Testimony

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C 03-S-1672
Copies:
Mr. K. Lang
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March 16, 2004

Hon. Jaclyn A. Brilling
Secretary
New York State Department of
Public Service
Three Empire State Plaza
Albany, New York 12223

Re: Case No. 03-S-1672 – Con Edison Steam Rate Case.

Dear Secretary Brilling:

Enclosed is an original and five copies of the pre-filed testimony and exhibits of Paul M. Doherty in the above-referenced case, on behalf of TransGas Energy Systems, LLC.

Very truly yours,

READ and LANIADO, LLP
Attorneys for TransGas Energy Systems, LLC

By: [signature]
Sam M. Laniado

cc: Hon. William Bouteiller
All Parties to Case 03-S-1672

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Case No. 03-S-1672

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
STEAM RATES

DIRECT TESTIMONY OF
PAUL M. DOHERTY
ON BEHALF OF
TRANSGAS ENERGY SYSTEMS, LLC

March 16, 2004

Q. Please state your name and business address.

A. My name is Paul M. Doherty. I am employed by R.W. Beck as a Senior Project Manager/Mechanical Engineer at 550 Cochituate Road, East Wing, Framingham, Massachusetts.

Q. Please describe your educational training and professional experience.

A. I received an A.S. in Mechanical Design Engineering and a B.S. in Mechanical Engineering from Wentworth College of Technology. I have over 30 years of continuous experience in project and asset management, including development, contracts, supervision, design, operation and maintenance of power generation facilities. I am a registered professional engineer in Massachusetts and Alaska. A summary of my professional experience is attached as Exhibit __ PMD-1.

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-1)

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony on behalf of TransGas Energy Systems, LLC. ("TGE") TGE is the developer of a 1100 MW gas-fired, combined cycle cogeneration facility in Brooklyn, capable of selling steam, whose application for a certificate of environmental compatibility and public need is pending before the State Siting Board

Q. What is the purpose of your testimony?

A. My testimony addresses Con Edison's proposed cost allocation, between the electric and steam departments, of the capital and operation and maintenance costs (including fuel) of the East River Repowering Project ("ERRP"). I have also prepared illustrative opinions of probable avoided capital and operation and maintenance costs for Con Edison's steam operations. My analysis does not address retail ratemaking aspects.

Q. Why do you present opinions of probable avoided costs?

A. Counsel has advised that Con Edison is subject to a Commission order to negotiate in good faith for the purchase of steam from any competitive producer.[1] The Commission also stated that Con Edison "should be willing to enter into negotiations with any producer that can offer pricing under terms that are competitive with Con Edison's own avoided steam costs," so long as the new producer did not have excessive market power.[2] This steam rate case, in which all of Con Edison's steam costs, revenues, allocations and rates are scrutinized, is an appropriate forum to commence an examination of avoided costs.

Q. Please describe generally Con Edison's proposed allocation of ERRP costs between electricity and steam.

A. Con Edison witnesses Shansky and Rasmussen address the proposed allocation for ERRP. ERRP will become part of the steam rate base, but approximately two-thirds of the carrying costs (67%) will be allocated to the Electric Department. (Rasmussen, pp. 7-8, Shansky, p. 10). Approximately 90% of the ERRP fuel cost appears to be allocated to the Electric Department. (*See,* Exhibit __ PMD-2; Con Edison Response to Westchester No. 28)

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-2)

With respect to capital costs, Mr. Shansky allocated the heat recovery steam generators ("HRSGs"), associated piping, water treatment plant and steam interconnection to steam.

[1] Cases 96-S-1065, *et al.*, Order Concerning Phase II Steam Plan Report (December 2, 1999), p. 13.
[2] *Id.*, p. 7.

All other costs were allocated to the Electric Department (p. 10), including the gas turbine, generators, gas compressors, electrical and control equipment, pollution control equipment, foundations, balance of plant and miscellaneous equipment, construction contracts and contingency, pre-ERRP relocations and building alterations, upgrading electric and gas interconnection facilities, engineering, legal and startup costs and administrative and general (A&G) overhead costs.

All of the fuel consumed by the gas turbine is proposed by Mr. Shansky to be allocated to electric production "...since the gas turbines would have to be operated to produce electricity even if no steam were produced." The fuel used for supplemental firing in the HRSGs to increase steam production would be allocated to steam." (p. 11)

Q. Do you agree with Mr. Shansky's proposed allocations?

A. No, I do not. According to Mr. Shansky "...the cost of facilities that are jointly used by the Steam and Electric Departments are carried in the Electric Department Accounts and only the incremental costs related to steam production are allocated to the Steam Department." (pp. 9-10). In my opinion, the technology and engineering inherent in a cogeneration facility of this type do not lend themselves to such a cross-subsidized allocation. By way of background, Counsel advises me that in Case 27276, the case cited by Mr. Shansky, the PSC accepted Con Edison's proposal to transfer certain "processing charges and interdepartmental rents" from steam to electric. The PSC accepted Con Edison's argument that steam should be treated as a byproduct of steam-electric plants, especially given their increased electric generation after the summer 1977 blackout (18 NYPSC 1769). It thus reversed the proportional savings allocation established in the previous steam rate case.[3] The PSC also feared a continuing "exodus"

[3] 15 NY PSL 2220, 2237.

from the steam system: "[i]f the ultimate result of ever-increasing rates is the departure of all steam customers from the system, it will be disadvantageous to Con Edison's gas and electric customers." (18 NYPSC 1770).

Over the years this "steam subsidy" has been a matter of contention, and some exceptions have been made: For example, in 1981 (and again in 1991), the PSC found that labor costs at two steam-electric plants (Waterside and Hudson Avenue) should be divided 50-50; it noted Con Edison's argument that the plants were "dispatched" to meet steam department requirements, not electric power requirements. The PSC then repeated its earlier conclusion that although it may be difficult to say whether these plants exist for the benefit of electric customers or steam customers, that difficulty suggests that a 50-50 allocation of labor expense would be the most equitable solution (31 NYPSC 2181, 2192-93).

This cross-subsidy was continued in the most recent steam rate plan (Opinion No. 00-15),[4] where it was expected that ERRP would be operational and the proceeds from the First Avenue Properties sale would be available during the term of the steam rate plan. Con Edison now expects ERRP to become operational <u>after</u> the expiration of the current steam rate plan (September 30, 2004, Rasmussen at 8), and the First Avenue proceeds will not be available until later.

Counsel also advises that the settlement adopted in Opinion No. 00-15 proposed an allocation of the "net benefits" of the ERRP between steam and electric through the fuel adjustment clause.[5] The parties, however, were careful to state that "these provisions are only effective for the term of this Settlement and recognize that such

[4] Case 99-E-1621, *Opinion and Order Adopting Terms of Settlement*, Opinion No. 00-15 (issued December 1, 2000).

[5] *See* Agreement and Settlement, ¶ 5.

benefits and/or costs may be reallocated by the Commission when steam base rates are reset."

Q. Did counsel also provide you with any statements from the ERRP Article X proceeding that appear inconsistent with Con Edison's proposed allocations?

A. Yes. Section 2 of Con Edison's application to the Siting Board in Case 99-F-1621. Con Edison stated that the ERRP "is primarily a steam supply option and, therefore, its electric output is an ancillary benefit of its efficient cogeneration technology." (p. 2-10) In issuing a certificate for ERRP, the Siting Board stated:

> The primary purpose of the Project is to ensure that Con Edison can continue to supply its customers with reliable, reasonably priced steam by replacing the aging Waterside Generating Station (Waterside Station) with new, highly efficient natural gas-fired combined cycle equipment. It is the ancillary electrical output of the Project that requires the submission of the application under PSL Article X.[6]

It added that since the ERRP "is primarily a steam system supply option, an understanding of Con Edison's steam system is necessary to demonstrate the need for the Project" (p. 10), and then it proceeded to explain how ERRP would meet Con Edison's steam demands.

Q. Please describe the analyses R.W. Beck performed under your supervision to address the proposed allocation of ERRP.

A. Beck developed an opinion of probable cost of the capital cost of an electric-only generating plant with the electrical output equal to that provided by ERRP and that could be constructed on adjacent land controlled by Con Edison and within the time frame discussed by Con Edison for avoiding a lower Manhattan electric load pocket deficiency,

[6] Case 99-F-1314, *Opinion and Order Granting Certificate of Environmental Compatibility and Public Need*, (issued August 30, 2001), p. 5.

an assertion made by Con Edison in its Article X application (p. 2-8). After developing the opinion of probable cost, I compared the cost of this electric-only plant – $264.7 million – to Con Edison's current $670 million cost estimate for ERRP. With respect to the allocation of ERRP capital costs between the Electric and Steam Departments, I believe a more representative cost allocation is derived by dividing the equivalent electric plant-cost by the $670 million ERRP cogeneration plant cost. The result is that 39.6% of the ERRP capital cost should be allocated to the Electric Department and 60.4% should be allocated to the Steam Department.

Q. Has Beck performed another analysis to test this cost allocation?

A. Yes. An examination of the useful energy further substantiates this cost allocation. The total thermal efficiency of ERRP approximates 80 percent. The energy conversion efficiency of the combustion turbine alone is 30.4 percent (3,413 (Btu/kW-hr. ÷ 11,200 Btu/kW-hr. (net)). Comparing the combustion turbine electrical energy efficiency and the overall cogeneration efficiency for electric and steam results in a useful energy allocation of 30.4 percent ÷ 80 percent or 37.2 percent for electricity production and 62.8 percent remaining for steam production.

Q. Please describe the assumptions used in your equivalent-electric plant capital cost analyses.

A. To duplicate the electric generating technology included in the ERRP, Beck's opinion of probable cost was based on constructing a dual-fuel, dual-unit, simple-cycle General Electric ("GE") 7241 FA combustion turbine electric generating facility ("Facility") capable of producing a net electric output at 34 degrees F of 348,000 kW and operating at a heat rate of 11,200 Btu/kWh. The assumed site was in New York City, and more specifically: north of the existing East River Station on land controlled by Con Edison and capable of providing equivalent support to the lower Manhattan 69 kV and 138 kV systems.

In developing the cost opinion of probable cost, Beck assumed a time period of 20 months for detailed engineering, construction and startup. The time period selected was February 1, 2002 through September 30, 2003 with construction activities lasting from April 1, 2002 through September 30, 2003, or approximately 18 months. This is shorter than the overall time needed for the engineering and construction of ERRP because it takes advantage of a more orderly construction sequence. Repowering, as a general rule, tends to be more difficult and costly than new construction. A detailed summary of the cost analysis is presented in Exhibit __ PMD-3 and Exhibit __ PMD-4.

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-3)

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-4)

Q. Please describe Beck's other analysis to derive allocation percentages for capital, operating and maintenance, and fuel costs for ERRP.

A. Beck reviewed the fuel input and electric and steam energy outputs of ERRP. Our analysis is contained in Exhibit __ PMD-5.

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-5)

We examined the energy input and outputs of ERRP with the combustion turbine generators ("CTGs") producing maximum electrical output capacity and the HRSGs producing the maximum steam output capacity, with and without the duct burners in service. The duct burner, burning natural gas with CTG at full power output, provides increased heat input into the CTG exhaust, which is then used by the HRSG to produce additional steam.

We converted the electric output of ERRP from kilowatts to Btus per hour to facilitate consistent calculation and comparison of the natural gas heat energy input, steam heat energy output, and electric energy output of the cogeneration plant. With the CTGs at full capacity and the duct burners turned off, and the CTGs at full capacity and duct burners at full capacity, Beck calculated the useful electric and steam energy outputs of the ERRP in Btus per hour and expressed them as percent allocation of useful energy output.

With the duct burners not in use (off), we calculated 41% of the energy output was produced as electricity and 59% of the energy output was steam production. Repeating the same calculation method with the duct burners turned on at full capacity, electric and steam output was 25% and 75%, respectively, for the useful energy output of the cogeneration facility. Thus, the above analyses indicate that Con Edison's assignment of 67% of the capital costs and 90% of the fuel costs of ERRP to the Electric Department is unjustified.

Q. Please address Con Edison's proposed allocation of ERRP fuel costs.

A. As noted above, Mr. Shansky proposes to allocate all fuel costs associated with the gas turbines to the Electric Department, and the fuel associated with supplementary firing of the HRSGs for steam production would be allocated to steam. Again, his reasoning is that the gas turbines would have to be operated to produce electricity even if no steam were produced. (Shansky, pp. 10-11). However, these assumptions are flawed. If no steam production were required, the gas turbines would not be economic to operate in a base load fashion. Therefore, only the portion of fuel consumed by the gas turbines for economic electricity production should be allocated to electric. For the gas turbines, the difference between the base load fuel consumption and the fuel consumption for economic electricity production should be allocated to steam. All supplemental firing in the HRSGs should be allocated to steam.

Q. How can the amount of fuel required for economic electricity production be estimated?

A. Beck used historical electricity prices as an indicator for the amount of time that ERRP would have been economic to operate strictly for economic electricity production. To construct this analysis, Beck obtained the previous two years (February 7, 2002 – February 7, 2004) of hourly day-ahead electricity prices for Zone J in the competitive market administered by the New York Independent System Operator ("NYISO"), which encompasses the location of ERRP. To reconstruct the economic dispatch price of ERRP over this time period, Beck used the daily gas prices for Transco Zone 6 (NY) from the industry-leading publication of *Gas Daily*. Multiplying the daily gas price by the gas turbine net heat rate of 11,200 Btu per kWh and adding a variable O&M charge of $1.90 per MWh, a daily dispatch price was obtained. This daily dispatch price was matched against the hourly electricity prices for each day to determine the number of hours of economic electricity production for each day. The number of hours of economic electricity production were then averaged for the two calendar years. The percentage of hours per year of economic electricity production indicates the percentage amount of fuel that should be allocated to the electric department.

Q. Based on this analysis, what is the amount of gas turbine fuel that should be allocated to electric?

A. The historical electricity price analysis indicates that ERRP would have been economic to operate for electricity production, if no steam were produced, for 30 percent of the hours in a year. This percentage of hours of economic electricity production is expected to decline in the future as new, more efficient and lower cost combined-cycle gas turbine generators are built in New York City and Long Island. Consequently, the amount of fuel consumed by the gas turbine that should be allocated to electric should not exceed 30 percent. (Exhibit __ PMD-6 provides the workpapers for this analysis).

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-6)

Q. Do you have any other observations about Con Edison's proposed allocation of ERRP fuel costs?

A. Yes. The principal savings associated with ERRP stem from the significant change in the allocation of fuel costs for ERRP compared to the previous allocation of Waterside fuel costs. In the test year, Waterside sendout was 9,698,149 Mlbs., and the fuel costs assigned to steam production at Waterside were about $68,135,000 million. (Con Edison Witness Northrup workpapers). In the rate year, with about 90% of the fuel costs of ERRP assigned to electric, the projected sendout from that plant (which essentially replaces Waterside) is 11,847,600 Mlbs. of steam, yet the assigned fuel cost is only $10,803,600. (Northrup workpapers).

For the calendar year 2005 (as shown in Exhibit ___ PMD-2), the steam production is projected at 12,550,000 M/lbs., with a cost of $13,200,000, whereas electric production of 2143 GWH is projected to cost $141,229,000. Thus, the rate year fuel cost savings of $64 million advanced by Mr. Rasmussen (p. 10) is largely the result of the fuel cost allocation shift. (A part of the fuel cost savings results from a lower fuel price forecast and the improved efficiency of ERRP over Waterside.)

Q. Does Con Edison employ a different fuel allocation methodology for Waterside?

A. Yes. As noted in Con Edison Response to TGE-4, the steam heat rates, in Btu/lb., were used to allocate fuel usage between electric and steam production at Waterside. According to that response, the Turbine Exhaust and the Live Heat Rates are multiplied by the steam sendout generated via Turbine Exhaust or Live, resulting in the fuel Btus allocated to steam. The remaining fuel Btus are allocated to electric.

In contrast, as noted above, Mr. Shansky allocated only the fuel costs associated with the supplemental firing of the HRSGs at ERRP to steam. Though the plants' configurations are different, the allocation chosen by Mr. Shansky is flawed for the reasons noted above. The results of Con Edison's allocation are startling: for the rate year (as noted above), ERRP has a projected sendout of 11,847,600 M/lbs., with the cost of fuel only $10,803,600. In total, the steam electric plants produced a sendout of 14,197,000 M/lbs. at a cost of $98,280,000 during the test year, but in the rate year, assuming ERRP operation, the steam electric plants would produce 14,196,900 M/lbs. of sendout at a fuel cost of only $29,390.500.

Q. Considering that a simple electric plant is only forecasted to operate approximately 30 percent or less of all hours in a year, do you believe this type of facility could obtain financing if it operated without a power purchase contract?

A. No, I do not. Combined cycle units have faced difficulties obtaining financing and a simple cycle unit being less efficient would have even greater problems as it is difficult to cover debt and operating costs with competitive pricing for fuel and electricity.

Q. Can illustrative avoided costs be estimated from your analysis?

A. Yes. Exhibit __ (PMD-7) provides the results of that analysis. These opinions of probable cost are based on a proxy plant methodology using ERRP as the proxy plant.

MARK FOR IDENTIFICATION AS EXHIBIT __ (PMD-7)

For the avoided capital cost component, the electric-only plant opinion of probable cost ($264.7 million) is subtracted from Con Edison's current ERRP capital cost opinion of probable cost ($670 million), and the result ($405.3 million) is translated into an annual carrying charge ($69.115 million). This amount is then divided by the projected rate year steam sendout of ERRP to obtain a $/Mlb. figure. The resulting capital avoided cost is $5.83 Mlb. The non-fuel variable operating and maintenance costs are based on Con Edison's estimated cost of $0.34 Mlb. For avoided fuel costs, Con Edison's projected fuel costs have been accepted, but an alternative allocation between electric and steam consistent with my prior testimony, which reflects Con Edison's projected steam sendout from the HRSGs, was developed. The result is an opinion of probable avoided fuel cost of $6.72 Mlb. The sum of these figures results in an overall avoided steam cost for Con Edison of $12.90 Mlb. These opinions of probable cost are preliminary; for example, they do not include components such as fixed labor and administrative and general (including insurance) costs.

Q. Please summarize your conclusions and recommendations.

A. Con Edison's proposed allocation of the capital and variable costs of ERRP disproportionately and improperly assigns costs to the electric department. Based on the several analyses provided above, a proper allocation of these costs would result in the steam department bearing most of the ERRP capital and variable O&M costs. The illustrative opinions of probable avoided cost for Con Edison's steam operations presented above, should form the basis for deriving Con Edison's avoided steam costs.

Q. Does this conclude your pre-filed testimony?

A. Yes.

EXH. ___
PMD-1

Exh. ___
PMD-1

Paul M. Doherty, P.E.

Wentworth College of Technology
A.S. in Mechanical Design Engineering
B.S. in Mechanical Engineering

Mr. Doherty joined R. W. Beck in June 2001, as a Senior Project Manager/Mechanical Engineer. Mr. Doherty brings extensive senior level engineering and management expertise with over 30 years of continuous experience in project management, asset management, project development, site selection and assessment, acquisitions, due diligence, contracts, supervision, design, operation, and maintenance related to coal, biomass, and gas turbine power generation facilities.

Mr. Doherty has over 30 years of continuous experience in project management, asset management, development, contracts, supervision, design, operation and maintenance of power generation facilities.

Registered Professional Engineer in Massachusetts and Alaska.

R. W. BECK EXPERIENCE

Senior Project Manager. As a Project Manager, Mr. Doherty manages an inter-disciplinary team of seasoned engineering personnel to fulfill the scope of work requests of clients to high technical standards and within the budget constraints. He represents the client as the independent or owner's engineer. Mr. Doherty has performed operating, commissioning, and management assignments, in direct management control of the client. Mr. Doherty also performs due diligence for project financings, project acquisitions, and EPC construction contracts, construction implementation and plant commissioning.

Projects engaged included:

- Owner's Start–up and Commissioning Manager for a gas turbine generator co-generation unit in a manufacturing plant.
- Owner's engineer for 1,000 MWe cogeneration project
- Expert witness testimony in support of Owner's New York State Article X application for a new large cogeneration resource.
- Power augmentation feasibility study for a 50 MW cogeneration facility
- Facility design of larger replacement boiler feed pumps and related systems for a cogeneration facility.
- Interim Plant Manager during the transition from termination of a previous O&M contractor to alternate facility management structure in a biomass composting facility.
- Owners engineer review during design and construction of a repowered steam plant with an 'F' Class combustion turbine generator and heat recovery steam generator, utilizing an existing and a new steam turbine generators.
- Review and comment on EPC contract prior to solicitation for bids for a 1,200 MW combined-cycle facility.
- Review and comment on EPC contract prior to financing for a 50 MW combined-cycle facility.

R·W·BECK

- Design and cost study to repower steam plant with an 'F' Class combustion turbine generator and heat recovery steam generator utilizing two existing steam turbine generators.
- Design, cost and permitting feasibility review for LM6000 peaking and combined-cycle generation units.
- O&M audit of two LM6000 peaking facilities.
- Consult on gas turbine, combined-cycle, solid fuel, and biomass plant operation, maintenance and overhauls, focusing on technical, cost, long-range planning and commercial issues.

PREVIOUS EXPERIENCE

Thermo Ecotek Corporation

Waltham, Massachusetts

Director, Engineering Projects. As Director of Engineering Projects, Mr. Doherty had responsibilities for the following:

- Member of project development team for 7FA combined-cycle repower project in the southeastern United States. Agreements for gas turbine procurement, EPC contracts, energy conversion, gas/electrical interconnection, land lease, operation and maintenance, as well as permits for air emissions, water use and drainage and local zoning approval were completed.
- Lead negotiation for open book EPC contract for 1,000 MW 7FA combined-cycle merchant project in California.
- Searched and screened business opportunities and project sites for future power plant development. Made presentations to potential partners, power marketers and power customers.
- Instrumental in preparing successful bid to acquire two California utility power generation plants for future repowering and development as merchant plants.
- Functioned as Project Manager for site selection, acquisition, and future technical development and permitting of the newly acquired assets or projects.

Director, Operations and Engineering (Asset Management). In this position, Mr. Doherty had responsibilities for the following:

- Managed, coordinated, and oversaw engineering, maintenance and operations activities with a specific focus on optimizing operations and revenues of three existing biomass power plants, burning high moisture whole tree chips, sawmill waste and bark.
- Technical, financial, environmental, personnel, community and contractual commitments were managed to achieve financial objectives, while sustaining high availability and capacity factor.
- Perform due diligence, feasibility studies and negotiations for project/corporate acquisitions.
- Developed and negotiated national agreement for water treatment chemical supply.
- Developed and managed contracts for engineering services, fuel procurement, steam turbine generator and boiler repairs and overhauls as in internal consultant.
- Negotiated payment in lieu tax agreement with plant host city reducing real-estate tax significantly.

Lead Engineer. In this position, Mr. Doherty was responsible for the following:

- Start-up and ongoing operation and maintenance support of seven biomass generating units and one municipal waste recycling plant.
- Design and construction of a 25 MW fluidized bed biomass power plant.
  - Administered boiler and fuel receiving and handling contracts.
  - Coordinated design and contracts with in-house staff and A/E design engineers, and construction site.
  - Functioned as Chief Resident Engineer and Accounts Payable Manager during start-up and initial operation.
- Responsible for technical development of a 28 MW fluidized bed biomass unit, trash recycling facility, and a 55 MW gas-fired combined-cycle plant.
  - Performed research, analysis, and preliminary design to support licensing and project development.
  - Supervise development of specifications, general arrangements and process diagrams.
- Responsible for multi-discipline project management activities for a turnkey 31 MW fluidized bed biomass power plant.
  - Oversaw the design by an engineer and construction by a general contractor to ensure unit performance, quality, workmanship, schedule and cost.

Massachusetts Municipal Wholesale Electric Company

Ludlow, Massachusetts

Manager, Technical Services. In his capacity of Manager, Technical Services, Mr. Doherty performed the following tasks:

- Managed a multi-disciplinary engineering group providing technical/outage/environmental compliance support to an operating gas-fired 511 MW simple- and combined-cycle, GE 7001E gas turbine plant.
- Developed design modifications and supervised implementation into plant equipment and systems to enhance plant availability, heat rate and environmental compliance.
- Developed and specified gas and steam turbine maintenance procedures/contracts, including hot section refurbishment and major overhauls.
- Managed site selection, and relative ranking studies, for proposed generating facilities.

Charles T. Main, Inc.

Boston, Massachusetts

Lead Mechanical Engineer. As the Lead Mechanical Engineer for the Arkansas Power and Light Company, Mr. Doherty performed the duties:

- Primary responsibilities included engineering and design assistance to client and field personnel during plant construction and start-up of two 800 MW coal-fired units. Also supervised engineers, designers, and draftsmen to ensure accurate and timely flow of data to the construction site.

Project Engineer. As Project Engineer for Texaco, Inc./United Technologies, Mr. Doherty's duties encompassed:

- Supervised all engineering disciplines with respect to system design, project goals, procedures and fast-track schedule. The project included the design and construction of a cogeneration plant with two gas turbines (FT-4) exhausting to two steam generators to produce 80,000 LB/HR of steam and 44 MW for refining use.

Mechanical Engineer. Mr. Doherty's responsibilities included preparation of:

- Company guidelines for standardized design of compressed air, boiler blow-down/blow-off and condenser vacuum systems.
- Flow diagrams and developed specifications for plant equipment and systems for a proposal for a four-unit 800 MW oil- and gas-fired power plant for Nigeria.
- Conceptual design of a 600 MW coal-fired power plant for China.
- Technical training to foreign client personnel on power plant design and operation.

Stone & Webster Engineering Corporation

Boston, Massachusetts

Mechanical Engineer. Mr. Doherty was the Mechanical Engineer for the Beaver Valley Power Station – Unit 2:

- Responsible for the 900 MW turbine generator and ancillary systems and developed or revised flow diagrams, piping drawings and equipment specifications of major equipment and piping for above power plant systems.
- Completed extensive career development training program on technical and business subjects.

General Electric Company

Schenectady, New York

Gas/Steam Turbine Field Engineer, Installation and Service Engineering Department. In this capacity, Mr. Doherty's responsibilities included:

- Involved in the installation and maintenance of steam and gas turbine generators.
- Completed General Electric Turbine School and learned electro-hydraulic control systems, analog and digital controls, electrical and mechanical design of turbine generators, start-up and operating procedures, turbine generator installation, heavy rigging, project management and labor relations.

PROFESSIONAL ENGINEERING REGISTRATION

- Massachusetts, #32972M
- Alaska, #ME-6001

PROFESSIONAL AFFILIATIONS

Mr. Doherty is a member of ASME.

EXH. ___
PMD-2

COW-28

A handout distributed at the January 7, 2004 briefing by Con Edison indicates that PROMOD simulation will produce 2143 GWH annually from a plant having 288 MW of generating capability. From this simulated operation please provide a table showing for a year with normal weather:

a. Monthly Electric Peak power output.
b. Monthly electric energy output.
c. Monthly peak steam output.
d. Monthly steam production.
e. Quantity of fuel charged to the Electric system.
f. Cost of fuel charged to the Electric system.
g. O&M cost charged to the Electric system.
h. Quantity of fuel charged to the Steam system.
i. Cost of fuel charged to the Steam system.
j. O&M cost charged to the Steam system.

Response

The table below provides the data requested in b, d, e, f, h, and i. No estimates were made for the data requested in a and c in the PROMOD simulations. The data requested in g and j is provided in the response to COW – 15.

2005	(b.) Monthly Electric Energy Output (GWH)	(d.) Monthly Steam Production (MMLBS)	(e.) Quantity of Fuel Charged to the Electric System Gas (MMCF)	(f.) Cost of Fuel Charged to the Electric System Gas ($1000)	(h.) Quantity of Fuel Charged to the Steam System Gas (MMCF)	(i.) Cost of Fuel Charged to the Steam System Gas ($1000)
Jan	248	1,219	2,554.1	$ 19,441	207.2	$ 1,577
Feb	226	1,092	2,327.9	$ 17,599	172.0	$ 1,301
Mar	210	1,258	2,246.0	$ 13,649	301.3	$ 1,831
Apr	149	882	1,596.3	$ 8,484	202.6	$ 1,077
May	161	994	1,962.5	$ 10,390	122.0	$ 646
Jun	144	953	1,656.1	$ 8,683	130.9	$ 686
Jul	173	1,112	2,031.9	$ 10,820	218.1	$ 1,162
Aug	171	1,101	1,936.1	$ 10,250	211.8	$ 1,122
Sep	155	957	1,741.6	$ 9,023	112.7	$ 584
Oct	122	726	1,457.9	$ 7,733	70.7	$ 375
Nov	141	866	1,630.9	$ 9,155	44.2	$ 248
Dec	244	1,390	2,550.8	$ 16,001	413.3	$ 2,592
Total	2,143	12,550	23,692.1	$ 141,229	2,206.8	$ 13,200

EXH. ___
PMD-3

Exhibit__
PMD-3

Beck Engineering, PC
Equivalent-Electric Plant Cost Estimate

To compare the cost of constructing an electric-only generating plant with an electrical output equal to that provided by the East River Repowering Project ("ERRP"), Beck Engineering, PC ("Beck") prepared a Conceptual Planning Level Estimate of the Engineering, Procurement and Construction ("EPC") Costs for an electric-only generating plant.

To duplicate the electric generating technology included in the ERRP, Beck's estimate was based on constructing a dual-fuel, dual-unit, simple-cycle General Electric ("GE") 7241 FA combustion turbine electric generating facility ("Facility") capable of producing a net electrical output at 34 degrees F of 348,000 kW and operating at a heat rate of 11,200 Btu/kWh. The assumed site was in New York City.

In developing the cost estimate, Beck assumed a time period of 20 months for detailed engineering, construction and startup. The time period selected was February 1, 2002 through September 30, 2003 with construction activities lasting from April 1, 2002 through September 30, 2003 or approximately 18-months. This approximates the time that engineering and construction were underway for ERRP.

Beck's opinion of probable cost is $254,717,313 for the Total EPC Construction Cost of the Facility as presented in the attached summary. Beck's estimate of the major components of the cost was developed as follows:

Pre-Purchased Equipment

Beck assumed that the major equipment with long fabrication and delivery time (major long-lead equipment) would be pre-purchased by the Owner and then the equipment would either be physically supplied to the selected construction contractor by the Owner, or the applicable equipment purchase documents would be assigned to the construction contractor at the time the construction contract was signed.

Costs for the long lead equipment were developed from Beck's proprietary database containing historical data on the costs of similar equipment bought for similar electric generating facilities. Pricing used was based on equipment purchased at the time similar equipment would have been purchased to support the assumed Facility construction schedule.

Beck estimated total costs of $80,176,000 to purchase: two GE 7241 FA dual-fuel, dry low NOx, combustion turbine electric generators configured for inlet fogging; two generator step up transformers rated to 18kV/138kV service; two generator breakers; and one lot of major equipment spare parts.

Site Preparation and Earthwork

Site preparation and earthwork costs were estimated based on an assumed site area of approximately 3.5 acres to accommodate the required equipment and provide access for maintenance.

Costs for contractor mobilization, survey and plot work, and site clearing were developed based on historical data for similar projects with costs adjusted for timing and construction in New York City. Costs for placement of crushed stone surfacing, site paving, fencing and gates, and excavation and backfill for pipe trenches and electrical ductbanks was estimated based on developing quantities and then applying pricing from Beck's proprietary database and published sources for the associated costs.

All costs were adjusted for timing and location, including labor adjustments for productivity and prevailing wage rates during the period that construction was assumed to occur.

Beck estimated total costs of $1,617,000 for site preparation and earthwork, excluding demolition and site remediation which were estimated separately as noted below.

Structures and Improvements

Costs for structures for improvements including excavation and backfill, foundations, other concrete, buildings, and miscellaneous steel structures were developed mainly based on estimated quantities. Some miscellaneous items were estimated based on historical data in Beck's proprietary database for similar projects.

For the foundations, Beck conservatively assumed that pile foundations would be required. Only two buildings were included; one to house the gas compression equipment and one to house the water treatment equipment and ammonia storage facilities. The turbines and ancillary equipment were assumed to be furnished with noise-attenuating enclosures suitable for outdoor installation.

Pricing was based on Beck's proprietary database and published sources for the associated costs. All costs were adjusted for timing and location, including labor adjustments for productivity and prevailing wage rates during the period that construction was assumed to occur.

Beck estimated total costs of $7,938,000 for Structures and Improvements.

Mechanical

Mechanical costs were developed using appropriate techniques for the item. Costs, for equipment that was not pre-purchased and for the balance of plant equipment and tanks, were based on historical data from Beck's proprietary database supplemented by vendor quotes where required.

Installation costs for the tanks and equipment, including the pre-purchased equipment were based on historical data from Beck's proprietary database. Installation costs for other items such as piping and specialties, fire protection, water treatment, painting and insulation, and the compressed air system were also based on Beck's proprietary database.

All costs were adjusted for timing and location, including labor adjustments for productivity and prevailing wage rates during the period that construction was assumed to occur.

Beck estimated total costs of $55,917,100 for Mechanical.

Demolition and Modification

Demolition and modification costs were provided for by allowances. Very little demolition was included based on the assumption that the site chosen would not include significant existing structures.

This cost area also included an allowance of $2,000,000 for site remediation.

Beck estimated total costs of $2,050,000 for Demolition and Modification.

Electrical

Electrical costs were developed using appropriate techniques for the item. Costs, for equipment that was not pre-purchased were based on historical data from Beck's proprietary database supplemented by vendor budgetary quotes where required. Installation costs were based on historical data from Beck's proprietary database.

Beck also included an allowance of $4,200,000 for interconnection with the electric utility that includes the replacement of 69 and 138 KV breakers located at the East River and East 13th substations identified as in need of replacement by the Interconnection Study.

All costs were adjusted for timing and location, including labor adjustments for productivity and prevailing wage rates during the period that construction was assumed to occur.

Beck estimated total costs of $26,086,000 for Electrical.

Contractor's Indirect Costs

Contractor indirect costs for supervision labor, site offices, and other similar costs are commonly estimated as a percentage of the total directs costs. Beck has used a higher percentage than typical for similar large projects due to the New York City site location.

Beck estimated total costs of $20,854,092 for Contractor Indirect Costs.

Contractor Risk and Fee

Contractor Risk and Fee (profit) are commonly estimated as a percentage of the contractor's total direct and indirect costs. Beck has used a higher percentage than typical for similar large projects due to the higher risk associated with construction in New York City.

Beck estimated total costs of $29,195,729 for Contractor Risk and Fee.

Engineering Cost

Beck estimated total costs of $6,000,000 for Engineering Costs based on historical data from Beck's proprietary database.

Owner's Project Management and Permitting Costs

Beck estimated total costs of $2,500,000 for Project Management and Permitting Costs is based on historical data from Beck's proprietary database.

Allowance for Unknowns

Beck included an allowance of $22,383,000 for unknown costs based on historical data from Beck's proprietary database. This allowance is a higher percentage than typical for similar large projects due to the higher risk associated with construction in New York City.

Total EPC Construction Cost

Beck's opinion of probable cost is $254,717,313 for the Total EPC Construction Cost of the Facility based on the sum of the other items discussed above.

Other Estimate Basis Stipulations

Beck's conceptual planning level estimate is based on the following:

1. Budgetary quotes from manufacturers, vendors or suppliers.
2. In-house data base and historical records from similar projects of similar size.
3. Published cost estimating standard handbooks and/or vendors cost catalogs.
4. CTG procurement (pre-purchased equipment) cost for GE 7241 FA based on GE prices of $35,000,000 per machine prevailing at a period of high demand in early 2001 (when the equipment would have been pre-purchased to support the construction schedule). Late in 2001 and early in 2002, following the 911 attacks and Enron Bankruptcy, CTG prices began to slide significantly due to the weaker deregulated electric market and national economy. CTG procurement costs in 2004 have decreased by approximately 25% due to reduced demand.
5. Labor Rates: Average union rates including an allowance for premium time. Average rates were based on "all in" union labor rates for the construction period published in Engineering News Record for New York City.
6. Schedule: As discussed above; 20-months total, with 18 months from construction mobilization on April 1, 2002 to commercial operation on September 30, 2003.
7. Exclusions: Sales and use taxes and duties, financing costs (including interest during construction), insurance, development, land costs, property taxes, and other Owner's costs not shown above are not included.

8. Net electrical output at 34 °F = 356,000 kW gross less 8,000 kW for auxiliaries = 348,000 kW (net). Of the total 8000 kW of auxiliary load, 6000kW is for gas compression. The net electrical heat rate is 11,200 Btu/kWh.

9. Estimate Tolerance is approximately +25% to -5%.

EXH. ___
PMD-4

Exh. __
PMD-4

Beck Engineering, PC

Equivalent-Electric Plant Cost Estimate

GE Frame 7FA - Two Units

10-Mar-04

	ITEM AND DESCRIPTION	QTY	UNIT	LABOR COST	MATERIAL COST	SUBCONTR. COST	PLANT TOTAL
1	**Pre-Purchase Equipment**						
a	Pre-Purchase CTG, Dual Fuel, DLN, Inlet Fogging	2	EACH	$0	$70,000,000	$0	$70,000,000
b	Pre-Purchase Generator Step Up Transformer 18KV/138KV	2	EACH	$0	$5,876,000	$0	$5,876,000
c	Pre-Purchase Generator Breaker	2	EACH	$0	$300,000	$0	$300,000
d	Pre- Purchase CTG and Major Equipment Spare Parts	1	LOT	$0	$4,000,000	$0	$4,000,000
							$80,176,000
	CONSTRUCTION CONTRACTOR COSTS						
2	**SITE PREPARATION & EARTHWORK:**						
a	Mobilize	1	L.S.	$0	$0	$150,000	$150,000
b	Survey & Plot Work	1	L.S.	$11,000	$1,000	$0	$12,000
c	Site Clearing	1	L.S.	$158,000	$62,000	$0	$220,000
d	Crushed Stone Surfacing	12,702	Sq. Yd.	$139,000	$331,000	$0	$470,000
e	Site Paving (Bituminous Concrete)	1,233	Sq. Yd.	$12,000	$23,000	$0	$35,000
f	Fencing & Gates	3,726	L.F.	$112,000	$150,000	$0	$262,000
g	Trench Excavation - Oil, Water & Gas Piping	1200	L.F.	$7,000	$2,000	$0	$9,000
h	Duct Bank Trenching & Backfill	1500	L.F.	$234,000	$225,000	$0	$459,000
	SUBTOTAL - SITE PREPARATION & EARTHWORK						**$1,617,000**
3	**STRUCTURES & IMPROVEMENTS:**						
a	Structural Excavation	7,063	Cu. Yd	$208,000	$250,000	$0	$458,000
b	Structural Backfill	3,613	Cu. Yd	$100,000	$147,000	$0	$247,000
c	Concrete, Turbine Foundations	1,525	Cu. Yd	$456,000	$529,000	$0	$985,000
d	Concrete, SCR & Stack Foundations	1,562	Cu. Yd	$350,000	$433,000	$0	$783,000
e	Concrete, Compressor Building	558	Cu. Yd	$133,000	$154,000	$0	$287,000
f	Concrete, Water Treatment/Ammonia Bldg	286	Cu. Yd	$77,000	$78,000	$0	$155,000
g	Concrete - 55' Dia Fuel Oil Storage Tank Fdns	29	Cu. Yd	$8,000	$9,000	$0	$17,000
h	Concrete - 30' Dia Raw/Fire Water Storage Tank Fdns	18	Cu. Yd	$5,000	$5,000	$0	$10,000
i	Breaker & XFMR Foundations	1	L.S.	$59,000	$73,000	$0	$132,000
j	Piles	1	L.S.	$883,000	$1,722,000	$0	$2,605,000
k	Compressor Bldg	1	L.S.	$269,000	$194,000	$0	$463,000
l	Water Treatment/Ammonia Bldg	1	L.S.	$446,000	$317,000	$0	$763,000
m	Misc Steel & Concrete (Equipment Support)	1	L.S.	$510,000	$523,000	$0	$1,033,000
	SUBTOTAL - STRUCTURES & IMPROVEMENTS						**$7,938,000**
4	**MECHANICAL:**						
a	CTG Installation, Barge Unloading and Heavy Haul	2	EACH	$3,920,000	$0	$0	$3,920,000

Beck Engineering, PC

Equivalent-Electric Plant Cost Estimate

GE Frame 7FA - Two Units **10-Mar-04**

	ITEM AND DESCRIPTION	QTY	UNIT	LABOR COST	MATERIAL COST	SUBCONTR. COST	PLANT TOTAL
b	Gas Compressors with Knockout & Receiving Vessels	3	EACH	$2,700,000	$7,000,000	$0	$9,700,000
c	Stack, Silencer, SCR NOx &CO,Housing and Transition Duct	2	EACH	$900,000	$11,500,000	$0	$12,400,000
d	Fin Fan Cooler & Circ Pumps for GT auxiliaries	2	EACH	$450,000	$600,000	$0	$1,050,000
e	Fogging System For CTG Inlet Air Cooling - off base	2	EACH	$674,000	$552,000	$0	$1,226,000
f	Piping, Pipe Supports & Specialties	1	L.S.	$5,400,000	$4,000,000	$0	$9,400,000
g	Fire Protection (Allowance)	1	L.S.	$450,000	$450,000	$0	$900,000
h	Water Treatment - Carbon Filters, RO/Mixed Bed + DI Storage tank (	1	L.S.	$352,500	$1,200,000	$0	$1,552,500
I	BOP Equipment (Allowance)	1	L.S.	$6,000,000	$3,000,000	$0	$9,000,000
J	Painting and Insulation (Allowance)	1	L.S.	$0	$0	$5,250,000	$5,250,000
k	Instrument Air System w/ compressors and dryers	1	L.S.	$225,000	$237,600	$0	$462,600
l	Aqueous Ammonia Tank- 30,000 gal	1	Each	$30,000	$50,000	$0	$80,000
m	Fuel Oil Day Tank - 840,000 gal	1	Each	$0	$0	$336,000	$336,000
n	Fire and Raw Water Storage Tank - 350,000 gal	1	Each	$0	$0	$250,000	$250,000
o	Demineralizer Water Storage Tank-lined- 900,000 gal	1	Each	$0	$0	$390,000	$390,000
	SUBTOTAL - MECHANICAL						**$55,917,100**
5	**DEMOLITION and MODIFICATION**						
a	Demolition Allowance					$50,000	$50,000
b	Remediation Contingency					$2,000,000	$2,000,000
	SUBTOTAL - DEMO AND MODS						**$2,050,000**
6	**ELECTRICAL:**						
a	Control Room:						
	i. DCS Control System	1	L.S.	$612,500	$750,000	$0	$1,362,500
	ii. Controls & Instrumentation	1	L.S.	$210,000	$219,000	$0	$429,000
b	CEMS	1	L.S.	$245,000	$450,000	$0	$695,000
c	Lighting	1	L.S.	$147,000	$160,000	$0	$307,000
d	Power Cable, Wiring,- Conduit $ Raceways	1	L.S.	$6,002,500	$7,500,000	$0	$13,502,500
e	Elect. Equipment (Switchgear, MCC's & etc.)	1	L.S.	$1,729,000	$2,000,000	$0	$3,729,000
f	Auxiliary & Station Service Transformers	4	EACH	$122,500	$250,000	$0	$372,500
g	Install Generator Breaker	2	EACH	$245,000	$0	$0	$245,000
h	Isolated Phase Bus	2	EACH	$276,500	$750,000	$0	$1,026,500
I	GSU Transformers	2	EACH	$217,000	$0	$0	$217,000
j	Utility Interconnection Allocation	1	L.S.	$0	$0	$4,200,000	$4,200,000
	SUBTOTAL - ELECTRICAL						**$26,086,000**
7	**SUBTOTAL - CONSTRUCTION DIRECTS**						**$173,784,100**

Beck Engineering, PC

Equivalent-Electric Plant Cost Estimate

GE Frame 7FA - Two Units

10-Mar-04

	ITEM AND DESCRIPTION	QTY	UNIT	LABOR COST	MATERIAL COST	SUBCONTR. COST	PLANT TOTAL
8	CONTRACTOR'S INDIRECT COSTS						$20,854,092
9	SUBTOTAL - CONSTRUCTION DIRECTS & INDIRECTS						$194,638,192
10	CONTRACTOR RISK & FEE						$29,195,729
11	SUBTOTAL CONSTRUCTION CONTRACT VALUE						$223,833,921
12	ENGINEERING COST						$6,000,000
13	OWNER'S PROJECT MANAGEMENT AND PERMITTING COSTS						$2,500,000
14	SUBTOTAL PROJECT COST						$232,333,921
15	ALLOWANCE FOR UNKNOWNS						$22,383,392
16	ALLOWANCE FOR INTEREST DURING CONSTRUCTION						$10,000,000
17	TOTAL - EPC CONSTRUCTION COST						$264,717,313
	Nominal Rating at 34°F		348,000 kW (net)				$761/kW

ESTIMATE BASIS STIPULATIONS:

a. Budgetary quotes from manufacturer, vendor or supplier.

b. In-house data base and historical records from similar projects of similar size.

c. Published cost estimating standard handbooks and/or vendors cost catalogs.

d. CTG procurement cost for 7FA based on GE prices prevailing in 2001 due to high demand. CTG procurement costs in 2004 have decreased by approximately 25% due to reduced demand.

e. Labor Rates: Average union rates including an allowance for premium time. Average rates were based on "all in" union labor rates for the construction period published in Engineering News Record for New York City.

f. Schedule: Limited Notice to Proceed (engineering) on February 1, 2002. Assuming that the CTG's and other pre-purchased equipment were already purchased, site remediation characterized, and significant preliminary engineering completed to support permits and define the work. This 2 month advance work period allows for the start of detailed engineering, long lead procurements (other than turbines), and other activities required to support the Final Notice to Proceed and Construction Mobilization. Final Notice to Proceed April 1, 2002, which would allow site mobilization. An 18 Month Construction period including remediation, assuming a limited amount of remediation is required and that the time required for remediation in the field would allow for completion of critical engineering, procurement and construction staging/logistics activities. Substantial Completion/Provsional Acceptance (allowing Commercial Operation) on September 30, 2003.

Beck Engineering, PC

Equivalent-Electric Plant Cost Estimate

GE Frame 7FA - Two Units

10-Mar-04

ITEM AND DESCRIPTION	QTY	UNIT	LABOR COST	MATERIAL COST	SUBCONTR. COST	PLANT TOTAL

g. Exclusions: Sales and use taxes and duties, financing costs, insurance, development, land costs, property taxes, and other Owner's costs not shown above are not included.

h. Net electrical output at 34°F = 356,000 kW gross less 8,000 kW for auxiliaries = 348,000 kW (net). The net electrical heat rate is 11,200 Btu/kW

i. Estimate Tolerance +25% / -5%

EXH. ___
PMD-6

Exh. PMD-5

R·W·BECK

ERRP Economic Dispatch Analysis

Premise

- ConEd assumes that a simple cycle gas turbine ("CTG") cogeneration unit located in NY Zone J will dispatch in a baseload fashion, roughly 6000 hours per year
- To facilitate the allocation of cost between power and steam, an estimate of CTG operation without cogeneration is required
- A historical dispatch simulation was performed to estimate the amount of CTG operation without cogeneration over the prior two-year period in NY Zone J

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Exh. PMD-5

Market Assumptions

Exh. PMD-5

- Power Prices
  - Day-ahead NY Zone J hourly prices
  - 2/7/2002 through 2/7/2004
- Gas Prices
  - Daily Transco Zone 6 (NY) has price from GasDaily publication
  - Same time period as power prices
  - $0.30/MMBtu LDC transportation cost

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Generator Assumptions

- Generator Operating Characteristics
  - 11,200 Btu/kWh (HHV) full-load heat rate
  - $1.90 /MWh variable O&M cost
- Dispatch Cost = ((Transco gas + LDC transport charge) * Heat Rate) + VO&M

Exh. PMD-5

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Monthly Dispatch Results

Exh. ___
PMD-5

Year	Month	Dispatch Hours
2002	2	14
2002	3	41
2002	4	90
2002	5	161
2002	6	409
2002	7	579
2002	8	625
2002	9	344
2002	10	348
2002	11	359
2002	12	157
2003	1	148
2003	2	74
2003	3	177
2003	4	115
2003	5	27
2003	6	115
2003	7	372
2003	8	486
2003	9	325
2003	10	130
2003	11	169
2003	12	58
2004	1	118
2004	2	19

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Annual Dispatch Results
February to February

Exh. PMD-5

Year	Dispatch Hours
2002	3301
2003	2159

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Observations

Exh. ___
PMD-5

- It appears that a simple-cycle gas turbine without cogeneration would have dispatched significantly less than 6000 hours per year in the last two years
- With the expected construction of new, more efficient combined-cycle gas turbine power plants in Zone J, the expected dispatch should be further reduced in the future

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EXH. ___
PMD-6

Exh. __
PMD-6

East River Repowering Project - Useful Energy and Cost Allocation

Beck Engineering P.C. (Beck) reviewed the energy fuel energy input and electric and steam energy outputs of the East River Repowering Project (ERRP). Beck believes that cost allocation to electric and steam customers for reimbursement of capital, operating, maintenance and administrative costs to Consolidated Edison should be representative and proportional of actual electric and steam capacity and energy being produced by ERRP.

Beck analysis is summarized in the attached Tables 1, 2, 3 and 4. Beck examined the energy input and outputs of the ERRP project with combustion turbine (CTG) producing maximum electrical output capacity and the heat recovery steam generator (HRSG) producing the maximum steam output capacity, with and without the duct burners in service. The duct burner, burning natural gas with CTG at full power output, provides increased heat input into the CTG exhaust used by the HRSG to produce addition steam.

Beck converted the electric output of ERRP from kilowatts to Btu per hour to facilitate consistent calculation and comparison of the natural gas heat energy input, steam heat energy output, and electric energy output of the cogeneration plant. With CTG at full capacity and duct burners on at full capacity and turned off, Beck calculated the useful electric and steam energy outputs of the ERRP in Btu per hour and expressed them as percent allocation of useful energy output.

With duct burner not in use (off), Beck calculated 41% of the energy output was produced as electricity and 59% of the energy output was steam production. Repeating the same calculation method with the duct burner turned on at full capacity, electric and steam output was 25% and 75%, respectively, for the useful energy output of the cogeneration facility.

Exh. ___
PMD-6

Maximum CTG and HRSG Output - Fired Duct Burner Off
East River Repowering Project

Table 1 Energy Export Calculations		
CTG Output at ISO	kW	344,364
Electric Energy Exported	Btu/hr	1,174,969,968
Unfired Steam output at ISO	lbs/hr	1,413,086
Enthalpy of Export Steam	Btu/lb	1,226
Enthalpy of Condensate	Btu/lb	30
Steam Energy Exported	Btu/hr	1,690,785,661
Total Plant Energy Output	Btu/hr	2,865,755,629
% of Total Exported Energy as Electricity		**41%**
% of Total Exported Energy as Steam		**59%**

Table 2 Thermal Efficiency Duct Burner Off		
Total Fuel Consumption	mmBtu/hr HHV	3,604
Total Plant Energy Output	mmBtu/hr HHV	2,866
Thermal Efficiency		80%
Steam Heat Rate	Btu/lb steam	2,550

Maximum CTG and HRSG Output - Fired Duct Burner On
East River Repowering Project

Table 3 Energy Export Calculations		
CTG Output at ISO	kW	344,364
Electric Energy Exported	Btu/hr	1,174,969,968
Fired Steam output at ISO	lbs/hr	3,000,000
Enthalpy of Export Steam	Btu/lb	1,226
Enthalpy of Condensate	Btu/lb	30
Steam Energy Exported	Btu/hr	3,589,560,000
Total Plant Energy Output	Btu/hr	4,764,529,968
% of Total Exported Energy as Electricity		**25%**
% of Total Exported Energy as Steam		**75%**

Exh. ___
PMD-6

Table 4 Thermal Efficiency Duct Burner On		
Total Fuel Consumption	mmBtu/hr HHV	5,731
Total Plant Energy Output	mmBtu/hr HHV	4,765
Thermal Efficiency		83%
Steam Heat Rate	Btu/lb steam	1,910
Duct Fired Incremental Heat Rate	Btu/lb steam	1,340

EXH. ___
PMD-7

Exh. PMD-7

East River Repowering Fuel Cost Chargeable to Electric and Steam

Fired case @ 54°F			
Heat Input	3246.8	mmbtu/hr	LHV
	3600.4	mmbtu/hr	HHV
Duct Burner Heat Input	958.0	mmbtu/hr	LHV
	1062.3	mmbtu/hr	HHV
Total Fuel Usage	4662.7	mmbtu/hr	HHV
Fuel Cost	$5.71	/mmbtu	HHV
Hourly Fuel Cost	$26,624.03	$USD/HR	
Electric	344,364	KW	
Electric Equivalent as Heat	1,176,003,060	Btu/hr	
Percent Output-Electric	24.2%		
Fuel Cost Chargeable to Electric	$6,450.33	$USD/HR	
Steam Flow Output	3,000,000	Lb/hr	
Enthalpy	1,226	Btu/lb	
Heat Output	3,678,000,000	Btu/hr	
Percent Output-Steam	75.8%		
Fuel Cost Chargeable to Steam	$20,173.70	$USD/HR	
Fuel Cost Chargeable to Steam	$6.72	$USD/1000LB Stm	
Total Output-Elect&Steam	4,854,003,060	Btu/hr	

Illustrative
East River Repowering Project
Avoided Steam Costs*

Line Number			Source
1	Total ERRP Capital Cost	$ 670,000,000	Exhibit (VG-1)
2	Proxy Electric Plant Cost	$ 264,700,000	Doherty Analysis
3	ERRP Allocated Steam Capital Cost	$ 405,300,000	Line 1 minus Line 2
4	ERRP Annual Carrying Charge	$ 114,254,000	Exhibit (EJR-1)
5	ERRP Percentage Carrying Charge	17.1%	Line 1 divided by Line 4
6	ERRP Steam Annual Carrying Charge	$ 69,115,144	Line 3 times Line 5
7	ERRP Variable O&M	$ 5,357,000	Exhibit (EJR-1)
8	Percent Allocated to Steam	75.8%	Doherty Analysis
9	ERRP Steam Variable O&M	$ 4,060,606	Line 7 times Line 8
10	ERRP GTs 04/05 Steam Sendout (Mlbs)	10,293,900	Workpapers for Exhibit (IN-1)
11	ERRP Duct 04/05 Steam Sendout (Mlbs)	1,553,600	Workpapers for Exhibit (IN-1)
12	ERRP Total 04/05 Steam Sendout (Mlbs)	11,847,500	Sum of Lines 10 and 11
13	Average 04/05 Fuel Price ($/MMBtu)	$ 5.71	Average of Oct 04 - Sept 05 Prices from Exhibit (IN-2)
14	ERRP Avoided Capital Cost ($/Mlbs)	$ 5.83	Line 6 divided by Line 12
15	ERRP Avoided Variable O&M ($/Mlbs)	$ 0.34	Line 9 divided by Line 12
16	ERRP Avoided Fuel Cost ($/Mlbs)	$ 6.72	Doherty Analysis at Fuel Price from Line 13
17	Total ERRP Avoided Cost ($/Mlbs)	$ 12.90	Sum of Lines 14, 15 and 16

*Does not include cost components such as fixed labor, administrative and general (including insurance).