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November 4, 2004

Mary L. Cottrell, Secretary
Department of Telecommunication and Energy
One South Station, 2nd Floor
Boston, MA 02202

Re: D.T.E. 04-78 - Petition of Commonwealth Electric Company d/b/a NSTAR Electric for Approvals Relating to the Assignment of Power Purchase Agreements with Dartmouth PPA Holdings LLC

Dear Secretary Cottrell:

Enclosed please find the responses of Commonwealth Electric Company d/b/a NSTAR Electric ("Commonwealth") to discovery questions asked by the Department of Telecommunications and Energy in the above-referenced proceeding, as listed on the following Discovery Log. Please note that certain documents that are responsive to these questions are confidential and are being filed under separate cover with the Attorney General and the Hearing Officer only.

Thank you for your attention to this matter.

Very truly yours,

John K. Habib

John K. Habib

Enclosures

cc: Service List
Joan Foster Evans, Hearing Officer (2)
Colleen McConnell, Assistant Attorney General (2)

LOG OF RESPONSES FILED

D.T.E. 04-78

November 4, 2004

AG-1-1	Filed October 19	Attachments AG-1-1 (a), (b) and (c)
AG-1-2	Filed October 22	Attachment AG-1-2 **CONFIDENTIAL BULK (And CD-ROM)**
AG-1-3	Filed October 21	Attachment AG-1-3 **CONFIDENTIAL (And CD-ROM)**
AG-1-4	Filed October 21	Attachment AG-1-4 (a) Attachment AG-1-4 (b) **CONFIDENTIAL** Attachment AG-1-4 (c) **CONFIDENTIAL** Attachment AG-1-4 (d) **CONFIDENTIAL** Attachment AG-1-4 (e) **CONFIDENTIAL**
AG-1-5	Filed October 22	Attachment AG-1-5 (a) **CONFIDENTIAL** Attachment AG-1-5 (b) **CONFIDENTIAL** Attachment AG-1-5 (c) **CONFIDENTIAL** Attachment AG-1-5 (d) **CONFIDENTIAL** Attachment AG-1-5 (e) **CONFIDENTIAL** Attachment AG-1-5 (f) **CONFIDENTIAL**
AG-1-6	Filed October 22	
AG-1-7	Filed October 19	
AG-1-8	Filed October 19	
AG-1-9	Filed October 21	
AG-1-10	Filed October 21	Attachment AG-1-10 (a) **CONFIDENTIAL (and CD-ROM)** Attachment AG-1-10 (b) **CONFIDENTIAL (and CD-ROM)**
AG-1-11	Filed October 21	Attachment AG-1-11
AG-1-12	Filed October 21	Attachment AG-1-12
AG-1-13	Filed October 21	Attachment AG-1-13 **CONFIDENTIAL (and CD-ROM)**
AG-1-14	Filed October 21	
AG-1-15	Filed October 21	
AG-1-16	Filed October 21	
AG-1-17	Filed October 21	
AG-1-18	Filed October 21	
AG-1-19	Filed October 21	Attachment AG-1-19 **CONFIDENTIAL**
AG-1-20	Filed October 21	Attachment AG-1-20 **CONFIDENTIAL BULK**
AG-1-21	Filed October 21	
AG-1-22	Filed October 21	
AG-1-23	Filed October 22	
AG-1-24	Filed October 22	Attachment AG-1-24 **CONFIDENTIAL (And CD-ROM)**
AG-1-25	Filed October 21	Attachment AG-1-25 **BULK**
AG-1-26	Filed October 21	

AG-1-26 (Supplemental)	Filed Herewith	Attachment AG-1-26 **CONFIDENTIAL**
AG-1-27	Filed October 21	
AG-1-28	Filed October 21	
AG-1-29	Filed October 19	Attachment AG-1-29 **BULK**
AG-1-30	Filed October 19	Attachment AG-1-30 **CONFIDENTIAL**
AG-2-1		
AG-2-2	Filed Herewith	
AG-2-3	Filed Herewith	Attachment AG-2-3(a) Attachment AG-2-3(b) Attachment AG-2-3(c) Attachment AG-2-3(d) Attachment AG-2-3(e)
AG-2-4	Filed Herewith	Attachment AG-2-4(a) Attachment AG-2-4(b) Attachment AG-2-4(c) Attachment AG-2-4(d)
AG-2-5	Filed November 3	
AG-2-6	Filed Herewith	Attachment AG-2-6(a) **CONFIDENTIAL** Attachment AG-2-6(b) **CONFIDENTIAL** Attachment AG-2-6(c)
AG-2-7	Filed Herewith	Attachment AG-2-7(a) Attachment AG-2-7(b) **CONFIDENTIAL CD-ROM**
DTE-1-1	Filed Herewith	
DTE-1-2	Filed Herewith	Attachment DTE-1-2 **CONFIDENTIAL BULK**
DTE-1-3	Filed November 2	
DTE-1-4	Filed November 2	Attachment DTE-1-4
DTE-1-5	Filed November 2	Attachment DTE-1-5 **CONFIDENTIAL**
DTE-1-6	Filed November 2	
DTE-1-7	Filed November 2	
DTE-1-8	Filed Herewith	
DTE-1-9 **CONFIDENTIAL**	Filed November 2	
DTE-1-10 **CONFIDENTIAL**	Filed Herewith	
DTE-1-11	Filed November 3	Attachment DTE-1-11(a) **CONFIDENTIAL** Attachment DTE-1-11(b)
DTE-1-12	Filed November 3	
DTE-1-13	Filed November 2	Attachment DTE-1-13
DTE-1-14	Filed November 2	Attachment DTE-1-14
DTE-1-15	Filed November 2	
DTE-1-16	Filed November 2	
DTE-1-17	Filed November 2	
DTE-1-18	Filed November 2	
DTE-1-19	Filed November 2	
DTE-1-20	Filed November 2	Attachment DTE-1-20 **CONFIDENTIAL CD-ROM**
DTE-1-21	Filed Herewith	

DTE-1-22 **CONFIDENTIAL**	Filed November 3	
DTE-1-23	Filed November 2	
DTE-1-24	Filed November 2	

Information Request DTE-1-1

Have any disputes emerged regarding the choice of the Dartmouth contract auction winner?

Response

No disputes have emerged regarding the choice of the Dartmouth contract auction winner.

Information Request DTE-1-2

Refer to Exh. NSTAR-RBH at 18, lines 10-13. Please explain how Dartmouth was involved in the auction process. Provide copies of all communication between CEA, NSTAR and Dartmouth relating to the auction and the termination of the Dartmouth contracts.

Response

BULK CONFIDENTIAL ATTACHMENT

The Company has been in contact with Dartmouth PPA Holdings LLC ("Dartmouth Holdings") during the entire period, but because Dartmouth Holdings was in the process of being sold, it did not actively participate in the auction process until late in the process. Negotiations for the Dartmouth Purchase and Sale Agreement began during July of 2004 after AIG, now the parent of Dartmouth Holdings, acquired the facility from El Paso Corporation. Because the Dartmouth transaction involved a large lump-sum payment, it was in the best interest of customers to take advantage of the synergies that would be gained by combining the Dartmouth and MASSPOWER payments into a single securitization financing. Attachment DTE-1-2 **CONFIDENTIAL BULK** contains copies of communications between CEA, NSTAR and Dartmouth relating to the auction and the Dartmouth Purchase and Sale Agreement.

Information Request DTE-1-8

On what date did each of the bidders make their initial bid for the contracts? On what date did each of the bidders make their final bid for the contracts?

Response

Bidders submitted final bids for the NSTAR PPA auction on December 3, 2003. After negotiations and discussions with CEA and the Company, bidders and were asked to re-price their final bids based on these discussions. The chart below shows the dates each bidder submitted their re-priced bids[1].

	Bidder A	Bidder B	Bidder C	Bidder D	Bidder E	Bidder F
Final Bid	Dec. 3	Dec. 3	Dec. 3	Dec. 3	Dec. 3	August
Bid Re-Price	Dec. 4	Dec. 5			Jan. 7	July
	Dec. 22	Jan. 12				
	Jan. 13	Feb. 11				
	Feb. 10	Feb. 12				
	Feb. 24	Mar. 25				
	Mar. 1	Mar. 31				
	Mar. 2					

[1] Other than Bidder F, none of the final bids were binding.

Information Request DTE-1-10

Refer to Exh. NSTAR-GOL-2, at 1, line 7. Please explain why the estimated income tax payments associated with the recovery of securitization principle must be present valued. In addition, provide a detailed calculation of the present value amount found on line 7.

Response

REDACTED RESPONSE

This response is identical to the response given in the revised Exhibit DTE-1-15 (Revised) in D.T.E. 04-61 with the exception that the references and numbers tie to D.T.E. 04-78. The method of calculation and formulae are identical.

The objective of the securitization is that all benefits (and costs) flow to the customers and the Company is held harmless from the securitization. All the cash flows associated with the securitization are present valued at the securitization rate to arrive at the securitization amount.

The Company recovers in rates the principal payments of the securitized debt from customers each month over the securitization period of eight years. As the Company receives the revenue, it pays federal and state taxes because the income is taxable but there is no current offsetting tax deductible expense (this is in contrast to the interest revenue which is equally offset by interest expense in the same period – thus no net tax impact). The tax offset to the principal revenue is the tax deductibility of the buyout, which occurs when the buyout takes place (see Information Request DTE-1-9). The amounts differ slightly because the securitization is not exactly the same as the buyout amount due to the difference in present valuing the tax streams. These taxes are cash payments made by the Company that must be recovered from customers so that the Company will be kept whole. The cash payments will be made over an eight year period and are present valued so that their impact can be included in the up front securitization amount.

For a detailed calculation of the present value amount of **[REDACTED]** million on Exhibit NSTAR-GOL-2, line 7 on page 1, please refer to page 2, line 1, column E as

shown on the reference. The explanation in my testimony page 21 gives a better explanation of how the taxes are calculated[1].

An example of the tax calculation for the year 2006 may be useful. First the annual revenue is calculated from column F – the principal monthly payments. Since the monthly payment is **[REDACTED]** (rounded in column F), the annual payment for 2006 is twelve times that amount or **[REDACTED]**.

- In March 40% (Page 3, line 6, Column B) of the annual state tax is due, which is **[REDACTED]** (**[REDACTED]**times 40% times 6.5%). This number can be seen on page 2, line 14 (Mar-06) column E.
- In June 25% (Page 5, line 8, Column B) of the annual state tax is due, which is **[REDACTED]** (**[REDACTED]** times 25% times 6.5%). This number can be seen on page 2, line 17 (Jun-06) column E.
- In September 25% (Page 5, line 9, Column B) of the annual state tax is due, which is **[REDACTED]** (**[REDACTED]** times 25% times 6.5%). This number can be seen on page 2, line 20 (Sep-06) column E.
- In December **[REDACTED]** State Tax and **[REDACTED]** Federal Tax is due totaling **[REDACTED]** This number can be seen on page 2, line 23 (Dec-06) column E.
    - In December 10% (Page 5, line 10, Column B) of the annual state tax is due, which is **[REDACTED]** (**[REDACTED]**times 10% times 6.5%).
    - In December 100% of the annual Federal tax is due, which is **[REDACTED]** (**[REDACTED]**times 32.725% - Page 3 line 24, Column C).

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[1] Q. What is displayed in each of the columns?

A. Column B shows the total buyout amounts as shown on page 1 line 4. Column C shows the cash inflow (avoidance of tax cash outflows – i.e., tax shields) to the Company from the deductibility of the buyout and make-whole amounts. The Company must have sufficient income to make the deductions. The tax payments are made quarterly for state tax purposes based on the forecast income for the year as follows: 40 percent in March; 25 percent in June; 25 percent in September; and 10 percent in December (as shown on page 5 lines 7 through 10). Federal tax payments are made on December 15th each year. Column D shows the tax shield relating to the issuance costs. The issuance costs on page 1, line 9 are divided by the 96 months over the eight-year period and multiplied by the effective tax rate on page 6. Column E shows the tax that is paid on the principal repayment from customers. It is calculated by multiplying the principal repayment for each year as shown on column F and applying the state tax percentage (6.5 percent) for each quarter and applying the federal tax rate (page 5 line 25 being 32.725 percent after the state tax deduction allowed for federal taxes) to arrive at the federal tax in December.

This calculation method is used for the remaining years, except that it is assumed at April for the first year when the securitization is assumed to occur at the end of March, and 100 percent of the tax for 2013 is assumed to occur in March when the securitization ends.

The tax payments are present valued on line 1 at the securitization rate divided by 12 to arrive at a monthly securitization rate.

Information Request DTE-1-21

Do any of the corrections made to the initial filings in D.T.E. 04-60, D.T.E. 04-61, or D.T.E. 04-68 affect the customer savings analyses filed in D.T.E. 04-78? If yes, (1) please describe each correction and explain how it impacts the savings analyses in this proceeding, and (2) provide corrected copies of the exhibits.

Response

None of the corrections made to the initial filings in D.T.E. 04-60, D.T.E. 04-61, or D.T.E. 04-68 affects the customer-savings analyses filed in D.T.E. 04-78.

The corrections in D.T.E. 04-60 affect Cambridge, only, and therefore have no impact on this proceeding, which concerns Commonwealth. The corrections in D.T.E. 04-61 and D.T.E. 04-68 that affect the analysis of costs and savings have no effect on the savings for Dartmouth since they would be included in both the "before" and "after" cases set forth in Exhibit NSTAR-COM-GOL-3 and Exhibit NSTAR-COM-GOL-4. Additionally, in D.T.E. 04-61, securitization cost estimates were updated, however those updates were included as necessary in the original filing in D.T.E. 04-78.

Information Request AG-1-26

Please provide a complete copy of the Fall 2004 Henwood Energy Service Inc.'s Northeast Electricity and Gas Price Outlook, when it becomes available.

Supplemental Response

CONFIDENTIAL ATTACHMENT

Attachment AG-1-26 is the Fall 2004 Henwood Power and Fuel Forecast received by NSTAR Electric on November 1, 2004. The Fall 2004 forecast changed the composition of the load zones and nodes within the Northeast market and did not provide a forecast for the SEMA-RI zone. Therefore, NSTAR Electric does not have a comparable forecast that is an update to the Fall 2003 forecast used in this case. At NSTAR Electric's request, Henwood will prepare an updated SEMA-RI load zone forecast, which should be available to NSTAR Electric on or about Tuesday November 9, 2004. NSTAR Electric will provide the updated forecast as soon as it is available and will update exhibits, as requested, based on that forecast upon receipt.

Information Request AG-2-2

Please itemize and quantify the Company's current estimate of the total cost for outside services related to the contract divestiture for which the Company seeks recovery from the its customers. Please also provide copies of all invoices for those services that have been received to date.

Response

Please refer to the response the Information Request DTE-1-16 for the Company's current estimate of the total cost for outside services. Please refer to Exhibit AG-1-3, Attachment AG-1-3(a) in D.T.E. 04-60 for copies of invoices from CEA for the period August 2003 through May 2004. Please refer to Attachment AG-1-43 in D.T.E. 04-85 for copies of invoices from Keegan, Werlin & Pabian, LLP for the period January through August 2004. The Company is gathering copies of the remaining invoices and will supplement this response when completed.

Information Request AG-2-3

Please provide copies of all Department orders approving the RFP which resulted in the Companies' original contract with Dartmouth, approving the original contract with Dartmouth and each contract amendment. Include any related orders on appeal by the Department and/or the courts.

Response

As indicated in Attachment AG-2-3(a), Dartmouth was not a qualifying facility and therefore the he original contract was not the result of the RFP process, which at the time was limited to QFs.

Copies of the other requested documents are attached as follows:

Attachment AG-2-3(a)	Approval of the Original Contract
Attachment AG-2-3(b)	Approval of the 1st Amendment
Attachment AG-2-3(c)	Approval of the 2nd Amendment
Attachment AG-2-3(d)	Approval of the 3rd Amendment
Attachment AG-2-3(e)	Approval of the 4th Amendment

No appeals were taken of any orders.

Attachment
AG-2-3(a)

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

March 30, 1990

D.P.U. 89-218

Investigation by the Department on its own motion of the propriety of a unit power agreement between Dartmouth Power Associates and Commonwealth Electric Company.

I. SUMMARY OF PROPOSED AGREEMENT

On September 27, 1989, Commonwealth Electric Company ("Commonwealth" or "Company"), pursuant to G.L. c. 164, § 94A, submitted to the Department of Public Utilities ("Department") a power purchase agreement with Dartmouth Power Associates ("Dartmouth Power"). The agreement calls for Commonwealth to purchase a 50-megawatt ("MW") entitlement to the electric power produced by a 186.8 MW gas-fired generating facility that Dartmouth Power plans to construct ("Unit").

Commonwealth states that, in some respects, its filing constitutes a case of first impression before the Department. Dartmouth Power is reputed to be the first independent power producer located in Massachusetts to be the subject of a filing under G.L. c. 164, § 94A. The Company suggests, because Dartmouth Power is neither a traditional regulated utility nor a qualifying facility, that the Department's jurisdictional authority vis-a-vis the Federal Energy Regulatory Commission ("FERC") is not clear. Commonwealth maintains that the Dartmouth Power contract will be filed with and fully subject to the rate jurisdiction of the FERC under section 205 of the Federal Power Act (16 U.S.C. § 824d). However, the Company also claims that the "FERC has indicated in one case involving another independent power producer that its own exercise of jurisdiction is inclined to be facilitated by the determination of state regulatory authorities with respect to the extent to which the rates contained in a wholesale contract fall below the

rates otherwise available to the purchasing utility" (Company Petition, p. 2). Therefore, while Commonwealth states that a filing under Section 94A is appropriate "in order to expedite its participation in this project," it also asserts a right to argue before the FERC any challenge that may be made to the contract (id.).

Dartmouth Power would own the Unit, which is to be constructed on a site in Dartmouth, Massachusetts (Purchase Power Agreement, p. 1). The Unit is to use two gas turbines and a supplementary-fired waste heat boiler with a dual inlet steam turbine (id.). The Unit is to be fueled with natural gas transported from Alberta, Canada. It is intended that the Unit be operated in conformance with the applicable New England Power Pool ("NEPOOL") Criteria, Rules, and Standards, and Operating Procedures, and dispatch instructions (id., p. 3). The proposed in-service date is July 1, 1992 (id.).

Commonwealth proposes to purchase a 50-MW entitlement to the capacity and associated energy produced by the Unit. Under the terms of the 25-year agreement, the total purchase price that Commonwealth would pay to Dartmouth Power each month would have two components, a monthly capacity charge and a monthly energy charge (Company Petition, p. 2). As outlined in Appendix B (Parts 2 and 3) to the Power Purchase Agreement, the monthly capacity charge consists of:

(1) A Monthly Capacity Cost, the initial amount of which shall be set at $192,706. The Monthly Capacity Cost shall be subject to the following adjustments:

(a) Changes in the GNP Implicit Price Deflator as published by the Bureau of Economic Analysis of the U.S. Department of Commerce; and,

(b) Additional operating and maintenance costs that Dartmouth power may incur in the event that NEPOOL requests in excess of 100 stops and 100 starts of the Unit in any calendar year.

(2) A Monthly Investment Cost, which shall equal $697,186.

(3) A Monthly Pipeline Transportation Capacity Demand Cost, which shall reflect the various pipeline capacity charges associated with transportation of natural gas from Alberta, Canada, and which shall be assessed in proportion to Commonwealth's entitlement to power from the Unit.

(4) A performance-based, Bonus or Penalty Adjustment, which shall be assessed depending on whether the Unit, on a moving twelve-month basis, exceeds or falls short of a designated availability level.

As outlined in Appendix B (Part 4) to the Power Purchase Agreement, the monthly energy charge consists of the product of the Delivered Energy (kilowatthours) for the billing period and the sum of the Variable Fuel Supply Rate and the Variable Fuel Transportation Throughput Rate, defined as follows:

(1) The Variable Fuel Supply Rate is set at $1.35 per million British Thermal Units and shall be adjusted for pipeline gas transmission losses and a predetermined price index.

(2) The Variable Fuel Transportation Throughput Rate shall reflect the firm commodity throughput rates associated with procuring natural gas from Alberta, Canada.

II. ANALYSIS AND FINDINGS

The Department has articulated the requirement that utilities analyze alternative resource options to ensure that

reliable and economic supplies are procured for their customers. Boston Gas Company, D.P.U. 89-180, p. 12 (1990); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A, p. 170 (1985); Boston Edison Company, D.P.U. 1720, pp. 200-206 (1984). Accordingly, the Department's review of the proposed purchased power agreement requires us to determine whether the agreement benefits ratepayers in that it is likely to represent a cost-effective means of providing reliable service vis-a-vis other resource options that may be available to the Company. Boston Edison Company, D.P.U. 86-262, p. 7 (1987).

For this agreement, two issues must be evaluated in order to assess whether the agreement meets the Department's standard. First, a determination must be made as to whether contract payments are likely to be less than costs that the Company would otherwise be required to incur to provide service, i.e., its calculated avoided costs. Second, the agreement must be reviewed to ensure that ratepayers are reasonably protected from undue financial risk, such as may be associated with project cancellation or inefficient operation of the Unit.

In support of its filing, the Company compared expected contract payments to its avoided costs, as filed with the Department with its second Request for Proposal ("RFP 2") approval request (docketed as D.P.U. 89-119). These comparisons are contained in Commonwealth's "Response to the Standard Information Requirements" (December 29, 1989) in Schedules 1, 2, and 3. Based on the information contained in these schedules,

MAR 30 '90 12:45 FROM PMBE 617 482 3092 PAGE 006

the Department finds that significant financial benefits can be expected to accrue to ratepayers under the proposed agreement between Commonwealth and Dartmouth Power. In particular, the Department finds that, over the course of the 25-year agreement, Commonwealth's ratepayers should recognize savings of roughly $25 million (1989 dollars) over its avoided costs. Schedules 2 and 3 show that, under the agreement, ratepayers' financial exposure if fuel prices fall will be far lower than the benefits that would be anticipated if oil prices rise. Accordingly, the Department finds the agreement is cost-effective.

On the issue of whether the Dartmouth Power agreement provides ratepayers with reasonable protection from undue financial risks, a review of the pricing provisions presented supra reveals that the agreement provides for substantial reductions in the monthly capacity payments should the Unit fail to operate efficiently. The Department finds this to provide a strong incentive for Dartmouth Power to strive to maintain high unit availability. The performance-based nature of the contract is also similar to other agreements that the Department has found likely to protect the financial interests of ratepayers while promoting the efficient utilization of generation resources. Boston Edison Company, D.P.U. 88-28, 88-48, 89-100 (1989). Generic Rulemaking, D.P.U. 86-36-G, Proposed 220 C.M.R. 10.06(2)(e) (1989).

Moreover, other contract provisions augment the risk-mitigating performance incentives built into the pricing

provisions of the agreement. Article 4 of the agreement requires Dartmouth Power to post a $750,000 security deposit, payable to Commonwealth in whole or in part if the project is cancelled or delayed. Article 14.4 permits Commonwealth to withhold capacity payments if the Unit is not maintained in accordance with Good Utility Practice. Several provisions Articles 2 and 14 of the agreement grant Commonwealth authority to monitor and to oversee certain aspects of the operation and maintenance of the Unit.

Particularly noteworthy is Article 15.4 of the agreement, which requires Dartmouth Power to obtain an irrevocable Letter of Credit by which to secure payments expected to exceed Commonwealth's avoided costs during the early years of the contract. The agreement requires Dartmouth Power to secure credit amounts according to the following schedule:

From	Through	Amount
In-service date	December 31, 1992	$2,526,162
January 1, 1993	December 31, 1993	$3,692,380
January 1, 1994	December 31, 1994	$5,667,578
January 1, 1995	December 31, 1995	$7,511,116
January 1, 1996	December 31, 1996	$9,515,361
January 1, 1997	December 31, 1997	$10,546,831
January 1, 1998	December 31, 1998	$9,866,184
January 1, 1999	December 31, 1999	$6,918,707
January 1, 2000	December 31, 2000	$5,848,890
January 1, 2001	December 31, 2001	$3,615,810

The Department finds these, and other security provisions of the agreement with Dartmouth Power, to provide Commonwealth's ratepayers with reasonable protection from undue financial risk. The Department finds additionally that Commonwealth's

ratepayers may benefit from the provision that grants to the Company a right of first refusal on any additional electricity offered for sale as a consequence of expansion of the unit or after expiration of the contract.

Based on a review of the information presented in support of the agreement, the Department finds that the proposed Dartmouth Power purchase is cost-effective and will result in net savings for Commonwealth ratepayers compared to its avoided costs. Therefore, the Department finds that the power purchase agreement is in the public interest.

Accordingly, after due consideration, it is

ORDERED: That the contract filed with the Department on September 27, 1989, governing the purchase by Commonwealth Electric Company of a 50-MW entitlement and associated energy from the Dartmouth Power Associates Unit, be and hereby is APPROVED.

By Order of the Department,

/s/ BERNICE K. McINTYRE

Bernice K. McIntyre, Chairman

A true copy
Attest:

MARY L. COTTRELL
Secretary

MAR 30 '90 13:47 FROM RMBF 617 482 3097 PAGE.009

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, Order or ruling of the Commission, or within such further time as to the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, Order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said court. (G.L. Ter. Ed., c. 25, s. 5, as most recently amended by c. 485 of the Acts of 1971)

Attachment
AG-2-3(b)

APPROVED
Oct. 23, 1990
COMMISSIONERS, D.P.U.

COM/Electric
Commonwealth Electric Company
Post Office Box 9150
Cambridge, Massachusetts 02142-9150
Telephone (617) 225-4000

August 15, 1990

RECEIVED
AUG 15 1990
DEPT. OF PUBLIC UTILITIES
ADMINISTRATION

Department of Public Utilities
100 Cambridge Street
Boston, MA 02202

Attention: Henry Yoshimura
Electric Power Division

Re: Amendment to Power Purchase Agreement
Dartmouth Power Associates Limited Partnership

Dear Mr. Yoshimura:

Commonwealth Electric Company ("Commonwealth" or the "Company") submits herewith an Amendment, dated August 3, 1990, to a Power Purchase Agreement (the "Amendment") by and between itself and Dartmouth Power Associates Limited Partnership ("Dartmouth Power"). The Amendment modifies certain terms of a Power Purchase Agreement, dated September 5, 1989, between Commonwealth and Dartmouth Power (the "Agreement"). The Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "Department") on September 27, 1989 and was approved by the Department on March 30, 1990 in DPU 89-218.

Pursuant to the Agreement, Commonwealth had agreed to purchase a 50 MW entitlement to the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned and operated by Dartmouth Power at a site in the Town of Dartmouth. As set forth in the Agreement, the Unit was to be capable of generating approximately 168.8 MW of electricity. However, Dartmouth Power has determined that the Unit will be constructed so as to be capable of generating approximately 67.6 MW. Dartmouth Power offered to sell to Commonwealth an additional 17.6 MW of electricity, which would make the Company the sole purchaser of the electricity that will be produced by the downsized Unit. The Company has determined that this additional purchase of electricity would be beneficial to its ratepayers and would facilitate its administration of the Agreement. Accordingly, Commonwealth has accepted Dartmouth Power's offer.

In addition to modifying the Agreement to reflect the Company's purchase of additional power, the Amendment adds provisions to the Agreement regarding economic dispatch and income tax liabilities, amends the provisions in the

Agreement regarding the security deposit to be furnished by Dartmouth Power to the Company and reflects a reduction in the size of the expected energy bank. The Company notes that the Amendment does not change the pricing mechanism as set forth in the Agreement. The unit prices for capacity and energy will not change. The calculation of the Monthly Capacity Charge component in the price formula will change to reflect the increase in the amount of power that the Company will purchase.

In order to assist the Department in its review of this Amendment, the Company has included in this filing, the base case, low and high fuel cost scenarios of Tables 1 through 5 from the Department's Standard Information Requirements. In addition, the Company has included schedules providing information responsive to Standard Information Requirement #3. The remainder of the information responsive to the Department's Standard Information Requirements is identical in substance to that contained in Appendix C to the Company's Second Request for Proposal for Qualifying Facility Generation ("RFP #2") filed on June 29, 1990 and approved by the Department on July 12, 1990.

As is apparent from the materials included in this filing the Company's ratepayers have a strong prospect of realizing substantial benefits from the purchase by the Company of the additional 17.6 MW output of the Unit. Commonwealth has compared its projected payment stream to Dartmouth Power to the ceiling prices as developed from RFP#2. As can be seen from the attached schedules in the base case fuel scenario, the expected lifetime cumulative net present value benefit from the additional 17.6 MW increment is approximately $16.6 million. As can also be seen from the attached schedules, the cumulative net present value of projected payments to Dartmouth Power over the life of the Agreement is equal to 80% of the cumulative net present value of the Company's avoided costs.

The Company would be pleased to provide such additional information as the Department may request concerning this matter.

Very truly yours,

Marcy S. Rosenzweig/KAB

Marcy S. Rosenzweig
Manager - Rate Regulation

cc: Brian J. Abbanat, Electric Power Division
George B. Dean, Department of Attorney General

The Commonwealth of Massachusetts
Department of Public Utilities
Leverett Saltonstall Building, Government Center
100 Cambridge Street, Boston 02202

August 12, 1994

Mr. James J. Keane
Vice-President of Power Supply
and Transmission
Commonwealth Electric Company
2421 Cranberry Highway
Wareham, MA 02571

Dear Mr. Keane:

The Department hereby approves the Second Amendment ("Second Amendment") to Power Purchase Agreement ("Agreement") between Commonwealth Electric Company ("Commonwealth") and Dartmouth Power Associates Limited Partnership ("Dartmouth"), which was filed with the Department on July 18, 1994. The Agreement was submitted to the Department on September 27, 1989 and was approved on March 30, 1990 in D.P.U. 89-218.[1] The Department notes that the Second Amendment has been submitted to the Department and to FERC for approval, and that it takes effect upon receipt of approvals "in form and substance acceptable to Commonwealth and Dartmouth."

The Department understands the Second Amendment replaces natural gas price indices which are used in calculating Dartmouth's Variable Fuel Supply Rate as a component of its Monthly Energy Charge. The Department further understands that the Second Amendment allows for redeterminations of natural gas price indices at designated intervals.

The Department understands that the natural gas indices referenced in the Agreement are no longer published. Specifically, the Tennessee CD-6 index; and (2) the Algonquin F-1 index are no longer available due to gas pipeline service restructuring pursuant to FERC Order No. 636. In addition, the Department understands that an index calculated by the

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[1] Commonwealth is the sole purchaser of output from Dartmouth's 67,600 kilowatt generating facility located in Dartmouth, Massachusetts.

Alberta Petroleum Marketing Commission for the Minister of Energy for the Province of Alberta, known as the Alberta Market Price ("AMP") has been replaced with the Alberta Reference Price ("ARP") as a consequence of Canada's Natural Gas Marketing Act.

Due to the unavailability of the Tennessee CD-6 and the Algonquin F-1 indices, Commonwealth and Dartmouth have agreed to replace these with a composite spot price indicator ("T2").[2] In addition, Commonwealth and Dartmouth have agreed to accept the ARP as a replacement for the AMP. Commonwealth and Dartmouth have also agreed that either party may elect to require a redetermination of the composition of the Variable Fuel Supply Rate during 1997, 2002, 2007, or 2012.

The Department understands that the Second Amendment does not change the amount of power purchased by Commonwealth under the Agreement, nor does it change any pricing provisions beyond the indexing provisions of the Variable Fuel Supply Rate as a component of the Monthly Energy Charge.

Sincerely,

Kenneth Gordon
Chairman

Barbara Kates-Garnick
Commissioner

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[2] The T2 index is to consist of the following: (1) the Offshore and Louisiana (Zone 1) Index for Tennessee; (2) the Louisiana and Texas (Zone 0) Index for Tennessee; (3) the arithmetic average of the East Texas and South Texas Indices for the Texas Eastern Transmission Company; and (4) the arithmetic average of the East Louisiana and West Louisiana Indices for the Texas Eastern Transmission Corporation.

Attachment
AG-2-3(d)

The Commonwealth of Massachusetts
Department of Public Utilities
Leverett Saltonstall Building, Government Center
100 Cambridge Street, Boston 02202

June 27, 1996

James J. Keane
Vice President - Power
Supply and Transmission
Commonwealth Electric Company
2421 Cranberry Highway
Wareham, MA 02571

Dear Mr. Keane:

The Department hereby approves the Third Amendment ("Third Amendment") to the Power Purchase Agreement ("Agreement") between Commonwealth Electric Company ("Commonwealth") and Dartmouth Power Associates Limited Partnership ("Dartmouth"), which was filed with the Department on May 8, 1996.

The Agreement was submitted to the Department on September 27, 1989 and was approved on March 30, 1990 in D.P.U. 89-218. The Department notes that the Third Amendment has been submitted to the Department and to the FERC for approval, and that it would take effect upon receipt of approvals "in form and substance acceptable to both Commonwealth and Dartmouth."

The Department understands that the Third Amendment specifies the pipeline capacities for purposes of determining the portion of the Monthly Pipeline Transportation Demand Cost component of the demand charge set forth in section 2.3 of Appendix B of the Agreement.

The Third Amendment also provides an opportunity for Dartmouth and Commonwealth to engage in short-term arrangements under mutually acceptable conditions, where Commonwealth would purchase electricity from suppliers other than Dartmouth in replacement of the purchase of electricity that would otherwise occur pursuant to the agreement. This would enable Dartmouth to enter into short-term transactions with third parties for the sale of electricity, and/or gas (related to the Dartmouth Power Unit) to such parties.

In addition, Commonwealth agrees to purchase from Dartmouth the electricity generated from "Extra Capacity." The Third Amendment defines Extra Capacity as the capacity in excess of the Unit's current winter or summer capacity (but not capacity relating to future improvements or expansions to the Unit or any additional generation facilities located at the site) up to 6 MW. Commonwealth will pay Dartmouth fuel and variable transportation costs (but no incremental demand charges). The electricity from the Extra Capacity could be called upon only during

[1A-90]

System Emergency conditions and/or during a capability test, for a 54 month period commencing upon receipt of all required regulatory approvals and pursuant to the receipt by Commonwealth of additional NEPOOL capacity credit.

With respect to pipeline capacities and the Monthly Pipeline Transportation Demand Cost, this approval is limited to the level of capacity specified in Section 1 of the Third Amendment. This approval also reflects our understanding that the "appropriate amount of gas" for each pipeline is the amount of the contractual transportation capacity required to operate the Dartmouth Power Unit at the contractual Design Capacity and thereby deliver Commonwealth's contractual entitlement (67.6 MW).

The Department is aware that opportunities to reduce costs may arise due to "capacity decontracting," or from Dartmouth's selection of pipeline capacities. The Department encourages Commonwealth to pursue all reasonable opportunities to minimize costs to Commonwealth's customers. Furthermore, any stranded costs that are attributable exclusively to the Third Amendment are the responsibility of Commonwealth's shareholders and not its customers. See Electric Industry Restructuring, D.P.U. 95-30, at 33 (1995).

Sincerely,

John B Howe /MC

John B. Howe, Chairman

Mary Clark Webster

Mary Clark Webster, Commissioner

Janet Gail Besser

Janet Gail Besser, Commissioner

cc: Mary L. Cottrell, Secretary

Attachment
AG-2-3(c)

KEEGAN, WERLIN & PABIAN, LLP

ATTORNEYS AT LAW
21 CUSTOM HOUSE STREET
BOSTON, MASSACHUSETTS 02110-3525

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DAVID S. ROSENZWEIG
E-mail: drosen@kwplaw.com

APPROVED
DATE November 20, 2002
COMMISSIONERS, D.T.E.

October 25, 2002

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, Massachusetts 02110

Re: Fourth Amendment to Power Purchase Agreement Between Commonwealth Electric Company and Dartmouth Power Associates, L.P.

Dear Secretary Cottrell:

Pursuant to G.L. c. 164, § 94A, enclosed for approval by the Department of Telecommunications and Energy (the "Department") is the Fourth Amendment to the Power Purchase Agreement (the "Amendment") that the Company executed with Dartmouth Power Associates, Limited Partnership ("Dartmouth") on October 15, 2002.[1] The Amendment replaces a gas index that the parties use to calculate Dartmouth's Variable Fuel Supply Rate as a component of its Monthly Energy Charge. The gas index previously used to calculate the Monthly Energy Charge (i.e., the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company) is no longer reported. In accordance with the PPA, the monthly energy charge will now be calculated using the arithmetic average of the Tennessee Gas Pipeline Louisiana 500 Leg index and the Tennessee Gas Pipeline Louisiana 800 Leg index. See PPA, § 4.14 (as amended).

In agreeing to the proposed replacement index, the parties attempted to select a mechanism that replicated the original index and maintained the underlying intent of the initial PPA. As demonstrated in Attachment 1 (appended to this letter), there is virtually no difference to the resultant monthly energy charge whether the charge is calculated

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1 The Power Purchase Agreement ("PPA") executed on September 5, 1989 was approved by the Department on March 30, 1990 (Commonwealth Electric Company, D.P.U. 89-219 (1990)). Subsequent amendments to the PPA were approved by the Department in letter orders. Specifically, the first amendment to the PPA was executed on August 3, 1990, and approved by the Department on October 23, 1990. The second amendment to the PPA was executed on June 23, 1994, and approved by the Department on August 12, 1994. The third amendment to the PPA was executed on April 25, 1996, and approved by the Department on June 27, 1996.

using the former or proposed index. The Fourth Amendment does not change the amount of power purchased by the Company under the PPA, nor does it change any pricing provisions beyond the indexing provisions for the Variable Fuel Supply Rate as a component of the Monthly Energy Charge.

The Company respectfully requests that the Department approve the enclosed Agreement by November 30, 2002. If you have any questions concerning this filing, please contact me.

Very truly yours,

David S. Rosenzweig

Enclosures

cc: Paul G. Afonso, General Counsel
Ronald LeComte, Director, Electric Power Division

FOURTH AMENDMENT TO POWER PURCHASE AGREEMENT

This Fourth Amendment to Power Purchase Agreement, dated as of the 15th day of October, 2002 (the "Amendment"), is made by and between COMMONWEALTH ELECTRIC COMPANY, a Massachusetts corporation with its place of business at 800 Boylston Street, Boston, MA 02199 ("Buyer") and DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP, a Massachusetts limited partnership with its place of business at 1001 Louisiana Street, Houston, TX 77002 ("Seller", and collectively with Buyer, the "Parties").

WHEREAS, the Parties have previously entered into a Power Purchase Agreement, dated as of September 5, 1989, as amended by 1) an Amendment to Power Purchase Agreement, dated as of August 3, 1990, 2) a Second Amendment to Power Purchase Agreement, dated as of June 23, 1994, 3) a Third Amendment to Power Purchase Agreement, dated as of April 23, 1996 (as amended, the "Power Purchase Agreement");

WHEREAS, pursuant to the Power Purchase Agreement, Buyer pays to Seller each Billing Period the sum of the Monthly Capacity Charge and the Monthly Energy Charge;

WHEREAS, the Monthly Energy Charge is comprised of various components, one of which is calculated by multiplying the Delivered Energy for the prior Billing Period by the sum of the Variable Fuel Transportation Throughput Rate and the Variable Fuel Supply Rate;

WHEREAS, the Variable Fuel Supply Rate is adjusted monthly by an Index Factor, one component of which includes the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company ("Tennessee Zone 1 Index"); and

WHEREAS, the Parties wish to recognize that the Tennessee Zone 1 Index is no longer reported and in accordance with the terms of the Power Purchase Agreement such index shall be succeeded by the arithmetic average of the Tennessee Gas P/L Louisiana 500 Leg index and the Tennessee Gas P/L Louisiana 800 Leg index;

NOW, THEREFORE, in consideration of the foregoing, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. All terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Power Purchase Agreement.

2. In Article 4.14 of Appendix B of the Power Purchase Agreement, the definition of "T2" is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> "T2" shall be calculated as the arithmetic average of the following four indices for the Billing Period:

(a) the arithmetic average of the Tennessee Gas P/L Louisiana 500 Leg index and the Tennessee Gas P/L Louisiana 800 Leg index;

(b) the Louisiana and Texas (Zone 0) index for Tennessee Gas Pipeline Company;

(c) the arithmetic average of the East Texas and South Texas indices for the Texas Eastern Transmission Corporation; and

(d) the arithmetic average of the East Louisiana and West Louisiana indices for the Texas Eastern Transmission Corporation;

all as reported in the table entitled "Prices of Spot Gas Delivered to Pipelines" in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, provided that if any of the above described indices, or their successors, are not reported in any month, T2 shall be equal to the arithmetic average of the indices that are reported, provided that at least three of the above indices are so reported. If at least three of the above indices are not reported in any month, then the Henry Hub Cash Price, as reported in the first of the month edition of Inside F.E.R.C.'s Gas Market Report will serve as a Proxy for T2. However, the Henry Hub Cash Price shall not be used as a Proxy for T2 for two consecutive months unless agreed to by both parties.

3. This Amendment shall be filed by Buyer for review and approval with the Massachusetts Department of Telecommunications and Energy (MDTE). Seller agrees to reasonably cooperate with Buyer in the activities necessary to obtain such approval, provided that under no circumstances shall Seller be obligated to amend the terms of this Amendment or the Power Purchase Agreement to obtain such approval.

4. This Amendment shall be effective only as to the specific provision of the Power Purchase Agreement amended hereby. All other provisions of the Power Purchase Agreement shall remain unchanged.

5. This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement.

6. This Amendment shall be governed by, and construed in accordance with, the laws of the Commonwealth of Massachusetts, without giving effect to conflict of laws provisions thereof.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered as of the date first above written.

COMMONWEALTH ELECTRIC COMPANY, a Massachusetts corporation

By: _____
Name: Douglas Horan
Title: Sr. Vice President, Strategy Law & Policy

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP,
a Massachusetts limited partnership

By: _____
Name: J J O'ROURKE
Title: Vice Managing Director

[*Signature Page to Fourth Amendment to ComElectric PPA*]

Comparison of Gas Indices					
Fourth Amendment to the Dartmouth Power Power Purchase Agreement					
	Inside FERC Gas Mkt Report Tennessee Gas Pipeline Co		Gas Daily Monthly Contract Price Tennesse Gas Pipeline Co		
	Louisiana & Offshore Zone 1		Louisiana 500 Leg	Louisiana 800 Leg	Average
2001					
February	$6.13		$6.10	$6.13	$6.12
March	$4.91		$4.90	$4.91	$4.91
April	$5.28		$5.28	$5.29	$5.29
May	$4.79		$4.79	$4.80	$4.80
June	$3.62		$3.62	$3.61	$3.62
July	$3.09		$3.11	$3.14	$3.13
August	$3.09		$3.08	$3.11	$3.10
September	$2.22		$2.22	$2.26	$2.24
October	$1.75		$1.78	$1.75	$1.77
November	$3.08		$3.09	$3.09	$3.09
December	$2.20		$2.24	$2.22	$2.23
2002					
January	$2.53		$2.53	$2.49	$2.51
February	$1.96		$1.98	$1.97	$1.98
March	$2.32		$2.31	$2.31	$2.31
April	$3.32		$3.31	$3.28	$3.30
May	$3.26		$3.28	$3.28	$3.28
June	$3.27		$3.30	$3.28	$3.29
July	*		$3.18	$3.16	$3.17
August			$2.87	$2.87	$2.87
	* Effective July 2002 prices reflect the Index change reported in the Inside FERC Gas Market Report on the first of the month				

Information Request AG-2-4

Please provide copies of the Company's filings requesting approval of the contract amendments to the original contract.

Response

Copies of the other requested documents are attached as follows:

Attachment AG-2-4(a)	Filing of the 1st Amendment
Attachment AG-2-4(b)	Filing of the 2nd Amendment
Attachment AG-2-4(c)	Filing of the 3rd Amendment
Attachment AG-2-4(d)	Filing of the 4th Amendment

Attachment
AG-2-4(a)

COM Electric

Commonwealth Electric Company
Post Office Box 9150
Cambridge, Massachusetts 02142-9150
Telephone (617) 225-4000

August 15, 1990

Department of Public Utilities
100 Cambridge Street
Boston, MA 02202

Attention: Henry Yoshimura
Electric Power Division

Re: Amendment to Power Purchase Agreement
Dartmouth Power Associates Limited Partnership

Dear Mr. Yoshimura:

Commonwealth Electric Company ("Commonwealth" or the "Company") submits herewith an Amendment, dated August 3, 1990, to a Power Purchase Agreement (the "Amendment") by and between itself and Dartmouth Power Associates Limited Partnership ("Dartmouth Power"). The Amendment modifies certain terms of a Power Purchase Agreement, dated September 5, 1989, between Commonwealth and Dartmouth Power (the "Agreement"). The Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "Department") on September 27, 1989 and was approved by the Department on March 30, 1990 in DPU 89-218.

Pursuant to the Agreement, Commonwealth had agreed to purchase a 50 MW entitlement to the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned and operated by Dartmouth Power at a site in the Town of Dartmouth. As set forth in the Agreement, the Unit was to be capable of generating approximately 168.8 MW of electricity. However, Dartmouth Power has determined that the Unit will be constructed so as to be capable of generating approximately 67.6 MW. Dartmouth Power offered to sell to Commonwealth an additional 17.6 MW of electricity, which would make the Company the sole purchaser of the electricity that will be produced by the downsized Unit. The Company has determined that this additional purchase of electricity would be beneficial to its ratepayers and would facilitate its administration of the Agreement. Accordingly, Commonwealth has accepted Dartmouth Power's offer.

In addition to modifying the Agreement to reflect the Company's purchase of additional power, the Amendment adds provisions to the Agreement regarding economic dispatch and income tax liabilities, amends the provisions in the

Agreement regarding the security deposit to be furnished by Dartmouth Power to the Company and reflects a reduction in the size of the expected energy bank. The Company notes that the Amendment does not change the pricing mechanism as set forth in the Agreement. The unit prices for capacity and energy will not change. The calculation of the Monthly Capacity Charge component in the price formula will change to reflect the increase in the amount of power that the Company will purchase.

In order to assist the Department in its review of this Amendment, the Company has included in this filing, the base case, low and high fuel cost scenarios of Tables 1 through 5 from the Department's Standard Information Requirements. In addition, the Company has included schedules providing information responsive to Standard Information Requirement #3. The remainder of the information responsive to the Department's Standard Information Requirements is identical in substance to that contained in Appendix C to the Company's Second Request for Proposal for Qualifying Facility Generation ("RFP #2") filed on June 29, 1990 and approved by the Department on July 12, 1990.

As is apparent from the materials included in this filing the Company's ratepayers have a strong prospect of realizing substantial benefits from the purchase by the Company of the additional 17.6 MW output of the Unit. Commonwealth has compared its projected payment stream to Dartmouth Power to the ceiling prices as developed from RFP#2. As can be seen from the attached schedules in the base case fuel scenario, the expected lifetime cumulative net present value benefit from the additional 17.6 MW increment is approximately $16.6 million. As can also be seen from the attached schedules, the cumulative net present value of projected payments to Dartmouth Power over the life of the Agreement is equal to 80% of the cumulative net present value of the Company's avoided costs.

The Company would be pleased to provide such additional information as the Department may request concerning this matter.

Very truly yours,

Marcy S. Rosenzweig /KMB

Marcy S. Rosenzweig
Manager - Rate Regulation

cc: Brian J. Abbanat, Electric Power Division
George B. Dean, Department of Attorney General

AMENDMENT TO POWER PURCHASE AGREEMENT

Amendment, dated as of this third (3d) day of August, 1990, by and between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Dartmouth Power Associates Limited Partnership, a Massachusetts limited partnership with its principal place of business at 8 Newbury Street, Suite 5, Boston, Massachusetts (the "Seller"), to Power Purchase Agreement, by and between the Company and the Seller, dated as of September 5, 1989 (the "Agreement").

SECTION ONE. Recitals.

1.1 The Company and the Seller entered into the Agreement, pursuant to which the Seller agreed to sell and deliver and the Company agreed to purchase and take delivery of a portion of the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned, and operated by the Seller, at a site in Dartmouth, Massachusetts (the "Site"). In accordance with applicable law, the Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "MDPU") for approval, which approval was received by order dated March 30, 1990; and was submitted by the Seller to the Federal Energy Regulatory Commission (the "FERC"), which agency is in the process of reviewing the Agreement as of the date hereof.

1.2 As set forth in the Agreement, the Unit was to utilize two gas turbines and was to be capable of generating approximately one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW) of electricity (the "Original Design Capacity").

1.3 Subsequent to the execution of the Agreement, the Seller determined, and duly notified the Company, that the Unit will utilize a single gas turbine and will be capable of generating approximately sixty-seven thousand, six hundred kilowatts (67,600 kW) of electricity.

1.4 Also as set forth in the Agreement, the Company was to purchase a portion of the electric capacity and related energy produced by the Unit equal to fifty megawatts (50 MW) divided by the Original Design Capacity (the "Original Entitlement").

1.5 Subsequent to the execution of the Agreement and the determination by the Seller to reduce the capability of the Unit as described above, the Seller offered to sell and deliver to the Company approximately seventeen thousand, six hundred kilowatts (17,600 kW) in addition to the Original Entitlement, such that the Company would purchase all of the electricity produced by the Unit. The Company has determined that the purchase of such additional electricity would benefit its ratepayers and would facilitate the administration of the Agreement, and accordingly the Company has accepted such offer of the Seller.

1.6 By virtue of the determination of the Seller to decrease the capability of the Unit and the acceptance by the Company of the Seller's offer to purchase

the entire output of the downsized Unit, several provisions in the Agreement must be modified. These provisions include definitional sections, the section governing the amount of the security deposit to be delivered by the Seller, the section governing the billing mechanism, the section governing the letter of credit to be delivered by the Seller, and the section setting forth the mechanism for calculating the price to be paid under the Agreement.

1.7 Although both the Seller and the Company have understood that the Unit was to be subject to economic dispatch by the New England Power Pool ("NEPOOL"), a provision governing such dispatchability was inadvertently omitted from the Agreement and the parties desire to insert such a provision into the Agreement. In addition, the parties desire to insert a provision into the Agreement protecting the Company and its ratepayers from any income tax liability that the Company might incur as a result of its accepting any contributed property from the Seller.

1.8 The Seller has indicated to the Company that it has made substantial progress with respect to securing necessary financing for the construction and operation of the Unit. Such progress notwithstanding, the Seller has requested that it be permitted to defer delivering to the Company the security deposit required pursuant to the Agreement until sixty (60) days following the approval of this Amendment by the MDPU, and that such security deposit be in the form of a letter of credit in lieu of cash. As an accommodation to the Seller, the Company has agreed to grant these requests of the Seller.

1.9 Accordingly, the Company and the Seller, each in consideration of the foregoing and of the agreements of the other, hereby agree as hereinafter provided.

SECTION TWO. The second introductory paragraph of the Agreement is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> The Seller plans to construct, own, and operate an electric generation facility, utilizing a single gas turbine and a supplementary-fired waste heat boiler with a dual inlet steam turbine, together with housings and other integral equipment, which will be capable of generating approximately sixty-seven thousand, six hundred kilowatts (67,600 kW) of electricity (the "Unit"). The Unit will be located at a site in the Town of Dartmouth, Massachusetts, which will be owned by the Seller, more particularly described in Appendix A attached hereto (the "Site"). The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of all of the electricity produced by the Unit, pursuant to the terms and conditions set forth in this Agreement.

SECTION THREE. Article 1 of the Agreement is hereby amended in accordance with the following:

3.1 The definition of Actual In-Service Date is amended by deleting "the Company's Entitlement of" from such definition.

3.2 The definition of Company's Entitlement is deleted in its entirety.

3.3 The definition of Contract Capacity is deleted in its entirety.

3.4 The definition of Delivered Energy is amended by deleting "the Company's portion of" from such definition.

3.5 The definition of Design Capacity is amended by deleting "one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW)" from such definition and substituting "sixty-seven thousand, six hundred kilowatts (67,600 kW)" in lieu thereof.

3.6 The following definition is to be inserted immediately before the definition of FERC:

> Economic Dispatch shall mean the operation of the Unit in accordance with such procedures as may be established by NEPOOL from time to time to foster the objective of satisfying the energy requirements of the participants of NEPOOL at the lowest practicable cost.

SECTION FOUR. Article 2.1 of the Agreement is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of all electric capacity and related energy produced by the Unit during the term of this Agreement; provided, however, that in no event shall the Company be obligated to purchase and take delivery of electric capacity and related energy in excess of the Design Capacity.

SECTION FIVE. Article 2.4 of the Agreement is hereby amended by deleting "up to the Company's Entitlement and related energy," from such article.

SECTION SIX. The following is to be inserted into the Agreement as Article 2.5:

> The Unit shall be subject to Economic Dispatch at the direction of the Company or its designee. The Unit shall also be subject to changes in the level of its output at the direction of the Company or its designee, provided that such changes are within the Unit's reasonable design limitations.
>
> 2.5.1 If the Seller fails to dispatch the Unit as called for by the Company, then the Company shall calculate the uneconomic

incremental production costs it incurs that are attributable to such failure of the Seller (the "Incremental Production Cost Penalty"). The Company shall also not pay for any electric capacity or energy produced at the Unit as a result of the Seller's failure to comply with the Company's calls pursuant to this Article 2.5. The Company shall deduct any Incremental Production Cost Penalty from any payments due the Seller for any electric capacity and energy purchased by the Company during the Billing Period ("Net Billing Amount"). In the event that the Net Billing Amount for a Billing Period is due to the Company, such Net Billing Amount shall be billed to the Seller and the Seller shall reimburse the Company therefor according to the same standards as are established for payments to the Seller.

2.5.2 The Incremental Production Cost Penalty shall be the difference between (i) the production costs that the Company experienced during the period of the Seller's failure to dispatch the Unit as called for by the Company, and (ii) the production costs that the Company would have experienced during such period had the Seller complied with the Company's call to dispatch the Unit.

SECTION SEVEN. Article 4 of the Agreement is hereby amended by deleting it in its entirety and inserting the following in lieu thereof:

4.1 Within sixty (60) days following the date that the MDPU approves the amendment to this Agreement dated as of August 3, 1990, the Seller shall deliver to the Company an irrevocable letter of credit in favor of the Company (the "Security Deposit Letter of Credit"), from an issuer and in form and substance acceptable to the Company, in the amount of one million, two hundred twenty-eight thousand, six hundred seven dollars ($1,228,607) as a security deposit (the "Security Deposit"). The Security Deposit is calculated as the sum of (i) one million, fourteen thousand dollars ($1,014,000, the "Principal"), which is the product of sixty-seven thousand, six hundred kilowatts (67,600 kW, which is the Design Capacity) and fifteen dollars ($15) per kilowatt; and (ii) two hundred fourteen thousand, six hundred seven dollars ($214,607, the "Interest Component"), which is approximately equal to the simple interest that would accrue on the Principal between the date of this Agreement (i.e., September 5, 1989) and the Proposed In-Service Date (i.e., July 1, 1992) at a rate of seven and one-half percent (7½%) per annum.

4.2 If, prior to the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, or if this Agreement is terminated in accordance with the provisions of Article 3.2, the Company may draw under the Security Deposit Letter of Credit an amount equal to a percentage of the Interest Component plus a percentage of the Principal, which percentage in both cases shall be equal

to the ratio of (i) the elapsed time between the date of this Agreement and the cancellation date, to (ii) the total time between the date of this Agreement and the Proposed In-Service Date; provided, however, that if the reason for such cancellation, abandonment, or termination is the failure of the FERC to approve or accept this Agreement, in a form acceptable to both parties, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.3 If, after the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, the Company may draw upon the entire Security Deposit Letter of Credit; provided, however, that if the reason for such cancellation, abandonment, or termination is the inability or refusal of the Company to interconnect, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.4 If the Actual In-Service Date occurs on or before the Proposed In-Service Date, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.5 If the Actual In-Service Date occurs within twenty-four (24) months after the Proposed In-Service Date, the Company may draw under the Security Deposit Letter of Credit an amount equal to a percentage of the Interest Component, which percentage shall be equal to the ratio of (i) the elapsed time between the Proposed In-Service Date and the Actual In-Service Date, to (ii) the total time between the date of this Agreement and the Proposed In-Service Date; provided, however, that if the reason for the occurrence of the Actual In-Service Date after the Proposed In-Service Date is the inability or refusal of the Company to interconnect, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.6 If the Actual In-Service Date does not occur within twenty-four (24) months after the Proposed In-Service Date, the Company may draw upon the entire Security Deposit Letter of Credit and may terminate this Agreement according to the provisions of Article 3.2.

SECTION EIGHT. Article 5 of the Agreement is hereby amended by correcting the spelling of the word "calculating" found at the beginning of the fifth (5th) line of such article.

SECTION NINE. Article 8.1 of the Agreement is hereby amended by deleting the third sentence of such article in its entirety and inserting the following in lieu thereof:

> Any amount payable hereunder not paid within thirty (30) days (or, if such date is not a working day, then by the next working day thereafter) from the date of receipt by the Company of all actual metered values for the Billing Period shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston from the date of receipt of such monthly statement until the date of payment.

SECTION TEN. Article 15.2 of the Agreement is hereby amended by deleting "the Company's Entitlement thereto" from such definition and substituting "such electricity" in lieu thereof.

SECTION ELEVEN. Article 15.4 of the Agreement is hereby amended by deleting the schedule currently contained in such article and substituting the following in lieu thereof:

from	through	amount
Actual In-Service Date	December 31, 1993	$0
January 1, 1994	December 31, 1994	$179,206
Janusry 1, 1995	remainder of term of Agreement	$0

SECTION TWELVE. The following is to be inserted into the Agreement as Article 17.7:

> The Seller shall reimburse the Company for any costs relating to income tax liabilities incurred by the Company as a result of its acceptance of any contributed property from the Seller.

SECTION THIRTEEN. Appendix B to the Agreement is hereby amended in accordance with the following:

13.1 Article 2.1 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> Monthly Capacity Cost: The initial Monthly Capacity Cost shall equal the product of the Design Capacity and three thousand, eight hundred fifty-four dollars and twelve cents per megawatt-month ($3,854.12/MW-mo.). The Monthly Capacity Cost shall be subject to the following adjustments.

13.2 Article 2.2 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> Monthly Investment Cost: The Monthly Investment Cost shall equal

the product of the Design Capacity and thirteen thousand, nine hundred forty-three dollars and seventy-two cents per megawatt-month ($13,943.72/MW-mo.).

13.3 Article 2.3 of Appendix B is hereby amended by deleting "the product of 0.2962 (which is equal to the Contract Capacity divided by the Design Capacity) and" from such article.

13.4 Article 3 of Appendix B is hereby amended by deleting the example currently contained in such article and substituting the following in lieu thereof:

Example:

	Hour 1	Hour 2	Hour 3
available MW:	64	66	65
maximum net:	67.6	67.6	67.6

$$EAH = \frac{64}{67.6} + \frac{66}{67.6} + \frac{65}{67.6} = 2.885$$

$$EAF = \frac{2.885}{3} = .962$$

13.5 Article 6 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

<u>Illustration of projected Total Purchase Price assuming delivery of sixty-seven thousand, six hundred kilowatts (67,600 kW) at a ninety-one percent (91%) availability</u>:

Monthly Capacity Cost [initial amount: $3854.12/MW x 67.6 MW]:	$260,538.51	[= 0.5802¢/kWh*]
Monthly Investment Cost [fixed amount: $13,943.72/MW x 67.6 MW]:	942,595.47	[= 2.0990¢/kWh*]
Monthly Pipeline Demand Cost [assuming total of transportation capacity demand charges = $531,965]:	531,965.00	[= 1.1846¢/kWh*]
CAPACITY CHARGE [unadjusted; <u>see</u> §3]:	$1,735,098.98	[= 3.8638¢/kWh*]
Variable Fuel Supply Rate [assuming commodity rate of $1.425/MMBTU following index adjustment and accounting for "pipeline gas" amounts: .008583 MMBTU/kWh x $1.425/MMBTU]:	$549,243.50**	1.2231¢/kWh

Variable Fuel Transportation Throughput Rate [assuming sum of pipeline throughput rates = 42¢/MMBTU: .008583 MMBTU/kWh x $0.42/MMBTU]:	161,882.29**	0.3605¢/kWh
ENERGY CHARGE:	$711,125.79	1.5836¢/kWh
	==========	==========
TOTAL PURCHASE PRICE:	$2,446,224.77	[= 5.4474¢/kWh*]

* calculated by dividing the actual dollar amount by the following: (365 days/yr.)(1/12 yr./mo.)(24 hrs./day)(.91)(67,600 kW)

** calculated by multiplying the actual, unrounded ¢/kWh rate by the following: (365 days/yr.)(1/12 yr./mo.)(24 hrs./day)(.91)(67,600 kW)

SECTION FOURTEEN. The Company shall submit this Amendment to the MDPU, and the Seller shall submit this Amendment to the FERC, for the approval of each of the MDPU and the FERC. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

In witness whereof, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP,
By EMI/Dartmouth, Inc., its General Partner,

By James L. Gordon,
Its President.

COMMONWEALTH ELECTRIC COMPANY,

By [illegible]
Its VICE PRESIDENT.

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BASE CASE

TABLES 1, 2, 3, 4, 5

Eastern Standard Time
and Daylight Savings Time

TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.19	0.16	0.00	0.34	0.000%	3.69	0.99	0.000%	0.99	4.68
1990	3.30	0.17	0.00	0.34	0.000%	3.81	0.99	0.000%	0.99	4.80
1991	3.47	0.17	0.00	0.34	0.000%	3.98	0.99	0.000%	0.99	4.97
1992	4.35	0.23	0.00	0.34	0.000%	4.92	0.99	0.000%	0.99	5.91
1993	4.35	0.31	0.00	0.34	0.000%	5.00	0.99	0.000%	0.99	5.99
1994	3.38	0.16	0.52	0.34	0.000%	4.40	0.90	0.000%	0.90	5.30
1995	4.69	0.20	0.55	0.34	0.000%	5.78	0.95	0.000%	0.95	6.73
1996	5.08	0.21	0.59	0.34	0.000%	6.22	1.01	0.000%	1.01	7.23
1997	5.52	0.21	0.63	0.34	0.000%	6.70	1.08	0.000%	1.08	7.78
1998	5.74	0.20	0.67	0.34	0.000%	6.95	1.15	0.000%	1.15	8.10
1999	7.02	0.21	0.71	0.34	0.000%	8.28	1.23	0.000%	1.23	9.51
2000	7.74	0.25	0.76	0.34	0.000%	9.09	1.31	0.000%	1.31	10.40
2001	7.48	0.28	0.81	0.34	0.000%	8.91	1.40	0.000%	1.40	10.31
2002	9.05	0.28	0.87	0.34	0.000%	10.54	1.49	0.000%	1.49	12.03
2003	10.14	0.31	0.93	0.34	0.000%	11.72	1.59	0.000%	1.59	13.31
2004	12.70	0.38	1.00	0.34	0.000%	14.42	1.69	0.000%	1.69	16.11
2005	11.95	0.40	1.07	0.34	0.000%	13.76	1.80	0.000%	1.80	15.56
2006	14.57	0.49	1.14	0.34	0.000%	16.54	1.91	0.000%	1.91	18.45
2007	15.40	0.51	1.22	0.34	0.000%	17.47	2.03	0.000%	2.03	19.50
2008	16.63	0.49	1.30	0.34	0.000%	18.76	2.16	0.000%	2.16	20.92
2009	18.14	0.56	1.39	0.34	0.000%	20.43	2.30	0.000%	2.30	22.73
2010	19.48	0.59	1.49	0.34	0.000%	21.90	2.44	0.000%	2.44	24.34
2011	20.51	0.62	1.60	0.34	0.000%	23.07	2.60	0.000%	2.60	25.67
2012	21.31	0.66	1.70	0.34	0.000%	24.01	2.76	0.000%	2.76	26.77
2013	21.46	0.66	1.81	0.34	0.000%	24.27	2.93	0.000%	2.93	27.20
2014	25.95	0.78	1.93	0.34	0.000%	29.00	3.12	0.000%	3.12	32.12
2015	25.72	0.81	2.06	0.34	0.000%	28.93	3.32	0.000%	3.32	32.25
2016	28.23	0.86	2.20	0.34	0.000%	31.63	3.52	0.000%	3.52	35.15
2017	30.50	0.92	2.34	0.34	0.000%	34.10	3.75	0.000%	3.75	37.85
2018	31.29	0.95	2.49	0.34	0.000%	35.07	3.98	0.000%	3.98	39.05

TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Primary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.19	0.16	0.00	0.34	4.645%	3.88	0.99	6.991%	1.06	4.92
1990	3.30	0.17	0.00	0.34	4.645%	3.99	0.99	6.991%	1.06	5.05
1991	3.47	0.17	0.00	0.34	4.645%	4.16	0.99	6.991%	1.06	5.22
1992	4.35	0.23	0.00	0.34	4.645%	5.15	0.99	6.991%	1.06	6.21
1993	4.35	0.31	0.00	0.34	4.645%	5.23	0.99	6.991%	1.06	6.29
1994	3.38	0.16	0.52	0.34	4.645%	4.60	0.96	6.991%	0.96	5.56
1995	4.69	0.20	0.55	0.34	4.645%	6.05	0.95	6.991%	1.02	7.07
1996	5.08	0.21	0.59	0.34	4.645%	6.51	1.01	6.991%	1.08	7.59
1997	5.52	0.21	0.63	0.34	4.645%	7.01	1.08	6.991%	1.16	8.17
1998	5.74	0.20	0.67	0.34	4.645%	7.27	1.15	6.991%	1.23	8.50
1999	7.02	0.21	0.71	0.34	4.645%	8.66	1.23	6.991%	1.32	9.98
2000	7.74	0.25	0.76	0.34	4.645%	9.51	1.31	6.991%	1.40	10.91
2001	7.48	0.28	0.81	0.34	4.645%	9.32	1.40	6.991%	1.50	10.82
2002	9.05	0.28	0.87	0.34	4.645%	11.03	1.49	6.991%	1.59	12.62
2003	10.14	0.31	0.93	0.34	4.645%	12.26	1.59	6.991%	1.70	13.96
2004	12.70	0.38	1.00	0.34	4.645%	15.09	1.69	6.991%	1.81	16.90
2005	11.95	0.40	1.07	0.34	4.645%	14.40	1.80	6.991%	1.93	16.33
2006	14.57	0.49	1.14	0.34	4.645%	17.31	1.91	6.991%	2.04	19.35
2007	15.40	0.51	1.22	0.34	4.645%	18.28	2.03	6.991%	2.17	20.45
2008	16.63	0.49	1.30	0.34	4.645%	19.63	2.16	6.991%	2.31	21.94
2009	18.14	0.56	1.39	0.34	4.645%	21.38	2.30	6.991%	2.46	23.84
2010	19.48	0.59	1.49	0.34	4.645%	22.92	2.44	6.991%	2.61	25.53
2011	20.51	0.62	1.60	0.34	4.645%	24.14	2.60	6.991%	2.78	26.92
2012	21.31	0.66	1.70	0.34	4.645%	25.13	2.75	6.991%	2.95	28.08
2013	21.46	0.66	1.81	0.34	4.645%	25.40	2.93	6.991%	3.13	28.53
2014	25.95	0.78	1.93	0.34	4.645%	30.35	3.12	6.991%	3.34	33.69
2015	25.72	0.81	2.06	0.34	4.645%	30.27	3.32	6.991%	3.55	33.82
2016	28.23	0.86	2.20	0.34	4.645%	33.10	3.52	6.991%	3.77	36.87
2017	30.50	0.92	2.34	0.34	4.645%	35.68	3.75	6.991%	4.01	39.69
2018	31.29	0.95	2.49	0.34	4.645%	36.70	3.98	6.991%	4.26	40.96

TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.19	0.16	0.00	0.34	7.352%	3.96	0.99	8.861%	1.08	5.04
1990	3.30	0.17	0.00	0.34	7.352%	4.09	0.99	8.861%	1.08	5.17
1991	3.47	0.17	0.00	0.34	7.352%	4.27	0.99	8.861%	1.08	5.35
1992	4.35	0.23	0.00	0.34	7.352%	5.28	0.99	8.861%	1.08	6.36
1993	4.35	0.31	0.00	0.34	7.352%	5.37	0.99	8.861%	1.08	6.45
1994	3.38	0.16	0.52	0.34	7.352%	4.72	0.90	8.861%	0.98	5.70
1995	4.69	0.20	0.55	0.34	7.352%	6.20	0.95	8.861%	1.03	7.23
1996	5.08	0.21	0.59	0.34	7.352%	6.68	1.01	8.861%	1.10	7.78
1997	5.52	0.21	0.63	0.34	7.352%	7.19	1.08	8.861%	1.18	8.37
1998	5.74	0.20	0.67	0.34	7.352%	7.46	1.15	8.861%	1.25	8.71
1999	7.02	0.21	0.71	0.34	7.352%	8.89	1.23	8.861%	1.34	10.23
2000	7.74	0.25	0.76	0.34	7.352%	9.76	1.31	8.861%	1.43	11.19
2001	7.48	0.28	0.81	0.34	7.352%	9.57	1.40	8.861%	1.52	11.09
2002	9.05	0.28	0.87	0.34	7.352%	11.31	1.49	8.861%	1.62	12.93
2003	10.14	0.31	0.93	0.34	7.352%	12.58	1.59	8.861%	1.73	14.31
2004	12.70	0.38	1.00	0.34	7.352%	15.48	1.69	8.861%	1.84	17.32
2005	11.95	0.40	1.07	0.34	7.352%	14.77	1.80	8.861%	1.96	16.73
2006	14.57	0.49	1.14	0.34	7.352%	17.76	1.91	8.861%	2.08	19.84
2007	15.40	0.51	1.22	0.34	7.352%	18.75	2.03	8.861%	2.21	20.96
2008	16.63	0.49	1.30	0.34	7.352%	20.14	2.16	8.861%	2.35	22.49
2009	18.14	0.56	1.39	0.34	7.352%	21.93	2.30	8.861%	2.50	24.43
2010	19.48	0.59	1.49	0.34	7.352%	23.51	2.44	8.861%	2.66	26.17
2011	20.51	0.62	1.60	0.34	7.352%	24.77	2.60	8.861%	2.83	27.60
2012	21.31	0.66	1.70	0.34	7.352%	25.78	2.76	8.861%	3.00	28.78
2013	21.46	0.66	1.81	0.34	7.352%	26.05	2.93	8.861%	3.19	29.24
2014	25.95	0.78	1.93	0.34	7.352%	31.13	3.12	8.861%	3.40	34.53
2015	25.72	0.81	2.06	0.34	7.352%	31.06	3.32	8.861%	3.61	34.67
2016	28.23	0.86	2.20	0.34	7.352%	33.96	3.52	8.861%	3.83	37.79
2017	30.50	0.92	2.34	0.34	7.352%	36.61	3.75	8.861%	4.08	40.69
2018	31.29	0.95	2.49	0.34	7.352%	37.65	3.98	8.861%	4.33	41.98

TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.19	0.16	0.00	0.34	9.321%	4.03	0.99	12.183%	1.11	5.14
1990	3.30	0.17	0.00	0.34	9.321%	4.17	0.99	12.183%	1.11	5.28
1991	3.47	0.17	0.00	0.34	9.321%	4.35	0.99	12.183%	1.11	5.46
1992	4.35	0.23	0.00	0.34	9.321%	5.38	0.99	12.183%	1.11	6.49
1993	4.35	0.31	0.00	0.34	9.321%	5.47	0.99	12.183%	1.11	6.58
1994	3.38	0.16	0.52	0.34	9.321%	4.81	0.90	12.183%	1.01	5.82
1995	4.69	0.20	0.55	0.34	9.321%	6.32	0.95	12.183%	1.07	7.39
1996	5.08	0.21	0.59	0.34	9.321%	6.80	1.01	12.183%	1.13	7.93
1997	5.52	0.21	0.63	0.34	9.321%	7.32	1.08	12.183%	1.21	8.53
1998	5.74	0.20	0.67	0.34	9.321%	7.60	1.15	12.183%	1.29	8.89
1999	7.02	0.21	0.71	0.34	9.321%	9.05	1.23	12.183%	1.38	10.43
2000	7.74	0.25	0.76	0.34	9.321%	9.94	1.31	12.183%	1.47	11.41
2001	7.48	0.28	0.81	0.34	9.321%	9.74	1.40	12.183%	1.57	11.31
2002	9.05	0.28	0.87	0.34	9.321%	11.52	1.49	12.183%	1.67	13.19
2003	10.14	0.31	0.93	0.34	9.321%	12.81	1.59	12.183%	1.78	14.59
2004	12.70	0.38	1.00	0.34	9.321%	15.76	1.69	12.183%	1.90	17.66
2005	11.95	0.40	1.07	0.34	9.321%	15.04	1.80	12.183%	2.02	17.06
2006	14.57	0.49	1.14	0.34	9.321%	18.08	1.91	12.183%	2.14	20.22
2007	15.40	0.51	1.22	0.34	9.321%	19.10	2.03	12.183%	2.28	21.38
2008	16.63	0.49	1.30	0.34	9.321%	20.51	2.16	12.183%	2.42	22.93
2009	18.14	0.56	1.39	0.34	9.321%	22.33	2.30	12.183%	2.58	24.91
2010	19.48	0.59	1.49	0.34	9.321%	23.94	2.44	12.183%	2.74	26.68
2011	20.51	0.62	1.60	0.34	9.321%	25.22	2.60	12.183%	2.92	28.14
2012	21.31	0.66	1.70	0.34	9.321%	26.25	2.76	12.183%	3.10	29.35
2013	21.46	0.66	1.81	0.34	9.321%	26.53	2.93	12.183%	3.29	29.82
2014	25.95	0.78	1.93	0.34	9.321%	31.70	3.12	12.183%	3.50	35.20
2015	25.72	0.81	2.06	0.34	9.321%	31.63	3.32	12.183%	3.72	35.35
2016	28.23	0.85	2.20	0.34	9.321%	34.58	3.52	12.183%	3.95	38.53
2017	30.50	0.92	2.34	0.34	9.321%	37.28	3.75	12.183%	4.21	41.49
2018	31.29	0.95	2.49	0.34	9.321%	38.34	3.98	12.183%	4.46	42.80

TABLE 2
(Commonwealth - EST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.06	0.00	165.29
2018	327.15	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.18	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.80	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - EST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.66	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.76	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.69	4.34	1041.95			
2032	253.29	4.05	1108.82			
2033	263.62	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - EST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	59.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - EST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	6.06
1995	140.85	113.94	68.27	0.95	6.42
1996	134.76	98.04	72.64	1.01	6.83
1997	128.69	84.21	77.36	1.08	7.27
1998	123.05	72.42	82.47	1.15	7.76
1999	117.82	62.37	88.00	1.23	8.28
2000	113.02	53.81	93.90	1.31	8.83
2001	108.24	46.35	100.19	1.40	9.42
2002	103.44	39.84	106.71	1.49	10.03
2003	98.67	34.18	113.65	1.59	10.69
2004	93.89	29.25	121.04	1.69	11.38
2005	89.10	24.96	128.79	1.80	12.11
2006	84.33	21.25	137.04	1.91	12.89
2007	79.56	18.03	145.68	2.03	13.70
2008	74.80	15.25	154.87	2.16	14.56
2009	70.02	12.84	164.64	2.30	15.48
2010	66.99	11.05	175.02	2.44	16.46
2011	64.78	9.61	186.05	2.60	17.50
2012	62.58	8.35	197.79	2.76	18.60
2013	60.41	7.25	210.26	2.93	19.77
2014	58.21	6.28	223.52	3.12	21.02
2015	56.04	5.44	237.61	3.32	22.34
2016	53.86	4.70	252.59	3.52	23.75
2017	51.68	4.05	268.52	3.75	25.25
2018	49.53	3.50	285.45	3.98	26.84
2019	47.39	3.01	303.45	4.23	28.54
2020	45.25	2.58	322.59	4.50	30.34
2021	43.11	2.21	342.93	4.79	32.25
2022	40.99	1.89	364.55	5.09	34.28
2023	38.86	1.61	387.54	5.41	36.44
SUMS	2443.32	927.25	5477.60		

TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.79	0.23	0.00	0.34	0.000%	4.36	0.99	0.000%	0.99	5.35
1990	3.41	0.25	0.00	0.34	0.000%	4.00	0.99	0.000%	0.99	4.99
1991	3.73	0.30	0.00	0.34	0.000%	4.37	0.99	0.000%	0.99	5.36
1992	3.75	0.27	0.00	0.34	0.000%	4.36	0.99	0.000%	0.99	5.35
1993	4.11	0.42	0.00	0.34	0.000%	4.87	0.99	0.000%	0.99	5.86
1994	3.55	0.49	0.52	0.34	0.000%	4.90	0.90	0.000%	0.90	5.80
1995	3.43	0.43	0.55	0.34	0.000%	4.75	0.95	0.000%	0.95	5.70
1996	3.40	0.42	0.59	0.34	0.000%	4.75	1.01	0.000%	1.01	5.76
1997	4.03	0.50	0.63	0.34	0.000%	5.50	1.08	0.000%	1.08	6.58
1998	4.33	0.50	0.67	0.34	0.000%	5.84	1.15	0.000%	1.15	6.99
1999	4.67	0.53	0.71	0.34	0.000%	6.25	1.23	0.000%	1.23	7.48
2000	5.40	0.57	0.76	0.34	0.000%	7.07	1.31	0.000%	1.31	8.38
2001	5.90	0.59	0.81	0.34	0.000%	7.64	1.40	0.000%	1.40	9.04
2002	7.64	0.73	0.87	0.34	0.000%	9.58	1.49	0.000%	1.49	11.07
2003	6.61	0.65	0.93	0.34	0.000%	8.53	1.59	0.000%	1.59	10.12
2004	6.90	0.67	1.00	0.34	0.000%	8.91	1.69	0.000%	1.69	10.60
2005	8.63	0.78	1.07	0.34	0.000%	10.82	1.80	0.000%	1.80	12.62
2006	9.02	0.81	1.14	0.34	0.000%	11.31	1.91	0.000%	1.91	13.22
2007	9.27	0.85	1.22	0.34	0.000%	11.68	2.03	0.000%	2.03	13.71
2008	10.29	0.95	1.30	0.34	0.000%	12.88	2.16	0.000%	2.16	15.04
2009	11.78	1.04	1.39	0.34	0.000%	14.55	2.30	0.000%	2.30	16.85
2010	12.00	1.08	1.49	0.34	0.000%	14.91	2.44	0.000%	2.44	17.35
2011	12.93	1.14	1.60	0.34	0.000%	16.01	2.60	0.000%	2.60	18.61
2012	13.80	1.23	1.70	0.34	0.000%	17.07	2.76	0.000%	2.76	19.83
2013	14.28	1.30	1.81	0.34	0.000%	17.73	2.93	0.000%	2.93	20.66
2014	15.22	1.39	1.93	0.34	0.000%	18.88	3.12	0.000%	3.12	22.00
2015	16.15	1.49	2.06	0.34	0.000%	20.04	3.32	0.000%	3.32	23.36
2016	17.15	1.58	2.20	0.34	0.000%	21.27	3.52	0.000%	3.52	24.79
2017	17.84	1.66	2.34	0.34	0.000%	22.18	3.75	0.000%	3.75	25.93
2018	18.95	1.77	2.49	0.34	0.000%	23.55	3.98	0.000%	3.98	27.53

TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Primary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.79	0.23	0.00	0.34	4.645%	4.56	0.99	6.991%	1.06	5.62
1990	3.41	0.25	0.00	0.34	4.645%	4.19	0.99	6.991%	1.06	5.25
1991	3.73	0.30	0.00	0.34	4.645%	4.57	0.99	6.991%	1.06	5.63
1992	3.75	0.27	0.00	0.34	4.645%	4.56	0.99	6.991%	1.06	5.62
1993	4.11	0.42	0.00	0.34	4.645%	5.10	0.99	6.991%	1.06	6.16
1994	3.55	0.49	0.52	0.34	4.645%	5.13	0.90	6.991%	0.96	6.09
1995	3.43	0.43	0.55	0.34	4.645%	4.97	0.95	6.991%	1.02	5.99
1996	3.40	0.42	0.59	0.34	4.645%	4.97	1.01	6.991%	1.08	6.05
1997	4.03	0.50	0.63	0.34	4.645%	5.76	1.08	6.991%	1.15	6.92
1998	4.33	0.50	0.67	0.34	4.645%	6.11	1.15	6.991%	1.23	7.34
1999	4.67	0.53	0.71	0.34	4.645%	6.54	1.23	6.991%	1.32	7.86
2000	5.40	0.57	0.76	0.34	4.645%	7.40	1.31	6.991%	1.40	8.80
2001	5.90	0.59	0.81	0.34	4.645%	7.99	1.40	6.991%	1.50	9.49
2002	7.64	0.73	0.87	0.34	4.645%	10.02	1.49	6.991%	1.59	11.61
2003	6.61	0.65	0.93	0.34	4.645%	8.93	1.59	6.991%	1.70	10.63
2004	6.90	0.67	1.00	0.34	4.645%	9.32	1.69	6.991%	1.81	11.13
2005	8.63	0.78	1.07	0.34	4.645%	11.32	1.80	6.991%	1.93	13.25
2006	9.02	0.81	1.14	0.34	4.645%	11.84	1.91	6.991%	2.04	13.88
2007	9.27	0.85	1.22	0.34	4.645%	12.22	2.03	6.991%	2.17	14.39
2008	10.29	0.95	1.30	0.34	4.645%	13.48	2.16	6.991%	2.31	15.79
2009	11.78	1.04	1.39	0.34	4.645%	15.23	2.30	6.991%	2.46	17.69
2010	12.00	1.08	1.49	0.34	4.645%	15.60	2.44	6.991%	2.61	18.21
2011	12.93	1.14	1.60	0.34	4.645%	16.75	2.60	6.991%	2.78	19.53
2012	13.80	1.23	1.70	0.34	4.645%	17.86	2.76	6.991%	2.95	20.81
2013	14.28	1.30	1.81	0.34	4.645%	18.55	2.93	6.991%	3.13	21.68
2014	15.22	1.39	1.93	0.34	4.645%	19.75	3.12	6.991%	3.34	23.10
2015	16.15	1.49	2.06	0.34	4.645%	20.97	3.32	6.991%	3.55	24.52
2016	17.15	1.58	2.20	0.34	4.645%	22.26	3.52	6.991%	3.77	26.03
2017	17.84	1.65	2.34	0.34	4.645%	23.21	3.75	6.991%	4.01	27.22
2018	18.95	1.77	2.49	0.34	4.645%	24.64	3.98	6.991%	4.26	28.90

TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-lized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.79	0.23	0.00	0.34	7.352%	4.68	0.99	8.861%	1.08	5.76
1990	3.41	0.25	0.00	0.34	7.352%	4.29	0.99	8.861%	1.08	5.37
1991	3.73	0.30	0.00	0.34	7.352%	4.69	0.99	8.861%	1.08	5.77
1992	3.75	0.27	0.00	0.34	7.352%	4.68	0.99	8.861%	1.08	5.76
1993	4.11	0.42	0.00	0.34	7.352%	5.23	0.99	8.861%	1.08	6.31
1994	3.55	0.49	0.52	0.34	7.352%	5.26	0.90	8.861%	0.98	6.24
1995	3.43	0.43	0.55	0.34	7.352%	5.10	0.95	8.861%	1.03	6.13
1996	3.40	0.42	0.59	0.34	7.352%	5.10	1.01	8.861%	1.10	6.20
1997	4.03	0.50	0.63	0.34	7.352%	5.90	1.08	8.861%	1.18	7.08
1998	4.33	0.50	0.67	0.34	7.352%	6.27	1.15	8.861%	1.25	7.52
1999	4.67	0.53	0.71	0.34	7.352%	6.71	1.23	8.861%	1.34	8.05
2000	5.40	0.57	0.76	0.34	7.352%	7.59	1.31	8.861%	1.43	9.02
2001	5.90	0.59	0.81	0.34	7.352%	8.20	1.40	8.861%	1.52	9.72
2002	7.64	0.73	0.87	0.34	7.352%	10.28	1.49	8.861%	1.62	11.90
2003	6.61	0.65	0.93	0.34	7.352%	9.16	1.59	8.861%	1.73	10.89
2004	6.90	0.67	1.00	0.34	7.352%	9.57	1.69	8.861%	1.84	11.41
2005	8.63	0.78	1.07	0.34	7.352%	11.62	1.80	8.861%	1.96	13.58
2006	9.02	0.81	1.14	0.34	7.352%	12.14	1.91	8.861%	2.08	14.22
2007	9.27	0.85	1.22	0.34	7.352%	12.54	2.03	8.861%	2.21	14.75
2008	10.29	0.95	1.30	0.34	7.352%	13.83	2.16	8.861%	2.35	16.18
2009	11.78	1.04	1.39	0.34	7.352%	15.62	2.30	8.861%	2.50	18.12
2010	12.00	1.08	1.49	0.34	7.352%	16.01	2.44	8.861%	2.66	18.67
2011	12.93	1.14	1.60	0.34	7.352%	17.19	2.60	8.861%	2.83	20.02
2012	13.80	1.23	1.70	0.34	7.352%	18.32	2.76	8.861%	3.00	21.32
2013	14.28	1.30	1.81	0.34	7.352%	19.03	2.93	8.861%	3.19	22.22
2014	15.22	1.39	1.93	0.34	7.352%	20.27	3.12	8.861%	3.40	23.67
2015	16.15	1.49	2.06	0.34	7.352%	21.51	3.32	8.861%	3.61	25.12
2016	17.15	1.58	2.20	0.34	7.352%	22.83	3.52	8.861%	3.83	26.66
2017	17.84	1.66	2.34	0.34	7.352%	23.81	3.75	8.861%	4.08	27.89
2018	18.95	1.77	2.49	0.34	7.352%	25.28	3.98	8.861%	4.33	29.61

TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.79	0.23	0.00	0.34	9.321%	4.77	0.99	12.183%	1.11	5.88
1990	3.41	0.25	0.00	0.34	9.321%	4.37	0.99	12.183%	1.11	5.48
1991	3.73	0.30	0.00	0.34	9.321%	4.78	0.99	12.183%	1.11	5.89
1992	3.75	0.27	0.00	0.34	9.321%	4.77	0.99	12.183%	1.11	5.88
1993	4.11	0.42	0.00	0.34	9.321%	5.32	0.99	12.183%	1.11	6.43
1994	3.55	0.49	0.52	0.34	9.321%	5.36	0.90	12.183%	1.01	6.37
1995	3.43	0.43	0.55	0.34	9.321%	5.19	0.95	12.183%	1.07	6.26
1996	3.40	0.42	0.59	0.34	9.321%	5.19	1.01	12.183%	1.13	6.32
1997	4.03	0.50	0.63	0.34	9.321%	6.01	1.08	12.183%	1.21	7.22
1998	4.33	0.50	0.67	0.34	9.321%	6.38	1.15	12.183%	1.29	7.67
1999	4.67	0.53	0.71	0.34	9.321%	6.83	1.23	12.183%	1.38	8.21
2000	5.40	0.57	0.76	0.34	9.321%	7.73	1.31	12.183%	1.47	9.20
2001	5.90	0.59	0.81	0.34	9.321%	8.35	1.40	12.183%	1.57	9.92
2002	7.64	0.73	0.87	0.34	9.321%	10.47	1.49	12.183%	1.67	12.14
2003	6.61	0.65	0.93	0.34	9.321%	9.33	1.59	12.183%	1.78	11.11
2004	6.90	0.67	1.00	0.34	9.321%	9.74	1.69	12.183%	1.90	11.64
2005	8.63	0.78	1.07	0.34	9.321%	11.83	1.80	12.183%	2.02	13.85
2006	9.02	0.81	1.14	0.34	9.321%	12.36	1.91	12.183%	2.14	14.50
2007	9.27	0.85	1.22	0.34	9.321%	12.77	2.03	12.183%	2.28	15.05
2008	10.29	0.95	1.30	0.34	9.321%	14.08	2.16	12.183%	2.42	16.50
2009	11.78	1.04	1.39	0.34	9.321%	15.91	2.30	12.183%	2.58	18.49
2010	12.00	1.08	1.49	0.34	9.321%	16.30	2.44	12.183%	2.74	19.04
2011	12.93	1.14	1.60	0.34	9.321%	17.50	2.60	12.183%	2.92	20.42
2012	13.80	1.23	1.70	0.34	9.321%	18.66	2.76	12.183%	3.10	21.76
2013	14.28	1.30	1.81	0.34	9.321%	19.38	2.93	12.183%	3.29	22.67
2014	15.22	1.39	1.93	0.34	9.321%	20.64	3.12	12.183%	3.50	24.14
2015	16.15	1.49	2.06	0.34	9.321%	21.91	3.32	12.183%	3.72	25.63
2016	17.15	1.58	2.20	0.34	9.321%	23.25	3.52	12.183%	3.95	27.20
2017	17.84	1.66	2.34	0.34	9.321%	24.25	3.75	12.183%	4.21	28.46
2018	18.95	1.77	2.49	0.34	9.321%	25.75	3.98	12.183%	4.46	30.21

TABLE 2
(Commonwealth - DST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.06	0.00	165.29
2018	327.16	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.18	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.80	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - DST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.66	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.76	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.59	4.34	1041.96			
2032	253.29	4.05	1108.82			
2033	263.52	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - DST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Year	Book Value ($/kw)	Book Deprec. ($/kw)	Required Return ($/kw)	Federal & State Income Tax ($/kw)	Deferred Tax ($/kw)	Property Tax ($/kw)	Fixed O&M ($/kw)	Other Charges ($/kw)	Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	58.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - DST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	3.37
1995	140.85	113.94	68.27	0.95	3.57
1996	134.76	98.04	72.64	1.01	3.79
1997	128.69	84.21	77.36	1.08	4.04
1998	123.06	72.42	82.47	1.15	4.31
1999	117.82	62.37	88.00	1.23	4.60
2000	113.02	53.81	93.98	1.31	4.91
2001	108.24	46.35	100.19	1.40	5.23
2002	103.44	39.84	106.71	1.49	5.57
2003	98.67	34.18	113.65	1.59	5.94
2004	93.89	29.25	121.04	1.69	6.32
2005	89.10	24.96	128.79	1.80	6.73
2006	84.33	21.25	137.04	1.91	7.16
2007	79.56	18.03	145.68	2.03	7.61
2008	74.80	15.25	154.87	2.16	8.09
2009	70.02	12.84	164.64	2.30	8.60
2010	66.99	11.05	175.02	2.44	9.14
2011	64.78	9.61	186.06	2.60	9.72
2012	62.58	8.35	197.79	2.76	10.33
2013	60.41	7.25	210.26	2.93	10.98
2014	58.21	6.28	223.52	3.12	11.68
2015	56.04	5.44	237.61	3.32	12.41
2016	53.86	4.70	252.59	3.52	13.20
2017	51.68	4.06	268.52	3.75	14.03
2018	49.53	3.50	285.45	3.98	14.91
2019	47.39	3.01	303.45	4.23	15.85
2020	45.25	2.58	322.59	4.50	16.85
2021	43.11	2.21	342.93	4.79	17.92
2022	40.99	1.89	364.55	5.09	19.05
2023	38.86	1.61	387.54	5.41	20.25
SUMS	2443.32	927.25	5477.60		

LOW CASE

TABLES 1, 2, 3, 4, 5

Eastern Standard Time
and Daylight Savings Time

LOW FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.18	0.16	0.00	0.34	0.000%	3.68	0.99	0.000%	0.99	4.67
1990	2.56	0.17	0.00	0.34	0.000%	3.07	0.99	0.000%	0.99	4.06
1991	2.63	0.17	0.00	0.34	0.000%	3.14	0.99	0.000%	0.99	4.13
1992	3.32	0.23	0.00	0.34	0.000%	3.89	0.99	0.000%	0.99	4.88
1993	3.34	0.27	0.00	0.34	0.000%	3.95	0.99	0.000%	0.99	4.94
1994	2.53	0.15	0.52	0.34	0.000%	3.54	0.90	0.000%	0.90	4.44
1995	3.38	0.19	0.55	0.34	0.000%	4.46	0.95	0.000%	0.95	5.41
1996	3.61	0.21	0.59	0.34	0.000%	4.75	1.01	0.000%	1.01	5.76
1997	4.12	0.21	0.63	0.34	0.000%	5.30	1.08	0.000%	1.08	6.38
1998	4.56	0.20	0.67	0.34	0.000%	5.77	1.15	0.000%	1.15	6.92
1999	5.83	0.21	0.71	0.34	0.000%	7.09	1.23	0.000%	1.23	8.32
2000	6.80	0.23	0.76	0.34	0.000%	8.13	1.31	0.000%	1.31	9.44
2001	6.68	0.25	0.81	0.34	0.000%	8.08	1.40	0.000%	1.40	9.48
2002	8.02	0.28	0.87	0.34	0.000%	9.51	1.49	0.000%	1.49	11.00
2003	8.83	0.32	0.93	0.34	0.000%	10.42	1.59	0.000%	1.59	12.01
2004	11.02	0.38	1.00	0.34	0.000%	12.74	1.69	0.000%	1.69	14.43
2005	10.28	0.40	1.07	0.34	0.000%	12.09	1.80	0.000%	1.80	13.89
2006	12.27	0.48	1.14	0.34	0.000%	14.23	1.91	0.000%	1.91	16.14
2007	12.75	0.50	1.22	0.34	0.000%	14.81	2.03	0.000%	2.03	16.84
2008	13.46	0.49	1.30	0.34	0.000%	15.59	2.16	0.000%	2.16	17.75
2009	14.46	0.55	1.39	0.34	0.000%	16.74	2.30	0.000%	2.30	19.04
2010	15.25	0.59	1.49	0.34	0.000%	17.67	2.44	0.000%	2.44	20.11
2011	16.07	0.62	1.60	0.34	0.000%	18.63	2.60	0.000%	2.60	21.23
2012	16.72	0.66	1.70	0.34	0.000%	19.42	2.76	0.000%	2.76	22.18
2013	16.84	0.66	1.81	0.34	0.000%	19.65	2.93	0.000%	2.93	22.58
2014	20.35	0.78	1.93	0.34	0.000%	23.40	3.12	0.000%	3.12	26.52
2015	20.18	0.80	2.06	0.34	0.000%	23.38	3.32	0.000%	3.32	26.70
2016	22.11	0.86	2.20	0.34	0.000%	25.51	3.52	0.000%	3.52	29.03
2017	23.87	0.92	2.34	0.34	0.000%	27.47	3.75	0.000%	3.75	31.22
2018	24.53	0.95	2.49	0.34	0.000%	28.31	3.98	0.000%	3.98	32.29

LOW FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Primary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.18	0.16	0.00	0.34	4.645%	3.85	0.99	6.991%	1.06	4.91
1990	2.56	0.17	0.00	0.34	4.645%	3.21	0.99	6.991%	1.06	4.27
1991	2.63	0.17	0.00	0.34	4.645%	3.29	0.99	6.991%	1.06	4.35
1992	3.32	0.23	0.00	0.34	4.645%	4.07	0.99	6.991%	1.06	5.13
1993	3.34	0.27	0.00	0.34	4.645%	4.13	0.99	6.991%	1.06	5.19
1994	2.53	0.15	0.52	0.34	4.645%	3.70	0.90	6.991%	0.96	4.66
1995	3.38	0.19	0.55	0.34	4.645%	4.67	0.95	6.991%	1.02	5.69
1996	3.61	0.21	0.59	0.34	4.645%	4.97	1.01	6.991%	1.08	6.05
1997	4.12	0.21	0.63	0.34	4.645%	5.55	1.08	6.991%	1.16	6.71
1998	4.56	0.20	0.67	0.34	4.645%	6.04	1.15	6.991%	1.23	7.27
1999	5.83	0.21	0.71	0.34	4.645%	7.42	1.23	6.991%	1.32	8.74
2000	6.80	0.23	0.76	0.34	4.645%	8.51	1.31	6.991%	1.40	9.91
2001	6.68	0.25	0.81	0.34	4.645%	8.46	1.40	6.991%	1.50	9.96
2002	8.02	0.28	0.87	0.34	4.645%	9.95	1.49	6.991%	1.59	11.54
2003	8.83	0.32	0.93	0.34	4.645%	10.90	1.59	6.991%	1.70	12.60
2004	11.02	0.38	1.00	0.34	4.645%	13.33	1.69	6.991%	1.81	15.14
2005	10.28	0.40	1.07	0.34	4.645%	12.65	1.80	6.991%	1.93	14.58
2006	12.27	0.48	1.14	0.34	4.645%	14.89	1.91	6.991%	2.04	16.93
2007	12.75	0.50	1.22	0.34	4.645%	15.50	2.03	6.991%	2.17	17.67
2008	13.46	0.49	1.30	0.34	4.645%	16.31	2.16	6.991%	2.31	18.62
2009	14.46	0.55	1.39	0.34	4.645%	17.52	2.30	6.991%	2.46	19.98
2010	15.25	0.59	1.49	0.34	4.645%	18.49	2.44	6.991%	2.61	21.10
2011	16.07	0.62	1.60	0.34	4.645%	19.50	2.60	6.991%	2.78	22.28
2012	16.72	0.66	1.70	0.34	4.645%	20.32	2.76	6.991%	2.95	23.27
2013	16.84	0.66	1.81	0.34	4.645%	20.56	2.93	6.991%	3.13	23.69
2014	20.35	0.78	1.93	0.34	4.645%	24.49	3.12	6.991%	3.34	27.83
2015	20.18	0.80	2.06	0.34	4.645%	24.47	3.32	6.991%	3.55	28.02
2016	22.11	0.86	2.20	0.34	4.645%	26.69	3.52	6.991%	3.77	30.46
2017	23.87	0.92	2.34	0.34	4.645%	28.75	3.75	6.991%	4.01	32.76
2018	24.53	0.95	2.49	0.34	4.645%	29.62	3.98	6.991%	4.26	33.88

LOW FUEL CASE
TABLE I
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.18	0.16	0.00	0.34	7.352%	3.95	0.99	8.861%	1.08	5.03
1990	2.56	0.17	0.00	0.34	7.352%	3.30	0.99	8.861%	1.08	4.38
1991	2.63	0.17	0.00	0.34	7.352%	3.37	0.99	8.861%	1.08	4.45
1992	3.32	0.23	0.00	0.34	7.352%	4.18	0.99	8.861%	1.08	5.26
1993	3.34	0.27	0.00	0.34	7.352%	4.24	0.99	8.861%	1.08	5.32
1994	2.53	0.15	0.52	0.34	7.352%	3.80	0.90	8.861%	0.98	4.78
1995	3.38	0.19	0.55	0.34	7.352%	4.79	0.95	8.861%	1.03	5.82
1996	3.61	0.21	0.59	0.34	7.352%	5.10	1.01	8.861%	1.10	6.20
1997	4.12	0.21	0.63	0.34	7.352%	5.69	1.08	8.861%	1.18	6.87
1998	4.56	0.20	0.67	0.34	7.352%	6.19	1.15	8.861%	1.25	7.44
1999	5.83	0.21	0.71	0.34	7.352%	7.61	1.23	8.861%	1.34	8.95
2000	6.80	0.23	0.76	0.34	7.352%	8.73	1.31	8.861%	1.43	10.16
2001	6.68	0.25	0.81	0.34	7.352%	8.67	1.40	8.861%	1.52	10.19
2002	8.02	0.28	0.87	0.34	7.352%	10.21	1.49	8.861%	1.62	11.83
2003	8.83	0.32	0.93	0.34	7.352%	11.19	1.59	8.861%	1.73	12.92
2004	11.02	0.38	1.00	0.34	7.352%	13.68	1.69	8.861%	1.84	15.52
2005	10.28	0.40	1.07	0.34	7.352%	12.98	1.80	8.861%	1.96	14.94
2006	12.27	0.48	1.14	0.34	7.352%	15.28	1.91	8.861%	2.08	17.36
2007	12.75	0.50	1.22	0.34	7.352%	15.90	2.03	8.861%	2.21	18.11
2008	13.46	0.49	1.30	0.34	7.352%	16.74	2.16	8.861%	2.35	19.09
2009	14.46	0.55	1.39	0.34	7.352%	17.97	2.30	8.861%	2.50	20.47
2010	15.25	0.59	1.49	0.34	7.352%	18.97	2.44	8.861%	2.66	21.63
2011	16.07	0.62	1.60	0.34	7.352%	20.00	2.60	8.861%	2.83	22.83
2012	16.72	0.66	1.70	0.34	7.352%	20.85	2.76	8.861%	3.00	23.85
2013	16.84	0.66	1.81	0.34	7.352%	21.09	2.93	8.861%	3.19	24.28
2014	20.35	0.78	1.93	0.34	7.352%	25.12	3.12	8.861%	3.40	28.52
2015	20.18	0.80	2.06	0.34	7.352%	25.10	3.32	8.861%	3.61	28.71
2016	22.11	0.86	2.20	0.34	7.352%	27.39	3.52	8.861%	3.83	31.22
2017	23.87	0.92	2.34	0.34	7.352%	29.49	3.75	8.861%	4.08	33.57
2018	24.53	0.95	2.49	0.34	7.352%	30.39	3.98	8.861%	4.33	34.72

LOW FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-lzed Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.18	0.16	0.00	0.34	9.321%	4.02	0.99	12.183%	1.11	5.13
1990	2.56	0.17	0.00	0.34	9.321%	3.36	0.99	12.183%	1.11	4.47
1991	2.63	0.17	0.00	0.34	9.321%	3.43	0.99	12.183%	1.11	4.54
1992	3.32	0.23	0.00	0.34	9.321%	4.25	0.99	12.183%	1.11	5.36
1993	3.34	0.27	0.00	0.34	9.321%	4.32	0.99	12.183%	1.11	5.43
1994	2.53	0.15	0.52	0.34	9.321%	3.87	0.90	12.183%	1.01	4.88
1995	3.38	0.19	0.55	0.34	9.321%	4.88	0.95	12.183%	1.07	5.95
1996	3.61	0.21	0.59	0.34	9.321%	5.19	1.01	12.183%	1.13	6.32
1997	4.12	0.21	0.63	0.34	9.321%	5.79	1.08	12.183%	1.21	7.00
1998	4.56	0.20	0.67	0.34	9.321%	6.31	1.15	12.183%	1.29	7.60
1999	5.83	0.21	0.71	0.34	9.321%	7.75	1.23	12.183%	1.38	9.13
2000	6.80	0.23	0.76	0.34	9.321%	8.89	1.31	12.183%	1.47	10.36
2001	6.68	0.25	0.81	0.34	9.321%	8.83	1.40	12.183%	1.57	10.40
2002	8.02	0.28	0.87	0.34	9.321%	10.40	1.49	12.183%	1.67	12.07
2003	8.83	0.32	0.93	0.34	9.321%	11.39	1.59	12.183%	1.78	13.17
2004	11.02	0.38	1.00	0.34	9.321%	13.93	1.69	12.183%	1.90	15.83
2005	10.28	0.40	1.07	0.34	9.321%	13.22	1.80	12.183%	2.02	15.24
2006	12.27	0.48	1.14	0.34	9.321%	15.56	1.91	12.183%	2.14	17.70
2007	12.75	0.50	1.22	0.34	9.321%	16.19	2.03	12.183%	2.28	18.47
2008	13.46	0.49	1.30	0.34	9.321%	17.04	2.16	12.183%	2.42	19.46
2009	14.46	0.55	1.39	0.34	9.321%	18.30	2.30	12.183%	2.58	20.88
2010	15.25	0.59	1.49	0.34	9.321%	19.32	2.44	12.183%	2.74	22.06
2011	16.07	0.62	1.50	0.34	9.321%	20.37	2.60	12.183%	2.92	23.29
2012	16.72	0.66	1.70	0.34	9.321%	21.23	2.76	12.183%	3.10	24.33
2013	16.84	0.66	1.81	0.34	9.321%	21.48	2.93	12.183%	3.29	24.77
2014	20.35	0.78	1.93	0.34	9.321%	25.58	3.12	12.183%	3.50	29.08
2015	20.18	0.80	2.06	0.34	9.321%	25.58	3.32	12.183%	3.72	29.28
2016	22.11	0.86	2.20	0.34	9.321%	27.89	3.52	12.183%	3.95	31.84
2017	23.87	0.92	2.34	0.34	9.321%	30.03	3.75	12.183%	4.21	34.24
2018	24.53	0.95	2.49	0.34	9.321%	30.95	3.98	12.183%	4.46	35.41

TABLE 2
(Commonwealth - EST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.05	0.00	165.29
2018	327.16	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.18	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.80	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - EST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.66	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.76	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.69	4.34	1041.96			
2032	253.29	4.05	1108.82			
2033	263.62	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - EST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	58.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - EST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	6.06
1995	140.85	113.94	68.27	0.95	6.42
1996	134.76	98.04	72.64	1.01	6.83
1997	128.69	84.21	77.36	1.08	7.27
1998	123.05	72.42	82.47	1.15	7.76
1999	117.82	62.37	88.00	1.23	8.28
2000	113.02	53.81	93.90	1.31	8.83
2001	108.24	46.35	100.19	1.40	9.42
2002	103.44	39.84	106.71	1.49	10.03
2003	98.67	34.18	113.65	1.59	10.69
2004	93.89	29.25	121.04	1.69	11.38
2005	89.10	24.96	128.79	1.80	12.11
2006	84.33	21.25	137.04	1.91	12.89
2007	79.55	18.03	145.68	2.03	13.70
2008	74.80	15.25	154.87	2.16	14.56
2009	70.02	12.84	164.64	2.30	15.48
2010	66.99	11.05	175.02	2.44	16.46
2011	64.78	9.61	186.06	2.60	17.50
2012	62.58	8.35	197.79	2.76	18.60
2013	60.41	7.25	210.26	2.93	19.77
2014	58.21	6.28	223.52	3.12	21.02
2015	56.04	5.44	237.61	3.32	22.34
2016	53.86	4.70	252.59	3.52	23.75
2017	51.68	4.06	268.52	3.75	25.25
2018	49.53	3.50	285.45	3.98	26.84
2019	47.39	3.01	303.45	4.23	28.54
2020	45.25	2.58	322.59	4.50	30.34
2021	43.11	2.21	342.93	4.79	32.25
2022	40.99	1.89	364.55	5.09	34.28
2023	38.86	1.61	387.54	5.41	36.44
SUMS	2443.32	927.25	5477.60		

LOW FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.78	0.23	0.00	0.34	0.000%	4.35	0.99	0.000%	0.99	5.34
1990	2.66	0.25	0.00	0.34	0.000%	3.25	0.99	0.000%	0.99	4.24
1991	2.84	0.30	0.00	0.34	0.000%	3.48	0.99	0.000%	0.99	4.47
1992	2.88	0.26	0.00	0.34	0.000%	3.48	0.99	0.000%	0.99	4.47
1993	3.16	0.38	0.00	0.34	0.000%	3.88	0.99	0.000%	0.99	4.87
1994	2.57	0.47	0.52	0.34	0.000%	3.90	0.90	0.000%	0.90	4.80
1995	2.30	0.46	0.55	0.34	0.000%	3.65	0.95	0.000%	0.95	4.60
1996	2.17	0.46	0.59	0.34	0.000%	3.56	1.01	0.000%	1.01	4.57
1997	2.43	0.53	0.63	0.34	0.000%	3.93	1.08	0.000%	1.08	5.01
1998	2.48	0.53	0.67	0.34	0.000%	4.02	1.15	0.000%	1.15	5.17
1999	2.42	0.56	0.71	0.34	0.000%	4.03	1.23	0.000%	1.23	5.26
2000	2.69	0.60	0.76	0.34	0.000%	4.39	1.31	0.000%	1.31	5.70
2001	2.85	0.62	0.81	0.34	0.000%	4.62	1.40	0.000%	1.40	6.02
2002	4.04	0.71	0.87	0.34	0.000%	5.96	1.49	0.000%	1.49	7.45
2003	3.21	0.65	0.93	0.34	0.000%	5.13	1.59	0.000%	1.59	6.72
2004	3.37	0.70	1.00	0.34	0.000%	5.41	1.69	0.000%	1.69	7.10
2005	4.79	0.78	1.07	0.34	0.000%	6.98	1.80	0.000%	1.80	8.78
2006	5.10	0.80	1.14	0.34	0.000%	7.38	1.91	0.000%	1.91	9.29
2007	5.32	0.80	1.22	0.34	0.000%	7.68	2.03	0.000%	2.03	9.71
2008	6.01	0.90	1.30	0.34	0.000%	8.55	2.16	0.000%	2.16	10.71
2009	7.07	1.01	1.39	0.34	0.000%	9.81	2.30	0.000%	2.30	12.11
2010	7.28	1.07	1.49	0.34	0.000%	10.18	2.44	0.000%	2.44	12.62
2011	7.89	1.14	1.60	0.34	0.000%	10.97	2.60	0.000%	2.60	13.57
2012	8.28	1.24	1.70	0.34	0.000%	11.56	2.76	0.000%	2.76	14.32
2013	8.47	1.29	1.81	0.34	0.000%	11.91	2.93	0.000%	2.93	14.84
2014	8.91	1.39	1.93	0.34	0.000%	12.57	3.12	0.000%	3.12	15.69
2015	9.33	1.49	2.06	0.34	0.000%	13.22	3.32	0.000%	3.32	16.54
2016	9.90	1.47	2.20	0.34	0.000%	13.91	3.52	0.000%	3.52	17.43
2017	10.21	1.50	2.34	0.34	0.000%	14.39	3.75	0.000%	3.75	18.14
2018	10.68	1.62	2.49	0.34	0.000%	15.13	3.98	0.000%	3.98	19.11

LOW FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Primary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.78	0.23	0.00	0.34	4.645%	4.55	0.99	6.991%	1.06	5.61
1990	2.66	0.25	0.00	0.34	4.645%	3.40	0.99	6.991%	1.06	4.46
1991	2.84	0.30	0.00	0.34	4.645%	3.64	0.99	6.991%	1.06	4.70
1992	2.88	0.26	0.00	0.34	4.645%	3.64	0.99	6.991%	1.06	4.70
1993	3.16	0.38	0.00	0.34	4.645%	4.06	0.99	6.991%	1.06	5.12
1994	2.57	0.47	0.52	0.34	4.645%	4.08	0.90	6.991%	0.96	5.04
1995	2.30	0.46	0.55	0.34	4.645%	3.82	0.95	6.991%	1.02	4.84
1996	2.17	0.46	0.59	0.34	4.645%	3.73	1.01	6.991%	1.08	4.81
1997	2.43	0.53	0.63	0.34	4.645%	4.11	1.08	6.991%	1.16	5.27
1998	2.48	0.53	0.67	0.34	4.645%	4.21	1.15	6.991%	1.23	5.44
1999	2.42	0.56	0.71	0.34	4.645%	4.22	1.23	6.991%	1.32	5.54
2000	2.69	0.60	0.76	0.34	4.645%	4.59	1.31	6.991%	1.40	5.99
2001	2.85	0.62	0.81	0.34	4.645%	4.83	1.40	6.991%	1.50	6.33
2002	4.04	0.71	0.87	0.34	4.645%	6.24	1.49	6.991%	1.59	7.83
2003	3.21	0.65	0.93	0.34	4.645%	5.37	1.59	6.991%	1.70	7.07
2004	3.37	0.70	1.00	0.34	4.645%	5.65	1.69	6.991%	1.81	7.47
2005	4.79	0.78	1.07	0.34	4.645%	7.30	1.80	6.991%	1.93	9.23
2006	5.10	0.80	1.14	0.34	4.645%	7.72	1.91	6.991%	2.04	9.76
2007	5.32	0.80	1.22	0.34	4.645%	8.04	2.03	6.991%	2.17	10.21
2008	6.01	0.90	1.30	0.34	4.645%	8.95	2.16	6.991%	2.31	11.26
2009	7.07	1.01	1.39	0.34	4.645%	10.27	2.30	6.991%	2.46	12.73
2010	7.28	1.07	1.49	0.34	4.645%	10.65	2.44	6.991%	2.61	13.26
2011	7.89	1.14	1.60	0.34	4.645%	11.48	2.60	6.991%	2.78	14.26
2012	8.28	1.24	1.70	0.34	4.645%	12.10	2.76	6.991%	2.95	15.05
2013	8.47	1.29	1.81	0.34	4.645%	12.46	2.93	6.991%	3.13	15.59
2014	8.91	1.39	1.93	0.34	4.645%	13.15	3.12	6.991%	3.34	16.49
2015	9.33	1.49	2.06	0.34	4.645%	13.83	3.32	6.991%	3.55	17.38
2016	9.90	1.47	2.20	0.34	4.645%	14.56	3.52	6.991%	3.77	18.33
2017	10.21	1.50	2.34	0.34	4.645%	15.06	3.75	6.991%	4.01	19.07
2018	10.68	1.62	2.49	0.34	4.645%	15.83	3.98	6.991%	4.26	20.09

LOW FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.78	0.23	0.00	0.34	7.352%	4.67	0.99	8.861%	1.08	5.75
1990	2.66	0.25	0.00	0.34	7.352%	3.49	0.99	8.861%	1.08	4.57
1991	2.84	0.30	0.00	0.34	7.352%	3.74	0.99	8.861%	1.08	4.82
1992	2.88	0.26	0.00	0.34	7.352%	3.74	0.99	8.861%	1.08	4.82
1993	3.16	0.38	0.00	0.34	7.352%	4.17	0.99	8.861%	1.08	5.25
1994	2.57	0.47	0.52	0.34	7.352%	4.19	0.90	8.861%	0.98	5.17
1995	2.30	0.46	0.55	0.34	7.352%	3.92	0.95	8.861%	1.03	4.95
1996	2.17	0.46	0.59	0.34	7.352%	3.82	1.01	8.861%	1.10	4.92
1997	2.43	0.53	0.63	0.34	7.352%	4.22	1.08	8.861%	1.18	5.40
1998	2.48	0.53	0.67	0.34	7.352%	4.32	1.15	8.861%	1.25	5.57
1999	2.42	0.56	0.71	0.34	7.352%	4.33	1.23	8.861%	1.34	5.67
2000	2.69	0.60	0.76	0.34	7.352%	4.71	1.31	8.861%	1.43	6.14
2001	2.85	0.62	0.81	0.34	7.352%	4.95	1.40	8.861%	1.52	6.48
2002	4.04	0.71	0.87	0.34	7.352%	6.40	1.49	8.861%	1.62	8.02
2003	3.21	0.65	0.93	0.34	7.352%	5.51	1.59	8.861%	1.73	7.24
2004	3.37	0.70	1.00	0.34	7.352%	5.81	1.69	8.861%	1.84	7.65
2005	4.79	0.78	1.07	0.34	7.352%	7.49	1.80	8.861%	1.96	9.45
2006	5.10	0.80	1.14	0.34	7.352%	7.92	1.91	8.861%	2.08	10.00
2007	5.32	0.80	1.22	0.34	7.352%	8.24	2.03	8.861%	2.21	10.45
2008	6.01	0.90	1.30	0.34	7.352%	9.18	2.16	8.861%	2.35	11.53
2009	7.07	1.01	1.39	0.34	7.352%	10.53	2.30	8.861%	2.50	13.03
2010	7.28	1.07	1.49	0.34	7.352%	10.93	2.44	8.861%	2.66	13.59
2011	7.89	1.14	1.60	0.34	7.352%	11.78	2.60	8.861%	2.83	14.61
2012	8.28	1.24	1.70	0.34	7.352%	12.41	2.76	8.861%	3.00	15.41
2013	8.47	1.29	1.81	0.34	7.352%	12.79	2.93	8.861%	3.19	15.98
2014	8.91	1.39	1.93	0.34	7.352%	13.49	3.12	8.861%	3.40	16.89
2015	9.33	1.49	2.06	0.34	7.352%	14.19	3.32	8.861%	3.61	17.80
2016	9.90	1.47	2.20	0.34	7.352%	14.93	3.52	8.861%	3.83	18.76
2017	10.21	1.50	2.34	0.34	7.352%	15.45	3.75	8.861%	4.08	19.53
2018	10.68	1.62	2.49	0.34	7.352%	16.24	3.98	8.861%	4.33	20.57

LOW FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.78	0.23	0.00	0.34	9.321%	4.76	0.99	12.183%	1.11	5.87
1990	2.66	0.25	0.00	0.34	9.321%	3.55	0.99	12.183%	1.11	4.66
1991	2.84	0.30	0.00	0.34	9.321%	3.80	0.99	12.183%	1.11	4.91
1992	2.88	0.26	0.00	0.34	9.321%	3.80	0.99	12.183%	1.11	4.91
1993	3.16	0.38	0.00	0.34	9.321%	4.24	0.99	12.183%	1.11	5.35
1994	2.57	0.47	0.52	0.34	9.321%	4.26	0.90	12.183%	1.01	5.27
1995	2.30	0.46	0.55	0.34	9.321%	3.99	0.95	12.183%	1.07	5.06
1996	2.17	0.46	0.59	0.34	9.321%	3.89	1.01	12.183%	1.13	5.02
1997	2.43	0.53	0.63	0.34	9.321%	4.30	1.08	12.183%	1.21	5.51
1998	2.48	0.53	0.67	0.34	9.321%	4.39	1.15	12.183%	1.29	5.68
1999	2.42	0.56	0.71	0.34	9.321%	4.41	1.23	12.183%	1.38	5.79
2000	2.69	0.60	0.76	0.34	9.321%	4.80	1.31	12.183%	1.47	6.27
2001	2.85	0.62	0.81	0.34	9.321%	5.05	1.40	12.183%	1.57	6.62
2002	4.04	0.71	0.87	0.34	9.321%	6.52	1.49	12.183%	1.67	8.19
2003	3.21	0.65	0.93	0.34	9.321%	5.61	1.59	12.183%	1.78	7.39
2004	3.37	0.70	1.00	0.34	9.321%	5.91	1.69	12.183%	1.90	7.81
2005	4.79	0.78	1.07	0.34	9.321%	7.63	1.80	12.183%	2.02	9.65
2006	5.10	0.80	1.14	0.34	9.321%	8.07	1.91	12.183%	2.14	10.21
2007	5.32	0.80	1.22	0.34	9.321%	8.40	2.03	12.183%	2.28	10.68
2008	6.01	0.90	1.30	0.34	9.321%	9.35	2.16	12.183%	2.42	11.77
2009	7.07	1.01	1.39	0.34	9.321%	10.72	2.30	12.183%	2.58	13.30
2010	7.28	1.07	1.49	0.34	9.321%	11.13	2.44	12.183%	2.74	13.87
2011	7.89	1.14	1.60	0.34	9.321%	11.99	2.60	12.183%	2.92	14.91
2012	8.28	1.24	1.70	0.34	9.321%	12.64	2.76	12.183%	3.10	15.74
2013	8.47	1.29	1.81	0.34	9.321%	13.02	2.93	12.183%	3.29	16.31
2014	8.91	1.39	1.93	0.34	9.321%	13.74	3.12	12.183%	3.50	17.24
2015	9.33	1.49	2.06	0.34	9.321%	14.45	3.32	12.183%	3.72	18.17
2016	9.90	1.47	2.20	0.34	9.321%	15.21	3.52	12.183%	3.95	19.16
2017	10.21	1.50	2.34	0.34	9.321%	15.73	3.75	12.183%	4.21	19.94
2018	10.68	1.62	2.49	0.34	9.321%	16.54	3.98	12.183%	4.46	21.00

TABLE 2
(Commonwealth - DST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.06	0.00	165.29
2018	327.16	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.18	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.80	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - DST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.56	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.76	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.69	4.34	1041.96			
2032	253.29	4.05	1108.82			
2033	263.62	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - DST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	58.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - DST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	3.37
1995	140.85	113.94	68.27	0.95	3.57
1996	134.76	98.04	72.64	1.01	3.79
1997	128.69	84.21	77.36	1.08	4.04
1998	123.05	72.42	82.47	1.15	4.31
1999	117.82	62.37	88.00	1.23	4.60
2000	113.02	53.81	93.90	1.31	4.91
2001	108.24	46.35	100.19	1.40	5.23
2002	103.44	39.84	106.71	1.49	5.57
2003	98.67	34.18	113.65	1.59	5.94
2004	93.89	29.25	121.04	1.69	6.32
2005	89.10	24.96	128.79	1.80	6.73
2006	84.33	21.25	137.04	1.91	7.16
2007	79.56	18.03	145.68	2.03	7.61
2008	74.80	15.25	154.87	2.16	8.09
2009	70.02	12.84	164.64	2.30	8.60
2010	66.99	11.05	175.02	2.44	9.14
2011	64.78	9.61	186.06	2.60	9.72
2012	62.58	8.35	197.79	2.76	10.33
2013	60.41	7.25	210.26	2.93	10.98
2014	58.21	6.28	223.52	3.12	11.68
2015	56.04	5.44	237.61	3.32	12.41
2016	53.86	4.70	252.59	3.52	13.20
2017	51.68	4.06	268.52	3.75	14.03
2018	49.53	3.50	285.45	3.98	14.91
2019	47.39	3.01	303.45	4.23	15.85
2020	45.25	2.58	322.59	4.50	16.85
2021	43.11	2.21	342.93	4.79	17.92
2022	40.99	1.89	364.55	5.09	19.05
2023	38.86	1.61	387.54	5.41	20.25
SUMS	2443.32	927.25	5477.60		

HIGH CASE

TABLES 1, 2, 3, 4, 5

Eastern Standard Time
and Daylight Savings Time

HIGH FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-lzed Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.20	0.16	0.00	0.34	0.000%	3.70	0.99	0.000%	0.99	4.69
1990	3.91	0.19	0.00	0.34	0.000%	4.44	0.99	0.000%	0.99	5.43
1991	4.45	0.18	0.00	0.34	0.000%	4.97	0.99	0.000%	0.99	5.95
1992	5.71	0.26	0.00	0.34	0.000%	6.31	0.99	0.000%	0.99	7.30
1993	5.86	0.32	0.00	0.34	0.000%	6.52	0.99	0.000%	0.99	7.51
1994	4.62	0.16	0.52	0.34	0.000%	5.64	0.90	0.000%	0.90	6.54
1995	5.35	0.20	0.55	0.34	0.000%	7.44	0.95	0.000%	0.95	8.39
1996	6.74	0.21	0.59	0.34	0.000%	7.88	1.01	0.000%	1.01	8.89
1997	7.10	0.21	0.63	0.34	0.000%	8.28	1.08	0.000%	1.08	9.36
1998	7.07	0.23	0.67	0.34	0.000%	8.31	1.15	0.000%	1.15	9.46
1999	8.31	0.37	0.71	0.34	0.000%	9.73	1.23	0.000%	1.23	10.96
2000	9.26	0.30	0.76	0.34	0.000%	10.66	1.31	0.000%	1.31	11.97
2001	9.03	0.26	0.81	0.34	0.000%	10.44	1.40	0.000%	1.40	11.84
2002	11.01	0.28	0.87	0.34	0.000%	12.50	1.49	0.000%	1.49	13.99
2003	12.25	0.31	0.93	0.34	0.000%	13.83	1.59	0.000%	1.59	15.42
2004	15.11	0.36	1.00	0.34	0.000%	16.83	1.69	0.000%	1.69	18.52
2005	14.16	0.40	1.07	0.34	0.000%	15.97	1.80	0.000%	1.80	17.77
2006	17.17	0.49	1.14	0.34	0.000%	19.14	1.91	0.000%	1.91	21.05
2007	17.85	0.51	1.22	0.34	0.000%	19.92	2.03	0.000%	2.03	21.95
2008	18.95	0.49	1.30	0.34	0.000%	21.08	2.16	0.000%	2.16	23.24
2009	20.31	0.56	1.39	0.34	0.000%	22.60	2.30	0.000%	2.30	24.90
2010	21.49	0.59	1.49	0.34	0.000%	23.91	2.44	0.000%	2.44	26.35
2011	22.63	0.62	1.60	0.34	0.000%	25.19	2.60	0.000%	2.60	27.79
2012	23.51	0.66	1.70	0.34	0.000%	26.21	2.76	0.000%	2.76	28.97
2013	23.68	0.66	1.81	0.34	0.000%	26.49	2.93	0.000%	2.93	29.42
2014	28.64	0.78	1.93	0.34	0.000%	31.69	3.12	0.000%	3.12	34.81
2015	28.38	0.80	2.06	0.34	0.000%	31.58	3.32	0.000%	3.32	34.90
2016	31.17	0.86	2.20	0.34	0.000%	34.57	3.52	0.000%	3.52	38.09
2017	33.67	0.91	2.34	0.34	0.000%	37.26	3.75	0.000%	3.75	41.01
2018	34.54	0.95	2.49	0.34	0.000%	38.32	3.98	0.000%	3.98	42.30

HIGH FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Primary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.20	0.16	0.00	0.34	4.645%	3.87	0.99	6.991%	1.06	4.93
1990	3.91	0.19	0.00	0.34	4.645%	4.65	0.99	6.991%	1.06	5.71
1991	4.45	0.18	0.00	0.34	4.645%	5.20	0.99	6.991%	1.06	6.26
1992	5.71	0.26	0.00	0.34	4.645%	6.60	0.99	6.991%	1.06	7.66
1993	5.86	0.32	0.00	0.34	4.645%	6.82	0.99	6.991%	1.06	7.88
1994	4.62	0.16	0.52	0.34	4.645%	5.90	0.90	6.991%	0.96	6.86
1995	6.35	0.20	0.55	0.34	4.645%	7.79	0.95	6.991%	1.02	8.81
1996	6.74	0.21	0.59	0.34	4.645%	8.25	1.01	6.991%	1.08	9.33
1997	7.10	0.21	0.63	0.34	4.645%	8.66	1.08	6.991%	1.16	9.82
1998	7.07	0.23	0.67	0.34	4.645%	8.70	1.15	6.991%	1.23	9.93
1999	8.31	0.37	0.71	0.34	4.645%	10.18	1.23	6.991%	1.32	11.50
2000	9.26	0.30	0.76	0.34	4.645%	11.16	1.31	6.991%	1.40	12.56
2001	9.03	0.26	0.81	0.34	4.645%	10.92	1.40	6.991%	1.50	12.42
2002	11.01	0.28	0.87	0.34	4.645%	13.08	1.49	6.991%	1.59	14.67
2003	12.25	0.31	0.93	0.34	4.645%	14.47	1.59	6.991%	1.70	16.17
2004	15.11	0.38	1.00	0.34	4.645%	17.61	1.69	6.991%	1.81	19.42
2005	14.16	0.40	1.07	0.34	4.645%	16.71	1.80	6.991%	1.93	18.64
2006	17.17	0.49	1.14	0.34	4.645%	20.03	1.91	6.991%	2.04	22.07
2007	17.85	0.51	1.22	0.34	4.645%	20.85	2.03	6.991%	2.17	23.02
2008	18.95	0.49	1.30	0.34	4.645%	22.06	2.16	6.991%	2.31	24.37
2009	20.31	0.56	1.39	0.34	4.645%	23.65	2.30	6.991%	2.46	26.11
2010	21.49	0.59	1.49	0.34	4.645%	25.02	2.44	6.991%	2.61	27.63
2011	22.63	0.62	1.60	0.34	4.645%	26.36	2.60	6.991%	2.78	29.14
2012	23.51	0.66	1.70	0.34	4.645%	27.43	2.76	6.991%	2.95	30.38
2013	23.68	0.66	1.81	0.34	4.645%	27.72	2.93	6.991%	3.13	30.85
2014	28.64	0.78	1.93	0.34	4.645%	33.16	3.12	6.991%	3.34	36.50
2015	28.38	0.80	2.06	0.34	4.645%	33.05	3.32	6.991%	3.55	36.60
2016	31.17	0.86	2.20	0.34	4.645%	36.18	3.52	6.991%	3.77	39.95
2017	33.67	0.91	2.34	0.34	4.645%	38.99	3.75	6.991%	4.01	43.00
2018	34.54	0.95	2.49	0.34	4.645%	40.10	3.98	6.991%	4.26	44.36

HIGH FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.20	0.16	0.00	0.34	7.352%	3.97	0.99	8.861%	1.08	5.05
1990	3.91	0.19	0.00	0.34	7.352%	4.77	0.99	8.861%	1.08	5.85
1991	4.45	0.18	0.00	0.34	7.352%	5.34	0.99	8.861%	1.08	6.42
1992	5.71	0.26	0.00	0.34	7.352%	6.77	0.99	8.861%	1.08	7.85
1993	5.85	0.32	0.00	0.34	7.352%	7.00	0.99	8.861%	1.08	8.08
1994	4.62	0.16	0.52	0.34	7.352%	6.05	0.90	8.861%	0.98	7.03
1995	6.35	0.20	0.55	0.34	7.352%	7.99	0.95	8.861%	1.03	9.02
1996	6.74	0.21	0.59	0.34	7.352%	8.46	1.01	8.861%	1.10	9.56
1997	7.10	0.21	0.63	0.34	7.352%	8.89	1.08	8.861%	1.18	10.07
1998	7.07	0.23	0.67	0.34	7.352%	8.92	1.15	8.861%	1.25	10.17
1999	8.31	0.37	0.71	0.34	7.352%	10.45	1.23	8.861%	1.34	11.79
2000	9.26	0.30	0.76	0.34	7.352%	11.44	1.31	8.861%	1.43	12.87
2001	9.03	0.26	0.81	0.34	7.352%	11.21	1.40	8.861%	1.52	12.73
2002	11.01	0.28	0.87	0.34	7.352%	13.42	1.49	8.861%	1.62	15.04
2003	12.25	0.31	0.93	0.34	7.352%	14.85	1.59	8.861%	1.73	16.58
2004	15.11	0.38	1.00	0.34	7.352%	18.07	1.69	8.861%	1.84	19.91
2005	14.16	0.40	1.07	0.34	7.352%	17.14	1.80	8.861%	1.96	19.10
2006	17.17	0.49	1.14	0.34	7.352%	20.55	1.91	8.861%	2.08	22.63
2007	17.85	0.51	1.22	0.34	7.352%	21.38	2.03	8.861%	2.21	23.59
2008	18.95	0.49	1.30	0.34	7.352%	22.63	2.16	8.861%	2.35	24.98
2009	20.31	0.56	1.39	0.34	7.352%	24.26	2.30	8.861%	2.50	26.76
2010	21.49	0.59	1.49	0.34	7.352%	25.67	2.44	8.861%	2.66	28.33
2011	22.63	0.62	1.60	0.34	7.352%	27.04	2.60	8.861%	2.83	29.87
2012	23.51	0.66	1.70	0.34	7.352%	28.14	2.76	8.861%	3.00	31.14
2013	23.68	0.66	1.81	0.34	7.352%	28.44	2.93	8.861%	3.19	31.63
2014	28.64	0.78	1.93	0.34	7.352%	34.02	3.12	8.861%	3.40	37.42
2015	28.38	0.80	2.06	0.34	7.352%	33.90	3.32	8.861%	3.61	37.51
2016	31.17	0.86	2.20	0.34	7.352%	37.11	3.52	8.861%	3.83	40.94
2017	33.67	0.91	2.34	0.34	7.352%	40.00	3.75	8.861%	4.08	44.08
2018	34.54	0.95	2.49	0.34	7.352%	41.14	3.98	8.861%	4.33	45.47

HIGH FUEL CASE
TABLE 1
(Commonwealth - EST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-lized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.20	0.16	0.00	0.34	9.321%	4.04	0.99	12.183%	1.11	5.15
1990	3.91	0.19	0.00	0.34	9.321%	4.85	0.99	12.183%	1.11	5.96
1991	4.45	0.18	0.00	0.34	9.321%	5.43	0.99	12.183%	1.11	6.54
1992	5.71	0.26	0.00	0.34	9.321%	6.90	0.99	12.183%	1.11	8.01
1993	5.86	0.32	0.00	0.34	9.321%	7.13	0.99	12.183%	1.11	8.24
1994	4.62	0.16	0.52	0.34	9.321%	6.17	0.90	12.183%	1.01	7.18
1995	6.35	0.20	0.55	0.34	9.321%	8.13	0.95	12.183%	1.07	9.20
1996	6.74	0.21	0.59	0.34	9.321%	8.61	1.01	12.183%	1.13	9.74
1997	7.10	0.21	0.63	0.34	9.321%	9.05	1.08	12.183%	1.21	10.26
1998	7.07	0.23	0.67	0.34	9.321%	9.08	1.15	12.183%	1.29	10.37
1999	8.31	0.27	0.71	0.34	9.321%	10.64	1.23	12.183%	1.38	12.02
2000	9.26	0.30	0.76	0.34	9.321%	11.65	1.31	12.183%	1.47	13.12
2001	9.03	0.26	0.81	0.34	9.321%	11.41	1.40	12.183%	1.57	12.98
2002	11.01	0.28	0.87	0.34	9.321%	13.67	1.49	12.183%	1.67	15.34
2003	12.25	0.31	0.93	0.34	9.321%	15.12	1.59	12.183%	1.78	16.90
2004	15.11	0.38	1.00	0.34	9.321%	18.40	1.69	12.183%	1.90	20.30
2005	14.16	0.40	1.07	0.34	9.321%	17.46	1.80	12.183%	2.02	19.48
2006	17.17	0.49	1.14	0.34	9.321%	20.92	1.91	12.183%	2.14	23.06
2007	17.85	0.51	1.22	0.34	9.321%	21.78	2.03	12.183%	2.28	24.06
2008	18.95	0.49	1.30	0.34	9.321%	23.04	2.16	12.183%	2.42	25.46
2009	20.31	0.56	1.39	0.34	9.321%	24.71	2.30	12.183%	2.58	27.29
2010	21.49	0.59	1.49	0.34	9.321%	26.14	2.44	12.183%	2.74	28.88
2011	22.53	0.62	1.60	0.34	9.321%	27.54	2.60	12.183%	2.92	30.46
2012	23.51	0.66	1.70	0.34	9.321%	28.65	2.76	12.183%	3.10	31.75
2013	23.68	0.66	1.81	0.34	9.321%	28.96	2.93	12.183%	3.29	32.25
2014	28.64	0.78	1.93	0.34	9.321%	34.64	3.12	12.183%	3.50	38.14
2015	28.38	0.80	2.05	0.34	9.321%	34.52	3.32	12.183%	3.72	38.24
2016	31.17	0.86	2.20	0.34	9.321%	37.79	3.52	12.183%	3.95	41.74
2017	33.67	0.91	2.34	0.34	9.321%	40.73	3.75	12.183%	4.21	44.94
2018	34.54	0.95	2.49	0.34	9.321%	41.89	3.98	12.183%	4.46	46.35

TABLE 2
(Commonwealth - EST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.06	0.00	165.29
2018	327.16	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.10	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.80	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - EST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.66	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.75	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.69	4.34	1041.96			
2032	253.29	4.05	1108.82			
2033	263.62	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - EST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Year	Book Value ($/kw)	Book Deprec. ($/kw)	Required Return ($/kw)	Federal & State Income Tax ($/kw)	Deferred Tax ($/kw)	Property Tax ($/kw)	Fixed O&M ($/kw)	Other Charges ($/kw)	Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	58.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - EST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levellized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	6.06
1995	140.85	113.94	68.27	0.95	6.42
1996	134.76	98.04	72.64	1.01	6.83
1997	128.69	84.21	77.36	1.08	7.27
1998	123.05	72.42	82.47	1.15	7.76
1999	117.82	62.37	88.00	1.23	8.28
2000	113.02	53.81	93.90	1.31	8.83
2001	108.24	46.35	100.19	1.40	9.42
2002	103.44	39.84	106.71	1.49	10.03
2003	98.67	34.18	113.55	1.59	10.69
2004	93.89	29.25	121.04	1.69	11.38
2005	89.10	24.96	128.79	1.80	12.11
2006	84.33	21.25	137.04	1.91	12.89
2007	79.55	18.03	145.68	2.03	13.70
2008	74.80	15.25	154.87	2.16	14.56
2009	70.02	12.84	164.64	2.30	15.48
2010	66.99	11.05	175.02	2.44	16.46
2011	64.78	9.51	186.06	2.60	17.50
2012	62.58	8.35	197.79	2.76	18.60
2013	60.41	7.25	210.26	2.93	19.77
2014	58.21	6.28	223.52	3.12	21.02
2015	56.04	5.44	237.61	3.32	22.34
2016	53.86	4.70	252.59	3.52	23.75
2017	51.68	4.05	268.52	3.75	25.25
2018	49.53	3.50	285.45	3.98	26.84
2019	47.39	3.01	303.45	4.23	28.54
2020	45.25	2.58	322.59	4.50	30.34
2021	43.11	2.21	342.93	4.79	32.25
2022	40.99	1.89	364.55	5.09	34.28
2023	38.86	1.61	387.54	5.41	36.44
SUMS	2443.32	927.25	5477.60		

HIGH FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Excluding Losses

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-Ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.81	0.23	0.00	0.34	0.000%	4.38	0.99	0.000%	0.99	5.37
1990	4.03	0.28	0.00	0.34	0.000%	4.65	0.99	0.000%	0.99	5.64
1991	4.74	0.35	0.00	0.34	0.000%	5.43	0.99	0.000%	0.99	6.42
1992	4.91	0.29	0.00	0.34	0.000%	5.54	0.99	0.000%	0.99	6.53
1993	5.54	0.42	0.00	0.34	0.000%	6.30	0.99	0.000%	0.99	7.29
1994	4.64	0.49	0.52	0.34	0.000%	5.99	0.90	0.000%	0.90	6.89
1995	4.44	0.46	0.55	0.34	0.000%	5.79	0.95	0.000%	0.95	6.74
1996	4.50	0.46	0.59	0.34	0.000%	5.89	1.01	0.000%	1.01	6.90
1997	5.54	0.50	0.63	0.34	0.000%	7.01	1.08	0.000%	1.08	8.09
1998	6.07	0.39	0.67	0.34	0.000%	7.47	1.15	0.000%	1.15	8.62
1999	6.41	0.41	0.71	0.34	0.000%	7.87	1.23	0.000%	1.23	9.10
2000	7.24	0.44	0.76	0.34	0.000%	8.78	1.31	0.000%	1.31	10.09
2001	7.93	0.49	0.81	0.34	0.000%	9.57	1.40	0.000%	1.40	10.97
2002	10.14	0.73	0.87	0.34	0.000%	12.08	1.49	0.000%	1.49	13.57
2003	8.64	0.67	0.93	0.34	0.000%	10.58	1.59	0.000%	1.59	12.17
2004	8.96	0.67	1.00	0.34	0.000%	10.97	1.69	0.000%	1.69	12.66
2005	10.99	0.77	1.07	0.34	0.000%	13.17	1.80	0.000%	1.80	14.97
2006	11.53	0.79	1.14	0.34	0.000%	13.80	1.91	0.000%	1.91	15.71
2007	11.82	0.84	1.22	0.34	0.000%	14.22	2.03	0.000%	2.03	16.25
2008	13.01	0.91	1.30	0.34	0.000%	15.56	2.16	0.000%	2.16	17.72
2009	14.79	1.01	1.39	0.34	0.000%	17.53	2.30	0.000%	2.30	19.83
2010	15.12	1.02	1.49	0.34	0.000%	17.97	2.44	0.000%	2.44	20.41
2011	16.25	1.08	1.60	0.34	0.000%	19.27	2.60	0.000%	2.60	21.87
2012	17.20	1.21	1.70	0.34	0.000%	20.45	2.76	0.000%	2.76	23.21
2013	17.67	1.25	1.81	0.34	0.000%	21.07	2.93	0.000%	2.93	24.00
2014	18.69	1.34	1.93	0.34	0.000%	22.30	3.12	0.000%	3.12	25.42
2015	19.68	1.43	2.06	0.34	0.000%	23.51	3.32	0.000%	3.32	26.83
2016	20.70	1.52	2.20	0.34	0.000%	24.76	3.52	0.000%	3.52	28.28
2017	21.35	1.59	2.34	0.34	0.000%	25.62	3.75	0.000%	3.75	29.37
2018	22.46	1.70	2.49	0.34	0.000%	26.99	3.98	0.000%	3.98	30.97

HIGH FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Primary Voltage

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.81	0.23	0.00	0.34	4.645%	4.58	0.99	6.991%	1.06	5.64
1990	4.03	0.28	0.00	0.34	4.645%	4.87	0.99	6.991%	1.06	5.93
1991	4.74	0.35	0.00	0.34	4.645%	5.68	0.99	6.991%	1.06	6.74
1992	4.91	0.29	0.00	0.34	4.645%	5.80	0.99	6.991%	1.06	6.86
1993	5.54	0.42	0.00	0.34	4.645%	6.59	0.99	6.991%	1.06	7.65
1994	4.64	0.49	0.52	0.34	4.645%	6.27	0.90	6.991%	0.96	7.23
1995	4.44	0.46	0.55	0.34	4.645%	6.06	0.95	6.991%	1.02	7.08
1996	4.50	0.46	0.59	0.34	4.645%	6.16	1.01	6.991%	1.08	7.24
1997	5.54	0.50	0.63	0.34	4.645%	7.34	1.08	6.991%	1.16	8.50
1998	6.07	0.39	0.67	0.34	4.645%	7.82	1.15	6.991%	1.23	9.05
1999	6.41	0.41	0.71	0.34	4.645%	8.24	1.23	6.991%	1.32	9.56
2000	7.24	0.44	0.76	0.34	4.645%	9.19	1.31	6.991%	1.40	10.59
2001	7.93	0.49	0.81	0.34	4.645%	10.01	1.40	6.991%	1.50	11.51
2002	10.14	0.73	0.87	0.34	4.645%	12.64	1.49	6.991%	1.59	14.23
2003	8.64	0.67	0.93	0.34	4.645%	11.07	1.59	6.991%	1.70	12.77
2004	8.96	0.67	1.00	0.34	4.645%	11.48	1.69	6.991%	1.81	13.29
2005	10.99	0.77	1.07	0.34	4.645%	13.78	1.80	6.991%	1.93	15.71
2006	11.53	0.79	1.14	0.34	4.645%	14.44	1.91	6.991%	2.04	16.48
2007	11.82	0.84	1.22	0.34	4.645%	14.88	2.03	6.991%	2.17	17.05
2008	13.01	0.91	1.30	0.34	4.645%	16.28	2.16	6.991%	2.31	18.59
2009	14.79	1.01	1.39	0.34	4.645%	18.34	2.30	6.991%	2.46	20.80
2010	15.12	1.02	1.49	0.34	4.645%	18.80	2.44	6.991%	2.61	21.41
2011	16.25	1.08	1.60	0.34	4.645%	20.17	2.60	6.991%	2.78	22.95
2012	17.20	1.21	1.70	0.34	4.645%	21.40	2.76	6.991%	2.95	24.35
2013	17.67	1.25	1.81	0.34	4.645%	22.05	2.93	6.991%	3.13	25.18
2014	18.69	1.34	1.93	0.34	4.645%	23.34	3.12	6.991%	3.34	26.68
2015	19.68	1.43	2.06	0.34	4.645%	24.60	3.32	6.991%	3.55	28.15
2016	20.70	1.52	2.20	0.34	4.645%	25.91	3.52	6.991%	3.77	29.68
2017	21.35	1.59	2.34	0.34	4.645%	26.81	3.75	6.991%	4.01	30.82
2018	22.46	1.70	2.49	0.34	4.645%	28.24	3.98	6.991%	4.26	32.50

HIGH FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Large Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-lized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.81	0.23	0.00	0.34	7.352%	4.70	0.99	8.861%	1.08	5.78
1990	4.03	0.28	0.00	0.34	7.352%	4.99	0.99	8.861%	1.08	6.07
1991	4.74	0.35	0.00	0.34	7.352%	5.83	0.99	8.861%	1.08	6.91
1992	4.91	0.29	0.00	0.34	7.352%	5.95	0.99	8.861%	1.08	7.03
1993	5.54	0.42	0.00	0.34	7.352%	6.76	0.99	8.861%	1.08	7.84
1994	4.64	0.49	0.52	0.34	7.352%	6.43	0.90	8.861%	0.98	7.41
1995	4.44	0.46	0.55	0.34	7.352%	6.22	0.95	8.861%	1.03	7.25
1996	4.50	0.46	0.59	0.34	7.352%	6.32	1.01	8.861%	1.10	7.42
1997	5.54	0.50	0.63	0.34	7.352%	7.53	1.08	8.861%	1.18	8.71
1998	6.07	0.39	0.67	0.34	7.352%	8.02	1.15	8.861%	1.25	9.27
1999	6.41	0.41	0.71	0.34	7.352%	8.45	1.23	8.861%	1.34	9.79
2000	7.24	0.44	0.76	0.34	7.352%	9.43	1.31	8.861%	1.43	10.86
2001	7.93	0.49	0.81	0.34	7.352%	10.27	1.40	8.861%	1.52	11.79
2002	10.14	0.73	0.87	0.34	7.352%	12.97	1.49	8.861%	1.62	14.59
2003	8.64	0.67	0.93	0.34	7.352%	11.36	1.59	8.861%	1.73	13.09
2004	8.96	0.67	1.00	0.34	7.352%	11.78	1.69	8.861%	1.84	13.62
2005	10.99	0.77	1.07	0.34	7.352%	14.14	1.80	8.861%	1.96	16.10
2006	11.53	0.79	1.14	0.34	7.352%	14.81	1.91	8.861%	2.08	16.89
2007	11.82	0.84	1.22	0.34	7.352%	15.27	2.03	8.861%	2.21	17.48
2008	13.01	0.91	1.30	0.34	7.352%	16.70	2.15	8.861%	2.35	19.05
2009	14.79	1.01	1.39	0.34	7.352%	18.82	2.30	8.861%	2.50	21.32
2010	15.12	1.02	1.49	0.34	7.352%	19.29	2.44	8.861%	2.66	21.95
2011	16.25	1.08	1.60	0.34	7.352%	20.69	2.60	8.861%	2.83	23.52
2012	17.20	1.21	1.70	0.34	7.352%	21.95	2.76	8.861%	3.00	24.95
2013	17.67	1.25	1.81	0.34	7.352%	22.62	2.93	8.861%	3.19	25.81
2014	18.69	1.34	1.93	0.34	7.352%	23.94	3.12	8.861%	3.40	27.34
2015	19.68	1.43	2.06	0.34	7.352%	25.24	3.32	8.861%	3.61	28.85
2016	20.70	1.52	2.20	0.34	7.352%	26.58	3.52	8.861%	3.83	30.41
2017	21.35	1.59	2.34	0.34	7.352%	27.50	3.75	8.861%	4.08	31.58
2018	22.46	1.70	2.49	0.34	7.352%	28.97	3.98	8.861%	4.33	33.30

HIGH FUEL CASE
TABLE 1
(Commonwealth - DST)
Total Period Long-Run Avoided Costs
Small Secondary Voltage

	Total Period Avoided Energy Rates (cents/kwh)						Total Period Avoided Capacity Rates (cents/kwh)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Year	Avoided Fuel Cost	Avoided Variable O&M	Avoided Capital-ized Energy Costs	Avoided NEPEX Savings Share	Line Loss Factor	Avoided Energy Rate	Avoided Capacity Cost	Demand Loss Factor	Avoided Capacity Rate	Total Period Avoided Cost Rate (cents/KWH)
1989	3.81	0.23	0.00	0.34	9.321%	4.79	0.99	12.183%	1.11	5.90
1990	4.03	0.28	0.00	0.34	9.321%	5.08	0.99	12.183%	1.11	6.19
1991	4.74	0.35	0.00	0.34	9.321%	5.94	0.99	12.183%	1.11	7.05
1992	4.91	0.29	0.00	0.34	9.321%	6.06	0.99	12.183%	1.11	7.17
1993	5.54	0.42	0.00	0.34	9.321%	6.89	0.99	12.183%	1.11	8.00
1994	4.64	0.49	0.52	0.34	9.321%	6.55	0.90	12.183%	1.01	7.56
1995	4.44	0.46	0.56	0.34	9.321%	6.33	0.95	12.183%	1.07	7.40
1996	4.50	0.46	0.59	0.34	9.321%	6.44	1.01	12.183%	1.13	7.57
1997	5.54	0.50	0.63	0.34	9.321%	7.66	1.08	12.183%	1.21	8.87
1998	6.07	0.39	0.67	0.34	9.321%	8.17	1.15	12.183%	1.29	9.46
1999	6.41	0.41	0.71	0.34	9.321%	8.60	1.23	12.183%	1.38	9.98
2000	7.24	0.44	0.76	0.34	9.321%	9.60	1.31	12.183%	1.47	11.07
2001	7.93	0.49	0.81	0.34	9.321%	10.46	1.40	12.183%	1.57	12.03
2002	10.14	0.73	0.87	0.34	9.321%	13.21	1.49	12.183%	1.67	14.88
2003	8.64	0.67	0.93	0.34	9.321%	11.67	1.59	12.183%	1.78	13.35
2004	8.96	0.67	1.00	0.34	9.321%	11.99	1.69	12.183%	1.90	13.89
2005	10.99	0.77	1.07	0.34	9.321%	14.40	1.80	12.183%	2.02	16.42
2006	11.53	0.79	1.14	0.34	9.321%	15.09	1.91	12.183%	2.14	17.23
2007	11.82	0.84	1.22	0.34	9.321%	15.55	2.03	12.183%	2.28	17.83
2008	13.01	0.91	1.30	0.34	9.321%	17.01	2.16	12.183%	2.42	19.43
2009	14.79	1.01	1.39	0.34	9.321%	19.16	2.30	12.183%	2.58	21.74
2010	15.12	1.02	1.49	0.34	9.321%	19.64	2.44	12.183%	2.74	22.38
2011	16.25	1.08	1.60	0.34	9.321%	21.07	2.60	12.183%	2.92	23.99
2012	17.20	1.21	1.70	0.34	9.321%	22.36	2.76	12.183%	3.10	25.46
2013	17.67	1.25	1.81	0.34	9.321%	23.03	2.93	12.183%	3.29	26.32
2014	18.69	1.34	1.93	0.34	9.321%	24.38	3.12	12.183%	3.50	27.88
2015	19.68	1.43	2.06	0.34	9.321%	25.70	3.32	12.183%	3.72	29.42
2016	20.70	1.52	2.20	0.34	9.321%	27.07	3.52	12.183%	3.95	31.02
2017	21.35	1.59	2.34	0.34	9.321%	28.01	3.75	12.183%	4.21	32.22
2018	22.46	1.70	2.49	0.34	9.321%	29.51	3.98	12.183%	4.46	33.97

TABLE 2
(Commonwealth - DST)
Calculation of Capital Costs of Next Supply Addition

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	850.84	21.82	111.80	34.24	5.01	16.40	22.72	0.00	211.99
1995	829.02	21.82	108.36	21.35	15.03	16.40	23.97	0.00	206.93
1996	807.20	21.82	103.63	19.70	15.03	16.40	25.31	0.00	201.89
1997	785.38	21.82	98.91	21.53	11.70	16.40	26.75	0.00	197.11
1998	763.56	21.82	94.63	20.03	11.70	16.40	28.33	0.00	192.91
1999	741.74	21.82	90.33	22.01	8.35	16.40	30.06	0.00	188.97
2000	719.92	21.82	86.46	20.65	8.35	16.40	31.95	0.00	185.63
2001	698.10	21.82	82.60	19.29	8.35	16.40	33.96	0.00	182.42
2002	676.28	21.82	78.73	17.93	8.35	16.40	36.10	0.00	179.33
2003	654.46	21.82	74.87	16.58	8.35	16.40	38.41	0.00	176.43
2004	632.64	21.82	71.01	15.22	8.35	16.40	40.83	0.00	173.63
2005	610.82	21.82	67.15	13.87	8.35	16.40	43.36	0.00	170.95
2006	589.00	21.82	63.28	12.51	8.35	16.40	46.09	0.00	168.45
2007	567.18	21.82	59.41	14.64	5.01	16.40	48.99	0.00	166.27
2008	545.36	21.82	55.97	13.43	5.01	16.40	51.98	0.00	164.61
2009	523.54	21.82	52.54	12.22	5.01	16.40	55.15	0.00	163.14
2010	501.72	21.82	49.10	11.02	5.01	16.40	58.51	0.00	161.86
2011	479.90	21.82	45.67	9.81	5.01	16.40	62.08	0.00	160.79
2012	458.08	21.82	42.22	8.61	5.01	16.40	65.80	0.00	159.86
2013	436.26	21.82	38.79	7.40	5.01	16.40	69.75	0.00	159.17
2014	414.44	21.82	35.35	13.18	-1.67	16.40	73.94	0.00	159.02
2015	392.62	21.82	32.78	19.26	-8.36	16.40	78.38	0.00	160.28
2016	370.80	21.82	31.05	18.65	-8.36	16.40	83.08	0.00	162.64
2017	348.98	21.82	29.33	18.04	-8.36	16.40	88.06	0.00	165.29
2018	327.16	21.82	27.60	17.43	-8.36	16.40	93.34	0.00	168.23
2019	305.34	21.82	25.87	16.83	-8.36	16.40	98.94	0.00	171.50
2020	283.52	21.82	24.15	16.23	-8.36	16.40	104.88	0.00	175.12
2021	261.70	21.82	22.42	15.62	-8.36	16.40	111.17	0.00	179.07
2022	239.88	21.82	20.70	15.01	-8.36	16.40	117.84	0.00	183.41
2023	218.06	21.82	18.97	14.40	-8.36	16.40	124.91	0.00	188.14
2024	196.24	21.82	17.25	13.81	-8.36	16.40	132.40	0.00	193.32
2025	174.42	21.82	15.53	13.20	-8.36	16.40	140.34	0.00	198.93
2026	152.60	21.82	13.81	12.60	-8.36	16.40	148.76	0.00	205.03
2027	130.78	21.82	12.08	11.99	-8.36	16.40	157.69	0.00	211.62
2028	108.96	21.82	10.35	11.38	-8.36	16.40	167.15	0.00	218.74
2029	87.14	21.82	8.62	10.77	-8.36	16.40	177.18	0.00	226.43
2030	65.32	21.82	6.89	10.17	-8.36	16.40	187.81	0.00	234.73
2031	43.50	21.82	5.18	9.57	-8.36	16.40	199.08	0.00	243.69
2032	21.68	21.82	3.45	8.96	-8.36	16.40	211.02	0.00	253.29
2033	-0.14	21.82	1.73	8.35	-8.36	16.40	223.68	0.00	263.62
	SUMS	872.00	1838.57	607.49	-0.17	656.00	3559.75	0.00	7534.44

Table 2: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combined cycle, installed in 1994 can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combined Cycle

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$698.63	$93.90	$29.18	$50.85	$872.56

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 40 years

Tax Life: 20 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 3
(Commonwealth - DST)
Calculation of Avoided Capitalized Energy Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement ($/kw)	(e) Levelized Real Revenue Requirement of Capacity ($/kw)	(f) Levelized Real Capitalized Energy Costs ($/kw)	(g) Avoided Capitalized Energy Cost (cents/kwh)
1994	211.99	190.66	101.81	64.47	37.34	0.52
1995	206.93	167.39	107.92	68.27	39.65	0.55
1996	201.89	146.88	114.72	72.64	42.08	0.59
1997	197.11	128.98	122.18	77.36	44.82	0.63
1998	192.91	113.53	130.24	82.47	47.77	0.67
1999	188.97	100.03	139.10	88.00	51.10	0.71
2000	185.63	88.37	148.56	93.90	54.66	0.76
2001	182.42	78.11	158.52	100.19	58.33	0.81
2002	179.33	69.06	169.15	106.71	62.44	0.87
2003	176.43	61.11	180.49	113.65	66.84	0.93
2004	173.63	54.09	192.42	121.04	71.38	1.00
2005	170.95	47.90	205.14	128.79	76.35	1.07
2006	168.45	42.45	218.70	137.04	81.66	1.14
2007	166.27	37.68	232.94	145.68	87.26	1.22
2008	164.61	33.56	248.11	154.87	93.24	1.30
2009	163.14	29.91	264.51	164.64	99.87	1.39
2010	161.86	26.69	281.99	175.02	106.97	1.49
2011	160.79	23.85	300.36	186.06	114.30	1.60
2012	159.86	21.32	319.63	197.79	121.84	1.70
2013	159.17	19.10	340.14	210.26	129.88	1.81
2014	159.02	17.16	361.97	223.52	138.45	1.93
2015	160.28	15.55	385.20	237.61	147.59	2.06
2016	162.64	14.20	409.92	252.59	157.33	2.20
2017	165.29	12.98	436.22	268.52	167.70	2.34
2018	168.23	11.88	464.21	285.45	178.76	2.49
2019	171.50	10.89	494.00	303.45	190.55	2.66
2020	175.12	10.00	525.70	322.59	203.11	2.83
2021	179.07	9.20	559.43	342.93	216.50	3.02
2022	183.41	8.47	595.33	364.55	230.78	3.22
2023	188.14	7.82	633.53	387.54	245.99	3.43
2024	193.32	7.23	674.18			
2025	198.93	6.69	717.44			
2026	205.03	6.20	763.48			
2027	211.62	5.75	812.47			
2028	218.74	5.35	864.61			
2029	226.43	4.98	920.09			
2030	234.73	4.64	979.13			
2031	243.69	4.34	1041.96			
2032	253.29	4.05	1108.82			
2033	263.62	3.79	1179.97			
SUMS	7534.44	1651.84	17904.29	5477.60	3364.54	

TABLE 4
(Commonwealth - DST)
Calculation of Capital Capacity Costs
(Based on a New Utility Peaker)

(a) Year	(b) Book Value ($/kw)	(c) Book Deprec. ($/kw)	(d) Required Return ($/kw)	(e) Federal & State Income Tax ($/kw)	(f) Deferred Tax ($/kw)	(g) Property Tax ($/kw)	(h) Fixed O&M ($/kw)	(i) Other Charges ($/kw)	(j) Annual Nominal Revenue Requirement ($/kw)
1994	620.76	21.41	80.91	24.31	4.10	12.07	0.60	0.00	143.40
1995	599.35	21.41	79.01	13.80	13.93	12.07	0.63	0.00	140.85
1996	577.94	21.41	74.48	12.21	13.93	12.07	0.66	0.00	134.76
1997	556.53	21.41	69.95	13.09	11.47	12.07	0.70	0.00	128.69
1998	535.12	21.41	65.74	14.07	9.02	12.07	0.74	0.00	123.05
1999	513.71	21.41	61.84	15.16	6.56	12.07	0.78	0.00	117.82
2000	492.30	21.41	58.26	13.89	6.56	12.07	0.83	0.00	113.02
2001	470.89	21.41	54.68	12.64	6.56	12.07	0.88	0.00	108.24
2002	449.48	21.41	51.09	11.38	6.56	12.07	0.93	0.00	103.44
2003	428.07	21.41	47.51	10.13	6.56	12.07	0.99	0.00	98.67
2004	406.66	21.41	43.93	8.87	6.56	12.07	1.05	0.00	93.89
2005	385.25	21.41	40.35	7.60	6.56	12.07	1.11	0.00	89.10
2006	363.84	21.41	36.76	6.35	6.56	12.07	1.18	0.00	84.33
2007	342.43	21.41	33.18	5.09	6.56	12.07	1.25	0.00	79.56
2008	321.02	21.41	29.60	3.84	6.56	12.07	1.32	0.00	74.80
2009	299.61	21.41	26.01	12.41	-3.28	12.07	1.40	0.00	70.02
2010	278.20	21.41	23.70	16.52	-8.19	12.07	1.48	0.00	66.99
2011	256.79	21.41	22.00	15.92	-8.19	12.07	1.57	0.00	64.78
2012	235.38	21.41	20.31	15.32	-8.19	12.07	1.66	0.00	62.58
2013	213.97	21.41	18.62	14.74	-8.19	12.07	1.76	0.00	60.41
2014	192.56	21.41	16.92	14.14	-8.19	12.07	1.86	0.00	58.21
2015	171.15	21.41	15.23	13.55	-8.19	12.07	1.97	0.00	56.04
2016	150.00	21.41	13.54	12.95	-8.19	12.07	2.08	0.00	53.86
2017	129.00	21.41	11.84	12.35	-8.19	12.07	2.20	0.00	51.68
2018	108.00	21.41	10.15	11.76	-8.19	12.07	2.33	0.00	49.53
2019	87.00	21.41	8.47	11.16	-8.19	12.07	2.47	0.00	47.39
2020	66.00	21.41	6.77	10.58	-8.19	12.07	2.61	0.00	45.25
2021	45.00	21.41	5.08	9.98	-8.19	12.07	2.76	0.00	43.11
2022	24.00	21.41	3.39	9.39	-8.19	12.07	2.92	0.00	40.99
2023	3.00	21.41	1.69	8.79	-8.19	12.07	3.09	0.00	38.86
	SUMS	642.30	1031.01	361.99	0.11	362.10	45.81	0.00	2443.32

Table 4: Additional Information

(1) Document direct expenditures and AFUDC.

Response:

The cost of a combustion turbine, installed in 1994, can be broken up into the following components, assuming an AFUDC rate of 9.67%:

1994 Costs of
a Combustion Turbine

Direct ($/kw)	AFUDC ($/kw)	T&D ($/kw)	SCR ($/KW)	Total ($/kw)
$491.87	$60.60	$38.86	$50.85	$642.18

(2) Document the tax calculations and assumptions.

Response:

The "Engineering Economic Analysis Package" (ECAN), a model produced by The United Illuminating Company, was the model used to produce the tax information. The tax calculations used by the model are not accessible.

In addition to the information provided on the Financial and Rating Period Assumptions sheet the following assumptions were needed for the tax calculations:

Book Life: 30 years

Tax Life: 15 years

Book Depreciation Method: Straight Line

Tax Depreciation Method: ACRS

(3) Completely document all "Other Charges".

Response:

N/A

TABLE 5
(Commonwealth - DST)
Calculation of Avoided Capacity Costs

(a) Year	(b) Annual Nominal Revenue Requirement ($/kw)	(c) Annual PV Revenue Requirement ($/kw)	(d) Levelized Real Revenue Requirement of Capacity ($/kw)	(e) Total Period Avoided Capacity Costs (cents/kwh)	(f) Peak Period Avoided Capacity Costs (cents/kwh)
1994	143.40	128.97	64.47	0.90	3.37
1995	140.85	113.94	68.27	0.95	3.57
1996	134.76	98.04	72.64	1.01	3.79
1997	128.69	84.21	77.36	1.08	4.04
1998	123.05	72.42	82.47	1.15	4.31
1999	117.82	62.37	88.00	1.23	4.60
2000	113.02	53.81	93.90	1.31	4.91
2001	108.24	46.35	100.19	1.40	5.23
2002	103.44	39.84	106.71	1.49	5.57
2003	98.67	34.18	113.65	1.59	5.94
2004	93.89	29.25	121.04	1.69	6.32
2005	89.10	24.96	128.79	1.80	6.73
2006	84.33	21.25	137.04	1.91	7.16
2007	79.56	18.03	145.68	2.03	7.61
2008	74.80	15.25	154.87	2.16	8.09
2009	70.02	12.84	164.64	2.30	8.60
2010	66.99	11.05	175.02	2.44	9.14
2011	64.78	9.61	186.05	2.60	9.72
2012	62.58	8.35	197.79	2.76	10.33
2013	60.41	7.25	210.25	2.93	10.98
2014	58.21	6.28	223.52	3.12	11.68
2015	56.04	5.44	237.61	3.32	12.41
2016	53.85	4.70	252.59	3.52	13.20
2017	51.68	4.06	268.52	3.75	14.03
2018	49.53	3.50	285.45	3.98	14.91
2019	47.39	3.01	303.45	4.23	15.85
2020	45.25	2.58	322.59	4.50	16.85
2021	43.11	2.21	342.93	4.79	17.92
2022	40.99	1.89	364.55	5.09	19.05
2023	38.86	1.61	387.54	5.41	20.25
SUMS	2443.32	927.25	5477.60		

07-AUG-1990 BASE FUEL PRICE SCENARIO
Leon Sirois

D A R T M O U T H P O W E R R A T E S T R U C T U R E

Installed Capacity: 17,600
Contract Capacity: 17,600
Percent of Unit: 100.00%
Discount Rate: 11.185%
Annual Mwh: 140,300

	Year	Annual Mwh	E.S.T. Avoid. Cost (6 mo.) Cts/kwh	D.S.T. Avoid. Cost (7 mo.) Cts/kwh	Yearly Avoid. Cost (12 mo.) Cts/kwh	PGNP Index %	F-1 Gas Index %	[2.1] Capacity Cost $	[2.2] Investment Cost $	[2.3] Pipeline Dmd. Costs $	Total Capacity Costs $	Fuel Cost $/mmbtu
	1988											1.300
	1989		4.68	5.35	5.07							1.300
	1990		4.80	4.99	4.91		3.44%					1.345
	1991		4.97	5.36	5.20		2.58%					1.380
1	1992	140,300	5.91	5.35	5.58		3.24%	813,990	2,944,914	1,662,000	5,420,904	1.425
2	1993	140,300	5.99	5.86	5.91	5.0%	3.48%	854,690	2,944,914	1,662,000	5,461,604	1.475
3	1994	140,300	5.30	5.80	5.59	5.0%	3.70%	897,425	2,944,914	1,662,000	5,504,339	1.530
4	1995	140,300	6.73	5.70	6.13	5.1%	11.36%	943,194	2,944,914	1,662,000	5,550,108	1.704
5	1996	140,300	7.23	6.76	6.37	5.3%	11.37%	993,183	2,944,914	1,662,000	5,600,097	1.898
6	1997	140,300	7.78	6.58	7.08	5.4%	13.35%	1,046,815	2,944,914	1,662,000	5,653,729	2.151
7	1998	140,300	8.10	6.99	7.45	5.5%	13.53%	1,104,390	2,944,914	1,662,000	5,711,304	2.444
8	1999	140,300	9.51	7.48	8.33	5.6%	14.63%	1,166,236	2,944,914	1,662,000	5,773,150	2.802
9	2000	140,300	10.40	8.38	9.22	5.6%	14.18%	1,231,545	2,944,914	1,662,000	5,838,459	3.199
10	2001	140,300	10.31	9.04	9.57	5.5%	11.49%	1,299,280	2,944,914	1,662,000	5,906,194	3.567
11	2002	140,300	12.03	11.07	11.47	5.5%	10.86%	1,370,740	2,944,914	1,662,000	5,977,654	3.954
12	2003	140,300	13.31	10.12	11.45	5.4%	10.18%	1,444,760	2,944,914	1,662,000	6,051,674	4.357
13	2004	140,300	16.11	10.60	12.90	5.3%	9.24%	1,521,332	2,944,914	1,662,000	6,128,246	4.760
14	2005	140,300	15.56	12.62	13.85	5.3%	8.46%	1,601,963	2,944,914	1,662,000	6,208,877	5.163
15	2006	140,300	18.45	13.22	15.40	5.2%	8.18%	1,685,265	2,944,914	1,662,000	6,292,179	5.585
16	2007	140,300	19.50	13.71	16.12	5.2%	8.01%	1,772,899	2,944,914	1,662,000	6,379,813	6.032
17	2008	140,300	20.92	15.04	17.49	5.2%	7.50%	1,865,090	2,944,914	1,662,000	6,472,004	6.489
18	2009	140,300	22.73	16.85	19.30	5.2%	7.20%	1,962,075	2,944,914	1,662,000	6,568,989	6.956
19	2010	140,300	24.34	17.35	20.26	5.2%	6.79%	2,064,103	2,944,914	1,662,000	6,671,017	7.428
20	2011	140,300	25.67	18.61	21.55	5.2%	6.15%	2,171,436	2,944,914	1,662,000	6,778,350	7.885
21	2012	140,300	26.77	19.83	22.72	5.2%	6.18%	2,284,351	2,944,914	1,662,000	6,891,265	8.372
22	2013	140,300	27.20	20.66	23.39	5.3%	6.23%	2,405,422	2,944,914	1,662,000	7,012,336	8.894
23	2014	140,300	32.12	22.00	26.22	5.3%	6.37%	2,532,909	2,944,914	1,662,000	7,139,823	9.461
24	2015	140,300	32.25	23.36	27.06	5.3%	6.30%	2,667,153	2,944,914	1,662,000	7,274,067	10.057
25	2016	140,300	35.15	24.79	29.11	5.3%	6.30%	2,808,512	2,944,914	1,662,000	7,415,426	10.691

Schedule 1

Variable Pipeline Cost $/mmbtu	Total Variable Cost $/mmbtu	Total Variable Cost Cts/Kwh	Total Variable Cost $	Total Cost $	Total Avoided Cost $	Pres.Val Factor @ 11.185%	P.V. Total Cost $	P.V. Avoid.Cost $	Cumulative PV Difference	Year	
										1988	
						0.8994				1989	
						0.8089				1990	
						0.7275				1991	
0.420	1.845	1.58	2,216,740	7,637,644	7,828,740	0.6544	4,998,074	5,123,127	-125,053	1992	1
0.435	1.910	1.64	2,300,920	7,762,524	8,291,730	0.5885	4,568,245	4,879,683	-436,491	1993	2
0.451	1.981	1.70	2,385,100	7,889,439	7,842,770	0.5293	4,175,880	4,151,178	-411,789	1994	3
0.502	2.206	1.89	2,651,670	8,201,778	8,600,390	0.4761	3,904,867	4,094,646	-601,668	1995	4
0.559	2.457	2.11	2,960,330	8,560,427	8,937,110	0.4282	3,665,575	3,826,871	-762,864	1996	5
0.634	2.785	2.39	3,353,170	9,006,899	9,933,240	0.3851	3,468,557	3,825,291	-1,119,598	1997	6
0.720	3.164	2.72	3,816,160	9,527,464	10,452,350	0.3464	3,300,314	3,620,694	-1,439,978	1998	7
0.825	3.627	3.11	4,363,330	10,136,480	11,686,990	0.3115	3,157,514	3,640,497	-1,922,961	1999	8
0.942	4.141	3.55	4,980,650	10,819,109	12,935,660	0.2802	3,031,514	3,624,572	-2,516,019	2000	9
1.050	4.617	3.96	5,555,880	11,462,074	13,426,710	0.2520	2,888,443	3,383,531	-3,011,107	2001	10
1.164	5.118	4.39	6,159,170	12,136,824	16,092,410	0.2266	2,750,204	3,646,540	-3,907,443	2002	11
1.282	5.639	4.84	6,790,520	12,842,194	16,064,350	0.2038	2,617,239	3,273,915	-4,564,119	2003	12
1.400	6.160	5.29	7,421,870	13,550,116	18,098,700	0.1833	2,483,736	3,317,492	-5,397,875	2004	13
1.518	6.681	5.73	8,039,190	14,248,067	19,431,550	0.1649	2,349,506	3,204,263	-6,252,632	2005	14
1.642	7.227	6.20	8,698,600	14,990,779	21,606,200	0.1483	2,223,133	3,204,199	-7,233,698	2006	15
1.774	7.806	6.70	9,400,100	15,779,913	22,616,360	0.1334	2,105,040	3,017,022	-8,145,680	2007	16
1.908	8.397	7.21	10,115,630	16,587,634	24,538,470	0.1200	1,990,516	2,944,616	-9,099,780	2008	17
2.045	9.001	7.73	10,845,190	17,414,179	27,077,900	0.1079	1,878,990	2,921,705	-10,142,495	2009	18
2.184	9.612	8.25	11,574,750	18,245,767	28,424,780	0.0970	1,769,839	2,757,204	-11,129,860	2010	19
2.318	10.203	8.76	12,290,280	19,068,630	30,234,550	0.0873	1,664,691	2,639,485	-12,104,654	2011	20
2.461	10.833	9.30	13,047,900	19,939,165	31,876,160	0.0785	1,565,224	2,502,279	-13,041,709	2012	21
2.614	11.508	9.88	13,861,640	20,873,976	32,816,170	0.0705	1,473,703	2,316,822	-13,884,828	2013	22
2.781	12.242	10.51	14,745,530	21,885,353	36,786,660	0.0635	1,389,720	2,335,953	-14,831,061	2014	23
2.955	13.013	11.17	15,671,510	22,945,577	37,965,180	0.0571	1,310,192	2,167,812	-15,688,681	2015	24
3.142	13.833	11.87	16,653,610	24,069,036	40,841,330	0.0514	1,237,148	2,099,244	-16,550,777	2016	25
				Sum Present Value:			65,967,864	82,518,641			
				Percent of Avoided Cost:			80%				

13-AUG-1990 LOW FUEL PRICE SCENARIO
Leon Sirois

D A R T M O U T H P O W E R R A T E S T R U C T U R E

Installed Capacity: 17,600
Contract Capacity: 17,600
Percent of Unit: 100.00%
Discount Rate: 11.185%
Annual Mwh: 140,300

	Year	Annual Mwh	E.S.T. Avoid. Cost (5 mo.) Cts/kwh	D.S.T. Avoid. Cost (7 mo.) Cts/kwh	Yearly Avoid. Cost (12 mo.) Cts/kwh	PGNP Index %	F-1 Gas Index %	[2.1] Capacity Cost $	[2.2] Investment Cost $	[2.3] Pipeline Dmd. Costs $	Total Capacity Costs $	Fuel Cost $/mmbtu
	1988											1.300
	1989		4.67	5.34	5.06							1.300
	1990		4.06	4.24	4.17		2.43%					1.332
	1991		4.13	4.47	4.33		4.27%					1.389
1	1992	140,300	4.88	4.47	4.64		6.36%	813,990	2,944,914	1,662,000	5,420,904	1.477
2	1993	140,300	4.94	4.87	4.90	5.0%	4.27%	854,690	2,944,914	1,662,000	5,461,604	1.540
3	1994	140,300	4.44	4.80	4.65	5.0%	2.05%	897,425	2,944,914	1,662,000	5,504,339	1.572
4	1995	140,300	5.41	4.60	4.94	5.1%	1.20%	943,194	2,944,914	1,662,000	5,550,108	1.591
5	1996	140,300	5.76	4.57	5.07	5.3%	7.14%	993,183	2,944,914	1,662,000	5,600,097	1.705
6	1997	140,300	6.38	5.01	5.50	5.4%	8.15%	1,046,815	2,944,914	1,662,000	5,653,729	1.844
7	1998	140,300	6.92	5.17	5.90	5.5%	6.51%	1,104,398	2,944,914	1,662,000	5,711,304	1.964
8	1999	140,300	8.32	5.26	6.54	5.6%	7.07%	1,166,236	2,944,914	1,662,000	5,773,150	2.103
9	2000	140,300	9.44	5.70	7.26	5.6%	8.41%	1,231,545	2,944,914	1,662,000	5,838,459	2.280
10	2001	140,300	9.48	6.02	7.46	5.5%	9.14%	1,299,280	2,944,914	1,662,000	5,906,194	2.488
11	2002	140,300	11.00	7.46	8.93	5.5%	10.41%	1,370,740	2,944,914	1,662,000	5,977,654	2.747
12	2003	140,300	12.01	6.72	8.92	5.4%	11.72%	1,444,760	2,944,914	1,662,000	6,051,674	3.069
13	2004	140,300	14.43	7.10	10.15	5.3%	12.76%	1,521,332	2,944,914	1,662,000	6,128,246	3.461
14	2005	140,300	13.89	8.78	10.91	5.3%	11.86%	1,601,963	2,944,914	1,662,000	6,208,877	3.871
15	2006	140,300	16.14	9.29	12.14	5.2%	10.93%	1,685,265	2,944,914	1,662,000	6,292,179	4.294
16	2007	140,300	16.84	9.71	12.68	5.2%	9.85%	1,772,899	2,944,914	1,662,000	6,379,813	4.717
17	2008	140,300	17.75	10.71	13.64	5.2%	9.50%	1,865,090	2,944,914	1,662,000	6,472,004	5.165
18	2009	140,300	19.04	12.11	15.00	5.2%	8.92%	1,962,075	2,944,914	1,662,000	6,568,989	5.626
19	2010	140,300	20.11	12.62	15.74	5.2%	8.53%	2,064,103	2,944,914	1,662,000	6,671,017	6.106
20	2011	140,300	21.23	13.57	16.76	5.2%	5.89%	2,171,436	2,944,914	1,662,000	6,778,350	6.466
21	2012	140,300	22.18	14.32	17.60	5.2%	5.18%	2,284,351	2,944,914	1,662,000	6,891,265	6.801
22	2013	140,300	22.58	14.84	18.07	5.3%	5.20%	2,405,422	2,944,914	1,662,000	7,012,336	7.165
23	2014	140,300	25.52	15.69	20.20	5.3%	5.30%	2,532,909	2,944,914	1,662,000	7,139,823	7.534
24	2015	140,300	26.70	16.54	20.77	5.3%	5.28%	2,667,153	2,944,914	1,662,000	7,274,067	7.932
25	2016	140,300	29.03	17.43	22.26	5.3%	5.25%	2,808,512	2,944,914	1,662,000	7,415,426	8.348

Schedule 2

Variable Pipeline Cost $/mmbtu	Total Variable Cost $/mmbtu	Total Variable Cost Cts/Kwh	Total Variable Cost $	Total Cost $	Total Avoided Cost $	Pres.Val Factor @ 11.185%	P.V. Total Cost $	P.V. Avoid.Cost $	Cumulative PV Difference	Year	
										1988	
						0.8994				1989	
						0.8089				1990	
						0.7275				1991	
0.420	1.897	1.63	2,286,890	7,707,794	6,509,920	0.6544	5,043,980	4,260,092	783,888	1992	1
0.438	1.978	1.70	2,385,100	7,846,704	6,874,700	0.5885	4,617,785	4,045,761	1,355,912	1993	2
0.447	2.019	1.73	2,427,190	7,931,529	6,523,950	0.5293	4,198,158	3,453,127	2,100,943	1994	3
0.452	2.043	1.75	2,455,250	8,005,358	6,930,820	0.4761	3,811,351	3,299,763	2,612,531	1995	4
0.484	2.189	1.88	2,637,640	8,237,737	7,113,210	0.4282	3,527,399	3,045,877	3,094,053	1996	5
0.523	2.367	2.03	2,848,090	8,501,819	7,828,740	0.3851	3,274,050	3,014,848	3,353,255	1997	6
0.557	2.521	2.16	3,030,480	8,741,784	8,277,700	0.3464	3,028,154	2,867,395	3,514,014	1998	7
0.598	2.699	2.32	3,254,960	9,028,110	9,175,620	0.3115	2,812,256	2,858,206	3,469,064	1999	8
0.646	2.926	2.51	3,521,530	9,359,989	10,185,780	0.2802	2,622,669	2,854,056	3,236,677	2000	9
0.705	3.193	2.74	3,844,220	9,750,414	10,466,380	0.2520	2,457,104	2,637,528	3,056,253	2001	10
0.778	3.525	3.03	4,251,090	10,228,744	12,528,790	0.2266	2,317,833	2,839,024	2,535,062	2002	11
0.869	3.938	3.38	4,742,140	10,793,814	12,514,760	0.2038	2,199,779	2,550,508	2,184,333	2003	12
0.980	4.441	3.81	5,345,430	11,473,676	14,240,450	0.1833	2,103,125	2,610,274	1,677,184	2004	13
1.096	4.967	4.26	5,976,780	12,185,657	15,306,730	0.1649	2,009,415	2,524,080	1,162,519	2005	14
1.216	5.510	4.73	6,636,190	12,928,369	17,032,420	0.1483	1,917,277	2,525,908	553,888	2006	15
1.336	6.053	5.20	7,295,600	13,675,413	17,790,040	0.1334	1,824,300	2,373,191	4,997	2007	16
1.463	6.628	5.69	7,983,070	14,455,074	19,136,920	0.1200	1,734,609	2,295,430	-555,824	2008	17
1.593	7.219	6.20	8,698,600	15,267,589	21,045,000	0.1079	1,647,373	2,270,756	-1,180,207	2009	18
1.729	7.835	6.73	9,442,190	16,113,207	22,083,220	0.0970	1,562,981	2,142,072	-1,759,298	2010	19
1.831	8.297	7.12	9,989,360	16,767,710	23,514,280	0.0873	1,463,821	2,052,797	-2,348,274	2011	20
1.925	8.727	7.49	10,508,470	17,399,735	24,692,800	0.0785	1,365,879	1,938,385	-2,920,780	2012	21
2.026	9.181	7.88	11,055,640	18,067,976	25,352,210	0.0706	1,275,599	1,789,866	-3,435,047	2013	22
2.133	9.667	8.30	11,644,900	18,784,723	28,340,600	0.0635	1,192,830	1,799,628	-4,041,845	2014	23
2.246	10.178	8.74	12,262,220	19,536,287	29,140,310	0.0571	1,115,522	1,663,912	-4,590,235	2015	24
2.364	10.712	9.19	12,893,570	20,308,996	31,230,780	0.0514	1,043,882	1,605,262	-5,151,615	2016	25
				Sum Present Value:			60,167,131	65,318,746			
				Percent of Avoided Cost:			92%				

13-AUG-1990 HIGH FUEL PRICE SCENARIO
Leon Sirols

D A R T M O U T H P O W E R R A T E S T R U C T U R E

Installed Capacity: 17,600
Contract Capacity: 17,600
Percent of Unit: 100.00%
Discount Rate: 11.185%
Annual Mwh: 140,300

	Year	Annual Mwh	E.S.T. Avoid. Cost (5 mo.) Cts/kwh	D.S.T. Avoid. Cost (7 mo.) Cts/kwh	Yearly Avoid. Cost (12 mo.) Cts/kwh	PGNP Index %	F-1 Gas Index %	[2.1] Capacity Cost $	[2.2] Investment Cost $	[2.3] Pipeline Dmd. Costs $	Total Capacity Costs $	Fuel Cost $/mmbtu
	1988											1.300
	1989		4.69	5.37	5.09							1.300
	1990		5.43	5.64	5.55		20.71%					1.569
	1991		5.96	6.42	6.23		6.51%					1.671
1	1992	140,300	7.30	6.53	6.85		8.61%	813,990	2,944,914	1,662,000	5,420,904	1.815
2	1993	140,300	7.51	7.29	7.38	5.0%	7.16%	854,690	2,944,914	1,662,000	5,461,604	1.945
3	1994	140,300	6.54	6.89	6.74	5.0%	7.40%	897,425	2,944,914	1,662,000	5,504,339	2.089
4	1995	140,300	8.39	6.74	7.43	5.1%	7.78%	943,194	2,944,914	1,662,000	5,550,108	2.252
5	1996	140,300	8.89	6.90	7.73	5.3%	14.23%	993,183	2,944,914	1,662,000	5,600,097	2.572
6	1997	140,300	9.36	8.09	8.62	5.4%	16.43%	1,046,815	2,944,914	1,662,000	5,653,729	2.995
7	1998	140,300	9.46	8.62	8.97	5.5%	14.26%	1,104,390	2,944,914	1,662,000	5,711,304	3.422
8	1999	140,300	10.96	9.10	9.88	5.6%	11.13%	1,166,236	2,944,914	1,662,000	5,773,150	3.803
9	2000	140,300	11.97	10.09	10.87	5.6%	11.36%	1,231,545	2,944,914	1,662,000	5,838,459	4.235
10	2001	140,300	11.84	10.97	11.33	5.5%	11.40%	1,299,280	2,944,914	1,662,000	5,906,194	4.718
11	2002	140,300	13.99	13.57	13.75	5.5%	10.04%	1,370,740	2,944,914	1,662,000	5,977,654	5.192
12	2003	140,300	15.42	12.17	13.52	5.4%	8.41%	1,444,760	2,944,914	1,662,000	6,051,674	5.629
13	2004	140,300	18.52	12.66	15.10	5.3%	8.00%	1,521,332	2,944,914	1,662,000	6,128,246	6.079
14	2005	140,300	17.77	14.97	16.14	5.3%	6.95%	1,601,963	2,944,914	1,662,000	6,208,877	6.501
15	2006	140,300	21.05	15.71	17.94	5.2%	8.21%	1,685,265	2,944,914	1,662,000	6,292,179	7.035
16	2007	140,300	21.95	16.25	18.63	5.2%	7.19%	1,772,899	2,944,914	1,662,000	6,379,813	7.541
17	2008	140,300	23.24	17.72	20.02	5.2%	6.53%	1,865,098	2,944,914	1,662,000	6,472,004	8.033
18	2009	140,300	24.90	19.83	21.94	5.2%	6.71%	1,962,075	2,944,914	1,662,000	6,568,989	8.572
19	2010	140,300	26.35	20.41	22.89	5.2%	6.55%	2,064,103	2,944,914	1,662,000	6,671,017	9.133
20	2011	140,300	27.79	21.87	24.34	5.2%	5.80%	2,171,436	2,944,914	1,662,000	6,778,350	9.653
21	2012	140,300	28.97	23.21	25.51	5.2%	5.24%	2,284,351	2,944,914	1,662,000	6,891,265	10.169
22	2013	140,300	29.42	24.00	26.26	5.3%	5.21%	2,405,422	2,944,914	1,662,000	7,012,336	10.699
23	2014	140,300	34.81	25.42	29.33	5.3%	5.25%	2,532,909	2,944,914	1,662,000	7,139,823	11.261
24	2015	140,300	34.90	26.83	30.19	5.3%	5.32%	2,667,153	2,944,914	1,662,000	7,274,067	11.860
25	2016	140,300	38.09	28.28	32.37	5.3%	5.21%	2,808,512	2,944,914	1,662,000	7,415,426	12.478

Schedule 3

Variable Pipeline Cost $/mmbtu	Total Variable Cost $/mmbtu	Total Variable Cost Cts/Kwh	Total Variable Cost $	Total Cost $	Total Avoided Cost $	Pres.Val Factor @ 11.185%	P.V. Total Cost $	P.V. Avoid.Cost $	Cumulative PV Difference	Year	
										1988	
						0.8994				1989	
						0.8089				1990	
						0.7275				1991	
0.420	2.235	1.92	2,693,760	8,114,664	9,610,550	0.6544	5,310,236	6,289,144	-978,908	1992	1
0.450	2.395	2.06	2,890,180	8,351,784	10,354,140	0.5885	4,915,025	6,093,411	-2,157,294	1993	2
0.483	2.572	2.21	3,100,630	8,604,969	9,456,220	0.5293	4,554,610	5,005,177	-2,607,861	1994	3
0.521	2.773	2.38	3,339,140	8,889,248	10,424,290	0.4761	4,232,171	4,963,004	-3,338,694	1995	4
0.595	3.167	2.72	3,816,160	9,416,257	10,845,190	0.4282	4,032,041	4,643,910	-3,950,563	1996	5
0.693	3.688	3.17	4,447,510	10,101,239	12,093,860	0.3851	3,889,987	4,657,345	-4,717,921	1997	6
0.792	4.214	3.62	5,078,860	10,790,164	12,584,910	0.3464	3,737,713	4,359,413	-5,339,621	1998	7
0.880	4.683	4.02	5,640,060	11,413,210	13,861,640	0.3115	3,555,215	4,317,901	-6,102,307	1999	8
0.980	5.215	4.48	6,285,440	12,123,899	15,250,610	0.2802	3,397,116	4,273,221	-6,978,412	2000	9
1.092	5.810	4.99	7,000,970	12,907,164	15,895,990	0.2520	3,252,605	4,005,789	-7,731,596	2001	10
1.202	6.394	5.49	7,702,470	13,680,124	19,291,250	0.2266	3,099,916	4,371,397	-9,003,077	2002	11
1.303	6.932	5.95	8,347,850	14,399,524	18,968,560	0.2038	2,934,623	3,865,793	-9,934,247	2003	12
1.407	7.486	6.43	9,021,290	15,149,536	21,185,300	0.1833	2,776,910	3,883,265	-11,040,602	2004	13
1.505	8.006	6.87	9,638,610	15,847,487	22,644,420	0.1649	2,613,251	3,734,065	-12,161,416	2005	14
1.629	8.664	7.44	10,438,320	16,730,499	25,169,820	0.1483	2,401,133	3,732,684	-13,412,967	2006	15
1.746	9.287	7.97	11,181,910	17,561,723	26,137,890	0.1334	2,342,734	3,486,795	-14,557,028	2007	16
1.860	9.893	8.49	11,911,470	18,383,474	28,088,060	0.1200	2,206,017	3,370,567	-15,721,578	2008	17
1.985	10.557	9.05	12,711,180	19,280,159	30,781,820	0.1079	2,080,330	3,321,358	-16,962,606	2009	18
2.115	11.248	9.65	13,538,950	20,209,967	32,114,670	0.0970	1,960,367	3,115,123	-18,117,362	2010	19
2.238	11.901	10.22	14,338,660	21,117,010	34,149,020	0.0873	1,843,515	2,981,209	-19,255,056	2011	20
2.355	12.524	10.75	15,082,250	21,973,515	35,930,830	0.0785	1,724,921	2,820,570	-20,350,705	2012	21
2.478	13.177	11.31	15,867,930	22,880,266	36,842,780	0.0706	1,615,347	2,601,100	-21,336,458	2013	22
2.608	13.869	11.90	16,695,700	23,835,523	41,149,990	0.0635	1,513,556	2,613,024	-22,435,926	2014	23
2.747	14.607	12.54	17,593,620	24,867,687	42,356,570	0.0571	1,419,945	2,418,560	-23,434,541	2015	24
2.890	15.368	13.19	18,505,570	25,920,996	45,415,110	0.0514	1,332,339	2,334,337	-24,436,539	2016	25
				Sum Present Value:			72,821,623	97,258,162			
				Percent of Avoided Cost:			75%				

Attachment
AG-2-4(b)

BEFORE

THE

MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

SECOND AMENDMENT

TO

POWER PURCHASE AGREEMENT

BETWEEN

COMMONWEALTH ELECTRIC COMPANY

AND

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP

July 18, 1994

COM/Electric

Commonwealth Electric Company
2421 Cranberry Highway
Wareham, Massachusetts 02571
Telephone (508) 291-0950

July 18, 1994

Department of Public Utilities
100 Cambridge Street
Boston, MA 02202

Attention: Mary L. Cottrell, Secretary

Re: Second Amendment to Power Purchase Agreement between Commonwealth Electric Company ("Commonwealth") and Dartmouth Power Associates Limited Partnership ("Dartmouth")

Dear Madam Secretary:

Commonwealth submits herewith for filing and Department approval a Second Amendment, dated as of June 23, 1994 (the "Second Amendment") to a Power Purchase Agreement by and between Commonwealth and Dartmouth dated September 5, 1989 and amended by an Amendment to Power Purchase Agreement by and between Commonwealth and Dartmouth dated as of August 3, 1990 (as amended the "Agreement"). In accordance with the Agreement, Commonwealth purchases all electricity produced by Dartmouth's 67,600 kW generating facility located in Dartmouth, Massachusetts.

The Second Amendment filed here today is intended to replace certain language relating primarily to the Variable Fuel Supply Rate used to determine the Monthly Energy Charge in Section 4 of Appendix B to the Agreement. As indicated in the Second Amendment, the Variable Fuel Supply Rate in the Agreement is calculated, in part, by reference to the following indices for natural gas pipeline service: (1) the Tennessee CD-6 index (for service pursuant to the CD-6 rate under a FERC approved tariff by Tennessee Gas Pipeline Company ("Tennessee"); (2) the Algonquin F-1 index (for service pursuant to the F-1 rate under a FERC approved tariff by Algonquin Gas Transmission Company ("Algonquin")); and as a final reference, (3) an index calculated by the Alberta Petroleum Marketing Commission for the Minister of Energy for the Province of Alberta, Canada known as the Alberta Market Price ("AMP").

As a consequence of the restructuring of pipeline services pursuant to FERC Order No. 636, the Tennessee CD-6 rate and the Algonquin F-1 rate are no longer available. In addition, as part of Canada's Natural Gas Marketing Act, Alberta's Minister of Energy has replaced the AMP with the Alberta Reference Price ("ARP") effective January 1, 1994.

Due to the changes indicated above, it was necessary for Commonwealth and Dartmouth to replace the aforementioned indices. Both Commonwealth and Dartmouth (the "Parties") have agreed to replace the Tennessee CD-6 and the Algonquin F-1 with a composite spot price which the Parties have named "T-2." T-2 is defined as the arithmetic average of four indices, as found in *Inside FERC'S* Gas Market Report or as calculated from data found in *Inside FERC*. The indices are as follows:

1) the Offshore and Louisiana (Zone 1) Index for Tennessee;
2) the Louisiana and Texas (Zone 0) Index for Tennessee;
3) the arithmetic average of the East Texas and South Texas Indices for the Texas Eastern Transmission Corporation ("Texas"); and
4) the arithmetic average of the East Louisiana and West Louisiana Indices for Texas.

The Parties have further agreed to accept the ARP as a replacement for the AMP.

Finally, in addition to modifying the Agreement to accommodate new indices, both Commonwealth and Dartmouth have agreed to include reopener language in the Second Amendment which gives either Party the right to require a redetermination of the Variable Fuel Supply Rate. Due to the uncertainties in the gas industry, the Parties thought it prudent to be able to renegotiate the provisions of the Variable Fuel Supply Rate component of the Monthly Energy Charge relating to the composition of the Index Factor so that it continues to be a market sensitive index. The new language would allow a redetermination of the terms of the Index Factor at five-year intervals for the purpose of bringing the price of natural gas in Dartmouth's rate in line with the price of other long-term baseload gas supplies in Massachusetts and Rhode Island, subject to a minimum average capacity factor of 60%.

Commonwealth notes that the Second Amendment does not change the amount of power purchased by the Company under the Agreement nor does it change any pricing provisions beyond the indexing provisions of the Monthly Energy Charge previously discussed.

Commonwealth believes that the Second Amendment is in the best interest of the Company and its customers and requests Department approval.

For convenience of reference Commonwealth provides the following additional materials:

Attachment A September 5, 1989 Power Purchase Agreement with March 30, 1990 DPU approval.

Attachment B August 3, 1990 Amendment to Power Purchase Agreement with October 23, 1990 DPU approval.

Please address any communication regarding this filing to:

Marcy S. Rosenzweig
Manager of Rate Regulation
COM/Energy Services Company
One Main Street
Cambridge, MA 02142
Telephone: (617) 225-4372
Facsimile: (617) 225-4595

Commonwealth would be pleased to provide such additional information as the Department may request.

Very truly yours,

James J. Keane (MTG)

James J. Keane
Vice-President of Power Supply
and Transmission

Enclosures

cc: James Connelly, Esq. - General Counsel
Brian Abbanat, Assistant Director - Electric Power Division
Edward G. Bohlen, Esq. - Assistant Attorney General

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bcc: J. J. Keane
A. R. Johnson (2)
M. R. Kirkwood
D. P. Ciullo
T. N. Cronin
S. A. Brav
M. S. Rosenzweig
D. T. Griffiths
R/D File

SECOND AMENDMENT TO POWER PURCHASE AGREEMENT

AMENDMENT dated as of this 23rd day of June, 1994, by and between Commonwealth Electric Company, a Massachusetts corporation with a principal place of business at One Main Street, Cambridge, Massachusetts ("the Company") and Dartmouth Power Associates Limited Partnership, a Massachusetts Limited Partnership with a place of business at One Energy Road, Dartmouth, Massachusetts ("Seller"), to the Power Purchase Agreement by and between the Company and Seller, dated as of September 5, 1989 and amended by an Amendment to Power Purchase Agreement by and between the Company and Seller, dated as of August 3, 1990 (as amended, "the Agreement").

WHEREAS the Company, pursuant to the Agreement, purchases all electricity produced by the Seller's 67,600 KW generating facility located at One Energy Road, in Dartmouth, Massachusetts ("the Unit"); and

WHEREAS the Total Purchase Price for electricity purchased by the Company pursuant to the Agreement includes a component known as the Monthly Energy Charge, which is defined (in section 4 of Appendix B of the Agreement) as including a component known as the Variable Fuel Supply Rate; and

WHEREAS, the Variable Fuel Supply Rate is calculated, in part, by reference to the following indices for natural gas pipeline service: The "Tennessee CD-6" index (for service pursuant to the CD-6 rate under a FERC approved tariff by Tennessee Gas Pipeline Company, "Tennessee") and (2) the "Algonquin F-1" index (for service pursuant to the F-1 rate under a FERC approved tariff by Algonquin Gas Transmission Company, "Algonquin"); and

WHEREAS, both the Algonquin F-1 rate and the Tennessee CD-6 rate have ceased to be available as a consequence of the restructuring of services of each of those respective pipelines pursuant to Federal Energy Regulatory Commission ("FERC") Order No. 636; and

WHEREAS, the Variable Fuel Supply Rate is calculated, in, part, by reference to an index calculated by the Alberta Petroleum Marketing Commission for the Minister of Energy for the Province of Alberta, Canada known as the Alberta Market Price (AMP); and

WHEREAS, the AMP, effective December 31, 1993 is no longer published; and

WHEREAS, the Company and Seller have agreed upon the terms of an index to replace the F-1, CD-6 and AMP indices for purposes of calculating the Variable Fuel Supply Rate, and desire to execute this Amendment for purposes of memorializing their agreement.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein, the Company and Seller agree as follows:

1. That for the purposes of determining the Variable Fuel Supply Rate as referenced in section 4.1 of Appendix B of the Agreement, the last paragraph (including the table) of said section shall be deleted in its entirety and the following shall be substituted in place thereof:

The Initial Variable Fuel Supply Rate shall be adjusted monthly to reflect the proportional change in the T2 index (as hereinafter defined) and the Alberta Reference Price, using the year 1988 as a base, and shall be calculated pursuant to the provisions of subsection 4.14.

4.14 For each Billing Period during the term of this Agreement, the Variable Fuel Supply Rate shall equal the product of (i) the Initial Variable Fuel Supply Rate and (ii) an Index Factor, the numerator of which shall be "N1" (as hereinafter defined) and the denominator of which shall be "D1" (as hereinafter defined);

Where:

"N1" shall equal the sum of (i) "T2" (as hereinafter defined) and (ii) the available Alberta Reference Price for the billing month.

"D1" shall equal two (2) multiplied by "AFC-1".

"T2" shall be calculated as the arithmetic average of the following four indices for the Billing Period:

(a) the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company;

(b) the Louisiana and Texas (Zone 0) index for Tennessee Gas Pipeline Company;

(c) the arithmetic average of the East Texas and South Texas indices for Texas Eastern Transmission Corporation;

(d) the arithmetic average of the East Louisiana and West Louisiana indices for the Texas Eastern Transmission Corporation.

all as reported in the table entitled "Prices of Spot Gas Delivered to Pipelines" in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, provided that if any of the above described indices, or their successors, are not reported in any month, T2 shall be equal to the arithmetic average of the indices that are reported, provided that at least three of the above indices are so reported. If at least three of the above indices are not reported in any month, then the Henry Hub Cash Price, as reported in the first of the month edition of Inside F.E.R.C.'s Gas Market Report will serve as a Proxy for T2. However, the Henry Hub Cash Price shall not be used as a Proxy for T2 for two consecutive months unless agreed to by both parties.

"AFC-1" shall equal $1.486 per MMBTU. This value is the sum of (i) the average "T2" value for calendar year 1988 and (ii) the average Alberta Market Price for calendar year 1988, divided by two (2).

The "Alberta Reference Price" is the gas reference price prescribed by the Minister of Energy for the Province of Alberta, Canada for the calendar month of the Billing Period (for example, the gas reference price published by the Minister for June, 1994 would be the Alberta Reference Price used to calculate the Variable Fuel Supply Rate for June, 1994 but actually reflect data for the month of April, 1994). The data is published by the Alberta Petroleum Marketing Commission.

2. The following shall be inserted as section 4.3 of Appendix B of the Agreement:

4.3 Redetermination of the Variable Fuel Supply Rate:

Either the Seller or the Company shall have the right to require a redetermination of the provisions of subsection 4.14 of this Appendix relating to the composition of the Index Factor, effective upon November 1 of each of the following years: 1997, 2002, 2007 and 2012 (the "Redetermination Dates"). A party electing to require such a redetermination shall provide written notice (the "Redetermination Notice") to the other party no less than six (6) months and no more than one (1) year before the Redetermination Date on which such redetermination is to take effect.

If a Redetermination Notice is not served by either party upon the other party during the specified time period, the Variable Fuel Supply Rate in effect immediately prior to the relevant Redetermination Date shall continue to be calculated in the manner in effect prior to such Redetermination Date. If a Redetermination Notice is served within the time required, then the provisions of subsections 4.3.1 through 4.3.4 below shall apply.

4.3.1 Following receipt of a Redetermination Notice, the parties will negotiate in good faith to determine mutually satisfactory modifications to the Variable Fuel Supply Rate.

4.3.2 If the parties are unable to agree upon renegotiated Variable Fuel Supply Rate provisions on or before the date which is three (3) months prior to the Redetermination Date, either party may elect by written notice (the "Arbitration Notice") to the other party, to refer the redetermination of the Variable Fuel Supply Rate provisions to binding arbitration pursuant to Article 12 of the Agreement. If an Arbitration Notice is not issued by either party before the date which is three (3) months prior to the Redetermination Date, and the parties have not agreed upon renegotiated Variable Fuel Supply Rate provisions on or before the Redetermination Date, the Variable Fuel Supply Rate provisions shall continue to be calculated in the manner in effect immediately prior to such Redetermination Date.

4.3.3 During the renegotiation of the Variable Fuel Supply Rate provisions and during any arbitration relating thereto, the parties and the arbitrators

shall work to modify the Index Factor, N1/D1, as defined in subsection 4.14, such that the renegotiated Variable Fuel Supply Rate provisions will yield:

(a) a price of natural gas that reflects the value of other long-term baseload gas supplies delivered at the city gate to local electric utility companies in Massachusetts and Rhode Island, where such prices have been adjusted by subtracting all applicable costs (at 100% load factor) of firm pipeline transportation from the wellhead to the respective city gates, including commodity charges, demand charges and fuel gas costs.

(b) a Variable Fuel Supply Rate that the parties anticipate will enable the Unit to operate at an average capacity factor of at least sixty percent (60%) over the following five year period.

(c) in the event that the objectives in (a) and (b) above are in conflict, objective (b) relating to operation at a capacity factor of at least sixty percent (60%) shall be considered the controlling factor.

4.3.4 Whenever there is a redetermination of the Variable Fuel Supply Rate in progress, transactions under this Agreement shall continue in the same fashion as they were conducted before such redetermination was initiated, without prejudice to the rights of either party under this section 4.3, pending a redetermination resulting from renegotiation or arbitration. The Variable Fuel Supply Rate in effect prior to such redetermination shall be applied to all electricity delivered pursuant to this Agreement during the time period after the Redetermination Date until the day upon which a renegotiated or arbitrated decision is reached and issued (in this section, the "Subject Period"), whereupon the Variable Fuel Supply Rate Provisions as determined by the renegotiation or arbitration shall, unless otherwise agreed by the parties, be applied to the Subject Period with interest (at the annual rate of two percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston) and with appropriate adjustments (i.e., payment by the Company to the extent the Redetermined Variable Fuel Supply Rate is greater; payment by the Seller to the extent the Redetermined Rate is less) being made between the parties to reflect the change in the Variable Fuel Supply Rate Provisions.

3. The Company shall submit this Amendment to the MDPU, and the Seller shall submit this Amendment to the FERC, for the approval of each of the MDPU and the FERC. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

4. All other terms and conditions of said Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES
LIMITED PARTNERSHIP BY
EMI/DARTMOUTH, INC.,
ITS GENERAL PARTNER

By: James L. Gordon

Title: President

COMMONWEALTH ELECTRIC COMPANY

By: James J. Keane

Title: Vice President - Power Supply & Transmission

POWER PURCHASE AGREEMENT

Agreement entered into this fifth (5th) day of September, 1989, by and between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Dartmouth Power Associates Limited Partnership, a Massachusetts limited partnership with its principal place of business at 8 Newbury Street, Suite 5, Boston, Massachusetts (the "Seller").

The Seller plans to construct, own, and operate an electric generation facility, utilizing two gas turbines and a supplementary-fired waste heat boiler with a dual inlet steam turbine, together with housings and other integral equipment, which will be capable of generating approximately one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW) of electricity (the "Unit"). The Unit will be located at a site in the Town of Dartmouth, Massachusetts, which will be owned by the Seller, more particularly described in Appendix A attached hereto (the "Site"). The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of a portion of the electricity produced by the Unit, pursuant to the terms and conditions as set forth in this Agreement.

Therefore, the parties, each in consideration of the agreements of the other, hereby agree as follows.

ARTICLE 1. Definitions.

When used with initial capitalizations, whether in the singular or in the plural, the following terms shall have the following meanings.

Actual In-Service Date shall mean the date upon which the Seller shall have both (i) produced electricity while operating the Unit at or above an average of ninety percent (90%) of the Design Capacity for five (5) consecutive days, and (ii) delivered the Company's Entitlement of such electricity to the Company.

Adjusted Capability for each Seasonal Period shall be the greater of (i) the seasonal Capability as determined by the first Capability Audit performed during each Seasonal Period following the Actual In-Service Date, or (ii) the Design Capacity.

Billing Period shall mean any calendar month in which the Unit produces electricity pursuant to this Agreement and for which the Company is obligated to pay for such electricity produced for such month pursuant to this Agreement.

Capability shall mean the maximum dependable load carrying ability in kilowatts of the Unit during the applicable Seasonal Period (exclusive of capacity required for Unit use). Capability shall be determined by the NEPOOL Operations Committee in accordance with NEPOOL Criteria, Rules and Standards ("CRS") No. 4. In the event that CRS 4 ceases to be established, or if the Company ceases participation in NEPOOL, the Company may impose

reasonable substitute standards that would have the same effect as this CRS in determining Capability.

Capability Audit shall mean a test of the Unit's Capability conducted periodically pursuant to the provisions of Section 8.13 of the NEPOOL Agreement and CRS 4, or any properly issued replacements therefor created from time to time during the term of this Agreement.

Capacity Deficiency shall mean the amount, if any, by which the audited Capability of the Unit is less than the Adjusted Capability.

Company's Entitlement shall mean that percentage of Unit capacity equal to the ratio of the Contract Capacity to the Adjusted Capability.

Contract Capacity shall mean fifty thousand kilowatts (50,000 kW).

Delivered Energy shall mean, for each Billing Period, the Company's portion of the kilowatthours metered during the Billing Period pursuant to Article 7 hereof.

Delivery Point shall mean the point at which the Unit shall be interconnected with the Company's system, in accordance with an interconnection agreement to be agreed to by the Seller and the Company.

Design Capacity shall mean one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW), at fifty-nine (59) degrees Fahrenheit.

FERC shall mean the Federal Energy Regulatory Commission.

Force Majeure shall include those events set forth in Article 10.1 hereof.

Good Utility Practice shall mean the practice, methods, and acts (including but not limited to the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy, and expediency. With respect to the Unit, Good Utility Practice includes but is not limited to taking reasonable steps to ensure the following.

(1) That adequate materials, resources, and supplies, including fuel, are available to meet the Unit's needs;

(2) That sufficient operating personnel are available and are adequately experienced, trained, and licensed as necessary to operate the Unit properly and efficiently, and who are capable of responding to emergency conditions whether caused by events on or off the Site;

(3) That preventative, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(4) That appropriate monitoring and testing are performed to ensure that equipment is functioning as designed;

(5) That equipment is not operated recklessly, or in a manner that is unsafe to workers, the general public, or the environment, or without regard to defined limitations such as steam pressure, temperature and moisture content, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, frequency, rotational speed, polarity, synchronization, or control system limits;

(6) That equipment will function properly under both normal and emergency conditions; and

(7) That the Unit is operated in conformance with the applicable NEPOOL CRS and Operating Procedures, and NEPEX dispatch instructions.

MDPU shall mean the Massachusetts Department of Public Utilities.

NEPEX shall mean the central dispatching agency, as defined in Section 15.22 of the NEPOOL Agreement, operating through such satellite dispatching centers as the NEPOOL Management Committee may determine to be appropriate.

NEPOOL shall mean the New England Power Pool.

NEPOOL Agreement shall mean the New England Power Pool Agreement, dated September 1, 1971, as amended.

Proposed In-Service Date shall be July 1, 1992.

Seasonal Period shall mean either the summer period, June through September, or the winter period, October through May, as appropriate.

System Emergency shall mean an imminent condition on the Company's or a neighboring utility's system that is likely to result in significant disruption of service or is likely to endanger life or property.

Testing Period shall mean any period of time during which the Unit is being tested and may produce electric energy prior to the Actual In-Service Date.

Test Power shall mean any electric energy produced by the Unit during the Testing Period.

ARTICLE 2. Sale of Power.

2.1 The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of the Company's Entitlement and related energy produced by the Unit during the term of this Agreement.

2.2 The Unit shall be staffed, operated, and maintained in a manner consistent with the standards applicable to generating facilities owned

and operated by participants in NEPOOL, as such standards may be in effect from time to time during the term of this Agreement. The Seller also agrees to make the Unit available for NEPOOL dispatch in accordance with the provisions of Section 12.2 of the NEPOOL Agreement.

2.3 In addition to the foregoing, the Seller shall undergo periodic Capability Audits upon the request of NEPOOL or of the Company. In the event that the Unit demonstrates a Capacity Deficiency in excess of two thousand kilowatts (2,000 kW), the Company may assess the Seller an offset charge each month, which shall be equal to one twelfth (1/12) of the sum of the Capability Responsibility Adjustment Charge plus the Capability Responsibility Deficiency Charge, established from time to time by NEPOOL pursuant to the provisions of Section 9.4 of the NEPOOL Agreement, multiplied by such Capacity Deficiency.

2.4 During the Testing Period, the Unit may generate Test Power. The Company agrees to take and pay for any Test Power offered for sale, up to the Company's Entitlement and related energy, subject to the following conditions:

2.4.1 The tests conducted during the Testing Period shall be performed in accordance with Good Utility Practice,

2.4.2 The administrative committee established pursuant to this agreement shall be kept informed of operations during the Test Period, and

2.4.3 The Company shall pay for any Test Power monthly at a price determined pursuant to the Company's generally available Rate P-1 "Power Purchase Rate" (MDPU No. 182) or the generally available replacement therefor.

ARTICLE 3. Effective Date and Term.

3.1 This Agreement shall become effective when all necessary approvals have been received from the FERC and from the MDPU, in a form acceptable to both parties; provided, however, that the Company's obligation to purchase the Company's Entitlement and related energy (other than pursuant to Article 2.4) shall not commence until the Actual In-Service Date. Unless sooner terminated in accordance with any applicable provision hereof, this Agreement shall remain in full force and effect until the twenty-fifth (25th) anniversary of the Actual In-Service Date.

3.2 If all necessary permits or licenses to build and operate the facility have not been obtained, or construction of the Unit has not commenced, within twenty-four (24) months following the date first above-written, or if, in the reasonable judgment of either party exercised not sooner than twenty-four (24) months following the date first above written, the Actual In-Service Date is likely to occur later than twenty-four (24) months after the Proposed In-Service Date, either party may terminate this Agreement upon sixty (60) days written notice to the other.

ARTICLE 4. Security Deposit.

4.1 Within thirty (30) days following the date that this Agreement is approved by the MDPU, the Seller shall deliver to the Company seven hundred fifty thousand dollars ($750,000) as a security deposit (the "Security Deposit"). The Security Deposit is calculated as the product of (i) fifty thousand kilowatts (50,000 kW), which is the Contract Capacity, and (ii) fifteen dollars ($15) per kilowatt. The Company shall hold the Security Deposit in an interest-bearing escrow account.

4.2 If, prior to the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, or if this Agreement is terminated in accordance with the provisions of Article 3.2, the entire Security Deposit shall be returned to the Seller after payment to the Company of accumulated interest and a percentage of the principal equal to the ratio of the elapsed time between Agreement execution and the cancellation date to the total time between Agreement execution and Proposed In-Service Date; provided, however, that if the reason for such cancellation, abandonment, or termination is the failure of the FERC to approve or accept this Agreement, in a form acceptable to both parties, then the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.3 If, after the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, the entire Security Deposit plus any accumulated interest shall be paid to the Company; provided, however, that if the reason for such cancellation, abandonment, or termination is the inability or refusal of the Company to interconnect, the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.4 If the Actual In-Service Date occurs on or before the Proposed In-Service Date, the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.5 If the Actual In-Service Date occurs within twenty-four (24) months after the Proposed In-Service Date, the entire Security Deposit and any accumulated interest through the Proposed In-Service Date shall be paid to the Seller and any interest accumulated after the Proposed In-Service Date shall be paid to the Company; provided, however, that if the reason for the occurrence of the Actual In-Service Date after the Proposed In-Service Date is the inability or refusal of the Company to interconnect, any interest accumulated after the Proposed In-Service Date shall also be paid to the Seller.

4.6 If the Actual In-Service Date does not occur within twenty-four (24) months after the Proposed In-Service Date, the entire Security Deposit plus any accumulated interest shall be paid to the Company and the Agreement shall be terminated according to the provisions of Article 3.2.

ARTICLE 5. Purchase Price.

From and after the Actual In-Service Date, the Company shall pay to the

Seller each Billing Period, in accordance with the provisions of Article 8 of this Agreement, the sum of the Monthly Capacity Charge and the Monthly Energy Charge, as determined pursuant to Appendix B attached hereto. In calculting the Monthly Energy Charge, rates shall be rounded to the nearest one-hundredth of one cent ($.0001) per kilowatthour and shall be multiplied by the Delivered Energy for the prior Billing Period. If the Actual In-Service Date does not fall on the first day of the Billing Period in which such Date occurs, then the Monthly Capacity Charge for such first Billing Period shall be prorated appropriately. Sales or other ad valorem taxes upon the sale of electricity pursuant to this Agreement shall be borne by the Company.

ARTICLE 6. Delivery by the Seller.

6.1 The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electric energy at or near normal seasonal Capability on a continuous twenty-four (24) hour basis for the full term of this Agreement.

6.2 Electric energy generated by the Unit shall be delivered to the Company at the Delivery Point and shall be in the form of three (3) phase, sixty (60) hertz, alternating current at approximately one hundred fifteen thousand (115,000) volts nominal (the "Nominal Voltage"). However, in no event shall said Nominal Voltage be less than one hundred fifteen thousand volts (115 kV), nor shall electricity be delivered at greater than five (5) percent above the Nominal Voltage, nor shall the frequency vary by more than one hundredth (.01) hertz from sixty (60.00) hertz except for unavoidable momentary fluctuations.

6.3 The Seller may from time to time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance or repair upon the Unit. The Seller shall comply with the provisions of NEPOOL Operating Procedure No. 5 as in effect from time to time when planning any scheduled maintenance or repair upon the Unit. The Seller shall give the Company such notice as may be practicable in the circumstances when withdrawing the Unit from service for unscheduled maintenance or repair.

ARTICLE 7. Meters and Metering.

7.1 The Company shall review and approve the metering installations required to record the quantities of electricity purchased from the Seller. Such metering equipment shall be capable, inter alia, of providing data required to determine kilowatthours per hour purchased during each hour of the month as well as total kilowatthours purchased each month under the terms of this Agreement. The Seller shall install, own, operate, and maintain such metering equipment, which equipment shall be located at the Seller's high voltage bus or buses. If, for any reason, it is impractical to install meters at such bus or buses, appropriate adjustments shall be made to reflect the actual amount of electric energy that would have been recorded by meters located at such bus or buses.

7.2 The Seller shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards. The metering equipment shall be sealed, and the Seller will comply with any reasonable request of the Company with regard to the presence of the Company's representative when such seals are to be broken or when the meters are to be inspected, tested, or adjusted. The Company may request at any time a test of the accuracy of any metering equipment installed pursuant hereto and shall bear the costs thereof in the event that said requests are made more frequently than once in each twelve (12) months. The results of all meter calibrations or tests, regardless of whether performed at the Company's request, shall be open to examination by the Company at all reasonable times.

7.3 Any meter tested and found to register less than or equal to one half of one percent (0.5%) above or below the recognized comparative standard shall be considered correct and accurate. If the metering fails to operate or, as a result of such tests, the metering equipment is found to be defective or inaccurate, the Seller shall restore it to a condition of accuracy or replace it. In such event, appropriate adjustments shall be agreed to by the Seller and the Company and reflected in the next monthly statement of the Seller rendered pursuant to Article 8.1. Such adjustments shall correct all measurements made by the defective or inaccurate meter for either (i) the actual period during which inaccurate measurements were made, if determinable to the mutual satisfaction of the Company and the Seller, or (ii) if such period is not determinable, for a period equal to one-half of the time elapsed since the last prior test, but in no event greater than twelve (12) months.

7.4 Other provisions of this Article notwithstanding, the Company may elect to install its own metering equipment in supplement to the Seller's metering equipment. Should any metering equipment installed by the Seller fail to register the amount of electric energy delivered to the Company during any period, the Company's metering equipment shall, if so installed, be used to determine the amount of energy so delivered. If the Company wishes its metering equipment to be so used, the Company agrees to operate, maintain, and read such equipment according to the standards established by this Article with respect to the Seller's metering equipment. The Seller agrees, upon the request of the Company, to provide a suitable location at the Site for installation of the Company's meters at no cost to the Company.

7.5 Upon the written request of the Company, the Seller shall install, own, operate, and maintain, pursuant to the provisions of this Article, such telemetering equipment and data circuits as the Company may reasonably require for the transmission of various metered values to its operations center. The design equipment and data circuits shall be approved by the Company prior to their installation by the Seller.

ARTICLE 8. <u>Billing and Payment.</u>

8.1 The Seller shall render monthly statements for the Billing Period then most recently ended within ten (10) working days following the receipt

by the Company of all actual metered values for such Billing Period. The monthly statement shall detail the amount of Delivered Energy during such Billing Period. Any amount payable hereunder not paid within thirty (30) days from the date of receipt by the Company of all actual metered values for the Billing Period shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston from the date of receipt of such monthly statement until the date of payment.

8.2 In the event that any data required for billing purposes hereunder are unavailable when required for such billing, the unavailable data may be estimated by the Company, subject to any required adjustment, based upon actual data, in a subsequent Billing Period within the following twelve (12) months.

8.3 Neither the Company nor the Seller shall have the right to challenge any monthly statement rendered or received hereunder, to invoke arbitration of the same, or to bring any court or administrative action of any kind questioning the propriety of said monthly statement, after a period of one (1) year from the date such monthly statement was rendered. In the event that any such monthly statement depends in whole or part upon estimated data, this one (1) year limitation period shall be deemed to begin in the Billing Period in which such estimated data are adjusted to actual.

ARTICLE 9. Governmental Regulation.

9.1 This Agreement shall be submitted by the Company to the MDPU in accordance with the regulations of the MDPU, and by the Seller to the FERC in accordance with the regulations of the FERC as set forth at 18 C.F.R. Part 35.

9.2 Each party hereto shall be responsible for taking all necessary actions to satisfy any regulatory requirements that may be imposed by any federal, state, or municipal statute, rule, regulation, or ordinance that may be in effect from time to time relative to the performance of such party hereunder.

9.3 This Agreement and all rights and obligations of the parties hereunder are subject to applicable state and federal laws and duly promulgated orders and duly authorized actions of governmental authorities.

ARTICLE 10. Liability and Force Majeure.

10.1 The parties hereto shall be excused from performing hereunder, and shall not be liable in damages or otherwise, if and to the extent that they are unable to do so or are prevented from doing so by an event of Force Majeure, including, without limitation, by statute or regulation, or by action or inaction of any court or public authority having or purporting to have jurisdiction in the premises; or by reason of storm,

flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or regulatory agency, or any other cause, whether or not similar thereto, beyond the reasonable control of the affected party. Each party shall have the obligation to operate in accordance with Good Utility Practice at all times and to use diligent effort to overcome and remove any cause of failure to perform; provided, however, that neither party shall be required to settle any labor dispute on terms that, in the sole judgment of the party involved in such dispute, are contrary to its interests, so long as such party is acting in good faith and otherwise in compliance with applicable labor laws and regulations.

10.2 Neither the Company nor the Seller shall, in any event, be liable to the other or to any third party for any consequential, indirect, or special damages to persons or property, whether arising in tort, contract, or otherwise, by reason of this Agreement or any services performed or undertaken to be performed by the Company or the Seller hereunder.

10.3 Whenever the Company's system or the systems with which it is directly or indirectly interconnected experiences a System Emergency, or whenever it is necessary or desirable to aid in the restoration of service on its system or on the systems with which it is directly or indirectly interconnected, the Company may, in its reasonable judgment, curtail or interrupt the taking of electric energy hereunder, provided such curtailment or interruption shall continue only for so long as is reasonably necessary. Such curtailment,interruption, or reduction shall not be deemed to be a default by the Company nor shall the Company be liable therefor to the Seller or to any other party.

10.4 The Company and the Seller agree that each shall be responsible for the electricity on its respective side of the Delivery Point and shall indemnify, save harmless, and defend the other against all claims, demands, costs, or expenses for loss, damage, or injury to persons or property in any manner directly or indirectly arising from, connected with, or growing out of the presence, use, or transmission of electricity over the wires, cables, devices, or appurtenances owned by it. The Company and the Seller each assumes full responsibility in connection with the service rendered hereunder for its respective wires, cables, and other devices used in connection with such service. Each party hereto shall be solely liable for all claims of its own employees arising from any worker's compensation laws.

10.5 Neither by inspection, by non-rejection, nor in any other way does either party give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any equipment, apparatus, or devices installed on the other party's premises.

ARTICLE 11. Governing Law.

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the Commonwealth of Massachusetts.

ARTICLE 12. Arbitration.

12.1 In the case of any dispute between the parties with respect to the interpretation of this Agreement or the performance of the same, either party may give notice in writing to the other of its desire to submit such questions to arbitration and may designate an arbitrator. Within thirty (30) days after the receipt of such notice the other party may, in writing, serve upon the party invoking such arbitration a notice designating an arbitrator on its behalf. The two arbitrators so chosen shall, within twenty (20) days after the appointment of the second arbitrator, in writing, designate a third arbitrator. Upon the failure of the party notified to appoint the second arbitrator within such time, the party invoking such arbitration may proceed with the single arbitrator. If the first and second arbitrators are unable to agree on a third arbitrator within twenty (20) days of the appointment of the second arbitrator, the first and second arbitrator shall invoke the services of the American Arbitration Association to appoint a third arbitrator. This third arbitrator shall, to the extent practicable, have special competence and experience with respect to the subject matter under consideration. An arbitrator so appointed shall have full authority to act pursuant to this Article. No arbitrator, whether chosen by a party hereto or appointed, shall have the power to amend or add to this Agreement.

12.2 The party calling the arbitration shall, within twenty (20) days after either the failure of the other party to name an arbitrator, or the appointment of the third arbitrator, as the case may be, fix, in writing, a time and a place of hearing, to be not less than twenty (20) days from the delivery of notice to the other party. The arbitrator or arbitrators (the "Arbitrators") shall, thereupon, proceed promptly to hear and determine the controversy pursuant to the then current rules of the American Arbitration Association for the conduct of commercial arbitration proceedings, except that if such rules conflict with the then current provisions of the laws of the Commonwealth of Massachusetts relating to arbitration, such conflict shall be governed by the then current provisions of such laws. The Arbitrators shall fix a time within which the matter shall be submitted to them by either or both of the parties, and shall render a decision within ten (10) days after receiving the final submission from the parties unless, for good reasons to be certified by them in writing, the Arbitrators extend such time. The decision of the single arbitrator, or two of the three arbitrators, shall be taken as the arbitration decision. Such decision shall be made in writing and in duplicate, and one copy shall be delivered to each of the parties. The Arbitrators, by their award, shall determine the manner in which the expenses of the arbitration shall be borne, except that each party shall pay the costs of its own counsel. Each party shall accept and abide by the arbitration decision. The award of the Arbitrators shall be final except as otherwise provided by applicable law. Judgment upon such award may be entered by the prevailing party in any court having jurisdiction thereof, or application may be made by such party to any such court for judicial acceptance of such award and an order of enforcement.

ARTICLE 13. Insurance.

13.1 From and after the Actual In-Service Date, the Seller shall (i) keep the Unit insured by means of a policy or policies of insurance protecting against loss or damage to the Unit by fire, lightning, and other casualties normally insured against with a uniform standard extended coverage endorsement, and (ii) maintain liability insurance as described in Appendix C attached hereto. Such insurance is to be at all times in amounts not less than that reasonably required by the Company. The Company shall be the named insured in these policies, which policies shall contain a waiver of subrogation in favor of the named insured. All policies, or copies thereof, together with a certificate from the insurers evidencing that the policies are currently in force, shall be delivered to the Company.

13.2 Such insurance shall be provided by policies that shall be written by such companies and in such form as shall be generally commercially available and acceptable to the Company, such acceptance not to be unreasonably withheld; shall be primary and without right to contribution from other insurance that may be available; shall provide that, with respect to the Company, the insurance shall not be invalidated by any action or inaction by the Seller including, without limitation, any representation made by or on behalf of the Seller in the procurement of such insurance; and shall provide that such insurance shall not be cancelled or amended without at least thirty (30) days' prior written notice to the Company.

13.3 Not less than thirty (30) days prior to the expiration date of each policy furnished by the Seller pursuant to this Article, the Seller will deliver to the Company a renewal policy or policies accompanied by evidence of payment of the premium therefor.

13.4 In the event of a loss occurring after completion of the construction of the Unit, the amount of any proceeds of insurance described in this Article remaining after deducting all expenses (including attorney fees) incurred in the collection of such proceeds from the gross proceeds thereof (the "Net Proceeds") shall be applied to the prompt repair, restoration, modification, or improvement of that portion of the Unit damaged or destroyed by such casualty, unless the Seller and the Company have agreed that such repair, restoration, modification, or improvement is not practicable under the circumstances.

ARTICLE 14. Preservation of the Unit.

14.1 The Seller in its sole discretion may sell or otherwise dispose of any machinery, equipment, or other personal property constituting part of the Unit that the Seller determines has become inadequate, obsolete, worn out, unsuitable, undesirable, or unnecessary, provided that (i) substitute property having equal or greater utility, but not necessarily the same function, in the operation of the Unit is installed at the Unit and such removal and substitution would not materially impair the efficiency of operation of the Unit, adversely affect the structural integrity or electrical output of the Unit, or change the nature of the

Unit to the extent that it would not constitute the type of electricity generation facility operated prior to such replacement; and (ii) the prior written consent of the Company is obtained, which consent shall not be unreasonably withheld; provided, however, that such consent shall not be required for removals and substitutions made during ordinary and routine repair and maintenance. The Seller shall promptly report to the Company each such removal, substitution, sale, or other disposition. In addition, not less often than semi-annually, the Seller shall make available to the Company's representatives on the administrative committee described in Article 17.6 all records with respect to prior dispositions and substitutions, together with information as to planned dispositions and substitutions during the next six months.

14.2 The Seller shall pay or cause to be paid all taxes, payments in lieu of taxes, assessments, and other charges now or hereafter levied against the Unit or any part thereof, together with any penalties or interest on any of the foregoing, and upon request of the Company, the Seller shall exhibit to the Company receipts for the payment of such charges prior to the date when they would become delinquent; the foregoing to be subject, however, to the right of the Seller and other parties in interest to contest in good faith the levying of such charges.

14.3 At the time of providing security to the Company pursuant to Article 15 hereof, the Seller shall warrant that good record and marketable title to the Site and to the Unit is held by the Seller (subject only to any mortgages, liens, leases, or other encumbrances existing as of record and copies of which have been provided to the Company). The Seller shall not enter into any transaction involving the transfer, sale, or lease of the Site or the Unit, or any interest therein, without the prior written consent of the Company in each case obtained, which consent shall not be unreasonably withheld. Such transfer, sale, or lease shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against an entity that might thereby obtain title to or possession of the Site or Unit.

14.4 The Seller will maintain the Unit, or cause the Unit to be maintained, in accordance with Good Utility Practice, will not commit or suffer any waste thereof or the conduct of any nuisance or unlawful occupation or business on, or use of, the Unit, and will comply, or cause compliance, with all statutes, ordinances, and requirements of any governmental authority relating to the Unit; and the Seller at its expense shall provide the Company with a report on an annual basis prepared by a nationally recognized firm of consulting engineers, chosen by the Seller and approved by the Company, such approval not to be unreasonably withheld, attesting to the fact that the Unit is being maintained in accordance with Good Utility Practice. If substantial items affecting long-term efficient operation of the Unit that are described in any such annual report as being in need of correction are not corrected within six months following such annual report, the Company may withhold payment of the Monthly Capacity Charge component of the Total Purchase Price, with such amounts to be held in escrow by the Company until the cited item has been corrected, upon which correction the escrowed funds shall be released to the Seller. Notwithstanding the foregoing, if any such

correction is not made within twelve (12) months from the date of such annual report, the Company may elect to cause such correction to be made and the escrowed funds shall be applied to cover the costs of such correction.

14.5 The Company and any persons authorized by the Company shall have the right to enter and inspect the Unit at all reasonable times upon reasonable prior written notice to the Seller, and to examine Unit operating manuals and maintenance records.

ARTICLE 15. Security of Continued Performance.

In order to secure such complete performance of the Seller's obligations as is necessary for the Company to provide service to its ratepayers, the Seller, prior to the Actual In-Service Date, shall provide to the Company security in the form and scope set forth below:

15.1 Mortgage and Security Agreement. The Seller shall execute and deliver to the Company a mortgage and security agreement creating liens and security interests in the Unit, the Site, all improvements upon the Site, and all rents, profits, income, and other benefits derived from the foregoing, subordinate only to the lien of the institutional or unaffiliated lenders securing amounts lent for the construction or permanent financing or refinancing of the Unit. Such liens and security interests of the Company shall secure (i) all amounts paid by the Company to the Seller pursuant to this Agreement in excess of the Company's actual avoided costs and (ii) performance of Seller's obligations under this Agreement for the full anticipated term thereof, including all damages resulting from the Seller's failure to perform such obligations. Such mortgage and security agreement will be in form and substance acceptable to the Company.

15.2 Declaration of Easements, Covenants, and Restrictions. The Seller shall cause to be granted to the Company an unsubordinated declaration of easements, covenants, and restrictions encumbering the Site for a period equal to the anticipated full term of this Agreement (the "Declaration"). The Declaration shall grant to the Company easements for access to the Site and for the placement and operation of facilities thereon (which shall not interfere with the rights of the Seller to design, construct, and operate the Unit), as well as create restrictions and covenants to the effect that if any electricity is produced at the Site during the term of the Declaration, the Company's Entitlement thereto shall not be tendered or sold except to the Company in accordance with this Agreement. The Declaration shall reserve to the Seller the right to grant other easements, so long as such other easements do not interfere with the rights of the Company. The Declaration shall be in form and substance acceptable to the Company and shall run with the Site and be binding upon the successors of the Seller and inure to the benefit of the Company and its successors.

15.3 Accommodation Agreement. The Seller shall cause any lender of funds to the Seller for the acquisition of the Site or Unit (the "Lender") to execute and deliver an Accommodation Agreement, under which such

Lender shall agree: (i) to make its own interests subject to the Declaration described above; (ii) to honor this Agreement to the extent the Lender is in possession of the Site or Unit; (iii) to transfer interests in the Site or Unit only upon the condition that the transferee become obligated to honor this Agreement from the date of such transfer; and (iv) to avoid interference with the Company's rights hereunder, provided that the Company continues to make payments hereunder to the Seller's successor-in-interest and that the Company otherwise performs in accordance with this Agreement.

15.4 Letter of Credit. The Seller shall provide, in form and substance acceptable to the Company, an irrevocable letter of credit in favor of the Company. The Seller shall maintain such letter of credit throughout the period during which payments by the Company to the Seller are expected to exceed the Company's anticipated avoided cost for power, and such letter of credit shall be in an amount equal to the expected amount by which such payments will exceed of the Company's anticipated avoided cost for power, according to the following schedule:

from	through	amount
Actual In-Service Date	December 31, 1992	$2,526,162
January 1, 1993	December 31, 1993	3,962,380
January 1, 1994	December 31, 1994	5,667,578
January 1, 1995	December 31, 1995	7,511,116
January 1, 1996	December 31, 1996	9,515,361
January 1, 1997	December 31, 1997	10,546,831
January 1, 1998	December 31, 1998	9,866,184
January 1, 1999	December 31, 1999	6,918,707
January 1, 2000	December 31, 2000	5,848,890
January 1, 2001	December 31, 2001	3,615,810

ARTICLE 16. Rights of Company with respect to Expansion of Plant and Extension of Unit Life.

The Seller shall not enter into any contract for the sale of electricity from any addition to or expansion of the Unit, or from any other electric generation facilities located at the Site, until and unless (i) the Seller shall have first offered to enter into a contract with the Company on substantially the same business terms as those specified in any proposal or letter of intent between the Seller and any other party with respect thereto and (ii) the Company does not accept such offer within thirty (30) days of the date presented to the Company in writing and enter into a contract reflecting such business terms within sixty (60) days thereafter. Further, should the Seller operate the Unit beyond the term of this Agreement, the Seller shall enter into a contract for the sale of electricity from the Unit or any other electrical generation facilities located at the Site only under the conditions set forth in the foregoing sentence. The Seller agrees to keep the Company fully and promptly apprised, through the administrative committee described in Article 17.6, of any plans the Seller may develop for any addition to or expansion of the Unit or the development of any other generation facilities at the Site, which information the Company agrees not to disclose except with the Seller's prior written permission.

ARTICLE 17. Miscellaneous Provisions.

17.1 This Agreement shall constitute the entire Agreement between the parties hereto relating to the subject matter hereof and all previous agreements, discussions, communications, and correspondence with respect to the subject matter hereof shall be superseded by the execution of this Agreement.

17.2 This Agreement may not be modified or amended except in writing signed by or on behalf of both parties by their duly authorized officers.

17.3 In the event that any or all of the NEPOOL standards referred to herein shall cease to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that do not materially alter the obligations of the Seller as such obligations existed under the NEPOOL standards.

17.4 This Agreement shall inure to the benefit of and bind the respective successors and assigns of the parties hereto, provided however, that no assignment by either party (or any successor or assignee thereof) of its rights and obligations hereunder, except an assignment by the Company of such rights and obligations to a wholly-owned subsidiary or an affiliate wholly-owned by the same holding company, shall be made or become effective without the prior written consent of the other party in each case obtained, which consent shall not be unreasonably withheld. All assignments by the Seller or the Seller's successors and assigns shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against any entity that might obtain title to or possession of the Site or Unit.

17.5 Notwithstanding any assignments of rights or duties hereunder, neither party shall be relieved of any duties or responsibilities under this Agreement and this Agreement shall continue in accordance with its terms and each party shall be and remain liable to the other under all provisions of this Agreement unless the other party has expressly consented in writing to such release of duties and responsibilities, such consent not to be unreasonably withheld. Further, any payments made by one party to an assignee of the other party or any other actions taken by such party with respect to such assignee shall be in full satisfaction of any duties or responsibilities that the party would otherwise owe to the other party, as if made or taken directly to such other party.

17.6 The parties hereto agree to establish an administrative committee, which shall serve informational functions only. Unless otherwise agreed by the administrative committee, such committee shall meet at least once each calendar quarter prior to the Actual In-Service Date and at least twice each year thereafter. The Company and the Seller shall have equal representation upon such committee.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP
By its General Partner, EMI/Development, Inc.

By James L. Gordon
Its President

COMMONWEATLH ELECTRIC COMPANY

By Donald J. O'Blane
Its VICE PRESIDENT

APPENDIX A
TO POWER PURCHASE AGREEMENT

Description of the Site

The Site consists of thirty-seven and sixty-one hundredth (37.61) acres in an L-shaped configuration as shown on the Town of Dartmouth Assessors Map as Parcel 67.9.

The Site is primarily vacant woodlands and brush with the exception of a small wooden building in the northwest sector. A portion of the land has been cleared for timber.

The approximate elevation of the Site is one hundred sixty (160) feet above sea level. The Site is basically flat, sloping toward the southwest into wetlands. An Algonquin Gas Transmission Company pipeline bisects the Site in an east-west direction.

APPENDIX B
TO POWER PURCHASE AGREEMENT

1. Total Purchase Price: Each Billing Period, commencing with the Actual In-Service Date, the Company shall pay to the Seller the sum of the following:

1.1 The Monthly Capacity Charge, as defined in and computed in accordance with Section 2 of this Appendix B, and as adjusted in accordance with Section 3 of this Appendix B; and

1.2 The Monthly Energy Charge, as defined in and computed in accordance with Section 4 of this Appendix B.

2. Monthly Capacity Charge: The Monthly Capacity Charge shall consist of the sum of the Monthly Capacity Cost, the Monthly Investment Cost, and the Monthly Pipeline Transportation Capacity Demand Cost, all as defined and computed as follows.

2.1 Monthly Capacity Cost: The initial Monthly Capacity Cost shall equal one hundred ninety-two thousand, seven hundred six dollars ($192,706). The Monthly Capacity Cost shall be subject to the following adjustments.

2.1.1 Following the first month after the Actual In-Service Date, the Monthly Capacity Cost shall be adjusted quarterly to reflect changes in the GNP Implicit Price Deflator, such changes to be measured from the month of the Actual In-Service Date. The GNP Implicit Price Deflator is revised quarterly and is published by the Bureau of Economic Analysis of the United States Department of Commerce in the Survey of Current Business.

2.1.2 In the event that NEPEX or the Company requests in excess of one hundred (100) stops and one hundred (100) starts of the Unit in any calendar year, the Seller may include the additional operation and maintenance costs that it incurs as a direct result of such excess stops and starts, as such costs are determined by the firm of consulting engineers described in Article 14.4 of this Agreement.

2.2 Monthly Investment Cost: The Monthly Investment Cost shall equal six hundred ninety-seven thousand, one hundred eighty-six dollars ($697,186).

2.3 Monthly Pipeline Transportation Capacity Demand Cost: The Monthly Pipeline Transportation Capacity Demand Cost shall equal the product of 0.2962 (which is equal to the Contract Capacity divided by the Design Capacity) and the sum of the following firm transportation demand charges: .742942

2.3.1 The applicable and approved NOVA pipeline transportation capacity demand rate, expressed in dollars per million British

Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the appropriate regulatory authorities;

2.3.2 The applicable and approved TransCanada pipeline transportation capacity demand rate, expressed in dollars per million British Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the appropriate regulatory authorities; and

2.3.3 The applicable and approved pipeline transportation capacity demand rate contained in the United States Domestic Pipeline Tariff (as defined in Section 5 of this Appendix B), expressed in dollars per million British Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the applicable regulatory authorities.

3. Bonus or Penalty Cost Adjustment: A bonus or penalty cost adjustment shall be made to the Monthly Capacity Cost or to the Monthly Capacity Charge, based on the ability of the Seller to operate the Unit as measured on a moving, twelve month, cumulative equivalent availability factor basis. This adjustment shall be made pursuant to the following formula:

If EAF is less than .85,

$$\text{Adjustment} = \left(\left(\frac{EAF}{.91}\right) - 1\right) \times \text{Monthly Capacity Charge}$$

If EAF is equal to or greater than .85,

$$\text{Adjustment} = \left(\left(\frac{EAF}{.91}\right) - 1\right) \times \text{Monthly Capacity Cost}$$

Where EAF = Equivalent Availability Factor

$$EAF = \frac{EAH}{\text{Hours in Period}}$$

EAH = Equivalent Available Hours

$$EAH = \text{sum, over all hours in period, of } \frac{\text{megawatts available in hour*}}{\text{Seasonal Maximum Net Claimed Capability Rating in Hour**}}$$

* The megawatts available in an hour shall reflect Seasonal Maximum Claimed Capability, adjusted only for non-temperature related outages and/or limitations.

** Seasonal Maximum Net Claimed Capability shall be established pursuant to NEPOOL CRS 4, "Rating and Auditing of Generating Capability."

Example:

	Hour 1	Hour 2	Hour 3
available MW:	160	165	162
maximum net:	168	168	168

$$EAH = \frac{160}{168} + \frac{165}{168} + \frac{162}{168} = 2.899$$

$$EAF = \frac{2.899}{3} = .966$$

4. Monthly Energy Charge: The Monthly Energy Charge shall consist of the product of (a) the Delivered Energy for the prior Billing Period, expressed in kilowatthours; and (b) the sum of the Variable Fuel Supply Rate and the Variable Fuel Transportation Throughput Rate, expressed in dollars per kilowatthour ($/kWh), both as defined and computed as follows.

4.1 Variable Fuel Supply Rate: The Initial Variable Fuel Supply Rate, as of December 31, 1988, is set equal to the following:

4.11 One dollar and thirty-five cents per million British Thermal Units ($1.35/MMBTU); divided by

4.12 One (1) minus the appropriate quantity, expressed as a decimal, of "pipeline" and "unaccounted for" gas, as included in the applicable and approved commodity charges; multiplied by

4.13 The Adjusted Heat Rate. The Adjusted Heat Rate is equal to eight thousand, five hundred eighty three British Thermal Units per kilowatthour (8,583 BTU/kWh), expressed in millions of British Thermal Units per kilowatthour (i.e., 0.008583 MMBTU/kWh), and is equal to the Unit heat rate of eight thousand three hundred seventy-four British Thermal Units per kilowatthour (8,374 BTU/kWh) multiplied by the sum of one (1) plus a degradation of two and one-half (2.5) percent.

The Initial Variable Fuel Supply Rate shall be adjusted monthly to reflect the proportional change in the following index, which uses the year 1988 as its base:

	Weighting	12 mo. avg.
Tennessee CD-6	25%	$2.508/MMBTU
Algonquin F-1	25%	2.185
Alberta Market Price	50%	1.329
Weighted Cost		$1.838/MMBTU

4.2 Variable Fuel Transportation Throughput Rate: The Variable Fuel Transportation Throughput Rate shall equal the Adjusted Heat Rate, multiplied by the sum of the following firm commodity throughput rates:

4.2.1 The NOVA commodity throughput rate, expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities;

4.2.2 The TransCanada commodity throughput rate, expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities; and

4.2.3 The commodity throughput rate contained in the United States Domestic Pipeline Tariff (as defined in Section 5 of this Appendix B), expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities.

5. For purposes of this Appendix B, the United States Domestic Pipeline Tariff shall be the tariff or tariffs for each of the pipeline companies and local distribution companies transporting natural gas from the Canadian border to the Unit's meter station. In the event that firm transportation is unavailable to the unit's meter station upon the Actual In-Service Date, the United States Domestic Pipeline Tariff shall reflect the most recently filed charges with the Canadian and United States regulatory agencies to transport gas to the Unit's meter station.

6. Illustration of projected Total Purchase Price assuming a fifty megawatt (50 MW) allocation at ninety-one percent (91%) capacity:

Monthly Capacity Cost [initial amount]:	$192,706	[=0.5802 ¢/kWh*]
Monthly Investment Cost [fixed amount]:	697,186	[=2.0990 ¢/kWh*]
Monthly Pipeline Demand Cost [assuming total of transportation capacity demand charges = $1,328,380]:	393,466	[=1.1846 ¢/kWh*]
CAPACITY CHARGE [unadjusted; see §3]:	$1,283,358	[=3.8638 ¢/kWh*]

Variable Fuel Supply Rate [assuming index adjustment and accounting for "pipeline gas" amounts]:	$472,118**	1.4214 ¢/kWh
Variable Fuel Transportation Throughput Rate [assuming sum of pipeline throughput rates = $.4199/MMBTU]:	119,740**	0.3605 ¢/kWh
ENERGY CHARGE:	$591,858**	1.7819 ¢/kWh
TOTAL PURCHASE PRICE:	$1,875,216	[=5.6457 ¢/kWh]

* calculated by dividing the actual dollar amount by the following: (365 days/year)(1/12 year/month)(24 hours/day)(.91)(50,000 kW)

** calculated by multiplying the actual ¢/kWh rate by the following: (365 days/year)(1/12 year/month)(24 hours/day)(.91)(50,000 kW)

APPENDIX C
TO POWER PURCHASE AGREEMENT

Liability Insurance

From and after the Actual In-Service Date, the Seller shall take out, carry, and maintain, or cause to be taken out, carried, and maintained, comprehensive general liability insurance, including automobile and contractual liability, and liability arising out of aircraft or watercraft, if applicable, with a combined single limit per occurrence of a least five million dollars ($5,000,000) applicable to bodily injury, sickness or death, and loss of or damage to property, subject to an aggregate limit of not less than five million dollars ($5,000,000) for products and completed operations. Endorsements shall be included for X, C, and U hazards (blasting, collapse, and underground property damage), broad form property damage, and personal injury in addition to bodily injury.

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The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

March 30, 1990

D.P.U. 89-218

Investigation by the Department on its own motion of the propriety of a unit power agreement between Dartmouth Power Associates and Commonwealth Electric Company.

I. SUMMARY OF PROPOSED AGREEMENT

On September 27, 1989, Commonwealth Electric Company ("Commonwealth" or "Company"), pursuant to G.L. c. 164, § 94A, submitted to the Department of Public Utilities ("Department") a power purchase agreement with Dartmouth Power Associates ("Dartmouth Power"). The agreement calls for Commonwealth to purchase a 50-megawatt ("MW") entitlement to the electric power produced by a 186.8 MW gas-fired generating facility that Dartmouth Power plans to construct ("Unit").

Commonwealth states that, in some respects, its filing constitutes a case of first impression before the Department. Dartmouth Power is reputed to be the first independent power producer located in Massachusetts to be the subject of a filing under G.L. c. 164, § 94A. The Company suggests, because Dartmouth Power is neither a traditional regulated utility nor a qualifying facility, that the Department's jurisdictional authority vis-a-vis the Federal Energy Regulatory Commission ("FERC") is not clear. Commonwealth maintains that the Dartmouth Power contract will be filed with and fully subject to the rate jurisdiction of the FERC under section 205 of the Federal Power Act (16 U.S.C. § 824d). However, the Company also claims that the "FERC has indicated in one case involving another independent power producer that its own exercise of jurisdiction is inclined to be facilitated by the determination of state regulatory authorities with respect to the extent to which the rates contained in a wholesale contract fall below the

rates otherwise available to the purchasing utility" (Company Petition, p. 2). Therefore, while Commonwealth states that a filing under Section 94A is appropriate "in order to expedite its participation in this project," it also asserts a right to argue before the FERC any challenge that may be made to the contract (id.).

Dartmouth Power would own the Unit, which is to be constructed on a site in Dartmouth, Massachusetts (Purchase Power Agreement, p. 1). The Unit is to use two gas turbines and a supplementary-fired waste heat boiler with a dual inlet steam turbine (id.). The Unit is to be fueled with natural gas transported from Alberta, Canada. It is intended that the Unit be operated in conformance with the applicable New England Power Pool ("NEPOOL") Criteria, Rules, and Standards, and Operating Procedures, and dispatch instructions (id., p. 3). The proposed in-service date is July 1, 1992 (id.).

Commonwealth proposes to purchase a 50-MW entitlement to the capacity and associated energy produced by the Unit. Under the terms of the 25-year agreement, the total purchase price that Commonwealth would pay to Dartmouth Power each month would have two components, a monthly capacity charge and a monthly energy charge (Company Petition, p. 2). As outlined in Appendix B (Parts 2 and 3) to the Power Purchase Agreement, the monthly capacity charge consists of:

(1) A Monthly Capacity Cost, the initial amount of which shall be set at $192,706. The Monthly Capacity Cost shall be subject to the following adjustments:

(a) Changes in the GNP Implicit Price Deflator as published by the Bureau of Economic Analysis of the U.S. Department of Commerce; and,

(b) Additional operating and maintenance costs that Dartmouth power may incur in the event that NEPOOL requests in excess of 100 stops and 100 starts of the Unit in any calendar year.

(2) A Monthly Investment Cost, which shall equal $697,186.

(3) A Monthly Pipeline Transportation Capacity Demand Cost, which shall reflect the various pipeline capacity charges associated with transportation of natural gas from Alberta, Canada, and which shall be assessed in proportion to Commonwealth's entitlement to power from the Unit.

(4) A performance-based, Bonus or Penalty Adjustment, which shall be assessed depending on whether the Unit, on a moving twelve-month basis, exceeds or falls short of a designated availability level.

As outlined in Appendix B (Part 4) to the Power Purchase Agreement, the monthly energy charge consists of the product of the Delivered Energy (kilowatthours) for the billing period and the sum of the Variable Fuel Supply Rate and the Variable Fuel Transportation Throughput Rate, defined as follows:

(1) The Variable Fuel Supply Rate is set at $1.35 per million British Thermal Units and shall be adjusted for pipeline gas transmission losses and a predetermined price index.

(2) The Variable Fuel Transportation Throughput Rate shall reflect the firm commodity throughput rates associated with procuring natural gas from Alberta, Canada.

II. ANALYSIS AND FINDINGS

The Department has articulated the requirement that utilities analyze alternative resource options to ensure that

reliable and economic supplies are procured for their customers. Boston Gas Company, D.P.U. 89-180, p. 12 (1990); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A, p. 170 (1985); Boston Edison Company, D.P.U. 1720, pp. 200-206 (1984). Accordingly, the Department's review of the proposed purchased power agreement requires us to determine whether the agreement benefits ratepayers in that it is likely to represent a cost-effective means of providing reliable service vis-a-vis other resource options that may be available to the Company. Boston Edison Company, D.P.U. 86-262, p. 7 (1987).

For this agreement, two issues must be evaluated in order to assess whether the agreement meets the Department's standard. First, a determination must be made as to whether contract payments are likely to be less than costs that the Company would otherwise be required to incur to provide service, i.e., its calculated avoided costs. Second, the agreement must be reviewed to ensure that ratepayers are reasonably protected from undue financial risk, such as may be associated with project cancellation or inefficient operation of the Unit.

In support of its filing, the Company compared expected contract payments to its avoided costs, as filed with the Department with its second Request for Proposal ("RFP 2") approval request (docketed as D.P.U. 89-119). These comparisons are contained in Commonwealth's "Response to the Standard Information Requirements" (December 29, 1989) in Schedules 1, 2, and 3. Based on the information contained in these schedules,

the Department finds that significant financial benefits can be expected to accrue to ratepayers under the proposed agreement between Commonwealth and Dartmouth Power. In particular, the Department finds that, over the course of the 25-year agreement, Commonwealth's ratepayers should recognize savings of roughly $25 million (1989 dollars) over its avoided costs. Schedules 2 and 3 show that, under the agreement, ratepayers' financial exposure if fuel prices fall will be far lower than the benefits that would be anticipated if oil prices rise. Accordingly, the Department finds the agreement is cost-effective.

On the issue of whether the Dartmouth Power agreement provides ratepayers with reasonable protection from undue financial risks, a review of the pricing provisions presented supra reveals that the agreement provides for substantial reductions in the monthly capacity payments should the Unit fail to operate efficiently. The Department finds this to provide a strong incentive for Dartmouth Power to strive to maintain high unit availability. The performance-based nature of the contract is also similar to other agreements that the Department has found likely to protect the financial interests of ratepayers while promoting the efficient utilization of generation resources. Boston Edison Company, D.P.U. 88-28, 88-48, 89-100 (1989). Generic Rulemaking, D.P.U. 86-36-G, Proposed 220 C.M.R. 10.06(2)(e) (1989).

Moreover, other contract provisions augment the risk-mitigating performance incentives built into the pricing

provisions of the agreement. Article 4 of the agreement requires Dartmouth Power to post a $750,000 security deposit, payable to Commonwealth in whole or in part if the project is cancelled or delayed. Article 14.4 permits Commonwealth to withhold capacity payments if the Unit is not maintained in accordance with Good Utility Practice. Several provisions Articles 2 and 14 of the agreement grant Commonwealth authority to monitor and to oversee certain aspects of the operation and maintenance of the Unit.

Particularly noteworthy is Article 15.4 of the agreement, which requires Dartmouth Power to obtain an irrevocable Letter of Credit by which to secure payments expected to exceed Commonwealth's avoided costs during the early years of the contract. The agreement requires Dartmouth Power to secure credit amounts according to the following schedule:

From	Through	Amount
In-service date	December 31, 1992	$2,526,162
January 1, 1993	December 31, 1993	$3,692,380
January 1, 1994	December 31, 1994	$5,667,578
January 1, 1995	December 31, 1995	$7,511,116
January 1, 1996	December 31, 1996	$9,515,361
January 1, 1997	December 31, 1997	$10,546,831
January 1, 1998	December 31, 1998	$9,866,184
January 1, 1999	December 31, 1999	$6,918,707
January 1, 2000	December 31, 2000	$5,848,890
January 1, 2001	December 31, 2001	$3,615,810

The Department finds these, and other security provisions of the agreement with Dartmouth Power, to provide Commonwealth's ratepayers with reasonable protection from undue financial risk. The Department finds additionally that Commonwealth's

ratepayers may benefit from the provision that grants to the Company a right of first refusal on any additional electricity offered for sale as a consequence of expansion of the unit or after expiration of the contract.

Based on a review of the information presented in support of the agreement, the Department finds that the proposed Dartmouth Power purchase is cost-effective and will result in net savings for Commonwealth ratepayers compared to its avoided costs. Therefore, the Department finds that the power purchase agreement is in the public interest.

Accordingly, after due consideration, it is

ORDERED: That the contract filed with the Department on September 27, 1989, governing the purchase by Commonwealth Electric Company of a 50-MW entitlement and associated energy from the Dartmouth Power Associates Unit, be and hereby is APPROVED.

By Order of the Department,

/s/ BERNICE K. McINTYRE

Bernice K. McIntyre, Chairman

A true copy
Attest:

MARY L. COTTRELL
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, Order or ruling of the Commission, or within such further time as to the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, Order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said court. (G.L. Ter. Ed., c. 25, s. 5, as most recently amended by c. 485 of the Acts of 1971)

AMENDMENT TO POWER PURCHASE AGREEMENT

Amendment, dated as of this third (3d) day of August, 1990, by and between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Dartmouth Power Associates Limited Partnership, a Massachusetts limited partnership with its principal place of business at 8 Newbury Street, Suite 5, Boston, Massachusetts (the "Seller"), to Power Purchase Agreement, by and between the Company and the Seller, dated as of September 5, 1989 (the "Agreement").

SECTION ONE. Recitals.

1.1 The Company and the Seller entered into the Agreement, pursuant to which the Seller agreed to sell and deliver and the Company agreed to purchase and take delivery of a portion of the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned, and operated by the Seller, at a site in Dartmouth, Massachusetts (the "Site"). In accordance with applicable law, the Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "MDPU") for approval, which approval was received by order dated March 30, 1990; and was submitted by the Seller to the Federal Energy Regulatory Commission (the "FERC"), which agency is in the process of reviewing the Agreement as of the date hereof.

1.2 As set forth in the Agreement, the Unit was to utilize two gas turbines and was to be capable of generating approximately one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW) of electricity (the "Original Design Capacity").

1.3 Subsequent to the execution of the Agreement, the Seller determined, and duly notified the Company, that the Unit will utilize a single gas turbine and will be capable of generating approximately sixty-seven thousand, six hundred kilowatts (67,600 kW) of electricity.

1.4 Also as set forth in the Agreement, the Company was to purchase a portion of the electric capacity and related energy produced by the Unit equal to fifty megawatts (50 MW) divided by the Original Design Capacity (the "Original Entitlement").

1.5 Subsequent to the execution of the Agreement and the determination by the Seller to reduce the capability of the Unit as described above, the Seller offered to sell and deliver to the Company approximately seventeen thousand, six hundred kilowatts (17,600 kW) in addition to the Original Entitlement, such that the Company would purchase all of the electricity produced by the Unit. The Company has determined that the purchase of such additional electricity would benefit its ratepayers and would facilitate the administration of the Agreement, and accordingly the Company has accepted such offer of the Seller.

1.6 By virtue of the determination of the Seller to decrease the capability of the Unit and the acceptance by the Company of the Seller's offer to purchase

the entire output of the downsized Unit, several provisions in the Agreement must be modified. These provisions include definitional sections, the section governing the amount of the security deposit to be delivered by the Seller, the section governing the billing mechanism, the section governing the letter of credit to be delivered by the Seller, and the section setting forth the mechanism for calculating the price to be paid under the Agreement.

1.7 Although both the Seller and the Company have understood that the Unit was to be subject to economic dispatch by the New England Power Pool ("NEPOOL"), a provision governing such dispatchability was inadvertently omitted from the Agreement and the parties desire to insert such a provision into the Agreement. In addition, the parties desire to insert a provision into the Agreement protecting the Company and its ratepayers from any income tax liability that the Company might incur as a result of its accepting any contributed property from the Seller.

1.8 The Seller has indicated to the Company that it has made substantial progress with respect to securing necessary financing for the construction and operation of the Unit. Such progress notwithstanding, the Seller has requested that it be permitted to defer delivering to the Company the security deposit required pursuant to the Agreement until sixty (60) days following the approval of this Amendment by the MDPU, and that such security deposit be in the form of a letter of credit in lieu of cash. As an accommodation to the Seller, the Company has agreed to grant these requests of the Seller.

1.9 Accordingly, the Company and the Seller, each in consideration of the foregoing and of the agreements of the other, hereby agree as hereinafter provided.

SECTION TWO. The second introductory paragraph of the Agreement is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> The Seller plans to construct, own, and operate an electric generation facility, utilizing a single gas turbine and a supplementary-fired waste heat boiler with a dual inlet steam turbine, together with housings and other integral equipment, which will be capable of generating approximately sixty-seven thousand, six hundred kilowatts (67,600 kW) of electricity (the "Unit"). The Unit will be located at a site in the Town of Dartmouth, Massachusetts, which will be owned by the Seller, more particularly described in Appendix A attached hereto (the "Site"). The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of all of the electricity produced by the Unit, pursuant to the terms and conditions set forth in this Agreement.

SECTION THREE. Article 1 of the Agreement is hereby amended in accordance with the following:

3.1 The definition of Actual In-Service Date is amended by deleting "the Company's Entitlement of" from such definition.

3.2 The definition of Company's Entitlement is deleted in its entirety.

3.3 The definition of Contract Capacity is deleted in its entirety.

3.4 The definition of Delivered Energy is amended by deleting "the Company's portion of" from such definition.

3.5 The definition of Design Capacity is amended by deleting "one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW)" from such definition and substituting "sixty-seven thousand, six hundred kilowatts (67,600 kW)" in lieu thereof.

3.6 The following definition is to be inserted immediately before the definition of FERC:

> Economic Dispatch shall mean the operation of the Unit in accordance with such procedures as may be established by NEPOOL from time to time to foster the objective of satisfying the energy requirements of the participants of NEPOOL at the lowest practicable cost.

SECTION FOUR. Article 2.1 of the Agreement is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of all electric capacity and related energy produced by the Unit during the term of this Agreement; provided, however, that in no event shall the Company be obligated to purchase and take delivery of electric capacity and related energy in excess of the Design Capacity.

SECTION FIVE. Article 2.4 of the Agreement is hereby amended by deleting "up to the Company's Entitlement and related energy," from such article.

SECTION SIX. The following is to be inserted into the Agreement as Article 2.5:

> The Unit shall be subject to Economic Dispatch at the direction of the Company or its designee. The Unit shall also be subject to changes in the level of its output at the direction of the Company or its designee, provided that such changes are within the Unit's reasonable design limitations.
>
> 2.5.1 If the Seller fails to dispatch the Unit as called for by the Company, then the Company shall calculate the uneconomic

incremental production costs it incurs that are attributable to such failure of the Seller (the "Incremental Production Cost Penalty"). The Company shall also not pay for any electric capacity or energy produced at the Unit as a result of the Seller's failure to comply with the Company's calls pursuant to this Article 2.5. The Company shall deduct any Incremental Production Cost Penalty from any payments due the Seller for any electric capacity and energy purchased by the Company during the Billing Period ("Net Billing Amount"). In the event that the Net Billing Amount for a Billing Period is due to the Company, such Net Billing Amount shall be billed to the Seller and the Seller shall reimburse the Company therefor according to the same standards as are established for payments to the Seller.

2.5.2 The Incremental Production Cost Penalty shall be the difference between (i) the production costs that the Company experienced during the period of the Seller's failure to dispatch the Unit as called for by the Company, and (ii) the production costs that the Company would have experienced during such period had the Seller complied with the Company's call to dispatch the Unit.

SECTION SEVEN. Article 4 of the Agreement is hereby amended by deleting it in its entirety and inserting the following in lieu thereof:

4.1 Within sixty (60) days following the date that the MDPU approves the amendment to this Agreement dated as of August 3, 1990, the Seller shall deliver to the Company an irrevocable letter of credit in favor of the Company (the "Security Deposit Letter of Credit"), from an issuer and in form and substance acceptable to the Company, in the amount of one million, two hundred twenty-eight thousand, six hundred seven dollars ($1,228,607) as a security deposit (the "Security Deposit"). The Security Deposit is calculated as the sum of (i) one million, fourteen thousand dollars ($1,014,000, the "Principal"), which is the product of sixty-seven thousand, six hundred kilowatts (67,600 kW, which is the Design Capacity) and fifteen dollars ($15) per kilowatt; and (ii) two hundred fourteen thousand, six hundred seven dollars ($214,607, the "Interest Component"), which is approximately equal to the simple interest that would accrue on the Principal between the date of this Agreement (i.e., September 5, 1989) and the Proposed In-Service Date (i.e., July 1, 1992) at a rate of seven and one-half percent (7½%) per annum.

4.2 If, prior to the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, or if this Agreement is terminated in accordance with the provisions of Article 3.2, the Company may draw under the Security Deposit Letter of Credit an amount equal to a percentage of the Interest Component plus a percentage of the Principal, which percentage in both cases shall be equal

to the ratio of (i) the elapsed time between the date of this Agreement and the cancellation date, to (ii) the total time between the date of this Agreement and the Proposed In-Service Date; provided, however, that if the reason for such cancellation, abandonment, or termination is the failure of the FERC to approve or accept this Agreement, in a form acceptable to both parties, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.3 If, after the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, the Company may draw upon the entire Security Deposit Letter of Credit; provided, however, that if the reason for such cancellation, abandonment, or termination is the inability or refusal of the Company to interconnect, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.4 If the Actual In-Service Date occurs on or before the Proposed In-Service Date, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.5 If the Actual In-Service Date occurs within twenty-four (24) months after the Proposed In-Service Date, the Company may draw under the Security Deposit Letter of Credit an amount equal to a percentage of the Interest Component, which percentage shall be equal to the ratio of (i) the elapsed time between the Proposed In-Service Date and the Actual In-Service Date, to (ii) the total time between the date of this Agreement and the Proposed In-Service Date; provided, however, that if the reason for the occurrence of the Actual In-Service Date after the Proposed In-Service Date is the inability or refusal of the Company to interconnect, the Company shall deliver to the issuer of the Security Deposit Letter of Credit a notice of cancellation of such letter of credit.

4.6 If the Actual In-Service Date does not occur within twenty-four (24) months after the Proposed In-Service Date, the Company may draw upon the entire Security Deposit Letter of Credit and may terminate this Agreement according to the provisions of Article 3.2.

SECTION EIGHT. Article 5 of the Agreement is hereby amended by correcting the spelling of the word "calculating" found at the beginning of the fifth (5th) line of such article.

SECTION NINE. Article 8.1 of the Agreement is hereby amended by deleting the third sentence of such article in its entirety and inserting the following in lieu thereof:

> Any amount payable hereunder not paid within thirty (30) days (or, if such date is not a working day, then by the next working day thereafter) from the date of receipt by the Company of all actual metered values for the Billing Period shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston from the date of receipt of such monthly statement until the date of payment.

SECTION TEN. Article 15.2 of the Agreement is hereby amended by deleting "the Company's Entitlement thereto" from such definition and substituting "such electricity" in lieu thereof.

SECTION ELEVEN. Article 15.4 of the Agreement is hereby amended by deleting the schedule currently contained in such article and substituting the following in lieu thereof:

from	through	amount
Actual In-Service Date	December 31, 1993	$0
January 1, 1994	December 31, 1994	$179,206
January 1, 1995	remainder of term of Agreement	$0

SECTION TWELVE. The following is to be inserted into the Agreement as Article 17.7:

> The Seller shall reimburse the Company for any costs relating to income tax liabilities incurred by the Company as a result of its acceptance of any contributed property from the Seller.

SECTION THIRTEEN. Appendix B to the Agreement is hereby amended in accordance with the following:

13.1 Article 2.1 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> Monthly Capacity Cost: The initial Monthly Capacity Cost shall equal the product of the Design Capacity and three thousand, eight hundred fifty-four dollars and twelve cents per megawatt-month ($3,854.12/MW-mo.). The Monthly Capacity Cost shall be subject to the following adjustments.

13.2 Article 2.2 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> Monthly Investment Cost: The Monthly Investment Cost shall equal

the product of the Design Capacity and thirteen thousand, nine hundred forty-three dollars and seventy-two cents per megawatt-month ($13,943.72/MW-mo.).

13.3 Article 2.3 of Appendix B is hereby amended by deleting "the product of 0.2962 (which is equal to the Contract Capacity divided by the Design Capacity) and" from such article.

13.4 Article 3 of Appendix B is hereby amended by deleting the example currently contained in such article and substituting the following in lieu thereof:

Example:

	Hour 1	Hour 2	Hour 3
available MW:	64	66	65
maximum net:	67.6	67.6	67.6

$$EAH = \frac{64}{67.6} + \frac{66}{67.6} + \frac{65}{67.6} = 2.885$$

$$EAF = \frac{2.885}{3} = .962$$

13.5 Article 6 of Appendix B is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

Illustration of projected Total Purchase Price assuming delivery of sixty-seven thousand, six hundred kilowatts (67,600 kW) at a ninety-one percent (91%) availability:

Monthly Capacity Cost [initial amount: $3854.12/MW x 67.6 MW]:	$260,538.51	[= 0.5802¢/kWh*]
Monthly Investment Cost [fixed amount: $13,943.72/MW x 67.6 MW]:	942,595.47	[= 2.0990¢/kWh*]
Monthly Pipeline Demand Cost [assuming total of transportation capacity demand charges = $531,965]:	531,965.00	[= 1.1846¢/kWh*]
CAPACITY CHARGE [unadjusted; see §3]:	$1,735,098.98	[= 3.8638¢/kWh*]
Variable Fuel Supply Rate [assuming commodity rate of $1.425/MMBTU following index adjustment and accounting for "pipeline gas" amounts: .008583 MMBTU/kWh x $1.425/MMBTU]:	$549,243.50**	1.2231¢/kWh

Variable Fuel Transportation Throughput Rate [assuming sum of pipeline throughput rates = 42¢/MMBTU: .008583 MMBTU/kWh x $0.42/MMBTU]:	161,882.29**	0.3605¢/kWh
ENERGY CHARGE:	$711,125.79	1.5836¢/kWh
	==========	==========
TOTAL PURCHASE PRICE:	$2,446,224.77	[= 5.4474¢/kWh*]

* calculated by dividing the actual dollar amount by the following: (365 days/yr.)(1/12 yr./mo.)(24 hrs./day)(.91)(67,600 kW)

** calculated by multiplying the actual, unrounded ¢/kWh rate by the following: (365 days/yr.)(1/12 yr./mo.)(24 hrs./day)(.91)(67,600 kW)

SECTION FOURTEEN. The Company shall submit this Amendment to the MDPU, and the Seller shall submit this Amendment to the FERC, for the approval of each of the MDPU and the FERC. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

In witness whereof, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP,
By EMI/Dartmouth, Inc., its General Partner,

By James L. Gordon,
Its President.

COMMONWEALTH ELECTRIC COMPANY,

By [illegible]
Its VICE PRESIDENT.

R:\UTL\NEE\69DartAm.NEE

APPROVED
Oct. 23, 1990
COMMISSIONERS, D.P.U.

COM Electric

Commonwealth Electric Company
Post Office Box 9150
Cambridge, Massachusetts 02142-9150
Telephone (617) 225-4000

August 15, 1990

RECEIVED
AUG 15 1990
DEPT. OF PUBLIC UTILITIES
ADMINISTRATION

Department of Public Utilities
100 Cambridge Street
Boston, MA 02202

Attention: Henry Yoshimura
Electric Power Division

Re: Amendment to Power Purchase Agreement
Dartmouth Power Associates Limited Partnership

Dear Mr. Yoshimura:

Commonwealth Electric Company ("Commonwealth" or the "Company") submits herewith an Amendment, dated August 3, 1990, to a Power Purchase Agreement (the "Amendment") by and between itself and Dartmouth Power Associates Limited Partnership ("Dartmouth Power"). The Amendment modifies certain terms of a Power Purchase Agreement, dated September 5, 1989, between Commonwealth and Dartmouth Power (the "Agreement"). The Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "Department") on September 27, 1989 and was approved by the Department on March 30, 1990 in DPU 89-218.

Pursuant to the Agreement, Commonwealth had agreed to purchase a 50 MW entitlement to the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned and operated by Dartmouth Power at a site in the Town of Dartmouth. As set forth in the Agreement, the Unit was to be capable of generating approximately 168.8 MW of electricity. However, Dartmouth Power has determined that the Unit will be constructed so as to be capable of generating approximately 67.6 MW. Dartmouth Power offered to sell to Commonwealth an additional 17.6 MW of electricity, which would make the Company the sole purchaser of the electricity that will be produced by the downsized Unit. The Company has determined that this additional purchase of electricity would be beneficial to its ratepayers and would facilitate its administration of the Agreement. Accordingly, Commonwealth has accepted Dartmouth Power's offer.

In addition to modifying the Agreement to reflect the Company's purchase of additional power, the Amendment adds provisions to the Agreement regarding economic dispatch and income tax liabilities, amends the provisions in the

Agreement regarding the security deposit to be furnished by Dartmouth Power to the Company and reflects a reduction in the size of the expected energy bank. The Company notes that the Amendment does not change the pricing mechanism as set forth in the Agreement. The unit prices for capacity and energy will not change. The calculation of the Monthly Capacity Charge component in the price formula will change to reflect the increase in the amount of power that the Company will purchase.

In order to assist the Department in its review of this Amendment, the Company has included in this filing, the base case, low and high fuel cost scenarios of Tables 1 through 5 from the Department's Standard Information Requirements. In addition, the Company has included schedules providing information responsive to Standard Information Requirement #3. The remainder of the information responsive to the Department's Standard Information Requirements is identical in substance to that contained in Appendix C to the Company's Second Request for Proposal for Qualifying Facility Generation ("RFP #2") filed on June 29, 1990 and approved by the Department on July 12, 1990.

As is apparent from the materials included in this filing the Company's ratepayers have a strong prospect of realizing substantial benefits from the purchase by the Company of the additional 17.6 MW output of the Unit. Commonwealth has compared its projected payment stream to Dartmouth Power to the ceiling prices as developed from RFP#2. As can be seen from the attached schedules in the base case fuel scenario, the expected lifetime cumulative net present value benefit from the additional 17.6 MW increment is approximately $16.6 million. As can also be seen from the attached schedules, the cumulative net present value of projected payments to Dartmouth Power over the life of the Agreement is equal to 80% of the cumulative net present value of the Company's avoided costs.

The Company would be pleased to provide such additional information as the Department may request concerning this matter.

Very truly yours,

Marcy S. Rosenzweig /WAB

Marcy S. Rosenzweig
Manager - Rate Regulation

cc: Brian J. Abbanat, Electric Power Division
George B. Dean, Department of Attorney General

Attachment
AG-2-4(c)

Commonwealth Electric Company
2421 Cranberry Highway
Wareham, Massachusetts 02571
Telephone (508) 291-0950

Electric

May 8, 1996

Mary L. Cottrell
Secretary
Department of Public Utilities
100 Cambridge Street, Room 1210
Boston, Massachusetts 02202

Re: Third Amendment to the Power Purchase Agreement Between Commonwealth Electric Company and Dartmouth Power Associates Limited Partnership

Dear Secretary Cottrell:

Pursuant to M.G.L. c. 164, section 94A, Commonwealth Electric Company (Commonwealth) encloses herewith for filing and approval the Third Amendment, dated April 25, 1996, to the Power Purchase Agreement dated September 5, 1989 (the Agreement), as amended, by and between Commonwealth and Dartmouth Power Associates Limited Partnership (Dartmouth). Under the terms of the Agreement, Commonwealth purchases the output of Dartmouth's gas-fired generating plant located in Dartmouth, Massachusetts. Commonwealth notes that this Agreement was the subject of two prior amendments filed with and approved by the Department: the first Amendment, dated August 3, 1990, set forth the terms whereby Commonwealth agreed to purchase the entire output (as opposed to a portion of that output as originally contemplated) of the unit; the Second Amendment constituted a revision to certain indices used to determine the Variable Fuel Supply Rate Component of the Monthly Energy Charge paid by Commonwealth.[1]

The Third Amendment is the result of a series of settlement discussions which have taken place over the last several months and which covered a wide range of issues, including disputes between the contracting parties regarding the interpretation of various provisions of the Agreement, which were the subject of protracted litigation. In this regard, section 1 of the Third Amendment specifies the volumes of pipeline capacity for purposes of determining the portion of the Monthly Pipeline Transportation Demand Cost component of the demand charge set forth in section 2.3 of Appendix B of the Agreement (the original contract language simply referred to "the appropriate amount of gas", as the volumes of gas necessary to fire the unit were not known at the time of execution of the Agreement) . This Third Amendment also provides an opportunity for

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[1]The Agreement was submitted to the Department on September 27, 1989 and was approved on March 30, 1990 in D.P.U. 89-218. The first Amendment to the Agreement was approved by the Department on October 23, 1990, and the Second Amendment to the Agreement was approved by the Department on August 12, 1994.

Dartmouth and Commonwealth to engage in short-term arrangements under appropriate market conditions, where Commonwealth would purchase electricity from suppliers other than Dartmouth, in order to enable Dartmouth to enter into short-term transactions with third parties to sell electricity and/ or gas (related to the Dartmouth unit) to such parties. Commonwealth believes that these transactions, which would be entered into on a case-by-case basis, would yield economic benefits which have been agreed to be shared by the parties; Commonwealth proposes that its share of the net profits (i.e. after accounting for Commonwealth's replacement power costs) associated with these transactions would be passed through to its customers (as a credit to Commonwealth's fuel charge). Finally, the Amendment provides that Dartmouth will provide Commonwealth, on very favorable pricing terms, with energy and capacity (anticipated to be approximately 6 MW during the winter period) from the Dartmouth plant (i.e. in excess of the current winter maximum claimed capability of 68.18 MW covered by the Agreement), which recently became available as a result of certain improvements at the plant.

Commonwealth believes that the Third Amendment is in the best interest of Commonwealth and its customers and requests Department approval. For convenience of reference Commonwealth provides herewith the following additional materials:

Attachment A September 5, 1989 Power Purchase Agreement with March 30, 1990 Department approval

Attachment B August 3, 1990 Amendment to Power Purchase Agreement with October 23, 1990 Department approval

Attachment C June 23, 1994 Second Amendment to Power Purchased Agreement with August 12, 1994 Department approval

Please note that I have also enclosed herewith a check for the $15.00 fee associated with the filing of this Third Amendment. Commonwealth would be pleased to provide such additional information as the Department may request; in this regard please direct any inquiries or correspondence to:

Timothy N. Cronin, Esq.
COM/Energy Services Company
One Main Street. P.O. Box 9150
Cambridge, MA 02142-9150
Telephone (617) 225- 4649
Facsimile (617) 225-4284

Very truly yours,

James J. Keane /TNC

James J. Keane
Vice President - Power
Supply and Transmission

Enclosures

cc: Michael Ernst, Esq., Acting General Counsel
Brian Abbanat, Director, Electric Power Division
Kevin T. Brannelly, Director, Rates and Revenue Requirements Division
George B. Dean, Esq., Assistant Attorney General

THIRD AMENDMENT TO POWER PURCHASE AGREEMENT

AMENDMENT dated as of this 25th day of April, 1996, by and between Commonwealth Electric Company, a Massachusetts corporation with a principle place of business at One Main Street, Cambridge, Massachusetts (the "Company") and Dartmouth Power Associates Limited Partnership, a Massachusetts Limited Partnership with a place of business at One Energy Road, Dartmouth, Massachusetts ("Seller"), to the Power Purchase Agreement by and between the Company and Seller, dated as of September 5, 1989 and amended by an Amendment to Power Purchase Agreement by and between the Company and Seller, dated as of August 3, 1990, and by a Second Amendment to Power Purchase Agreement between the Company and Seller, dated as of June 23, 1994 (as amended, the "Agreement").

WHEREAS, the Company and the Seller have had disputes as to the interpretation and application of the terms of the Agreement which have now been resolved to mutual satisfaction and which the parties seek to confirm and memorialize by this agreement;

WHEREAS, the Company and Seller wish to establish procedures allowing, where mutually beneficial, for Commonwealth to purchase electricity from other market sources on a short-term basis in replacement of the purchases of electricity that would otherwise occur pursuant to the Agreement; and

WHEREAS, the Company and Seller wish to establish a commitment to purchase and sell certain capacity and related energy generated by the expansion to the Seller's generating plant (the "Unit") in excess of the entitlements to the Unit now subject to the Agreement.

NOW, THEREFORE, in consideration of the premises and mutual agreement set forth herein, receipt and adequacy of which is mutually acknowledge, the parties agree as follows:

SECTION 1. Confirmation as to Monthly Pipeline Transportation Demand Cost. The parties agree and confirm their intention and understanding that the applicable and approved pipeline transportation capacity demand rates under Section 2.3 of Appendix B of the Agreement for each Billing Period (as defined in the Agreement) shall hereinafter (i) be the demand rates specified in such Section 2.3 as then-effective for the Billing Period and (ii) be multiplied by the following contractual pipeline capacity volumes as the "appropriate amount of gas" thereunder:

NOVA	R450.9 10^3M^3
	D445.2 10^3M^3
TCPL	400.9 10^3M^3
Iroquois	14,150 Decatherm
Tennessee	14,010 Decatherm
Algonquin	14,010 Decatherm,

and that billing adjustments and credits shall be made from time to time to include and reflect any and all amounts of related pipeline refunds received by or credited to Seller or surcharges applied to Seller, all as pertaining to such demand rates. Seller will make available to Company for review any and all pipeline records or invoices necessary to determine the existence and applicability of any such charges, refunds, and surcharges, and Seller shall further provide to Company an annual reconciliation of such amounts from each of the specified pipelines.

SECTION 2. Short Term Power Purchases. Seller and Company agree that, from time to time, they may agree to consensual arrangements to allow and accommodate the short-term purchase by Company of electricity from other market sources in replacement of the purchase of electricity that would otherwise occur pursuant to the Agreement, and that the terms and conditions of such arrangements shall be negotiated on a case-by-case basis, but that the Agreement shall otherwise remain and continue in full force and effect.

SECTION 3. Additional Current Capacity of the Unit. Seller will run its winter and summer claimed capability tests in accordance with NEPOOL criteria using its best efforts to provide a maximum claimed capability of the existing Unit for the period subject to this Section 4 in excess of 68.18 MW at 20°F and 61.80 MW at 90°F, its current respective winter and summer normal claimed capability ratings. Such excess amount of the Unit's current winter or summer capacity (but not any capacity relating to future improvements or expansions to the Unit or any additional generation facilities located at the Site) up to 6 MW will be referred to as the "Extra Capacity." Pursuant to Seller's Rate Schedule FERC No. 3 and its marketing authority thereunder, Seller agrees to provide and sell, and Company agrees to take, the Extra Capacity during the eight-month winter season and four-month summer season, respectively, for a fifty-four (54) month period commencing upon receipt of all required regulatory approvals hereof and the first receipt by Commonwealth of additional NEPOOL capacity credit pursuant hereto. The electricity from such Extra Capacity could be called upon and provided only during System Emergency ("Op4") conditions and during any capability test of the type described in the first sentence of this section, as defined by the applicable NEPOOL and NEPEX guidelines. Seller would provide a new Max Claimed Capability Temperature/Output Matrix to Company for purposes of NEPOOL reporting and dispatch. During the dispatch of the Extra Capacity during any such System Emergency conditions, Company would pay Seller the fuel and variable transportation costs (but no incremental demand charges for the Extra Capacity) associated therewith equal to Seller's actual costs, as adjusted by the contractual heat rate, which fuel the parties anticipate would be natural gas or No.2 fuel oil (.05% sulphur or such distillate fuel oil as Seller is permitted to burn.) Such transactions will be reported to the FERC in the normal course pursuant to the reporting requirements established in connection with the acceptance by the FERC of Seller's Rate Schedule FERC No. 3. The benefits and obligations of this Section 3 are related to the special inter-relationship of Seller and Company and may not be assigned by Company to an unaffiliated party and shall terminate upon any assignment or transfer by Company to an unaffiliated third party of its interests or obligations under the Agreement.

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

March 30, 1990

D.P.U. 89-218

Investigation by the Department on its own motion of the propriety of a unit power agreement between Dartmouth Power Associates and Commonwealth Electric Company.

I. SUMMARY OF PROPOSED AGREEMENT

On September 27, 1989, Commonwealth Electric Company ("Commonwealth" or "Company"), pursuant to G.L. c. 164, § 94A, submitted to the Department of Public Utilities ("Department") a power purchase agreement with Dartmouth Power Associates ("Dartmouth Power"). The agreement calls for Commonwealth to purchase a 50-megawatt ("MW") entitlement to the electric power produced by a 186.8 MW gas-fired generating facility that Dartmouth Power plans to construct ("Unit").

Commonwealth states that, in some respects, its filing constitutes a case of first impression before the Department. Dartmouth Power is reputed to be the first independent power producer located in Massachusetts to be the subject of a filing under G.L. c. 164, § 94A. The Company suggests, because Dartmouth Power is neither a traditional regulated utility nor a qualifying facility, that the Department's jurisdictional authority vis-a-vis the Federal Energy Regulatory Commission ("FERC") is not clear. Commonwealth maintains that the Dartmouth Power contract will be filed with and fully subject to the rate jurisdiction of the FERC under section 205 of the Federal Power Act (16 U.S.C. § 824d). However, the Company also claims that the "FERC has indicated in one case involving another independent power producer that its own exercise of jurisdiction is inclined to be facilitated by the determination of state regulatory authorities with respect to the extent to which the rates contained in a wholesale contract fall below the

rates otherwise available to the purchasing utility" (Company Petition, p. 2). Therefore, while Commonwealth states that a filing under Section 94A is appropriate "in order to expedite its participation in this project," it also asserts a right to argue before the FERC any challenge that may be made to the contract (id.).

Dartmouth Power would own the Unit, which is to be constructed on a site in Dartmouth, Massachusetts (Purchase Power Agreement, p. 1). The Unit is to use two gas turbines and a supplementary-fired waste heat boiler with a dual inlet steam turbine (id.). The Unit is to be fueled with natural gas transported from Alberta, Canada. It is intended that the Unit be operated in conformance with the applicable New England Power Pool ("NEPOOL") Criteria, Rules, and Standards, and Operating Procedures, and dispatch instructions (id., p. 3). The proposed in-service date is July 1, 1992 (id.).

Commonwealth proposes to purchase a 50-MW entitlement to the capacity and associated energy produced by the Unit. Under the terms of the 25-year agreement, the total purchase price that Commonwealth would pay to Dartmouth Power each month would have two components, a monthly capacity charge and a monthly energy charge (Company Petition, p. 2). As outlined in Appendix B (Parts 2 and 3) to the Power Purchase Agreement, the monthly capacity charge consists of:

(1) A Monthly Capacity Cost, the initial amount of which shall be set at $192,706. The Monthly Capacity Cost shall be subject to the following adjustments:

(a) Changes in the GNP Implicit Price Deflator as published by the Bureau of Economic Analysis of the U.S. Department of Commerce; and,

(b) Additional operating and maintenance costs that Dartmouth power may incur in the event that NEPOOL requests in excess of 100 stops and 100 starts of the Unit in any calendar year.

(2) A Monthly Investment Cost, which shall equal $697,186.

(3) A Monthly Pipeline Transportation Capacity Demand Cost, which shall reflect the various pipeline capacity charges associated with transportation of natural gas from Alberta, Canada, and which shall be assessed in proportion to Commonwealth's entitlement to power from the Unit.

(4) A performance-based, Bonus or Penalty Adjustment, which shall be assessed depending on whether the Unit, on a moving twelve-month basis, exceeds or falls short of a designated availability level.

As outlined in Appendix B (Part 4) to the Power Purchase Agreement, the monthly energy charge consists of the product of the Delivered Energy (kilowatthours) for the billing period and the sum of the Variable Fuel Supply Rate and the Variable Fuel Transportation Throughput Rate, defined as follows:

(1) The Variable Fuel Supply Rate is set at $1.35 per million British Thermal Units and shall be adjusted for pipeline gas transmission losses and a predetermined price index.

(2) The Variable Fuel Transportation Throughput Rate shall reflect the firm commodity throughput rates associated with procuring natural gas from Alberta, Canada.

II. ANALYSIS AND FINDINGS

The Department has articulated the requirement that utilities analyze alternative resource options to ensure that

reliable and economic supplies are procured for their customers. Boston Gas Company, D.P.U. 89-180, p. 12 (1990); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A, p. 170 (1985); Boston Edison Company, D.P.U. 1720, pp. 200-206 (1984). Accordingly, the Department's review of the proposed purchased power agreement requires us to determine whether the agreement benefits ratepayers in that it is likely to represent a cost-effective means of providing reliable service vis-a-vis other resource options that may be available to the Company. Boston Edison Company, D.P.U. 86-262, p. 7 (1987).

For this agreement, two issues must be evaluated in order to assess whether the agreement meets the Department's standard. First, a determination must be made as to whether contract payments are likely to be less than costs that the Company would otherwise be required to incur to provide service, i.e., its calculated avoided costs. Second, the agreement must be reviewed to ensure that ratepayers are reasonably protected from undue financial risk, such as may be associated with project cancellation or inefficient operation of the Unit.

In support of its filing, the Company compared expected contract payments to its avoided costs, as filed with the Department with its second Request for Proposal ("RFP 2") approval request (docketed as D.P.U. 89-119). These comparisons are contained in Commonwealth's "Response to the Standard Information Requirements" (December 29, 1989) in Schedules 1, 2, and 3. Based on the information contained in these schedules,

the Department finds that significant financial benefits can be expected to accrue to ratepayers under the proposed agreement between Commonwealth and Dartmouth Power. In particular, the Department finds that, over the course of the 25-year agreement, Commonwealth's ratepayers should recognize savings of roughly $25 million (1989 dollars) over its avoided costs. Schedules 2 and 3 show that, under the agreement, ratepayers' financial exposure if fuel prices fall will be far lower than the benefits that would be anticipated if oil prices rise. Accordingly, the Department finds the agreement is cost-effective.

On the issue of whether the Dartmouth Power agreement provides ratepayers with reasonable protection from undue financial risks, a review of the pricing provisions presented supra reveals that the agreement provides for substantial reductions in the monthly capacity payments should the Unit fail to operate efficiently. The Department finds this to provide a strong incentive for Dartmouth Power to strive to maintain high unit availability. The performance-based nature of the contract is also similar to other agreements that the Department has found likely to protect the financial interests of ratepayers while promoting the efficient utilization of generation resources. Boston Edison Company, D.P.U. 88-28, 88-48, 89-100 (1989). Generic Rulemaking, D.P.U. 86-36-G, Proposed 220 C.M.R. 10.06(2)(e) (1989).

Moreover, other contract provisions augment the risk-mitigating performance incentives built into the pricing

provisions of the agreement. Article 4 of the agreement requires Dartmouth Power to post a $750,000 security deposit, payable to Commonwealth in whole or in part if the project is cancelled or delayed. Article 14.4 permits Commonwealth to withhold capacity payments if the Unit is not maintained in accordance with Good Utility Practice. Several provisions Articles 2 and 14 of the agreement grant Commonwealth authority to monitor and to oversee certain aspects of the operation and maintenance of the Unit.

Particularly noteworthy is Article 15.4 of the agreement, which requires Dartmouth Power to obtain an irrevocable Letter of Credit by which to secure payments expected to exceed Commonwealth's avoided costs during the early years of the contract. The agreement requires Dartmouth Power to secure credit amounts according to the following schedule:

From	Through	Amount
In-service date	December 31, 1992	$2,526,162
January 1, 1993	December 31, 1993	$3,692,380
January 1, 1994	December 31, 1994	$5,667,578
January 1, 1995	December 31, 1995	$7,511,116
January 1, 1996	December 31, 1996	$9,515,361
January 1, 1997	December 31, 1997	$10,546,831
January 1, 1998	December 31, 1998	$9,866,184
January 1, 1999	December 31, 1999	$6,918,707
January 1, 2000	December 31, 2000	$5,848,890
January 1, 2001	December 31, 2001	$3,615,810

The Department finds these, and other security provisions of the agreement with Dartmouth Power, to provide Commonwealth's ratepayers with reasonable protection from undue financial risk. The Department finds additionally that Commonwealth's

ratepayers may benefit from the provision that grants to the Company a right of first refusal on any additional electricity offered for sale as a consequence of expansion of the unit or after expiration of the contract.

Based on a review of the information presented in support of the agreement, the Department finds that the proposed Dartmouth Power purchase is cost-effective and will result in net savings for Commonwealth ratepayers compared to its avoided costs. Therefore, the Department finds that the power purchase agreement is in the public interest.

Accordingly, after due consideration, it is

ORDERED: That the contract filed with the Department on September 27, 1989, governing the purchase by Commonwealth Electric Company of a 50-MW entitlement and associated energy from the Dartmouth Power Associates Unit, be and hereby is APPROVED.

By Order of the Department,

/s/ BERNICE K. McINTYRE

Bernice K. McIntyre, Chairman

A true copy
Attest:

MARY L. COTTRELL
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, Order or ruling of the Commission, or within such further time as to the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, Order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said court. (G.L. Ter. Ed., c. 25, s. 5, as most recently amended by c. 485 of the Acts of 1971)

POWER PURCHASE AGREEMENT

Agreement entered into this fifth (5th) day of September, 1989, by and between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Dartmouth Power Associates Limited Partnership, a Massachusetts limited partnership with its principal place of business at 8 Newbury Street, Suite 5, Boston, Massachusetts (the "Seller").

The Seller plans to construct, own, and operate an electric generation facility, utilizing two gas turbines and a supplementary-fired waste heat boiler with a dual inlet steam turbine, together with housings and other integral equipment, which will be capable of generating approximately one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW) of electricity (the "Unit"). The Unit will be located at a site in the Town of Dartmouth, Massachusetts, which will be owned by the Seller, more particularly described in Appendix A attached hereto (the "Site"). The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of a portion of the electricity produced by the Unit, pursuant to the terms and conditions as set forth in this Agreement.

Therefore, the parties, each in consideration of the agreements of the other, hereby agree as follows.

ARTICLE 1. Definitions.

When used with initial capitalizations, whether in the singular or in the plural, the following terms shall have the following meanings.

Actual In-Service Date shall mean the date upon which the Seller shall have both (i) produced electricity while operating the Unit at or above an average of ninety percent (90%) of the Design Capacity for five (5) consecutive days, and (ii) delivered the Company's Entitlement of such electricity to the Company.

Adjusted Capability for each Seasonal Period shall be the greater of (i) the seasonal Capability as determined by the first Capability Audit performed during each Seasonal Period following the Actual In-Service Date, or (ii) the Design Capacity.

Billing Period shall mean any calendar month in which the Unit produces electricity pursuant to this Agreement and for which the Company is obligated to pay for such electricity produced for such month pursuant to this Agreement.

Capability shall mean the maximum dependable load carrying ability in kilowatts of the Unit during the applicable Seasonal Period (exclusive of capacity required for Unit use). Capability shall be determined by the NEPOOL Operations Committee in accordance with NEPOOL Criteria, Rules and Standards ("CRS") No. 4. In the event that CRS 4 ceases to be established, or if the Company ceases participation in NEPOOL, the Company may impose

reasonable substitute standards that would have the same effect as this CRS in determining Capability.

Capability Audit shall mean a test of the Unit's Capability conducted periodically pursuant to the provisions of Section 8.13 of the NEPOOL Agreement and CRS 4, or any properly issued replacements therefor created from time to time during the term of this Agreement.

Capacity Deficiency shall mean the amount, if any, by which the audited Capability of the Unit is less than the Adjusted Capability.

Company's Entitlement shall mean that percentage of Unit capacity equal to the ratio of the Contract Capacity to the Adjusted Capability.

Contract Capacity shall mean fifty thousand kilowatts (50,000 kW).

Delivered Energy shall mean, for each Billing Period, the Company's portion of the kilowatthours metered during the Billing Period pursuant to Article 7 hereof.

Delivery Point shall mean the point at which the Unit shall be interconnected with the Company's system, in accordance with an interconnection agreement to be agreed to by the Seller and the Company.

Design Capacity shall mean one hundred sixty-eight thousand, eight hundred kilowatts (168,800 kW), at fifty-nine (59) degrees Fahrenheit.

FERC shall mean the Federal Energy Regulatory Commission.

Force Majeure shall include those events set forth in Article 10.1 hereof.

Good Utility Practice shall mean the practice, methods, and acts (including but not limited to the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy, and expediency. With respect to the Unit, Good Utility Practice includes but is not limited to taking reasonable steps to ensure the following.

(1) That adequate materials, resources, and supplies, including fuel, are available to meet the Unit's needs;

(2) That sufficient operating personnel are available and are adequately experienced, trained, and licensed as necessary to operate the Unit properly and efficiently, and who are capable of responding to emergency conditions whether caused by events on or off the Site;

(3) That preventative, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(4) That appropriate monitoring and testing are performed to ensure that equipment is functioning as designed;

(5) That equipment is not operated recklessly, or in a manner that is unsafe to workers, the general public, or the environment, or without regard to defined limitations such as steam pressure, temperature and moisture content, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, frequency, rotational speed, polarity, synchronization, or control system limits;

(6) That equipment will function properly under both normal and emergency conditions; and

(7) That the Unit is operated in conformance with the applicable NEPOOL CRS and Operating Procedures, and NEPEX dispatch instructions.

MDPU shall mean the Massachusetts Department of Public Utilities.

NEPEX shall mean the central dispatching agency, as defined in Section 15.22 of the NEPOOL Agreement, operating through such satellite dispatching centers as the NEPOOL Management Committee may determine to be appropriate.

NEPOOL shall mean the New England Power Pool.

NEPOOL Agreement shall mean the New England Power Pool Agreement, dated September 1, 1971, as amended.

Proposed In-Service Date shall be July 1, 1992.

Seasonal Period shall mean either the summer period, June through September, or the winter period, October through May, as appropriate.

System Emergency shall mean an imminent condition on the Company's or a neighboring utility's system that is likely to result in significant disruption of service or is likely to endanger life or property.

Testing Period shall mean any period of time during which the Unit is being tested and may produce electric energy prior to the Actual In-Service Date.

Test Power shall mean any electric energy produced by the Unit during the Testing Period.

ARTICLE 2. Sale of Power.

2.1 The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of the Company's Entitlement and related energy produced by the Unit during the term of this Agreement.

2.2 The Unit shall be staffed, operated, and maintained in a manner consistent with the standards applicable to generating facilities owned

and operated by participants in NEPOOL, as such standards may be in effect from time to time during the term of this Agreement. The Seller also agrees to make the Unit available for NEPOOL dispatch in accordance with the provisions of Section 12.2 of the NEPOOL Agreement.

2.3 In addition to the foregoing, the Seller shall undergo periodic Capability Audits upon the request of NEPOOL or of the Company. In the event that the Unit demonstrates a Capacity Deficiency in excess of two thousand kilowatts (2,000 kW), the Company may assess the Seller an offset charge each month, which shall be equal to one twelfth (1/12) of the sum of the Capability Responsibility Adjustment Charge plus the Capability Responsibility Deficiency Charge, established from time to time by NEPOOL pursuant to the provisions of Section 9.4 of the NEPOOL Agreement, multiplied by such Capacity Deficiency.

2.4 During the Testing Period, the Unit may generate Test Power. The Company agrees to take and pay for any Test Power offered for sale, up to the Company's Entitlement and related energy, subject to the following conditions:

2.4.1 The tests conducted during the Testing Period shall be performed in accordance with Good Utility Practice,

2.4.2 The administrative committee established pursuant to this agreement shall be kept informed of operations during the Test Period, and

2.4.3 The Company shall pay for any Test Power monthly at a price determined pursuant to the Company's generally available Rate P-1 "Power Purchase Rate" (MDPU No. 182) or the generally available replacement therefor.

ARTICLE 3. Effective Date and Term.

3.1 This Agreement shall become effective when all necessary approvals have been received from the FERC and from the MDPU, in a form acceptable to both parties; provided, however, that the Company's obligation to purchase the Company's Entitlement and related energy (other than pursuant to Article 2.4) shall not commence until the Actual In-Service Date. Unless sooner terminated in accordance with any applicable provision hereof, this Agreement shall remain in full force and effect until the twenty-fifth (25th) anniversary of the Actual In-Service Date.

3.2 If all necessary permits or licenses to build and operate the facility have not been obtained, or construction of the Unit has not commenced, within twenty-four (24) months following the date first above-written, or if, in the reasonable judgment of either party exercised not sooner than twenty-four (24) months following the date first above written, the Actual In-Service Date is likely to occur later than twenty-four (24) months after the Proposed In-Service Date, either party may terminate this Agreement upon sixty (60) days written notice to the other.

ARTICLE 4. Security Deposit.

4.1 Within thirty (30) days following the date that this Agreement is approved by the MDPU, the Seller shall deliver to the Company seven hundred fifty thousand dollars ($750,000) as a security deposit (the "Security Deposit"). The Security Deposit is calculated as the product of (i) fifty thousand kilowatts (50,000 kW), which is the Contract Capacity, and (ii) fifteen dollars ($15) per kilowatt. The Company shall hold the Security Deposit in an interest-bearing escrow account.

4.2 If, prior to the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, or if this Agreement is terminated in accordance with the provisions of Article 3.2, the entire Security Deposit shall be returned to the Seller after payment to the Company of accumulated interest and a percentage of the principal equal to the ratio of the elapsed time between Agreement execution and the cancellation date to the total time between Agreement execution and Proposed In-Service Date; provided, however, that if the reason for such cancellation, abandonment, or termination is the failure of the FERC to approve or accept this Agreement, in a form acceptable to both parties, then the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.3 If, after the Proposed In-Service Date, the project is cancelled or abandoned or this Agreement is terminated, the entire Security Deposit plus any accumulated interest shall be paid to the Company; provided, however, that if the reason for such cancellation, abandonment, or termination is the inability or refusal of the Company to interconnect, the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.4 If the Actual In-Service Date occurs on or before the Proposed In-Service Date, the entire Security Deposit plus any accumulated interest shall be returned to the Seller.

4.5 If the Actual In-Service Date occurs within twenty-four (24) months after the Proposed In-Service Date, the entire Security Deposit and any accumulated interest through the Proposed In-Service Date shall be paid to the Seller and any interest accumulated after the Proposed In-Service Date shall be paid to the Company; provided, however, that if the reason for the occurrence of the Actual In-Service Date after the Proposed In-Service Date is the inability or refusal of the Company to interconnect, any interest accumulated after the Proposed In-Service Date shall also be paid to the Seller.

4.6 If the Actual In-Service Date does not occur within twenty-four (24) months after the Proposed In-Service Date, the entire Security Deposit plus any accumulated interest shall be paid to the Company and the Agreement shall be terminated according to the provisions of Article 3.2.

ARTICLE 5. Purchase Price.

From and after the Actual In-Service Date, the Company shall pay to the

Seller each Billing Period, in accordance with the provisions of Article 8 of this Agreement, the sum of the Monthly Capacity Charge and the Monthly Energy Charge, as determined pursuant to Appendix B attached hereto. In calculting the Monthly Energy Charge, rates shall be rounded to the nearest one-hundredth of one cent ($.0001) per kilowatthour and shall be multiplied by the Delivered Energy for the prior Billing Period. If the Actual In-Service Date does not fall on the first day of the Billing Period in which such Date occurs, then the Monthly Capacity Charge for such first Billing Period shall be prorated appropriately. Sales or other ad valorem taxes upon the sale of electricity pursuant to this Agreement shall be borne by the Company.

ARTICLE 6. Delivery by the Seller.

6.1 The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electric energy at or near normal seasonal Capability on a continuous twenty-four (24) hour basis for the full term of this Agreement.

6.2 Electric energy generated by the Unit shall be delivered to the Company at the Delivery Point and shall be in the form of three (3) phase, sixty (60) hertz, alternating current at approximately one hundred fifteen thousand (115,000) volts nominal (the "Nominal Voltage"). However, in no event shall said Nominal Voltage be less than one hundred fifteen thousand volts (115 kV), nor shall electricity be delivered at greater than five (5) percent above the Nominal Voltage, nor shall the frequency vary by more than one hundredth (.01) hertz from sixty (60.00) hertz except for unavoidable momentary fluctuations.

6.3 The Seller may from time to time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance or repair upon the Unit. The Seller shall comply with the provisions of NEPOOL Operating Procedure No. 5 as in effect from time to time when planning any scheduled maintenance or repair upon the Unit. The Seller shall give the Company such notice as may be practicable in the circumstances when withdrawing the Unit from service for unscheduled maintenance or repair.

ARTICLE 7. Meters and Metering.

7.1 The Company shall review and approve the metering installations required to record the quantities of electricity purchased from the Seller. Such metering equipment shall be capable, inter alia, of providing data required to determine kilowatthours per hour purchased during each hour of the month as well as total kilowatthours purchased each month under the terms of this Agreement. The Seller shall install, own, operate, and maintain such metering equipment, which equipment shall be located at the Seller's high voltage bus or buses. If, for any reason, it is impractical to install meters at such bus or buses, appropriate adjustments shall be made to reflect the actual amount of electric energy that would have been recorded by meters located at such bus or buses.

7.2 The Seller shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards. The metering equipment shall be sealed, and the Seller will comply with any reasonable request of the Company with regard to the presence of the Company's representative when such seals are to be broken or when the meters are to be inspected, tested, or adjusted. The Company may request at any time a test of the accuracy of any metering equipment installed pursuant hereto and shall bear the costs thereof in the event that said requests are made more frequently than once in each twelve (12) months. The results of all meter calibrations or tests, regardless of whether performed at the Company's request, shall be open to examination by the Company at all reasonable times.

7.3 Any meter tested and found to register less than or equal to one half of one percent (0.5%) above or below the recognized comparative standard shall be considered correct and accurate. If the metering fails to operate or, as a result of such tests, the metering equipment is found to be defective or inaccurate, the Seller shall restore it to a condition of accuracy or replace it. In such event, appropriate adjustments shall be agreed to by the Seller and the Company and reflected in the next monthly statement of the Seller rendered pursuant to Article 8.1. Such adjustments shall correct all measurements made by the defective or inaccurate meter for either (i) the actual period during which inaccurate measurements were made, if determinable to the mutual satisfaction of the Company and the Seller, or (ii) if such period is not determinable, for a period equal to one-half of the time elapsed since the last prior test, but in no event greater than twelve (12) months.

7.4 Other provisions of this Article notwithstanding, the Company may elect to install its own metering equipment in supplement to the Seller's metering equipment. Should any metering equipment installed by the Seller fail to register the amount of electric energy delivered to the Company during any period, the Company's metering equipment shall, if so installed, be used to determine the amount of energy so delivered. If the Company wishes its metering equipment to be so used, the Company agrees to operate, maintain, and read such equipment according to the standards established by this Article with respect to the Seller's metering equipment. The Seller agrees, upon the request of the Company, to provide a suitable location at the Site for installation of the Company's meters at no cost to the Company.

7.5 Upon the written request of the Company, the Seller shall install, own, operate, and maintain, pursuant to the provisions of this Article, such telemetering equipment and data circuits as the Company may reasonably require for the transmission of various metered values to its operations center. The design equipment and data circuits shall be approved by the Company prior to their installation by the Seller.

ARTICLE 8. <u>Billing and Payment.</u>

8.1 The Seller shall render monthly statements for the Billing Period then most recently ended within ten (10) working days following the receipt

by the Company of all actual metered values for such Billing Period. The monthly statement shall detail the amount of Delivered Energy during such Billing Period. Any amount payable hereunder not paid within thirty (30) days from the date of receipt by the Company of all actual metered values for the Billing Period shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston from the date of receipt of such monthly statement until the date of payment.

8.2 In the event that any data required for billing purposes hereunder are unavailable when required for such billing, the unavailable data may be estimated by the Company, subject to any required adjustment, based upon actual data, in a subsequent Billing Period within the following twelve (12) months.

8.3 Neither the Company nor the Seller shall have the right to challenge any monthly statement rendered or received hereunder, to invoke arbitration of the same, or to bring any court or administrative action of any kind questioning the propriety of said monthly statement, after a period of one (1) year from the date such monthly statement was rendered. In the event that any such monthly statement depends in whole or part upon estimated data, this one (1) year limitation period shall be deemed to begin in the Billing Period in which such estimated data are adjusted to actual.

ARTICLE 9. Governmental Regulation.

9.1 This Agreement shall be submitted by the Company to the MDPU in accordance with the regulations of the MDPU, and by the Seller to the FERC in accordance with the regulations of the FERC as set forth at 18 C.F.R. Part 35.

9.2 Each party hereto shall be responsible for taking all necessary actions to satisfy any regulatory requirements that may be imposed by any federal, state, or municipal statute, rule, regulation, or ordinance that may be in effect from time to time relative to the performance of such party hereunder.

9.3 This Agreement and all rights and obligations of the parties hereunder are subject to applicable state and federal laws and duly promulgated orders and duly authorized actions of governmental authorities.

ARTICLE 10. Liability and Force Majeure.

10.1 The parties hereto shall be excused from performing hereunder, and shall not be liable in damages or otherwise, if and to the extent that they are unable to do so or are prevented from doing so by an event of Force Majeure, including, without limitation, by statute or regulation, or by action or inaction of any court or public authority having or purporting to have jurisdiction in the premises; or by reason of storm,

flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or regulatory agency, or any other cause, whether or not similar thereto, beyond the reasonable control of the affected party. Each party shall have the obligation to operate in accordance with Good Utility Practice at all times and to use diligent effort to overcome and remove any cause of failure to perform; provided, however, that neither party shall be required to settle any labor dispute on terms that, in the sole judgment of the party involved in such dispute, are contrary to its interests, so long as such party is acting in good faith and otherwise in compliance with applicable labor laws and regulations.

10.2 Neither the Company nor the Seller shall, in any event, be liable to the other or to any third party for any consequential, indirect, or special damages to persons or property, whether arising in tort, contract, or otherwise, by reason of this Agreement or any services performed or undertaken to be performed by the Company or the Seller hereunder.

10.3 Whenever the Company's system or the systems with which it is directly or indirectly interconnected experiences a System Emergency, or whenever it is necessary or desirable to aid in the restoration of service on its system or on the systems with which it is directly or indirectly interconnected, the Company may, in its reasonable judgment, curtail or interrupt the taking of electric energy hereunder, provided such curtailment or interruption shall continue only for so long as is reasonably necessary. Such curtailment, interruption, or reduction shall not be deemed to be a default by the Company nor shall the Company be liable therefor to the Seller or to any other party.

10.4 The Company and the Seller agree that each shall be responsible for the electricity on its respective side of the Delivery Point and shall indemnify, save harmless, and defend the other against all claims, demands, costs, or expenses for loss, damage, or injury to persons or property in any manner directly or indirectly arising from, connected with, or growing out of the presence, use, or transmission of electricity over the wires, cables, devices, or appurtenances owned by it. The Company and the Seller each assumes full responsibility in connection with the service rendered hereunder for its respective wires, cables, and other devices used in connection with such service. Each party hereto shall be solely liable for all claims of its own employees arising from any worker's compensation laws.

10.5 Neither by inspection, by non-rejection, nor in any other way does either party give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any equipment, apparatus, or devices installed on the other party's premises.

ARTICLE 11. Governing Law.

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the Commonwealth of Massachusetts.

ARTICLE 12. Arbitration.

12.1 In the case of any dispute between the parties with respect to the interpretation of this Agreement or the performance of the same, either party may give notice in writing to the other of its desire to submit such questions to arbitration and may designate an arbitrator. Within thirty (30) days after the receipt of such notice the other party may, in writing, serve upon the party invoking such arbitration a notice designating an arbitrator on its behalf. The two arbitrators so chosen shall, within twenty (20) days after the appointment of the second arbitrator, in writing, designate a third arbitrator. Upon the failure of the party notified to appoint the second arbitrator within such time, the party invoking such arbitration may proceed with the single arbitrator. If the first and second arbitrators are unable to agree on a third arbitrator within twenty (20) days of the appointment of the second arbitrator, the first and second arbitrator shall invoke the services of the American Arbitration Association to appoint a third arbitrator. This third arbitrator shall, to the extent practicable, have special competence and experience with respect to the subject matter under consideration. An arbitrator so appointed shall have full authority to act pursuant to this Article. No arbitrator, whether chosen by a party hereto or appointed, shall have the power to amend or add to this Agreement.

12.2 The party calling the arbitration shall, within twenty (20) days after either the failure of the other party to name an arbitrator, or the appointment of the third arbitrator, as the case may be, fix, in writing, a time and a place of hearing, to be not less than twenty (20) days from the delivery of notice to the other party. The arbitrator or arbitrators (the "Arbitrators") shall, thereupon, proceed promptly to hear and determine the controversy pursuant to the then current rules of the American Arbitration Association for the conduct of commercial arbitration proceedings, except that if such rules conflict with the then current provisions of the laws of the Commonwealth of Massachusetts relating to arbitration, such conflict shall be governed by the then current provisions of such laws. The Arbitrators shall fix a time within which the matter shall be submitted to them by either or both of the parties, and shall render a decision within ten (10) days after receiving the final submission from the parties unless, for good reasons to be certified by them in writing, the Arbitrators extend such time. The decision of the single arbitrator, or two of the three arbitrators, shall be taken as the arbitration decision. Such decision shall be made in writing and in duplicate, and one copy shall be delivered to each of the parties. The Arbitrators, by their award, shall determine the manner in which the expenses of the arbitration shall be borne, except that each party shall pay the costs of its own counsel. Each party shall accept and abide by the arbitration decision. The award of the Arbitrators shall be final except as otherwise provided by applicable law. Judgment upon such award may be entered by the prevailing party in any court having jurisdiction thereof, or application may be made by such party to any such court for judicial acceptance of such award and an order of enforcement.

ARTICLE 13. Insurance.

13.1 From and after the Actual In-Service Date, the Seller shall (i) keep the Unit insured by means of a policy or policies of insurance protecting against loss or damage to the Unit by fire, lightning, and other casualties normally insured against with a uniform standard extended coverage endorsement, and (ii) maintain liability insurance as described in Appendix C attached hereto. Such insurance is to be at all times in amounts not less than that reasonably required by the Company. The Company shall be the named insured in these policies, which policies shall contain a waiver of subrogation in favor of the named insured. All policies, or copies thereof, together with a certificate from the insurers evidencing that the policies are currently in force, shall be delivered to the Company.

13.2 Such insurance shall be provided by policies that shall be written by such companies and in such form as shall be generally commercially available and acceptable to the Company, such acceptance not to be unreasonably withheld; shall be primary and without right to contribution from other insurance that may be available; shall provide that, with respect to the Company, the insurance shall not be invalidated by any action or inaction by the Seller including, without limitation, any representation made by or on behalf of the Seller in the procurement of such insurance; and shall provide that such insurance shall not be cancelled or amended without at least thirty (30) days' prior written notice to the Company.

13.3 Not less than thirty (30) days prior to the expiration date of each policy furnished by the Seller pursuant to this Article, the Seller will deliver to the Company a renewal policy or policies accompanied by evidence of payment of the premium therefor.

13.4 In the event of a loss occurring after completion of the construction of the Unit, the amount of any proceeds of insurance described in this Article remaining after deducting all expenses (including attorney fees) incurred in the collection of such proceeds from the gross proceeds thereof (the "Net Proceeds") shall be applied to the prompt repair, restoration, modification, or improvement of that portion of the Unit damaged or destroyed by such casualty, unless the Seller and the Company have agreed that such repair, restoration, modification, or improvement is not practicable under the circumstances.

ARTICLE 14. Preservation of the Unit.

14.1 The Seller in its sole discretion may sell or otherwise dispose of any machinery, equipment, or other personal property constituting part of the Unit that the Seller determines has become inadequate, obsolete, worn out, unsuitable, undesirable, or unnecessary, provided that (i) substitute property having equal or greater utility, but not necessarily the same function, in the operation of the Unit is installed at the Unit and such removal and substitution would not materially impair the efficiency of operation of the Unit, adversely affect the structural integrity or electrical output of the Unit, or change the nature of the

Unit to the extent that it would not constitute the type of electricity generation facility operated prior to such replacement; and (ii) the prior written consent of the Company is obtained, which consent shall not be unreasonably withheld; provided, however, that such consent shall not be required for removals and substitutions made during ordinary and routine repair and maintenance. The Seller shall promptly report to the Company each such removal, substitution, sale, or other disposition. In addition, not less often than semi-annually, the Seller shall make available to the Company's representatives on the administrative committee described in Article 17.6 all records with respect to prior dispositions and substitutions, together with information as to planned dispositions and substitutions during the next six months.

14.2 The Seller shall pay or cause to be paid all taxes, payments in lieu of taxes, assessments, and other charges now or hereafter levied against the Unit or any part thereof, together with any penalties or interest on any of the foregoing, and upon request of the Company, the Seller shall exhibit to the Company receipts for the payment of such charges prior to the date when they would become delinquent; the foregoing to be subject, however, to the right of the Seller and other parties in interest to contest in good faith the levying of such charges.

14.3 At the time of providing security to the Company pursuant to Article 15 hereof, the Seller shall warrant that good record and marketable title to the Site and to the Unit is held by the Seller (subject only to any mortgages, liens, leases, or other encumbrances existing as of record and copies of which have been provided to the Company). The Seller shall not enter into any transaction involving the transfer, sale, or lease of the Site or the Unit, or any interest therein, without the prior written consent of the Company in each case obtained, which consent shall not be unreasonably withheld. Such transfer, sale, or lease shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against an entity that might thereby obtain title to or possession of the Site or Unit.

14.4 The Seller will maintain the Unit, or cause the Unit to be maintained, in accordance with Good Utility Practice, will not commit or suffer any waste thereof or the conduct of any nuisance or unlawful occupation or business on, or use of, the Unit, and will comply, or cause compliance, with all statutes, ordinances, and requirements of any governmental authority relating to the Unit; and the Seller at its expense shall provide the Company with a report on an annual basis prepared by a nationally recognized firm of consulting engineers, chosen by the Seller and approved by the Company, such approval not to be unreasonably withheld, attesting to the fact that the Unit is being maintained in accordance with Good Utility Practice. If substantial items affecting long-term efficient operation of the Unit that are described in any such annual report as being in need of correction are not corrected within six months following such annual report, the Company may withhold payment of the Monthly Capacity Charge component of the Total Purchase Price, with such amounts to be held in escrow by the Company until the cited item has been corrected, upon which correction the escrowed funds shall be released to the Seller. Notwithstanding the foregoing, if any such

correction is not made within twelve (12) months from the date of such annual report, the Company may elect to cause such correction to be made and the escrowed funds shall be applied to cover the costs of such correction.

14.5 The Company and any persons authorized by the Company shall have the right to enter and inspect the Unit at all reasonable times upon reasonable prior written notice to the Seller, and to examine Unit operating manuals and maintenance records.

ARTICLE 15. Security of Continued Performance.

In order to secure such complete performance of the Seller's obligations as is necessary for the Company to provide service to its ratepayers, the Seller, prior to the Actual In-Service Date, shall provide to the Company security in the form and scope set forth below:

15.1 Mortgage and Security Agreement. The Seller shall execute and deliver to the Company a mortgage and security agreement creating liens and security interests in the Unit, the Site, all improvements upon the Site, and all rents, profits, income, and other benefits derived from the foregoing, subordinate only to the lien of the institutional or unaffiliated lenders securing amounts lent for the construction or permanent financing or refinancing of the Unit. Such liens and security interests of the Company shall secure (i) all amounts paid by the Company to the Seller pursuant to this Agreement in excess of the Company's actual avoided costs and (ii) performance of Seller's obligations under this Agreement for the full anticipated term thereof, including all damages resulting from the Seller's failure to perform such obligations. Such mortgage and security agreement will be in form and substance acceptable to the Company.

15.2 Declaration of Easements, Covenants, and Restrictions. The Seller shall cause to be granted to the Company an unsubordinated declaration of easements, covenants, and restrictions encumbering the Site for a period equal to the anticipated full term of this Agreement (the "Declaration"). The Declaration shall grant to the Company easements for access to the Site and for the placement and operation of facilities thereon (which shall not interfere with the rights of the Seller to design, construct, and operate the Unit), as well as create restrictions and covenants to the effect that if any electricity is produced at the Site during the term of the Declaration, the Company's Entitlement thereto shall not be tendered or sold except to the Company in accordance with this Agreement. The Declaration shall reserve to the Seller the right to grant other easements, so long as such other easements do not interfere with the rights of the Company. The Declaration shall be in form and substance acceptable to the Company and shall run with the Site and be binding upon the successors of the Seller and inure to the benefit of the Company and its successors.

15.3 Accommodation Agreement. The Seller shall cause any lender of funds to the Seller for the acquisition of the Site or Unit (the "Lender") to execute and deliver an Accommodation Agreement, under which such

Lender shall agree: (i) to make its own interests subject to the Declaration described above; (ii) to honor this Agreement to the extent the Lender is in possession of the Site or Unit; (iii) to transfer interests in the Site or Unit only upon the condition that the transferee become obligated to honor this Agreement from the date of such transfer; and (iv) to avoid interference with the Company's rights hereunder, provided that the Company continues to make payments hereunder to the Seller's successor-in-interest and that the Company otherwise performs in accordance with this Agreement.

15.4 Letter of Credit. The Seller shall provide, in form and substance acceptable to the Company, an irrevocable letter of credit in favor of the Company. The Seller shall maintain such letter of credit throughout the period during which payments by the Company to the Seller are expected to exceed the Company's anticipated avoided cost for power, and such letter of credit shall be in an amount equal to the expected amount by which such payments will exceed of the Company's anticipated avoided cost for power, according to the following schedule:

from	through	amount
Actual In-Service Date	December 31, 1992	$2,526,162
January 1, 1993	December 31, 1993	3,962,380
January 1, 1994	December 31, 1994	5,667,578
January 1, 1995	December 31, 1995	7,511,116
January 1, 1996	December 31, 1996	9,515,361
January 1, 1997	December 31, 1997	10,546,831
January 1, 1998	December 31, 1998	9,866,184
January 1, 1999	December 31, 1999	6,918,707
January 1, 2000	December 31, 2000	5,848,890
January 1, 2001	December 31, 2001	3,615,810

ARTICLE 16. Rights of Company with respect to Expansion of Plant and Extension of Unit Life.

The Seller shall not enter into any contract for the sale of electricity from any addition to or expansion of the Unit, or from any other electric generation facilities located at the Site, until and unless (i) the Seller shall have first offered to enter into a contract with the Company on substantially the same business terms as those specified in any proposal or letter of intent between the Seller and any other party with respect thereto and (ii) the Company does not accept such offer within thirty (30) days of the date presented to the Company in writing and enter into a contract reflecting such business terms within sixty (60) days thereafter. Further, should the Seller operate the Unit beyond the term of this Agreement, the Seller shall enter into a contract for the sale of electricity from the Unit or any other electrical generation facilities located at the Site only under the conditions set forth in the foregoing sentence. The Seller agrees to keep the Company fully and promptly apprised, through the administrative committee described in Article 17.6, of any plans the Seller may develop for any addition to or expansion of the Unit or the development of any other generation facilities at the Site, which information the Company agrees not to disclose except with the Seller's prior written permission.

ARTICLE 17. Miscellaneous Provisions.

17.1 This Agreement shall constitute the entire Agreement between the parties hereto relating to the subject matter hereof and all previous agreements, discussions, communications, and correspondence with respect to the subject matter hereof shall be superseded by the execution of this Agreement.

17.2 This Agreement may not be modified or amended except in writing signed by or on behalf of both parties by their duly authorized officers.

17.3 In the event that any or all of the NEPOOL standards referred to herein shall cease to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that do not materially alter the obligations of the Seller as such obligations existed under the NEPOOL standards.

17.4 This Agreement shall inure to the benefit of and bind the respective successors and assigns of the parties hereto, provided however, that no assignment by either party (or any successor or assignee thereof) of its rights and obligations hereunder, except an assignment by the Company of such rights and obligations to a wholly-owned subsidiary or an affiliate wholly-owned by the same holding company, shall be made or become effective without the prior written consent of the other party in each case obtained, which consent shall not be unreasonably withheld. All assignments by the Seller or the Seller's successors and assigns shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against any entity that might obtain title to or possession of the Site or Unit.

17.5 Notwithstanding any assignments of rights or duties hereunder, neither party shall be relieved of any duties or responsibilities under this Agreement and this Agreement shall continue in accordance with its terms and each party shall be and remain liable to the other under all provisions of this Agreement unless the other party has expressly consented in writing to such release of duties and responsibilities, such consent not to be unreasonably withheld. Further, any payments made by one party to an assignee of the other party or any other actions taken by such party with respect to such assignee shall be in full satisfaction of any duties or responsibilities that the party would otherwise owe to the other party, as if made or taken directly to such other party.

17.6 The parties hereto agree to establish an administrative committee, which shall serve informational functions only. Unless otherwise agreed by the administrative committee, such committee shall meet at least once each calendar quarter prior to the Actual In-Service Date and at least twice each year thereafter. The Company and the Seller shall have equal representation upon such committee.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP
By its General Partner, EMI/Development, Inc.

By James L. Gordon

Its President

COMMONWEATLH ELECTRIC COMPANY

By Donald J. O'Blane

Its VICE PRESIDENT

APPENDIX A
TO POWER PURCHASE AGREEMENT

Description of the Site

The Site consists of thirty-seven and sixty-one hundredth (37.61) acres in an L-shaped configuration as shown on the Town of Dartmouth Assessors Map as Parcel 67.9.

The Site is primarily vacant woodlands and brush with the exception of a small wooden building in the northwest sector. A portion of the land has been cleared for timber.

The approximate elevation of the Site is one hundred sixty (160) feet above sea level. The Site is basically flat, sloping toward the southwest into wetlands. An Algonquin Gas Transmission Company pipeline bisects the Site in an east-west direction.

APPENDIX B
TO POWER PURCHASE AGREEMENT

1. Total Purchase Price: Each Billing Period, commencing with the Actual In-Service Date, the Company shall pay to the Seller the sum of the following:

1.1 The Monthly Capacity Charge, as defined in and computed in accordance with Section 2 of this Appendix B, and as adjusted in accordance with Section 3 of this Appendix B; and

1.2 The Monthly Energy Charge, as defined in and computed in accordance with Section 4 of this Appendix B.

2. Monthly Capacity Charge: The Monthly Capacity Charge shall consist of the sum of the Monthly Capacity Cost, the Monthly Investment Cost, and the Monthly Pipeline Transportation Capacity Demand Cost, all as defined and computed as follows.

2.1 Monthly Capacity Cost: The initial Monthly Capacity Cost shall equal one hundred ninety-two thousand, seven hundred six dollars ($192,706). The Monthly Capacity Cost shall be subject to the following adjustments.

2.1.1 Following the first month after the Actual In-Service Date, the Monthly Capacity Cost shall be adjusted quarterly to reflect changes in the GNP Implicit Price Deflator, such changes to be measured from the month of the Actual In-Service Date. The GNP Implicit Price Deflator is revised quarterly and is published by the Bureau of Economic Analysis of the United States Department of Commerce in the Survey of Current Business.

2.1.2 In the event that NEPEX or the Company requests in excess of one hundred (100) stops and one hundred (100) starts of the Unit in any calendar year, the Seller may include the additional operation and maintenance costs that it incurs as a direct result of such excess stops and starts, as such costs are determined by the firm of consulting engineers described in Article 14.4 of this Agreement.

2.2 Monthly Investment Cost: The Monthly Investment Cost shall equal six hundred ninety-seven thousand, one hundred eighty-six dollars ($697,186).

2.3 Monthly Pipeline Transportation Capacity Demand Cost: The Monthly Pipeline Transportation Capacity Demand Cost shall equal the product of 0.2962 (which is equal to the Contract Capacity divided by the Design Capacity) and the sum of the following firm transportation demand charges: .742942

2.3.1 The applicable and approved NOVA pipeline transportation capacity demand rate, expressed in dollars per million British

Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the appropriate regulatory authorities;

2.3.2 The applicable and approved TransCanada pipeline transportation capacity demand rate, expressed in dollars per million British Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the appropriate regulatory authorities; and

2.3.3 The applicable and approved pipeline transportation capacity demand rate contained in the United States Domestic Pipeline Tariff (as defined in Section 5 of this Appendix B), expressed in dollars per million British Thermal Units ($/MMBTU), multiplied by the appropriate amount of gas, as such rate is on file with the applicable regulatory authorities.

3. Bonus or Penalty Cost Adjustment: A bonus or penalty cost adjustment shall be made to the Monthly Capacity Cost or to the Monthly Capacity Charge, based on the ability of the Seller to operate the Unit as measured on a moving, twelve month, cumulative equivalent availability factor basis. This adjustment shall be made pursuant to the following formula:

If EAF is less than .85,

$$\text{Adjustment} = \left(\left(\frac{EAF}{.91}\right) - 1\right) \times \text{Monthly Capacity Charge}$$

If EAF is equal to or greater than .85,

$$\text{Adjustment} = \left(\left(\frac{EAF}{.91}\right) - 1\right) \times \text{Monthly Capacity Cost}$$

Where EAF = Equivalent Availability Factor

$$EAF = \frac{EAH}{\text{Hours in Period}}$$

EAH = Equivalent Available Hours

$$EAH = \text{sum, over all hours in period, of } \frac{\text{megawatts available in hour*}}{\text{Seasonal Maximum Net Claimed Capability Rating in Hour**}}$$

* The megawatts available in an hour shall reflect Seasonal Maximum Claimed Capability, adjusted only for non-temperature related outages and/or limitations.

** Seasonal Maximum Net Claimed Capability shall be established pursuant to NEPOOL CRS 4, "Rating and Auditing of Generating Capability."

Example:

	Hour 1	Hour 2	Hour 3
available MW:	160	165	162
maximum net:	168	168	168

$$EAH = \frac{160}{168} + \frac{165}{168} + \frac{162}{168} = 2.899$$

$$EAF = \frac{2.899}{3} = .966$$

4. Monthly Energy Charge: The Monthly Energy Charge shall consist of the product of (a) the Delivered Energy for the prior Billing Period, expressed in kilowatthours; and (b) the sum of the Variable Fuel Supply Rate and the Variable Fuel Transportation Throughput Rate, expressed in dollars per kilowatthour ($/kWh), both as defined and computed as follows.

4.1 Variable Fuel Supply Rate: The Initial Variable Fuel Supply Rate, as of December 31, 1988, is set equal to the following:

4.11 One dollar and thirty-five cents per million British Thermal Units ($1.35/MMBTU); divided by

4.12 One (1) minus the appropriate quantity, expressed as a decimal, of "pipeline" and "unaccounted for" gas, as included in the applicable and approved commodity charges; multiplied by

4.13 The Adjusted Heat Rate. The Adjusted Heat Rate is equal to eight thousand, five hundred eighty three British Thermal Units per kilowatthour (8,583 BTU/kWh), expressed in millions of British Thermal Units per kilowatthour (i.e., 0.008583 MMBTU/kWh), and is equal to the Unit heat rate of eight thousand three hundred seventy-four British Thermal Units per kilowatthour (8,374 BTU/kWh) multiplied by the sum of one (1) plus a degradation of two and one-half (2.5) percent.

The Initial Variable Fuel Supply Rate shall be adjusted monthly to reflect the proportional change in the following index, which uses the year 1988 as its base:

	Weighting	12 mo. avg.
Tennessee CD-6	25%	$2.508/MMBTU
Algonquin F-1	25%	2.185
Alberta Market Price	50%	1.329
Weighted Cost		$1.838/MMBTU

4.2 Variable Fuel Transportation Throughput Rate: The Variable Fuel Transportation Throughput Rate shall equal the Adjusted Heat Rate, multiplied by the sum of the following firm commodity throughput rates:

4.2.1 The NOVA commodity throughput rate, expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities;

4.2.2 The TransCanada commodity throughput rate, expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities; and

4.2.3 The commodity throughput rate contained in the United States Domestic Pipeline Tariff (as defined in Section 5 of this Appendix B), expressed in dollars per million British Thermal Units ($/MMBTU), as such rate is on file with the appropriate regulatory authorities.

5. For purposes of this Appendix B, the United States Domestic Pipeline Tariff shall be the tariff or tariffs for each of the pipeline companies and local distribution companies transporting natural gas from the Canadian border to the Unit's meter station. In the event that firm transportation is unavailable to the unit's meter station upon the Actual In-Service Date, the United States Domestic Pipeline Tariff shall reflect the most recently filed charges with the Canadian and United States regulatory agencies to transport gas to the Unit's meter station.

6. Illustration of projected Total Purchase Price assuming a fifty megawatt (50 MW) allocation at ninety-one percent (91%) capacity:

Monthly Capacity Cost [initial amount]:	$192,706	[=0.5802 ¢/kWh*]
Monthly Investment Cost [fixed amount]:	697,186	[=2.0990 ¢/kWh*]
Monthly Pipeline Demand Cost [assuming total of transportation capacity demand charges = $1,328,380]:	393,466	[=1.1846 ¢/kWh*]
CAPACITY CHARGE [unadjusted; see §3]:	$1,283,358	[=3.8638 ¢/kWh*]

Variable Fuel Supply Rate [assuming index adjustment and accounting for "pipeline gas" amounts]:	$472,118**	1.4214 ¢/kWh
Variable Fuel Transportation Throughput Rate [assuming sum of pipeline throughput rates = $.4199/MMBTU]:	119,740**	0.3605 ¢/kWh
ENERGY CHARGE:	$591,858**	1.7819 ¢/kWh
TOTAL PURCHASE PRICE:	$1,875,216	[=5.6457 ¢/kWh]

* calculated by dividing the actual dollar amount by the following: (365 days/year)(1/12 year/month)(24 hours/day)(.91)(50,000 kW)

** calculated by multiplying the actual ¢/kWh rate by the following: (365 days/year)(1/12 year/month)(24 hours/day)(.91)(50,000 kW)

APPENDIX C
TO POWER PURCHASE AGREEMENT

Liability Insurance

From and after the Actual In-Service Date, the Seller shall take out, carry, and maintain, or cause to be taken out, carried, and maintained, comprehensive general liability insurance, including automobile and contractual liability, and liability arising out of aircraft or watercraft, if applicable, with a combined single limit per occurrence of a least five million dollars ($5,000,000) applicable to bodily injury, sickness or death, and loss of or damage to property, subject to an aggregate limit of not less than five million dollars ($5,000,000) for products and completed operations. Endorsements shall be included for X, C, and U hazards (blasting, collapse, and underground property damage), broad form property damage, and personal injury in addition to bodily injury.

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APPROVED
Oct 23, 1990
COMMISSIONERS, D.P.U.

COM Electric

Commonwealth Electric Company
Post Office Box 9150
Cambridge, Massachusetts 02142-9150
Telephone (617) 225-4000

August 15, 1990

RECEIVED
AUG 15 1990
DEPT. OF PUBLIC UTILITIES
ADMINISTRATION

Department of Public Utilities
100 Cambridge Street
Boston, MA 02202

Attention: Henry Yoshimura
Electric Power Division

Re: Amendment to Power Purchase Agreement
Dartmouth Power Associates Limited Partnership

Dear Mr. Yoshimura:

Commonwealth Electric Company ("Commonwealth" or the "Company") submits herewith an Amendment, dated August 3, 1990, to a Power Purchase Agreement (the "Amendment") by and between itself and Dartmouth Power Associates Limited Partnership ("Dartmouth Power"). The Amendment modifies certain terms of a Power Purchase Agreement, dated September 5, 1989, between Commonwealth and Dartmouth Power (the "Agreement"). The Agreement was submitted by the Company to the Massachusetts Department of Public Utilities (the "Department") on September 27, 1989 and was approved by the Department on March 30, 1990 in DPU 89-218.

Pursuant to the Agreement, Commonwealth had agreed to purchase a 50 MW entitlement to the electric capacity and related energy to be produced by an electric generation facility (the "Unit"), which is to be constructed, owned and operated by Dartmouth Power at a site in the Town of Dartmouth. As set forth in the Agreement, the Unit was to be capable of generating approximately 168.8 MW of electricity. However, Dartmouth Power has determined that the Unit will be constructed so as to be capable of generating approximately 67.6 MW. Dartmouth Power offered to sell to Commonwealth an additional 17.6 MW of electricity, which would make the Company the sole purchaser of the electricity that will be produced by the downsized Unit. The Company has determined that this additional purchase of electricity would be beneficial to its ratepayers and would facilitate its administration of the Agreement. Accordingly, Commonwealth has accepted Dartmouth Power's offer.

In addition to modifying the Agreement to reflect the Company's purchase of additional power, the Amendment adds provisions to the Agreement regarding economic dispatch and income tax liabilities, amends the provisions in the

Agreement regarding the security deposit to be furnished by Dartmouth Power to the Company and reflects a reduction in the size of the expected energy bank. The Company notes that the Amendment does not change the pricing mechanism as set forth in the Agreement. The unit prices for capacity and energy will not change. The calculation of the Monthly Capacity Charge component in the price formula will change to reflect the increase in the amount of power that the Company will purchase.

In order to assist the Department in its review of this Amendment, the Company has included in this filing, the base case, low and high fuel cost scenarios of Tables 1 through 5 from the Department's Standard Information Requirements. In addition, the Company has included schedules providing information responsive to Standard Information Requirement #3. The remainder of the information responsive to the Department's Standard Information Requirements is identical in substance to that contained in Appendix C to the Company's Second Request for Proposal for Qualifying Facility Generation ("RFP #2") filed on June 29, 1990 and approved by the Department on July 12, 1990.

As is apparent from the materials included in this filing the Company's ratepayers have a strong prospect of realizing substantial benefits from the purchase by the Company of the additional 17.6 MW output of the Unit. Commonwealth has compared its projected payment stream to Dartmouth Power to the ceiling prices as developed from RFP#2. As can be seen from the attached schedules in the base case fuel scenario, the expected lifetime cumulative net present value benefit from the additional 17.6 MW increment is approximately $16.6 million. As can also be seen from the attached schedules, the cumulative net present value of projected payments to Dartmouth Power over the life of the Agreement is equal to 80% of the cumulative net present value of the Company's avoided costs.

The Company would be pleased to provide such additional information as the Department may request concerning this matter.

Very truly yours,

Marcy S. Rosenzweig /KAB

Marcy S. Rosenzweig
Manager - Rate Regulation

cc: Brian J. Abbanat, Electric Power Division
George B. Dean, Department of Attorney General

cc. DPU
AJ

The Commonwealth of Massachusetts
Department of Public Utilities
Leverett Saltonstall Building, Government Center
100 Cambridge Street, Boston 02202

Copy to Library

August 12, 1994

Mr. James J. Keane
Vice-President of Power Supply
and Transmission
Commonwealth Electric Company
2421 Cranberry Highway
Wareham, MA 02571

Dear Mr. Keane:

The Department hereby approves the Second Amendment ("Second Amendment") to Power Purchase Agreement ("Agreement") between Commonwealth Electric Company ("Commonwealth") and Dartmouth Power Associates Limited Partnership ("Dartmouth"), which was filed with the Department on July 18, 1994. The Agreement was submitted to the Department on September 27, 1989 and was approved on March 30, 1990 in D.P.U. 89-218.[1] The Department notes that the Second Amendment has been submitted to the Department and to FERC for approval, and that it takes effect upon receipt of approvals "in form and substance acceptable to Commonwealth and Dartmouth."

The Department understands the Second Amendment replaces natural gas price indices which are used in calculating Dartmouth's Variable Fuel Supply Rate as a component of its Monthly Energy Charge. The Department further understands that the Second Amendment allows for redeterminations of natural gas price indices at designated intervals.

The Department understands that the natural gas indices referenced in the Agreement are no longer published. Specifically, the Tennessee CD-6 index; and (2) the Algonquin F-1 index are no longer available due to gas pipeline service restructuring pursuant to FERC Order No. 636. In addition, the Department understands that an index calculated by the

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1 Commonwealth is the sole purchaser of output from Dartmouth's 67,600 kilowatt generating facility located in Dartmouth, Massachusetts.

Alberta Petroleum Marketing Commission for the Minister of Energy for the Province of Alberta, known as the Alberta Market Price ("AMP") has been replaced with the Alberta Reference Price ("ARP") as a consequence of Canada's Natural Gas Marketing Act.

Due to the unavailability of the Tennessee CD-6 and the Algonquin F-1 indices, Commonwealth and Dartmouth have agreed to replace these with a composite spot price indicator ("T2").[2] In addition, Commonwealth and Dartmouth have agreed to accept the ARP as a replacement for the AMP. Commonwealth and Dartmouth have also agreed that either party may elect to require a redetermination of the composition of the Variable Fuel Supply Rate during 1997, 2002, 2007, or 2012.

The Department understands that the Second Amendment does not change the amount of power purchased by Commonwealth under the Agreement, nor does it change any pricing provisions beyond the indexing provisions of the Variable Fuel Supply Rate as a component of the Monthly Energy Charge.

Sincerely,

Kenneth Gordon
Chairman

Barbara Kates-Garnick
Commissioner

---

2 The T2 index is to consist of the following: (1) the Offshore and Louisiana (Zone 1) Index for Tennessee; (2) the Louisiana and Texas (Zone 0) Index for Tennessee; (3) the arithmetic average of the East Texas and South Texas Indices for the Texas Eastern Transmission Company; and (4) the arithmetic average of the East Louisiana and West Louisiana Indices for the Texas Eastern Transmission Corporation.

SECOND AMENDMENT TO POWER PURCHASE AGREEMENT

AMENDMENT dated as of this 23rd day of June, 1994, by and between Commonwealth Electric Company, a Massachusetts corporation with a principal place of business at One Main Street, Cambridge, Massachusetts ("the Company") and Dartmouth Power Associates Limited Partnership, a Massachusetts Limited Partnership with a place of business at One Energy Road, Dartmouth, Massachusetts ("Seller"), to the Power Purchase Agreement by and between the Company and Seller, dated as of September 5, 1989 and amended by an Amendment to Power Purchase Agreement by and between the Company and Seller, dated as of August 3, 1990 (as amended, "the Agreement").

WHEREAS the Company, pursuant to the Agreement, purchases all electricity produced by the Seller's 67,600 KW generating facility located at One Energy Road, in Dartmouth, Massachusetts ("the Unit"); and

WHEREAS the Total Purchase Price for electricity purchased by the Company pursuant to the Agreement includes a component known as the Monthly Energy Charge, which is defined (in section 4 of Appendix B of the Agreement) as including a component known as the Variable Fuel Supply Rate; and

WHEREAS, the Variable Fuel Supply Rate is calculated, in part, by reference to the following indices for natural gas pipeline service: The "Tennessee CD-6" index (for service pursuant to the CD-6 rate under a FERC approved tariff by Tennessee Gas Pipeline Company, "Tennessee") and (2) the "Algonquin F-1" index (for service pursuant to the F-1 rate under a FERC approved tariff by Algonquin Gas Transmission Company, "Algonquin"); and

WHEREAS, both the Algonquin F-1 rate and the Tennessee CD-6 rate have ceased to be available as a consequence of the restructuring of services of each of those respective pipelines pursuant to Federal Energy Regulatory Commission ("FERC") Order No. 636; and

WHEREAS, the Variable Fuel Supply Rate is calculated, in, part, by reference to an index calculated by the Alberta Petroleum Marketing Commission for the Minister of Energy for the Province of Alberta, Canada known as the Alberta Market Price (AMP); and

WHEREAS, the AMP, effective December 31, 1993 is no longer published; and

WHEREAS, the Company and Seller have agreed upon the terms of an index to replace the F-1, CD-6 and AMP indices for purposes of calculating the Variable Fuel Supply Rate, and desire to execute this Amendment for purposes of memorializing their agreement.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein, the Company and Seller agree as follows:

1. That for the purposes of determining the Variable Fuel Supply Rate as referenced in section 4.1 of Appendix B of the Agreement, the last paragraph (including the table) of said section shall be deleted in its entirety and the following shall be substituted in place thereof:

The Initial Variable Fuel Supply Rate shall be adjusted monthly to reflect the proportional change in the T2 index (as hereinafter defined) and the Alberta Reference Price, using the year 1988 as a base, and shall be calculated pursuant to the provisions of subsection 4.14.

4.14 For each Billing Period during the term of this Agreement, the Variable Fuel Supply Rate shall equal the product of (i) the Initial Variable Fuel Supply Rate and (ii) an Index Factor, the numerator of which shall be "N1" (as hereinafter defined) and the denominator of which shall be "D1" (as hereinafter defined):

Where:

"N1" shall equal the sum of (i) "T2" (as hereinafter defined) and (ii) the available Alberta Reference Price for the billing month.

"D1" shall equal two (2) multiplied by "AFC-1".

"T2" shall be calculated as the arithmetic average of the following four indices for the Billing Period:

(a) the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company;

(b) the Louisiana and Texas (Zone 0) index for Tennessee Gas Pipeline Company;

(c) the arithmetic average of the East Texas and South Texas indices for Texas Eastern Transmission Corporation;

(d) the arithmetic average of the East Louisiana and West Louisiana indices for the Texas Eastern Transmission Corporation.

all as reported in the table entitled "Prices of Spot Gas Delivered to Pipelines" in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, provided that if any of the above described indices, or their successors, are not reported in any month, T2 shall be equal to the arithmetic average of the indices that are reported, provided that at least three of the above indices are so reported. If at least three of the above indices are not reported in any month, then the Henry Hub Cash Price, as reported in the first of the month edition of Inside F.E.R.C.'s Gas Market Report will serve as a Proxy for T2. However, the Henry Hub Cash Price shall not be used as a Proxy for T2 for two consecutive months unless agreed to by both parties.

"AFC-1" shall equal $1.486 per MMBTU. This value is the sum of (i) the average "T2" value for calendar year 1988 and (ii) the average Alberta Market Price for calendar year 1988, divided by two (2).

The "Alberta Reference Price" is the gas reference price prescribed by the Minister of Energy for the Province of Alberta, Canada for the calendar month of the Billing Period (for example, the gas reference price published by the Minister for June, 1994 would be the Alberta Reference Price used to calculate the Variable Fuel Supply Rate for June, 1994 but actually reflect data for the month of April, 1994). The data is published by the Alberta Petroleum Marketing Commission.

2. The following shall be inserted as section 4.3 of Appendix B of the Agreement:

4.3 Redetermination of the Variable Fuel Supply Rate:

Either the Seller or the Company shall have the right to require a redetermination of the provisions of subsection 4.14 of this Appendix relating to the composition of the Index Factor, effective upon November 1 of each of the following years: 1997, 2002, 2007 and 2012 (the "Redetermination Dates"). A party electing to require such a redetermination shall provide written notice (the "Redetermination Notice") to the other party no less than six (6) months and no more than one (1) year before the Redetermination Date on which such redetermination is to take effect.

If a Redetermination Notice is not served by either party upon the other party during the specified time period, the Variable Fuel Supply Rate in effect immediately prior to the relevant Redetermination Date shall continue to be calculated in the manner in effect prior to such Redetermination Date. If a Redetermination Notice is served within the time required, then the provisions of subsections 4.3.1 through 4.3.4 below shall apply.

4.3.1 Following receipt of a Redetermination Notice, the parties will negotiate in good faith to determine mutually satisfactory modifications to the Variable Fuel Supply Rate.

4.3.2 If the parties are unable to agree upon renegotiated Variable Fuel Supply Rate provisions on or before the date which is three (3) months prior to the Redetermination Date, either party may elect by written notice (the "Arbitration Notice") to the other party, to refer the redetermination of the Variable Fuel Supply Rate provisions to binding arbitration pursuant to Article 12 of the Agreement. If an Arbitration Notice is not issued by either party before the date which is three (3) months prior to the Redetermination Date, and the parties have not agreed upon renegotiated Variable Fuel Supply Rate provisions on or before the Redetermination Date, the Variable Fuel Supply Rate provisions shall continue to be calculated in the manner in effect immediately prior to such Redetermination Date.

4.3.3 During the renegotiation of the Variable Fuel Supply Rate provisions and during any arbitration relating thereto, the parties and the arbitrators

shall work to modify the Index Factor, N1/D1, as defined in subsection 4.14, such that the renegotiated Variable Fuel Supply Rate provisions will yield:

(a) a price of natural gas that reflects the value of other long-term baseload gas supplies delivered at the city gate to local electric utility companies in Massachusetts and Rhode Island, where such prices have been adjusted by subtracting all applicable costs (at 100% load factor) of firm pipeline transportation from the wellhead to the respective city gates, including commodity charges, demand charges and fuel gas costs.

(b) a Variable Fuel Supply Rate that the parties anticipate will enable the Unit to operate at an average capacity factor of at least sixty percent (60%) over the following five year period.

(c) in the event that the objectives in (a) and (b) above are in conflict, objective (b) relating to operation at a capacity factor of at least sixty percent (60%) shall be considered the controlling factor.

4.3.4 Whenever there is a redetermination of the Variable Fuel Supply Rate in progress, transactions under this Agreement shall continue in the same fashion as they were conducted before such redetermination was initiated, without prejudice to the rights of either party under this section 4.3, pending a redetermination resulting from renegotiation or arbitration. The Variable Fuel Supply Rate in effect prior to such redetermination shall be applied to all electricity delivered pursuant to this Agreement during the time period after the Redetermination Date until the day upon which a renegotiated or arbitrated decision is reached and issued (in this section, the "Subject Period"), whereupon the Variable Fuel Supply Rate Provisions as determined by the renegotiation or arbitration shall, unless otherwise agreed by the parties, be applied to the Subject Period with interest (at the annual rate of two percentage points over the current interest rate on prime commercial loans then in effect at the First National Bank of Boston) and with appropriate adjustments (i.e., payment by the Company to the extent the Redetermined Variable Fuel Supply Rate is greater; payment by the Seller to the extent the Redetermined Rate is less) being made between the parties to reflect the change in the Variable Fuel Supply Rate Provisions.

3. The Company shall submit this Amendment to the MDPU, and the Seller shall submit this Amendment to the FERC, for the approval of each of the MDPU and the FERC. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

4. All other terms and conditions of said Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

DARTMOUTH POWER ASSOCIATES
LIMITED PARTNERSHIP BY
EMI/DARTMOUTH, INC.,
ITS GENERAL PARTNER

By: James A. Gordon

Title: President

COMMONWEALTH ELECTRIC COMPANY

By: James J. Keane

Title: Vice President - Power Supply & Transmission

Attachment
AG-2-4(d)

KEEGAN, WERLIN & PABIAN, LLP

ATTORNEYS AT LAW
21 CUSTOM HOUSE STREET
BOSTON, MASSACHUSETTS 02110-3525

(617) 951-1400

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(617) 951-1354
(617) 951-0588

DAVID S. ROSENZWEIG
E-mail: drosen@kwplaw.com

APPROVED
DATE November 26, 2002
COMMISSIONERS, D.T.E.

October 25, 2002

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, Massachusetts 02110

Re: Fourth Amendment to Power Purchase Agreement Between Commonwealth Electric Company and Dartmouth Power Associates, L.P.

Dear Secretary Cottrell:

Pursuant to G.L. c. 164, § 94A, enclosed for approval by the Department of Telecommunications and Energy (the "Department") is the Fourth Amendment to the Power Purchase Agreement (the "Amendment") that the Company executed with Dartmouth Power Associates, Limited Partnership ("Dartmouth") on October 15, 2002.[1] The Amendment replaces a gas index that the parties use to calculate Dartmouth's Variable Fuel Supply Rate as a component of its Monthly Energy Charge. The gas index previously used to calculate the Monthly Energy Charge (i.e., the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company) is no longer reported. In accordance with the PPA, the monthly energy charge will now be calculated using the arithmetic average of the Tennessee Gas Pipeline Louisiana 500 Leg index and the Tennessee Gas Pipeline Louisiana 800 Leg index. See PPA, § 4.14 (as amended).

In agreeing to the proposed replacement index, the parties attempted to select a mechanism that replicated the original index and maintained the underlying intent of the initial PPA. As demonstrated in Attachment 1 (appended to this letter), there is virtually no difference to the resultant monthly energy charge whether the charge is calculated

[1] The Power Purchase Agreement ("PPA") executed on September 5, 1989 was approved by the Department on March 30, 1990 (Commonwealth Electric Company, D.P.U. 89-219 (1990)). Subsequent amendments to the PPA were approved by the Department in letter orders. Specifically, the first amendment to the PPA was executed on August 3, 1990, and approved by the Department on October 23, 1990. The second amendment to the PPA was executed on June 23, 1994, and approved by the Department on August 12, 1994. The third amendment to the PPA was executed on April 25, 1996, and approved by the Department on June 27, 1996.

using the former or proposed index. The Fourth Amendment does not change the amount of power purchased by the Company under the PPA, nor does it change any pricing provisions beyond the indexing provisions for the Variable Fuel Supply Rate as a component of the Monthly Energy Charge.

The Company respectfully requests that the Department approve the enclosed Agreement by November 30, 2002. If you have any questions concerning this filing, please contact me.

Very truly yours,

David S. Rosenzweig

Enclosures

cc: Paul G. Afonso, General Counsel
Ronald LeComte, Director, Electric Power Division

FOURTH AMENDMENT TO POWER PURCHASE AGREEMENT

This Fourth Amendment to Power Purchase Agreement, dated as of the 15th day of October, 2002 (the "Amendment"), is made by and between COMMONWEALTH ELECTRIC COMPANY, a Massachusetts corporation with its place of business at 800 Boylston Street, Boston, MA 02199 ("Buyer") and DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP, a Massachusetts limited partnership with its place of business at 1001 Louisiana Street, Houston, TX 77002 ("Seller", and collectively with Buyer, the "Parties").

WHEREAS, the Parties have previously entered into a Power Purchase Agreement, dated as of September 5, 1989, as amended by 1) an Amendment to Power Purchase Agreement, dated as of August 3, 1990, 2) a Second Amendment to Power Purchase Agreement, dated as of June 23, 1994, 3) a Third Amendment to Power Purchase Agreement, dated as of April 23, 1996 (as amended, the "Power Purchase Agreement");

WHEREAS, pursuant to the Power Purchase Agreement, Buyer pays to Seller each Billing Period the sum of the Monthly Capacity Charge and the Monthly Energy Charge;

WHEREAS, the Monthly Energy Charge is comprised of various components, one of which is calculated by multiplying the Delivered Energy for the prior Billing Period by the sum of the Variable Fuel Transportation Throughput Rate and the Variable Fuel Supply Rate;

WHEREAS, the Variable Fuel Supply Rate is adjusted monthly by an Index Factor, one component of which includes the Offshore and Louisiana (Zone 1) index for Tennessee Gas Pipeline Company ("Tennessee Zone 1 Index"); and

WHEREAS, the Parties wish to recognize that the Tennessee Zone 1 Index is no longer reported and in accordance with the terms of the Power Purchase Agreement such index shall be succeeded by the arithmetic average of the Tennessee Gas P/L Louisiana 500 Leg index and the Tennessee Gas P/L Louisiana 800 Leg index;

NOW, THEREFORE, in consideration of the foregoing, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. All terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Power Purchase Agreement.

2. In Article 4.14 of Appendix B of the Power Purchase Agreement, the definition of "T2" is hereby amended by deleting it in its entirety and substituting the following in lieu thereof:

> "T2" shall be calculated as the arithmetic average of the following four indices for the Billing Period:

(a) the arithmetic average of the Tennessee Gas P/L Louisiana 500 Leg index and the Tennessee Gas P/L Louisiana 800 Leg index;

(b) the Louisiana and Texas (Zone 0) index for Tennessee Gas Pipeline Company;

(c) the arithmetic average of the East Texas and South Texas indices for the Texas Eastern Transmission Corporation; and

(d) the arithmetic average of the East Louisiana and West Louisiana indices for the Texas Eastern Transmission Corporation;

all as reported in the table entitled "Prices of Spot Gas Delivered to Pipelines" in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, provided that if any of the above described indices, or their successors, are not reported in any month, T2 shall be equal to the arithmetic average of the indices that are reported, provided that at least three of the above indices are so reported. If at least three of the above indices are not reported in any month, then the Henry Hub Cash Price, as reported in the first of the month edition of Inside F.E.R.C.'s Gas Market Report will serve as a Proxy for T2. However, the Henry Hub Cash Price shall not be used as a Proxy for T2 for two consecutive months unless agreed to by both parties.

3. This Amendment shall be filed by Buyer for review and approval with the Massachusetts Department of Telecommunications and Energy (MDTE). Seller agrees to reasonably cooperate with Buyer in the activities necessary to obtain such approval, provided that under no circumstances shall Seller be obligated to amend the terms of this Amendment or the Power Purchase Agreement to obtain such approval.

4. This Amendment shall be effective only as to the specific provision of the Power Purchase Agreement amended hereby. All other provisions of the Power Purchase Agreement shall remain unchanged.

5. This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement.

6. This Amendment shall be governed by, and construed in accordance with, the laws of the Commonwealth of Massachusetts, without giving effect to conflict of laws provisions thereof.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered as of the date first above written.

COMMONWEALTH ELECTRIC COMPANY, a Massachusetts corporation

By: _____
Name: Douglas Horan
Title: Sr. Vice President, Strategy Law & Policy

DARTMOUTH POWER ASSOCIATES LIMITED PARTNERSHIP,
a Massachusetts limited partnership

By: _____
Name: J J O'ROURKE
Title: Vice Managing Director

[*Signature Page to Fourth Amendment to ComElectric PPA*]

Comparison of Gas Indices					
Fourth Amendment to the Dartmouth Power Power Purchase Agreement					
	Inside FERC Gas Mkt Report Tennessee Gas Pipeline Co		Gas Daily Monthly Contract Price Tennesse Gas Pipeline Co		
	Louisiana & Offshore Zone 1		Louisiana 500 Leg	Louisiana 800 Leg	Average
2001					
February	$6.13		$6.10	$6.13	$6.12
March	$4.91		$4.90	$4.91	$4.91
April	$5.28		$5.28	$5.29	$5.29
May	$4.79		$4.79	$4.80	$4.80
June	$3.62		$3.62	$3.61	$3.62
July	$3.09		$3.11	$3.14	$3.13
August	$3.09		$3.08	$3.11	$3.10
September	$2.22		$2.22	$2.26	$2.24
October	$1.75		$1.78	$1.75	$1.77
November	$3.08		$3.09	$3.09	$3.09
December	$2.20		$2.24	$2.22	$2.23
2002					
January	$2.53		$2.53	$2.49	$2.51
February	$1.96		$1.98	$1.97	$1.98
March	$2.32		$2.31	$2.31	$2.31
April	$3.32		$3.31	$3.28	$3.30
May	$3.26		$3.28	$3.28	$3.28
June	$3.27		$3.30	$3.28	$3.29
July	*		$3.18	$3.16	$3.17
August			$2.87	$2.87	$2.87
	* Effective July 2002 prices reflect the Index change reported in the Inside FERC Gas Market Report on the first of the month				

Information Request AG-2-6

Please provide a recalculation of Exhibits NSTAR-GOL-2 through-4 and Exhibits NSTAR-RBH-5 and -6 using a discount rate of 8.80 percent.

Response

Please refer to the following attachments for the requested schedules using a discount rate of 8.80 percent.

Attachment AG-2-6(a)	Exhibit NSTAR-RBH-5 **CONFIDENTIAL**
Attachment AG-2-6(b)	Exhibit NSTAR-RBH-6 **CONFIDENTIAL**
Attachment AG-2-6(c)	Exhibit NSTAR-COM-GOL-2

Please note that the requested change in the discount rate has no effect on Exhibit NSTAR-COM-GOL-3 and Exhibit NSTAR-COM-GOL-4.

Year	Base Case Revenues	Dartmouth With Securitization Revenues	Customer Savings
Col. A	Col. B	Col. C	Col. D
2004	$ 74.654	$ 74.654	$ -
2005	174.902	174.902	$ -
2006	178.400	178.400	$ -
2007	138.764	151.548	$ (12.784)
2008	98.448	102.139	$ (3.691)
2009	76.608	79.069	$ (2.461)
2010	76.096	77.433	$ (1.337)
2011	75.796	76.058	$ (0.262)
2012	76.565	75.719	$ 0.846
2013	74.217	54.849	$ 19.368
2014	76.517	51.280	$ 25.237
2015	75.539	50.249	$ 25.290
2016	58.196	33.080	$ 25.116
2017	14.584	5.517	$ 9.067
2018	5.357	5.357	$ -
2019	5.094	5.094	$ -
2020	5.030	5.030	$ -
2021	5.321	5.321	$ -
2022	2.803	2.803	$ -
2023	1.160	1.160	$ -
2024	0.404	0.404	$ -
2025	0.265	0.265	$ -
2026	0.345	0.345	$ -
Total	$ 1,295.065	$ 1,210.676	$ 84.389
8.800%	$ 871.471	$ 844.084	$ 27.388

Discounted at rate specified in IR-AG-2-6

Information Request AG-2-7

Please provide copies of Concentric's engagement letter and contract for services for the auction and bid evaluation in this case, along with copies of all correspondence between Concentric and the Company regarding the engagement and the auction process and subsequent evaluation of the bids.

Response

CONFIDENTIAL CD-ROM ATTACHED

Please see Attachment AG-2-7(a) for the agreement between NSTAR Electric and Concentric Energy Advisors ("CEA"). Copies of all correspondence between NSTAR Electric and CEA with regard to the Dartmouth negotiations are being filed in response to Information Request DTE-1-2 **CON FIDENTIAL BULK**. In addition, correspondence between the parties regarding the auction generally is attached as Attachment AG-2-7(b) **CONFIDENTIAL CD-ROM.** This CD-ROM was previously provided in D.T.E.-04-60 as Attachment AG-1-5 **CONFIDENTIAL CD-ROM.**

Attachment
AG-2-7(a)

NSTAR ELECTRIC GAS
One NSTAR Way
Westwood, Massachusetts 02090

August 15, 2003

Mr. Robert B. Hevert
President
Commonwealth Energy Advisors
313 Boston Post Road West, Suite 210
Marlborough, MA 01752

Subject: Request for Proposal (RFP) #695, dated July 1, 2003

Dear Mr. Hevert:

We are pleased to inform you that your company has been chosen to perform services as outlined in our RFP noted above.

The Consulting Services Agreement (CSA), which is attached, will serve as the master agreement governing the Contract, with the scope of work for this project. Please sign both attached copies of the CSA, and Contract #15468, and return one set of originals to my attention.

NSTAR Electric & Gas Corporation appreciates your professional response to this solicitation, and looks forward to a continuing, successful business relationship. If you have any questions, please do not hesitate to contact me at 781-441-8103.

Very truly yours,

Jeanne Brewer, C.P.M.

Jeanne T. Brewer, C.P.M.
Sr. Contracts Agent

Attachment
1. Consulting Services Agreement (2 copies)
2. Contract #15468 (2 copies)

NSTAR ELECTRIC GAS

NSTAR Electric & Gas Corporation

Contract:	00015468
Release :	
Executed:	08/08/03
Printed :	08/15/03
Page :	1

Mail Invoice To:

Accounts Payable (781)441-8363
NSTAR Electric&Gas Corp, Agent
PO Box 250
Norwood MA 02062-0250

Vendor:

Robert B. Hevert
COMMONWEALTH ENERGY ADVISORS
313 BOSTON POST ROAD WEST
SUITE 210
MARLBOROUGH MA 01752

Please Direct Inquiries to:

JEANNE T. BREWER, C.P.M.
Title: SR CONTRACTS AGENT
Phone: 781 441-8103 Ext:
Fax : 781 441-8503

NSTAR Electric & Gas Corp agent for

NSTAR ELECTRIC & GAS CORP.
ONE NSTAR WAY
SE 250
WESTWOOD MA 02090-9230

Title: ENERGY AUCTION SERVICES

Contract Type : STANDARD CONTRACT
Project :

Start Date: 07/14/03
End Date : 12/31/03

James M. Stephens
Vendor Authorized Signature

James M. Stephens
Printed Name/Title

8/19/03 (508) 263-6228
Date Signed Phone

Jeanne Brewer C.P.M.
Authorized Signature

JEANNE T. BREWER, C.P.M. / SR. CONTRACTS AGENT
Printed Name/Title 781-441-8103

8/15/03
Date Signed Phone

Key Contacts

Role	Contact Name	Phone/Fax	Company
BUYER	JULIE HORIGAN	781-441-8523	120 Boston E
INVOICE REVW	ROSE FAHERTY	781-441-8019	120 Boston E

* * * End of Contract * * *

NSTAR ELECTRIC GAS	Contract: 00015468 Release: Amendment:
Procurement One NSTAR Way Westwood, MA 02090	COMMONWEALTH ENERGY ADVISORS, INC

SCOPE OF SERVICES

CONTRACT #15468 DATED AUGUST 15, 2003 ISSUED TO COVER REQUIREMENTS FOR ENERGY AUCTION SERVICES AS OUTLINED IN RFP #695 AND YOUR RESPONSE TO SAME.

TERMS AND CONDITIONS OF THIS CONTRACT ARE IN ACCORDANCE WITH THE ATTACHED CONSULTING SERVICES AGREEMENT DATED AUGUST 15, 2003.

ACCEPTANCE OF CONTRACT

IF SUPPLIER FAILS TO EITHER REJECT OR EXECUTE THIS CONTRACT, CONTRACT RELEASE OR AMENDMENT THERETO (THE CONTRACT), THEN THIS CONTRACT SHALL BECOME BINDING WHEN ACCEPTED BY THE SUPPLIER. PERFORMANCE BY THE SUPPLIER UNDER A CONTRACT SHALL CONSTITUTE ACCEPTANCE OF THAT CONTRACT. MODIFICATIONS, SUBSTITUTIONS OR CONDITIONS STATED BY THE SUPPLIER IN ACCEPTING OR ACKNOWLEDGING THIS CONTRACT, WHETHER IN CONFLICT WITH OR IN ADDITION TO THE TERMS AND CONDITIONS SET FORTH HEREIN, SHALL NOT BE BINDING UPON THE COMPANY, UNLESS SPECIFICALLY ACCEPTED IN WRITING BY THE COMPANY'S PROCUREMENT DEPARTMENT. IF THIS CONTRACT HAS BEEN ISSUED IN RESPONSE TO SUPPLIER'S PROPOSAL, THEN ISSUANCE OF THIS CONTRACT SHALL CONSTITUTE AN ACCEPTANCE OF SUCH PROPOSAL, BUT SUBJECT TO THE EXPRESS CONDITION THAT THE SUPPLIER ASSENT TO ANY ADDITIONAL OR DIFFERENT TERMS HEREIN, REGARDLESS OF WHETHER PERFORMANCE HAD PREVIOUSLY BEGUN. SUPPLIER SHALL BE DEEMED TO HAVE SO ASSENTED, UNLESS SUPPLIER NOTIFIES THE COMPANY TO THE CONTRARY WITHIN TEN (10) DAYS OF THE DATE OF ISSUANCE OF THIS CONTRACT.

IN ORDER TO ENSURE TIMELY PAYMENTS FOR THE GOODS AND SERVICES PROVIDED UNDER THIS CONTRACT, IT IS **IMPERATIVE THAT ALL INVOICES ISSUED BY YOUR COMPANY NOW REFERENCE THE ABOVE CONTRACT NUMBER, AND, IF APPLICABLE, THE ASSOCIATED BLANKET CONTRACT RELEASE NUMBER**. FAILURE TO REFERENCE THESE NUMBERS MAY RESULT IN LATE PAYMENT OR REJECTION OF INVOICES.

IT IS THE INTENT OF THIS CONTRACT THAT THE RELATIONSHIP OF THE OWNER AND CONTRACTOR BE THAT OF "OWNER AND INDEPENDENT CONTRACTOR." THE MEANS AND METHODS EMPLOYED FOR PERFORMING THE DETAILS OF THE WORK SHALL BE THE CONTRACTOR'S RESPONSIBILITY.

THE TYPES AND LIMITS OF YOUR INSURANCE CERTIFICATES OF WHICH ARE ON FILE WITH OUR INSURANCE DEPARTMENT ARE SATISFACTORY AND SHALL REMAIN IN FORCE FOR THE DURATION OF THE CONTRACT.

THE CONTRACTOR SHALL MAKE ALL STATUTORY REQUIRED PAYMENTS BY THE STATE AND FEDERAL AUTHORITIES FOR ALL PERSONS UTILIZED BY THE CONTRACTOR IN THE EXECUTION OF THE CONTRACTED WORK, AND SHALL, ON REQUEST, PROVIDE EVIDENCE OF SUCH PAYMENTS FOR THE ABOVE-MENTIONED ITEMS.

WORK PREPARATION OR ACTUAL WORK IS NOT TO BE INITIATED UNTIL SPECIFICALLY DIRECTED AND AS SPECIFIED BY THE DESIGNATED ENGINEER OR THE DEPARTMENT SUPERVISOR.

INSTRUCTIONS TO VENDOR TO CHARGE SALES TAX

MASSACHUSETTS LAWS REQUIRE THAT NSTAR SERVICES PAY A 5% SALES TAX ON ALL MATERIALS SUCH AS BUILDING MATERIALS, CONSUMABLES, TOOLS, FENCING, PAINTING, ETC. (EXCEPT THOSE MATERIALS USED DIRECTLY IN THE GENERATION, TRANSMISSION AND DISTRIBUTION OF ELECTRICITY), AND ON CERTAIN SERVICES INCLUDING PAVING AND EQUIPMENT RENTALS.

PLEASE ENSURE THAT ALL INVOICES TO NSTAR SERVICES INCLUDE ACCURATE MASSACHUSETTS SALES TAX AMOUNTS FOR THE ABOVE ITEMS OR THEY WILL NOT BE PROCESSED.

NSTAR SERVICES PAYS ALL SALES TAXES TO VENDORS AND DOES NOT MAKE TAX PAYMENTS DIRECTLY TO THE MASSACHUSETTS DEPARTMENT OF REVENUE AS WE MAY HAVE IN THE PAST.

THEREFORE, IT IS IMPERATIVE THAT VENDOR INVOICING INCLUDE ACCURATE SALES TAX AMOUNTS. IF YOU HAVE ANY QUESTIONS OR CANNOT BILL THE TAX BECAUSE YOU ARE NOT REGISTERED TO CONDUCT BUSINESS IN THE COMMONWEALTH OF MASSACHUSETTS, PLEASE CONTACT THE BUYER OR AGENT NAMED ON THIS CONTRACT.

ONE NSTAR WAY, SE 250
WESTWOOD, MA 02090

CONSULTING SERVICES AGREEMENT

by

NSTAR ELECTRIC AND GAS CORPORATION

And

COMMONWEALTH ENERGY ADVISORS, INC.

August 15, 2003

Updated 01/22/02

CONSULTING SERVICES AGREEMENT

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PREFACE

The CONSULTING SERVICES AGREEMENT, hereafter referred to as the Agreement, is the standard Terms and Conditions under which NSTAR Electric & Gas Corporation (Company) will contract for consulting and technical services. It does not preclude a service provider (Supplier) from submitting more favorable or competitive terms in the future, which may be accepted by the Company.

CONSULTING SERVICES AGREEMENT

THIS CONSULTING SERVICES AGREEMENT is entered into effective August 15, 2003, between NSTAR Electric & Gas Corporation , its present and future Affiliates (Company), a Massachusetts corporation with a principal place of business at One NSTAR Way, Westwood, MA 02090 and Commonwealth Energy Advisors (Supplier), a consulting services Corporation with a principal place of business at 313 Boston Post Road West, Marlborough, MA 01752.

1.0 SCOPE OF SERVICES

Supplier agrees to perform for the Company services as may be requested from time to time by the Company. In the event that the Company shall desire any such Services ("Services"), then the Services desired, their cost, and the milestones for performance and payment will be more particularly described in a Contract or Contract Release (Contract) issued by the Company. "Contract" means the document issued by the Company awarding the work to the Contractor, describing generally the work to be performed by the Contractor, the time for commencement and completion of the work, and the amounts and manner of payment to the Contractor for the work. "Contract Release", as appropriate, is a document issued by the Company implementing a scope of work made under a blanket master Contract. Such Contract shall specifically refer to this Agreement and shall also indicate whether reimbursement is to be made on a Fixed Price (Section 2.1) or Recoverable Cost (Section 2.2) basis. Supplier shall indicate its acceptance by having each Contract signed by an authorized representative of the Supplier and returning it to the Company. No work is to be performed without a fully-executed Agreement and applicable Contract.

The Company shall designate, when necessary, a representative authorized to act on its behalf with respect to technical matters on each assignment who will furnish information for the Supplier.

This Agreement is not exclusive, and nothing herein shall be deemed to prevent the Company from engaging other suppliers to perform such Services or from performing such Services using its own employees.

2.0 COMPENSATION AND PAYMENT

The Contract shall specify whether Services are to be provided on a Fixed Price or Recoverable Cost basis.

2.1 Contracts on Fixed Price Basis

2.1.1 For performance of the Services described in each Contract, Company shall pay Supplier the Fixed Price set forth in such Contract in accordance with the payment schedule set forth in the Contract.

2.1.2 At any time, in accordance with procedure agreed upon by the parties, Company may request changes in writing, for additions or deletions to the Services in each Contract. In the event of any such change, Supplier shall promptly prepare and submit to Company a statement of the increase or decrease in cost, if any, to the Services and shall also inform Company as to whether such change may result in an extension of time to complete the Services. An amendment to such Contract describing the change, the effect, if any, on the schedule and cost of the Services shall be promptly agreed to and signed by Company and Supplier.

2.2 Contracts on a Recoverable Cost Basis

Each Contract shall include an estimate of the charges to be paid to Supplier on a Recoverable Cost basis, and Supplier shall not incur costs exceeding such estimate without an executed amendment to the applicable Contract

2.2.1 Recoverable Costs

The Company shall reimburse Supplier for costs and expenses incurred by Supplier in the performance of the Services in accordance with rates established by Supplier and provided in Appendix A (attached) and the expense guidelines set forth herein. Recoverable costs and expenses include the following:

2.2.1.1 Payroll and Related Personnel Costs

The hourly rates in Appendix A shall be fully loaded rates, including, but not limited to salaries (including vacation and holiday allowances), social and retirement benefits, all payroll taxes and all premiums for liability and property damage insurance, Workers' Compensation and Employer's Insurance and all insurance premiums measured by payroll costs, other benefits and contributions or taxes imposed by any applicable law or regulations, all overhead costs.

2.2.1.2 Other Costs and Rates

All expenses must be reasonable and directly associated with the delivery of the services. The supplier shall provide with each proposal an estimate of the expenses anticipated to be necessary to accomplish the scope of work authorized by the Company. In no circumstance shall such expenses exceed 15% of the costs incurred pursuant to 2.2.1.1 above.

NOTE: For local personnel, travel costs shall be limited to the difference in mileage from the Company required work location and the normal work location with no other allowances made.

2.2.1.2.1 The cost of all materials and supplies other than engineering supplies used or consumed in the performance of the Services. Engineering supplies used or consumed in the performance of the Services shall be included in Section 2.2.1.1.

2.2.1.2.2 All costs associated with models (including the cost of floor space occupied by models), reproduction of plans, specifications, reports and other data, at rates listed in Appendix "A".

2.2.1.2.3 Use of Data Processing computers, including related operator time, and use of standard programs at rates listed in Appendix "A".

2.2.2 Rate Stability & Volume Discount

Rates are to be fixed for a period of one year or for the duration of the Contract or Contract Release, whichever is longer. If both parties agree that extenuating circumstances warrant a modification to these rates prior to the time period described above, an amendment to this agreement or to the affected Contract or Contract Release shall be issued to incorporate the new rate(s).

When aggregate job hours accumulated under this Agreement for each calendar year exceeds the specified limits, the Billing Rate in Appendix "A" shall be adjusted as follows:

Annual Aggregate Job Hours	Discount

2.3 Invoicing

As soon as possible, after the end of each calendar month or completion of each payment milestone, in accordance with the agreed payment procedures, the Supplier shall submit an invoice, supported by copies of payroll abstracts, vouchers and other supporting documentation required by the Company. For reimbursable expenses, copies of all invoices, receipts, etc. for amounts greater than $25 should be included, in accordance with Internal Revenue Service Guidelines. Final invoicing shall be rendered within 30 days of submitting the notice of completion, referred to in Section 10.0. The Company shall pay all undisputed invoices within thirty (30) days of receipt of such invoice. A sample invoice is included as Appendix "B" showing minimum data required to process an invoice.

2.4 Examination of Accounts

The Supplier shall maintain, during the course of work, and retain, for not less than six (6) years after completion thereof, complete and accurate records of all of the Supplier's costs which are chargeable to the Company. The Company shall have the right at its expense, and upon notice to Supplier, at any time during ordinary business hours, to inspect and audit such records. The records to be maintained and retained by the Supplier shall include (without limitation): (a) payroll records accounting for the total-time distribution of the Supplier's employees working full or part time on the work (to permit tracing to payrolls and related tax returns) as well as canceled payroll checks or signed receipts for payroll payments in cash; (b) invoices and receipts for purchases, receiving and issuing documents, and all the other unit-inventory records for the Supplier's stores stock or capital items; and (c) paid invoices and canceled checks for materials purchased and for the subcontractors' and any other third parties' charges; (d) other documents and information relating to the achievement of performance or payment milestones, or deliverables.

3.0 CALCULATIONS, DRAWINGS, PLANS AND SPECIFICATIONS

All calculations, drawings, plans, specifications, reports and other deliverables developed by the Supplier under this Agreement, shall be the property of Company. All such calculations, drawings, plans, specifications, reports and other deliverables shall be delivered to Company in accordance with the schedule in the applicable attachments hereto and the Contract. The Company shall have access to work in process.

4.0 PROFESSIONAL RESPONSIBILITIES

4.1 General Responsibility and Warranty

Supplier assumes professional and technical responsibility for the performance of its services in connection with work assignments under this Agreement in accordance with best professional standards and practices and any additional guarantee or warranty offered in the applicable Contract. If, during the performance of Services or within three (3) years following completion thereof, such Services fail to meet the aforesaid standards or a defect is found, and Company notifies Supplier thereof in writing, Supplier shall promptly furnish remedial services and products necessary to correct such deficiencies.

4.2 Independent Contractor

It is the intent of this Agreement that the relationship of the Company and the Supplier be that of 'contracting party for services and independent contractor,' respectively.

4.3 OSHA Hazard Communication Standard

Supplier, prior to bringing hazardous chemicals or substances onto a Company facility and/or arranging for transportation of such chemicals or substances to a Company facility, shall notify Company management and provide the required MSDS for those items. Supplier is hereby notified that the Company has in place a Hazardous Communication Program in accordance with 29 CFR 1910.1200. This document is available for review and inspection by the Supplier or its representative.

4.4 Protection of Company Property

Supplier shall protect all Company property in its possession or utilized in the performance of the Services from any damage or loss. Company property destroyed, damaged, lost or stolen, except by act or omission of the Company, shall be replaced or repaired to the Company's satisfaction at Supplier's expense.

4.5 Compliance With Laws

Supplier will comply with all applicable laws, ordinances, rules regulations, codes and orders of any public body having jurisdiction.

4.6 Removal Of Supplier's Employees

The Supplier agrees to use only experienced, responsible, and qualified personnel to perform the work and further agrees to follow Company policies and procedures during the course of the same. The Company may require that the Supplier remove from the project persons who do not satisfy the aforementioned requirements or endanger persons or property, or whose continued work is inconsistent with the successful completion of the Services.

5.0 INDEMNIFICATION

5.1 The Supplier shall be responsible for the proper execution and completion of the Services and shall take all necessary precautions for prevention of injury to persons or damage to property in, about, or in connection with the Services. The Supplier shall indemnify, defend and save harmless the Company, its officers, employees, agents and contractors from all claims for damage to property or person, including death, suffered by any persons (including Supplier, his employees, contractors or agents) to the extent caused by the Supplier or its employees, agents, contractors or invitees.

5.2 Supplier shall also indemnify, defend (with counsel acceptable to Company) and save harmless the Company, its officers, employees and agents from all actions, claims, costs, damages, expenses and liability whatsoever arising or resulting from allegations that the services or any products or deliverables provided by Supplier infringe on or violate any patent, trademark, copyright, trade secret or any other proprietary interest. If the Company is enjoined from the use of services on the basis of infringement, the Supplier shall, at its expense, and at the option of the Company, either (a) procure for the Company the right of continued use, (b) replace or modify the same to make them non-infringing, or (c) remove the same at no cost to the Company, and refund the purchase price and all associated costs.

6.0 INSURANCE

Without limiting any of the other obligations or liabilities of the Supplier, the Supplier shall provide and maintain at its own expense (including deductibles) the following minimum insurance coverages:

6.1 Worker's Compensation and Employer's Liability Insurance in statutory amounts, with a minimum coverage amount of $500,000, to provide for payment to Supplier's employees employed on or in connection with the work covered by this Agreement and/or their dependents, of Workers' Compensation benefits including, when required, Occupational Disease benefits in accordance with applicable law (including, without limitations, the U. S. Longshoremen's and Harbor Workers' Compensation Act and the Jones Act).

6.2 Primary Comprehensive General Liability Insurance including Premises-Operations, Owners' and Contractors' Protective Liability and Completed Operations Insurance with combined single limit of $1,000,000 each occurrence for bodily and/or personal injury, including death and property damage. This policy is to also include Broad Form Property Damage, Blanket Contractual Liability (including obligations assumed under the indemnity provisions of this contract) and XCU hazards. Underwriters shall waive all rights of recovery against the Company.

6.3 Primary Comprehensive Automobile Public Liability (including owned, nonowned and hired automotive equipment), used in connection with the Supplier's Services; with a combined single limit for bodily injury or death and property damage of $1,000,000 per accident. This policy will also provide coverage for Automobile Comprehensive Fire and Theft, and Collision insurance. Underwriters shall waive all rights of recovery against the Company.

6.4 Professional Liability Insurance with limits of $1,000,000 per day with an annual aggregate cap of $1,000,000. Such insurance shall provide coverage for claims brought against the Supplier during the performance of his Services.

6.5 General Aggregate Insurance with a combined single limit for bodily injury and/or personal injury including death and property damage of $2,000,000 each occurrence excess of the above Primary Workers' Compensation/Employer's Liability, Primary Comprehensive General Liability and Primary Automobile Public Liability Insurance. Underwriters shall waive all rights of recovery against the Company.

6.7 Except as to Item 6.1, the Company shall be included as an additional named insured on all policies specified herein. The naming of the Company as an additional named insured shall not obligate the Company to pay any premium on the policies. Such insurance shall be primary insurance and shall contain a Severability of Interest clause with respect to each insured. The "Other Insurance" clause of such policies shall be modified, if necessary, to specify that any separate insurance maintained in force by the Company shall be considered excess insurance and shall not contribute with insurance extended by Supplier's and/or subcontractor's insurer(s) under this requirement.

6.8 Supplier shall, ten (10) days before commencing work under this Agreement and prior to expiration of any policy of insurance, deliver to NSTAR Electric & Gas Corporation, One NSTAR Way, Westwood, MA 02090 Attention: Procurement Director, three (3) copies of the Certificate(s) of Insurance completed by his insurance carrier or agent certifying that minimum insurance coverages as required above are in effect and will not be canceled or changed until thirty (30) days after written notice is given to the Company. The Supplier further agrees to deliver within ten (10) days of requests two copies of each of the above policies to the NSTAR Electric & Gas Corporation, One NSTAR Way, Westwood, MA 02090 Attention: Procurement Director, if so requested by the Company.

7.0 ASSIGNMENT

The Supplier shall not assign this Agreement, the services, nor any monies due or to become due hereunder without the advance written consent of the Company, which may be withheld at the Company's discretion.

8.0 SUBCONTRACTING

The Supplier shall not subcontract portions of the work without the prior written approval of the Company. Supplier hereby guarantees to the Company compliance by any such approved subcontractor (s) with the responsibilities and liabilities herein. The Supplier further agrees that the Company will not incur any duplicate costs as a result of such subcontracting.

9.0 TERMINATION

9.1 Termination for Default

The Company may terminate this Agreement or any Contract or Contract Release without prejudice to any other right or remedy Company may have, and without recourse against the Company, upon written notice to Supplier if: (1) Supplier should be adjudged bankrupt, (2) Supplier should make a general assignment for the benefit of his creditors or becomes insolvent, or (3) Supplier shall fail to comply with any of the provisions, commitments, schedules, covenants, specifications, instructions, and conditions of this Agreement or a Contract.

9.2 Termination for Convenience of the Company

The Company may terminate for convenience a Contract or Contract Release, in whole or in part by written notice to the Supplier. In such event, the Company shall make payment to the Supplier for those charges incurred prior to such termination that are recoverable pursuant to the terms hereof. This provision shall not be deemed to limit or otherwise affect the Company's right to terminate this Agreement or any Contract or Contract Release on account of the default of the Supplier.

10.0 NOTICE OF COMPLETION AND ACCEPTANCE

Upon completion of the Services under each Contract Release, Supplier shall notify the Company in writing in the form of notice letter, Attachment #1, of the date of said completion, and request confirmation of same by Company. Upon receipt of said notice, Company shall confirm to Supplier in writing if the Services referred to in said notice were completed on the date indicated in said notice or provide Supplier with a written listing of the Services not completed.

With respect to Services listed by Company as incomplete, Supplier shall promptly complete such Services and the above acceptance procedure shall be repeated.

11.0 SEVERABILITY

In the event that any of the provisions, or portions or application thereof, of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, Company and Supplier shall negotiate an equitable adjustment in the provisions of this Agreement with a view toward effecting the purpose of this Agreement and the validity and enforceability of the remaining provisions, or portions or applications thereof, shall not be affected thereby.

12.0 ARBITRATION

Any controversy or claim arising out of or relating to this Agreement, which might be the subject of a personal action at law or of a suit in equity may by agreement of the parties be submitted to the decision of a majority of three arbitrators in accordance with the applicable rules then obtaining of the American Arbitration Association, including the selection of the arbitrators. The controversy shall be submitted to the arbitrators within a reasonable time thereafter. Hearings shall be held in Boston, Massachusetts. The arbitrators shall determine which party shall pay the cost of arbitration or the manner in which such cost shall be divided between the parties. The submission and enforcement of the award shall be governed by Massachusetts law. Pending the result of the arbitration the Supplier shall proceed with the work in accordance with the instructions of the Company.

13.0 LAW CONTROLLING

This Agreement is executed with reference to the laws of the Commonwealth of Massachusetts and the rights and liabilities of the parties and the construction and effect of every provision hereof shall be subject to and construed according to said laws. The courts of the Commonwealth of Massachusetts shall be the venue for resolving any dispute hereunder, unless the parties otherwise agree in writing.

14.0 LIENS AND ATTACHMENTS

The Supplier shall not place nor permit any lien or attachment to be placed upon any property of the Company. In the event that any such lien or attachment is imposed, Supplier shall immediately discharge the same at Supplier's expense. Until such lien or attachment is removed, no payment will be made for any claim hereunder.

15.0 TAXES, INSURANCE, PREMIUMS

All Massachusetts State Sales Tax on materials and equipment rentals or any other taxable items will be paid for directly by the Supplier and not the Company. Said Massachusetts State Sales Tax shall be included in all proposals submitted. If appropriate, Company shall provide applicable sales tax exemption certificates upon request.

The Supplier agrees to assume full responsibility with respect to the Services covered by this Agreement for the payment of any federal or state payroll taxes or contributions, for unemployment insurance, workmen's compensation, old age pensions, annuities, and the like, in conformity with applicable law, regulations and rules and to indemnify the Company for any liability therefore.

16.0 AMENDMENTS

It is understood and agreed that amendments, when issued, shall be subject to all the terms, provisions and conditions of this Agreement and any applicable Contract.

17.0 EQUAL OPPORTUNITY CLAUSE

The terms and provisions of the Equal Opportunity Clause, Section 60-1.4 of Chapter 60 of Title 41 of the Code of Federal Regulations, regarding "Nondiscrimination in Employment by Government Contractors and Subcontractors", are incorporated by reference and made a part of this Agreement. Upon request, the Supplier shall supply the Company with a certificate demonstrating compliance with the foregoing.

18.0 ORDER OF PRECEDENCE

Should a conflict arise among the various documents which comprise the Agreement between the parties, the order of precedence shall be as follows:

18.1 The Contract and Subsequent Amendments

18.2 Any Addenda Specifically Referenced in the Contract

18.3 This Consulting Services Agreement

18.4 The Supplier's Technical Proposal

19.0 CONFORMITY WITH THE COMPANY'S PRACTICES AND PROCEDURES

Supplier agrees to comply with Company's standard practices and procedures regarding access to and activity performed at all the Company's facilities.

20.0 NONWAIVER

The Company's failure to insist on strict performance of any term, condition, or instruction, or to exercise any right or privilege here included or its waiver of any breach, shall not constitute a waiver of any failure in the future to observe such term, condition, instruction and/or any other right or privilege.

21.0 ENTIRE AGREEMENT

This Agreement constitutes the entire agreement between the parties hereto relating to the subject matter hereof, and supersedes any previous agreements or understandings. No preprinted terms and conditions contained in the Supplier's documents with respect to the Services shall be effective to modify or add to the terms and conditions which are contained in this Agreement unless agreed to in writing by both parties.

22.0 TERM OF AGREEMENT

This Agreement shall remain in force and effect from the effective date until the completion of the Services, unless earlier terminated in accordance with the terms hereof. This Agreement may be extended by mutual written agreement of the parties.

23.0 NOTICES AND CORRESPONDENCE

All notices and correspondence permitted or required to be given under this Agreement shall be in writing and shall be deemed duly given if delivered personally, by facsimile by confirmation of receipt, by courier, by evidence of delivery or on the fifth day following the date on which each such notices is deposited postage prepaid in the United States Mail. All notices, requests or communications shall be delivered or sent to the other party at the address shown below or to any other address as the party may designate by ten (10) days prior written notice given in accordance with this provision.

If to Company:
NSTAR Electric & Gas Corporation
One NSTAR Way – SE250
Westwood, Massachusetts 02090
Attention: Jeanne T. Brewer, C.P.M.

If to Supplier:
Commonwealth Energy Advisors
313 Boston Post Road West, Suite 210
Marlborough, MA 01752
Attention: Robert B. Hevert

24.0 CONFIDENTIALITY

The Supplier agrees to keep confidential all information provided by the Company (Confidential Information) pursuant to this Agreement. Confidential Information is not to be reproduced or disclosed to any third party, without the Company's permission, except to governmental or regulatory agencies. Confidential Information is not to be used by anyone other than the party to whom disclosed, nor used for any purpose other than the performance of Services and the completion of the Work.

25.0 LIMITATION ON PUBLICITY - REVISED

In order to provide the services described in this Proposal, the Supplier may indicate that it has (1) been awarded this assignment and/or (2) is performing this service. The Supplier may not otherwise advertise or promote using the name of the Company, the terms or existence of this Agreement, or the Supplier's relationship with the Company without the express written consent of the company. Supplier agrees to provide the Company with a copy in advance of distribution of any written material using Company name and/or information, for review, comment, and approval.

26.0 GIFTS, GRATUITIES AND CONFLICTS OF INTEREST

The exchange or offer of any money, gifts, services, or other benefits or gratuities by either party hereto to the other party hereto is hereby prohibited. This prohibition shall be applicable to the party's officers, employees, agents, employees and family members of the foregoing. Supplier hereby represents that to the best of its knowledge and/or belief, no economic, beneficial or employment, or managerial relationship exists between Supplier and any employee of the Company, or any member of such employee's family, which may tend to influence such employee (or those family members) in the performance of his or her duties on behalf of the Company. In the event Supplier becomes aware of any of the foregoing, the Supplier shall promptly advise the Company. Supplier further agrees to disclose any claim against the Company or the Company's affiliates, or the existence of any relationship with any other entity which is or may be adverse to the interests of the Company. In the event any activities or circumstances as described in this Section 26 arise, the Company shall have the right to elect to terminate this Agreement, effective upon the provision of written notice to the Supplier, without further recourse against the Supplier, and Supplier shall further retain all other rights and remedies in law or equity.

IN WITNESS WHEREOF, the parties have executed this Agreement on the day and year first above written.

NSTAR ELECTRIC & GAS CORPORATION

By:	Jeanne Brewer, C.P.M.	By:	James M. Stephens
Printed: Name:	Jeanne T. Brewer, C.P.M.	Printed: Name:	James M. Stephens
Title:	Sr. Contracts Agent	Title:	Vice President
Date:	August 15, 2003		8/18/03

APPENDIX "A"

SCHEDULE OF RATES

TABLE OF CONTENTS

Section	Description	Page
1.0	Billing Rates by Category	
2.0	Support Rates	
3.0	Other (Specify)	

CONSULTING SERVICES AGREEMENT

APPENDIX "B"

INVOICE

DATE:_____ Invoice #_____

JOHN DOE CORP.
10 HIGH STREET
BOSTON, MA 02111

TO: NSTAR ELECTRIC & GAS CORPORATION
Accounts Payable
P.O. Box 250
NORWOOD, MA 02062-0250

Contract #_____

Contract Release #:_____

BRIEF DESCRIPTION OF SERVICES PERFORMED IN ACCORDANCE WITH CONTRACT

LABOR	Description	Hours	Rate	Extension
	Consulting Engineer	8	$10.00	$ 80.00
	Technician	8	9.00	72.00
	Draftsman	8	8.00	64.00
	Secretary	8	7.00	56.00
		Sub-Total		$272.00

MATERIALS SUPPLIES: Itemized with paid vouchers attached

EXPENSES/PER DIEM RATES: Itemized with vouchers attached

SUB-CONTRACT WORK: Totals with paid vouchers attached

Sub-Total $000.00

GRAND TOTAL $272.00

CONSULTING SERVICES AGREEMENT

ATTACHMENT #1

NOTICE OF COMPLETION
CONTRACT NUMBER_____
CONTRACT DATED_____, 20__

The work provided pursuant to the Contract or Contract Release dated _____. 20_____. including all amendments as of the date of this Notice, (hereinafter called the "Project") between NSTAR Electric & Gas Corporation ("Company") and_____"Supplier") has been completed as of_____, 20__.

All defects in workmanship and materials reported during the period of construction of the Project have been corrected.

Agreed to this _____ day of _____, 20_____.

_____

BY:_____

TITLE:_____

NSTAR ELECTRIC & GAS CORPORATION

BY:_____

TITLE:_____