

PAUL A. OLMSTED - GAS

- 1 Q. Please state your name and business address.
- 2 A. My name is Paul A. Olmsted and my business address is
3 111 Broadway, Suite 1601, New York, New York 10006.
- 4 Q. By whom are you employed and in what capacity?
- 5 A. I am Director, Energy Management Gas Supply of
6 Consolidated Edison Company of New York, Inc. ("Con
7 Edison").
- 8 Q. Please state your educational background.
- 9 A. I graduated from the University of California at
10 Berkeley in 1980 with a Bachelor of Arts degree in
11 History and received a Master's in Business
12 Administration from New York University in 1996.
- 13 Q. Please describe your work experience.
- 14 A. Between 1981 and 1989, I was a Senior Economist with
15 Petroleum Research Associates, an energy consulting
16 firm in New York City. I joined the Gas Supply
17 Department of Con Edison in 1989 as a Senior Analyst.
18 I became Manager of Planning and Economic Analysis in
19 1992. In 1996, I became Director of Gas Supply; in
20 1999, General Manager of Technical Operations in Gas
21 Engineering; and, in October 2003, Director of
22 Purchasing. I assumed my current responsibilities as
23 Director of Gas Supply in April 2006.
- 24 Q. Please generally describe your current

1 responsibilities.

2 A. I am responsible for the following areas in the Gas
3 Supply Department: (i) gas purchasing and scheduling;
4 (ii) gas billing and analysis and contract
5 administration; (iii) gas hedging and market analysis;
6 (iv) gas transportation services; and (v) and long- and
7 short-term planning. As Director of Gas Supply, I
8 oversee these areas for both Con Edison and Orange and
9 Rockland Utilities, Inc. ("O&R" or "Orange and
10 Rockland") (jointly referred to as "the Companies"),
11 except that O&R is responsible for its own gas
12 transportation services.

13 Q. Do you belong to any professional organizations?

14 A. Yes, I am a member of the Society of Gas Operators.

15 Q. Have you previously testified before the New York State
16 Public Service Commission ("Commission")?

17 A. I submitted testimony in Case 93-G-0096, Case 06-G-1332
18 and Case 08-G-1398.

19 Q. Please summarize the areas covered in your testimony.

20 A. I will discuss the Companies' gas purchasing and
21 hedging programs and explain how the Companies strive
22 to provide a reasonably-priced gas supply for their
23 customers that reflect the Companies' efforts to (i)
24 maintain a reliable gas supply, (ii) minimize gas costs

1 to their firm customers, and (iii) reduce gas price
2 volatility, consistent with Commission policy for gas
3 utilities. I will also address: (i) the measures that
4 the Companies undertake to maintain system reliability;
5 (ii) the Companies' gas supplier and transportation
6 contract procurement process; (iii) the Companies'
7 long-term planning process; (iv) the Companies'
8 Marginal Supply Cost Study; and (v) lost and
9 unaccounted for gas.

10 Q. I show you Exhibit ___ (PAO-1), Schedules 1 through 12,
11 and ask if this was prepared under your direction and
12 supervision?

13 A. Yes, it was.

14 MARK FOR IDENTIFICATION AS EXHIBIT ___ (PAO-1)

15 GAS SUPPLY PROGRAM

16 Q. Please describe the nature of the Companies' gas supply
17 portfolio.

18 A. Con Edison and O&R have implemented a combined
19 portfolio that allows for the joint utilization of
20 their gas supply and pipeline contracts. The combined
21 portfolio is operated for the benefit of the firm gas
22 customers of both Con Edison, including its steam
23 customers, and O&R. The structure of the Companies'
24 combined portfolio is illustrated on Schedules 1, 2, 3,

1 and 4 of Exhibit __ (PAO-1).

2 Q. Please describe the objective of the Companies' gas
3 purchasing and hedging programs.

4 A. The Companies' objective is to obtain a reasonably-
5 priced gas supply that reflects their efforts to (i)
6 maintain a reliable gas supply, (ii) minimize gas costs
7 to their firm customers, and (iii) reduce gas price
8 volatility. The objective also includes maintaining a
9 diverse gas supply and capacity portfolio, thus giving
10 the Companies the ability to meet design winter
11 requirements of firm gas customers, the flexibility to
12 react to changing weather conditions, and to maximize
13 the ability to maintain service during a contingency
14 event affecting a major pipeline or supply basin.

15 Q. How do the Companies seek to maintain reliability of
16 supply?

17 A. One of the cornerstones of a reliable gas supply
18 portfolio is its diversity. The Companies' combined
19 gas supply and capacity portfolio includes supplies of
20 both domestic and Canadian gas production, as set forth
21 on Exhibit __ (PAO-1), Schedule 1, Gas Supply
22 Contracts. The Companies also have firm pipeline
23 capacity contracts with nine different interstate
24 pipeline transportation companies, as set forth on

1 Exhibit __ (PAO-1), Schedule 2, Pipeline Transportation
2 Contracts, which illustrates the various points. In
3 addition, the Companies have a number of contracts for
4 underground storage. These storage contracts are
5 listed on Exhibit __ (PAO-1), Schedule 3, Storage
6 Contracts. As a note, the Company's Middletown propane
7 facility was decommissioned and retired in the spring
8 of 2009 following completion of the Millennium gas
9 transmission pipeline, which was operational December
10 2008. The deliverability of the LNG peaking facility
11 is set forth on Exhibit __ (PAO-1), Schedule 4.

12 Q. What are design weather conditions?

13 A. The peak day represents the quantity of gas that Con
14 Edison's firm customers would require in a twenty-four
15 hour period at an average daily temperature of zero
16 degrees Fahrenheit. Exhibit __ (PAO-1), Schedule 5,
17 Consolidated Edison/O&R Peak Day Forecasted
18 Requirements, shows the forecast of each Company's firm
19 customers' peak day demand for each winter period
20 (*i.e.*, November through March) beginning with the
21 winter of 2010/2011 through winter 2012/2013. Gas
22 Supply also calculates the gas requirements for meeting
23 demand over the course of a winter under severe weather

1 conditions (a "design winter") in order to establish
2 storage and peaking supplies that are adequate.

3 Q. Please explain how the Companies' contracts enable them
4 to meet these design weather conditions.

5 A. Peak day demand is met through the delivery of firm
6 supply via the Companies' firm pipeline transportation
7 capacity, withdrawals from firm market area storage
8 capacity, delivery of firm peaking supplies to the
9 Companies' city gates, and gas vaporized at the LNG
10 plant. Exhibit __ (PAO-1), Schedules 2, 3, and 4,
11 demonstrate how the Companies plan to meet design
12 winter conditions.

13 Q. Why is underground market area storage an important
14 component of the Companies' gas supply portfolio?

15 A. Underground market area storage serves three purposes
16 for local distribution companies.

17 First, the proximity of market area storage to the
18 service territory avoids the higher costs of
19 contracting for long-haul pipeline transportation
20 capacity to meet load on only the coldest days and
21 increases utilization of existing long-haul pipeline
22 transportation capacity during the summer storage
23 injection season to fill market area storage fields.

24 Second, market area storage provides flexibility

1 for gas deliveries that helps keep the Companies'
2 system supply in balance with both full service and
3 retail choice customer demand. That is, market area
4 storage is an integral part of the Companies' ability
5 to provide essential load-following services, which in
6 turn provides the Companies with flexibility to react
7 to lower customer demand during warmer-than-normal
8 periods and higher demand during colder-than-normal
9 periods. The Company is recommending changes to
10 simplify its load-following service as outlined in the
11 Gas Rate Panel testimony. In addition, the ability to
12 divert city gate deliveries into storage or to move gas
13 out of storage to the city gate within a gas day
14 enables the Companies to balance their system
15 deliveries with customer usage and gas marketers'
16 deliveries.

17 Third, market area storage allows the Companies to
18 take advantage of seasonal price opportunities. Gas
19 prices in the summer have been lower on average than
20 during winter months. The process of filling storage
21 to the Companies' targeted levels during the summer and
22 withdrawing this gas during the winter assists in
23 reducing price volatility to firm gas customers.

24 Q. Why is production area storage a component of the

1 Companies' portfolio?

2 A. Production area storage provides the following
3 benefits:

4 (1) Production area storage offers protection from
5 wellhead freeze-offs and delivery disruptions
6 during hurricane-related events, which proved to
7 be critical during August and September 2005, when
8 the Companies experienced supply disruptions
9 totaling approximately 8 Bcf during Hurricanes
10 Katrina and Rita.

11 (2) Depending on market conditions, production area
12 storage can act as a supply source displacing
13 higher cost gas purchases that would otherwise be
14 needed to satisfy the requirements of the full
15 service customers.

16 (3) Production area storage also provides flexibility
17 to balance the intra-day changes in system loads
18 by allowing deliveries in and out of the fields as
19 required. As the Companies' retail choice
20 programs have grown, this flexibility has
21 increased in importance.

22 Q. Please describe the initiatives the Companies have
23 taken in the wholesale market to minimize gas costs.

24 A. The Companies strive to minimize gas costs by using a

1 competitive bidding process through Requests for
2 Proposals ("RFPs") to the marketplace and by taking
3 advantage of opportunities that arise through the
4 Companies' participation in the Northeast Gas Markets
5 group. The Companies also seek to optimize their
6 combined portfolio primarily through capacity releases,
7 as well as off-system bundled sales.

8 Q. Please provide an illustration of the benefits from the
9 Companies' portfolio optimization efforts.

10 A. Exhibit __ (PAO-1), Schedule 6, Non-Traditional
11 Revenues, illustrates annual benefits received from the
12 Companies' portfolio optimization efforts to minimize
13 overall costs to their firm gas customers.

14 Q. Do the Companies incur any fees associated with the
15 purchase of natural gas supply?

16 A. Yes. The Companies have a management services
17 agreement with Alberta Northeast Gas Limited ("ANE").
18 ANE provides services associated with Canadian pipeline
19 transportation capacity and gas supply through its
20 designee Northeast Gas Markets LLC ("NEGM"). NEGM
21 provides management services to a number of other gas
22 distribution companies in the northeast. NEGM provides
23 day-to-day services needed to permit the Companies to
24 use their Canadian supplies. These services include

1 scheduling, process and auditing bills to ensure
2 accuracy, and preparing and filing regulatory and
3 customers reports in Canada and U.S. relating to the
4 gas supply. NEGM also assists with negotiation and
5 execution of Canadian gas transportation contracts and
6 gas supply contracts. The fees paid to NEGM are a
7 fixed per-unit cost and do not vary with the cost of
8 gas. The price, terms, and conditions included in the
9 management services agreement with the Companies are
10 identical to those that NEGM has with the other
11 utilities for the same services.

12 Q. How does the Company recover these fees?

13 A. The Company recovers the fees paid to ANE through its
14 Gas Cost Factor mechanism.

15 PRICE VOLATILITY REDUCTION

16 Q. What efforts have the Companies undertaken to reduce
17 the volatility of gas prices to their firm gas
18 customers?

19 A. Through active management of the combined gas supply
20 and transportation portfolio, the Companies seek to
21 reduce the volatility of gas prices delivered to their
22 firm gas customers. Specifically, the Companies take
23 advantage of: (1) pricing mechanisms in their gas
24 supply contracts, (2) storage utilization, (3) firm

1 transportation agreements on numerous interstate
2 pipelines, and (4) a gas hedging program.

3 Q. Please explain.

4 A. The Companies' gas supply contracts generally provide
5 the option to trigger a NYMEX price, use first-of-the
6 month index prices, or negotiate a monthly commodity
7 price months before commencement of the delivery
8 period. If the future commodity price is agreed upon
9 in advance, the cost of gas for these quantities is no
10 longer subject to market volatility. As I previously
11 described, storage also plays a significant role in
12 reducing the volatility of total gas costs. Gas is
13 injected into storage during the summer months, when
14 the price of gas has traditionally been lower than in
15 the winter months, and stored for use by firm customers
16 during colder winter days.

17 Long-haul firm transportation agreements, in
18 addition to satisfying the need for reliability of gas
19 deliveries, enables the Companies to avoid the
20 volatility of basis (*i.e.*, the value of transporting
21 gas from a supply point to a delivery point), which
22 would be the case if the Companies were to buy
23 transportation capacity to the market area on an as-
24 needed basis.

1 Q. Please describe the Companies' gas hedging program.

2 A. The Companies' hedging program is designed to reduce
3 gas price volatility. One of the hedging program's
4 components is the Monthly Plan, which dictates the use
5 of physical price locks and/or various financial
6 instruments to hedge natural gas prices for part of the
7 gas supply necessary to meet the monthly requirements
8 of firm sales customers. The program provides for the
9 Companies to hedge a minimum quantity of its forecasted
10 sales using physical and/or financial price hedges
11 throughout the year.

12 Q. How have the Companies managed credit issues?

13 A. Credit risk is managed by the oversight of two risk
14 committees. One is the Risk Oversight Committee
15 ("ROC"), comprised of senior officers of the Companies,
16 and the other is the Regulated Risk Management
17 Committee ("RRMC"), comprised of other officers of the
18 Companies. The ROC oversees corporate risk strategy
19 and establishes risk policies from an enterprise-wide
20 perspective, including credit risk. The ROC also
21 establishes credit risk tolerances, including the
22 amount of credit the Companies will extend to a
23 counterparty. The RRMC approves credit risk policies
24 and procedures and assures compliance with the policies

1 and procedures governing the wholesale energy
2 activities of the Companies. The RRMC approves the
3 appropriate risk measurement methodologies so that
4 exposures are consistent with the Companies' risk
5 policies and credit limits.

6 Furthermore, the Companies have a separate
7 department, Energy Risk Management Utilities ("ERM"),
8 to oversee and manage credit risks associated with gas
9 and electric purchases. ERM establishes a credit limit
10 for each counterparty with whom the Companies have
11 physical or financial exposure. ERM monitors and
12 reports to the RRMC and ROC on the counterparties'
13 credit limits and ratings and the Companies' exposure
14 to these counterparties.

15 SUPPLY AND CAPACITY PORTFOLIO CHANGES

16 Q. What changes in the Companies' supply portfolio do you
17 anticipate prior to and within the rate year?

18 A. As illustrated in Exhibit __ (PAO-1), Schedule 1,
19 certain of the Companies' gas supply contracts expire
20 each year. Existing domestic contracts may be
21 renegotiated or replaced through competitive bidding or
22 RFPs; and Canadian supplies may be added/replaced
23 through NEGM, which (as discussed above) acts as the
24 agent for a group of utilities, including the

1 Companies.

2 The gas supply contracts typically have one-,
3 three-, or five-year terms. Prior to contract
4 expiration, Gas Supply evaluates whether the supply is
5 required, which depends on, among other things, the
6 status of retail access in the Companies' service
7 territories. Exhibit ___ (PAO-1), Schedule 1, lists
8 all gas supply contracts effective winter 2009/2010.

9 Q. Do you anticipate any changes in the capacity
10 portfolio?

11 A. As transportation and storage contracts near the end of
12 their existing terms, Gas Supply evaluates and
13 determines the need for each contract. Assuming the
14 contract is required to meet firm gas customer load
15 and/or manage gas system operations, Gas Supply
16 conducts an assessment of the marketplace to determine
17 if alternative transportation and/or storage contracts
18 of at least equal reliability and flexibility can be
19 acquired more economically. If more desirable
20 replacement contracts cannot be supplied by the
21 marketplace, these contracts will be renewed,
22 consistent with existing pipeline tariff Right of First
23 Refusal ("ROFR") provisions or other applicable
24 contract provisions. This past year, the Company let

1 approximately 3 Mdt/day of capacity on Columbia Gas
2 Transmission expire based on operational and economic
3 considerations. The capacity was replaced with
4 peaking supply.

5 REGULATORY ACTIVITIES

6 Q. Have the Companies been involved in any regulatory
7 efforts taken to maintain the reasonableness of their
8 gas costs and the reliability of their supply?

9 A. The Companies participate in a myriad of Federal Energy
10 Regulatory Commission ("FERC") proceedings involving
11 (i) their pipeline and storage providers ("service
12 providers") and (ii) FERC generic issues that impact
13 the cost and quality of the gas service received by the
14 Companies from FERC-regulated entities. Exhibit ____
15 (PAO-1), Schedule 7, lists the FERC dockets in which
16 Con Edison has intervened since August 2006. When
17 appropriate, the Companies also participate in FERC
18 dockets and other forums such as collaboratives, the
19 North American Energy Standards Board ("NAESB"), and
20 the Natural Gas Council ("NGC") through their
21 membership in the American Gas Association ("AGA").
22 The Companies are also active in the AGA FERC
23 Regulatory Committee, which is involved with a range of
24 federal regulatory issues relating to gas supply. In

1 2010, a Company representative will be taking a
2 leadership position in that committee. The Companies
3 closely follow FERC proceedings that impact rates and
4 terms of service of their pipeline service providers
5 and actively participate in litigation as well as
6 negotiations relating to the rates that their pipeline
7 and storage service providers are permitted to charge
8 the Companies. For example, the Companies actively
9 participated in the 2007 Transco Rate Case Settlement
10 (RP06-569), which reduced Transco's rate increase
11 request from 35 percent (about \$17 million) to about 14
12 percent (\$7 million). The Companies' key issue in the
13 case was the allocation of O&M and A&G between
14 expansion project shippers, who generally must pay an
15 incremental rate, and system shippers, like Con Edison.
16 The settlement assigns \$23 million of a possible \$30
17 million in costs to expansion shippers. Other FERC
18 proceedings the Companies are following relate to
19 pipeline cost allocation issues involving, for example,
20 fuel retention and electric power compression charges.
21 The Companies closely monitor proposed tariff changes
22 by service providers that modify their terms of
23 service, including matters related to rights of first
24 refusal, bidding rules, service provider credit

1 policies and tariff and negotiated agreement filings
2 that could affect the quality of pipeline service to
3 the Companies. The Companies also closely monitor new
4 incremental services being offered by the Companies'
5 current service providers so that the rates of those
6 new incremental services are not subsidized by existing
7 customers, such as the Companies.

8 Q. What other steps have the Companies taken to maintain
9 the reliability of their supply?

10 A. The Companies have actively supported the adoption by
11 the natural gas industry of gas quality specifications
12 that will allow for the safe integration of increased
13 supplies, particularly from new LNG import terminals
14 and so-called unconventional gas supplies such as shale
15 gas. The Companies have also been active in
16 negotiating gas quality tariff changes with their
17 supplier pipelines, which balance the needs of end
18 users and Con Edison's LNG liquefaction plant and other
19 system equipment with the beneficial effect of
20 additional supplies. For two of the pipelines serving
21 Con Edison, these gas quality tariff changes have been
22 approved by FERC and implemented by the pipelines, and
23 have served to set precedent for other pipelines in the
24 process of changing their own gas quality tariffs.

1 Q. Are the Companies a member of any groups addressing gas
2 reliability issues in New York State?

3 A. Yes. The Companies have been an active participant in
4 the Natural Gas Reliability Advisory Group ("NGRAG")
5 from its initiation. During the past year, the NGRAG
6 focused discussion on the FERC rule regarding Capacity
7 Release, specifically on how it would affect the
8 State's retail access programs. The revised FERC Rule,
9 among other things, exempts state retail access
10 programs from the capacity bidding requirement and
11 allows capacity releases under the retail programs to
12 be at the utilities' weighted average cost of capacity
13 instead of at maximum pipeline rates. On July 20,
14 2009, the Companies filed tariff revisions addressing
15 this change for the winter of 2009/2010. On October 1,
16 2009, after discussions with Staff, the Companies
17 issued a supplemental filing to postpone the pricing
18 change to April 1, 2010. The postponement is intended
19 to provide energy services companies with additional
20 time to reflect the change in capacity pricing in their
21 supply prices to end users.

22 Q. Are the Companies active members of industry
23 organizations?

24 A. Yes. In addition to the AGA, the Companies are active

1 members of the Northeast Gas Association ("NGA") and in
2 the Wholesale Gas Quadrant of the North American Energy
3 Standards Board ("NAESB").

4 Q. Please describe the Companies efforts in connection
5 with NAESB.

6 A. We have been a member of NAESB and its predecessor
7 organization, the Gas Industry Standards Board
8 ("GISB"), since the latter's inception in 1994. The
9 transformation of GISB to NAESB in 2001 was designed to
10 address changes in the energy industry. We have
11 participated actively in NAESB's efforts (i) in
12 connection with establishing intra-day capacity recall
13 standards and (ii) in amending its Standard Gas
14 Purchase and Sales Contract and model Credit Support
15 Addendum. For example, the updated Standard Gas
16 Purchase and Sales Contract was adopted in 2006 by the
17 industry and includes changes suggested by Con Edison
18 that allow purchasers of natural gas additional time to
19 change payment information, thereby minimizing the
20 possibility of inaccurate or costly payment errors.

21 Q. Please describe the Companies' efforts in connection
22 with the NGA.

23 A. The Companies' participation in the NGA is through
24 their New York State Gas Utility Planning Committee

1 ("NYPLAN"). It is comprised of planning, supply and
2 regulatory personnel from New York's investor-owned
3 natural gas utilities. Its mission is to provide a
4 forum for New York State gas companies to address the
5 broad spectrum of issues relating to the natural gas
6 supply, transportation, storage, peak shaving and
7 demand planning process. This includes, but is not
8 limited to, such responsibilities as responding to
9 mandated regulatory requests, discussion/follow-up on
10 key regulatory/ legislative issues, and working in
11 collaboration with NYSEARCH on R&D projects. NYPLAN
12 has worked with NGA in 2009 to provide comments on the
13 developing "New York State Energy Plan" among other
14 activities.

15 MARGINAL COST STUDY

16 Q. Please address Con Edison's marginal cost study with
17 respect to gas supply costs.

18 A. Supply-side marginal costs are the costs of procuring
19 and transporting an additional unit of gas to the
20 Companies' distribution systems. Fixed costs that are
21 associated with existing resources are not considered
22 because they do not vary with additional usage and
23 because Con Edison cannot avoid paying them.

24 Q. Did you consider individual marginal cost components?

1 A. Yes, I considered marginal capacity costs and commodity
2 costs.

3 Q. Please define marginal capacity cost.

4 A. Marginal capacity cost is the cost of adding reliable
5 gas deliverability, which may include pipeline
6 capacity, storage capacity, and/or firm gas supply at
7 the city gate, to satisfy additional firm customer
8 demand at design conditions.

9 Q. Please define marginal commodity cost.

10 A. Marginal commodity cost is the cost of an incremental
11 purchase of gas required to meet system demand that
12 exceeds committed supply sources and planned supply
13 additions

14 Q. What is the forecast period used in your marginal cost
15 study?

16 A. The forecast period for the marginal cost study is the
17 three-year period from November 2010 through October
18 2013.

19 Q. Please explain the development of the marginal cost.

20 A. Exhibit __ (PAO-1), Schedule 8, Combined Consolidated
21 Edison Company of New York, Inc./Orange & Rockland,
22 Inc. Summer Season Supply/Demand Balance, Schedule 9,
23 Combined Consolidated Edison Company of New York,
24 Inc./Orange & Rockland, Inc. Winter Season

1 Supply/Demand Balance, and Schedule 10, Combined
2 Consolidated Edison Company of New York, Inc./Orange &
3 Rockland, Inc. Peak Day Supply/Demand Balance compare
4 the Companies' firm transportation and supply
5 capability to gas demand on a summer season, normal
6 winter season, and peak-day basis. The firm
7 transportation and supply capability includes all firm
8 transportation deliverability and currently flowing
9 firm supplies. These Schedules demonstrate that the
10 need to add capacity to serve firm customer
11 requirements is driven by the Companies' requirement to
12 provide for firm customer needs on a design-day basis.

13 Q. Please explain the calculation of the marginal
14 commodity cost.

15 A. The marginal commodity cost is measured by using an
16 optimization model that compares the difference in
17 system utilization costs between two scenarios, the
18 second, featuring a small increase in incremental load.
19 The unitized costs are calculated by dividing the
20 incremental costs by incremental loads. Exhibit __
21 (PAO-1), Schedule 11, Combined Consolidated Edison
22 Company of New York, Inc./Orange & Rockland, Inc.
23 Natural Gas Marginal Monthly Commodity Costs, displays
24 the monthly marginal commodity costs for the three

1 years of the study. Exhibit __ (PAO-1), Schedule 12,
2 Combined Consolidated Edison Company of New York,
3 Inc./Orange & Rockland, Inc. Marginal Commodity Costs,
4 summarizes these costs to show the impact of the
5 incremental increase on an average annual, summer
6 season, winter season and design day basis.

7 LOST AND UNACCOUNTED FOR GAS

8 Q. Please explain the methodology for the calculation of
9 lost and unaccounted for gas.

10 A. The current methodology compares the total distribution
11 sendout (which includes Retail Access, direct customers
12 and Con Edison deliveries while netting out gas for
13 power generation and LNG injections) against the total
14 customer metered volumes (firm sales, firm
15 transportation, interruptible and off-peak firm sales
16 and transportation and Company use while netting out
17 gas for power generation).

18 Q. How does this comparison determine the adjusted line
19 loss factor ("LLF")?

20 A. If, for a twelve-month period ended August, actual line
21 losses are less than the LLF target in effect for the
22 period, the Company retains a benefit based on the
23 difference between the LLF and the actual line losses.
24 If the actual line losses are greater than the LLF

1 target in effect for the period, the Company bears an
2 additional cost based on the difference between the LLF
3 and the actual line losses.

4 Q. Is the Company proposing any changes in this current
5 methodology?

6 A. Yes, we are proposing to change the method by which the
7 LLF target is established. Currently, the Company
8 compares the current year's line loss to a target LLF
9 in effect for the period (currently the average of the
10 LLF from the past three years). For example, the LLF
11 target effective October 1, 2008 is based on the
12 average actual line loss results for the three-year
13 period ended August 2008. Each August, a new three-
14 year average LLF is calculated (e.g., in September
15 2009, the average for the three-year period ended
16 August 2009 was calculated). If the new LLF falls
17 outside of a five-percent band from the effective LLF
18 target, the existing LLF target is changed to the most
19 current three-year average, which drops the oldest year
20 from the effective LLF target and absorbs the current
21 year. If the newly calculated LLF falls within the 5
22 percent band, the effective LLF target remains
23 unchanged. The Company is proposing to change the
24 determination of the LLF target from a three-year

1 average to a five-year. For Rate Year 1, the LLF
2 target would be based on the average line loss for the
3 five-year period ending August 2010. In the case of a
4 multi-year rate plan, for Rate Years 2 and 3, the
5 average line loss for the five-year periods ending
6 August 2011 and August 2012, respectively, would be
7 used. This approach will establish a target that
8 reflects a longer duration of time and an established
9 pattern of line loss activity. The longer duration
10 minimizes the impact that any single year included in
11 the average has on the overall target and reduces the
12 effect that a given year may have when the line loss
13 falls outside normal statistical parameters. Examples
14 of this might include large prior period adjustments to
15 sales data in a given year, or the effect of actual
16 heating degree days on the accuracy of billing month
17 normalization. All other elements of the Company's
18 LAUF mechanism will remain unchanged.

19 Q. Does this conclude your testimony?

20 A. Yes, it does.

Gas Supply Contracts
Combined ConEdison and Orange & Rockland

<u>Firm Gas Supplier</u>	<u>Expiration Date</u>	<u>Volume (Mdt/d)</u>
<u>ALGONQUIN</u>		
Contract 1	02/28/10	5,000
Contract 2	02/28/10	15,000
<u>COLUMBIA GULF/COLUMBIA GAS</u>		
Contract 3	10/31/10	3,600
Contract 4	03/31/12	2,200
Contract 5	10/31/10	5,000
Contract 6	10/31/10	5,000
Contract 7	03/31/13	1,900
<u>DOMINION</u>		
Contract 8	03/31/12	7,575
<u>IROQUOIS</u>		
Contract 9	10/31/10	11,128
Contract 10	10/31/11	9,106
Contract 11	03/31/10	30,000
<u>NATIONAL FUEL</u>		
Contract 12	10/31/13	20,000
Contract 13	03/31/10	10,000
Contract 14	03/31/10	30,000
Contract 15	03/31/10	7,000
<u>TENNESSEE</u>		
Contract 16	03/31/10	4,000
Contract 17	03/31/10	10,000
Contract 18	10/31/10	10,000
Contract 19	10/31/10	4,000
Contract 20	03/31/12	3,600
Contract 21	03/31/12	3,500
Contract 22	03/31/12	3,400
<u>TEXAS EASTERN</u>		
Contract 23	03/31/14	5,900
Contract 24	10/31/14	2,600
Contract 25	03/31/10	7,000
Contract 26	10/31/13	3,200
Contract 27	03/31/12	7,700
<u>TRANSCANADA</u>		
Contract 28	10/31/10	40,000
<u>TRANSCO</u>		
Contract 29	03/31/10	10,000
Contract 30	10/31/12	22,800
Contract 31	03/31/12	30,000
Contract 32	03/31/12	10,200
Contract 33	10/31/11	23,000
Contract 34	03/31/12	6,000
Contract 35	10/31/10	10,000
Contract 36	10/31/11	5,000
Contract 37	03/31/12	6,000
Contract 38	10/31/13	5,000
Contract 39	03/31/10	27,000

Total: 422,409

Pipeline Transportation Contracts
Combined Con Edison and Orange & Rockland FT (Mdt/d)

<u>Pipeline</u>	<u>Rate Schedule</u>	<u>Contract Number</u>	<u>Upstream MDQ</u>	<u>Con-Edison City-Gate MDQ</u>	<u>O&R City-Gate MDQ</u>	<u>Expiration Date</u>
Iroquois	RTS12	560-01		20,234		11/1/2011
	RTS12	560-16		32,998		10/31/2023
Columbia	FTS	80100			51,660	3/31/2019
	FTS	80156	19,186			10/31/2013
Algonquin	AFT-11	93010C			5,470	10/31/2012
	AFT-14	93406			246	10/31/2012
	AFT-1Z	86013			225	4/30/2010
	T-1	931003			5,292	8/31/2010
	AFT-1	97033		20,000		10/31/2010
	AFT-E	9W005EC			6,676	9/30/2010
	FT-1	510371R2	125,000			10/31/2023
Transco	FT	1002239		2,084		Evergreen
	FT	100659		3,800		4/30/2010
	FT	100658		4,500		10/31/2009
	FT	1016007		30,344		10/31/2010
	FT	1003683		335,880		3/31/2010
	FT-PS	100511		10,143		3/31/2010
Tennessee	FT-A	31585			5,035	11/30/2013
	FT-A	2185		31,212		10/31/2014
	FT-A	330			25,000	10/31/2013
	FT-A	2511/2530/3908/3910	11,630			10/31/2014
	FT-A	8402	12,440			10/31/2013
	FT-A	36656	10,000			4/2/2013
Tetco	CDS	800410		55,238		10/31/2010
	FT-1	800410		10,000		10/31/2010
	FTS	330836		3,075		10/31/2009
	FT-1	910226		14,770		10/31/2010
	CDSA	800437	384			10/31/2014
	FT-1	800403	10,836			10/31/2014
	CDS	800438	507			10/31/2012
	CDS	400514	507			10/31/2012
	SS-1	400216	1,140			4/30/2013
National Fuel	EFT	E00522	3,800			4/2/2010
	EFT	F01775	31,212			10/31/2009
	EFT	N11192/F11185	75,000			10/31/2023
Dominion/CNG	FT	200398	7,575			10/31/2011
Millenium		FT01-0001	180,000			10/31/2023
Millenium/National Fuel/Columbia	FT	FT			19,340	10/31/2023
Millenium/Algonquin	FT	FT		8,791		10/31/2023
Incremental Winter Delivered Service	Peaking			41,000		3/31/2010
		Total:	489,217	630,745	112,268	

Storage Contracts
Combined ConEdison and Orange and Rockland

Market Area Storage	<u>Max Daily Withdrawal</u>	<u>Max Storage Capacity</u>	<u>Expiration Date</u>
Transco SS2	19,355 Dt/d	2,129 Mdt	3/31/2010
Transco GSS	10,040 Dt/d	515 Mdt	3/31/2013
Dominion/CNG-GSSTE	23,115 Dt/d	2,409 Mdt	4/2/2013
Tetco SS1	69,150 Dt/d	4,169 Mdt	4/30/2013
Tetco SS1	507 Dt/d	100 Mdt	4/30/2012
Tetco FSS1	1,141 Dt/d	30 Mdt	4/30/2013
Tenn FSMA (1)	90,477 Dt/d	6,664 Mdt	10/31/2013
Honeoye (1)	10,000 Dt/d	1,226 Mdt	3/31/2010
Stagecoach FT-A	25,000 Dt/d	760 Mdt	12/31/2011
Stagecoach FT-A	15,000 Dt/d	456 Mdt	12/31/2011
Stagecoach FT-A	25,000 Dt/d	760 Mdt	12/31/2011
Stagecoach FT-A	105,000 Dt/d	4,200 Mdt	10/31/2023
National Fuel	7,871 Dt/d	589 Mdt	10/31/2023
Columbia FSS	20,000 Dt/d	1,432 Mdt	3/31/2019
National Grid - LNG	<u>20,000 Dt/d</u>	<u>500 Mdt</u>	<u>10/31/2009</u>
	441,656 Dt/d	25,939 Mdt	
Production Area Storage			
Transco ESS	52,424 Dth/d	527 Mdt	3/31/2010
Transco ESS	90,050 Dth/d	897 Mdt	3/23/2010
Transco WSS	145,164 Dth/d	12,339 Mdt	3/31/2010
Hattisburgh	<u>48,471 Dth/d</u>	<u>485 Mdt</u>	<u>3/31/2010</u>
	336,109 Dth/d	14,248 Mdt	

Peaking Shaving Facilities
Combined Con Edison and Orange & Rockland

	<u>Contract Expiration</u>	<u>Con Edison Peaking Supply (Dt/d)</u>	<u>O&R Peaking Supply (Dt/d)</u>	<u>Total (Dt/d)</u>
LNG ⁽¹⁾	N/A	166,000	N/A	166,000
Total		166,000	0	166,000

Notes:

(1) The LNG facility is within the Con Edison distribution system located in Astoria, New York.

Consolidated Edison/O&R Peak Day Forecasted
Requirements
Peak Day MDT/d

Winter	Consolidated Edison	Orange & Rockland	Total
2010/11	1,146	216	1,362
2011/12	1,152	216	1,368
2012/13	1,158	217	1,375

Non Traditional Revenues

Combined ConEdison and Orange and Rockland

	<u>Actual 2005/06 Nov - Oct</u>	<u>Actual 2006/07 Nov - Oct</u>	<u>Actual 2007/08 Nov - Oct</u>	<u>Forecast Rate Year 2008/09 Nov - Oct</u>	<u>Forecast Rate Year 2009/10 Nov - Oct</u>
Off System Transactions	(\$45,963.60)	\$718,046	\$26,107	\$1,018,184	\$0
Capacity Release	<u>\$19,260,807</u>	<u>\$19,498,665</u>	<u>\$4,411,790</u>	<u>\$5,263,264</u>	<u>\$5,263,264</u>
TOTAL	\$19,214,843	\$20,216,711	\$4,437,897	\$6,281,448	\$5,263,264
CECONY	\$15,181,648	\$15,973,223	\$3,506,382	\$5,226,165	\$4,379,035
ORU	\$4,033,196	\$4,243,488	\$931,515	\$1,055,283	\$884,228

FERC Docket Interventions

Algonquin Gas Transmission - CP

Date	Docket
11/27/2006	CP07-21-000
06/03/2008	CP08-256-000
07/11/2008	CP08-420-000
09/16/2008	CP08-462-000
07/21/2009	CP08-420-001

Algonquin Gas Transmission - RP

Date	Docket
09/06/2006	RP06-519-000
10/18/2006	RP07-13-000
01/31/2007	RP07-139-000
11/02/2006	RP07-32-000
04/30/2007	RP07-395-000
11/05/2007	RP07-395-000
06/04/2007	RP07-459-000
07/11/2007	RP07-504-000
08/14/2007	RP07-553-000
08/13/2007	RP07-554-000
08/14/2007	RP07-557-000
11/27/2006	RP07-66-000
03/10/2008	RP08-212-000
03/19/2008	RP08-268-000
11/07/2007	RP08-35-000
08/12/2008	RP08-474-000
02/17/2009	RP09-348-000
11/10/2008	RP09-48-000
11/17/2008	RP09-56-000
05/27/2009	RP09-600-000
11/25/2008	RP09-72-000
06/15/2009	RP09-720-000
07/22/2009	RP09-823-000
07/29/2009	RP09-834-000
08/12/2009	RP09-864-000
12/02/2008	RP09-97-000

Central New York Oil and Gas - CP

Date	Docket
11/16/2006	CP07-15-000
01/26/2007	CP07-15-001

Central New York Oil and Gas - RP

Date	Docket
11/12/2008	RP09-51-000
07/27/2009	RP09-826-000

Columbia Gas Transmission - CP

Date	Docket
11/30/2006	CP07-23-000
09/11/2008	CP08-464-000
04/10/2006	CP08-91-002

Columbia Gas Transmission - RP

Date	Docket
05/09/2008	RP06-231-000
10/13/2006	RP06-231-002
04/30/2007	RP06-231-003
04/07/2008	RP06-231-005
04/07/2008	RP06-231-006
10/13/2006	RP06-365-000
05/09/2008	RP06-365-000
04/30/2007	RP06-365-001
04/16/2007	RP06-365-002
04/07/2008	RP06-365-003
04/07/2008	RP06-365-004

Dominion Transmission - CP

Date	Docket
11/16/2006	CP07-10-000
01/08/2007	CP07-31-000
02/15/2007	CP07-66-000
04/11/2007	CP07-66-000
02/13/2007	CP07-67-000
02/15/2007	CP07-71-000
02/15/2007	CP07-73-000
12/14/2007	CP08-3-000
01/09/2008	CP08-33-000
01/28/2008	CP08-45-000
11/17/2008	CP09-10-000
12/04/2008	CP09-18-000
02/17/2009	CP09-44-000
04/24/2009	CP09-83-000

Dominion Transmission - RP

Date	Docket
10/11/2006	RP06-635-000
10/11/2006	RP06-636-000
05/07/2007	RP07-404-000
05/11/2007	RP07-430-000
05/11/2007	RP07-434-000
07/24/2007	RP07-523-000
07/31/2007	RP07-532-000
07/31/2007	RP07-534-000

10/10/2007	RP07-713-000
10/10/2007	RP07-717-000
12/12/2006	RP07-97-000
07/14/2008	RP08-435-000
11/13/2007	RP08-51-000
10/14/2008	RP08-638-000
10/14/2008	RP08-646-000
02/09/2009	RP09-277-000
02/23/2009	RP09-360-000
03/11/2009	RP09-425-000
03/31/2009	RP09-461-000
11/14/2008	RP09-53-000
06/15/2009	RP09-675-000
07/06/2009	RP09-775-000
07/13/2009	RP09-806-000

Honeoye Storage - CP

Date	Docket
11/09/2006	CP06-462-000

Honeoye Storage - RP

Date	Docket
03/07/2007	RP07-182-000
02/09/2009	RP09-263-000
06/15/2009	RP09-726-000

Honeoye Storage - TS

Date	Docket
04/27/2009	TS09-5-000

Iroquois Gas Transmission System - CP

Date	Docket
11/06/2007	CP07-457-000

Iroquois Gas Transmission System - RP

Date	Docket
09/28/2006	RP06-605-000
01/09/2007	RP07-121-000
05/16/2007	RP07-443-000
07/18/2007	RP07-516-000
11/27/2006	RP07-65-000
10/10/2007	RP07-716-000
01/09/2008	RP08-139-000
03/19/2008	RP08-263-000
11/13/2007	RP08-41-000
06/30/2008	RP08-410-000
07/02/2008	RP08-416-000
07/29/2008	RP08-454-000

10/14/2008	RP08-639-000
10/10/2008	RP08-641-000
12/08/2008	RP09-109-000
01/12/2009	RP09-188-000
01/21/2009	RP09-206-000
02/09/2009	RP09-283-000
02/11/2009	RP09-327-000
06/15/2009	RP09-739-000
07/13/2009	RP09-789-000
07/13/2009	RP09-805-000
08/26/2009	RP09-904-000
11/13/2007	RP98-18-029
03/03/2008	RP98-18-031
03/03/2008	RP98-18-033

Millennium Pipeline Company - CP

Date	Docket
07/11/2008	CP98-150-011
11/25/2008	CP98-150-012

National Fuel Gas Supply Corporation -
 CP

Date	Docket
04/11/2007	CP07-101-000
10/14/2008	CP08-450-000
12/08/2008	CP08-482-000
06/15/2009	CP09-151-000
07/20/2009	CP09-439-000
03/23/2009	CP09-46-000

National Fuel Gas Supply Corporation -
 RP

Date	Docket
12/29/2006	RP07-116-000
05/07/2007	RP07-406-000
10/03/2007	RP07-702-000
12/08/2006	RP07-86-000
12/08/2006	RP07-87-000
02/04/2008	RP08-170-000
06/23/2008	RP08-405-000
07/23/2008	RP08-442-000
10/07/2008	RP08-633-000
12/10/2007	RP08-88-000
12/10/2007	RP08-93-000
12/15/2008	RP09-126-000
12/15/2008	RP09-127-000
02/09/2009	RP09-269-000
11/03/2008	RP09-27-000

03/23/2009	RP09-452-000
06/15/2009	RP09-694-000
07/08/2009	RP09-781-000

Tennessee Gas Pipeline Company

Date	Docket
09/11/2006	CP05-100-000
11/16/2006	CP07-13-000
11/19/2007	CP08-11-000
07/07/2008	CP08-164-000
05/23/2008	CP08-165-000
12/18/2007	CP08-27-000
07/21/2008	CP08-400-000
08/05/2008	CP08-435-000
09/11/2008	CP08-464-001
11/17/2008	CP08-469-000
02/19/2008	CP08-55-000
02/26/2008	CP08-63-000
03/03/2008	CP08-65-000
04/07/2008	CP08-67-000
03/17/2008	CP08-86-000
04/10/2006	CP08-91-001
04/30/2009	CP09-108-000
01/05/2009	CP09-15-000
01/05/2009	CP09-16-000
06/04/2009	CP09-191-000
07/27/2009	CP09-419-000
03/09/2009	CP09-42-000
08/20/2009	CP09-444-000
03/13/2009	CP09-63-000

Tennessee Gas Pipeline Company - RP

Date	Docket
09/13/2006	RP04-99-002
02/12/2007	RP07-151-000
04/11/2007	RP07-375-000
04/23/2007	RP07-396-000
06/04/2007	RP07-396-001
12/10/2007	RP08-101-000
10/22/2007	RP08-22-000
03/12/2008	RP08-234-000
05/12/2008	RP08-338-000
07/07/2008	RP08-420-000
12/08/2008	RP09-116-000
01/12/2009	RP09-194-000
01/21/2009	RP09-207-000
02/09/2009	RP09-282-000
02/10/2009	RP09-312-000

02/11/2009	RP09-320-000
02/17/2009	RP09-339-000
05/12/2009	RP09-555-000
06/10/2009	RP09-633-000
06/15/2009	RP09-657-000
06/15/2009	RP09-737-000
10/14/2008	RP91-203-076
10/14/2008	RP92-132-064
09/19/2007	RP96-312-167

Texas Eastern Transmission - CP

Date	Docket
11/21/2007	CP05-392-001
11/07/2007	CP06-115-003
11/27/2006	CP07-20-000
08/01/2007	CP07-411-000
04/30/2008	CP08-100-000
06/09/2008	CP08-111-000
05/08/2008	CP08-120-000
09/19/2008	CP08-461-000
04/11/2008	CP08-75-000
05/12/2008	CP08-88-000
04/29/2009	CP09-111-000
07/09/2009	CP09-431-000
03/12/2009	CP09-61-000
04/01/2009	CP09-68-000

Texas Eastern Transmission - RP

Date	Docket
09/13/2006	RP06-588-000
01/10/2007	RP07-127-000
10/30/2006	RP07-20-000
10/30/2006	RP07-27-000
06/04/2007	RP07-460-000
07/11/2007	RP07-502-000
08/14/2007	RP07-550-000
08/14/2007	RP07-552-000
08/28/2007	RP07-590-000
09/12/2007	RP07-650-000
11/27/2006	RP07-67-000
09/26/2007	RP07-693-000
10/18/2006	RP07-8-000
01/04/2008	RP08-133-000
10/15/2007	RP08-14-000
01/14/2008	RP08-148-000
02/13/2008	RP08-185-000
03/10/2008	RP08-216-000
03/19/2008	RP08-267-000

11/07/2007	RP08-33-000
06/16/2008	RP08-399-000
07/14/2008	RP08-434-000
08/12/2008	RP08-476-000
09/15/2008	RP08-605-000
11/21/2007	RP08-62-000
12/10/2007	RP08-73-000
12/10/2007	RP08-80-000
12/11/2007	RP08-83-000
12/17/2008	RP09-143-000
12/30/2008	RP09-169-000
12/31/2008	RP09-173-000
01/12/2009	RP09-193-000
02/17/2009	RP09-346-000
04/22/2009	RP09-508-000
11/17/2008	RP09-57-000
05/27/2009	RP09-591-000
11/24/2008	RP09-66-000
11/25/2008	RP09-70-000
06/15/2009	RP09-721-000
06/12/2009	RP09-756-000
07/13/2009	RP09-802-000
07/29/2008	RP09-834-001
12/02/2008	RP09-98-000
11/13/2007	RP99-480-018

Transcontinental Gas Pipeline - AC

Date	Docket
01/04/2007	AC06-153-000

Transcontinental Gas Pipeline - CP

Date	Docket
10/24/2006	CP07-1-000
08/06/2007	CP07-385-000
08/01/2007	CP07-412-000
09/19/2007	CP07-445-001
11/06/2006	CP07-7-000
04/15/2008	CP08-124-000
06/06/2008	CP08-153-000
05/28/2008	CP08-207-000
12/19/2007	CP08-25-000
01/07/2008	CP08-31-000
07/08/2008	CP08-343-000
01/16/2008	CP08-41-000
08/18/2008	CP08-421-000
07/22/2008	CP08-430-000
10/20/2008	CP08-476-000
03/24/2008	CP08-58-000

04/11/2008	CP08-94-000
06/04/2009	CP09-237-000
12/22/2008	CP09-28-000
01/27/2009	CP09-38-000
06/19/2009	CP09-417-000
03/05/2009	CP09-57-000
06/15/2009	CP09-88-000
01/04/2007	CP88-391-033

Transcontinental Gas Pipeline - RP

Date	Docket
07/16/2007	RP01-245-024
07/13/2009	RP01-245-025
07/13/2009	RP01-245-026
07/13/2009	RP01-245-029
09/12/2006	RP06-569-000
09/12/2006	RP06-569-000
07/16/2007	RP06-569-003
10/11/2006	RP06-619-000
10/11/2006	RP06-621-000
02/06/2007	RP07-147-000
02/06/2007	RP07-148-000
03/05/2007	RP07-178-000
03/13/2007	RP07-328-000
03/13/2007	RP07-338-000
04/11/2007	RP07-376-000
08/15/2007	RP07-559-000
11/15/2006	RP07-57-000
11/15/2006	RP07-59-000
09/19/2007	RP07-687-000
10/03/2007	RP07-704-000
10/09/2007	RP07-711-000
10/10/2007	RP07-719-000
10/15/2007	RP08-15-000
03/07/2008	RP08-208-000
03/12/2008	RP08-250-000
03/12/2008	RP08-251-000
03/26/2008	RP08-272-000
11/07/2007	RP08-32-000
08/04/2008	RP08-449-000
08/11/2008	RP08-457-000
08/13/2008	RP08-477-000
11/19/2007	RP08-58-000
10/06/2008	RP08-631-000
12/29/2008	RP09-158-000
01/05/2009	RP09-183-000
01/27/2009	RP09-215-000
02/03/2009	RP09-245-000

11/05/2008	RP09-32-000
11/10/2008	RP09-34-000
02/23/2009	RP09-355-000
11/10/2008	RP09-37-000
03/11/2009	RP09-402-000
03/11/2009	RP09-410-000
03/18/2009	RP09-441-000
11/10/2008	RP09-52-000
05/05/2009	RP09-541-000
05/12/2009	RP09-558-000
05/26/2009	RP09-588-000
06/10/2009	RP09-630-000
06/15/2009	RP09-692-000
06/23/2009	RP09-763-000
07/13/2009	RP09-793-000
07/27/2009	RP09-830-000
08/11/2009	RP09-851-000
01/04/2007	RP93-162-013

Other

Date	Docket
04/10/2006	CP08-91-000
02/21/2007	CP07-62-000
02/21/2007	CP07-63-000
02/21/2007	CP07-64-000
02/21/2007	CP07-65-000
09/19/2007	CP07-445-000
11/13/2007	RP08-46-000
01/25/2008	CP08-49-000
05/27/2008	RP08-374-000
12/15/2008	RP08-648-000

Chart 1
Consolidated Edison Company of New York, Inc./Orange & Rockand, Inc.
Summer Season Supply/Demand Balance

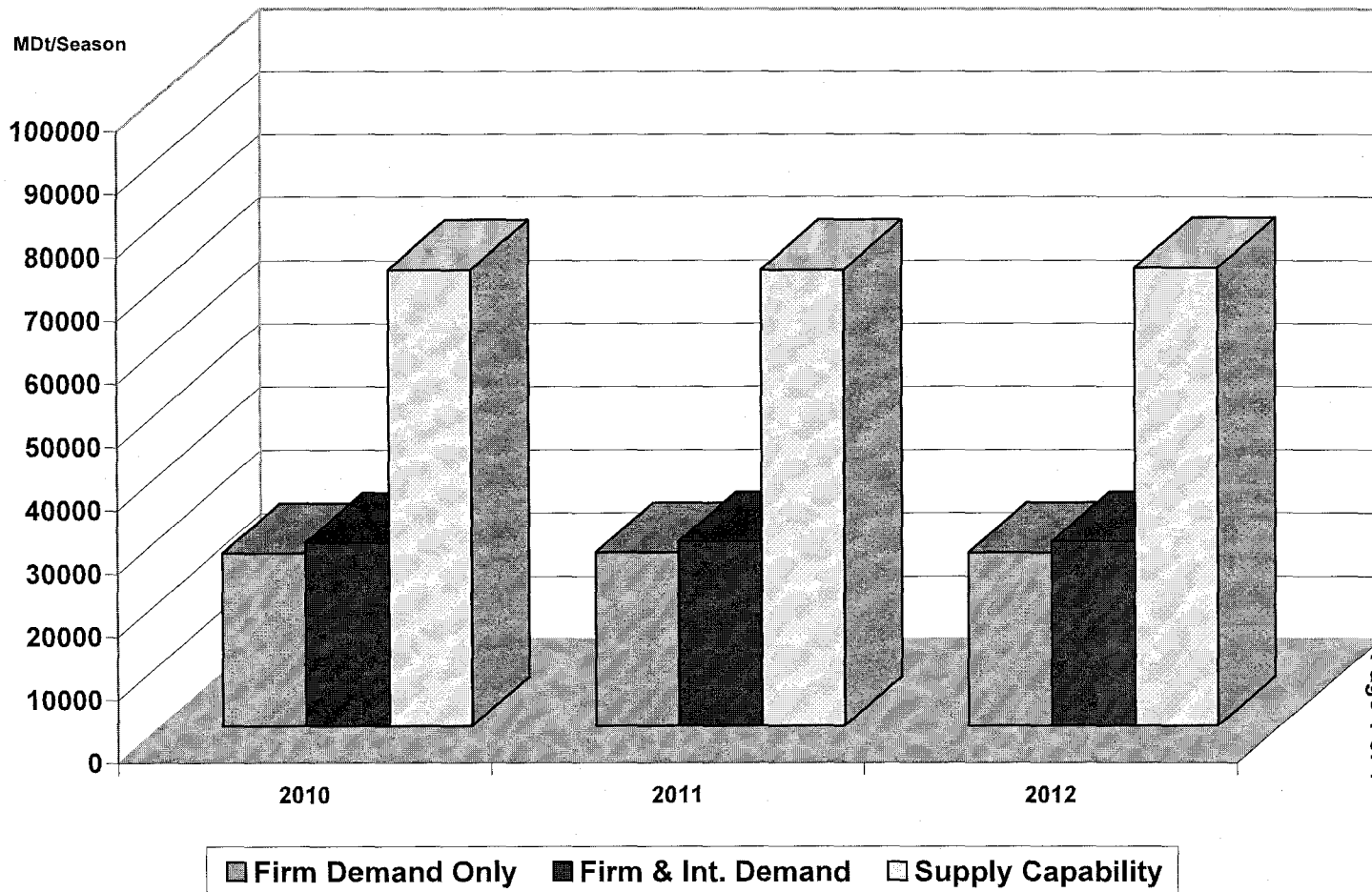


Chart 2
Consolidated Edison Company of New York, Inc./Orange & Rockand, Inc.
Winter Season Supply/Demand Balance

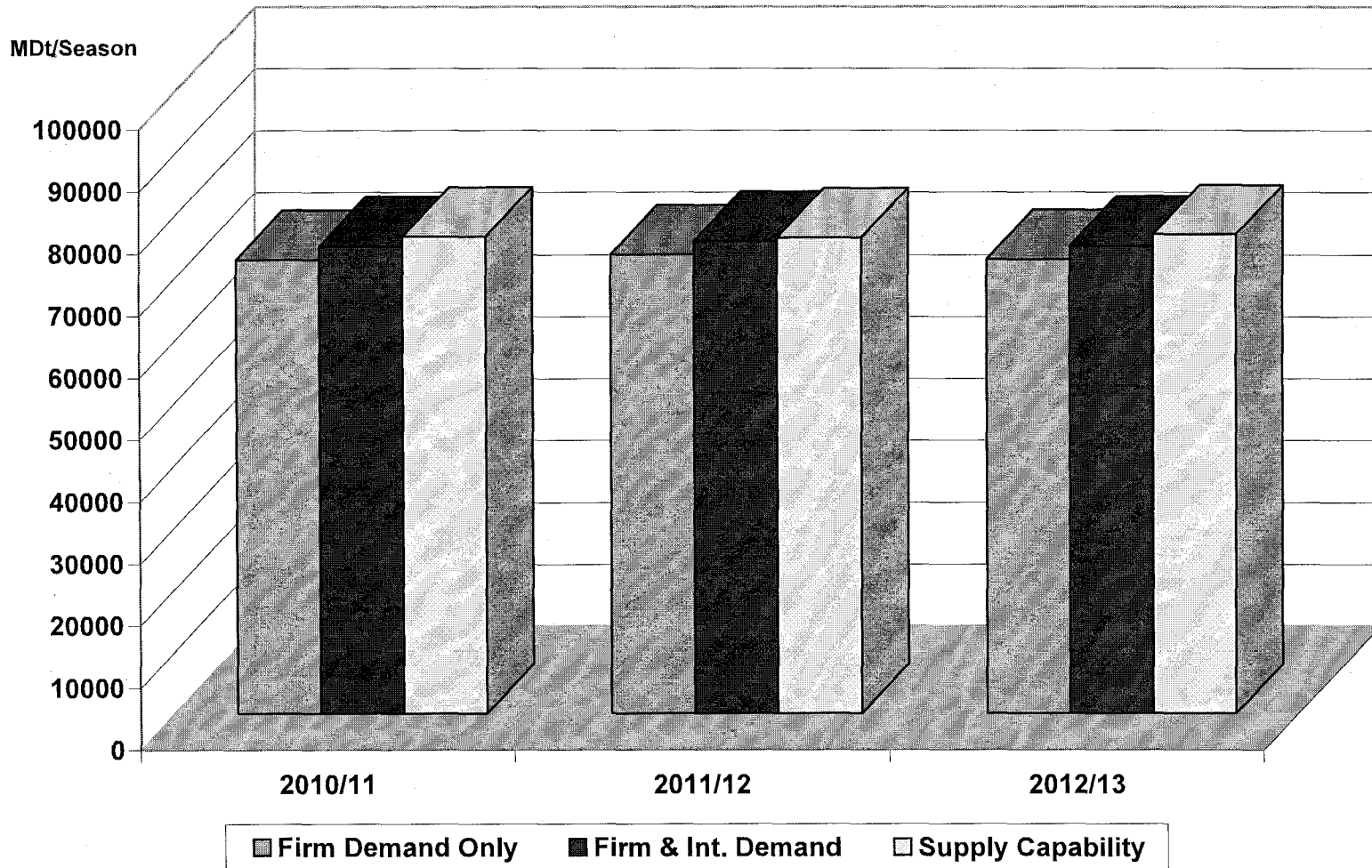


Chart 3
Consolidated Edison Company of New York, Inc./Orange & Rockand, Inc.
Design Day Supply/Demand Balance

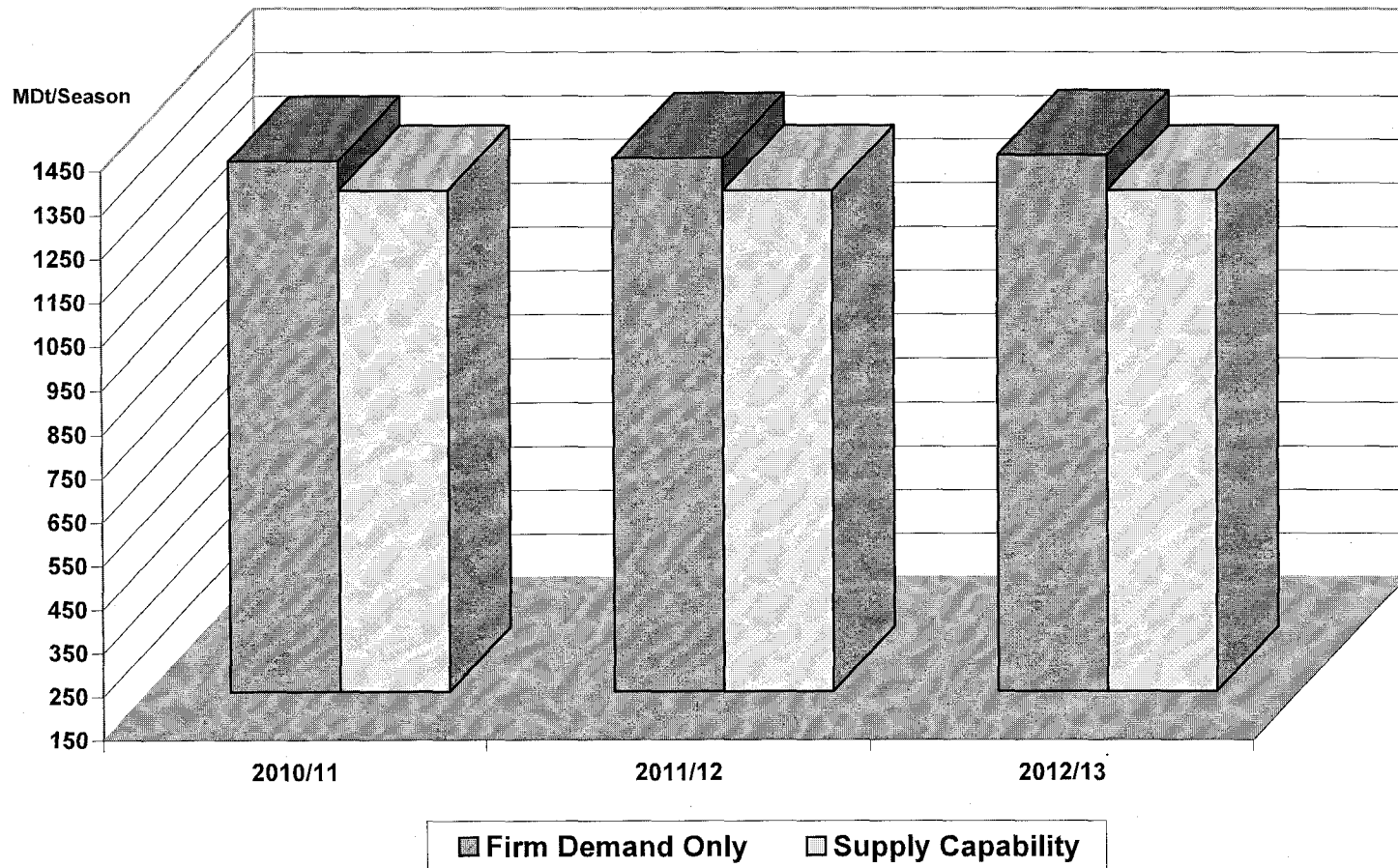


Chart 4
Consolidated Edison Company of New York, Inc./Orange & Rockland, Inc.
Marginal Commodity Costs

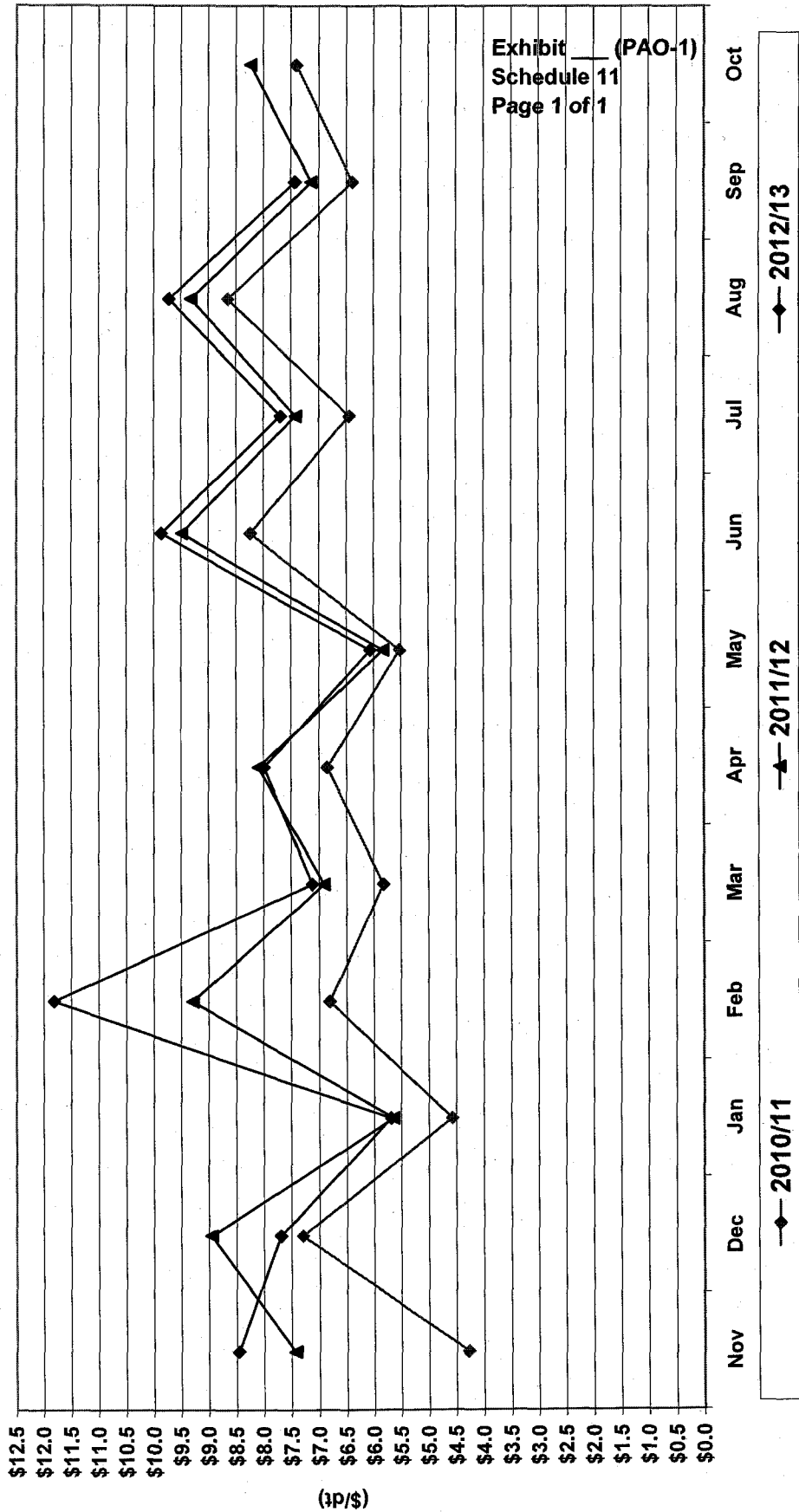


Chart 5

Combined Consolidated Edison Company of New York, Inc./Orange & Rockland, Inc.

Natural Gas Marginal Commodity Costs (\$/Dth)

Gas Year	Average Annual (1) (commodity)	Average Summer (1) (commodity)	Average Winter (1) (commodity)	Design Day (2) (commodity)
2010/11	\$6.52	\$7.07	\$5.76	\$18.19
2011/12	\$7.81	\$7.93	\$7.64	\$18.85
2012/13	\$8.17	\$8.19	\$8.15	\$19.13

Notes:

1) based on the difference in variable costs between two optimization scenarios, based on an incremental load increase of approximately 0.5%

2) Henry-Hub index, plus a presumed premium for a 10-day, incremental supply service of \$11.75/dt