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December 22, 2021

VIA ELECTRONIC MAIL

aida.camacho@bpu.nj.gov
board.secretary@bpu.nj.gov

Aida Camacho-Welch
Secretary to the Board
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, NJ 08625-0350

RE: In the Matter of the Petition of Atlantic City Electric Company for Approval of the Modification of Power Purchase Agreements with Chambers Cogeneration Limited Partnership and Logan Generating Company, L.P.
BPU Docket No. _____

Dear Secretary Camacho-Welch:

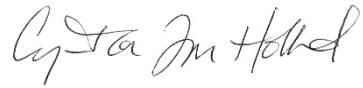
Enclosed herewith for filing is an electronic copy of a Petition, including certain exhibits, initiating the above-entitled matter for Atlantic City Electric Company (“ACE” or the “Company”). Also attached and filed herewith is the Direct Testimony and accompanying Schedules of Mario Giovannini, Director of Energy Acquisition, in support of the Company’s Petition. Finally, the Company provides a fully executed Non-Disclosure Agreement (“NDA”).

Consistent with the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities’ Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being electronically filed with the Secretary of the Board of Public Utilities and the New Jersey Division of Rate Counsel. No paper copies will follow.

Aida Camacho-Welch
December 22, 2021
Page 2

Thank you for your cooperation and all courtesies extended. Please contact me with any questions or concerns with this filing. I am happy to provide any further assistance that I can.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Cynthia L.M. Holland". The signature is written in a cursive, flowing style.

Cynthia L.M. Holland
An Attorney at Law of the
State of New Jersey

Enclosure

cc: Service List

**IN THE MATTER OF THE PETITION
OF ATLANTIC CITY ELECTRIC
COMPANY FOR APPROVAL OF THE
MODIFICATION OF POWER
PURCHASE AGREEMENTS WITH
CHAMBERS COGENERATION
LIMITED PARTNERSHIP AND LOGAN
GENERATING COMPANY, L.P.**

**STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
BPU DOCKET NO. _____
CERTIFIED PETITION¹**

ATLANTIC CITY ELECTRIC COMPANY (“ACE” or the “Company”), a corporation organized and existing under the laws of the State of New Jersey, which is subject to the jurisdiction of the New Jersey Board of Public Utilities (“Board”) and which maintains a regional office at 5100 Harding Highway, Mays Landing, New Jersey 08330, respectfully petitions the Board for the approval of Settlement Agreements between ACE and **CHAMBERS COGENERATION LIMITED PARTNERSHIP** (“Chambers”), and ACE and **LOGAN GENERATING COMPANY, L.P.** (“Logan”) (the “Settlement Agreements”) and Modified Power Purchase Agreements (“Modified PPAs”) pursuant to which ACE will modify existing Power Purchase Agreements (“PPAs”) and terminate existing Power Sales Agreements (“PSAs”) with Chambers and Logan, respectively. In support of this Petition, ACE provides the information set out below.

I. BACKGROUND

1. ACE is engaged in the transmission and distribution of electric energy for light, heat, and power to approximately 560,000 residential, commercial, and industrial customers

¹ In light of the exigencies created by the COVID-19 pandemic and the Executive Orders issued pursuant thereto, this Petition is being submitted under Certification in lieu of an Affidavit of Verification.

located in eight counties in the southern portion of New Jersey.² This proceeding involves the modification and termination of the last of ACE's contracts to purchase electricity from Non-Utility Generators ("NUGs"), which agreements were originally required pursuant to federal legislation known as the Public Utilities Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C.A §§ 791-828(c). Specifically, this proceeding entails a request to modify the existing Chambers and Logan PPAs such that existing interconnection rights would be preserved but coal-fired electric generation would cease, as well as the termination of the existing Chambers and Logan PSAs.

2. Chambers is a 285 MW cogeneration qualifying facility ("QF") located in Carney's Point, New Jersey. The primary fuel source used by the Chambers facility is pulverized coal that is transported to the site by rail, and the secondary fuel source is fuel oil. Chambers commenced commercial operation on March 15, 1994 and is jointly owned, indirectly, by affiliates of Starwood Energy Group Global, LLC ("Starwood") (60% ownership) and by Atlantic Power (40% ownership).

3. Logan is a 225 MW cogeneration QF located in Logan Township, New Jersey. The primary fuel source used by the Logan facility is pulverized coal that is transported to the site by barge, and the secondary fuel source is fuel oil. Logan commenced commercial operation on September 22, 1994 and is indirectly owned by affiliates of Starwood.

² See *I/M/O the Merger of Exelon Corporation and Pepco Holdings, Inc.*, BPU Docket No. EM14060581, Order Approving Stipulation of Settlement (dated March 6, 2015), in which the Board approved the merger of Exelon Corporation and Pepco Holdings, Inc., and ACE became a direct subsidiary of PHI. Also, PHI became Pepco Holdings LLC, a Delaware limited liability company, and is referred to as PHI.

4. Although they are not parties to this proceeding, Chambers and Logan actively participated in the negotiation of the Term Sheets and Settlement Agreements, and they have advised ACE of their intention to file a letter with the Board supporting the Company's requests in this docket.

A. Existing Agreements

5. Congress enacted PURPA in the wake of the 1970s energy crisis for the purpose of, among other things, encouraging the use of domestically produced fuels and promoting competition in the electric generation sector. Pursuant to PURPA, electric public utilities were required to purchase electricity from QFs at rates that were "just and reasonable," that is, rates that were no greater than the utility's forecasted avoided cost (i.e., the estimated cost the utility would have incurred if it generated the electricity itself or purchased it from another party). Consistent with PURPA, ACE executed agreements with Chambers and Logan in 1988 which contained terms and pricing that were consistent with the Board's avoided costs policies in effect at the time.

6. Specifically, in September 1988, ACE and Chambers entered into a PPA pursuant to which Chambers sells 184 MW of capacity and up to 187.6 MWH of energy during winter, and 173.2 MWH of energy during summer, to ACE. The existing PPA sets out the rights and obligations of the parties, including interconnection rights, and will terminate in March 2024. ACE and Chambers are also parties to a separate Power Sales Agreement ("PSA").³ The PSA monetizes the value of energy and capacity above the maximum values set in the PPA, and allows the Company to generate additional revenues for the benefit of customers. ACE and Chambers have negotiated annual PSAs for more than a decade, with the PSAs typically renewing on January 1 of

³ The Chambers PSA is negotiated each year and is typically renewed in January. In 2021, there were delays in executing the PSA and the agreement was not signed until June 9, 2021.

each year. The Board reviewed and approved the PPA between ACE and Chambers in BPU Docket No. EM88111219 (Order dated March 31, 1989). A copy of the Chambers PPA (and subsequent amendments) can be found in Exhibit A. A copy of the Chambers PSA can be found in Exhibit B, attached hereto. As a QF, Chambers also sells electricity and steam to Chemours.⁴

7. In August 1988, ACE and Logan entered into a PPA pursuant to which Logan sells 200 MW of energy and capacity to ACE. The existing PPA sets out the rights and obligations of the parties, including interconnection rights, and will terminate in 2024. ACE and Logan are also parties to a separate PSA.⁵ The PSA monetizes the value of energy and capacity above the maximum values set in the PPA and allows the Company to generate additional revenues for the benefit of customers. ACE and Logan have implemented annual PSAs for more than a decade, with the PSAs automatically renewing on January 1 of each year. The Board reviewed and approved the PPA between ACE and Logan in BPU Docket No. EM88091074 (Order dated December 28, 1988). A copy of the Logan PPA (and subsequent amendments) can be found in Exhibit C. A copy of the Logan PSA can be found in Exhibit D, attached hereto. As a QF, Logan also sells steam to the Valtris Specialty Chemicals Company (“Valtris”).⁶

8. Although the Board determined that the NUG agreements appropriately reflected avoided cost policy when they granted approval, by the time the Chambers and Logan generating

⁴ The Chambers facility sells electricity and steam to the Chambers Works facility owned by the Chemours Company pursuant to a long-term agreement that will also terminate in 2024. Chambers’ electricity and steam agreement with Chemours Company is not a subject of this proceeding.

⁵ The currently operative Logan PSA was negotiated in 2012 and executed on December 18, 2012. The Logan PSA automatically renews each year.

⁶ The Logan facility sells steam to the Valtris facility pursuant to a long-term agreement that will also terminate in 2024. Logan’s steam agreement with Valtris is not a subject of this proceeding.

plants were operational in 1994, the pricing terms included in the contracts resulted in payments in excess of the market value of the output of the facilities.

9. Subsequent administrative and legislative action at both the federal and State levels sought more efficient means to promote competition in the energy sector. Notably, in 1999, the Legislature enacted the Electric Discount and Energy Competition Act (“EDECA”), N.J.S.A. 48:3-49 *et seq.*, intended to restructure the electric utility industry in New Jersey and address various types of stranded costs that were identified because of restructuring. EDECA expressly determined that the above-market costs associated with existing long term NUG PPAs, such as Chambers and Logan, were stranded costs subject to cost recovery. N.J.S.A. 48:3-61(a)(3). Further, EDECA authorized the Board to approve the renegotiation, restructuring, and/or termination of existing long-term NUG contracts where such actions “will result in a substantial reduction in the total stranded costs of the utility, which resulting savings will be passed through to ratepayers on a full and timely basis.” N.J.S.A. 48:3-61(l)(1).

10. In an effort to mitigate cost impacts to ACE customers, currently all of the energy and capacity purchased by ACE pursuant to the PPAs and the PSAs with Chambers and Logan is sold into the PJM wholesale market. The electricity ACE receives through the Logan and Chambers PPAs and PSAs is not used by ACE to supply the needs of its retail distribution customers. As such, ACE customers *do not receive direct supply benefits from these agreements*, but do shoulder the financial burden of the above-market costs. Moreover, ACE does not earn a return on, or benefit from, these agreements in any way.

11. Consequently, as discussed further below, ACE has sought for many years to identify and employ strategies for renegotiating, modifying, and/or eliminating the Chambers and Logan agreements.

B. Existing Contract Obligations

12. Although the full agreements are provided in Exhibits A through D, to further assist the Board in understanding the contracting parties' rights and obligations under the existing PPAs and PSAs, the Company has prepared a high-level summary of important contract and operating provisions. Attached as Exhibit E is a summary of relevant contract provisions for the Chambers PPA and PSA and attached as Exhibit F is a summary of relevant terms for the Logan PPA and PSA.

C. Interconnection Rights/Obligations

13. As noted in the Term Sheets, the PPAs will be modified such that certain interconnection rights and obligations in the PPAs will survive. The reason for this is relatively straightforward. Generators connected to the PJM grid have a stand-alone Interconnection Agreement ("IA") with PJM. This allows the generator to sell into the PJM market. Without an IA, no sales can occur. Many NUGs have three-party IAs which include PJM, the utility, and the generator. In the case of Chambers and Logan, the plant owners are not PJM members; however, the IA is included in the PPA itself because the IA is between ACE and PJM. When the PPAs end, the IA rights will end, and the facilities will need to have an IA in place for the transition period and to serve the steam host. The timing of getting a new IA in place between the facilities and PJM could take up to 4 months or longer given delays at PJM. Chambers and Logan have requested that ACE terminate the PPAs, except for the IA provisions, so that Chambers and Logan can continue to sell into the PJM market through the existing interconnection facilities. This approach will allow status quo operations with respect to the plants until the transaction and transition are completed. Consequently, this strategy is contemplated in the Term Sheets and is the reason for the modification of the PPAs rather than termination.

II. PROPOSED TRANSACTIONS

A. Negotiation Process

14. As set out in the Board's Order in BPU Docket No. ER13030186, dated May 29, 2013, and referenced in subsequent orders, ACE is required to make a good faith effort to negotiate with Chambers and Logan in an effort to mitigate the stranded costs associated with these long-term NUG contracts. Indeed, the Order recognizes ACE's efforts to renegotiate the NUG contracts before 2013 by indicating that ACE was to "re-initiate" good faith negotiations.

15. Since 2013, ACE has been required to file quarterly reports with the Board concerning its NUG contract negotiations. ACE has held multiple discussions concerning renegotiation and/or termination of the Logan and Chambers PPAs and PSAs, as has been described in the quarterly reports filed in compliance with the Order in BPU Docket No. ER13030186.

16. In recent months, those discussions have become more productive, and ACE, Logan, and Chambers have negotiated two Term Sheets, attached hereto as Exhibit G (Chambers Term Sheet) and Exhibit H (Logan Term Sheet), containing the critical terms pursuant to which the PPAs and PSAs will be modified and/or terminated, and the use of pulverized coal at the two facilities will end. The Term Sheets will be memorialized in two Settlement Agreements, one each with Chambers and Logan, which Settlement Agreements are presently being finalized. In addition, Modified PPAs will also be prepared to retain the interconnection provisions discussed above.

17. Upon execution, ACE will supplement this filing with the Settlement Agreements and Modified PPAs and so has designated Exhibit I (Chambers Agreements) and Exhibit J (Logan Agreements) as placeholders for those materials. As explained below and in the Direct Testimony

of Company Witness Mario Giovannini, the Company believes the key terms of the Settlement Agreements and Modified PPAs are contained in the Term Sheets and provides these detailed materials now in an effort to provide the parties with the information needed to evaluate the Company's requests in this proceeding. Further, as noted above, Chambers and Logan have indicated to ACE that such parties will file with the Board a letter supporting the relief requested by the Company.

B. Overview of Key Transaction Terms

18. As explained in greater detail in the Direct Testimony of Company Witness Giovannini, upon receipt of required regulatory approvals and satisfaction of all conditions precedent, ACE will make a series of negotiated fixed monthly payments for the remaining term of the existing PPAs and PSAs. The fixed monthly payment amounts reflect negotiated payments by Chambers and Logan, and result in savings to customers of up to \$30 million over the remaining term of the existing agreements.⁷ Specifically, customers will see savings of up to \$14,047,165 on the Chambers agreements and up to \$15,952,835 on the Logan agreements. Exhibit A to each of the Term Sheets is a schedule of the monthly payments by ACE to the facilities and monthly customer benefit payments by the respective projects that will offset a portion of ACE's monthly payments. Ultimately, the customer benefit amounts will reduce ACE's payments to the facilities and reduce the stranded costs paid by customers.

⁷ The actual amount of customer savings will depend on the date of the closing of the PPA modifications and PSA terminations. As set out in the Term Sheets, monthly customer benefit payments by Chambers and Logan will not commence until the Board has approved this proposal and the various contract modifications and terminations have closed. Consequently, this timing may decrease the total amount of the benefits customers receive. For example, if the transaction has not been approved by the Board in January 2022, then the \$245,595 customer benefit payment scheduled for that month will not be provided by Chambers to ACE and its customers, and there is no opportunity to recoup this customer benefit at a later point.

19. In exchange for the fixed payments, ACE, Chambers, and Logan have agreed that coal-fired electric generation will cease at the facilities permanently, following brief transition periods. The purpose of the specified transition periods is to facilitate the orderly cessation of coal-fired operations, and in the case of Chambers, to obtain necessary approvals to produce steam for the Chemours Chambers Works facility using natural gas-fired boilers with fuel oil back-up. For the avoidance of doubt, the intention of ACE, Chambers, and Logan is that the use of coal at Chambers and Logan will cease permanently.

20. ACE, Chambers, and Logan have negotiated brief transition periods applicable to the individual projects. Specifically, within three months after the closing of the PPA modification and PSA termination, Logan will permanently cease any coal-fired electric generation and the combustion of any coal at its facility. With respect to Chambers, within three months after the later to occur of the closing of the NUG contracts termination/modification and receipt of all regulatory approvals for steam production with gas-fired boilers, and subject to the provisions set forth under “*Plant Operations*” in the Chambers Term Sheet outlined below, Chambers will permanently cease any coal-fired electric generation and the combustion of any coal at its facility. In the event Chambers has not permanently ceased the combustion of coal within three months of the closing, then, subject to minimum output levels required to meet regulatory requirements and technical specifications for the applicable equipment, Chambers will reduce the coal combustion at its power plant to the level necessary only to satisfy its steam obligations to Chemours and any incidental energy produced.

21. As noted above, the Board is authorized to approve the renegotiation, restructuring, and/or termination of existing long-term NUG contracts where such actions “will result in a substantial reduction in the total stranded costs of the utility, which resulting savings will be passed

through to ratepayers on a full and timely basis.” N.J.S.A. 48:3-61(l)(1). In the instant proceeding, expeditiously approving the modification and termination of the NUG contracts will result in the reduction of stranded costs of up to \$30 million, which benefit will be passed through to customers in the annual filings of the Non-Utility Generation Charge (“NGC”), as described below. In addition, there are significant environmental benefits resulting from the cessation of coal-fired operations at the units that will be discussed further below and in the Direct Testimony of Company Witness Giovannini. Taken together, these benefits demonstrate that approval of the modification and termination of the NUG contracts is in the public interest and should be approved by the Board on an expedited basis as described herein.

C. Environmental Benefits

22. Improving air quality has long been a concern in New Jersey. In 2005, the New Jersey Department of Environmental Protection (“DEP”) classified carbon dioxide (“CO₂”) as an air contaminant, which encouraged the State to look critically at the harmful effects that polluting coal was having on air quality. That same year, the State was a founding member of the Regional Greenhouse Gas Initiative (“RGGI”), which is a cooperative effort among several states in New England and the Mid-Atlantic regions to reduce greenhouse gas emissions through the operation of a CO₂ budget trading program. The State subsequently withdrew from RGGI, but, by Executive Order No. 7, dated January 29, 2018, Governor Murphy directed the Board and DEP to re-join RGGI as a means of achieving State goals for combatting climate change.

23. Despite these and other efforts to address climate change, the 2019 Energy Master Plan (“EMP”) plainly states that “there is also evidence that New Jersey’s current trajectory and efforts will be insufficient to reach the goals we have established to address climate change.”⁸

⁸ See 2019 New Jersey Energy Master Plan, at Section 2, page 11.

DEP's 2020 Global Warming Response Act 80 x 50 Report ("GWRA Report") also asserts that, "[w]ithout steep and permanent reductions in global GHG emissions within the next several years, New Jersey's people and their property will experience significant adverse effects of climate change."⁹

24. Both the EMP and GWRA Report recognize the environmental benefits that have been achieved by transitioning the State's resource mix away from traditional coal-fired generation and toward cleaner resources. However, Goal 2.1.9 of the EMP indicates that additional regulation of CO₂ may be prudent to ensure that the state meets its statutory mandate of an 80% reduction in GHG by 2050. In Executive Order No. 100, dated January 27, 2020, Governor Murphy directed the DEP Commissioner to "[e]stablish criteria that shall govern and reduce emissions of carbon dioxide."

25. Following a lengthy stakeholder process, DEP recently published its "Control and Prohibition of Carbon Dioxide Emissions" rule proposal on December 6, 2021. This rule proposal, if adopted, will limit GHG emissions from fossil-fuel powered electric generation units. Because the rulemaking process takes time, immediate greenhouse gas reductions may not be realized in 2022.

26. As the EMP references the positive benefits associated with the closure of many coal units in the State, it also acknowledges that two coal units remain. Chambers and Logan represent the last large-scale coal-fired generation units in the State. The Settlement Agreements will require Chambers and Logan to permanently cease coal-fired generation activities within a matter of months, well before DEP's rule adoption. This represents a significant and lasting environmental benefit to customers and to the State. Indeed, but for the terms of the Settlement

⁹ See GWRA Report, Executive Summary, at page v.

Agreements, Chambers and Logan could continue to operate on a coal-fired basis following the expiration of the existing PPAs and PSAs—an outcome that is clearly inconsistent with the State’s focus on a clean energy future.

27. Consistent with the State’s policy, as well as the administrative efforts of the Board and DEP, ACE believes that climate change and its social and environmental effects are among the most significant challenges facing the world today. ACE is committed to providing its electric service to customers in the State in a manner that aligns with Governor Murphy’s climate and clean energy goals.

28. Finally, the Board has the statutory jurisdiction, power, and duty to “require any public utility to furnish safe, adequate, and proper service, including furnishing and performance of service in a manner that tends to conserve and preserve the quality of the environment and prevent the pollution of the waters, land, and air of this State.” N.J.S.A. 48:2-23. ACE believes these Settlement Agreements comport with the State’s climate change policies, providing environmental benefits in the public interest. The Board’s approval of these Settlement Agreements will conserve and preserve the quality of the environment and prevent air pollution.

D. Payment Stream Calculation

29. At the core of the proposed transaction is the stream of monthly payments and customer benefits. The Company engaged a third-party consultant, ICF, to assist it with performing projections of generation output, forward PJM Locational Marginal Prices (“LMPs”) and provided capacity prices for forward PJM planning years to model the PJM revenues and contract payments. These projections enabled ACE to estimate the stream of payments to Logan and Chambers as well as offsetting revenues from selling the energy and capacity back into PJM that would have occurred if the PPAs and PSAs were to remain unchanged and run to termination

in 2024. These projections were utilized in negotiations with Logan and Chambers. A copy of the internal price curve comparison used in this process is included as Exhibit K hereto. Company Witness Giovannini provides a detailed discussion of this process and the model used by ICF for its projections. Further, the Company has arranged for ICF to assist Board Staff and the Division of Rate Counsel (“Rate Counsel”) in the event that either party wishes to conduct sensitivity analyses using alternative data inputs into the model used by ICF to assist the Company with its analysis.

30. In support of the relief requested in this Petition, the Company also provides the Direct Testimony of Mario Giovannini, Director of Energy Acquisition for PHI, who was directly involved in the analysis supporting the fixed payments set out in the Term Sheets. Mr. Giovannini testifies in detail regarding the forecasting process used by the Company, the key terms in the Term Sheets, and the environmental and financial benefits that will result from approval of the proposed modification of the PPAs and termination of the PSAs.

E. Timing of Required Approval

31. As noted in the Term Sheets, Settlement Agreements and Modified PPAs, if the closing of the modification of the NUG contracts does not occur by April 10, 2022, then the proposed Settlement Agreements and Modified PPAs will automatically terminate and the existing NUG contracts will remain in full force and effect in accordance with their terms. In addition, because the amount of customer benefits is linked to the timing of the closing of the proposed transaction, there are important financial incentives to resolve this proceeding promptly.

32. Given this timing, the Company respectfully requests that the Board retain this matter, review it on an expedited basis, and approve the requests made herein no later than the Board’s public agenda meeting scheduled for March 23, 2022. Based in part upon a review of

prior Orders approving such transactions, ACE has endeavored to anticipate information that could be helpful to Board Staff and Rate Counsel in reviewing this request and has provided that information in this filing to facilitate expedited action.

III. COST RECOVERY

33. As noted above, ACE is not proposing to address NUG contract cost recovery in this docket. Instead, the Company proposes to address cost recovery through the well-established annual NGC filing process pursuant to which the Company currently recovers the above-market costs of the Chambers and Logan NUG agreements. The NGC is updated annually in a filing made on, or about, February 1. The Company believes that cost recovery related to the fixed payments reflected in the Term Sheets and Settlement Agreements is appropriately addressed in the annual NGC filings and should continue to be reviewed and approved in those proceedings. The Company provides this cost recovery discussion now in order to demonstrate that approval of the modification and/or termination of the NUG contracts is warranted because there will be a material reduction in stranded costs and there is an existing, well-functioning mechanism for ensuring that those benefits are passed through to customers in a full and timely manner.

34. The Company's intention is to continue its annual NGC filings, including its next scheduled filing on or before February 1, 2022 which will reflect a proposed rate effective date of June 1, 2022. That filing would include a forecast of costs for the period of April 1, 2022 through March 31, 2023 (ACE's annual period) as well as any under/over recovery from the previous year (i.e., April 1, 2021 – March 31, 2022).

35. ACE's current plan is to make its February 2022 filing using its standard forecasting methodology. Should the Board approve the requests in this proceeding, ACE will update its forecast to reflect the approved fixed payments, and reduced stranded costs, which will occur in

2022 as a result of the modification of the PPAs and termination of the PSAs. In addition, the resultant NGC rate would be updated at that time and in that proceeding.

36. Given the April 10, 2022 termination date of the Term Sheets, ACE anticipates that the impact of this NUG contract proceeding will be known in sufficient time to accurately reflect a reduction of stranded costs in the NGC proceeding and for a new NGC rate to become effective on June 1, 2022. Thereafter, ACE would continue to make annual NGC filings to reset the NGC rate until the final payments are made to the Chambers and Logan projects. ACE anticipates that those filings will continue to occur by February 1 of each subsequent year¹⁰ and reflect the fixed payments to be made under the modified PPAs as well as any under/over recovery from the prior period.¹¹

¹⁰ ACE notes that once the final payments are made to Chambers and Logan, there will be one additional filing for the NGC to true-up the balance based on that year's actual activity. The Company highlights this final filing in the interest of clarity and for avoidance of doubt as to the complete filing schedule.

¹¹ ACE typically experiences some under/over recoveries due to the differences between actual sales and budgeted sales projections that are used in the NGC filings.

IV. SUPPORTING TESTIMONY AND EXHIBITS

37. The proposed relief described in this Petition and Exhibits is supported by the Direct Testimony and supporting schedules of Mario Giovannini, Director of Energy Acquisition for PHI, which is attached hereto and made a part hereof.

38. The following Exhibits are attached to this Petition:

Exhibit A: Chambers PPA, and amendments;

Exhibit B: Chambers PSA dated June 9, 2021;

Exhibit C: Logan PPA, and amendments;

Exhibit D: Logan PSA dated December 18, 2012, as renewed annually;

Exhibit E: Summary of Chambers PPA and PSA key contract terms;

Exhibit F: Summary of Logan PPA and PSA key contract terms;

Exhibit G: Chambers Term Sheet;

Exhibit H: Logan Term Sheet;

Exhibit I: Chambers Settlement Agreement and Modified PPA [to be filed];

Exhibit J: Logan Settlement Agreement and Modified PPA [to be filed]; and

Exhibit K: Internal Price Curve Comparison.

V. COMMUNICATIONS

39. Communications and correspondence concerning this proceeding should be sent to the following representatives of the Company:

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VI. CONCLUSION

WHEREFORE, **ATLANTIC CITY ELECTRIC COMPANY** respectfully requests that the Board make the following determinations:

A. that the Settlement Agreements and Modified PPAs between the Company and Chambers and the Company and Logan will result in a substantial reduction in stranded costs and so are in the public interest;


B. that the cessation of the use of coal at the Chambers and Logan facilities provides environmental benefits to customers and the State of New Jersey, and is in the public interest;

C. that the payments required under the Settlement Agreements are just and reasonable and shall be subject to recovery in the Company's future NGC filings; and

D. that the Company shall have such other and further relief as the Board may determine is just and reasonable.

Respectfully submitted,

Dated: December 22, 2021



CYNTHIA L. M. HOLLAND
An Attorney at Law of the
State of New Jersey

Counsel for Atlantic City Electric Company

**IN THE MATTER OF THE PETITION
OF ATLANTIC CITY ELECTRIC
COMPANY FOR APPROVAL OF THE
MODIFICATION OF POWER
PURCHASE AGREEMENTS WITH
CHAMBERS COGENERATION
LIMITED PARTNERSHIP AND LOGAN
GENERATING COMPANY, L.P.**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
BPU DOCKET NO. _____

CERTIFICATION OF MARISSA E. HUMPHREY

MARISSA E. HUMPHREY, of full age, certifies as follows:

1. I am the Vice President of Regulatory Policy and Strategy of and for Atlantic City Electric Company (“ACE”). In light of the constraints associated with the COVID-19 pandemic, I am submitting this Certification in lieu of Verification in support of ACE’s requests in the above-captioned docket.
2. I hereby certify that, as Vice President of Regulatory Policy and Strategy, I am duly authorized to make this Certification on ACE’s behalf.
3. I further certify that the information and data contained in the Petition are true and correct to the best of my knowledge, information, and belief.
4. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: December 22, 2021



MARISSA E. HUMPHREY

Exhibit A

Chambers PPA and Amendments

AGREEMENT FOR PURCHASE
OF ELECTRIC POWER

between

ATLANTIC CITY ELECTRIC COMPANY
as Purchaser

and

CHAMBERS COGENERATION LIMITED PARTNERSHIP
as Seller

DATED AS OF

September 29, 1988

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TABLE OF EXHIBITS

- Exhibit A - Description of Seller's Facility.
- Exhibit B - PJM Minimum Generation Obligations and Procedures.
- Exhibit C - Technical Guidelines For Cogenerators and Small Power Producers (Dated October, 1985; Revised January, 1988).
- Exhibit D - Drawing Showing Interconnection and Point of Delivery.
- Exhibit E - Stipulation between Purchaser and the BPU Staff, ad BPU Order dated August 28, 1987 approving the Stipulation.
- Exhibit F - Technical Guidelines for Customer Service at Sub-Transmission and Transmission Voltages (Dated May, 1985).
- Exhibit G - Purchaser's Rules and Procedures for Determination of Generating Capability to Meet the Requirements of the PJM Interconnection, dated August, 1984.
- Exhibit H - Purchaser's Interconnection Study for Seller's Facility.
- Exhibit I - Methodology for Calculating Availability Factor.
- Exhibit J - Procedures for Billing Work Done at the Expense of Others.
- Exhibit L- Amendments

AGREEMENT FOR PURCHASE OF ELECTRIC POWER

This agreement (hereinafter referred to as the "Agreement") is entered into and effective as of this 29th day of September, 1988 by and between ATLANTIC CITY ELECTRIC COMPANY, 1199 Black Horse Pike, Pleasantville, New Jersey 08232 (hereinafter referred to as "Purchaser"), and CHAMBERS COGENERATION LIMITED PARTNERSHIP, having offices at P. O. BOX 3965, San Francisco, California 94119 (hereinafter referred to as "Seller").

WHEREAS, Seller is undertaking to acquire, construct, install, and operate a cogeneration facility of which 184,000 kilowatts will be interconnected to Purchaser's system (hereinafter referred to as the "Facility") all as more particularly described in Exhibit "A" attached hereto and incorporated as part of this Agreement, to be located within the electric service territory of Purchaser on property owned by E.I. Dupont de Nemours & Company, Inc. (hereinafter referred to as "Dupont") adjacent to the Chambers Works plant, New Jersey; and

WHEREAS, Seller intends to sell electric power and capacity to Purchaser, and Purchaser, in recognition of its obligations under the Public Utility Regulatory Policies Act of 1978 as implemented by the Federal Energy Regulatory Commission (hereinafter referred to as the "FERC") and the State of New Jersey Board of Public Utilities (hereinafter referred to as the "Board"), will purchase the Net Plant Output and capacity from the Facility; and

WHEREAS, it is necessary for Seller to obtain a long-term commitment for the purchase of its Net Plant Output and capacity in order to plan and obtain financing and other necessary commitments for the construction and operation of the Facility; and

WHEREAS, Purchaser expects to require added generating capacity on its system and desires an arrangement under which Purchaser shall have sufficient opera-

tional control over Seller's generating capacity such that the Facility can be dispatched upward or downward, i.e., operated at its maximum or minimum rated electrical capacity (or any point in between) to generate above Seller's Minimum Load when and if needed by Purchaser, and that in all other respects Purchaser will have sufficient control to be able to count Seller's Facility as part of its capacity for purposes of meeting Purchaser's obligations under the PJM Interconnection Agreement, as hereinafter defined, and associated guidelines and standards; and

WHEREAS, subject to Seller's obligations hereunder, Seller intends to sell electric energy and capacity to Dupont; and

WHEREAS, Seller and Purchaser have agreed to enter into this Agreement subject to Seller's obtaining all required financing and obtaining and maintaining all requisite governmental permits, licenses, waivers, franchises, easements, regulatory approvals and other approvals for the construction and operation of the Facility.

NOW THEREFORE, in consideration of the mutual promises, covenants and conditions contained herein, Purchaser and Seller agree as follows:

ARTICLE 1

DEFINITIONS

1.1. Definitions For purposes of this Agreement, the following terms shall have the following meanings:

- A. "Availability Factor" shall mean the ratio of Seller's Facility's availability to Purchaser's system's availability based on a contract year calculation of "Availability", as defined in Exhibit "I" attached hereto and made a part hereof.
- B. "Base Escalator" or "Base Index" shall mean the escalation index selected by Seller from those indices available under the Standard Offer

to be used to adjust the variable energy portion (Base) of the payment to Seller pursuant to Article 5 hereof.

C. "Billing Period" shall mean the period between any two consecutive regularly scheduled meter readings by Purchaser at Seller's Facility, nominally, one calendar month.

D. "Board" or "BPU" shall mean the State of New Jersey Board of Public Utilities or any successor thereto having jurisdiction over this Agreement.

E. "Contract Year" shall mean each of the successive twelve (12) month periods commencing with the Date of Commercial Operation.

F. "Date of Commercial Operation" shall have the meaning set forth in Article 4 hereof.

G. "Dispatchable" shall mean the capability to increase energy output above Minimum Load or decrease the energy output to Minimum Load and to correspondingly modify the voltage level of the Facility in response to directions from the System Control Center (i.e., within the time requirements of the PJM guidelines identified and incorporated as part of this Agreement, and as same may be amended from time to time after notice to Seller), consistent with the requirements of Articles 3 and 10 of this Agreement, including but not limited to Purchaser's rights under Article 3.4.

H. "Effective Date" shall mean September 29, 1988.

I. "Escalation Factor" for each calendar year for purposes of calculating the administrative fee specified in Article 5.2 hereof, shall mean the Consumer Price Index of the Bureau of Labor Statistics, United States Department of Labor (1967 = 100) for the Metropolitan Philadel-

phia/New Jersey area for the September preceding the calendar year divided by the indice for September, 1987. In the event the above-referenced index is discontinued, the National Consumer Price Index shall be utilized. In the event a new index is developed solely for the southern portion of New Jersey, then such index may be utilized upon the mutual consent of the parties. The calculation of the Escalation Factor shall be based upon the most recent calendar year for which such index has been published.

J. "Forced Outage" shall mean any outage caused by mechanical or electric equipment failure that either fully or partially curtails the electrical output of the Facility.

K. "Hourly Interchange Cost" shall mean the hourly interchange cost for Purchaser as such cost is defined by the PJM Interconnection, divided by the number of kilowatt-hours of energy delivered to the PJM Interconnection by Purchaser or received by Purchaser from the PJM Interconnection for each hour.

L. "Independent Engineer" shall mean the engineering firm to be designated by mutual agreement of Seller and Purchaser and any successor thereto designated by the same method.

M. "Indirect Costs" shall mean those reasonable costs described as indirect in Purchaser's then current "Procedures for Billing Work Done at the Expense of Others", as may be amended from time to time without notice to Seller, the current edition of which is attached hereto as Exhibit "J".

N. "Minimum Generation Emergency Condition" shall mean a condition declared by the PJM Interconnection Office in accordance with the

standards and procedures set forth in the "PJM Minimum Generation Obligations and Procedures", a copy of which is attached hereto as Exhibit "B".

- O. "Minimum Load" shall mean 46,000 kilowatts, subject without limitation to Purchaser's rights under Article 3.4.
- P. "Net Deliverable Capacity" shall mean the maximum net summer capability of the Facility deliverable to Purchaser at the Point of Delivery, as measured pursuant to Article 3.3A(iv).
- Q. "Net Plant Output" shall mean the amount of electrical energy delivered by Seller's Facility to the Point of Delivery.
- R. "Off-Peak Period" shall mean all hours of a week exclusive of the On-Peak Period.
- S. "On-Peak Period" shall mean the period from 9:00 A.M. to 11:00 P.M., seven days per week, or as otherwise designated by Purchaser, provided that such other designation results in a total on-peak period which is substantially equivalent in total annual hours to the above-designated On-Peak Period and provided further that Seller shall have consented to such other designation, which consent shall not be unreasonably withheld by Seller.
- T. "Ordinary Maintenance and Operations" shall mean that maintenance and operations customarily performed on other transmission or distribution facilities of like voltages. Ordinary Maintenance and Operations shall not cover replacement of equipment nor shall Ordinary Maintenance and Operations cover repairs due to Force Majeure as provided under Article 15 hereof.

U. "PJM Capacity Deficiency Charge" shall mean the rate determined annually by the Management Committee of the PJM Interconnection and approved by FERC or otherwise in effect pursuant to FERC practice, for short-term capacity supplied by PJM companies, which have capacity in excess of their PJM capacity obligation, to those PJM companies which are deficient in meeting their PJM capacity obligation.

V. "PJM Interconnection" or "PJM" shall mean the Pennsylvania-New Jersey-Maryland Interconnection, a power pool cooperatively operated under the Pennsylvania-New Jersey-Maryland (PJM) Interconnection Agreement originally entered into among the members thereof on September 26, 1956, as such Agreement has and may be amended or supplemented from time to time, or the successor thereof.

W. "Point(s) of Delivery" shall mean the location(s) where Purchaser's and Seller's facilities are interconnected, as shown on Exhibit "D".

X. "Purchaser's Interconnection Facilities" shall mean the transmission and/or distribution lines, transformers, circuit breakers, relaying and other devices that are to be installed or modified by Purchaser at the expense of Seller on Purchaser's side of the Point of Delivery to allow the delivery to Purchaser by Seller of the energy produced by Seller's Facility and the delivery to Seller's Facility of energy produced by Purchaser.

Y. "Prudent Electrical Practices" shall be those practices that are commonly used in prudent electrical engineering and utility operations to operate electric equipment within the constraints of safety, efficiency, economy and reliability.

Z. "Qualifying Facility" shall mean a facility that is a qualifying facility pursuant to Section 292.101 et seq. of FERC's rules in effect as of the Effective Date implementing the Public Utility Regulatory Policies Act of 1978.

AA. "Reserve Fund" shall mean the fund described in Article 13.4 hereof.

BB. "Scheduled Maintenance" shall be the periods of time during which any generation unit of the Facility is shut down totally or partially for routine maintenance operations in accordance with Article 10.5.

CC. "Seller's Facility" or "Facility" shall mean the cogeneration facility described in Exhibit "A", of which 184,000 kilowatts will be interconnected to Purchaser's system.

DD. "Seller's Interconnection Facilities" shall mean all the transformers, circuit breakers, relays, switches, synchronizing equipment control and protective devices that are to be installed or modified by Seller on Seller's side of the Point of Delivery in accordance with this Agreement.

EE. "Standard Offer" shall mean the Stipulation, including all exhibits attached thereto and incorporated therein, entered into between Purchaser and the Board's Staff and the Order of the Board dated August 28, 1987 approving that Stipulation. The Stipulation and the Board's Order are attached hereto as Exhibit "E".

FF. "Summer Season" shall mean during any calendar year the period from June 1st through November 30th.

GG. "System Control Center" shall mean Purchaser's System control center currently located at 1199 Black Horse Pike, Pleasantville, New Jersey.

HH. "System Emergency" shall mean a condition on Purchaser's or the PJM system which is likely to result in imminent, significant disruption of service to Purchaser's customers or is imminently likely to endanger life or property or would result in unsafe or unreliable operation.

II. "Winter Season" shall mean during any calendar year the period from December 1st through May 31st.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. This Agreement shall be binding on the parties as of the Effective Date and shall continue in effect for a term of thirty (30) years (the "Term"), commencing on the Date of Commercial Operation, subject to Paragraph 2.2 below.

2.2 Conditions Precedent to Commencement of Term. The conditions precedent to the commencement of the Term shall be:

- (i) Compliance by Seller with the requirements of Article 4;
- (ii) Seller's obtaining the requisite Qualifying Facility status as set forth in the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of the FERC implementing same, as in effect on the Effective Date;
- (iii) Execution by Seller of a contract with Dupont for the sale of steam and/or electricity and a site lease for the Facility; and
- (iv) A finding by Order of the BPU that this Agreement is reasonable and prudent for the Term of this Agreement and that Purchaser will be able to flow through to and/or fully and timely recover from its ratepayers through a Levelized Energy Adjustment Clause proceeding or comparable regulatory proceeding all purchased

energy and capacity costs incurred by Purchaser pursuant to this Agreement. Such Order by the Board shall be under such other terms and conditions as are acceptable to the parties hereunder.

After the Board issues its Order, the parties shall, within twenty (20) days of the date thereof, affirm in writing, executed by both parties, that this fourth condition precedent has been satisfied, and that the parties agree to such other terms and conditions as the Board may or shall have imposed.

In the event (1) said condition precedent with respect to BPU approval is not satisfied within three (3) months of the Effective Date; (2) the third condition precedent with respect to the Dupont contract and site lease is not satisfied or waived by Seller on or before November 1, 1988; or (3) after the BPU has issued its Order either party fails to affirm said satisfaction in writing within the period set forth above; this Agreement shall be void as of such date, the parties hereto shall thereafter be released from any and all obligations hereunder without further notice and the Reserve Fund shall be promptly refunded to Seller.

2.3 Effect of Termination. Termination of this Agreement pursuant to Articles 2.2(iii) or 2.2(iv) shall operate to terminate all obligations and liabilities of either party under this Agreement, and the Reserve Fund shall be promptly returned to Seller.

ARTICLE 3

BASIC RIGHTS AND OBLIGATIONS

3.1 Delivery of Electric Energy and Capacity. Seller shall sell and deliver and Purchaser shall purchase and accept on and after the Date of Commercial Operation and for the Term of this Agreement, the Net Plant Output from Seller's Facility on a dispatchable basis in accordance with Article 5 hereof. Purchases of Net Plant Output prior

to the commencement of the Term shall also be made by Purchaser in accordance with Article 5. In order to fulfill obligation to supply, Seller agrees to proceed and perform with reasonable promptness and diligence, the work necessary for construction of the Facility.

Purchaser agrees that in consideration of Seller's Facility being dispatchable, Seller shall, in addition to the monthly payment provided for in Article 5.1.B(i), be entitled to payment for the equivalent of 3500 hours of operation per Contract Year times the Net Deliverable Capacity, less 5,400 Kw, multiplied by the energy rate specified in Article 5.1 B(ii) and (iii) or Article 5.1C (a minimum of 58% of such hours will be during On-Peak Periods at the Net Deliverable Capacity, less 5,400 Kw); provided, however, that in the event Purchaser makes payment to Seller for periods during which Seller did not actually produce energy, then such payments by Purchaser shall be net of fuel and other operating expenses avoided by Seller during such periods (but such payments shall not be less than zero) and provided further that Seller's Facility was available for energy production for at least 3500 hours during the course of the Contract Year. Seller agrees that the minimum notice to cold start-up shall be eight (8) hours, the minimum notice to warm start-up shall be four (4) hours, the minimum notice to shutdown shall be two (2) hours and that the run-time between start-up and shutdown shall be ten (10) hours. Seller's Minimum Load shall be included in the 3500 hours referred to above.

3.2 Purchaser's Obligation. At Seller's option, Purchaser shall supply any energy required by Seller for purposes of stand-by, back-up, supplemental, interruptible and maintenance services for Seller's Facility under Purchaser's applicable tariff and contract terms approved by the BPU and in effect at the time of purchase. If Seller elects to purchase these requirements from Purchaser, Seller shall be charged the lesser of contracted for stand-by demand charges for alternate energy producers, or standard demand charges as provided in Purchaser's tariff. All payments for energy purchased shall be

billed in accordance with Purchaser's standard practices for all other customers and shall not affect any charges or payments subject to the section above. There shall be no right of offset by Seller for any charges incurred outside this Agreement. Metering of sales from Purchaser to Seller shall be pursuant to the provisions set forth in Purchaser's standard tariff for electric service. In the event Purchaser is required by the BPU or other governmental agencies to institute curtailment of energy deliveries to its customers, Purchaser may require Seller to curtail its purchase of electricity in the same manner and to the same degree as other customers within the same customer or rate class who do not own facilities for generating electricity.

3.3 Seller's Obligations.

A. Capacity Levels, Capacity Deficiencies and Capacity Testing. Seller acknowledges that Purchaser has entered into this Agreement in reliance on Seller's representation that a certain level of capacity will be available throughout the Term of this Agreement. Seller agrees capacity from the Facility shall be available as follows:

(i) During the Summer Season, a total of 187,600 Kw (the "Summer Capacity"); provided, however, that the capacity payment due Seller pursuant to Article 5.1B(i) shall be based on capacity levels not to exceed 184,000 Kw.

(ii) During the Winter Season, a total of 173,200 Kw (the "Winter Capacity").

(iii) Should the capacity of the Facility as determined pursuant to subparagraph (iv) hereof during, as the case may be, the Summer Season or the Winter Season be less than as set forth above, Seller shall be obligated to make deficiency payments as follows: (a) During the Summer Season in any calendar year, the PJM Capacity De-

iciency Charge times the difference between the capacity as determined pursuant to subparagraph (iv) hereof and 178,220 kilowatts; or

(b) During the Winter Season in any calendar year, the PJM Capacity Deficiency Charge times the difference between the capacity as determined pursuant to subparagraph (iv) hereof and 164,540 kilowatts. Seller shall continue to make deficiency payments until the Facility obtains 95% of Summer Capacity or Winter Capacity, as the case may be, according to PJM standards and tests as set forth below.

(iv) Both Summer Capacity and Winter Capacity shall be confirmed annually. The Summer Capacity suitable for the requirements of the PJM will be based, at Seller's discretion, on the Facility's performance on a test result corrected to standard conditions (as defined in PJM guidelines) in the months of June, July or August. The Winter Capacity suitable for the requirements of the PJM will be based, at Seller's discretion, on the Facility's performance or a test result corrected to standard conditions (as defined in PJM guidelines) in the months of December, January or February. In addition to the foregoing, Seller may retest the Facility during any other month for purposes of establishing capacity levels in accordance with the above requirements and thereby terminating Seller's obligation to continue paying deficiency payments pursuant to subparagraph (iii) above.

B. Qualifying Facility Status. Seller shall maintain those conditions during the term of this Agreement specified by the FERC and applicable to the Facility with respect to Qualifying Facility status as of the Effective Date. If Seller loses its Qualifying Facility status, this Agreement shall remain in effect except payment to Seller shall be

the lower of the Purchase Price under Article 5 hereof or ninety-nine percent (99%) of Purchaser's Hourly Interchange Cost multiplied by the kilowatt hours delivered until such time as Qualifying Facility status is restored. In the event Seller is unable for any reason to have Qualifying Facility status restored, Seller shall be entitled to file with FERC for approval of a tariff price for the remaining portion of the Base Term; provided, however, that Purchaser shall only be obligated to pay the lower of (i) the tariff price as approved by FERC, or (ii) the Purchase Price under Article 5 hereof. If Seller fails for any reason to have such FERC-approved tariff price within two (2) years of the date of loss of Qualifying Facility status, then the price hereunder shall be based on the above-referenced formula using Purchaser's Hourly Interchange Cost. Qualifying Facility status will be determined by Seller in accordance with the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of the FERC, presently in force and effect as of the Effective Date, once every Contract Year using annual average data, beginning at the end of the twenty-fourth (24th) month after the Date of Commercial Operation. Seller shall forward to Purchaser a copy of its report within thirty (30) days of such measurement of Qualifying Facility status.

C. Seller's Obligation to Provide Power During System Emergencies. At Purchaser's request, Seller shall use reasonable best efforts to provide Net Deliverable Capacity to Purchaser during a System Emergency. Seller agrees that during situations where the safety, reliability or security of Purchaser's system or that of the PJM Interconnection is threatened, the Seller shall, at Purchaser's request, use its reasonable

best efforts, to the extent consistent with Seller's obligations to other persons and subject to the requirements of Seller's Facility, to provide the energy or capacity above Net Deliverable Capacity as requested by Purchaser's System Control Center, and shall, if necessary, make its reasonable best efforts, to the extent consistent with Seller's obligations to other persons and subject to the requirements of Seller's Facility, to delay any Scheduled Maintenance of the Facility.

3.4. Exceptions To Purchaser's Obligation To Accept Net Plant Output. Notwithstanding the above, and in addition to the provisions of Article 15 of this Agreement, Purchaser shall be excepted from accepting Seller's Net Plant Output if:

A. After being provided with notice and an opportunity to cure, Seller's Facility fails to comply with (i) the Technical Guidelines for Cogenerators and Small Power Producers (Dated October, 1985; Revised January, 1988) as set forth in Exhibit "C"; and (ii) the Technical Guidelines for Customer Service at Sub-Transmission and Transmission Voltages (Dated May, 1985) as set forth in Exhibit "F"; both of which are attached hereto and incorporated herein as part of this Agreement.

B. A System Emergency occurs on the part of Purchaser's (or the PJM) system interconnected with Seller's Facility such that there would be no means of delivering the Net Plant Output to the remainder of Purchaser's system. Such refusal to purchase may occur on an instantaneous basis; provided, however, that Purchaser shall give Seller advance notice of such occurrence(s) to the extent practical under the circumstances then prevailing and shall give Seller an explanation of such occurrence(s) after the fact where advance notice is impractical.

- C. During any Minimum Generator Emergency Condition declared by PJM or Purchaser's System Control Center, Purchaser shall give notice to Seller in time for Seller's Facility to curtail the delivery of Net Plant Output to Purchaser, consistent with the PJM guidelines. Seller's Facility shall be treated in a manner consistent with all other comparable dispatchable units operated by Purchaser or dispatchable Qualified Facilities supplying Purchaser.
- D. Purchaser intentionally interrupts acceptance of Seller's Net Plant Output to conduct necessary maintenance of Purchaser's Interconnection Facilities or adjacent transmission and distribution facilities. In such instances, Seller will receive as much advance notice as possible but in no event less than seventy-two (72) hours prior to any such planned maintenance. Purchaser shall use its reasonable efforts in accordance with Prudent Electrical Practices to minimize such interruptions and to the extent reasonably possible to coordinate the same with Seller's maintenance under Article 10 hereof.
- E. In the reasonable opinion of Purchaser, Seller's Facility produces energy or energy and capacity of a character of service which may adversely affect the safety, reliability or security of Purchaser's equipment, facilities, personnel, or system or the safety, reliability or security of those of any other supplier of electricity to Purchaser or to Purchaser's customers, or does not meet Purchaser's obligation to the PJM in terms of safety, reliability or security, Purchaser shall notify Seller of this condition and allow Seller reasonable time to correct it. If Seller fails to correct the condition within a reasonable time, Purchaser may physically interrupt the flow of energy from the

Facility until the condition is corrected or Seller demonstrates to the reasonable satisfaction of Purchaser that Seller is operating in accordance with the operating standards set forth in Article 10.

Purchaser agrees to file a notice within five (5) working days with the BPU and provide Seller with reasonable advance notice in all cases of refusal to purchase from Seller. Purchaser will promptly resume the acceptance of Seller's Net Plant Output as soon as the reason for the interruption no longer exists. In the event of an instantaneous or other refusal to accept power as provided in this Article 3.4, Purchaser agrees to use its reasonable best efforts (consistent with Purchaser's existing obligations to restore service to its retail and wholesale customers and provided further that Seller will not be treated in a discriminatory manner with respect to any other Qualifying Facility) to correct any condition and to restore acceptance of such power. Interruption or reduction of deliveries shall be of no greater scope and of no longer duration than is necessary. During the period of reduction or interruption Purchaser shall not be obligated to make payments for other than energy actually delivered to Purchaser and capacity, as specified in Article 5 of this Agreement; provided, however, that this exception shall not reduce Purchaser's minimum purchase obligations under Article 3.1 hereof.

3.5 Prudent Electrical Practices. Seller and Purchaser agree that all actions required or taken under this Agreement including, but not limited to, this Article 3 shall be consistent with Prudent Electrical Practices.

3.6 Sales to DuPont. Purchaser acknowledges that Seller, pursuant to a separate agreement, will be providing some or all of the electric energy and capacity required by DuPont by means of generating capacity within the Facility that is not part of Summer Capacity or Winter Capacity, as the case may be. Purchaser further agrees that during periods in which Purchaser dispatches the Facility below Summer Capacity or Winter Capacity, as the case may be, Seller may sell to DuPont the output of the Facility which is in excess of the electric energy and capacity required by Purchaser.

ARTICLE 4

DATE OF COMMERCIAL OPERATION

4.1 The scheduled Date of Commercial Operation for Seller's Facility is October 1, 1993 and Seller shall use best efforts to have the Facility in commercial operation by said date, subject to the terms of this Agreement.

4.2 The actual Date of Commercial Operation shall be the day commencing at 12:01 A.M. following the day during which the equipment of the Facility and Seller's and Purchaser's Interconnection Facilities have reached a degree of completion and reliability such that they are capable of delivering energy continuously into Purchaser's system. For the purposes of this Agreement, said completion and reliability shall be deemed as having been reached when all of the following procedures have been successfully completed:

(i) The Seller has provided thirty (30) working days' advance written notice to Purchaser of the time that Seller proposes to begin demonstration of any of the Facility's electrical generation units completion and reliability. In the event of any change in the proposed demonstration date, prompt written notice will be given to Purchaser.

(ii) Purchaser, at its own expense, has the opportunity to have one or more designated representatives to observe all or part of said demonstration.

(iii) Each of the Facility's electrical generation units have been started, synchronized, connected and then disconnected from Purchaser's system a minimum of four (4) separate times. Two (2) of the disconnects in this procedure shall be remotely triggered from Purchaser's substation relay or other designated control point.

(iv) Each of the Facility's electrical generation units have been successfully started, synchronized, connected and operated in parallel with Purchaser's system for a continuous 48-hour period at not less than eighty percent (80%) of Net Deliverable Capacity, subject to Prudent Electrical Practices; provided, however, that Seller shall pay to Purchaser a deficiency payment computed in accordance with Article 3.3A for the difference between (a) 95% of Net Deliverable Capacity and (b) the amount of capacity determined to be available pursuant to this Article 4.2(iv) until Seller's Facility operates in parallel for a continuous 48-hour period at Net Deliverable Capacity.

(v) The Facility has demonstrated the capability to operate throughout the range of power factors and range of capacities required by Purchaser as set forth in subparagraph (iv) above with input from Seller and as set forth in Exhibit C. Upon successful completion of start-up and acceptance testing of the Facility, Purchaser will send written confirmation of test results to Seller.

(vi) Successful completion of the above requirements shall be determined by Seller and Purchaser, or failing their prompt concurrence thereon, by the Independent Engineer.

ARTICLE 5

PURCHASE PRICE AND OTHER CHARGES

5.1 Purchaser agrees to pay Seller, prior to the Date of Commercial Operation and during the Term of this Agreement, as follows:

A. For test energy received before the Date of Commercial Operation, the pricing structure shall be as follows:

- (i) An energy payment equal to the Hourly Interchange Cost times the energy delivered for all energy delivered at the Point of Delivery.
- (ii) No capacity payments shall be made prior to the Date of Commercial Operation.

B. On and after the Date of Commercial Operation, the pricing structure hereunder shall be based on the following formulas:

- (i) A monthly payment equal to: Net Deliverable Capacity x \$26.33/KW month x Availability Factor, where the Net Deliverable Capacity shall not exceed 184,000 kilowatts. Where the Availability Factor exceeds 0.90, its value shall be set to 1.0. Seller's availability calculated hereunder shall be based on the Net Deliverable Capacity and shall be calculated consistent with PJM guidelines for the appropriate period.
- (ii) For all energy delivered during On-Peak Periods, the price shall be: $\$0.021418 + \$0.018175/\text{KWH} \times I$ where I is the Base Escalator.

NOTE:

"Base Escalator" shall be the Coal Price, as defined by the annual average coal cost to NJ Utilities as reported on FERC Form 423 and determined pursuant to Page A-6 of the Stipulation attached hereto as Exhibit E.

I (for year N) = Cost of fuel as defined above, for the preceding year ($N-1$) relative to the cost of fuel in 1992; cost of coal in ($N-1$) divided by cost of coal in 1992 = I .

i.e., For year N , I then becomes:

$$\frac{\text{Indices in year } (N-1)}{\text{Indices in 1992}}$$

Values of I will be established in the first quarter of each year based on available published values of the indices.

(iii) For all energy delivered during Off-Peak Periods, the price shall be: $\$0.014713/\text{KWH} + \$0.012485/\text{KWH} \times I$ where I is the Base Escalator.

C. In lieu of the prices for energy provided for in Articles 5.1(B) (ii) and (iii) above, on or before 24 months from the date of the BPU order referred in Section 13.4(i) and Article 2 hereof, Seller shall have the option to elect the following prices, which election shall be binding on the Seller and Purchaser for the Term of this Agreement:

(i) For all energy delivered during On-Peak Periods the price shall be: $\$0.021418/\text{KWH} + (0.5060 \times \text{PJM Cost} \times I)$, where I is the Base Escalator.

NOTE:

"Base Escalator" shall be the Coal Price, as defined by the annual average coal cost to N.J. Utilities as reported on FERC Form 423 and determined pursuant to Page A-6 of the Stipulation attached hereto as Exhibit E.

I (for year N) = Cost of fuel as defined above, for the preceding year ($N-1$) relative to the cost of fuel in 1992; cost of coal in ($N-1$) divided by cost of coal in 1992 = I .

i.e., For year N , I then becomes:

$$\frac{\text{Indices in year } (N-1)}{\text{Indices in 1992}}.$$

Values of I will be established in the first quarter of each year based on available published values of the indices.

(ii) For all energy delivered during Off-Peak Periods, the price shall be: $\$0.014713/\text{KWH} + (0.3476 \times \text{PJM Cost} \times I)$, where I is the Base Escalator.

(iii) "PJM Cost" for purposes of calculating the pricing under Articles 5.1C (i) and (ii) above shall mean the unweighted average of the actual Hourly Interchange Cost (energy only) in dollars per kilowatt hours for every hour in calendar year 1992.

D. Payment for Net Plant Output delivered during periods of Minimum Generation Emergency Condition shall be as follows: The payment provided by 5.1 B(i) plus an energy rate calculated by multiplying the Kwh delivered times the Hourly Interchange Cost (energy only). This energy payment shall be calculated on an hour-by-hour basis.

5.2 Other Charges. The following charges shall be due Purchaser: (1) beginning in the first month after acceptance of the BPU order referred to in Article 2.2(iv), an administrative fee, initially \$2,000 per month, adjusted annually by the Escalation Factor, which administrative fee, as so adjusted, is also subject to further adjustment at Purchaser's reasonable discretion in the event Purchaser is required to spend in excess of twenty (20) man hours per month reviewing plans, specifications, drawings or other doc-

umentation relating to the design or construction of Seller's Facility, said adjustment to be based on the average hourly cost of Purchaser's reviewing personnel; (2) itemized charges for metering and testing requested by Seller and out of the normal course of business; (3) the costs (including Purchaser's standard overhead) of repair or replacement to any portion of Purchaser's Interconnection Facilities; and (4) a capacity deficiency payment, if applicable, pursuant to Article 3.3A.

ARTICLE 6

BILLING AND RECORDS

6.1 Billing and Payment.

A. For each Billing Period, Purchaser shall:

(i) read the meters, prepare a statement of payments due to Seller and submit the same to Seller, together with Purchaser's payment therefor, within thirty (30) days of the end of each Billing Period ("Due Date"). Such statement shall indicate the total kilowatt-hours and kilowatts delivered during each hour of the Billing Period.

(ii) prepare a statement of any payments due to Purchaser under this Agreement arising during such Billing Period and submit the same to Seller. Such statement shall set forth in detail the bases for calculation of each charge due. Seller shall make payment to Purchaser within thirty (30) days of receipt of Purchaser's statement ("Due Date").

B. If the transmittal of payment is not received by the applicable Due Date, the party responsible for said payment shall pay to the other party an interest charge on uncollected amounts which shall accrue

daily from the Due Date until the date upon which collection is made at the then current late payment charge for industrial customers prescribed in Purchaser's Standard Terms and Conditions as may be amended from time to time, but in no event less than two percent (2%) above the prime rate of Chase Manhattan Bank, N.A., or its successor, in effect as of the payment Due Date.

- C. Neither party shall have the right to offset any payments due to one party against payments otherwise due to the other party, except as provided in Article 13.3.
- D. In the event of a dispute as to any payment due under this Agreement, the parties agree that such dispute will not affect the obligation to pay any amounts due except as specifically provided in Articles 13.4 and 16. Interest shall accrue as provided in Article 6.1B on any payment subsequently determined not to have been properly due.

6.2 Records. Purchaser and Seller shall each keep properly stored and maintained at their offices in New Jersey and shall make available for the inspection, examination and audit of the other party, its authorized employees, agents or representatives and auditors at all reasonable times, such records as required by the PJM Interconnection and this Agreement and all data, documents and other materials relating to or substantiating any charges to be paid by or to Purchaser or Seller, as the case may be, for a minimum period of five (5) years from the date that such records are gathered under this Agreement.

6.3 PJM Amendments. Purchaser will provide Seller with a copy of any proposed changes to the PJM Agreement which have been filed with the Federal Energy Regulatory Commission or successor agency and which have been specifically requested by Seller.

ARTICLE 7

MEASUREMENT AND METERING

7.1 Metering. Purchaser shall install, own, maintain and test the meters and associated equipment which in Purchaser's judgment are needed to determine the amounts and time of delivery of electrical power and ending by Seller to Purchaser or Purchaser to Seller. For energy and power deliveries to Purchaser, the meter(s) shall be of a type to record hourly readings and shall be capable of being read by both Purchaser and Seller. Meters used to determine power and energy sales to Seller shall be in accordance with Purchaser's appropriate tariff. Seller may install check meters of the same type on Seller's Interconnection Facilities.

7.2 Measurement. All meters, instruments, and measuring devices affecting payments by Purchaser hereunder shall be tested and calibrated at such times as determined by Purchaser in accordance with the regulations of the BPU. Seller shall have the right to have a representative present at any such test. Seller shall have the right to require at Seller's expense a test of any of the above meters at least annually. In the event that any metering equipment used for measuring deliveries to Purchaser is found to be inaccurate by more than one percent (1%), deliveries shall be measured by reference to Seller's check meters or the meter readings for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by the Seller from the best available data, subject to review and acceptance by Purchaser. Purchaser shall promptly cause such meter(s) to be corrected.

ARTICLE 8

DELIVERY

8.1 Point of Delivery. Purchaser agrees to interconnect and operate in parallel its electric system with Seller's Facility and Seller agrees to interconnect the Facility with the electric system of Purchaser on the terms and conditions herein contained. Seller shall not operate the Facility in parallel with Purchaser's system until the conditions set forth in Article 4 have been met except to the extent necessary to meet the requirements of Article 4.

8.2 Title to Energy. Delivery of energy shall be completed when transmitted to the Point of Delivery, and title to energy shall pass to Purchaser upon delivery.

ARTICLE 9

INTERCONNECTION

9.1 Interconnection Costs Generally. The parties acknowledge that by mutual agreement an interconnection study has been undertaken by Purchaser and that a copy thereof has heretofore been delivered to and approved by Seller. A copy of the interconnection study is attached hereto as Exhibit H. Purchaser agrees to install the interconnection between Seller's Facility and Purchaser's system and provide all necessary labor and materials therefor. Subject to Article 15 hereof, Purchaser agrees to use reasonable best efforts to install the interconnection between Seller's Facility and Purchaser's system in a timely manner consistent with Seller's scheduled Date of Commercial Operation. Seller agrees to reimburse Purchaser for all costs, which shall be deemed to include costs for any and all modifications to Purchaser's system at any location over and above what Purchaser would have incurred, assuming Seller was only a customer, to meet the standby power requirements to be contracted for by the Facility, subject to the limitation established in Article 9.12.

9.2 Payment. The costs and charges for Interconnection between Seller and Purchaser shall be determined and paid as follows:

(1) The costs for supplying Seller will be estimated by Purchaser based on Purchaser supplying the Facility's maximum expected internal power requirements.

(2) The costs for Purchaser's accepting the maximum anticipated Net Plant Output from the Facility will be estimated by Purchaser.

(3) The excess of item (2) over Item (1) will be the contribution made by Seller. Such contribution shall be paid by Seller in the form of a non-refundable contribution in aid of construction for the Interconnection Facilities. Payment shall be made as follows: (i) forty percent (40%) of the contribution upon at least twenty (20) days' notice from Purchaser before the ordering of materials; (ii) the balance of costs incurred over and above such initial 40% of the contribution shall be paid during the course of construction based on monthly invoices prepared by Purchaser and submitted to Seller for payment within twenty (20) days of receipt by Seller; and (iii) upon Purchaser's completion of construction, Seller shall pay or be refunded the difference, if any, between Purchaser's actual construction costs and the sum of the initial 40% payment and Item (ii). Upon reasonable request by Purchaser after Seller has made the 40% payment, Seller shall provide, at Seller's option either (i) an irrevocable letter of credit or performance bond to guarantee payment of the above-mentioned remaining sixty

percent (60%) of the contribution in aid of construction, or (ii) evidence that funds sufficient to meet the contribution will be specifically committed by Seller's lender as part of project financing for disbursement to Purchaser consistent with this Agreement and the loan documents with Seller's construction lender.

9.3 Instrumentation. Meters, remote transmitting units, modifications to Purchaser's System Control Center, instrument transformers and auxiliary equipment of a standard type and manufacturer shall be part of Purchaser's Interconnection Facilities. Purchaser shall install, own and maintain, at Seller's expense, said equipment satisfactory to Purchaser and Seller. Meters shall provide signals to both parties on a real time basis.

9.4 Operation and Maintenance of Interconnection. All maintenance and other direct and Indirect Costs of operation and maintenance associated with the Purchaser's Interconnection Facilities related solely to operation of the Facility shall be borne by Seller for the term of this Agreement.

9.5 Rearrangement or Reinforcement of Interconnection. All changes, relocations, additions or modifications directly related to the Purchaser's Interconnection Facilities reasonably incurred to rearrange or reinforce the Purchaser's Interconnection Facilities or that are necessary to meet changing requirements and conditions of Purchaser's system related solely to operation of the Facility shall be at the expense of Seller. Purchaser reserves the right to make changes, including voltage conversions, in its transmission system used to purchase Net Plant Output at this location and any reasonable changes in Purchaser's electric system which would require changes in the Purchaser's Interconnection Facilities shall be deemed costs that are necessary to meet changing requirements and conditions of Purchaser's system. Any and all changes to Seller's Interconnection Facilities shall be subject to Purchaser's approval as provided in Article 10.3.

9.6 Relocation of Purchaser's Facilities. If Purchaser is required to relocate any of its facilities in the vicinity of Seller's Facility (which are essential to provide service to Seller's Facility) as a result of the construction, operation or maintenance of Seller's Facility, including ingress or egress to Seller's Facility whether on or off Seller's property, Seller agrees to reimburse Purchaser for all reasonable direct and indirect Costs associated with such relocation.

9.7 Protection of Purchaser's Facilities. In the event Purchaser reasonably determines that its existing facilities, in and around Seller's Facility, need to be either mechanically or electrically protected due to the construction, operation or maintenance of Seller's Facility, Seller agrees to reimburse Purchaser for all reasonable direct and Indirect Costs required to provide such protection.

9.8 Taxes On Interconnection Facilities.

A. Property Tax. If a direct real property tax on the portion of the Purchaser's Interconnection Facilities constituting real property and related solely to operation of the Facility (and over and above that which Purchaser would have incurred assuming Seller was a customer, to meet standby power requirements to be contracted for by Seller's Facility) is levied and/or assessed against Purchaser, Seller shall reimburse Purchaser for the amount of said direct real property tax paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment.

B. Federal Income Tax. If a federal income tax shall be imposed on the Purchaser upon or with respect to the construction and/or installation of Purchaser's Interconnection Facilities, and Purchaser's tax liability is greater as a result of such payments than it would have been if such payments had not been made, Seller shall fully reimburse Purchaser

for the amount of said increased tax liability paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment; provided, however, that Seller's obligation hereunder is subject to the \$10,000,000.00 limitation contained in Article 9.12, but only to the extent Seller's liability arises under laws in existence as of the Effective Date, it being the intention that any increased tax liability imposed on Purchaser as a result of changes in the law after the Effective Date is not subject to the limitation in Article 9.12 and shall be reimbursed by Seller consistent herewith.

C. New Jersey Tax. If there should be imposed on Purchaser any New Jersey tax upon or with respect to payments made by Seller for services rendered by Purchaser under this Agreement, including, but not limited to the construction and/or installation of Purchaser's Interconnection Facilities, or if any such payments by Seller should be required under such tax laws to be included in the receipts of the Purchaser which may at any time be reported for tax purposes, and the tax liability of Purchaser as a result of either of such events should be increased over and above an amount which would constitute such tax liability except for the happening of such event, Seller shall fully reimburse Purchaser for the amount of said increased tax liability paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment.

D. Any Different or Additional Tax. If any form of tax, other than income or excess profits tax, under any present or future federal, state or other law different from or in addition to the taxes for which participation in or payment by Seller is herein elsewhere in this

Agreement provided, should be levied and/or assessed against Purchaser with respect to any property, property right, commodity, service, or other thing involved in, growing out of, or accruing from the performance of this Agreement, which different or additional tax would not be required to be paid by Purchaser except as a result of the performance of this Agreement and, with respect to which such different or additional tax no obligation of Seller to participate or pay would have attached under the provisions of this Agreement elsewhere than in this paragraph, then in such event Seller shall fully reimburse Purchaser for the full amount of such different or additional tax paid by Purchaser within thirty (30) days of being notified by the Purchaser of said payment.

E. Increased Income Tax to Purchaser Arising from Seller's Payment or Reimbursement of Tax under the Preceding Provisions. Seller shall fully reimburse Purchaser for any net actual federal income tax or New Jersey tax ("Tax"), if any, arising out of any payment or reimbursement of tax by Seller under the preceding paragraphs of this Article 9.8. The amount reimbursed to Purchaser under this paragraph shall consist of the following components: (1) the initial amount of net actual Tax arising under this paragraph (the "First Amount"); (2) the net actual Tax on the First Amount (the "Second Amount"); (3) the net actual Tax on the Second Amount (the "Third Amount"); and (4) the net actual Tax on the Third Amount and on each succeeding amount until the final amount is less than one dollar.

F. Purchaser agrees to cooperate with Seller in attempting to minimize Seller's costs under this Article, provided Seller reimburses Purchaser

for all reasonable costs incurred by Purchaser in connection therewith, including reasonable attorneys fees and provided further that Seller shall indemnify Purchaser against any and all penalties, judgments, fines or other costs which may be imposed by any governmental authority as a result hereof. Notwithstanding the foregoing, Seller shall have the right to contest, appeal or seek abatement of any tax, levy or assessment against Purchaser and for which Seller may be required to reimburse Purchaser under this Article. Purchaser will cooperate with Seller in prosecuting any such contest, appeal or abatement, and no reimbursement shall be payable by Seller to Purchaser under this Article until such tax, levy or assessment is due by a final and non-appealable order by a court or agency of competent jurisdiction. Seller shall reimburse Purchaser for all reasonable costs incurred by Purchaser in connection with such contest, appeal or abatement request, including but not limited to interest charges, penalties, or reasonable attorneys' fees.

Purchaser agrees that Seller shall be promptly reimbursed for (i) any payments made by Seller under this Article 9.8, with interest in accordance with Article 6.1, to the extent that Purchaser is allowed to flow through such liability to its ratepayers; and (ii) any reductions in the tax liability of Purchaser, by reason of any net tax benefits realized by Purchaser, including depreciation deductions and tax credits, as a result of this Article 9.8 or any other provision of this Agreement, with interest in accordance with Article 6.1, but only to the extent that Purchaser is not required to flow through such benefits to its ratepayers.

9.9 Title to Interconnection. Title and risk of loss shall pass on the Date of Commercial Operation, at which time Purchaser shall have title to Purchaser's Intercon-

nection Facilities constructed by Purchaser at the expense of Seller and Seller shall have title to Seller's Interconnection Facilities.

9.10 Construction Notice. Seller shall give Purchaser not less than six (6) months notice of the date of its readiness to initiate interconnection at Seller's Facility.

9.11 Removal of Interconnection. When Seller's Facility will no longer supply energy to Purchaser, Seller shall reimburse Purchaser for net costs (minus salvage) incurred by Purchaser to disconnect and remove the Purchaser's Interconnection Facilities in accordance with Purchaser's then current "Procedure for Billing Work Done at the Expense of Others".

9.12 Amendments Regarding Interconnection Costs. The parties recognize and acknowledge that the issue of interconnection costs for Qualifying Facilities on Purchaser's system is presently being reviewed by Purchaser, the Board and other parties. Purchaser and Seller agree that this Agreement shall be subject to amendment to properly reflect the resolution of this issue; provided, however, that Seller agrees that so long as the total costs and charges of interconnection to be borne by Seller for interconnection equipment on Purchaser's side of the Point of Delivery, pursuant to this Article 9 other than Articles 9.4, 9.5, 9.6, 9.7, 9.11 and 9.8B (in cases where there is an increased federal income tax imposed on Purchaser due to changes in the laws in existence as of the Effective Date), including costs and charges for interconnection work specific to Seller's Facility, do not exceed \$10,000,000.00 under any such resolution or otherwise, that this Agreement shall remain in full force and effect and such costs and charges shall be borne by Seller. In the event that Seller reasonably and in good faith estimates that such costs and charges will exceed \$10,000,000.00, then Seller may terminate this Agreement by written notice to Purchaser within seven (7) days of Seller's determination; provided, however, that Seller's termination shall be void and this Agreement shall continue in full force and effect if, within four (4) months of receipt of Seller's termination

notice, Purchaser elects to pay directly or reimburse Seller, as the case may be, such costs and charges as are in excess of \$10,000,000.00. Any other provision of this Agreement notwithstanding, termination pursuant to this Article 9.12 shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination, and the parties shall be mutually released without liability to the other party except liability regarding the Reserve Fund as arising under Article 13.4, it being the intention that in such event amounts remaining in the Reserve Fund shall be promptly returned to Seller with accrued interest thereon, and that any amounts claimed by Purchaser in accordance with Article 13.4 and prior to termination hereunder shall be retained by Purchaser.

ARTICLE 10

CONSTRUCTION, OPERATION AND MAINTENANCE

10.1 Progress Reports. Commencing fifteen (15) days after the end of the first full calendar month after the Effective Date and each quarter thereafter, Seller shall provide Purchaser with a monthly progress report, which report shall detail Seller's efforts toward meeting the milestones specified in Article 13 hereof and provide Purchaser with such other information as Purchaser may reasonably require.

10.2 Seller's Property. Seller shall provide for the design, construction, installation, and maintenance of all equipment (other than Purchaser's meters and monitoring equipment specified in this Agreement) required to generate and deliver Net Plant Output which shall be located on Seller's side of the Point of Delivery.

10.3 Plans and Specifications. Seller agrees to comply with the interconnection, protection, and safety requirements and standards for customer-owned generating facilities set forth in Exhibits "C" and "F". The respective equipment and facilities owned by the parties shall be designed, installed and maintained in accordance with the applicable

portions of the National Electric Safety Code, the National Electric Code, and in the condition required by any governmental authorities having jurisdiction.

Seller shall submit to Purchaser the preliminary design and all specifications for the electrical system of the Facility for review of the safety of the interconnection. Purchaser shall notify Seller in writing of the outcome of Purchaser's review within forty-five (45) calendar days of receipt of the design and specifications. Purchaser's review and acceptance of Seller's specifications and drawings shall constitute authorization for Seller to commence construction and installation but shall not be interpreted as an endorsement or confirmation of any aspect of the design nor as any warranty whatsoever of the reliability, safety, or applicability of Seller's Facility. Purchaser's review shall not relieve Seller of its responsibilities or liabilities for its design and specifications. Purchaser's review, or failure to review, shall not subject Purchaser to responsibility for any design or operational defects or unsuitability of Seller's Facility including, but not limited to, strength, capacity, design, details, performance or adequacy of any aspects of Seller's Facility. Any review by Purchaser of the design, construction, operation, or maintenance of Seller's Facility is solely for ascertaining and assuring the safety of the interconnect. By making such review, Purchaser makes no representation as to the economic and technical feasibility, operational capability, and/or reliability of Seller's Facility. Seller shall in no way represent to any third party that any such review by Purchaser of Seller's Facility, including but not limited to any review of the design, construction, operation, or maintenance of Seller's Facility by Purchaser, is a representation by Purchaser, as to the economic and technical feasibility, operational capability, and/or reliability of said Facility.

10.4 Operating Standards. Seller shall not operate the Facility in parallel with Purchaser until the conditions set forth in Article 4 have been met except for the purposes of meeting the requirements of Article 4. Seller shall operate and maintain the

electrical generation and transmission equipment at the Facility in conformance with Prudent Electrical Practices. Specifically, Seller shall operate in accordance with the standards for interconnection and metering set forth in Exhibits C and F to this Agreement, the National Electrical Safety Code as modified from time to time, and any other applicable local, state or federal codes, rules, regulations, statutes, or ordinances. Purchaser may issue operating instructions to Seller in order to coordinate the safe and reliable operation of the Interconnection Facilities which shall be followed by Seller so long as such instructions would not jeopardize Seller's Facility.

Seller shall provide suitable equipment and operating practices to insure that the Facility is properly synchronized and voltages are maintained prior to closing of the main breaker so as to minimize to an acceptable level the effect on Purchaser's system and service to its other customers. Seller shall provide suitable equipment to prevent generator circuitbreaker closing when Purchaser's system is de-energized. Seller shall provide for the installation and maintenance of adequate protective equipment, in order to prevent damage or injury to the Facility and Interconnection Facilities, as well as the facilities and personnel of Purchaser, Purchaser's other customers, and Purchaser's other suppliers of electricity. Seller shall use whatever means necessary to minimize voltage swings and to maintain voltage levels in accordance with Prudent Electrical Practices.

Seller shall report to Purchaser's System Control Center at the time of occurrence, or as soon thereafter as practicable, the opening and closing times of its generator circuit breaker(s). Seller's closing of its generator circuit breaker without the prior permission of Purchaser's System Control Center shall be deemed a violation of Prudent Electrical Practices. Purchaser and Seller shall maintain appropriate operating communications and data channels through Purchaser's System Control Center at Seller's expense. Meter readings may be requested at any time by Purchaser's System Control Center. Except in an emergency, Seller shall give prior notice of not less than eight (8)

hours for any anticipated outage other than Scheduled Maintenance. Seller agrees to attempt to give notice to Purchaser as soon as practical in the event of emergencies or other unanticipated outages.

Seller shall maintain a power factor at the Point of Delivery consistent with the requirements set forth in Exhibit C.

10.5. Scheduled Maintenance. Seller may shut down the Facility or portions thereof for Scheduled Maintenance for a total period not to exceed forty-five (45) days during each contract year. This allowance may be used in increments of an hour or longer on a consecutive or non-consecutive basis. Seller may accumulate unused maintenance hours from one twelve-month period to another up to a maximum of one thousand eighty (1,080) hours (45 days) which shall then be added to the 45-day maintenance period allowed for that annual period. This accrued time must be used consecutively and only for scheduled major overhauls (i.e., planned scheduled outages of one (1) week or more). Seller shall provide Purchaser with the following advance notices: twenty-four (24) hours for scheduled outages of less than one day, one week for a scheduled outage of one day or more (except for scheduled major overhauls), and six months for a scheduled major overhaul unless the parties mutually agree to a shorter period. Seller shall not schedule maintenance from June 15 to September 15, or such other period designated by the Purchaser in accordance with the then current PJM requirements, during any year of this Agreement unless agreed to in advance by Purchaser in writing which agreement shall not be unreasonably withheld. Purchaser will review the effect of the proposed schedule on the overall maintenance schedules of PJM and Purchaser and advise Seller of problems that may be created by Seller's scheduled outage within thirty (30) working days of receipt of Seller's notice for scheduled major overhauls and suggest reasonable alternative schedules for such maintenance. The monthly payment set forth in Article 5.1B(i) shall continue to be made to Seller during such outages. Charges by Purchaser to Seller (if any) shall continue to be assessed as provided for in this Agreement.

10.6 Operating Statistics. Seller shall maintain and classify (in a timely manner) outage statistics in accordance with the then current PJM Interconnection outage classification procedures (which Purchaser shall provide to Seller in a timely manner) and shall supply such statistics to Purchaser as requested. Seller and Purchaser shall keep or cause to be kept such records as required by the PJM Interconnection. Upon notice in writing from Purchaser to Seller, Seller will keep or cause to be kept such other records (such as operating statistics) as the BPU or FERC or other regulatory body having jurisdiction over this Agreement, or any of the parties, may from time to time require Seller specifically, or cogenerators generally to keep.

10.7 Changes in Operating Voltage. Purchaser may, upon three (3) years' notice to Seller, change its nominal operating voltage level by more than plus or minus ten percent (10%) at the Point of Delivery, in which case Seller, at its own expense, shall modify its equipment as necessary to accommodate the modified nominal operating voltage level. Purchaser represents that as of the date of this Agreement it has no present plans for changing its operating voltage at the Point of Delivery.

ARTICLE 11

ACCESS TO FACILITIES

11.1 Access During Construction. Upon reasonable notice, Seller shall permit employees and inspectors of Purchaser to visit the Facility during construction to ascertain the status of construction. Purchaser shall comply with applicable construction site rules and limitations. Purchaser's rights hereunder shall also include the right to observe acceptance testing of major equipment for the Facility conducted at the equipment manufacturer's plant or other place of testing.

11.2 Inspections and Tests. Upon reasonable notice, Seller shall permit employees and inspectors of Purchaser, when properly identified, to enter Seller's premises during

normal business hours (except during emergencies) in order to read meters and instruments, perform maintenance on Purchaser's equipment and make equipment repairs, to conduct such operating tests as are necessary to ascertain that protective devices function properly, to examine and test Purchaser's meters and monitoring equipment, and to examine all other services and equipment related thereto provided that Purchaser's employees and inspectors shall not interfere with Seller's normal operation and shall comply with Seller's safety and related standards and conditions. Purchaser shall have the further right to request Seller to load the Facility for its own use or for tests; provided, however, that such operation shall be carried out in accordance with Prudent Electrical Practices, under the direct supervision of Seller and Purchaser shall pay the full Purchase Price under Article 5 for all electrical output.

11.3. Easements. Seller shall grant in favor of Purchaser such easements or rights-of-way with respect to the property on which Seller's Facility is located that are necessary to construct, operate, maintain, replace and remove all or any portion of the Purchaser's Interconnection Facilities. In the event that easements or right-of-way are required on property other than that of Seller (which necessity shall be mutually determined by the parties), Seller shall provide such easements or rights-of-way. If Seller is unable to provide such easements or rights-of-way, all obligations of Purchaser pursuant to this Agreement shall be suspended until and unless such easements or rights-of-way are provided; provided, however, that Purchaser will use reasonable efforts to assist Seller in acquiring such easements or rights-of-way at Seller's sole cost and expense. All costs of easements or rights-of-way, including the acquisition and maintenance costs thereof, shall be borne by Seller and all such easements or rights-of-way are subject to the prior review and acceptance of Purchaser.

ARTICLE 12

LIABILITY AND INDEMNIFICATION

12.1 Limitation of Liability. Neither the Purchaser nor the Seller, nor their respective officers, directors, partners, agents, employees or affiliates, shall be liable to the other party or its affiliates, officers, directors, partners, agents or employees for claims for incidental, special, indirect or consequential damages of any nature connected with or resulting from performance or non-performance of this Agreement, including, without limitation, claims in the nature of lost revenues, income or profits or losses, damages or liabilities under any financing, lending or construction contracts, agreements or arrangements to which the Seller or Purchaser may be party irrespective of whether such claims are based upon warranty, negligence, strict liability, contract, operation of law or otherwise. Nothing in this Article 12.1 shall limit either party's rights or remedies to recover, in an appropriate action, direct damages for a breach of this Agreement as provided in Article 13.2. Nothing in this Agreement shall be construed to create any duty to, standard of care with respect to, or any liability to any person not a party to this Agreement.

12.2 Indemnification. The Seller hereby agrees to indemnify, defend and hold harmless the Purchaser, its officers, directors, agents, partners, employees and affiliates against all loss, damage, expense, and liability to third persons for injury to or death of persons or for injury to property, caused by the gross negligence or wilful misconduct of Seller, its employees, contractors or agents with respect to the construction, ownership, operation, or maintenance of Seller's Facility. The Purchaser hereby agrees to indemnify, defend and hold harmless the Seller, its officers, directors, agents, partners, employees and affiliates against all loss, damage, expense and liability to third persons for injury to or death of persons or for injury to property, caused by the gross negligence or wilful misconduct of Purchaser, its employees, contractors or agents with respect to the

construction, ownership, operation or maintenance of Purchaser's Interconnection Facilities or Purchaser's system.

Each party hereto shall promptly furnish the other party with written notification (but in no event later than ten (10) days prior to the time any response is required by law) after such party becomes aware of any event or circumstance which might give rise to such indemnification. At the indemnified party's request, the indemnifying party shall defend any suit asserting a claim covered by this indemnity and shall pay all costs and expenses (including reasonable attorney's fees and expenses) that may be incurred in enforcing this indemnity. The indemnified party may, at its own expense, retain separate counsel and participate in the defense of any such suit or action. The indemnifying party shall not compromise or settle a claim hereunder without the prior written consent of the indemnified party; provided, however, that in the event such consent shall be withheld, then the liability of the indemnifying party shall be limited to the aggregate of the amount of the proposed compromise or settlement, the amount of counsel fees and expenses outstanding at the time such consent shall have been withheld, and the amount of any outstanding claim against which indemnification applies and which is not covered by the proposed compromise or settlement (together with all costs and expenses associated with such outstanding claim). Thereafter, the party withholding such consent shall hold harmless and reimburse the indemnifying party, upon demand, for the amount of any additional liability, counsel fees and expenses incurred by the indemnifying party over and above the amounts described above after the time such consent shall have been withheld.

ARTICLE 13

BREACH, TERMINATION, AND REMEDIES

13.1 Definition of Breach. A breach of this Agreement shall be deemed to exist if for reasons other than Force Majeure as specified in Article 15:

- A. Either party fails to make payment of any amounts due the other party under this Agreement, which failure continues for a period of thirty (30) days after notice of such non-payment.
- B. Either party fails to substantially comply with any other material provision of this Agreement, which failure continues for a period of thirty (30) days after notice of such non-performance, unless the non-performing party has commenced to cure such non-performance within the thirty (30) day notice period and is thereafter diligently pursuing such efforts. With respect to the Facility's failure to achieve at least 95% of Summer Capacity or Winter Capacity as specified under Article 3.3, Seller shall not be in breach under this paragraph if Seller makes deficiency payments described therein to the extent applicable under Article 3.3A.
- C. Seller fails to deliver any Net Plant Output for more than one hundred twenty (120) consecutive days, or more than one hundred eighty (180) days in any three hundred sixty-five (365) day period, subsequent to the Date of Commercial Operation, not including any days attributable to any Forced Outage, any Scheduled Maintenance or Purchaser's actions under Article 3.4.
- D. Seller sells any Net Deliverable Capacity agreed to be sold under this Agreement to any party other than Purchaser except as provided in Article 3.6.
- E. The Date of Commercial Operation does not occur on or before October 1, 1995.
- F. By order of a court of competent jurisdiction, a receiver or liquidator or trustee of either party or of a substantial part of the assets of

either party shall be appointed, and such receiver or liquidator or trustee shall not have been discharged within a period of sixty (60) days; or if by decree of such a court, a party shall be adjudicated bankrupt or insolvent or a substantial part of the assets of such party shall have been sequestered, and such decree shall have continued undischarged and unstayed for a period of sixty (60) days after the entry thereof; or if a petition to declare bankruptcy or to reorganize a party pursuant to any of the provisions of the Federal Bankruptcy Act, as it now exists or as it may hereafter be amended, or pursuant to any other similar state statute applicable to such party, as now or hereafter in effect, shall be filed against such party and shall not be dismissed within sixty (60) days after such filing; or

G. If either party shall file a voluntary petition in bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; or, without limitation of the generality of the foregoing, if a party shall file a petition or answer or consent seeking relief or assisting in seeking relief in a proceeding under any of the provisions of the Federal Bankruptcy Act, as it now exists or as it may hereafter be amended, or pursuant to any other similar state statute applicable to such party, as now or hereafter in effect, or an answer admitting the material allegations of a petition filed against it in such a proceeding; or if a party shall make an assignment of a substantial part of its assets for the benefit of its creditors, or if a party shall become unable to pay its debts generally as they become due; or if a party shall consent to the appointment of a receiver or receivers, or trustees, or liquidator or liquidators of it or of all or a substantial part of its assets.

13.2 Remedies for Breach.

A. If either party claims that the other party has breached this Agreement, as defined in Article 13.1, then subject to the provisions of Articles 15 and 18.9 hereof, the non-breaching party may terminate this Agreement by giving written notice of such breach and intention to terminate to the other party, which termination shall be effective no earlier than the thirtieth (30th) day following the date of said notice whereupon the terminating party shall be excused and relieved of all obligations and liabilities under this Agreement, except those liabilities incurred before the effective of termination. The non-breaching party may thereafter exercise its rights and remedies available at law to recover, in an appropriate action, direct damages against the breaching party.

B. Both parties shall have the obligation and shall use best efforts to mitigate any such damages.

13.3 Purchaser's Right to Operate Facility. In lieu of Purchaser's rights under this Article 13 relating to termination, but in addition to all of Purchaser's other rights under this Article 13 in the event of a breach by Seller as specified in this Article 13 and if operation of the Facility is not assumed by any financier or assignee of the Seller, Purchaser shall have the right but under no circumstances the obligation to assume operational responsibility for the Facility in the place and stead of Seller in order to complete construction, continue operation or complete any necessary repairs so as to assure uninterrupted availability of electric power; provided, however, that Purchaser's rights under this Article 13.3 shall be subordinate to the rights of any Lender providing financing for the Facility under Article 18.9 hereof. In no event shall Purchaser's election to operate the Facility be deemed to be a transfer of title or a transfer of Seller's

obligations as owner thereof. During any period in which Purchaser operates the Facility, Purchaser shall pay all fuel, maintenance, repairs, insurance and other operating costs thereof only to the extent that such costs to Purchaser may be offset by deducting the costs thereof from payments which would normally be due to Seller under this Agreement, and shall continue to pay the capacity charge set forth in Article 5.1B hereof. During any period in which Purchaser operates the Facility, Purchaser shall exercise its reasonable best efforts to produce and deliver electrical energy subject to the Facility being operable at the time of Purchaser's takeover, or later being made operable by repairs or otherwise.

13.4 Purchaser's Right to Retain Reserve Fund as Liquidated Damages. Seller acknowledges and understands that Purchaser has entered into this Agreement in reliance on and in consideration of Seller's representation that Seller's Facility will be in operation and be rated capacity for purposes of the PJM no later than the scheduled Date of Commercial Operation and, in addition, that Purchaser will include Seller's Facility in its various capacity forecasts for the PJM and otherwise effective June 1, 1988. Seller further acknowledges and understands that in order to meet its obligations to its retail and wholesale customers as a public utility, Purchaser must have adequate assurance that construction of Seller's Facility is proceeding in a timely fashion in order to adequately forecast and meet its system's capacity needs as well as to avoid incurring short-term energy costs or capacity deficiency payments from the PJM. In accordance with the Standard Offer, Seller has previously deposited with Purchaser on January 6, 1988 the sum of One Million Six Hundred Seventy Thousand Dollars (\$1,670,000.00) and on September 29, 1988, the sum of One Hundred Seventy Thousand Dollars (\$170,000.00) (collectively, and together with accrued interest thereon, the "Reserve Fund"), to secure Seller's timely construction and operation of Seller's Facility. The Reserve Fund has been deposited in Purchaser's general corporate account and is accruing interest at Purchaser's short-term cost of capital.

Based on the foregoing, and in addition to all of Purchaser's rights and remedies as set forth in Articles 13.1, 13.2 and 13.3 and Seller's rights under Articles 15 and 18.9 hereof, Seller agrees that Purchaser shall have the right in each instance to retain so much of the Reserve Fund as is set forth below, plus accrued interest thereon, as liquidated damages if any one or more of the following milestone dates have not been satisfied within the time periods herein established unless delayed by an event of Force Majeure:

(i) Five percent (5%) in the event Seller shall have failed to obtain and deliver to Purchaser fuel supply contracts within 24 months from the BPU order referred to in Article 2 hereof. For purposes of this Article, fuel supply contracts shall mean agreements with coal suppliers to provide 100% of the coal required for the first 5 years of commercial operation.

(ii) Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser all required environmental permits (local, state and federal) within 36 months from the BPU order referred to in Article 2 hereof.

(iii) Five percent (5%) in the event Seller shall have failed to obtain and deliver to Purchaser firm supply and price commitments from reputable manufacturers of major equipment within 24 months from the BPU order referred to in Article 2 hereof. Major equipment shall be deemed to include: boilers, turbine, and steam condensers.

(iv) Five percent (5%) in the event Seller shall have failed to prepare and deliver to Purchaser all necessary detailed engineering drawings within 24 months from the BPU order referred to in Article 2 hereof. Detailed engineering drawings shall be deemed to consist of a

one-line electrical drawing, site plan, heat and mass-flow diagrams, general arrangement drawings showing major equipment and drawing schedule.

(v) Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser evidence of financial commitments for construction and permanent financing, subject only to such conditions as are reasonably satisfactory to Purchaser and sufficient to complete Seller's Facility, within 36 months from the BPU order referred to in Article 2 hereof. For purposes of this Article, satisfactory evidence of financial commitments consist of binding commitments of lenders and equity participants sufficient to fund 100% of construction and permanent financing.

(vi) Fifteen percent (15%) in the event Seller shall have failed to commence construction (as evidenced by active foundation construction) of Seller's Facility within three (3) years of the BPU order referred to in Article 2 hereof;

Purchaser shall deliver written notice to Seller (by registered or certified mail) of Purchaser's election to retain the Reserve Fund (or applicable portion thereof), whereupon receipt of such notice Seller shall have an additional thirty (30) days to comply with the requirements hereof. If Seller shall have failed to cure said breach within the additional thirty (30) day cure period, except in the event of force majeure as defined in Article 15 then Purchaser shall be entitled to retain the Reserve Fund (or applicable portion thereof) without further notice to Seller.

Purchaser shall return fifty percent (50%) of the Reserve Fund (or applicable portion thereof), together with accrued interest thereon, to Seller within thirty (30) days of Seller's notice to Purchaser that all or certain of the milestone dates established here-

in have been complied with and that Seller is entitled to the return of the Reserve Fund (or applicable portion thereof), provided that Purchaser shall not have objected in writing to said return based on Purchaser's good faith claim that Seller has not so complied, in which case Purchaser shall retain only so much of the Reserve Fund as may relate to the matter in dispute.

The remaining fifty percent (50%) of the Reserve Fund shall continue to be held by Purchaser as security for Seller's timely operation of Seller's Facility and shall be either returned to Seller or retained by Purchaser as follows:

- (i) In the event Seller's Facility is operational within the meaning of this Agreement on or before the scheduled Date of Commercial Operation, Purchaser shall return the balance of the Reserve Fund within thirty (30) days of said date;
- (ii) In the event Seller's Facility is operational within twelve (12) months after the scheduled Date of Commercial Operation, Purchaser shall be entitled to retain an amount equal to Net Deliverable Capacity X PJM Capacity Deficiency Charge for each day after the scheduled Date of Commercial Operation, but in no event will the amount retained exceed 50% of the Reserve Fund, plus accrued interest; or
- (iii) In the event Seller's Facility becomes operational more than twelve (12) months but less than twenty-four (24) months after the scheduled Date of Commercial Operation, Purchaser shall be entitled to retain an amount equal to Purchaser's cost to obtain Net Deliverable Capacity, but in no event will the amount retained exceed 100% of the Reserve Fund. This provision shall take effect only if Seller replenishes the Reserve Fund on or before the 365th day after the scheduled Date of Commercial Operation.

ARTICLE 14

INSURANCE

14.1 Prior to the Interconnection of the Facility with Purchaser's system and until termination of the Agreement, Seller shall obtain and maintain in force, as hereinafter provided, property insurance for the full replacement value of Seller's Facility, blanket comprehensive general liability insurance including all risk endorsements, including contractual liability coverage with a combined single limit of not less than ten million dollars (\$10,000,000.00) each occurrence, and worker's compensation coverage. The insurance carrier or carriers and form of policy to be used by Seller shall be subject to prior submission to, and approval by, Purchaser to assure compliance with provisions of this Article 14. Seller shall provide to Purchaser fifteen (15) days prior to the commencement of construction evidence of satisfactory insurance coverage. Prior to the date Seller's Facility is first operated in parallel with Purchaser's system, Seller shall (i) furnish certificate(s) of insurance to Purchaser which certificate(s) shall provide that such insurance shall not be terminated nor expire except upon thirty (30) days prior written notice to Purchaser, and (ii) maintain such insurance in effect for so long as Seller's Facility is operated in parallel with Purchaser's system, and shall bear in substance the following clauses:

A. In consideration of the premium charged, Purchaser, its directors, officers and employees are named as additional insureds on Seller's insurance with respect to all covered liabilities arising out of Seller's use and ownership of Seller's Facility.

B. The inclusion of more than one insured under this policy shall not operate to impair the rights of one insured against another insured; and the coverages afforded by this policy will apply as though separate

policies had been issued to each insured. The inclusion of more than one insured will not, however, operate to increase the limit of the carriers' liability. Purchaser will not, by reason of its inclusion under this policy, incur liability to the insurance carrier for payment of premium for this policy.

C. Any other insurance carried by Purchaser which may be applicable, shall be deemed excess insurance and Seller's insurance primary for all purposes despite any conflicting provision in Seller's policy to the contrary.

D. It is expressly agreed and understood that the insurer(s) of Seller's Facility, naming Purchaser as an additional insured, shall waive any right it has to subrogation with respect to Purchaser.

14.2 Seller shall comply with all reasonable loss control recommendations made by Purchaser's insurance carriers as a condition of issuance, continuation or renewal of Purchaser's policies of insurance at Seller's sole cost and expense to the extent such recommendations are utilized by Purchaser in Purchaser's comparable facilities. If Seller fails to comply with any provision of this Article, Seller shall, at its own cost, defend, indemnify, and hold harmless Purchaser, its directors, officers, employees, agents, assigns, and successors in interest from and against any and all loss, damage, claim, cost, charge, or expense of any kind or nature (including direct, indirect, or consequential loss, damage, claim, cost, charge, or expense, including attorney's fees and other costs of litigation) resulting from the death or injury to any person or damage to any property, including the personnel and property of Purchaser, to the extent that Purchaser would have been protected had Seller complied with all of the provisions of this Article.

14.3 In addition to and not by way of limitation of any of Purchaser's other rights and/or remedies under this Agreement, if Seller fails to continuously comply with the

requirements of this Article 14 within forty-five (45) days following written notice from Purchaser of such failure, Purchaser shall have the right to immediately remove the Seller from interconnection with Purchaser's system and shall not permit reconnection until such time as the requirements of this Article have been met. If Seller or its assignees fails to comply with the requirements of this Article and has not to Purchaser's reasonable satisfaction demonstrated its efforts to cure within an additional sixty (60) day time period after written notice to Seller and/or its assignees, Purchaser may terminate this Agreement and Seller shall satisfy all obligations due Purchaser that are outstanding. The provisions of this Article shall survive the term of this Agreement.

ARTICLE 15

FORCE MAJEURE

15.1 Except for the obligations of either party to make payments under this Agreement for amounts due prior to the occurrence of an event of force majeure, either party shall be excused from performance and shall not be considered to be in default in respect to any obligation hereunder, if failure of performance shall be due to an event of force majeure. The term "force majeure" shall mean any cause beyond the control of the party affected, including, but not limited to, failure of facilities due to drought, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, strike or labor difficulty, accident or curtailment of supply, unavailability of construction materials or replacement equipment beyond the affected party's control, Forced Outage, inability to obtain and maintain rights-of-way, permits, licenses, and other required authorizations from any local, state, or federal agency or person for any of the facilities or equipment necessary to provide service hereunder, and restraint by court. Neither party shall be required to prevent or settle a strike against its will. However, in the event of a strike affecting Purchaser's system or Seller's Facilities, Seller and Purchaser

shall use reasonable best efforts to operate their respective facilities with management personnel.

15.2 If either party's ability to perform its obligations under this Agreement, is affected by an event of force majeure described above, such party shall promptly, upon learning of such event and ascertaining that it will affect its performance hereunder, give notice to the other party stating the nature of the event, its anticipated duration, and any action being taken to avoid or minimize its effect. The burden of proof shall be on the party claiming force majeure pursuant to this Article 15.

15.3 The suspension of performance shall be of no greater scope and no longer duration than is required. The excused party shall use its reasonable best efforts to remedy its inability to perform.

15.4 No obligations of either party which arose before the occurrence of an event of force majeure causing the suspension of performance shall be excused as a result of such occurrence. The obligation to pay money in a timely manner for obligations and liabilities which matured prior to the occurrence of an event of force majeure is absolute and shall not be subject to the force majeure provisions.

ARTICLE 16

GOVERNMENTAL AUTHORITY

In addition to the rights of the parties hereunder, including but not limited to Article 15 hereof, in the event any of the material terms and conditions hereof shall without fault of either party be or become impossible of performance on account of any law, statute, ordinance, order or regulation passed, adopted or promulgated by any governmental authority, the parties hereto shall be excused for any failure of performance caused by such impossibility of performance and the party which has not been rendered incapable of performing shall be entitled to terminate this Agreement upon thirty (30)

days written notice; provided, however, that this Article 16 shall not be invoked by either party if (i) the validity, scope or application of any such law, statute, ordinance, order or regulation is diligently and in good faith being challenged or under appeal by the other party; and (ii) the party challenging same agrees to reimburse the non-challenging party for all costs of litigation, including reasonable attorneys' fees, in the event such challenge is unsuccessful. Termination pursuant to this Article 16 shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination and the parties shall be mutually released without liability to the other party except liability regarding the Reserve Fund as arising under Article 13.4, in which event the Reserve Fund shall be promptly returned to Seller or retained by Purchaser as provided in Article 13.4.

ARTICLE 17

ARBITRATION OF DISPUTES

17.1 In any matter where the BPU does not have jurisdiction, any controversy or dispute arising out of or relating to this Agreement or the breach thereof shall be settled by arbitration except as limited by Article 17.2 hereof. Such arbitration shall be effected by arbitrators selected as hereinafter provided and shall be conducted in accordance with the rules, existing at the date thereof, of the American Arbitration Association. The dispute shall be submitted to three arbitrators, one arbitrator being selected by Seller, one arbitrator being selected by Purchaser, and the third being selected by the two so selected, or if they cannot agree on a third, by the American Arbitration Association. In the event that either Seller or Purchaser, within fifteen (15) days after any notification of any demand for arbitration hereunder, shall not have selected its arbitrator and given notice thereof by registered or certified mail to the other, such arbitrator shall be selected by the American Arbitration Association. The meetings of the arbitrators

shall be held at such place or places in southern New Jersey or elsewhere, as agreed upon by the arbitrators. Judgment may be entered on any award rendered by the arbitrators in any court having jurisdiction. During the pendency of any arbitration proceeding, the parties shall continue making timely payments due under the terms of this Agreement and the failure to do so shall constitute a breach of this Agreement. There shall be added to any monetary award for sums found to have been due under this Agreement an interest charge calculated the same manner as for late payments under Article 6.1 hereof. The cost of arbitration shall be borne in full by the losing party.

17.2 In the case of any dispute or controversy between Purchaser and Seller with respect to the amount of any payment made or to be made by either party to the other pursuant to this Agreement, the party aggrieved shall notify the other party in writing of any such dispute or controversy. Such notice must be made within sixty (60) days after the discovery of facts underlying the dispute or controversy. The notice shall set forth in reasonable detail the reasons for the dispute or controversy. Both parties agree not to make any demand for arbitration pursuant to Article 17.1 above, or to take any other action for a period of sixty (60) days following said notice in order to provide the party receiving same with the opportunity to respond, during which sixty (60) day period the parties shall continue to perform pursuant to the terms of this Agreement and the failure to do so shall constitute a breach of this Agreement.

ARTICLE 18

MISCELLANEOUS

18.1 Effect of Agreement. No undertaking by one party to the other under any provision of this Agreement shall constitute the dedication of that party's system or any portion thereof to the other party, or to the public or affect the status of Purchaser as an independent public utility corporation or Seller as an independent entity and not a

public utility. Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a party to it.

18.2 Law Governing. This Agreement shall be governed by and construed in accordance with the laws of the State of New Jersey.

18.3 Non-Discrimination Provision. The parties mutually agree and covenant that in the performance of this Agreement, they shall not discriminate against any person or groups of persons on the grounds of race, creed, color, national origin, ancestry, age, sex or marital status, in any manner prohibited by the laws of the United States or of the State of New Jersey, as applicable to the parties.

18.4 Notices. All notices hereunder shall be sent by immediate telex or telecopy and confirmed in writing by registered or certified mail, postage prepaid. If to Seller, the following address shall be used:

Chambers Cogeneration Limited Partnership
P. O. Box 3965
San Francisco, California 94119

Attention: J. L. Moore, Jr.

If to Purchaser, the following address shall be used:

Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, New Jersey 08232

Attention: Manager, Contract Capacity

Seller and Purchaser, by like notice, may designate any further or different addresses to which notice shall be sent.

18.5 Severability. If any clause, provision, or section of this Agreement be ruled invalid by any court of competent jurisdiction, the invalidity of such clause, provision, or section shall not affect any of the remaining provisions hereof.

18.6 Entire Agreement. This Agreement and all Exhibits attached hereto (A through J, inclusive) and made a part hereof constitute the entire agreement between the

parties with respect to the matters contained herein and all prior agreements with respect thereto are superseded hereby. Each party confirms that it is not relying on any oral representations or warranties of the other party except as specifically set forth herein.

18.7 Amendment and Waiver. This Agreement may be amended, modified, superseded, or cancelled, and any of the terms hereof may be waived, only by a written instrument executed by both parties' duly authorized representatives hereto or, in the case of a waiver, by the party waiving compliance. The failure of either party to require performance of any provision hereof shall in no manner affect the right at a later time to enforce the same. No waiver by either party of any condition or of any breach of any term of the Agreement shall be construed as a further or continuing waiver of any such condition or breach or as a waiver of any other condition or of any breach of any other term.

18.8 Several Obligations. Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the parties are intended to be several and not joint or collective. Each party shall be individually and severally liable for its own obligations under this Agreement.

18.9 Project Financing. The parties acknowledge that construction of the Facility will require financing by a lender and that such lender will require the financing to be secured by a first lien upon the Facility and other assets of the Seller, including a collateral assignment of this Agreement and all rights and obligation of Seller hereunder. In order to facilitate the obtaining of such financing, and notwithstanding any provision hereof expressly or impliedly to the contrary, Purchaser hereby confirms its agreement that in the event of any breach or violation on the part of Seller of any provision of this Agreement or the occurrence of any other event, which Purchaser may claim as grounds for terminating this Agreement or for terminating acceptance of power from the Facility

(except for a period where safety considerations require it), or for withholding or termination of any obligation to make any payment now or hereafter due to Seller hereunder, that Purchaser (having received prior written notice of the name and address of lender) will give written notice to lender thereof. Lender shall have 60 days next following the giving of such notice within which to effect, or commence and diligently pursue the completion of, a cure of such violation and to exercise its rights and remedies under its loan documents with Seller; provided, however, that any takeover of the Facility and the rights of Seller under this Agreement by lender, or the foreclosure and sale of the Facility and Seller's rights under this Agreement to a new operator, shall be on terms requiring compliance with all provisions of this Agreement, including, without limitation, all safety standards and further provided that the designation of any new operator shall be subject to the approval of Purchaser, which approval shall not be unreasonably withheld or delayed. Purchaser shall also execute such consent and agreement or similar documents with respect to a collateral assignment hereof, as lender may reasonably request in connection with the documentation of the project financing; provided, however, that Seller shall reimburse Purchaser for reasonable costs incurred in connection therewith, including reasonable attorney's fees.

18.10 Assignment. Except with respect to an assignment made in connection with project financing or to an affiliate or a wholly owned subsidiary of either party, neither party shall (by operation of law or otherwise) assign its rights or delegate its performance under this Agreement without the prior written consent of the other, and any attempted assignment or delegation without such consent shall be void. Subject to the preceding sentence, this Agreement and all of its covenants, terms and provisions shall be binding upon and inure to the benefit of and be enforceable by the parties and their respective successors and assigns.

18.11 Captions. All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to be inclusive, definitive, or to affect the meaning of the contents or scope of this Agreement.

18.12 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed in their corporate or partnership names by their duly authorized officers, as of the day and year indicated on the face of this Agreement.

ATLANTIC CITY ELECTRIC COMPANY

BY: _____
Name:
Title:

ATTEST:

CHAMBERS COGENERATION LIMITED PARTNERSHIP
by Maple Power Corporation as General Partner

BY: _____
Name:
Title:

ATTEST:

EXHIBIT A

DESCRIPTION OF SELLER'S FACILITIES

Project Description

The project is a pulverized coal fired cogeneration plant located at DuPont's Chambers Works facility in Carney's Point, New Jersey. This cogeneration plant will produce process steam and electric power for the DuPont facility and electric power for sale to Atlantic Electric.

The power plant consists of two steam generators, each with a full train of flue gas cleaning, supplying a single automatic extraction turbine generator. Each flue gas cleaning train consists of a spray dryer utilizing lime reagent and a fabric filter particulate removal system. The plant is designed for cycling from part to full load operation.

Major systems include:

- o Coal unloading, stackout, and reclaim
- o Ash and flue gas waste conveying and storage for offsite disposal
- o Circulating water including cooling tower and makeup
- o Service water
- o Main steam, process steam, feedwater and condensate
- o Fire protection
- o DCS based control room
- o Demineralized water treatment for boiler and process steam makeup
- o Plant water pretreatment, waste water treatment, and process water treatment
- o Plant electrical interconnection
- o Plant electrical distribution
- o Foundations, building, and architectural treatment
- o Site grading, paving, and fencing

Coal will be an Eastern, 2% sulfur fuel delivered by rail. Ash and flue gas solid waste will be hauled back to the mine.

Construction of the cogeneration facility is scheduled to commence in 1990 after permitting has been obtained. Start-up is scheduled to start in late 1992 with commercial operation in the third quarter of 1993.

EXHIBIT B

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**PJM MINIMUM GENERATION
OBLIGATIONS AND PROCEDURES**

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9.00 PJM LIGHT LOAD OBLIGATION AND OPERATING PROCEDURE

9.10 GENERAL STATEMENTS

- 9.11 PJM is a control area in the interconnected systems of the Eastern United States and Canada. Each control area has a commitment to control its generation in a manner so as not to burden the interconnected systems.
- 9.12 For PJM to meet its commitment to the interconnected systems during light load periods, it may be necessary for PJM to deviate appreciably from normal operating procedures.
- 9.13 The following obligation and procedure are applicable to PJM operation during light load periods and to the constrained dispatch of a PJM area for thermal, reactive, or other operating restrictions.

9.20 OBLIGATION

- 9.21 During light load periods, each PJM company shall be able to, and shall, upon request of the Interconnection Office (IO) reduce generation and purchases from systems external to PJM to meet the PJM system load. This action may include, for example, reducing fossil units to emergency minimums, reducing nuclear units below normal operating levels, and shutting down fossil units to meet the PJM system load.

9.30 DAY OR DAYS PRIOR TO LIGHT LOAD PERIOD

- 9.31 IO scheduling personnel are responsible for identifying light load conditions and projecting the extent of operating actions required by light load conditions. Operating actions are projected for PJM areas as well as PJM as a whole.
- 9.32 If the reduction of nuclear units and/or Non-Utility Generators (NUGs) is likely, or the expected generation levels of all units is within 1000 MW of normal minimum energy limits, the Interconnection Dispatcher (ID) will issue a Minimum Generation Alert for a specified light load period.

Company Response:

Upon receipt of a Minimum Generation Alert, system operators will notify appropriate personnel that a Minimum Generation Alert has been issued.

Additional unit maintenance should be scheduled, as appropriate, for the expected light load periods.

PJM-OI

Unit model data in the Unit Commitment Database should be reviewed and updated by scheduling personnel. Particular attention should be given to unit availabilities and energy limits (normal maximum, normal minimum, and emergency minimum).

Note:

Only the Unit Commitment Database contains emergency minimum energy limit information which will be used by the IO for both scheduling and dispatching.

9.33 If the extent of projected operating actions is likely to include reduction of nuclear units (including response to economic dispatch signal), IO scheduling personnel will collect the following information from company System Operations Subcommittee (SOS) members.

a. Nuclear unit operating constraints

b. Estimates of NUG energy which can be reduced or disconnected within two hours of a Minimum Generation Emergency declaration.

9.34 Based on updated Unit Commitment Database information, NUG reducible energy estimates, and additional nuclear unit operating constraints, IO scheduling personnel will formulate a scheduling strategy for the light load period.

Note:

The scheduling strategy will recognize the reduction of NUGs following the declaration of a Minimum Generation Emergency. IO scheduling personnel will increase forecast PJM loads during the light load period by NUG reducible energy estimates.

Company Response:

Scheduling personnel will update Unit Commitment Database unit availabilities to reflect the scheduling strategy and company must-run generation requirements.

9.35 Hydro plants shall be scheduled by IO scheduling personnel to maximize pumping at pumped storage plants and to minimize generation at run-of-river plants during the period(s) covered by a Minimum Generation Alert.

9.36 IO scheduling personnel will advise external systems of PJM conditions expected during a light load period. Arrangements will be made with external systems supplying company and PJM energy purchase agreements to minimize such energy deliveries to PJM during light load periods. Such arrangements may necessitate reduced energy deliveries during on-peak periods. Where feasible and economic, energy sales to external systems will be arranged.

9.37 IO scheduling personnel will review the light load scheduling strategy with appropriate SOS members and finalize the scheduling strategy.

9.38 The IO will convey the current scheduling strategy to company scheduling personnel.

Company Response:

Scheduling personnel will update Unit Commitment Database unit availabilities.

Scheduling personnel or system operator supervisors will provide system operators with listing of unit normal maximum and minimum energy limits to be used for updating energy limits available to the PJM Energy Management System (EMS) computer. Also provided will be a listing of emergency minimum energy limits.

9.39 Written documentation of the scheduling strategy for the ID will be prepared by IO scheduling personnel as appropriate.

9.40 FOUR HOURS PRIOR TO LIGHT LOAD PERIOD

9.41 The IO scheduling dispatcher will maintain a current list of unit emergency minimum energy limits, nuclear unit operating constraints, and reducible NUG energy.

Company Response:

System operators will review, with station operating personnel, unit normal maximum and minimum energy limits as well as emergency minimum energy limits provided in 9.38.

System operators will update normal maximum and minimum energy limits available to the PJM EMS computer. Changes in emergency minimum energy limits and nuclear unit operating constraints must be reported to the IO scheduling dispatcher.

Note:

Emergency minimum energy limits are not available to the PJM EMS computer.

9.42 The IO scheduling dispatcher will update the projection of light load conditions and, if required, update the light load scheduling strategy.

Note:

Documentation provided in action 9.39 should be used as a guide in revising the strategy. Significant changes in the operating strategy must be reported to the company system operators via the "all-call".

9.50 LIGHT LOAD PERIOD

9.51 The ID will declare a Minimum Generation Emergency when the following measures will produce energy reductions less than the expected load decrease:

- a. Reduction of all units to normal minimum energy limits.
- b. Energy sales to external systems (not dump power).
- c. Reduction of company and PJM purchases to supplier minimum energy limits.

9.52 The ID will request company system operators to reduce and/or disconnect NUGs. Requests to reduce NUGs will be rotated among the companies.

9.53 As the load decreases, the ID will reduce the PJM and/or area dispatch signal.

Company Response:

Company system operators will assure that fossil and nuclear units follow a decreasing dispatch signal without confirming communication between the ID and the company system operator.

9.54 The ID will reduce company and PJM purchases from external systems to supplier minimum energy limits.

9.55 When the ID can no longer match the decreasing load by reducing the dispatch signal, the ID will request company system operators to remove regulation from all units and reduce all units to normal economic minimum energy limits.

Company Response:

The system operator will update maximum and minimum energy limits available to the PJM EMS computer to reflect the removal of regulation.

The system operator will request station personnel to expedite the reduction of units to normal minimum energy limits. If a unit cannot reduce to normal economic minimum due to a new physical constraint, the system operator will advise the ID and update the normal minimum energy limit available to the PJM EMS computer for that unit.

9.56 The ID will request company system operators to load all pumped hydro units as pumps and reduce run-of-river plant energy, where reservoir elevation and riverflow will allow without spilling water or violating reservoir elevation limits.

9.57 The ID will reduce the PJM dispatch signal to zero and will attempt to sell excess generation to external systems. The excess generation will be quoted at a zero rate.

- 9.58 If further reduction of generation is required, the ID will request company system operators to reduce units (including nuclear units) to emergency minimums as required. Requests to reduce units to emergency minimums will be rotated among the companies with Keystone and Conemaugh considered as GPU units.

Note:

No update of minimum energy limits available to the PJM EMS computer is required. The ID will use the listing of emergency minimum energy limits prepared in 9.39 as a guide to attainable generation reduction. The ID will request company system operators to reduce units to emergency minimums in the order prepared in 9.39. Loading units to normal minimum energy limits will be in the same order.

- 9.59 For a severe light load condition requiring extraordinary actions, the ID will refer to the light load strategy prepared in 9.39 and exercise judgement in deciding which units should be shut down and energy of PJM external purchases cancelled.

Note:

The ID will request the company system operators to shut down specific units not required for area protection during the light load period or a subsequent on-peak period. Unless the ID issues specific start-up instructions, units should be restarted when the Minimum Generation Emergency is cancelled (no request by the ID is required).

9.60 LAST RESORT

- 9.61 As a last resort, the ID, taking into account reliability considerations, will request system operators of over-generating companies to reduce generation to meet the PJM system load (pro-rating the reduction among the over-generating companies in proportion to the amount each company is over-generating). The over-generating company system operators have the prerogative of reducing their generation by any means to achieve the level requested by the ID.

Note:

An over-generating company is a PJM company with current internal energy (including allocation of jointly owned unit energy) in excess of current internal load. Energy associated with a capacity and/or energy sale by one PJM company to another is internal energy of the supplying company. Energy associated with a capacity and/or energy sale by a PJM company to an external system is internal load of the PJM company (an energy purchase is internal energy).

9.70 CANCELLATION

9.71 The above steps will be followed in reverse order as the PJM load beings to exceed the generation. The ID will cancel a Minimum Generation Emergency when all units are requested loaded to normal minimums and regulation restored.

4538E

Last Revised: 5/15/87

SECTION 8

GUIDELINES:

I. OBLIGATIONS

During low load periods each PJM system must be able to, and shall upon request by the Interconnection Dispatcher, reduce its system generation to emergency minimums. All PJM systems shall cooperate in attempting to reduce generation to meet the PJM system load in the most economical way possible on an overall PJM basis while meeting reliability constraints.

II. PROCEDURES

In recognition of the above obligation, the following sequence of events will be followed in order to meet PJM minimum load requirements:

A. Verification Tests

Verification tests of minimum generation levels of all units on PJM shall be conducted. The development of procedures, the timing of such tests and the review of results shall be the responsibility of the Operating Committee.

B. Scheduling Minimum Generation

The Interconnection Office shall schedule all generating facilities on the interconnection in the best possible manner to reliably meet a minimum load problem. Consideration shall be given to the proper scheduling of pumped storage facilities, planned and maintenance outages, delaying the return of units to service, outside sales to neighboring systems, the shutting down of base load units, power transfer limitations, and voltage and reactive constraints. Where practical, the system should be scheduled to avoid emergency minimums. The Interconnection Dispatcher shall issue to the companies, via the ALL-CALL, a Minimum Generation Warning with maximum possible lead time together with the forecast conditions when the forecast PJM minimum load, including the pumping load, is 1,000 MW or less above the forecast PJM normal minimum generation level. Upon receipt of a Minimum Generation Warning, each company shall review unit minimums and prepare a sequential action plan to meet its requirements. The IO shall be kept apprised of these plans. Stations shall be notified of possible requirements and they shall be prepared to act if so required. As an emergency minimum period approaches, the ID shall, via the ALL-CALL, issue a Minimum Generation Alert to inform the systems of the situation in order that

SECTION M

they may prepare to reduce to normal and emergency minimums. During the period, the ID shall utilize the ALL-CALL system to keep the systems informed of the situation. Upon receipt of a Minimum Generation Alert, the systems shall review minimum generation limits and the status of units in Dispatch Lambda. Updates should be made when required.

C. Reduction of Generation

The reduction of generation during light load periods will be accomplished by economically reducing unit outputs to their normal minimum levels according to the Dispatch Lambda incremental cost schedule. This includes nuclear units as preplanned. At all times, the ID should attempt to sell excess generation at normal economy. When PJM is operated at normal minimum generation, the dispatch rate shall be equal to the lowest incremental cost included in the Dispatch Lambda incremental cost schedule.

D. Minimum Generation Emergency

If normal minimums are not adequate to relieve the problem, the ID, via the ALL-CALL, should declare a Minimum Generation Emergency. Prior to reducing units to their emergency minimums, the ID should load all unloaded pumped hydro units and reduce run-of-river plant output where forebay elevation and river flow will allow without spilling water, and attempt to sell excess generation on PJM to neighboring systems as dump power. This power should be quoted at a zero rate. The payment to PJM for the power then will be halfway between the buying company's replacement quote and our zero rate.

E. Additional Reductions

If additional reduction of PJM generation is required, PJM systems will be requested to reduce generation, as required, to stated emergency minimum levels.

F. Further Reductions

If more reductions are required, the ID shall survey the companies, requesting the following information: a) each company's load and generation; b) which of the companies are in a position to further reduce generation by other than normal procedures (such as further reductions on nuclear units or spilling water at run-of-river plants) and the associated incremental cost or time recovery penalty imposed by such actions; and c) which units operating have the lowest max capacity and the highest cost that could be shut down without adversely affecting reliability. The ID will use his best judgement

SECTION M

to decide which units should further reduce generation by other than normal procedures or which units should be shut down to satisfy the existing emergency without jeopardizing the ability to carry tomorrow's load reliably and economically. Since an emergency situation has been declared, any costs incurred by buying companies taking special reductions to aid selling companies will be reimbursed through appropriate accounting procedures as established by the Operating Committee. (see MC 168-3, page M-5)

G. Emergency Generation Reduction by Overgenerating Companies

As a last resort, the Interconnection Dispatcher, taking into account the reliability considerations, will request the overgenerating companies to reduce generation (pro-rating the drop among the overgenerating companies in proportion to their MW values of overgeneration) to meet the PJM system load. The overgenerating companies have the prerogative to reduce their generation by any means to achieve the level requested by the IO. The impact of such a procedure shall be accounted for under practices as established by the Operating Committee.

H. Reversal of Minimum Generation Procedures

The above steps shall be followed in reverse order as the load begins to exceed the generation, and the ID shall cancel the Minimum Generation Emergency when the lowest normal minimum generation level is reached.

OC 271-3
(superseding OC 232-15)

SECTION M

III. PJM MINIMUM GENERATION (MIN GEN) ACCOUNTING

A. Forecast Min Gen Emergency

1. Based on a forecast PJM Min Gen Emergency by the Interconnection Office (IO), a company may submit to the ASc for consideration extraordinary costs associated with any unit taken off in advance: a) voluntarily at the request of the IO, or b) at the direction of the IO.
2. These costs are to be tabulated for the period of time that the unit(s) is requested to be off-line by the IO and should be based on the estimated hourly cost of the unit versus either the Dispatch Rate, if the company was forced to curtail sales, or the Billing Rate, if the company was forced to purchase more energy. A start-up cost may be included if applicable.
3. All costs should be allocated under separate billing in accordance with an allocation method and removed from the daily accounting as specified by the ASc and approved by the Operating Committee.
4. Any extraordinary costs associated with jointly-owned units shall be submitted by owning companies for their respective shares of energy under the coordination of the operating company or the IO, in the case of Keystone and Conemaugh.

ASc 373-4

B. Actual Min Gen Operation

1. No company which is operating below its load shall pay more for energy received than the cost it would have incurred if it had generated the energy itself.
MC 168-3, (reaffirmed OC 272-9)
2. When the generation on PJM is at the emergency minimum level, and PJM is generating above its load, the costs incurred will be developed by the company or companies which shut down or reduce units at the request of the IO to correct the minimum generation problem. These costs are to be tabulated for the period of time until the units can be returned to economical operation, and should be based on the estimated hourly cost of the unit versus either the Dispatch Rate, if the company was forced to curtail sales, or the Billing Rate, if the company was forced to purchase more.

EXHIBIT C

TECHNICAL GUIDELINES

FOR

COGENERATORS AND

SMALL POWER PRODUCERS

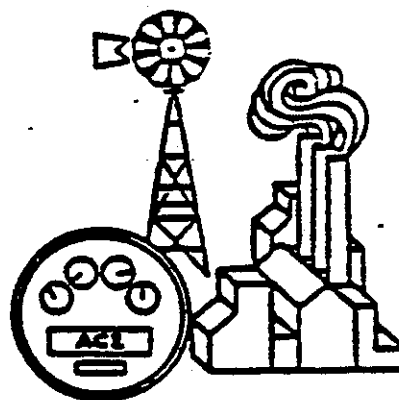
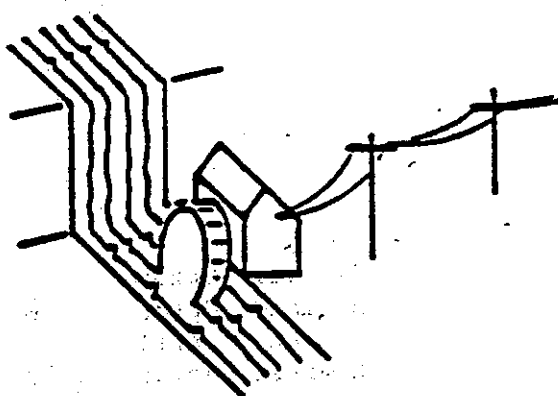


TECHNICAL

GUIDELINES

for

Co-Generators & Small Power Producers.



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GUIDELINES

FOR

**CO-GENERATORS
& SMALL POWER PRODUCERS**

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DISCLAIMER

"The material contained herein is designed to be informational in nature only. It should be utilized by you as an aid in making the decision as to whether or not to proceed to a more detailed investigation. The material is current as of the date of issue of this document, and it must be recognized that future actions may render any given item obsolete."

Atlantic Electric makes no representation or warranty of any nature whatsoever concerning the technical information contained herein. THE INFORMATION CONTAINED HEREIN IS INTENDED TO BE TYPICAL, FOR INFORMATIONAL PURPOSES ONLY, AND IS NOT INTENDED TO BE SITE SPECIFIC OR FACILITY SPECIFIC.

INTRODUCTION

The purpose of this Information Guide is to provide preliminary information to all Atlantic Electric (sometimes referred as "A.E.") customers who are interested in investigating the potential for cogeneration or small power production at their facility. Although it is impossible for this document to provide all the answers, this information is offered as a starting point for any customer who is considering authorized cogeneration of electric power.

The purpose of this Information Guide is also to consider technical and safety requirements and the need for adequate protective equipment to be designed and installed by customer in order to operate customer generation in parallel with the Atlantic Electric system without affecting the reliability of electric service to other customers and the safety of the general public and Atlantic Electric employees.

We believe that the information contained in this guide may be useful in understanding the need for proper design and analysis in the pursuit of a comprehensive customer generation feasibility study.

1.0.0 General Design Requirements

- 1.1.1 The customer's installation must meet all applicable national, state and local construction, safety and electrical codes.
- 1.1.2 Adequate protective devices (relays, circuit breakers, etc.) for the protection of AE's system, metering equipment and synchronizing equipment must be installed by customer. The protective devices may differ with the size of the installation. See section 5.3.0 for more specific requirements which must be installed by customer.
- 1.1.3 The customer shall provide A.E. controlled manual disconnecting device on the A.E. side of the interconnection. The type of device will vary with service voltage and capacity. This device must have a visible indication of its position and must accept a padlock to be provided by Atlantic Electric Co.
- 1.1.4 In installations where the customer is to provide protective devices for the protection of AE's system, the customer shall submit a single-line drawing of this equipment sealed by a licensed professional engineer to AE for informational purposes only. This shall not and is not intended to relieve customer of its design and installation obligations.
- 1.1.5 All cogeneration/small power producer customers must have a dedicated service transformer. This transformer will decrease voltage variations experienced by other customers, attenuate harmonics, and reduce the effects of fault current. In general, for multi-phase customers, the dedicated transformer should be connected in delta or wye ungrounded on the Atlantic Electric side so as not to be a contributor to 1L-G faults on the Atlantic Electric system.
- 1.1.6 The cogeneration/small power producer customer has sole responsibility for properly synchronizing his generation with Atlantic Electric's frequency and voltage.
- 1.1.7 Relay and Control:

Typical installations of Customer owned generators connected to the Atlantic Electric System illustrating some possible different configurations are indicated in Figure 1 to Figure 7. The primary purpose of the illustrations are to provide protection and metering design information. Typical connections to the Atlantic Electric subtransmission or transmission systems are shown in the diagrams provided in the following guidelines published by Atlantic Electric: "Technical Guidelines for Customer Service at Subtransmission and Transmission Voltages."

1.1.8 Supervisory Control and Data Acquisition (SCADA) System Requirement:

A. Customers installing generators 10MW and larger size will be required to install equipment at their generating site and also pay for equipment and installation needed at Atlantic Electric's System Control Center for the following.

- 1) Telemetry of generator watts and vars
- 2) Remote states of interface breaker
- 3) Remote control of interface breaker

B. The customer must lease a dedicated telephone circuit or other dedicated means of communication from the customer location to the AE System Control Center.

C. The customers must supply meters to indicate hourly demand for use in case of loss of telemetry equipment or the telephone circuit.

D. kWhr meters for end of month reading to provide adjustments to hourly data must also be supplied by the customer.

1.1.9 Any interface services which separate the generation facilities from AE's lines must be capable of interrupting the maximum fault current available at that location. The customer will be advised by AE the max fault current available.

1.1.10 In addition to the provisions in this guide, the customer shall meet the provisions published in "Technical guidelines for Customer Service at Subtransmission and Transmission Voltages" (where applicable). Where any conflicts exist, the provisions of the Cogeneration guide shall govern.

2.0.0 General Operating Requirements

- 2.1.1** The interconnection of the customer's generating equipment with the AE system shall be designed and operated by customer to cause no reduction in the quality of service being provided to other customers. No abnormal voltages, frequencies, or interruptions shall be permitted. The customer's facility shall produce 60 Hertz sinusoidal output with harmonic distortion no greater than 5%. If other customers complain about waveform distortion high or low voltage or flicker due to operation of customer's generation, such generating equipment shall be disconnected without notice until the problem has been resolved. There shall be no responsibility on the part of AE, its directors, officers, agents, servants or employees for disconnection.
- 2.1.2** The customer may not commence parallel operation with Atlantic Electric System until final written approval has been granted by AE. AE reserves the right to inspect the customer's facility and witness testing of any equipment or devices associated with the interconnection.
- 2.1.3** The customer shall operate and maintain his equipment in good and proper working order which shall be consistent with all industry standards and in compliance with all applicable rules, codes, regulations, orders and requirements. AE reserves the right to inspect the customer's facilities whenever it appears that the customer is operating in a manner which may pose a risk to AE's system integrity and, in such event, AE shall have the right to disconnect customer's facilities without notice and shall have no liability therefore.
- 2.1.4** Switching of the interface breaker or switch device shall be under the administrative control of Atlantic Electric's System Operator. If, for any reason, Atlantic Electric believes the continuation of the interconnected system is, or may be, detrimental to the operation of Atlantic Electric's facilities, the supplier shall be required to disconnect the generator from Atlantic Electric's system which may be done with or without notice by AE and there shall be no liability to AE, its directors, officers, agents, servants or employees therefore. This includes Atlantic Electric's right to open the interface breaker or switching device with or without prior notice to the supplier for any of the following reasons:
- A.** To facilitate maintenance, test or repair of utility facilities.
 - B.** During system emergencies.

- C. When the customer's generating equipment is interfering with other customers on the system.
- D. When an inspection of the customer's generating equipment reveals a condition hazardous to the AE system or a lack of scheduled maintenance records for equipment necessary to protect the AE system.

2.1.5 Automatic disconnecting devices with appropriate automatic control apparatus must be provided by the customer to isolate the customer's facility from the utility system for, but not necessary limited to, the following abnormal conditions:

- A. A fault on the customer's equipment.
- B. A fault on the utility system.
- C. A deenergized utility line to which the customer is connected.
- D. An abnormal operating voltage or frequency.
- E. Failure of automatic synchronization with the utility system.
- F. Loss of a phase or improper phase sequence.
- G. Total harmonic content in excess of 5%.
- H. Abnormal power factor.
- I. Load flow exceeding an established limit.

2.1.6 The customer will not be permitted to energize a deenergized AE circuit.

2.1.7 Operation of the customer's generator shall not adversely affect the voltage regulation of the AE system to which it is connected. Adequate voltage control shall be provided, by the customer, to minimize voltage regulation on the AE system caused by changing generator loading conditions.

For synchronous generators, sufficient generator reactive power capability shall be provided to withstand normal voltage changes on the AE system.

In cases where starting or changing load on induction generators will have an adverse impact on AE system voltage, step-switched capacitors or other techniques may be required to bring the voltage changes to acceptable levels.

- 2.1.8 The customer shall maintain an operating log at generating facility indicating all changes in operating status, maintenance outages, trip indications or other unusual conditions found upon inspection and such other information as AE may from time to time require, which log shall be available to AE upon request and which shall be maintained at all times on the premises of the generating facility where it will be available for inspection.
- 2.1.9 The customer shall notify AE, in writing, of the monthly KWH production of each generator on the first regular working day of the following month. Producer of power 10MW or larger may be required to report energy and peak demand information daily.
- 2.1.10 It is the nature of the distribution system that, for efficient operation, loads are sometimes switched from one feeder to another or from one supply substation to another. If such a situation should arise affecting the supplier's facility, recoordination of the supplier's protective devices will be solely the supplier's responsibility. Where practicable, Atlantic Electric shall exercise its reasonable best efforts to inform supplier four weeks prior to any proposed changes in AE system that will require any changes in coordination of protective devices.

3.0.0 Design Information - Atlantic Electric System

3.1.1 AE's primary distribution system consists of either 4kV or 12kV, grounded wye. Atlantic Electric's transmission system consists of 23 kV and above also grounded wye. The customer's generator should be designed to be tripped or isolated from Atlantic Electric system before the first automatic reclose occurs following a fault on customer's system. First reclosing time varies from circuit to circuit. At some locations, for close in faults near the AE substation, the distribution feeder breaker will not be allowed to reclose. Once the customer's generator is isolated from the Atlantic Electric system, the customer's generator can be paralleled with AE System only after approval by AE System Control Center, by telephone confirmation using the authorized communication number to be issued by AE.

3.1.2 Customers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the customer to protect his equipment from excessive negative sequence currents.

4.0.0 Design Considerations

4.1.0 Parallel Operation

- 4.1.1 A parallel system is defined as one in which the customer's generation can be connected to a bus common with the utility's system. A transfer of power between the two systems is a direct and often desired result. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the utility system which must be considered in the electrical protection of the utility's facilities.
- 4.1.2 Utility lines are subject to a variety of natural and man-made hazards. Among these are lightning, wind, animals, automobiles, malicious mischief and human error. Residential and commercial electric systems are subject to these same hazards, although perhaps to a different degree, because of the limited extent and protected environment of such systems.
- 4.1.3 The electric problems which can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that the damaged equipment be deenergized as soon as possible because of the hazards they pose to the public and the operation of the system.
- 4.1.4 In systems without parallel generation, the utility controls the only source of supply to a given line and therefore, has the responsibility to install equipment which is adequate, under expected circumstances, to detect faulted equipment and deenergize it. A parallel generator connected to a utility line represents another source of power to energize the line and must also have adequate protective devices installed to sense trouble on the utility system.
- 4.1.5 Parallel generation can also cause another condition, called "accidental isolation," in which a portion of the utility's load becomes isolated from the utility source but still connected to the parallel generation. In this condition, the voltage may collapse or the isolated system may continue to operate independent of the utility (but probably with abnormal voltage or frequency). The probability of an isolated system continuing to operate increases with increasing size of the parallel generator compared to the amount of potentially isolated load.
- 4.1.6 The protective devices and other requirements required by AE in the section #5 are intended to provide protection against the hazards noted above by disconnecting the parallel generator when trouble occurs. These requirements are few for small installations but increase as the size of the generation increases. For small installations, the basic philosophy is to ensure that the generator

output is small compared with the magnitude of any load with which it might be isolated. Thus, for any fault, AE's protective relays will operate and isolate the generation with a large amount of load, causing voltage collapse and automatic shutdown of the generator. This approach is particularly appropriate for the induction generator or inverter systems commonly proposed for small parallel generators since these systems do not contribute sustained overcurrents which could be used to detect faults directly. In instances where the AE system arrangement is such that it is possible that the generators will not always be isolated with large amounts of load, AE requires the use of voltage and frequency measuring relays to detect isolation and trip generators.

4.1.7 For larger installations the probability of isolated operation is higher since the available generation may be sufficient to carry the entire load of AE's circuit. For these installations, specific devices must be installed by customer for the detection of short circuits and grounds on the utility system as well as voltage and frequency relays to detect isolated operation.

4.1.8 The list of design considerations contained herein is not intended to be all inclusive. Other hazards and considerations must be taken into consideration by the design engineer based upon the circumstances, the site, the customer's needs and other appropriate criteria.

4.2.0 Reactive Power Requirements when Supplier is Delivering Real Power

When delivering real power (kilowatts) to Atlantic Electric, supplier must be capable of operating with a power factor at the Point of Delivery to AE between 90% leading to unity, such that supplier would receive lagging reactive power (kilovars) from AE.

In general, when a supplier is connected to AE at the distribution voltage level (4 kV or 12 kV) the supplier must maintain a power factor between 90% leading to unity while delivering real power to AE. However, it may be acceptable and/or desirable for supplier to deliver lagging reactive power when connected at a distribution level if supplier is connected at a point close to an AE substation or connected with a dedicated distribution line.

In general, when a supplier is connected to AE at a voltage level above distribution voltages, the supplier will be required to have a capacity to operate between a 90% leading to a 90% lagging power factor at the point of delivery while simultaneously delivering real power to AE.

If the supplier has the capacity to operate beyond the above specified limits, AE may choose to operate beyond those limits. Actual reactive power flow at the point of delivery will be dispatched by AE.

4.2.1 Reactive Power Requirements when AE is Supplying Real Power

Any time AE is supplying power to the Point of Delivery, it is desirable that the power factor be corrected to 95% lagging or better (closer to unity or slightly leading).

4.3.0 Induction Generators

Reactive power supply for induction generators may pose difficult design problems, depending on the generator size. Installations over 200 KVA capacity may require capacitors to be installed to limit the adverse effects of reactive power flow on AE system voltage regulation. Such capacitors will be at the expense of the generating facility. The installation of capacitors for reactive power supply at, or near, an induction generator greatly increases the risk that the induction machine may become self-excited if accidentally isolated from AE's system. The self-excited induction generator can produce abnormally high voltage which can cause damage to the equipment of other customers. Overvoltage relays can detect such overvoltages but cannot control their magnitude because of the rapid voltage rise which occurs with self-excitation. Because of these problems, reactive power supply for large induction generators must be studied on an individual basis. In general, self-excitation problems are most likely where the AE system capacity and load density are low. Since such areas are likely to be chosen for certain forms of small power production such as wind and hydro. No induction machines may be connected to existing distribution lines without the express written consent of AE. Any damage to equipment of other customers as a result of self-excited induction generator shall be the responsibility of customer.

4.4.0 Inverter Systems

Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines discussed in Section 4.3.0 apply. Likewise, inverter systems are also capable of isolated operation. Self-commutated inverters have this capability by design. Line commutated inverters could operate isolated if connected to rotating machines which provide the necessary commutation. Because of these possibilities of self-excited operation, inverter systems are treated as induction machines in these guidelines. Harmonics generated by inverter shall not distort the waveforms more than 5%. If a customer using such a device for parallel generation is found to exceed 5% waveform distortion limit, the generating customer will be required to install, at customer's cost, filtering equipment to bring the harmonic output of his inverter to a level acceptable to AE.

4.5.0 Synchronous Generators

Synchronous generators can be either separately excited or self-excited. In either case, these units are capable of supplying sustained fault current for fault conditions on the Atlantic Electric supply system. Such units are also capable of operating independently and can supply isolated load, providing the load is within the unit's output capability.

4.6.0 Wind Generators

Generally, wind generators are induction generators and, therefore, the same design considerations apply. It is also required that no wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact, land upon, or interfere with any utility lines or equipment, or constitute a safety hazard.

A typical homeowner thinking about installing a wind generator will most likely be required at the cost of customer incoming service equipment such as transformer, service cable, distribution panel, etc. because existing equipment rating may not be adequate.

In considering installation of a wind generator or any other equipment the customer is cautioned to carefully take into consideration and examine all land use and zoning rules and regulations. Permits, approvals and/or variances may be required and customer should discuss such requirements with his engineer, his counsel and the representatives of the local governing bodies prior to proceeding with such projects.

5.0.0 Protection Guidelines -- Objectives

5.1.0 The required protection equipment to be installed by the customer is selected and installed to meet the following objectives, which are not intended to be all inclusive:

- A. Provide adequate protection for faults, overloads or other abnormal conditions on the customer's equipment.
- B. Provide adequate protection for faults and overloads on Atlantic Electric's lines, transformers or other equipment.
- C. Prevent outages or other adverse effects to other Atlantic Electric customers.
- D. Provide a safe means to control, operate, connect and disconnect the intertie of the customer's generation and the Atlantic Electric system.
- E. Provide a free flow of normal power transfer.

5.2.0 Protection Guidelines -- General Requirements:

- A. It is the customer's responsibility to select, install and maintain adequate protection for their own generator and switchgear equipment. Fuse size/type information, single line diagram and other information on the overall protective relaying scheme must be provided to Atlantic Electric. Atlantic Electric will review the compatibility of the customer's proposal with the Atlantic Electric protective relaying on the source line. Atlantic Electric must approve the design of the finalized protection arrangement.
- B. A point of intertie must be defined between the Atlantic Electric system and the cogeneration/small power producer. Most likely, this point will be a circuit breaker or a switch used to intertie the two systems. The intertie breaker could be on the high side of the customer's transformer or on the low side if the transformer is fuse protected. All protective relaying used to trip the intertie breaker must be reviewed and approved by Atlantic Electric. The automatic reclosing, if any, of the intertie breaker must also be reviewed and approved by Atlantic Electric. No approval by AE is intended to relieve customer of its obligation. Customer shall remain responsible for its equipment and the design and operation thereof. Approval by Atlantic Electric is for informational purposes only and to provide assurance to AE for the protection of its equipment.

- C. Atlantic Electric will supply settings for the protective relaying schemes that trip the intertie breaker. An exception is Atlantic Electric will not set those relays solely used for protection of the customer's generator. If desired, Atlantic Electric will, for a nominal fee, physically set the intertie breaker protective relays and periodically test the protective relaying scheme. However, AE will do so without liability or responsibility to customer and the liability of AE, whether in contract or in tort or otherwise shall be limited to return to the customer of the nominal fee. AE will perform this service for convenience only.

5.3.0 Protection Guidelines -- Specific Requirements for Cogeneration/Small Power Producer Customers Supplied Off Atlantic Electric's Transmission System

- A. Generators connected to Atlantic Electric's transmission system must be 3-phase units.
- B. A customer with a large dedicated transformer (ie. low impedance) that is tapped off a transmission line that utilizes a power line carrier protective relaying scheme may need to install a carrier relaying terminal at their site. This equipment may be needed to maintain the reliability and security of the carrier relaying scheme on the transmission line.
- C. A customer tapped off a transmission line with high-speed circuit breaker reclosing may require transfer trip from the Atlantic Electric source terminal to insure that the customer's generator is tripped "off-line" before the high speed breaker reclose occurs at Atlantic Electric's end.
- D. The customer's dedicated transformer may be protected by fuses. If customer supplied, Atlantic Electric will check the compatibility of the customer's fuse type/size with the protective relaying on the source end(s) and, if acceptable to AE for that purpose, will give its approval for the use of the customer's supplied fuse, which shall be for purpose of determining compatibility only.
- E. 1. The customer's dedicated transformer may be protected by protective relays and:
 - a. High side fault interrupting device such as a circuit breaker or circuit switcher, or
 - b. Transfer trip to Atlantic Electric's source end(s) and an automatic isolation device such as an airbreak switch so that after clearing of the fault, the transformer can be automatically isolated and the transmission line can be restored. (The automatic isolation device may not be necessary if the source line supplies only the customer.)
- E. 2. The transformer may be protected by a combination of the following types of protective relays:
 - a. Differential relay protection operating on a percentage of differential current.
 - b. Sudden pressure relay detecting internal fault pressure.

- c. Primary phase and ground overcurrent relay with the setting based on transformer size or loading whichever is more applicable.
 - d. Secondary phase and ground overcurrent relay with the setting based on transformer size or loading whichever is more applicable.
- F. The cogeneration/small power producer must trip their intertie breaker for a fault on the Atlantic Electric transmission system. This tripping could be accomplished by:
- 1. Transfer trip from Atlantic Electric's source end.
 - 2. A combination of local protective relays at the customer's site. Examples include:
 - a. One or more zones of phase impedance relays and associated timers.
 - b. Overcurrent relays set above the maximum output of the customer's generator. Directional overcurrent relays may be needed if customer load could exceed generator output.
 - c. Power relay set above the maximum output of the customer's generator.
- G. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must be "off line" before an automatic reclose occurs on the source end(s). The preceding trips can be accomplished with the following protective relays:
- 1. Overvoltage relay with time delay.
 - 2. Undervoltage relay with time delay.
 - 3. One/two step underfrequency relay(s) with independent time delays.
 - 4. One/two step overfrequency relay(s) with independent time delays.

5.4.0 Protection Guidelines, And Specific Requirements For Cogeneration/Small Power Producer Customers Supplied Off Atlantic Electric's Distribution System

- A. Generators connected to Atlantic Electric's distribution system may be either single phase or 3-phase units. (Three phase units, obviously, can only be connected where Atlantic Electric's distribution circuit is of 3-phase construction).
- B. The customer's dedicated transformer may be protected by high side fuses. Atlantic Electric will check compatibility of customer's fuse type/size with the protective relaying of the AE end and, if acceptable, give approval. A 3-phase generator should employ negative sequence relaying to detect an open fuse condition.
- C. The cogeneration/small power producer must trip their intertie breaker for a fault on the Atlantic Electric distribution circuit. This tripping may be accomplished by the following, which are not intended to be all inclusive:
 - 1. Transfer trip from Atlantic Electric's source end.
 - 2. A combination of local protective relays at the customer's site. Examples include:
 - a. Overcurrent relays set above the maximum output of the customer's generator. Directional overcurrent relays may be needed if the customer's load can exceed the generator output.
 - b. Power relay set above the maximum output of the customer's generator.
- D. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must be "off line" before an automatic reclose occurs on the source end. The preceding trips may be accomplished by the following protective relays, which are not intended to be all inclusive:
 - 1. Overvoltage relay with time delay.
 - 2. Undervoltage relay with time delay.
 - 3. One/two step underfrequency relay with independent time delay.

4. One/two step overfrequency relay with independent time delay.

5.4.1 Protection Guidelines, And Specific Requirement For Cogeneration/Small Power Producer Customers Supplied Off Atlantic Electric's Distribution System That Use Induction Generators

These customers use induction generators which contain no field for excitation purposes. These generators draw reactive power from the Atlantic Electric system to satisfy their excitation needs. The units can only produce power when they are energized from the Atlantic Electric distribution circuit. As such, induction generators cannot supply sustained fault current or, in most cases, supply isolated load.

NOTE: Self excitation may be possible in some cases if the customer uses capacitors for power factor correction or if the Atlantic Electric distribution circuit has a high number of capacitors.

- A. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must trip "off line" before an automatic reclose occurs at Atlantic Electric end.

The preceding trips can be accomplished by the following protective relays:

1. Undervoltage relay with time delay.
2. Underfrequency relay with time delay.
- B. In cases where self-excitation is possible, the above relays shall be supplemented by:
 1. Instantaneous overvoltage relay.
 2. Overfrequency relay.

5.4.2 Protection Guidelines, And Specific Requirements For Cogeneration/Small Power Producer Customers That Use DC Generation And Are Supplied Off Atlantic Electric's Distribution System

These customers employ DC generation and transform the DC output to AC through synchronous static inverters that use electronic switching. The electronic switching is controlled by either the utility AC voltage or by internal electronic circuitry. Static inverter installations on the Atlantic Electric system must be the

type that utilize the Atlantic Electric AC voltage as their switching reference. These systems cannot supply fault current or supply isolated load. Therefore, if properly designed by customer, no special protection equipment is necessary for faults on the Atlantic Electric source feeder or for an outage of the Atlantic Electric source. The protection for the customer's dedicated transformer is the same as that required for other cogeneration/small power producer customers supplied off Atlantic Electric's distribution system.

6.0.0 Information To Be Supplied by Cogenerator or Small Power Producer

List of Drawings:

- A. A one line diagram of entire system.
- B. A potential elementary of customer-owned generation system.
- C. A current elementary of customer-owned generation system.
- D. A control elementary of generator breaker.
- E. A three line diagram of generation system.

6.1.0 One Line Diagram and Three Line Diagram to include the following information:

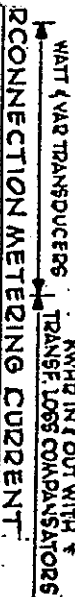
- A. Equipment names and/or numerical designations for all circuit breakers, contactors, air switches, transformers, generators, etc., associated with the generation as required by Atlantic Electric to facilitate switching.
- B. Power Transformers - Name or designation, nominal kVA, nominal primary, secondary, tertiary voltages, vector diagram, a tap setting and transformer impedance.
- C. Station Service Transformers - Designate phase(s) connected to, and estimated kVA load.
- D. Instrument Transformers - Voltage and current, phase connections.
- E. Lightning Arresters/Gas Tubes/Metal Oxide Varistors/Avalanche Diode/Spill Gaps/Surge Capacitors - Ratings.
- F. Capacitor Banks - kVAR rating.
- G. Air Switches - Indicate status normally open with a (N.O.) and type of operation manual or motor.

- H. Safety Switch - Continuous ampere and interrupting ratings.
- I. Circuit Breakers and/or Contactors - Interrupting rating, continuous rating, operating times.
- J. Generator(s) - Include type, connection, kVA, voltage, current, rpm, PF, impedances, time constants, etc.
- K. Point of Connection to Atlantic Electric and phase identification.
- L. Fuses - Type, size, speed, and location.
- M. Grounding.

6.1.1 Elementary Diagrams To Include The Following Information

- A. Terminal designation of all devices - relay coils and contacts, switches, transducers, etc.
- B. Relay functional designation - per latest ANSI Standard. The same functional designation shall be used on all drawings showing the relay.
- C. Complete relay type (such as CV-2, CV-5, CW, IJS51A) and relay range.
- D. Switch contacts shall be referenced to the switch development if development is shown on a separate drawing.
- E. Switch developments and escutcheons shall be shown on the drawing where the majority of contacts are used. Where contacts of a switch are used on a separate drawing, that drawing should be referenced adjacent to the contacts in the switch development. Any contacts not used should be referenced as spare.
- F. All switch contacts are to be shown open with each labeled to indicate the positions in which the contact will be closed.
- G. Explanatory notes defining switch coordination and adjustment where misadjustment could result in equipment failure, or safety hazard.
- H. Auxiliary relay contacts shall be referenced to the coil location drawing if coil is shown on a separate drawing. All contacts of auxiliary relays should be shown and the appropriate drawing referenced adjacent to the respective contacts.

- I. Device auxiliary switches (circuit breakers, contactor) should be referenced to the drawing where they are used.
- J. Any interlocks electromechanical, key, etc., associated with the generation.
- K. Ranges of all timers, and setting if dictated by control logic.
- L. All target ratings; on dual ratings underline the appropriate tap setting.
- M. Complete internal for electromechanical protective relays. Solid-state relays may be shown as a "black box", but manufacturer's instruction book number shall be referenced, and terminal connections shown.
- N. Isolation points (states links, PK-2 and FT-1 blocks), etc., including terminal identification.
- O. All circuit elements and components, with device designation, rating and setting where applicable. Coil voltage is shown only if different from nominal control voltage.
- P. Size, type, rating and designation of all fuses.
- Q. Phase designation as ABC or CBA.
- R. Potential transformers - nameplate ratio, polarity marks, rating, primary and secondary connections (see Guidelines for minimum ratings).
- S. Current transformers - polarity marks, rating, tap, ratio and connection.
- T. Auxiliary CT ratios, connection, winding current rating and arrows to indicate assumed current flow.
- U. Such other information as AE may request.



ATLANTIC CITY ELECTRIC COMPANY

TYPICAL
INTERCONNECTION RING

DIAGNOSIS

- GENERAL NOTES:
1. CURRENT & POTENTIAL TRANSFORMERS ARE NOT REQUIRED FOR 120/240V A.C. SYSTEM METERING.
 2. TRANSFORMERS ARE NOT REQUIRED WHEN CUSTOMER'S GENERATOR IS LESS THAN 100 KW.
 3. TRANSFORMER LOSS COMPENSATION (TLC) ARE REQUIRED ONLY WHEN METERING POINT VOLTAGE IS DIFFERENT THAN THE VOLTAGE AT INTERCONNECTION POINT.
 4. D-DENOTES SLIDE LINK TIE B.M. B.L.K
 5. A-DENOTES SHIELDED CABLE
6. THIS DWG. IS NOT TO BE USED FOR CONSTRUCTION.

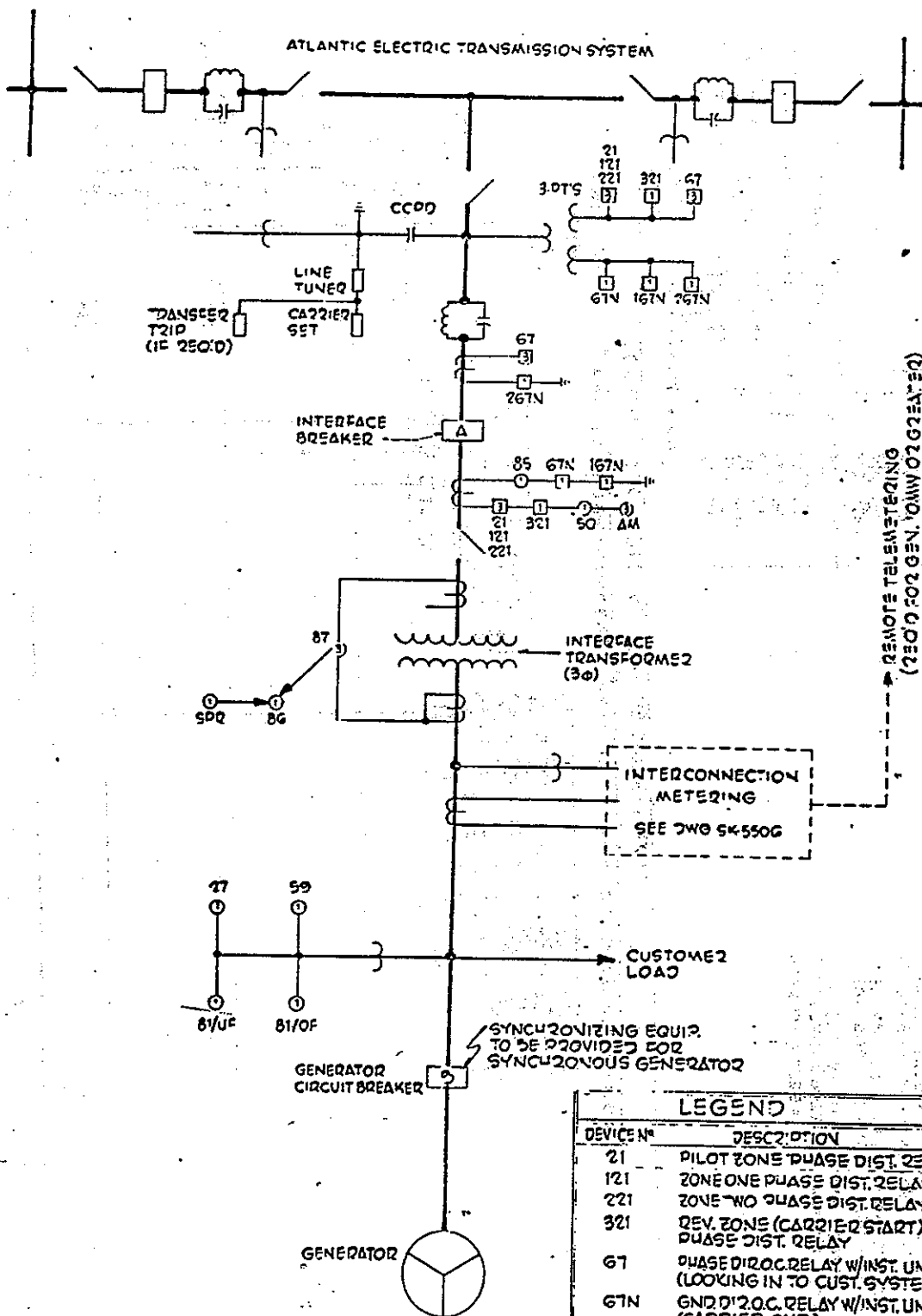


DIAGRAM # 2

LEGEND

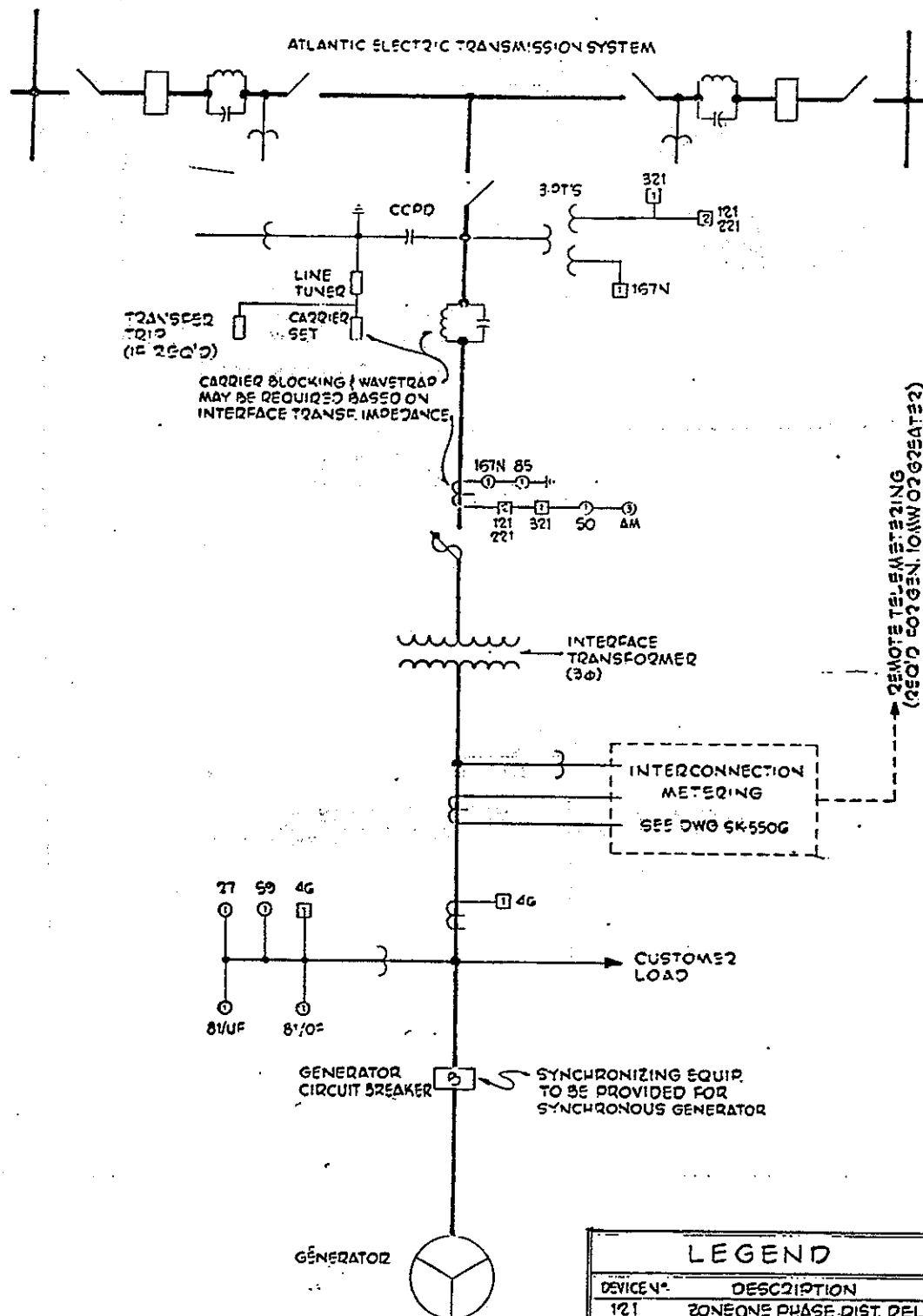
DEVICE #	DESCRIPTION
21	PILOT ZONE PHASE DIST. RELAY
121	ZONE ONE PHASE DIST. RELAY
221	ZONE TWO PHASE DIST. RELAY
321	REV. ZONE (CARRIER START) PHASE DIST. RELAY
67	PHASE DIST. OC. RELAY W/INST. UNIT (LOOKING IN TO CUST. SYSTEM)
67N	GROUND DIST. OC. RELAY W/INST. UNIT (CARRIER GND.)
167N	GROUND DIST. OC. RELAY W/INST. UNIT (LOOKING INTO A.E. SYSTEM)
267N	GROUND DIST. OC. RELAY W/INST. UNIT (LOOKING INTO CUST. SYSTEM)
85	CARRIER AUX. RELAY (IF NEEDED)
50	FAULT DETECT. RELAY TO SUPERVISE PHASE DIST. RELAY (IF NEEDED)
27	UNDERVOLT. RELAY
59	OVERVOLT. RELAY
87	TRANSF. DIFF. RELAY
81/UF	UNDERFREQ. RELAY
81/OF	OVERFREQ. RELAY

REMOTE TELEMETERING
(221 RELAY)

ATLANTIC CITY ELECTRIC COMPANY
ATLANTIC CITY, N. J.
DATE 4-11-65
NO. SK-5502

DIAGRAM # 2

Typical Installation of Customer owned Generator connected to Atlantic Electric Transmission System with transformer with high side circuit breaker.



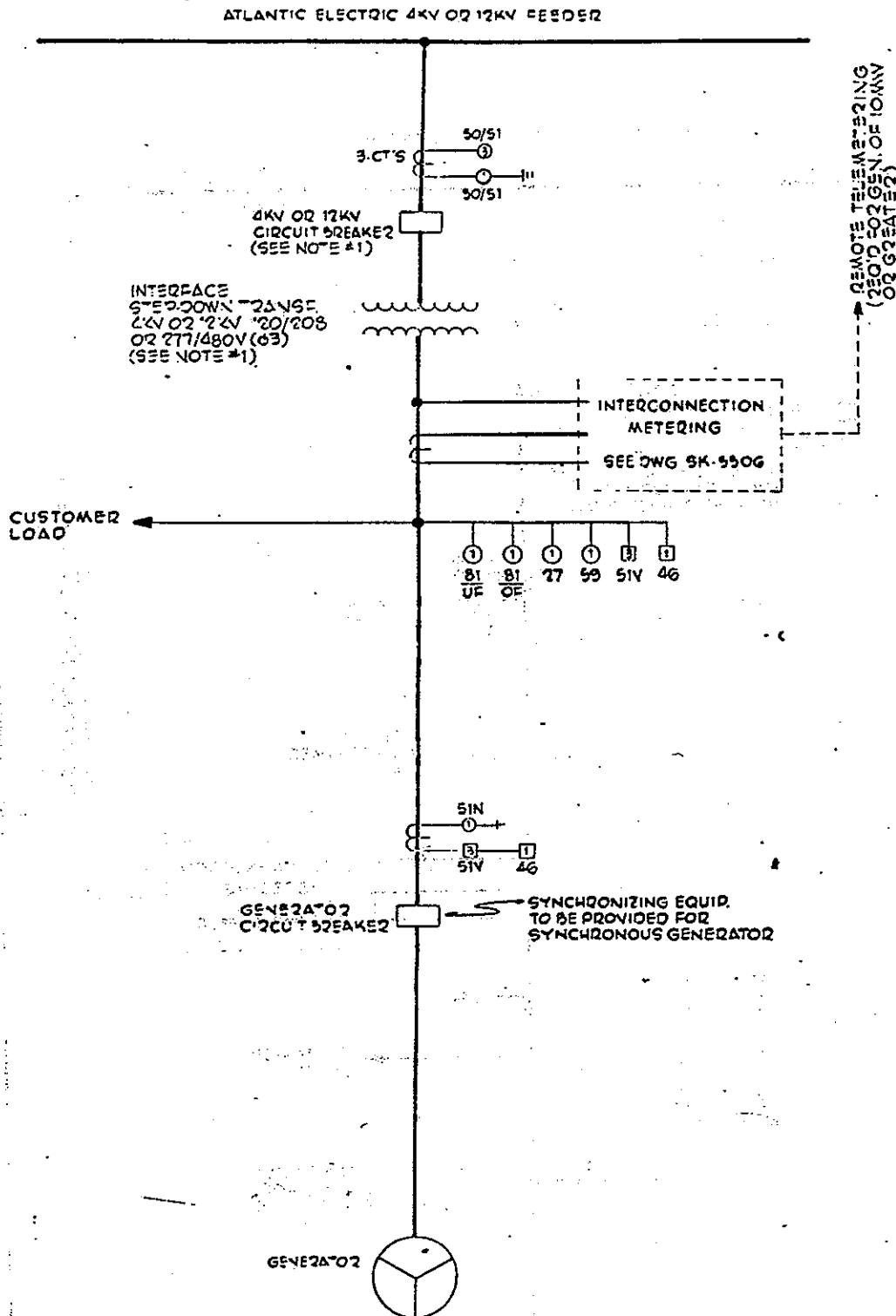


DIAGRAM # 4

NOTES

- #1. WHEN A.E.CO. HAS 4KV PRI., THE INTERFACE SK2 SHOULD BE RATED AT 12KV & THE INTERFACE STEP-DOWN TRANSF. PRI. SHOULD BE DUAL VOLT 4/12KV TO ALLOW FOR FUTURE CONNECTION OF 4KV TO 12KV SYSTEM.

LEGEND

Device No.	Description
46	Negative Sequence phase time overcurrent relay
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restrain
27	Undervoltage relay
59	Overvoltage relay
81/UF	Underfrequency relay
81/OF	Overfrequency relay

DIAGRAM #4

ATLANTIC CITY ELECTRIC COMPANY			
ATLANTIC CITY, N. J.			
DR. L. BROS.	CH.	DATE	NO.
SCALE	APP.	4/1/05	SK-5510

Typical installation of Customer owned Generator connected to Atlantic Electric Distribution System with transformer with high side circuit breaker.

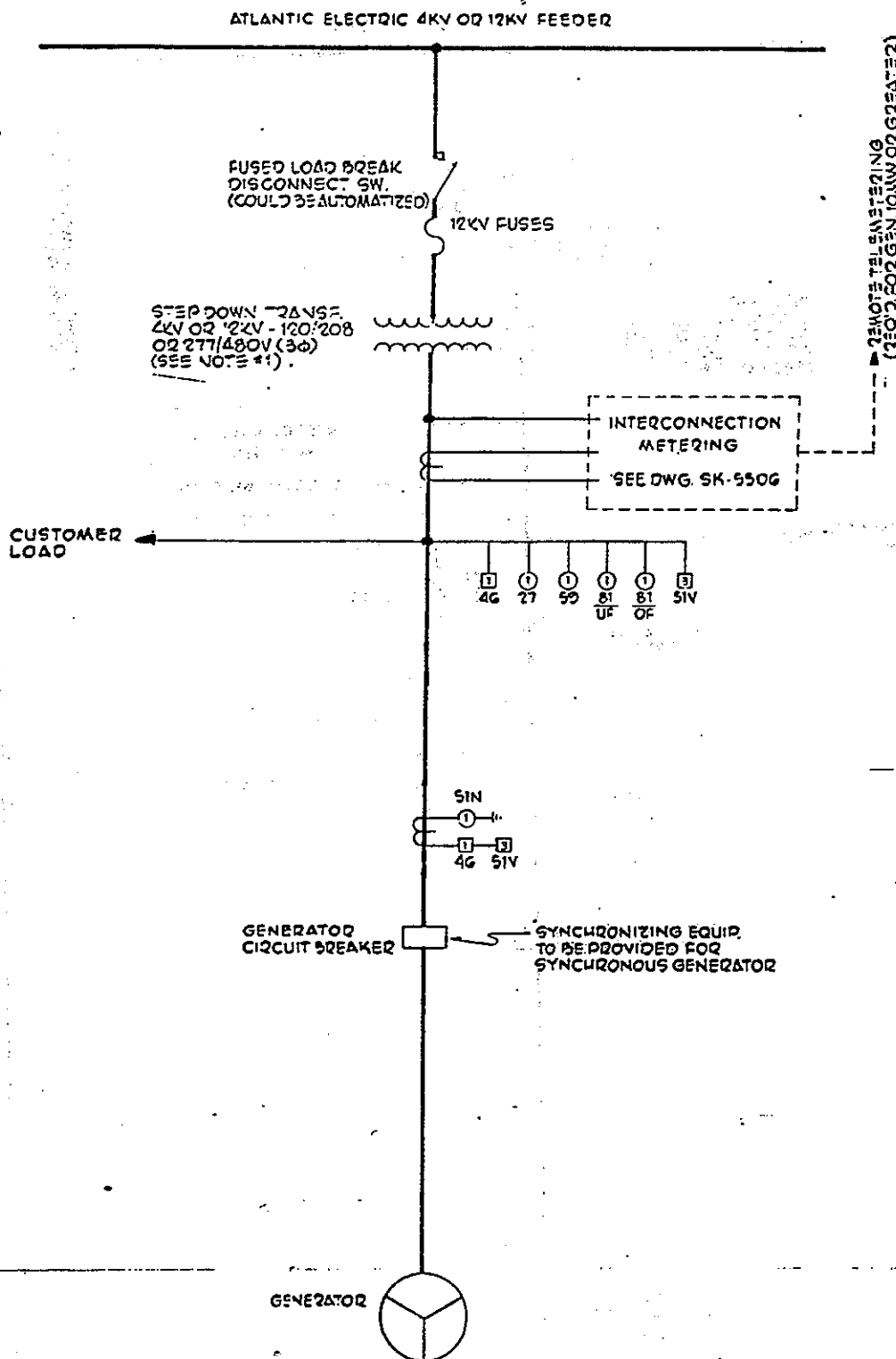


DIAGRAM #5

DIAGRAM #5

NOTES -

- #1. WHEN A.E.CO. HAS 4KV PRI., THE STEPDOWN TRANSF. P21. SHOULD BE DUAL VOLT. 4/12KV TO ALLOW FOR FUTURE CONVERSION OF 4KV TO 12KV SYSTEM.

LEGEND

Device No.	Description
46	Negative Sequence phase time overcurrent relay
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restrain
27	Undervoltage relay
59	Overvoltage relay
81/Uf	Underfrequency relay
81/of	Overfrequency relay

ATLANTIC CITY ELECTRIC COMPANY

ATLANTIC CITY, N.J.

DATE 4-11-85 NO. SK-5510

Typical installation of customer generator connected to Atlantic Electric distribution system with high side fuses.

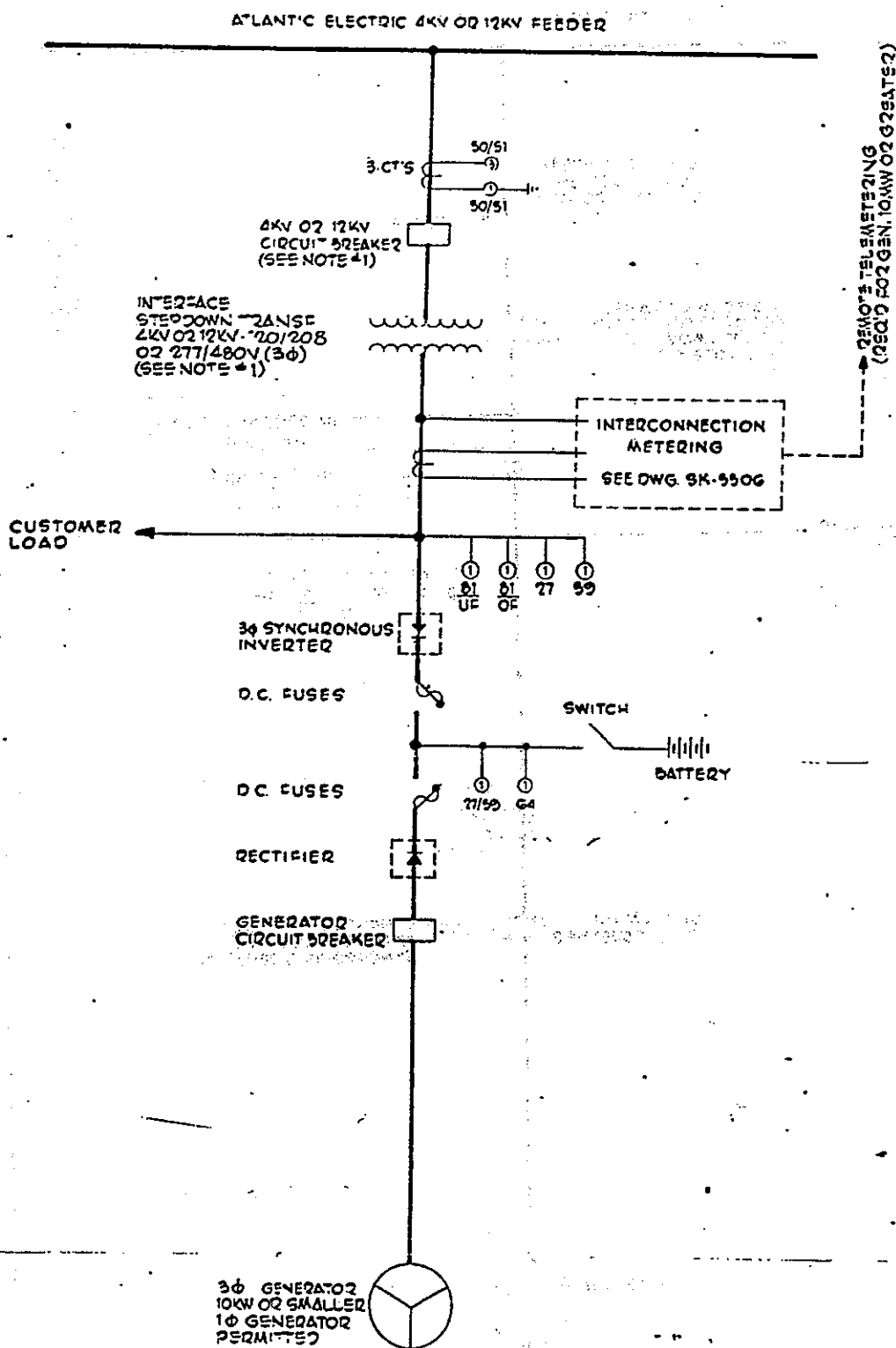


DIAGRAM #6

NOTES-

- *1. WHEN A.E. CO. HAS 4KV PRI. THE INTERFACE SKR. SHOULD BE RATED AT 12KV & THE INTERFACE STEP DOWN TRANS. PRI. SHOULD BE DUAL VOLT. 4/12KV TO ALLOW FOR FUTURE CONVERSION OF 4KV TO 12KV SYSTEM.

LEGEND

Device No.	Description
46	Negative Sequence phase time overcurrent relay
64	DC SYSTEM GND. DETECT. RELAY
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restrain
27	Undervoltage relay
59	Overvoltage relay
81/UF	Underfrequency relay
81/OF	Overfrequency relay

DIAGRAM #6

ATLANTIC CITY ELECTRIC COMPANY

ATLANTIC CITY, N. J.

DATE 4.11.85

NO. SK-5521

Typical Installation of Customer owned Generator connected to Atlantic Electric Distribution System with rectifier-inverter interface and transformer with high side circuit breaker.

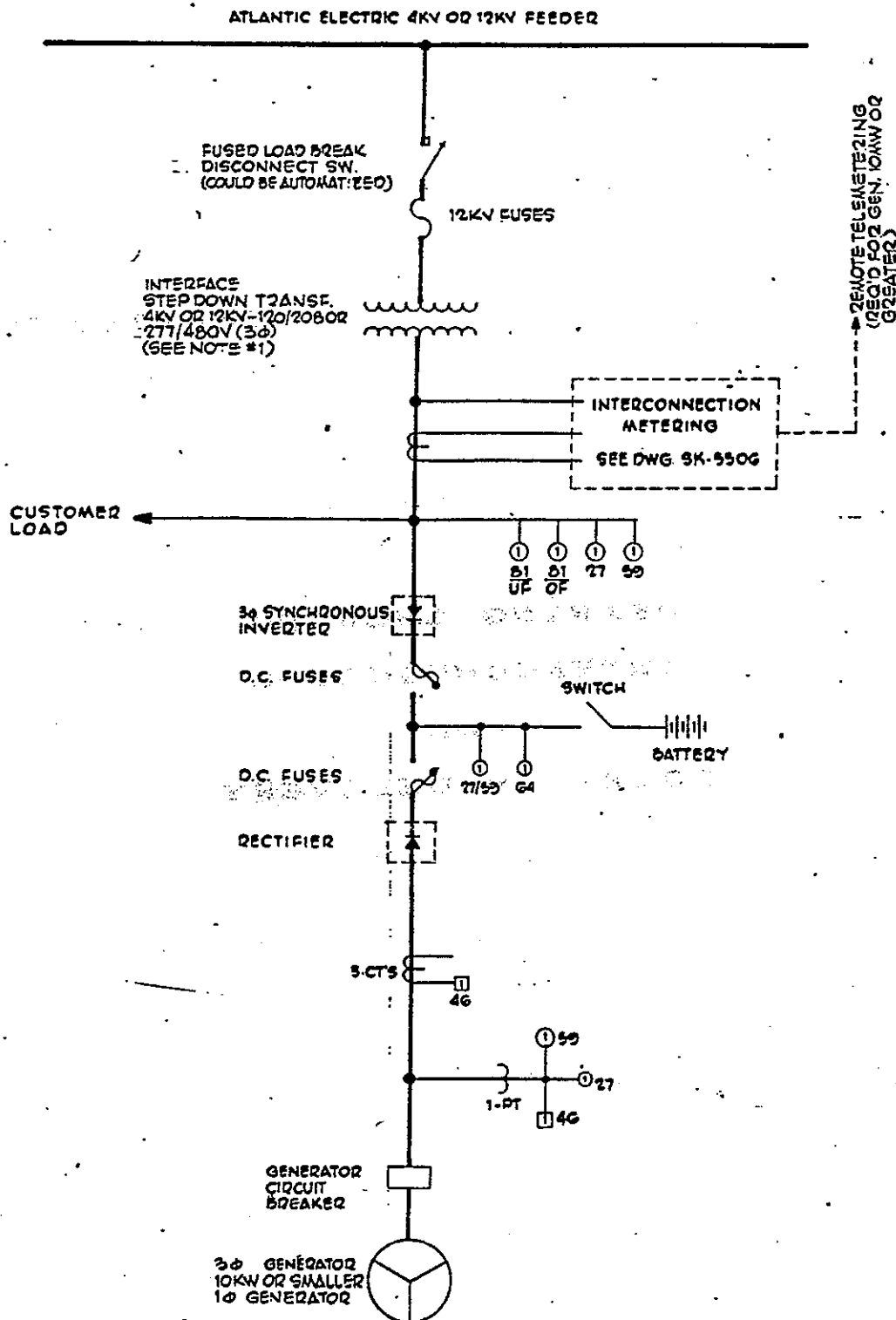


DIAGRAM #7

NOTES -

- #1. WHEN A.E.C.O. HAS 4KV P21., THE INTERFACE STEP DOWN TRANSF. P21. SHOULD BE DUAL VOLT. 4/12KV TO ALLOW FOR FUTURE CONVERSION OF 4KV TO 12KV SYSTEM.

LEGEND

Device No.	Description
46	Negative Sequence phase time overcurrent relay
G4	DC SYSTEM GND. DETECT. RELAY
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restrain
27	Undervoltage relay
59	Overvoltage relay
81/Uf	Underfrequency relay
81/Of	Overfrequency relay

ATLANTIC CITY ELECTRIC COMPANY
ATLANTIC CITY, N. J.

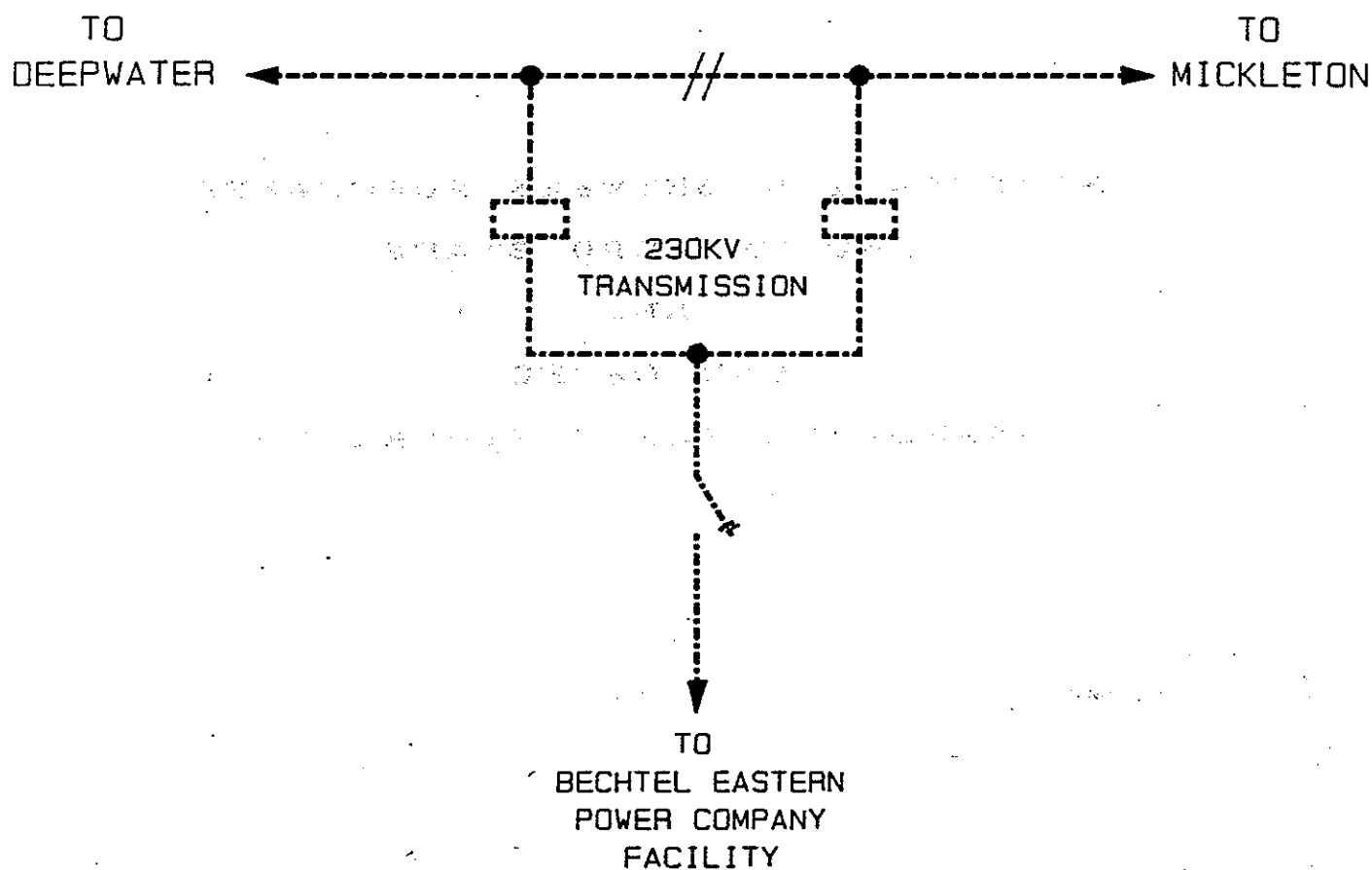
DIAGRAM #7

SCALE: 1" = 10' 11.05' 12.05' 13.05' 14.05' 15.05' 16.05' 17.05' 18.05' 19.05' 20.05' 21.05' 22.05' 23.05' 24.05' 25.05' 26.05' 27.05' 28.05' 29.05' 30.05' 31.05' 32.05' 33.05' 34.05' 35.05' 36.05' 37.05' 38.05' 39.05' 40.05' 41.05' 42.05' 43.05' 44.05' 45.05' 46.05' 47.05' 48.05' 49.05' 50.05' 51.05' 52.05' 53.05' 54.05' 55.05' 56.05' 57.05' 58.05' 59.05' 60.05' 61.05' 62.05' 63.05' 64.05' 65.05' 66.05' 67.05' 68.05' 69.05' 70.05' 71.05' 72.05' 73.05' 74.05' 75.05' 76.05' 77.05' 78.05' 79.05' 80.05' 81.05' 82.05' 83.05' 84.05' 85.05' 86.05' 87.05' 88.05' 89.05' 90.05' 91.05' 92.05' 93.05' 94.05' 95.05' 96.05' 97.05' 98.05' 99.05' 100.05'

Typical Installation of Customer Generator connected to Atlantic City Electric Company Distribution System with rectifier interface and transformer with high voltage side.

EXHIBIT D.

DRAWING SHOWING
INTERCONNECTION
AND
POINT OF DELIVERY



BECHTEL EASTERN POWER CO. COGENERATION FACILITY
INTERCONNECTION AND POINT OF DELIVERY

DR.	FAM	CH.	CH.	APP.	DATE	SCALE	ROUTE
ATLANTIC ELECTRIC CO.	P'VILLE, N.J.	NO.	SK-8294-0				

EXHIBIT E

**STIPULATION BETWEEN PURCHASER
AND THE BPU STAFF
AND
BPU ORDER
APPROVING THE STIPULATION**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF INVESTIGATION BY :
THE STAFF OF THE NEW JERSEY BOARD :
OF PUBLIC UTILITIES OF ATLANTIC : STIPULATION
CITY ELECTRIC COMPANY'S PROPOSED :
COGENERATION AND SMALL POWER :
PRODUCTION POLICY :

1. Since May of 1986, Atlantic City Electric Company (hereinafter referred to as the "Company" or "Atlantic Electric") has been in the process of evaluating twelve (12) independent proposals which were submitted to the Company relating to the construction and development of qualifying facilities (hereinafter referred to as "QFs") and small power production facilities pursuant to the Public Utilities Regulatory Policies Act of 1978 (hereinafter referred to as "PURPA") and the sale of the electrical output therefrom to the Company in accordance with PURPA. In connection with its review of the proposals, the Company developed an evaluation and ranking system. In January, 1987, the staff of the Board of Public Utilities (hereinafter referred to as the "Staff") was advised that Atlantic Electric had completed its evaluations and was about to notify three of the QFs to commence negotiations with the Company. On January 14, 1987 the Staff requested and Atlantic agreed to withhold notification to the QFs until Staff had had an opportunity to review the methodology utilized by the Company to insure that it comported with Board policy on cogeneration and small power production. After its review of Atlantic Electric's procedures, on May 13, 1987 Staff issued its "Evaluation by the Staff of the New Jersey Board of Public Utilities of Atlantic Electric's Proposed Cogeneration and Small

Power Production Policy" (hereinafter referred to as the "Staff Report"). The Staff Report was distributed to the Company as well as to all QFs who had submitted proposals to the Company. The Staff Report was critical of the Company's procedures and policy and recommended a standard offer approach. Comments from all parties were solicited by the Staff by June 15, 1987. The Company, as well as all QFs, submitted comments covering a wide range of policy and other issues raised not only by Atlantic Electric's procedures but also by PURPA and the Board's existing policies on cogeneration.

2. The Staff has reviewed and considered all of the comments from the parties and has discussed with the Company a proposal for resolving the policy and procedural disagreements between the Company and the Staff over the development of cogeneration in Atlantic Electric's service territory, as well as the State of New Jersey. To this end, the Company and the Staff have entered into this Stipulation to promote the development of alternative power supplies in accord with the mutual desires of the parties and the Board.

3. The Board has expressed its position in favor of contract terms and conditions that foster development of alternative power sources. Under Docket No. 8010-687, the Board established guidelines for the determination of avoided cost to be paid to QFs under PURPA. In Atlantic Electric's case, that Order establishes (1) the PJM billing rate plus 10% as the avoided energy cost and (2) the PJM capacity deficiency value as the avoided capacity cost consistent with PURPA. The Board's determinations included the following quotations:

A. "The central guideline for the Board's consideration of this Docket is FERC Order No. 69 which suggests that the price that the QF receives for its energy or capacity sales to an electric utility be based upon avoided costs. Avoided cost is defined as follows:

The incremental cost to an electric utility of electric energy or capacity or both which,

but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source. (Order 69, Section 292.201(b)(6)).

The Board interprets this definition to mean that the purchase of energy from a QF will not significantly affect the bills of all other utility customers and that the QF will at the same time receive the true and full economic value for its energy or capacity. The Board's decision and order in this proceeding has thus been drawn with the intent of encouraging cogeneration and small power production but not to the detriment of electric utility customers."

B. "In setting the value of avoided energy costs at a figure of 10% above the PJM billing rate, the Board determined that such a rate "will help to adequately promote cogeneration and small power production in New Jersey and, at the same time, will yield long term benefits to utility ratepayers."

C. "It is the belief of this Board that it is sound policy for a larger QF to negotiate the rates for the sale of its power to electric utilities. Through such negotiations, a contract may be developed which will address and meet the particular financing and technical needs of a QF investor. For example, a hydroelectric or a resource recovery investor may desire a contract which yields greater revenues during the initial years of the agreement; conversely, a cogenerator utilizing natural gas may favor a contract rate which increases over time in order to keep pace with the cost of fossil fuels."

D. "It is our firm belief, however, that the negotiation of long term contracts that are tailored to the specific characteristics of a particular QF will maximize benefits to the QF as well as to the affected utility and its ratepayers. We are further of the opinion that the use of a basis should not adversely affect the negotiation process."

E. "Thus the Board recommends that the parties in future power sales negotiations, where financial constraints demand, consider establishment of a levelized price for energy sales, such levelization to be based upon long-term projections of avoided costs as presently defined by the Board."

F. "Further, the Board recommends, as it did in Docket No. 833-236, that a contract life equal in duration to the period of debt financing, or economic life of the facility should be an option made available by the electric utility to the QF. Such contracts should be based on long-term avoided cost as presently defined by the Board. Within this concept, mechanisms can be incorporated which assure that ratepayers will be held harmless by such pricing structures."

4. Staff represents that the concepts and agreements embodied within this Stipulation, including pricing levels, are consistent with the above and other determinations of the Board, including:

A. Establishment of a "Standard Price Methodology" to facilitate price agreement while still retaining an option on the part of QF developers to negotiate other pricing.

B. Use of the current PJM billing rate + 10% + avoided capacity costs as a basis for developing payment rates determined "before the fact" for long-term contracts.

C. Use of levelized payments, which have a substantial beneficial effect upon the financing of such projects because of the more stable, predictable cash flow they produce for the project than does a variable after-the-fact determined, avoided-cost price. It is recognized that this method of pricing yields payments for energy and capacity that exceed the utility's near-term avoided cost in the front years and are lower than avoided cost projections in the end years. It is anticipated that the aggregate long-term avoided costs will reasonably match the contract payments over the contract term,

provided that energy delivery is sustained throughout the contract term.

D. Contract terms extending up to 30 years from the date a QF facility starts operation.

5. The parties are not in full agreement as to the proper methodology to be used to establish avoided cost and the before-the-fact energy and capacity rates to be paid to QFs. The positions of the parties in this regard are:

A. The Company has proposed that payments under long-term contracts be based upon avoided costs (energy plus capacity) determined as a result of comparing alternate capacity expansion plans utilizing the Company's system planning approach. The Company further believes that once its forecasted capacity needs are met, the avoided cost for additional cogeneration capacity diminishes to the PJM running rate for energy, and that therefore any fixed payment recognizing a value for capacity also diminishes to zero. The Company incorporates herein by reference all of the positions and comments submitted to the Board in this matter and dated June 15, 1987.

B. Staff believes that further commercial incentives to QF project development are appropriate, including pricing to yield customer break-even (present value) on a contract life cycle basis (end of contract term) based upon the Company's projection of PJM energy costs, plus 10%, and capacity payments based on the PJM capacity deficiency values. Establishment of levelized rates ensures and allows calculation of, to the extent that electric production of a facility is maintained at expected levels, revenue streams from electric sales over the economic life of the project. Staff proposes that several payment schedules be developed in which a certain portion is levelized and the remainder tracks avoided cost or some other significant index. The more capital intensive the project, the higher is the degree of allowable levelization. This allows QFs flexibility to choose the degree of levelization required to meet

specific financing needs. This approach will appropriately value and attract long-term purchase of QF capacity and energy to the benefit of Atlantic Electric and its customers.

6. Notwithstanding these differences in approach, the parties have reached agreement upon a standard price methodology to be used at the present time. The parties have done this in the interest of assuring continued development of QF energy and capacity to service Atlantic Electric's customers and to protect the resources which have been expended by the QFs who submitted proposals to the Company and have an interest in the outcome of this proceeding.

7. Exhibit A to this Stipulation establishes the Standard Price Methodology agreed to by the parties for purchases by Atlantic Electric from QFs. The Standard Price Methodology has the following significant features:

A. Projects are categorized by technology and fuel source, that is, renewables (e.g., resource recovery; conventional hydroelectric); oil and gas; and coal. The percent of the price which is paid in levelized form may vary to reflect the degree of capital intensity of such projects and, therefore, the realities of project financing. In the Company's first 500 megawatt tier, the Company will provide energy levelization rates at the QFs' option not to exceed: 80% for renewable resource projects; 60% for coal projects; and 35% for oil and gas projects. In the second tier, the maximum energy levelization rates will be as follows: for in-territory renewable resource projects--50%; for coal projects--40%; and for oil and gas projects--20%.

B. In an effort to further improve project viability, the variable portion varies with (i) either PJM billing rate, the appropriate fuel index, or any mix thereof at the developer's option for oil, gas and coal projects, or (ii) GNP deflator, the PJM billing rate or any mix thereof at the developer's option, in the case of resource recovery and conventional hydroelectric projects.

C The capacity value is determined in the Standard Price Methodology to reflect the Board's Order in Docket No. 8010-687. A levelized capacity value will be payable in a manner to encourage on-peak and peak season production.

D The total payment derived in paragraphs A, B and C reflects the Board's Order in Docket No. 8010-687.

E The Standard Price Methodology shall provide for contract terms of between 15 and 30 years.

8. The purpose of the Standard Price Methodology is to establish standard pricing offers which will be available to any and all QF developers so as to facilitate the development of QF capacity and energy to the benefit of Atlantic Electric and its customers. The Board will pre-approve standard pricing offers, and standard pricing agreements signed between Atlantic Electric and a QF developer will be treated by the Board as having its approval. It is anticipated that resultant full contracts would receive the Board's final approval in an expedited fashion. In view of the fact that the remaining eleven (11) QFs have been held in abeyance, Staff agrees that these QFs should have the first opportunity to sign standard offers with the Company. In the event the Company's standard offer is not fully subscribed by the existing eleven proposals, the Company will continue to entertain and accept other offers made in accordance with this Stipulation as they are received.

9. The Standard Price Methodology will serve the additional function of assuring equal access and opportunity to all QF developers to contract with the Company.

10. A QF developer will not be eligible for a pricing agreement under the Standard Pricing Methodology unless the following minimum submittals have been made available to and are satisfactory to the Company:

A. FERC certification granting qualifying status to the facility; provided, however, that the Company may accept proposals

based on evidence that the project is certifiable under FERC's rules and regulations;

B. A statement of project definition including preliminary project design and construction schedule, anticipated project operation commencement and life, and year-by-year energy delivery;

C. Letter of intent or similar evidence of host site control;

D. Adequate fuel supply consistent with anticipated project life and energy production;

E. A plan for obtaining all necessary project licensing;

F. Preliminary evidence of financeability of the project, and a preliminary financing plan;

G. Evidence of thermal customer, if a cogenerator; and

H. A milestone chart for the project and payment into a reserve fund not to exceed \$10.00/KW, which reserve fund shall be payable to the Company in the event milestones established in the contract are not substantially complied with by the QF. Full payment into the reserve fund will be due upon the QF's acceptance of a standard offer.

11. The Company's standard offer tiers are based on the Company's forecasted energy and capacity needs, which are based on existing capacity, planned retirement, forecasted load growth and planned and/or anticipated capacity additions. The Company and Staff agree that the first tier will be 500 megawatts and that there will be one subsequent 200 megawatt tier. Exhibit A to this Stipulation contains the prices applicable to each tier. To the extent a project does not fall completely within the first 500 megawatt tier (e.g., if there is 40 MW of power unallocated in the first tier and the next qualified project is 60 MW), so long as more than 50% of the

project's rated capacity is in the higher tier, the higher tier price shall apply to all sales to the Company. Over-subscribed tiers will be awarded by random drawings.

12. The Company shall be allowed to prioritize the proposals it has received using the following criteria:

- A. In-territory renewable QFs;
- B. In-territory dispatchable QFs;
- C. In-territory QFs;
- D. In-state dispatchable QFs;
- E. In-state renewable QFs;
- F. In-state QFs; and
- G. All others.

13. The parties agree that it is necessary and desirable to establish a procedure to review the pricing mechanisms and the level of price reflected in the standard price methodology, and the process by which contracts are to be developed and executed. This will assure both appropriate development of QFs and protection to the Company's customers against problems in the selection process. It is explicitly anticipated that the experience during the offer period together with the updated anticipation of the Company's energy needs will be the basis for a review and revision of the program. However, it is the intent of the parties to maintain continuity in the QF development program by maintaining ongoing communications regarding status, outlook and potential problem areas, and to jointly attempt to resolve such problem areas for prompt approval by the Board. Ongoing communications will include periodic review meetings and prompt written notifications to the Board regarding signed standard pricing agreements.

14. The Parties recognize that many QF projects will require negotiations on price and non-price terms which are not reflected in, or may require variation from, the Standard Price Methodology. These include, but are not limited to, terms such as:

- A. A technology not reflected in the Standard Price Methodology;
- B. Dispatchability;
- C. Electric system interconnection, operation and integration requirements;
- D. Energy delivery incentives and penalties; and
- E. Any other non-standard term or condition.

Atlantic Electric agrees not to impose suspense accounts, recapture pools, or other performance penalties, except as specifically identified in this Stipulation for dispatchable facilities. The parties recognize that such contracts and provisions will be subject to Board approval.

15. The signed offer under the Standard Price Methodology will not remain in force unless the QF developer executes a full contract within six (6) months of the date of signing of the standard price offer, provided, however, that a QF may request an extension of time for good cause, but in no event shall such an extension, together with the initial six-month period, exceed twelve (12) months. Each contract will specify initial target dates for construction commencement and operation commencement, along with limit dates which must be met in order for the signed pricing offer to remain in force.

16. All payments made to QFs for capacity and/or energy under this standard offer and contracts approved by the Board shall be recognized as having been a prudently incurred expense, a just and reasonable rate clearly in the public interest and, accordingly,

the Board will allow Atlantic Electric to flow-through and/or permit full and timely recovery in a LEAC proceeding of any such long-term contract purchase rates from its customers throughout the term of such contracts, regardless of subsequently approved avoided cost definitions.

17. The Exhibit A standard pricing offers will be effective on the date of the Board Order in this matter.

18. This Stipulation is subject to the understanding that it is solely for standardized pricing offer development and implementation as described herein. Any party may, without prejudice, fully litigate and contest such issues in future proceedings should this Stipulation not be approved by the Board.

19. The parties agree that the within Stipulation reflects mutual balancing of various issues and positions and is intended to be accepted and approved in its entirety. Each term is vital to this Stipulation as a whole, since the parties hereto expressly and jointly state that they would not have signed this Stipulation had any terms been modified in any way. In the event any particular aspect of this Stipulation is not accepted and approved by the Board, then either party hereto aggrieved thereby shall not be bound to proceed with this Stipulation and shall have the right to brief or argue all issues to a conclusion. The parties further recognize and agree that this Stipulation has been accepted and agreed to by the Staff and the Company in the interest of expediting the development of cogeneration and small power production and that with respect to any policy or other issues which were compromised in the spirit of reaching an agreement, neither party shall be prohibited from or prejudiced by arguing a different policy or position before the Board in its pending 5-year review of cogeneration and small power production policy in the State of New Jersey, which proceeding has been undertaken by the Board concurrently herewith.

20. The Company shall be entitled to amend its standard offer prices and procedures consistent with the Board's subsequent

findings in the 5-year review of cogeneration and small power production policies; provided, however, that such amendments shall apply only to standard offers which have not been accepted by the QF as of the time of such amendment. The policies and procedures agreed to herein shall remain in effect until such time as the Board acts on its 5-year review.

21. Attached hereto as Exhibit B is a "Schedule of Procedures and Timetable" for implementing the standard offer process contained in this Stipulation.

IN WITNESS WHEREOF, the parties hereto have this day caused this Stipulation to be duly executed.

ATLANTIC CITY ELECTRIC COMPANY
1199 Black Horse Pike
Pleasantville, New Jersey 08232

By: _____
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STAFF OF THE NEW JERSEY BOARD
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Steven Gabel
Director, Division of Electric

EXHIBIT A

STANDARD PRICE METHODOLOGY

FOR

PURCHASE OF ENERGY---

BY

ATLANTIC CITY ELECTRIC COMPANY

FROM

QUALIFYING FACILITIES

IN

NEW JERSEY

A. Objectives

1. Promote development of different types of QF energy resources in the Atlantic Electric's service territory, and State of New Jersey on behalf of Atlantic Electric customers, including gas/oil fired projects, coal or coal waste fueled projects, conventional hydroelectric projects, and resource recovery projects.
2. Promote availability of QF energy on a long term basis, at times when it is most valuable to Atlantic Electric's customers.
3. Implement, with Board approval, pricing that is consistent with the requirements of PURPA and Board orders.

B. Definition of Avoided Cost

Under Docket No. 8010-687, the Board established guidelines for the determination of the avoided cost to be paid to QFs. That Order established (1) the PJM billing rate plus 10% as the avoided energy cost and (2) the PJM capacity deficiency rate as the avoided capacity cost.

Notwithstanding different positions as to the appropriate pricing methodology for before-the-fact pricing of purchases from QFs, the Company and Staff have agreed to base this standard pricing methodology on the Board's methodology for after-the-fact determination of avoided cost.

C. Forecast of Avoided Cost

1. Capacity avoided costs are derived from projections of revenue requirements for the estimated costs associated with the PJM Capacity Deficiency rate.

The parties have agreed that capacity payments will be offered for capacity which meets PJM's criteria.

2. Energy avoided costs are derived from computer model production cost simulations of the operation of the Company and PJM generating stations over the term of the contract. This model is based on a current best estimate (base case) of future conditions, including:

- a) energy and peak load forecasts for the Company and other members of PJM;
- b) energy supply sources available to the Company and other members of PJM;
- c) fuel price forecasts; and,
- d) forecasts of relevant economic conditions, such as inflation.

3. The data presented here are based on economic and production cost forecasts as of November 1986.
4. Discounting and levelization are based on the Company's projected weighted cost of permanent capital, currently 11.35%

D. Pricing Precepts

The fundamental precept of this standard pricing methodology is to reasonably match pricing to projected avoided cost over the contract term, on a present value or levelized basis, for the current best estimate of future conditions. A second precept is sustained annual delivery of energy by the QF over the term of the contract.

It is the intent of the standard price methodology to:

1. Provide a mix of fixed (level) and variable price components that will help developers meet the financing needs of projects of different capital intensity and potential fuel cost volatility. This means:
 - a) allowing higher levelization for capital intensive projects with low fuel cost volatility; and,
 - b) allowing lower levelization and hence more "indexing" to projects with low capital intensity but potentially high fuel cost volatility.
 - c) developing a dispatchable unit methodology
2. Provide developers with a choice of escalators (indices) to be applied to variable price components, reflective of either energy value to Atlantic Electric's customers or major cost to QF operator.
3. Allow for contract terms of between 15 and 30 years.
4. Control the level of early year rate exposure to Atlantic Electric customers that results from levelizing contract payments in excess of avoided costs. This requires capping the amount of levelization.
5. Within the framework of the precepts noted above, namely break-even on a present value basis at the end of the contract and sustained annual energy delivery over the contract term, control the risk to Atlantic Electric customers of not realizing enough subsequent cost advantages (relative to the avoided cost) to compensate for early year incentive payments in excess of avoided cost.

E. Standard Price Formula for Contract Pricing

The parties have agreed to the following pricing formula:

$$\text{Payment in Year n, c/KWH} = \text{Levelized Cap'y Payment} + \text{Levelized Energy Payment} + \text{Variable Energy Payment}$$

Each of these terms will be described in more detail in the following sections, and numerical data will be displayed.

For Dispatchable Units the formula is expressed as two parts:

$$\text{Payment in Year n c/KWH} = \text{Variable Energy Payment} + \text{Levelized Energy Payment (to be determined)}$$

Plus

$$\text{Annual Payment} = \left[\text{Levelized Cap'y Payment} + \text{Levelized Energy Payment (to be determined)} \right] \times$$

$$\frac{8760 \text{ hours}}{\text{year}} \times .85 \text{ (Capacity Factor)} \times \text{Availability Factor}$$

$$\text{Availability Factor} = \frac{\text{QF Availability in year n}}{\text{AE System Availability in year n}}$$

Where Availability Factor exceeds 90% its value shall be set at 1.0

F. Dispatchable

Dispatchable is defined as Atlantic Electric's ability to call upon or not call upon the unit for its capacity at any hour during the year. Atlantic Electric will guarantee 3500 hours (non negotiable) of operation in any calendar year as established by its computer model production costing. Minimum starting notice and minimum run durations are subject to negotiation. The intent of the dispatchable pricing option is to provide a level annual capacity payment per kilowatt for the life of the contract which varies only with the ratio of a QF's availability as compared to Atlantic Electric's availability. This level annual capacity payment per kilowatt to be applied to the rated capacity of the QF is the sum of the levelized capacity payment and levelized energy payment presuming a capacity factor of 85% and 8760 hours per year.

G. Payments Depend on Time and Season of Generation

Energy and capacity payments are varied according to time and season of generation so as to encourage energy supply to Atlantic Electric when such energy has the highest value to Atlantic Electric customers.

On-Peak period: Seven days per week 9:00 A.M. to 11:00 P.M. EST; about 58% of the hours in a year. (1) The choice of hours is consistent with existing Atlantic Electric load patterns.

Off-Peak period: All other hours.

Peak Season: Dec. through Feb. and June through September (7mo. or 212.25 days)

Off Season: March through May and October through November (5 mos. or 153 days)

Peak Season = 58.1% of year

(1) $365.2 \times \frac{14 \text{ Hrs.}}{\text{day}} = 0.5833$

$\frac{365.25 (24) \frac{\text{hr}}{\text{yr}}}{14} = 0.5833$

Energy and capacity payments are adjusted for time of delivery as follows:

1. Energy payments, for simplicity, are adjusted only for on-peak vs off-peak hours, with no seasonal adjustment. The adjustments are derived from production cost simulations, and reflect the relative value of energy to Atlantic Electric customers in these two periods, on an annual average basis.

$$R = \frac{\text{On-Peak or off-peak billing rate}}{\text{Annual average billing rate}} = \begin{matrix} 1.15 \text{ for on-peak hours} \\ 0.79 \text{ for off-peak hours} \end{matrix}$$

Note that

$$1.15 (0.583) + 0.79 (1-0.583) = 1.0$$

so that the hourly price weighting yields the correct annual average energy price if energy is produced uniformly throughout the year.

2. Capacity payments, for non dispatchable units for simplicity, are provided only during on-peak hours during peak seasons, to strongly encourage production when energy is most valuable to Atlantic Electric customers. The intent is to encourage scheduling of maintenance and other outages for off-season months.

$$\text{capacity payment} = \frac{\text{annual average capacity payment}}{(0.581) (0.583)}$$

$$= 2.95 * (\text{annual average capacity payment})$$

H. Levelized Capacity Payment

This payment is based on the projected PJM Capacity Deficiency payments. As described above, it is paid only for energy delivered during on-peak hours, and only during peak seasons. Capacity payments are predicated on an assumed annual capacity factor of about 85% for the QF. The entire capacity payment is levelized over the term of the QF contract.

Table-1 summarizes the levelized annual average capacity payments for QF's placed in service for each of the years from 1988 through 1994.

I. Levelized Energy Payment

Levelized Energy Payment, c/kWh = (L) * Energy Cost, \$/kWh * (R)
annual avg basis

L = Fraction of levelized avoided energy cost that is to be fixed for all years of the contract. L depends on type of project (technology and fuel), and has been chosen to provide higher levelization for capital intensive projects and lower levelization (higher variability) for fuel price sensitive projects.

As derived in Section F,

R = 1.15 for on-peak hours

R = 0.79 for off-peak hours

LAEC = Levelized Avoided Energy Cost, on an annual average basis, as derived from production cost projections of PJM billing rates + 10%. These values depend on contract start year (because of escalation) and contract term (because of levelization). See Table 3.

Criteria for Selecting Values of L

1. Values of L are tailored to match capital intensity/potential fuel cost volatility tradeoffs for each type of QF to facilitate project financing.
2. For all projects, and contract terms maximum values of L have been established. This is intended to control the level of early year excess rate exposure to Atlantic Electric customers.
3. Values of L range from 0 up to the maximum shown in Table 2.

J. Variable Energy Payment

Variable Energy Payment, c/KWH in year n = $(1-L) * (\text{Base}) * (\text{Index I}) * (R)$

L, R Have been previously defined.

The following indices are available to the developer on a one-time election basis at the time contract is executed:

1. The PJM billing rate.
2. Natural gas price, as defined by the annual average natural gas cost to N.J. utilities as reported on FERC Form 423 and published in the DOE/EIA Publication "Cost and Quality of Fuels for Electric Utility Plants."
3. Oil price, defined as above for natural gas, but based on "Petroleum" as reported.
4. Coal price, as above for natural gas, but based on bituminous cost coal used by all plants owned (or partly owned) by N.J. utilities. Index is tonnage weighted and based on N.J. utility ownership of joint owned stations.
5. GNP deflator, as defined by the annual Implicit Price Deflator Index for Gross National Product referenced in Table 7.7 of the U.S.D.O.C./B.E.A. "Survey of Current Business" publication.
6. Any mix of the above indices subject to certain restrictions as follows:

Fuel price indices are available only to fossil fuel projects having single fuel capability, where the fuel being used establishes the index that may be used. For projects with dual or multi-fuel capability, the applicable fuel index associated with the lower cost fuel will be used on a year-by-year basis to encourage use of the most economical fuel.

$I = \frac{\text{Value of indices for the preceding year (n-1) relative to year value of the indices in 1987}}{\text{value of the indices in 1987}}$

"Base" is defined as the variable portion of the energy payment (Table 4-Estimated Values of Base) for the year of contract in service adjusted to 1987 values by the ratio of the estimated value of the chosen escalator for the year preceding in-service relative to the value of the chosen escalator in 1987.

For year n, I then becomes $\frac{\text{Indices in year (n-1)}}{\text{Indices in 1987}}$

Values of I will be established in the first quarter of each year based on available published values of the indices.

Table 5 presents a comparison of First Year estimated contract payments to projected avoided costs.

FIGURE 1

SUMMARY OF STANDARD PRICE METHODOLOGY

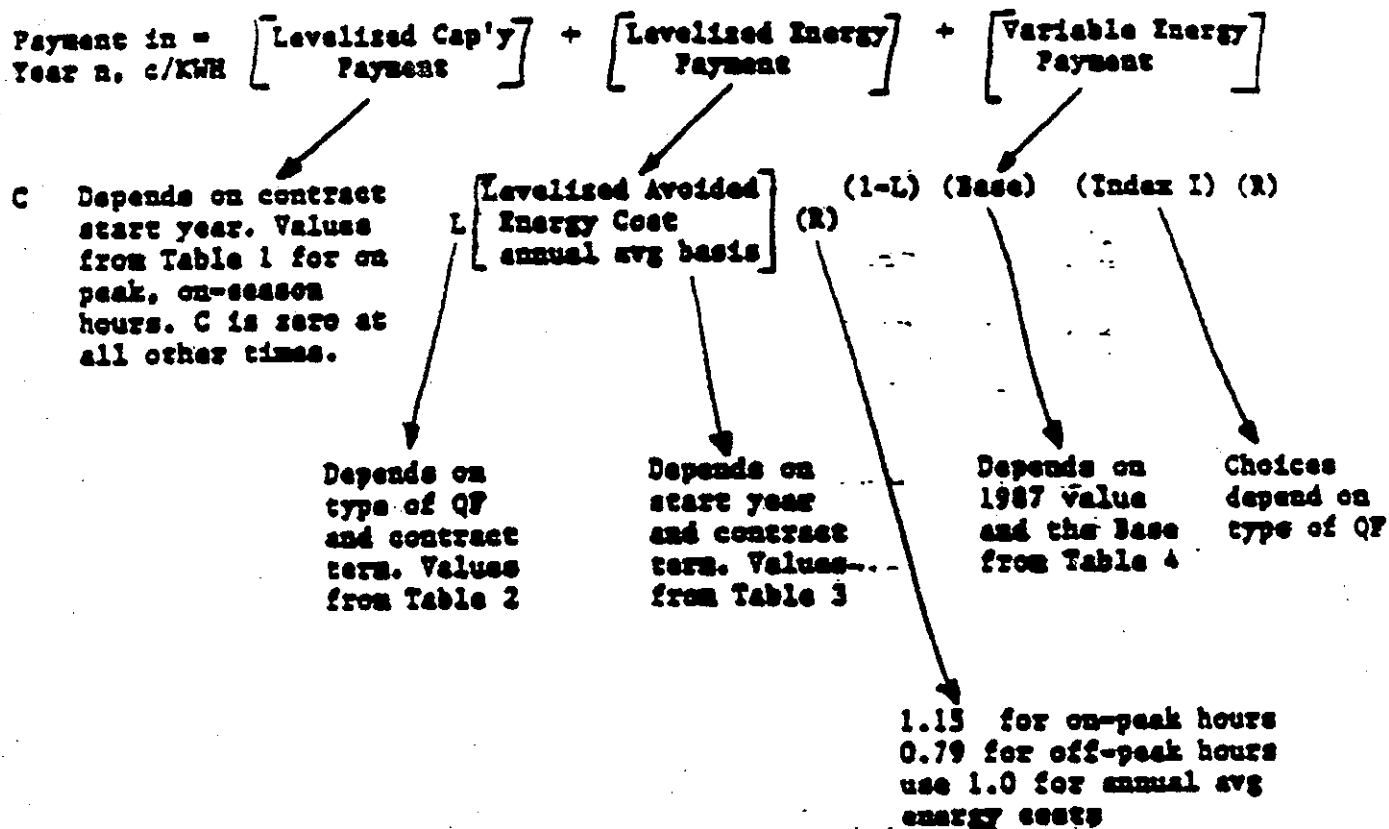


TABLE 1 - FIRST TIER

VALUES OF LEVELIZED ANNUAL AVERAGE CAPACITY PAYMENTS - cents/kwhr

Starting Year -----	Contract Term(Yrs) -----	Annual Average Basis -----	Actual Payment: Peak Season, On-Peak Period -----
1988	15	1.0147	2.9934
	20	1.0746	3.1701
	25	1.1258	3.3210
	30	1.1681	3.4459
1989	15	1.0590	3.1240
	20	1.1217	3.3091
	25	1.1752	3.4669
	30	1.2195	3.5975
1990	15	1.1054	3.2610
	20	1.1711	3.4547
	25	1.2270	3.6197
	30	1.2733	3.7562
1991	15	1.1532	3.4030
	20	1.2223	3.6058
	25	1.2608	3.7784
	30	1.3292	3.9211
1992	15	1.2031	3.5490
	20	1.2751	3.7613
	25	1.3363	3.9421
	30	1.3869	4.0914
1993	15	1.2551	3.7025
	20	1.3305	3.9249
	25	1.3945	4.1139
	30	1.4500	4.2775
1994	15	1.3097	3.8635
	20	1.3886	4.0964
	25	1.4556	4.2941
	30	1.5100	4.4545

TABLE 2 - FIRST TIER

Maximum Percentage of Levelized Avoided Costs to Be Fixed For Each Contract Term

PROJECT FUEL TYPE:		GAS/OIL	COAL	RENEWABLE RESOURCE (IN SERVICE TERRITORY)
Contract Term Yrs.	All Projects Capacity Payments	(1) L	(1) L	(1) L
15	100%	35%	60%	80%
20	100%	35%	60%	80%
25	100%	35%	60%	80%
30	100%	35%	60%	80%

(1) L = Fraction of levelized Avoided Energy Cost (PJN Billing Rate - 10%) that is to be fixed for all years of the contract. Values of L, from 0 up to the maximum indicated above, are available for each contract term.

TABLE 3 - FIRST TIER

Value of LREC(1), cents/KWH

Annual Average Basis

Starting Year	1988	1989	1990	1991	1992	1993	1994
Contract Term, Years							
15	4.5814	4.8401	5.1309	5.4771	5.8469	6.2433	6.6465
20	4.9823	5.2712	5.5870	5.9632	6.3849	6.7822	7.2252
25	5.3463	5.6621	6.0189	6.4144	6.8430	7.2974	7.7729
30	5.6806	6.0187	6.3961	6.8223	7.2784	7.7600	8.2700

(1) 100% Levelized Avoided Energy Cost (BPN Billing Rate + 10%)

TABLE 4 - FIRST TIER

ESTIMATED VALUES OF "BASE"

(Actual Values to be Determined based on Paragraph J6,
"After the Fact")

Contract In-Service Year	Forecast PJN Billing Rate + 10% For Preceding Year cents/KWH
1988	3.0558
1989	3.4078
1990	3.4542
1991	3.4623
1992	3.6806
1993	3.9509
1994	4.2880

TABLE 3 - FIRST TIER

COMPARISON OF ESTIMATED CONTRACT PAYMENTS
TO PROJECTED AVOIDED COSTS

Year	Avoided Cost (PJN + 10% + Levelized Capacity) M/KWH	Contract Term	Estimated Starting Price For Maximum x Levelized		
			Gas/Oil	Coal	R.R.
1988	44.2253	15	46.0442	49.8583	52.9096
	44.8244	20	48.0463	52.8626	56.7157
	45.3358	25	49.8318	55.5581	60.1391
	45.7594	30	51.4257	57.9879	63.2377
1989	45.1317	15	49.6814	53.2622	56.1266
	45.7590	20	51.8173	56.4757	60.2024
	46.2339	25	53.7206	59.3563	63.8649
	46.7366	30	55.4113	61.9385	67.1602
1990	45.6774	15	51.4644	55.6563	59.0098
	46.3340	20	53.7171	59.0491	63.3146
	46.8934	25	55.7683	62.2003	67.3298
	47.3562	30	57.5713	64.9261	70.8100
1991	48.3415	15	53.2108	58.2478	62.2774
	49.0288	20	55.5995	61.8517	66.8535
	49.6139	25	57.7635	65.1437	71.0478
	50.0978	30	59.6751	68.0749	74.7947
1992	51.5397	15	56.4186	61.8345	66.1672
	52.2599	20	58.9517	65.6625	71.0311
	52.8721	25	61.2374	69.1435	75.4683
	53.3783	30	63.2672	72.2616	79.4572
1993	55.4307	15	60.0832	65.8142	70.3989
	56.1849	20	62.7236	69.8019	75.4645
	56.8255	25	65.1672	73.5334	80.2263
	57.4000	30	67.3000	76.9000	84.5000
1994	59.8351	15	64.2387	70.1400	74.8611
	60.6246	20	67.0468	74.3896	80.2640
	61.2946	25	69.6335	78.3457	85.3155
	61.8000	30	71.9000	81.9000	89.8000

TABLE 1 - SECOND TIER

VALUES OF LEVELIZED ANNUAL AVERAGE CAPACITY PAYMENTS - cents/kwhr

Starting Year	Contract Term(Yrs)	Annual Average Basic	Actual Payment: Peak Season, On-Peak Period
1988	15	1.0147	2.9934
	20	1.0746	3.1701
	25	1.1258	3.3210
	30	1.1681	3.4459
1989	15	1.0590	3.1240
	20	1.1217	3.3091
	25	1.1752	3.4669
	30	1.2195	3.5975
1990	15	1.1054	3.2610
	20	1.1711	3.4547
	25	1.2270	3.6197
	30	1.2733	3.7562
1991	15	1.1536	3.4030
	20	1.2223	3.6058
	25	1.2808	3.7784
	30	1.3292	3.9211
1992	15	1.2031	3.5490
	20	1.2751	3.7615
	25	1.3363	3.9421
	30	1.3869	4.0914
1993	15	1.2551	3.7025
	20	1.3305	3.9249
	25	1.3945	4.1139
	30	1.4500	4.2775
1994	15	1.3097	3.8635
	20	1.3886	4.0964
	25	1.4556	4.2941
	30	1.5100	4.4545

TABLE 2 - SECOND TIER

Maximum Percentage of Levelized Avoided Costs to Be Fixed For Each Contract Term

PROJECT FUEL TYPE:		GAS/OIL	COAL	RENEWABLE RESOURCE (IN SERVICE TERRITORY)
Contract Term Yrs. -----	All Projects Capacity Payments -----	(1) L -----	(1) L -----	(1) L -----
15	100%	20%	40%	50%
20	100%	20%	40%	50%
25	100%	20%	40%	50%
30	100%	20%	40%	50%

(1) L = Fraction of levelized Avoided Energy Cost (PJH Billing Rate - 10%) that is to be fixed for all years of the contract. Values of L, from 0 up to the maximum indicated above, are available for each contract term.

TABLE 3 - SECOND TIER

Values of LREC(1), cents/KWH

Annual Average Basis

Starting Year	1988	1989	1990	1991	1992	1993	1994
Contract Term, Years							
15	4.0707	4.3000	4.5576	4.8657	5.1949	5.5476	5.9083
20	4.4273	4.6835	4.9630	5.2984	5.6599	6.0273	6.4215
25	4.7511	5.0314	5.3479	5.6999	6.0814	6.4858	6.9090
30	5.0487	5.3487	5.6835	6.0629	6.4688	6.8994	7.3508

(1) 100% Levelized Avoided Energy Cost (AJN Billing Rate + 10%)

TABLE 4 - SECOND TIER

ESTIMATED VALUES OF "BASE"

(Actual Values to be Determined based on Paragraph J6,
"After the Fact")

Contract In-Service Year		Forecast EPJM Billing Rate - 10% For Preceding Year cents/KWH	
-----		-----	
	1988		3.0558
	1989		3.0330
	1990		3.0742
	1991		3.0726
	1992		3.2668
	1993		3.5074
	1994		3.8074

TABLE 5 - SECOND TIER

COMPARISON OF ESTIMATED CONTRACT PAYMENTS
TO PROJECTED AVOIDED COSTS

Year	Avoided Cost (PJH - 10% Levelized Capacity) M/KWH	Contract Term	Estimated Starting Price For Maximum & Levelized		
			Gas/Oil	Coal	R.R.
1988	40.4767	15	42.7343	44.7642	45.7791
	41.0758	20	44.0466	46.7896	48.1611
	41.5872	25	45.2057	48.5965	50.2919
	42.0107	30	46.2244	50.2102	52.2031
1989	41.3321	15	43.4537	45.9877	47.2547
	41.9594	20	44.8480	48.1490	49.7995
	42.4943	25	46.0787	50.0755	52.0739
	42.9371	30	47.1561	51.7875	54.1033
1990	41.7798	15	44.7630	47.7298	49.2132
	42.4364	20	46.2313	50.0099	51.8992
	42.9958	25	47.5596	52.1071	54.3808
	43.4587	30	48.6938	53.9126	56.5221
1991	44.2039	15	45.8478	49.4341	51.2273
	44.8912	20	47.4004	51.8520	54.0778
	45.4762	25	48.7885	54.0431	56.6704
	45.9602	30	49.9984	55.9791	58.9694
1992	47.1047	15	48.5549	52.4110	54.3390
	47.8249	20	50.1970	54.9791	57.3641
	48.4371	25	51.6603	57.2895	60.1040
	48.9433	30	52.9414	59.3454	62.5475
1993	50.6249	15	51.7053	55.7857	57.8260
	51.3791	20	53.4188	58.4585	60.9784
	52.0197	25	54.9763	60.9330	63.9114
	52.5490	30	56.3329	63.1169	66.5089
1994	54.6049	15	55.3727	59.5745	61.6754
	55.3944	20	57.1887	62.4170	65.0311
	56.0644	25	58.8336	65.0368	68.1383
	56.6179	30	60.2708	67.3577	70.9011

EXHIBIT B

SCHEDULE OF PROCEDURES AND TIMETABLE

<u>ACTION</u>	<u>RESPONSIBLE PARTY</u>	<u>DEADLINE</u>
BOARD APPROVAL	BOARD	--
LETTER TO COGENERATORS	COMPANY	14 DAYS
COGENERATORS RESPONSE, INCLUDING DISPATCH- ABILITY, IN-SERVICE DATE, AND CAPACITY	COGENERATORS	28 DAYS
TIER PLACEMENT	COMPANY	35 DAYS
ACCEPTANCE BY COGENERATOR OF TIER PLACEMENT, PLUS CASH = \$10/KW	COGENERATOR	45 DAYS
ALTERNATE TIER PLACEMENT	COMPANY	60 DAYS

As indicated above, the deadlines shall run by calendar day from the date of the Board Order accepting this Stipulation. To the extent a cogenerator advises the Company that it does not wish to participate as placed, the next qualified cogenerator will advance to the position vacated thereby. The Company reserves the right to reject any proposal that does not satisfy all of the requirements of this Stipulation. Any resubmittal of a rejected proposal or modification of a previously accepted proposal (other than in the case of a modification pursuant to the terms of this Stipulation) will be considered a new proposal for purposes of paragraph 8.



STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
TWO GATEWAY CENTER
NEWARK, N.J. 07102

ELECTRIC

IN THE MATTER OF INVESTIGATION)
BY THE STAFF OF THE BOARD OF)
PUBLIC UTILITIES OF ATLANTIC)
ELECTRIC COMPANY'S PROPOSED)
COGENERATION AND SMALL POWER)
PRODUCTION POLICY)

ORDER ADOPTING
STIPULATION OF
ATLANTIC CITY
ELECTRIC COMPANY

SERVICE LIST ATTACHED

BY THE BOARD:

Since May of 1986, Atlantic City Electric Company (Atlantic Electric or the Company) has been evaluating twelve proposals from potential cogenerators and small power producers (QFs) for the construction and development of cogeneration and small production facilities and the sale of the electrical output therefrom to the Company.

The Company independently developed an evaluation and ranking for the proposals and in January, 1987, advised staff of the Board of Public Utilities (staff) that it had chosen three potential QFs from the twelve applicants and was about to notify them so that negotiations with the Company could begin concerning these proposals. On January 14, 1987 the staff requested and Atlantic Electric agreed to withhold notification to the QFs until staff had had an opportunity to review the method used by the Company in choosing the three cogenerators to insure that it was in agreement with Board policy on cogeneration and small power production.

After its review of Atlantic Electric's selection process, on May 13, 1987, Staff issued its "Evaluation by the Staff of the New Jersey Board of Public Utilities of Atlantic Electric's Proposed Cogeneration and Small Power Production Policy" (hereinafter referred to as the "Staff Report"). The Staff Report was distributed to the Company as well as to all QFs who had submitted proposals to the Company and to the Department of Commerce and Economic Development and the Division of Rate Counsel.

The Staff Report was critical of the Company's selection process and recommended that the Company abandon that procedure and implement a standard offer approach. Staff's major concern with the procedure implemented by Atlantic Electric is that Staff believes the bidding procedure used by Atlantic is contrary to previous Board Orders and the Public Utilities Regulatory Policies Act (PURPA) since Atlantic Electric's policy does not base pricing on avoided cost, which is designed to imitate a competitive market, but instead bases prices on a bid approach whereby many sellers face only one potential buyer. This monopsony process is exactly what PURPA was intended to eliminate. Atlantic Electric would have had QFs, in effect, bid against each other rather than against the utility's avoided cost. Further, Staff believes that Atlantic Electric's approach was flawed in its implementation since the participating QFs did not know the rules of process and were not cognizant of Atlantic Electric's assessment criteria, to the disadvantage of themselves and to the State as a whole. Atlantic Electric believes their selection process comported with Board policy and PURPA and would provide long term benefits to their customers.

Comments from all parties were solicited by the Staff by June 15, 1987. The Company, eleven of the twelve QFs, the New Jersey Department of Commerce, Division of Energy, and Rate Counsel submitted comments covering a wide range of policy and other issues raised not only by Atlantic Electric's procedures but also by PURPA and Board's existing policies on cogeneration and small power production.

The Federal Energy Regulatory Commission (FERC) Order No. 69 issued February 19, 1980, provides that the price a qualified facility (QF) receives for its energy or capacity from an electric utility be based upon avoided costs. Avoided cost is defined as follows:

The incremental cost to an electric utility of electric energy or capacity or both, but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source., Order 69, Section 292. 201(b)(6).

In addition, Section 292. 304(b)(5) of the FERC PURPA guidelines states:

In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for purchases differ from avoided costs at the time of delivery.

This section supports the development of levelized avoided cost pricing, which levelizes estimates of avoided cost so that the QFs receives a more stable payment pattern but, on a present value basis, the avoided cost standard is adhered to.

The Board, on October 20, 1980, initiated a generic proceedings pursuant to PURPA Section 210 (16USCA §24a-3). After reviewing the final compliance plans submitted by each utility, together with comments from all parties to the proceedings, and after hearing considerable public statements and testimony, the Board set the avoided energy cost at the PJM billing rate plus 10% and the avoided capacity rate at the PJM capacity deficiency payment.

Consistent with guidelines established in PURPA Section 210, FERC Order 69, and previous Board Orders, and upon review and consideration of the comments received regarding this matter, a proposed stipulation for resolving the policy and procedural disagreements between the Company and the Staff over the development of cogeneration and small power production in Atlantic Electric's service territory and the state of New Jersey was submitted to the Board by the Board's Staff and the Company. The agreement incorporates standard long term levelized contracts for the purchase of QF power by Atlantic Electric and assures that QFs receive the full economic value for their energy and capacity. Said Stipulation was submitted to the Board on August 20, 1987.

The standard price offers were established by the signatories to the agreement as a means of facilitating a pricing agreement between QFs and the company. It is recognized that certain QFs may require contract terms or conditions which differ from the standard price offers. Accordingly, the establishment of standard price offers should not limit the ability of a QF to negotiate a power purchase agreement with the company which differs from the standard offer so that any specific project requirements can be met.

The Agreement embodies the following significant features:

- A) Establishes a "Standard Price Methodology" to facilitate price agreement while retaining an option on the part of QF developers to negotiate other pricing terms to meet the specific needs of individual projects.
- B) Bases pricing levels upon projections of the PJM billing rate + 10% for energy and the PJM capacity deficiency payment for capacity consistent with Board policy.

- C) Establishes a levelized rate which allows for the calculation of revenue streams from electric sales over the economic life to the project to the extent that electric production of a facility is maintained at expected levels.
- D) Provides for contract terms of up to 30 years.
- E) Varies the degree of allowable levelization to reflect the degree of capital intensity associated with different technologies such as hydroelectric, resource recovery and fossil fuel projects.
- F) Provides levelization, up to the maximum degree allowed, at the option of the developer. The variable portion of the payment varies with either (i) the PJM billing rate (ii) a fuel index for oil, gas and coal projects or (iii) the GNP deflator for resource recovery and hydroelectric projects, or any mix thereof, at the developer's option.
- G) Provides for energy and capacity payments to be made in a manner that will encourage on-peak and peak season production.
- H) Provides all QF developers equal access and opportunity to contract with the company.
- I) Offer developers an optional payment scheme for those willing to be dispatchable.
- J) Protects the company from entering into contracts with developers of highly speculative projects by requiring minimum developer qualifications for obtaining and retaining the standard pricing offer.
- K) Ranks projects based on their potential benefits to the company and the State.

The Board believes the Standard Price Methodology described above represent a significant step in furthering the Board's policy of promoting cogeneration and small power production in the state. The Board recognizes that the use of levelized pricing yields payments for energy and capacity that exceed costs for the utility's near-term alternative, and therefore, raises the immediate charges to customers. However, in the long term, contract pricing is expected to fall below avoided costs, thereby reasonably matching pricing to the projected avoided costs over the contract term and providing economic energy and capacity to the ratepayers. Levelized payments could result in payments to QFs which exceed avoided costs over the term of the contract if actual avoided costs are below projected values. However, this risk is balanced by the fact that if actual avoided costs are above projected values, levelized payments will result in the QF receiving less than avoided cost.

Due to the special circumstances surrounding the remaining eleven QFs who have been unable to negotiate a power purchase agreement with Atlantic Electric for a significant period of time, they will be considered first in filling the 700 MWs of capacity incorporated in the agreement. The standard price methodology embodied in the agreement will remain in effect at a minimum until such time as the Company has offered a standard price offer in accordance with the stipulation to all eleven QFs or until 700 MWs have been contracted for by QFs included in the eleven. If the 700 MWs of capacity is not filled by the eleven QFs, the standard price methodology will remain in effect pending the outcome and effective date of the Board's Five Year Review of Cogeneration and Small Power Production Policies or until 700 MWs have been contracted for, whichever comes first.

The parties have agreed that it is necessary and desirable to establish a procedure to review the pricing mechanisms and the level of price reflected in the standard pricing methodology, and the process by which contracts are to be developed and executed. The Board concurs. Therefore the Company shall provide periodic updates to staff regarding the status of the agreement.

The Company has agreed not to impose suspense accounts, recapture fees, or other performance penalties, except as specifically identified in the stipulation for dispatchable facilities.

Neither party to the stipulation shall be prohibited from or prejudiced by arguing a different policy or position before the Board in its pending Five Year Review of Cogeneration and Small Power Production Policy.

The Company shall be entitled to amend its standard offer prices and procedures consistent with the Board's subsequent findings in the Five Year Review; provided, however, that such amendments shall apply only to standard offers which have not been accepted by the QF as of the time of such amendment.

The Board also has before it a letter motion from Mobil for expeditious action in this matter and a motion from Atlantic Electric requesting a hearing. Both are considered moot by the Board's acceptance of the stipulation which will allow expeditious implementation of a QF's contracting policy. A motion from Rate Counsel for a hearing; similarly rendered moot. The policy concerns of the Public Advocate, as well as those of all other parties, can be fully aired in the Board's procedure for its Five Year Review of Cogeneration and Small Power Production Policies (Docket No. 8010-687 B).

After careful review of the record in this matter, the Board HEREBY FINDS that:

- 1) The written stipulation and Standard Price Methodology attached hereto and made a part hereof with regard to Atlantic City Electric Company is reasonable, is in the public interest, and is in accordance with applicable law.
- 2) All payments made to QFs under the Standard Price Methodology will be considered pre-approved price agreements and are recognized as having been prudently incurred and therefore;
- 3) The Board will allow Atlantic Electric to fully and timely recover the payments therein throughout the term of any final agreements with QFs that receive Board approval.
- 4) The review of the Standard Price Methodology will be conducted in accordance with terms of the stipulation.
- 5) This Order renders moot any motions currently pending before the Board regarding this matter.

Accordingly, the Board HEREBY APPROVES the attached stipulation and HEREBY DIRECTS the company to take all steps necessary for its expeditious implementation.

DATED: August 28, 1987

BOARD OF PUBLIC UTILITIES
BY:


BARBARA A. CURRAN
PRESIDENT


GEORGE H. BARBOUR
COMMISSIONER


ROBERT N. GUIDO
COMMISSIONER

ATTEST:


IDA MARIE ENGELHART
ACTING SECRETARY

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EXHIBIT F

TECHNICAL GUIDELINES

FOR

CUSTOMER SERVICE

AT

**SUB-TRANSMISSION AND TRANSMISSION
VOLTAGES**



People Meeting Your Energy Needs

TECHNICAL

GUIDELINES

for

Customer Service

at

**SUB-TRANSMISSION AND TRANSMISSION
VOLTAGES**

MAY, 1985

INTRODUCTION

The purpose of this Information Guide is to provide preliminary information to all Atlantic Electric customers who are interested in receiving service at transmission or subtransmission voltage at their facility. Although it is impossible for this guide to provide all answers for the customers' particular needs, this information should be a starting point for any transmission class and subtransmission class customers who are considering electric service from Atlantic Electric at 23kV and above.

The purpose of this guide is also to consider technical and safety requirements so that adequate protective equipment can be installed to allow reliable operation of the Atlantic Electric system without affecting the reliability of electric service to other customers and provide safety for the general public as well as Atlantic Electric employees.

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I.	General
II.	Types Of Services Furnished
III.	Information Furnished By Atlantic Electric
IV.	General Technical Requirements
V.	General Operating Requirements
VI.	Protection Requirements
VII.	Metering Requirements
VIII.	Responsibility

CUSTOMER SERVICE ENTRANCE REQUIREMENTS FOR
TRANSMISSION CLASS AND SUBTRANSMISSION CLASS CUSTOMERS

I. GENERAL:

The following requirements and standards for connection of a customer to the Atlantic Electric system shall be met to attempt to assure the integrity and safe operation of the Atlantic Electric system with no deterioration to the quality and reliability of service to other customers.

A. All customers shall make application to Atlantic Electric for approval to interconnect their facilities with the Atlantic Electric system.

B. Atlantic Electric shall require the following as part of the application:

1. Plans and specifications for the proposed installation (to be sealed by a licensed New Jersey engineer).
2. One line diagram and details of the proposed protection schemes.
3. Service details (underground or aerial).
4. Interrupting device types and ratings.
5. Electrical load requirements including motor loads, type and sizes

C. Atlantic Electric may require the following additional information as part of the application.

1. Transformer ratings, connections and impedance data.
2. Power factor correction capacitor ratings and connections

3. Unusual load characteristics, such as those due to furnaces, thyristors and other non-linear loads.
4. Voltage balance requirements.
5. Switchgear specifications including protection device types and ranges.
6. Protection and control schematic drawings as appropriate.
7. Point of interconnection physical arrangement drawings.
8. Expansion plans, projected loads, future substation development and timing.

II. TYPES OF SERVICES FURNISHED:

It is the customer's responsibility to secure information pertaining to types of service available from Atlantic Electric before he completes his electrical plans. Atlantic Electric will generally supply service from a facility close to the load. Normal service voltages provided by Atlantic Electric are: 23kV, 34.5kV, 69kV and 138kV; 60 Hertz; three-phase nominal. However, all service voltages are not available in every locality. Depending upon the location of the customer's service, cost of extension of service may be the responsibility of customer. Specific information can be obtained from Atlantic Electric Representatives.

A. Single Line Supply:

A typical example of Atlantic Electric-customer interconnection is shown in Figure 1 and is intended to be illustrative only. It consists of a single line from a single substation bus and connects to a single transformer with multiple connections to the customer's load center on the low voltage side of the transformer.

B. Multiple Interconnection Lines:

When a single-line supply is not adequate, multiple supply lines may be provided by Atlantic Electric at an additional cost. Typical configurations of two interconnection lines which Atlantic Electric may provide are shown in figures 2, 3, 4 and 5. However, all these configurations may not be available at all locations within Atlantic Electric service area. For a particular interconnection requirement, the customer should contact Atlantic Electric Commercial/Industrial Representatives.

Figure 2 is an illustration of a single interconnection line that is supplied from a second utility source operated normally open at or near the customer's installation. The second utility source may be from the same substation or from a second nearby substation. The advantage of this type of service is that the customer is more likely to experience only a momentary outage (if the switches are automatic) or short-time outage (if the switches are manual) instead of an extended outage on his substation during a fault on Atlantic Electric's line.

Figure 3 illustrates a single interconnection made in the middle of a transmission line with automatic switching to isolate a faulted line section. The advantage of this type of service is that the customer is more likely to experience only a momentary outage instead of an extended outage on his substation during a fault on Atlantic Electric's line. Atlantic Electric, however, can not guarantee continuous uninterrupted service under any circumstances.

If a customer desires two interconnection points with two Atlantic Electric sources, they can be supplied to the customer as shown in Figure 4. The advantage of this type of service is that the customer should experience a momentary outage on only one of the two customer's transformers during a fault on Atlantic Electric's line. Atlantic Electric can offer two interconnection lines to the large industrial customer as shown in Figure 5. The advantage of this type of service is that the customer should experience no interruption on his line during a fault on the Atlantic Electric's line, unless a fault should occur on both lines simultaneously.

III. INFORMATION FURNISHED BY ATLANTIC ELECTRIC:

- A. Initial short circuit duty at the customer's delivery point - minimum and maximum - three-phase and phase to ground.
- B. Anticipated future short circuit duty at the customer's delivery point - minimum and maximum - three-phase and phase to ground.
- C. Expected minimum, maximum and normal voltage at the customer's delivery point.
- D. X/R ratios.
- E. Specific protection requirements to coordinate with the Atlantic Electric System.
- F. Specific reclosing practices on normal and alternate supply facilities.
- G. Harmonic content, voltage fluctuation, and current unbalance constraints required by Atlantic Electric.

H. The customer may request additional information such as:

- a. Supply line construction and routing.
- b. Supply substation arrangement and location
- c. Utility grounding and lightning protection schemes.
- d. Characteristics and protection of other customers' facilities served from the same source.

IV. GENERAL TECHNICAL REQUIREMENTS:

A. Prior to construction, the customer shall submit electrical and site plans and specifications of the proposed installation sealed by a licensed New Jersey engineer for review by Atlantic Electric. A single-line diagram and details of the proposed protection schemes are required. The Company shall not, by acceptance of the plans and specifications, assume responsibility for damage to customer's property, or the property of any other individual or entity, whether customer of Atlantic Electric or otherwise, and/or personal or bodily injury or death to any person or persons caused by or arising out of or in connection with the customer's installation. Responsibility for design and installation remains with customer and customer's professionals and contractors. Review by Atlantic Electric is for informational purposes only and to permit Atlantic Electric to review compatibility with the Atlantic Electric system. Review by Atlantic Electric is without liability or responsibility to customer and Atlantic Electric shall have no responsibility for consequential, special or other damages.

B. The installation must be in compliance with the requirements of the National Electrical Code and all applicable local, state and federal codes or regulations and customer shall remain solely responsible for compliance therewith. Prior to interconnection, the Company must be provided with evidence of satisfactory electrical inspection by an authorized inspection agency.

C. The installation shall be done in a proper and workmanlike manner utilizing licensed professionals where required, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, the National Electrical Manufacturers Association and the American National Standards Institute shall at a minimum, be observed to the extent that they are applicable.

D. Atlantic Electric will designate the location of the interconnection between the Atlantic Electric's incoming overhead line (or incoming underground insulated cable) and the customer's service entrance line (or insulated cable).

1. For underground service installations, Atlantic Electric will splice the customer's cable(s) into Atlantic Electric's cable(s) at the manhole designated by Atlantic Electric as the point of interconnection between the customer's and Atlantic Electric's systems.

To insure compatibility with Atlantic Electric's cable(s) and to expedite replacement of a faulted customer owned cable, the

selection of the customers service cable(s) shall be reviewed by Atlantic Electric prior to purchase.

2. For overhead service installations, Atlantic Electric will provide the necessary dead end strain assemblies and make the connections to the customer's service entrance line(s) at the point of interconnection between the customer's and Atlantic Electric's system. The customer shall provide Atlantic Electric full details on the customer's service entrance conductor(s) at the point of interconnection.

Design of the customer's point of interconnection structure shall be based on Atlantic Electric's requirements for incoming line tension, mounting height above ground and phase spacing of Atlantic Electric's dead end assemblies.

- E. Atlantic Electric reserves the right, but shall not have the obligation, to inspect the service entrance facilities before energizing. Such inspection, or failure to inspect, shall not render the Company liable or responsible for any loss or damage resulting from defects in the installation or failure to comply with the Company requirements. Responsibility and liability for any and all claims of damage, personal injury, death and/or property damage shall be solely that of customer and customer's professionals.
- F. The customer shall at a minimum meet the requirements contained in this guide in addition to the requirements published in the following A.E. guides (where applicable).

1. Information and Requirements For Electric Service Installations.

2. Requirements For Multifeed Primary Service.
3. Technical Guidelines For Cogenerators And Small Power Producers.
- G. The customer may obtain a copy of these guides from an Atlantic Electric Commercial/Industrial Representative, at an appropriate division office listed below:

Bridgeton -- 451-7995	Manahawkin -- 597-5301
Clementon -- 589-3161	Pleasantville -- 645-4154
Swainton -- 465-3177	

V. GENERAL OPERATING REQUIREMENTS:

A. The connection of the customer's equipment with the Atlantic Electric system must be designed by customer so as not to cause any reduction in the quality of service which Atlantic Electric provides to other customers with regard to abnormal voltages, frequencies or service interruptions. Violation of this provision shall give Atlantic Electric the right to open the disconnect device with prior notice to the customer if it is not an emergency situation and the right to open the disconnect device without prior notice if it is an emergency situation.

B. Atlantic Electric reserves the right to inspect customer's equipment or devices associated with the interconnection.

C. Three-phase standard transmission class voltages supplied by Atlantic Electric are 23kV, 34.5kV, 69kV and 138kV. However, all of these voltages are not available at all locations. The Company must be consulted for the voltages available at the customer's desired service location.

- D. The average operating power factor of a customer's load at the point where the electric service is metered shall not be less than 90% lagging. The customer will be charged an additional cost for not meeting this requirement.
- E. Switching of the disconnect device (manual or automatic) shall be under the administrative control of the Atlantic Electric System Operator. Atlantic Electric reserves the right to open the disconnect device without prior notice to the customer during a system emergency, or where customer's equipment interferes with service to other customers of Atlantic Electric.
- F. In such circumstances where an emergency does not exist, Atlantic Electric may request the opening of (or open) the disconnect device with prior notice to the customers. The following are circumstances by way of illustration in which Atlantic Electric might exercise this right.
1. Atlantic Electric's inspection of customer's interface station equipment reveals a potentially unsafe condition.
 2. The customer's equipment interferes with other customers on the Atlantic Electric system.
 3. Atlantic Electric requires repair, test or maintenance of utility facilities.

In each instance adequacy of notice will be determined solely by Atlantic Electric under the circumstances existing. If the customer fails to take corrective action within the time specified, Atlantic Electric may disconnect customer and in such event Atlantic Electric shall have no liability to customer.

- G. An automatic disconnecting device, when provided, must isolate the customer's facility from the Atlantic Electric system within a time period specified by Atlantic Electric for, but not necessarily limited to, the following conditions:
1. A fault on the customer's equipment.
 2. A fault on the Atlantic Electric system.
 3. A deenergized Atlantic Electric line to which the customer is connected.
 4. An abnormal operating voltage or frequency on the line.
 5. Loss of phase or improper phase sequence.
 6. Total harmonic content in excess of 5%.
 7. Abnormal power factor.
- H. The customer's primary transformer shall be delta connected on the source side (i.e. Atlantic Electric) so as not to be a contributor to one-line to ground faults on the Atlantic Electric system. There shall be no deviation from this practice without express authorization from Atlantic Electric in writing.
- I. The customer's equipment must be so designed and installed that power cannot flow into (back feed) Company facilities which are faulted (short circuited) or which have been de-energized. In addition, unless waived in writing by Atlantic Electric, the customer shall make provision for the disconnect device to accept an Atlantic Electric padlock. Atlantic Electric personnel shall have access to the padlock at all times.

- J. The customer shall bear the cost of any interconnection and protective relays deemed necessary by Atlantic Electric. The need for these devices is outlined in general protective requirements in section VI.
- K. The protective scheme will be reviewed by Atlantic Electric and tailored to the individual customer's requirements. This measure is intended solely to ensure coordination with existing protective devices on Atlantic Electric's line. The Company shall not, by its review, assume responsibility or liability for damage to the customer's property, or the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facilities. The customer will be responsible for the procurement of any protective devices specified by Atlantic Electric. The customer will be required to modify the protective relay scheme, at his cost, should future alterations in Atlantic Electric's line configuration warrant such changes.
- L. Atlantic Electric requires a mandatory initial inspection of the interface protective devices and also requires an annual inspection of these devices. The testing and inspection must be done by a reputable testing firm which will submit an official report to Atlantic Electric. This testing will be at the customer's expense. Atlantic Electric may, at its option, provide testing service to the customer at a fee to be fixed by Atlantic Electric. In such event, however, Atlantic Electric shall not be responsible for nor assume

any responsibility for damage to the customer's property, or the property of any other individual or entity, and/or injury or death to person or persons caused by or arising out of or in connection with the customer's facilities, the testing of such facilities, or the failure to test such facilities. Such responsibility shall remain solely with customer and customer shall indemnify, defend and agree to hold harmless Atlantic Electric from and against any and all such liabilities.

In addition, Atlantic Electric reserves the right, for its own purpose, to inspect the interfaced protective devices at anytime.

Atlantic Electric reserves the right to disconnect the customer if it is evident that proper maintenance and testing is not being provided.

- M. The customer shall design and provide adequate lightning protection to its facility in order to protect both their equipment and Atlantic Electric's equipment.

VI. PROTECTION REQUIREMENTS:

- A. The protection equipment provided on the customer's equipment must at a minimum be designed to:
1. Provide adequate protection against faults, overloads, or other abnormal conditions in the customer's equipment.
 2. Prevent damage to Atlantic Electric's equipment (lines, transformers, etc.) in the event of a fault or other problem in the customer's equipment.

3. Prevent outages or other adverse effects on other Atlantic Electric customers.

4. Provide a safe means to control, operate and disconnect the customer's equipment.

B. The customer must at all times provide access for Atlantic Electric personnel to the entrance equipment.

C. All switching of the customer's entrance equipment must be under the direction of the Atlantic Electric's Load Supervisor.

D. It is the customer's responsibility to select, install and maintain adequate protection for their own equipment. Fuse size/type information, single line and other information on the overall protective relaying schemes must be provided to Atlantic Electric. Atlantic Electric will review the compatibility of the customer's proposal with the Atlantic Electric protective relaying on the source terminal. Atlantic Electric shall be given the opportunity to review the design of the finalized protection arrangements for informational purposes. Such review by Atlantic Electric shall not, however, relieve customer from liability and responsibility for design, installation or operation. The review is intended solely for determination of compatibility with the Atlantic Electric system. Responsibility for damage to the customer's property, the property of any other individual or entity, and/or injury or death to person or persons caused by or arising out of or in connection with the customer's facilities shall remain the sole responsibility of customer and Atlantic Electric shall have no liability therefore.

E. The protective relaying supplied by Atlantic Electric at the source end of the customer's supply line is primarily intended for protection of that supply line.

F. Transformers and all low side equipment must be protected solely by the customer's protective equipment. Transformers must be protected by either primary fuses or protective relays. Relaying schemes without a high side interrupting device must either include transfer trip to Atlantic Electric's source substation or simulate a high side line fault. If the source line supplies other customers, the faulted equipment must be automatically disconnected so that other customers may be restored.

G. For customers with an automatic throwover scheme between a normal and an alternate source, the customer must provide a blocking scheme to prevent transfer of a fault on the customer's equipment.

1. The transfer blocking requirement may be waived if both source lines solely supply the customer.
2. Atlantic Electric will provide settings for the transfer scheme. The purpose of the settings is to provide proper timing in coordination with Atlantic Electric facilities and not for the protection of customer's equipment or customer's facility.

Atlantic Electric will also set the relays and periodically test the transfer scheme for a fee to be established by Atlantic Electric. The customer also has the option of selecting an outside contractor for testing the transfer scheme. In the event Atlantic Electric sets the relays and/or tests the relays,

such setting or testing shall be solely for the purpose of timing and coordination for compatibility of Atlantic Electric equipment and not for the protection of customer's equipment and facilities. Atlantic Electric does not assume any responsibility for damage to the customer's property, or to the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facility, the setting of the relays, or the testing thereof. Such responsibility shall remain solely with customer.

H. Customers with larger transformers (75 MVA or larger) that are tapped on a transmission line using a power line carrier protective relaying scheme may need a carrier blocking terminal at their site and/or a carrier wave trap to insure the reliability and security of the relaying scheme which shall be designed and installed by customer, at customer's expense if required.

I. Reclosing:

1. If the source line is of overhead construction, an automatic breaker reclose could be employed at the Atlantic Electric source end following trips for line faults. If the line is used solely to supply the customer, a reclose time acceptable to both the customer and Atlantic Electric shall be determined.
2. Usually a high-speed reclose is not acceptable due to fault stress on Atlantic Electric equipment and torque stress on the customer's motors and other equipment.

3. A cable source line or other possible constraints will prohibit an automatic breaker reclose.

J. Customers with Internal Generation:

1. The customer must supply an adequate protective relaying scheme to trip their end for a fault on the Atlantic Electric source line. Atlantic Electric shall be given the opportunity to review the acceptability of any such proposal. The Company, in making such review, does not assume any responsibility for damage to the property of customer, the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facilities, the design of the protective relaying scheme, or the operation of the protective relaying scheme. Such responsibility shall remain solely with customer.

Examples of schemes:

- a. Transfer trip from Atlantic Electric's end.
 - b. Directional overcurrent or reverse power relaying.
 - c. Larger generating units may require full impedance relaying terminal and power line carrier equipment.
2. The customer's generation must be tripped off line for voltages and frequencies outside acceptable limits.
 3. Customer shall obtain a copy of "Technical Guidelines for Cogenerators and Small Power Producers" from Atlantic Electric.

VII. METERING REQUIREMENTS:

A. GENERAL

Normally, service will be metered at secondary voltage. However, metering at other voltages may be available subject to negotiation. The type, size, location and number of meters to be installed will be determined by Atlantic Electric. The customer shall notify Atlantic Electric promptly of any proposed additions to the equipment or changes in their present wiring system. Noncompliance with this requirement will be deemed sufficient cause to hold the customer liable for damage to the Company's equipment or other loss to company or other customers caused as a result of changes in the customer's installation. All equipment furnished by the Company located in the customer's premises shall remain the property of the Company and may be removed or attended by the Company in the event such equipment is no longer required or the customer discontinues service. Meters must not be connected, disconnected, altered or removed except by written permission from the Company.

B. Meter Location

Atlantic Electric must be consulted and will endeavor to select a location of metering equipment that will be mutually satisfactory to both parties. However, Atlantic Electric will have final determination of the location of the metering equipment in all cases. Not less than 3 feet of clear unobstructed space shall be provided under and in front of all metering equipment.

C. Metering Equipment

1. Atlantic Electric will provide the customer information about the number of transformers (CT's or VT's) per circuit. The metering current and potential transformers will be furnished by Atlantic Electric for installation by the customer. The current transformer location shall be designed so that after proper electrical isolation the transformer can be removed or changed. The meter location shall be determined by Atlantic Electric in accordance with Atlantic Electric's booklet "Information and Requirements for Electric Service Installation". A rigid conduit (1½" min.) is required from the transformer location to the meter location.
2. Customers will be required to mount all equipment (transformers, meter enclosures, etc.), purchase and install conduit and pull in meter control cable from the transformers to the meter enclosure. Atlantic Electric will provide this control cable. Secondary transformer connections and all meter connections will be done by Atlantic Electric.
3. The metering voltage transformers are to be fused and connected through a disconnecting device to permit changing the transformers without de-energizing the main bus. Atlantic Electric will furnish the disconnects for installation on site by the customers. Atlantic Electric will also supply the current limiting fuses.

D. Additional Information & Requirements for Metering:

Customers shall review the Atlantic Electric booklet "Information & Requirements for Electric Service Installation" for additional metering requirements.

VIII. RESPONSIBILITY:

Atlantic Electric makes no representation or warranty of any nature concerning the technical information contained herein. The information contained herein is intended to be typical and for informational purposes only, and is not intended to be site specific or facility specific. This information is offered as a starting point for any customer who is considering service at subtransmission and transmission voltages. Design responsibility remains solely with customer. The obligations and responsibilities of customer shall be further limited and defined by any agreement between customer and Atlantic Electric and by the provisions and terms of the applicable tariffs.

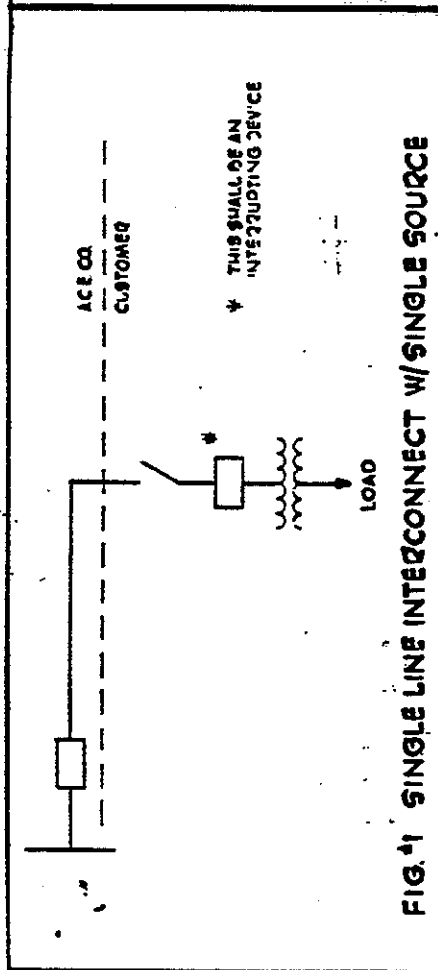


FIG. 1 SINGLE LINE INTERCONNECT W/ SINGLE SOURCE

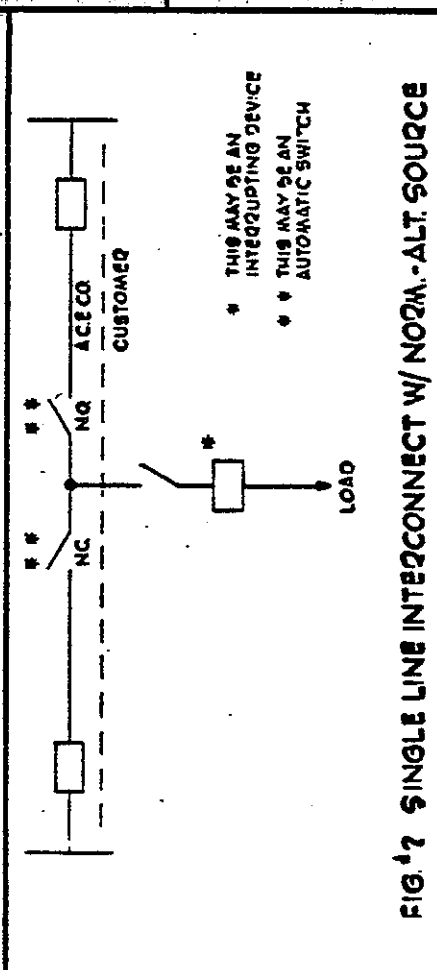


FIG. 2 SINGLE LINE INTERCONNECT W/ NORM. -ALT. SOURCE

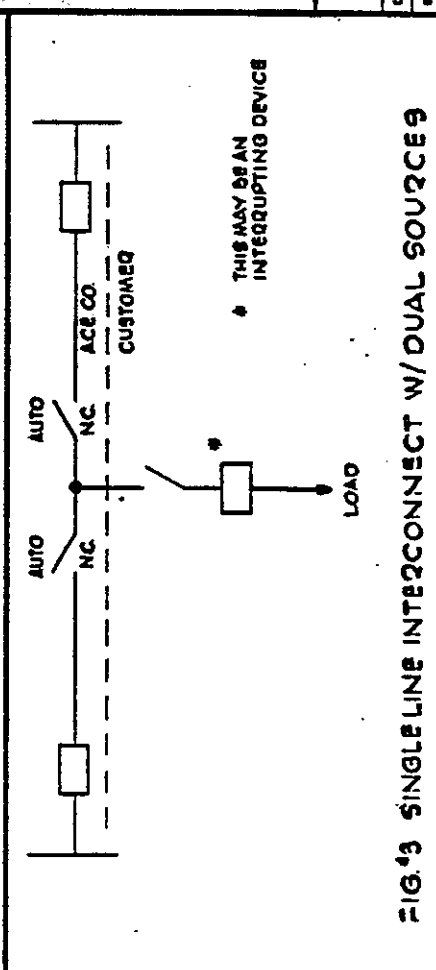


FIG. 3 SINGLE LINE INTERCONNECT W/ DUAL SOURCE

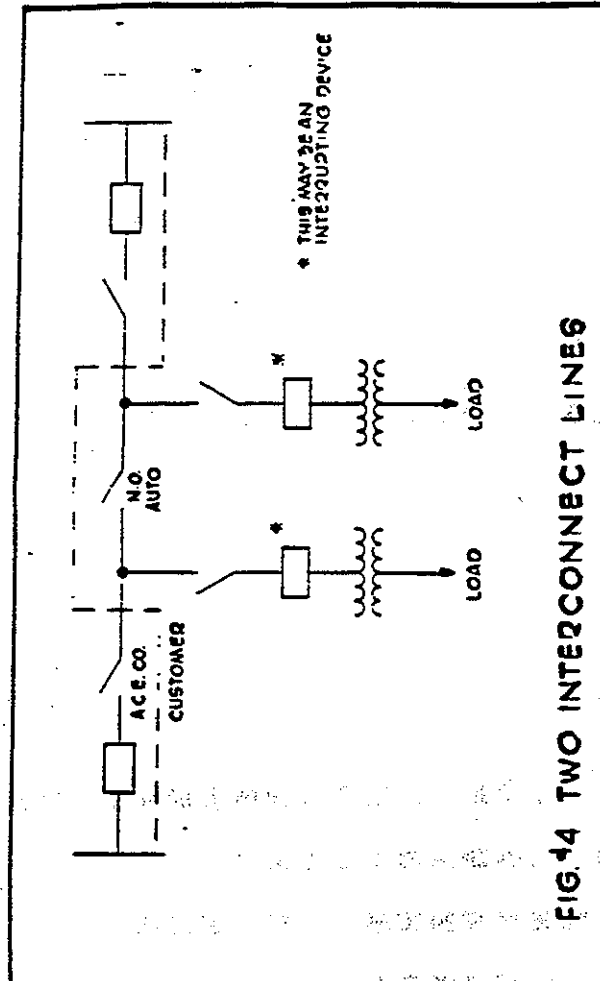


FIG. 4 TWO INTERCONNECT LINES

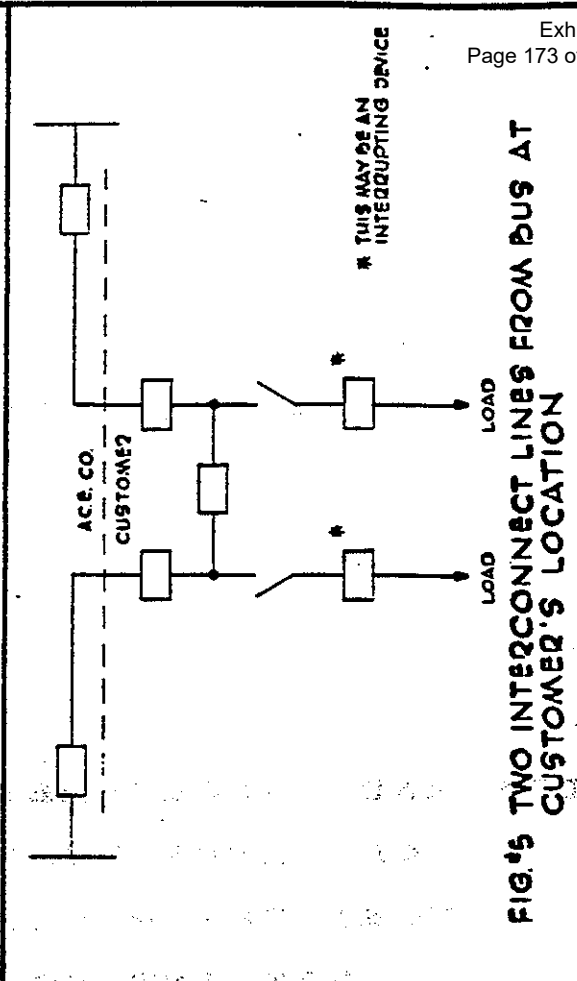


FIG. 5 TWO INTERCONNECT LINES FROM BUS AT CUSTOMER'S LOCATION

ATLANTIC CITY ELECTRIC COMPANY ATLANTIC CITY, N. J.		TYPICAL TYPES OF SERVICES FURNISHED BY ATLANTIC CITY ELECTRIC CO.	
CH. V.C.J.	DATE 3-7-05	NO. 34-5551	
SCALE 1/4"	APP. V.C.J.		

EXHIBIT G

ATLANTIC ELECTRIC'S

**RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY
TO MEET THE REQUIREMENTS OF THE
PJM INTERCONNECTION**

NOVEMBER 1987

EXHIBIT H

PURCHASER'S

INTERCONNECTION STUDY

FOR

SELLER'S FACILITY

Approved: [Signature]
[Signature]
[Signature]

MEMORANDUM

March 4, 1988

TO: H.S. Solganick

FROM: L.M. Svensen

SUBJECT: Current Summer and Winter Rating
Temperatures for Combustion Turbines (C.T.'s)

The current ambient temperatures used for summer and winter ratings for CTs in the western territory are 91°F and 30°F respectively. These temperatures are based on sections 1.2 and 1.3 of PJM's Rules and Procedures for Determination of Generating Capacity.

The above temperatures could change if the PJM Generator Capability Ratings Procedures Task Force decides that all PJM member companies update their rating temperatures.



L.M. Svensen

jnk
xc: J.C. McCullough
J.R. Brignola
G. Hogg

SPECIFIC INSTRUCTIONS

1. Company - Enter reporting company name.
2. Plant/Unit
NERC I.D. Enter plant name, unit number, and
NERC identification number
3. Period Enter the test period date, (Example - S83, W83/84)
4. Capability
 - a. Rating Enter Rated Net Capability - MW (Line 8 from
PJM NET CAPABILITY VERIFICATION REPORT)
 - b. Difference Enter Difference - MW (+) (Line 9 from PJM
NET CAPABILITY VERIFICATION REPORT)
5. Megawatt Reduction Enter the megawatt reduction assigned to each NERC
outage event. Event data can have more than one
entry for the difference reported. Megawatt
reduction can be greater than difference reported.
6. NERC Event Type Enter NERC event type and class as defined in the
PJM GENERATING UNIT PERFORMANCE DEFINITIONS for
each megawatt reduction.
7. NERC Cause Code Enter the NERC Cause Code as defined in the PJM
GENERATING UNIT PERFORMANCE DEFINITIONS for each
NERC event.
8. Start/End
 - a. Date Enter Start/End month, day, and year (example -
01/30/84).
 - b. Time Enter Start/End time, use military time (Example -
1429).
9. Notes Enter a sequence number. Use the sequence number
as a reference to the narrative in the space
provided at the bottom of the summary or use a
separate page. If no event information exists,
assign a sequence number and explain in the notes.

PJM CAPABILITY VERIFICATION REPORT SUMMARY
COMPANY

[illegible]

Notes:

Specific Instructions

- Line 1. Company plant and unit number identification
- Line 2. Use NERC numerical designations only
- Line 3. Indicate Test, if unit started or current operating load change for capability verification.

Indicate Operational, if unit is currently operating at capability rating. Historical data is also acceptable; two (2) hour average (steam units); one (1) hour (combustion turbines).
- Line 4. Enter date of test - month, day, and year.
- Line 5., 6. Enter time of test, use military time.
- Line 7.(MW) Test Net Capability (Line 20) plus Water Correction (Line 21) steam units - Otherwise Test Net Capability (Line 20) plus Air Correction (Line 22) for combustion turbines.
- Line 8.(MW) Current Net Capability - First character - S (Summer) W (Winter) Remaining characters - Rated Net Capability
- Line 9.(MW) Corrected Net Capability (Line 7) minus Rated Net Capability (Line 8); - Include (+) sign.
- Line 10., 11
12., & 13 Enter data for steam units only - Temp. (°F), Pressure (PSI) Otherwise enter NA
- Line 14. Enter data for combustion turbines and cooling tower steam units only (°F) - Otherwise enter NA
- Line 15. Enter data for steam units only (°F) - Otherwise enter NA
- Line 16. Enter data for approved extraction steam units only (1000lb/hr) Otherwise enter NA.
- Line 17.(MVAR) Enter (+) into system (LAG); (-) into unit (LEAD). Enter two (2) hour average for steam units
- Line 18. (MW) Enter two (2) hour average for steam units.
- Line 19. (MW) Enter two (2) hour average for steam units
- Line 20. (MW) Gross Generation (Line 18) minus Station Use (Line 19)
- Line 21. (MW) Steam units only. Enter NA for combustion turbine units
- Line 22. (MW) Combustion turbine units only. Enter NA for steam turbine units
- Line 23. (MW) Approved extraction steam units only. Otherwise enter NA.
- Line 24. (MVA) Vector sum, Gross Generation (Line 18) and Reactive Generation (Line 17.)
- Line 25.(DEC.) Gross Generation (Line 18) divided by Total Power (Line 24)
- Line 26. Enter narrative to explain negative difference (Line 9) - Otherwise

PJM NET CAPABILITY VERIFICATION REPORT
COMPANY

1. Plant and Unit No. _____	4. Date _____
2. NERC Unit Identification _____	5. Start Time _____
3. Method: Operational <input type="checkbox"/> Test <input type="checkbox"/>	6. End Time _____

7. Corrected Test Net Capability-MW	_____
8. Rated Net Capability-MW	_____
9. Difference-MW (+)	_____

	<u>RATED</u>	<u>OBSERVED</u>
10. Main Steam Temperature- OF *	_____	_____
11. Reheat Steam Temperature- OF *	_____	_____
12. 2nd Reheat Steam Temperature- OF*	_____	_____
13. Main Steam Pressure- PSIG *	_____	_____
14. Air Dry Bulb Temperature- OF	_____	_____
15. Cooling Water Temperature OF	_____	_____
16. Extraction Steam Flow - 1000 Lb/Hr.	_____	_____

17. Reactive Generation-MVAR (+)	_____
18. Gross Generation- MW	_____
19. Station Use-MW	_____
20. Test Net Capability-MW	_____
21. Cooling Water Correction-MW (+)	_____
22. Air Correction-MW (+)	_____
23. Extraction Steam Flow Correction-MW (+)	_____
24. Total Power-MVA *	_____
25. Power Factor *	_____

26. Explanation for Difference

MW

Explanation

SIGNED: _____
STATION MANAGER

APPROVED: _____
MEMBER
PJM OPERATING COMMITTEE

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

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PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

Purpose

These rules and procedures for determining the capability of generating units on the systems of the PJM Interconnection have been adopted to provide uniformity for planning, operating, accounting and reporting purposes, and have been designed to meet the following two requirements in the coordinated operation of the PJM Interconnection.

1. Net Capability of generating units installed and scheduled for installation on the systems of PJM is required for planning and reporting purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented. For the same reasons, there is need to define certain limitations that prevent the simultaneous utilization of the total of the system's separate unit Net Capabilities.

2. Available Capability of generating units installed on the systems of PJM is required for planning and daily operating purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented.

The rules and procedures recognize the difference in types of generating units installed on the systems of PJM and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, system operating policies, and others. Whenever a unit or plant output cannot be maintained at its stated capability during the time specified, it shall be considered as a limited energy resource and the stated capability of the system of which it is a part may require modification in accordance with the procedures set forth in Section 3, Limited Energy Resources, for purposes of planning, operating and accounting.

1. NET CAPABILITY

1.1 General

1.1.1 Net Capability shall mean the number of megawatts of electric power which can be delivered by an electric generating unit or station of a system after its date of commercial operation without restriction by the owner under the conditions and criteria specified herein and shall be determined as the gross output of the unit or station less power generated and used for unit auxiliaries and other station use.

1.1.2 Without restriction means that Net Capability values so determined are available for utilization at the request of the PJM Interconnection Office (IO) for supply of operating capacity and energy before any operating procedures are placed in effect anticipatory to a voltage reduction on the PJM system except as such utilization may at times be limited in duration by water or fuel availability.

1.1.3 The determination of the Net Capability of a steam unit or plant shall recognize the use of any procedures for increasing unit output such as turbine over-pressure, boiler overrating, cycle modification or any others which are normally utilized in operation.

1.1.4 The determination of Net Capability for a combustion turbine unit shall be consistent with the owner system policy with respect to maximum output.

1.1.5 The determination of Net Capability for a hydro or pumped storage plant shall recognize the head available giving proper consideration to operating restrictions and the reservoir storage program during a normal plant cycle at the probable time of the PJM peak.

1.1.6 The determination of the Net Capability of a nuclear unit shall recognize its nuclear fuel management program and any restrictions (except as noted in 1.1.9) imposed by regulatory authority.

1.1.7 The Net Capability of a planned steam unit shall be based on the manufacturer's guarantee or estimate of performance. The Net Capability of a planned combustion turbine unit shall give recognition to the elevation of the unit location, the type of fuel available for use, and owner system policy with respect to the maximum output. The Net Capability of a planned hydro unit shall be based on the owner system's estimate of head in accordance with 1.1.5.

1.1.8 After a unit is in operation, its Net Capability shall be based on current operating performance or test results. Both Summer and Winter Net Capability values shall be confirmed annually. If adequate data is available from normal operation to confirm Net Capability values during the seasonal peak period, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. When a known change occurs in the Net Capability of a unit, or is indicated by operating data or test results, it shall become effective as soon as possible except as noted in 1.1.9.

1.1.9 The Net Capability of a unit shall not be reduced to reflect unannounced deratings or temporary capacity restrictions provided it is the intention of the owner to restore the reduced capability. The time of this restoration may depend on availability of parts and scheduling of the outage required for repairs. However, if the owner does not intend to restore the reduced capability, the owner shall so notify the Operating Committee in writing and a reduced Net Capability value shall become effective for that unit at the time notice is given not to restore the capability.

1.1.10 All or any part of a unit's capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 12 hours, shall be considered as unlimited energy capability. All any part of a unit's capability shall be considered as limited energy capability only for those periods in which it does not meet the foregoing criteria sustained operation. Such limited energy capability will be used to meet energy requirements of PJM and depending on the extent to which it meets these requirements such capability may be reduced as provided in Section 3 of these rules.

1.1.11 Each PJM system shall be responsible for the determination of Summer and Winter Net Capability values; and for reporting same to the Operating Committee. The Operating Committee shall be responsible for the establishment of test procedures required to confirm such values including any amount which shall be treated as limited energy capability.

1.1.12 The Net Capability reported for a unit following its date of commercial operation shall in no case exceed an amount determined by the owner in accordance with 1.1.1 and 1.1.8 but for PJM accounting purposes may initially be less than that amount. The extent of any such reduction in reported capability shall be determined by the company in such manner as will permit the most effective use of its own resources. A unit or portion thereof placed in service and reported by the IO for operating purposes may be reported and accounted for as being unavailable before it is placed in commercial operation, limited to the extent that the total daily unavailable reported by system shall not be less than zero.

Summer Net Capability

1.2.1 The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit at the time of the PJM summer peak load.

1.2.2 Summer conditions shall reflect the 50% probability of occurrence of temperature and humidity conditions of the time of the PJM summer peak load shall be based on local weather bureau records for the past 15 years. When weather records are not available, the values shall be estimated from the data available. (see attached memo dated March 4, 1988)

1.2.3 For steam and combustion turbine units, summer conditions shall be where applicable the probable intake water temperature of once-through or cooling systems experienced in June, July and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity conditions experienced at the unit location at the time of the annual summer PJM peak.

1.2.4 The determination of the Summer Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

1.3 Winter Net Capability

1.3.1 The Winter Net Capability of each unit or station shall be based on winter conditions and on the power factor level normally expected for that unit or station at the time of the PJM winter peak load.

1.3.2 Winter conditions shall reflect the 50% probability of occurrence of temperature and humidity conditions at the time of the PJM winter peak load and shall be based on local weather bureau records for the past 15 years. When local weather records are not available, the value shall be estimated from the best data available. (see attached memo dated March 4, 1988)

1.3.3 For steam and combustion turbine units, winter conditions shall mean where applicable the probable intake water temperature of once-through or open cooling systems experienced in December and January at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the Annual winter PJM peak.

1.3.4 The determination of the Winter Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Summer Net Capability.

1.4 System Limitations

1.4.1 Certain system limitations may at times prevent the simultaneous utilization of the total Net Capabilities of the units in a system. Such limitations may include, but are not necessarily confined to, the availability of energy or fuel, and transmission limitations. The determination of energy and fuel limitations is described in section 4 and Appendix A, and of transmission limitations in Section 4 and Appendix B.

2. AVAILABLE CAPABILITY

2.1 Available Capability of a system shall be the sum of the reported Summer Net Capabilities for all units installed on a system less the Planned Outages and Deratings, Unplanned Outages and Derating, and Miscellaneous Adjustments. All such modifications shall be measured, except as to 2.1.3 (a), during the hour of the daily system peak load. Reductions of capability shall be reported as positive quantities and increases as negative, and the net used as a reduction from the Summer Net Capability values.

2.1.1 Planned Outages and Deratings shall be a reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions.

2.1.2 Unplanned Outage and Deratings shall be:

- (a) A reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions; and
- (b) For planning and accounting purposes required by the PJM Agreement as supplemented, an additional daily reduction in the capability of a system due to energy limitations determined in accordance with section 3 of the Rules and Procedures.

2.1.3 Miscellaneous Adjustments shall be:

- (a) A reduction from the Summer Net Capability of any equipment out of service for any reason not covered by 2.1.1 and 2.1.2 and which could not be made ready, upon notice, to carry load at its reported Summer Net Capability value, as modified by (b) and (c), within six hours.
- (b) A reduction from the Summer Net Capability of a unit or plant which could not be produced because of higher circulating water temperatures, higher ambient air temperatures, reduced head on hydro plants, and other causes consistent with the PJM Report on Generating Unit Performance Definitions.
- (c) An increase from the Summer Net Capability of a unit or plant which was produced or was capable of production over the specified period and was reported in operation or available for scheduling by the IO, because of lower circulating water temperatures, lower ambient air temperatures, recent condenser cleaning, higher stream flows, etc., and other causes such as a new unit operating for test.
- (d) The actual output, at the time of a system's daily peak load, of a unit or portion thereof, operating for test and not included in the Summer Net Capability of the system.
- (e) A reduction in the reported Summer Net Capability of a system which could not be delivered to load areas because of area or system transmission limitations as specified in Section 4.

2.2 Weekly Available Capability of a system shall be the arithmetical average of that system's daily Available Capability as determined in 2.1 above for each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.3 Weekly Summer Net Capability of a system shall be the arithmetical average of that system's total reported Summer Net Capability values for all units installed at the time of the system peak load on each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.4 Weekly Unavailable Capability of a system shall be the algebraic difference between the average values determined in 2.2 and 2.3.

3. LIMITED ENERGY RESOURCES

3.1 General

3.1.1 The available output of all or any part of a unit's capability which is considered limited energy capability in accordance with 1.1.10 shall be utilized, as hereafter specified, on a daily basis excluding weekends and holidays to determine what amount, if any of such capability, is the equivalent of unavailable capability of unlimited resources. Such amounts of unavailable capability shall be determined both for actual and forecast conditions for use in PJM planning and accounting as follows:

- (a) Unavailable capability based on actual hourly loads, actual average daily river flows, actual outages of limited energy resources and other conditions applicable to the day, will be used as an addition to unplanned forced events in the after-the-fact accounting for capacity as provided in 2.1.2 (b).
- (b) Forecast unavailable capabilities based on daily computations but expressed as monthly averages and based on predicted load shapes, experienced probabilities of river flows or output, scheduled capacity additions, and predicted outages of limited energy resources will be for use in the determination of capacity requirements of PJM and the member companies as follows:
 - (i) To the extent that the forecast unavailable capabilities under summer and winter operating conditions exceeded the amount specified in 3.3.3, the forecast excess will be applied as a reduction in the net capabilities of systems owning the limited energy resources.
 - (ii) All forecast unavailable capabilities, except the portion applied in (i) for summer conditions, shall be used as an addition to forecast average unplanned forced events.

3.1.2 The available capability of limited energy resources of PJM shall be determined by fitting the total daily energy of these resources into the peak of the daily PJM load curve (to the best advantage of the limited energy resources) so as to minimize the required operation of unlimited resources. The total daily energy of the limited energy resources shall include all energy which is available or renewable only on a daily basis plus any additional daily energy available from the drawdown or refill of storage on a weekly or longer basis.

3.1.3 Whenever the determinations in 3.1.2 result in some amount of unavailable capability due to energy limitations, this amount shall be allocated among the several companies owning limited energy resources. Each company's own limited energy resources shall be tested on its own load curve to determine the resultant unavailable capability of that company's resources due

to energy limitations, and each company shall then be allocated a share of the total PJM unavailable capability due to energy limitations in proportion to the ratio of its unavailable capability on its own load curve to the sum of such unavailable capabilities for all companies.

3.1.4 The available capability of limited energy resources shall be determined, and any unavailable capability shall be allocated on the basis of data and procedures specified in Appendix A.

3.1.5 The Operating Committee shall maintain records of daily Available Capabilities of limited energy resources on the PJM system and of the resulting unavailable capabilities and their allocations, and shall review from time to time the determination of the effects of limited energy on the forecast Net Capabilities and Available Capabilities.

3.2 Fuel Shortages

3.2.1 If any generating capability is classified as limited energy capability because of fuel shortages, the determination of the amount of available capability of such limited energy resources will depend on the predictability of the limited fuel supply.

- (a) When the limited fuel supply is predicted in advance for forecast conditions, it shall be treated as all other limited energy resources in fitting its total daily energy into the daily PJM load curve.
- (b) When the limited fuel supply is not predicted in advance for forecast conditions but is imposed on any member company by external conditions (such as national policies, strikes, fuel supplying companies, etc.), the determination of available capability shall be made in two steps. First, a determination shall be made for all other limited energy resources to obtain the unavailable capability of these resources. Second, another determination shall be made for the total limited energy resources, including those for which fuel is limited by external conditions, but fitting this total available energy into the load curve and obtaining a second value for unavailable capability. The amount of unavailable charged to the fuel limited resources shall be the difference between the values obtained in the first and second determination.

3.2.2 If any unavailable capability charged to fuel limited resources is determined under 3.2.1 (b), this amount shall be allocated by making the same two determinations of unavailable capability as are required and by determining the additional unavailabilities charged to fuel limited resources on each owner company's own load curve. The unavailable capabilities on the PJM load curve that are charged to the fuel limited resources determined under 3.2.1 (b) shall then be allocated in proportion to the additional unavailabilities on the load curves of the owning companies. In no case shall the amount so allocated to any company, as a result of the separate allocation for fuel

limited resources, exceed the additional unavailability on its own load curve. Any amount of additional unavailable that cannot be allocated on this basis shall be allocated on the basis applicable for all other limited energy resources under 3.1.3.

3.3 Reduction in Net Capability

3.3.1 Energy limitations that cause reductions in load carrying capability are in some respects similar to unplanned forced events in unlimited energy capability. In either case, if the limitations on energy or reductions in capability are sufficiently severe, failure to carry load may result. Since the reported Net Capabilities of unlimited energy units are not reduced to reflect unplanned forced events experience, it is reasonable not to reduce the reported Net Capabilities of limited energy resources simply on the basis of energy limitations, unless such limitations are expected to be unusually severe at the time of the PJM peak load.

3.3.2 Whenever the forecast weighted average daily unavailable capability of limited energy resources of PJM, determined in accordance with 3.4.1 for the months of July and August (for determination of Summer Net Capability) and December and January (for determination of Winter Net Capability), is an amount which exceeds a specified percentage of the unlimited net capabilities of the total limited energy resources of PJM, such excess amount shall be applied as a reduction of the Net Capabilities of these resources. Such reductions shall be allocated among the owners of limited energy resources, generally in accordance with 3.1.3 and Appendix A except that, as to each owner, only that portion of the unavailable capability which exceeds the specified percentage of its own limited energy resources shall be used in determining the allocation factor.

3.3.3 The specified percentage shall be 12%, based on the recent actual weighted average PJM forced outage rate for thermal units less the actual weighted average PJM forced outage rate for hydro units, such averages based on three years of experience. The specified percentage shall be changed by the Operating Committee to conform to changes in unplanned forced events experience.

3.4 Forecast Unavailable Capabilities

3.4.1 The forecast monthly average unavailable capability of the limited energy resources of PJM shall be determined and allocated in accordance with 3.1.3, based on appropriately estimated daily load shapes and on experienced probabilities of river flow or output, scheduled capacity additions, and predicted outages of limited energy resources. Whenever the Net Capabilities of limited energy resources of PJM are reduced in accordance with 3.3.2, then that amount of unavailable capability that has been applied as a reduction of the Net Capabilities of PJM and the member companies for summer conditions shall be subtracted from the respective forecast average monthly values of unavailable capability.

3.4.2 Average monthly values of unavailable capability for PJM determined in 3.4.1 and reductions in Net Capabilities determined in 3.3.2, to the extent they are significant shall be used as input to the calculations of

Forecast Requirements of the Interconnection. Values lower than 2.5% of the Net Capability of the PJM Limited Energy Resources are considered to have an insignificant effect on the calculations of requirements, but may be included as input at the discretion of the P&E Committee.

3.4.3 The average monthly values of unavailable capability in excess of the reduction in summer Net Capability for each system determined in 3.4.1 for the 12 months of each planning period, shall be averaged to determine the average annual addition to unplanned forced events. The ratio of this average addition to the average total of the system's Net Capabilities for the planning period shall be used as an addition to its forecast forced outage rate.

4. TRANSMISSION LIMITATIONS

4.1 The availability of transmission capacity may limit the output of a unit, station, area or an entire system. The limitation may be the deliberate result of planning, the unintended result of delays in construction, the result of planned outages for maintenance or reconstruction, or the result of an unplanned forced outage for various reasons. The resulting effect on the availability of generating capacity is to be determined and be classified, based on the cause and extent of the transmission limitation.

4.2 Transmission limitations shall be determined as required for after-the-fact accounting and in forecast periods for use in the determination of capacity requirements of PJM and the member companies, by comparison of transmission capability with the excess of the Net Capabilities for a unit, station, area or system over the peak load for the day or period under consideration, with adjustment as necessary for firm purchases and sales, use of jointly owned units, and unavailable generating capability. The Net Capabilities used in such determination shall be appropriate for the season of the peak load under consideration. Transmission limitations shall be determined on the basis of data and procedures specified in Appendix B.

4.3 A transmission limitation caused by an outage of transmission facilities shall be recognized in the after-the-fact accounting as follows:

(a) When the limitation affects a unit or station, the amount of the limitation shall be considered as either a Planned or Unplanned Outage or Derating (as defined by the PJM report on Generating Unit Performance Definitions) in the determination of Available Capability as provided in 2.1.1 and 2.1.2.

(b) When the limitation affects an area or system, the amount of the limitation shall be considered as a Miscellaneous Adjustment to the reported Summer Net Capability of a system as provided in 2.1.3 (d).

4.4 Examination must be made to determine transmission limitations during forecast periods and any such limitations predicted shall be accounted for as follows:

- (a) Limitations predicted during July and August (1) which affect a unit or station shall be recognized in the reported Summer Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Summer Net Capabilities of units of the system in the determination of its System Capacity (as defined in the PJM Contract).
- (b) Limitations predicted during December and January (1) which affect a unit or station shall be recognized in the reported Winter Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Winter Net Capabilities of units of the system.
- (c) Limitations predicted during forecast periods other than as specified in (a) shall be recognized in the determination of forecast average Miscellaneous Adjustments.

APPENDIX A

DETERMINATION OF AVAILABLE CAPABILITY OF LIMITED ENERGY RESOURCES

The determination of this Available Capability shall be made: (A) for each weekday, after-the-fact, based on certain actual data and on procedures set forth below in further detail; and (B) for study and forecast purposes, based on probabilities of river flow and other appropriately assumed future conditions and on procedures otherwise consistent with the daily determination.

A. Daily Determinations

A determination shall be made by the Interconnection Office for each weekday, excluding holidays, of the Available Capabilities: (1) of the total limited energy resources operated on the PJM load curve and (2) if any Unavailable Capability is thus determined, of the limited energy resources of each company operated on the respective company load curve. These determinations involve the following steps:

1. Determine for the limited energy resources that amount of energy which is available or renewable only on a daily basis.
2. Determine that amount of additional daily energy available from the drawdown and refill of storage on a weekly or longer basis.
3. Determine the Available Capability of the limited energy resources by fitting the total daily energy (sum of 1 and 2) into the peak of the daily load curve (to best advantage of the limited energy resources, but observing all necessary limitations on their use) so as to minimize the required operation of other generating capacity. The Available Capability is the difference between the daily peak and the required maximum generation of such other capacity.

1. Daily Energy

The energy that is available or renewable only on a daily basis should be determined for the various types of capacity as follows:

- (a) Limited energy thermal capacity - if the unit or incremental capacity of a unit that provides such limited energy output can be considered available under the general provisions for "Available Capacity," Section 2.1, then the associated energy should also be considered available. The energy output of thermal capacity may be limited either by inability to operate continuously at high levels of output or by fuel availability.
- (b) Run-of-river hydro without weekly storage - for those plants that must generate daily whatever amount of energy is available from river flow, the available energy is that part of the actual daily generation which was, or could have been generated within the daily period of operation of all the limited energy resources, as determined by the load curve.

- (c) Run-of-river hydro with weekly storage - for those plants that can operate in part on the basis of weekly storage, the daily available energy (whether or not actually generated and without regard to actual storage use) should be the daily amount normally available for the actual river flow experienced on that day. Such amounts are to be shown by appropriate equations, curves or tabulations of energy versus river flow.
- (d) Storage hydro - for those plants that operate on a seasonal storage basis, the available energy will be determined as described below under item 2(b).
- (e) Pumped storage - the daily available energy (whether actually generated or not and without regard to actual storage use) should be the amount of energy that can be normally replaced by daily pumping within a period determined by load shape or other appropriate limitation, but not including economy of operation. The daily available energy shall be reduced, as compared to that normally replaced on a daily basis, by an amount corresponding to any pumping foregone because of unscheduled equipment outage or other limitation (other than economy) during the prior normal pumping period.

2. Additional Energy From Storage

For those plants which have storage that can be used on a weekly or longer basis, the additional amount of energy that is available should recognize that, within limits, the use of storage can be shifted from one day to another to fit system needs. The same amount of storage energy need not be used and ordinarily will not be used on every day; and general PJM experience has indicated a use of storage energy, on one or two days per week, at an average rate approximately double the rate which could be maintained on every weekday. Such use of storage appears to be a reasonable representation of the use that could and would be made of storage energy to meet normal capacity requirements. It shall therefore be assumed, in determination of available capacities, that the daily available energy from use of storage on any weekday will be twice the amount that could be used on every weekday. The amounts of additional daily energy from storage for the various types of capacity shall be determined as follows:

- (a) Run-of-river hydro with weekly storage - the daily amount shall be 40% of the available weekly storage as limited by the smaller of (i) flow available for weekend refill or (ii) excess of total usable storage over that required for daily operation. Amounts are to be shown by appropriate equations, curves or tabulations of storage energy versus river flow; and each daily amount shall be determined on the basis of an assumed constant flow throughout the week.

- (b) Storage hydro - the total available daily energy at such plants shall be 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.
- (c) Pumped storage - the daily amount shall be 40% of the additional stored energy that can be replaced only by weekend pumping. The amount of weekend pumping shall be considered to be the useful reservoir capacity less the pumping that could have been done on a daily basis in the absence of any unscheduled outage.
- (d) If the energy output of thermal capacity is limited by fuel availability and such availability is determined on a weekly or longer basis, rather than by daily deliveries, for example, then the available energy on each day shall be (comparable to that for storage hydro) 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.

Because the above specified use of storage energy at various types of plants is the principal factor in the determination that is not related to actual current conditions, its validity shall be re-examined from time to time by the Operating Committee; and, if necessary, change shall be made in the above specified procedures.

3. The Daily Load Curve

The total of the daily available energy amounts, as described in 1 and 2 above, shall be fitted into the daily load curve to "firm up" the maximum amount of limited energy capacity. A direct determination of the available capacity in KW shall be made from a tabulation of peak capacity versus energy at the level indicated by the available energy. Recognition of the various limitations that may apply is important at this point in the computations. These include at least the following:

- (a) The usable amount of energy as determined in 1 and 2 above for any plant shall be no more than that plant could generate within the daily period of operation of all limited energy resources. (Alternatively, if the amount from 1 and 2 above is more than the plant can generate in the period determined by the load shape, the plant and its energy may be dropped out of the computation and be temporarily treated as an unlimited energy resource. This shall be the normal treatment of the run-of-river plants in period of adequate flow.)
- (b) The amount of available capacity for any plant that is firmed up by its available energy shall not exceed the physical capability of the plant during the peak hour of the day. This physical capability shall be determined by head, unit outages, and capacity limitations due to ice, trash, heat, or other causes.

- (c) A check shall be made, even when the total available capacity of the limited energy resources appears to be energy limited, to determine if some part of this capacity may not be energy limited (i.e., may be limited by physical capability). This is particularly likely in very low flows, when the run-of-river plants will be energy limited, but the pumped storage may not be. Under these conditions, the available capacity of the pumped storage is limited to its physical capability on the peak hour. At high flows, the situation may reverse.

B. Determination for Study and Forecast Purposes

Forecasts of Unavailable Capability, including those due to energy limitations, are needed under the terms of the PJM contract as supplemented, and similar forecasts are required for study of additional limited energy installations. Such forecasts shall be basically consistent with the above specified determinations for after-the-fact conditions; but certain difference in method of computation are appropriate in recognition of the nature of uncertainties inherent in all such forecasts. The Operating Committee shall review these procedures with respect to new capacity to determine if modifications are required.

1. Susquehanna River Flow

For forecast purposes, the flow of Susquehanna River shall be considered on a probability basis related to each month's experience over a long period. That is, for various ranges of river flow there shall be an assigned probability of occurrence for each month, based on the recorded experience in that month for 50 or more years. For this purpose, flow records accumulated at any one plant on the Susquehanna River (initially, Safe Harbor) may be used for all plants, with appropriate factors for conversion to daily energy.

2. Hydro Plants on Other Rivers

There are now in operation in PJM several small hydro plants (Deep Creek, Piney and Wallenpaupack) on other rivers or streams, not within the Susquehanna River drainage. Because the flow in these other rivers is not related to the flow in the Susquehanna River, and no correlations have been developed, and because the plants are small, it is satisfactory for forecast purposes to assign to each of these plants for each month a fixed amount of generation per day which is reasonably representative of less than average flow conditions. So long as these other plants are small and the available river flow is unrelated to the Susquehanna River flow, the forecast shall be based on this approximate representation of the available energy at such plants.

3. Pumped Storage and Limited Energy Thermal Capacity

The available energies for these plants on a forecast basis shall be consistent with those used, or which would be used in the after-the-fact determinations.

4. Load Curves

Forecasts of Unavailable Capability shall be based on the use of forecast energy amounts in forecast daily load curves. Such daily load curves shall be based on the adjustment of one or more years of experienced loads to be representative of the higher loads by the future years for which forecasts are required. The method of adjustment shall be specified by the Planning and Engineering Committee and shall be consistent with that used for other PJM purposes.

5. Adjustment for Unavailability Due to Unit Outages

Because hydro and pumped storage units are likely to be scheduled for inspection and maintenance at those times when their Available Capability would otherwise be limited by the available energy, recognition shall be given to the probability (related primarily to river flow) of the overlapping of unavailability due to both planned and unplanned maintenance outages and energy limitations. In the forecasting of Unavailable Capability, planned and unplanned maintenance outages shall be recorded at their full amounts and durations, and average unavailability due to energy limitations shall be appropriately reduced by an amount that recognizes the probability of overlap between the two causes of unavailability.

APPENDIX B

DETERMINATION OF TRANSMISSION LIMITATIONS

When determining the capability of a unit, station, area or system and the availability of this capability for PJM contract purposes, it is necessary to examine the ability to deliver the capability to the load areas. In order to make this examination, the following standard formula is presented to determine if a Transmission Limitation exists.

$$\text{Transmission Limitation} = \text{Net Capability} + \text{Firm Capacity Sales}^{(1)} \\ \text{Firm Capacity Purchases}^{(2)} - \text{Peak Load} - \\ \text{Unavailable Capacity} - \text{Transmission Capability}^{(3)}$$

- (1) Includes only sales that must be delivered outside the System and any other system's share of jointly owned internal generation.
- (2) Includes system's share of jointly owned external generation and purchases from outside the System.
- (3) Transmission Capability of any transmission path must be compatible with the values used for emergency ratings as specified in the PJM Operating Principles and Standards and for parallel paths must be such a total that the loading of no line exceeds its emergency rating.

A. Daily Unavailability Due to Transmission Limitation

A Transmission Limitation associated with a unit or station shall be determined for each weekday excluding holidays using the standard formula with the following data:

<u>Item</u>	<u>Unit</u>	<u>Station</u>
Net Capability	Unit Net	Station Net
Firm Capacity Sale	Only when part of unit or station is jointly owned or is specified source of firm sale.	
Firm Capacity Purchase	Not Applicable	Not Applicable
Peak Load	Local Bus Load	Local Bus Load
Unavailable Capability	Of Unit	Of Station
Transmission Capability	For Lines Available	For Lines Available

A Transmission Limitation associated with an area or system shall be determined for each weekday excluding holidays using the standard formula with the following data:

<u>Item</u>	<u>Area</u>	<u>Station</u>
Net Capability	Of Stations in Area	Of all System Stations
Firm Capacity Sale	Only when part of station in area is jointly owned or is specified source of Firm Sale.	Total Value
Firm Capacity Purchase	Not Applicable	Total Value
Peak Load	Of Area	Of System
Unavailable Capability	Of Units in Area (Including Unavailability) (of Units or Stations Due) (to Transmission Limitation)	Of Units on System

B. Negative Values of Transmission Limitations

When the determination shows a negative Transmission Limitation the value shall be considered as zero for all cases except the daily System determination.

A negative value of Transmission Limitation as a result of the daily System determination can be considered as negative Unavailable Capability up to the value of the Transmission Limitation applied to the System Capacity. If there is Transmission Limitation applied to the System Capacity then any negative value of Transmission Limitation as a result of the daily System determination shall be considered as zero.

APPENDIX C
NET CAPABILITY VERIFICATION GUIDELINES

PURPOSE

These guidelines are to supplement the requirements set forth in the PJM Rules and Procedures For Determination of Generating Capability (Green Book) by setting forth requirements for Net Capability verification, reporting and review of results to assure uniform and consistent compliance. These guidelines address questions that occur frequently at the Generating Capability Ratings Procedure Task Force (GCRPTF) meetings.

A. PHILOSOPHY OF NET CAPABILITY VERIFICATION

1. Responsibility

- a. Member Companies through the GCRPTF are responsible to comply with these requirements at their own expense.
- b. GCRPTF consists of representatives from each member Company signatory to the Supplemental Agreement and an IO representative serving as secretary. The GCRPTF is responsible to review verification and to tender recommendations to the Operating Committee. Nonconformance(s) shall be communicated in writing to the Operating Committee.
- c. The Operating Committee Member is responsible for the approval of Net Capability verification reports and Company compliance to these guidelines.
- d. Individual Company Task Force members are responsible as delegated by their Company Operating Committee Member for the collection and reporting of net capability verification results.

2. Exceptions and Deviations

Exceptions to and deviations from these Net Capability verification guidelines shall be by Operating Committee approval. These exceptions shall be made in writing prior to the end of the test window for known occurrences such as environmental restrictions and fuel limitations.

B. NET CAPABILITY VERIFICATION

1. Net Capability verification is to demonstrate the maximum Net Capability of each unit. If that Net Capability cannot be demonstrated during the verification window, a reduction or derating shall be enacted to account for the deficiency.
2. Both Summer and Winter Net Capability shall be confirmed annually during the verification windows that correspond to the seasonal peak periods:
 - a. Summer verification window shall be the first day of June through the last day of August.
 - b. Winter verification window shall be the first day of December through the last day of February.
3. If adequate data is available from normal operation to confirm Net Capability values and to satisfy the reporting requirements during the seasonal verification window, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. A test shall include any unit brought on-line or a unit that is on-line and its mode of operation altered for the specific purpose of capability verification.
4. If a unit does not meet its stated Summer or Winter Net Capability due to a temporary condition, the deficiency shall be covered by the appropriate outage/reduction(s) from the date of the problem. If a capability deficiency is uncovered during this verification, a reduction covering the deficiency shall be coded retroactive to June 1 or January 1 for summer and winter verification windows, respectively.
5. Net Capability verification is required outside of the verification period when an outage or reduction occurred prior to or during the verification period which prevented demonstration of maximum Net Capability. The Net Capability shall be demonstrated by either operating performance data or test results.

C. REPORTING

1. Two standardized forms are provided to facilitate the review of results:
 - a. Attachment One is the individual unit PJM Net Capability Verification Reports to be used for documenting operating performance or test data.
 - b. Attachment Two is the PJM Verification Summary Report.
2. Net Capability Verification Reports shall be approved by the Operating Committee Member.
3. Reports shall be submitted to the GCRPTF Secretary no later than September 30th and March 31st for the summer and winter verification periods, respectively. Copies of the summary sheets shall be mailed to the GCRPTF Members.
4. Outages and reductions for the discrepant capability greater than 1 MW (Rated Net Capability less the Corrected Test Net Capability) shall be recorded on the reports, including:
 - a. MW's out shall be reported on the Capability Reporting Form along with a brief explanation of the reason completed by Plant personnel.
 - b. The MW reduction shall be covered in the Summary Report notes with event data including: MW reduction, NERC event type, cause code, event start date and time, event end date and time (if appropriate). The Summary Report shall be submitted by the GCRPTF member.
5. When the owner has submitted output adjustment methodology and received GCRPTF approval, the following output corrections may be made:
 - a. For combustion turbines, ambient air temperature correction.
 - b. For steam units, circulating water temperature correction.
 - c. For cogeneration units where heating system extraction steam limits the output, a limited steam flow correction.
6. Units shall be verified and reported on a block basis as opposed to an individual basis when the units are rated and dispatched as a block.
7. Net Capability Verification Reports shall be submitted to the GCRPTF Members for verification outside of the verification period to document end of outages or reductions (reference paragraph B.5).

8. Reports shall indicate the nearest whole MW output for units rated 10 MW's or greater, and the nearest one-tenth MW output for units rated less than 10 MW. When a figure is to be rounded to fewer digits than the total number available, the procedure adapted from ISO-R370, should be as follows:

- a. When the first digit discarded is less than 5, the last digit retained should not be changed. For example, 3.463 25, if rounded to three digits, 3.46.
- b. When the first digit discarded is greater than 5, or if it is a 5 followed by at least one digit other than 0, the last digit retained should be increased by one unit. For example, 8.376 52, if rounded to four digits, would be 8.377; if rounded to three digits 8.38.
- c. When the first digit discarded is exactly 5, followed only by zeros, the last digit retained should be rounded upward if it is an odd number, but no adjustment made if it is an even number. For example, 4.365, when rounded to three digits, becomes 4.36. The number 4.355 would also be rounded to the same value, 4.36, if rounded to three digits.

D. REVIEW

1. A GCRPTF Working Group composed of the immediate past chairman, the present chairman, next apparent chairman, and the secretary (IO member) shall review all reports to verify completeness of records and verify outage tickets as required.
2. Each owner shall have a representative in attendance (GRCPTF member or alternate) at the GCRPTF verification review meeting. The review should be reported in minutes to the Operating Committee including a summary of results, a list of follow up items, and nonconformances to these procedures.

APPENDIX D

GUIDELINE FOR CLASSIFICATION OF EXTENDED DURATION OUTAGES RESULTING FROM - VOLUNTARY DEFERRAL OF REPAIRS TO GENERATING UNITS

(Deferred Maintenance Guidelines)

Purpose

The purpose of this guideline is to define a procedure for implementing a PJM policy which permits the voluntary deferment of generating unit repairs for financial reasons while minimizing the effect that such a deferment has on the determination of forecast installed reserve obligations and allocations.

During periods of high PJM system installed reserves, it may not be economically feasible to perform extensive repairs on units with high operating costs, since such units are unlikely to be called on to supply load. Whenever such a unit fails and is not repaired immediately, the outage associated with the failure is lengthened due solely to company economic and system reserve conditions, rather than to any special nature of the unit failure. PJM reserve obligations and allocations are both based in part on company outage history. The straightforward inclusion of the total time associated with a deferred maintenance outage in a company's outage history leads to a pessimistic model of unit repair time.

The PJM companies recognized that in times of lower excess system installed reserves, units would be repaired with minimum delay, since system conditions would dictate more frequent unit operation. The procedure outlined in the following paragraphs is designed to allow companies to single out those outages which are lengthened due solely to company economic constraints, so that such outages can be more accurately modelled in PJM planning studies.

It should be noted that a company requesting deferred maintenance status for a unit agrees to attempt accelerated repairs in the event of an Operating Committee determination that the unit is required to bolster PJM system or sub-area reserves. Also, the physical coding of such outages in the PJM outage data base is not changed as a result of application of this procedure. Neither is the deferred maintenance classification recognized for any uses of the outage data base other than the determination of forecast installed reserve obligations and allocations.

Scope of Application

This procedure may be applied to an outage on any generating unit or portion thereof, so long as repairs are to be deferred for at least 90 days due solely to company financial constraints.

Procedure

I. In the event that a unit is out of service in the unplanned forced classifications,* either wholly or partially, and repairs are to be deferred for at least 90 days due solely to company financial constraints, the owning company shall have the option to request that the portion of the outage associated with the deferment be excluded from consideration as an unplanned forced outage in planning studies. Authority to grant or deny such a request rests with the PJM Operating Committee, as advised by the Maintenance Committee and the Interconnection Office.

II. A request for official recognition of the voluntary deferment period must include the following information:

1. Name of unit.
2. MW of installed capability affected.
3. Is this a reduction in unit capability, or a full outage?
4. Starting date of original unplanned forced outage.
5. Planned return to service date.
6. Scope of repairs required.
7. Estimate of unplanned forced outage time required to effect repairs to the unit. This estimate should be based on crews working a 40-hour week and must include any time waiting for manpower or parts to become available or for technical problems to be solved.

III. Copies of each request will be sent to the Maintenance Committee and the Interconnection Office, as well as to the Operating Committee.

- A. The Maintenance Committee will review the scope of required repairs compared with the estimated repair time, and advise the Operating Committee on the adequacy of the repair time estimate.
- B. The Operations Planning Branch of the Interconnection Office will analyze the effect of the repair deferment on PJM system reserves and risk during the outage period, as well as sub-area reserves (if the unit is located in a deficient area) and make recommendations to the Operating Committee.

IV. The Operating Committee can either approve or disapprove a request for deferred maintenance status based on the recommendations of the Maintenance Committee and the Interconnection Office.

- A. If the Operating Committee disapproves the request, the entire outage duration will be considered as unplanned forced outage time and will be accounted for as such on all planning studies.

*The basis for this definition is set forth in IEEE Standard 762 entitled "Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity."

- B. If the Operating Committee approves a request for deferred maintenance status for a particular unit, relevant information concerning the deferral period will be passed to the Generator Unavailability Subcommittee, of the Planning and Engineering Committee, so that the outage can be properly modelled in all planning studies.
- C. The revised modelling of any approved deferred maintenance outage for planning study purposes is a manual process. Reporting of the outage in the PJM outage data base will not be affected by Operating Committee approval or disapproval of a deferral period.
- D. After-the-fact accounting is not affected by Operating Committee action on a deferral request. Such a unit will be considered unavailable for purposes of after-the-fact accounting whether or not the Operating Committee grants a deferred maintenance request.

Extensions to Existing Deferral Periods

I. If a unit has not been repaired by the planned return to service date, its outage classification for planning study purposes will revert back to unplanned forced as of the planned return to service date, unless an extension to the deferral period is allowed by the Operating Committee.

II. Any request for an extension to an existing deferral period should be handled just like any new request for deferred maintenance status, with the owning company proposing a revised in-service date for review by the Operations Planning Branch of the Interconnection Office and final action by the Operating Committee.

III. Because of the system planning aspects of the deferred maintenance classification, all requests for extensions to existing deferral periods should be made as soon as possible after determination that company financial constraints will not allow repair of a particular unit to begin before the original planned in-service date.

Returning Deferred Maintenance Units to Service

I. Voluntary Return by Owning Company

- A. The company owning a unit with deferred maintenance status should keep all interested parties notified of any changes in the expected return-to-service date of the subject unit.
- B. If a company decides to delay the return to service of a deferred maintenance unit, an extension of the deferral period may be requested as outlined above.
- C. A company may decide to return a deferred maintenance unit to service at any time prior to the originally scheduled return date. If such a decision is made, the outage will be classified as follows:

1. No additional unplanned forced outage time will be assigned to unit repaired and reported available for service at any time after the minimum 90-day deferral period but before the original return-to-service date.
2. If a unit is repaired and returned to service prior to the minimum 90-day deferral period, the outage duration will be classified as forced for planning study purposes.

II. Return Requested by Operating Committee

- A. When dictated by changing system conditions, the Operating Committee can request that companies owning units with deferred repairs effect repair of the subject units in order to bring PJM system or sub-area installed reserves up to more acceptable levels.
- B. Should such a recall become necessary, units which have been granted extensions to their original deferral periods will be the first ones called back to service.
- C. If a unit is repaired and returned to service at the request of the Operating Committee, no additional unplanned forced outage penalty will be assigned, even if the repairs are completed prior to the end of the original 90-day deferral period.
- D. If a company is not able to respond to a recall request on a deferred maintenance unit, the outage on the unit in question will be considered unplanned forced for planning study purposes, after a period of time equal to the estimated repair time.

Control

I. The Operations Planning Branch of the Interconnection Office will analyze system conditions and make recommendations to the Operating Committee regarding each request for a new or extended deferral period.

II. On a continuing basis, the Interconnection Office will review system conditions to determine the impact of existing deferred maintenance on PJM operations.

- A. The Interconnection Office will make recommendations to the Operating Committee concerning the need for accelerated return of units on deferred maintenance.
- B. Reserve and risk criteria used shall be approved by the Operating Committee.

Revised and approved by the PJM Operating Committee 11/87

5174B

BECHTEL EASTERN POWER COMPANY

INTERCONNECTION STUDY

**System Planning
August 1988**

I. INTRODUCTION

The purpose of this study is to determine the interconnection feasibility for the proposed site between Bechtel Eastern Power Company and Atlantic Electric (AE) so that AE may receive the electric generation in a safe and reliable manner.

This study covers transmission requirements to connect from AE to the cogeneration facility, effect of cogenerator on AE's system along with the cost estimates for interconnection and associated work. Costs have an order of accuracy of $\pm 20\%$. They include the transmission/substation improvements required on AE's system. The cost for a switching station is also included. Costs to provide two transmission lines from the high side of the switching station to AE's line are provided as a per mile cost.

II. RECOMMENDATION

It is recommended that Bechtel interconnect to AE at 230 kV to a new Deepwater - Mickleton 230 kV line. The interconnection of Bechtel's facility to AE's system will be via a newly constructed 230 kV switching station.

III. CONCLUSION

1. Character of service

- A. Generation 167 MW net at a power factor of 90% leading or lagging.
- B. Maximum load of 0 MW 0 MVARs.
- C. 60 Hertz
- D. 3 phase
- E. Interconnection voltage 230 kV.
- F. Ability to vary generator terminal voltage $\pm 5\%$.
- G. Maximum generation 167 MW at a power factor of 90% leading or lagging.

2. All cost are based on an in service date of 6/1/92.

3. The study was based on the assumption that Bechtel's net generation is 167 MW. Subsequently, the amount was increased to 184 MW. A quick analysis shows that the additional generation does not have any significant impact on the result.

IV. DISCUSSION

A. Transmission Study Assumptions

1. MW (MVA) - MVA assumed to be at 90% power factor.
2. All cost are without AFDC
3. Cash flows do not include interconnection line from transmission line to switching station.
4. Major switching station assumptions are shown in Figure 1.

Figure 1

List of Equipment included in the Switching Station

2 - Breakers

An Isolation Switch

Energy Management System (EMS)

All high side bus structure

5. Reconductoring - Can be from replacing the conductor to completely rebuilding the line including replacing the poles.
6. New Line - Construction of new transmission line on new Right of Way.

7. Uprate Substations - Replacing various substation equipment to obtain desired capability.

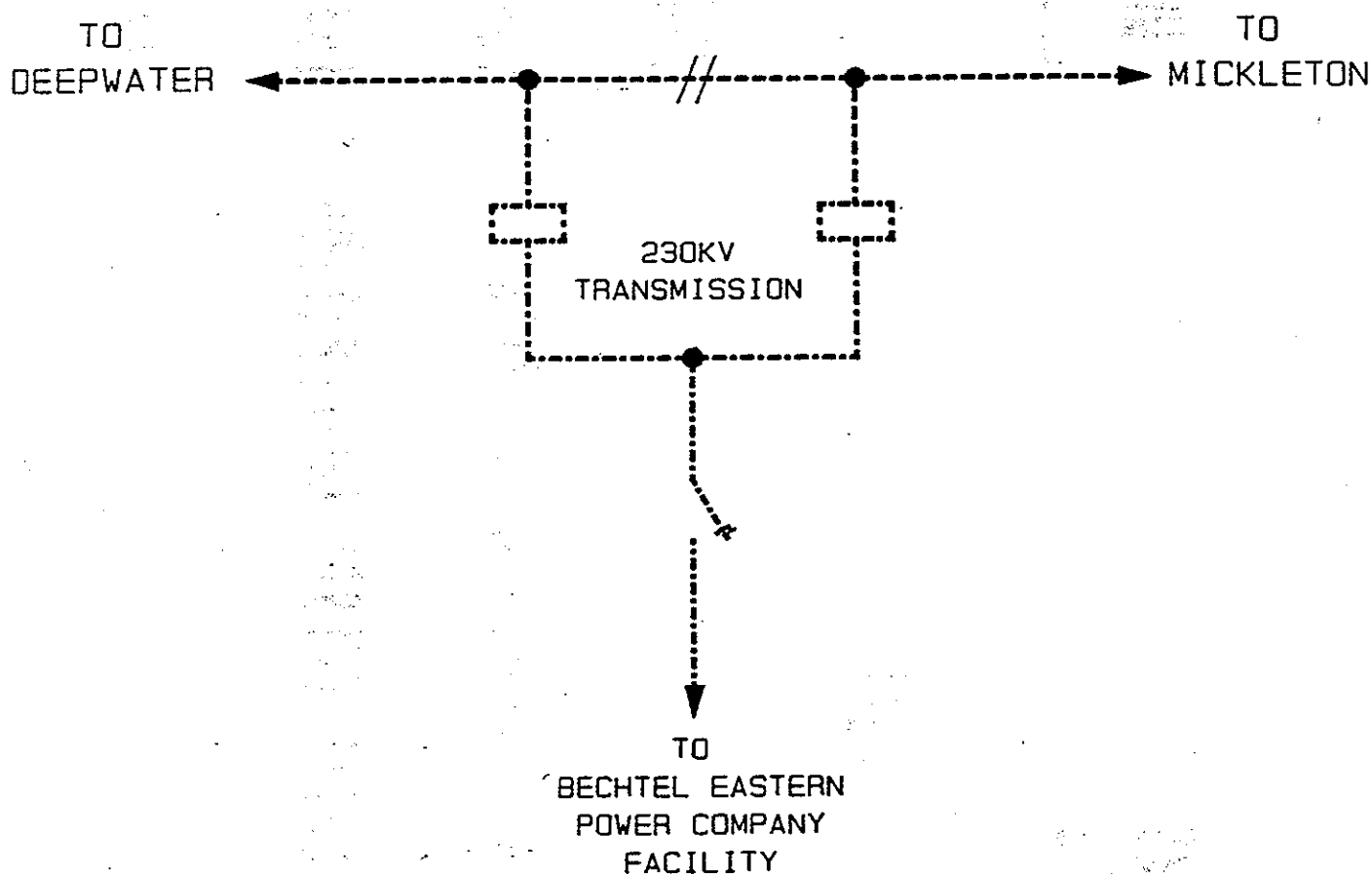
B. Transmission Connections

Actual interconnection voltage and system improvements have not been finalized. At present 230 kV interconnection is being considered in order to have flexibility in the size and amount of future cogenerators.

The interconnection one line is shown in Figure 2.

DELAWARE RIVER COGENERATORS

The number and aggregate total capacity of the eventual river area cogenerators that indicate their desire to interconnect can vary (Figure 3). To illustrate the progressive nature of the system improvements/new construction the following figures are provided. The increments are determined by existing and upgraded facilities. It should be remembered that each of these alternatives may be exclusive and costs can not be considered incremental from one MVA level to another unless noted. The system costs do not include the facility specific interconnection switching facility and lateral transmission line.



- NEW 230KV LINE
- BREAKER
- /--- ISOLATION SWITCH
- // DISCONNECT
- NEW 230KV SWITCHING STATION

BECHTEL EASTERN POWER CO. COGENERATION FACILITY
INTERCONNECTION AND POINT OF DELIVERY

DR.	FAM	CH.	CH.	APP.	DATE	SCALE	ROUTE
ATLANTIC ELECTRIC CO.	P'VILLE, N.J.	NO.	SK-8294-0				

Figure 3

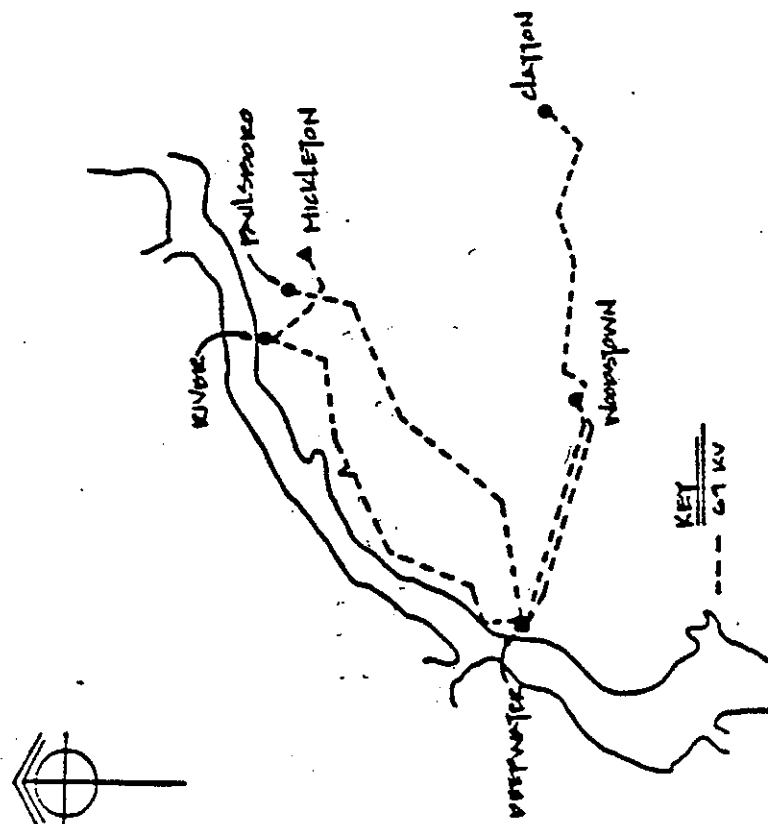
COGENERATORS	MW	MVA (@ 90%)
-----	---	---
WILMINGTON THERMAL	80	90
KEYSTONE	200	220
COGENERATION PARTNERS OF AMERICA	106	120
INTERCONTINENTAL ENERGY CORPORATION	154	170
BECHTEL	167	185

NET COGENERATION UP TO 80 MW

The cost for connecting up to 80 MW of cogeneration is shown in Figure 4. This cost includes the reconductoring of approximately 20 miles of existing 69 kV transmission line to 1200 amps and the uprating of 3 existing 69 kV substations. Also, shown is the cost of one 69 kV switching station including modifications to AE's Energy Management System and the approximate cost/mile for new 69 kV transmission line from AE's transmission line to switching station.

Figure 4

NET COGENERATION UP TO 60MW (90MW) CONNECTED BETWEEN
DEEPWATER AND RIVER



		LINE IMPROVEMENTS		COST PER 69KV	
		W/O CROSS UP		SWITCHING STATION	
		W/O CROSS UP	W/CROSS UP	W/O CROSS UP	W/CROSS UP
		*****	*****	*****	*****
1990:					
1st QUARTER	9	14		7	11
2nd QUARTER	69	105		10	15
3rd QUARTER	83	126		44	67
4th QUARTER	400	606		53	80
1991:					
1st QUARTER	693	1050		202	306
2nd QUARTER	723	1095		272	412
3rd QUARTER	679	1029		120	182
4th QUARTER	700	1061		98	148
1992:					
1st QUARTER	749	1135		231	350
2nd QUARTER	276	418		395	598
3rd QUARTER		0			0
4th QUARTER		0			0
TOTAL:	4381	6639		1432	2169

COSTS DO NOT INCLUDE LINE WORK FROM AE LINE TO SWITCHING STATION
APPROXIMATELY 500 K\$/MILE

NO AFDC

NET COGENERATION BETWEEN 80 MW TO 125 MW

The cost for connecting between 80 MW and 125 MW of cogeneration is shown in Figure 5. This cost includes the reconductoring of approximately 35 miles of existing 69 kV transmission line to 1200 amps and the upgrading of 6 existing 69 kV switching stations. Also shown is the cost per 69 kV switching station including modifications to AE's Energy Management System and estimated cost/mile for new 69 kV transmission line from AE's transmission line to switching station.

Figure 5

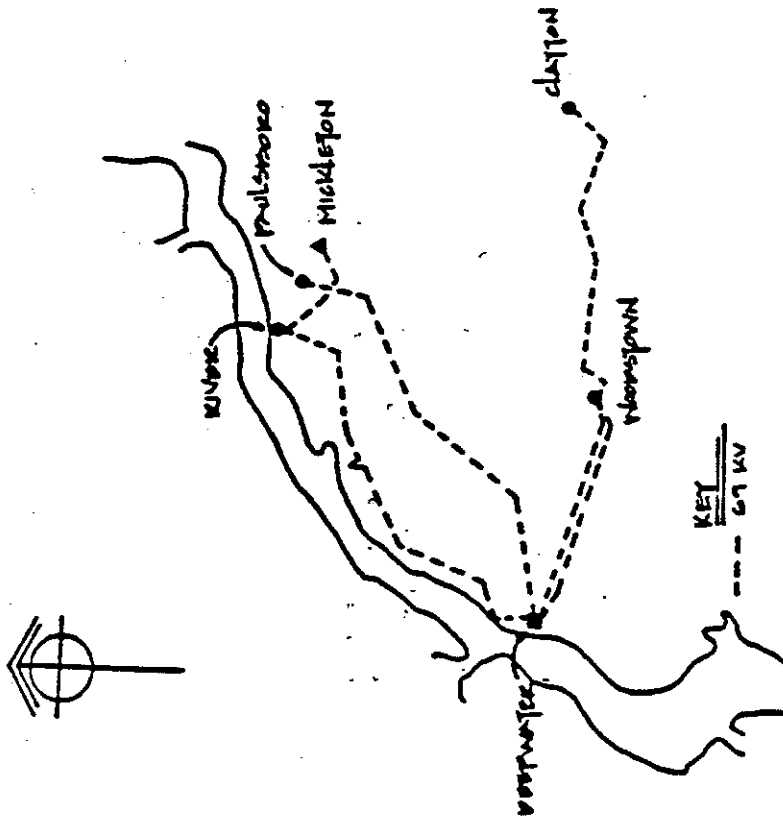
NET COGENERATION 80MW (90MVA) TO 125MW (110MVA) CONNECTED
BETWEEN DEEPWATER AND RIVER

(0 X 1000)

	LINE IMPROVEMENTS		COST PER 69KV	
	W/O GROSS UP	W/GROSS UP	SWITCHING STATION	W/GROSS UP
1989:
1st QUARTER	54	82		0
2nd QUARTER	54	82		0
3rd QUARTER	353	535		0
4th QUARTER	466	706		0
1990:				
1st QUARTER	518	785	7	11
2nd QUARTER	526	797	10	15
3rd QUARTER	551	835	44	67
4th QUARTER	563	853	53	80
1991:				
1st QUARTER	737	1117	202	306
2nd QUARTER	781	1183	272	412
3rd QUARTER	720	1091	120	182
4th QUARTER	720	1091	98	148
1992:				
1st QUARTER	822	1245	231	350
2nd QUARTER	831	1259	395	598
3rd QUARTER		0		0
4th QUARTER		0		0
TOTAL:	7696	11661	1432	2169

COSTS DO NOT INCLUDE LINE WORK FROM AE LINE TO SWITCHING STATION
APPROXIMATELY 500 K\$/MILE

NO AFDC



NET COGENERATION 125 MW TO 180 MW

The cost for connecting between 125 MW to 180 MW of cogeneration is shown in Figure 6. This cost includes the reconductoring of approximately 23 miles of existing 69 kV transmission line to 2000 amps and approximately 16 miles of 69 kV transmission line to 1200 amps and the uprating of 8 existing 69 kV substations. Also, shown is the cost of one 69 kV switching station including modifications to AE's Energy Management System and the approximate cost/mile for new 69 kV transmission line from AE's transmission line to switching station is also tabulated.

Figure 6

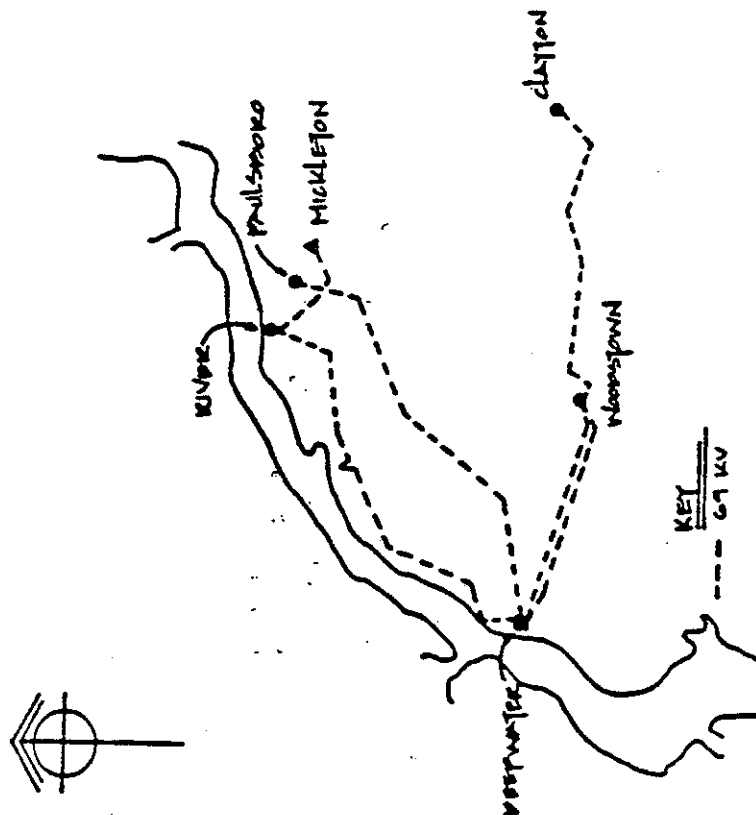
NET COGENERATION 125MW (140MVA) TO 180MW (200MVA) CONNECTED
BETWEEN DEEPWATER AND RIVER

(# X 1000)

	LINE IMPROVEMENTS		COST PER 69KV	
	W/O CROSS UP	W/GROSS UP	SWITCHING STATION	W/GROSS UP
1989:				
1st QUARTER	54	82	0	0
2nd QUARTER	54	82	0	0
3rd QUARTER	353	535	0	0
4th QUARTER	529	802	0	0
1990:				
1st QUARTER	535	811	9	14
2nd QUARTER	553	838	9	14
3rd QUARTER	591	895	49	74
4th QUARTER	1303	1974	57	86
1991:				
1st QUARTER	1013	1535	225	341
2nd QUARTER	1498	2270	282	427
3rd QUARTER	1005	1523	138	209
4th QUARTER	1074	1627	114	173
1992:				
1st QUARTER	1316	1994	314	476
2nd QUARTER	1328	2012	319	483
TOTAL:	11206	16980	1516	2297

COSTS DO NOT INCLUDE LINE WORK FROM AE LINE TO SWITCHING STATION
APPROXIMATELY 500 K\$/MILE

NO AFDC



NET COGENERATION 167 MW CONNECTING DIRECTLY TO DEEPWATER

The cost for connecting a 167 MW cogenerator directly to Deepwater station is shown in Figure 7. This cost is for one cogenerator connected to Deepwater station and assumes no other cogenerator in the area or along the river. This cost includes the reconductoring of approximately 54 miles of 69 kV lines to 1200 amps, the rebuilding of 7 - 69 kV substations, the upgrading of 7 existing breakers, and the establishment of 2 - 138 kV terminals at Deepwater. Also shown is the estimated cost/mile for new 138 kV transmission line.

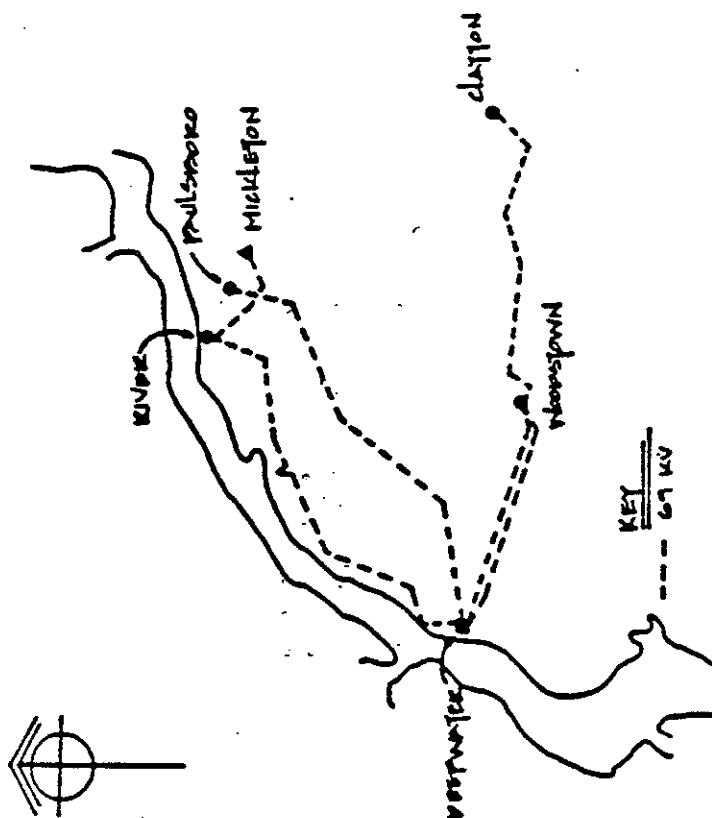
Figure 7

NET COGENERATION UP TO 167MW (1185MVA)
CONNECTED DIRECTLY TO DEEPWATER

	(0 X 1000)	LINE IMPROVEMENTS: W/O GROSS UP	W/GROSS UP
1989:			
1st QUARTER	54	82	
2nd QUARTER	54	82	
3rd QUARTER	843	1277	
4th QUARTER	850	1280	
1990:			
1st QUARTER	936	1410	
2nd QUARTER	984	1491	
3rd QUARTER	1066	1615	
4th QUARTER	1396	2115	
1991:			
1st QUARTER	1630	2482	
2nd QUARTER	1706	2585	
3rd QUARTER	1417	2147	
4th QUARTER	1646	2494	
1992:			
1st QUARTER	1400	2121	
2nd QUARTER	1414	2142	
TOTAL:	15404	23339	

COSTS DO NOT INCLUDE LINE WORK FROM AE LINE TO SWITCHING STATION
APPROXIMATELY 700 K\$/MILE OR SWITCHING STATION

NO AFDC



NET COGENERATION 180 MW TO 360 MW

The cost for connecting between 180 MW and 360 MW of cogeneration in the Deepwater-Mickleton area (including cogeneration at or near Deepwater) is shown in Figure 8.

The cost shown in Figure 8 includes the construction of approximately 18 miles of 230 kV transmission line, the establishment of 6 - 230 kV line terminals at Mickleton, the establishment of a 230 kV station at Deepwater including two 230/138 kV transformers, the reconductoring of approximately 16 miles of existing 69 kV transmission line, the rebuilding of 3 - 69 kV substations and the upgrading of 7 existing breakers. Also, detailed is the cost of a 230 kV switching station including modifications to AE's Energy Management System, and the approximate cost per mile to construct 230 kV transmission from the 230 kV line to the switching station.

Figure 8

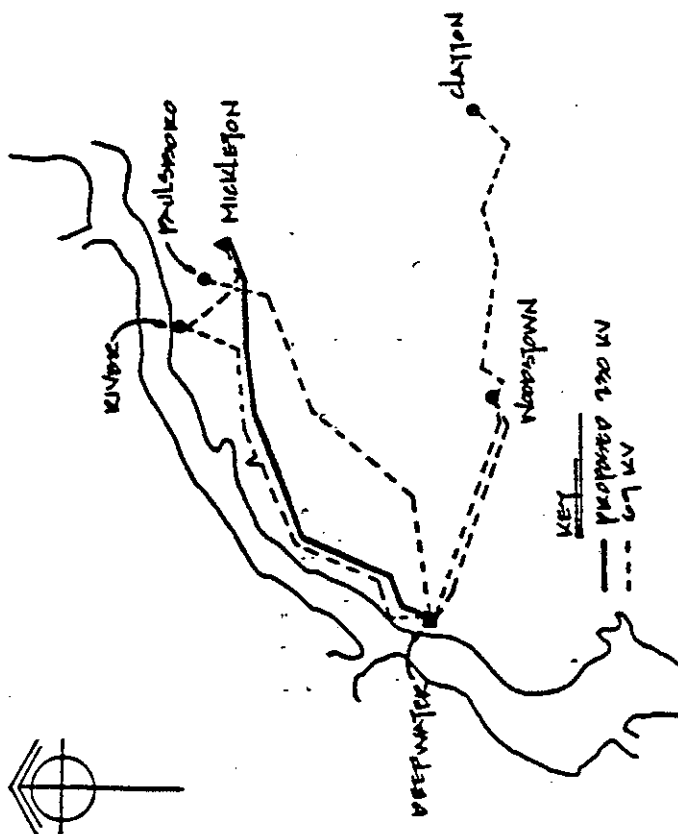
NET COGENERATION 180MW (200MVA) TO 360MW (400MVA) CONNECTED
BETWEEN DEEPWATER AND RIVER

(# X 1000)

	LINE IMPROVEMENTS		COST PER 230KV SWITCHING STATION	
	W/O CROSS UP	W/CROSS UP	W/O CROSS UP	W/CROSS UP
1988:				
2nd QUARTER	246	373	0	0
3rd QUARTER	251	380	0	0
4th QUARTER	222	336	0	0
1989:				
1st QUARTER	262	397	13	20
2nd QUARTER	264	400	13	20
3rd QUARTER	267	405	16	24
4th QUARTER	366	555	13	20
1990:				
1st QUARTER	1896	2873	591	895
2nd QUARTER	2001	3032	598	906
3rd QUARTER	2019	3059	605	917
4th QUARTER	2543	3853	609	923
1991:				
1st QUARTER	4354	6597	305	462
2nd QUARTER	4397	6662	309	460
3rd QUARTER	4440	6727	312	473
4th QUARTER	4483	6792	325	492
1992:				
1st QUARTER	3586	5433	77	117
2nd QUARTER	3625	5492	70	118
TOTAL:	35222	53366	3864	5855

COSTS TO CONNECT FROM AB LINE TO SWITCHING STATION ADDITIONAL 9000\$/MILE.

NO AFDC



NET COGENERATION 360 MW TO 500 MW

The additional cost for connecting between 360 MW to 500 MW of cogeneration is shown in Figure 9. This is an incremental cost to the cost shown in Figure 8 and the improvement must be done in addition to the improvements mentioned in the previous section (Net Cogeneration 180 MW to 360 MW). The transmission line improvement would also be required if enough cogeneration comes in along the Deepwater-Mickleton line to provide support to AE's eastern service territory in lieu of other transmission improvements. This cost consists of the reconductoring to 2000 amps and converting from 138 kV to 230 kV of approximately 31 miles of an existing 138 kV transmission line, the establishment of a 230 kV line terminal at Deepwater, the establishment of a 230 kV station at Sherman Avenue with two 230/138 kV transformers.

Figure 9

SYSTEM IMPROVEMENTS
R/C AND CONVERT D/V-SHERMAN 138KV LINE TO 230KV

	(S X 1000)	LINE IMPROVEMENTS W/O AFDC	W/AFDC
1988:			
1st QUARTER			
2nd QUARTER			
3rd QUARTER			
4th QUARTER		171	172
1989:			
1st QUARTER		224	229
2nd QUARTER		226	236
3rd QUARTER		227	243
4th QUARTER		230	250
1990:			
1st QUARTER		1258	1289
2nd QUARTER		1270	1328
3rd QUARTER		1282	1371
4th QUARTER		6487	6631
1991:			
1st QUARTER		4973	5253
2nd QUARTER		5021	5414
3rd QUARTER		5071	5591
4th QUARTER		5125	5759
1992:			
1st QUARTER		4066	4835
2nd QUARTER		4110	4971
3rd QUARTER			
4th QUARTER			
TOTAL:		39741	43572

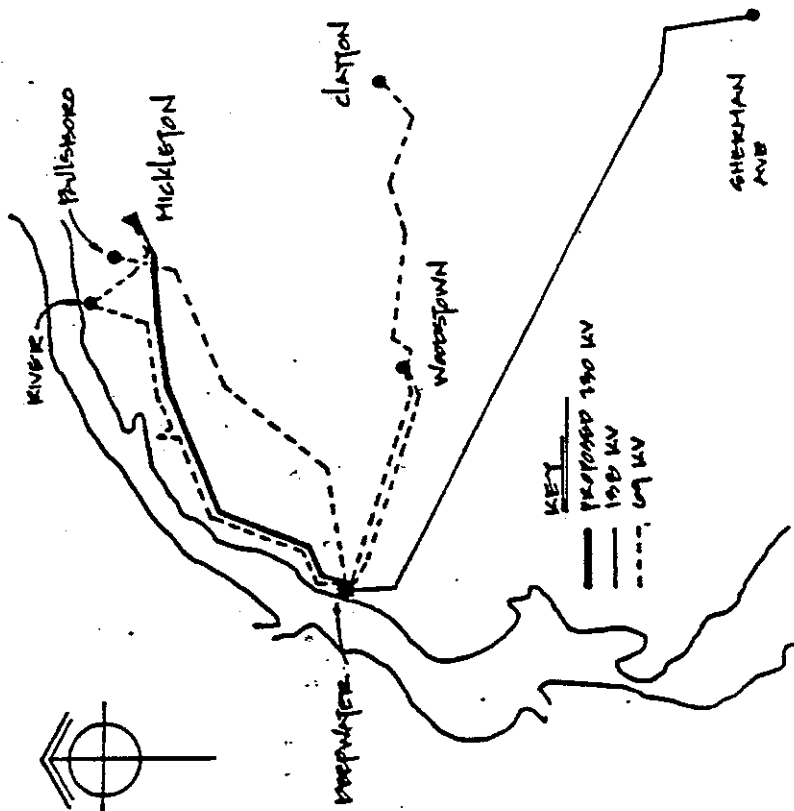


EXHIBIT I

METHODOLOGY

for

CALCULATING

AVAILABILITY FACTOR

METHODOLOGY FOR CALCULATING AVAILABILITY FACTOR

Availability Factor is defined as the ratio of Seller's availability to Purchaser's system's availability based on a calendar year calculation of availability. Therefore,

$$\text{Availability Factor} = \frac{\text{Seller' Availability}}{\text{Purchaser's System's Availability}}$$

Attachments A shows the methodology used to determine the Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit and for Atlantic Electric Company (System). It is these equations that will be used to determine the denominator of the above equation, i.e.,

$$\text{Purchaser's System's Availability} = \text{EAF \% (company)}$$

Attachment B shows the types of capacity derations/outages used in the calclation of EAF %.

Attachment A

Below is the definition of Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit:

$$\text{EAF \%} = \frac{\text{PH} - \text{EOH}}{\text{PH}} \times 100.0$$

Where:

EOH = Equivalent Outage Hours

PH = Period Hours (i.e. one year = 8760 hours)

Equivalent outage hours are defined as:

$$\text{EOH} = \frac{\sum_{n=1}^i (D_n * T_n)}{C}$$

Where:

D_n = Capacity deration¹ for outage n, MW

T_n = Time accumulated during outage n, hours (whole and fractional)

C = Unit maximum net dependable capacity² for the period of outage n, MW

i = Total number of outages for the period

Note 1 -- See attachment B for types of capacity derations/outages

Note 2 -- Net summer installed capacity + adjustments for ambient conditions

Attachment A (continued)

Defined below is Atlantic Electric Company EAF:

$$\text{EAF \% (company)} = \frac{\sum_{m=1}^j (\text{EAF}_m * C_m)}{\sum_{m=1}^j C_m}$$

Where:

EAF_m = EAF of unit m , per cent

C_m = Net summer installed capacity³ of unit m , MW

j = Total number of units in the company

Note 3 -- If jointly owned unit, Atlantic Electric's prorata share

Attachment B

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage. Below is a listing of outage types, along with their specific definitions:

- RS - Reserve Shutdown - A reserve shutdown (RS) exists whenever a unit is available, but is not synchronized. This event is sometimes referred to as an economy shutdown or economy outage.
- PO - Planned Outage - Planned outages (PO) are scheduled well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections and testing are typical planned outages (PO). Characteristically, planned outages (PO) are planned well in advance and usually occur during those seasons of the year when the peak demand on the system is lowest, have flexible start dates, have a predetermined duration, last for several weeks, and occur only once or twice a year.
- MO - Maintenance Outage - This is an outage which can be deferred beyond the next weekend but requires that the unit be removed from service before the next planned outage (PO). Characteristically, these maintenance outages (MO) may occur throughout the year, have flexible start dates, are much shorter than planned outages (PO), and have a predetermined duration established at the start of the outage.
- SE - Scheduled Outage Extension - This is the extension of a planned outage (PO) or maintenance outage (MO) beyond its originally estimated completion date, such date being established at the start of these outages. A scheduled outage extension (SE) must start at the same time the PO or MO (being extended) ends.
- SF - Startup Failure - This is an outage that results from the unsuccessful attempt to place the unit in service following the unit's being in a full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) state. The unit is considered to be in a startup failure (SF) state if the unit cannot be placed in service within the utility specified time for that specific startup and/or requires significant repairs to the equipment or control systems which halted the normal startup cycle. Repeated failures to start for the same reason are considered as part of the same startup failure (SF). The startup failure (SF) begins when the unit is no longer able to continue its startup cycle or surpasses the originally estimated synchronization time. The startup failure (SF) ends when the unit is synchronized or enters some other (permissible) outage or shutdown state. A startup failure (SF) must start at the time the previous full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) ends.
- U1 - Unplanned Outage (Immediate) - This is an outage that requires immediate removal of a unit from service such as immediate mechanical/electrical/hydraulic control system trips and immediate operator initiated trips/shutdowns in response to unit alarms.
- U2 - Unplanned Outage (Delayed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service within six hours.

Attachment B (continued)

- U3 - Unplanned Outage (Postponed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service before the end of the next weekend.
- PD - Planned Derating - A derating that is scheduled well in advance and is of a predetermined duration. The actual start date of a planned deration (PD) is flexible, since it usually coincides with periods of low peak or seasonal demand.
- D1 - Unplanned Derating (Immediate) - A derating that requires an immediate capacity reduction.
- D2 - Unplanned Derating (Delayed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction within six hours.
- D3 - Unplanned Derating (Postponed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction before the end of the next weekend.
- D4 - Unplanned Derating (Deferred) - A derating which can be deferred beyond the the end of the next weekend, but requires a capacity reduction before the next planned outage (PO). These deratings have flexible start dates and have a predetermined duration established at the start of these outages. This derating is also known as a maintenance derating.
- DE - Derating Extension - This is the extension of a planned derating (PD) or maintenance derating (D4) beyond its originally estimated completion date, such as being established at the start of these outages.

Exhibit J

PROCEDURE FOR BILLING WORK
DONE AT THE EXPENSE
OF OTHERS

INSTRUCTION VI

JWP and Emergency Service

Jobbing Work in Progress (JWP) Procedure

VI-1

G.O.I. 63-9 Jobbing Work and Emergency Service
to Commercial & Industrial Customers

VI-2 &
VI-3

JOBGING WORK IN PROGRESS (JWP)

General

A JWP is required when costs for any temporary installation or other unusual activity are to be billed to a customer, governmental authority or other contracting agency or person.

The key phrase regarding the need for a JWP is "any temporary installation". If the company does not install an item solely for temporary use by the customer, such as a transformer or a line extension, then there would be no need for a JWP. For example, when a single phase service is installed for construction (saw pole), this is usually provided from an existing secondary or one that will be required for permanent service to the customer. However, a three phase service that is installed for construction that will be removed when the building is completed warrants a JWP.

Procedure

1. Prepare 50-14 requesting cost estimate for JWP. Indicate proper name and address for billing purposes. Cost estimates to include installation and removal of facilities.
2. Upon receipt of cost estimate advise the customer in writing of estimated cost and request payment in advance of construction work. State specifically that customer will be charged actual costs upon job completion, either refunding money if actual cost is less than estimate, or billing for additional money if actual cost is greater than estimate.
3. Monies received are to be deposited in account 253.31 (Misc. Deposits-General).
4. Upon receipt of monies the 50-14 can be released for construction.

REPLACES SAME PAGE
DATE 4-20-81

GENERAL OFFICE INSTRUCTIONS

CUSTOMER SERVICES

NEW BUSINESS

S.O.L.	63-9
DATE	9-14-84
PAGE	1

JOBGING WORK

POLICY

REV. The Company assists customers with house moving as well as other jobging work functions.

PROCEDURE

House Moving

Customer Service Clerk 1. Receives request for house moving from customer or mover.

2. Requests following information from customer or mover:

- (a.) Customer's name, address, and home or business phone number.
- (b.) Address of building to be moved
- (c.) Proposed date of move - Company requires five workin day advance notice
- (d.) Destination
- (e.) Proposed route
- (f.) Name and telephone number of mover
- (g.) Estimated moving height

3. Sends memorandum to District Engineer with information from step 2.

District Engineer

4. Prepares JOBBING WORK PROGRESS AUTHORIZATION (ACE 40-349) for approval:

a. If under \$5000 - District Engineer and District Supervisor of - T&D.

b. If over \$5000 - District Engineer, District Supervisor T&D, Manager - T&D Engineering/Manager - T&D.

5. Forwards copy of estimated cost and a sketch of the best moving route to the Customer Service Clerk.

VI-2

10/84

REPLACES SAME PAGE
DATED 4-20-81

GENERAL OFFICE INSTRUCTIONS

CUSTOMER SERVICES

NEW BUSINESS

S.O.L.	63-9
DATE	9-14-84
PAGE	2

JOBGING WORK

REV.

PROCEDURE

House Moving

- Customer Service Clerk 6. Prepares and distributes FORM LETTER/AGREEMENT (ACE 50-173) as follows:
- Original and 2nd copy - Owner/Customer
 - 3rd copy - Mover
 - 4th copy - File
- Customer 7. Signs and returns original ACE 50-173 with the deposit to the Customer Service Clerk; keeps a copy.
- Customer Service Clerk 8. Prepares MISCELLANEOUS RECEIPT (ACE 50-135) crediting Account 253.31, Miscellaneous Deposits - General and distributes as follows:
- Original - Cashier
 - 2nd copy - Customer
 - 3rd copy - File
- Cashier 9. Reports deposit on DAILY CASH RECEIPTS REPORT (ACE 50-15) and DAILY CASH RECEIPTS REPORT SUPPLEMENT (ACE 50-15.1).
- Customer Service Clerk 10. Notifies District Engineer and the appropriate Division Manager by memorandum that the customer's deposit for house moving has been received along with the proposed moving date.
- Division Manager/ Delegate 11. Prepares and distributes CUSTOMER NOTIFICATION (ACE 50-155) in advance of the move to customers on the affected route.
- Accounting Department- General Ledger 12. Refunds excess portion of deposit to the customer, based on actual cost of completed work.
- a. If the cost of the job exceeds the estimate given to the customer, submits bill to the Vice President - Electric Operations for approval before rendering bill to the customer.

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GENERAL OFFICE INSTRUCTIONS

CUSTOMER SERVICES

NEW BUSINESS

G.O.I.	63-9
DATE	4-20-81
PAGE	3

JOBGING WORK

C. Other Jobging Work

PROCEDURE

- | | |
|-----------------------------------|-------------------------------------------------------------------------------------------|
| District Engineer | 1. Notifies Commercial/Industrial Representative of complex jobging work. |
| Commercial/Indust. Representative | 2. Prepares New Business Work Sheet (ACE 50-14) including all the required information. |
| | 3. Forwards ACE 50-14 to District Engineer. |
| District Engineer | 4. Prepares Jobging Work In Progress Authorization (ACE 40-349) for estimate of job cost. |

NOTE: See G.O.I. 54.88 concerning billing of Jobging Work procedures.

DEPARTMENT GUIDELINES

D. Emergency Service to Commercial/Industrial Customers

Emergency Service is defined as and is limited to the temporary repair or replacement of customer's primary cables or transformers. Material and/or labor is provided for customer owned facilities only when repairs cannot be made by conventional commercial service contractors. The customer is billed for services rendered, or equipment rented.

o Labor charges

- are made at the prevailing rate, including meals, overtime, etc.
- See G.O.I. 54.88 Jobging Work In Progress to accumulate costs.

o Transformer Rentals

- are made at current rental rates as stated in Terms and Conditions, Sheet 22, Para. 9.3, payable in equal installments along with the bill for electric service.
- rental period is as short as practical. (See G.O.I. 55.8, Material or Equipment Loaned for guidelines).

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GENERAL OFFICE INSTRUCTIONS

CUSTOMER SERVICES

NEW BUSINESS

Exhibit A Page 253 of 254
DATE 4-02-81
PAGE 4

JOBGING WORK

DEPARTMENTAL GUIDELINES - (Cont'd)

D. Emergency Service To Commercial/Industrial Customers - (Cont'd)

o Transformer Rentals - (Cont'd)

- when 2400 volt transformers are required, they should be sold.
- transportation of transformers should be handled by the customer.

o Mobile Substations (or mobile emergency distribution transformers) rental

- must be at management's discretion.
- equipment not generally available for rental as it could limit availability for a company emergency.
- rental charges are made at current rental rates as stated in Terms and Conditions, Sheet 22, Para. 9.3, payable in equal installments along with the bill for electric service.

o Any emergency service work performed must be limited to temporary repairs. The customer must be advised and told that permanent repairs should be made by a contractor as soon as possible.



Atlantic Electric

**ATLANTIC CITY ELECTRIC COMPANY
P.U.C.N.J. No.9-ELECTRIC SERVICE**

Original Sheet No. 27

TERMS AND CONDITIONS OF SERVICE

6. METERING, BILLING AND PAYMENT FOR SERVICE (continued)

6.4 Payment of Bills: Bills are payable upon presentation, at any business office of the Company, or any authorized collection agency within ten (10) days of the mailing date. The Company may require earlier payment to prevent fraud or illegal use of energy, or when is clearly evident that customer is preparing to vacate the premise

For customers designated as commercial and industrial receiving service under rate schedules MGS, AGS, TS, HCS, DDC, CSL, and SPL, any overdue bill is subject to a late payment charge as specified on Rate Schedule CHG. This charge will be applied to amounts billed including accounts payable and unpaid late payment charge amounts applied to previous bills, which are not received by the Company within 45 days (60 days, for governmental bodies) following the due date specified on the bill. The amount of the late payment charge to be added to the unpaid balance shall be determined by multiplying the unpaid balance by the late payment charge rate. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

New Jersey Public Utilities, subject to the New Jersey Gross Receipts and Franchise Tax, shall be billed net of such taxes.

6.5 Billing Period: Except as hereinafter provided, meters shall be read monthly. The word "month" as used in the schedules is hereby defined to be the elapsed time between two (2) successive meter readings normally 30 days apart. Bills for other than 30 days shall be properly prorated. Where credit situations require, the Company may read meters and render bills at shorter intervals.

Date of Issue: December 6, 1982

Effective: December 14, 1982

Issued by: JOHN D. FEEHAN, President
Pleasantville, N.J.

**RATE SCHEDULE CHG
(Charges)**

APPLICABILITY OF SERVICE

Applicable to all customers in accord with the tariff paragraph noted below.

SERVICE CHARGES

- | | |
|---------------------------------------------------------------------------------------------------|---------|
| 1. Installation of Service at Original Location
(See paragraph 2.6) | \$65.00 |
| 2. Connection, Reconnection, or Succession
of Service at Existing Location (See paragraph 2.7) | \$15.00 |
| 3. Disconnection (See paragraph 7.1, 7.2, or 7.3) | \$15.00 |
| 4. Special Reading of Meters (See paragraph 6.7) | \$15.00 |

LATE PAYMENT CHARGES

(See paragraph 6.4)
(Non-residential only)

0.952% Per Month
(11.42% APR)

UNCOLLECTIBLE CHECKS

(See paragraph 6.9)

\$ 7.50

Date of Issue: February 26, 1987

Effective: February 27, 1987

Issued by: E. D. HUGGARD, President
Pleasantville, N.J.

Filed pursuant to Order of the Board of Public Utilities of the
State of New Jersey as presented in Docket No. ER 8504434

EXHIBIT I

**METHODOLOGY
for
CALCULATING
AVAILABILITY FACTOR**

METHODOLOGY FOR CALCULATING AVAILABILITY FACTOR

Availability Factor is defined as the ratio of Seller's availability to Purchaser's system's availability based on a calendar year calculation of availability. Therefore,

$$\text{Availability Factor} = \frac{\text{Seller' Availability}}{\text{Purchaser's System's Availability}}$$

Attachments A shows the methodology used to determine the Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit and for Atlantic Electric Company (System). It is these equations that will be used to determine the denominator of the above equation, i.e.,

$$\text{Purchaser's System's Availability} = \text{EAF \% (company)}$$

Attachment B shows the types of capacity derations/outages used in the calclation of EAF %.

Attachment A

Below is the definition of Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit:

$$EAF \% = \frac{PH - EOH}{PH} \times 100.0$$

Where:

EOH = Equivalent Outage Hours

PH = Period Hours (i.e. one year = 8760 hours)

Equivalent outage hours are defined as:

$$EOH = \frac{\sum_{n=1}^i (D_n * T_n)}{C}$$

Where:

D_n = Capacity deration¹ for outage n, MW

T_n = Time accumulated during outage n, hours (whole and fractional)

C = Unit maximum net dependable capacity² for the period of outage n, MW

i = Total number of outages for the period

Note 1 -- See attachment B for types of capacity derations/outages

Note 2 -- Net summer installed capacity + adjustments for ambient conditions

Attachment A (continued)

Defined below is Atlantic Electric Company EAF:

$$\text{EAF \% (company)} = \frac{\sum_{m=1}^j (\text{EAF}_m \times C_m)}{\sum_{m=1}^j C_m}$$

Where:

EAF_m = EAF of unit m , per cent

C_m = Net summer installed capacity³ of unit m , MW

j = Total number of units in the company

Note 3 -- If jointly owned unit, Atlantic Electric's prorata share

Attachment B

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage. Below is a listing of outage types, along with their specific definitions:

- RS - Reserve Shutdown - A reserve shutdown (RS) exists whenever a unit is available, but is not synchronized. This event is sometimes referred to as an economy shutdown or economy outage.
- PO - Planned Outage - Planned outages (PO) are scheduled well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections and testing are typical planned outages (PO). Characteristically, planned outages (PO) are planned well in advance and usually occur during those seasons of the year when the peak demand on the system is lowest, have flexible start dates, have a predetermined duration, last for several weeks, and occur only once or twice a year.
- MO - Maintenance Outage - This is an outage which can be deferred beyond the next weekend but requires that the unit be removed from service before the next planned outage (PO). Characteristically, these maintenance outages (MO) may occur throughout the year, have flexible start dates, are much shorter than planned outages (PO), and have a predetermined duration established at the start of the outage.
- SE - Scheduled Outage Extension - This is the extension of a planned outage (PO) or maintenance outage (MO) beyond its originally estimated completion date, such date being established at the start of these outages. A scheduled outage extension (SE) must start at the same time the PO or MO (being extended) ends.
- SF - Startup Failure - This is an outage that results from the unsuccessful attempt to place the unit in service following the unit's being in a full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) state. The unit is considered to be in a startup failure (SF) state if the unit cannot be placed in service within the utility specified time for that specific startup and/or requires significant repairs to the equipment or control systems which halted the normal startup cycle. Repeated failures to start for the same reason are considered as part of the same startup failure (SF). The startup failure (SF) begins when the unit is no longer able to continue its startup cycle or surpasses the originally estimated synchronization time. The startup failure (SF) ends when the unit is synchronized or enters some other (permissible) outage or shutdown state. A startup failure (SF) must start at the time the previous full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) ends.
- U1 - Unplanned Outage (Immediate) - This is an outage that requires immediate removal of a unit from service such as immediate mechanical/electrical/hydraulic control system trips and immediate operator initiated trips/shutdowns in response to unit alarms.
- U2 - Unplanned Outage (Delayed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service within six hours.

Attachment B (continued)

- U3 - Unplanned Outage (Postponed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service before the end of the next weekend.
- PD - Planned Derating - A derating that is scheduled well in advance and is of a predetermined duration. The actual start date of a planned deration (PD) is flexible, since it usually coincides with periods of low peak or seasonal demand.
- D1 - Unplanned Derating (Immediate) - A derating that requires an immediate capacity reduction.
- D2 - Unplanned Derating (Delayed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction within six hours.
- D3 - Unplanned Derating (Postponed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction before the end of the next weekend.
- D4 - Unplanned Derating (Deferred) - A derating which can be deferred beyond the the end of the next weekend, but requires a capacity reduction before the next planned outage (PO). These deratings have flexible start dates and have a predetermined duration established at the start of these outages. This derating is also known as a maintenance derating.
- DE - Derating Extension - This is the extension of a planned derating (PD) or maintenance derating (D4) beyond its originally estimated completion date, such as being established at the start of these outages.

EXHIBIT K

AMENDMENTS TO

POWER PURCHASE AGREEMENT



Copy # 5

December 19, 1988

Chambers Cogeneration Limited Partnership
P.O. Box 3965
San Francisco, California 94119

Attention: Mr. J. L. Moore, Jr.

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.273
Amendment No. 001

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 2: paragraph 2.2 - change - BPU approval process "within three (3) months of the Effective Date" to "by January 31, 1989".

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.273, dated September 29, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.273 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

CHAMBERS COGENERATION LIMITED PARTNERSHIP

ATLANTIC ELECTRIC

BY

Vice President of
Maple Power Corporation
43.3 General Partner

BY

Atlantic City Electric
P.O. Box 1500
Pleasantville, N.J. 08232
609-645-4100

Copy # 5

January 25, 1989

Chambers Cogeneration Limited Partnership
P.O. Box 3965
San Francisco, California 94119

Attention: Mr. J. L. Moore, Jr.

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.273
Amendment No. 002

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 2: paragraph 2.2 - change - BPU approval process "by January 31, 1989" to "by February 28, 1989".

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.273, dated September 29, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.273 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

CHAMBERS COGENERATION LIMITED PARTNERSHIP

ATLANTIC ELECTRIC

BY 

BY 

43.3

Atlantic City Electric
P.O. Box 1500
Pleasantville, N.J. 08232
609-645-4100

Copy # 1

February 23, 1989

Chambers Cogeneration Limited Partnership
P.O. Box 3965
San Francisco, California 94119

Attention: Mr. J. L. Moore, Jr.

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.273
Amendment No. 003

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

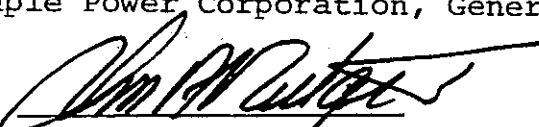
Article 2: paragraph 2.2 - change - BPU approval process "by February 28, 1989" to "by March 31, 1989".

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.273, dated September 29, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.273 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

CHAMBERS COGENERATION LIMITED PARTNERSHIP
Maple Power Corporation, General Partner

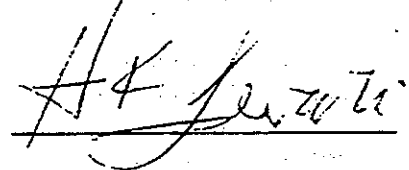
BY


Vice President

43.4

ATLANTIC ELECTRIC

BY



Atlantic City Electric
P.O. Box 1500
Pleasantville, N.J. 08232
609-645-4100



Copy # 5

December 20, 1989

Chambers Cogeneration Limited Partnership
P. O. Box 3965
San Francisco, California 94119

Attention: Mr. J. L. Moore, Jr.

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.273
Amendment No. 004

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 1: paragraph 1.1FF is deleted and substituted with the following: "Summer Season" shall mean during any calendar year the period from May 1st through October 31st.

Article 1: paragraph 1.1 II is deleted and substituted with the following: "Winter Season" shall mean during any calendar year the period from November 1st through April 30th.

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.273, dated September 29, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.273 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files, and return the other signed copies to us.

CHAMBERS COGENERATION LIMITED PARTNERSHIP

ATLANTIC ELECTRIC

BY

43.4

BY

Copy # 1

March 20, 1991

Chambers Cogeneration
Limited Partnership
7475 Wisconsin Avenue, 10th Floor
Bethesda, MD 20814-3422

Attention: Joseph Kearney

Re: Amendment No. 005 (this "Amendment") to the Agreement for Purchase of Electric Power dated as of September 29, 1988, as amended (the "Agreement"), between Atlantic City Electric Company and Chambers Cogeneration Limited Partnership.

Gentlemen:

Atlantic City Electric Company and Chambers Cogeneration Limited Partnership hereby amend the Agreement to make the changes set forth herein. Capitalized terms used herein, but not otherwise defined, shall have the meaning given to such terms in the Agreement.

A. Article 4.2(iv) of the Agreement shall be amended by deleting the three references to the phrase "Net Deliverable Capacity" where it appears in such Article 4.2(iv) and replacing such phrase with the phrase "187,600 kw."

B. A sentence is added at the end of Article 4.2(iv) to read as follows:

"Such deficiency payments will be credited against any amounts payable by Seller pursuant to Article 3.3(A)(iii)."

C. The final sentence of Article 3.3(A)(iv) of the Agreement shall be deleted in its entirety and replaced with the following sentence:

"In addition to the foregoing, Seller may retest the Facility at any time for purposes of establishing capacity levels in accordance with the above requirements, thereby reducing or terminating Seller's obligation to continue paying deficiency payments pursuant to subparagraph (iii) above."

D. Article 3.1 of the Agreement is amended by deleting the word "dispatchable" in such Article and replacing it with the word "Dispatchable."

F. The last two sentences of the last paragraph of Article 3.4 of the Agreement shall be deleted in their entirety and shall be replaced with the following sentence:

"Interruption or reduction of deliveries shall be of no greater scope and of no longer duration than is necessary and shall not reduce Purchaser's minimum purchase obligations under Article 3.1 hereof."

G. Article 15.1 of the Agreement is hereby amended by deleting the phrase "prior to the occurrence of an event of force majeure" as it appears in the first sentence of such article. Article 15.4 of the Agreement is amended by deleting the phrase "which matured prior to the occurrence of an event of force majeure" and replacing it with the phrase "due hereunder."

Except as expressly modified and amended herein, all terms and conditions of the Agreement shall remain unchanged and in full force and effect. This Amendment shall be supplemental to and shall become an integral part of the Agreement upon the signing by Purchaser and Seller.

Atlantic City Electric Company

By: 

Name: Henry K. Levari, Jr.

Title: Vice President, Power Delivery

Agreed and Accepted:

Chambers Cogeneration
Limited Partnership

By: 

Name: Joseph P. Kearney

Title: Chairman

Exhibit B

Chambers PSA, Dated June 9, 2021



An Exelon Company

PO Box 231
Mailstop 88MK62
Wilmington, DE 19899-0231
James B. Jacoby
NUG Administrator
302-429-3148 office
302-379-3783 mobile

June 9, 2021

Chambers Cogeneration Limited Partnership
500 Shell Road
Carneys Point, New Jersey 08069-2926

RE: January 1, 2021 – December 31, 2021 Power Sales Agreement

Dear Sirs:

Chambers Cogeneration Limited Partnership (“CCLP”), a Delaware limited partnership, and Atlantic City Electric Company (“Atlantic”), a New Jersey corporation, are parties to an Agreement for Purchase of Electric Power by and between Atlantic and Chambers Cogeneration Limited Partnership, originally dated September 29, 1988 (the “PPA”), as amended.

This letter constitutes a Power Sales Agreement (referred to herein as the “PSA” or “Agreement”) that establishes terms and conditions that govern CCLP’s sales of Excess Energy and Un-dispatched Energy as defined below (collectively referred to herein as “Energy”) (MWh) and Excess Capacity (MW) as defined below from the cogeneration facility owned by CCLP located at Carneys Point (the “Facility”) to Atlantic that are in excess of the amounts that Atlantic dispatches under the terms of the PPA. Atlantic and CCLP, when referred to together in this PSA, shall be referred to as the “Parties”. This PSA modifies the PPA only to the extent necessary to implement the terms and conditions of this PSA. The execution of this PSA by the Parties operates to terminate, extinguish and replace in its entirety the Power Sales Agreement executed by CCLP and Atlantic dated January 1, 2019 and accepted and agreed to.

1. Definitions.

- A. “Summer Season” shall mean, during any calendar year, the period from May 1st through October 31st.
- B. “Winter Season” shall mean, during any calendar year, the period from November 1st through April 30th.
- C. “Excess Capacity” shall mean the capability of the Facility, tested in accordance with PJM capability verification requirements, in excess of 187.6 MW during the Summer Season and in excess of 173.2 MW during the Winter Season.

- D. “Excess Energy” shall mean the energy associated with the Excess Capacity (i.e., above 187.6 MWh per hour and 173.2 MWh per hour during the Summer Season and Winter Season, respectively).
 - E. “Un-dispatched Energy” shall mean the energy from the Facility above the amount dispatched by Atlantic under the PPA up to 187.6 MWh per hour during the Summer Season and the energy from the Facility above the amount dispatched by Atlantic under the PPA up to 173.2 MWh per hour during the Winter Season.
 - F. “Day-Ahead LMP” shall mean the net hourly integrated PJM Interchange price calculated by PJM for cleared day-ahead generation offers, demand bids, decrements bids and energy transactions.
 - G. “Real-Time LMP” shall mean the net hourly integrated PJM Interchange price calculated by PJM for real-time energy transactions, load and generation and metered tie flows.
 - H. “Operating Reserve Charges” shall mean the sum of the PJM daily day-ahead and balancing Operating Reserves Charges, as such term is defined in the PJM Agreements, for the Facility.
 - I. “PPA Dispatch Price” shall mean the on and off peak prices Atlantic provides CCLP to be used for PPA billing purposes following the billing period. The prices will be at or below the then current PPA energy prices.
 - J. “Cost Base” shall equal \$ 41.54 per MWh
 - K. “RGGI CO₂ Cost Quarterly True Up” shall mean the quarterly adjustment of the CCLP invoice for actual versus forecast RGGI CO₂ cost for PSA MWhs.
 - L. “PJM” means PJM Interconnection, L.L.C. or its successor or lawful assignee.
 - M. “PJM Agreements” means the PJM Open Access Transmission Tariff, Operating Agreement of PJM and any other applicable PJM agreements, tariffs, manuals or rules setting forth the rights and obligations of the Parties with respect to PJM.
 - N. “Entitlement Payment” shall mean any payment made by Atlantic to CCLP pursuant to Article 3.1 of the PPA
2. Contract Term. This PSA shall commence at hour ending 0100 on January 1, 2021 and continue through hour ending 2400 on December 31, 2021 (referred to herein as the “Term”).
3. Delivery Point. Energy shall be delivered and title to the Energy shall pass at the Chambers CCLPGEN 23 kV bus.

4. Scheduling and Dispatch. For purposes of making sales to Atlantic under the terms of this PSA, CCLP may, at its discretion, dispatch the Facility to produce MWh in excess of the amount dispatched by Atlantic under the terms of the PPA. During the term of this PSA, CCLP will dispatch the unit 24/7 (“self-dispatch”).

Whereas CCLP assumes full responsibility for around the clock self-dispatch of the unit in accordance with the Atlantic City Electric and CCLP PPA/PSA Agreements and all PJM including but not limited to PJM rules, PJM dispatcher’s directions, economic market signals, reliability issues as well as local reliability issues.

CCLP must inform the PHI Control Room Operations at the New Castle Regional Office (“NCRO”) before moving the unit when dispatching the Facility for the purpose of making sales under the PPA/PSA. CCLP must convey all load changes and any mechanical or operational issues the plant may have via phone in a real time manner. During the normal business hours, reporting of mechanical or operational issues must be made to the PHI generation scheduler and during non-business hours reporting must be made to the Manager Control Room Operations through the Dispatch Desk at NCRO (see 4.c.). The PHI dispatchers will record, approve and convey all load level changes to PJM as necessary and convey any PJM instructions to CCLP for PJM. Mechanical and operational issues must also be backed up via email to PHI dispatching and scheduling personnel.

For purposes of making purchases by Atlantic under the terms of the PPA and PSA , Atlantic and CCLP agree for the billing model, that the hourly output from the Facility will automatically be designated “on for Atlantic” when the real-time or day-ahead bus LMP is equal to or greater than the PPA Dispatch Price.

Energy considered “dispatched” by Atlantic for PPA purposes will be calculated as follows:

- a. During hours when PJM prices the output of all or a portion of the Facility energy for the applicable Chambers CCLPGEN 23 kV bus using the Day-Ahead LMP and;
 - i. that LMP is below the PPA Dispatch Price, PPA energy will be calculated as the lesser of PJM accepted MWh or 46 MWh.
 - ii. that LMP is above the PPA Dispatch Price, PPA energy will be calculated as the lesser of (x) PJM accepted MWh or (y) 173.2 MWh during the Winter Season and 187.6 MWh in the Summer Season.
- b. During hours when PJM prices the output of all or a portion of Facility energy for the applicable Chambers CCLPGEN 23 kV bus using the Real-Time LMP and;
 - i. that LMP is below the PPA Dispatch Price, PPA energy will be calculated as the lesser of actual metered MWh or 46 MWh.

- ii. that LMP is above the PPA Dispatch Price, PPA energy will be calculated as the lesser of (x) actual metered MWh or (y) 173.2 MWh during the Winter Season and 187.6 MWh in the Summer Season.

c. PHI Contact List

CONTACT	email	Number
PHI / Atlantic City Electric Company		
Manager OCC Operations-Jim Summers	Jim.summers@pepcoholdings.com	302-454-4137
Shift Manager TSO-Bill Esterling	William.esterling@delmarva.com	302-454-4922
Business hour scheduling		
Dan Curtis (primary)	dcurtis@delmarva.com	302-429-3139
Marge Brubaker (back up)	marge.brubaker@pepcoholdings.com	609-625-5992
Non business hours scheduling		
Dispatchers		302-454-4583
Contract Administrator		
Jim Jacoby	Jim.jacoby@pepcoholdings.com	302-429-3148

5 Contract Price and Fees. The MWh purchased and sold under this PSA shall be priced based on the PJM two-settlement system using Day-Ahead and Real-Time LMPs at the Chambers CCLPGEN 23 kV bus as Facility generation is scheduled and dispatched by PJM, Day-Ahead and Real-Time quantities, including all applicable reconciliations of price and quantity consistent with PJM practices. Prices are determined as follows:

A. During hours when PJM prices the output of all or a portion of the Un-Dispatched Energy or Excess Energy for the applicable Chambers CCLPGEN 23 kV bus using the Day-Ahead LMP and that LMP is above the Cost Base:

- (1) For each of the MWh priced by PJM using the Day-Ahead LMP of Un-dispatched Energy:

$$\text{Cost Base} + (\text{LMP}-\text{Cost Base})(0.60)$$

- (2) For each of the MWh priced by PJM using the Day-Ahead LMP of Excess Energy:

$$\text{Cost Base} + (\text{LMP}-\text{Cost Base})(0.70)$$

B. During hours when PJM prices the output of all or a portion of the Un-Dispatched Energy or Excess Energy for the applicable Chambers CCLPGEN 23 kV bus using the Real-Time LMP and that LMP is above the Cost Base:

- (1) For each of the MWh priced by PJM using the Real-Time LMP of Un-Dispatched Energy:

$\text{Cost Base} + (\text{LMP} - \text{Cost Base})(0.60)$

- (2) For each of the MWh priced by PJM using the Real-Time LMP of Excess Energy:

$\text{Cost Base} + (\text{LMP} - \text{Cost Base})(0.70)$

- C. If during any month Atlantic is required to make an Entitlement Payment to CCLP, then energy payments to CCLP during such month made pursuant to A(1) and B(1) above shall be recalculated by changing the 0.60 to 0.50. The difference in payments between the calculation at 0.60 and the calculation at 0.50 shall be credited to Atlantic and shall be limited to the value of the Entitlement Payment.
- D. All reconciliations of quantities and prices applied by PJM under its two-settlement system as applicable to the computations of the amounts set forth in subsections 5A. and 5B. above shall be correspondingly applied by Atlantic.
- E. During hours when the applicable Chambers CCLPGEN 23 kV bus LMP is below the Cost Base (after all applicable reconciliations), each MWh of either Un-dispatched or Excess Energy purchased and sold under this PSA shall be priced at the applicable LMP.
- F. Atlantic shall purchase all Excess Capacity at the following rate:
- $(.70)(\text{RPM Capacity Clearing Price for the LDA wherein CCLP is located})(\text{Excess Capacity})$
- Atlantic and CCLP will share any replacement capacity cost charges, either penalty payments, including but not limited to PJM's peak hour availability charge, or positive incremental capacity market price differences, related to the sale of Excess Capacity, 70% of such replacement capacity cost charges for CCLP and 30% of such replacement capacity cost charges for Atlantic.
- G. CCLP shall pay Atlantic a fixed fee of \$13,000 per month to cover administrative costs during the term of this Agreement.
- H. CCLP recognizes that PJM charges Atlantic for Operating Reserve Charges for generation deviations based on the total output of the Facility. CCLP agrees that Atlantic shall determine, based on good faith and its best understanding of PJM rules as defined in the PJM Agreements any such deviations attributable to the Excess Energy, Un-dispatched Energy, and CCLP's self-dispatch of the Facility. CCLP shall pay Atlantic for Operating Reserve Charges for generation deviations attributable to the Facility based on this determination. In addition, CCLP shall pay Atlantic for any costs incurred by Atlantic as a result of settlement during hours when the Un-dispatched Energy or Excess Energy has been accepted for

operation in the day-ahead market and the Facility fails to operate as accepted by PJM.

- I. Atlantic shall adjust CCLP's payment on a quarterly basis for the RGGI CO₂ Cost Quarterly True Up. This line item adjustment shall be the difference between CCLP's actual RGGI CO₂ cost incurred to cover the prior quarter's PSA generation and CCLP's forecasted CO₂ cost for that quarter. This adjustment to the can be a debit or credit to the CCLP invoice. The actual cost of RGGI CO₂ allowances will be calculated by multiplying the PSA emitted RGGI CO₂ tons by the RGGI CO₂ allowance market cost per ton. The forecasted cost of RGGI CO₂ allowances will be calculated by multiplying the estimated PSA emitted RGGI CO₂ tons by the estimated RGGI CO₂ allowance market cost per ton. CCLP shall provide its forecast of RGGI CO₂ costs to Atlantic prior to the start of the quarter. CCLP shall provide detailed documentation of the purchased RGGI cost component upon written request from Atlantic.
Allowances to cover PSA generation will be purchased at market and are not part of those offered for direct sale to facilities meeting the Dispatch Agreement Facility criteria pursuant to the State of New Jersey Air Quality Management CO₂ Budget Trading Program.
6. Contract Firmness. Atlantic will accept, purchase and pay for Energy delivered under this PSA subject only to Section 9C. CCLP shall not be liable for any damages in the event CCLP fails to deliver any specified quantity of Energy or Excess Capacity under this PSA.
7. Operating Procedures. Atlantic and CCLP shall operate using established and mutually developed written Operating Procedures as soon as possible after the commencement of the Term. Such Operating Procedures shall include, but not be limited to, method of day-to-day communications, designation of Authorized Representatives pursuant to Section 12, and any other key personnel lists for CCLP and Atlantic.
8. Control Area Services. Atlantic shall be responsible, at its cost, for control area services as are necessary or appropriate to effect the Energy and Excess Capacity purchases and sales under this PSA.
9. Relationship of this PSA to the PPA.
 - A. This PSA shall be expressly subordinate to the PPA and the rights and obligations of the Parties under the PPA shall not be affected by this PSA, except as noted in Section 4.
 - B. The Parties acknowledge and agree that Atlantic will be purchasing Energy and Excess Capacity for sale under this PSA from the Facility. They also acknowledge and agree that CCLP's dispatch of the Facility under this PSA and

all terms and conditions of this PSA shall be subordinate to Atlantic's dispatch of the Facility under the PPA and all of the terms and conditions of the PPA.

- C. During any hour for which Maximum Emergency Generation has been called on line (as declared by PJM, in accordance with the PJM Operating Agreement), CCLP will sell no Energy to Atlantic under this PSA.
- D. Nothing in this Agreement shall be construed as an admission of any right or obligation by any party to the PPA with respect to Excess Energy and Excess Capacity.

10. Billing and Payment.

- A. This PSA shall be accounted for on the basis of actual hourly quantities. The accounting period shall be one calendar month. The Parties' scheduling representatives shall maintain records of hourly schedules for accounting and operating purposes.
- B. Atlantic shall provide PJM market and billing data to CCLP as necessary in an electronic format to validate PSA billing on a monthly basis. Such data shall include day-ahead accepted MWh and pricing, real-time MWh and pricing, and relevant Operating Reserve Charge data for the Facility.
- C. Atlantic will provide hourly dispatch records/meter readings in electronic format to CCLP and submit payment simultaneously to CCLP no later than the last business day of the calendar month following the delivery of Energy and Excess Capacity. Payments shall be made by electronic wire transfer to CCLP at the address set forth in Section 10G.
- D. In the absence of a written agreement to the contrary, amounts not paid on or before the due date shall be payable with interest accrued daily at the prime rate of interest per annum established by Citibank, N.A., or its successor, on the last business day of the month in which service was rendered, plus one and one half percent per annum, but in no event greater than the maximum interest rate permitted by law.
- E. In the event any portion of any payment is in dispute, the undisputed portion shall be paid in full and such disputes shall first be discussed and both Parties agree to use commercially reasonable efforts to amicably and promptly resolve the dispute. In the event the Parties are unable to do so, the dispute resolution procedures set forth in Section 11 shall apply. Upon determination of the correct payment amount, the proper adjustment shall be paid or refunded promptly, or as agreed upon, after such determination with interest accrued in accordance with Section 10D and computed from the date payment was due to the date the adjustment is made.

F. All billings, if any, to Atlantic shall be sent to:

Atlantic City Electric Company
c/o Pepco Holdings Inc.
Mailstop 88MK62
P. O. Box 231
Wilmington, DE19899-0231
Attn: James B. Jacoby

G. All payments to CCLP shall be wire transferred to:

The Bank of New York Mellon.
Account Number: ACH-8900086440;
Fed Wire-111-565 F/F/C TAS # 362788
ABA Number: 021-000-018

11. Dispute Resolution. Any dispute or need of interpretation arising out of this PSA shall be submitted to binding arbitration by one arbitrator qualified by education, experience or training to render a decision upon the issues in dispute and who has not previously been employed by either CCLP or Atlantic (or its and/or their predecessors), and does not have a direct or indirect interest in either Party or the subject matter of the arbitration. Such arbitrator shall either be mutually agreed to by the Parties within thirty (30) days after written notice from either Party requesting arbitration, or failing agreement, the arbitration shall be conducted by a panel of three (3) arbitrators having the qualifications set forth in the preceding sentence, one (1) arbitrator to be selected by each Party and the third arbitrator to be selected by the two (2) arbitrators selected by the Parties. If either Party fails to notify the other Party of the arbitrator selected by it within ten (10) days after receiving a notice of the other Party's arbitrator, or if the two (2) arbitrators selected fail to select a third arbitrator within ten (10) days after notice is given of the selection of the second arbitrator, then such arbitrator shall be selected under the expedited rules of the American Arbitration Association (the "AAA"). Each Party shall divide equally the cost of the arbitration, and each shall be responsible for its own expenses and those of its counsel or other representation. The commercial arbitration rules of the AAA shall apply to the extent not inconsistent with the rules specified above. Arbitration shall be conducted within 75 miles of Newark, Delaware.
12. Authorized Representative. Each Party shall designate in writing one or more "Authorized Representative(s)" who shall be authorized to act on its behalf with respect to matters contained herein which are the functions and responsibilities of the Authorized Representatives. Each Party shall give written notice to the other Party of its designation, and shall promptly notify the other Party in writing of any subsequent changes in such designation. The Authorized Representatives shall have no authority to modify any of the provisions of this PSA.
13. Notices. All written notices under this PSA shall be deemed properly sent if delivered in person or sent by confirmed facsimile, registered, certified mail, or a guaranteed

overnight delivery service such as Federal Express, postage prepaid to the persons specified below:

If to Atlantic:

Atlantic City Electric Company
c/o Pepco Holdings Inc.
Mailstop 88MK62
P. O. Box 231
Wilmington, DE 19899-0231
Attn: James B. Jacoby
Phone: (302) 429-3148
Fax: (302) 429-3207

With a copy to:

Atlantic City Electric Company
150 W. State Street
Suite 5
Trenton, NJ 08608-1105
Attn: Philip J. Passanante, Esq., Associate General Counsel
Phone: (302) 429-3105
Fax: (302) 429-3801

If to CCLP:

Chambers Cogeneration Limited Partnership
500 Shell Road
Carneys Point, NJ 08069
Attn: Plant General Manager
Phone: (856) 299-1300
Fax: (856) 351-6399

With a copy to:

Chambers Cogeneration Limited Partnership
c/o
PurEnergy Management Services, LLC
4488 Onondaga Boulevard
Syracuse, NY 13219
Attn: Vice President Asset Management
Phone: (315) 448-2268
Fax: (315) 448-0264

14. Necessary Authorization. Each Party represents that it has the necessary corporate, regulatory and legal authority to enter into this PSA and to perform each and every duty and obligation imposed by this PSA, and that this PSA, when executed by the duly authorized representatives of each Party, represents a valid, binding and enforceable legal

obligation of each Party in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally or by equitable principles.

15. Limitations of Liability. Neither Party, nor any of their respective partners or their affiliates nor any of their officers, directors, agents, subcontractors, vendors or employees shall be liable to the other for any incidental, consequential, punitive or other special damages, including, but not limited to, lost profits, for nonperformance of its and/or their obligations hereunder.
16. Uncontrollable Forces. Neither Party shall be considered to be in default in the performance of any obligations under this PSA (other than obligations of a Party to pay amounts due hereunder) when a failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" shall be physical causes of the kind hereafter listed which are beyond the control of the Party affected: flood, earthquake, tornado, storm, fire, civil disobedience, labor dispute, labor or material shortage, acts of sabotage or terrorism, restraint by court order or public authority (whether valid or invalid), and action or non-action by or inability to obtain or keep the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome. No Party shall, however, be relieved of liability for failure of performance if such failure is due to causes arising out of its own negligence or due to removable or remediable causes which it fails to remove or remedy within a reasonable time period. Either Party rendered unable to fulfill any of its obligations under this PSA by reason of Uncontrollable Force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.
17. Assignment. Neither Party shall assign this PSA or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned or delayed. This PSA shall inure to and be binding upon the successors and permitted assignees of the Parties. Notwithstanding the foregoing, either Party may, without the consent from the other Party (and without relieving itself from liability hereunder), transfer or assign this PSA to an affiliate of such Party; provided, however, that any such assignee shall agree to be bound by the terms and conditions hereof. In addition, either Party may, without the consent of the other, collaterally assign this PSA to any financial institution extending it credit.
18. Taxes. Each Party shall pay those sales, use, excise, gross receipts, ad valorem, income, and any other taxes imposed or levied by the state or any governmental agency applicable to it in connection with this PSA.
19. Administration. Each Party shall each use reasonable efforts to implement the provisions of and to administer this PSA in accordance with its intent to minimize taxes, so long as neither Party is materially adversely affected by such efforts. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably

satisfactory evidence of exemption if either Party is exempt from taxes, and shall use reasonable efforts to obtain and cooperate with obtaining any exemption from or reduction of tax. Either Party with knowledge of a tax that may be applicable to the transaction contemplated by this PSA shall notify the other Party of the applicability of such tax and shall also notify the other Party of any proposal to implement a new tax or apply an existing tax to such transaction.

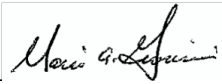
20. CHOICE OF LAWS. THIS PSA SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW JERSEY.
21. Other Agreements. This PSA constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter, except that the PPA is modified or superseded only to the extent necessary to implement the terms of this PSA.
22. Binding Effect. The terms and provisions of this PSA, and the respective rights and obligations hereunder of each Party, shall be binding upon, and inure to the benefit of, its permitted successors and assigns.
23. Non-Waiver of Defaults. No waiver by either Party of any default of the other Party under this PSA shall operate as a waiver of a future default whether of a like or different character.
24. Written Amendments. No modification of the terms and provisions of this PSA shall be or become effective except by written amendment executed by the Parties hereto.
25. Severability and Renegotiation. Should any provisions of this PSA for any reason be declared invalid or unenforceable by final and non-appealable order of any court or regulatory body having jurisdiction, such decision shall not affect the validity of the remaining portions, and the remaining portions shall remain in force and effect as if this PSA had been executed without the invalid portion. In the event any provision of this PSA is declared invalid, the Parties shall promptly renegotiate to restore this PSA as near as possible to its original intent and effect.
26. Headings. The headings used herein are for convenience only and shall not affect the meaning or interpretation of the provisions of this PSA. Any terms not defined herein shall have the meaning ordinarily and customarily assigned to them in connection with transactions occurring in PJM as of the execution date of this PSA.
27. Survival. Any provision(s) of this PSA that expressly or by implication remains in force following the termination or expiration of this PSA shall survive the termination or expiration of this PSA.
28. Termination of Agreement. Both parties agree to early termination of this Agreement under the following conditions.

- A. Should CCLP and Atlantic agree to terminate the underlying PPA, then this Agreement will automatically terminate without a need for notice upon the effectiveness of the termination of the PPA.
- B. If the FERC or the New Jersey Board of Public Utilities (or their successor agencies) modify their current policies or regulations such that the terms of this Agreement would be economically prohibitive for either party due to such changes in policies or regulations, then the party claiming such economic harm may terminate this Agreement with thirty (30) days written notice to the other. In the event the non-terminating party disputes the economic harm alleged by the terminating party, the dispute shall be resolved as provided in Section 11 above.

If the foregoing terms are acceptable to CCLP, please sign and return one copy of this PSA. The remaining copy is for your files.

Sincerely,

ATLANTIC CITY ELECTRIC COMPANY

By:  _____

Name: Mario Giovannini

Title: Director, Energy Acquisition

ACCEPTED AND AGREED TO as of
this ____ day of June 2021

CHAMBERS COGENERATION LIMITED PARTNERSHIP

By: _____

Name: Jeffrey Delgado

Title: Managing Director

Exhibit C

Logan PPA and Amendments

**AGREEMENT FOR PURCHASE
OF ELECTRIC POWER**

between

**ATLANTIC CITY ELECTRIC COMPANY
as Purchaser**

and

**KEYSTONE COGENERATION SYSTEMS, INC.
as Seller**

DATED

August 25, 1988

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AGREEMENT FOR PURCHASE OF ELECTRIC POWER

This agreement (hereinafter referred to as the "Agreement") is entered into and effective this 25th day of August, 1988 by and between ATLANTIC CITY ELECTRIC COMPANY, 1199 Black Horse Pike, Pleasantville, New Jersey 08232 (hereinafter referred to as "Purchaser"), and KEYSTONE COGENERATION SYSTEMS, INC., having offices at 313 Chestnut Street, Philadelphia, Pennsylvania 19106 (hereinafter referred to as "Seller").

WHEREAS, Seller is undertaking to acquire, construct, install, and operate a grid connected, coal-fired cogeneration facility (hereinafter referred to as the "Facility") all as more particularly described in Exhibit "A" attached hereto and incorporated as part of this Agreement, to be located within the electric service territory of Purchaser; and

WHEREAS, Seller intends to sell electric power and capacity to Purchaser, and Purchaser, in recognition of its obligations under the Public Utility Regulatory Policies Act of 1978 as implemented by the Federal Energy Regulatory Commission (hereinafter referred to as the "FERC") and the State of New Jersey Board of Public Utilities (hereinafter referred to as the "Board"), will purchase the Net Plant Output and capacity from the Facility; and

WHEREAS, it is necessary for Seller to obtain a long-term commitment for the purchase of its Net Plant Output and capacity in order to plan and obtain financing and other necessary commitments for the construction and operation of the Facility; and

WHEREAS, Purchaser expects to require added generating capacity on its system and desires an arrangement under which Purchaser shall have sufficient operational control over Seller's Facility such that the Facility is Dispatchable when and if needed by Purchaser, and such that in all other respects Purchaser will have sufficient control to be able to count Seller's Facility as part of its capacity for purposes of meet-

ing Purchaser's obligations under the PJM Interconnection Agreement, as hereinafter defined, and associated guidelines and standards; and

WHEREAS, Seller and Purchaser have agreed to enter into this Agreement subject to Seller's obtaining all required financing and obtaining and maintaining all requisite governmental permits, licenses, waivers, franchises, easements, regulatory approvals and other approvals material to the construction and operation of the Facility.

NOW THEREFORE, in consideration of the mutual promises, covenants and conditions contained herein, Purchaser and Seller agree as follows:

ARTICLE I

DEFINITIONS

1.1 Definitions For purposes of this Agreement, the following terms shall have the following meanings:

- A. "Availability Factor" shall mean the ratio of Seller's Facility's availability to Purchaser's system's availability based on a Contract Year calculation of availability, all as more particularly described in Exhibit I.
- B. "Base Escalator" or "Base Index" shall have the meaning set forth in Article 5 hereof.
- C. "Billing Period" shall mean the period between any two consecutive regularly scheduled meter readings by Purchaser at Seller's Facility, nominally, one calendar month.
- D. "Board" or "BPU" shall mean the State of New Jersey Board of Public Utilities or any successor thereto having jurisdiction over this Agreement.

- E. "Contract Year" shall mean each of the successive twelve (12) month periods commencing with the Date of Commercial Operation.
- F. "Date of Commercial Operation" shall have the meaning set forth in Article 4 hereof, except that for purposes of Article 5.1 such date shall be deemed to occur no earlier than January 1, 1993.
- G. "Dispatchable" shall mean the capability to increase or decrease the energy output and voltage level of the Facility in response to directions from the System Control Center (i.e., within the time requirements of the PJM guidelines identified and incorporated as part of this Agreement, and as same may be amended from time to time after notice to Seller), consistent with the provisions of Articles 3 and 10 of this Agreement.
- H. "Escalation Factor" for each calendar year for purposes of calculating the administrative fee specified in Article 5.2 hereof, shall mean the Consumer Price Index of the Bureau of Labor Statistics, United States Department of Labor (1967 = 100) for the Metropolitan Philadelphia/New Jersey area for the September preceding the calendar year divided by the indice for September, 1987. In the event the above-referenced index is discontinued, the National Consumer Price Index shall be utilized. In the event a new index is developed solely for the southern portion of New Jersey, then such index may be utilized upon the mutual consent of the parties. The calculation of the Escalation Factor shall be based upon the most recent calendar year for which such index has been published.
- I. "Effective Date" shall mean the date of execution of this Agreement.
- J. "Force Majeure" shall have the meaning set forth in Article 15 hereof.

- K. "Forced Outage" shall mean any outage caused by mechanical or electric equipment failure that either fully or partially curtails the electrical output of the Facility.
- L. "Hourly Interchange Cost" shall mean the hourly interchange cost for Purchaser as such cost is defined by the PJM Interconnection, divided by the number of kilowatt-hours of energy delivered to the PJM Interconnection by Purchaser or received by Purchaser from the PJM Interconnection for each hour.
- M. "Independent Engineer" shall mean the engineering firm or any successor thereto designated by mutual agreement of Seller and Purchaser.
- N. "Indirect Costs" shall mean those reasonable costs described as indirect in Purchaser's then current "Procedures for Billing Work Done at the Expense of Others", as may be amended from time to time.
- O. "Lender" shall mean the lending institution or institutions providing the construction and permanent financing for the Facility.
- P. "Levelized Energy Adjustment Clause" shall have the meaning set forth in Article 2.2(iii).
- Q. "Minimum Generation Emergency Condition" shall mean a condition declared by the PJM Interconnection Office in accordance with the standards and procedures set forth in the "PJM Minimum Generation Obligations and Procedures", a copy of which is attached hereto as Exhibit "B".
- R. "Net Deliverable Capacity" shall mean the maximum net summer capability of the Facility deliverable to Purchaser at the Point of Delivery, as measured pursuant to Article 3.

- S. "Net Plant Output" shall mean the amount of electrical energy delivered by Seller's Facility to the Point of Delivery.
- T. "Off-Peak Period" shall mean all hours of a week exclusive of the On-Peak Period.
- U. "Off-Peak Season" shall mean all other periods of a calendar year exclusive of the On-Peak Season.
- V. "On-Peak Period" shall mean the period from 9:00 A.M. to 11:00 P.M., seven days per week, or as otherwise designated by Purchaser, provided that such other designation results in a total on-peak period which is substantially equivalent in total annual hours to the above-designated On-Peak Period and provided further that Seller shall have consented to such other designation, which consent shall not be unreasonably withheld by Seller.
- W. "On-Peak Season" shall mean the calendar periods December 1st through February 28th or 29th (whichever is appropriate) and June 1st through September 30th (totalling approximately 212.25 days per year).
- X. "Ordinary Maintenance and Operations" shall mean that maintenance and operations customarily performed on other transmission or distribution facilities of like voltages. Ordinary Maintenance and Operations shall not cover replacement of equipment nor shall Ordinary Maintenance and Operations cover repairs due to Force Majeure as provided under Article 15 hereof.
- Y. "PJM Capacity Deficiency Charge" shall mean the rate determined annually (but for purposes of this Agreement computed on a daily basis) by the Management Committee of the PJM Interconnection and

approved by FERC or otherwise in effect pursuant to FERC practice, for short-term capacity supplied by PJM companies, which have capacity in excess of their PJM capacity obligation, to those PJM companies which are deficient in meeting their PJM capacity obligation.

- Z. "PJM Interconnection" or "PJM" shall mean the Pennsylvania-New Jersey-Maryland Interconnection, a power pool cooperatively operated under the Pennsylvania-New Jersey-Maryland (PJM) Interconnection Agreement originally entered into among the members thereof on September 26, 1956, as such Agreement has and may be amended or supplemented from time to time, or the successor thereof.
- AA. "Point(s) of Delivery" shall mean the location(s) where Purchaser's and Seller's facilities are interconnected, as shown on Exhibit "D".
- BB. "Prudent Electrical Practices" shall be those practices that are commonly used in prudent electrical engineering and utility operations to operate electric equipment within the constraints of safety, efficiency, economy and reliability.
- CC. "Purchaser's Interconnection Facilities" shall mean the transmission and/or distribution lines, transformers, circuit breakers, relaying and other devices that are to be installed or modified by Purchaser at the expense of Seller on Purchaser's side of the Point of Delivery to allow the delivery to Purchaser by Seller of the energy produced by Seller's Facility and the delivery to Seller's Facility of energy produced by Purchaser.
- DD. "Qualifying Facility" shall mean a facility that is a qualifying facility pursuant to Section 292.101 et seq. of FERC's rules in effect as of the

Effective Date Implementing the Public Utility Regulatory Policies Act of 1978.

- EE. "Reserve Fund" shall mean the fund described in Article 13.4 hereof.
- FF. "Seller's Facility" or "Facility" shall mean the grid connected, coal-fired fluidized bed cogeneration facility described in Exhibit "A".
- GG. "Seller's Interconnection Facilities" shall mean all the transformers, circuit breakers, relays, switches, synchronizing equipment, control and protective devices that are to be installed or modified by Seller on Seller's side of the Point of Delivery in accordance with this Agreement.
- HH. "Scheduled Maintenance" shall be the periods of time during which any generation unit of the Facility is shut down totally or partially for routine maintenance operations in accordance with Article 10.5.
- II. "Standard Offer" shall mean the Stipulation, including all exhibits attached thereto and incorporated therein, entered into between Purchaser and the Board's Staff and the Order of the Board dated August 28, 1987 approving that Stipulation. The Stipulation and the Board's Order are attached hereto as Exhibit "E".
- JJ. "System Control Center" shall be Purchaser's system control center currently located at 1199 Black Horse Pike, Pleasantville, New Jersey.
- KK. "System Emergency" shall mean a condition on Purchaser's or the PJM system which is likely to result in imminent, significant disruption of service to Purchaser's customers or is imminently likely to endanger life or property or would result in unsafe or unreliable operation.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. This Agreement shall be effective upon execution and shall continue in effect for a Term of thirty (30) years (the "Term"), commencing on the later to occur of January 1, 1993 or the Date of Commercial Operation, subject to Article 2.2 below.

2.2 Conditions Precedent to Commencement of Term. The conditions precedent to the commencement of the Term shall be:

- (i) Compliance by Seller with the requirements of Article 4;
- (ii) Seller's obtaining the requisite Qualifying Facility status as set forth in the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of the FERC, as in effect as of the Effective Date, implementing same; and
- (iii) A finding by Order of the BPU that this Agreement is reasonable and prudent for the Term of this Agreement and that Purchaser will be able to flow through to and/or fully and timely recover from its ratepayers through a Levelized Energy Adjustment Clause proceeding or comparable regulatory proceeding all purchased energy and capacity costs incurred by Purchaser pursuant to this Agreement for the Term thereof. Such Order by the Board shall be under such other terms and conditions as are acceptable to the parties hereunder. After the Board issues its Order, the parties shall, within twenty (20) days of the date thereof, affirm in writing, executed by both parties, that this third condition precedent has been satisfied, and that the parties agree to such other terms and conditions as the Board may or shall have imposed. In the event (i) said condition precedent with respect to BPU approval is

not satisfied within three (3) months of the Effective Date, or (ii) after the BPU has issued its Order either party fails to agree in writing to any terms and/or conditions imposed in such Order within the period set forth above; this Agreement shall be void as of such date and the parties hereto shall thereafter be released from any and all obligations hereunder without further notice.

2.3 Effect of Termination. Termination of this Agreement based on Section 2.2(iii) hereof shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination, except as otherwise specifically provided in this Agreement. Upon such termination, the Reserve Fund shall be returned to Seller together with accrued interest thereon.

ARTICLE 3

BASIC RIGHTS AND OBLIGATIONS

3.1 Delivery of Electric Energy and Capacity. Seller shall sell and deliver and Purchaser shall purchase and accept on and after the Date of Commercial Operation and for the Term of this Agreement, the Net Plant Output from Seller's Facility on a dispatchable basis in accordance with Article 5 hereof. Purchases of Net Plant Output prior to the commencement of the Term shall also be made by Purchaser in accordance with Article 5. In order to fulfill its obligation to supply, Seller agrees to proceed and perform with reasonable promptness and diligence, the work necessary for construction of the Facility.

Purchaser agrees that in consideration of Seller's Facility being Dispatchable, Seller shall be entitled to payment for the equivalent of 3500 hours of operation per Contract Year at the Net Deliverable Capacity (a minimum of 58% of such hours will be

during On-Peak Periods); provided, however, that in the event Purchaser makes payment to Seller for periods during which Seller did not actually produce energy, then such payments by Purchaser shall be net of fuel and other operating expenses avoided by Seller during such periods and provided further that Seller's Facility was available for energy production. Seller agrees that the minimum notice to start-up shall be eight (8) hours from cold start and four (4) hours from warm start, the minimum notice to shutdown shall be two (2) hours and that the minimum run-time between start-up and shutdown shall be ten (10) hours. Seller further agrees that the minimum load during non-dispatch periods shall be 50,000 KW, and such minimum load shall be included in the 3500 hours of operation referred to herein.

3.2 Purchaser's Obligation. At Seller's option, Purchaser shall supply any energy required by Seller for purposes of stand-by, back-up, supplemental, interruptible and maintenance services for Seller's Facility under Purchaser's applicable tariff and contract terms approved by the BPU and in effect at the time of purchase. If Seller elects to purchase these requirements from Purchaser, Seller shall be charged the lesser of contracted for stand-by demand charges for alternate energy producers, or standard demand charges as provided in Purchaser's tariff. All payments for energy purchased shall be billed in accordance with Purchaser's standard practices for all other customers and shall not affect any charges or payments under this Agreement. There shall be no right of offset by Seller for any charges incurred outside this Agreement. Metering of sales from Purchaser to Seller shall be pursuant to the provisions set forth in Purchaser's standard tariff for electric service. In the event Purchaser is required by the BPU or other governmental agencies to institute curtailment of energy deliveries to its customers, Purchaser may require Seller to curtail its purchase of electricity in the same manner and to the same degree as other customers within the same customer or rate class who do not own facilities for generating electricity.

3.3

Seller's Obligations.

- A. Capacity Levels. The Net Deliverable Capacity of Seller's Facility shall be 200,000 KW, unless redesignated pursuant to Article 3.3D, and Seller acknowledges that Purchaser has entered into this Agreement in reliance on Seller's representation that such level of capacity will be available during the term of this Agreement. Should the actual Net Deliverable Capacity of the Facility be less than 190,000 KW, except as allowed pursuant to Article 3.3D, Seller shall be obligated to make a deficiency payment equal to the PJM Capacity Deficiency Charge times the difference between 190,000 KW and the actual rate of output below 190,000 KW as accepted and determined by PJM standards and tests. Capacity shall be measured in kilowatts, adjusted for seasonal ambient temperature variations, as determined by periodic, pre-scheduled capacity capability tests conducted and measured in accordance with Exhibit H. Net Deliverable Capacity shall be confirmed annually and shall be determined by subtracting the Seller's estimated summer load of the Facility and further subtracting the estimated summer load of the Monsanto Corporation as designated by Seller before June 1 of each year from the Facility's total maximum summer generating capacity capability measured in accordance with Exhibit H. Net Deliverable Capacity, as measured in accordance herewith, shall be independent of unit availability and shall not be affected by Forced Outages or Scheduled Maintenance. The net summer capacity as defined by the requirements of the PJM will be based on the Facility's performance or test results corrected to standard conditions (as defined in PJM guidelines) in the months of June, July, and August.

- B. Qualifying Facility Status. Seller shall maintain those conditions during the term of this Agreement specified by the FERC and applicable to the Facility with respect to Qualifying Facility status as of the Effective Date. In the absence of an agreement to the contrary approved by the BPU, if Seller loses its Qualifying Facility status, this Agreement shall remain in effect except payment to Seller shall be the lower of the Purchase Price under Article 5 hereof or ninety-nine percent (99%) of Purchaser's Hourly Interchange Cost multiplied by the kilowatt hours delivered until such time as Qualifying Facility status is restored. In the event Seller is unable for any reason to have Qualifying Facility status restored, Seller shall be entitled to file with FERC (or other appropriate regulatory authority having jurisdiction) for approval of a tariff price for the remaining portion of the Term; provided, however, that Purchaser shall only be obligated to pay the lower of (i) the tariff price as approved by FERC (or other appropriate regulatory authority having jurisdiction), or (ii) the Purchase Price under Article 5 hereof. If Seller fails for any reason to have such tariff price approved by FERC (or other appropriate regulatory authority having jurisdiction) within two (2) years of the date of loss of Qualifying Facility status, then the price hereunder shall be based on the above-referenced formula using Purchaser's Hourly Interchange Cost. Purchaser shall cooperate with Seller in obtaining approval for such tariff provided that (i) such cooperation is not inconsistent with Purchaser's rights and obligations under this Agreement; and (ii) Seller reimburses Purchaser for reasonable costs incurred in connection with such proceedings, including reasonable attorneys' fees. Qualifying

Facility status will be measured by Seller in accordance with the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of the FERC, in force and effect as of the Effective Date, once every Contract Year, beginning at the end of the twenty-fourth (24th) month after the Date of Initial Commercial Operation. Seller shall forward to Purchaser a copy of the measurement report prepared by Seller within thirty (30) days of such measurement of Qualifying Facility status.

- C. Seller's Obligation to Provide Power During System Emergencies. At Purchaser's request, Seller shall use reasonable best efforts to provide Net Deliverable Capacity to Purchaser during a System Emergency. Seller agrees that during situations where the safety, reliability or security of Purchaser's system or that of the PJM Interconnection is threatened, the Seller shall, at Purchaser's request, use its reasonable best efforts, to the extent consistent with Seller's obligations to other persons and subject to the requirements of Seller's Facility, to provide the energy or capacity above Net Deliverable Capacity as requested by Purchaser's System Control Center, and shall, if requested, make its reasonable best efforts, to the extent consistent with Seller's obligations to other persons and subject to the requirements of Seller's Facility, to delay any Scheduled Maintenance of the Facility.
- D. Redesignation of Net Deliverable Capacity.
- (i) The Net Deliverable Capacity is 200,000 kilowatts, unless redesignated pursuant to this Article 3.3D.
 - (ii) Not later than two (2) years after the Date of Commencement of Operation, Seller may, after notice to Purchaser, redesignate

Net Deliverable Capacity downward to an amount not less than 180,000 kilowatts. This redesignation shall be no less than 2,000 kilowatts and shall be effective three (3) years after such notice.

(iii) The reimbursement due Purchaser as a result of Seller's redesignation under Article 3.3D(ii) shall be the sum of (a), (b), and (c) below, calculated from the Date of Commercial Operation until the effective date of such redesignation:

(a) the difference between:

- (1) the aggregate capacity payments made for each month for each kilowatt of reduction of Net Deliverable Capacity subject to the redesignation pursuant to Article 3.3D(ii), and
- (2) the aggregate PJM Capacity Deficiency Charge in effect at the time of each monthly payment for each kilowatt available for each month;

(b) the difference between:

- (1) the aggregate energy payments (up to 3500 hours per Contract Year) made for each hour related to each kilowatt of reduction of Net Deliverable Capacity subject to the redesignation pursuant to Article 3.3D(ii), and
- (2) the aggregate Hourly Interchange Cost in effect at the time of each hourly payment related to each kilowatt for each hour; and

(c) interest on any balance under Article 3.3D(iii)(a) and (b) at a rate equal to Purchaser's overall rate of return allowed by the Board for the period such rate is in effect.

Upon Seller's request and solely for the purpose of illustrating the reimbursement which may be required as a result of redesignation hereunder, Purchaser shall provide Seller with a

statement computing the reimbursement which would be due Purchaser under this Article 3.3D(iii), or a 2,000 kilowatt reduction of Net Deliverable Capacity. Reimbursement calculated under this paragraph shall be due to Purchaser at the time notice of redesignation is delivered to Purchaser and shall be calculated on the basis of the PJM Capacity Deficiency Charge in effect at the time of delivery of such notice of redesignation. Within thirty (30) days following the effective date of such redesignation, Purchaser shall recompute the capacity reimbursement owed by Seller under Article 3.3D(iii)(a) based on the actual PJM Capacity Deficiency Charge in effect each month between the date of delivery of Seller's notice of redesignation and the effective date of such redesignation. Any overpayments or underpayments made in conjunction with the Seller's reimbursement to Purchaser at the time of such notice of redesignation shall be refunded by Purchaser or Seller, as the case may be, within thirty (30) days of Purchaser's recomputation of the actual capacity reimbursements owed by Seller as described above.

3.4 Exceptions To Purchaser's Obligation To Accept Net Plant Output. Notwithstanding the provisions of Article 3.1, and in addition to the provisions of Article 15 of this Agreement, Purchaser shall be excepted from accepting Seller's Net Plant Output if:

- A. After being provided with notice and a reasonable opportunity to cure, Seller's Facility fails to comply with (i) the Technical Guidelines for Cogenerators and Small Power Producers (Dated October, 1985; Revised January, 1988) as set forth in Exhibit "C"; and (ii) the Technical Guidelines for Customer Service at Sub-Transmission and

Transmission Voltages (Dated May, 1985) as set forth in Exhibit "F", both of which are attached hereto and incorporated herein as part of this Agreement.

- B. A System Emergency occurs on the part of Purchaser's (or the PJM) system interconnected with Seller's Facility such that there would be no means of delivering the Net Plant Output to the remainder of Purchaser's system. Such refusal to purchase may occur on an instantaneous basis; provided, however, that (a) Purchaser shall use reasonable best efforts consistent with Prudent Electrical Practices to attempt to minimize the duration of such occurrences, (b) Purchaser shall give Seller advance notice of such occurrence(s) to the extent practical under the circumstances then prevailing and shall give Seller an explanation of such occurrence(s) after the fact where advance notice is impractical, and (c) a System Emergency shall not affect Purchaser's obligation to make payment to Seller for the minimum purchase requirements provided in Article 3.1 hereof.
- C. During any Minimum Generation Emergency Condition declared by PJM or Purchaser's System Control Center, Purchaser shall give notice to Seller in time for Seller's Facility to curtail the delivery of Net Plant Output to Purchaser, consistent with the PJM guidelines. Purchaser shall use reasonable efforts consistent with Prudent Electrical Practices to attempt to minimize the duration of such occurrences and Seller's Facility shall be treated in a manner consistent with all other Dispatchable units operated by Purchaser or dispatchable Qualifying Facilities supplying Purchaser. Such occurrences shall not affect Purchaser's obligation to make payment to Seller for the minimum purchase requirements provided in Article 3.1 hereof.

- D. Purchaser intentionally interrupts acceptance of Seller's Net Plant Output to conduct necessary maintenance of Purchaser's Interconnection Facilities or adjacent transmission and distribution facilities. In such instances, Seller will receive as much advance notice as possible but in no event less than seven (7) days prior to any such planned maintenance. Purchaser shall use its reasonable efforts consistent with Prudent Electrical Practices to minimize such interruptions and to the extent reasonably possible to coordinate the same with Seller's maintenance under Article 10 hereof. Such interruptions shall not affect Purchaser's obligation to make payment to Seller for the minimum purchase requirements provided in Article 3.1 hereof.
- E. In the reasonable opinion of Purchaser, Seller's Facility produces energy or energy and capacity of a character of service which may adversely affect the safety, reliability or security of Purchaser's equipment, facilities, personnel, or system or the safety, reliability or security or those of any other supplier of electricity to Purchaser or to Purchaser's customers, or does not meet Purchaser's obligation to the PJM in terms of safety, reliability or security, as stated in the PJM Interconnection Agreement, Purchaser shall notify Seller of this condition and allow Seller reasonable time to correct it. If Seller fails to correct the condition within a reasonable time, Purchaser may physically interrupt the flow of energy from the Facility until the condition is corrected or Seller demonstrates to the reasonable satisfaction of Purchaser that Seller is operating in accordance with the operating standards set forth in Article 10.

Purchaser agrees to file a notice within five (5) working days with the BPU and provide Seller with reasonable advance notice in all cases of refusal to purchase from

Seller. Purchaser will promptly resume the acceptance of Seller's Net Plant Output as soon as the reason for the interruption no longer exists. In the event of an instantaneous or other refusal to accept power as provided in this Article 3.4, Purchaser agrees to use its reasonable best efforts (consistent with Purchaser's existing obligations to restore service to its retail and wholesale customers and provided further that Seller will not be treated in a discriminatory manner with respect to any other Qualifying Facility) to correct any condition and to restore acceptance of such power. Interruption or reduction of deliveries shall be of no greater scope and of no longer duration than is necessary. During periods of reduction or interruption pursuant to this Article 3.4 Purchaser shall not be obligated to make payments other than for energy actually delivered to Purchaser and for capacity as specified in Article 5 of this Agreement; provided, however, that in the case of exceptions arising under Articles 3.4B, 3.4C or 3.4D, such occurrences shall not reduce Purchaser's minimum purchase requirements under Article 3.1 hereof.

ARTICLE 4

DATE OF COMMERCIAL OPERATION

4.1 The scheduled Date of Commercial Operation for Seller's Facility is January 1, 1993 and Seller shall use best efforts to have the Facility in commercial operation by said date, subject to the terms of this Agreement.

4.2 The actual Date of Commercial Operation shall be the day commencing at 12:01 A.M. following the day during which the equipment of the Facility and Seller's and Purchaser's Interconnection Facilities have reached a degree of completion and reliability such that they are capable of delivering energy continuously into Purchaser's system. For the purposes of this Agreement, said completion and reliability shall be deemed as having been reached when all of the following procedures have been successfully completed:

- (i) The Seller has provided thirty (30) working days' advance written notice to Purchaser of the time that Seller proposes to begin demonstration of any of the Facility's electrical generation units completion and reliability. In the event of any change in the proposed demonstration date, prompt written notice will be given to Purchaser.
- (ii) Purchaser, at its own expense, has the opportunity to have one or more designated representatives to observe all or part of said demonstration.
- (iii) Each of the Facility's electrical generation units has been started, synchronized, connected and then disconnected from Purchaser's system a minimum of four (4) separate times. Two (2) of the disconnects in this procedure shall be remotely triggered from Purchaser's substation relay or other designated control point.
- (iv) Each of the Facility's electrical generation units has been successfully started, synchronized, connected and operated in parallel with Purchaser's system for a continuous 48-hour period at Net Deliverable Capacity, subject to Prudent Electrical Practices.
- (v) The Facility has demonstrated the capability to operate throughout the range of power factors and range of capacities required by Purchaser with input from Seller and as set forth in Exhibit C. Upon successful completion of start-up and acceptance testing of the Facility, Purchaser shall send written confirmation of test results to Seller within five (5) business days.
- (vi) Successful completion of the above requirements shall be determined by Seller and Purchaser, or failing prompt concurrence thereon, by the Independent Engineer.

ARTICLE 5

PURCHASE PRICE AND OTHER CHARGES

5.1

Purchase Price. Purchaser agrees to pay Seller as follows:

- A. For test energy received before the Date of Commercial Operation, the pricing structure shall be as follows:
 - (i) An energy payment equal to the Hourly Interchange Cost times the energy delivered for all energy delivered at the Point of Delivery.
 - (ii) No capacity payments shall be made prior to the Date of Commercial Operation.
- B. For energy received and for capacity on or after the Date of Commercial Operation, the pricing structure hereunder shall be based on the following formulas:
 - (i)
 - a. During each of the first fifteen (15) Contract Years, a monthly capacity payment equal to: Net Deliverable Capacity x \$25.00/KW Month x Availability Factor, where the Net Deliverable Capacity shall not exceed 200,000 kilowatts and subject also to redesignation pursuant to Article 3.3D. Where the Availability Factor exceeds 0.90, its value shall be set to 1.0.
 - b. During each of the last fifteen (15) Contract Years, a monthly capacity payment equal to: Net Deliverable Capacity x \$13.33/KW Month x Availability Factor, where the Net Deliverable Capacity shall not exceed 200,000 kilowatts and subject also to redesignation pursuant to Article 3.3D. Where the Availability Factor exceeds 0.90, its value shall be set to 1.0.

- (ii) a. For all energy delivered during each of the first eight (8) Contract Years, the price shall be: $\$0.023189/\text{KWH} + \$0.015804/\text{KWH} \times I$, where I is the Base Escalator.

NOTE:

Base Escalator shall be the cost of coal as defined by the annual average cost of bituminous coal used by New Jersey Utilities as reported on FERC Form 423. The index is tonnage weighted.

I (for year N) = Cost of fuel as defined above, for the preceding year (N-1) relative to the cost of fuel in 1992; cost of coal in (N-1) divided by cost of coal in 1992 = I .

i.e., For year N, I then becomes

$\text{Indices in year (N-1)} / \text{Indices in 1992}$

Values of I will be established in the first quarter of each year based on available published values of the indices.

- b. For all energy delivered during each of Contracts Years nine (9) through fifteen (15), the price shall be: $\$0.015000/\text{KWH} + \$0.032000/\text{KWH} \times I$, where I is the Base Escalator.

- c. For all energy delivered during each of the final fifteen (15) Contract Years, the price shall be: $\$0.032000/\text{KWH} \times I$, where I is the Base Escalator.

- C. For each cold start to synchronization requested by Purchaser in excess of ten (10) such starts during any Contract Year, Purchaser shall make payment to Seller in the amount of \$900.00, multiplied by the then prevailing Escalation Factor.

- D. When not dispatched by Purchaser, payment for Net Plant Output delivered during periods of Minimum Generation Emergency Condition shall be as follows: KWH delivered times the Hourly Interchange Cost (energy only). This payment shall be calculated on an hour-by-hour basis.

5.2 Other Charges. The following charges shall be due Purchaser: (1) beginning in the first month after acceptance of the BPU order referred to in Section 2.2(iii), an administrative fee, initially \$2,000 per month, adjusted annually by the Escalation Factor, which administrative fee, as so adjusted, is also subject to further adjustment at Purchaser's reasonable discretion in the event Purchaser is required to spend in excess of twenty (20) man hours per month reviewing plans, specifications, drawings or other documentation relating to the design or construction of Seller's Facility, said adjustment to be based on the average hourly cost of Purchaser's reviewing personnel; (2) itemized charges for metering and testing requested by Seller and out of the normal course of business; (3) the costs (including overhead charges computed in accordance with Purchaser's customary practices) of repair or replacement to any portion of Purchaser's Interconnection Facilities which are otherwise billable to Seller pursuant to this Agreement; and (4) a capacity deficiency payment, if applicable, pursuant to Article 3.3A.

5.3 Excess Pool: Second Lien.

- A. Effective upon the Date of Commercial Operation, Seller and Purchaser hereby agree to establish a fund, referred to herein as the "Excess Pool". The Excess Pool is intended to track, on a dollar for dollar basis, overpayments to Seller during the first fifteen (15) Contract Years resulting from increased levels of payments beyond the maximum levels established by the Standard Offer (for the first 3500 hours of dispatch) and to provide a mechanism for the repayment of

such overpayments in the final fifteen (15) Contract Years by means of reduced payments to Seller below the maximum levels established by the Standard Offer (for the first 3500 hours of dispatch) pursuant to Section 5.1B(i)(b). Commencing on the Date of Commercial Operation, sums shall be added (i.e., credited) to the Excess Pool each month in amounts calculated pursuant to the formulas set forth in Exhibit "J" hereto. Commencing on the 15th anniversary of the Date of Commercial Operation, the amounts in the Excess Pool, including interest accrued thereon as set forth in paragraph B below, shall commence to be repaid to Purchaser (i.e., debited to the Excess Pool) in the manner described in paragraph E below. It is the intent of Seller and Purchaser that all additions to and deletions from the Excess Pool shall be made on the basis of all capacity payments actually made to Seller pursuant to this Agreement and on energy payments actually made to Seller pursuant to this Agreement for the first 3,500 hours of operation per Contract Year; any energy payments made to Seller pursuant to this Agreement in excess of 3,500 hours of operation per Contract Year shall not be taken into account in the calculation of the level of the Excess Pool or the value of Purchaser's second lien.

- B. The principal balance in the Excess Pool shall earn interest at the rate of 11.35% per annum compounded monthly.
- C. On a monthly basis, Purchaser shall prepare or cause to be prepared a statement (the "Excess Pool Statement") showing the calculation of principal and interest balances in the Excess Pool for the prior billing period. The Excess Pool Statement shall include:

- (1) The amount of capacity and the number of kilowatt hours purchased by Purchaser from Seller during such prior Billing Period, but in no event more than the 3500 hours provided for in Article 3.1 for any Contract Year;
 - (2) The amount of any credits to be added or debits subtracted from the Excess Pool for such prior Billing Period;
 - (3) The net principal and interest credit in the Excess Pool at the end of such prior Billing Period; and
 - (4) Such other information, data or calculations as Purchaser deems necessary or Seller requests to adequately advise Seller of the status of the Excess Pool.
- D. Purchaser shall submit the Excess Pool Statement (dated at the end of such prior billing period) with its payment for energy purchased from Seller within thirty (30) days of the end of each Billing Period. Upon receipt of the Excess Pool Statement, Seller shall promptly review its contents and advise Purchaser in writing of any errors, misstatements or other problems with the Excess Pool Statement. Upon reasonable notice, Purchaser agrees to have available for inspection by Seller appropriate documentation reflecting the calculations of payments for energy purchased from Seller and of the value of such energy if it were purchased in accordance with the Standard Offer. Any such errors shall be settled by the parties as expeditiously as possible.
- E. Principal additions to the Excess Pool, but not interest accruals, shall end on the 15th anniversary of the Date of Commercial Operation. On such date, if a credit balance exists in the Excess Pool, from and after such date and until the 30th anniversary of the Date of Com-

mercial Operation, principal amounts in the Excess Pool and accrued interest thereon shall be repaid solely in the following manner:

1. Purchaser shall credit to Seller in the Excess Pool (i.e., debit the Excess Pool) any monthly payment due to Seller for energy or capacity in an amount calculated in accordance with the formula and examples set forth in Exhibit "J" but in no event more than the 3500 hours provided for in Article 3.1 for any Contract Year;
2. The aggregate amount of such deductions shall equal the principal balance in the Excess Pool and accrued interest thereon at the date of such 15th anniversary plus subsequent interest accruals thereon;
3. Such deductions shall be made until all principal amounts in the Excess Pool and accrued interest thereon shall have been paid to Purchaser, following which event the Excess Pool and all obligations of Seller with respect thereto shall terminate.

In the event that this Agreement is terminated, whether by expiration of the Term or otherwise, at any time prior to payment in full of the principal balance of the Excess Pool and accrued interest thereon, the then outstanding principal balance and accrued interest thereon shall be immediately due and payable by Seller to Purchaser, and Purchaser shall be entitled to exercise all of its rights and remedies under this Agreement in addition to the rights and remedies created by the documents evidencing its second lien and security interest to collect the same; provided, however, that the provisions hereof shall be subject to the rights of the Lender under Article 18.9 hereof and the intercreditor agreement or other similar agreement described in paragraph F below.

- F. On or before the Date of Commercial Operation, Seller shall grant Purchaser a second mortgage and security interest in the Seller's Facility substantially similar to the first mortgage and security interest granted to the Lender; provided, however, that such second mortgage and security interest and the debt secured thereby will be in all respects subordinate to all construction and permanent financing provided by Lender for Seller's Facility and the first mortgage and security interest securing the same. Purchaser will enter into an intercreditor agreement or other similar agreement with the Lender containing terms substantially similar to those set forth in Exhibit K hereto and such other terms as may be reasonably required by the Lender. Such terms shall also be appropriately reflected as Lender may reasonably require in the documentation for the second mortgage and security interest of Purchaser.
- G. Unless otherwise agreed upon by Purchaser and Seller, the permanent debt financing for the Facility provided by the Lender shall be limited to a 15-year period, and there shall be no refinancing thereof where the result would be to increase the principal balance outstanding at the time or to lengthen the term over which the same may be repaid; provided, however, that nothing herein contained shall prohibit or restrict Seller's right to finance major equipment additions or replacements necessary for the continued operation of the Facility and arising after the Date of Commercial Operation.
- H. Seller shall provide Purchaser with copies of all documents to be executed by Seller or its assigns in connection with Seller's construction and permanent debt financing not less than fifteen (15) days prior to closing on such financing.

ARTICLE 6

BILLING AND RECORDS

6.1

Billing and Payment.

A. For each Billing Period, Purchaser shall:

- (i) read the meters, prepare a statement of energy and capacity payments due to Seller and submit the same to Seller, together with Purchaser's payment therefor by electric wire funds transfer, within thirty (30) days of the end of each Billing Period ("Due Date"). Such statement shall indicate the monthly capacity payment and the total kilowatt-hours and kilowatts delivered during each hour of the Billing Period.
- (ii) prepare a statement of any payments due to Purchaser under this Agreement pursuant to Article 5.2 or otherwise and arising during such Billing Period and submit the same to Seller. Such statement shall set forth in detail the bases for calculation of each charge due. Seller shall make payment to Purchaser by electric wire funds transfer within thirty (30) days of receipt of Purchaser's statement ("Due Date").

B. If the transmittal of payment is not received by the applicable Due Date, the party responsible for said payment shall pay to the other party an interest charge on uncollected amounts which shall accrue daily from the Due Date until the date upon which collection is made at the then current late payment charge for industrial customers prescribed in Purchaser's Standard Terms and Conditions as may be amended from time to time, but in no event less than two percent

(2%) above the prime rate of Chase Manhattan Bank, N.A., or its successor, in effect as of the payment Due Date.

- C. Neither party shall have the right to offset any payments due to one party against payments otherwise due to the other party, except as provided in Article 13.3.
- D. In the event of a dispute as to any payment due under this Agreement, the parties agree that such dispute will not affect the obligation to pay any amounts due except as specifically provided in Articles 13.4 and 17. Interest shall accrue as provided in Article 6.1B on any payment subsequently determined not to have been properly due.
- E. The parties agree that payments under this Agreement may be subject to year end adjustment or "true-up" so as to correct billing errors, reconcile overpayments or underpayments, including but not limited to payments for the difference between actual operation and the 3,500 hour obligation, computed on a Contract Year basis, or satisfy other accounting requirements so as to accomplish the purposes of this Agreement.

6.2 Records. Purchaser and Seller shall each keep properly stored and maintained at their offices in New Jersey and shall make available for the inspection, examination and audit of the other party, its authorized employees, agents or representatives and auditors at all reasonable times, such records as required by the PJM Interconnection and this Agreement and all data, documents and other materials relating to or substantiating any charges to be paid by or to Purchaser or Seller, as the case may be, for a minimum period of five (5) years from the date that such records are gathered under this Agreement.

ARTICLE 7

MEASUREMENT AND METERING

7.1 Metering. Purchaser shall install, own, maintain and test the meters and associated equipment which in Purchaser's reasonable judgment are needed to determine the amounts and time of delivery of electrical capacity and energy by Seller to Purchaser or Purchaser to Seller. For energy and capacity deliveries to Purchaser, the meter(s) shall be of a type to record hourly readings and shall be capable of being read by both Purchaser and Seller. Meters used to determine energy and capacity sales to Seller shall be in accordance with Purchaser's appropriate tariff. Seller may install check meters of the same type on Seller's Interconnection Facilities.

7.2 Measurement. All meters, instruments, and measuring devices affecting payments by Purchaser hereunder shall be tested and calibrated at such times as determined by Purchaser in accordance with the regulations of the BPU. Seller shall have the right to have a representative present at any such test. Seller shall have the right to require at Seller's expense a test of any of the above meters at least annually. In the event that any metering equipment used for measuring deliveries to Purchaser is found to be inaccurate by more than one percent (1%), deliveries shall be measured by reference to Seller's check meters or the meter readings for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by the Seller from the best available data, subject to review and acceptance by Purchaser. Purchaser shall promptly cause such meter(s) to be corrected.

ARTICLE 8

DELIVERY

8.1 Point of Delivery. Purchaser agrees to interconnect and operate in parallel its electric system with Seller's Facility and Seller agrees to interconnect the Facility

with the electric system of Purchaser on the terms and conditions herein contained. Seller shall not operate the Facility in parallel with Purchaser's system until the conditions set forth in Article 4 have been met.

8.2 Title to Energy. Delivery of energy shall be completed when transmitted to the Point of Delivery, and title to energy shall pass to Purchaser upon delivery.

ARTICLE 9

INTERCONNECTION

9.1 Interconnection Costs Generally. The parties acknowledge that by mutual agreement an interconnection study has been undertaken by Purchaser and that a copy thereof has heretofore been delivered to and approved by Seller. Subject to Article 15 hereof, Purchaser agrees to use reasonable best efforts to install the interconnection between Seller's Facility and Purchaser's existing system in a timely manner consistent with Seller's scheduled Date of Commercial Operation and to provide all necessary labor and materials therefor. Subject to Article 9.12 hereof, Seller agrees to reimburse Purchaser for all costs, which shall be deemed to include costs for any and all modifications to Purchaser's system at any location, over and above what Purchaser would have incurred, assuming Seller was only a customer, to meet the standby power requirements to be contracted for by the Facility.

9.2 Payment. The costs and charges for interconnection between Seller and Purchaser shall be determined and paid as follows:

- (1) The costs for supplying Seller will be estimated by Purchaser based on Purchaser supplying the Facility's maximum expected internal power requirements.
- (2) The costs for Purchaser's accepting the maximum anticipated Net Plant Output from the Facility will be estimated by Purchaser.

- (3) The excess of item (2) over Item (1) will be the contribution made by Seller. Such contribution, together with any tax payments due under this Article 9, shall be paid by Seller in the form of a non-refundable contribution in aid of construction for the Interconnection Facilities. Payment shall be made as follows: (i) forty percent (40%) of the contribution upon at least twenty (20) days' notice from Purchaser before the ordering of materials; (ii) the balance of the contribution shall be paid during the course of construction based on monthly invoices prepared by Purchaser and submitted to Seller for payment within twenty (20) days of receipt by Seller; and (iii) Upon Purchaser's completion of construction, Seller shall pay the difference, if any, between Purchaser's actual construction costs and the sum of the initial 40% payment and Item (ii). Upon reasonable request by Purchaser, Seller shall provide either an irrevocable letter of credit or performance bond to guarantee payment of the above-mentioned remaining sixty percent (60%) of the contribution in aid of construction.

9.3 Instrumentation. Meters, remote transmitting units, modifications to Purchaser's System Control Center, instrument transformers and auxiliary equipment of a standard type and manufacturer shall be part of Purchaser's Interconnection Facilities. Purchaser shall install, own and maintain, at Seller's expense, said equipment satisfactory to Purchaser and Seller. Meters shall provide signals to both parties on a real time basis.

9.4 Operation and Maintenance of Interconnection. All reasonable maintenance and other direct and Indirect Costs associated with the Purchaser's Interconnection

Facilities related solely to operation of the Facility shall be borne by Seller for the term of this Agreement.

9.5 Rearrangement or Reinforcement of Interconnection. All reasonable changes, relocations, additions or modifications directly related to the Purchaser's Interconnection Facilities after initial construction reasonably incurred to rearrange or reinforce the Purchaser's Interconnection Facilities or that are necessary to meet changing requirements and conditions of Purchaser's system related solely to operation of the Facility shall be at the expense of Seller. Subject to Article 9.12 hereof, Purchaser reserves the right to make changes, including voltage conversions, in its transmission system used to purchase Net Plant Output at this location and any reasonable changes in Purchaser's electric system which would require changes in the Purchaser's Interconnection Facilities shall be deemed costs that are necessary to meet changing requirements and conditions of Purchaser's system. Any and all changes to Seller's Interconnection Facilities shall be subject to Purchaser's approval as provided in Article 10.2.

9.6 Relocation of Purchaser's Facilities. If Purchaser is required to relocate any of its facilities in the vicinity of Seller's Facility (which are essential to provide service to Seller's Facility) as a result of the construction, operation or maintenance of Seller's Facility, including ingress or egress to Seller's Facility whether on or off Seller's property, Seller agrees to reimburse Purchaser for all reasonable direct and Indirect Costs associated with such relocation.

9.7 Protection of Purchaser's Facilities. In the event Purchaser reasonably determines that its existing facilities, in and around Seller's Facility, need to be either mechanically or electrically protected due to the construction, operation or maintenance of Seller's Facility, Seller agrees to reimburse Purchaser for all reasonable direct and Indirect Costs required to provide such protection.

9.8

Taxes On Interconnection Facilities.

- A. Property Tax. If a direct real property tax on the portion of the Purchaser's Interconnection Facilities constituting real property and related solely to operation of the Facility (and over and above that which Purchaser would have incurred assuming Seller was a customer, to meet standby power requirements to be contracted for by Seller's Facility) is levied and/or assessed against Purchaser, Seller shall reimburse Purchaser for the amount of said direct real property tax paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment.
- B. Federal Income Tax. If a federal income tax shall be imposed on the Purchaser upon or with respect to the construction and/or installation of Purchaser's Interconnection Facilities, and Purchaser's tax liability is greater as a result of such payments than it would have been if such payments had not been made, Seller shall fully reimburse Purchaser for the amount of said increased tax liability paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment.
- C. New Jersey Tax. If there should be imposed on Purchaser any New Jersey tax upon or with respect to payments made by Seller for services rendered by Purchaser under this Agreement, including, but not limited to the construction and/or installation of Purchaser's Interconnection Facilities, or if any such payments by Seller should be required under such tax laws to be included in the receipts of the Purchaser which may at any time be reported for tax purposes, and the tax liability of Purchaser as a result of either of such events should be increased over and above an amount which would constitute such tax

liability except for the happening of such event, Seller shall fully reimburse Purchaser for the amount of said increased tax liability paid by Purchaser within thirty (30) days of being notified by Purchaser of said payment.

- D. Any Different or Additional Tax. If any form of tax, other than income or excess profits tax, under any present or future federal, state or other law different from or in addition to the taxes for which participation in or payment by Seller is herein elsewhere in this Agreement provided, should be levied and/or assessed against Purchaser with respect to any property, property right, commodity, service, or other thing involved in, growing out of, or accruing from the performance of this Agreement, which different or additional tax would not be required to be paid by Purchaser except as a result of the performance of this Agreement and, with respect to which such different or additional tax no obligation of Seller to participate or pay would have attached under the provisions of this Agreement elsewhere than in this paragraph, then in such event Seller shall fully reimburse Purchaser for the full amount of such different or additional tax paid by Purchaser within thirty (30) days of being notified by the Purchaser of said payment.
- E. Increased Federal Income Tax to Purchaser Arising from Seller's Payment or Reimbursement of Tax under the Preceding Provisions. Seller shall fully reimburse Purchaser for any net actual federal income tax or New Jersey tax ("Tax"), if any, arising out of any payment or reimbursement of tax by Seller under the preceding paragraphs of this Article 9.8. The amount reimbursed to Purchaser under

this paragraph shall consist of the following components: (1) the initial amount of net actual Tax arising under this paragraph (the "First Amount"); (2) the net actual Tax on the First Amount (the "Second Amount"); (3) the net actual Tax on the Second Amount (the "Third Amount"); and (4) the net actual Tax on the Third Amount and on each succeeding amount until the final amount is less than one dollar.

- F. Purchaser agrees to cooperate with Seller in attempting to minimize Seller's costs under this Article, provided Seller reimburses Purchaser for all reasonable costs incurred by Purchaser in connection therewith, including reasonable attorneys fees and provided further that Seller shall indemnify Purchaser against any and all penalties, judgments, fines or other costs which may be imposed by any governmental authority as a result hereof. Notwithstanding the foregoing, Seller shall have the right to contest, appeal or seek abatement of any tax, levy or assessment against Purchaser and for which Seller may be required to reimburse Purchaser under this Article. Purchaser will cooperate with Seller in prosecuting any such contest, appeal or abatement, and no reimbursement shall be payable by Seller to Purchaser under this Article until such tax, levy or assessment is due by a final and non-appealable order by a court or agency of competent jurisdiction. Seller shall reimburse Purchaser for all reasonable costs incurred by Purchaser in connection with such contest, appeal or abatement request, including but not limited to interest charges, penalties, or reasonable attorneys' fees.

Purchaser agrees that Seller shall be promptly reimbursed for (i) any payments made by Seller under this Article 9.8, with interest in accordance with Article 6.1, to the extent that Purchaser is allowed to flow through such liability to its ratepayers; and (ii) any reductions in the tax liability of Purchaser, by reason of any net tax benefits realized by Purchaser, including depreciation deductions and tax credits, as a result of this Article 9.8 or any other provision of this Agreement, with interest in accordance with Article 6.1, but only to the extent that Purchaser is not required to flow through such benefits to its ratepayers.

9.9 Title to Interconnection. Title and risk of loss shall pass on the Date of Commercial Operation, at which time Purchaser shall have title to Purchaser's Interconnection Facilities constructed by Purchaser at the expense of Seller and Seller shall have title to Seller's Interconnection Facilities.

9.10 Construction Notice. Seller shall give Purchaser not less than six (6) months notice of the date of its readiness to receive the interconnection at Seller's Facility. Following receipt of said notice, Purchaser agrees to proceed and perform with reasonable promptness and diligence the work necessary for commencement of the interconnection.

9.11 Removal of Interconnection. When Seller's Facility will no longer supply energy to Purchaser, Seller shall reimburse Purchaser for net costs (minus salvage) incurred by Purchaser to disconnect and remove the Purchaser's Interconnection Facilities in accordance with Purchaser's then current "Procedure for Billing Work Done at the Expense of Others", as may be amended from time to time.

9.12 Amendments Regarding Interconnection Costs. The parties recognize and acknowledge that the issue of interconnection costs for Qualifying Facilities on Purchaser's system is presently being reviewed by Purchaser, the Board and other parties. Purchaser and Seller agree that this Agreement shall be subject to amendment to prop-

erly reflect the resolution of this issue; provided, however, that Seller agrees that so long as the total costs and charges to be borne by Seller for interconnection equipment on Purchaser's side of the Point of Delivery, including costs and charges for interconnection work specific to Seller's Facility do not exceed \$11,000,000.00 under any such resolution or otherwise, that this Agreement shall remain in full force and effect and such costs and charges shall be borne by Seller. In the event that Seller reasonably and in good faith estimates that such costs and charges will exceed \$11,000,000.00, then Seller may terminate this Agreement by written notice to Purchaser within seven (7) days of Seller's determination; provided, however, that Seller's termination shall be void and this Agreement shall continue in full force and effect if, within four (4) months of receipt of Seller's termination notice, Purchaser elects to pay directly or reimburse Seller, as the case may be, such costs and charges as are in excess of \$11,000,000.00. Any other provision of this Agreement notwithstanding, termination pursuant to this Article 9.12 shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination, and the parties shall be mutually released without liability to the other party except liability regarding the Reserve Fund as arising under Article 13.4, it being the intention that in such event amounts remaining in the Reserve Fund shall be returned to Seller with accrued interest thereon, and that any amounts claimed by Purchaser in accordance with Article 13.4 and prior to termination hereunder shall be retained by Purchaser.

ARTICLE 10

CONSTRUCTION, OPERATION AND MAINTENANCE

10.1 Progress Reports. Commencing fifteen (15) days after the end of the first full calendar month after the Effective Date and each quarter thereafter, Seller shall provide Purchaser with quarterly progress reports, which reports shall detail Seller's

efforts toward meeting the milestones specified in Article 13 hereof and shall also provide Purchaser with such other information as Purchaser may reasonably require.

10.2 Seller's Property. Seller shall provide for the design, construction, installation, and maintenance of all equipment (other than Purchaser's meters and monitoring equipment specified in this Agreement) required to generate and deliver Net Plant Output which shall be located on Seller's side of the Point of Delivery.

10.3 Plans and Specifications. Seller agrees to comply with the interconnection, protection, and safety requirements and standards for customer-owned generating facilities set forth in Exhibits "C" and "F". The respective equipment and facilities owned by the parties shall be designed, installed and maintained in accordance with the applicable portions of the National Electric Safety Code, the National Electric Code, and in the condition required by any governmental authorities having jurisdiction.

Seller shall submit to Purchaser the preliminary design and all specifications for the electrical system of the Facility for review of the safety of the interconnection. Purchaser shall notify Seller in writing of the outcome of Purchaser's review within thirty (30) calendar days of receipt of the design and specifications or earlier, if practicable. Purchaser's review and acceptance of Seller's specifications and drawings relating to the safety of the interconnection shall constitute authorization for Seller to commence construction and installation but shall not be interpreted as an endorsement or confirmation of any aspect of the design nor as any warranty whatsoever of the reliability, safety, or applicability of Seller's Facility. Purchaser's review shall not relieve Seller of its responsibilities or liabilities for its design and specifications. Purchaser's review, or failure to review, shall not subject Purchaser to responsibility for any design or operational defects or unsuitability of Seller's Facility including, but not limited to, strength, capacity, design, details, performance or adequacy of any aspects of Seller's Facility. Any review by Purchaser of the design, construction, operation, or maintenance

of Seller's Facility is solely for ascertaining and assuring the safety of the interconnection. By making such review, Purchaser makes no representation as to the economic and technical feasibility, operational capability, and/or reliability of Seller's Facility. Seller shall in no way represent to any third party that any such review by Purchaser of Seller's Facility, including but not limited to any review of the design, construction, operation, or maintenance of Seller's Facility by Purchaser, is a representation by Purchaser, as to the economic and technical feasibility, operational capability, and/or reliability of said Facility.

10.4 Operating Standards. Seller shall not operate the Facility in parallel with Purchaser until the conditions set forth in Article 4 have been met. Seller shall operate and maintain the electrical generation and transmission equipment at the Facility in conformance with Prudent Electrical Practices. Specifically, Seller shall operate in accordance with the standards for interconnection and metering set forth in Exhibits C and F to this Agreement, the National Electrical Safety Code as modified from time to time, and any other applicable local, state or federal codes, rules, regulations, statutes, or ordinances. Purchaser may issue operating instructions to Seller in order to coordinate the safe and reliable operation of the Interconnection Facilities which shall be followed by Seller so long as such instructions would not damage Seller's Facility or personnel.

Seller shall provide suitable equipment and operating practices to insure that the Facility is properly synchronized and voltages are maintained prior to closing of the main breaker so as to minimize to an acceptable level the effect on Purchaser's system and service to its other customers. Seller shall provide suitable equipment to prevent generator circuit breaker closing when Purchaser's system is de-energized. Seller shall provide for the installation and maintenance of adequate protective equipment, in order to prevent damage or injury to the Facility and Interconnection Facilities, as well as the facilities and personnel of Purchaser, Purchaser's other customers, and Purchaser's other

suppliers of electricity. Seller shall use whatever means necessary to minimize voltage swings and to maintain voltage levels in accordance with Prudent Electrical Practices.

Seller shall report to Purchaser's System Control Center at the time of occurrence, or as soon thereafter as practicable, the opening and closing times of its generator circuit breaker(s). Seller's closing of its generator circuit breaker without the prior permission of Purchaser's System Control Center shall be deemed a violation of Prudent Electrical Practices. Purchaser and Seller shall maintain appropriate operating communications and data channels through Purchaser's System Control Center at Seller's expense. Meter readings may be requested at any time by Purchaser's System Control Center. Except in an emergency, Seller shall give prior notice of not less than eight (8) hours for any anticipated outage other than Scheduled Maintenance. Seller agrees to attempt to give notice to Purchaser as soon as practical in the event of emergencies or other unanticipated outages.

Seller shall maintain a power factor at the Point of Delivery consistent with the requirements set forth in Exhibit C.

10.5 Scheduled Maintenance. Seller may shut down the Facility or portions thereof for Scheduled Maintenance for a total period not to exceed fifty-six (56) days during each Contract Year. This allowance may be used in increments of an hour or longer on a consecutive or non-consecutive basis. Seller may accumulate unused maintenance hours from one twelve-month period to another up to a maximum of one thousand three hundred forty-four (1344) hours (56 days) which shall then be added to the 56-day maintenance period allowed for that annual period. This accrued time must be used consecutively and only for scheduled major overhauls (i.e., planned scheduled outages of one (1) week or more). Seller shall provide Purchaser with the following advance notices: twenty-four (24) hours for scheduled outages of less than one day, one week for a scheduled outage of one day or more (except for scheduled major overhauls), and six months

for a scheduled major overhaul. Seller shall not schedule maintenance from June 15 to September 15, or such other period designated by the Purchaser in accordance with the then current PJM requirements, during any year of this Agreement unless agreed to in advance by Purchaser in writing which agreement shall not be unreasonably withheld. Purchaser will review the effect of the proposed schedule on the overall maintenance schedules of PJM and Purchaser and advise Seller of problems that may be created by Seller's scheduled outage within thirty (30) working days of receipt of Seller's notice for scheduled major overhauls and suggest reasonable alternative schedules for such maintenance. No payment except for capacity shall be made to Seller during any such outages. Charges by Purchaser to Seller (if any) shall continue to be assessed as provided for in this Agreement.

10.6 Operating Statistics. Seller shall maintain and classify (in a timely manner) outage statistics in accordance with the then current PJM Interconnection outage classification procedures (which Purchaser shall provide to Seller in a timely manner) and shall supply such statistics to Purchaser as requested. Seller and Purchaser shall keep or cause to be kept such records as required by the PJM Interconnection. Upon notice in writing from Purchaser to Seller, Seller will keep or cause to be kept such other records (such as operating statistics) as the BPU or FERC or other regulatory body having jurisdiction over this Agreement, or any of the parties, may from time to time require Seller specifically, or cogenerators generally to keep.

10.7 Changes in Operating Voltage. Subject to Article 9.12 herein, Purchaser may, upon three (3) years' notice to Seller, change its nominal operating voltage level by more than plus or minus ten percent (10%) at the Point of Delivery, in which case Seller, at its own expense, shall modify its equipment as necessary to accommodate the modified nominal operating voltage level. Purchaser represents that as of the date of this Agreement it has no present plans for changing its operating voltage at the Point of Delivery.

ARTICLE 11

ACCESS TO FACILITIES

11.1 Access During Construction. Upon reasonable notice, Seller shall permit employees and inspectors of Purchaser to walk through the Facility during construction to ascertain the status of construction. Purchaser shall comply with applicable construction site rules and limitations. Purchaser's rights hereunder shall also include the right to observe acceptance testing of major equipment for the Facility conducted at the equipment manufacturer's plant or other place of testing.

11.2 Inspections and Tests. Upon reasonable notice, Seller shall permit employees and inspectors of Purchaser, when properly identified, to enter Seller's premises during normal business hours (except during emergencies) in order to read meters and instruments, perform maintenance on Purchaser's equipment and make equipment repairs, to conduct such operating tests as are necessary to ascertain that protective devices function properly, to examine and test Purchaser's meters and monitoring equipment, and to examine all other services and equipment related thereto provided that Purchaser's employees and inspectors shall not interfere with Seller's normal operation and shall comply with Seller's safety and related standards and conditions. Purchaser shall have the further right to request Seller to load the Facility for its own use or for tests; provided, however, that such operation shall be carried out in accordance with Prudent Electrical Practices, under the direct supervision of Seller and Purchaser shall pay the full purchase price under Article 5 for all electrical output. In addition to summer capacity testing pursuant to Article 3.3A hereof, Seller shall perform winter capacity tests in accordance with Exhibit H and the net winter capacity will be based on the Facility's performance or test results corrected to standard conditions (as defined in PJM guidelines) in the months of December, January and February.

11.3 Easements. Seller shall grant in favor of Purchaser such easements or rights-of-way with respect to the property on which Seller's Facility is located that are necessary to construct, operate, maintain, replace and remove all or any portion of the Purchaser's Interconnection Facilities. In the event that easements or right-of-way are required on property other than that of Seller (which necessity shall be mutually determined by the parties), Seller shall provide such easements or rights-of-way. If Seller is unable to provide such easements or rights-of-way, all obligations of Purchaser pursuant to this Agreement shall be suspended until and unless such easements or rights-of-way are provided; provided, however, that Purchaser will use reasonable efforts to assist Seller in acquiring such easements at Seller's sole cost and expense, including exercise of Purchaser's powers of eminent domain if so requested by Seller. All costs of easements or rights-of-way, including the acquisition and maintenance costs thereof, shall be borne by Seller and all such easements or rights-of-way are subject to the prior review and acceptance of Purchaser.

ARTICLE 12

LIABILITY AND INDEMNIFICATION

12.1 Limitation of Liability. Neither the Purchaser nor the Seller, nor their respective officers, directors, partners, agents, employees or affiliates, shall be liable to the other party or its affiliates, officers, directors, partners, agents or employees for claims for incidental, special, indirect or consequential damages of any nature connected with or resulting from performance or non-performance of this Agreement, including, without limitation, claims in the nature of lost revenues, income or profits or losses, damages or liabilities under any financing, lending or construction contracts, agreements or arrangements to which the Seller or Purchaser may be party irrespective of whether such claims are based upon warranty, negligence, strict liability, contract, operation of

law or otherwise. Nothing in this Article 12.1 shall limit either party's rights or remedies to recover, in an appropriate action, direct damages for a breach of this Agreement as provided in Article 13.2. Nothing in this Agreement shall be construed to create any duty to, standard of care with respect to, or any liability to any person or entity not a party to this Agreement.

12.2 Indemnification. The Seller hereby agrees to indemnify, defend and hold harmless the Purchaser, its officers, directors, agents, partners, employees and affiliates against all loss, damage, expense, and liability to third persons for injury to or death of persons or for injury to property, caused by the gross negligence or wilful misconduct of Seller, its employees, contractors or agents with respect to the construction, ownership, operation, or maintenance of Seller's Facility. The Purchaser hereby agrees to indemnify, defend and hold harmless the Seller, its officers, directors, agents, partners, employees and affiliates against all loss, damage, expense and liability to third persons for injury to or death of persons or for injury to property, caused by the gross negligence or wilful misconduct of Purchaser, its employees, contractors or agents with respect to the construction, ownership, operation or maintenance of Purchaser's Interconnection Facilities or Purchaser's system.

Each party hereto shall promptly furnish the other party with written notification (but in no event later than ten (10) days prior to the time any response is required by law) after such party becomes aware of any event or circumstance which might give rise to such indemnification. At the indemnified party's request, the indemnifying party shall defend any suit asserting a claim covered by this indemnity and shall pay all costs and expenses (including reasonable attorney's fees and expenses) that may be incurred in enforcing this indemnity. The indemnified party may, at its own expense, retain separate counsel and participate in the defense of any such suit or action. The indemnifying party shall not compromise or settle a claim hereunder without the prior written consent of the

indemnified party; provided, however, that in the event such consent shall be withheld, then the liability of the indemnifying party shall be limited to the aggregate of the amount of the proposed compromise or settlement, the amount of counsel fees and expenses outstanding at the time such consent shall have been withheld, and the amount of any outstanding claim against which indemnification applies and which is not covered by the proposed compromise or settlement (together with all costs and expenses associated with such outstanding claim). Thereafter, the party withholding such consent shall hold harmless and reimburse the indemnifying party, upon demand, for the amount of any additional liability, counsel fees and expenses incurred by the indemnifying party over and above the amounts described above after the time such consent shall have been withheld.

ARTICLE 13

BREACH, TERMINATION, AND REMEDIES

13.1 Definition of Breach. A breach of this Agreement shall be deemed to exist if:

- A. Either party fails to make payment of any amounts due the other party under this Agreement, which failure continues for a period of thirty (30) days after notice of such non-payment.
- B. Either party fails to substantially comply with any other material provision of this Agreement, which failure continues for a period of thirty (30) days after notice of such non-performance, unless the non-performing party has commenced to cure such non-performance within the thirty (30) day notice period and is thereafter diligently pursuing such efforts. With respect to the Facility's failure to achieve at least 95% of Net Deliverable Capacity under Article 3.3, Seller shall not be in breach under this paragraph if Seller makes

deficiency payments described therein to the extent applicable under Article 3.3A(iii).

- C. Seller fails to deliver any Net Plant Output for more than one hundred twenty (120) consecutive days, or more than one hundred eighty (180) days in any three hundred sixty-five (365) day period, subsequent to the Date of Commercial Operation, not including any days attributable to any Forced Outage, any Scheduled Maintenance or Purchaser's actions under Article 3.4.
- D. Seller sells any Net Deliverable Capacity agreed to be sold under this Agreement to any party other than Purchaser and its permitted successors and assigns, unless otherwise permitted by Purchaser.
- E. The Date of Commercial Operation does not occur on or before January 1, 1995.
- F. By order of a court of competent jurisdiction, a receiver or liquidator or trustee of either party or of a substantial part of the assets of either party shall be appointed, and such receiver or liquidator or trustee shall not have been discharged within a period of one hundred twenty (120) days; or if by decree of such a court, a party shall be adjudicated bankrupt or insolvent or a substantial part of the assets of such party shall have been sequestered, and such decree shall have continued undischarged and unstayed for a period of one hundred twenty (120) days after the entry thereof; or if a petition to declare bankruptcy or to reorganize a party pursuant to any of the provisions of the Federal Bankruptcy Act, as it now exists or as it may hereafter be amended, or pursuant to any other similar state statute applicable to such party, as now or hereafter in effect, shall be filed against

such party and shall not be dismissed or stayed within one hundred twenty (120) days after such filing; or

- G. If either party shall file a voluntary petition in bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; or, without limitation of the generality of the foregoing, if a party shall file a petition or answer or consent seeking relief or assisting in seeking relief in a proceeding under any of the provisions of the Federal Bankruptcy Act, as it now exists or as it may hereafter be amended, or pursuant to any other similar state statute applicable to such party, as now or hereafter in effect, or an answer admitting the material allegations of a petition filed against it in such a proceeding; or if a party shall make an assignment of a substantial part of its assets for the benefit of its creditors, or if a party shall become unable to pay its debts generally as they become due; or if a party shall consent to the appointment of a receiver or receivers, or trustees, or liquidator or liquidators of it or of all or a substantial part of its assets.

13.2

Remedies for Breach.

- A. If either party claims that the other party has breached this Agreement, as defined in Article 13.1, the non-breaching party may terminate this Agreement by giving written notice of such breach and intention to terminate to the other party, which termination shall be effective no earlier than the thirtieth (30th) day following the date of said notice whereupon the terminating party shall be excused and relieved of all obligations and liabilities under this Agreement, except those liabilities incurred before the effective of termination. The

non-breaching party may thereafter exercise its rights and remedies available at law to recover, in an appropriate action, direct damages against the breaching party.

B. Both parties shall have the obligation and shall use best efforts to mitigate any such damages.

13.3 Purchaser's Right to Operate Facility. In addition to all of Purchaser's rights under this Article 13 but subject to Article 18.9 hereof, in the event of termination due to a breach by Seller as specified in this Article 13 and if operation of the Facility is not assumed by any Lender or assignee of the Seller, Purchaser shall have the right but under no circumstances the obligation to assume operational responsibility for the Facility in the place and stead of Seller in order to complete construction, continue operation or complete any necessary repairs so as to assure uninterrupted availability of electric power. In no event shall Purchaser's election to operate the Facility be deemed to be a transfer of title or a transfer of Seller's obligations as owner thereof. During any period in which Purchaser operates the Facility, Purchaser shall pay all fuel, maintenance, repairs, insurance and other operating costs thereof only to the extent that such costs to Purchaser may be offset by deducting the costs thereof from payments which would normally be due to Seller under this Agreement, and shall continue to pay the capacity charge set forth in Article 5.1B hereof. During any period in which Purchaser operates the Facility, Purchaser shall exercise its reasonable best efforts to produce and deliver electrical energy subject to the Facility being operable at the time of Purchaser's take-over, or later being made operable by repairs or otherwise.

13.4 Purchaser's Right to Retain Reserve Fund as Liquidated Damages. Seller acknowledges and understands that Purchaser has entered into this Agreement in reliance on and in consideration of Seller's representation that Seller's Facility will be in operation and be rated capacity for purposes of the PJM no later than the scheduled Date of

Commercial Operation and, in addition, that Purchaser will include Seller's Facility in its various capacity forecasts for the PJM and otherwise effective June 1, 1988. Seller further acknowledges and understands that in order to meet its obligations to its retail and wholesale customers as a public utility, Purchaser must have adequate assurance that construction of Seller's Facility is proceeding in a timely fashion in order to adequately forecast and meet its system's capacity needs as well as to avoid incurring short-term energy costs or capacity deficiency payments from the PJM. In accordance with the Standard Offer, Seller has previously deposited with Purchaser on October 13, 1987 the sum of Two Million Dollars (\$2,000,000.00) (the "Reserve Fund"), to secure Seller's timely construction and operation of Seller's Facility. The Reserve Fund has been deposited in Purchaser's general corporate account and is accruing interest at Purchaser's short-term commercial rates.

Based on the foregoing, and in addition to all of Purchaser's rights and remedies as set forth in Articles 13.1, 13.2 and 13.3, Seller agrees that Purchaser shall have the right in each instance described in this Article 13.4 to retain so much of the Reserve Fund as is set forth below, plus accrued interest thereon, as liquidated damages if any one or more of the following milestone dates have not been satisfied within the time periods herein established subject to extension only in the case of an event of force majeure:

- (i) Five percent (5%) in the event Seller shall have failed to obtain and deliver to Purchaser evidence of the existence of an adequate fuel supply and delivery contract reasonably satisfactory to Purchaser within 24 months of the BPU order referred to in Article 2 hereof. The evidence required shall be deemed to be written verification with the fuel supplier.

(ii) Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser all required environmental permits (local, state and federal) within 36 months of the BPU order referred to in Article 2 hereof.

(iii) Five percent (5%) in the event Seller shall have failed to obtain and deliver to Purchaser within 12 months of the BPU order referred to in Article 2 hereof, either (a) a certified copy of the executed "turn-key" construction contract for the Facility, which construction contract shall be with a reputable construction company or other entity with an established record and capability of completing the Facility, or (b) firm supply and price commitments from reputable manufacturers of major equipment required for the Facility. Major equipment shall be deemed to include: boilers, turbine, and steam condensers.

(iv) Five percent (5%) in the event Seller shall have failed to prepare and deliver to Purchaser all necessary detailed engineering drawings within 12 months of the BPU order referred to in Article 2 hereof. Detailed engineering drawings shall be deemed to consist of one-line and three-line electrical drawings, site plan, heat and mass-flow diagrams, general arrangement drawings for major equipment and drawing schedule.

(v) Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser evidence of financial commitments for construction and permanent financing, subject only to such conditions as are reasonably satisfactory to Purchaser and sufficient to complete Seller's Facility, within 24 months of the BPU order re-

ferred to in Article 2 hereof. For purposes of this Article, satisfactory evidence of financial commitments shall mean firm commitments for construction and permanent project financing from a reputable lending or banking institution. Seller and Purchaser agree that Seller's obligation to proceed under this Agreement is contingent upon its obtaining permanent, non-recourse project financing, from a reputable lending or banking institution or institutions, with a maximum debt to equity ratio of 90 percent debt to 10 percent equity, and a minimum straight-line amortization period for the debt of 15 years, such that, regardless of the actual capitalized construction costs for the project and actual rate of interest on the permanent project debt financing, total annual payments required to be made by Seller for principal amortization and interest charges on the permanent project debt financing do not exceed \$42 million per year. If at any time within nine (9) months of the BPU order referred to in Article 2 hereof, Seller determines that obtaining permanent project financing on the foregoing terms and conditions cannot be obtained and establishes failure to obtain such financing to Purchaser's reasonable satisfaction, then Seller may terminate this Agreement upon thirty (30) days written notice to Buyer. Any other provision to this Agreement notwithstanding, termination pursuant to this Article 13.4(v) shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination, and the parties shall be mutually released without liability to the other party, except liability regarding the Reserve Fund as arising under this Article 13.4, it being the intention that in such event the amounts remaining in the Reserve

Fund shall be returned to Seller with accrued interest thereon, and that any amounts claimed by Purchaser in accordance with this Article 13.4 and prior to termination hereunder (including the \$200,000 arising from Seller's failure to meet the milestone described in this Article 13.4(v)), shall be retained by Purchaser.

(vi) Fifteen percent (15%) in the event Seller shall have failed to commence construction (as evidenced by active foundation construction) of Seller's Facility within 36 months of the Effective Date.

Purchaser shall deliver written notice to Seller (by registered or certified mail) of Purchaser's election to retain the Reserve Fund (or applicable portion thereof), whereupon receipt of such notice Seller shall have an additional thirty (30) days to comply with the requirements hereof. If Seller shall have failed to meet the applicable milestone within the additional thirty (30) day cure period, except in the event of force majeure as defined in Article 15, then Purchaser shall be entitled to retain the Reserve Fund (or applicable portion thereof) without further notice to Seller; provided, however, that Purchaser's retention of the Reserve Fund shall act to prohibit Purchaser from exercising any other rights hereunder to terminate this Agreement based on Seller's failure to meet their applicable milestone.

Purchaser shall return fifty percent (50%) of the Reserve Fund (or applicable portion thereof), together with accrued interest thereon, to Seller within thirty (30) days of Seller's notice to Purchaser that all or certain of the milestone dates established herein have been complied with and that Seller is entitled to the return of the Reserve Fund (or applicable portion thereof), provided that Purchaser shall not have objected in writing to said return based on Purchaser's good faith claim that Seller has not so complied, in which case Purchaser shall retain only so much of the Reserve Fund as may relate to the matter in dispute.

Subject to the force majeure provisions of Article 15, the remaining fifty percent (50%) of the Reserve Fund shall continue to be held by Purchaser as security for Seller's timely operation of Seller's Facility and shall be either returned to Seller or retained by Purchaser as follows:

- (i) In the event Seller's Facility is operational within the meaning of this Agreement on or before the scheduled Date of Commercial Operation, Purchaser shall return the balance of the Reserve Fund within thirty (30) days of said date;
- (ii) In the event Seller's Facility is operational within twelve (12) months after the scheduled Date of Commercial Operation, Purchaser shall be entitled to retain an amount equal to Net Deliverable Capacity multiplied by the PJM Capacity Deficiency Charge for each day after the scheduled Date of Commercial Operation, but in no event will the amount retained exceed 50% of the Reserve Fund, plus accrued interest; or
- (iii) In the event Seller's Facility becomes operational more than twelve (12) months but less than twenty-four (24) months after the scheduled Date of Commercial Operation, Purchaser shall be entitled to retain an amount equal to Purchaser's cost to obtain Net Deliverable Capacity, but in no event will the amount retained exceed 100% of the Reserve Fund. This provision shall take effect only if Seller deposits the additional sum of \$2,000,000.00 into the Reserve Fund on or before the 365th day after the scheduled Date of Commercial Operation.

ARTICLE 14

INSURANCE

14.1 Prior to the Interconnection of the Facility with Purchaser's system, which shall be deemed to include any period during which Seller's Facility is in transit, and until termination of the Agreement, Seller shall obtain and maintain in force, as hereinafter provided, property insurance for the full replacement value of Seller's Facility, blanket comprehensive general liability insurance including all risk endorsements, including contractual liability coverage with a combined single limit of not less than ten million dollars (\$10,000,000.00) each occurrence, and worker's compensation coverage. The insurance carrier or carriers and form of policy to be used by Seller shall be subject to prior submission to, and approval by, Purchaser to assure compliance with provisions of this Article 14. Seller shall provide to Purchaser fifteen (15) days prior to the commencement of construction evidence of satisfactory insurance coverage. Prior to the date Seller's Facility is first operated in parallel with Purchaser's system, Seller shall (i) furnish certificate(s) of insurance to Purchaser which certificate(s) shall provide that such insurance shall not be terminated nor expire except upon thirty (30) days prior written notice to Purchaser, and (ii) maintain such insurance in effect for so long as Seller's Facility is operated in parallel with Purchaser's system, and shall bear in substance the following clauses:

- A. In consideration of the premium charged, Purchaser, its directors, officers and employees are named as additional insureds on Seller's insurance with respect to all covered liabilities arising out of Seller's use and ownership of Seller's Facility.
- B. The inclusion of more than one insured under this policy shall not operate to impair the rights of one insured against another insured;

and the coverages afforded by this policy will apply as though separate policies had been issued to each insured. The inclusion of more than one insured will not, however, operate to increase the limit of the carriers' liability. Purchaser will not, by reason of its inclusion under this policy, incur liability to the insurance carrier for payment of premium for this policy.

- C. Any other insurance carried by Purchaser which may be applicable, shall be deemed excess insurance and Seller's insurance primary for all purposes despite any conflicting provision in Seller's policy to the contrary.
- D. It is expressly agreed and understood that the insurer(s) of Seller's Facility, naming Purchaser as an additional insured, shall waive any right it has to subrogation with respect to Purchaser.

14.2 Seller shall comply with reasonable loss control recommendations made by Purchaser's insurance carriers as a condition of issuance, continuation or renewal of Purchaser's policies of insurance at Seller's sole cost and expense. Disputes as to Seller's obligations to comply with such recommendations shall be referred to arbitration pursuant to Article 17 hereof. If Seller fails to comply with any provision of this Article, Seller shall, at its own cost, defend, indemnify, and hold harmless Purchaser, its directors, officers, employees, agents, assigns, and successors in interest from and against any and all loss, damage, claim, cost, charge, or expense of any kind or nature (including direct, indirect, or consequential loss, damage, claim, cost, charge, or expense, including attorney's fees and other costs of litigation) resulting from the death or injury to any person or damage to any property, including the personnel and property of Purchaser, to the extent that Purchaser would have been protected had Seller complied with all of the provisions of this Article.

14.3 In addition to and not by way of limitation of any of Purchaser's other rights and/or remedies under this Agreement, if Seller fails to continuously comply with the requirements of this Article 14, Purchaser shall have the right immediately to remove the Seller from interconnection with Purchaser's system and shall not permit reconnection until such time as the requirements of this Article have been met. If Seller fails to comply with the requirements of this Article and has not to Purchaser's reasonable satisfaction demonstrated its efforts to cure within a forty-five (45) day time period after written notice to Seller, Purchaser may terminate this Agreement and Seller shall satisfy all obligations due Purchaser that are outstanding. The provisions of this Article shall survive the term of this Agreement.

ARTICLE 15

FORCE MAJEURE

15.1 Either party shall be excused from performance and shall not be considered to be in default in respect to any obligation or condition hereunder, if failure of performance shall be due to an event of force majeure. The term "force majeure" shall mean any cause beyond the control of the party affected, including, but not limited to, failure of facilities due to drought, flood, perils of the sea, earthquake, storm, fire, lightning, epidemic, other acts of God, war, riot, civil disturbance, sabotage, strike or labor difficulty, accident or curtailment of supply, unavailability of construction materials or replacement equipment beyond the affected party's control, Forced Outage, inability to finance the Facility at then available commercial rates, impossibility to obtain insurance or only to obtain at a cost that is unreasonably high in relation to the risk insured against, inability to obtain and maintain easements, rights-of-way, permits, licenses, and other required authorizations from any local, state, or federal agency or person for any of the facilities or equipment necessary to provide service hereunder, and restraint by court or

other public authority having jurisdiction over the matter. Neither party shall be required to prevent or settle a strike against its will. However, in the event of a strike affecting Purchaser's system or Seller's Facility, Seller and Purchaser shall use reasonable best efforts to operate their respective facilities with management personnel.

15.2 If either party's ability to perform its obligations under this Agreement, is affected by an event of force majeure described above, such party shall promptly, upon learning of such event and ascertaining that it will affect its performance hereunder, give notice to the other party stating the nature of the event, its anticipated duration, and any action being taken to avoid or minimize its effect. The burden of proof shall be on the party claiming force majeure pursuant to this Article 15.

15.3 The suspension of performance shall be of no greater scope and no longer duration than is required. The excused party shall use its reasonable best efforts to remedy its inability to perform.

15.4 No obligations of either party which arose before the occurrence of an event of force majeure causing the suspension of performance shall be excused as a result of such occurrence. The obligation to pay money in a timely manner for obligations and liabilities which matured prior to the occurrence of an event of force majeure is absolute and shall not be subject to the force majeure provisions.

ARTICLE 16

GOVERNMENTAL AUTHORITY

In addition to the rights of the parties hereunder, including but not limited to Article 15 hereof, in the event any of the terms and conditions hereof shall without fault of either party be or become impossible of performance on account of any law, statute, ordinance, order or regulation passed, adopted or promulgated by any governmental authority, the parties hereto shall be excused for any failure of performance caused by

such impossibility of performance and either party shall be entitled to terminate this Agreement upon thirty (30) days written notice; provided, however, that this Article 16 shall not be invoked by either party if (i) the validity, scope or application of any such law, statute, ordinance, order or regulation is diligently and in good faith being challenged or under appeal by the other party; and (ii) the party challenging same agrees to reimburse the non-challenging party for all costs of litigation, including reasonable attorneys' fees, in the event such challenge is unsuccessful. Termination pursuant to this Article 16 shall operate to terminate all obligations and liabilities of either party under this Agreement, except those liabilities incurred before the effective date of termination and the parties shall be mutually released without liability to the other party except liability regarding the Reserve Fund as arising under Article 13.4, in which event the Reserve Fund shall be returned to Seller or retained by Purchaser as provided in Article 13.4.

ARTICLE 17

ARBITRATION OF DISPUTES

17.1 In any matter where the BPU does not have jurisdiction, any controversy or dispute arising out of or relating to this Agreement or the breach thereof shall be settled by arbitration except as limited by Article 17.2 hereof. Such arbitration shall be effected by arbitrators selected as hereinafter provided and shall be conducted in accordance with the rules, existing at the date thereof, of the American Arbitration Association. The dispute shall be submitted to three arbitrators, one arbitrator being selected by Seller, one arbitrator being selected by Purchaser, and the third being selected by the two so selected, or if they cannot agree on a third, by the American Arbitration Association. In the event that either Seller or Purchaser, within fifteen (15) days after any notification of any demand for arbitration hereunder, shall not have selected its arbitrator and given notice thereof by registered or certified mail to the other, such arbitrator shall

be selected by the American Arbitration Association. The meetings of the arbitrators shall be held at such place or places in southern New Jersey or elsewhere, as agreed upon by the arbitrators. Judgment may be entered on any award rendered by the arbitrators in any court having jurisdiction. During the pendency of any arbitration proceeding, the parties shall continue making timely payments due under the terms of this Agreement and the failure to do so shall constitute a breach of this Agreement. There shall be added to any monetary award for sums found to have been due under this Agreement an interest charge calculated in the same manner as for late payments under Article 6.1 hereof. The cost of arbitration shall be borne in full by the losing party.

17.2 In the case of any dispute or controversy between Purchaser and Seller with respect to the amount of any payment made or to be made by either party to the other pursuant to this Agreement, the party aggrieved shall notify the other party in writing of any such dispute or controversy. Such notice must be made within sixty (60) days after the discovery of facts underlying the dispute or controversy. The notice shall set forth in reasonable detail the reasons for the dispute or controversy. Both parties agree not to make any demand for arbitration pursuant to Article 17.1 above, or to take any other action for a period of sixty (60) days following said notice in order to provide the party receiving same with the opportunity to respond, during which sixty (60) day period the parties shall continue to perform pursuant to the terms of this Agreement and the failure to do so shall constitute a breach of this Agreement.

ARTICLE 18

MISCELLANEOUS

18.1 Effect of Agreement. No undertaking by one party to the other under any provision of this Agreement shall constitute the dedication of that party's system or any portion thereof to the other party, or to the public or affect the status of Purchaser as an independent public utility corporation or Seller as an independent entity and not a

public utility. Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a party to it.

18.2 Law Governing. This Agreement shall be governed by and construed in accordance with the laws of the State of New Jersey.

18.3 Non-Discrimination Provision. The parties mutually agree and covenant that in the performance of this Agreement, they shall not discriminate against any person or groups of persons on the grounds of race, creed, color, national origin, ancestry, age, sex or marital status, in any manner prohibited by the laws of the United States or of the State of New Jersey, as applicable to the parties.

18.4 Notices. Except as may be otherwise provided herein, all notices hereunder shall be sent by immediate telex or telecopy and confirmed in writing by registered or certified mail, postage prepaid. If to Seller, the following address shall be used:

Keystone Cogeneration Systems, Inc.
313 Chestnut Street
Philadelphia, Pennsylvania 19106

Attention: Comptroller

If to Purchaser, the following address shall be used:

Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, New Jersey 08232

Attention: Manager, Contract Capacity

Seller and Purchaser, by like notice, may designate any further or different addresses to which notice shall be sent.

18.5 Severability. If any clause, provision, or section of this Agreement be ruled invalid by any court of competent jurisdiction, the invalidity of such clause, provision, or section shall not affect any of the remaining provisions hereof.

18.6 Entire Agreement. This Agreement and all Exhibits attached hereto (A through K inclusive) and made a part hereof constitute the entire agreement between the

parties with respect to the matters contained herein and all prior agreements with respect thereto are superseded hereby. Each party confirms that it is not relying on any oral representations or warranties of the other party except as specifically set forth herein.

18.7 Amendment and Waiver. This Agreement may be amended, modified, superseded, or cancelled, and any of the terms hereof may be waived, only by a written instrument executed by both parties' duly authorized representatives hereto or, in the case of a waiver, by the party waiving compliance. The failure of either party to require performance of any provision hereof shall in no manner affect the right at a later time to enforce the same. No waiver by either party of any condition or of any breach of any term of the Agreement shall be construed as a further or continuing waiver of any such condition or breach or as a waiver of any other condition or of any breach of any other term.

18.8 Several Obligations. Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the parties are intended to be several and not joint or collective. Each party shall be individually and severally liable for its own obligations under this Agreement.

18.9 Project Financing. The parties acknowledge that the construction of the Facility will require financing by the Lender and that Lender will require the financing to be secured by a first lien upon the Facility and other assets of the Seller including a collateral assignment of related agreements and particularly this Agreement and all rights and obligations of the Seller hereunder. In order to facilitate the obtaining of such financing, and notwithstanding any provision hereof expressly or impliedly to the contrary, Purchaser agrees to negotiate with Lender regarding such changes to this Agreement as may reasonably be required by Lender to cure any defaults by Seller hereunder and to otherwise exercise its rights and remedies under its loan documents with Seller.

Purchaser shall execute such consents, agreements or similar documents with respect to a collateral assignment hereof to Lender, as Lender any reasonably request in connection with the documentation of the project financing; provided, however, that Seller shall reimburse Purchaser for reasonable costs incurred in connection therewith, including reasonable attorneys' fees.

18.10 Assignment. Except with respect to an assignment made in connection with project financing or to an affiliate or a wholly owned subsidiary of either party, neither party shall (by operation of law or otherwise) assign its rights or delegate its performance under this Agreement without the prior written consent of the other, and any attempted assignment or delegation without such consent shall be void. Subject to the preceding sentence, this Agreement and all of its covenants, terms and provisions shall be binding upon and inure to the benefit of and be enforceable by the parties and their respective successors and assigns.

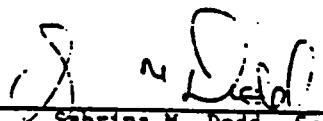
18.11 Captions. All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to be inclusive, definitive, or to affect the meaning of the contents or scope of this Agreement.

18.12 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

18.13 Confidentiality. Neither party hereto shall disclose or otherwise make available to any other person or entity the contents of this Agreement or any other documents, data or information previously delivered or to be delivered to the other party in connection herewith, except as such disclosure may be required by governmental or regulatory authorities. In the event disclosure is required, the parties agree to use reasonable efforts to obtain protective orders or other similar restraints as conditions to disclosure.

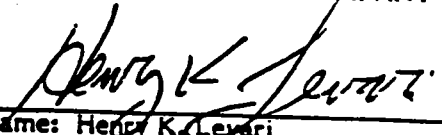
IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed in their corporate names by their duly authorized officers, and their corporate seals to be hereunto affixed and duly attested as of the day and year indicated on the face of this Agreement.

ATTEST:



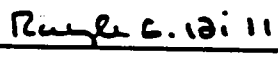
X Sabrina M. Dodd, Secretary

ATLANTIC CITY ELECTRIC COMPANY

BY: 

Name: Henry K. Levart
Title: Vice President

ATTEST:



SECRETARY

KEYSTONE COGENERATION SYSTEMS, INC.

BY: 

Name: Dan R. [unclear]
Title: President

TABLE OF EXHIBITS

- Exhibit A - Description of Seller's Facility.
- Exhibit B - PJM Minimum Generation Obligations and Procedures.
- Exhibit C - Technical Guidelines For Cogenerators and Small Power Producers (Dated October, 1985; Revised January, 1988).
- Exhibit D - Drawing Showing Interconnection and Point of Delivery.
- Exhibit E - Stipulation between Purchaser and the BPU Staff, and BPU Order dated August 28, 1987 approving the Stipulation.
- Exhibit F - Technical Guidelines for Customer Service at Sub-Transmission and Transmission Voltages (Dated May, 1985).
- Exhibit G - Purchaser's Rules and Procedures for Determination of Generating Capability to Meet the Requirements of the PJM Interconnection, dated August, 1984.
- Exhibit H - Purchaser's Interconnection Study for Seller's Facility.
- Exhibit I - Methodology for Calculating Availability Factor.
- Exhibit J - Formulas and Examples for Calculating Credits to and Deductions from Excess Pool.
- Exhibit K - Terms of Intercreditor Agreement

EXHIBIT A

DESCRIPTION OF SELLER'S FACILITIES

DESCRIPTION OF PROJECT

The 200 net MW coal-fired cogeneration facility will be either a floating power plant berthed on the river side of the Monsanto Chemical Company plant in Logan Township, Bridgeport, New Jersey; or, if land based, to the south of Monsanto's plant on adjacent land. The boilers will be circulating fluidized-bed (CFB) types. The facility will provide 250 psig extraction steam and approximately 2 MW of electricity to Monsanto. The majority of electric power will be sold to Atlantic City Electric under a dispatching contract whereby 3500 hours at maximum capacity is guaranteed.

The power plant facility will consist of two independent units, each capable of operating in the range of 50 to 100 MW net. There will be four steam generators, two for each unit supplying steam to two net 100 MW turbines, each with five feed heaters. The steam generators shall be of the balanced draft, fully entrained circulating fluidized bed type, natural circulation, non-reheat design with welded wall construction. Nominal steam generation for each boiler will be 480,000 lb/hr at 1500 psig/1000°F.

Run of mine coal will be used as the summary fuel, injected into the CFB with reactive limestone for the removal of sulfur. Both bottom and fly ash will be removed via barge to a landfill outside the State of New Jersey. The facility is estimated to require an additional 20 MW for the in-plant requirements. It is designed to operate at full or partial load 24 hours per day, seven days per week.

Construction of the cogeneration facility is scheduled to commence in 1989 after permitting has been approved. Startup is scheduled for third quarter 1992 for commercial operation in the first quarter of 1993. Attached as part of this Appendix is a site layout showing the floating concept in relationship to the steam host, Monsanto. (If the project is land based, a new layout will be provided.)

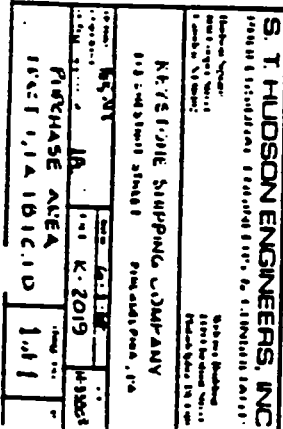


EXHIBIT B

**PJM MINIMUM GENERATION
OBLIGATIONS AND PROCEDURES**

9.00 PJM LIGHT LOAD OBLIGATION AND OPERATING PROCEDURE

9.10 GENERAL STATEMENTS

- 9.11 PJM is a control area in the interconnected systems of the Eastern United States and Canada. Each control area has a commitment to control its generation in a manner so as not to burden the interconnected systems.
- 9.12 For PJM to meet its commitment to the interconnected systems during light load periods, it may be necessary for PJM to deviate appreciably from normal operating procedures.
- 9.13 The following obligation and procedure are applicable to PJM operation during light load periods and to the constrained dispatch of a PJM area for thermal, reactive, or other operating restrictions.

9.20 OBLIGATION

- 9.21 During light load periods, each PJM company shall be able to, and shall, upon request of the Interconnection Office (IO) reduce generation and purchases from systems external to PJM to meet the PJM system load. This action may include, for example, reducing fossil units to emergency minimums, reducing nuclear units below normal operating levels, and shutting down fossil units to meet the PJM system load.

9.30 DAY OR DAYS PRIOR TO LIGHT LOAD PERIOD

- 9.31 IO scheduling personnel are responsible for identifying light load conditions and projecting the extent of operating actions required by light load conditions. Operating actions are projected for PJM areas as well as PJM as a whole.
- 9.32 If the reduction of nuclear units and/or Non-Utility Generators (NUGs) is likely, or the expected generation levels of all units is within 1000 MW of normal minimum energy limits, the Interconnection Dispatcher (ID) will issue a Minimum Generation Alert for a specified light load period.

Company Response:

Upon receipt of a Minimum Generation Alert, system operators will notify appropriate personnel that a Minimum Generation Alert has been issued.

Additional unit maintenance should be scheduled, as appropriate, for the expected light load periods.

PJM-OI

Unit model data in the Unit Commitment Database should be reviewed and updated by scheduling personnel. Particular attention should be given to unit availabilities and energy limits (normal maximum, normal minimum, and emergency minimum).

Note:

Only the Unit Commitment Database contains emergency minimum energy limit information which will be used by the IO for both scheduling and dispatching.

- 9.33 If the extent of projected operating actions is likely to include reduction of nuclear units (including response to economic dispatch signal), IO scheduling personnel will collect the following information from company System Operations Subcommittee (SOS) members.

a. Nuclear unit operating constraints

b. Estimates of NUG energy which can be reduced or disconnected within two hours of a Minimum Generation Emergency declaration.

- 9.34 Based on updated Unit Commitment Database information, NUG reducible energy estimates, and additional nuclear unit operating constraints, IO scheduling personnel will formulate a scheduling strategy for the light load period.

Note:

The scheduling strategy will recognize the reduction of NUGs following the declaration of a Minimum Generation Emergency. IO scheduling personnel will increase forecast PJM loads during the light load period by NUG reducible energy estimates.

Company Response:

Scheduling personnel will update Unit Commitment Database unit availabilities to reflect the scheduling strategy and company must-run generation requirements.

- 9.35 Hydro plants shall be scheduled by IO scheduling personnel to maximize pumping at pumped storage plants and to minimize generation at run-of-river plants during the period(s) covered by a Minimum Generation Alert.
- 9.36 IO scheduling personnel will advise external systems of PJM conditions expected during a light load period. Arrangements will be made with external systems supplying company and PJM energy purchase agreements to minimize such energy deliveries to PJM during light load periods. Such arrangements may necessitate reduced energy deliveries during on-peak periods. Where feasible and economic, energy sales to external systems will be arranged.

9.37 IO scheduling personnel will review the light load scheduling strategy with appropriate SOS members and finalize the scheduling strategy.

9.38 The IO will convey the current scheduling strategy to company scheduling personnel.

Company Response:

Scheduling personnel will update Unit Commitment Database unit availabilities.

Scheduling personnel or system operator supervisors will provide system operators with listing of unit normal maximum and minimum energy limits to be used for updating energy limits available to the PJM Energy Management System (EMS) computer. Also provided will be a listing of emergency minimum energy limits.

9.39 Written documentation of the scheduling strategy for the ID will be prepared by IO scheduling personnel as appropriate.

9.40 FOUR HOURS PRIOR TO LIGHT LOAD PERIOD

9.41 The IO scheduling dispatcher will maintain a current list of unit emergency minimum energy limits, nuclear unit operating constraints, and reducible NUC energy.

Company Response:

System operators will review, with station operating personnel, unit normal maximum and minimum energy limits as well as emergency minimum energy limits provided in 9.38.

System operators will update normal maximum and minimum energy limits available to the PJM EMS computer. Changes in emergency minimum energy limits and nuclear unit operating constraints must be reported to the IO scheduling dispatcher.

Note:

Emergency minimum energy limits are not available to the PJM EMS computer.

9.42 The IO scheduling dispatcher will update the projection of light load conditions and, if required, update the light load scheduling strategy.

Note:

Documentation provided in action 9.39 should be used as a guide in revising the strategy. Significant changes in the operating strategy must be reported to the company system operators via the "all-call".

9.50 LIGHT LOAD PERIOD

9.51 The ID will declare a Minimum Generation Emergency when the following measures will produce energy reductions less than the expected load decrease:

- a. Reduction of all units to normal minimum energy limits.
- b. Energy sales to external systems (not dump power).
- c. Reduction of company and PJM purchases to supplier minimum energy limits.

9.52 The ID will request company system operators to reduce and/or disconnect NUGs. Requests to reduce NUGs will be rotated among the companies.

9.53 As the load decreases, the ID will reduce the PJM and/or area dispatch signal.

Company Response:

Company system operators will assure that fossil and nuclear units follow a decreasing dispatch signal without confirming communication between the ID and the company system operator.

9.54 The ID will reduce company and PJM purchases from external systems to supplier minimum energy limits.

9.55 When the ID can no longer match the decreasing load by reducing the dispatch signal, the ID will request company system operators to remove regulation from all units and reduce all units to normal economic minimum energy limits.

Company Response:

The system operator will update maximum and minimum energy limits available to the PJM EMS computer to reflect the removal of regulation.

The system operator will request station personnel to expedite the reduction of units to normal minimum energy limits. If a unit cannot reduce to normal economic minimum due to a new physical constraint, the system operator will advise the ID and update the normal minimum energy limit available to the PJM EMS computer for that unit.

9.56 The ID will request company system operators to load all pumped hydro units as pumps and reduce run-of-river plant energy, where reservoir elevation and riverflow will allow without spilling water or violating reservoir elevation limits.

9.57 The ID will reduce the PJM dispatch signal to zero and will attempt to sell excess generation to external systems. The excess generation will be quoted at a zero rate.

- 9.58 If further reduction of generation is required, the ID will request company system operators to reduce units (including nuclear units) to emergency minimums as required. Requests to reduce units to emergency minimums will be rotated among the companies with Keystone and Conemaugh considered as GPU units.

Note:

No update of minimum energy limits available to the PJM EMS computer is required. The ID will use the listing of emergency minimum energy limits prepared in 9.39 as a guide to attainable generation reduction. The ID will request company system operators to reduce units to emergency minimums in the order prepared in 9.39. Loading units to normal minimum energy limits will be in the same order.

- 9.59 For a severe light load condition requiring extraordinary actions, the ID will refer to the light load strategy prepared in 9.39 and exercise judgement in deciding which units should be shut down and energy of PJM external purchases cancelled.

Note:

The ID will request the company system operators to shut down specific units not required for area protection during the light load period or a subsequent on-peak period. Unless the ID issues specific start-up instructions, units should be restarted when the Minimum Generation Emergency is cancelled (no request by the ID is required).

9.60

LAST RESORT

- 9.61 As a last resort, the ID, taking into account reliability considerations, will request system operators of over-generating companies to reduce generation to meet the PJM system load (pro-rating the reduction among the over-generating companies in proportion to the amount each company is over-generating). The over-generating company system operators have the prerogative of reducing their generation by any means to achieve the level requested by the ID.

Note:

An over-generating company is a PJM company with current internal energy (including allocation of jointly owned unit energy) in excess of current internal load. Energy associated with a capacity and/or energy sale by one PJM company to another is internal energy of the supplying company. Energy associated with a capacity and/or energy sale by a PJM company to an external system is internal load of the PJM company (an energy purchase is internal energy).

9.70 CANCELLATION

9.71 The above steps will be followed in reverse order as the PJM load beings to exceed the generation. The ID will cancel a Minimum Generation Emergency when all units are requested loaded to normal minimums and regulation restored.

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Last Revised: 5/15/87

SECTION M

GUIDELINES:

I. OBLIGATIONS

During low load periods each PJM system must be able to, and shall upon request by the Interconnection Dispatcher, reduce its system generation to emergency minimums. All PJM systems shall cooperate in attempting to reduce generation to meet the PJM system load in the most economical way possible on an overall PJM basis while meeting reliability constraints.

II. PROCEDURES

In recognition of the above obligation, the following sequence of events will be followed in order to meet PJM minimum load requirements:

A. Verification Tests

Verification tests of minimum generation levels of all units on PJM shall be conducted. The development of procedures, the timing of such tests and the review of results shall be the responsibility of the Operating Committee.

B. Scheduling Minimum Generation

The Interconnection Office shall schedule all generating facilities on the interconnection in the best possible manner to reliably meet a minimum load problem. Consideration shall be given to the proper scheduling of pumped storage facilities, planned and maintenance outages, delaying the return of units to service, outside sales to neighboring systems, the shutting down of base load units, power transfer limitations, and voltage and reactive constraints. Where practical, the system should be scheduled to avoid emergency minimums. The Interconnection Dispatcher shall issue to the companies, via the ALL-CALL, a Minimum Generation Warning with maximum possible lead time together with the forecast conditions when the forecast PJM minimum load, including the pumping load, is 1,000 MW or less above the forecast PJM normal minimum generation level. Upon receipt of a Minimum Generation Warning, each company shall review unit minimums and prepare a sequential action plan to meet its requirements. The IO shall be kept apprised of these plans. Stations shall be notified of possible requirements and they shall be prepared to act if so required. As an emergency minimum period approaches, the IO shall, via the ALL-CALL, issue a Minimum Generation Alert to inform the systems of the situation in order that

Revised August 1986

M-2

Accounting Guidelines

SECTION M

they may prepare to reduce to normal and emergency minimums. During the period, the ID shall utilize the ALL-CALL system to keep the systems informed of the situation. Upon receipt of a Minimum Generation Alert, the systems shall review minimum generation limits and the status of units in Dispatch Lambda. Updates should be made when required.

C. Reduction of Generation

The reduction of generation during light load periods will be accomplished by economically reducing unit outputs to their normal minimum levels according to the Dispatch Lambda incremental cost schedule. This includes nuclear units as preplanned. At all times, the ID should attempt to sell excess generation at normal economy. When PJM is operated at normal minimum generation, the dispatch rate shall be equal to the lowest incremental cost included in the Dispatch Lambda incremental cost schedule.

D. Minimum Generation Emergency

If normal minimums are not adequate to relieve the problem, the ID, via the ALL-CALL, should declare a Minimum Generation Emergency. Prior to reducing units to their emergency minimums, the ID should load all unloaded pumped hydro units and reduce run-of-river plant output where forebay elevation and river flow will allow without spilling water, and attempt to sell excess generation on PJM to neighboring systems as dump power. This power should be quoted at a zero rate. The payment to PJM for the power then will be halfway between the buying company's replacement quote and our zero rate.

E. Additional Reductions

If additional reduction of PJM generation is required, PJM systems will be requested to reduce generation, as required, to stated emergency minimum levels.

F. Further Reductions

If more reductions are required, the ID shall survey the companies, requesting the following information: a) each company's load and generation; b) which of the companies are in a position to further reduce generation by other than normal procedures (such as further reductions on nuclear units or spilling water at run-of-river plants) and the associated incremental cost or time recovery penalty imposed by such actions; and c) which units operating have the lowest max capacity and the highest cost that could be shut down without adversely affecting reliability. The ID will use his best judgement

SECTION M

to decide which units should further reduce generation by other than normal procedures or which units should be shut down to satisfy the existing emergency without jeopardizing the ability to carry tomorrow's load reliably and economically. Since an emergency situation has been declared, any costs incurred by buying companies taking special reductions to aid selling companies will be reimbursed through appropriate accounting procedures as established by the Operating Committee. (see MC 168-3, page M-5)

G. Emergency Generation Reduction by Overgenerating Companies

As a last resort, the Interconnection Dispatcher, taking into account the reliability considerations, will request the overgenerating companies to reduce generation (pro-rating the drop among the overgenerating companies in proportion to their MW values of overgeneration) to meet the PJM system load. The overgenerating companies have the prerogative to reduce their generation by any means to achieve the level requested by the IO. The impact of such a procedure shall be accounted for under practices as established by the Operating Committee.

H. Reversal of Minimum Generation Procedures

The above steps shall be followed in reverse order as the load begins to exceed the generation, and the IO shall cancel the Minimum Generation Emergency when the lowest normal minimum generation level is reached.

OC 271-3
(superseding OC 232-15)

Revised August 1986

M-4

SECTION M

III. PJM MINIMUM GENERATION (MIN GEN) ACCOUNTING

A. Forecast Min Gen Emergency

1. Based on a forecast PJM Min Gen Emergency by the Interconnection Office (IO), a company may submit to the ASc for consideration extraordinary costs associated with any unit taken off in advance: a) voluntarily at the request of the IO, or b) at the direction of the IO.
2. These costs are to be tabulated for the period of time that the unit(s) is requested to be off-line by the IO and should be based on the estimated hourly cost of the unit versus either the Dispatch Rate, if the company was forced to curtail sales, or the Billing Rate, if the company was forced to purchase more energy. A start-up cost may be included if applicable.
3. All costs should be allocated under separate billing in accordance with an allocation method and removed from the daily accounting as specified by the ASc and approved by the Operating Committee.
4. Any extraordinary costs associated with jointly-owned units shall be submitted by owning companies for their respective shares of energy under the coordination of the operating company or the IO, in the case of Keystone and Conemaugh.

ASc 373-4

B. Actual Min Gen Operation

1. No company which is operating below its load shall pay more for energy received than the cost it would have incurred if it had generated the energy itself.
MC 168-3, (reaffirmed OC 272-9)
2. When the generation on PJM is at the emergency minimum level, and PJM is generating above its load, the costs incurred will be developed by the company or companies which shut down or reduce units at the request of the IO to correct the minimum generation problem. These costs are to be tabulated for the period of time until the units can be returned to economical operation, and should be based on the estimated hourly cost of the unit versus either the Dispatch Rate, if the company was forced to curtail sales, or the Billing Rate, if the company was forced to purchase more.

EXHIBIT C

**TECHNICAL GUIDELINES
FOR
COGENERATORS AND
SMALL POWER PRODUCERS**

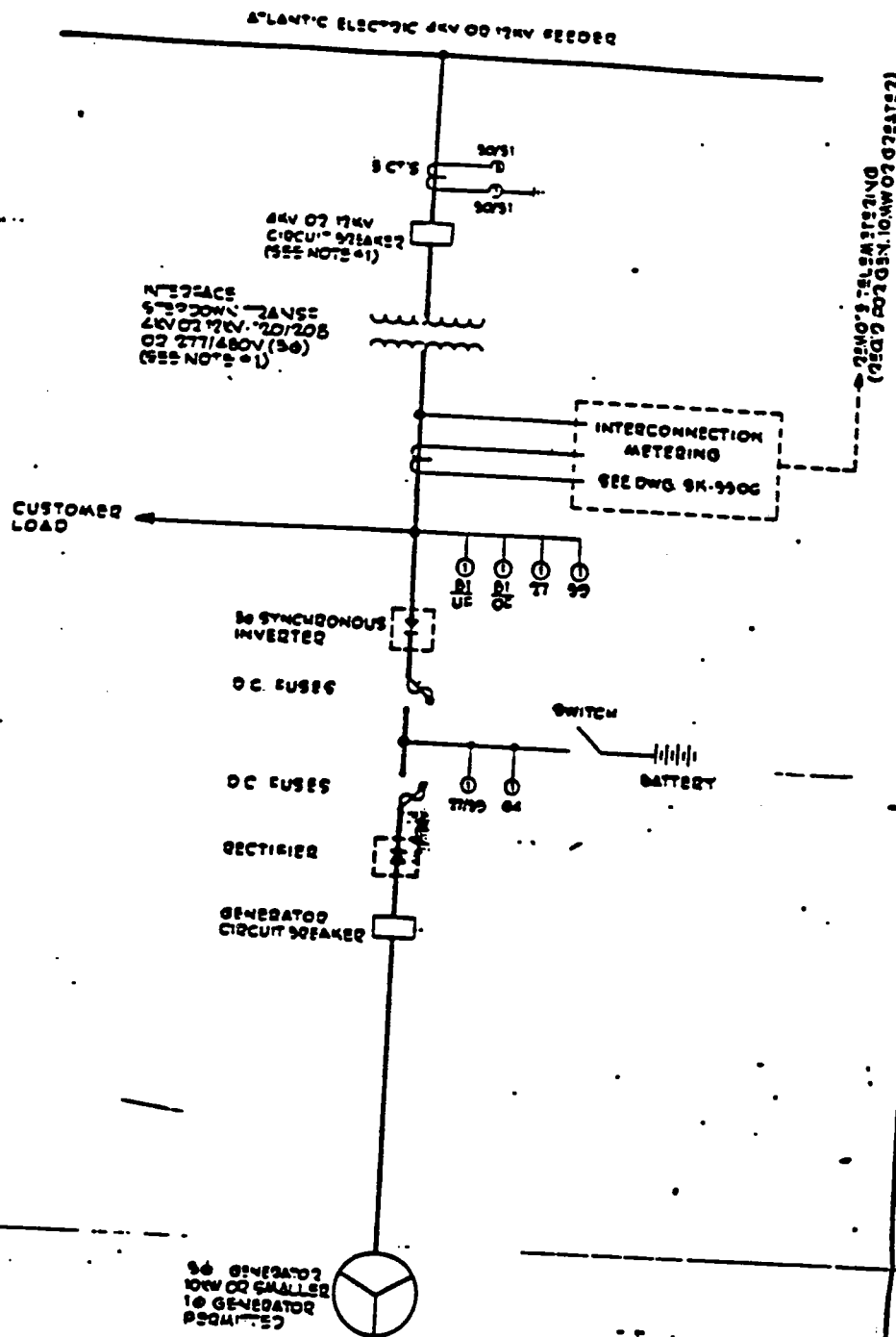


DIAGRAM #C

NOTES.

- #1. WHEN A.S.CO. HAS 4KV 021, THE
INTERFACE 302. SHOULD BE RATED
AT 12KV / THE INTERFACS STEP-DOWN
TRANS. 021. SHOULD BE DUAL VOLT.
4/12KV TO ALLOW FOR FUTURE CON-
VERSION OF 4KV TO 12KV SYSTEM.

LEGEND

Device No.	Description
44	Negative Sequence phase time overcurrent relay
64	DC SYSTEM GND. DETECT. RELAY
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restrain
27	Undervoltage relay
59	Overvoltage relay
81/8F	Underfrequency relay
81/8C	Overfrequency relay

ATLANTIC CITY ELECTRIC COMPANY			
DATE	BY	CHKD	APP.
11-05	5521		

Typical Installation of Captian brand
generator connected to Atlantic Electric
Distribution System with rectifier-inverter
interface and transformer of 10kv side

DIAGRAM #C

ATLANTIC ELECTRIC

TECHNICAL

GUIDELINES

FOR

CO-GENERATORS
& SMALL POWER PRODUCERS

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DISCLAIMER

"The material contained herein is designed to be informational in nature only. It should be utilized by you as an aid in making the decision as to whether or not to proceed to a more detailed investigation. The material is current as of the date of issue of this document, and it must be recognized that future actions may render any given item obsolete."

Atlantic Electric makes no representation or warranty of any nature whatsoever concerning the technical information contained herein. THE INFORMATION CONTAINED HEREIN IS INTENDED TO BE TYPICAL, FOR INFORMATIONAL PURPOSES ONLY, AND IS NOT INTENDED TO BE SITE SPECIFIC OR FACILITY SPECIFIC.

INTRODUCTION

The purpose of this Information Guide is to provide preliminary information to all Atlantic Electric (sometimes referred as "A.E.") customers who are interested in investigating the potential for cogeneration or small power production at their facility. Although it is impossible for this document to provide all the answers, this information is offered as a starting point for any customer who is considering authorized cogeneration of electric power.

The purpose of this Information Guide is also to consider technical and safety requirements and the need for adequate protective equipment to be designed and installed by customer in order to operate customer generation in parallel with the Atlantic Electric system without affecting the reliability of electric service to other customers and the safety of the general public and Atlantic Electric employees.

We believe that the information contained in this guide may be useful in understanding the need for proper design and analysis in the pursuit of a comprehensive customer generation feasibility study.

1.0.0 General Design Requirements

- 1.1.1 The customer's installation must meet all applicable national, state and local construction, safety and electrical codes.
- 1.1.2 Adequate protective devices (relays, circuit breakers, etc.) for the protection of AE's system, metering equipment and synchronizing equipment must be installed by customer. The protective devices may differ with the size of the installation. See section 5.3.0 for more specific requirements which must be installed by customer.
- 1.1.3 The customer shall provide A.E. controlled manual disconnecting device on the A.E. side of the interconnection. The type of device will vary with service voltage and capacity. This device must have a visible indication of its position and must accept a padlock to be provided by Atlantic Electric Co.
- 1.1.4 In installations where the customer is to provide protective devices for the protection of AE's system, the customer shall submit a single-line drawing of this equipment sealed by a licensed professional engineer to AE for informational purposes only. This shall not and is not intended to relieve customer of its design and installation obligations.
- 1.1.5 All cogeneration/small power producer customers must have a dedicated service transformer. This transformer will decrease voltage variations experienced by other customers, attenuate harmonics, and reduce the effects of fault current. In general, for multi-phase customers, the dedicated transformer should be connected in delta or wye ungrounded on the Atlantic Electric side so as not to be a contributor to LL-G faults on the Atlantic Electric system.
- 1.1.6 The cogeneration/small power producer customer has sole responsibility for properly synchronizing his generation with Atlantic Electric's frequency and voltage.
- 1.1.7 Relay and Control:

Typical installations of Customer owned generators connected to the Atlantic Electric System illustrating some possible different configurations are indicated in Figure 1 to Figure 7. The primary purpose of the illustrations are to provide protection and metering design information. Typical connections to the Atlantic Electric subtransmission or transmission systems are shown in the diagrams provided in the following guidelines published by Atlantic Electric: "Technical Guidelines for Customer Service at Subtransmission and Transmission Voltages."

1.1.8 Supervisory Control and Data Acquisition (SCADA) System Requirement:

A. Customers installing generators 10MW and larger size will be required to install equipment at their generating site and also pay for equipment and installation needed at Atlantic Electric's System Control Center for the following.

- 1) Telemetering of generator watts and vars**
- 2) Remote states of interface breaker**
- 3) Remote control of interface breaker**

B. The customer must lease a dedicated telephone circuit or other dedicated means of communication from the customer location to the AE System Control Center.

C. The customers must supply meters to indicate hourly demand for use in case of loss of telemetering equipment or the telephone circuit.

D. kWhr meters for end of month reading to provide adjustments to hourly data must also be supplied by the customer.

1.1.9 Any interface services which separate the generation facilities from AE's lines must be capable of interrupting the maximum fault current available at that location. The customer will be advised by AE the max fault current available.

1.1.10 In addition to the provisions in this guide, the customer shall meet the provisions published in "Technical guidelines for Customer Service at Subtransmission and Transmission Voltages" (where applicable). Where any conflicts exist, the provisions of the Cogeneration guide shall govern.

2.0.0 General Operating Requirements

- 2.1.1 The interconnection of the customer's generating equipment with the AE system shall be designed and operated by customer to cause no reduction in the quality of service being provided to other customers. No abnormal voltages, frequencies, or interruptions shall be permitted. The customer's facility shall produce 60 Hertz sinusoidal output with harmonic distortion no greater than 5%. If other customers complain about waveform distortion high or low voltage or flicker due to operation of customer's generation, such generating equipment shall be disconnected without notice until the problem has been resolved. There shall be no responsibility on the part of AE, its directors, officers, agents, servants or employees for disconnection.
- 2.1.2 The customer may not commence parallel operation with Atlantic Electric System until final written approval has been granted by AE. AE reserves the right to inspect the customer's facility and witness testing of any equipment or devices associated with the interconnection.
- 2.1.3 The customer shall operate and maintain his equipment in good and proper working order which shall be consistent with all industry standards and in compliance with all applicable rules, codes, regulations, orders and requirements. AE reserves the right to inspect the customer's facilities whenever it appears that the customer is operating in a manner which may pose a risk to AE's system integrity and, in such event, AE shall have the right to disconnect customer's facilities without notice and shall have no liability therefore.
- 2.1.4 Switching of the interface breaker or switch device shall be under the administrative control of Atlantic Electric's System Operator. If, for any reason, Atlantic Electric believes the continuation of the interconnected system is, or may be, detrimental to the operation of Atlantic Electric's facilities, the supplier shall be required to disconnect the generator from Atlantic Electric's system which may be done with or without notice by AE and there shall be no liability to AE, its directors, officers, agents, servants or employees therefore. This includes Atlantic Electric's right to open the interface breaker or switching device with or without prior notice to the supplier for any of the following reasons:
- A. To facilitate maintenance, test or repair of utility facilities.
 - B. During system emergencies.

- C. When the customer's generating equipment is interfering with other customers on the system.
 - D. When an inspection of the customer's generating equipment reveals a condition hazardous to the AE system or a lack of scheduled maintenance records for equipment necessary to protect the AE system.
- 2.1.5 Automatic disconnecting devices with appropriate automatic control apparatus must be provided by the customer to isolate the customer's facility from the utility system for, but not necessary limited to, the following abnormal conditions:
- A. A fault on the customer's equipment.
 - B. A fault on the utility system.
 - C. A deenergized utility line to which the customer is connected.
 - D. An abnormal operating voltage or frequency.
 - E. Failure of automatic synchronization with the utility system.
 - F. Loss of a phase or improper phase sequence.
 - G. Total harmonic content in excess of 5%.
 - H. Abnormal power factor.
 - I. Load flow exceeding an established limit.
- 2.1.6 The customer will not be permitted to energize a deenergized AE circuit.
- 2.1.7 Operation of the customer's generator shall not adversely affect the voltage regulation of the AE system to which it is connected. Adequate voltage control shall be provided, by the customer, to minimize voltage regulation on the AE system caused by changing generator loading conditions.

For synchronous generators, sufficient generator reactive power capability shall be provided to withstand normal voltage changes on the AE system.

In cases where starting or changing load on induction generators will have an adverse impact on AE system voltage, step-switched capacitors or other techniques may be required to bring the voltage changes to acceptable levels.

- 2.1.8 The customer shall maintain an operating log at generating facility indicating all changes in operating status, maintenance outages, trip indications or other unusual conditions found upon inspection and such other information as AE may from time to time require, which log shall be available to AE upon request and which shall be maintained at all times on the premises of the generating facility where it will be available for inspection.
- 2.1.9 The customer shall notify AE, in writing, of the monthly KWH production of each generator on the first regular working day of the following month. Producer of power 10MW or larger may be required to report energy and peak demand information daily.
- 2.1.10 It is the nature of the distribution system that, for efficient operation, loads are sometimes switched from one feeder to another or from one supply substation to another. If such a situation should arise affecting the supplier's facility, recoordination of the supplier's protective devices will be solely the supplier's responsibility. Where practicable, Atlantic Electric shall exercise its reasonable best efforts to inform supplier four weeks prior to any proposed changes in AE system that will require any changes in coordination of protective devices.

3.0.0 Design Information - Atlantic Electric System

- 3.1.1** AE's primary distribution system consists of either 4kV or 12kV, grounded wye. Atlantic Electric's transmission system consists of 23 kV and above also grounded wye. The customer's generator should be designed to be tripped or isolated from Atlantic Electric system before the first automatic reclose occurs following a fault on customer's system. First reclosing time varies from circuit to circuit. At some locations, for close in faults near the AE substation, the distribution feeder breaker will not be allowed to reclose. Once the customer's generator is isolated from the Atlantic Electric system, the customer's generator can be paralleled with AE System only after approval by AE System Control Center, by telephone confirmation using the authorized communication number to be issued by AE.
- 3.1.2** Customers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the customer to protect his equipment from excessive negative sequence currents.

4.0.0 Design Considerations

4.1.0 Parallel Operation

- 4.1.1 A parallel system is defined as one in which the customer's generation can be connected to a bus common with the utility's system. A transfer of power between the two systems is a direct and often desired result. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the utility system which must be considered in the electrical protection of the utility's facilities.
- 4.1.2 Utility lines are subject to a variety of natural and man-made hazards. Among these are lightning, wind, animals, automobiles, malicious mischief and human error. Residential and commercial electric systems are subject to these same hazards, although perhaps to a different degree, because of the limited extent and protected environment of such systems.
- 4.1.3 The electric problems which can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that the damaged equipment be deenergized as soon as possible because of the hazards they pose to the public and the operation of the system.
- 4.1.4 In systems without parallel generation, the utility controls the only source of supply to a given line and therefore, has the responsibility to install equipment which is adequate, under expected circumstances, to detect faulted equipment and deenergize it. A parallel generator connected to a utility line represents another source of power to energize the line and must also have adequate protective devices installed to sense trouble on the utility system.
- 4.1.5 Parallel generation can also cause another condition, called "accidental isolation," in which a portion of the utility's load becomes isolated from the utility source but still connected to the parallel generation. In this condition, the voltage may collapse or the isolated system may continue to operate independent of the utility (but probably with abnormal voltage or frequency). The probability of an isolated system continuing to operate increases with increasing size of the parallel generator compared to the amount of potentially isolated load.
- 4.1.6 The protective devices and other requirements required by AE in the section #5 are intended to provide protection against the hazards noted above by disconnecting the parallel generator when trouble occurs. These requirements are few for small installations but increase as the size of the generation increases. For small installations, the basic philosophy is to ensure that the generator

output is small compared with the magnitude of any load with which it might be isolated. Thus, for any fault, AE's protective relays will operate and isolate the generation with a large amount of load, causing voltage collapse and automatic shutdown of the generator. This approach is particularly appropriate for the induction generator or inverter systems commonly proposed for small parallel generators since these systems do not contribute sustained overcurrents which could be used to detect faults directly. In instances where the AE system arrangement is such that it is possible that the generators will not always be isolated with large amounts of load, AE requires the use of voltage and frequency measuring relays to detect isolation and trip generators.

- 4.1.7 For larger installations the probability of isolated operation is higher since the available generation may be sufficient to carry the entire load of AE's circuit. For these installations, specific devices must be installed by customer for the detection of short circuits and grounds on the utility system as well as voltage and frequency relays to detect isolated operation.
- 4.1.8 The list of design considerations contained herein is not intended to be all inclusive. Other hazards and considerations must be taken into consideration by the design engineer based upon the circumstances, the site, the customer's needs and other appropriate criteria.

4.2.0 Reactive Power Requirements when Supplier is Delivering Real Power

When delivering real power (kilowatts) to Atlantic Electric, supplier must be capable of operating with a power factor at the Point of Delivery to AE between 90% leading to unity, such that supplier would receive lagging reactive power (kilovars) from AE.

In general, when a supplier is connected to AE at the distribution voltage level (4 kV or 12 kV) the supplier must maintain a power factor between 90% leading to unity while delivering real power to AE. However, it may be acceptable and/or desirable for supplier to deliver lagging reactive power when connected at a distribution level if supplier is connected at a point close to an AE substation or connected with a dedicated distribution line.

In general, when a supplier is connected to AE at a voltage level above distribution voltages, the supplier will be required to have a capacity to operate between a 90% leading to a 90% lagging power factor at the point of delivery while simultaneously delivering real power to AE.

If the supplier has the capacity to operate beyond the above specified limits, AE may choose to operate beyond those limits. Actual reactive power flow at the point of delivery will be dispatched by AE.

4.2.1 Reactive Power Requirements when AE is Supplying Real Power

Any time AE is supplying power to the Point of Delivery, it is desirable that the power factor be corrected to 95% lagging or better (closer to unity or slightly leading).

4.3.0 Induction Generators

Reactive power supply for induction generators may pose difficult design problems, depending on the generator size. Installations over 200 KVA capacity may require capacitors to be installed to limit the adverse effects of reactive power flow on AE system voltage regulation. Such capacitors will be at the expense of the generating facility. The installation of capacitors for reactive power supply at, or near, an induction generator greatly increases the risk that the induction machine may become self-excited if accidentally isolated from AE's system. The self-excited induction generator can produce abnormally high voltage which can cause damage to the equipment of other customers. Overvoltage relays can detect such overvoltages but cannot control their magnitude because of the rapid voltage rise which occurs with self-excitation. Because of these problems, reactive power supply for large induction generators must be studied on an individual basis. In general, self-excitation problems are most likely where the AE system capacity and load density are low. Since such areas are likely to be chosen for certain forms of small power production such as wind and hydro. No induction machines may be connected to existing distribution lines without the express written consent of AE. Any damage to equipment of other customers as a result of self-excited induction generator shall be the responsibility of customer.

4.4.0 Inverter Systems

Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines discussed in Section 4.3.0 apply. Likewise, inverter systems are also capable of isolated operation. Self-commutated inverters have this capability by design. Line commutated inverters could operate isolated if connected to rotating machines which provide the necessary commutation. Because of these possibilities of self-excited operation, inverter systems are treated as induction machines in these guidelines. Harmonics generated by inverter shall not distort the waveforms more than 5%. If a customer using such a device for parallel generation is found to exceed 5% waveform distortion limit, the generating customer will be required to install, at customer's cost, filtering equipment to bring the harmonic output of his inverter to a level acceptable to AE.

4.5.0 Synchronous Generators

Synchronous generators can be either separately excited or self-excited. In either case, these units are capable of supplying sustained fault current for fault conditions on the Atlantic Electric supply system. Such units are also capable of operating independently and can supply isolated load, providing the load is within the unit's output capability.

4.6.0 Wind Generators

Generally, wind generators are induction generators and, therefore, the same design considerations apply. It is also required that no wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact land upon, or interfere with any utility lines or equipment, or constitute a safety hazard.

A typical homeowner thinking about installing a wind generator will most likely be required at the cost of customer incoming service equipment such as transformer, service cable, distribution panel, etc. because existing equipment rating may not be adequate.

In considering installation of a wind generator or any other equipment the customer is cautioned to carefully take into consideration and examine all land use and zoning rules and regulations. Permits, approvals and/or variances may be required and customer should discuss such requirements with his engineer, his counsel and the representatives of the local governing bodies prior to proceeding with such projects.

5.0.0 Protection Guidelines — Objectives

5.1.0 The required protection equipment to be installed by the customer is selected and installed to meet the following objectives, which are not intended to be all inclusive:

- A. Provide adequate protection for faults, overloads or other abnormal conditions on the customer's equipment.
- B. Provide adequate protection for faults and overloads on Atlantic Electric's lines, transformers or other equipment.
- C. Prevent outages or other adverse effects to other Atlantic Electric customers.
- D. Provide a safe means to control, operate, connect and disconnect the intertie of the customer's generation and the Atlantic Electric system.
- E. Provide a free flow of normal power transfer.

5.2.0 Protection Guidelines — General Requirements:

- A. It is the customer's responsibility to select, install and maintain adequate protection for their own generator and switchgear equipment. Fuse size/type information, single line diagram and other information on the overall protective relaying scheme must be provided to Atlantic Electric. Atlantic Electric will review the compatibility of the customer's proposal with the Atlantic Electric protective relaying on the source line. Atlantic Electric must approve the design of the finalized protection arrangement.
- B. A point of intertie must be defined between the Atlantic Electric system and the cogeneration/small power producer. Most likely, this point will be a circuit breaker or a switch used to intertie the two systems. The intertie breaker could be on the high side of the customer's transformer or on the low side if the transformer is fuse protected. All protective relaying used to trip the intertie breaker must be reviewed and approved by Atlantic Electric. The automatic reclosing, if any, of the intertie breaker must also be reviewed and approved by Atlantic Electric. No approval by AE is intended to relieve customer of its obligation. Customer shall remain responsible for its equipment and the design and operation thereof. Approval by Atlantic Electric is for informational purposes only and to provide assurance to AE for the protection of its equipment.

- C. Atlantic Electric will supply settings for the protective relaying schemes that trip the intertie breaker. An exception is Atlantic Electric will not set those relays solely used for protection of the customer's generator. If desired, Atlantic Electric will, for a nominal fee, physically set the intertie breaker protective relays and periodically test the protective relaying scheme. However, AE will do so without liability or responsibility to customer and the liability of AE, whether in contract or in tort or otherwise shall be limited to return to the customer of the nominal fee. AE will perform this service for convenience only.

**5.3.0 Protection Guidelines -- Specific Requirements for
Cogeneration/Small Power Producer Customers Supplied Off Atlantic
Electric's Transmission System**

- A. Generators connected to Atlantic Electric's transmission system must be 3-phase units.
- B. A customer with a large dedicated transformer (i.e. low impedance) that is tapped off a transmission line that utilizes a power line carrier protective relaying scheme may need to install a carrier relaying terminal at their site. This equipment may be needed to maintain the reliability and security of the carrier relaying scheme on the transmission line.
- C. A customer tapped off a transmission line with high-speed circuit breaker reclosing may require transfer trip from the Atlantic Electric source terminal to insure that the customer's generator is tripped "off-line" before the high speed breaker reclose occurs at Atlantic Electric's end.
- D. The customer's dedicated transformer may be protected by fuses. If customer supplied, Atlantic Electric will check the compatibility of the customer's fuse type/size with the protective relaying on the source end(s) and, if acceptable to AE for that purpose, will give its approval for the use of the customer's supplied fuse, which shall be for purpose of determining compatibility only.
- E. 1. The customer's dedicated transformer may be protected by protective relays and:
 - a. High side fault interrupting device such as a circuit breaker or circuit switcher, or
 - b. Transfer trip to Atlantic Electric's source end(s) and an automatic isolation device such as an airbreak switch so that after clearing of the fault, the transformer can be automatically isolated and the transmission line can be restored. (The automatic isolation device may not be necessary if the source line supplies only the customer.)
- E. 2. The transformer may be protected by a combination of the following types of protective relays:
 - a. Differential relay protection operating on a percentage of differential current.
 - b. Sudden pressure relay detecting internal fault pressure.

- c. Primary phase and ground overcurrent relay with the setting based on transformer size or loading whichever is more applicable.
 - d. Secondary phase and ground overcurrent relay with the setting based on transformer size or loading whichever is more applicable.
- F. The cogeneration/small power producer must trip their intertie breaker for a fault on the Atlantic Electric transmission system. This tripping could be accomplished by:
1. Transfer trip from Atlantic Electric's source end.
 2. A combination of local protective relays at the customer's site. Examples include:
 - a. One or more zones of phase impedance relays and associated timers.
 - b. Overcurrent relays set above the maximum output of the customer's generator. Directional overcurrent relays may be needed if customer load could exceed generator output.
 - c. Power relay set above the maximum output of the customer's generator.
- G. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must be "off line" before an automatic reclose occurs on the source end(s). The preceding trips can be accomplished with the following protective relays:
1. Overvoltage relay with time delay.
 2. Undervoltage relay with time delay.
 3. One/two step underfrequency relay(s) with independent time delays.
 4. One/two step overfrequency relay(s) with independent time delays.

**5.4.0 Protection Guidelines, And Specific Requirements For
Cogeneration/Small Power Producer Customers Supplied Off Atlantic
Electric's Distribution System**

- A. Generators connected to Atlantic Electric's distribution system may be either single phase or 3-phase units. (Three phase units, obviously, can only be connected where Atlantic Electric's distribution circuit is of 3-phase construction).
- B. The customer's dedicated transformer may be protected by high side fuses. Atlantic Electric will check compatibility of customer's fuse type/size with the protective relaying of the AE end and, if acceptable, give approval. A 3-phase generator should employ negative sequence relaying to detect an open fuse condition.
- C. The cogeneration/small power producer must trip their intertie breaker for a fault on the Atlantic Electric distribution circuit. This tripping may be accomplished by the following, which are not intended to be all inclusive:
 1. Transfer trip from Atlantic Electric's source end.
 2. A combination of local protective relays at the customer's site. Examples include:
 - a. Overcurrent relays set above the maximum output of the customer's generator. Directional overcurrent relays may be needed if the customer's load can exceed the generator output.
 - b. Power relay set above the maximum output of the customer's generator.
- D. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must be "off line" before an automatic reclose occurs on the source end. The preceding trips may be accomplished by the following protective relays, which are not intended to be all inclusive:
 1. Overvoltage relay with time delay.
 2. Undervoltage relay with time delay.
 3. One/two step underfrequency relay with independent time delay.

4. One/two step overfrequency relay with independent time delay.

5.4.1 Protection Guidelines, And Specific Requirement For Cogeneration/Small Power Producer Customers Supplied Off Atlantic Electric's Distribution System That Use Induction Generators

These customers use induction generators which contain no field for excitation purposes. These generators draw reactive power from the Atlantic Electric system to satisfy their excitation needs. The units can only produce power when they are energized from the Atlantic Electric distribution circuit. As such, induction generators cannot supply sustained fault current or, in most cases, supply isolated load.

NOTE: Self excitation may be possible in some cases if the customer uses capacitors for power factor correction or if the Atlantic Electric distribution circuit has a high number of capacitors.

- A. The cogeneration/small power producer must trip their intertie breaker for loss of the Atlantic Electric source or if the bus voltage or frequency goes outside acceptable limits. For loss of the Atlantic Electric source, the generator must trip "off line" before an automatic reclose occurs at Atlantic Electric end.

The preceding trips can be accomplished by the following protective relays:

1. Undervoltage relay with time delay.
2. Underfrequency relay with time delay.
- B. In cases where self-excitation is possible, the above relays shall be supplemented by:
 1. Instantaneous overvoltage relay.
 2. Overfrequency relay.

5.4.2 Protection Guidelines, And Specific Requirements For Cogeneration/Small Power Producer Customers That Use DC Generation And Are Supplied Off Atlantic Electric's Distribution System

These customers employ DC generation and transform the DC output to AC through synchronous static inverters that use electronic switching. The electronic switching is controlled by either the utility AC voltage or by internal electronic circuitry. Static inverter installations on the Atlantic Electric system must be the

type that utilize the Atlantic Electric AC voltage as their switching reference. These systems cannot supply fault current or supply isolated load. Therefore, if properly designed by customer, no special protection equipment is necessary for faults on the Atlantic Electric source feeder or for an outage of the Atlantic Electric source. The protection for the customer's dedicated transformer is the same as that required for other cogeneration/small power producer customers supplied off Atlantic Electric's distribution system.

6.0.0 Information To Be Supplied by Cogenerator or Small Power Producer

List of Drawings:

- A. A one line diagram of entire system.
- B. A potential elementary of customer-owned generation system.
- C. A current elementary of customer-owned generation system.
- D. A control elementary of generator breaker.
- E. A three line diagram of generation system.

6.1.0 One Line Diagram and Three Line Diagram to include the following information:

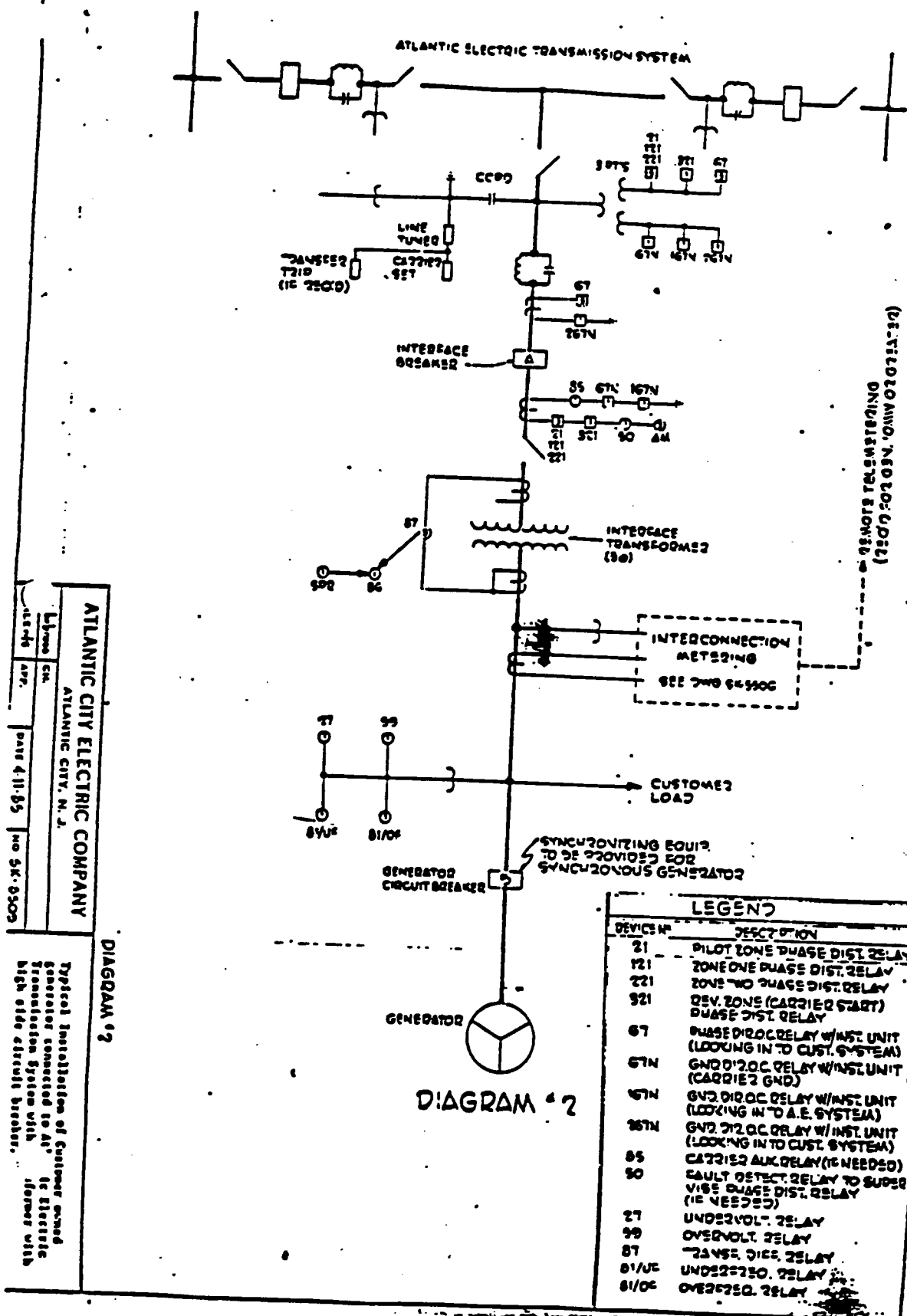
- A. Equipment names and/or numerical designations for all circuit breakers, contactors, air switches, transformers, generators, etc., associated with the generation as required by Atlantic Electric to facilitate switching.
- B. Power Transformers - Name or designation, nominal kVA, nominal primary, secondary, tertiary voltages, vector diagram, a tap setting and transformer impedance.
- C. Station Service Transformers - Designate phase(s) connected to, and estimated kVA load.
- D. Instrument Transformers - Voltage and current, phase connections.
- E. Lightning Arresters/Gas Tubes/Metal Oxide Varistors/Avalanche Diode/Spill Caps/Surge Capacitors - Ratings.
- F. Capacitor Banks - kVAR rating.
- G. Air Switches - Indicate status normally open with a (N.O.) and type of operation manual or motor.

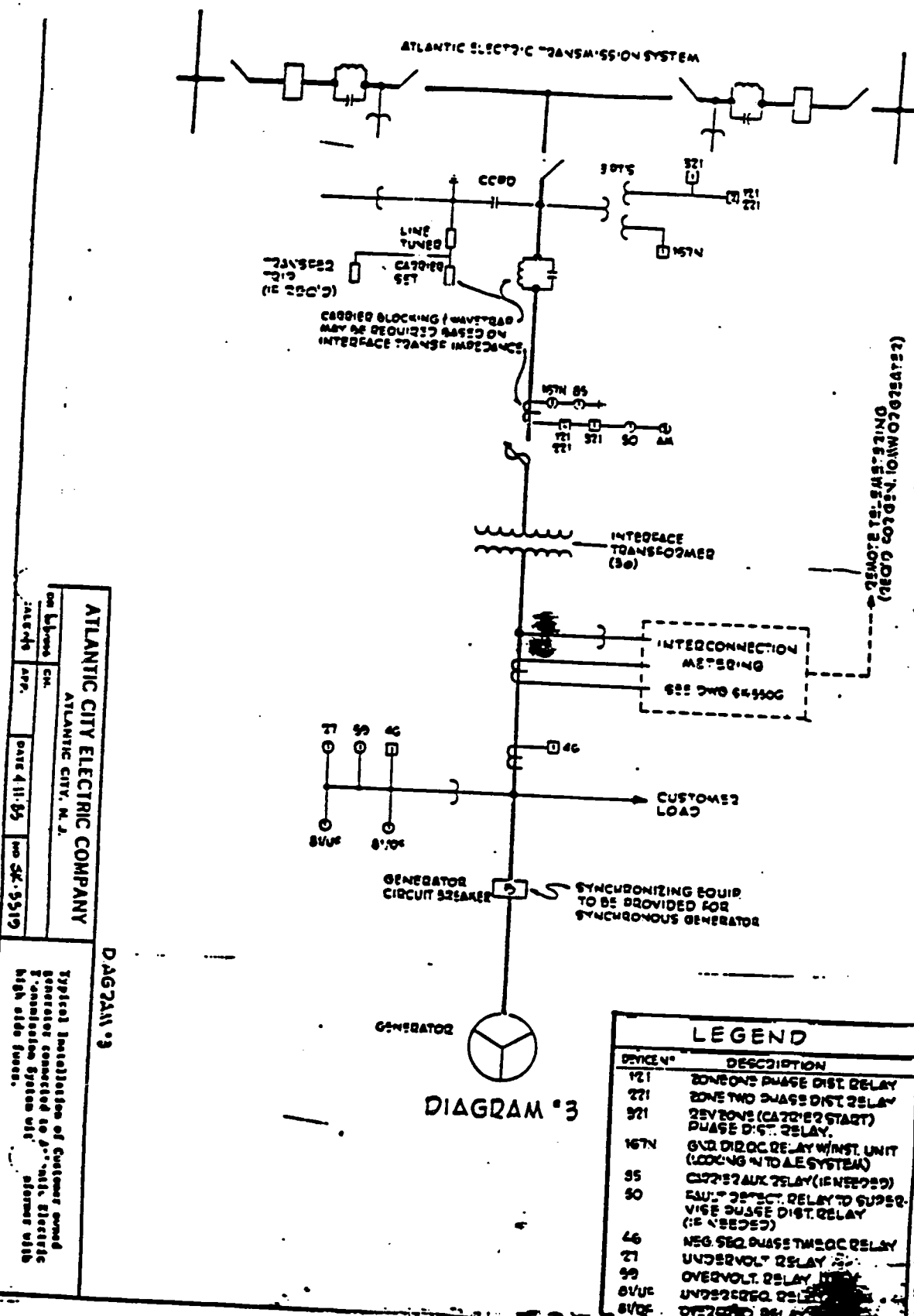
- H. Safety Switch - Continuous ampere and interrupting ratings.
- I. Circuit Breakers and/or Contactors - Interrupting rating, continuous rating, operating times.
- J. Generator(s) - Include type, connection, kVA, voltage, current, rpm, PF, impedances, time constants, etc.
- K. Point of Connection to Atlantic Electric and phase identification.
- L. Fuses - Type, size, speed, and location.
- M. Grounding.

6.1.1 Elementary Diagrams To Include The Following Information

- A. Terminal designation of all devices - relay coils and contacts, switches, transducers, etc.
- B. Relay functional designation - per latest ANSI Standard. The same functional designation shall be used on all drawings showing the relay.
- C. Complete relay type (such as CV-2, CV-5, CW, IJS51A) and relay range.
- D. Switch contacts shall be referenced to the switch development if development is shown on a separate drawing.
- E. Switch developments and escutcheons shall be shown on the drawing where the majority of contacts are used. Where contacts of a switch are used on a separate drawing, that drawing should be referenced adjacent to the contacts in the switch development. Any contacts not used should be referenced as spare.
- F. All switch contacts are to be shown open with each labeled to indicate the positions in which the contact will be closed.
- G. Explanatory notes defining switch coordination and adjustment where misadjustment could result in equipment failure, or safety hazard.
- H. Auxiliary relay contacts shall be referenced to the coil location drawing if coil is shown on a separate drawing. All contacts of auxiliary relays should be shown and the appropriate drawing referenced adjacent to the respective contacts.

- I. Device auxiliary switches (circuit breakers, contactor) should be referenced to the drawing where they are used.
- J. Any interlocks electromechanical, key, etc., associated with the generation.
- K. Ranges of all timers, and setting if dictated by control logic.
- L. All target ratings; on dual ratings underline the appropriate tap setting.
- M. Complete internal for electromechanical protective relays. Solid-state relays may be shown as a "black box", but manufacturer's instruction book number shall be referenced, and terminal connections shown.
- N. Isolation points (states links, PK-2 and FT-1 blocks), etc., including terminal identification.
- O. All circuit elements and components, with device designation, rating and setting where applicable. Coil voltage is shown only if different from nominal control voltage.
- P. Size, type, rating and designation of all fuses.
- Q. Phase designation as ABC or CBA.
- R. Potential transformers - nameplate ratio, polarity marks, rating, primary and secondary connections (see Guidelines for minimum ratings).
- S. Current transformers - polarity marks, rating, tap, ratio and connection.
- T. Auxiliary CT ratios, connection, winding current rating and arrows to indicate assumed current flow.
- U. Such other information as AE may request.





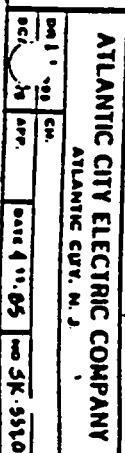


DIAGRAM 4

DIAGRAM # 4

01. WHEN A.E.C.O. HAS 6KV 271.. THE
INTERFACE 9K2 SHOULD BE
DATED AT 17KV. THE INTERFACE
STEPDOWN TRANSF. PRI. SHOULD
BE DUAL VOLT 6/17KV TO ALLOW
FOR FUTURE CONVERSION OF
6KV TO 12KV SYSTEM.

<u>Device No.</u>	<u>Description</u>
46	Negative Sequence phase time overcurrent relay
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restraint
27	Undervoltage relay
59	Overvoltage relay
51/5I	Underfrequency relay
51/OF	Overfrequency relay

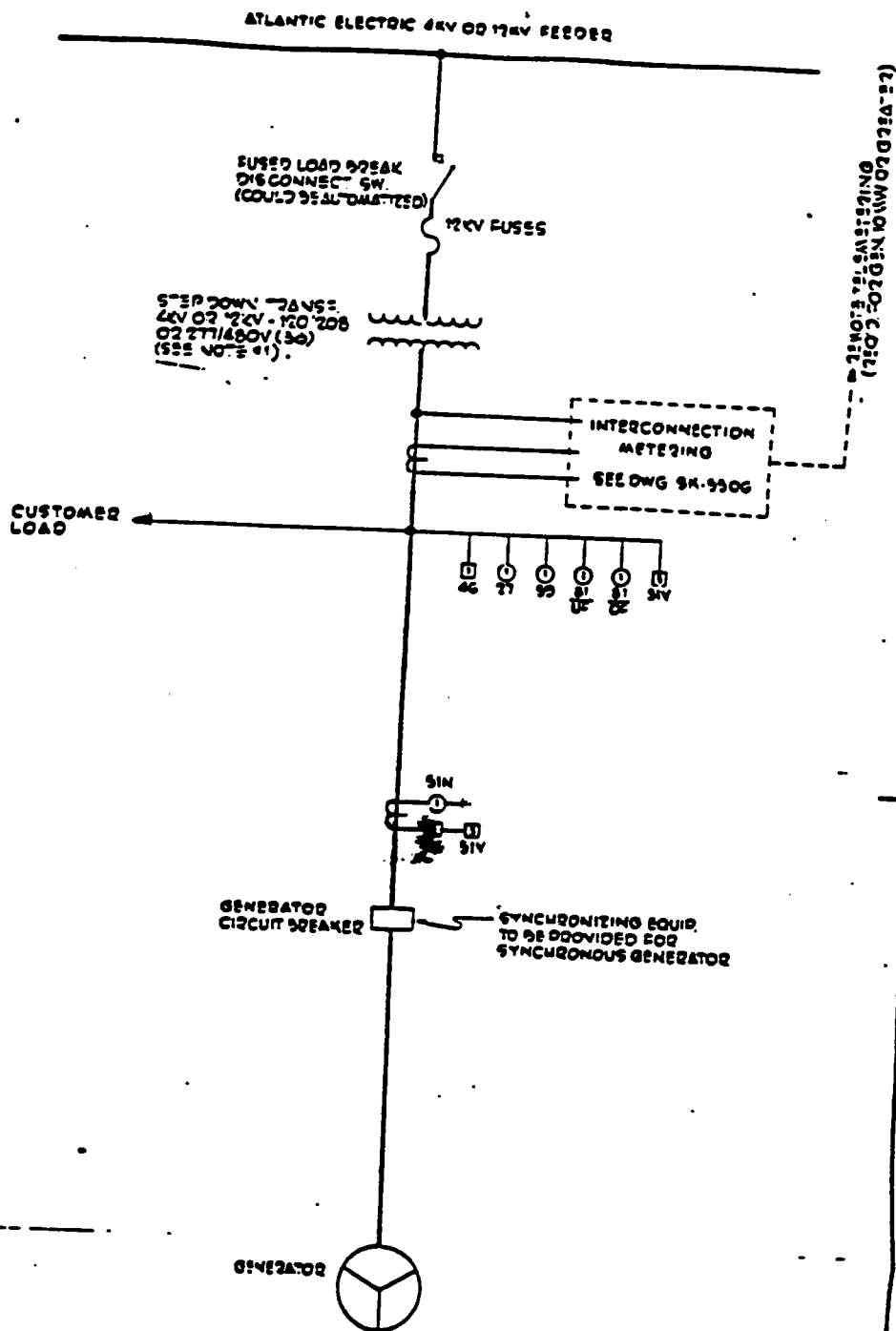


DIAGRAM 45

NOTES.

41. WHEN A.E.CO HAS 4KV P21, THE
STEPDOWN TRANSF. P21, SHOULD
BE DUAL VOLT. 4/12KV TO ALLOW
FOR FUTURE CONVERSION OF 4KV
TO 12KV SYSTEM.

<u>Device No.</u>	<u>Description</u>
46	Negative Sequence phase time overcurrent relay
51	Time overcurrent relay
51V	Time overcurrent relay with voltage restraint
27	Undervoltage relay
59	Overvoltage relay
61/UF	Underfrequency relay
61/OF	Overfrequency relay

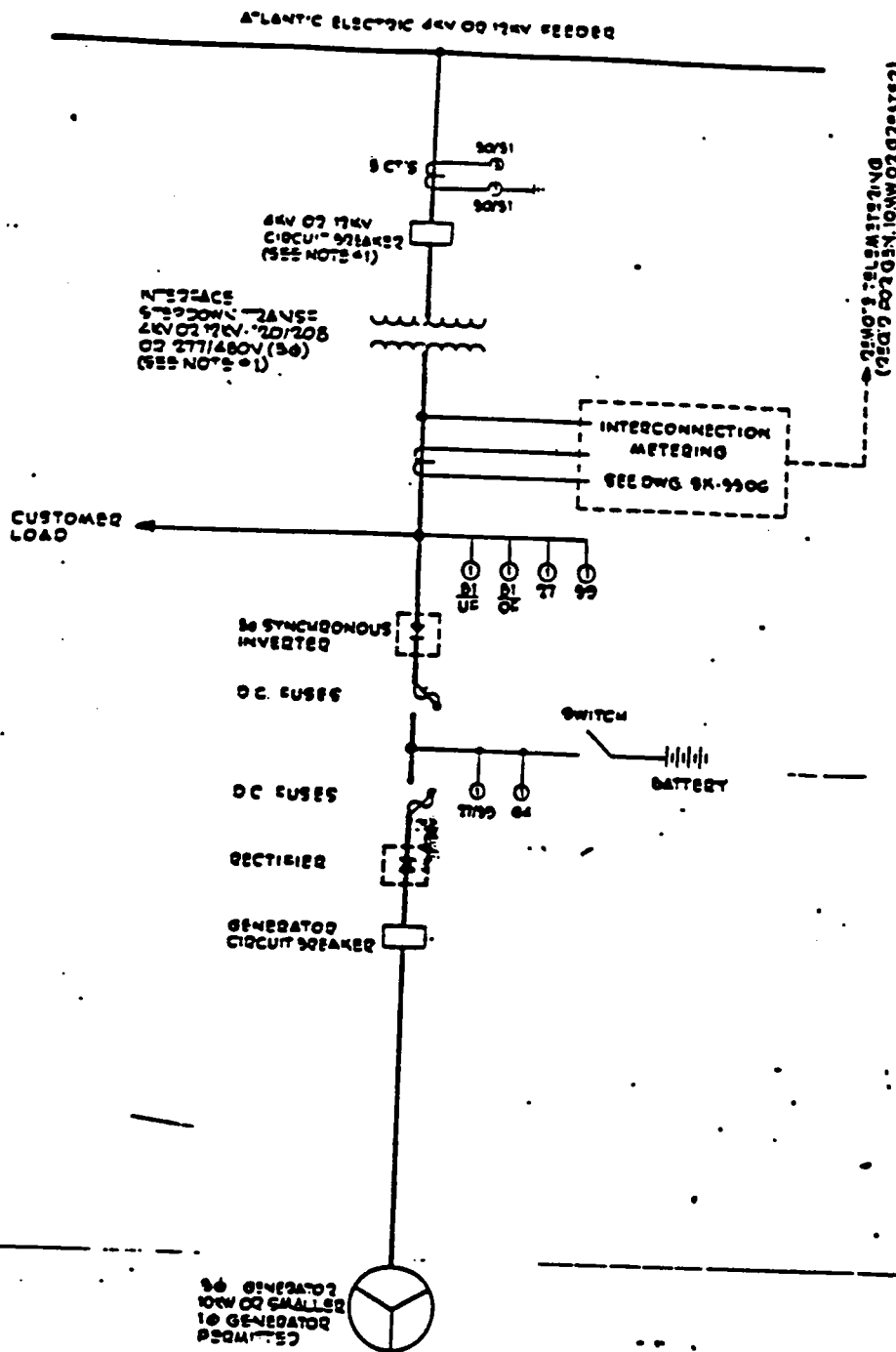
ATLANTIC CITY ELECTRIC COMPANY

ATLANTIC CITY, N. J.

CM	DATE 4-11-05	NO 6K-5510
APR.		

Typical installation of Customer owned generator connected to Air Conditioning Distribution System with its own control with high side fuse.

DIAGRAM '5



ATLANTIC CITY ELECTRIC COMPANY
ATLANTIC CITY, N. J.
DATE 11-05 NO. SK-5521

DIAGRAM *C

DIAGRAM *C

NOTES.

1. WHEN A.E. CO. HAS 4KV B21, THE INTERFACE B21 SHOULD BE RATED AT 12KV. THE INTERFACE STEP-DOWN TRANS. B21 SHOULD BE DUAL VOLT. 4/12KV TO ALLOW FOR FUTURE CONVERSION OF 4KV TO 12KV SYSTEM.

Typical Installation of Customer owned generator connected to Atlantic Electric Interphase and transformer of 15kV side circuit breaker.

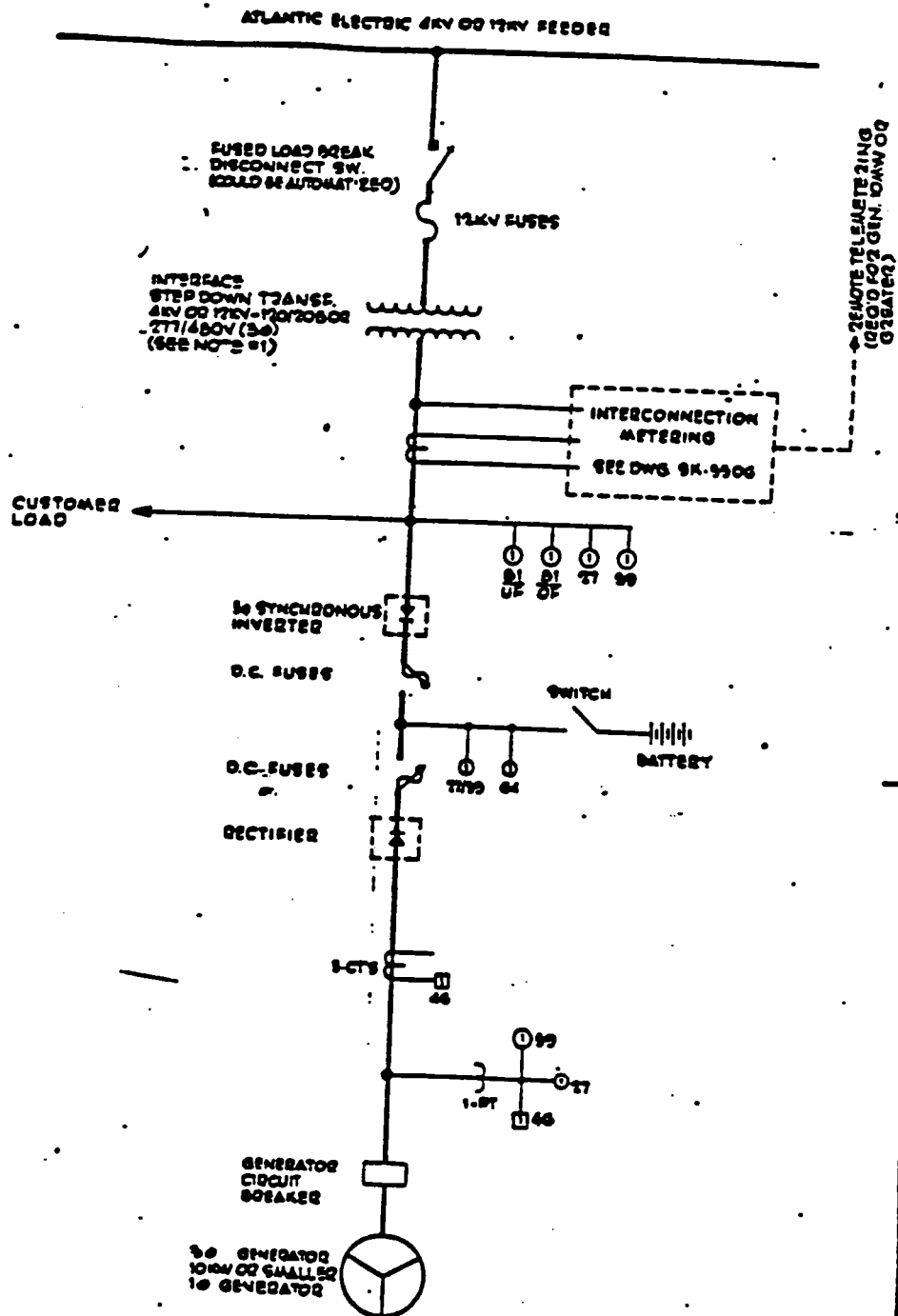


DIAGRAM 47

NOTES -

- #1. WHEN A.E.CO. HAS 4KV DCL, THE INTERFACE STEP DOWN TRANSFORMER SHOULD BE DUAL VOLT. 4/12KV TO ALLOW FOR FUTURE CONVERSION OF 4KV TO 12KV SYSTEM.

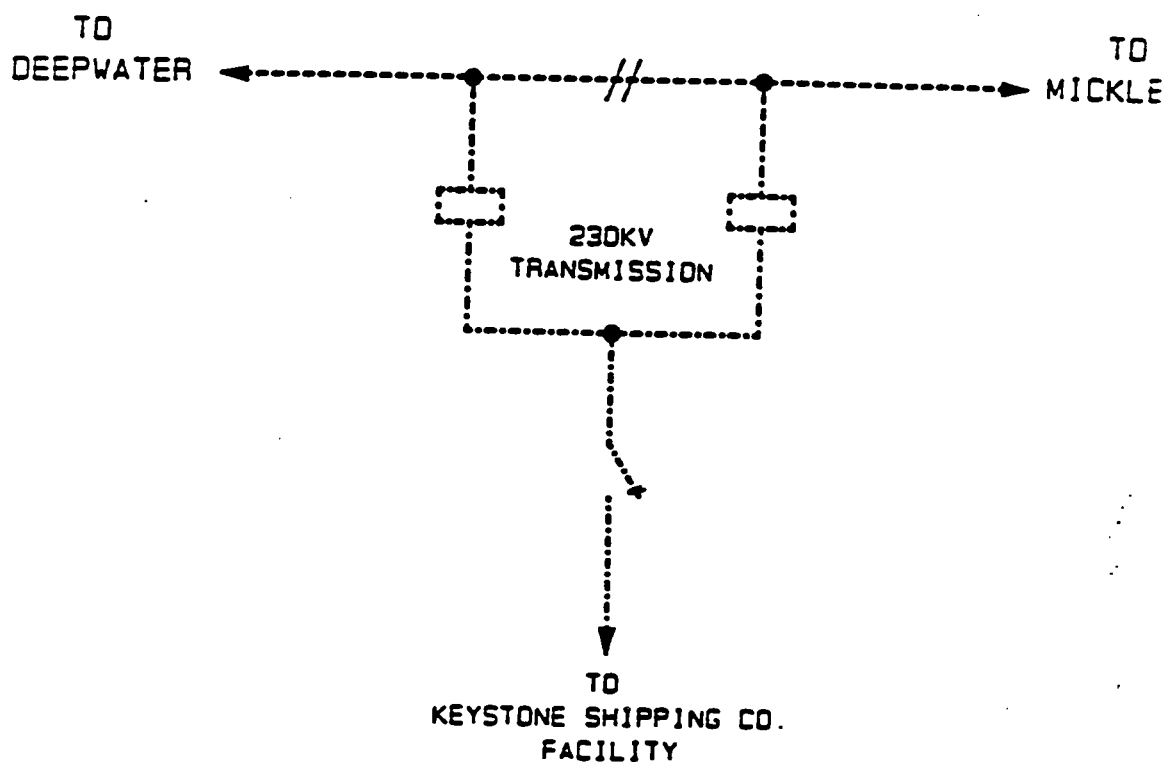
Device No.	Description
46	Negative Sequence phase time overcurrent relay
64	DC GROUND DETECT. RELAY
31	Time overcurrent relay
31V	Time overcurrent relay with voltage restraint
27	Under-voltage relay
39	Over-voltage relay
81/82	Under-frequency relay
81/85	Over-frequency relay

ATLANTIC CITY ELECTRIC COMPANY			
ATLANTIC CITY, N. J.			
on Line	ck	date 4-11-05	mk. G.L. 5672
scale 1/2	av.		

Typical Installation of Customer owned generator connected to Atlantic Electric. Distribution system with rectifier-inverter interface and transformer with high side.

EXHIBIT D

**DRAWING SHOWING
INTERCONNECTION
AND
POINT OF DELIVERY**



- NEW 230KV LINE
- BREAKER
- /--- ISOLATION SWITCH
- // DISCONNECT
- NEW 230KV SWITCHING STATION

KEYSTONE SHIPPING CO. COGENERATION FACILITY
INTERCONNECTION AND POINT OF DELIVERY

DR. NAME	CH.	CH.	APP.	DATE	SCALE	ROUTE
ATLANTIC ELECTRIC CO. D.VILLE N. I.					NO	SK. P. 12R. 1

EXHIBIT E

**STIPULATION BETWEEN PURCHASER
AND THE BPU STAFF
AND
BPU ORDER
APPROVING THE STIPULATION**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF INVESTIGATION BY :
THE STAFF OF THE NEW JERSEY BOARD :
OF PUBLIC UTILITIES OF ATLANTIC :
CITY ELECTRIC COMPANY'S PROPOSED :
COGENERATION AND SMALL POWER :
PRODUCTION POLICY :

STIPULATION

1. Since May of 1986, Atlantic City Electric Company (hereinafter referred to as the "Company" or "Atlantic Electric") has been in the process of evaluating twelve (12) independent proposals which were submitted to the Company relating to the construction and development of qualifying facilities (hereinafter referred to as "QFs") and small power production facilities pursuant to the Public Utilities Regulatory Policies Act of 1978 (hereinafter referred to as "PURPA") and the sale of the electrical output therefrom to the Company in accordance with PURPA. In connection with its review of the proposals, the Company developed an evaluation and ranking system. In January, 1987, the staff of the Board of Public Utilities (hereinafter referred to as the "Staff") was advised that Atlantic Electric had completed its evaluations and was about to notify three of the QFs to commence negotiations with the Company. On January 14, 1987 the Staff requested and Atlantic agreed to withhold notification to the QFs until Staff had had an opportunity to review the methodology utilized by the Company to insure that it comported with Board policy on cogeneration and small power production. After its review of Atlantic Electric's procedures, on May 13, 1987 Staff issued its "Evaluation by the Staff of the New Jersey Board of Public Utilities of Atlantic Electric's Proposed Cogeneration and Small

Power Production Policy" (hereinafter referred to as the "Staff Report"). The Staff Report was distributed to the Company as well as to all QFs who had submitted proposals to the Company. The Staff Report was critical of the Company's procedures and policy and recommended a standard offer approach. Comments from all parties were solicited by the Staff by June 15, 1987. The Company, as well as all QFs, submitted comments covering a wide range of policy and other issues raised not only by Atlantic Electric's procedures but also by PURPA and the Board's existing policies on cogeneration.

2. The Staff has reviewed and considered all of the comments from the parties and has discussed with the Company a proposal for resolving the policy and procedural disagreements between the Company and the Staff over the development of cogeneration in Atlantic Electric's service territory, as well as the State of New Jersey. To this end, the Company and the Staff have entered into this Stipulation to promote the development of alternative power supplies in accord with the mutual desires of the parties and the Board.

3. The Board has expressed its position in favor of contract terms and conditions that foster development of alternative power sources. Under Docket No. 8010-687, the Board established guidelines for the determination of avoided cost to be paid to QFs under PURPA. In Atlantic Electric's case, that Order establishes (1) the PJM billing rate plus 10% as the avoided energy cost and (2) the PJM capacity deficiency value as the avoided capacity cost consistent with PURPA. The Board's determinations included the following quotations:

A. "The central guideline for the Board's consideration of this Docket is FERC Order No. 69 which suggests that the price that the QF receives for its energy or capacity sales to an electric utility be based upon avoided costs. Avoided cost is defined as follows:

The incremental cost to an electric utility of electric energy or capacity or both which,

but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source. (Order 69, Section 292.201(b)(6)).

The Board interprets this definition to mean that the purchase of energy from a QF will not significantly affect the bills of all other utility customers and that the QF will at the same time receive the true and full economic value for its energy or capacity. The Board's decision and order in this proceeding has thus been drawn with the intent of encouraging cogeneration and small power production but not to the detriment of electric utility customers."

B. "In setting the value of avoided energy costs at a figure of 10% above the PJM billing rate, the Board determined that such a rate "will help to adequately promote cogeneration and small power production in New Jersey and, at the same time, will yield long term benefits to utility ratepayers."

C. "It is the belief of this Board that it is sound policy for a larger QF to negotiate the rates for the sale of its power to electric utilities. Through such negotiations, a contract may be developed which will address and meet the particular financing and technical needs of a QF investor. For example, a hydroelectric or a resource recovery investor may desire a contract which yields greater revenues during the initial years of the agreement; conversely, a cogenerator utilizing natural gas may favor a contract rate which increases over time in order to keep pace with the cost of fossil fuels."

D. "It is our firm belief, however, that the negotiation of long term contracts that are tailored to the specific characteristics of a particular QF will maximize benefits to the QF as well as to the affected utility and its ratepayers. We are further of the opinion that the use of a basis should not adversely affect the negotiation process."

-E "Thus the Board recommends that the parties in future power sales negotiations, where financial constraints demand, consider establishment of a levelized price for energy sales, such levelization to be based upon long-term projections of avoided costs as presently defined by the Board."

F. "Further, the Board recommends, as it did in Docket No. 833-236, that a contract life equal in duration to the period of debt financing, or economic life of the facility should be an option made available by the electric utility to the QF. Such contracts should be based on long-term avoided cost as presently defined by the Board. Within this concept, mechanisms can be incorporated which assure that ratepayers will be held harmless by such pricing structures."

4. Staff represents that the concepts and agreements embodied within this Stipulation, including pricing levels, are consistent with the above and other determinations of the Board, including:

A. Establishment of a "Standard Price Methodology" to facilitate price agreement while still retaining an option on the part of QF developers to negotiate other pricing.

B. Use of the current PJM billing rate + 10% + avoided capacity costs as a basis for developing payment rates determined "before the fact" for long-term contracts.

C. Use of levelized payments, which have a substantial beneficial effect upon the financing of such projects because of the more stable, predictable cash flow they produce for the project than does a variable after-the-fact determined, avoided-cost price. It is recognized that this method of pricing yields payments for energy and capacity that exceed the utility's near-term avoided cost in the front years and are lower than avoided cost projections in the end years. It is anticipated that the aggregate long-term avoided costs will reasonably match the contract payments over the contract term,

provided that energy delivery is sustained throughout the contract term.

D. Contract terms extending up to 30 years from the date a QF facility starts operation.

5. The parties are not in full agreement as to the proper methodology to be used to establish avoided cost and the before-the-fact energy and capacity rates to be paid to QFs. The positions of the parties in this regard are:

A. The Company has proposed that payments under long-term contracts be based upon avoided costs (energy plus capacity) determined as a result of comparing alternate capacity expansion plans utilizing the Company's system planning approach. The Company further believes that once its forecasted capacity needs are met, the avoided cost for additional cogeneration capacity diminishes to the PJM running rate for energy; and that therefore any fixed payment recognizing a value for capacity also diminishes to zero. The Company incorporates herein by reference all of the positions and comments submitted to the Board in this matter and dated June 15, 1987.

B. Staff believes that further commercial incentives to QF project development are appropriate, including pricing to yield customer break-even (present value) on a contract life cycle basis (end of contract term) based upon the Company's projection of PJM energy costs, plus 10%, and capacity payments based on the PJM capacity deficiency values. Establishment of levelized rates ensures and allows calculation of, to the extent that electric production of a facility is maintained at expected levels, revenue streams from electric sales over the economic life of the project. Staff proposes that several payment schedules be developed in which a certain portion is levelized and the remainder tracks avoided cost or some other significant index. The more capital intensive the project, the higher is the degree of allowable levelization. This allows QFs flexibility to choose the degree of levelization required to meet

specific financing needs. This approach will appropriately value and attract long-term purchase of QF capacity and energy to the benefit of Atlantic Electric and its customers.

6. Notwithstanding these differences in approach, the parties have reached agreement upon a standard price methodology to be used at the present time. The parties have done this in the interest of assuring continued development of QF energy and capacity to service Atlantic Electric's customers and to protect the resources which have been expended by the QFs who submitted proposals to the Company and have an interest in the outcome of this proceeding.

7. Exhibit A to this Stipulation establishes the Standard Price Methodology agreed to by the parties for purchases by Atlantic Electric from QFs. The Standard Price Methodology has the following significant features:

A. Projects are categorized by technology and fuel source, that is, renewables (e.g., resource recovery; conventional hydroelectric); oil and gas; and coal. The percent of the price which is paid in levelized form may vary to reflect the degree of capital intensity of such projects and, therefore, the realities of project financing. In the Company's first 500 megawatt tier, the Company will provide energy levelization rates at the QFs' option not to exceed: 80% for renewable resource projects; 60% for coal projects; and 35% for oil and gas projects. In the second tier, the maximum energy levelization rates will be as follows: for in-territory renewable resource projects--50%; for coal projects--40%; and for oil and gas projects--20%.

B. In an effort to further improve project viability, the variable portion varies with (i) either PJM billing rate, the appropriate fuel index, or any mix thereof at the developer's option for oil, gas and coal projects; or (ii) GNP deflator, the PJM billing rate or any mix thereof at the developer's option, in the case of resource recovery and conventional hydroelectric projects.

C The capacity value is determined in the Standard Price Methodology to reflect the Board's Order in Docket No. 8010-687. A levelized capacity value will be payable in a manner to encourage on-peak and peak season production.

D The total payment derived in paragraphs A, B and C reflects the Board's Order in Docket No. 8010-687.

E The Standard Price Methodology shall provide for contract terms of between 15 and 30 years.

8. The purpose of the Standard Price Methodology is to establish standard pricing offers which will be available to any and all QF developers so as to facilitate the development of QF capacity and energy to the benefit of Atlantic Electric and its customers. The Board will pre-approve standard pricing offers, and standard pricing agreements signed between Atlantic Electric and a QF developer will be treated by the Board as having its approval. It is anticipated that resultant full contracts would receive the Board's final approval in an expedited fashion. In view of the fact that the remaining eleven (11) QFs have been held in abeyance, Staff agrees that these QFs should have the first opportunity to sign standard offers with the Company. In the event the Company's standard offer is not fully subscribed by the existing eleven proposals, the Company will continue to entertain and accept other offers made in accordance with this Stipulation as they are received.

9. The Standard Price Methodology will serve the additional function of assuring equal access and opportunity to all QF developers to contract with the Company.

10. A QF developer will not be eligible for a pricing agreement under the Standard Pricing Methodology unless the following minimum submittals have been made available to and are satisfactory to the Company:

A. FERC certification granting qualifying status to the facility; provided, however, that the Company may accept proposals

based on evidence that the project is certifiable under FERC's rules and regulations;

B. A statement of project definition including preliminary project design and construction schedule, anticipated project operation commencement and life, and year-by-year energy delivery;

C Letter of intent or similar evidence of host site control;

D Adequate fuel supply consistent with anticipated project life and energy production;

E A plan for obtaining all necessary project licensing;

F. Preliminary evidence of financeability of the project, and a preliminary financing plan;

G Evidence of thermal customer, if a cogenerator; and

H A milestone chart for the project and payment into a reserve fund not to exceed \$10.00/KW, which reserve fund shall be payable to the Company in the event milestones established in the contract are not substantially complied with by the QF. Full payment into the reserve fund will be due upon the QF's acceptance of a standard offer.

11. The Company's standard offer tiers are based on the Company's forecasted energy and capacity needs, which are based on existing capacity, planned retirement, forecasted load growth and planned and/or anticipated capacity additions. The Company and Staff agree that the first tier will be 500 megawatts and that there will be one subsequent 200 megawatt tier. Exhibit A to this Stipulation contains the prices applicable to each tier. To the extent a project does not fall completely within the first 500 megawatt tier (e.g., if there is 40 MW of power unallocated in the first tier and the next qualified project is 60 MW), so long as more than 50% of the

project's rated capacity is in the higher tier, the higher tier price shall apply to all sales to the Company. Over-subscribed tiers will be awarded by random drawings.

12. The Company shall be allowed to prioritize the proposals it has received using the following criteria:

- A. In-territory renewable QFs;
- B. In-territory dispatchable QFs;
- C. In-territory QFs;
- D. In-state dispatchable QFs;
- E. In-state renewable QFs;
- F. In-state QFs; and
- G. All others.

13. The parties agree that it is necessary and desirable to establish a procedure to review the pricing mechanisms and the level of price reflected in the standard price methodology, and the process by which contracts are to be developed and executed. This will assure both appropriate development of QFs and protection to the Company's customers against problems in the selection process. It is explicitly anticipated that the experience during the offer period together with the updated anticipation of the Company's energy needs will be the basis for a review and revision of the program. However, it is the intent of the parties to maintain continuity in the QF development program by maintaining ongoing communications regarding status, outlook and potential problem areas, and to jointly attempt to resolve such problem areas for prompt approval by the Board. Ongoing communications will include periodic review meetings and prompt written notifications to the Board regarding signed standard pricing agreements.

14. The Parties recognize that many QF projects will require negotiations on price and non-price terms which are not reflected in, or may require variation from, the Standard Price Methodology. These include, but are not limited to, terms such as:

- A. A technology not reflected in the Standard Price Methodology;
- B. Dispatchability;
- C. Electric system interconnection, operation and integration requirements;
- D. Energy delivery incentives and penalties; and
- E. Any other non-standard term or condition.

Atlantic Electric agrees not to impose suspense accounts, recapture pools, or other performance penalties, except as specifically identified in this Stipulation for dispatchable facilities. The parties recognize that such contracts and provisions will be subject to Board approval.

15. The signed offer under the Standard Price Methodology will not remain in force unless the QF developer executes a full contract within six (6) months of the date of signing of the standard price offer, provided, however, that a QF may request an extension of time for good cause, but in no event shall such an extension, together with the initial six-month period, exceed twelve (12) months. Each contract will specify initial target dates for construction commencement and operation commencement, along with limit dates which must be met in order for the signed pricing offer to remain in force.

16. All payments made to QFs for capacity and/or energy under this standard offer and contracts approved by the Board shall be recognized as having been a prudently incurred expense, a just and reasonable rate clearly in the public interest and, accordingly,

the Board will allow Atlantic Electric to flow-through and/or permit full and timely recovery in a LEAC proceeding of any such long-term contract purchase rates from its customers throughout the term of such contracts, regardless of subsequently approved avoided cost definitions.

17. The Exhibit A standard pricing offers will be effective on the date of the Board Order in this manner.

18. This Stipulation is subject to the understanding that it is solely for standardized pricing offer development and implementation as described herein. Any party may, without prejudice, fully litigate and contest such issues in future proceedings should this Stipulation not be approved by the Board.

19. The parties agree that the within Stipulation reflects mutual balancing of various issues and positions and is intended to be accepted and approved in its entirety. Each term is vital to this Stipulation as a whole, since the parties hereto expressly and jointly state that they would not have signed this Stipulation had any terms been modified in any way. In the event any particular aspect of this Stipulation is not accepted and approved by the Board, then either party hereto aggrieved thereby shall not be bound to proceed with this Stipulation and shall have the right to brief or argue all issues to a conclusion. The parties further recognize and agree that this Stipulation has been accepted and agreed to by the Staff and the Company in the interest of expediting the development of cogeneration and small power production and that with respect to any policy or other issues which were compromised in the spirit of reaching an agreement, neither party shall be prohibited from or prejudiced by arguing a different policy or position before the Board in its pending 5-year review of cogeneration and small power production policy in the State of New Jersey, which proceeding has been undertaken by the Board concurrently herewith.

20. The Company shall be entitled to amend its standard offer prices and procedures consistent with the Board's subsequent

findings in the 5-year review of cogeneration and small power production policies; provided, however, that such amendments shall apply only to standard offers which have not been accepted by the QF as of the time of such amendment. The policies and procedures agreed to herein shall remain in effect until such time as the Board acts on its 5-year review.

21. Attached hereto as Exhibit B is a "Schedule of Procedures and Timetable" for implementing the standard offer process contained in this Stipulation.

IN WITNESS WHEREOF, the parties hereto have this day caused this Stipulation to be duly executed.

ATLANTIC CITY ELECTRIC COMPANY
1199 Black Horse Pike
Pleasantville, New Jersey 08232

By: _____

Richard B. McGlynn, Esq.
Stryker, Tams & Dill
Attorneys for Atlantic City
Electric Company

STAFF OF THE NEW JERSEY BOARD
OF PUBLIC UTILITIES

Two Gateway Center
Newark, New Jersey 07102

By: _____

Steven Gabel
Steven Gabel
Director, Division of Electric

EXHIBIT A

**STANDARD PRICE METHODOLOGY
FOR
PURCHASE OF ENERGY...
BY
ATLANTIC CITY ELECTRIC COMPANY
FROM
QUALIFYING FACILITIES
IN
NEW JERSEY**

A. Objectives

1. Promote development of different types of Q7 energy resources in the Atlantic Electric's service territory, and State of New Jersey on behalf of Atlantic Electric customers, including gas/oil fired projects, coal or coal waste fueled projects, conventional hydroelectric projects, and resource recovery projects.
2. Promote availability of Q7 energy on a long term basis, at times when it is most valuable to Atlantic Electric's customers.
3. Implement, with Board approval, pricing that is consistent with the requirements of PURPA and Board orders.

B. Definition of Avoided Cost

Under Docket No. 8010-687, the Board established guidelines for the determination of the avoided cost to be paid to Q7s. That Order established (1) the PJM billing rate plus 10% as the avoided energy cost and (2) the PJM capacity deficiency rate as the avoided capacity cost.

Notwithstanding different positions as to the appropriate pricing methodology for before-the-fact pricing of purchases from Q7s, the Company and Staff have agreed to base this standard pricing methodology on the Board's methodology for after-the-fact determination of avoided cost.

C. Forecast of Avoided Cost

1. Capacity avoided costs are derived from projections of revenue requirements for the estimated costs associated with the PJM Capacity Deficiency rate.

The parties have agreed that capacity payments will be offered for capacity which meets PJM's criteria.

2. Energy avoided costs are derived from computer model production cost simulations of the operation of the Company and PJM generating stations over the term of the contract. This model is based on a current best estimate (base case) of future conditions, including:
 - a) energy and peak load forecasts for the Company and other members of PJM;
 - b) energy supply sources available to the Company and other members of PJM;
 - c) fuel price forecasts; and,
 - d) forecasts of relevant economic conditions, such as inflation.

3. The data presented here are based on economic and production cost forecasts as of November 1986.
4. Discounting and levelisation are based on the Company's projected weighted cost of permanent capital, currently 11.35%

D. Pricing Precepts

The fundamental precept of this standard pricing methodology is to reasonably match pricing to projected avoided cost over the contract term, on a present value or levelised basis, for the current best estimate of future conditions. A second precept is sustained annual delivery of energy by the QF over the term of the contract.

It is the intent of the standard price methodology to:

1. Provide a mix of fixed (level) and variable price components that will help developers meet the financing needs of projects of different capital intensity and potential fuel cost volatility. This means:
 - a) allowing higher levelisation for capital intensive projects with low fuel cost volatility; and,
 - b) allowing lower levelisation and hence more "indexing" to projects with low capital intensity but potentially high fuel cost volatility.
- c) developing a dispatchable unit methodology
2. Provide developers with a choice of escalators (indices) to be applied to variable price components, reflective of either energy value to Atlantic Electric's customers or major cost to QF operator.
3. Allow for contract terms of between 15 and 30 years.
4. Control the level of early year rate exposure to Atlantic Electric customers that results from leveling contract payments in excess of avoided costs. This requires capping the amount of levelisation.
5. Within the framework of the precepts noted above, namely break-even on a present value basis at the end of the contract and sustained annual energy delivery over the contract term, control the risk to Atlantic Electric customers of not realizing enough subsequent cost advantages (relative to the avoided cost) to compensate for early year incentive payments in excess of avoided cost.

I. Standard Price Formula for Contract Pricing

The parties have agreed to the following pricing formula:

$$\text{Payment in Year n, c/KWH} = \text{Levelized Cap'y Payment} + \text{Levelized Energy Payment} + \text{Variable Energy Payment}$$

Each of these terms will be described in more detail in the following sections, and numerical data will be displayed.

For Dispatchable Units the formula is expressed as two parts:

$$\text{Payment in Year n c/KWH} = \text{Variable Energy Payment} + \text{Levelized Energy Payment (to be determined)}$$

Plus

$$\text{Annual Payment} = \left[\text{Levelized Cap'y Payment} + \text{Levelized Energy Payment (to be determined)} \right] \times$$

$$8760 \frac{\text{hours}}{\text{year}} \times .85 \text{ (Capacity Factor)} \times \text{Availability Factor}$$

$$\text{Availability Factor} = \frac{\text{QF Availability in year n}}{\text{All System Availability in year n}}$$

Where Availability Factor exceeds 90% its value shall be set at 1.0

F. Dispatchable

Dispatchable is defined as Atlantic Electric's ability to call upon or not call upon the unit for its capacity at any hour during the year. Atlantic Electric will guarantee 3500 hours (non negotiable) of operation in any calendar year as established by its computer model production costing. Minimum starting notice and minimum run durations are subject to negotiation. The intent of the dispatchable pricing option is to provide a level annual capacity payment per kilowatt for the life of the contract which varies only with the ratio of a QF's availability as compared to Atlantic Electric's availability. This level annual capacity payment per kilowatt to be applied to the rated capacity of the QF is the sum of the levelized capacity payment and levelized energy payment presuming a capacity factor of 85% and 8760 hours per year.

G. Payments Depend on Time and Season of Generation

Energy and capacity payments are varied according to time and season of generation so as to encourage energy supply to Atlantic Electric when such energy has the highest value to Atlantic Electric customers.

On-Peak period:

Seven days per week 9:00 A.M. to 11:00 P.M. EST; about 58% of the hours in a year. (1) The choice of hours is consistent with existing Atlantic Electric load patterns.

Off-Peak period:

All other hours.

Peak Season:

Dec. through Feb. and June through September (7mo. or 212.25 days)

Off Season:

March through May and October through November (5 mos. or 153 days)

Peak Season = 58.1% of year

$$(1) 365.2 \times \frac{14 \text{ hrs.}}{\text{day}} = 0.5833 \checkmark$$

$$\frac{365.25 (24) \text{ hr}}{\text{yr}}$$

Energy and capacity payments are adjusted for time of delivery as follows:

1. Energy payments, for simplicity, are adjusted only for on-peak vs off-peak hours, with no seasonal adjustment. The adjustments are derived from production cost simulations, and reflect the relative value of energy to Atlantic Electric customers in these two periods, on an annual average basis.

$$2 = \frac{\text{On-Peak or off-peak billing rate}}{\text{Annual average billing rate}} = \begin{matrix} 1.15 \text{ for on-peak hours} \\ 0.79 \text{ for off-peak hours} \end{matrix}$$

Note that

$$1.15 (0.583) + 0.79 (1-0.583) = 1.0$$

so that the hourly price weighting yields the correct annual average energy price if energy is produced uniformly throughout the year.

2. Capacity payments, for non dispatchable units for simplicity, are provided only during on-peak hours during peak seasons, to strongly encourage production when energy is most valuable to Atlantic Electric customers. The intent is to encourage scheduling of maintenance and other outages for off-season months.

$$\text{capacity payment} = \frac{\text{annual average capacity payment}}{(0.581) (0.583)}$$

$$= 2.95 \times (\text{annual average capacity payment})$$

K. Levelized Capacity Payment

This payment is based on the projected PJM Capacity Deficiency payments. As described above, it is paid only for energy delivered during on-peak hours, and only during peak seasons. Capacity payments are predicated on an assumed annual capacity factor of about 85% for the QF. The entire capacity payment is levelized over the term of the QF contract.

Table-1 summarizes the levelized annual average capacity payments for QF's placed in service for each of the years from 1988 through 1994.

L. Levelized Energy Payment

Levelized Energy Payment, c/kWh = (L) $\frac{\text{Levelized Avoided Energy Cost, annual avg basis}}{\text{c/kWh}}$ (R)

L = Fraction of levelized avoided energy cost that is to be fixed for all years of the contract. L depends on type of project (technology and fuel), and has been chosen to provide higher levelization for capital intensive projects and lower levelization (higher variability) for fuel price sensitive projects.

As derived in Section 7,

R = 1.15 for on-peak hours

R = 0.79 for off-peak hours

LAVC = Levelized Avoided Energy Cost, on an annual average basis, as derived from production cost projections of PJM billing rates + 10%. These values depend on contract start year (because of escalation) and contract term (because of levelization). See Table 3.

Criteria for Selecting Values of L

1. Values of L are tailored to match capital intensity/potential fuel cost volatility tradeoffs for each type of QF to facilitate project financing.
2. For all projects, and contract terms maximum values of L have been established. This is intended to control the level of early year excess rate exposure to Atlantic Electric customers.
3. Values of L range from 0 up to the maximum shown in Table 2.

J. Variable Energy Payment

Variable Energy Payment, c/KWH in year n = (1-L) * (Base) * (Index I) * (X)

L, X Have been previously defined.

The following indices are available to the developer on a one-time election basis at the time contract is executed:

1. The PJM billing rate.
2. Natural gas price, as defined by the annual average natural gas cost to N.J. utilities as reported on FERC Form 423 and published in the DOE/EIA Publication "Cost and Quality of Fuels for Electric Utility Plants."
3. Oil price, defined as above for natural gas, but based on "Petroleum" as reported.
4. Coal price, as above for natural gas, but based on bituminous cost coal used by all plants owned (or partly owned) by N.J. utilities. Index is tonnage weighted and based on N.J. utility ownership of joint owned stations.
5. GNP deflator, as defined by the annual Implicit Price Deflator Index for Gross National Product referenced in Table 7.7 of the U.S.D.O.C./B.E.A. "Survey of Current Business" publication.
6. Any mix of the above indices subject to certain restrictions as follows:

Fuel price indices are available only to fossil fuel projects having single fuel capability, where the fuel being used establishes the index that may be used. For projects with dual or multi-fuel capability, the applicable fuel index associated with the lower cost fuel will be used on a year-by-year basis to encourage use of the most economical fuel.

I = Value of indices for the preceding year (n-1) relative to year value of the indices in 1987

"Base" is defined as the variable portion of the energy payment (Table 4-Estimated Values of Base) for the year of contract in service adjusted to 1987 values by the ratio of the estimated value of the chosen escalator for the year preceding in-service relative to the value of the chosen escalator in 1987.

For year n, I then becomes Indices in year (n-1)
Indices in 1987

Values of I will be established in the first quarter of each year based on available published values of the indices.

Table 3 presents a comparison of First Year estimated contract payments to projected avoided costs.

FIGURE 1

SUMMARY OF STANDARD PRICE METHODOLOGY

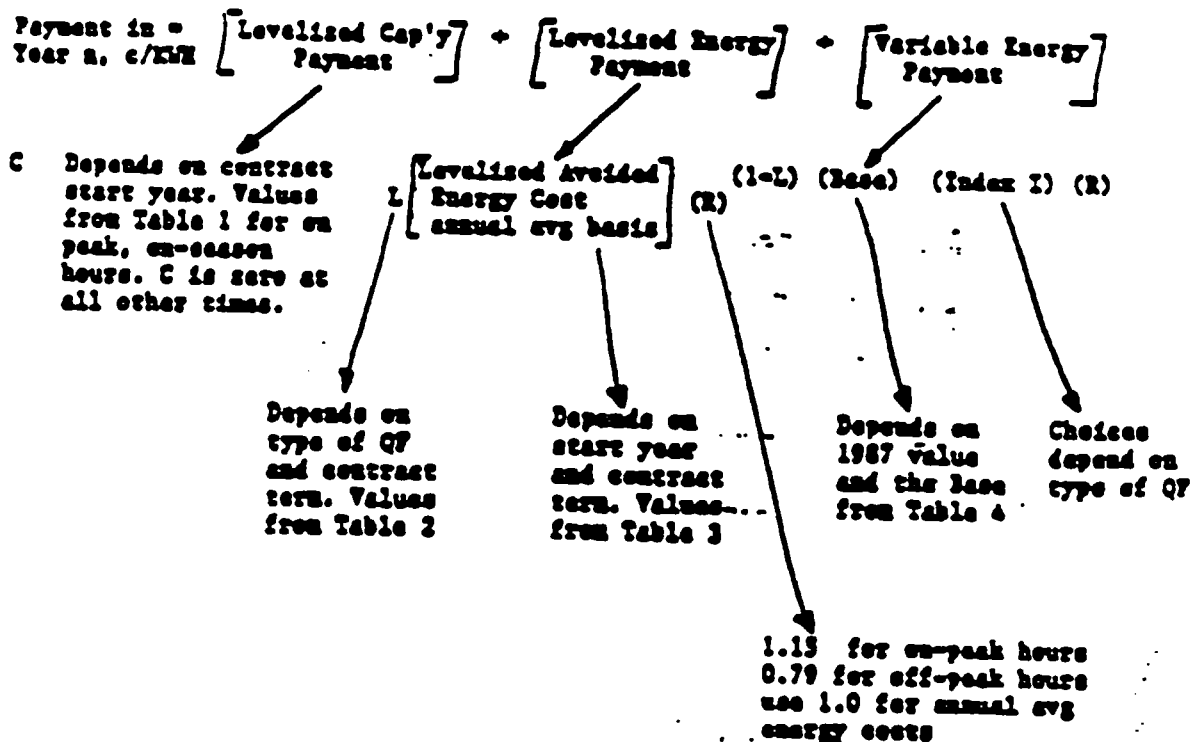


TABLE 1 - FIRST TIER

VALUES OF LEVELIZED ANNUAL AVERAGE CAPACITY PAYMENTS - cents/kwh

Starting Year -----	Contract Term (Yrs) -----	Annual Average Base -----	Actual Payment: Peak Season, On-Peak Period -----
1988	15	1.0147	
	20	1.0746	2.9934
	25	1.1238	3.1701
	30	1.1681	3.3210
1989	15	1.0590	3.4439
	20	1.1217	3.1240
	25	1.1732	3.3091
	30	1.2193	3.4669
1990	15	1.1034	3.5973
	20	1.1711	3.2610
	25	1.2270	3.4547
	30	1.2733	3.6197
1991	15	1.1332	3.7362
	20	1.2223	3.4030
	25	1.2608	3.6058
	30	1.3292	3.7784
1992	15	1.2031	3.9211
	20	1.2731	3.5490
	25	1.3363	3.7613
	30	1.3862	3.9421
1993	15	1.2981	4.0914
	20	1.3303	3.7025
	25	1.3945	3.9249
	30	1.4300	4.1139
1994	15	1.3097	4.2775
	20	1.3886	3.8635
	25	1.4536	4.0964
	30	1.5100	4.2941
			4.4343

TABLE 2 - FIRST TIER

Maximum Percentage of Levelized Avoided Costs to Be Fixed For Each Contract Term

PROJECT FUEL TYPE:		GAS/OIL	COAL	RENEWABLE RESOURCE (IN SERVICE TERRITC)
Contract Term Yrs. -----	All Projects Capacity Payments -----	(1) L -----	(1) L -----	(1) L -----
15	100%	35%	60%	80%
20	100%	35%	60%	80%
25	100%	35%	60%	80%
30	100%	35%	60%	80%

(1) L = Fraction of levelized Avoided Energy Cost (PJN Billing Rate - 10¢ that is to be fixed for all years of the contract. Values of L, from 0 up to the maximum indicated above, are available for each contract term.

TABLE 3 - FIRST TIER
Values of LREC(1), CENTS/KWH
Annual Average Basis

Starting Year Contract Term, Years	1988	1989	1990	1991	1992	1993	1994
15	4.2814	4.6401	5.1309	5.4771	5.8468	6.2433	6.6445
20	4.9823	5.2712	5.5870	5.9532	6.3849	6.7882	7.2532
25	5.3453	5.6621	6.0189	6.4144	6.8430	7.2974	7.7723
30	5.6806	6.0187	6.3951	6.8223	7.2784	7.7600	8.2700

(1) 100% Levelized Average Energy Cost (LREC) Billing Rate = 10%

TABLE 4 - FIRST TIER

ESTIMATED VALUES OF "BASE"

(Actual Values to be Determined based on Paragraph J6,
"After the Fact")

Contract In-Service Year -----	Forecast PJN Billing Rate - 10% For Preceding Year cents/KWH -----
1988	3.0386
1989	3.4078
1990	3.4542
1991	3.4623
1992	3.6406
1993	3.9309
1994	4.2860

TABLE 3 - FIRST TIER

COMPARISON OF ESTIMATED CONTRACT PAYMENTS
TO PROJECTED AVOIDED COSTS

Year	Avoided Cost (PJN - 10K - Levelized Capacity) M/KWH	Contract Term	Estimated Starting Price For Maximum & Levelized		
			Gas/Oil	Coal	R.R.
1988	44.2253	15	46.0442	49.8583	52.9096
	44.8244	20	48.0463	52.8626	56.7157
	45.3336	25	49.8318	55.5581	60.1391
	45.7394	30	51.4237	57.9879	63.2377
1989	45.1317	15	49.6814	53.2622	56.1266
	45.7590	20	51.8173	56.4757	60.2024
	46.2739	25	53.7206	59.3563	63.8649
	46.7366	30	55.4113	61.9385	67.1602
1990	45.6774	15	51.4644	55.6363	59.0098
	46.3340	20	53.7171	59.0491	63.3146
	46.8934	25	55.7683	62.2003	67.3298
	47.3562	30	57.5713	64.8261	70.8100
1991	48.3415	15	53.2108	58.2478	62.2774
	49.0288	20	55.5995	61.8517	66.8535
	49.6139	25	57.7635	65.1437	71.0478
	50.0978	30	59.6751	68.0749	74.7947
1992	51.5397	15	56.4186	61.8345	66.1672
	52.2599	20	58.9517	65.4425	71.0311
	52.8721	25	61.2374	69.1435	75.4683
	53.3783	30	63.2672	72.2616	79.4572
1993	55.4307	15	60.0832	65.8142	70.3989
	56.1849	20	62.7236	69.8019	75.4645
	56.8255	25	65.1672	73.5334	80.2263
	57.4000	30	67.3000	76.9000	84.5000
1994	59.8331	15	64.2367	70.1400	74.8611
	60.6246	20	67.0468	74.3896	80.2640
	61.2946	25	69.6338	78.3457	85.3155
	61.8000	30	71.9000	81.9000	89.8000

TABLE 1 - SECOND TIER

VALUES OF LEVELIZED ANNUAL AVERAGE CAPACITY PAYMENTS - cents/kwh:

Starting Year -----	Contract Term(Yrs) -----	Annual Average Basis -----	Actual Payment: Peak Season, On-Peak Period -----
1988	15	1.0147	
	20	1.0746	2.9934
	25	1.1256	3.1701
	30	1.1681	3.3210
1989			3.4439
	15	1.0390	
	20	1.1217	3.1240
	25	1.1732	3.3091
1990	30	1.2195	3.4669
			3.5973
	15	1.1034	
	20	1.1711	3.2610
1991	25	1.2270	3.4847
	30	1.2733	3.6197
			3.7362
	15	1.1536	
1992	20	1.2223	3.4030
	25	1.2606	3.6038
	30	1.3292	3.7784
			3.9211
1993	15	1.2031	
	20	1.2731	3.5490
	25	1.3363	3.7613
	30	1.3869	3.9421
1994			4.0914
	15	1.2351	
	20	1.3303	3.7025
	25	1.3943	3.9249
1995	30	1.4300	4.1139
			4.2773
	15	1.3097	
	20	1.3886	3.8633
1996	25	1.4556	4.0964
	30	1.5100	4.2941
			4.4545

TABLE 2 - SECOND TIER

Maximum Percentage of Levelized Avoided Costs to Be Fixed For Each Contract Term

PROJECT FUEL TYPE:		GAS/OIL	COAL	RENEWABLE RESOURCE (IN SERVICE TERRITOR
Contract Term Yrs.	All Projects Capacity Payments	(1) L	(1) L	(1) L
15	100%	20%	40%	50%
20	100%	20%	40%	50%
25	100%	20%	40%	50%
30	100%	20%	40%	50%

(1) L = Fraction of levelized Avoided Energy Cost (PJN Billing Rate - 10%) that is to be fixed for all years of the contract. Values of L, from 0 up to the maximum indicated above, are available for each contract term.

TABLE 3 - BIDDING TIER
Values of LME(11), cents/kWh
Annual Average Basis

Starting Year Contract Term, Years	1988	1989	1990	1991	1992	1993	1994
15	4.0707	4.3008	4.5576	4.8657	5.1949	5.5476	5.9363
20	4.4273	4.6638	4.9638	5.3384	5.6899	6.0273	6.4213
25	4.7311	5.0316	5.3479	5.6799	6.0316	6.4028	6.8090
30	5.0467	5.3467	5.6638	6.0029	6.4666	6.8994	7.3506

(1) 100% Levelized Average Energy Cost (LME) Billing Rate = 100%

TABLE 4 - SECOND TIER

ESTIMATED VALUES OF "BASE"

(Actual Values to be Determined based on Paragraph J6,
"After the Fact")

Contract In-Service Year -----	Forecast PJN Billing Rate - 10% For Preceding Year cents/KWH -----
1988	3.0558
1989	3.0830
1990	3.0742
1991	3.0728
1992	3.2668
1993	3.3074
1994	3.8074

TABLE 5 - SECOND TIER

COMPARISON OF ESTIMATED CONTRACT PAYMENTS
TO PROJECTED AVOIDED COSTS

Year	Avoided Cost (PJH - 10% - Levelized Capacity) M/KWH	Contract Term	Estimated Starting Price For Maximum & Levelized		
			Gas/Oil	Coal	R.R.
1988	40.4767	15	42.7343	44.7642	45.7791
	41.0758	20	44.0466	46.7896	48.1611
	41.5872	25	45.2057	48.5965	50.2919
	42.0107	30	46.2244	50.2102	52.2031
1989	41.3321	15	43.4837	45.9677	47.2547
	41.8394	20	44.8480	48.1490	49.7995
	42.4943	25	46.0787	50.0758	52.0739
	42.9371	30	47.1961	51.7875	54.1033
1990	41.7798	15	44.7630	47.7298	49.2132
	42.4364	20	46.2313	50.0099	51.8992
	42.9958	25	47.5896	52.1072	54.3808
	43.4587	30	48.8938	53.9126	56.5221
1991	44.2039	15	45.8478	49.4341	51.2273
	44.8912	20	47.4004	51.8320	54.0778
	45.4762	25	48.7885	54.0431	56.6704
	45.9602	30	49.9984	55.9791	58.9694
1992	47.1047	15	48.5549	52.4110	54.3390
	47.8249	20	50.1970	54.9751	57.3641
	48.4371	25	51.6603	57.2895	60.1040
	48.9433	30	52.9414	59.3454	62.5475
1993	50.8249	15	51.7053	55.7857	57.8260
	51.3791	20	53.4188	58.4585	60.9784
	52.0197	25	54.9763	60.9330	63.9114
	52.5490	30	56.3329	63.1169	66.5089
1994	54.6049	15	55.3727	59.5745	61.6754
	55.3944	20	57.1887	62.4170	65.0311
	56.0644	25	58.8336	65.0368	68.1383
	56.6179	30	60.2708	67.3877	70.9011

A -

EXHIBIT B**SCHEDULE OF PROCEDURES AND TIMETABLE**

<u>ACTION</u>	<u>RESPONSIBLE PARTY</u>	<u>DEADLINE</u>
BOARD APPROVAL	BOARD	-
LETTER TO COGENERATORS	COMPANY	14 DAYS
COGENERATORS' RESPONSE, INCLUDING DISPATCH- ABILITY, IN-SERVICE DATE, AND CAPACITY	COGENERATORS	28 DAYS
TIER PLACEMENT	COMPANY	35 DAYS
ACCEPTANCE BY COGENERATOR OF TIER PLACEMENT, PLUS CASH = \$10/KW	COGENERATOR	45 DAYS
ALTERNATE TIER PLACEMENT	COMPANY	60 DAYS

As indicated above, the deadlines shall run by calendar day from the date of the Board Order accepting this Stipulation. To the extent a cogenerator advises the Company that it does not wish to participate as placed, the next qualified cogenerator will advance to the position vacated thereby. The Company reserves the right to reject any proposal that does not satisfy all of the requirements of this Stipulation. Any resubmittal of a rejected proposal or modification of a previously accepted proposal (other than in the case of a modification pursuant to the terms of this Stipulation) will be considered a new proposal for purposes of paragraph 8.



STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

TWO BATTERY CENTER
TRENTON, N.J. 08646

ELECTRIC

IN THE MATTER OF INVESTIGATION
BY THE STAFF OF THE BOARD OF
PUBLIC UTILITIES OF ATLANTIC
ELECTRIC COMPANY'S PROPOSED
COGENERATION AND SMALL POWER
PRODUCTION POLICY

ORDER ADOPTING
STIPULATION OF
ATLANTIC CITY
ELECTRIC COMPANY

SERVICE LIST ATTACHED

BY THE BOARD:

Since May of 1986, Atlantic City Electric Company (Atlantic Electric or the Company) has been evaluating twelve proposals from potential cogenerators and small power producers (QPs) for the construction and development of cogeneration and small production facilities and the sale of the electrical output therefrom to the Company.

The Company independently developed an evaluation and ranking for the proposals and in January, 1987, advised staff of the Board of Public Utilities (staff) that it had chosen three potential QPs from the twelve applicants and was about to notify them so that negotiations with the Company could begin concerning these proposals. On January 14, 1987 the staff requested and Atlantic Electric agreed to withhold notification to the QPs until staff had had an opportunity to review the method used by the Company in choosing the three cogenerators to insure that it was in agreement with Board policy on cogeneration and small power production.

After its review of Atlantic Electric's selection process, on May 13, 1987, Staff issued its "Evaluation by the Staff of the New Jersey Board of Public Utilities of Atlantic Electric's Proposed Cogeneration and Small Power Production Policy" (hereinafter referred to as the "Staff Report"). The Staff Report was distributed to the Company as well as to all QPs who had submitted proposals to the Company and to the Department of Commerce and Economic Development and the Division of Rate Counsel.

The Staff Report was critical of the Company's selection process and recommended that the Company abandon that procedure and implement a standard offer approach. Staff's major concern with the procedure implemented by Atlantic Electric is that Staff believes the bidding procedure used by Atlantic is contrary to previous Board Orders and the Public Utilities Regulatory Policies Act (PURPA) since Atlantic Electric's policy does not base pricing on avoided cost, which is designed to imitate a competitive market, but instead bases prices on a bid approach whereby many sellers face only one potential buyer. This monopoly process is exactly what PURPA was intended to eliminate. Atlantic Electric would have had QPs, in effect, bid against each other rather than against the utility's avoided cost. Further, Staff believes that Atlantic Electric's approach was flawed in its implementation since the participating QPs did not know the rules of process and were not cognizant of Atlantic Electric's assessment criteria, to the disadvantage of themselves and to the State as a whole. Atlantic Electric believes their selection process comported with Board policy and PURPA and would provide long term benefits to their customers.

Comments from all parties were solicited by the Staff by June 15, 1987. The Company, eleven of the twelve QFs, the New Jersey Department of Commerce, Division of Energy, and Rate Counsel submitted comments covering a wide range of policy and other issues raised not only by Atlantic Electric's procedures but also by PURPA and the Board's existing policies on cogeneration and small power production.

The Federal Energy Regulatory Commission (FERC) Order No. 69 issued February 19, 1980, provides that the price a qualified facility (QF) receives for its energy or capacity from an electric utility be based upon avoided costs. Avoided cost is defined as follows:

The incremental cost to an electric utility of electric energy or capacity or both, but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source. Order 69, Section 29: 201(b)(6).

In addition, Section 292.304(b)(5) of the FERC PURPA guidelines states:

In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for purchases differ from avoided costs at the time of delivery.

This section supports the development of levelized avoided cost pricing, which levelizes estimates of avoided cost so that the QFs receive a more stable payment pattern but, on a present value basis, the avoided cost standard is adhered to.

The Board, on October 20, 1980, initiated a generic proceedings pursuant to PURPA Section 210 (16USCA 824a-3). After reviewing the final compliance plans submitted by each utility, together with comments from all parties to the proceedings, and after hearing considerable public statements and testimony, the Board set the avoided energy cost at the PJM billing rate plus 10% and the avoided capacity rate at the PJM capacity deficiency payment.

Consistent with guidelines established in PURPA Section 210, FERC Order 69, and previous Board Orders, and upon review and consideration of the comments received regarding this matter, a proposed stipulation for resolving the policy and procedural disagreements between the Company and the Staff over the development of cogeneration and small power production in Atlantic Electric's service territory and the state of New Jersey was submitted to the Board by the Board's Staff and the Company. The agreement incorporates standard long term levelized contracts for the purchase of QF power by Atlantic Electric and assures that QFs receive the full economic value for their energy and capacity. Said Stipulation was submitted to the Board on August 20, 1987.

The standard price offers were established by the signatories to the agreement as a means of facilitating a pricing agreement between QFs and the company. It is recognized that certain QFs may require contract terms or conditions which differ from the standard price offers. Accordingly, the establishment of standard price offers should not limit the ability of a QF to negotiate a power purchase agreement with the company which differs from the standard offer so that any specific project requirements can be met.

The Agreement embodies the following significant features:

- A) Establishes a "Standard Price Methodology" to facilitate price agreement: while retaining an option on the part of QF developers to negotiate other pricing terms to meet the specific needs of individual projects.
- B) Bases pricing levels upon projections of the PJM billing rate + 10% for energy and the PJM capacity deficiency payment for capacity consistent with Board policy.

- C) Establishes a levelized rate which allows for the calculation of revenue streams from electric sales over the economic life to the project to the extent that electric production of a facility is maintained at expected levels.
- D) Provides for contract terms of up to 30 years.
- E) Varies the degree of allowable levelization to reflect the degree of capital intensity associated with different technologies such as hydroelectric, resource recovery and fossil fuel projects.
- F) Provides levelization, up to the maximum degree allowed, at the option of the developer. The variable portion of the payment varies with either (i) the PJM billing rate (ii) a fuel index for oil, gas and coal projects or (iii) the GNP deflator for resource recovery and hydroelectric projects, or any mix thereof, at the developer's option.
- G) Provides for energy and capacity payments to be made in a manner that will encourage on-peak and peak season production.
- H) Provides all QF developers equal access and opportunity to contract with the company.
- I) Offer developers an optional payment scheme for those willing to be dispatchable.
- J) Protects the company from entering into contracts with developers of highly speculative projects by requiring minimum developer qualifications for obtaining and retaining the standard pricing offer.
- K) Ranks projects based on their potential benefits to the company and the State.

The Board believes the Standard Price Methodology described above represents a significant step in furthering the Board's policy of promoting cogeneration and small power production in the state. The Board recognizes that the use of levelized pricing yields payments for energy and capacity that exceed costs for the utility's near-term alternative, and therefore, raises the immediate charges to customers. However, in the long term, contract pricing is expected to fall below avoided costs, thereby reasonably matching pricing to the projected avoided costs over the contract term and providing economic energy and capacity to the ratepayers. Levelized payments could result in payments to QFs which exceed avoided costs over the term of the contract if actual avoided costs are below projected values. However, this risk is balanced by the fact that if actual avoided costs are above projected values, levelized payments will result in the QF receiving less than avoided cost.

Due to the special circumstances surrounding the remaining eleven QFs who have been unable to negotiate a power purchase agreement with Atlantic Electric for a significant period of time, they will be considered first in filling the 700 MWs of capacity incorporated in the agreement. The standard price methodology embodied in the agreement will remain in effect at a minimum until such time as the Company has offered a standard price offer in accordance with the stipulation to all eleven QFs or until 700 MWs have been contracted for by QFs included in the eleven. If the 700 MWs of capacity is not filled by the eleven QFs, the standard price methodology will remain in effect pending the outcome and effective date of the Board's Five Year Review of Cogeneration and Small Power Production Policies or until 700 MWs have been contracted for, whichever comes first.

The parties have agreed that it is necessary and desirable to establish a procedure to review the pricing mechanisms and the level of price reflected in the standard pricing methodology, and the process by which contracts are to be developed and executed. The Board concurs. Therefore the Company shall provide periodic updates to staff regarding the status of the agreement.

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Steven Gabel, Director:
Michael Ambrosio, Principal Engineer
Denise Chilton, Rate Analyst II
New Jersey Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

The Company has agreed not to impose suspension accounts, recapture costs, or other performance penalties, except as specifically identified in the stipulation for dispatchable facilities.

Neither party to the stipulation shall be prohibited from or prejudiced by arguing a different policy or position before the Board in its pending Five Year Review of Cogeneration and Small Power Production Policy.

The Company shall be entitled to amend its standard offer prices and procedures consistent with the Board's subsequent findings in the Five Year Review; provided, however, that such amendments shall apply only to standard offers which have not been accepted by the QF as of the time of such amendment.

The Board also has before it a letter motion from Mobil for expeditious action in this matter and a motion from Atlantic Electric requesting a hearing. Both are considered moot by the Board's acceptance of the stipulation which will allow expeditious implementation of a QF's contracting policy. A motion from Rate Counsel for a hearing is similarly rendered moot. The policy concerns of the Public Advocate, as well as those of all other parties, can be fully aired in the Board's procedure for its Five Year Review of Cogeneration and Small Power Production Policies (Docket No. 8010-487 B).

After careful review of the record in this matter, the Board HERESY FINDS that:

- 1) The written stipulation and Standard Price Methodology attached hereto and made a part hereof with regard to Atlantic City Electric Company is reasonable, is in the public interest, and is in accordance with applicable law.
- 2) All payments made to QFs under the Standard Price Methodology will be considered pre-approved price agreements and are recognized as having been prudently incurred and therefore:
- 3) The Board will allow Atlantic Electric to fully and timely recover the payments therein throughout the term of any final agreements with QFs that receive Board approval.
- 4) The review of the Standard Price Methodology will be conducted in accordance with terms of the stipulation.
- 5) This Order renders moot any motions currently pending before the Board regarding this matter.

Accordingly, the Board HERESY APPROVES the attached stipulation and HERESY DIRECTS the company to take all steps necessary for its expeditious implementation.

DATED: August 28, 1987

BOARD OF PUBLIC UTILITIES
BY:

Barbara A. Curran
BARBARA A. CURRAN
PRESIDENT

George H. Barbour
GEORGE H. BARBOUR
COMMISSIONER

Robert N. Guido
ROBERT N. GUIDO
COMMISSIONER

ATTEST:

Ida Marie Engelhardt
IDA MARIE ENGELHART
ACTING SECRETARY

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Cogeneration and Small Power Production Service List

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TRANSCO Energy Company
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EXHIBIT F

**TECHNICAL GUIDELINES
FOR
CUSTOMER SERVICE
AT
SUB-TRANSMISSION AND TRANSMISSION
VOLTAGES**



TECHNICAL
GUIDELINES
for
Customer Service
at
SUB-TRANSMISSION AND TRANSMISSION
VOLTAGES

MAY, 1985

INTRODUCTION

The purpose of this Information Guide is to provide preliminary information to all Atlantic Electric customers who are interested in receiving service at transmission or subtransmission voltage at their facility. Although it is impossible for this guide to provide all answers for the customers' particular needs, this information should be a starting point for any transmission class and subtransmission class customers who are considering electric service from Atlantic Electric at 23kV and above.

The purpose of this guide is also to consider technical and safety requirements so that adequate protective equipment can be installed to allow reliable operation of the Atlantic Electric system without affecting the reliability of electric service to other customers and provide safety for the general public as well as Atlantic Electric employees.

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II.	Types Of Services Furnished
III.	Information Furnished By Atlantic Electric
IV.	General Technical Requirements
V.	General Operating Requirements
VI.	Protection Requirements
VII.	Metering Requirements
VIII.	Responsibility

CUSTOMER SERVICE ENTRANCE REQUIREMENTS FOR
TRANSMISSION CLASS AND SUBTRANSMISSION CLASS CUSTOMERS

I. GENERAL:

The following requirements and standards for connection of a customer to the Atlantic Electric system shall be met to attempt to assure the integrity and safe operation of the Atlantic Electric system with no deterioration to the quality and reliability of service to other customers.

- A. All customers shall make application to Atlantic Electric for approval to interconnect their facilities with the Atlantic Electric system.
- B. Atlantic Electric shall require the following as part of the application:
 - 1. Plans and specifications for the proposed installation (to be sealed by a licensed New Jersey engineer).
 - 2. One line diagram and details of the proposed protection schemes.
 - 3. Service details (underground or aerial).
 - 4. Interrupting device types and ratings.
 - 5. Electrical load requirements including motor loads, type and sizes
- C. Atlantic Electric may require the following additional information as part of the application.
 - 1. Transformer ratings, connections and impedance data.
 - 2. Power factor correction capacitor ratings and connections

3. Unusual load characteristics, such as those due to furnaces, thyristors and other non-linear loads.
4. Voltage balance requirements.
5. Switchgear specifications including protection device types and ranges.
6. Protection and control schematic drawings as appropriate.
7. Point of interconnection physical arrangement drawings.
8. Expansion plans, projected loads, future substation development and timing.

II. TYPES OF SERVICES FURNISHED:

It is the customer's responsibility to secure information pertaining to types of service available from Atlantic Electric before he completes his electrical plans. Atlantic Electric will generally supply service from a facility close to the load. Normal service voltages provided by Atlantic Electric are: 23kV, 34.5kV, 69kV and 138kV; 60 Hertz; three-phase nominal. However, all service voltages are not available in every locality. Depending upon the location of the customer's service, cost of extension of service may be the responsibility of customer. Specific information can be obtained from Atlantic Electric Representatives.

A. Single Line Supply:

A typical example of Atlantic Electric-customer interconnection is shown in Figure 1 and is intended to be illustrative only. It consists of a single line from a single substation bus and connects to a single transformer with multiple connections to the customer's load center on the low voltage side of the transformer.

B. Multiple Interconnection Lines:

When a single-line supply is not adequate, multiple supply lines may be provided by Atlantic Electric at an additional cost. Typical configurations of two interconnection lines which Atlantic Electric may provide are shown in figures 2, 3, 4 and 5. However, all these configurations may not be available at all locations within Atlantic Electric service area. For a particular interconnection requirement, the customer should contact Atlantic Electric Commercial/Industrial Representatives.

Figure 2 is an illustration of a single interconnection line that is supplied from a second utility source operated normally open at or near the customer's installation. The second utility source may be from the same substation or from a second nearby substation. The advantage of this type of service is that the customer is more likely to experience only a momentary outage (if the switches are automatic) or short-time outage (if the switches are manual) instead of an extended outage on his substation during a fault on Atlantic Electric's line.

Figure 3 illustrates a single interconnection made in the middle of a transmission line with automatic switching to isolate a faulted line section. The advantage of this type of service is that the customer is more likely to experience only a momentary outage instead of an extended outage on his substation during a fault on Atlantic Electric's line. Atlantic Electric, however, can not guarantee continuous uninterrupted service under any circumstances.

If a customer desires two interconnection points with two Atlantic Electric sources, they can be supplied to the customer as shown in Figure 4. The advantage of this type of service is that the customer should experience a momentary outage on only one of the two customer's transformers during a fault on Atlantic Electric's line. Atlantic Electric can offer two interconnection lines to the large industrial customer as shown in Figure 5. The advantage of this type of service is that the customer should experience no interruption on his line during a fault on the Atlantic Electric's line, unless a fault should occur on both lines simultaneously.

III. INFORMATION FURNISHED BY ATLANTIC ELECTRIC:

- A. Initial short circuit duty at the customer's delivery point - minimum and maximum - three-phase and phase to ground.
- B. Anticipated future short circuit duty at the customer's delivery point - minimum and maximum - three-phase and phase to ground.
- C. Expected minimum, maximum and normal voltage at the customer's delivery point.
- D. X/R ratios.
- E. Specific protection requirements to coordinate with the Atlantic Electric System.
- F. Specific reclosing practices on normal and alternate supply facilities.
- G. Harmonic content, voltage fluctuation, and current unbalance constraints required by Atlantic Electric.

- K. The customer may request additional information such as:
- a. Supply line construction and routing.
 - b. Supply substation arrangement and location
 - c. Utility grounding and lightning protection schemes.
 - d. Characteristics and protection of other customers' facilities served from the same source.

IV. GENERAL TECHNICAL REQUIREMENTS:

- A. Prior to construction, the customer shall submit electrical and site plans and specifications of the proposed installation sealed by a licensed New Jersey engineer for review by Atlantic Electric. A single-line diagram and details of the proposed protection schemes are required. The Company shall not, by acceptance of the plans and specifications, assume responsibility for damage to customer's property, or the property of any other individual or entity, whether customer of Atlantic Electric or otherwise, and/or personal or bodily injury or death to any person or persons caused by or arising out of or in connection with the customer's installation. Responsibility for design and installation remains with customer and customer's professionals and contractors. Review by Atlantic Electric is for informational purposes only and to permit Atlantic Electric to review compatibility with the Atlantic Electric system. Review by Atlantic Electric is without liability or responsibility to customer and Atlantic Electric shall have no responsibility for consequential, special or other damages.

- E. The installation must be in compliance with the requirements of the National Electrical Code and all applicable local, state and federal codes or regulations and customer shall remain solely responsible for compliance therewith. Prior to interconnection, the Company must be provided with evidence of satisfactory electrical inspection by an authorized inspection agency.
 - C. The installation shall be done in a proper and workmanlike manner utilizing licensed professionals where required, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, the National Electrical Manufacturers Association and the American National Standards Institute shall at a minimum, be observed to the extent that they are applicable.
 - D. Atlantic Electric will designate the location of the interconnection between the Atlantic Electric's incoming overhead line (or incoming underground insulated cable) and the customer's service entrance line (or insulated cable).
 - 1. For underground service installations, Atlantic Electric will splice the customer's cable(s) into Atlantic Electric's cable(s) at the manhole designated by Atlantic Electric as the point of interconnection between the customer's and Atlantic Electric's systems.
- To insure compatibility with Atlantic Electric's cable(s) and to expedite replacement of a faulted customer owned cable, the

selection of the customers service cable(s) shall be reviewed by Atlantic Electric prior to purchase.

2. For overhead service installations, Atlantic Electric will provide the necessary dead end strain assemblies and make the connections to the customer's service entrance line(s) at the point of interconnection between the customer's and Atlantic Electric's system. The customer shall provide Atlantic Electric full details on the customer's service entrance conductor(s) at the point of interconnection.

Design of the customer's point of interconnection structure shall be based on Atlantic Electric's requirements for incoming line tension, mounting height above ground and phase spacing of Atlantic Electric's dead end assemblies.

- E. Atlantic Electric reserves the right, but shall not have the obligation, to inspect the service entrance facilities before energizing. Such inspection, or failure to inspect, shall not render the Company liable or responsible for any loss or damage resulting from defects in the installation or failure to comply with the Company requirements. Responsibility and liability for any and all claims of damage, personal injury, death and/or property damage shall be solely that of customer and customer's professionals.
- F. The customer shall at a minimum meet the requirements contained in this guide in addition to the requirements published in the following A.E. guides (where applicable).
 1. Information and Requirements For Electric Service Installations.

2. Requirements For Multifed Primary Service.
3. Technical Guidelines For Cogenerators And Small Power Producers.
- G. The customer may obtain a copy of these guides from an Atlantic Electric Commercial/Industrial Representative, at an appropriate division office listed below:

Bridgeton — 431-7995

Manahawkin — 397-5301

Clementon — 589-3161

Pleasantville — 645-4154

Swanton — 465-3177

V. GENERAL OPERATING REQUIREMENTS:

- A. The connection of the customer's equipment with the Atlantic Electric system must be designed by customer so as not to cause any reduction in the quality of service which Atlantic Electric provides to other customers with regard to abnormal voltages, frequencies or service interruptions. Violation of this provision shall give Atlantic Electric the right to open the disconnect device with prior notice to the customer if it is not an emergency situation and the right to open the disconnect device without prior notice if it is an emergency situation.
- B. Atlantic Electric reserves the right to inspect customer's equipment or devices associated with the interconnection.
- C. Three-phase standard transmission class voltages supplied by Atlantic Electric are 23kV, 34.5kV, 69kV and 138kV. However, all of these voltages are not available at all locations. The Company must be consulted for the voltages available at the customer's desired service location.

- D. The average operating power factor of a customer's load at the point where the electric service is metered shall not be less than 90% lagging. The customer will be charged an additional cost for not meeting this requirement.
- E. Switching of the disconnect device (manual or automatic) shall be under the administrative control of the Atlantic Electric System Operator. Atlantic Electric reserves the right to open the disconnect device without prior notice to the customer during a system emergency, or where customer's equipment interferes with service to other customers of Atlantic Electric.
- F. In such circumstances where an emergency does not exist, Atlantic Electric may request the opening of (or open) the disconnect device with prior notice to the customers. The following are circumstances by way of illustration in which Atlantic Electric might exercise this right.
1. Atlantic Electric's inspection of customer's interface station equipment reveals a potentially unsafe condition.
 2. The customer's equipment interferes with other customers on the Atlantic Electric system.
 3. Atlantic Electric requires repair, test or maintenance of utility facilities.

In each instance adequacy of notice will be determined solely by Atlantic Electric under the circumstances existing. If the customer fails to take corrective action within the time specified, Atlantic Electric may disconnect customer and in such event Atlantic Electric shall have no liability to customer.

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- G. An automatic disconnecting device, when provided, must isolate the customer's facility from the Atlantic Electric system within a time period specified by Atlantic Electric for, but not necessarily limited to, the following conditions:
1. A fault on the customer's equipment.
 2. A fault on the Atlantic Electric system.
 3. A deenergized Atlantic Electric line to which the customer is connected.
 4. An abnormal operating voltage or frequency on the line.
 5. Loss of phase or improper phase sequence.
 6. Total harmonic content in excess of 5%.
 7. Abnormal power factor.
- H. The customer's primary transformer shall be delta connected on the source side (i.e. Atlantic Electric) so as not to be a contributor to one-line to ground faults on the Atlantic Electric system. There shall be no deviation from this practice without express authorization from Atlantic Electric in writing.
- I. The customer's equipment must be so designed and installed that power cannot flow into (back feed) Company facilities which are faulted (short circuited) or which have been de-energized. In addition, unless waived in writing by Atlantic Electric, the customer shall make provision for the disconnect device to accept an Atlantic Electric padlock. Atlantic Electric personnel shall have access to the padlock at all times.

- J. The customer shall bear the cost of any interconnection and protective relays deemed necessary by Atlantic Electric. The need for these devices is outlined in general protective requirements in section VI.
- K. The protective scheme will be reviewed by Atlantic Electric and tailored to the individual customer's requirements. This measure is intended solely to ensure coordination with existing protective devices on Atlantic Electric's line. The Company shall not, by its review, assume responsibility or liability for damage to the customer's property, or the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facilities. The customer will be responsible for the procurement of any protective devices specified by Atlantic Electric. The customer will be required to modify the protective relay scheme, at his cost, should future alterations in Atlantic Electric's line configuration warrant such changes.
- L. Atlantic Electric requires a mandatory initial inspection of the interface protective devices and also requires an annual inspection of these devices. The testing and inspection must be done by a reputable testing firm which will submit an official report to Atlantic Electric. This testing will be at the customer's expense. Atlantic Electric may, at its option, provide testing service to the customer at a fee to be fixed by Atlantic Electric. In such event, however, Atlantic Electric shall not be responsible for nor assume

any responsibility for damage to the customer's property, or the property of any other individual or entity, and/or injury or death to person or persons caused by or arising out of or in connection with the customer's facilities, the testing of such facilities, or the failure to test such facilities. Such responsibility shall remain solely with customer and customer shall indemnify, defend and agree to hold harmless Atlantic Electric from and against any and all such liabilities.

In addition, Atlantic Electric reserves the right, for its own purpose, to inspect the interfaced protective devices at anytime. Atlantic Electric reserves the right to disconnect the customer if it is evident that proper maintenance and testing is not being provided.

- M. The customer shall design and provide adequate lightning protection to its facility in order to protect both their equipment and Atlantic Electric's equipment.

VI. PROTECTION REQUIREMENTS:

- A. The protection equipment provided on the customer's equipment must at a minimum be designed to:
1. Provide adequate protection against faults, overloads, or other abnormal conditions in the customer's equipment.
 2. Prevent damage to Atlantic Electric's equipment (lines, transformers, etc.) in the event of a fault or other problem in the customer's equipment.

3. Prevent outages or other adverse effects on other Atlantic Electric customers.
4. Provide a safe means to control, operate and disconnect the customer's equipment.
- B. The customer must at all times provide access for Atlantic Electric personnel to the entrance equipment.
- C. All switching of the customer's entrance equipment must be under the direction of the Atlantic Electric's Load Supervisor.
- D. It is the customer's responsibility to select, install and maintain adequate protection for their own equipment. Fuse size/type information, single line and other information on the overall protective relaying schemes must be provided to Atlantic Electric. Atlantic Electric will review the compatibility of the customer's proposal with the Atlantic Electric protective relaying on the source terminal. Atlantic Electric shall be given the opportunity to review the design of the finalized protection arrangements for informational purposes. Such review by Atlantic Electric shall not, however, relieve customer from liability and responsibility for design, installation or operation. The review is intended solely for determination of compatibility with the Atlantic Electric system. Responsibility for damage to the customer's property, the property of any other individual or entity, and/or injury or death to person or persons caused by or arising out of or in connection with the customer's facilities shall remain the sole responsibility of customer and Atlantic Electric shall have no liability therefore.

- E. The protective relaying supplied by Atlantic Electric at the source end of the customer's supply line is primarily intended for protection of that supply line.
- F. Transformers and all low side equipment must be protected solely by the customer's protective equipment. Transformers must be protected by either primary fuses or protective relays. Relaying schemes without a high side interrupting device must either include transfer trip to Atlantic Electric's source substation or simulate a high side line fault. If the source line supplies other customers, the faulted equipment must be automatically disconnected so that other customers may be restored.
- G. For customers with an automatic throwover scheme between a normal and an alternate source, the customer must provide a blocking scheme to prevent transfer of a fault on the customer's equipment.
 - 1. The transfer blocking requirement may be waived if both source lines solely supply the customer.
 - 2. Atlantic Electric will provide settings for the transfer scheme. The purpose of the settings is to provide proper timing in coordination with Atlantic Electric facilities and not for the protection of customer's equipment or customer's facility. Atlantic Electric will also set the relays and periodically test the transfer scheme for a fee to be established by Atlantic Electric. The customer also has the option of selecting an outside contractor for testing the transfer scheme. In the event Atlantic Electric sets the relays and/or tests the relays,

such setting or testing shall be solely for the purpose of timing and coordination for compatibility of Atlantic Electric equipment and not for the protection of customer's equipment and facilities. Atlantic Electric does not assume any responsibility for damage to the customer's property, or to the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facility, the setting of the relays, or the testing thereof. Such responsibility shall remain solely with customer.

H. Customers with larger transformers (75 MVA or larger) that are tapped on a transmission line using a power line carrier protective relaying scheme may need a carrier blocking terminal at their site and/or a carrier wave trap to insure the reliability and security of the relaying scheme which shall be designed and installed by customer, at customer's expense if required.

I. Reclosing:

1. If the source line is of overhead construction, an automatic breaker reclose could be employed at the Atlantic Electric source and following trips for line faults. If the line is used solely to supply the customer, a reclose time acceptable to both the customer and Atlantic Electric shall be determined.
2. Usually a high-speed reclose is not acceptable due to fault stress on Atlantic Electric equipment and torque stress on the customer's motors and other equipment.

3. A cable source line or other possible constraints will prohibit an automatic breaker reclose.

J. Customers with Internal Generation:

1. The customer must supply an adequate protective relaying scheme to trip their end for a fault on the Atlantic Electric source line. Atlantic Electric shall be given the opportunity to review the acceptability of any such proposal. The Company, in making such review, does not assume any responsibility for damage to the property of customer, the property of any other individual or entity, and/or injury or death to any person or persons caused by or arising out of or in connection with the customer's facilities, the design of the protective relaying scheme, or the operation of the protective relaying scheme. Such responsibility shall remain solely with customer.

Examples of schemes:

- a. Transfer trip from Atlantic Electric's end.
 - b. Directional overcurrent or reverse power relaying.
 - c. Larger generating units may require full impedance relaying terminal and power line carrier equipment.
2. The customer's generation must be tripped off line for voltages and frequencies outside acceptable limits.
 3. Customer shall obtain a copy of "Technical Guidelines for Cogenerators and Small Power Producers" from Atlantic Electric.

VII. METERING REQUIREMENTS:

A. GENERAL

Normally, service will be metered at secondary voltage. However, metering at other voltages may be available subject to negotiation. The type, size, location and number of meters to be installed will be determined by Atlantic Electric. The customer shall notify Atlantic Electric promptly of any proposed additions to the equipment or changes in their present wiring system. Noncompliance with this requirement will be deemed sufficient cause to hold the customer liable for damage to the Company's equipment or other loss to company or other customers caused as a result of changes in the customer's installation. All equipment furnished by the Company located in the customer's premises shall remain the property of the Company and may be removed or attended by the Company in the event such equipment is no longer required or the customer discontinues service. Meters must not be connected, disconnected, altered or removed except by written permission from the Company.

B. Meter Location

Atlantic Electric must be consulted and will endeavor to select a location of metering equipment that will be mutually satisfactory to both parties. However, Atlantic Electric will have final determination of the location of the metering equipment in all cases. Not less than 3 feet of clear unobstructed space shall be provided under and in front of all metering equipment.

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C. Metering Equipment

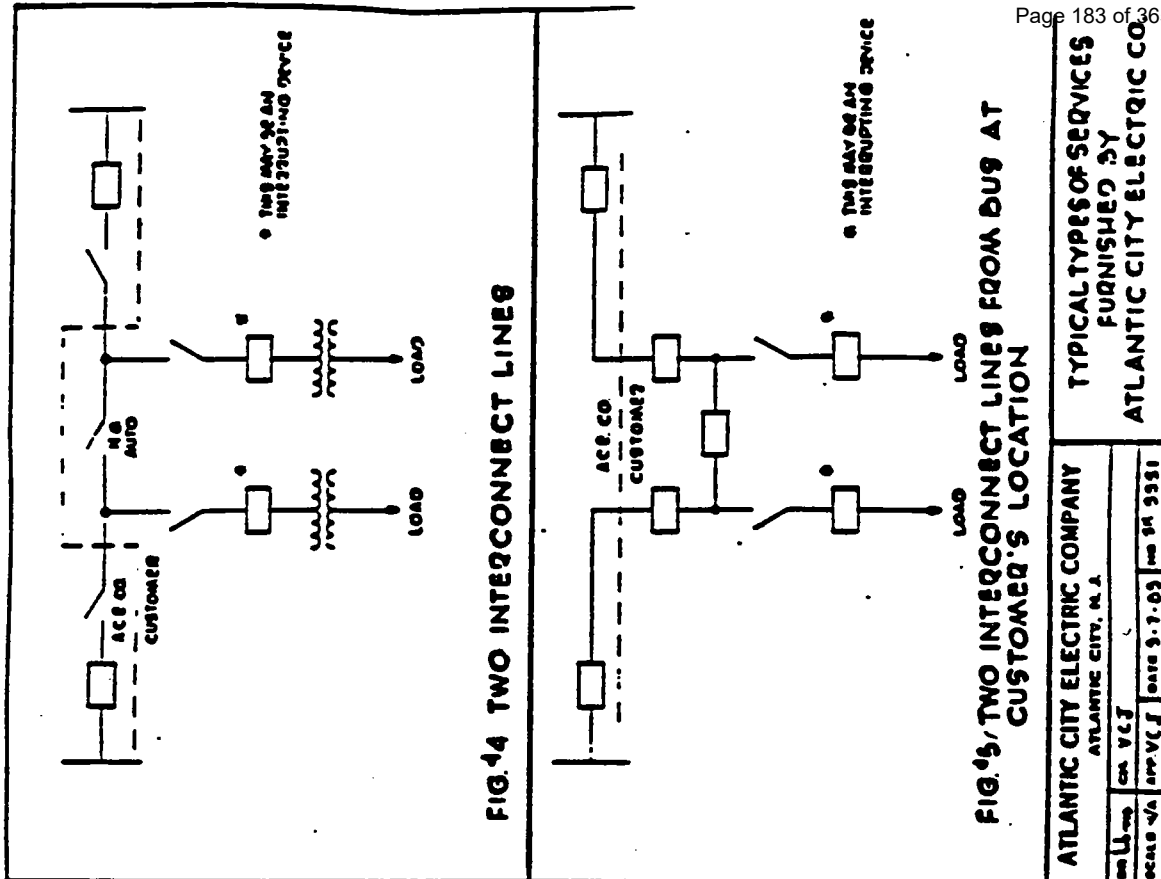
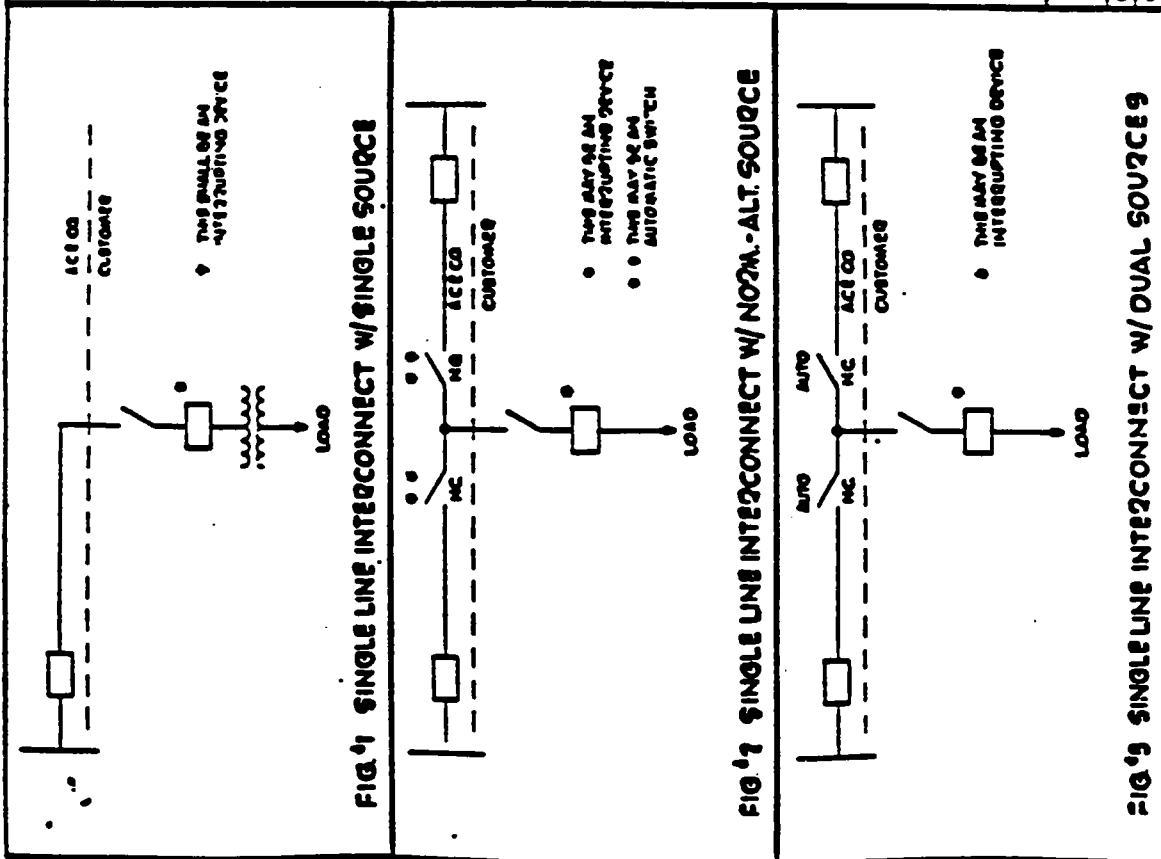
1. Atlantic Electric will provide the customer information about the number of transformers (CT's or VT's) per circuit. The metering current and potential transformers will be furnished by Atlantic Electric for installation by the customer. The current transformer location shall be designed so that after proper electrical isolation the transformer can be removed or changed. The meter location shall be determined by Atlantic Electric in accordance with Atlantic Electric's booklet "Information and Requirements for Electric Service Installation". A rigid conduit (1½" min.) is required from the transformer location to the meter location.
2. Customers will be required to mount all equipment (transformers, meter enclosures, etc.), purchase and install conduit and pull in meter control cable from the transformers to the meter enclosure. Atlantic Electric will provide this control cable. Secondary transformer connections and all meter connections will be done by Atlantic Electric.
3. The metering voltage transformers are to be fused and connected through a disconnecting device to permit changing the transformers without de-energizing the main bus. Atlantic Electric will furnish the disconnects for installation on site by the customers. Atlantic Electric will also supply the current limiting fuses.

D. Additional Information & Requirements for Metering:

Customers shall review the Atlantic Electric booklet "Information & Requirements for Electric Service Installation" for additional metering requirements.

VIII. RESPONSIBILITY:

Atlantic Electric makes no representation or warranty of any nature concerning the technical information contained herein. The information contained herein is intended to be typical and for informational purposes only, and is not intended to be site specific or facility specific. This information is offered as a starting point for any customer who is considering service at subtransmission and transmission voltages. Design responsibility remains solely with customer. The obligations and responsibilities of customer shall be further limited and defined by any agreement between customer and Atlantic Electric and by the provisions and terms of the applicable tariffs.



ATLANTIC CITY ELECTRIC COMPANY			
ATLANTIC CITY, N. J.			
NO. 11-100	CH. V.C.F.	DATE 3-1-03	NO. 31 3351
SCALE 1/4"	APP. V.C.F.		

TYPICAL TYPES OF SERVICES
FURNISHED BY
ATLANTIC CITY ELECTRIC CO.

ATLANTIC ELECTRIC'S

**RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY
TO MEET THE REQUIREMENTS OF THE
PJM INTERCONNECTION**

OCTOBER 1991

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

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PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

Purpose

These rules and procedures for determining the capability of generating units on the systems of the PJM Interconnection have been adopted to provide uniformity for planning, operating, accounting and reporting purposes, and have been designed to meet the following two requirements in the coordinated operation of the PJM Interconnection.

1. Net Capability of generating units installed and scheduled for installation on the systems of PJM is required for planning and reporting purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented. For the same reasons, there is need to define certain limitations that prevent the simultaneous utilization of the total of the system's separate unit Net Capabilities.

2. Available Capability of generating units installed on the systems of PJM is required for planning and daily operating purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented.

The rules and procedures recognize the difference in types of generating units installed on the systems of PJM and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, system operating policies, and others. Whenever a unit or plant output cannot be maintained at its stated capability during the time specified, it shall be considered as a limited energy resource and the stated capability of the system of which it is a part may require modification in accordance with the procedures set forth in Section 3, Limited Energy Resources, for purposes of planning, operating and accounting.

1. NET CAPABILITY

1.1 General

1.1.1 Net Capability shall mean the number of megawatts of electric power which can be delivered by an electric generating unit or station of a system after its date of commercial operation without restriction by the owner under the conditions and criteria specified herein and shall be determined as the gross output of the unit or station less power generated and used for unit auxiliaries and other station use required for electrical generation.

1.1.2 Without restriction means that Net Capability values so determined are available for utilization at the request of the PJM Interconnection Office (IO) for supply of operating capacity and energy before any operating procedures are placed in effect anticipatory to a voltage reduction on the PJM system except as such utilization may at times be limited in duration by water or fuel availability.

1.1.3 The determination of the Net Capability of a combined-cycle unit will depend on the structure of the complete unit and its components. The steam turbine and combustion turbines shall adhere to the existing guidelines set forth in this reporting manual. In the case of thermally dependent components, the determination of the Net Capability shall require the operation of both combustion turbine and steam components simultaneously.

1.1.4 The determination of the Net Capability of a steam unit or plant shall recognize the use of any procedures for increasing unit output such as turbine over-pressure, boiler overrating, cycle modification or any others which are normally utilized in operation.

1.1.5 The determination of Net Capability for a combustion turbine unit shall be consistent with the owner system policy with respect to maximum output.

1.1.6 The determination of Net Capability for a hydro or pumped storage plant shall recognize the head available giving proper consideration to operating restrictions and the reservoir storage program during a normal plant cycle at the probable time of the PJM peak.

1.1.7 The determination of the Net Capability of a nuclear unit shall recognize its nuclear fuel management program and any restrictions (except as noted in 1.1.10) imposed by regulatory authority.

1.1.8 The determination of the Net Capability of a non-utility generator (NUG) shall recognize the following three cases:

- (a) A NUG which supplies energy and/or capacity to the utility and which has no process electrical load.
- (b) A NUG which supplies energy and/or capacity to the utility and which has process electrical load as part of the utilities' load.
- (c) A NUG which supplies energy and/or capacity to the utility and which has process load which is also served by the NUG generator.

In cases "a" and "b", the preferred procedure is to treat the NUG in a manner similar to that of a utility's unit. In case "c", the preferred test procedure is to meter the generation of NUG along with the plant process electrical load. When the option of metering only the net output to the utility is used, estimated values supported by documentation should be supplied for gross generation, station service, and (where applicable) NUG process load.

1.1.9 The Net Capability of a planned steam or combined-cycle unit shall be based on the manufacturer's guarantee or estimate of performance. The Net Capability of a planned combustion turbine or combined-cycle unit shall give recognition to the elevation of the unit location, the type of fuel available for use, and owner system policy with respect to the maximum output. The Net Capability of a planned hydro unit shall be based on the owner system's estimate of head in accordance with 1.1.6.

1.1.10 After a unit is in operation, its Net Capability shall be based on current operating performance or test results. Both Summer and Winter Net Capability values shall be confirmed annually. If adequate data is available from normal operation to confirm Net Capability values during the seasonal peak period, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. When a known change occurs in the Net Capability of a unit, or is indicated by operating data or test results, it shall become effective as soon as possible except as noted in 1.1.11.

1.1.11 The Net Capability of a unit shall not be reduced to reflect unplanned deratings or temporary capacity restrictions provided it is the intention of the owner to restore the reduced capability. The time of this restoration may depend on availability of parts and scheduling of the outage required for repairs. If the owner does not intend to restore the reduced capability by the end of the next Planning period, a reduced Net Capability value may become effective at the request of the owner. The owner shall then notify the Operating Committee in writing.

1.1.12 All or any part of a unit's capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 12 hours, shall be considered as unlimited energy capability. All or any part of a unit's capability shall be considered as limited energy capability only for those periods in which it does not meet the foregoing criteria for sustained operation. Such limited energy capability will be used to meet the energy requirements of PJM and depending on the extent to which it meets these requirements such capability may be reduced as provided in Section 3 of these rules.

1.1.13 Each PJM system shall be responsible for the determination of Summer and Winter Net Capability values, and for reporting same to the Operating Committee. The Operating Committee shall be responsible for the establishment of test procedures required to confirm such values including any amount which must be treated as limited energy capability.

1.1.14 The Net Capability reported for a unit following its date of commercial operation shall in no case exceed an amount determined by the owner in accordance with 1.1.1 and 1.1.10 but for PJM accounting purposes may initially be less than that amount. The extent of any such reduction in reported capability may be determined by the company in such manner as will permit the most effective use of its own resources. A unit or portion thereof placed in service and accepted by the IO for operating purposes may be reported and accounted for as negative unavailable before it is placed in commercial operation, limited to the extent that the total daily unavailable reported by system shall not be less than zero.

1.2 Summer Net Capability

1.2.1 The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

1.2.2 Summer conditions shall reflect the 50% probability of occurrence (the median) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

1.2.3 For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday. For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

1.2.4 The determination of the Summer Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

1.2.5 For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

1.3 Winter Net Capability

1.3.1 The Winter Net Capability of each unit or station shall be based on winter conditions and on the power factor level normally expected for that unit or station at the time of the PJM winter peak load.

1.3.2 Winter conditions shall reflect the 50% probability of occurrence (the median) of temperature and humidity conditions at the time of the PJM winter peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

1.3.3 For steam units, winter conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in December and January at the time of the PJM peak each weekday. For combustion turbine units, winter conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual winter PJM peak.

1.3.4 The determination of the Winter Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Summer Net Capability.

1.3.5 For combined-cycle units, winter conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in December and January at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual winter PJM peak.

1.4 System Limitations

1.4.1 Certain system limitations may at times prevent the simultaneous utilization of the total Net Capabilities of the units in a system. Such limitations may include, but are not necessarily confined to, the availability of energy or fuel, and transmission limitations. The determination of energy and fuel limitations is described in section 4 and Appendix A, and of transmission limitations in Section 4 and Appendix B.

2. AVAILABLE CAPABILITY

2.1 Available Capability of a system shall be the sum of the reported Summer Net Capabilities for all units installed on a system less the Planned Outages and Deratings, Unplanned Outages and Derating, and Miscellaneous Adjustments. All such modifications shall be measured, except as to 2.1.3 (a), during the hour of the daily system peak load. Reductions of capability shall be reported as positive quantities and increases as negative, and the net used as a reduction from the Summer Net Capability values.

2.1.1 Planned Outages and Deratings shall be a reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions.

2.1.2 Unplanned Outage and Deratings shall be:

- (a) A reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions; and
- (b) For planning and accounting purposes required by the PJM Agreement as supplemented, an additional daily reduction in the capability of a system due to energy limitations determined in accordance with section 3 of the Rules and Procedures.

2.1.3 Miscellaneous Adjustments shall be:

- (a) A reduction from the Summer Net Capability of any equipment out of service for any reason not covered by 2.1.1 and 2.1.2 and which could not be made ready, upon notice, to carry load at its reported Summer Net Capability value, as modified by (b) and (c), within six hours.
- (b) A reduction from the Summer Net Capability of a unit or plant which could not be produced because of higher circulating water temperatures, higher ambient air temperatures, reduced head on hydro plants, and other causes consistent with the PJM Report on Generating Unit Performance Definitions.
- (c) An increase from the Summer Net Capability of a unit or plant which was produced or was capable of production over the specified period and was reported in operation or available for scheduling by the IO, because of lower circulating water temperatures, lower ambient air temperatures, recent condenser cleaning, higher stream flows, etc., and other causes such as a new unit operating for test.
- (d) The actual output, at the time of a system's daily peak load, of a unit or portion thereof, operating for test and not included in the Summer Net Capability of the system.
- (e) A reduction in the reported Summer Net Capability of a system which could not be delivered to load areas because of area or system transmission limitations as specified in Section 4.

2.2 Weekly Available Capability of a system shall be the arithmetical average of that system's daily Available Capability as determined in 2.1 above for each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.3 Weekly Summer Net Capability of a system shall be the arithmetical average of that system's total reported Summer Net Capability values for all units installed at the time of the system peak load on each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.4 Weekly Unavailable Capability of a system shall be the algebraic difference between the average values determined in 2.2 and 2.3.

3. LIMITED ENERGY RESOURCES

3.1 General

3.1.1 The available output of all or any part of a unit's capability which is considered limited energy capability in accordance with 1.1.12 shall be utilized, as hereafter specified, on a daily basis excluding weekends and holidays to determine what amount, if any of such capability, is the equiv-

alent of unavailable capability of unlimited resources. Such amounts of unavailable capability shall be determined both for actual and forecast conditions for use in PJM planning and accounting as follows:

- (a) Unavailable capability based on actual hourly loads, actual average daily river flows, actual outages of limited energy resources and other conditions applicable to the day, will be used as an addition to unplanned forced events in the after-the-fact accounting for capacity as provided in 2.1.2 (b).
- (b) Forecast unavailable capabilities based on daily computations but expressed as monthly averages and based on predicted load shapes, experienced probabilities of river flows or output, scheduled capacity additions, and predicted outages of limited energy resources will be for use in the determination of capacity requirements of PJM and the member companies as follows:
 - (i) To the extent that the forecast unavailable capabilities under summer and winter operating conditions exceeded the amount specified in 3.3.3, the forecast excess will be applied as a reduction in the net capabilities of systems owning the limited energy resources.
 - (ii) All forecast unavailable capabilities, except the portion applied in (i) for summer conditions, shall be used as an addition to forecast average unplanned forced events.

3.1.2 The available capability of limited energy resources of PJM shall be determined by fitting the total daily energy of these resources into the peak of the daily PJM load curve (to the best advantage of the limited energy resources) so as to minimize the required operation of unlimited resources. The total daily energy of the limited energy resources shall include all energy which is available or renewable only on a daily basis plus any additional daily energy available from the drawdown or refill of storage on a weekly or longer basis.

3.1.3 Whenever the determinations in 3.1.2 result in some amount of unavailable capability due to energy limitations, this amount shall be allocated among the several companies owning limited energy resources. Each company's own limited energy resources shall be tested on its own load curve to determine the resultant unavailable capability of that company's resources due to energy limitations, and each company shall then be allocated a share of the total PJM unavailable capability due to energy limitations in proportion to the ratio of its unavailable capability on its own load curve to the sum of such unavailable capabilities for all companies.

3.1.4 The available capability of limited energy resources shall be determined, and any unavailable capability shall be allocated on the basis of data and procedures specified in Appendix A.

3.1.5 The Operating Committee shall maintain records of daily Available Capabilities of limited energy resources on the PJM system and of the resulting unavailable capabilities and their allocations, and shall review from time to time the determination of the effects of limited energy on the forecast Net Capabilities and Available Capabilities.

3.2 Fuel Shortages

3.2.1 If any generating capability is classified as limited energy capability because of fuel shortages, the determination of the amount of available capability of such limited energy resources will depend on the predictability of the limited fuel supply.

- (a) When the limited fuel supply is predicted in advance for forecast conditions, it shall be treated as all other limited energy resources in fitting its total daily energy into the daily PJM load curve.
- (b) When the limited fuel supply is not predicted in advance for forecast conditions but is imposed on any member company by external conditions (such as national policies, strikes, fuel supplying companies, etc.), the determination of available capability shall be made in two steps. First, a determination shall be made for all other limited energy resources to obtain the unavailable capability of these resources. Second, another determination shall be made for the total limited energy resources, including those for which fuel is limited by external conditions, but fitting this total available energy into the load curve and obtaining a second value for unavailable capability. The amount of unavailable charged to the fuel limited resources shall be the difference between the values obtained in the first and second determination.

3.2.2 If any unavailable capability charged to fuel limited resources is determined under 3.2.1 (b), this amount shall be allocated by making the same two determinations of unavailable capability as are required and by determining the additional unavailabilities charged to fuel limited resources on each owner company's own load curve. The unavailable capabilities on the PJM load curve that are charged to the fuel limited resources determined under 3.2.1 (b) shall then be allocated in proportion to the additional unavailabilities on the load curves of the owning companies. In no case shall the amount so allocated to any company, as a result of the separate allocation for fuel limited resources, exceed the additional unavailability on its own load curve. Any amount of additional unavailable that cannot be allocated on this basis shall be allocated on the basis applicable for all other limited energy resources under 3.1.3.

3.3 Reduction in Net Capability

3.3.1 Energy limitations that cause reductions in load carrying capability are in some respects similar to unplanned forced events in unlimited energy capability. In either case, if the limitations on energy or reductions in capability are sufficiently severe, failure to carry load may result. Since the reported Net Capabilities of unlimited energy units are not reduced to reflect unplanned forced events experience, it is reasonable not to reduce the reported Net Capabilities of limited energy resources simply on the basis of energy limitations, unless such limitations are expected to be unusually severe at the time of the PJM peak load.

3.3.2 Whenever the forecast weighted average daily unavailable capability of limited energy resources of PJM, determined in accordance with 3.4.1 for the months of July and August (for determination of Summer Net Capability) and December and January (for determination of Winter Net Capability), is an amount which exceeds a specified percentage of the unlimited net capabilities of the total limited energy resources of PJM, such excess amount shall be applied as a reduction of the Net Capabilities of these resources. Such reductions shall be allocated among the owners of limited energy resources, generally in accordance with 3.1.3 and Appendix A except that, as to each owner, only that portion of the unavailable capability which exceeds the specified percentage of its own limited energy resources shall be used in determining the allocation factor.

3.3.3 The specified percentage shall be 12%, based on the recent actual weighted average PJM forced outage rate for thermal units less the actual weighted average PJM forced outage rate for hydro units, such averages based on three years of experience. The specified percentage shall be changed by the Operating Committee to conform to changes in unplanned forced events experience.

3.4 Forecast Unavailable Capabilities

3.4.1 The forecast monthly average unavailable capability of the limited energy resources of PJM shall be determined and allocated in accordance with 3.1.3, based on appropriately estimated daily load shapes and on experienced probabilities of river flow or output, scheduled capacity additions, and predicted outages of limited energy resources. Whenever the Net Capabilities of limited energy resources of PJM are reduced in accordance with 3.3.2, then that amount of unavailable capability that has been applied as a reduction of the Net Capabilities of PJM and the member companies for summer conditions shall be subtracted from the respective forecast average monthly values of unavailable capability.

3.4.2 Average monthly values of unavailable capability for PJM determined in 3.4.1 and reductions in Net Capabilities determined in 3.3.2, to the extent they are significant shall be used as input to the calculations of Forecast Requirements of the Interconnection. Values lower than 2.5% of the Net Capability of the PJM Limited Energy Resources are considered to have an insignificant effect on the calculations of requirements, but may be included as input at the discretion of the P&E Committee.

3.4.3 The average monthly values of unavailable capability in excess of the reduction in summer Net Capability for each system determined in 3.4.1 for the 12 months of each Planning period, shall be averaged to determine the average annual addition to unplanned forced events. The ratio of this average addition to the average total of the system's Net Capabilities for the planning period shall be used as an addition to its forecast forced outage rate.

4. TRANSMISSION LIMITATIONS

4.1 The availability of transmission capacity may limit the output of a unit, station, area or an entire system. The limitation may be the deliberate result of planning, the unintended result of delays in construction, the result of planned outages for maintenance or reconstruction, or the result of an unplanned forced outage for various reasons. The resulting effect on the availability of generating capacity is to be determined and be classified, based on the cause and extent of the transmission limitation.

4.2 Transmission limitations shall be determined as required for after-the-fact accounting and in forecast periods for use in the determination of capacity requirements of PJM and the member companies, by comparison of transmission capability with the excess of the Net Capabilities for a unit, station, area or system over the peak load for the day or period under consideration, with adjustment as necessary for firm purchases and sales, use of jointly owned units, and unavailable generating capability. The Net Capabilities used in such determination shall be appropriate for the season of the peak load under consideration. Transmission limitations shall be determined on the basis of data and procedures specified in Appendix B.

4.3 A transmission limitation caused by an outage of transmission facilities shall be recognized in the after-the-fact accounting as follows:

- (a) When the limitation affects a unit or station, the amount of the limitation shall be considered as either a Planned or Unplanned Outage or Derating (as defined by the PJM report on Generating Unit Performance Definitions) in the determination of Available Capability as provided in 2.1.1 and 2.1.2.
- (b) When the limitation affects an area or system, the amount of the limitation shall be considered as a Miscellaneous Adjustment to the reported Summer Net Capability of a system as provided in 2.1.3 (d).

4.4 Examination must be made to determine transmission limitations during forecast periods and any such limitations predicted shall be accounted for as follows:

- (a) Limitations predicted during July and August (1) which affect a unit or station shall be recognized in the reported Summer Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Summer Net Capabilities of units of the system in the determination of its System Capacity (as defined in the PJM Contract).

- (b) Limitations predicted during December and January (1) which affect a unit or station shall be recognized in the reported Winter Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Winter Net Capabilities of units of the system.
- (c) Limitations predicted during forecast periods other than as specified in (a) shall be recognized in the determination of forecast average Miscellaneous Adjustments.

- (b) Limitations predicted during December and January (1) which affect a unit or station shall be recognized in the reported Winter Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Winter Net Capabilities of units of the system.
- (c) Limitations predicted during forecast periods other than as specified in (a) shall be recognized in the determination of forecast average Miscellaneous Adjustments.

APPENDIX A

DETERMINATION OF AVAILABLE CAPABILITY OF LIMITED ENERGY RESOURCES

The determination of this Available Capability shall be made: (A) for each weekday, after-the-fact, based on certain actual data and on procedures set forth below in further detail; and (B) for study and forecast purposes, based on probabilities of river flow and other appropriately assumed future conditions and on procedures otherwise consistent with the daily determination.

A. Daily Determinations

A determination shall be made by the Interconnection Office for each weekday, excluding holidays, of the Available Capabilities: (1) of the total limited energy resources operated on the PJM load curve and (2) if any Unavailable Capability is thus determined, of the limited energy resources of each company operated on the respective company load curve. These determinations involve the following steps:

1. Determine for the limited energy resources that amount of energy which is available or renewable only on a daily basis.
2. Determine that amount of additional daily energy available from the drawdown and refill of storage on a weekly or longer basis.
3. Determine the Available Capability of the limited energy resources by fitting the total daily energy (sum of 1 and 2) into the peak of the daily load curve (to best advantage of the limited energy resources, but observing all necessary limitations on their use) so as to minimize the required operation of other generating capacity. The Available Capability is the difference between the daily peak and the required maximum generation of such other capacity.

1. Daily Energy

The energy that is available or renewable only on a daily basis should be determined for the various types of capacity as follows:

- (a) Limited energy thermal capacity - if the unit or incremental capacity of a unit that provides such limited energy output can be considered available under the general provisions for "Available Capacity," Section 2.1, then the associated energy should also be considered available. The energy output of thermal capacity may be limited either by inability to operate continuously at high levels of output or by fuel availability.
- (b) Run-of-river hydro without weekly storage - for those plants that must generate daily whatever amount of energy is available from river flow, the available energy is that part of the actual daily generation which was, or could have been generated within the daily period of operation of all the limited energy resources, as determined by the load curve.

- (c) Run-of-river hydro with weekly storage - for those plants that can operate in part on the basis of weekly storage, the daily available energy (whether or not actually generated and without regard to actual storage use) should be the daily amount normally available for the actual river flow experienced on that day. Such amounts are to be shown by appropriate equations, curves or tabulations of energy versus river flow.
- (d) Storage hydro - for those plants that operate on a seasonal storage basis, the available energy will be determined as described below under item 2(b).
- (e) Pumped storage - the daily available energy (whether actually generated or not and without regard to actual storage use) should be the amount of energy that can be normally replaced by daily pumping within a period determined by load shape or other appropriate limitation, but not including economy of operation. The daily available energy shall be reduced, as compared to that normally replaced on a daily basis, by an amount corresponding to any pumping foregone because of unscheduled equipment outage or other limitation (other than economy) during the prior normal pumping period.

2. Additional Energy From Storage

For those plants which have storage that can be used on a weekly or longer basis, the additional amount of energy that is available should recognize that, within limits, the use of storage can be shifted from one day to another to fit system needs. The same amount of storage energy need not be used and ordinarily will not be used on every day; and general PJM experience has indicated a use of storage energy, on one or two days per week, at an average rate approximately double the rate which could be maintained on every weekday. Such use of storage appears to be a reasonable representation of the use that could and would be made of storage energy to meet normal capacity requirements. It shall therefore be assumed, in determination of available capacities, that the daily available energy from use of storage on any weekday will be twice the amount that could be used on every weekday. The amounts of additional daily energy from storage for the various types of capacity shall be determined as follows:

- (a) Run-of-river hydro with weekly storage - the daily amount shall be 40% of the available weekly storage as limited by the smaller of (i) flow available for weekend refill or (ii) excess of total usable storage over that required for daily operation. Amounts are to be shown by appropriate equations, curves or tabulations of storage energy versus river flow; and each daily amount shall be determined on the basis of an assumed constant flow throughout the week.

- (b) Storage hydro - the total available daily energy at such plants shall be 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.
- (c) Pumped storage - the daily amount shall be 40% of the additional stored energy that can be replaced only by weekend pumping. The amount of weekend pumping shall be considered to be the useful reservoir capacity less the pumping that could have been done on a daily basis in the absence of any unscheduled outage.
- (d) If the energy output of thermal capacity is limited by fuel availability and such availability is determined on a weekly or longer basis, rather than by daily deliveries, for example, then the available energy on each day shall be (comparable to that for storage hydro) 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.

Because the above specified use of storage energy at various types of plants is the principal factor in the determination that is not related to actual current conditions, its validity shall be re-examined from time to time by the Operating Committee; and, if necessary, change shall be made in the above specified procedures.

3. The Daily Load Curve

The total of the daily available energy amounts, as described in 1 and 2 above, shall be fitted into the daily load curve to "firm up" the maximum amount of limited energy capacity. A direct determination of the available capacity in KW shall be made from a tabulation of peak capacity versus energy at the level indicated by the available energy. Recognition of the various limitations that may apply is important at this point in the computations. These include at least the following:

- (a) The usable amount of energy as determined in 1 and 2 above for any plant shall be no more than that plant could generate within the daily period of operation of all limited energy resources. (Alternatively, if the amount from 1 and 2 above is more than the plant can generate in the period determined by the load shape, the plant and its energy may be dropped out of the computation and be temporarily treated as an unlimited energy resource. This shall be the normal treatment of the run-of-river plants in period of adequate flow.)
- (b) The amount of available capacity for any plant that is firmed up by its available energy shall not exceed the physical capability of the plant during the peak hour of the day. This physical capability shall be determined by head, unit outages, and capacity limitations due to ice, trash, heat, or other causes.

- (c) A check shall be made, even when the total available capacity of the limited energy resources appears to be energy limited, to determine if some part of this capacity may not be energy limited (i.e., may be limited by physical capability). This is particularly likely in very low flows, when the run-of-river plants will be energy limited, but the pumped storage may not be. Under these conditions, the available capacity of the pumped storage is limited to its physical capability on the peak hour. At high flows, the situation may reverse.

B. Determination for Study and Forecast Purposes

Forecasts of Unavailable Capability, including those due to energy limitations, are needed under the terms of the PJM contract as supplemented, and similar forecasts are required for study of additional limited energy installations. Such forecasts shall be basically consistent with the above specified determinations for after-the-fact conditions; but certain difference in method of computation are appropriate in recognition of the nature of uncertainties inherent in all such forecasts. The Operating Committee shall review these procedures with respect to new capacity to determine if modifications are required.

1. Susquehanna River Flow

For forecast purposes, the flow of Susquehanna River shall be considered on a probability basis related to each month's experience over a long period. That is, for various ranges of river flow there shall be an assigned probability of occurrence for each month, based on the recorded experience in that month for 50 or more years. For this purpose, flow records accumulated at any one plant on the Susquehanna River (initially, Safe Harbor) may be used for all plants, with appropriate factors for conversion to daily energy.

2. Hydro Plants on Other Rivers

There are now in operation in PJM several small hydro plants (Deep Creek, Piney and Wallenpaupack) on other rivers or streams, not within the Susquehanna River drainage. Because the flow in these other rivers is not related to the flow in the Susquehanna River, and no correlations have been developed, and because the plants are small, it is satisfactory for forecast purposes to assign to each of these plants for each month a fixed amount of generation per day which is reasonably representative of less than average flow conditions. So long as these other plants are small and the available river flow is unrelated to the Susquehanna River flow, the forecast shall be based on this approximate representation of the available energy at such plants.

3. Pumped Storage and Limited Energy Thermal Capacity

The available energies for these plants on a forecast basis shall be consistent with those used, or which would be used in the after-the-fact determinations.

4. Load Curves

Forecasts of Unavailable Capability shall be based on the use of forecast energy amounts in forecast daily load curves. Such daily load curves shall be based on the adjustment of one or more years of experienced loads to be representative of the higher loads by the future years for which forecasts are required. The method of adjustment shall be specified by the Planning and Engineering Committee and shall be consistent with that used for other PJM purposes.

5. Adjustment for Unavailability Due to Unit Outages

Because hydro and pumped storage units are likely to be scheduled for inspection and maintenance at those times when their Available Capability would otherwise be limited by the available energy, recognition shall be given to the probability (related primarily to river flow) of the overlapping of unavailability due to both planned and unplanned maintenance outages and energy limitations. In the forecasting of Unavailable Capability, planned and unplanned maintenance outages shall be recorded at their full amounts and durations, and average unavailability due to energy limitations shall be appropriately reduced by an amount that recognizes the probability of overlap between the two causes of unavailability.

APPENDIX B

DETERMINATION OF TRANSMISSION LIMITATIONS

When determining the capability of a unit, station, area or system and the availability of this capability for PJM contract purposes, it is necessary to examine the ability to deliver the capability to the load areas. In order to make this examination, the following standard formula is presented to determine if a Transmission Limitation exists.

$$\text{Transmission Limitation} = \text{Net Capability} + \text{Firm Capacity Sales (1)} \\ \text{Firm Capacity Purchases (2)} - \text{Peak Load} - \\ \text{Unavailable Capacity} - \text{Transmission Capability(3)}$$

- (1) Includes only sales that must be delivered outside the System and any other system's share of jointly owned internal generation.
- (2) Includes system's share of jointly owned external generation and purchases from outside the System.
- (3) Transmission Capability of any transmission path must be compatible with the values used for emergency ratings as specified in the PJM Operating Principles and Standards and for parallel paths must be such a total that the loading of no line exceeds its emergency rating.

A. Daily Unavailability Due to Transmission Limitation

A Transmission Limitation associated with a unit or station shall be determined for each weekday excluding holidays using the standard formula with the following data:

<u>Item</u>	<u>Unit</u>	<u>Station</u>
Net Capability	Unit Net	Station Net
Firm Capacity Sale	Only when part of unit or station is jointly owned or is specified source of firm sale.	
Firm Capacity Purchase	Not Applicable	Not Applicable
Peak Load	Local Bus Load	Local Bus Load
Unavailable Capacity	Of Unit	Of Station
Transmission Capability	For Lines Available	For Lines Available

A Transmission Limitation associated with an area or system shall be determined for each weekday excluding holidays using the standard formula with the following data: -

<u>Item</u>	<u>Area</u>	<u>Station</u>
Net Capability	Of Stations in Area	Of all System Stations
Firm Capacity Sale	Only when part of station in area is jointly owned or is specified source of Firm Sale.	Total Value
Firm Capacity Purchase	Not Applicable	Total Value
Peak Load	Of Area	Of System
Unavailable Capability	Of Units in Area (Including Unavailability) (of Units or Stations Due) (to Transmission Limitation)	Of Units on System

B. Negative Values of Transmission Limitations

When the determination shows a negative Transmission Limitation the value shall be considered as zero for all cases except the daily System determination.

A negative value of Transmission Limitation as a result of the daily System determination can be considered as negative Unavailable Capability up to the value of the Transmission Limitation applied to the System Capacity. If there is no Transmission Limitation applied to the System Capacity then any negative value of Transmission Limitation as a result of the daily System determination shall be considered as zero.

APPENDIX C
NET CAPABILITY VERIFICATION GUIDELINES

PURPOSE

These guidelines are to supplement the requirements set forth in the PJM Rules and Procedures For Determination of Generating Capability (Green Book) by setting forth requirements for Net Capability verification, reporting and review of results to assure uniform and consistent compliance. These guidelines address questions that occur frequently at the Generating Capability Ratings Procedure Task Force (GCRPTF) meetings.

A. PHILOSOPHY OF NET CAPABILITY VERIFICATION

1. Responsibility

- a. Member Companies through the GCRPTF are responsible to comply with these requirements at their own expense.
- b. GCRPTF consists of representatives from each member Company signatory to the Supplemental Agreement and an IO representative serving as secretary. The GCRPTF is responsible to review verification and to tender recommendations to the Operating Committee. Nonconformance(s) shall be communicated in writing to the Operating Committee.
- c. The Operating Committee Member is responsible for the approval of Net Capability verification reports and Company compliance to these guidelines.
- d. Individual Company Task Force members are responsible as delegated by their Company Operating Committee Member for the collection and reporting of net capability verification results.
- e. Verification of NUG capability is the responsibility of the utility which declares that net capability as installed capacity.

2. Exceptions and Deviations

Exceptions to and deviations from these Net Capability verification guidelines shall be by Operating Committee approval. These exceptions shall be made in writing prior to the end of the test window for known occurrences such as environmental restrictions and fuel limitations.

B. NET CAPABILITY VERIFICATION

1. Net Capability verification is to demonstrate the maximum Net Capability of each unit. If that Net Capability was not demonstrated during the verification window, a reduction or derating shall be enacted to account for the deficiency.
2. Both Summer and Winter Net Capability shall be confirmed annually during the verification windows that correspond to the seasonal peak periods:
 - a. Summer verification window shall be the first day of June through the last day of August.
 - b. Winter verification window shall be the first day of December through the last day of February.
3. If adequate data is available from normal operation to confirm Net Capability values and to satisfy the reporting requirements during the seasonal verification window, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. A test shall include any unit brought on-line or a unit that is on-line and its mode of operation altered for the specific purpose of capability verification.
4. If a unit does not meet its stated Summer or Winter Net Capability due to a temporary condition, the deficiency shall be covered by the appropriate outage/reduction(s) from the date of the problem. If a capability deficiency is uncovered during this verification, a reduction covering the deficiency shall be coded retroactive to June 1 or January 1 for summer and winter verification windows, respectively.
5. Net Capability verification is required outside of the verification period when an outage or reduction occurred prior to or during the verification period which prevented demonstration of maximum Net Capability. The Net Capability shall be demonstrated by either operating performance data or test results.

C. REPORTING

1. Two standardized forms are provided to facilitate the review of results:
 - a. Attachment One is the individual unit PJM Net Capability Verification Reports to be used for documenting operating performance or test data.
 - b. Attachment Two is the PJM Verification Summary Report.
2. Net Capability Verification Reports shall be approved by the Operating Committee Member.
3. Reports shall be submitted to the GCRPTF Secretary no later than September 30th and March 31st for the summer and winter verification periods, respectively. Copies of the summary sheets shall be mailed to the GCRPTF Members.
4. Outages and reductions for the discrepant capability greater than 1 MW (Rated Net Capability less the Corrected Test Net Capability) shall be recorded on the reports, including:
 - a. MW's out shall be reported on the Capability Reporting Form along with a brief explanation of the reason completed by Plant personnel.
 - b. The MW reduction shall be covered in the Summary Report notes with event data including: MW reduction, NERC event type, NERC event number, cause code, event start date and time, event end date and time (if appropriate). The Summary Report shall be submitted by the GCRPTF member.
5. When the owner has submitted output adjustment methodology and received GCRPTF approval, the following output corrections may be made:
 - a. For combustion turbines or combined-cycle units, ambient air temperature correction.
 - b. For steam or combined-cycle units, circulating water temperature correction.
 - c. For cogeneration units where heating system extraction steam limits the output, a limited steam flow correction.
6. Units shall be verified and reported on a block basis as opposed to an individual basis when the units are rated and dispatched as a block.
7. Net Capability Verification Reports shall be submitted to the GCRPTF Members for verification outside of the verification period to document end of outages or reductions (reference paragraph B.5).

8. Reports shall indicate the nearest whole MW output for units rated 10 MW's or greater, and the nearest one-tenth MW output for units rated less than 10 MW. When a figure is to be rounded to fewer digits than the total number available, the procedure adapted from ISO-R370, should be as follows:
 - a. When the first digit discarded is less than 5, the last digit retained should not be changed. For example, 3.463 25, if rounded to three digits, 3.46.
 - b. When the first digit discarded is greater than 5, or if it is a 5 followed by at least one digit other than 0, the last digit retained should be increased by one unit. For example, 8.376 52, if rounded to four digits, would be 8.377; if rounded to three digits 8.38.
 - c. When the first digit discarded is exactly 5, followed only by zeros, the last digit retained should be rounded upward if it is an odd number, but no adjustment made if it is an even number. For example, 4.365, when rounded to three digits, becomes 4.36. The number 4.355 would also be rounded to the same value, 4.36, if rounded to three digits.

D. REVIEW

1. A GCRPTF Working Group composed of the immediate past chairman, the present chairman, next apparent chairman, and the secretary (IO member) shall review all reports to verify completeness of records and verify outage tickets as required.
2. Each owner shall have a representative in attendance (GRCPTF member or alternate) at the GCRPTF verification review meeting.
3. The verification review should be reported to the Operating Committee including a summary report, reflecting all units which have not met their Net Capability for three consecutive summer or winter test periods. The summary report will include documentation of the problem from the appropriate company and corrective action taken to prevent the problem from recurring, if possible. It should also be noted on this summary report, if any of these units were tested outside of the test periods being reviewed.

1. Plant and Unit No. _____ 4. Date _____
 2. NERC Unit Identification _____ 5. Start Time _____
 3. Method: Operational '___' Test '___' 6. End Time _____

7. Corrected Test Net Capability-MW _____

8. Rated Net Capability-MW '___' _____

9. Difference-MW (\pm) '___' _____RATEDOBSERVED10. Main Steam Temperature- $^{\circ}$ F * _____11. Reheat Steam Temperature- $^{\circ}$ F * _____12. 2nd Reheat Steam Temperature- $^{\circ}$ F* _____

13. Main Steam Pressure- PSIG * _____

14. Air Dry Bulb Temperature $^{\circ}$ F _____15. Cooling Water Temperature $^{\circ}$ F _____

16. Extraction Steam Flow - 1000 Lb/Hr. _____

17. Reactive Generation-MVAR (\pm) '___' _____

18. Gross Generation-MW _____

19. Station Use-MW _____

19a. NUG Process Load _____

20. Test Net Capability-MW _____

21. Cooling Water Correction-MW (\pm) '___' _____22. Air Correction-MW (\pm) '___' _____23. Extraction Steam Flow Correction-MW (\pm) '___' _____

24. Total Power-MVA * _____

25. Power Factor * _____

26. Explanation for DifferenceMWExplanation

SIGNED: _____

STATION MANAGER

APPROVED: _____

MEMBER

PJM OPERATING COMMITTEE

* Data is optional and not required by PJM

Specific Instructions

- Line 1. Company plant and unit number identification
- Line 2. Use NERC numerical designations only
- Line 3. Indicate Test, if unit started or current operating load changed for capability verification.
- Indicate Operational, if unit is currently operating at capability rating. Historical data is also acceptable; two (2) hour average (steam and combined-cycle units), one (1) hour (combustion turbines and diesel units).
- Line 4. Enter date of test - month, day, and year.
- Line 5., 6. Enter time of test, use military time.
- Line 7. (MW) Test Net Capability (Line 20) plus Water Correction (Line 21) for steam units - Otherwise Test Net Capability (Line 20) plus Air Correction (Line 22) for combustion turbines.
- Line 8. (MW) Current Net Capability - First character - S (Summer) W (Winter) Remaining characters - Rated Net Capability
- Line 9. (MW) Corrected Net Capability (Line 7) minus Rated Net Capability (Line 8); - Include (+) sign.
- Line 10., 11
12., & 13 Enter data for steam or combined-cycle units - Temp. (°F), Pressure (PSIG). Otherwise enter NA
- Line 14. Enter data for combustion turbines, combined-cycle and cooling tower steam Units only (°F) - Otherwise enter NA
- Line 15. Enter data for steam or combined-cycle units (°F). Otherwise enter NA
- Line 16. Enter data for approved extraction steam units only (1000 lb/hr) Otherwise enter NA.
- Line 17. (MVAR) Enter (+) into system (LAG); (-) into unit (LEAD). Enter two (2) hour average for steam units
- Line 18. (MW) Enter two (2) hour average for steam or combined-cycle units.
- Line 19. (MW) Enter two (2) hour average for steam or combined-cycle units.
- Line 19a. (MW) Enter NUG process electrical load.
- Line 20. (MW) Gross Generation (Line 18) minus station use (Line 19) minus NUG Process Load (Line 19a)

Specific Instructions (continued)

- Line 21. (MW) Steam or combined-cycle units - if correction curves are available. Otherwise enter NA.
- Line 22. (MW) Combustion turbine or combined-cycle units. Otherwise enter NA.
- Line 23. (MW) Approved extraction steam units only. Otherwise enter NA.
- Line 24. (MVA) Vector sum, Gross Generation (Line 18) and Reactive Generation (Line 17.)
- Line 25. (DEC.) Gross Generation (Line 18) divided by Total Power (Line 24)
- Line 26. Enter narrative to explain negative difference (Line 9) - Otherwise narrative requirement is optional.

1.

Notes:

Member GCNPTF:

Date:

Revision

SPECIFIC INSTRUCTIONS

1. Company Enter reporting company name.
2. Plant/Unit
NERC I.D. Enter plant name, unit number, and Nerc
identification number.
3. Period Enter the test period date, (example: S83, W83/84)
4. Capability
 - a. Rating Enter Rated Net Capability - MW (Line 8 from PJM NET
CAPABILITY VERIFICATION REPORT)
 - b. Difference Enter Difference - MW (\pm) (Line 9 from PJM NET
CAPABILITY VERIFICATION REPORT)
5. Megawatt Reduction Enter the megawatt reduction assigned to each NERC
outage event. Event data can have more than one entry
for the difference reported. Megawatt reduction can be
greater than difference reported.
6. NERC Number Enter the corresponding NERC event number.
7. NERC Event type Enter NERC Event type and class as defined in the PJM
GENERATING UNIT PERFORMANCE DEFINITIONS for each
megawatt reduction.
8. NERC Cause Code Enter the NERC Cause Code as defined in the PJM
GENERATING UNIT PERFORMANCE DEFINITIONS for each NERC
event.
9. Start/End
 - a. Date Enter Start/End month, day, and year (example:
01/30/84).
 - b. Time Enter Start/End time, use military time (example:
1429).
10. Notes Enter a sequence number. Use the sequence number as a
reference to the narrative in the space provided at the
bottom of the summary or use a separate page. If no
event information exists, assign a sequence number and
explain in the notes.
11. Member GCRPTF GCRPTF member's signature.
12. Date Enter reporting month, day, and year.
13. Revision Number Enter sequential revision number. The first issuance
of the report is revision number zero.

APPENDIX D

GUIDELINE FOR CLASSIFICATION OF EXTENDED DURATION OUTAGES RESULTING FROM VOLUNTARY DEFERRAL OF REPAIRS TO GENERATING UNITS

(Deferred Maintenance Guidelines)

Purpose

The purpose of this guideline is to define a procedure for implementing a PJM policy which permits the voluntary deferment of generating unit repairs for financial reasons while minimizing the effect that such a deferment has on the determination of forecast installed reserve obligations and allocations.

During periods of high PJM system installed reserves, it may not be economically feasible to perform extensive repairs on units with high operating costs, since such units are unlikely to be called on to supply load. Whenever such a unit fails and is not repaired immediately, the outage associated with the failure is lengthened due solely to company economic and system reserve conditions, rather than to any special nature of the unit failure. PJM reserve obligations and allocations are both based in part on company outage history. The straightforward inclusion of the total time associated with a deferred maintenance outage in a company's outage history leads to a pessimistic model of unit repair time.

The PJM companies recognized that in times of lower excess system installed reserves, units would be repaired with minimum delay, since system conditions would dictate more frequent unit operation. The procedure outlined in the following paragraphs is designed to allow companies to single out those outages which are lengthened due solely to company economic constraints, so that such outages can be more accurately modelled in PJM planning studies.

It should be noted that a company requesting deferred maintenance status for a unit agrees to attempt accelerated repairs in the event of an Operating Committee determination that the unit is required to bolster PJM system or sub-area reserves. Also, the physical coding of such outages in the PJM outage data base is not changed as a result of application of this procedure. Neither is the deferred maintenance classification recognized for any uses of the outage data base other than the determination of forecast installed reserve obligations and allocations.

Scope of Application

This procedure may be applied to an outage on any generating unit or portion thereof, so long as repairs are to be deferred for at least 90 days due solely to company financial constraints.

Procedure

I. In the event that a unit is out of service in the unplanned forced classifications*, either wholly or partially, and repairs are to be deferred for at least 90 days due solely to company financial constraints, the owning company shall have the option to request that the portion of the outage associated with the deferment be excluded from consideration as an unplanned forced outage in planning studies. Authority to grant or deny such a request rests with the PJM Operating Committee, as advised by the Maintenance Committee and the Interconnection Office.

II. A request for official recognition of the voluntary deferment period must include the following information:

1. Name of unit.
2. MW of installed capability affected.
3. Is this a reduction in unit capability, or a full outage?
4. Starting date of original unplanned forced outage.
5. Planned return to service date.
6. Scope of repairs required.
7. Estimate of unplanned forced outage time required to effect repairs to the unit. This estimate should be based on crews working a 40-hour week and must include any time waiting for manpower or parts to become available or for technical problems to be solved.

III. Copies of each request will be sent to the Maintenance Committee and the Interconnection Office, as well as to the Operating Committee.

- A. The Maintenance Committee will review the scope of required repairs compare with the estimated repair time, and advise the Operating Committee on the adequacy of the repair time estimate.
- B. The Operations Planning Branch of the Interconnection Office will analyze the effect of the repair deferment on PJM system reserves and risk during the outage period, as well as sub-area reserves (if the unit is located in a deficient area) and make recommendations to the Operating Committee.

IV. The Operating Committee can either approve or disapprove a request for deferred maintenance status based on the recommendations of the Maintenance Committee and the Interconnection Office.

- A. If the Operating Committee disapproves the request, the entire outage duration will be considered as unplanned forced outage time and will be accounted for as such on all planning studies.

* The basis for this definition is set forth in IEEE Standard 762 entitled "Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity".

- B. If the Operating Committee approves a request for deferred maintenance status for a particular unit, relevant information concerning the deferral period will be passed to the Generator Unavailability Subcommittee, of the Planning and Engineering Committee, so that the outage can be properly modelled in all planning studies.
- C. The revised modelling of any approved deferred maintenance outage for planning study purposes is a manual process. Reporting of the outage in the PJM outage data base will not be affected by Operating Committee approval or disapproval of a deferral period.
- D. After-the-fact accounting is not affected by Operating Committee action on the deferral request. Such a unit will be considered unavailable for purposes of after-the-fact accounting whether or not the Operating Committee grants a deferred maintenance request.

Extensions to Existing Deferral Periods

- I. If a unit has not been repaired by the planned return-to-service date, its outage classification for planning study purposes will revert back to unplanned forced as of the planned return-to-service date, unless an extension to the deferral period is allowed by the Operating Committee.
- II. Any request for an extension to an existing deferral period should be handled just like any new request for deferred maintenance status, with the owning company proposing a revised in-service date for review by the Operations Planning Branch of the Interconnection Office and final action by the Operating Committee.
- III. Because of the system planning aspects of the deferred maintenance classification, all requests for extensions to existing deferral periods should be made as soon as possible after determination that company financial constraints will not allow repair of a particular unit to begin before the original planned in-service date.

Returning Deferred Maintenance Units to Service

- I. Voluntary Return by Owning Company
 - A. The company owning a unit with deferred maintenance status should keep all interested parties notified of any changes in the expected return-to-service date of the subject unit.
 - B. If a company decides to delay the return to service of a deferred maintenance unit, an extension of the deferral period may be requested as outline above.
 - C. A company may decide to return a deferred maintenance unit to service at any time prior to the originally scheduled return date. If such a decision is made, the outage will be classified as follows:

1. No additional unplanned forced outage time will be assigned to a unit repaired and reported available for service at any time after the minimum 90-day deferral period but before the original return-to-service date.
2. If a unit is repaired and returned to service prior to the minimum 90-day deferral period, the outage duration will be classified as forced for planning study purposes.

II. Return Requested by Operating Committee

- A. When dictated by changing system conditions, the Operating Committee can request that companies owning units with deferred repairs effect the repair of the subject units in order to bring PJM system or sub-area installed reserves up to more acceptable levels.
- B. Should such a recall become necessary, units which have been granted extensions to their original deferral periods will be the first ones called back to service.
- C. If a unit is repaired and returned to service at the request of the Operating Committee, no additional unplanned forced outage penalty will be assigned, even if the repairs are completed prior to the end of the original 90-day deferral period.
- D. If a company is not able to respond to a recall request on a deferred maintenance unit, the outage on the unit in question will be considered unplanned forced for planning study purposes, after a period of time equal to the estimated repair time.

Control

I. The Operations Planning Branch of the Interconnection Office will analyze system conditions and make recommendations to the Operating Committee regarding each request for a new or extended deferral period.

II. On a continuing basis, the Interconnection Office will review system conditions to determine the impact of existing deferred maintenance on PJM operations.

- A. The Interconnection Office will make recommendations to the Operating committee concerning the need for accelerated return of units on deferred maintenance.
- B. Reserve and risk criteria used shall be approved by the Operating Committee.

Revised and approved by the PJM Operating Committee 10/91
CIT/gks:+657

EXHIBIT C

ATLANTIC ELECTRIC'S

**RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY
TO MEET THE REQUIREMENTS OF THE
PJM INTERCONNECTION**

NOVEMBER 1987

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

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PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION

RULES AND PROCEDURES FOR DETERMINATION
OF GENERATING CAPABILITY

Purpose

These rules and procedures for determining the capability of generating units on the systems of the PJM Interconnection have been adopted to provide uniformity for planning, operating, accounting and reporting purposes, and have been designed to meet the following two requirements in the coordinated operation of the PJM Interconnection.

1. Net Capability of generating units installed and scheduled for installation on the systems of PJM is required for planning and reporting purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented. For the same reasons, there is need to define certain limitations that prevent the simultaneous utilization of the total of the system's separate unit Net Capabilities.

2. Available Capability of generating units installed on the systems of PJM is required for planning and daily operating purposes and for use in accounting for deficiencies of a PJM system in meeting its contract capacity obligations under the PJM Agreement as supplemented.

The rules and procedures recognize the difference in types of generating units installed on the systems of PJM and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, system operating policies, and others. Whenever a unit or plant output cannot be maintained at its stated capability during the time specified, it shall be considered as a limited energy resource and the stated capability of the system of which it is a part may require modification in accordance with the procedures set forth in Section 3, Limited Energy Resources, for purposes of planning, operating and accounting.

1. NET CAPABILITY

1.1 General

1.1.1 Net Capability shall mean the number of megawatts of electric power which can be delivered by an electric generating unit or station of a system after its date of commercial operation without restriction by the owner under the conditions and criteria specified herein and shall be determined as the gross output of the unit or station less power generated and used for unit auxiliaries and other station use.

1.1.2 Without restriction means that Net Capability values so determined are available for utilization at the request of the PJM Interconnection Office (IO) for supply of operating capacity and energy before any operating procedures are placed in effect anticipatory to a voltage reduction on the PJM system except as such utilization may at times be limited in duration by water or fuel availability.

1.1.3 The determination of the Net Capability of a steam unit or plant shall recognize the use of any procedures for increasing unit output such as turbine over-pressure, boiler overrating, cycle modification or any others which are normally utilized in operation.

1.1.4 The determination of Net Capability for a combustion turbine unit shall be consistent with the owner system policy with respect to maximum output.

1.1.5 The determination of Net Capability for a hydro or pumped storage plant shall recognize the head available giving proper consideration to operating restrictions and the reservoir storage program during a normal plant cycle at the probable time of the PJM peak.

1.1.6 The determination of the Net Capability of a nuclear unit shall recognize its nuclear fuel management program and any restrictions (except as noted in 1.1.9) imposed by regulatory authority.

1.1.7 The Net Capability of a planned steam unit shall be based on the manufacturer's guarantee or estimate of performance. The Net Capability of a planned combustion turbine unit shall give recognition to the elevation of the unit location, the type of fuel available for use, and owner system policy with respect to the maximum output. The Net Capability of a planned hydro unit shall be based on the owner system's estimate of head in accordance with 1.1.5.

1.1.8 After a unit is in operation, its Net Capability shall be based on current operating performance or test results. Both Summer and Winter Net Capability values shall be confirmed annually. If adequate data is available from normal operation to confirm Net Capability values during the seasonal peak period, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. When a known change occurs in the Net Capability of a unit, or is indicated by operating data or test results, it shall become effective as soon as possible except as noted in 1.1.9.

1.1.9 The Net Capability of a unit shall not be reduced to reflect unplanned deratings or temporary capacity restrictions provided it is the intention of the owner to restore the reduced capability. The time of this restoration may depend on availability of parts and scheduling of the outage required for repairs. However, if the owner does not intend to restore the reduced capability, the owner shall so notify the Operating Committee in writing and a reduced Net Capability value shall become effective for that unit at the time the notice is given not to restore the capability.

1.1.10 All or any part of a unit's capability that can be sustained for a number of hours of continuous operation commensurate with PJM load requirements, specified as 12 hours, shall be considered as unlimited energy capability. All or any part of a unit's capability shall be considered as limited energy capability only for those periods in which it does not meet the foregoing criteria for sustained operation. Such limited energy capability will be used to meet the energy requirements of PJM and depending on the extent to which it meets these requirements such capability may be reduced as provided in Section 3 of these rules.

1.1.11 Each PJM system shall be responsible for the determination of Summer and Winter Net Capability values, and for reporting same to the Operating Committee. The Operating Committee shall be responsible for the establishment of test procedures required to confirm such values including any amount which must be treated as limited energy capability.

1.1.12 The Net Capability reported for a unit following its date of commercial operation shall in no case exceed an amount determined by the owner in accordance with 1.1.1 and 1.1.8 but for PJM accounting purposes may initially be less than that amount. The extent of any such reduction in reported capability may be determined by the company in such manner as will permit the most effective use of its own resources. A unit or portion thereof placed in service and accepted by the IO for operating purposes may be reported and accounted for as negative unavailable before it is placed in commercial operation, limited to the extent that the total daily unavailable reported by system shall not be less than zero.

1.2 Summer Net Capability

1.2.1 The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

1.2.2 Summer conditions shall reflect the 50% probability of occurrence of temperature and humidity conditions of the time of the PJM summer peak load and shall be based on local weather bureau records for the past 15 years. When local weather records are not available, the values shall be estimated from the best data available. (see *attached memo dated March 4, 1988*)

1.2.3 For steam and combustion turbine units, summer conditions shall mean where applicable the probable intake water temperature of once-through or open cooling systems experienced in June, July and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

1.2.4 The determination of the Summer Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

1.3 Winter Net Capability

1.3.1 The Winter Net Capability of each unit or station shall be based on winter conditions and on the power factor level normally expected for that unit or station at the time of the PJM winter peak load.

1.3.2 Winter conditions shall reflect the 50% probability of occurrence of temperature and humidity conditions at the time of the PJM winter peak load and shall be based on local weather bureau records for the past 15 years. When local weather records are not available, the value shall be estimated from the best data available. (see attached memo dated March 4, 1980)

1.3.3 For steam and combustion turbine units, winter conditions shall mean where applicable the probable intake water temperature of once-through or open cooling systems experienced in December and January at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the Annual winter PJM peak.

1.3.4 The determination of the Winter Net Capability of hydro and pumped storage plants shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Summer Net Capability.

1.4 System Limitations

1.4.1 Certain system limitations may at times prevent the simultaneous utilization of the total Net Capabilities of the units in a system. Such limitations may include, but are not necessarily confined to, the availability of energy or fuel, and transmission limitations. The determination of energy and fuel limitations is described in section 4 and Appendix A, and of transmission limitations in Section 4 and Appendix B.

2. AVAILABLE CAPABILITY

2.1 Available Capability of a system shall be the sum of the reported Summer Net Capabilities for all units installed on a system less the Planned Outages and Deratings, Unplanned Outages and Derating, and Miscellaneous Adjustments. All such modifications shall be measured, except as to 2.1.3 (a), during the hour of the daily system peak load. Reductions of capability shall be reported as positive quantities and increases as negative, and the net used as a reduction from the Summer Net Capability values.

2.1.1 Planned Outages and Deratings shall be a reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions.

- 1

2.1.2 Unplanned Outage and Deratings shall be:

- (a) A reduction from the Summer Net Capability of a unit due to equipment out of service or other restrictions as defined in the PJM Report on Generating Unit Performance Definitions; and
- (b) For planning and accounting purposes required by the PJM Agreement as supplemented, an additional daily reduction in the capability of a system due to energy limitations determined in accordance with section 3 of the Rules and Procedures.

2.1.3 Miscellaneous Adjustments shall be:

- (a) A reduction from the Summer Net Capability of any equipment out of service for any reason not covered by 2.1.1 and 2.1.2 and which could not be made ready, upon notice, to carry load at its reported Summer Net Capability value, as modified by (b) and (c), within six hours.
- (b) A reduction from the Summer Net Capability of a unit or plant which could not be produced because of higher circulating water temperatures, higher ambient air temperatures, reduced head on hydro plants, and other causes consistent with the PJM Report on Generating Unit Performance Definitions.
- (c) An increase from the Summer Net Capability of a unit or plant which was produced or was capable of production over the specified period and was reported in operation or available for scheduling by the IO, because of lower circulating water temperatures, lower ambient air temperatures, recent condenser cleaning, higher stream flows, etc., and other causes such as a new unit operating for test.
- (d) The actual output, at the time of a system's daily peak load, of a unit or portion thereof, operating for test and not included in the Summer Net Capability of the system.
- (e) A reduction in the reported Summer Net Capability of a system which could not be delivered to load areas because of area or system transmission limitations as specified in Section 4.

2.2 Weekly Available Capability of a system shall be the arithmetical average of that system's daily Available Capability as determined in 2.1 above for each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.3 Weekly Summer Net Capability of a system shall be the arithmetical average of that system's total reported Summer Net Capability values for all units installed at the time of the system peak load on each weekday, excluding holidays, recognized by the IO for accounting purposes.

2.4 Weekly Unavailable Capability of a system shall be the algebraic difference between the average values determined in 2.2 and 2.3.

3. LIMITED ENERGY RESOURCES

3.1 General

3.1.1 The available output of all or any part of a unit's capability which is considered limited energy capability in accordance with 1.1.10 shall be utilized, as hereafter specified, on a daily basis excluding weekends and holidays to determine what amount, if any of such capability, is the equivalent of unavailable capability of unlimited resources. Such amounts of unavailable capability shall be determined both for actual and forecast conditions for use in PJM planning and accounting as follows:

- (a) Unavailable capability based on actual hourly loads, actual average daily river flows, actual outages of limited energy resources and other conditions applicable to the day, will be used as an addition to unplanned forced events in the after-the-fact accounting for capacity as provided in 2.1.2 (b).
- (b) Forecast unavailable capabilities based on daily computations but expressed as monthly averages and based on predicted load shapes, experienced probabilities of river flows or output, scheduled capacity additions, and predicted outages of limited energy resources will be for use in the determination of capacity requirements of PJM and the member companies as follows:
 - (i) To the extent that the forecast unavailable capabilities under summer and winter operating conditions exceeded the amount specified in 3.3.3, the forecast excess will be applied as a reduction in the net capabilities of systems owning the limited energy resources.
 - (ii) All forecast unavailable capabilities, except the portion applied in (i) for summer conditions, shall be used as an addition to forecast average unplanned forced events.

3.1.2 The available capability of limited energy resources of PJM shall be determined by fitting the total daily energy of these resources into the peak of the daily PJM load curve (to the best advantage of the limited energy resources) so as to minimize the required operation of unlimited resources. The total daily energy of the limited energy resources shall include all energy which is available or renewable only on a daily basis plus any additional daily energy available from the drawdown or refill of storage on a weekly or longer basis.

3.1.3 Whenever the determinations in 3.1.2 result in some amount of unavailable capability due to energy limitations, this amount shall be allocated among the several companies owning limited energy resources. Each company's own limited energy resources shall be tested on its own load curve to determine the resultant unavailable capability of that company's resources due

to energy limitations, and each company shall then be allocated a share of the total PJM unavailable capability due to energy limitations in proportion to the ratio of its unavailable capability on its own load curve to the sum of such unavailable capabilities for all companies.

3.1.4 The available capability of limited energy resources shall be determined, and any unavailable capability shall be allocated on the basis of data and procedures specified in Appendix A.

3.1.5 The Operating Committee shall maintain records of daily Available Capabilities of limited energy resources on the PJM system and of the resulting unavailable capabilities and their allocations, and shall review from time to time the determination of the effects of limited energy on the forecast Net Capabilities and Available Capabilities.

3.2 Fuel Shortages

3.2.1 If any generating capability is classified as limited energy capability because of fuel shortages, the determination of the amount of available capability of such limited energy resources will depend on the predictability of the limited fuel supply.

(a) When the limited fuel supply is predicted in advance for forecast conditions, it shall be treated as all other limited energy resources in fitting its total daily energy into the daily PJM load curve.

(b) When the limited fuel supply is not predicted in advance for forecast conditions but is imposed on any member company by external conditions (such as national policies, strikes, fuel supplying companies, etc.), the determination of available capability shall be made in two steps. First, a determination shall be made for all other limited energy resources to obtain the unavailable capability of these resources. Second, another determination shall be made for the total limited energy resources, including those for which fuel is limited by external conditions, but fitting this total available energy into the load curve and obtaining a second value for unavailable capability. The amount of unavailable charged to the fuel limited resources shall be the difference between the values obtained in the first and second determination.

3.2.2 If any unavailable capability charged to fuel limited resources is determined under 3.2.1 (b), this amount shall be allocated by making the same two determinations of unavailable capability as are required and by determining the additional unavailabilities charged to fuel limited resources on each owner company's own load curve. The unavailable capabilities on the PJM load curve that are charged to the fuel limited resources determined under 3.2.1 (b) shall then be allocated in proportion to the additional unavailabilities on the load curves of the owning companies. In no case shall the amount so allocated to any company, as a result of the separate allocation for fuel

limited resources, exceed the additional unavailability on its own load curve. Any amount of additional unavailable that cannot be allocated on this basis shall be allocated on the basis applicable for all other limited energy resources under 3.1.3.

3.3 Reduction in Net Capability

3.3.1 Energy limitations that cause reductions in load carrying capability are in some respects similar to unplanned forced events in unlimited energy capability. In either case, if the limitations on energy or reductions in capability are sufficiently severe, failure to carry load may result. Since the reported Net Capabilities of unlimited energy units are not reduced to reflect unplanned forced events experience, it is reasonable not to reduce the reported Net Capabilities of limited energy resources simply on the basis of energy limitations, unless such limitations are expected to be unusually severe at the time of the PJM peak load.

3.3.2 Whenever the forecast weighted average daily unavailable capability of limited energy resources of PJM, determined in accordance with 3.4.1 for the months of July and August (for determination of Summer Net Capability) and December and January (for determination of Winter Net Capability), is an amount which exceeds a specified percentage of the unlimited net capabilities of the total limited energy resources of PJM, such excess amount shall be applied as a reduction of the Net Capabilities of these resources. Such reductions shall be allocated among the owners of limited energy resources, generally in accordance with 3.1.3 and Appendix A except that, as to each owner, only that portion of the unavailable capability which exceeds the specified percentage of its own limited energy resources shall be used in determining the allocation factor.

3.3.3 The specified percentage shall be 12%, based on the recent actual weighted average PJM forced outage rate for thermal units less the actual weighted average PJM forced outage rate for hydro units, such averages based on three years of experience. The specified percentage shall be changed by the Operating Committee to conform to changes in unplanned forced events experience.

3.4 Forecast Unavailable Capabilities

3.4.1 The forecast monthly average unavailable capability of the limited energy resources of PJM shall be determined and allocated in accordance with 3.1.3, based on appropriately estimated daily load shapes and on experienced probabilities of river flow or output, scheduled capacity additions, and predicted outages of limited energy resources. Whenever the Net Capabilities of limited energy resources of PJM are reduced in accordance with 3.3.2, then that amount of unavailable capability that has been applied as a reduction of the Net Capabilities of PJM and the member companies for summer conditions shall be subtracted from the respective forecast average monthly values of unavailable capability.

3.4.2 Average monthly values of unavailable capability for PJM determined in 3.4.1 and reductions in Net Capabilities determined in 3.3.2, to the extent they are significant shall be used as input to the calculations of

Forecast Requirements of the Interconnection. Values lower than 2.5% of the Net Capability of the PJM Limited Energy Resources are considered to have an insignificant effect on the calculations of requirements, but may be included as input at the discretion of the P&E Committee.

3.4.3 The average monthly values of unavailable capability in excess of the reduction in summer Net Capability for each system determined in 3.4.1 for the 12 months of each planning period, shall be averaged to determine the average annual addition to unplanned forced events. The ratio of this average addition to the average total of the system's Net Capabilities for the planning period shall be used as an addition to its forecast forced outage rate.

4. TRANSMISSION LIMITATIONS

4.1 The availability of transmission capacity may limit the output of a unit, station, area or an entire system. The limitation may be the deliberate result of planning, the unintended result of delays in construction, the result of planned outages for maintenance or reconstruction, or the result of an unplanned forced outage for various reasons. The resulting effect on the availability of generating capacity is to be determined and be classified, based on the cause and extent of the transmission limitation.

4.2 Transmission limitations shall be determined as required for after-the-fact accounting and in forecast periods for use in the determination of capacity requirements of PJM and the member companies, by comparison of transmission capability with the excess of the Net Capabilities for a unit, station, area or system over the peak load for the day or period under consideration, with adjustment as necessary for firm purchases and sales, use of jointly owned units, and unavailable generating capability. The Net Capabilities used in such determination shall be appropriate for the season of the peak load under consideration. Transmission limitations shall be determined on the basis of data and procedures specified in Appendix B.

4.3 A transmission limitation caused by an outage of transmission facilities shall be recognized in the after-the-fact accounting as follows:

(a) When the limitation affects a unit or station, the amount of the limitation shall be considered as either a Planned or Unplanned Outage or Derating (as defined by the PJM report on Generating Unit Performance Definitions) in the determination of Available Capability as provided in 2.1.1 and 2.1.2.

(b) When the limitation affects an area or system, the amount of the limitation shall be considered as a Miscellaneous Adjustment to the reported Summer Net Capability of a system as provided in 2.1.3 (d).

4.4 Examination must be made to determine transmission limitations during forecast periods and any such limitations predicted shall be accounted for as follows:

- (a) Limitations predicted during July and August (1) which affect a unit or station shall be recognized in the reported Summer Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Summer Net Capabilities of units of the system in the determination of its System Capacity (as defined in the PJM Contract).
- (b) Limitations predicted during December and January (1) which affect a unit or station shall be recognized in the reported Winter Net Capability of such unit or station, and (2) which affect an area or system shall be recognized as a reduction in the total Winter Net Capabilities of units of the system.
- (c) Limitations predicted during forecast periods other than as specified in (a) shall be recognized in the determination of forecast average Miscellaneous Adjustments.

- 4 -
APPENDIX A

**DETERMINATION OF AVAILABLE CAPABILITY OF
LIMITED ENERGY RESOURCES**

The determination of this Available Capability shall be made: (A) for each weekday, after-the-fact, based on certain actual data and on procedures set forth below in further detail; and (B) for study and forecast purposes, based on probabilities of river flow and other appropriately assumed future conditions and on procedures otherwise consistent with the daily determination.

A. Daily Determinations

A determination shall be made by the Interconnection Office for each weekday, excluding holidays, of the Available Capabilities: (1) of the total limited energy resources operated on the PJM load curve and (2) if any Unavailable Capability is thus determined, of the limited energy resources of each company operated on the respective company load curve. These determinations involve the following steps:

1. Determine for the limited energy resources that amount of energy which is available or renewable only on a daily basis.
2. Determine that amount of additional daily energy available from the drawdown and refill of storage on a weekly or longer basis.
3. Determine the Available Capability of the limited energy resources by fitting the total daily energy (sum of 1 and 2) into the peak of the daily load curve (to best advantage of the limited energy resources, but observing all necessary limitations on their use) so as to minimize the required operation of other generating capacity. The Available Capability is the difference between the daily peak and the required maximum generation of such other capacity.

1. Daily Energy

The energy that is available or renewable only on a daily basis should be determined for the various types of capacity as follows:

- (a) Limited energy thermal capacity - if the unit or incremental capacity of a unit that provides such limited energy output can be considered available under the general provisions for "Available Capacity," Section 2.1, then the associated energy should also be considered available. The energy output of thermal capacity may be limited either by inability to operate continuously at high levels of output or by fuel availability.
- (b) Run-of-river hydro without weekly storage - for those plants that must generate daily whatever amount of energy is available from river flow, the available energy is that part of the actual daily generation which was, or could have been generated within the daily period of operation of all the limited energy resources, as determined by the load curve.

- (c) Run-of-river hydro with weekly storage - for those plants that can operate in part on the basis of weekly storage, the daily available energy (whether or not actually generated and without regard to actual storage use) should be the daily amount normally available for the actual river flow experienced on that day. Such amounts are to be shown by appropriate equations, curves or tabulations of energy versus river flow.
- (d) Storage hydro - for those plants that operate on a seasonal storage basis, the available energy will be determined as described below under item 2(b).
- (e) Pumped storage - the daily available energy (whether actually generated or not and without regard to actual storage use) should be the amount of energy that can be normally replaced by daily pumping within a period determined by load shape or other appropriate limitation, but not including economy of operation. The daily available energy shall be reduced, as compared to that normally replaced on a daily basis, by an amount corresponding to any pumping foregone because of unscheduled equipment outage or other limitation (other than economy) during the prior normal pumping period.

2. Additional Energy From Storage

For those plants which have storage that can be used on a weekly or longer basis, the additional amount of energy that is available should recognize that, within limits, the use of storage can be shifted from one day to another to fit system needs. The same amount of storage energy need not be used and ordinarily will not be used on every day; and general PJM experience has indicated a use of storage energy, on one or two days per week, at an average rate approximately double the rate which could be maintained on every weekday. Such use of storage appears to be a reasonable representation of the use that could and would be made of storage energy to meet normal capacity requirements. It shall therefore be assumed, in determination of available capacities, that the daily available energy from use of storage on any weekday will be twice the amount that could be used on every weekday. The amounts of additional daily energy from storage for the various types of capacity shall be determined as follows:

- (a) Run-of-river hydro with weekly storage - the daily amount shall be 40% of the available weekly storage as limited by the smaller of (i) flow available for weekend refill or (ii) excess of total usable storage over that required for daily operation. Amounts are to be shown by appropriate equations, curves or tabulations of storage energy versus river flow; and each daily amount shall be determined on the basis of an assumed constant flow throughout the week.

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- (b) Storage hydro - the total available daily energy at such plant shall be 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.
- (c) Pumped storage - the daily amount shall be 40% of the additional stored energy that can be replaced only by weekend pumping. The amount of weekend pumping shall be considered to be the useful reservoir capacity less the pumping that could have been done on a daily basis in the absence of any unscheduled outage.
- (d) If the energy output of thermal capacity is limited by fuel availability and such availability is determined on a weekly or longer basis, rather than by daily deliveries, for example, then the available energy on each day shall be (comparable to that for storage hydro) 40% of the greater of (i) the amount scheduled as available for generation during the week or (ii) the actual plant generation during the week whenever additional energy becomes available.

Because the above specified use of storage energy at various types of plants is the principal factor in the determination that is not related to actual current conditions, its validity shall be re-examined from time to time by the Operating Committee; and, if necessary, change shall be made in the above specified procedures.

3. The Daily Load Curve

The total of the daily available energy amounts, as described in 1 and 2 above, shall be fitted into the daily load curve to "firm up" the maximum amount of limited energy capacity. A direct determination of the available capacity in KW shall be made from a tabulation of peak capacity versus energy at the level indicated by the available energy. Recognition of the various limitations that may apply is important at this point in the computations. These include at least the following:

- (a) The usable amount of energy as determined in 1 and 2 above for any plant shall be no more than that plant could generate within the daily period of operation of all limited energy resources. (Alternatively, if the amount from 1 and 2 above is more than the plant can generate in the period determined by the load shape, the plant and its energy may be dropped out of the computation and be temporarily treated as an unlimited energy resource. This shall be the normal treatment of the run-of-river plants in period of adequate flow.)
- (b) The amount of available capacity for any plant that is firmed up by its available energy shall not exceed the physical capability of the plant during the peak hour of the day. This physical capability shall be determined by head, unit outages, and capacity limitations due to ice, trash, heat, or other causes.

- (c) A check shall be made, even when the total available capacity of the limited energy resources appears to be energy limited, to determine if some part of this capacity may not be energy limited (i.e., may be limited by physical capability). This is particularly likely in very low flows, when the run-of-river plants will be energy limited, but the pumped storage may not be. Under these conditions, the available capacity of the pumped storage is limited to its physical capability on the peak hour. At high flows, the situation may reverse.

B. Determination for Study and Forecast Purposes

Forecasts of Unavailable Capability, including those due to energy limitations, are needed under the terms of the PJM contract as supplemented, and similar forecasts are required for study of additional limited energy installations. Such forecasts shall be basically consistent with the above specified determinations for after-the-fact conditions; but certain difference in method of computation are appropriate in recognition of the nature of uncertainties inherent in all such forecasts. The Operating Committee shall review these procedures with respect to new capacity to determine if modifications are required.

1. Susquehanna River Flow

For forecast purposes, the flow of Susquehanna River shall be considered on a probability basis related to each month's experience over a long period. That is, for various ranges of river flow there shall be an assigned probability of occurrence for each month, based on the recorded experience in that month for 50 or more years. For this purpose, flow records accumulated at any one plant on the Susquehanna River (initially, Safe Harbor) may be used for all plants, with appropriate factors for conversion to daily energy.

2. Hydro Plants on Other Rivers

There are now in operation in PJM several small hydro plants (Deep Creek, Piney and Wallenpaupack) on other rivers or streams, not within the Susquehanna River drainage. Because the flow in these other rivers is not related to the flow in the Susquehanna River, and no correlations have been developed, and because the plants are small, it is satisfactory for forecast purposes to assign to each of these plants for each month a fixed amount of generation per day which is reasonably representative of less than average flow conditions. So long as these other plants are small and the available river flow is unrelated to the Susquehanna River flow, the forecast shall be based on this approximate representation of the available energy at such plants.

3. Pumped Storage and Limited Energy Thermal Capacity

The available energies for these plants on a forecast basis shall be consistent with those used, or which would be used in the after-the-fact determinations.

4. Load Curves

Forecasts of Unavailable Capability shall be based on the use of forecast energy amounts in forecast daily load curves. Such daily load curves shall be based on the adjustment of one or more years of experienced loads to be representative of the higher loads by the future years for which forecasts are required. The method of adjustment shall be specified by the Planning and Engineering Committee and shall be consistent with that used for other PJM purposes.

5. Adjustment for Unavailability Due to Unit Outages

Because hydro and pumped storage units are likely to be scheduled for inspection and maintenance at those times when their Available Capability would otherwise be limited by the available energy, recognition shall be given to the probability (related primarily to river flow) of the overlapping of unavailability due to both planned and unplanned maintenance outages and energy limitations. In the forecasting of Unavailable Capability, planned and unplanned maintenance outages shall be recorded at their full amounts and durations, and average unavailability due to energy limitations shall be appropriately reduced by an amount that recognizes the probability of overlap between the two causes of unavailability.

APPENDIX B

DETERMINATION OF TRANSMISSION LIMITATIONS

When determining the capability of a unit, station, area or system and the availability of this capability for PJM contract purposes, it is necessary to examine the ability to deliver the capability to the load areas. In order to make this examination, the following standard formula is presented to determine if a Transmission Limitation exists.

$$\text{Transmission Limitation} = \text{Net Capability} + \text{Firm Capacity Sales (1)} \\ \text{Firm Capacity Purchases (2)} - \text{Peak Load} - \\ \text{Unavailable Capacity} - \text{Transmission Capability (3)}$$

- (1) Includes only sales that must be delivered outside the System and any other system's share of jointly owned internal generation.
- (2) Includes system's share of jointly owned external generation and purchases from outside the System.
- (3) Transmission Capability of any transmission path must be compatible with the values used for emergency ratings as specified in the PJM Operating Principles and Standards and for parallel paths must be such a total that the loading of no line exceeds its emergency rating.

A. Daily Unavailability Due to Transmission Limitation

A Transmission Limitation associated with a unit or station shall be determined for each weekday excluding holidays using the standard formula with the following data:

<u>Item</u>	<u>Unit</u>	<u>Station</u>
Net Capability	Unit Net	Station Net
Firm Capacity Sale	Only when part of unit or station is jointly owned, or is specified source of firm sale.	
Firm Capacity Purchase	Not Applicable	Not Applicable
Peak Load	Local Bus Load	Local Bus Load
Unavailable Capacity	Of Unit	Of Station
Transmission Capability	For Lines Available	For Lines Available

A Transmission Limitation associated with an area or system shall be determined for each weekday excluding holidays using the standard formula with the following data:

<u>Item</u>	<u>Area</u>	<u>Station</u>
Net Capability	Of Stations in Area	Of all System Stations
Firm Capacity Sale	Only when part of station in area is jointly owned or is specified source of Firm Sale.	Total Value
Firm Capacity Purchase	Not Applicable	Total Value
Peak Load	Of Area	Of System
Unavailable Capability	Of Units in Area (Including Unavailability) (of Units or Stations Due) (to Transmission Limitation)	Of Units on System

B. Negative Values of Transmission Limitations

When the determination shows a negative Transmission Limitation the value shall be considered as zero for all cases except the daily System determination.

A negative value of Transmission Limitation as a result of the daily System determination can be considered as negative Unavailable Capability up to the value of the Transmission Limitation applied to the System Capacity. If there is no Transmission Limitation applied to the System Capacity then any negative value of Transmission Limitation as a result of the daily System determination shall be considered as zero.

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APPENDIX C
NET CAPABILITY VERIFICATION GUIDELINES

PURPOSE

These guidelines are to supplement the requirements set forth in the PJM Rules and Procedures for Determination of Generating Capability (Green Book) by setting forth requirements for Net Capability verification, reporting and review of results to assure uniform and consistent compliance. These guidelines address questions that occur frequently at the Generating Capability Ratings Procedure Task Force (GCRPTF) meetings.

A. PHILOSOPHY OF NET CAPABILITY VERIFICATION

1. Responsibility

- a. Member Companies through the GCRPTF are responsible to comply with these requirements at their own expense.
- b. GCRPTF consists of representatives from each member Company signatory to the Supplemental Agreement and an IO representative serving as secretary. The GCRPTF is responsible to review verification and to tender recommendations to the Operating Committee. Nonconformance(s) shall be communicated in writing to the Operating Committee.
- c. The Operating Committee Member is responsible for the approval of Net Capability verification reports and Company compliance to these guidelines.
- d. Individual Company Task Force members are responsible as delegated by their Company Operating Committee Member for the collection and reporting of net capability verification results.

2. Exceptions and Deviations

Exceptions to and deviations from these Net Capability verification guidelines shall be by Operating Committee approval. These exceptions shall be made in writing prior to the end of the test window for known occurrences such as environmental restrictions and fuel limitations.

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Exceptions to and deviations from these Net Capability verification guidelines shall be by Operating Committee approval. These exceptions shall be made in writing prior to the end of the test window for known occurrences such as environmental restrictions and fuel limitations.

8. NET CAPABILITY VERIFICATION

1. Net Capability verification is to demonstrate the maximum Net Capability of each unit. If that Net Capability cannot be demonstrated during the verification window, a reduction or derating shall be enacted to account for the deficiency.
2. Both Summer and Winter Net Capability shall be confirmed annually during the verification windows that correspond to the seasonal peak periods:
 - a. Summer verification window shall be the first day of June through the last day of August.
 - b. Winter verification window shall be the first day of December through the last day of February.
3. If adequate data is available from normal operation to confirm Net Capability values and to satisfy the reporting requirements during the seasonal verification window, no test is required. Units for which the foregoing data is not available shall be tested to confirm Summer and Winter Net Capability values. A test shall include any unit brought on-line or a unit that is on-line and its mode of operation altered for the specific purpose of capability verification.
4. If a unit does not meet its stated Summer or Winter Net Capability due to a temporary condition, the deficiency shall be covered by the appropriate outage/reduction(s) from the date of the problem. If a capability deficiency is uncovered during this verification, a reduction covering the deficiency shall be coded retroactive to June 1 or January 1 for summer and winter verification windows, respectively.
5. Net Capability verification is required outside of the verification period when an outage or reduction occurred prior to or during the verification period which prevented demonstration of maximum Net Capability. The Net Capability shall be demonstrated by either operating performance data or test results.

C. REPORTING

1. Two standardized forms are provided to facilitate the review of results:
 - a. Attachment One is the individual unit PJM Net Capability Verification Reports to be used for documenting operating performance or test data.
 - b. Attachment Two is the PJM Verification Summary Report.
2. Net Capability Verification Reports shall be approved by the Operating Committee Member.
3. Reports shall be submitted to the GCRPTF Secretary no later than September 30th and March 31st for the summer and winter verification periods, respectively. Copies of the summary sheets shall be mailed to the GCRPTF Members.
4. Outages and reductions for the discrepant capability greater than 1 MW (Rated Net Capability less the Corrected Test Net Capability) shall be recorded on the reports, including:
 - a. MW's out shall be reported on the Capability Reporting Form along with a brief explanation of the reason completed by Plant personnel.
 - b. The MW reduction shall be covered in the Summary Report notes with event data including: MW reduction, NERC event type, cause code, event start date and time, event end date and time (if appropriate). The Summary Report shall be submitted by the GCRPTF member.
5. When the owner has submitted output adjustment methodology and received GCRPTF approval, the following output corrections may be made:
 - a. For combustion turbines, ambient air temperature correction.
 - b. For steam units, circulating water temperature correction.
 - c. For cogeneration units where heating system extraction steam limits the output, a limited steam flow correction.
6. Units shall be verified and reported on a block basis as opposed to an individual basis when the units are rated and dispatched as a block.
7. Net Capability Verification Reports shall be submitted to the GCRPTF Members for verification outside of the verification period to document end of outages or reductions (reference paragraph B.5).

8. Reports shall indicate the nearest whole MW output for units rated 10 MW's or greater, and the nearest one-tenth MW output for units rated less than 10 MW. When a figure is to be rounded to fewer digits than the total number available, the procedure adapted from ISO-R170, should be as follows:

- a. When the first digit discarded is less than 5, the last digit retained should not be changed. For example, 3.463 25, if rounded to three digits, 3.46.
- b. When the first digit discarded is greater than 5, or if it is a 5 followed by at least one digit other than 0, the last digit retained should be increased by one unit. For example, 8.376 52, if rounded to four digits, would be 8.377; if rounded to three digits 8.38.
- c. When the first digit discarded is exactly 5, followed only by zeros, the last digit retained should be rounded upward if it is an odd number, but no adjustment made if it is an even number. For example, 4.365, when rounded to three digits, becomes 4.36. The number 4.355 would also be rounded to the same value, 4.36, if rounded to three digits.

D. REVIEW

1. A GCRPTF Working Group composed of the immediate past chairman, the present chairman, next apparent chairman, and the secretary (IO member) shall review all reports to verify completeness of records and verify outage tickets as required.
2. Each owner shall have a representative in attendance (GCRPTF member or alternate) at the GCRPTF verification review meeting. The review should be reported in minutes to the Operating Committee including a summary of results, a list of follow up items, and nonconformances to these procedures.

PJM NET CAPABILITY VERIFICATION REPORT
COMPANY

- | | |
|-------------------------------------------------------------------------------|---------------------|
| 1. Plant and Unit No. _____ | 4. Date _____ |
| 2. NERC Unit Identification _____ | 5. Start Time _____ |
| 3. Method: Operational <input type="checkbox"/> Test <input type="checkbox"/> | 6. End Time _____ |

7. Corrected Test Net Capability-MW _____
8. Rated Net Capability-MW _____
9. Difference-MW (+) _____

RATED

OBSERVED

- | | | |
|-----------------------------------------|-------|-------|
| 10. Main Steam Temperature- OF ° | _____ | _____ |
| 11. Reheat Steam Temperature- OF ° | _____ | _____ |
| 12. 2nd Reheat Steam Temperature- OF ° | _____ | _____ |
| 13. Main Steam Pressure- PSIG ° | _____ | _____ |
| 14. Air Dry Bulb Temperature- OF | _____ | _____ |
| 15. Cooling Water Temperature OF | _____ | _____ |
| 16. Extraction Steam Flow - 1000 Lb/Hr. | _____ | _____ |

- | | |
|---------------------------------------------|-------|
| 17. Reactive Generation-MVAR (+) | _____ |
| 18. Gross Generation- MW | _____ |
| 19. Station Use-MW | _____ |
| 20. Test Net Capability-MW | _____ |
| 21. Cooling Water Correction-MW (+) | _____ |
| 22. Air Correction-MW (+) | _____ |
| 23. Extraction Steam Flow Correction-MW (+) | _____ |
| 24. Total Power-MVA ° | _____ |
| 25. Power Factor ° | _____ |

26. Explanation for Difference

MW

Explanation

SIGNED: _____

STATION MANAGER

APPROVED: _____

MEMBER
PJM OPERATING COMMITTEE

Data is optional and not required by PJM

Specific Instructions

- Line 1. Company plant and unit number identification
- Line 2. Use NERC numerical designations only
- Line 3. Indicate Test, if unit started or current operating load changed for capability verification.
Indicate Operational, if unit is currently operating at capability rating. Historical data is also acceptable; two (2) hour average (steam units), one (1) hour (combustion turbines).
- Line 4. Enter date of test - month, day, and year.
- Line 5., 6. Enter time of test, use military time.
- Line 7.(MW) Test Net Capability (Line 20) plus Water Correction (Line 21) for steam units - Otherwise Test Net Capability (Line 20) plus Air Correction (Line 22) for combustion turbines.
- Line 8.(MW) Current Net Capability - First character - S (Summer) W (Winter)
Remaining characters - Rated Net Capability
- Line 9.(MW) Corrected Net Capability (Line 7) minus Rated Net Capability (Line 8); - Include (+) sign.
- Line 10., 11
12., & 13 Enter data for steam units only - Temp. (OF), Pressure (PSIG)
Otherwise enter NA
- Line 14. Enter data for combustion turbines and cooling tower steam Units only (OF) - Otherwise enter NA
- Line 15. Enter data for steam units only (OF) - Otherwise enter NA
- Line 16. Enter data for approved extraction steam units only (1000lb/hr)
Otherwise enter NA.
- Line 17.(MVAR) Enter (+) into system (LAG); (-) into unit (LEAD). Enter two (2) hour average for steam units
- Line 18. (MW) Enter two (2) hour average for steam units.
- Line 19. (MW) Enter two (2) hour average for steam units
- Line 20. (MW) Gross Generation (Line 18) minus Station Use (Line 19)
- Line 21. (MW) Steam units only. Enter NA for combustion turbine units
- Line 22. (MW) Combustion turbine units only. Enter NA for steam turbine units
- Line 23. (MW) Approved extraction steam units only. Otherwise enter NA.
- Line 24. (MVA) Vector sum, Gross Generation (Line 18) and Reactive Generation (Line 17.)
- Line 25.(DEC.) Gross Generation (Line 18) divided by Total Power (Line 24)
- Line 26. Enter narrative to explain negative difference (Line 9) - Otherwise narrative requirement is optional.

**PJM CAPABILITY VERIFICATION REPORT SUMMARY
COMPANY**

[illegible]

Motors:

SPECIFIC INSTRUCTIONS

1. Company - Enter reporting company name.
2. Plant/Unit
NERC I.D. Enter plant name, unit number, and
NERC identification number
3. Period -- Enter the test period date. (Example - 583, W83/84)
4. Capability
 - a. Rating Enter Rated Net Capability - MW (Line 8 from
PJH NET CAPABILITY VERIFICATION REPORT)
 - b. Difference Enter Difference - MW (+) (Line 9 from PJH
NET CAPABILITY VERIFICATION REPORT)
5. Megawatt Reduction Enter the megawatt reduction assigned to each NERC
outage event. Event data can have more than one
entry for the difference reported. Megawatt
reduction can be greater than difference reported.
6. NERC Event Type Enter NERC event type and class as defined in the
PJH GENERATING UNIT PERFORMANCE DEFINITIONS for
each megawatt reduction.
7. NERC Cause Code Enter the NERC Cause Code as defined in the PJH
GENERATING UNIT PERFORMANCE DEFINITIONS for each
NERC event.
8. Start/End
 - a. Date Enter Start/End month, day, and year (example -
01/30/84).
 - b. Time Enter Start/End time, use military time (Example -
1429).
9. Notes Enter a sequence number. Use the sequence number
as a reference to the narrative in the space
provided at the bottom of the summary or use a
separate page. If no event information exists,
assign a sequence number and explain in the notes.

APPENDIX D

GUIDELINE FOR CLASSIFICATION OF EXTENDED DURATION OUTAGES RESULTING FROM
VOLUNTARY DEFERRAL OF REPAIRS TO GENERATING UNITS

(Deferred Maintenance Guidelines)

Purpose

The purpose of this guideline is to define a procedure for implementing a PJM policy which permits the voluntary deferment of generating unit repairs for financial reasons while minimizing the effect that such a deferment has on the determination of forecast installed reserve obligations and allocations.

During periods of high PJM system installed reserves, it may not be economically feasible to perform extensive repairs on units with high operating costs, since such units are unlikely to be called on to supply load. Whenever such a unit fails and is not repaired immediately, the outage associated with the failure is lengthened due solely to company economic and system reserve conditions, rather than to any special nature of the unit failure. PJM reserve obligations and allocations are both based in part on company outage history. The straightforward inclusion of the total time associated with a deferred maintenance outage in a company's outage history leads to a pessimistic model of unit repair time.

The PJM companies recognized that in times of lower excess system installed reserves, units would be repaired with minimum delay, since system conditions would dictate more frequent unit operation. The procedure outlined in the following paragraphs is designed to allow companies to single out those outages which are lengthened due solely to company economic constraints, so that such outages can be more accurately modelled in PJM planning studies.

It should be noted that a company requesting deferred maintenance status for a unit agrees to attempt accelerated repairs in the event of an Operating Committee determination that the unit is required to bolster PJM system or sub-area reserves. Also, the physical coding of such outages in the PJM outage data base is not changed as a result of application of this procedure. Neither is the deferred maintenance classification recognized for any uses of the outage data base other than the determination of forecast installed reserve obligations and allocations.

Scope of Application

This procedure may be applied to an outage on any generating unit or portion thereof, so long as repairs are to be deferred for at least 90 days due solely to company financial constraints.

Procedure

I. In the event that a unit is out of service in the unplanned forced classifications,* either wholly or partially, and repairs are to be deferred for at least 90 days due solely to company financial constraints, the owning company shall have the option to request that the portion of the outage associated with the deferment be excluded from consideration as an unplanned forced outage in planning studies. Authority to grant or deny such a request rests with the PJM Operating Committee, as advised by the Maintenance Committee and the Interconnection Office.

II. A request for official recognition of the voluntary deferment period must include the following information:

1. Name of unit.
2. MW of installed capability affected.
3. Is this a reduction in unit capability, or a full outage?
4. Starting date of original unplanned forced outage.
5. Planned return to service date.
6. Scope of repairs required.
7. Estimate of unplanned forced outage time required to effect repairs to the unit. This estimate should be based on crews working a 40-hour week and must include any time waiting for manpower or parts to become available or for technical problems to be solved.

III. Copies of each request will be sent to the Maintenance Committee and the Interconnection Office, as well as to the Operating Committee.

A. The Maintenance Committee will review the scope of required repairs compared with the estimated repair time, and advise the Operating Committee on the adequacy of the repair time estimate.

B. The Operations Planning Branch of the Interconnection Office will analyze the effect of the repair deferment on PJM system reserves and risk during the outage period, as well as sub-area reserves (if the unit is located in a deficient area) and make recommendations to the Operating Committee.

IV. The Operating Committee can either approve or disapprove a request for deferred maintenance status based on the recommendations of the Maintenance Committee and the Interconnection Office.

A. If the Operating Committee disapproves the request, the entire outage duration will be considered as unplanned forced outage time and will be accounted for as such on all planning studies.

*The basis for this definition is set forth in IEEE Standard 762 entitled "Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity."

- B. If the Operating Committee approves a request for deferred maintenance status for a particular unit, relevant information concerning the deferral period will be passed to the Generator Unavailability Subcommittee, of the Planning and Engineering Committee, so that the outage can be properly modelled in all planning studies.
- C. The revised modelling of any approved deferred maintenance outage for planning study purposes is a manual process. Reporting of the outage in the PJM outage data base will not be affected by Operating Committee approval or disapproval of a deferral period.
- D. After-the-fact accounting is not affected by Operating Committee action on a deferral request. Such a unit will be considered unavailable for purposes of after-the-fact accounting whether or not the Operating Committee grants a deferred maintenance request.

Extensions to Existing Deferral Periods

- I. If a unit has not been repaired by the planned return to service date, its outage classification for planning study purposes will revert back to unplanned forced as of the planned return to service date, unless an extension to the deferral period is allowed by the Operating Committee.
- II. Any request for an extension to an existing deferral period should be handled just like any new request for deferred maintenance status, with the owning company proposing a revised in-service date for review by the Operations Planning Branch of the Interconnection Office and final action by the Operating Committee.
- III. Because of the system planning aspects of the deferred maintenance classification, all requests for extensions to existing deferral periods should be made as soon as possible after determination that company financial constraints will not allow repair of a particular unit to begin before the original planned in-service date.

Returning Deferred Maintenance Units to Service

- I. Voluntary Return by Owning Company
 - A. The company owning a unit with deferred maintenance status should keep all interested parties notified of any changes in the expected return-to-service date of the subject unit.
 - B. If a company decides to delay the return to service of a deferred maintenance unit, an extension of the deferral period may be requested as outlined above.
 - C. A company may decide to return a deferred maintenance unit to service at any time prior to the originally scheduled return date. If such a decision is made, the outage will be classified as follows:

1. No additional unplanned forced outage time will be assigned to a unit repaired and reported available for service at any time after the minimum 90-day deferral period but before the original return-to-service date.
2. If a unit is repaired and returned to service prior to the minimum 90-day deferral period, the outage duration will be classified as forced for planning study purposes.

II. Return Requested by Operating Committee

- A. When dictated by changing system conditions, the Operating Committee can request that companies owning units with deferred repairs effect repair of the subject units in order to bring PJM system or sub-area installed reserves up to more acceptable levels.
- B. Should such a recall become necessary, units which have been granted extensions to their original deferral periods will be the first ones called back to service.
- C. If a unit is repaired and returned to service at the request of the Operating Committee, no additional unplanned forced outage penalty will be assigned, even if the repairs are completed prior to the end of the original 90-day deferral period.
- D. If a company is not able to respond to a recall request on a deferred maintenance unit, the outage on the unit in question will be considered unplanned forced for planning study purposes, after a period of time equal to the estimated repair time.

Control

I. The Operations Planning Branch of the Interconnection Office will analyze system conditions and make recommendations to the Operating Committee regarding each request for a new or extended deferral period.

II. On a continuing basis, the Interconnection Office will review system conditions to determine the impact of existing deferred maintenance on PJM operations.

- A. The Interconnection Office will make recommendations to the Operating Committee concerning the need for accelerated return of units on deferred maintenance.
- B. Reserve and risk criteria used shall be approved by the Operating Committee.

Revised and approved by the PJM Operating Committee 11/87

51748

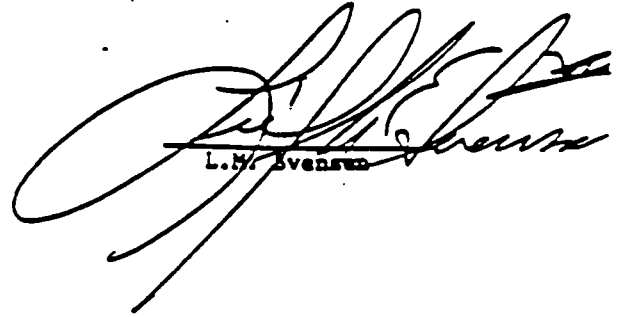
MEMORANDUM

March 4, 1988

TO: H.S. Solganick
FROM: L.M. Svensen
SUBJECT: Current Summer and Winter Rating
Temperatures for Combustion Turbines (C.T.'s)

The current ambient temperatures used for summer and winter ratings for C.T.s in the western territory are 91°F and 30°F respectively. These temperatures are based on sections 1.2 and 1.3 of PJM's Rules and Procedures for Determination of Generating Capacity.

The above temperatures could change if the PJM Generator Capability Ratings Procedures Task Force decides that all PJM member companies update their rating temperatures.



L.M. Svensen

jnk
xc: J.C. McCullough
J.R. Brignola
G. Hogg

EXHIBIT B

**PURCHASER'S
INTERCONNECTION STUDY
FOR
SELLER'S FACILITY**

KEYSTONE SHIPPING COMPANY
INTERCONNECTION STUDY

System Planning
June 1988

1. INTRODUCTION

The purpose of this study is to determine the interconnection feasibility for the proposed site between Keystone Shipping Company and Atlantic Electric (AE) so that AE may receive the electric generation in a safe and reliable manner.

This study covers transmission requirements to connect from AE to the cogeneration facility, effect of cogenerator on AE's system along with the cost estimates for interconnection and associated work. Costs have an order of accuracy of $\pm 20\%$. They include the transmission/substation improvements required on AE's system. The cost for a switching station is also included. Costs to provide two transmission lines from the high side of the switching station to AE's line are provided as a per mile cost.

II. RECOMMENDATION

It is recommended that Keystone interconnect to AE at 230 kV to a new Deepwater - Mickleton 230 kV line. The interconnection of Keystone's facility to AE's system will be via a newly constructed 230 kV switching station.

III. CONCLUSION

1. Character of service

- A. Generation 200 MW net at a power factor of 90% leading or lagging.
- B. Maximum load of 0 MW 0 MVARs.
- C. 60 Hertz
- D. 3 phase
- E. Interconnection voltage 230 kV.
- F. Ability to vary generator terminal voltage $\pm 5\%$.
- G. Maximum generation 200 MW at a power factor of 90% leading or lagging.

- 2. Although Keystone is not scheduled to be in service until 1/1/93, all cost are based on an in service date of 6/1/92.

IV. DISCUSSION

A. Transmission Study Assumptions

1. MW (MVA) - MVA assumed to be at 90% power factor.
2. All cost are without AFDC
3. Cash flows do not include interconnection line from transmission line to switching station.
4. Major switching station assumptions are shown in Figure 1.

Figure 1

List of Equipment included in the Switching Station

2 - Breakers

An Isolation Switch

Energy Management System (EMS)

All high side bus structure

5. Reconductoring - Can be from replacing the conductor to completely rebuilding the line including replacing the poles.
6. New Line - Construction of new transmission line on new Right of Way.

7. Upgrade Substations - Replacing various substation equipment to obtain desired capability.

8. Transmission Connections

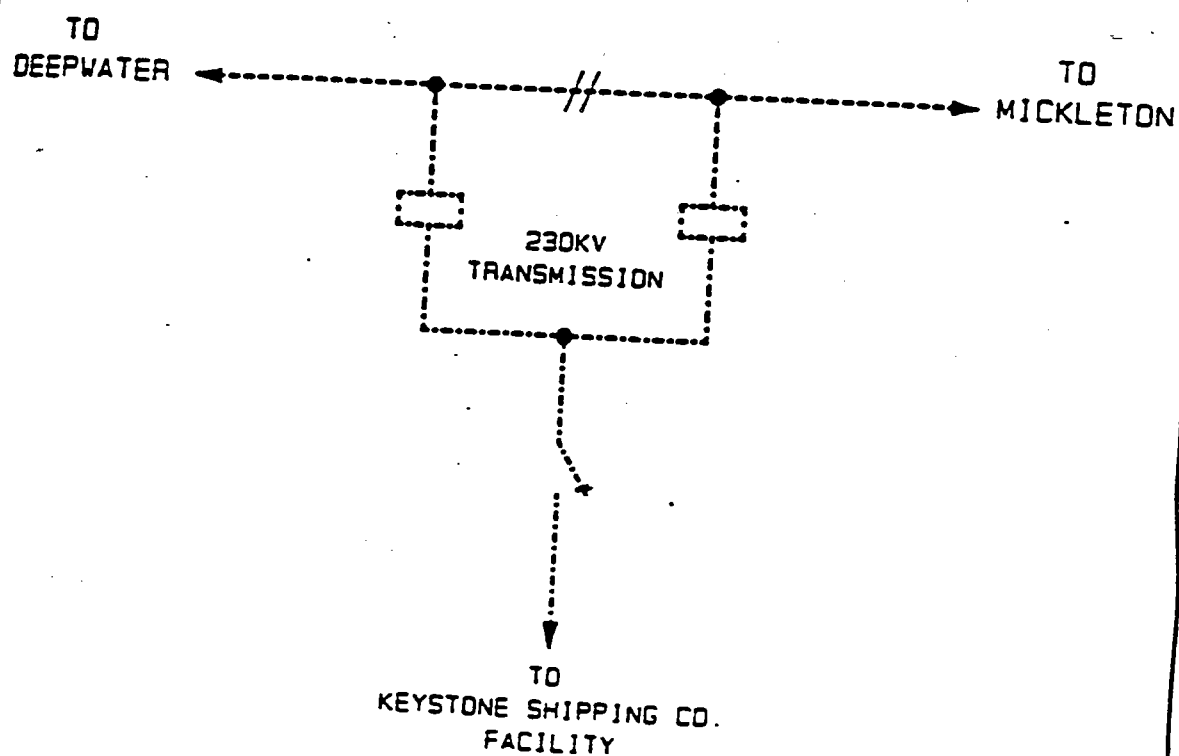
Actual interconnection voltage and system improvements have not been finalized. At present 230 kV interconnection is being considered in order to have flexibility in the size and amount of future cogenerators.

The interconnection one line is shown in Figure 2.

DELAWARE RIVER COGENERATORS

The number and aggregate total capacity of the eventual river area cogenerators that indicate their desire to interconnect can vary (Figure 3). To illustrate the progressive nature of the system improvements/new construction the following figures are provided. The increments are determined by existing and upgraded facilities. It should be remembered that each of these alternatives may be exclusive and costs can not be considered incremental from one MVA level to another unless noted. The system costs do not include the facility specific interconnection switching facility and lateral transmission line.

Figure 2



NEW 230KV LINE
BREAKER
ISOLATION SWITCH
// DISCONNECT
NEW 230KV SWITCHING STATION

KEYSTONE SHIPPING CO. COGENERATION FACILITY
INTERCONNECTION AND POINT OF DELIVERY

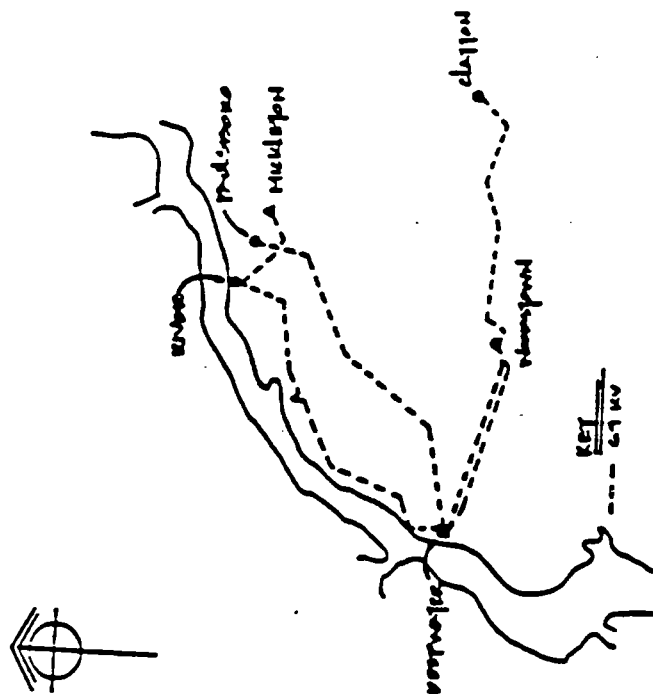
INTERCONNECTION AND POINT OF DELIVERY						
DR. <i>FAM</i>	CH.	CH.	APP.	DATE	SCALE	ROUTE
ATLANTIC ELECTRIC CO. P. VILLE. N. J.					NO.	<u>SK-8138-0</u>

Figure 3

COGENERATORS -----	MW -----	MVA (e 90%) -----
WILMINGTON THERMAL	80	90
KEYSTONE	200	220
COGENERATION PARTNERS OF AMERICA	106	120
INTERCONTINENTAL ENERGY CORPORATION	154	170
BECHTEL -----	167	185

NET COGENERATION UP TO 80 MW

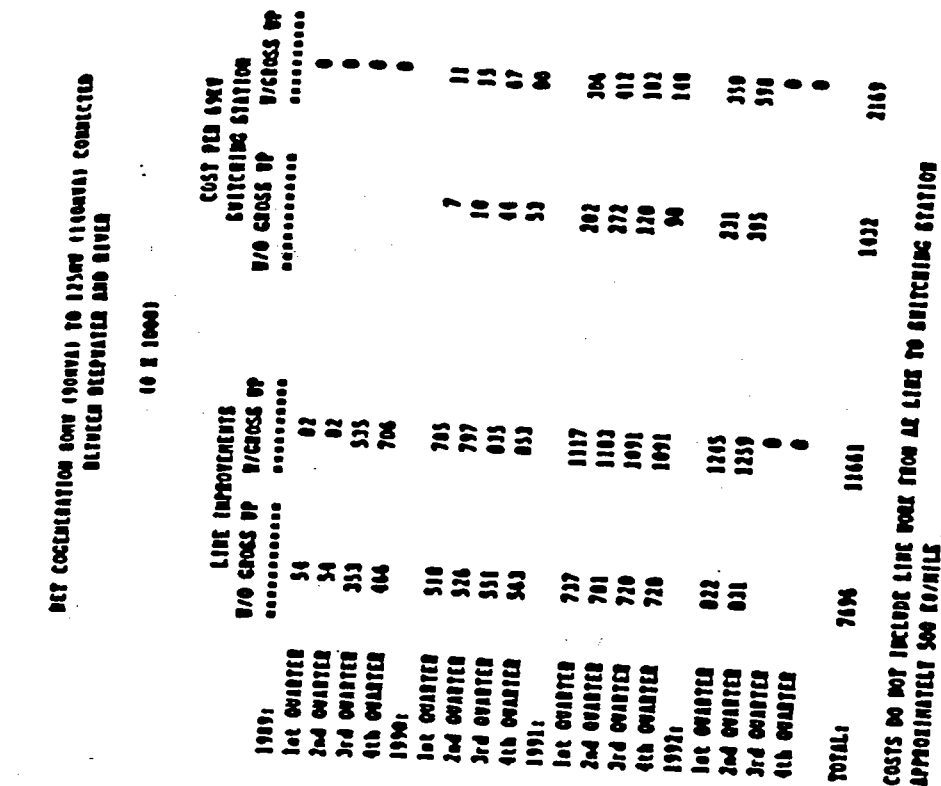
The cost for connecting up to 80 MW of cogeneration is shown in Figure 4. This cost includes the reconductoring of approximately 20 miles of existing 69 kV transmission line to 1200 amps and the uprating of 3 existing 69 kV substations. Also, shown is the cost of one 69 kV switching station including modifications to AE's Energy Management System and the approximate cost/mile for new 69 kV transmission line from AE's transmission line to switching station.



NET COGENERATION BETWEEN 80 MW TO 125 MW

The cost for connecting between 80 MW and 125 MW of cogeneration is shown in Figure 5. This cost includes the reconductoring of approximately 35 miles of existing 69 kV transmission line to 1200 amps and the uprating of 6 existing 69 kV switching stations. Also shown is the cost per 69 kV switching station including modifications to AE's Energy Management System and estimated cost/mile for new 69 kV transmission line from AE's transmission line to switching station.

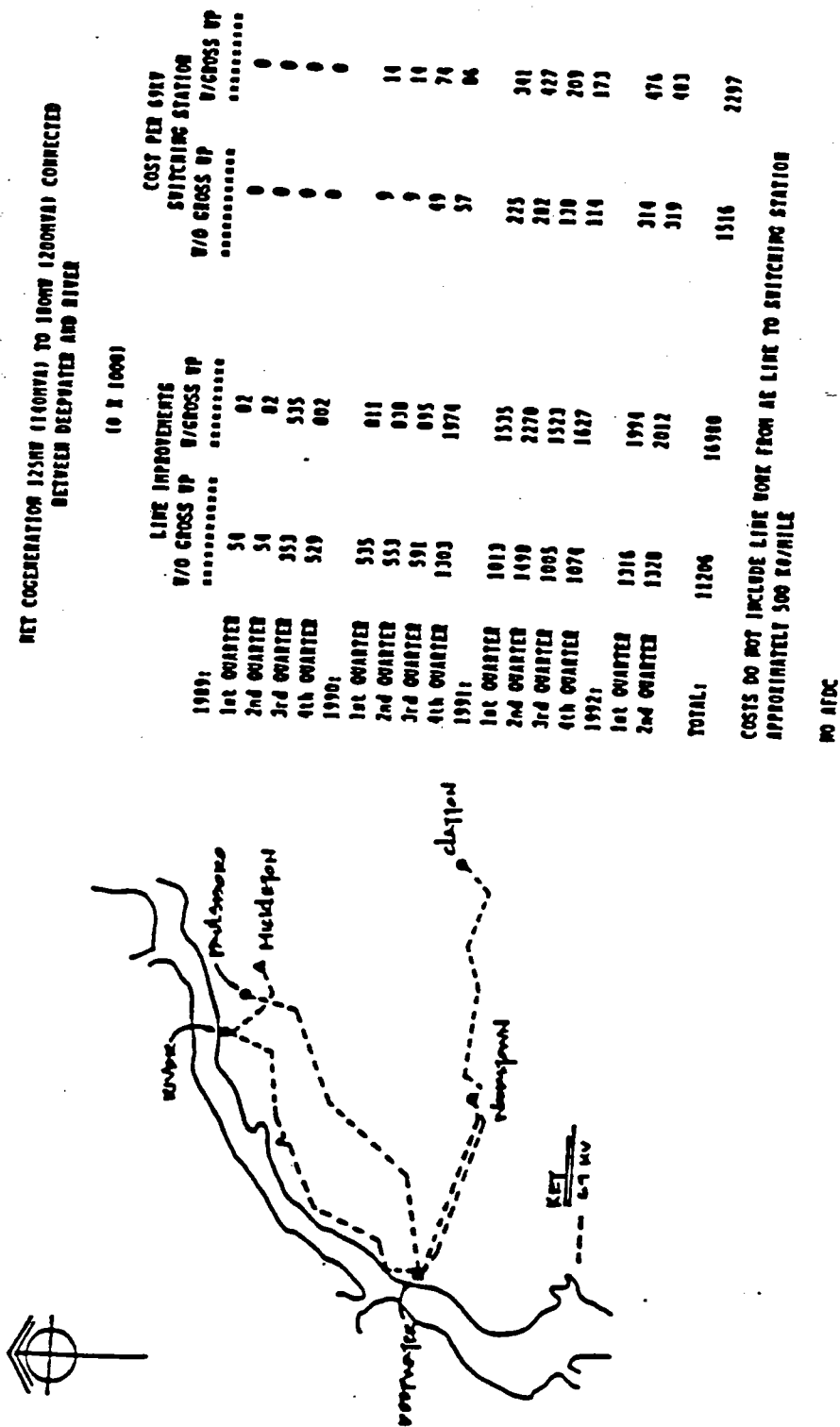
Figure 5



NET COGENERATION 125 MW TO 180 MW

The cost for connecting between 125 MW to 180 MW of cogeneration is shown in Figure 6. This cost includes the reconductoring of approximately 23 miles of existing 69 kV transmission line to 2000 amps and approximately 16 miles of 69 kV transmission line to 1200 amps and the uprating of 8 existing 69 kV substations. Also, shown is the cost of one 69 kV switching station including modifications to AE's Energy Management System and the approximate cost/mile for new 69 kV transmission line from AE's transmission line to switching station is also tabulated.

Figure 6



NET COGENERATION 167 MW CONNECTING DIRECTLY TO DEEPWATER

The cost for connecting a 167 MW cogenerator directly to Deepwater station is shown in Figure 7. This cost is for one cogenerator connected to Deepwater station and assumes no other cogenerator in the area or along the river. This cost includes the reconductoring of approximately 54 miles of 69 kV lines to 1200 amps, the rebuilding of 7 - 69 kV substations, the upgrading of 7 existing breakers, and the establishment of 2 - 138 kV terminals at Deepwater. Also shown is the estimated cost/mile for new 138 kV transmission line.

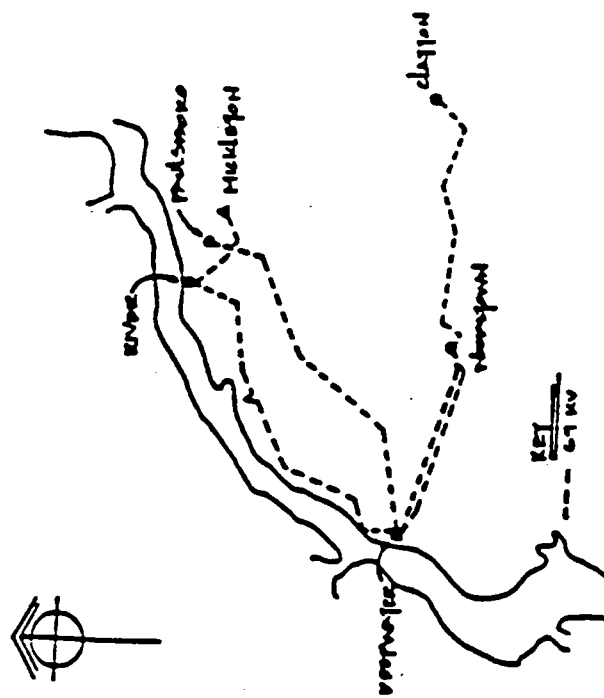
Figure 7

NET COGENERATION UP TO 167MW (110MW) CONNECTED DIRECTLY TO DEPLETED

	(0 IN 1000)	LINE IMPROVEMENTS	U/CROSS UP	U/CROSS UP
	
1991:				
1st QUARTER	50		02	
2nd QUARTER	54		02	
3rd QUARTER	613		1277	
4th QUARTER	850		1200	
1990:				
1st QUARTER	936		1410	
2nd QUARTER	904		1491	
3rd QUARTER	1066		1613	
4th QUARTER	1396		2115	
1991:				
1st QUARTER	1630		2002	
2nd QUARTER	1706		2305	
3rd QUARTER	1917		2147	
4th QUARTER	1646		2494	
1992:				
1st QUARTER	1400		2121	
2nd QUARTER	1410		2142	
TOTAL:	15494		23359	

COSTS DO NOT INCLUDE LINE FROM AIR LINE TO SWITCHING STATION
APPROXIMATELY 700 C/MILE OR SWITCHING STATION

DO NOT



NET COGENERATION 180 MW TO 360 MW

The cost for connecting between 180 MW and 360 MW of cogeneration in the Deepwater-Mickleton area (including cogeneration at or near Deepwater) is shown in Figure 8.

The cost shown in Figure 8 includes the construction of approximately 18 miles of 230 kV transmission line, the establishment of 6 - 230 kV line terminals at Mickleton, the establishment of a 230 kV station at Deepwater including two 230/138 kV transformers, the reconductoring of approximately 16 miles of existing 69 kV transmission line, the rebuilding of 3 - 69 kV substations and the upgrading of 7 existing breakers. Also, detailed is the cost of a 230 kV switching station including modifications to AE's Energy Management System, and the approximate cost per mile to construct 230 kV transmission from the 230 kV line to the switching station.

Figure 8

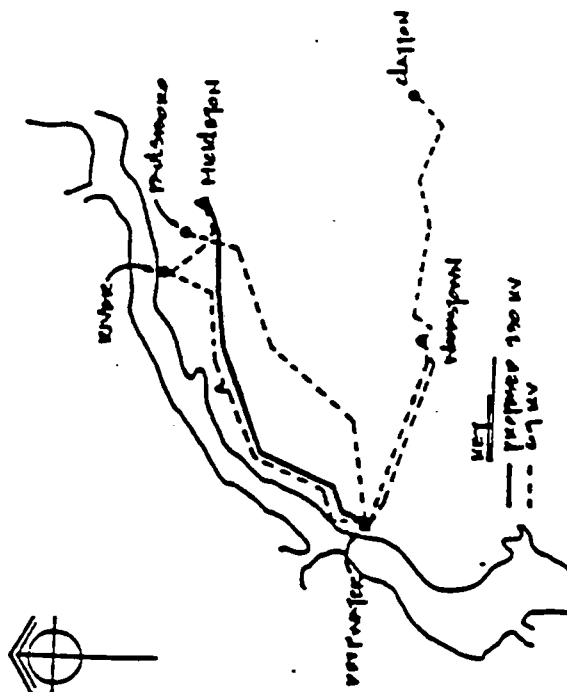
**NET COGENERATION 100MW (200MW) TO 300MW (400MW) CONNECTED
BETWEEN DELPATER AND RIVER**

(IN \$ 1000)

	LINE IMPROVEMENTS		COST PER 230KV SWITCHING STATION	
	W/O CROSS UP	W/CROSS UP	W/O CROSS UP	W/CROSS UP
1988:				
2nd QUARTER	216	373	0	0
3rd QUARTER	251	300	0	0
4th QUARTER	222	336	0	0
1989:				
1st QUARTER	262	397	13	20
2nd QUARTER	264	400	13	20
3rd QUARTER	267	403	16	24
4th QUARTER	306	555	13	20
1990:				
1st QUARTER	1896	2073	591	895
2nd QUARTER	2001	2032	590	906
3rd QUARTER	2619	3059	605	917
4th QUARTER	2543	3053	609	923
1991:				
1st QUARTER	4354	6597	305	462
2nd QUARTER	4397	6662	309	460
3rd QUARTER	4440	6727	312	473
4th QUARTER	4403	6792	325	492
1992:				
1st QUARTER	3586	5433	77	117
2nd QUARTER	3625	5492	70	110
TOTAL:	33222	53366	3864	5855

COSTS TO CONNECT FROM AR LINE TO SWITCHING STATION ADDITIONAL 9000\$/MILE.

NO AFDC



NET COGENERATION 360 MW TO 500 MW

The additional cost for connecting between 360 MW to 500 MW of cogeneration is shown in Figure 9. This is an incremental cost to the cost shown in Figure 8 and the improvement must be done in addition to the improvements mentioned in the previous section (Net Cogeneration 180 MW to 360 MW). The transmission line improvement would also be required if enough cogeneration comes in along the Deepwater-Mickleton line to provide support to AE's eastern service territory in lieu of other transmission improvements. This cost consists of the reconductoring to 2000 amps and converting from 138 kV to 230 kV of approximately 31 miles of an existing 138 kV transmission line, the establishment of a 230 kV line terminal at Deepwater, the establishment of a 230 kV station at Sherman Avenue with two 230/138 kV transformers.

Figure 9

SYSTEM IMPROVEMENTS
W/C AND CONVERT D/W-SHEPHERD 130KV LINE TO 230KV

(in \$ 1000)

LINE IMPROVEMENTS
W/O AFDC W/AFDC
.....

1988:		
1st QUARTER	171	172
2nd QUARTER		
3rd QUARTER		
4th QUARTER		
1989:		
1st QUARTER	228	229
2nd QUARTER	226	236
3rd QUARTER	227	243
4th QUARTER	230	250
1990:		
1st QUARTER	1258	1289
2nd QUARTER	1270	1320
3rd QUARTER	1282	1371
4th QUARTER	6487	6631
1991:		
1st QUARTER	4973	5253
2nd QUARTER	5021	5414
3rd QUARTER	5071	5591
4th QUARTER	5125	5759
1992:		
1st QUARTER	4066	4835
2nd QUARTER	4110	4971
3rd QUARTER		
4th QUARTER		
TOTAL:	39741	43572

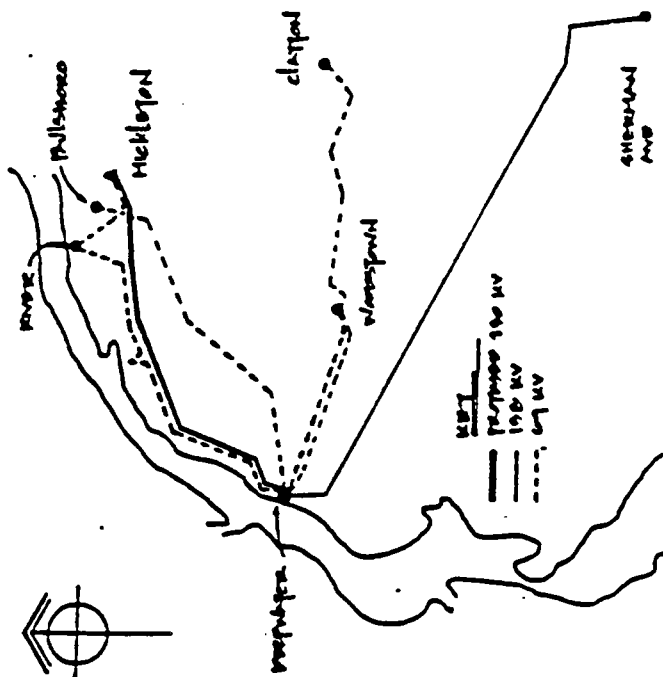


EXHIBIT I

**METHODOLOGY
for
CALCULATING
AVAILABILITY FACTOR**

METHODOLOGY FOR CALCULATING
AVAILABILITY FACTOR

Availability Factor is defined as the ratio of Seller's availability to Purchaser's system's availability based on a calendar year calculation of availability. Therefore,

$$\text{Availability Factor} = \frac{\text{Seller' Availability}}{\text{Purchaser's System's Availability}}$$

Attachment A shows the methodology used to determine the Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit and for Atlantic Electric Company (System). It is these equations that will be used to determine the denominator of the above equation, i.e.,

$$\text{Purchaser's System's Availability} = \text{EAF} \times (\text{company})$$

Attachment B shows the types of capacity derations/outages used in the calculation of EAF X.

Attachment A

Below is the definition of Equivalent Availability Factor (EAF) for any specific Atlantic Electric generating unit:

$$EAF \% = \frac{PH - EOH}{PH} \times 100.0$$

Where:

EOH = Equivalent Outage Hours
PH = Period Hours (i.e. one year = 8760 hours)

Equivalent outage hours are defined as:

$$EOH = \frac{\sum_{n=1}^i (D_n \times T_n)}{C}$$

Where:

D_n = Capacity deration¹ for outage n, MW

T_n = Time accumulated during outage n,
hours (whole and fractional)

C = Unit maximum net dependable capacity¹
for the period of outage n, MW

i = Total number of outages for the period

Note 1 -- See attachment B for types of capacity derations/outages

Note 2 -- Net summer installed capacity + adjustments for ambient conditions

Attachment A (continued)

Defined below is Atlantic Electric Company EAF:

$$\text{EAF \% (company)} = \frac{\sum_{m=1}^j (\text{EAF}_m * C_m)}{\sum_{m=1}^j C_m}$$

Where:

EAF_m = EAF of unit m , per cent

C_m = Net summer installed capacity³ of unit m , MW

j = Total number of units in the company

Note 3 -- If jointly owned unit, Atlantic Electric's prorata share

Attachment B

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage. Below is a listing of outage types, along with their specific definitions:

- RS - Reserve Shutdown - A reserve shutdown (RS) exists whenever a unit is available, but is not synchronized. This event is sometimes referred to as an economy shutdown or economy outage.
- PO - Planned Outage - Planned outages (PO) are scheduled well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections and testing are typical planned outages (PO). Characteristically, planned outages (PO) are planned well in advance and usually occur during those seasons of the year when the peak demand on the system is lowest, have flexible start dates, have a predetermined duration, last for several weeks, and occur only once or twice a year.
- MO - Maintenance Outage - This is an outage which can be deferred beyond the next weekend but requires that the unit be removed from service before the next planned outage (PO). Characteristically, these maintenance outages (MO) may occur throughout the year, have flexible start dates, are much shorter than planned outages (PO), and have a predetermined duration established at the start of the outage.
- SE - Scheduled Outage Extension - This is the extension of a planned outage (PO) or maintenance outage (MO) beyond its originally estimated completion date, such date being established at the start of these outages. A scheduled outage extension (SE) must start at the same time the PO or MO (being extended) ends.
- SF - Startup Failure - This is an outage that results from the unsuccessful attempt to place the unit in service following the unit's being in a full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) state. The unit is considered to be in a startup failure (SF) state if the unit cannot be placed in service within the utility specified time for that specific startup and/or requires significant repairs to the equipment or control systems which halted the normal startup cycle. Repeated failures to start for the same reason are considered as part of the same startup failure (SF). The startup failure (SF) begins when the unit is no longer able to continue its startup cycle or surpasses the originally estimated synchronization time. The startup failure (SF) ends when the unit is synchronized or enters some other (permissible) outage or shutdown state. A startup failure (SF) must start at the time the previous full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) ends.
- U1 - Unplanned Outage (Immediate) - This is an outage that requires immediate removal of a unit from service such as immediate mechanical/electrical/hydraulic control system trips and immediate operator initiated trips/shutdowns in response to unit alarms.
- U2 - Unplanned Outage (Delayed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service within six hours.

Attachment B (continued)

- U3 - Unplanned Outage (Postponed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service before the end of the next weekend.
- PD - Planned Derating - A derating that is scheduled well in advance and is of a predetermined duration. The actual start date of a planned deration (PD) is flexible, since it usually coincides with periods of low peak or seasonal demand.
- D1 - Unplanned Derating (Immediate) - A derating that requires an immediate capacity reduction.
- D2 - Unplanned Derating (Delayed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction within six hours.
- D3 - Unplanned Derating (Postponed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction before the end of the next weekend.
- D4 - Unplanned Derating (Deferred) - A derating which can be deferred beyond the the end of the next weekend, but requires a capacity reduction before the next planned outage (PO). These deratings have flexible start dates and have a predetermined duration established at the start of these outages. This derating is also known as a maintenance derating.
- DE - Derating Extension - This is the extension of a planned derating (PD) or maintenance derating (D4) beyond its originally estimated completion date, such as being established at the start of these outages.

EXHIBIT J

FORMULAS AND EXAMPLES
FOR
CALCULATING REQUIRED VALUE
OF
SECOND LIEN
TO
COVER OVERPAYMENTS

EXHIBIT J

PROJECTED ESTIMATES
OF
SECOND LIEN VALUE
TO COVER OVERPAYMENTS

During the life of the Power Purchase Agreement, the Purchaser shall hold a second lien on the facility. The value of this lien shall be calculated using the following formula:

$$\text{Value of Lien} = [A_{(M-1)} + (B_{(M)} - C_{(M)})] \times (1-i)$$

(in month M)

where,

$A_{(M-1)}$ = Previous month's balance including accrued interest

$B_{(M)}$ = Payments to Keystone Shipping Company in month M

$C_{(M)}$ = Payments that would have been paid under the Standard Offer Stipulation using an $L = 60\%$ and a $D = 60\%$ and expressed by the following equations:

Capacity Payment = \$315.98/Kw-month

Average Energy Payment = \$0.018624/KwH + \$0.015804/KwH \times I

"Base Escalator", I, shall be the the cost of coal, as defined by the annual average cost of bituminous coal used by N.J. utilities as reported on FERC Form 423. The index is tonnage weighted.

- 1 • interest rate to be applied to balance of overpayments. The value of 1 will be set at the Atlantic Electric discount rate used to develop the Standard Offer Stipulation, i.e., 11.35% per year or 0.9% per month.

Table 1 shows the estimated value of the lien over the term of the agreement for a minimum operation of 3500 hours. Escalators used to develop this table were those for Coal per the June 30, 1987 PURPA 210 filing (used to generate the Standard Offer Stipulation).

EXHIBIT J

TABLE 1

PROJECTED ESTIMATES OF SECOND LIEN VALUES
TO COVER OVERPAYMENTS

in Millions of Dollars
Capacity Factor = 39.95% or 3500 hours

CONTRACT YEAR	STANDARD OFFER PAYMENT	KEYSTONE PAYMENT	DIFFERENCE	PLUS INTEREST 11.35%	SECOND LIEN VALUE
1	\$87.30	\$87.30	\$0.00	\$0.00	\$0.00
2	\$87.73	\$87.73	\$0.00	\$0.00	\$0.00
3	\$88.17	\$88.17	\$0.00	\$0.00	\$0.00
4	\$88.66	\$88.66	\$0.00	\$0.00	\$0.00
5	\$89.17	\$89.17	\$0.00	\$0.00	\$0.00
6	\$89.71	\$89.71	\$0.00	\$0.00	\$0.00
7	\$90.26	\$90.26	\$0.00	\$0.00	\$0.00
8	\$90.83	\$90.83	\$0.00	\$0.00	\$0.00
9	\$91.43	\$101.27	\$9.84	\$0.00	\$0.00
10	\$92.05	\$102.54	\$10.48	\$1.12	\$10.97
11	\$92.70	\$103.85	\$11.15	\$2.43	\$23.88
12	\$93.37	\$105.21	\$11.83	\$3.98	\$39.01
13	\$94.08	\$106.63	\$12.56	\$5.77	\$56.61
14	\$94.81	\$108.11	\$13.31	\$7.85	\$77.02
15	\$95.58	\$109.67	\$14.09	\$10.25	\$100.57
16	\$96.41	\$72.85	(\$23.56)	\$13.01	\$127.68
17	\$97.29	\$74.64	(\$22.65)	\$11.82	\$115.94
18	\$98.24	\$76.56	(\$21.68)	\$10.59	\$103.88
19	\$99.25	\$78.61	(\$20.64)	\$9.33	\$91.53
20	\$100.34	\$80.80	(\$19.53)	\$8.05	\$78.94
21	\$101.49	\$83.15	(\$18.35)	\$6.74	\$66.15
22	\$102.70	\$85.60	(\$17.11)	\$5.43	\$53.23
23	\$103.97	\$88.17	(\$15.80)	\$4.10	\$40.22
24	\$105.30	\$90.86	(\$14.44)	\$2.77	\$27.20
25	\$106.70	\$93.70	(\$13.01)	\$1.45	\$14.20
26	\$108.17	\$96.67	(\$11.50)	\$0.14	\$1.33
27	\$109.71	\$99.78	(\$9.93)	(\$1.15)	(\$11.32)
28	\$111.32	\$103.04	(\$8.27)	(\$2.41)	(\$23.66)
29	\$113.01	\$106.47	(\$6.54)	(\$3.62)	(\$35.56)
30	\$114.78	\$110.05	(\$4.73)	(\$4.78)	(\$46.88)
				(\$5.86)	(\$57.47)

Exhibit K

The intercreditor or other agreements between Purchaser and Lender shall include provisions substantially similar to the following:

(1) All indebtedness, liabilities and obligations of Seller to Purchaser in any way relating to the Excess Pool, due or to become due, now or hereafter arising, including without limitation, principal, interest and all other charges provided for under any documentation now and hereafter in effect relating thereto, and whether due after acceleration or otherwise (collectively the "Excess Pool Liabilities") shall be subordinated to the prior and full payment, performance, satisfaction and discharge of all indebtedness, liabilities and obligations of the Seller to the Lender, whether or not deferred, due or to become due, direct or indirect, primary or secondary, fixed or contingent, secured or unsecured, now or hereafter arising out of or relating to the construction and permanent financing of the Seller's Facility, including principal, interest, fees, premiums, penalties, and legal expenses, and whether due after acceleration or otherwise (the "Financing Liabilities").

(2) Any mortgage, pledge, security interest, encumbrance, lien or charge of any kind, including any agreement to give any of the foregoing, and the filing thereof, and any financing statement under the Uniform Commercial Code of any jurisdiction (collectively, the "Lien") securing the Financing Liabilities (the "Financing Lien") shall be superior and prior in right to the Lien of Purchaser securing the Excess Pool Liabilities (the "Excess Pool Lien"), and the Excess Pool Lien shall be subject, subordinate and junior to the Financing Lien in all respects notwithstanding the time or order of the execution or delivery of any document purporting to create a Lien to or in favor of Purchaser, or the time or order of attachment, perfection or recording of any Lien to or in favor of Purchaser.

(3) So long as there shall remain outstanding and unpaid any amount with respect to the Financing Liabilities, the Lender shall first be entitled to receive payment in full, or have provision satisfactory to the Lender made for payment in full, of the Financing Liabilities before Purchaser is entitled to receive any payment or distribution with respect to the Excess Pool Liabilities.

(4) So long as there shall remain outstanding and unpaid any amount with respect to the Financing Liabilities, should any of the collateral securing the Financing Liabilities, or proceeds of any such collateral, or any payment of any kind whatsoever for or on account of the Excess Pool Liabilities (whether in cash, securities or other property), be received or collected by Purchaser from any source whatsoever which Purchaser is not specifically entitled to receive and retain under the provisions of the Agreement for Purchase of Electric Power between Atlantic City Electric Company and Keystone Cogeneration Systems, Inc. dated August 25, 1988 (the "Purchase Power Agreement"), Purchaser will forthwith deliver such receipt or collection to the Lender in the form received, together with all endorsements or executed instruments of transfer required to allow the Lender to collect thereon.

(5) Purchaser shall, and does hereby, waive all rights of subrogation it might otherwise have from time to time with respect to the Lender and the Lender's rights and the Financing Lien until such time as all the Financing Liabilities have been indefeasibly paid in full.

(6) In the event of the occurrence of any breach of or default under, any of the documents evidencing the Financing Liabilities and the Financing Lien (the "Financing Documents"), and notwithstanding any related provision of this Agreement or the Purchase Power Agreement to the contrary, Purchaser shall not pursue any rights or remedies permitted under the Purchase Power Agreement relating to the Excess Pool or under any other document evidencing the Excess Pool Liabilities or the Excess Pool Lien

(the "Excess Pool Documents"), unless and until all Financing Liabilities are indefeasibly satisfied in full, and until such time, Purchaser shall not take any action which shall have the effect, directly or indirectly, of

(a) receiving payment from Seller for, or on account of, Excess Pool Liabilities;

(b) causing the termination of the Purchase Power Agreement or other interference with the continued use and operation of the Seller's Facility to produce power or with the payment by Purchaser for power or capacity or receipt of revenues therefor by Seller in accordance with the terms of the Purchase Power Agreement (and as if the same were not in default); or

(c) interfering with the exercise on the part of the Lender of any of its rights and remedies under the Financing Documents or the collection by the Lender of any of the sums due the Lender from Seller, or the realization by Lender upon any of the collateral covered by the Financing Lien or otherwise securing the Financing Liabilities.

AMENDMENT NO. 1



HENRY K. LEVARI, JR.
VICE PRESIDENT
CORPORATE PLANNING & PERFORMANCE

Copy # 6

November 22, 1988

Keystone Cogeneration Systems, I
313 Chestnut Street
Philadelphia, Pennsylvania 1910

Attention: Comptroller

Gentlemen:

Post-It™ brand fax transmittal memo 7671		of pages 8
To John Gulliver	From G. Hogg	
Co.	Co.	
Dept.	Phone 609-645-4165	
Fax 207-773-3419	Fax	

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.238
Amendment No. 001

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 2; paragraph 2.2 - change - "BPU approval process within three (3) months of the Effective Date" to "by December 31, 1988."

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.238, dated August 25, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.238 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

CO
KEYSTONE/GENERATION SYSTEMS, INC.

ATLANTIC ELECTRIC

BY:

BY:

Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, N.J. 08232
609-645-4436

HENRY K. LEVARI, JR.

VICE PRESIDENT
CORPORATE PLANNING & PERFORMANCE

Copy # 2

November 22, 1988

Keystone Cogeneration Systems, Inc.
313 Chestnut Street
Philadelphia, Pennsylvania 19106

Attention: Comptroller

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.238
Amendment No. 001

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 2; paragraph 2.2 - change - "BPU approval process within three (3) months of the Effective Date" to "by December 31, 1988."

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.238, dated August 25, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.238 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

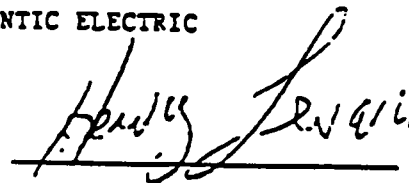
CO
KEYSTONE/GENERATION SYSTEMS, INC.

ATLANTIC ELECTRIC

BY:



BY:



Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, N.J. 08232
609-645-4436

AMENDMENT NO. 2



Copy # _____

December 19, 1988

Keystone Cogeneration Systems, Inc.
313 Chestnut Street
Philadelphia, Pennsylvania 19106

Attention: Comptroller

Gentlemen:

ATLANTIC ELECTRIC Power
Purchase Agreement No. 88.238
Amendment No. 002

In connection with the subject agreement, Atlantic Electric hereby amends said agreement to include the following:

Article 2: paragraph 2.2 - change - BPU approval process "by December 31, 1988" to "by January 31, 1989".

Except as modified and amended herein, all the terms and conditions contained in Agreement No. 88.238, dated August 25, 1988, remain unchanged. This letter shall be a supplement to and shall become an integral part of Agreement No. 88.238 upon the signing hereof.

Please have all copies of this letter signed, retain copy #2 for your files and return the other signed copies to us.

KEYSTONE COGENERATION SYSTEMS, INC.

ATLANTIC ELECTRIC

BY _____

BY  _____

42-3

Atlantic City Electric
P.O. Box 1500
Pleasantville, N.J. 08232

AMENDMENT NO. 3



November 3, 1989

Mr. Robert P. McKeever
Keystone Cogeneration Systems, Inc.
313 Chestnut Street
Philadelphia, PA 19106

Re: Agreement for Purchase of Electric Power, dated
August 25, 1988

Dear Mr. McKeever:

In connection with the above-referenced agreement (hereinafter, the "Agreement"), this letter shall confirm our mutual intent to amend the Agreement as set forth herein. All terms used herein shall have the same meaning as defined in the Agreement. The parties hereto agree as follows:

1. In consideration of Seller not exercising its rights to terminate the Agreement pursuant to Article 13.4(v) and the deadline therein contained, Purchaser and Seller agree that the current provisions of Article 13.4(v) shall be deleted in their entirety and the following new provision inserted in place thereof:

- (v) Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser within 24 months of the BPU order referred to in Article 2 hereof, evidence of financial commitments for construction and permanent financing sufficient to complete Seller's Facility, subject only to such conditions as are reasonably satisfactory to Purchaser, it being understood and agreed by Seller that in order to provide the proper level of project equity to cover overpayments made by Purchaser in Contract Years nine (9) through fifteen (15), inclusive, as set forth in Table 1 of Exhibit J, such permanent financing commitments shall provide (i) for a term not to exceed twenty (20) years; (ii) that the maximum principal amount outstanding at the end of Contract Year fifteen (15) shall not exceed \$90 million; and (iii) for a funded debt service reserve to be created by Seller for the benefit of



lenders that has a remaining balance at the end of Contract Year fifteen (15) of no less than \$22,000,000, which balance may be reduced in Contract Years sixteen (16) through twenty (20) at a percentage rate not to exceed 20% a year.

2. It is further agreed by Purchaser and Seller that the following change be made to Article 5.3(G)

Change: "the permanent debt financing for the Facility provided by the Lender shall be limited to a 15-year period" to "the permanent debt financing for the Facility provided by the Lender shall be limited to a 20-year period."

3. This amendment shall be effective as of November 3, 1989 and shall be deemed duly incorporated into and made a part of the Agreement as of said date as Amendment No. 003. Except as modified by this amendment, all other terms and conditions contained in the Agreement shall remain in full force and effect.

If the foregoing reflects your understanding and agreement, kindly have all execution copies of this amendment duly executed on the line provided below by Keystone Cogeneration Systems, Inc. Please return all execution copies to Atlantic Electric other than copy #2, which you may retain for your files.

ATLANTIC CITY ELECTRIC COMPANY

By: 

Henry K. Levari, Jr.
Vice President
Corporate Planning and
Performance

ACCEPTED & APPROVED:

KEYSTONE COGENERATION SYSTEMS, INC.

By: 

Robert P. McKeever
President

EXECUTION COPY # 6 of 6

AMENDMENT NO. 4

HENRY K. LEVARI, JR.
VICE PRESIDENT
CORPORATE PLANNING & PERFORMANCE

March 28, 1990

Mr. Robert P. McKeever
Keystone Cogeneration Systems, Inc.
313 Chestnut Street
Philadelphia, PA 19106

Dear Mr. McKeever:

RE: Atlantic Electric Power Purchase
Agreement No. 88.238 dated
August 25, 1988 - Amendment No. 004

In connection with the above-referenced agreement (hereinafter, the "Agreement"), this letter shall confirm our mutual intent to amend the Agreement as set forth herein. All terms used herein shall have the same meaning as defined in the Agreement. The parties hereto agree as follows:

1. Purchaser and Seller agree that the current provisions of Article 13.4 (iii) shall be deleted in their entirety and the following new provision inserted in place thereof:

(iii) Five percent (5%) in the event Seller have failed to obtain and deliver to Purchaser a certified copy of the executed "turn-key" construction contract for the Facility by June 1, 1990, which construction contract shall be either with a reputable construction company or other entity with an established record and capability of completing the Facility, or executed purchase orders with reputable manufacturers of major equipment required for the Facility. Major equipment shall be deemed to include: boiler, turbine generator, and flue gas de-sulphurization system.

2. This amendment shall be effective as of March 28, 1990 and shall be deemed duly incorporated into and made part of the Agreement as of said date as Amendment No. 004. Except as modified by this amendment, all other terms and conditions constrained in the Agreement shall remain in full force and effect.

Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, N.J. 08232
609-645-4436



Mr. Robert P. McKeever
Page 2
March 28, 1990

If the foregoing reflects your understanding and agreement, kindly have all execution copies of this amendment duly executed on the line provided below by Keystone Cogeneration Systems, Inc. Please return all execution copies to Atlantic Electric other than copy #2, which you may retain for your files.

ATLANTIC CITY ELECTRIC COMPANY

By: Henry K. Levari, Jr.
Henry K. Levari, Jr.
Vice President
Corporate Planning and
Performance

ACCEPTED & APPROVED:

KEYSTONE COGENERATION SYSTEMS, INC.

By: Robert P. McKeever
Robert P. McKeever
President

EXECUTION COPY # 2 of 6

AMENDMENT NO. 5

1
MAR 7 1991 MON 10:30 AM. ELECTRIC/MAILROOM
HENRY K. LEVARI, JR.
VICE PRESIDENT
POWER DELIVERY



January 24, 1991

Mr. Robert P. McKeever
Keystone Cogeneration Systems, Inc.
P. O. Box 1589
Philadelphia, PA 19105-1589

RE: Agreement for Purchase of Electric Power, dated August 25, 1988

Dear Mr. McKeever:

In connection with the above-referenced agreement (hereinafter, the "Agreement"), this letter shall confirm our mutual intent to amend the Agreement as set forth herein. All terms used herein shall have the same meaning as defined in the Agreement. The parties hereto agree as follows:

1. Purchaser and Seller agree that the provisions of Article 5.1(B)(11)(a), except for the Note defining the Base Escalator, shall be deleted in their entirety and the following new provision inserted in place thereof:
 - (a) For all energy delivered during On-Peak Periods in each of the first eight (8) Contract Years, the price shall be $\$0.026667/\text{KWH} + \$0.018175/\text{KWH} \times I$, where I is the Base Escalator, and for all energy delivered during Off-Peak Periods in each of the first eight Contract Years, the price shall be $\$0.018319/\text{KWH} + \$0.012485/\text{KWH} \times I$.
2. Purchaser and Seller agree that the provisions of Article 5.1(B)(11)(b) shall be deleted in their entirety and the following new provision inserted in place thereof:
 - (b) For all energy delivered during On-Peak Periods in each of Contract Years nine (9) through fifteen (15), the price shall be $\$0.017250/\text{KWH} + \$0.036800/\text{KWH} \times I$, where I is the Base Escalator, and for all energy delivered during Off-Peak Periods in each of Contract Years nine (9) through fifteen (15), the price shall be $\$0.011850/\text{KWH} + \$0.025280/\text{KWH} \times I$.
3. Purchaser and Seller agree that the provisions of Article 5.1(B)(11)(c) shall be deleted in their entirety and the following new provision inserted in place thereof:

Atlantic Electric
1199 Black Horse Pike
Pleasantville, New Jersey 08232
609.645.4478



Mr. Robert McKeever
Page 2
January 24, 1991

- (c) For all energy delivered during On-Peak Periods in each of the final fifteen (15) Contract Years, the price shall be $\$0.036800/\text{KWH} \times I$, where I is the Base Escalator, and for all energy delivered during Off-Peak Periods in each of the final fifteen Contract Years, the price shall be $\$0.025280/\text{KWH} \times I$.

4. This amendment shall be effective as of January 24, 1991 and shall be deemed duly incorporated into and made part of the Agreement as of said date as amendment No. 005. Except as modified by this amendment, all other terms and conditions ~~contained~~ in this Agreement shall remain in force and effect. *CONTAINED mk*

If the foregoing reflects your understanding and agreement, kindly have all execution copies of this amendment duly executed on the line provided below by Keystone Cogeneration Systems, Inc. Please return all execution copies to Atlantic Electric other than copy #2, which you may retain for your files.

ATLANTIC CITY ELECTRIC COMPANY

By: *Henry K. Levari, Jr.*

Henry K. Levari, Jr.
Vice President
Power Delivery

ACCEPTED & APPROVED:

KEYSTONE COGENERATION SYSTEMS, INC.

By: *Robert P. McKeever*

Robert P. McKeever
President

EXECUTION COPY #6 of 6

AMENDMENT NO. 6

**AMENDMENT No. 006 TO AGREEMENT FOR PURCHASE OF ELECTRIC POWER
BETWEEN ATLANTIC CITY ELECTRIC COMPANY, AS PURCHASER, AND
KEYSTONE COGENERATION SYSTEMS, INC., AS SELLER.**

This amendment (hereinafter referred to as the
("Amendment") is entered into and effective as of this 5th day
of April, 1991 by and between ATLANTIC CITY ELECTRIC COMPANY,
1199 Blackhorse Pike, Pleasantville, New Jersey 08232
(hereinafter referred to as "Purchaser"), and KEYSTONE
COGENERATION SYSTEMS, INC., having offices at 313 Chestnut
Street, Philadelphia, Pennsylvania 19106 (hereinafter referred
to as "Seller").

WHEREAS, Purchaser and Seller have previously entered into
a certain AGREEMENT FOR PURCHASE OF ELECTRIC POWER
("Agreement"), dated as of August 25, 1988, and amended
pursuant to amendments dated as of November 22, 1988, December
19, 1988, November 3, 1989, March 28, 1990, and January 24,
1991; and

WHEREAS, Purchaser and Seller further wish to amend the
Agreement, all as more particularly described in this
Amendment; and

WHEREAS, Purchaser and Seller wish to memorialize their
agreement on certain issues, as set forth in this Amendment.

NOW THEREFORE, in consideration of the mutual promises, covenants and conditions contained herein, Purchaser and Seller agree as follows:

1. Except as otherwise stated in this Amendment, all terms shall have the same meaning as set forth in the Agreement.

2. Articles 4.2(iv) and (v) of the Agreement shall be deleted in their entirety, and the following new provisions shall be inserted in place thereof:

(iv) The Facility's electrical generation unit has been successfully started, synchronized, connected and operated in parallel with Purchaser's system for a continuous 48-hour period at not less than eighty-eight percent (88%) of Net Deliverable Capacity, subject to Prudent Electrical Practices; provided, however, that Seller shall pay to Purchaser a deficiency payment computed in accordance with Article 3.3A for the difference, if any, between (a) 95% of Net Deliverable Capacity and (b) any lesser amount of capacity determined to be available pursuant to this Article 4.2(iv) until Seller's Facility operates in parallel for a continuous 48-hour period at Net Deliverable Capacity.

(v) The Facility has demonstrated the capability to operate throughout the range of power factors and range of capacities required by Purchaser as set forth in subparagraph (iv) above with input from Seller and as set forth in Exhibit C. Upon successful completion of start-up and acceptance testing of the Facility, Purchaser will send written confirmation of test results to Seller.

3. Article 13.1E of the Agreement shall be amended by deleting the date "January 1, 1995," and the following new date shall be inserted in place thereof:

January 1, 1996.

4. Article 13.4(v) of the Agreement shall be modified by deleting in its entirety the first sentence thereof, and the following new provision shall be inserted in place thereof:

Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser by November 29, 1991, evidence of financial commitments for construction and permanent financing, subject only to such conditions as are consistent with this Agreement as amended, reasonably satisfactory to Purchaser and sufficient to complete Seller's Facility.

5. Article 13.4 shall be further modified by deleting in its entirety the last clause of Article 13.4, which appears in its entirety on page 53 of the Agreement and which commences "Subject to the force majeure provisions of Article 15" and which ends "on or before the 365th day after the scheduled Date of Commercial Operation," and the following new provision shall be inserted in place thereof:

The remaining fifty percent (50%) of the Reserve Fund shall continue to be held by Purchaser as security for Seller's timely operation of Seller's Facility and shall be retained by Purchaser, together with accrued interest thereon, upon the earlier of Seller's financial closing on construction financing for the Facility or January 1, 1992. Purchaser and Seller recognize and agree that this retention of the Reserve Fund shall serve as liquidated damages to Purchaser for the inability of the Facility to achieve the Date of Commercial Operation by January 1, 1993. Purchaser shall be entitled to retain this sum, regardless of the actual Date of Commercial Operation.

In addition, at Seller's financial closing for the construction financing of the Facility, Seller shall pay to Purchaser the additional sum of \$2,000,000 as liquidated damages for the inability of the Facility to achieve the Date of Commercial Operation by January 1, 1994. Purchaser shall be entitled to retain this sum, regardless of the actual Date of Commercial Operation.

In each instance, the retention of the Reserve Fund and the payment of the additional \$2,000,000, shall constitute Purchaser's sole remedy for the inability of Seller's Facility to become operational within the meaning

of the Agreement on or before the scheduled Date of Commercial Operation or on or before the dates specified herein.

Purchaser and Seller further recognize that Seller's Facility may not achieve the Date of Commercial Operation on or before January 1, 1995. In such event, and subject to the force majeure provisions of Article 15, Seller shall pay Purchaser, as liquidated damages ~~and as Purchaser's sole remedy, as against Seller,~~ the following amounts for each month of delay in the Date of Commercial Operation beyond January 1, 1995:

<u>Month</u>	<u>Liquidated Damages per Month</u>
January - May	0
June - September	\$400,000
October	\$200,000
November - December	\$100,000

This provision shall take effect only if Seller pays the additional sum specified in the above table with Purchaser on or before the first day of the month for which Seller seeks the additional extension in the Date of Commercial Operation. If Seller's Facility has not achieved the Date of Commercial Operation on or before January 1, 1995, Seller's failure to pay the additional sum with Purchaser when and as specified in the above table shall constitute a breach of this Agreement for failure to pay an amount when due, as defined in Article 13.1(A) of this Agreement.

6. Purchaser and Seller agree that this Amendment is conditioned upon a finding by Order of the BPU that this Amendment is reasonable and prudent and that, if the Facility fails to attain the Date of Commercial Operation by January 1, 1995, that Purchaser, consistent with the BPU's October 2, 1990 Order of Approval in the Matter of Joint Petition of Public Service Electric and Gas Company and Camden Cogen, L.P., Docket No. EM88050655, will be able flow through to and/or fully and timely recover from its ratepayers through a Levelized Energy Adjustment Clause proceeding or comparable regulatory

proceeding all purchased capacity costs incurred by the Purchaser as a result of the Facility's inability to attain the Date of Commercial Operation by January 1, 1995. Such Order by the BPU shall be under such other terms and conditions as are acceptable to the parties hereunder. After the BPU issues its Order, the parties shall, within twenty (20) days of the date thereof, affirm in writing, executed by both parties, that this condition has been satisfied and that the parties agree to such other terms and conditions as the Board may or shall have imposed. In the event (i) this condition with respect to BPU approval is not satisfied within two (2) months of the date of this Amendment or (ii) after the BPU has issued its Order either party fails to agree in writing to any terms and/or conditions imposed in such Order within the period set forth above, this Amendment shall be void as of such date and the parties shall thereafter be released from any and all obligations hereunder without further notice. Purchaser and Seller shall expeditiously file this Amendment with the BPU for approval upon execution hereof and shall diligently seek to obtain such Order on a timely basis.

7. Promptly upon both parties affirming in writing such Order of the BPU as described in paragraph 6 above, Seller shall deliver to Purchaser a letter in form and substance as contained in Exhibit 1 hereof withdrawing its demand for arbitration dated February 3, 1991 and filed pursuant to Article 17 of the Agreement. Upon the withdrawal of its demand

for arbitration, Seller hereby waives with prejudice any claims for delay occurring on or before the date of this Amendment as a result of the New Jersey Department of Environmental Protection's ("NJDEP") rejection of advanced combustion as Best Available Control Technology ("BACT") to control nitrogen oxide ("NOX") emissions from Seller's Facility, insofar as these claims for delay were the subject of Seller's demand for arbitration filed pursuant to Article 17 of the Agreement and dated February 3, 1991. This waiver shall not be construed in any way to prejudice, and Seller hereby expressly reserves, all rights to claim as an event of force majeure any delay arising from any cause beyond the Seller's control and defined as an event of force majeure within the meaning of Article 15 of the Agreement, which delay occurs after the date of this Amendment, and regardless of the date of the force majeure event.

8. Any payments of liquidated damages as described in this Amendment shall be without prejudice to the rights of Purchaser or Seller under the force majeure provisions of Article 15 of the Agreement with regard to any other obligation or condition under the Agreement.

9. This Amendment shall be effective as of April 5, 1991 and shall be deemed duly incorporated into and made a part of the Agreement as of said date as amendment No. 006. Except as

modified by this Amendment, all of the terms and conditions contained in the Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be signed in their corporate names by their duly authorized officers and their corporate seals to be hereto affixed and duly attested as of the day and year indicated on the face of this Amendment.

ATTEST: J. D. McInnis ATLANTIC CITY ELECTRIC COMPANY
By: Henry K. Levari, Jr.
Name: Henry K. Levari, Jr.
Title: Vice President, Power Delivery

ATTEST: P. H. Morris KEYSTONE COGENERATION SYSTEMS, INC.
By: Robert P. McKeever
Name: Robert P. McKeever
Title: President

EXHIBIT 1

April __, 1991

Atlantic City Electric Company
1199 Blackhorse Pike
Pleasantville, NJ 08232

Attention: Mr. Louis A. DeCicco
Manager, Contract Capacity

Re: Atlantic City Electric Company and
Keystone Cogeneration Systems, Inc.
Agreement for Purchase of Electric Power dated
August 25, 1988, as Amended.

Dear Mr. DeCicco:

In accordance with a certain Amendment Agreement between
Keystone Cogeneration Systems, Inc. and Atlantic City Electric
Company, Inc. dated as of April 15, 1991, Keystone hereby
withdraws its demand for arbitration of Atlantic Electric dated
February 3, 1991 and submitted pursuant to Article 17 of the
Agreement for Purchase of Electric Power.

Very truly yours,

Robert P. McKeever
President

AMENDMENT NO. 7

SENT BY:STRYKER TAMS & DILL : 9-24-91 :10:10AM : STRYKER TAMS & DILL-

9845550:8 4

KEYSTONE COGENERATION SYSTEMS, INC.
SUITE 721
MARKET TOWER BUILDING
801 MARKET STREET
WILMINGTON, DELAWARE 19801

Post-It brand fax transmittal memo 7571		# of pages - 3	
To	Bob McKee	From	L. DeCicco
Co.		Co.	ACE
Dept.		Phone	209-645-4385
Fax	215-928-2876	Fax	

September 24, 1991

DIST:
10-7-91
GULLIVER
HAUSER

Atlantic City Electric Company
1199 Black Horse Pike
Pleasantville, New Jersey 08232

RE: Memorandum of Understanding and Amendment No. 007
concerning the Agreement for Purchase of Electric Power
Between Atlantic City Electric Company and Keystone
Cogeneration Systems, Inc., dated August 25, 1988, as
Amended

Dear Mr. McCann:

In connection with the above-referenced agreement (the "Agreement"), this memorandum shall confirm our mutual understanding with respect to certain provisions of and transactions contemplated by the Agreement, for the purpose of enhancing the benefits accruing under the Agreement to the ratepayers of Atlantic City Electric Company ("Atlantic"), and of enacting certain amendments to the Agreement, and in further consideration of Atlantic's agreement to amend the Agreement to price sales of electricity under the Agreement on the basis of on-peak and off-peak times of delivery as set forth in the 1987 Standard Offer Stipulation approved by the New Jersey Board of Public Utilities:

1. Atlantic is to purchase electric energy on a dispatchable basis, at rates and subject to terms and conditions set forth in the Agreement, as amended. The Seller agrees to exercise its reasonable best efforts to reach agreement with Atlantic on terms that do not conflict with Atlantic's obligations under other power purchase agreements or violate any requirements of the Board of Regulatory Commissioners (formerly the Board of Public Utilities) concerning the purchase of energy and/or capacity from qualifying facilities, and that would enable Atlantic to purchase energy available from the facility from time to time which, because the price under the Agreement exceeds Atlantic's avoided cost, would not otherwise be dispatched ("Additional Energy"), at prices lower than those presently contemplated by the Agreement but in excess of the costs to the Seller of producing

SEP-24-91 TUE 11:01 ATL. ELECTRIC/MAILROOM

P.02

SENT BY:STRYKER TAMS & DILL : 9-24-91 :10:19AM : STRYKER TAMS & DILL-

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Mr. J. David McCann
Page 2
September 24, 1991

Additional Energy. The parties agree to exercise their reasonable best efforts to agree upon procedures to ensure that sales of Additional Energy pursuant to this paragraph i shall only be made at such times and only to the extent that the Facility would not otherwise be dispatched by Atlantic under the contract.

2. In order to provide Atlantic, at no cost to Atlantic, with further opportunities not presently available under the Agreement to purchase from the Seller energy and capacity at competitive prices, the Seller hereby grants to Atlantic a right of first negotiation and agrees to engage in negotiations with Atlantic for a reasonable period of time with respect to the sale to Atlantic of all or substantially all of the output of the Facility commencing upon the expiration of the Term of the Agreement. Seller agrees to enter into such negotiations with Atlantic prior to entering into any negotiations with any third party and sufficiently in advance of the expiration of the Term to enable Atlantic to evaluate the Facility in light of its long-term capacity planning for the period commencing upon expiration of the Term. Seller and Atlantic recognize and agree that such negotiations may not result in agreement and that after Seller's exercise of reasonable best efforts, Seller shall be free to commence negotiation with third parties with respect to such sale.
3. Article 1.1.A of the Agreement is hereby amended to read in its entirety as follows:
"A. "Availability Factor" shall mean the ratio of Seller's Facility's availability to Purchaser's system's availability for all of Purchaser's non-nuclear generating facilities based on a Contract Year calculation of availability, all as more particularly described in Exhibit I."
4. In order to eliminate potential disincentives to Atlantic requesting a cold start of the Facility and, thus, to better enable Atlantic and its ratepayers to realize the full benefit of operating the Facility, the parties agree that Article 5.1.C. of the Agreement, providing for a charge of \$900 (multiplied by the then applicable Escalation Factor) to Atlantic for each cold start (in excess of ten (10) cold starts) of the Facility during any Contract Year, is hereby deleted in its entirety, and that paragraph D of Article 5.1 of the Agreement is amended to be designated paragraph C of Article 5.1.

SENT BY:STRYKER TAMS & DILL ; 9-24-91 10:20AM ; STRYKER TAMS & DILL-

8645550:W 8

Mr. J. David McCann
Page 3
September 24, 1991

5. The parties recognize and agree that in entering into Amendment No. 006, dated as of April 5, 1991, their intent was to modify various remaining milestones in the Agreement in exchange for payment of additional earnest money. Amendment No. 006 did not amend the milestone in Article 13.4(vi) so that the completion date for that milestone is changed from 36 months from the Effective Date to December 28, 1991, consistent with the other milestone revisions in Amendment No. 006. Accordingly, to clarify Amendment No. 006 and to confirm the intent of the parties, Article 13.4(vi) of the Agreement is hereby amended to read in its entirety as follows: "(vi) Fifteen percent (15%) in the event Seller shall have failed to commence construction (as evidenced by active foundation construction) of Seller's Facility by December 28, 1991." It is further agreed that the provision of paragraph (6) of Amendment No. 006, stating that, if BPU approval of the condition contained in that paragraph is not obtained within two months of the date of the Amendment, then the Amendment shall be void, is hereby waived by mutual consent of the parties hereto.

Except as modified herein, all other terms and conditions contained in the Agreement, as amended, shall remain in full force and effect. All capitalized terms not otherwise specifically defined herein shall have the same meaning as set forth in the Agreement.

If the foregoing reflects your understanding and agreement, kindly have all execution copies of this memorandum of understanding duly executed on the line provided below by Atlantic City Electric Company. Please return all execution copies to Keystone except for two copies which you may retain for your files.

KEYSTONE COGENERATION SYSTEMS, INC.

By: Robert P. McKeever
Robert P. McKeever
President

ACCEPTED AND APPROVED:
ATLANTIC CITY ELECTRIC COMPANY

By: J. D. McCann
J. D. McCann
Vice President -- Power Delivery

AMENDMENT NO. 8

SENT BY:STRYKER TAMS & DILL : 2- 8-92 : 2:16PM : STRYKER TAMS & DILL-

2153252875: 4

AMENDMENT NO. 008

TO

AGREEMENT FOR PURCHASE OF ELECTRIC POWER

This AMENDMENT NO. 008 dated as of February 6, 1992 (the "Amendment") to AGREEMENT FOR PURCHASE OF ELECTRIC POWER dated as of August 25, 1988, as heretofore amended, by and between ATLANTIC CITY ELECTRIC COMPANY, having offices at 1199 Black Horse Pike, Pleasantville, New Jersey 08232 (the "Purchaser"), and KEYSTONE COGENERATION SYSTEMS, INC., having offices at 313 Chestnut Street, Philadelphia, Pennsylvania 19106 (the "Seller").

RECITALS:

A. Purchaser and Seller have heretofore entered into amendments to the above-referenced Agreement for Purchase of Electric Power dated as of November 22, 1988 (No. 001), December 19, 1988 (No. 002), November 3, 1989 (No. 003), March 28, 1990 (No. 004), January 24, 1991 (No. 005), April 5, 1991 (No. 006), and September 24, 1991 (No. 007) (as amended, the "Power Purchase Agreement").

B. Purchaser and Seller now wish to further amend and clarify the Power Purchase Agreement, as more particularly described herein, and to memorialize their intent by this Amendment.

NOW, THEREFORE, in consideration of the foregoing and for such other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Purchaser and Seller, intending to be legally bound, hereby agree as follows:

SENT BY:STRYKER TAMS & DILL : 2- 6-92 : 2:17PM : STRYKER TAMS & DILL-

2156252275::

1. **Definitions.** All capitalized terms used but not defined in this Amendment shall have the respective meanings ascribed thereto in the Power Purchase Agreement.

2. **Financing Milestone.** Article 13.4(v) is hereby amended to read in its entirety as follows:

"Ten percent (10%) in the event Seller shall have failed to obtain and deliver to Purchaser by November 29, 1991, evidence of financial commitments for construction and permanent financing, subject only to such conditions as are consistent with this Agreement, as amended, reasonably satisfactory to Purchaser and sufficient to complete Seller's Facility; it being understood and agreed by Seller that in order to provide the proper level of project equity to cover overpayments made by Purchaser in Contract Years nine (9) through fifteen (15), inclusive, as set forth in Table 1 of Exhibit J, such permanent financing commitments shall provide (i) for a term not to exceed twenty (20) years; (ii) that the maximum principal amount outstanding at the end of Contract Year fifteen (15) shall not exceed \$90 million; and (iii) for a funded debt service reserve to be created by Seller for the benefit of lenders that has a remaining balance at the end of Contract Year fifteen (15) of no less than an amount equal to the lesser of (A) the product of (I) the aggregate principal amount of such permanent financing outstanding at the end of Contract Year fifteen (15) times (II) 24.4% or (B) \$22,000,000, which debt service reserve balance may be reduced annually thereafter but only on a ratable basis and then only in such amount as will result in such debt service reserve being in an amount no less than 24.4% of the then outstanding balance of such permanent financing indebtedness. For purposes of clause (iii) of the preceding sentence, Seller and Purchaser agree that if the principal balance of the above-referenced permanent indebtedness outstanding at the end of Contract Year 15 is \$58,700,000, the minimum funded debt service reserve required by said clause (iii) for that Contract Year shall be the sum of \$14,000,000."

3. **Condition Precedent.** The effectiveness of this Amendment is conditioned upon the issuance by the New Jersey Board of Regulatory Commissioners (the "BRC") of a final order approving

SENT BY:STRYKER TAMS & DILL : 2-5-92 : 2:18PM : STRYKER TAMS & DILL-

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the terms and conditions hereof. Purchaser and Seller shall expeditiously file this Amendment with the ERC for approval upon the execution hereof and shall diligently seek to obtain such order on a timely basis.

4. Effectiveness. Subject to Section 3 hereof, this Amendment shall be effective as of the date first above written and shall be deemed duly incorporated into and made part of the Power Purchase Agreement as of that date as Amendment No. 008. Except as and to the extent amended and modified by this Amendment, all of the terms and conditions contained in the Power Purchase Agreement, as heretofore amended, shall be and remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed in their respective corporate names by their duly authorized officers and their corporate seals to be hereunto affixed and duly attested as of the day and year first above written.

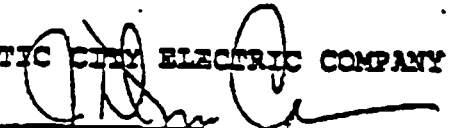
ATTEST:


Name: S.D. McManis
Title: Secretary

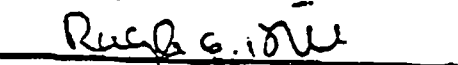
(Corporate Seal)

ATLANTIC CITY ELECTRIC COMPANY

By:


Name: J.D.M. Caw
Title: Vice President - Power Delivery

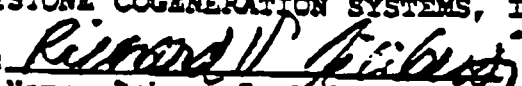
ATTEST:


Name: Ralph G. Hill
Title: SECRETARY

(Corporate Seal)

KEYSTONE COGENERATION SYSTEMS, INC.

By:


Name: Robert P. McKee
Title: President

RICHARD V. CILIBERTI
VICE PRESIDENT

AMENDMENT NO. 9

ORIGINAL

AMENDMENT NO. 009 TO AGREEMENT FOR PURCHASE OF
ELECTRIC POWER BETWEEN ATLANTIC CITY ELECTRIC COMPANY,
AS PURCHASER, AND KEYSTONE ENERGY SERVICE COMPANY, L.P.,
ASSIGNEE OF KEYSTONE COGENERATION SYSTEMS, INC., AS SELLER

This Amendment (hereinafter referred to as the
"Amendment") is entered into as of this 9th day of June,
1993, by and between ATLANTIC CITY ELECTRIC COMPANY, having
offices at 6801 Black Horse Pike, Pleasantville, New Jersey
08232 (hereinafter referred to as "Purchaser"), and KEYSTONE
ENERGY SERVICE COMPANY, L.P., having offices at 7475
Wisconsin Avenue, Bethesda, Maryland 20814-3422 (hereinafter
referred to as "Seller").

WHEREAS, Purchaser and Keystone Cogeneration Systems,
Inc. ("KCSI") have previously entered into a certain
Agreement for Purchase of Electric Power, dated as of
August 25, 1988, and amended pursuant to amendments dated as
of November 22, 1988, December 19, 1988, November 3, 1989,
March 28, 1990, January 24, 1991, April 5, 1991,
September 24, 1991 and February 6, 1992 (the "Agreement"),
and as clarified through a letter, dated as of March 31,
1992, from Purchaser to KCSI, and a letter, dated as of
April 14, 1992, from Purchaser to Seller; and

WHEREAS, pursuant to the Assignment and Assumption
Agreement, dated as of April 1, 1992, between KCSI and
Seller, KCSI assigned to Seller, and Seller assumed from
KCSI, all of KCSI's rights and obligations arising under the
Agreement, which assignment and assumption was made in
accordance with Section 18.10 of the Agreement; and

WHEREAS, Purchaser and Seller further wish to amend the Agreement, all as more particularly described in this Amendment, the effectiveness of which is subject to and conditioned upon the occurrence of certain events described herein.

NOW, THEREFORE, in consideration of the mutual promises, covenants and conditions contained herein, Purchaser and Seller agree as follows:

1. Definitions.

(a) Except as otherwise provided in this Amendment, all terms shall have the same meaning as set forth in the Agreement.

(b) Article 1.1 of the Agreement is hereby amended to insert the following definitions immediately following Article 1.1KK:

LL. "Base Capacity Payment", with respect to any Billing Period starting with the Date of Commercial Operation, shall equal the payment amount shown on the table set forth in Exhibit A attached to Amendment No. 009 to the Agreement and made a part thereof corresponding to the Contract Year in which such Billing Period occurs, as such amounts may be adjusted as described in Exhibit A. These amounts do not include the Energy Payment, the Fixed O&M Payment and the Interest Payment.

MM. "Capacity Payment", with respect to any Billing Period starting with the Date of Commercial Operation, shall mean the sum of the Base Capacity Payment and the Fixed O&M Payment with respect to such Billing Period.

NN. "Dispatch Incentive" shall have the meaning set forth in Exhibit C attached to Amendment No. 009 to the Agreement and made a part thereof.

OO. "Dispatch Incentive Payment", with respect to any Billing Period starting with the Date of Commercial Operation, shall have the meaning set forth in Exhibit

C attached to Amendment No. 009 to the Agreement and made a part thereof.

PP. "EAF Incentive" shall have the meaning set forth in Exhibit C attached to Amendment No. 009 to the Agreement and made a part thereof.

QQ. "EAF Incentive Payment", with respect to any Billing Period starting with the Date of Commercial Operation, shall have the meaning set forth in Exhibit C attached to Amendment No. 009 to the Agreement and made a part thereof.

RR. "Energy Payment", with respect to any Billing Period starting with the Date of Commercial Operation, shall equal the sum of:

(i) any provision of Article 9.8 to the contrary notwithstanding, any and all Energy Taxes paid by Seller during such Billing Period; and

(ii) the sum for all hours during such Billing Period of the product of:

(a) the Facility Energy Cost, for each such hour;

(b) the Facility Heat Rate Multiplier, for each such hour; and

(c) the purchases of energy (expressed in kWh) by Purchaser hereunder (excluding purchases contemplated by Sections 10(d) and 10(e) of Amendment No. 009 to the Agreement) for each such hour, delivered at the Point of Delivery.

SS. "Energy Taxes" shall mean any taxes (other than income taxes), calculated on the basis of fuel consumption, Btu content, or other measurement of energy or fuel use or production that are imposed on Seller as a result of the production or sale of energy or capacity by Seller to Purchaser hereunder and that result from enactment of the Revenue Reconciliation Act of 1993, H.R. 2264, or the enactment of another act in substitution for or supplemental to the Revenue Reconciliation Act of 1993 prior to the adjournment of the 103rd Congress, together with any Tax related to such taxes. Energy Taxes shall reflect only such taxes as are actually paid by Seller, or the taxpaying owners of Seller, taking into account all credits, deductions, offsets and similar items applicable to Seller, or the taxpaying owners of Seller. Energy Taxes shall not

include any taxes that arise directly as a result of Seller's Facility not being a Qualifying Facility.

TT. "Equivalent Availability Factor" with respect to Seller's Facility shall have the meaning set forth in Exhibit D attached to Amendment No. 009 to the Agreement and made a part thereof, and shall be expressed as a percentage.

UU. "Facility Energy Cost" with respect to any hour in any Billing Period starting with the Date of Commercial Operation shall equal the sum of: (i) a variable operation and maintenance charge (which charge also reflects, among other items, Seller's lime purchase and ash disposal costs) equal to \$0.0042/kWh, expressed in January 1, 1993 dollars, adjusted annually by the O&M Escalation Factor, commencing on January 1, 1994, and (ii) the product of (a) a fuel commodity charge, expressed in dollars per MMBtu, representing the actual unit price to Seller of coal in effect during such hour, together with the cost to Seller of transporting such coal to Seller's Facility, times (b) the Full Load Heat Rate expressed in Btu/kWh divided by 1,000,000 Btu/MMBtu.

VV. "Facility Heat Rate Multiplier" shall mean the ratio of (i) the heat rate for Seller's Facility at a given load level to (ii) the Full Load Heat Rate, all as more fully defined herein and as set forth in Exhibit E to Amendment No. 009 to the Agreement.

WW. "Fixed O&M Payment" with respect to any Billing Period starting with the Date of Commercial Operation shall equal \$5.055/kW month, expressed in January 1, 1993 dollars, adjusted annually by the O&M Escalation Factor commencing January 1, 1994.

XX. "Full Load Heat Rate" for Seller's Facility initially shall equal 10,145 Btu per kWh. The initial heat rate for Seller's Facility at load levels less than full load shall be as set forth in Exhibit E to Amendment No. 009 to the Agreement. Within sixty (60) days after Seller's final acceptance testing of the Facility with its engineering, procurement and construction contractor, the Full Load Heat Rate, and the heat rate for load levels less than full load, as specified in Exhibit E, shall be reset to equal the results of such final acceptance testing. The Full Load Heat Rate, and the heat rate for load levels less than full load, shall be subject to further adjustment on the basis of a test conducted by Seller, in accordance with the testing procedures referred to in

Exhibit E, within sixty (60) days after the completion of each major turbine overhaul of Seller's Facility, with such tests and adjustments to occur not more frequently than once every five years. The Full Load Heat Rate, and the heat rate for load levels less than full load, shall not be adjusted below the values established by the final acceptance testing described above, and the Full Load Heat Rate, and the heat rate for load levels less than full load, shall be subject to further increase (but not decrease) on the basis of tests conducted at Seller's election in accordance with testing procedures referred to in Exhibit E, at times other than in conjunction with major turbine overhauls as described above, not more frequently than once in any Contract Year, which tests must be conducted within sixty (60) days after the maintenance outage for Seller's Facility during that Contract Year.

YY. "Interest Payment" with respect to Seller's permanent taxable and tax-exempt debt under the Senior Loan Agreement as modified and the Bond Documents, respectively, for any Billing Period beginning with the Date of Commercial Operation, shall equal the sum, over all days in such Billing Period (without duplication of any day) of (a) the daily equivalent of the letter of credit fees payable under the Senior Loan Agreement applicable to outstanding letters of credit supporting the tax-exempt debt under the Senior Loan Agreement and (b) the product of (i) the interest rates selected by, or at the direction of Purchaser under the IRMA, and subject to the provisions of the Senior Loan Agreement (modified as contemplated by Amendment No. 009 to the Agreement) and in the Bond Documents, as applicable, inclusive of the applicable interest rate margins, similar fees, charges or interest rate equivalents set forth in the Senior Loan Agreement as modified and in the Bond Documents, and, to the extent applicable, the interest rates that Seller is obligated to pay under such of the Interest Rate Protection Agreements as are then in effect (or under any other interest rate protection agreements as may be in effect in the event that Purchaser shall direct Seller to enter into such other interest rate protection agreements or as may be required under the provisions of the Senior Loan Agreement as modified and approved by Purchaser pursuant to Section 9(a) to Amendment No. 009 to the Agreement), and (ii) the projected outstanding principal amounts (the "Projected O/S Amount") of Seller's permanent taxable and tax-exempt debt financing, as applicable, to which all such interest rates (or amounts, as the case may be) described in clause (b) (i) relate, as appropriate, on each day of such Billing Period, as calculated in accordance with

the calculation methods applicable under the Senior Loan Agreement, the Bond Documents and other related financing documents as applicable. As of any day in a Billing Period the Projected O/S Amount shall be:

(A) the assumed aggregate outstanding principal amount set forth in the first sentence of the first paragraph of Exhibit A to Amendment No. 009 to the Agreement and made a part thereof with respect to the Senior Loan, the tax-exempt debt and the working capital amounts, adjusted, as of the Date of the Commercial Operation as provided in Exhibit A, (the "Original O/S Amount"), less

(B) The cumulative principal repayments, scheduled to be made in accordance with the amortization schedules in Exhibit A, calculated by summing all the scheduled principal repayments through, but not including, the principal repayment, if any, scheduled to be made on the day for which such Interest Payment is to be calculated. Each such repayment shall be calculated by multiplying the Senior Loan, tax-exempt and working capital amount included in the Original O/S Amount by the appropriate percentage set forth in the amortization schedules in Exhibit A.

For the purposes of this definition of "Interest Payment", the Projected O/S Amount will control irrespective of any changes in the actual outstanding principal amounts other than adjustments thereto that are expressly described in Exhibit A and that pursuant to Exhibit A, the parties agree will be reflected in such Projected O/S Amount.

Calculation of the Interest Payment shall be subject to the adjustments described in Exhibit B pertaining to the amount of Seller's Swap Termination Contribution to which the fixed interest rate set forth therein applies.

ZZ. "Interest Rate Protection Agreements" shall mean the eight Interest Rate and Currency Exchange Agreements, each dated as of April 1, 1992, among Seller, Urban and certain financial institutions.

AAA. "IRMA" (Interest Rate Mode Adjustment) shall have the meaning set forth in Exhibit F attached to Amendment No. 009 to the Agreement and made a part thereof.

BBB. "O&M Escalation Factor" with respect to any twelve month period shall mean a factor expressed in

percentage terms comprised of (i) forty percent (40%) of the percentage change in the Gross Domestic Product Implicit Price Deflator for such twelve month period as published by the Bureau of Economic Analysis, United States Department of Commerce, and (ii) sixty percent (60%) of the percentage change in the Consumer Price Index of the Bureau of Labor Statistics, United States Department of Labor for the "Philadelphia-Wilmington-Trenton, PA-NJ-DE-MD-CMSA" area during such twelve month period. The factor shall be calculated annually, and become effective on each January 1, on the basis of twelve month actual data for the period ending the immediately preceding September 30, or, in the event that such actual data are not available, on the basis of the most recent twelve month period for which actual data are available. If either index is discontinued, the O&M Escalation Factor will incorporate another index reasonably acceptable to Seller and Purchaser.

CCC. "Purchaser's Swap Termination Contribution" shall have the meaning set forth in Exhibit B attached to Amendment No. 009 to the Agreement and made a part thereof.

DDD. "Seller's Swap Termination Contribution" shall mean the excess of the expenses incurred in connection with the Swap Termination Event over Purchaser's Swap Termination Contribution, subject to the limitations set forth in Exhibit B attached to Amendment No. 009 to the Agreement and made a part thereof.

EEE. "Tax", subject to Section 9(h) of Amendment No. 009 to the Agreement, shall mean any net federal income tax or New Jersey (or other state or local) tax, if any, payable by Seller, or the taxpaying owners of Seller, and arising out of the payment of specified amounts by Purchaser, which Tax shall consist of the following components: (i) the initial amount of net Tax (the "First Amount"); (ii) the net Tax on the First Amount (the "Second Amount"); (iii) the net Tax on the Second Amount (the "Third Amount"); and (iv) the net Tax on the Third Amount and on each succeeding amount until the final amount is less than one dollar. Taxes shall reflect only such taxes as are payable by Seller, or the taxpaying owners of Seller, taking into account all credits, deductions, offsets and similar items applicable to Seller, or the taxpaying owners of Seller, arising from ownership and operation of Seller's Facility.

FFF. "Swap Termination Event" shall have the meaning set forth in Exhibit B attached to the Amendment No. 009 to the Agreement and made a part thereof.

GGG. "Restructuring Expenses" shall mean the out-of-pocket expenses incurred by Seller in connection with the negotiation, preparation and execution of Amendment No. 009 and the obtaining of all required agreements, amendments, consents or approvals from third parties that are referred to in or are contemplated by Section 9 of Amendment No. 009 to the Agreement, the estimate for which is set forth in Exhibit A to the Amendment.

HHH. "Information" shall have the meaning set forth in Section 10(k) to Amendment No. 009 to the Agreement.

III. "Senior Loan Agreement" shall have the meaning set forth in Section 9(a) to Amendment No. 009 to the Agreement.

JJJ. "Subordinated Loan Agreement" shall have the meaning set forth in Section 9(b) to Amendment No. 009 to this Agreement.

KKK. "Bond Documents" shall have the meaning set forth in the Senior Loan Agreement.

LLL. "Original O/S Amount" shall have the meaning set forth in Article 1.1YY.

MMM. "Projected O/S Amount" shall have the meaning set forth in Article 1.1YY.

(c) Article 1.1A of the Agreement shall be deleted in its entirety, and the following new provision shall be inserted in place thereof:

"A. "Availability Factor" shall mean the ratio of (i) the Equivalent Availability Factor of Seller's Facility based on a Contract Year calculation of availability, calculated as of the end of each Contract Year in accordance with Exhibit D attached to Amendment No.009 to the Agreement and made a part thereof, to (ii) eighty-three percent (83%), to be applied retroactively to such Contract Year as contemplated by Article 6.1F and prospectively to the immediately succeeding Contract Year solely for purposes of monthly billing and payment as provided in Article 5.1D(i) and Exhibit C to Amendment No. 009 to the Agreement, subject to year end reconciliation as provided in Article 6.1F; provided, however, that the Availability Factor for the first Contract Year shall be calculated only on the basis of the last six months of such Contract Year. The Availability Factor shall be deemed to equal 1.0 during the first Contract Year for purposes of monthly

billing. Notwithstanding the foregoing, the Availability Factor shall be deemed to equal 1.0 when the Equivalent Availability Factor of Seller's Facility equals or exceeds eighty-three percent (83%)."

(d) Exhibit I to the Agreement shall be deleted in its entirety.

2. Qualifying Facility Status.

Article 3.3B of the Agreement shall be deleted in its entirety, and the following new provision shall be inserted in place thereof:

"B. Qualifying Facility Status. Except as otherwise provided in this subparagraph B, Seller shall maintain those conditions during the term of the Agreement specified by the FERC and applicable to the Facility with respect to Qualifying Facility status as of the Effective Date. In the absence of an agreement to the contrary approved by the BRC, and unless FERC (or other appropriate regulatory authority having jurisdiction) shall have previously approved a rate schedule for service hereunder for the remaining portion of the Term, if Seller loses its Qualifying Facility status, to the extent legally permissible this Agreement shall remain in effect except payment to Seller shall be the lower of the Purchase Price under Article 5 hereof, or ninety-nine percent (99%) of Purchaser's Hourly Interchange Cost, or its equivalent, multiplied by the kilowatt hours delivered, until such time as Qualifying Facility status is attained or until such time as FERC (or other appropriate regulatory authority having jurisdiction) shall approve a rate schedule for the remaining portion of the Term. Seller shall, at any time, be entitled to file with FERC (or other appropriate regulatory authority having jurisdiction), pursuant to the Federal Power Act, as amended, for approval of a rate schedule for the remaining portion of the Term at no greater rates than the Purchase Price under Article 5 hereof; provided, however, that Purchaser shall only be obligated to pay the lower of (i) the rate schedule as approved by FERC (or other appropriate regulatory authority having jurisdiction), or (ii) the Purchase Price under Article 5 hereof. Purchaser shall not oppose such rate schedule. If Seller fails for any reason to have such rate

schedule approved by FERC (or other appropriate regulatory authority having jurisdiction) within two (2) years of the date of loss of Qualifying Facility status, then the price hereunder shall be based on the lower of the Purchase Price under Article 5 hereof or ninety-nine percent (99%) of Purchaser's Hourly Interchange Cost, or its equivalent, to the extent legally permissible. Qualifying Facility status will be measured by Seller in accordance with the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of the FERC, in force and effect as of the Effective Date, once every Contract Year, beginning at the end of the twenty-fourth (24th) month after the Date of Commercial Operation. Seller shall forward to Purchaser a copy of the measurement report prepared by Seller within thirty (30) days of such measurement of Qualifying Facility status. Notwithstanding anything in this subparagraph B to the contrary, Seller's Facility shall remain a cogenerator as long as the Steam Supply Agreement dated as of November 22, 1989 between Monsanto Company and Seller (as assignee) remains in effect."

3. Basic Rights and Obligations.

(a) Article 3.1 of the Agreement shall be deleted in its entirety, and the following new provision shall be inserted in place thereof:

"3.1 Delivery of Electric Energy and Capacity. Seller shall sell and deliver and Purchaser shall purchase and accept on and after the Date of Commercial Operation and for the Term of this Agreement, such of the Net Plant Output from Seller's Facility as Purchaser shall from time to time elect to purchase in accordance with the provisions of this Agreement, including the procedures set forth in Article 5 hereof. Purchase of Net Plant Output prior to the commencement of the Term shall also be made by Purchaser in accordance with Article 5. In order to fulfill its obligation to supply, Seller agrees to proceed and perform, with reasonable promptness and diligence, the work necessary for construction of Seller's Facility. The parties agree that, subject only to the express limitations contained in this Article and elsewhere in the Agreement, and notwithstanding the provisions of Article 3.4

hereof, Purchaser shall control the dispatch of Seller's Facility in its sole discretion.

Purchaser agrees that in consideration of Seller's Facility being Dispatchable, Purchaser shall be obligated to dispatch Seller's Facility and to purchase all energy produced by Seller's Facility operating at a continuous minimum dispatch of not less than 50,000 kW.

Without limiting or qualifying in any manner the obligations of Purchaser contained in this Article 3.1, the parties agree that the minimum notice to start-up shall be eight (8) hours from cold start and four (4) hours from warm start, the minimum notice to shutdown shall be two (2) hours and that the minimum run time between start-up and shutdown shall be ten (10) hours. The Facility can be ramped up or down at the average rate of 2,000 kW per minute."

(b) Article 3.3D(ii) shall be amended by adding the following sentence at the end thereof: "Such redesignation shall only result from operating limitations at Seller's Facility." Article 3.3D(iii)(a)(1) shall be amended by substituting "\$25.84/kW month" for the words "the aggregate capacity payments made" in the first textual line thereof. Article 3.3D(iii)(b) shall be deleted in its entirety, and Article 3.3D(iii)(c) (and all references thereto) shall be amended by renumbering it as Article 3.3D(iii)(b).

4. Purchase Price and Other Charges.

(a) Article 5.1B of the Agreement shall be deleted in its entirety, the following new provision shall be inserted in place thereof and the following new provisions (Articles 5.1D and 5.1E) shall be added:

"B. For non-dispatched, test energy received after the Date of Commercial Operation, the pricing structure shall be an energy payment equal to the lowest market price for energy

purchased by Purchaser available at the time of the receipt of such test energy.

D. On and after the Date of Commercial Operation, except as otherwise contemplated by Article 3.3B hereof and Sections 10 (d) and (e) of Amendment No. 009 to the Agreement, the pricing structure hereunder shall be based on the following formulas:

(i) During the Term, regardless of the level of dispatch of Seller's Facility, a monthly capacity payment equal to the sum of the following amounts relating to the immediately preceding Billing Period: (A) the Capacity Payment multiplied by Net Deliverable Capacity multiplied by Availability Factor, where the Net Deliverable Capacity shall not exceed 200,000 kilowatts and subject also to redesignation pursuant to Article 3.3D, plus (B) the Interest Payment for such applicable Billing Period, plus (C) the EAF Incentive Payment, plus (D) the Dispatch Incentive Payment.

(ii) For all energy received, when dispatched, the price shall be equal to the Energy Payment.

E. Purchaser shall pay to Seller any and all fees, expenses, and letter of credit fees resulting from the execution of Purchaser's selections made under the IRMA, or resulting from the requirements of the Senior Banks pursuant to the Senior Loan Agreement (modified as contemplated by Section 9(a) of Amendment No. 009 to the Agreement) pertaining to interest rate elections, in all events to the extent that such amounts are not otherwise included in Article 5.1D hereof, together with any Tax arising out of such payment by Purchaser. Purchaser shall make such payments concurrently with the execution of such selections and in accordance with any further procedures relating to the IRMA that may be adopted as described in Exhibit F to this Amendment. Notwithstanding the foregoing, the parties agree that Purchaser's Swap Termination Contribution and Seller's Swap Termination Contribution shall be calculated and paid as provided in Exhibit B to Amendment No. 009 to the Agreement and made a part thereof.

In addition, if required under the provisions of the Senior Loan Agreement as amended and approved by Purchaser pursuant to Section 9(a) to

Amendment No. 009 to the Agreement, Purchaser shall pay to Seller, from time to time prior to the Date of Commercial Operation, aggregate actual interest accruals on the projected principal amounts of Seller's debt financing (such projected principal amounts to be computed pursuant to Exhibit A) in excess of the assumed aggregate interest accruals on such projected principal amounts set forth in item 3 of the Information, together with any Tax on such excess interest accruals, concurrently on the due dates of such excess interest accruals. No payments of excess interest shall be made prior to the Date of Commercial Operation with respect to the amount, if any, of the difference described in the first sentence of the third paragraph of Exhibit B."

- (b) Article 5.3 of the Agreement, as well as Exhibit J to the Agreement, shall be deleted in their entirety.

5. Billing and Payment.

- (a) Article 6.1A(i) of the Agreement shall be deleted in its entirety and the following new provision shall be inserted in place thereof:

"(i) read the meters, prepare a statement of all payments due to Seller, incorporating information furnished to Purchaser by Seller in writing following the end of such Billing Period concerning the applicable O&M Escalation Factor, any Energy Taxes accrued with respect to such Billing Period, and the fuel commodity charge relating to the Facility Energy Cost with respect to such Billing Period, and shall submit the same to Seller, together with Purchaser's payment therefor by electronic wire funds transfer, within the last to elapse of: (a) the thirty (30) day period following the end of such Billing Period, and (b) the fifteen (15) day period following receipt by Purchaser of the aforementioned information from Seller ("Due Date"). Such statement shall indicate the monthly capacity payment and the total kilowatt-hours and kilowatts delivered during each hour of the Billing Period."

- (b) Article 6.1C of the Agreement shall be deleted in its entirety and the following new provision shall be inserted in place thereof:

"C. Neither party shall have the right to offset any payments due to one party against payments otherwise due to the other party, except as provided in Articles 1.1NN, 1.1PP, 5.1D(i), 6.1F and 13.3"

- (c) Article 6.1E of the Agreement shall be revised as follows and the following new provisions (Articles 6.1F and 6.1G) shall be added:

- "E. The parties agree that all payments under this Agreement shall be subject to year end adjustment or "true up" so as to correct billing errors, reconcile overpayments or underpayments, or to satisfy other accounting requirements so as to accomplish the purposes of this Agreement.
- F. The parties agree that the EAF Incentive and the Dispatch Incentive (including any payments from Seller to Purchaser due under the EAF Incentive) shall be recalculated at the end of each Contract Year on the basis of the Equivalent Availability Factor of Seller's Facility during such Contract Year, as measured in accordance with Exhibit D to Amendment No. 009 to the Agreement, and the actual run of Seller's Facility during such Contract Year, and any overpayments or underpayments shall be reconciled through adjustments to the amounts payable by Purchaser with respect to the first Billing Period of the next succeeding Contract Year.
- G. The parties agree that, anything to the contrary contained in the Agreement notwithstanding, no correction or reconciliation of overpayments or underpayments may be made more than twenty-four (24) months following the date on which such overpayment or underpayment occurred."

- (d) Purchaser and Seller agree that Article 6.2 of the Agreement shall be amended by inserting the following at the end of such Article:

"Anything to the contrary in this Article 6.2 notwithstanding, unless Seller's coal suppliers agree to permit Purchaser access to Seller's coal purchase agreements, Purchaser and its authorized employees, agents or representatives and auditors shall not be entitled to have access to any data, documents and other materials in Seller's possession relating to the coal purchase price component of the fuel commodity charge described in Article 1.1UU hereof, including without limitation Seller's coal purchase agreements; provided, however, that if Purchaser is not permitted access to such agreements, Purchaser shall be entitled, from time to time as Purchaser reasonably deems appropriate, to request the appointment of a mutually acceptable independent auditor who shall perform an audit of the Energy Payments paid by Purchaser hereunder relating to the fuel commodity charge described in Article 1.1UU hereof, during the then current Contract Year or the immediately preceding Contract Year. The results of the audit shall be binding, the cost of the audit shall be borne equally by the parties, and the auditor's report shall preserve the confidentiality of Seller's coal purchase agreements. Any resulting adjustments shall be paid in accordance with Article 6.1E.

The parties agree that Purchaser shall be entitled, not more frequently than once in any five Contract Year period (commencing no earlier than the end of the second Contract Year), to request the appointment of a mutually acceptable independent auditor who shall perform an audit of the variable operation and maintenance charge component of the Facility Energy Cost. The results of the audit shall be binding and shall take effect only prospectively, by means of an adjustment to the amount stated in clause (i) of Article 1.1UU (as such amount may have been previously adjusted hereunder). Neither party shall have any obligation to the other with respect to any overpayments or underpayments of such charges made prior to such audit."

6. Changes in Operating Voltage. The first sentence of Article 10.7 of the Agreement shall be deleted in its entirety, and the following new provision shall be inserted in place thereof:

"Subject to Article 9.12 hereof, Purchaser may, upon three (3) years' notice to Seller, change its nominal operating voltage level by more than plus or minus ten percent (10%) at the Point of Delivery, in which case Seller shall modify its equipment as necessary to accommodate the modified nominal operating voltage level. The parties agree that the expense of so modifying Seller's equipment shall be allocated between them as determined pursuant to good faith negotiations between the parties. The failure of the parties to reach agreement on the allocation of said expenses shall not relieve Seller of its obligation to implement said modifications."

7. Breach, Termination and Remedies.

The parties agree that clause (v) of Article 13.4 shall be of no further force or effect. The parties further agree that, other than as expressly provided in this Amendment (including, without limitation, the provisions of this Amendment relating to Purchaser's rights under and with respect to the IRMA), there are and shall be no restrictions relating to or affecting Seller's construction and permanent financing which are enforceable by or for the benefit of Purchaser, and that the provisions set forth in a letter, dated as of April 14, 1992, from Purchaser to Seller with respect to Section 13.4(v) of the Agreement and certain related matters are and shall be of no further force or effect.

8. Additional Amendments.

(a) The parenthetical phrase contained in the first and second textual lines of Article 18.6 shall be deleted in

its entirety, and the following new language shall be inserted in place thereof: "(A through H inclusive)".

(b) Exhibit K to the Agreement shall be deleted in its entirety.

9. Conditions to the Effectiveness of this Amendment.

Purchaser and Seller agree that this Amendment shall not become effective (other than Sections 10(a) and 10(b) hereof, which shall become effective as of the date hereof) until and unless each of the following conditions has been timely fulfilled:

- (a) Seller, Keystone Urban Renewal Limited Partnership ("Urban"), a Delaware limited partnership, and the other parties (the "Senior Banks") to the Amended and Restated Reimbursement and Loan Agreement (the "Senior Loan Agreement"), dated as of August 3, 1992 shall have executed definitive amendments to Seller's construction and permanent financing, such amendments to be in form and substance satisfactory to Seller, and the execution and delivery by Purchaser and Seller of this Amendment and the consummation of the transactions contemplated hereby shall have been consented to in writing by the Senior Banks as provided in the Senior Loan Agreement. The interest rate election provisions available to Seller under such amendments and any other provisions under such amendments that would have,

or are reasonably likely to have, an adverse effect on any payments to be made by Purchaser under the Agreement as amended by this Amendment No. 009 shall be subject to Purchaser's reasonable approval, which approval shall not be unreasonably withheld or delayed, and any such provision shall be deemed approved by Purchaser if there is a corresponding provision in the Senior Loan Agreement in effect on the date of this Amendment No. 009 with substantially the same economic effect on such payments to be made by Purchaser.

- (b) Seller shall have prepaid in full or cancelled its indebtedness arising under the Subordinated Loan Agreement (the "Subordinated Loan Agreement"), dated as of April 1, 1992, among Seller, Urban and the lenders named therein (the "Subordinated Lenders"), and under the Junior Loan Agreement (the "Junior Loan Agreement"), dated as of April 1, 1992, among Seller, Urban and the junior lender named therein (the "Junior Lender") with proceeds of the amended construction and permanent financing described herein, and all other agreements to which Seller, on the one hand, and the Subordinated Lenders or the Junior Lender, on the other hand, are parties shall have been terminated or amended, as appropriate, and any and

all mortgages or security interests granted by Seller or Urban in favor of the Subordinated Lenders or the Junior Lender shall have been discharged in full and terminated in their entirety. Seller shall provide Purchaser satisfactory evidence of such discharge and termination.

- (c) In the event that the Restructuring Expenses exceed (or are reasonably expected by Purchaser to exceed) the estimated amount set forth in Exhibit A to an extent that, in Purchaser's sole judgment, if paid by Purchaser directly or through the Capacity Payment, such payment with respect to such excess amount would materially and adversely affect the economic feasibility of the transactions contemplated by this Amendment from Purchaser's perspective, Purchaser and Seller shall have agreed in writing upon a means of apportioning such excess amounts between them within thirty (30) days after receipt by Seller of written notice of Purchaser's determination with respect to such amounts as contemplated hereby. This condition shall be deemed satisfied if Purchaser's total obligations with respect to Restructuring Expenses do not exceed the estimated amount set forth in Exhibit A.

- (d) Seller, Urban, Purchaser and the Senior Banks shall have executed (i) an amendment to the Intercreditor Agreement and Consent to Assignment, dated as of April 1, 1992, providing for the deletion from such agreement of the provisions contained in Sections 2, 3, 4, 5, 6, 7 and 10 thereof and making such other changes therein as are reasonably necessary to reflect the actions and transactions contemplated by this Amendment, or (ii) a substitute agreement to substantially similar effect.
- (e) The Board shall have issued an order approving this Amendment and the consummation of each of the transactions contemplated hereby requiring its approval, and permitting the Purchaser to flow through to and fully and timely recover from its ratepayers, through a Levelized Energy Adjustment Clause proceeding or comparable regulatory proceeding, all costs incurred or reimbursed by the Purchaser under the Agreement as amended hereby, including but not limited to any payments made pursuant to any rate schedule filed with FERC by Seller pursuant to Section 2 of this Amendment. Such order shall be subject only to such substantive conditions or limitations as are acceptable to Purchaser and Seller in the sole discretion of each of them, the parties'

acceptance of which shall be evidenced by a writing to that effect executed by each of them not later than twenty (20) days after the issuance of such order by the Board. Such order, as accepted in writing by the parties, shall have become final and non-appealable on or prior to December 31, 1993, unless an extension is agreeable to both parties.

- (f) Seller and Purchaser shall have obtained all other consents or approvals, including, without limitation, third party consents or approvals, and amendments to all such other agreements or instruments that are reasonably necessary for the effectuation of the transactions contemplated by this Amendment and shall have agreed in writing upon the procedures governing the Swap Termination Event referred to in Exhibit B and the IRMA procedures referred to in Exhibit F to this Amendment.
- (g) At the time of consummation of the transactions contemplated hereby, there shall be no judicial or administrative proceeding pending or, to the knowledge of Seller or Purchaser, threatened which contests or is expected to contest the legality of, or otherwise seeks (or is expected to seek) to prevent or materially impair the consummation of, any of the transactions contemplated hereby, and

all appeal periods in respect of any approvals shall have expired.

- (h) Purchaser and Seller shall (x) exercise their respective reasonable best efforts, (y) negotiate diligently and in good faith, and (z) achieve, not later than thirty (30) days after the date of this Amendment, unless such date is extended by mutual agreement, the following: (i) a mutually satisfactory tax indemnity agreement dealing with the circumstances in which any Tax is payable by Purchaser to Seller under this Amendment and (ii) a mutually satisfactory agreement governing the general procedures and conditions whereby the Seller and Purchaser will mutually pursue refinancing of the construction and/or permanent debt financing associated with the Seller's Facility, prior to the fourth anniversary of the Date of Commercial Operation, with the objective of providing mutually agreed upon benefits to create cost savings for Purchaser without harm to Seller, on terms and conditions mutually acceptable to Purchaser and Seller. Nothing contained elsewhere in this Amendment shall be of precedent or shall prejudice in any way the negotiation of the tax indemnity agreement described above.

- (i) Seller shall diligently, and in good faith, enter into and conclude negotiations with coal suppliers for the purpose of reducing the Purchaser's Energy Payment under the Agreement as amended hereby, subject to Purchaser's reasonable right of participation in, and Purchaser's reasonable approval of the outcome of, such negotiations. Purchaser's approval shall not be unreasonably withheld or delayed.

10. Covenants and Agreements of Purchaser and Seller.

- (a) Purchaser and Seller agree to negotiate in good faith with each other and with the third parties referred to in Section 9 hereof and to exercise their respective reasonable best efforts to cause each of the conditions set forth in said Section 9 to be fulfilled.
- (b) Purchaser and Seller agree that Seller shall have primary responsibility for the negotiation and preparation of the agreements described in Sections 9(a) and 9(d) and for the fulfillment of the conditions set forth in Sections 9(b) and, to the extent applicable to Seller, 9(f), and that Purchaser shall have primary responsibility for the fulfillment of the conditions described in Sections 9(e) and, to the extent applicable to Purchaser, 9(f).

- (c) Concurrently with the fulfillment of the last of the conditions set forth in Section 9 hereof to be fulfilled, Purchaser agrees to execute such instruments and to take such further steps that Seller deems necessary or desirable in order to discharge all mortgages in favor of Purchaser with respect to any interest in Seller's Facility and to terminate Purchaser's security interests in and to any of Seller's or Urban's assets.
- (d) Purchaser and Seller agree to negotiate diligently and in good faith with respect to the sale by Seller to Purchaser, and the purchase by Purchaser from Seller, of 2,000 kW of capacity and energy produced at Seller's Facility for the sole purpose of enabling Purchaser, with the consent of Monsanto Company ("Monsanto"), to supply such capacity and energy to Monsanto. The parties agree and acknowledge that the consummation of such further agreement with respect to the sale to Purchaser of such 2,000 kW of capacity and energy shall be subject to (i) the prior receipt of all necessary approvals and consents (including, without limitation, the approval of the BRC), and the expiration of any appeal periods relating thereto, for said agreement between Seller and Purchaser, (ii) the termination (at no expense to Seller or Purchaser) of the Electric Power Sales

Agreement (the "Monsanto Agreement"), dated as of November 22, 1989, by and between Monsanto and Seller (as assignee of KCSI) with the consent of Monsanto, (iii) the execution of an agreement satisfactory to Purchaser between Purchaser and Monsanto with respect to the sale by Purchaser to Monsanto of such 2,000 kW of capacity and energy, and (iv) the receipt of all necessary approvals and consents (including, without limitation, the approval of the BRC), and the expiration of any appeal periods relating thereto, for said agreement between Purchaser and Monsanto. The parties agree and acknowledge that the price at which such 2,000 kW of capacity and energy is sold to Purchaser by Seller shall be no greater than the price payable by Monsanto to Seller under the Monsanto Agreement as presently in effect for such capacity and energy.

- (e) Seller shall extend to Purchaser a right of first negotiation, whereby Seller agrees to engage in good faith negotiations with Purchaser for a reasonable period of time prior to entering into negotiations with one or more third parties, with respect to the sale by Seller of the Facility's energy and capacity, if any, in excess of 202,000 kW. Seller and Purchaser recognize and agree that such negotiations may not result in agreement and

that after Seller's exercise of its reasonable best efforts to reach a satisfactory agreement with Purchaser with respect to such sales, Seller shall be free to commence negotiations with and to conclude agreements with one or more third parties with respect to such sales.

- (f) The parties agree to work together, including periodic meetings, to solve problems or pursue opportunities including any refinancing (other than the refinancing referenced in Section 9(h) hereof, which will be governed by the agreement referenced therein) in a mutually beneficial fashion to achieve common objectives.
- (g) Subject to the Confidentiality Agreement of January 22, 1993, Seller and Purchaser each agree to provide to the other, within 10 days after written request by the other, with true and complete copies (including without limitation all exhibits, appendices, schedules and amendments) of such documentation, or such information, as is reasonably necessary for the requesting party to proceed under this Amendment; provided, however, that the party of whom such request is made shall not be required to furnish documentation or information which it is prohibited from disclosing pursuant to any contract, agreement, governmental order, or rule prohibiting said disclosure;

provided further, however, that in such event the party asserting the prohibition will use reasonable efforts to seek release from such prohibition, and failing such release, will seek to provide the requested documentation or information by alternative means, not inconsistent with such prohibition.

- (h) Seller covenants that it will not enter into any agreement or amendment to the Senior Loan Agreement or any other agreement, other than as set forth in Section 9(a) hereof, without the prior written consent of Purchaser if the effect of any provision of any such agreement or amendment would change the Capacity Payment or the Interest Payment payable by Purchaser in any Billing Period during the Term.
- (i) Seller hereby represents and warrants that: (i) as of the date of this Amendment the only loans that are secured by an interest in Seller's Facility, and/or all or any portion of the Agreement, or other security interest in Seller's Facility are represented by or arise under the Senior Loan Agreement, the Subordinated Loan Agreement, the Interest Rate Protection Agreements, the Bond Documents and the Intercreditor Agreement and Consent to Assignment between Purchaser and Seller, (ii) the total loan commitment amounts

under such agreements and documents have remained unchanged since their execution and, (iii) such agreements and documents have not been amended since their execution.

- (j) Seller shall report to Purchaser on a periodic basis, as reasonably requested by Purchaser, the amount of Restructuring Expenses incurred as of the date of such report.
- (k) Seller shall deliver to Purchaser not later than sixty (60) days prior to the date that all of the conditions set forth in Section 9 to this Amendment to the Agreement are satisfied, a certificate setting forth the information required by Exhibit G hereto. The information in such certificate shall be complete and accurate in all material respects and shall be referred to herein as the "Information".

11. Miscellaneous.

This Amendment, together with the Agreement and the other agreements and instruments expressly referred to herein or therein, constitutes the parties' entire agreement with respect to the subject matter hereof and thereof, and supersedes any and all prior oral or written agreements or understandings between the parties with respect thereto. Except as modified in this Amendment, all other terms and conditions

contained in the Agreement, as amended, shall remain in full force and effect.

12. Governing Law

This Amendment No. 009 shall be governed by and construed in accordance with the laws of the state as set forth in the Agreement.

13. Further Assurances.

Seller and Purchaser agree that they will execute and deliver such further instruments and do such further acts as may reasonably be necessary or convenient to carry out the purposes of this Amendment.

IN WITNESS WHEREOF, each of the undersigned has caused this Amendment to be executed by its duly authorized official as of the day and year first above written.

ATLANTIC CITY ELECTRIC COMPANY

Witness:

[Signature]

By:

[Signature]

Name: Meredith I. Harlecher

Title: Sr. Vice President - Energy Supply

KEYSTONE ENERGY SERVICE
COMPANY, L.P.

Witness:

[Signature]

By:

[Signature]

Name: EK HAUSER

Title: AUTHORIZED AGENT

Exhibit A
to Amendment No. 009

Base Capacity Payment

<u>Contract Year</u>	<u>Payment (in \$/kW month)</u>
Year 1	\$10.50
Year 2	\$10.29
Year 3	\$10.85
Year 4	\$11.75
Year 5	\$12.00
Years 6-10	\$19.12
Years 11-16	\$32.50
Years 17-30	\$ 9.20

The Base Capacity Payment amounts set forth in the above table include projected repayments of the principal amount of Seller's permanent debt financing, assuming an aggregate outstanding principal amount on the Date of Commercial Operation of \$440 million (consisting of \$340.5 million, \$90 million and \$9.5 million in Senior Loan, tax-exempt debt, and working capital loan amounts respectively). Such projected principal amount has been calculated based on (i) the assumptions that this Amendment and the amendment to the Senior Loan Agreement will become effective on December 31, 1993, the Interest Rate Protection Agreements will be terminated as of December 31, 1993 and Restructuring Expenses will be funded under the Senior Loan Agreement, as amended, on December 31, 1993; (ii) the assumption that after December 31, 1993 the interest rate on the taxable portion of Seller's construction debt financing (Senior Loan and working capital loan amounts) will be 5.00% per annum, and the interest rate on the tax-exempt debt, excluding letter of credit fees, will be 3.575% per annum; (iii) the assumption that the Date of Commercial Operation will occur on April 1, 1995; and (iv) the other assumptions ("Other Assumptions") to be set forth in the Information.

The projected aggregate principal amount of \$440 million and, therefore, the Base Capacity Payments amounts shown in the above table shall be subject to adjustment pursuant to procedures agreed upon by the Purchaser and Seller, and subject to the approval of the Senior Banks by the effective date of the amendment to the Senior Loan Agreement referred to in clause (i) above, solely to reflect changes attributable to:

(a) any differences in the actual dates on which the events described in clause (i) above occur and the assumed dates for such events stated in clause (i);

(b) any difference in the actual interest accruals up to the assumed Date of Commercial Operation resulting from Purchaser's elections under the IRMA (including elections to leave the Interest Rate Protection Agreements in place) or

EXHIBIT A
to Amendment No. 009 (continued)

from requirements under provisions of the Senior Loan Agreement, as modified and approved by Purchaser pursuant to Section 9(a) of this Amendment, net of any payment of accrued interest paid by the Purchaser pursuant to Section 4(a) of the Amendment, from the assumed rates stated in clause (ii) above;

(c) the amount by which \$6,000,000 exceeds the actual amount of Restructuring Expenses;

(d) any amount of Purchaser's Swap Termination Contribution or any amount of excess Restructuring Expenses, as agreed to by Purchaser and Seller, that is not otherwise reflected in such projected principal amount and that is financed under the Senior Loan Agreement; and

(e) any differences in the basis on which interest has actually been calculated from that set forth in item 2 of Exhibit G.

For purposes of the adjustments contemplated in clauses (b) and (e) above, construction financing shall be deemed to be drawn, irrespective of the actual timing and amount of drawings by Seller, in accordance with the drawdown schedule to be provided in the Information. No adjustments shall be made to reflect changes in actual interest accruals from those assumed in this Exhibit A that are attributable to the actual Date of Commercial Operation not occurring on April 1, 1995. The parties agree and acknowledge that the financing on Purchaser's behalf described in clause (d) of the preceding paragraph is and shall be subject to the approval of the Senior Banks, and that the unavailability of such financing shall not excuse, impair or modify any of Purchaser's obligations under the Agreement, as modified by this Amendment.

In addition, the applicable interest rates may change as a result of the repayment of the tax-exempt debt portion of Seller's permanent debt financing prior to its scheduled maturity with proceeds of refunding loans issued under the Senior Loan Agreement, as described in Exhibit F; provided however, that, if such repayment is at the discretion of the Seller, such repayment shall only proceed with the consent of Purchaser. Seller shall promptly provide Purchaser with true and complete documentation evidencing any such change. The parties further acknowledge that the amortization of Seller's permanent debt financing shall be deemed, for purposes of calculating Purchaser's Interest Payments and Base Capacity Payments, to occur on a quarterly basis on the last business day of each March, June, September and

EXHIBIT A
to Amendment No. 009 (continued)

December, commencing with the last business day of
September, 1995.

Amortization Schedules

	<u>Senior Loan Principal</u>	<u>Tax Exempt Principal</u>	<u>Working Capital Principal</u>
1993	0.00%	0.00%	0.00%
1994	0.00%	0.00%	0.00%
1995	2.73%	0.00%	0.00%
1996	3.91%	0.00%	0.00%
1997	4.20%	0.00%	0.00%
1998	4.26%	0.00%	0.00%
1999	4.42%	1.31%	0.00%
2000	6.30%	2.24%	0.00%
2001	6.79%	2.96%	0.00%
2002	6.88%	5.25%	0.00%
2003	6.89%	6.10%	0.00%
2004	7.01%	4.76%	0.00%
2005	11.41%	4.30%	0.00%
2006	13.23%	4.49%	25.00%
2007	11.72%	8.64%	25.00%
2008	10.17%	18.63%	25.00%
2009	0.08%	41.32%	25.00%
2010	0.00%	0.00%	0.00%
2011	0.00%	0.00%	0.00%
2012	0.00%	0.00%	0.00%
2013	0.00%	0.00%	0.00%
2014	0.00%	0.00%	0.00%
2015	0.00%	0.00%	0.00%
2016	0.00%	0.00%	0.00%
2017	0.00%	0.00%	0.00%
2018	0.00%	0.00%	0.00%
2019	0.00%	0.00%	0.00%
2020	0.00%	0.00%	0.00%
2021	0.00%	0.00%	0.00%
2022	0.00%	0.00%	0.00%
2023	0.00%	0.00%	0.00%
2024	0.00%	0.00%	0.00%
2025	<u>0.00%</u>	<u>0.00%</u>	<u>0.00%</u>
Total	100%	100%	100%

Exhibit B
to Amendment No. 009
(continued)

Exhibit B to Amendment No. 009

Purchaser and Seller agree that, in the event Purchaser elects to terminate the Interest Rate Protection Agreements pursuant to Purchaser's direction to Seller under the IRMA, or in the event the Senior Banks require the termination of the Interest Rate Protection Agreements as part of the amendments contemplated by and subject to Purchaser's approval under Section 9(a) hereof (in either case, the "Swap Termination Event"), Purchaser's contribution to the costs and expenses incurred in connection with such termination ("Purchaser's Swap Termination Contribution") shall be equal to the lesser of (i) \$20,000,000 or (ii) the actual amount of such costs and expenses, together with any Tax payable by Seller, or the taxpaying owners of Seller, arising out of payment of such termination costs and expenses by Purchaser. Purchaser's Swap Termination Contribution, together with the amount of any Tax related to such contribution, shall be paid to Seller concurrently with the termination of the Interest Rate Protection Agreements giving rise to such obligation of Purchaser, or in lieu of such payment by Purchaser, and subject to the amendment of the Senior Loan Agreement and other conditions pertaining to such potential financing as described in Exhibit A hereof, shall be borrowed by Seller under the Senior Loan Agreement. Seller shall be responsible for the payment of Seller's Swap Termination Contribution; provided, however, that in no event shall Seller's Swap Termination Contribution exceed \$26,000,000 in the aggregate.

If the total costs and expenses incurred in connection with such Swap Termination Event exceed \$46,000,000, Seller shall be entitled to terminate this Amendment if such excess would, in Seller's sole judgement, materially and adversely affect the economic feasibility of entering into the transactions contemplated by this Amendment; provided, further, that prior to Seller's terminating this Amendment, Seller shall notify Purchaser of such proposed termination, and Purchaser shall have the right, within thirty (30) days thereafter, to propose a reallocation of such excess costs or such other measures as, in Seller's sole judgement, will eliminate the material adverse affect of such excess on the economic feasibility of entering into such transactions.

In the event that Seller's actual Swap Termination Contribution is less than \$26,000,000, then, for purposes of calculating any Interest Payment due from Purchaser to Seller

Exhibit B
to Amendment No. 009
(continued)

under the Agreement as amended by this Amendment No. 009, the Interest Payment solely with respect to the difference between \$26,000,000 and Seller's actual Swap Termination Contribution shall be calculated at the fixed rate of 6% per annum rather than the actual interest rate otherwise applicable thereto under the IRMA, with no further charges for interest rate margins and similar fees, charges or interest rate equivalents. No other adjustments shall be made to (i) the assumed aggregate outstanding principal amount of debt on the Date of Commercial Operation, as described in and otherwise adjusted in accordance with Exhibit A thereof, or (ii) any other payments due from Purchaser to Seller under the Agreement as amended by this Amendment, in either case as a consequence of such event. Furthermore, any refinancing as contemplated in Section 9(h)(ii) of this Amendment shall provide for a refinanced amount that includes the outstanding portion of Seller's actual Swap Termination Contribution, up to \$26,000,000. In the event that Seller's actual Swap Termination Contribution is less than \$26,000,000, the payments due from Purchaser to Seller under the Agreement, as may be amended in the future, shall include amounts sufficient to capture the value to Seller of that portion of the Interest Payment that is fixed pursuant to the first sentence of this paragraph.

Seller shall not terminate the Interest Rate Protection Agreements absent the direction of Purchaser, unless so required by the Senior Banks as described above. Purchaser and Seller agree to negotiate diligently and in good faith to establish in writing further procedures governing the implementation of the Swap Termination Event, including mutually satisfactory alternative arrangements that provide benefits comparable to the Swap Termination Event.

Exhibit C
to Amendment No. 009

1. EAF Incentive. The EAF Incentive shall be an annual incentive calculated pursuant to the table set forth below, and shall be payable monthly on an estimated basis during each Contract Year and subject to reconciliation at the end of each Contract Year on the basis of actual Contract Year measurements. At least sixty (60) days but not more than one hundred and twenty (120) days prior to the commencement of each Contract Year, Seller shall prepare and submit to Purchaser a good faith forecast of the Equivalent Availability Factor of Seller's Facility for such Contract Year or, in the case of the first Contract Year, for the seventh through the twelfth months of such Contract Year. The forecast shall be prepared taking into account Seller's reasonable expectations for maintenance of Seller's Facility as contemplated by Article 10.5 of the Agreement, the recent operating history of Seller's Facility and such other factors as Seller may reasonably deem relevant. As an estimate of the EAF Incentive ultimately earned by Seller with respect to a Contract Year, Seller shall be entitled to receive a monthly EAF Incentive Payment equal to one-twelfth (1/12) of the EAF Incentive shown on the table below that would be payable to Seller if the Equivalent Availability Factor of Seller's Facility for the entire Contract Year in which such Billing Period occurs were to equal the Equivalent Availability Factor of Seller's Facility for that Contract Year as set forth in the forecast described above relating to that Contract Year. Notwithstanding the foregoing, during the first Contract Year the EAF Incentive Payments shall commence with the seventh Billing Period of such year, and shall equal one-sixth (1/6) of the EAF Incentive shown on the table below that would be payable to Seller if the Equivalent Availability Factor of Seller's Facility for that entire Contract Year were to equal the Equivalent Availability Factor of Seller's Facility for the seventh through twelfth months of that Contract Year as set forth in the forecast described above relating to such period. At the end of each Contract Year, the EAF Incentive Payments made to Seller during the Contract Year shall be reconciled to the EAF Incentive actually earned by Seller with respect to such year, and any overpayments or underpayments shall be reconciled in accordance with Article 6.1F; provided, however, that the EAF Incentive for the first Contract Year shall be calculated solely with reference to the seventh through the twelfth Billing Periods in such year.

<u>Equivalent Availability Factor of Seller's Facility</u>	<u>Annual Availability Incentive</u>
Less than 83%	\$0 (adjustment to Capacity Payment as provided in Article 5.1D(i))
Less than or equal to 85%	\$0
Greater than 85% but not more than 87%	\$500,000
Greater than 87%	\$1,000,000

The dollar amounts shown in the table shall be aggregated; thus, \$1,500,000 (adjusted as described herein) in EAF Incentive Payments is potentially available in each Contract Year.

2. Dispatch Incentive. The Dispatch Incentive shall be an annual incentive, payable monthly on an estimated basis and subject to reconciliation at the end of each Contract Year on the basis of actual measurements of the running of Seller's Facility in accordance with the table set forth below. At least sixty (60) days but not more than one hundred and twenty (120) days prior to the commencement of each Contract Year, Purchaser shall prepare and submit to Seller a good faith monthly forecast of Purchaser's projected dispatch of Seller's Facility covering the entire Contract Year. Each such forecast shall be prepared in accordance with the procedures and standards, if any, which are then applicable to Purchaser's Levelized Energy Adjustment Clause ("LEAC") filings submitted to the New Jersey Board of Regulatory Commissioners (formerly BPU), and shall include any projected dispatch information with respect to Seller's Facility for the relevant Contract Year that is contained in any such LEAC filing previously made by Purchaser. Seller shall be entitled to receive a monthly Dispatch Incentive Payment with respect to each Billing Period during such Contract Year equal to one-twelfth (1/12) of the estimated annual Dispatch Incentive shown on the table below that would be payable to Seller if Seller's Facility were actually to run when dispatched, including the 50,000 kW minimum dispatch referred to in Article 3.1 of the Agreement as amended by the Amendment, during such Contract Year at the level projected in such forecast. At the end of each Contract Year, the Dispatch Incentive Payments made to Seller during such year shall be reconciled to the Dispatch Incentive as provided in Article 6.1F.

<u>Actual Run Per Contract Year When Dispatched</u>	<u>Annual Dispatch Incentive</u>
Equal to or greater than 1,000 GWh (equivalent to full load run at or above 5,000 hours)	\$500,000
Greater than 1,100 GWh (equivalent to full load run above 5,500 hours)	\$500,000
Greater than 1,200 GWh (equivalent to full load run above 6,000 hours)	\$500,000
Greater than 1,300 GWh (equivalent to full load run above 6,500 hours)	\$500,000
Greater than 1,400 GWh (equivalent to full load run above 7,000 hours)	\$500,000
Greater than 1,500 GWh (equivalent to full load run above 7,500 hours)	\$1,000,000
Greater than 1,600 GWh (equivalent to full load run above 8,000 hours)	\$1,000,000

The dollar amounts shown in the table shall be aggregated; thus, \$4,500,000 (adjusted as described herein) in Dispatch Incentive Payments is potentially available in each Contract Year. The amounts shown in the table, "Actual Run Per Contract Year, When Dispatched", at levels of greater than 1,300 GWh or greater, shall be increased annually by 2%, commencing January 1, 1996.

Exhibit D
to Amendment No. 009

Below is the definition of Equivalent Availability Factor (EAF) for any specific generating unit:

$$\text{EAF \%} = \frac{\text{PH} - \text{EOH}}{\text{PH}} \times 100.0$$

Where:

EOH = Equivalent Outage Hours
PH = Period Hours (i.e. one year = 8760 hours except that, no more frequently than once in any five year period, one year shall equal 8000 hours for major turbine overhauls)

Equivalent outage hours are defined as:

$$\text{EOH} = \frac{\sum_{n=1}^i (D_n \times T_n)}{C}$$

Where:

D_n = Capacity deration¹ for outage n, MW

T_n = Time accumulated during outage n, hours (whole and fractional)

C = Unit maximum net dependable capacity² for the period of outage n, MW

i = Total number of outages for the period

Note 1 -- See attachment B for types of capacity derations/outages

Note 2 -- Net summer installed capacity + adjustments for ambient conditions

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage. Below is a listing of outage types, along with their specific definitions:

- RS - Reserve Shutdown - A reserve shutdown (RS) exists whenever a unit is available, but is not synchronized. This event is sometimes referred to as an economy shutdown or economy outage.
- PO - Planned Outage - Planned outages (PO) are scheduled well in advance and are of a predetermined duration. Turbine and boiler overhauls or inspections and testing are typical planned outages (PO). Characteristically, planned outages (PO) are planned well in advance and usually occur during those seasons of the year when the peak demand on the system is lowest, have flexible start dates, have a predetermined duration, last for several weeks, and occur only once or twice a year.
- MO - Maintenance Outage - This is an outage which can be deferred beyond the next weekend but requires that the unit be removed from service before the next planned outage (PO). Characteristically, these maintenance outages (MO) may occur throughout the year, have flexible start dates, are much shorter than planned outages (PO), and have a predetermined duration established at the start of the outage.
- SE - Scheduled Outage Extension - This is the extension of a planned outage (PO) or maintenance outage (MO) beyond its originally estimated completion date, such date being established at the start of these outages. A scheduled outage extension (SE) must start at the same time the PO or MO (being extended) ends.
- SF - Startup Failure - This is an outage that results from the unsuccessful attempt to place the unit in service following the unit's being in a full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) state. The unit is considered to be in a startup failure (SF) state if the unit cannot be placed in service within the utility specified time for that specific startup and/or requires significant repairs to the equipment or control systems which halted the normal startup cycle. Repeated failures to start for the same reason are considered as part of the same startup failure (SF). The startup failure (SF) begins when the unit is no longer able to continue its startup cycle or surpasses the originally estimated synchronization time. The startup failure (SF) ends when the unit is synchronized or enters some other (permissible) outage or shutdown state. A startup failure (SF) must start at the time the previous full outage (PO, MO, SE, SF, U1, U2, U3) or reserve shutdown (RS) ends.
- U1 - Unplanned Outage (Immediate) - This is an outage that requires immediate removal of a unit from service such as immediate mechanical/electrical/hydraulic control system trips and immediate operator initiated trips/shutdowns in response to unit alarms.
- U2 - Unplanned Outage (Delayed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service within six hours.

- U3 - Unplanned Outage (Postponed) - This is an outage which does not require immediate removal of a unit from service but requires the unit be removed from service before the end of the next weekend.
- PD - Planned Derating - A derating that is scheduled well in advance and is of a predetermined duration. The actual start date of a planned deration (PD) is flexible, since it usually coincides with periods of low peak or seasonal demand.
- D1 - Unplanned Derating (Immediate) - A derating that requires an immediate capacity reduction.
- D2 - Unplanned Derating (Delayed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction within six hours.
- D3 - Unplanned Derating (Postponed) - A derating which does not require an immediate capacity reduction but which requires a capacity reduction before the end of the next weekend.
- D4 - Unplanned Derating (Deferred) - A derating which can be deferred beyond the the end of the next weekend, but requires a capacity reduction before the next planned outage (PO). These deratings have flexible start dates and have a predetermined duration established at the start of these outages. This derating is also known as a maintenance derating.
- DE - Derating Extension - This is the extension of a planned derating (PD) or maintenance derating (D4) beyond its originally estimated completion date, such as being established at the start of these outages.

Exhibit E
to Amendment No. 009

Facility Heat Rate Multiplier

<u>MW to Purchaser</u>	<u>Heat Rate in Btu/kWh</u>	<u>Facility Heat Rate Multiplier</u>
200 or greater (Full Load)	10,145	1.0000
175-199.999	10,349	1.0201
150-174.999	10,464	1.0315
125-149.999	10,704	1.0551
100-124.999	11,282	1.1120
75-99.999	12,409	1.2232
50-74.999	14,299	1.4095
N.A.		N.A.

Seller shall provide to Purchaser in writing heat rate testing procedures, which procedures shall include test points at 50, 75, 100, 125, 150, 175 and 200 MW, two weeks' notice to Purchaser prior to any such test, and shall extend to Purchaser the right to observe all tests. Purchaser shall also have right to request retest, with cost of retest divided equally between Seller and Purchaser. The results of any test (or, if applicable, retest) shall govern unless taken to arbitration under Article 17.

arbitration result:
new heat rate test
will adjust HR
+ ratios (multiplier)

Exhibit F
to Amendment No. 009

Seller and Purchaser agree that the substance of certain of the amendments to the Senior Loan Agreement referred to in Section 9(a) of this Amendment will be to provide the Seller with (i) the ability to terminate one or more of the Interest Rate Protection Agreements, (ii) the preservation of the multiple interest rate option floating rate credit facility set forth therein, (iii) the right to enter into other interest rate protection agreements (the items referred to in clauses (i), (ii) and (iii) of this sentence, along with the interest rate election provisions contained in the Bond Documents, being referred to as the "IRMA"). Subject to the execution of an amendment to the Senior Loan Agreement to the effect referred to above, Purchaser shall be entitled to direct the Seller, subject to the provisions of the Senior Loan Agreement, as amended, and the Bond Documents, to elect the interest rates applicable to Seller's permanent and construction debt financing as set forth in the IRMA. To the extent provided in the Senior Loan Agreement, as amended, the interest rate election options therein as available under IRMA shall be subject to confirmation by the Senior Banks of the availability of the interest rate mode and term elected, including but not limited to, sufficient credit capacity among the Senior Banks to enter into any subsequent or additional interest rate protection agreements. In the event such options elected by the Purchaser are not so confirmed by the Senior Banks, in their sole discretion, then the interest rate mode will be elected by Purchaser from among those otherwise available to Seller under the Senior Loan Agreement, as amended, and the Bond Documents. Seller and Purchaser further agree and acknowledge that the IRMA shall apply, without limitation, to the entirety of Seller's construction financing as described in the Information furnished pursuant to Section 10(k) of this Amendment, but excluding the amount, if any, of the difference described in the first sentence of the third paragraph of Exhibit B. In addition, the parties acknowledge that, under certain circumstances, the tax-exempt portion of Seller's Facility's permanent debt financing may become subject to repayment prior to scheduled maturity, and that such repayment may be made with the proceeds of taxable refunding loans provided under the terms of the Senior Loan Agreement as amended; provided, however, that if said repayment is at the discretion of the Seller, such repayment shall only proceed with the consent of the Purchaser. In addition, the Purchaser and Seller agree to negotiate diligently and in good faith to establish in writing further procedures governing the implementation and operation of the IRMA.

Exhibit G
to Amendment No. 009

INFORMATION

1) Construction Period

Drawdown Amounts		SENIOR LOAN		TAX-EXEMPT LOAN		WORKING CAPITAL LOAN		
As Of Monthly Date	Drawdown Amount	Outstanding Balance	Drawdown Amount	Outstanding Balance	Drawdown Amount	Outstanding Balance	Total	
12/31/93	\$	\$ *	\$	\$	\$	\$		
1/31/94								
2/28/94								
3/31/94								
4/30/94								
5/31/94								
6/30/94								
7/30/94								
8/31/94								
9/30/94								
10/31/94								
11/30/94								
12/31/94								
1/31/95								
2/28/95								
3/31/95								
Total Construction Period	-----		-----		-----			
Amount to be Repaid at Conversion	-----		-----		-----			
Total Operating Period	-----		-----		-----		\$440,000,000	

*After assumed payment in full of Subordinated Debt

**AMENDMENT NO. 010 TO AGREEMENT FOR PURCHASE OF ELECTRIC
POWER BETWEEN ATLANTIC CITY ELECTRIC COMPANY, AS PURCHASER,
AND KEYSTONE ENERGY SERVICE COMPANY, L.P., ASSIGNEE OF
KEYSTONE COGENERATION SYSTEMS, INC., AS SELLER**

This Amendment (hereinafter referred to as the "Amendment") is entered into as of this 24th day of July, 1993, by and between ATLANTIC CITY ELECTRIC COMPANY, having offices at 6801 Black Horse Pike, Pleasantville, New Jersey 08232 (hereinafter referred to as "Purchaser"), and KEYSTONE ENERGY SERVICE COMPANY, L.P., having offices at 7475 Wisconsin Avenue, Bethesda, Maryland 20814-3422 (hereinafter referred to as "Seller").

WHEREAS, Purchaser and Keystone Cogeneration Systems, Inc. ("KCSI") have previously entered into a certain Agreement for Purchase of Electric Power, dated as of August 25, 1988, and amended pursuant to amendments dated as of November 22, 1988, December 19, 1988, November 3, 1989, March 28, 1990, January 24, 1991, April 5, 1991, September 24, 1991, February 6, 1992 and June 9, 1993 (the latter amendment having been entered into by Purchaser and Seller) (the "Agreement"), and as clarified through a letter, dated as of March 31, 1992, from Purchaser to KCSI, and a letter, dated as of April 14, 1992, from Purchaser to Seller; and

WHEREAS, pursuant to the Assignment and Assumption Agreement, dated as of April 1, 1992, between KCSI and Seller, KCSI assigned to Seller, and Seller assumed from KCSI, all of KCSI's rights and obligations arising under the Agreement, which assignment and assumption was made in accordance with Section 18.10 of the Agreement; and

WHEREAS, in connection with the obtaining of the regulatory approvals required as a precondition to the effectiveness of Amendment No. 009 to the Agreement, Purchaser and Seller further wish to amend the Agreement, all as more particularly described in this Amendment, the effectiveness of which is subject to and conditioned upon the occurrence of certain events described herein.

NOW, THEREFORE, in consideration of the mutual promises, covenants and conditions contained herein, Purchaser and Seller agree as follows:

1. Definitions. Except as otherwise provided in this Amendment, all terms shall have the same meaning as set forth in the Agreement.

2. Modification of Amendment No. 009.

(a) The introductory sentence of Article 5.1D of the Agreement shall be deleted in its entirety, and the following new language shall be inserted in place thereof.

"D. On and after the Date of Commercial Operation, except as otherwise contemplated by Article 3.3B hereof and Section 10(e) of Amendment No. 009 to the Agreement, the pricing structure hereunder shall be based on the following formulas:"

(b) Section 10(d) of Amendment No. 009 to the Agreement shall be deleted in its entirety.

3. Conditions to the Effectiveness of this Amendment.

Purchaser and Seller agree that this Amendment shall not become effective until and unless:

(a) Amendment No. 009 to the Agreement shall have become effective in accordance with its terms.

(b) The Board shall have issued an order approving this Amendment and the consummation of the transactions contemplated hereby requiring its approval. Such order shall be subject only to such substantive conditions or limitations as are acceptable to Purchaser and Seller in the sole discretion of each of them, the parties' acceptance of which shall be evidenced by a writing to that effect executed by each of them not later than twenty (20) days after the issuance of such order by the Board. Such order, as accepted in writing by the parties, shall have become final and non-appealable on or prior to December 31, 1993 unless an extension is agreeable to both parties.

(c) Seller and Purchaser shall have obtained all other consents or approvals, including, without limitation, third party consents or approvals, that are necessary for the effectuation of this Amendment.

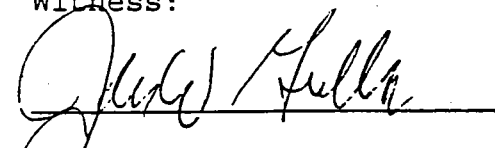
4. Miscellaneous. This Amendment, together with the Agreement and the other agreements and instruments expressly referred to herein or therein, constitutes the parties' entire agreement with respect to the subject matter hereof and thereof, and supersedes any and all prior oral or written agreements or understandings between the parties with respect thereto. Except as modified in this Amendment, all other terms and conditions contained in the Agreement, as amended, shall remain in full force and effect.

5. Governing Law. This Amendment No. 010 shall be governed by and construed in accordance with the laws of the State of New Jersey as set forth in the Agreement.


6. Further Assurances. Seller and Purchaser agree that they will execute and deliver such further instruments and do such further acts as may reasonably be necessary or convenient to carry out the purposes of this Amendment.

IN WITNESS WHEREOF, each of the undersigned has caused this Amendment to be executed by its duly authorized official as of the day and year first above written.

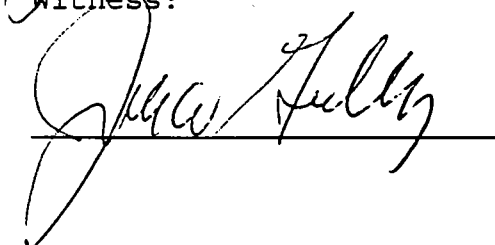
Witness:



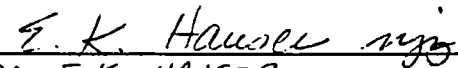
ATLANTIC CITY ELECTRIC COMPANY

By: 
Name: JOSEPH A. ISABELLA
Title: MGR BULK POWER PLANNING & MARKETING

Witness:



KEYSTONE ENERGY SERVICE
COMPANY, L.P.

By: 
Name: E.K. HAUSER
Title: AUTHORIZED AGENT

19096 I-COR

Exhibit D

Logan PSA, Dated December 18, 2012,
as Renewed Annually



A PHI Company

December 18, 2012

Logan Generating Company, L. P.
c/o Power Plant Management Services, LLC
1 Collins Ave., Suite 100
Carneys Point, NJ 08069

Attention: Steven DiCarlo

RE: January 1, 2013 – December 31, 2013 Power Sales Agreement

Dear Sir:

This letter constitutes a Power Sales Agreement ("PSA") between Logan Generating Company, L.P. ("LOGAN") a Delaware limited partnership, and Atlantic City Electric Company ("Atlantic"), a New Jersey corporation (LOGAN and Atlantic collectively to be referred to as the "Parties"), pursuant to which Atlantic shall purchase excess energy and capacity from LOGAN in accordance with the terms and conditions set forth herein. Atlantic and LOGAN are parties to the Agreement for Purchase of Electric Power, dated August 25, 1988, as amended (the "PPA").

1. Definitions.

- A. "Excess Installed Capacity" shall mean any Installed Capacity in excess of 203 MW from the Logan Generating Plant ("the Facility".)
- B. "Excess Energy" shall mean the on-peak and off-peak energy above 203 MWh.
- C. "Day-Ahead LMP" shall mean the net hourly integrated PJM Interchange price calculated by PJM for cleared day-ahead generation offers, demand bids, decrements bids and energy transactions.
- D. "Real-Time LMP" shall mean the net hourly integrated PJM Interchange price calculated by PJM for real-time energy transactions, load and generation and metered tie flows.
- E. "Operating Reserve Charges" shall mean the difference between the PJM daily balancing Operating Reserves charges for the Logan Generating Plant between the day-ahead and real-time markets.

- F. "PPA Incremental Rate" means the calculated rate used to dispatch the Facility from minimum load to full load in accordance with the PPA.
- G. "PJM" shall mean the PJM Interconnection, LLC.
- H. "Escalation Factor" shall mean the Consumer Price Index of the Bureau of Labor Statistics, United States Department of Labor for the Metropolitan Philadelphia/New Jersey area for the October preceding the contract year divided by the indice for June 2003.
- I. "Market Support Charge" shall have the meaning as defined in the PJM Open Access Transmission Tariff Billing. The charge is fixed at \$0.0640/MWh for 2004.
- J. "Transitional Market Expansion Charge" shall have the meaning as defined in the PJM Open Access Transmission Tariff Billing. The charge is fixed at \$0.0070/MWh for 2004 and is target to end December 31, 2004.
- K. "Expansion Integration Charge" shall have the meaning as defined in the PJM Open Access Transmission Tariff Billing. The charge is fixed at \$0.0134/MWh for 2004 and is target to end November 30, 2004.

2. Contract Term.

The Term of this PSA shall commence at hour ending 0100 on January 1, 2013 and continue through hour ending 2400 on December 31, 2013. This PSA shall automatically renew for additional 12 month periods indefinitely unless terminated by either party by written notice 30 days prior to the end of any contract year.

3. Dispatch Commitment.

Logan commits that it will ramp the facility to 211 MWs when dispatched by Atlantic to full load under the PPA. Furthermore, if Logan's output is above 203 MWs and Atlantic dispatches the Facility down, the allowed time for ramp down as specified in the PPA shall assume that Logan is at a starting point of 203 MWs regardless of the level of output of the Facility above 203 MWs. All MWs above 211 will be dispatched at Logan's discretion.

4. Delivery Point.

Excess Energy shall be delivered and title to the Energy shall pass at the Bridgeport 230 kV bus.

5. Bidding Obligation

Atlantic will use commercially reasonable efforts to bid in the Excess Energy at the PPA dispatch price for a MW amount specified by Logan. Atlantic provides no warranty to LOGAN that this will result in the most economical outcome for LOGAN.

6. Contract Price and Fees.

Atlantic shall pay to Logan, on a monthly basis, the Contract Price for Excess Energy and Excess Capacity as set forth in Articles 6(A) and 6(C) below:

A. Excess Energy: The MWh purchased and sold under this PSA shall be priced based on the PJM two-settlement system using Day-Ahead and Real-Time LMPs at the Bridgeport 230 kV bus as Logan generation is scheduled and dispatched by PJM, Day Ahead and Real Time quantities, and all applicable reconciliation of price and quantity consistent with PJM practices. Price is determined as follows:

1. During hours when PJM prices the output of all or a portion of the Excess Energy for the applicable Bridgeport 230 kV bus using the Day-Ahead Locational Marginal Pricing ("LMP") and that LMP is above the PPA Incremental Rate:

- (a) For each MWh priced by PJM using the Day-Ahead LMP of Excess Energy:

$$[(\text{BRIDGEPORT Bus DA LMP} - \text{PPA Incremental Rate}) * 0.90] + \text{PPA Incremental Rate.}$$

2. During hours when PJM prices the output of all or a portion of the Excess Energy for the applicable Bridgeport 230 kV bus using the Real-Time Locational Marginal Pricing ("LMP") and that LMP is above the PPA Incremental Rate:

- (a) For each MWh priced by PJM using the Real-Time LMP of Excess Energy:

$$[(\text{BRIDGEPORT Bus RT LMP} - \text{PPA Incremental Rate}) * 0.90] + \text{PPA Incremental Rate.}$$

3. All reconciliations of quantities and prices applied by PJM under its two settlement system and applicable to the computations of the amounts set forth in subsections 6 A.1.a and 6 A.2.a shall be correspondingly applied by Atlantic.
4. During the hours when the applicable Bridgeport 230 kV bus LMP is below the PPA Incremental rate, Atlantic will pay Logan 100% of the applicable Bridgeport LMP.
5. In addition to any charges under the PPA, LOGAN shall pay to Atlantic an administrative fee equal to \$8,150 per month for each month during the Term. If the PSA is automatically renewed for an additional 12 months pursuant to Section 2 of this PSA, then the monthly administrative fee shall be escalated annually using the Escalation Factor.
6. Logan recognizes that PJM charges Atlantic for all Operating Reserve Charges for generation deviation based on the total output of the Facility. Logan agrees that Atlantic shall determine, based on good faith and its best understanding of the

PJM rules as defined in the PJM Open Access Transmission Tariff and other PJM official documents, any such deviations attributable to the Excess Energy and dispatch of the Facility. Logan shall pay Atlantic for Operating Reserve Charges for generation deviations attributable to the Facility based on this determination. In addition, LOGAN shall pay Atlantic for any costs incurred by Atlantic as a result of settlement during hours when the Excess Energy has been accepted for operation in the day-ahead market and the Facility fails to operate as accepted.

7. Logan agrees to reimburse Atlantic 90% of the following generation charges as imposed by PJM on all MWh's sold under this agreement:
 - a. Market Support Charge
 - b. Transitional Market Expansion Charge
 - c. Expansion Integration Charge

Atlantic shall deduct the aforementioned charges from each monthly payment to Logan made pursuant to Section 10 of this agreement.

B. Maximum Generation Emergency:

During any Maximum Generation Emergency as declared under Section 3.3C of the PPA by PJM, Logan shall sell no Excess Energy to Atlantic under this PSA.

C. Excess Installed Capacity:

The Excess Installed Capacity quantity shall be measured in Unforced Capacity Credits in excess of 203 MWs ("Excess UCCs"), to the degree that such UCCs are available from the Facility. UCCs shall be calculated for each of the three interval periods identified in the PJM guidelines (Jan-May, Jun-Sep and Oct-Dec) using historical Equivalent Forced Outage Rate data (EFORd) for the plant according to the rules outlined in the pertinent PJM guidelines. Equivalent Unforced Capacity will be rounded to the nearest 1/10th of a megawatt.

- Logan will provide advance written notice to Atlantic, Atlantic will offer Excess UCCs into PJM's seasonal, monthly or daily auctions at the price and periods requested by LOGAN. LOGAN shall be responsible for determining when and how Excess UCCs shall be bid into PJM's markets and Atlantic shall be responsible solely for bidding into PJM. Atlantic shall not be liable for costs incurred, or opportunities lost, by LOGAN due to LOGAN'S failure to provide timely notice.
- Atlantic will pass through to LOGAN the revenue received from PJM associated with the aforementioned auction settlements.
- In the event, that for any period of time, Atlantic and LOGAN both sell some UCCs at the same clearing price each Party will receive a pro rata (based on UCCs sold) share of the revenue received by Atlantic from PJM.

- LOGAN is responsible for all replacement capacity cost charges, either penalty payments, including but not limited to PJM's peak hour availability charge, or positive incremental capacity market price differences, related to the sale of Excess Capacity.
7. Contract Firmness. Atlantic will only pay for energy delivered. Except to the extent provided in Section 6.A.6 above, LOGAN shall not be liable for any damages to Atlantic for failure to deliver Excess Energy or Excess Installed Capacity under this PSA.
 8. Operating Procedures. Atlantic and LOGAN shall mutually develop written Operating Procedures prior to the commencement of the Term. Such Operating Procedures shall include, but not be limited to, method of day-to-day communications, designation of Authorized Representatives pursuant to Section 13, and any other key personnel lists for LOGAN and Atlantic.
 9. Control Area Services. Atlantic shall be responsible for control area services as are necessary or appropriate to effect the transaction agreed to hereunder.
 10. Prior Power Sales Agreements. Atlantic acknowledges and agrees that Logan's supply of Excess Energy and Excess Installed Capacity under this PSA shall be subordinate to its supply of energy and capacity under the PPA. Without limiting the foregoing, and for the Term of this PSA, and only for that time, LOGAN and Atlantic agree that the Excess Energy and Excess Installed Capacity that the Facility supplies under this PSA shall not be considered to be within the definition of the "Dispatchable" capacity and associated energy that the Facility supplies under the PPA. In the event that LOGAN enters into any subsequent excess power sales agreement during the Term of this PSA, such excess power sales agreement shall be subordinate to this PSA.
 11. Billing and Payment.
 - (a) This PSA shall be accounted for on the basis of actual hourly quantities. The accounting period shall be one calendar month. The Parties' scheduling representatives shall maintain records of hourly schedules for accounting and operating purposes.
 - (b) Atlantic shall provide PJM market and billing data to Logan as necessary in an electronic format to validate PSA billing on a monthly basis. Such data shall include day-ahead accepted MWhs and pricing, real time MWhs and pricing, and relevant operating reserve charge data for the Logan facility.
 - (c) Atlantic will provide hourly dispatch records/meter readings in electronic format to LOGAN and submit payment simultaneously to LOGAN no later than the last business day of the calendar month following the delivery of Energy. Payments shall be made by electronic wire transfer to LOGAN at the address set forth in Section 11(g).

(d) Amounts not paid on or before the due date shall be payable with interest accrued daily at the prime rate of interest per annum established by Citibank, N.A., or its successor, on the last business day of the month in which service was rendered, plus one and one half percent per annum, but in no event greater than the maximum interest rate permitted by law.

(e) In the event any portion of any payment is in dispute, the undisputed portion shall be paid in full and such disputes shall first be discussed and both Parties agree to use commercially reasonable efforts to amicably and promptly resolve the dispute. In the event the Parties are unable to do so, the dispute resolution procedures set forth in Section 12 shall apply. Upon determination of the correct payment amount, the proper adjustment shall be paid or refunded promptly, or as agreed upon, after such determination with interest accrued in accordance with Section 11(d) and computed from the date payment was due to the date the adjustment is made.

(f) All billings, if any, to Atlantic shall be sent via US Mail to:

Atlantic City Electric Company
c/o New Castle Regional Office
Mailstop 79NC82
P. O. Box 9239
Newark, DE 19714-9239
Attn: Jane M. Juhnden

(g) All payments to LOGAN shall be wire transferred to:

Citibank, N. A.
Corp. Trust Admin., Attention: Sandy Cruz
ABA Number: 021-000-089
Account Number: 3611-4317

Refer the credit to Account #102322-NJEDA/Keystone Operating Account

12. Dispute Resolution. Any dispute or need of interpretation arising out of this PSA shall be submitted to binding arbitration by one arbitrator qualified by education, experience or training to render a decision upon the issues in dispute and who has not previously been employed by either LOGAN or Atlantic (or its predecessors), and does not have a direct or indirect interest in either Party or the subject matter of the arbitration. Such arbitrator shall either be mutually agreed to by the Parties within thirty days after written notice from either Party requesting arbitration, or failing agreement, the arbitration shall be conducted by a panel of three arbitrators having the qualifications set forth in the preceding sentence, one to be selected by each Party and the third arbitrator to be selected

by the two arbitrators selected by the Parties. If either Party fails to notify the other Party of the arbitrator selected by it within ten days after receiving a notice of the other Party's arbitrator, or if the two arbitrators selected fail to select a third arbitrator within 10 days after notice is given of the selection of the second arbitrator, then such arbitrator shall be selected under the expedited rules of the American Arbitration Association (the "AAA"). Each Party shall divide equally the cost of the arbitration, and each shall be responsible for its own expenses and those of its counsel or other representation. The commercial arbitration rules of the AAA shall apply to the extent not inconsistent with the rules specified above. Arbitration shall be conducted within 75 miles of Newark, Delaware.

13. Authorized Representative. Each Party shall designate in writing one or more Authorized Representative(s) who shall be authorized to act on its behalf with respect to matters contained herein which are the functions and responsibilities of the Authorized Representatives. Prior to the commencement of the Contract Term, each Party shall give written notice to the other Party of its designation, and shall promptly notify the other Party in writing of any subsequent changes in such designation. The Authorized Representatives shall have no authority to modify any of the provisions of this PSA except by written amendment, which shall be executed by the Parties hereto.
14. Notices. All written notices under this PSA shall be deemed properly sent if delivered in person or sent by facsimile, registered, certified mail, or a guaranteed overnight delivery service such as Federal Express, postage prepaid to the persons specified below:

If to Atlantic:

Atlantic City Electric Company
c/o New Castle Regional Office
Mailstop 79NC82
P. O. Box 9239
Newark, DE 19714-9239
Attn: Jane M. Juhden
Phone: (302) 283-5874
Fax: (302) 283-6090

With a copy to:

Atlantic City Electric Company
150 W. State Street
Suite 5
Trenton, NJ 08608-1105
Attn: Philip J. Passanante, Esq., Associate General Counsel -
Phone: (302) 429-3105
Fax: (302) 429-3801

If to LOGAN:

Logan Generating Company, L. P.
c/o Power Plant Management Services, LLC
1 Collins Ave., Suite 100

Carneys Point, NJ 08069
Attention: Steven DiCarlo
Phone: (856) 376-2344
Fax: (856) 299-8058

With a copy to:

Logan Generating Company, L. P.
c/o Power Plant Management Services, LLC
10710 Sikes Place, Suite 300
Charlotte, NC 28277
Phone: (704) 815-8000
Fax: (704) 815-8080

15. Necessary Authorization. Each Party represents that it has the necessary corporate and/or legal authority to enter into this PSA and to perform each and every duty and obligation imposed by this PSA, and that this PSA, when executed by the duly Authorized Representatives of each Party in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally or by equitable principles.
16. Limitations of Liability. Neither Party nor any of their respective partners or their affiliates nor any of their officers, directors, agents, subcontractors, vendors or employees shall be liable to the other for any incidental, consequential, punitive or other special damages for nonperformance of its obligations hereunder.
17. Uncontrollable Forces. Neither Party shall be considered to be in default in the performance of any obligations under this PSA (other than obligations of a Party to pay amounts due hereunder) when a failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" shall be physical causes of the kind hereafter listed which are beyond the control of the Party affected: flood, earthquake, tornado, storm, fire, civil disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order or public authority (whether valid or invalid), and action or non-action by or inability to obtain or keep the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome. No Party shall, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or due to removable or remediable causes which it fails to remove or remedy within a reasonable time period. Either Party rendered unable to fulfill any of its obligations under this PSA by reason of Uncontrollable Force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.
18. Assignment. Neither Party shall assign this PSA or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. This PSA shall inure to and be binding upon the successors and permitted

assignees of the Parties. Notwithstanding the foregoing, either Party may, without the consent from the other Party (and without relieving itself from liability hereunder), transfer or assign this PSA to an affiliate of such Party; provided, however, that any such assignee shall agree to be bound by the terms and conditions hereof. In addition, LOGAN may collaterally assign this PSA to any financial institution extending it credit.

19. Taxes.

(a) Each Party shall pay those sales, use, excise, gross receipts, *ad valorem*, income, and any other taxes imposed or levied by the state or any governmental agency applicable to it in connection with this PSA.

(b) Administration. Each Party shall each use reasonable efforts to implement the provisions of and to administer this PSA in accordance with its intent to minimize taxes, so long as neither Party is materially adversely affected by such efforts. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if either Party is exempt from taxes, and shall use reasonable efforts to obtain and cooperate with obtaining any exemption from or reduction of tax. Either Party with knowledge of a tax that may be applicable to the transaction contemplated by this PSA shall notify the other Party of the applicability of such tax and shall also notify the other Party of any proposal to implement a new tax or apply an existing tax to any Transaction.

20. CHOICE OF LAWS. THIS PSA SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF NEW JERSEY.

21. Other Agreements. This PSA constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. Notwithstanding the foregoing Atlantic and LOGAN expressly acknowledge and agree that terms and conditions of the Enabling Agreement between the parties dated April 11, 1995 shall be superseded by this PSA with respect to the subject matter herein, but that the Enabling Agreement shall remain in place for all other purposes.

22. Binding Effect. The terms and provisions of this PSA, and the respective rights and obligations hereunder of each Party, shall be binding upon, and inure to the benefit of, its successors and assigns.

23. Non-Waiver of Defaults. No waiver by either Party of any default of the other Party under this PSA shall operate as a waiver of a future default whether of a like or different character.

24. Written Amendments. No modification of the terms and provisions of this PSA shall be or become effective except by written amendment executed by the Parties hereto.

25. Severability and Renegotiation. Should any provisions of this PSA for any reason be declared invalid or unenforceable by final and non appealable order of any court or

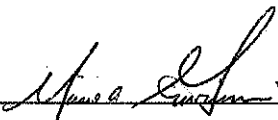
regulatory body having jurisdiction, such decision shall not affect the validity of the remaining portions, and the remaining portions shall remain in force and effect as if this PSA had been executed without the invalid portion. In the event any provision of this PSA is declared invalid, the Parties shall promptly renegotiate to restore this PSA as near as possible to its original intent and effect.

26. Headings. The headings used herein are for convenience only and shall not affect the meaning or interpretation of the provisions of this PSA. Any terms not defined herein shall have the meaning ordinarily and customarily assigned to them in connection with transactions occurring in PJM as of the execution date of this PSA.
27. Survival. Any provision(s) of this PSA that expressly or by implication comes into or remains in force following the termination or expiration of this PSA shall survive the termination or expiration of this PSA.
28. Termination of Agreement. Both parties agree to early termination of this Agreement under the following conditions.
- A. Should the owners of Logan and Atlantic agree to restructure or terminate the underlying PPA, then this Agreement will become invalid after 30 days of such termination.
- B. If the FERC or New Jersey BPU modify their current policies or regulations such that the terms of the Agreement would be economically prohibitive for either party due to such changes in policies or regulations, then the party claiming such economic harm may terminate this Agreement with 30 days written notice to the other party. In the event the non-terminating party disputes the economic harm alleged by the terminating party, the dispute shall be resolved as provided in Section 12 above.

If the foregoing terms are acceptable to Atlantic, please sign and return one copy of this PSA. The remaining copy is for your files.

Sincerely,

ATLANTIC CITY ELECTRIC COMPANY

By:  _____

Name: Mario A. Giovannini

Title: Director Supply Customer Energy

ACCEPTED AND AGREED TO as of this
1st day of January, 2013

LOGAN GENERATING COMPANY, L. P.

By: 

Name: **Robert D. Franson**
Title: **Vice President**

Exhibit E

Summary of Chambers PPA
and PSA Contract Terms

Chambers PPA

- **Unit Availability Factor**

Ratio of Seller's Facility's availability to Purchaser's system's availability based on a contract year calculation of "Availability", as defined in Exhibit I.

- **Entitlement Payment**

Seller shall be entitled to payment for the equivalent of 3500 hours of operation per year times the net deliverable capacity multiplied by the on and off-peak energy rates.

- **Force Majeure**

The term "force majeure" shall mean any cause beyond the control of the party affected, including, but not limited to, failure of facilities due to drought, flood, earthquake, storm, fire, lighting, epidemic, war, riot, civil disturbance, sabotage, strike or labor difficulty, accident or curtailment of supply, unavailability of construction materials or replacement requirement beyond the affected party's control, forced outage, inability to obtain and maintain rights-of-way, permits, licenses, and other required authorizations from any local, state or federal agency or person for any of the facilities or equipment necessary to provide service hereunder, and restraint by court.

- **Outages**

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage.¹

- **Contract Termination Rights (Article 13)**

Determination of Breach. A breach of this Agreement shall be deemed to exist if:

- a. Either party fails to make payment of any amounts due the other party under this Agreement, which failure continues for a period of thirty (30) days after notice of such non-payment.
- b. Either party fails to substantially comply with any other material provision of this Agreement, which failure continues for a period of thirty (30) days after notice of such non-performance unless the non-performing party has commenced to cure such non-performance within the thirty (30) day notice period and is thereafter diligently pursuing such efforts.
- c. Seller fails to deliver any Net Plant Output for more than one hundred twenty (120) consecutive days, or more than one hundred eighty (180) days in any three hundred sixty-five (365) day period, subsequent to the Date of Commercial Operation, not including any days attributable to any Forced Outage, any Scheduled Maintenance or Purchaser's actions under Article 3.4
- d. Seller sells any Net Deliverable Capacity agreed to be sold under this Agreement to any party other than Purchaser except as provided in Article 3.6

¹ Outage descriptions defined in Exhibit B to Amendment I

- e. The Date of Commercial Operation does not occur on or before October 1, 1995
- f. By order of a court of competent jurisdiction, a receiver or liquidator or trustee of either party or of a substantial part of the assets of either party shall be appointed, and such receiver or liquidator or trustee shall not have been discharged within a period of sixty (60) days.
- g. If either party shall file a voluntary petition in bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law.

Chambers PSA

- **Contract Term**

This PSA shall commence at hour ending 0100 on January 1, 2021 and continue through hour ending 2400 on December 31, 2021 (referred to herein as the “Term”).

- **Relationship of this PSA to the PPA²**

- This PSA shall be expressly subordinate to the PPA and the rights and obligations of the Parties under the PPA shall not be affected by this PSA, except as noted in Section 4.
- The Parties acknowledge and agree that Atlantic will be purchasing Energy and Excess Capacity for sale under this PSA from the Facility. They also acknowledge and agree that CCLP’s dispatch of the Facility under this PSA and 7 all terms and conditions of this PSA shall be subordinate to Atlantic’s dispatch of the Facility under the PPA and all of the terms and conditions of the PPA.
- During any hour for which Maximum Emergency Generation has been called on line (as declared by PJM, in accordance with the PJM Operating Agreement), CCLP will sell no Energy to Atlantic under this PSA.
- Nothing in this Agreement shall be construed as an admission of any right or obligation by any party to the PPA with respect to Excess Energy and Excess Capacity.

- **Force Majeure³**

Uncontrollable Forces. Neither Party shall be considered to be in default in the performance of any obligations under this PSA (other than obligations of a Party to pay amounts due hereunder) when a failure of performance shall be due to an Uncontrollable Force. The term “Uncontrollable Force” shall be physical causes of the kind hereafter listed which are beyond the control of the Party affected: flood, earthquake, tornado, storm, fire, civil disobedience, labor dispute, labor or material shortage, acts of sabotage or terrorism, restraint by court order or public authority (whether valid or invalid), and action or non-action by or inability to obtain or keep the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome. No Party shall, however, be relieved of liability for failure of performance if such failure is due to causes arising out of its own negligence or due to removable or remediable causes which it fails to remove or remedy within a reasonable time period. Either Party rendered unable to fulfill any of its obligations

² PSA Section 9

³ PSA Section 16

under this PSA by reason of Uncontrollable Force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

○ **Contract Termination Rights⁴**

Both parties agree to early termination of this Agreement under the following conditions. 12

A. Should CCLP and Atlantic agree to terminate the underlying PPA, then this Agreement will automatically terminate without a need for notice upon the effectiveness of the termination of the PPA.

B. If the FERC or the New Jersey Board of Public Utilities (or their successor agencies) modify their current policies or regulations such that the terms of this Agreement would be economically prohibitive for either party due to such changes in policies or regulations, then the party claiming such economic harm may terminate this Agreement with thirty (30) days written notice to the other. In the event the non-terminating party disputes the economic harm alleged by the terminating party, the dispute shall be resolved as provided in Section 11 above.

⁴ PSA Section 28

Exhibit F

Summary of Logan PPA and
PSA Contract Terms

Logan PPA

- **Unit availability**

"Availability Factor" shall mean the ratio of (i) the Equivalent Availability Factor of Seller's Facility based on a Contract Year calculation of availability, calculated as of the end of each Contract Year.

The Availability Factor shall be deemed to equal 1.0 during the first Contract Year for purposes of monthly billing. Notwithstanding the foregoing, the Availability Factor shall be deemed to equal 1.0 when the Equivalent Availability Factor of Seller's Facility equals or exceeds eighty-three percent (83%).

¹

- **EAF Incentive**

The EAF Incentive shall be an annual incentive calculated pursuant to the table set forth below and shall be payable monthly on an estimated basis during each Contract Year and subject to reconciliation at the end of each Contract Year on the basis of actual Contract Year measurements. ² **ACE pays \$125K /Month to Logan. (\$1.5M total/Year)**

<u>Equivalent Availability Factor of Seller's Facility</u>	<u>Annual Availability Incentive</u>
Less than 83%	\$0 (adjustment to Capacity Payment as provided in Article 5.1D(i))
Less than or equal to 85%	\$0
Greater than 85% but not more than 87%	\$500,000
Greater than 87%	\$1,000,000

- **Dispatch Incentive**

The Dispatch Incentive shall be an annual incentive, payable monthly on an estimated basis and subject to reconciliation at the end of each Contract Year on the basis of actual measurements of the running of Seller's Facility. ³ **Logan has not been dispatched greater than 1,000 GWh/Year since 2010.**

- **Force Majeure**

Either party shall be excused from performance and shall not be considered to be in default in respect to any obligation or condition hereunder, if failure of performance shall be due to an event of force majeure. The term "force majeure" shall mean any cause beyond the control of the party affected, including, but not limited to, failure of facilities due to drought, flood, perils of the sea, earthquake, storm, fire, lightening, epidemic, other acts of God, war, riot, civil disturbance, sabotage, strike or labor difficulty, accident or curtailment of supply, unavailability of construction materials or replacement

¹ Exhibit D to Amendment 9

² Exhibit C to Amendment 9

³ Exhibit C to Amendment 9

equipment beyond the affected party's control, Forced Outage, inability to finance the Facility at then available commercial rates, impossibility to obtain insurance or only to obtain at a cost that is unreasonably high in relation to the risk insured against, inability to obtain and maintain easements, rights-of-way, permits, licenses, and other required authorizations from any local, state, or federal agency or person for any of the facilities or equipment necessary to provide service hereunder, and restraint by court or other public authority having jurisdiction over the matter.

The suspension of performance shall be of no greater scope and no longer duration than is required. The excused party shall use its reasonable best efforts to remedy its inability to perform.

No obligations of either party which arose before the occurrence of an event of force majeure causing the suspension of performance shall be excused as a result of such occurrence.⁴

○ **Outages**

An outage must be taken whenever a unit is not capable of meeting its maximum net dependable capacity. All outages have capacity reductions associated with them: when there is no capacity available (full capacity reduction) it is considered a full outage; when a portion of capacity is unavailable (partial capacity reduction) it is considered a partial outage.⁵

○ **Contract Termination Rights (Article 13)**

- A. If either party claims that the other party has breached this Agreement, as defined in Article 13.1, the non-breaching party may terminate this Agreement by giving written notice of such breach and intention to terminate to the other party, which termination shall be no earlier than the thirtieth (30th) day following the date of said notice whereupon the terminating party shall be excused and relieved of all obligations and liabilities under this Agreement, except those liabilities incurred before the effective of termination.
- B. Both parties shall have the obligation and shall use best efforts to mitigate any such damages.
- C. Determination of Breach. A breach of this Agreement shall be deemed to exist if:
 - a. Either party fails to make payment of any amounts due the other party under this Agreement, which failure continues for a period of thirty (30) days after notice of such non-payment.
 - b. Either party fails to substantially comply with any other material provision of this Agreement, which failure continues for a period of thirty (30) days after notice of such non-performance unless the non-performing party has commenced to cure such non-performance within the thirty (30) day notice period and is thereafter diligently pursuing such efforts.
 - c. Seller fails to deliver any Net Plant Output for more than one hundred twenty (120) consecutive days, or more than one hundred eighty (180) days in any three hundred sixty-five (365) day period, subsequent to the Date of Commercial Operation, not including any days attributable to any Forced Outage, any Scheduled Maintenance or Purchaser's actions under Article 3.4

⁴ PPA Section 15

⁵ Outage details defined in Exhibit D to Amendment 9

- d. Seller sells any Net Deliverable Capacity agreed to be sold under this Agreement to any party other than Purchaser and its permitted successors and assigns, unless otherwise permitted by Purchaser.
- e. By order of a court of competent jurisdiction, a receiver or liquidator or trustee of either party or of a substantial part of the assets of either party shall be appointed, and such receiver or liquidator or trustee shall not have been discharged within a period of one hundred twenty (120) days.
- f. If either party shall file a voluntary petition in bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law.

Logan PSA

- **Contract Term**

This PSA shall automatically renew for additional 12-month periods indefinitely unless terminated by either party by written notice 30 days prior to the end of any contract year.

- **Prior Power Sales Agreement**

Atlantic acknowledges and agrees that Logan's supply of Excess Energy and Excess Installed Capacity under this PSA shall be subordinate to its supply of energy and capacity under the PPA. Without limiting the foregoing, and for the Term of this PSA, and only for that time, LOGAN and Atlantic agree that the Excess Energy and Excess Installed Capacity that the Facility supplies under this PSA shall not be considered to be within the definition of the "Dispatchable" capacity and associated energy that the Facility supplies under the PPA. In the event that LOGAN enters into any subsequent excess power sales agreement during the Term of this PSA, such excess power sales agreement shall be subordinate to this PSA.

- **Force Majeure**

The term "Uncontrollable Force" shall be physical causes of the kind hereafter listed which are beyond the control of the Party affected: flood, earthquake, tornado, storm, fire, civil disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order or public authority (whether valid or invalid), and action or non-action by or inability to obtain or keep the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome. No Party shall, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or due to removable or remediable causes which it fails to remove or remedy within a reasonable time period. Either Party rendered unable to fulfill any of its obligations under this PSA by reason of Uncontrollable Force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.⁶

- **Contract Termination Rights**

Both parties agree to early termination of this Agreement (PSA) under the following conditions.

- A. Should the owners of Logan and Atlantic City Electric agree to restructure or terminate the underlying PPA, then this Agreement (PSA) will become invalid after 30 days of such termination.
- B. If the FERC or New Jersey BPU modify their current policies or regulations such that the terms of the Agreement would be economically prohibitive for either party due to such changes in policies or regulations, then the party claiming such economic harm may terminate this Agreement with 30 days written notice to the other party. In the event the non-terminating party disputes the

⁶ PSA Section 17

economic harm alleged by the terminating party, the dispute shall be resolved as provided in Section 12 above.⁷

⁷ PSA Section 28

Exhibit G

Chambers Term Sheet

TERM SHEET FOR PARTIAL TERMINATION OF CHAMBERS POWER PURCHASE AGREEMENT

This Term Sheet summarizes the principal terms for the partial termination of the Contracts and the entering into of a related Settlement Agreement (the “**Transaction**”). No legally binding obligations will be created unless and until definitive agreements are executed and delivered by all parties thereto. This Term Sheet shall be governed in all respects by the laws of New Jersey.

- Parties:* Atlantic City Electric Company (“**ACE**”).
Chambers Cogeneration Limited Partnership (“**Seller**”).
- Settlement Agreement:* Seller and ACE shall enter into a Settlement Agreement, which will only become effective upon the satisfaction of the Conditions Precedent described below (the “**Closing**”). The Settlement Agreement shall provide for the following to occur upon Closing:
- the PPA, the PSA and any related agreements to which Seller and ACE are a party (the “**Contracts**”) shall terminate, except that with respect to necessary interconnection rights to effect the other terms provided herein, the parties will agree to modify the PPA to preserve and maintain such interconnection rights of Seller and further eliminate the terms that would require the removal of the interconnect facilities at the termination of the PPA, in each case subject to all applicable law and rules and regulations of the FERC, the BPU and PJM (the “**Modified Agreement**”);
 - during any period in which Seller is in compliance in all material respects with its obligations under the Settlement Agreement, ACE shall make monthly Settlement Payments to Seller for each month occurring after the Closing during what would have been the remaining term of the PPA if the PPA had not been partially terminated; provided, however, that ACE shall be entitled to offset against such Settlement Payments any amounts due to ACE from Seller under the Settlement Agreement with Seller;
 - prior to the Closing, Seller shall relieve ACE of its PJM capacity obligations related to the power plant owned by Seller (the “**Power Plant**”) by assuming from ACE all PJM capacity obligations and related rights associated with its Power Plant arising after the Closing, as described in “Conditions Precedent”

below. If the Transaction fails to close, Seller shall pay ACE an amount equal to (i) its lost revenue and (ii) any other losses that result from any capacity resource deficiency payments and/or capacity non-performance penalties imposed by PJM in each case as a result of ACE's failure to bid into the PJM capacity market the capacity that is attributable to the 2023/24 planning year under its PSA; and

- Seller and ACE shall release each other and their respective affiliates from any and all known and unknown claims, demands, obligations, causes of action and damages under or related to the Contracts (collectively, "**Claims**") (other than post-Closing obligations arising under the Settlement Agreement or the Modified Agreement) except with respect to any Claims that are expressly disclosed in writing prior to or at the Closing (the "**Disclosed Claims**"), and any Claims that were previously asserted in writing by either party and remain unresolved. During the period between the execution of the Settlement Agreement and the Closing, the parties will disclose in writing any Claims not previously disclosed as soon as reasonably practicable. The parties will mutually represent to each other at the Closing that there are no undisclosed or unresolved Claims other than any Unresolved Claims (defined below) specified as exceptions to such representation.

ACE shall continue to pay Seller in accordance with the terms of the Contracts up until Closing. From and after Closing, ACE's payment obligations to Seller shall be exclusively as set forth in the Settlement Agreement.

At all times, both before and after Closing, Seller shall bear all costs related to the ownership of its Power Plant, including, without limitation, operations, shut-down, termination of contracts related to plant operations or otherwise, and compliance with legal and regulatory obligations; provided, however, that the foregoing shall not be construed as relieving either party to the Contracts of its obligations thereunder that arise or accrue prior to the Closing.

*Separate Settlement
Agreements:*

Closing under the Settlement Agreement will not be contingent on closing under any other settlement agreement.

- PPA:* Agreement for Purchase of Electric Power, dated as of September 29, 1988, between ACE, as Purchaser, and Chambers Cogeneration Limited Partnership, as Seller, as amended, modified or supplemented from time to time.
- PSA:* Power Sales Agreement, dated January 1, 2021, between ACE and Chambers Cogeneration Limited Partnership, amended, modified or supplemented from time to time.
- Exhibit A (the December 31st Settlement Schedule):* If the Closing occurs on December 31, 2021, ACE shall pay an aggregate of \$106,974,350.00 in monthly payments to Seller, in accordance with the settlement schedule attached as Exhibit A hereto.
- The amounts in the “Customer Costs” column on Exhibit A (the December 31st Settlement Schedule) were determined by ACE consistently with ACE’s customary methods for determining, and previously reported estimates for, customer costs under the Contracts by using a third-party consultant’s projection of generation run-time with respect to Seller’s Power Plant based on forward price curves for energy and such consultant’s capacity price assumptions for the 2023/2024 and 2024/2025 PJM Base Residual Auctions.
- Closing after December 31, 2021:* If the Closing occurs after December 31, 2021, ACE shall pay Seller in accordance with the section below entitled “Settlement Payments” only for the months referenced on Exhibit A (the December 31st Settlement Schedule) occurring after the Closing. For example, if the Closing occurs on February 28, 2022, ACE will make payments in accordance with the section below entitled “Settlement Payments” only with respect to the third through twenty-seventh months referenced on Exhibit A (the December 31st Settlement Schedule).
- Settlement Payments:* ACE’s monthly payment under the Settlement Agreement will equal the amount specified for Seller for such month as set forth on the column entitled “Total Payment” on the December 31st Settlement Schedule.
- The amounts payable by ACE under the Settlement Agreement will be fixed and not subject to any sort of escalation or other adjustment.
- Final Contract Payments:* The final payments between ACE and Seller under the Contracts shall be estimated as of the Closing and true-up within sixty days thereafter (other than with respect to any

Unresolved Claims under the Contracts). For the avoidance of doubt, the final Contract payments shall only cover periods of time before the Closing date.

PJM penalties:

Seller shall pay ACE for any pre-Closing PJM penalties associated with the Contracts that are incurred by ACE and for which Seller is responsible under the Contracts.

Plant Operations:

Within three months after the later to occur of Closing and receipt of all regulatory approvals for steam generation with gas fired boilers, Seller shall permanently cease any coal-fired electric generation at its Power Plant and the associated real property and thereafter on or before the end of such three month period, Seller shall permanently cease the combustion of any coal at its Power Plant and the associated real property; provided that, in the event that Seller has not permanently ceased the combustion of any coal at its Power Plant and the associated real property within three months after Closing, Seller will reduce the coal combustion at its Power Plant to the level necessary to only satisfy its steam obligations and any incidental energy produced; provided, however, that the aforesaid reduction obligation shall be subject to minimum output levels required to meet regulatory requirements and technical specifications for the applicable equipment. Seller will use commercially reasonable efforts to obtain such regulatory approvals for steam generation with gas and/or oil-fired boilers in an expedient manner. For avoidance of doubt, ACE acknowledges that the interconnection for the Power Plant will remain subject to the terms of its existing interconnection rights in the Modified Agreement and all applicable law and rules and regulations of the FERC, the BPU and PJM.

Subject to the Closing having occurred, Seller shall cause any future owners of its Power Plant or the associated real property not to combust coal at the Power Plant or the associated real property.

Conditions Precedent:

The following conditions precedent shall be satisfied before either Closing can occur and the parties are obligated to consummate the Transaction under the Settlement Agreement:

- *Assumption of Capacity Obligations.* Prior to Closing, Seller shall have assumed from ACE all PJM capacity obligations and related rights associated with its Power Plant arising after the

Closing. Specifically, Seller shall accept from ACE via PJM, transfers in 1) PJM ownership, and 2) all capacity unit specific transactions for Seller. In order to make these transfers, Seller must become a PJM member or secure third-party PJM member ownership;

- *Modified Agreement.* The parties shall have executed and will deliver at the Closing the Modified Agreement, subject to all applicable law and rules and regulations of the FERC, the BPU and PJM;
- *Resolution of Disclosed Claims.* The parties shall have mutually agreed to the full resolution of all Disclosed Claims; provided, however, that a waiver by a party of this condition precedent (which would allow the Closing to occur under the Settlement Agreement but would also exclude from the general release any unresolved Disclosed Claims and any other Claims that were previously asserted in writing by either party and remain unresolved (each, an “**Unresolved Claim**”)) shall be without prejudice to its rights to pursue or to contest any such Unresolved Claims;
- *Power Plant Operation.* The Power Plant shall not have suffered physical damage to the extent that the Power Plant is unable to deliver any “Net Plant Output” as required under the PPA for more than 120 consecutive days;
- *QF Status.* The Power Plant shall have maintained its status as a “qualifying facility” under the Public Utilities Regulatory Policy Act and the regulations thereunder through Closing;
- *No Termination.* Neither party shall have terminated either of the Contracts for the Power Plant; and
- *Regulatory Filings and Approvals.* All regulatory filings and approvals and the like required for the consummation of the Transaction in accordance with terms and

conditions described in this Term Sheet shall have been made or obtained, and all applicable waiting periods expired. No party shall be obligated to close the Transaction to the extent changes to the Transaction are required by any regulators.

No Rescission

If Closing occurs, then all conditions precedent shall be deemed satisfied or waived (other than with respect to Unresolved Claims as described above) and in no event shall the Settlement Agreement be subject to rescission.

End Date:

If Closing has not occurred by April 10, 2022, then the Settlement Agreement will automatically terminate with no further force and effect and the Contracts shall remain in full force and effect in accordance with their terms.

Financing

Upon closing of a financing for Seller, ACE agrees to provide any lender holding a security interest in Seller's rights under the Settlement Agreement and Modified Agreement with a customary consent to collateral assignment which may include a representation by ACE addressing its knowledge of any Claims related to the Contracts.

Exhibit A

DECEMBER 31st SETTLEMENT SCHEDULE

Chambers Payment Schedule

Pymt	Date	Chambers		
		Customer Costs	Customer Benefits	Total Payment
1	Jan-22	\$2,133,126	(\$247,595)	\$1,885,530
2	Feb-22	\$2,577,971	(\$299,229)	\$2,278,741
3	Mar-22	\$5,671,706	(\$658,324)	\$5,013,382
4	Apr-22	\$4,776,456	(\$554,411)	\$4,222,045
5	May-22	\$4,777,536	(\$554,536)	\$4,223,000
6	Jun-22	\$5,099,111	(\$591,862)	\$4,507,249
7	Jul-22	\$4,574,921	(\$531,019)	\$4,043,903
8	Aug-22	\$4,603,802	(\$534,371)	\$4,069,431
9	Sep-22	\$5,149,600	(\$597,722)	\$4,551,877
10	Oct-22	\$4,585,043	(\$532,193)	\$4,052,849
11	Nov-22	\$5,078,700	(\$589,493)	\$4,489,207
12	Dec-22	\$4,644,391	(\$539,082)	\$4,105,309
13	Jan-23	\$2,877,577	(\$334,005)	\$2,543,572
14	Feb-23	\$3,741,749	(\$434,311)	\$3,307,438
15	Mar-23	\$6,459,325	(\$749,744)	\$5,709,580
16	Apr-23	\$5,091,623	(\$590,993)	\$4,500,630
17	May-23	\$5,119,679	(\$594,249)	\$4,525,429
18	Jun-23	\$4,909,455	(\$569,848)	\$4,339,607
19	Jul-23	\$4,548,507	(\$527,953)	\$4,020,555
20	Aug-23	\$4,606,965	(\$534,738)	\$4,072,227
21	Sep-23	\$4,972,972	(\$577,221)	\$4,395,751
22	Oct-23	\$4,418,551	(\$512,868)	\$3,905,682
23	Nov-23	\$4,908,487	(\$569,736)	\$4,338,751
24	Dec-23	\$4,629,392	(\$537,341)	\$4,092,051
25	Jan-24	\$3,288,951	(\$381,754)	\$2,907,197
26	Feb-24	\$3,913,745	(\$454,275)	\$3,459,471
27	Mar-24	\$3,862,174	(\$448,289)	\$3,413,885
28	Apr-24			
29	May-24			
30	Jun-24			
31	Jul-24			
32	Aug-24			
33	Sep-24			
34	Oct-24			
35	Nov-24			
36	Dec-24			
37	Total	\$121,021,515	(\$14,047,165)	\$106,974,350

Exhibit H

Logan Term Sheet

TERM SHEET FOR PARTIAL TERMINATION OF LOGAN POWER PURCHASE AGREEMENT

This Term Sheet summarizes the principal terms for the partial termination of the Contracts and the entering into of a related Settlement Agreement (the “**Transaction**”). No legally binding obligations will be created unless and until definitive agreements are executed and delivered by all parties thereto. This Term Sheet shall be governed in all respects by the laws of New Jersey.

Parties: Atlantic City Electric Company (“**ACE**”).
Logan Generating Company, L.P. (“**Seller**”).

Settlement Agreement: Seller and ACE shall enter into a Settlement Agreement, which will only become effective upon the satisfaction of the Conditions Precedent described below (the “**Closing**”). The Settlement Agreement shall provide for the following to occur upon Closing:

- the PPA, the PSA and any related agreements to which Seller and ACE are a party (the “**Contracts**”) shall terminate, except that with respect to necessary interconnection rights to effect the other terms provided herein, the parties will agree to modify the PPA to preserve and maintain such interconnection rights of Seller and further eliminate the terms that would require the removal of the interconnect facilities at the termination of the PPA, in each case subject to all applicable law and rules and regulations of the FERC, the BPU and PJM (the “**Modified Agreement**”);
- during any period in which Seller is in compliance in all material respects with its obligations under the Settlement Agreement, ACE shall make monthly Settlement Payments to Seller for each month occurring after the Closing during what would have been the remaining term of the PPA if the PPA had not been partially terminated; provided, however, that ACE shall be entitled to offset against such Settlement Payments any amounts due to ACE from Seller under the Settlement Agreement with Seller;
- prior to the Closing, Seller shall relieve ACE of its PJM capacity obligations related to the power plant owned by Seller (the “**Power Plant**”) by assuming from ACE all PJM capacity obligations and related rights associated with its Power Plant arising after the Closing, as described in “Conditions Precedent”

below. If the Transaction fails to close, Seller shall pay ACE an amount equal to (i) its lost revenue and (ii) any other losses that result from any capacity resource deficiency payments and/or capacity non-performance penalties imposed by PJM in each case as a result of ACE's failure to bid into the PJM capacity market the capacity that is attributable to the 2023/24 planning year under its PSA; and

- Seller and ACE shall release each other and their respective affiliates from any and all known and unknown claims, demands, obligations, causes of action and damages under or related to the Contracts (collectively, "**Claims**") (other than post-Closing obligations arising under the Settlement Agreement or the Modified Agreement) except with respect to any Claims that are expressly disclosed in writing prior to or at the Closing (the "**Disclosed Claims**"), and any Claims that were previously asserted in writing by either party and remain unresolved. During the period between the execution of the Settlement Agreement and the Closing, the parties will disclose in writing any Claims not previously disclosed as soon as reasonably practicable. The parties will mutually represent to each other at the Closing that there are no undisclosed or unresolved Claims other than any Unresolved Claims (defined below) specified as exceptions to such representation.

ACE shall continue to pay Seller in accordance with the terms of the Contracts up until Closing. From and after Closing, ACE's payment obligations to Seller shall be exclusively as set forth in the Settlement Agreement.

At all times, both before and after Closing, Seller shall bear all costs related to the ownership of its Power Plant, including, without limitation, operations, shut-down, termination of contracts related to plant operations or otherwise, and compliance with legal and regulatory obligations; provided, however, that the foregoing shall not be construed as relieving either party to the Contracts of its obligations thereunder that arise or accrue prior to the Closing.

*Separate Settlement
Agreements:*

Closing under the Settlement Agreement will not be contingent on closing under any other settlement agreement.

- PPA:* Agreement for Purchase of Electric Power, dated August 25, 1988, between ACE, as Purchaser, and Logan Generating Company, L.P., as Seller, as amended, modified, or supplemented from time to time.
- PSA:* Power Sales Agreement, dated January 1, 2021, between ACE and Logan Generating Company, L.P., as amended, modified or supplemented from time to time.
- Exhibit A (the December 31st Settlement Schedule):* If the Closing occurs on December 31, 2021, ACE shall pay an aggregate of \$121,486,736.00 in monthly payments to Seller, in accordance with the settlement schedule attached as Exhibit A hereto.
- The amounts in the “Customer Costs” column on Exhibit A (the December 31st Settlement Schedule) were determined by ACE consistently with ACE’s customary methods for determining, and previously reported estimates for, customer costs under the Contracts by using a third-party consultant’s projection of generation run-time with respect to Seller’s Power Plant based on forward price curves for energy and such consultant’s capacity price assumptions for the 2023/2024 and 2024/2025 PJM Base Residual Auctions.
- Closing after December 31, 2021:* If the Closing occurs after December 31, 2021, ACE shall pay Seller in accordance with the section below entitled “Settlement Payments” only for the months referenced on Exhibit A (the December 31st Settlement Schedule) occurring after the Closing. For example, if the Closing occurs on February 28, 2022, ACE will make payments in accordance with the section below entitled “Settlement Payments” only with respect to the third through thirty-sixth months referenced on Exhibit A (the December 31st Settlement Schedule).
- Settlement Payments:* ACE’s monthly payment under the Settlement Agreement will equal the amount specified for Seller for such month as set forth on the column entitled “Total Payment” on the December 31st Settlement Schedule.
- The amounts payable by ACE under the Settlement Agreement will be fixed and not subject to any sort of escalation or other adjustment.
- Final Contract Payments:* The final payments between ACE and Seller under the Contracts shall be estimated as of the Closing and trued-up within sixty days thereafter (other than with respect to any

Unresolved Claims under the Contracts). For the avoidance of doubt, the final Contract payments shall only cover periods of time before the Closing date.

PJM penalties:

Seller shall pay ACE for any pre-Closing PJM penalties associated with the Contracts that are incurred by ACE and for which Seller is responsible under the Contracts.

Plant Operations:

Within three months after Closing, Seller shall permanently cease any coal-fired electric generation at its Power Plant and the associated real property and, thereafter on or before the end of such three month period, Seller shall permanently cease the combustion of any coal at its Power Plant and the associated real property. For avoidance of doubt, ACE acknowledges that the interconnection for the Power Plant will remain subject to the terms of its existing interconnection rights in the Modified Agreement and all applicable law and rules and regulations of the FERC, the BPU and PJM.

Subject to the Closing having occurred, Seller shall cause any future owners of its Power Plant or the associated real property not to combust coal at the Power Plant or the associated real property.

Conditions Precedent:

The following conditions precedent shall be satisfied before either Closing can occur and the parties are obligated to consummate the Transaction under the Settlement Agreement:

- *Assumption of Capacity Obligations.* Prior to Closing, Seller shall have assumed from ACE all PJM capacity obligations and related rights associated with its Power Plant arising after the Closing. Specifically, Seller shall accept from ACE via PJM, transfers in 1) PJM ownership, and 2) all capacity unit specific transactions for Seller. In order to make these transfers, Seller must become a PJM member or secure third-party PJM member ownership;
- *Modified Agreement.* The parties shall have executed and will deliver at the Closing the Modified Agreement, subject to all applicable law and rules and regulations of the FERC, the BPU and PJM;

- *Resolution of Disclosed Claims.* The parties shall have mutually agreed to the full resolution of all Disclosed Claims; provided, however, that a waiver by a party of this condition precedent (which would allow the Closing to occur under the Settlement Agreement but would also exclude from the general release any unresolved Disclosed Claims and any other Claims that were previously asserted in writing by either party and remain unresolved (each, an “**Unresolved Claim**”)) shall be without prejudice to its rights to pursue or to contest any such Unresolved Claims;
- *Power Plant Operation.* The Power Plant shall not have suffered physical damage to the extent that the Power Plant is unable to deliver any “Net Plant Output” as required under the PPA for more than 120 consecutive days;
- *QF Status.* The Power Plant shall have maintained its status as a “qualifying facility” under the Public Utilities Regulatory Policy Act and the regulations thereunder through Closing;
- *No Termination.* Neither party shall have terminated either of the Contracts for the Power Plant; and
- *Regulatory Filings and Approvals.* All regulatory filings and approvals and the like required for the consummation of the Transaction in accordance with terms and conditions described in this Term Sheet shall have been made or obtained, and all applicable waiting periods expired. No party shall be obligated to close the Transaction to the extent changes to the Transaction are required by any regulators.

No Rescission

If Closing occurs, then all conditions precedent shall be deemed satisfied or waived (other than with respect to Unresolved Claims as described above) and in no event shall the Settlement Agreement be subject to rescission.

End Date:

If Closing has not occurred by April 10, 2022, then the Settlement Agreement will automatically terminate with no

further force and effect and the Contracts shall remain in full force and effect in accordance with their terms.

Financing

Upon closing of a financing for Seller, ACE agrees to provide any lender holding a security interest in Seller's rights under the Settlement Agreement and Modified Agreement with a customary consent to collateral assignment which may include a representation by ACE addressing its knowledge of any Claims related to the Contracts.

Exhibit A

DECEMBER 31st SETTLEMENT SCHEDULE

Logan Payment Schedule

Pymt	Date	Logan		
		Customer Costs	Customer Benefits	Total Payment
1	Jan-22	\$2,719,561	(\$315,664)	\$2,403,897
2	Feb-22	\$3,513,522	(\$407,820)	\$3,105,702
3	Mar-22	\$4,357,405	(\$505,771)	\$3,851,634
4	Apr-22	\$3,969,176	(\$460,709)	\$3,508,467
5	May-22	\$4,009,825	(\$465,427)	\$3,544,398
6	Jun-22	\$4,292,063	(\$498,187)	\$3,793,876
7	Jul-22	\$3,893,815	(\$451,961)	\$3,441,854
8	Aug-22	\$4,034,349	(\$468,274)	\$3,566,076
9	Sep-22	\$4,338,534	(\$503,581)	\$3,834,953
10	Oct-22	\$3,158,268	(\$366,585)	\$2,791,683
11	Nov-22	\$4,250,510	(\$493,364)	\$3,757,146
12	Dec-22	\$3,745,650	(\$434,764)	\$3,310,887
13	Jan-23	\$2,288,777	(\$265,662)	\$2,023,115
14	Feb-23	\$3,192,802	(\$370,594)	\$2,822,208
15	Mar-23	\$3,957,090	(\$459,306)	\$3,497,784
16	Apr-23	\$4,330,575	(\$502,657)	\$3,827,918
17	May-23	\$4,370,109	(\$507,246)	\$3,862,863
18	Jun-23	\$4,134,707	(\$479,922)	\$3,654,785
19	Jul-23	\$3,803,077	(\$441,429)	\$3,361,648
20	Aug-23	\$3,929,289	(\$456,079)	\$3,473,210
21	Sep-23	\$4,233,169	(\$491,351)	\$3,741,818
22	Oct-23	\$3,440,715	(\$399,369)	\$3,041,346
23	Nov-23	\$4,194,038	(\$486,809)	\$3,707,230
24	Dec-23	\$3,830,041	(\$444,559)	\$3,385,482
25	Jan-24	\$2,630,383	(\$305,313)	\$2,325,070
26	Feb-24	\$3,339,600	(\$387,633)	\$2,951,967
27	Mar-24	\$3,890,365	(\$451,561)	\$3,438,804
28	Apr-24	\$4,229,414	(\$490,915)	\$3,738,499
29	May-24	\$4,290,649	(\$498,023)	\$3,792,627
30	Jun-24	\$4,094,982	(\$475,311)	\$3,619,671
31	Jul-24	\$3,548,383	(\$411,867)	\$3,136,516
32	Aug-24	\$3,929,209	(\$456,070)	\$3,473,140
33	Sep-24	\$4,151,581	(\$481,881)	\$3,669,700
34	Oct-24	\$3,426,782	(\$397,752)	\$3,029,030
35	Nov-24	\$4,126,383	(\$478,956)	\$3,647,427
36	Dec-24	\$3,794,774	(\$440,466)	\$3,354,308
37	Total	\$137,439,572	(\$15,952,835)	\$121,486,736

Exhibit I

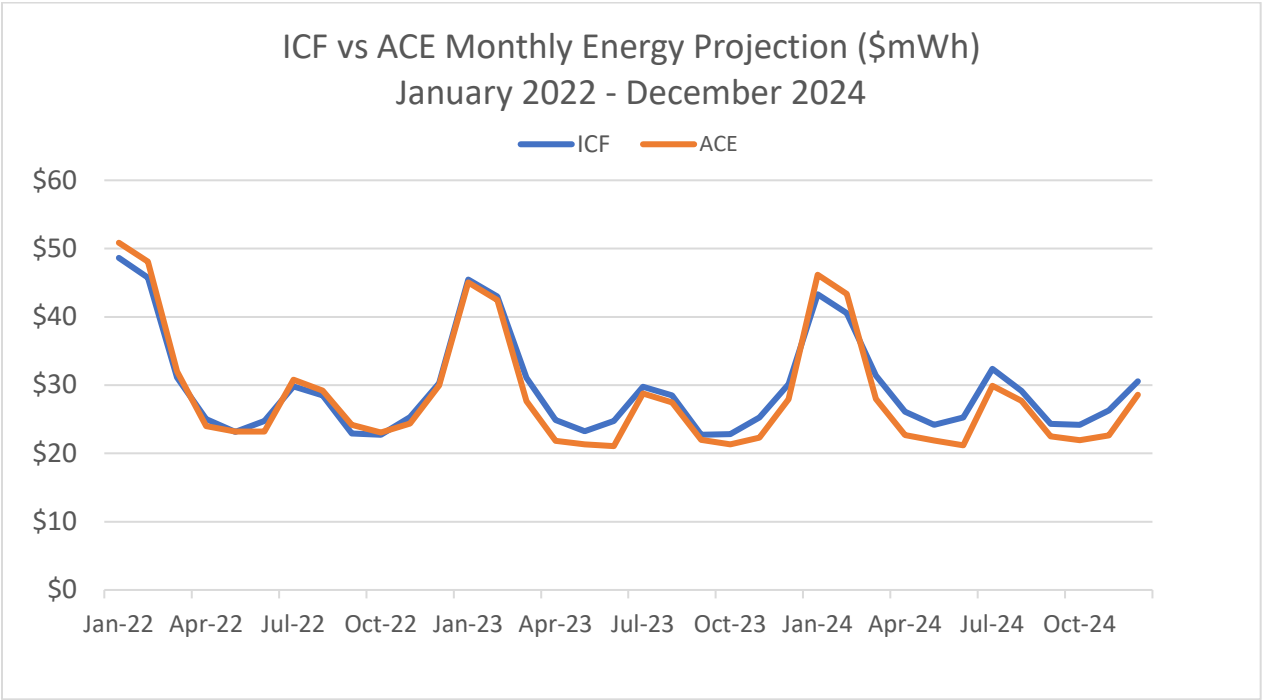
Chambers Settlement Agreement
and Modified PPA
[to be filed]

Exhibit J

Logan Settlement Agreement
and Modified PPA
[to be filed]

Exhibit K

Internal Price Curve Comparison



ATLANTIC CITY ELECTRIC COMPANY
BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES
DIRECT TESTIMONY OF MARIO GIOVANNINI
BPU DOCKET NO. _____

1 **Q1. Please state your name and position.**

2 A1. My name is Mario Giovannini. I am the Director of Energy Acquisition for
3 Pepco Holdings LLC (“PHI”). I am testifying on behalf of Atlantic City Electric
4 Company (“ACE” or the “Company”) in support of the Petition.

5 **Q2. What are your responsibilities as the Director of Energy Acquisition?**

6 A2. I oversee natural gas and energy procurement for the PHI utilities, including
7 ACE, Pepco Electric Power Company and Delmarva Power & Light, load settlement
8 transactions with the ISO, load research and analysis, third-party supplier relations and
9 wholesale billing and administration. I also oversee the Non-Utility Generation
10 (“NUG”) agreements presented with this Petition. Further, I manage PHI’s demand
11 response programs.

12 **Q3. Please state your educational background and professional experience.**

13 A3. I hold a Bachelor of Science Degree in Finance from King’s College and a
14 Master of Business Administration from La Salle University. I have been employed
15 by PHI, the parent of ACE and its affiliates since August of 1998 serving in risk
16 management, finance, planning, and operations. Prior to this, I was employed for eight
17 years by RCN Corporation mainly in finance and planning.

18 **Q4. Have you testified on behalf of PHI in the past?**

19 A4. While I have not testified in front of the New Jersey Board of Public Utilities
20 (“BPU”), I have testified for other PHI companies. I testified in Delmarva Power &

1 Light's Gas Cost Recovery (GCR) proceedings and testified before the Maryland
2 Public Service Commission in support of Pepco Electric Power Company and
3 Delmarva Power & Light's Advanced Metering Infrastructure (AMI) cost recovery. I
4 also testified before the Maryland Public Service Commission related to Standard Offer
5 Service (SOS) cash working capital for Pepco Electric Power Company and Delmarva
6 Power and Light.

7 **Q5. What is the purpose of your Direct Testimony?**

8 A5. My testimony supports the Company's proposed modification/partial
9 termination of the Chambers Cogeneration Limited Partnership ("Chambers") and
10 Logan Generating Company, L.P. ("Logan") Agreements for Purchase of Electric
11 Power ("PPAs") and termination of the Power Sales Agreements ("PSAs"). My
12 testimony also supports and presents the Term Sheets between the parties, which will
13 ultimately be memorialized in Settlement Agreements between the parties. This
14 testimony was prepared by me or under my direct supervision and control. The sources
15 for my testimony and schedules are Company records and public documents. I also
16 relied upon my personal knowledge and experience.

17 **Q6. Does ACE derive any financial benefit from the NUG contracts?**

18 A6. No. ACE does not derive any financial benefit from the agreements and does
19 not earn a return. All costs incurred and PJM revenues earned are directly passed
20 through to customers.

1 **Q7. Please describe the NUG agreements between ACE and the Chambers and Logan**
2 **plants.**

3 A7. The PPAs and PSAs with the Chambers and Logan plants are listed below.

4 1. Chambers PPA: Agreement for Purchase of Electric Power, dated as of
5 September 29, 1988, between ACE, as Purchaser, and Chambers, as Seller,
6 as amended, modified, or supplemented from time to time.

7 2. Logan PPA: Agreement for Purchase of Electric Power dated August 25,
8 1988, between ACE, as Purchaser, and Keystone Cogeneration Station
9 (now Logan Generation), as Seller, as amended, modified, or supplemented
10 from time to time.

11 3. Chambers PSA: Power Sales Agreement dated June 9, 2021, between ACE
12 and Chambers, as amended, modified, or supplemented from time to time.

13 4. Logan PSA: Power Sales Agreement dated December 18, 2012, between
14 ACE and Logan, as amended, modified, or supplemented from time to time.

15 The PPAs are long-term agreements between the parties where ACE purchases
16 electricity and capacity from the Chambers and Logan plants. The background
17 regarding the history of the PPAs and why ACE entered these agreements is provided
18 in the Petition. The PPAs are now recognized as above-market contracts, meaning that
19 the prices in the PPAs are higher than the current market prices for energy and capacity.
20 For a typical ACE residential customer that uses on average 680 kWh, the charge on
21 their current monthly bill is \$9.87 to pay the costs associated with the Chambers and
22 Logan agreements for the current NGC period.

1 The PSAs are annual agreements among the parties, which are used to capture
2 and share incremental energy and capacity payments from the PJM Interconnection
3 L.L.C. (“PJM”) wholesale markets. This sharing arrangement is for energy and
4 capacity above the contracted PPA amounts. Basically, the units can generate slightly
5 more electricity for the wholesale energy market and have more capacity than what
6 ACE is obligated to purchase through the PPAs. Without these PSAs, ACE would miss
7 the opportunity to make additional revenue for ACE customers by failing to monetize
8 this incremental energy and capacity and offset a portion of the above-market costs of
9 the PPAs. ACE and the plants have been doing these reoccurring PSAs each year for
10 more than 10 years, which benefits both the plants and ACE customers.

11 **Q8. Do ACE customers need the electricity generated by the Chambers and Logan**
12 **plants?**

13 A8. No. ACE customers do not need the electricity generated by Logan and
14 Chambers. Alternative, cleaner, and less expensive sources of energy and capacity are
15 available to ACE customers through the PJM wholesale markets. New Jersey’s retail
16 market, in turn, allows ACE customers to choose their electricity supply to be provided
17 through either Basic Generation Service (“BGS”) or a competitive third-party supplier.

18 **Q9. Please provide the reasons why ACE has pursued negotiations.**

19 A9. As described in the Petition, ACE has tried for many years to modify,
20 restructure, or terminate the NUG agreements which are scheduled to end in March and
21 December of 2024, respectively. Recently, ACE and the plants’ majority owners,
22 affiliates of Starwood Energy Group Global LLC (“Starwood”), began to consider a
23 proposal to modify the PPAs, terminate the PSAs, and gain customer benefits in the

1 form of monetary payment Chambers and Logan. Early termination also presents
2 positive environmental benefits for the State of New Jersey (“State”) and ACE
3 customers. The potential to reduce customer costs by gaining customer benefits while
4 providing environmental benefits to all residents of New Jersey was appealing to ACE.

5 It is important to note from the beginning of negotiations, ACE has made it
6 abundantly clear that it would not enter into a transaction where ACE’s customers were
7 left worse off financially or at higher financial risk than they would be under the
8 existing agreements, which created some challenges with earlier termination proposals
9 from Chambers and Logan.

10 In addition to seeking financial benefits for ACE customers, ACE actively
11 supports the State’s efforts to combat climate change and advance a clean energy
12 economy. The Chambers and Logan plants burn coal to generate electricity. Coal
13 when burned releases airborne toxins and creates carbon dioxide, a heat trapping
14 “greenhouse” gas, contributing to the warming of the earth and climate change. Logan
15 and Chambers are the last large-scale coal units remaining in the State; closing these
16 units will contribute to reducing State emissions and advancing the State’s climate
17 change objectives, providing a public benefit. As part of this transaction, Chambers
18 and Logan have agreed to retire their respective coal units.

19 In September of 2021, ACE created a proposed transaction structure and term
20 sheets to re-initiate negotiations with Starwood.

21 **Q10. Please explain the benefits customers will gain from this transaction.**

22 A10. ACE customers will receive both financial and environmental benefits from this
23 transaction.

1 ACE customers will receive a negotiated monetary benefit of up to \$30 million
2 of the projected customer costs through December 2024 of \$258.5 million.
3 Specifically, customers will see savings of up to \$14 million and \$16 million from the
4 modification/partial termination of the Chambers and Logan agreements, respectively,
5 which can be seen on Exhibit A of the Term Sheets attached to the Petition. This benefit
6 will reduce the Company's Non-Utility Generation Charge ("NGC") on customer's
7 bills monthly through December 2024.

8 Perhaps even more importantly, ACE customers and all New Jersey residents
9 will also obtain the health and environmental benefits from the closure of the last two
10 coal generation plants in the State.

11 **Q11. How do the customer benefits compare with other NUG termination transactions?**

12 A11. It can be challenging to compare transactions since each transaction presents
13 unique factual, financial, and operational circumstances that must be looked at on an
14 individual and comprehensive basis. It is possible that operational circumstances and
15 risks associated with termination could skew the publicly stated customer benefits
16 presented in past transactions. As such, it is difficult to evaluate the economics of past
17 transactions without full insight into all the terms of those transactions.

18 The BPU has approved the restructuring or termination of several Public
19 Utility Regulatory Policies Act of 1978 ("PURPA") PPA contracts over the last 20
20 years. Notably, ACE and Rockland Electric Company ("Rockland") terminated PPAs
21 in 1999 and 2005, respectively; with both termination transactions achieving customer
22 savings. In 1999, the BPU approved the termination of ACE's PPA with Pedricktown
23 Cogeneration Limited Partnership, resulting in \$84 million in customer savings of

1 customer costs for New Jersey ratepayers with 22 years remaining on the contract (BPU
2 Docket No. EE99090685). More recently, Rockland along with two other utilities
3 terminated a 4 MW PPA with 2 years remaining on the contract term and achieved
4 approximately \$250,000 in customer savings for the utilities based on an approximate
5 termination value of \$1,500,000. (BPU Docket No. EM05121072).

6 There are many risks involved in terminating agreements and shutting-down
7 coal units. A transaction that appears to have a higher customer financial benefit may
8 also have greater risks shifted to customers or higher undisclosed costs to the
9 counterparties. In this transaction, ACE has sought to mitigate the risk to customers.
10 For instance, Logan and Chambers have agreed to assume the cost and risk of securing
11 replacement capacity for the plants that have already been bid into PJM; the cost of this
12 replacement capacity for them is not quantified or reflected in the deal terms. The same
13 goes for plant closure and other costs. Chambers and Logan have agreed to assume the
14 plant closure and other costs, which are sometimes borne by the customers.

15 In addition, there may be quantifiable environmental benefits for New Jersey
16 from shuttering these plants that should also be taken into consideration when
17 evaluating the total customer benefits of the transaction. The legislative and
18 administrative policies of the State strongly support emissions reductions, and some
19 New Jersey legislation has sought to quantify the benefits associated with zero
20 emissions. The Company does not propose or endorse a particular methodology for
21 quantifying the environmental benefits but believes there are benefits that should be
22 considered.

1 **Q12. Please discuss the payment schedules in Exhibit A of the Term Sheets.**

2 A12. The Chambers and Logan payment schedules in Exhibit A of the Term Sheets
3 reflect how ACE has historically managed these agreements. In general, the Company
4 makes PPA and PSA payments monthly to the Chambers and Logan plants. ACE has
5 always committed Chambers and Logan into the PJM markets to earn revenues to offset
6 the high costs of the PPAs for ACE's customers. ACE refers to these revenues as
7 offsets since they offset the above-market PPA costs.

8 Based on forward prices and simulated dispatch of the Chambers and Logan
9 plants, the expected contract payments or amounts that will be owed to the plants from
10 January 2022 through December 2024, totaled \$417.8 million (Table A, Column E).
11 As noted above, the PJM offset revenues earned during the same term were forecasted
12 to total \$159.3 million (Table A, Column H). While these revenues were not
13 traditionally borne by Chambers and Logan but instead from PJM, the Settlement
14 Agreements will ensure that customers are made whole to the offsets the Company
15 would have procured for them had the contracts run to completion. The total forecasted
16 customer costs shown in Table A, Column I match the customer costs on the Chambers
17 and Logan payment schedules in Exhibit A of the Term Sheets. The monthly detail to
18 the numbers found in Table A can be found in Schedule (MG)-2 of my testimony.

Table A
(\$ Millions)

	A	B	C	[A+B+C] E	F	G	[F+G] H	[E+H] I
Plant	Contract Capacity Costs	Contract Energy Costs	Incentive Payment	Contract Costs	PJM Capacity Revenue Offset	PJM Energy Revenue Offset	PJM Revenue Offsets	Customer Costs
Chambers	\$131.8	\$56.0	\$4.7	\$192.5	(\$22.0)	(\$49.4)	(\$71.5)	\$121.0
Logan	\$134.8	\$86.0	\$4.5	\$225.3	(\$27.5)	(\$60.4)	(\$87.9)	\$137.4
Total	\$266.6	\$142.0	\$9.2	\$417.8	(\$49.6)	(\$109.8)	(\$159.3)	\$258.5

19
20 The payment schedules assume the costs of the agreements and the PJM
21 revenue offsets continue as if this transaction never occurred. The schedules consist of

1 monthly fixed payments based on estimated forward market pricing at a point in time
2 and will not change with evolving forward market prices. Furthermore, ACE will not
3 adjust the payment schedules once approved by the BPU.

4 This simple and concise approach leverages the existing monthly payment
5 process that has been in place for decades. In addition, the monthly payment process
6 nets the pro rata share of the customer benefit against the amounts owed to the plants,
7 which will total up to \$30 million upon completion of the payments in December 2024
8 if the transaction closes in January of 2022.

9 **Q13. Please explain who ACE hired to calculate the plants' generation output and PJM**
10 **prices used to calculate the net payments to the plants in the payment schedules.**

11 A13. ACE hired a third-party consultant known as ICF International ("ICF"), which
12 ACE normally uses, to derive the hourly generation output of the plants and PJM
13 Locational Marginal Prices ("LMPs") through December 2024 shown in Schedule
14 (MG)-1 to this Direct Testimony. ICF has over 30 years of experience in the energy
15 space and is equipped with an industry-leading suite of analytical tools including
16 PROMOD IV, a fundamental electric market simulation solution that incorporates
17 future demand, generating plant operational characteristics, the transmission grid, and
18 other constraints. ACE received a PJM capacity price forecast for the PJM Planning
19 Years of 2023/2024 and 2024/2025 also shown in Schedule (MG)-1. ICF's data
20 allowed ACE to calculate the contract payments to Chambers and Logan according to
21 the PPAs and PSAs and calculate the PJM energy and capacity revenue offsets for ACE
22 ratepayers shown in Exhibit A on the Term Sheets.

1 **Q14. Did ACE find the ICF results reasonable?**

2 A14. To evaluate the LMPs produced by ICF's model, ACE leveraged the
3 Company's internal price curve to compare to forward LMPs and found them to be
4 consistent, reflective of market conditions, and reasonable as of September 2021. The
5 internal price curve comparison is attached to the Petition as Exhibit K.

6 ICF provided capacity prices for the 2023/2024 and 2024/2025 PJM Planning
7 Years of \$113.05/MW-day and \$124.14/MW-day, respectively, since these Base
8 Residual Auctions ("BRAs") have yet to be conducted by PJM. The 2023/2024 and
9 2024/2025 PJM BRAs open on January 25, 2022 and June 15, 2022, respectively.
10 These prices are higher than the 2022/2023 capacity price of \$97.86/MW-day that
11 cleared in May of 2021, but lower than the 2021/2022 capacity prices of \$165.73/MW-
12 day. The Company consulted with ICF regarding the range of the forward prices, and
13 they confirmed the results and communicated their forecast was reflective of an
14 increase in demand based on PJM's release of their interim forecast in mid-2021,
15 partially offset by an increase in supply driven by a 2 GW Capacity Emergency
16 Transfer Limit ("CETL") to the Mid-Atlantic Area Council ("MAAC") region.

17 **Q15. Will ACE's operating procedures for the Chambers and Logan agreements**
18 **change prior to this transaction's completion?**

19 A15. With one exception, further detailed below, ACE's operating procedures for
20 these units will be unchanged prior to the transaction close. ACE is the front-facing
21 PJM member for the NUG agreements, as the Chambers and Logan plants are not PJM
22 members. ACE plans to maintain status quo operations with respect to the plants until
23 the transaction is completed. It is ACE's responsibility to continue to offer the

1 Chambers and Logan plants into PJM's energy market daily and offer the capacity of
2 these plants into PJM's BRAs to gain PJM offsets for ACE's customers. The one
3 change from an operational perspective came at the request of the Chambers and
4 Logan, respectively. They requested, and memorialized in the Term Sheets, that ACE
5 not offer in capacity derived from the PSAs for PJM Planning Year 2023/2024. ACE
6 agreed to this request and gained protections for ACE's customers by requiring the
7 plants to reimburse ACE for all lost revenue and any penalties incurred from not
8 offering the PSAs' capacity into the BRA.

9 Finally, all monitoring of the plant's performance and PJM reporting in place
10 today will continue until the transaction and transition is completed.

11 **Q16. What risks are associated with this transaction from ACE's perspective and how**
12 **has ACE mitigated these risks through the Term Sheets?**

13 A16. To avoid the risk of non-payment, the Company modeled the payment
14 schedules consistently with how ACE has historically paid the Chambers and Logan
15 plants. The customer benefits will be netted against the payments ACE will make to
16 the plants. ACE will continue to be a net payer to the plants, which protects ACE
17 customers. ACE will always owe the plants money based on the payment schedules
18 and will be not exposed to payments from the plants.

19 In reference to PJM penalties, according to the Term Sheets, the Chambers and
20 Logan plants will pay for any penalties incurred before the closing that they would have
21 paid under the NUG contracts. This protects ACE from the risk of absorbing PJM
22 penalties that it would not otherwise had had to pay and that could erode the \$30 million
23 customer benefit. The risk of PJM penalties post-closing is also eliminated in the Term

1 Sheets since all of ACE's capacity obligations will be transferred to Chambers and
2 Logan at closing.

3 To protect against the risk of any costs for plant closures, operations, and the
4 termination of the contracts flowing to ACE customers, the Term Sheets specifically
5 state that Chambers and Logan must assume all these costs in their respective
6 Settlement Agreements.

7 ACE is requiring the Chambers and Logan plants to adhere to all applicable
8 provisions under the current PPAs within the term sheets. This will ensure plant
9 operations remain consistent with historical operations, remain responsive to PJM to
10 avoid penalties, and continue to produce PJM energy and capacity revenues for ACE
11 customers prior to close.

12 As noted above, the pricing assumptions that underlie the payment schedules
13 are set based on a point in time, derived from the modeling, and will not move with
14 forward energy and capacity prices. Energy prices and, more importantly, capacity
15 prices, which comprise the majority of the contract payments to Chambers and Logan,
16 can fluctuate up or down. Thus, the transaction structure, with a payment schedule that
17 will not move, does present some risk. However, this structure can also be an
18 opportunity for gain if the capacity clearing prices, and energy prices are lower than
19 what the Company modeled for this transaction.

20 **Q17. Does this conclude your Direct Testimony?**

21 A17. Yes, it does.

Schedule (MG)-1

	MWh Output	LMP Price (\$/MWh)	Contract Price^{1,2} (\$/MWh)	Capacity Price \$MW-day
Jan-22	173,170	\$59.88	\$50.04	\$165.73
Feb-22	137,370	\$51.39	\$46.56	\$165.73
Mar-22	86,770	\$34.12	\$58.64	\$165.73
Apr-22	71,280	\$25.03	\$54.81	\$165.73
May-22	77,755	\$24.44	\$53.13	\$165.73
Jun-22	79,733	\$27.80	\$52.32	\$97.86
Jul-22	99,466	\$36.70	\$47.47	\$97.86
Aug-22	96,458	\$34.15	\$47.02	\$97.86
Sep-22	80,426	\$26.79	\$52.30	\$97.86
Oct-22 ³	16,268	\$26.48	\$47.76	\$97.86
Nov-22	76,787	\$26.89	\$51.54	\$97.86
Dec-22	101,496	\$39.62	\$49.41	\$97.86
Jan-23	172,718	\$56.00	\$42.77	\$97.86
Feb-23	121,148	\$48.78	\$43.54	\$97.86
Mar-23	94,096	\$35.54	\$48.11	\$97.86
Apr-23	71,799	\$25.01	\$51.92	\$97.86
May-23	77,406	\$24.52	\$50.85	\$97.86
Jun-23	81,011	\$27.96	\$49.38	\$113.05
Jul-23	96,192	\$35.75	\$47.07	\$113.05
Aug-23	94,099	\$33.50	\$47.03	\$113.05
Sep-23	80,769	\$26.95	\$50.44	\$113.05
Oct-23	31,869	\$28.71	\$47.41	\$113.05
Nov-23	79,251	\$27.57	\$50.21	\$113.05
Dec-23	95,915	\$36.57	\$49.04	\$113.05
Jan-24	149,988	\$53.41	\$44.08	\$113.05
Feb-24	111,044	\$46.40	\$45.00	\$113.05
Mar-24	70,735	\$36.26	\$48.87	\$113.05
Apr-24	38,997	\$26.49	\$52.97	\$113.05
May-24	41,369	\$25.17	\$52.16	\$113.05
Jun-24	43,518	\$28.18	\$50.35	\$124.14
Jul-24	57,400	\$39.36	\$47.08	\$124.14
Aug-24	49,031	\$32.88	\$49.68	\$124.14
Sep-24	43,218	\$27.95	\$51.59	\$124.14
Oct-24	13,723	\$28.95	\$52.37	\$124.14
Nov-24	43,175	\$28.68	\$51.75	\$124.14
Dec-24	51,002	\$36.80	\$50.31	\$124.14

1. Contract price calculated by ACE per agreements.

2. Contract price does not include entitlement and incentive payments for Chambers and Logan units, respectively.

3. Logan planned outage during October 2022.

Schedule (MG)-2

EXHIBIT C

Pymt	Date	Chambers							
		CONTRACT COSTS				PJM REVENUE			
		Contract Energy Cost	Contract Capacity Costs	Entitlement Fee	Contract Costs	PJM Energy Revenue	PJM Capacity Revenue	PJM Revenue	Customer Costs
1	Jan-22	\$4,217,067	\$5,031,226	\$0	\$9,248,293	(\$5,903,406)	(\$1,211,761)	(\$7,115,167)	\$2,133,126
2	Feb-22	\$3,120,847	\$5,013,177	\$0	\$8,134,024	(\$4,461,559)	(\$1,094,494)	(\$5,556,053)	\$2,577,971
3	Mar-22	\$2,079,174	\$5,031,226	\$1,344,480	\$8,454,880	(\$1,571,413)	(\$1,211,761)	(\$2,783,174)	\$5,671,706
4	Apr-22	\$1,753,055	\$5,025,210	\$0	\$6,778,265	(\$829,137)	(\$1,172,672)	(\$2,001,810)	\$4,776,456
5	May-22	\$1,843,184	\$5,031,226	\$0	\$6,874,411	(\$885,113)	(\$1,211,761)	(\$2,096,874)	\$4,777,536
6	Jun-22	\$1,913,863	\$4,952,405	\$0	\$6,866,268	(\$1,073,134)	(\$694,023)	(\$1,767,157)	\$5,099,111
7	Jul-22	\$2,148,963	\$4,955,995	\$0	\$7,104,958	(\$1,812,879)	(\$717,157)	(\$2,530,037)	\$4,574,921
8	Aug-22	\$1,998,403	\$4,955,995	\$0	\$6,954,397	(\$1,633,438)	(\$717,157)	(\$2,350,595)	\$4,603,802
9	Sep-22	\$1,937,608	\$4,952,405	\$0	\$6,890,013	(\$1,046,391)	(\$694,023)	(\$1,740,414)	\$5,149,600
10	Oct-22	\$776,974	\$4,955,995	\$0	\$5,732,968	(\$430,768)	(\$717,157)	(\$1,147,926)	\$4,585,043
11	Nov-22	\$1,782,955	\$4,952,405	\$0	\$6,735,360	(\$962,637)	(\$694,023)	(\$1,656,660)	\$5,078,700
12	Dec-22	\$2,375,388	\$4,955,995	\$0	\$7,331,382	(\$1,969,834)	(\$717,157)	(\$2,686,991)	\$4,644,391
13	Jan-23	\$3,585,081	\$4,955,995	\$0	\$8,541,075	(\$4,946,341)	(\$717,157)	(\$5,663,498)	\$2,877,577
14	Feb-23	\$2,403,522	\$4,945,226	\$0	\$7,348,748	(\$2,959,244)	(\$647,755)	(\$3,606,999)	\$3,741,749
15	Mar-23	\$2,014,050	\$4,955,995	\$1,782,168	\$8,752,213	(\$1,575,731)	(\$717,157)	(\$2,292,889)	\$6,459,325
16	Apr-23	\$1,667,585	\$4,952,405	\$0	\$6,619,990	(\$834,344)	(\$694,023)	(\$1,528,367)	\$5,091,623
17	May-23	\$1,761,359	\$4,955,995	\$0	\$6,717,353	(\$880,517)	(\$717,157)	(\$1,597,675)	\$5,119,679
18	Jun-23	\$1,822,183	\$4,968,171	\$0	\$6,790,354	(\$1,080,505)	(\$800,394)	(\$1,880,899)	\$4,909,455
19	Jul-23	\$2,003,718	\$4,972,286	\$0	\$6,976,004	(\$1,600,423)	(\$827,074)	(\$2,427,497)	\$4,548,507
20	Aug-23	\$1,915,532	\$4,972,286	\$0	\$6,887,818	(\$1,453,779)	(\$827,074)	(\$2,280,853)	\$4,606,965
21	Sep-23	\$1,845,726	\$4,968,171	\$0	\$6,813,897	(\$1,040,530)	(\$800,394)	(\$1,840,924)	\$4,972,972
22	Oct-23	\$746,526	\$4,972,286	\$0	\$5,718,812	(\$473,187)	(\$827,074)	(\$1,300,261)	\$4,418,551
23	Nov-23	\$1,754,860	\$4,968,171	\$0	\$6,723,031	(\$1,014,150)	(\$800,394)	(\$1,814,544)	\$4,908,487
24	Dec-23	\$2,121,904	\$4,972,286	\$0	\$7,094,189	(\$1,637,723)	(\$827,074)	(\$2,464,797)	\$4,629,392
25	Jan-24	\$3,178,752	\$4,972,286	\$0	\$8,151,038	(\$4,035,013)	(\$827,074)	\$4,862,087)	\$3,288,951
26	Feb-24	\$2,250,681	\$4,964,056	\$0	\$7,214,736	(\$2,527,277)	(\$773,714)	(\$3,300,991)	\$3,913,745
27	Mar-24	\$964,087	\$2,486,143	\$1,583,295	\$5,033,525	(\$789,016)	(\$382,335)	(\$1,171,351)	\$3,862,174
28	Total	\$55,983,047	\$131,795,013	\$4,709,943	\$192,488,004	(\$49,427,490)	(\$22,038,999)	(\$71,466,489)	\$121,021,515

Pymt	Date	Logan							
		CONTRACT COSTS				PJM REVENUE			
		Contract Energy Cost	Contract Capacity Costs	Incentive	Contract Costs	PJM Energy Revenue	PJM Capacity Revenue	PJM Revenue	Customer Costs
1	Jan-22	\$4,447,561	\$3,712,441	\$125,000	\$8,285,002	(\$4,465,474)	(\$1,099,967)	(\$5,565,440)	\$2,719,561
2	Feb-22	\$3,274,851	\$3,705,430	\$125,000	\$7,105,282	(\$2,598,242)	(\$993,518)	(\$3,591,760)	\$3,513,522
3	Mar-22	\$3,009,262	\$3,712,441	\$125,000	\$6,846,702	(\$1,389,331)	(\$1,099,967)	(\$2,489,298)	\$4,357,405
4	Apr-22	\$2,153,866	\$3,710,104	\$125,000	\$5,988,970	(\$955,310)	(\$1,064,484)	(\$2,019,794)	\$3,969,176
5	May-22	\$2,287,948	\$3,712,441	\$125,000	\$6,125,389	(\$1,015,597)	(\$1,099,967)	(\$2,115,563)	\$4,009,825
6	Jun-22	\$2,257,471	\$3,679,340	\$125,000	\$6,061,811	(\$1,143,249)	(\$626,500)	(\$1,769,749)	\$4,292,063
7	Jul-22	\$2,573,176	\$3,680,651	\$125,000	\$6,378,827	(\$1,837,629)	(\$647,383)	(\$2,485,012)	\$3,893,815
8	Aug-22	\$2,537,020	\$3,680,651	\$125,000	\$6,342,671	(\$1,660,939)	(\$647,383)	(\$2,308,322)	\$4,034,349
9	Sep-22	\$2,268,669	\$3,679,340	\$125,000	\$6,073,009	(\$1,107,975)	(\$626,500)	(\$1,734,475)	\$4,338,534
10	Oct-22	\$0	\$3,680,651	\$125,000	\$3,805,651	\$0	(\$647,383)	(\$647,383)	\$3,158,268
11	Nov-22	\$2,174,961	\$3,679,340	\$125,000	\$5,979,301	(\$1,102,292)	(\$626,500)	(\$1,728,792)	\$4,250,510
12	Dec-22	\$2,639,170	\$3,680,651	\$125,000	\$6,444,821	(\$2,051,787)	(\$647,383)	(\$2,699,170)	\$3,745,650
13	Jan-23	\$3,802,671	\$3,734,651	\$125,000	\$7,662,322	(\$4,726,162)	(\$647,383)	(\$5,373,545)	\$2,288,777
14	Feb-23	\$2,871,746	\$3,730,717	\$125,000	\$6,727,463	(\$2,949,928)	(\$584,733)	(\$3,534,661)	\$3,192,802
15	Mar-23	\$2,513,304	\$3,734,651	\$125,000	\$6,372,955	(\$1,768,482)	(\$647,383)	(\$2,415,865)	\$3,957,090
16	Apr-23	\$2,060,298	\$3,733,340	\$125,000	\$5,918,638	(\$961,563)	(\$626,500)	(\$1,588,063)	\$4,330,575
17	May-23	\$2,175,055	\$3,734,651	\$125,000	\$6,034,706	(\$1,017,214)	(\$647,383)	(\$1,664,597)	\$4,370,109
18	Jun-23	\$2,178,294	\$3,741,481	\$125,000	\$6,044,775	(\$1,184,287)	(\$725,781)	(\$1,910,068)	\$4,134,707
19	Jul-23	\$2,523,842	\$3,743,064	\$125,000	\$6,391,906	(\$1,838,854)	(\$749,974)	(\$2,588,828)	\$3,803,077
20	Aug-23	\$2,509,563	\$3,743,064	\$125,000	\$6,377,627	(\$1,698,364)	(\$749,974)	(\$2,448,337)	\$3,929,289
21	Sep-23	\$2,228,572	\$3,741,481	\$125,000	\$6,095,053	(\$1,136,104)	(\$725,781)	(\$1,861,885)	\$4,233,169
22	Oct-23	\$764,501	\$3,743,064	\$125,000	\$4,632,565	(\$441,876)	(\$749,974)	(\$1,191,850)	\$3,440,715
23	Nov-23	\$2,224,474	\$3,741,481	\$125,000	\$6,090,955	(\$1,171,136)	(\$725,781)	(\$1,896,917)	\$4,194,038
24	Dec-23	\$2,581,648	\$3,743,064	\$125,000	\$6,449,711	(\$1,869,696)	(\$749,974)	(\$2,619,670)	\$3,830,041
25	Jan-24	\$3,432,111	\$3,799,064	\$125,000	\$7,356,174	(\$3,975,817)	(\$749,974)	(\$4,725,791)	\$2,630,383
26	Feb-24	\$2,745,789	\$3,795,898	\$125,000	\$6,666,688	(\$2,625,500)	(\$701,588)	(\$3,327,088)	\$3,339,600
27	Mar-24	\$2,492,375	\$3,799,064	\$125,000	\$6,416,439	(\$1,776,100)	(\$749,974)	(\$2,526,074)	\$3,890,365
28	Apr-24	\$2,065,553	\$3,797,481	\$125,000	\$5,988,034	(\$1,032,839)	(\$725,781)	(\$1,758,620)	\$4,229,414
29	May-24	\$2,157,753	\$3,799,064	\$125,000	\$6,081,816	(\$1,041,193)	(\$749,974)	(\$1,791,167)	\$4,290,649
30	Jun-24	\$2,191,119	\$3,802,137	\$125,000	\$6,118,256	(\$1,226,328)	(\$796,947)	(\$2,023,274)	\$4,094,982
31	Jul-24	\$2,702,214	\$3,803,875	\$125,000	\$6,631,088	(\$2,259,194)	(\$823,512)	(\$3,082,706)	\$3,548,383
32	Aug-24	\$2,435,957	\$3,803,875	\$125,000	\$6,364,832	(\$1,612,111)	(\$823,512)	(\$2,435,623)	\$3,929,209
33	Sep-24	\$2,229,408	\$3,802,137	\$125,000	\$6,156,545	(\$1,208,017)	(\$796,947)	(\$2,004,964)	\$4,151,581
34	Oct-24	\$718,651	\$3,803,875	\$125,000	\$4,647,525	(\$397,231)	(\$823,512)	(\$1,220,743)	\$3,426,782
35	Nov-24	\$2,234,308	\$3,802,137	\$125,000	\$6,161,445	(\$1,238,115)	(\$796,947)	(\$2,035,062)	\$4,126,383
36	Dec-24	\$2,566,042	\$3,803,875	\$125,000	\$6,494,917	(\$1,876,631)	(\$823,512)	(\$2,700,143)	\$3,794,774
37	Total	\$86,029,203	\$134,790,666	\$4,500,000	\$225,319,869	(\$60,360,568)	(\$27,519,730)	(\$87,880,298)	\$137,439,572

**IN THE MATTER OF THE PETITION
OF ATLANTIC CITY ELECTRIC
COMPANY FOR APPROVAL OF THE
MODIFICATION OF POWER
PURCHASE AGREEMENTS WITH
CHAMBERS COGENERATION
LIMITED PARTNERSHIP AND LOGAN
GENERATING COMPANY, L.P.**

**STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES**

CERTIFICATION OF SERVICE

CYNTHIA L.M. HOLLAND, of full age, certifies as follows:

1. I am an attorney at law of the State of New Jersey and am Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.
2. I hereby certify that, on December 22, 2021, I caused the within Petition and the supporting testimony, schedules, and exhibits thereto, to be filed with the New Jersey Board of Public Utilities (the “Board” or “BPU”) through its eFiling Portal. I also caused an electronic copy to be sent to the Board Secretary’s office at board.secretary@bpu.state.nj.us.
3. I further certify that, on December 22, 2021, I caused a complete copy of the Petition and the supporting testimony, schedules, and exhibits thereto, to be sent by electronic mail to each of the parties listed in the attached Service List.
4. Consistent with the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities’ Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, only electronic copies of this Petition have been served on persons on the Service List.

5. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: December 22, 2021



CYNTHIA L.M. HOLLAND

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In the Matter of the Petition of Atlantic City Electric Company for Approval of the Modification of Power Purchase Agreements with Chambers Cogeneration Limited Partnership and Logan Generating Company, L.P.

BPU Docket No. _____

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