to the customer, up to ____ feet of service connection, measured at right angles from the nearest curb line to the customer's building, at the point of service entrance designated by PSE&G. Where the distance is in excess of ____ feet, the service will be installed subject to a charge equal to the amount by which the cost of the service connection exceeds the greater of either twice the customer's annual revenue as estimated by PSE&G or the cost of the first ____ feet of service connection which otherwise would be furnished without charge as provided above. Should the customer request a service entrance at a location other than that designated by PSE&G, the customer shall pay the additional cost associated with said change in point of service entrance provided that the customer shall not be required to pay for the first ____ feet of service connection in any case and, provided further, that the customer shall not be required to pay for any portion of the cost of the service connection if the cost thereof does not exceed twice the estimated annual revenue. PSE&G will waive the charge to the customer when the amount is \$____ or less.

The charge for the service connection shall be based on actual construction costs.

SERVICE CONNECTIONS (Continued)

- 5.3. Change in Location of Existing Service Piping: Any change requested by the customer in the location of the existing service piping, if approved by PSE&G, will be made at the expense of the customer.

6. METERS AND ASSOCIATED EQUIPMENT

- 6.1. General: A single meter and associated equipment, as necessary, will be furnished and installed by PSE&G for each separately billed rate schedule under which a customer receives service.

Additional meters and associated equipment will be installed only where, in the judgement of PSE&G, its economic considerations; conditions on its distribution system; improvement of service conditions; or the volume of the customer's requirements, make it desirable to install such additional equipment.

- 6.2. Seals: PSE&G may seal or lock any meters or enclosures containing meters and associated metering equipment. No person except a duly authorized employee of PSE&G shall break or remove a PSE&G seal or lock.

- 6.3. Protection of Meter and Service Equipment: Customer shall furnish and maintain a suitable space for the meter and associated equipment. Such space shall be as near as practicable to the point of entrance of the service pipe, adequately ventilated, dry and free from corrosive vapors, not subject to

METERS AND ASSOCIATED EQUIPMENT (Continued)

extreme temperatures, readily accessible to duly authorized employees or agents of PSE&G. Customer shall not tamper with or remove meters or other equipment, nor permit access thereto except by duly authorized employees or agents of PSE&G. In case of loss or damage to the property of PSE&G from the act or negligence of the customer or his agents or servants, or of failure to return equipment supplied by PSE&G, customer shall pay to PSE&G the amount of such loss or damage to the property. All equipment furnished at the expense of PSE&G shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to PSE&G but shall immediately notify PSE&G to have the defects remedied.

6.4. PSE&G to Turn on Service: No person other than a duly authorized employee or agent of PSE&G shall turn thermal energy into any new system of piping or into any old system of piping from which the use of thermal energy has been discontinued.

6.5. Change in Location of Meters and Associated Equipment: Any change requested by the customer in the existing location of the meters and associated equipment, if approved by PSE&G, will be made at the expense of the customer.

7. CUSTOMER'S INSTALLATION

7.1. General: No material change in the size, total capacity, or method of operation of customer's equipment shall be made without previous written notice to PSE&G.

7.2. Piping: Piping installed on the customer's premises must conform to all requirements of the State Uniform Construction Code, municipal or other properly constituted public authorities.

Piping on customer's premises, owned by PSE&G, on the primary side of the heat exchanger is designed to operate as a closed loop system. Customer shall not make any connection which will divert the flow of water from this primary loop.

7.3. Maintenance of Customer's Installation: Customer's entire installation shall be maintained in the condition required by the State Uniform Construction Code, municipal or other public authorities having jurisdiction and by PSE&G.

7.4. Appliance Adjustments: PSE&G will not make any adjustments nor conduct any maintenance on customers' thermal appliances.

7.5. Adequacy and Safety of Installation: PSE&G shall not be required to supply thermal service until the customer's installation shall have been approved by the authorities having jurisdiction. PSE&G may withhold or discontinue its service whenever such installation or part thereof is deemed by PSE&G to be unsafe, inadequate, or unsuitable for receiving service, or to interfere with or impair

CUSTOMER'S INSTALLATION (Continued)

the continuity or quality of service to the customer or to others.

PSE&G will assume no responsibility for the condition of customer's thermal installation or for accidents, fires, or failures which may occur as the result of the condition of such installation.

Neither by inspection or nonrejection, nor in any other way, does PSE&G give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the customer.

8. METER READING AND BILLING

8.1. Measurement of Energy Used: PSE&G will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

Where service through more than one meter is permitted by PSE&G as outlined under Section 6.1 of these Standard Terms and Conditions, the use registered by the individual meters will be combined for billing purposes. In all other instances, each meter shall be billed separately.

Bills will be based upon registration of PSE&G meters except as otherwise provided for in this Tariff.

METER READING AND BILLING (Continued)

- 8.2. Separate Billing for Each Installation: The thermal service used by a customer through each service connection shall be billed separately at the applicable rate schedule selected by the customer. See Sections 5.1 and 6.1 of these Standard Terms and Conditions.
- 8.3. Submetering: The service and supply of thermal energy by PSE&G for the use of owners, tenants, or occupants of buildings or premises, will be furnished to them as customers of PSE&G through PSE&G individual meters, and will not be supplied for submetering for resale by or to any owner, tenant or occupant of any such building or premises.
- 8.4. Testing of Meters: At such times as PSE&G may deem proper, PSE&G will test its meters.
- 8.5. Billing Adjustments: Whenever a meter is found to be registering fast or slow by 5% or more, an adjustment of charges shall be made.
- 8.6. Meter Reading and Billing Period: Unless otherwise specified in this Tariff, the charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provides for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by PSE&G and are available for inspection.

METER READING AND BILLING (Continued)

PSE&G may read meters and render bills on a "bimonthly" basis, with the monthly charges prorated on a two-month basis.

- 8.7. Proration of Monthly Charges: For all billings for service, including initial bills, final bills, and bill for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts, the monthly charges will be prorated on the basis of one-thirtieth for each day of service, each month being considered as thirty days when determining the number of days on which prorating is based. For temporary service accounts the minimum period for billing purposes shall be one month.
- 8.8. Averaged Bills: Where PSE&G is unable to read the meter, PSE&G may estimate the amount of energy supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.
- 8.9. Malfunctioning Meter: In case the seal of the meter is broken otherwise than by employees of PSE&G, or the meter fails to register with commercial accuracy, the amount of thermal service used and to be paid for (for the number of days the meter is not properly in service) shall be the equivalent of the next former or, if no former, subsequent equivalent number of days of proper metered use.

METER READING AND BILLING (Continued)

8.10. Billing of Changes in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of thermal service subsequent to the scheduled meter reading date for the immediately preceding month.

8.11. Payment of Bills: for service are due on presentation and are payable at any Commercial Office of PSE&G or to any collector or collection agency duly authorized by PSE&G.

8.12. Rate: Customer will be required to sign a contract for thermal service. The terms and conditions of said contract shall reflect the specific operating characteristics and the facilities required to supply thermal service.

9. LEAKAGE

Customer shall immediately give notice to PSE&G at its office of any leakage in the PSE&G system in or about the customer's premises.

10. ACCESS TO CUSTOMER'S PREMISES

PSE&G shall have the right of reasonable access to customer's premises, and to all property furnished by PSE&G, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting,

ACCESS TO CUSTOMER'S PREMISES

testing or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by PSE&G for access to its facilities. Access to facilities of PSE&G shall not be given except to authorized employees of PSE&G or duly authorized governmental officials.

11. DISCONTINUANCE OF SERVICE

11.1. By PSE&G: PSE&G, upon reasonable notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) For the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) For compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) For any of the following acts or omissions on the part of the customer: (a) non-payment of a valid bill due for service furnished at a present or previous location. However, non-payment of business service shall not be a reason for discontinuance of residence service; (b) tampering with any facility of PSE&G; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of PSE&G; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h)

DISCONTINUANCE OF SERVICE (Continued)

connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) For refusal of reasonable access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of PSE&G.

- 11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable contract. Where such notice is not received by PSE&G, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

12. RECONNECTION CHARGE

A reconnection charge of \$_____ will be made for restoration of service when service has been suspended or discontinued for non-payment of any bill due.

13. SERVICE LIMITATIONS

- 13.1. Continuity of Service: PSE&G will use reasonable diligence to provide a regular and uninterrupted supply of service. Should the supply be suspended, curtailed, or discontinued by PSE&G

SERVICE LIMITATIONS (Continued)

for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid PSE&G shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect of failure.

13.2. Emergencies: PSE&G may curtail or interrupt service to any customer or customers in the event of emergency threatening integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: PSE&G may place limitations on the amount and character of service it will supply and may refuse service to new customers or to existing customers for additional load if PSE&G is unable to obtain or does not have assured the necessary production raw materials or equipment and facilities to supply such service.

14. TERMINATION, CHANGE, OR MODIFICATION OF PROVISIONS OF TARIFF

This Tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

TERMINATION, CHANGE, OR MODIFICATION OF PROVISIONS OF TARIFF (Continued)

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part hereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Newark, New Jersey

CONTRACT FOR THERMAL SERVICE

THIS AGREEMENT, made by and between Public Service Electric and Gas Company (hereinafter called the "Company"), and _____

(hereinafter called the "Customer"), whose premises are located at _____

WITNESSETH: That in consideration of the mutual covenants and agreements herein contained, the parties hereto contract and agree with each other as follows:

FIRST: That for and during the ____ year period commencing on and from the date on which the delivery of thermal service hereunder is actually begun, which, it is estimated, will be approximately the _____ day of _____, 19____, and ending on the _____ day of _____, 19____, the Company agrees to furnish to the Customer, and the Customer agrees to receive from the Company and to use and pay for, all thermal service that shall be required by the Customer for the operation of equipment located on the premises described above. Thermal service so rendered shall be delivered to the Customer at a delivery point located as follows:

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SECOND: Thermal service so rendered shall be billed by the Company and paid for by the Customer as follows:

1. Rate:

First _____ million Btu per month @ \$_____ per Million Btu

Over _____ million Btu per month @ \$_____ per Million Btu

2. Fuel Clause:

The bill calculated from the above shall be increased or decreased in the amount of \$_____ per million Btu billed for every full \$_____ variation above or below \$_____ fuel related cost per million Btu sold as determined by the fuel related cost for the month immediately preceding the current billing period.

3. Minimum Charge:

There shall be a minimum monthly charge of \$_____.

4. Adjustments (Applicable to Consumption Charges):

The preceding rates will be increased or decreased on the following basis for costs incurred in the operation of the thermal heating service..

Power and Water

An adjustment shall be made monthly for the increase (or decrease) in the cost of electricity and water used for the heating system based upon the variation of the actual preceding month's costs of these items from the specified base cost. Included in these costs shall be any electricity penalty costs for excess fuel cost associated with noneconomic dispatch of electric energy. The

adjustment shall be an increase or decrease of \$_____ per million Btu (MMBtu) of consumption for each variation of \$_____ per MMBtu from a base cost of \$_____ per MMBtu.

Operating, Maintenance and Labor Charges

There shall be a monthly adjustment for the actual fixed and variable operating (excluding fuel, power and water), maintenance, taxes and labor charges applicable to the thermal heating service for increases (or decreases) of those costs during the twelve-month period ending the preceding month, above (or below) the specified base cost. The adjustment shall include as a cost any penalty charges (excluding fuel, power and water) assessed to the heating service for operation of the production plant where not otherwise economical for electric operations alone. The adjustment shall be an increase or decrease of \$_____ per MMBtu of consumption for each variation of \$_____ per MMBtu from a base cost of \$_____ per MMBtu.

5. Terms of Payment:

Bills are due on presentation. The customer agrees to pay a 10% premium for any bills payed beyond 15 days after presentation.

6. Deposit:

As detailed in the standard terms and conditions the customer agrees to furnish a deposit of \$_____ upon completion of this contract.

These charges are subject to approval and revision by the New Jersey Board of Public Utilities.

THIRD: The Company shall be under no obligation to supply thermal service to any equipment other than that which is installed on the Customer's premises on the effective commencement date of this agreement, but may, at its option, decline to serve any such additional equipment when, in the opinion of the Company, capacity is not available either in the Company's thermal service generating equipment or its distribution mains. The Customer agrees that no additions to or alterations in existing equipment will be made unless and until the written consent of the Company has been first obtained.

FOURTH: This contract shall be binding upon the parties hereto, their successors and assigns (but the customers shall not assign any interest in this contract without the Company's prior written consent), and shall remain in full force and effect for the term stated herein, and is to be considered renewed for periods of one year and from year to year thereafter unless written notice to the contrary is given by either party to the other at least thirty (30) days prior to the date of beginning or any renewal thereof.

FIFTH: The Customer hereby agrees to all of the terms and conditions set forth in detail in the standard terms and conditions which are hereby made an integral part of this agreement.

IN WITNESS WHEREOF, the parties hereto have caused this contract to be
executed in duplicate by their duly authorized officers on this the

_____ day of _____, 19__.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By _____

Customer

By _____

Title _____

Hackensack Meadowland Development
Commission - Definitions

Research Park Zone

A. Purposes

This district is designed to accommodate research facilities and office facilities in a park-like environment, with substantial amounts of landscaped open space.

B. Permitted Uses

1. Establishments for scientific research and development, and business offices accessory thereto, where the manufacturing, fabrication, production, repair, storage, sale and resale of materials, goods and products are incidental and accessory to the principal use of scientific research and development;

2. Office facilities;

3. Warehouses.

C. Special Exceptions

Special exceptions in the research park zone include:

1. Helistops;

2. Hotels and motels;

3. Restaurants;

4. Light public utility uses.

Research Distribution Park Zone

A. Purposes

This district is designed to accommodate research facilities, office facilities and warehouse facilities in a park-like environment, with substantial amounts of landscaped open space.

B. Permitted Uses

1. Establishments for scientific research and development, and business offices accessory thereto, where the manufacturing, fabrication, production, repair, storage, sale and resale of materials, goods and products are incidental and accessory to the principal use of scientific research and development.

2. Any production, processing, manufacture or fabrication of goods, materials and products, and the storage of raw materials and products incidental to such manufacture, production, processing or fabrication;

3. Office facilities;

4. Warehouses.

C. Special Exceptions

Special exceptions in the research park zone include:

1. Helistops;

2. Hotels and motels;

3. Restaurants;

4. Light public utility uses.

Light Industrial Zone A

A. Purpose

This zone is designed to accommodate on large lots a wide range of industrial, distribution, commercial and business uses that generate a minimum of detrimental environmental effects.

B. Permitted Uses

1. Any production, processing, manufacture, fabrication, cleaning, servicing, testing, repair or storage of goods, materials or products, and business offices accessory thereto, but not including the storage of flammable or explosive materials as a principal use;

2. Establishments for scientific research and development, and business offices accessory thereto, where the manufacturing, fabrication, production, repair, storage, sale and resale of materials, goods and products is incidental and accessory to the principal use of scientific research and development;

3. Business or commercial establishments which provide supplies and/or services primarily to industrial and manufacturing customers, and business offices accessory thereto;

4. Warehouses, wholesale establishments and other storage facilities;

5. Business offices, but not including professional office buildings principally for doctors, dentists, lawyers, real estate brokers and/or similar professional persons, except as an accessory use to an otherwise permitted use or as a special permit;

6. Light public utility uses.

C. Special Exceptions

Special exceptions in light industrial zone A include:

1. Automobile service stations;
2. Governmental uses;
3. Heavy public utility uses;
4. Helistops;
5. Hotels and motels;
6. Restaurants;
7. Retail uses;
8. Radio, television and microwave transmission towers;
9. Hospitals, clinics, and medical facilities.

Light Industrial Zone B

A. Purpose

This zone is designed to accommodate a wide range of industrial, distribution, commercial and business uses that generate a minimum of detrimental environmental effects.

B. Permitted Uses

1. Any production, processing, manufacture, fabrication, cleaning, servicing, testing, repair or storage of goods, materials or products, and business offices accessory thereto, but not including the storage of flammable or explosive materials as a principal use;
2. Establishments for scientific research and development, and business offices accessory thereto, where the manufacturing, fabrication, production, repair, storage, sale and resale of materials, goods and products is incidental and accessory to the principal use of scientific research and development;
3. Business or commercial establishments which provide supplies and/or services primarily to industrial and manufacturing customers, and business offices accessory thereto;
4. Automobile service stations;
5. Mobile home and trailer sales, rental and repair;
6. Automobile and truck leasing and sales, exclusive of semitrailers;
7. Boat sales, rental and repair;
8. Warehouses, wholesale establishments and other storage facilities;
9. Light public utility uses.

C. Special Exceptions

Special exceptions in light industrial zone B include:

1. Governmental uses;
2. Heavy public utility uses;
3. Helistops;
4. Hotels and motels;
5. Restaurants;
6. Retail uses;
7. Radio, television and microwave transmission towers;
8. Hospitals and clinics.

Heavy Industrial Zone

A. Purpose

This zone is designed to accommodate industrial and commercial uses that are not appropriate in other industrial districts.

B. Permitted Uses

1. Establishments for scientific research and development, and business offices accessory thereto, including the manufacturing, fabrication, production, repair, storage, sale and resale of materials, goods and products;
2. Any production, processing, manufacture, fabrication, cleaning, servicing, testing, repair or storage of goods, materials or products and business offices accessory thereto;
3. Meat and produce markets for sale at wholesale or retail, including the processing dress meat products; provided that no slaughtering shall be done on the premises;
4. Construction equipment sales, service and rental;
5. Contractor and construction offices, shops and yards;

6. Building materials' yards and facilities;
7. Cartage and express facilities;
8. Motor freight terminals;
9. Railroad terminals and yards;
10. Garages for the storage, repair and servicing of motor vehicles
(including body repair, painting and engine rebuilding);
11. Light public utility uses;
12. Heavy public utility uses;
13. Automobile service stations;
14. Automobile laundries;
15. Resource recovery systems;
16. Retail uses.

C. Special Exceptions

Special exceptions in the heavy industrial zone include:

1. Governmental uses;
2. Helistops.

Waterfront Recreation Zone

A. Purpose

This zone is designed to accommodate water-oriented recreation facilities.

B. Permitted Uses

1. Marinas for the docking, repair, sale, servicing and storage of boats;
2. Other water recreation oriented uses.

C. Special Exceptions

Small retail shops and restaurants accessory to permitted uses are special exceptions within the waterfront recreation zone.

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Highway Commercial Zone

A. Purpose

This zone is designed to accommodate a selected group of commercial uses that are best located in close proximity to highways.

B. Permitted Uses

1. Banks, savings and loan associations and similar financial institutions:

1. Business and professional offices;
2. Medical and dental clinics and laboratories;
3. Hotels and motels;
4. Convention centers;
5. Restaurants which may include cocktail lounges;
6. Theaters (not including drive-in theaters);
7. Automobile showrooms, including outdoor display

facilities;

8. Accessory retail and service uses in connection with office, hotels and motels.

C. Special Exceptions

Special exceptions in the highway commercial zone include:

1. Light public utility uses;
2. Governmental uses;
3. Institutional uses;
4. Automobile service stations, no closer than 1,000 feet to each

other.

Service Highway Commercial Zone

A. Purpose

This zone is designed to accommodate those business and commercial

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uses that are oriented toward, and ideally located in direct proximity to highway automobile traffic.

B. Permitted Uses

1. Ambulance services;
2. Automobile laundries;
3. Automobile service stations no closer than 1,000 feet to each other;
4. Hotels and motels;
5. Restaurants, including drive-in establishments serving food or beverage to customers for consumption on the premises in parked motor vehicles;
6. Retail and service uses;
7. Banks;
8. Other drive-in establishments.

C. Special Exceptions

Special exceptions in the service highway commercial zone include:

1. Light public utility uses;
2. Governmental uses;
3. Funeral homes and mortuaries.

Low Density Residential Zone

A. Purpose

This zone is designed to accommodate low density residential uses.

B. Permitted Uses

1. Single-family dwellings, duplexes and two-family dwellings;
2. Multiple-family dwellings;
3. Churches, chapels, synagogues and temples;

4. Group day care centers and nursery schools;
5. Primary and secondary schools;
6. Parks and playgrounds;
7. Swimming clubs, swimming pools and recreational facilities

incidental thereto.

C. Special Exceptions

Special exceptions in the low density residential zone include:

1. Light public utility use;
2. Governmental uses;
3. Welfare and charitable services;
4. Neighborhood health centers and medical centers;
5. Mobile home parks, not exceeding the density permitted for

other single family dwellings and conforming with all other regulations applicable to development within the LDR District.

Specically Planned Area Regulations

A. Purpose

(a) The strategic location of large parcels of largely-undeveloped land in the heart of an intensely-developed metropolitan area gives the public the opportunity to require that development be undertaken on a large scale in order that the available land be used in the most efficient manner possible and in accordance with the most comprehensive and far sighted planning techniques which will be of substantial benefit to both the developers and landowners and to the public.

(b) These regulations take advantage of this opportunity by requiring that specific areas be used for the purposes envisaged for them in the comprehensive land use plan and be developed in the best possible manner.

(c) These regulations are designed to promote, moreover, the innovative and creative design of such areas, to facilitate the use of the most advantageous construction techniques in the development and use of land, and to assure a comprehensive treatment of environmental factors.

1. Parkside Residential

These specifically planned areas are designed to accommodate residential uses in a setting of large areas of open and recreation space. The regulations are designed to require unified planning and development of well-designed large-scale projects in order to provide amenities and services to residents not customarily found in typical residential developments.

2. Island Residential

These specially planned area are designed to accommodate relatively dense residential uses that will be clustered on man-made islands. The islands will be located within man-made lagoons of the Hackensack River, which will be surrounded by substantial areas of marshland open space. The regulations are designed to require unified planning and development of large-scale projects that will occupy a minimum amount of land area and will disturb to the least extent possible existing marshland areas.

3. Berry's Creek Center

The Berry's Creek Center is intended to be the focal point of the Meadowlands District. It shall be a business, shopping, civic, cultural and transportation center, built along parks and plazas, pedestrian ways and the restored Berry's Creek Canal and containing as its peripheries park-like open spaces and marshland preserves.

STONE & WEBSTER ENGINEERING CORPORATION

NEW YORK OPERATIONS CENTER

ONE PENN PLAZA

NEW YORK, NEW YORK

ADDRESS ALL CORRESPONDENCE TO P. O. BOX 1350, NEW YORK, N. Y. 10001

NEW YORK
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DENVER
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PORTLAND, OREGON

DESIGN
CONSTRUCTION
REPORTS
EXAMINATIONS
CONSULTING
ENGINEERING

Mr. Gerald S. Levitt
Stone & Webster Management Consultants, Inc.
90 Broad Street
New York, N.Y. 10004

May 23, 1979

J.O. 13222

Dear Gerry:

PSE&G/DOE
DISTRICT HEATING STUDY
OPERATING & MAINTENANCE COSTS

Confirming our telephone conversation of May 22, 1979, the following costs are the incremental operating and maintenance costs due to District Heating at the four operating stations, and the maintenance costs of the piping distribution system for the three schemes developed. Also listed are the maintenance costs for the conversion schemes at the consumer's end. These costs were developed using guidelines supplied to us by our Swedish Consultant, they do not include fuel costs, storage or pumping costs.

<u>Building O&M (\$/Yr)</u>		<u>District Heating Equipment O&M (\$/Yr)</u>
Hudson	10,000	270,000
Bergen	10,000	150,000
Kearny	5,000	50,000
Essex	5,000	100,000

<u>Distribution System</u>	<u>O&M</u>
Scheme #1	\$ 523,000/yr
Scheme #2	\$ 292,000/yr
Scheme #3	\$1,208,000/yr

<u>Conversion Scheme</u>	<u>Maintenance Costs</u>
1) small commercial	\$ 52/yr
2) large commercial	\$210/yr
3) small industrial	\$ 52/yr
4) large industrial	\$160/yr
5) large apartment complex	\$ 0.53/yr/unit

If you have any questions, please call me.

Very truly yours,

V. A. Saleta

V. A. Saleta
Power Engineer

VAS:mcf

6-89

Public Service Electric and Gas Company 80 Park Place, Newark, N.J. 07101 Phone: 201/430-7000

March 27, 1979

Memorandum

METHODOLOGY FOR ECONOMIC ANALYSIS AND PRELIMINARY
COST ALLOCATION FOR DISTRICT HEATING

As an initial economic analysis of a district heating system all the costs for the construction, operation and maintenance and penalties or benefits of a district heating system will be allocated in such a manner that the electric and gas customers will not be penalized for this district heating operation. However, this initial economic analysis is intended to only identify any potential savings with district heating and is not intended to be the basis for thermal rate making. If there is potential savings with district heating it would seem reasonable that the electric and gas rate payers should share in the benefits. The subject of thermal rate schedules will be addressed at a later time.

The capital costs associated with the district heating system are:

- 1) Retrofit cost
- 2) Thermal distribution system
- 3) Capacity penalty due to decrease in electric capacity or the possible need for or advancement of additional electric generating capacity
- 4) Allocation of general overheads

The operation and maintenance expenses associated with the district heating system will include:

- 1) Increase in system operating costs to provide thermal power
- 2) O&M associated with the plant retrofit

ENCLOSURE

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ENCLOSURE 2 28

- 3) O&M associated with the thermal distribution network
- 4) Allocation of general and administrative cost

Other expenses allocated to the district heating system:

- 1) Penalty for forced operation of retired electric production facilities
- 2) Capacity credit for reactivation of retired electric capacity

All economic analysis will be performed on constant 1978 dollars. The fuel and O&M costs in the production cost base case and the PJM capacity payment estimates in the PJM Supplemental Agreement will be deescalated with the use of the GNP deflator figures.

Retrofit and Thermal Distribution Costs

The cost for retrofitting an existing PSE&G unit and the thermal distribution system will be estimated by Stone and Webster. PSE&G's Engineering Department will have an opportunity to review S&W cost estimates. These costs will be allocated to the district heating operation.

Capacity Penalty

The penalty for the decrease in electric capacity will be evaluated based on the PJM Supplemental Agreement. The change in forecast obligation due to a change in system winter capacity (and summer capacity if appropriate) with the district heating system will be determined along with the change in either deficit or surplus capacity. The change in either capacity purchases or sales along with the PJM capacity payment estimates will be used to determine the capacity penalty allocated to the district heating system.

If the electric capacity deficit as a result of district heating is sufficient enough to cause PSE&G to either advance a future unit or to add an additional unit in the future, then the penalty associated with the additional capacity will be assigned to the district heating operation.

Increase in System Operating Costs to Provide Thermal Power

The increase in system fuel and variable O&M costs to provide thermal energy will be assigned to the district heating operation. These incremental costs will be determined by a comparison of the total system production costs, from PSE&G's production cost simulation program, for a base case without district heating and a case in which the retrofitted plant or plants are operated to

meet thermal requirements. In the base case without district heating electric generation will be dispatched on an incremental cost basis using specific heat rate, fuel costs and O&M data. In the district heating case the retrofitted plant will be simulated as a must run unit during those periods determined by the thermal requirements of the district heating network.

The retrofitted plant will have less electric capacity. In order to properly simulate the total fuel input and the fuel cost of the plant for both electric and thermal production the heat rate of the plant will have to be adjusted upward. The upward adjustment in heat rate will be developed with the use of heat balance information to be provided by Stone and Webster. See the attached figure for further clarification.

Simulation of district heating plants as must run units during the heating season will force the production cost program to schedule maintenance at other times. Any penalty for restricted maintenance will be included in the total production costs.

O&M Allocation

The O&M expenses associated with the thermal portion of a retrofitted plant will be assigned to district heating. If there is an increase in the O&M expenses of the electric portion of the retrofitted plant due to a district heating operation, those O&M expenses will also be assigned to district heating. The O&M costs of the thermal distribution network will all be assigned to district heating.

Penalty for Forced Operation of Retired Electric Production Facilities

Presently, Essex No. 1 is on retirement status and Kearny No. 7 and No. 8 are to be placed in temporary retirement between June 1986 and May 1991. If these units or any other retired units are to be considered for retrofitting to provide district heat then during the period of normal retirement, all fixed and variable O&M costs associated with the plant will be allocated to district heating. The cost associated with reactivating a retired unit will also be allocated to the district heating system. The electric energy produced will be credited at the PJM running rate. If the capacity of the reactivated unit has value based on the PJM contract, then the district heating system will be credited for the capacity.

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TMP:mec
Attach.

Simulation of a Retrofitted Steam Station in the Production Cost Program to Provide Thermal Power for a District Heating Network

(Note: All numbers are only for illustration purposes)

Without District Heating

- 1) Unit will be dispatched on incremental cost basis
- 2) Total PSE&G production costs will be calculated in Production Cost Program

With District Heating

- 1) Unit not dispatched, MW output fixed by Thermal demand
- 2) Total PSE&G production costs will be calculated in Production Cost Program

Amount of Fuel for Thermal

$$\frac{410,000}{.85 \text{ (Boiler \%)}} = 480,000 \text{ BTU}$$

Cogeneration Electric Heat Rate

$$\frac{520,000}{20} = 26,000 \frac{\text{BTU}}{\text{kwhr}}$$

Amount of Fuel for Electricity

$$1,000,000 - 480,000 = 520,000 \text{ BTU}$$

Heat Rate Used in Production Cost Program

$$\frac{1,000,000}{20} = 50,000 \frac{\text{BTU}}{\text{kwhr}}$$

Capacity Penalty

Public Service Electric and Gas Company and other Pennsylvania-New Jersey-Maryland (PJM) Power Pool companies are required to maintain adequate margins of electric generating capacity according to the PJM Supplemental Agreement. A forecast obligation is determined for each PJM company based on that companies summer and winter peak electric loads, summer and winter electric generating capacities, average forced outage rates, average weekly peaks, and average planned and maintenance outages. If a PJM company is unable to meet its forecast obligation due to insufficient installed electric capacity, then that company must purchase the required capacity from other PJM companies with installed capacity in excess of their forecast obligation. Capacity payments are based on a predetermined per diem rate schedule and remain in affect for the duration of the capacity shortage.

The capacity payment penalty for the decrease in electric generating capacity, as a result of a district heating operation, can be determined based on the change in PSE&G's capacity payments and/or receipts as a result of the district heating electric generating capacity. If PSE&G is able to meet its PJM forecast obligation with the district heating operation and there are no PJM companies with a capacity deficit then there will be no capacity payment penalty levied against the district heating operation.

<u>Period</u>	<u>Unamort. Balance</u>	<u>Compen. Balance</u>	<u>Penalty</u>	<u>PV Factor</u>	<u>Present Worth</u>
1	100.000	112.766	3.32426	.905837	3.011238
2	96.970	109.349	3.22352	.820541	2.645034
3	93.939	105.932	3.12279	.743277	2.321097
4	90.909	102.515	3.02205	.673288	2.034712
5	87.879	99.097	2.92132	.609889	1.781681
6	84.848	95.680	2.82058	.552460	1.558261
7	81.818	92.263	2.71985	.500439	1.361119
8	78.788	88.846	2.61911	.453317	1.187287
9	75.758	85.429	2.51838	.410631	1.034124
10	72.727	82.012	2.41764	.371965	.899278
11	69.697	78.594	2.31691	.336940	.780658
12	66.667	75.177	2.21617	.305213	.676404
13	63.636	71.760	2.11544	.276473	.584861
14	60.606	68.343	2.01470	.250440	.504561
15	57.576	64.926	1.91397	.226857	.434198
16	54.545	61.509	1.81323	.205496	.372612
17	51.515	58.092	1.71250	.186146	.318774
18	48.485	54.674	1.61176	.168618	.271772
19	45.455	51.257	1.51103	.152740	.230795
20	42.424	47.840	1.41029	.138358	.195125
21	39.394	44.423	1.30956	.125330	.164126
22	36.364	41.006	1.20882	.113528	.137236
23	33.333	37.589	1.10809	.102838	.113954
24	30.303	34.172	1.00735	.093155	.093840
25	27.273	30.754	.90662	.084383	.076503
26	24.242	27.337	.80589	.076437	.061599
27	21.212	23.920	.70515	.069240	.048924
28	18.182	20.503	.60441	.062720	.037907
29	15.152	17.086	.50368	.056814	.028616
30	12.121	13.669	.40294	.051464	.020137
31	9.091	10.251	.30221	.046618	.014080
32	6.061	6.834	.20147	.042229	.008508
33	3.030	3.417	.10074	.038252	.003853

23.013384

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Equity Penalty

One scenario considered for the financing of the Demonstration Project involves 100% debt financing via tax free bonds. The economic analysis of this scenario incorporates an equity penalty. An explanation of this equity penalty and an illustration of the method by which it is calculated are given below. It should be pointed out that the imposition of the equity penalty is not unique to tax free bond financing. An equity penalty would be imposed on any financing scheme utilizing a higher proportion of debt (whether or not tax-free) to equity than the optimum.

A qualitative explanation of the equity penalty may be given as follows:

Funds can be borrowed by individuals, corporations or governmental bodies only because they have credit. It is this credit that is traded for the borrowed funds. In the case of governmental bodies it is the credit of the taxpaying public that is traded for borrowed funds. In the case of corporations it is the credit of the owners, the holders of equity, that is traded for borrowed funds. As borrowed funds are increased there is a decrease in the amount of credit that can be used for future borrowing. When corporations borrow funds, the line of credit of the equity investors can be restored to its pre-borrowing status only if the return to the equity investor is increased by an appropriate amount. It is the purpose of equity penalty to include this amount.

A privately owned utility must have specific common equity, preferred and long term debt ratios in order to maintain favorable bond ratings from the financial community. Bond ratings determine both the market for and cost of new debt financing for the company.

If it is proposed to finance a new venture with a mix of capital in other than the specified proportions, total company capitalization is changed. If the proposed district heating system is financed with 100% debt, more equity will have to be issued for other projects in order to maintain the desired mix of common equity, preferred and debt.

Since the cost of equity is greater than bond interest, issuing greater equity will cause a penalty on the other project or projects. The net impact of this would be a penalty to the other utility customers. To prevent this "subsidy" to the district heating customers, the amount of penalty ("equity penalty") is calculated and assigned to the district heating project and amortized over the life of the plant.

Another explanation for the equity penalty is as follows. Funds for all corporate projects come from a pool of capital provided by the company's investors, both debt and equity. It is improper to say that a particular debt security is used to purchase one piece of equipment while equity is used to finance another. Otherwise the additional equipment could appear economic or uneconomic depending on which type of security (debt) or equity happens to be issued concurrently. Even though a particular project may allow a corporation to utilize special financing (tax free bonds, leases, etc.) one must include the cost of the hidden equity backing for the project, which we call the equity penalty.

Calculation of Equity Penalty

Cost of Capital:

	<u>Rate - %</u>	<u>Ratio</u>	<u>Weighted - %</u>
Debt	8.600	0.470	4.042
PFD	8.870	0.130	1.153
Common	13.000	0.400	5.200
Total			10.395

Cost of Equity:

	<u>Rate - %</u>	<u>Ratio</u>	<u>Weighted - %</u>
PFD	8.870	13/(13+40)	2.176
Common	13.000	40/(13+40)	9.811
Total			11.987

$$\text{Compensating Ratio} = \frac{\text{Debt}}{\text{Equity}} = \frac{53}{47} = 1.128$$

$$\begin{aligned} &\text{Additional Equity Cost over Total Cost of Capital} \\ &= \text{Cost of Equity} - \text{Cost of capital} \\ &= 11.987 - 10.395 \\ &= 1.592 \end{aligned}$$

$$\begin{aligned} &\text{Additional Revenue required to cover Additional Equity Cost,} \\ &= 1.592 \times 1.128 \\ &= 1.7952 \end{aligned}$$

$$\begin{aligned} &\text{Federal Income Tax on Additional Revenue} \\ &= 1.7952 \times \frac{46}{54} \\ &= 1.5293 \end{aligned}$$

$$\begin{aligned} &\text{Total Additional Revenue Required or Equity Penalty} \\ &= 1.7952 + 1.5293 \\ &= 3.3245 \end{aligned}$$

212-769-4224

STONE & WEBSTER MANAGEMENT CONSULTANTS, INC.
90 BROAD STREET
NEW YORK, NEW YORK 10004

April 30, 1979

Mr. Carlos R. Guerra
Assistant Manager
PSE&G Research Corporation
80 Park Place
Newark, New Jersey 07101

Dear Carlos:

As you requested, this letter summarizes the financial assumptions which were agreed to at our April 25 meeting. I have also indicated those items which we anticipate receiving from Mort Plawner, Manager - Financial Planning & Research.

1. Conventional Financing

a.	Capital Cost	Percent
<u>Capitalization</u>	<u>Cost</u>
	Debt	47.0	8.6
	Preferred	13.0	8.87
	Equity	<u>40.0</u>	<u>13.00</u>
		100.0	
- b. Project Life - 33 years (based on PSE&G System Average).
- c. Tax Life - 22.5 years.
- d. Tax Rate - 46%, Deferred Tax Rate - 46%.
- e. Gross Receipts Tax - 13.9% (applicability to District Heating to be confirmed by M. A. Plawner).
- f. Investment tax credit - 10%.
- g. Project qualifies for progress payments; normalize over 22.5 years.
- h. Tax Depreciation Method - (to be supplied by M. A. Plawner).
- i. Interest capitalized at 8%.
- j. Construction Overhead Loading - as percent of equipment and labor costs (to be supplied by M. A. Plawner).

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Mr. Carlos R. Guerra
April 30, 1979
Page 2

2. Tax Exempt Financing

- a. Assume 100% debt at 200 basic points below conventional debt cost (pollution control bonds).
- b. Add equity penalty (to be supplied by M. A. Plawner).

3. Lease

- a. Equivalent Lease Rate - to be supplied by M. A. Plawner.

The receipt of information listed above will allow us to perform the analyses required for the district heating study. We also anticipate receiving, from Mort Plawner, a written explanation of why certain financing schemes are not acceptable to PSE&G.

Very truly yours,

Gerald S. Levitt
Senior Consultant

cc: L. A. Brown
R. A. Smalls
A. Calafiore
M. A. Plawner

Calculation of Customer Cost

Using Scheme II as an example, the number of each customer type of 1985 in Newark area can be calculated and shown in the following table.

<u>Customer</u>	<u>No. of Customers</u>
Small Commercial	85
Large Commercial	2
Small Industrial	113
Large Industrial	5
Residential	1,250 (apt. units)

The customer cost per unit has been estimated as follows:

<u>Customer</u>	<u>Metering</u>	<u>Conversion</u>	<u>Combined</u>
Small Commercial	\$1,500	\$21,000	\$22,500
Large Commercial	2,200	84,000	86,200
Small Industrial	1,500	21,000	22,500
Large Industrial	2,200	63,000	65,200
Residential	625	210	835

Therefore, the customer costs for each customer type and for the total are calculated as follows:

<u>Customer</u>	<u>Costs</u>
Small Commercial	\$1,912,500
Large Commercial	172,400
Small Industrial	2,542,500
Large Industrial	326,000
Residential	1,043,750
Total	<u>\$5,997,150</u>

USDOE DISTRICT HEATING AND
COOLING PROJECT

TASK 7

PROPOSAL OUTLINE - PHASE 2

Proposal Outline - Phase 2
Preliminary Feasibility and Conceptual
Institutional Arrangements

The Contractor shall conduct Phase 2 of the U.S. Department of Energy's Program to demonstrate a district heating and cooling system for communities through power plant retrofit and distribution network.

1.0 Objective

The objective of this phase of the project is to:

(a) conduct a detailed technical feasibility analysis of the most technologically attractive scenarios identified in Phase 1; (b) establish the technical feasibility of the most promising Demonstration Project; (c) establish the economic feasibility and environmental acceptability; (d) establish the institutional arrangements and framework required to bring this alternative to demonstration.

The aforementioned Phase 2 tasks are set forth below and the Contractor shall perform said tasks in accordance with it's proposal to DOE to continue to Phase 2 as defined in his project Phase 1 Final Report, except as hereinafter modified.

2.0 Scope of Work for Phase 2

2.1 Task 1 - Develop a Detailed Work Management Plan

- 2.1.1 Develop a detailed Work Management Plan to accomplish the objective of Phase 2.
- 2.1.2 Provide a PERT chart, a cost for each task, a milestone chart, a manpower resource requirement plan, a definition of the corporate and program organizational structure, and allocation of responsibility for performance of required tasks

2.2 Task 2 - Load and Service Area Assessment

- 2.2.1 Characterize the service areas to be supplied by Essex and Hudson Stations, according to thermal and electric energy use, to construct load duration curves for diurnal, weekly, seasonal and annual cycles

- a. Existing heating/cooling load shall be examined on a building-by-building basis for buildings above a specified size
- b. Selected new building developments shall be examined jointly with the developers
- c. Local authorities involved in promoting industrial and commercial development shall be consulted to estimate non-residential load
- d. Selected local industries shall be examined as producers/users of thermal energy

2.2.2 Evaluate thermal storage and energy allocation alternatives, in selected service areas, to assess possibilities in thermal-electric load balancing which improve plant and system utilization

2.2.3 Evaluate alternative configurations of selected service areas to bring the thermal electric loads in balance with the preferred operating modes of retrofitted plants

2.3 Task 3 - Technical Assessment

2.3.1 Evaluate retrofit alternatives suited to Essex and Hudson stations according to efficiency (waste heat capture) and relate to service load. Develop a preferred plant retrofit scheme for each station (Essex and Hudson) and intermediate/back-up plant (Harrison Gas Plant) to obtain refined estimates for cost analysis

- a. Based on data from Phase 1 and other available data at PSE&G, consider the following factors in the selection of the preferred retrofit scheme for Hudson and Essex stations

- Number of heating stages
- Number of turbines
- Peaking supply from crossover
- Economy of drain coolers
- Condensate quality monitoring
- Pumped condensate feedback
- Boiler operation independent of turbines

- Crossover pressure control
 - Hot water temperature controls
 - Various equipment (heat exchangers, pumps and pump drives)
- b. Consult with turbine and feedwater heater manufacturers to confirm maximum allowable extracted flows and resolve steam-extraction related problems
 - c. Examine alternative water heater exchanger arrangements and impact of steam extraction
 - d. Evaluate alternative auxiliary steam boiler arrangements
 - e. Consider different back pressure turbine designs and their applicability to preferred retrofit concepts
 - f. Update the heat balance diagrams and the district-heating system description and flow diagrams
 - g. Develop water heating plant design and update in-plant piping and electric system drawings
 - h. Evaluate the impact of the plant retrofit and district heating operation on the existing plant equipment. Examine plant retrofit systems reliability
 - i. Reassess potential annual energy savings and scarce fuel saving attributable to the district heating for a typical annually cycle
- 2.3.2 Evaluate alternative thermal distribution network configuration and select a preferred scheme for cost analysis giving consideration to the following factors:
- a. Hydraulics
 - Pumping substations and allowable pressures by users
 - Flow velocities/pressure drops
 - Place and method of pressurization
 - User pressure/temperature rating determination

- Topography of region
- Operation of looped systems
- Operation of systems fed by multiple sources
- Winter/summer regimes

b. Distribution Alternatives

- Rights-of-Way
- River crossing
- Loading on bridges and viaducts
- Expansion compensation and valving philosophy
- Types of piping systems and insulation
- Update transmission/distribution layouts

Layout the transmission piping system, distribution network and water pumping arrangements for the candidate retrofit stations

2.3.3 Evaluate alternative and cyclic schemes of thermal energy distribution media including hot and cold water and thermal storage both above and underground

2.3.4 Analyze the problems of in-building systems conversion

- a. Conduct and document an investigation of domestic and foreign products in order to assure potential customers and installers of the availability and cost of district heating equipment
- b. Investigate problems associated with providing cooling including:
 - Heated water interface with in-house absorption cooling systems
 - Chilled water interface with in-house cooling systems
 - Relative merits of absorption and compressor cooling and mixes of these two types of cooling
- c. Survey in-building system compatibility
 - Heat exchanger and meter survey
 - Preliminary equipment selection
 - Potential heat pump applications
 - Schematics

- 2.3.5 Analyze alternative combinations of plant retrofit and distribution schemes to evaluate consequences on cost allocations and delivered energy prices
- 2.3.6 Analyze alternative combinations of plant retrofit and distribution schemes to evaluate consequences on heat availability to meet thermal load and plant utilization improvements
- 2.3.7 Analyze system reliability requirements for each service area and evaluate alternative plant retrofit and distribution schemes

2.4 Task 4 - Conceptual Institutional Arrangements

- 2.4.1 Identify alternative ownership-lease arrangements for the retrofit plant(s), assess advantages/disadvantages and develop the preferred options
- 2.4.2 Identify alternative ownership-lease arrangements for the thermal distribution system and the customer conversion module, and assess the advantages and disadvantages of each
- 2.4.3 Analyze the legal, economic and financial issues related to the preferred ownership-lease arrangements
- 2.4.4 Analyze the risk associated with the preferred ownership-lease arrangements and develop recommendations for minimizing the associated risks
- 2.4.5 Evaluate the potential of structuring long-term contracts with selected end-users with a thermal load above certain level
- 2.4.6 Evaluate alternative contractual arrangements involving leases and end-users. Resolve questions related to franchises, local zoning and siting laws
- 2.4.7 Evaluate alternative arrangements to finance construction of the Demonstration Project, including conventional, lease and third party financing

- 2.4.8 Evaluate the effect of State and Federal air quality regulations and the Power Plant Industrial Fuel Use Act on the implementation and operation of the Demonstration Project. Consult with U.S. EPA and DOE and N.J. DEP and DOE
- 2.4.9 Contact and work with principal local and regional interest groups and decision makers
- 2.4.10 Develop institutional arrangements to involve these groups and decision makers as active participants in the Demonstration Program and to facilitate implementation of the Demonstration Project

2.5 Task 5 - Economic and Financial Feasibility and Rate Design

Taking account of the information developed in Tasks 2, 3, and 4:

- 2.5.1 Prepare a comprehensive summary of fuel and electricity price projections applicable to the district heating area based on the best information available from reliable sources. Place particular emphasis on the price of scarce fuel (natural gas and oil where applicable). Select probable price project ranges acceptable to the decision makers who will be responsible for the decision to proceed with construction
- 2.5.2 Modify the PSE&G Production Cost Simulation Program so that increases in electric system operating costs and changes in fuel use due to the operation of a district heating (and cooling) system can be simulated more adequately
- 2.5.3 Evaluate the potential for either conventional or non-conventional financing of the district heating system. Identify the benefits and disadvantage of both forms of financing. Determine the necessary procedures to implement either type of financing

- 2.5.4 Survey representative buildings in service areas to determine the extent of retrofit required including costs of and barriers to retrofit.
- 2.5.5 Determine the cost of service over a typical annual operating cycle for each of the district heating alternative systems investigated in Phase 2. Consideration will be given to the trade-offs between capital costs, operating costs, system size and system load factor
- 2.5.6 Choose an optimum district heating system with consideration of standard PSE&G engineering lifecycle criteria, including capital investment, operation and maintenance costs, system size, system load factor, financing and impact on the electric and gas operations of PSE&G
- 2.5.7 Refine the operating costs determined for conventional heating plants, determine the cost of service and predict representative customer utility bills. Provide a Pro-Forma income statement and balance sheet in normal accounting format for each alternative considered. Determine the price for thermal service necessary to encourage customers to switch to district heating. Evaluate the ultimate market potential of thermal service. Support all assumptions with appropriate data and include enough information to duplicate calculations. Provide sufficient documentation of computer programs employed to permit a numerical check of results.
- 2.5.8 For the optimum district heating system identify and evaluate a multi-stage development scheme for the thermal supply system.
- 2.5.9 Determine the impact of a district heating system on PSE&G electric and gas operations
- 2.5.10 Determine the impact of implementing a district heating system on the overall financial condition of PSE&G considering the profitability of the thermal service and its impact on the electric and gas operations

- 2.5.11 Refine the proposed thermal rate structure defined in Phase 1 and obtain N.J. Board of Public utilities comments on this proposed rate structure
- 2.5.12 Identify the change in fuel use by type with the district heating system compared to the conventional thermal systems

2.6 Task 6 - Proposal for Implementation

- 2.6.1 Based upon the work accomplished in Phase 2, prepare a detailed implementation plan for the remainder of the demonstration program. The steps to be included in this plan are outlined below. As a minimum, the plan should include:
 - a. Description of the Demonstration Project including the preferred retrofit scheme and thermal distribution network
 - b. Demonstration Master Schedule
 - c. Detailed Task Schedule for subsequent phases with PERT Charts for each subsequent phase.
 - d. Management Plan, including:
 - Demonstration Team organizational structure
 - Description of tasks necessary for managing the Demonstration Program
 - Functional relationships of members of the Demonstration Team
 - Identification of key personnel including qualifications and level of effort
 - Man-power Schedule and
 - Cost Schedule

ISSUES AFFECTING DECISION TO CONSTRUCT,
OWN AND OPERATE A DISTRICT HEATING
AND COOLING SYSTEM

In the August 13, 1979 letter from Mr. John C. Rodousakis to Dr. Carlos Guerra, it was asked what issues needed to be resolved to facilitate the above mentioned decision, and how the proposed Scope of Work for Phase 2 addressed these issues.

The issues are described in the letter of transmittal from Mr. Harold W. Sonn, President - PSE&G Research Corporation, which is contained in Volume I (Executive Summary) of this report. These issues will be repeated below (underlined) and the way in which Phase 2 addresses them will be shown.

1. Engineering soundness of the selected project concept and its integration with the PSE&G system

In Phase 2, all technical aspects will be reviewed by the PSE&G Engineering and Electric Production Departments and by the Swedish District Heating consultant (AB EnergiKonsult). Turbine steam extraction capability will be verified by the turbine manufacturers, (General Electric and Westinghouse). (Task 3)

Acceptability of impact of loss in electric capacity and any effects on PSE&G interaction with the Pennsylvania-New Jersey-Maryland (PJM) Interconnection

Detailed computer modeling by the PSE&G System Planning Department will evaluate impact on our electric and gas operations and the PJM Interconnection. (Task 5, Items 2.5.2 and 2.5.9)

2. Economic advantages over other feasible alternative investments. Acceptable return-on-investment

Phase 2 will include technical optimization, refinement of cost estimates and refined economic analysis to reduce uncertainties in this area. The required return-on-investment will be incorporated into the economic analysis to determine the cost of service. (Task 3, Item 2.3.1, Task 5, Items 2.5.5 and 2.5.7)

3. Continued ability by PSE&G to raise additional capital for financing the project

Financing of the project will be studied in Task 4, Items 2.4.1 - 2.4.7. We do not expect difficulty in financing a project like this if the economics appear favorable and the risk reasonable. Financing costs will be sensitive to money market conditions and risk of the project as perceived by investors.

4. Acceptability from the legal and regulatory standpoint

To address this issue we intend to consult closely with the N.J. Board of Public Utilities and N.J.DOE in Phase 2, and involve N.J.DOE as an active participant in Phase 2. The PSE&G Law Department will also be consulted on legal matters. (Task 4, Items 2.4.3 and 2.4.8; Task 5, Item 2.5.11)

5. Compatibility with PSE&G existing labor union agreements regarding the operation of such facilities

The PSE&G Law Department will examine this matter closely during Phase 2. (Task 4, Item 2.4.3 and Task 5, Item 2.5.9)

6. Satisfactory agreement with customers, particularly regarding the thermal energy supply rates.

In Phase 2, a detailed survey of specific potential customers will be made and letters of intent obtained. Local and regional interest groups and decision makers will be contacted and actively involved in Phase 2. (Task 2, Item 2.2.1; Task 4 Items 2.4.9 and 2.4.10; Task 5, Items 2.5.5 and 2.5.7)